Review of Manitoba Hydro Export Price Forecast for Needs For and Alternatives To (NFAT)

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Introduction

Based on the market valuation, export sales revenue represents a very significant part of the plan to meet expenditures (over $9.3 billion in present value from exports). Thus, if export prices are even slightly lower than the projected price, there will be significantly reduced revenue. Alternative plans have reduced (but still significant) revenue from export sales.

Manitoba Hydro uses an export price forecast that is an average of six forecasts provided by various consultants. With the exception of one of these forecasts, prepared by The Brattle Group, these forecasts are not available due to the proprietary nature of the models and the competitively sensitive nature of the information. Furthermore, the assumptions behind these forecasts are not available. Thus, it is not possible to speak definitively about the reasonability of the export price forecast and assumptions. Manitoba Hydro did include supporting information in its Business Case that raises concerns about the assumptions behind its export price forecast and thus, about the export price forecast itself.

This document looks at three general areas: the applicability of the supporting information provided by Manitoba Hydro, the implication of the inclusion of carbon costs in the export price forecast, and the reasonability of the export price forecast from The Brattle Group.

Manitoba Hydro's Supporting Information

This section examines two potential issues: the existence of transmission congestion between the export region, the area into which Manitoba Hydro will be selling electricity, and the rest of the MISO market; and the future load growth in the export region.

Transmission Congestion

Manitoba Hydro indicates that there are no significant transmission congestion issues between the Minnesota/Wisconsin region and the rest of the Mid-continent Independent System Operator (MISO). This contradicts determinations by the MISO Independent Market Monitor and the U.S. Federal Energy Regulatory Commission (FERC), as well as evidence based on wholesale electricity prices. The existence of congestion is significant because it means that the additional transactions between Manitoba Hydro and the Minnesota/Wisconsin region of MISO will have a larger impact on market prices than would occur without congestion. In essence, congestion shrinks the size of the market since it excludes participants from outside the congested area. Thus, one would expect lower market prices when Manitoba Hydro is selling into the market (and lower revenues for Manitoba Hydro) and higher market prices when Manitoba Hydro is purchasing from the market (and higher costs for Manitoba Hydro).

To examine the impact of transmission congestion on market prices, an analysis of published day-ahead market price indices for the period of March through December 2013 was performed.

The specifics of that analysis are included as an appendix and the pertinent results are provided here. The analysis uses on-peak and off-peak price indices published in Megawatt Daily for four hubs in the MISO market: Illinois Hub (IL), Indiana Hub (IN), Michigan Hub (MI), and Minnesota Hub (MN). A comparison of those price indices (for March-December 2013) was performed to look for consistent variations between the Minnesota Hub and the other three MISO hubs.

If congestion exists between the Minnesota Hub and the rest of MISO, it will show up in one of two ways. If the Minnesota Hub has an excess of supply which cannot get out of the region due to congestion, the hub price will be lower than the prices at the other hubs. If the Minnesota Hub has a shortage of supply and congestion keeps outside suppliers from getting energy to the region, the hub price will be higher than prices at the other hubs. It should be noted that the existence of lower (or higher) prices is not sufficient to show that congestion exists. Losses associated with transmitting the energy will result in a price differential between the exporting and importing regions. Transmission losses are generally low (a few percent), so larger price differences between hubs would be an indicator of congestion.

In order to look for evidence of congestion, the magnitude of the difference between hub price indices was examined. Figure 1 shows the percentage of days that a particular hub's off-peak price exceeded the all other hub prices by more than 10 % (in blue) or was more than 10 % less than any other hub price (in red). Since a difference of that magnitude is unlikely to arise from transmission losses alone, the figure indicates that congestion exists frequently and that the congestion affects market prices in the Minnesota region. In particular, the off-peak prices in the Minnesota Hub are often suppressed relative to the rest of MISO, with indices more than 10 % lower than any of the other three hub occurring 36 % of the time. In some hours, this effect was even larger: in 19 % of the off-peak periods, the Minnesota Hub was more than 20 % lower than any of the other three. It was more than 30 % lower in 9 % of the off-peak periods and more than 40 % lower in 5 % of the periods.

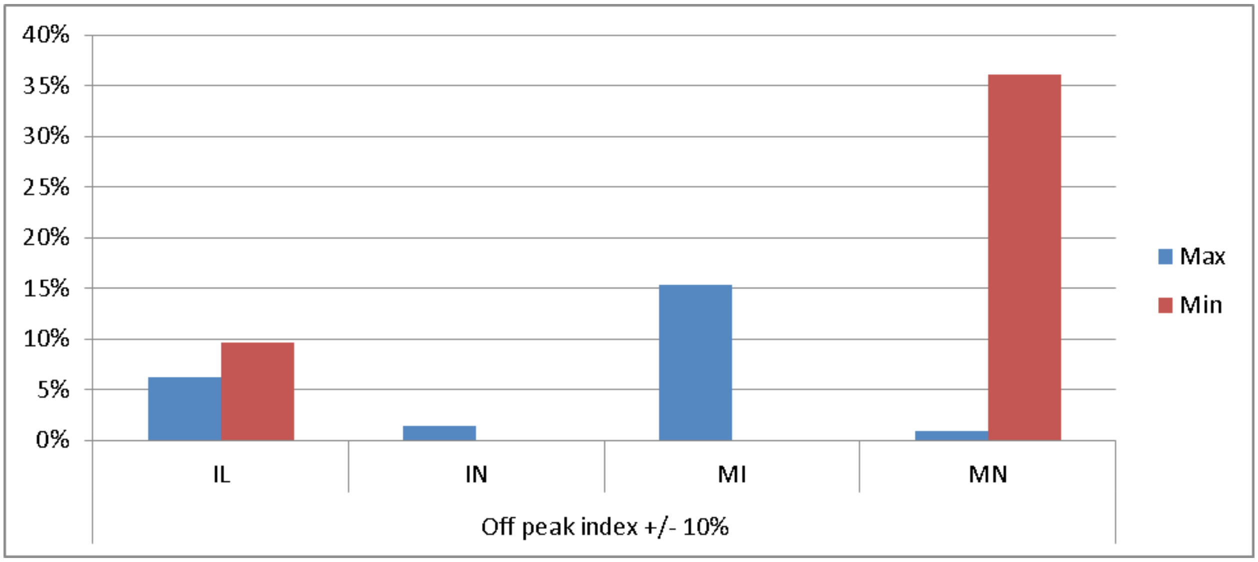

Figure 1. Percentage of days where the off-peak index for a hub was 10 % more (blue) or 10 % less (red) than any other hub

It should be noted that on-peak price indices indicate that congestion also affects Minnesota Hub prices during those periods as well. This happens less frequently than in the off-peak periods and prices can be lower than others on some days (indicating that congestion is limiting the ability to export power) while prices can be higher than others on some days (indicating that congestion is limiting imports). Minnesota Hub on-peak prices are more than 10 % higher than any of the others 13 % of the time and more than 10 % lower than the others 7 % of the time.

The observations of persistent low off-peak prices and on-peak prices that are sometimes high and low at other times are consistent with the high levels of wind generation capacity in the region. The wind generation is generally higher during the off-peak periods when demand is low. This results in a surplus of supply in the region and the excess generation is unable to move to other regions due to the transmission congestion. If the wind is not blowing during on-peak periods, a shortage of supply can occur (with congestion limiting imports). If the wind is blowing and weather is mild during the on-peak hours, the conditions observed during a number of off-peak days can be replicated. That is, excess supply plus congestion results in low prices.

The existence of transmission congestion has also been identified by independent sources. According to the U.S. Federal Energy Regulatory Commission (FERC) website, "*Since the start of the Day-2 market on April 1, 2005, persistent transmission constraints in the Wisconsin and the Upper Peninsula of Michigan (WUMS) and Minnesota areas have caused their prices to diverge from other areas of MISO, usually at times of high loads or decreased generation supply.*"[1]

[1] http://www.ferc.gov/market-oversight/mkt-electric/midwest.asp, updated November 26, 2013 and accessed January 27, 2014.

The existence of transmission congestion in the Minnesota and Wisconsin regions is further borne out by the MISO Independent Market Monitor, Potomac Economics. In their most recent State of the Market Report, they identified three Narrow Constrained Areas, all of which are in the Minnesota, Wisconsin, and Upper Michigan areas. Narrow Constrained Areas are defined as "*chronically constrained areas that raise more severe potential local market power concerns (i.e., tighter market power mitigation measures are employed).*"[2] When asked about this in the Information Request process, Manitoba Hydro dismisses the significance of the classification by focusing on the second half of the statement regarding market power mitigation.[3] Unfortunately, transmission constraints that affect market power will also affect market prices. Regardless of the purpose of the analysis, the MISO Independent Market Monitor found evidence that the transmission system is chronically constrained in that region.

Furthermore, Potomac Economics identified transmission congestion as a factor affecting wholesale market prices in the Minnesota region in its IEC report.[4]

Further evidence of transmission congestion impacting market prices in the Minnesota region comes from MISO's modeling for its transmission planning process. MISO published hourly Locational Marginal Prices (LMPs) for 2017, 2022, and 2027 as part of 2012 MISO Transmission Expansion Planning (MTEP12) process.[5] In addition to LMPs, hourly transmission loss and congestion components were provided for four scenarios. For the Business as Usual (BAU) scenario, "*demand, energy and inflation growth rates are based on recent historical data and assume existing standards for resource adequacy and renewable mandates.*" The Combined Policy (COMBO) scenario is intended to capture the effects of a number of federal policies, including a $50/ton carbon cost, a national renewable portfolio standard, the widespread implementation of smart grid technologies, and the deployment of electric vehicles. It also includes 23 GW of coal retirements (compared to 12 GW in the other scenarios). The Historical Growth (HG) scenario is similar to the BAU but assumes that load growth will occur at the rate experienced prior to the recent economic downturn. The Limited Growth (LG) scenario assumes that energy and demand will grow at ½ the rate used in the BAU.

The annual average LMPs, transmission loss components, and transmission congestion components for the Minnesota Hub are provided in Tables 1-3. It should be noted that a negative value for loss or congestion indicates a reduction in the locational price from the system-wide average, while a positive value corresponds to a higher locational price. Congestion reduces

[2] "2012 State of the Market Report for the MISO Electricity Markets," Potomac Economics, June 2013, pg. 61.
[3] Manitoba Hydro response to CAC/MH II-209.
[4] "Report on Export Prices and Revenues relating to the Need For and Alternatives To (NFAT) Manitoba Hydro's Preferred Development Plan," Potomac Economics, January 15, 2014, Section II.C.2.
[5] https://www.misoenergy.org/Planning/TransmissionExpansionPlanning/Pages/MTEPFutures.aspx

Minnesota Hub annual average price by 3 to 12 % depending on the scenario and year. Table 4 shows the average system-wide marginal price for the MISO region.

Table 1. Average LMPs for Minnesota Hub ($/MWh)

	BAU	COMBO	HG	LG
2017	29.65	80.10	33.14	24.94
2022	32.54	107.68	40.76	24.39
2027	37.78	100.13	51.24	26.57

Table 2. Average Loss Component ($/MWh)

	BAU	COMBO	HG	LG
2017	-1.47	-3.39	-1.59	-1.52
2022	-1.85	-5.45	-1.59	-1.37
2027	-2.75	-6.48	-2.82	-2.05

Table 3. Average Congestion Component ($/MWh)

	BAU	COMBO	HG	LG
2017	-0.96	-5.21	-2.22	-1.85
2022	-1.50	-8.30	-3.33	-2.72
2027	-2.40	-10.73	-7.43	-3.24

Table 4. Average MISO System Marginal Price ($/MWh)

	BAU	COMBO	HG	LG
2017	32.08	88.71	36.95	28.32
2022	35.89	121.43	45.67	28.48
2027	42.93	117.35	61.50	31.86

The export price forecast prepared by The Brattle Group provides price projections for the Midwest Reliability Organization (MRO) West region, which includes Minnesota and western Wisconsin, along with Iowa and much of Nebraska and the Dakotas.[6] It also includes price projections for the entire region modeled, which includes the rest of MISO (excluding the MISO South addition) and portions of the PJM Interconnection and the Southwest Power Pool. A comparison of the price projections for the MRO West region and the aggregate results for the larger area indicates that the MRO West prices are generally $3-4/MWh less than the aggregate area prices. This is consistent with the combined transmission loss and congestion components

[6] "NFAT Business Case," Manitoba Hydro, Appendix 3.1

from the MISO MTEP12 process and to the observed differences in price indices from Megawatt Daily, which indicates that the modeling from The Brattle Group likely captured some congestion impacts. It should be noted that the MISO MTEP12 process indicated that congestion impacts would increase in the future but the price difference between the smaller region and the larger area from The Brattle Group did not change appreciably over time.

Load Growth in the Export Region

The supporting information from Manitoba Hydro includes projected load growth in the export region that may be too robust. Manitoba Hydro includes load growth from the EIA 2013 Annual Outlook that is for the U.S. as a whole. A more appropriate load growth would be for the two census divisions that represent the states comprising the area into which they would be selling energy. The growth rates for these regions are lower than the U.S. average in EIA's analysis.

The EIA growth rates also do not include the impacts of carbon costs. Inclusion of carbon costs would result in higher electricity prices and a corresponding lower growth in electricity demand. This is significant because Manitoba Hydro does include carbon costs in their export prices. This indicates that there may be inconsistency within the export price forecast assumptions. The use of higher load growth plus carbon costs would bias the export price forecast upwards.

Manitoba Hydro provides forecast energy growth at a U.S. national level from the U.S. Energy Information Administration (EIA) of 0.9 % per year in its 2013 Annual Energy Outlook (AEO) as supporting evidence, as well as MISO system-wide forecasts from MTEP12. It should be noted that the 2013 MTEP assumptions for the BAU are 0.81 % energy growth and 0.75 % demand growth.[7] Considering the uncertainty of future electricity usage, these numbers are not unreasonable.

However, load growth varies considerably from one area to another and a smaller region that is more representative of the area into which Manitoba Hydro would be exporting would be more appropriate. EIA forecasts load growth at the census division level in the AEO. For the 2013 AEO, the energy growth in the East North Central census division (Indiana, Illinois, Michigan, Ohio, and Wisconsin) is only 0.3 %. The energy growth for the West North Central census division (Iowa, Kansas, Minnesota, Missouri, Nebraska, North Dakota, and South Dakota) is 0.6 %.

Manitoba Hydro also provided load forecasts from Minnesota Power (0.6% for both energy and demand) and Northern States Power (0.5% for energy and 0.7% for demand).[8] Based on these forecasts, load growth of 0.5-0.6 % would be more appropriate than the U.S. projection of 0.9 %.

[7] "MISO Transmission Expansion Plan 2013," MISO.
[8] "NFAT Business Case," Manitoba Hydro, Chapter 6

It is important to note that none of the projections from EIA, MISO, or Northern States Power include the impact of higher prices from imposing a cost on CO_2 emissions. Minnesota Power includes a very low price of $2.50/ton in 2013 increasing to $3.50/ton in 2017.[9] The Brattle Group did include the price impact on load growth in the export price forecast. The Brattle Group used a base forecast growth of 0.4% per year and adjusted that using a price elasticity of -0.4. Thus, for every 10 percent increase in customer rates, usage was dropped by 4 %.

CO2 Cost

There is considerably uncertainty surrounding the use of CO_2 costs in the export price forecast. The imposition of CO_2 restrictions in the Midwestern U.S. is not a foregone conclusion. If such restrictions are imposed, when will they happen, what form will the take, and how stringent will they be? Inclusion of these costs represents a significant risk to Manitoba Hydro's revenue if they should not develop as expected. It should be noted that Potomac Economics assigned a 50% total probability for the scenarios that included CO_2 costs in its IEC report.

Based on a comparison of The Brattle Group's Base and Low CO_2 cases, inclusion of moderate CO_2 costs will result in an increase of $13-14/MWh in the export price. Alternatively, if the CO_2 costs do not materialize, the price of (and corresponding revenue from) exports would be about 20-25% lower. The expected present value of export revenues in Manitoba Hydro's preferred development plan is $9.3 billion. However, a portion of this is based on existing and pending long-term contracts of which the details are unavailable. Therefore, while CO_2 costs will have a direct impact on the export prices associated with short-term (i.e., opportunity) export sales, it is unknown how the price determination in these long-term contracts would be affected and thus, what the overall effect will be. Finally, a material change in exports prices would likely lead to changes in Manitoba Hydro's forecasts regarding system dispatch. As a result, without access to additional information, it is not possible to determine the impact these percentage changes in export price would have on the economic analysis performed by Manitoba Hydro.

Comparison of the Brattle Forecast to MISO MTEP12 and Potomac Economics Report

A comparison of the all hours energy price projections (without capacity prices) for the BAU/Base/Reference cases for the MTEP12, Brattle, and Potomac Economics IEC report is provided in Table 5. It should be noted that the MTEP12 BAU did not include a cost of CO_2, while the Brattle and Potomac numbers are estimated from figures in the reports. The Potomac is further adjusted from the peak and off-peak numbers on a weighted average basis (using 80 on-peak and 88 off-peak hours per week). It should also be noted that the Brattle projections are for a similar but slightly different geographical region (MRO West vs. Minnesota Hub).

[9] Manitoba Hydro response to IR CAC/MH I-201

Table 5. BAU/Base/Reference Export Region All Hours Energy Price Projections

	MTEP12	Brattle	Potomac
2017	29.65	30	25
2022	32.54	46	39
2027	37.78	51	43

Since the MTEP BAU does not include CO2 costs, a more direct comparison of the outputs of the three models would be to compare the MTEP12 BAU, Brattle Low CO2 (which actually has no CO2 costs), and Potomac No Carbon cases. Table 6 provides that comparison, using the same estimation methods as described earlier.

Table 6. MTEP BAU vs. Brattle Low CO2 vs. Potomac No Carbon All Hours Energy Prices

	MTEP	Brattle	Potomac
2017	29.65	30	25
2022	32.54	33	29
2027	37.78	37	31

The MTEP12 BAU and Brattle Low CO2 energy forecasts are very similar; with the Potomac No Carbon forecast roughly 10-20 % lower. It should be noted that the MTEP12 BAU assumes more robust load growth than is assumed by The Brattle Group.

The Brattle Group energy price forecast for the MRO West Region (which includes Minnesota) is about $3-4/MWh less than the energy price forecast for the entire region (which is larger than MISO), at least in the earlier years. That difference is consistent with what can be observed from the historical price indices from Megawatt Daily and from MISO's MTEP LMPs. In Brattle's case, the difference declines over time while in MISO's it increases, so there is something of a difference in later years.

The load growth Brattle used is more realistic than the numbers that Hydro used for the U.S. to support their business case. They start with a 0.4 % load growth and adjust downward for price elasticity (as we know, Hydro failed to do this in their domestic load forecast).

In comparing the MISO BAU numbers for 2017, 2022, and 2027 (the 3 years provided) to the Brattle Low CO2 case (the closest match in terms of assumptions), the energy prices for both the Minnesota region and the larger areas modeled were pretty close. The Potomac forecast prices were lower than that, but they have already spoken to that.

The Brattle Base Case includes CO2 prices, which are a huge uncertainty. Potomac used a lower CO2 price in two of their four scenarios and only gave a 50 % probability to a CO2 price occurring at all. MISO had one scenario out of 4 with CO2 prices. It was a combined policy scenario with a national renewable standard and a very high CO2 price (a very low probability, very high cost bookend).

Summary

While Manitoba Hydro does not acknowledge it, there is substantial evidence from multiple sources that significant congestion exists between Minnesota and Wisconsin and the rest of the MISO market. This congestion has the potential to reduce market prices in the region into which Manitoba Hydro would be exporting. In turn, this would reduce the revenue from sales.

The actual export price forecast and the assumptions behind it are not known due to confidentiality concerns. Supplemental evidence provided by Manitoba Hydro was in the range of reasonable expectations, but likely on the high end of the range. The reasons for this include using load forecasts that were not representative of the export region and that did not include the impact of higher prices that would be consistent with the CO2 costs assumed by Manitoba Hydro.

Of the six proprietary forecasts used to develop Manitoba Hydro's export price forecast, information was only available for the forecast from The Brattle Group. The load growth and resultant price projections were reasonable (similar to the MISO MTEP12 and higher than Potomac Economics). The Brattle Group's forecast included a price reduction due to transmission losses and congestion similar to what was seen elsewhere, used a load forecast that was similar to others for that region, and included a reduction in load when prices increase.

If the electricity price projections from The Brattle Group are indicative of Manitoba Hydro's forecast from the average of the vendor forecasts, it is reasonable. If the Manitoba Hydro forecast is higher than the Brattle forecast, there is cause for concern.

The inclusion of CO2 costs in the export price forecast is inherently uncertain and poses a substantial risk. Even if CO2 restrictions are imposed, the level and timing of the costs are critical to the revenue needed by Manitoba Hydro.

Appendix

Beginning on March 4, 2013, Megawatt Daily, an electric industry report published Monday through Friday (excepting holidays) by Platts, a division of McGraw-Hill, has published day-ahead price indices for various U.S. trading hubs. The indices reported are for both on-peak and off-peak periods and include four hubs in the MISO region: Illinois Hub, Indiana Hub, Michigan Hub, and Minnesota Hub. According to Platts, the Minnesota Hub "*comprises approximately 170 nodes in and around the cities of Minneapolis and St. Paul, Minn.*"[10] A comparison of those price indices (for March-December 2013) was performed to look for consistent variations between the Minnesota Hub and the other three MISO hubs.

If congestion exists between the Minnesota Hub and the rest of MISO, it will show up in one of two ways. If the Minnesota Hub has an excess of supply which cannot get out of the region due to congestion, the hub price will be lower than the prices at the other hubs. If the Minnesota Hub has a shortage of supply and congestion keeps outside suppliers from getting energy to the region, the hub price will be higher than prices at the other hubs. It should be noted that the existence of lower (or higher) prices is not sufficient to show that congestion exists. Losses associated with transmitting the energy will result in a price differential between the exporting and importing regions. Transmission losses are generally low (a few percent), so larger price differences between hubs would be an indicator of congestion.

The following figures show the percentage of days when a given hub had the highest (blue) or lowest (red) indices for either the on-peak (Figure 2) or off-peak (Figure 3) periods. During the on-peak periods, the Minnesota Hub had the highest price index 42 % of the time and the lowest price index 27 % of the time. During the off-peak periods, the Minnesota Hub had the highest price 7 % of the time and the lowest price 70 % of the time. This indicates that the Minnesota Hub area was exporting energy during most of the off-peak hours, while it imported during some of the on-peak periods and exported during others.

[10] "Methodology and Specifications Guide: North American Electricity," Platts, updated January 2014.

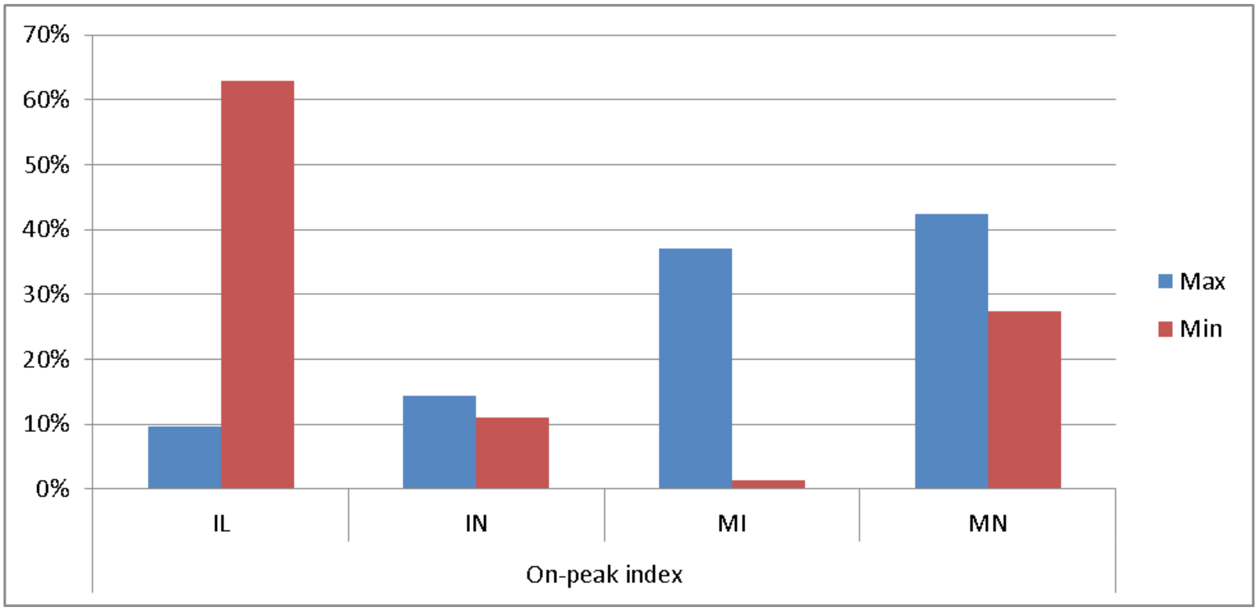

Figure 2. Percentage of days where the on-peak index for a hub was the highest (blue) or lowest (red) of any hub

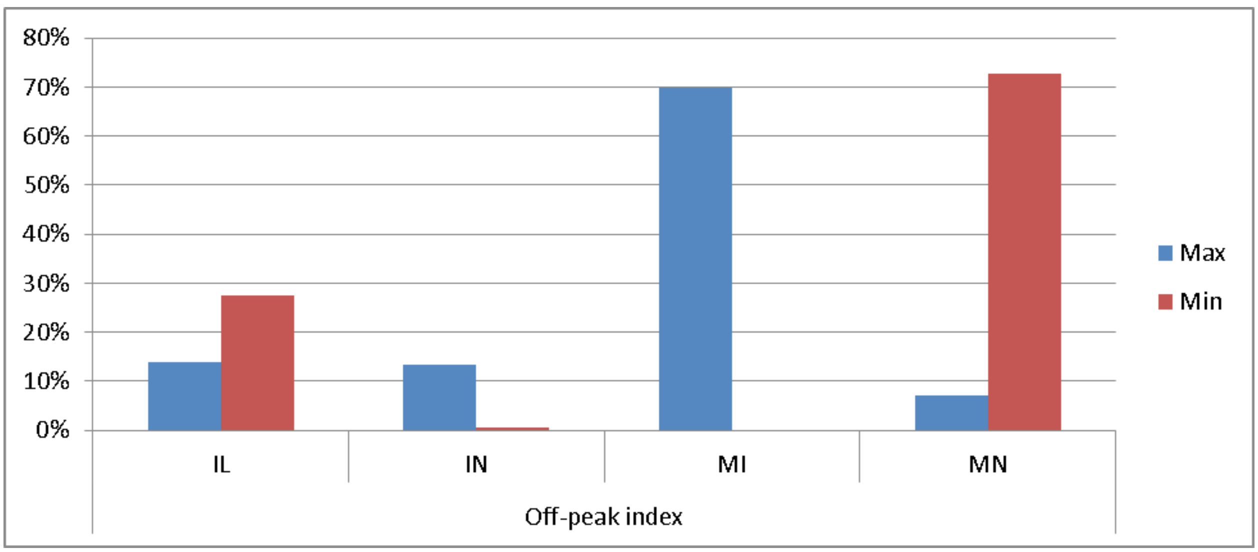

Figure 3. Percentage of days where the off-peak index for a hub was the highest (blue) or lowest (red) of any hub

In order to look for evidence of congestion, the magnitude of the difference between hub price indices was examined. Figures 4 and 5 show the percentage of time that a particular hub's price exceeded the all other hub prices by more than 10% (in blue) or was more than 10% less than any other hub price (in red). Since a difference of that magnitude is unlikely to arise from transmission losses alone, the figures indicate that congestion exists frequently and that the congestion affects market prices in the Minnesota region. In particular, the off-peak prices in the

Minnesota Hub are often suppressed relative to the rest of MISO, with indices more than 10% lower than any of the other three hub occurring 36% of the time. In some hours, this effect was even larger: in 19% of the off-peak periods, the Minnesota Hub was more than 20% lower than any of the other three. It was more than 30% lower in 9% of the off-peak periods and more than 40% lower in 5% of the periods.

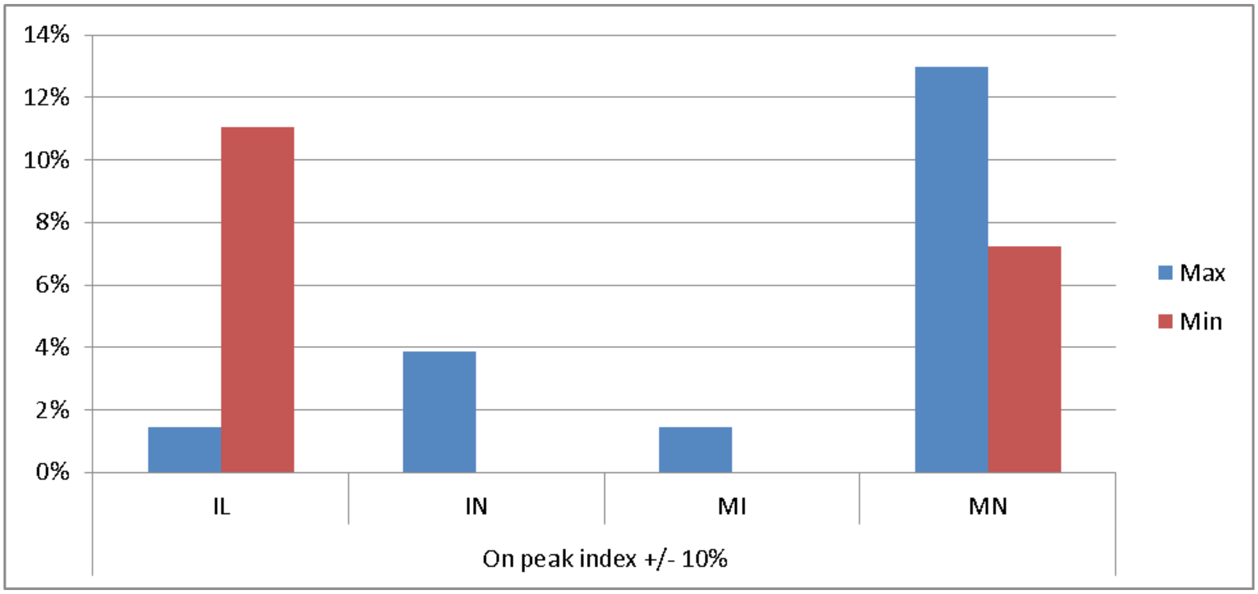

Figure 4. Percentage of days where the on-peak index for a hub was 10 % more (blue) or 10 % less (red) than any other hub

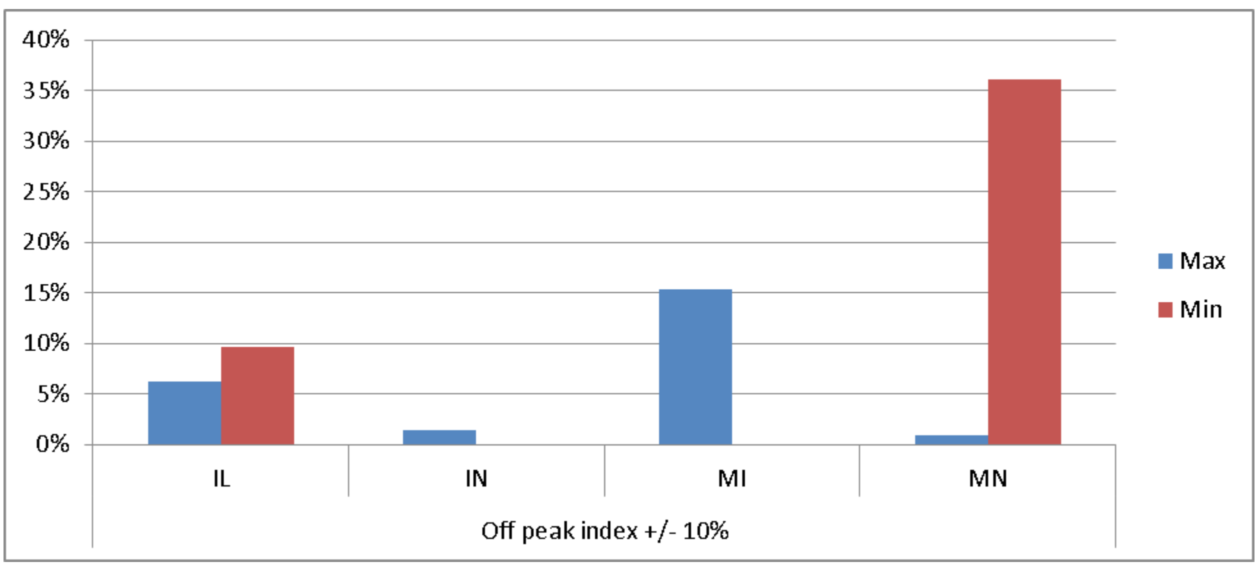

Figure 5. Percentage of days where the off-peak index for a hub was 10 % more (blue) or 10 % less (red) than any other hub