REPORT ON EXPORT PRICES AND REVENUES RELATING TO THE NEED FOR AND ALTERNATIVES TO (NFAT) MANITOBA HYDRO'S PREFERRED DEVELOPMENT PLAN

Report by:

Potomac Economics, Ltd.
Independent Expert Consultant

POTOMAC ECONOMICS

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Executive Summary

A. Overview

Manitoba Hydro is seeking government approval of its preferred development plan for investments in generation and transmission capacity in order to support domestic load growth and expand opportunities in export markets.

The Manitoba Public Utilities Board ("PUB") was asked by the Government of Manitoba to conduct a Needs For and Alternatives To ("NFAT") review of the Manitoba Hydro development plan. A panel of PUB members ("the NFAT Panel") was selected by the PUB Chair to conduct the review. In order to proceed with its review, the NFAT Panel will use evidence presented by Manitoba Hydro, interveners, and independent experts provided by PUB. Potomac Economics is one of the PUB independent experts and our report addresses expected export market conditions in the markets administered by the Mid-Continent Independent System Operator ("MISO"). The MISO markets are the primary source of export revenues for the preferred development plan.

Potomac Economics is the Independent Market Monitor for the MISO. In this role, we closely monitor prices, investments, market structure, and market outcomes. We are also the Independent Market Monitor for ISO-New England, the New York ISO, and ERCOT (Texas). We rely on this broad experience with the development and performance of wholesale electricity markets to conduct this study.

Manitoba Hydro's preferred development plan establishes generation capacity which exceeds the projected domestic load requirements for a significant period of time. The excess capacity, along with other investments in the plan to expand transmission ties to the US, would support export sales. According to the plan, by building larger plants and using the excess capacity to support export sales, the cost of meeting the growing domestic load in Manitoba is lower than if capacity was built to meet load growth alone. The preferred development plan is expected to deliver the expected benefits if actual conditions meet certain critical projections. Among these critical projections is the revenue that can be earned from sales of energy and capacity to the MISO markets in the US. These revenues are based on export price forecasts from six consultants retained by Manitoba Hydro. Our report assesses the price forecasts and other associated issues that form the basis for Manitoba Hydro's projected MISO export revenues.

In order to assess Manitoba Hydro's price forecasts, we developed our own price forecast based on a method and approach that we find to be a reasonable and transparent. Our method is based on forecasts of key drivers of MISO market prices. These key drivers are fuel prices, load growth, generation retirement and additions, new-build generation capital and operating costs, environmental regulations, and congestion.

Manitoba Hydro's six consultants based their forecasts on essentially the same key drivers. However, we believe certain assumptions made by the consultants tended to overstate the level of future prices. Due to limits on the availability of the underlying data from the consultants' models, we were not able to perform a detailed review of the consultants' models nor could we adjust the specific assumptions in the consultants' forecasts to address differences. As result, we provide an alternative forecast and recommend that these forecasts be used to assess revenues projected under the development plans.

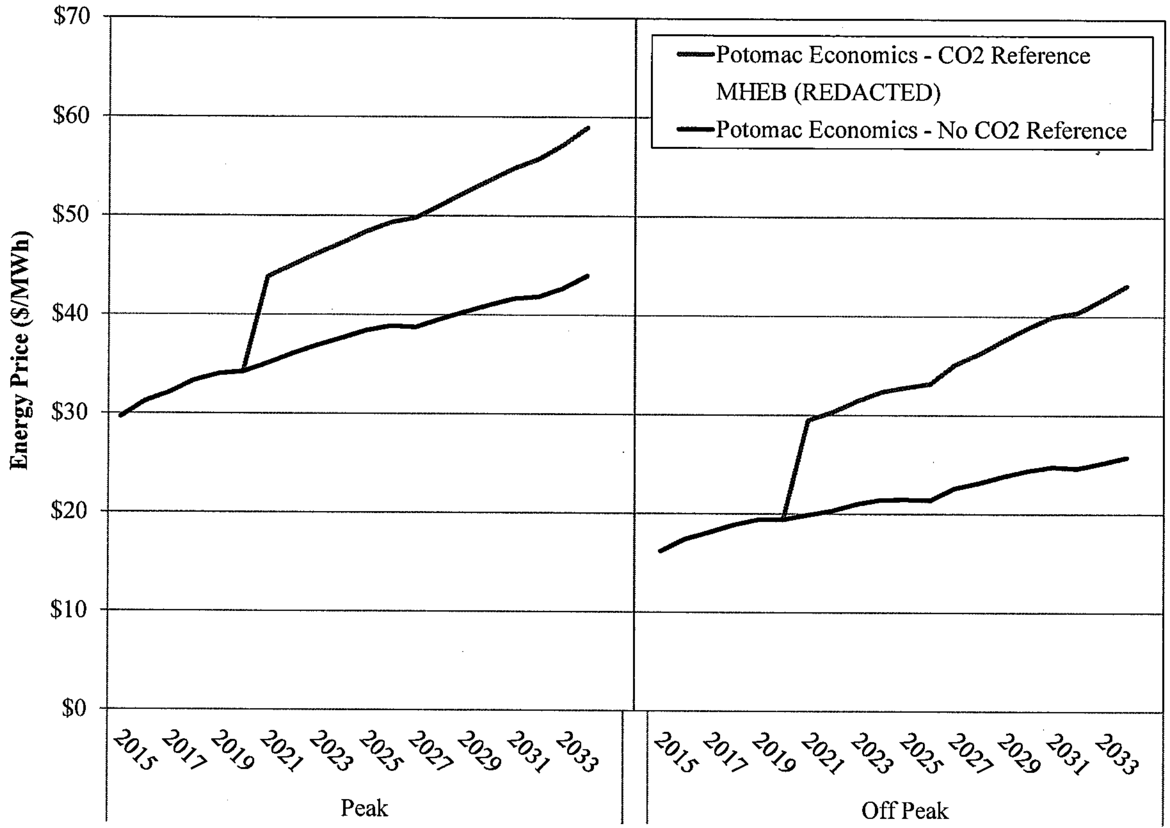
B. Summary of Results

Our forecast is based on MISO supply and demand characteristics and recent market outcomes. Changes in these characteristics and outcomes are forecasted for future years based on assumptions regarding the evolution of key drivers noted above.

Our results generally forecast lower prices than Manitoba Hydro's consultants due to assumptions on key inputs. In particular, our models generally rely on lower natural gas price forecasts, lower growth rates of demand, and lower quantities of coal plant retirements. As explained herein, our point-of-view on these key assumptions is based on the reference case used by the US Energy Information Agency (EIA) in its 2013 Annual Energy Outlook.

Figure 1 shows our two reference case forecasts for on-peak energy and off-peak energy prices compared to the Manitoba Hydro reference price forecasts. Manitoba Hydro's reference price forecast is the composite of its six consultants' forecasts. We produce two reference case forecast in order to reflect two CO2 price scenarios – one scenario is based on the reference forecast of Mr. Craig Sabine of MNP, and the other is a reference case with no CO2 costs. We explain these various cases in Section II.

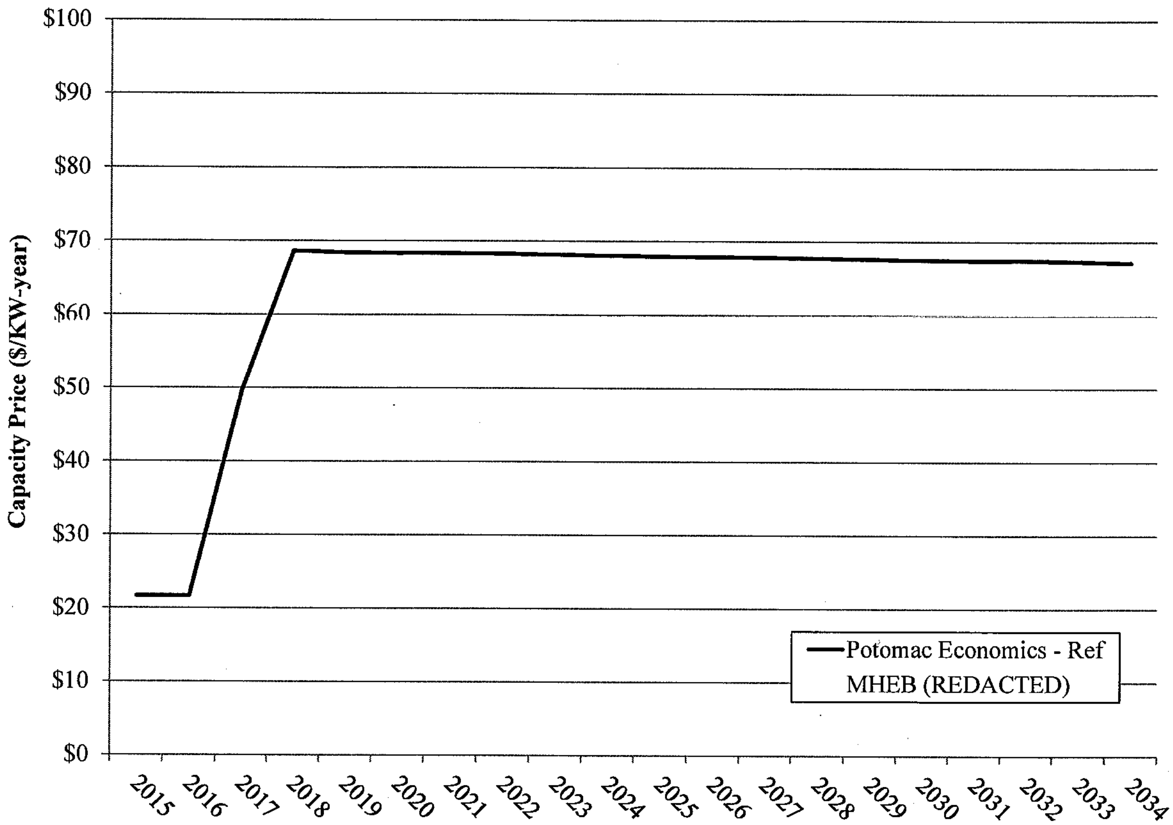
Figure 1: MH and Potomac Economics Reference Case Energy Forecasts



As the figure shows, the Manitoba Hydro forecasts [redacted] for both on-peak and off-peak energy prices, although our reference forecas[redacted] forecast period for on-peak energy. In this report, we will explain how we developed our price series and why they are different from the Manitoba Hydro prices.

We also forecast capacity prices, which are based on our estimate of the net cost of new entry ("net CONE"). We assume that when surplus capacity dissipates, the capacity price will rise to the level necessary to incent the construction of new resources. As we explain herein, this capacity price is at most the net CONE of a new peaking resource, which is equal to the resource's cost of new entry less the variable profit it would earn in the MISO's energy and ancillary services markets. However, in the short-run, we do not expect the market to support the net CONE. Figure 2 shows the comparison of our reference case capacity price forecast and Manitoba Hydro's forecast.

Figure 2: MH and Potomac Economics Reference Case Capacity Forecasts



As the figure shows, our price [redacted] estimates by Manitoba Hydro. The main reason for this is our assumptions regarding the cost of new entry. Our assumptions regarding the costs to build an advanced combustion turbine [redacted] that assumed by Manitoba Hydro consultants. We note that the capacity prices that we forecast [redacted] han that which Manitoba Hydro can actually achieve, due to regulatory and other constraints, discussed herein.

We present forecasts for energy and capacity prices under four scenarios that examine alternative assumptions. In addition to our two reference cases, we examine alternative assumptions concerning natural gas prices and economic growth. Changes in these assumptions can substantially affect Manitoba Hydro's forecasted revenues.

C. Organization of Report

We were asked by the PUB to provide an Independent Expert Report on MISO market conditions that Manitoba Hydro will face under its proposed development plan. Because the critical factor in the MISO markets is prices, the main part of our report is in the following three sections:

Section I discusses the price forecasts used by Manitoba Hydro;

Section II presents our own forecasts for energy prices; and

Section III presents our own forecasts for capacity prices.

In addition to assessing the price forecasts, we also assess issues associated with other expected market conditions that affect future export prospects. These other issues include: (2) developments in neighboring regions; and (3) export volumes and pricing. These other issues are discussed in Section IV.

I. THE CONSULTANTS' PRICE FORECASTS

Manitoba Hydro used six external consultants to produce price forecasts for its financial model. These six forecasts are used on an equal-weight basis to establish a single consolidated forecast. In this section, we review and discuss the six forecasts.

A. Products

The company expects to sell an on-peak energy product, an off-peak energy product, and a long-term "dependable" product. The on- and off-peak products are assumed to be priced based on the consultants' on- and off-peak price forecasts. The long-term dependable product is assumed to include a capacity component. Accordingly, Manitoba Hydro asked the consultants for 20-year forecasts for the period 2015-2034 for on-peak energy, off-peak energy, and capacity prices.

B. Summary of Consultants' Forecasts

The six consultants use variations on a common approach to forecast energy prices. The approach uses a so-called "fundamentals" model that basically attempts to simulate the energy dispatch of the electrical system to determine which units are on margin during each hour of the year. The hourly prices simulated for on-peak periods are the basis for the on-peak prices and the hourly prices simulated in the off-peak periods are the basis for the off-peak prices.

The consultants generally use the forecasted energy prices and the estimated cost of new entry for a new peaking resource to forecast capacity prices. In particular, the forecasted capacity price in each year is generally equal to the annual fixed cost of new entry less the anticipated "net revenues" earned by a peaking unit. Net revenues are the revenues a unit would earn in MISO's energy and ancillary services market in excess of its variable production costs. This net revenue approach is a reasonable way to forecast the capacity price. It is important to recognize that the MISO does not currently have a well-functioning capacity market that would establish prices consistent with this net revenue methodology. Nonetheless, one may assume that Manitoba Hydro may be able to sign bilateral contracts to sell capacity at these price levels to load-serving entities in MISO that would otherwise be short of capacity. There is some uncertainty about this assumption which is discussed in Section III.

The following is the list of consultants and the summary of the results of their analysis and our discussion of their process and results. The consultants each provided forecasts of off- and on-peak energy prices and annual capacity prices. The consultants provided a "reference case" and most consultants provided a "low" and "high" case. Our discussion of the consultants' models is confined to the on-peak energy price and the capacity prices associated with the "reference case." The issues identified with the reference case also tend to adversely affect the consultants "high"- and "low" cases in comparable ways. Similarly, the problems we see with the on-peak energy price estimates, also affect the off-peak estimates in the same manner. Therefore, we focus on the areas of concern associated with the reference case for on-peak energy and capacity.

At the outset, we note that detailed information regarding each of the consultants' models, assumptions, and output was limited. We generally only received high-level representations of the models and inputs. This limited our ability to critically review the consultants' results and ultimately compelled us to produce our own forecast. Nonetheless, we briefly summarize each of the six consultants' forecasts in the following subsections.

1. The Brattle Group

The Brattle Group forecasts reference case on-peak energy prices in the near term just under \$40/MWh until about 2020, then increase to over \$60/MWh by the end of the 20-year forecast period. As indicated above, the forecast is based on a simulated dispatch of the system using a variety of assumptions. Given our limited information regarding the model and assumptions, it is not straightforward to determine exactly what drives the price forecast. However, we note three key assumptions used by the consultant (and which generally are the key assumptions used by all of the consultants). The first is the assumed introduction of carbon taxes in 2020. This starts at \$15/ton and grows until 2034 to about \$24/ton. The second key assumption is the increase in the price of input fuel -- natural gas prices increase by 60 percent over the 20-year period. This has an impact on the on-peak price directly, but is also interconnected with the third key assumption, which is the retirement of coal plants. Lower coal capacity causes natural gas-fired units to be on the margin in more hours. Both the additional hours on the margin and the higher natural gas prices will cause energy prices to be higher. Brattle did not report MISO-wide retirements in its work papers. It reports MRO-West retirements because its forecast model focuses on the MRO West sub-region of MISO. However, a report by Brattle in 2013 indicates between 11 and 16 GW of MISO coal plant retirements. This level of MISO coal plant retirements is substantially above the level we assume in our reference case. As explained below, we assume 6 GW of MISO-wide coal plant retirements. The emissions and fuel cost assumption along with the high level of coal plant retirements are likely to overstate energy prices.

Capacity prices are based on the least-cost capital investment needed to meet planning reserves over the 20-year horizon. The annual fixed cost of this investment (primarily capital carrying costs) net of revenues earned in the energy markets, establishes the capacity price for each year. This is affected primarily by the energy price forecast and the net retirement, but also capital costs of new facilities. As a noted above, this approach assumes Manitoba Hydro will sell capacity to utilities in MISO on a bilateral basis to meet the utilities' planning reserve requirements, rather than selling in the short-term capacity market presently existing in MISO.

Capacity prices estimated by Brattle are zero until 2019, reflecting an assumed capacity surplus in MISO until that time. After 2019, the price rises to over $70/kW-year. The Brattle work papers do not specify what type of unit is setting the capacity price in a given year. However, the capacity price is consistent with the capital cost identified by the consultant for both the natural gas-fired combustion turbine and the natural gas-fired combined cycle plant ($1200/kW net of modest energy market revenues). Both the CT and the CC are assumed to have capital cost of about $1200/kW, which is roughly $120/kW-year in carrying and fixed costs. The lower value of $70/kW-year could reasonably reflect variable profits in the energy markets.

[redacted]. In particular, the consultant assumes a cost of $1200/kW for a CT, whereas the EIA has identified an advanced CT as having a capital cost of approximately $700/kW. This would have a significant effect on the consultant's capacity prices. EIA's estimate of the advanced combined cycle plant ($1000) and the conventional combined cycle plant ($900/kWh) are also somewhat lower than the estimated cost used by the consultants.[1]

1 See, EIA, "Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants", April 2013, http://www.eia.gov/forecasts/capitalcost/pdf/updated_capcost.pdf

We believe the emissions and fuel cost forecasts assumptions may overstate the expected cost profile of fossil-fuel fired resources and, thus, overstate energy prices. This may also understate capacity prices since net revenues would likely decline under a projection of lower energy prices. But this effect is confounded by the apparent overstatement of generator capital costs. Based on the information provide, we are not able to disentangle these countervailing effects and so we cannot recommend using the Brattle estimates as a basis of future prices.

2. [redacted]

[redacted]

[redacted]

[redacted]

3. [redacted]

[redacted]

[redacted]

[redacted] [redacted]

[redacted]

[redacted]

[redacted] [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

C. Conclusions on Consultants' Price Forecast.

In general, the key assumptions used by the Consultants [redacted] This is particularly the case with respect to (1) natural gas prices, load growth, coal retirements, and cost of new entry. With respect to CO2 prices, our reference case assumptions tend to be [redacted] We explain our forecasting approach in the next section. In the Tables below, we compare our forecasts to the consultants.

The Table below shows a comparison among the six consultants along with our own forecasts of (1) on-peak energy; (2) off-peak energy; and (3) capacity.

Figure 3: Comparison of Reference Case On-Peak Energy Prices

REDACTED

Figure 4: Comparison of Reference Case Off-Peak Energy Prices

REDACTED

Figure 5: Comparison of Reference Case Capacity Prices

REDACTED

D. Composite Forecasts and Alternative Cases

Manitoba Hydro used the consultant's price forecast to create a single composite forecast, which is basically an average of the consultants' forecasts. The following three charts show the composite price forecasts for the three power products (1) on-peak energy; (2) off-peak energy; and (3) capacity. In each case, we show the Manitoba Hydro composite forecast the consultants' reference case as well as the composite "high" and "low" forecast cases. We also show our reference case and the "high" and "low" alternatives for each forecast.

The low and high case alternatives were produced by each consultant at the request of Manitoba Hydro. Manitoba Hydro required plausible scenarios that could represent the lower and upper limits of pricing trends. While we also produce two alternative cases, our cases are based on likely alternatives that together with the reference case, represent a large range of probable outcomes. In other words, we expect that future prices are very likely to fall within the bounds of our three forecast scenarios.

Figure 6: Manitoba Hydro On-Peak Energy Price Forecasts

REDACTED

Figure 7: Manitoba Hydro Off-Peak Energy Price Forecasts

REDACTED

Figure 8: Manitoba Hydro Capacity Price Forecasts

REDACTED

II. Potomac Economics Energy Price Forecast

Because detailed information regarding the consultants' models, input data, and results was not available to Potomac Economics, we evaluated their reasonableness by comparing their forecasts to a range of forecasts we developed. This section of the report describes our methodology and provides a detailed discussion of the results.

A. Overview of Forecast Model

Our forecast is based on historical publicly-available market outcomes in the MISO markets for 2011 and 2012. Our approach uses these actual day-ahead market results and adjusts them to anticipated changes in future market conditions, such as fuel prices, capacity, carbon taxes, and load growth. The MISO market data we use includes hourly data on system load and capacity, system marginal price, and supply offers. The day-ahead supply offers specify offer price, offered quantity (MW), fuel, and whether the offer was accepted. By stacking the offers in accordance with energy offer price we establish an hourly supply curve. We adjust the hourly supply curves to account for changes in fuel costs, new capacity additions and retirements, and carbon taxes. Hence, we establish a supply curve for all future hours in the twenty-year forecast horizon (2015-2034). Using actual hourly generation demand and assumptions regarding the growth of load, we establish forecasted load in every hour of the forecast horizon. Based on the intersection the hourly supply curve and the hourly system load (along with some operational adjustments described below), we can establish a system marginal price for each hour of the twenty-year forecast period. These hourly prices are the basis for our on-peak and off-peak energy prices.

Locational Marginal Prices. The prices estimated using the hourly supply curves are the system marginal prices ("SMP"). They do not reflect the locational marginal prices (LMP) that would be received by a seller of power at various locations in MISO. Congestion and marginal losses will cause a locational price to be different from the SMP. Therefore, we compute a locational marginal price at the Manitoba interface with MISO by subtracting losses and congestion costs from the SMP. Congestion costs are estimated based on the historical relationship between congestion and factors that tend to explain their level, such as time of day, generation, load levels, and exports from Manitoba Hydro to MISO. We use the historical average marginal losses as the estimate of future losses.

Capacity Prices. Capacity prices are estimated based on the net cost of new entry (net CONE). This net CONE is the annual carrying cost and other fixed cost of a new combustion turbine less the variable profits earned in the MISO energy and ancillary services markets. Based on the heat rate of a new combustion turbine (CT), any hour when the SMP is above the variable energy cost for the CT, the difference in marginal energy cost and the LMP is the net revenue for that hour. The resulting total net revenues are deducted from the annual fixed cost of the new unit to arrive at the estimated capacity price. The estimated price is the amount an investor would need to be paid to profitably enter the market with the prospect of earning MISO energy and ancillary services revenues. However, this price is relevant only if capacity is needed. In times of capacity surplus, the capacity price is likely to be less than this price and, indeed, sometimes close to zero. This presents a substantial risk for Manitoba Hydro that its capacity revenues may be much lower than expected.

B. Specifics of Forecast Model

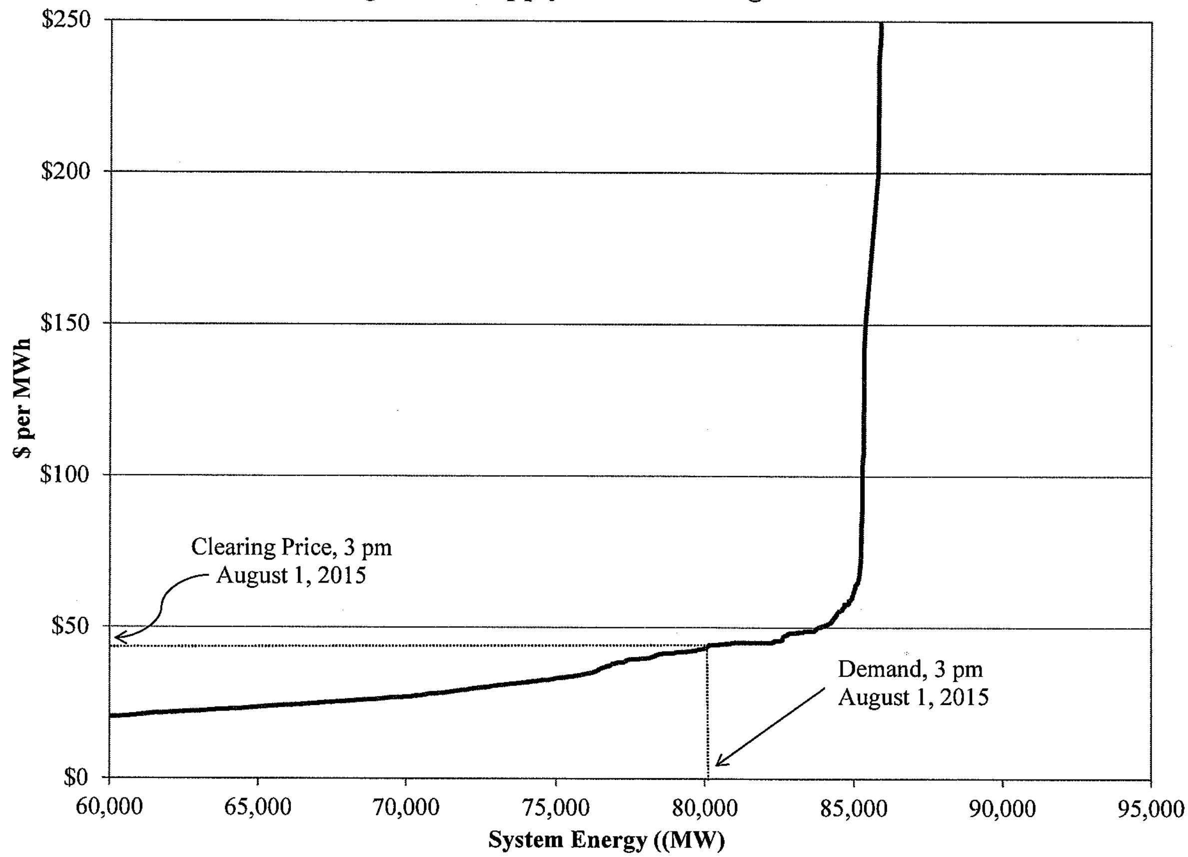
1. Hourly Supply Curves and Demand

Our forecast model uses two years of historical MISO market data and creates two forecasts for each hour for the forecast period 2015-2034. There are two forecast for each hour, one based on 2011 hourly market data and the other on 2012 hourly market data. We average the two forecasts to get the forecast for each future hour.

For each historical hour, the day-ahead MISO data contains an offer curve for each resource that indicates the quantity, fuel type, and offer price (for start-up, energy, and ancillary services). We use these offers to establish an hourly supply curve for each historical hour, which is a simple stack of the MW offers in ascending order of offer price for each MW block.

We next use hourly generation demand to identify where system demand intersects the historical supply curve for each historical hour. Hourly system demand also is publicly available from MISO. It contains day-ahead system demand as well as net imports so that we can identify the hourly load that was served by the available supply in each historical hour. Comparing the hourly load level to the supply curve identifies which unit would supply the last MW of load under the assumption that all units are dispatched fully.

Figure 9: Supply Curve for August 2015



Note: The "clearing price" shown is the basis of the forecast SMP. To arrive at the SMP, the clearing price is increased to reflect operational issues. This increase is derived from the historical clearing price and the historical SMP for each hour.

This marginal unit representing the direct intersection of the hourly supply curve and the hourly load is not likely to be the one that actually sets the system marginal price. This is because of operational constraints. Operational constraints occur as a result of constraints in the operation of generators. There are a number of operating constraints that may cause the strict stacking of units from low to high marginal cost not to match the actual dispatch. First, units may not be fully dispatched due to ramp limits in a given hour. In such a case, units may be dispatched at a higher or lower output level than would be indicated by running costs alone. A high cost unit may also be running because it is meeting a minimum run time. Such a unit may be more expensive than other units not fully running because the more expensive unit is needed in some future hour and needs to be started in advance. Or the more expensive unit was needed in a recent hour and needs some time to turn down or turn off.

In each hour, MISO publishes the day-ahead SMP. With the SMP we can identify the unit that sets the marginal price on the historical hourly supply curves. Because this is rarely the unit that would clear in a "pure" sense from stacking the units against demand, in each historical hour we measure the movement up the supply curve that was necessary for MISO to undertake to dispatch the system in that hour given the operational restrictions it must accommodate. This value is expressed as a percentage increase in the energy "clearing" price. We retain this value, which we call the hourly "operational adjustment," because it is important for estimating the market clearing price for future periods.

2. Clearing the Hourly Forward Market in Future Hours

To clear the hourly market, and establish the forecast price for that hour, we adjust each historical hourly supply curve based on anticipated changes in key supply variables (fuel costs, etc.). We explain the evolution of the supply curve over the time horizon below. We also assume load grows at certain rates. Hence, in every future hour, we have (1) the estimated forecast hour supply curve; (2) the forecast hourly load; and (3) the "operational adjustment" (based on historical movement along the supply curve to clear the market, described above). Matching the estimated supply curve to the forecast demand for each hour, we identify the marginal unit in a "pure" market clearing. We then adjust the forecasted price by a percentage amount equal to the "operational adjustment," discussed above, to account for operating constraints. The resulting price is the forecast SMP for that hour.

3. Formation of Supply Curves

The process of clearing the hourly market described in the previous subsection is based on estimated supply and demand. The estimated supply curves for future hours evolve from the historical supply curves. If all key supply variables remained fixed, then the forecast of each future hour would be identical to the base historical hours from 2011-2012. However, of course, key variables change. In particular, we create new supply curves for each hour based on projections of (1) fuel prices; (2) additions and retirements of generating capacity; (3) load growth; and (4) carbon taxes. In addition, we make assumptions about the cost of new capacity in order to estimate the cost of new entry to support the capacity price forecasts. We discuss the particular projections of these key assumptions in the next subsection. In this section, we describe how the supply curves change as a result of the key assumptions.

Fuel Prices. When fuel prices change, the marginal cost of producing energy from a resource using that fuel will change. In a competitive market, suppliers submit offers that are consistent with their marginal costs. Therefore, the offer prices of the unit will change as fuel prices change. Hence, each hourly supply curve in a given year will change based on the change in fuel prices for that year compared to the historical year.

CO2 Prices. CO2 prices are projected for potential changes in law regarding green-house-gas emissions.[2] CO2 prices are based on cost per ton of CO2 output. Coal and natural gas have specific CO2 content. According to the US EPA, Average CO2 output of a coal unit is 1.02 (metric)\tons/MWH and for a natural gas units about 0.516 tons/MWh.[3] This emissions rate is multiplied by the CO2 price forecast for each year to estimate the additional cost to be added to the unit's offer curve. For example, the CO2 price in 2021 is projected to be $13.14/(metric) ton. Therefore, offer curves for coal units have an increased incremental energy component of $13.14/ton x 1.02/tons/MWH = $13.40/MWh. For natural gas units, their incremental energy offers increase by $13.14/ton x 0.516/tons/MWh = $6.78/MWh.

Generating Resources. The historical supply curves for each hour are based on units that are in-service during that particular historical hour in the 2011-2012 historical years. In each subsequent year, the set of in-service units changes based on assumptions regarding *new* additions and retirements. This can result in a re-ordering of the capacity in the supply curve through "re-commitment" discussed in the next subsection. Our base assumptions regarding additions and retirements are based on the EIA Annual Energy Outlook assumptions.[4] We adjust these assumptions as needed to satisfy MISO's resource adequacy needs. When additional

2 We adopt the CO2 prices developed by Independent Expert Consultant Mr. Craig Sabine of MNP.

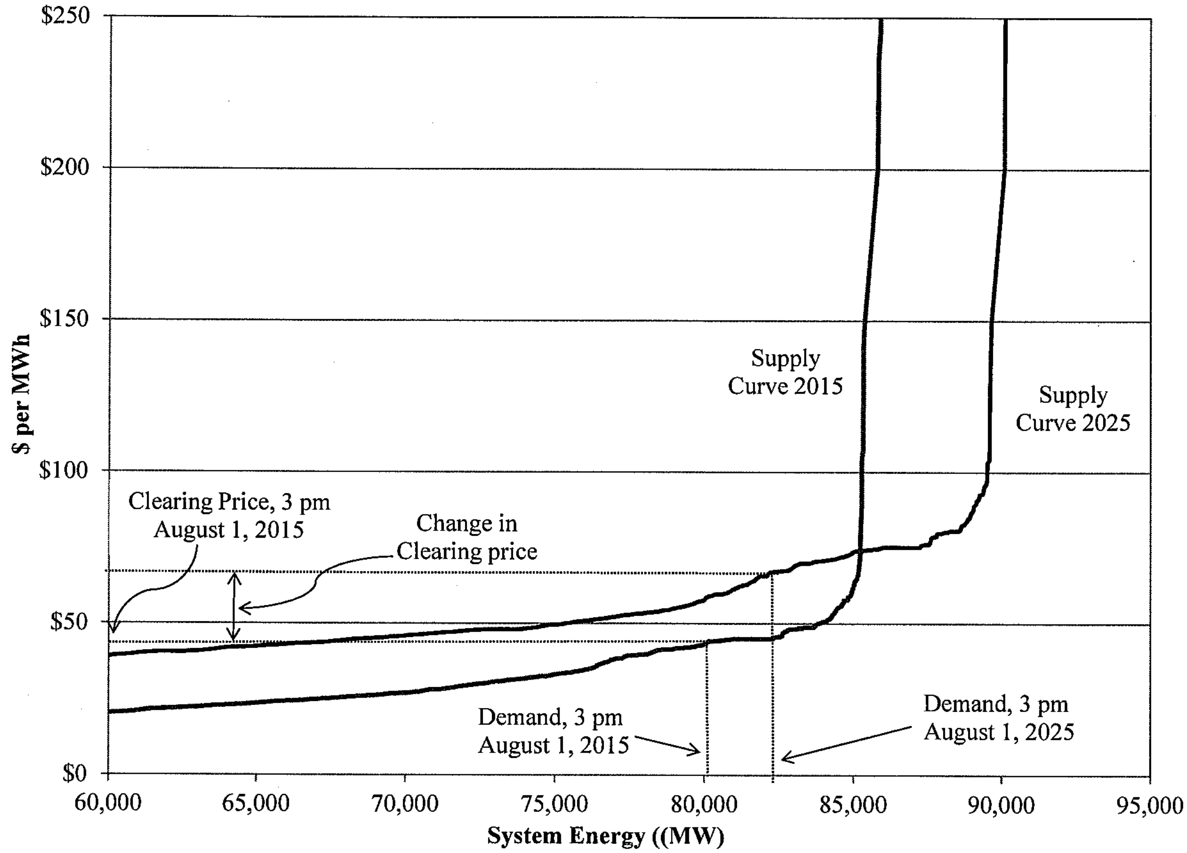
3 See EPA, http://www.epa.gov/cleanenergy/energy-and-you/affect/air-emissions.html

4 See, http://www.eia.gov/forecasts/aeo/data.cfm

resources are needed, we assume one-half of the new resources are combined cycle natural gas units and one-half are natural gas combustion turbines.

When the EIA data indicates retirements of a unit type for a specific year (e.g., coal units), we choose units to retire based on units net revenue for the previous year. The least profitable are retired first.

Figure 10: Example of Change in Supply Curve



Note: The figure shows the change in forecast clearing price in our model resulting from changes in supply and demand between 2015 and 2025.

4. "Headroom" and Daily Recommitment

The supply curve for each future period also is adjusted to reflect the fact that future periods will have different supply and demand characteristics due to changes in key drivers, mainly load and the composition and quantity of available generating capacity. The supply curve for a historical hour is based on the historical load and the commitment of units in service at the time. When load changes in a future hour, it is not reasonable to simply move along the historical supply curve to a new load level to clear the market for that future hour. Instead, at a new load level, some units that were not committed in the historical hour may be economic for commitment at a higher or lower load level and therefore be added to the supply curve. This type of recommitment may also be appropriate if new units are added or existing units retire - these new units may replace existing units in the stack or existing units not initially committed may replace retired units in the stack.

In order to recommit generation, we seek to ensure the system has adequate resources to meet forecasted load, ancillary services, and the market headroom requirement (the headroom requirement is the additional operating flexibility required by RTOs to meet ramp demands). Much like MISO's day-ahead market, our process for re-committing resources is performed on a daily basis. If headroom is inadequate in some hour, the daily commitment is revised to ensure that sufficient generating capacity is available for dispatch.

The revised commitments are is then used as the basis for the hourly supply curves for that day and the market is cleared in accordance with the process described above.

5. Reference Forecast Assumptions and Alternative Cases

We develop forecasts under three alternative scenarios. Each differs from the other according to different assumptions on key supply and demand inputs. As we discussed above, aside from the historical MISO data that form the base case supply curves, a price forecast depends on assumptions about (1) load growth; (2) fuels costs; (3) retirements and additions; (4) CO2 prices; and (5) cost of new generation (for capacity prices). Our three scenarios are as follows:

a. Reference Cases

We use two reference cases due to the significant uncertainty regarding the introduction of CO2 costs. We develop a first case, called simply, the "Reference Case," which includes positive CO2 costs. Our "Reference No Carbon" case is very similar to the reference Case except CO2 costs are zero, and the load growth is slightly higher.

Both the Reference Case and the Reference No Carbon case are based on the assumptions used by the EIA in its 2013 Annual Energy Outlook for its own reference case. The EIA reference case assumes CO2 costs are zero. Therefore, the EIA reference case assumptions on load, capacity, and fuel prices are used in our Reference No carbon Case.

For our Reference Case (with Carbon), we depart from the EIA reference case in order to reflect CO2 prices. We introduce a CO2 price in 2021, consistent with the forecast of Mr. Craig Sabine of MNP who is the Independent Expert Consultant for the PUB in this NFAT on matters relating to CO2 pricing. According to Mr. Sabine's reference case, the CO2 price will be zero until 2021, at which point it will be $13.14/ton and increases by 5 percent per year thereafter. We reflect Mr. Sabine's forecast by adjusting offer curves for fossil fuel plants to account for the additional CO2 cost. The adjustment to offer curves to reflect this additional cost was described above.

We also slightly reduce the EIA Reference Case load growth starting in 2021 to reflect non-zero CO2 prices starting in year 2021. In particular, for the years 2015-2021, we use the compound average growth rate (CAGR) from the EIA reference case for those years. Starting in 2022, we adopt the load growth rates envisioned by EIA under a $10/ton CO2 price ("EIA GHG10"), wherein the EIA assumes a 2014 CO2 price of $10/ton. We use the CAGR from EIA GHG10 for the years 2015-2034 for our years 2022-2034 in our reference Case. We use the earlier years in the EIA GHG10 to match the growth rates that would be expected once the non-zero CO2 prices are realized (assumed to be realized in 2021 in our Reference Case).

For both of our reference cases, fuel prices were taken directly from the EIA reference case -- Henry Hub for natural gas prices and Wyoming Powder River Basin for coal. We assumed a further coal transportation cost into MISO of $1.7/MMBTU, a value typically used in the MISO to account for coal transportation. Natural gas transportation costs are assumed to be $0.75/MMBTU. Generation retirements and additions are taken directly from the EIA reference case. We began 2013 with a MISO capacity surplus of 6,200 MW.[5] When load growth together with net capacity retirements resulted in a year with a capacity deficit, some future EIA reference case additions were moved forward or additional natural gas capacity was added beyond that scheduled in the EIA reference series. These key input series are shown in Appendix A.

[5] See Potomac Economics, "2012 State of the Market Report for the MISO Electricity Markets", p. 18, figure 8. It shows a capacity market surplus for July 2012 of 6200 MW.

For each year, we simulate the SMP for all hours using the historical supply curves adjusted for the assumptions of this case. For the 16 peak hours of each (non-holiday) weekday, we calculate the average SMP to establish the on-peak SMP for that hour of that year. The average price for all other hours establishes the off-peak SMP for that hour of that year.

b. High Resource Production (Low Fuel Price) Case

We believe a credible case is one in which natural gas prices may show little change over the next 20 years. This is credible because of the additional natural gas supply that has been made available through hydraulic fracturing technology, which has already been shown to increase natural gas production in North America. Accordingly, we produce a price forecast using the assumptions associated with EIA's "High Oil and Gas Resource" case, which models the effect of high resource production on fuel prices and the secondary effects on electricity markets.

For load growth in the High Resource Case, we used the levelized growth rate of load for the 2015-2034 period used in EIA's High Resource case. We assume no CO2 costs for this case. Fuel prices were taken directly from the EIA High Resource case (the Henry Hub natural gas and Powder River Basin coal prices).

Generation retirement and addition assumptions are taken directly from the EIA High resource case, but adjusted to ensure that MISO's resource needs are satisfied. Like our reference case, we began 2013 with a MISO capacity surplus of 6,200 MW. When load growth together with net capacity retirement resulted in a year with a capacity deficit, some future EIA reference case additions were moved forward or additional natural gas capacity was added beyond that scheduled in EIA High Resource series. These key input series are shown in Appendix A.

c. High Economic Growth Case

We also believe there is a significant likelihood that economic growth may be higher than assumed in the EIA reference case. Accordingly, we produce a price forecast using the assumptions associated with EIA's "High Growth" case, which models the effect of higher macroeconomic growth on electricity markets. We assume CO2 cost in accordance with the reference case developed by Mr. Sabine (the same CO2 costs as in our reference case above), which start at REDACTED . For the years 2022-2034, load grows more slowly than in the EIA High Growth case. We assume a lower growth rate in later years to reflect the effects of the CO2 costs. In particular, the growth rate is the average of (1) the levelized growth rate in the EIA High growth case for 2022-2034 and (2) the levelized growth rate in the EIA GHG10 case for the year 2015-2034.

Fuel prices were taken directly from the EIA High Growth case (Henry Hub natural gas and Powder River Basin coal).

The quantity and timing of generation retirements and additions are taken directly from the EIA High Growth case, adjusted as needed to satisfy MISO's resource needs. Like our Reference Case, we began 2013 with a MISO capacity surplus of 6,200 MW. When load growth together with net capacity retirement resulted in a year with a capacity deficiency, some future EIA High growth case additions were moved forward or additional natural gas capacity was added beyond that schedule in EIA High Growth series. These key input series are shown in Appendix A.

C. Estimates of Losses and Congestion

The previous section described the forecast of the MISO System Marginal Price, which is the underlying commodity price throughout MISO. This price does not include the effects of losses or transmission that can cause locational marginal prices ("LMPs") at a location to be higher or lower than the SMP. Manitoba hydro will settle its energy imports at the Manitoba interface location. Therefore, we forecast the losses and congestion that will be incurred at the Manitoba interface relative to the SMP. We use the historical relationships in the 2011 and 2012 data to forecast future losses and congestion.

1. Losses

For losses, we use the average observed marginal losses calculated by MISO over the two year period 2011-2012 as the marginal loss factor going forward. We do not believe there are any currently known changes to the system that would raise or lower losses significantly going forward. For on-peak hours, we assume an average marginal loss factor of 8.8 percent. For off-peak hours, we assume a marginal loss factor of 9.4 percent.

2. Congestion

Unlike losses, transmission congestion can change substantially as the dispatch of the system or the topology of the network changes. To forecast congestion, we develop an econometric model to estimate how key factors will affect congestion. We use standard linear regression techniques to develop this model. The estimated relationship is then used to forecast the future value of congestion based on projections of future key variables. The results of this estimated model, along with the standard statistical diagnostics, are provided in Appendix B.

We use the hourly data from 2011-2012 and hypothesize that congestion depends on a number of "explanatory" variables. These variables include:

System Marginal Price. The system marginal price is the price calculated by MISO that represents the marginal cost of meeting the next increment of load in MISO. We hypothesize that a higher SMP will result in higher congestion costs at the Manitoba interface with MISO. This hypothesis is based on the fact that at a high SMP, MISO is dispatching high-cost units to serve demand. These same units will be redispatched to manage congestion. All else equal, this should result in higher congestion costs.

Our regression analysis indicates a statistically significant estimate that congestion costs at the Manitoba border with MISO increase by $0.10/MWh for every $1/MWh change in the SMP.

Market Generation. Market generation is the level of generation dispatched within MISO to serve MISO demand. We hypothesize that the congestion cost at the Manitoba interface with MISO will be higher when market generation is higher. This hypothesis is based on the fact that at a higher dispatch, the transmission network is more fully utilized and congestion is more likely to arise.

Our regression analysis indicates a statistically significant estimate that congestion costs increase by $0.04/MWh for every 1,000 MW increase in system generation.

Ramp Requirements. Ramp requirements are the amount of capacity MISO expects to increase or decrease in a given hour to respond to anticipated increases or decrease in market demand or supply. In hours when demand is increasing or decreasing quickly (mid-morning and late evening), MISO may be constrained in responding to congestion and be required to use expensive re-dispatch to manage flows over transmission facilities. We hypothesize that ramp requirements will cause higher congestion.

Our regression analysis indicates a statistically significant estimate that congestion costs increase by $0.21/MWh for every 1000 MW increase in ramp requirements.

Wind Share of Generation. Wind share of generation is the percentage share of dispatched generation that is from wind resources. When output of wind resources increases relative to the rest of the system, there tends to be higher congestion. This occurs because most wind resources are located in Western MISO so higher wind output raises west-to-east flows and congestion on the MISO system. The Manitoba interface is significantly affected because is it located in the western part of MISO. Therefore, we hypothesize that higher wind share will cause higher congestion costs for Manitoba Hydro.

Our regression analysis indicates a statistically significant estimate that congestion costs increase by $0.45/MWh for every one percentage point increase in the share of wind resources on the system.

Manitoba Hydro Exports to MISO. Manitoba Hydro export to MISO is the MW volume of exports from Manitoba Hydro to MISO. When Manitoba Hydro exports power, congestion costs are likely to increase because MISO must manage the additional west-to-east power flow in an area already affected by west-to east-congestion. We hypothesize that higher Manitoba Hydro exports to MISO will cause higher congestion costs for Manitoba Hydro.

Our regression analysis indicates a statistically significant estimate that congestion costs increase by $0.78/MWh for every 1000 MW increase in Manitoba Hydro exports to MISO.

Headroom West. Headroom West is the amount of capacity that is on line in the west (sum of the maximum output level for each unit) in excess of energy being produced from each resource. As discussed above, headroom is used to ensure operational requirements for MISO. When the MISO west headroom requirement increases, flexibility in managing west-to-east congestion decreases, because units have lower limits to which they can be dispatched in order to reduce west-to-east flows. This will tend to result in more expensive redispatch to address congestion.

Accordingly, we hypothesize that higher MISO west headroom will cause higher congestion costs for Manitoba Hydro.

Our regression analysis indicates a statistically significant estimate that congestion costs increase by $0.87/MWh for every 1,000 MW increase in MISO west headroom.

Natural Gas-Coal Price Spread. The ratio of natural gas prices to coal prices spread is used in the regression equation to account for a significant factor that affects redispatch costs. If natural gas prices increase relative to coal prices, the cost of displacing coal with gas to resolve congestion increases. We hypothesize that congestion costs will increase when the natural gas-coal price spread increases.

Our regression analysis indicates a statistically significant estimate that congestion costs increase by $1. 37/MWh for every $1/MMBTU increase in the spread between coal and natural gas prices.

Qualitative Variables. The variables described above are the "quantitative" variables used in the regression. These variables can take on a range of values, for example, natural gas prices can have a rather broad range. The regression measures the effect of changes in quantitative variable on the congestion costs. Qualitative variables measure a change in state. They generally reflect the presence or absence of a condition, for example, whether a particular observation is an on-peak hour or an off-peak hour. The following are our qualitative variables used in the regression.

Peak Hour Indicator. The peak hour indicator signals whether the observation is an on-peak hour or not. Peak hours are the 16 hours ending at 11PM on (non-holiday) weekdays. During these hours, load grows in the west and helps to alleviate the usual west-to-east flow that creates congestion. We hypothesize that congestion cost will decrease during on-peak hours.

Our regression analysis indicates a statistically significant estimate that congestion costs are $0.21/MWh lower during on-peak hours.

Winter Indicator. The winter indicator signals whether the hour is during December, January, or February. Like the peak hour indicator, we expect load in the west to grow relative to the rest of MISO in these months and help alleviate the usual west-to-east flow that creates congestion. We hypothesize that congestion cost will decrease during winter months.

Our regression analysis indicates a statistically significant estimate that congestion costs are $1.86/MWh lower for hours in the winter.

Summer Indicator. The summer indicator signals whether the hour is in a summer month. For summer peak hours, we expect load in the rest of MISO grow relative to the west of MISO and aggravate the prevailing west-to-east flow that creates congestion. We hypothesize that congestion cost will increase in these hours.

Our regression analysis indicates a statistically significant estimate that congestion costs are $0.62/MWh higher in the summer peak hours.

The results of the regression equation are shown in Appendix B. The regression is an AR(1) model. For the ordinary least squares model, the Durbin-Watson statistic indicated that the data had a high degree of correlation between the hourly observations, which was not unexpected. Accordingly, we used an AR(1) model to account for this correlation. The results in Appendix B are the AR(1) results.

3. Effect of New Transmission Investment on Congestion.

The future congestion facing Manitoba Hydro in the western part of MISO should take into account two significant transmission expansion projects. The first is Manitoba Hydro's proposal to build additional capacity from the Manitoba Interface to Minnesota and Wisconsin as part of its preferred plan. The second is the investment that MISO initiated in 2011 to integrate wind capacity in western MISO. The regression equation used to forecast congestion is based on the state of the transmission network as it existed in 2011 and 2012. Hence, we adjust the congestion forecast to account for the prospect that congestion will be changing.

a. Wind Integration and MISO's Multi-Value Projects

MISO's planning process includes provisions to plan for and develop projects to facilitate the integration of resources to meet regulatory policies, for example, projects related to renewable energy requirements. MISO's process has resulted in substantial investments aimed at integrating existing and future wind capacity in the western part of MISO. In fact, MISO has approved over $5 billion in projects since 2011. We believe many of these projects will be in service by 2015.

As a result of this new investment, we recognize that the congestion estimated in our forecast is likely to be overstated. In particular, the variable in our regression analysis associated with "Wind Share" measures the higher levels of congestion at the Manitoba Hydro interface when the share of wind in MISO increases. However, with the new investments in MISO aimed at integrating wind, we believe additional congestion from new wind resources is likely to be offset by the additional transmission capability. Therefore, in forecasting the congestion at the Manitoba Hydro interface, we assume changes in wind share above the level projected in 2015 will have no additional effects on congestion by capping the wind share in future years at the 2015 level. In other words, we assume the new MVP projects will completely offset the forecasted increases in output from new wind projects.

b. Manitoba Hydro Transmission Projects

As part of Manitoba Hydro's preferred development plan, Manitoba Hydro proposes to build new transmission into Minnesota and Wisconsin. These investments will help eliminate congestion into the Minnesota Hub caused by additional Manitoba Hydro exports. As our regression indicates, Manitoba Hydro export volumes into MISO create additional congestion costs at the rate of $0.78/MWh for each 1,000 MW of Manitoba Hydro exports. However, this is congestion as measured at the MISO SMP. Some of this is congestion is between Manitoba Hydro interface and the Minnesota Hub and some of it is congestion from the Minnesota Hub into the rest of MISO.

In order to separate the effects, we estimate the same regression model using the Minnesota Hub congestion cost as the dependent variable instead of the Manitoba Hydro interface congestion costs. This could identify the effect of congestion from MISO to the Minnesota Hub. We found this value to be $0.59/MWh for each 1,000 MW increase in Manitoba Hydro exports to MISO. The regression results are in Appendix B.

Therefore, the congestion caused by additional Manitoba Hydro exports is mostly between the Minnesota Hub and the rest of MISO. As a result, for additional exports into MISO after 2021 when the projects are proposed to be ready, we reduce the rate of additional congestion costs caused by imports to the coefficient estimated in the second regression model ($0.59/MWh for each 1000 MW of additional exports, instead of $0.78/MWh).

D. Full Price Forecasts

In this section we present the final results of our price forecasts: the System Margin Price combined with congestion costs and losses.

The following four figures show our estimated prices, including losses and congestion. The top line indicates the SMP. After removing congestion and losses, the bottom line indicates the LMP that Manitoba Hydro is forecasted to receive when exporting energy to MISO.

Figure 11: Potomac Economics Reference Case Energy Prices

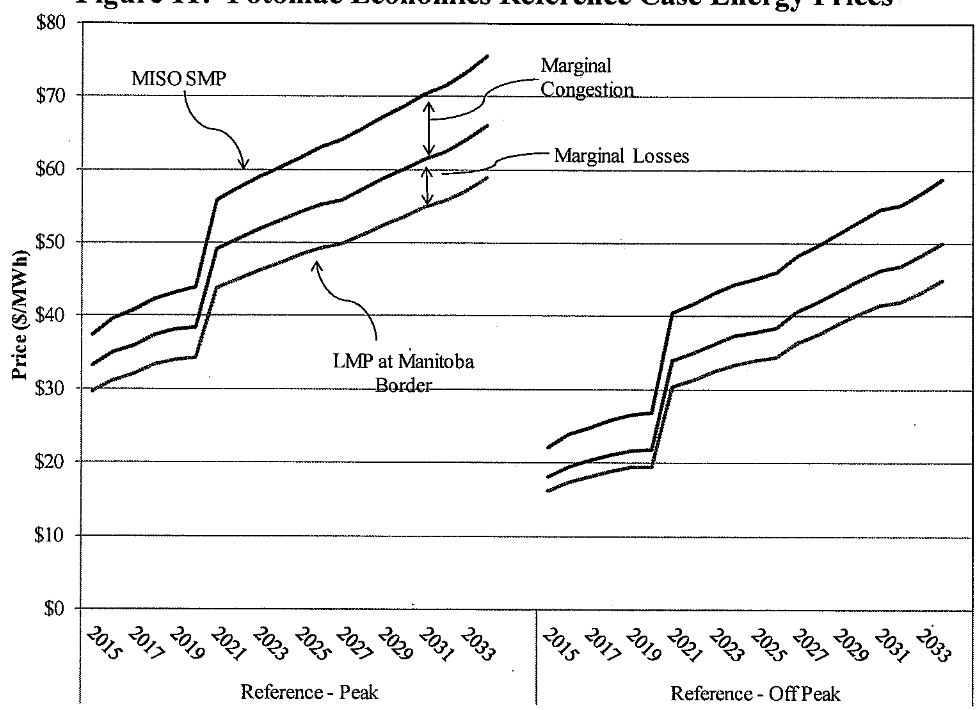


Figure 12: Potomac Economics Reference No Carbon Case Energy Prices

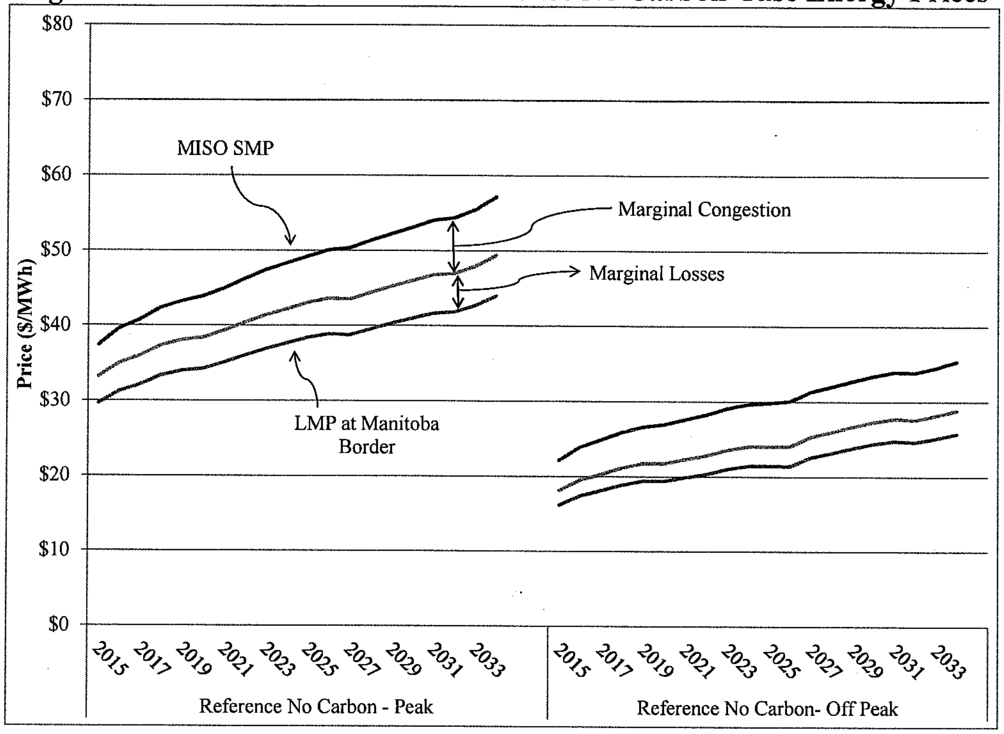


Figure 13: Potomac Economics High Resource Case Energy Prices

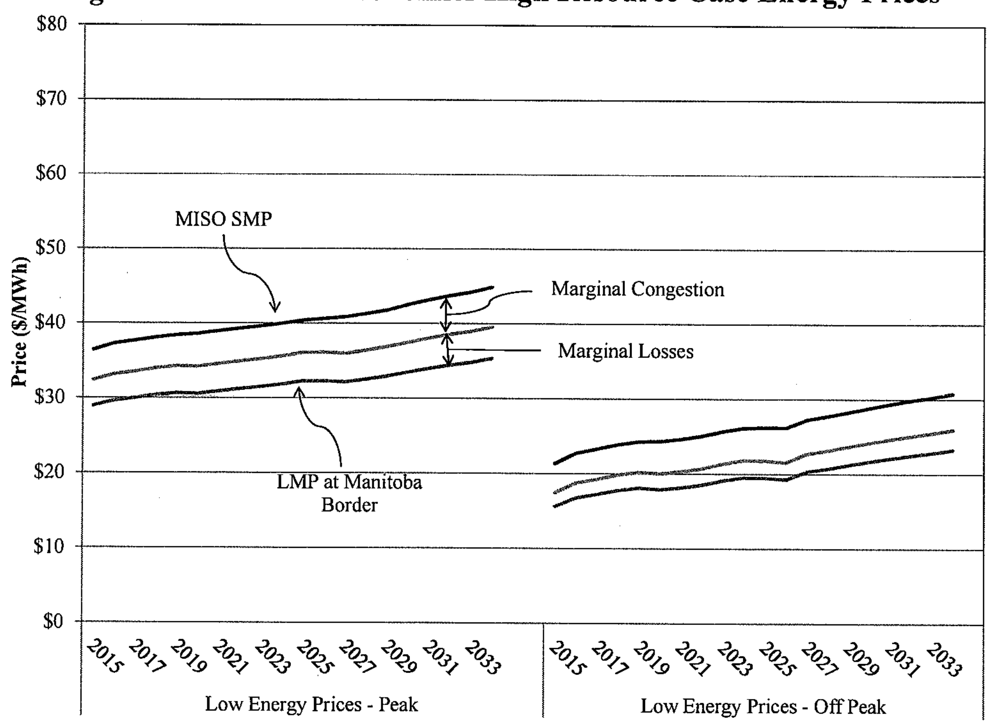
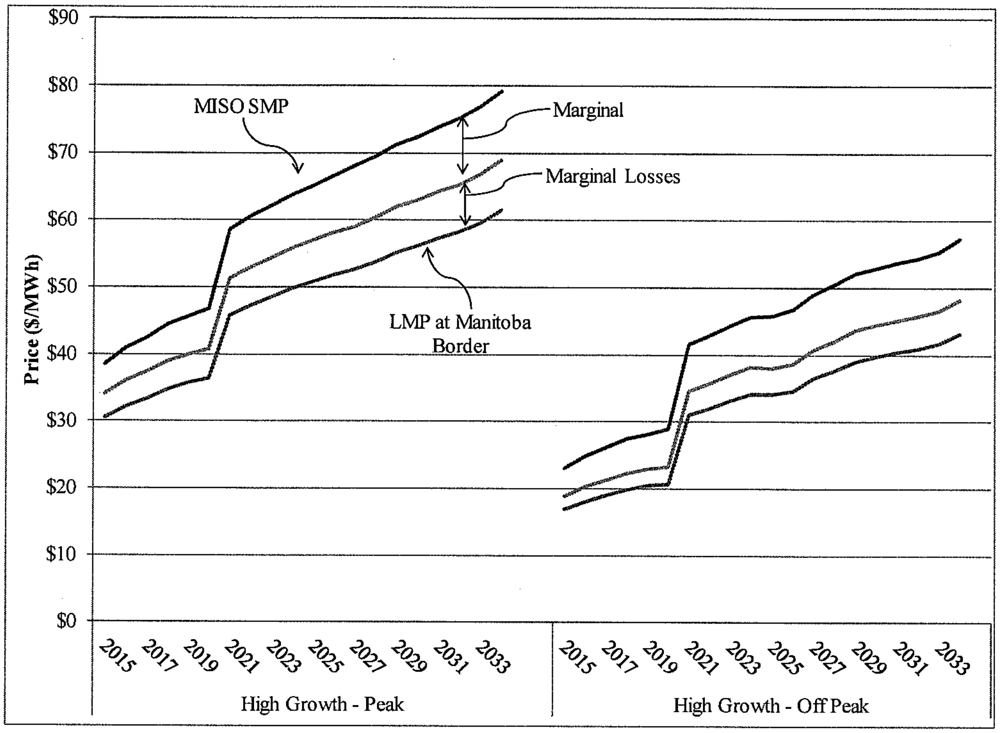


Figure 14: Potomac Economics High Growth Case Energy Prices



III. Potomac Economics Capacity Price Forecast

Capacity prices in MISO's planning reserve auction have been close to zero since its introduction. This has been partly due to the prevailing capacity surplus in MISO and partly due to market design flaws that lead prices to be understated.[6] While these flaws tend to reduce the value of capacity in MISO, load serving entities will still procure capacity through bilateral contracts or build capacity when needed to meet their planning reserve requirements.

Therefore, we assume that when surplus capacity dissipates, the capacity price will rise to the level necessary to incent the construction of new resources. As a result, our capacity price forecast is based on our estimate of the net cost of new entry ("net CONE"). The net CONE of a resource is equal to the resource's annual fixed cost of new entry less the variable profit it would earn in the MISO's energy and ancillary services markets. Therefore, the estimation of the capacity price requires calculation of (1) the variable profit a new resource can earn in the MISO markets (which requires forecast of the energy and ancillary services prices); and (2) the annual fixed cost of entry for the resource.

We estimate the net CONE of an "advanced" CT, given the parameters published by EIA[7]. Given the typical price duration curve in the MISO market, a CT is generally the most economical way to meet capacity needs. While it conceivable that a CCGT, because it runs longer at lower costs, could overcome its higher capital cost relative to a CT, our analysis indicates that the forecasted energy prices always results in a CT being the most economical addition for capacity (i.e., having the lower net CONE).

A. Cost of New Entry

The cost of new entry is an annual number that reflects carrying cost of the fixed investment plus fixed operating costs (fixed O&M), as well as smaller fixed elements like taxes. We use a value that was published by MISO in support of the capacity auction prices in MISO South. Updating this value to 2013 dollars and incorporating updates in EIA's assumptions for an advanced CT,

6 See, Potomac Economics, "2012 State of the Market Report for the MISO Electricity Markets."

7 See, EIA, "Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants", April 2013, *supra.*

we estimate the CONE of a CT to be $89.95. The capacity price is estimated as this value less estimated net revenues, as described in the next subsection

B. Net Revenues

Net revenues for a new advanced CT are estimated using the variable production costs of the CT and the prices forecasted for each year. If in a given hour the price is greater than the variable cost of the CT, the unit is assumed to earn the difference in the variable cost and the price. This is part of the net revenue for that hour. We also assume a CT can earn ancillary services revenue by providing off-line supplemental reserves to MISO.[8] The annual net revenues are the annual sum over all hours of the hourly net revenues and the hourly ancillary services revenues.

In the long-run equilibrium, capacity prices together with net revenues from the energy and ancillary services markets must be sufficient to cover the cost of building new resources. This is the basis for our long-run forecast of capacity prices. However, MISO currently has a surplus of capacity and has been exporting capacity to PJM. Most recently, MISO suppliers exported more than 4 GW of capacity to PJM in its auction for 2016/2017. This capacity can be repurchased from PJM in subsequent actions if it is needed to meet MISO's planning reserve needs and its costs are lower than the costs of building new resources. Therefore, we must determine when the MISO capacity market is likely to transition from its current surplus condition (which will produce lower capacity prices) to a long-run equilibrium where capacity prices should cover the cost of building new resources.

Given the current surplus of more than 6 GW and our assumed coal retirements, MISO could experience a shortfall as soon as 2016. However, the ability to repurchase MISO capacity from PJM and fund environmental upgrades that would allow some existing capacity to remain in service will push this date out. Given these factors, we project that MISO will need to begin adding new resources in 2018. Because MISO does not currently have a functional centralized capacity market, we adopt the most recent price from the PJM RPM auction of $57.39/MW-Day as our forecast for 2015 and 2016, which translates to a price of $21.65/kW-Year. In 2017,

8 The ancillary services revenue is earned at the rate of $1/MW when the unit is not operating to provide energy. Although the average operating reserve prices are slightly higher than this level, the $1/MW assumption accounts for (1) the generator being likely to incur some costs in order to be prepared to be deployed and (2) the generator likely to be providing energy in hours when the operating reserve prices are the highest.

MISO's repurchasing of capacity from PJM should increase capacity prices throughout the region to levels similar to those that prevailed prior to the increased sales to PJM. Therefore, we forecast a capacity price comparable to the PJM clearing price in the prior RPM auction of \$160/MW-Day or \$49.64/kW-Year.

In 2018 and beyond, we forecast that prices will rise to the long-run equilibrium level based on the net CONE of a new CT. Table 1 shows the net revenue for each year of the forecast period, along with the annual fixed cost, and the resulting estimated capacity price. We show this for all four of our cases.

Table 1: Summary of Capacity Price Estimates

	Reference Case			Reference Case No Carbon			High Resource (Low Fuel Price)			High Growth		
Year	Net revenue	Fixed Annual Cost	Capacity Price	Net revenue	Fixed Annual Cost	Capacity Price	Net revenue	Fixed Annual Cost	Capacity Price	Net revenue	Fixed Annual Cost	Capacity Price
	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW
2015	$20.23	$89.95	$69.72	$20.23	$89.95	$69.72	$19.76	$89.95	$70.19	$20.97	$89.95	$68.98
2016	$20.51	$89.95	$69.44	$20.51	$89.95	$69.44	$20.56	$89.95	$69.39	$21.12	$89.95	$68.83
2017	$20.92	$89.95	$69.03	$20.93	$89.95	$69.02	$20.84	$89.95	$69.11	$21.53	$89.95	$68.42
2018	$21.32	$89.95	$68.63	$21.32	$89.95	$68.63	$21.10	$89.95	$68.85	$21.84	$89.95	$68.11
2019	$21.51	$89.95	$68.44	$21.51	$89.95	$68.44	$21.26	$89.95	$68.69	$22.12	$89.95	$67.83
2020	$21.61	$89.95	$68.34	$21.61	$89.95	$68.34	$21.37	$89.95	$68.58	$22.31	$89.95	$67.64
2021	$21.59	$89.95	$68.36	$21.78	$89.95	$68.17	$21.59	$89.95	$68.36	$22.15	$89.95	$67.80
2022	$21.66	$89.95	$68.29	$22.03	$89.95	$67.92	$21.81	$89.95	$68.14	$22.35	$89.95	$67.60
2023	$21.77	$89.95	$68.18	$22.24	$89.95	$67.71	$22.00	$89.95	$67.95	$22.52	$89.95	$67.43
2024	$21.85	$89.95	$68.10	$22.38	$89.95	$67.57	$22.24	$89.95	$67.71	$22.69	$89.95	$67.26
2025	$21.99	$89.95	$67.96	$22.50	$89.95	$67.45	$22.40	$89.95	$67.55	$22.70	$89.95	$67.25
2026	$22.05	$89.95	$67.90	$22.62	$89.95	$67.33	$22.60	$89.95	$67.35	$22.84	$89.95	$67.11
2027	$22.08	$89.95	$67.87	$22.72	$89.95	$67.23	$22.59	$89.95	$67.36	$22.94	$89.95	$67.01
2028	$22.19	$89.95	$67.76	$22.90	$89.95	$67.05	$22.63	$89.95	$67.32	$23.03	$89.95	$66.92
2029	$22.31	$89.95	$67.64	$23.04	$89.95	$66.91	$22.76	$89.95	$67.19	$23.24	$89.95	$66.71
2030	$22.42	$89.95	$67.53	$23.20	$89.95	$66.75	$22.46	$89.95	$67.49	$23.20	$89.95	$66.75
2031	$22.49	$89.95	$67.46	$23.34	$89.95	$66.61	$22.29	$89.95	$67.66	$23.29	$89.95	$66.66
2032	$22.47	$89.95	$67.48	$23.37	$89.95	$66.58	$22.25	$89.95	$67.70	$23.26	$89.95	$66.69
2033	$22.59	$89.95	$67.36	$23.56	$89.95	$66.39	$22.24	$89.95	$67.71	$23.35	$89.95	$66.60
2034	$22.79	$89.95	$67.16	$23.88	$89.95	$66.07	$22.19	$89.95	$67.76	$23.60	$89.95	$66.35

Note: The "Capacity Price" column for 2015-2017 shows the estimated net revenue based on a long-run equilibrium. As discussed in the text, this price is not likely to be attained in the short run. The capacity prices for those three years (and all cases) are 2015: \$21.65/kW; 2016: \$21.65/kW; and 2017: \$49.64/kW.

As this table shows, the net revenues from the energy and ancillary services markets do not vary substantially over time or between the various energy price cases. This is expected because the primary changes over time and between cases are related to changes in fuel prices and CO_2 prices. Changes in both natural gas prices and CO_2 prices will directly increase the CT's marginal costs and, therefore, its assumed offer prices. In most hours that a CT is running, a natural gas-fired unit with similar CO2 emission rates will be the marginal unit setting the price in the energy market. This causes energy prices to increase or decrease at substantially the same rate as the change in the CT's production costs, which in turn causes its net revenue to be relatively unresponsive to these changes.

Likewise, changes in the generator mix over time. as coal plants retire and are replaced by other units, generally changes energy prices at lower load and price levels when the CT would not be forecasted to be running. Therefore, these changes do not tend to affect the CT's net revenues substantially.

Lastly, we assume no real increase over time in the capital cost of building a CT (i.e., capital costs rise at the same rate of inflation). Therefore, the CONE of the CT is flat over time and, when combined with net revenues that are relatively flat as well, we forecast a long-run capacity price trend that is comparably flat.

C. Potomac Economics' Capacity Price Forecast v. Manitoba Hydro's Consultants

Figure 15 shows our reference capacity price forecast compared to the forecasts of Manitoba's consultants. The Potomac Economics forecast rises, as discussed in the prior section, from 2015 to 2017 before achieving a long-run equilibrium that prevails from 2018 to 2034.

Figure 15: Capacity Prices Reference Case Manitoba Hydro v. Potomac Economics

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The figure shows that the consultants' forecasts are [redacted] the Potomac Economics forecast after 2020 when most of Manitoba Hydro's new capacity enters the MISO market. As we discussed in Section I, most of the consultants assume capital costs for new resources that [redacted] than the EIA forecast that we assume. Additionally, some of the consultants appear [redacted] that a new resource would earn in MISO's energy and ancillary services markets, without which the forecasted capacity price [redacted]

We were unable to obtain detailed information on the models and inputs used by Manitoba Hydro's consultants to forecast capacity prices. Given that they are [redacted] than the fundamental approach that we used, we do not find them to be credible and recommend that PUB evaluate the business case for the Manitoba Hydro development plans on the basis of Potomac Economics' forecast.

D. Uncertainties

Although the theory underlying our capacity price forecast is sound, there is significant risk associated with these Manitoba Hydro revenues. The capacity prices forecasted for the long run may not be readily attainable by Manitoba Hydro. This is true for at least three main reasons.

First, the capacity price is based on the amount of revenue a new entrant would need to be profitable. This assumes load serving entities are seeking capacity under relatively open and competitive market structures. However, the MISO capacity market is not currently structured to establish efficient capacity prices where capacity is cleared on a multi-lateral basis. Instead, capacity prices under the MISO planning reserve auction tend to be understated. They are likely to be close to zero during periods when even a small surplus of capacity exists. This can put downward pressure on bilateral capacity prices and result in lower revenues for Manitoba Hydro.

Because of this, Manitoba Hydro will likely participate in the bilateral market, as it has in the recent past. The risk that Manitoba Hydro faces in the bilateral market is that regulated utilities may have an incentive to engage in self-build projects when they need capacity rather than purchasing from Manitoba Hydro. We have not quantified this effect in the capacity price, but only cite it as a potential risk.

Second, given the relatively long timeframe of these forecasts, it is plausible that technological advances could reduce the cost or increase the efficiency of the marginal CT, or cause alternative technology to displace the CT. In both cases, the long-run capacity price could fall and reduce the forecast capacity revenues.

A third reason why the capacity price may overstate the revenue Manitoba Hydro may earn is that the capacity price is based on net revenues earned at the MISO system marginal price. If constrained areas emerge where energy prices are much higher than the SMP, the net CONE of units built in these areas will fall. This would potentially reduce the MISO capacity price because units in these areas may be the marginal economic entrant.

IV. Other Export Market Issues

In this section we address other issues that could significantly impact the price forecasts and revenues expectations under Manitoba Hydro's development plans.

1. Regional Issues

MISO South. In December 2013, Entergy transitioned its operation to MISO and began participation in the MISO markets. The Entergy system along with several other nearby smaller systems are part of what is known as "MISO South". The rest of MISO is referred to as "MISO Midwest." MISO Midwest and MISO South are connected by way of a transmission path that is managed on a regional basis through the Operations Reliability Coordination Agreement ("ORCA"). ORCA is an agreement among MISO and other non-MISO regional utilities to coordinate certain operations that may be impacted by the joint dispatch of MISO Midwest and MISO South. Currently, among other things, the agreement limits transfers between MISO Classic and MISO South to 2000 MW in any given hour. In the future, this limit may increase.

While the integration of MISO Midwest and MISO South promises to better allocate resources between the two areas, we do not believe it will have a significant effect on the supply and demand conditions in the western part of MISO where Manitoba Hydro anticipates making sales.

Capacity Exports to PJM. Another regional issue is the current level of MISO capacity exports to PJM. MISO is currently in a capacity surplus and exports to PJM through the PJM capacity auctions. These exports are committed for up to three years in advance As we discussed above, as the MISO capacity surplus declines, capacity exports to PJM from MISO will likely decline and this capacity will be available to meet MISO requirements.

2. Export Volumes

Manitoba Hydro assumes all additional surplus electricity can be sold either as long-term "dependable" (firm) energy or as on- and off-peak opportunity sales. Projected export volumes of long-term dependable energy are based on the surplus dependable capacity that Manitoba Hydro calculates based on historical water conditions and forecast load and resources. Manitoba assumes 100 percent of available dependable energy can be sold as long-term firm.

Manitoba Hydro on-peak and off-peak energy volumes are estimated based on simulations of the Manitoba Hydro system using its "SPLASH" model. The SPLASH model uses anticipated hydro conditions, load, resources, and export prices. The model optimizes the use of the available water to determine the volumes of exports and imports. The reasonableness of the export volumes produced by the SPLASH model was evaluated by Independent Expert Consultant, La Capra Associates.

Our role was to examine whether Manitoba Hydro can actually sell the volumes into MISO. Overall, given the small volume of additional capacity and energy resulting from the development plans relative to the size of the MISO market, we conclude that Manitoba will likely be able to sell the volumes it assumes in its plans. Our price forecasts take into account the additional volumes in estimating the market clearing prices. We also take into account the additional volumes when estimating the congestion component of the location marginal price at the Manitoba Hydro border with MISO.

Aside from the risk associated with selling capacity in the MISO market described above, we have a minor concern that the assumed volumes of long-term dependable energy may be slightly high. Manitoba Hydro assumes all dependable capacity is sold under long-term firm contracts. We do not believe all dependable capacity should be assumed to be sold forward on a long-term basis. Instead, an historical ratio could be applied. Manitoba Hydro has provided an analysis that indicates the value is close approximately 91 percent in recent years. We recommend that nine percent of the Manitoba Hydro projected long term dependable energy be "re-priced" at peak opportunity sales levels. We understand that La Capra will be addressing the effect of this issue.

We also examined Manitoba Hydro's assumption that its [redacted] We found there is some justification for this [redacted]. However, this [redacted] is not always attained. [redacted]

[redacted] We recommend the Company provide additional analysis supporting [redacted] preferably one that estimates [redacted]

3. Longer-Term Price Forecasts

Manitoba Hydro's Consultants provide forecasts to 2034. However, Manitoba Hydro projects revenues until 2080. To calculate the forward revenues, Manitoba Hydro assumes a growth rate for the years 2035-2049 based on the compound average growth rate ("CAGR") for the years 2030-2034, but declining to a growth rate of zero by 2049. Basically, growth rates in prices are linearly interpolated between the value equal to the average CAGR for the years 2030-2034 and zero value for 2049. After 2049, growth rates in prices are assumed to be zero.

With regard to capacity prices, we find no basis for assuming the real price will increase after 2034. For reasons stated above, such prices may even decline. For energy prices, we find it difficult to recommend an approach that would be reliable given the long-term nature of this assumption. We recommend that alternative post 2034 growth rates be examined in order to understand the sensitivity of the results to alternative growth assumptions. At least one such sensitivity should be a zero real growth rate, which would effectively assume that fuel prices and CO2 prices escalate at the rate of inflation after 2034.

4. Probability of Potomac Economics Cases

In this subsection, we provide a discussion of the probability of realizing the various cases we developed. We believe our reference cases are the most likely to represent the future path of prices. We believe our Reference Case and our Reference No Carbon Case are equally likely but will ultimately depend on the direction of future policy in the U.S. Therefore, we assign a probability of 30 percent to each of these two reference cases

9 Manitoba Hydro informed us that relatively high water levels in 2011 allowed them to sell large quantities during on-peak hours in the shoulder load months, bringing down the overall on-peak per-MW sales revenue for that year.

Our high growth case assumptions do not depart significantly from our reference case. Mainly load grows faster and natural gas prices are higher.

We believe our last case reflects on-going progress in developing shale gas, which has proved to substantially increase natural gas supply in the U.S. The high resource case also shows slower load growth, primarily because gas substitutes for electricity for heating and may also become a transportation fuel, lessening load growth in the transportation sector. The slower load growth can also be a proxy for overall slower macroeconomic activity, which is reflected in this case.

We believe the High Growth and the High Resource cases are also equally likely, but less likely than the reference cases. Therefore, we assign a probability of 20 percent each to these two cases.

Appendix A – Summary of Key Assumptions in Potomac Economics Forecasts[10]

Figure A-1: Natural Gas Prices

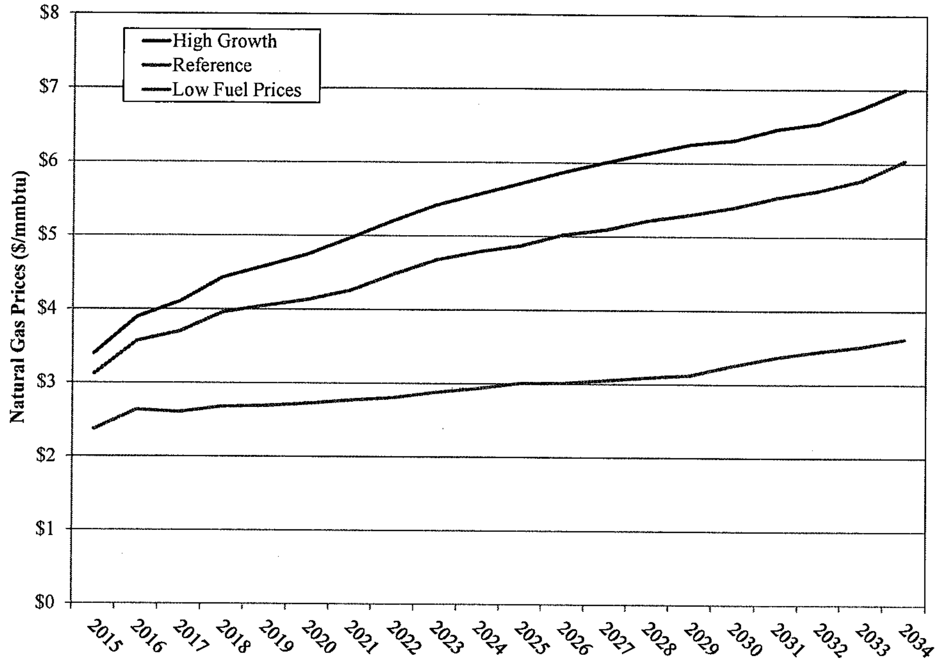
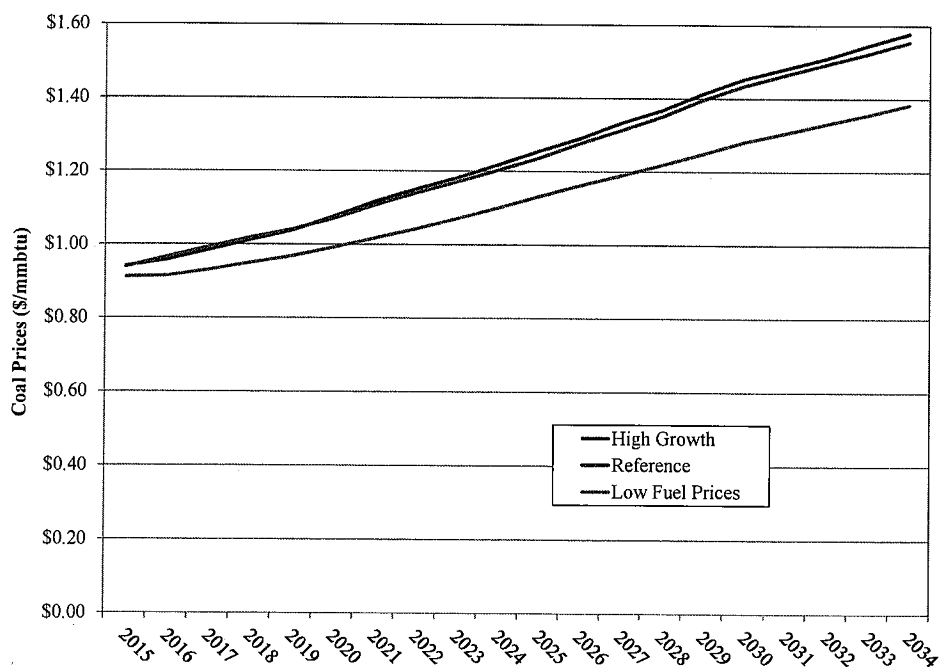


Figure A-2: Coal Prices



[10] Unless otherwise indicated, the Reference Case assumptions are also used in the Reference No Carbon Case.

Figure A-3: CO2 Prices

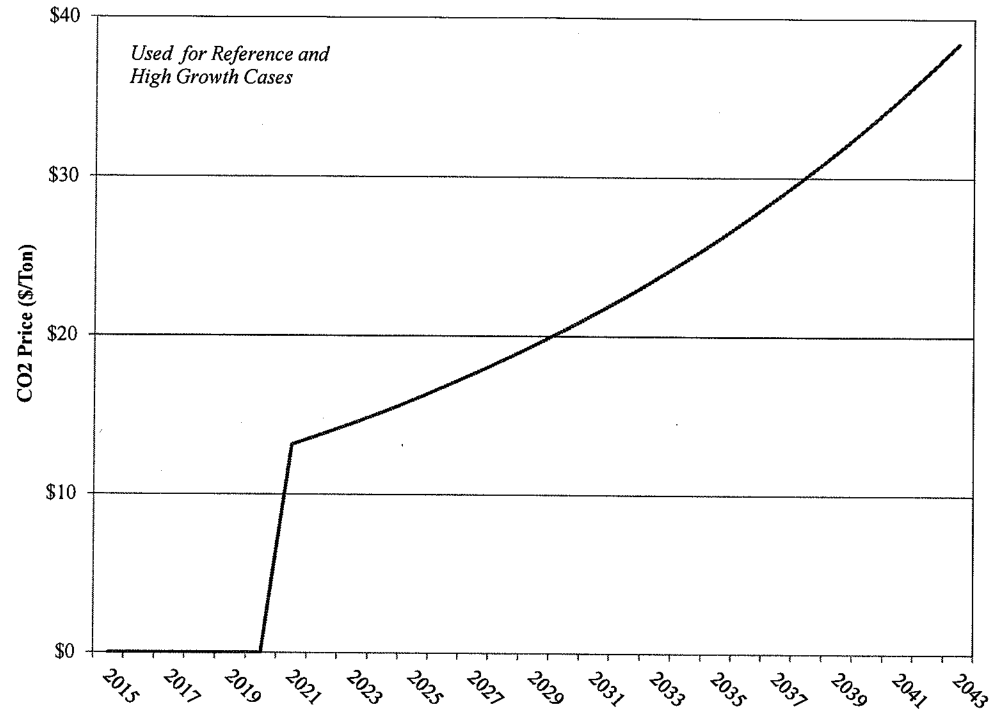


Figure A-4: Load Growth

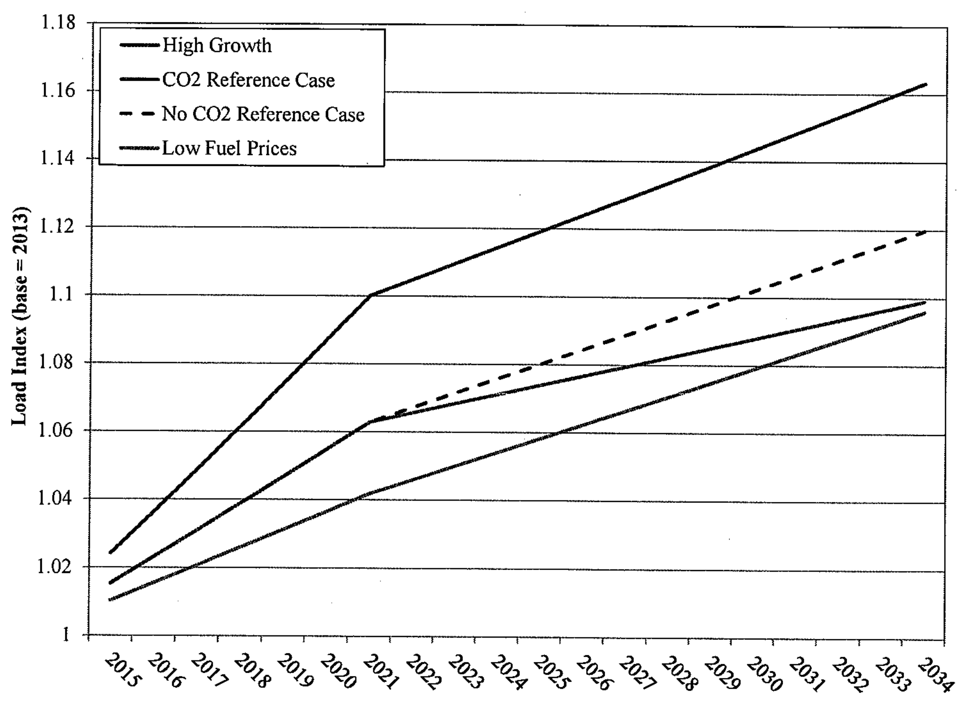
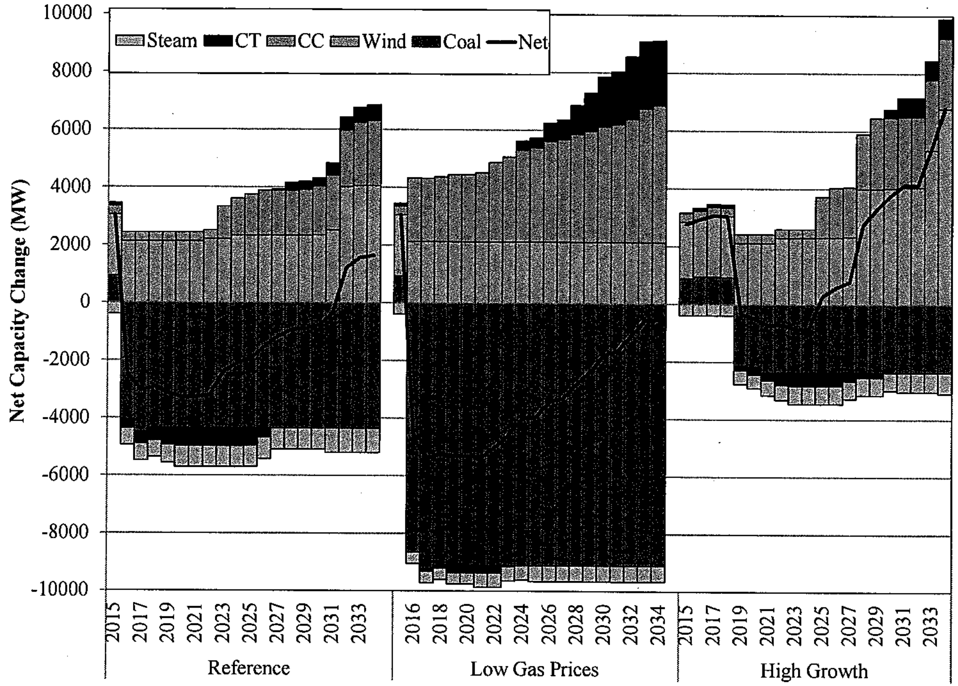


Figure A-5: Capacity Changes



Appendix B -- Regression Result Summaries

B-1: Regression Model used to Estimate the Determinants of Marginal Congestion at the Manitoba Hydro Interface with MISO

Estimates of Autoregressive Parameters

Lag	Coefficient	Std Error	t Value
1	-0.896657	0.003347	-267.88

Regress R-Square	0.1107	Total R-Square	0.8776

Yule-Walker Estimates

Parameter Estimates

Variable	Estimate	Std Error	t Value	Approx. Pr > |t|
Intercept	8.6284	1.0976	7.86	<.0001
MEC	-0.0971	0.005231	-18.56	<.0001
MARKET_GEN	-0.000042	0.0000117	-3.64	0.0003
RAMPDEMAND	-0.000206	9.0498E-6	-22.79	<.0001
WINDSHARE	-45.2384	3.2332	-13.99	<.0001
MHEB_EXPORT	-0.000778	0.0000857	-9.08	<.0001
PEAK	0.2125	0.0738	2.88	0.0040
SUMMER	-0.6233	0.3377	-1.85	0.0650
WINTER	1.8698	0.3580	5.22	<.0001
HEADROOM_WEST	-0.000873	0.0000495	-17.63	<.0001
SPARK	-1.3718	0.5028	-2.73	0.0064

B-2: Regression Model used to Estimate the Determinants of Marginal Congestion at the Minnesota Hub

Estimates of Autoregressive Parameters

Lag	Coefficient	Std Error	t Value
1	-0.872090	0.003700	-235.72

Yule-Walker Estimates

Regress R-Square	0.1123	Total R-Square	0.8513

Parameter Estimates

Variable	Estimate	Std Error	t Value	Approx Pr > |t|
Intercept	12.0768	0.9322	12.96	<.0001
MEC	-0.0288	0.005248	-5.49	<.0001
MARKET_GEN	-0.000031	0.0000112	-2.74	0.0062
RAMPDEMAND	-0.000235	9.1225E-6	-25.73	<.0001
WINDSHARE	-38.2088	3.0165	-12.67	<.0001
MHEB_EXPORT	-0.000590	0.0000860	-6.86	<.0001
PEAK	0.1562	0.0745	2.10	0.0361
SUMMER	-0.4452	0.2824	-1.58	0.1149
WINTER	0.9854	0.2979	3.31	0.0009
HEADROOM_WEST	-0.001047	0.0000487	-21.48	<.0001
SPARK	-3.8936	0.4190	-9.29	<.0001