# ADDITIONAL REPORTING REQUIREMENTS (NON-MISO)

## 5. Wind Curtailment Report (Docket Nos. E002/M-00-622, E002/M-02-51, E002/M-04-404, E002/CN-01-1958, E002/M-04-864, E,G999/AA-04-1279, E002/M-05-1850, E002/M-05-1934 and E002/M-06-85)

The Company has been providing wind curtailment reporting in its monthly FCA reports since the May FCA report dated April 28, 2004. Additionally, the Commission's April 4, 2006 Order regarding curtailment payments to wind developers introduced a new element to the regulatory review of wind power purchases—projection of curtailment costs given existing and planned wind-generated energy purchases and the transmission system. Part H, Section 5, Schedule 1 contains a summary of wind production and curtailment payments during the July 1, 2017 – June 30, 2018 AAA reporting period.

Part H, Section 5, Schedule 2 contains an explanation of the factors affecting wind curtailment costs for the 2017-2018 AAA reporting period, and our projection of expenses associated with wind curtailment for the next five years. The actual curtailment expenses will depend on the wind resource experienced at each turbine, the timing of outages of existing transmission facilities and construction of additional transmission facilities, and the operation of wind generators as Dispatchable Intermittent Resources (DIR) in the MISO energy market.

**Northern States Power Company**
**Electric Utility - State of Minnesota**
**Wind Curtailment Summary Report - Total**
**For January 2016 to June 2018**



| Production Month | Date Paid: Delivered MWh | Date Paid: Lost MWh | Wind Production Delivered: MWh Delivered | Wind Production Delivered: Amount Xcel Energy Paid | Lost Production: Lost MWh | Lost Production: Amount Xcel Energy Paid | Total Xcel Energy Paid |
|---|---|---|---|---|---|---|---|
| Jan-16 | | | 374,389.00 | 15,077,234.58 | 5,120.00 | 222,057.33 | $ 15,299,291.91 |
| Feb-16 | | | 388,803.00 | 15,722,028.86 | 7,923.00 | 302,623.95 | $ 16,024,652.81 |
| Mar-16 | | | 386,342.00 | 15,537,502.86 | 17,246.00 | 688,637.00 | $ 16,226,139.86 |
| Apr-16 | | | 488,078.00 | 19,628,605.94 | 16,513.00 | 701,619.02 | $ 20,330,224.96 |
| May-16 | | | 300,210.00 | 12,086,544.34 | 13,389.00 | 522,839.56 | $ 12,609,383.90 |
| Jun-16 | | | 283,453.00 | 11,516,998.71 | 9,418.00 | 392,281.62 | $ 11,830,709.52 |
| Jul-16 | | | 222,615.00 | 8,835,936.12 | 6,738.00 | 258,663.79 | $ 9,045,420.14 |
| Aug-16 | | | 185,274.00 | 7,513,341.19 | 5,140.00 | 188,369.29 | $ 7,701,710.48 |
| Sep-16 | | | 323,595.00 | 13,054,247.43 | 3,101.00 | 152,864.95 | $ 13,207,112.38 |
| Oct-16 | | | 383,683.00 | 15,048,348.05 | 5,221.00 | 269,424.99 | $ 15,094,832.64 |
| Nov-16 | | | 394,308.00 | 15,747,276.81 | 5,418.00 | 204,925.09 | $ 15,952,201.90 |
| Dec-16 | | | 486,347.00 | 19,376,718.44 | 1,955.00 | 79,007.00 | $ 19,455,725.44 |
| **Total-16** | | | 4,217,097.00 | $ 169,144,783.33 | 97,182.00 | $ 3,983,313.59 | $ 172,777,405.94 |
| Jan-17 | | | 430,915.00 | 16,121,114.26 | 3,697.00 | 157,640.79 | $ 16,278,755.05 |
| Feb-17 | | | 413,435.00 | 16,507,567.11 | 6,934.00 | 276,825.34 | $ 16,784,392.45 |
| Mar-17 | | | 416,890.00 | 16,715,428.81 | 11,980.00 | 523,111.92 | $ 17,238,540.73 |
| Apr-17 | | | 457,766.00 | 14,278,919.80 | 7,291.00 | 309,809.33 | $ 14,588,729.13 |
| May-17 | | | 419,789.00 | 15,783,918.29 | 5,970.00 | 243,464.35 | $ 16,027,382.64 |
| Jun-17 | | | 325,258.00 | 12,144,565.98 | 6,822.00 | 309,043.74 | $ 12,453,609.72 |
| Jul-17 | | | 225,540.00 | 8,477,405.53 | 277.00 | 14,625.98 | $ 8,492,031.51 |
| Aug-17 | | | 179,181.00 | 6,687,158.36 | 54.00 | 2,734.06 | $ 6,689,892.42 |
| Sep-17 | | | 348,409.00 | 13,076,351.03 | 1,268.00 | 65,237.53 | $ 13,141,588.56 |
| Oct-17 | | | 516,819.00 | 19,352,565.13 | 2,931.00 | 133,307.49 | $ 19,485,872.62 |
| Nov-17 | | | 496,866.00 | 18,739,626.55 | 435.00 | 18,782.21 | $ 18,758,408.76 |
| Dec-17 | | | 494,304.00 | 18,583,732.70 | 479.00 | 16,365.01 | $ 18,600,097.71 |
| **Total-17** | | | 4,725,172.00 | $ 176,468,353.55 | 48,138.00 | $ 2,070,947.75 | $ 178,539,301.30 |
| Jan-18 | | | 517,112.61 | 19,554,286.92 | 1,458.00 | 58,950.29 | $ 19,613,237.21 |
| Feb-18 | | | 418,166.06 | 15,810,253.22 | 134.82 | 5,843.30 | $ 15,816,096.52 |
| Mar-18 | | | 456,664.46 | 17,253,894.46 | 548.61 | 21,570.10 | $ 17,275,464.56 |
| Apr-18 | | | 389,872.84 | 14,871,852.82 | 2,303.34 | 100,761.56 | $ 14,972,614.38 |
| May-18 | | | 321,602.85 | 12,231,504.86 | 428.37 | 18,532.00 | $ 12,250,036.86 |
| Jun-18 | | | | | | | |
| Jul-18 | | | | | | | |
| Aug-18 | | | | | | | |
| Sep-18 | | | | | | | |
| Oct-18 | | | | | | | |
| Nov-18 | | | | | | | |
| Dec-18 | | | | | | | |
| **Total-17** | | | 2,103,418.81 | 79,721,792.28 | 4,873.14 | 205,657.25 | 79,927,449.53 |

**Northern States Power Company**
**Electric Utility - State of Minnesota**
**Wind Curtailment Summary Report - Curtailment Reason Code 1 (ATC)**
**For January 2016 to June 2018**



| | Date Paid | | Wind Production Delivered | | Lost Production | | |
|---|---|---|---|---|---|---|---|
| Production Month | Delivered MWh | Lost MWh | MWh Delivered | Amount Xcel Energy Paid | Lost MWh | Amount Xcel Energy Paid | Total Xcel Energy Paid |
| Jan-16 | | | - | *0.00* | - | *0.00* | |
| Feb-16 | | | - | *0.00* | - | *0.00* | |
| Mar-16 | | | - | *0.00* | - | *0.00* | |
| Apr-16 | | | - | *0.00* | - | *0.00* | |
| May-16 | | | - | *0.00* | - | *0.00* | |
| Jun-16 | | | - | *0.00* | - | *0.00* | |
| Jul-16 | | | - | *0.00* | - | *0.00* | |
| Aug-16 | | | - | *0.00* | - | *0.00* | |
| Sep-16 | | | - | *0.00* | - | *0.00* | |
| Oct-16 | | | - | *0.00* | - | *0.00* | |
| Nov-16 | | | - | *0.00* | - | *0.00* | |
| Dec-16 | | | - | *0.00* | - | *0.00* | |
| **Total-16** | | | | | | | |
| Jan-17 | | | - | *0.00* | - | *0.00* | |
| Feb-17 | | | - | *0.00* | - | *0.00* | |
| Mar-17 | | | - | *0.00* | - | *0.00* | |
| Apr-17 | | | - | *0.00* | - | *0.00* | |
| May-17 | | | - | *0.00* | - | *0.00* | |
| Jun-17 | | | - | *0.00* | - | *0.00* | |
| Jul-17 | | | - | *0.00* | - | *0.00* | |
| Aug-17 | | | - | *0.00* | - | *0.00* | |
| Sep-17 | | | - | *0.00* | - | *0.00* | |
| Oct-17 | | | - | *0.00* | - | *0.00* | |
| Nov-17 | | | - | *0.00* | - | *0.00* | |
| Dec-17 | | | - | *0.00* | - | *0.00* | |
| **Total-17** | | | | | | | |
| Jan-18 | | | - | *0.00* | - | *0.00* | |
| Feb-18 | | | - | *0.00* | - | *0.00* | |
| Mar-18 | | | - | *0.00* | - | *0.00* | |
| Apr-18 | | | - | *0.00* | - | *0.00* | |
| May-18 | | | - | *0.00* | - | *0.00* | |
| Jun-18 | | | | | | | |
| Jul-18 | | | | | | | |
| Aug-18 | | | | | | | |
| Sep-18 | | | | | | | |
| Oct-18 | | | | | | | |
| Nov-18 | | | | | | | |
| Dec-18 | | | | | | | |
| **Total-18** | | | | | | | |

**Northern States Power Company**
**Electric Utility - State of Minnesota**
**Wind Curtailment Summary Report - Curtailment Reason Code 2 (Low Load)**
**For January 2016 to June 2018**



| | Date Paid | | Wind Production Delivered | | Lost Production | | |
|---|---|---|---|---|---|---|---|
| Production Month | Delivered MWh | Lost MWh | MWh Delivered | Amount Xcel Energy Paid | Lost MWh | Amount Xcel Energy Paid | Total Xcel Energy Paid |
| Jan-16 | | | - | *0.00* | - | *0.00* | |
| Feb-16 | | | - | *0.00* | - | *0.00* | |
| Mar-16 | | | - | *0.00* | - | *0.00* | |
| Apr-16 | | | - | *0.00* | - | *0.00* | |
| May-16 | | | - | *0.00* | - | *0.00* | |
| Jun-16 | | | - | *0.00* | - | *0.00* | |
| Jul-16 | | | - | *0.00* | - | *0.00* | |
| Aug-16 | | | - | *0.00* | - | *0.00* | |
| Sep-16 | | | - | *0.00* | - | *0.00* | |
| Oct-16 | | | - | *0.00* | - | *0.00* | |
| Nov-16 | | | - | *0.00* | - | *0.00* | |
| Dec-16 | | | - | *0.00* | - | *0.00* | |
| **Total-16** | | | | | | | |
| Jan-17 | | | - | *0.00* | - | *0.00* | |
| Feb-17 | | | - | *0.00* | - | *0.00* | |
| Mar-17 | | | - | *0.00* | - | *0.00* | |
| Apr-17 | | | - | *0.00* | - | *0.00* | |
| May-17 | | | - | *0.00* | - | *0.00* | |
| Jun-17 | | | - | *0.00* | - | *0.00* | |
| Jul-17 | | | - | *0.00* | - | *0.00* | |
| Aug-17 | | | - | *0.00* | - | *0.00* | |
| Sep-17 | | | - | *0.00* | - | *0.00* | |
| Oct-17 | | | - | *0.00* | - | *0.00* | |
| Nov-17 | | | - | *0.00* | - | *0.00* | |
| Dec-17 | | | - | *0.00* | - | *0.00* | |
| **Total-17** | | | | | | | |
| Jan-18 | | | - | *0.00* | - | *0.00* | |
| Feb-18 | | | - | *0.00* | - | *0.00* | |
| Mar-18 | | | - | *0.00* | - | *0.00* | |
| Apr-18 | | | - | *0.00* | - | *0.00* | |
| May-18 | | | - | *0.00* | - | *0.00* | |
| Jun-18 | | | | | | | |
| Jul-18 | | | | | | | |
| Aug-18 | | | | | | | |
| Sep-18 | | | | | | | |
| Oct-18 | | | | | | | |
| Nov-18 | | | | | | | |
| Dec-18 | | | | | | | |
| **Total-18** | | | | | | | |

**Northern States Power Company**
**Electric Utility - State of Minnesota**
**Wind Curtailment Summary Report - Curtailment Reason Code 3 (MISO)**
**For January 2016 to June 2018**



| | Date Paid | | Wind Production Delivered | | Lost Production | | |
|---|---|---|---|---|---|---|---|
| Production Month | Delivered MWh | Lost MWh | MWh Delivered | Amount Xcel Energy Paid | Lost MWh | Amount Xcel Energy Paid | Total Xcel Energy Paid |
| Jan-16 | | | 225,468.00 | 9,135,666.90 | 5,120.00 | 222,057.33 | $ 9,357,724.23 |
| Feb-16 | | | 230,076.00 | 9,421,305.86 | 7,923.00 | 302,623.95 | $ 9,723,929.81 |
| Mar-16 | | | 251,333.00 | 10,190,224.97 | 17,246.00 | 688,637.00 | $ 10,878,861.97 |
| Apr-16 | | | 332,804.00 | 13,160,914.46 | 16,513.00 | 703,186.58 | $ 13,864,101.04 |
| May-16 | | | 96,831.00 | 3,733,261.17 | 13,389.00 | 522,839.56 | $ 4,256,100.73 |
| Jun-16 | | | 207,896.00 | 8,356,565.77 | 9,418.00 | 392,281.62 | $ 8,748,847.39 |
| Jul-16 | | | 184,949.00 | 7,356,397.69 | 6,738.00 | 258,663.79 | $ 7,615,061.48 |
| Aug-16 | | | 93,543.00 | 3,878,745.12 | 5,140.00 | 188,369.29 | $ 4,067,114.41 |
| Sep-16 | | | 282,377.00 | 11,190,785.34 | 3,101.00 | 152,864.95 | $ 11,343,650.29 |
| Oct-16 | | | 265,571.00 | 10,430,700.92 | 5,221.00 | 269,424.99 | $ 10,700,125.91 |
| Nov-16 | | | 133,867.00 | 5,020,146.81 | 5,418.00 | 204,925.09 | $ 5,225,071.90 |
| Dec-16 | | | 117,644.00 | 5,206,149.55 | 1,955.00 | 79,007.00 | $ 5,285,156.55 |
| **Total-16** | | | 2,422,359.00 | $ 97,080,864.56 | 97,182.00 | $ 3,984,881.15 | $ 101,065,745.71 |
| Jan-17 | | | 185,333.00 | 6,652,404.63 | 3,697.00 | 157,640.77 | $ 6,810,045.40 |
| Feb-17 | | | 186,522.00 | 7,471,418.20 | 6,934.00 | 276,825.34 | $ 7,748,243.54 |
| Mar-17 | | | 173,389.00 | 6,688,109.31 | 11,980.00 | 523,111.92 | $ 7,211,221.23 |
| Apr-17 | | | 208,551.00 | 8,133,830.65 | 7,291.00 | 309,809.33 | $ 8,443,639.98 |
| May-17 | | | 140,001.00 | 5,528,045.13 | 5,970.00 | 243,464.35 | $ 5,771,509.48 |
| Jun-17 | | | 142,504.00 | 5,704,337.23 | 6,822.00 | 309,043.74 | $ 6,013,380.97 |
| Jul-17 | | | 22,344.00 | 1,266,241.66 | 277.00 | 14,625.98 | $ 1,280,867.64 |
| Aug-17 | | | 22,910.00 | 1,180,091.68 | 54.00 | 2,734.06 | $ 1,182,825.74 |
| Sep-17 | | | 75,520.00 | 3,539,468.64 | 1,268.00 | 65,237.53 | $ 3,604,706.17 |
| Oct-17 | | | 109,037.00 | 5,029,142.90 | 2,931.00 | 133,307.49 | $ 5,162,450.39 |
| Nov-17 | | | 129,002.00 | 5,142,020.66 | 435.00 | 18,782.21 | $ 5,160,802.87 |
| Dec-17 | | | 97,506.00 | 4,362,695.93 | 479.00 | 16,365.01 | $ 4,379,060.94 |
| **Total-17** | | | 1,492,619.00 | $ 60,697,806.62 | 48,138.00 | $ 2,070,947.73 | $ 62,768,754.35 |
| Jan-18 | | | 90,734.12 | 3,924,799.96 | 1,458.00 | 58,950.29 | $ 3,983,750.25 |
| Feb-18 | | | 54,843.51 | 2,785,838.57 | 134.82 | 5,843.30 | $ 2,791,681.87 |
| Mar-18 | | | 144,991.48 | 5,587,088.09 | 548.61 | 21,570.10 | $ 5,608,658.19 |
| Apr-18 | | | 93,370.50 | 4,258,543.18 | 2,303.34 | 100,761.56 | $ 4,359,304.74 |
| May-18 | | | 82,315.24 | 3,741,116.04 | 428.37 | 18,532.00 | $ 3,759,648.04 |
| Jun-18 | | | | | | | |
| Jul-18 | | | | | | | |
| Aug-18 | | | | | | | |
| Sep-18 | | | | | | | |
| Oct-18 | | | | | | | |
| Nov-18 | | | | | | | |
| Dec-18 | | | | | | | |
| **Total-18** | | | 466,254.85 | $ 20,297,385.84 | 4,873.14 | $ 205,657.25 | 20,503,043.09 |

**Northern States Power Company**
**Electric Utility - State of Minnesota**
**Wind Curtailment Summary Report - Curtailment Reason Code 4 (Other-Paid)**
**For January 2016 to June 2018**



| Production Month | Date Paid: Delivered MWh | Date Paid: Lost MWh | Wind Production Delivered: MWh Delivered | Wind Production Delivered: Amount Xcel Energy Paid | Lost Production: Lost MWh | Lost Production: Amount Xcel Energy Paid | Total Xcel Energy Paid |
|---|---|---|---|---|---|---|---|
| Jan-16 | | | - | *0.00* | - | *0.00* | |
| Feb-16 | | | - | *0.00* | - | *0.00* | |
| Mar-16 | | | - | *0.00* | - | *0.00* | |
| Apr-16 | | | - | *0.00* | - | *0.00* | |
| May-16 | | | - | *0.00* | - | *0.00* | |
| Jun-16 | | | - | *0.00* | - | *0.00* | |
| Jul-16 | | | - | *0.00* | - | *0.00* | |
| Aug-16 | | | - | *0.00* | - | *0.00* | |
| Sep-16 | | | - | *0.00* | - | *0.00* | |
| Oct-16 | | | - | *0.00* | - | *0.00* | |
| Nov-16 | | | - | *0.00* | - | *0.00* | |
| Dec-16 | | | - | *0.00* | - | *0.00* | |
| **Total-16** | | | | | | | |
| Jan-17 | | | - | *0.00* | - | *0.00* | |
| Feb-17 | | | - | *0.00* | - | *0.00* | |
| Mar-17 | | | - | *0.00* | - | *0.00* | |
| Apr-17 | | | - | *0.00* | - | *0.00* | |
| May-17 | | | - | *0.00* | - | *0.00* | |
| Jun-17 | | | - | *0.00* | - | *0.00* | |
| Jul-17 | | | - | *0.00* | - | *0.00* | |
| Aug-17 | | | - | *0.00* | - | *0.00* | |
| Sep-17 | | | - | *0.00* | - | *0.00* | |
| Oct-17 | | | - | *0.00* | - | *0.00* | |
| Nov-17 | | | - | *0.00* | - | *0.00* | |
| Dec-17 | | | - | *0.00* | - | *0.00* | |
| **Total-17** | | | | | | | |
| Jan-18 | | | - | *0.00* | - | *0.00* | |
| Feb-18 | | | - | *0.00* | - | *0.00* | |
| Mar-18 | | | - | *0.00* | - | *0.00* | |
| Apr-18 | | | - | *0.00* | - | *0.00* | |
| May-18 | | | - | *0.00* | - | *0.00* | |
| Jun-18 | | | | | | | |
| Jul-18 | | | | | | | |
| Aug-18 | | | | | | | |
| Sep-18 | | | | | | | |
| Oct-18 | | | | | | | |
| Nov-18 | | | | | | | |
| Dec-18 | | | | | | | |
| **Total-17** | | | | | | | |

# 2017 – 2018 WIND CURTAILMENT REPORT

## I. INTRODUCTION

The Commission's April 4, 2006 Order regarding curtailment payments to wind developers (Docket No. E999/AA-04-1279) requires the Company to provide in future AAA reports a projection of wind generation curtailment costs given existing and planned wind-generated energy purchases and transmission system needs. In compliance with the Commission's Order, this report provides a summary of the Company's experience regarding wind curtailment payments, an estimate of potential curtailment payments over the next five years, and the assumptions used to develop our forecast.

## II. CURTAILMENT UPDATE

In past AAA Curtailment Reports, the Company has worked with the Department and made efforts to improve communications about the events and activity that cause wind generation curtailment. The Department's review and evaluation over the years has helped identify areas where our reports could be more descriptive of the reasons for wind curtailment and efforts made to minimize resulting costs. In addition, the Company continues to utilize initiatives to reduce curtailment which we believe are having a positive impact on curtailment or costs associated with curtailment. Examples include, where possible, scheduling transmission activities which can impact curtailment during low wind months and manual economic curtailment.

The Company expects that some level of wind curtailment from Power Purchase Agreement (PPA) facilities will occur during the foreseeable future. The reasons driving the curtailment have shifted from primarily local transmission constraints on NSP's transmission system in southwest Minnesota to regional transmission system congestion on the MISO system. The regional congestion, which results in negative LMP, was the largest driver of curtailment during this reporting period. Additionally, the nature of transmission congestion is accentuated by the large concentration and increased level of wind facility operations in Minnesota, North Dakota, South Dakota and Iowa.

Significant transmission improvements in southwestern Minnesota and the region such as the CapX2020 transmission projects (CapX2020) and a number of MISO Multi-Value Projects (MVPs) are now in-service and will positively impact curtailment by reducing local congestion. However, the Company believes future curtailment in this area will continue to occur because of regional congestion and the resulting negative LMP in the MISO energy market, along with transmission outages required

for construction, maintenance or repair activities and wind generation projects going into service before all required transmission facilities are completed.

To better manage regional congestion, MISO and the industry utilize Dispatchable Intermittent Resources (DIRs), which provides better management of the wind resources. Under this system, a number of existing PPA wind facilities that are capable of operating as DIR, along with all new wind facilities, are registered with MISO as DIR. DIR facilities are given set point instructions every five minutes and rely on Automated Generation Control (AGC) technology, which automatically controls wind project output. DIR allows wind generators to be operated more like traditional generating facilities and, as a result, MISO is able to more quickly and accurately respond to system conditions. Manual curtailment of non-DIR PPA wind facilities, which were developed prior to DIR reform measures, also continues to be used to manage the wind resources when appropriate.

Table 1 shows the existing PPA wind facilities associated with this report that are registered and operate as DIR.

**Table 1**
**DIR PPA Facilities**

| Wind Project | MW |
|---|---|
| Fenton | 200 |
| Odell | 200 |
| Prairie Rose | 200 |
| MinnDakota | 150 |
| Mower County | 100 |
| Moraine II | 50 |
| Big Blue | 36 |
| Zephyr | 30 |
| Valley View | 10 |
| Total | 976 |

The federal Production Tax Credit (PTC), which provides tax benefits to wind generating plants, is scheduled to expire over the next few years. As in the past, the uncertainty of PTC expiration is closely connected with increases in wind curtailment, since wind projects are often put into service to meet PTC eligibility requirements even though the necessary transmission upgrades were not completed. The Company

is aware of 5,550 MW of planned wind generation in Minnesota, North Dakota, South Dakota and Iowa that is expected to go into service in in the next three years – which includes 1,850 MW of Company-owned and PPA wind. Table 2 shows planned wind developments by other regional companies. All of these wind developments will be registered and operated as DIRs.

**Table 2**
**Wind Generation Additions**

| Company | MW | Location | In-Service Date |
|---|---|---|---|
| NSP | 1850 | ND, SD, MN | 2019-2021 |
| Alliant Energy | 1000 | Iowa | 2019-2020 |
| Great River Energy | 300 | ND | 2019 |
| MidAmerican | 2000 | Iowa | 2018-2020 |
| Minnesota Power | 250 | MN | 2019 |
| Ottertail Power | 150 | ND | 2020 |
| Total | 5550 | | |

The required transmission upgrades for these wind projects will likely not all be in-service by the time the projects begin producing energy. This will have a negative effect on LMP pricing in the MISO regional energy market that could potentially impact real-time wind generation on the NSP System. This potential impact will lessen due to mitigation measures such as: (1) the use of DIR and set-point control technology, (2) placing in service the required transmission facilities and transmission system improvements, and (3) improved transmission outage scheduling.

## III. Transmission System Improvements

Since 1994, wind energy resources have been the dominant factor in determining the need for transmission infrastructure improvements in southwestern Minnesota. To meet this need, the Company, often in cooperation with other utilities, has planned, engineered and constructed a number of projects designed to increase the transmission capacity in that area. Table 3 shows historic southwest Minnesota projects that increased the available transmission outlet in that area.

**Table 3**
**Southwest Minnesota Wind Limits**

| Transmission Project | Transmission Owner | In-Service Date |
|---|---|---|
| 425 MW Wind Transmission Expansion Project | Xcel Energy | December 2006 |
| 825 MW Wind Transmission Expansion Project | Xcel Energy | June 2008 |
| Buffalo Ridge Incremental Generation Outlet (BRIGO) | Xcel Energy | December 2009 |

The Company also participated in the development of three CapX2020 transmission projects, all of which have gone into service and are helping reduce wind curtailment on the NSP system. Table 4 lists the CapX2020 transmission projects.

**Table 4**
**CapX2020 Transmission Projects**

| Transmission Project | Transmission Owner | Actual/Planned In-Service Date |
|---|---|---|
| Brookings County - Southeast Twin Cities 345 kV Line | Xcel Energy, Great River Energy | March 2015 |
| Fargo North Dakota - Northwest Twin Cities 345 kV Line | Xcel Energy, Great River Energy | April 2015 |
| Southeast Twin Cities - LaCrosse, Wisconsin 345 kV Line | Xcel Energy, SMMPA and non-MISO | September 2016 |

In addition to transmission projects developed by the Company, MISO has identified and approved a number of new transmission infrastructure projects including 17 MVPs designed to accommodate the planned and expected generation expansion in the MISO footprint.[1] The MVPs will help expand and enhance the region's transmission system, reduce congestion, provide access to affordable energy sources and meet public policy requirements including renewable energy mandates. The completion of the MVP projects, particularly the ones listed in the following table, have, or will have, a positive impact on Company-owned and PPA wind facilities.

[1] The MISO Board of Directors approved the new transmission projects, which included the CapX2020 Brookings County – Southeast Twin Citites 345 kV line as an MVP, on December 13, 2012.

**Table 5**
**MVP Projects**

| Transmission Project | Transmission Owner | Planned/Actual In-Service Date |
|---|---|---|
| Big Stone South to Brookings County 345 kV Line | Ottertail Power Company, Xcel Energy | September 2017 |
| Lakefield Jct. - Winnebago - Winco - Kossuth County & Obrien County - Kossuth County - Webster 345 kV Line | MidAmerica Energy, ITC Midwest | End 2018 |
| North LaCrosse - North Madison | American Transmission Company, Xcel Energy | End 2018 |
| Winco to Hazleton 345 kV Line | MidAmerica Energy, ITC Midwest | End 2019 |
| Ellendale to Big Stone South 345 kV Line | Ottertail Power Company, Montana Dakota Utilities | End 2019 |
| North Madison - Cardinal - Spring Green - Dubuque area 345 kV Line | American Transmission Company, ITC Midwest | End 2023 |

## IV. Wind Generation, Curtailment and Curtailment Projections

Chart 1 shows Company-owned and PPA wind generation facilities throughout the NSP service territory on an incremental and cumulative basis. No wind projects have come on-line, or are scheduled to come on-line in 2018.

**Chart 1**
**NSP Wind Development**
(1993 – 2018)

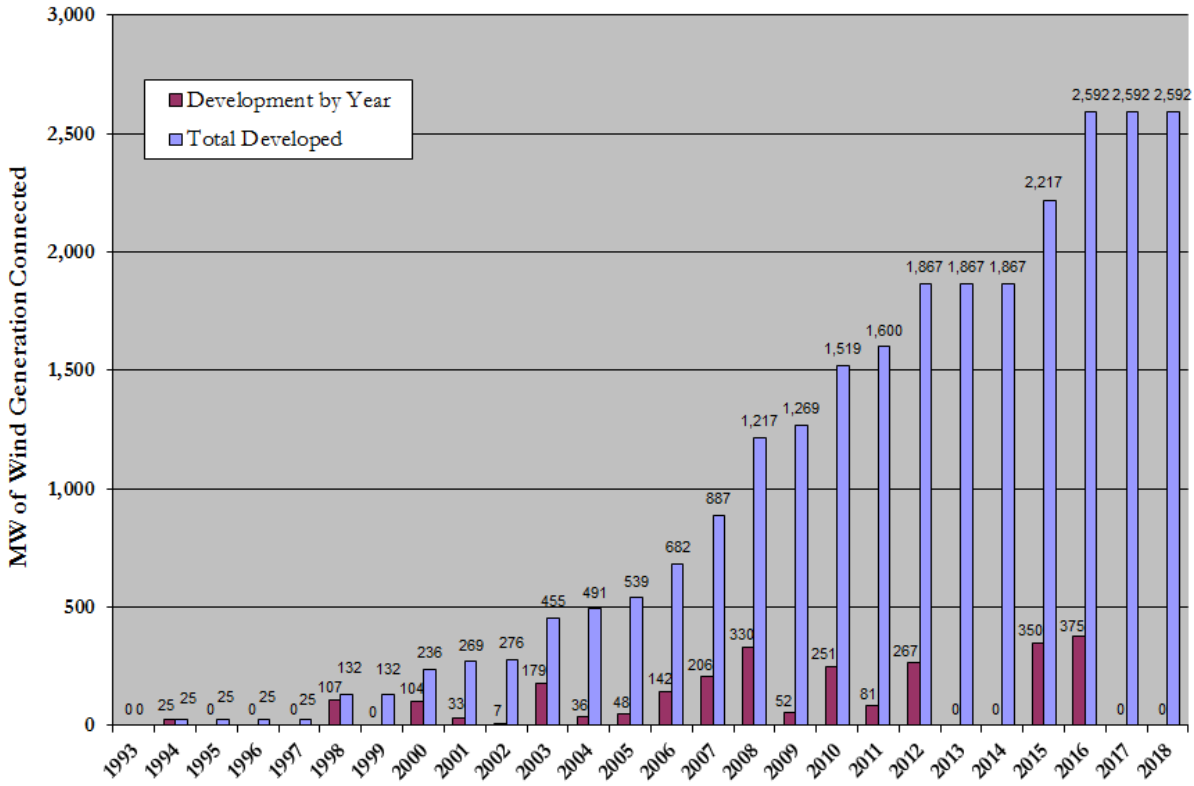
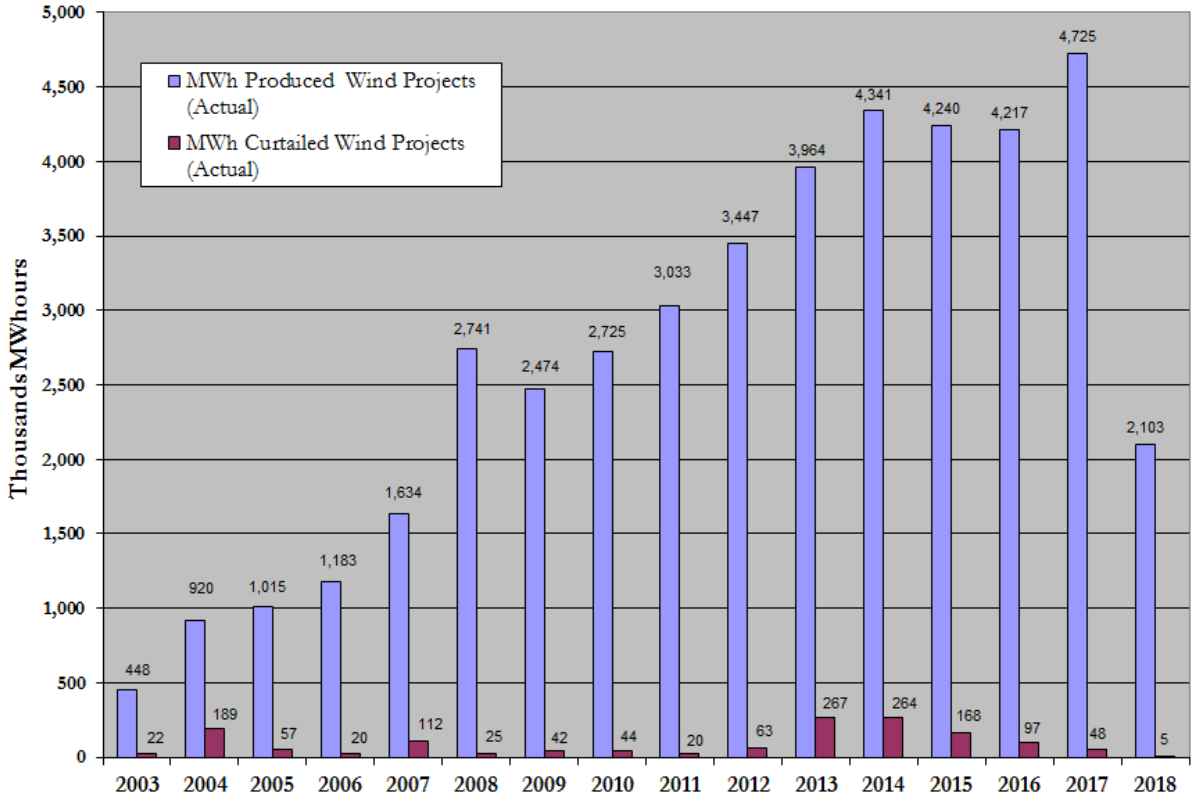



Chart 2 shows the comparison between total wind energy produced and the wind energy curtailed from the projects through May 2018[2]. Despite the lead/lag time associated with generation and transmission development, Chart 2 shows that wind curtailment is small compared to the total wind generation delivered.

Wind curtailment, as a tool to manage wind generation volumes when necessary, has had the positive benefit of facilitating a large amount of wind resources to be added to the system, which would not otherwise have been possible.

[2] AAA Part H, Section 5, Schedule 1.

**Chart 2**
**NSP Wind Production & Curtailment (MWh)**
(2003 – 2017 Full Calendar Years, 2018 Partial Year through May)




Curtailment during July 2017 to June 2018 was broken up into three categories to better explain the reasons for the curtailment and its cause. To support the analysis the Company identified hours during the 2017/2018 AAA period where transmission-related outages impacted wind projects. During hours where transmission outages did not occur, or where transmission outages did not impact a specific wind farm, the hours were assigned as either manual curtailment or DIR curtailment based on if a project was registered as a DIR. This hourly information was then compared to hourly curtailment data for each of the reporting wind farms and total MWh and curtailment costs were calculated. It should be noted that the hourly data was only assigned one category and did not overlap.

A total of $452,457 in curtailment payments[3] were made during this reporting period for these three categories:

1) Transmission Events ($255). This includes Chanarambie and Yankee transformer outages;
2) DIR Curtailments Events ($413,132). This was driven by negative LMP related reasons; and
3) Manual Curtailments Events ($39,071). This was also driven by negative LMP related reasons.

The MWh and curtailment costs determined during the curtailment analysis are compiled in Table 6 and Table 7 below. These results are further separated to show MWh and curtailment costs for projects that are still eligible for the PTC and those that are not. Note: the curtailment values in this section do not exactly match the curtailment values shown in AAA Part H, Section 5, Schedule 1. This data is based on the Company's analysis and estimated volumes from curtailment events and not based on the customer submitted invoices.

**Table 6**
**2017/2018 Wind Curtailment MWh**

| Events | MWh | | |
|---|---|---|---|
| | Total | Projects / No PTC | Projects / PTC |
| Transmission Events | 5 | 5 | 0 |
| DIR Curtailment Events | 8,950 | 8,950 | 0 |
| Manual Curtailment Events | 1,069 | 1,069 | 0 |
| Totals | 10,024 | 10,024 | 0 |

[3] The curtailment analysis in this section used Company data – not AAA Part H, Section 5, Schedule 1 data and included June of 2018.

**Table 7**
**2017/2018 Wind Curtailment Costs**

| Events | Payments | | |
|---|---|---|---|
| | Total | Projects / No PTC | Projects / PTC |
| Transmission Events | $255 | $255 | $0 |
| DIR Curtailment Events | $413,004 | $413,004 | $0 |
| Manual Curtailment Events | $39,198 | $39,198 | $0 |
| Totals | $452,457 | $452,457 | $0 |

As can be seen in Tables 6 and 7, the majority of the curtailment was related to DIR and Manual Curtailment Events and occurred at projects that are no longer eligible for the PTC.

It is important to note that of the $452,457 in total curtailment costs, the vast majority of these total costs are associated with the contractual energy price of the PPAs. These are contractually obligated sunk costs which are not economically relevant to the decision to curtail the generation from a wind farm.[4]

Transmission Curtailment Events

Wind curtailment costs totaling $255 were due to the transmission events described below.

The primary goal when planning construction and maintenance work that will impact wind generation output is to perform multiple outages at the same time, and schedule these activities during times when wind is normally at its lowest levels – typically the summer months in the NSP service territory. While Xcel Energy attempts to plan outage work with this principle in mind, this is not always possible. For example, from September through the end of 2013, there were unavoidable transmission outages taken which resulted in significantly increased levels of curtailment than had been experienced in a number of years. Summer months are also high load months and transmission outages may not be possible due to load serving needs.

[4] The PPA contract language can generally be described as "take or pay" in which NSP must pay for the wind energy that could be produced, regardless of whether it actually is produced or if it is curtailed.

If should be noted that only specific wind generation are used to manage the different transmission events. For example, Chanarambie transformer outages can impact Lake Benton II, Chanarambie Power Partners, Ridgewind, Moraine I, and Moraine II while Yankee transformer outages can impact MinnDakota.

Chanarambie and Yankee Transformer outages.
The Company experienced planned and unplanned outages of transformers at the Chanarambie and Yankee substations that contributed to curtailment during this period. The facilities were taken out of service for maintenance activies and as the result of adverse weather conditions.

Curtailment Procedures
The Company has detailed wind curtailment guidelines in place to ensure that wind resources are managed economically and for the reliability of the system, consistent with the terms of the related purchased power contracts. NSP Generation Control and Dispatch strives to minimize total generation costs including the consideration of wind farm curtailment costs and production tax credits. Specific curtailment procedures are in place that take into account how the asset is registered in the MISO Market, whether the wind farm is equipped with setpoint control equipment, which wind farms are registered as DIR, and which are Intermittent. A curtailment matrix has been established and is maintained that lists CP Node location, contract price, compensable curtailment threshold, and curtailment for economics. The list is organized from highest to lowest curtailment threshold, that is, the market price below which it is economic to curtail if curtailment is compensable.

For DIR units, MISO performs a 10-minute forecast every five minutes. This forecast is used as the maximum limit for the wind farm in the Unit Dispatch System. MISO sends five-minute dispatch instructions to DIR wind farms. When LMP drops below the offer price of the DIR unit, the farm is automatically dispatched down. The setpoint is sent to the DIR wind farm, and the facility is automatically curtailed. It should be noted that not all DIR farms are equipped with setpoint controls. In such situations, a phone call or e-mail is required to initiate a manual curtailment. Non-DIR units are not equipped with setpoint control.

DIR Curtailment Events
Wind curtailment costs totaling $413,004 were due to the MISO-directed DIR control as described below.

DIR related curtailment was due to negative LMP prices associated with congestion throughout the Minnesota and Iowa region due to regional transmission outages, as well as the higher levels of wind generation present where all required transmission

improvements have not been completed or where sufficient transmission outlet did not exist.

Both PTC and non-PTC DIR wind farms are managed by MISO through automatic control and these facilities are required to comply with the MISO cost signals. Failure to comply would expose the Company to Revenue Sufficiency Guarantee charges.

Manual Curtailment Events

Wind curtailment costs totaling $39,198 were due to the Manual Curtailment Events as described below.

Concerning the prudency of non-transmission limited, manual economic, congestion and negative LMP related curtailments, NSP performed an analysis of the economic impact of this curtailment type and determined that the curtailments produced customer economic value by reducing costs by $265.41 as shown in Table 7.

**Table 8**
**Manual Actions Related to Economics**
(July 2017 – June 2018)

| Connection Node | MWh | Curtailment Benefit $ | Average Benefit $/MWh | PTC or No PTC |
|---|---|---|---|---|
| Lake Benton I | 828.00 | $157.25 | $ 0.19 | No PTC |
| Lake Benton II | 20.00 | $67.82 | $ 3.39 | No PTC |
| ValleyView Wind | 2.00 | ($5.78) | $(2.89) | No PTC |
| Ridgewind Power Partners | 219.00 | $46.12 | $ 0.21 | No PTC |
| Totals | 1,069.00 | $265.41 | $ 0.25 | |

To perform this analysis the Company started with estimated hourly averaged curtailment volumes[5] and hourly averaged LMP values for all non-DIR wind farms. The Company then manually subtracted the curtailment volumes for hours that were specifically identified as Transmission Curtailment Events. The resulting hourly curtailment data represents all manual curtailments that were made for economic reasons and not due to a transmission limitation. The hourly curtailment volume for

[5] NSP used hourly averaged curtailment data based on the Company's analysis and estimated volumes from curtailment events and not based on the customer submitted invoices. As a result, the data does not perfectly match the curtailment volumes on the customer invoices, which is the basis for the volumes used in the Company's response to Information Request No. DOC-008, Attachment B in Docket No. E002/AA-14-579.

each wind farm was then multiplied by the corresponding hourly LMP for that wind farm to determine the hourly settlement impact of the curtailed wind generation. It is important to note that the bulk of these total costs are associated with the contractual energy price of the PPA. These are contractually obligated sunk costs which are not economically relevant to the decision to curtail the generation from a wind farm. The only economically relevant factor in the decision whether or not to curtail a wind farm is whether the real-time LMP is above or below the dispatch price for the wind farm.

## III. Wind Production and Curtailment Payments

Chart 3 shows the corresponding production and curtailment costs through May, 2018.[6] As with wind generation produced and curtailed, paid curtailment is a very small portion of total cost of wind generation on the system.

[6] AAA Part H, Section 5, Schedule 1

**Chart 3**
**NSP Wind Production & Curtailment Payments**
(2003 – 2017 Full Calendar Years, 2018 Partial Year through May)

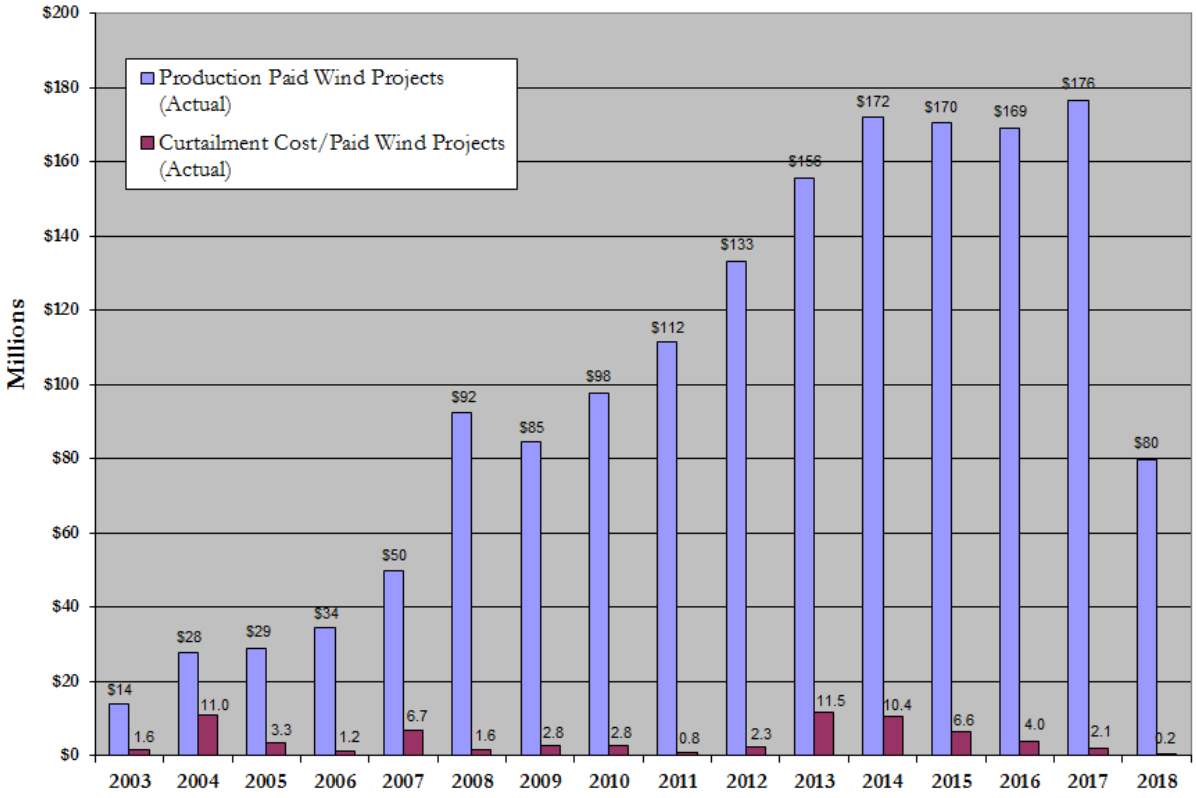
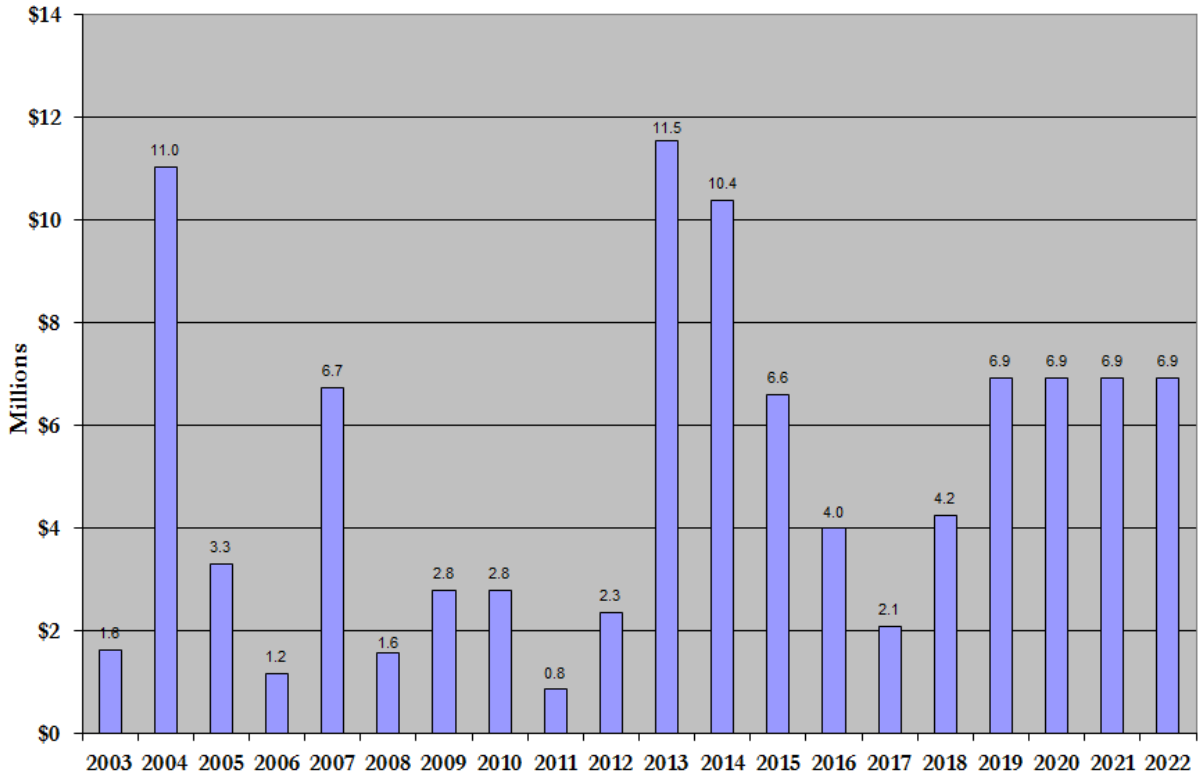


Chart 4 shows the Company's historical wind curtailment costs along with the five-year estimate of future costs.[7]

**Chart 4**
**NSP Wind Curtailment Payments**
(2003 –2017 Actual, 2018 – 2022 Projected)




As was the case in the 2016 - 2017 AAA Report, we are projecting future curtailment will occur because of regional congestion and the resulting negative LMP in the MISO energy market, along with transmission outages required for construction, maintenance or repair activities and wind generation projects going into service before all required transmission facilities are completed. Our projections used the average of the last five years of historical curtailment data to project the level of future curtailment. This approach will help capture and reflect ongoing trends with wind and transmission development, as well as the outages necessary for maintenance, repair and construction activity.

[7] AAA Part H, Section 5, Schedule 1

Future wind generation additions and completion of the MVP transmission projects will likely impact the amount of future curtailment experienced. While it is reasonable to expect curtailment levels will be reduced once the new transmission lines are in service, the reduction will likely be off-set by the new wind projects going into service. In the Company's recent filing for Acquisition of Wind Generation under Docket No. E002/M-16-777, a detailed discussion on wind curtailment was also provided. The filing stated that the Company expects wind curtailment to be higher when the new projects first go into service, and then decline as new transmission and other changes on the MISO system occur to better accommodate increased wind penetration. While we continue to believe that this will be the case there is no certainty as to when, and if, the numerous wind generation projects currently in the development queue will actually come to fruition. As such, the Company did not try to predict the specific impact that future wind generation or completion of the MVP transmission projects would have on curtailment.

## VI. CONCLUSION

The Company anticipates that wind generation curtailment and associated payment to vendors will occur over the next five years because of regional congestion and the resulting negative LMP in the MISO energy market, along with transmission outages required for construction, maintenance or repair activities and wind generation projects going into service before all required transmission facilities are completed. System conditions and wind project development are very dynamic and actual curtailment may vary from that projected in this report. The Company will continue to participate in discussions regarding transmission planning and operations to identify needs and work to manage future costs. We will continue to refine and gather information for use in future updates to be submitted with subsequent AAA reports.