APPENDIX I

Manitoba Hydro Wind Synergy Study

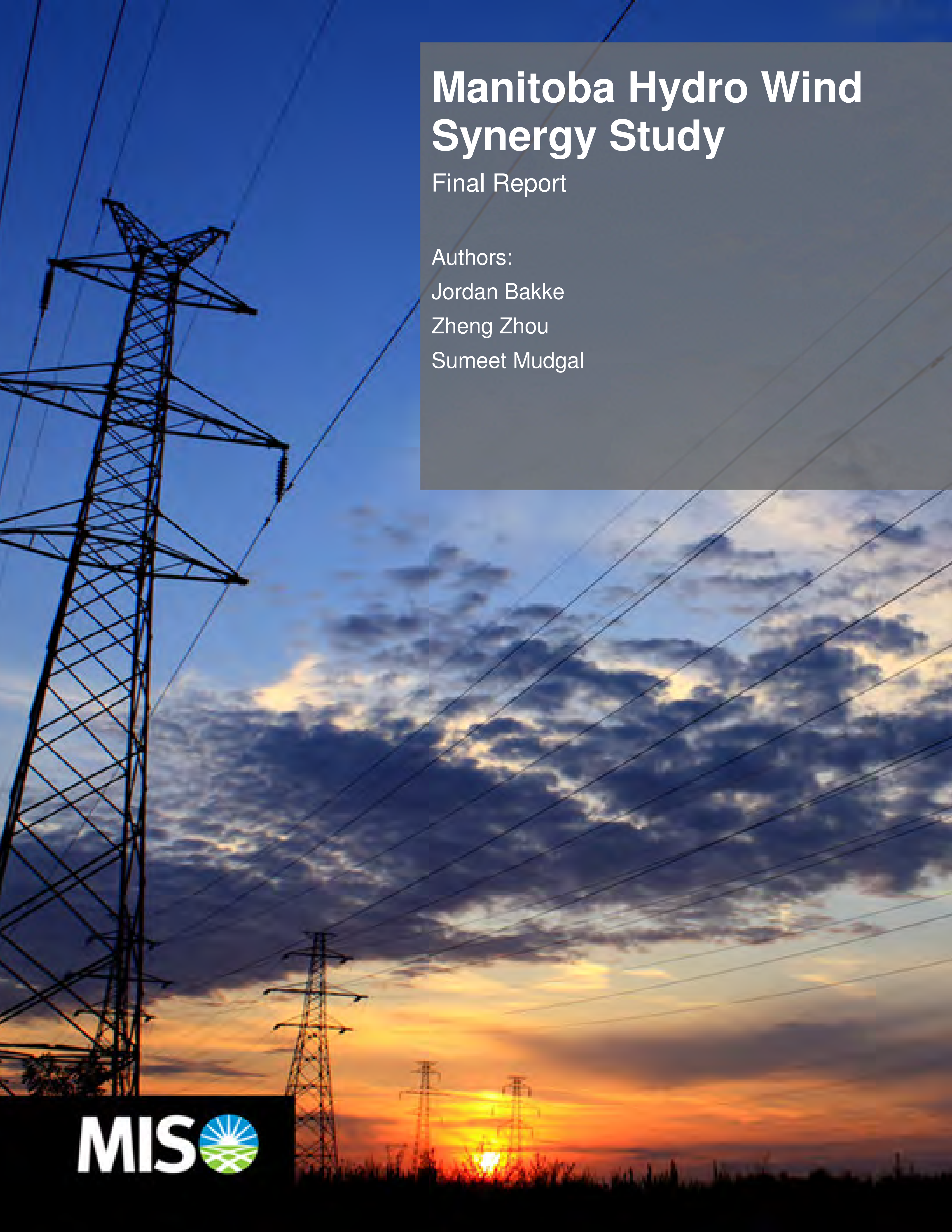
Final Report

Authors:

Jordan Bakke

Zheng Zhou

Sumeet Mudgal



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Executive Summary – Manitoba Hydro Wind Synergy Study

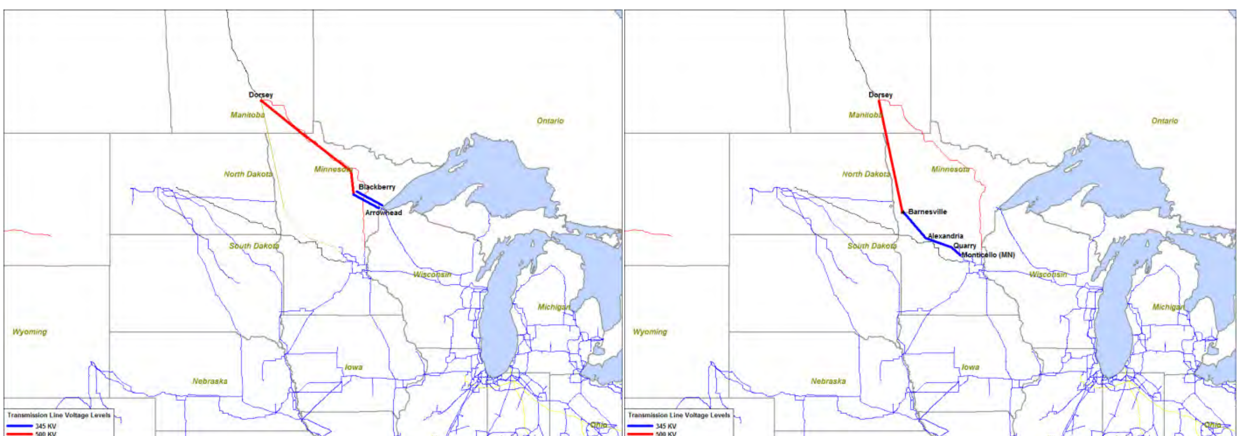
The Manitoba Hydro Wind Synergy Study found significant benefits can be realized from adding a 500 kV transmission line from Manitoba to MISO

The variable and non-peak nature of wind creates integration challenges within MISO. Manitoba Hydro, with its large and flexible system, offers potential solutions for meeting these challenges. MISO conducted this study to evaluate whether the cost of expanding the transmission capacity between Manitoba and MISO would enable greater wind participation in the MISO market.

MISO completed its first comprehensive study that looks at the synergy between hydro power and wind power in June 2013. The purpose of the study, called the Manitoba Hydro Wind Synergy Study, assessed how Canadian hydro power can work with MISO wind to provide benefits to MISO.

The Manitoba Hydro Wind Synergy Study found significant benefits can be realized from the addition of either an eastern 500 kV line between Dorsey, Manitoba, and Duluth, Minn., or a western 500 kV line between Dorsey, Manitoba, and Fargo, N.D./Moorhead, Minn. (Figure E1).

The study also found that expanding the External Asynchronous Resource (EAR) structure from unidirectional to bidirectional would provide near-term benefits, as well.



East Option: Dorsey to Blackberry	West Option: Dorsey to Fargo/Moorhead Area
- 500kV line from Winnipeg to Grand Rapids - 345kV double circuit line from Grand Rapids to Duluth	- 500kV line from Winnipeg to Fargo/Moorhead Area - 345kV line from Fargo/Moorhead to Monticello

Figure E1: East and West Transmission Options

Benefits

MISO evaluated the projects for benefits that included the following measures:

- Production cost savings and modified production cost savings
- Load cost savings
- Reserve cost savings
- Wind curtailment reduction

The benefit metrics are indicative of savings MISO may experience if either of the transmission plans were constructed, but they cannot be used to justify cost sharing of either project under the current MISO tariff. The benefits found in this study cannot be used in the Market Efficiency Planning Study (MEPS) to justify project eligibility since the studies use different assumptions and different benefit metrics. The main difference between the two studies is the Manitoba Hydro Wind Synergy Study includes the benefits of incremental hydro generation in the benefit metric. A hypothetical Market Efficiency Project eligibility test was conducted and found that MISO would receive no Adjusted Production Cost benefit from the construction of either line under the current MISO tariff and using the current MTEP12 models. Looking at these projects from a market efficiency perspective does not capture the purpose of the transmission plans.

The modified production cost metric was created to address the challenges presented by this study. Adjustments are made to the production cost to reduce the biases between the simulations. Biases can occur because of changes in the amount of water used by hydro generators or imports and exports from a particular region.

The benefit-to-cost ratios for the East and West plans ranged from 1.70 to 3.84 across all futures using the modified production cost metric developed specifically for this study. The weighted averages of the benefit-to-cost ratio differ only because of the construction costs of the lines (Table E1). These plans show similar benefits across a wide range of plausible futures.

Based on these preliminary analyses, MISO recommends both projects for inclusion in MTEP13 Appendix B on the basis that they show potential merit under possible future benefit metric constructs or as parts of a possible future more expansive Multi Value Project portfolio. Neither, however, would qualify for cost sharing under the current provisions of the MISO tariff.

Transmission Options	20 Year Present Value Benefits ($M-2012)	20 Year Present Value Costs, transmission only ($M-2012)	B/C Ratio averaged over all futures	2012 Nominal Cost Estimate ($M-2012)
East 500kV Option	$1,586	$666	2.38	$685
West 500kV Option	$1,588	$582	2.73	$598

Table E1: Weighted Present Value Benefits and costs (averaged across futures)

External Asynchronous Resource

The Manitoba Hydro Wind Synergy Study also evaluated whether expanding the external asynchronous resources (EAR) structure from unidirectional to bidirectional would provide economic benefits. An EAR is a market-designated resource separated from the main market by a DC tie. EAR participants, under the current real-time market structure, are only allowed to sell into the MISO market, but not buy from the market. Allowing a bidirectional EAR enables Manitoba Hydro to submit price sensitive bids and offers to the real time market, enabling the co-optimized real time economic dispatch of flexible hydro generation with wind or load changes in the MISO market. The study found $8.74 million dollars in production cost savings to the MISO market and $100,000 in reserve cost savings for the planning year 2012. The changes are currently being evaluated and are expected to take effect in 2015.

Synergy

Wind synergy benefits from the expanded use of hydro generators in Manitoba Hydro are demonstrated in three ways: by wind curtailment reduction in MISO; by an inverse correlation between imports from Manitoba Hydro and MISO wind generation; and by a better utilization of both wind and hydro resources.

Wind curtailment in the northern MISO region was reduced by 50 to 100 GWh, depending on the plan studied and future examined during the 2027 planning year. The interface between Manitoba Hydro and wind generation in northern MISO showed an inverse correlation between the two of between -0.2 to -0.5 demonstrating the strong response of the hydro generators to fluctuations in MISO wind. The wind synergy between Manitoba Hydro and MISO wind leads to a reduction in cost for MISO and expanded revenue for Manitoba Hydro.

Context and Methodology

The Manitoba Hydro Wind Synergy Study set out to evaluate the benefits and costs of expanding the interface between Manitoba Hydro and MISO. The study looked at adding an additional hydro generator in Manitoba Hydro along with the addition of one of three new tie lines. The combined benefits were examined including production cost savings, modified production cost savings, load cost savings, reserve cost savings, thermal generator ramping changes and wind curtailment changes. Given the wide variety of benefit metrics along with the exploratory nature of the study, the specific allocation of benefits was not possible. This study simply showed that the total benefits in the MISO area are greater than the costs to build either line.

MISO currently has 12 GW of wind online and 15 GW of active wind projects in the MISO generator interconnection queue as of July 2013. Manitoba Hydro currently looks to expand its hydro system by 2,230 MW over the next 15 years. Manitoba Hydro's current export capacity is limited to 1,850 MW, which cannot meet the needs of future wind variability. Thus this study looks at expanding transmission capacity between MISO and Manitoba Hydro to facilitate the realization of these benefits.

This study came at the request of various stakeholders who asked MISO to look into the best way to resolve possible operational challenges related to high levels of wind penetration. MISO developed a four-phase study to address these concerns and develop a cost-benefit analysis for an expanded Manitoba Hydro to MISO interface.

Given the goal to look at the synergy between wind and hydro, MISO developed models that were much more detailed than those used in the past. The uncertainty of wind and load can only be seen when examining the real-time market and cannot be captured effectively using the traditional techniques of day-ahead market simulations. MISO developed a novel approach to extract the additional synergy benefits.

MISO used a new simulation tool, PLEXOS, to model the day-ahead and real-time markets as well as to capture the uncertainties of wind and load between what is forecasted in the day-ahead market and actual conditions in the real time market. Significant effort was employed throughout the study to validate and improve the software. Many new concepts and modeling techniques were developed over the course of this study.

Statistics were gathered from historical MISO market data to create a year's worth of wind data at the individual wind farm level and load data at the company level. Generating resources were committed and dispatched against the day-ahead forecasted profiles and then re-dispatched against the real-time profiles leaving a gap filled by flexible resources such as gas turbines and dispatchable hydro units.

A new simulation technique was developed to best model the added complexity of a hydro storage system and Manitoba Hydro's market participation. This was necessary to reflect the reality that traders adjust their bids and offers depending on what storage operations occurred as a result of previous day's day-ahead and real-time market activities. A value of water in storage (VWS) curve was introduced to take into account the opportunity cost of water of the entire planning period to allow for daily bids. Real-time bidding offers were calculated from the VWS curve along with offer bands representing the uncertainty presented between the day ahead and real time markets. New offers were determined after each simulated day.

MISO developed a new process with the assistance of Manitoba Hydro and Energy Exemplar, named Interleave, to capture the effect of the real-time response to changing forecasts. This planning study is the first to use this advanced technique. The Interleave simulation best represents the sequential nature of the day-ahead and real-time markets. After completion of a single day-ahead simulation, the unit commitment and other outputs are passed to the real-time simulation. After this simulation is completed, the ending conditions are then passed into the next day-ahead simulation. This continues for every day of the planning year, interleaving the days to create a realistic market simulation (Figure E2).

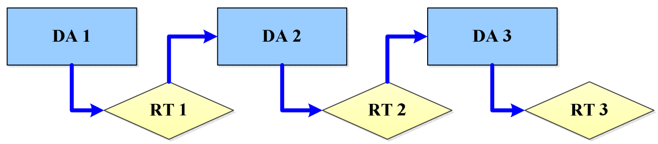


Figure E2: Interleave Method

A combination of traditional simulation techniques and new ones developed specifically for this study allowed for a diverse set of benefits to be examined. The synergy between wind and hydro was explored in great detail along with the cost savings of increasing energy delivered into MISO. The benefits of these findings are substantial and show that expanded participation of Manitoba Hydro in the MISO market through increased transmission, generation and market changes would benefit all parties involved.

Over the course of this study, significant amount of effort was spent integrating and validating a new simulation tool, creating detailed hydraulic systems for Manitoba Hydro, simulating the uncertainties of the real time market, developing new methods to examine the benefits of wind-hydro synergy and determining the benefits of new transmission and generation to the MISO footprint. Many lessons were learned. It takes a long time and a lot of effort to fully integrate and test a new production cost model, but MISO found it worth the effort to ensure the accurate representation of the electric and hydraulic systems. Also, determining the benefits additional hydro generation and transmission have on MISO's wind resources is a complex task.

Ultimately, the benefits of hydro-wind synergy will be reflected in production cost savings, but separating the benefits of the synergy itself from the other benefits to the system is a challenge. The best methods to capture the benefits include examining the reduction in wind curtailment, visually inspecting the wind and hydro outputs and analyzing the correlation between wind and hydro. This provides some evidence that the total cost savings include hydro-wind synergy benefits.

1 Study Overview

The intermittent and non-peak nature of wind creates integration challenges within MISO. Conversely Manitoba Hydro has a large and very flexible system which has the potential to mitigate challenges with large amounts of wind generation. MISO undertook this study in order to determine if the cost of expanding the connection with Manitoba Hydro is justified by the benefits of greater Manitoba Hydro participation in the MISO market.

MISO currently has 12GW of wind online and 15GW of active wind projects in the queue. Manitoba Hydro is looking to expand its hydro system by 2,230MW over the next 15 years. Manitoba Hydro's current export capacity is limited to 1850MW which is insufficient to meet the needs of future wind generation in MISO. Thus, this study looks at expanding transmission capacity between MISO and Manitoba Hydro to facilitate the realization of these benefits.

This study was set in motion at the request of various stakeholders to address the above situation. MISO developed a four phase study to address these concerns and developed a cost benefit analysis for an expanded Manitoba Hydro-to-MISO interface.

1.1 Study Scope and Timeline

The entire Manitoba Hydro Wind Synergy Study ran from June 2011 until June 2013. The project consisted of four unique phases completed sequentially. The first phase consisted of collecting the data for the model, assembling information from Manitoba Hydro, developing concepts to evaluate the costs and benefits of the other stages of the project, and validating the simulation of Manitoba Hydro's system operation. The second phase looked at the existing system with additional market participation by Manitoba Hydro through the External Asynchronous Resource (EAR). The third phase looked at the value of expanding the transmission capacity between MISO and Manitoba Hydro along with additional hydro capacity in Manitoba Hydro in order to increase energy and compensate for wind variability and uncertainty. Phase four finished the project by doing sensitivity and risk assessment of the results of phase three. This ultimately led to a final recommendation.

Study timeline:

- Complete Phase 1 in March 2012
- Complete Phase 2 in June 2012
- Complete Phase 3 in January 2013
- Complete Phase 4 in June 2013

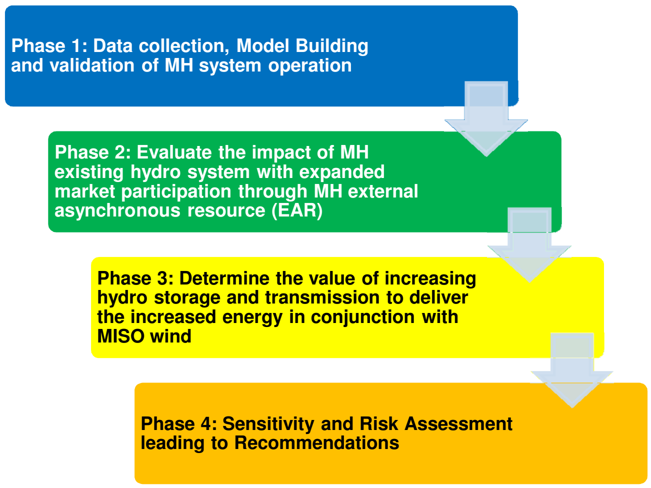


Figure 1.1: Four Phases of the Study

Because of the intricacies in modeling Manitoba Hydro's resources, its ability to efficiently respond to wind variability, and the ability to provide ancillary services, we chose to use PLEXOS as the primary simulation tool for this study. To fully develop the cost-benefit calculation we also determined it would be prudent to develop both Day Ahead (DA) and Real Time (RT) simulations. The RT simulation was necessary in order to model the effect of wind and load forecast uncertainty between DA and RT. In addition, wind generation can experience large variations within the hour. For this study to capture those variances, sub-hourly (5-minute) level dispatch was simulated.

MISO evaluated a variety of future scenarios to fully evaluate the best overall solution and to account for the effect of water supply on Manitoba Hydro's export and import activity. Three different hydrologic conditions along with appropriate MTEP future scenarios were used as sensitivities. A decision tree was constructed to determine what the best possible transmission expansion should be.

Over the course of nine meetings, a Technical Review Group (TRG) advised on study methodology, verified the models, designed the solutions and reviewed results. Manitoba Hydro worked closely with MISO staff to ensure its system has been modeled correctly.

2 Phase 1

The model that was used for this study was sourced from the MTEP11 production cost model. Additional information was added detailing Manitoba Hydro's generation and reserve resources. Detailed MISO reserve data was also included in this model.

2.1 Model Development

The model used for the Manitoba Hydro Wind Synergy Study includes the entire Eastern Interconnect except Florida, ISO-NE, and eastern Canada. The base model is the same as that used in PROMOD for MTEP11. The line limits, interfaces and contingencies were obtained from the MTEP11 PROMOD event file. Manitoba Hydro was simplified to six generation nodes and two transmission nodes with help from Manitoba Hydro staff.

Reserve products are modeled for both MISO and Manitoba Hydro with MISO products consisting of regulating, spinning and non-spinning reserves. Data was received from MISO operations concerning which generators provided reserves in the market.

The Phase 1 simulation is for the April 1, 2012, to March 31, 2013, time period.

Two of the hydro generators, Lower Nelson and Grand Rapids, are modeled in detail including generator characteristics with storage and waterway details. Compared with traditional thermal units, the hydro units operate differently, i.e. past a certain point the efficiency of the unit decreases as the amount of fuel used by the unit increases. This is because of turbine-generator characteristics and reductions in effective water head (the difference between water levels upstream and downstream of the dam) as more water is discharged through the station. If the hydro unit needs to release more water than the generator is able to handle, it will spill and will have an efficiency curve which has a negative slope.

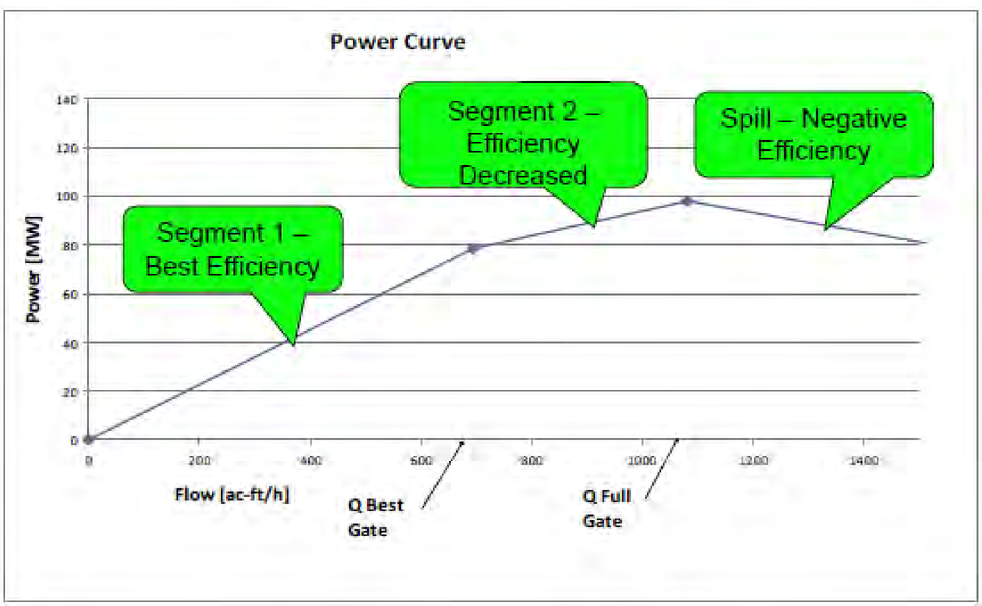


Figure 2.1: Power Curve of a Typical Hydro Unit

2.1.1 Initial Simulation Process

This type of simulation requires a multi-step process. The goal is to simulate the dynamics that exist in the market and determine the economic value that can be brought by expanded transmission capacity. Both the Day Ahead (DA) and Real Time (RT) markets are simulated. The simulation processes were as follows:

1) Manitoba Hydro provided detailed hydro system operating conditions and schedules, such as water conditions and monthly storage targets. Based on that information, a PLEXOS Mid-term (MT) simulation is performed to decompose the long-term storage targets into daily storage targets for the DA simulation.
2) The first pass of DA simulation is performed to generate hourly Locational Marginal Price (LMP) prices. This pass of DA simulation is comprised of two sequential parts: the Unit Commitment (UC) run and the Economic Dispatch (ED) run, both of which are hourly simulations.
3) The LMP prices for the Manitoba Hydro system are then sent to Manitoba Hydro staff in order to refine the water targets for the formal simulation. The refined water targets are then fed into the PLEXOS model.
4) The DA simulation is then conducted using forecasted wind and load (explained in section 2.2.1) to determine the unit commitment schedule, energy limited unit generation profiles, and DA LMPs/MCPs for energy/reserves. Both UC and ED runs are executed.
5) Based on the UC schedule and energy-limited unit generation profiles generated by the DA simulation, the RT simulation is conducted using actual wind and load profiles (explained in section 2.2.2) to obtain the unit dispatch schedules and LMPs/MCPs in the real-time market. Unlike the DA simulation, the RT simulation only considers the economic dispatch of committed resources every five minutes.

In both the DA and RT simulations, the co-optimization of energy and ancillary services markets is considered. The time step for DA simulation is one hour, while the time step of the RT simulation is five minutes.

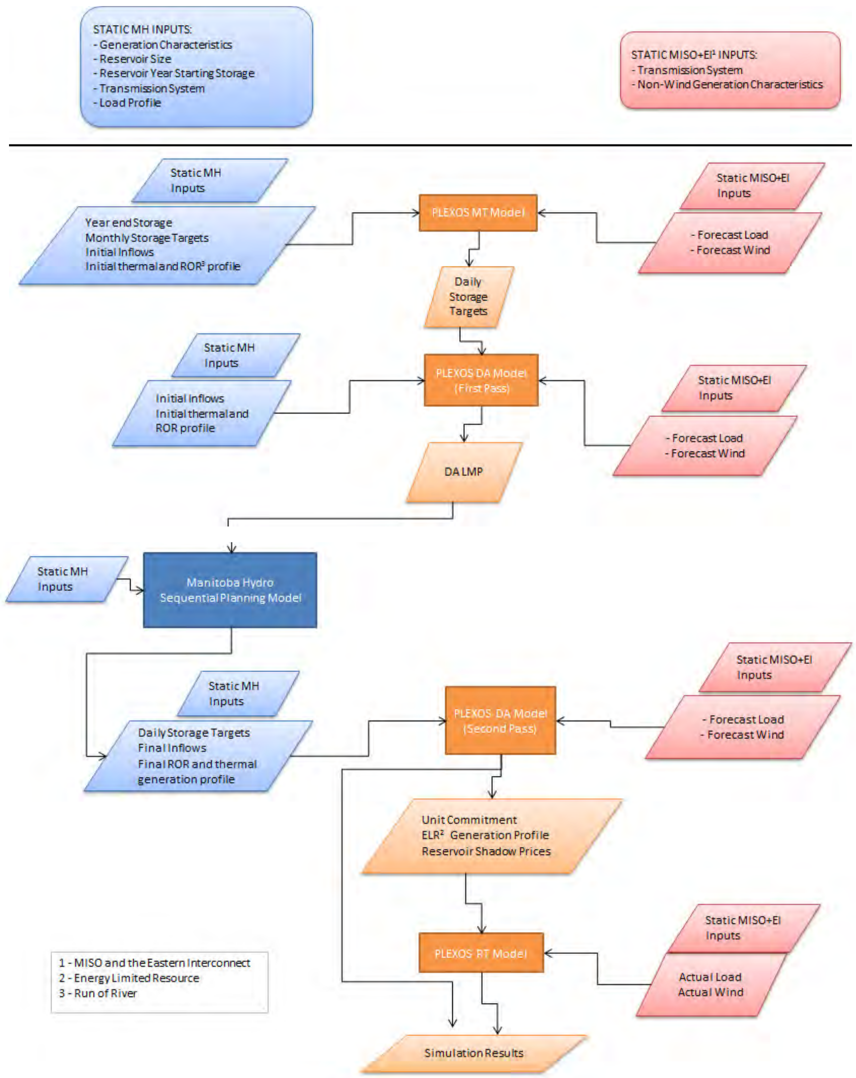


Figure 2.2: Initial DA and RT simulation process with detailed hydro modeling

2.2 Modeling Challenges

Several issues encountered during the Phase 1 analysis needed resolution before the Phase 2 implementation. The issues were:

- Create hourly and 5-minute wind and load profiles needed to simulate the divergence between the DA and RT simulations.
- Design and implement a RT bidding strategy for Manitoba Hydro in order to absorb these divergences.
- Balance the value gained by a short-term deviation with the opportunity cost of using stored water and foregoing future exports (or conversely reducing exports in the real time and storing water for future sales).

2.2.1 Hourly and 5-minute wind and load profile creation

MISO has historically used hourly wind and load profiles for production cost simulations, but because this study looks at both the hourly and the 5-minute levels along with the variances between them, we created new profiles to represent these factors.

Data for the creation of the new profiles was sourced from 2008-2011 MISO market data. The wind has a greater variance than the load and the DA has more variance than the intra-hour (Table 2.1).

	Wind Variance		Load Variance	
Statistics	DA	5 Min	DA	5 Min
Mean	13.08%	0.03%	0.35%	0.01%
Std Dev	39.89%	2.42%	1.89%	1.20%
Max	308.65%	108.93%	14.15%	56.48%
Min	-96.50%	-46.40%	-17.03%	-38.54%

Table 2.1: Wind and Load Variation Statistics

The data is used in a two-step process to transform the initial forecasted load into RT actual load. The data given above is converted into a 50-point array for both the DA and RT variances that are then applied to the forecasted values. The DA variance is first applied to the forecasted load on the hourly level to get the new RT hourly profiles (Figure 2.3).

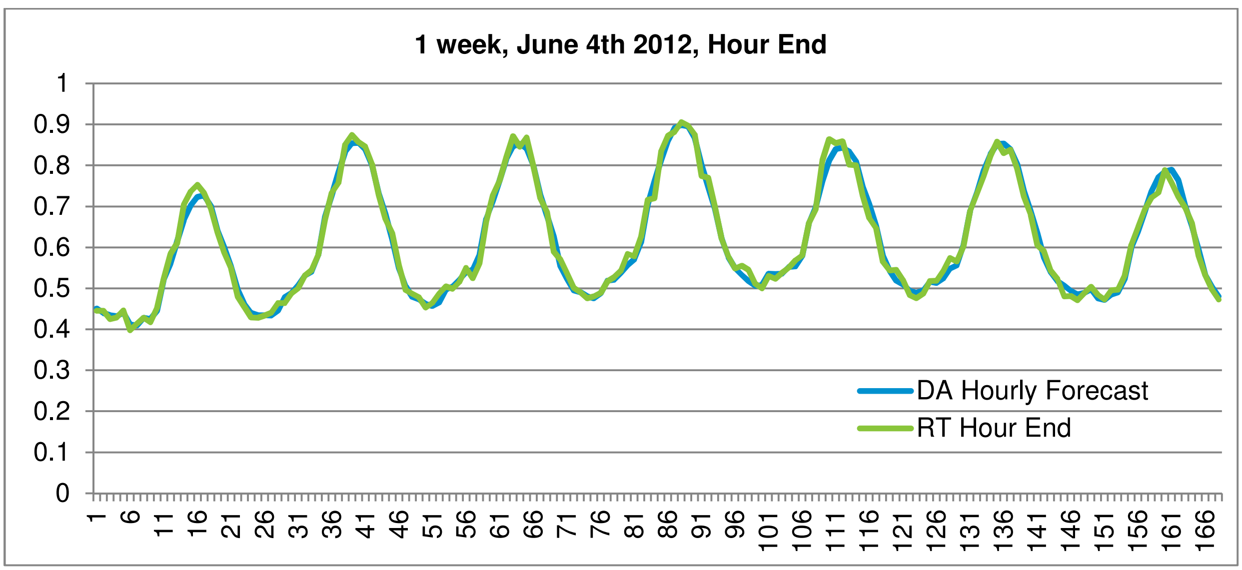


Figure 2.3: Hourly DA and Forecasted Hourly RT Load Profiles

The second step is to apply the intra-hour variances by interpolating the new RT hourly profiles into 5-minute profiles and applying the 5-minute variances to those new values. The new profile is now considered the actual profile that will be used in the RT simulation (Figure 2.4).

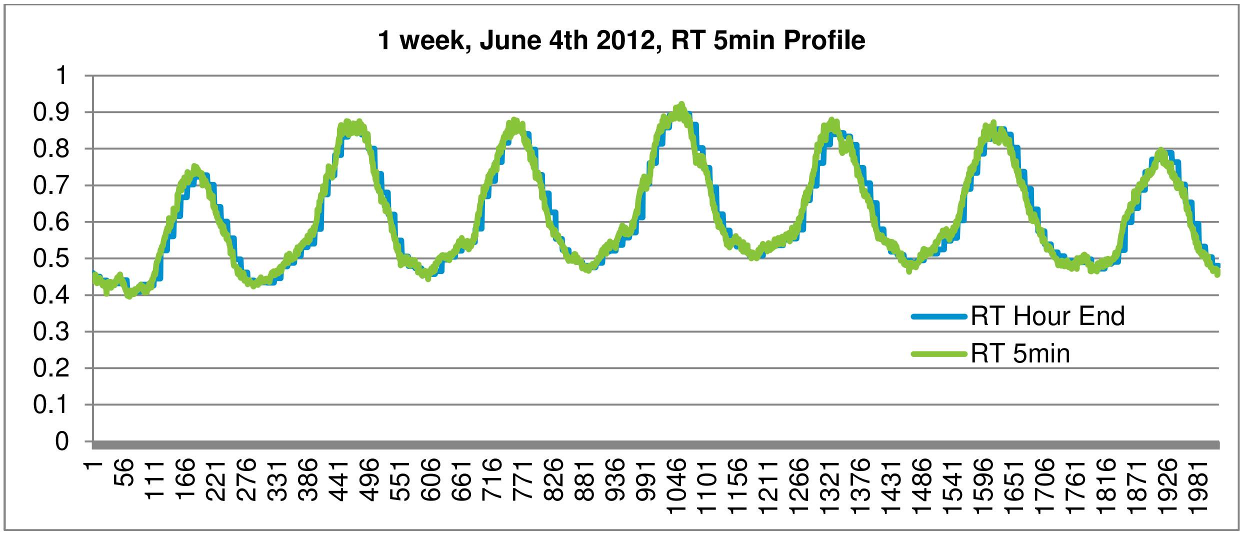


Figure 2.4: Forecasted Hourly and 5 Minute RT Load Profiles

The same two-step process is used for the forecasted wind profiles, as well. Both the first and second steps are combined to show the differences between the application of the wind variances verses that of the load variances (Figure 2.5).

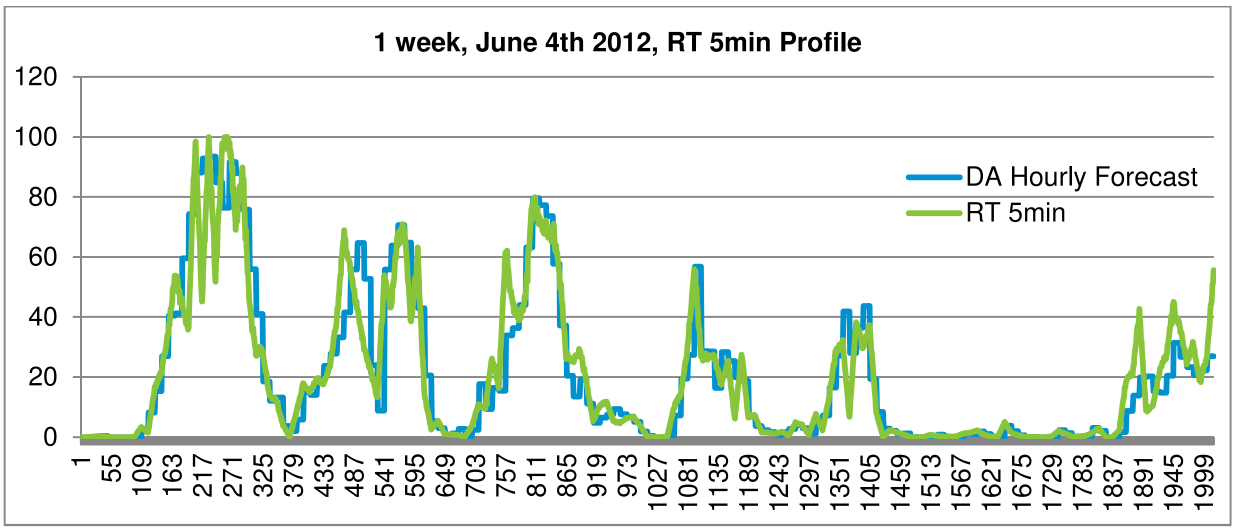


Figure 2.5: Hourly DA and Forecasted 5 Minute RT Wind Profiles

2.2.2 Real Time Hydro Dispatch

In the DA market, the simulation engine determines the best use of energy limited resources, but in the RT market the simulation engine only has access to the current state of the system and is unable to know if a unit should generate or wait for better opportunities. Because of this, information is needed to be passed from the DA simulation to the RT simulation, but while the DA simulation optimizes the hourly system operations using forecasted wind and load profiles, the RT simulation looks at the 5-minute level that has actual wind and load information in it. This implies the simulation needs to be flexible in order to trade the long-term value gained by following the DA information and the short-term value of compensating for the fluctuations between the DA and RT markets.

Three different methods were tested to find the best way to accomplish this tradeoff. The first is to only use the information provided by the DA simulation and strictly follow the DA dispatch schedule. This method is the least realistic as wind/load forecast errors and increased detail within each hour changes the system conditions and renders the DA dispatch schedule less optimal. The second method is to generate based on the DA hourly prices. This method works well because the generator can weigh the value of participating in RT with the future loss of market participation. The generator offers to change its scheduled generation using tiered offers based on the prices in the DA, as illustrated in Figure 2.6. The offer bands are offset to balance the dynamic RT market participation with the long-term value of the resource

When submitting the RT bids, the DA prices and dispatch schedules are used as the base, which means if the RT prices are exactly the same as the DA prices, hydro units will follow the DA dispatch schedule exactly. Besides the base of RT bids, hydro units also submit tiered offers, which mean multiple offers are submitted at each hour, each with a different offer price and quantity. For example, there are eight offers at each hour, with offer prices ranging from 0.6*DA to 2*DA (Figure 2.6). Higher quantities of energy are associated with higher-offer prices. For example, the offer quantities are 0 MWh at the 0.6*DA price, DA dispatch value at the 1*DA price, and the 10*DA dispatch value at the 2*DA price. As a result of the tiered offer, the RT simulation will dispatch less energy than DA schedule when the RT price is lower than the 0.9*DA price and dispatch more energy than DA schedule when RT price is higher than the 1.3*DA price. Note that the gap between the 0.9*DA and 1.3*DA prices is a dead band, meaning the RT schedule will be the same as the DA schedule when the RT price is within that range. The gap considers the uncertainty in RT prices, inefficient operation of hydro units, and more. This makes sure the RT dispatch does not overreact to small divergence between DA price and RT price.

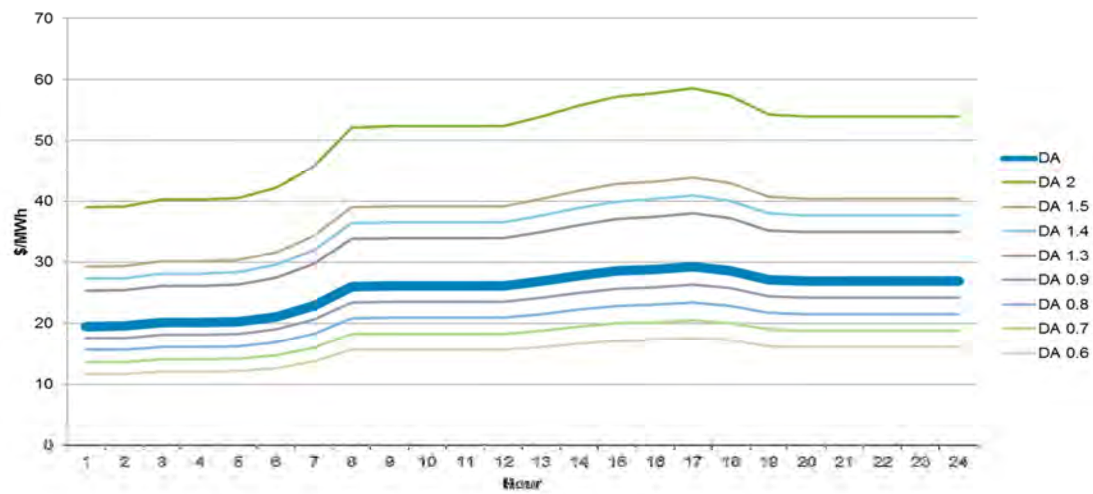


Figure 2.6: Tiered Offers based on DA Prices

Figure 2.7 shows how changing generation in RT can impact the price. As the price increases, the hydro generators offer in more generation to take advantage of the situation, thus tempering the price increase. The same effect happens as prices fall.

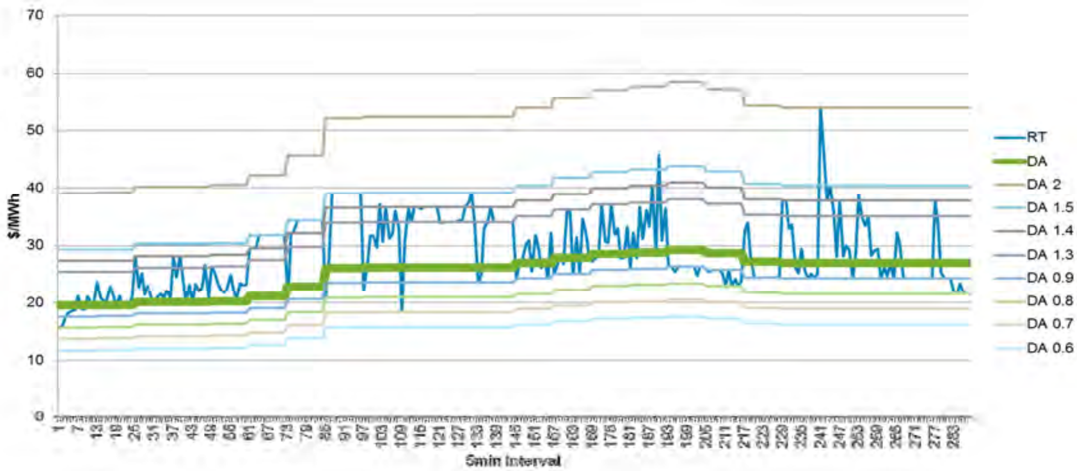


Figure 2.7: RT Prices vs. Tiered Offers

The third method is to use the same strategy as method two, but only track the lowest export price from the DA market. The term "lowest export price" is defined as the lowest DA price when Manitoba Hydro is exporting to MISO. So instead of submitting tiered offers based on hourly DA prices, hydro units submit the same set of offers for 24 hours based on lowest export price. This method represents the buy-sell decision that Manitoba Hydro makes when participating in the real-time market as an organization and not simply as individual generators.

Figure 2.8 shows how the lowest export price used in the RT simulation is set for a day that is predominantly exporting. In this example, Manitoba Hydro is exporting from hour 4 to hour 24. The lowest export price is determined as the DA price at hour 4.

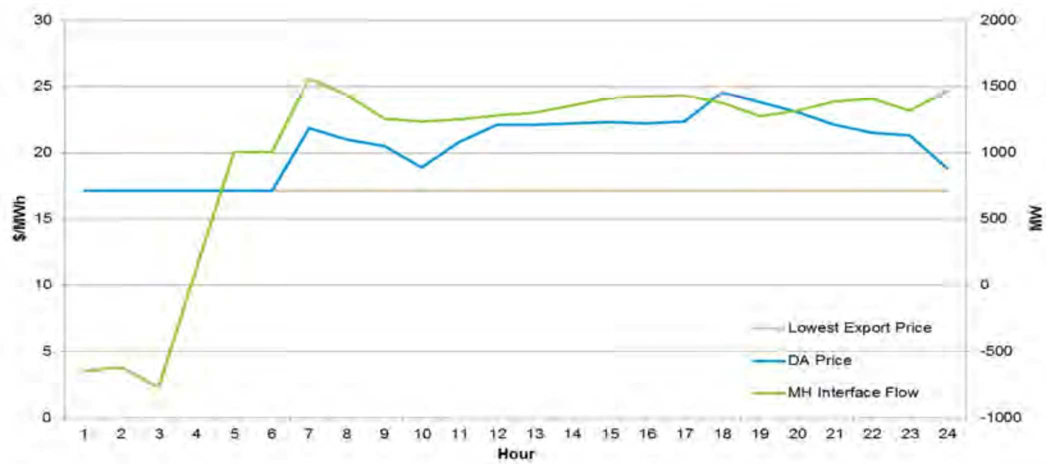


Figure 2.8: Obtaining the Lowest Export Price in an Exporting Day

Figure 2.9 shows how the lowest export price used in the RT simulation is set for a day that is predominantly importing. Manitoba Hydro is exporting at hours 14 to 20 and hours 22 to 23. The lowest export is determined as the DA price at hour 19.

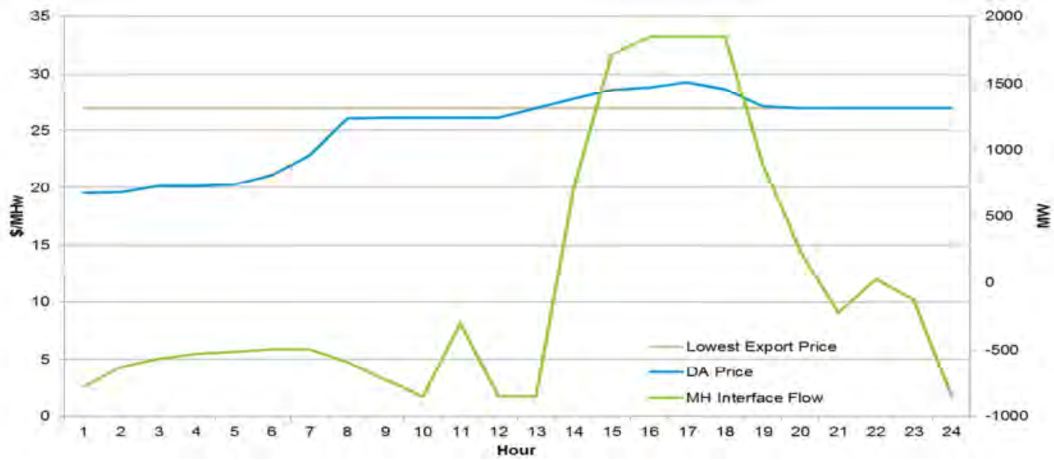


Figure 2.9: Obtaining the Lowest Export Price in an Importing Day

2.2.3 Water Target Deviations in RT

Allowing energy limited resources to change energy usage in RT presents the problem of a possible over or under allocation of energy in the long run. This problem is dealt with using a combination of calibration and after-the-fact accounting.

When using the three RT dispatch methods previously discussed, the RT simulation is able to get most of the information it needs to automatically adjust for any tradeoffs. Calibration is done to account for the average price differences between RT and DA.

After the RT simulation is completed, the differences from the forecasted to actual ending storage values are calculated and the value of the difference is combined with the total cost in order to put all of the different scenarios on a level playing field. The unit value of water in storage is determined using the average MISO production cost, i.e. Total MISO Production Cost divided by Total MISO Generation. At the end of the year, the ending storage value is compared with the water target. Adjustment is made to capture the economic gain/loss when ending storage value is higher/lower than the water target. The yearend water value adjustment is calculated by (Water Target – Ending Value) x production per acre-ft x MISO average production cost.

2.3 Phase 1 Results

The main purpose of Phase 1 was to build a complete model and test the different methodologies to be used for the next phases of the project. The positive results from Phase 1 were encouraging. The results shown here were not unexpected: Manitoba Hydro's increased participation in the MISO market benefits both Manitoba Hydro and MISO. As explained in Phase 2, the simulation method was improved for later phases of the study.

2.3.1 Results - Graphs

Figure 2.10 shows the MISO production cost over the three-month period of April 1, 2012, to June 31, 2012. In this case, method 2 is the least cost, but both methods 2 and 3 have savings over method 1, which means Manitoba Hydro's active participation in the RT market will benefit the MISO system. The total production cost decreases by about $5 million between no RT participation (method 1) and full RT participation (method 2).

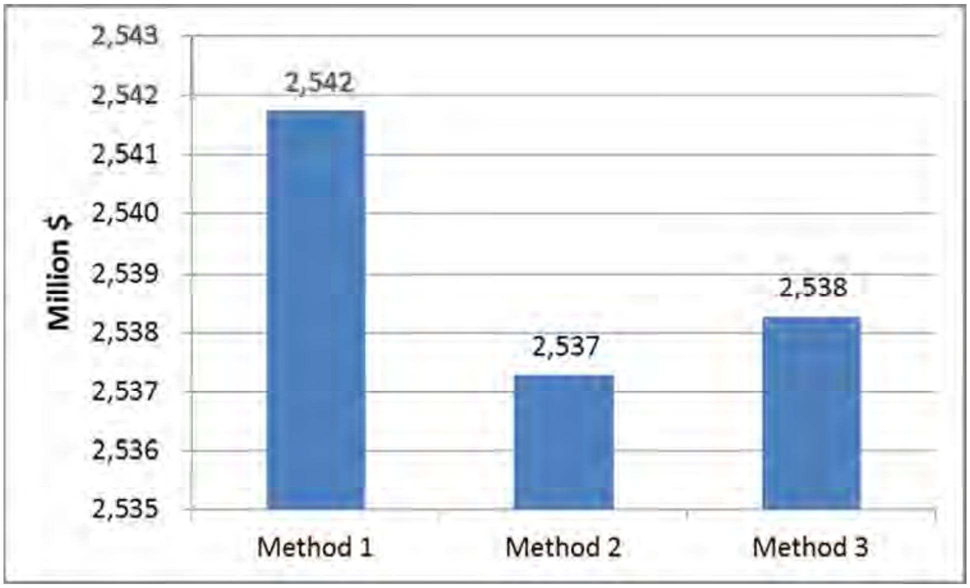


Figure 2.10: Total RT Production Costs Calculated by the Three Methods

Figure 2.11 shows the MISO load cost over the three-month period of April 1, 2012, to June 31, 2012. In this case method 3 is the least cost, but both 2 and 3 have savings over method 1. By comparing method 3 with method 1, the total MISO load cost reduction is about $30 million over the three month period when Manitoba Hydro actively participates in the RT market.

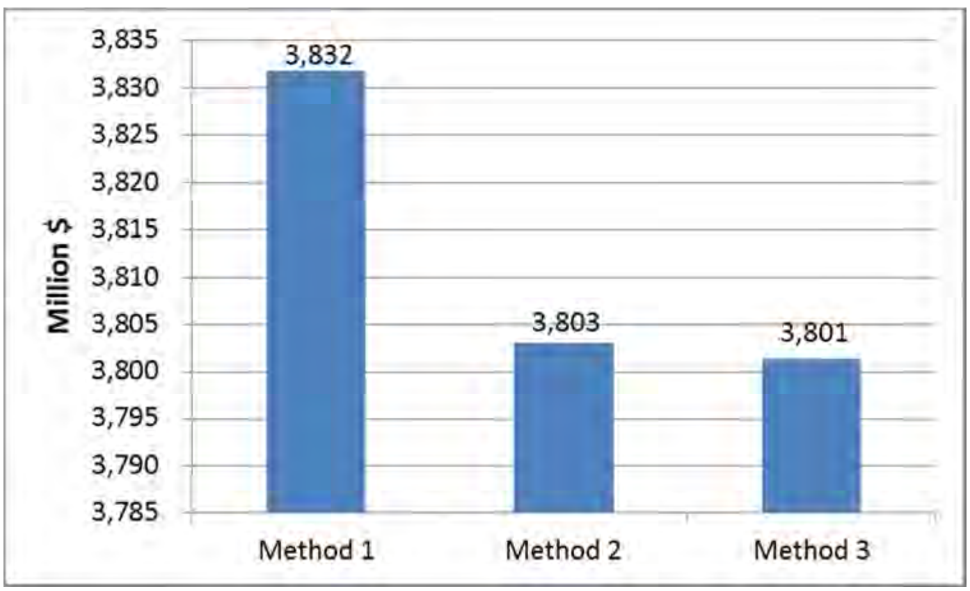


Figure 2.11: Total RT Load Costs Calculated by the Three Methods

Figure 2.12 shows the MISO reserve market cost over the three-month period of April 1, 2012, to June 31, 2012. In this case, method 2 is the least cost, but both 2 and 3 have savings over 1.

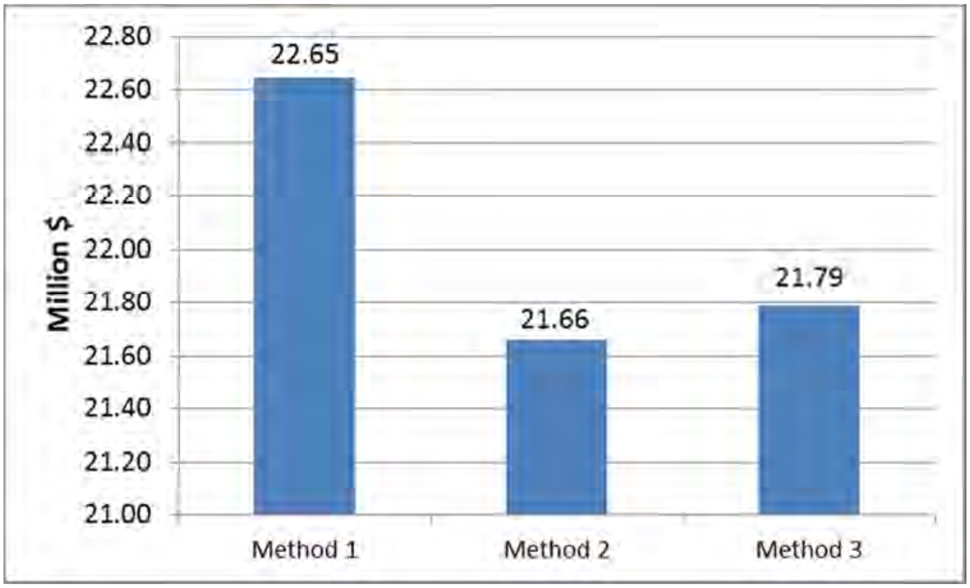


Figure 2.12: Total RT Reserve Market Costs Calculated by the Three Methods

2.3.2 Findings

As can be seen from the graphs and other results, both Manitoba Hydro and MISO benefit from dynamic real time Manitoba Hydro market participation. These benefits include, but are not limited to, production cost savings, load cost savings, reserve cost savings and wind energy curtailment reductions.

Methods 2 and 3 are constructed similarly and provide a similar outcome, but because method 3 matches more closely with real-world market participation it was used for the next phases of the study.

Phase 1 of the Manitoba Hydro Wind Synergy study ended successfully. In this study, the project team modeled Manitoba Hydro system in great detail. The major achievements of the Phase 1 study were:

- **Modeled the complex structure of the Manitoba Hydro water storage system**
- **Simulated the day-ahead practices of the MISO energy and ancillary services markets with Manitoba Hydro participation**
- **Designed and implemented three methods to model Manitoba Hydro's participation in the real-time market**

In evaluating the simulation model and results, MISO and Manitoba Hydro agreed that the model assumptions and outputs are reasonable. Both organizations suggested some model refinements, which were implemented in the next phase.

3 Phase 2

The primary purpose of Phase 2 was to evaluate the value of expanding Manitoba Hydro's real-time market participation through the External Asynchronous Resource (EAR) product. In order to fully test this, new modeling innovations were developed to account for the complex interaction between the Manitoba Hydro's hydro generation and activity in the MISO market from other participants throughout the Eastern Interconnection.

3.1 Model Improvements

3.1.1 Reasons for Improvements

Three major modeling challenges existed while pursuing the goal of modeling an EAR in PLEXOS. First, the EAR is a market product that enables Manitoba Hydro to submit price sensitive offers and bids into the Real Time (RT) market and thus needed a detailed RT simulation. In Phase 1, the Day Ahead (DA) and RT markets were conducted separately with information from the DA only passed to the RT at the end of the full simulation period (in the case of Phase 1, a 3-month period). This process, however, ignored the real-world effects that the RT market has on the next day's DA market because it didn't account for deviations in the RT market on the bid prices for the next day and, therefore, could not predict how much fuel (i.e. storage) on the Manitoba Hydro system would be available in the next day.

The second challenge was to consider the opportunity cost of water in storage in the simulation. Water is a limited resource and once used, more water cannot be obtained for a period of time. This is in contrast to how thermal generators are modeled. Most large-scale electric system simulation assumes thermal units have an infinite amount of fuel at a given marginal cost. This is a valid assumption because most fuel can be obtained at the marginal cost of extracting and transporting it to the generator, and the generator will not use more fuel when the selling price is less than the cost to produce and deliver the fuel. Hydro units, on the other hand, have a marginal cost of zero because they are designed to take water as it comes and not pay for extraction and transportation. This leads to a situation in which the generator is limited to the amount of water flowing into the unit. Although the marginal cost of the water is free, the generator wants to maximize its profit by using the water when the price is the highest; likewise, the system cost is minimized when water is only used when the system needs it most. In order to accomplish this behavior, the simulation needs to determine the best time to use the water based on many variables and constraints that are both inside the simulation day and outside it.

The final challenge was to develop a method to model the current and expanded EAR. The current EAR product allows EAR participants to sell energy through the EAR in the RT market, but not buy. These participants have the option of buying and selling energy outside the EAR, but not with any price certainty. A method needed to be developed to capture this dichotomy in the simulation software.

3.1.2 Interleave Method

In the day-ahead market, energy and ancillary services products are cleared based on forecasted wind outputs/demand levels and generator maintenance schedules. In the 5-minute real-time market, the generator dispatch might be different due to wind/demand forecast errors, wind/demand intra-hour fluctuations, generation/transmission forced outages, generation bid changes, or other factors.

Most long-term production cost simulation tools replicate the hourly operations of the system (DA market) for the whole simulation timeframe without considering the interactions between the hourly simulation and sub-hourly simulation (if that function is available). In the real system, however, it is important for generation companies to evaluate the RT settlement results from the previous day in order to prepare the next DA bids. This need is especially critical for energy limited resources as the DA/RT dispatch difference will change the available energy for those units. The price and volume of bids and offers to the DA market is a function of the storage available, which is impacted by the prior day's RT dispatch. A DA-only or RT-only simulation model cannot adequately represent energy limited resources.

In Phase 2 of this study, a simulation called the Interleave method was developed and implemented. To the best of our knowledge, it is the first time that this approach has been proposed and applied on a large electric system. The simulation process of the Interleave method is demonstrated in

Figure 3.1. Both the long-term DA market simulation and RT market simulation are broken into daily simulation problems. After each daily DA simulation, the unit commitment and economic dispatch decisions are passed to the hydro storage model and the RT problem. Based on DA results, the hydro storage model adjusts hydro units' bids in the RT problem. Then the RT problem conducts a 5-minute simulation for the same day. After the RT problem is finished, the hydro storage model is updated again using the RT economic dispatch results. This process is repeated throughout the simulation horizon.

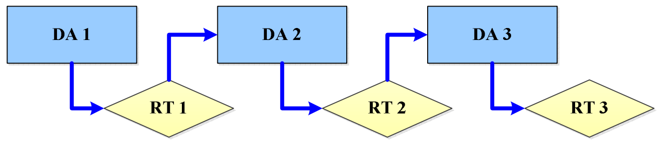


Figure 3.1: DA/RT interleave method

3.1.3 Value of Water in Storage Curve

Given the challenges faced when modeling limited energy resources, a more holistic method was required to model added complexities of hydro generation market participation. To get a complete picture of the economic value created by the usage of water, the model needs to look at multiple short- and long-term value streams. The usage of water resource needs to consider the trade-off between the short-term value of water, which means the economic benefits gained by selling energy now, as well as the long-term value of water, which means potential benefits of selling energy in the future. In the DA market, the value of water in the storage reservoir determines hydro energy's offer curve. In the RT market, the hydro units can deviate from the DA schedule if there is the economic incentive, such as higher Locational Marginal Price (LMP), which may result in more generation than the DA schedule, and conversely if RT prices are low, hydro generation may deviate below the DA schedule. However, if the hydro unit always generates more in RT than in DA, the reservoir will be prematurely drained of water, which prevents it from generating and getting paid if there are higher LMPs in the future. In order to balance the value gained by a short-term deviation with the long-term loss of water, it is critical to appropriately value the water in the storage.

When there is limited water in the storage reservoir, the value of water is high because Manitoba Hydro needs to save enough water to supply Manitoba Hydro's own demand. Consequently, Manitoba Hydro will bid in MISO's market more conservatively, such as by submitting high-priced offers in the market. When there is abundant water in the storage reservoir, the value of water drops, so Manitoba Hydro will submit low-priced offers to MISO's market. When the storage reservoir is full, the value of water drops to zero because the dam needs to spill excess water; this sends water downstream without generating any electric energy. In order to represent the relationship between water storage volume and water value, a value of water in storage (VWS) curve is derived from the projected value of long-term water storage throughout a year (Figure 3.2).

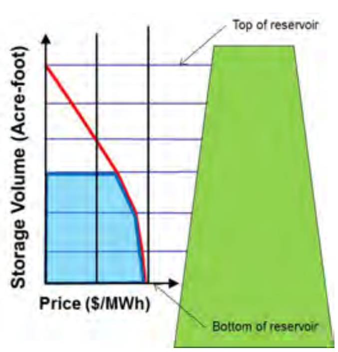


Figure 3.2: A typical VWS curve

The VWS curve is derived using an initial LMP forecast for the simulation period and determining the value of water for various points in time at different reservoir levels (Figure 3.3). Multiple simulations are conducted using different starting volumes for the different reservoirs in the system and different inflow scenarios to determine how the water's value changes at specified energy storage increments. The curves are then averaged for each reservoir from the different starting points to create the VWS curve. This process is shown in Figure 3.3.

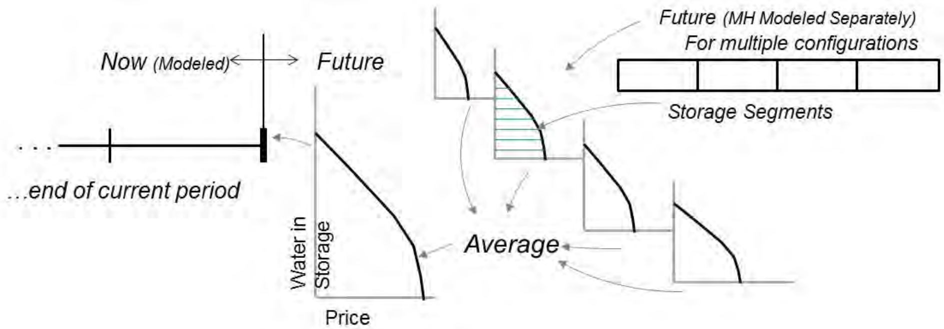


Figure 3.3: Construction of a VWS Curve

Based on the corresponding storage reservoir volume, this curve is then used to create the daily price for water with which Manitoba Hydro uses to price its offers and bids in the DA and RT markets.

3.2 EAR Modeling

3.2.1 Manitoba Hydro Real Time Operation

Under the current market structure only real time *offers can be submitted using the* External Asynchronous Resource (EAR) and the existing structure cannot be used to buy from the RT market. The EAR participant may submit an e-tag if the participant wants to buy or sell energy outside the EAR. This process doesn't allow for any certainty in price because e-tags act as fixed interchange schedule changes and are, thus, price takers. Also, the MISO market software cannot optimize the interface if a participant submits a fixed schedule instead of a set of bids and offers.

3.2.2 Current EAR

Manitoba Hydro's RT decision on whether to use the EAR or an e-tag is a complex trade-off made by Manitoba Hydro traders every day. For this study the process is simplified by creating a twenty percent additional offset for buy decisions (Figure 3.4). The offers and bids are submitted to the RT market in the same fashion as outlined in Phase 1, but the dead-band is biased in the buy direction to represent the increased uncertainty Manitoba Hydro faces when buying energy in the RT market.

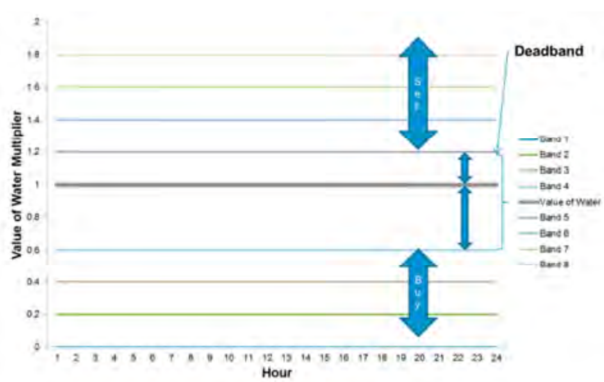


Figure 3.4: Model of Current EAR

3.2.3 Expanded EAR

An expanded EAR means the participant is allowed to submit both bids and offers to the RT MISO market engine. They will then be dispatched only if the bid or offer clears, which provides certainty on minimum sell price or maximum buy price for the party offering or bidding the EAR resource. The expanded EAR is represented in the model by symmetrical bids and offers separated by a dead-band to reduce swings in generation with small added value (Figure 3.5).

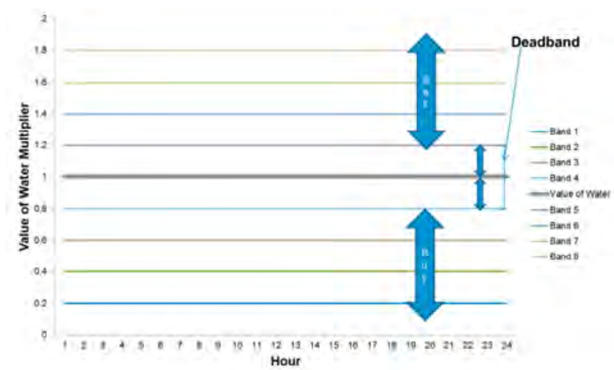


Figure 3.5: Model of Expanded EAR

3.3 Simulation Process

3.3.1 Simulation Process Overview (Revised for Phase 2)

The proposed simulation process is comprised of sequential steps mixed with an iterative market mechanism to simulate the operations of a hydro storage system (Figure 3.6).

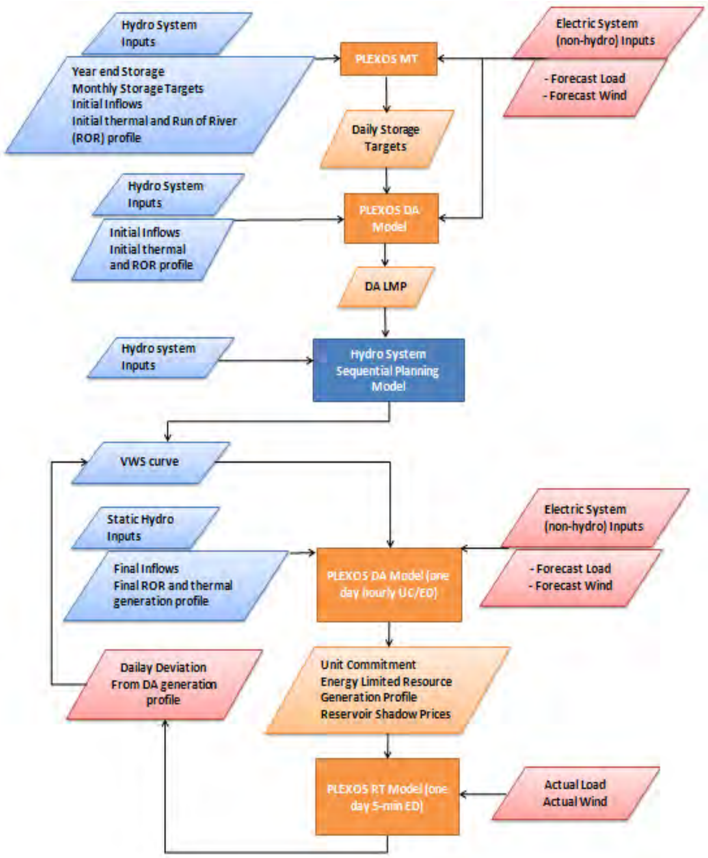


Figure 3.6: Revised DA and RT Interleaved simulation process with detailed hydro modeling

This process is the same as the process shown in section 2.1.1 with the addition of modeling Manitoba Hydro's hydro units using a VWS curve instead of storage targets and conducting the simulation using the interleave method instead of two semi-independent simulations.

3.4 Phase 2 Results

3.4.1 Results – Graphs

The benefits of an expanded EAR product consist of production cost savings, reserve cost savings, wind curtailment reduction and others that are not accounted for in this analysis. The study calculated benefits by taking the difference of the current EAR model and the expanded EAR model. Production cost savings are $8.74 million for the planning year 2012 for MISO (Figure 3.8). Most of the benefits occur during the shoulder months when Manitoba Hydro has the most flexibility to conduct energy arbitrage. Some of the months show negative benefits, but these are mostly due to the time shifting of when water is used.

Figure 3.8: MISO Production Cost Savings $Million

MISO receives a much smaller, but still significant, amount of reserve cost savings by moving to an expanded EAR. Total reserve cost savings are $100,000 for the planning year 2012 (Figure 3.9).

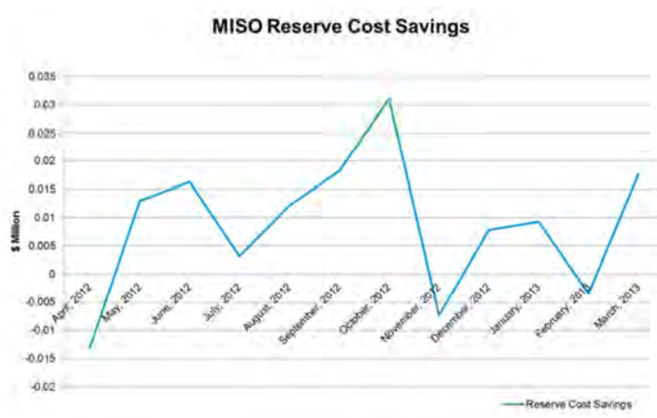


Figure 3.9: MISO Reserve Cost Savings $Million

Lastly, wind generation curtailment in MISO was reduced by 21 GWh, which represents 0.05% of the potential wind generation in MISO.

3.4.2 Findings

Expanding the EAR allows Manitoba Hydro increased flexibility to shift its energy usage around, buy in the real-time market with more certainty and store the water for future use. These changes benefit both Manitoba Hydro, which receives increased generation revenue, and MISO, which receives lower overall costs. By submitting both bids and offers in the real-time market through the expanded EAR, Manitoba Hydro can compensate for unforeseen changes in wind and load. Overall the benefits of an expanded EAR product outweigh the relatively small cost needed to implement this change in the market.

4 Phase 3

The primary purpose of Phase 3 is to evaluate the costs and benefits of adding additional transmission between MISO and Manitoba Hydro. Three transmission options were studied along with hydro expansion in Manitoba. A wide variety of benefit metrics were analyzed.

4.1 Model Development 2027

The MTEP12 2027 Business as Usual (BAU) future was used for Phase 3 of the Manitoba Hydro Wind Synergy Study. Additional detailed data provided by Manitoba Hydro was included in the model.

4.1.1 MTEP12 2027 Business as Usual Model

The MTEP12 2027 Business as Usual model uses Ventyx's 2012 annual PowerBase release with MISO-specific data updates. These updates include MISO and external queued generation updates, demand and energy updates, commercial model updates, unit retirement and maintenance schedules, fuel price and escalation updates along with the event file with includes updated transmission ratings, contingencies and interface definitions. These values were approved by the MISO Planning Advisory Committee (PAC) and used to forecast the resources needed to meet MISO's reliability criteria as well as inputs into this study.

Assumptions from the 2027 Base Model include:

- Base Gas Price - $4.25/MMBtu in 2012
- MISO Effective Demand Growth Rate – 0.67%
- MISO Effective Energy Growth Rate – 1.12%
- Manitoba Hydro Effective Demand Growth Rate – 1.02%
- Manitoba Hydro Effective Energy Growth Rate – 1.39%
- 12.6 GW Coal retirements in MISO
- 27.1 GW of installed wind capacity in MISO
- MVPs are included

The resource mix in 2027 still includes a large amount of coal, but 12.6 GW were retired between 2012 and 2027. This was replaced with gas fired units, wind and demand response (Figure 4.1).

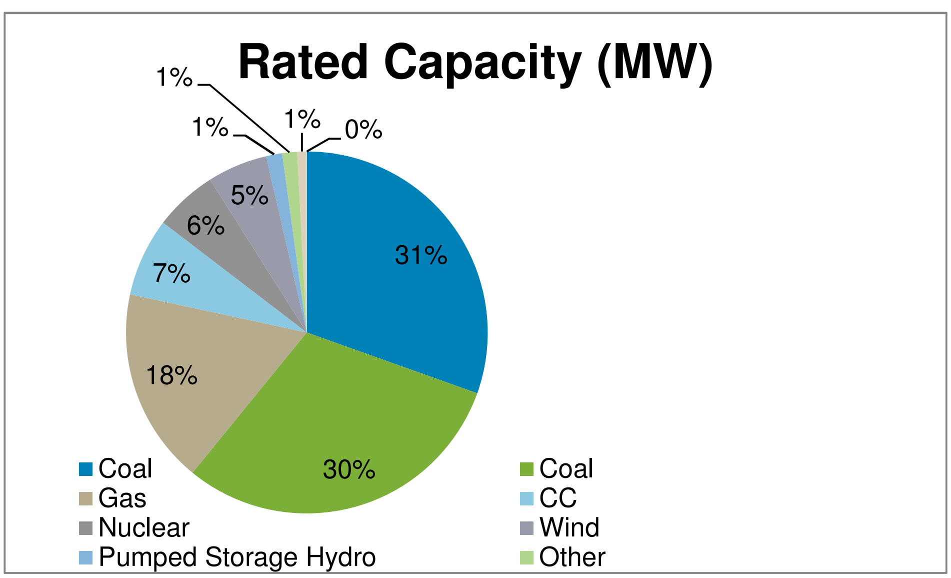


Figure 4.1: 2027 MISO Resource Mix

Large additions of gas fired power plants and demand response was added in the Business as Usual future (Figure 4.2). Renewables were added to meet all renewable portfolio standards which are currently in effect in the respective states.

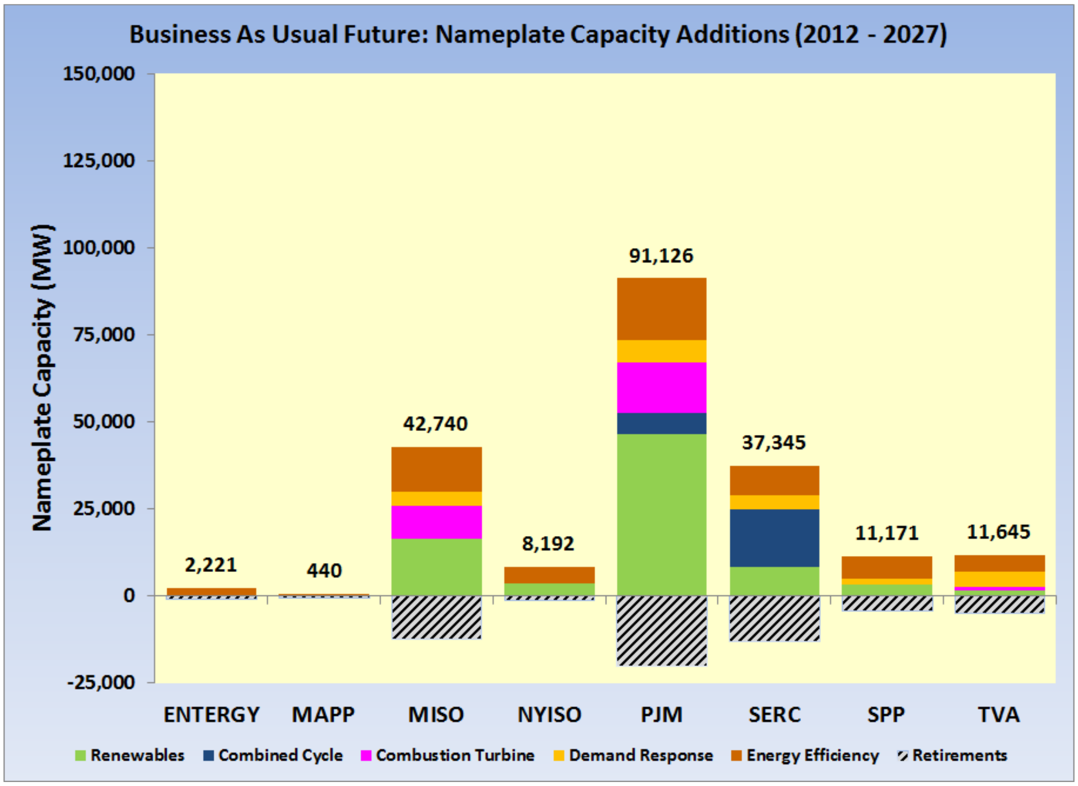


Figure 4.2: BAU Nameplate Capacity Additions

Generation was sited using a detailed process which includes mapping software (MAPINFO) and a set of practical guidelines to determine the locations of all resources (Figure 4.3). The siting and generation in this study is the exact same as used in other MISO studies such as the Market Efficiency Planning Study (MEPS) with the exception of additional details added to the Manitoba Hydro region. All base assumptions and generation siting was approved by the MISO Planning Advisory Committee prior to implementation in this study.

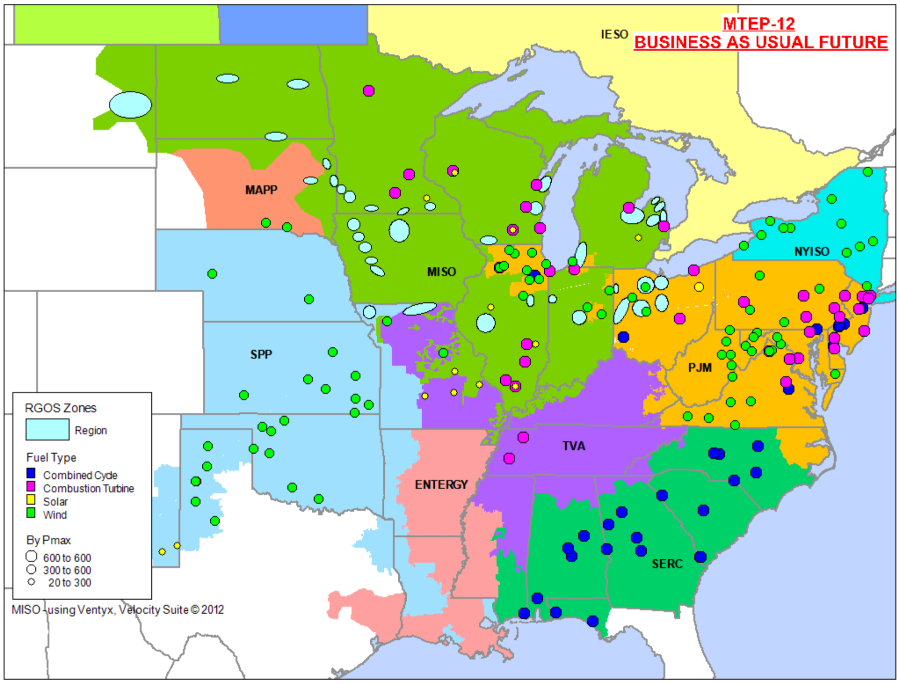


Figure 4.3: 2027 Capacity Expansion

4.1.2 2027 Changes to the Base Model

By default all hydro generators are modeled as energy limited units since limited data is available about the actual operations of these units. For the Manitoba Hydro Wind Synergy Study additional detail was provided by Manitoba Hydro about its generation fleet. These hydro generators were changed to either fixed run of river, or detailed dispatchable hydro. For Phase 3, two dispatchable hydro units and thirteen run of rivers units were modeled. The dispatchable units consist of Grand Rapids and an aggregation of three stations (Kettle, Limestone and Longspruce) on the lower Nelson River, which will simply be referred to as the Lower Nelson unit. Manitoba Hydro provided water condition assumptions for all units and used internal software to pre-schedule the run of river units. Manitoba Hydro also included updated thermal unit parameters.

4.2 Manitoba Hydro Generation Expansion

Two additional hydro units are being studied by Manitoba Hydro for construction: Keeyask (695 MW) and Conawapa (1495 MW). Conawapa was included in the base case for Phase 3 and Keeyask was included in the change case. This arrangement was changed during Phase 4 and the benefits described in Phase 3 are not directly comparable to those in Phase 4. As explained in section 5.1.1, Keeyask as the base case with no line constructed is certainly a plausible scenario because Keeyask is earlier in the generation sequence than Conawapa and there is more momentum behind this project in terms of the planning and development activities. Following the completion of Phase 3 it was also identified that having Conawapa excluded from the no new-line scenario will better measure the flexibility/synergy benefits of additional hydraulic generation on the Manitoba Hydro system – which is the objective of this study.

4.2.1 Manitoba Hydro System

The Manitoba Hydro system is expected to expand both its transmission and generation fleet by 2027 (Figure 4.4). A new HVDC line named Bi-Pole 3, along with one or two new hydro generators will be added. The new hydro capacity will be placed on the Lower Nelson River on the north end of the HVDC line. This placement will allow Manitoba Hydro to bid the generators into the MISO market through the

External Asynchronous Resource (EAR) product and the new HVDC line will allow Manitoba Hydro to serve its load and deliver energy to MISO. In the Phase 3 base case, only Conawapa and not Keeyask will be added to the Manitoba Hydro system since it won't have the transmission capacity to export the total combined energy to MISO. If a 500 kV transmission line is constructed between Manitoba Hydro and MISO, the capacity will exist to export the entire amount of excess generator into MISO.

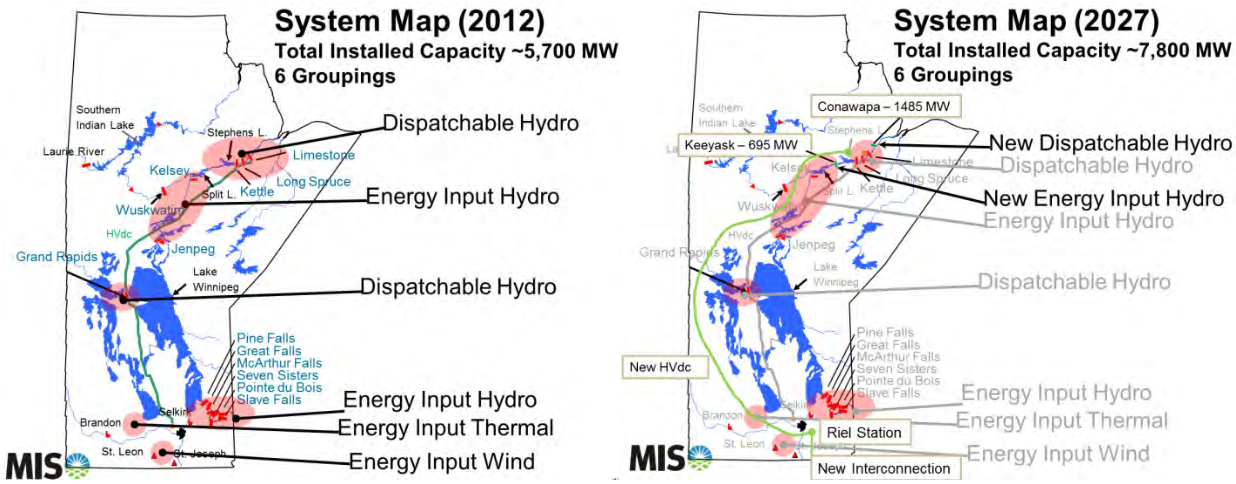


Figure 4.4: 2012 and 2027 Manitoba Hydro System Map

4.3 Transmission Plan Options

Three distinct transmission plans were proposed for analysis during Phase 3. All three options are designed to deliver the additional hydro generation in Manitoba Hydro into MISO.

4.3.1 Option 1 – East Option

The East option consists of a 500 kV line from Winnipeg, Manitoba, to Grand Rapids, Minn., along with a double circuit 345 kV line from Grand Rapids to Duluth, Minn. (Figure 4.5).

Figure 4.5: Option 1 East

4.3.2 Option 2 – West Option

The West option consists of a 500kV line from Winnipeg, Manitoba, to Barnesville, Minn., which represents a line into the Fargo, N.D., or Moorhead, Minn., area since an exact site has not been determined. A single circuit 345 kV was added to the existing single circuit 345 kV line between Fargo and Monticello, Minn. (Figure 4.6).

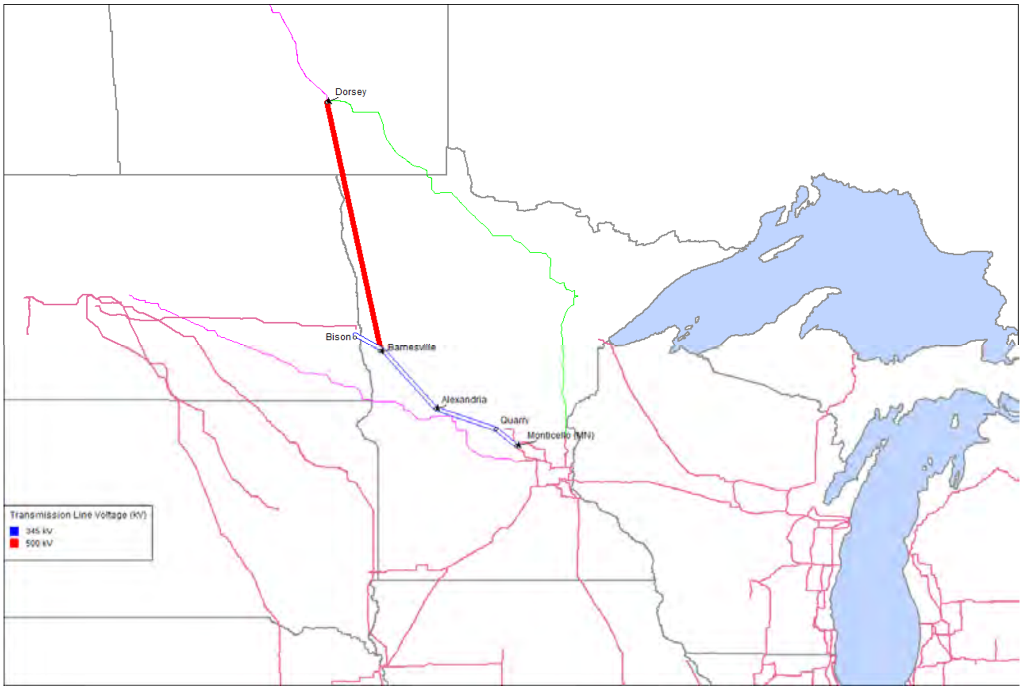


Figure 4.6: Option 2 West

4.3.3 Option 3 – Central Option

The Central option was designed to be a combination of the East and West options. It consists of a 500kV line to a central Minnesota location and then branching out with a 500 kV line to Grand Rapids and a double circuit 345 kV lines to Fargo. A double circuit 345 kV line was also included from Grand Rapids to Duluth (Figure 4.7).

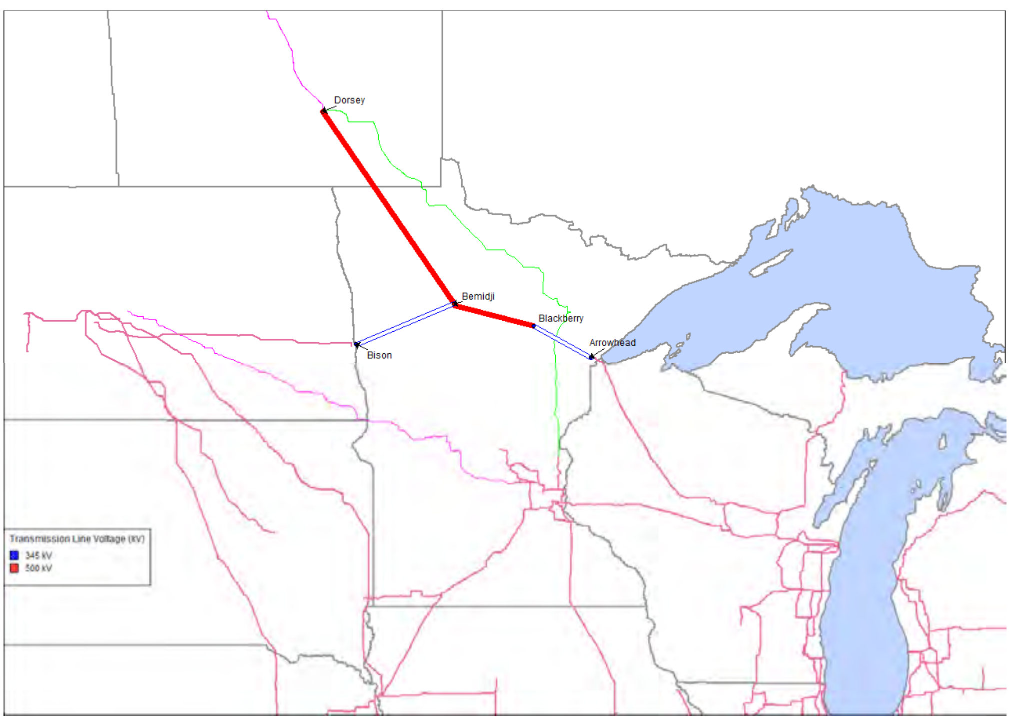


Figure 4.7: Option 3 Central

4.3.4 Transmission Construction Costs

The estimated construction costs for Phase 3 are shown in 2012 dollars and range from $726 to $1,018 million (Figure 4.8). These figures include the total costs for transmission facilities from the point the line crosses the Canada/U.S. border until its final destination in MISO.

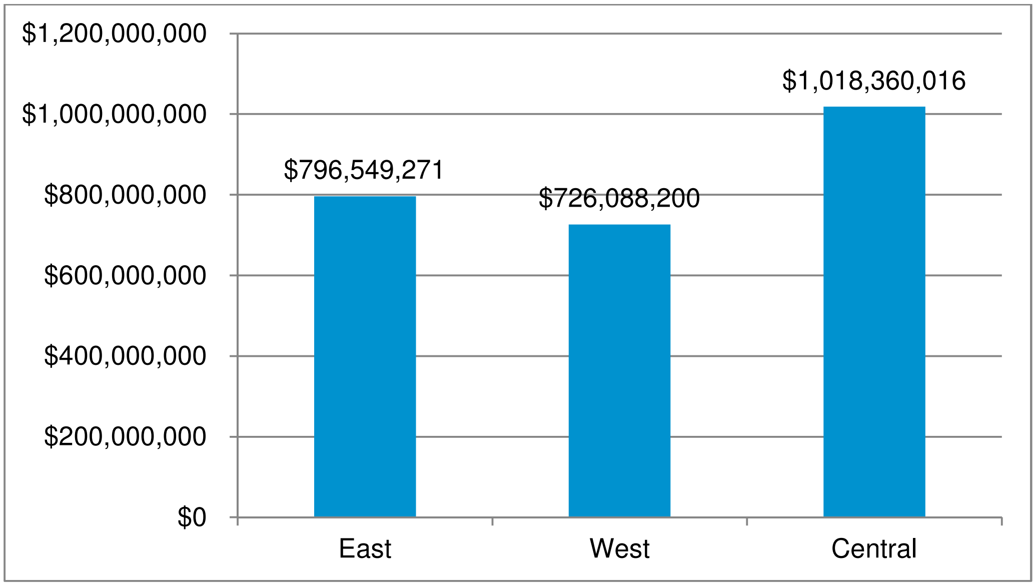


Figure 4.8: Transmission Construction Cost (note costs were later updated in Phase IV)

4.4 Production Cost Adjustment

Adjustments need to be made to the production cost reported by the simulation to reduce the biases between the simulations. Biases can occur because of changes in the amount of water used by hydro generators or imports and exports from a particular region.

4.4.1 Ending Manitoba Hydro Storage Reservoir Adjustment

The MISO production cost needs to be adjusted based on the differences in the ending volumes of the Manitoba Hydro storage reservoirs as to not bias the results from over- or under-use of the reservoirs.

The adjustment is made by taking the difference in the ending storage volumes between the base case and change case, converting it to MWh and then multiplying it by the average production cost in $/MWh in MISO.

4.4.2 Interface Flow Adjustments

The interpool flows (MISO-PJM, MISO-SPP, etc.) in and out of MISO are different between the simulations.

The adjustment is made by taking the difference in the interchange (MWh) with all regions except Manitoba Hydro between the base case and change case and multiplying it by the average production cost in $/MWh in MISO.

4.4.3 Present Value Calculation

A single run for the year 2027 is conducted, but in order to get a benefit-to-cost ratio a total benefit number must be calculated. This is done by determining the relevant life time benefits of the line and dividing it by the relevant cost.

Total Benefits are calculated by estimating the annual benefits between 2022 and 2041 using an inflation rate of 1.74 percent and then taking the Present Value (PV) with a discount rate of 8.2 percent to 2012 dollars.

Total Costs are calculated by taking the 2012 construction cost estimates and escalating them using an inflation rate of 1.74 percent in order to determine the costs for the years 2022 to 2041. They are then multiplied by the average MISO Transmission Owner's (TO) annual charge rate and discounted back to 2012 using a discount rate of 8.2 percent.

The benefit-to-cost ratio is determined by dividing the present value of the benefits by the present value of the costs.

4.5 Phase 3 Results

Phase 3 looked at the effects of adding transmission and generation in both the day ahead and real time markets. The following tables show two different types of runs. The first is Day Ahead (DA) Only, which simulates the DA market alone without considering any contributions from the Real Time (RT) market. This means that wind and load uncertainties are not included in the DA Only simulations. The RT simulations include the contributions from the RT market, which models the uncertainties of the wind and load forecasts.

4.5.1 Day Ahead and Real Time Annual Savings

Modified production cost savings are calculated by adjusting the unmodified production cost savings by the steps described previously in 4.4.1 and 4.4.2. The benefits in the RT market are generally higher than that of the DA only market since the RT market better captures the flexibility of the hydro units. The reserve cost savings are very small compared with the energy savings.

Run	Unmodified Production Cost Savings ($M-2027)	Modified Production Cost Savings ($M-2027)	Reserve Cost Savings ($M-2027)
MISO DA Only East	79.02	131.78	1.87
MISO DA Only West	82.99	145.55	1.24
MISO DA Only Central	101.37	150.22	1.65
MISO RT East	94.88	139.55	0.75
MISO RT West	86.70	146.03	(3.40)
MISO RT Central	101.70	149.23	(2.87)

Table 4.1: DA and RT annual savings (2027)

4.5.2 Day Ahead and Real Time 20 Year Present Value Savings

Run	20 Year Present Value (PV) Savings ($M-2012)	20 Year Present Value (PV) Cost ($M-2012)	Benefit to Cost (B/C) Ratio
MISO DA Only East	651.92	774.32	0.84
MISO DA Only West	720.01	705.83	1.02
MISO DA Only Central	743.12	989.94	0.75
MISO RT East	690.34	774.32	0.89
MISO RT West	722.42	705.83	1.02
MISO RT Central	738.24	989.94	0.75

Table 4.2: DA and RT annual 20 years NPV savings

4.5.3 Wind Synergy – Curtailment Reduction

The addition of the new line and flexible hydro generation provided wind curtailment reductions in the Minnesota (MN) and North Dakota (ND) portions of MISO (Table 4.3). The percentage reduction is the portion of the total curtailments helped by the new additions.

Run	MN/ND MISO Wind Generation Curtailment Reduction (GWh)	MN/ND MISO Wind Generation Curtailment Reduction (Percentage)
MISO DA Only East	47.93	40.60%
MISO DA Only West	58.40	45.22%
MISO DA Only Central	105.99	55.10%
MISO RT East	29.67	21.72%
MISO RT West	42.93	31.43%
MISO RT Central	52.20	38.22%

Table 4.3: Wind Curtailment Reduction

4.5.4 Wind Synergy – Visual Example

Manitoba Hydro can respond rapidly and compensate for both daily changes in wind and short term wind spikes. The large compensations can be seen when the wind peaks and the import from Manitoba Hydro is at its lowest (Figure 4.9). Compensation for short-term wind spikes can be seen as small rapid changes in the wind can be taken care of by small rapid changes in hydro generation (Figure 4.10).

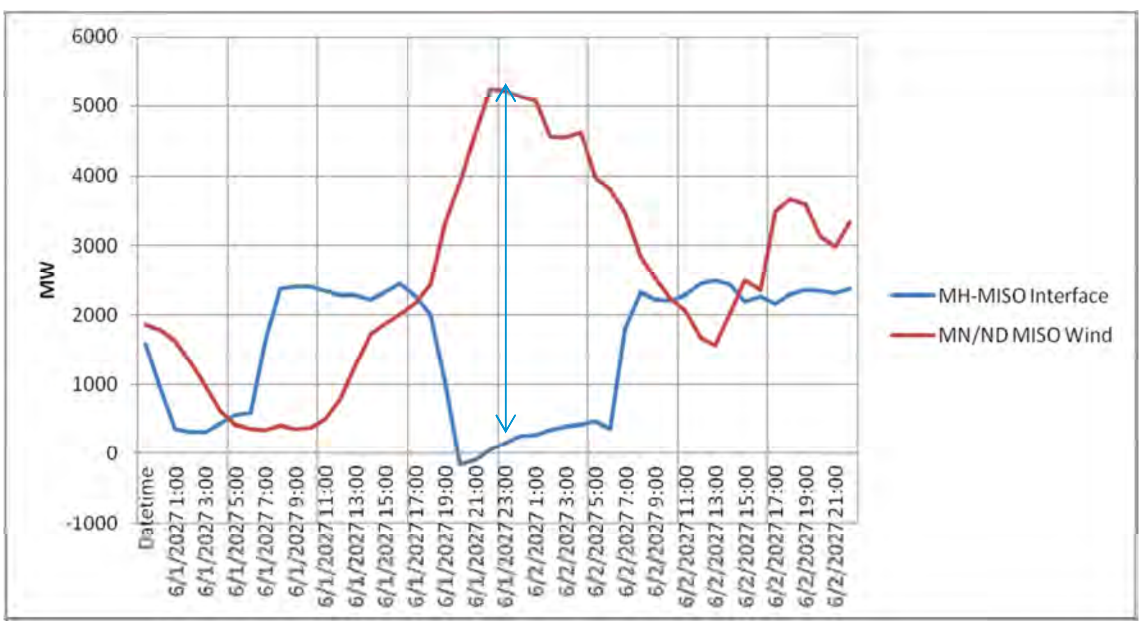


Figure 4.9: Wind Synergy, Visual Example 1

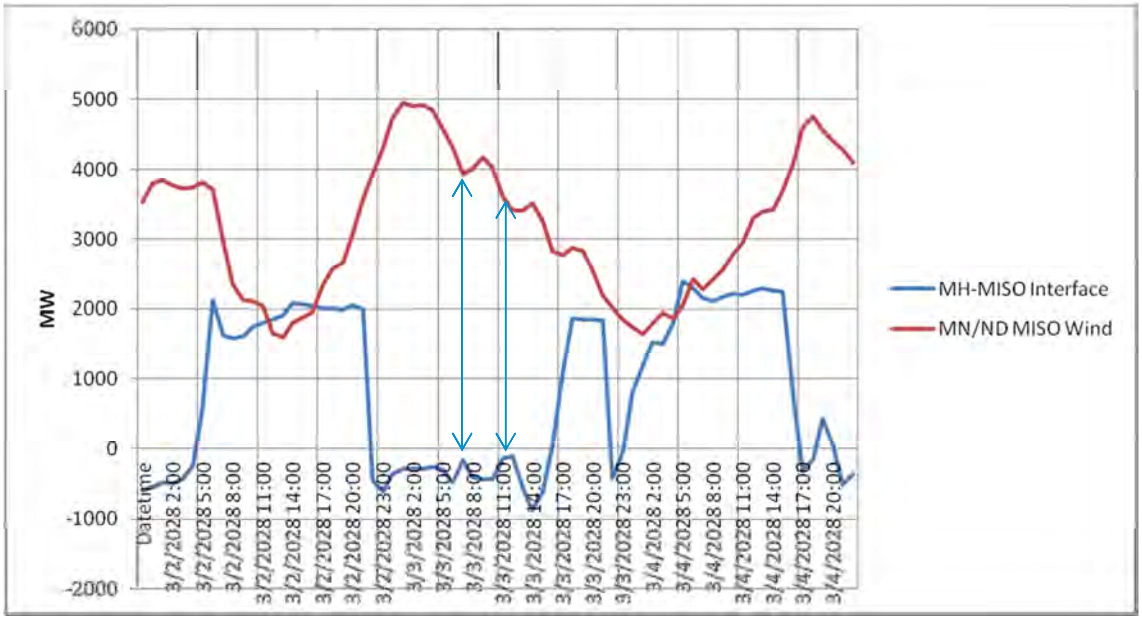


Figure 4.10: Wind Synergy, Visual Example 2

4.5.5 Wind Synergy – Correlation

Correlation coefficients provide a good general indication how the system is performing and the synergy between hydro storage and wind generation (Table 4.4). The Manitoba Hydro to MISO interface activity shows a strong inverse correlation with the wind generation in MISO. This means that when the wind picks up and adds downward pressure on prices, Manitoba Hydro reduces its generation. Conversely, when the wind dies down, Manitoba Hydro increases its generation. The opposite is true with MISO load. When MISO load increases, Manitoba Hydro increases generation and when MISO load decreases, Manitoba Hydro generation decreases. This is shown by the positive correlation between the Manitoba Hydro-MISO interface to MISO load. The correlation between wind and load is about zero which means each varies independent of the other.

Variables	Correlation Coefficient
Manitoba Hydro-MISO Interface Vs. MISO Wind	**-0.40 to -0.44**
Manitoba Hydro-MISO Interface Vs. MISO Load	**0.38**
MISO Wind Vs. MISO Load	**-0.005 to -0.007**

Table 4.4: Correlation Coefficients

4.5.6 Generation Changes

Figures 4.11, 4.12 and 4.13 show how generation changes when a new 500 kV transmission line and new hydro generation in Manitoba Hydro are added. The blue areas represent generation decreases and the red areas represent generation increases. The main areas of generation decreases are near load centers which are served with higher priced local generation. New imports from Manitoba Hydro help relieve the need for this generation.

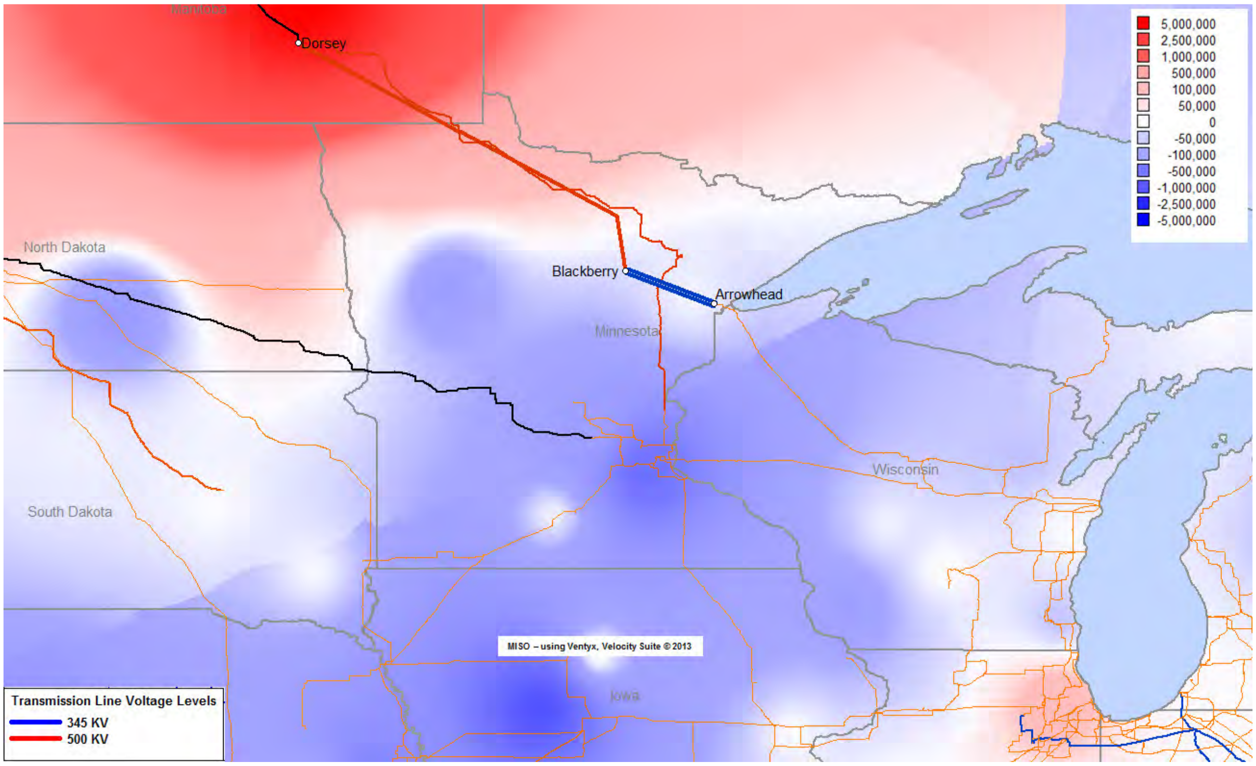


Figure 4.11: East Generation Changes (MWh)

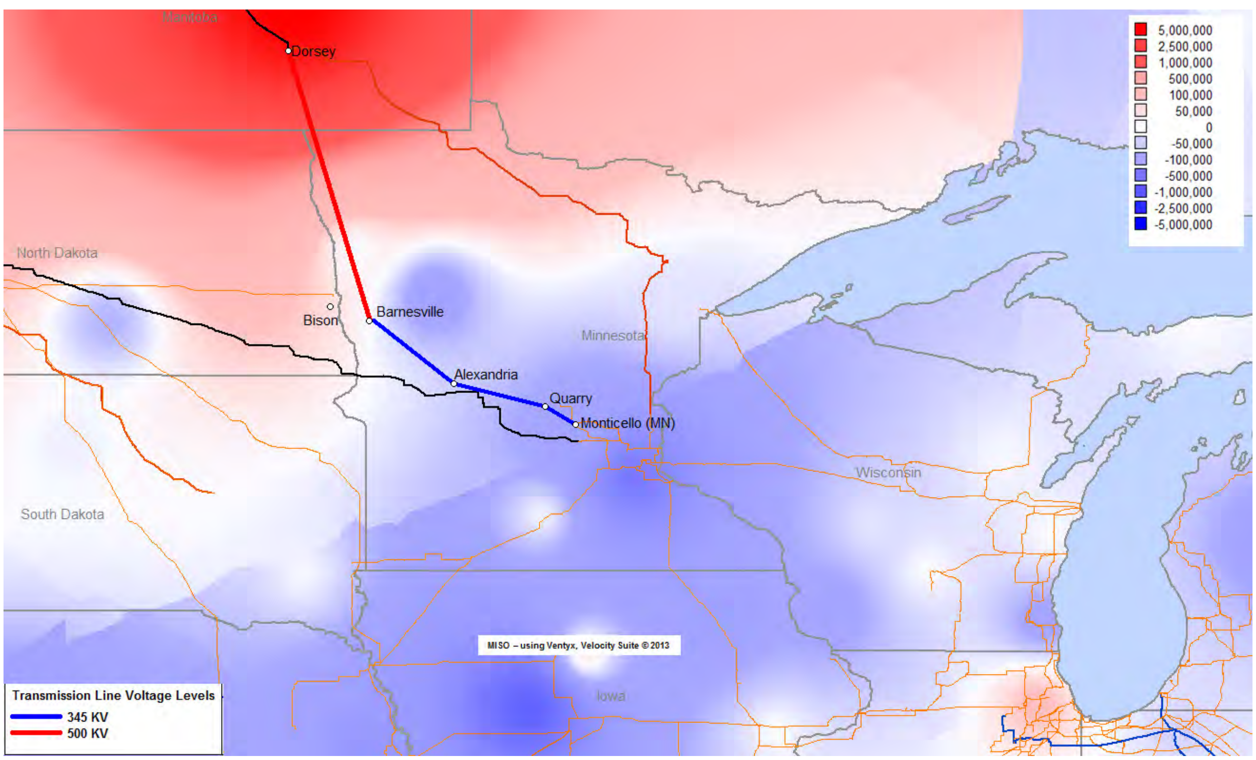


Figure 4.12: West Generation Changes (MWh)

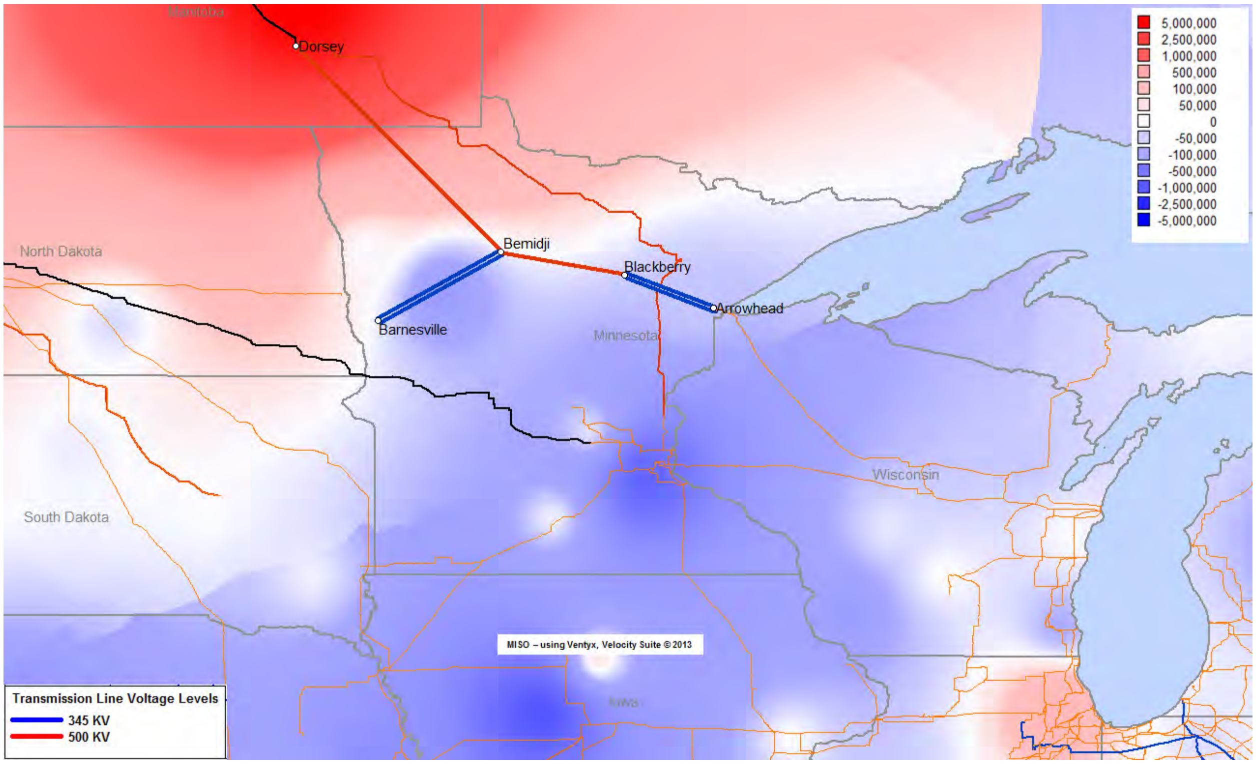


Figure 4.13: Central Generation Changes (MWh)

4.6 Phase 3 Conclusion

Phase 3 looked at the interactions between wind and hydro in both the day ahead and real time markets. The annual modified production cost savings for 2027 ranged from $130 to $150 million. The east and west options show similar benefit-to-cost ratios while the central option shows a lower benefit to cost given the increased cost of the line. With the addition of transmission, good synergy between Manitoba Hydro generation and MN/ND MISO wind was observed. Benefit-to-cost ratios are between 0.75 and 1.02 using the assumptions from the MTEP 12 Business as Usual (BAU) future. Phase 3 looked at the additional benefits that can be gained by conducting a real time market simulation instead of the traditional approach of looking only at the day-ahead market. Phase 4 continued to explore the benefits of these projects under a wide range of scenarios to get a more complete picture of potential benefits.

5 Phase 4

5.1 Model Development of Multiple Scenarios

The purpose of Phase 4 of the Manitoba Hydro Wind Synergy Study was to evaluate the cost and benefits of adding additional transmission between MISO and Manitoba Hydro along with the construction of a new Manitoba Hydro generator. Phase 4 expands on the work done in Phase 3. Three MTEP12 Futures and three hydrologic futures were studied in Phase 4 to get a robust picture of the benefits under a wide variety of scenarios.

5.1.1 Changes from Phase 3

At the end of Phase 3 it was determined that the Central option did not provide enough benefits to justify the construction cost. In Phase 4, the Central option is no longer included and only the East and West options remain (Figure 5.1, 5.2).

Figure 5.1: Dorsey to Blackberry (**East**)

- 500 kV line from Winnipeg to Grand Rapids
- 345 kV double circuit line from Grand Rapids to Duluth

Figure 5.2: Dorsey to Fargo/Moorhead Area (**West**)

- 500 kV line from Winnipeg to Fargo/Moorhead Area
- 345 kV line from Fargo/Moorhead to Monticello

Manitoba Hydro plans to build two new hydraulic generators during the next 15 years if a new transmission line is constructed between MISO and Manitoba Hydro. In Phase 3, Conawapa (1485 MW) was assumed to be online in the base case while Keeyask(695 MW) was assumed to only be built if a new transmission line was built. In Phase 4, these two generators have been switched, but both still remain in the new transmission line case. Although Manitoba Hydro's Power Resource Plan had not changed, the Keeyask as the only new hydraulic generation with no line constructed is certainly a plausible scenario. Keeyask is earlier in the generation sequence than Conawapa and there is more momentum behind this project in terms of the planning and development activities. Moreover, having Conawapa excluded from the no new-line scenario will better measure the flexibility/synergy benefits of additional hydraulic generation on the Manitoba Hydro system – which is the objective of this study.

5.1.2 MTEP12 Futures

Phase IV of the study analyzed the Business as Usual (BAU), Historic Growth (HG) and Combined Policy (COMBO) futures to study the impact of adding a new transmission line between Manitoba Hydro and MISO along with a new hydro generator in Manitoba Hydro. The Low Growth (LG) future will not be used because no new external resources/transmission are required. This is similar to the methodology used in the Northern Area Study (NAS). The Joint MISO-SPP future will not be used because this study focuses on northern MISO issues. A brief overview of each future is shown in Table 5.1.

Business As Usual (BAU)
• Continues the economic downturn-affected growth in demand and energy rates

Historical Growth (HG)
• Assumes a quick recovery from the economic downturn in demand and energy rates

Limited Growth (LG)
• Assumes no recovery from the economic downturn; lowest growth in demand and energy rates

Combined Policy (COMBO)
• Models a variety of future energy policies, including a 20 percent federal RPS, a "smart" grid, and electric vehicles

MISO-SPP Joint Future
• Establishes common assumptions between MISO and SPP

Table 5.1: MTEP12 futures (blue highlighted scenarios modeled in this study)

Resources are forecasted following the MISO MTEP seven-step planning process (Figure 5.3). Generation was sited using a detailed process which includes mapping software (MAPINFO) and a set of practical guidelines to determine the locations of all resources. The siting and generation in this study is the exact same as used in other MISO studies such as the Market Efficiency Planning Study (MEPS) with the exception of additional details added to the Manitoba Hydro region. All base assumptions and generation siting was approved by the MISO Planning Advisory Committee prior to implementation in this study.

Since the price of natural gas is low and the cost of meeting the new environmental regulations is high, the resources added to the model consist of predominantly natural gas combustion turbines and combined cycle units. No coal is added to the system and 12 to 23 GW is retired. Wind resources are added into the model to meet the state Renewable Portfolio Standards (RPS). Demand response and energy efficiency are also added due to the low cost forecasted by Global Energy Partners.

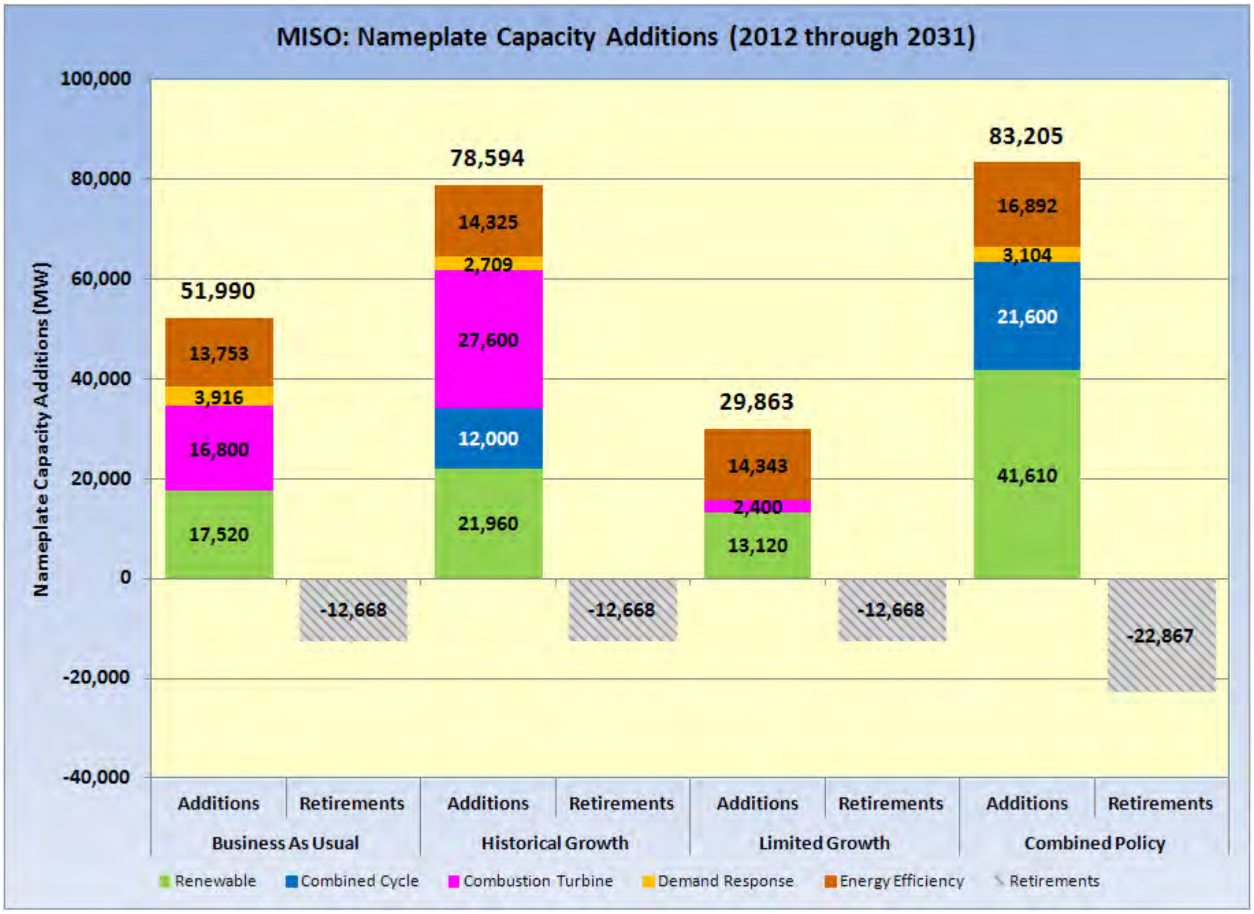


Figure 5.3: MTEP12 Capacity Additions

The uncertainty variables, shown in Table 5.2, included in this study are the same as those used in the general MTEP12 studies. These values were approved by the MISO Planning Advisory Committee (PAC) and used to forecast the resources needed to meet MISO's reliability criteria as well as inputs into this study.

	Uncertainties																																	
	Demand and Energy				Capital Costs															Fuel Costs				Fuel Escalations				Emission Costs			Wind		Other Variables	
Future	Demand Response Level	Energy Efficiency Level	Demand Growth Rate	Energy Growth Rate	Coal	CC	CT	Nuclear	Wind Onshore	IGCC	IGCC w/ Carbon Capture & Sequestration	CC w/ Carbon Capture & Sequestration	Pumped Storage Hydro	Compressed Air Energy	Photovoltaic	Biomass	Conventional Hydro	Wind Offshore	Distributive Generation - Peak	Gas	Oil	Coal	Uranium	Gas	Oil	Coal	Uranium	SO_2	NO_x	CO_2	MISO Wind Penetration Mandate	National Mandate	Inflation	EPA Coal Retirement
Business as Usual	M	M	M	M	M	M	M	M	L	M	N/A	N/A	M	M	M	M	M	M	M	M	M	M	M	L	L	L	L	M	M	L	M	L	L	M
Historical Growth	M	M	H	H	M	M	M	M	L	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	L	M	L	M	M
Limited Growth	M	M	L	L	H	M	M	M	L	M	N/A	N/A	M	M	M	M	M	M	M	M	M	L	H	L	L	L	L	M	M	L	M	L	L	M
Combined Policy	M	M	M	H	H	H	H	H	L	H	H	H	H	H	H	H	H	M	H	H	M	L	H	M	M	M	M	M	M	M	M	M	M	H
MISO-SPP Joint Future	N/A	N/A	*	*	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	*	M	M	M	*	*	*	*	M	M	L	H	L	*	M

Table 5.2: MTEP12 Futures Matrix

The most important differences between the futures are listed in Table 5.3. The demand and energy growth rates drive the need for future resources to be included in the simulation. Coal retirements need to be replaced with additional capacity causing the power flow patterns to change. A low natural gas price enables gas-fired units to run more often and lower the LMP spread between on and off peak. Lastly, increased wind penetration levels create a need for flexible generation to compensate for the unpredictability of the wind.

Future	Demand Growth Rate	Energy Growth Rate	Coal Retirement (MW)	Gas Price ($/MMBtu)	Gas Price Escalation	Wind Penetration
Business As Usual	**1.41%**	**1.67%**	**12,668**	**4.25**	**1.74%**	**Existing State Mandates**
Historical Growth	**2.12%**	**2.51%**	**12,668**	**4.25**	**2.91%**	**Existing State Mandates**
Combined Policy	**1.41%**	**2.51%**	**22,867**	**8**	**2.91%**	**Existing State Mandates + National Mandate (20% by 2025)**

Table 5.3: Significant MTEP12 variables

5.1.3 Hydrologic Futures

The volume and timing of imports and exports between Manitoba Hydro and MISO are highly dependent on the water supply conditions on the Manitoba Hydro system. To account for this dependency and represent the benefits of the added transmission line over a range of water supply conditions, three different water supply conditions were modeled. Low, median and high water futures based on historical water inflows to Manitoba Hydro were examined. The hydrologic futures were developed as a joint effort between Manitoba Hydro and MISO staff before being inputted into PLEXOS for the final simulations. Figure 5.4 shows the monthly energy produced by Manitoba Hydro in the model. The differences between the low, median and high cases were caused by the change in assumed available water.

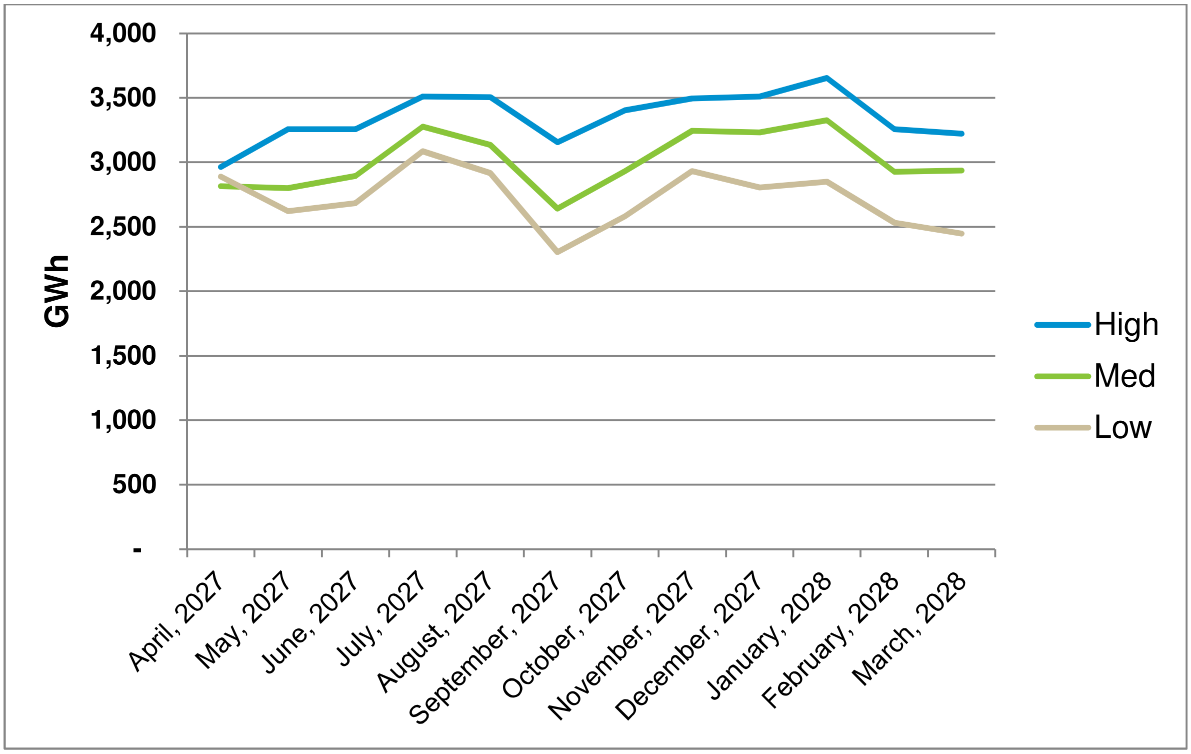


Figure 5.4: Manitoba Hydro Monthly Generation (Business as Usual, Base Case)

When looking at the expanded transmission scenarios an additional hydro generator was added to the model. This increased the generation on Manitoba Hydro by 8 to 10 TWh over the base case (BC). Figure 5.5 illustrates the differences of changing generation and water inflow across the Business as Usual (BAU) future.

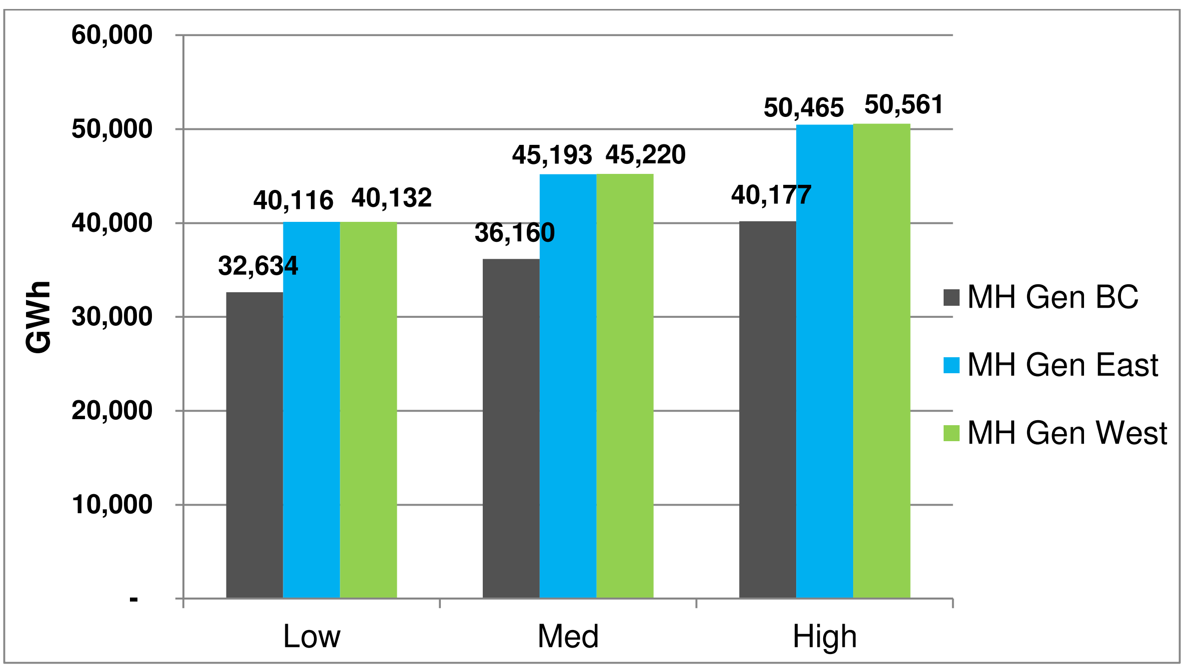


Figure 5.5: Manitoba Hydro Annual Generation

5.1.4 Scenario Weights

To produce a single, representative metric for the study a weighting approach was used to calculate an expected benefit given the multiple possible future scenarios and water conditions. Probabilities for each hydrologic and MTEP12 future were developed to create a weighted average of the benefits. The probability of the hydrologic futures were determined using historical water flow information, whereas the probabilities for the MTEP12 futures were determined in a vote of the Planning Advisory Committee (PAC) and then adjusted to exclude the Limited Growth Future. After each scenario was completed, the benefits were multiplied by the scenario weight and then were added together to create a final benefit metric.

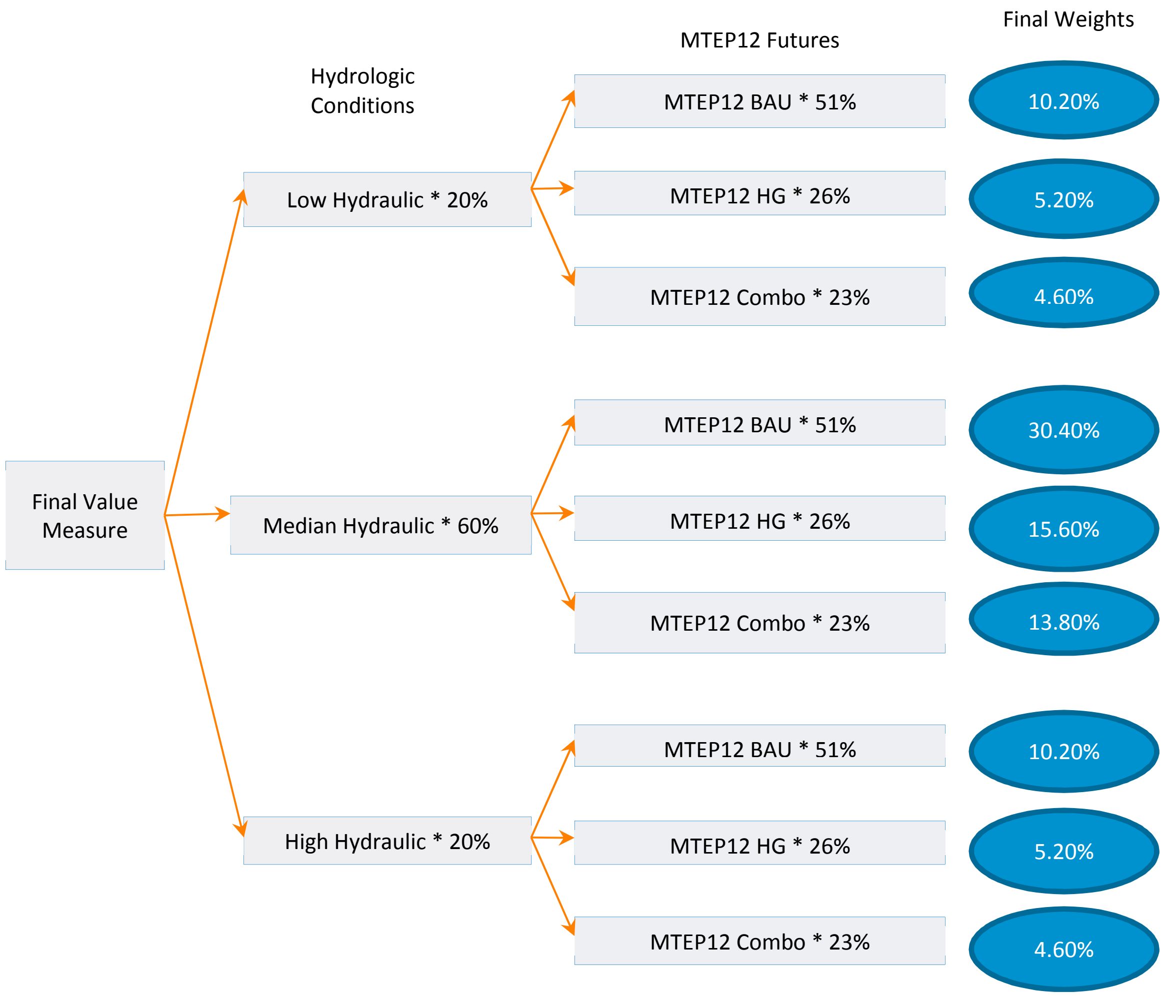


Figure 5.6: Scenario Weights

5.1.5 Transmission Construction Costs

The transmission construction costs were updated from Phase 3 after the respective parties reviewed the preliminary estimates and developed a more accurate estimate (Table 5.4). Mitigation costs were also included in Phase 4 from the output of the reliability analysis presented in section 6 of this report. The breakdown of costs is shown. The total cost was used in the benefit-to-cost (B/C) ratio calculation (Table 5.8). Present value costs are calculated using the methodology in section 4.4.3.

	Transmission Construction Costs ($M-2012)			
Transmission Option	**U.S. Construction Costs**	**Mitigation Cost**	**Total Costs**	**20 Year Present Value Costs**
East 500 kV Line	685	0	685	666
West 500 kV Line	590	8	598	582

Table 5.4: Transmission Construction Costs

5.2 Phase 4 Results

Phase 4 looked at a wide variety of scenarios in order to capture a wide range of benefits. This study only looked at the benefits that can be found using a production cost simulation and didn't examine capacity benefits or changes in market structure or requirements. The primary metric used to determine the value of additional transmission is modified production cost savings, but the other benefits included in this report help complete the picture.

5.2.1 Modified Production Cost Savings ($M-2027)

Modified production cost savings for the year 2027 ranged from $228 to $455 million (Table 5.5). The weighted total for all scenarios came out equal for both the East and West 500 kV transmission lines. This metric is the primary one used for determining the relative benefits of either line and is the metric used in the B/C ratio calculation.

	Modified Production Cost Savings ($M-2027)		
Run	**Weights**	**East**	**West**
BAU Low	10.20%	228	236
BAU Med	30.60%	261	270
BAU High	10.20%	278	286
HG Low	5.20%	287	271
HG Med	15.60%	339	329
HG High	5.20%	370	360
COMBO Low	4.60%	418	405
COMBO Med	13.80%	447	452
COMBO High	4.60%	455	440
Weighted Total	100.00%	321	321

Table 5.5: Modified Production Cost Savings

5.2.2 Unmodified Production Cost Savings ($M-2027)

The unmodified production cost savings are the raw savings before any adjustments are made. This metric gives an indication of generation savings in MISO without taking into account changes in water usage or changes in the imports and exports to other regions (Table 5.6).

	Unmodified Production Cost Savings ($M-2027)		
Run	**Weights**	**East**	**West**
BAU Low	10.20%	123	140
BAU Med	30.60%	140	161
BAU High	10.20%	162	183
HG Low	5.20%	182	147
HG Med	15.60%	207	183
HG High	5.20%	216	194
COMBO Low	4.60%	351	320
COMBO Med	13.80%	368	370
COMBO High	4.60%	370	347
Weighted Total	100.00%	209	210

Table 5.6: Unmodified Production Cost Savings

5.2.3 20 Year Present Value Benefits ($M-2012)

The 20 year present value benefits (Table 5.7) use the modified production cost savings (Table 5.5) to calculate a metric which can be directly compared to the construction cost of a new transmission line. This metric is considered the total benefit of the project for the purposes of calculating a benefit-to-cost ratio. Other benefits are present and are shown in this report, but production cost savings are the most common metric to use for comparing the benefits and costs of a project.

	20 Year Present Value Benefits ($M-2012)		
Run	**Weights**	**East**	**West**
BAU Low	10.20%	1,130	1,165
BAU Med	30.60%	1,293	1,334
BAU High	10.20%	1,376	1,415
HG Low	5.20%	1,419	1,339
HG Med	15.60%	1,679	1,626
HG High	5.20%	1,829	1,780
COMBO Low	4.60%	2,065	2,003
COMBO Med	13.80%	2,210	2,235
COMBO High	4.60%	2,253	2,177
Weighted Total	100.00%	1,586	1,588

Table 5.7: 20 Year Present Value Benefits

5.2.4 Benefit-to-Cost Ratios

The B/C ratio is calculated by taking the present value (Section 4.4.3) of the modified production cost savings (Table 5.7) and dividing it by the present value of the U.S-based construction cost of the line including any needed mitigation (Table 5.4). This metric gives a more complete picture of how the lines compare to each other and if they are worth building or not (Table 5.8).

	Benefit to Cost Ratios		
Run	**Weights**	**East**	**West**
BAU Low	10.20%	1.70	2.00
BAU Med	30.60%	1.94	2.29
BAU High	10.20%	2.07	2.43
HG Low	5.20%	2.13	2.30
HG Med	15.60%	2.52	2.80
HG High	5.20%	2.75	3.06
COMBO Low	4.60%	3.10	3.44
COMBO Med	13.80%	3.32	3.84
COMBO High	4.60%	3.38	3.74
Weighted Total	100.00%	2.38	2.73

Table 5.8: Benefit to Cost Ratios

5.2.5 Load Cost Savings ($M-2027)

The load cost savings are calculated by taking the change in load multiplied by the change in LMP (Table 5.9). This metric is sensitive to small changes in locational marginal price. Hedging or ownership of generation by load tends to offset load cost savings due to an associated reduction in generator revenue. Thus load cost savings is not an appropriate metric to be used in isolation when evaluating projects.

	Load Cost Savings ($M-2027)		
Run	**Weights**	**East**	**West**
BAU Low	10.20%	273	321
BAU Med	30.60%	335	371
BAU High	10.20%	363	432
HG Low	5.20%	248	193
HG Med	15.60%	249	202
HG High	5.20%	218	183
COMBO Low	4.60%	508	391
COMBO Med	13.80%	860	825
COMBO High	4.60%	1,302	1,251
Weighted Total	100.00%	432	431

Table 5.9: Load Cost Savings

5.2.6 Reserve Cost Savings ($M-2027)

Reserves are modeled for both MISO and Manitoba Hydro (Table 5.10). Three products are examined for each region, regulation, spinning and supplemental reserves. Reserve cost savings are for MISO alone. The savings are very small relative to the energy savings and thus do not sway the build decision in any way.

	Reserve Cost Savings ($M-2027)		
Run	**Weights**	**East**	**West**
BAU Low	10.20%	(0.05)	(0.44)
BAU Med	30.60%	0.25	(0.16)
BAU High	10.20%	0.83	0.54
HG Low	5.20%	(0.27)	(0.46)
HG Med	15.60%	0.52	0.09
HG High	5.20%	1.53	1.01
COMBO Low	4.60%	0.41	0.53
COMBO Med	13.80%	0.82	0.53
COMBO High	4.60%	2.45	2.20
Weighted Total	100.00%	0.55	0.20

Table 5.10: Reserve Cost Savings

5.2.7 Average Annual LMP ($/MWh)

Average annual LMP is shown to give an indication of what each MTEP12 future looks like along with the relative differences between Manitoba Hydro and MISO (Table 5.11). The Combined Policy (COMBO) future has the highest LMP given it has the highest gas price and coal retirements. The Historic Growth (HG) future has an LMP in between the Business as Usual (BAU) and COMBO given the high demand and energy growth rates and the BAU future has an LMP in line with what the current system would produce.

	Average Annual LMP ($/MWh)		
Region	**BAU**	**HG**	**COMBO**
Manitoba Hydro	32	57	73
MISO	41	60	85

Table 5.11: Average Annual LMP

5.2.8 Generation Displaced (GWh-2027)

In the change case a new hydro generator is added in Manitoba Hydro and a 500 kV line is added between MISO and Manitoba Hydro. This causes a large amount of generation to be displaced within MISO. The total amount of generation displaced is because of the additions to the case along with a breakdown of the types of units (Figure 5.7). Total displacement depends on the amount of water available to the hydro generators in Manitoba Hydro.

The Business as Usual (BAU) future shows a significant amount of coal generation being displaced by the new generation in Manitoba. This future has the lowest gas price, which causes most of the displacement to happen with the coal fleet.

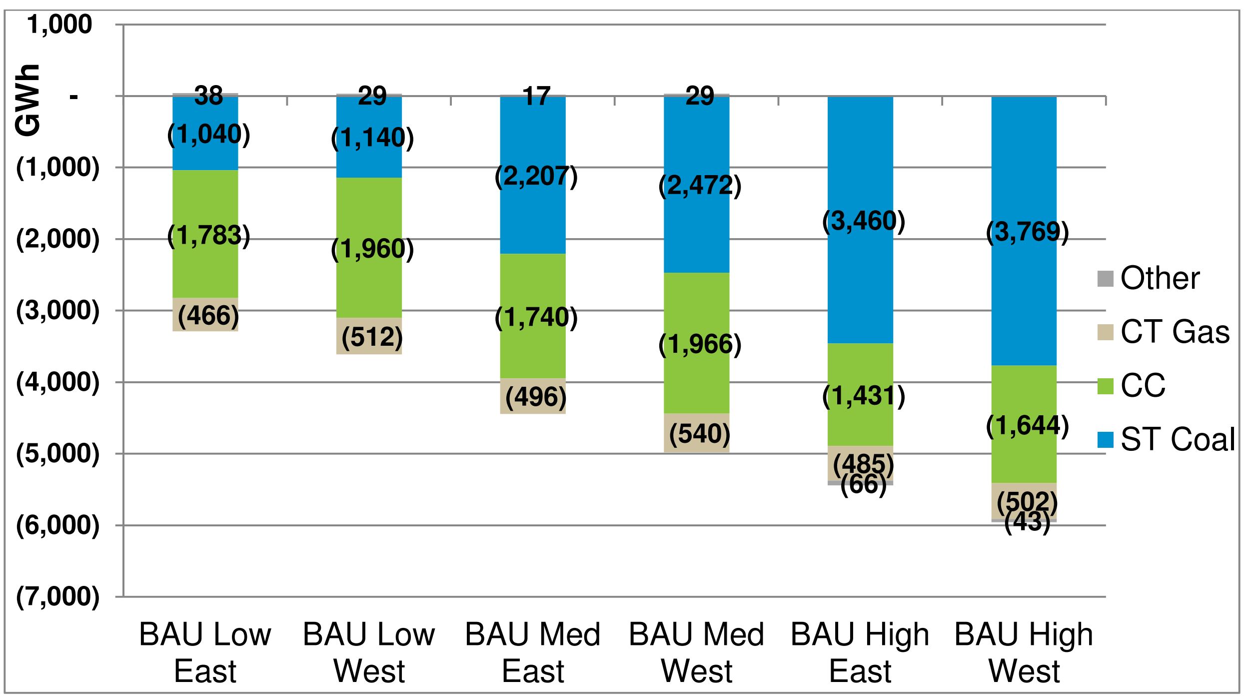


Figure 5.7: MISO BAU Generation Displaced

The Historic Growth (HG) future has a higher gas price which causes more gas units to be displaced and only a minimal amount of coal (Figure 5.8). This future also has higher demand and energy, which causes more peaking units to be displaced instead of the base load units in the BAU future.

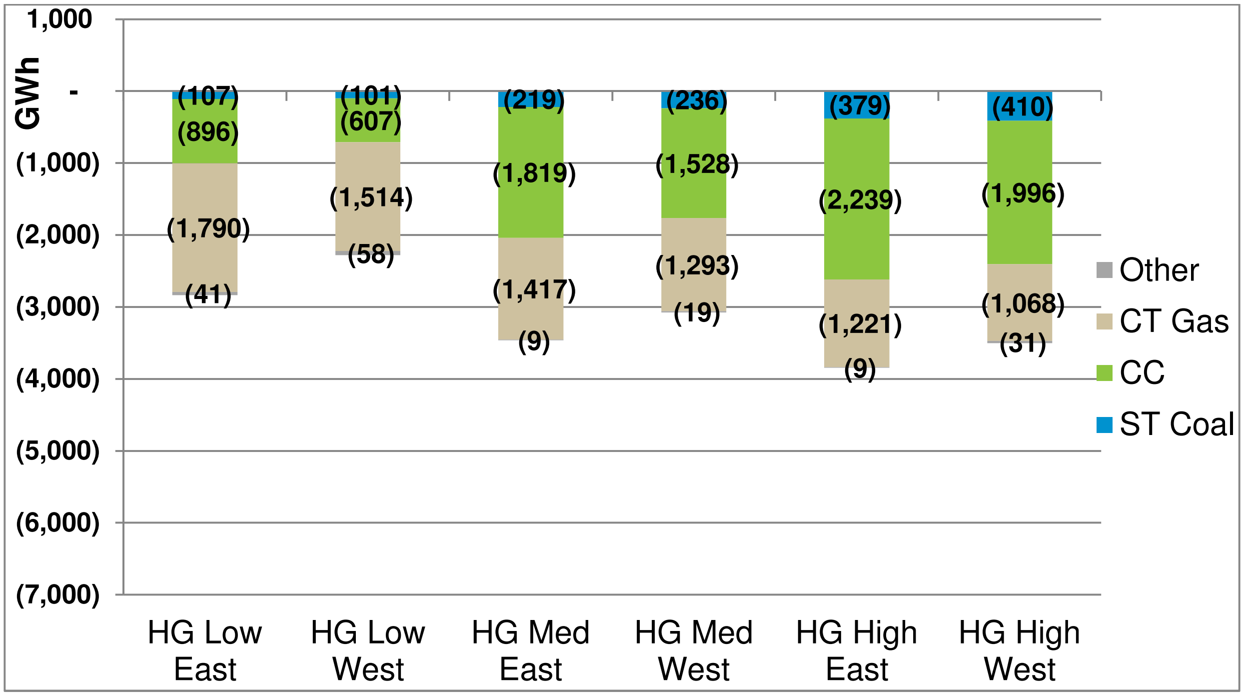


Figure 5.8: MISO HG Generation Displaced

The Combined Policy (COMBO) future shows the largest portion of the displacement happening with combined cycle units (Figure 5.9). This future has the highest gas price which causes these units to be displaced.

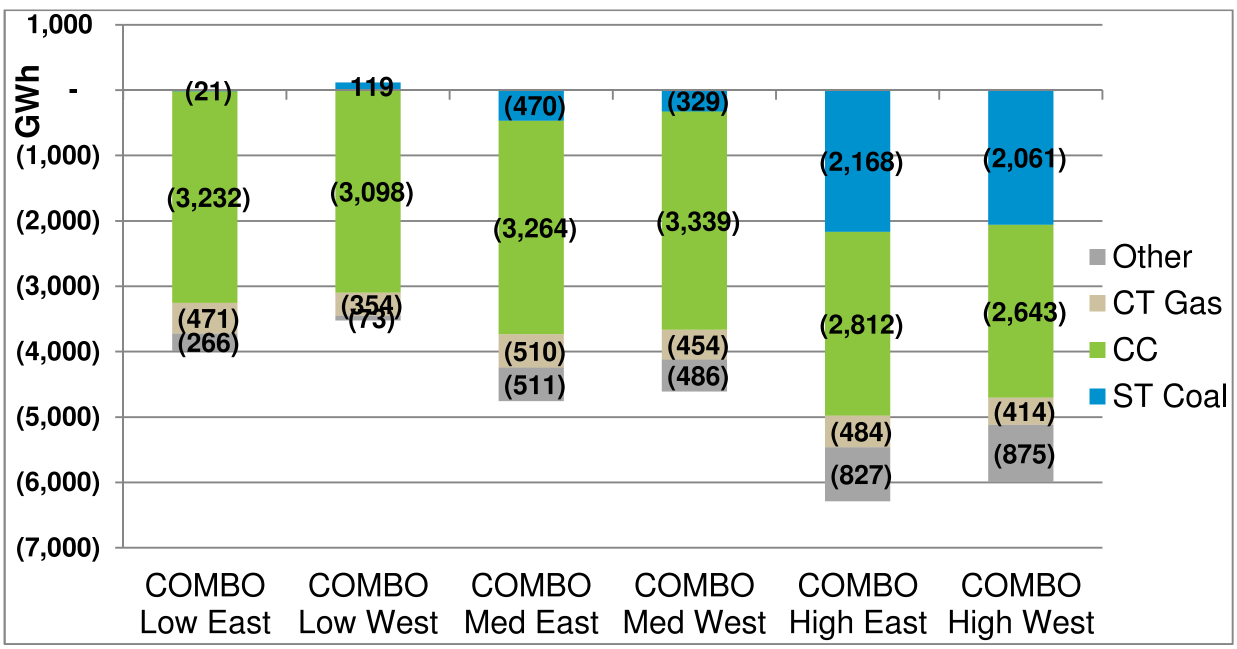


Figure 5.9: MISO COMBO Generation Displaced

5.2.9 Correlation Coefficients

Correlation coefficients provide a good general indication how the system is performing and the synergy between hydro storage and wind generation (Table 5.11). The Manitoba Hydro to MISO interface activity shows a strong inverse correlation with the wind generation in MISO. This means that when the wind picks up and adds downward pressure on prices, Manitoba Hydro reduces its generation. Conversely, when the wind dies down, Manitoba Hydro increases its generation. The opposite is true with MISO load. When MISO load increases, Manitoba Hydro increases generation and when MISO load decreases, Manitoba Hydro generation decreases. This is shown by the positive correlation between the Manitoba Hydro-MISO interface to MISO load. The correlation between wind and load is about zero which means each varies independent of the other.

. The Combined Policy (COMBO) future shows the strongest correlation between MISO wind generation and the flow on the MISO to Manitoba Hydro interface. This is because this future contains almost twice as much wind as the other two. The Manitoba Hydro generators are needed to compensate for this additional wind penetration. The Historic Growth (HG) future shows the strong correlation of the three futures between MISO load and the Manitoba Hydro to MISO interface since this future has the highest demand and energy in 2027.

The high water future reduces Manitoba Hydro's incentive to follow small changes in MISO while a low water future increases Manitoba Hydro's incentive to follow these changes. This gives the range of correlation coefficients.

Variables	BAU Correlation	HG Correlation	COMBO Correlation
Manitoba Hydro-MISO Interface Vs. MISO Wind	-0.21 to -0.38	-0.10 to -0.21	-0.47 to -0.52
Manitoba Hydro-MISO Interface Vs. MISO Load	0.18 to 0.38	0.31 to 0.54	0.14 to 0.29
MISO Wind Vs. MISO Load	-0.004 to -0.008	-0.002 to -0.003	-0.003 to -0.006

Table 5.12: Manitoba Hydro-MISO interface and MISO Wind correlation

5.2.10 MISO Coal Generation Cycling

Phase 4 examined the Business as Usual Median Water case in greater detail to determine the effect new hydro generation in Manitoba along with the addition of a new transmission line would have on coal cycling in MISO. Cycling can be thought of as the combination of ramping up and down of the unit to respond to changes in the system. There is currently no price placed on ramping in the MISO market, so power plants need to recover wear and tear costs caused by ramping in the energy and/or ancillary services markets.

Cycling changes are shown in MWs per five minute interval which is the time step in the real time market. It is also broken down to the unit level and aggregate level. The unit level looks at the ramping of individual units in MISO. This method captures times when different coal units are ramping up and down at the same time in different locations. The aggregate level treats all coal units in MISO as a single unit when comparing ramping activity. This method time synchronizes the ramping of the units to better capture the MISO system wide changes in coal ramp up and ramp down. Average ramp is calculated by taking the absolute value of the change in generation between five minute intervals and then averaging them over the simulation horizon. Ramp up examines the maximum change in increasing generation in a single five minute period. Ramp down examines the maximum change in decreasing generation in a single five minute period.

Values are listed as the change in ramping from the base case to an expanded generation and transmission case and are the sum of the individual coal units (Table 5.13). Positive numbers indicate a reduction in the ramping requirements for MISO coal units while a negative number indicates the units had increased ramping requirements. Total MWs traveled can be calculated by multiply the average ramp by the number of periods in the year (105,408) to get a MW per year metric. Coal units affected varied between the runs and were spread throughout the year.

	MISO Coal Generation Cycling (MW/5min)		
Run	**Change in Average Ramp**	**Change in Max Ramp Up**	**Change in Max Ramp Down**
East Unit Level	-1.70 / -1.32%	-43.61 / -0.20%	163.76 / 0.34%
West Unit Level	1.85 / 1.44%	3.34 / 0.02%	143.60 / 0.30%
East Aggregate Level	-0.23 / -0.34%	22.64 / 0.74%	29.46 / 0.50%
West Aggregate Level	2.16 / 3.13%	72.47 / 2.36%	50.40 / 0.85%

Table 5.13: MISO Coal Generation Cycling

A further analysis was conducted that examined the 5-minute dispatch of MISO coal units to determine the number of starts and significant load following events as well as the additional construction and maintenance costs associated with those events. The definitions of the different start types, significant load following events, and their associated costs used are from a NREL report on power plant cycling costs[1] and are also included here, escalated to 2027 dollars (Table 5.14). Unit starts fell into one of three categories, hot, warm or cold, depending on how long the unit was offline. Significant load follows were counted when a unit cycles down below a certain percentage of its capacity and back up again. The general method for calculating the costs is the number of events for the unit (#), multiplied by the unit capacity (MW), multiplied by a cost factor ($/MW). The available cost factors are considered 'lower bound', but do have significant variability associated with them. Median values from the report were used in the analysis.

Type	Hot Start Cost ($2027 /MW)	Warm Start Cost ($2027 /MW)	Cold Start Cost ($2027 /MW)	Warm Start Lower Bound (hours)	Warm Start Upper Bound (hours)	Load Follow Range (% of Capacity)	Load Follow Cost ($2027 /MW)
Small Coal (35 -300 MW)	123.88	206.90	193.72	4	24	0.30	4.40
Big Coal (300+ MW)	77.75	85.66	138.37	12	40	0.35	3.23

Table 5.14: Start and load follow characteristics and costs used

[1] National Renewable Energy Laboratory's *Power Plant Cycling Costs*, April 2012, prepared by Intertek APTECH

The number of starts, significant load follows and the costs of each are grouped into small coal units (35 – 300 MW) and large coal units (300+ MW) (Table 5.15 & 5.16). The results show a slight decrease in starts and load follows overall, with the exception of increased load follows for the East case. Cost data shows that the East case had a decrease in cycling costs of $344,000 whereas the West case had an increase in cycling costs of $97,000, over the year. Note that even though the total number of events may move in one direction (i.e. decrease), costs may increase as the events may have shifted to larger capacity units. The costs are relatively small relative to the energy savings and have significant uncertainty associated with them, and therefore do not sway the build decision any way.

Case & Type	Change in Number of Starts (Case *less* Base)			Change in Cost of All Starts ($-2027) (Case *less* Base)
	Hot Starts	Warm Starts	Cold Starts	
East, Small Coal	+6	-22	+7	(387,000)
East, Big Coal	0	0	0	0
West, Small Coal	0	-41	+3	213,000
West, Big Coal	0	0	0	0

Table 5.15: Incremental coal unit starts and costs

Case &Type	Change in Number of Load Follows (Case *less* Base)	Change in Cost of Load Follows ($-2027) (Case *less* Base)
East, Small Coal	+24	48,000
East, Big Coal	+4	(5,000)
West, Small Coal	-63	(18,000)
West, Big Coal	-36	(98,000)

Table 5.16: Incremental coal unit significant load follows and costs

5.2.11 Wind Curtailment

Another topic from Phase 3 that was reexamined in Phase 4 was wind curtailment. A few changes were made between the phases which contributed to the difference in results between Phase 3 (Table 4.3) and Phase 4 (Table 5.17). In Phase 3 wind units bid into the market at their variable cost. This was changed in Phase 4 to account for the production tax credit. A broad assumption was made that all wind units would get the production tax credit and that their variable cost would be negative $20/MWh. This greatly reduced that amount of curtailment reduction available between the base case and change case. Wind curtailment reduction is shown for the real time market. The change to the base case between Phase 3 and Phase 4 will also have had an effect on wind curtailment; however, the change in the bidding of wind units has a much larger affect. The reduction is present because the system is better able to handle unexpected fluctuations in wind output with the addition of a new hydro generator in Manitoba and a new transmission line. Table 5.17 is considered to be more representative of the reduction of northern MISO wind curtailment reduction than Phase 3 study results (Table 4.3).

Run	Northern MISO Wind Curtailment Reduction (GWh)
East	4.54
West	1.35

Table 5.17: Northern MISO Wind Curtailment Reduction

Phase 4 Conclusion

Phase 4 of the Manitoba Hydro Wind Synergy Study was a culmination of the work done throughout the previous three phases. This phase looked at a wide range of sensitivities while the previous phases concentrated on the specifics of a single scenario. A wide range of benefits were found showing the importance of each of these transmission options. The following are highlights of this phase.

- Both transmission options show very similar benefits in aggregate for both modified and unmodified production cost savings as well as load cost savings
- Reserve cost savings are very small compared to production cost and load cost savings
- In both options, the increased savings shown in the modified production cost are largely due to increased exports to other regions excluding Manitoba Hydro
- Annual Modified Production Cost Savings range from $228 to $455 million for 2027
- Annual load cost savings range from $183 to $1,302 million for 2027
- Benefit-to-cost (B/C) ratios range from 1.70-3.84
- The East and West 500 kV transmission options show similar benefits and both have a B/C ratio higher than one
- Benefits vary depending on how imports into MISO are priced and how exports are valued
- Three MTEP12 futures were analyzed along with three hydrological conditions

6 Reliability Analysis

A reliability analysis was conducted to determine whether either the East or West 500 kV transmission options could harm grid reliability when placed into service.

6.1 Model Setup

The MTEP 2012 power flow model representing a 2022 Summer Peak condition was utilized. Modeling of Transmission Service Requests (TSRs) and Generator Interconnection Procedures (GIPs) was based on “Manitoba Hydro Group TSR System Impact Study Transmission Options W.1 and W.2” with the revision date of April 19, 2010. Flow on the Manitoba HydroEX is 1,850 MW (south) in the summer peak benchmark case.

The three HVDC Bi-Poles are set at 3670 MW in the benchmark case as follows:

- Bi-Pole 1 = 958 MW
- Bi-Pole 2 = 1032 MW
- Bi-Pole 3 = 1680 MW

The Bi-Pole inverters were used to source the south bound requests (Table 6.1).

250 MW Injection	750 MW Injection	1100 MW Injection
• Bi-Pole 1 = 1241.4 MW • Bi-Pole 2 = 1339.3 MW • Bi-Pole 3 = 1335.4 MW	• Bi-Pole 1 = 1405.7 MW • Bi-Pole 2 = 1516.5 MW • Bi-Pole 3 = 1512.1 MW	• Bi-Pole 1 = 1519.6 MW • Bi-Pole 2 = 1639.5 MW • Bi-Pole 3 = 1634.7 MW

Table 6.1: Manitoba Hydro to United States TSR Sources

Study TSRs were sunk to the generators in Table 6.2.

Bus #	Generator Name	MW
WPS (A380)		
699993	Skygen Unit #1	172
699661	West Marinette Unit #3	75.0
699597	Pulliam Unit #31	74.0
698925	AP_PPRGT Unit	42.3
699591	Pulliam Unit #5	51.0
699679	Weston Unit #1	62.0
699595	Pulliam Unit #6	23.7
GRE (A388)		
615031	Pleasant Valley Unit #1	29.0
615041	Lakefield Unit #1	84.9
615045	LakefieldUnit #5	86.1
MP (A383)		
608667	Potlatch	24
608676	Hibbard Unit #3	20
608676	Hibbard Unit #4	15
608776	Boswell Unit #1	54

Bus #	Generator Name	MW
608777	Boswell Unit #2	54
608665	Thomson	36
608702	Laskin Unit #1	25
608702	Laskin Unit #2	22
Xcel Energy (A416)		
600073	River Falls	20
605308	Hatfield	6
600035	Wheaton Unit #4	24
WEC (A417)		
699322	Germantown Unit #5	83
699507	Valley Unit #2	17

Table 6.2: Manitoba Hydro to United States TSR Sinks

6.2 Criteria

The following system conditions were considered for the steady-state analysis.

- NERC Category A with system intact (no contingencies)
- NERC Category B contingencies
- NERC Category C contingencies
- Outage of single element 100 kV or higher (B.2 and B.3) associated with single contingency event in the following areas: ATCLLC (WEC, ALTE, WPS, MGE, UPPC), DPC, GRE, ITC Midwest, Manitoba Hydro, MP, OTP, SMMPA, WAPA, XEL
- Outage of multiple-elements 100 kV or higher (B.2 and B.3) associated with single contingency events in the Dakotas, Manitoba, Minnesota, Wisconsin

The Manitoba HVDC power order reduction scheme was not simulated for this study. Overloads that would be properly mitigated by a Manitoba HVDC runback were not included in the results of this study report. Thermal limits were identified using AC solve methods. Voltage and stability considerations were not included in the sensitivities.

6.3 Methodology

No-harm test studied the impact of both transfer and the transmission plan put together. Pre-case for this study didn't have transmission plan or the transfer modeled in it, whereas post-case included both transfer and the transmission plan in it. AC contingency analysis was performed on pre and post cases followed by a comparison of results.

6.4 Grid Upgrades Needed

It was found that the West option needs $8 million worth of upgrades and the East option didn't need any system upgrades for it to be constructed. The specific upgrades needed are.

- **West 500 kV Option**
  - Maple River Transformer R3 230/345 (Cost: $4 million)
  - Maple River Transformer R4 230/345 (Cost: $4 million)
- **East 500 kV Option**
  - No valid constraints found.

7 Conclusions and Lessons Learned

Over the course of this study, significant amount of effort was spent integrating and validating a new simulation tool, creating detailed hydraulic systems for Manitoba Hydro, simulating the uncertainties of the real time market, developing new methods to examine the benefits of wind-hydro synergy and determining the benefits of new transmission and generation to the MISO footprint.

Many lessons were learned over this time. It takes a long time and a lot of effort to fully integrate and test a new production cost model, though it is worth the effort to ensure the accurate representation of the electric and hydraulic systems. Also, determining the benefits additional hydro generation and transmission have on MISO's wind resources is a difficult task. Novel improvements were made to the simulation approach, most noteworthy being the Interleave Method and use of Value of Water in Storage. These changes modeled the sequential DA-RT dispatch of hydro generation and its response to market signals. Ultimately, the benefits of hydro-wind synergy will be reflected in production cost savings and in load cost savings, but separating the benefits of the synergy itself from the other benefits to the system is a challenge. The best methods to identify wind synergy benefits include examining the reduction in wind curtailment, visually inspecting the wind and hydro outputs and looking at the correlation between wind and hydro. This provides some evidence that the total cost savings include hydro-wind synergy benefits.

Using a combination of traditional simulation techniques, and the new ones developed specifically for this study, allowed for examination of a diverse set of benefits. The synergy between wind and hydro was explored in great detail along with the cost savings of increasing energy delivered into MISO. The benefits of these findings are plentiful and show that expanded participation of Manitoba Hydro in the MISO market through increased transmission, generation and market changes would benefit all parties involved.

Phase 1 laid the building blocks for the rest of the study by developing the processes needed to examine the benefits of increased hydro exports into MISO and explore the synergy between wind and hydro. This was also the time when the PLEXOS model was fully integrated with the MISO planning processes and tested for accuracy.

Phase 2 examined possible changes in MISO's External Asynchronous Resource (EAR). Savings were found when extending the EAR to include price sensitive participation in both directions instead of the current design of only allowing price sensitive exports into MISO. MISO was able to realize $8.74 million in benefits over the planning year of 2012. The change to move to a bi-directional EAR is already under way within the MISO market and is expected to be completed in 2015.

Phase 3 examined three possible future 500kV transmission options (East, West and Central) which would be able to deliver new hydro generation in Manitoba Hydro to MISO. The planning year of 2027 was used because all relevant construction would be completed by this time. This phase delved into the synergy between the wind and hydro generation, finding how increased hydro generation and transmission could help issues associated with increased wind penetration in MISO. A wide variety of benefits were found for all three transmission projects, but the Central option was abandoned because it had the lowest benefit/cost ratio.

Phase 4 expanded on Phase 3, including nine scenarios to stress test the remaining two transmission options. Three MTEP12 futures and three hydrologic futures were used to test a wide variety of potential benefits. The Benefit-to-Cost (B/C) ratios for the East and West plans ranged from 1.69 to 3.84 using the modified production cost metric developed specifically for this study.

The Manitoba Hydro Wind Synergy Study is an exploratory study and the results cannot be used to justify including a project in MTEP13 Appendix A as the assumptions used for analysis are different than those outlined in the MISO tariff.

The projects show large benefits to MISO and exceed the cost to build the line, thus final recommendation from this study is to include both the East and West 500kV transmission options in the MTEP13 Appendix B.