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September 4, 2015

Chairman Keith Regier
Energy and Telecommunications Interim Committee
PO Box 201706
Helena, MT 59620-1706

Dear Representative Regier,

Enclosed please find Montana Dakota Utilities' responses to the questionnaire regarding net metering you sent with your letter dated June 12, 2015. We look forward to working with your committee over this interim. Please contact our office should you have any questions.

Thank you.

Sincerely,

Michael Green

Enclosure

ec: Sonja Nowakowski

General Costs and Costs of Integration **[(2)(a)(i)—(2)(a)(i) and (2)(b)(ii) of SJ 12]**

1. Generally describe the specific costs your utility incurs to implement and administer net metering accordance with the current Public Service Commission tariff. Identify issues and concerns, if any, associated with implementing and administering the current tariff and how those issues and concerns could be addressed.

   Given the small number of current net metering installations on Montana-Dakota's system and the nature of net metering process, Montana-Dakota cannot identify any "specific costs" it incurs at present. Montana-Dakota currently has four customers on its system that have a distributed generator in place that are utilizing the Net Metering option implemented pursuant to an Order issued by the Montana Public Service Commission in Docket No.D2007.7.79. Each of the four customers, currently utilizing the net metering process, on Montana-Dakota's system has a small wind generator installed at their premise.

   Despite the lack of currently identifiable direct costs, Montana-Dakota remains concerned about the potential for increased cost in the future if policy decisions materially change the nature allowed net-metering in the future. As a result, comments throughout this survey will reflect a discussion of costs and benefits associated with net metering on a general basis and not specific to the current installations on its system.

   Montana-Dakota recognizes that the concept of net metering has become synonymous with the concept of distributed generation (DG), but contends that net metering constitutes an unfair subsidy to certain users, and provides incentives for development that are not necessarily aligned with the purported benefits of DG. Net Metering is an unfair subsidy for the following two primary reasons:

   a) It decouples the amount a net metering customer pays for the services provided by the utility operating and maintaining the electric grid from the customer's actual use of that system, so shifts fixed system costs to other customers. This is the rationale for proposing a demand charge for residential customers in its Rate Case Docket. A demand meter will measure the maximum demand placed on the system and provide for recovery of a portion of the fixed costs that are not adequately recovered from the DG customer.

   b) It requires DG customers with net metering to be paid the full retail energy rate for energy they produce above their energy use, despite the fact it is replacing power which can be produced or purchased for a much lower cost from more reliable sources. Montana-Dakota's residential energy charge currently pending, before the Public Service Commission of Montana in Docket No. D2015.6.51 (Rate Case Docket) is approximately $.096 per Kwh on an annual average basis. The current avoided energy cost rate (under Rate 93) is $.038 per Kwh for energy delivered during on-peak hours and $.027 per Kwh for energy delivered during off-peak hours.

This subsidy structure then creates incentives for development that are distinct from the needs of the utilities and its other customers. For example, net metering incentivizes installation of DG where a customer can afford the installation costs, rather than where the system or other customers may actually benefit from installation of DG.

Consider a simplified example of an agricultural operation that installs a wind or solar array to offset its irrigation pumping costs. Assume the irrigation system, uses 86.4 Mwh between June and August (a consistent draw of 40 kw all day for 90 days). That operator decides to take full advantage of the net metering credit by installing a DG that generates an aggregate of 86.4 Mwh. While that will result in net metering to zero power usage, the net metering mechanism does not reflect the actual impacts on the utility system. If the irrigator wants to use a net metered renewable power system, it will take all year to generate 86.4 Mwh. For example, a 50 kw system would have to operate at a roughly 20% to generate 86.4 Mwhs in a year. A 40 kw system would have to operate at a 25% capacity factor. While a wind or solar generator at those sizes could theoretically meet the irrigation system demand at peak performance, it would not satisfy the demand consistently or for lengthy or predictable periods of time. As a result, the system would not meet the operation's actual energy needs during the irrigation season, and will deliver most of the power it generates into the utility's system outside the irrigation season. Under this arrangement, the irrigation system makes significant peak demands on the utility's system to meet its operating needs, and then depends on the utility's system to provide a market for its excess generation the rest of the time. A net metering system that fails to require that operation to pay for the value it receives from the utility system creates perverse incentives and cost shifts.

Bill crediting and rate forms providing fixed cost recovery provide a resolution to the "net metering issue". Under a bill credit the customer will continue to pay for all energy consumed and the utility would pay the generator its avoided cost for all of the generation supplied (both to serve the customer and the amount above the customer's use that is delivered to the electric system. This recognizes that a customer with a generator behind the Company's meter is continuing to utilize the electric system on a 24x7 basis as follows: 1) Immediate access to energy during times when the customer generator is not producing enough energy to meet 100% of the customer's needs 2) a connection to the electric system where the customer may export excess energy 3) providing power quality and stability for the customer and 4) providing backup power so that the customer is not interrupted when the customer generator is not operating such as loss of solar rays or loss of wind.

DG can lead to increased operations equipment required as DG use is expanded on a circuit which causes the need for operational tracking of the DG sources to be treated as a safety concern/threat for emergency response situations on the system. i.e. going to the service point to open the service disconnect switch. DG can lead to additional operating costs to read meters and calculate bills, can lead to additional costs to visit the service point to test for compliance with quality and safe operation of the DG equipment, power quality concerns and mitigation as these loads increase on the system. If DG systems fail to operate properly when system failures occur, system damage and customer equipment damage can occur.

2. What is your utility's current total annual cost of service and what amount is fixed and unresponsive to changes in your customers' electricity use in the near term?

   Montana-Dakota's total annual electric cost of service is $67,360,358. This represents the proposed pro forma 2015 electric cost of service submitted in the Rate Case Docket. Based on the embedded class cost of service study submitted in the Rate Case Docket, fixed costs represent 68% of the total cost of service. The fixed costs include demand related costs and customer related costs associated with electric system providing service to customers.

3. What is your utility's total current annual revenue from fixed charges that are unresponsive to changes in your customers' electricity use in the near term and what amount is from variable charges?

   Based on the test year in the rate case docket, Montana-Dakota currently collects 5.4 percent on a pure fixed cost basis i.e., the amount collected through the fixed charge per month charged per customer. 20.2% is collected through a demand charge component which is billed based on the measured maximum demand in a 15 minute period each month as currently applicable to general service customers. 74.5% of the cost of service is collected on a volumetric basis.

4. What is the distribution of residential and commercial (by rate class) customers' annual energy use, average annual non-coincident peak demand, and average annual coincident peak demand? Where, within these distributions, do residential and commercial (by rate class) net metering customers fall, on average?

   The following is based on calendar year 2014 data and information provided in the Rate Case Docket.

Class	Annual Energy (Kwh)	Avg Annual Non-Coincident Demand (kW)	Avg Annual Coincident Demand (kW)
Residential	9,731	2.35	1.80
Small General Service (50 Kw or Less)	22,400	17.27	14.28
Large General Service (> 50 Kw)	781,875	104.81	83.15

5. For 2014, what was the impact on your utility's revenue of the reductions in residential and commercial electricity use and demand identified in questions 10-15? Describe how the revenue impact affects the bills of other residential and commercial customers, including the magnitude of any bill impacts.

   As noted above, Montana-Dakota currently has only four customers on its system in Montana that are utilizing the net metering option. Two of those customers are residential service customers and two are general service customers. The two residential customers have not provided energy back to Montana-Dakota's system and the two general service customers have provided minimum energy (less than 500 Kwh) that was credited back to future bills. Therefore, impact of the crediting mechanism under Net Metering was also minimal. Montana-Dakota does not meter the generators and therefore, the loss of revenue is not available.

6. Is all or part of the utility impact or customer bill impact a subsidy? If so, describe the basis for determining that the impact is a subsidy.

   The subsidy is present in two forms 1) the utility paying the full retail rate for energy that is carried forward to offset future bills rather than avoided costs and 2) under recovery of fixed costs. The subsidy occurs at the time rates are changed in the rate case process and the unit charges necessary to recover costs are higher than if the net metering customer was not on the system. This occurs to the extent fixed costs are recovered through a volumetric charge and therefore, the cost is not avoided but there are fewer volumes over which the fixed cost will be recovered.

7. In your opinion, are the utility revenue and customer bill impacts from net metering distinguishable from the impacts from other activities that change customer electricity use and demand and result in potential cost shifts, such as upgrades to building structures and equipment, and if so, why?

   Yes, the net metering impacts are distinguishable because net metering does not result in a reduction in the requirement to deliver power. Put another way, net metering does not necessarily result in reduced demand on the system, while customer conservation efforts through permanent changes like improved buildings and structures have the potential to reduce demand. While both may result in some short term losses for the utility because revenue under both situations is decreased, in the long term, upgrades that decrease the demand on the system will reduce costs. Those same benefits are not seen with net metering customers because they pay less for system fixed costs, but their overall demand on the system is not decreased. Energy efficiency does not require the utility to be available with standby generation, transmission and distribution investments as with DG customers. The impact is lessened if all fixed related costs are recovered on a fixed basis.

8. What are the pros and cons of extending Montana's net metering policy to apply to MDU? Is it appropriate to treat MDU differently from other regulated utilities in terms of net metering requirements, and if so, why?

   Montana's net metering policy currently applies to MDU. The MPSC adopted a net-metering requirement for MDU in 2008. In its Order 6846f, in Docket No. D2007.7.79, the MPSC ordered MDU to file a net-metering tariff for customers with generating capacity up to 50 Kw. In imposing this requirement, the MPSC expressly noted the requirements of the federal Energy Policy Act of 2005, and imposed required it noted were similar to the standard applied under § 69-8-103(19), MCA. Order 6846f, p. 11, para. 36. MDU complied and filed its tariff 92, which has been effective for service rendered since June 27, 2008. The requirements of federal law have not changed, and in its most recent rate case, MDU seeks to modify, but maintain its net-metering tariff. As a result, there is no need for legislative action to require MDU to allow net metering.

   It is appropriate, and consistent with current state and federal law that each utility's net metering requirements be specifically tailored to the utility. Sections 69-8-602 and 604, MCA, authorize and anticipate the MPSC will determine relative costs and benefits of net-metering for each utility, and requires imposing utility specific conditions and cost allocations. The focus, therefore, of any analysis of net metering requirements is the impact on the customers of a particular utility. Furthermore, MDU's Montana system differs significantly from Northwestern Energy's in terms of customer numbers, size, load, and transmission requirements. It is appropriate, therefore, to allow the MPSC to continue regulation of MDU's net metering standards without extension of the existing Montana net-metering statutes.

9. Provide a distribution of net metering systems by installed capacity, by customer class on MDU's system.

   Montana-Dakota currently has 2 residential customers with combined installed capacity of 3 Kw and 2 commercial customers with 4.8 kW of combined installed capacity on its system. The DG resource is wind.

<u>Residential Operating and Fixed Plant Costs</u>

10. Based on residential net metering systems in your utility service area, for each month of the year, what is the average electricity use (kWh) per met-metered customer before and after metering out electricity produced by the customers' generators? Separate this information for solar, wind, and other generators. If net metering does not provide this, provide information base on modeling (including an

explanation of assumptions) and outline steps the utility is taking to acquire actual usage information.

Montana-Dakota does not currently install separate metering on a customer generator. Metering the customer generation would presumably require customer permission and would also result in an additional cost. The bill credit concept noted above would require that the generator be metered because the bill credit would be based on energy provided by the customer's system each month. Notwithstanding a change in the Commission's requirement to offer net metering, Montana-Dakota has no immediate plans to meter customer generators. The cost of such metering would essentially be the same as the standard meter used to meter customer usage.

11. How does average use per residential net-metered customer before and after netting out electricity produced by customers' generators compare to average electricity use by residential customers that do not net meter?

    This information is not available as noted in Response No. 10.

Commercial Operating and Fixed Plant Costs

12. Based on the commercial net metering systems in your utility service area, for each month of the year, what is the average electricity use per met-metered customer before and after netting out electricity produced by the customers' generators? Separate this information for solar, wind, and other generators and by specific commercial customer rate classes If net metering does not provide this, provide information based on modeling (including an explanation of assumptions) and outline steps the utility is taking to acquire actual usage information.

    This information is not available as noted in Response No. 10.

13. How does average use per commercial net-metered customer before and after netting out electricity produced by customers' generators compare to average electricity use by commercial customers in the same rate class that do not met meter?

    This information is not available as noted in Response No. 10.

14. Based on the commercial net metering systems in your utility service area, for each month of the year, what is the average electricity demand (KW) per met-metered customer before and after netting out electricity produced by the customers' generators? Separate this information for solar, wind, and other generators and by specific commercial customer rate classes. If net metering does not provide this,

provide information based on modeling (including an explanation of assumptions) and outline steps the utility is taking to acquire actual usage information.

This information is not available as noted in Response No. 10.

15. How does average demand per net –metered commercial customer before and after netting out electricity produced by customers' generators compare to average electricity demand by commercial customers in the same rate class that do not net meter?

This information is not available as noted in Response No. 10.

<u>Prospective Balancing Test</u> [(2)(a)(iv) of SJ12]

16. Describe how increasing the current 50 kilowatt (KW) net metering cap to 100 KW, 1,000 KW, and 5,000 KW would likely impact residential net metering trends in your utility service area and associated utility revenue and customer bill impacts.

Montana-Dakota does not have a study available that would provide information necessary to project net metering trends on its system. It is expected that the issues identified above would be exacerbated to the extent larger generators are allowed under net metering. The extent of the problem would be affected by the size of the customer load that is being supplied by the generator. Many factors other than the availability of net metering would certainly also affect the DG trends including but not limited to; tax incentives, cost of entry, wind and solar energy availability.

The total capacity for a traditional feeder size at Montana-Dakota is to design for 200 amps max per feeder. That is 4320KVA at peak at 12.47KV and 1440KVA at 4.16KV. Most of the time these circuits will run around 2000 KW(12.47KV) and 1000 KW(4.16KV) or less. Loads with the size of 500-1000 kw will be operationally significant from a system protection, coordination, safety, and a power quality concern on an MDU feeder and may require an RTU and other operational equipment to prevent operational and safety issues. Each substation and feeder will have to be evaluated to determine the concerns for a specific generation load. Loads of this size, from a generation standpoint, will affect the existing circuit operational characteristics.

17. Describe how increasing the current 50 KW net metering cap to 100 KW, 1,000 KW, and 5,000 KW and how those issues and concerns could be addressed.

Again, the concerns with net metering would only be exacerbated by increasing the number of customers and size of the generation allowed under a net metering scheme. In addition to net metering concerns, interconnections issues will also arise with the addition of DG of the magnitude of 1 MW up to 5 MW. Many of the distribution systems in Montana-Dakota's service territory would not be able to accommodate generation of this magnitude without significant upgrades that would be chargeable to the DG. Costs for this would vary for a larger transformer or line re-conductoring the amount could run over $250,000 to several million dollars depending on the actual system requirements and location. The interconnection issues would be lessened if the size of the customer load being served by the DG was commensurate with the size of the generator. The expansion of Net Metering has the potential to provide significant benefits to a select few at the expense of many.

18. Identify issues and concerns, if any, associated with increasing the current 50 KW net metering cap to 100 KW, 1,000 KW, and 5,000 KW and how those issues and concerns could be addressed.

    See Response No. 17.

19. Identify potential operational issues associated with expanding net metering and provide suggestions for how the utility could address those issues.

    See Response No. 17. Also the larger the generation the greater potential for power swings on the utility company's system as the generation come online or goes offline. Net metering DG is not controlled by the utility like other sources of generation and can be disruptive to power balancing as evident by concerns that California utilities have raised regarding the penetration of residential rooftop solar into that market.[1]

<u>Benefits</u> [(2)(f)(v) and (2)(i) of SJ 12]

20. Identify one or more methods for quantifying the benefits of net metering. In your option, what are the advantages of each method?

    Net metering arrangements generally do not provide benefits to the system as a whole. As discussed previously, they provide cost shifts between customers; they can be disruptive to the operations of the utility; and they do not reduce the amount of infrastructure facilities required by the utility as the utility system needs to be designed to handle the maximum customer load without the support of the net metering resource. If system requirements would be reduced (i.e. less wires and generation) then the net metering customer would need to be curtailed first during periods of power balance or system support issues.

[1] *See* http://instituteforenergyresearch.org/solar-energys-duck-curve/

21a. Identify the benefits of net metering that are shared between net metering customers and customers that do not net meter. Identify the avoided:

- cost for supply-related energy and capacity, accounting for the timing of energy and capacity produced by net-metered generations

  Schedulable DG may allow the avoidance of the energy purchase/generation of the last unit of energy produced which generally is the highest cost unit. DG only allows the avoidance of supply related capacity if it is generating during the Company's monthly coincident peak.

  Under net metering, there is no benefit for the reasons noted in Response No. 1.

- cost for transmission and distribution line losses

  Marginal line losses may be avoided when the DG resource is delivering power, but due to the location of net-metered facilities at the end of the transmission and distribution system those savings are minimal if, they exist at all.

- cost for transmission and distribution capacity and operation and maintenance

  Systems must continue to be operated and maintained. Fixed costs are not avoidable.

- cost for load following, regulation, and frequency response

  There is no direct benefit associated with the avoidance of load following, regulation, and frequency response on the MISO system.

- pollution control costs

  Fixed investment costs are not avoided; Schedulable DG may reduce variable costs such as reagents to the extent they allow a reduction in use.

- generation capacity investments or purchases

  Investments are not avoided and capacity purchases are also not avoided as the Company provides a standby service to the net metering customers.

- renewable energy standard compliance costs

  Schedulable DG resources might reduce the amount of energy the Company needs to generate or purchase and therefore reduces the amount of renewable energy credits the Company needs to purchase or generate for compliance purposes. The value of energy credits is minimal at this time and Montana-Dakota does not require additional renewable resources to meets its renewable energy standard compliance at this time.

21b. Identify the benefits of net metering that are shared between net metering customers and customers that do not net meter. Identify the value of:

- excess net metering credits sacrificed to the utility by net metering customers at the end of billing periods; and
- unclaimed Bonneville Power Administration (BPA) residential exchange credits.

To the extent energy is sacrificed to the utility, its value would be the avoided costs provided in Response No. 1.

22. Describe methods used to determine each of the avoided cost categories in question 21.

Montana Dakota does not believe there are any real avoided costs from its net-metering customers because they are not considered in its power purchasing and scheduling and has not been able to quantify any avoided costs.

23. Describe how increasing the current 50 KW net metering cap to 100 KW, 1,000 KW, and 5,000 KW would likely impact each of the avoided cost categories in question 21.

Not applicable. Montana-Dakota has not identified quantifiable avoided costs as noted in Response No. 21.

<u>Safety and Maintenance</u> [(2)(c)(i) – (2)(d)(i) of SJ 12]

The safety and maintenance issues are associated with the presence of a DG installation and not necessarily associated with Net Metering.

24. Do the retail inverters in rooftop systems have adequate EMF (voltage) protection from induced seasonal electrical storms? Is there a risk for any level of loss of phase synchronicity?

Montana-Dakota has no experience with this issue.

25. Are there national standards for the inverters established by IEEE or other such institutions?

    IEEE 929 is the standard for Utility Interface of Residential and Intermediate Photovoltaic PV systems. UL 1741 is the standard for the safety testing of Inverters that includes an Anti-Islanding Requirement. IEEE1547 and IEEE 1547.1 are used in conjunction with UL1741 to establish safety operations with inverters/converters used for stand-alone or grid tied DG.

26. At what level of loss of synchronization is there an electrical risk (due to wire heating) or efficiency loss?

    Montana-Dakota expects that UL designed equipment should be designed to protect for electrical risks associated with incorrect operation of NEC associated electrical equipment.

27. If an inverter's lockout fails and there is a backflip of power on a "downed" line, for what distance does a shock risk remain for linemen engaged in repairing the distribution line?

    The shock or safety issue extends for the entire circuit isolated by the outage or event back to the open protection interruption equipment that isolated the circuit for the situation. This could be a fuse, switcher, or back to the circuit breaker in the substation.