# Rate Impacts of the Montana Renewable Portfolio Standard (RPS) and Community Renewable Energy Project (CREP) Requirements

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## Background

The Renewable Power Production and Rural Economic Development Act (69-3-20, MCA) was enacted on April 2005 and went into effect on June 2006. It includes both a Renewable Portfolio Standard (RPS) component (a percentage of retail sales that must be met with "eligible renewable resources," new resources meeting certain size and energy source requirements) and a Community Renewable Energy Project (CREP) component (projects that are locally or utility owned with a nameplate capacity of 25 MW or less) that public utilities and competitive electric suppliers must satisfy. The RPS component is as follows:

January 1, 2008 through December 31, 2009: 5% of retail sales.

January 1, 2010 through December 31, 2014: 10% of retail sales.

January 1, 2015 and each succeeding compliance year: 15% of retail sales.

Beginning January 1, 2012, as part of the compliance with the RPS, public utilities must also purchase at least 50 MW in CREP nameplate capacity, increasing to 75 MW on January 1, 2015. This total number is allocated proportionally among public utilities based on their respective retail sales and both the energy and associated Renewable Energy Credits (RECs) included in CREPs. NorthWestern's share of the statewide CREP requirement is 44MW; MDU is responsible for 5.6MW.

## Role of Qualifying Facilities (QFs)

The Public Utility Regulatory Policies Act (PURPA) (1978) established a class of generators that receive favorable rate and regulatory treatment. These facilities are either small power production facilities or cogeneration facilities.

Small power production facilities are generally 80 MW or less and are primarily fueled by renewable, biomass, waste, or geothermal resources. Cogeneration facilities are facilities that produce electricity and a useful form of thermal energy in a way that is more efficient than just the production of electricity or thermal energy alone. There is no size limit on eligible cogeneration facilities.

Under PURPA, utilities must purchase the energy produced by QFs in one of two ways. If the QF is below a certain threshold (100 kW or less under Federal law, 3 MW or less currently under Montana Public Service Commission rule A.R.M. 38-5-1902) it must be offered a standard rate equal to a utility's avoided cost. If the QF is above the threshold, then utilities only have to purchase energy from them if the QF is selected as the winner through a competitive solicitation process.

QFs generally count towards the RPS and the CREP standard because they are usually renewable and often locally owned. They are also often below the size threshold (currently 3 MW, but formerly 10 MW) that allows them to take advantage of the standard offer rate which forces utilities to purchase energy from them at avoided cost. Therefore, any analysis of rate impacts that are attributable to the RPS and the CREP standard must account for QFs and remove them from the impact because even though they may help satisfy the RPS and CREP standards, Federal law requires Montana utilities to purchase from them if they fall below the 3 MW threshold. However, for QF contracts signed after the effective date of Order D2010.7.77, RECs must be purchased separately from the QF power output and any RECs purchased from QFs used for compliance with the RPS must be attributed to the RPS.

## Regulation

Wind resources tend to be highly variable and create challenges for NorthWestern in meeting mandatory reliability standards set by the North American Electric Reliability Corporation (NERC) and enforced by the Federal Energy Regulatory Commission (FERC). Meeting those standards requires regulation service to offset the fluctuations in wind production. Before Dave Gates Generating Station (DGGS) was built, NorthWestern bought regulation service from third party providers. Since the plant has been in service it has been the main, if not sole provider of regulation service for NorthWestern.

For MDU, regulation is provided by Midcontinent Independent System Operator (MISO).

## NorthWestern Energy (NWE)

In a January 2014 response to an ETIC Survey for Utilities and Suppliers, NWE stated that it used the following resources to comply with the RPS:

Judith Gap: 135 MW

Gordon Butte: 9.6 MW

Turnbull: 13 MW

Spion Kop: 40 MW

Flint Creek: 2 MW

Lower South Fork: 0.5 MW

Additionally, the Company stated Gordon Butte, Flint Creek, and Lower South Fork were used to comply with the CREP requirement.

### Analysis of Resources Used For Compliance

**Judith Gap:** Judith Gap is a wind powered generation facility with a 135 MW nameplate capacity. This windfarm pre-dates the RPS (construction started 1/1/2005 and went into service 2/16/2006) but is used to comply with it. There is no evidence in testimony or orders in the preapproval filing (Docket No.

D2005.2.14) that this facility was approved with any thought of a future RPS in Montana so it cannot be directly attributed to the RPS.

**Gordon Butte:** Gordon Butte is a windfarm with a 9.6 MW nameplate capacity and an in-service date of 1/3/2012. This facility is both RPS and CREP compliant but it is also a QF and the developer is paid under the standard offer QF-1 rate that was available at the time that included RECs. Therefore, RPS and CREP compliance are ancillary benefits NWE receives because the Company is required to purchase energy from it under PURPA. (Note that in the absence of a Montana RPS, the RECs generated by bundled QFs could be sold off-system. These opportunity costs are not counted in this analysis.)

**Turnbull:** Turnbull is a hydroelectric facility with a 13 MW nameplate capacity and an in-service date of 7/15/2011. This facility is both RPS and CREP compliant and NWE states that they procured Turnbull via a competitive bid for CREP resources.

**Spion Kop:** Spion Kop is a windfarm with a 40 MW nameplate capacity and an in-service date of 12/1/2012. (Full production began the previous month.) It is owned by NWE and was purchased at a capacity cost of $1947/kW. It is used to comply with the RPS and it is reasonable to conclude that it was built for compliance based on testimony (Docket No. D2011.5.41).

**Flint Creek:** Flint creek is a hydroelectric facility with a 2 MW nameplate capacity and an in-service date of 3/14/2013. This facility is both RPS and CREP compliant but energy is purchased from it based on the QF-1, Option 1(a) tariff rate. NWE would be required to purchase its output in the absence of both RPS and CREP legislation. RECs do not come bundled with the electricity but are purchased separately. Therefore associated REC costs are attributable to the RPS and CREP standard.

**Lower South Fork:** Lower South Fork is a hydroelectric facility with a 0.5 MW nameplate capacity and an in-service date of 8/14/2012. This facility is both RPS and CREP compliant but energy is purchase based on the QF-1, Option 1(a) tariff rate. NWE would be required to purchase its output in the absence of both RPS and CREP legislation. RECs do not come bundled with the electricity; so associated REC costs are attributable to the RPS and CREP standard.

**Musselshell:** Musselshell is a wind facility with a 20 MW nameplate capacity and an in service date of 1/1/2013. This facility is RPS compliant but it is a Qualifying Facility with energy purchased under the old REC-bundled QF rate option at $69.21/MWh. It was not used to meet the RPS standard during the period studied in this report (through the 2012-13 Tracking Year).

ETIC has requested that MCC estimate the costs, if any, to ratepayers that are attributable to the RPS and CREP standards. MCC's analyses are constrained by the availability of data. Estimation of the costs to ratepayers requires assumptions about what resources would have been purchased, and the cost of those resources, in lieu of those acquired for the purpose of meeting the RPS and CREP standards. For example, one possible assumption could be that the utility's avoided cost is a measure of the costs that would have been incurred. For QF resources this means the only additional costs would be the costs of RECs purchased separately. For non-QF resources the additional costs would be the difference between the relevant QF rate and the cost actually paid, plus regulation costs if appropriate, plus the costs of

RECs purchased separately, also if appropriate. An alternate assumption could be that the power provided by the CREP and RPS resources would have been purchased in the spot market. A third alternative is that the power would have been purchased at a cost similar to that of other assumed long term resources. Another alternative could be a weighted average of the long term and spot market costs.

NorthWestern's non-QF RPS and CREP resources are Judith Gap, Spion Kop, and Turnbull Hydro. Judith Gap's cost is considerably lower than the QF rate. When NorthWestern built the DGGS plant for regulation it assigned wind the incremental capital costs of the plant above that needed for regulation of load and transmission customers, in the range of $13 per MWh of wind. Even adding this value for regulation the total cost of Judith Gap is below avoided cost. Spion Kop, including current estimates for the cost of regulation, is $45.22, also well below avoided cost. Turnbull Hydro's cost is $65.75; regulation is not an issue for hydro plants. Because this rate is below the average avoided cost (75.26) for peak months of July and August, when most of Turnbull's production arises, Turnbull has lower overall costs than the avoided cost alternative. Therefore the net impact of CREP and RPS to ratepayers, when measured by the avoided cost example would be negative.

The following analyses compare the cost to ratepayers of the CREP and RPS resources using the spot market and the weighted average spot and long term contract cost alternatives.

**Analysis of Rate Impacts Pre 2012-2013 Tracker Year**

For the first several years of the RPS requirement, through the 2009-2010 tracking year, the Judith Gap plant provided sufficient RECs for NorthWestern's full requirement for RECs. Because the Judith Gap facility was purchased at such an advantageous rate before the imposition of RPS, for this period no additional costs were placed on ratepayers by the RPS requirement. Therefore, our analysis begins with the 2010-2011 tracking year.

Rate impacts were determined by analyzing the change in supply rates in NWE's Annual Electric Tracker filings by removing the resources directly attributable to the RPS and replacing them with either (a) market purchases or (b) a 50/50 mix of market purchases and long-term contacts. This allows us to compare the change in costs (under the two assumptions about alternative resources) that can be directly attributed to the RPS. As noted above, different assumptions could be used and different impacts would be derived.

NWE Annual Electric Tracker filings were analyzed from the beginning of the implementation of the RPS up to the point that the last actual tracker information was present, in this analysis the 2011-2012 tracker year. Beyond the 2011-2012 tracker year there currently is no actual production and cost information filed (the 2012-2013 tracker filing is expected in May, 2014). This analysis only looks at the rate impact of Turnbull and leaves out any rate impact of Spion Kop, Flint Creek, Lower South Fork, or Musselshell, because they were not in operation during that period.

## Market Replacement

| | Jul-10 | Aug-10 | Sep-10 | Oct-10 | Nov-10 | Dec-10 | Jan-11 | Feb-11 | Mar-11 | Apr-11 | May-11 | Jun-11 | Average |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Total delivered cost ($/MWh) | $43.5349 | $40.5213 | $38.7577 | $38.5227 | $38.7338 | $40.3214 | $31.8041 | $32.3079 | $30.4854 | $37.7652 | $35.0958 | $36.4529 | $36.9442 |
| Total delivered cost w/o Turnbull | $43.5349 | $40.5213 | $38.7577 | $38.5227 | $38.7338 | $40.3214 | $31.8041 | $32.3079 | $30.4854 | $37.7652 | $35.0958 | $36.3375 | $36.9361 |
| % change w/o Turnbull | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | -0.32% | -0.02% |
| | | | | | | | | | | | | | |
| | Jul-10 | Aug-10 | Sep-10 | Oct-10 | Nov-10 | Dec-10 | Jan-11 | Feb-11 | Mar-11 | Apr-11 | May-11 | Jun-11 | Total |
| Total delivered cost | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $61,672.65 | $61,672.65 |
| Total delivered cost w/o Turnbull | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $9,207.34 | $9,207.34 |
| Difference in Cost w/o Turnbull | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | -$52,465.31 | -$52,465.31 |
| | | | | | | | | | | | | | |
| | Jul-11 | Aug-11 | Sep-11 | Oct-11 | Nov-11 | Dec-11 | Jan-12 | Feb-12 | Mar-12 | Apr-12 | May-12 | Jun-12 | Average |
| Total delivered cost ($/MWh) | $33.7801 | $31.9969 | $32.8019 | $33.8572 | $35.7915 | $32.7086 | $34.1850 | $32.3373 | $33.8536 | $37.0074 | $42.2958 | $32.4703 | $34.3349 |
| Total delivered cost w/o Turnbull | $33.1601 | $31.3626 | $32.3353 | $33.9075 | $35.7915 | $32.7086 | $34.1850 | $32.3373 | $33.8536 | $37.0074 | $41.7021 | $31.5114 | $34.0643 |
| % change w/o Turnbull | -1.84% | -1.98% | -1.42% | 0.15% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | -1.40% | -2.95% | -0.79% |
| | | | | | | | | | | | | | |
| | Jul-11 | Aug-11 | Sep-11 | Oct-11 | Nov-11 | Dec-11 | Jan-12 | Feb-12 | Mar-12 | Apr-12 | May-12 | Jun-12 | Total |
| Total delivered cost | $445,335.75 | $519,807.80 | $381,248.57 | $55,581.84 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $315,218.62 | $559,493.45 | $2,276,686.03 |
| Total delivered cost w/o Turnbull | $92,371.47 | $130,550.78 | $149,187.91 | $79,726.85 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $14,210.42 | $43,588.12 | $509,635.55 |
| Difference in Cost w/o Turnbull | -$352,964.28 | -$389,257.02 | -$232,060.66 | $24,145.01 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | -$301,008.20 | -$515,905.33 | -$1,767,050.48 |

## 50/50 Market/Long-Term

| | Jul-10 | Aug-10 | Sep-10 | Oct-10 | Nov-10 | Dec-10 | Jan-11 | Feb-11 | Mar-11 | Apr-11 | May-11 | Jun-11 | Average |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Total delivered cost ($/MWh) | $43.5349 | $40.5213 | $38.7577 | $38.5227 | $38.7338 | $40.3214 | $31.8041 | $32.3079 | $30.4854 | $37.7652 | $35.0958 | $36.4529 | $36.9442 |
| Total delivered cost w/o Turnbull | $43.5349 | $40.5213 | $38.7577 | $38.5227 | $38.7338 | $40.3214 | $31.8041 | $32.3079 | $30.4854 | $37.7652 | $35.0958 | $36.3428 | $36.9365 |
| % change w/o Turnbull | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | -0.30% | -0.02% |
| | | | | | | | | | | | | | |
| | Jul-10 | Aug-10 | Sep-10 | Oct-10 | Nov-10 | Dec-10 | Jan-11 | Feb-11 | Mar-11 | Apr-11 | May-11 | Jun-11 | Total |
| Total delivered cost | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $61,672.65 | $61,672.65 |
| Total delivered cost w/o Turnbull | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $11,628.00 | $11,628.00 |
| Difference in Cost w/o Turnbull | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | -$50,044.65 | -$50,044.65 |
| | | | | | | | | | | | | | |
| | Jul-11 | Aug-11 | Sep-11 | Oct-11 | Nov-11 | Dec-11 | Jan-12 | Feb-12 | Mar-12 | Apr-12 | May-12 | Jun-12 | Average |
| Total delivered cost ($/MWh) | $33.7801 | $31.9969 | $32.8019 | $33.8572 | $35.7915 | $32.7086 | $34.1850 | $32.3373 | $33.8536 | $37.0074 | $42.2958 | $32.4703 | $34.3349 |
| Total delivered cost w/o Turnbull | $33.2770 | $31.5110 | $32.4673 | $33.8365 | $35.7915 | $32.7086 | $34.1850 | $32.3373 | $33.8536 | $37.0074 | $41.8175 | $31.7560 | $34.1224 |
| % change w/o Turnbull | -1.49% | -1.52% | -1.02% | -0.06% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | -1.13% | -2.20% | -0.62% |
| | | | | | | | | | | | | | |
| | Jul-11 | Aug-11 | Sep-11 | Oct-11 | Nov-11 | Dec-11 | Jan-12 | Feb-12 | Mar-12 | Apr-12 | May-12 | Jun-12 | Total |
| Total delivered cost | $445,335.75 | $519,807.80 | $381,248.57 | $55,581.84 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $315,218.62 | $559,493.45 | $2,276,686.03 |
| Total delivered cost w/oTurnbull | $158,940.42 | $221,608.14 | $214,825.96 | $45,638.43 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $72,734.39 | $175,211.77 | $888,959.10 |
| Difference in Cost w/o Turnbull | -$286,395.33 | -$298,199.66 | -$166,422.61 | -$9,943.41 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | -$242,484.23 | -$384,281.68 | -$1,387,726.93 |

## Regulation and Other Costs of Wind Resources

We do not have an unambiguous estimate of the cost of regulation from DGGS. NorthWestern's original estimate was approximately $13 per MWh of wind; this estimate charged load and transmission regulation with almost all the capital costs of DGGS and treated wind as an incremental user of regulation services. A fully allocated cost of regulation from DGGS would be much higher. FERC's decisions on how much transmission customers may be charged has created additional uncertainty over who will be responsible for resulting shortfalls in cost recovery. More recently, based on sunk costs of

DGGS, NWE testimony in the Spion Kop docket estimated incremental regulation costs for that resource as less than $1.30 per MWh (based upon a 39% capacity factor for Spion Kop and increased operating costs at DGGS equal to $.03 per MWh of utility load); the Commission evaluated alternate levelized regulation costs as high as $4.32. Further uncertainty comes from both FERC and the Genivar study with regard to how much regulation service is necessary to accommodate wind, and therefore how much wind NorthWestern can integrate on its system before having to expand its regulating resource capability. For this analysis we will accept NorthWestern's Spion Kop value of $1.30 for the current incremental operating costs that would be associated with the presence or absence of RPS and CREP resources.

NorthWestern indicates that its imbalance costs have risen as the reliance on wind has increased. Total utility imbalance costs are now in the neighborhood of $5.5 million per year; however neither we nor NorthWestern have any estimate of either an allocation of these annual costs to wind and other sources of imbalance or of the marginal imbalance costs associated with additional MW of installed wind on NorthWestern's system. There are also minor additional costs directly attributable to wind, such as the cost of participating in the Western Renewable Energy Generation Information System (WREGIS) used for tracking RECs in the Western Interconnection, and for the installation and operation of meteorological towers for purposes of wind forecasting. These costs have not been included here but would likely lead to a small increase in the estimated cost to ratepayers of the RPS and CREP standards.

**Post 2011-2012 Tracker Year**

Post 2011-2012 Electric Tracker data is not yet available. Therefore, we cannot conduct an identical impact analysis in supply rates. Rather we estimate the impact using REC purchases, QF contract or PPA contract prices, and estimated regulation costs to calculate the resource cost, and either a 50-50 mix of Mid-C prices and a surrogate measure of long term contracts calculated from the median ratio of long term to market in the 2010-2011 and 2011-2012 tracker years, or spot market purchases as the surrogate for the cost of power that would have been purchased in the absence of the CREP and RPS requirements[1]. As discussed previously, an alternate assumption which values the surrogate cost of power at NorthWestern's avoided cost would result in negative costs to ratepayers for Spion Kop and Turnbull, offset only by the very modest cost of purchasing RECs from South Fork and Flint Creek. Our estimate of the ratepayer impacts is therefore bracketed by alternate assumptions about the cost of resources that would otherwise have been acquired.

**Turnbull Hydro:** The rate for electricity NWE pays for Turnbull is $65.75/MWh, with RECs bundled. We estimate the additional costs to ratepayers, compared with the spot market alternative, at $1,352,872

[1] Also, we have assumed that purchases at Mid-C would be swapped for Colstrip power to avoid wheeling costs. If that option were not possible, wheeling charges of $5 to $8 per MWh would have to be added to the alternate power costs, also significantly reducing the estimated excess cost to ratepayers of the RPS.

for the 2012-13 Tracking Year. Using a 50/50 assumption for the alternate supply, we estimate the additional costs for Turnbull at $1,020,813.

**Spion Kop**: We can estimate the costs for 2013 from the actual costs associated with the plant ($6,217,339 fixed costs plus $113,139 variable costs), and the actual production by month for calendar year 2013 (144,150 MWh). The resulting cost estimate for the first year of production is $43.92/MWh. Regulation brings this estimate to $45.22/MWh. We estimate additional costs attributable to the RPS, compared with the spot market alternative, to be $2,739,714 for the 2012-13 Tracking Year. Using a 50/50 assumption for the alternate supply, we estimate the additional costs for Spion Kop at $1,156,405.

**Flint Creek:** NWE purchases power from Flint Creek at a rate of $90.87/MWh for high load hours and $54.44/MWh for low load hours. (High load hours are 16 hours a day, 6 days a week during the months of December, January, February, July and August. Low load hours are all other hours during those months, and all hours during the other seven months.) RECs are purchased separately at a price of $6.73. We estimate the additional cost associated with the RPS and CREP to be $22,061 for the 2012-13 Tracking Year.

**Lower South Fork:** NWE purchases power from Lower South Fork under the QF-1 rate of $90.87/MWh for high load hours and $54.44/MWh for low load hours. RECs are purchased separately at a price of $6.73. We estimate the additional cost associated with the RPS and CREP standards at $6,232 for the 2012-13 Tracking Year.

**Musselshell Wind:** NWE purchases power from Musselshell under the old bundled-REC QF rate option of $69.21/MWh. RECs are included. Because Musselshell Wind would still have to be acquired under PURPA if there were no RPS or CREP requirements, there are no additional costs to ratepayers associated with this facility.

## Montana-Dakota Utilities (MDU)

MDU serves loads in Montana, North Dakota and South Dakota, with loads split approximately 66 percent in North Dakota, 5 percent in South Dakota, and 29 percent in Montana. North Dakota and South Dakota each have legislation setting renewable goals for utilities to meet 10 percent of load within the state by “renewable, recycled or conserved” energy, but do not require the retirement of RECs to satisfy the goal.

MDU has acquired three wind generating facilities: Diamond Willow I and Diamond Willow II, in Montana, and Cedar Hills in North Dakota. All three generate RECs that are tracked by the Midwest Renewable Energy Tracking System (M-RETS).

**Diamond Willow 1:** Diamond Willow 1 is a windfarm with a nameplate capacity of 19.5 MW and an in-service date of 12/27/2007. This facility is both RPS and CREP compliant and is owned by MDU with a capacity cost of approximately $2020/kW. MDU has stated that this facility was not constructed solely to comply with the RPS, but instead as part of a broader resource plan that resulted from its Integrated Resource Planning process.

**Diamond Willow 2:** Diamond Willow 2 is a windfarm with a nameplate capacity of 10.5 MW and an in-service date of 6/16/2010. This facility is both RPS and CREP compliant and is owned by MDU with a capacity cost of approximately $2419/kW. MDU has stated that this facility was not constructed solely to comply with the RPS, but instead as part of a broader resource plan that resulted from its Integrated Resource Planning process.

**Cedar Hills:** Cedar Hills is a windfarm with a nameplate capacity of 20 MW and an in-service date of 5/20/2010. This facility is both RPS and CREP compliant and is owned by MDU with a capacity cost of approximately $2370/kW. MDU has stated that this facility was not constructed solely to comply with the RPS, but instead as part of a broader resource plan that resulted from its Integrated Resource Planning process.

These three facilities generate roughly 150-160,000 RECs per year. MDU has also acquired a small (7.5 MW) waste heat plant in North Dakota, not certified as an eligible renewable resource under Montana law. It is not used by MDU to meet Montana's standards, but it generates RECs under the rules of the M-RETS and is used to help meet the North Dakota and South Dakota renewable goals. MDU's Montana load is approximately 750,000 MWh, requiring roughly 75,000 RECs. The remainder of the wind RECs are available for carryover for up to two years to meet future Montana REC needs, or are sold (together with those generated by the waste heat plant) and the proceeds credited to customers in North Dakota and South Dakota. The generation associated with the excess RECs, together with that of the waste heat plant and conserved energy, is used to demonstrate compliance with North Dakota and South Dakota "renewable, recycled or conserved" energy goals.

MDU does not separate out or track the annual costs of its individual generating resources. Accordingly it was not possible to estimate the cost of MDU's compliance with Montana RPS and CREP requirements and the difference in overall costs to ratepayers compared with the resources that might have been used to meet load in the absence of those requirements.

## Summary

The RPS and accompanying CREP legislation in Montana has had relatively minimal rate impact on NWE's customers. This is mainly due to the fact that almost all the resources that NWE uses to comply with both standards were either purchased before the implementation of the RPS (Judith Gap) or they are QFs that can take advantage of the Standard Offer Rate which NWE is required to extend to them under Federal law. QF resources that are contracted under legacy tariffs have RECs bundled, while QFs that are contracted under more recent tariffs do not have RECs bundled, so any costs related to the separate purchase of RECs are attributable to the RPS.

The rate impact of the RPS and CREPs on MDU's Montana customers is difficult to discern as MDU currently does not separate or track costs of its individual generators. Also, its renewable resources were procured as part of its Integrated Resource Planning Process which incorporates a multitude of factors beyond the need for RPS and CREP compliance.  Given MDU's statements that the Diamond Willow and Cedar Hills resources would likely have been built absent the RPS, it is reasonable to assume that the impact has been minimal.