COMMERCE DEPARTMENT

January 26, 2018

Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, Minnesota 55101

RE: **Comments of the Minnesota Department of Commerce, Division of Energy Resources**
Docket No. E111/M-17-821

Dear Mr. Wolf:

Attached are the comments of the Minnesota Department of Commerce, Division of Energy Resources (Department) in the following matter:

Petition of Dakota Electric Association to Implement Tracker Recovery for Advanced Grid Infrastructure Investments.

The petition was filed on November 20, 2017 by:

Douglas R. Larson
Vice President of Regulatory Services
Dakota Electric Association
4300 220th Street West
Farmington, MN 55024.

The Department expects to recommend approval with modifications and will provide a final recommendation after reviewing Dakota Electric's reply comments. The Department's team of Mark Johnson and myself is available to respond to any questions the Minnesota Public Utilities Commission may have.

Sincerely,

/s/ STEPHEN COLLINS
Rates Analyst

SC/lt
Attachment

Before the Minnesota Public Utilities Commission

Comments of the Minnesota Department of Commerce
Division of Energy Resources

Docket No. E111/M-17-821

I. INTRODUCTION

On November 20, 2017, Dakota Electric Association (Dakota Electric or the Cooperative) filed a petition requesting that, by April 23, 2018, the Minnesota Public Utilities Commission (Commission):

- Approve Dakota Electric's proposed Advanced Grid Infrastructure (AGi) Rider to allow the Cooperative to recover the capital costs (rate of return, incremental property taxes, and incremental depreciation expense) not yet in Dakota Electric's rate base of advanced metering infrastructure and meter data management, net of operational savings, and

- Affirm that Dakota Electric is authorized to recover the capital costs (rate of return, incremental property taxes, and incremental depreciation expense) of new load control receivers through the conservation component of the Cooperative's existing Resource and Tax Adjustment (RTA).

To support its petition, Dakota Electric created a business case provided to the Cooperative's board of directors. The petition only contains a summary of the business case, but Dakota Electric provided the full version to the Minnesota Department of Commerce, Division of Energy Resources (Department) in response to an information request. The Department provides the full version of the business case as Attachment 1 to these comments.

II. SUMMARY OF DAKOTA ELECTRIC'S PETITION AND BUSINESS CASE

A. SUMMARY OF CAPITAL COSTS

Dakota Electric places the projects for which it is requesting capital-cost recovery into three categories: Advanced Metering Infrastructure (AMI), Meter Data Management (MDM), and Load Management (LM). As indicated above, Dakota Electric proposes to recover the AMI and MDM capital costs through a new recovery mechanism called the AGi Rider and the LM costs through the pre-existing RTA. The Department describes each of these three categories in the following paragraphs.

AMI consists primarily of the capital costs for replacing existing meters with new AMI meters. The AMI meters would be able to read 15-minute usage intervals as well as report data on voltage, temperature, reverse power flows, and tampering. Dakota Electric's existing meters do not have any of these capabilities. AMI also includes a system-wide communication network that allows for increased communication to and from devices on Dakota Electric's system, including the AMI meters as well as newly installed load control receivers (part of the LM category, described later), and the supervisory control and data acquisition (SCADA) system that aids in distribution operations and monitoring.[1]

MDM consists of the capital costs for a database with analytics and reporting tools. The database would store, validate, analyze, and report data collected by the AMI communication system and other communication systems such as the SCADA system, customer information system (CIS), outage management system (OMS), and geographic information system (GIS). As such, MDM would provide a large usable database of Dakota Electric's electrical system and member usage. Dakota Electric would use the data to better monitor its system. Dakota Electric would also give members a web portal to view their load over 15-minute intervals and other member-level information stored in the MDM.

LM, the last category, consists of the capital costs for replacing existing load control receivers with new load control receivers. The existing load control receivers can only receive information *from* Dakota Electric. In contrast, the new load control receivers would also communicate information *to* Dakota Electric. The information communicated to Dakota Electric would allow the Cooperative to determine whether load control receivers are working, which the Cooperative cannot do with the existing load control receivers.[2] To communicate to Dakota Electric, the new load control receivers would use the communication network installed under the AMI category.

The capital costs for these three categories total $39.6 million in nominal dollars. About half of the cost is for the AMI meters, at $20.2 million. About a third of the cost is for the new load-control receivers, at $13.4 million. The remainder of the capital costs are for the communication network, MDM system, and shared project management and delivery costs.

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[1] One particular benefit touted of the communication network is information can flow both ways. For meters, two-way functionality means that Dakota Electric can not only receive information *from* meters, but also send information such as commands *to* meters. Dakota Electric's petition does not go into detail about how or why this functionality is beneficial.

[2] A load control receiver is a device that, during peak periods, automatically shuts off or turns down member appliances such as air conditioners and water heaters. In exchange, members whose load is controlled get a discount. The load-control program is voluntary and about half of Dakota Electric's members participate. The LM component of AGi would not alter the existing load-control program; it would only install new load control receivers that have the ability to communicate to Dakota Electric instead of only being able to receive signals from Dakota Electric about when to reduce load.

As for the timing of the capital costs, Dakota Electric proposes to incur the costs primarily over the 2018-2023 period, which could span two in-between-rate-case periods as Dakota Electric anticipates filing its next rate case in 2019 and a subsequent rate case in 2024. The capital costs for new meters—the largest cost bucket—would be incurred between 2019 and 2021. The capital cost for the new load control receivers (LCRs)—the second largest cost bucket—would be incurred between 2019 and 2023. Therefore, it is highly likely that the AGi Rider would continue to recover costs after Dakota Electric's next rate case.

B. DAKOTA ELECTRIC'S PROPOSED RECOVERY MECHANISM FOR AMI AND MDM CAPITAL COSTS

For the AMI and MDM capital costs, Dakota Electric proposes to establish an "AGi Rider" that recovers the associated rate of return, incremental property taxes, and incremental depreciation, net of operational savings resulting from AMI and MDM. Dakota Electric proposes to recover the costs through a per-kilowatt-hour (kWh) charge, but cap the charge to any one member at $25 per month. Dakota Electric estimates that this proposal would result in an average charge of $0.73 per month for residential members, with the amount being higher for higher-use members. If the costs were recovered through a fixed monthly charge regardless of usage, Dakota Electric estimates that the monthly charge would be $1.35 on average per member. Dakota Electric proposes to adjust the AGi Rider through an annual filing.

Dakota Electric proposes to establish the rider pursuant to Minnesota Statutes section 216B.1636, Recovery of Electric Utility Infrastructure Costs (EUIC), which allows utilities to submit petitions for rider recovery of EUIC. EUIC is defined as "costs for electric utility infrastructure projects that were not included in the electric utility's rate base in its most recent general rate case" and "electric utility infrastructure projects" are defined as "projects owned by an electric utility that … replace or modify existing electric utility infrastructure, including utility-owned buildings, if the replacement or modification is shown to conserve energy or use energy more efficiently, consistent with section 216B.241, subdivision 1c."

C. DAKOTA ELECTRIC'S PROPOSED RECOVERY MECHANISM FOR LM COSTS

For LM capital costs, Dakota Electric is not requesting the establishment of a new rider, but rather is requesting that the Commission affirm that the Cooperative is authorized to use the conservation component of the existing RTA to recover LM capital costs.[3] The capital costs for the LM category include the rate of return, incremental property taxes, and incremental depreciation expense of the new load control receivers.

[3] The RTA is a rider that recovers changes in Dakota Electric's purchased power costs, conservation costs, and property taxes.

D. DAKOTA ELECTRIC'S COST-BENEFIT ANALYSIS

Dakota Electric estimates that the total undiscounted AGi costs over the 15-year planning period (2018-2033) equal $77.2 million, compared to total undiscounted benefits over the same period of $72.6 million. Note that the costs and benefits include operational costs and benefits; whereas the cost recovery proposal is only for capital costs. The Department summarizes the components and results of this analysis in the table below:

Table 1: Dakota Electric's Cost-Benefit Analysis

Costs (undiscounted millions USD)		**Benefits (undiscounted millions USD)**	
AMI meters and MDM database	$37.0	Avoided meter-reading costs	$17.4
New LCRs	$13.4	Avoided member-support costs	$6.4
Communication Infrastructure	$2.1	Avoided losses costs	$9.9
Project Delivery	$3.9	Avoided revenue-delay costs	$0.3
New positions created	$9.0	Avoided system-operation costs	$7.5
Interest on loans	$11.8	Avoided meter-replacement costs	$6.7
		Avoided purchased-power costs	$24.4
Total	**$77.2**	**Total**	**$72.6**

Despite the benefits included in Dakota Electric's analysis being slightly lower than costs on an undiscounted basis, Dakota Electric believes that the overall benefits of AGi will outweigh the costs because several significant benefits were omitted. Some of these omitted benefits were practical to quantify, but Dakota Electric omitted them because it felt the benefits were not sufficiently certain or reasonable to include. These readily quantifiable benefits include the avoided costs of replacing load control receivers, the avoided costs of replacing automated meter reading equipment, and the avoided costs of feeder monitoring.[4] The remaining omitted benefits were excluded simply because they were not were not practical to quantify. These difficult-to-quantify benefits include allowing members access to more data, being able to offer new types of rates such as mandatory time-of-use pricing, and quicker responses to power outages.

[4] The Department provides more detail on these readily quantifiable but omitted benefits in a later section of these comments.

III. DEPARTMENT ANALYSIS

The Department reviews the two requests in Dakota Electric's petition: the proposed AGi Rider for AMI and MDM capital costs, and the proposed recovery of LM capital costs through the existing RTA (another rider).

A. AGI RIDER

1. Applicable Statute

As noted above, Dakota Electric is proposing to establish the AGi Rider pursuant to Minnesota Statutes section 216B.1636. **The Department agrees with Dakota Electric that the Cooperative can request rider recovery pursuant to section 216B.1636.** Per section 216B.026, Dakota Electric's members elected to be regulated by the Commission pursuant to sections 216B.03 to 216B.23, and section 216B.1636 falls squarely within this range.

The Department acknowledges that one objection to this conclusion is that section 216B.1636, subdivision 1, defines eligible utilities using the definition of "public utility" in section 216B.02, and this definition excludes cooperatives organized under chapter 308A, such as Dakota Electric. However, since section 216B.026 clearly states that Dakota Electric is subject to regulation under section 216B.1636 and other statutes with the specified range, the Department concludes that section 216B.026 overrides the definition of "electric utility" in section 216B.02.

While Dakota Electric's petition agrees that section 216B.026 overrides the definition of "public utility" in section 216B.02, the Department notes that in the past Dakota Electric has held a different view from that set forth in its petition. See the Cooperative's January 12, 2015 letter to the Commission,[5] included as Attachment 2 to these comments, arguing that section 216B.1614—another statute within the range of sections 216B.03 to 216B.23—does not apply to the Cooperative due to the 216B.02 definition. As noted above, the Department concludes that Dakota Electric's current interpretation of its regulatory obligations is correct.

2. Requirements for Approval

Minnesota Statutes section 216B.1636 specifies five requirements for approval:

1. The rider must only include costs that were not in Dakota Electric's rate base in the Cooperative's most recent general rate case, per 216B.1636 subd. 1(b);

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[5] The letter was filed in Docket No. E111/M-12-874, *In the Matter of Dakota Electric's Petition to Implement an Electric Vehicle Rate.*

2. Dakota Electric must show that the associated projects increase energy conservation or efficiency, consistent with section 216B.241, subdivision 1c, by replacing or modifying existing electric utility infrastructure, per 216B.1636 subd. 1(c);

3. Dakota Electric must not have submitted another request under section 216B.1636 at any other time this year, per 216B.1636 subd. 2(b)(1);

4. Dakota Electric must submit all required information required under 216B.1636 subd. 2(b)(2); and

5. Dakota Electric must show that the rider is in the public interest by, at minimum, providing a justification of the proposed rate design, per 216B.1636 subd. 2(b)(2)(v), and a cost-benefit analysis of the project, per 216B.1636 subd. 2(b)(2)(xi).

The Department reviews each of these requirements in the following sub-sections.

a. The rider must only include costs that were not in Dakota Electric's rate base in the Cooperative's most recent general rate case, per 216B.1636 subd. 1(b)

While representative meter costs are included in Dakota Electric's rate base set in its most recent rate case (Docket No. E111/GR-14-482), the incremental revenue requirements for the AMI capital costs appear to be higher than those for the meter costs. Further, the capital costs for MDM represent expenditures for equipment of a sufficiently different purpose and capability that they can be reasonably considered incremental from that included in base rates. However, as discussed below, Dakota Electric has not provided a description of the costs, and salvage value, if any, associated with the existing infrastructure replaced or modified as a result of the project. **The Department concludes that the costs of the new meters and the resulting annual revenue requirements should be offset by the annual revenue requirements included in base rates for the meters that are being replaced. The difference between these two annual revenue requirements would constitute the incremental annual revenue requirements associated with the new meters.[6] With this cost-recovery methodology, the Department concludes that the AGi rider will effectively only include costs that were not in Dakota Electric's rate base in the Cooperative's most recent general rate case.**

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[6] DEA would post any loss associated with the retirement of the existing meters to FERC Account 108 (Accumulated Depreciation), which would allow DEA to propose to recover any remaining capital costs associated with the old meters in future depreciation rates.

b. *The associated projects must be shown to increase energy conservation or efficiency, consistent with section 216B.241, subdivision 1c, by replacing or modifying existing electric utility infrastructure, per 216B.1636 subd. 1(c);*

The AMI and MDM projects would both replace and modify existing electric utility infrastructure. The new meters would be replacements, and the communication and data infrastructure would be modifications. The remaining question is thus whether they have been shown to increase energy conservation or efficiency, consistent with section 216B.241, subdivision 1c.

Minnesota Statutes section 216B.241, subd. 1c, states that "electric utility infrastructure projects must result in increased energy efficiency greater than that which would have occurred through normal maintenance activity," where "energy efficiency" is defined in subd. 1 of the same section to include "measures … that target … equipment, processes, or devices designed to produce ... a decrease in consumption of electric energy … on a per unit of production basis without a reduction in the quality or level of service provided to the energy consumer." The Department interprets "decrease in consumption of electric energy … on a per unit of production basis" to mean an increase in the efficiency of the electric-supply system. **Because Dakota Electric's business case describes several ways in which AMI and MDM would reduce system losses, the Department concludes that the AGi Rider satisfies this requirement.** For clarity, the Department provides lengthy examples of these descriptions, below:

From page 12:

One of the fastest growing areas within the MDM systems is their power to analyze vast amounts of data. The distribution transformer peak load is just one of many ways the MDM can look at the data and help find ways to improve the efficiency and operation of the system.

Loss Analysis is another analytic program which MDM systems can provide. This is used to identify parts of the distribution system with greater than expected losses. These losses could be caused by bad metering, energy diversion, or that part of the system needs to be rebuilt to reduce the technical energy losses.

Energy Diversion – The MDM can take several different alarms and values and using analysis can identify where energy is being diverted. The processes used by MDMs are quite extensive and together with information from the GIS and other systems, energy diversion can more easily be identified.

From page 31:

The utilities who have implemented AMI have reported a higher than expected level of energy diversion. They typically have reported 0.5% or higher of energy sales improvement after identifying and resolving the locations with energy diversion. As part of the installation of the new AMI meters, most of the energy diversion is identified. The AMI system is also designed to identify future energy diversion through several different techniques. Dakota Electric has a very low system loss percentage, presently fewer than 3%. Given the low system line losses, it is not expected that Dakota Electric has a significant issue with energy diversion. So, a 0.125% improvement in energy sales was assumed as the annual benefit for reducing energy diversion within the Business case.

From pages 44-45:

The AGi system also allows Dakota Electric to better implement conservation voltage reduction during system peaks and reduce peak demand power costs. The AMI system provides voltage readings from each feeder which allows Dakota Electric to reduce the system voltage over system peak. A reduction in system voltage will result in an overall reduction in system demand. This is the expected power cost savings from implementing a conservative voltage reduction (CVR) during system peaks to reduce the demand charge from our power supplier. If Dakota Electric would want to implement peak demand reduction today without AMI, we would need to install expensive real-time voltage sensors on each of the phases of each circuit. Bellwether AMI meters can provide these near-real-time voltage readings using the AMI communication network.

Based upon work done by EPRI, in their Green Circuits Collaborative Project, published in 2011 (Green Circuit Distribution Efficiency Case Studies #1023518), "the percent change in load for a 1% change in voltage generally ranges from 0.6 to 0.8" In the studies, the voltage on the circuits was normally able to be reduced 2% to 4%; so assuming the typical Dakota Electric feeder voltage could be reduced only 2%, and a 0.7% load reduction factor would result in a conservative 1.4% demand reduction on a typical Dakota Electric circuit. EPRI has also reported that not all circuits are candidates for CVR and the benefits of CVR change between the seasons. CVR during the summer provides the greatest benefits. So, for the business case we have further reduced the expected benefit to only being able to achieve 20% of the conservative 1.4% peak demand reduction. …

In addition, there are system capital and energy savings from improved engineering design, resulting from the additional information provided by the AGi system. One example of how the AMI data would help reduce losses is using

> the AMI data to right size the distribution transformer to the load rather than oversizing the transformers. Currently, we are sizing the transformer based upon a single energy reading each month. From this reading the engineer must estimate the coincident peak demand of each of the loads. Because of this limited data, a larger transformer then what would be necessary with accurate data may be installed. Through this and other planning benefits, it is conservatively estimated that an annual loss savings of 0.1% would be achieved using the AMI data.

c. *Dakota Electric must not have submitted another request under section 216B.1636 at any other time this year, per 216B.1636 subd. 2(b)(1)*

The Department reviewed all Dakota Electric petitions submitted in 2017. The petition in this case is the only one relating to a request under section 216B.1636. **Therefore, this requirement is satisfied.**

d. *Dakota Electric must submit all required information required under 216B.1636 subd. 2(b)(2)*

Minnesota Statutes section 216B.1636, subd. 2(b)(2) lists 11 filing requirements. The Department reviews Dakota Electric's compliance with each filing requirement, one by one.

The first filing requirement is "the location, description, and costs associated with the project." Dakota Electric provides this information on page 24 of its petition. **Therefore, the first filing requirement is satisfied.**

The second filing requirement is "evidence that the electric utility infrastructure project will conserve energy or use energy more efficiently than similar utility facilities currently used by the electric utility." As indicated above, Dakota Electric's petition and business case show that AMI and MDM would reduce system losses. **Therefore, the project will use energy more efficiently than similar utility facilities currently used by Dakota Electric and the second filing requirement is satisfied.**

The third filing requirement is "the proposed schedule for implementation." Dakota Electric provides this information on page 21 of its filing. **Therefore, the third filing requirement is satisfied.**

The fourth filing requirement is "a description of the costs, and salvage value, if any, associated with the existing infrastructure replaced or modified as a result of the project." Dakota Electric claims to have included this information, stating on page 24 of their petition that "the description of the status quo costs of continuing to operate are described in [the petition elsewhere]." The costs Dakota Electric refers to are future-looking costs, not the embedded costs and salvage value specified by this requirement. **Therefore, Dakota Electric has not satisfied the fourth filing requirement. Further, this information is necessary in order to establish the costs allowed to be recovered through the AGi Rider. For these reasons, the Department requests that Dakota Electric provide in reply comments the annual revenue requirements associated with the existing infrastructure being replaced or modified because of AMI or MDM.**

The fifth filing requirement is "the proposed rate design and an explanation of why the proposed rate design is in the public interest." Dakota Electric provides this information on page 25 of its petition. As stated earlier, Dakota Electric is proposing a per-kWh charge for all members capped at $25 per monthly bill. Dakota Electric states that this design is in the public interest because most riders are assessed on a per-kWh basis, and the cap "provides some uniformity in the average estimated bill impacts of implementing AGi until such costs are allocated in a future general rate case process." **As Dakota Electric has provided the needed information, the fifth filing requirement is satisfied. However, as discussed below, the Department recommends modifications to Dakota Electric's rate design proposal, given the type of costs that Dakota Electric proposes to recover from ratepayers.**

The sixth filing requirement is "the magnitude and timing of any known future electric utility projects that the utility may seek to recover under this section." Dakota Electric indicates on page 25 of its petition that it does not intend to seek recovery of any additional electric utility projects under section 216B.1636. **Therefore, the sixth filing requirement is satisfied.**

The seventh filing requirement is "the magnitude of EUIC in relation to the electric utility's base revenue as approved by the commission in the electric utility's most recent general rate case, exclusive of fuel cost adjustments." Dakota Electric provides this information on page 25 of its petition, stating that the magnitude of the AGi Rider revenue is about 1% as large as their base revenue approved in their most recent rate case. **Therefore, the seventh filing requirement is satisfied.**

The eighth filing requirement is "the magnitude of EUIC in relation to the electric utility's capital expenditures since its most recent general rate case." Dakota Electric provides this information on pages 25-26 of their petition, stating that the AGi capital expenditures are somewhat over half their capital expenditures since the test year of their last rate case. **Therefore, the eighth filing requirement is satisfied.**

The ninth filing requirement is "the amount of time since the utility last filed a general rate case and the utility's reasons for seeking recovery outside of a general rate case." Dakota Electric provides this information on page 26 of its petition, stating that the Cooperative last filed a general rate case on July 2, 2014 and the reason for seeking recovery outside of a general rate case is to provide sufficient revenue to recover the capital costs of AMI and MDM. **Therefore, the ninth filing requirement is satisfied.**

The tenth filing requirement is "documentation supporting the calculation of the EUIC." Dakota Electric provides this information in Exhibit F of its petition. However, it is not clear how this information was calculated. Through an information request (IR), the Department asked Dakota Electric for the spreadsheet showing this calculation, but Dakota Electric did not provide it. See Dakota Electric's response to Department IR No. 1(b)—provided as Attachment 3 to these comments—in which the Department requested "all spreadsheets used for the information in the petition and full business case" and Dakota Electric did not provide the spreadsheets for Exhibit F, but rather stated that "Exhibit F in the filing includes the AGi Adjustment example calculations."

Due to the lack of clarity regarding the calculations in Exhibit F (with notes such as "From Model"), the Department concludes that Dakota Electric has not sufficiently documented its proposed calculation of the AGi Rider and therefore that **the tenth filing requirement is not yet satisfied. The Department requests that Dakota Electric provide the needed information in reply comments, including a spreadsheet showing the calculation and full documentation for the sources and derivations of the numbers. That is, all numbers should be fully linked to their original inputs, all links should be intact, and all source should be labeled.**

Further, Minnesota Statutes section 216B.1636 states that the costs eligible for recovery are rate of return, incremental property taxes, and incremental depreciation expense. Dakota Electric's petition makes clear how the Cooperative intends to calculate rate of return; however, it is not clear how Dakota Electric arrived at either the incremental property taxes or incremental depreciation. As noted above, since Dakota Electric would be replacing meters in the AMI component of the AGi Rider, any rate of return, property taxes, and depreciation expense of meters replaced that is currently recovered through base rates should be netted out from the costs recovered in the AGi Rider. **Therefore, to ensure that the AGi Rider is calculated correctly and reflects incremental costs, the Department requests that Dakota Electric provide a detailed breakdown of the amount currently being recovered in base rates for equipment that would be replaced as a result of AGi.** While it appears Dakota Electric also intends to net out non-capital costs currently being recovered in base rates, through the "operational savings" component specified in Exhibit F, more information on their proposed calculation methodology is needed. **Therefore, the Department also requests that Dakota Electric show that the operational savings in their proposed calculation include all AMI/MDM-related reductions to non-capital costs included in Dakota Electric's base rates.**

The eleventh and last filing requirement is "a cost and benefit analysis." Dakota Electric's petition provides a summary-level cost-benefit analysis on pages 18-19 of its petition and a more detailed version in its business case. **Therefore, the eleventh filing requirement is satisfied.**

e. Dakota Electric must show the rider is in the public interest by, at minimum, providing a justification of the proposed rate design, per 216B.1636 subd. 2(b)(2)(v), and a cost-benefit analysis of the project, per 216B.1636 subd. 2(b)(2)(xi)

The Department first reviews rate design and then reviews the costs and benefits of AGi.

i. Rate Design

As noted earlier in these comments, Dakota Electric proposes that the AGi Rider recover AMI and MDM capital costs through a per-kWh charge, but cap the charge to any one member at $25 per month. While this rate design is aligned with the many other riders that recover costs on a per-kWh, it has downsides given the type of costs that are being recovered. Using a variable charge to recover fixed costs will make it harder to match costs recovered with costs incurred, with the $25 cap adding further complicatons. In addition, given the majority of the costs in questions are for meters, the variable charge may result in larger-usage members contributing to the costs of meters for smaller-usage customers, which could be considered unfair.

Given the downsides of Dakota Electric's proposal, and the nature of the costs in question, the Department proposes to instead recover AMI and MDM costs using a fixed charge. To estimate the fixed charge, the Department proposes using the following steps.

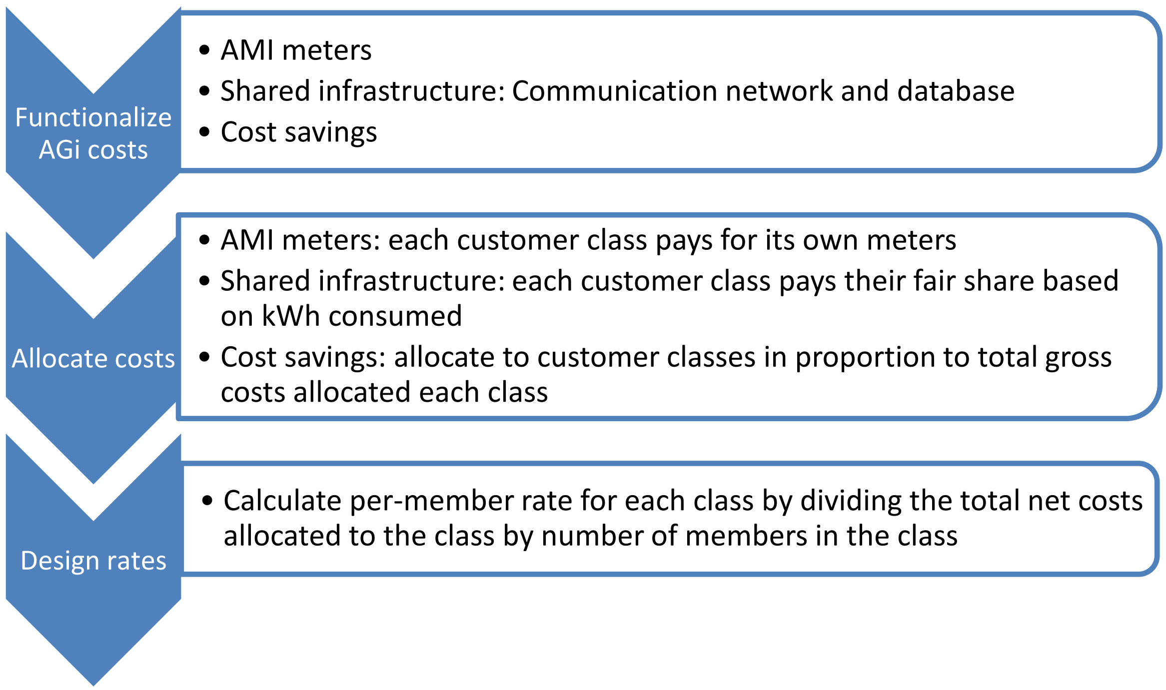
- First, group the AMI/MDM capital costs into three categories: AMI meters, shared infrastructure (the communication network and any capital costs of the data system).

- Second, require each member class to pay for the costs of its own meters, under the principle that each member should pay for its own meter; and allocate the shared infrastructure costs among customer classes on a per-kWh basis, under the principle that members benefit from the communication and data system in accordance to how much energy they consume. After this gross sum is calculated for each class, allocate the reduction in base revenue requirements due to AMI/MDM (capital-cost savings associated with existing meters and operational-cost savings) proportionately to arrive at a net amount to recover from each member class. The total net amount to recover from each member class is thus the sum of their cost responsibility for the AMI and MDM costs, minus their share of the resulting cost savings, allocated on the same basis.

- Third, set the fixed charge for each member class by dividing the net costs allocated to the class by the number of members in the class.

Schematically, these steps are as follows:

Figure 1: Department's Proposed Rate Design



Implementing this methodology would require performing these basic steps each year, which the Department expects to be a relatively simple exercise given the limited amount of costs considered. Like Dakota Electric's proposed method, this method would require a true-up to account for any over- or under-recovery from the prior year, but the true-up would likely be lower under the Department's proposed method, as recovering fixed costs based on kilowatt-hours consumed will likely result less accurate cost recovery versus recovering fixed costs based on the number of members (because consumption of kilowatt-hours is more volatile than the number of members).

The Department summarizes the pros and cons of its proposed method versus Dakota Electric's preferred method in Table 2 on the following page. **Given the pros and cons in Table 2, the Department concludes that the alternative method described above is preferable to Dakota Electric's proposed method. Therefore, the Department recommends that the Commission adopt the alternative method. The Department requests that Dakota Electric provide in reply comments the rate calculations using the Department's proposed rate design.**

Table 2: Pros and Cons of Different Recovery Mechanisms

	Dakota Electric Method: Per-kWh charge with $25 monthly cap	**Department Method:** Fixed charge, with each member paying for their own meter and sharing other costs on a per-kWh basis
Stability of Cost Recovery	**Poor** The amount recovered depends on kWh consumed, which varies a lot; $25 cap an additional complication	**Good** The amount recovered depends on the number of members, which varies little
Fairness	**Poor** Forces larger-usage members to contribute towards the cost of meters for smaller-usage members, and $25 cap distorts cost recovery	**Good** Each member pays for their own meter and their fair share of common infrastructure; no need for cap to protect against volatile billings because recovery amount set in advance
Admin-istration	**Adequate** Relatively easy to allocate costs, but higher need for true-ups due to using kWh and $25 cap	**Adequate** More steps needed to allocate costs, but less need for true-ups

ii. Cost-Benefit Analysis

Dakota Electric's cost-benefit analysis made three choices that, in the Department's view, limit its usefulness in providing information on the net benefit or cost of AGi. First, the cost-benefit analysis is not directly based on cash flows and thus does not accurately reflect how funds are expected to flow in and out of Dakota Electric. Second, it does not discount cost or benefits and therefore does not account for uncertainty or the time-value of money. Third, as indicated earlier in these comments, it does not include several streams of readily quantifiable benefits, which the Department concludes are reasonable to include. As noted earlier in these comments, these omitted but readily quantifiable benefits are the avoided costs of replacing load control receivers, the avoided costs of replacing Dakota Electric's automated meter reading system, and avoided feeder monitoring costs.

Given these limitations, the Department performed its own cost-benefit analysis, provided as Attachment 4 to these comments.[7] The starting point for the Department's analysis was the forecasted AGi cash flows in Dakota Electric's business-case spreadsheet, which Dakota Electric provided to the Department in response to an information request. The Department then

[7] The attachment is nonpublic in its entirety because it relies on Dakota Electric's business-case spreadsheet, which Dakota Electric has classified as nonpublic in its entirety.

adjusted the net cash flows upwards by its estimate of the annual cost reductions resulting from the three benefit streams missing from Dakota Electric's analysis.

The first benefit stream, the avoided costs of LCR replacements, assumed that Dakota Electric replaced 80% of its LCRs over the 15-year base case, which is a proxy for the amount needed to maintain the current working rate of LCRs and current level of power cost savings. To estimate the annual amounts, the Department used the $12,558,000 total cost of replacing all load-control receivers from page 26 of Dakota Electric's full business case as an input. It is appropriate to include this benefit stream in the cost-benefit analysis because Dakota Electric states on the same page that "the load management system has reached its end of life and needs to be replaced." Therefore, installing new LCRs allows Dakota Electric to avoid replacing its existing LCRs with non-AMI technology.

The second benefit stream, avoided costs related to automated meter reading (AMR) for members in more rural areas, used the costs cited on page 47 of Dakota Electric's business case. It is appropriate to include this benefit stream because the same page of the business case states: "the existing AMR system … is no longer supported or manufactured. At some point Dakota Electric will need to replace this system. [The costs cited are] the expected cost of operation of the existing system and the cost of replacement. With the installation of AGi technology, these costs would be avoided."

The third benefit stream, avoided feeder monitoring costs, uses the cost estimates on page 48 of Dakota Electric's business case. It is appropriate to include this benefit stream because Dakota Electric states that it would avoid feeder monitoring costs due to having AGi. According to Dakota Electric, the AMI meters and communication system allow Dakota Electric to monitor the voltage of each feeder, which Dakota Electric indicates is not currently possible and will be needed to ensure that the distribution system functions properly as the penetration of distributed solar increases. Therefore, according to Dakota Electric, without AMI the Cooperative will need to install other equipment to properly monitor feeders as more members install distributed solar.

Having added these annual cash flows to the equation, the Department then discounted each stream of cash flows with an appropriate discount rate. The Department used the average of the 10- and 20-year treasury yields to account for the time-value of money and then added a risk premium based on the Department's view of the uncertainty regarding each stream of cash flows. For example, the risk premium for the costs was only 3% because these costs are relatively certain, whereas the risk premium for avoided LCR replacements was 10% because these benefits are relatively uncertain.

The Department's analysis estimates that AGi will save Dakota Electric's ratepayers $2.8 million in today's dollars over the 15-year business case. However, this result is sensitive to the discount chosen for each stream of costs and benefits. For example, decreasing the discount rate for the cash outflows (the costs) by only 1 percentage point results a net present value of *negative* $0.5 million (meaning that AGi would cost ratepayers $0.5 million); and increasing the discount rate for the cash outflows by only 1 percentage point results in a net present value of $5.7 million (meaning that AGi would save ratepayers $5.7 million). The $2.8 million figure should thus be viewed as a point estimate.

Even if AGi does not save ratepayers money, it may be worth pursuing, up to a point, given that the unquantifiable benefits of AGi identified by Dakota Electric—such as allowing members access to more data, being able to offer new types of rates such as mandatory time-of-use pricing, and quicker responses to power outages—on the whole add value to members. Therefore, if AGi does add to ratepayer costs, the question is whether the added value from these unquantified benefits is worth the costs. The answer to this question will vary by member, but Dakota Member's board appears to think the answer for members as a whole is yes, as it authorized Dakota Electric's management to seek cost recovery despite Dakota Electric's cost-benefit analysis estimating that the project costs more money than it saves.

Given all of the above, the Department concludes that the benefits of AGi—quantifiable and unquantifiable—appear to outweigh the costs. Therefore, the Department expects to recommend that the Commission approve Dakota Electric's requested AGi Rider, but with the rate design modified as recommended earlier in these comments and the costs recovered reflecting all reductions to existing revenue requirements (also described earlier). The Department will provide its final recommendation after reviewing Dakota Electric's reply comments, since the Department has requested that Dakota Electric provide more information needed to fully understand other aspects of their proposal.

B. RTA

The Department agrees that Dakota Electric can use the energy conservation component of the RTA to recover the rate of return, incremental property taxes, and incremental depreciation expense of the new load control receivers[8]—with two conditions. First, the costs must satisfy the requirements of section 216B.16, subdivision 6b, paragraphs (c) and (d),[9] which allows rider recovery of conservation costs and prohibits recovery of EUIC through a conservation cost rider. Second, the costs must be approved by the Deputy Commissioner of the Department of Commerce, as required by Minnesota Statutes section 216B.241, subd. 1b. **Therefore, the Department recommends that the Commission make Dakota Electric's requested**

[8] Note that unlike the AGi Rider, this proposal does not net out any operational savings. There is no need to do so because operational savings occur through lower purchased power costs, and lower purchased power costs automatically flow to members through a reduction in the power-cost component of the RTA.
[9] For load management, the requirements are that the costs must exclude electric utility infrastructure costs recovered under section 216B.1636 and reduce overall energy use.

confirmation, but with the conditions just specified to ensure compliance with Minnesota Statutes.

IV. DEPARTMENT RECOMMENDATION

The Department concludes that Dakota Electric's proposal may be reasonable, but the Cooperative needs to provide further information required by Minnesota Statutes section 216B.1636 to allow for adequate evaluation of their proposal. For this reason, the Department requests that Dakota Electric's reply comments provide more information, as specified earlier in these comments and listed below. The Department will provide a final recommendation after reviewing the additional information that Dakota Electric provides in its reply comments.

At this time, the Department expects to recommend that the Commission:

- Approve the AGi Rider, modified to recover costs on a per-meter basis as described in these comments and with the costs recovered reflecting all reductions to existing revenue requirements;

- Affirm that Dakota Electric is authorized to use the conservation component of the RTA to recover the load management capital costs as requested by Dakota Electric, with the condition that the costs must satisfy the requirements of Minnesota Statutes section 216B.16, subdivision 6b, paragraphs (c) and (d), and be approved by the Deputy Commissioner of the Department of Commerce.

The Department requests that Dakota Electric provide the following information in reply comments:

- A detailed breakdown of the annual revenue requirements associated with the existing infrastructure being replaced or modified as a result of AMI or MDM;

- Full documentation supporting Dakota Electric's proposed calculation of EUIC as shown in Exhibit F of the Cooperative's petition, including a spreadsheet fully showing all calculations and the sources and derivations of any inputs, with all cells fully linked to their original inputs, all links be intact, and all sources be labeled;

- A demonstration that the operational savings in their proposed AGi Rider calculation (again in Exhibit F) include all AMI/MDM-related reductions to non-capital revenue requirements; and

- The charge for each customer class using the Department's proposed rate design.

/lt

Technology to serve you *even* better

Advanced Grid Infrastructure Project (AGi) 2017 Business Case Report

Business Case for:
Advanced Meter Infrastructure (AMI)
Meter Data Management (MDM)
Load Management (LM)

Your Touchstone Energy® Cooperative

November 6th, 2017

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Table of Contents

1 - Introduction

Should Dakota Electric move forward with Advanced Grid Infrastructure projects? Advanced Grid Infrastructure (AGi) is the term Dakota Electric is using to refer to new technologies that would enhance the communication and operation of our distribution system that delivers electricity to our members. These technologies will help Dakota Electric monitor our distribution system for better efficiency and operation and allow us to have increased capabilities for two-way communication to field equipment, providing numerous benefits to our members and Dakota Electric. The main AGi components include Advanced Metering Infrastructure (AMI), Meter Data Management (MDM), and the Load Management (LM) system. Dakota Electric has assembled a cross functional team to review the AGi technologies. The decision to implement AGi technologies at Dakota Electric represents a critical decision for the future of the Cooperative. There are many factors to consider including traditional economic and financial factors, but also important member, public, and community issues.

To put the AGi decision in perspective, it is important to consider what happens if Dakota Electric does nothing regarding implementing AGi technologies. A decision to do nothing does not mean that nothing happens. Doing nothing means accepting the status quo, which in and of itself, is a decision. It is equally important to understand that the decision to do nothing carries significant risk and cost.

This report details what it could cost to keep operating status quo vs. implementing new AGi technology. It also goes into detail about the existing systems and the risks involved with continuing to operate those systems, which have reached the end of their useful life. It compares the status quo to the cost and benefits provided with implementing the Advanced Grid Infrastructure (AGi) technology.

A Dakota Electric employee team, including staff from across the company, has worked together with an NRECA Technology Business Associate. Over the past three years, members of the AGi team have viewed over 40 vendor presentations, attended several conferences, met as a team more than 30 times, and visited 9 different utilities outside of the State of Minnesota who have already implemented AGi technologies. The AGi Team heard from the other utilities about the benefits they have achieved and how implementation of AGi has transformed their utilities, from improved member communications and support to overall improved efficiency of their organizations. The team also heard how AGi technology has improved service to their members by identifying issues before they became serious problems.

The overall costs of continuing with the status quo vs. the cost to implement AGi technology are very similar. The additional services supported by the Advanced Grid Infrastructure and the operational flexibility available with the AGi systems were the deciding factors between the two decisions. The business case supports a deployment throughout the Dakota Electric service territory of Advanced Metering Infrastructure (AMI) coupled with installation of a Meter Data

Management system (MDM) and the replacement of the existing Load Management (LM) system.

2 - Background Discussion

Dakota Electric is facing several major transitions: one is with technology, the second is with the makeup of and wants of the membership, and the third is within the core business due to the interconnection of renewables. Coupled with these transitional elements impacting the Cooperative, several of the existing systems have reached the end of their useful life and require significant investment just to maintain the status quo.

Changes in technology have driven new and innovative options for providing services to our members. These technology changes are also affecting the expectations which the members have for the services provided by Dakota Electric. The members now expect to be able to use mobile apps to interact with the utility and that information about how they are using energy will be readily available to them.

Dakota Electric is faced with a mix of members that have different wants and needs. The transition with more technologically savvy members increasingly using the internet to pay their bills and answer their questions is creating pressure to provide new services. Members are also looking for information 24/7, especially about how they are using energy. Many want the ability to make choices and customize their relationship with the Cooperative, such as changing when and how they pay for electrical usage. They are no-longer ok with just getting a single kWh meter value each month. Instead, members want access to more information about how they are using energy and help on identifying ways to save.

Dakota Electric has been a leader in helping our members save energy and money. Dakota Electric's off-peak programs and demand reduction systems have been saving our members millions of dollars annually since before the 1990s. The options available to our members have been designed to make it easier for the member to take advantage of these programs. Unfortunately, the infrastructure used to support these programs has reached its end of life. Many of the load control receivers have been out in the field working for 20 years and the number of these devices which are no longer working is becoming significant.

While new technology has changed what services the member is looking for, this same new technology can enable many new capabilities to reduce labor costs and improve responses. Dakota Electric is at a crossroads. The Cooperative could continue to provide electrical services as it has done well for many years or embark on the installation of new foundational technology. The tradeoff between the two options is costs and risks.

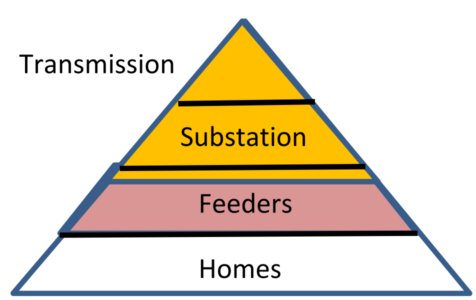
This document looks at the cost of continuing to provide electricity using existing systems with existing technology vs. the cost of moving forward with implementing new Advanced Grid technology. Also explored in this paper are the risks associated with not moving forward vs. the risks associated with implementation of Advanced Grid Infrastructure (AGi) technology. Making a decision to not move forward with AGi technology has risks just as implementing any new technology has risks.

Several times over the past 12 years, Dakota Electric has evaluated the feasibility, cost and benefits of Automated Meter Reading (AMR) and Advanced Metering Infrastructure (AMI) technologies. However, in the past, the business case did not seem to support implementing these technologies system wide. In 2013, as two-way communication technologies matured, and we saw many other utilities similar to Dakota Electric implement and enjoy the benefits of these systems; it had become apparent to Dakota Electric that another evaluation regarding Advance Grid System technologies was warranted.

Over the past four years, the AGi team has viewed well over 40 vendor presentations, attended several conferences, met as a team more than 30 times and visited 9 different utilities outside of the State of Minnesota who have already implemented AGi technologies. The AGi Team heard from the other utilities about the benefits they have achieved and how implementation of AGi technologies has transformed their utility and improved the efficiency of the organization. These four years of education, research, and evaluation have resulted in the development of a business case which is described in this document.

As this document will show, the overall costs of continuing with the status quo vs. the cost to implement AGi technology are very similar. This comparison is done over a 15year time span, which is the expected life of the core AGi technology. The additional services supported by the Advanced Grid technology and the operational flexibility available with the AGi systems were the teams deciding factors between the two options. After a significant evaluation process and the creation of this business case, the Dakota Electric employee team supports a deployment of Advanced Metering Infrastructure (AMI) coupled with installation of a Meter Data Management system (MDM) along with the replacement of the existing Load Management (LM) system throughout the Dakota Electric service territory.

As a result of implementing the recommended Advanced Grid technology at Dakota Electric, our members will see more accurate and timely meter readings, which will diminish the need for estimating usage and the resultant billing inquiries and errors. AGi will eliminate the need to send employees out in inclement weather to read the meters and the safety concerns which result. Members will benefit from improved proactive outage management detection and improved services related to having tools available to monitor daily usage. AGi will improve efficiency and turnaround time needed for disconnects, re-reads, and outage restoration. AGi will improve cash flow by narrowing the window between the meter reading date and the effective billing date to the member. AGi will improve the power cost benefits derived through improved verification of load control. The AGi systems of AMI coupled with the MDM will provide the foundation to offer members new and improved rate options, allow members to choose their billing due dates and provide increased energy management options.



The AGi team believes that implementing AGi technology at Dakota Electric is an essential building block and platform for deploying other advanced grid systems and services in the future. The implementation of AGi is a foundation for the future as illustrated in this triangle. The visibility triangle shows the different parts of the electrical system and what parts are monitored in near real-time. In the 1980s, utilities started at the top by obtaining visibility of the *Transmission* Systems. During the 1990s and 2000s, utilities have completed the installation of SCADA to achieve visibility at the *Substation* level. Some work has been done to gain some visibility at the *Feeders* level, but there is room for improvement. The next step in the evolution is to increase visibility of the feeders and then enable the members to have visibility of their energy usage, laying the foundation for in-home automation. AGi systems will improve the visibility level and provide the communication and sensor foundation to achieve the visibility of the feeders and support the member's interaction with the utility's distribution system. For the utility, this visibility will provide data from throughout the distribution system that can identify issues before they become a problem or result in an outage.

The AGi team believes that Dakota Electric must begin preparing the business for a future state that integrates many technologies not present today, which require advanced capabilities for monitoring, communication and control. The system-wide communication network provided by the installation of AGi will support future operational monitoring. This monitoring will be required to support the operation of the system with the installation of renewables, such as solar. Together these advanced grid systems will provide options for Dakota Electric to increase service levels and meet the future expectations of our members. The Advanced Grid Infrastructure technology will also provide the foundation and flexibility for Dakota Electric to respond to the issues as they arise.

3 - What is Advance Grid Infrastructure Technology?

The Advanced Grid Infrastructure, or AGi, has many components, some of which rely on each other to operate and deliver the benefits. The following is a description of the AGi components and the benefits gained from implementing this technology. Of course, with any technology, there are risks involved with implementation. The good news is that Dakota Electric is not on the bleeding or even leading edge for implementing these technologies. Other utilities have implemented these systems and are presently experiencing benefits greater than expected within their original business cases. The key component of selecting and implementing any technology is to clearly understand what the technology is going to do and how it will provide that functionality.

Advanced Metering Infrastructure (AMI)

AMI is the foundational component of the Advanced Grid functions. AMI is a system wide communication network that also happens to communicate with meters and other devices. AMI provides a communication path which can be used by the system to read meters; the Load Management system to control loads; and the SCADA system to talk with downline devices such as fault indicators.

Electrical Usage: The basic function of the AMI system is to communicate with the meters. Any system Dakota Electric considered provided 15-minute usage data from each of the electrical meters. The usage data will not only be available for Dakota Electric's use but also can be used by the member to better understand how they consume energy and allow them to identify ways to save on their electric bill.

One example of how Dakota Electric would use this AMI data is to ensure that the facilities, including the transformer supplying the member's home or business, are correctly sized. Presently, Dakota Electric engineering uses educated estimates of the member's peak usage to size and decide when to upgrade the member's transformer. Currently, engineering only has a single monthly kWh reading. From this, the coincident peak demand (kW) must be estimated for all the members which are supplied by that transformer. This estimating process leads to conservative estimates that sometimes have the following results: replacing transformers that may not needed to be replaced, installing transformers larger than required, and missing transformers that need to be replaced due to overloading. Having concurrent 15-minute electrical usage values from all of the meters would eliminate the need for engineering to estimate the coincident peak demand.

Without AGi technology, the engineering model also uses estimates and other estimated peak load levels (aggregated for all of the members) to develop the system models. So, the estimates are aggregated up to the feeder and substation level, and any estimate that deviate from the actual situation accumulate all the way up. The engineering models based upon these aggregated estimates are used to decide which fuses to replace, which lines to rebuild, and when to build new substations. The engineering models drive a large part of the multi-million dollar annual capital budget at Dakota Electric. Having actual 15-minute energy usage data, from each meter supplied by the AMI system, would result in a more accurate engineering model and allow the engineers to better pin point where the electrical distribution system needs improvement thereby minimizing excess capacity and excess facilities.

<u>Meter Alarms and Events</u> – Beyond the kWh usage data and the kW demand values, the AMI system will also communicate events and alarms from each of the meters. The events and alarms available from the meter depend upon the brand and type of meter and the AMI vendor, but typically the following alarms and events are provided by any AMI system:

- High Temp – If there is an electrical connection problem, such as the service wires loosening within the meter socket, the connection can heat up. There have been occasions where these weak electrical connections have resulted in damage or even fires. To help combat this issue, meter manufacturers have incorporated temperature sensors within the meter so "hot sockets" can be quickly reported by the meter through the AMI communication network to the utility. This allows the utility to inspect the meter socket and identify any issues before they develop into a major problem.

- Reverse Power – The power normally flows from the utility to the member, but when a member installs a generation system, such as a solar generation system, the power can flow in both directions. The AMI meter has the ability to alarm on reverse power and also report kWh (energy) flow in both directions. Utilities are using this information to provide billing information for renewable generation installations without needing to install a special meter and to identify members who have installed a generation system without coordinating with the utility and completing the required safety inspection.

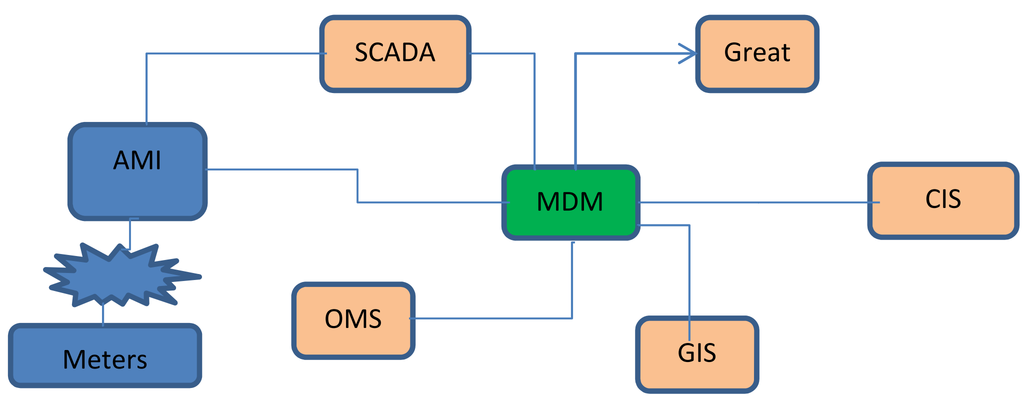
- Hi/Low Voltage Alarms – The AMI meter provides options for reporting problems with the service voltage. The AMI meter can report the actual voltage, high and low voltages, and/or provide alarms for voltage issues. Utilities are using this data to identify the following: transformers which are failing, portions of the distribution system which need more support, areas where the distribution system has voltage regulating equipment not working correctly, locations where a member's distributed energy resource is not operating properly, or places where voltage is higher or lower then is reasonable. Using AGi technology, Dakota Electric can receive an alarm and then dispatch crews to discover and repair the issue before it grows into something larger.

  When responding to a power quality complaint, presently Dakota Electric is called by the member and responds to the site to investigate. Before a cause can be identified and fixed, it may take multiple trips to the site to hang voltage recorders and track down the extent of the issue. This is costly for Dakota Electric in labor, and causes frustration and sometimes loss of production for commercial members. The AMI meter would provide alarms that identify how many meters are seeing the voltage issue which helps us understand the scale of the problem. Also, the AMI system would allow Dakota Electric to remotely interrogate the meter to see the voltage. This provides very useful data to help quickly identify the scope of the problem and help direct us to a resolution.

- Meter Tamper – Most meters are equipped with a motion, tip sensor, or other sensor which triggers an alarm back to the AMI system if the meter is removed from the meter socket. When the meter is removed from the socket, one of these sensors will report back to the office. This alarm, coupled with an outage event report, alerts the utility that someone has removed the meter.

Meter Data Management (MDM)

The AMI system does a great job of collecting data from the field and while a few of the AMI systems have a limited ability to present that data in useful reports and alarms, all of the AMI systems have a limitation when it comes to management of that data. The amount of data collected by the AMI system is simply huge! The Meter Data Management system (MDM) provides an organized place to store, retrieve, report, and analyze the data collected by the AMI and many other interconnected systems. The MDM is a data warehouse and a hub, with integration to many of the other Advanced Grid technologies. Below is a diagram of one possible way the MDM integrates all the Advanced Grid Infrastructure systems.



Let's look at how the MDM would be used at Dakota Electric by reviewing some of the key usages.

Storage - The AMI system is focused on getting more data and quickly runs out of capability to store data for more than a couple of months. Customer Information Systems (CIS) have no need to store 15-minute interval data since they are designed to only keep what is required to produce the monthly bill and support the billing function. With the huge amount of data being collected by the MDM system, the MDM is first a database. The system is designed to get data in and out of the database quickly and to have the horsepower to support many users at the same time. In addition to the AMI metering data, the MDM takes in data from many other systems: customer classification information from the CIS, weather information from outside sources, graphical information from the GIS, Demand Management information from the Load Management System, and reliability information from the meters and from the Outage Management System (OMS), etc.

Data Integrity - With all of the 15-minute data coming back from all of the meters, the chance for data issues becomes significant. Is the data missing due to an outage or did the communication fail to the meter? The MDM is designed to handle these questions using validation and estimating rules and processes. Internal rules are available to automate the validation and estimating of the data. If the data needs to be changed or edited, the MDM has audit trails included in the program to track any editing of the metering data. This is referred to as VEE or Validation, Estimating and Editing. This is a key function of the MDM program.

Billing – The CIS system is designed to take meter readings and produce a bill for the member. While the CIS has many capabilities and can be programmed to support many different billing rates, the CIS is not intended to be used for more than billing. The billing system has no need to store 15-minute data for the past few years and is only designed to keep what is needed to produce the bill. The MDM is designed to be flexible and easy to configure supporting new and unique rates which may be developed now and in the future.

The MDM can aggregate groups of meters together for the CIS or complete complex calculations using the metering data. For example, Dakota Electric's standby rate requires 15-minute data, from multiple meters. To produce a bill, analysis to identify which 15-minute period resulted in the greatest member load, must be done for each billing cycle. The MDM will do this analysis which frees up the CIS to receive the calculated monthly billing information from the MDM and then produce the bill.

Virtual Meters - Groups of meters can be associated together to form a virtual meter within the MDM. A good example of this is for all of the members supplied by a single transformer to be united by a virtual meter representing the power flowing through the transformer. That data can then be used by the engineers to check on the loading for the transformer. No more estimating the peak load! Virtual metering can also allow members to keep track of the total load used by all their meters on their campus or for many other uses.

Special Rates – The MDM can support Time-of-Use (TOU) rates for those members who want it. The MDM allows Dakota Electric to have TOU rates without requiring installation of special TOU meters. This eliminates need for batteries in the meters, which are now required in these special meters to keep their internal clocks accurate. The AMI communication network maintains the meter's internal clock and can quickly reset the meter's internal clock after a power outage.

Analysis or Analytics – One of the fastest growing areas within the MDM systems is their power to analyze vast amounts of data. The distribution transformer peak load is just one of many ways the MDM can look at the data and help find ways to improve the efficiency and operation of the system.

> Loss Analysis is another analytic program which MDM systems can provide. This is used to identify parts of the distribution system with greater than expected losses. These losses could be caused by bad metering, energy diversion, or that part of the system needs to be rebuilt to reduce the technical energy losses.
>
> Energy Diversion – The MDM can take several different alarms and values and using analysis can identify where energy is being diverted. The processes used by MDMs are quite extensive and together with information from the GIS and other systems, energy diversion can more easily be identified.
>
> Rate Analysis – The data stored with the MDM would allow accurate analysis of the effect of new rates and rate structures. The analysis required for new rates has always involved an estimate of how and when the energy is being used. MDM could easily provide real data to benchmark the new rates and the resulting impact on revenue. Also, the MDM data could be used to provide more accurate cost of service studies and analysis, which is critical when supporting the cost allocation across classes of members.
>
> Accounting – Since the existing meters are read throughout the month, at the end of each month there is electricity usage which has been recorded by the meter but has not yet been read and billed. While Great River Energy reads its meters at the end of each month and bills for the energy delivered to Dakota Electric, Dakota Electric can only estimate the total unbilled usage occurring after the monthly reading to the end of the month. Finance is currently estimating the unbilled revenue each month and using that estimated number in the financial reports. With AMI getting energy usage readings each day from every meter, the actual unbilled energy usage would be known and then used for more accurate monthly financial reports.

Member Services – The data residing within an MDM is a perfect place to better understand the needs of individual members. Instead of bothering members who don’t have or need specific services, MDM would allow improved communication with members based upon their individual usage. Members could be given specific information allowing them to choose the best programs to fit their needs.

Other Types of Analysis – There are many other types of analysis which the MDM system supports. New uses of the data are identified by utilities each year and the MDM selected by Dakota Electric is designed with enough flexibility to support those future uses.

The MDM systems are starting to add the capability to interact with the utilities Graphical Information Systems (GIS) and utilize the interconnected relationships contained within the GIS. Information, such as voltage dips that affected all the members on one section of the line, can be graphically correlated to quickly identify the problem area. As MDM systems continue to develop, these new features can be incorporated within the existing MDM or added on to the MDM as an additional option.

Member Presentment - One of the components of the AGi technology is interacting with the members. Presenting data collected by the AMI system using a web based portal is a key component. Through this web portal, members can view their daily usage profile, billing and past payments, load management history, outage history and the causes. Some of the web portals allow the members to set up automatic text notifications if their usage goes above a set level or is projected to exceed a dollar amount for the billing period.

For businesses, the web portal can allow them to view their usage profile and make comparisons between different operations as well as see changes in usage patterns. This can help the business find ways to reduce peak demand or usage. Business members are seeking this information.

For all members, a potential future use of the portal could be to show their savings resulting from their participation in programs such as load management or show the member how their billing would be on other available rates.

4 - Summary of Existing Systems at Dakota Electric

Dakota Electric has systems which have worked well for our members for many years. Overall, Dakota Electric's costs for reading meters is low and the existing load management system is saving our members millions of dollars each year in costs through the reduction of monthly peak demands. The problem is many of these existing systems have reached the end of their useful life. The load management and rural meter reading systems are using equipment that is no longer supported nor manufactured. Spare parts are hard to find and the systems need to be replaced. The following is a description of the state of each of these key systems and includes what is recommended to be done if AGi technology is not implemented soon. The discussion includes the potential ways these systems could be replaced without AGi technology implementation and the costs and issues involved. Also, how the installation of AGi technology would replace or impact these systems is included in the discussion.

Metering

Existing Meter Reading – The existing meter reading process is working well. We are getting the information required for billing our existing rates. The overall cost of meter reading is very low. The meters are read with Dakota Electric employees and by contract meter readers. In the early 2000s, Dakota Electric decided to install meters equipped with ERTS radios on the hard to access and more expensive to read meters. These ERTS radios allow the meter reader to "drive by" the location to read the meter using a radio link. These devices broadcast a radio signal a few hundred feet and allow us to easily read the meter. We have installed drive by ERTS in more than 1/3 of the residential meter locations and for the past few years all new single-phase meters installed have ERTS modules automatically included. The ERTS have reduced our metering reading costs and have also improved the safety for our meter readers.

One of the problems with our existing stock of meters is Dakota Electric's meters continue to age. As electro-mechanical meters age, they are known to "slowdown". In 2017, the age of an average meter is 22 years old. This includes 1,790 meters over 47 years old and almost 25% of our meters over 30 years old. Meters purchased before the early 1990s are electro-mechanical and operate using internal gears. These older meters have bearings and slow down over time and record less energy then what was consumed. The newer digital meters are designed to not only maintain their calibration over time, but also do not require energy to turn the gears to record usage, and thus are able to more accurately record energy during periods of light usage. It is important to note that Dakota Electric continues to sample test our meters to ensure we don't have a wide spread accuracy issue with our older meters and that they remain within the +/- 2% required accuracy window.

In the early 2000s, Dakota Electric identified and replaced all meters which were older than a mid-1960s vintage. This was done to reduce the number of very old electro-mechanical meters which were more prone to under recording consumption. With the thought that we would soon be installing all new meters with an AMI metering system, there is no meter replacement program for replacing meters based solely upon their age. If meters are found to be out of tolerance, they are replaced.

If Dakota Electric would decide not to install an AMI system, we would need to initiate a meter replacement plan for the oldest meters and make sure that none of the existing meters would be greater than a determined age threshold, such as 40 years old. This would involve replacing a portion of the existing meters each year. With the implementation of AGi technology, The AGi meters are more expensive than a normal meter and initially would result in a higher capital cost. Over time, however, the AGi meters would not require the labor for monthly meter reading and would provide 15-minute interval data and other power quality monitoring. This would result in greater benefits and help lower internal costs for the future.

Turtle AMR System – For the rural more sparsely populated portion of the Dakota Electric system, the cost to read meters is much greater than for the more densely populated urban area. In the mid-1990s, Dakota Electric invested in an AMR system called “Turtle.” The system supported reading the meters using a system which communicated over the distribution lines. This is referred to as a Power Line Carrier system or PLC. Only a single daily kWh reading is available using this system and that is transmitted back to the Dakota Electric offices. In the 1990s when this system was installed, it was the most cost effective system available for rural meter reading and has worked well for the past 20 plus years. However, many of the Cooperatives who installed this system in the 1990s have already replaced this with newer AMI technology.

The existing Turtle remote metering reading system is no longer manufactured nor supported. Finding meters and equipment required to keep this system operating is getting harder each year. We are able to purchase used equipment and that can sustain us for a couple more years, but we estimate that we can only continue with the existing system until 2020 or 2021. Without the installation of AMI, the only option we would have involves replacing all the meters with ERT meters and going back to reading the meters by hand. The reason the meters would need to be replaced with ERT meters, is due to the cost of manually reading the meters and the difficulty of accessing the meters in the rural area. The cost of reading the meters without the ERTS installed would be very costly and, in some cases, impossible as the meter is in the middle of a field connected to an irrigation system. Replacing the meters with ERTS enabled metering would reduce the monthly meter reading costs, as the meter reader would not need to drive all the way up to the farm yards.

By implementing the AGi technology all of the existing Turtle meters could be replaced with standard AGi meters. The AGi meters are more expensive than a normal meter and initially would result in a higher capital cost, but over time, the AGi meters would not require the labor for monthly meter reading and would provide 15-minute interval data and other power quality monitoring, which would result in greater benefits.

Generation Metering – All the Rate 70 and 71 meters for commercial accounts on the interruptible rates require 15-minute data to support the rate and to verify operation and load levels for credits to Great River Energy. This is presently accomplished via cellular modem or a direct dial connection to the meter. The cellular communication is working fairly well and the member is paying for the additional monthly cellular costs as part of the rate. AMI metering would eliminate the need for purchasing and maintaining this special metering. Also, the AMI meters would be less costly than the cellular and phone modem meters presently being used. Implementing AGi technology would result in a significant initial capital cost for replacing all of the existing meters, but over time would result in labor savings with maintaining the existing special meters.

Load Management System

Presently, Dakota Electric is installing load control receivers (LCRs) at member's homes and businesses to directly control the load when required. Air conditioners, water heaters, electric heat, etc., are remotely controlled by a signal sent to the load control receiver box mounted on the side of the home. This Load Management (LM) system also includes some commercial loads, which manually shed load in response to a load control signal. This is called Rate 71, where the member manually curtails their total load to a predetermined level.

There are over 50,000 LCRs installed on the Dakota Electric system, so many of our members are directly impacted by the Load Management system and are receiving savings from the program. All of our members, even members not on the program, benefit from reduced wholesale power costs and lower distribution system capital costs resulting from the reduced peak demands.

Another form of Load Management at Dakota Electric is through the starting of member-owned generation located at their business. This generation has been installed to provide the member back-up power during outages and shed their total load from the Dakota Electric system during periods of peak demand. Dakota Electric has installed SCADA (System Control And Data Acquisition) control and monitoring units, referred to as RTUs (Remote Terminal Unit) which allow Dakota Electric to start and stop the generation systems. Through the Dakota Electric SCADA system, a signal is sent to each of the member's generation systems and their entire load is then transferred to the generation and off the distribution system. The existing SCADA system will not be replaced as part of the AGi project.

The existing Load Management control system was not designed to quickly shed or restore loads. In the 1990s, there was no need for a fast load control response. The process to initiate control of the loads involved Dakota Electric receiving a phone call from Great River Energy telling us when to control. The Great River Energy and Dakota Electric computer systems are not interconnected and thus this communication is a manual process. Switching to a new load control technology and redesigning the implementation of the load control software will allow Dakota Electric to shed loads within minutes. We believe that changes in the power supply due to the interconnection of renewables, will make it necessary to be able to quickly initiate load control, which will also allow the interconnection of more renewables to the system.

Dakota Electric's load management system is very effective at controlling billing peak loads. We have well over 100MWs of load controlled during our billing system peak. Dakota Electric is about 1/3 of Great River Energy's total load control. How Dakota Electric operates its load control is critical to Great River Energy.

The existing Load Management system has two separate methods where load is controlled. One method of load control is with the SCADA system. The second method of load control is using load control receivers (LCRs) which are mounted at each member's residence or business.

Overall the Load Management system is working well given its age. Dakota Electric has calculated that the entire Load Management system, including the SCADA controlled generators, saves Dakota Electric's members millions of dollars annually in reduced power costs. About 60% of that savings is from the SCADA controlled Rate 70 generators. The other 40% of the power cost savings is from the operation of the load control receivers (LCRs) through the existing Cannon Yukon system. The actual dollar savings from load management varies from year to year depending upon weather and other factors. The member directly receives the benefits from the load control demand reduction, through lower energy charges, credits, or via automatic power cost adjustments.

The existing LCR control system is comprised of a central software controller program called Yukon. This system was developed by Cannon Technologies (Now Eaton). The Yukon central controller communicates with the LCRs that are installed in the homes and business via 900 Mhz pager system or a carrier current injection system, which uses the Dakota Electric lines to propagate the signal to the LCR.

During 1999-2002, significant effort was expended to review the daily operation of the load management system. During that review, it was found that the carrier signal was not reaching many of the LCRs. Over 25% of the LCRs were found to not be functioning correctly. Most of the issues with the operation of the LCRs were because the carrier signal for control was not reaching the LCRs. Significant effort to look for ways to fix this propagation issue were tried, but after many attempts it was decided that we needed to switch to using pager signals for controlling the load control receivers. All new LCRs installed after that time were pager units. We also replaced existing LCRs that were identified as not getting a good signal via the carrier system with pager units. Since 2001, all LCRs connected to rural substations were converted to pager LCRs and around half of the urban substations have also been converted.

In 2010, we learned about the potential elimination of pagers as a communication option for the new LCRs, so the conversion from PLC to pager LCRs was suspended. Also in 2011 and 2012, we started talking about the possibility of implementing AMI and replacing the load management system with newer technology. So efforts to inspect the existing load management units located in the field were curtailed.

The existing load control system was installed at Dakota Electric in the mid-1990s. The original Power Line Carrier (PLC) equipment is well over 20 years old. Also, when the program started in the mid-1990s, a significant number of LCRs were installed during those first few years as the program was first kicked off, so many of the LCRs are also over 20 years old. According to Dakota Electric's Graphical Information System (GIS), we presently have over 50,000 LCRs installed on our system.

The greatest limitation of the existing Load Control system is that communication to the LCR is one-way and does not provide any operational feedback to Dakota Electric headquarters. When we send out a shed signal, we do not know if the LCR operated or not. We also do not know if the LCR has been bypassed or removed. New Load Management units use the AMI communication network and provide a two-way response of their operation making it possible to identify the non-working units and direct the field crews to repair/replace non-working equipment. Using the data from the AMI meter we will also be able to verify the operation of the load management system at every location and identify non-working LCRs allowing for quick repair of those units.

Issues with the existing system Load Management System

The team has reviewed and determined that the existing load management system has reached the end of its life and needs to be replaced. The decision on what is the best course to take with the load management system depends greatly on the AGi technology implementation decision. The reason for this is the communication network required for the AMI portion of the AGi project can also be utilized for load management system communication. Without the AMI communication system, installing a replacement load management system would be significantly more expensive and the options are limited. Pairing the installation of AMI with a new load management system would greatly enhance the operational benefits from the load management system as the two would work in tandem.

<u>Failure of LCRs</u> - This is a commonly reported problem with load control systems. There are many reasons for a LCR to not work correctly. The following are some of the main reasons for failure of the unit to operate correctly:

- Electronic failure within the unit. - –This is typically due to lightning damage, water egress or just age. The damage could be to the relay, the electronics board, the wiring, or the radio receiver.
- Bypass or Removal of the unit by owner. -The unit is simply bypassed, turned off or removed by the owner of the home, or a repair tech is working on the AC unit, water heater or other off-peak device. To help hide the bypass of the load control wiring, people will bypass the control wires inside the unit, instead of inside the LCR, so load control is bypassed downstream of the control. This type of bypass is harder to find and requires considerable time and effort.
- Signal does not reach the unit. - With the power line carrier system, the propagation of the signal is a known problem. In 2002, we checked each unit to see if they were receiving a signal and fixed those which were not. No significant inspections of the units since that time have been completed. This is due to the high cost of labor required to inspect each of the LCRs.

In 2013, a random inspection of 480 residential LCR receivers found only 81% of the receivers appeared to be functional. The remaining 19% were non-working and would not interrupt the load when called upon to do so.

	Urban Group 1		Urban Group 2		Urban Group 3		Urban Group 4		Urban Group 5		Rural Group 1				
Passed	30		91		74		70		84		38			387	
														0	
Amber Light Blinking ?					1		3							4	
could not Scan (lights are on) ?	2				4						5			11	
No Power to LCR ?							1		1		1			3	
														0	
LCR Removed *					3		2							5	
LCR Bypassed *	2		3		2		1							8	
LCR Power Supply Failed *							1		1					2	
LCR Door bad *			5		9				7		4			25	
Amber or Green light not on *	13				1		16		2		1			33	
LCR Damaged (no note) *					1									1	
Low Voltage Wire damaged *											1			1	
No Access to LCR (locked or Shrubs)	3		1		5		6		4					19	
Total Inspected	47		99		95		94		95		50			480	
Total OK (Passed)	30	64%	91	92%	74	78%	70	74%	84	88%	38	76%		387	81%
Total Failed = "*"	15	32%	8	8%	16	17%	20	21%	10	11%	6	12%		75	16%
Total Questionable = "?"	2	4%	0	0%	5	5%	4	4%	1	1%	6	12%		18	4%

LCR were not inspected for bypassed in the AC unit. (only LCR's which were bypassed in the LCR are noted)

2013 LCR Inspection Summary

The inspection did not look for receivers in which the wires were physically bypassed downstream of the Load Control Receiver, as that required a more invasive and expensive inspection of each installation. Installations in which the control wires were jumpered or bypassed within the air conditioners have been reported by neighboring utilities as the number one reason for the load not being controlled. So the actual failure rate is expected to be greater than just the 19% of the non-working LCRs found in the 2013 survey. For the business case, we have estimated that 20% of our LCRs are not functioning correctly and that percentage is expected to grow 1% annually because of age, bypassing, and other causes.

With the proposal to implement AMI and replace the load management system, Dakota Electric is not presently inspecting the existing Load Control receivers for failure or bypass. The cost to inspect and repair a failed LCR over the short term is not economical as the cost to inspect all the units, including all the working units, is close to the benefits received. Only an estimated 1 out of 5 installations are non-working. If there was a method to just identify the non-working units and only drive out to those units and repair or replace them, the economics would make it worthwhile.

During the 2013 review, the team did not identify a method for finding the non-working LCRs better than installing an AMI system and using the interval metering data from that system. If the decision is made to not install an AMI system, then some method or process to inspect the units and repair or replace the non-working units will need to be established. This will be costly and, based upon experience, will only result in identifying a portion of the non-functioning installations.

Replacement units for the existing LCR receivers - In the past, we could purchase replacement LCR front doors from the vendor which allowed us to easily remove a LCR door and install a new door on a failed unit. A couple of years ago, Cooper-Eaton decided to change the design of their new units and that new design is not compatible with our existing units. In 2013, Dakota Electric worked out a plan with another utility to purchase their used LCRs that they were removing to go with a newer technology. The plan was to reprogram these used LCRs and use them for necessary repairs, replacements, and new installations. This was hoped to allow us to bridge the gap for 3-5 years until a replacement load management system was identified and installed.

Power Line Carrier – Around 20% of the existing load control receivers use a one-way power line carrier signal which is imposed on the 12.5kV distribution system. The equipment supplying this signal is located at the substations and has some significant limitations for how well it propagates on the distribution system. The propagation issue results in failure of the load control signal to get to some of the load control receivers. Due to this issue, Dakota Electric was converting all the existing power line carrier (PLC) LCRs to the pager communication. The existing PLC injection equipment is well over 20 years old and is no longer manufactured. Dakota Electric has limited spares for the PLC communication equipment. The PLC system LCRs and signal injection equipment has reached the end of its expected life and is prone to a high rate of failure. This equipment needs to be replaced.

Load Control Receiver Programming Devices – The existing LCRs are programmed using a Palm Pilot handheld device. These devices are no longer being manufactured. We have a few of these devices on hand, but we are experiencing a failure of one unit each year. We are estimating that by 2019 or 2020 we will no longer be able to program or modify the existing fleet of more than 50,000 LCRs. This would then require a physical change out of the LCR in the event of a failure or the need to modify the control. This is just one more reason the existing load management system needs to be replaced.

Options for the existing Load Management System

There are few options available to reliably operate the existing load management system. Given the failure rate, age of the existing equipment, and the lack of replacement units and parts, eventually the existing system will no longer be able to effectively deliver the load control the system was designed for. This means that either Dakota Electric will continue to see reduced power cost savings or will need to replace the system with a new load management system.

In 2013, the load management team considered 4 different options for the load management system.

Option A - Do nothing and let it slowly fade away. This was quickly discarded as there is great benefit for our members from operating the load management system and a significant payback from what we have. Also, Dakota Electric is corporately committed to continuing the program.

Option B - Continue with the present limited replacement and inspection program, but also go out and replace the oldest LCRs units that use the power line carrier to communicate (PLC). These LCR units and the substation injection equipment are more than 20 years old and no longer manufactured. This has a slightly better payback then Option A, but the cost of doing this work is overshadowed by the failure rate of the rest of the LCR units. In addition, we still would not know which units were failing.

Option C - A five (5) year inspection program for all the LCRs. The idea here is we could at least find many of the non-working LCRs and replace them. This option also includes the replacement of the 20 years old PLC units as they are inspected. The summary below shows the cost for this option is several million dollars higher than Option A or B but the benefits of having more of the LCR units working would offset that additional inspection and replacement cost. The major problem with Option C is even after 10 years of inspection, it is estimated that there would be 7% of the LCRs still not working correctly and we do not have a viable replacement LCR unit which works with our existing system. Also, if the LCRs were bypassed within the AC unit, the inspection process would not always identify this. In addition, any homeowner wiring for hot tubs and other loads controlled with current transformers could not be easily inspected. It would require a very costly inspection using an electrician and requires gaining access into the member's home. The greatest issue with Option C is that we would be spending money installing older technology, which is only one-way communication, and does not support many of the features with a new system.

Option D -Replace all the existing LCRs with new 2-way load control receivers using a new 2-way communication system. For the 2013 study, it was also assumed that no AMI was to be installed concurrent with the new load management system. This 2-way technology allows us to monitor the operation of the LCR relays and would report if a unit's relays failed to operate. Being able to identify which LCRs have stopped working in Option D provides more benefits than Option C, but this comes with a significant installation cost.

As the team learned during the 2013 study, the installation of a new LCR system without an AMI system would not provide as many benefits as installing a new load management system coupled with an AMI system. This is due to the LCR itself. It would not be able to report if wiring to the load was bypassed within the AC unit (or other load being controlled). Installing a new load management system along with an AMI system provides increased benefits for Dakota Electric. The load management system could utilize the same communication network required for the AMI system, resulting in less infrastructure cost and less long term maintenance expense. The interval data from the AMI could be used to confirm the actual load that was shed thus helping to identify nearly 100% of the non-working Load Control Receiver installations and reduce inspection costs.

The costs shown in the following comparison chart from a 2013 study include the estimated cost of the communication system. All of these options assume that AMI is not installed. If an AMI system is installed along with the new load management system, there would be additional cost savings. The 2017 AGi business case includes a new load management system coupled with an AMI system as that is the option recommended by the AGi team.

Load Management Options Summary

Four possible options are explored with this summary

1 - Do nothing and let the Load Control program slowly expire over the next 10 years
2 - Continue to do what we are doing now. LCR's will continue to fail and no acceleration of this failure is considered,
We will continue to replace known failures and add new LCR's as requested.
this option includes converting all existing (1,600 power line carrier units to pager LCR's. (Business as usual option)
3 - Continue to do what we are doing now but, be more aggressive at finding and fixing the failure - add routine inspections of LCR's every 5 years
this option includes converting all the existing 17,000 PLC receivers with Pager units over the first 5 years during the period inspections
4 - Leverage a new AMI communication system for Load Management and replace all the exsiting LCR's over a 2 year period.

	Option A	Option B	Option C	Option D
10 YEAR NPV Costs	**Let LM slowly fade away**	**Business as usual**	**More Aggressive Inspection / Repair**	**New LM System**
Cost to maintain the existing infrastructure	$2,046,010	$2,046,010	$2,046,010	
Cost to maintain the new communication (Covered by AMI)				$0
Cost to maintain the new LM software				$838,811
Cost to purchase the new Software				$238,095
Replace LCR injection boxes	$0	$285,714	$0	$0
Cost for paging communication	$1,114,865	$1,114,865	$1,114,865	$0
Cost to repair Failed LCR's (as required)	$62,911		$62,911	
Cost to replace PLC LCR's with Pager LCR's		$2,013,145	$1,682,050	
LCR Inspection Costs				
Inspect 20% of the LCR's each year		$0	$3,503,410	$0
Trip costs to inspect and fix the LCR's reporting not working		$125,822	$0	$382,992
Additional cost to repair the ones found not working		$0	$2,408,594	$290,469
Cost to install new LCR receivers				$10,458,644
Additional Distribution Infrastructure due to Loss of LM KW	$1,465,581			
Cost Summary	**$4,689,367**	**$5,585,556**	**$10,817,840**	**$12,209,010**
BENEFITS				
Benefit from Load Control Savings (power cost savings)	**$53,038,666**	**$54,645,603**	**$61,543,985**	**$67,842,584**
Net Power Purchase Cost Benefit	**$48,349,299**	**$49,060,047**	**$50,726,145**	**$55,633,574**
		$710,748	**$2,376,846**	**$7,284,275**
Percentage over base case		**1%**	**5%**	**15%**

* All cost/benefits are NPV over 10 years

5 - Base Case – No AGi Technology Installation - Status Quo

For this report, we wanted to look at what the estimated costs are if we did not install the AGi technology. The base case analysis is continuing as is, or "status quo," and resolving each issue as it develops. With the base case option, little if any additional new capabilities will be added, and some of the existing functionality and capabilities will be lost over time. We will continue to spend dollars on old technologies and, in most cases, we will not be able to implement systems with new technology that could provide increased flexibility and benefits.

The decision to continue with the status quo involves spending new money on new equipment. As the following discussion shows, the load management system is old and must be replaced. Additional special metering and monitoring will be required to support the integration of distributed energy systems, including solar systems. Also, rural Turtle meter reading system must be replaced and the existing aging metering infrastructure must be addressed. These costs are significant and many are new capital expenses Dakota Electric is facing over the next several years.

If the decision is made to not implement AMI and MDM (components of the AGi system), the following system by system review is what is expected to be spent during the 15-year term of the business case.

<u>Meter Reading</u> – Without AMI we will continue to utilize the existing meter readers and contract meter readers to complete the monthly meter reads. The annual cost to read meters with internal and contract crews is around $1 million annually. This includes labor, benefits and cost of equipment, including vehicles to support the meter readers. For the business case, this cost is assumed to be escalating due to increasing labor rates. There are 8 existing internal meter reading positions which would be expected to remain at that level for the 15 years of the business case. The contract meter reading levels would be increased to support additional meter reading as required by member growth.

The need to continue to operate the ITRON meter reading handhelds, including the annual software support costs, would continue. This is the MVRS software and hardware. In addition to the MVRS software system, Dakota Electric maintains and operates a computer system which dials into the cellular meters and the meters with dial-up phone lines. This software is called MV90 and also has an annual maintenance cost.

To support the rural AMR meter reading system, there is another program called Command Center, which has annual support costs and requires work to maintain the devices in the field.

Over the 15 years of the business case, the total expected expense for personnel, their vehicles and the equipment needed to read the meters is $17.9 Million.

Rural Meter Reading – The existing Turtle AMR system is no longer supported by the manufacturer and is expected last only until around 2020. Without the installation of new meters with the AMI system, the existing Turtle AMR system will stop working reliably at some point during the 15 years of the business case.

The existing meter reading Turtle system is assumed to be unreliable and unrepairable by 2020. The existing 5,500 Turtle meters will need to be manually read each month. To accomplish this manual reading, many of the meters will need to be replaced with ERT meters. ERT meters are required for all the irrigation meters and also many of the farm sites where the reduction in meter reader time makes it economical to install the ERT meter. It is estimated that 5,000 of the meters would need to be replaced with ERTS. The replacement cost for each meter in 2017 is $67 including the labor. That's an estimated total replacement cost of $335,000 and is included as a one-time cost. Additionally, the cost of the monthly meter readers for all of the 5,500 meters would be incurred for years 4 and beyond. The monthly cost to read an individual meter is estimated to be $1 per month. The meter reading would be accomplished by contract meter readers. This meter reading cost would be $66,000 annually and that per meter reading cost is greater than our cost to read the suburban meters, due to the greater distances between the rural meters.

So, for the status quo option we would spend an estimated $335,000 for new replacement meters and a total of $792,000 to read those meters for the last 12 years of the business case. This is assuming the existing Turtle AMR system will continue to operate for the next five (5) years.

Metering Accuracy – Without implementing AGi technologies Dakota Electric will continue to have the following costs:

- Without new digital AMI meters, Dakota Electric will continue to have the existing metering which is less accurate and this would result in an unrealized benefit. This cost is calculated to be $219,094 annually.
- Without going through the process of replacing and inspecting all the existing metering, which would be completed as part of an AMI installation, Dakota Electric will not be identifying and resolving existing metering problems. Also, Dakota Electric will not have the new AMI capable metering which can automatically identify and report on the failure of the meter or the associated voltage sources. This is calculated to be a unrealized benefit of $200,000 annually.
- Also, during the process of replacing the existing meters with AMI meters, utilities are identifying energy diversion. A conservative estimate of 0.125% reduction in losses due to diversion for Dakota Electric has been assumed. This is calculated to be $153,214 cost annually to Dakota Electric and without AMI installation this also would result in an unrealized benefit.

The initial annual cost of these issues is calculated to be $572,879 and over the 15 years of the business case, this would amount to $9.93 Million in unrealized benefits.

Replacing Aging Meters - If Dakota Electric decides not to install an AMI system, we would need to initiate an age based meter replacement plan and make sure that none of the existing meters are over 40 years old. To ensure that none of the meters on the system are older than 40 years, we would replace around 3,000 single-phase and 350 three-phase meters per year. So, we would spend $420,000 per year to replace the aging fleet of meters. If we chose 40 years as the age of replacement over the term of the business case, this would cost $6,300,000.

Description	Meters per year	Meter	Labor & Vehicle	Total
Single Phase Meter	3,000	$42	$25	$201,000
3 Phase Meters	350	$500	$125	$219,000
Total Annual				$420,000
15 Years Total				$6,300,000

Special Metering Costs due to DER (including Solar) – Every DER (Distributed Energy Resource), which is interconnected with the distribution system, currently requires the installation of a new bi-directional meter at a cost of about $200 per installation. With the solar rebate presently offered, a second production meter is also required at an additional cost of $50. These costs are for all solar systems smaller than 40kW.

Any system larger then 40kW will be selling the excess power to Great River Energy. Great River Energy requires 15-minute interval data to be supplied at least monthly.. Dakota Electric's lowest cost option is to install a cellular based meter at a cost of about $1,300 per meter. The member is also required to pay a monthly cellular communication cost.

For systems larger than 60kW, Dakota Electric has a standby rate. Two meters with cellular communication are required at a cost of about $2,600 per solar installation. The member is required to pay for the monthly communication cost per meter. A portion of this metering cost may be charged to the member, but the long term maintenance and replacement costs will be Dakota Electric's.

With the implementation of an AMI system, these special cellular meters would no longer be required and normal AMI meters that communicate their usage back to the AMI system would meet this need. The main meter would already be AMI and not need to be changed, so the only cost would be the additional production meter. That cost would be about $200 vs. the $1,300 meter with cellular communication. The member would also not need to pay the monthly cellular communication charge.

Following is one scenario showing the cost of special metering required to meter a solar system smaller than 40kW on Dakota Electric's system. These costs are what Dakota Electric is spending for this metering today. This scenario is based on a very minimal solar penetration of 3% of our members by 2030. You can see that even under this conservative estimate of members owning solar installations, the additional metering costs add up. This chart does not include the metering costs for solar systems larger then 60kW where more costly metering is required. It is unknown how many solar systems larger than 40kW will be interconnected with the Dakota Electric system, but at a cost of several thousand dollars each, these larger units would also add to the costs. The installation of AMI would help control these costs for both Dakota Electric and our members as the normal AMI meter would supply the necessary metering data without requiring the installation of special metering. It would also reduce barriers to distributed energy resource integration.

Estimated Solar System Metering Costs

3% penetration by 2030

Year	# of New Systems	Total # of Systems	% of system	Annual Metering $
2019	30	105	0.10%	$7,500
2020	75	180	0.17%	$18,750
2021	100	280	0.27%	$25,000
2022	150	430	0.41%	$37,500
2023	200	630	0.60%	$50,000
2024	225	855	0.81%	$56,250
2025	275	1130	1.08%	$68,750
2026	300	1430	1.36%	$75,000
2027	325	1755	1.67%	$81,250
2028	400	2155	2.05%	$100,000
2029	450	2605	2.48%	$112,500
2030	550	3155	3.00%	$137,500
				$770,000

Assumptions

$200	Bi-directional meter (Meter & Installation)
$50	Production meter (Standard Meter)
$250	Total Cost for <40kW solar installation
105,000	Members without growth (used for % of system)

Load Management - As discussed previously, the load management system has reached its end of life and needs to be replaced. The load management system will need to be replaced regardless of the decision to implement AGi technology. The cost to install a load management system without an AMI system is greater than if it is able to use the AMI communication network.

The status quo cost in 2017 dollars to replace all the existing LCRs is estimated at $12,558,000, plus $250,000 project management and support expenses. Separate communication system and control software would also need to be installed. This cost is estimated at $2,000,000 plus annual maintenance of this system. It is assumed the maintenance costs would be the same as we are spending now for operating the pager system or$50,000 annually, and $125,000 for other load control system support costs. So, the support costs over the 15 years would be $2,625,000. The total 15-year cost for replacing and operating the load management system would be around $15.4 Million.

Customer Service Costs – We learned when visiting other cooperatives, the AGi technology has been shown to reduce the number of trips required to the member's site, the number of phone calls and complaints from the members, and greatly improved the internal operation of the utility. The total costs for these customer service issues over the 15 years of the business case is estimated at $6.4 Million. Without the installation of AGi, we will continue to have these costs. The following describes the components of these costs.

Customer Service – Transfers – Without the implementation of AMI, we will need to continue to make special trips to read the member's meter when the residence or business changes hands. In 2015, we had 14,196 service transfers. The annual cost for transfers is estimated to be $167,087. With AMI we would eliminate one position and one vehicle, together with the associated maintenance and insurance costs

Reconnecting Meters – By using the remote on/off switch within an AMI meter, we could remotely reconnect a member and thus eliminate the labor and vehicle expense of traveling to the member's location. There are two different reasons for reconnecting a service. One is to restore service after a disconnect for nonpayment and the other is reconnecting a service after a service was disconnected due to an ownership transfer. Without an AMI system, we will continue to have our employees drive to the site and manually reconnect the service for both reasons. This annual cost is estimated at $69,000.

Meter Problems – With the age of the existing meters and the manual meter reading process, there are problems which need someone to go out and re-read or replace the meter. This could be due to a stuck meter, a display not working correctly, or reader misread where the meter reader typed in a wrong number and we had to re-read the meter. Without AMI, we will continue to drive to the site to resolve these issues. The estimated labor and travel costs for this effort are $62,928 annually.

Unnecessary Outage Trips – Dakota Electric crews experience times when they are sent to the member's home only to find the problem is on the member's equipment. A typical problem is the member's breaker has tripped. AMI will eliminate many of these trips and their associated costs since it has the ability to remotely read the voltage from the meter and determine if there is or is not electrical service.. The Control Center Manager has looked at 2015 service orders and found that we averaged 15 visits to the member's home which could have been avoided. The installation of AMI will not eliminate all of these but we have estimated that 2/3 of these could easily have been avoided. So, without the installation of AMI, Dakota Electric will continue to incur an average of 10 monthly visits at an estimated annual cost of $13,237.

Voltage Recorder Installations – With the installation of AMI meters, we will have the ability to get voltage readings from the meter and high/low voltage alarms. So, when a member calls to complain about power quality issues, we will quickly know if the problem is with our system or not. Presently, we dispatch a crew to first look at the installation. If they don't find anything, they come back to the office and the next day we send them back to install a voltage/current recorder. This is left at the site for a few days to record the service voltage. The crew then returns to the site to recover the device and it is brought back to the office to download the data for analysis. With AMI, many of these trips could be avoided. In 2015, we had 23 locations where we installed recorders. At some of these locations, we installed and then removed the voltage recorders multiple times trying to find the problem. Typically, all of the voltage recorders we own are actively being used.

End of the Line and Feeder Voltage Monitoring - With the expected DER installations, especially solar and the two-way flow of energy on the distribution system, there will be a need to install downline feeder voltage monitoring. At this time, the magnitude of the solar penetration and the amount of voltage monitoring which will be required it is unknown, but it is clear that downline feeder voltage monitoring will be required at some point in the next 10-15 years. The assumption for this business case is that each phase on each feeder will need one voltage monitor and that cellular communication will be used to gather the information from each of the voltage monitoring. This is a very conservative estimate of the number of voltage monitors, as we will not be able to clearly identify the locations on each feeder to monitor the voltage. So, we would need to install additional sensors on many of the feeders to ensure we are monitoring the portions of the feeder with the voltage issues.

The cost of a voltage monitor and labor to install it is estimated at $1500 each. With approximately 175 feeders, 525 units would be required. The initial cost is estimated at $787,000. The communication cost in 2017 would be about $10/unit per month depending upon the data utilized. With cellular costs dropping and the quantity that we are considering, however, we are conservatively estimating $5/unit/month, $31,500 per year. This cost is assumed to start in 2020 along with increased solar installations, so only 12 years of communication costs are considered.

Description	Device	Cellular Communication	Annual $	Total
Voltage Devices	$1,500 / each			$787,000
Voltage Monitoring	525 units	$5 per month	$31,500	$378,000 (12 years)
				$1,165,000

Within the AGi business case are savings for many areas which, if AGi is not done, we will continue with those expenses. The above were the clearly identifiable costs which Dakota Electric will incur if AGi technology is not implemented. The following is a discussion on the other costs which Dakota Electric will incur without implementing AGi technology.

Operational Cost Savings – With the implementation of AGi technologies, utilities report a savings in crew overtime, the ability to implement conservation voltage reduction over peak,savings in power costs, and the ability to better size our transformers and design the system. The AGi business case shows $339,848 annually in the reduction in costs for all of these areas.

The greatest share of this is the reduction in peak demand charges through the use of conservation voltage reduction. The idea here is for each 1% reduction in voltage you can see a 0.6% to 0.8% reduction in kW. This ratio is very dependent upon the characteristics of the load. Electrical resistive heating or induction lights will have a direct reduction in demand with a reduction in the voltage, but motors will typically have no reduction in demand with a reduction in voltage. For the business case, a very conservative reduction in peak monthly demand would provide Dakota Electric with a calculated $255,782 in annual demand costs. Without AGi technology implemented, Dakota Electric will be paying for these costs.

Summary of Costs for Continuing to Operate Status Quo

The following costs are an estimate and do not include the interest expense resulting from the replacement of the Turtle AMR meters, Aging Meters, Special metering for Solar, and the Load Management system installation. The costs estimated in this table would be incurred throughout the 15 years of the business case.

Estimated COSTS for Continuing to Operate Status Quo (2018-2033)	
Reason	Cost (Millions)
Costs to Read Meters	$17.9
Replacing Rural AMR meters (Turtles)	$1.1
Replacing Aging Meters	$6.3
Special Meters for DER (Solar)	$0.8
Replacing Load Management System	$15.4
Unrealized Customer Service Savings	$6.4
Necessary Feeder Voltage Monitoring	$1.2
Less accurate metering and resolving metering issues	$9.9
Unrealized Operational Savings	$7.5
Total Status Quo Costs	**$66.5 Million**

6 - Advanced Grid Technology Benefits

The demands of Dakota Electric's membership~~s~~ is changing. Members who are in their 20's and 30's are asking for choices that were not possible to provide just a few years ago. The following member benefits are part of implementing the AMI and MDM portions of the AGi suite of systems.

With AMI and MDM the members will benefit by:

- A reduction in estimated bills or incorrect bills, and the disputes associated with estimated or billing based on miss-read metering.
- Enhanced reliability and knowing that while away from their home, power outages will automatically be known by Dakota Electric and responded to promptly.
- Easier activation or transfer of their service through remote meter readings.
- Fewer people walking through their property to read the meters.
- New capabilities to engage low income members to help manage usage and costs.
- Availability of increased information to the member showing their energy usage patterns.
- Being able to customize their billing date to better fit their lifestyle, financial needs, pay cycle, or other considerations.

The environment will also benefit through the use of AMI:

- Reduced energy use through consumer behavior changes resulting from improved energy use information.
- Reduced vehicle emissions resulting from significantly reduced vehicle miles through:
    - Elimination of travel required to read the meter each month
    - Elimination of travel required for transfers read in/out
    - Reduction in travel for service disconnects and reconnects
    - Avoidance of false outage service calls and efficiencies in service restoration following storms.
    - Reduction in power quality investigation visits

Additional notable service delivery improvements include the following:

- Enhanced meter reading accuracy: AMI's remote meter reading capability will significantly eliminate the need to estimate customer usage when meter readers are unable to read the meters, and the AMI system is able to consistently deliver accurate meter readings without the manual entry errors possible with Dakota Electric's present system.

- Improved member service and convenience: AMI enables Dakota Electric to remotely perform many functions that currently require a trip to the member's home or business.

This remote capability improves the member experience by providing quick answers to their questions with a great amount of information.

- Reduced costs for services: New options are available with AMI such as remote disconnect and reconnect. Where members are now charged for the cost to send out a field crew to reconnect their service after a non-payment disconnect, the new meters equipped with remotely controlled on/off switches within the meter would eliminate this charge. The AMI meters would allow Dakota Electric to simply send a signal to the meter to reconnect the member upon payment.

- Flexible payment options: With AMI meters coupled with internal on/off switches, new flexible payment options are possible. Many utilities have implemented pre-pay systems which allow the member to choose to pay in smaller or larger amounts, better fitting with their life style. This pre-pay option is not part of the AGi project, but the foundation for providing these enhanced services will be created.

Metering Accuracy - With AMI, not only will the meter readings be coming back electronically and thus eliminate all of the issues involved with a meter reader miss typing the meter reading, but also will more accurately record the member's electrical usage. Prior to the late 1990s, the meters purchased and installed were not digital electronic meters. They were instead electro-mechanical meters which operated based upon the magnetic field induced when current would flow through the meter. This induced field would turn gears within the meter and record electrical usage. Because a minimum amount of energy is required to spin the elements within the meter, the electro-mechanical meters are less accurate vs. a newer digital meter at low usage levels. Digital meters consume a very small amount of energy to operate but are able to record electrical usage at all levels and thus more accurately record the member's electrical usage. Presently, Dakota Electric has a mix of digital and electro-mechanical meters and moving to all digital AMI meters will ensure that all members are billed using the same technology.

Energy Diversion - The utilities who have implemented AMI have reported a higher than expected level of energy diversion. They typically have reported 0.5% or higher of energy sales improvement after identifying and resolving the locations with energy diversion. As part of the installation of the new AMI meters, most of the energy diversion is identified. The AMI system is also designed to identify future energy diversion through several different techniques. Dakota Electric has a very low system loss percentage, presently fewer than 3%. Given the low system line losses, it is not expected that Dakota Electric has a significant issue with energy diversion. So, a 0.125% improvement in energy sales was assumed as the annual benefit for reducing energy diversion within the Business case.

Eliminate Special Metering for DER Interconnection – As stated in the status quo costs, special bi-directional meters are required to meter DER installations. Standard AMI meters with AMI communication back to the office would perform the same functions as is presently done with special bi-directional meters and would eliminate the cost of installing special metering for DER installation. This would help reduce Dakota Electric's costs for integration of distributed energy system.

Provide increased monitoring of distribution systems. - "Increased monitoring and characterization of distribution systems is a fundamental need in order to facilitate higher levels of DG integration," said Dr. Alexandra von Meier of the California Institute for Energy and Environment at a IEPR Committee Workshop in 2011. The AMI communication system provides a platform for sensors to get their information back to the control center, and the AMI meters provide voltage and utilization information which can be used to model and monitor the distribution system.

With higher penetrations of distributed energy resources, including solar and without an AMI system, Dakota Electric will need to install a separate system to monitor the feeder voltages and possibly other key parameters. Without this monitoring, high or low voltages that might damage members and utility equipment, could easily occur and not be identified until the equipment was damaged.

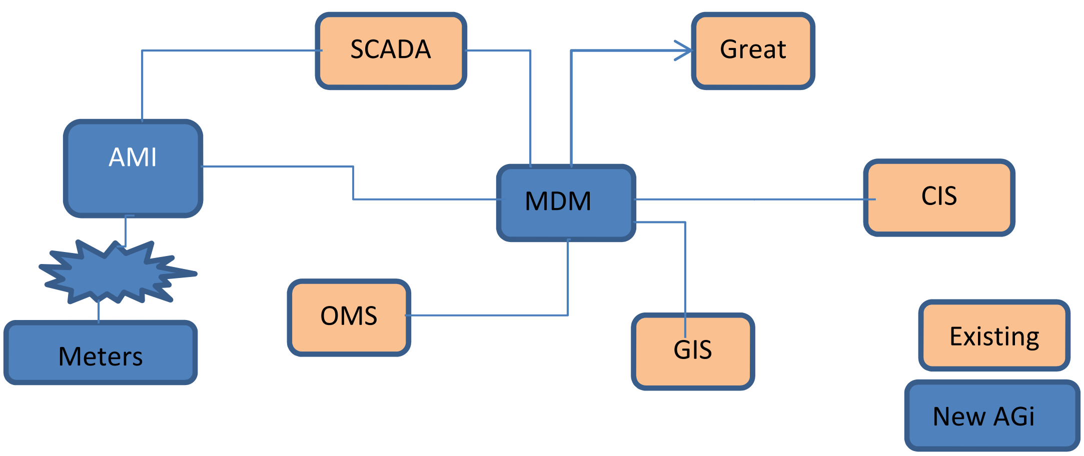
All utilities are required to maintain the distribution voltage within ANSI standard operating levels. Presently with the one-way flow of electricity, the need for monitoring is significantly less. The addition of DER systems and the two-way flow on the distribution feeder coupled with the intermittency of some renewable generation creates a very dynamic operating environment.

7 - Advanced Grid Technology Implementation Issues

As with any new technology there are risks and issues involved with the implementation of the technology. There are both general risks and technology specific risks inherent with all projects. Specific risks such as security are discussed in the sections following the general project risks. The most significant general risks are: (i) project implementation risks, (ii) technology or material defect risks, and (iii) failure to achieve the benefits.

Implementation and Integration Risk: The AGi systems are a complex group of software and hardware that, when working together, provide significant benefits. The primary project implementation risks are failure to control cost, deliver scope, or meet schedule. These risks are mitigated through a variety of means such as following standard project management practices with qualified personnel, proper management oversight and check-in, contract and vendor management, and most importantly a well thought out upfront plan and scope. The AGi team does not believe that any of these project risks are show stoppers and through contracting with personnel experienced with AMI implementation projects, we will be able to manage the risks.

Since the systems are developed by different vendors, the integration between the systems is a key risk. As you can see from the following diagram, the new AGi systems also need to be integrated with our existing systems for Dakota Electric to obtain all of the benefits. Prior to starting the project, each of these interfaces will need to be documented and clear use-cases will be developed. The contracts will directly address the required interfaces and the data to be moved across these connections.



<u>Technology and Material/Manufacturing Defect Risk</u>: Purchasing serial 1 of any technology would greatly increase this risk. The good news is current AMI and MDM technologies have been installed for at least 5 years. In many cases, the vendors are on versions 2, 3 and 4 of these products so many serial 1 risks are no longer present. We do not expect fundamental technology risks to be an issue, and we will mitigate this risk through contractual means such as acceptance testing and criteria and payment terms and conditions.

Material and manufacturing defect risks are always an issue with any long-lived product whether old or new technology. The main form of mitigation of this risk is to have excellent warranty terms and conditions. Also, pretesting of all equipment that is being installed in the field before wide spread installation is also key.

<u>Failure to Achieve Benefits:</u> Even if the project is implemented on time and under budget, a project may not live up to the business case expectations. This can occur due to overestimation of benefits in the original business case or failure to realize benefits during and after implementation. The primary method used to mitigate the overestimation of benefits risk is to build a reasonably conservative business case which includes contingencies in the cost estimates and have a solid contract that has performance requirements that must be met by the vendor. While many costs, such as meters, can be pinned down with a high degree of certainty, there are other costs and benefits that are less certain.

One of the key benefits in the business case is labor savings due to the implementation of the technology. Several positions are proposed to be eliminated due to the AGi project. We fully expect that the labor reductions estimated in the business case will be realized. We have conservatively estimated the labor savings and included several new positions in the business case which will support the new technology. No benefits have been taken in areas where the labor savings does not include eliminating an entire position, i.e., no reduction in head count would occur.

The business case has been developed with conservative assumptions for many of the benefit areas. The AGi team with the aid of an experienced consultant has looked at Dakota Electric operations and included benefits which have been achieved at other Cooperatives. The AGi team believes the benefits included in the business case are reasonably achievable.

The following paragraphs discus a variety of risks and public considerations and concerns that have been heard when visiting the other utilities. Note: The following section was based upon a 2012 “Eugene Water & Electric Board” Advanced Metering Infrastructure (AMI) business case.

Privacy Concerns:
A basic issue that has surfaced relative to AMI meters is the issue of privacy. Some claims are that the utility will watch you when you use your electric toothbrush or open your refrigerator. The meter can tell usage at a higher frequency, but cannot directly distinguish between equipment and appliances. It is theoretically possible that someone could develop detailed analytical tools to create pattern templates and profiles of electrical usage and then compare to AMI meter data to assess how a member is using electricity within their home. While this may be interesting for a YouTube video, the reality is that utilities don’t really have any business need or interest in such use. On the other hand, this information could be useful for the member, to allow them to see how they are using electricity and empower them to identify ways to save energy.

The plan is for Dakota Electric to share the meter data collected with the member for the member to use for their needs.

Time-of-Use (TOU) Rates and Customer Choice

One concern that is raised about AMI meters by some members, regulators or other advocacy groups is that AMI meters will enable TOU rates and that TOU rates are either (i) member unfriendly or (ii) will hurt members and limited income members in particular.

First, AMI meters are not necessary to implement TOU rates. There are existing digital meters that can store periodic reads for a month and place that information into TOU buckets. Those reads can be read via a meter reader and can already be used for TOU billing. TOU rates have been available to our members for many years. The problem with this approach is that no incremental data is available to the members in this model. The members do not know how a TOU rate would affect them before they would choose the rate and once on the rate they do not have near real-time readings to inform them about how they are using energy. AMI meters could provide this historical and near real-time consumption information to the members and allow true member choice.

TOU rates, unlike traditional utility rates, have time differentiated costs (typically higher costs for on-peak rate periods and lower costs for off-peak periods). Herein lies the concern of some members and regulators; that members can't change behavior or consumption patterns to avoid these higher rates. This is especially a concern if members don't have real time information to make consumption decisions.

One claim about AMI meters is that they could enable effective TOU rates which would result in members paying more. The problem is this view is based upon a false premise that members don't already pay these higher costs today. In reality, members pay these higher costs today and don't even know that they are paying them because the 20th century utility rate model actually masks the higher costs by spreading them out over all member consumption. These costs are actually incurred by members right now.

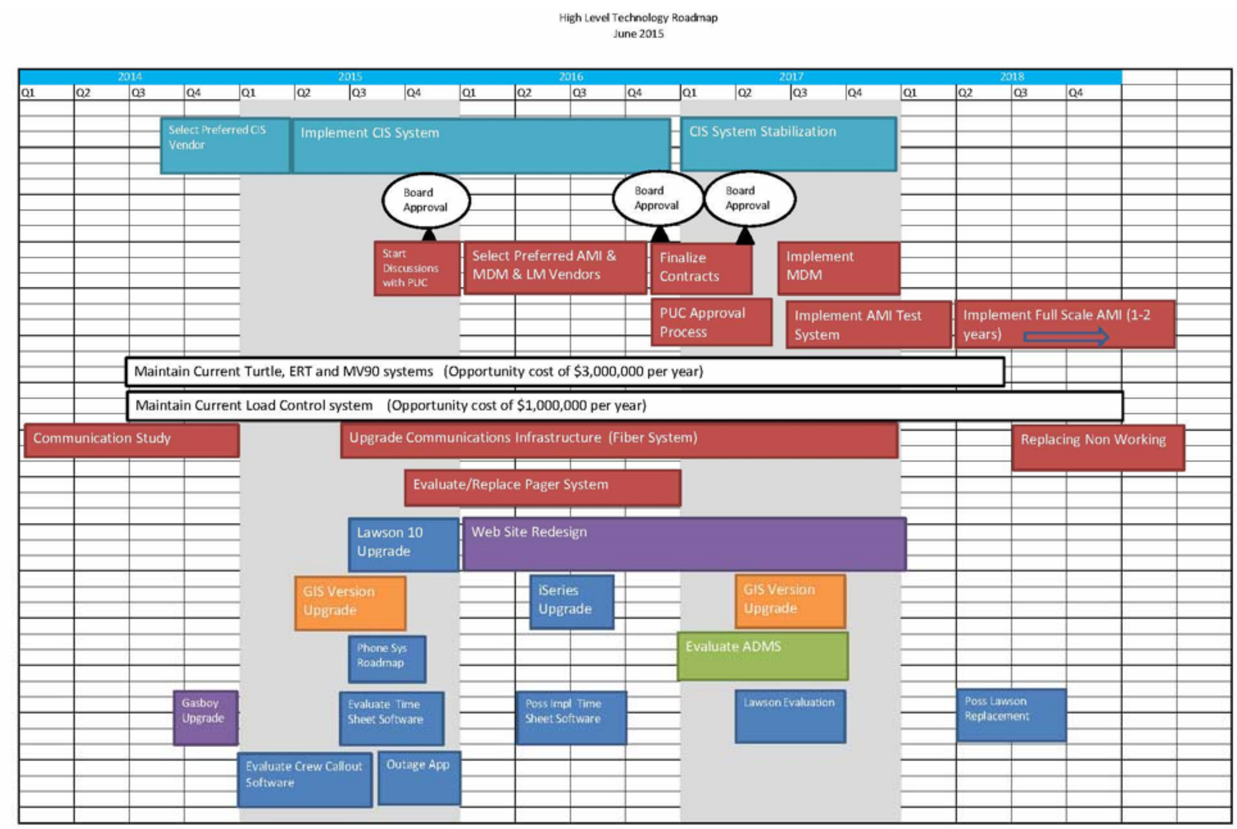
The wholesale power market is the most volatile commodity market on the planet. In spite of this high volatility, the industry has historically priced power as if it was the most stable commodity on the planet. In reality, members pay the higher costs without even knowing it and because they don't know it they have absolutely no choice. TOU rate combined with AMI meters would give members an actual choice while today they have no choice. TOU rates should not be forced on the members, but AMI coupled with TOU rates would provide choices for members who want the option to control their costs. The power cost savings provided by an affective TOU rate would then be passed on to the members who generate those savings. TOU rates would not be designed to shift costs between members.

8 - Business Case Development Process

Business Case Development Background

In 2013, a team of employees from across the Cooperative was formed to develop a business case for AMI. An NRECA Technology Business Associate was hired to work with the employee team to create a business case for AMI and to look at the needs of Dakota Electric. The business case development process included the NRECA consultant interviewing the key staff. The consultant worked with the AGi project team to develop a strategic technology plan for Dakota Electric. That 2013 effort resulted in the development of a high level technology plan; the 2014 Communication Study and accelerated replacement of the CIS system.

Technology Plan - Since 2013, Dakota Electric's Technology Committee has refined the technology plan several times. Below is the 2016 revision of the technology roadmap.



The load management system was not included in the 2013 business case's financial model. As part of the 2013 business case development, the load management system was identified as needing to be updated. It was also learned that the AMI communication system could also support a load management system and thus reduce the overall communication installation and long-term support costs of supporting two separate communication systems.

Technology Road Map Projects

Communication Study - In 2014, a Communication Study was completed that resulted in the identification of significant amount of communication fiber within the Dakota Electric Service area. In 2015, Dakota Electric entered into discussions with Dakota County in regard to Dakota Electric access to the fiber which Dakota County manages. This resulted in a 2016 MOU with the county which allows access to that fiber.

In 2015, a fiber communication team was formed to identify possible fiber routes and to find what fiber electronics would work best for Dakota Electric's needs. Significant efforts were expended to identify Dakota Electric's needs, especially in the area of cyber security with the fiber network, and fiber switching equipment for the substations was chosen. At this same time, Great River Energy and Dakota Electric extended existing transmission fiber into 13 of Dakota Electric's substations. During 2016, Dakota Electric connected several of the substations to the transmission fiber and expects to have most of the substations connected to the overall fiber network by the end of 2018.

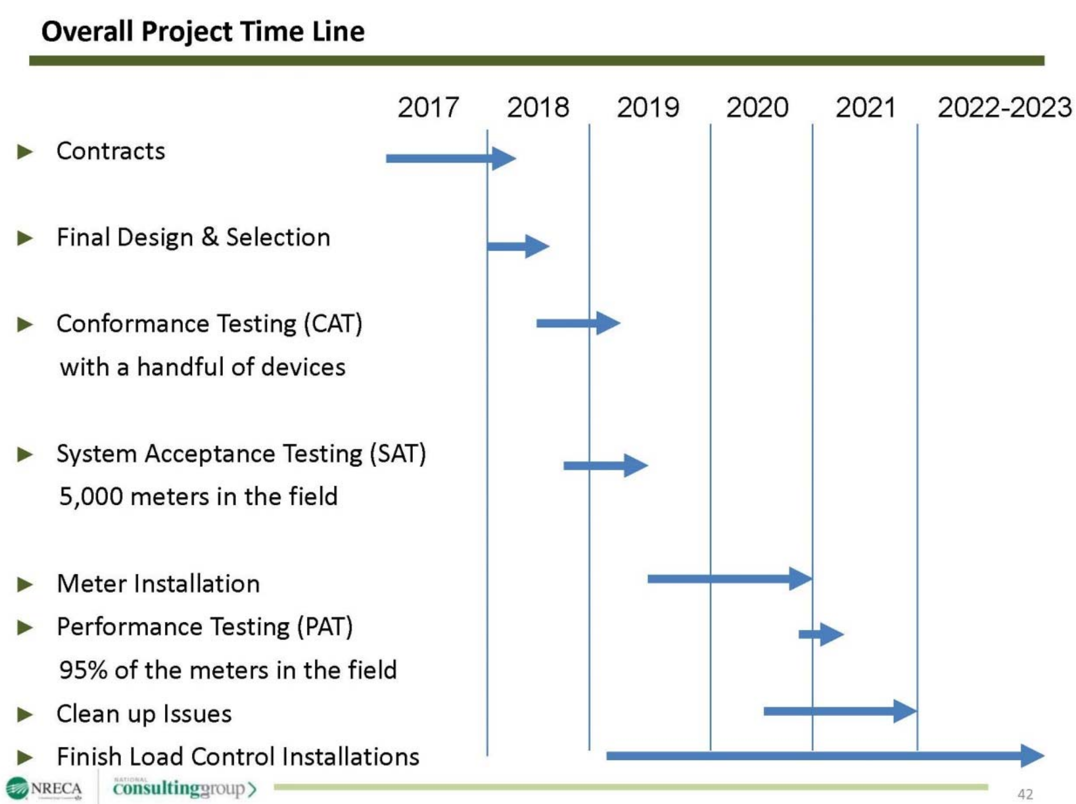
CIS Replacement Project – In 2014, the CIS replacement project was initiated. The existing CIS was well over 15 years old and was no longer supported by the vendor. The existing CIS is expected to be cut over to the new CIS in early 2018. The rest of 2018 will be used to stabilize the CIS and work out any issues with the program.

9 - 2017 AGi Business Case

The business case included in this report is the 2017 update of the 2013 and 2016 business cases. Also included within this latest business case is additional information gathered from vendor presentations and from visits to other utilities which have implemented AMI.

The 2017 business case covers a period of 15 years.. The first (1) year of the business case assumes no benefit from the AGi technology would be realized, as that time would include the installation of the AMI metering and some of the load control receivers. The business case has a ramping up of benefits over the first couple of years following the first year of meter installation. Dakota Electric wants to ensure that a project of this magnitude will provide the benefits for our members as forecasted within the business case, so the team has taken a conservative approach.

The installation of the AGi system would include a pilot application (SAT) of about 5,000 meters and 500 load control devices. The pilot would involve a 3-4 months installation phase, followed by 5-6 months testing and shake down of the system. It is important that we have sufficient numbers of meters installed to stress the communication system, and enough time to fully test the functions of the system before a complete installation. Upon completing successful testing of the pilot AGi system, the complete roll out of the remaining AMI meters and LCRs would begin.



The business case comprises the installation of an Advanced Metering Infrastructure (AMI) system including all new meters and a communication network to support two way communication to the meters and other devices; a Meter Data Management software (MDM) which provides storage, retrieval, reporting, and analysis of the meter and sensor data collected by the AMI system, and the replacement of the existing load management system (LM) including all the load control receivers at members' homes and businesses. The Load Management system is expected to utilize the AMI communication network and will be integrated with the rest of the Advanced Grid Systems.

Business Case Assumptions

The following are the key business case assumptions:

- Wage inflation is included at 3%.
- System is financed with 15-year loans at 3.73% interest.
- Dakota Electric labor overhead costs are included at 50%.
- Sales tax of 7.125% is included for the purchase of the system.
- System hardware, including meter and LCRs are depreciate over 15 years.
- Computer Hardware and software are depreciated over 4 years.
- Business Case includes $1,000,000 for contingencies.
- $1,021,000 is included for internal project management, contractors and integration.
- All residential meters include a remote controlled internal on/off switch.
- An annual equipment failure rate of 0.5% is used for the meters.

9 A – AGi Benefits

The following is a summary of the benefits included in the 2017 business case:

Reduction in Meter Reading Costs

With AGi technologies implemented, there will not be the cost to send out employees to read the meters each month. So, their labor, tools, software, hardware, and vehicle expenses will no longer be incurred.

Reason		**Annual Cost Reduction**	**Total Project Cost Reduction**
Eliminate Contractor Meter Readers (1) (2)	~ 450,000 reads per year	$172,500	
Eliminate the costs for supporting the MV90, MVRS, Itron Handhelds and the Command Center. (3)		$56,000	
Eliminate 6 meter readers (1)(2)(4)		$726,454	$17,900,000
Less Meter Reader Retention (4)			-($500,000)
Total for the Business Case			**$17,400,000**

(1) The number of meters to be read will continue to grow by 1% per year.
(2) Includes labor cost increases.
(3) Includes annual costs for vehicles for meter readers ($89,040) and annual costs for Itron metering handhelds and computer system ($51,100). The costs included in this section are:
    a. Software costs for supporting MV90 and MVRS Software.
    b. Hardware maintenance costs for Itron handhelds.
    c. Cost to send out postcards to confirm Turtle AMR readings.
    d. Cost for parts to maintain Turtle System.
(4) The meter reading positions will not all be eliminated on day one of the project. The following chart shows the staged retention of the meter readers. The meter reading benefits were reduced by $530,105 for the retention of meter readers per this table.

	Year 1	Year 2	Year 3	Year 4-12
Meter Readers	8	4	3	2

Member Service Cost Savings

With the implementation of AGi technologies, there are several areas where Dakota Electric's internal cost for coordinating the billing and support for the member will be reduced. The AGi implementation will create efficiencies within Dakota Electric.

Reason	Number of Trips per month (1)	Typical Cost per trip	Total Project Cost Reduction
After-hour support for disconnect/ reconnects (2)	1	$162	
Number of unnecessary outage visits per month (3)	10	$110	
Visits due to meter problems (stuck meter or miss-typed reading etc.) (4)	138	$38	
Delinquent reconnect visits (2)	95	$41	
Transfer read out trips (5)	1,183	$12	
Reconnect readings	48	$37	
Disconnect meter readings (2)	24	$37	
Voltage recorder installations (6)	4	$84	
Total for the Business Case			**$6,400,000**

(1) These numbers are based upon 2015 actual service orders.
(2) Reconnecting Meters – Through the use of the remote on/off switch within an AMI meter, we could remotely reconnect a member eliminating the labor and vehicle expense of traveling to the member's location.
(3) Unnecessary Outage Trips – Dakota Electric crews experience times when they are sent to the member's home only to find the problem is on the member's equipment. With AMI, many of these trips and their associated costs can be eliminated by using the ability to read the voltage from the meter and see if they have electrical service or not.
(4) Meter Problems – Reduce the need to drive to a meter to deal with non-functioning meters due to the installation of new meters.
(5) Customer Service – Transfers – The AGi project would eliminate the Transfer Clerk position and their vehicle. With the implementation of AMI, we will no longer need to make special trips to read the member's meter when the house or business changes hands.
(6) Voltage Recorder Installations – With the installation of AMI meters, we will have the ability to get voltage readings from the meter along with high/low voltage alarms. So, when a member calls in to complain about power quality issues, we will quickly know if the problem is with our system or not. This will eliminate crew trips to install voltage recorders.

Reduction in Metering Losses

With the installation of all new meters, there will be metering accuracy improvements, and existing metering problems and energy diversion will be identified. Also, the new AMI meters will automatically report back to Dakota Electric when the meter is not working correctly, so metering problems will not persist in the field as they now can.

Reason		Annual Cost Reduction	Total Project Cost Reduction
Reduction in Meter Calibration and Testing (1)		$220,000	
Three Phase Meter Application Audit (2)		$200,000	
Reduction in Energy Diversion (3)	0.125%	$150,000	
Total for the Business Case (4)			**$9,900,000**

(1) With the new digital meters, the accuracy of the meters is better than the existing meters; also more energy will be metered, especially at light loads.
(2) As part of the installation of the new AMI meters, auditing of the fleet of existing metering PTs and CTs is completed and very often there are errors identified. Also, the new digital meters proposed to be installed can automatically detect and alarm if the CTs or PTs are missed wired or if any of the potential transformers fail.
(3) Utilities that implement AMI systems have consistently reduced system losses. Frequently, most utilities have experienced a significant reduction in energy diversion losses. This business case is taking a conservative 0.125% reduction in diversion.
(4) Total includes additional meters and accumulated benefits from identifying future metering issues. Annual Cost is the estimated amount for the first year.

Meter Revenue Finance Cost Savings

With the new AMI meters accurately reporting back their usage each day, Dakota Electric will be able to advance revenue collection of energy usage due to faster and more accurate collection and processing of metering information.

Reason	Annual Cost Reduction	Total Project Cost Reduction
Advance revenue Collection of Energy (1)	$19,000	
Total for the Business Case (2)		**$300,000**

(1) It is estimated that Dakota Electric will be able to advance revenue collection of energy usage by 10 days. This is the estimated initial annual amount.
(2) Annual Cost is the estimated amount for the first year.

Operations Costs Savings

There are several operational improvements which occur with the implementation of the AGi technologies. The first is a reduction in field crew over time, as they are more efficient during outages because of additional information and are less likely to be dispatched to a member location for problems which occur on the member's side of the meter.

The AGi system also allows Dakota Electric to better implement conservation voltage reduction during system peaks and reduce peak demand power costs. The AMI system provides voltage readings from each feeder which allows Dakota Electric to reduce the system voltage over system peak. A reduction in system voltage will result in an overall reduction in system demand. This is the expected power cost savings from implementing a conservative voltage reduction (CVR) during system peaks to reduce the demand charge from our power supplier. If Dakota Electric would want to implement peak demand reduction today without AMI, we would need to install expensive real-time voltage sensors on each of the phases of each circuit. Bellwether AMI meters can provide these near-real-time voltage readings using the AMI communication network.

Based upon work done by EPRI, in their Green Circuits Collaborative Project, published in 2011 (Green Circuit Distribution Efficiency Case Studies #1023518), "the percent change in load for a 1% change in voltage generally ranges from 0.6 to 0.8" In the studies, the voltage on the circuits was normally able to be reduced 2% to 4%; so assuming the typical Dakota Electric feeder voltage could be reduced only 2%, and a 0.7% load reduction factor would result in a conservative 1.4% demand reduction on a typical Dakota Electric circuit. EPRI has also reported that not all circuits are candidates for CVR and the benefits of CVR change between the seasons. CVR during the summer provides the greatest benefits. So, for the business case we have further reduced the expected benefit to only being able to achieve 20% of the conservative 1.4% peak demand reduction.

Voltage Reduction Benefits (over peak) Benefit Formula

*1.4% / kW * Coincident kW @ Great River Energy Peak (408MW) * 0.2 (reduction) * 12 months * $18.02/MW average monthly kW charge*

In addition, there are system capital and energy savings from improved engineering design, resulting from the additional information provided by the AGi system. One example of how the AMI data would help reduce losses is using the AMI data to right size the distribution transformer to the load rather than oversizing the transformers. Currently, we are sizing the transformer based upon a single energy reading each month. From this reading the engineer must estimate the coincident peak demand of each of the loads. Because of this limited data, a larger transformer then what would be necessary with accurate data may be installed. Through this and other planning benefits, it is conservatively estimated that an annual loss savings of 0.1% would be achieved using the AMI data.

Reason		Annual Cost Reduction	
Overtime savings		$84,000	
Savings from Voltage Reduction		$256,000	
Loss savings from right size transformers, better designed system, better balanced loads, improved data for engineering	-0.1% lower losses	$90,000	
Total for the Business Case (1)			**$7,500,000**

(1) Since it will take time to install the meters and utilize the data, the loss reduction benefit is not included in the business case till year four (4). (Two (2) years of deployment are assumed, plus two (2) more years for the design benefits to take effect.)

Metering Cost Benefits

The problems Dakota Electric is experiencing with the existing older meters, such as stuck meters and other meter failures will be greatly reduced with the installation of all new AMI meters,. As a result, there will be fewer costs to replace metering and less crew field trips.

Reason	Annual Cost Reduction (year 2)	
Reduction in annual meter retirements	$390,000	
Total for the Business Case (1)		**$6,700,000**

(1) Total includes additional growth in meters and accumulated benefits from avoided future metering issues. Annual Cost is the estimated amount for the first year.

Benefits from Improved Load Control

By installing a new load management system with new load control receivers at each of the member's homes or business, Dakota Electric will ensure that all LCRs are working. With an estimated 20% of the existing load control receivers believed to not be interrupting the load when requested, it is calculated that around $1,000,000 annually in unrealized power cost savings are not being captured.

In addition, with all new LCR technologies, Dakota Electric believes that we can achieved improved load control using "True-Cycle" or similar methods which ensure obtaining control benefits even from oversized AC units.

Reason		**Annual Cost Benefit**	**Total Business Case Benefit**
Reduction in non-working Load Control receivers (1) (2)	20% non-working	$1,000,000	
Improvement for AC control by using True-Cycle or similar method (3)		$500,000	
Total for the Business Case			**$24,400,000**

(1) Based upon a survey of 480 LCRs in 2013, 20% of the LCRs are estimated to not be interrupting the load when requested. For the total business case benefits, the improved load control does not start until year four (4) of the business case to allow time for the replacement of the non-working LCRs.

(2) The number of non-working LCRs is expected to continue to increase at 1% per year, so the annual benefits are also increased at 1% annually. The total benefits include the elimination of this increasing failure rate.

(3) With a new load control system, the ability to implement greater control over individual loads and to assess the impact on the load to more evenly distribute the control, will enable Dakota Electric to achieve a greater benefit from the existing loads under control. Vendors have seen a 20-30% increase in load control benefits. For this business case, a conservative 10% improvement in load control benefits has been estimated.

(4) Total assumes it will take a couple of years to fix the non-working LCRs and start obtaining the benefits. Benefits have been phased in over 4-5 years

Summary of total expected Benefits of implementing AGi technology

Expected BENEFITS With AGi Implementation (2018-2033)	
Reason	**Benefits with AGi**
Reduction in Meter Reading Costs	$17,400,000
Member Service Savings	$6,400,000
Reduction in Meter Losses	$9,900,000
Meter Revenue Finance Cost Savings	$300,000
Operational Cost Savings	$7,500,000
Meter Capital Costs Savings	$6,700,000
Load Control Power Cost Savings	$24,400,000
Total AGi Business Case Benefits	**$72,600,000**

9 B – AGi Hard Benefits not included in the Business Case

There are several benefits which have hard dollars associate with them that many utilities we visited with included in their business case. Each of these areas is future looking and thus we are not presently spending dollars on these issues. It is reasonable to assume we will need to spend capital dollars on these areas before 2033, but the timing and amount is not firmly known. As such these benefits have not been included in the Dakota Electric business case.

Elimination of existing AMR system

As discussed above, the existing AMR system used to read 5,500 of the meters is no longer supported or manufactured. At some point Dakota Electric will need to replace this system. The following is the expected cost of operation of the existing system and the cost of replacement. With the installation of AGi technology, these costs would be avoided.

Reason		Annual Cost	Project Cost Reduction
Cost to support the Turtle AMR Software and the field hardware	463 field trips in 2015 by Meter Techs	$64,000	$192,000 (First 3 years)
Cost to replace existing Turtle Meters with ERT meters (1)	Occurs in Year 3		$335,000
Annual cost to read the new meters		$66,000	$792,000 (12 years)
Total Expected Benefit			**$1,319,000**

(1) Assumes that by 2020 the Turtle system is no longer reliable and the meters must be replaced and manually read.

Feeder Monitoring

With the expected DER installations, especially solar and the two-way flow of energy on the distribution system, there will be a need to install downline feeder voltage monitoring. At this time, it is unknown the magnitude of the solar penetration and the number of voltage monitoring which will be required., It is clear, however, that downline feeder voltage monitoring will be required at some point before 2030. The assumption here is that each phase on each feeder will need only one voltage monitor, and that cellular communication will be used to gather the information from each of the voltage monitoring. Clearly, this is a very conservative estimate as we will not know the best location for these sensors and may need several sensors on some feeders and perhaps none on other feeders.

The cost of a voltage monitor and labor to install it is estimated at $1500 each. This cost could range from $1,000 to $2,500 per device depending upon features. There are about 175 feeders (175 * three phase = 525 units). The initial cost is estimated at $787,500. The communication cost in 2017 would be about $10/unit per month depending upon the data used, but with cellular costs dropping and the quantity that we are considering, we are conservatively estimating $5/unit/month or $34,500 per year.

Reason	Annual Costs	Capital Costs	
Eliminate the need for Feeder Voltage Monitoring System	$31,500 (Years 4-15)	$787,000	
Total Expected Benefit			**$1,165,000**

Special Metering for Interconnecting DER (Solar) System

Each time a member interconnects with Dakota Electric, the existing meter is replaced with a bi-directional meter. This cost is about $200 per installation for the smaller solar meters. Depending upon the growth in solar, this cost will add up. The above estimate is assuming 3% of our members add solar to their service by 2030.

Reason	Cost	Number	
Bi-directional metering for Solar Installations	$200 each	3,155 over 12 years	
Total Expected Benefit			**$770,000**

9 C - Additional Direct Member Benefits Not included in the Business Case

Not included in the business case benefits are the following additional direct benefits the member's will see. These were not included in the business case, as they are not offsetting expenses realized by Dakota Electric. Since the members will see these benefits, however, they need to be considered in the decision for going forward with the AGi project.

A) <u>Cellular phone charges for Rate 70 and 71</u> - Members are presently charged a monthly cost for cellular communication to the meter. AMI would eliminate this cost for our members.

B) <u>Cellular phone charges for DER (solar) installations larger than 40kW</u> - The members are charged a monthly cost for cellular communication to the main meter and for greater than 60kW to the production meter. This is required to retrieve the 15-minute interval data used to calculate the billing by Great River Energy and Dakota Electric. The production meter is used to calculate the standby rates. AMI would eliminate the need for the cellular communication as the AMI communication would provide the 15-minute interval data back to Dakota Electric as part of the normal AMI metering. Few members are presently paying this rate, but as more of these larger solar installations are interconnected with the system, this number will grow.

C) <u>Additional metering costs for the DER (solar) installation</u> - The member is required to pay for the additional cost of the special meter and the cellular card within the meter. Dakota Electric pays for the first $250 of the meter cost and the member installing the solar system pays the additional $950. For larger solar installations, the member's cost is doubled due to the need for the production meter. The installation of AMI will eliminate the need for cellular communication as standard AMI metering can be used.

9 D - Soft Benefits of the AGi Project

Thus far, the business case includes the dollars for the hard benefits in the analysis, except for those listed in section 9B. The team has learned from talking with other utilities, however, that the soft benefits are by far the driving force behind implementing AGi. The following is a short discussion on many of the soft benefits the team has learned about during the visits with the other utilities.

Environmental Benefits
The installation of AMI would greatly reduce the number of miles driven by Dakota Electric for monthly meter reading. No longer would the meter readers be driving out to read each meter every month. No longer would the transfer clerk be driving out to the meter to do a final read when a member moves out of a property. The ability to remotely read the meter and get the voltage reading would eliminate crew travel to the site for electrical outages on the member's side of the meter greatly reducing crew travel for power quality investigations.

Historically, each meter reader vehicle averages around 15,000 miles per year. By eliminating 6 meter readers and one transfer clerk, we expect to drive around 105,000 fewer miles per year. If we assume 25 miles per gallon, this will result in saving 4,200 gallons of fuel. This does not even include fewer miles driven by other field crews to service the meters or from improved outage response.

Safety
The safety of our employees will be improved through the reduction of miles traveled, the reduction of the number of times we need to enter the member's property to read the meter, and the reduction in the number of times we need to pull the meter from the meter socket. AMI will greatly reduce the need for Dakota Electric personnel to enter the member's property and thus reduce the potential for issues.

Improved Service
The AMI meter will automatically report most outages to the Dakota Electric System Control Center, even when the member is on vacation.

With the Dakota Electric Member Service Representatives and the Control Center personal having extensive metering data from the AMI system at their fingertips, they will be better able to answer the member's questions on the first call.

Member Knowledge
With ability to view AGi data via the web, the member will have 24/7 access to the information. The AMI and MDM system will provide 15-minute interval data to each member. The member can use this information to learn how they are using energy and then identify ways to reduce this usage. Businesses will especially be able to utilize the interval energy data to help them manage their business.

Through the AGi web portal, the member can compare their usage to past years, business owners can compare usage between different stores, or Cities or Schools can compare similar facilities electrical usage. Some systems have alarm thresholds which can be set by the member to alert them, via a text or email, if their usage goes over a specified level for a given billing cycle.

Responsiveness
When a member is experiencing an electrical problem, the member must wait for Dakota Electric to drive out to the site and start the investigation. Many times, the issue is caused by member owned equipment on their side of the meter. With AMI, Dakota Electric will often be able to quickly tell the member, over the phone, that they need to get an electrician. This will allow the member to skip the time waiting for Dakota Electric to get on site.

A second area where the implementation of AMI will make Dakota Electric more responsive is with power quality issues. Presently, the member must call and complain of a problem with their service for Dakota Electric to know there is a problem. This then starts the process of identifying and resolving the issue. In many cases with AMI, Dakota Electric will automatically get the information from the AMI meter. This will allow Dakota Electric to identify that there is an issue before the member has to call, and in some cases, be able to fix the problem before the member is aware!

A good example of this is when we have a failing transformer. Currently, the member will report either high or low voltage. We will respond by sending crews to take voltage readings, and, if necessary, replace the transformer. Unfortunately, this means that the member could have already experienced equipment damage before they called Dakota Electric. With AMI, we would get an over or under voltage alarm from the meter and then dispatch a crew. They would be at the member's site replacing the transformer, typically before the member knows there is a problem.

Member Privacy
With the implementation of AMI, Dakota Electric will not need to be walking across the member's yard each month. While we will still need to periodically inspect our facilities on the member's property and have emergency access to the meter, we will be able to greatly reduce the times we are on the member's property.

Flexibility
The AGi project would provide more flexibility for our members. Allowing the member to choose their monthly billing date would become a possibility as individual meters are no longer tied to a meter reading route. New rates and rate options could be more easily implemented. With 15-minute interval data coming back into the MDM system for all the meters, new rates would not require special metering, but rather a configuration or programing change within the system.

Efficiency
The AGi system has a cost to implement the technology and initially this will affect the member's rates. But with the automation and flexibility provided by the AGi, the cost of operation for Dakota Electric will be reduced over the long term and thus will help keep future rate increases

lower. In talking with other utilities who have implemented AMI, they have reported a significant reduction in member issues with billing as the result of less estimated bills, less meter reading data entry errors and the availability of improved member information. Initially there are no planned employee reductions within the business case for this, but if the AGi project results in less labor requirements, Dakota Electric can look at eliminating some positions through attrition or as new members are added, defer adding additional personnel.

9 E – AGi System Costs

AGi Project System Capital Costs

The costs for the project include all new meters and all new Load Control Receivers and the cost of installation.

Item	
Cost for Communication Infrastructure	**$2,100,000**
AMI 1-PH Meters (1)	$16,600,000
1-PH Meter Install	$2,000,000
AMI 3-Phase Meters	$1,300,000
AMI 3-PH Meter Installation (2)	$300,000
Cost for Meters	**$20,200,000**
LM Receivers	$8,900,000
LM Receiver Installation (includes permit fee) (2)	$4,500,000
Cost for LM Receivers	**$13,400,000**
Project Management & Delivery	$3,900,000
Total Capital Costs	**$39,600,000**

(1) Includes cost of a disconnect in every single phase 2S meter.
(2) Installation costs are inflated each year during the 15-year business case.

Expenses to Maintain the System

Once the system is purchased, there will be costs with maintaining the system. These include the annual fees from the vendors, costs to utilize cellular communication for hard to reach meters, training costs for employees, and costs to repair failed meters and equipment. There is also the interest cost to finance the project over the 15-year term of the loan.

Item	Total
AMI & MDM Vendor Fees (1)	$14,800,000
Communication Backhaul (2)	$500,000
Training Costs	$300,000
AMI Meter Repairs (3)	$1,200,000
Total System Expenses	**$16,800,000**
System Management (personal) (4)	$9,000,000
Project Interest Expense	$11,800,000
Total Operating Expense	**$20,800,000**

(1) Annual support fees for the software license.

(2) There will be some areas where our existing backhaul communication will not easily communicate to, so cellular or other form of communication will need to be utilized which has a monthly fee.

(3) The business case has costs for meter and communication failures and repairs estimated to start at year three (3) of the project and increasing as the meters age.

(4) Project Labor Costs
The Business Case assumes that seven (7) existing positions at Dakota Electric will be eliminated. Six (6) are meter readers and one is the transfer clerk. These will be eliminated over the first four (4) years of the project as the new AGi technology is implemented. The business case also assumes the addition of four (4) new positions. These are all assumed to be filled in the first year of the project.

Assumptions
- Existing employees are providing back-up support for these new positions.
- The hardware/software administration of the MDM system is provided by existing Dakota Electric employees.
- Many Dakota Electric employees existing work load will be reduced due to the efficiencies created with the AGi system. These existing positions will have some of the additional work load created by the new AGi system assigned to them.

<u>New Positions required with implementation of the AGi systems</u>

- <u>AMI/LM System Administrator</u> (A medium level position that does not need to be an analyst or engineer. This is a full-time position that would start early in the project. This could be sourced from within, dependent on skill set and availability.)
  - Serves as the overall owner of the AMI system
  - Operates the AMI and LM systems
  - Monitors daily the systems for operational issues
  - Creates work orders to fix failed/problem meters, communications systems, and LCRs reporting as failed
  - Establishes standards and procedures for AMI system maintenance and operation
  - Serves as the overall owner of the LM System
  - Operates the LM system
  - Coordinates internally on the LM operation
  - Works with Great River Energy and internally to manage the LM system.
  - Provides 24hr support for both systems.

- Data Analyst (AMI/LM/MDM/GIS) (A higher level position that requires, understanding database structures and SQL languages, etc. This position would be hired early in the project to get up to speed on the systems. With the GIS, there is a present need to have a Data Analyst so their initial work could be with the existing GIS and CityWorks systems.)
  - Understands databases
  - Owns and operates the MDM system and is the key MDM user
  - Provides data analytical support for all departments
  - Writes reports as requested using MDM, GIS, CIS databases
  - Supports the web presentment data from the MDM to the CIS
  - Provides training on using the systems to others
  - Needs to be clearly separate from the IT software & hardware support positions and not affected by IT support duties

- IT Analyst (AMI/LM/MDM/GIS/CIS) (Higher level position)
  - <u>Wait to hire</u> this position until we see how much work is required. Only fill this position unless internal staff is not able to absorb this additional work. This also depends upon database systems like Oracle and the support needs required with that software. We may look at outside service agreements to fill some of this need.
  - Support the hardware and coordinate the software upgrades. The GIS system could be part of this support role.
  - Provides support of the software and the hardware behind the systems

  - Installs application patches from vendors and keeps the systems updated and running
  - Provides 24 / 7 support for the systems

- Field Tech – one additional
  - After visiting the utilities, this appears to be a key needed position. The amount of work and number of pieces of field equipment to maintain/support depends upon the AMI system chosen. One of the concerns is the additional work required to update the firmware and maintain the 120,000 meters, 52,000 LCRs and the 1,000 collectors and repeaters.
  - When to hire this position will depend upon the system chosen
  - Test firmware updates
  - Apply firmware updates to meters, collectors, repeaters, etc.
  - Help RMA failed equipment
  - Maintain collectors and repeaters, routinly

Converted Positions

- Field Inspectors
  - Convert two (2) meter reader positions to inspectors
  - Inspect the entire distribution system for issues on a periodic basis. Since we are not sending meter readers out to the homes, we need to inspect the meters about every 2 years. These inspectors would examine the meters and other Dakota Electric distribution assets. Training would have to be developed and provided.
  - Two inspectors would each need to visit 100 services per day in order to visit all locations on a two-year cycle.

<u>Positions Eliminated</u>

- 6 staff meter readers
- Transfer Field Representative Coordinator Position (Transfer Clerk)

Summary of total expected Cost of implementing AGi technology

Summary of Total Expected COST of AGi Technology (2018-2033)	
Reason	**Costs**
AMI & MDM system (Meters and Database)	$37,000,000
LM System (New LCRs)	$13,400,000
Communication Infrastructure	$2,100,000
Project Delivery	$3,900,000
New Positions Created	$9,000,000
Project Interest Expense	$11,800,000
Total AGi Costs	**$77,200,000**

10 - Summary

The AGi team recommends the implementation of AMI and MDM and the replacement of the existing Load Management system at Dakota Electric, as an essential building block and platform to support the future needs of Dakota Electric. The team is recommending that implementation of the AGi system would best benefit the members of Dakota Electric and be in their long-term interest vs. a decision to maintain the status quo.

This report shows that the cost to implement Advanced Grid Technology is similar to the cost of continuing to operate in the same way Dakota Electric has been operating. There are similar risks associated with going in either direction, and delaying the decision is not an option as we need to replace the existing load management system.

The $77 million-dollar cost of the project includes $13.4 million dollars for replacing the existing load control switches and over $20 million dollars for replacing all meters on the system. The estimated $72.6 million dollars in benefits does not include all benefits which other Cooperatives reported to us during our visits. The team instead took a conservative approach with the benefits. Benefits such as a reduction in bad debt, eliminating the costs for replacing the existing rural meter reading system, or the potential costs resulting from the integration of DER including solar generation metering and monitoring, were not included in the project's 15-year business case.

So, the overall cost of the AGi system is similar to the expected benefits. When a group of Dakota Electric members were surveyed, nearly 60% of the members said they would pay up to $1 per month more for Dakota Electric to install Advanced Metering Infrastructure (AMI). Dakota Electric's members trust Dakota Electric to invest their money wisely and to deliver their electricity.

Dakota Electric has a choice to invest now in new technology, which over the systems lifetime will provide operational savings and new capabilities, or spend those same dollars maintaining and replacing existing systems that utilize old technology. The team has found that two of our key systems, Load Management and the Turtle AMR system have reached the end of their useful life and must be replaced. The team believes that due to the condition of the existing systems and the lengthy time it will take to install the AGi technology, Dakota Electric must move forward quickly with the AGi project. At this point, a decision to not decide will be a decision for the status quo and the associated costs.

This is a major decision for Dakota Electric, but as the AGi team has found during our visits with other Cooperatives, the ability to implement this technology is proven and the benefits received are significant. For the AGi team, it is clearly the soft benefits which made the decision to recommend going forward with the implementation of AGi technology.

As shown in this report, there are many changes coming in the next decade. The interconnection of DER to the distribution system is just one of the many changes impacting

Dakota Electric. It is clear, that without AGi technologies there will be significant costs to monitor and operate the distribution system due to the interconnection of DER systems. With AGi technologies, Dakota Electric will have a greater ability to monitor and react to these changes.

It is also clear the $13 million dollars to replace the load management system is beneficial and needs to be done regardless of the decision to implement AMI and MDM systems. It just makes sense to leverage the same communication network for both AMI and LM, and leverage the power of the AMI data and the MDM system to identify the LM receivers which are not interrupting loads. Installing and operating these systems together reduces implementation costs and provides benefits greater than if they were installed separately.

The AGi team believes that Dakota Electric must begin preparing the business for a future state that integrates many technologies not present today. These future technologies will require a more advanced state of monitoring, communication and control. The system wide communication network provided by the installation of AMI will support future operational monitoring. This will be required to support the operation of the system with the installation of renewables, such as solar. Together the AGi systems will provide options for Dakota Electric to provide increased service levels and meet the future needs and wants of our members. The Advanced Grid Infrastructure technology will also provide the foundation and flexibility for Dakota Electric to respond to future issues as they arise.

This business case is conservative and the team believes that benefits greater than those outlined can be realized. The AGi team recommends proceeding with the project and the implementation of this new technology to help our members. The project includes: the installation of a communication network which will be utilized by both AMI and LM; all new AMI meters and new load management receivers which both include two-way communication capabilities and 15-minute interval data reporting; a Meter Data Management system which is a data repository, with an analytics engine and reporting tools; the development and installation of a web portal for our members to have access to their data to allow them to make decisions about their electrical usage.

January 12, 2015

Dan Wolf, Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101-2147

Subject: Dakota Electric Association
Electric Vehicles and Minnesota Statute 216B.1614

Dear Mr. Wolf:

Dakota Electric Association (Dakota Electric or Cooperative) is sending this letter for two purposes. First, Minnesota Statute 216B.1614 requires public utilities to file a tariff for electric vehicles (EV) by February 1, 2015. This letter will show that, while Dakota Electric's existing electric vehicle tariffs are consistent with the provisions of this statute, the statute does not apply to Dakota Electric as an electric distribution cooperative. Second, we will provide an update on electric vehicle participation in Dakota Electric EV tariffs.

Minnesota Statute 216B.1614

Minnesota Statute 216B.1614 requires that, by February 1, 2015, "each public utility selling electricity at retail must file with the commission a tariff that allows a customer to purchase electricity solely for the purpose of recharging an electric vehicle." The definitions in this statute specify that a "public utility" has the meaning given in section 216B.02, subdivision 4. Minnesota Statute 216B.02, subdivision 4 reads in part:

> "Public utility" means persons, corporations, or other legal entities, their lessees, trustees, and receivers, now or hereafter operating, maintaining, or controlling in this state equipment or facilities for furnishing at retail natural, manufactured, or mixed gas or electric service to or for the public or engaged in the production and

> retail sale thereof ***but does not include*** (1) a municipality or ***a cooperative electric association***, organized under the provisions of chapter 308A, producing or furnishing natural, manufactured, or mixed gas or electric service … (***emphasis added***)

Through this definition, Minnesota Statute 216B.1614 does not apply to an electric cooperative. Accordingly, as an electric distribution cooperative, Dakota Electric is not subject to the requirements of Minnesota Statute 216B.1614.

While not subject to the requirements of Minnesota Statute 216B.1614, Dakota Electric's time-of-use residential electric vehicle tariff approved by the Commission in Docket No. E-111/M-12-874 is consistent with the requirements of this statute. Minnesota Statute 216B.1614 requires that an electric vehicle tariff must:

- contain either a time-of-day or off-peak rate, as elected by the public utility,
- offer a customer the option to purchase electricity:
  - from the utility's current mix of energy supply sources; or
  - entirely from renewable energy sources, and
- be made available to the residential customer class.

Dakota Electric offers two rate options for electric vehicles in addition to standard firm residential service. The EV-1 residential electric vehicle tariff approved by the Commission in Docket No. E-111/M-12-874 includes time-of-use pricing that includes off-peak, intermediate, and on-peak periods. Dakota Electric members may also charge an electric vehicle on the Cooperative's energy storage rate. This tariff allows consumers to charge vehicles between the hours of 11 pm and 7 am. Consumers with electric vehicles may receive service from the utility's current resource mix or participate in the Cooperative's Wellspring renewable energy program and obtain a portion or all of the electricity for the electric vehicle from renewable resources. Finally, Dakota Electric's electric vehicle tariffs are available to residential consumers.

Regarding cost recovery and rate design, Minnesota Statute 216B.1614 requires that an electric vehicle tariff must:

- appropriately reflect off-peak versus peak cost differences in the rate charged,
- include a mechanism to allow the recovery of costs reasonably necessary to comply with this section,

- provide for clear and transparent customer billing statements including, but not limited to, the amount of energy consumed under the tariff, and
- incorporate the cost of metering or submetering within the rate charged to the customer.

The rates charged under both of Dakota Electric's electric vehicle tariffs are based on a cost analysis that reflects differences in the cost of providing service during different times. Billing statements have separate line items for consumption on respective rate offerings. Metering costs are incorporated into the energy charges for each service.

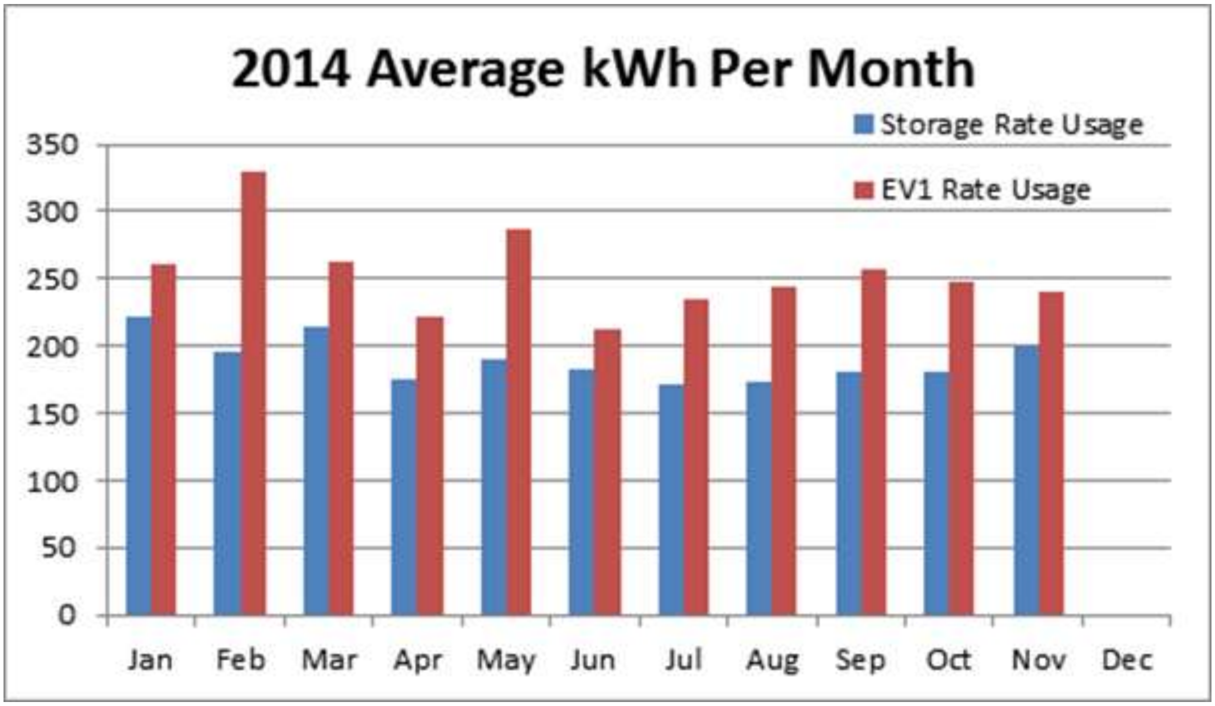
Dakota Electric's electric vehicle tariffs approved by the Commission are consistent with the requirements of Minnesota Statute 216B.1614.

Electric Vehicles Served by Dakota Electric

Since Dakota Electric is submitting this letter regarding electric vehicles, we thought the Commission may be interested in information on the most recent participation in Dakota Electric's EV tariffs.

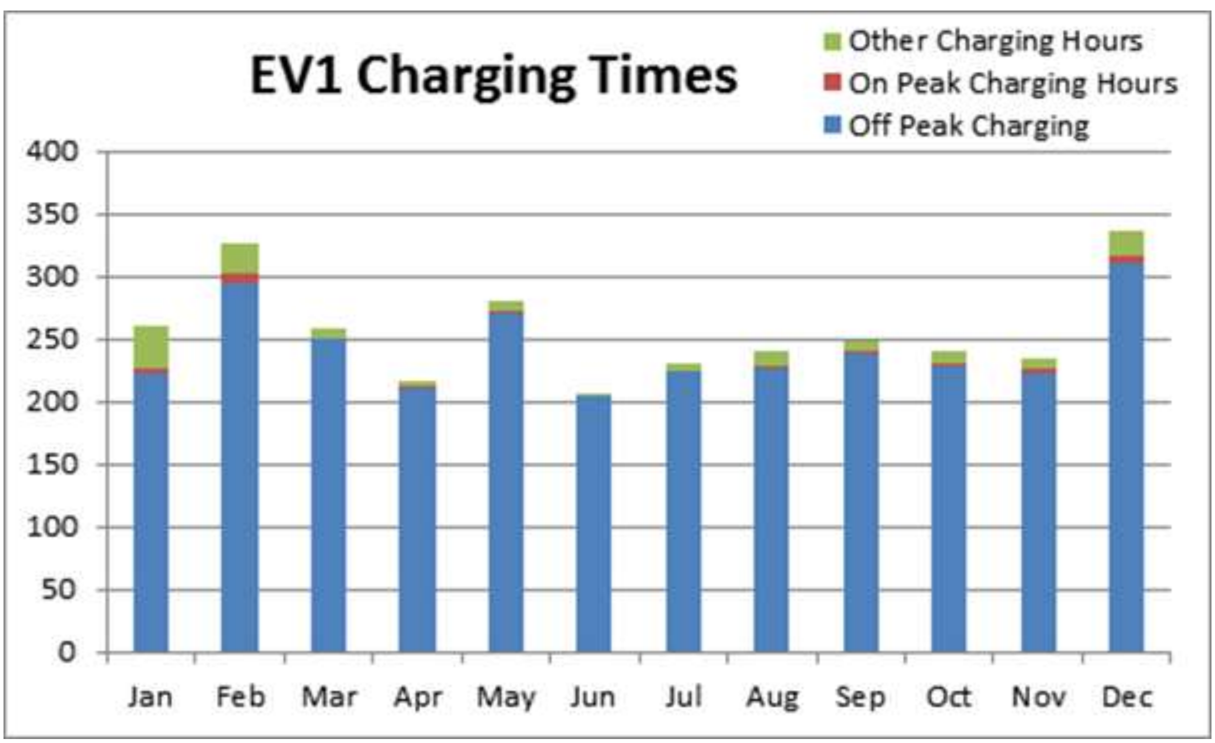
When Dakota Electric submitted our petition for approval of a new time-of-use residential electric vehicle rate in August 2012, we were aware of 7 electric vehicles receiving service from the Cooperative. As of December 2014, the Cooperative is providing service to 44 electric vehicles, with 19 on the EV-1 rate (the time-of-use rate) and 25 on the Storage Rate 51.

The average monthly usage for members on the EV-1 Rate is 254 kWh per month or 8.5 kWh per day, while members on the Storage Rate 51 use 193 kWh per month or 6.4 kWh per day. There also appears to be a seasonal difference between summer and winter charging levels for all vehicles as shown in the following table.



The profile of EV-1 energy consumption by rate schedule time period is as follows:

94%	Off-Peak (9:00 pm to 8:00 am Mon. – Fri., and all day Weekends and Holidays)
1%	On-Peak (4:00 pm to 9:00 pm Mon. – Fri., excluding Holidays)
5%	Other (8:00 am to 4:00 pm Mon. – Fri., excluding Holidays)



Dakota Electric continues to be pleased with these consumption results. The purpose of the EV-1 rate schedule was to provide a flexible alternative for charging electric vehicles that would encourage off-peak charging without mandatory load control. Off-peak energy use now accounts for 94 percent of energy consumption on this rate schedule. On-peak energy use continues to be minimal at about one percent.

Conclusion

If you have any questions about the information provided above, please call me at (651) 463-6258.

Sincerely,

Douglas R. Larson

Vice President of Regulatory Services
Dakota Electric Association
4300 220th Street West
Farmington, MN 55024

Dakota Electric Association

Response to

Minnesota Department of Commerce

Utility Information Request

Docket Number:	***E-111/M-17-821***
Request Number:	***1***
Requested By:	***Stephen Collins***
Date of Request:	***December 4, 2017***
Response Prepared By:	***Doug Larson*** ***Dakota Electric Association*** ***651-463-6258***
Date of Response:	***December 13, 2017***

Question 1

(a) Please provide the full business case report referred to on page 15 of the petition.

(b) Please provide all spreadsheets used for the information in the petition and full business case report.

Answer

(a) Dakota Electric's "Advanced Grid Infrastructure Project (AGi) 2017 Business Case Report" was provided in response to OAG Information Request #002.
(b) Attached, as an Excel document, is the spreadsheet used in the development of the business case report as referenced in Dakota Electric's filing. **This is a trade secret document / non-public document that is not for public disclosure.** This spreadsheet was developed by a consultant for use by cooperatives for predicting financial impacts from AMI deployment. You may notice cells that are grayed in the spreadsheet. This "clutter" is left intact, but is not part of the output of the model.

Exhibit F in the filing includes the AGi Adjustment example calculations.

CERTIFICATE OF SERVICE

I, Sharon Ferguson, hereby certify that I have this day, served copies of the following document on the attached list of persons by electronic filing, certified mail, e-mail, or by depositing a true and correct copy thereof properly enveloped with postage paid in the United States Mail at St. Paul, Minnesota.

Minnesota Department of Commerce
Comments

Docket No. E111/M-17-821

Dated this 26th day of January 2018

/s/Sharon Ferguson

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1800 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_17-821_M-17-821
Ian	Dobson	ian.dobson@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012130	Paper Service	Yes	OFF_SL_17-821_M-17-821
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 280 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_17-821_M-17-821
Corey	Hintz	chintz@dakotaelectric.com	Dakota Electric Association	4300 220th Street Farmington, MN 550249583	Electronic Service	No	OFF_SL_17-821_M-17-821
Douglas	Larson	dlarson@dakotaelectric.com	Dakota Electric Association	4300 220th St W Farmington, MN 55024	Electronic Service	No	OFF_SL_17-821_M-17-821
Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 7th St E St. Paul, MN 55106	Electronic Service	No	OFF_SL_17-821_M-17-821
David	Moeller	dmoeller@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022093	Electronic Service	No	OFF_SL_17-821_M-17-821
Eric	Swanson	eswanson@winthrop.com	Winthrop & Weinstine	225 S 6th St Ste 3500 Capella Tower Minneapolis, MN 554024629	Electronic Service	No	OFF_SL_17-821_M-17-821
Daniel P	Wolf	dan.wolf@state.mn.us	Public Utilities Commission	121 7th Place East Suite 350 St. Paul, MN 551012147	Electronic Service	Yes	OFF_SL_17-821_M-17-821