February 5, 2018

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

Subject: ***Dakota Electric Association Reply Comments***
In the Matter of a Petition to Implement Tracker Recovery for Advanced Grid Infrastructure Investments
Docket No. E-111/M-17-821

Dear Mr. Wolf:

On November 20, 2017, Dakota Electric Association (Dakota Electric or Cooperative) submitted a petition requesting Minnesota Public Utilities Commission (Commission or MPUC) approval to implement tracker recovery for Advanced Grid Infrastructure (AGi) investments. The proposed tracker would provide recovery for distribution grid modernization and load management investments that occur between Cooperative general rate cases.

On December 13, 2017, the Office of the Attorney General – Residential Utilities and Antitrust Division requested an extension for filing Comments in this docket. On December 14, 2017, the Commission issued a *Notice of Extended Comment Period* (Notice) specifying that Comments must be filed in this docket by January 19, 2019, and Reply Comments must be filed by January 29, 2018.

On January 19, 2018, the Minnesota Department of Commerce requested a 7-day extension for filing Comments in this docket. On January 22, 2018, the Commission issued a *Notice of Extended Comment Period* (Notice) specifying that Comments must be filed in this docket by January 26, 2019, and Reply Comments must be filed by February 5, 2018.

Dakota Electric Reply Comments

Dakota Electric's Reply Comments will respond to comments and recommendations included in the January 19 Comments submitted by the Office of the Attorney General – Residential Utilities and Antitrust Division and the January 26 Comments submitted by the Minnesota Department of Commerce.

<u>Minnesota Office of the Attorney General</u>

The Minnesota Office of the Attorney General (OAG) summarized its analysis of Dakota Electric's petition on Page 6 of their January 19 Comments as follows:

> *The Commission will need to make several important decisions as it considers Dakota's request. As a threshold matter, the Commission must decide whether grid modernization costs can be recovered in a rider other than the TCR Rider. If these costs can only be recovered in a TCR Rider, then Dakota's request must be rejected. If, however, grid modernization costs can be recovered in another rider, then the Commission might be able to approve Dakota's request if Dakota has met the standards of the applicable rider.*

The OAG offered the following conclusion on Pages 15 and 16 of their January 19 Comments:

> *Dakota has not requested rider recovery for its proposed AGi costs under the statute that explicitly allows it. As a result, the Commission cannot limit its review to determining whether the utility's proposal is reasonable or will generally benefit its members. The Commission must also determine whether grid modernization costs can be recovered in one of the riders proposed by Dakota and, if so, whether Dakota has met the standards of its proposed riders.*

Dakota Electric respectfully suggests that the OAG adopts an incorrect and overly narrow reading of the statutes and of the Commission's authority to approve the Cooperative's filing. The OAG reading of the statutes could deny this member-owned Cooperative the ability to recover the costs associated with grid modernization through a tracker account, while investor owned utilities could do so. Such a reading is not supported by the language of the statutes, not supported by clear legislative intent and not consistent with the public interest.

In its Initial Filing, Dakota Electric acknowledged that, as a cooperative electing to be rate regulated under Minnesota Statutes 216B.03 to 216B.23, Minnesota Statutes Section 216B.2425, regarding the State Transmission and Distribution Plan, does not directly apply. However, this is not the only statute discussing electric utility infrastructure costs (EUIC). Minnesota Statute 216B.1636 (EUIC Statute) also addresses recovery of EUIC and falls squarely within the range of statutes that apply to a rate-regulated electric cooperative.

The EUIC statute specifically states that “The commission may approve an electric utility's petition for a rate schedule to recover EUIC under this section. An electric utility may petition the commission to recover a rate of return, income taxes on the rate of return, incremental property taxes, if any, plus incremental depreciation expense associated with 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”, with utility infrastructure projects defined in part 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.”

The OAG argues that the EUIC Statute defines “electric utility” as a public utility as defined In M.S. 216B.02, subdivision 4. However, as the Department noted, Dakota Electric members elected “to become subject to rate regulation by the Commission pursuant to sections 216B.03 to 216B.23.” This election clearly makes the Cooperative subject to the EUIC Statute. As such, provided Dakota Electric has met the requirements of the EUIC Statute, its filing should be approved.

Moreover, even if the Commission determines that Section 216B.1636 does not specifically apply to Dakota Electric, the AGi tracker mechanism should be approved. Minnesota Statute Section 216B.03 provides the Commission broad overall authority to approve rates and specifically requires that: “To the maximum reasonable extent, the Commission shall set rates to encourage energy conservation and renewable energy use and to further the goals of sections 216B.164, 216B.241, and 216C.05.” Again, as the Department noted, Dakota Electric’s grid modernization efforts will result in more efficient energy use. Such efforts should be supported, not denied due to an overly narrow reading of one particular statute. Moreover, the OAG offers no rationale for why a tracker mechanism for recovery of such costs should be made available to investor-owned utilities, while being denied to member-owned utilities such as Dakota Electric. For all of these reasons, pursuant to both Minnesota Statute 216B.1636 and 216B.03, the Minnesota Public Utilities Commission can approve an AGi tracker mechanism for the Cooperative.

As stated above, we also note that the Department supports Dakota Electric's use of Minnesota Statute 216B.1636 to establish the AGi Rider for the recovery of distribution grid modernization (AMI and MDM equipment) net costs that occur between Cooperative general rate cases. Specifically, at Page 5 of the DOC Comments, the Department states that:

> "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 goes on to observe:

> "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."

Minnesota Department of Commerce

The Minnesota Department of Commerce made the following conclusions, requests for information, and expected recommendations on Page 17 of their January 26 Comments:

> *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.*

Dakota Electric offers the following Reply Comments on the requested information and recommendations included in the Minnesota Department of Commerce (Department or DOC) January 26 Comments.

Dakota Electric concurs with the DOC expected recommendation to approve the AGi Rider, including recovering costs on a per-meter basis. The Department performed its own cost-benefit analysis (based on data from Dakota Electric's AGi Business Case) which showed a positive financial impact for Dakota Electric members, while acknowledging that the results are "sensitive to the discount chosen for each stream of costs and benefits." As noted on Page 16 of the DOC Comments, even if AGi does not save ratepayers money, it may be worth pursuing, up to a point, giving consideration to the unquantifiable benefits of AGi identified by Dakota Electric. Dakota Electric has identified a number of unquantifiable benefits of AGi such as allowing members access to more data, being able to offer new types of rates, quicker response to power outages, and more information to improve the operation of the distribution system. These benefits, and others, are consistent with the Guiding Principles for Grid Modernization included in a March 2016 staff report referenced in our initial filing – and as summarized in a January 23, 2018, Commission Planning Meeting as follows:

- Maintain and enhance the safety, security, reliability, and resilience of the electricity grid, at fair and reasonable costs, consistent with the state's energy policies;
- Enable greater customer engagement, empowerment, and options for energy services;
- Move toward the creation of efficient, cost-effective, accessible grid platforms for new products, new services, and opportunities for adoption of new distributed technologies;
- Ensure optimized utilization of electricity grid assets and resources to minimize total system costs;
- Facilitate comprehensive, coordinated, transparent, integrated distribution system planning.

Dakota Electric agrees that the Department's proposed rate design for implementing the AGi Rider results in fairer charges to members for the facilities being installed. The Department's alternative rate design approach spreads relative meter costs based on the cost of meters to each rate class and other common costs based on energy usage – with total costs then collected through a monthly per meter charge. Attached to these Reply Comments are sample rate calculations using the Department's outlined method using estimated operational savings netted against identified estimated annual revenue requirements for the AMI and MDM facilities to be installed. Dakota Electric notes that we have applied one refinement to the Department methodology related to project management costs. Certain AGi project management costs will be capitalized. We have apportioned these common costs according to the overall allocation of all other costs.

Dakota Electric concurs with the DOC expected recommendation that the Commission 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. Since the DOC submitted their Comments on January 26, Dakota Electric has been in communication with Department staff responsible for over-sight of utility Conservation Improvement Programs (CIP) and staff at Great River Energy that administer the coordinated electric CIP filings to the Department. These conversations support the inclusion of load management capital costs in the conservation component of Dakota Electric's annual Resource and Tax Adjustment – subject to the filing requirements in Minnesota Statutes. As these future costs are incurred, Dakota Electric will coordinate their reporting through the CIP process for inclusion in the RTA filings with the Commission.

Dakota Electric also provides information requested in the DOC Comments as follows:

- The existing infrastructure being replaced or modified as a result of AMI or MDM consists of the Cooperative's existing meters that will be replaced – that still carry an undepreciated balance of over $3 million. While being replaced, Dakota Electric will still need to collect revenue for some period of time to "pay for" these meters. Dakota Electric has been in communication with the Department regarding these undepreciated balances and how they could be handled in the Cooperative's accounting system as the facilities are removed from service.
- Attached to these Reply Comments is the full documentation supporting Dakota Electric's proposed calculation of EUIC as shown in Exhibit F of the Cooperative's petition. This spreadsheet shows all calculations and references the sources and derivations of any inputs. The Excel version of this file has been provided to the Department and OAG.
- The operational savings included in the AGi Rider calculations reflect cost savings estimates that are directly attributable to Dakota Electric for costs that are presently recovered in rates and will not otherwise be provided to members through other means. These operational savings directly attributable to Dakota Electric through AGi

include reductions in meter readers, member support, and operations overtime which are shown on the attached AGi rate recovery analysis with references to the AMI Business Planning Model.

Dakota Electric notes that there are estimated potential avoided costs and additional revenue identified in the AMI Business Planning Model that we have not included in the estimated operational savings for calculating AGi Rider recovery. Following is an identification of these components and an explanation of why Dakota Electric has not included them in the operational savings:

- *Avoided costs for calibration and testing, audits, losses (reduction in meter losses) (Business Case page 42)*

  What is labeled "Annual Cost Reduction" on Page 42 of the AGi Business Case is really estimated potential revenue gains. In general, these potential revenue numbers were arrived at by considering revenue impact curves from other utilities (industry data) and then estimating where Dakota Electric may fall on the curve. While these estimates may be reasonable numbers to consider in the Business Case, they are not directly attributable to Dakota Electric. By comparison, we have included reductions in costs for 1) contract and Dakota Electric meter readers as the new automated meters are installed and 2) reductions in overtime expenditures resulting in operational savings – which are both directly attributable to Dakota Electric as AGi is implemented. It is also worth noting that, based on the present project schedule, the new meters would not be fully deployed until sometime in 2021. The first year where a portion of potential revenue benefits would be reflected in the AGi adjustment is in 2021. However, if there is any schedule slippage, which we have already seen, this could delay the full deployment of meters. In any event, actual revenue gains (or losses) would be incorporated in Dakota Electric's subsequent rate case test year results (potentially in 2024 assuming we stay on the 5-year filing pattern from the past few cases). Because we are a Cooperative, we return any/all margins to our members.
- *Avoided revenue-delay costs (meter revenue finance cost savings) (Business Case page 43)*

The meter revenue finance savings in the business case assumed Dakota Electric would adjust relative meter reading and billing cycles. Dakota Electric has no present plans to change the meter reading and billing cycles. Even if they are adjusted, this would not be possible until after all meters are fully deployed.

  - *Avoided voltage, and system management costs (operational cost savings) (Business Case pages 43-44)*
    The savings from voltage reduction and loss savings from right sized transformers etc. are wholesale power cost related savings that will directly – and automatically - flow through the Cooperative's Resource and Tax Adjustment. The operational overtime cost savings were included in the annual operational savings.
  - *Avoided rural meter reading costs (Business Case page 24)*
    The operational savings for our existing rural meter reading system are included in the calculated meter reading savings.

- The estimated monthly charge for each customer class using the Department's proposed rate design applied to numbers from the AGi rate recovery analysis is attached. These calculations include a refinement as discussed above.

Conclusion

Dakota Electric appreciates the thoughtful review of our filing provided in comments from the OAG and DOC.

Dakota Electric is facing several major transitions; one is with technology; another with the makeup of and wants of our members; and the third is within the core business due to the interconnection of renewables. Advanced Grid Infrastructure technologies will 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. Two-way communication to field equipment will provide 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 been monitoring and evaluating components of AGi for many years. During the past four years these efforts have intensified as the underlying AGi systems have matured. Dakota Electric's monitoring and evaluation over the past four years has included:

- Dozens of internal meetings,
- Visits to utilities around the country that have implemented similar systems,
- Member survey,
- Extensive RFP process,
- Internal risk assessment evaluation,
- Updates for Dakota Electric's Board of Directors, and
- Presentations at two Commission Planning Meetings.

Based on the Cooperative's evaluation, Dakota Electric believes that we must begin preparing for a future state that integrates many technologies not present today, which requires advanced capabilities for monitoring, communication and control. The Cooperative's evaluation 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. The system wide communication network provided by the installation of AGi will support future operational monitoring. This will be required to support the operation of the distribution system with the installation of renewables, such as solar. Together these systems will provide options for Dakota Electric to provide increased 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 future issues as they arise. This conclusion is consistent with Dakota Electric's strategic vision adopted by the Cooperative's Board of Directors. We believe that implementation of AGi is also consistent with – and supports – the Guiding Principles articulated in the Commission's Grid Modernization docket.

Based on the information contained in our initial filing and these Reply Comments, Dakota Electric concurs with the expected recommendations identified in the DOC Comments as follows:

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

- 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.

We further request that the Commission issue a decision in this matter by April 23, 2018, to maintain the pricing offered in proposals to the Cooperative.

Dakota Electric appreciates the opportunity to provide Reply Comments in this matter. If you have any questions about these Reply Comments and recommendations, please contact me at 651-463-6258 or at dlarson@dakotaelectric.com.

Sincerely,

/s/ Douglas R. Larson

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

Certificate of Service

I, Cherry Jordan, hereby certify that I have this day served copies of the attached document to those on the following service list by e-filing, personal service, or by causing to be placed in the U.S. mail at Farmington, Minnesota.

Docket No. ***E-111/M-17-821***

Dated this 5th day of February 2018

/s/ Cherry Jordan

Cherry Jordan

AGI Rider
Sample Rate Design Calculations

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
				Allocated Capitalized Costs			*Annual*	*Operational*	*Net*	*Per Meter*
Schedule	*Meters*	*MWh Sales*	*Meters*	*Comm & MDM*	*Proj Mgmt*	*Sum*	*Costs*	*Savings*	*Recovery*	*Per Mo.*
Residential	97,493	898,633	$ 14,972,064	$ 859,787	$ 1,092,063	$ 16,923,913	$ 2,531,607	$ (1,104,172)	$ 1,427,436	$ 1.22
Irrigation	392	7,002	$ 165,330	$ 6,699	$ 11,866	$ 183,895	$ 27,508	$ (11,998)	$ 15,511	$ 3.30
Lighting	211	11,236	$ 32,403	$ 10,750	$ 2,977	$ 46,130	$ 6,901	$ (3,010)	$ 3,891	$ 1.54
Small General	4,349	42,839	$ 667,879	$ 40,987	$ 48,897	$ 757,763	$ 113,352	$ (49,439)	$ 63,913	$ 1.22
General	2,633	448,838	$ 1,110,492	$ 429,436	$ 106,222	$ 1,646,150	$ 246,244	$ (107,400)	$ 138,843	$ 4.39
C&I Interruptible	251	412,077	$ 105,862	$ 394,264	$ 34,498	$ 534,623	$ 79,973	$ (34,881)	$ 45,092	$ 14.97
	105,329	1,820,625	$ 17,054,029	$ 1,741,923	$ 1,296,523	$ 20,092,475	$ 3,005,585	$ (1,310,899)	$ 1,694,686	

	Capitalized Costs
$ 15,672,346	Meters (Residential and Single Phase)
$ 1,381,683	Meters (Irrigation, General, C&I Interruptible)
$ 1,741,923	Communication, MDM & Software
$ 1,296,523	Project Management
$ 20,092,475	
$ 3,005,585	Annual ROE, Property Tax, Depreciation
$ (1,310,899)	Annual Operational Savings

NOTES:

Column a	Dakota Electric rate classes.
Columns b and c	Calendar year 2016 meter and energy consumption data.
Column d	Relative applicable rate class meter costs.
Column e	Relative applicable rate class communication, MDM, and software costs.
Column f	Project management costs allocated based on proportion of costs from Columns d and e.
Column g	Sum of Columns d + e + f.
Column h	Estimated annual ROE, Property Tax and Depreciation divided by relative allocated capital costs.
Column i	Estimated annual Operational Savings allocated based on allocated costs in Column h.
Column j	Sum of Columns h + i.
Column k	Column j divided by Column b divided by 12 months.
Capitalized Costs	Source: Estimated total capitalized costs from "Detail (AGi)" tab of AGi rate recovery analysis.
Annualized Costs	Source: Estimated recoverable rate of return, property taxes, and depreciation from "Recovery Summary" tab of AGi rate recovery analysis.
Operational Savings	Source: Estimated operational Savings from "Detail (AGi)" tab of AGi rate recovery analysis.

Rate Recovery for AGi - Meters & Communication

		Statute	Notes
Capitalized Costs - Added to Rate Base		$ 20,092,475	***Initial Capitalized Outlay***
Rate of Return Recovery	6.47%	1,299,983	***Rate from 2014 Rate Case***
Income Taxes	N/A	-	
Incremental Property Taxes		179,000	***See Property Tax***
Incremental Depreciation		1,526,602	
Subtotal Before Savings		3,005,585	
Operational Savings		(1,310,899)	***From Model***
Net to Recover		1,694,686	
Number of Members		**105,000**	*Estimated values based on history*
kWh		**1,810,000,000**	*"*
Monthly Average kWh - Residential		**772**	"
Recovery per kWh		$ 0.00094	
Monthly Recovery per Avg. Residential member		$ 0.73	
Fixed Monthly Recovery - per member		*$ 1.35*	

Details for Recovery of AMI costs

Source Document: AMI Business Planning Model

	Meters	Tab	Cell	Installation	Tab	Cell	Total	Current Model/ Life	Annual Depr
Meters									
2S w/Disconnect	$ 11,552,295	*Summary of System Costs*	L36+L37+L46	$ 1,428,199	*Summary of System Costs*	L39	$ 12,980,494		
3S/4S/12S	2,430,492	*Summary of System Costs*	L40+L41	261,360	*Summary of System Costs*	L44	2,691,852		
3 phase	1,135,967	*Summary of System Costs*	L60+L61	245,716	*Summary of System Costs*	L65+L67	1,381,683		
	15,118,754			1,935,275			17,054,029	15	1,136,935
Project Management & Delivery									
AM Vendor Mgmt & Support				966,810	*Summary of System Costs*	L25		E	
Contingency				1,000,000	*Summary of System Costs*	L26		E	
Training				20,000	*Summary of System Costs*	L27		E	
Spare Parts & Test Equip				624,923	*Summary of System Costs*	L28		15	41,662
Integration/Miscellaneous Costs				671,600	*Summary of System Costs*	L29		15	44,773
Internal Project Management				150,000	*Summary of System Costs*	L30		E	
Consulting & Contractor Fees				250,000	*Summary of System Costs*	L31		E	
Subtotal							3,683,333		86,435
Communications & Infrastructure									
Cellular Access Points				307,394	*Summary of System Costs*	L15			
Network Access Points				289,748	*Summary of System Costs*	L16			
Installation of Routers/Collectors				185,980	*Summary of System Costs*	L17			
Other Material Costs				109,276	*Summary of System Costs*	L18			
Relays				278,145	*Summary of System Costs*	L19			
Tools				22,282	*Summary of System Costs*	L21			
Subtotal							1,192,825	15	79,522
Master Station									
AMI Software				124,758	*Summary of System Costs*	L9			
MDM & LC Software				424,340	*Summary of System Costs*	L11			
Subtotal							549,098	4	137,275
							5,425,256		
Total Capitalized in Model							20,092,475		1,526,602
Costs not Capitalized							**2,386,810**		
Total Costs							**22,479,285**		
Annual Operational Savings									
Meter Readers					*Summary of Savings*	M10	(898,954)		
Member Support					*Summary of Savings*	M18	(327,879)		
Operations Overtime					*Summary of Savings*	K30	(84,066)		
							(1,310,899)		

Impact of New Meter Assets on Increased Property Tax

Capitalized Cost of New Meters, etc.	$ 20,092,475	
Retirement of Old Meters	(7,021,000)	Asset Value in Account 37000 as of 8-31-17
Net Addition to Meters, etc.	$ 13,071,475	
Assessed Value of Personal Property		
Incorporated	166,206,366	*Property & Real Estate Tax through 2016*
Unincorporated	51,726,293	*Market Value Return*
Total Distribution Plant	217,932,659	
% Allocation to Incorporated Property	76.27%	
Estimated Increase to Cost Indicator portion of Value	9,970,000	
% of Cost Used for Apportioned Market Value	50%	
Increase to Cost Indicator of Apportioned Market Value	4,985,000	
Average Property tax Rate	3.59%	*Based on History*
Estimated Increase in Personal Property Tax	$ 179,000	

Methods of Rate Recovery for AGi - Load Control

			Year 1	Year 2	Year 3	Year 4	Year 5	Notes
Capitalized Costs - Added to Rate Base		$	1,970,719	$ 4,236,691	$ 6,549,351	$ 8,910,158	$ 11,320,620	*Cumulative*
Rate of Return Recovery	6.47%		127,506	274,114	423,743	576,487	732,444	*Rate from 2014 Rate Case*
Income Taxes	N/A		-					
Incremental Property Taxes			27,000	58,000	90,000	122,000	155,000	*See Property Tax (LC)*
Incremental Depreciation			131,381	282,446	436,623	594,010	754,707	*15 year life*
			285,887	614,560	950,366	1,292,497	1,642,151	
Total to Add to CIP		$	285,887	$ 614,560	$ 950,366	$ 1,292,497	$ 1,642,151	
Total kWh Sales			1,810,000,000	1,810,000,000	1,810,000,000	1,810,000,000	1,810,000,000	
Cost per kWh - Tracker		$	0.00016	$ 0.00034	$ 0.00053	$ 0.00071	$ 0.00091	
Avg Residential kWh			772	772	772	772	772	
Per month avg residential cost			0.12	0.26	0.41	0.55	0.70	

Details for Recovery of Load Control Depreciation

Source Document: AMI Business Planning Model

	Year 1	Year 2	Year 3	Year 4	Year 5	Tab	Cell
Load Control Devices							
#	10,000	11,280	11,292	11,304	11,316	*Fifteen Year Cash Flow*	C24-G24
LCRs	1,270,719	1,476,372	1,522,241	1,569,557	1,618,368	*Fifteen Year Cash Flow*	C25-G25
Installation	700,000	789,600	790,419	791,250	792,094	*Fifteen Year Cash Flow*	C26-G26
Total Capital Cost	1,970,719	2,265,972	2,312,660	2,360,807	2,410,462		
Life in years	15	15	15	15	15		
Annual Depreciation	131,381	151,065	154,177	157,387	160,697		
Cumulative Depreciation	131,381	282,446	436,623	594,010	754,707		
kWh	1,810,000,000	1,810,000,000	1,810,000,000	1,810,000,000	1,810,000,000		
Recovery per kWh	$ 0.00007	$ 0.00016	$ 0.00024	$ 0.00033	$ 0.00042		
Avg Monthly Residential kWh	772	772	772	772	772		
Avg Monthly Residential Cost	$ 0.05	$ 0.12	$ 0.19	$ 0.25	$ 0.32		

Impact of New LCRs on Increased Property Tax

	Year 1	Year 2	Year 3	Year 4	Year 5
Cost of Load Control Devices	$ 1,970,719	$ 4,236,691	$ 6,549,351	$ 8,910,158	$ 11,320,620
Net Addition if Capitalized	$ 1,970,719	$ 4,236,691	$ 6,549,351	$ 8,910,158	$ 11,320,620
Assessed Value of Personal Property					
Incorporated	166,206,366	166,206,366	166,206,366	166,206,366	166,206,366
Unincorporated	51,726,293	51,726,293	51,726,293	51,726,293	51,726,293
Total Distribution Plant	217,932,659	217,932,659	217,932,659	217,932,659	217,932,659
% Allocation to Incorporated Property	76.27%	76.27%	76.27%	76.27%	76.27%
Estimated Increase to Cost Indicator portion of Value	1,503,000	3,231,000	4,995,000	6,796,000	8,634,000
% of Cost Used for Apportioned Market Value	50%	50%	50%	50%	50%
Increase to Cost Indicator of Apportioned Market Value	752,000	1,616,000	2,498,000	3,398,000	4,317,000
Average Property tax Rate	3.59%	3.59%	3.59%	3.59%	3.59%
Estimated Increase in Personal Property Tax	$ 27,000	$ 58,000	$ 90,000	$ 122,000	$ 155,000

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 500 Saint Paul, MN 551012198	Electronic Service	No	GEN_SL_Dakota Electric Association_General Service List
Corey	Hintz	chintz@dakotaelectric.com	Dakota Electric Association	4300 220th Street Farmington, MN 550249583	Electronic Service	No	GEN_SL_Dakota Electric Association_General Service List
Douglas	Larson	dlarson@dakotaelectric.com	Dakota Electric Association	4300 220th St W Farmington, MN 55024	Electronic Service	No	GEN_SL_Dakota Electric Association_General Service List
John	Lindell	agorud.ecf@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012130	Electronic Service	No	GEN_SL_Dakota Electric Association_General Service List
Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 7th St E St. Paul, MN 55106	Electronic Service	No	GEN_SL_Dakota Electric Association_General Service List
David	Moeller	dmoeller@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022093	Electronic Service	No	GEN_SL_Dakota Electric Association_General Service List
Ron	Spangler, Jr.	rlspangler@otpco.com	Otter Tail Power Company	215 So. Cascade St. PO Box 496 Fergus Falls, MN 565380496	Electronic Service	No	GEN_SL_Dakota Electric Association_General Service List
Eric	Swanson	eswanson@winthrop.com	Winthrop Weinstine	225 S 6th St Ste 3500 Capella Tower Minneapolis, MN 554024629	Electronic Service	No	GEN_SL_Dakota Electric Association_General Service List
Daniel P	Wolf	dan.wolf@state.mn.us	Public Utilities Commission	121 7th Place East Suite 350 St. Paul, MN 551012147	Electronic Service	No	GEN_SL_Dakota Electric Association_General Service List