EISPC
EASTERN INTERCONNECTION STATES' PLANNING COUNCIL

Co-Optimization of Transmission and Other Resources

Study

January 26th, 2015

Energy Exemplar, LLC
For EISPC and NARUC
Funded by the U.S. Department of Energy

Acknowledgement:
This material is based upon work supported by the Department of Energy, National Energy Technology Laboratory, under Award Number DE-OE0000316.

Disclaimers:
This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights.

Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

The information and studies discussed in this report are intended to provide general information to policy-makers and stakeholders but are not a specific plan of action and are not intended to be used in any State electric facility approval or planning processes. The work of the Eastern Interconnection States' Planning Council or the Stakeholder Steering Committee does not bind any State agency or Regulator in any State proceeding.

EISPC – Co-Optimization of Transmission and Other Resources

NARUC Project Number: Task Order #3316T4

Final Report
January 26, 2015

Prepared for:
Grants & Research Department
National Association of Regulatory Utility Commissioners
1101 Vermont Avenue NW, Suite 200
Washington, D.C. 20005

Report submitted by:
Principal Investigator
Dr. Randell Johnson, P.E.
Energy Exemplar, LLC
20 Church Street, Suite 790
Hartford, CT 06103
Tel: 860-461-0761; Fax: 860-461-7876
Email: randell.johnson@energyexemplar.com
www.energyexemplar.com

Contents

Tables

Figures

I. Executive Summary

This white paper demonstrates the benefits of co-optimization of transmission and other resources, including generation, energy storage, energy efficiency and natural gas infrastructure. The benefits of this co-optimization demonstration encompasses all regions of the Eastern Interconnect using the EIPC Phase I dataset.

Typically, the expansion of resources and transmission are evaluated "separately" on the local cost effectiveness of resources to serve energy and provide system security. This demonstration shows the benefits of co-optimization of transmission and other resources as improving the transmission planning process to reduce manual iterations between transmission scenarios to fit possible resource scenarios. The co-optimizations minimize the total costs – capital and operational costs, both for transmission and resources. Co-optimization method for transmission planning is applicable to regions with markets as well as regions with vertically integrated utilities.

Co-optimization of transmission and other resources is consistent with open access principles as all possible resource alternatives along with transmission alternatives are optimized together to meet demand subject to system security constraints with in a least cost objective. Co-optimization of transmission and other resources assist utilities, ISO/RTO's, and regulators in evaluating transmission planning alternatives. The overall impact to end users is a lower optimal cost solution for network and other resource expansions.

This demonstration of co-optimizations shows that public policy trends and regulatory impacts can be quickly evaluated and screened. For example an EIPC Phase I de-carbonization scenario was chosen for the co-optimization demonstration where cost reductions were found in comparison to manual methods of transmission planning.

Co-optimizations were also demonstrated in this white paper as applicable to gas electric coordination.

II. Regulatory Summary

States across the USA continually navigate the challenges of developments and operations of the power sector in an economical, clean, sustainable, and reliable manner. Many states are interconnected through energy transport systems such as transmission lines, pipelines, rail, roadways, waterways and others, savings can be obtained by adopting a holistic planning approach for expansion and operation of these networks to efficiently achieve a state's or region's multiple energy objectives. In this white paper, methods are demonstrated for co-optimizing expansion of energy resources and transmission/transport networks. Co-optimization of resources and transmission can also lead to time and cost savings as it substitutes an integrated and efficient process instead of current practices of multiple models and manual planning processes, thereby allowing the rapid development of multiple integrated candidate plans that, for instance, emphasize different planning objectives or alternative scenarios of future economic, technological, policy, and or regulatory developments. These methods for simultaneously optimizing transmission and other resources together can be based on deterministic planning methods that consider one scenario at a time, or use probabilistic or adaptive planning methods that explicitly include uncertainties that confront planners.

Methods for simultaneously optimizing transmission and other resources together are demonstrated in this white paper using real world planning data of the Eastern Interconnect Planning Collaborative (EIPC). The methods applied satisfy the principles of being transparent, repeatable, useful, used, defendable, and efficient such that these methods of co-optimizations can be relied upon in planning processes.

Many applications of co-optimizations are demonstrated in this white paper including the following:

- Co-optimization of transmission and generation resources investment. As explained in the Co-optimization White Paper published by NARUC in 2013,[1] such methods are applicable not only in integrated resource planning for combination generation-transmission utilities, but also for anticipative planning by RTOs/ISOs who must evaluate transmission investments considering how generation investment and operations would respond to the changed availability of network services.

[1] A. Liu, B.F. Hobbs, J. Ho, J. McCalley, V. Krishnan, M. Shahidehpour, and Q. Zheng, "Co-optimization of Transmission and Other Supply Resources," Prepared for the Eastern Interconnection States' Planning Council, National Association of Regulatory Utility Commissioners, Washington, DC, 20 Dec. 2013, www.naruc.org/grants/Documents/Co-optimization-White-paper_Final_rv1.pdf.

- Co-optimization of transmission and generation together with other types of electricity resources such as demand response and energy storage.
- Co-optimization of gas and electric systems

As part of this project, the project team benchmarked these methods to the previous EIPC Phase I report and demonstrated how these methods can automate transmission iterations that took months and rooms of experts in that study. Also, given the growing inter-dependence of the electric sector on the gas sector, the co-optimization methods were extended to co-optimizations between the power and gas sectors.

This white paper also demonstrates higher level analysis to test how regulatory and policy changes could affect the power sector and demonstrate how co-optimization could improve efficiency of planning procedures and quickly and robustly provide insights and conclusions. Policymakers and regulators may leverage these results to develop and refine energy and environmental strategies at utility, regional, state or federal level.

Co-optimization of transmission, generation, and other resources can provide economic and environmental benefits to power sector development for utilities, ISO/RTO, and for large interconnections such as The Eastern Interconnect or The Western Interconnection, as it allows planners and regulators to evaluate resource and transmission investments in market orientated or in vertically integrated contexts with regulatory and policy considerations.

The rational for the economic benefits of co-optimization of transmission and other resources is to encompass a wider range of variables and uncertainties into the policy, regulatory, and planning process. For example, for a certain generation expansion plan there is an optimal network configuration and for a certain network configuration, there is an optimal generation expansion plan. As a result, individual planning processes with one being reactive to the other may give inferior transmission results compared to simultaneous planning that and examine all options inclusively. For example, the ability of transmission and flexible thermal generation or energy storage to integrate renewables generation can be considered in a consistent manner so that, for instance, the ability of transmission to access diverse resources throughout a region can be carefully compared to additions of local flexible generation. As another example, co-optimization can quantify the value to consumers and states of transmission to access remote regions that have higher quality renewable resources or other resource potential that is more economical or efficient to develop. Consideration of how transmission and generation siting affect each other is essential for addressing such questions.

Similarly, those regions, states, and utility footprints that have limited or expensive generation resources can utilize co-optimization methods for evaluation of cheaper supply alternatives. Having the ability to co-optimize the construction decisions for both transmission/transport and generation, as well as multiple other resources, allows planners and regulators to expand their options and suggest more economic solutions. Automated co-optimization methods, such as those featured in this report provides this valuable information while avoiding the expense of manual generation build/retire "what-if" studies.

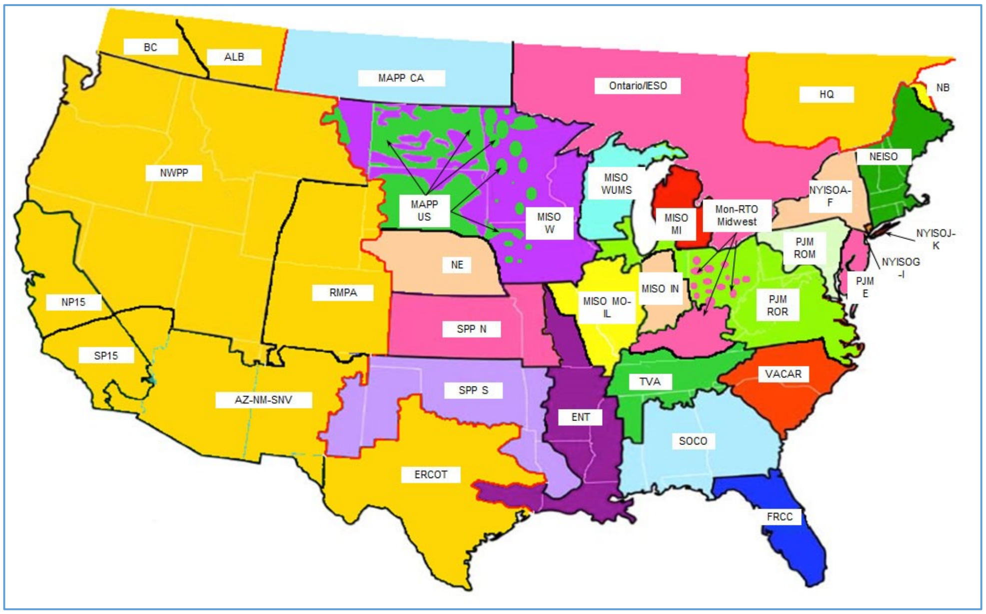
Co-optimization of transmission and other resources can also benefit inter-regional coordination when evaluating greater resource diversity in combination with future generation siting which also depends on transmission availability, seams issues, environmental regulations, and a host of other potential regulatory or policy evolutions. With co-optimization of transmission and generation, the analysis can move from reactive transmission planning to optimal proactive transmission planning, anticipating how generation investment decisions respond to network design.

Previously, co-optimization of transmission and other resources was not an easily available or recognized tool in the arsenal of utilities and planners. However, in this analysis we have demonstrated that co-optimization of multiple resources, with transmission and other resources, can be done efficiently and provides economic justification for future planning processes and analyses of the power sector.

In this study we have evaluated economic benefits of co-optimization of transmission and other resources by first adopting the EIPC Phase I study as the reference case for The Eastern Interconnection. This was configured by combining the regions of The Eastern Interconnection (see Figure 1 below) with transmission interfaces between the regions as set by Planning Authorities during the EIPC Phase I study.

The commercial simulation tool PLEXOS® and the Johns Hopkins University (JHU) model were then used to optimize power sector development over 20 years. The optimizations in PLEXOS® and JHU model can add new resources and retire existing resources in regions, simulate their operations, and expand transmission interfaces between regions.

Figure 1: Graphical Representation of the Eastern Interconnection Regions



The study Initial results of the co-optimizations with PLEXOS® and JHU indicates that billions of dollars of savings in Net Present Value Terms can be saved for a 20 year power sector development scenario of de-carbonization of The Eastern Interconnection as compared to the same scenario without co-optimizations. These savings happen yearly over the planning horizon. The estimated savings amount to 1.0% - 3.0% of total generation and transmission investment and operations costs, and is comparable in magnitude to the incremental investment costs of new transmission over that period.

The study has found that the transmission build decisions have varied from the original EIPC modelling, with transmission builds between regions which are justified economically but might not have been selected in the original study. Furthermore, by using co-optimization, the timing of resource and transmission investments can be determined over the 20 year study horizon. In contrast, the non-co-optimized methods in EIPC Phase I could not determine timing of resource and transmission investments simultaneously and instead could only yield a less useful snapshot analysis at the end of the study horizon. Thus, co-optimization can be highly useful to harmonize the plans of ISO/RTOs with twenty year power sector co-optimizations or for use in integrated resource plans of utilities, considering how reliability, energy, capacity, and ancillary service needs affect the timing of transmission and pipeline or other transport investments.

III. Planning Process Implications

This demonstration project has implications for planning processes in the US. The current planning processes in the US frequently rely on iterations between transmission planning analyses and resource developments or resource retirements, which are often based on manual construction of resource build/retire scenarios. Co-optimization methods allow utilities, regulators, ISO/RTO's, or others with responsibility in planning of grids to optimize together resource development/retirement and transmission. These methods are applicable to ISO/RTO transmission planning processes with markets as well as for integrated resource planning processes of vertically integrated utilities. These co-optimizations yield new metrics that can be relied on for justification of transmission investments or other resources in planning processes.

The demonstration of the methods in this white paper included collaboration and participation of leading academic institutions, collaboration of ISO/RTOs, collaboration of a US Government National Lab, and a leading integrated energy modeling software maker. Notwithstanding the valuable input provided by these parties, the authors of the report are solely responsible for any errors and opinions.

The demonstrations in this white paper of co-optimizations of transmission and other resources show that the methods are practical for adoption in planning processes because the methods have the following characteristics:

1. **Transparency** – the datasets, models, and simulations, and outputs that were used to demonstrate the co-optimization of transmission and other resources methods were provided to multiple organizations and made transparent for verification and validation of methods and results during this project
2. **Repeatability** – two different modeling platforms were used in this demonstration project using similar inputs to each platform, and each platform yielded similar outputs
3. **Defendability** – the methods are defendable, based on state-of-the-art optimization and modeling methods according to academic and industry experts, and were benchmarked to the previous EIPC Phase I study of the Eastern Interconnection.
4. **Usefulness** – The methods are useful as the optimizations take in a wide set of inputs and yield outputs that can inform public policy and regulatory deliberations at both the federal and state

levels, as well as stakeholder or utility planning processes for testing scenarios and cases in a cost-effective and efficient manner.

5. **Used** – current planning processes in US use manual iterations to determine transmission needs for resource developments, whereas the methods in this demonstration automate that process through optimizations of transmission and other resources. As an example, the Australian Energy Market Operator use co-optimization of transmission and other resources with the modeling tool PLEXOS® to determine inter-regional transmission requirements.
6. **Efficiency** – this demonstration project was of short duration of six months where the modeling component of co-optimizations of transmission and other resources took around 3 months to complete for the Eastern Interconnection for one major scenario of De-Carbonization, with multiple sensitivity analyses. Many cases were constructed of non-co-optimized and co-optimized as well as benchmarks with multiple models of commercially grade model PLEXOS® and research model JHU in a very short time. Similar studies have taken much longer with rooms full of experts incurring higher cost while depending on a higher level of manual optimizations.

Co-optimization methods implemented in, for example, advanced commercial optimization tools such as PLEXOS® or the Johns Hopkins University model also facilitate the assessment of capacity sharing across regions or zones, enforcement of ancillary services requirements with increased levels of intermittent generation resources, analysis of seams issues, integrated gas and electric optimization for electric sector adequacy of supply under increased gas-fired generation, and other applications such as probabilistic planning and reliability considerations.

Benefit cost ratio (B/C) metrics can be used in the planning processes using co-optimizations of transmission and other resources. Co-optimizations yield additional metrics for assessment of value of transmission, value of reliability, and value of resources such as generation, demand diversity, energy efficiency, demand response, smart grid technologies, battery energy storage or other storage and other resource options. Current planning processes in market-oriented grids often focus on production cost savings or congestion savings or other short-run savings or savings of offset transmission costs. By using co-optimization, the set of benefits considered can be broadened to include other metrics such as minimizing both operational and capital costs of the power sector as a whole while maintaining reliability standards. As such, some transmission investments may increase the options of resource investments to supply demand, while co-optimization with resource options may delay or offset the need for particular transmission expansions or upgrades.

Example:

Using the EIPC Phase I dataset and the CO2+ de-carbonization scenario with PLEXOS® Co-Optimizations two cases were simulated to determine The Eastern Interconnection wide benefits of co-optimization of transmission and other resources:

1. CO2+ with BAU Transmission Limits: CO2+ with the transmission limits of the Business as Usual Case as derived in the EIPC Phase I study by the Planning Coordinators.
2. CO2+ Co-Optimized Case: CO2+ with co-optimization of Transmission and Other Resources including transmission interface expansions and costs.

CO2+ Combined Energy Case	**Objective Function**	**Description**
CO2+ with BAU Transmission Limits	2,848,866,365,300	Only resource optimization – no transmission expansion
CO2+ Co-Optimized Case	2,765,105,038,600	Co-Optimization of Transmission and Other Resources including the transmission interface expansions and costs
Co-Optimization Savings	83,761,326,700	Savings

For the above example the savings are $84 billion dollars of Eastern Interconnection savings for a transmission cost of around $51 billion. It is noted that the benefits of co-optimizations can be across a larger geographic area than the specific transmission costs as predicted by the co-optimization model.

Critical to the transmission planning process is the timing of transmission developments. The EIPC planning study did not include co-optimization of transmission and other resources and as such could not yield timing or sequential nature of transmission developments, e.g., which transmission upgrades in which years are required to facilitate resource developments/retirements. The EIPC Phase I study was limited to snapshot analysis of a distant future year of 2030, while co-optimizations yield yearly results of transmission development to facilitate resource optimizations. Thus co-optimization methods can be used in the planning process to time transmission investments year-by-year according to reliability, economic, and public policy expansion signals. Combining co-optimization with multi-scenario analysis can further refine timing to consider how alternative transmission investments affect the flexibility and adaptability of the transmission system to future regulatory, economic, and technological developments.

IV. White Paper Summary

1. Background

The goal of this study is to present a demonstration of methods of co-optimization of transmission with other resources, including generation, storage, and demand response. The co-optimization is applied to the Eastern Interconnection using CO2+ scenario assumptions from the EIPC Phase I and II datasets. The EIPC dataset was selected as a dataset because it was developed in a collaborative and consensus effort including major stakeholders, regulators, and planning coordinators. In order to derive transmission requirements several methodologies were developed in the EIPC Phase I study and averaged to estimate transmission capacity requirements of inter-regional interfaces.

More recently, in September 2013, a white paper on Co-optimization of Transmission and Other Supply Resources proposed that co-optimization of transmission and generation planning could be very useful for planning. Simulation results presented in the white paper suggest savings from 0% to 11.26% in net present value (NPV) cost terms over a 20 year planning horizon[2] for a highly simplified national network. These savings were measured against a generation-only planning approach without transmission expansion. In that report, the result of an iterative approach, which alternated between generation-only and transmission-only planning, improved the solution as it was able to capture 80% of the cost savings observed by comparing full co-optimization to generation-only planning (i.e., no new transmission). The savings reported vary depending on certain scenario assumptions regarding carbon tax levels and which generation technologies can be built.

This study is a follow-on to the white paper in which project team applies the co-optimization methodology to a more detailed representation of the EI network with commercial and university modeling and simulation tools. We demonstrate the co-optimization methodology and find the savings it yields by comparing its NPV cost over a 20 year planning horizon against a generation-only planning case with fixed transfer limits at hardened limits found by soft constrained methodology for the CO2+ case in EIPC Phase I. As the soft-constraint methodology is a type of a transmission planning heuristic, it is expected to capture part of the savings observed if co-optimization is compared against generation-only planning with fixed

[2] 2010-2030 is the planning horizon with investments allowed in 2020 and 2030 and then 2030 runs iteratively for 30 years.

transmission limits at existing values. For brevity in the rest of this report, we call the transmission investments resulting from using the soft constraint methodology for transmission planning the "reference case."

The soft constraint methodology [1] consists of three basic steps. First, the base case for each scenario was run in which generation capacity and operations were optimized subject to fixed transmission capacity; then a percent[3] of the resulting shadow prices for each interface were used as variable transmission charges (effectively, hurdle rates between regions) for a "soft future" model. Second, the soft future model with an additional pipe of unlimited capacity for each transmission interface was run for each scenario with those charges. Third, three heuristic algorithms were developed and applied to suggest fixed updated transfer limits based on flows observed in the soft future model. Finally, stakeholders chose the "hardened limits" for each transmission interface, which were assumed to be fixed from the beginning of the model horizon for all model simulations. These are the reference transmission investments that are assumed to be in place when we run the generation-only (investment and dispatch) model to define the reference power system case against which we compare the co-optimization solution.

2. Study Questions

This study aims to answer the following questions:

1. What is the order of magnitude of cost savings realized from co-optimization vs. generation-only planning with hardened transmission limits? What is the source of savings? How do major cost components change in light of co-optimization?
2. Does inter-regional co-ordination, in the form of energy exchanges, increase in light of co-optimization?
3. Does the energy mix change as a result of co-optimization?
4. Does co-optimization result in different generation investments than the hardened limit case?
5. Does co-optimization select to expand different transmission interfaces than the soft-constraint methodology?
6. How do carbon emissions change as a result of co-optimization?

[3] 25% and 75% sensitivities were run.

7. Can co-optimization be integrated with the planning process of ISO/RTO's or utility integrated resource plans for analysis of regulatory and policy considerations?

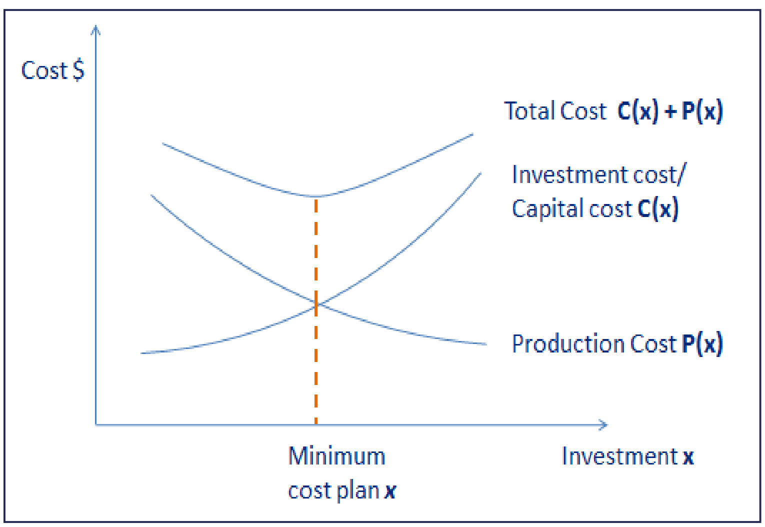
8. Do co-optimizations reduce study processing time and reduce study costs by automation via simultaneous optimization of transmission and other resources?

3. Study Overview

The EISPC Study: "Co-optimization of Transmission and Other Resources" initial results indicate savings when using co-optimization of transmission and other resources compared to sequential optimization of generation then transmission. In this study, using EIPC Phase I assumptions, the economic benefits of co-optimization of transmission and other resources was configured with the regions of The Eastern Interconnection with transmission interfaces between the regions as set by Planning Authorities during the EIPC Phase I study. The initial results suggest possible savings of around $66.5 billion or 2.4% when the transmission and other resources are co-optimized relative to the initial case without co-optimization.

The co-optimization solution minimizes capital costs and production costs over the 20 year horizon of the cases as graphically described in Figure 2 below.

Figure 2: PLEXOS® and JHU Model Least Cost Optimization



The study replicated the EIPC CO2+ Combined Energy Case for the co-optimization study of transmission and other resources. The initial Combined Energy Case includes the Hardened Transmission Limits as originally established by the EIPC Phase 1 study results. In the co-optimized case, we allow PLEXOS® to co-optimize across all interfaces in addition to the generation expansion. Our results indicate that there are significant savings from the study when a co-optimized approach is taken for transmission and other resources.

Co-Optimization of Transmission and Other Resources Forecasted Savings

In Table 1, we have summarized the results from the PLEXOS® and JHU model objective function, which is the total least cost optimization solution from this analysis. The Reference case is the CO2+ Non-Co-Optimized Case with the EIPC Hardened transmission limits. This is compared to the Co-optimized Case where the transmission is allowed to expand along with the generation expansion.

The following tabulation shows the results for the CO2+ co-optimized and non-co-optimized cases. Respectively the PLEXOS® co-optimization economic savings are $66.5 billion in terms of capital costs and production cost. Consumer savings were found to be more significant than the production and capital cost savings.

Table 1: Task 1A – Co-Optimization Savings PLEXOS® and JHU Models (Net Present Value, $2010)

CO2+ Combined Energy Case	PLEXOS ® Model Base Case Assumptions	JHU Model Base Case Assumptions
CO2+ Non-Co-Optimized Case	$ 2,831,608,688,956	$ 2,994,300,000,000
CO2+ Co-Optimized Case	$ 2,765,105,038,600	$ 2,938,000,000,000
Co-Optimization Savings	$ 66,503,650,356	$ 55,800,000,000

The JHU model also found significant cost savings. These amounted to $55.8 billion in the base comparison of the CO2+ cases. This amount is on the order of 2% of the total net present value of transmission and generation costs, and is the same order of magnitude of the incremental transmission investments made by the model. The amount is higher than the PLEXOS® estimate, primarily because of some differences in generation and transmission siting flexibility and costs, which are outlined in the Appendix. Thus, although the exact benefits of co-optimization depend on study assumptions, we can conclude that the magnitude of co-optimization's value can be comparable to the cost of transmission construction itself.

In both the PLEXOS® and JHU analyses, the distribution of generation and transmission investments depended on each other, and were appreciably different than the EIPC study Phase I analysis.

Co-optimization of Transmission and other Resources Sensitivities

A series of sensitivity analyses illustrate the type of planning insights that can be obtained quickly from the integrated co-optimization models. Both the PLEXOS® sensitivity analysis and the JHU sensitivity analysis shows that if co-optimization contributes to regional co-operation in the acquisition of generation reserves (modelled as an EI-wide planning reserve constraint, rather than a region-by-region constraint) or in super region planning reserve constraint (clusters of EI sub-regions), then additional cost savings can be realized. The PLEXOS® model showed this savings to range from $7 billion when hurdle rates are maintained to $45 billion when hurdle rates or seams issues are eliminated. The JHU model showed this savings to be $7 billion when hurdle rates are maintained (mainly in the form of reduced expenses for combustion turbines or other peaking facilities) and $57 billion when they are eliminated.

Table 2: Task 1A: PLEXOS® Model Planning Reserve Sensitivities (Net Present Value, $2010)

CO2+ Combined Energy Case	Super Region Planning Constraint	EI-Wide Planning Reserve Constraint
CO2+ Reference Case (Co-opt)	$ 2,765,105,038,600	$ 2,765,105,038,600
CO2+ Sensitivity Case (Co-opt)	$ 2,743,931,012,400	$ 2,719,558,080,300
Additional Co-opt Benefits	$ 21,174,026,200	$ 45,546,958,300

Table 3: Task 1A: JHU Model Planning Reserve Sensitivities (Net Present Value, $2010)

CO2+ Combined Energy Case	Super Region Planning Constraint	EI-Wide Planning Reserve Constraint
CO2+ Reference Case (Co-opt)	$ 2,938,467,275,135	$ 2,938,467,275,135
CO2+ Sensitivity Case (Co-opt)	$ 2,905,253,510,302	$ 2,880,945,942,854
Additional Co-opt Benefits	$ 33,213,764,833	$ 57,521,332,281

These sensitivities have been run in the CO2+ Co-optimized case and the benefits are

Co-Optimization of Transmission and other Resources taking into account Transmission Impedances

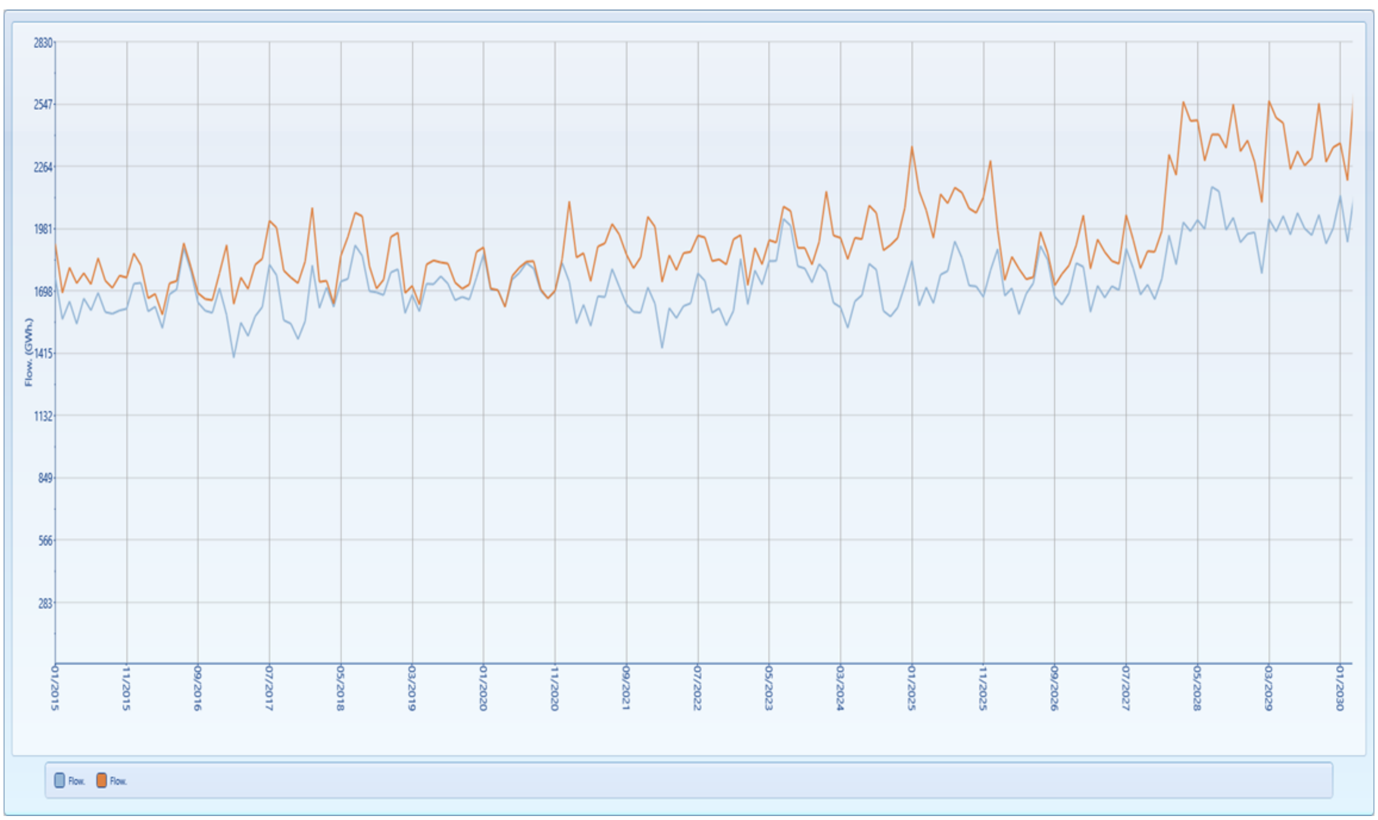
In the previous section and in the EIPC Phase I study the methodology used was a "pipe and bubble" co-optimization model where effects of power flows following paths of least impedance was neglected.

Thus the PLEXOS® model was used with Energy Exemplar EI commercial database that contains a detailed transmission model for demonstrating Co-Optimization of Transmission and other Resources taking into account transmission impedances for power flows.

For the demonstration of Task 1b, Generator expansion candidates have been placed in all the zones of PJM classic, NYISO & ISO-NE and are co-optimized with Transmission Interface expansion for a 20-year horizon.

Below is the figure which shows monthly flows on the UPNY-ConED Interface 2015 through 2030 with and without co-optimization and it shows that in the co-optimized case the expanded interface picked up additional flow according to impedance division of power flow.

Figure 3: UPNY-ConED Interface Flow with (orange) & without (blue) Co-optimization



Co-Optimization of Transmission and other resources and Demand Response

We also report results for co-optimization with demand response, and show that it is practical to diversify the alternatives considered to include those increasingly important resources.

CO2+ Combined Energy Case with Demand Response	**PLEXOS ® Model Base Case Assumptions**	**JHU Model Base Case Assumptions**
CO2+ Non-Co-Optimized DR	$ 2,828,562,278,156	$ 2,994,300,000,000
CO2+ Co-Optimized DR	$ 2,763,017,492,000	$ 2,936,407,000,000
Co-Optimization Savings DR	$ 65,544,786,156	$ 57,893,000,000

The Co-optimization of Transmission and other resources and Demand Response produced a net savings of the objective function of $65.5 billion. The result is significant in that the co-optimization was achieved with both the expansion of the transmission interfaces, generation expansion candidates as well as DSM. In this case, PLEXOS® solved for the least cost expansion of all these different variables in the same solution. The net build of DSM is 151,100 MW across the entire EI.

Our analyses include a number of sensitivity analyses. One sensitivity analysis shows that much, but not all of the benefits of full co-optimization can be achieved by multiple iterations of separate generation and transmission planning processes. In such processes, two planning models alternate, one obtaining optimal generation investments subject to an assumed network, and the other optimizing the network subject to an assumed generation siting scenario. This confirms the conclusion of the 2013 NARUC Co-optimization White Paper,[4] which points out that mathematically such an iterative process cannot guarantee the fully optimal co-optimized solution but can capture the majority of the benefits of co-optimization.

Co-Optimization of Natural Gas and Electric Sectors

From the EIPC Phase I study an observation was made that significant natural gas fired power generation was forecasted however the natural gas transport network and production was not considered in the EIPC Phase I study. An EIPC Gas Electric study was later commissioned to consider the implications of natural gas transport network on the adequacy of supply of natural gas fired electric power generation in the electric power sector. The EIPC Gas Electric study relies on a multi model and multi dataset framework of

---

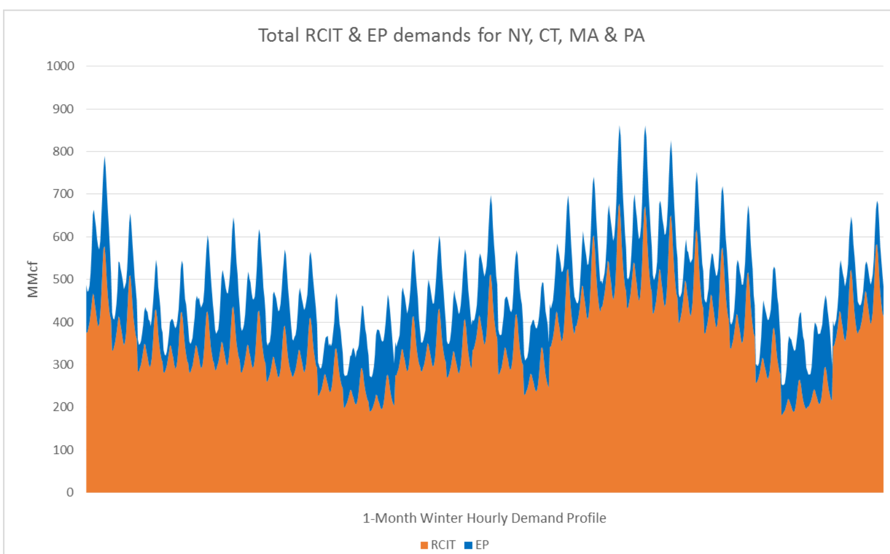
[4] A. Liu, B.F. Hobbs, J. Ho, J. McCalley, V. Krishnan, M. Shahidehpour, and Q. Zheng, "Co-optimization of Transmission and Other Supply Resources," Prepared for the Eastern Interconnection States' Planning Council, National Association of Regulatory Utility Commissioners, Washington, DC, 20 Dec. 2013, www.naruc.org/grants/Documents/Co-optimization-White-paper_Final_rv1.pdf.

running electric sector model and dataset, then sequentially feeding those natural gas requirements from the electrical sector to the gas sector model and dataset to determine constraints and limitations of the natural gas transport infrastructure.

As part of EISPC project of Co-Optimization of Transmission and Other Resources the EISPC requested demonstration of methods that would co-optimize gas and electric via a single model interactions of both natural gas and electric sectors as well as a combined database. This way inter-dependencies of the natural gas and electric sectors can be studied and observations made in response to analysis of public policy and regulatory evolutions in both sectors.

For demonstrating Task 3, Energy Exemplar's PLEXOS® Gas Electric Database has been configured to simulate Gas Electric Co-optimization in PJM Classic, NYISO & ISO-NE footprint. Below is the area stack chart of Residential, Commercial, Industrial, Transport (RCIT) & Electric Power (EP) demands for Jan 2015. The EP is the Gas Fuel Offtake which is calculated as a result of Gas Electric Co-optimization in PLEXOS®, where the detailed power market dispatch is run simultaneously with the Natural Gas pipeline and production model.

Figure 4: Hourly RCIT & EP demands for NY, CT, MA & PA combined



V. Introduction

1. NARUC / EISPC RFP

The National Association of Regulatory Utility Commissioners (NARUC) and Eastern Interconnection States' Planning Council (EISPC) issued a Request for Proposals to address the demonstration of Co -Optimization of Transmission with other Resources. This demonstration study is a proof of concept to test the efficacy of co-optimizing investments and planning of transmission with other resources. EISPC believes co-optimization has the potential for advancing the state-of-the-art in planning processes to enhance the resource planning analysis.

The RFP requested the demonstration of three primary tasks:

Task 1: Evaluation of co-optimization of transmission and other resources.

Task 2: Evaluation of co-optimization of transmission with generation and at least one of the following: demand response or energy storage.

Task 3: Evaluation of co-optimization techniques to address electric and natural gas operational and planning issues.

2. Team

Energy Exemplar, the developer of PLEXOS® Integrated Energy Model, has joined with Johns Hopkins and Iowa State Universities to demonstrate the current tools available for the co-optimization of transmission and other resources to NARUC and EISPC. In additional to this team of experts and researchers in co-optimization of energy resources, the team collaborated with two ISO/RTOs and a US Government National Lab for this EISPC demonstration project:

- Midcontinent Independent System Operator (MISO);
- Independent System Operator of New England (ISO-NE); and
- Oak Ridge National Laboratory.

However, it should be noted that the responsibility for any errors or opinions in this document is the responsibility of the authors alone.

3. Study

This study was designed to be collaborative with planning authorities, national labs and other academia and the team was assembled to motivate practical methods of co-optimization of transmission and other resources. The approach and methods that we propose have the principles of demonstrating co-optimizations across The Eastern Interconnection, utility footprints, states, regions, zones, using a common and trusted dataset of the EIPC Phase I and II and EIPC Gas Electric and testing co-optimization techniques that can be transparent, repeatable, defendable, and have the highest likelihood of being used and useful in planning processes.

We are confident in the viability of developing practical methods for co-optimization for potential use in planning processes with the use of PLEXOS® Integrated Energy Model, shown to be repeatable via use of the JHU model. These co-optimizations in PLEXOS® and the JHU model are true "simultaneous" co-optimizations based on world class operations research methods. PLEXOS® is licensed in over 38 countries by regulators, planning coordinators, utilities, research labs, and others. In addition to the PLEXOS® documented ability to co-optimize of transmission and other resources, PLEXOS® can also co-optimize natural gas and electric production cost and capacity planning.

Energy Exemplar along with the JHU and ISU and collaborators converted the EIPC data for Phase I into PLEXOS® and are currently mapping the most up to date EIPC Gas Electric data. Johns Hopkins University, Iowa State University, Oakridge National Laboratory, ISO-NE and MISO all have had access to the PLEXOS® EIPC Phase I database and have provided comments and suggestions for refinements as well as ran simulations and observed results and applications of the co-optimization methods.

4. EISPC Co-optimization Study Committee with NARUC / EISPC meeting

The Co-optimization Study team suggested the following approach to the NARUC / EISPC representatives following the award of the NARUC/EISPC RFP and kickoff off of the Project.

Task 1

To demonstrate Task 1, the team proposed using the combined energy policy future of existing EIPC Phase I datasets, which is a pipe and bubble model with regions and transmission flows modelled between these regions.

However, this model is a simplified version of a full nodal model and therefore does not include impedance properties and a full DC-OPF analysis. As such, in addition to a “pipe and bubble” modelling approach, a separate sub-Task Task-1B has been completed to model a more granular method of co-optimization of transmission and other resources, including transmission impedance in expansions using a DC-OPF model on the Energy Exemplar PLEXOS® EI Database.

Task 1B is demonstrated with the use of Energy Exemplar’s commercial Eastern Interconnection (“EI”) full nodal dataset for evaluation of DC-OPF analysis in the co-optimization of transmission and other resources with focus on the Northeast.

Task 2

For Task 2, starting with the models developed in Task 1A with the EIPC Phase I, II dataset, additional resources of energy efficiency demand response and Energy Storage are optimized. Battery Energy Storage builds in the capacity planning framework of PLEXOS® in addition to other energy storage types were co-optimized.

Task 3

Energy Exemplar has prepared a 60,000 node EI model of the Electrical Market with a natural gas pipeline market model where the two models are co-optimized. As part of this demonstration Energy Exemplar evaluated co-optimization of gas electric production cost and capacity planning. Energy Exemplar has developed a commercial gas-electric datasets with some input data and assumptions of the EIPC gas-electric.

5. Project Team

The table below includes Project Team including Collaborators.

Table 4: Project Team

Name	Organization	Role
Randell Johnson	Energy Exemplar LLC	EISPC Consultant and Report Authors
Andrew Bachert	Energy Exemplar LLC	
Sai Koppolu	Energy Exemplar LLC	
Jordan Bakke	MISO	Collaborators
Dale Osborn	MISO	
Mark Babula	ISO-NE	
Wayne Coste	ISO-NE	
Haifeng Ge	ISO-NE	
Stan Hadley	Oakridge National Laboratory	
Benjamin Hobbs	Johns Hopkins University	Sub-Contractors and Report Authors
Jonathan Ho	Johns Hopkins University	
Evangelia Spyrou	Johns Hopkins University	
Jim McCalley	Iowa State University	
Armando Figueroa	Iowa State University	
Santiago Lemos-Cano	Iowa State University	

The team and collaborators have reviewed the proposed tasks as part of the final activities. A summary of these tasks are defined below.

Tasks Scope Defined

Following the initial committee project discussion and the project team meeting with all team members and collaborators, the team completed the following defined Tasks.

VI. EISPC Co-optimization Demonstration Tasks

Task 1: Co-optimization of Transmission and Other Resources

The team used information from EIPC Phase I and II, selecting the combined energy policy case, otherwise known as CO2+. This has the benefit of providing a useful context since it would be using information that is familiar to the States and Planning Coordinators. In addition to this task, the team proposes to also evaluate the co-optimization of Transmission and Other Resources using a full DC-OPF model.

As such, the group proposed that Task 1 be split into Task 1A and Task 1B and defined as follows:

Task 1A: Demonstrate Co-Optimization transmission and other resources based on the EIPC Phase I Combined Energy Policy (aka CO2+). This is a "pipe and bubble" model with simplified transmission properties. Task 1A was demonstrated into two modelling groups by the team: PLEXOS® and the model developed by Johns Hopkins University (referred to here as JHU model). In this case, results for both PLEXOS® and JHU are published below.

Task 1B: Demonstrate Co-Optimize transmission and other resources of Energy Exemplar Eastern Interconnect ("EI") nodal database. This is a full nodal model with an impedance DC-OPF that will be simplified to regions interconnected via transmission with impedances. This model uses the PLEXOS® model.

Task 2: Co-optimization with Energy Storage

Task 2: The team Co-optimized transmission with other resources and demand response or energy storage according. Similar to Task 1A, this task was demonstrated by two modelling groups: PLEXOS® and JHU model. For the PLEXOS® model, both demand response and energy storage were co-optimized while for the JHU models only the demand response was modelled for this task. The JHU modeling effort compared two different representations of demand response: pseudo-generators (as in PLEXOS) with high strike prices ($165 or above) and continuous demand functions in which load is a function of price and the model is solved iteratively (JHU model).

Task 3: Co-optimization of Electric and Natural Gas

Task 3: EISPC is interested in the applicability of using co-optimization techniques to address electric and natural gas operational and planning issues. The Energy Exemplar team prepared a case to evaluate the co-optimization of both electric gas production as well as the co-optimization of the generation and gas expansion. Energy Exemplar used some inputs from the EIPC gas electric study.

Task 3A: Evaluate Co-Optimization of Gas and Electric Production Cost for gas constraint and contingency analysis according to NERC gas electricity contingency concept.

Task 3B: Evaluate case of Co-Optimization of Gas and Electric Capacity Expansion for Dual Fuel, Gas Storage, Pipeline Expansion, Transmission Expansion, Generation Expansion, and Environmental Retro-fits. A simple demonstration model is used for Task 3B.

The team assembled a Northeast-focused case with ISO-New England collaborating.

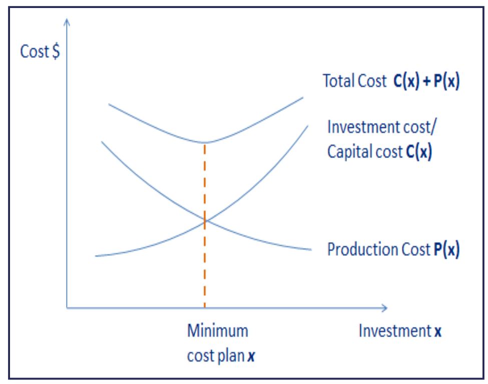
VII. Co-Optimization Methodology

1. PLEXOS® Co-Optimization Model

Overview:

The method "co-optimization of transmission and other resources" refers to the problem of finding the optimal combination of generation new builds and retirements and transmission upgrades (and retirements) and other resources that minimizes the net present value of the total costs of the system over a long-term planning horizon. PLEXOS® simultaneously solves generation and transmission capacity expansion problem and a dispatch problem from a central planning, long-term perspective.

Figure 5: PLEXOS® LT Co-optimization



The following types of functions and features are supported:

- DC-OPF (Kirchhoff's Current Law)
- Building new generating plant
- Retiring existing generating plant
- Multi-stage projects
- Building new AC or DC transmission lines
- Retiring existing AC or DC transmission lines
- Multi-stage transmission projects
- Expanding the capacity on existing transmission interfaces
- Reliability Metrics of LOLE and LOLP
- Demand Response and Energy Efficiency
- Energy Storage
- Complex Hydro Models
- Gas Electric Co-Optimization

Co-Optimized Expansion:

The generation capacity expansion problem in PLEXOS® resolves the problem of finding the optimal investment of new generators and/or optimal generation retirements, transmission expansion or retirements, interface expansion and other resources. It uses the list of locational candidates which, for each of them, the user is able to define a complete list of key investment project properties like building costs, discount rate, economical life, and other financial and physical characteristics. PLEXOS can also assume fixed new entries (e.g., known firm projects). PLEXOS® appropriately deals with discounting and end-year effects to correctly account for economic life of new builds during the latest years. Annualized cost financial equivalent and perpetuity of the last year can be defined for this purpose.

Generator and transmission forced outage and maintenance outage rates can be included in the LT Plan formulation. It is assumed that forced outages affect capacity but both forced and maintenance outages subtract from available energy. PLEXOS® can alternatively use the Effective Load Approach method to appropriately modify the load demand with respect to the convolved capacity outages. The effective load approach uses the LOLP convolution method, to take the forced outage rates of generators and adjust each load energy block to reflect the capacity affected.

The natural trade-off between energy shortage and build cost will ensure that capacity is built if it is economic and that the energy price compensates the marginal build for its production and build costs (notion of unserved energy costs). However, realistic reliability standards can be introduced defining reserve capacity margins during peak load periods. Such reliability indexes (e.g. LOLP, LOLE or EENS) can be computed ex-post using the subsequent reserve adequacy (PASA) module.

PLEXOS® can also formulate and optimize generation retirements by seeking to compare FOM costs of unused plants as drivers for retirements (against retirement costs, from a centralized point of view).

Problem formulation

Figure 6: Problem Formulation

Minimize:

$$\sum_{candidates} Build\ Cost$$
$$+ \sum_{\substack{Existant+\\candidates}} FOM\ Cost$$
$$+ \sum_{\substack{Existant+\\Candidates}} Operational\ Cost$$

Subject to:

- *Energy Balance,*
- *System Operational limits,*
- *Security: Ancillary Services, Transmission limits, Capacity reserves,*
- *Hydro energy constraints…*

The capacity expansion problem is by definition a large scale mixed integer programming (MIP) problem. The objective function of PLEXOS® seeks to minimize the net present value of build costs plus fixed operational and maintenance (FOM) costs and production costs. For each defined trading period, most relevant feasibility and system security constraints have to be imposed. The block-wise energy balance operational problem is then co-optimized along with the fixed and retirement costs of existing units. The transmission detail level can be selected from simplified across-region to fully nodal representation. Among other security capacity and operational related constraints, it is possible to define capacity reserve margins (over annual peak load), ancillary services (e.g., spinning reserve), maximum fuel usages, minimum energy production, CHP, cogeneration and other must-run constrained conditions. Operational limits such as fuel availability, emissions production limits, can also be included into the co-optimization task. Very long term constraints such as major hydro inter annual storages and long term emission allowances can be solved and decomposed in order to be included in subsequent more detailed operational runs of midterm and production cost.

Solving Methodology

In order to solve the large scale MIP problem PLEXOS® uses the LDC method to create a reduced form of the energy balance operational problem. The user can fully customize the size of the horizon, control the integerization horizon, divide task into chronological steps, adjust step length and resolution and many other performance parameters. The chronological unit commitment problem can be solved in subsequent stages coupling results from LT module (i.e. new builds/retirements and long term decomposed constraints). PLEXOS® can be run in deterministic or stochastic modes.

In deterministic mode, PLEXOS® can solve the expansion planning problem for each sampled sequence from the random variables or it can solve one unique run using the expected values for each variable.

In stochastic mode it can be used to find the single optimal set of building decisions in the face of uncertainties of any input e.g., load, fuel prices, hydro inflows or wind generation. PLEXOS® uses the scenario-wise decomposition methodology to solve the multi-stage deterministic equivalent optimization problem. A unique generation build/retirement plan as well as transmission reinforcements should be optimal for all possible incomes of the random variables (usually referred to as non-anticipativity decisions).

PLEXOS® has world renowned hydro modeling features as well as complex energy storage models that are integrated with the capacity planning module of PLEXOS®. PLEXOS® can perform multi-year analysis, for example for The Eastern Interconnection system the model horizon is 20 years or more of demand and fuel forecasts for capacity expansion calculations to capture end effects.

PLEXOS® has efficient stochastic optimization features for robust capacity planning forecasts.

PLEXOS® will yield a stream of investment decisions in generation with estimation of deployment year. PLEXOS® is easy to configure for scenario analysis such as high demand, low demand, high fuel price low fuel price, high carbon price low carbon price, high renewables deployment and or moderate renewables deployment.

PLEXOS® will co-optimize with a DC-OPF where the capacity expansion problem can be spatially disaggregated to a reasonable level. Also PLEXOS® can co-optimize generation and transmission expansion and yield both generation and transmission investment streams and deployment times.

PLEXOS® has detailed environmental models and constraints and decision variables that allow for assessment of GHG emissions for any scenario studied.

PLEXOS® has well over 1000 metrics for cost benefit analysis in terms of capital costs, operating costs, emissions, transmission, congestion and others.

Multistage Stochastic Optimization in PLEXOS®

In some cases, decision making problems comprise more than two stages. This fact motivates the use of multi-stage stochastic programming when it is possible that observations are made at "T" different stages. Stages correspond to time instances when some information is revealed (or where uncertainty partially or totally vanishes) and a decision can be made. The amount of information available to the decision maker is usually different from stage to stage.

This decision framework is conveniently visualized though a scenario tree. The nodes represent states of the problem at a particular instant: where the decisions are made. In the first node, called "The Root", the first stage decisions are made. The nodes connected to the root node are the second stage nodes and represents the points where the second stages decisions are made. The number of nodes in the last stage equals the number of scenarios. The branches are different realizations of the random variables.

Figure 7: Two Stage

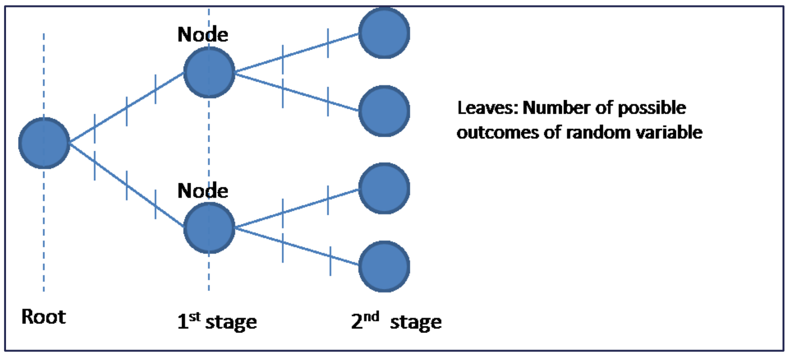
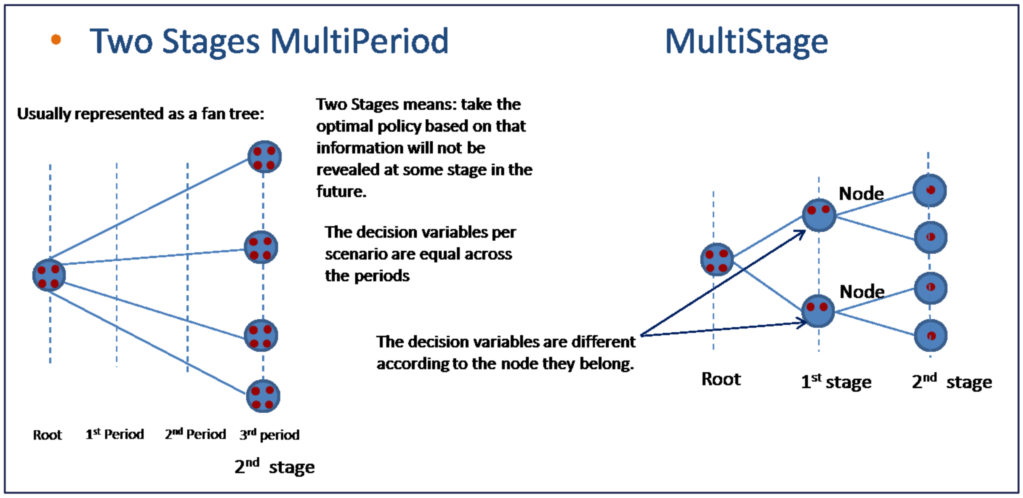


Figure 8: Two Stages vs Multistage



In Multistage different optimal policy trajectories can be obtained, since the optimal trajectory will depend on the information revealed through time.

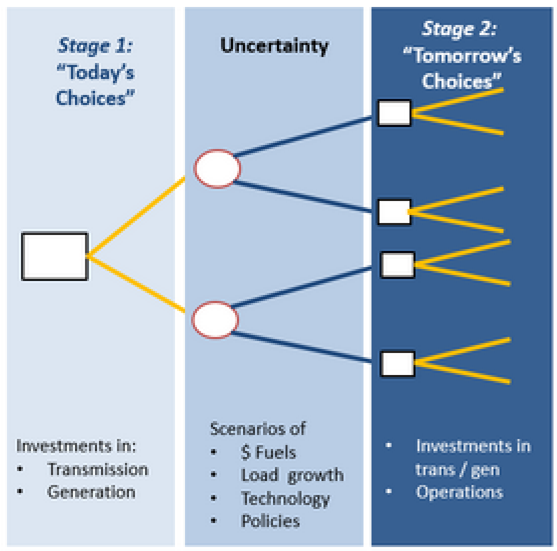
2. JHU Co-Optimization Model

The Johns Hopkins University co-optimization software is an in-house research-grade model developed initially by Drs. van der Weijde and Hobbs in 2011. Since then, the JHU software has been applied and tested using realistic systems in Great Britain and the Western US, and results have been published in peer-reviewed journals [3, 4]. The model was used as part of the 2013 NARUC co-optimization benefits study [2], when it was applied to a simplified zonal model of the US power system to demonstrate the benefits of co-optimization.

The JHU model is a multi-stage stochastic transmission planning model that aims to capture the multistage nature of transmission planning under uncertainty over a two or more decade time horizon (Figure 1). In the JHU model, a proactive transmission planner makes investment decisions in two time periods, each time followed by the response of the generation market, in terms of investment and operations. Uncertainty is represented by economic, technology, and regulatory scenarios, and first-stage investments must be made before it is known which scenario will occur. The model allows us to identify expected cost-minimizing first-stage investments, as well as estimate the value of information, the cost of ignoring uncertainty, and the value of flexibility. It is worth mentioning that the JHU model is actually a model that concurrently co-optimizes transmission and generation planning as we have assumed that the transmission planner attempts to maximize social welfare (defined as net market surplus) and generators are modeled as price-taking profit maximizers. Therefore, under Samuelson's (1952) principle, this problem is equivalent to a single optimization problem of generation and transmission planning under a net surplus objective.

The JHU model is flexible and can be extended to consider more detailed representations of the electricity system. Example of such features include unit commitment, demand response, and Kirchhoff's Voltage Laws. For purposes of the present study, a modified deterministic version of the JHU model has been applied. Previous publications document the model's formulation and assumptions, as well as applications of the full multi-stage stochastic transmission planning model.

Figure 9: Schematic Diagram of Structure of JHU Stochastic Multi-stage, Multi-Scenario Model



Specific Model Implementation

A deterministic, linear programming version of the stochastic, mixed integer programming[5] JHU model was applied to meet the specific needs of the EISPC Report, and required updates were made to reflect assumptions made in the CO2+ case from the previous EIPC Study [5-9]. Results of the JHU model were benchmarked against results from the F8S7 (CO2+ case) from the previous study [10] and are presented in Section VIII of this document. Then the JHU model was applied to identify the least-cost generation and transmission investments for the Eastern-Interconnection using co-optimization.

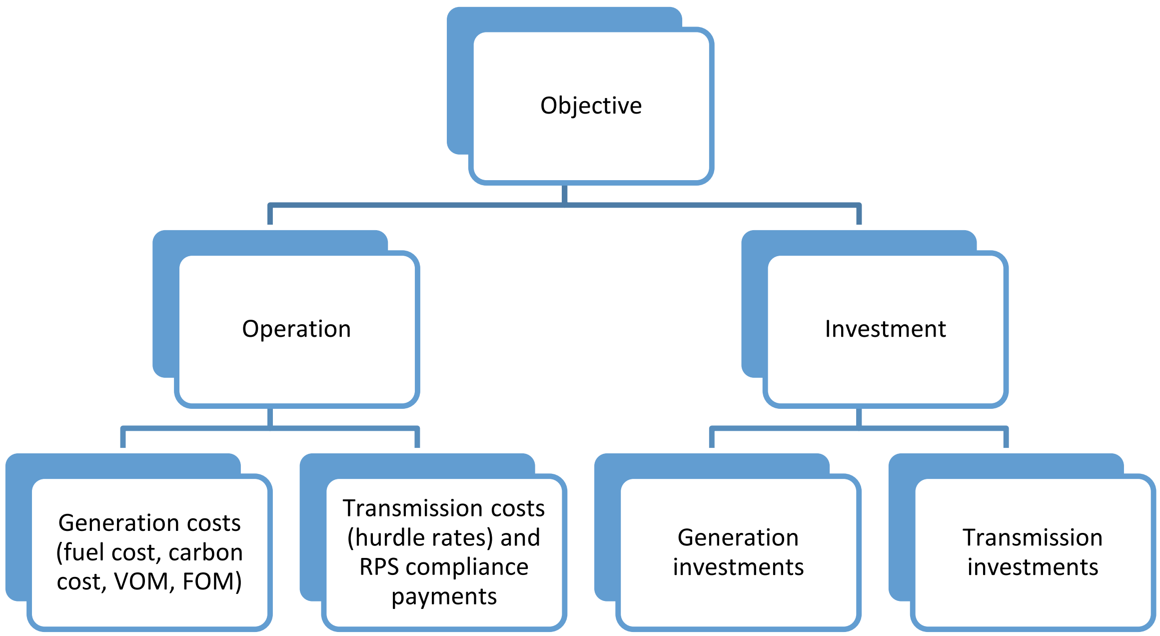
[5] The model is a MIP for Task 1A and Task 2 with demand response modeled as pseudo-generators and using linear demand curve.

Demand Response was also modeled in two ways. First, demand response was modeled through pseudo-generators with known supply curve at fixed price of $750/MWh in Task 1A and with known 6-tier supply curves in Task 2, which were considered for dispatch as conventional generators. Second, Demand Response was also modeled using Gauss-Seidel iterations to demonstrate the impact of price responsive demand response. This is accomplished by iterating between demand curves (representing the assumed response of load in each time period and each region to the real-time price) and the JHU model, as in [11]. The JHU model is executed to obtain a set of prices, which are then inserted in the demand curves, which then produce a modified set of loads. This produces an updated set of loads, which are subsequently returned to the JHU model, which can then be re-solved. This iterative process (which is mathematically called "Gauss-Seidel iteration") is repeated until convergence is achieved, which usually occurs quickly. The mathematical approach is described elsewhere [11].

Model objective function

The JHU model's objective function is the NPV value discounted back in 2010 (in 2010$ to account for real vs. nominal values) of investments made in generation and transmission expansion throughout the horizon modeled, along with operations and maintenance (O&M) costs of the electric network and generators.

Figure 10: Schematic Representation of JHU model objective function



Type of investments decisions considered

Investment decisions include transmission line additions for each transmission interface modeled and new generation capacity at each of the 24 regions modeled, both modeled as integer decision variables in MW.

For generators added, unit sizes assumed are presented in Table 129. Transmission investments are considered in integer sizes in increments of 1 MW.

Number of generators considered in the JHU model

Generators were modeled in a more aggregated way in the JHU model compared to PLEXOS® model. Twenty-six generator types were considered in order to be able to keep the level of aggregation high without missing economically important differences among generation types. For example, nuclear is modeled through two categories: nuclear existing and new to take into consideration the different FOM and VOM, while for Wind, we modeled existing and new in one generator category with FOM and VOM of new wind units, which does not distort the decisions as insignificant numbers of old wind units are expected to retire. On the other hand, difference in wind shapes and resource potential between category 4+ and category 3 was considered important, so the JHU model included two categories of wind[6]. For each of the 24 regions, JHU model has an aggregated representation of each of the 26 types of generation.

Horizon, model stages and end effects

The model runs from 2011 to 2030. Every year, a single round of generation retirements and generation & transmission investments occurs, with their costs equaling the overnight cost including the financing cost for the assumed technology; the operations are also simulated, based on cost-minimization. Detailed assumptions on overnight capital cost by generation technology, regional multipliers applied and FCR assumed are presented in Table 6, Table 79, Table 96*: Regional Multipliers*. Interface expansion costs are detailed in Table 99: *Interface Build Assumptions* . After the year 2030, we repeat the final period of operations for 30 years to capture end effects. This is to ensure that the model still values investment decisions in the final stage. A real discount rate of 5% is used to take into consideration of time value of money.

Load representation

Each year of operations is modeled through 20 appropriately weighted load blocks (consistent with CO2+case), which allows us to determine operational decisions at block level. Load assumptions are presented in detail in subsection 4 of Section VII.

Outage rate considerations

Forced and Planned outage rates (FOR and POR, respectively) are considered by de-rating capacity by the fixed percent of FOR across the 20 blocks. Capacity is also de-rated for POR (ratio of planned outage days by 365 days) across 13 blocks (bottom 5 summer blocks, bottom 4 winter blocks, bottom 4 shoulder blocks). Planned Outage Rate assumptions are based on the previous study assumptions and are summarized in Table 5. A similar approach was followed for Forced Outage Rates in the JHU model, where the aggregate category FOR is calculated by weighting the FOR based on capacity of individual units in that category.

[6] See Table 114 & Table 115 for capacity factors of wind category 3.

Table 5: Planned Outage Days and Forced Outage Rates (JHU model)

Technology type	Planned Outage Days	Force Outage Rate
Combined Cycle- existing	25	6.1%
Combined Cycle- new units	21	6.1%
Coal existing units	27.1-32.4[7]	5.72%- 7.26%[7]
Coal -new units	27.1	6.96%
Combustion Turbine	10.8-15.8[7]	8.3%-9.5%[7]
Geothermal	5.0	8.00%
Biomass	5.0	8.00%
IGCC	27.1	8.00%[8]
LFG	18.3	8.00%
Nuclear	28.6	3.20%[9]
Photovoltaic	36.5	6.00%
STOG	32.1	6.70%
STWD	36.5	10.00%
Wind offshore	10.4	5.00%
ST	20.8	5.00%
Hydro	0	5.00%

Generation constraints

Generation at each load block is constrained by the named capacity adjusted for FOR, POR, and capacity factor in case of intermittent resources.

[7] Differs by region.

[8] 12% for IGCC_CCS

[9] 3.4% for new units.

Network representation and transmission options

The transmission grid is modeled as a "pipe and bubbles" network in the EI application, consisting of 47 interfaces (for detailed information on interfaces considered, see table 52: Transmission Line Information of the Appendix). This feature is represented by a regional energy balance (Kirchhoff's current law, KCL) constraint in JHU model. This constraint ensures that incoming power flows to a node (one of the 24 regions) and generation at that node equals the outgoing power flows plus the load. Capacity constraints are also enforced to ensure that power flow at a specific interface does not exceed available capacity in any block.

Representation of Renewable Portfolio Standards

Renewable portfolio standards can be enforced in two ways:

1. At the state level for both renewable energy and solar requirements. The overall North American Electricity and Environment Model (NEEM) region load and generation is allocated to states using population weights. For each, both renewable energy and solar RPS's in each region have an Alternative Compliance Payment fine which can be paid in lieu of renewable generation to satisfy the requirement.
2. At pool levels, as used in EIPC Phases I and II [5]. In previous phases, NEEM regions were grouped in 8 super-regions for representation of RPSs and 7 regions for representation of solar RPSs. Detailed assumptions were made concerning the contribution of each technology to each RPS as well as the contribution of existing units to the different pools. For detailed assumptions used in the JHU model, see Table 102: 2011-2020 RPS targets by super-region, Table 113: Alternative Compliance Payment for Solar RPSs**.** The results of the JHU model presented below reflect our enforcement of these constraints in the same manner as EIPC Phases I and II for consistency.

A national RPS is also enforced at Eastern-Interconnection level (excluding the Canadian IESO) to reflect the assumptions of the previous study. Qualifying resources for national RPS include: hydro (existing and new, including Canadian), wind, solar, biomass and landfill gas.

Planning reserve constraints

Planning reserve constraints are enforced every year at the NEEM region level for all regions except regions in NYISO, MISO and PJM, where the constraint is enforced at the ISO level and SPP-NE. The assumptions of the CO2+ case regarding planning reserve margins, as well as the reserve contributions of demand response and intermittent resources were adopted. Detailed assumptions one planning reserves margins are presented in Table 89 and assumptions on peak demand are presented in Table 117 and Table 118.

Horizon expansion

The amount and location of generation expansion is constrained according to new resource limits specified in previous study over the horizon of the project (Table 88*: Resource Potentials*). Transmission expansion is constrained to 20,000 MW per interface over the planning horizon. This limit was agreed among partners and collaborators.

Features and computational methods

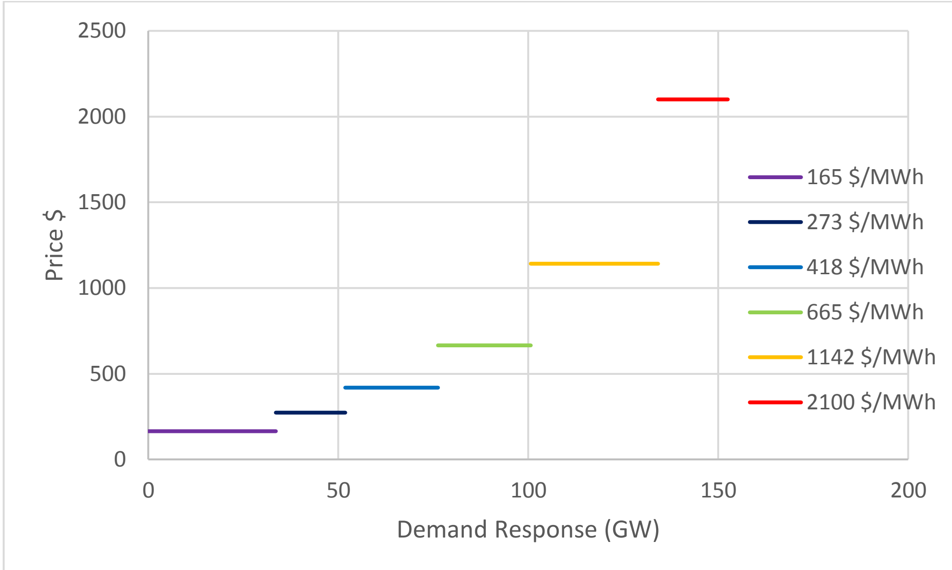
The JHU optimization problem, as noted above, is currently a MIP. The model is currently implemented in AIMMS v4.1, using the CPLEX 12.6 solver.

Demand Response

Demand response is represented using two distinct approaches in the JHU model. The first approach represents demand response using pseudo-generators: for Task 1A pseudo-generators are assumed to provide energy at a fixed price of 750$/MWh, while in Task 2 a step-wise supply curve is assumed and represented using a set of six pseudo-generators. The pseudo-generators each represent a different bid level between $165/MWh to $2100/MWh. The capacity of each pseudo-generator was set by year and region. This approach is similar to the approach taken by the EIPC Phase I study.

An alternative approach considered price responsive demand curves under which consumers directly respond to real-time prices in a more continuous fashion. A Gauss-Seidel iterative approach previously applied using COMPETES on the EU27 network [11] is applied. In this approach, demand functions are used to adjust assumed loads by region in response to the price of electricity in that region (locational marginal prices). Mean reference prices for each stage and region are first determined by taking the weighted average, across the 20 load periods for each year and region, of the shadow price of that region's energy balance (KCL constraint). The model is then run iteratively with demand being updated between iterations using elastic demand curves specific to the region and year. Sufficient iterations are run until the model converges to a satisfactory solution.

Figure 11: Aggregate Supply of Demand Response 2030



Pumped Storage and Hydro

Pumped Storage is modeled as a load in the lowest load blocks and as a generator for the peak blocks of the three seasonal load demand curves. Efficiency was assumed to be 75% in line with the previous study, and energy generated by PS was constrained by energy observed in the F8S7 results [10]. Three energy balance constraints, one per season, were enforced for pumped hydro that account for the duration of each season, and that prevent storage of energy in one season for use in another.

For Hydro, an annual capacity factor applied to all blocks was considered (see Table 116: Existing hydro constant capacity factor). This approach underestimates hydro contribution to peaks and it was adopted due to unavailability of seasonal data for hydro generation.

JHU model also considered investments in new US non-power-dam hydro generators and pseudo-generators in Canadian regions. Detailed assumptions are presented in Table 119 and Table 124.

Case-specific constraints

Case specific constraints regarding intermittent penetration limits and timing of investments were modeled consistent with the previous study.

Note on generation representation

Generators are currently represented by aggregated generators, one per technology and region. The majority of the assumptions are consistent with assumptions used in the PLEXOS® model, although there are some minor differences. One of the differences relates to representation of existing coal units. In EIPC Phase I and II and PLEXOS, 221 stand-alone units were modeled in addition to the aggregated units modeled in each region. In the JHU model, the stand-alone coal units were aggregated into 24 aggregated units for the entire study region. The capacity of each aggregated unit across the total capacity of coal capacity in each region. An overall heat rate of 10,042 BTU/kWh was calculated as a weighted average, by capacity, of generator heat rates. Forced Outage Rates and Planned Outage Rates were calculated as capacity-weighted averages of generator FORs and PORs by region.

JHU Limitations

The simulations are useful for demonstrating the co-optimization methodology, and estimates of cost savings are important to give a sense of the order of magnitude that can be expected if co-optimization methodology is applied in planning. However, the current modeling approach has certain limitations that should be kept in mind while interpreting the results. These limitations are described here to make clear that the transmission and generation investments that are made in the simulations should not be interpreted as recommendations for actual investments. Detailed and carefully re-viewed planning studies would be needed to support an actual transmission investment program.

Some of the limitations include the following:

- A major limitation of the dataset is the representation of EI network as a "pipe and bubble" network, which does not enforce Kirchhoff's Voltage Laws. As a result, the model can route flows to avoid bottlenecks, unlike real AC power systems in which power flows along all parallel paths.

- Another limitation is the use of load duration curve representations of demand instead of chronological load data, so that chronological operating constraints for thermal generation (e.g., ramp limits, start-ups) and pumped hydro (limits on pumping/generation schedules) are unenforced.

- RPS were approximately applied following the methodology adopted in the previous study, making them deviate from the actual situation in which, for instance, states have divergent definitions of qualifying resources.

- Generators were also aggregated for purposes of the study, precluding the ability to model individual unit characteristics and constraints.
- The data base itself has a number of limitations, such as being based on a particular set of fuel, carbon price and capital cost assumptions without recognizing their uncertainty.

References:

1. A.H. van der Weijde and B.F. Hobbs, The Economics of Planning Electricity Transmission to Accommodate Renewables: Using Two-Stage Optimisation to Evaluate Flexibility and the Cost of Disregarding Uncertainty, Energy Economics, 34(5), Sept. 2012, 2089-2101
2. F.D. Munoz, B.F. Hobbs, J. Ho, and S. Kasina, An Engineering-Economic Approach to Transmission Planning Under Market and Regulatory Uncertainties: WECC Case Study, IEEE Transactions on Power Systems, 29(1), January 2014, 307-317.
3. A. Liu, B.F. Hobbs, J. Ho, J. McCalley, V. Krishnan, M. Shahidehpour, and Q. Zheng, "Co-optimization of Transmission and Other Supply Resources," Prepared for the Eastern Interconnection States' Planning Council, National Association of Regulatory Utility Commissioners, Washington, DC, 20 Dec. 2013.
4. Charles Rivers Associates, 2010, Working Draft of MRN-NEEM Modeling Assumptions and Data Sources for EIPC Capacity Expansion Modeling, EIPC, December. Available online at http://www.eipconline.com/uploads/MRN-NEEM_Assumptions_Document_Draft_12-22-10.pdf
5. EIPC 2011, Phase 1 Report: Formation of Stakeholder Process, Regional Plan Integration and Macroeconomic Analysis, EIPC, December. Available online at http://www.eipconline.com/uploads/Phase_1_Report_Final_12-23-2011.pdf
6. EIPC 2012, Phase 2 Report: DOE Draft – Part 1 Interregional Transmission Development and Analysis for Three Stakeholder Selected Scenarios, EIPC, December. Available online at http://www.eipconline.com/uploads/20130103_Phase2Report_Part1_Final.pdf
7. EIPC 2012, Phase 2 Report: DOE Draft – Part 2-7 Interregional Transmission Development and Analysis for Three Stakeholder Selected Scenarios, EIPC, December. Available online at http://www.eipconline.com/uploads/20130103_Phase2Report_Part2_Final.pdf
8. EIPC 2012, Phase 2 Report: DOE Draft – Appendices Interregional Transmission Development and Analysis for Three Stakeholder Selected Scenarios, EIPC, December. Available online athttp://www.eipconline.com/uploads/20130103_Phase2Report_Part3_Final.pdf
9. Available online at http://www.eipconline.com/uploads/F8S7_Stakeholder_Report.xlsx
10. O. Ozdemir, F. Munoz, J. Ho, and B.F. Hobbs, Economic Analysis of Transmission Expansion Planning with Price-Responsive Demand and Quadratic Losses by Successive LP, Working Paper, The Johns Hopkins University, November, 2014.

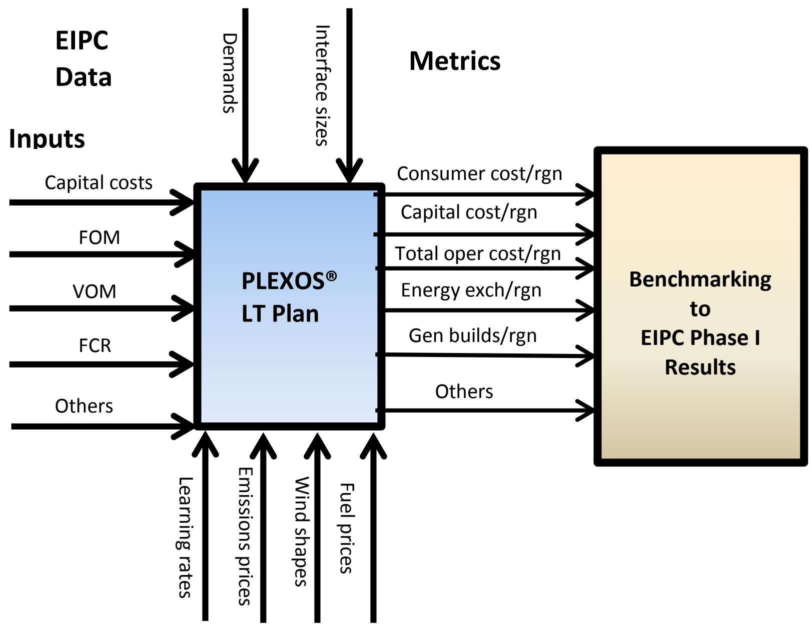
VIII. EIPC Dataset for Co-Optimization for Task 1A and Task 2

This section aims to describe the population of the EIPC dataset in the PLEXOS® LT Plan and create models and simulations of capacity planning for sub-regions in the Eastern Interconnect. The EIPC data was chosen as it was well-vetted and derived through a multi-sector consensus stakeholder process. PLEXOS® simulations will then be benchmarked against the EIPC's capacity expansion study results. PLEXOS® LT plan provides a long-term, capacity planning framework in which generation and transmission capacity expansion problems, as well as dispatch problems, can be solved, minimizing capital and operational expenditures. The scope of this document will be creating a framework for the use of PLEXOS® LT plan in providing solutions for capacity problems within the Eastern Interconnect where PLEXOS® can co-optimize natural gas and electric and PLEXOS® can co-optimize generation and transmission as well as co-optimize energy and ancillary services on a sub-hourly basis and is used in 38 countries.

Capacity expansion refers to an optimization problem that seeks to find an optimal combination of new builds, retirements and transmission expansions in order to minimize capital expenses and operational costs over a defined horizon. In this case, the problem has been defined based on a set of input assumptions such as the EIPC Phase I assumptions as derived by stakeholders, regulators, planning authorities, consultants, and data providers. The following section outlines the detailed nature of the EIPC Phase I assumptions as implemented in PLEXOS, highlighting the data required to provide accuracy and detail, the methods required to keep simulations feasible, and the models and formulations required to synthesize demand, capacity, transmission, cost and constraint data into informative and edifying solutions to generation and transmission expansion problems. A detailed set of tables of EIPC Phase I parameters that have been input to the PLEXOS® model is provided in the Appendix A to this document (PLEXOS® LT Plan with EIPC data is in the benchmarking process).

The following diagram provides a simple visual framework showing how the PLEXOS LT Plan simulations with EIPC Input data were benchmarked to EIPC output results.

Figure 12: PLEXOS to EIPC Modeling and Benchmarking Diagram



The CO2+ Combined Energy Case was modelled for the co-optimization study of transmission and other resources. The initial Combined Energy Case includes the Hardened Transmission Limits as originally established by the EIPC Phase 1 study results. In the co-optimized case, we allow PLEXOS® to co-optimize across all interfaces in addition to the generation expansion.

The EIPC Phase I results were published in detailed output spreadsheets for each base case and for each sensitivity. These results were used to benchmark PLEXOS for the EIPC CO2+ Combined Energy Plus (Future 8 Scenario 7).

1. EIPC Phase I Future 8

The EIPC Future 8, or CO2+ Combined Energy case, was a high carbon price scenario which also encompassed different aspects of the previous Futures. The primary aspects of the Future 8 case was the inclusion of a high carbon tax price, inclusion of a Federal RPS and super regional intermittency regions for wind and solar units.

The carbon price was included through a high price of carbon starting at \$26.82/ton in 2015 and increasing to \$139.74/ton by 2030. In addition to the carbon constraint, a Federal RPS was imposed on this case, increasing to 25% by 2030. This was assumed to be in addition to the existing various State RPS. The Future 8 also included an aggregated solar plus wind intermittency energy constraint of 35% into 4 "super regions":

Northeast; PJM; South and Ontario. Lastly there was an adjustment made to this case where a significant amount of gas combined cycle and wind units were forced in specific regions to achieve a better allocation of investments between regions.

The following are a summary of the primary assumptions for the CO2+ Combined Energy Plus Case (F8S7):

1. Carbon Constraint: Carbon Constraint is modeled as a Carbon Price.
2. Federal Renewable Portfolio Standards (RPS):
    - RPS starts at 0% in 2010 and increases 1.25 percentage points per year to 25% by 2030.
    - Qualifying resources include existing and new hydro, wind, biomass, solar and landfill gas.
    - RPS must be met by acquiring Renewable Energy Credits (RECs). No Alternative Compliance Payment (ACP) will be used for RPS compliance.
3. Existing state RPS policies are assumed to be the same as in the Business As Usual Case.
4. RPS and Canadian resources –Canadian load will be covered by national RPS and all Canadian qualifying resources can be utilized to meet RPS obligations, with the exception of Ontario, which will not be covered by the RPS and will be prohibited from trading RECs.
5. Four intermittency regions will be modeled:
    - Northeast (NYISO, NEISO),
    - PJM+ (PJM, MISO, MAPP, Non-RTO Midwest),
    - South (SPP, NE, ENT, SOCO, VACAR, TVA, FRCC), and
    - Ontario.
    - 35% variable resource penetration limits will be used.
6. Reserve margin contribution differ from the BAU case for some regions (see Table 89 in Appendix A).
7. MISO and other Region Resources Adjustments for Anomalies.
8. Expansion Candidates Constraints: Up to 2015, only gas units are allowed to expand. After 2015, all units are eligible for expansion except for nuclear, which is allowed to expand after 2020.

2. Study Horizon

The EIPC's Eastern Interconnect study focuses on a timeline beyond the 10-year planning horizons of the regional planning processes. A 30- to 40-year horizon was considered for the EIPC in this case as increasing environmental constraints on power generation become more relevant and salient in the coming years. A planning horizon on this scale allowed the EIPC to capture longer term system developments. Certain outputs, by region, including new capacity builds, retirements, generation level by type, fuel and operational costs, capital costs and energy flows were calculated and provided as outputs every five years. The EIPC study years were 2015, 2020, 2025, 2030, 2035, 2040, 2045, and 2050.

For this study, the Project team decided to focus on a shorter horizon from 2010 to 2030. In addition, PLEXOS® has the capability of including a perpetuity calculation at the end of the horizon which was included in this analysis. Lastly, PLEXOS® can be run continuously rather than every 5th year like the EIPC Phase I study.

3. Optimization

The EIPC study optimizes capacity planning decisions by first fixing transmission interfaces between regions. Then the transmission interfaces were increased according to a soft constraint methodology, which was developed to make informed decisions on transmission expansions but they were not calculated based on co-optimization of generation and transmission expansion. The distinction is that EIPC was unable to co-optimize generation and transmission expansion. For the Combined Energy CO2+ Case, the Project team was able to incorporate the Hardened Transmission Limits (after expansion) from the EIPC study results and estimated costs. This case was run in PLEXOS® as the base case CO2+ Case. Then the transmission interfaces were allowed to expand from the BAU limits (interfaces expansions occur incrementally by MW as opposed to specific block expansions by each transmission line) in the co-optimized case.

4. Demand

For the EIPC study, demand data enters into capacity planning formulations in dispatch and capacity planning decisions. All require various EIPC-formulated demand data to be input. The data used by EIPC was represented in 20 load blocks, with different hours per load block, load blocks by region and season (which were derived from load duration curves of historical ISO demand data), average and expected demand growth. As demand, loss and reserves requirements, taken together, must equal generation, demand data are used as an input to capacity decisions by defining energy and peak load per region.

4.1 Demand data

Relatively high or low demands in particular regions will drive dispatch and expansion optimizations. Data on existing demand as per the EIPC study is provided in Table 81 and Table 82 of the Appendix A.

4.2 Load Duration Curve

Typically a long term capacity plan study will employ a load duration curve approach to measure the relationship between demand and generating capacity requirements for each region. The EIPC study used load blocks to represent seasonal load across each region. As such, the load is represented by 20 load blocks: 10 of them represent the load duration curve for summer, 5 for shoulder seasons and 5 for winter. The load blocks were selected based on EI sorting.

A normalized load duration curve shows the ratio of power demanded in a particular load block/region, relative to the maximum load block in megawatts. Aggregate data of this nature allows modeling of realistically-sized power systems over long planning horizons, which could otherwise lead to extremely large chronologies and problem formulations were a model based on hourly unit commitments. The demand data required to derive load duration curves is available from the EIPC, and is provided in Table 81 and Table 82 of the Appendix A to this document.

4.3 Demand growth

The EIPC used historical and forecast data to determine the expected rate of demand growth in percentages. The estimate demand growth rates are reported over 10-30 year horizons, broken down by NEEM regions. As such, they reflect different levels of energy intensity and economic growth in different regions of the Eastern Interconnect. Demand growth data, based on the extrapolations provided by the EIPC study will allow PLEXOS® to extrapolate demand in future periods.

4.4 Losses for Transmission

A certain percentage of generated capacity within a region can be attributed to losses for transmission in that region. The effect of this transmission loss must be taken into account to ensure enough capacity expansion to meet demand plus losses. The EIPC data set takes these losses into account by adding them to the load data where necessary. As PLEXOS® will be populated with the EIPC dataset, all simulations will take into account transmission losses via this method.

4.5 Demand Response and Energy Efficiency

The EIPC study takes into account the effects of both demand response and energy efficiency in meeting power needs. Economically achievable efficiency allows new technologies to reduce overall energy demand. Energy efficiency is taken into account in the EIPC model by adjusting full load forecasts by a certain percentage per year. Increased levels of demand response directly offset the need for generation resources to meet installed capacity requirements.

In the NEEM runs, the EIPC models demand response in each region as a high variable cost generator ($750/MWh) - a resource that is in the range of system production costs during high or peak periods of demand, but nonetheless reduces need for generation expansion. PLEXOS® will model energy efficiency and demand response using the same techniques as EIPC.

Also note that the Demand Response modelling differs between Task 1 and Task 2. The flat $750/MWh price was used in Task 1 while in Task 2 a more detailed approach using supply bid curves was used, the same approach followed in the Phase II of the EIPC study.

5. Generation Short Term Production

The Generation in the study is composed of three basic categories per each region: Existing units; Forced Build Units; and Expansion Candidates. The Existing Units are aggregated units for each region for all fuel types other than coal. Most coal units are modelled as individual units with the capability to add retrofits (clean air mandates) to the unit. The Forced Build units are those units identified during the study (originally in 2010) as new capacity expansions, either ISO transmission interconnections queues or publically announced expansions, which were likely to come on line in the first several years of the study (ranging between 2010 and 2015). Lastly, the expansion units are hypothetical units of 14 different technology and fuel types.

5.1 Machine types

The presence of various machine or unit types in the EIPC dataset highlights the diversity of generation methods available for modeling. These generator types include: nuclear, coal (advanced coal, IGCC and IGCC with CCS), natural gas (Combined Cycle, which includes H Frame and F Frame technologies; and combustion turbines), wind (on-and off-shore), photovoltaic, solar thermal, landfill gas, biomass and geothermal. Combined cycle generating units differ widely in a number of ways. Certain machine types are constrained by assumed resource potential by geography (especially prevalent in intermittent and renewable unit types). Some types may be preferred under certain regulatory assumptions, others may be dissuaded. Some types may generate capacity more quickly or efficiently than others. This diversity of unit type requires data on units to be clearly provided and must by benchmarked by PLEXOS® in its simulation. The chart of existing units provided in Table 86 of the Appendix A notes the unit type per generator.

5.2 Variable costs

The first step in determining candidates for entry or exit is the relative economic competitiveness of generation cost data for entry and over capacity and age for exits. Short term generation costs include: Variable costs (fuel costs as a function of heat rates, VO&M charges and emissions costs). Long term production costs include Fixed Operations and Maintenance costs (FO&M).

Variable costs- or operational costs- pertinent to capacity planning decisions can be calculated using a simple formulation: *heat rate × fuel price + VO&M charge + (emission rate × emission cost).* Heat rates, fuel price data and variable operation and maintenance charges (a function of capacity decisions) are also available from the EIPC's study. Data on fixed and variable costs are provided both in the body of this document and in Table 80 and Table 83 of the Appendix A.

5.3 Forced outage rates

Forced outages can take place in certain generators which must also be taken into account. Any outage which cannot be successfully delayed within 48 hours is considered a forced outage. The EIPC includes a weighted average forced outage rate for each existing generator. PLEXOS® will model forced outages using this weighted average forced outage rate data.

5.4 Wind and Solar Profiles

Wind and solar profiles were created by region based on the EIPC data. These wind and solar profiles match the load block data with 20 wind blocks per year divided into peak or summer, winter and fall and correspond to the contribution of wind for the same load block per region. See Table 87 in the Appendix A for the wind profiles.

5.5 Hydro and Pump Storage Energy Limits

Existing Hydro units typically include an energy constraint to reflect the limited energy provided from these units relative to the name plate capacity. This can be done either though a ratings factor, or percentage of energy provided from the unit for all hours or through a max energy per month constraint. The former will limit hydro units availability during peak hours, possibly underestimating the energy available for these units. The later will optimize the energy over the constraint period, possibly over estimating the energy available from these units. The model has both the ratings factor and max energy month included for this analysis and is currently using the max energy month in the analysis.

5.6 Fixed operation and maintenance costs

Fixed and variable operation and maintenance costs are built up from base assumptions on unit type. They are subsequently adjusted for the specific generator's operating cycle and staffing procedures. FO&M costs are reported as a $2010 dollar cost per kilowatt-year. This parameter is relevant both to expansion and retirement decisions. EIPC historical data pertinent to FO&M costs are summarized in Table 83 of the Appendix A to this document. PLEXOS® uses this data to populate its dataset.

5.7 HQ Imports

There are Hydro and units assumed to represent imports from

- HQ to NEISO:
- HQ to NYISO; and
- HQ to IESO.
- New Brunswick (Maritimes) exports: NEISO.

See Table 101 in Appendix A for HQ and NB Export the generation profiles.

6. Generation Expansion

The Generation Expansion candidates have similar short term production profiles as described above. In addition, they have several expansion properties which include build costs; cost of capital or financing; economic life; the number and timing of units built; and total resource limits by region.

6.1 Forced New Builds

Certain generators are already the subject of long-term planning and investment decisions for the EIPC study horizon. These generators must be defined; otherwise modeling could result in an artificially high (or low) number of generating units being reported. The EIPC defined forced new builds individually by region, machine type, capacity, units built and the year the generator is set to go online. PLEXOS® will use this forced build data to populate its models and simulations. This data is provided in Table 91 of the Appendix A to this document.

6.2 Build costs

The overnight cost, in dollars, of building a new generator. These data depend specifically on the unique specifications and requirement of the generator in question, but such data can be reliably estimated based on historical data on costs of comparable builds. Such data are available in the EIPC's modeling assumptions document and in Table 79 and Table 80 of the Appendix A to this document. The build costs were also adjusted by the learning rates and regional multipliers (see below).

6.3 Learning Rates

The EIPC study includes data on learning rates- that is- reductions in capital costs of capacity generation as technologies improve. These are implemented by the EIPC study as a percentage reduction in capital costs by a certain point in the future. These learning rates reflected in PLEXOS® through the use of the EIPC's estimations.

6.4 Regional multipliers

Note that the generator capital cost data mentioned above need to be adjusted by regional multipliers which adjust costs both according to region and according to method of energy generation. PLEXOS® will apply a fixed cost scalar, disaggregated by region, to generator capital cost data. See Table 96 in the Appendix A for all pertinent regional multiplier data.

6.5 Financing costs

The cost of the company to finance its assets, expressed as a percentage. These financing costs were based on fixed charge rates (FCR) - the percentage charge required over the project life, per year, in order to cover annual revenue requirements. The FCR's were the basis for the Weighted Average Cost to Capital (WACC) used for this study.

6.6 Economic life

The length of time for which the investment is assumed to be viable- the EIPC study in particular considers the economic lives of its generators a function of plant type. PLEXOS® reconstructs these life horizons in its simulations. If a certain generator is expected to continue operation beyond the final year of the model, PLEXOS® can annualize built costs and apply a perpetuity calculation to the last year.

Table 6: Operating Life and FCR

Source: MRN-NEEM Assumptions, EIPC, Jan 25 2011

Technology	Operating Life (yrs)	FCR
NG Combined-Cycle	25	11.30%
NG Combustion Turbine	20	11.80%
Advanced Pulverized Coal, Coal IGCC, Coal IGCC-CCS	40	10.50%
Nuclear	40	11.20%
Photovoltaics	20	11.80%
Biomass	30	11.60%
Landfill Gas	20	11.80%
Wind	20	11.80%
Wind Offshore	20	11.80%
Solar Thermal	20	11.80%
Geothermal	20	11.80%

6.7 Resources potentials

As far as resources such as wind are concerned, there exist practical- as opposed to theoretical- limits on generation. The EIPC calculated data on resource potentials per region- the upper limit of generation capacity that region will allow. The PLEXOS® model uses the same resource potential data to prevent simulating beyond practical capacity. Data on resource potentials are available in Table 88 of the Appendix A to this document.

6.8 Generation Build Timing Limits

The EIPC assumed that only gas generation would be available for build in the initial period of the study other than the forced unit builds. The other expansion candidates are only available after 2015.

6.9 Intermittent resource capacity credit

The capacity of intermittent resources, primarily wind and solar (both photovoltaic and thermal) units, are not considered fully to contribute towards the planning reserve constraint, usually to match or approximate the annual capacity factor they would contribute. In the EIPC study, capacity credits were assumed per region, which allowed a specific fraction of the intermittent resource capacity to contribute towards the planning reserve constraint. PLEXOS® recreates these intermittent resource capacity credits as a limit on generation from intermittent resources- the required data can be found in Table 131 of the Appendix A to this document.

6.10 Retirements

The EIPC model considers capacity expansions as well as retirements. Retirement decisions may take place when a particular generator is no longer necessary to meet reserve requirements. Some generators may reach the end of their economic lives throughout the horizon of study. Similarly, certain machine types may fall prey to shifts in market or regulatory preferences: the EIPC study notes certain futures in which capacity generation from coal becomes minimal. Fixed and operating costs, constraints and regulations are vital in making retirement decisions. Cost data is provided throughout this document: both in the main body and in the Appendix A; specific data on forced generator retirements is provided in Table 92 of the Appendix A.

6.11 HQ Pseudo-generation

The EIPC also included expansion generator from HQ to NYISO; NEISO; and IESO. These expansion candidates were assumed to be Hydro expansion with exports from HQ. The assumptions for these units can be found in Table 122 in the Appendix A.

7. Storage Devices

For the second phase of this project, storage devices and demand response will be also considered within the co-optimization analyses.

In addition to the Pumped Storage Hydroelectricity (PSH) generation units already modeled inside the EIPC Phase I study, PLEXOS® allows to model additional storage devices such as Compressed Air Energy Storage (CAES) units, batteries, etc. Typical values for some storage devices using these technologies are reported below. However, these values are indicative.

Table 7: Typical parameters of bulk-level storage technologies

Type	Compressed Air (CAES)	Sodium Sulfur (NaS)	Advanced Lead Acid (PbA)	Lithium Sulfur (LiS)
Capacity (MWh)	1080	300	200	600
Max. Power (MW)	135	50	50	100
Charge Eff. (%)	75	75	85	94
Discharge Eff. (%)	75	75	85	94
VO&M Charge ($/MWh)	3	2.23	0.92	0.5
Build cost ($/kW)	1000	3300	1900	2500
FO&M Costs ($/kW)	27.23	45.47	19.04	19.04
FOR (%)	0	0	0	0
MTTR (hours)	120	120	120	120

8. Prices

There are two primary price inputs into the EI LT plan models. The first is fuel prices for all of the non-renewable generators, primarily fossil fuels. The second is the cost of emissions.

8.1 Fuel prices

The EIPC report considers fuel prices, as well as fuel availability, key drivers of future modeling. The EIPC study bases coal, oil and gas prices on economic parameters- fuel prices can be affected by demand, carbon policies and other such macro-economic realities. The PLEXOS® LT plan will formulate the effects of fuel prices comparatively to the EIPC model, provided below and in Table 84 and Table 85 of the Appendix A of this document.

Table 8: Coal Prices

Source: MRN-NEEM Assumptions, EIPC, Jan 25 2011

	2012 Minemouth Price, 2010$/MMBtu	MMBtu per Ton	2012 Minemouth Price, 2010$ per Ton
Central Appalachian Compliance	$2.29	25.0	$57.30
Illinois Basin, medium-sulfur	$1.77	23.0	$40.69
Northern Appalachian, high-Btu, high-sulfur	$2.01	25.9	$51.91
Power River Basin South	$0.69	17.6	$12.12

8.2 Emissions prices

The relative cost of emissions can play a large role in determining not only levels of capacity generation but also the relative economic value of different unit types. The EIPC model uses emissions costs as an exogenous input variable, and the PLEXOS® LT plan will also use this method to capture the effect of per-unit emissions pricing.

9. Constraints

The EIPC study includes many constraints in the EIPC Phase I capacity expansion plan: reserve margin, renewable portfolio standards, transmission limits, emissions limits, intermittency limits, resource potentials, and demand and others. Such constraints can be direct inputs in the PLEXOS® model. The simulation uses shadow prices to reflect economic effects when constraints become binding.

9.1 Intermittent Resource Limits

As an intermittent resource, wind power generation and expansion must be planned by using wind generation output shapes in order to help mitigate the issue of modeling non-continuous generation. Wind, solar, and other such resources are often subject to intermittent generation limits. The EIPC model capped the generation from these resources at a specific fraction of the annual energy consumed in a given intermittency region, thereby providing a proxy for the interregional coordination that can facilitate VER integration by leveraging geographic diversity of the resource.

An intermittent resource limit was modelled in the CO2+ Combined Energy Case as a constraint based on the following four super regions:

- Northeast (NYISO, NEISO),
- PJM+ (PJM, MISO, MAPP, Non-RTO Midwest),
- South (SPP, NE, ENT, SOCO, VACAR, TVA, FRCC), and
- Ontario.

Each region had a 35% variable resource penetration limit applied. The Intermittent Resource Limits are presented in Table 90 of the Appendix A. Data on wind capacity factors are provided in Table 87 of the Appendix A.

9.2 Reserve Margins

Capacity planning in EIPC defines minimum reserve margins- specifically the reserve capacity margin within each region, as well as the degree to which these reserve margins are enforced.

For this analysis, most regions have a single minimum requirement. However, there a few regions which form part of a larger region for minimum reserve margin requirements. For example, the NY region is modelled into three regions, with the upstate and two downstate regions. Separate constraints have been modelled to reflect these three regional constraints for NY.

These data are available from the EIPC's modeling assumptions document, and in Table 89 of the Appendix A to this document.

9.3 Federal Renewable Portfolio Standards (RPS)

The Federal Renewable Portfolio Standard is an additional National RPS that is an overlay on the State RPS. The Federal or national RPS properties are as follows:

- RPS starts at 0% in 2010 and increases 1.25 percentage points per year to 25% by 2030.
- Qualifying resources include existing and new hydro, wind, biomass, solar and landfill gas.
- RPS must be met by acquiring Renewable Energy Credits (RECs). No Alternative Compliance Payment (ACP) will be used for RPS compliance.

The Federal RPS is modelled as a single constraint with all regions participating (except IESO).

9.4 Resource potentials

Regions often face practical limits on the number of generating units that can be placed within it. These regional limits can act as a constraint on capacity planning decisions. The EIPC study provides detailed documents on resource potentials, broken down by region; these data have been recreated in the PLEXOS® models and simulations. Data on resource potentials are available in Table 88 of the Appendix A to this document.

In addition to these limits on resource potentials, the EIPC Project Team also included a constraint on the total builds of nuclear plants across the study horizon to address the concerns of large builds of nuclear builds to reflect the political and regulatory hurdles in building large fleets of nuclear power plants in North America. This constraint replicated the EIPC builds of nuclear units for the Combined Energy Case.

9.5 MISO Resource Builds

As part of the EIPC Future 8, the EIPC developed some additional resource build limits for the specific regions and generators. This was described as the "Wind and CC new build adjustments based on Recommendations by CRA (from Anomaly_Fix_9-29-11.xlsx)" where a fixed or forced build of wind expansion and combined cycle plant expansions were prescribed for MISO and additional surrounding regions. These have been modelled per each region, separately for wind and combined cycle units. This effectively forced the timing and built of the majority of wind and gas combined cycle units in these regions. See Appendix A - Table 100 for a summary of these builds.

9.6 State Renewable portfolio standards (RPS)

The EIPC study contains an expansive section on the constraints provided by renewable portfolio standards, and the methodologies required in order to model them sufficiently. Renewable portfolio standards, or RPS, require that a certain percentage of energy (that is, a certain percentage of total megawatts hours generated) be derived from renewable resources, such as wind, solar, landfill gas, geothermal and biomass power. For states where there are standards that demand a certain minimum generation of renewable resources, PLEXOS® offers RPS modeling within its LT plan. These models can be adjusted to net out hydro resources and loads that are exempt from this constraint.

RPS requirements were mapped to PLEXOS® NEEM regions via a using a three step process.

1. The population fraction of state's population belonging was allocated to NEEMS region.

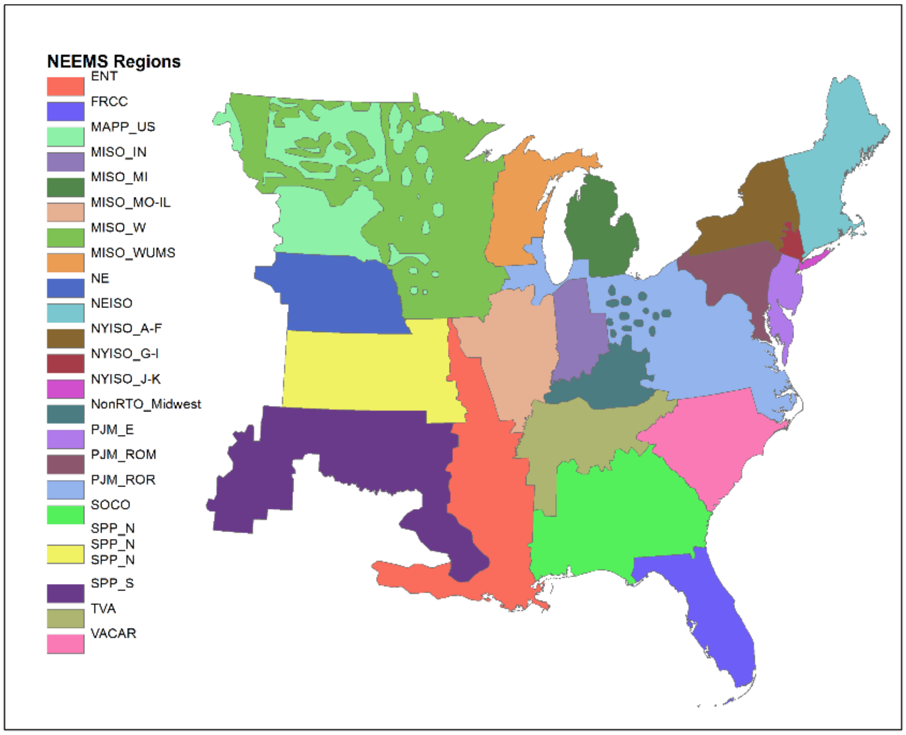
2. Annual electricity for NEEM regions was calculated for each year.

3. State RPS's were reallocated to regional equivalents.

Population Weighting

In order to reallocate the state level RPS to the regional level it was necessary to determine an appropriate mapping of states to the 24 NEEM regions modeled in PLEXOS®. While in some cases states fall completely within regions as is the case with the New England states and NEISO, most states were divided amongst two or more regions. The most direct method of reallocation would be to have for each state the fraction of its load that was served by a particular NEEM region. While this information was not directly available we chose to use population, which is highly correlated with load, for the reallocation.

Figure 13: Map of NEEMS Regions



Each of the US NEEM's regions were mapped in ArcGIS through georeferenced maps. County level population data from the 2010 US census was used. By combining these two maps it was possible to determine the fraction of a particular state's population that was served by a particular NEEM region.

Annual Electricity

In order to accurately allocate State RPS's to regions it was necessary to know the total electricity demanded by year. In most cases the renewable energy requirement is set as a fraction of the total energy demanded by a particular state.

The annual electricity was first assessed by summing the product of number of hours in a load block and the amount of load. This was performed in each NEEM region for each year. State annual electricity requirements were calculated using population weights which identified the percentage of load in a NEEM region belonging to a particular state.

State RPS Reallocation

The State RPSs were formally reallocated to regional values by combining annual load for each state, the fraction of load covered by the RPS for each state, the population weight from each state to region, and the RPS fraction in that state. Performing this for each region and year for both RE and Solar the result was an annual renewable energy budget for each region.

$$\begin{aligned} &\mathit{Regional\ Energy\ Requirement}_{regions} \\ &\quad = \sum_{States} \mathit{Annual\ State\ Load}_{states} * \mathit{Load\ Covered\ by\ RPS}_{states} \\ &\quad * \mathit{State\ Population\ Fraction\ in\ Region}_{states,regions} * \mathit{RPS\ Fraction}_{states} \end{aligned}$$

Finally the renewable energy requirement was normalized by the regional annual load to produce the normalized load values. In addition to this RPS rules were accurately handled if they differed from the above assumption. For example Michigan's state RPS grows as a fraction of load until 2015, after which it remains a fixed energy requirement. As a result after 2015 the Michigan state RPS appears to decline. Finally only states with mandatory RPS requirements were considered during the reallocation.

For the BAU Case, the Project team modelled the State RPS as noted above and outlined in the data on state RPS specifications are available in Table 97 of the Appendix A of this document. However for the Combined Energy Case, the Project team adopted the national RPS constraints as described in the EIPC for that scenario. These national RPS constraints are set as a hard constraint that allows additional technologies to be qualified as RPS resources as well the state level RPS are enforced as soft constraints with a penalty price of the alternative compliance payment.

9.7 Emissions

The EIPC study notes that increasingly concern about emissions levels now requires some states and regions to keep their emissions below a certain level- provided in detail through the EIPC dataset. Such constraints can be inputs into the PLEXOS® model and be changed as desired. PLEXOS® can model cap-and-trade as well as command-and-control forms of emissions limits. Specifically, the Regional Greenhouse Gas Initiative (or RGGI), a state-level cap-and-trade agreement to reduce greenhouse gas emissions in the Northeast, becomes a relevant constraint in the BAU model. Greenhouse gas emissions can effectively be modelled either through a constraint on the emissions or alternatively through an emissions price. In EIPC CO2+

Combined Energy, they adopted an emissions price designed to act as an emissions constraint. The Project team adopted the same approach. The Emissions prices can be found for the CO2+ Combined Energy Case in Table 125 in the Appendix A.

10. Transmission

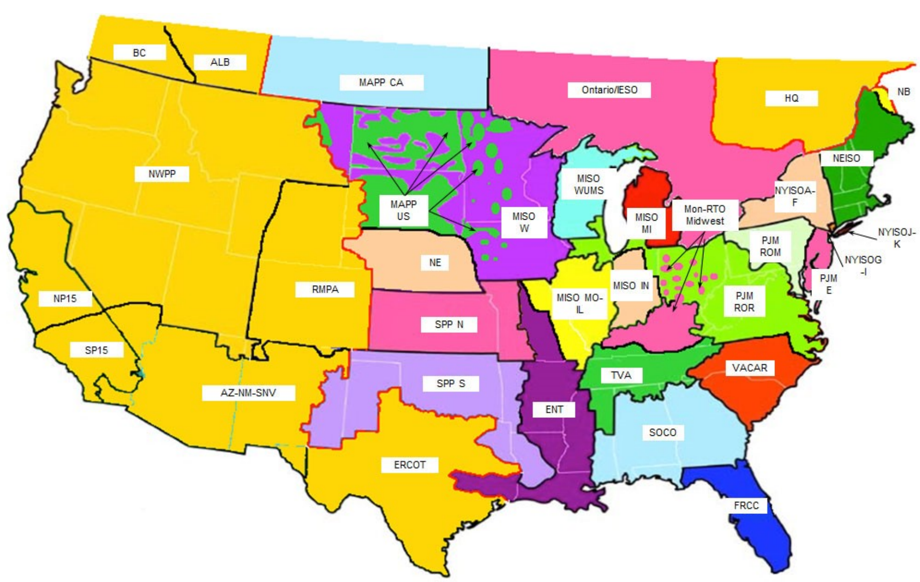
In order to capture the geographical diversity of regions and zones, the EIPC study defined interface capacity between regions.

10.1 Zonal models

Within the EIPC study, the Eastern Interconnect is divided into various zones, each of which would be responsible for generation within a certain area. Each zone's span is defined by buses- all generators belonging to the same zone also belong to the same aggregated generator bus. These aggregated generator buses are in turn linked by aggregated transmission lines, creating a zonal 'bubble' model of energy generation. PLEXOS® reconstructed the mapping methods used in the EIPC study to provide a simulation that kept the scale of formulations and simulations feasible.

Figure 14: Map of NEEM regions within the United States

Source: Phase I Report, EIPC, Nov 24 2011

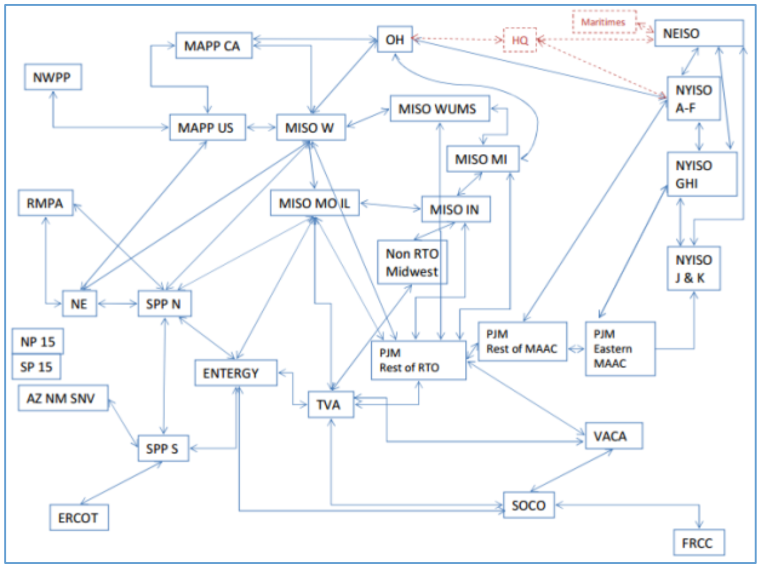


The EIPC's modeling assumptions document provides a mapping of control areas to NEEM regions which would be usable as a basis for zonal modeling. Further data on regions are provided in the Appendix A -

Table 78. Only the regions of the EI are modelled and for this analysis the connections to neighboring regions have not been modelled.

Figure 15: Pipe and Bubble Model of Eastern Interconnect

Source: Phase I Report, EIPC, Nov 24 2011



10.2 Hardened Transmission Limits

The Base Case of this study assumed the Hardened CO2+ Limits devised by the EIPC Study, with prescribed flows on the Transmission lines. These Hardened Limits and Build Costs are represented in Table 94 in the Appendix A.

10.3 Transmission Interface Expansion Cost Assumptions

Transmission interface limits add a constraint to capacity planning simulations. Transmission interface limits, expressed in megawatts, limit the amount of power that can flow safely across zones. This modeling approach allows a continuous and linear representation of the transmission network within the optimization problem. The EIPC defines transfer paths and capacities between regions. The data is provided in Table 99 of Appendix A.

In addition, the expansion cost for the transmission interfaces where derived from the EIPC documentation by following the procedure below:

- A list of representative sites can be derived for each the areas in the model, and therefore, the distance between two regions can be approximated as the distance between their two representative sites (when two areas have the same site associated, one of them is modified considering the geographical footprints).
- Investments costs for the transmission interfaces in $ / [MW x mile] are determined for different voltage levels and capacities considering both HVAC and HVDC alternatives.
- The differences in the investments costs across the regions are considered by using regional multipliers (in cases in which the regional multipliers for the two areas linked by the transmission interface were different, the ones with the highest values where selected).
- Finally, investments costs in $ / MW are calculated for each transmission interface.
- When investment costs for different transmission alternatives are available for one interface, the one with the highest cost was selected. Also, when it is not possible to derive the expansion cost at least for one transmission technology (this is because there are not regional multipliers available for one or both of their linked regions for all the technologies considered), we consider a unitary value for all the multipliers not available.

Considering that the EIPC documentation provides minimum and maximum values for the regional cost multipliers, minimum and maximum investment costs are derived for each interface.

10.4 Wheeling costs and hurdle rates

Wheeling costs are tariffs that are charged to transmit across borders, while trading frictions are due to economic inefficiencies of trading between two regions with imperfect information. The EIPC has hurdle rates defined as the sum of wheeling costs and trading friction, expressed as a certain 2010 dollar cost per megawatt hour. In some cases, no costs are applied at all. The PLEXOS® model will handle these costs similarly to the EIPC study, as costs appended to transmissions of energy between regions. These data are provided in Table 95 of the Appendix A to this document.

11. Dollar Values

It is important to contrast nominal dollars- dollar values in which the effect of inflation is not reflected. EIPC used 2010 dollar values for all quantities. As a result, all figures reported by PLEXOS® models and simulations must necessary reflect 2010 nominal dollars for the for co-optimization tests.

Also, the objective of Long Term (LT) Plan is to minimize the Net Present Value (NPV) of all future costs. An assumed Discount Rate of 5% was used for this study, which is consistent with the EIPC study, to translate costs incurred in future years to present day value reflecting the time value of money and excluding inflation.

12. Solver

As the data in the Appendix A demonstrate, the parameters in these models include both integer and continuous values. The need to maintain certain values in integer form becomes especially salient when considering new and existing builds- clearly, generators can only be added or removed in discrete integers. In order to simulate model viably, EIPC uses a mixed-integer solver. PLEXOS® reflects this solver method in modeling capacity expansion.

IX. Task 1A and Task 2: Benchmarking and Metrics

Benchmarking Methodology

The process of benchmarking PLEXOS® results against those of the EIPC study begins with an extraction of the results provided by PLEXOS. This data is then organized by region and, further, by machine type within regions. While the LT plan model in PLEXOS® can provide yearly data running out to end of the horizon for the benchmarking results below are summarized in five yearly blocks for the sake of consistency with the EIPC study.

A variety of metrics are used in the benchmarking process, including capacity expanded, capacity retirements, total generation, emission, emission prices, base costs, capital costs, operating costs, retrofit capacities, etc. All of these metrics are organized as per the EIPC study and compared individually. This method allows for an extremely detailed analysis of the PLEXOS® outputs against those of the EIPC study. Specifically, a systematic study of the differences between a wide range of parameters allows for modeling issues to be pinpointed and corrected far more quickly than if the benchmarking process were limited merely to final outputs.

Finally, accurate pinpoints of modeling differences can be easily corrected within PLEXOS® to reflect better estimates with successive modeling iterations.

Task 1A and Task 2

For Task 1A and Task 2, the study group sought to benchmark the respective models to the EIPC results prior demonstrating the capabilities of the co-optimization of Transmission and other resources. For this purpose, a benchmark target result of 5% to 10% tolerance of the EIPC results was considered to be credible for this analysis. Furthermore, the benchmarked case will serve as the base case against which the co-optimized case would be compared.

The respective models were successfully benchmarked to the EIPC CO2+ Combined Energy Case, specifically the Future 8 Scenario 7 ("F8S7") results. For benchmarking purposes, the group choose the following properties through the end of the study period in 2030:

- Generation Capacity Build (2010 to 2030);
- Generation Capacity Retired (2010 to 2030);

- Installed Capacity (2030);
- DSM Capacity (2030); and
- Installed Capacity with DSM (2030).

In this analysis, we compared the PLEXOS® and JHU model to the EIPC Reporting Type referred to as "EI".

We believe the results of the benchmarking suggest that both the PLEXOS® model and the JHU closely approximate the initial results of the EIPC work and independently verify the previous modelling analysis conducted by NEEM.

Generation Capacity Build

The Generation Capacity Build is the total capacity build, including forced build units as was originally considered by the EIPC Study. Note that Demand Response is considered separately and not included in this table.

The total Generation Capacity Build between 2010 – 2030 by PLEXOS® was 396,056 MWs and 441,434 MW for the JHU model. This compares to 421,131 MWs for the EIPC F8S7 case. The PLEXOS® model results in capacity build of 5.95% less than the EIPC F8S7 case and the JHU model results in 4.82% greater than the EIPC F8S7 Case.

Note that the timing of the capacity build is also roughly in line with the EIPC study F8S7 with the large proportion of builds in the first two 5 yearly blocks and gradually tapering off in the later years of the study. This is due in part to the large volume of retirements by the coal and oil fired units in the F8S7 case which were driven by very high CO2 emissions costs. Additional renewable capacity was built in the last two 5 year blocks of the analyses, as the National RPS begins to reach the 25% level considered for this case.

Table 9: Capacity Build Benchmark

Capacity Build			
	PLEXOS	**JHU**	**EIPC F8S7**
2015	76,162	114,955	125,093
2020	124,074	125,562	138,291
2025	89,910	116,393	94,840
2030	105,910	84,525	62,907
Total	396,056	441,435	421,131
% of NEEM	-5.95%	4.82%	

Generation Capacity Retired

The Generation Capacity Retired is the total capacity retired, including forced retired units. The total Generation Capacity retired between 2010 – 2030 by PLEXOS was 411,571 MWs and 431,975 MW for the JHU model. This compares to 433,951 MWs for the EIPC F8S7 case. The PLEXOS model results in capacity retired of 5.16 % less than the EIPC F8S7 case and the JHU model results in 0.46% less than the EIPC F8S7 Case.

Table 10: Capacity Retired Benchmark

Capacity Retired			
	PLEXOS	**JHU**	**EIPC F8S7**
2015	165,764	198,354	204,459
2020	101,811	108,126	104,715
2025	82,845	85,839	78,689
2030	61,151	39,656	46,088
Total	411,571	431,975	433,951
% of NEEM	-5.16%	-0.46%	

In this case, that the timing of the capacity retirements is also consistent with the EIPC study F8S7 with the large proportion of retirements in the first two 5 yearly blocks and gradually tapering off in the later years of the study.

Installed Capacity 2030

The Installed Capacity at 2030 is the total installed capacity at 2030, not including Demand Side Management (DSM). The total Installed Capacity in 2030 by PLEXOS was 785,683 MWs and 795,902 MW for the JHU model. This compares to 770,482 MWs for the EIPC F8S7 case. The PLEXOS model results in installed capacity of 1.97% greater than the EIPC F8S7 case and the JHU model results in 3.3% greater than the EIPC F8S7 Case.

Table 11: Installed Capacity 2030 Benchmark

Installed Capacity			
	PLEXOS	JHU	EIPC F8S7
2015	711,596	703,044	703,935
2020	733,858	720,480	737,512
2025	740,923	751,034	753,662
2030	785,683	795,902	770,482
Total	2,972,060	2,970,460	2,965,591
% of NEEM	1.97%	3.30%	

In this case, both the PLEXOS® and JHU models result in slightly higher Installed Capacity at the end of the study period as compared to the EIPC F8S7 results.

Demand Side Management

Demand Side Management (DSM) is the available capacity of DSM throughout the study period. The total available Capacity by PLEXOS® is 152,722 MWs and 152,450 MW for the JHU model. This compares to 152,450 MWs for the EIPC F8S7 case. The PLEXOS® model DSM 0.18% greater than the EIPC F8S7 case and the JHU model results in 0.00% less than the EIPC F8S7 Case.

Table 12: DSM Benchmark

Demand Response Builds			
	PLEXOS	JHU	EIPC F8S7
2015	32,027	31,756	31,756
2020	54,727	54,725	54,725
2025	60,427	60,425	60,425
2030	5,541	5,544	5,544
	152,722	152,450	152,450
% of NEEM	0.18%	0.00%	

Installed Capacity with DSM

The Installed Capacity at 2030 is the total installed capacity at 2030, including Demand Side Management (DSM). The total Installed Capacity in 2030 by PLEXOS was 938,133 MWs and 948,352 MW for the JHU model. This compares to 922,932 MWs for the EIPC F8S7 case. The PLEXOS model results in installed capacity of 1.65% greater than the EIPC F8S7 case and the JHU model results in 2.8% greater than the EIPC F8S7 Case.

Table 13: Installed Capacity with DSM Benchmark

Installed Capacity with DSM			
	PLEXOS	JHU	EIPC F8S7
2015	743,351	734,800	735,691
2020	820,340	806,961	823,992
2025	887,832	897,940	900,568
2030	938,133	948,352	922,932
% of NEEM	1.65%	2.75%	

X. Task 1 Study: Co-optimization of Transmission and Other Resources

Task 1A starts with the EIPC Phase I modelling assumptions for Future 8, otherwise known as the CO2+ combined energy policy case. This is a “pipe and bubble” model with simplified transmission properties.

The basic premise of Task 1A is that the previous EIPC study was unable to co-optimize transmission and other resources expansion in the same objective function. Thus the EIPC study could not yield precise timing of resource and transmission developments e.g., which transmission upgrades in which years are required to facilitate resource developments. The EIPC study was limited to snapshot analysis of a distant future year of 2030 where co-optimizations yield yearly results of transmission development to facilitate resource optimizations. The EIPC study overcame this limitation in the previous study through a process of “soft constraints” which were used to estimate which transmission interfaces would require expansion. This process conducted in the original EIPC Phase I and II studies is summarized by Stanton Hadley as follows:

> Phase 1 and Phase 2 show significant differences in transmission between some of the key regions, largely because of refinements in the transmission system design in Phase 2. In Phase 1, transmission (or rather "transfer capacity") was modeled in a complicated process to let the NEEM model expand the capacity in connection with the relative cost difference between regions. First, the reference case was run with no expansion of transmission. Next, a "soft" future was run where the capacity was allowed to fluctuate based on the relative marginal generating costs between regions determined in the reference case. Lastly, the SSC examined the results over the 2025-2040 period and created a set of algorithms that "hardened" that capacity into available transfer capacity that applied in all years. In Phase 2, the EIPC began with the hardened transfer capacity calculated in Phase 1 as a target and set the generation and demand for each region based on the NEEM results from two points during 2030. Transmission lines were then added in the PSS/E build-outs so that generation would supply the demand along with meeting key North American Electric Reliability Corporation (NERC) reliability requirements. [10]

Then for every future case, this was process was repeated for the base future case. Stan Hadley summarizes as follows:

> For every future the transmission system was only expanded during development of the base scenario. A three step process consisting of the following was used (1) run the MRN-NEEM with the input assumptions for the future and no change to the transmission system, (2) use the consequent regional cost differences to allow the model to build variable capacities of

[10] Page 11, Stan Hadley, ORNL, Comments on EIPC Phase I Modeling

transmission between regions, and (3) harden the sizes of the resulting transmission to be the same over the study period. This method was not applied to each sensitivity, since sensitivities by definition are modest changes to one or a few inputs without major changes to the future as a whole.[11]

This co-optimization study has developed a set of expansion properties of the transmission interfaces that allows the optimization of both transmission and other resources without having to adopt this soft, and subsequent hardened transmission, approaches described above.

The Base Case or reference case is the CO2+ Combined Energy Case with the respective hardened limits. In this case, the transmission limits are fixed and there are no transmission expansions as would have been the case for the original EIPC Future 8 analysis. Then the group optimized the Generation expansions and retirements with a prescribed set of constraints for Future 8 Scenario 7, resulting in a large number of renewable generator expansions (primarily wind generation) and retirements of a large number of fossil fuel plants (primarily coal and oil units). The results of this reference case is also benchmarked to the original F8S7 results from the EIPC study in section IX below. Both the PLEXOS® and JHU models were benchmarked to within +/- 5% percent of key metrics from the EIPC results.

In the co-optimized case, the group begins with the original BAU limits and allows the optimization to expand both the transmission and other resources, given an estimated cost of transmission expansion for the same lines. This results in a different set of generation expansions as well as transmission expansions from the original EIPC Study. Furthermore, the transmission interface expansions are allowed to expand gradually over time as required to meet the new generation builds. This differs from the original case, where the hardened limits were set for a specific year, in this case 2020, and did not alter thereafter.

The results of the PLEXOS® and JHU applications are presented in separate subsections below.

[11] Page 97, Stan Hadley, ORNL, Document

1. Task 1A: Co-optimization of Transmission and Other Resources with simplified transmission

The EISPC co-optimization project team has developed the models in Table 14 in PLEXOS® to simulate the CO2+ Combined Energy Case (F8S7). The table below summarizes the modelling for the simulations for Tasks 1A.

Table 14: Task 1A Cases

	Task	Model	Transmission Settings	Optimization Method
Task 1A	Task 1A.02 CO2+	1A.02.01 CO2+ Gen w Hard Tx	Transmission Limits Fixed Tx Interface Hardened Limits from the EIPC Phase I CO2+.	Generation Expansion Optimization with EIPC Phase I CO2+ Transmission Limits
	Task 1A.02 CO2+	1A.02.02 CO2+ Co-Opt	Transmission Limits Expandable at cost from BAU limits from EIPC Phase I	Transmission Co-optimization Case. Expand Transmission and Generation together.

As noted previously, Task 1A was modelled in both PLEXOS® and the JHU models. The results are reported for both models below, first with PLEXOS® and then with JHU results.

2. Task 1A: PLEXOS® Results

The PLEXOS® summary of the results for Task 1A has been provided in Table 15 and Table 16 below. Table 15 provides the summary for metrics spanning the entire horizon from 2010 to 2030 while Table 16 provides summary or snapshot metrics for the final year of the analysis, or 2030.

Table 15: PLEXOS® Task 1A Summary Results 2010 to 2030 (Net Present Value, $2010)

PLEXOS® Model (2010-2030)	PLEXOS[1A.02.01 CO2+ Gen w Hard Tx]	PLEXOS[1A.02.02 CO2+ Co-Opt]	Change
Objective Function (NPV)	$2,831,608,688,956	$2,765,105,038,600	(66,503,650,356)
Transmission Build Costs	$89,357,099,056	$ 51,200,054,000	(38,157,044,675)
Wheeling Charges on Interfaces	$6,091,397,806	$6,078,615,375	(12,782,430)
Gen Production Cost (NPV)	$1,173,488,182,735	$1,177,444,949,759	3,956,767,024
Generation Build Costs (NPV)	$403,416,487,340	$418,692,378,554	15,275,891,214
Carbon Revenue	$ 335,109,790,374	$ 336,976,509,111	1,866,718,737
Retired Capacity (MW)	411,571	416,308	4,737
Generation Build (MW)	396,056	416,846	20,790
Annualized Build Cost	$ 298,601,462,170	$ 296,436,101,972	(2,165,360,198)

The co-optimized case results in $66.5 billion in savings when the transmission expansion is co-optimized with generation and other resources. The result is significant in that the co-optimization was achieved with both the expansion of the transmission interfaces and generation expansion candidates. PLEXOS® solved for the least cost expansion of all these different variables by considering multiple alternative build solutions for both transmission and other resources and finding an optimal solution for both across time.

In addition to a total savings of $66.5 billion, the co-optimized case also results in 20,790 MW of additional generation capacity build and 4,737 MW of additional retirements. These are substantial increases in generation expansions from the reference case with associated build costs, and still able to maintain an overall savings with co-optimization.

Other notable differences are that the co-optimized case results in lower transmission build costs and a reduction in wheeling charges relative to the reference case over the life of the study.

Note that all of the costs in Table 15 are net present value (NPV) of the annual costs discounted back in 2010 at 5%, the assumed discount rate for this study, to a single cost estimate. Yearly savings would accrue such that the summation of those savings would be materially higher than the present value metric.

While there are ultimately significant savings from the co-optimized case results relative to the original hardened limits, the team has found that additional savings from co-optimization could have been achieved. This was due to the prescribed constraints which made up the Future 8 case described more fully below in the sensitivity section. Specifically, Future 8 consists of a number of regional and super-regional constraints which encourages a specific type of generation expansion, primarily wind and other renewables, as well as the prescribed policies encouraging retirements of the current fossil fuel fleet, primarily coal units and to a lesser extent oil fired units. Also while significant transmission expansion took place benefits of transmission expansion can also come from reserves sharing and capacity market sharing.

These constraints include a fixed intermittent limit on a super-regional basis, a national Renewable Portfolio Standard (RPS), and a high carbon price which by the end of the study reaches $139.74/ton by 2030. Lastly, there are additional constraints which include a minimum fixed generation build of combined cycle and wind units in specific regions, referred to as the MISO and other Region Resources Adjustments for Anomalies. All of these constraints limit the potential savings from the co-optimized results, as alternative transmission and generation builds are not economic in this case.

We later explore sensitivities for the Task 1A case, including relaxing or removing some of these constraints to reveal additional possible benefits from the co-optimization of transmission and other resources.

Table 16: PLEXOS® Task 1A Metrics 2030

PLEXOS® Model (2030)	PLEXOS[1A.02.01 CO2+ Gen w Hard Tx]	PLEXOS[1A.02.02 CO2+ Co-Opt]	Change
Wheeled Energy (GWh)	453,256,793	464,724,485	11,467,692
Generation Energy (GWh)	3,029,883,488	3,029,883,488	-
Installed Capacity (MW)	938,133	954,186	16,053
Cost to Load	$326,605,715,322	$320,042,989,583	(6,562,725,739)
Gen Production Cost	$96,728,049,549	$89,965,084,694	(6,762,964,854)
Carbon Emissions (tons)	330,561,155	303,192,343	(27,368,812)
Transmission Network Utilization Factor	65%	67%	1.9%

Table 16 above summarizes the results in the last year of the horizon, or 2030, to provide a different perspective of the two analyses.

The reference case and the co-optimized case results in increases in both generation expansion and transmission expansion in the last year of the study, from 2028 to 2030. For example, the reference case includes an additional build of 80,700 MW of generation in this period while in the co-optimized case, the build increases by 21,000 MW to 101,700 MW. To accommodate these generation builds, the interfaces also increases significantly in the last three years of the co-optimized case with an increase capacity 48,200 MW compared to 27,120 MW in the previous years of the co-optimized results.

Figure 16: Co-opt Cumulative Transmission vs Generation Build 2010 to 2030

With the increase in the last three years of the study of the transmission network and renewable energy generation, we see the following results:

- Wheeled Energy has increased in the co-optimized case as the transmission network has expanded to accommodate additional resources.
- Installed Capacity has increased by a total of 16 GW through a combination of additional builds and retirements.
- Cost of Load: Cost of load, as defined in this case, is the price of energy in $/MWh times the total load. By 2030, the cost of load has decreased by $6.5 billion in the co-optimized case. This is attributed to a large increase in generation expansion in the co-optimized case. These units are primarily renewable generation or wind units. This large increase in generation to serve load has been able to decrease the total system price and therefore the cost of load, particularly peak periods. If this is compounded over the horizon the cost to load savings amounts to significant savings.
- Generation Production Cost: There is also a comparable drop in the Generation Production cost of $6.7 billion, which can also be attributed, at least in part, to the increase in generation builds with low short run marginal costs, including wind units, in the later part of study.

In addition to the whole horizon summary noted above, below summarizes the results by region:

- Table 17 is the Installed Capacity in MW by region for 2030;
- Table 18 is the Generation in GWh by region in 2030 between the two cases;
- Table 19 is the Generation Build in MW by region for 2010 to 2030; and
- Table 20: Region Result- Capacity Retired by Region
  2010 to 2030 (MW)

As much of the wind capacity exists in the western portions of the Eastern Interconnect, it is not surprising that the bulk of the generation expansions originate from these western regions of the MISO and SPP footprints and deliver expanded transmission to the load centers to the east. The PLEXOS® transmission expansions results in gradual interface expansions over the horizon of the study as intermittent resources are added to system where the hardened transmission limits are assumed to be built in one large transmission build in 2020.

Table 18: PLEXOS® Task 1A Regional Results—Generation in 2030 (GWh)

Year 2030	Task 1A Generation by Region	
Region	1A.02.01 CO2+ Gen w Hard Tx	1A.02.02 CO2+ Co-Opt
ENT	86,062	80,233
FRCC	248,284	248,162
IESO	163,076	162,997
MAPP_CA	44,135	43,380
MAPP_US	44,610	52,284
MISO_IN	65,628	83,672
MISO_MI	93,149	80,447
MISO_MO-IL	94,436	93,161
MISO_W	286,448	230,403
MISO_WUMS	55,257	43,560
NE	62,141	57,958
NEISO	78,804	77,914
NonRTO_Midwest	57,115	52,283
NYISO_A-F	84,490	84,107
NYISO_G-I	22,462	20,561
NYISO_J-K	12,918	21,516
PJM_E	131,798	111,330
PJM_ROM	85,360	85,747
PJM_ROR	315,417	340,112
SOCO	252,947	256,554
SPP_N	144,334	182,576
SPP_S	167,459	196,903
TVA	150,833	145,209
VACAR	247,185	243,280

Table 17: PLEXOS® Task 1A Regional Results—Installed Capacity 2030 (MW)

Year 2030	Task 1A Installed Capacity by Region	
Region	1A.02.01 CO2+ Gen w Hard Tx	1A.02.02 CO2+ Co-Opt
ENT	33,170	33,170
FRCC	62,738	63,326
IESO	32,989	32,989
MAPP_CA	9,269	9,269
MAPP_US	14,133	16,333
MISO_IN	26,006	36,006
MISO_MI	28,829	29,877
MISO_MO-IL	34,615	37,285
MISO_W	95,024	79,878
MISO_WUMS	17,938	16,822
NE	20,344	19,144
NEISO	30,302	29,968
NonRTO_Midwest	11,891	11,901
NYISO_A-F	22,026	22,026
NYISO_G-I	4,524	4,676
NYISO_J-K	13,638	13,885
PJM_E	42,424	42,424
PJM_ROM	35,431	33,643
PJM_ROR	108,037	110,237
SOCO	63,968	63,762
SPP_N	52,179	60,421
SPP_S	70,324	79,889
TVA	37,657	36,360
VACAR	61,757	61,975

Table 19: Region Result-Generation Build by Region 2010 to 2030 (MW)

Year 2030	Task 1A Capacity Retired by Region	
Region	1A.02.01 CO2+ Gen w Hard Tx	1A.02.02 CO2+ Co-Opt
ENT	23,645	23,645
FRCC	25,823	24,735
IESO	19,322	19,322
MAPP_CA	2,435	2,435
MAPP_US	5,746	5,746
MISO_IN	13,752	13,752
MISO_MI	18,172	17,124
MISO_MO-IL	18,238	15,558
MISO_W	16,742	19,688
MISO_WUMS	8,647	9,763
NE	4,148	4,148
NEISO	20,360	20,695
NonRTO_Midwest	12,245	11,236
NYISO_A-F	9,503	9,503
NYISO_G-I	2,952	2,800
NYISO_J-K	6,337	6,089
PJM_E	8,639	8,639
PJM_ROM	18,247	20,435
PJM_ROR	63,862	64,462
SOCO	37,046	38,252
SPP_N	10,750	14,108
SPP_S	24,075	23,710
TVA	19,621	19,918
VACAR	21,264	20,545

Table 20: Region Result- Capacity Retired by Region 2010 to 2030 (MW)

2010 to 2030	Task 1A Generation Build by Region	
Region	1A.02.01 CO2+ Gen w Hard Tx	1A.02.02 CO2+ Co-Opt
ENT	3,150	3,150
FRCC	15,198	14,698
IESO	5,146	5,146
MAPP_CA	943	943
MAPP_US	9,328	11,528
MISO_IN	16,118	26,118
MISO_MI	16,500	16,500
MISO_MO-IL	21,070	21,060
MISO_W	74,202	62,002
MISO_WUMS	7,782	7,782
NE	15,034	13,834
NEISO	10,795	10,795
NonRTO_Midwest	7,190	6,190
NYISO_A-F	9,041	9,041
NYISO_G-I	400	400
NYISO_J-K	1,205	1,205
PJM_E	13,197	13,197
PJM_ROM	8,684	9,084
PJM_ROR	30,038	32,838
SOCO	19,469	20,469
SPP_N	40,095	51,695
SPP_S	43,481	52,681
TVA	7,622	6,622
VACAR	20,367	19,867

Table 21: PLEXOS® Task 1A Capacity Retired by Generation Type 2010 to 2030 (MW)

2010 to 2030	Task 1A Capacity Retired by Gen Type	
Region	1A.02.01 CO2+ Gen w Hard Tx	1A.02.02 CO2+ Co-Opt
BM	0	0
Coal	273,909	276,696
Gas	64,333	66,283
GEO	0	0
HY	0	0
LFG	0	0
NU	2,124	2,124
PS	0	0
PV	0	0
STOG	70,397	70,397
STWD	807	807
WT	0	0
DSM	0	0

Table 22: PLEXOS® TASK 1A Installed Capacity by Generation Type 2010 to 2030 (MW)

Year 2030	Task 1A Installed Capacity By Gen Type	
Region	1A.02.01 CO2+ Gen w Hard Tx	1A.02.02 CO2+ Co-Opt
BM	1,067	1,067
Coal	13,827	11,040
Gas	266,532	264,583
GEO	44	44
HY	44,618	44,618
LFG	3,966	3,956
NU	132,147	132,147
PS	17,054	17,054
PV	9,150	9,150
STOG	992	992
STWD	2,311	2,311
WT	285,055	305,855
DSM	152,450	152,450

Table 23: Installed Capacity Build by Generation Type 2010 to 2030 (MW)

2010 to 2030	Task 1A Installed Capacity Build by Gen Type	
Region	1A.02.01 CO2+ Gen w Hard Tx	1A.02.02 CO2+ Co-Opt
BM	1,067	1,067
Coal	8,375	8,375
Gas	76,863	76,863
GEO	0	0
HY	641	641
LFG	545	535
NU	33,234	33,234
PS	0	0
PV	9,000	9,000
STOG	0	0
STWD	0	0
WT	266,331	287,131
DSM	0	0

Table 24: PLEXOS® Task 1A Generation by Generation Type (GWh)

2030	Task 1A Generation Gen Type	
Region	1A.02.01 CO2+ Gen w Hard Tx	1A.02.02 CO2+ Co-Opt
BM	7	10
Coal	695	242
Gas	791,942	729,173
GEO	355	355
HY	196,413	196,413
LFG	14,151	11,094
NU	1,114,871	1,115,700
PS	9,298	9,298
PV	9,964	9,964
STOG	9	7
STWD	40	42
WT	856,550	922,007
DSM	53	43

From the regional results in Table 17 through Table 20 above, the co-optimized case has shifted wind resources from MISO W to SPP S and SPP N as well as MISO IN. In the Interface expansion results in the next section, the interfaces have built primarily between MISO to PJM as well as between SPP and MISO. This is due in part to the differential transmission build costs assumptions in these regions which we will expand upon in that section.

In addition to the regional tables, we have also provided summary tables by generation type: Table 21 to Table 24 below summarizes the results by generation type:

- Table 21 is the Generation Retired in MW generation type for 2010 to 2030;
- Table 22 is the Installed Capacity in MW by generation type for 2030;
- Table 23 is the Generation Build in MW by generation type for 2010 to 2030; and
- Table 24 is the Generation in GWh by generation type for 2030.

From the generation type summary tables, there are very little difference between the reference case and the co-optimized case. There is a slight increase in coal and gas retirements in the co-optimized case of 4737 MW and there is an increase in wind build units of 20,800 MW. The other summary generation type tables reflect these same results.

3. Task 1A: JHU Results

The JHU results are organized around six questions concerning the effects of co-optimization upon costs, transmission amounts, generation mix, investments, and emissions. The specific assumptions made in the JHU analysis are summarized in the Appendix A, noting where data assumptions differ from the PLEXOS® analysis described above.

Question 1: What are the cost savings realized by co-optimization vs. generation only planning with hardened transmission limits?

The below table summarizes the individual cost components of the objective function of the two models (hard transmission constraints vs. co-optimization) for the JHU model.

Table 25: Objective value components (All figures in $billion) (JHU)

JHU Model objective function and its components in billion $ (Present Value in 2010)	[1A.02.01 CO2+ Gen w Hard Tx]	[1A.02.02 CO2+ Co-Opt] with max assumptions for transmission expansion costs	Delta	Savings
Objective function	$2,994.3	$2,938.5	$55.8	1.9%
Transmission Investment (2010-2030)	$64.8[12]	$40.5	$24.3	37.5%
Generation Investment (2011-2030)	$770.8	$809.4	-$38.5	-5.0%
Generation Operation (2011-2030)[13]	$1,443.0	$1,426.4	$16.6	1.2%
Transmission Operation (2011-2030)[14]	$11.4	$13.7	-$2.2	-19.5%
Final Stage Transmission and Generation Operation (2030 iterative operation for 30 years)	$704.2	$648.5	$55.7	7.9%

[12] The transmission capital cost for the hardened case is not part of the JHU objective function as the transmission network is assumed to be fixed and all investments occur in 2010. In order to have a consistent comparison between the two cases, transmission investment cost is calculated and added to the objective value metric.

[13] Generation operation costs include fuel costs, variables and fixed operations & maintenance costs, carbon tax payments, and RPS compliance payments, where the remaining energy amount required to meet the RPS is bought at the Alternative Compliance Payment (ACP) price.

[14] Transmission operation costs include costs associated with hurdle rate charges. See Table 95 of the Appendix.

Simulations run for the CO2+ case demonstrate that co-optimization can yield total cost savings of up to 2% in present-value terms vs. transmission and generation planning employing the soft-constraint methodology. These savings are primarily derived from generation operational and transmission capital cost savings over the model horizon and more than compensate for increases in transmission operational costs and generation capital costs. Transmission costs decrease as the model is able to decide on best timing of expanding each line, shifting them later in time. So, although the co-optimization model identifies more economically justified investments in Eastern Interconnection than the soft-constraint methodology, the present value of transmission cost decreases, both in absolute terms or expressed as a cost per MW of transmission capacity. As inter-regional coordination increases in the co-optimization case, transmission operation costs also increase, as more energy is wheeled between regions. Generation investment costs also increase because the co-optimization model replaces investments in CC with investments in wind technology. The wind investments are more expensive in terms of capital required for two reasons: wind is more costly on a per installed MW-year basis and more wind capacity than the replaced CC capacity is required to generate the same amount of energy. However, the operating cost (including carbon cost) savings from building more wind more than make up for the higher capital cost of wind.

In Table 26 below, the 2030 operations costs are further disaggregated to provide an insight on the sources of the savings. Carbon tax payments are responsible for 60% of the savings while Generation Production (mainly fuel) cost savings explain the rest. With the high carbon tax price assumed in CO2+ case, co-optimization model is able to leverage more wind production in order to reduce emissions and avoid carbon tax payments.

Table 26: 2030 Generation production costs and its components (in millions of $) (JHU)

JHU Model generation production cost and its components in 2030 (Nominal values in million $)	[1A.02.01 CO2+ Gen w Hard Tx]	[1A.02.02 CO2+ Co-Opt] with max assumptions for transmission expansion costs	% Savings
FOM Cost	$30,899	$31,608	-2%
VOM and fuel cost	$47,611	$42,532	11%
Carbon Taxes	$40,988	$34,543	16%
Gen Production cost	$119,499	$108,683	9%

It is interesting to note that savings come mainly from the operations in the final iterative stage as the majority of new generation investments become operational after 2020 and the benefits of these additions are spread across their operational lifetime. For some generation investments this is because of construction lead time constraints, but other investments are delayed for economic reasons until later years. Further, the price of carbon almost doubles in terms of NPV from 2020 to 2030, which magnifies the economic impact of efficiency improvements in later years.

Question 2: Does inter-regional co-ordination, in the form of energy exchanges, increase as a result of co-optimization?

Interregional co-ordination significantly increases in the co-optimization case as the energy transferred among 24 NEEM regions almost doubles, as the below table shows.

Table 27: 2030 Transmission network metrics (JHU)

EI Transmission network metrics in 2030	**[1A.02.01 CO2+ Gen w Hard Tx]**	**[1A.02.02 CO2+ Co-Opt] with max assumptions for transmission expansion costs**
EI transmission capacity connecting 24 NEEM regions (MW)[15]	151,649	231,693
Wheeled energy among 24 NEEM regions 2030 (GWh)[16]	709,784	1,266,918
Transmission network utilization factor[17]	53%	62%
Utilization factor (on lines not selected to expand)[18]	40%	44%
Utilization factor (on lines selected to expand)	71%	71%

[15] Transmission capacity of each interface is defined for the purposes of this table as the maximum of the limits allowed in each direction.

[16] The wheeled energy here is the sum of absolute values of power flows over transmission interfaces for total hours.

[17] Utilization factor is defined as the ratio of wheeled energy flowing divided by the EI transmission capacity in row 1, divided by 8760 hours. The utilization factor is not adjusted to consider differences in the transfer limits in different directions. Utilization factors adjusted for the different limits in each direction are a bit higher. In the 1A.02.01 case, utilization factors rise from 53%, 40%, 71% to 58%, 43% and 76%, respectively. Meanwhile, in the 1A.02.02 case, utilization factors increase from 62%, 44%, 71% to 67%, 51%, 75%, respectively.

[18] The set of expanded lines differs between the two cases compared.

It is also apparent from the table above that transmission capability/capacity of EI interregional interfaces almost doubles[19] under the co-optimization case, while it increases approximately by 30% in the reference case (hardened limits case) in 2030. The transmission additions made by that year under co-optimization are over three times as high as the reference case (115 GW vs 37 GW). However, when transmission additions are measured in MW-miles, they are only twice as high as the reference case (35 TW-mile vs. 17 TW-mile), indicating that shorter interfaces are expanded on average under the co-optimization case. This point will be discussed further under Question 5, below. It is interesting to note that the co-optimization case also increases use of transmission interfaces, increasing the utilization factor of the Eastern Interconnection interfaces from 53% to 62%.

For the utilization factor analysis, the transmission network was also grouped in two subsets: one that included transmission interfaces that are not expanded in the solution and a second subset that included all interfaces that are expanded. Please note that the two subsets are different in each of the two cases, as the transmission expansion decisions are different. It is interesting to note that the set of expanded lines presents approximately the same utilization factor in both cases. However, in the co-optimization case their capacity is much higher, leading to much more transmitted energy. In addition to that, it is interesting to observe that the utilization factor for the set of lines that are not selected to expand is higher in the co-optimization case demonstrating the ability of co-optimization to optimize network operation. This is at least in part because the co-optimization has a holistic view of generation and transmission investment, vs. a line by line approach that soft constraint methodology had, allowing the co-optimization to best leverage the existing network configuration.

[19] Existing network transmission capacity before any additions is 116,739 MW.

Table 28: Net energy (exports) per NEEM region in 2030 (JHU)

Net energy produced in 2030 (GWh)	[1A.02.01 CO2+ Gen w Hard Tx]	[1A.02.02 CO2+ Co-Opt] with max assumptions for transmission expansion costs
ENT	(74,178)	(86,306)
FRCC	(3,312)	(3,038)
IESO	38,338	50,773
MAPP_CA	16,082	16,117
MAPP_US	14,382	16,353
MISO_IN	7,610	(48,035)
MISO_MI	(23,948)	(27,972)
MISO_MO-IL	(3,324)	(241)
MISO_W	121,859	154,440
MISO_WUMS	(12,194)	(22,615)
NE	32,310	27,434
NEISO	14,267	10,499
Non_RTO_Midwest	(2,299)	(12,717)
NYISO_A-F	39,500	40,710
NYISO_G-I	1,849	1,898
NYISO_J-K	(54,652)	(53,045)
PJM_E	(2,292)	(1,704)
PJM_ROM	(65,273)	(65,474)
PJM_ROR	(88,221)	(115,244)
SOCO	(6,654)	(27,523)
SPP_N	78,269	136,984
SPP_S	11,183	68,510
TVA	(26,349)	(38,435)
VACAR	(12,955)	(21,370)

A review of the energy generated, net of load, in 2030 per EI NEEM region reveals that in both cases, status of a region as an importing or exporting region does not change in the co-optimization solution relative to hard transmission constraint case, with the exception of MISO_IN. Meanwhile MISO_MO_IL, NE and NEISO maintain the same importing/ exporting status but they import/ export less energy compared to the reference case. For the rest of the regions, net energy generated remains fairly similar between the two cases, or co-optimization merely intensifies the profile of the region (more exports for an exporting region or more imports for an importing region). This is indicated by the sum of the absolute values of the imports/exports, which is 39% higher in the co-optimization case.

Question 3: Does the energy mix changes in light of co-optimization?

Table 29: Energy mix (% of energy generated by technology type in 2030) (JHU)

Energy mix in 2030 (% of total energy produced)[20]	**[1A.02.01 CO2+ Gen w Hard Tx]**	**[1A.02.02 CO2+ Co-Opt] with max assumptions for transmission expansion costs**
Nuclear	34.3%	34.5%
On-Shore Wind category 4	22.6%	27.9%
CC	23.9%	20.2%
Hydro	7.3%	7.4%
On-Shore Wind category 3	5.7%	4.0%
Other Renewable	3.2%	3.3%
Hydro Canadian imports (from outside 24 NEEM regions)	2.2%	2.3%
CT	0.5%	0.4%
Coal	0.2%	0.1%

In Table 29 , the energy mix in 2030 is presented for both cases. The mix does not greatly change as the major technology types in both cases are nuclear, on-shore wind and combined cycle-gas. The contribution of combined cycle to the energy mix falls from 24% to 20% under co-optimization, being replaced by increased wind production, whose contribution increases from 28% to 32%. It is also interesting to note that co-optimization methodology uses more energy from category 4+ wind resources, while it reduces the use of wind energy from category 3 resources. This is because co-optimization expands the transmission network in a different manner, leveraging better the high quality wind resources from the MISO_W and SPP regions.

[20] Energy from Demand Response was also produced in both cases but its contribution to the energy mix was minor (approximately 0.001% in both cases, or 49 and 26 GWH respectively). In the co-optimization case, a minor amount of energy was also produced by Steam/Oil and Gas Units.

Table 30: EI Capacity by technology type in 2030 (MW) (JHU)

2030 EI Capacity (GW)	[1A.02.01 CO2+ Gen w Hard Tx]	[1A.02.02 CO2+ Co-Opt] with max assumptions for transmission expansion costs	Delta
Combined Cycle	218.2	213.5	4.7
Coal	8.4	8.4	-
Combustion Turbine	62.6	63.3	(0.7)
Demand Response	152.5	152.5	-
Hydro	57.3	57.3	(0.0)
Nuclear	134.6	134.6	-
On-Shore Wind	277.7	305.3	(27.6)
Other Renewable	19.5	19.5	(0.0)
Pumped Storage	16.6	16.6	-
Steam Oil/Gas	1.0	0.2	0.8
Total	**948.4**	**971.2**	**(22.8)**

In Table 30, the installed capacity in the EI in 2030 is presented. For most technology types, capacity does not change between the two cases. Only combined cycle capacity is reduced (by ~5 GW), which is replaced with ~28 GW of wind capacity. Note that the on-shore wind capacity only increases by 10% under co-optimization (278 GW to 305 GW), but the previous table shows that wind generation increases by 13%. This is because of the substitution of remote, high quality wind resources (category 4) for the lower capacity factor category 3 capacity.

Question 4: Does co-optimization results in different generation investments than the hardened limit case?

In the below tables, we contrast the generation investments and retirements made by type in the two solutions.

Table 31: EI 2010-2030 Cumulative investments (MW) (JHU)

Cumulative investments 2010-2030 (MW)[21]	[1A.02.01 CO2+ Gen w Hard Tx]	[1A.02.02 CO2+ Co-Opt] with max assumptions for transmission expansion costs
Biomass	1,667	1,667
Coal	8,375	8,375
Combined Cycle	105,687	99,687
Combustion	4,992	4,992
Hydro	15,742	15,745
Landfill Gas	4,676	4,676
Nuclear	34,734	34,734
On shore Wind	258,993	286,593
Photovoltaic	6,570	6,570

Table 32: EI 2010-2030 Cumulative Retirements by Technology Type (MW) (JHU)

Cumulative retirements 2010-2030 (MW)	[1A.02.01 CO2+ Gen w Hard Tx]	[1A.02.02 CO2+ Co-Opt] with max assumptions for transmission expansion costs
Coal	277,571	277,571
Steam Oil/ Gas	70,406	71,209
Combustion	62,956	62,267
Combined Cycle	20,903	19,605
Steam Turbine	139	114

The assumption of a high carbon tax price drives retirement and investment decisions in both cases. In particular, nuclear is among the most preferred technologies for expansion because of low operational costs and zero CO2+ emission rates. So, the model exhausts the nuclear potential allowed to be built (assumed to be 35 GW[22]). Similarly, Landfill Gas (LFG) resource potential is exhausted as both capital

[21] 2010 is included as some forced investments became operational in 2010.
[22] 35 GW is the sum of 29 GW of potential new nuclear units and 6 GW of forced nuclear investments.

requirements and operational costs are relatively low and CO_2 emissions from LFG units are assumed not to be penalized under the carbon tax program. HY also proves to be a preferable option for generation expansion. For combustion turbines, the model does not decide any further expansions than the forced expansions and it retires a large amount of existing capacity as indicated in Table 32 a high carbon tax price also leads to massive retirement of almost all the coal and Steam Oil and Gas (STOG) capacity (assumed to operate only with fuel oil) that was on-line in 2010. This massive de-carbonization and investment in nuclear and wind was not observed in the Business-as-Usual case of the previous phase [12], which assumed a zero carbon price.

Table 33: Cumulative wind investments by region (MW) (JHU)[23]

2010-2030 Cumulative wind onshore investment (MW)	[1A.02.01 CO2+ Gen w Hard Tx]	[1A.02.02 CO2+ Co-Opt] with max assumptions for transmission expansion costs	% change
ENT	2,200	-	-100%
FRCC	-	-	N/A
IESO	2,104	2,104	0%
MAPP_CA	302	302	0%
MAPP_US	9,017	9,017	0%
MISO_IN	27,633	10,833	-61%
MISO_MI	8,899	8,899	0%
MISO_MO-IL	17,120	18,720	9%
MISO_W	60,931	71,931	18%
MISO_WUMS	3,055	3,055	0%
NE	15,186	13,586	-11%
NEISO	4,500	5,100	13%
NonRTO_Midwest	-	-	N/A
NYISO_A-F	5,271	5,271	0%
NYISO_G-I	-	-	N/A
NYISO_J-K	-	-	N/A
PJM_E	1,150	1,150	0%
PJM_ROM	1,080	1,080	0%
PJM_ROR	14,925	14,925	0%
SOCO	-	-	N/A
SPP_N	41,326	58,126	41%
SPP_S	41,097	59,297	44%
TVA	-	-	N/A
VACAR	3,200	3,200	0%

[23] Wind investments include a large amount of investments modeled as forced (196 GW) to fix an anomaly observed in MISO investments consistent with the previous study [13].

Investments in wind generation increase in SPP_N, SPP_S and MISO_W as wind shapes at these regions are of good quality with high average capacity factors and very good capacity factors at peak demand load blocks. As a result, the co-optimization methodology expands transmission interfaces connecting these regions with regions with high demand such as PJM-ROR and ENT, as will become clear in our discussion below under Question 5.

On the other hand, wind investments in ENT, NE and MISO_IN are reduced. Wind shapes in ENT and NE underperform during summer peak hours although their overall capacity factor is very high.

Question 5: Does co-optimization choose to expand different transmission interfaces than soft-constraint methodology?

The below table highlights the transmission investment differences between the two solutions.

Table 34: 2010-2030 Cumulative transmission expansion by interface (JHU)

2010-2030 Cumulative capacity expansion by interface (MW)	[1A.02.01 CO2+ Gen w Hard Tx]	[1A.02.02 CO2+ Co-Opt] with max assumptions for transmission expansion costs
ENT to SPP_N	5,546	-
ENT to SPP_S	3,430	10,814
IESO to MAPP_CA	7	-
IESO to MISO_MI	1,285	3,940
IESO to MISO_W	55	-
IESO to NYISO_A-F	499	-
MAPP_CA to MAPP_US	-	46
MAPP_CA to MISO_W	-	211
MISO_IN to MISO_MI	490	-
MISO_IN to MISO_MO-IL	-	19,999
MISO_IN to PJM-ROR	-	13,343
MISO_MI to MISO_WUMS	195	1,778
MISO_MO_IL to MISO_W	248	16,908
MISO_MO_IL to PJM-ROR	-	8,074
MISO_MO_IL to SPP_N	1,954	19,400
MISO_MO_IL to TVA	-	7,996
MISO_W to MISO_WUMS	118	4,975
MISO_W to NE	2,014	704
MISO_W to PJM_ROR	19,066	-
MISO_W to SPP_N	250	-
NE to SPP_N	-	324
NEISO to NYISO_J-K	608	-
NYISO_A-F to NYISO_G-I	1,016	1,348
SOCO to TVA	-	3,424
SPP_N to SPP_S	-	1,670

The above table indicates that of the co-optimization transmission expansion investments, 63% of added capacity connects MISO_MO-IL with another region, converting MISO_MO-IL to a hub in which energy from exporting regions (such as MISO_W and SPP_N) comes to be redirected to importing regions such as PJM-ROR (the EI region with the highest energy demand) and TVA. Although both total energy flows and transmission expansion decisions differ strongly between the reference and co-optimization cases, the qualitative pattern of flows are the same: from the same exporting regions to the same importing regions.

The co-optimization model decides on expansions based on the cost of lines relative to their economic benefits in terms of both generation investment and operating cost savings. As a result, even if the power flows from the same source to the same destination (e.g., MISO-W to PJM-ROR), the co-optimization methodology prefers to expand indirect paths through intermediate regions for two reasons. First, the co-optimization model is able to decide on expansions based on transmission costs expansion set as an input. As a result, the model sees that it costs less to expand the indirect paths: MISO-W to MISO-MO-IL to PJM-ROR and MISO_W to MISO-MO-IL to MISO-IN to PJM-ROR. These indirect paths are chosen instead of the direct path MISO-W to PJM-ROR, which the reference case adds. The indirect paths chosen are more economic given the current regional multipliers incorporated in transmission cost expansion assumptions which favor expansion within MISO regions compared to MISO with an outside region. Second, an indirect paths expansion gives the model more flexibility during operations (e.g., MISO-IN and MISO-MO-IL can also benefit from MISO-W generation), whereas the direct path has no intermediate buses.

As indicated in Figure 17 and Figure 18, the co-optimization case's net power flows from SPP_N to MISO_MO-IL and MISO_MO-IL to TVA increase significantly. This is because the model decides to expand these interfaces significantly under co-optimization case to be able to better leverage good quality SPP_N wind resources and transfer this energy through MISO_MO-IL to regions with high load and low wind potential of lesser quality such as TVA and PJM.

Finally, due to the heuristic nature of the soft-constraint methodology, transmission investments are better determined by the co-optimization model as it optimizes concurrently every aspect of operation. In contrast, in the soft constraint methodology, decisions on hardening the interfaces (selecting the amount of the expansion and then keeping the limit fixed) are made based on simulations already run with unlimited capacity. So, all interfaces are hardened based on the initial results without updating results of the unlimited capacity methodology every time a transmission interface is hardened. Last but not least, the co-optimization methodology is able to indicate the best timing for the transmission expansions, spreading the investments across the years modeled (see Table 35).

Figure 17: Relative values of average net flow in 2030 [1A.02.01 CO2+ Gen w Hard Tx] (GW)

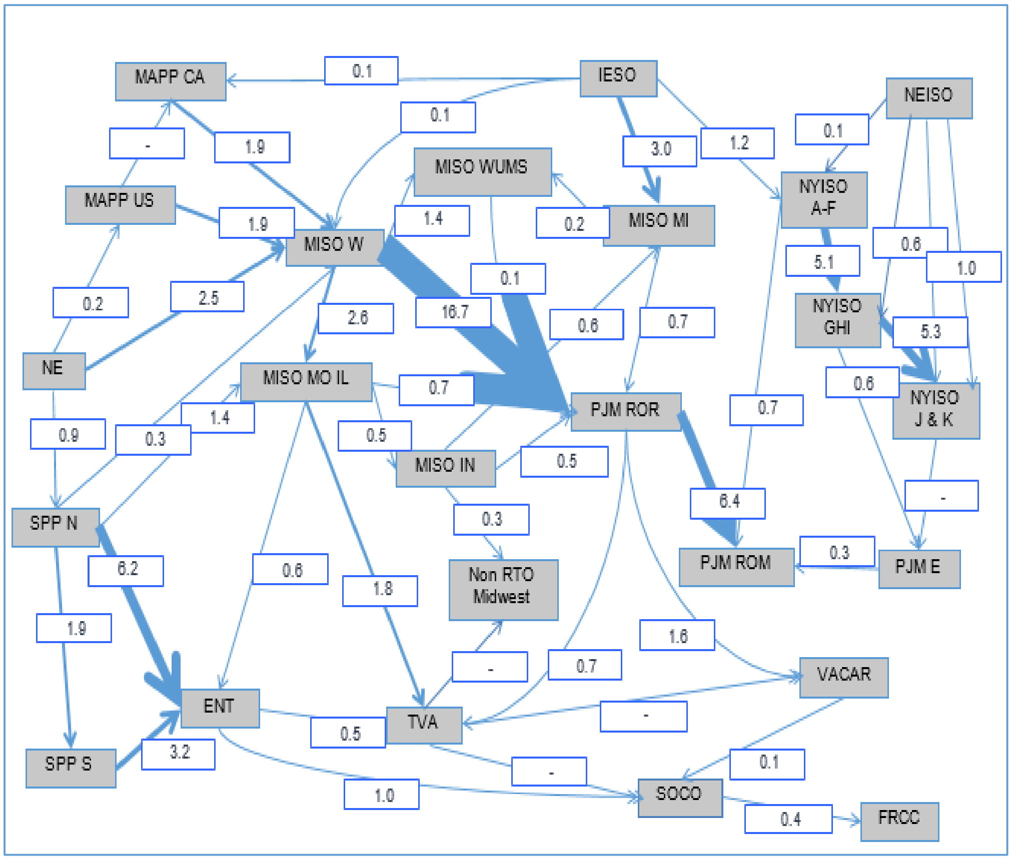


Figure 18: Relative values of average net flow in 2030 [1A.02.02 CO2+ Co-Opt] with max assumptions for transmission expansion costs

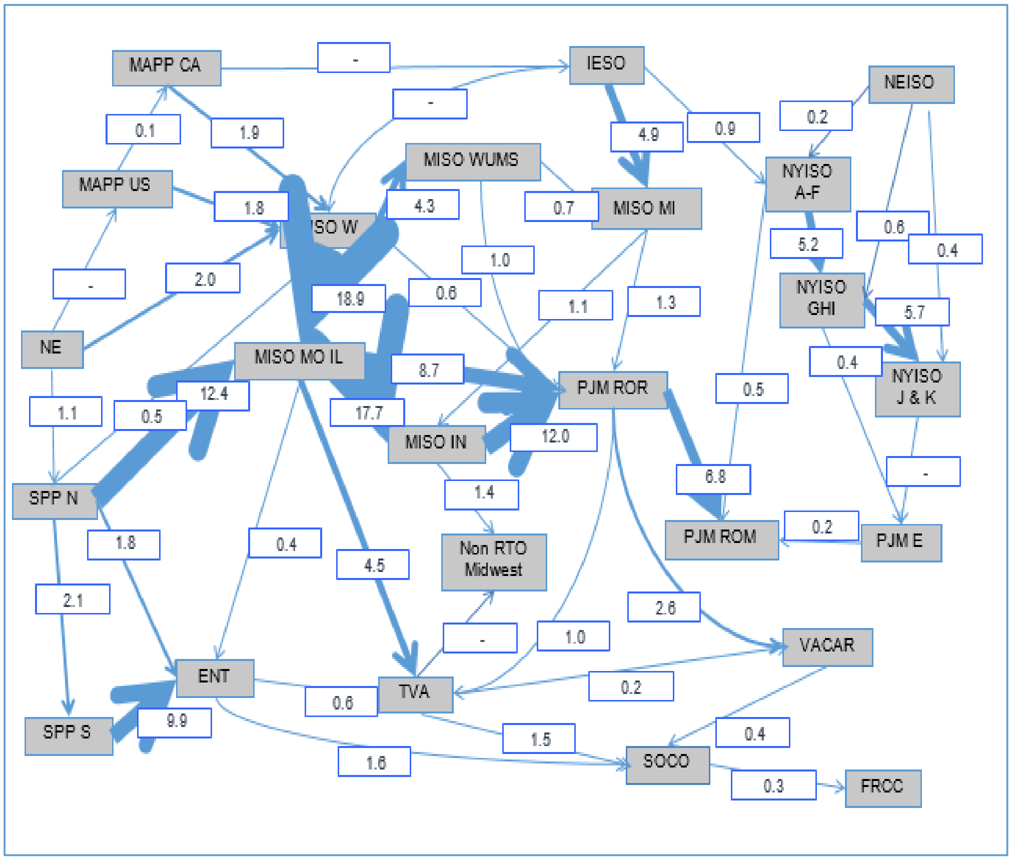


Table 35: Cumulative EI transmission expansion decisions by 5 year increments (MW) (JHU)

Cumulative EI transmission interfaces built Year 2010 to … (MW)	1A.02.01 CO2+ Gen w Hard Tx	1A.02.02 CO2+ Co-Opt
2010	36,781	-
2015		7624
2020		6,415
2025		69,647
2030		38,816

[24] No transmission investments were allowed before 2015.

Question 6: How do carbon emissions change as a result of co-optimization?

The relative impacts of the two solutions upon carbon emissions are shown in the table below (total tons over the 2010-2030 period, including the repeated years after 2030).

Table 36: 2030 Carbon emissions (JHU)

EI-wide 2030	**[1A.02.01 CO2+ Gen w Hard Tx]**	**[1A.02.02 CO2+ Co-Opt] with max assumptions for transmission expansion costs**	**Savings**
Carbon emissions (tn)	293,317,051	247,193,586	16%

As Table 36 indicates, carbon emissions are considerably reduced in the co-optimization case. This is because the co-optimization model, driven by a high carbon price, chooses to invest more in distant, high quality wind (Category 4) and less in combined cycle generation compared to the reference case. The additional wind generation displaces the carbon emitting gas-fired generation from combined cycle units.

4. Task 1A & 2: PLEXOS® Transmission Expansions Results

For the co-optimized case, in order to create a co-optimization of transmission and other resources, the project team created transmission build-cost assumptions for the entire transmission network between all regions. As part of this analysis, the group created build cost estimates with a $/MW build cost input (see the transmission modelling assumptions in section)

Table 37: Interface Builds for Task 1A and Task 2 (PLEXOS) (MW)

Year 2010 to 2030	Task 1A Interface Builds		Task 2 Interface Builds	
Interface	1A.02.01 CO2+ Gen w Hard Tx	1A.02.02 CO2+ Co-Opt	2A.02.01 CO2+ Gen w Hard Tx ST and DR	2A.02.02 CO2+ Co-Opt ST and DR
ENT to MISO_MO-IL	-	-	-	-
ENT to SOCO	-	-	-	-
ENT to SPP_N	5,546	-	5,546	-
ENT to SPP_S	3,430	7,918	3,430	7,918
ENT to TVA	-	-	-	-
FRCC to SOCO	-	-	-	-
IESO to MAPP_CA	7	-	7	-
IESO to MISO_MI	1,285	-	1,285	-
IESO to MISO_W	55	1,365	55	1,335
IESO to NYISO_A-F	499	-	499	-
MAPP_CA to MAPP_US	-	2,003	-	2,089
MAPP_CA to MISO_W	-	-	-	-
MAPP_US to MISO_W	-	-	-	-
MAPP_US to NE	-	-	-	-
MISO_IN to MISO_MI	490	-	490	-
MISO_IN to MISO_MO-IL	-	19,069	-	17,992
MISO_IN to NonRTO-Midwest	-	-	-	-
MISO_IN to PJM-ROR	-	16,642	-	15,807
MISO_MI to MISO_WUMS	195	-	195	-
MISO_MI to PJM-ROR	-	-	-	-
MISO_MO_IL to MISO_W	248	8,224	248	8,268
MISO_MO_IL to PJM-ROR	-	-	-	-
MISO_MO_IL to SPP_N	1,954	15,227	1,954	14,105
MISO_MO_IL to TVA	-	-	-	-
MISO_W to MISO_WUMS	118	2,848	118	2,848
MISO_W to NE	2,014	972	2,014	1,111
MISO_W to PJM_ROR	19,066	-	19,066	-
MISO_W to SPP_N	250	-	250	-
MISO_WUMS to PJM-ROR	-	-	-	-
NE to SPP_N	-	61	-	180
NEISO to NYISO_A-F	-	-	-	-
NEISO to NYISO_G-I	-	-	-	-

NEISO to NYISO_J-K	608	-	608	-
Non RTO_Midwest to TVA	-	-	-	-
NYISO_A-F to NYISO_G-I	1,016	-	1,016	-
NYISO_A-F to PJM-ROM	-	-	-	-
NYISO_G-I to NYISO_J-K	-	-	-	-
NYISO_G-I to PJM_E	-	-	-	-
NYISO_J-K to PJM_E	330	-	330	-
PJM_E to PJM_ROM	-	-	-	-
PJM_ROM to PJM_ROR	-	-	-	-
PJM_ROR to TVA	-	-	-	-
PJM_ROR to VACAR	-	-	-	-
SOCO to TVA	-	-	-	-
SOCO to VACAR	-	-	-	-
SPP_N to SPP_S	-	1,090	-	1,090
TVA to VACAR	-	-	-	-

The differences in the transmission expansion results of the co-optimized build case are more pronounced than the other metrics noted in the summary of results. In particular, the builds in the original EIPC study expanded primarily between **MISO_W to PJM_ROR** with an expansion of 19,066 MWs and at a build cost of $20.67 billion. Alternatively, in the co-optimized case, a more indirect path was found with transmission builds from **MISO_IN to MISO_MO-IL** and from **MISO_IN to PJM-ROR** for a combined build cost of $8.57 billion. This happened because the expansion costs were calculated as a function of the mileage and some geographical multipliers as presented by EIPC, which are usually higher for the PJM regions, when compared with the MISO regions.

In this particular case, the MISO_W to PJM_ROR direct path combines high values for both mileage and geographical multipliers, which results in relatively high costs. On the other hand, the indirect paths combines high mileages with low multipliers values in the MISO regions and low mileages with high multipliers values when linking the last MISO regions with the PJM region, making this estimated cost lower.

The other primary difference between the co-optimized transmissions builds and the hardened case is the timing of the transmission builds. Because the co-optimized case was able to use the interface expansion with incremental build, as opposed to single transmission line build decisions, the co-optimized case was able to build out the network over time to match the changes in the generation build decisions. This is most evident when looking at the total generation and total transmission builds over the 20 year horizon.

Table 38: Interface Builds Cost for Task 1A and Task 2 (PLEXOS) (Billion $)

Year 2010 to 2030	Task 1A Interface Build Costs		Task 2 Interface Build Cost	
Interface	1A.02.01 CO2+ Gen w Hard Tx	1A.02.02 CO2+ Co-Opt	2A.02.01 CO2+ Gen w Hard Tx ST and DR	2A.02.02 CO2+ Co-Opt ST and DR
ENT to MISO_MO-IL	-	-	-	-
ENT to SOCO	-	-	-	-
ENT to SPP_N	6.48	-	6.48	-
ENT to SPP_S	4.62	6.27	4.62	6.27
ENT to TVA	-	-	-	-
FRCC to SOCO	-	-	-	-
IESO to MAPP_CA	-	-	-	-
IESO to MISO_MI	0.38	-	0.38	-
IESO to MISO_W	0.32	1.22	0.32	1.19
IESO to NYISO_A-F	0.07	-	0.07	-
MAPP_CA to MAPP_US	-	0.73	-	0.76
MAPP_CA to MISO_W	-	-	-	-
MAPP_US to MISO_W	-	-	-	-
MAPP_US to NE	-	-	-	-
MISO_IN to MISO_MI	0.20	-	0.20	-
MISO_IN to MISO_MO-IL	-	4.87	-	4.60
MISO_IN to NonRTO-Midwest	-	-	-	-
MISO_IN to PJM-ROR	-	3.70	-	3.51
MISO_MI to MISO_WUMS	0.45	-	0.45	-
MISO_MI to PJM-ROR	-	-	-	-
MISO_MO_IL to MISO_W	0.12	3.76	0.12	3.78
MISO_MO_IL to PJM-ROR	-	-	-	-
MISO_MO_IL to SPP_N	0.22	7.27	0.22	6.74
MISO_MO_IL to TVA	-	-	-	-
MISO_W to MISO_WUMS	0.08	0.87	0.08	0.87
MISO_W to NE	0.53	0.34	0.53	0.39
MISO_W to PJM_ROR	20.67	-	20.67	-
MISO_W to SPP_N	-	-	-	-
MISO_WUMS to PJM-ROR	-	-	-	-
NE to SPP_N	-	0.02	-	0.06
NEISO to NYISO_A-F	-	-	-	-
NEISO to NYISO_G-I	-	-	-	-
NEISO to NYISO_J-K	1.07	-	1.07	-
Non RTO_Midwest to TVA	-	-	-	-
NYISO_A-F to NYISO_G-I	0.55	-	0.55	-
NYISO_A-F to PJM-ROM	-	-	-	-
NYISO_G-I to NYISO_J-K	-	-	-	-
NYISO_G-I to PJM_E	-	-	-	-
NYISO_J-K to PJM_E	0.10	-	0.10	-
PJM_E to PJM_ROM	-	-	-	-

PJM_ROM to PJM_ROR	-	-	-	-
PJM_ROR to TVA	-	-	-	-
PJM_ROR to VACAR	-	-	-	-
SOCO to TVA	-	-	-	-
SOCO to VACAR	-	-	-	-
SPP_N to SPP_S	-	0.20	-	0.20
TVA to VACAR	-	-	-	-

5. Task 1A: PLEXOS® Sensitivity Results

Three sensitivities were developed for analyzing changes in generation and transmission investments within the Eastern Interconnection, when modeling the planning reserve requirements using different geographical aggregations for the NEEM regions, and different values for the transmission hurdle rates between areas.

PLEXOS® [1A.02.02 CO2+ Co-Opt] model was used as the reference case. Planning reserve constraints were imposed for this case as defined in F8S7 from the EIPC Phase I project. Two initial sensitivities, PLEXOS® [1A.02.02 CO2+ Co-Opt – Cases 1a and 1b], were built considering a single constraint for determining the planning reserve requirements inside the complete Eastern Interconnection Area, but using different transmission hurdle rates. A third case, PLEXOS® [1A.02.02 CO2+ Co-Opt – Case 2], was developed by aggregating the NEEM regions into Super Regions, as defined by the Intermittent Generation Limits Constraints in F8S7.

Regarding the transmission hurdle rates, case 1a considers them as defined in the reference case. However for cases 1b and 2, they were considered for the transmission interfaces connecting the regions defined in each sensitivity, but not for the ones within them. Therefore, PLEXOS® [1A.02.02 CO2+ Co-Opt – Case 1b], can be described as a zero hurdle rates scenario. Table 39 identifies the region definition for imposing reserve constraints.

Table 39: Region Definition for Imposing Reserve Constraints

<table>
<tr><th>PLEXOS[1A.02.02 CO2+ Co-Opt]</th><th>PLEXOS[1A.02.02 CO2+ Co-Opt – Cases 1a and b]</th><th>PLEXOS[1A.02.02 CO2+ Co-Opt – Case 2]</th></tr>
<tr><td>IESO</td><td rowspan="24">EASTERN INTERCONNECTION

Planning Reserve Margin: 15.3 %

Case 1a. Base case values for hurdle rates

Case 1b. Zero hurdle rates for all the transmission interfaces</td><td>IESO

Planning Reserve Margin: 17.0 %</td></tr>
<tr><td>ENT</td><td rowspan="8">SUPER REGION 1

Planning Reserve Margin: 14.4 %</td></tr>
<tr><td>FRCC</td></tr>
<tr><td>NE</td></tr>
<tr><td>SOCO</td></tr>
<tr><td>SPP-N</td></tr>
<tr><td>SPP-S</td></tr>
<tr><td>TVA</td></tr>
<tr><td>VACAR</td></tr>
<tr><td>MAPP CA</td><td rowspan="11">SUPER REGION 2

Planning Reserve Margin: 15.9 %</td></tr>
<tr><td>MAPP US</td></tr>
<tr><td>MISO IN</td></tr>
<tr><td>MISO MI</td></tr>
<tr><td>MISO MO-IL</td></tr>
<tr><td>MISO W</td></tr>
<tr><td>MISO WUMS</td></tr>
<tr><td>NonRTO Midwest</td></tr>
<tr><td>PJM E</td></tr>
<tr><td>PJM ROM</td></tr>
<tr><td>PJM ROR</td></tr>
<tr><td>NYISO A-F</td><td rowspan="4">SUPER REGION 3

Planning Reserve Margin: 16.3 %</td></tr>
<tr><td>NYISO G-I</td></tr>
<tr><td>NYISO J-K</td></tr>
<tr><td>NEISO</td></tr>
</table>

The results for the reference case and the three sensitivities are presented in Table 40 and Table 41. The objective function of the four cases are also compared in Table 42 to derive the co-optimization savings.

Table 40: Sensitivity Results

PLEXOS® Model (2010-2030)	PLEXOS[1A.02.02 CO2+ Co-Opt]	PLEXOS[1A.02.02 CO2+ Co-Opt – Case 1a]	PLEXOS[1A.02.02 CO2+ Co-Opt – Case 1b]	PLEXOS[1A.02.02 CO2+ Co-Opt – Case 2]
Objective Function (NPV)	$2,765,105,038,600	$2,757,575,373,300	$2,719,558,080,300	$2,743,931,012,400
Transmission Build Costs	$12,470,330,643	$13,617,059,451	$17,217,509,128	$17,557,190,021
Wheeling Charges on Interfaces	$6,078,615,375	$5,864,931,055	$0	$4,288,406,219
Gen Production Cost (NPV)	$1,177,444,949,759	$1,178,963,184,199	$1,169,159,284,043	$1,171,702,788,372
Generation Build Costs (NPV)	$418,692,378,554	$421,420,250,222	$428,530,570,186	$429,291,947,805
Carbon Revenue				
Retired Capacity	416,308	424,458	421,488	418,459
Generation Build	416,846	417,836	421,546	422,846
Annualized Build Cost	$296,426,634,432	$296,141,996,927	$297,062,040,167	$299,376,930,710

Table 41: Sensitivity Results

PLEXOS® Model (2030)	PLEXOS[1A.02.02 CO2+ Co-Opt]	PLEXOS[1A.02.02 CO2+ Co-Opt – Case 1a]	PLEXOS[1A.02.02 CO2+ Co-Opt – Case 1b]	PLEXOS[1A.02.02 CO2+ Co-Opt – Case 2]
Wheeled Energy				
Generation Energy	3,029,883,488	3,029,883,488	3,029,883,488	3,029,883,488
Installed Capacity	954,186	947,026	953,706	958,035
Cost to Load	$320,042,989,583	$324,994,250,577	$333,903,548,333	$323,198,140,780
Gen Production Cost	$89,965,084,694	$88,450,967,993	$84,062,670,038	$84,840,665,984
Carbon Emissions (tons)	303,192,343	298,410,854	282,539,901	284,853,868

Table 42: Summary of Savings

CO2+ Combined Energy Case	Objective Function (NPV)	Savings
PLEXOS[1A.02.02 CO2+ Co-Opt]	$2,765,105,038,600	
PLEXOS[1A.02.02 CO2+ Co-Opt – Case 1a]	$2,757,575,373,300	$7,529,665,300
PLEXOS[1A.02.02 CO2+ Co-Opt – Case 1b]	$2,719,558,080,300	$45,546,958,300
PLEXOS[1A.02.02 CO2+ Co-Opt – Case 2]	$2,743,931,012,400	$21,174,026,200

As the planning reserve constraints are defined in a wider area, the objective function, which represents the net present value of the total cost for the optimization problem, decreases while transmission and generation investment increases and production and wheeling costs decrease. The additional cost of investment is more than offset by savings in wheeling and production cost. The decreased production cost is due to availability of less expensive resources brought about by the increase in transmission capacity and use of more economic energy resources across the Eastern Interconnection Region.

As presented in Table 43 when planning reserves constraints are defined across a larger area, investments in gas-fired units decrease along the Eastern Interconnection, particularly in PJM ROR, while investments in wind generation increases, with the Midwest regions, particularly MAPP US and SPP N, showing the highest wind growth. This is due to the wider geographical choice of building capacity and consequential benefit in production costs that arise from capacity that has lower variable costs.

Table 43: Locations of Wind and Gas Fired Capacity Built*

	Capacity Built (MW) - Wind Generation			Capacity Built (MW) - Gas Fired Units		
Regions	PLEXOS[1A.02.02 CO2+ Co-Opt]	PLEXOS[1A.02.02 CO2+ Co-Opt – Case 2]	PLEXOS[1A.02.02 CO2+ Co-Opt – Case 1b]	PLEXOS[1A.02.02 CO2+ Co-Opt]	PLEXOS[1A.02.02 CO2+ Co-Opt – Case 2]	PLEXOS[1A.02.02 CO2+ Co-Opt – Case 1b]
ENT	2,400	200	200	0	0	0
FRCC	0	0	0	3,000	4,500	5,500
IESO	0	0	0	0	0	0
MAPP CA	0	0	0	0	0	0
MAPP US	10,800	16,400	19,000	0	0	0
MISO IN	21,000	15,600	12,600	4,500	4,500	4,500
MISO MI	9,000	9,000	9,000	5,500	5,500	5,500
MISO MO-IL	13,200	13,200	13,200	5,000	5,000	5,000
MISO W	55,200	55,200	55,200	4,000	4,000	4,000
MISO WUMS	2,800	2,800	2,800	3,500	3,500	3,500
NE	13,400	13,400	18,400	0	0	0
NEISO	7,000	8,200	8,200	0	0	0
NonRTO Midwest	0	0	0	6,000	2,500	2,500
NYISO A-F	5,400	5,400	5,400	0	0	0
NYISO G-I	400	400	400	0	0	0
NYISO J-K	0	0	0	0	1,000	0
PJM E	4,600	4,600	4,600	0	0	0
PJM ROM	5,400	5,000	5,000	0	400	0
PJM ROR	8,200	7,200	6,800	8,000	700	500
SOCO	0	0	0	0	0	0
SPP N	51,200	59,800	67,800	0	0	0
SPP S	50,400	59,400	49,000	0	0	0
TVA	0	0	0	1,000	0	0
VACAR	3,400	3,400	3,400	6,500	6,000	3,500
Total	**263,800**	**279,200**	**281,000**	**47,000**	**37,600**	**34,500**

(*) Forced New Builds, which have the same values under the three scenarios, were not considered in this Table.

6. Task 1A: JHU Sensitivity Results

The modeling team decided to run several sensitivities to test how the results under the co-optimization case change as input assumptions are varied. Sensitivities related to planning reserve constraints were identified as important, as one goal of co-optimization is to increase inter-regional co-ordination. The base co-optimization case increases energy wheeled between regions but the modeling team was concerned that the model does not exploit the full economic potential of co-optimization as no co-ordination is assumed in capacity reserves planning. Three cases (respectively, 1a, 1b, and 2) were designed to address how co-optimization case results are affected by installed reserves assumptions:

1. An overall planning reserve margin is applied to the whole Eastern Interconnection. The reserve margin assumed is 15.3%, which was calculated as a peak load-weighted average of the base case assumed margins
    a. One case was simulated with the EI planning reserve constraint and the base case levels for transmission hurdle rates.
    b. One case was simulated with the EI planning reserve constraint and zero hurdle rates for all the interfaces.
2. Planning reserve constraints are applied to same super-regions that we used for intermittency limits. Zero hurdle rates are assumed for trade within each super-region and base case hurdle rates are used for trade between regions that belong to different super-regions. See Table 45 for planning reserve margins used.

In the following subsections, we describe and contrast the results for the three cases.

Table 44: Planning reserve margins assumed for 4 Super-regions (JHU)

Super-region	Planning reserve margin (%)
Super Region 1	14.4%
Super Region 2	15.9%
Super Region 3	16.3%
IESO	17.0%

Sensitivity Case 1a: EI planning reserve constraint and base case hurdle rates

Table 45: Case 1a Sensitivity summary metrics (JHU)

JHU Model (2011-2030)	JHU [1A.02.02 CO2+ Co-Opt] case 1a	JHU [1A.02.02 CO2+ Co-Opt]	% change
Objective Function (NPV)	2,930,966,659,814	2,938,467,275,135	-0.26%
Transmission Build Costs	$40,536,428,038.81	$40,538,917,040	-0.01%
Wheeling Charges on Interfaces	$20,408,437,481	$20,554,108,043	-0.71%
Gen Production Cost (NPV)	$1,575,254,081,650	$1,579,764,258,978	-0.29%
Generation Build Costs (NPV)	806,386,458,232	$809,366,004,712	-0.37%
Carbon Revenue	$470,889,779,123	$471,696,289,564	-0.17%
Retired Capacity	451,476	430,766	4.81%
Generation Build	461,127	463,037	-0.41%
Transmission Build	114,628	114,954	-0.28%

Table 46: Case 1a 2030 snapshot metrics (JHU)

JHU Model (2030)	JHU [1A.02.02 CO2+ Co-Opt] case 1a	JHU [1A.02.02 CO2+ Co-Opt]	% change
Wheeled Energy	1,268,464,042	1,266,917,518	0.12%
Generation Energy	3,031,745,510	3,031,532,048	0.01%
Installed Capacity	948,544	971,164	-2.33%
Gen Production Cost	73,871,785,742	74,140,239,478	-0.36%
Carbon Emissions (tons)	247,396,849	247,193,586	0.08%

Under this sensitivity case, in which a single overall reserve margin is applied to all regions and the base case hurdle rates are maintained, metrics do not seem to change considerably. The only major change is observed in the retirements, which increase by ~5%. Specifically, additional 22 GW Combustion Turbine units are retired by 2030. As a consequence, FOM costs for these units are avoided and generation production cost is reduced.

Sensitivity Case 1b: EI planning reserve constraint and zero hurdle rates

Table 47: Case 1b Sensitivity Summary Metrics (JHU)

JHU Model (2011-2030)	JHU [1A.02.02 CO2+ Co-Opt] case 1b	JHU [1A.02.02 CO2+ Co-Opt]	% change
Objective Function (NPV)	2,880,945,942,854	2,938,467,275,135	-2.0%
Transmission Build Costs	$46,183,824,556.63	$40,538,917,040	13.9%
Wheeling Charges on Interfaces	$0	$20,554,108,043	-100.0%
Gen Production Cost (NPV)	$1,555,507,483,616	$1,579,764,258,978	-1.5%
Generation Build Costs (NPV)	$811,390,091,568	$809,366,004,712	0.3%
Carbon Revenue	$462,689,312,142	$471,696,289,564	-1.9%
Retired Capacity	443,377	430,766	2.9%
Generation Build	455,800	463,037	-1.6%
Transmission Build	131,358	114,954	14.3%

Table 48: Case 1b 2030 Snapshot Metrics (JHU)

JHU Model (2030)	JHU [1A.02.02 CO2+ Co-Opt] case 1b	JHU [1A.02.02 CO2+ Co-Opt]	% change
Wheeled Energy	1,713,729,482	1,266,917,518	35.3%
Generation Energy	3,031,532,615	3,031,532,048	0.0%
Installed Capacity	951,316	971,164	-2.0%
Gen Production Cost	72,719,686,967	74,140,239,478	-1.9%
Carbon Emissions (tons)	243,515,102	247,193,586	-1.5%

The difference between Cases 1a and 1b is the removal of hurdle rates, which leads to a significant improvement in the objective function of the model. Approximately one third of that reduction is explained by the removal of hurdle rate charges. But the model is able to make decisions that lead to more savings than simple accounting savings derived by the ignorance of hurdle rates. The model is able to invest in more economically efficient resources and the geographical pattern of generation investments changes considerably. For wind investments, part of MISO_W wind investments is replaced with investments in MAPP_US. This was not a preferable solution in the previous case as the slightly better wind capacity factor in MAPP_US compared to MISO_W did not compensate for the transmission expansion required together the higher hurdle rate expenses required to transfer wind energy to importing regions. Under this case, model also decides to invest in more wind units in NYISO A-F.

The pattern of siting of combined-cycle units also changes, as the model is no longer forced to satisfy regional planning reserve constraints and is free to invest in gas units where it is more economically efficient. For example, a total reduction of 26.5 GW of combined-cycle investments is observed in non RTO Midwest, SOCO, TVA and VACAR, while a total increase of 17 GW of combined cycle investments results in MISO_IN, MISO_WUMS, PJM_RO. These siting shifts are to a large extent explained by lower natural gas prices in those regions.

Transmission interfaces expand even more in this sensitivity case, includes expansions of interfaces that were not expanded in Case 1a (base case high hurdle rates). TVA to VACAR increased significantly, whereas MISO_MO_IL to TVA expansion is +10 GW higher. Co-ordination between regions, as indicated by wheeled energy, increases significantly. The network is utilized more efficiently as the utilization factor implies, which rises to ~79%.

Finally, a comparison of sensitivity cases 1a and 1b reveal the importance of hurdle rates and, thus, the important effects of seams issues on efficient inter-regional planning and operations.

Sensitivity Case 2: Super-regional planning reserve constraints

Table 49: Case 2 Sensitivity Summary Metrics (JHU)

JHU Model (2011-2030)	JHU [1A.02.02 CO2+ Co-Opt] case 2	JHU [1A.02.02 CO2+ Co-Opt]	% change
Objective Function (NPV)	2,905,253,510,302	2,938,467,275,135	-1.1%
Transmission Build Costs	$49,158,023,083.19	$40,538,917,040	21.3%
Wheeling Charges on Interfaces	$8,249,775,820	$20,554,108,043	-59.9%
Gen Production Cost (NPV)	$1,567,031,498,720	$1,579,764,258,978	-0.8%
Generation Build Costs (NPV)	$803,039,237,923	$809,366,004,712	-0.8%
Carbon Revenue	$469,498,300,548	$471,696,289,564	-0.5%
Retired Capacity	444,411	430,766	3.2%
Generation Build	455,087	463,037	-1.7%
Transmission Build	122,005	114,954	6.1%

Table 50: Case 2 Sensitivity 2030 Snapshot metrics (JHU)

JHU Model (2030)	JHU [1A.02.02 CO2+ Co-Opt] case 2	JHU [1A.02.02 CO2+ Co-Opt]	% change
Wheeled Energy	1,489,635,090	1,266,917,518	17.6%
Generation Energy	3,031,209,359	3,031,532,048	-0.01%
Installed Capacity	949,569	971,164	-2.2%
Gen Production Cost	73,424,768,937	74,140,239,478	-1.0%
Carbon Emissions (tons)	246,420,517	247,193,586	-0.3%

Enforcement of the planning reserve constraints at the super-regional level leads to a slight improvement of the objective function relative to the base co-optimization case. As in case 1a, relaxation of planning reserve constraints from a regional to super-regional level leads to retirement of more combustion turbine units (18 GW) and avoidance of FOM expenses for those units.

Transmission interface expand slightly more under this sensitivity but it is more interesting to note that the pattern of new transmission siting significantly changes. In summary, the model seems to prefer to expand interfaces within the super-regions to avoid the hurdle rate charges between other regions. Under base co-optimization case, 72% of the transmission capacity expansions (82.9 GW) lie within one of the three intermittency super-regions (with 28% taking place between regions). In contrast, under this sensitivity case, this percentage increases to 86%, while 14% are between regions. Under the co-optimization base case, excess energy produced in SPP was transferred to ENT and MISO_MO-IL. In contrast, under sensitivity case 2, most of the excess energy produced in SPP is directed to ENT and then part of that energy is wheeled from ENT to SOCO. Last, the utilization of the network is high, with a utilization factor of 71%.

Generation expansions are reduced by ~8 GW as the model selects to invest in less combined-cycle capacity, which is reduced by 10 GW in SPP+ intermittency region. It is also interesting to observe that enforcement of the planning reserve constraint at PJM+ region led to +2 GW more combined cycle units in this region but model sites these units in a different way, as it prefers to invest in PJM_ROR and MISO_IN compared to the non_RTO_Midwest region, demonstrating the same behavior as case 1b.

Sensitivity Case 3: Reference case sensitivity: Value of co-optimization versus iterative generation-only/transmission-only planning

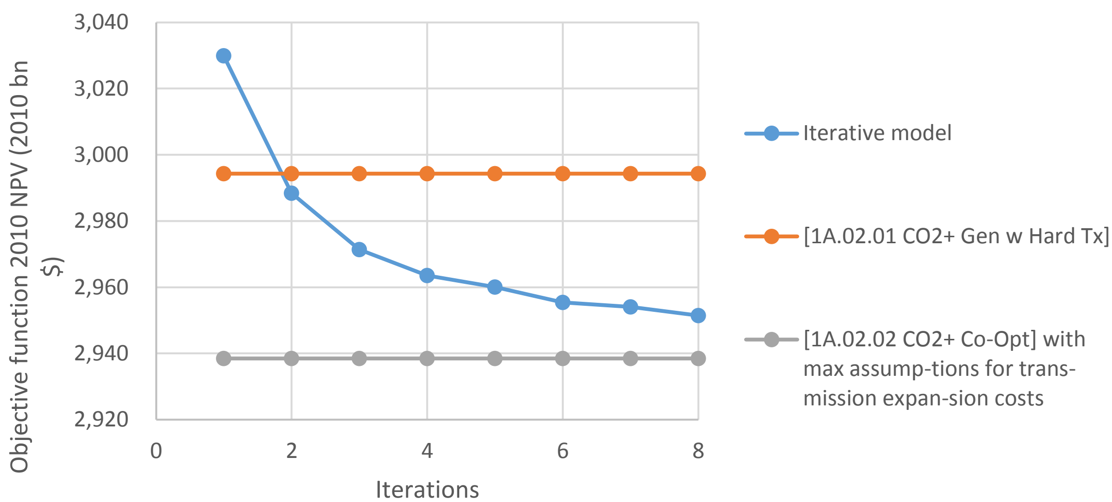
The JHU modeling team also decided to run an additional sensitivity to compare the objective function under co-optimization case vs. a different reference case that does not employ the hardened limits as determined by the soft-constraint methodology. This is also a way to benchmark the reference case against more traditional approaches of iterative planning.

More specifically, the model was set up in a manner that allowed it to alternate between generation only and transmission only planning mode given the decisions made in previous mode/iteration. This was done as follows:

- Gen-planning (iteration 1): Imposing the 2010 transmission network without any network additions, optimize generation investments and operations.
- Trans-planning (iteration 2): Taking the generation investments from iteration 1, optimize transmission investments and generation operations only.
- Gen-planning (iteration 3): Using the transmission network determined in iteration 3, optimize generation investments and operations again.
- Trans-planning (iteration 4): Taking the generation investments from iteration 4, optimize transmission investments and generation operations only.
- …And so forth.

According to Figure 19 the reference case with hardened limits does better (in NPV terms) than no network expansion at all (compare the upper horizontal lines, which is the reference case cost) with the cost of gen-planning (iteration 2)). The first of the trans-planning iterations (iteration 2) brings total cost to just less than the reference cost. Thus, the hardened limit plan is roughly equivalent at least in NPV value terms with an iterative planning approach consisting of two iterations: generation planning (subject to fixed grid) followed by transmission planning (subject to fixed generation siting scenario). Moreover, the figure shows that iterative planning can capture most but not all of the benefits of full co-optimization as number of iterations increases but even after 8 iterations, it is still $13 billion higher than the fully co-optimized case (the lower horizontal line).

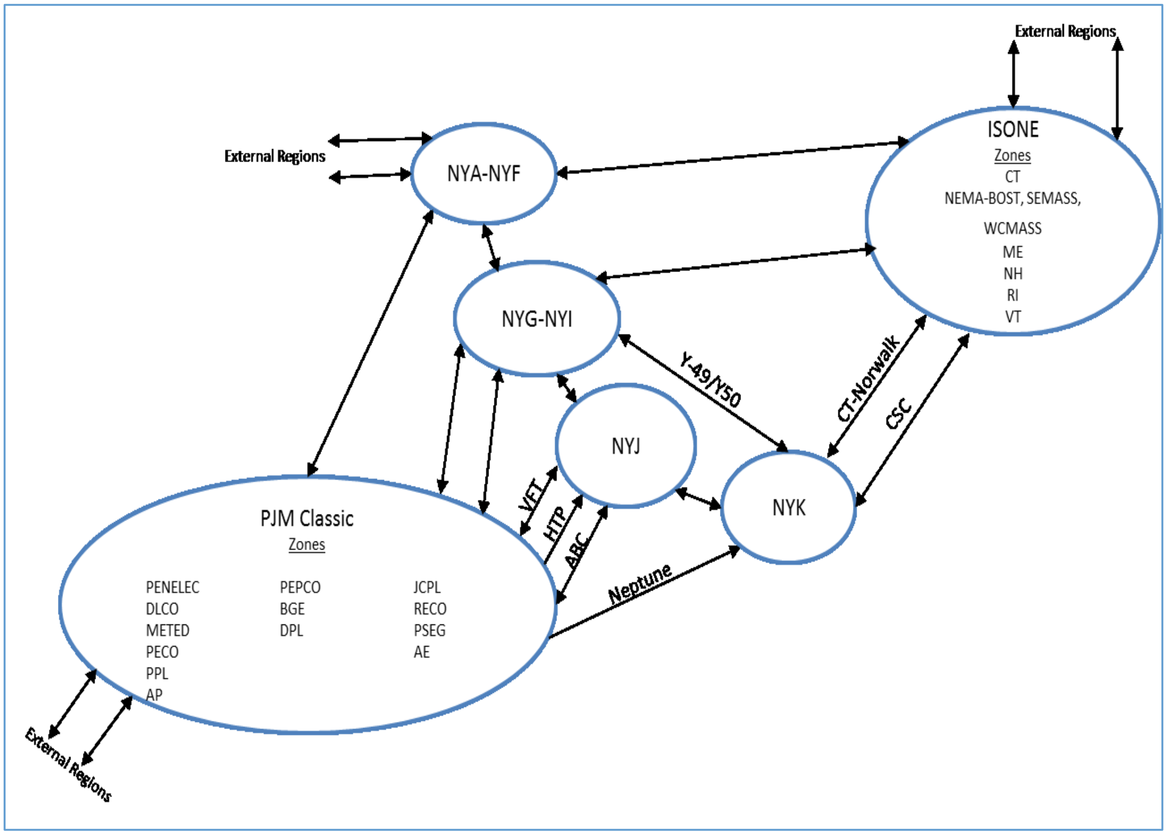
Figure 19: Comparison of NPV of total costs for Task 1a solutions (JHU Reference and Co-Optimization Cases) to the results of iterative generation / transmission planning



7. Task 1B: Co-optimization of Transmission and Other Resources with full nodal and impedance model

This will be a 20 year Long Term Plan using Energy Exemplar's Eastern Interconnect (EI) dataset (Appendix B) and impedance model. Task 1B used a subset of the Energy Exemplar's PLEXOS® EI database for the following regions: PJM Classic; NYISO and ISO-NE (see simplified figure below).

Figure 20: PJM Classic+NYISO+ISO-NE Footprint



Below is the table listing all the zones in the PJM Classic+NYISO+ISO-NE footprint configured to demonstrate Task 1B using PLEXOS®.

Table 51: PJM Classic+ NYISO+ ISO-NE Zones

NYISO	ISO-NE	PJM Classic
NYA	CT	AE
NYB	ME	AP
NYC	NEMA-BOST	BGE
NYD	NH	DLCO
NYE	RI	DP&L
NYF	SEMASS	JCP&L
NYG	VT	METED
NYH	WCMASS	PECO
NYI		PENELEC
NYJ		PEPCO
NYK		PJM
		PPL
		PSE&G
		RECO

Task 1B Inputs and Modelling

1.1. Generator Expansion Candidates:

Generator Expansion candidates have been setup using the Templates feature in PLEXOS®. First, we a group of Template Expansion Candidates with the following properties (see below) are created as a separate Generation Category. These will include properties in the following table with the relative unit / technology capabilities and costs. The Template Candidates will not have any memberships (other than Template / Inheritor memberships) but will have the relative generator properties.

Table 52: Expansion Candidate properties

Source: EIA Capital Cost Forecasts, April 2013

Expansion Candidates	Max Capacity	Heat Rate	VO&M Charge	Max Ramp Up	Max Ramp Up Penalty	Max Ramp Down	Max Ramp Down Penalty	FO&M Charge	Maintenance Rate	Forced Outage Rate	Mean Time to Repair	Build Cost	WACC	Economic Life	Max Units Built
Advanced Coal	100	8800	4.25	2	450	2	450	29.67	2.5	6.961	650	2844	10.5	30	10
Biomass	100	13500	5	2	450	2	450	100.5	2.5	8	120	3680	11.6	30	10
Gas 2x0 Frame CT	417	9750	9.87	3	450	3	450	6.7	2.5	2	48	702	8	30	10
Gas 2x0 LMS100	188	9260	2.5	5	450	5	450	6.7	2.5	2	48	1754	8	30	10
Gas 2x1 CC	715	6430	3.43	3	450	3	450	14.39	2.5	2	48	1021	8	30	10
Geothermal	100	0	9.64		450		450	84.27	2.5	8	120	4045	11.8	30	10
Hydro	200	0	7	2	450	2	450	14.24	2.5	1	48	3076	11.2	100	10
IGCC	100	8700	6.87	2	450	2	450	48.9	2.5	8	650	3216	10.5	30	10
Landfill Gas	100	13648	0	2	450	2	450	120.33	2.5	8	400	2490	11.8	30	10
Nuclear	1000	10488	2.04	2	450	2	450	88.75	2.5	3.4	600	5462	11.2	30	10
Photovoltaic	100	0	0		450		450	16.7	2.5	1	24	4505	11.8	30	10
Solar Thermal	100	0	0		450		450	64	2.5	5	500	4446	11.8	30	10
Wind Onshore	100	0	0		450		450	28.07	2.5	5	250	2390	11.8	30	10
Wind Offshore	200	0	0		450		450	53.33	2.5	5	250	5655	11.8	30	10

Once, the template expansion candidates are created, they are hooked to each of the zonal expansion candidates placed in each zone of the study footprint. The expansion candidates in each zone can be cloned at different locations by identifying key nodes.

1.2. Scaling Load By Hour

The load is represented at all zones in the PJM Classic+NYISO+ISO-NE study footprint at hourly resolution. The load participation factors are defined at the Nodal level and the nodes are associated to a zone. The energy and peak values for each region are obtained from sources like 2014 Gold Book, 2014 CELTS report & 2014 PJM Load Forecast report. The Data File in PLEXOS® class can be used to create load (or other) forecasts for input to a simulation. The load forecasting exercise takes as input:

- a "base" year's profile of demand i.e., period-by-period demands;
- a forecast of total energy (GWh) and maximum demands (MW) over the forecasting horizon; and
- As an option, a list of holiday periods that must be preserved in mapping the forecast years to the base year.

Having created the input data for one or more Data File objects the forecast algorithm is invoked using the "Build" command. Currently, the EI dataset has NYISO & ISO-NE hourly load forecasts extending to 2054 and PJM hourly load forecasts extending to 2054. Below is table which shows yearly Energy & Peak values for NYISO region:

Table 53: Forecast Annual Energy by Zone for NYISO (MW)

Forecast of Annual Energy by Zone - GWh												
Year	A	B	C	D	E	F	G	H	I	J	K	NYCA
2014	15,837	10,011	16,342	6,027	8,153	11,993	9,979	2,957	6,157	53,498	22,207	163,161
2015	15,870	10,005	16,372	6,042	8,167	12,043	10,025	2,946	6,132	53,284	22,328	163,214
2016	15,942	10,025	16,441	6,072	8,214	12,128	10,062	2,953	6,146	53,402	22,522	163,907
2017	15,913	9,993	16,423	6,066	8,233	12,148	10,040	2,938	6,116	53,144	22,590	163,604
2018	15,925	9,988	16,447	6,075	8,277	12,201	10,038	2,931	6,105	53,046	22,720	163,753
2019	15,942	9,985	16,475	6,493	8,319	12,256	10,026	2,927	6,092	52,940	22,850	164,305
2020	16,012	10,009	16,553	6,721	8,395	12,334	10,042	2,927	6,096	52,969	23,043	165,101
2021	15,988	9,980	16,546	6,711	8,431	12,345	10,008	2,916	6,068	52,727	23,110	164,830
2022	15,998	9,979	16,583	6,717	8,480	12,391	9,999	2,910	6,056	52,622	23,240	164,975
2023	16,007	9,979	16,615	6,722	8,524	12,439	9,989	2,903	6,044	52,517	23,370	165,109
2024	16,060	10,009	16,696	6,744	8,608	12,525	10,004	2,905	6,049	52,556	23,565	165,721

Table 54: Forecast Non-Coincident Summer Peak Demand by Zone for NYISO (Gwh)

Forecast of Non-Coincident Summer Peak Demand by Zone - MW												
Year	A	B	C	D	E	F	G	H	I	J	K	NYCA
2014	2,717	2,095	2,935	773	1,484	2,398	2,317	698	1,525	11,783	5,496	33,666
2015	2,731	2,103	2,955	775	1,500	2,429	2,337	692	1,511	12,050	5,543	34,066
2016	2,753	2,119	2,982	778	1,515	2,461	2,352	696	1,519	12,215	5,588	34,412
2017	2,777	2,135	3,012	781	1,535	2,500	2,364	696	1,524	12,385	5,629	34,766
2018	2,792	2,145	3,033	787	1,551	2,528	2,375	702	1,536	12,570	5,668	35,111
2019	2,800	2,152	3,050	861	1,565	2,554	2,383	710	1,552	12,700	5,708	35,454
2020	2,807	2,154	3,061	866	1,576	2,572	2,391	714	1,561	12,790	5,748	35,656
2021	2,813	2,157	3,074	870	1,590	2,596	2,398	718	1,573	12,900	5,789	35,890
2022	2,817	2,159	3,085	874	1,601	2,621	2,406	733	1,601	12,990	5,831	36,127
2023	2,821	2,163	3,096	878	1,613	2,650	2,412	739	1,613	13,100	5,879	36,369
2024	2,824	2,166	3,108	883	1,627	2,675	2,417	743	1,626	13,185	5,923	36,580

1.3. Modeling Dual Fuel Resources

PLEXOS® provides you the flexibility to feed in multiple fuels for a generator. PLEXOS® automatically switches between fuels subject to constraints & fuel prices that are fed into PLEXOS® as data files. EIPC dual fuel data has been used to model Dual Fuels for the entire Eastern Interconnect in PLEXOS®.

1.4. Modeling Interfaces

An interface is a collection of lines in the transmission network that together deliver power from one area to another. It has a notional direction for positive flows; interface flow is the net flow across the lines in the interface. Defining an interface consists of creating an interface object and adding lines or transformers to it. Flow coefficients can be used to set both the direction of flow and participation of the line. With PLEXOS® it is possible to enable or disable enforcement of interface limits. For this study, NYISO, ISO-NE & PJM Interfaces have been modeled in PLEXOS®.

1.5. Modeling Imports & Exports from outside the Study Footprint

Imports and Exports have been modeled for NYISO & ISONE using the Generator and Purchasers class in PLEXOS®. Historical Imports & Exports data from the ISO website is being used to simulate the imports and exports for the study footprint.

1.6. Populating Generator Cost Data (Heat Rate, Startup and Shutdown)

Generators in the footprint under study have average heat rates defined, generic startup and shut down costs based on the fuel and technology type, VO&M charge defined on a unit by unit basis as well.

1.7. Modeling Time-Varying Max Potential Capacity of Renewable Plants

EWITS data from 2004-2006 10 min data been mapped to the wind generators in the footprint and this data is imported into PLEXOS® via a datafile and tagged to the "Rating Factor" property of the wind units. Similarly, a generic solar profile is used for all the solar units in the footprint under study.

1.8. Modeling Outages of Generators and Lines

The simulator can model random outages for generators, transmission lines and gas pipelines for use in a Monte Carlo simulation. Partial and full outages are supported. Outages occur at a frequency that is controlled by the user-defined forced outage rate which in combination with an expected outage duration implies a mean time between failures (MTBF). The expected number, timing, and severity (duration and size) of outages is determined by the Forced Outage Rate, the repair time distribution and the Outage Rating. Currently, Generators in the study footprint include outage parameters such as Forced Outage Rate (%), Maintenance Rate (%) and Mean Time to repair (hrs).

1.9. Modeling Hydro Limits

Currently, hydro generators in PJM Classic+NYISO+ISO-NE footprint are being modelled as Energy Constrained generators with a "Max Energy Month" property tagged to them. Also, the database has Pump Storage (PS) for NYISO and ISO-NE modelled as well. The annual decomposition of these energy limit constraints are handled by MT Schedule and the targets are passed onto ST Schedule. See below image for NYISO and ISO-NE PS units:

1.10. Task 1B: Simulation Settings

Simulation Settings	Expansion Model	Description
Horizon	20-Year (2015-2034)	The Horizon the Model simulates over.
LT Plan	Chronology-Partial, Compute Indices OFF, Step size 5 years, Overlap 0 year, 20 Blocks a Year, Linear expansion, Nodal, Capacity payments ON, Write expansion plan to text file ON	These settings control the capacity expansion planning function in the simulator and are defined on LT Plan
Transmission	FS – OPF	Method for solving optimal power flow.
	PTDF Threshold – 0.04	Minimum absolute value of PTDF as coefficient in transmission flow constraints
	No Transmission Line Limits enforced	Voltage level at which thermal limits are modeled.
	Enforce Interface Line limits	Enforcement of interface limits
	Allow Node Unserved Energy – ON [Own Implementation of Node USE]	Model Node [Unserved Energy] in the mathematical program.
	USE Threshold – 100 %	Formulates the [Unserved Energy] variables on the top x% nodes (highest load).
	Report Tx Solution – ON	Transmission reporting is enabled.
Production	LR	Unit commitment integerization scheme.
Performance	Relative Gap: 1%	Declare the integer solution optimal when this gap is reached between the current integer solution and best-bound linear relaxation
Diagnostics	Task Components ON,NPV Diagnostics ON	Diagnostics for LT Plan NPV of optimal plan
Additional Settings	Interface Expansion Costs set to 0 for Interface Expansion	

Task 1B Results

Energy Exemplar PLEXOS® EI Database as described in the Appendix B consists of a full nodal model with impedance properties and a full DC-OPF analysis is used to model a more granular method of co-optimization of transmission and other resources, including transmission impedance in expansions using a DC-OPF model. For the demonstration of Task 1b, Generator expansion candidates have been placed in all the zones of PJM classic, NYISO & ISO-NE and are co-optimized with Transmission Interface expansion for a 20-year horizon. Below are the 2 cases that have been setup in order to demonstrate the co-optimization in PLEXOS® and the following are the results with and without co-optimization.

Case A: 20-year Generator & Energy Storage Expansion over PJM Classic NYISO & ISO-NE footprint.

Case B: 20-year Co-optimization of Generator and Transmission Interface Expansion over PJM Classic NYISO & ISO-NE footprint.

Table 55: High level Metrics with & without Co-optimization

Metrics	**Case A: without Co-optimization**	**Case B: with Co-optimization**	**Delta**
Objective Function	524,175,221,460	524,024,695,940	150,525,520
Production Cost	$ 357,420,254,916	$ 357,345,118,886	$ 75,136,029
Total Cost	$ 482,530,822,674	$ 482,167,654,693	$ 363,167,981

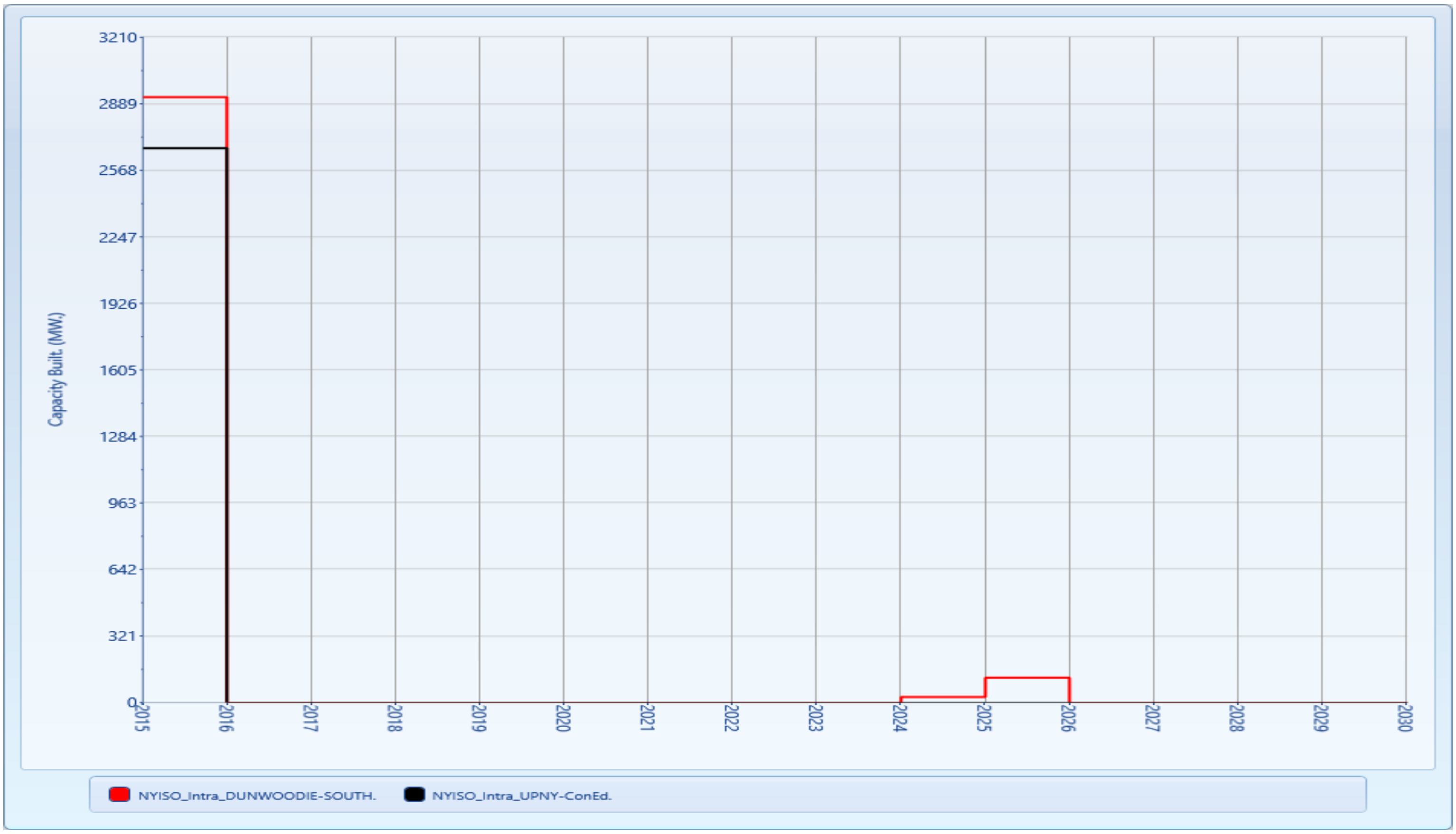
Objective function of Long Term (LT) Plan seeks to minimize the net present value of build costs plus fixed operations and maintenance costs plus production costs.

Production Cost is the Total generation cost including fuel, VO&M, start and shutdown costs and emissions costs.

Total Cost is the total of generator fixed and variable generation costs.

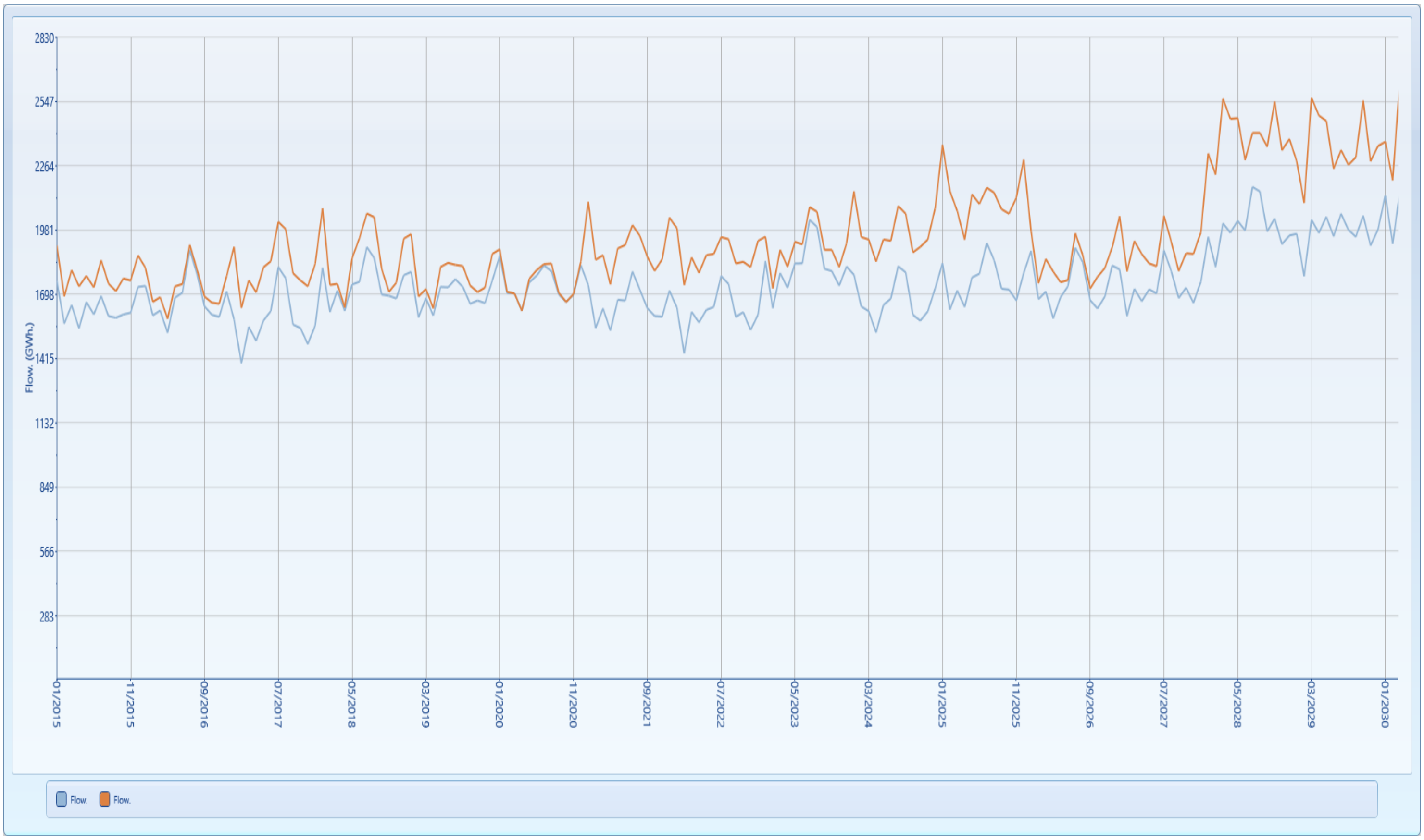
Two Interfaces "Dunwoodie-South" and "UPNY-ConED" in NYISO were considered for expansion as they were congested during most of time. Below is the PLEXOS® chart which shows the Capacity Built in MW on those two interfaces through 2030.

Figure 21: Interface Capacity Built on Dunwoodie-South & UPNY-ConED Interfaces



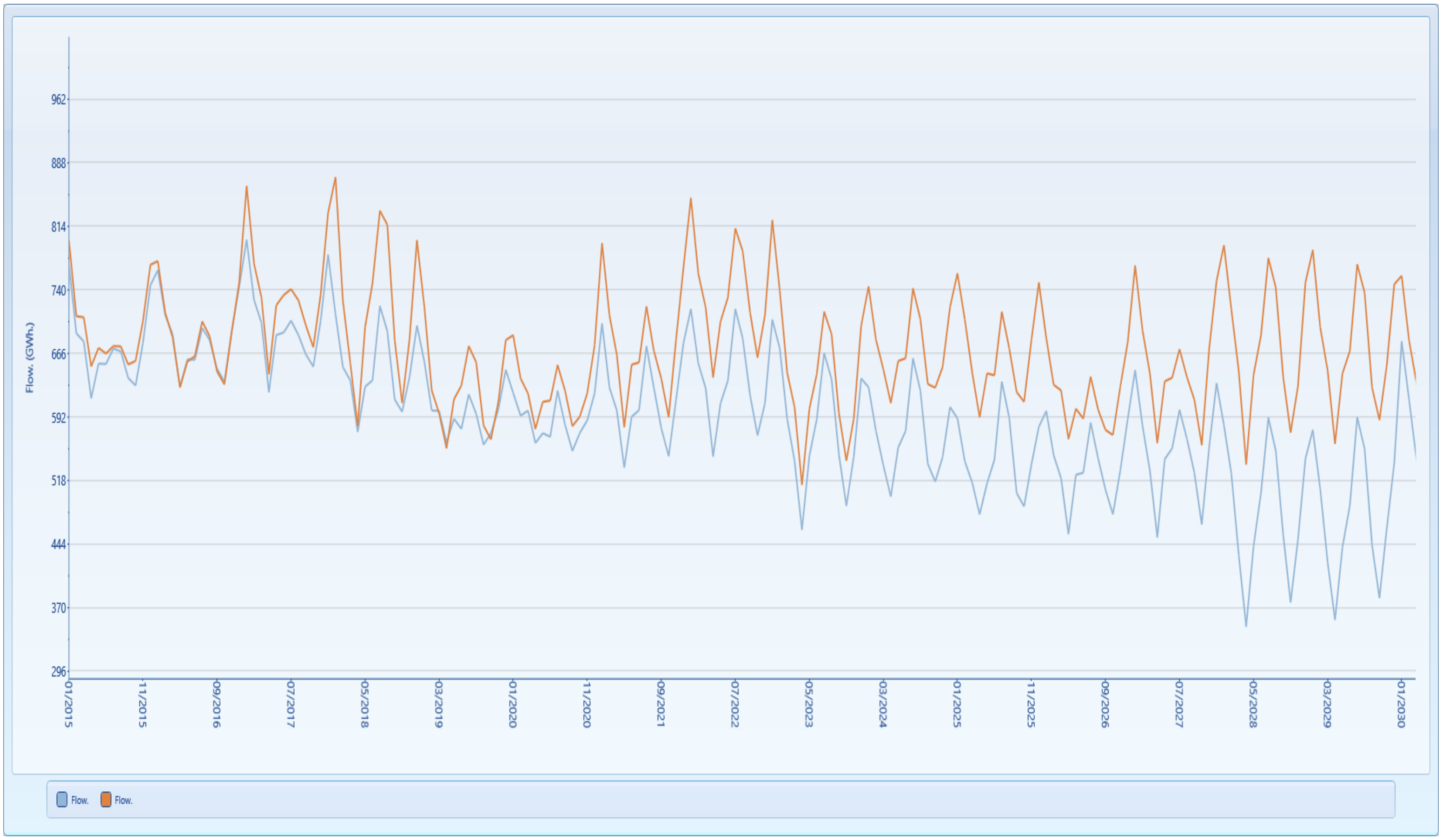
Below is the figure which shows monthly energy flows on the UPNY-ConED Interface for 2015 through 2030 with and without co-optimization and it shows that in the co-optimized case the expanded Interface picked up additional flow according to Impedance division of power flow.

Figure 22: UPNY-ConED Interface Flow with (orange) & without (blue) Co-optimization



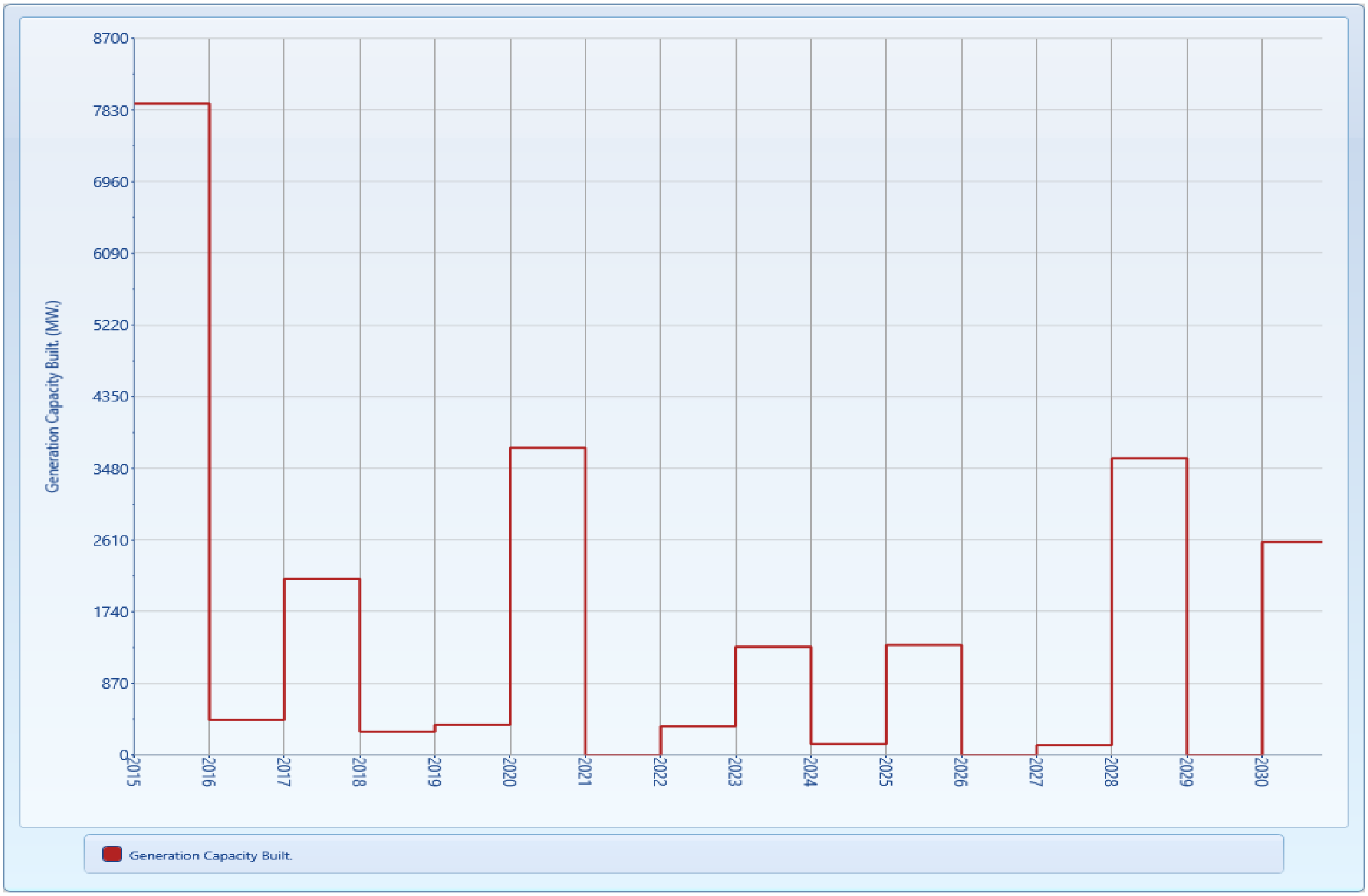
Similarly, UPNY-ConED Interface element (Roseton-E FishKill line) picks up additional flow as the Interface expanded in the Co-optimized case.

Figure 23: UPNY-ConED Interface Element (Roseton-E FishKill) flow with (orange) & without (blue) Co-optimization



The figure below shows the Generation capacity built (MW) in each year across the PJM Classic+NYISO+ISONE footprint in the Co-optimized case.

Figure 24: Generation Capacity Built (MW) across the Entire Footprint in the Co-optimized case



Summary:

The purpose of this case is to demonstrate Co-optimization of Transmission and other resources when Network Impedances are considered. In this case, the elements of the expanded Interface pickup additional power flow as the interface expanded according to Impedance division of power flow.

XI. Task 2: Co-optimization with DSM

The intent of the second part of this study is to evaluate co-optimization features beyond the transmission and generation. In Task 2, the group has added additional resource types to be evaluated as part of the co-optimization process. In particular, we have added Demand Side Management (DSM) expansion. Thus, we co-optimize transmission and other resources with DSM. This task uses the EIPC Phase I Combined Energy Policy with expanded demand response.

In addition energy storage was modeled using the Pumped Storage Hydroelectricity (PSH) generation units already modeled inside the EIPC Phase I study based on PLEXOS rating factors or max energy month with scenarios, PLEXOS® allows the modelling of additional storage devices such as Compressed Air Energy Storage (CAES) units, batteries, etc. Typical values for some storage devices using these technologies are reported in the Appendix.

The EISPC co-optimization project team developed the simulations in Table 56 in PLEXOS® to simulate the CO2+ Combined Energy Case (F8S7) with Demand Side Management. The Table below summarizes the modelling the simulations for Tasks 2.

Table 56: Task 2 Cases (PLEXOS® and JHU Analysis)

	Category	Model	Transmission Settings	Optimization Method
Task 2	Task 2 Storage and DR	2.01.01 CO2+ Hard Tx w DSM	Transmission Limits Fixed Tx Interface Hardened Limits from the EIPC Phase I CO2+.	Transmission Co-Optimization (Generation, Transmission & DSM).
	Task 2 Storage and DR	2.01.02 CO2+ Co-Opt w DSM	Transmission Limits Expandable at cost starting from BAU limits	Transmission Co-Optimization (Generation, Transmission & DSM)

As noted previously, Task 2 was modelled in both PLEXOS® and the JHU models. The results are reported for both models below, first with PLEXOS® and then with JHU results. PLEXOS® uses pseudo-generators to represent demand response, while there are two versions of the JHU model with DR: one with pseudo-generations and another that instead uses linear demand functions to represent demand response to prices.

Task 2: Co-optimization with Energy Storage and DSM PLEXOS® Results

In addition to demonstrating the co-optimization of transmission and other resources, Task 2 has add two additional build decisions added to the original analysis. In this case, an additional Demand Side Management (DSM) expansion object has been added as well as energy or battery storage to the co-optimization.

This study also used the same EIPC properties as in Task 1A, with the addition of DSM builds.

To include the DSM as a build decision in PLEXOS, we have included a generator expansion candidate for DSM with a six point generation bid curve. There are assumed to be no build costs for this expansion candidate and will generate (or reduce demand) if it is economic relative to the generation bid curve. The DSM were assumed to build in reach region.

In addition to the DSM build optionality, we have also included 4 types of energy storage expansion candidates with their respective operating parameters and builds costs. The four energy or battery storage candidates were allowed to expand in each region and composed of the following types: Compressed Air (CAES); Sodium Sulfur (NaS); Advanced Lead Acid (PbA); and Lithium Sulfur (LiS). See section VII subsection 7 for more details.

Table 57: Task 2 Summary Results

PLEXOS® Model (2010-2030)	PLEXOS[2A.02.01 CO2+ Gen w Hard Tx ST and DR]	PLEXOS[2A.02.02 CO2+ Co-Opt ST and DR]	Change
Objective Function (NPV)	$ 2,828,562,278,156	$ 2,763,017,492,000	(65,544,786,156)
Transmission Build Costs	$ 89,357,099,056	$ 49,648,321,316	(39,708,777,740)
Wheeling Charges on Interfaces	$6,194,509,200	$6,088,678,725	(105,830,474)
Gen Production Cost (NPV)	$1,173,386,038,057	$1,177,693,020,340	4,306,982,282
Generation Build Costs (NPV)	$403,048,393,433	$417,734,419,678	14,686,026,246
Carbon Revenue	$ 332,690,968,199	$ 335,595,405,296	2,904,437,097
Retired Capacity	428,037	430,040	2,004
Generation Build	549,066	568,296	19,230
DSM MW	151,100	151,100	0
Annualized Build Cost	$ 299,485,792,834	$297,613,779,785	(1,862,327,601)

The results of Task 2 are similar to Task 1A in terms of the overall savings from the co-optimization with the net savings of the objective function of $65.5 billion. The result is significant in that the co-optimization was achieved with both the expansion of the transmission interfaces, generation expansion candidates as well as DSM candidates. In this case, PLEXOS® solved for the least cost expansion of all these different variables in the same solution.

In Task 2, the net savings of the objective function is achieved in addition to 19,230 MW of generation build in the co-optimized case as compared to the hardened case.

The Total Transmission Build costs are similar to Task 1A for the co-optimized case with DSM as well as Wheeling Charges and Generation Build Costs.

The changes in the summary results for this case are found in the Retired Capacity and Generation Build values. Because the DSM are expandable generation candidates, the starting point total generation build in the hardened case is now 549,066 MW with an increase of 19,230 MW in the co-optimized case. The net build of DSM in both cases is 151,100 MW across the entire EI.

An Energy Storage sensitivity has been configured however this sensitivity was under testing at the time of issuing this final report for comment.

Energy storage tends to operate most effectively between peak and off-peak periods, providing energy during the day when prices are highest and charging overnight when prices are at their lowest. To make energy storage effective the energy price between the on and off peak periods should be greater than or equal the equivalent efficiency of the charging cycle. So if the charge or pump is 80% efficient, then the spread between peak and off-peak period prices should be at least 20% or greater.

In addition to the whole horizon summary noted above, Table 58, below summarizes the results in the last year of the horizon, or 2030, to provide a different perspective of the two analyses.

Table 58: Task 2 Summary Results for Metrics 2030

PLEXOS® Model (2030)	PLEXOS[2A.02.01 CO2+ Gen w Hard Tx ST and DR]	PLEXOS[2A.02.02 CO2+ Co-Opt ST and DR]	Change
Wheeled Energy	447,836,400	455,406,049	7,569,649
Generation Energy	3,029,883,488	3,029,881,318	(2,170)
Installed Capacity	1,074,677	1,091,903	17,226
Cost to Load	$323,761,041,575	$320,155,680,884	(3,605,360,691)
Gen Production Cost	$96,678,824,409	$90,303,637,736	(6,375,186,673)
Carbon Emissions (tons)	330,689,577	304,947,435	(25,742,142)
Transmission Network Utilization Factor	65%	66%	1.0%

Due to the overall reduction in demand through the additional DSM resources deployed in this co-optimized case, the results differ from the previous Task 1A. Most notable is the decline in Cost to Load savings, which in this case is a total savings of $3.61 billion for 2030. The reason for this is the generation bid curve employed in the DSM expansion candidates will have a positive impact on system prices during peak periods, effectively setting energy prices at a higher pricing point that would have been the case otherwise. This is effectively how DSM are employed in existing markets operated by an ISO. The DSM is typically called during peak periods and often only after reaching a certain price threshold. So, in this case, the co-optimized results Cost to Load savings are reduced relative to the Task 1A due to the higher price profiles.

In addition to the whole horizon summary noted above, Table 59 to Table 62 below summarizes the results by region:

- Table 59 is the Installed Capacity in MW by region for 2030;
- Table 60 is the Generation Retired in MW by region for 2010 to 2030;
- Table 61 is the Generation Build in MW by region for 2010 to 2030; and
- Table 62 is the Generation in GWh by Region for 2030

Table 59: PLEXOS® Results Task 2 Installed Capacity by Region (MW)

Year 2030	Task 2 Installed Capacity by Region	
Region	2A.02.01 CO2+ Gen w Hard Tx ST and DR	2A.02.02 CO2+ Co-Opt ST and DR
ENT	40,810	40,310
FRCC	76,097	75,587
IESO	37,389	37,389
MAPP_CA	10,769	10,769
MAPP_US	15,133	17,533
MISO_IN	30,406	40,206
MISO_MI	33,263	33,672
MISO_MO-IL	40,555	41,349
MISO_W	98,078	85,878
MISO_WUMS	20,110	19,194
NE	21,218	20,455
NEISO	35,266	34,683
NonRTO_Midwest	14,055	14,064
NYISO_A-F	24,126	24,126
NYISO_G-I	5,324	5,324
NYISO_J-K	16,847	16,847
PJM_E	48,324	48,324
PJM_ROM	42,293	39,878
PJM_ROR	125,837	129,837
SOCO	76,656	78,518
SPP_N	55,679	62,581
SPP_S	78,024	87,589
TVA	47,170	46,562
VACAR	72,329	72,308

Table 60: PLEXOS® Results Task 2 Capacity Retired by Region (MW)

Year 2030	Task 2 Capacity Retired by Region	
Region	2A.02.01 CO2+ Gen w Hard Tx ST and DR	2A.02.02 CO2+ Co-Opt ST and DR
ENT	23,095	23,645
FRCC	30,174	30,174
IESO	19,322	19,322
MAPP_CA	2,435	2,435
MAPP_US	5,746	5,746
MISO_IN	13,752	13,752
MISO_MI	17,738	17,329
MISO_MO-IL	16,898	16,094
MISO_W	19,688	19,688
MISO_WUMS	8,275	9,391
NE	4,474	4,637
NEISO	21,507	22,080
NonRTO_Midwest	12,582	11,572
NYISO_A-F	9,503	9,503
NYISO_G-I	2,952	2,952
NYISO_J-K	6,428	6,428
PJM_E	8,639	8,639
PJM_ROM	18,685	21,310
PJM_ROR	64,462	64,462
SOCO	39,458	37,596
SPP_N	10,750	13,548
SPP_S	24,075	23,710
TVA	21,108	20,216
VACAR	26,291	25,812

Table 61: Generation Build by Region (GWh)

Year 2030	Task 2 Generation Build by Region	
Region	2A.02.01 CO2+ Gen w Hard Tx ST and DR	2A.02.02 CO2+ Co-Opt ST and DR
ENT	85,426	80,316
FRCC	248,601	248,440
IESO	163,044	162,994
MAPP_CA	44,012	43,380
MAPP_US	45,085	52,802
MISO_IN	70,244	82,117
MISO_MI	89,039	84,791
MISO_MO-IL	94,982	90,414
MISO_W	286,133	230,606
MISO_WUMS	54,641	43,438
NE	60,325	57,913
NEISO	77,531	77,132
NonRTO_Midwest	56,909	52,170
NYISO_A-F	84,539	84,248
NYISO_G-I	23,297	20,259
NYISO_J-K	12,677	22,371
PJM_E	125,335	111,813
PJM_ROM	82,285	86,460
PJM_ROR	328,588	347,641
SOCO	252,034	252,620
SPP_N	144,547	175,204
SPP_S	167,550	197,187
TVA	149,820	145,241
VACAR	247,705	244,788

Table 62: Task 2 Generation by Region (MW)

Year 2030	Task 2 Generation Build by Region	
Region	2A.02.01 CO2+ Gen w Hard Tx ST and DR	2A.02.02 CO2+ Co-Opt ST and DR
ENT	10,240	10,290
FRCC	32,908	32,398
IESO	9,546	9,546
MAPP_CA	2,443	2,443
MAPP_US	10,328	12,728
MISO_IN	20,518	30,318
MISO_MI	20,500	20,500
MISO_MO-IL	25,670	25,660
MISO_W	80,202	68,002
MISO_WUMS	9,582	9,782
NE	16,234	15,634
NEISO	16,905	16,895
NonRTO_Midwest	9,690	8,690
NYISO_A-F	11,141	11,141
NYISO_G-I	1,200	1,200
NYISO_J-K	4,505	4,505
PJM_E	19,097	19,097
PJM_ROM	15,984	16,194
PJM_ROR	48,438	52,438
SOCO	34,569	34,569
SPP_N	43,595	53,295
SPP_S	51,181	60,381
TVA	18,622	17,122
VACAR	35,967	35,467

Table 63: Task 2 Installed Capacity by Generation Type (MW)

Year 2030	Task 2 Installed Capacity By Gen Type	
Region	2A.02.01 CO2+ Gen w Hard Tx ST and DR	2A.02.02 CO2+ Co-Opt ST and DR
BM	1,067	1,117
Coal	13,340	12,027
Gas	253,093	251,402
GEO	44	44
HY	43,977	43,977
LFG	3,976	3,956
NU	132,147	132,147
PS	17,054	17,054
PV	9,150	9,150
STOG	653.3	653
STWD	2,311	2,311
WT	282,678	302,878
DSM	303,550	303,550

Table 64: Task 2 Capacity Retired by Generation Type (MW)

2010 to 2030	Task 2 Capacity Retired by Gen Type	
Region	2A.02.01 CO2+ Gen w Hard Tx ST and DR	2A.02.02 CO2+ Co-Opt ST and DR
BM	-	-
Coal	273,558	274,871
Gas	79,973	80,664
GEO	-	-
HY	-	-
LFG	-	-
NU	2,124	2,124
PS	-	-
PV	-	-
STOG	70,736	70,736
STWD	807	807
WT	-	-
DSM	-	-

Table 65: Task 2 Installed Capacity Build by Generation Type (MW)

2010 to 2030	Task 2 Installed Capacity Build by Gen Type	
Region	2A.02.01 CO2+ Gen w Hard Tx ST and DR	2A.02.02 CO2+ Co-Opt ST and DR
BM	1,067	1,117
Coal	8,375	8,375
Gas	79,063	78,063
GEO	0	0
HY	0	0
LFG	555	535
NU	33,234	33,234
PS	0	0
PV	9,000	9,000
STOG	0	0
STWD	0	0
WT	264,229	284,429
DSM	151,100	151,100

Table 66: Task 2 Generation by Generation type in 2030 (GWh)

2030	Task 2 Generation Gen Type	
Region	2A.02.01 CO2+ Gen w Hard Tx ST and DR	2A.02.02 CO2+ Co-Opt ST and DR
BM	1	1
Coal	744	406
Gas	793,601	733,475
GEO	355	355
HY	192,302	192,302
LFG	14,655	11,798
NU	1,115,371	1,115,700
PS	9,298	9,298
PV	9,964	9,964
STOG	-	-
STWD	34	34
WT	849,982	912,935
DSM	2,557	2,593

From the regional results in Table 59 through Table 61 above, we see a similar deployment of wind as in the previous Task1A.

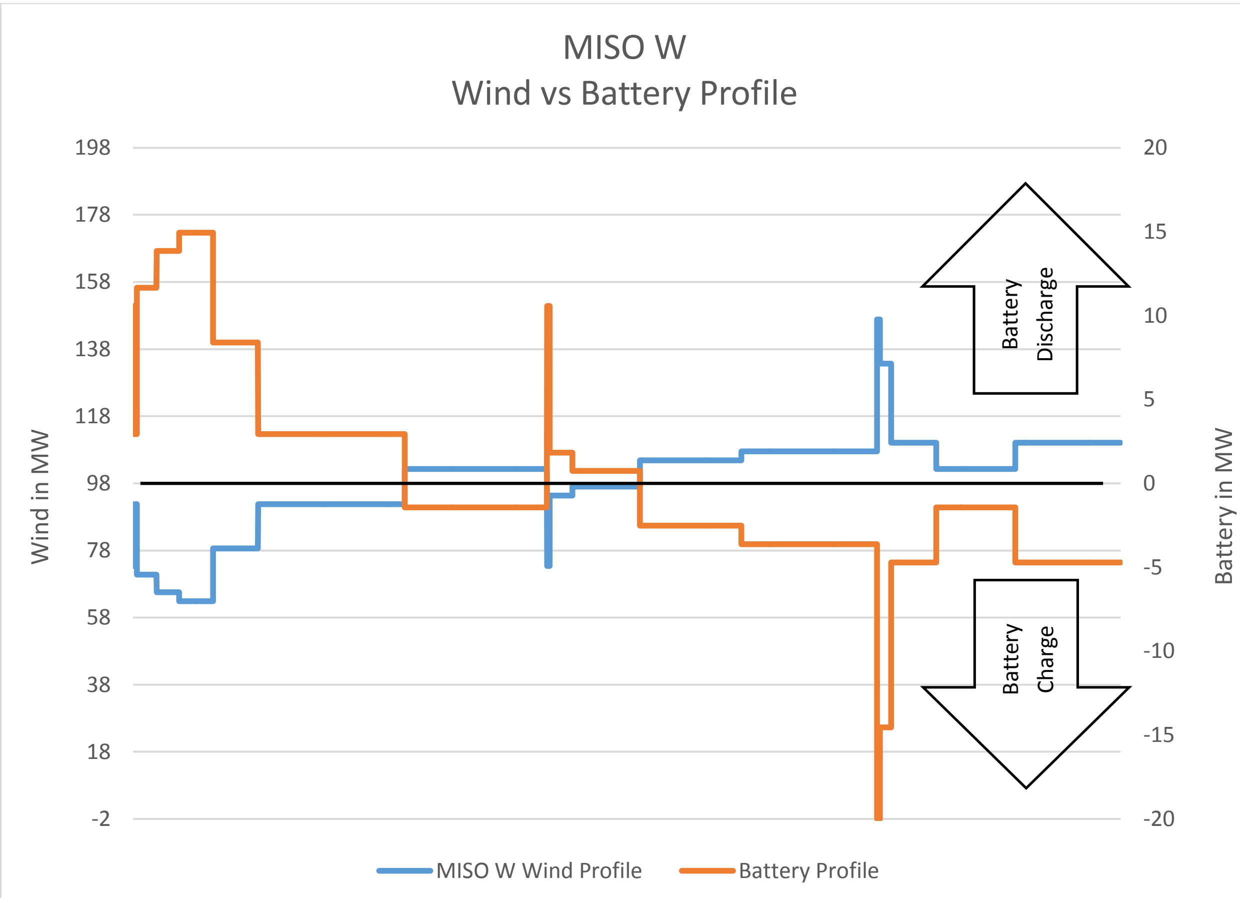
In addition to the regional tables, we have also provided summary tables by generation type: Table 63 to Table 66 below summarizes the results by generation type:

- Table 63 is the is the Installed Capacity in MW by generation type for 2030;
- Table 64 is the Generation Retired in MW by generation type for 2010 to2030
- Table 65 is the Generation Build in MW by generation type for 2010 to 2030; and
- Table 66 is the Generation in GWh by generation type for 2030.

From the generation type summary tables, there are very little difference between the reference case and the co-optimized case.

PLEXOS® Co-Optimization Sensitivity - Battery Energy Storage for Intermittency

From the region wind average capacity factor duration profile, a battery energy storage wind following duration profile is assumed as follows for an example region of MISO W. A sum of the battery profile in the below figure yields a negative number representing the battery cycling losses.



Battery Energy Storage duration profiles were then made for all EI regions according to their respective wind capacity duration profiles. A constraint was placed on battery expansion limiting to no more than 10% of the wind expansion capacity.

A Battery Energy Storage sensitivity was run with $0 capital costs to observe bookend value of benefits associated with intermittency storage assuming an expansion plan with co-optimization of transmission and other resources.

A co-optimization was run with Battery Energy Storage where 25,100 MW of battery capacity was expanded by the optimization for the EI where many batteries expanded in the wind rich regions for total benefits of $10 billion as summarized in the following table.

CO2+ Combined Energy Case	**Results**
CO2+ Co-Optimized Base Assumptions	$ 2,765,105,038,600
CO2+ Co-Optimized Energy Storage	$ 2,754,496,487,700
Co-Optimization Savings	$ 10,608,550,900

The Batteries almost surely would provide additional benefits in terms of curtailment reduction, reliability benefits, time shifting of energy for demand peaks, ancillary services, and transmission deferral as a detailed transmission plan of the EI CO2+ case with 40% wind penetration of The Eastern Interconnection may require significant ramping and storage capability that batteries could provide or other flexible units. Further study would be required, however, as this sensitivity was for demonstration purposes of co-optimization of transmission and other resources, including energy storage.

Task 2: JHU Demand Response Results

There are two sets of JHU results: one for the same DR representation using pseudo-generators as used by PLEXOS® (with six tranches or "steps", the lowest cost one having a strike price of $165/MWh), and a second using linear demand curves in which prices from the co-optimization models are then inserted in demand functions, and the resulting revised estimates are then put back in the co-optimization model which is re-solved. This iterative process is repeated until convergence occurs.

We address two questions in this section. First, what are the cost and investment impacts of demand response, as modeled using pseudo-generators (as in PLEXOS)? Second, is modeling demand response using continuous demand functions (load as a function price) possible using an iterative approach?[25]

Question 1: What is the impact of Demand Response?

This question is addressed with the pseudo-generator version of the JHU model. As shown in the below figure, the assumed amount of demand response in the pseudo-generator version of the JHU model starts with 33 GW of demand response in 2010-2015, which provides peak capacity treated free of capital costs and fixed OM. Between 2016 and 2025 demand response capacity is assumed to grow on average by ~11 GW annually. By 2030 there is a total of 152 GW of demand response capacity, which is 18.5% of the total installed generation capacity in the original co-optimization model.

Figure 25: Total Demand Response Capacity for years 2010-2030 for each of six strike prices ("steps")

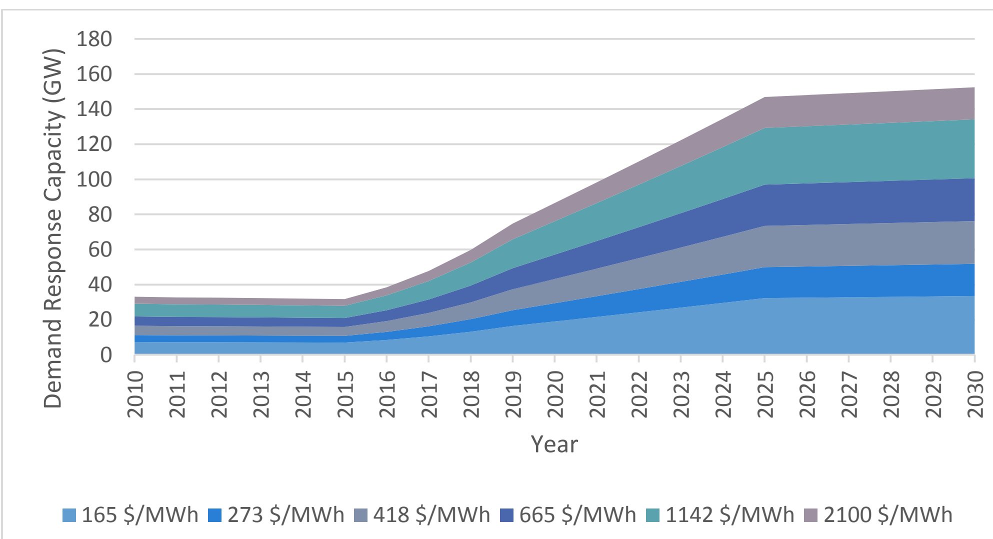


Table 67: Task 2 Summary Results: Demand Response modeled by pseudo-generators (JHU)

[25] As previously implemented by the JHU team for a European Union transmission planning model (O. Ozdemir, F. Munoz, J. Ho, and B.F. Hobbs, "Economic Analysis of Transmission with Demand Response and Quadratic Losses by Successive LP", IEEE Transactions on Power Systems, to appear).

JHU Model (2011-2030)	JHU [1A.02.02 CO2+ Co-Opt]	JHU [2.02.02 CO2+ Co-Opt] + Pseudo DR	% change
Objective Function (NPV)	2,938,467,275,135	2,936,407,846,823	-0.07%
Transmission Build Costs	$40,538,917,040	$40,334,258,824	-0.50%
Wheeling Charges on Interfaces	$20,554,108,043	$20,444,770,366	-0.53%
Gen Production Cost (NPV)	$1,579,764,258,978	$ 1,583,466,383,923	0.23%
Generation Build Costs (NPV)	$809,366,004,712	$808,189,910,200	-0.15%
Carbon Revenue	$471,696,289,564	$468,317,878,181	-0.72%
Retired Capacity	430,766	436,711	1.38%
Generation Build	463,037	461,627	-0.30%
Transmission Build	114,954	112,885	-1.80%

With the addition of demand response, there are slight changes to the co-optimization solution that reflect the impact of demand response. The inclusion of the step-wise pseudo-generator demand response saves $2.2 billion (net present value). Demand response obtains some of its savings through reductions in capital costs of transmission and generation. The inclusion of dispatchable demand response also reduces the levels of carbon emissions, and there is a 0.72% reduction in carbon tax revenue. This reduction implies that demand response has environmental benefits since there is less output from less efficient/higher emitting peaking units. There is an increase in production costs with higher dispatch of demand response, which can be more expensive on a variable cost basis than the peaking units that are displaced.

Table 68: 2030 Generation production costs and its components

JHU Model Generation Production cost and its components in 2030 (Nominal values in Billion $)	***[1A.02.02 CO2+ Co-Opt]***	***[2.02.02 CO2+ Co-Opt] with Step-wise Pseudo-generator Demand Response***	% change
FOM Cost	**31.6**	**31.50**	**-0.32%**
VOM and fuel cost (including the cost of DR dispatch)	42.5	43.30	1.88%
Carbon Taxes	34.5	33.95	-1.60%
Total Gen Variable Production cost	108.7	109.00	0.28%

Turning now to generation operations costs, a breakdown of those costs for 2030 reveals more about the impact of pseudo-generator-based model of demand response. The reduction in FOM costs in the final stage reflects the reduction in generation capacity built with pseudo-generator demand response. There is an increase in the variable costs, as demand response is used frequently by the model. Much of the variable cost increase is offset by savings in carbon emissions. Overall there is a net increase in generation production costs due to considering demand response.

Table 69: Energy mix (% of energy generated by technology type in 2030)

Energy mix in 2030 (% of total energy produced)	**[1A.02.02 CO2+ Co-Opt]**	**[2.02.02 CO2+ Co-Opt] *with Step-wise Pseudo-generator Demand Response***
Nuclear	34.5%	34.5%
On-Shore Wind category 4	27.9%	27.9%
CC	20.2%	20.1%
Hydro	9.7%	9.7%
On-Shore Wind category 3	4.0%	4.1%
Other Renewable	3.3%	3.3%
CT	0.4%	0.2%
Coal	0.1%	0.1%

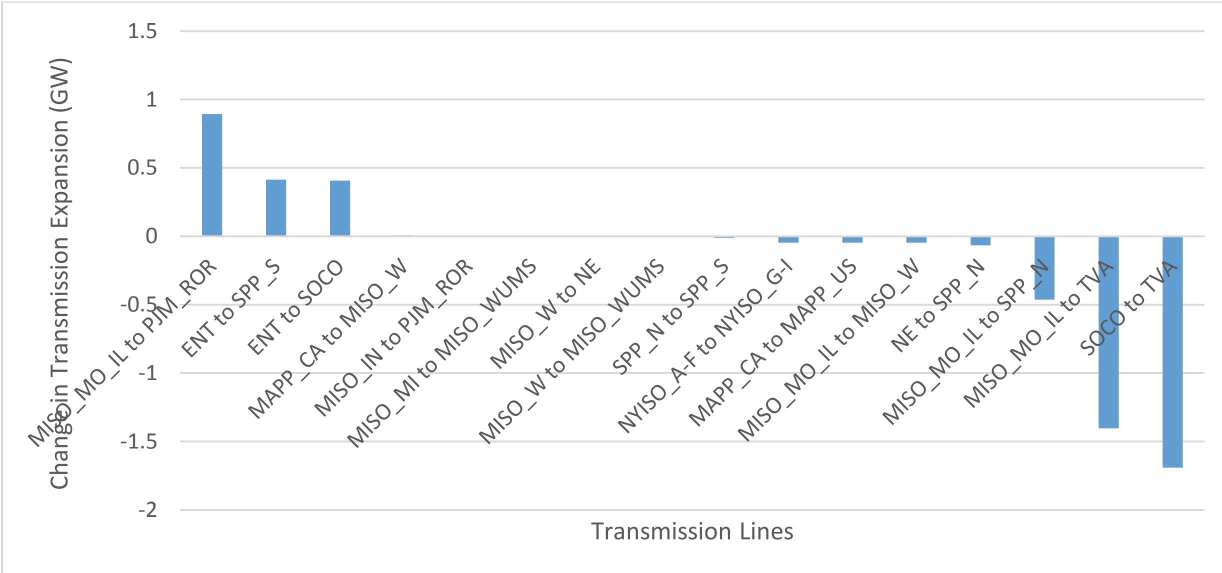
As the above table shows, for the most part, the energy mix remains largely unchanged. However, demand response does have an impact on some key components of the energy mix. On the basis of total energy, demand response is used sparingly and represents 0.25% of the total energy needs. With the step-wise demand response, the operation of combustion turbines is cut in half since demand response trims peak loads and displaces the need for peaking units.

Table 70: Total Generation Capacity 2030

2030 EI Capacity (GW)	[1A.02.02 CO2+ Co-Opt]	[2.02.02 CO2+ Co-Opt] *with Step-wise Pseudo-generator Demand Response*	Delta
Combined Cycle	213.5	210.1	-3.4
Coal	8.4	8.4	0.0
Combustion Turbine	63.3	59.3	-4.0
Hydro	57.3	57.3	0.0
Nuclear	134.6	134.6	0.0
On-Shore Wind	305.3	305.3	0.0
Other Renewable	19.5	19.6	0.1
Pumped Storage	16.6	16.6	0.0
Steam Oil/Gas	0.2	0.2	0.0
Total	818.7	811.4	-7.3

The impacts on generation from demand response are clearer if we look at shifts in investment decisions rather than operations. Demand response results in a 0.89% reduction in installed capacity, and this impact is more visible than the small changes it has on the energy mix. Under demand response, the largest single shift occurs for combustion turbines which constitute 56% of the net change in generation capacity. This displacement is in line with the expectation that demand response will be used as an alternative to constructing new units to satisfy peak demand. In addition to the impact on peaking turbines, there is also a reduction in combined-cycle capacity. All other capacity remains essentially unchanged.

Figure 26: Shifts in Transmission Investment Decisions



With the addition of demand response, there is also a shift in the siting of transmission investments (see the above figure). These shifts are measured here using two different metrics. One is the change in overall transmission investment, which can be measured using the sum of differences across all interfaces. A second metric used to measure the effect on transmission investment siting, by looking at the sum of absolute differences across interfaces. If the two numbers are close in magnitude then transmission capacity changed but was not appreciably shifted in space. On the other hand, if the second index is much larger, then transmission investment changes consisted mostly of shifts in location.

Table 71: Metrics Comparing Transmission Investments

Normalized Sum of Differences %	Normalized Sum of Absolute Differences
-1.80%	4.79%

Based upon these metrics, there was a small net decrease in transmission investments as a consequence of demand response reducing the pressure to accommodate flows during system peaks. However, most of the differences in transmission investments were a result of moving transmission investments due to significant differences in the existing network when the system is planned considering demand response.

With demand response represented as pseudo-generators there are is a significant addition of free generation capacity. The following table shows the resulting shifts in new transmission built.

Table 72: Cumulative Transmission Investment Decisions (2010-2030)

Line	[1A.02.02 CO2+ Co-Opt] with *Step-wise Pseudo-generator Demand Response*	[2.02.02 CO2+ Co-Opt] with Demand Response	Delta
MISO_IN to MISO_MO_IL	20.00	20.00	0.00
MISO_MO_IL to MISO_W	16.91	16.86	-0.05
MISO_MO_IL to SPP_N	19.40	18.94	-0.46
MISO_IN to PJM_ROR	13.34	13.34	0.00
ENT to SPP_S	10.81	11.22	0.41
MISO_MO_IL to PJM_ROR	8.07	8.96	0.89
MISO_MO_IL to TVA	8.00	6.60	-1.40
MISO_W to MISO_WUMS	4.98	4.98	-0.01
IESO to MISO_MI	3.94	3.94	0.00
ENT to SOCO	0.00	0.41	0.41
SPP_N to SPP_S	1.67	1.66	-0.01
SOCO to TVA	3.42	1.73	-1.69
MISO_MI to MISO_WUMS	1.78	1.78	0.00
NYISO_A-F to NYISO_G-I	1.35	1.30	-0.05
NE to SPP_N	0.32	0.25	-0.07
PJM_ROR to VACAR	0.00	0.00	0.00
MISO_W to NE	0.70	0.70	0.00
MAPP_CA to MISO_W	0.21	0.22	0.01
TVA to VACAR	0.00	0.00	0.00
NYISO_G-I to NYISO_J-K	0.00	0.00	0.00
NEISO to NYISO_G-I	0.00	0.00	0.00
MISO_IN to Non_RTO_Midwest	0.00	0.00	0.00
NEISO to NYISO_J-K	0.00	0.00	0.00
MAPP_CA to MAPP_US	0.05	0.00	-0.05
Total Capacity	114.95	112.89	-2.07

Question 2: How do different implementations of demand response impact our decisions?

While representing demand response using pseudo-generators is one approach to modeling demand response. It has certain drawbacks in its representation. For example, with pseudo-generators, the available supply of demand response is modeled through a coarse step-wise supply curve (in the above case, having six steps), and modeling impacts of prices in other periods upon load (e.g., load-shifting) takes additional effort. Representing demand response as pseudo-generation is not inherently unrealistic as demand response aggregators could behave like generators in the electricity markets. However the supply curve for demand response would be anticipated to be significantly smoother and more varied than the six step supply curve used, and might also include load-shifting over the day which can be done with a pseudo generator too.

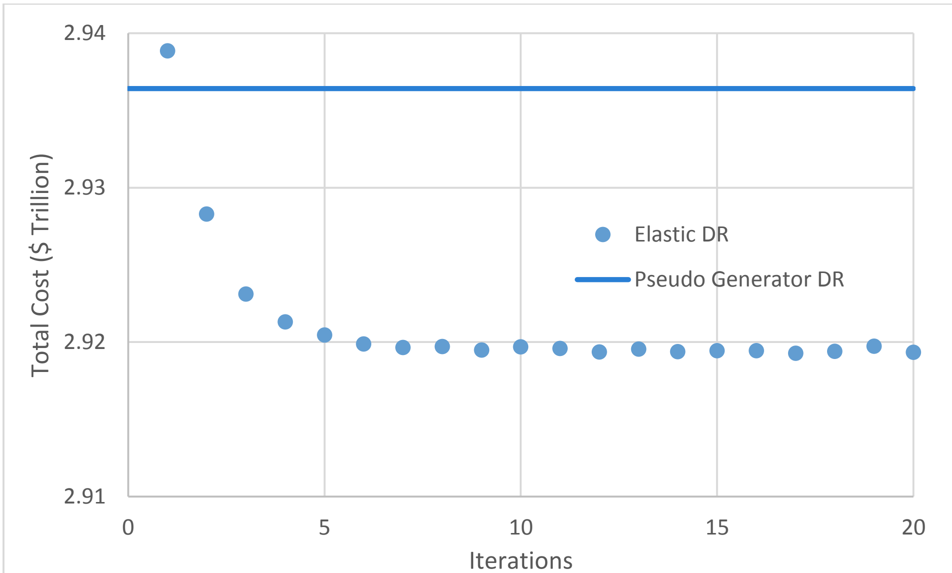
An alternate implementation of demand response which can address these shortcomings is to instead use elastic demand curves. This also allows for demand response to be represented with a smooth demand curve and can also represent load-shifting (cross-price elasticities over different hours[26]). Elastic demand response can also be viewed as a market where consumers are exposed and responsive to real time prices. The disadvantage of this implementation is that the inclusion of elastic demand introduces a nonlinearity to the problem. This nonlinear problem can be solved through the use of the numerical computation technique of Gauss-Seidel iteration, which is easily implemented. This proceeds by iterating between two submodels:

- A supply model, in which generation and transmission costs are minimized subject to assumed fixed loads, yielding locational marginal prices (shadow prices for regional energy balances for each time period); and
- A demand model, in which load is adjusted in each period and each region, based on the locational marginal prices.

The Gauss-Seidel procedure iterates between these two submodels until convergence occurs (the supply model's prices are consistent with the demands from the demand models).

[26] For instance, see C. De Jonghe, B.F. Hobbs, and R. Belmans, "Optimal generation mix with short-term demand response and wind penetration," IEEE Transactions on Power Systems, May 2012, 27(2), 830-839.

Figure 27: Convergence of Price Responsive Demand Response



With elastic demand response, we iterated between the two submodels for twenty iterations to achieve convergence in the solution. The solution converges by the sixth iteration of the problem, as the figure above shows. It should be noted that the elastic demand response implementation does not guarantee convergence; cycling may occur. After the sixth iteration a slight instability in the objective is visible, however the perturbations are relatively small, and our experience with this and other applications indicates that the procedure converges relatively quickly if demand elasticity is not too large.

The model is able to converge to lower cost solutions relative to the implementation with pseudo-generators. The difference in costs does not necessarily imply that the elastic demand response is better since there are fundamental differences as to how demand response is represented. Our implementation of the two approaches imply different elasticities as well as threshold prices for when demand response is dispatched within the model. Despite these fundamental differences a comparison between these models to explore the impact of this alternate implementation remains a valuable exercise.

Table 73: Energy mix comparison: two demand response representations (JHU)

Energy mix in 2030 (% of total energy produced)	[2.02.02 CO2+ Co-Opt] with Pseudo Demand Response	[2.02.02 CO2+ Co-Opt] with Elastic Demand Response
Nuclear	34.5%	34.6%
On-Shore Wind category 4	27.9%	27.9%
CC	20.1%	20.3%
Hydro	9.7%	9.7%
On-Shore Wind category 3	4.1%	4.1%
Other Renewable	3.3%	3.3%
CT	0.2%	0.1%

When compared on the basis of energy mixes the two solutions appear relatively similar (see the above table), with only minor differences in the mix of energy generated. The similarity between the two approaches is also reflected in the similarity of the installed generation capacities. The most significant difference is an increase in investment in combustion turbines under elastic demand response relative to the implementation with pseudo-generators. This is possibly an effect of difference between the step-wise supply curve represented by the pseudo-generators and the linear demand curves used in the elastic approach. It should be noted that while the elastic case slightly expanded generation capacity relative to the pseudo-generator implementation, both cases reduce combustion turbine capacity compared to an implementation with no demand response, as expected.

Table 74: Generation Capacities with Different Implantations of DR (MW)

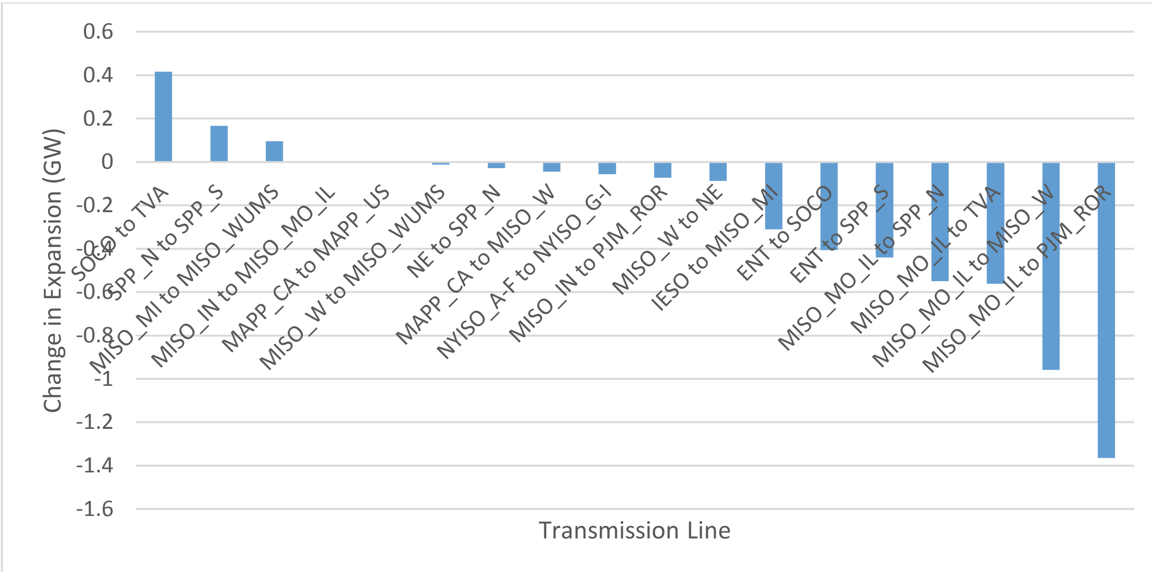
Cumulative Generation Capacity (GW)	[2.02.02 CO2+ Co-Opt] with Pseudo Demand Response	[2.02.02 CO2+ Co-Opt] with Elastic Demand Response	Delta
Combined Cycle	210.1	211.7	1.5
Coal	8.4	8.4	0.0
Combustion Turbine	59.3	62.5	3.3
Hydro	57.3	57.3	0.0
Nuclear	134.6	134.6	0.0
On-Shore Wind	305.3	305.1	-0.2
Other Renewable	19.6	19.5	-0.1
Pumped Storage	16.6	16.6	0.0
Steam Oil/Gas	0.2	0.2	0.0
Total	811.4	815.8	4.5

While generator operations and investments were largely similar between the two implementations of demand response, there were noticeable impacts on transmission investment decisions. Using the two metrics of transmission investment impacts from Table 71, there was an overall increase in transmission capacity (see below table and figure). The difference between the two metrics indicates that while there is significant expansion there some shifting of the location of transmission. However it should be noted that the difference in magnitudes between the two demand response representations is much less than when the demand-response solutions are compared to the original co-optimization solution. The transmission expansion plans from the two demand response cases are largely similar.

Table 75: Metrics Comparing Transmission Siting Pseudo-generator with Elastic DR

Normalized Sum of Differences	Normalized Sum of Absolute Differences
-3.74%	**4.94%**

Figure 28: Changes in Transmission Expansion between Pseudo-generator DR and Elastic DR



- .

XII. Task 3: Natural Gas and Electric Co-Optimizations

EISPC is interested in the applicability of using co-optimization techniques to address electric and natural gas operational and planning issues. The Energy Exemplar team prepared a case to evaluate the co-optimization of both electric gas production as well as the co-optimization of the generation and gas expansion. Energy Exemplar used some inputs from the EIPC gas electric study.

Task 3A: Evaluate Co-Optimization of Gas and Electric Production Cost for gas constraint and contingency analysis according to NERC gas electricity contingency concept.

Task 3B: Evaluate case of Co-Optimization of Gas and Electric Capacity Expansion for Dual Fuel, Gas Storage, Pipeline Expansion, Transmission Expansion, Generation Expansion, and Environmental Retro-fits. A simple demonstration model is used for Task 3B.

Task 3A: Co-optimization of Electric and Natural Gas Production Cost Modelling

The following sections outline the inputs and modelling for natural gas and electric co-optimizations.

1.11. Source for Gas Model

Energy Exemplar collected North American natural gas data from multiple sources. Some of the sources include:

- Natural gas pipeline specifications submitted to FERC;
- EIPC Gas-Electric documentation including nodal gas network with capacities, peak demand assumptions, expected hourly natural gas profile; dual fuel generators.
- Monthly EIA gas data by state including production; demands (RCIT and EP); imports and exports; prices.
- EIA Annual Energy Outlook including production growth by region; imports and exports; long term fuel price forecasts;
- Historical Daily natural gas prices by natural gas trading hub.
- Pipeline Daily Flow and Available capacity from gas bulletin boards.

1.12. Development of Natural Gas Model

Energy Exemplar has taken a top down approach to the development of its North American Natural Gas model. A state model with gas demands is built, where production and storage are modeled according to each state. This includes all of the pipelines with their respective capacities built between each state. This data is currently published by EIA as monthly data which is then converted to daily or hourly as required.

The gas pipeline network with multiple gas pipeline segments and gas nodes is built as per the EIPC Gas Electric study. Here, the expanded natural gas pipeline network will increase the fidelity of the natural gas model considerably. This build out process has been completed and demand and generation memberships are being developed. Finally, further expansion of gas pipeline network to a full gas nodal network for all pipelines is being done. This incorporate data from all data sources, including pipeline available capacity and flows from pipeline bulletin boards.

1.13. Gas Demands

Historical monthly gas demands are collected by state for the 5 natural gas market segments: Residential, Commercial, Industrial, Transport, and Electric Power (RCIT & EP) and have been used to develop an hourly gas demand profile for RCIT and EP.

Daily demands are created for each market segment. Residential and commercial are estimated using state Daily Heating Degree Days relative to each month. While, Industrial and Transport are assumed to have a flat daily profile as these demands should not change relative to weather events. Gas consumption by the Electric Power sector are estimated using state Daily Heating/Cooling Degree Days relative to each month. The daily profiles are then converted to hourly based on the EIPC Gas Electric gas profile with following guidelines:

- Residential and Commercial hourly profiles have been created for winter; summer; and rest-of-year hourly.
- Industrial and Transport are assumed to have a flat hourly profile.
- Electric Power is assumed to have profiles which match the electric grid demand for the respective season.

Gas demands for each state are represented as Residential, Commercial, Industrial, Transport, and Electric Power (RCIT & EP) for each state. Individual gas markets only have demand profiles for RCIT as the EP demands were derived from the commitment and dispatches of electric sector model. For running gas electric simulations the complete North American gas model runs with the user selectable electric markets.

Figure 29: North American Gas Model

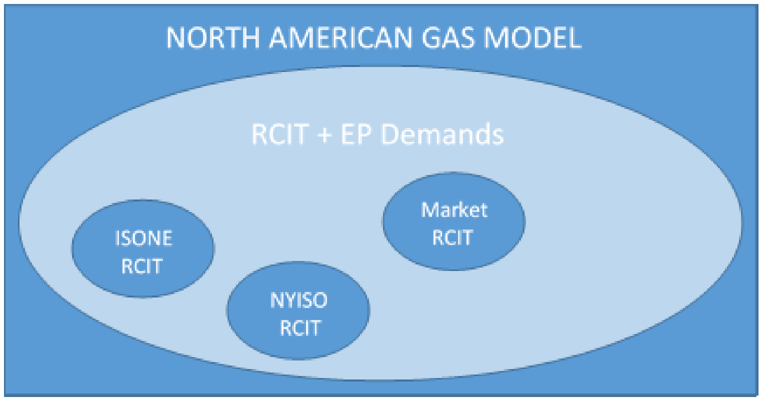
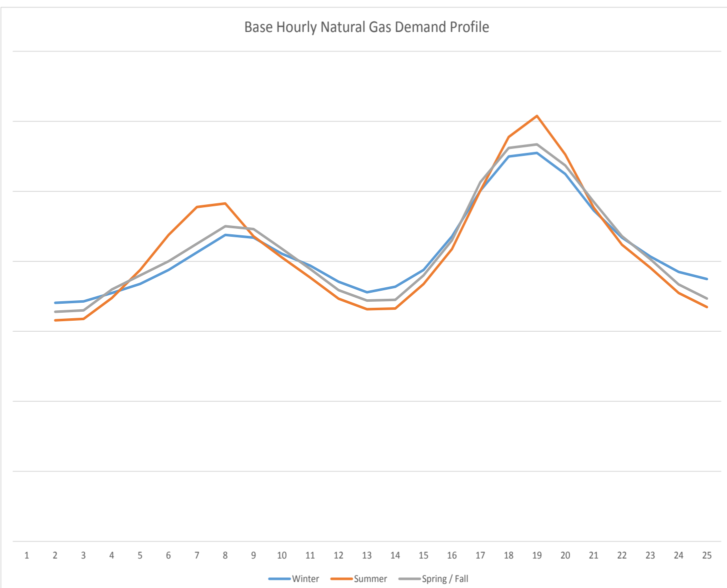


Figure 30: Hourly and Daily gas demand



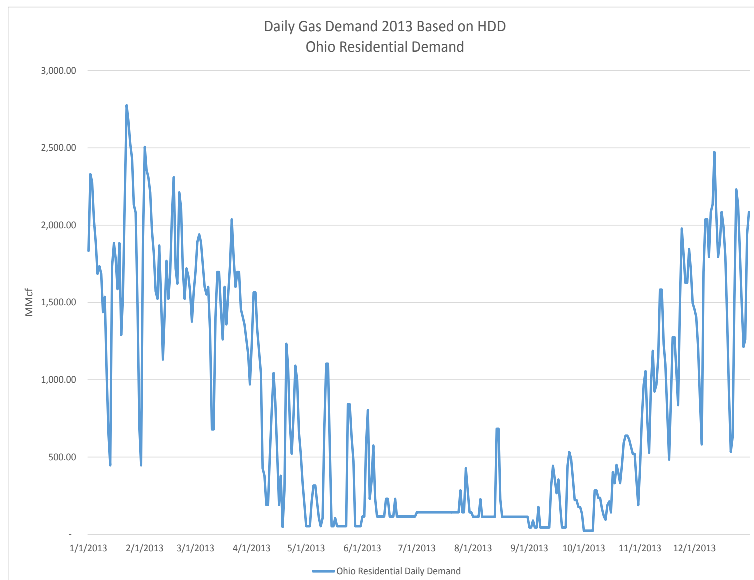
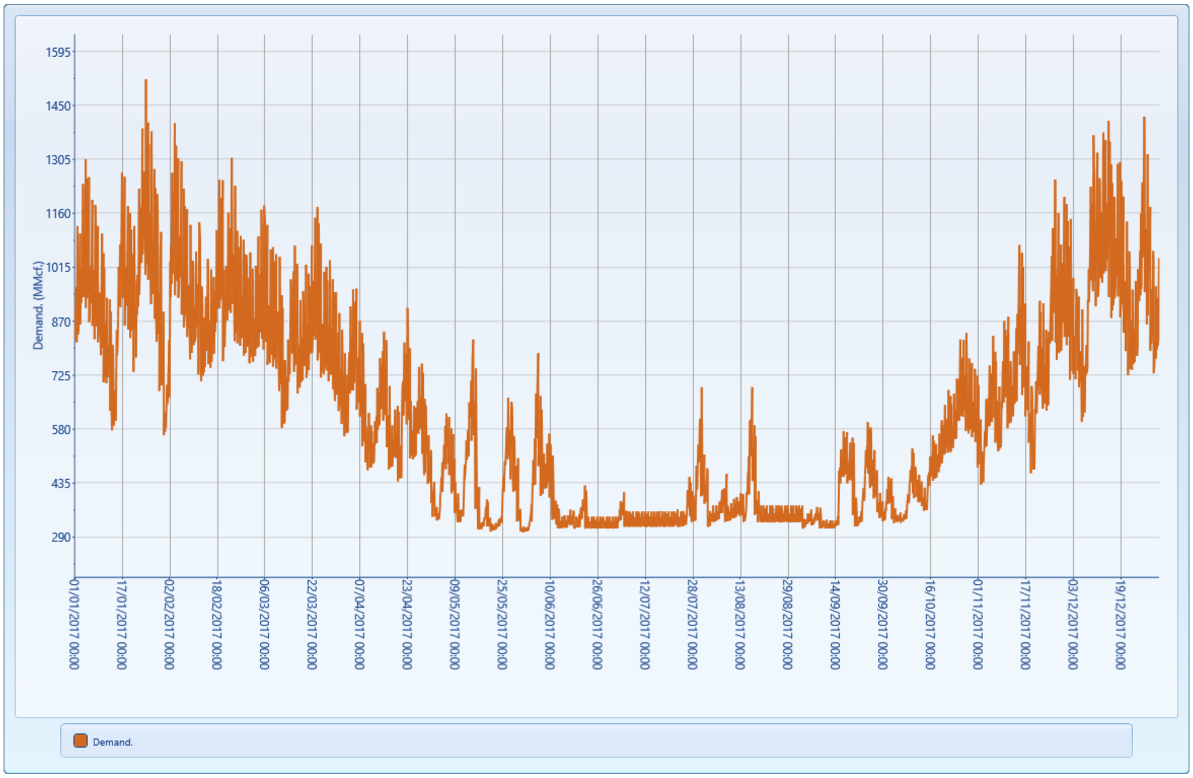


Figure 31: RCIT Gas Demand



1.14. Gas Fields

Gas fields are defined according to their physical location by state. Currently, we have 33 state production fields in the mainland US and the Gulf of Mexico. Furthermore, 7 historical liquefied natural gas (LNG) import points as well as 2 Foreign Production fields, one each for Canada and Mexico are present.

Historical Production is based on Monthly EIA production by state, which is then calculated to a daily max and min production. Historical Imports is based on Monthly EIA imports and exports which is then calculated to a daily max and min production. Forecast from the Annual Energy Outlook (AEO) estimate future regional contribution to production fields as well as imports.

1.15. Gas Pipelines

Pipelines carry natural gas from the production fields and natural gas storage to the end demand and gas generators. The pipelines are categorized according to the owner/operator of the pipeline. A combination of Min and Max Volume is used to calculate the capacity of the gas pipeline system. In addition, we include Max Flow is specified for each pipeline to manage the flows across the pipelines.

1.16. Gas Storage

State natural gas storage points are defined in PLEXOS, arranged according to the state in which they are located. Max and Min Volume are based on EIA most recent storage data by state. The difference between Max and Min Volume is the Base or Working Volume. Max Ramp Day has been used for Winter Withdrawal and Summer Injection rates per each storage.

1.17. Gas Nodes

Currently, the gas model in PLEXOS® is localized into nodes- one domestic node exists for each of the 48 states and DC. Two nodes (one representing exports, one imports) exist for Canada and Mexico, totaling to four foreign nodes.

1.18. Production Price Index

Production price index is included as a necessary variable in the gas database. These price indices reflect product cost price differences between the major natural gas production regions. These indices are linked to the Henry Hub pricing forecast. The Henry hub pricing forecast has been shown in the figure below, while the indices are shown in table below.

Figure 32: Henry Hub Price forecast

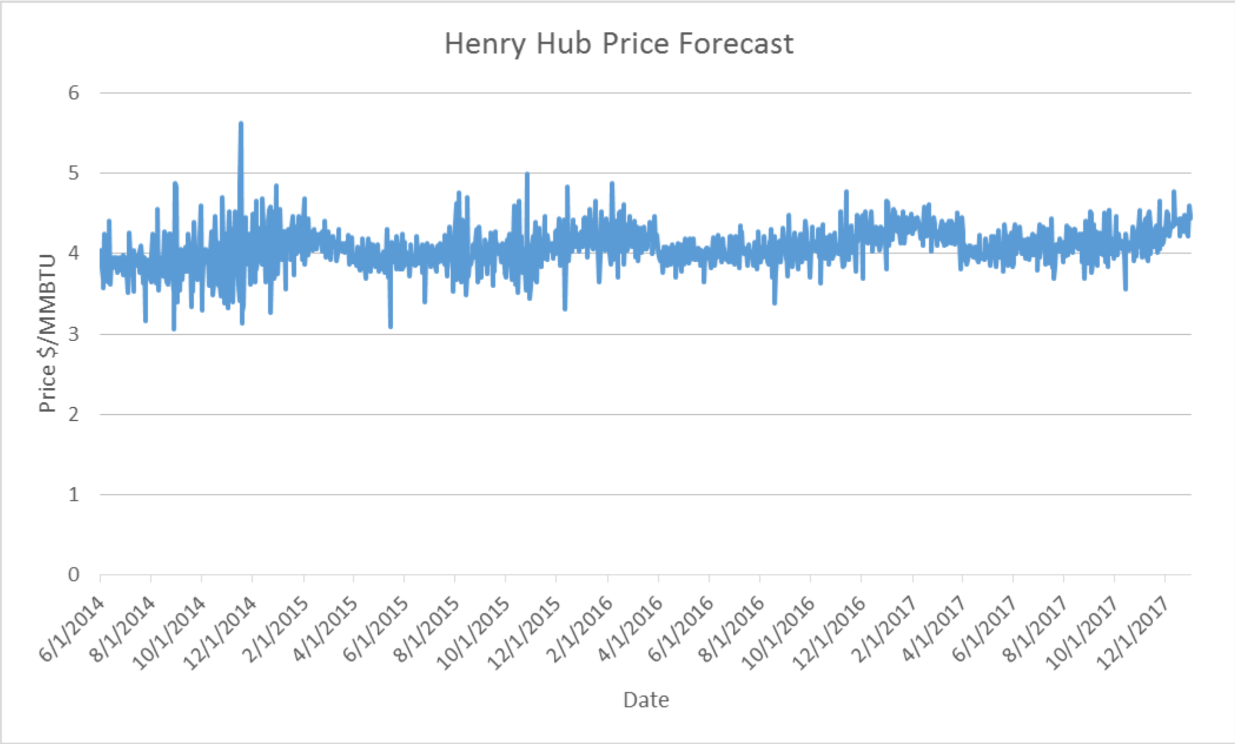


Table 76: Index per producer

Producer	Index
Canada Index	1.1
LNG Imports Index	2
Marginal Producers Index	1.1
Mexico Index	1
Secondary Producers Index	1
Shale Producers Index	0.95
Storage Withdrawal Index	0.1
Traditional Producers Index	0.9

1.19. Scenarios

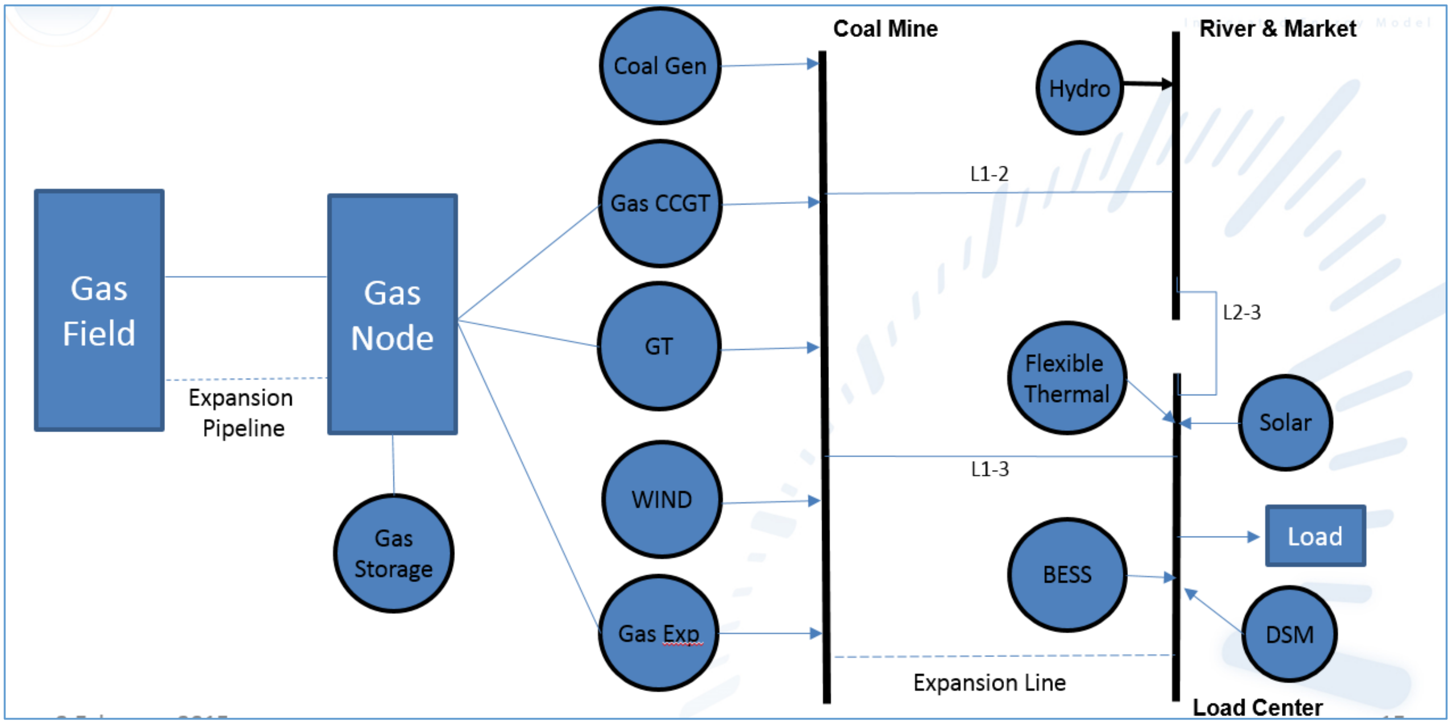
A variety of data is also placed into the scenarios section of PLEXOS. The gas model setting determines if the gas model will be run or not and will switch over to conventional csv files for fuel prices if the gas model is not used. EP and RCIT Hourly Gas demands reflect gas demands as defined through the PLEXOS® electric simulation and through RCIT forecasts, respectively. Hourly and Monthly demands reflect existing historical data on demand shapes. Gas storage and gas pipelines reflect storage and pipeline .csv data relevant to specific scenarios.

Task 3B: Co-optimization of Electric and Natural Gas Production Cost Modelling

For Task 3B, we have developed an initial simplified model to demonstrate the co-optimization with of gas electric capacity expansion. In this model, we have made the following overlying network assumptions:

- Electric: a nodal impedence model with generation and load across the 3 nodes (Coal Mine; River & Market; and Load Center). See Figure below.
- Natural Gas: a separate gas model with a single production field and two demand nodes. In addition, the natural gas generators are located at a third gas node, creating an additional variable gas load with the fuel offtake from the natural gas generation.

Figure: Simplified Electric and Gas Expansion Model Network



XIII. Task 3: Gas Electric Production Cost Results

Task 3A: Co-optimization of Electric and Natural Gas Results

For demonstrating Task 3A, Energy Exemplar's PLEXOS® Gas Electric Database (described in Appendix B) has been configured to simulate Gas Electric Co-optimization in the PJM Classic, NYISO and ISO-Ne footprint. Below are the PLEXOS® results for Gas Electric production cost simulation for 1-month (Jan 2015).

1. **PJM Classic+NYISO+ISO-NE Gas Electric Production cost for January 2015**

Regional Production Cost is the total generation cost including fuel, variable operations and maintenance costs, start and shutdown costs and emissions costs and is defined as:

Total Generation Cost = Generation Cost + Start & Shutdown Cost + Emissions Cost

Jan 2015 Production Cost - PJM Classic+NYISO+ISO-NE
$ 1,468,072,559.08

2. Gas Prices for Jan 2015

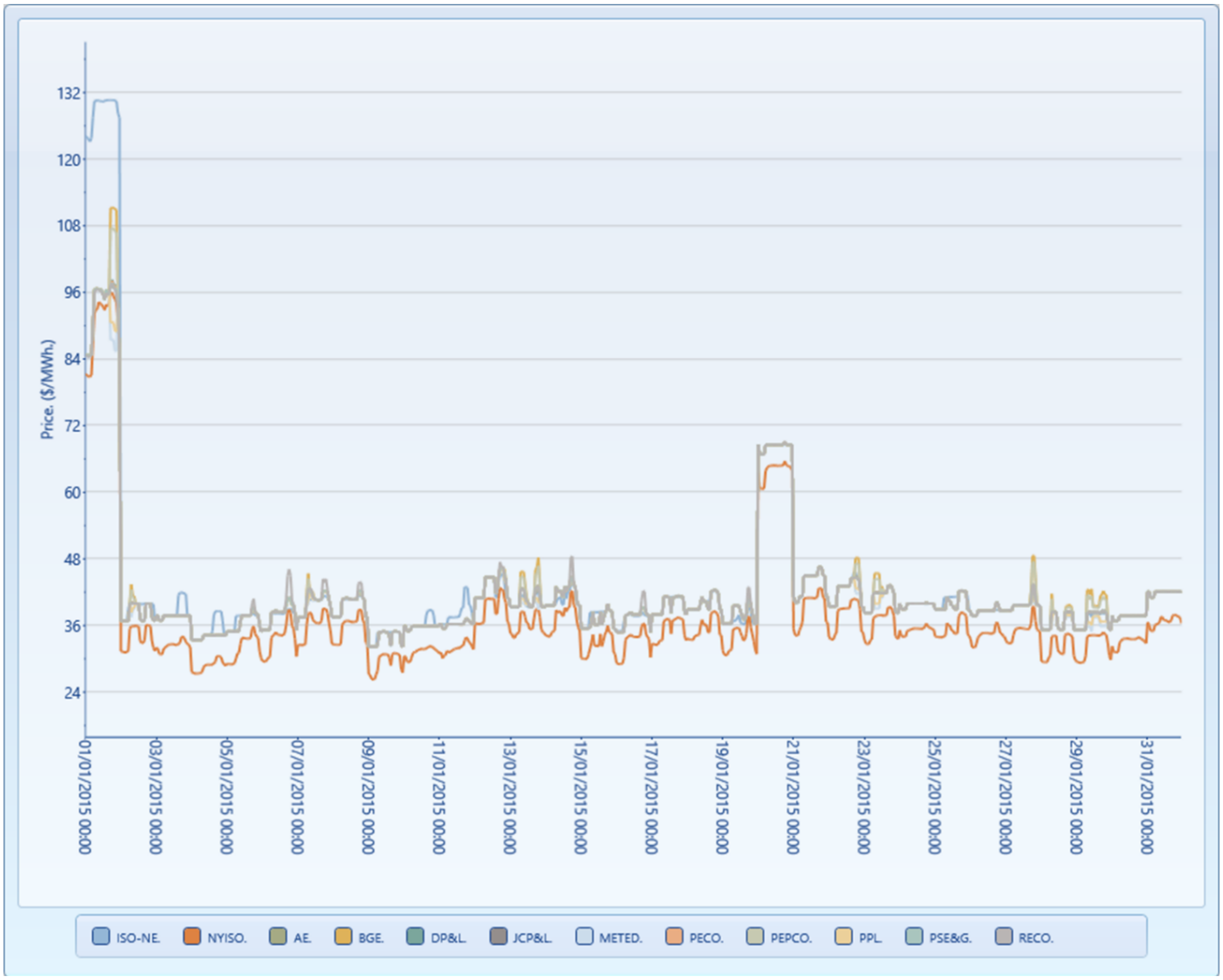
Below are the hourly Gas prices for the states CT, MA, NJ, NY & PA which are an output of the Gas model for Jan 2015.

Figure 33: Hourly Gas Prices ($/MMBTU)

3. Electricity Prices for Jan 2015

Due to the higher Gas prices in the initial periods, the electricity prices ($/MWh) are also high. Below is a figure of hourly LMP's for NYISO, ISO-NE and PJM Classic zones.

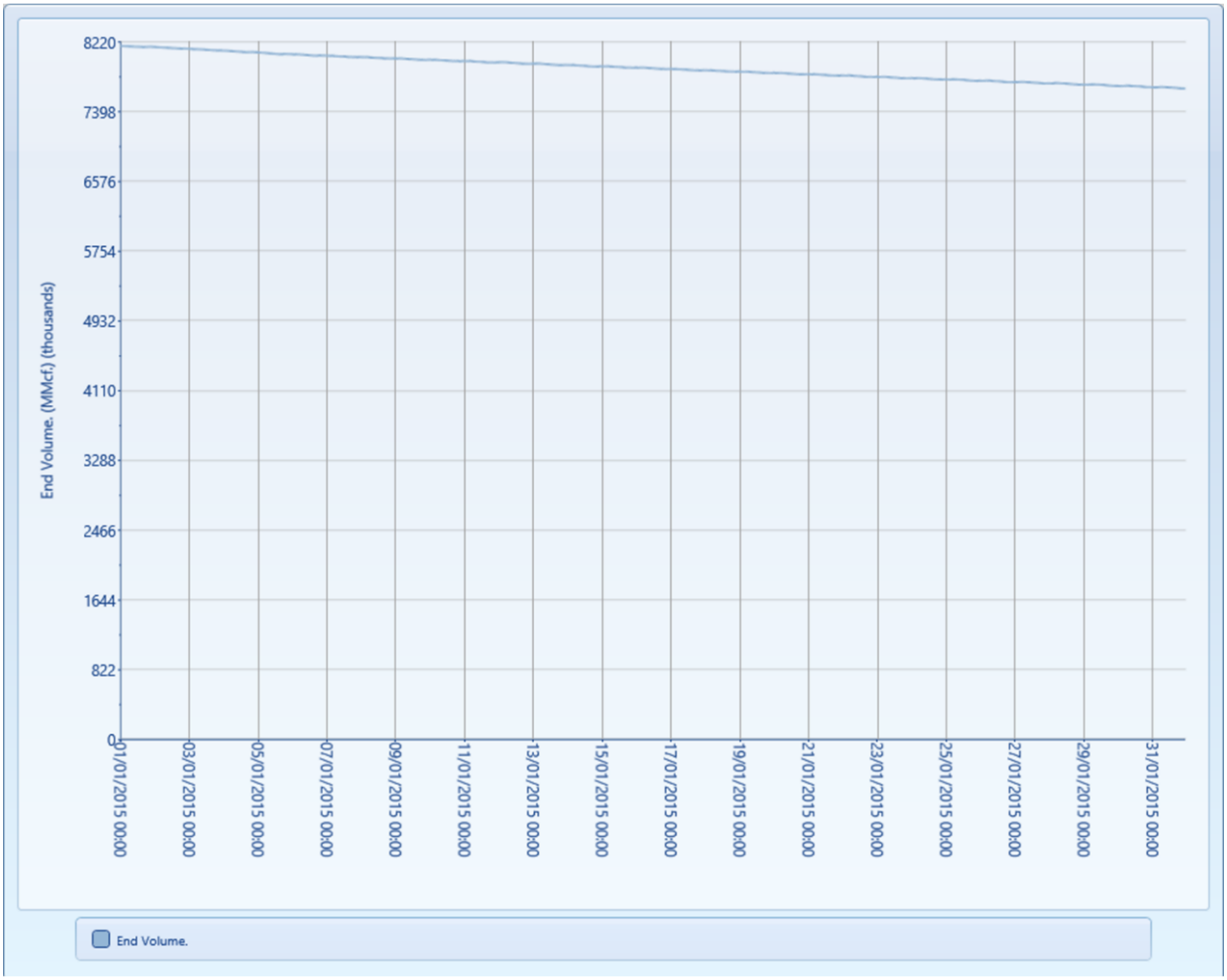
Figure 34: Hourly LMP's ($/MWh) for Jan 2015



4. US Gas Storage

The figure below shows the overall US Gas Storage End Volume (MMcf) which is being utilized over the course of the horizon and hence is decreasing.

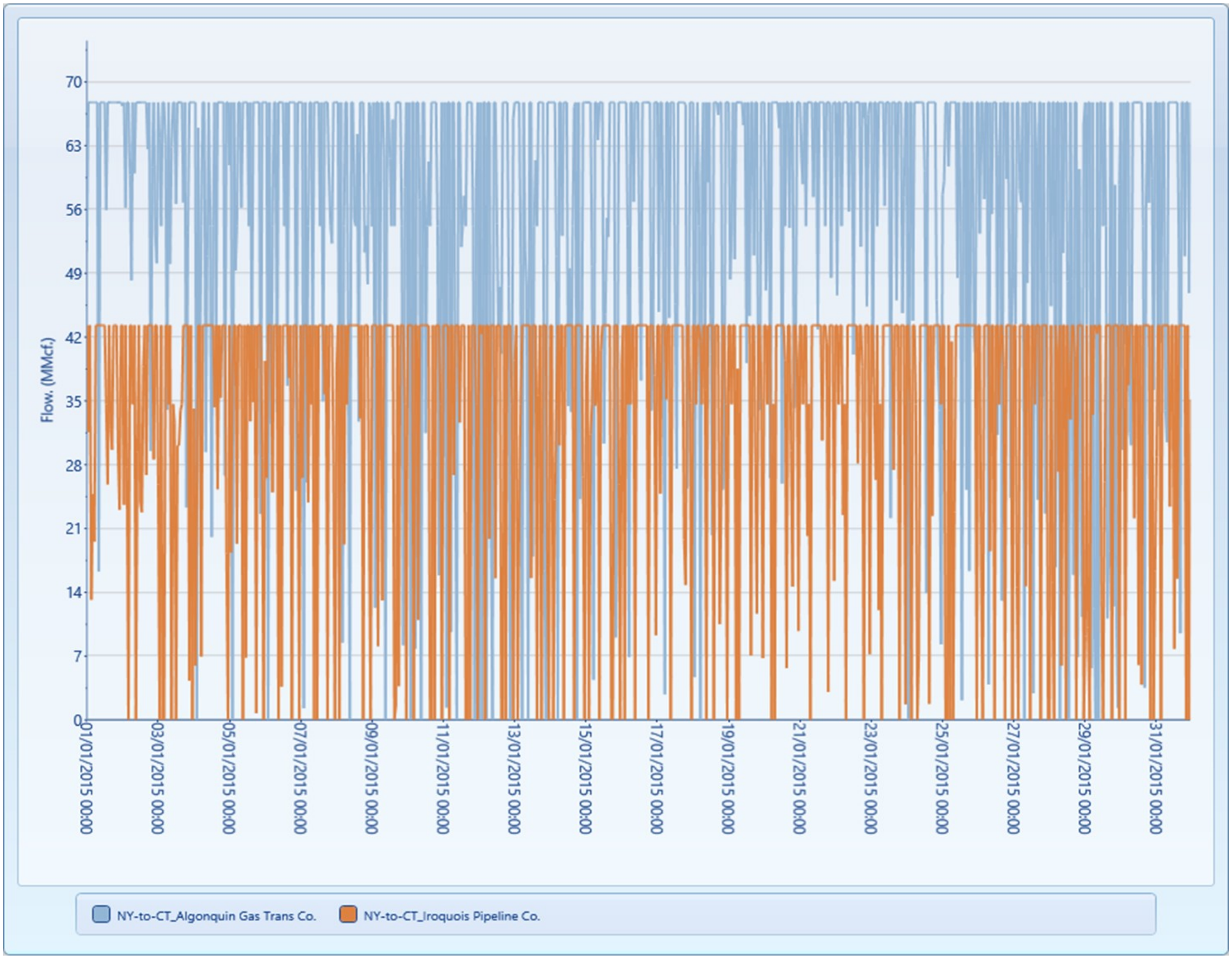
Figure 35: US Gas Storage End Volume (MMcf)



5. Gas Pipeline Flows

Hourly Gas Pipeline flows for Jan 2015 have been charted below for "NY to CT Algonquin Gas Transmission Co." & "NY to CT Iroquois Pipeline Co.".

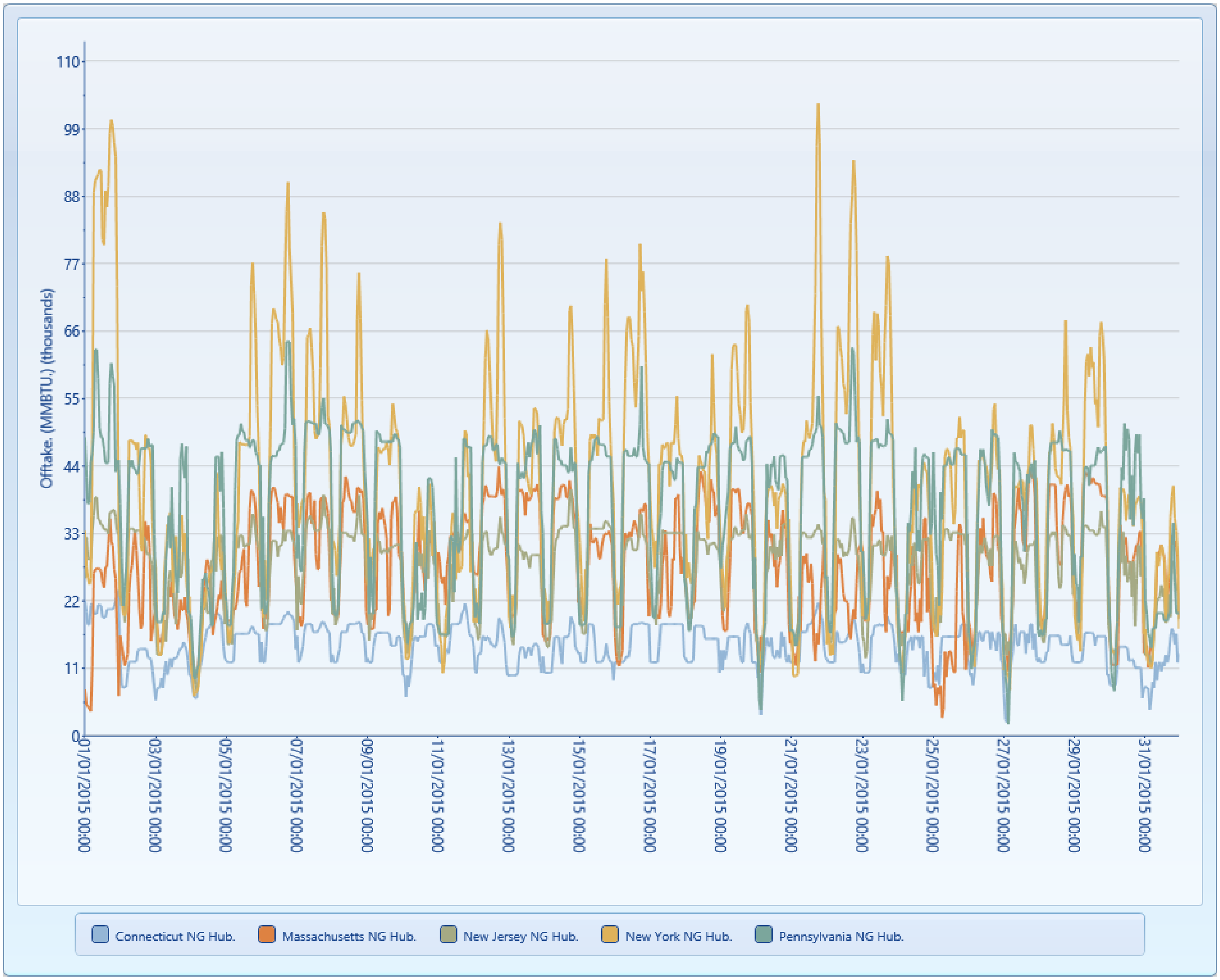
Figure 36: Hourly Gas Pipeline flows (MMcf)



6. Gas Generation

January 2015 Hourly Gas generation for CT, MA, NY, NJ and PA hubs are shown below:

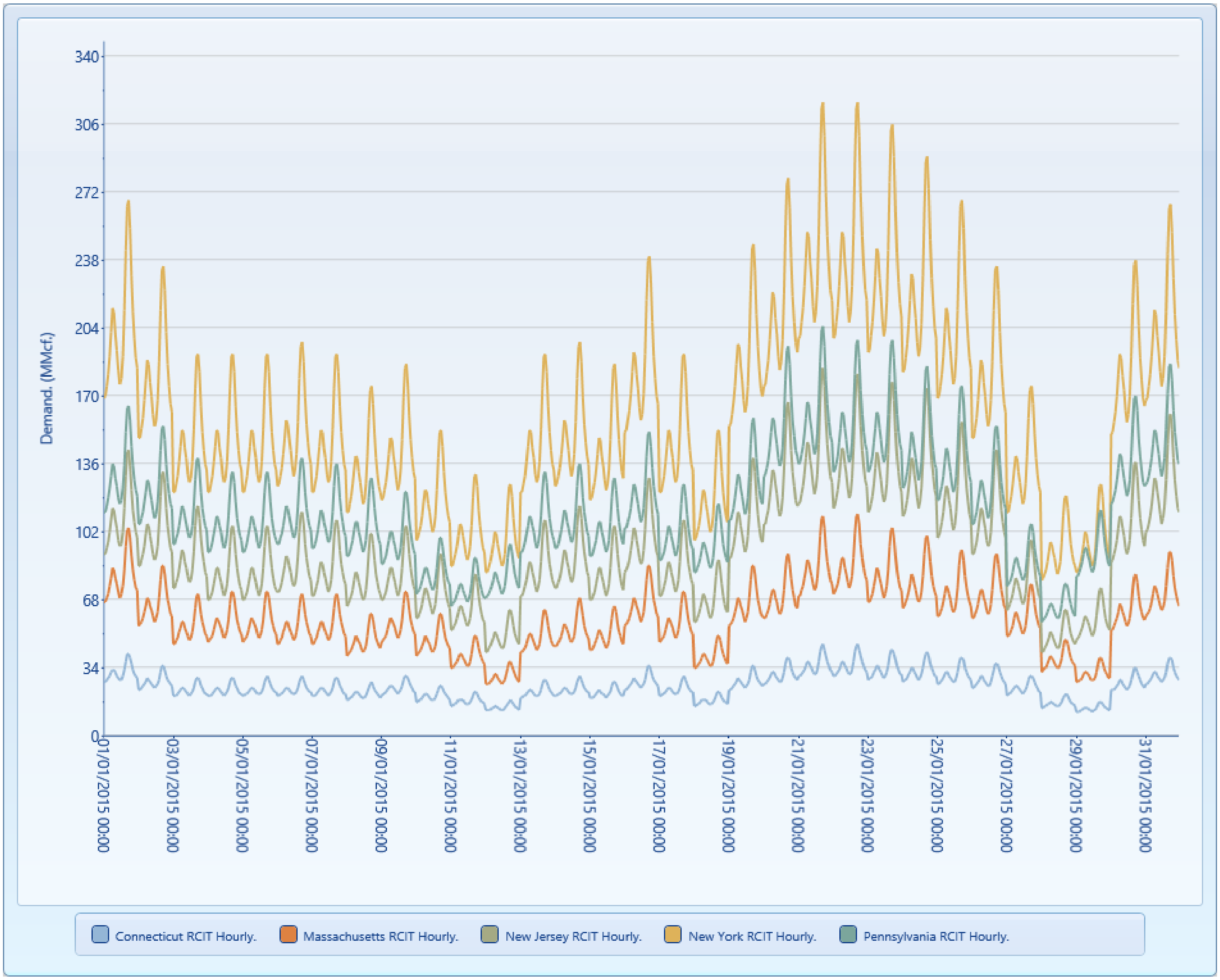
Figure 37: Hourly Gas Generation (MMBTU)



7. **RCIT Gas Demands (RCIT – Residential, Commercial, Industrial, Transport Demand)**

An area stack chart of January 2015 Hourly RCIT Gas Demands for CT, MA, NY, NJ and PA is shown below:

Figure 38: Hourly RCIT Gas Demand (MMcf)



Task 3B: Gas Electric Co-optimization Expansion Results

Task 3B evaluates the benefits of co-optimization across transmission expansion, generation expansion and natural gas pipeline expansions. To demonstrate this, we began with a simplified three node model as described in the previous section. First we allow only the expansion of generation resources. Then we allow the expansion of generation resources and transmission line expansion followed by the expansion of all three resources. The result is a reduction in the total system costs through each step as summarized below with a total system benefit of all three resources of 25.4% with the co-optimization of gas and electric.

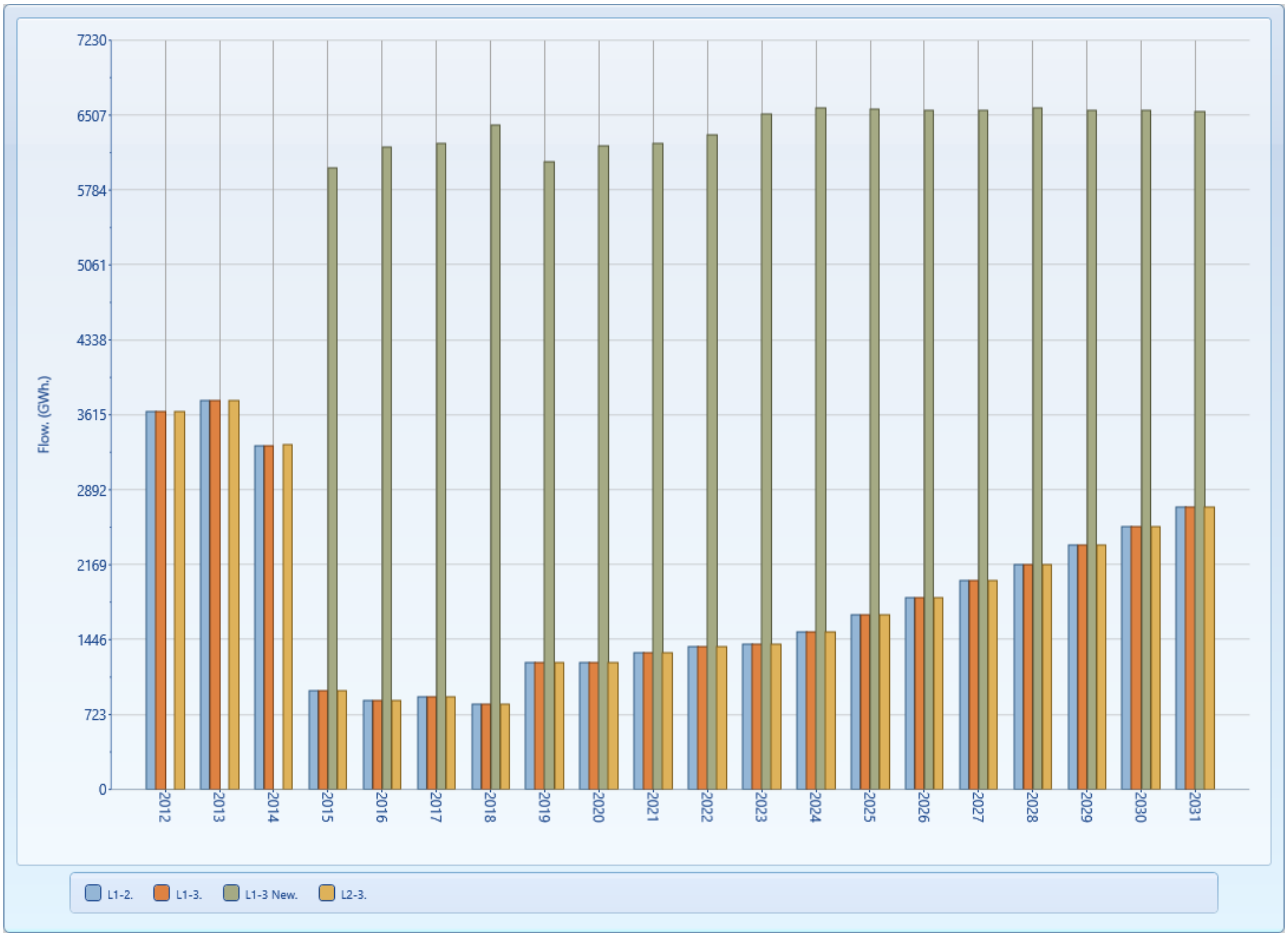
Table: Summary Results of Gas / Electric Co-optimization

Gas Electric Demonstration Model	**Total System Costs**	**Dollar Savings**	**Percentage Savings**
Base Case: Generation Expansion	$27,840,057,031		
Co-Opt of Tx and Generation	$22,730,045,052	$5,110,011,979	22.5%
Co-Opt of Gas and Electric	$22,196,120,472	$533,924,580	2.4%
Total Savings		$5,643,936,559	25.4%

The following is a summary of the expansion results for the Co-opt of Gas and Electric

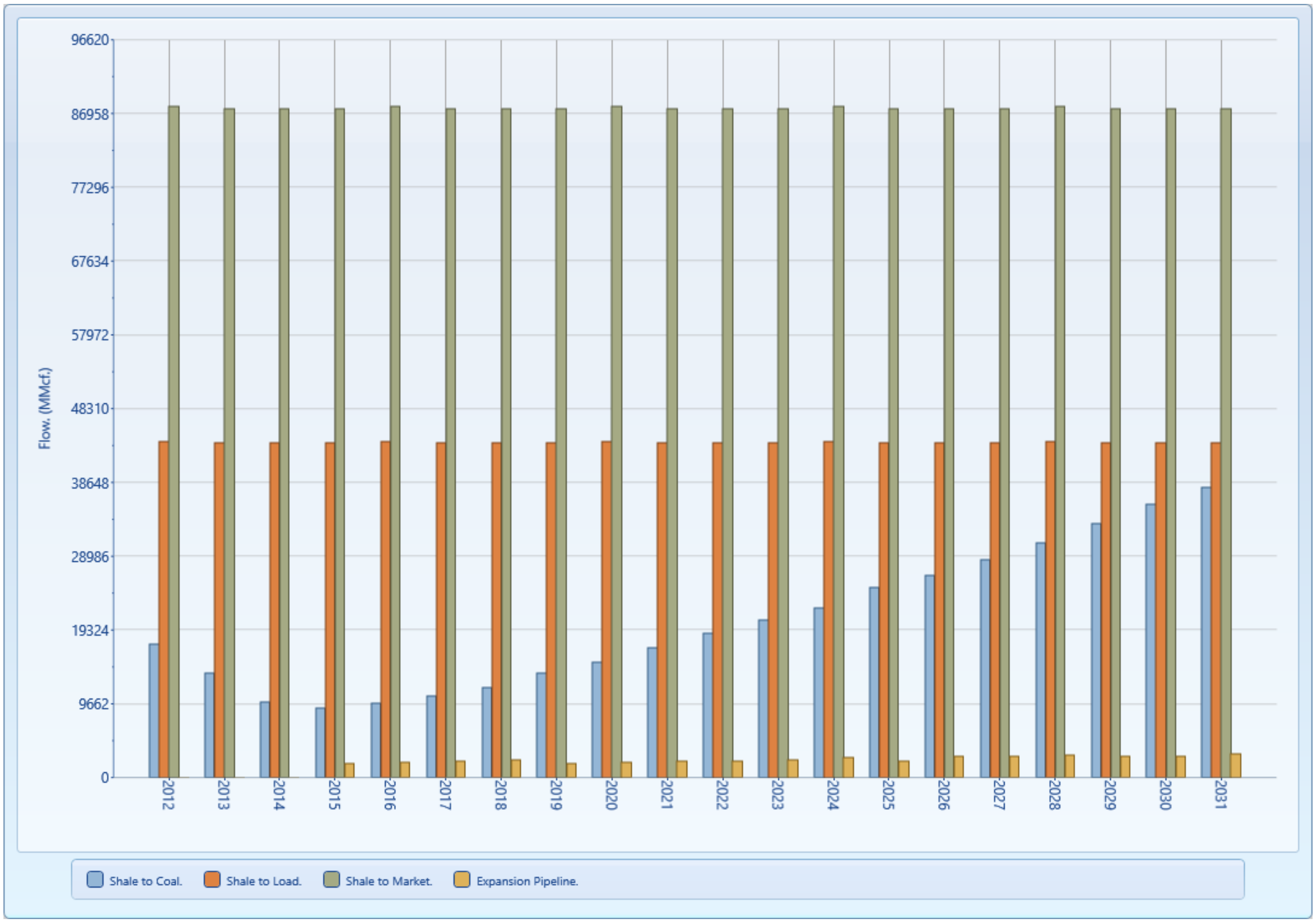
1. Expansion of Transmission Line

Beginning in 2015, the co-optimization of gas electric solution expands the transmission line from the generation center (L1) to the load (L3). This is depicted with the annual flows on the transmission network below with flows on the new line beginning in 2015.



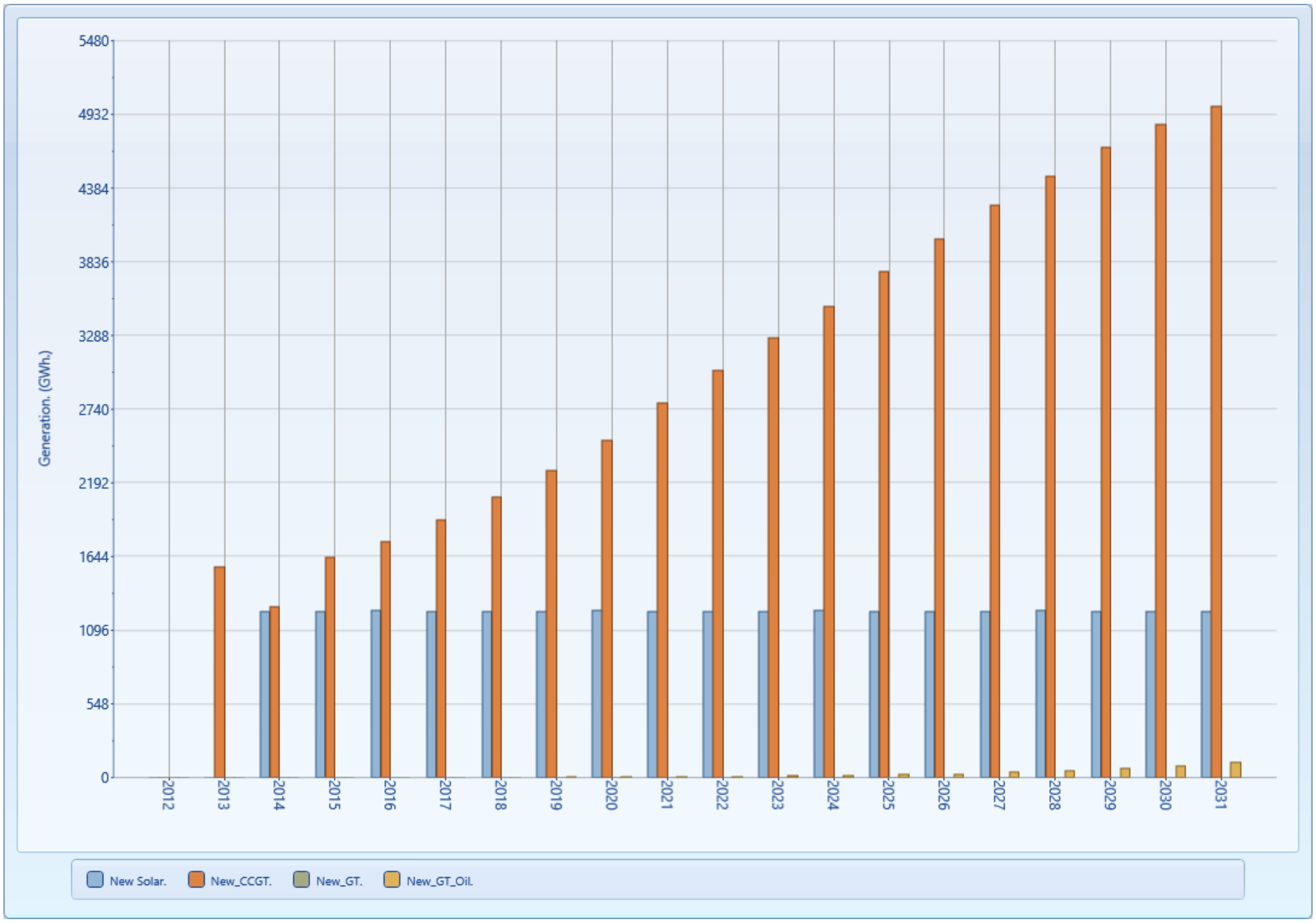
2. Expansion of Pipeline

Beginning in 2015, the co-optimization of gas electric solution expands natural gas pipeline from the gas production field to the generation gas node (Expansion Pipeline). This is depicted with the annual flows on the gas pipeline network below with flows on the new line beginning in 2015.



3. Generation by Expansion Candidate

In the co-optimization of gas and electric, there is a significant expansion of new CCGT, in part due to the availability of natural gas from the pipeline expansion. This is represented by the total annual generation of the New CCGT, with expansion generation from 2015.



Appendix A

Table 77: Chart of PLEXOS® Parameters

Source: MRN-NEEM Assumptions, EIPC

PLEXOS® Variable/Parameter	Description	Type	Units	Source
$GenBuild_{(g,y)}$	Number of generating units build in year *y* for generator *g*	integer	integer	input
$GenLoad_{(g,t)}$	Dispatch level of generating unit *g* in period *t*	continuous	MW	input
USE_t	Unserved energy in dispatch period *t*	continuous	MW	Can be derived from EIPC Load Blocks and existing capacity data
$CapShort_y$	Capacity shortage in year *y*	continuous	MW	See above
D	Discount rate	continuous	percentage	National/macro data
DF_y	Discount factor applied to year, i.e., $DFy = 1/1(1+D)y$	continuous	percentage	See above
DF_t	Discount factor applied to period	continuous	percentage	See above
L_t	Duration of dispatch period	integer	hours	EIPC - MRN-NEEM Master Exhibit 2, Table 1
$MaxUnitsBuilt_{(g,y)}$	Maximum number of units of generator *g* allowed to be built by the end of year *y*	integer	integer	EIPC - MRN-NEEM Master Exhibit 11, 12
$PMAX_g$	Maximum generating capacity of each unit of generator *g*	continuous	MW	EIPC - MRN-NEEM Master Exhibit 11, 12
$Units_g$	Number of installed generating units of generator *g*	integer	integer	EIPC - MRN-NEEM Master Exhibit 11, 12
Heat Rate	Thermal efficiency of turning fuel into electricity	continuous	BTU/KWh	EIPC - MRN-NEEM Master Table 4
Fuel Price	Average cost of fuel	continuous	2010 $	
$VOMCharge_g$	Variable operations and maintenance charge of generator *g*	continuous	2010 $/MW·hour	EIPC - MRN-NEEM Master Table 4
$FOMCharge_g$	Fixed operations and maintenance charge of generator *g*	continuous	2010 $/KW·year	EIPC - MRN-NEEM Master Table 4
$Load_t$	Average power demand in dispatch period *t* relative to power demand in peak demand	continuous	MW/MW	EIPC - MRN-NEEM Master
$ReserveMargin_y$	Margin required over maximum power demand in year *y*	continuous	MW	EIPC - MRN-NEEM Master Table 15
Economic Life	Economic life of investment	integer	years	EIPC - MRN-NEEM Master Table 12
RegMult	Regional multipliers	continuous		EIPC - MRN-NEEM Master Exhibit 10
TransLim	Transmission limits by line	continuous	MW	EIPC - MRN-NEEM Transfer Limits
WindCap	Wind capacity as percentage of total capacity by load block	continuous	percentage	EIPC - MRN-NEEM Master Exhibit 4
StateACP	Alternative compliance payments	continuous	2010 $	EIPC - MRN-NEEM Master Exhibit 15
DemandGrowth	Average demand growth rate	continuous	percentage	EIPC - MRN-NEEM Master Table 3
LoadBlockHour	Hours in top load block	integer		EIPC - MRN-NEEM Master Exhibit 3

Table 78: Planning Areas and NEEM Regions

Source: MRN-NEEM Assumptions, EIPC

Planning Area	NEEM Region
Allegheney Power	AE
Arizona Electric Power Coop Inc	AZ_NM_SNV
Arizona Public Service Co	AZ_NM_SNV
El Paso Electric Co	AZ_NM_SNV
Nevada Power Co	AZ_NM_SNV
Public Service Co of New Mexico	AZ_NM_SNV
Salt River Project	AZ_NM_SNV
Tucson Electric Power Co	AZ_NM_SNV
WAPA Lower Colorado Region	AZ_NM_SNV
Ameren Corporation Control Area	EMO
Associated Electric Coop Inc	EMO
Columbia (MO) Water & Light	EMO
City of Conway	ENT
Entergy Services Inc	ENT
North Little Rock AR (City of)	ENT
Sam Rayburn G&T Electric Coop Inc	ENT
Clarksdale Public Utilities Commission	ENT
Louisiana Generating LLC	ENT
ERCOT	ERCOT
Florida Municipal Power Agency	FRCC
Florida Power & Light Co	FRCC
Gainesville Regional Utilities	FRCC
JEA	FRCC
Lakeland Dept of Electric Water Utilities	FRCC
Orlando Utilities Commission	FRCC
Progress Energy (Florida Power Corp.)	FRCC
Seminole Electric Coop Inc	FRCC
St Cloud (City of)	FRCC
Tallahassee FL (City of)	FRCC
Tampa Electric Co	FRCC
Algona Municipal Utilities	MAPP_US
Allete (Minnesota Power)	MAPP_US
Alliant Energy-West	MAPP_US
Ames Municipal Electric System	MAPP_US
Atlantic Municipal Utilities	MAPP_US
Basin Electric Power Cooperative	MAPP_US
Central Minnesota Municipal Power Agency	MAPP_US
Great River Energy	MAPP_US
Harlan Municipal Utilities	MAPP_US
Heartland Consumers Power District	MAPP_US
Hutchinson Utilities Commission	MAPP_US
Marshall Municipal Utilities	MAPP_US
MidAmerican Energy Company	MAPP_US
Minnesota Municipal Power Agency	MAPP_US
Minnkota Power Coop	MAPP_US
Missouri River Energy Services	MAPP_US
Montana-Dakota Utilities Company	MAPP_US
Muscatine Power & Water	MAPP_US
New Ulm Public Utilities	MAPP_US
Northern States Power Company	MAPP_US
NorthWestern Energy (South Dakota)	MAPP_US
Otter Tail Power Company	MAPP_US
Pella (City of)	MAPP_US
Rochester Public Utilities	MAPP_US
Southern Minnesota Municipal Power Agency	MAPP_US
Square Butte Electric Coop	MAPP_US

WAPA Upper Great Plains East	MAPP_US
Willmar Municipal Utilities Commission	MAPP_US
Consumers Energy Company	MI
Detroit Edison Company	MI
Wolverine Power Supply Coop Inc	MI
Duke Energy Corp.	MISO_E
Hoosier Energy REC, Inc.	MISO_E
Indianapolis Power & Light Company	MISO_E
Northern Indiana Public Service Company	MISO_E
Southern Indiana Gas & Electric Company	MISO_E
Wabash Valley Power Association	MISO_E
American Municipal Power-Ohio, Inc.	MISO_E
Indiana Municipal Power Agency	MISO_E
Hastings Utilities (NE)	NE
Lincoln Electric System	NE
Municipal Energy Agency of Nebraska	NE
Nebraska Public Power District	NE
Omaha Public Power District	NE
NEISO	NEISO
Commonwealth Edison	NI
Big Rivers Electric Corp	NonRTO_Midwest
Buckeye Power Inc	NonRTO_Midwest
East Kentucky Power Coop Inc	NonRTO_Midwest
Louisville Gas & Electric Co	NonRTO_Midwest
Ohio Valley Electric Corp	NonRTO_Midwest
Modesto Irrigation District	NP15
Pacific Gas & Electric Co	NP15
Sacramento Municipal Utility District	NP15
Turlock Irrigation District	NP15
Avista Corp	NWPP
Bonneville Power Administration	NWPP
Eugene Water & Electric Board	NWPP
Idaho Power Co	NWPP
NorthWestern Energy	NWPP
PacifiCorp	NWPP
Portland General Electric Co	NWPP
PUD No 1 of Chelan County	NWPP
PUD No 1 of Douglas County	NWPP
PUD No 2 of Grant County	NWPP
Puget Sound Energy Inc	NWPP
Seattle City Light	NWPP
Sierra Pacific Power Co	NWPP
Tacoma Power	NWPP
WAPA Upper Great Plains West	NWPP
NYISO Zone F	NYISO_Capital
NYISO Zone G	NYISO_Downstate
NYISO Zone H	NYISO_Downstate
NYISO Zone I	NYISO_Downstate
NYISO Zone K	NYISO_LIPA
NYISO Zone J	NYISO_NYC
NYISO Zone A	NYISO_Upstate
NYISO Zone B	NYISO_Upstate

NYISO Zone C	NYISO_Upstate
NYISO Zone D	NYISO_Upstate
NYISO Zone E	NYISO_Upstate
Dominion	PJM_D
Atlantic Electric	PJM_E
Delmarva Power & Light	PJM_E
Jersey Central	PJM_E
PECO	PJM_E
Public Service	PJM_E
Rockland Electric	PJM_E
American Electric Power	PJM_Midwest
Dayton Power & Light	PJM_Midwest
Duquesne Light Company	PJM_Midwest
First Energy	PJM_Midwest
Baltimore Gas & Electric	PJM_SW
PEPCO	PJM_SW
Metropolitan Edison	PJM_W
PennElec	PJM_W
PP&L and UGI	PJM_W
Black Hills Corp	RMPA
Colorado Springs Utilities	RMPA
Platte River Power Authority	RMPA
Public Service Co of Colorado	RMPA
Tri State G & T Association Inc	RMPA
WAPA Rocky Mountain Region	RMPA
Ameren (Illinois Power Co. Control Area)	SCIL
City of Springfield	SCIL
Southern Illinois Power Coop	SCIL
Alabama Power Co	SOCO
Georgia Power Co	SOCO
Gulf Power Co	SOCO
Mississippi Power Co	SOCO
Oglethorpe Power Corp	SOCO
PowerSouth Energy Coop	SOCO
South Mississippi Electric Power Association	SOCO
Southern Power Co	SOCO
MEAG Power	SOCO
Burbank (City of)	SP15
Imperial Irrigation District	SP15
Los Angeles Dept of Water & Power	SP15
Metropolitan Water District	SP15
San Diego Gas & Electric Co	SP15
Southern California Edison	SP15
City of Independence MO	SPP_N
City Utilities of Springfield (MO)	SPP_N
Empire District Electric Co (The)	SPP_N
Kansas City KS (City of)	SPP_N
Kansas City Power & Light Co	SPP_N
KCP&L Greater Missouri Operations	SPP_N
Sunflower Electric Power Corp	SPP_N
Westar Energy (KPL)	SPP_N
American Electric Power Co Inc (AEP West)	SPP_S

Cleco Corp	SPP_S
Golden Spread Electric Coop Inc	SPP_S
Grand River Dam Authority	SPP_S
Lafayette Utilities System	SPP_S
Louisiana Energy & Power Authority	SPP_S
Northeast Texas Electric Coop Inc	SPP_S
Oklahoma Gas & Electric Co	SPP_S
Oklahoma Municipal Power Authority	SPP_S
Southwestern Power Administration	SPP_S
Southwestern Public Service Co	SPP_S
Tex La Electric Coop of Texas Inc	SPP_S
Western Farmers Electric Coop	SPP_S
Arkansas Electric Cooperative	SPP_S
Fayetteville Public Service	TVA
Tennessee Valley Authority	TVA
Central Electric Power Coop Inc	VACAR
Duke Energy Carolinas LLC	VACAR
Greenville Utilities Commission	VACAR
Progress Energy Carolina	VACAR
South Carolina Electric & Gas	VACAR
South Carolina Public Service Authority	VACAR
Alliant Energy-East	WUMS
Dairyland Power Coop	WUMS
Madison Gas & Electric Company	WUMS
Upper Peninsula Power Company	WUMS
Wisconsin Electric Power Company	WUMS
Wisconsin Public Service Corporation	WUMS
WPPI Energy	WUMS

Table 79: Capital Costs

Source: MRN-NEEM Assumptions, EIPC

Technology	AEO: Base Overnight Costs in 2011 (2010$/kW)	Learning by 2025	Base Overnight Capital Costs in 2025 ($2010/kW)	Gas Pipeline Cost	Electrical transmission	Rail Spur	Nuclear Decommissioning Cost	All-in Capital Cost in 2011 w/o IDC ($2010/kW)	All-in Capital Cost in 2025 w/o IDC ($2010/kW)
Nuclear	5,339	10%	4,805	0	21.92	0.00	253.97	5,615	5,081
Advanced Coal	2,844	5%	2,702	0	21.92	18.99	0.00	2,885	2,743
CC F-Frame	978	5%	929	9.98	21.92	0.00	0.00	1,010	961
CC H-Frame	1,003	5%	953	9.98	21.92	0.00	0.00	1,035	985
CT F-Frame	665	5%	632	24.41	21.92	0.00	0.00	711	678
IGCC	3,221	5%	3,060	0	21.92	18.99	0.00	3,262	3,101
IGCC w/seq	5,348	11.0%	4,762	0	21.92	18.99	0.00	5,389	4,802
Wind (options B&A)	2,438	10%	2,194	0	21.92	0.00	0.00	2,460	2,216
Wind Offshore	5,975	20%	4,780	0	21.92	0.00	0.00	5,997	4,802
Photovoltaic	4,755	20%	3,804	0	21.92	0.00	0.00	4,777	3,826
Solar Thermal	4,692	20%	3,754	0	21.92	0.00	0.00	4,714	3,776
Landfill Gas	2,503	5%	2,378	0	21.92	0.00	0.00	2,525	2,400
Biomass	3,860	20%	3,088	0	21.92	18.99	0.00	3,901	3,129
Geothermal	4,141	10%	3,727	0	21.92	0.00	0.00	4,163	3,749

Table 80: Capital and Operational Costs

Source: MRN-NEEM Assumptions, EIPC

	Capital Costs		Performance Data			
Technology	**2015 All-in Capital Cost (2010$/kW)**	**2025 All-in Capital Cost (2010$/kW)**	**Total FOM (2010$/kW-yr)**	**Total VOM (2010$/MWh)**	**2010 Heat Rate - HHV (Btu/kWh)**	**2015+ Heat Rate - HHV (Btu/kWh)**
Nuclear	5,462	5,081	88.75	2.04	10,488	10,488
Advanced Coal	2,844	2,743	29.67	4.25	9,200	8,800
CC H-Frame	1,021	985	14.39	3.43	7,050	6,430
CT	702	678	6.70	9.87	9,750	9,750
IGCC	3,216	3,101	48.90	6.87	8,700	8,700
IGCC w/seq	5,221	4,802	69.30	8.04	10,700	10,235
Wind	2,390	2,216	28.07	0.00	NA	NA
Wind Offshore	5,655	4,802	53.33	0.00	NA	NA
Photovoltaic	4,505	3,826	16.70	0.00	NA	NA
Solar Thermal	4,446	3,776	64.00	0.00	NA	NA
Landfill Gas	2,490	2,400	120.33	0.00	13,648	13,648
Biomass	3,680	3,129	100.50	5.00	13,500	13,500
Geothermal	4,045	3,749	84.27	9.64	NA	NA

Table 81: Load Blocks for Eastern Interconnection Regions (Summer)

Source: MRN-NEEM Assumptions, EIPC, Jan 25 2011

NEEM Region	Season Hours Year	Summer 10 B1	 25 B2	 75 B3	 100 B4	 200 B5	 300 B6	 400 B7	 500 B8	 800 B9	 1262 B10
ENT	2011	1.000	0.996	0.946	0.946	0.910	0.862	0.824	0.774	0.698	0.601
FRCC	2011	1.000	0.943	0.914	0.900	0.876	0.831	0.793	0.743	0.674	0.515
MAPP_US	2011	1.000	1.064	1.058	1.005	0.960	0.905	0.852	0.784	0.721	0.627
MISO_IN	2011	1.000	0.986	0.927	0.875	0.842	0.785	0.716	0.652	0.591	0.514
MISO_MI	2011	1.000	0.921	0.829	0.772	0.730	0.690	0.647	0.607	0.565	0.485
MISO_MO-IL	2011	1.000	0.964	0.882	0.823	0.795	0.733	0.682	0.617	0.543	0.458
MISO_W	2011	1.000	1.058	1.017	0.958	0.906	0.837	0.785	0.702	0.634	0.533
MISO_WUMS	2011	1.000	0.985	0.907	0.838	0.787	0.740	0.693	0.646	0.596	0.495
NE	2011	1.000	1.031	1.013	0.989	0.951	0.908	0.865	0.795	0.717	0.610
NEISO	2011	1.000	0.935	0.860	0.785	0.748	0.703	0.653	0.614	0.565	0.450
NYISO_A-F	2011	1.000	0.952	0.902	0.843	0.808	0.773	0.734	0.707	0.670	0.566
NYISO_G-I	2011	1.000	0.950	0.852	0.780	0.748	0.698	0.649	0.609	0.557	0.445
NYISO_J-K	2011	1.000	0.959	0.874	0.797	0.763	0.705	0.641	0.597	0.540	0.429
NonRTO_Midwest	2011	1.000	0.981	0.930	0.888	0.857	0.808	0.750	0.696	0.627	0.529
PJM_E	2011	1.000	0.960	0.868	0.800	0.768	0.708	0.643	0.592	0.538	0.439
PJM_ROM	2011	1.000	0.971	0.908	0.853	0.827	0.783	0.719	0.669	0.619	0.513
PJM_ROR	2011	1.000	0.959	0.889	0.838	0.805	0.760	0.705	0.658	0.606	0.512
SOCO	2011	1.000	0.975	0.962	0.938	0.907	0.861	0.801	0.734	0.650	0.528
SPP_N	2011	1.000	0.980	0.935	0.907	0.869	0.811	0.764	0.699	0.618	0.510
SPP_S	2011	1.000	0.995	0.958	0.946	0.897	0.836	0.792	0.733	0.654	0.552
TVA	2011	1.000	0.982	0.942	0.926	0.884	0.824	0.763	0.705	0.629	0.533
VACAR	2011	1.000	0.970	0.937	0.894	0.859	0.811	0.737	0.677	0.610	0.496
MAPP_CA	2011	1.000	1.014	1.012	0.993	0.979	0.957	0.934	0.901	0.853	0.753
IESO	2011	1.000	0.956	0.894	0.855	0.825	0.800	0.770	0.736	0.699	0.604

Table 82: Load Curves (Shoulder and Winter)

Source: MRN-NEEM Assumptions, EIPC, Jan 25 2011

NEEM Region	Season Hours Year	Shoulder 25 B11	 200 B12	 600 B13	 900 B14	 1203 B15	Winter 25 B16	 100 B17	 400 B18	 700 B19	 935 B20
ENT	2011	0.822	0.681	0.629	0.594	0.532	0.747	0.687	0.647	0.613	0.561
FRCC	2011	0.800	0.680	0.631	0.583	0.445	0.704	0.632	0.582	0.552	0.450
MAPP_US	2011	0.792	0.851	0.837	0.806	0.715	0.996	1.011	0.989	0.944	0.782
MISO_IN	2011	0.695	0.657	0.632	0.594	0.521	0.806	0.737	0.683	0.637	0.560
MISO_MI	2011	0.605	0.602	0.585	0.539	0.450	0.714	0.654	0.622	0.574	0.473
MISO_MO-IL	2011	0.705	0.586	0.553	0.518	0.445	0.742	0.653	0.605	0.560	0.492
MISO_W	2011	0.735	0.706	0.686	0.638	0.542	0.868	0.798	0.771	0.708	0.545
MISO_WUMS	2011	0.667	0.657	0.637	0.588	0.481	0.773	0.708	0.673	0.625	0.513
NE	2011	0.772	0.703	0.679	0.635	0.542	0.797	0.742	0.721	0.685	0.591
NEISO	2011	0.630	0.624	0.599	0.555	0.435	0.718	0.683	0.656	0.606	0.486
NYISO_A-F	2011	0.727	0.742	0.715	0.671	0.559	0.823	0.801	0.776	0.730	0.615
NYISO_G-I	2011	0.604	0.586	0.556	0.517	0.411	0.659	0.625	0.607	0.563	0.461
NYISO_J-K	2011	0.595	0.550	0.532	0.487	0.383	0.577	0.551	0.545	0.516	0.411
NonRTO_Midwest	2011	0.745	0.708	0.658	0.613	0.529	0.933	0.836	0.757	0.687	0.605
PJM_E	2011	0.580	0.552	0.526	0.488	0.399	0.635	0.601	0.575	0.533	0.446
PJM_ROM	2011	0.683	0.672	0.641	0.597	0.496	0.833	0.776	0.719	0.664	0.565
PJM_ROR	2011	0.675	0.661	0.631	0.588	0.501	0.814	0.752	0.694	0.644	0.557
SOCO	2011	0.749	0.648	0.595	0.555	0.473	0.801	0.708	0.629	0.579	0.512
SPP_N	2011	0.760	0.609	0.574	0.537	0.451	0.712	0.638	0.610	0.577	0.498
SPP_S	2011	0.773	0.619	0.579	0.549	0.478	0.704	0.640	0.607	0.575	0.518
TVA	2011	0.746	0.681	0.634	0.598	0.527	0.921	0.799	0.702	0.644	0.580
VACAR	2011	0.672	0.641	0.588	0.551	0.472	0.843	0.746	0.647	0.591	0.525
MAPP_CA	2011	0.898	0.965	0.949	0.913	0.810	1.078	1.093	1.076	1.043	0.931

Table 83: Existing Fixed and Variable Costs

Source: MRN-NEEM Assumptions, EIPC

Unit Type	FOM ($2010/kW-yr)	VOM ($2010/MWh)
Coal	48.22	3.56
CC	29.68	2.37
Peak Gas	16.62	8.31
Peak Oil	22.55	8.31
STOG	37.15	2.37
Nuclear	112.77	2.37
Hydro	14.24	NA
Pumped Storage	23.74	2.37
Photovoltaic	14.66	NA
Solar Thermal	60.32	NA
Wind	34.22	NA
Steam Wood	32.05	2.37
Landfill Gas	120.65	NA
Geothermal	89.76	NA

Table 84: Natural Gas Prices

Source: MRN-NEEM Assumptions, EIPC

2010$/MMBtu											
Region	**Season**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
ALB	Summer	4.17	4.02	3.97	3.84	3.96	4.26	4.43	4.59	4.70	4.83
ALB	Winter	4.50	4.35	4.39	4.26	4.40	4.74	4.92	5.10	5.22	5.37
ALB	Shoulder	4.34	4.15	4.11	3.98	4.10	4.42	4.60	4.75	4.87	5.01
AZ_NM_SNV_Gas	Summer	4.56	4.31	4.27	4.22	4.26	4.38	4.50	4.65	4.80	4.92
AZ_NM_SNV_Gas	Winter	4.72	4.69	4.72	4.72	4.77	4.89	5.03	5.20	5.36	5.51
AZ_NM_SNV_Gas	Shoulder	4.54	4.43	4.43	4.39	4.43	4.56	4.68	4.85	5.00	5.13
BC	Summer	4.12	3.92	3.87	3.75	3.86	4.15	4.32	4.47	4.58	4.71
BC	Winter	4.60	4.48	4.50	4.38	4.51	4.86	5.06	5.23	5.36	5.51
BC	Shoulder	4.30	4.15	4.12	3.99	4.12	4.43	4.61	4.77	4.89	5.03
ENT	Summer	4.57	4.41	4.44	4.38	4.46	4.55	4.60	4.67	4.73	4.83
ENT	Winter	4.79	4.79	4.87	4.83	4.91	5.00	5.07	5.15	5.21	5.33
ENT	Shoulder	4.65	4.54	4.59	4.53	4.61	4.70	4.75	4.83	4.89	5.00
ERCOT	Summer	4.59	4.41	4.42	4.36	4.43	4.52	4.58	4.65	4.71	4.82
ERCOT	Winter	4.69	4.73	4.81	4.75	4.85	4.95	5.01	5.09	5.16	5.28
ERCOT	Shoulder	4.62	4.50	4.55	4.48	4.57	4.66	4.72	4.80	4.85	4.97
FRCC	Summer	5.78	5.56	5.49	5.43	5.48	5.54	5.60	5.65	5.69	5.81
FRCC	Winter	5.78	5.82	5.81	5.77	5.84	5.90	5.96	6.01	6.06	6.18
FRCC	Shoulder	5.75	5.62	5.56	5.52	5.57	5.63	5.69	5.74	5.78	5.90
HQ	Summer	3.78	4.13	4.43	4.55	4.43	4.28	4.29	4.32	4.33	4.35
HQ	Winter	6.47	5.74	5.89	6.04	5.87	5.67	5.68	5.71	5.72	5.74
HQ	Shoulder	4.16	4.55	4.83	4.96	4.83	4.66	4.67	4.70	4.71	4.72
MAPP_CA	Summer	4.23	4.06	3.99	3.93	4.02	4.13	4.24	4.36	4.48	4.61
MAPP_CA	Winter	4.58	4.44	4.46	4.41	4.51	4.64	4.78	4.91	5.04	5.18
MAPP_CA	Shoulder	4.40	4.20	4.16	4.10	4.19	4.30	4.43	4.55	4.67	4.80
MAPP_US	Summer	4.23	4.06	3.99	3.93	4.02	4.13	4.24	4.36	4.48	4.61
MAPP_US	Winter	4.58	4.44	4.46	4.41	4.51	4.64	4.78	4.91	5.04	5.18
MAPP_US	Shoulder	4.40	4.20	4.16	4.10	4.19	4.30	4.43	4.55	4.67	4.80

2010$/MMBtu											
Region	**Season**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
MISO_IN	Summer	4.33	4.11	4.17	4.12	4.23	4.22	4.30	4.40	4.35	4.44
MISO_IN	Winter	4.62	4.51	4.59	4.56	4.68	4.66	4.76	4.87	4.81	4.91
MISO_IN	Shoulder	4.42	4.25	4.31	4.27	4.39	4.37	4.46	4.56	4.51	4.60
MISO_MI	Summer	4.19	3.99	3.94	3.89	3.98	4.07	4.18	4.27	4.34	4.45
MISO_MI	Winter	4.30	4.23	4.24	4.21	4.31	4.42	4.53	4.62	4.70	4.81
MISO_MI	Shoulder	4.23	4.05	4.03	3.98	4.07	4.17	4.28	4.38	4.44	4.56
MISO_MO_IL	Summer	4.28	4.09	4.04	3.98	4.06	4.23	4.31	4.37	4.45	4.47
MISO_MO_IL	Winter	4.62	4.49	4.46	4.42	4.51	4.69	4.78	4.85	4.95	4.98
MISO_MO_IL	Shoulder	4.39	4.23	4.18	4.13	4.22	4.38	4.47	4.54	4.62	4.65
MISO_W	Summer	4.23	4.05	4.00	3.94	4.02	4.14	4.25	4.37	4.49	4.62
MISO_W	Winter	4.59	4.45	4.45	4.41	4.50	4.63	4.76	4.90	5.03	5.17
MISO_W	Shoulder	4.38	4.20	4.16	4.10	4.19	4.31	4.43	4.56	4.67	4.80
MISO_WUMS	Summer	4.12	3.92	3.90	3.85	3.93	4.03	4.14	4.22	4.29	4.40
MISO_WUMS	Winter	4.40	4.30	4.29	4.26	4.35	4.46	4.58	4.68	4.75	4.87
MISO_WUMS	Shoulder	4.21	4.06	4.03	3.99	4.08	4.18	4.29	4.38	4.45	4.56
NE	Summer	4.23	4.05	4.00	3.94	4.03	4.14	4.26	4.38	4.50	4.62
NE	Winter	4.60	4.45	4.44	4.40	4.49	4.62	4.75	4.88	5.01	5.15
NE	Shoulder	4.36	4.20	4.16	4.10	4.19	4.31	4.43	4.56	4.68	4.81
NEISO	Summer	3.76	4.11	4.42	4.53	4.40	4.25	4.25	4.28	4.29	4.30
NEISO	Winter	6.54	5.80	5.94	6.11	5.95	5.74	5.75	5.80	5.81	5.84
NEISO	Shoulder	4.08	4.50	4.78	4.91	4.77	4.61	4.62	4.65	4.66	4.68
NonRTO_midwest	Summer	4.79	4.67	4.69	4.65	4.72	4.80	4.83	4.89	4.93	5.02
NonRTO_midwest	Winter	5.12	5.09	5.17	5.15	5.22	5.30	5.36	5.41	5.45	5.55
NonRTO_midwest	Shoulder	4.88	4.81	4.86	4.83	4.89	4.97	5.02	5.08	5.11	5.20
NP15	Summer	4.87	4.65	4.61	4.52	4.55	4.62	4.79	4.97	5.15	5.26
NP15	Winter	5.00	4.97	4.99	4.93	4.96	5.03	5.22	5.42	5.61	5.73
NP15	Shoulder	4.92	4.74	4.72	4.65	4.67	4.74	4.92	5.11	5.28	5.40
NWPP_Gas	Summer	4.15	3.94	3.89	3.77	3.88	4.18	4.35	4.50	4.61	4.74
NWPP_Gas	Winter	4.56	4.46	4.47	4.35	4.49	4.83	5.02	5.19	5.33	5.48
NWPP_Gas	Shoulder	4.29	4.14	4.12	3.99	4.12	4.43	4.61	4.77	4.89	5.02

2010$/MMBtu											
Region	**Season**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
NYISO_A-F	Summer	4.86	4.87	5.16	5.37	5.30	4.96	4.90	4.87	4.83	4.80
NYISO_A-F	Winter	5.21	5.32	5.72	5.96	5.88	5.49	5.42	5.39	5.33	5.29
NYISO_A-F	Shoulder	4.99	5.03	5.37	5.59	5.51	5.15	5.08	5.06	5.01	4.97
NYISO_G-I	Summer	4.14	4.47	4.83	5.04	4.97	4.65	4.59	4.56	4.52	4.48
NYISO_G-I	Winter	6.50	5.96	6.24	6.50	6.40	5.98	5.91	5.88	5.83	5.78
NYISO_G-I	Shoulder	4.46	4.85	5.21	5.43	5.36	5.01	4.95	4.92	4.87	4.84
NYISO_J-K	Summer	3.88	4.28	4.67	4.86	4.79	4.48	4.42	4.40	4.36	4.32
NYISO_J-K	Winter	7.03	6.30	6.54	6.83	6.73	6.30	6.22	6.18	6.13	6.08
NYISO_J-K	Shoulder	4.19	4.71	5.08	5.29	5.22	4.88	4.82	4.79	4.75	4.71
OH	Summer	4.85	4.86	5.16	5.37	5.30	4.96	4.90	4.89	4.85	4.81
OH	Winter	5.22	5.33	5.72	5.97	5.88	5.49	5.42	5.38	5.32	5.27
OH	Shoulder	4.98	5.03	5.36	5.58	5.50	5.15	5.08	5.05	5.00	4.96
PJM_E	Summer	4.26	4.64	4.98	5.04	5.07	4.82	4.77	4.75	4.72	4.71
PJM_E	Winter	6.46	5.87	6.10	6.16	6.17	5.87	5.80	5.78	5.74	5.72
PJM_E	Shoulder	4.60	4.99	5.32	5.38	5.40	5.14	5.08	5.06	5.03	5.01
PJM_ROM	Summer	4.38	4.70	5.02	5.09	5.11	4.86	4.80	4.79	4.76	4.74
PJM_ROM	Winter	6.25	5.77	6.04	6.09	6.11	5.81	5.75	5.73	5.68	5.66
PJM_ROM	Shoulder	4.67	5.01	5.33	5.40	5.42	5.16	5.10	5.08	5.04	5.02
PJM_ROR	Summer	4.21	4.08	4.14	4.09	4.20	4.19	4.28	4.37	4.32	4.41
PJM_ROR	Winter	4.83	4.57	4.64	4.60	4.72	4.71	4.81	4.92	4.86	4.96
PJM_ROR	Shoulder	4.33	4.23	4.30	4.26	4.38	4.36	4.45	4.55	4.50	4.59
RMPA	Summer	4.50	4.34	4.31	4.25	4.31	4.42	4.53	4.67	4.79	4.93
RMPA	Winter	4.84	4.78	4.82	4.77	4.83	4.96	5.08	5.24	5.39	5.54
RMPA	Shoulder	4.60	4.49	4.49	4.43	4.48	4.61	4.72	4.87	5.00	5.14
SOCO	Summer	4.98	4.77	4.84	4.82	4.86	4.92	4.93	4.98	5.00	5.09
SOCO	Winter	5.14	5.14	5.29	5.29	5.33	5.40	5.41	5.46	5.49	5.59
SOCO	Shoulder	5.04	4.89	4.99	4.97	5.01	5.08	5.09	5.14	5.16	5.25
SP15	Summer	4.84	4.62	4.58	4.50	4.53	4.59	4.76	4.96	5.13	5.24
SP15	Winter	5.05	4.99	5.02	4.96	4.98	5.06	5.24	5.44	5.63	5.76
SP15	Shoulder	4.91	4.74	4.73	4.65	4.68	4.74	4.93	5.11	5.29	5.40

2010$/MMBtu											
Region	**Season**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
SPP_N	Summer	4.44	4.23	4.15	4.08	4.16	4.30	4.44	4.56	4.64	4.77
SPP_N	Winter	4.66	4.59	4.57	4.52	4.61	4.77	4.93	5.06	5.15	5.29
SPP_N	Shoulder	4.50	4.34	4.29	4.22	4.30	4.47	4.61	4.72	4.82	4.95
SPP_S	Summer	4.54	4.38	4.39	4.32	4.40	4.49	4.55	4.62	4.68	4.80
SPP_S	Winter	4.77	4.75	4.84	4.79	4.88	4.98	5.05	5.13	5.20	5.32
SPP_S	Shoulder	4.61	4.50	4.54	4.48	4.56	4.66	4.72	4.79	4.86	4.98
TVA	Summer	4.81	4.66	4.69	4.66	4.72	4.80	4.84	4.90	4.94	5.03
TVA	Winter	5.06	5.09	5.17	5.15	5.22	5.30	5.35	5.41	5.44	5.54
TVA	Shoulder	4.91	4.81	4.86	4.82	4.89	4.97	5.02	5.07	5.11	5.20
VACAR	Summer	5.16	5.19	5.27	5.07	5.14	5.23	5.32	5.38	5.43	5.50
VACAR	Winter	6.41	6.00	6.03	5.80	5.89	5.99	6.09	6.15	6.21	6.31
VACAR	Shoulder	5.35	5.43	5.50	5.29	5.37	5.47	5.55	5.61	5.67	5.75

Table 85: Natural Gas Prices, cont'd

Source: MRN-NEEM Assumptions, EIPC

2010$/MMBtu Region	Season	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
ALB	Summer	4.97	5.15	5.34	5.48	5.60	5.70	5.81	5.94	6.05	6.15
ALB	Winter	5.53	5.72	5.93	6.08	6.22	6.34	6.45	6.60	6.73	6.84
ALB	Shoulder	5.15	5.34	5.54	5.67	5.80	5.91	6.03	6.15	6.27	6.38
AZ_NM_SNV_Gas	Summer	5.08	5.27	5.41	5.53	5.63	5.76	5.89	6.02	6.13	6.22
AZ_NM_SNV_Gas	Winter	5.68	5.89	6.04	6.18	6.29	6.44	6.59	6.74	6.85	6.95
AZ_NM_SNV_Gas	Shoulder	5.28	5.48	5.63	5.76	5.86	6.00	6.14	6.27	6.38	6.48
BC	Summer	4.84	5.02	5.20	5.34	5.45	5.56	5.67	5.78	5.90	6.00
BC	Winter	5.67	5.87	6.09	6.24	6.39	6.51	6.63	6.77	6.90	7.02
BC	Shoulder	5.17	5.35	5.55	5.70	5.82	5.93	6.04	6.17	6.29	6.40
ENT	Summer	4.97	5.08	5.24	5.39	5.53	5.65	5.77	5.84	5.87	5.92
ENT	Winter	5.47	5.61	5.77	5.95	6.09	6.23	6.36	6.43	6.47	6.52
ENT	Shoulder	5.13	5.26	5.42	5.58	5.72	5.85	5.97	6.03	6.07	6.13
ERCOT	Summer	4.96	5.08	5.23	5.39	5.52	5.64	5.76	5.83	5.86	5.91
ERCOT	Winter	5.42	5.56	5.73	5.90	6.04	6.17	6.30	6.37	6.41	6.47
ERCOT	Shoulder	5.10	5.23	5.39	5.55	5.69	5.81	5.93	6.00	6.03	6.09
FRCC	Summer	5.91	6.07	6.25	6.44	6.61	6.73	6.85	6.92	6.96	7.02
FRCC	Winter	6.30	6.46	6.66	6.86	7.04	7.17	7.29	7.36	7.41	7.48
FRCC	Shoulder	6.01	6.17	6.35	6.54	6.71	6.84	6.96	7.03	7.07	7.13
HQ	Summer	4.38	4.44	4.56	4.63	4.74	4.80	4.87	4.96	5.05	5.16
HQ	Winter	5.77	5.86	6.00	6.09	6.24	6.30	6.38	6.51	6.62	6.76
HQ	Shoulder	4.76	4.82	4.95	5.02	5.14	5.20	5.27	5.37	5.46	5.58
MAPP_CA	Summer	4.72	4.84	4.99	5.14	5.32	5.43	5.54	5.65	5.74	5.83
MAPP_CA	Winter	5.33	5.45	5.62	5.79	6.00	6.13	6.26	6.37	6.48	6.59
MAPP_CA	Shoulder	4.94	5.06	5.21	5.36	5.56	5.68	5.80	5.90	6.00	6.10
MAPP_US	Summer	4.72	4.84	4.99	5.14	5.32	5.43	5.54	5.65	5.74	5.83
MAPP_US	Winter	5.33	5.45	5.62	5.79	6.00	6.13	6.26	6.37	6.48	6.59
MAPP_US	Shoulder	4.94	5.06	5.21	5.36	5.56	5.68	5.80	5.90	6.00	6.10

2010$/MMBtu Region	Season	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
MISO_IN	Summer	4.55	4.67	4.83	4.97	5.11	5.22	5.34	5.43	5.49	5.57
MISO_IN	Winter	5.04	5.17	5.34	5.50	5.65	5.79	5.91	6.02	6.08	6.17
MISO_IN	Shoulder	4.72	4.84	5.01	5.15	5.29	5.42	5.54	5.63	5.70	5.77
MISO_MI	Summer	4.55	4.67	4.82	4.96	5.10	5.21	5.32	5.43	5.50	5.58
MISO_MI	Winter	4.93	5.06	5.23	5.37	5.52	5.64	5.77	5.88	5.95	6.04
MISO_MI	Shoulder	4.67	4.79	4.95	5.09	5.22	5.34	5.46	5.56	5.63	5.71
MISO_MO_IL	Summer	4.61	4.67	4.83	4.96	5.16	5.27	5.39	5.53	5.64	5.71
MISO_MO_IL	Winter	5.12	5.20	5.37	5.52	5.74	5.85	5.98	6.15	6.26	6.35
MISO_MO_IL	Shoulder	4.78	4.86	5.02	5.15	5.36	5.48	5.59	5.75	5.85	5.93
MISO_W	Summer	4.74	4.85	5.00	5.15	5.33	5.45	5.56	5.66	5.76	5.85
MISO_W	Winter	5.31	5.44	5.61	5.78	5.98	6.11	6.24	6.36	6.47	6.56
MISO_W	Shoulder	4.94	5.06	5.21	5.37	5.56	5.68	5.79	5.91	6.00	6.10
MISO_WUMS	Summer	4.50	4.62	4.77	4.90	5.04	5.15	5.27	5.37	5.44	5.52
MISO_WUMS	Winter	4.99	5.12	5.28	5.44	5.58	5.71	5.83	5.95	6.02	6.11
MISO_WUMS	Shoulder	4.67	4.79	4.95	5.09	5.23	5.34	5.46	5.57	5.64	5.72
NE	Summer	4.75	4.86	5.01	5.16	5.35	5.46	5.57	5.68	5.77	5.86
NE	Winter	5.30	5.42	5.59	5.75	5.96	6.10	6.22	6.33	6.44	6.54
NE	Shoulder	4.94	5.06	5.21	5.37	5.57	5.68	5.80	5.91	6.01	6.10
NEISO	Summer	4.33	4.39	4.50	4.56	4.68	4.72	4.79	4.88	4.96	5.07
NEISO	Winter	5.87	5.96	6.12	6.21	6.36	6.44	6.52	6.65	6.77	6.91
NEISO	Shoulder	4.70	4.77	4.89	4.97	5.09	5.14	5.21	5.31	5.41	5.52
NonRTO_midwest	Summer	5.16	5.27	5.43	5.59	5.73	5.86	5.97	6.03	6.06	6.11
NonRTO_midwest	Winter	5.71	5.83	6.00	6.18	6.34	6.47	6.60	6.66	6.70	6.75
NonRTO_midwest	Shoulder	5.35	5.46	5.63	5.79	5.94	6.07	6.19	6.25	6.28	6.34
NP15	Summer	5.44	5.63	5.76	5.91	6.05	6.19	6.31	6.44	6.54	6.63
NP15	Winter	5.93	6.13	6.28	6.45	6.60	6.75	6.88	7.01	7.13	7.22
NP15	Shoulder	5.58	5.77	5.91	6.07	6.22	6.36	6.48	6.61	6.71	6.80
NWPP_Gas	Summer	4.87	5.04	5.24	5.37	5.49	5.59	5.70	5.82	5.93	6.03
NWPP_Gas	Winter	5.63	5.84	6.06	6.20	6.35	6.47	6.59	6.73	6.86	6.98
NWPP_Gas	Shoulder	5.16	5.35	5.55	5.69	5.82	5.93	6.04	6.17	6.29	6.40

2010$/MMBtu Region	Season	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
NYISO_A-F	Summer	4.81	4.86	4.98	5.06	5.23	5.30	5.39	5.50	5.58	5.71
NYISO_A-F	Winter	5.30	5.35	5.48	5.57	5.74	5.81	5.91	6.02	6.11	6.25
NYISO_A-F	Shoulder	4.98	5.04	5.15	5.23	5.40	5.47	5.57	5.68	5.76	5.89
NYISO_G-I	Summer	4.50	4.55	4.66	4.74	4.89	4.95	5.04	5.13	5.22	5.33
NYISO_G-I	Winter	5.79	5.85	5.98	6.08	6.28	6.36	6.47	6.59	6.69	6.84
NYISO_G-I	Shoulder	4.84	4.89	5.01	5.09	5.26	5.33	5.42	5.52	5.60	5.74
NYISO_J-K	Summer	4.33	4.38	4.48	4.55	4.70	4.76	4.84	4.94	5.01	5.12
NYISO_J-K	Winter	6.09	6.15	6.30	6.40	6.62	6.70	6.82	6.95	7.05	7.21
NYISO_J-K	Shoulder	4.72	4.77	4.88	4.96	5.12	5.19	5.28	5.37	5.46	5.59
OH	Summer	4.83	4.88	5.00	5.09	5.26	5.33	5.43	5.53	5.62	5.75
OH	Winter	5.29	5.33	5.46	5.54	5.71	5.78	5.87	5.98	6.07	6.21
OH	Shoulder	4.97	5.02	5.14	5.23	5.39	5.46	5.56	5.66	5.75	5.88
PJM_E	Summer	4.73	4.79	4.91	5.00	5.15	5.23	5.32	5.43	5.50	5.61
PJM_E	Winter	5.75	5.81	5.95	6.07	6.25	6.34	6.45	6.58	6.67	6.81
PJM_E	Shoulder	5.04	5.10	5.22	5.32	5.48	5.56	5.66	5.77	5.85	5.97
PJM_ROM	Summer	4.77	4.82	4.95	5.04	5.19	5.27	5.36	5.47	5.55	5.66
PJM_ROM	Winter	5.69	5.76	5.90	6.01	6.19	6.28	6.39	6.51	6.61	6.74
PJM_ROM	Shoulder	5.05	5.11	5.23	5.33	5.50	5.58	5.67	5.78	5.87	5.98
PJM_ROR	Summer	4.52	4.64	4.80	4.94	5.07	5.19	5.31	5.40	5.46	5.53
PJM_ROR	Winter	5.08	5.22	5.40	5.55	5.70	5.84	5.96	6.07	6.14	6.22
PJM_ROR	Shoulder	4.71	4.83	5.00	5.14	5.28	5.40	5.52	5.62	5.68	5.76
RMPA	Summer	5.07	5.25	5.40	5.53	5.63	5.77	5.92	6.06	6.16	6.25
RMPA	Winter	5.69	5.89	6.06	6.21	6.33	6.49	6.65	6.81	6.92	7.02
RMPA	Shoulder	5.28	5.47	5.63	5.77	5.87	6.02	6.18	6.32	6.42	6.52
SOCO	Summer	5.23	5.34	5.50	5.66	5.81	5.92	6.05	6.10	6.15	6.18
SOCO	Winter	5.73	5.86	6.03	6.20	6.36	6.49	6.63	6.69	6.74	6.79
SOCO	Shoulder	5.40	5.51	5.67	5.84	5.98	6.12	6.23	6.30	6.34	6.38
SP15	Summer	5.42	5.60	5.73	5.89	6.02	6.16	6.28	6.41	6.51	6.60
SP15	Winter	5.96	6.16	6.31	6.47	6.63	6.78	6.91	7.05	7.16	7.26
SP15	Shoulder	5.59	5.78	5.92	6.07	6.22	6.36	6.49	6.62	6.72	6.81

2010$/MMBtu Region	Season	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
SPP_N	Summer	4.89	5.05	5.22	5.36	5.50	5.61	5.72	5.82	5.92	6.00
SPP_N	Winter	5.43	5.60	5.79	5.95	6.10	6.22	6.34	6.46	6.57	6.66
SPP_N	Shoulder	5.08	5.23	5.41	5.57	5.70	5.82	5.93	6.04	6.15	6.23
SPP_S	Summer	4.93	5.06	5.21	5.36	5.49	5.61	5.73	5.80	5.83	5.88
SPP_S	Winter	5.47	5.61	5.78	5.95	6.09	6.22	6.35	6.43	6.47	6.53
SPP_S	Shoulder	5.11	5.24	5.40	5.56	5.69	5.82	5.94	6.01	6.05	6.10
TVA	Summer	5.17	5.28	5.44	5.60	5.75	5.88	5.99	6.05	6.09	6.14
TVA	Winter	5.69	5.81	5.98	6.16	6.32	6.45	6.58	6.64	6.67	6.73
TVA	Shoulder	5.35	5.46	5.63	5.79	5.93	6.07	6.18	6.24	6.28	6.33
VACAR	Summer	5.61	5.71	5.85	6.02	6.16	6.29	6.43	6.53	6.61	6.66
VACAR	Winter	6.41	6.53	6.71	6.90	7.06	7.21	7.37	7.49	7.57	7.63
VACAR	Shoulder	5.85	5.96	6.12	6.29	6.44	6.57	6.72	6.83	6.90	6.97

Table 86: Existing Generators

Source: MRN-NEEM Assumptions, EIPC

Capacity Description	Aggregated/Stand Alone	Gen Type	NEEM Region	Summer Capacity MW	Wtd. Avg. Forced Outage Rate	Wtd. Avg. Planned Outage Days
Big Cajun 2	Stand Alone	Coal	ENT	1,743	7.7%	34.4
Independence (AR)	Stand Alone	Coal	ENT	1,678	3.6%	31.6
New Madrid (Memphis)	Stand Alone	Coal	ENT	1,160	7.7%	34.4
Roy S Nelson	Stand Alone	Coal	ENT	550	7.7%	34.4
Thomas Hill	Stand Alone	Coal	ENT	945	6.2%	32.2
White Bluff	Stand Alone	Coal	ENT	1,655	3.6%	31.6
Big Bend (FL)	Stand Alone	Coal	FRCC	1,550	6.7%	31.1
C D McIntosh Jr	Stand Alone	Coal	FRCC	342	6.4%	29.9
Cedar Bay Generating Co LP	Stand Alone	Coal	FRCC	250	6.0%	28.3
Crystal River	Stand Alone	Coal	FRCC	2,388	6.6%	33.3
Deerhaven Generating Station	Stand Alone	Coal	FRCC	228	6.0%	28.3
Indiantown Cogeneration Facility	Stand Alone	Coal	FRCC	330	6.4%	29.9
Northside Generating	Stand Alone	Coal	FRCC	550	6.0%	28.3
Polk Station	Stand Alone	Coal	FRCC	235	6.0%	28.3
Seminole (FL)	Stand Alone	Coal	FRCC	1,316	6.3%	33.8
St Johns River Power Park	Stand Alone	Coal	FRCC	1,252	6.3%	33.8
Stanton Energy Center	Stand Alone	Coal	FRCC	886	7.7%	34.4
Atikokan GS	Stand Alone	Coal	IESO	211	6.0%	28.3
Lambton GS	Stand Alone	Coal	IESO	1,961	7.7%	34.4
Nanticoke	Stand Alone	Coal	IESO	3,938	7.7%	34.4
Boundary Dam	Stand Alone	Coal	MAPP_CA	273	6.6%	27.3
Poplar River	Stand Alone	Coal	MAPP_CA	562	6.6%	27.3
Shand	Stand Alone	Coal	MAPP_CA	276	6.6%	27.3
Antelope Valley	Stand Alone	Coal	MAPP_US	900	6.7%	29.8
Coal Creek	Stand Alone	Coal	MAPP_US	1,114	5.8%	25.2
Coyote	Stand Alone	Coal	MAPP_US	427	5.8%	25.2
Laramie River	Stand Alone	Coal	MAPP_US	565	7.7%	34.4
Leland Olds 1 & 2	Stand Alone	Coal	MAPP_US	669	5.8%	25.2
Milton R Young	Stand Alone	Coal	MAPP_US	697	5.8%	25.2
A B Brown	Stand Alone	Coal	MISO_IN	490	6.0%	28.3
AES Petersburg (IN)	Stand Alone	Coal	MISO_IN	1,752	7.5%	33.6
Bailly	Stand Alone	Coal	MISO_IN	320	6.4%	29.9
D B Wilson	Stand Alone	Coal	MISO_IN	417	7.7%	34.4

Capacity Description	Aggregated/Stand Alone	Gen Type	NEEM Region	Summer Capacity MW	Wtd. Avg. Forced Outage Rate	Wtd. Avg. Planned Outage Days
F B Culley	Stand Alone	Coal	MISO_IN	270	6.0%	28.3
Gibson Station	Stand Alone	Coal	MISO_IN	3,131	6.3%	33.8
Harding Street	Stand Alone	Coal	MISO_IN	435	7.7%	34.4
Merom	Stand Alone	Coal	MISO_IN	955	7.7%	34.4
Michigan City	Stand Alone	Coal	MISO_IN	469	7.7%	34.4
R M Schahfer	Stand Alone	Coal	MISO_IN	1,625	7.1%	32.4
Robert D Green	Stand Alone	Coal	MISO_IN	454	6.0%	28.3
Wabash River	Stand Alone	Coal	MISO_IN	592	6.2%	29.2
Belle River	Stand Alone	Coal	MISO_MI	1,270	6.3%	33.8
D E Karn	Stand Alone	Coal	MISO_MI	515	6.0%	28.3
J H Campbell	Stand Alone	Coal	MISO_MI	1,440	4.7%	30.6
Monroe (MI)	Stand Alone	Coal	MISO_MI	3,115	6.3%	33.8
River Rouge	Stand Alone	Coal	MISO_MI	523	6.0%	28.3
St Clair	Stand Alone	Coal	MISO_MI	752	7.1%	32.6
Trenton Channel	Stand Alone	Coal	MISO_MI	520	7.7%	34.4
Baldwin Energy Complex	Stand Alone	Coal	MISO_MO-IL	1,764	7.7%	34.4
Coffeen	Stand Alone	Coal	MISO_MO-IL	900	7.2%	32.7
Dallman	Stand Alone	Coal	MISO_MO-IL	200	6.0%	28.3
Duck Creek	Stand Alone	Coal	MISO_MO-IL	358	6.4%	29.9
E D Edwards	Stand Alone	Coal	MISO_MO-IL	598	6.2%	29.2
Havana	Stand Alone	Coal	MISO_MO-IL	438	7.7%	34.4
Hennepin Power Station	Stand Alone	Coal	MISO_MO-IL	215	6.0%	28.3
Labadie	Stand Alone	Coal	MISO_MO-IL	2,406	6.6%	33.9
Meramec	Stand Alone	Coal	MISO_MO-IL	603	6.2%	29.2
Meredosia	Stand Alone	Coal	MISO_MO-IL	203	6.0%	28.3
Newton (IL)	Stand Alone	Coal	MISO_MO-IL	1,201	7.0%	34.1
Rush Island	Stand Alone	Coal	MISO_MO-IL	1,181	7.0%	34.1
Sioux	Stand Alone	Coal	MISO_MO-IL	993	7.7%	34.4
Wood River (IL)	Stand Alone	Coal	MISO_MO-IL	355	6.4%	29.9
Allen S King Plant	Stand Alone	Coal	MISO_W	528	7.7%	34.4
Big Stone	Stand Alone	Coal	MISO_W	475	7.7%	34.4
Clay Boswell	Stand Alone	Coal	MISO_W	886	7.2%	32.6
Genoa No3	Stand Alone	Coal	MISO_W	351	6.4%	29.9
George Neal North	Stand Alone	Coal	MISO_W	810	7.1%	32.2
George Neal South	Stand Alone	Coal	MISO_W	644	6.3%	33.8

Capacity Description	Aggregated/Stand Alone	Gen Type	NEEM Region	Summer Capacity MW	Wtd. Avg. Forced Outage Rate	Wtd. Avg. Planned Outage Days
John P Madgett	Stand Alone	Coal	MISO_W	393	6.4%	29.9
Lansing	Stand Alone	Coal	MISO_W	262	6.0%	28.3
Louisa	Stand Alone	Coal	MISO_W	745	6.3%	33.8
M L Kapp	Stand Alone	Coal	MISO_W	212	6.0%	28.3
Ottumwa (IA IPL)	Stand Alone	Coal	MISO_W	710	6.3%	33.8
Sherburne County	Stand Alone	Coal	MISO_W	2,243	5.2%	32.9
Walter Scott Jr Energy Center	Stand Alone	Coal	MISO_W	1,490	4.8%	32.6
Columbia (WI)	Stand Alone	Coal	MISO_WUMS	1,118	7.7%	34.4
Edgewater (WI)	Stand Alone	Coal	MISO_WUMS	734	7.1%	32.5
Oak Creek Power Plant	Stand Alone	Coal	MISO_WUMS	615	6.3%	33.8
Pleasant Prairie	Stand Alone	Coal	MISO_WUMS	1,216	6.3%	33.8
South Oak Creek	Stand Alone	Coal	MISO_WUMS	1,135	6.1%	28.7
Weston	Stand Alone	Coal	MISO_WUMS	870	7.2%	32.7
Gerald Gentleman	Stand Alone	Coal	NE	1,365	6.3%	33.8
Nebraska City	Stand Alone	Coal	NE	1,328	6.0%	29.4
North Omaha	Stand Alone	Coal	NE	224	6.0%	28.3
Brayton PT	Stand Alone	Coal	NEISO	1,100	6.2%	31.3
Bridgeport Station	Stand Alone	Coal	NEISO	383	6.4%	29.9
Merrimack	Stand Alone	Coal	NEISO	320	6.4%	29.9
Cane Run	Stand Alone	Coal	NonRTO_Midwest	240	6.0%	28.3
Clifty Creek	Stand Alone	Coal	NonRTO_Midwest	1,203	6.0%	28.3
E W Brown	Stand Alone	Coal	NonRTO_Midwest	429	7.7%	34.4
Elmer Smith	Stand Alone	Coal	NonRTO_Midwest	261	6.0%	28.3
Ghent	Stand Alone	Coal	NonRTO_Midwest	1,918	7.7%	34.4
Hugh L Spurlock	Stand Alone	Coal	NonRTO_Midwest	1,381	6.7%	30.9
J Sherman Cooper	Stand Alone	Coal	NonRTO_Midwest	225	6.0%	28.3
Kyger Creek	Stand Alone	Coal	NonRTO_Midwest	200	6.0%	28.3
Mill Creek (KY)	Stand Alone	Coal	NonRTO_Midwest	1,472	6.8%	31.4
Trimble Station (LGE)	Stand Alone	Coal	NonRTO_Midwest	1,243	6.9%	34.0
AES Somerset LLC	Stand Alone	Coal	NYISO_A-F	684	6.3%	33.8
Cayuga	Stand Alone	Coal	NYISO_A-F	995	7.7%	34.4
Danskammer Generating Station	Stand Alone	Coal	NYISO_G-I	233	6.0%	28.3
Carneys Point Generating Plant	Stand Alone	Coal	PJM_E	262	6.0%	28.3
Eddystone Generating Station	Stand Alone	Coal	PJM_E	588	6.2%	29.2
Hudson Generating Station	Stand Alone	Coal	PJM_E	568	7.7%	34.4

Capacity Description	Aggregated/Stand Alone	Gen Type	NEEM Region	Summer Capacity MW	Wtd. Avg. Forced Outage Rate	Wtd. Avg. Planned Outage Days
Indian River Generating Station	Stand Alone	Coal	PJM_E	436	7.7%	34.4
Logan Generating Plant	Stand Alone	Coal	PJM_E	219	6.0%	28.3
Mercer Generating Station	Stand Alone	Coal	PJM_E	648	6.4%	29.9
Brandon Shores	Stand Alone	Coal	PJM_ROM	1,286	6.3%	33.8
Chalk Point	Stand Alone	Coal	PJM_ROM	683	6.4%	29.9
Conemaugh	Stand Alone	Coal	PJM_ROM	1,700	3.6%	31.6
Herbert A Wagner	Stand Alone	Coal	PJM_ROM	324	6.4%	29.9
Homer City Station	Stand Alone	Coal	PJM_ROM	1,884	6.3%	33.8
Keystone (PA)	Stand Alone	Coal	PJM_ROM	1,700	3.6%	31.6
Montour	Stand Alone	Coal	PJM_ROM	1,525	6.3%	33.8
Morgantown Generating Station	Stand Alone	Coal	PJM_ROM	1,244	6.3%	33.8
Portland (PA)	Stand Alone	Coal	PJM_ROM	243	6.0%	28.3
PPL Brunner Island	Stand Alone	Coal	PJM_ROM	1,442	6.3%	31.9
Seward	Stand Alone	Coal	PJM_ROM	521	7.7%	34.4
Ashtabula	Stand Alone	Coal	PJM_ROR	244	6.0%	28.3
Avon Lake	Stand Alone	Coal	PJM_ROR	625	6.3%	33.8
Bay Shore	Stand Alone	Coal	PJM_ROR	215	6.0%	28.3
Big Sandy	Stand Alone	Coal	PJM_ROR	1,060	4.2%	30.8
Birchwood Power Facility	Stand Alone	Coal	PJM_ROR	238	6.0%	28.3
Bruce Mansfield	Stand Alone	Coal	PJM_ROR	2,510	3.6%	31.6
Cardinal	Stand Alone	Coal	PJM_ROR	1,800	7.2%	34.2
Chesapeake	Stand Alone	Coal	PJM_ROR	217	6.0%	28.3
Chesterfield	Stand Alone	Coal	PJM_ROR	982	6.3%	32.5
Cheswick Power Plant	Stand Alone	Coal	PJM_ROR	580	7.7%	34.4
Clinch River	Stand Alone	Coal	PJM_ROR	690	6.0%	28.3
Clover	Stand Alone	Coal	PJM_ROR	865	7.7%	34.4
Conesville	Stand Alone	Coal	PJM_ROR	1,530	6.3%	31.9
Crawford (IL)	Stand Alone	Coal	PJM_ROR	532	6.2%	29.3
East Bend	Stand Alone	Coal	PJM_ROR	600	6.3%	33.8
Eastlake (OH)	Stand Alone	Coal	PJM_ROR	837	7.2%	32.7
Fisk Street	Stand Alone	Coal	PJM_ROR	326	6.4%	29.9
Fort Martin	Stand Alone	Coal	PJM_ROR	1,107	7.7%	34.4
Gavin	Stand Alone	Coal	PJM_ROR	2,640	7.6%	35.3
Glen Lyn	Stand Alone	Coal	PJM_ROR	235	6.0%	28.3
Harrison (WV)	Stand Alone	Coal	PJM_ROR	1,954	6.3%	33.8

Capacity Description	Aggregated/Stand Alone	Gen Type	NEEM Region	Summer Capacity MW	Wtd. Avg. Forced Outage Rate	Wtd. Avg. Planned Outage Days
Hatfields Ferry Power Station	Stand Alone	Coal	PJM_ROR	1,590	7.7%	34.4
J M Stuart	Stand Alone	Coal	PJM_ROR	2,340	7.7%	34.4
John E Amos	Stand Alone	Coal	PJM_ROR	2,900	5.4%	33.3
Joliet 29	Stand Alone	Coal	PJM_ROR	1,036	7.7%	34.4
Joliet 9	Stand Alone	Coal	PJM_ROR	314	6.4%	29.9
Kammer	Stand Alone	Coal	PJM_ROR	600	6.0%	28.3
Kanawha River	Stand Alone	Coal	PJM_ROR	400	6.0%	28.3
Killen Station	Stand Alone	Coal	PJM_ROR	600	6.3%	33.8
Kincaid Generation LLC	Stand Alone	Coal	PJM_ROR	1,158	7.7%	34.4
Lake Shore	Stand Alone	Coal	PJM_ROR	245	6.0%	28.3
Miami Fort	Stand Alone	Coal	PJM_ROR	1,000	7.7%	34.4
Mitchell (WV)	Stand Alone	Coal	PJM_ROR	1,560	6.3%	33.8
Mitchell Power Station	Stand Alone	Coal	PJM_ROR	277	6.0%	28.3
Mountaineer	Stand Alone	Coal	PJM_ROR	1,310	7.6%	35.3
MT Storm	Stand Alone	Coal	PJM_ROR	1,560	7.7%	34.4
Muskingum River	Stand Alone	Coal	PJM_ROR	995	7.0%	31.9
Phil Sporn	Stand Alone	Coal	PJM_ROR	440	7.7%	34.4
Pleasants	Stand Alone	Coal	PJM_ROR	1,278	6.3%	33.8
Powerton	Stand Alone	Coal	PJM_ROR	1,538	6.3%	33.8
Rockport	Stand Alone	Coal	PJM_ROR	2,600	7.6%	35.3
State Line Energy	Stand Alone	Coal	PJM_ROR	318	6.4%	29.9
Tanners Creek	Stand Alone	Coal	PJM_ROR	700	7.2%	32.7
W H Sammis	Stand Alone	Coal	PJM_ROR	1,500	6.3%	33.0
W H Zimmer	Stand Alone	Coal	PJM_ROR	1,300	7.6%	35.3
Walter C Beckjord	Stand Alone	Coal	PJM_ROR	652	7.1%	32.2
Waukegan	Stand Alone	Coal	PJM_ROR	689	6.4%	29.9
Will County	Stand Alone	Coal	PJM_ROR	761	7.1%	32.4
Bowen	Stand Alone	Coal	SOCO	3,221	4.8%	32.6
Charles R Lowman	Stand Alone	Coal	SOCO	470	6.0%	28.3
Crist	Stand Alone	Coal	SOCO	774	7.2%	32.7
E C Gaston	Stand Alone	Coal	SOCO	1,862	4.9%	29.8
Gorgas 2 & 3	Stand Alone	Coal	SOCO	677	6.3%	33.8
Greene County (AL)	Stand Alone	Coal	SOCO	497	6.0%	28.3
Hammond	Stand Alone	Coal	SOCO	503	7.7%	34.4
Harllee Branch	Stand Alone	Coal	SOCO	1,607	7.1%	32.5

Capacity Description	Aggregated/Stand Alone	Gen Type	NEEM Region	Summer Capacity MW	Wtd. Avg. Forced Outage Rate	Wtd. Avg. Planned Outage Days
Jack McDonough	Stand Alone	Coal	SOCO	503	6.0%	28.3
Jack Watson	Stand Alone	Coal	SOCO	706	7.1%	32.4
James H Miller Jr	Stand Alone	Coal	SOCO	2,752	6.3%	33.8
James M Barry Electric	Stand Alone	Coal	SOCO	1,345	6.3%	31.7
Scherer	Stand Alone	Coal	SOCO	3,405	3.6%	31.6
Victor J Daniel Jr	Stand Alone	Coal	SOCO	1,020	7.7%	34.4
Wansley (GPC)	Stand Alone	Coal	SOCO	1,752	3.6%	31.6
Yates	Stand Alone	Coal	SOCO	707	6.4%	29.9
Hawthorne (MO)	Stand Alone	Coal	SPP_N	563	7.7%	34.4
Holcomb East	Stand Alone	Coal	SPP_N	362	6.4%	29.9
Iatan	Stand Alone	Coal	SPP_N	651	6.3%	33.8
Jeffrey Energy Center	Stand Alone	Coal	SPP_N	2,170	6.3%	33.8
La Cygne	Stand Alone	Coal	SPP_N	1,418	6.3%	33.8
Lawrence Energy Center (KS)	Stand Alone	Coal	SPP_N	373	6.4%	29.9
Nearman Creek	Stand Alone	Coal	SPP_N	229	6.0%	28.3
Sibley (MO)	Stand Alone	Coal	SPP_N	401	7.7%	34.4
Brame Energy Center	Stand Alone	Coal	SPP_S	1,112	7.7%	34.4
Dolet Hills	Stand Alone	Coal	SPP_S	672	5.8%	25.2
Flint Creek (AR)	Stand Alone	Coal	SPP_S	528	7.7%	34.4
Grda 1 & 2	Stand Alone	Coal	SPP_S	1,010	7.7%	34.4
Harrington	Stand Alone	Coal	SPP_S	1,041	6.4%	29.9
Hugo (OK)	Stand Alone	Coal	SPP_S	440	7.7%	34.4
Muskogee	Stand Alone	Coal	SPP_S	1,530	7.7%	34.4
Northeastern	Stand Alone	Coal	SPP_S	920	7.7%	34.4
Oklaunion	Stand Alone	Coal	SPP_S	533	6.0%	28.3
Pirkey	Stand Alone	Coal	SPP_S	675	5.8%	25.2
Sikeston	Stand Alone	Coal	SPP_S	233	6.0%	28.3
Sooner	Stand Alone	Coal	SPP_S	1,046	7.7%	34.4
Tolk	Stand Alone	Coal	SPP_S	1,080	7.7%	34.4
Welsh Station	Stand Alone	Coal	SPP_S	1,584	7.7%	34.4
Allen Steam Plant (TN)	Stand Alone	Coal	TVA	741	6.0%	28.3
Bull Run (TN)	Stand Alone	Coal	TVA	870	3.6%	31.6
Colbert	Stand Alone	Coal	TVA	472	7.7%	34.4
Cumberland (TN)	Stand Alone	Coal	TVA	2,478	7.6%	35.3
Gallatin (TN)	Stand Alone	Coal	TVA	976	6.0%	28.3

Capacity Description	Aggregated/Stand Alone	Gen Type	NEEM Region	Summer Capacity MW	Wtd. Avg. Forced Outage Rate	Wtd. Avg. Planned Outage Days
Paradise (KY)	Stand Alone	Coal	TVA	2,201	5.1%	32.8
Red Hills Generating Facility	Stand Alone	Coal	TVA	440	5.8%	25.2
Widows Creek	Stand Alone	Coal	TVA	938	7.7%	34.4
Belews Creek	Stand Alone	Coal	VACAR	2,270	7.6%	35.3
Cliffside	Stand Alone	Coal	VACAR	562	7.7%	34.4
Cope	Stand Alone	Coal	VACAR	420	7.7%	34.4
Cross	Stand Alone	Coal	VACAR	2,320	7.3%	34.2
G G Allen	Stand Alone	Coal	VACAR	815	6.0%	28.3
L V Sutton	Stand Alone	Coal	VACAR	403	7.7%	34.4
Lee	Stand Alone	Coal	VACAR	246	6.0%	28.3
Marshall (NC DUKE)	Stand Alone	Coal	VACAR	2,110	6.3%	32.4
Mayo	Stand Alone	Coal	VACAR	742	6.3%	33.8
Roxboro	Stand Alone	Coal	VACAR	2,424	6.3%	33.2
Wateree	Stand Alone	Coal	VACAR	700	6.4%	29.9
Williams (SC SCGC)	Stand Alone	Coal	VACAR	615	6.3%	33.8
Winyah	Stand Alone	Coal	VACAR	1,155	6.0%	28.3
ENT Aggregated CC	Aggregated	CC	ENT	13,885	6.1%	24.7
ENT Aggregated Coal	Aggregated	Coal	ENT	753	6.9%	26.8
ENT Aggregated CT	Aggregated	CT	ENT	2,960	8.4%	15.4
ENT Aggregated HY	Aggregated	HY	ENT	744	4.9%	0.0
ENT Aggregated LFG	Aggregated	LFG	ENT	8	5.0%	18.3
ENT Aggregated NU	Aggregated	NU	ENT	5,252	3.2%	28.6
ENT Aggregated PS	Aggregated	PS	ENT	59	0.0%	0.0
ENT Aggregated STOG	Aggregated	STOG	ENT	14,865	6.7%	32.1
ENT Aggregated STWD	Aggregated	STWD	ENT	206	10.0%	36.5
ENT Aggregated WT	Aggregated	WT	ENT	107	0.0%	0.0
FRCC Aggregated CC	Aggregated	CC	FRCC	21,784	6.1%	24.7
FRCC Aggregated Coal	Aggregated	Coal	FRCC	136	6.6%	27.3
FRCC Aggregated CT	Aggregated	CT	FRCC	10,878	8.8%	14.0
FRCC Aggregated HY	Aggregated	HY	FRCC	55	4.9%	0.0
FRCC Aggregated LFG	Aggregated	LFG	FRCC	486	5.0%	18.3
FRCC Aggregated NU	Aggregated	NU	FRCC	3,902	3.2%	28.6
FRCC Aggregated PV	Aggregated	PV	FRCC	51	60.0%	36.5
FRCC Aggregated STOG	Aggregated	STOG	FRCC	9,833	6.7%	32.1
FRCC Aggregated STWD	Aggregated	STWD	FRCC	195	10.0%	36.5

Capacity Description	Aggregated/Stand Alone	Gen Type	NEEM Region	Summer Capacity MW	Wtd. Avg. Forced Outage Rate	Wtd. Avg. Planned Outage Days
IESO Aggregated CC	Aggregated	CC	IESO	5,943	6.1%	24.7
IESO Aggregated Coal	Aggregated	Coal	IESO	4,244	6.6%	27.3
IESO Aggregated CT	Aggregated	CT	IESO	760	8.8%	13.8
IESO Aggregated HY	Aggregated	HY	IESO	8,004	4.9%	0.0
IESO Aggregated LFG	Aggregated	LFG	IESO	103	5.0%	18.3
IESO Aggregated NU	Aggregated	NU	IESO	11,478	6.9%	28.6
IESO Aggregated PS	Aggregated	PS	IESO	123	0.0%	0.0
IESO Aggregated PV	Aggregated	PV	IESO	30	60.0%	36.5
IESO Aggregated STOG	Aggregated	STOG	IESO	2,126	6.7%	32.1
IESO Aggregated STWD	Aggregated	STWD	IESO	139	10.0%	36.5
IESO Aggregated WT	Aggregated	WT	IESO	1,280	0.0%	0.0
MAPP_CA Aggregated CC	Aggregated	CC	MAPP_CA	730	6.1%	24.7
MAPP_CA Aggregated Coal	Aggregated	Coal	MAPP_CA	635	7.0%	26.7
MAPP_CA Aggregated CT	Aggregated	CT	MAPP_CA	563	8.3%	15.8
MAPP_CA Aggregated HY	Aggregated	HY	MAPP_CA	5,834	4.9%	0.0
MAPP_CA Aggregated STOG	Aggregated	STOG	MAPP_CA	126	6.7%	32.1
MAPP_CA Aggregated WT	Aggregated	WT	MAPP_CA	275	0.0%	0.0
MAPP_US Aggregated CC	Aggregated	CC	MAPP_US	289	6.1%	24.7
MAPP_US Aggregated Coal	Aggregated	Coal	MAPP_US	318	7.8%	25.5
MAPP_US Aggregated CT	Aggregated	CT	MAPP_US	1,056	9.0%	13.0
MAPP_US Aggregated GEO	Aggregated	GEO	MAPP_US	44	8.0%	0.0
MAPP_US Aggregated HY	Aggregated	HY	MAPP_US	2,186	4.9%	0.0
MAPP_US Aggregated LFG	Aggregated	LFG	MAPP_US	2	5.0%	18.3
MAPP_US Aggregated STOG	Aggregated	STOG	MAPP_US	36	6.7%	32.1
MAPP_US Aggregated WT	Aggregated	WT	MAPP_US	1,268	0.0%	0.0
MISO_IN Aggregated CC	Aggregated	CC	MISO_IN	1,396	6.1%	24.7
MISO_IN Aggregated Coal	Aggregated	Coal	MISO_IN	2,842	6.9%	26.8
MISO_IN Aggregated CT	Aggregated	CT	MISO_IN	3,415	8.5%	14.9
MISO_IN Aggregated HY	Aggregated	HY	MISO_IN	75	4.9%	0.0
MISO_IN Aggregated LFG	Aggregated	LFG	MISO_IN	37	5.0%	18.3
MISO_IN Aggregated STOG	Aggregated	STOG	MISO_IN	279	6.7%	32.1
MISO_IN Aggregated WT	Aggregated	WT	MISO_IN	535	0.0%	0.0
MISO_MI Aggregated CC	Aggregated	CC	MISO_MI	4,338	6.1%	24.7
MISO_MI Aggregated Coal	Aggregated	Coal	MISO_MI	2,657	6.9%	26.9
MISO_MI Aggregated CT	Aggregated	CT	MISO_MI	4,094	8.6%	14.7

Capacity Description	Aggregated/Stand Alone	Gen Type	NEEM Region	Summer Capacity MW	Wtd. Avg. Forced Outage Rate	Wtd. Avg. Planned Outage Days
MISO_MI Aggregated HY	Aggregated	HY	MISO_MI	141	4.9%	0.0
MISO_MI Aggregated LFG	Aggregated	LFG	MISO_MI	163	5.0%	18.3
MISO_MI Aggregated NU	Aggregated	NU	MISO_MI	1,889	3.2%	28.6
MISO_MI Aggregated PS	Aggregated	PS	MISO_MI	1,872	0.0%	0.0
MISO_MI Aggregated STOG	Aggregated	STOG	MISO_MI	2,852	6.7%	32.1
MISO_MI Aggregated STWD	Aggregated	STWD	MISO_MI	163	10.0%	36.5
MISO_MI Aggregated WT	Aggregated	WT	MISO_MI	161	0.0%	0.0
MISO_MO-IL Aggregated CC	Aggregated	CC	MISO_MO-IL	1,058	6.1%	24.7
MISO_MO-IL Aggregated Coal	Aggregated	Coal	MISO_MO-IL	3,551	6.9%	26.9
MISO_MO-IL Aggregated CT	Aggregated	CT	MISO_MO-IL	5,360	8.6%	14.6
MISO_MO-IL Aggregated HY	Aggregated	HY	MISO_MO-IL	352	4.9%	0.0
MISO_MO-IL Aggregated LFG	Aggregated	LFG	MISO_MO-IL	18	5.0%	18.3
MISO_MO-IL Aggregated NU	Aggregated	NU	MISO_MO-IL	2,233	3.2%	28.6
MISO_MO-IL Aggregated PS	Aggregated	PS	MISO_MO-IL	440	0.0%	0.0
MISO_MO-IL Aggregated STOG	Aggregated	STOG	MISO_MO-IL	592	6.7%	32.1
MISO_MO-IL Aggregated WT	Aggregated	WT	MISO_MO-IL	378	0.0%	0.0
MISO_W Aggregated CC	Aggregated	CC	MISO_W	3,024	6.1%	24.7
MISO_W Aggregated Coal	Aggregated	Coal	MISO_W	3,071	7.3%	26.2
MISO_W Aggregated CT	Aggregated	CT	MISO_W	6,677	9.0%	13.0
MISO_W Aggregated HY	Aggregated	HY	MISO_W	497	4.9%	0.0
MISO_W Aggregated LFG	Aggregated	LFG	MISO_W	205	5.0%	18.3
MISO_W Aggregated NU	Aggregated	NU	MISO_W	2,267	3.2%	28.6
MISO_W Aggregated STOG	Aggregated	STOG	MISO_W	173	6.7%	32.1
MISO_W Aggregated STWD	Aggregated	STWD	MISO_W	313	10.0%	36.5
MISO_W Aggregated WT	Aggregated	WT	MISO_W	5,558	0.0%	0.0
MISO_WUMS Aggregated CC	Aggregated	CC	MISO_WUMS	2,724	6.1%	24.7
MISO_WUMS Aggregated Coal	Aggregated	Coal	MISO_WUMS	1,857	7.4%	26.1
MISO_WUMS Aggregated CT	Aggregated	CT	MISO_WUMS	3,720	8.6%	14.7
MISO_WUMS Aggregated HY	Aggregated	HY	MISO_WUMS	336	4.9%	0.0
MISO_WUMS Aggregated LFG	Aggregated	LFG	MISO_WUMS	71	5.0%	18.3
MISO_WUMS Aggregated NU	Aggregated	NU	MISO_WUMS	1,582	3.2%	28.6
MISO_WUMS Aggregated STOG	Aggregated	STOG	MISO_WUMS	359	6.7%	32.1
MISO_WUMS Aggregated STWD	Aggregated	STWD	MISO_WUMS	105	10.0%	36.5
MISO_WUMS Aggregated WT	Aggregated	WT	MISO_WUMS	560	0.0%	0.0
NE Aggregated CC	Aggregated	CC	NE	358	6.1%	24.7

Capacity Description	Aggregated/Stand Alone	Gen Type	NEEM Region	Summer Capacity MW	Wtd. Avg. Forced Outage Rate	Wtd. Avg. Planned Outage Days
NE Aggregated Coal	Aggregated	Coal	NE	961	7.0%	26.8
NE Aggregated CT	Aggregated	CT	NE	1,631	8.7%	14.1
NE Aggregated HY	Aggregated	HY	NE	167	4.9%	0.0
NE Aggregated LFG	Aggregated	LFG	NE	6	5.0%	18.3
NE Aggregated NU	Aggregated	NU	NE	1,252	3.2%	28.6
NE Aggregated STOG	Aggregated	STOG	NE	270	6.7%	32.1
NE Aggregated WT	Aggregated	WT	NE	142	0.0%	0.0
NEISO Aggregated CC	Aggregated	CC	NEISO	11,463	6.1%	24.7
NEISO Aggregated Coal	Aggregated	Coal	NEISO	767	7.0%	26.7
NEISO Aggregated CT	Aggregated	CT	NEISO	2,384	9.4%	11.5
NEISO Aggregated HY	Aggregated	HY	NEISO	1,933	4.9%	0.0
NEISO Aggregated LFG	Aggregated	LFG	NEISO	532	5.0%	18.3
NEISO Aggregated NU	Aggregated	NU	NEISO	4,645	3.2%	28.6
NEISO Aggregated PS	Aggregated	PS	NEISO	1,674	0.0%	0.0
NEISO Aggregated PV	Aggregated	PV	NEISO	2	60.0%	36.5
NEISO Aggregated STOG	Aggregated	STOG	NEISO	6,236	6.7%	32.1
NEISO Aggregated STWD	Aggregated	STWD	NEISO	609	10.0%	36.5
NEISO Aggregated WT	Aggregated	WT	NEISO	202	0.0%	0.0
NonRTO_Midwest Aggregate Coal	Aggregated	Coal	NonRTO_Midwest	2,327	6.8%	26.9
NonRTO_Midwest Aggregated CT	Aggregated	CT	NonRTO_Midwest	3,365	8.3%	15.8
NonRTO_Midwest Aggregated HY	Aggregated	HY	NonRTO_Midwest	143	4.9%	0.0
NonRTO_Midwest Aggregate LFG	Aggregated	LFG	NonRTO_Midwest	14	5.0%	18.3
NonRTO_Midwest Aggregate WT	Aggregated	WT	NonRTO_Midwest	66	0.0%	0.0
NYISO_A-F Aggregated CC	Aggregated	CC	NYISO_A-F	3,594	6.1%	24.7
NYISO_A-F Aggregated Coal	Aggregated	Coal	NYISO_A-F	1,568	6.9%	26.8
NYISO_A-F Aggregated CT	Aggregated	CT	NYISO_A-F	260	8.6%	14.5
NYISO_A-F Aggregated HY	Aggregated	HY	NYISO_A-F	4,395	4.9%	0.0
NYISO_A-F Aggregated LFG	Aggregated	LFG	NYISO_A-F	166	5.0%	18.3
NYISO_A-F Aggregated NU	Aggregated	NU	NYISO_A-F	3,197	3.2%	28.6
NYISO_A-F Aggregated PS	Aggregated	PS	NYISO_A-F	1,412	0.0%	0.0
NYISO_A-F Aggregated STOG	Aggregated	STOG	NYISO_A-F	1,701	6.7%	32.1
NYISO_A-F Aggregated STWD	Aggregated	STWD	NYISO_A-F	86	10.0%	36.5
NYISO_A-F Aggregated WT	Aggregated	WT	NYISO_A-F	1,283	0.0%	0.0
NYISO_G-I Aggregated CC	Aggregated	CC	NYISO_G-I	1,157	6.1%	24.7
NYISO_G-I Aggregated Coal	Aggregated	Coal	NYISO_G-I	136	6.6%	27.3

Capacity Description	Aggregated/Stand Alone	Gen Type	NEEM Region	Summer Capacity MW	Wtd. Avg. Forced Outage Rate	Wtd. Avg. Planned Outage Days
NYISO_G-I Aggregated CT	Aggregated	CT	NYISO_G-I	152	9.5%	10.8
NYISO_G-I Aggregated HY	Aggregated	HY	NYISO_G-I	32	4.9%	0.0
NYISO_G-I Aggregated LFG	Aggregated	LFG	NYISO_G-I	64	5.0%	18.3
NYISO_G-I Aggregated NU	Aggregated	NU	NYISO_G-I	2,045	3.2%	28.6
NYISO_G-I Aggregated STOG	Aggregated	STOG	NYISO_G-I	2,431	6.7%	32.1
NYISO_J-K Aggregated CC	Aggregated	CC	NYISO_J-K	2,941	6.1%	24.7
NYISO_J-K Aggregated CT	Aggregated	CT	NYISO_J-K	4,948	9.2%	12.0
NYISO_J-K Aggregated LFG	Aggregated	LFG	NYISO_J-K	124	5.0%	18.3
NYISO_J-K Aggregated STOG	Aggregated	STOG	NYISO_J-K	6,799	6.7%	32.1
PJM_E Aggregated CC	Aggregated	CC	PJM_E	8,366	6.1%	24.7
PJM_E Aggregated Coal	Aggregated	Coal	PJM_E	1,132	7.0%	26.7
PJM_E Aggregated CT	Aggregated	CT	PJM_E	6,899	9.2%	12.3
PJM_E Aggregated HY	Aggregated	HY	PJM_E	4	4.9%	0.0
PJM_E Aggregated LFG	Aggregated	LFG	PJM_E	462	5.0%	18.3
PJM_E Aggregated NU	Aggregated	NU	PJM_E	8,472	3.2%	28.6
PJM_E Aggregated PS	Aggregated	PS	PJM_E	400	0.0%	0.0
PJM_E Aggregated PV	Aggregated	PV	PJM_E	22	60.0%	36.5
PJM_E Aggregated STOG	Aggregated	STOG	PJM_E	3,252	6.7%	32.1
PJM_E Aggregated WT	Aggregated	WT	PJM_E	10	0.0%	0.0
PJM_ROM Aggregated CC	Aggregated	CC	PJM_ROM	3,986	6.1%	24.7
PJM_ROM Aggregated Coal	Aggregated	Coal	PJM_ROM	4,375	7.0%	26.7
PJM_ROM Aggregated CT	Aggregated	CT	PJM_ROM	3,555	9.4%	11.3
PJM_ROM Aggregated HY	Aggregated	HY	PJM_ROM	1,236	4.9%	0.0
PJM_ROM Aggregated LFG	Aggregated	LFG	PJM_ROM	338	5.0%	18.3
PJM_ROM Aggregated NU	Aggregated	NU	PJM_ROM	5,036	3.2%	28.6
PJM_ROM Aggregated PS	Aggregated	PS	PJM_ROM	1,513	0.0%	0.0
PJM_ROM Aggregated PV	Aggregated	PV	PJM_ROM	4	60.0%	36.5
PJM_ROM Aggregated STOG	Aggregated	STOG	PJM_ROM	4,109	6.7%	32.1
PJM_ROM Aggregated STWD	Aggregated	STWD	PJM_ROM	70	10.0%	36.5
PJM_ROM Aggregated WT	Aggregated	WT	PJM_ROM	731	0.0%	0.0
PJM_ROR Aggregated CC	Aggregated	CC	PJM_ROR	10,542	6.1%	24.7
PJM_ROR Aggregated Coal	Aggregated	Coal	PJM_ROR	11,892	7.0%	26.8
PJM_ROR Aggregated CT	Aggregated	CT	PJM_ROR	21,073	8.5%	15.1
PJM_ROR Aggregated HY	Aggregated	HY	PJM_ROR	1,604	4.9%	0.0
PJM_ROR Aggregated LFG	Aggregated	LFG	PJM_ROR	482	5.0%	18.3

Capacity Description	Aggregated/Stand Alone	Gen Type	NEEM Region	Summer Capacity MW	Wtd. Avg. Forced Outage Rate	Wtd. Avg. Planned Outage Days
PJM_ROR Aggregated NU	Aggregated	NU	PJM_ROR	20,000	3.2%	28.6
PJM_ROR Aggregated PS	Aggregated	PS	PJM_ROR	3,081	0.0%	0.0
PJM_ROR Aggregated PV	Aggregated	PV	PJM_ROR	24	60.0%	36.5
PJM_ROR Aggregated STOG	Aggregated	STOG	PJM_ROR	2,122	6.7%	32.1
PJM_ROR Aggregated STWD	Aggregated	STWD	PJM_ROR	194	10.0%	36.5
PJM_ROR Aggregated WT	Aggregated	WT	PJM_ROR	2,597	0.0%	0.0
SOCO Aggregated CC	Aggregated	CC	SOCO	14,812	6.1%	24.7
SOCO Aggregated Coal	Aggregated	Coal	SOCO	4,073	6.8%	27.0
SOCO Aggregated CT	Aggregated	CT	SOCO	12,062	8.5%	15.0
SOCO Aggregated HY	Aggregated	HY	SOCO	4,194	4.9%	0.0
SOCO Aggregated LFG	Aggregated	LFG	SOCO	37	5.0%	18.3
SOCO Aggregated NU	Aggregated	NU	SOCO	5,771	3.2%	28.6
SOCO Aggregated PS	Aggregated	PS	SOCO	1,675	0.0%	0.0
SOCO Aggregated STOG	Aggregated	STOG	SOCO	854	6.7%	32.1
SOCO Aggregated STWD	Aggregated	STWD	SOCO	668	10.0%	36.5
SPP_N Aggregated CC	Aggregated	CC	SPP_N	1,386	6.1%	24.7
SPP_N Aggregated Coal	Aggregated	Coal	SPP_N	1,716	7.1%	26.6
SPP_N Aggregated CT	Aggregated	CT	SPP_N	5,596	8.8%	14.0
SPP_N Aggregated HY	Aggregated	HY	SPP_N	21	4.9%	0.0
SPP_N Aggregated LFG	Aggregated	LFG	SPP_N	7	5.0%	18.3
SPP_N Aggregated NU	Aggregated	NU	SPP_N	1,160	3.2%	28.6
SPP_N Aggregated STOG	Aggregated	STOG	SPP_N	1,748	6.7%	32.1
SPP_N Aggregated WT	Aggregated	WT	SPP_N	1,227	0.0%	0.0
SPP_S Aggregated CC	Aggregated	CC	SPP_S	10,917	6.1%	24.7
SPP_S Aggregated Coal	Aggregated	Coal	SPP_S	736	7.0%	26.7
SPP_S Aggregated CT	Aggregated	CT	SPP_S	3,564	8.4%	15.6
SPP_S Aggregated HY	Aggregated	HY	SPP_S	2,108	4.9%	0.0
SPP_S Aggregated LFG	Aggregated	LFG	SPP_S	19	5.0%	18.3
SPP_S Aggregated PS	Aggregated	PS	SPP_S	446	0.0%	0.0
SPP_S Aggregated STOG	Aggregated	STOG	SPP_S	10,570	6.7%	32.1
SPP_S Aggregated STWD	Aggregated	STWD	SPP_S	84	10.0%	36.5
SPP_S Aggregated WT	Aggregated	WT	SPP_S	2,297	0.0%	0.0
TVA Aggregated CC	Aggregated	CC	TVA	4,463	6.1%	24.7
TVA Aggregated Coal	Aggregated	Coal	TVA	6,043	6.6%	27.3
TVA Aggregated CT	Aggregated	CT	TVA	5,949	8.3%	15.8

Capacity Description	Aggregated/Stand Alone	Gen Type	NEEM Region	Summer Capacity MW	Wtd. Avg. Forced Outage Rate	Wtd. Avg. Planned Outage Days
TVA Aggregated HY	Aggregated	HY	TVA	5,111	4.9%	0.0
TVA Aggregated LFG	Aggregated	LFG	TVA	13	5.0%	18.3
TVA Aggregated NU	Aggregated	NU	TVA	6,697	3.2%	28.6
TVA Aggregated PS	Aggregated	PS	TVA	1,743	0.0%	0.0
TVA Aggregated STWD	Aggregated	STWD	TVA	5	10.0%	36.5
TVA Aggregated WT	Aggregated	WT	TVA	29	0.0%	0.0
VACAR Aggregated CC	Aggregated	CC	VACAR	3,524	6.1%	24.7
VACAR Aggregated Coal	Aggregated	Coal	VACAR	6,053	7.0%	26.7
VACAR Aggregated CT	Aggregated	CT	VACAR	9,576	8.6%	14.7
VACAR Aggregated HY	Aggregated	HY	VACAR	2,122	4.9%	0.0
VACAR Aggregated LFG	Aggregated	LFG	VACAR	63	5.0%	18.3
VACAR Aggregated NU	Aggregated	NU	VACAR	11,430	3.2%	28.6
VACAR Aggregated PS	Aggregated	PS	VACAR	2,616	0.0%	0.0
VACAR Aggregated PV	Aggregated	PV	VACAR	16	60.0%	36.5
VACAR Aggregated STOG	Aggregated	STOG	VACAR	92	6.7%	32.1
VACAR Aggregated STWD	Aggregated	STWD	VACAR	281	10.0%	36.5

Table 87: Wind Capacity Factors

Source: MRN-NEEM Assumptions, EIPC

ONSHORE WIND Class 4+		Summer										Shoulder					Winter					
	Hours	10	25	75	100	200	300	400	500	800	1262	25	200	600	900	1203	25	100	400	700	935	CF
NEEM Region	Year	B1	B2	B3	B4	B5	B6	B7	B8	B9	B10	B11	B12	B13	B14	B15	B16	B17	B18	B19	B20	
ENT	All	14%	9%	13%	13%	13%	17%	16%	22%	27%	34%	17%	30%	30%	36%	47%	41%	40%	36%	38%	46%	34%
FRCC	All																					0%
IESO	All	45%	32%	21%	20%	20%	19%	20%	20%	23%	22%	25%	33%	32%	33%	33%	39%	37%	38%	36%	33%	29%
MAPP_CA	All	45%	32%	21%	20%	20%	19%	20%	20%	23%	22%	25%	33%	32%	33%	33%	39%	37%	38%	36%	33%	29%
MAPP_US	All	19%	29%	28%	29%	26%	26%	32%	35%	37%	40%	31%	38%	40%	40%	44%	64%	54%	50%	43%	45%	40%
MISO_IN	All	41%	30%	26%	19%	21%	21%	21%	22%	25%	26%	44%	37%	34%	35%	38%	59%	39%	42%	42%	48%	33%
MISO_MI	All	63%	46%	24%	21%	21%	20%	20%	20%	23%	24%	30%	29%	29%	31%	32%	64%	44%	47%	44%	43%	30%
MISO_MO-IL	All	41%	32%	23%	19%	20%	22%	23%	25%	27%	29%	53%	40%	36%	37%	41%	59%	44%	42%	41%	49%	35%
MISO_W	All	28%	35%	27%	27%	25%	24%	30%	35%	35%	39%	28%	36%	37%	40%	41%	56%	51%	42%	39%	42%	38%
MISO_WUMS	All	59%	40%	23%	20%	20%	21%	22%	25%	27%	30%	31%	32%	30%	33%	38%	67%	46%	41%	38%	43%	33%
NE	All	25%	36%	29%	24%	25%	26%	30%	36%	35%	39%	28%	37%	41%	43%	46%	60%	53%	48%	45%	48%	40%
NEISO	All	36%	21%	20%	19%	21%	24%	19%	20%	27%	29%	41%	37%	34%	35%	37%	57%	49%	46%	45%	46%	34%
NonRTO_Midwest	All	5%	9%	16%	12%	14%	14%	15%	15%	19%	22%	17%	25%	27%	26%	32%	34%	29%	33%	35%	41%	26%
NYISO_A-F	All	59%	38%	27%	21%	21%	21%	18%	21%	26%	26%	35%	30%	34%	34%	35%	49%	48%	48%	49%	46%	33%
NYISO_G-I	All	51%	40%	36%	30%	32%	33%	26%	26%	29%	26%	49%	37%	36%	35%	33%	52%	49%	44%	41%	43%	34%
NYISO_J-K	All	50%	35%	32%	30%	32%	32%	28%	23%	27%	24%	51%	34%	33%	32%	32%	48%	42%	38%	38%	39%	32%
PJM_E	All	13%	11%	15%	14%	14%	16%	16%	16%	18%	16%	24%	25%	26%	25%	24%	39%	34%	30%	31%	31%	23%
PJM_ROM	All	17%	17%	17%	13%	14%	16%	15%	17%	21%	21%	30%	26%	30%	30%	31%	52%	48%	43%	43%	43%	28%
PJM_ROR	All	38%	30%	22%	17%	18%	19%	19%	21%	25%	25%	40%	33%	32%	33%	35%	62%	43%	44%	43%	46%	32%
SOCO (Note A)	All	5%	4%	9%	11%	10%	11%	13%	15%	22%	26%	11%	32%	31%	28%	40%	27%	30%	33%	36%	47%	29%
SPP_N	All	60%	40%	28%	31%	30%	29%	31%	34%	33%	38%	39%	38%	38%	45%	47%	46%	44%	37%	39%	45%	39%
SPP_S	All	64%	41%	27%	33%	33%	29%	30%	32%	32%	38%	38%	38%	37%	46%	49%	46%	42%	38%	39%	45%	39%
TVA	All	5%	4%	9%	11%	10%	11%	13%	15%	22%	26%	11%	32%	31%	28%	40%	27%	30%	33%	36%	47%	29%
VACAR	All	18%	12%	25%	28%	22%	23%	25%	22%	25%	23%	15%	29%	31%	30%	35%	42%	35%	35%	35%	39%	30%

Table 88: Resource Potentials

Source: MRN-NEEM Assumptions, EIPC

	Pulverized Coal	Nuclear	On-Shore Wind Class 3	On-Shore Wind Class 4+	Off-Shore Wind	Biomass	Photo-voltaic	Landfill Gas	Geoth-ermal	Solar Thermal	IGCC-CCS
AZ_NM_SNV	∞	∞	224.9	107.0	-	6.5	10.0	0.05	1.5	10.0	∞
ENT	∞	∞	2.3	0.1	-	10.1	5.0	0.1	0.0	0.0	∞
ERCOT	∞	∞	286.9	97.2	-	4.1	10.0	0.4	0.0	0.0	∞
FRCC	∞	∞	-	-	-	2.0	10.0	0.2	0.0	0.0	∞
MAPP_US	∞	∞	279.5	602.5	-	5.4	1.0	0.0	0.0	0.0	∞
MISO_IN	∞	∞	102.3	0.0	0.8	6.1	1.3	0.1	0.0	0.0	∞
MISO_MI	∞	∞	56.8	0.6	4.4	6.1	1.3	0.1	0.0	0.0	∞
MISO_MO_IL	∞	∞	105.7	5.9	-	8.9	7.0	0.4	0.0	0.0	∞
MISO_W	∞	∞	775.0	1199.9	-	5.4	1.0	0.0	0.0	0.0	∞
MISO_WUMS	∞	∞	16.5	0.3	2.1	3.2	2.0	0.2	0.0	0.0	∞
NE	∞	∞	417.8	464.2	-	10.8	2.0	0.1	0.0	0.0	∞
NEISO	0.0	∞	16.9	5.28	8.5	1.7	12.0	0.7	0.0	0.0	4.0
NonRTO_Midwest	∞	∞	0.1	0.0	-	6.1	1.3	0.1	0.0	0.0	∞
NP15	0.0	0.0	10.8	3.4	0.1	0.8	10.0	0.6	0.6	0.1	∞
NWPP	∞	∞	653.3	591.1	0.2	9.1	5.0	0.3	0.5	0.0	∞
NYISO_A-F	0.0	∞	12.7	0.8	0.5	1.0	4.0	0.4	0.0	0.0	∞
NYISO_G-I	0.0	0.0	0.3	0.1	0.2	0.8	2.0	0.2	0.0	0.0	∞
NYISO_J-K	0.0	0.0	0.2	0.2	2.4	0.0	4.0	0.4	0.0	0.0	0.0
PJM_E	0.0	∞	3.2	0.5	9.6	0.3	2.0	0.1	0.0	0.0	∞
PJM_ROM	∞	∞	5.8	1.2	16.9	2.4	4.0	0.3	0.0	0.0	∞
PJM_ROR	∞	∞	50.4	3.2	20.2	10.6	6.9	0.4	0.0	0.0	∞
RMPA	∞	∞	417.1	539.9	-	3.7	5.0	0.1	2.6	9.4	∞
SOCO	∞	∞	0.1	0.0	-	6.6	2.0	0.1	0.0	0.0	∞
SP15	0.0	0.0	31.2	14.9	-	0.7	10.0	0.6	1.5	10.0	∞
SPP_N	∞	∞	292.8	597.7	-	6.4	2.0	0.1	0.0	0.0	∞

SPP_S	∞	∞	420.4	496.5	-	4.5	2.0	0.1	0.0	0.0	∞
TVA	∞	∞	0.1	0.0	-	7.4	2.0	0.1	0.0	0.0	∞
VACAR	∞	∞	2.8	0.7	39.3	7.0	1.3	0.1	0.0	0.0	∞
ALB	0.0	∞	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
BC	0.0	∞	0.0	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OH	0.0	∞	0.0	300.0	6.4	0.0	0.1	0.0	0.0	0.0	0.0
MAPP_CA	0.0	∞	0.0	300.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	∞	∞	4,202.7	5,338.5	111.5	137.7	126.1	6.5	6.7	29.5	∞

Table 89: Reserve Margin Regions, Reserve Requirements, NEEM Regions

Source: MRN-NEEM Assumptions, EIPC

Reserve Margin Area	Reserve Requirement	NEEM Region(s)
ALB	18.0%	ALB
AZ_NM_SNV	15.7%	AZ_NM_SNV
BC	18.0%	BC
CA	16.6%	NP15
		SP15
ENT	14.0%	ENT
ERCOT	NA	ERCOT
FRCC	16.0%	FRCC
MAPP_US	14.0%	MAPP_US
MAPP_CA	12.0%	MAPP_CA
MISO	17.4%	MISO_IN
		MISO_MI
		MISO_MO-IL
		MISO_W
		MISO_WUMS
NEISO	16.0%	NEISO
NonRTO_Midwest	14.0%	NonRTO_Midwest
NWPP	18.0%	NWPP
NYISO	16.5%	NYISO_A-F
		NYISO_GHI
		NYISO_JK
NYISO_GHI_JK	-5.0%	NYISO_GHI
		NYISO_JK
NYISO_JK	-8.0%	NYISO_JK
OH (IESO)	17.0%	OH
PJM	15.3%	PJM_E
		PJM_ROM
		PJM_ROR
PJM_E	-2.2%	PJM_E
RMPA	14.0%	RMPA
SOCO	14.0%	SOCO
SPP	13.6%	NE
		SPP_N
		SPP_S
TVA	15.0%	TVA
VACAR	14.0%	VACAR

Table 90: CO2+ Combined Energy Case Intermittent Generation Limits

Source: MRN-NEEM Assumptions, EIPC

Intermittency Region	NEEM Regions	SSC Consensus
SPP+	SPP-S, SPP-N, NE, ENT, TVA, SOCO, FRCC, VACAR	0.35
PJM+	PJM_E, PJM_ROM, PJM_ROR, MAPP_US, MAPP_CA, MISO_W, MISO_MI, MISO_WUMS, MISO_IN, MISO_MO_IL, Non-RTO Midwest	0.35
New York+	NYISO_A-F, NYISO_G-I, NYISO_J-K, NEISO	0.35
IESO	IESO	0.35

Table 91: Forced New Builds

Source: MRN-NEEM Assumptions, EIPC

NEEM Region	Online Year	Plant Name	Unit	MW	Technology	Plant State
ENT	2011	Plum Point Energy ST	1	720	Coal	AR
FRCC	2011	WCE3-STE	1	498.9	CC	FL
FRCC	2013	CAPE-STE	1	515	CC	FL
FRCC	2014	RIV-STE	1	503	CC	FL
FRCC	2020	GEC ST 3	30	201	CC	FL
FRCC	2011	GEC CT 1	30	150	CT	FL
FRCC	2011	GEC CT 2	30	150	CT	FL
FRCC	2011	WCE3-CT1	1	240	CT	FL
FRCC	2011	WCE3-CT2	1	240	CT	FL
FRCC	2011	WCE3-CT3	1	240	CT	FL
FRCC	2013	CAPE-CT1	1	231	CT	FL
FRCC	2013	CAPE-CT2	1	242	CT	FL
FRCC	2013	CAPE-CT3	1	231	CT	FL
FRCC	2014	RIV-CT1	1	231	CT	FL
FRCC	2014	RIV-CT2	1	242	CT	FL
FRCC	2014	RIV-CT3	1	231	CT	FL
FRCC	2015	SWN P1&2	1	52	CT	FL
IESO	2011	RESOP Biomass	0	4.49	BM	ON
IESO	2011	RESOP Biomass	0	3.95	BM	ON
IESO	2011	RESOP Biomass	0	3.2	BM	ON
IESO	2012	Becker (Hornepayne)	0	15	BM	ON
IESO	2012	RESOP Biomass	0	10	BM	ON
IESO	2012	RESOP Biomass	0	10	BM	ON
IESO	2013	FIT Clearydale Farms	0	0.498	BM	ON
IESO	2013	FIT DeBruin Farms Biogas	0	0.36	BM	ON
IESO	2013	FIT Ferme Geranik Biogas	0	0.499	BM	ON
IESO	2013	FIT Grimsby Bioreactor Project	0	1	BM	ON
IESO	2013	FIT Haliburton Forest Biopower 1	0	0.775	BM	ON
IESO	2013	FIT Index Energy Mills Road Corporation	0	17.812	BM	ON
IESO	2013	FIT Kawartha Biogas Inc.	0	9.8	BM	ON
IESO	2013	FIT Powerbase / Gillette Farms Inc	0	0.498	BM	ON
IESO	2013	FIT Woolwich Bio-En Inc.	0	2.852	BM	ON
IESO	2013	RESOP Biomass	0	0.6	BM	ON
IESO	2014	ST MARYS	0	30	BM	ON
IESO	2015	Atikokan Biomass	0	215	BM	ON
IESO	2012	GRNFLDS_CTG116.500	1	140	CC	ON
IESO	2012	GRNFLDS_STG213.800	1	140	CC	ON
IESO	2014	Thunder Bay Gas Conversion 1	0	150	CC	ON
IESO	2015	Thunder Bay Gas Conversion 2	0	150	CC	ON
IESO	2011	Halton Hills Generating Station CC		683	CC	ON
IESO	2012	YORK_EC_LV1 16.500	1	184	CT	ON
IESO	2012	YORK_EC_LV2 16.500	1	184	CT	ON
IESO	2011	FIT_BIG_EDDY13.800	1	5.3	HY	ON
IESO	2011	FIT_WAHP_GEN13.800	1	6.5	HY	ON
IESO	2011	HOUND CHUTE	0	9.5	HY	ON
IESO	2011	ISLAND FALLS (Yellow Falls)	0	20	HY	ON

IESO	2011	LOWER STURGEON	0	14	HY	ON
IESO	2011	RESOP Water	0	1.17	HY	ON
IESO	2011	WAWAITIN	0	15	HY	ON
IESO	2012	FIT_BOUNDARY13.800	1	3.75	HY	ON
IESO	2012	FIT_HALF_MIL13.800	1	4.8	HY	ON
IESO	2012	FIT_IVANHOE 13.800	1	5.1	HY	ON
IESO	2012	FIT_LAPINIGA13.800	1	8.2	HY	ON
IESO	2012	FIT_MIDDLETW13.800	1	5	HY	ON
IESO	2012	FIT_OUTLET 13.800	1	2.5	HY	ON
IESO	2012	FIT_WAPO_GEN13.800	1	6.5	HY	ON
IESO	2014	FIT_NEES_GEN13.800	1	6.5	HY	ON
IESO	2014	FIT_PEES_GEN13.800	1	6.5	HY	ON
IESO	2015	FIT Allen and Struthers 2130769	0	2.8	HY	ON
IESO	2015	FIT At Soo Crossing 2154061	0	4.3	HY	ON
IESO	2015	FIT Big Beaver Falls Hydroelectric Project	0	5.5	HY	ON
IESO	2015	FIT Birch Creek Hydro	0	1	HY	ON
IESO	2015	FIT Bracebridge Falls Generating Station	0	2	HY	ON
IESO	2015	FIT Camp Three Rapids Hydroelectric Project	0	5.5	HY	ON
IESO	2015	FIT Cascade Fall 1723378	0	2.1	HY	ON
IESO	2015	FIT Charlton Dam GS Expansion	0	0.85	HY	ON
IESO	2015	FIT Driftwood Power	0	0.4	HY	ON
IESO	2015	FIT Elora Hydro Electric Generating Station	0	1	HY	ON
IESO	2015	FIT Four Slide Falls Ltd 1713400	0	7.3	HY	ON
IESO	2015	FIT High Falls Hydropower Development	0	6.4	HY	ON
IESO	2015	FIT Ivanhoe River, The Chute - 2124750	0	3.6	HY	ON
IESO	2015	FIT Larder Lake & Raven Falls 2118966	0	1.25	HY	ON
IESO	2015	FIT Latchford Dam	0	0.838	HY	ON
IESO	2015	FIT Latchford Dam 2	0	0.419	HY	ON
IESO	2015	FIT Lizard Creek Small Hydro Project	0	1.04	HY	ON
IESO	2015	FIT Marter Twp, Blanche River - 2154070	0	2.1	HY	ON
IESO	2015	FIT McCarthy Chute 1713399 Ltd.	0	2	HY	ON
IESO	2015	FIT McGraw Falls 2089284	0	2.4	HY	ON
IESO	2015	FIT McPherson Fall 2154065	0	2	HY	ON
IESO	2015	FIT North Bala Small Hydro Project	0	5	HY	ON
IESO	2015	FIT Okikendawt Hydroelectric Project	0	10	HY	ON
IESO	2015	FIT Old Woman Falls Hydroelectric Project	0	5.5	HY	ON
IESO	2015	FIT Pecors Power Small Hydro Project	0	2	HY	ON
IESO	2015	FIT Wabageshik Rapid at Outlet Lake 1723377	0	3.4	HY	ON
IESO	2015	FIT Wanatango Falls 2124716	0	4.67	HY	ON
IESO	2015	FIT Wasdell Falls Waterpower Project	0	1.9	HY	ON
IESO	2015	FIT Wendigo Waterpower Project	0	3	HY	ON
IESO	2015	FIT White Otter Falls Hydroelectric Project	0	5.5	HY	ON
IESO	2015	FIT Wilson Falls Generating Station	0	2.3	HY	ON
IESO	2015	FIT_GITCHIG113.800	1	10	HY	ON
IESO	2015	FIT_GITCHIG213.800	1	8.9	HY	ON
IESO	2015	FIT_NAME_G1 13.800	1	10	HY	ON
IESO	2015	FIT_TROU_GEN13.800	1	4	HY	ON
IESO	2016	Harmon	0	78	HY	ON
IESO	2016	Kipling	0	78	HY	ON
IESO	2016	Little Long	0	67	HY	ON
IESO	2016	Smoky Falls	0	215	HY	ON
IESO	2013	FIT Bensfort Road LFG Generation Project	0	2	LFG	ON

IESO	2013	FIT Lafleche Landfill Gas Utilization	0	4.5	LFG	ON
IESO	2013	FIT Merrick Landfill Project	0	1.6	LFG	ON
IESO	2013	FIT WM Ottawa Landfill Gas to Energy	0	6.4	LFG	ON
IESO	2011	RESOP Solar	0	20	PV	ON
IESO	2011	RESOP Solar	0	10	PV	ON
IESO	2011	RESOP Solar	0	10	PV	ON
IESO	2011	RESOP Solar	0	3.33	PV	ON
IESO	2011	RESOP Solar	0	2.95	PV	ON
IESO	2011	RESOP Solar	0	0.66	PV	ON
IESO	2011	RESOP Solar	0	0.02	PV	ON
IESO	2012	FIT_LISKEAR113.800	1	10	PV	ON
IESO	2012	FIT_LISKEAR313.800	1	10	PV	ON
IESO	2012	FIT_NP_MART_13.800	1	10	PV	ON
IESO	2012	RESOP Solar	0	130	PV	ON
IESO	2012	RESOP Solar	0	70	PV	ON
IESO	2012	RESOP Solar	0	59.76	PV	ON
IESO	2012	RESOP Solar	0	39.12	PV	ON
IESO	2012	RESOP Solar	0	20	PV	ON
IESO	2012	RESOP Solar	0	20	PV	ON
IESO	2013	FIT 2176047	0	10	PV	ON
IESO	2013	FIT 2176050	0	9	PV	ON
IESO	2013	FIT Alderville 3	0	5	PV	ON
IESO	2013	FIT Alfred	0	10	PV	ON
IESO	2013	FIT Belleville TS Demorestville	0	10	PV	ON
IESO	2013	FIT Black Bay Solar Project Phase 2	0	0.75	PV	ON
IESO	2013	FIT Burritts Rapids	0	7	PV	ON
IESO	2013	FIT Consolidated Maintenance facility Solar Roof	0	0.5	PV	ON
IESO	2013	FIT Dave Rampel Solar Park	0	10	PV	ON
IESO	2013	FIT EffiSolar Beckwith Solar Farm (10MW)	0	10	PV	ON
IESO	2013	FIT EffiSolar Brockville Solar Farm (10MW)	0	10	PV	ON
IESO	2013	FIT EffiSolar Cornwall Solar Farm A (10MW)	0	10	PV	ON
IESO	2013	FIT Glenarm	0	10	PV	ON
IESO	2013	FIT HPG Site A	0	2	PV	ON
IESO	2013	FIT Kap Solar Park	0	6	PV	ON
IESO	2013	FIT Kingston Gardiner Hwy2 North	0	10	PV	ON
IESO	2013	FIT Kingston Gardiner Hwy2 South	0	10	PV	ON
IESO	2013	FIT Kingston Gardiner TS Odessa	0	10	PV	ON
IESO	2013	FIT Kingston Gardiner TS Unity Road	0	10	PV	ON
IESO	2013	FIT Longueil TS Malbouef	0	10	PV	ON
IESO	2013	FIT Mattawishkwia Solar Park	0	10	PV	ON
IESO	2013	FIT Mississippi Mills Solar Park	0	10	PV	ON
IESO	2013	FIT Morley Solar Park	0	10	PV	ON
IESO	2013	FIT Napanee TS Taylor Kidd	0	10	PV	ON
IESO	2013	FIT Norfolk Bloomsburg TS	0	10	PV	ON
IESO	2013	FIT Northland Power Burks Falls West	0	10	PV	ON
IESO	2013	FIT Northland Power Solar Belleville North	0	10	PV	ON
IESO	2013	FIT Northland Power Solar Belleville South	0	10	PV	ON
IESO	2013	FIT Northland Power Solar Burks Falls East	0	10	PV	ON
IESO	2013	FIT Northland Power Solar Crosby	0	10	PV	ON
IESO	2013	FIT Northland Power Solar Glendale	0	10	PV	ON
IESO	2013	FIT Northland Power Solar McCann L.P.	0	10	PV	ON
IESO	2013	FIT Northland Power Solar North Burgess	0	10	PV	ON

IESO	2013	FIT Northland Power Solar Rideau Lakes	0	10	PV	ON
IESO	2013	FIT Penn Energy - Edwardsburgh_Morrisburg-1	0	9.333	PV	ON
IESO	2013	FIT Penn Energy - Hamilton_Port Hope-4	0	10	PV	ON
IESO	2013	FIT Penn Energy - S. Glengarry_St. Lawrence-1	0	9.333	PV	ON
IESO	2013	FIT Ramore Solar Park	0	8	PV	ON
IESO	2013	FIT RE Adelaide 1c	0	1	PV	ON
IESO	2013	FIT RE Adelaide 1d	0	0.5	PV	ON
IESO	2013	FIT RE Breen 2	0	10	PV	ON
IESO	2013	FIT RE Highbury 1	0	5	PV	ON
IESO	2013	FIT RE Ingersoll 1	0	8	PV	ON
IESO	2013	FIT RE Ingersoll 1a	0	1	PV	ON
IESO	2013	FIT RE Ingersoll 1b	0	0.5	PV	ON
IESO	2013	FIT RE Midhurst 2	0	3.5	PV	ON
IESO	2013	FIT RE Midhurst 3	0	3.5	PV	ON
IESO	2013	FIT RE Midhurst 4	0	6.5	PV	ON
IESO	2013	FIT RE Midhurst 6	0	9	PV	ON
IESO	2013	FIT RE Orillia 1	0	10	PV	ON
IESO	2013	FIT RE Orillia 2	0	10	PV	ON
IESO	2013	FIT RE Orillia 3	0	6.5	PV	ON
IESO	2013	FIT RE Smiths Falls 1	0	10	PV	ON
IESO	2013	FIT RE Smiths Falls 2	0	10	PV	ON
IESO	2013	FIT RE Smiths Falls 3	0	8	PV	ON
IESO	2013	FIT RE Smiths Falls 4	0	10	PV	ON
IESO	2013	FIT RE Smiths Falls 5	0	10	PV	ON
IESO	2013	FIT RE Smiths Falls 6	0	10	PV	ON
IESO	2013	FIT RE Waubaushene 3	0	10	PV	ON
IESO	2013	FIT RE Waubaushene 4	0	8	PV	ON
IESO	2013	FIT RE Waubaushene 5	0	3.5	PV	ON
IESO	2013	FIT Simcoe Solar Energy Centre I	0	10	PV	ON
IESO	2013	FIT Simcoe Solar Energy Centre III	0	10	PV	ON
IESO	2013	FIT SunE Rutley	0	10	PV	ON
IESO	2013	FIT SUNNY SHORES SOLAR FARM	0	10	PV	ON
IESO	2013	FIT Val Caron	0	10	PV	ON
IESO	2013	FIT Vanzwolf Solar Park	0	10	PV	ON
IESO	2013	FIT Wainwright Solar Park	0	10	PV	ON
IESO	2013	FIT Welland Ridge Road	0	10	PV	ON
IESO	2013	FIT William Rutley Solar Park	0	10	PV	ON
IESO	2013	RESOP Solar	0	30	PV	ON
IESO	2015	FIT_LISKEAR413.800	1	10	PV	ON
IESO	2015	FIT_NP_ABITI13.800	1	10	PV	ON
IESO	2015	FIT_NP_EMPIR13.800	1	10	PV	ON
IESO	2015	FIT_NP_LONG_13.800	1	10	PV	ON
IESO	2011	FIT_CONESTOG13.800	1	69	WT	ON
IESO	2011	RALEIGH-WTG20.5750	1	18	WT	ON
IESO	2011	RESOP Wind	0	106	WT	ON
IESO	2011	RESOP Wind	0	48	WT	ON
IESO	2011	RESOP Wind	0	9	WT	ON
IESO	2011	RESOP Wind	0	6.5	WT	ON
IESO	2012	FIT_BL_2A 13.800	1	20	WT	ON
IESO	2012	FIT_BL_2B 13.800	1	20	WT	ON
IESO	2012	FIT_BL_PH1 13.800	1	20	WT	ON
IESO	2012	FIT_COMBER23220.00	1	82.8	WT	ON

IESO	2012	FIT_COMBER24220.00	1	82.8	WT	ON
IESO	2012	FIT_FARM_OWN13.800	1	100	WT	ON
IESO	2012	FIT_GOUL_BAY13.800	1	25	WT	ON
IESO	2012	FIT_MCLEANS113.800	1	50	WT	ON
IESO	2012	FIT_MCLEANS213.800	1	10	WT	ON
IESO	2012	FIT_PAR_G1 13.800	1	48.6	WT	ON
IESO	2012	FIT_PRT_DOV 13.800	1	105	WT	ON
IESO	2012	FIT_SUMHV_G113.800	1	125	WT	ON
IESO	2012	FIT_WHE_PNE 13.800	1	60	WT	ON
IESO	2012	FIT_WOLF_IS 13.800	1	300	WT	ON
IESO	2012	GREENWCHWTG10.6900	1	25.3	WT	ON
IESO	2012	GREENWCHWTG20.6900	1	23	WT	ON
IESO	2012	RALEIGH-WTG10.5750	1	18	WT	ON
IESO	2012	RESOP Wind	0	20	WT	ON
IESO	2012	RESOP Wind	0	10	WT	ON
IESO	2012	TALBOT_WTG1 0.5750	1	25.3	WT	ON
IESO	2012	TALBOT_WTG2 0.5750	1	23	WT	ON
IESO	2012	TALBOT_WTG3 0.5750	1	25.3	WT	ON
IESO	2012	TALBOT_WTG4 0.5750	1	25.3	WT	ON
IESO	2013	FIT Ballyduff Wind Farm	0	11.5	WT	ON
IESO	2013	FIT Belwood Wind Farm	0	9.2	WT	ON
IESO	2013	FIT Big Thunder Beta Windpark	0	16.5	WT	ON
IESO	2013	FIT Clarington Wind Farm	0	10	WT	ON
IESO	2013	FIT CLEAN BREEZE WIND PARK	0	12.5	WT	ON
IESO	2013	FIT CLEAN BREEZE WIND PARK GRAFTON	0	10	WT	ON
IESO	2013	FIT Conestogo Wind Energy Centre	0	23	WT	ON
IESO	2013	FIT Conestogo Wind Energy Centre 2	0	19.5	WT	ON
IESO	2013	FIT Ernestown Wind Park	0	10	WT	ON
IESO	2013	FIT Fairview Wind Farm	0	18.4	WT	ON
IESO	2013	FIT Grand Valley Wind Farms (Phase 2)	0	10.8	WT	ON
IESO	2013	FIT GREY HIGHLANDS CLEAN ENERGY	0	20	WT	ON
IESO	2013	FIT GREY HIGHLANDS ZERO EMISSION PEOPLE	0	10	WT	ON
IESO	2013	FIT HAF Energy	0	10	WT	ON
IESO	2013	FIT Little Brit Power	0	1.5	WT	ON
IESO	2013	FIT Merlin Wind Farm	0	10	WT	ON
IESO	2013	FIT Mother Earth Renewable Energy Project - Phase I	0	4	WT	ON
IESO	2013	FIT Ostrander Point Wind Energy Park	0	24	WT	ON
IESO	2013	FIT Plateau I & II Wind	0	18	WT	ON
IESO	2013	FIT Plateau III Wind	0	9	WT	ON
IESO	2013	FIT Pukwis Community Wind Park	0	20	WT	ON
IESO	2013	FIT SETTLERS LANDING WIND PARK	0	10	WT	ON
IESO	2013	FIT skyway 125	0	10	WT	ON
IESO	2013	FIT SKYWAY 126 WIND ENERGY	0	10	WT	ON
IESO	2013	FIT SNOWY RIDGE WIND PARK	0	10	WT	ON
IESO	2013	FIT South Branch Wind Farm	0	30	WT	ON
IESO	2013	FIT Trout Creek	0	10	WT	ON
IESO	2013	FIT Wainfleet Wind Farm	0	10	WT	ON
IESO	2013	FIT WHISPERING WOODS WIND FARM	0	10	WT	ON
IESO	2013	FIT Whittington Wind Farm	0	6.9	WT	ON
IESO	2013	FIT WIND FARM COLLIE HILL	0	5.6	WT	ON
IESO	2013	FIT ZEP WIND FARM GANARASKA	0	20	WT	ON
IESO	2013	FIT Zurich	0	0.8	WT	ON

IESO	2013	GREENWCHWTG30.6900	1	25.3	WT	ON
IESO	2013	KRUGER-WTG1 0.6900	1	25.3	WT	ON
IESO	2013	KRUGER-WTG2 0.6900	1	25.3	WT	ON
IESO	2013	KRUGER-WTG3 0.6900	1	32.2	WT	ON
IESO	2013	KRUGER-WTG4 0.6900	1	18.4	WT	ON
IESO	2013	RALEIGH-WTG30.5750	1	21	WT	ON
IESO	2014	GREENWCHWTG40.6900	1	25.3	WT	ON
IESO	2014	RALEIGH-WTG40.5750	1	21	WT	ON
MAPP_CA	2012	KELSEY1G	1	45	HY	Manitoba
MAPP_CA	2012	KELSEY2G	2	45	HY	Manitoba
MAPP_CA	2012	KELSEY3G	3	45	HY	Manitoba
MAPP_CA	2012	KELSEY4G	4	45	HY	Manitoba
MAPP_CA	2012	KELSEY5G	5	45	HY	Manitoba
MAPP_CA	2012	KELSEY6G	6	45	HY	Manitoba
MAPP_CA	2012	KELSEY7G	7	45	HY	Manitoba
MAPP_CA	2012	WUSK 1G	1	74.3	HY	Manitoba
MAPP_CA	2012	WUSK 2G	2	74.3	HY	Manitoba
MAPP_CA	2012	WUSK 3G	3	74.3	HY	Manitoba
MAPP_CA	2013	PINFLS1G	1	16.7	HY	Manitoba
MAPP_CA	2013	PINFLS2G	2	16.7	HY	Manitoba
MAPP_CA	2013	PINFLS3G	3	18.4	HY	Manitoba
MAPP_CA	2013	PINFLS4G	4	18.4	HY	Manitoba
MAPP_CA	2013	PINFLS5G	5	16.5	HY	Manitoba
MAPP_CA	2013	PINFLS6G	6	16.8	HY	Manitoba
MAPP_CA	2011	STJOS1 W	1	151.2	WT	Manitoba
MAPP_CA	2011	STJOS2 W	1	151.2	WT	Manitoba
MAPP_US	2010	Larimore	0	3.5	CT	ND
MAPP_US	2010	Mobile	0	0.8	CT	ND
MAPP_US	2010	Park River	0	1	CT	ND
MAPP_US	2010	Valley City	0	3	CT	ND
MAPP_US	2010	Minot - Prairie Winds	1	115.5	WT	ND
MAPP_US	2010	Valley City St. Petersberg proj	0	0.9	WT	ND
MAPP_US	2011	Baldwin	1	102.4	WT	ND
MAPP_US	2012	DEERCREE	1	300	CT	SD
MAPP_US	2010	WESSINGT	1	51	WT	SD
MAPP_US	2011	SDPRAIRW	1	151.5	WT	SD
MISO_IN	2012	Edwardsport	1	618	IGCC	IN
MISO_MI	2015	19GRNEC 345.00	N1	500	WT	MI
MISO_MI	2015	19GRNECP 345.00	N1	500	WT	MI
MISO_MI	2015	MI-C STA 345345.00	N1	500	WT	MI
MISO_MI	2015	MI-D STA 345345.00	N1	500	WT	MI
MISO_MO-IL	2012	1PR STATE G126.000	1	895	Coal	IL
MISO_MO-IL	2012	1PR STATE G226.000	2	895	Coal	IL
MISO_MO-IL	2014	5ADAIR 161.00	N1	300	WT	MO
MISO_W	2015	LEHIGH 3 345.00	N1	300	WT	IA
MISO_W	2015	WEBSTER3 345.00	N1	300	WT	IA
MISO_W	Not Given	ATCHSN2W 0.6900	W2	250	WT	IA
MISO_W	Not Given	RLHILLSW 0.5750	W1	250	WT	IA
MISO_W	2012	MERRICT 1G 0.5750	W	50	WT	MN
MISO_W	2012	MERRICT 2G 0.5750	W	50	WT	MN
MISO_W	2012	MERRICT 3G 0.5750	W	50	WT	MN
MISO_W	2015	CHANRMB7 115.00	N1	500	WT	MN

MISO_W	2015	LAKEFLD3 345.00	N1	500	WT	MN
MISO_W	2006	Oliver Co 1	1	50.6	WT	ND
MISO_W	2007	Oliver Co 2	1	48	WT	ND
MISO_W	2004	Edgeley/Kulm	0	21	WT	ND
MISO_W	2010	Rugby	0	149.1	WT	ND
MISO_W	2011	Bison I	1	81.8	WT	ND
MISO_W	2015	BRKNGCO3 345.00	N1	200	WT	SD
MISO_WUMS	2011	Oak Creek Power Plant ST	2	512.541	Coal	WI
MISO_WUMS	2011	ATC_J084POI 69.000	N1	100	WT	WI
MISO_WUMS	2011	GLR HL WTG1 0.6900	W	99	WT	WI
MISO_WUMS	2011	GLR HL WTG2 0.6900	W	150	WT	WI
MISO_WUMS	2011	J079_80 138.00	N1	24	WT	WI
MISO_WUMS	2012	ECOMET WTG1 12.000	W	49.5	WT	WI
MISO_WUMS	2012	ECOMET WTG2 12.000	W	51	WT	WI
MISO_WUMS	2012	ECOMONT WTG 12.000	W	50	WT	WI
MISO_WUMS	2012	STONYBRK WTG0.6000	W	98.7	WT	WI
MISO_WUMS	2013	LAKBRZ G 0.6900	W	98	WT	WI
MISO_WUMS	2013	LDGE WD WTG 0.6900	W	150	WT	WI
MISO_WUMS	2013	QLT B W1 0.6000	W	25.2	WT	WI
MISO_WUMS	2013	QLT B W2 0.6000	W	25.2	WT	WI
MISO_WUMS	2013	QLT B W3 0.6000	W	25.2	WT	WI
MISO_WUMS	2013	QLT B W4 0.6000	W	23.1	WT	WI
NE	2011	EGYCTR2G 22.000	2	232.1	Coal	NE
NE	2010	CROFTON HILLS	1	42	WT	NE
NE	2011	BROKEN1X 34.500	1	80	WT	NE
NE	2011	PETSBG1X 34.500	1	80	WT	NE
NEISO	2014	PLAINFIELD	1	43	BM	CT
NEISO	2014	PLAINFIELD	1	43	BM	CT
NEISO	2011	KLEEN_C1	C1	158	CC	CT
NEISO	2011	KLEEN_C2	C2	158	CC	CT
NEISO	2011	KLEEN_S1	S1	318	CC	CT
NEISO	2012	ANSONIA GEN	C1	54.5	CC	CT
NEISO	2012	MERIDEN GT1	C1	182	CC	CT
NEISO	2012	MERIDEN GT2	C2	182	CC	CT
NEISO	2012	MERIDEN ST	S1	170	CC	CT
NEISO	2014	QP207-1_CT1	C1	168.4	CC	CT
NEISO	2014	QP207-1_CT2	C2	168.4	CC	CT
NEISO	2014	QP207-1_ST	S1	188.6	CC	CT
NEISO	2011	MIDDLETWN_11	11	112	CT	CT
NEISO	2011	MIDDLETWN_12	12	50	CT	CT
NEISO	2011	MIDDLETWN_13	13	50	CT	CT
NEISO	2011	MIDDLETWN_14	14	50	CT	CT
NEISO	2011	MIDDLETWN_15	15	50	CT	CT
NEISO	2012	QP273-1	1	40.3	BM	MA
NEISO	2013	RUSSELL BIO	1	60	BM	MA
NEISO	2014	QP174-1_CT	C3	190.6	CC	MA
NEISO	2014	QP174-1_ST	S3	111	CC	MA
NEISO	2014	MATEP_CC	C3	12.5	CT	MA
NEISO	2011	Northfield Mountain Unit 3	3	295	HY	MA
NEISO	2012	Northfield Mountain Unit 2	2	295	HY	MA
NEISO	2013	Northfield Mountain Unit 4	4	295	HY	MA
NEISO	2014	Northfield Mountain Unit 1	1	295	HY	MA

NEISO	Not Given	CAPE W CLR-1	1	126	WT	MA
NEISO	Not Given	CAPE W CLR-2	2	108	WT	MA
NEISO	Not Given	CAPE W CLR-3	3	126	WT	MA
NEISO	Not Given	CAPE W CLR-4	4	108	WT	MA
NEISO	2010	QP316-1_GT	5	9.5	CT	ME
NEISO	2011	QP197 STRNG1	1	25.3	WT	ME
NEISO	2011	QP197 STRNG2	2	25.3	WT	ME
NEISO	2012	QP221-1_CLR2	2	21.6	WT	ME
NEISO	2012	QP251-1	1	65.9	BM	NH
NEISO	2011	Comerford Unit 2	2	48.2	HY	NH
NEISO	2012	Comerford Unit 3	3	48.3	HY	NH
NEISO	2013	Comerford Unit 4	4	48.2	HY	NH
NEISO	2011	GRANITE DIX	7	21	WT	NH
NEISO	2011	GRANITE FISH	12	36	WT	NH
NEISO	2011	GRANITE OWLS	14	42	WT	NH
NEISO	2012	RIDGEWOOD LD	C1	6.1	LFG	RI
NEISO	2012	RIDGEWOOD LD	C2	6.1	LFG	RI
NEISO	2012	RIDGEWOOD LD	C3	6.1	LFG	RI
NEISO	2012	RIDGEWOOD LD	C4	6.1	LFG	RI
NEISO	2012	RIDGEWOOD LD	C5	6.1	LFG	RI
NEISO	2012	RIDGEWOOD LD	C6	6.1	LFG	RI
NEISO	2012	RIDGEWOOD LD	S1	12.66	LFG	RI
NEISO	2010	SHEFLD CLR-N	1	30	WT	VT
NEISO	2012	QP276-1 EAST	1	14	WT	VT
NEISO	2012	QP276-1 WEST	1	16	WT	VT
NYISO_A-F	2011	Empire Generating CC	CC	639	CC	NY
NYISO_A-F	2011	Q231SEN19-224.1600	1	6.4	LFG	NY
NYISO_A-F	2011	ECOGEN_SWT1 0.6900	W	9.2	WT	NY
NYISO_A-F	2011	ECOGEN_SWT2 0.6900	W	23	WT	NY
NYISO_A-F	2011	ECOGEN_SWT3 0.6900	W	23	WT	NY
NYISO_A-F	2011	ECOGEN_SWT4 0.6900	W	23	WT	NY
NYISO_A-F	2011	FRFLD_G1 0.6900	W	24	WT	NY
NYISO_A-F	2011	FRFLD_G2 0.6900	W	24	WT	NY
NYISO_A-F	2011	FRFLD_G3 0.6900	W	26	WT	NY
NYISO_A-F	2011	HOWD_C93_G1 0.6900	W	7.5	WT	NY
NYISO_A-F	2011	HOWD_C93_G2 0.6900	W	27.5	WT	NY
NYISO_A-F	2011	HOWD_C93_G3 0.6900	W	27.5	WT	NY
NYISO_A-F	2011	Q180A_CLIB_G0.6900	W	10	WT	NY
NYISO_A-F	2011	Q234_CLIB_G10.6900	W	7.5	WT	NY
NYISO_A-F	2011	Q234_CLIB_G20.6900	W	7.5	WT	NY
NYISO_A-F	2011	Q263STONY_1G0.6900	W	24	WT	NY
NYISO_A-F	2011	Q263STONY_2G0.6900	W	24	WT	NY
NYISO_A-F	2011	Q263STONY_3G0.6900	W	24	WT	NY
NYISO_A-F	2011	Q263STONY_4G0.6900	W	24	WT	NY
NYISO_A-F	2011	Q263STONY_5G0.6900	W	24	WT	NY
NYISO_A-F	2011	Q263STONY_6G0.6900	W	22.5	WT	NY
NYISO_A-F	2011	Q271STLINE1G0.6900	W	24	WT	NY
NYISO_A-F	2011	Q271STLINE2G0.6900	W	24	WT	NY
NYISO_A-F	2011	Q271STLINE3G0.6900	W	24	WT	NY
NYISO_A-F	2011	Q271STLINE4G0.6900	W	26.4	WT	NY
NYISO_A-F	2011	Q271STLINE5G0.6900	W	26.4	WT	NY
NYISO_A-F	2012	BALLHL1G 0.5750	W	12	WT	NY

NYISO_A-F	2012	BALLHL2G 0.5750	W	10.5	WT	NY
NYISO_A-F	2012	BALLHL3G 0.5750	W	10.5	WT	NY
NYISO_A-F	2012	BALLHL4G 0.5750	W	12	WT	NY
NYISO_A-F	2012	BALLHL5G 0.5750	W	10.5	WT	NY
NYISO_A-F	2012	BALLHL6G 0.5750	W	10.5	WT	NY
NYISO_A-F	2012	BALLHL7G 0.5750	W	12	WT	NY
NYISO_A-F	2012	BALLHL8G 0.5750	W	10.5	WT	NY
NYISO_A-F	2012	BALLHL9G 0.5750	W	10.5	WT	NY
NYISO_A-F	2012	JRCHO_1G 0.6900	W	19.8	WT	NY
NYISO_A-F	2012	JRCHO_2G 0.6900	W	19.8	WT	NY
NYISO_A-F	2012	JRCHO_3G 0.6900	W	19.8	WT	NY
NYISO_A-F	2012	JRCHO_4G 0.6900	W	19.8	WT	NY
NYISO_A-F	2012	JRDN_G87_G1 0.6900	W	8	WT	NY
NYISO_A-F	2012	JRDN_G87_G2 0.6900	W	24	WT	NY
NYISO_A-F	2012	JRDN_G87_G3 0.6900	W	24	WT	NY
NYISO_A-F	2012	JRDN_G87_G4 0.6900	W	24	WT	NY
NYISO_A-F	2012	MORESVL_1G 1.0000	W	21	WT	NY
NYISO_A-F	2012	MORESVL_2G 1.0000	W	21	WT	NY
NYISO_A-F	2012	MORESVL_5G 1.0000	W	21	WT	NY
NYISO_A-F	2012	MRBLRV1G_S880.6000	W	25.2	WT	NY
NYISO_A-F	2012	MRBLRV2G_S880.6000	W	21	WT	NY
NYISO_A-F	2012	MRBLRV3G_S880.6000	W	44.1	WT	NY
NYISO_A-F	2012	MRBLRV4G_S880.6000	W	44.1	WT	NY
NYISO_A-F	2012	MRBLRV5G_S880.6000	W	42	WT	NY
NYISO_A-F	2012	MRBLRV6G_S880.6000	W	39.9	WT	NY
NYISO_A-F	2012	Q168_PRY_1G 0.6900	W	28	WT	NY
NYISO_A-F	2012	Q168_PRY_2G 0.6900	W	28	WT	NY
NYISO_A-F	2012	Q168_PRY_3G 0.6900	W	24	WT	NY
NYISO_A-F	2012	Q168_PRY_4G 0.6900	W	28	WT	NY
NYISO_A-F	2012	Q168_PRY_5G 0.6900	W	28	WT	NY
NYISO_A-F	2012	Q169_V90_1G 1.0000	W	19.8	WT	NY
NYISO_A-F	2012	Q169_V90_2G 1.0000	W	19.8	WT	NY
NYISO_A-F	2012	Q169_V90_3G 1.0000	W	19.8	WT	NY
NYISO_A-F	2012	Q169_V90_4G 1.0000	W	19.8	WT	NY
NYISO_A-F	2012	Q197_G87_1G 0.6900	W	20	WT	NY
NYISO_A-F	2012	Q197_G87_2G 0.6900	W	20	WT	NY
NYISO_A-F	2012	Q197_G87_3G 0.6900	W	20	WT	NY
NYISO_A-F	2012	Q197_G87_4G 0.6900	W	18	WT	NY
NYISO_A-F	2012	Q198_V90_1G 1.0000	W	19.8	WT	NY
NYISO_A-F	2012	Q198_V90_2G 1.0000	W	19.8	WT	NY
NYISO_A-F	2012	Q198_V90_3G 1.0000	W	19.8	WT	NY
NYISO_A-F	2012	Q198_V90_4G 1.0000	W	19.8	WT	NY
NYISO_A-F	2012	Q237ALGANY1G0.6600	W	17.5	WT	NY
NYISO_A-F	2012	Q237ALGANY2G0.6600	W	30	WT	NY
NYISO_A-F	2012	Q237ALGANY3G0.6600	W	30	WT	NY
NYISO_A-F	2012	Q241CHTWND_G0.5750	W	19.5	WT	NY
NYISO_A-F	2012	Q246DUTCH_1G 0.6900	W	26	WT	NY
NYISO_A-F	2012	Q246DUTCH_2G 0.6900	W	26	WT	NY
NYISO_A-F	2012	Q246DUTCH_3G 0.6900	W	24	WT	NY
NYISO_A-F	2012	Q246DUTCH_4G 0.6900	W	24	WT	NY
NYISO_A-F	2012	Q246DUTCH_5G 0.6900	W	24	WT	NY
NYISO_A-F	2012	Q246DUTCH_6G 0.6900	W	26	WT	NY

NYISO_A-F	2012	Q246DUTCH_7G 0.6900	W	26	WT	NY
NYISO_A-F	2012	Q246DUTCH_8G 0.6900	W	26	WT	NY
NYISO_A-F	2012	Q246DUTCH_9G 0.6900	W	24	WT	NY
NYISO_A-F	2012	Q246DUTCH10G 0.6900	W	24	WT	NY
NYISO_A-F	2012	Q254RIPW_1G 0.6900	W	24	WT	NY
NYISO_A-F	2012	Q254RIPW_2G 0.6900	W	24	WT	NY
NYISO_A-F	2012	Q254RIPW_3G 0.6900	W	24	WT	NY
NYISO_A-F	2012	Q254RIPW_4G 0.6900	W	26.4	WT	NY
NYISO_A-F	2012	Q254RIPW_5G 0.6900	W	26.4	WT	NY
NYISO_A-F	2013	Q207_GE_01G 0.6900	1	24	WT	NY
NYISO_A-F	2013	Q207_GE_02G 0.6900	1	24	WT	NY
NYISO_A-F	2013	Q207_GE_03G 0.6900	1	24	WT	NY
NYISO_A-F	2013	Q207_GE_04G 0.6900	1	22.5	WT	NY
NYISO_A-F	2013	Q207_GE_05G 0.6900	1	12	WT	NY
NYISO_A-F	2013	Q207_GE_06G 0.6900	1	22.5	WT	NY
NYISO_A-F	2013	Q207_GE_07G 0.6900	1	12	WT	NY
NYISO_A-F	2013	Q207_GE_08G 0.6900	1	24	WT	NY
NYISO_A-F	2013	Q207_GE_09G 0.6900	1	9	WT	NY
NYISO_A-F	2013	Q207_GE_10G 0.6900	1	24	WT	NY
NYISO_A-F	2013	Q207_GE_11G 0.6900	1	12	WT	NY
NYISO_A-F	2013	STLAW_AW_G1 12.000	W	12	WT	NY
NYISO_A-F	2013	STLAW_AW_G2 12.000	W	39	WT	NY
NYISO_A-F	2013	STLAW_AW_G3 12.000	W	39	WT	NY
NYISO_A-F	2013	STLAW_AW_G4 12.000	W	39	WT	NY
NYISO_A-F	2013	WHILL_AW_1 12.000	W	12	WT	NY
NYISO_A-F	2013	WHILL_AW_2 12.000	W	12	WT	NY
NYISO_A-F	2013	WHILL_AW_3 12.000	W	13.5	WT	NY
NYISO_A-F	2013	WHORSE G 0.5750	1	19.5	WT	NY
NYISO_A-F	2014	MUNSVIL_GE1 0.5750	W	6	WT	NY
NYISO_A-F	2014	MUNSVIL_GE2 0.5750	W	16.5	WT	NY
NYISO_A-F	2014	MUNSVIL_GE3 0.5750	W	18	WT	NY
NYISO_A-F	2014	Q157_ORIN_1G0.5750	W	25.5	WT	NY
NYISO_A-F	2014	Q157_ORIN_2G0.5750	W	25.5	WT	NY
NYISO_A-F	2014	Q157_ORIN_3G0.5750	W	25.5	WT	NY
NYISO_A-F	2014	Q157_ORIN_4G0.5750	W	24	WT	NY
NYISO_A-F	2015	HRTVL_1G 0.6900	W	18.4	WT	NY
NYISO_A-F	2015	HRTVL_2G 0.6900	W	13.8	WT	NY
NYISO_A-F	2015	HRTVL_3G 0.6900	W	18.4	WT	NY
NYISO_A-F	2016	CNSTO_1G 0.5750	W	24	WT	NY
NYISO_A-F	2016	CNSTO_2G 0.5750	W	25.5	WT	NY
NYISO_A-F	2016	CNSTO_3G 0.5750	W	25.5	WT	NY
NYISO_A-F	2016	CNSTO_4G 0.5750	W	25.5	WT	NY
NYISO_A-F	2016	CNSTO_5G 0.5750	W	25.5	WT	NY
NYISO_A-F	2016	CNSTO_6G 0.5750	W	24	WT	NY
NYISO_A-F	2016	HOUNS10G 0.6900	W	28.8	WT	NY
NYISO_A-F	2016	HOUNSF1G 0.6900	W	26.4	WT	NY
NYISO_A-F	2016	HOUNSF2G 0.6900	W	26.4	WT	NY
NYISO_A-F	2016	HOUNSF3G 0.6900	W	26.4	WT	NY
NYISO_A-F	2016	HOUNSF4G 0.6900	W	26.4	WT	NY
NYISO_A-F	2016	HOUNSF5G 0.6900	W	28.8	WT	NY
NYISO_A-F	2016	HOUNSF6G 0.6900	W	26.4	WT	NY
NYISO_A-F	2016	HOUNSF7G 0.6900	W	26.4	WT	NY

NYISO_A-F	2016	HOUNSF8G 0.6900	W	26.4	WT	NY
NYISO_A-F	2016	HOUNSF9G 0.6900	W	26.4	WT	NY
NYISO_A-F	2016	Q239WDOOR_1G12.000	W	18	WT	NY
NYISO_A-F	2016	Q239WDOOR_2G12.000	W	18	WT	NY
NYISO_A-F	2016	Q239WDOOR_3G12.000	W	18	WT	NY
NYISO_A-F	2016	Q239WDOOR_4G12.000	W	18	WT	NY
NYISO_A-F	2016	Q239WDOOR_5G12.000	W	18	WT	NY
NYISO_A-F	2016	Q239WDOOR_6G12.000	W	9	WT	NY
NYISO_J-K	2011	BAY_G1&2 13.800	1	64	CC	NY
NYISO_J-K	2011	BAY_G1&2 13.800	2	64	CC	NY
NYISO_J-K	2011	BAY_G3&4 13.800	3	64	CC	NY
NYISO_J-K	2011	BAY_G3&4 13.800	4	64	CC	NY
NYISO_J-K	2011	BAY_G5&6 13.800	5	64	CC	NY
NYISO_J-K	2011	BAY_G5&6 13.800	6	64	CC	NY
NYISO_J-K	2011	BAY_G7&8 13.800	7	64	CC	NY
NYISO_J-K	2011	BAY_G7&8 13.800	8	64	CC	NY
NYISO_J-K	2011	Q308_GT1 18.000	1	193.1	CC	NY
NYISO_J-K	2011	Q308_GT2 18.000	1	193.1	CC	NY
NYISO_J-K	2011	Q308_ST 18.000	1	277.2	CC	NY
NYISO_J-K	2012	Q330 G 13.800	1	32	PV	NY
PJM_E	2010	O23	1	300	CC	DE
PJM_E	2010	T52	1	20	CC	DE
PJM_E	2010	T53	1	7.3	CT	DE
PJM_E	2010	T56	1	8.4	CT	DE
PJM_E	2010	T67	1	5.3	CT	DE
PJM_E	2010	T68	1	5.2	CT	DE
PJM_E	2015	R36	1	450	WT	DE
PJM_E	2014	Q41	1	30	BM	NJ
PJM_E	2010	S60	1	63	CC	NJ
PJM_E	2010	S61	1	20	CC	NJ
PJM_E	2010	T77	1	64	CC	NJ
PJM_E	2010	T54	1	6.6	CC	NJ
PJM_E	2010	T54	1	6.6	CC	NJ
PJM_E	2010	T55	1	15.3	CC	NJ
PJM_E	2010	T55	1	12.4	CC	NJ
PJM_E	2010	T59	1	12.9	CC	NJ
PJM_E	2010	T59	1	12.9	CC	NJ
PJM_E	2010	T76	1	27.3	CC	NJ
PJM_E	2010	T76	1	27.3	CC	NJ
PJM_E	2011	S107	1	580	CC	NJ
PJM_E	2011	T45	1	205	CC	NJ
PJM_E	2012	Q11	1	100	CC	NJ
PJM_E	2012	Q90	1	650	CC	NJ
PJM_E	2012	S121	1	63	CC	NJ
PJM_E	2012	T107	1	624.5	CC	NJ
PJM_E	2012	T41	1	178	CC	NJ
PJM_E	2012	T41	1	44.5	CC	NJ
PJM_E	2012	T42	1	88	CC	NJ
PJM_E	2012	T43	1	178	CC	NJ
PJM_E	2013	R11	1	440	CC	NJ
PJM_E	2010	T135	1	15	Coal	NJ
PJM_E	2011	U1-066	1	12	HY	NJ

PJM_E	2010	O20	1	9.1	LFG	NJ
PJM_E	2011	U3-032	1	20	PV	NJ
PJM_E	2011	U4-036	1	5.45	PV	NJ
PJM_E	2013	T84	1	350	WT	NJ
PJM_E	2014	U1-056	1	350	WT	NJ
PJM_E	2010	U1-090	1	12	Coal	OH
PJM_E	2010	T118	1	10	CC	PA
PJM_E	2010	T129	1	20	CC	PA
PJM_E	2012	P04	1	555	CC	PA
PJM_E	2012	U1-010	1	10	CC	PA
PJM_E	2013	U2-074	1	300	CC	PA
PJM_ROM	2011	S17	1	112.5	CC	MD
PJM_ROM	2011	T133	1	225	CC	MD
PJM_ROM	2012	T134	1	325	CC	MD
PJM_ROM	2013	R17	1	275	CC	MD
PJM_ROM	2011	S64	1	18	BM	PA
PJM_ROM	2011	S103	1	57	CC	PA
PJM_ROM	2011	U4-040	1	2	CC	PA
PJM_ROM	2012	T117	1	126	CC	PA
PJM_ROM	2011	Delta Power Plant CC	CC1	556	CC	PA
PJM_ROM	2010	Q46	1	10	Coal	PA
PJM_ROM	2010	T109	1	20	Coal	PA
PJM_ROM	2010	U2-067	1	2.5	Coal	PA
PJM_ROM	2011	U4-041	1	2	CT	PA
PJM_ROM	2011	U4-042	1	2	CT	PA
PJM_ROM	2011	U4-043	1	2	CT	PA
PJM_ROM	2011	U4-044	1	2	CT	PA
PJM_ROM	2011	U4-045	1	2	CT	PA
PJM_ROM	2011	U4-046	1	2	CT	PA
PJM_ROM	2011	U4-047	1	2	CT	PA
PJM_ROM	2011	U4-048	1	2	CT	PA
PJM_ROM	2010	Q63	1	16	HY	PA
PJM_ROM	2014	Q20	1	140	HY	PA
PJM_ROM	2010	T85	1	6	LFG	PA
PJM_ROM	2010	T86	1	1.5	LFG	PA
PJM_ROM	2011	S29B	1	5.7	LFG	PA
PJM_ROM	2011	S29B	1	5.7	LFG	PA
PJM_ROM	2010	O48, R40	1	37.8	WT	PA
PJM_ROM	2010	R32	1	75	WT	PA
PJM_ROM	2011	K02	1	70	WT	PA
PJM_ROM	2011	Q34	1	100	WT	PA
PJM_ROM	2011	Q36	1	50	WT	PA
PJM_ROM	2011	Q53	1	38	WT	PA
PJM_ROM	2012	O19	1	33	WT	PA
PJM_ROM	2012	R43	1	20	WT	PA
PJM_ROM	2014	U2-069	1	56	WT	PA
PJM_ROR	2012	R35	1	50	BM	IL
PJM_ROR	2010	O43	1	42	CC	IL
PJM_ROR	2010	U1-054	1	46	CC	IL
PJM_ROR	2010	U4-030	1	6	CC	IL
PJM_ROR	2010	R18	1	6.4	LFG	IL
PJM_ROR	2010	L12_CE23	1	4	WT	IL

PJM_ROR	2010	N21	1	6	WT	IL
PJM_ROR	2010	N22	1	11	WT	IL
PJM_ROR	2010	N23	1	11	WT	IL
PJM_ROR	2010	N24	1	11	WT	IL
PJM_ROR	2010	N25	1	11	WT	IL
PJM_ROR	2010	O33	1	20	WT	IL
PJM_ROR	2010	O09	1	212	WT	IL
PJM_ROR	2010	O24	1	100.8	WT	IL
PJM_ROR	2010	O29	1	225	WT	IL
PJM_ROR	2010	P11	1	100	WT	IL
PJM_ROR	2010	P14	1	80	WT	IL
PJM_ROR	2010	P20	1	210	WT	IL
PJM_ROR	2010	P24	1	20	WT	IL
PJM_ROR	2010	P25	1	20	WT	IL
PJM_ROR	2010	P26	1	20	WT	IL
PJM_ROR	2010	P37	1	212	WT	IL
PJM_ROR	2010	P39	1	60	WT	IL
PJM_ROR	2010	Q39	1	147	WT	IL
PJM_ROR	2010	LEEDK;1U	1	240	WT	IL
PJM_ROR	2010	O27	1	300	WT	IL
PJM_ROR	2010	P10	1	340.5	WT	IL
PJM_ROR	2010	P36	1	240	WT	IL
PJM_ROR	2011	O73	1	100	WT	IL
PJM_ROR	2011	P40	1	20	WT	IL
PJM_ROR	2012	FREEPT_G	1	80	WT	IL
PJM_ROR	2012	K02_CE18	1	80	WT	IL
PJM_ROR	2012	O49	1	200	WT	IL
PJM_ROR	2012	O68	1	100	WT	IL
PJM_ROR	2010	R97	1	20	Coal	IN
PJM_ROR	2010	R03	1	130	WT	IN
PJM_ROR	2011	S72	1	300	WT	IN
PJM_ROR	2011	S73	1	200	WT	IN
PJM_ROR	2012	R60	1	350	WT	IN
PJM_ROR	2013	Q03	1	250	WT	IN
PJM_ROR	2013	S71	1	120	WT	IN
PJM_ROR	2010	S38	1	8	Coal	MD
PJM_ROR	2010	S14	1	70	WT	MD
PJM_ROR	2011	K28	1	100	WT	MD
PJM_ROR	2011	U2-030	1	60	WT	MD
PJM_ROR	2011	U2-061	1	50	WT	MD
PJM_ROR	2010	T111	1	8	LFG	MI
PJM_ROR	2011	P43	1	63	BM	NC
PJM_ROR	2012	U1-031	1	80	BM	NC
PJM_ROR	2011	U1-66	1	9	CT	NJ
PJM_ROR	2010	L01_AEP137	1	165	BM	OH
PJM_ROR	2010	P30	1	20	BM	OH
PJM_ROR	2015	S101	1	580	CC	OH
PJM_ROR	2010	S35	1	20	Coal	OH
PJM_ROR	2010	T164	1	15	Coal	OH
PJM_ROR	2010	T165	1	20	Coal	OH
PJM_ROR	2010	T166	1	20	Coal	OH
PJM_ROR	2010	N42	1	600	Coal	OH

PJM_ROR	2010	U4-034	1	5	Coal	OH
PJM_ROR	2010	U4-035	1	5	Coal	OH
PJM_ROR	2010	T154	1	10	LFG	OH
PJM_ROR	2010	R52	1	200	WT	OH
PJM_ROR	2010	R52a	1	100	WT	OH
PJM_ROR	2010	S45	1	100	WT	OH
PJM_ROR	2011	T130	1	300	WT	OH
PJM_ROR	2011	T131	1	150	WT	OH
PJM_ROR	2011	T142	1	300	WT	OH
PJM_ROR	2011	U1-059	1	50	WT	OH
PJM_ROR	2012	R49	1	150	WT	OH
PJM_ROR	2012	U2-041	1	300	WT	OH
PJM_ROR	2013	02DAV-BE 345.00	1	375	WT	OH
PJM_ROR	2014	R48	1	48.3	WT	OH
PJM_ROR	2014	T48	1	50	WT	OH
PJM_ROR	2010	P34	1	7	BM	PA
PJM_ROR	2011	T174	1	930	CC	PA
PJM_ROR	2011	T156	1	20	Coal	PA
PJM_ROR	2010	T155	1	6	HY	PA
PJM_ROR	2011	N32	1	10.1	WT	PA
PJM_ROR	2011	T39	1	18	WT	PA
PJM_ROR	2013	Q25	1	80	WT	PA
PJM_ROR	2010	S82	1	20	CC	VA
PJM_ROR	2010	S83	1	20	CC	VA
PJM_ROR	2010	S84	1	20	CC	VA
PJM_ROR	2010	S85	1	20	CC	VA
PJM_ROR	2011	P38	1	625	CC	VA
PJM_ROR	2011	R31	1	18	CC	VA
PJM_ROR	2012	T180	1	650	CC	VA
PJM_ROR	2013	R80	1	60	CC	VA
PJM_ROR	2013	S97	1	20	CC	VA
PJM_ROR	2013	S98	1	20	CC	VA
PJM_ROR	2016	T167	1	120	CC	VA
PJM_ROR	2011	R63	1	19	Coal	VA
PJM_ROR	2011	S79	1	27	Coal	VA
PJM_ROR	2011	S80	1	20	Coal	VA
PJM_ROR	2012	Q43	1	534	Coal	VA
PJM_ROR	2012	Q43	1	534	Coal	VA
PJM_ROR	2012	S100	1	80	Coal	VA
PJM_ROR	2014	T06	1	20	CT	VA
PJM_ROR	2010	P09	1	91	HY	VA
PJM_ROR	2010	T10	1	3	LFG	VA
PJM_ROR	2011	U2-031	1	30	LFG	VA
PJM_ROR	2010	N07	1	38	WT	VA
PJM_ROR	2011	U2-050	1	100	WT	VA
PJM_ROR	2011	U2-051	1	60	WT	VA
PJM_ROR	2012	U2-068	1	130	WT	VA
PJM_ROR	2014	U4-026	1	100	WT	VA
PJM_ROR	2010	O32	1	20	Coal	WV
PJM_ROR	2010	O32	1	20	Coal	WV
PJM_ROR	2011	Q79	1	100	Coal	WV
PJM_ROR	2011	S74	1	25	Coal	WV

PJM_ROR	2012	S75	1	27	Coal	WV
PJM_ROR	2013	S76	1	25	Coal	WV
PJM_ROR	2011	R76	1	100	HY	WV
PJM_ROR	2013	S70	1	36.4	HY	WV
PJM_ROR	2010	Q55	1	100	WT	WV
PJM_ROR	2011	T157	1	160	WT	WV
PJM_ROR	2012	J07	1	124	WT	WV
PJM_ROR	2012	K26	1	31	WT	WV
PJM_ROR	2012	M23	1	150	WT	WV
PJM_ROR	2012	N47	1	85	WT	WV
PJM_ROR	2012	P59	1	125	WT	WV
PJM_ROR	2013	P52	1	80	WT	WV
SOCO	2019	MCNTSH6G	0	187	CC	AL
SOCO	2012	1FITZ BIO 13.800	1	55	BM	GA
SOCO	2011	1LIVEOAKS 1A18.000	1A	171	CC	GA
SOCO	2011	1LIVEOAKS 1B18.000	1B	171	CC	GA
SOCO	2011	1LIVEOAKS1ST18.000	1	250	CC	GA
SOCO	2011	1MCDON 4A 21.000	4A	240	CC	GA
SOCO	2011	1MCDON 4B 21.000	4B	240	CC	GA
SOCO	2011	1MCDON 4ST 18.000	4	379.7	CC	GA
SOCO	2011	1MCDON 5A 21.000	5A	240	CC	GA
SOCO	2011	1MCDON 5B 21.000	5B	240	CC	GA
SOCO	2011	1MCDON 5ST 18.000	5	373.1	CC	GA
SOCO	2011	1MCDON 6A 21.000	6A	240	CC	GA
SOCO	2011	1MCDON 6B 21.000	6B	240	CC	GA
SOCO	2011	1MCDON 6ST 18.000	6	375.1	CC	GA
SOCO	2011	1CONASAUGA 1A 18.000	1A	176	CC	GA
SOCO	2011	1CONASAUGA 1B 18.000	1B	176	CC	GA
SOCO	2011	1CONASAUGA 1ST 18.000	1	268	CC	GA
SOCO	2012	1LOOPERS 2A 18.000	2A	176	CC	GA
SOCO	2012	1LOOPERS 2B 18.000	2B	176	CC	GA
SOCO	2012	1LOOPERS 2ST 18.000	2	295	CC	GA
SOCO	2016	1VOGTLE3 26.000	3	1100	NU	GA
SOCO	2017	1VOGTLE4 26.000	4	1100	NU	GA
SOCO	2015	1KEMP CC1 1 18.000	1	268	CC	MS
SOCO	2015	1KEMP CC1 1A18.000	1A	166	CC	MS
SOCO	2015	1KEMP CC1 1B18.000	1B	166	CC	MS
SPP_N	2011	Iatan ST	2	465.035	Coal	MO
SPP_S	2012	TURKCOAL 24.000	1	713	Coal	AR
SPP_S	2011	SOUTHWEST 2	2	275	Coal	MO
SPP_S	2017	MORLND4 18.000	1	300	CT	OK
SPP_S	2011	KEENAN 1 34.500	1	150	WT	OK
SPP_S	2011	TLGAWND1 34.500	1	130	WT	OK
SPP_S	2012	OGEWND11 34.500	1	150	WT	OK
SPP_S	2016	OGEWND21 34.500	1	150	WT	OK
SPP_S	2011	ANTELOPE_A 113.800	A1	9.444	CT	TX
SPP_S	2011	ANTELOPE_A 113.800	A2	9.444	CT	TX
SPP_S	2011	ANTELOPE_A 113.800	A3	9.444	CT	TX
SPP_S	2011	ANTELOPE_A 113.800	A4	9.444	CT	TX
SPP_S	2011	ANTELOPE_A 113.800	A5	9.444	CT	TX
SPP_S	2011	ANTELOPE_A 113.800	A6	9.444	CT	TX
SPP_S	2011	ANTELOPE_B 113.800	B1	9.444	CT	TX

SPP_S	2011	ANTELOPE_B 113.800	B2	9.444	CT	TX
SPP_S	2011	ANTELOPE_B 113.800	B3	9.444	CT	TX
SPP_S	2011	ANTELOPE_B 113.800	B4	9.444	CT	TX
SPP_S	2011	ANTELOPE_B 113.800	B5	9.444	CT	TX
SPP_S	2011	ANTELOPE_B 113.800	B6	9.444	CT	TX
SPP_S	2011	ANTELOPE_C 113.800	C1	9.444	CT	TX
SPP_S	2011	ANTELOPE_C 113.800	C2	9.444	CT	TX
SPP_S	2011	ANTELOPE_C 113.800	C3	9.444	CT	TX
SPP_S	2011	ANTELOPE_C 113.800	C4	9.444	CT	TX
SPP_S	2011	ANTELOPE_C 113.800	C5	9.444	CT	TX
SPP_S	2011	ANTELOPE_C 113.800	C6	9.444	CT	TX
SPP_S	2012	JONES 3	1	243	CT	TX
TVA	2011	Lagoon Creek CC Steam Turbine	1	220	CC	TN
TVA	2010	Lagoon Creek CC Turbine 1	1	160	CC	TN
TVA	2010	Lagoon Creek CC Turbine 2	1	160	CC	TN
TVA	2012	John Sevier CC Steam Turbine	4	383	CC	TN
TVA	2012	John Sevier CC Turbine 1	1	165	CC	TN
TVA	2012	John Sevier CC Turbine 2	2	165	CC	TN
TVA	2012	John Sevier CC Turbine 3	3	165	CC	TN
TVA	2013	Watts Bar Nuclear 2	2	1203.89	NU	TN
VACAR	2011	1RICHCC2	A	643	CC	NC
VACAR	2011	BUCKG1 18.000	1	179	CC	NC
VACAR	2011	BUCKG2 18.000	2	179	CC	NC
VACAR	2011	BUCKS1 18.000	3	263	CC	NC
VACAR	2012	DNRVRG1 18.000	1	179	CC	NC
VACAR	2012	DNRVRG2 18.000	2	179	CC	NC
VACAR	2012	DNRVRS1 18.000	3	263	CC	NC
VACAR	2012	CLFSDGEN 27.000	6	825	Coal	SC
VACAR	2012	CLEVELAND1 18.000	1	179.3	CT	SC
VACAR	2012	CLEVELAND2 18.000	2	179.3	CT	SC
VACAR	2012	CLEVELAND3 18.000	3	179.3	CT	SC
VACAR	2012	CLEVELAND4 18.000	4	179.3	CT	SC
VACAR	2016	VC Summer #2	2	1165	NU	SC
VACAR	2019	VC Summer #3	3	1165	NU	SC

Table 92: Forced Retirements

Source: MRN-NEEM Assumptions, EIPC

Plant Name	Unit	MW	Technology	Retirement Year	Plant State	NEEM Region	NEEM MW
Cape Canaveral	1	402	STOG	2011	Florida	FRCC	402
Cape Canaveral	2	402	STOG	2011	Florida	FRCC	402
Crystal River	1	440.5	Coal	2020	Florida	FRCC	375
Crystal River	2	523.8	Coal	2020	Florida	FRCC	494
Atikokan GS	1	211	Coal	2013	Ontario	IESO	211
Lambton GS	1	520	Coal	2010	Ontario	IESO	485
Lambton GS	2	520	Coal	2010	Ontario	IESO	485
Lambton GS	3	489	Coal	2014	Ontario	IESO	489
Lambton GS	4	502	Coal	2014	Ontario	IESO	502
Nanticoke	3	510	Coal	2010	Ontario	IESO	490
Nanticoke	4	505	Coal	2010	Ontario	IESO	490
Nanticoke	1	490	Coal	2011	Ontario	IESO	490
Nanticoke	2	490	Coal	2011	Ontario	IESO	490
Nanticoke	5	490	Coal	2014	Ontario	IESO	490
Nanticoke	6	490	Coal	2014	Ontario	IESO	490
Nanticoke	7	508	Coal	2014	Ontario	IESO	508
Nanticoke	8	490	Coal	2014	Ontario	IESO	490
Thunder Bay	2	150	Coal	2014	Ontario	IESO	150
Thunder Bay	3	150	Coal	2014	Ontario	IESO	150
Webeque First Nation	GEN1	0.65	PeakO	2012	Ontario	IESO	0.65
Brandon #5	5	105.9	Coal	2018	Manitoba	MAPP_CA	105.9
Edwardsport	7	40.2	Coal	2011	Indiana	MISO_IN	40.2
Edwardsport	8	69	Coal	2011	Indiana	MISO_IN	69
Blount Street	3	34.5	STOG	2013	Wisconsin	MISO_WUMS	34.5
Blount Street	4	20	STOG	2013	Wisconsin	MISO_WUMS	20
Blount Street	5	23	Coal	2013	Wisconsin	MISO_WUMS	23
Rothschild (WI)	TG2	5	STOG	2014	Wisconsin	MISO_WUMS	5
Empire	OE11	1.2	GEO	2012	Nevada	NWPP	1.2
Empire	OE12	1.2	GEO	2012	Nevada	NWPP	1.2
Empire	OE13	1.2	GEO	2012	Nevada	NWPP	1.2
Empire	OE14	1.2	GEO	2012	Nevada	NWPP	1.2
Indian River Generating Station (DE)	1	81.6	Coal	2011	Delaware	PJM_E	81.6
Indian River Generating Station (DE)	3	176.8	Coal	2013	Delaware	PJM_E	176.8
Indian River Generating Station (DE)	2	89	Coal	2010	Delaware	PJM_E	89
Howard M Down	9	16.5	STOG	2011	New Jersey	PJM_E	16.5
Hudson Generating Station	1	383	STOG	2012	New Jersey	PJM_E	383
Kearny Generating Station	9	18.5	PeakG	2013	New Jersey	PJM_E	18.5
Kearny Generating Station	10	122	PeakG	2012	New Jersey	PJM_E	122
Kearny Generating Station	11	128	PeakG	2012	New Jersey	PJM_E	128
Cromby Generating Station	1	187.5	Coal	2011	Pennsylvania	PJM_E	187.5
Cromby Generating Station	2	230	STOG	2011	Pennsylvania	PJM_E	230
Cromby Generating Station	ICI	2.7	PeakO	2011	Pennsylvania	PJM_E	2.7
Eddystone Generating Station	1	353.6	Coal	2011	Pennsylvania	PJM_E	279
Eddystone Generating Station	2	353.6	Coal	2013	Pennsylvania	PJM_E	309
Benning	15	290	STOG	2012	District of Columbia	PJM_ROM	290
Benning	16	290	STOG	2012	District of Columbia	PJM_ROM	290
Buzzard Point	E1	18	PeakO	2012	District of Columbia	PJM_ROM	18
Buzzard Point	E2	18	PeakO	2012	District of Columbia	PJM_ROM	18

Buzzard Point	E4	18	PeakO	2012	District of Columbia	PJM_ROM	18
Buzzard Point	E5	18	PeakO	2012	District of Columbia	PJM_ROM	18
Buzzard Point	E6	18	PeakO	2012	District of Columbia	PJM_ROM	18
Buzzard Point	E7	18	PeakO	2012	District of Columbia	PJM_ROM	18
Buzzard Point	E8	18	PeakO	2012	District of Columbia	PJM_ROM	18
Buzzard Point	W10	18	PeakO	2012	District of Columbia	PJM_ROM	18
Buzzard Point	W11	18	PeakO	2012	District of Columbia	PJM_ROM	18
Buzzard Point	W12	18	PeakO	2012	District of Columbia	PJM_ROM	18
Buzzard Point	W13	18	PeakO	2012	District of Columbia	PJM_ROM	18
Buzzard Point	W14	18	PeakO	2012	District of Columbia	PJM_ROM	18
Buzzard Point	W15	18	PeakO	2012	District of Columbia	PJM_ROM	18
Buzzard Point	W16	18	PeakO	2012	District of Columbia	PJM_ROM	18
Buzzard Point	W9	18	PeakO	2012	District of Columbia	PJM_ROM	18
Will County	1	187.5	Coal	2010	Illinois	PJM_ROR	187.5
Will County	2	183.7	Coal	2010	Illinois	PJM_ROR	183.7
Richard H Gorsuch	1	50	Coal	2010	Ohio	PJM_ROR	50
Richard H Gorsuch	2	50	Coal	2010	Ohio	PJM_ROR	50
Richard H Gorsuch	3	50	Coal	2010	Ohio	PJM_ROR	50
Richard H Gorsuch	4	50	Coal	2010	Ohio	PJM_ROR	50
Hunlock Power Station	3	43	Coal	2010	Pennsylvania	PJM_ROR	43
WPP 1 Petersburg	1	3	CT	2013	Virginia	PJM_ROR	3
Chesapeake	7	16	CT	2012	Virginia	PJM_ROR	16
Altavista Power Station	1	63	Coal	2010	Virginia	PJM_ROR	63
North Branch (WV)	1	80	Coal	2010	West Virginia	PJM_ROR	80
Phil Sporn	5	495.5	Coal	2011	West Virginia	PJM_ROR	440
Arapahoe	4	109	Coal	2013	Colorado	RMPA	109
Jack McDonough	1	251	Coal	2013	Georgia	SOCO	251
Jack McDonough	2	252	Coal	2013	Georgia	SOCO	252
Buck Steam Station (NC)	3	80	Coal	2012	North Carolina	VACAR	80
Buck Steam Station (NC)	4	40	Coal	2012	North Carolina	VACAR	40
Cape Fear	5	140.6	Coal	2014	North Carolina	VACAR	140.6
Cape Fear	6	187.9	Coal	2014	North Carolina	VACAR	187.9
Cliffside	1	40	Coal	2011	North Carolina	VACAR	40
Cliffside	2	40	Coal	2011	North Carolina	VACAR	40
Cliffside	3	65	Coal	2011	North Carolina	VACAR	65
Cliffside	4	65	Coal	2011	North Carolina	VACAR	65
Dan River (NC)	1	70	Coal	2012	North Carolina	VACAR	70
Dan River (NC)	2	70	Coal	2012	North Carolina	VACAR	70
Dan River (NC)	3	142	Coal	2012	North Carolina	VACAR	142
L V Sutton	1	112.5	Coal	2014	North Carolina	VACAR	112.5
L V Sutton	2	112.5	Coal	2014	North Carolina	VACAR	112.5
L V Sutton	3	446.6	Coal	2014	North Carolina	VACAR	403
Lee	1	75	Coal	2013	North Carolina	VACAR	75
Lee	2	75	Coal	2013	North Carolina	VACAR	75
Lee	3	252.4	Coal	2013	North Carolina	VACAR	246
Riverbend (NC)	4	94	Coal	2015	North Carolina	VACAR	94
Riverbend (NC)	5	94	Coal	2015	North Carolina	VACAR	94
Riverbend (NC)	6	133	Coal	2015	North Carolina	VACAR	133
Riverbend (NC)	7	133	Coal	2015	North Carolina	VACAR	133
W H Weatherspoon	1	46	Coal	2014	North Carolina	VACAR	46
W H Weatherspoon	2	46	Coal	2014	North Carolina	VACAR	46
W H Weatherspoon	3	73.5	Coal	2014	North Carolina	VACAR	73.5

W S Lee	1	100	Coal	2015	South Carolina	VACAR	100
W S Lee	2	100	Coal	2015	South Carolina	VACAR	100
W S Lee	3	170	Coal	2015	South Carolina	VACAR	170

Table 93: Transmission Line Information

Source: Transfer Limits Description, EIPC, Feb 5 2011

FROM	TO	Description
ENTERGY	MISO_MO_IL	To obtain the MRM-NEEM Pipe Transfer Limit between MISO and Entergy, a linear transfer analysis was performed in PSS® MUST using the EIPC 2020 Baseline Infrastructure Case. The analysis results were then verified to be valid and coordinated between MISO and Entergy. The limiting facilities and associated contingencies identified are consistent with those found in other transmission planning studies.
ENTERGY	SOCO	To obtain the MRM-NEEM Pipe Transfer Limit between Southern Company and Entergy, a linear transfer analysis was performed in PSS® MUST using the EIPC 2020 Baseline Infrastructure Case. The analysis results were then verified to be valid and coordinated between Southern Company and Entergy. The limiting facilities and associated contingencies identified are consistent with those found in other transmission planning studies performed in SERC.
ENTERGY	SPP_N	To obtain the MRN-NEEM Pipe Transfer Limit between SPP and Entergy, a linear transfer analysis was performed in PSS® MUST using the EIPC 2020 Baseline Infrastructure Case. The analysis results were then coordinated between SPP and Entergy.
ENTERGY	SPP_S	To obtain the MRN-NEEM Pipe Transfer Limit between SPP and Entergy, a linear transfer analysis was performed in PSS® MUST using the EIPC 2020 Baseline Infrastructure Case. The analysis results were then coordinated between SPP and Entergy.
ENTERGY	TVA	To obtain the MRM-NEEM Pipe Transfer Limit between TVA and Entergy, a linear transfer analysis was performed in PSS® MUST using the EIPC 2020 Baseline Infrastructure Case. The analysis results were then verified to be valid and coordinated between TVA and Entergy. The limiting facilities and associated contingencies identified are consistent with those found in other transmission planning studies.
ERCOT	SPP_S	Ties with ERCOT were determined as the combined maximum capacity of the DC ties.
FRCC	SOCO	The transfer capabilities provided as input in the MRN-NEEM model were obtained from the most recent FRCC - Southern joint TTC study. This interface is voltage stability limited interface, and therefore, linear analysis on the baseline infrastructure case was not performed. There are no transmission enhancements that are currently planned that would increase the transfer capability between these regions.
MAPP_CA	MAPP_US	This value is the current Saskatchewan to MAPP_US operating limit plus the current MH to US operating limit, reduced by the value reported for "MAPP_CA to MISO_W".
MAPP_CA	MISO_W	This is part of the MH to US stability limited interface. This value is the current operating limit, reduced by 200 MW, which is included in the value for "MAPP_CA to MAPP_US".
MAPP_CA	IESO	This is the current MH to IESO operating limit as reported by IESO.
MAPP_US	MAPP_CA	This is the current MAPP_US to MAPP_CA operating limit on this single element tie line as reported by MH.
MAPP_US	MISO_W	Midwest ISO performed First Contingency Incremental Transfer Capability (FCITC) to determine the NEEMs transfer limits. The EIPC 2020 Summer Baseline Infrastructure model was used. The contingency and monitored element files that were used for the EIPC Linear Transfer Analysis (LTA) were used to perform the FCITC calculations. The NEEM regions were used for transfer sources and sinks. Transfers adjusted the load and generation in the transfer source area. Transfers reduced generation in sink area. FCITC analysis was performed using PSS® MUST version 8.3.2.
MAPP_US	NE	The values for the pipe from "MAPP US" to "NE" are found using transfer study from generation to generation.
MAPP_US	NWPP	This is a DC tie to WECC. This value is the current operating limit for the DC tie.
MAPP_US	RMPA	This is a DC tie to WECC. This value is the current operating limit for the DC tie.
MISO_IN	MISO_MI	Midwest ISO performed First Contingency Incremental Transfer Capability (FCITC) to determine the NEEMs transfer limits. The EIPC 2020 Summer Baseline Infrastructure model was used. The contingency and monitored element files that were used for the EIPC Linear Transfer Analysis (LTA) were used to perform the FCITC calculations. The NEEM regions were used for transfer sources and sinks. Transfers adjusted the load and generation in the transfer source area. Transfers reduced generation in sink area. FCITC analysis was performed using MUST version 8.3.2.
MISO_IN	MISO_MO_IL	Midwest ISO performed First Contingency Incremental Transfer Capability (FCITC) to determine the NEEMs transfer limits. The EIPC 2020 Summer Baseline Infrastructure model was used. The contingency and monitored element files that were used for the EIPC Linear Transfer Analysis (LTA) were used to perform the FCITC calculations. The NEEM regions were used for transfer sources and sinks. Transfers adjusted the load and generation in the transfer source area. Transfers reduced generation in sink area. FCITC analysis was performed using MUST version 8.3.2.
MISO_IN	Non_RTO_Midwest	Midwest ISO performed First Contingency Incremental Transfer Capability (FCITC) to determine the NEEMs transfer limits. The EIPC 2020 Summer Baseline Infrastructure model was used. The contingency and monitored element files that were used for the EIPC Linear Transfer Analysis (LTA) were used to perform the FCITC calculations. The NEEM regions were used for transfer sources and sinks. Transfers adjusted the load and generation in the transfer source area. Transfers reduced generation in sink area. FCITC analysis was performed using MUST version 8.3.2.

FROM	TO	Description
MISO_IN	PJM_Rest_of_RTO	Midwest ISO performed First Contingency Incremental Transfer Capability (FCITC) to determine the NEEMs transfer limits. The EIPC 2020 Summer Baseline Infrastructure model was used. The contingency and monitored element files that were used for the EIPC Linear Transfer Analysis (LTA) were used to perform the FCITC calculations. The NEEM regions were used for transfer sources and sinks. Transfers adjusted the load and generation in the transfer source area. Transfers reduced generation in sink area. FCITC analysis was performed using MUST version 8.3.2.
MISO_MI	MISO_IN	Midwest ISO performed First Contingency Incremental Transfer Capability (FCITC) to determine the NEEMs transfer limits. The EIPC 2020 Summer Baseline Infrastructure model was used. The contingency and monitored element files that were used for the EIPC Linear Transfer Analysis (LTA) were used to perform the FCITC calculations. The NEEM regions were used for transfer sources and sinks. Transfers adjusted the load and generation in the transfer source area. Transfers reduced generation in sink area. FCITC analysis was performed using MUST version 8.3.2.
MISO_MI	MISO_WUMS	Midwest ISO performed First Contingency Incremental Transfer Capability (FCITC) to determine the NEEMs transfer limits. The EIPC 2020 Summer Baseline Infrastructure model was used. The contingency and monitored element files that were used for the EIPC Linear Transfer Analysis (LTA) were used to perform the FCITC calculations. The NEEM regions were used for transfer sources and sinks. Transfers adjusted the load and generation in the transfer source area. Transfers reduced generation in sink area. FCITC analysis was performed using MUST version 8.3.2.
MISO_MI	IESO	Midwest ISO performed First Contingency Incremental Transfer Capability (FCITC) to determine the NEEMs transfer limits. The EIPC 2020 Summer Baseline Infrastructure model was used. The contingency and monitored element files that were used for the EIPC Linear Transfer Analysis (LTA) were used to perform the FCITC calculations. The NEEM regions were used for transfer sources and sinks. Transfers adjusted the load and generation in the transfer source area. Transfers reduced generation in sink area. FCITC analysis was performed using MUST version 8.3.2.
MISO_MI	PJM_Rest_of_RTO	Midwest ISO performed First Contingency Incremental Transfer Capability (FCITC) to determine the NEEMs transfer limits. The EIPC 2020 Summer Baseline Infrastructure model was used. The contingency and monitored element files that were used for the EIPC Linear Transfer Analysis (LTA) were used to perform the FCITC calculations. The NEEM regions were used for transfer sources and sinks. Transfers adjusted the load and generation in the transfer source area. Transfers reduced generation in sink area. FCITC analysis was performed using MUST version 8.3.2.
MISO_MO_IL	ENTERGY	Midwest ISO performed First Contingency Incremental Transfer Capability (FCITC) to determine the NEEMs transfer limits. The EIPC 2020 Summer Baseline Infrastructure model was used. The contingency and monitored element files that were used for the EIPC Linear Transfer Analysis (LTA) were used to perform the FCITC calculations. The NEEM regions were used for transfer sources and sinks. Transfers adjusted the load and generation in the transfer source area. Transfers reduced generation in sink area. FCITC analysis was performed using MUST version 8.3.2.
MISO_MO_IL	MISO_IN	Midwest ISO performed First Contingency Incremental Transfer Capability (FCITC) to determine the NEEMs transfer limits. The EIPC 2020 Summer Baseline Infrastructure model was used. The contingency and monitored element files that were used for the EIPC Linear Transfer Analysis (LTA) were used to perform the FCITC calculations. The NEEM regions were used for transfer sources and sinks. Transfers adjusted the load and generation in the transfer source area. Transfers reduced generation in sink area. FCITC analysis was performed using MUST version 8.3.2.
MISO_MO_IL	MISO_W	Midwest ISO performed First Contingency Incremental Transfer Capability (FCITC) to determine the NEEMs transfer limits. The EIPC 2020 Summer Baseline Infrastructure model was used. The contingency and monitored element files that were used for the EIPC Linear Transfer Analysis (LTA) were used to perform the FCITC calculations. The NEEM regions were used for transfer sources and sinks. Transfers adjusted the load and generation in the transfer source area. Transfers reduced generation in sink area. FCITC analysis was performed using MUST version 8.3.2.
MISO_MO_IL	PJM_Rest_of_RTO	Midwest ISO performed First Contingency Incremental Transfer Capability (FCITC) to determine the NEEMs transfer limits. The EIPC 2020 Summer Baseline Infrastructure model was used. The contingency and monitored element files that were used for the EIPC Linear Transfer Analysis (LTA) were used to perform the FCITC calculations. The NEEM regions were used for transfer sources and sinks. Transfers adjusted the load and generation in the transfer source area. Transfers reduced generation in sink area. FCITC analysis was performed using MUST version 8.3.2.

FROM	TO	Description
MISO_MO_IL	SPP_N	Midwest ISO performed First Contingency Incremental Transfer Capability (FCITC) to determine the NEEMs transfer limits. The EIPC 2020 Summer Baseline Infrastructure model was used. The contingency and monitored element files that were used for the EIPC Linear Transfer Analysis (LTA) were used to perform the FCITC calculations. The NEEM regions were used for transfer sources and sinks. Transfers adjusted the load and generation in the transfer source area. Transfers reduced generation in sink area. FCITC analysis was performed using MUST version 8.3.2.
MISO_MO_IL	TVA	To obtain the MRM-NEEM Pipe Transfer Limit between TVA and MISO_MO_IL, a linear transfer analysis was performed in PSS(r) MUST using the EIPC 2020 Baseline Infrastructure Case. The analysis results were then verified to be valid and coordinated between TVA and MISO_MO_IL. The limiting facilities and associated contingencies identified are consistent with those found in other transmission planning studies performed in SERC.
MISO_W	MAPP_CA	The pipe values from "MAPP CA" to "MISO W" are documented in operational guide.
MISO_W	MAPP_US	Midwest ISO performed First Contingency Incremental Transfer Capability (FCITC) to determine the NEEMs transfer limits. The EIPC 2020 Summer Baseline Infrastructure model was used. The contingency and monitored element files that were used for the EIPC Linear Transfer Analysis (LTA) were used to perform the FCITC calculations. The NEEM regions were used for transfer sources and sinks. Transfers adjusted the load and generation in the transfer source area. Transfers reduced generation in sink area. FCITC analysis was performed using MUST version 8.3.2.
MISO_W	MISO_MO_IL	Midwest ISO performed First Contingency Incremental Transfer Capability (FCITC) to determine the NEEMs transfer limits. The EIPC 2020 Summer Baseline Infrastructure model was used. The contingency and monitored element files that were used for the EIPC Linear Transfer Analysis (LTA) were used to perform the FCITC calculations. The NEEM regions were used for transfer sources and sinks. Transfers adjusted the load and generation in the transfer source area. Transfers reduced generation in sink area. FCITC analysis was performed using MUST version 8.3.2.
MISO_W	MISO_WUMS	Midwest ISO performed First Contingency Incremental Transfer Capability (FCITC) to determine the NEEMs transfer limits. The EIPC 2020 Summer Baseline Infrastructure model was used. The contingency and monitored element files that were used for the EIPC Linear Transfer Analysis (LTA) were used to perform the FCITC calculations. The NEEM regions were used for transfer sources and sinks. Transfers adjusted the load and generation in the transfer source area. Transfers reduced generation in sink area. FCITC analysis was performed using MUST version 8.3.2.
MISO_W	NE	Midwest ISO performed First Contingency Incremental Transfer Capability (FCITC) to determine the NEEMs transfer limits. The EIPC 2020 Summer Baseline Infrastructure model was used. The contingency and monitored element files that were used for the EIPC Linear Transfer Analysis (LTA) were used to perform the FCITC calculations. The NEEM regions were used for transfer sources and sinks. Transfers adjusted the load and generation in the transfer source area. Transfers reduced generation in sink area. FCITC analysis was performed using MUST version 8.3.2.
MISO_W	IESO	Midwest ISO performed First Contingency Incremental Transfer Capability (FCITC) to determine the NEEMs transfer limits. The EIPC 2020 Summer Baseline Infrastructure model was used. The contingency and monitored element files that were used for the EIPC Linear Transfer Analysis (LTA) were used to perform the FCITC calculations. The NEEM regions were used for transfer sources and sinks. Transfers adjusted the load and generation in the transfer source area. Transfers reduced generation in sink area. FCITC analysis was performed using MUST version 8.3.2.
MISO_W	PJM_Rest_of_RTO	Midwest ISO performed First Contingency Incremental Transfer Capability (FCITC) to determine the NEEMs transfer limits. The EIPC 2020 Summer Baseline Infrastructure model was used. The contingency and monitored element files that were used for the EIPC Linear Transfer Analysis (LTA) were used to perform the FCITC calculations. The NEEM regions were used for transfer sources and sinks. Transfers adjusted the load and generation in the transfer source area. Transfers reduced generation in sink area. FCITC analysis was performed using MUST version 8.3.2.
MISO_W	SPP_N	Midwest ISO performed First Contingency Incremental Transfer Capability (FCITC) to determine the NEEMs transfer limits. The EIPC 2020 Summer Baseline Infrastructure model was used. The contingency and monitored element files that were used for the EIPC Linear Transfer Analysis (LTA) were used to perform the FCITC calculations. The NEEM regions were used for transfer sources and sinks. Transfers adjusted the load and generation in the transfer source area. Transfers reduced generation in sink area. FCITC analysis was performed using MUST version 8.3.2.

FROM	TO	Description
MISO_WUMS	MISO_MI	Historical MISO_WUMS maximum import and export values as well as historical maximum import and export values for the individual "Pipes" connecting to the MISO_WUMS "Bubble" were gathered for the years 2008-2010. The MISO_WUMS maximum import and export values were then augmented by 70% of the rated normal capacity of the new tie facilities or upgraded tie facility ratings. The augmented MISO_WUMS maximum import and export values were then distributed over the "Pipes" connecting to the MISO_WUMS "Bubble" based on the historical maximum import and export values for the individual "Pipes" connecting to the MISO_WUMS "Bubble".
MISO_WUMS	MISO_W	Historical MISO_WUMS maximum import and export values as well as historical maximum import and export values for the individual "Pipes" connecting to the MISO_WUMS "Bubble" were gathered for the years 2008-2010. The MISO_WUMS maximum import and export values were then augmented by 70% of the rated normal capacity of the new tie facilities or upgraded tie facility ratings. The augmented MISO_WUMS maximum import and export values were then distributed over the "Pipes" connecting to the MISO_WUMS "Bubble" based on the historical maximum import and export values for the individual "Pipes" connecting to the MISO_WUMS "Bubble".
MISO_WUMS	PJM_Rest_of_RTO	Historical MISO_WUMS maximum import and export values as well as historical maximum import and export values for the individual "Pipes" connecting to the MISO_WUMS "Bubble" were gathered for the years 2008-2010. The MISO_WUMS maximum import and export values were then augmented by 70% of the rated normal capacity of the new tie facilities or upgraded tie facility ratings. The augmented MISO_WUMS maximum import and export values were then distributed over the "Pipes" connecting to the MISO_WUMS "Bubble" based on the historical maximum import and export values for the individual "Pipes" connecting to the MISO_WUMS "Bubble".
NE	MAPP_US	The values for the pipe from "MAPP US" to "NE" are found using transfer study from generation to generation.
NE	MISO_W	Values were coordinated between SPP and MISO_W and were detemined by averaging the values obtained by the two entities.
NE	RMPA	This is a DC tie to WECC. This value is the current operating limit for the DC tie.
NE	SPP_N	The transfer capacity to SPP_N was determined by using the first valid limiting FCITC transfer value under contingency.
NEISO	NYISO_A-F	The known 1200 MW New York-New England bi directional transfer limit (excluding the PAR controlled 1385 Norwalk-Northport cable at 200 MW and the Cross-Sound HVDC cable at 330 MW) was separated into the regions specified for NYISO in the NEEM bubble diagram. The 398 line (Pleasant Valley-Long Mountain) is the sole line connecting ISO-NE to the “NYISO GHI” region, while the rest of the lines between upstate New York and New England connect to the “NYISO A-F” region. (The 690 line, Salisbury-Smithfield, is open in the EIPC case, as usual, so that is not included in either interface.) Transfers between New York and New England were varied over a range of dispatch assumptions that resulted in an average split of 50/50 of the 1200 MW limit into the A-F and GHI regions resulting in the 600 MW ratings.
NEISO	NYISO_GHI	The known 1200 MW New York-New England transfer limit (excluding the PAR controlled 1385 Norwalk-Northport cable at 200 MW and the Cross-Sound HVDC cable at 330 MW) was separated into the regions specified for NYISO in the NEEM bubble diagram. The 398 line (Pleasant Valley-Long Mountain) is the sole line connecting ISO-NE to the “NYISO GHI” region, while the rest of the lines between upstate New York and New England connect to the “NYISO A-F” region. (The 690 line, Salisbury-Smithfield, is open in the EIPC case, as usual, so that is not included in either interface.) Transfers between New York and New England were varied over a range of dispatch assumptions that resulted in an average split of 50/50 of the 1200 MW limit into the A-F and GHI regions resulting in the 600 MW ratings.
NEISO	NYISO_J_&_K	The known 1200 MW New York-New England bi directional transfer limit (excluding the PAR controlled 1385 Norwalk-Northport cable at 200 MW and the Cross-Sound HVDC cable at 330 MW) was separated into the regions specified for NYISO in the NEEM bubble diagram. The 398 line (Pleasant Valley-Long Mountain) is the sole line connecting ISO-NE to the “NYISO GHI” region, while the rest of the lines between upstate New York and New England connect to the “NYISO A-F” region. (The 690 line, Salisbury-Smithfield, is open in the EIPC case, as usual, so that is not

FROM	TO	Description
		included in either interface.) Transfers between New York and New England were varied over a range of dispatch assumptions that resulted in an average split of 50/50 of the 1200 MW limit into the A-F and GHI regions resulting in the 600 MW ratings.
Non_RTO_Midwest	MISO_IN	Midwest ISO performed First Contingency Incremental Transfer Capability (FCITC) to determine the NEEMs transfer limits. The EIPC 2020 Summer Baseline Infrastructure model was used. The contingency and monitored element files that were used for the EIPC Linear Transfer Analysis (LTA) were used to perform the FCITC calculations. The NEEM regions were used for transfer sources and sinks. Transfers adjusted the load and generation in the transfer source area. Transfers reduced generation in sink area. FCITC analysis was performed using MUST version 8.3.2.
Non_RTO_Midwest	TVA	To obtain the MRM-NEEM Pipe Transfer Limit between TVA and Non_RTO_Midwest, a linear transfer analysis was performed in PSS(r) MUST using the EIPC 2020 Baseline Infrastructure Case. The analysis results were then verified to be valid and coordinated between TVA and Non_RTO_Midwest. The limiting facilities and associated contingencies identified are consistent with those found in other transmission planning studies performed in SERC.
NWPP	MAPP_US	This is a DC tie to WECC. This value is the current operating limit for the DC tie.
NYISO_A-F	NEISO	The known 1200 MW New York-New England bi directional transfer limit (excluding the PAR controlled 1385 Norwalk-Northport cable at 200 MW and the Cross-Sound HVDC cable at 330 MW) was separated into the regions specified for NYISO in the NEEM bubble diagram. The 398 line (Pleasant Valley-Long Mountain) is the sole line connecting ISO-NE to the “NYISO GHI” region, while the rest of the lines between upstate New York and New England connect to the “NYISO A-F” region. (The 690 line, Salisbury-Smithfield, is open in the EIPC case, as usual, so that is not included in either interface.) Transfers between New York and New England were varied over a range of dispatch assumptions that resulted in an average split of 50/50 of the 1200 MW limit into the A-F and GHI regions resulting in the 600 MW ratings.
NYISO_A-F	NYISO_GHI	NYISO performs analysis for the calculation of transfer limits for economic and reliability studies that employ a “pipe and bubble” model.These are done for the NYISO Comprehensive System Planning Process(CSPP) that covered the years 2010 through 2020.The internal pipes transfer limits were taken or derived from the most recent CSPP and represent the total transfer capability of the interface. External ties were coordinated with IESO, NYISO, and PJM. There are any not any differences between the EIPC 2020 roll-up case, the baseline infrastructure case, and the CSPP case that will significantly affect the results of this type of transfer analysis.
NYISO_A-F	IESO	Those numbers are coming from table 5.2 of the Ontario Transmission System document that is published along with the 18-Month Outlook Report. We also performed linear analysis (TLTG – generation to generation transfers) on BI case and the numbers (for some “pipes”) were very close to the ones from table 5.2.
NYISO_A-F	PJM_Rest_of_MAAC	NYISO performs analysis for the calculation of transfer limits for economic and reliability studies that employ a “pipe and bubble” model.These are done for the NYISO Comprehensive System Planning Process(CSPP) that covered the years 2010 through 2020.The internal pipes transfer limits were taken or derived from the most recent CSPP and represent the total transfer capability of the interface. External ties were coordinated with IESO, NYISO, and PJM. There are any not any differences between the EIPC 2020 roll-up case, the baseline infrastructure case, and the CSPP case that will significantly affect the results of this type of transfer analysis.
NYISO_GHI	NEISO	The known 1200 MW New York-New England bi directional transfer limit (excluding the PAR controlled 1385 Norwalk-Northport cable at 200 MW and the Cross-Sound HVDC cable at 330 MW) was separated into the regions specified for NYISO in the NEEM bubble diagram. The 398 line (Pleasant Valley-Long Mountain) is the sole line connecting ISO-NE to the “NYISO GHI” region, while the rest of the lines between upstate New York and New England connect to the “NYISO A-F” region. (The 690 line, Salisbury-Smithfield, is open in the EIPC case, as usual, so that is not included in either interface.) Transfers between New York and New England were varied over a range of dispatch assumptions that resulted in an average split of 50/50 of the 1200 MW limit into the A-F and GHI regions resulting in the 600 MW ratings.

FROM	TO	Description
NYISO_GHI	NYISO_A-F	NYISO performs analysis for the calculation of transfer limits for economic and reliability studies that employ a “pipe and bubble” model.These are done for the NYISO Comprehensive System Planning Process(CSPP) that covered the years 2010 through 2020.The internal pipes transfer limits were taken or derived from the most recent CSPP and represent the total transfer capability of the interface. External ties were coordinated with IESO, NYISO, and PJM. There are any not any differences between the EIPC 2020 roll-up case, the baseline infrastructure case, and the CSPP case that will significantly affect the results of this type of transfer analysis.
NYISO_GHI	NYISO_J_&_K	NYISO performs analysis for the calculation of transfer limits for economic and reliability studies that employ a “pipe and bubble” model.These are done for the NYISO Comprehensive System Planning Process(CSPP) that covered the years 2010 through 2020.The internal pipes transfer limits were taken or derived from the most recent CSPP and represent the total transfer capability of the interface. External ties were coordinated with IESO, NYISO, and PJM. There are any not any differences between the EIPC 2020 roll-up case, the baseline infrastructure case, and the CSPP case that will significantly affect the results of this type of transfer analysis. This pipe represents the merging of two pipes from the standard NYISO "pipe" model.
NYISO_GHI	PJM_Eastern_MAAC	NYISO performs analysis for the calculation of transfer limits for economic and reliability studies that employ a “pipe and bubble” model.These are done for the NYISO Comprehensive System Planning Process(CSPP) that covered the years 2010 through 2020.The internal pipes transfer limits were taken or derived from the most recent CSPP and represent the total transfer capability of the interface. External ties were coordinated with IESO, NYISO, and PJM. There are any not any differences between the EIPC 2020 roll-up case, the baseline infrastructure case, and the CSPP case that will significantly affect the results of this type of transfer analysis. This pipe represents the merging of two"bubbles" from the standard NYISO model to account for the RECO load included in the PJM_Eastern_MAAC bubble
NYISO_J_&_K	NEISO	The known 1200 MW New York-New England bi directional transfer limit (excluding the PAR controlled 1385 Norwalk-Northport cable at 200 MW and the Cross-Sound HVDC cable at 330 MW) was separated into the regions specified for NYISO in the NEEM bubble diagram. The 398 line (Pleasant Valley-Long Mountain) is the sole line connecting ISO-NE to the “NYISO GHI” region, while the rest of the lines between upstate New York and New England connect to the “NYISO A-F” region. (The 690 line, Salisbury-Smithfield, is open in the EIPC case, as usual, so that is not included in either interface.) Transfers between New York and New England were varied over a range of dispatch assumptions that resulted in an average split of 50/50 of the 1200 MW limit into the A-F and GHI regions resulting in the 600 MW ratings.
NYISO_J_&_K	NYISO_GHI	NYISO performs analysis for the calculation of transfer limits for economic and reliability studies that employ a “pipe and bubble” model.These are done for the NYISO Comprehensive System Planning Process(CSPP) that covered the years 2010 through 2020.The internal pipes transfer limits were taken or derived from the most recent CSPP and represent the total transfer capability of the interface. External ties were coordinated with IESO, NYISO, and PJM. There are any not any differences between the EIPC 2020 roll-up case, the baseline infrastructure case, and the CSPP case that will significantly affect the results of this type of transfer analysis. This pipe represents the merging of two pipes from the standard NYISO "pipe" model.
IESO	MAPP_CA	For pipe values from "MAPP CA" to "OH" we used an operational guide from IESO.
IESO	MISO_MI	The number is coming from table 5.2 of the Ontario Transmission System document that is published along with the 18-Month Outlook Report. We also performed linear analysis (TLTG – generation to generation transfers) on BI case and the numbers (for some “pipes”) were very close to the ones from table 5.2.
IESO	MISO_W	The number is coming from table 5.2 of the Ontario Transmission System document that is published along with the 18-Month Outlook Report. We also performed linear analysis (TLTG – generation to generation transfers) on BI case and the numbers (for some “pipes”) were very close to the ones from table 5.2.

FROM	TO	Description
IESO	NYISO_A-F	Those numbers are coming from table 5.2 of the Ontario Transmission System document that is published along with the 18-Month Outlook Report. We also performed linear analysis (TLTG – generation to generation transfers) on BI case and the numbers (for some "pipes") were very close to the ones from table 5.2.
PJM_Eastern_MAAC	NYISO_GHI	NYISO performs analysis for the calculation of transfer limits for economic and reliability studies that employ a "pipe and bubble" model.These are done for the NYISO Comprehensive System Planning Process(CSPP) that covered the years 2010 through 2020.The internal pipes transfer limits were taken or derived from the most recent CSPP and represent the total transfer capability of the interface. External ties were coordinated with IESO, NYISO, and PJM. There are any not any differences between the EIPC 2020 roll-up case, the baseline infrastructure case, and the CSPP case that will significantly affect the results of this type of transfer analysis. This pipe represents the merging of two"bubbles" from the standard NYISO model that represent controllable ties and assumptions of the NEEM model.
PJM_Eastern_MAAC	NYISO_J_&_K	NYISO performs analysis for the calculation of transfer limits for economic and reliability studies that employ a "pipe and bubble" model.These are done for the NYISO Comprehensive System Planning Process(CSPP) that covered the years 2010 through 2020.The internal pipes transfer limits were taken or derived from the most recent CSPP and represent the total transfer capability of the interface. External ties were coordinated with IESO, NYISO, and PJM. There are any not any differences between the EIPC 2020 roll-up case, the baseline infrastructure case, and the CSPP case that will significantly affect the results of this type of transfer analysis. This pipe represents the merging of two"bubbles" from the standard NYISO model that represent controllable ties and assumptions of the NEEM model.
PJM_Eastern_MAAC	PJM_Rest_of_MAAC	PJM determined consensus limits with the external interface owners by examining several "data points" and blending methods to reach agreement on the most appropriate initial value for the limits in the MRN-NEEM model. Rollup case interregional linear transfer analysis results, Current OASIS external interface transmission capability data, Actual 2010 hourly interface flow and schedule data for all PJM interfaces, 2010 PJM internal work assessing PJM's internal interface capability with backbone upgrades
PJM_Rest_of_MAAC	NYISO_A-F	PJM determined consensus limits with the external interface owners by examining several "data points" and blending methods to reach agreement on the most appropriate initial value for the limits in the MRN-NEEM model. Rollup case interregional linear transfer analysis results, Current OASIS external interface transmission capability data, Actual 2010 hourly interface flow and schedule data for all PJM interfaces, 2010 PJM internal work assessing PJM's internal interface capability with backbone upgrades
PJM_Rest_of_MAAC	PJM_Eastern_MAAC	PJM determined consensus limits with the external interface owners by examining several "data points" and blending methods to reach agreement on the most appropriate initial value for the limits in the MRN-NEEM model. Rollup case interregional linear transfer analysis results, Current OASIS external interface transmission capability data, Actual 2010 hourly interface flow and schedule data for all PJM interfaces, 2010 PJM internal work assessing PJM's internal interface capability with backbone upgrades
PJM_Rest_of_MAAC	PJM_Rest_of_RTO	PJM determined consensus limits with the external interface owners by examining several "data points" and blending methods to reach agreement on the most appropriate initial value for the limits in the MRN-NEEM model. Rollup case interregional linear transfer analysis results, Current OASIS external interface transmission capability data, Actual 2010 hourly interface flow and schedule data for all PJM interfaces, 2010 PJM internal work assessing PJM's internal interface capability with backbone upgrades
PJM_Rest_of_RTO	MISO_IN	PJM determined consensus limits with the external interface owners by examining several "data points" and blending methods to reach agreement on the most appropriate initial value for the limits in the MRN-NEEM model. Rollup case interregional linear transfer analysis results, Current OASIS external interface transmission capability data, Actual 2010 hourly interface flow and schedule data for all PJM interfaces, 2010 PJM internal work assessing PJM's internal interface capability with backbone upgrades and MISO Interface linear transfer analysis using the BI case.

FROM	TO	Description
PJM_Rest_of_RTO	MISO_MI	PJM determined consensus limits with the external interface owners by examining several "data points" and blending methods to reach agreement on the most appropriate initial value for the limits in the MRN-NEEM model. Rollup case interregional linear transfer analysis results, Current OASIS external interface transmission capability data, Actual 2010 hourly interface flow and schedule data for all PJM interfaces, 2010 PJM internal work assessing PJM's internal interface capability with backbone upgrades and MISO Interface linear transfer analysis using the BI case.
PJM_Rest_of_RTO	MISO_MO_IL	PJM determined consensus limits with the external interface owners by examining several "data points" and blending methods to reach agreement on the most appropriate initial value for the limits in the MRN-NEEM model. Rollup case interregional linear transfer analysis results, Current OASIS external interface transmission capability data, Actual 2010 hourly interface flow and schedule data for all PJM interfaces, 2010 PJM internal work assessing PJM's internal interface capability with backbone upgrades and MISO Interface linear transfer analysis using the BI case.
PJM_Rest_of_RTO	MISO_W	PJM determined consensus limits with the external interface owners by examining several "data points" and blending methods to reach agreement on the most appropriate initial value for the limits in the MRN-NEEM model. Rollup case interregional linear transfer analysis results, Current OASIS external interface transmission capability data, Actual 2010 hourly interface flow and schedule data for all PJM interfaces, 2010 PJM internal work assessing PJM's internal interface capability with backbone upgrades and MISO Interface linear transfer analysis using the BI case.
PJM_Rest_of_RTO	MISO_WUMS	PJM determined consensus limits with the external interface owners by examining several "data points" and blending methods to reach agreement on the most appropriate initial value for the limits in the MRN-NEEM model. Rollup case interregional linear transfer analysis results, Current OASIS external interface transmission capability data, Actual 2010 hourly interface flow and schedule data for all PJM interfaces, 2010 PJM internal work assessing PJM's internal interface capability with backbone upgrades and MISO Interface linear transfer analysis using the BI case.
PJM_Rest_of_RTO	PJM_Rest_of_MAAC	PJM determined consensus limits with the external interface owners by examining several "data points" and blending methods to reach agreement on the most appropriate initial value for the limits in the MRN-NEEM model. Rollup case interregional linear transfer analysis results, Current OASIS external interface transmission capability data, Actual 2010 hourly interface flow and schedule data for all PJM interfaces, 2010 PJM internal work assessing PJM's internal interface capability with backbone upgrades.
PJM_Rest_of_RTO	TVA	To obtain the MRM-NEEM Pipe Transfer Limit between PJM and TVA, OASIS data, operating history, a linear transfer analysis was performed in PSS® MUST using the EIPC 2020 Baseline Infrastructure Case, and the existing CRA NEEMS data were reviewed. The data was evaluated and coordinated pipe sizes were determined by PJM and TVA.
PJM_Rest_of_RTO	VACAR	To obtain the MRM-NEEM Pipe Transfer Limit between PJM and VACAR, OASIS data, operating history, and the existing CRA NEEMS data were reviewed; as well as a linear transfer analysis performed with PSS® MUST using the EIPC 2020 Baseline Infrastructure Case. The data and analysis results were evaluated and coordinated pipe sizes jointly determined by PJM and VACAR. The limiting facilities and associated contingencies identified are consistent with those found in other transmission planning economic and reliability studies.
RMPA	MAPP_US	This is a DC tie to WECC. This value is the current operating limit for the DC tie.
RMPA	NE	This is a DC tie to WECC. This value is the current operating limit for the DC tie.
RMPA	SPP_N	Ties with RMPA were determined as the combined maximum capacity of the DC ties.
SOCO	ENTERGY	To obtain the MRM-NEEM Pipe Transfer Limit between Southern Company and Entergy, a linear transfer analysis was performed in PSS® MUST using the EIPC 2020 Baseline Infrastructure Case. The analysis results were then verified to be valid and coordinated between Southern Company and Entergy. The limiting facilities and associated contingencies identified are consistent with those found in other transmission planning studies performed in SERC.

FROM	TO	Description
SOCO	FRCC	The transfer capabilities provided as input in the MRN-NEEM model were obtained from the most recent FRCC - Southern joint TTC study. This interface is voltage stability limited interface, and therefore, linear analysis on the baseline infrastructure case was not performed. There are no transmission enhancements that are currently planned that would increase the transfer capability between these regions.
SOCO	TVA	To obtain the MRM-NEEM Pipe Transfer Limit between Southern Company and TVA, a linear transfer analysis was performed in PSS® MUST using the EIPC 2020 Baseline Infrastructure Case. The analysis results were then verified to be valid and coordinated between Southern Company and TVA. The limiting facilities and associated contingencies identified are consistent with those found in other transmission planning studies performed in SERC.
SOCO	VACAR	To obtain the MRM-NEEM Pipe Transfer Limit between Southern Company and VACAR, a linear transfer analysis was performed in PSS® MUST using the EIPC 2020 Baseline Infrastructure Case. The analysis results were then verified to be valid and coordinated between Southern Company and VACAR. The limiting facilities and associated contingencies identified are consistent with those found in other transmission planning studies performed in SERC.
SPP_N	ENTERGY	To obtain the MRN-NEEM Pipe Transfer Limit between SPP and Entergy, a linear transfer analysis was performed in PSS® MUST using the EIPC 2020 Baseline Infrastructure Case. The analysis results were then coordinated between SPP and Entergy.
SPP_N	MISO_MO_IL	The transfer capacity was coordinated between SPP and MISO_MO_IL and was determined by averaging the values obtained by the two entities.
SPP_N	MISO_W	The transfer capacity was coordinated between SPP and MISO_W and was determined by averaging the values obtained by the two entities.
SPP_N	NE	The transfer capacity to NE was determined by using the first valid limiting FCITC transfer value under contingency.
SPP_N	RMPA	Ties with RMPA were determined as the combined maximum capacity of the DC ties.
SPP_N	SPP_S	The transfer capacity to SPP_S was determined by using the first valid limiting FCITC transfer value under contingency.
SPP_S	AZ_NM_SNV	Ties with AZ_NM_SW were determined as the combined maximum capacity of the DC ties.
SPP_S	ENTERGY	To obtain the MRN-NEEM Pipe Transfer Limit between SPP and Entergy, a linear transfer analysis was performed in PSS(r) MUST using the EIPC 2020 Baseline Infrastructure Case. The analysis results were then coordinated between SPP and Entergy.
SPP_S	ERCOT	Ties with ERCOT were determined as the combined maximum capacity of the DC ties.
SPP_S	SPP_N	The transfer capacity to SPP_N was determined as the first valid limiting FCITC transfer value under contingency.
TVA	ENTERGY	To obtain the MRM-NEEM Pipe Transfer Limit between TVA and Entergy, a linear transfer analysis was performed in PSS® MUST using the EIPC 2020 Baseline Infrastructure Case. The analysis results were then verified to be valid and coordinated between TVA and Entergy. The limiting facilities and associated contingencies identified are consistent with those found in other transmission planning studies.
TVA	MISO_MO_IL	To obtain the MRM-NEEM Pipe Transfer Limit between TVA and MISO_MO_IL, a linear transfer analysis was performed in PSS® MUST using the EIPC 2020 Baseline Infrastructure Case. The analysis results were then verified to be valid and coordinated between TVA and MISO_MO_IL. The limiting facilities and associated contingencies identified are consistent with those found in other transmission planning studies performed in SERC.
TVA	Non_RTO_Midwest	To obtain the MRM-NEEM Pipe Transfer Limit between TVA and Non_RTO_Midwest, a linear transfer analysis was performed in PSS® MUST using the EIPC 2020 Baseline Infrastructure Case. The analysis results were then verified to be valid and coordinated between TVA and Non_RTO_Midwest. The limiting facilities and associated contingencies identified are consistent with those found in other transmission planning studies performed in SERC.
TVA	PJM_Rest_of_RTO	To obtain the MRM-NEEM Pipe Transfer Limit between PJM and TVA, OASIS data, operating history, a linear transfer analysis was performed in PSS® MUST using the EIPC 2020 Baseline Infrastructure Case, and the existing CRA NEEMS data were reviewed. The data was evaluated and coordinated pipe sizes were determined by PJM and TVA.

FROM	TO	Description
TVA	SOCO	To obtain the MRM-NEEM Pipe Transfer Limit between Southern Company and TVA, a linear transfer analysis was performed in PSS® MUST using the EIPC 2020 Baseline Infrastructure Case. The analysis results were then verified to be valid and coordinated between Southern Company and TVA. The limiting facilities and associated contingencies identified are consistent with those found in other transmission planning studies performed in SERC.
TVA	VACAR	To obtain the MRM-NEEM Pipe Transfer Limit between TVA and VACAR, the tie line capacity (contract path) between the regions and the results of linear transfer analysis performed in PSS® MUST using the EIPC 2020 Baseline Infrastructure Case were reviewed. There were no limiting facilities identified at transfer levels below the contract path capacity of the tie lines between the regions. FERC tariff regulations limit the transfer capability to the lower of ATC or contract path capacity.
VACAR	PJM_Rest_of_RTO	To obtain the MRM-NEEM Pipe Transfer Limit between PJM and VACAR, OASIS data, operating history, and the existing CRA NEEMS data were reviewed; as well as a linear transfer analysis performed with PSS® MUST using the EIPC 2020 Baseline Infrastructure Case. The data and analysis results were evaluated and coordinated pipe sizes jointly determined by PJM and VACAR. The limiting facilities and associated contingencies identified are consistent with those found in other transmission planning economic and reliability studies.
VACAR	SOCO	To obtain the MRM-NEEM Pipe Transfer Limit between Southern Company and VACAR, a linear transfer analysis was performed in PSS® MUST using the EIPC 2020 Baseline Infrastructure Case. The analysis results were then verified to be valid and coordinated between Southern Company and VACAR. The limiting facilities and associated contingencies identified are consistent with those found in other transmission planning studies performed in SERC.
VACAR	TVA	To obtain the MRM-NEEM Pipe Transfer Limit between TVA and VACAR, the tie line capacity (contract path) between the regions and the results of linear transfer analysis performed in PSS® MUST using the EIPC 2020 Baseline Infrastructure Case were reviewed. There were no limiting facilities identified at transfer levels below the contract path capacity of the tie lines between the regions. FERC tariff regulations limit the transfer capability to the lower of ATC or contract path capacity.

Table 94: BAU Transmission Limits

Source: Transfer Limits Matrix, EIPC, Feb 5 2011

N.B.: Origins are reported on the rows, destinations on the columns

	AZ_NM_SNV	ENTERGY	ERCOT	FRCC	MAPP_CA	MAPP_US	MISO_IN	MISO_MI	MISO_MO_IL	MISO_W	MISO_WUMS	NE	NEISO	Non_RTO_Midwest
AZ_NM_SNV														
ENTERGY									2,260					
ERCOT														
FRCC														
MAPP_CA						372				1,970				
MAPP_US					165					2,635		2,000		
MISO_IN								5,000	5,000					4,800
MISO_MI							2,045				117			
MISO_MO_IL		2,540					2,100			960				
MISO_W					700	2,300			3,800		1,629	2,800		
MISO_WUMS								99		1,137				
NE						1,600				1,600				
NEISO														
Non_RTO_Midwest							4,450							
NWPP						150								
NYISO__A-F													600	
NYISO_GHI													600	
NYISO_J_&_K													0	
IESO					262			1,840		140				
PJM_Eastern_MAAC														
PJM_Rest_of_MAAC														
PJM_Rest_of_RTO							909	1,305	1,111	709	1,467			
RMPA						200						310		
SOCO		2,400		3,700										
SPP_N		1,800							2,000	750		330		
SPP_S	400	850	800											
TVA		3,000							4,000					700
VACAR														

	NWPP	NYISO_A-F	NYISO_G-I	NYISO_J-K	IESO	PJM_E	PJM_ROM	PJM_ROR	RMPA	SOCO	SPP_N	SPP_S	TVA	VACAR
AZ_NM_SNV												400		
ENTERGY										2000	1300	1300	2100	
ERCOT												800		
FRCC										900				
MAPP_CA					330									
MAPP_US	200								200					
MISO_IN								992						
MISO_MI					1580			1424						
MISO_MO_IL								1212			2000		4000	
MISO_W					90			773			3200			
MISO_WUMS								1600						
NE									310		1800			
NEISO		600	600	430										
NonRTO_Midwest													2400	
NWPP														
NYISO_A-F			4250		1600		1000							
NYISO_G-I		1999		6130		1500								
NYISO_J-K			1999											
IESO		1725												
PJM_E			500	330			8000							
PJM_ROM		2000				8000		8000						
PJM_ROR							8000						2500	3000
RMPA											210			
SOCO													2600	2000
SPP_N									210			4000		
SPP_S											0			
TVA								2000		3200				900
VACAR								2000		3000			900	

Table 95: Total Hurdle Rates (inclusive of wheeling costs and trading frictions)

Source: MRN-NEEM Assumptions, EIPC

Interfaces	Hurdle Charge ($/MWh)	Hurdle Charge Back ($/MWh)
ENT to MISO_MO-IL	8	8
ENT to SOCO	8	10
ENT to SPP_N	8	5
ENT to SPP_S	8	5
ENT to TVA	8	9
FRCC to SOCO	8	10
IESO to MAPP_CA	7	8
IESO to MISO_MI	7	8
IESO to MISO_W	7	8
IESO to NYISO_A-F	7	7
MAPP_CA to MAPP_US	7	7
MAPP_CA to MISO_W	0	0
MAPP_US to MISO_W	7	7
MAPP_US to NE	7	5
MISO_IN to MISO_MI	0	0
MISO_IN to MISO_MO-IL	0	0
MISO_IN to NonRTO_Midwest	8	8
MISO_IN to PJM_ROR	2	2
MISO_MI to MISO_WUMS	0	0
MISO_MI to PJM_ROR	2	2
MISO_MO-IL to MISO_W	0	0
MISO_MO-IL to PJM_ROR	2	2
MISO_MO-IL to SPP_N	8	5
MISO_MO-IL to TVA	8	9
MISO_W to MISO_WUMS	0	0
MISO_W to NE	7	5
MISO_W to PJM_ROR	2	2
MISO_W to SPP_N	7	5
MISO_WUMS to PJM_ROR	2	2
NE to SPP_N	0	0
NEISO to NYISO_A-F	3	3
NEISO to NYISO_G-I	3	3
NEISO to NYISO_J-K	3	3
NonRTO_Midwest to TVA	8	9
NYISO_A-F to NYISO_G-I	0	0
NYISO_A-F to PJM_ROM	8	6
NYISO_G-I to NYISO_J-K	0	0
NYISO_G-I to PJM_E	8	6
NYISO_J-K to PJM_E	8	6
PJM_E to PJM_ROM	0	0
PJM_ROM to PJM_ROR	0	0
PJM_ROR to TVA	6	9
PJM_ROR to VACAR	6	7

Interfaces	Hurdle Charge ($/MWh)	Hurdle Charge Back ($/MWh)
SOCO to TVA	10	9
SOCO to VACAR	10	7
SPP_N to SPP_S	0	0
TVA to VACAR	9	7

Table 96: Regional Multipliers

Source: MRN-NEEM Assumptions, EIPC

Representative AEO Region	NEEM Region	Nuclear	Adv Coal	CC F-Frame	CC H-Frame	CT F-Frame	IGCC	IGCC w/Seq	Wind	Wind Offshr	Photo-voltaic	Solar Thermal	Landfill Gas	Bio-mass	Geo-thermal
Phoenix, Arizona	AZ_NM_SNV_Coal	0.976	0.943	1.026	1.026	1.044	0.954	0.945	0.976	1.000	0.938	0.911	0.955	1.000	0.970
Little Rock, Arkansas	ENT	0.975	0.941	0.925	0.933	0.966	0.952	0.943	0.975	1.000	0.935	0.907	0.953	0.919	1.000
Houston, Texas	ERCOT	0.961	0.897	0.912	0.915	1.012	0.915	0.907	0.952	0.918	0.899	0.858	0.927	0.884	1.000
Tampa, Florida	FRCC	0.979	0.946	0.940	0.942	0.954	0.956	0.955	0.978	1.000	0.955	0.936	0.967	0.943	1.000
Bismarck, ND	MAPP_US	0.967	0.913	0.946	0.948	1.013	0.928	0.922	1.021	1.000	0.947	0.912	0.944	0.903	1.000
Bismarck, ND	MAPP_CA	0.967	0.913	0.946	0.948	1.013	0.928	0.922	1.021	1.000	0.947	0.912	0.944	0.903	1.000
Indianapolis, Indiana	MISO_IN	1.020	1.035	1.009	1.009	1.017	1.033	1.012	1.003	0.990	0.988	0.981	0.991	1.015	1.000
Detroit, Michigan	MISO_MI	1.016	1.040	1.053	1.052	0.970	1.035	1.035	1.027	1.028	1.034	1.048	1.027	1.039	1.000
St. Louis, Missouri	MISO_MO-IL	1.028	1.077	1.056	1.054	1.010	1.069	1.055	1.036	1.000	1.044	1.057	1.030	1.047	1.000
St. Pual, Minnesota	MISO_W	1.019	1.041	1.045	1.044	0.994	1.036	1.034	1.075	1.048	1.060	1.072	1.023	1.043	1.000
Green Bay, Wisconsin	MISO_WUMS	1.010	1.006	0.987	0.987	0.948	1.008	0.989	0.990	0.973	0.966	0.951	0.977	0.990	1.000
Omaha, Nebraska	NE	0.985	0.961	0.985	0.986	1.343	0.969	0.962	1.035	1.000	0.983	0.965	0.970	0.949	1.000
Average of 6-state region	NEISO	1.053	1.111	1.156	1.153	1.083	1.096	1.061	1.050	1.031	1.032	1.035	1.016	1.074	1.000
Louisville, Kentucky	NonRTO_Midwest	0.976	0.939	0.946	0.948	0.954	0.951	0.942	0.971	1.000	0.934	0.906	0.952	0.924	1.000
Sacramento, California	NP15	1.065	1.157	1.205	1.199	1.013	1.137	1.111	1.105	1.000	1.105	1.133	1.057	1.119	1.054
Salt Lake City, Utah	NWPP_Coal	0.985	0.967	0.960	0.962	1.047	0.976	0.954	1.037	1.000	0.962	0.931	0.951	1.000	0.971
Syracuse, New York	NYISO_A-F	1.066	1.120	1.163	1.159	1.056	1.108	1.055	1.008	0.988	0.986	0.976	0.996	1.075	1.000
Syracuse, New York	NYISO_G-I	1.066	1.120	1.163	1.159	1.056	1.108	1.055	1.008	0.988	0.986	0.976	0.996	1.075	1.000
New York City, New York	NYISO_J-K	1.134	1.348	1.684	1.664	0.966	1.295	1.314	1.246	1.294	1.366	1.501	1.263	1.383	1.000
Syracuse, New York	OH (IESO)	1.120	-	-	1.200	1.370	-	-	1.110	0.750	0.950	-	1.200	1.040	-
Philadelphia, Pennsylvania	PJM_E	1.049	1.129	1.261	1.253	1.037	1.110	1.113	1.061	1.000	1.116	1.161	1.085	1.131	1.000
Baltimore, Maryland	PJM_ROM	1.034	1.053	1.204	1.199	1.056	1.050	1.011	1.017	0.979	0.974	0.956	0.983	1.016	1.000
Cincinnati, Ohio	PJM_ROR	1.008	1.005	0.983	0.984	0.998	1.008	0.985	0.981	1.000	0.954	0.934	0.969	0.980	1.000
Denver, Colorado	RMPA	0.974	0.934	1.021	1.021	1.206	0.946	0.937	1.022	1.000	0.956	0.927	0.953	0.918	0.973
Atlanta, Georgia	SOCO	0.965	0.911	0.934	0.937	0.985	0.927	0.919	0.961	0.930	0.913	0.877	0.937	0.895	1.000
Los Angeles, California	SP15	1.095	1.224	1.290	1.282	1.056	1.198	1.137	1.124	1.077	1.096	1.114	1.052	1.134	0.935
Wichita, Kansas	SPP_N	0.972	0.927	0.950	0.957	0.970	0.940	0.931	1.019	1.000	0.949	0.917	0.946	0.909	1.000
Wichita, Kansas	SPP_S	0.972	0.927	0.950	0.957	0.970	0.940	0.931	1.019	1.000	0.949	0.917	0.946	0.909	1.000
Knoxville, Tennessee	TVA	0.963	0.903	0.915	0.918	0.985	0.921	0.909	0.954	1.000	0.898	0.856	0.927	0.883	1.000
Charlotte, North Carolina	VACAR	0.959	0.896	0.895	0.909	1.012	0.915	0.899	0.951	0.907	0.884	0.836	0.917	0.866	1.000

Table 97 and Table 98: State RPS and National RPS (%)

Source: MRN-NEEM Assumptions, EIPC

State	Tier	Load Covered (%)	Penalty or ACP ($/MWh)	State RPS Table (%)																			
				2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
CT	RE	100	55	11.00	12.00	13.00	14.00	15.50	17.00	18.50	20.00	22.50	23.00	23.00	23.00	23.00	23.00	23.00	23.00	23.00	23.00	23.00	23.00
DE	RE	100	80	4.98	6.80	8.10	9.40	10.70	12.00	13.25	14.50	15.75	17.00	17.75	18.50	19.25	20.00	20.75	21.50	22.50	22.50	22.50	22.50
	Solar	100	500	0.02	0.20	0.40	0.60	0.80	1.00	1.25	1.50	1.75	2.00	2.25	2.50	2.75	3.00	3.25	3.50	3.50	3.50	3.50	3.50
DC	RE	100	50	3.96	4.93	6.40	7.87	9.33	11.29	13.25	15.20	17.15	19.60	19.60	19.60	19.60	19.60	19.60	19.60	19.60	19.60	19.60	19.60
	Solar	100	500	0.04	0.07	0.10	0.13	0.17	0.21	0.25	0.30	0.35	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40
IL	RE	88.5	19.1	5.50	6.48	7.46	8.37	9.20	10.11	11.52	12.93	14.34	15.75	17.16	18.57	19.98	21.39	22.80	23.50	23.50	23.50	23.50	23.50
	Solar	88.5	19.1	0.00	0.02	0.04	0.14	0.30	0.65	0.74	0.83	0.92	1.01	1.10	1.19	1.28	1.37	1.46	1.50	1.50	1.50	1.50	1.50
KS	All RE	81.5	100	6.00	6.00	6.00	6.00	6.00	9.00	9.00	9.00	9.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00
ME	RE	98.3	60.93	34.00	35.00	36.00	37.00	38.00	39.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00
MD	RE	98	40	4.95	6.40	8.00	10.00	10.10	12.20	12.55	14.90	16.20	16.50	16.85	18.00	18.00	18.00	18.00	18.00	18.00	18.00	18.00	18.00
	Solar	98	300	0.05	0.10	0.20	0.30	0.40	0.50	0.55	0.90	1.20	1.50	1.85	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
MA	RE	100	60.93	9.44	10.33	11.18	11.99	12.73	13.69	14.69	15.69	16.69	17.69	18.69	19.69	20.69	21.69	22.69	23.69	24.69	25.69	26.69	27.69
	Solar	100	600	0.16	0.27	0.42	0.61	0.87	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91
MI	RE	100	40		4.80	5.65	6.75	10.00															
MN	Xcel	47.8	100	15.00	18.00	18.00	18.00	18.00	25.00	25.00	25.00	25.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00
	Other Utilities RE	52.2	100	7.00	12.00	12.00	12.00	12.00	17.00	17.00	17.00	17.00	20.00	20.00	20.00	20.00	20.00	25.00	25.00	25.00	25.00	25.00	25.00
MO	RE	70	100	1.96	1.96	1.96	4.90	4.90	4.90	4.90	9.80	9.80	9.80	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70
	Solar	70	600	0.04	0.04	0.04	0.10	0.10	0.10	0.10	0.20	0.20	0.20	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30
NH	RE	98.2	60.93	9.50	10.50	11.50	12.50	13.50	14.50	15.50	16.50	17.50	18.50	19.50	20.50	21.50	22.50	23.50	23.50	23.50	23.50	23.50	23.50
	Solar	98.2	160.01	0.08	0.15	0.20	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30
NJ	RE	98.3	50	7.99	8.82	9.64	10.48	11.31	12.15	12.99	14.83	16.68	18.53	20.38	20.38	20.38	20.38	20.38	20.38	20.38	20.38	20.38	20.38
	Solar (in GWh)	98.3	693	306	442	596	772	965	1150	1357	1591	1858	2164	2518	2928	3433	3989	4610	5316	5316	5316	5316	5316
	Offshore Wind (in MW)													1100									
NY	RE	100	$20	3.39	4.54	5.60	6.83	8.09	8.09	8.09	8.09	8.09	8.09	8.09	8.09	8.09	8.09	8.09	8.09	8.09	8.09	8.09	8.09
NC	RE	100	40	0.00	2.93	2.93	2.93	5.86	5.86	5.86	9.80	9.80	9.80	12.30	12.30	12.30	12.30	12.30	12.30	12.30	12.30	12.30	12.30
	Solar	100	200	0.02	0.07	0.07	0.07	0.14	0.14	0.14	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
OH	RE	88.6	45	0.97	1.44	1.91	2.38	3.35	4.32	5.28	6.24	7.20	8.16	9.12	10.08	11.04	12.00	12.00	12.00	12.00	12.00	12.00	12.00
	Solar	88.6	400	0.03	0.06	0.09	0.12	0.15	0.18	0.22	0.26	0.30	0.34	0.38	0.42	0.46	0.50	0.50	0.50	0.50	0.50	0.50	0.50
PA	RE	97.3	45	2.98	3.47	3.95	4.42	4.86	5.25	5.71	6.16	6.61	7.06	7.50	7.50	7.50	7.50	7.50	7.50	7.50	7.50	7.50	7.50
	Solar	97.3	654.37	0.02	0.03	0.05	0.08	0.14	0.25	0.29	0.34	0.39	0.44	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50
RI	RE	99.3	60.93	5.50	6.50	7.50	8.50	10.00	11.50	13.00	14.50	16.00	16.00	16.00	16.00	16.00	16.00	16.00	16.00	16.00	16.00	16.00	16.00

WI	RE	100	40	6.13	6.13	6.13	6.13	10.13	10.13	10.13	10.13	10.13	10.13	10.13	10.13	10.13	10.13	10.13	10.13	10.13	10.13	10.13	10.13
MT	RE	66.6	10	10.00	10.00	10.00	10.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00

Region	Allocated RE RPS Requirement by Year % of Load																			
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
ENT	0.08%	0.08%	0.08%	0.19%	0.19%	0.19%	0.19%	0.38%	0.38%	0.38%	0.56%	0.56%	0.56%	0.56%	0.56%	0.56%	0.56%	0.56%	0.56%	0.56%
FRCC	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
MAPP_US	4.73%	6.50%	6.50%	6.50%	6.50%	9.11%	9.11%	9.11%	9.11%	10.83%	10.83%	10.83%	10.83%	10.83%	11.97%	11.97%	11.97%	11.97%	11.97%	11.97%
MISO_IN	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
MISO_MI	0.00%	4.80%	5.64%	6.75%	10.00%	9.90%	9.84%	9.76%	9.69%	9.59%	9.53%	9.46%	9.39%	9.29%	9.24%	9.17%	9.09%	9.00%	8.95%	8.88%
MISO_MO-IL	3.33%	3.81%	4.30%	5.65%	6.07%	6.52%	7.21%	9.42%	10.12%	10.82%	13.03%	13.73%	14.42%	15.12%	15.82%	16.17%	16.17%	16.17%	16.17%	16.17%
MISO_W	6.04%	8.09%	8.10%	8.10%	8.47%	11.48%	11.49%	11.49%	11.49%	13.50%	13.50%	13.50%	13.51%	13.51%	14.83%	14.83%	14.83%	14.83%	14.83%	14.83%
MISO_WUMS	5.55%	6.00%	6.08%	6.18%	10.11%	10.10%	10.09%	10.08%	10.07%	10.06%	10.06%	10.05%	10.05%	10.04%	10.03%	10.03%	10.02%	10.02%	10.01%	10.01%
NE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
NEISO	11.32%	12.22%	13.11%	13.97%	14.97%	16.07%	17.18%	18.20%	19.47%	20.14%	20.68%	21.23%	21.77%	22.31%	22.85%	23.31%	23.76%	24.21%	24.67%	25.12%
NonRTO_Midwest	0.22%	0.33%	0.43%	0.54%	0.76%	0.98%	1.20%	1.41%	1.63%	1.85%	2.07%	2.28%	2.50%	2.72%	2.72%	2.72%	2.72%	2.72%	2.72%	2.72%
NYISO_A-F	3.39%	4.54%	5.60%	6.83%	8.09%	8.09%	8.09%	8.09%	8.09%	8.09%	8.09%	8.09%	8.09%	8.09%	8.09%	8.09%	8.09%	8.09%	8.09%	8.09%
NYISO_G-I	3.39%	4.54%	5.60%	6.83%	8.09%	8.09%	8.09%	8.09%	8.09%	8.09%	8.09%	8.09%	8.09%	8.09%	8.09%	8.09%	8.09%	8.09%	8.09%	8.09%
NYISO_J-K	3.39%	4.54%	5.60%	6.83%	8.09%	8.09%	8.09%	8.09%	8.09%	8.09%	8.09%	8.09%	8.09%	8.09%	8.09%	8.09%	8.09%	8.09%	8.09%	8.09%
PJM_E	6.02%	6.80%	7.55%	8.32%	9.02%	9.77%	10.48%	11.84%	13.17%	14.47%	15.74%	15.82%	15.86%	15.91%	15.96%	16.00%	16.06%	16.06%	16.06%	16.06%
PJM_ROM	3.78%	4.68%	5.67%	6.82%	7.17%	8.35%	8.85%	10.16%	11.04%	11.54%	11.91%	12.38%	12.38%	12.38%	12.38%	12.38%	12.38%	12.38%	12.38%	12.38%
PJM_ROR	2.11%	2.64%	3.06%	3.48%	4.24%	4.76%	5.34%	6.05%	6.66%	7.24%	7.86%	8.43%	8.97%	9.50%	9.80%	9.96%	9.95%	9.95%	9.95%	9.95%
SOCO	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
SPP_N	3.28%	3.28%	3.28%	4.20%	4.20%	5.53%	5.53%	7.08%	7.08%	8.41%	9.96%	9.96%	9.96%	9.96%	9.96%	9.96%	9.96%	9.96%	9.96%	9.96%
SPP_S	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
TVA	0.00%	0.01%	0.01%	0.01%	0.03%	0.03%	0.03%	0.05%	0.05%	0.05%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%
VACAR	0.00%	1.92%	1.92%	1.92%	3.84%	3.84%	3.84%	6.42%	6.42%	6.42%	8.06%	8.06%	8.06%	8.06%	8.06%	8.06%	8.06%	8.06%	8.06%	8.06%

Region	Allocated RPS Requirement by Year % of Load																			
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
ENT	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%
FRCC	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
MAPP_US	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
MISO_IN	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
MISO_MI	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
MISO_MO-IL	0.01%	0.02%	0.03%	0.10%	0.18%	0.35%	0.39%	0.47%	0.51%	0.56%	0.63%	0.68%	0.72%	0.77%	0.81%	0.84%	0.84%	0.84%	0.84%	0.84%
MISO_W	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
MISO_WUMS	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
NE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
NEISO	0.08%	0.14%	0.21%	0.31%	0.42%	0.44%	0.44%	0.44%	0.44%	0.44%	0.44%	0.44%	0.44%	0.44%	0.44%	0.44%	0.44%	0.44%	0.44%	0.44%
NonRTO_Midwest	0.01%	0.01%	0.02%	0.03%	0.03%	0.04%	0.05%	0.06%	0.07%	0.08%	0.09%	0.10%	0.10%	0.11%	0.11%	0.11%	0.11%	0.11%	0.11%	0.11%
NYISO_A-F	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
NYISO_G-I	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
NYISO_J-K	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
PJM_E	0.14%	0.21%	0.30%	0.41%	0.53%	0.66%	0.80%	0.95%	1.12%	1.31%	1.52%	1.72%	1.96%	2.21%	2.50%	2.82%	2.80%	2.78%	2.77%	2.76%
PJM_ROM	0.03%	0.06%	0.11%	0.17%	0.25%	0.34%	0.39%	0.56%	0.71%	0.87%	1.04%	1.10%	1.10%	1.10%	1.10%	1.10%	1.10%	1.10%	1.10%	1.10%
PJM_ROR	0.01%	0.02%	0.04%	0.07%	0.13%	0.22%	0.25%	0.30%	0.34%	0.38%	0.42%	0.46%	0.49%	0.52%	0.53%	0.54%	0.54%	0.54%	0.54%	0.54%
SOCO	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
SPP_N	0.01%	0.01%	0.01%	0.03%	0.03%	0.03%	0.03%	0.06%	0.06%	0.06%	0.09%	0.09%	0.09%	0.09%	0.09%	0.09%	0.09%	0.09%	0.09%	0.09%
SPP_S	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
TVA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
VACAR	0.01%	0.05%	0.05%	0.05%	0.09%	0.09%	0.09%	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%	0.13%

Table 99: Interface Build Assumptions

Interface	From (AEO Region)	To (AEO Region)	Mileage (miles)	Min Cost Build ($1000/MW)	Max Cost Build ($1000/MW)
ENT to MISO_MO-IL	Little Rock, Arkansas	St. Louis, Missouri	300	417	792
ENT to SOCO	Little Rock, Arkansas	Atlanta, Georgia	460	427	855
ENT to SPP_N	Little Rock, Arkansas	Wichita, Kansas	350	486	924
ENT to SPP_S	Little Rock, Arkansas	Oklahoma City, Oklahoma	300	417	792
ENT to TVA	Little Rock, Arkansas	Knoxville, Tennessee	480	446	892
FRCC to SOCO	Tampa, Florida	Atlanta, Georgia	420	390	669
IESO to MAPP_CA	Toronto, Ontario	Winnipeg, Manitoba	1,100	730	1,460
IESO to MISO_MI	Toronto, Ontario	Detroit, Michigan	215	299	299
IESO to MISO_W	Toronto, Ontario	St. Paul, Minnesota	840	557	892
IESO to NYISO_A-F	Toronto, Ontario	Syracuse, New York	250	347	347
MAPP_CA to MAPP_US	Winnipeg, Manitoba	Bismarck, ND	275	146	365
MAPP_CA to MISO_W	Winnipeg, Manitoba	St. Paul, Minnesota	385	255	511
MAPP_US to MISO_W	Bismarck, ND	St. Paul, Minnesota	385	321	481
MAPP_US to NE	Bismarck, ND	Omaha, Nebraska	450	375	563
MISO_IN to MISO_MI	Indianapolis, Indiana	Detroit, Michigan	250	208	312
MISO_IN to MISO_MO-IL	Indianapolis, Indiana	St. Louis, Missouri	230	192	256
MISO_IN to NonRTO-Midwest	Indianapolis, Indiana	Louisville, Kentucky	115	137	229
MISO_IN to PJM-ROR	Indianapolis, Indiana	Cincinnati, Ohio	100	181	222
MISO_MI to MISO_WUMS	Detroit, Michigan	Green Bay, Wisconsin	465	388	581
MISO_MI to PJM-ROR	Detroit, Michigan	Cincinnati, Ohio	240	433	533
MISO_MO_IL to MISO_W	St. Louis, Missouri	St. Paul, Minnesota	470	392	457
MISO_MO_IL to PJM-ROR	St. Louis, Missouri	Cincinnati, Ohio	310	560	689
MISO_MO_IL to SPP_N	St. Louis, Missouri	Wichita, Kansas	400	278	478

Interface	From (AEO Region)	To (AEO Region)	Mileage (miles)	Min Cost Build ($1000/MW)	Max Cost Build ($1000/MW)
MISO_MO_IL to TVA	St. Louis, Missouri	Knoxville, Tennessee	395	314	472
MISO_W to MISO_WUMS	St. Paul, Minnesota	Green Bay, Wisconsin	265	221	305
MISO_W to NE	St. Paul, Minnesota	Omaha, Nebraska	295	246	352
MISO_W to PJM_ROR	St. Paul, Minnesota	Cincinnati, Ohio	610	1,101	1,356
MISO_W to SPP_N	St. Paul, Minnesota	Wichita, Kansas	550	458	657
MISO_WUMS to PJM-ROR	Green Bay, Wisconsin	Cincinnati, Ohio	510	921	1,133
NE to SPP_N	Omaha, Nebraska	Wichita, Kansas	260	173	311
NEISO to NYISO_A-F	Boston, Massachusetts	Syracuse, New York	265	368	736
NEISO to NYISO_G-I	Boston, Massachusetts	Albany, New York	140	194	389
NEISO to NYISO_J-K	Boston, Massachusetts	New York City, New York	200	278	556
Non RTO_Midwest to TVA	Louisville, Kentucky	Knoxville, Tennessee	190	227	378
NYISO_A-F to NYISO_G-I	Syracuse, New York	Albany, New York	130	181	181
NYISO_A-F to PJM-ROM	Syracuse, New York	Baltimore, Maryland	265	846	1,030
NYISO_G-I to NYISO_J-K	Albany, New York	New York City, New York	135	188	188
NYISO_G-I to PJM_E	Albany, New York	Philadelphia, Pennsylvania	200	955	1,168
NYISO_J-K to PJM_E	New York City, New York	Philadelphia, Pennsylvania	85	406	496
PJM_E to PJM_ROM	Philadelphia, Pennsylvania	Baltimore, Maryland	95	454	555
PJM_ROM to PJM_ROR	Baltimore, Maryland	Cincinnati, Ohio	430	1,372	1,671
PJM_ROR to TVA	Cincinnati, Ohio	Knoxville, Tennessee	225	328	418
PJM_ROR to VACAR	Cincinnati, Ohio	Charlotte, North Carolina	340	496	632
SOCO to TVA	Atlanta, Georgia	Knoxville, Tennessee	160	149	234
SOCO to VACAR	Atlanta, Georgia	Charlotte, North Carolina	230	214	336
SPP_N to SPP_S	Wichita, Kansas	Oklahoma City, Oklahoma	155	103	185
TVA to VACAR	Knoxville, Tennessee	Charlotte, North Carolina	185	147	221

Table 100: Future 8 Forced Builds

Source: Future_8_Modeling_Assumptions_Master_1-20-2012
Sheet: F8S5 - Soft with adjustment

Forced-in Cum CC (MW)

	2015	2020	2025	2030	2035	2040
MISO_IN	2098	4163	4163	4163	4163	4163
MISO_MI	2357	5172	5172	5172	5172	5172
MISO_MO-IL	1562	4531	4531	4531	4531	4531
MISO_W	1385	3511	3511	3511	3511	3511
MISO_WUMS	1558	3139	3139	3139	3139	3139
MISO total	8961	20517	20517	20517	20517	20517

Source: Future_8_Modeling_Assumptions_Master_1-20-2012
Sheet: F8S5 - Soft with adjustment

Cum. Class 4 Wind Build Forced In to NEEM

	2015	2020	2025	2030	2035	2040
MISO_IN	0	0	0	0	0	0
MISO_MI	471	471	471	471	471	471
MISO_MO-IL	300	474	2489	5489	5489	5489
MISO_W	2801	2801	48140	55028	55028	55028
MISO_WUMS	0	0	0	0	0	0
MISO Total	3572	3745	51100	60988	60988	60988

Cum. Class 3 Wind Build Forced In to NEEM

	2015	2020	2025	2030	2035	2040
MISO_IN	0	148	1865	10833	10833	10833
MISO_MI	1529	1623	2716	8427	8427	8427
MISO_MO-IL	0	0	0	7530	7530	7530
MISO_W	0	0	0	0	0	0
MISO_WUMS	969	994	1279	2771	2771	2771
MISO Total	2498	2765	5860	29561	29561	29561

Cum. Class 4 Wind Build Forced In to NEEM

	2015	2020	2025	2030	2035	2040
MAPP_US	421	7691	8597	8597	8597	8597
NE	202	12766	13384	13384	13384	13384
NYISO_A-F	0	0	0	0	0	0
SPP_N	0	27058	35369	37325	37325	37325
SPP_S	430	30181	30181	41097	41097	41097

Cum. Class 3 Wind Build Forced In to NEEM

	2015	2020	2025	2030	2035	2040
MAPP_US	0	0	0	0	0	0
NE	0	0	0	0	0	0
NYISO_A-F	2476	3063	3063	5271	5271	5271
SPP_N	0	0	0	0	0	0
SPP_S	0	0	0	0	0	0

Table 101: HQ and NB Export Generation Profiles

Source: MRN-NEEM Assumptions, EIPC

Hydro Generation Capcity Factors for HQ and NB Imports																					
hours	10	25	75	100	200	300	400	500	800	1262	25	200	600	900	1203	25	100	400	700	935	
	B1	B2	B3	B4	B5	B6	B7	B8	B9	B10	B11	B12	B13	B14	B15	B16	B17	B18	B19	B20	Annual
HQ-NE	100%	100%	100%	100%	100%	99%	97%	91%	81%	44%	100%	100%	100%	98%	41%	100%	100%	99%	95%	46%	75%
HQ-NY	67%	67%	67%	66%	66%	63%	60%	55%	50%	20%	67%	67%	66%	58%	19%	67%	65%	64%	58%	23%	44%
HQ-OH	13%	13%	13%	13%	13%	13%	12%	11%	10%	4%	13%	13%	13%	12%	4%	13%	13%	13%	12%	5%	9%
NB-NE	100%	100%	100%	99%	99%	95%	91%	83%	74%	31%	100%	100%	99%	88%	29%	100%	97%	97%	87%	35%	67%

Table 102: 2011-2020 RPS targets by super-region

RPS targets											
Super-region name for RPS	Load covered under the super-region	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
PJM	PJM_E, PJM_ROM	5.34%	6.64%	7.84%	9.19%	10.10%	11.48%	12.42%	14.14%	15.59%	16.75%
MRETS	MAPP_US, MISO_WUMS, MISO_MO_IL, PJM_ROR, MISO_W	2.13%	2.58%	2.66%	2.79%	3.45%	4.01%	4.24%	4.45%	4.63%	5.04%
MI	MISO_MI	0.00%	5.13%	5.96%	7.03%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
Ohio	PJM_ROR	0.25%	0.37%	0.48%	0.60%	0.84%	1.09%	1.32%	1.56%	1.80%	1.95%
MOKSOKNE	MISO_MO_IL, ENT, SPP_N, SPP_S,NE	1.14%	1.15%	1.44%	1.76%	3.62%	3.84%	3.84%	4.37%	4.36%	4.56%
NEISO	NEISO	11.35%	12.33%	13.39%	14.23%	15.39%	16.44%	17.51%	18.50%	19.72%	20.37%
VACAR	VACAR	0.00%	1.64%	1.64%	1.64%	3.27%	3.27%	3.27%	5.47%	5.48%	5.47%
NY	NYISO A-F, NYISO_G-I, NYISO_J-K	3.15%	4.25%	5.27%	6.39%	7.56%	7.57%	7.57%	7.60%	7.61%	7.62%

Table 103: 2021-2030 RPS targets by super-region

RPS targets											
Super-region name for RPS	**Load covered under the super-region**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
PJM	PJM_E, PJM_ROM	17.78%	18.36%	18.73%	19.10%	19.43%	19.44%	19.45%	19.43%	19.37%	19.37%
MRETS	MAPP_US, MISO_WUMS, MISO_MO_IL, PJM_ROR, MISO_W	5.39%	5.59%	5.81%	6.03%	6.44%	6.54%	6.56%	6.57%	6.58%	6.59%
MI	MISO_MI	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
Ohio	PJM_ROR	2.27%	2.50%	2.74%	2.98%	2.98%	2.98%	2.98%	2.98%	2.98%	2.98%
MOKSOKNE	MISO_MO_IL, ENT, SPP_N, SPP_S,NE	5.07%	5.07%	5.07%	5.08%	5.08%	5.08%	5.09%	5.10%	5.10%	5.11%
NEISO	NEISO	20.83%	21.37%	21.89%	22.46%	22.97%	23.46%	23.92%	24.38%	24.76%	25.22%
VACAR	VACAR	6.82%	6.83%	6.83%	6.84%	6.82%	6.82%	6.83%	6.83%	6.82%	6.83%
NY	NYISO A-F, NYISO_G-I, NYISO_J-K	7.59%	7.58%	7.58%	7.59%	7.58%	7.59%	7.59%	7.59%	7.57%	7.58%

Table 104: Contribution to PJM RPS

type	PJM_E	PJM_ROM	PJM_ROR
BM	100%	100%	50%
HY	100%	22%	5%
LFG	100%	100%	50%
PV			50%
ST	100%		50%
STWD	100%	100%	81%
WT	100%	100%	50%
WT-OFF	100%	100%	50%

Table 105: Contribution to MRETS RPS

type	MAPP_US	MISO_MO-IL	MISO_W	MISO_WUMS	PJM_ROR
BM	100%	50%	100%	100%	
HY	0%	1%	97%	56%	2%
LFG	100%	50%	100%	100%	
PV	100%		100%	100%	
ST	100%		100%	100%	
STWD			100%	48%	4%
WT	100%	50%	100%	100%	

Table 106: Contribution to MISO_MI RPS

type	MISO_MI	MISO_W	MISO_WUMS	PJM_ROR
BM	100%			
HY	100%	1%	44%	1%
LFG	100%			
PV	300%			
ST	300%			
STWD	100%		52%	
WT	100%			

Table 107: Contribution to NY RPS

Type	NYISO_A-F	NYISO_G-I	NYISO_J-K
BM	100%	100%	100%
HY	1%		
LFG	100%	100%	100%
PV	100%	100%	100%
ST	100%	100%	100%
WT	100%	100%	100%

Table 108: Contribution to Ohio RPS

type	PJM_ROR
BM	50%
HY	6%
LFG	50%
STWD	4%
WT	50%

Table 109: Contribution to MOKSOKNE RPS

Type	ENT	MISO_MO-IL	NE	SPP_N	SPP_S
BM	100%	63%	100%	110%	50%
HY	1%		100%	117%	39%
LFG	100%	63%	100%	110%	50%
PV			100%	110%	50%
ST			100%	110%	50%
STWD					16%
WT	100%	63%	100%	110%	50%

Table 110: Contribution to VACAR RPS

Type	PJM_ROR	VACAR
BM		100%
HY	46%	7%
LFG		100%
STWD		57%
WT		100%

Table 111: Contribution to solar RPSs by PV and ST units

Contribution by PV and ST units	ENT	MISO_IN	MISO_MO-IL	NEISO	PJM_E	PJM_ROM	PJM_ROR	VACAR
PJM Solar					100%	100%		
MRETS Solar			50%					
Ohio Solar		100%					50%	
MOKSOKNE Solar	100%		63%					
Neiso Solar				100%				
NC Solar								100%

Table 112: Alternative Compliance Payment for RPS

RPS super-region	Alternative Compliance Payment (2010 $/MWh)
PJM	47.56
MRETS	53.18
MI	40.00
NY	20.00
Ohio	45.00
MOKSOKNE	100.00
NEISO	59.24
VACAR	200.00

Table 113: Alternative Compliance Payment for Solar RPSs

Solar RPS superregion	Alternative Compliance Payment (2010 $/MWh)
PJM Solar	533.00
MRETS Solar	19.00
Ohio Solar	400.00
MOKSOKNE Solar	600.00
Neiso Solar	380.00
NC Solar	200.00

Table 114: Wind on-shore category 3 capacity factors (summer)

NEEM Region	Year	B1	B2	B3	B4	B5	B6	B7	B8	B9	B10
ENT	All	0.12	0.08	0.12	0.11	0.12	0.15	0.14	0.19	0.24	0.30
MAPP_US	All	0.16	0.25	0.24	0.25	0.23	0.22	0.28	0.30	0.31	0.34
MISO_IN	All	0.36	0.26	0.23	0.17	0.18	0.19	0.18	0.20	0.22	0.23
MISO_MI	All	0.56	0.40	0.21	0.18	0.18	0.18	0.18	0.18	0.20	0.21
MISO_MO_IL	All	0.37	0.28	0.21	0.16	0.18	0.20	0.20	0.22	0.24	0.26
MISO_W	All	0.24	0.29	0.23	0.23	0.21	0.20	0.25	0.29	0.29	0.33
MISO_WUMS	All	0.51	0.35	0.20	0.17	0.17	0.18	0.19	0.22	0.23	0.26
NE	All	0.22	0.31	0.26	0.21	0.22	0.23	0.26	0.32	0.31	0.34
NEISO (Note D)	All	0.30	0.17	0.17	0.16	0.18	0.20	0.16	0.17	0.22	0.24
NonRTO_Midwest	All	0.05	0.08	0.14	0.10	0.12	0.12	0.13	0.13	0.16	0.19
NYISO_A-F	All	0.50	0.32	0.23	0.18	0.18	0.18	0.15	0.18	0.22	0.22
NYISO_G-I	All	0.42	0.33	0.30	0.24	0.26	0.27	0.21	0.21	0.24	0.21
NYISO_J-K	All	0.44	0.31	0.28	0.26	0.28	0.28	0.24	0.21	0.24	0.21
PJM_E	All	0.12	0.10	0.13	0.12	0.13	0.14	0.14	0.14	0.16	0.14
PJM_ROM	All	0.14	0.14	0.14	0.11	0.12	0.14	0.13	0.14	0.18	0.18
PJM_ROR	All	0.32	0.26	0.19	0.15	0.15	0.16	0.16	0.18	0.21	0.21
SOCO	All	0.04	0.03	0.08	0.09	0.08	0.09	0.11	0.13	0.18	0.21
SPP_N	All	0.50	0.33	0.24	0.26	0.26	0.24	0.26	0.29	0.28	0.32
SPP_S	All	0.56	0.36	0.24	0.29	0.29	0.25	0.26	0.29	0.28	0.33
TVA	All	0.04	0.03	0.08	0.09	0.08	0.09	0.11	0.13	0.18	0.21
VACAR	All	0.15	0.10	0.21	0.23	0.18	0.19	0.20	0.18	0.21	0.19

Table 115: Wind on-shore category 3 capacity factors (shoulder-winter)

NEEM Region	Year	B11	B12	B13	B14	B15	B16	B17	B18	B19	B20
ENT	All	0.15	0.26	0.26	0.32	0.41	0.36	0.35	0.32	0.33	0.41
MAPP_US	All	0.27	0.32	0.34	0.34	0.37	0.55	0.46	0.42	0.37	0.39
MISO_IN	All	0.39	0.33	0.30	0.31	0.34	0.52	0.34	0.38	0.37	0.42
MISO_MI	All	0.27	0.25	0.26	0.27	0.28	0.56	0.39	0.41	0.39	0.38
MISO_MO_IL	All	0.47	0.36	0.32	0.33	0.37	0.52	0.39	0.37	0.37	0.43
MISO_W	All	0.24	0.30	0.31	0.34	0.35	0.47	0.43	0.36	0.33	0.35
MISO_WUMS	All	0.27	0.28	0.26	0.29	0.33	0.58	0.40	0.35	0.33	0.38
NE	All	0.25	0.32	0.36	0.38	0.41	0.53	0.47	0.42	0.39	0.42
NEISO (Note D)	All	0.34	0.31	0.28	0.29	0.30	0.47	0.40	0.38	0.37	0.38
NonRTO_Midwest	All	0.15	0.21	0.23	0.22	0.28	0.29	0.25	0.28	0.30	0.35
NYISO_A-F	All	0.30	0.25	0.29	0.29	0.30	0.42	0.41	0.41	0.41	0.39
NYISO_G-I	All	0.40	0.31	0.29	0.29	0.27	0.43	0.40	0.36	0.34	0.36

NYISO_J-K	All	0.45	0.30	0.29	0.28	0.29	0.43	0.37	0.33	0.34	0.35
PJM_E	All	0.21	0.22	0.23	0.22	0.21	0.35	0.30	0.26	0.28	0.27
PJM_ROM	All	0.26	0.22	0.25	0.25	0.26	0.45	0.41	0.37	0.37	0.36
PJM_ROR	All	0.33	0.28	0.27	0.28	0.30	0.52	0.36	0.37	0.36	0.39
SOCO	All	0.09	0.26	0.26	0.23	0.32	0.22	0.24	0.27	0.30	0.39
SPP_N	All	0.33	0.32	0.32	0.38	0.40	0.38	0.37	0.31	0.32	0.38
SPP_S	All	0.33	0.33	0.32	0.40	0.43	0.41	0.36	0.34	0.34	0.40
TVA	All	0.09	0.26	0.26	0.23	0.32	0.22	0.24	0.27	0.30	0.39
VACAR	All	0.13	0.24	0.26	0.25	0.29	0.35	0.29	0.29	0.29	0.33

Table 116: Existing hydro constant capacity factor

Region	Capacity factor used over all blocks
ENT	0.02
FRCC	0.06
IESO	0.61
MAPP_CA	0.73
MAPP_US	0.53
MISO_IN	0.64
MISO_MI	0.33
MISO_MO-IL	0.43
MISO_W	0.38
MISO_WUMS	0.35
NE	0.40
NEISO	0.43
NonRTO_Midwest	0.37
NYISO_A-F	0.71
NYISO_G-I	0.95
PJM_E	0.78
PJM_ROM	0.30
PJM_ROR	0.29
SOCO	0.30
SPP_N	0.33
SPP_S	0.54
TVA	0.39
VACAR	0.23

Table 117: 2011-2020 Peak demand assumptions for planning reserves

Peak Demand (MW)	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
ENT	29,369	29,590	29,448	29,742	29,774	29,829	29,809	29,785	29,824	29,776
FRCC	46,453	46,750	47,129	46,886	47,364	47,611	48,006	48,315	48,694	49,037
IESO	23,625	23,420	23,217	22,784	22,356	22,180	21,840	21,582	21,292	21,034
MAPP_CA	8,007	8,118	8,246	8,352	8,318	8,334	8,357	8,445	8,468	8,506
MAPP_US	5,497	5,469	5,447	5,426	5,404	5,384	5,446	5,434	5,416	5,419
MISO_IN	17,751	17,758	17,770	17,782	17,792	17,802	17,819	17,836	17,851	17,867
MISO_MI	19,896	19,841	19,794	19,746	19,697	19,649	19,606	19,563	19,520	19,477
MISO_MO-IL	18,684	18,657	18,635	18,613	18,591	18,569	18,553	18,537	18,521	18,505
MISO_W	25,859	25,819	25,780	25,747	25,712	25,682	25,658	25,635	25,605	25,580
MISO_WUMS	12,706	12,707	12,709	12,717	12,707	12,714	12,719	12,729	12,722	12,721
NE	5,565	5,606	5,666	5,684	5,699	5,704	5,735	5,784	5,785	5,807
NEISO	26,915	26,899	26,729	26,628	26,477	26,243	26,053	25,860	25,651	25,443
NonRTO_Midwest	10,813	10,826	10,921	11,011	11,091	11,074	11,153	11,170	11,290	11,340
NYISO_A-F	11,223	10,978	10,838	10,573	10,276	10,261	10,260	10,262	10,262	10,264
NYISO_G-I	4,265	4,175	4,085	3,969	3,852	3,847	3,842	3,845	3,843	3,841
NYISO_J-K	16,594	16,241	15,868	15,444	15,010	15,066	15,113	15,146	15,182	15,231
PJM_E	31,121	30,816	30,506	29,913	29,204	28,540	27,918	27,303	26,665	26,014
PJM_ROM	25,722	25,471	25,339	25,185	24,958	24,907	24,901	24,883	24,913	24,908
PJM_ROR	94,885	96,385	97,428	97,011	96,151	94,921	93,798	92,515	91,159	89,817
SOCO	47,633	49,347	49,997	50,378	50,736	51,080	51,638	51,905	52,333	52,736

SPP_N	15,512	16,386	16,470	16,496	15,894	15,935	16,142	16,186	16,737	16,956
SPP_S	32,611	32,578	32,781	32,871	32,886	32,993	32,969	33,095	32,641	32,545
TVA	32,939	32,729	32,379	32,960	33,469	34,051	34,169	34,283	34,478	34,733
VACAR	46,292	46,480	46,773	47,006	47,198	47,409	47,643	47,865	48,121	48,356

Table 118: 2021- 2030 Peak demand assumptions for planning reserves

Peak Demand (MW)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
ENT	29,529	29,358	29,181	28,975	28,787	28,614	28,447	28,293	28,151	28,010
FRCC	49,142	49,239	49,343	49,455	49,567	49,678	49,789	49,901	50,015	50,130
IESO	20,965	20,896	20,828	20,760	20,692	20,624	20,557	20,490	20,423	20,356
MAPP_CA	8,486	8,467	8,448	8,428	8,409	8,390	8,371	8,352	8,333	8,314
MAPP_US	5,406	5,392	5,378	5,363	5,348	5,335	5,319	5,305	5,293	5,280
MISO_IN	17,796	17,721	17,645	17,567	17,488	17,407	17,325	17,252	17,181	17,111
MISO_MI	19,434	19,390	19,346	19,302	19,257	19,212	19,166	19,123	19,081	19,038
MISO_MO-IL	18,470	18,436	18,401	18,366	18,331	18,296	18,262	18,227	18,193	18,158
MISO_W	25,519	25,454	25,387	25,318	25,247	25,182	25,107	25,043	24,984	24,924
MISO_WUMS	12,674	12,585	12,474	12,344	12,191	12,020	11,830	11,737	11,677	11,618
NE	5,793	5,778	5,763	5,748	5,732	5,717	5,700	5,686	5,672	5,659
NEISO	25,208	24,958	24,706	24,462	24,228	24,003	23,782	23,578	23,366	23,158
NonRTO_Midwest	11,280	11,219	11,157	11,096	11,030	10,972	10,915	10,858	10,802	10,746

NYISO_A-F	10,209	10,146	10,082	10,023	9,968	9,912	9,864	9,812	9,760	9,709
NYISO_G-I	3,834	3,824	3,814	3,805	3,797	3,789	3,784	3,777	3,770	3,763
NYISO_J-K	15,210	15,190	15,169	15,148	15,127	15,105	15,084	15,062	15,041	15,019
PJM_E	25,922	25,820	25,718	25,621	25,528	25,435	25,349	25,259	25,170	25,081
PJM_ROM	24,818	24,719	24,619	24,526	24,436	24,346	24,263	24,177	24,091	24,005
PJM_ROR	89,452	89,064	88,676	88,287	87,891	87,488	87,080	86,709	86,355	86,004
SOCO	52,603	52,432	52,276	52,148	51,988	51,874	51,763	51,651	51,546	51,445
SPP_N	16,939	16,922	16,905	16,889	16,872	16,855	16,838	16,822	16,805	16,788
SPP_S	32,364	32,229	32,091	31,935	31,793	31,656	31,522	31,396	31,277	31,158
TVA	34,550	34,363	34,172	33,986	33,785	33,607	33,433	33,259	33,086	32,914
VACAR	48,312	48,245	48,199	48,171	48,143	48,115	48,085	48,055	48,031	48,010

Table 119: New US hydro capacity factors (summer)

New US Hydro from non-power dams	Year	B1	B2	B3	B4	B5	B6	B7	B8	B9	B10
ENT	All	0.172	0.222	0.238	0.245	0.24	0.241	0.258	0.242	0.284	0.299
FRCC	All	0.352	0.318	0.307	0.294	0.282	0.262	0.255	0.294	0.259	0.252
MISO_MO-IL	All	0.461	0.559	0.592	0.618	0.626	0.646	0.681	0.623	0.684	0.719
MISO_WUMS	All	0.456	0.504	0.52	0.558	0.59	0.62	0.653	0.598	0.62	0.654
NEISO	All	0.189	0.202	0.207	0.242	0.278	0.302	0.332	0.315	0.372	0.402
NonRTO_Midwest	All	0.204	0.224	0.231	0.248	0.261	0.268	0.29	0.287	0.345	0.365
PJM_ROM	All	0.23	0.244	0.249	0.261	0.27	0.274	0.293	0.3	0.342	0.358
PJM_ROR	All	0.363	0.436	0.46	0.481	0.488	0.502	0.532	0.493	0.551	0.58
SOCO	All	0.117	0.142	0.151	0.154	0.151	0.15	0.159	0.153	0.173	0.182
SPP_S	All	0.28	0.432	0.482	0.503	0.493	0.512	0.55	0.468	0.518	0.552
TVA	All	0.251	0.273	0.281	0.284	0.279	0.274	0.286	0.291	0.322	0.332
VACAR	All	0.188	0.182	0.18	0.182	0.184	0.18	0.19	0.214	0.213	0.218

Table 120: New US hydro capacity factors (shoulder- winter)

New US Hydro from non-power dams	B11	B12	B13	B14	B15	B16	B17	B18	B19	B20
ENT	0.173	0.378	0.387	0.43	0.404	0.476	0.543	0.533	0.524	0.515
FRCC	0.492	0.336	0.33	0.271	0.297	0.249	0.223	0.22	0.217	0.231
MISO_MO-IL	0.366	0.487	0.503	0.556	0.547	0.368	0.418	0.406	0.397	0.39
MISO_WUMS	0.367	0.529	0.545	0.598	0.581	0.41	0.458	0.441	0.431	0.422
NEISO	0.381	0.607	0.619	0.684	0.658	0.643	0.652	0.641	0.634	0.637
NonRTO_Midwest	0.286	0.511	0.517	0.563	0.537	0.614	0.682	0.682	0.674	0.668
PJM_ROM	0.326	0.541	0.544	0.587	0.563	0.612	0.63	0.633	0.627	0.636
PJM_ROR	0.327	0.507	0.517	0.571	0.554	0.446	0.501	0.492	0.483	0.476
SOCO	0.136	0.286	0.289	0.312	0.296	0.354	0.424	0.408	0.397	0.382
SPP_S	0.098	0.255	0.268	0.305	0.284	0.143	0.2	0.192	0.185	0.174
TVA	0.262	0.423	0.422	0.443	0.429	0.586	0.637	0.629	0.62	0.616
VACAR	0.211	0.298	0.303	0.315	0.308	0.304	0.324	0.318	0.311	0.314

Table 121: New US hydro resource potential

New resource potential (GW)	Hydro from Non-Power Dams
ENT	1.109
FRCC	0.028
MISO_MO_IL	0.280
MISO_WUMS	0.001
NEISO	0.003
NonRTO_Midwest	0.746
PJM_ROM	0.678
PJM_ROR	0.503
SOCO	0.867
SPP_S	0.091
TVA	0.027
VACAR	0.052

Table 122: Pseudo-generators characteristics

Parameter	Source/Definition	HQ/NE Hydro	HQ- New York Hydro	HQ-OH Hydro	Maritime-NE Hydro	Manitoba
First Year Available		2020	2,020	2020	2,020	2020
Overnight Capital Cost ($/kW)	AEO 2011 (in 2010 dollars)	3076	3,076	3076	3,076	3076
Operating Life	hydro asset life time around 100 Years	100	100	100	100	100
8760 hr gen shape	Use normalized load shapes	Based on load shape for NEISO	Based on load shape for NY	Based on load shape for OH	Based on load shape for NEISO	Based on load shape for MISO-W
FOM ($/kW-year)	AEO 2011 (in 2010 dollars) (table 4)	14.24	14	14.24	14	14.24
VOM ($/MWh)	AEO 2011 (in 2010 dollars) (table 4)	$7 - represent hurdle/wheel cost for transmision between regions	$7 - represent hurdle/wheel cost for transmision between regions	$7 - represent hurdle/wheel cost for transmision between regions	$7 - represent hurdle/wheel cost for transmision between regions	0 (hurdle/wheel cost already accounted for in NEEM regions)
Reserve Margin Contribution	Based on Regional Stakeholder Input	1	1	0	1	1
Resource Potential	provided by regional experts	Total possible HQ-NE by 2030 - 2500 MW. Total exports from HQ: 2020 - 3000 MW; 2025 - 4150 MW; 2030 - 5300 MW	Total possible HQ-NE by 2030 - 2500 MW. Total exports from HQ: 2020 - 3000 MW; 2025 - 4150 MW; 2030 - 5300 MW	Total possible HQ-OH by 2030 - 2500 MW. Total exports from HQ: 2020 - 3000 MW; 2025 - 4150 MW; 2030 - 5300 MW	500 MW - available 2020	695 (by 2020) +1495 (by2025) +2460 (by 2025)
Fixed Charge Rate	Use average EIPC FCR values for technologies as FCR spread is small	0.112	0	0.112	0	0.112
Change in Capital Cost over Time	Use AEO 2010 learning rates for hydro	0.05	0	0.05	0	0.05
Electrical Transmission ($/kW)	CRA from Exhibit 9 (based on coal plant)	21.92	22	21.92	22	21.92

Parameter	Source/Definition	HQ/NE Hydro	HQ- New York Hydro	HQ-OH Hydro	Maritime-NE Hydro	Manitoba
Regional Multiplier	For lack of data in AEO2011 assumed	1	1	1	1	1

Table 123: Capacity factor for pseudo-generators (summer)

Region	B1	B2	B3	B4	B5	B6	B7	B8	B9	B10
IESO	1.000	0.956	0.894	0.855	0.825	0.800	0.770	0.736	0.699	0.604
NEISO	1.000	0.935	0.860	0.785	0.748	0.703	0.653	0.614	0.565	0.450
NYISO_A-F	1.000	0.952	0.902	0.843	0.808	0.773	0.734	0.707	0.670	0.566
MAPP_CA	1.000	1.058	1.017	0.958	0.906	0.837	0.785	0.702	0.634	0.533

Table 124: Capacity factors for pseudo-generators (shoulder- winter)

Region	B11	B12	B13	B14	B15	B16	B17	B18	B19	B20
IESO	0.765	0.786	0.761	0.716	0.603	0.882	0.858	0.830	0.781	0.657
NEISO	0.630	0.624	0.599	0.555	0.435	0.718	0.683	0.656	0.606	0.486
NYISO_A-F	0.727	0.742	0.715	0.671	0.559	0.823	0.801	0.776	0.730	0.615
MAPP_CA	0.735	0.706	0.686	0.638	0.542	0.868	0.798	0.771	0.708	0.545

Table 125: CO2 emission rates

Fuel	CO2 emission rate (lb/MMBTU)
Coal	207.9
Fuel oil	170.4
Natural Gas	116.7

Table 126: Demand Response Supply Curve

Tier	Price ($/MWh)	Incremental percent of total capacity	Cumulative percent of total capacity
1	165	22%	22%
2	273	12%	34%
3	418	16%	50%
4	665	16%	66%
5	1,142	22%	88%
6	2,100	12%	100%

Table 127: 2011-2020 Demand Response Potential per Region (MW)

Region	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
ENT	306	307	303	303	302	702	1,253	1,961	2,838	3,514
FRCC	2,804	2,785	2,776	2,739	2,734	3,479	4,514	5,835	7,421	8,754
IESO	2,066	2,049	2,031	1,994	1,959	2,078	2,244	2,480	2,778	2,998
MAPP_CA	88	89	90	90	89	152	254	400	596	733
MAPP_US	61	61	60	60	59	100	168	262	387	474
MISO_IN	1,089	1,082	1,073	1,070	1,069	1,216	1,445	1,762	2,184	2,491
MISO_MI	1,884	1,873	1,860	1,849	1,839	1,984	2,149	2,332	2,563	2,774
MISO_MO-IL	311	309	307	304	301	605	968	1,379	1,854	2,265
MISO_W	2,702	2,679	2,661	2,640	2,623	2,784	3,022	3,339	3,738	4,071
MISO_WUMS	197	196	195	194	193	299	434	594	782	940
NE	625	625	628	626	624	667	747	865	1,012	1,126
NEISO	3,130	3,127	3,107	3,099	3,092	3,291	3,560	3,897	4,303	4,630
NonRTO_Midwest	194	193	193	194	194	297	466	703	1,039	1,269
NYISO_A-F	983	964	952	931	907	970	1,064	1,190	1,352	1,477
NYISO_G-I	374	366	359	349	340	363	398	445	505	552
NYISO_J-K	1,451	1,421	1,389	1,354	1,319	1,417	1,559	1,747	1,989	2,180
PJM_E	1,391	1,361	1,330	1,289	1,257	1,520	1,878	2,344	2,907	3,301
PJM_ROM	2,441	2,393	2,351	2,331	2,307	2,669	3,084	3,555	4,087	4,582
PJM_ROR	3,413	3,418	3,401	3,368	3,325	4,250	5,457	6,970	8,886	10,284
SOCO	2,492	2,565	2,579	2,574	2,570	3,448	4,509	5,725	7,197	8,503
SPP_N	444	467	467	466	447	614	870	1,187	1,636	1,974
SPP_S	62	61	61	61	61	544	1,179	1,976	2,894	3,634
TVA	1,837	1,813	1,779	1,793	1,805	2,179	2,820	3,757	5,007	5,911
VACAR	2,369	2,363	2,360	2,349	2,339	2,847	3,724	5,031	6,803	8,045

Table 128: 2011-2020 Demand Response Potential per Region (MW)

Region	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
ENT	4,179	4,851	5,530	6,216	6,910	6,946	6,983	7,020	7,057	7,095
FRCC	10,082	11,442	12,835	14,260	15,718	15,913	16,110	16,310	16,512	16,717
IESO	3,245	3,496	3,749	4,006	4,267	4,296	4,325	4,354	4,384	4,414
MAPP_CA	869	1,006	1,145	1,287	1,431	1,442	1,453	1,464	1,476	1,487
MAPP_US	562	651	741	833	926	933	940	948	955	962
MISO_IN	2,791	3,095	3,402	3,712	4,027	4,051	4,076	4,101	4,126	4,151
MISO_MI	2,989	3,207	3,428	3,652	3,880	3,911	3,941	3,973	4,004	4,036
MISO_MO-IL	2,681	3,104	3,533	3,969	4,413	4,449	4,485	4,522	4,559	4,596
MISO_W	4,403	4,741	5,083	5,430	5,783	5,828	5,873	5,919	5,965	6,012
MISO_WUMS	1,096	1,255	1,416	1,579	1,744	1,755	1,767	1,778	1,790	1,802
NE	1,235	1,345	1,458	1,572	1,687	1,700	1,714	1,727	1,740	1,754
NEISO	4,952	5,275	5,597	5,921	6,245	6,252	6,259	6,267	6,276	6,285
NonRTO_Midwest	1,491	1,715	1,941	2,169	2,399	2,411	2,423	2,435	2,447	2,459
NYISO_A-F	1,596	1,716	1,838	1,960	2,084	2,095	2,106	2,116	2,127	2,138
NYISO_G-I	598	645	693	742	792	799	805	812	819	826
NYISO_J-K	2,364	2,552	2,742	2,936	3,133	3,161	3,188	3,217	3,245	3,273
PJM_E	3,761	4,227	4,699	5,177	5,661	5,699	5,737	5,776	5,814	5,853
PJM_ROM	5,070	5,564	6,064	6,571	7,084	7,131	7,179	7,227	7,276	7,325
PJM_ROR	11,794	13,322	14,868	16,433	18,016	18,126	18,236	18,347	18,459	18,572
SOCO	9,759	11,034	12,329	13,645	14,981	15,102	15,225	15,348	15,472	15,598
SPP_N	2,296	2,622	2,955	3,294	3,638	3,671	3,704	3,738	3,772	3,806
SPP_S	4,377	5,129	5,890	6,661	7,442	7,489	7,537	7,586	7,634	7,683
TVA	6,759	7,615	8,480	9,352	10,234	10,284	10,334	10,385	10,436	10,487

Region	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
VACAR	9,272	10,523	11,796	13,093	14,414	14,552	14,692	14,833	14,975	15,119

Table 129: Unit Sizes for Expansion Candidate Generator Type

Technology	Unit size (MW)
Nuclear	500
Advanced Coal	500
CC F-Frame	500
CC H-Frame	500
CT F-Frame	200
IGCC	500
IGCC w/seq	500
Wind (options B&A)	200
Wind Offshore	200
Photovoltaic	10
Solar Thermal	100
Landfill Gas	10
Biomass	50
Geothermal	100

Table 130: National RPS (% of EI Load except IESO)

Year	National RPS
2011	1.25%
2012	2.50%
2013	3.75%
2014	5.00%
2015	6.25%
2016	7.50%
2017	8.75%
2018	10.00%
2019	11.25%
2020	12.50%
2021	13.75%
2022	15.00%
2023	16.25%
2024	17.50%
2025	18.75%
2026	20.00%
2027	21.25%
2028	22.50%
2029	23.75%
2030	25.00%

Table 131: Intermittent Resources Capacity Credit/ Reserve Contribution

NEEM Region	Technology	Reserve Contribution
All Regions	Photovoltaic	30%
All Regions	Solar Thermal	30%
All Regions	Offshore Wind	30%
California	Wind	25%
Canada	Wind	20%
ERCOT	Wind	9%
New York	Wind	15%
PJM (-E, -ROM, -ROR)	Wind	13%
SPP (including NE)	Wind	15%
TVA	Wind	12%
IESO	Wind	11%
MAPP_CA	Wind	11%
All Other Regions	Wind	15%

Appendix B: Energy Exemplar Eastern Interconnect Gas Electric PLEXOS® Database

Eastern Interconnect (EI) Gas Electric Dataset

Eastern Interconnect (EI) – Electric Production Cost Database

The Eastern Interconnect dataset is founded from the ERAG MMWG database as well as data from the public domain which are all referenced. Each dataset comes pre-loaded into PLEXOS® distinguished by NERC regions (ISO-NE, NYISO, PJM, MISO, SPP, SERC, FRCC, IESO, Hydro Quebec, etc.). All surrounding intertie flows are modelled within PLEXOS®.

General Dataset Properties included are:

1. **Generators** (Name, Fuel Type, Registered Maximum Capacity). Generators are provided with common empirical operational attributes (e.g., Min Stable Level, Average Heat Rates & Incremental Heat Rates, Ramp Up/Down Rate, Min Up & Min Down times, Generic start-up & shutdown costs, FO&M Charges, Forced Outage Rate, Maintenance Rates, Mean time to Repair, Variable Operating & Maintenance Costs (VOM)) based on the generator characteristics using trusted US databases & reports. Generators are also mapped to EIA 860 form which provides EIA 860 Plant code, Latitudes & Longitudes. For a given NERC region, the sum of the power plants capacity by technology is compared to the aggregated capacity of each technology.

2. **Fuels**: Fuel prices for Coal, Gas, Oil Monthly and Daily used in the datasets correspond to well-known indices (CME & ICE) and an escalator is used to adjust for taxes, transmission and distribution costs, Historical and 40-year fuel price forecasts are pre-loaded into PLEXOS, Multiple Fuels/Switching between fuels are modelled within PLEXOS® based on the most recent EIPC data.

3. **Emissions:** 2011, 2012 & 2013 historical Emission Production Rates (lbs/MWh) for CO2, SO2 and NOx sourced from EPA's Continuous Emissions Monitoring (CEMS) Database are included for the all the thermal generators in the Eastern Interconnect.

4. **PLEXOS® ® Transmission Network model:** The EI Database uses ERAG MMWG 2015 SUM_2013 series Transmission Network Model.

5. **Interfaces:** Interface definitions with seasonal Min/Max limits, NERC Region Imports & Exports modelled in PLEXOS®.

6. **Phase Shifters:** EI Phase Angle regulators have been modelled using the Phase Shifter class in PLEXOS® with Max Angle, Min Angle & Initial Angle properties defined.

7. **Ancillary Services:** Regulation, 10-min Spinning, 10-min Non-Sync & 30-Min Non-Sync reserves modelled for each of the ISO with generic reserve requirements.

8. **Demands:** Historical and 40-year Load Forecast at hourly granularity at each of the ISO zones have been modelled. The energy and peak data for each zone has been obtained from each ISO website (E.g., 2014 Gold Book, 2014 CELTS report).

9. **Wind & Solar profiles:** Eastern Wind Integration & Transmission Study (EWITS) data from NREL has been used to create wind profiles for each of the wind generator in the Eastern Interconnect. A generic solar profile is used for all the solar units in the EI database.

10. **Retirements:** Generator retirement data has been collected from various public sources such as 2014 Gold Book for NYISO, CELTS report for ISO-NE, PJM website and other ISO websites.

11. **Contingencies:** Line and Transformer contingencies have been modelled using the Contingencies class. Contingency shift factor scanning feature in PLEXOS® can be used to print out a set Monitored Lines, Transformers & Interfaces for each Contingency element.

US North American Natural Gas – Production Cost

The US North American Natural Gas – Production Cost dataset has residential, industrial, and commercial loads (RIC) state by state on a monthly basis with links to the natural gas powered plants of production cost model or can be run separate with natural gas fired power plant demand shapes. All interstate pipelines are included with various parameters, gas nodes, gas storages, injection and withdrawals from international boarders and import and export LNG facilities. The gas model has ten year price forecast at well head pricing zones and calculates price separation due to pipeline network constraints.

The first generation of the NA Gas Model was created with data sources from the US Energy Information Agency (EIA). This data is a state-by-state based analysis. From this foundation, the gas model will be expanded to include more detail, particularly by expanding number gas pipelines and gas nodes based on additional sources of information (EIPC, FERC 567 and pipeline bulletin board).

The limitations of the EIA gas data is most of this data is available on a monthly or annual basis. This works sufficiently for the historical gas production but over time will be supplemented with more granular detail.

The primary data from the EIA includes the following:

- Historical Monthly production data by state in MMcf;
- Total Storage Volumes (Working and Base Capacity) by state in MMcf;
- Gas pipelines capacities state to state MMcf;
- Historical natural gas demands with state Residential; Industrial; Commercial; Fuel (Transportation); and Electrical Power;
- Imports and Exports
- Production Prices

1. Historical Monthly Production

EIA publishes monthly historical Natural Gas Marketed Production on a state by state basis. We have used this data and calculated a max daily production rate (monthly data divided by the number of days per month) as well as an hourly max production (monthly data divided by the number of hours per month). The max daily production rate and the hourly max production rates creates a bound of production for the EI Natural Gas model.

2. **Storage Volumes**

EIA publishes monthly historical Total and Working capacity by state. Currently, while these volumes change over time as new gas storage capacity is expanded or built, the current EI Natural Gas model uses the most recent monthly available from the EIA as a static input assuming that the most recent monthly capacity will reflect the steady state capacity for natural gas storage. The EIA also published an EIA Daily withdrawal Capability for each state by state storage. This is currently used as the Max Ramp Day in PLEXOS.

3. **Pipeline Capacity**

EIA publishes annual pipeline capacities with state to state capacities for each pipeline. The pipeline data is published on an MMcf per day basis and is converted to hourly capacity (for PLEXOS) by dividing by 24. An example of this data is presented in Table 8: Summary of Major Pipelines by EIA. This data is converted into a static capacity csv file and will be updated each year as published by the EIA.

4. **Historical Gas Demands**

EIA publishes monthly natural gas demands on a state by state basis divided into the five primary demand categories: Residential; Commercial; Industrial; Fuel (Transportation); and Electrical Production. Energy Exemplar has taken these monthly data and created daily demand profiles. This was done by assuming that both Residential and Commercial gas demands are highly weather dependent, primarily to cold weather. The industrial and fuel demands are not assumed to be weather dependent and therefore have a relatively flat day to day profile.

To calculate the daily demands, we have sculpted the monthly residential and commercial demands using a daily heating degree day (HDD) as published by NOAA for the winter months and then assumed a relatively flat demand in the non-winter months. The daily profiles are then further refined into an hourly profile, using a natural gas hourly profile curve published by the EIPC for both winter and summer natural gas demands. Then we have combined the Residential; Commercial; Industrial and Fuel (Transportation) into a single hourly gas demand or base natural gas demand as well as a separate Electric Power Gas Demand.

5. **<u>Imports / Exports</u>**

EIA publishes monthly imports and exports. The imports are split into the pipeline imports from Canada and Mexico to each respective states as well as the LNG Imports to the receiving terminals in the various states. Due to the variable nature of the LNG imports, it was assumed that these imports are price sensitive and would only include LNG imports over a certain natural gas price threshold.

For the exports, we have also captured the pipeline exports to both Canada and Mexico from the respective states. However, the LNG exports are currently of such a small volume and variable from month to month that these have not been included in the NA Natural Gas Model. Once a more consistent export pattern from LNG becomes apparent, this will be added to the NA Natural Gas Model.

6. **<u>Producer Prices</u>**

The EIA used to publish producer prices for natural gas, but this data was limited to a national level production price as opposed to state to state pricing. As such, we have assumed producer prices are tied to the daily Henry Hub Price, which is the most liquid trading point for natural gas in North America and therefore the best proxy for production prices. We have assumed regional production multipliers to Henry Hub to reflect the cost of production by state to state. In those producing states with large production fields, we have assumed a multiplier of less than 1 relative to Henry Hub, reflecting the economies of scale of production in those state. In the states with smaller production fields or fewer pipelines to markets, we have assumed a multiplier of greater than 1 to reflect the less competitive production fields.

Bibliography:

1. EIPC 2011, Phase 1 Report: Formation of Stakeholder Process, Regional Plan Integration and Macroeconomic Analysis- Appendix 3: “Soft Constraint Methodology”, EIPC, December. Available online at www.eipconline.com/uploads/Phase_1_Report_Final_12-23-2011.pdf
2. A. Liu, B.F. Hobbs, J. Ho, J. McCalley, V. Krishnan, M. Shahidehpour, and Q. Zheng, “Co-optimization of Transmission and Other Supply Resources,” Prepared for the Eastern Interconnection States’ Planning Council, National Association of Regulatory Utility Commissioners, Washington, DC, 20 Dec. 2013.
3. A.H. van der Weijde and B.F. Hobbs, The Economics of Planning Electricity Transmission to Accommodate Renewables: Using Two-Stage Optimisation to Evaluate Flexibility and the Cost of Disregarding Uncertainty, *Energy Economics*, 34(5), Sept. 2012, 2089-2101
4. F.D. Munoz, B.F. Hobbs, J. Ho, and S. Kasina, An Engineering-Economic Approach to Transmission Planning Under Market and Regulatory Uncertainties: WECC Case Study, *IEEE Transactions on Power Systems*, 29(1), January 2014, 307-317.
5. EIPC 2011, Phase 1 Report: Formation of Stakeholder Process, Regional Plan Integration and Macroeconomic Analysis, EIPC, December. Available online at www.eipconline.com/uploads/Phase_1_Report_Final_12-23-2011.pdf
6. EIPC 2012, Phase 2 Report: DOE Draft – Part 1 Interregional Transmission Development and Analysis for Three Stakeholder Selected Scenarios, EIPC, December. Available online at www.eipconline.com/uploads/20130103_Phase2Report_Part1_Final.pdf
7. EIPC 2012, Phase 2 Report: DOE Draft – Parts 2-7 Interregional Transmission Development and Analysis for Three Stakeholder Selected Scenarios, EIPC, December. Available online at www.eipconline.com/uploads/20130103_Phase2Report_Part2_Final.pdf
8. EIPC 2012, Phase 2 Report: DOE Draft – Appendices Interregional Transmission Development and Analysis for Three Stakeholder Selected Scenarios, EIPC, December. Available online at www.eipconline.com/uploads/20130103_Phase2Report_Part3_Final.pdf
9. Charles Rivers Associates, 2010, Working Draft of MRN-NEEM Modeling Assumptions and Data Sources for EIPC Capacity Expansion Modeling, EIPC, December. Available online at www.eipconline.com/uploads/MRN-NEEM_Assumptions_Document_Draft_12-22-10.pdf.
10. Modeling results for Future 8 Sensitivity 7 (CO2+ case) available at eippgte conline.com/uploads/F8S7_Stakeholder_Report.xlsx
11. Ozdemir, F. Munoz, J. Ho, and B.F. Hobbs, Economic Analysis of Transmission with Demand Response and Quadratic Losses by Successive LP, *IEEE Transactions on Power Systems*, forthcoming, 2015
12. Modeling results for Future 1 Base case (Business As Usual case) available at eipconline.com/uploads/F1B_Output_Report_3-20.xls
13. Future 8 Sensitivity 7 Modeling Assumptions available online at www.eipconline.com/uploads/Future_8_Modeling_Assumptions_Master_1-20-2012.xls