July 26, 2019

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

RE: **Reply Comments of the Minnesota Commerce Department, Division of Energy Resources**
Docket No. E017/M-19-256

Dear Mr. Wolf:

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

Otter Tail Power's 2018 Demand Side Management Financial Incentive Project and Annual Filing to Update the Conservation Improvement Project Rider.

The *Petition* was filed on April 1, 2019 by:

Jason Grenier
Manager, Market Planning
Otter Tail Power Company
215 South Cascade Street
P.O. Box 496
Fergus Falls, MN 56538-0496

The Department recommends that the Commission **approve in part Otter Tail Power's *Petition*, with modifications, and deny in part.** The Department is available to answer any questions that the Minnesota Public Utilities Commission may have.

Sincerely,

/s/ CHRISTOPHER DAVIS
Rates Analyst

/s/ DANIELLE WINNER
Rates Analyst

CD/DW/ar

Before the Minnesota Public Utilities Commission

Comments of the Minnesota Department of Commerce
Division of Energy Resources

Docket No. E017/M-19-256

I. INTRODUCTION

On April 1, 2019, Otter Tail Power Company (Otter Tail, OTP, or the Company) submitted its annual Conservation Improvement Program (CIP) filing (*Petition*) for 2018 with the Minnesota Public Utilities Commission (Commission) in Docket No. E017/M-19-256. The *Petition* contained the following requests:

- Approval to include Otter Tail's Company-Owned Light Emitting Diode (LED) Street Light project expenses, less any rate of return for the project, within the financial incentive mechanism;
- Approval of a Demand Side Management (DSM) financial incentive of $3,004,311;
- Approval of proposed recoveries and expenditures in the Company's CIP tracker account during 2018 resulting in a year-end 2018 balance of $5,994,017;
- Approval of a 2019/2020 Conservation Cost Recovery Adjustment (CCRA) of $0.00710 per kWh for bills rendered on and after October 1, 2019; and
- Approval of a variance to Minnesota Rule 7820.3500 (E) and (K) to allow Otter Tail to continue to combine the Fuel Clause Adjustment (FCA) with the Conservation Improvement Adjustment on customer bills.

On May 31, 2019, the Department filed Comments analyzing Otter Tail's proposal. The Department requested that in Reply Comments, the Company provide:

- A revised 2018 CIP tracker that includes:
  - A beginning balance equal to the 2017 ending balance approved by the Commission in Docket No. E017/M-18-119; and
  - Carrying charges that reflect these adjustments (a revised Table 1 from Appendix A of the *Petition*).
- A recalculated CCRA that uses an October 1, 2019 beginning balance that reflects the Department's recommendations concerning the 2018 financial incentive and 2018 CIP tracker.

The Department also recommended that the Commission:

- Find that CIP expenditures for Otter Tail's Company-Owned Street and Area Lighting program be ineligible to be included in the Shared Savings DSM financial incentive calculation; however, if the Commission finds that these expenses are eligible, the Department was not opposed to the Company's proposal to adjust the 2018 financial incentive by ($148,786);
- Approve a 2018 Shared Savings DSM financial incentive of $2,728,752;
- Grant a variance to Minnesota Rules parts 7820.3500(K) and 7825.2600, effective until the Commission issues an Order setting the Company's 2020-2021 CCRA; and
- Direct Otter Tail to submit a compliance filing within ten days of the Commission's Order with revised tariff sheets reflecting the Commission's determinations in this matter.

On June 24, 2019, Otter Tail filed Reply Comments responding to the Department's requests and recommendations. The Department now files these Reply Comments in response to Otter Tail.

II. DEPARTMENT ANALYSIS OF CURRENT DOCKET

A. LED Expenditures Counting Towards Financial Incentive Expenditure Cap

In Otter Tail's *Petition*, the Company argued that it is appropriate to include LED street lighting expenditures when applying the financial incentive expenditure cap. In its May 31, 2019 Comments, the Department disagreed. Three issues have been discussed by the parties: whether the Commission's July 16, 2013 Order in Docket No. E,G999/DI-12-1342 (July 16, 2013 Order) supported including expenditures from Company-owned CIP projects when applying the financial incentive expenditure cap; the nature and context of the financial incentive at the time of the July 16, 2013 Order, and; whether lost sales due to the LED program support including LED expenses when applying the expenditure cap.

1. Whether the Commission's July 16, 2013 Order supported including expenditures from Company-owned CIP projects when applying the financial incentive expenditure cap

In its *Petition*, Otter Tail stated that the Commission's July 16, 2013 Order allows a utility to participate in its own CIP programs, provided no double recovery exists. Therefore, the Company argued, Otter Tail should be permitted to count LED expenditures when applying the expenditure cap. The Company cited Order Point 1 from the Commission's July 16, 2013 Order.

In its May 31, 2019 Comments, the Department pointed out that Order Point 1 is not applicable to the current issue, since the Order Point does not address whether or not CIP expenditures at a utility's own facilities may count when applying the financial incentive expenditure cap. The Department concluded that Otter Tail had not demonstrated that past Commission Orders support including expenditures on Company-owned CIP projects in the financial incentive calculation.

In its June 24, 2019 Reply Comments, Otter Tail agreed that Order Point 1 is not relevant because double recovery is not at issue in the current proceeding. Otter Tail then argued that since no double recovery exists, the Commission should permit the Company to count the LED expenditures when applying the expenditure cap, stating:[1]

> As long as there is no double recovery, the Commission should support Company project expenses towards the financial performance incentive to encourage cost-effective Company-owned projects which can produce immense customer benefits.

Again, the Department notes that the absence of double recovery is not the standard for whether or not the LED expenditures should count when applying the financial incentive expenditure cap. Order Point 1 in the Commission's July 16, 2013 Order is not relevant to the discussion at hand, and thus the absence of double recovery does not mean the Commission should approve Otter Tail's request. Thus, the Department again concludes Otter Tail has not demonstrated that past Commission Orders support including expenditures on Company-owned CIP projects in the financial incentive calculation.

2. The nature and context of the financial incentive at the time of the Commission's July 16, 2013 Order

In its *Petition*, Otter Tail argued that while the Commission's July 16, 2013 Order specified that energy savings and net benefits cannot count towards the financial incentive, the Order did not specify the same for expenditures. The Company cited Order Point 2 of that Order, which states:[2]

> The Commission further finds that energy savings and net benefits resulting from utility participation in CIP projects at their own facilities shall not count toward the determination of the utility's DSM financial incentive.

In its May 31, 2019 Comments, the Department agreed that expenditures are not explicitly mentioned in the Order Point, but noted that the nature and context of the financial incentive at the time of the July 16, 2013 Order was important to understand the Order Point. The Department noted two things in particular:

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[1] Otter Tail Reply Comments, p. 11 (June 24, 2019).

[2] Commission *Order Determining Ratemaking Treatment of Utility CIP Project Costs and Requiring Further Filings*, July 16, 2013, Docket No. E,G999/DI-12-1342, page 4.

- At the time of the July 16, 2013 Order, the financial incentive was calculated based on net benefits and energy savings. There was no expenditure cap, as there is now, and thus no need to specify whether expenditures should count towards the financial incentive.
- Net benefits are calculated by subtracting avoided costs from actual costs, and actual costs comprise both the financial incentive and expenditures. Since net benefits is included in the July 16, 2013 Order, and one component of net benefits is expenditures, that Order indirectly incorporates expenditures.

In its June 24, 2019 Reply Comments, Otter Tail did not address the Department's first point. The Department thus continues to conclude that it appears that the Commission found that Company-owned CIP projects should not count towards a utility's financial incentive.

However, Otter Tail did address the Department's second point. The Company argued that there are instances where expenditures count towards the spending cap, but not towards the net benefits cap. Specifically, OTP pointed to the following expenditures: POP Solar, House Therapy, and Regulatory Assessments. Otter Tail argued that the proposed treatment of the Company-owned LED project expenses are no different from the treatment of these other program expenses, and thus should be approved by the Commission.

The Department disagrees that the Company-owned LED project expenses should be treated the same as POP Solar, House Therapy, and Regulatory Assessment expenses; while the LED project occurs at the Company's own facilities, the other projects do not. The Commission's July 16, 2013 Order is specific to CIP projects at a utility's own facilities, and so is not applicable to these other projects. Thus, the Department continues to conclude that the Commission's July 16, 2013 Order may indirectly include expenditures because it includes net benefits.

3. Whether lost sales resulting from conservation supports inclusion of LED expenses towards the expenditure cap

In its *Petition*, the Company argued that one purpose of the DSM incentive is to compensate the utility for lost sales due to conservation. Otter Tail argued that since the Company has experienced lost sales, it should be permitted to include the LED expenditures towards the financial incentive expenditure cap.

In its May 31, 2019 Comments, the Department noted two important points:

- The CIP incentive is one mechanism in a suite of regulatory strategies designed to encourage conservation. However, its purpose is to incentivize utilities to maximize the amount and cost effectiveness of energy savings, not to mitigate lost sales due to conservation. Instead, the most appropriate regulatory mechanism to make up for lost sales is the decoupling mechanism.

- Otter Tail is not experiencing a loss in profit due to the LED street lighting project. This is because the street lighting rates were not changed as the Company switched to LEDs, and because street lighting rates are a monthly per-light fixed charge rather than a variable per-kWh charge. As a result, the Company should only be experiencing cost savings from the LED program, not lost sales.

In regards to the first point, Otter Tail appeared to maintain that the financial incentive should compensate the Company for lost sales revenue, stating:[3]

> Otter Tail has demonstrated that significant lost sales revenues have occurred in both 2017 and 2018 that are not being counterbalanced with performance incentive compensation.

The Department continues to conclude that the decoupling mechanism is the more appropriate tool for addressing lost sales due to conservation. However, since Otter Tail stated that it is experiencing significant lost sales revenues, the Department encourages the Company to file a petition with the Commission for a decoupling mechanism.

In regards to the Department's second point, Company argued that the Department is ignoring lost profits due to the portion of the financial incentive that is disallowed because of the expenditure cap.

On page 10 of its May 31, 2019 Comments, the Department noted that, in the case of the LED program, "the Company is not experiencing a loss in profit due to conservation." As the Company noted, this statement is incorrect, as the Company is indeed experiencing a loss in profit due to conservation because of the financial incentive expenditure cap. Instead, the Department should have stated that in the case of the LED program, "the Company is not experiencing a loss in *sales revenue* due to conservation." The Department apologizes for the oversight.

However, the Department is still not sympathetic to Otter Tail's argument. Otter Tail did not address the fact that the LED program does not result in lost sales revenue due to conservation. Furthermore, even if the Department agreed that the financial incentive is the appropriate mechanism to compensate for lost sales due to conservation (which it does not), "lost" financial incentive should not be treated the same as lost sales. Otter Tail is stating that because of a lower financial incentive (and thus a loss in profit), the Company should be permitted to earn a larger financial incentive (by counting the LED expenses towards the expenditure cap). This is nonsensical. Therefore, the Department continues to conclude that even if it were appropriate

[3] Otter Tail Reply Comments, p. 5 (June 24, 2019).

to use the financial incentive as a mechanism to account for lost sales revenue, the Company has not demonstrated that it has experienced loss sales revenue as a result of the LED program.

4. Department Conclusions

The Department is not persuaded by Otter Tail's arguments. Therefore, the Department continues to conclude that, consistent with the Commission's July 13, 2016 Order, the Company's LED program expenditures should be excluded from Otter Tail's financial incentive calculation for the following reasons:

- Otter Tail has not shown that past Commission Orders support inclusion of Company-owned CIP project expenses when calculating the financial incentive;
- The Commission's July 13, 2016 Order, when read in the context of the financial incentive calculation in place at the time, indicates that Company-owned CIP project expenditures are not to be included in the financial incentive calculation; and
- Contrary to OTP's argument that the CIP financial incentive is intended to mitigate lost sales, the Company is not experiencing a loss in sales revenue due to the LED street lighting project. Further, the CIP incentive encourages utilities to fully engage in CIP, whereas revenue decoupling is the appropriate mechanism to remove the disincentive of lost sales due to conservation.

B. OTTER TAIL'S PROPOSED 2018 DSM FINANCIAL INCENTIVE

In its *Petition*, Otter Tail requested recovery of a DSM financial incentive of $3,004,311 for 2018. This figure assumes that 2017 and 2018 LED expenditures are included in the calculation of the financial incentive. Since the Commission provisionally approved 2017 budgeted (but not actual) expenditures towards the 2017 financial incentive, subject to further discussion in the instant docket, the Company proposed an adjustment of ($148,786) to reflect the difference between budgeted versus actual expenditures.[4]

In its May 31, 2019 Comments, the Department recommended that the Commission approve a DSM financial incentive of $2,728,752. This figure assumes that neither 2017 nor 2018 LED expenditures are included in the calculation of the financial incentive. The Department-recommended financial incentive includes the Department's recommended adjustments for all 2017 and 2018 LED expenditures, but does not include Otter Tail's proposed adjustment for budgeted versus actual 2017 LED adjustments.[5]

In its June 24, 2019 Reply Comments, Otter Tail continued to request a 2018 financial incentive of $3,004,311, based on the Company's request to include LED expenditures in the financial incentive calculation.

[4] For further discussion, see Department's May 31, 2019 Comments, pp. 11-12.
[5] For a breakdown of costs, see Table 1 of the Department's May 31, 2019 Comments, p. 13.

As noted in the previous section, the Department is not convinced by Otter Tail's arguments that Company-owned LED CIP expenditures should count when applying the financial incentive expenditure cap. Therefore, the Department continues to recommend a DSM financial incentive of $2,728,752, based on the Department's recommendation to not permit LED expenditures towards the financial incentive. However, if the Commission determines that Otter Tail's LED street lighting expenditures should be included when calculating the financial incentive, the Department is not opposed to the Company's proposal for the Commission to approve an adjusted 2018 incentive of $3,004,311.

C. OTTER TAIL'S PROPOSED 2018 CIP TRACKER

In its *Petition*, Otter Tail requested approval of its 2018 CIP tracker account.

In its May 31, 2019 Comments, the Department noted a discrepancy between the December ending balance of the approved 2017 CIP Tracker,[6] and the proposed January 2018 beginning balance. The Department recommended that the Company set its 2018 beginning tracker balance to the 2017 ending balance approved by the Commission, and provide adjustments to the 2018 CIP tracker, if needed. The Department also recommended that, if appropriate, the Company submit an updated copy of Table 1 from Appendix A of the Company's *Petition*, which calculates the 2018 carrying charges.

In its June 24, 2019 Reply Comments, the Company explained that the discrepancy was due to two errors from the 2017 CIP tracker: the first was a data entry error, and the second was a carrying charge rate error (OTP used 2.55% instead of the rate-case approved 2.5549%). Instead of proposing an adjustment to the 2018 CIP tracker as recommended by the Department, Otter Tail requested that the Commission approve an amended 2017 CIP tracker, in addition to an updated 2018 CIP tracker.

The following tables summarize the Company's newly proposed 2017 and 2018 CIP trackers.

[6] Approved in Commission's October 30, 2018 *Order Approving Tracker Account, Approving Financial Incentive Subject to a True-Up, Setting CCRA, and Granting Variance*, Docket No. E017/M-18-119.

Table 1. Summary of Otter Tail's Amended 2017 and 2018 CIP Trackers, Proposed in June 24, 2019 Reply Comments

Line	Description	OTP Proposed 2017 CIP Tracker	OTP Proposed 2018 CIP Tracker
1	Beginning Balance	$4,835,852	$7,366,140
2	CIP Expenses	$6,605,899	$9,027,762
3	DSM Financial Incentive	$5,031,678	$2,938,110
4	Carrying Charges (set to short term cost of debt rate of 2.5549%)	$105,385	$120,245
5	CIP Expenses Subtotal [Line 1 + Line 2 + Line 3 + Line 4]	$16,578,815	$19,452,257
6	CIP Revenues (base rates and CCRA combined)	($9,212,675)	($13,457,820)
7	Ending Balance [Line 5 + Line 6]	$7,366,140	$5,994,437

The Department does not support amending the 2017 CIP tracker, which was approved in Docket No. E017/M-18-119. Typically, once a CIP tracker is approved, it is not later amended;[7] rather, adjustments are made going forward.[8] Varying from the expected regulatory construct is not necessary and is likely to cause confusion. For example, a party looking at the 2017 CIP tracker in Docket No. E017/M-18-119 might not know or expect that the same tracker would be re-examined in Docket No. E017/M-19-256. Further, any amendments to the 2017 CIP tracker would necessitate a new review of the 2018 CIP tracker and proposed CCRA. Adding these additional steps creates further regulatory resources, potential for error, and transparency issues. Instead, any needed adjustments to the 2017 CIP tracker should be captured in the 2018 CIP tracker, which is the tracker under review in the instant discussion.

The Company did not provide the 2018 CIP tracker with the 2017 adjustment, along with any needed carrying charge adjustments, as requested by the Department. Therefore, in Attachment A to these Reply Comments, the Department recreated the 2018 CIP tracker incorporating the corrections identified by Otter Tail. However, the Department notes that the Company did not provide monthly sales or recoveries by revenue source (base rates or CCRA) in its *Petition*, and so the Department was unable to show that information.

[7] Unless, potentially, if a party files a timely request for reconsideration.
[8] See, for example, the Department's explanation regarding how the timing mismatch between the Commerce Deputy Commissioner's decision on the triennial CIP plans and the Commission's decision on the CIP tracker and financial incentive is reconciled, page 6 of the Department's May 31, 2019 Comments.

As shown in the Department's recommended 2018 CIP tracker, the Company should use a January 2018 starting balance of $7,362,345 and make a separate line item adjustment of $3,795 in January of the 2018 CIP tracker to account for the December 2017 data entry error. According to the Company's calculations on page 10 of its June 24, 2019 Reply Comments, the resulting $7,366,140[9] reflects correction of the data entry error and the carrying charge error, and so no further adjustments need to be made. The following table summarizes the Department's recommended 2018 CIP tracker:

Table 2. Summary of Department's Proposed 2018 CIP Tracker for Otter Tail

Line	Description	Department Supported 2018 CIP Tracker
1	Beginning Balance	$7,362,345
2	Adjustment from 2017 Data Entry Error	$3,795
3	CIP Expenses	$9,027,762
4	DSM Financial Incentive	$2,938,110
5	Carrying Charges (set to short term cost of debt rate of 2.5549%)	$120,237
6	CIP Expenses Subtotal [Line 1 + Line 2 + Line 3 + Line 4 + Line 5]	$19,448,454
7	CCRC Recovery (in base rates)	($3,900,402)
8	CCRA Recovery	($9,557,418)
9	CIP Revenues Subtotal [Line 7 + Line 8]	($13,457,820)
10	Ending Balance [Line 6 + Line 9]	$5,990,634

The Department recommends that the Commission approve the Department's 2018 CIP tracker included in Attachment A and summarized in Table 2 above, with an ending balance of $5,990,634. The Department also recommends that the Commission require the Company to, in future filings, track monthly sales as well as recoveries by revenue source (base rates or CCRA) in its CIP tracker.

D. OTTER TAIL'S PROPOSED CCRA

For October 2019 through September 2020, Otter Tail proposed an 18.3 percent increase in its CCRA surcharge from $0.00600/kWh to $0.00710/kWh.

In its May 31, 2019 Comments, the Department asked that the Company recalculate its CCRA by using an October 1, 2019 beginning balance adjusted to reflect the Department's recommendations concerning the 2018 financial incentive and 2018 CIP tracker.

[9] Beginning balance of $7,362,345 + Adjustment of $3,795 = $7,366,140.

In its June 24, 2019 Reply Comments, the Company did not provide the requested information. Therefore, the Department calculated an alternative CCRA projection, provided in Attachment B and summarized in Table 3 below. This alternative CCRA would be set at $0.006900, a 15 percent increase over the current surcharge.

The Department's proposed calculation results use the same CIP expenses, forecasted incentive, base rate recoveries, and carrying charge rate assumed by the Company. The Department updated the beginning balance to reflect its recommendations concerning the Company's 2018 CIP tracker and 2018 financial incentive. With the updated information, the Department calculated slightly different totals for carrying charges, CCRA recoveries, and ending balance than the Company's proposal. The Department's proposed CCRA would bring the tracker balance closer to zero over the course of time the CCRA is in place, while incurring relatively low carrying charges.

Table 3: Department's Projected 2019-2020 CIP Tracker Account for Otter Tail, using a CCRA of $0.00690/kWh

Line	Description	Time Period	Amount
1	Beginning Balance	October 1, 2019	$3,253,891
2	CIP Program Expenses	October 1, 2019 - September 30, 2020	$9,342,954
3	CIP Incentive[10]	Forecasted 2019 incentive that would be approved in 2020	$2,716,510
4	Carrying Charges (set to short term cost of debt rate of 2.5549%)	October 1, 2019 - September 30, 2020	$7,121
5	CIP Expenses Subtotal [Line 1 + Line 2 + Line 3 + Line 4]	As of September 30, 2020	$15,320,476
6	CCRC Recovery (included in base rates)	October 1, 2019 - September 30, 2020	($3,745,650)
7	CCRA Recovery	October 1, 2019 - September 30, 2020	($11,589,678)
8	CIP Revenues Subtotal [Line 6 + Line 7]	As of September 30, 2020	($15,335,328)
9	Ending Balance [Line 5 + Line 8]	As of September 30, 2020	($14,850)

The Department therefore recommends the Commission approve a CCRA rate of $0.0069, effective October 1, 2019.

[10] This forecasted incentive for 2019 CIP achievements represents the third year in which the revised financial incentive mechanism will have been in place, as approved in the Commission's August 5, 2016 Order in Docket No. E,G999/CI-08-133. This financial incentive for 2019 CIP achievements should not be confused with OTP's proposed incentive of $3,004,311 for 2018 CIP achievements.

III. DEPARTMENT RESPONSE TO OTTER TAIL'S REQUEST THAT THE COMMISSION EXEMPT THE COMPANY FROM THE SHARED SAVINGS CIP EXPENDITURES CAP

A. INTRODUCTION

In its June 24, 2019 Reply Comments, Otter Tail requested that the Commission eliminate one of the incentive's key features for protecting ratepayers—the percent of CIP expenditures incentive cap. Specifically, Otter Tail proposed that the Commission exempt the Company from the expenditure cap provision for both its 2018 and 2019 achievements. The Department notes that this is a new proposal of Otter Tail's, not a direct response to the Department's May 31, 2019 Reply Comments in this docket. Thus, the Company has inappropriately expanded, not narrowed, the issues in this docket.

Otter Tail cited three reasons for why the Commission should approve its request. First, Otter Tail claimed that the incentive expenditure cap conflicts with Minnesota Statutes § 216B.16 Subd. 6c. Second, Otter Tail claimed that the expenditure cap treats Otter Tail differently from Minnesota's two other electric IOUs. Third, Otter Tail claimed that the expenditure cap incentivizes non-cost-effective program spending. Based on its request for exemption from the spending cap, Otter Tail now requests an incentive of $4,004,350,[11] an amount equal to 43% of the Company's 2018 total proposed CIP expenditures[12] and approximately $1 million more than the $3,004,311 that the Company requested in its April 1, 2019 *Petition*.

The Department notes that changes to the Shared Savings incentive plan have been, and continue to be, considered in Docket No. E,G999/CI-08-133, a docket that addresses the Shared Savings mechanism for all of the investor-owned utilities (IOUs) and that provides an opportunity for many parties to submit comments. On July 1, 2019, the Department submitted to the Commission its *REPORT ON THE IMPACTS OF THE 2010-2018 SHARED SAVINGS DEMAND-SIDE MANAGEMENT (DSM) FINANCIAL INCENTIVE ON INVESTOR-OWNED UTILITY CONSERVATION ACHIEVEMENTS AND CUSTOMER COSTS (*2019 Financial Incentive Report or Report*)*. One of the Department's recommendations in the Report was that the Commission approve for 2020 the same Shared Savings DSM financial incentive plan that the Commission approved for 2019. In its July 15, 2019 Reply Comments to the 2019 Financial Incentive Report, Otter Tail opposed the 30% CIP expenditure cap continuation and requested that the Commission discontinue the CIP expenditures cap. In response to Otter Tail's request, the

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[11] Otter Tail calculated an incentive of $4,004,350 by first multiplying its net benefits of $34,609,459 by 12.0% to get $4,153,135, then reducing that amount by $148,785 to account for actual versus budgeted LED Street Light expenses included in the 2017 incentive.

[12] Incentive of $4,004,350 divided by total 2018 CIP expenditures of $9,027,762 = 43%. This expenditure figure represents total 2018 CIP spend and does not necessarily represent the expenditures permitted to count towards the financial incentive expenditure cap. This distinction is discussed further below.

Department sent a letter on July 24, 2019 recommending that the Commission establish a comment period on the Department's recommendation that the Commission approve for 2020 an incentive mechanism similar to the 2019 approved one.
The Department summarizes and responds to Otter Tail's arguments for its proposal below.

B. HISTORY OF THE CIP EXPENDITURES CAP

The present (2017-2019) Shared Savings Incentive Plan was approved by the Commission on August 5, 2016.[13] The plan was designed to encourage IOUs to maximize cost-effective energy savings by providing utilities an increasing percent of net benefits created by their customers' investments in energy savings measures and processes. Under the plan, electric IOUs begin receiving an incentive once the utility achieves energy savings of at least 1.0% of the utility's retail sales. The share of net benefits awarded is shown in Attachment C. For each 0.1% of additional energy savings the electric utility achieves, the net benefits awarded increases by an additional 0.75% until the electric IOU reaches the percent of net benefits cap at an energy savings levels of 1.7% of retail sales. After a utility achieves 1.7% of retail sales, the utility receives a share of the net benefits equal to the net benefits cap, unless the utility reaches the expenditures cap (35% in 2018 and 30% in 2019).

The Department's January 19, 2016 proposal for the 2017-2019 Shared Savings mechanism included a net benefits cap on the incentive, but not a cap based on CIP expenditures. The Department proposed the addition of an expenditure cap in its February 19, 2016 Reply Comments in response to the January 19, 2016 Comments of the Office of the Attorney General—Residential Utilities and Antitrust Division (OAG or OAG-RUD) and Minnesota Chamber of Commerce, both of which recommended an incentive cap equal to 15% of CIP expenditures. In response to the OAG's Comments, the Department stated the following in its February 19, 2016 Reply Comments:[14]

> The OAG-RUD provided excellent, convincing analysis supporting its conclusion that Minnesota's DSM financial incentive mechanisms should be lower and that the Commission should include a percent of expenditures cap for the 2017-2019 Shared Savings mechanism.
>
> As the OAG-RUD points out in its comments, in 2012 the Department proposed modifications to the Shared Savings DSM financial incentive mechanism that were expected to result in an incentive with a maximum cost of approximately 30% of CIP expenditures. However, the 2013-2014 incentives have been much

[13] Commission *Order Adopting Modifications to Shared Savings Demand-Side Management Financial Incentive Plan*, August 5, 2016, Docket No. E,G999/CI-08-133.
[14] Department Reply Comments, Docket No. E,G999/CIP-08-133, pp. 10-11 (February 19, 2016).

> higher (and the 2015- 2016 incentives will continue to be much higher) because:
>
> - The Commission approved a $/first year energy saved incentive cap that was 25% higher than recommended by the Department,
> - The structure of the incentive led to wide variations of incentives awarded on percentage of net benefits and percentage of CIP expenditures bases.
>
> The result is that, as the OAG-RUD stresses, for every dollar spent on CIP, ratepayers pay utilities that dollar back plus an additional large amount. [Footnote omitted] For 2014, the Department calculates that ratepayers paid the dollar back plus an additional 44 cents.

Further, on pages 21-22 of the Department's February 19, 2016 Reply Comments, we stated:

> The Department agrees with the OAG-RUD and the Chamber that Shared Savings DSM financial incentives should be limited by a percent of CIP expenditures cap in order to protect ratepayers from excessive incentive costs. As discussed above, the Department recommends that any percent of net benefits cap [*sic* – should read "expenditures cap"] established be coordinated with the percent of net benefits cap.
>
> To go along with the Department's proposed net benefits caps of 13.5 percent in 2017, 12 percent in 2018, and 10 percent in 2019, the Department evaluated the range of incentives that may occur with our proposed caps, taking into account the potential reduction in electric IOU avoided costs. Based on our review, the Department recommends the following percent of CIP expenditures caps for 2017-2019.
>
> - 40 percent of CIP expenditures in 2017;
> - 35 percent of CIP expenditures in 2018; and
> - 30 percent of CIP expenditures in 2019.

On August 5, 2016 the Commission approved modifications to the Shared Savings incentive mechanism, including the percent of CIP expenditures cap recommended by the Department.

In 2017 and 2018, the first two years of the 2017-2019 Shared Savings incentive, the CIP expenditures cap limited the incentive amount three times out of a possible 14 times.[15] CenterPoint encountered the incentive expenditures cap in 2017[16] and Otter Tail encountered the incentive expenditures cap in 2017 and 2018 chiefly because Otter Tail had very large commercial and industrial (C&I) projects, which tend to be more cost-effective and thus provide higher net benefits. When a utility's annual CIP has very high net benefits, the corresponding financial incentive can rise to a level that brings the expenditures cap into play. The Department notes that, unlike Otter Tail, CenterPoint did not request that the Commission change the rules of the incentive retroactively so that it could receive a higher, ratepayer-funded incentive.

Without the 2017 expenditures cap, Otter Tail would have been awarded a 2017 Shared Savings incentive of $3,189,580 (13.5% of $23,626,518 in net benefits). However, the Department and the Company are in disagreement about what is the appropriate expenditures amount to consider eligible for counting towards the financial incentive expenditure cap. The Commission provisionally approved an incentive based upon the Company's preferred expenditure figure, subject to further discussion in the instant docket. Table 4 below shows the 2017 expenditures cap, using both Otter Tail's preferred expenditure amount and the Department's preferred expenditure amount.

Table 4. Otter Tail 2017 Expenditures Cap, Company-Supported vs. Department-Supported Expenditures

	Company-Supported 2017 Expenditures (used to calculate the provisionally-approved 2017 financial incentive)	**Department-Supported 2017 Expenditures**
Parameters	Includes Budgeted ($739,375) but not Actual ($0) 2017 LED expenditures[17]	Does not include any 2017 LED expenditures
Expenditures Amount	$7,345,274	$6,605,899

[15] The 2017-2019 Shared Savings mechanism covers three electric utilities and four gas utilities, for a total of 7 utilities. Thus, over 2017 and 2018, the expenditures cap could have come into play a total of 14 times.
[16] Without the 2017 expenditures cap, CenterPoint would have been awarded a 2017 Shared Savings incentive of $21,661,062 ($160,452,310 of 2017 net benefits x 13.5% net benefits cap). However, CenterPoint's qualifying 2017 CIP expenditures were $31,140,094. The 2017 expenditures cap was 40% of $31,140,094 or $12,456,038. Since the 2017-2019 Shared Savings incentive specifies that the utility is paid the lesser of the incentives resulting from the two caps, CenterPoint received an incentive of $12,456,038, which is $9.2 million less than if it had been awarded the incentive based on net benefits (and the net benefits cap).
[17] Does not include budgeted rate of return on LEDs.

40% of Expenditures Cap	$2,938,110	$2,642,360

Regardless of which expenditure figure was used, OTP's 2017 financial incentive under the expenditure cap was less than what it would have been under the 2017 net benefits cap. Using the Company's preferred expenditure figure, the 2017 incentive would be $2,938,110, or $251,470 less than the net-benefits-based incentive of $3,189,580. Using the Department's preferred expenditure figure, the incentive would be $2,642,360, or $547,220 less than the net-benefits-based incentive of $3,189,580.

In 2018, Otter Tail again encountered the expenditure cap. Without the expenditure cap, Otter Tail would be awarded a 2018 Shared Savings incentive of $4,153,135 (12.0% of $34,609,459 in net benefits). Table 5 below shows the 2018 financial incentive under the expenditures cap, using both Otter Tail's preferred expenditure amount and the Department's preferred expenditure amount.

Table 5. Otter Tail 2018 Expenditures Cap, Company-Supported vs. Department-Supported Expenditures

	Company-Proposed 2018 Expenditures	**Department-Supported 2018 Expenditures**
Parameters	Includes 2018 Actual LED expenditures without rate of return ($367,411)	Does not include any 2018 LED expenditures
Expenditures Amount	$9,008,846[18]	$8,641,435
35% of Expenditures Cap	$3,153,096	$3,024,502

Again, regardless of which expenditure figure is used, OTP encountered the expenditure cap. Using the Company's preferred expenditure figure, the incentive is $3,153,096, or $1,000,039 less than the net-benefits-based incentive of $4,153,135. Using the Department's preferred expenditure figure, the incentive is $3,024,502, or $1,128,633 less than the net-benefits-based incentive of $4,153,135.[19]

[18] Does not include rate of return on LEDs of $18,916.

[19] Both the Department and the Company proposed adjustments to the 2018 financial incentive to account for the 2017 LED project expenditures. The Department proposed an adjustment that removes all LED expenditures counted towards the 2017 incentive, equal to ($295,750) and resulting in a recommended incentive of $2,728,752. The Company proposed an adjustment that accounts for the difference in budgeted versus actual LED expenditures applied to the 2017 incentive, equal to ($148,786), resulting in a recommended incentive of $3,004,311. For further discussion on this, see pp. 11-13 of the Department's May 31, 2019 Comments.

The Department recommends that the Commission reject Otter Tail's proposal to exempt the Company from the Commission-approved CIP expenditures cap. As explained below, the untimely modification to the incentive mechanism would undermine the integrity of the Shared Savings incentive mechanism and harm Otter Tail's ratepayers. Modifications to the financial incentive mechanism should only be considered on a prospective basis. Further, changes to the incentive mechanism should be considered in Docket No. E,G999/CI-08-133, not in the filing of an individual utility, and applied to all IOUs.

C. OTTER TAIL'S CLAIM THAT THE CIP EXPENDITURES CAP ENCOURAGES THE COMPANY TO MAKE NON-COST-EFFECTIVE EXPENDITURES IS FLAWED

Otter Tail claimed that the Shared Savings incentive with an expenditure cap could motivate Otter Tail to invest in non-cost-effective projects because if the expenditure cap comes into play, the incentive increases as expenditures increase, not as net benefits increase. On page 6 of its June 24, 2019 Reply Comments, Otter Tail provided Table 1, reproduced as Table 6 below, which illustrated a scenario in which, given the Company's 2018 energy savings and costs, Otter Tail could inflate its Shared Savings incentive by spending $2,127,742 of CIP dollars on projects that provide no additional savings.

Table 6: Otter Tail's Incentive Example Using its 2018 Actual CIP Results (Table 1 from Otter Tail's Reply Comments)

	2018	Actual Year	Additional Spend
			$2,127,742
1	Benefits	$42,713,597	$42,713,597
2	Expenses	$9,008,847	$11,136,589
3	**35% CIP Expenditures Cap**	**$3,153,096**	**$3,897,806**
4	Net Benefits*	$34,609,459	$32,481,717
5	**12% Net Benefits Cap**	**$4,153,135**	**$3,897,806**
6	**Lesser of 3 and 5**	**$3,153,096**	**$3,897,806**
7	Additional Financial Incentive		$744,710
8	Financial Incentive per $1 of spending		$0.35
9	Additional Cost to Customers		$2,872,452

As can be seen in Table 6 above, before the additional spending, the incentive that would have been awarded if only the 12% net benefits cap were applied would be $4,153,135. However, the 35% expenditures cap would reduce the incentive to $3,153,096. Since the incentive resulting from the expenditures cap is lower, under the Company's scenario the incentive would be $3,153,096.

Otter Tail's Table 1 also shows that if the Company spent an additional $2,172,742, however, while everything else, including energy savings, stayed the same, the Company's incentive under the 12% net benefits cap would be $3,897,806 and not the $4,153,135 that would have resulted before the additional spending. In this particular case, both caps have the same results, thus the incentive would be $3,897,806. Under this example, Otter Tail could have increased its 2018 incentive by $744,710[20] by making non-cost-effective investments.

However, Otter Tail's example is completely unreasonable because it assumes that the Company knows, before the end of the year, its annual energy and demand savings, its total expenditures, and its net benefits. Otter Tail could not possibly know its exact achievements, budgets, and resulting net benefits at any point during the CIP year such that it would know if non-cost-effective expenditures would increase its incentive. For example, large C&I CIP projects sometimes get delayed and project savings are typically not counted until a project is completed. If Otter Tail tried to manipulate the Shared Savings mechanism while planning on the completion of a very large C&I project, Otter Tail's actions could easily backfire, resulting in a lower incentive than the Company would have earned if focused primarily on cost-effective projects.

To illustrate why trying to game the incentive would be unreasonably risky for Otter Tail, the Department created Table 7.

Table 7: Department Scenario for 2018, With 12% Net Benefits Cap and 35% Expenditures Cap

	2018		Additional Spend
			$2,127,742
1	Benefits	$43,000,000	$43,000,000
2	Expenses	$11,000,000	$13,127,742
3	**35% CIP Expenditures Cap**	**$3,850,000**	**$4,594,710**
4	Net Benefits	$32,000,000	$29,872,258
5	**12% Net Benefits Cap**	**$3,840,000**	**$3,584,671**
6	Lesser of 3 and 5	$3,850,000	$3,584,671
7	Additional Financial Incentive		($265,329)
8	Financial Incentive per $1 of spending		($0.12)
9	Additional Cost to Customers		$1,862,413

In the Department's example, Otter Tail's incentive would have been $3,840,000 if Otter Tail did not try to game the system. However, when the Company spent the same additional $2,172,742 that Otter Tail used in its scenario, Otter Tail would end up with $265,329 less in its 2018 Shared Savings incentive. Table 8 below shows a similar result if the same savings,

[20] The incentive would have been $3,153,096 before the additional spending and $3,897,806 after the additional spending. $3,897,806 - $3,153,096 = $744,410.

expenditures and net benefits were to occur in 2019, when the net benefits cap is 10% and the expenditures cap is 30%.

Table 8: Department Scenario for 2019,
With 10% Net Benefits Cap and 30% Expenditures Cap

	2019		**Additional Spend**
			$2,172,742
1	Benefits	$43,000,000	$43,000,000
2	Expenses	$11,000,000	$13,172,742
3	**30% CIP Expenditures Cap**	**$3,300,000**	**$4,610,460**
4	Net Benefits	$32,000,000	$29,827,258
5	**10% Net Benefits Cap**	**$3,200,000**	**$2,982,726**
6	**Lesser of 3 and 5**	**$3,200,000**	**$2,982,726**
7	Additional Financial Incentive		($217,274)
8	Financial Incentive per $1 of spending		($0.10)
9	Additional Cost to Customers		$1,955,468

In the Department's 2019 scenario, the Company could have tried to game the incentive mechanism by spending an additional $2,172,742 and ending up with a lower incentive, not a higher one. Thus, Otter Tail's example is too risky for a rational utility to undertake.

D. *THE CIP EXPENDITURE CAP IS NOT CONTRARY TO MINNESOTA STATUTES* § 216B.16 Subd. 6c

Minnesota Statutes § 216B.16 Subd. 6c specifies that the Commission must consider the following factors when approving a financial incentive plan:

(1) Whether the plan is likely to increase utility investment in cost-effective energy consumption;
(2) Whether the plan is compatible with the interest of utility ratepayers and other interested parties;
(3) Whether the plan links the incentive to the utility performance in achieving cost effective conservation; and
(4) Whether the plan is in conflict with other provisions of this chapter.

Removing the expenditure cap for Otter Tail in 2018 and 2019 would not be in the interest of utility ratepayers because the modification would increase ratepayer costs for Otter Tail's actions that have already happened or are in the process of happening. Thus, Otter Tail's proposal would be contrary to the first and second considerations above. First, retroactively removing the expenditure cap will not increase Otter Tail's 2018 investment in cost-effective

energy consumption and is unlikely to increase investment in the remainder of 2019. Further, and as discussed above, affirming the cap will not incent Otter Tail to invest in non-cost-effective CIP projects.
Second, removing the expenditure cap for Otter Tail is not compatible with the interest of utility ratepayers. Minnesota's incentive mechanism is already the highest in the country based on the percent of CIP expenditures. Otter Tail's proposal would increase ratepayers' costs even more. As detailed in the Department's January 19, 2016 Shared Savings proposal for 2017-2019, the highest expenditure cap for DSM financial incentives was 15%, for both Indiana and Michigan.[21] Since that time, Michigan increased its expenditure cap to 20%.[22] Even though Minnesota's expenditure cap has been reduced to 30% for 2019 as compared to 35% for 2018 and 40% for 2017, Minnesota's 2019 expenditure cap appears to be 50% higher than the expenditure cap of any other state.

Without the expenditure cap, CenterPoint Energy's 2017 incentive would have been 70 percent of its CIP expenditures.[23] Without the expenditure cap, Otter Tail's incentives would range between 43 percent and 48 percent of its expenditures, depending on which expenditure figures are used, as shown in Table 9 below.

Table 9. 2017-2018 Net Benefits Caps as Percentage of Otter Tail CIP Expenditures, Company-Supported vs. Department-Supported Expenditures

	Net Benefits Cap as Percentage of Company-Supported Expenditures	Net Benefits Cap as Percentage of Department-Supported Expenditures
2017	43[24]	48[25]
2018	46[26]	48[27]

Incentives of this magnitude are unreasonable. The expenditure cap worked as designed, protecting ratepayers, while still providing CenterPoint and Otter Tail with the highest incentive (as a percent of expenditures) in the nation.

The Department concludes that an evaluation of whether any changes need to be made to the incentive mechanism to ensure that it reasonably responds to the four factors outlined above should be considered in Docket No. E,G/CI-08-133 where the Commission must make decisions on the Shared Savings financial incentive for the 2020 and 2021-2023 CIP years.

[21] See page 8 of the Department's 2017-2019 Shared Savings Proposal.
[22] https://aceee.org/sites/default/files/pims-121118.pdf See page 6.
[23] Incentive of $21,662,062 divided by 2017 CIP expenditures of $31,140,094 = 70 percent.
[24] Incentive of $3,189,580 divided by 2017 CIP expenditures of $7,345,274 = 43 percent.
[25] Incentive of $4,153,135 divided by 2018 CIP expenditures of $9,008,846 = 46 percent.
[26] Incentive of $3,189,580 divided by 2017 expenditures of $6,605,899 = 48 percent.
[27] Incentive of $4,153,135 divided by 2018 expenditures of $8,641,435 = 48 percent.

E. MAINTAINING RULES OF THE INCENTIVE DURING A CIP YEAR PROTECTS BOTH RATEPAYERS AND UTILITIES

As explained below, the Department concludes that Otter Tail's request for the Commission to approve a modification to the Shared Savings incentive mechanism is untimely, unreasonable and undermines protections for ratepayers *and* utilities. Any changes to the modification should be made on a prospective basis.

1. Protecting Ratepayers

Otter Tail's request in this docket is a prime example of how retroactively approving a modification to an existing approved incentive mechanism can harm ratepayers. Otter Tail requests that the Commission approve an after-the-fact modification, which for 2018 CIP achievements alone would cost the Company's ratepayers an additional $1 million. If the Commission approved Otter Tail's request to retroactively modify the financial incentive in Otter Tail's favor, CenterPoint, the other utility impacted by the expenditures cap, could argue that the Commission should also retroactively modify its 2017 incentive and require ratepayers to pay an additional $9.2 million, an action that clearly would not be in in the interest of ratepayers.

2. Protecting Utilities

In Docket No. E999/CIP-18-783, the Deputy Commissioner approved the electric IOUs' avoided costs to be used for their CIPs for 2021-2023. Compared to the avoided costs used for 2017-2020, all of the electric utilities projected significant declines in their 2021-2023 avoided costs. For example, Otter Tail projected that its avoided capacity costs will decrease about 40 percent, its avoided marginal energy costs will decrease 35-50 percent, and its avoided Transmission and Distribution (T&D) costs will decline 60-77 percent. When avoided costs fall, so do net benefits.[28] The actual net benefits of projects that the electric utility's customers invested in during 2017-2019 will be considerably lower than the net benefits that were calculated using earlier estimates of avoided costs.

Given the drop in value of avoided costs, a party could petition the Commission to reduce an electric utility's financial incentive for 2018 and 2019 achievements, potentially arguing that the avoided costs in 2018-2020 should not be significantly different than avoided costs in 2021-

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[28] The Department notes that gas IOUs also face significantly lower avoided costs for 2021-2023. A gas commodity cost of $3.25 per dekatherm (Dth) was approved in Docket No. G999/CIP-18-782 for 2021-2023. The new commodity cost is $1.02 per Dth lower than the gas commodity cost approved for the 2017-2020 CIPs, a reduction of 24 percent.

2023, and/or that updated avoided cost figures should be used to calculate current financial incentives. Indeed, the Office of the Legislative Auditor's (OLA) January 2005 Evaluation Report of the Energy Conservation Improvement Program, Report No. 05-04,[29] recommended that the utilities use up to date economic assumptions when they would have a significant impact on cost-effectiveness.[30] However, the Department opposed this OLA recommendation because it believed changing the rules of the incentive retroactively would be unfair to the utilities. The same is true for Otter Tail's 2018 and 2019 CIP achievements. It would be unfair for the Commission to retroactively reduce Otter Tail's avoided costs at this point because the Company planned for and implemented its CIP through 2018 and half of 2019 without knowing that their avoided costs might be lowered. The same principle applies to any proposal to retroactively change the Shared Savings incentive calculation after a utility has planned, and while implementing, its CIP.

F. APPLICATION OF THE CIP EXPENDITURES CAP DOES NOT TREAT OTTER TAIL DIFFERENTLY FROM OTHER IOUS

Starting on page 2 of its June 24, 2019 Reply Comments, Otter Tail argued that the expenditure cap treats Otter Tail Power differently than it does Minnesota Power and Xcel Electric. Otter Tail's Chart 1 shows that Minnesota Power and Xcel's 2018 incentives were both equal to 12% of net benefits while the Department recommended an incentive level for Otter Tail that equals 7.9% of net benefits achieved. Otter Tail's Chart 2 shows that Minnesota Power's 2018 energy savings as a percent of non-CIP-opt-out retail sales were equivalent to 2.61%, Xcel Electric's were 2.35%, and Otter Tail's were 4.03%.

In its August 5, 2016 *Order Adopting Modifications to Shared Savings Demand-Side Management Financial Incentive Plan,* Order Point 1 established the same net benefits caps for all utilities, both gas and electric. Order Point 2 established the same expenditure caps for all utilities, both gas and electric. As previously noted, the application of these Order Points led to Otter Tail and CenterPoint Energy encountering the CIP expenditures cap in 2017 and Otter Tail in 2017 and 2018. The incentive mechanism has been applied to all of electric and gas utilities equally.

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[29] See https://www.auditor.leg.state.mn.us/ped/pedrep/0504all.pdf.

[30] Page 38 of the 2005 OLA Report stated, "The department should also allow the utilities to use up-to-date economic assumptions (such as natural gas prices and discount rates) when the updated information will have a significant impact on the benefit-cost calculations. While it would be unproductive for the department to reexamine and reassess all the utilities' benefit-cost calculations every time an economic indicator changes, some changes are large enough to warrant a reexamination. However, the department has concerns about the impact that updated economic assumptions will have on the operation of the department's incentive/bonus payment system. As we discussed earlier, utilities that meet or exceed their energy savings goals receive bonus payments, and the size of these payments are partially determined by the net benefits that the utilities' conservation programs generate. While we did not have the time to research all the ramifications that updated information will have on the process for determining the bonus payments, we strongly encourage the department to develop a mechanism for ensuring that benefit-cost ratios that are published in the utilities' status reports are accurate."

G. *THE COMMISSION'S 2013 MODIFICATIONS TO MINNESOTA POWER'S SHARED SAVINGS INCENTIVE MECHANISM WERE PROPOSED AND APPROVED ON A PROSPECTIVE BASIS*

1. Otter Tail's Argument

On page 9 of its June 24, 2019 Reply Comments, Otter Tail argued that the Commission should approve the Company's requested modification to the financial incentive mechanism for 2018 and 2019 just like the Commission approved a modification for Minnesota Power's incentive mechanism in 2013.

Below the Department provides a summary of the record concerning the Commission's approval of the change to Minnesota Power's incentive referenced by Otter Tail. As can be seen, the modification to Minnesota Power's incentive mechanism was discussed and approved by the Commission before the mechanism was applied beginning on January 1, 2014. The timing of the change in Minnesota Power's incentive mechanism was prospective, and therefore appropriate. Otter Tail Power's proposal to be exempted from the CIP expenditure cap is retroactive, and therefore not appropriate.

2. *Background on Minnesota Power Decision*

On July 3, 2012 in Docket No. E,G999/CI-08-133, the Department submitted *A Report on the Impacts of the 2011 New Shared Savings DSM Financial Incentive on Investor-Owned Utility Conservation Achievements and Customer Costs* (2011 Shared Savings Report or 2011 Report). In the 2011 Report, the Department concluded that:[31]

- Minnesota's natural gas utilities receive a significantly lower incentive on a per-expenditure and a per-dollar-of-net-benefits basis than Minnesota's electric utilities, and
- Although the Commission's removal of the non-linear adjustment[32] will rein in the costs of the incentive mechanism, Minnesota's incentive mechanism will continue to be one of the most expensive in the nation especially when compared on a per-expenditure basis.

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[31] See Cover Letter, page 1 of the Department's 2011 Shared Savings Report in Docket No. E,G999/CI-08-133 (July 3, 2012).

[32] The "non-linear" adjustment to the incentive was designed to ensure that utilities received approximately the incentive predicted by the Shared Savings model at energy savings levels higher than the utility's approved CIP goal. The adjustment was predicated on the assumption that once a utility surpassed its CIP goal, the net benefits would increase less with each unit of energy saved and the utility would not receive as high of an incentive as intended. To compensate for this possibility, an adjustment was made which effectively increased the percent of net benefits awarded at savings levels above each utility's approved CIP energy-savings goal. However, for the most part, utilities' net benefits did not decline below the level assumed into the utilities' Shared Savings model. Consequently, the net benefits were multiplied by a higher percent to be awarded, resulting in high incentives. As a result, the Department concluded that the non-linear adjustment is distorting the incentive mechanism and recommended that the Commission remove the mechanism beginning with 2012. The Commission approved this recommended modification on March 30, 2012.

Based on these conclusions, the Department recommended the following:[33]

- For the electric utilities, the Department recommended that the shared savings incentive mechanism:
  - Be calibrated and capped at 7.0 cents per kWh,
  - With another cap at 20 percent of net benefits.
- For the natural gas utilities, the Department recommended that the shared savings mechanism:
  - Be calibrated at $9 per Mcf, and capped at $5.25 per Mcf,
  - With another cap at 20 percent of net benefits.

In its August 3, 2012 Reply Comments Minnesota Power recommended that the cap for its incentive be set at 30% of net benefits, instead of at the 20% of net benefits recommended by the Department. Without the increase in the net benefits cap, Minnesota Power reasoned that its incentive would not approach the 7.0 cents per kWh cap.

On page 14 of the Department's September 11, 2012 Reply Comments, the Department stated the following:

> Minnesota Power provides analysis in its comments showing that if the cap of 20 percent of net benefits is implemented, the utility's incremental incentive would not increase once it reaches energy savings of approximately 1.1 percent of retail sales, and would only equal approximately 4.8 cents per kWh. Minnesota Power recommends increasing its cap to 30 percent of net benefits to rectify this situation. The Department notes that the new incentive mechanism will not be applied to MP until 2014. Our present analysis is based on MP's avoided cost assumptions that MP first filed with the Department in 2010 for use in its 2011-2013 CIP. Given that MP's avoided cost assumptions are likely to be significantly different when MP develops its new assumptions next year for its 2014-2016 CIP, the Department recommends that the Commission defer the issue of whether the 20 percent net benefits cap is appropriate for MP's incentive for its 2014-2016 activity until next year.

In the Commission's December 20, 2012 *Order Adopting Modifications to Shared Savings Demand Side Management Financial Incentive* Order Point 2D required the following:

> The incentive shall be capped at 20 percent of net benefits for all utilities except for Minnesota Power. The Commission will defer a

[33] See Cover Letter, pp. 1-2 of the Department's 2011 Shared Savings Report in Docket No. E,G999/CI-08-133 (July 3, 2012).

> decision on the application of the 20 percent cap of net benefits for Minnesota Power until 2013 to allow for the consideration of updated avoided cost information for this utility.

In addition, Order Point 2M stated:

> The Department shall file a recommendation with the Commission on the application of a net benefits cap for Minnesota Power's incentive by October 1, 2013. The recommendation should be filed in Docket No. E,G-999/CI-08- 133.

On October 1, 2013 the Department submitted Comments concerning *Modifications to Minnesota Power's Shared Savings DSM Financial Incentive Mechanism*. At that point, the common goal of the incentive mechanism was to deliver an incentive of approximately 8.75 cents per kWh when an electric IOU reached energy savings of 1.5% of retail sales.[34] Based on the Department's review, the Department recommended that the Commission approve a percent of net benefits cap of 30% for MP's Shared Savings DSM Financial Incentive Mechanism, which would be applied beginning in 2014.

On November 19, 2013, the Commission agreed with and adopted the recommendations of the Department and approved an incentive cap for Minnesota Power's Shared Savings DSM Financial Incentive equal to 30% of net benefits.[35]

Thus, the change to Minnesota Power's incentive mechanism was approved on a prospective basis, before it was applied, beginning January 1, 2014. Further, the modification was proposed and approved in the E,G999/CI-08-133, a more appropriate venue than a docket for an individual utility.

H. SUMMARY AND CONCLUSIONS

Otter Tail made the unreasonable proposal that the Commission exempt the Company from the Shared Savings CIP expenditures cap for 2018, a year that is already complete, and for 2019, which is already half over. The Department concludes that Otter Tail's request to modify its incentive mechanism should be rejected on grounds that any change to the incentive mechanism should only be made on a prospective basis. Further, Commission approval of the request would harm Otter Tail's ratepayers by requiring them to pay Otter Tail $1 million more than the Company's initial request for 2018 alone. In addition, approval of Otter Tail's request could lead to CenterPoint proposing that the Commission approve an additional $9.2 million for its 2017 CIP achievements.

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[34] The Commission's December 20, 2012 Order increased the cents per first year kWh cap to 8.75 cents per kWh.
[35] See Commission Order in Docket No. E,G999/CI-08-133 (November 19, 2013).

Finally, the Department concludes that Docket No. E,G999/CI-08-133 is the proper venue for Otter Tail to propose changes to the incentive mechanism, and only on a prospective basis.

IV. DEPARTMENT RECOMMENDATIONS

The Department suggests that Otter Tail consider filing a decoupling mechanism petition with the Commission if the Company is concerned about the revenue impact of any lost sales that may result from its conservation efforts.

The Department recommends that the Commission:

- Find that CIP expenditures for Otter Tail's Company-Owned Street and Area Lighting program be ineligible to be included in the Shared Savings DSM financial incentive calculation; however, if the Commission finds that these expenses are eligible, the Department is not opposed to the Company's proposal to adjust the 2018 financial incentive by ($148,786);
- Approve a 2018 financial incentive of $2,728,752;
- Approve the Department's 2018 CIP tracker included in Attachment A to these Reply Comments and summarized in Table 2 above, with an ending balance of $5,990,634;
- Require Otter Tail to, in future filings, track monthly sales as well as recoveries, by revenue source (base rates or CCRA) in its CIP tracker;
- Approve a Conservation Cost Recovery Adjustment rate of $0.0069/kWh, effective October 1, 2019, or the first of the month following the Commission's Order in the instant docket;
- Grant a variance to Minnesota Rules parts 7820.3500 (E) and (K) and 7825.2600, to allow Otter Tail to continue to combine the Fuel Clause Adjustment (FCA) with the Conservation Improvement Adjustment on customer bills, effective until the Commission issues an Order setting the Company's 2020-2021 CCRA;
- Direct Otter Tail to submit a compliance filing within ten days of the Commission's Order with revised tariff sheets reflecting the Commission's determinations in this matter; and
- Deny Otter Tail's request for the Commission to modify the Shared Savings incentive mechanism for the Company for 2018 and 2019.

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Commerce Department's 2018 CIP Tracker for Otter Tail Power

	Expenses	Jan 18 Actual	Feb 18 Actual	Mar 18 Actual	Apr 18 Actual	May 18 Actual	June 18 Actual	July 18 Actual	Aug 18 Actual	Sept 18 Actual	Oct 18 Actual	Nov 18 Actual	Dec 18 Actual	Annual Summary
1	Beginning Tracker Balance ($) - Under / (Over) Recovered	7,362,345	6,259,713	5,944,235	5,278,558	4,855,110	4,493,357	3,949,317	3,390,454	2,736,225	2,646,819	5,018,112	4,539,295	7,362,345
2	Carrying Charge Rate	0.21291%	0.21291%	0.21291%	0.21291%	0.21291%	0.21291%	0.21291%	0.21291%	0.21291%	0.21291%	0.21291%	0.21291%	
3	**Carrying Charge** (Line 1 x Line 2)	15,675	13,327	12,656	11,238	10,337	9,567	8,408	7,219	5,826	5,635	10,684	9,665	**120,237**
4	CIP Program Expenditures	309,062	1,030,817	515,209	663,730	603,781	440,261	477,475	365,051	880,227	430,086	671,208	2,640,855	9,027,762
5	Adjustments	3,795												3,795
6	Performance Incentive	-	-	-	-	-	-	-	-		2,938,110	-		2,938,110
7	**Total Expenses, Adjustments, & Incentive** (Line 1 + Line 3 + Line 4 + Line 5 + Line 6)	**7,690,878**	**7,303,858**	**6,472,100**	**5,953,526**	**5,469,227**	**4,943,185**	**4,435,200**	**3,762,724**	**3,622,278**	**6,020,650**	**5,700,005**	**7,189,815**	**19,448,454**
	Recovery													
8	Sales kWh													
9	Base Rate Recovery (CCRC) (per kWh)	0.00223	0.00223	0.00223	0.00223	0.00223	0.00223	0.00223	0.00223	0.00223	0.00223	0.00223	0.00223	
10	**Base Rate Cost Recovery ($)** (Line 8 x Line 9)													**(3,900,402)**
11	CCRA (per kWh)	0.00536	0.00536	0.00536	0.00536	0.00536	0.00536	0.00536	0.00536	0.00536	0.00600	0.00600	0.00600	
12	**CCRA Recovery ($)** (Line 8 x Line 11)													**(9,557,418)**
13	**Total Recovery** (Line 10 + Line 12)	**(1,431,164)**	**(1,359,622)**	**(1,193,543)**	**(1,098,417)**	**(975,870)**	**(993,869)**	**(1,044,746)**	**(1,026,498)**	**(975,459)**	**(1,002,537)**	**(1,160,709)**	**(1,195,384)**	**(13,457,820)**
14	**Ending Balance ($)** (Line 7 + Line 13)	6,259,713	5,944,235	5,278,558	4,855,110	4,493,357	3,949,317	3,390,454	2,736,225	2,646,819	5,018,112	4,539,295	5,994,430	**5,990,634**

Commerce Department's Projected CIP Tracker for Otter Tail Power using CCRA of $0.0069/kWh,
October 1, 2019- September 30, 2020

	Expenses	Oct 19 Forecast	Nov 19 Forecast	Dec 19 Forecast	Jan 20 Forecast	Feb 20 Forecast	Mar 20 Forecast	Apr 20 Forecast	May 20 Forecast	June 20 Forecast	July 20 Forecast	Aug 20 Forecast	Sept 20 Forecast	Annual Summary
1	Beginning Tracker Balance ($) - Under / (Over) Recovered	3,253,891	2,687,015	2,124,677	2,347,159	1,340,599	324,066	(191,345)	(761,292)	(1,303,338)	(1,833,271)	(2,304,130)	(2,339,308)	3,253,891
2	Carrying Charge Rate	0.21291%	0.21291%	0.21291%	0.21291%	0.21291%	0.21291%	0.21291%	0.21291%	0.21291%	0.21291%	0.21291%	0.21291%	
3	**Carrying Charge** (Line 15 x Line 16)	6,928	5,721	4,524	4,997	2,854	690	(407)	(1,621)	(2,775)	(3,903)	(4,906)	(4,981)	**7,121**
4	CIP Program Expenditures	661,062	798,564	1,736,251	516,955	489,033	832,405	655,806	524,825	541,897	673,777	1,151,156	761,224	9,342,955
5	Performance Incentive												2,716,510	2,716,510
6	**Total Expenses & Incentive** (Line 1 + Line 3 + Line 4 + Line 5)	**3,921,881**	**3,491,300**	**3,865,451**	**2,869,112**	**1,832,486**	**1,157,161**	**464,054**	**(238,088)**	**(764,216)**	**(1,163,397)**	**(1,157,880)**	**1,133,445**	**15,320,478**
	Recovery													
7	Sales kWh (Line 5 + Line 6)	135,253,662	149,684,930	166,297,042	167,416,479	165,215,775	147,700,563	134,210,986	116,675,775	117,092,535	124,943,380	129,400,704	125,771,690	1,679,663,521
8	Base Rate Recovery (CCRC) (per kWh)	0.00223	0.00223	0.00223	0.00223	0.00223	0.00223	0.00223	0.00223	0.00223	0.00223	0.00223	0.00223	
9	**Base Rate Cost Recovery ($)** (Line 7 x Line 8)	(301,615.67)	(333,797.39)	(370,842.40)	(373,338.75)	(368,431.18)	(329,372.26)	(299,290.50)	(260,186.98)	(261,116.35)	(278,623.74)	(288,563.57)	(280,470.87)	**(3,745,650)**
10	CCRA (per kWh)	0.0069000	0.0069000	0.0069000	0.0069000	0.0069000	0.0069000	0.0069000	0.0069000	0.0069000	0.0069000	0.0069000	0.0069000	
11	**CCRA Recovery ($)** (Line 7 x Line 10)	(933,250)	(1,032,826)	(1,147,450)	(1,155,174)	(1,139,989)	(1,019,134)	(926,056)	(805,063)	(807,938)	(862,109)	(892,865)	(867,825)	**(11,589,678)**
12	**Total Recovery** (Line 9 + Line 11)	**(1,234,866)**	**(1,366,623)**	**(1,518,292)**	**(1,528,512)**	**(1,508,420)**	**(1,348,506)**	**(1,225,346)**	**(1,065,250)**	**(1,069,055)**	**(1,140,733)**	**(1,181,428)**	**(1,148,296)**	**(15,335,328)**
13	**Sub-Balance ($)** (Line 6 + Line 12)	2,687,015	2,124,677	2,347,159	1,340,599	324,066	(191,345)	(761,292)	(1,303,338)	(1,833,271)	(2,304,130)	(2,339,308)	(14,850)	**(14,850)**

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	Chair
Nancy Lange	Commissioner
Dan Lipschultz	Commissioner
Matthew Schuerger	Commissioner
John A. Tuma	Commissioner

In the Matter of Commission Review of Utility Performance Incentives for Energy Conservation Pursuant to Minn. Stat. § 216B.241, Subd. 2c

ISSUE DATE: August 5, 2016

DOCKET NO. E,G-999/CI-08-133

ORDER ADOPTING MODIFICATIONS TO SHARED SAVINGS DEMAND-SIDE MANAGEMENT FINANCIAL INCENTIVE PLAN

PROCEDURAL HISTORY

Under Minn. Stat. § 216B.16, subd. 6c, the Commission has established an incentive plan to encourage utilities to promote energy conservation. This plan is designed to reduce the financial losses that a utility incurs when conservation programs succeed and thus reduce the amount of energy the utility sells.

On December 20, 2012, the Commission issued its 2012 Incentive Modification Order revising the mechanism for calculating the amount of financial incentives for Demand-Side Management (DSM) programs implemented by electric and natural gas utilities.[1] The order also directed the Minnesota Department of Commerce (the Department) to evaluate this mechanism and, by July 1, 2015, recommend whether to continue, discontinue, or change the incentive plan.[2]

On July 1, 2015, the Department issued a report on how conservation improvement programs implemented by investor-owned energy utilities in Minnesota influenced the amount of energy savings generated, and costs incurred, by those utilities for 2010-2014. The Department filed a revised report on July 14.

[1] Order Adopting Modifications to Shared Savings Demand Side Management Financial Incentive (December 20, 2012). Demand-side management (such as promoting conservation) and supply-side management (such as building generators) are two methods by which a utility may meet the demand for energy and power in their service areas. Minn. Stat. § 216B.241, subd. 1(c) states that "'Energy conservation' means demand-side management of energy supplies resulting in a net reduction in energy use."

[2] *Id*. at Ordering Paragraph 2.Q.

On January 19, 2016, the Department filed a proposal for modifying the DSM financial incentive mechanism.

The following parties filed comments on the Department's report, the Department's proposal, or both:

- Center for Energy and the Environment (CEE)
- CenterPoint Energy (CenterPoint)
- The Department
- Fresh Energy
- Great Plains Natural Gas Company (Great Plains)
- Minnesota Chamber of Commerce (the Chamber)[3]
- Minnesota Energy Resources Corporation (MERC)
- Minnesota Power
- Northern States Power Company d/b/a Xcel Energy (Xcel)
- Office of the Attorney General (OAG)
- Otter Tail Power Company (Otter Tail)

On May 25, 2016, the Commission met to consider the matter.

FINDINGS AND CONCLUSIONS

I. Background

A. Statutory Provisions

The Minnesota Legislature has given the Commission the duty to ensure that the rates charged by public utilities are just and reasonable.[4] Generally this means setting rates that would permit

[3] According to its filings, the Chamber represents more than 2300 businesses located throughout Minnesota.
[4] Minn. Stat. § 216B.03.

a prudently managed utility a fair opportunity to recover the costs of the resources it acquires to serve its customers, and to earn a fair return on investment.[5]

Energy conservation, a form of Demand-Side Management, provides a valuable resource to a utility. Conservation can help a utility reduce its fuel-related costs, including costs related to emissions. It can also help a utility avoid or defer investments in generation, transmission, and distribution facilities.[6]

The Legislature directs each electric and natural gas public utility to implement energy conservation improvement programs (CIPs). The Legislature established two CIP goals. First, the Legislature directs each energy public utility to invest in CIPs a sum equal to a specified percentage of the utility's Minnesota gross operating revenues, excluding revenues from certain large industrial customers (CIP-exempt customers).[7] Second, the Legislature directs each utility to pursue a goal of saving energy equal to 1.5 percent of gross annual retail energy sales, unless the Commissioner of Commerce establishes a more modest goal.[8]

Consistent with statute and implementing regulations, utilities file biennial or triennial CIP plans.[9] The Department then sets each utility's energy-savings goals[10] and approves its conservation programs,[11] while the Commission determines, under its ratemaking authority, if and how a utility may recover its CIP-related costs.[12]

For example, the Commission may authorize a utility to recover CIP-related costs via a Conservation Cost Recovery Charge built into the utility's rates.[13] And the Commission may authorize a utility to implement revenue decoupling, a rate design that helps ensure that a utility recovers certain fixed costs regardless of how much energy it sells.[14] But while these cost-recovery mechanisms may reduce a utility's *disincentive* to depress its own sales via conservation, they do not affirmatively *encourage* the practice of promoting conservation.

To that end, the Legislature authorized the Commission to approve a system of financial incentives to promote conservation. Minnesota Statutes § 216B.16, subdivision 6c, states:

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5 *Bluefield Water Works and Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923); *Federal Power Commission et al v. Hope Natural Gas Co*., 320 U.S. 591, 603 (1944).

6 Department Report, at 17 (July 14, 2015).

7 Minn. Stat. §§ 216B.16, subd. 6b(c); 216B.241, subp. 1a. Also, § 216B.241, subps. 2(d) and (g) forbids a public utility from investing in energy conservation improvements that directly benefit exempt customers.

8 Minn. Stat. §§ 216B.2401; 216B.241, subd. 1c.

9 Minn. R. 7690.0500, subp. 1 (providing for biennial CIP filings); *but see*, for example, *In the Matter of Xcel Energy's Conservation Improvement Program Notice of Intent to File Triennial Plan and Variance Request*, Docket No. E,G-002/CIP-06-80, Order (March 21, 2006) (granting a variance to permit triennial CIP filings).

10 Minn. Stat. § 216B.241, subd. 1c.

11 *Id.*, subd. 2.

12 *Id.*, subd. 2b.

13 Minn. Stat. § 216B.16, subd. 6b(c).

14 Minn. Stat. § 216B.2412.

(a) The commission may order public utilities to develop and submit for commission approval incentive plans that describe the method of recovery and accounting for utility conservation expenditures and savings….

(b) In approving incentive plans, the commission shall consider:

(1) whether the plan is likely to increase utility investment in cost-effective energy conservation;

(2) whether the plan is compatible with the interest of utility ratepayers and other interested parties;

(3) whether the plan links the incentive to the utility's performance in achieving cost-effective conservation; and

(4) whether the plan is in conflict with other provisions of this chapter.

(c) The commission may set rates to encourage the vigorous and effective implementation of utility conservation programs. The commission may:

(1) increase or decrease any otherwise allowed rate of return on net investment based upon the utility's skill, efforts, and success in conserving energy;

(2) share between ratepayers and utilities the net savings resulting from energy conservation programs to the extent justified by the utility's skill, efforts, and success in conserving energy; and

(3) adopt any mechanism that satisfies the criteria of this subdivision, such that implementation of cost-effective conservation is a preferred resource choice for the public utility considering the impact of conservation on earnings of the public utility.

B. History of the Current Shared Savings Incentive

1. Background

For more than 25 years the Commission has authorized financial incentives to encourage utilities to promote energy conservation.[15] But in 1998 the Department asked to terminate the Commission's financial incentive mechanism due to the unanticipated growth in incentive payments.[16]

So beginning in 2000 the Commission implemented its Shared Savings DSM Financial Incentive Plan, employing a formula that provides incentives only after a utility demonstrates that its conservation programs generate net benefits.[17] That is, utilities would earn incentive payments only when the present value of the generation, transmission, and distribution costs avoided as a result of CIP investments exceeds the net present value of any utility CIP costs.[18]

2. Current Mechanism's Incentive Formula

The incentive formula has changed over time,[19] but currently the formula employs thresholds, incremental incentives, and caps.[20]

Threshold: To avoid rewarding utilities for achieving only incidental savings, the formula provides incentive payments only for utilities that achieve a specified minimum level of savings. The Commission set this minimum threshold at the lesser of (A) 0.4 percent of retail sales or (B) half of the utility's average level of energy savings over a specified period of years, where the average is calculated after excluding data from the years with the maximum and minimum level of savings.

Incremental Incentive: After a utility achieves the threshold level of energy savings, the incentive formula awards the utility a specific dollar amount for each additional amount of energy saved. The Commission anticipated that utilities would pursue the least-cost savings first, and that the cost of achieving additional savings would increase as the savings increased; consequently the

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[15] *See, e.g., In the Matter of a Summary Investigation into Financial Incentives for Encouraging Demand-Side Resource Options for Minnesota Electric Utilities and Bidding Systems*, Docket No. E-999/CI-89-212, Order Requiring Electric Utilities to File Financial Incentive Proposals in 1991 (February 28, 1991).
[16] *See In the Matter of a Commission Investigation into Continuation of Demand-Side Management Financial Incentives for Electric Utilities*, Docket No. E-999/CI-98-755; Order Convening Chair's Round Table and Requiring Filings (December 2, 1998). *See also In the Matter of a Commission Investigation into Continuation of Demand-Side Management Financial Incentives for Gas Utilities*, Docket No. G-999/CI-98-1009.
[17] *In the Matter of Requests to Continue Demand-Side Management Financial Incentives Beyond 1998*, Docket No. E, G-999/CI-98-1759, Order Approving Demand-Side Management Financial Incentive Plans (April 7, 2000).
[18] *See* Department Report, at 17 (defining *net benefits*).
[19] *See* Order Establishing Utility Performance Incentives for Energy Conservation (January 27, 2010); Order Removing Non-Linear Adjustment from the Shared Savings DSM Financial Incentive (March 30, 2012); Decision (April 26, 2012) (adopting Average Savings Method for measuring the savings arising from behavior-modification programs).
[20] Order Adopting Modifications to Shared Savings Demand Side Management Financial Incentive (December 20, 2012) (2012 Incentive Modification Order).

Commission elected to award utilities ever larger incentives for achieving ever larger savings. The magnitude of this dollar amount is calibrated so that, at a savings level of 1.5 percent of retail sales, an electric utility would earn an incentive equal to $0.07 per kilowatt-hour (kWh) saved. Similarly, at a savings level of 1.5 percent, a gas utility would *theoretically* earn $9 per thousand cubic feet (Mcf) saved.[21]

The precise amounts of these earnings would be re-calibrated for each utility at the beginning of each year, based on data filed by the utility each February 1. The mechanism is intended to treat all investor-owned electric utilities comparably, and to treat all investor-owned gas utilities comparably, with respect to the financial incentive awarded per unit of energy saved in a CIP's first year.[22]

Cap: While the formula provides for a utility's incentives to grow as the utility achieves ever greater levels of conservation, the formula caps this growth in two ways.

First, the Commission established the maximum incentive a utility could earn per unit of energy saved. The formula is complicated and reflects an Energy Savings Benchmark of 1.5 percent of retail sales for electric utilities and 1.0 percent for gas utilities, resulting in a maximum incremental incentive of $0.0875 per kWh for electric utilities and $6.875 per Mcf for gas.[23]

Second, the Commission capped the amount that a utility could recover at 20 percent of the net benefits generated—except for Minnesota Power. Because Minnesota Power sells a disproportionate share of its energy to CIP-exempt customers, the 20 percent cap would result in inappropriately low incentive payments. Consequently the Commission authorized that utility to use a 30 percent cap.[24]

In summary, the current incentive formula is as follows:

[21] The $9 per Mcf figure is used for calibration, but in practice it exceeds the Commission's maximum incentive payment of $6.875 per Mcf; see below.
[22] Department Comments, at 16 (January 19, 2016).
[23] The disparity between the Energy Savings Benchmarks for electric and gas utilities reflects the Commission's desire to give similar treatment to utilities that achieve conservation goals of comparable difficulty. Between 2007 and 2011, a majority of the electric utilities were able to reach energy savings of 1.5 percent, while a majority of natural gas utilities were able to reach energy savings equal to 1.0 percent. See Department Comments, at 19 & n.9 (July 9, 2012).
[24] Order (November 19, 2013).

	Electric Utilities	Gas Utilities
Energy Savings Benchmark	1.5 percent of retail sales.	1.0 percent of retail sales.
Threshold	Withhold incentives from utilities that fail to achieve savings of at least – (A) 0.4 percent of retail sales or (B) half of the utility's previous level of energy savings.	
Net Benefit Cap	For each unit of energy saved, limit the utility's share of net benefits to no more than 20 percent (or 30 percent for Minnesota Power).	
Incremental Incentive	Set each utility's incremental incentive amounts at the beginning of each CIP year, with the incentive per unit of energy saved increasing as the savings increase, even beyond the Energy Savings Benchmark.	
Cap per Unit Saved	Cap a utility's incremental incentive at $0.0875 per kWh saved.	Cap a utility's incremental incentive at $6.875 per Mcf saved.
CIP Expenditure Cap	None specified.	

3. Current Mechanism's Miscellaneous Provisions

In addition, the 2012 Incentive Modification Order contained a number of the miscellaneous provisions refining how the incentives would be calculated. For example, these paragraphs clarify the following:

- For purposes of calculating a utility's incentives, utilities should ignore energy sales to CIP-exempt customers.

- The costs of any legislatively-mandated, non-third-party projects (*e.g.*, the 2007 Next Generation Energy Act assessments,[25] University of Minnesota Initiative for Renewable Energy and the Environment costs[26]) would be excluded from the calculation of net benefits awarded at specific energy savings levels (calculated before the CIP year begins) and in the calculations of net benefits and energy savings achieved and incentive awarded (calculated after the CIP year ends).

- Costs, energy savings, and energy production related to electric utility infrastructure costs,[27] solar installation, [28] and biomethane purchases[29] would not be included in energy savings for DSM financial incentive purposes.

[25] *See* 2007 Laws, art. 2.
[26] *Id.*, § 3, subd. 6.
[27] Minn. Stat. § 216B.1636.
[28] Minn. Stat. § 216B.241, subd. 5a.
[29] *Id.*, subd. 5b.

- By February 1 of each year, each utility would file data supporting a revised incentive plan for the following year.

Finally, the Commission directed the Department to file a report reviewing the financial incentive mechanism, recommending whether or not to continue the mechanism and whether to make changes to it. The report was due by July 1, 2015.

II. The Department's Report and Recommendation

A. The Department's Analysis of the Current Incentive Mechanism

The Department filed its report on the effect of CIPs implemented by Minnesota's investor-owned electric and natural gas utilities on July 1, 2015, and filed a revised version on July 14. As part of this report, the Department attached a study by the American Council for an Energy Efficient Economy (ACEEE).

And on January 19 and February 19, 2016, the Department filed recommendations for improving the existing incentive mechanism.

Briefly, the Department concluded that during the implementation of the Commission's Shared Savings DSM Financial Incentives Plan from 2010 and 2014, the affected utilities generated more than $2.1 billion of net benefits. But the Department also identified two faults in the current mechanism.

First, the Department argued that the existing formula is needlessly generous to utilities—and needlessly burdensome to ratepayers—and thus should be pared back. The ACEEE study documented that Minnesota provides greater incentives for conservation than any other state by almost every measure.[30]

Second, the Department argued that the existing formula is needlessly complicated and focused on the wrong variables, and thus should be redesigned. According to the Department, the present formula was designed to provide a similar level of incentives to investor-owned utilities for each unit of energy a utility saved in the first year of a CIP. The formula was not designed to equalize the share of a CIP's net benefits that would accrue to utilities with similar levels of savings, or equalize the share of CIP expenditures that utilities could recover via incentive payments. As a result, similarly situated utilities might derive very different levels of incentive compensation.

B. The Department's Proposal

The Department now proposes a more transparent incentive formula designed to provide all electric utilities that achieve an equivalent level of savings with an equivalent share of the

[30] *See* Department Report, Attachment 4 (ACEEE Report). In the cover letter to its report, the Department concludes that "Minnesota's incentives are higher than states with comparable utility programs when examining incentive per unit of energy saved, percent of net benefits created, or percent of expenditures…."

resulting net benefits, and to accord analogous treatment to all gas utilities.[31]

1. Similarities to Current Plan

The Department's proposed plan emulates the current one in certain respects. Both plans do the following:

- Identify a threshold level of savings that a utility must reach before the utility can begin qualifying for financial incentives.
- Focus on providing incentives for electric utilities to achieve savings of around 1.5 percent of retail sales, and for gas utilities to achieve savings of around 1.0 percent.
- Provide incentives for utilities even when their savings levels fall short of those goals, and additional incentives for utilities when their savings exceed those goals.
- Provide incremental incentives that grow as the utility's level of savings grows, but that eventually reach a plateau.

In addition, the Department's proposal would generally encompass the miscellaneous provisions that the Commission adopted as part of its current plan.

2. Differences from Current Formula

But the Department's new incentive formula differs from the current formula in many details—including its threshold, its incremental incentives, its caps, and its miscellaneous provisions.

Threshold: Under the current formula, the threshold is established based on a complicated calculation of half the utility's average level of energy savings or 0.4 percent of retail sales. In contrast, the Department's formula sets the threshold at roughly two-thirds of the energy savings benchmarks. That is, an electric utility with a savings benchmark of 1.5 percent of retail sales would qualify for incentives when it managed to save at least 1.0 percent; a gas utility with a 1.0 percent benchmark would qualify incentives when it managed to save at least 0.7 percent.[32]

Incremental Incentive: Incremental incentives are intended to encourage utilities that can achieve the threshold level of savings to pursue ever greater savings. In the interest of fairness, the mechanism is designed to give all investor-owned electric utilities an equivalent opportunity to earn incentives, and to do the same for all investor-owned gas utilities. The current mechanism provides electric utilities with a comparable amount of incentives if their CIP projects generate a comparable amount of savings in their first year—and provides analogous opportunities to gas utilities. In contrast, the new mechanism seeks to provide all electric utilities that reduce retail

[31] Department Reply Comments, at 6 (February 19, 2016).
[32] Department Reply Comments, at 22 (February 19, 2016).

sales by a given percentage with a comparable share of the net benefits created by those savings. And the Department favors according similar treatment to all gas utilities—and provides comparable opportunities to gas utilities.

The current mechanism requires each utility to make annual filings to establish an individually-tailored schedule of incremental incentives for the year. This schedule lists a growing amount of financial incentives that the utility could earn for each level of savings achieved, reaching a specified financial incentive when the utility achieves savings equal to 1.5 percent of retail sales. The incentive levels would continue to increase as savings levels increased.

In contrast, the Department's new mechanism establishes fixed schedules of incremental incentives, measured in terms of a share of net benefits achieved, based on the equation and table set forth in Attachment A. The schedule provides a list of financial incentives that grow at a rate of 0.75 percent of net benefits for each additional 0.1 percent of retail sales avoided, after the utility has achieved the threshold level of savings. Incentive levels would continue to grow as the utility's savings grow until the utility exceeded its Energy Savings Benchmark by 0.2 percent of retail sales. At that point, the Department's formula would award the utility the maximum allowable share of the net benefits generated by each additional unit of energy saved—the Net Benefit Cap.[33]

Caps: Under the current formula, the incentive levels increase as savings levels increase until the formula reaches one of two caps: a maximum price per unit of energy saved, or a maximum share of net benefits achieved. Having reached these caps, a utility may still earn more incentive payments by achieving more savings.

Under the Department's formula, incremental incentive levels would continue to grow as the utility's savings grow until the utility exceeds its Energy Savings Benchmark by 0.2 percent of retail sales. At that point, the utility would be earning the maximum allowed share of net benefits—the Net Benefits Cap. Again, the utility may continue to accrue incentive payments by achieving more savings. But the Department also caps the total amount of incentives a utility may earn in a year, measured as a fraction of the utility's investment in CIP projects—the CIP Expenditure Cap.

These caps are intended to reduce the total amount of incentive payments paid. To better enable utilities to adjust to this change, the Department recommends phasing the caps in gradually over three years.

So for the first year of the new formula, the Department recommends reducing the Net Benefits Cap from the current 20 percent (or, for Minnesota Power, 30 percent) to 13.5 percent. The Department picked this cap to match the state with the highest Net Benefits Cap in the country,

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[33] At the threshold level of savings, a utility would earn a portion of net benefits equal to:

*Net Benefit Cap – 0.75 % * [(Energy Savings Benchmark + 0.2 %) – threshold]/ 0.1%.*

See CenterPoint Reply Comments, Attachment A, at 2-3 (February 19, 2016).

other than Minnesota's.[34] The Department then recommends reducing this cap to 12.0 percent in the following year, and 10.0 percent the year after. If the Commission preferred to set the Net Benefits Cap lower, the Department would still recommend phasing in the change over a period of three years.[35]

Similarly the Department would phase in its CIP Expenditure Cap, establishing a limit of 40 percent in 2017, 35 percent in 2018, and 30 percent in 2019.

3. Summary

In summary, the Department proposes the following incentive formula:

	Electric Utilities	Gas Utilities
Energy Savings Benchmark	1.5 percent of retail sales.	1.0 percent of retail sales.
Threshold	1.0 percent of retail sales.	0.7 percent of retail sales.
Net Benefit Cap	For each unit of energy saved, the utility can earn no more than 13.5 percent of net benefits for 2017, 12.0 percent of net benefits for 2018, 10.0 percent of net benefits for 2019.	
Incremental Incentive[36]	For reaching the threshold level of savings, grant the utility a share of net benefits: $\textit{Net Benefit Cap} - \dfrac{0.75\,\% * (\textit{Energy Savings Benchmark} + 0.2\,\% - \textit{threshold})}{0.1\,\%}$ For each 0.1 percent increase in savings until the utility achieves the Energy Savings Benchmark + 0.2 percent, increase the utility's share of net benefits by 0.75 percent. For all additional savings, grant a share of the net benefits equal to the Net Benefits Cap.	
CIP Expenditure Cap	Limit a utility's total incentive payments to no more than 40 percent of CIP expenditures in 2017, 35 percent of CIP expenditures in 2018, 30 percent of CIP expenditures in 2019.	

4. Miscellaneous Provisions

Finally, the Department also recommends that the Commission adopt the miscellaneous

[34] Department Comments, at 24 and Attachment 1, at 1, 5 (January 19, 2016). The state with the next highest net benefits cap, Oklahoma, imposes a cap of 15 percent. But given the differences between Oklahoma's and Minnesota's regulatory regimes, the ACEEE concluded that a 15 percent net benefits cap in Oklahoma would be the equivalent of a 13.5 percent net benefits cap in Minnesota.
[35] Department Reply Comments, at 11 (February 19, 2016).
[36] For formula, *see* CenterPoint Reply Comments, Attachment A, at 2-3 & n.21 (February 19, 2016).

provisions that the Commission adopted as part of its current incentive formula—but simplified to omit language that is not relevant to the Department's formula.

III. Comments of the Parties

A summary of the parties' recommendations, generally arranged from parties who advocate retaining the current formula to parties proposing the largest changes, follows.

A. MERC

MERC praises the current incentive formula for motivating utilities to achieve high levels of energy savings in a cost-effective manner. MERC argues that the current formula has succeeded in motivating utilities to reduce environmental costs while also reducing overall financial costs for utilities and ratepayers, and cites the ACEEE Report in support of this claim. MERC argues that changes to the incentive formula would disrupt the environment that has made the past accomplishments possible and the plans that could make future savings a reality.

MERC questions the wisdom of reducing compensation for conservation in an era when the cost of maintaining current levels of conservation will likely increase. Because Minnesota utilities have been implementing conservation programs for decades, MERC argues that all the low-cost conservation opportunities have already been used, and thus utilities are now left to pursue ever more costly forms of conservation. And more stringent codes and standards will make certain conservation practices mandatory and therefore beyond the scope of CIP programs.

Even if lower financial incentives might be appropriate for some utilities, MERC claims to be an exception: MERC's customer base includes a disproportionate share of industrial and commercial customers, whereas residential customers provide the best opportunities for implementing low-cost conservation measures.[37]

B. Minnesota Power and Otter Tail Power

Likewise, Minnesota Power and Otter Tail Power favor retaining the current incentive formula. However, these parties acknowledge that it would be appropriate for the Commission to withhold incentives from electric utilities that fail to achieve savings equal to at least one percent of their retail sales.[38]

If the Commission elected to further reduce the amount of incentives paid to electric utilities, Minnesota Power would still recommend retaining the current incentive formula but adjusting a few of its variables. While Minnesota Power did not offer a specific alternative proposal, it suggested that the Commission might replace the current incremental benefits process with a fixed compensation for each kWh saved between 1.0 percent and 1.5 percent of retail sales, and a different compensation for each kWh saved beyond 1.5 percent. In addition, Minnesota Power

[37] MERC Comments (August 8, 2015).
[38] Minnesota Power Reply Comments, at 11 (February 19, 2016); Otter Tail Reply Comments, at 10-11 (February 19, 2016).

proposed that the Commission could reduce the Net Benefits Cap from 20 percent to 15 percent.[39]

C. Great Plains

In contrast to MERC, Minnesota Power, and Otter Tail Power, Great Plains did not oppose the Department's new incentive mechanism framework. But while Great Plains acknowledges the Department's objective to reduce the amount of financial incentives to be paid by ratepayers, the utility opposes the proposal to withhold incentive payments from gas utilities that cannot achieve savings equal to 0.7 percent of retail sales. Great Plains argues that this policy would effectively preclude the utility from qualifying for any financial incentives, given the utility's small customer base, peculiar customer mix, and slow growth.

Instead, Great Plains proposes that the Commission amend the Department's proposal to adopt a threshold for natural gas utilities equal to 0.3 percent of retail sales.
Alternatively, Great Plains proposes that the Commission establish a threshold that varies to reflect each utility's number of customers, customer mix, and/or region of the state.[40]

D. Center for Energy and the Environment

CEE supports the general principles and motivations reflected in the Department's proposal. CEE recognizes that reforms to the existing incentive mechanism may be warranted to keep incentives no larger than necessary to encourage conservation efforts, and to simplify the mechanism. And CEE supports withholding incentives from electric utilities that fail to achieve savings equal to 1.0 percent of retail sales, and allocating incentives based on the net benefits achieved.

That said, CEE agrees with MERC, Minnesota Power, and Otter Tail Power that future incentive payments are likely to decline due to the growing cost and declining return of future CIP projects, and echoes these utilities' concerns about the wisdom of reducing incentives at this time.

And CEE recommends that the Commission alter the Department's proposed Net Benefits Cap. Specifically, CEE asks the Commission to refrain from reducing the cap below 13.5 percent—and ideally set it at 15.0 percent. And in any event, CEE asks the Commission to refrain from reducing the Net Benefits Cap in later years when, CEE predicts, CIP projects will be generating less net benefits.

E. CenterPoint Energy

CenterPoint Energy advocates a position similar to CEE's, at least where gas utilities are concerned, but with two exceptions. First, CenterPoint recommends a threshold level of 0.67 percent rather than 0.7 percent. Second, CenterPoint takes no position regarding a CIP Expenditure Cap.

CenterPoint argues that a consistent Net Benefits Cap would provide utilities with a more

[39] Minnesota Power Reply Comments, at 11-14 (February 19, 2016).
[40] Great Plains Reply Comments, at 1-2 (February 19, 2016).

consistent regulatory regime in which to plan. And while CenterPoint appreciates the Department's objective to reduce overall incentive payments, CenterPoint argues that a drop from 20 or 30 percent of net benefits to 13.5 percent should suffice.

F. Fresh Energy and Xcel

Xcel echoes the arguments of the other utilities that incentives will naturally decline due to (1) declining marginal benefits due to the exhaustion of the least-cost energy-saving strategies, (2) more stringent codes and standards that will make certain conservation practices mandatory and therefore beyond the scope of CIP programs, and (3) previous incentive reductions that will render CIP programs less attractive.

Nevertheless, Fresh Energy and Xcel largely support the structure of the Department's formula. But these parties recommend changing some of the variables.

Threshold: Xcel and Fresh Energy support the Department's recommendation to set the threshold level at two-thirds of the earnings goal.[41] In the case of investor-owned electric utilities, two-thirds of the goal of 1.5 percent savings is 1.0 percent savings. In the case of investor-owned gas utilities, two-thirds of 1.0 percent savings is 0.67 percent savings—in contrast with the 0.7 percent proposed by the Department.

Incremental Incentive: For each 0.1 percent of increased savings a utility achieves above the threshold level, Xcel proposes increasing the incentive by 1.0 percent of the resulting net benefit, rather than 0.75 percent as the Department recommends. According to Xcel, this change would provide greater incentive for a utility to increase conservation, while still subjecting the incentive to the Net Benefit Cap.

Caps: Neither Fresh Energy nor Xcel recommended adoption of the Department's proposed CIP Expenditure Cap to limit the total amount of incentives that a utility could earn each year.

Fresh Energy and Xcel do acknowledge the merits of adjusting the Net Benefits Cap to ensure that ratepayers retain a larger share of the benefits of conservation. But they argue that reducing this cap below 15 percent would reflect an unreasonable drop from the current 20 percent (or, in the case of Minnesota Power, 30 percent). In support of their position, Xcel cites other states that have adopted a net benefits cap in the range of 15 percent, and still others—Arizona, Georgia, Kentucky, and South Carolina—that impose no net benefits cap at all.

Here is a summary of Xcel's position; Fresh Energy concurs, except that it takes no position on incremental incentives:

[41] *See, e.g.*, Fresh Energy Comments, at 3 (August 17, 2015).

	Electric Utilities	Gas Utilities
Energy Savings Benchmark	1.5 percent of retail sales.	1.2 percent of retail sales.
Threshold	1.0 percent of retail sales.	0.67 percent of retail sales.
Net Benefit Cap	For each unit of energy saved, the utility can earn no more than 15 percent of net benefits.	
Incremental Incentive	For each 0.1 percent increase in savings above the threshold, the utility's share of net benefits increases by 1.0 percent until the utility achieves the Energy Savings Benchmark. For all additional savings, the utility earns a share of the net benefits equal to the Net Benefits Cap.	
CIP Expenditure Cap	None specified.	

Finally, Fresh Energy proposes two additional methods to modify the incentive formula.

First, Fresh Energy observes that the concept of *net benefits* used in the incentive formula encompasses benefits that accrue to a utility and its ratepayers. Fresh Energy favors expanding this definition to also take account of the benefits that accrue to society in general, such as the environmental benefits of conservation.[42]

Second, Fresh Energy supports providing utilities with the opportunity to recover a portion of the profits they forego when promoting conservation—and argues that the Commission should similarly compensate utilities that forgo earnings by facilitating customer installation of distributed energy resources such as solar panels and wind turbines.[43] Fresh Energy suggests that the Commission address this matter in its pending grid modernization docket.[44]

G. Office of the Attorney General

The OAG favors the Department's proposed changes to the incentive formula, both as to the formula's structure and its effort to rein in incentive payments. But the OAG argues that the Department's reforms do not go far enough. Minnesota's high levels of conservation are not necessarily caused by Minnesota's high conservation incentives, the OAG argues, because Minnesota utilities already have ample reason to pursue conservation.[45] As a result, the OAG argues, utilities are earning incentives to do things that they would have done in any event.

[42] Fresh Energy Reply Comments, at 2 (February 19, 2016).
[43] *Id.*
[44] *In the Matter of the Commission Investigation into Grid Modernization*, Docket No. E-999/CI-15-556.
[45] OAG Reply Comments, at 2-3 (August 17, 2015).

And while the Department's proposal is intended to result in lower incentive payments, the OAG alleges three flaws in the Department's proposal. First, the OAG argues that the Department's proposal would continue to provide needlessly large incentive payments to utilities at the expense of ratepayers.

Second, the OAG cautions that the Department's formula is based on calculations of net benefits. A calculation of net benefits is inherently unreliable, the OAG argues, because it depends on estimating the amount of cost that a utility was able to avoid as a result of its CIP programs. Such speculative calculations can produce varying outcomes based on factors that are unrelated to a utility's CIP efforts—factors such as a change in calculation methodology or a change in commodity costs. In contrast, a calculation based on CIP expenditures and an estimate of saved energy can produce results that are more easily audited—and that are less likely to generate unanticipated outcomes.

Third, the OAG argues that the Department's proposal would focus utilities' attention on projects with the highest net benefit, to the detriment of other innovative projects.

To address the first two problems, the OAG recommends that the Commission reduce the size of three variables:

- For each time a utility increases its net savings by 0.1 percent of retail sales, the Commission should increase the utility's share of the net benefits by only 0.5 percent.

- The Commission should limit the amount of financial incentives a utility can earn in any given year to 15 percent of the utility's CIP expenditures.

- The Commission should limit a utility's share of any CIP project's net benefits to no more than 5.0 percent. And the Commission may want to periodically recalibrate this cap, and perhaps set different caps for each utility, to ensure that utilities earn incentives equal to roughly 15 percent of their CIP expenditures.[46]

To address the problem that the incentive formula might cause utilities to give undue attention merely to CIP projects with the highest net benefits, the OAG recommends that the Commission establish a separate incentive, equal to up to 3 percent of CIP expenditures, to reward utilities for pursuing Commission-designated projects that the utility might otherwise overlook. The task of designating appropriate projects would be delegated to a taskforce. The OAG calls this its "Shared Savings Plus" proposal.[47]

[46] OAG Reply Comments, at 12-13 (February 19, 2016).
[47] OAG Comments, at 33-38 (January 19, 2016); OAG Reply Comments, at 2-3 (February 19, 2016).

	Electric Utilities	Gas Utilities
Energy Savings Benchmark	1.5 percent of retail sales.	1.0 percent of retail sales.
Threshold	1.0 percent of retail sales.	0.7 percent of retail sales.
Net Benefit Cap	For each unit of energy saved, the utility can earn no more than 5.0 percent of net benefits.	
Incremental Incentive	For each 0.1 percent increase in savings above the threshold until the utility achieves the Energy Savings Benchmark + 0.2 percent, increase the utility's share of net benefits by 0.5 percent. For all additional savings, grant a share of the net benefits equal to the Net Benefits Cap.	
CIP Expenditure Cap	Limit a utility's total incentive payments to no more than 15 percent of CIP expenditures + 3 percent for achieving additional objectives.	

H. Minnesota Chamber of Commerce

The Chamber echoes many of the OAG's concerns, but proposes somewhat different remedies.

Like the OAG, the Chamber generally prefers the structure of the Department's new incentive formula over the current incentive formula. Like the OAG, the Chamber argues that the Department's proposal still provides for excessive incentive payments, to the detriment of ratepayers. Like the OAG, the Chamber recommends altering some of the variables to remedy this problem. The Chamber offers two proposals.

In one proposal, the Chamber recommends granting an incentive of 5.0 percent of net benefits, not to exceed 15 percent of the utility's CIP expenditures, to each electric utility that achieved savings equal to 1.5 percent of retail sales. The Chamber argues that this combination of criteria results in an amount of incentive per kWh saved that is comparable to the incentives offered by other states.[48]

	Electric Utilities	Gas Utilities
Threshold	1.5 percent of retail sales.	None specified.
Net Benefit Cap	For each unit of energy saved, the utility can earn no more than 5.0 percent of net benefits.	
CIP Expenditure Cap	Limit a utility's total incentive payments to no more than 15 percent of CIP expenditures.	

[48] Chamber Comments, at 5-6 (January 19, 2016).

In the other proposal, the Chamber recommends granting an incentive of 7.5 percent of net benefits to a utility that achieved savings equal to 1.5 percent of retail sales and had a CIP portfolio that passed the Ratepayer Impact Measure (RIM). Generally, the RIM compares how much a CIP project reduces a utility's costs to how much it reduces the utility's revenues.[49]

	Electric Utilities	Gas Utilities
Threshold	1.5 percent of retail sales, plus pass the RIM test	None specified.
Net Benefit Cap	For each unit of energy saved, the utility can earn no more than 7.5 percent of net benefits.	
CIP Expenditure Cap	Limit a utility's total incentive payments to no more than 15 percent of CIP expenditures.	

IV. Commission Analysis and Action

A. The Shared Savings DSM Financial Incentive Plan

Having reviewed the reports from ACEEE and from the Department, and the recommendations and comments of all parties, the Commission recognizes and appreciates the parties' continued efforts to improve and refine the CIP financial incentive program. These reports and comments provide a sufficient basis for evaluating and, in this case, revising the Commission's Shared Savings DSM Financial Incentive Plan.

1. Need for Change

The data show that Minnesota's investor-owned utilities have increased their levels of conservation, and have generated more benefits than costs, even after accounting for the incentive costs.[50] Given these facts, various commenters argue for maintaining the status quo. If the current system is making all parties—including ratepayers—better off, why change it?

The record provides three answers: First, the current formula provides incentives that exceed what is necessary to motivate conservation efforts that already generate more benefits than costs for the utility. Second, the current formula is needlessly complicated. Third, a revised formula could better encourage utilities to maximize the benefits of conservation.

a. Reducing Cost

The current formula provides for total incentive payments that are more than sufficient to motivate utilities to pursue cost-effective conservation measures.

[49] *Id*. at Attachment A.
[50] Department Report, Tables 7 & 8 (net benefits); Figures 21, 22, 30 & 31 (benefits net of incentive payments).

The Legislature directs the Commission, in approving incentive plans, to consider whether the plan (1) is likely to increase the utility's investment in cost-effective energy conservation, (2) is compatible with the interests of ratepayers and other interested parties, (3) provides incentives for the utility to pursue cost-effective conservation, and (4) complies with statute.[51] To this end, the Legislature authorizes the Commission to adopt a mechanism that would cause utilities to regard conservation as preferable to other means of meeting customer demand—including a mechanism to allocate the net savings from CIP projects in a manner that acknowledges a utility's skill, efforts, and success in conserving energy.[52]

The issue before the Commission is not whether Minnesota's CIP projects generate more benefit than cost; they do. The issue is how ratepayers can secure those benefits at lower cost.

The ACEEE Report documents that the regulatory environment in Minnesota is among the most conducive for conservation, and incentives are merely one component of that environment. The state directs utilities to pursue programs designed to reduce energy consumption by up to 1.5 percent of retail sales or more. The state has a resource planning process, a certificate of need process, and a siting and routing process, all of which require a utility to justify any choice to acquire a new source of energy or capacity instead of a demand-side resource such as conservation. The state permits utilities to implement automatic adjustment mechanisms to recover conservation costs between rate cases. The state permits utilities to adopt revenue decoupling, thereby partially shielding them from the financial risks of low energy sales. And, finally, the state provides for incentives under the Commission's Shared Savings DSM Financial Incentives Plan.

As a result, the OAG reports, utilities receive conservation incentives equal on average to 61 percent (for electric utilities) or 31 percent (for gas utilities) of CIP expenditures—while also recouping their CIP expenditures, plus interest, within a year.[53] In short, the Commission has succeeded in making conservation a utility's preferred resource whenever feasible. But it appears that the current incentive structure is needlessly generous and thus not compatible with the interest of ratepayers.

In contrast to the current mechanism, the Department proposes a formula with higher thresholds and lower caps, which should reduce the total amount of incentives paid.

Various parties argue that, whether or not incentive payments were needlessly generous in the past, in the future we should expect incentive payments to decline as utilities receive diminishing marginal returns from their CIP projects. And some utilities argue that their more modest proposed changes would still reduce the incentive program's burden on ratepayers. The Department evaluated these theories and found some support for them, but concluded that without changes to the current mechanism, ratepayers would still continue to pay needlessly high

[51] Minn. Stat. § 216B.16, subd. 6c(b).
[52] *Id.* at § 216B.16, subd. 6c(c).
[53] OAG Reply Comments, at 5 (August 17, 2015), citing the Department's Report, Attachments 2 & 3.

incentives.[54] And when the Department analyzed other parties' proposals, it often found that they would result in increasing the share of net benefits allocated to the utilities.[55]

b. Reducing Complexity

The current formula is needlessly complex. It relies on creating individualized incentive schedules based on annual filings. To some extent, this complexity reflects the goal of ensuring that a utility's level of compensation does not grow unreasonably large, a problem that occurred with the Commission's incentive plans in the 1990s. But as a result, the current formula is relatively burdensome to administer, and precludes a utility from learning the precise level of incentives they will face in future years.

c. Targeting Benefits

Both the current incentive plan and the Department's proposed revision seek to grant equal treatment to all investor-owned electric utilities, and to all investor-owned gas utilities—but they accord equal treatment with respect to different variables. Under the current plan, that equal treatment is measured with respect to the financial incentive awarded per unit of energy saved in a CIP's first year.[56]

Among projects that generate the same benefits in their first year, this incentive formula fails to distinguish between projects that generate long-lasting benefits (for example, subsidizing the purchase of energy-efficient equipment) and projects that generate more transitory benefits (for example, an ad campaign to encourage behavior change). In contrast, an incentive structure that focuses on net benefits would reward utilities for pursuing projects that generate more benefits, even if those benefits do not all accrue in the first year.

2. Revisions to the Formula

The Commission finds that the incentive formula fashioned by the Department is designed to target appropriate resources in a manner that will encourage conservation, without expending resources where they would be unlikely to improve the utility's performance.

The Commission expects that the Department's formula will successfully encourage energy savings because it retains many of the policies and structures that made the current formula successful. It continues the practice of requiring utilities to achieve some minimum level of savings before they can qualify for incentives. It continues to recognize the different challenges faced by electric and gas utilities, and thus maintains distinct Energy Savings Benchmarks for each industry. It continues providing incentives for savings achievements that fall short of these benchmarks. And it continues offering incremental incentives that grow as a utility's savings grow—even as a utility achieves savings that exceed the benchmark—but that eventually plateau to ensure that ratepayers do not pay more than necessary for the conservation benefits received.

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[54] *See, e.g.*, Department Reply Comments, at 6 (February 19, 2015) (rebutting Xcel's arguments).
[55] *See, e.g.*, *id.* at 7-8 (rebutting Xcel's arguments).
[56] Department Comments, at 16 (January 19, 2016).

The Department proposes changes to the formula's threshold, incremental incentives, and caps. The Commission finds that these changes appropriately balance the goals of providing an incentive for utilities, maximizing value for ratepayers, and easing administrative burdens, for the following reasons.

a. Threshold

The Department proposes that the Commission revise the threshold level of savings that a utility must achieve to earn financial incentives. Higher thresholds ensure that utilities receive incentives only for achieving savings beyond what they would generate under standard operating procedures. The revised thresholds would be much easier to calculate than the current ones; they are simply a fraction of a utility's retail sales. By setting thresholds at roughly two-thirds of the Energy Savings Benchmark, the Commission would better conform to practices in other states; the ACEEE Report found that states typically establish thresholds in the range of 70 percent of the utility's saving goal.[57] Finally, the higher threshold would help the Commission reduce overall incentive payments.

CenterPoint, Fresh Energy, and Xcel recommend setting the gas threshold at 0.67 percent of retail sales rather than 0.7 percent, consistent with a policy of setting the threshold at two-thirds of the gas utility's Energy Savings Benchmark of 1.0 percent of retail sales. The Commission notes, however, that the incremental incentive formulas recommended by most of the parties involve making 0.1 percent adjustments that eventually reach a cap measured to the first decimal place. For ease of computation, the Commission will round up the gas threshold to 0.7 percent as recommended by the Department and the OAG.

Finally, the Chamber proposes that the Commission withhold financial incentives where a CIP portfolio fails to pass the rate impact measure (RIM)—that is, where the portfolio fails to reduce the utility's costs more than its revenues. The Commission finds that a RIM analysis focuses on goals other than cost-effective conservation. In comparing two CIP projects with identical cost, the RIM would favor the project that reduces energy sales the least, which is inconsistent with the goal of CIP. Moreover, while the RIM purports to analyze how CIP affects utility rates, it fails to reflect how eliminating CIP—and having utilities meet growing demand with solely supply-side resources (such as new power plants)—would affect rates. Given these shortcomings, the Commission will decline to incorporate the RIM into the new financial incentive formula.

That said, the Commission finds the Department's proposed thresholds are well designed to focus utility incentives on rewarding a utility's concerted efforts to achieve energy savings. Consequently the Commission will adopt them.

b. Incremental Incentive

The Department created two innovations in proposing its escalating incremental incentive. First, the Department proposed to grant benefits not in terms of dollars per unit of energy saved during

[57] Department Report at 37-38 and Attachment 4.

a CIP program's first year, but in terms of shares of net benefit generated. Second, the Department proposed a specific rate at which the benefit would grow as a utility's savings grow.

The Commission finds that the Department's focus on net benefits is consistent with the Commission's statutory authority. The Legislature authorizes the Commission to establish an incentive plan to "encourage the vigorous and effective implementation of utility conservation programs [by sharing] between ratepayers and utilities the net savings resulting from energy conservation programs…."[58] This approach is also favored by CenterPoint Energy, the Chamber, the Department, and Xcel.

Moreover, the Commission finds that the Department's proposal provides advantages over the current mechanism. As previously noted, the new proposal would provide utilities with greater clarity about the incentives available. Under the current formula, utilities do not know the precise incentives they will face in the next CIP year until after they make their annual calibration filings on February 1. In contrast, the incremental incentive levels under the Department's formula are established by an equation and listed in Attachment A.

Some parties argue that an incentive formula that rewards utilities for generating net benefits would prompt utilities to abandon CIP programs with relatively high costs or low savings—such as programs directed at residential customers—in favor of programs with lower costs and higher savings.[59] Anticipating this concern, the Department modeled its proposal to see how it compares to the existing incentive plan. The Department demonstrated that the parties' concerns are unwarranted because the incremental incentives generated by its proposed formula would, in fact, generally exceed the incremental incentives under the current plan.[60]

Most parties supported the Department's proposal to grant an incremental incentive measured in terms of shares of a growing share of net benefit. But even among these parties, there was disagreement about the appropriate rate at which the incentive should grow as a utility's savings grow. The Department proposes that the Commission increase the size of the incremental incentive by 0.75 percent of net benefits for each 0.1 percent increase in savings above the threshold level and below the Net Benefit Cap. The OAG proposes a lower rate of growth; Xcel proposes a higher one. But the Department analyzed how changing the rate of growth would alter the structure of incentives relative to the current model, and concluded that its 0.75 percent growth rate would produce better results than either of the alternatives proposed.[61]

In sum, the Department's proposed incremental incentive, awarded in terms of shares of net benefits generated, will be more transparent and easier to administer. It will give utilities appropriate encouragement to pursue CIP projects that generate benefits exceeding their costs, without eliminating utility's incentive to pursue projects with lower net benefits. And the proposed rate of growth is well-tailored to challenge utilities to pursue ever greater levels of

[58] Minn. Stat. § 216B.16, subd. 6c(2).
[59] *See, e.g.*, CEE Comments (January 19, 2016); Chamber Comments (January 19, 2016); MERC Comments (January 19, 2016); Otter Tail Comments, at 3 (January 19, 2016).
[60] Department Reply Comments, at 14-16 (February 19, 2016).
[61] *Id.*, at 22-23.

savings. For these reasons, the Commission will adopt this change.

c. Caps

The Department proposes that the Commission establish two different kinds of caps.

First, the Department recommends that the Commission cap the size of the incremental incentive at 13.5 percent of net benefits generated, and gradually reduce this to 10 percent by 2019. Functionally, this cap would replace the current formula's cap on incremental incentives which is set in terms of dollars per unit of energy saved. Second, the Department proposes to cap the total amount a utility could earn in a year to no more than 40 percent of the utility's CIP expenditures for that year, and gradually reduce this cap to 30 percent by 2019. This cap does not correspond to any part of the current formula.

Finally, because these caps are expected to reduce the share of total conservation benefits that accrue to the utilities, the Department recommends that the Commission phase them in over a period of years.

Regarding the Net Benefits Cap, the Commission finds that the Department's proposal would bring Minnesota's incentive plan into closer alignment with the incentive plans of other states. Xcel disagrees, citing data in the ACEEE study to argue that other states permit utilities to accrue a higher share of net benefits. But the Department showed that the regulatory regimes in those other states make Xcel's comparison inapt.[62] In particular, the ACEEE study concluded that a net benefits cap of 15 percent in Kentucky would be the equivalent of a net benefits cap of 13.5 percent in Minnesota—which happens to match the Department's proposed level for 2017.[63] This fact supports the Department's proposal.

Regarding the CIP Expenditure Cap, the Department's proposal is supported by the Chamber and the OAG. This cap would preclude the possibility that incentives would grow to an unanticipated level as occurred in the 1990s. This cap would only become relevant when a utility earns incentives exceeding 30 percent of the utility's initial investment. The Commission is persuaded that a utility that is earning this level of incentives is fully motivated to invest in conservation, so the act of barring larger earnings would have no appreciable effect on the utility's efforts.

The Commission will adopt both these caps. They are designed to leave utilities with appropriate incentives to pursue conservation, while reducing the aggregate amount of incentive payments ratepayers must bear. And given that the caps are expected to reduce the share of total conservation benefits that accrue to the utilities, the Commission finds it reasonable to phase them in so as to better enable utilities to adjust to the change.

3. Other Proposals

Parties also propose other innovative ideas for changing the incentive formula, including the

[62] *Id.*, at 9-10.
[63] *Id.* at 10.

following:

- Expanding the definition of *net benefits* to encompass social benefits such as the environmental benefits of conservation.[64]

- Extending the incentive mechanism to reward utilities for facilitating customer installation of distributed energy resources such as solar panels and wind turbines.[65]

- Establishing a supplementary incentive, reflecting up to 3.0 percent of CIP expenditures, to reward innovative conservation projects that utilities might not otherwise pursue, to be selected by a new taskforce.[66]

- Appointing a third party to administer CIP projects, thereby removing the conflict of interest that utilities face in administering programs that reduce energy sales.[67]

Whatever the merits of these proposals, they have not received sufficient development in the record to permit the kind of rigorous evaluation they warrant. Consequently the Commission will decline to adopt them at this time.

4. Conclusion

The Commission has reviewed the parties' comments and considered how well their recommendations would help achieve the purposes of Minn. Stat. § 216B.241 (the Next Generation Energy Act), § 216B.16, subd. 6c (the conservation factors), and § 216B.03 (just and reasonable rates). On this basis the Commission concludes that the Shared Savings DSM Incentive Plan, with the modifications proposed by the Department, represents an improved means for achieving these statutory objectives.

Specifically, the Commission has reflected upon the four considerations listed in Minn. Stat. § 216B.16, subd. 6c:

> (b) In approving incentive plans, the commission shall consider:
>
> > (1) whether the plan is likely to increase utility investment in cost-effective energy conservation;
> >
> > (2) whether the plan is compatible with the interest of utility ratepayers and other interested parties;

[64] CEE Reply Comments (February 19, 2016); Fresh Energy Reply Comments, at 2 (February 19, 2016).
[65] *Id.*
[66] OAG Reply Comments (February 19, 2016).
[67] *Id.*

> (3) whether the plan links the incentive to the utility's performance in achieving cost-effective conservation; and
>
> (4) whether the plan is in conflict with other provisions of this chapter.

Based on its review of the proposed modifications to the Shared Savings DSM Incentive Plan, the Commission finds as follows.

The plan as modified is likely to maintain utility investment in cost-effective energy conservation. The formula remains generous by the standards of the industry. It provides incentives for utilities that can achieve roughly two-thirds of the prescribed savings benchmarks, and these incentives increase as a utility's savings increase to the benchmark level and beyond. Nevertheless, by awarding incentives as a share of net benefits generated, the plan rewards only utilities with cost-effective CIP projects.

The Department's proposal is compatible with the interests of utility ratepayers and other interested parties. The incentives received by the utilities are only a small part of the overall net benefits achieved by the CIP programs. Importantly, ratepayers will continue to receive the vast majority of benefits generated under the CIP programs.

The new formula continues to link financial incentive to utility performance in achieving cost-effective conservation. If a utility's CIP projects are not cost-effective, they will generate no net benefits and thus no incentive payments. Finally, the new plan does not conflict with any of the provisions of the Public Utilities Act.

For all these reasons, the Commission will adopt modifications to its Shared Savings DSM Incentive Plan as recommended by the Department.

B. Miscellaneous Provisions

The Commission established its current financial incentives formula in its 2012 Incentive Modification Order. That order set forth the mechanism for calculating the financial incentives in Ordering Paragraphs 2.A-F; it also included a number of miscellaneous provisions refining the mechanism in Ordering Paragraphs 2.G-P.

Consistent with the recommendations of the Department, the Commission will reaffirm most of the miscellaneous provisions refining the terms of the financial incentive mechanism from the 2012 Order. However, the Commission will omit certain provisions, and simplify others, to remove language that is no longer relevant in the context of the current order, as follows:

> G. The CIP-Exempt [customers] shall not be allocated costs for the new shared savings incentive. Sales to the

CIP-Exempt [customers] shall not be included in the calculation of utility energy savings goals.

H. If a utility elects not to include a third-party CIP project, the utility cannot change its election until the beginning of subsequent years.

I. If a utility elects to include a third-party project, the project's net benefits and savings will be included in the calculation of the ~~percentage of net benefits awarded at specific energy savings levels (calculated before the CIP year begins) and in the post CIP year calculations of net benefits and energy savings achieved and~~ incentive awarded. ~~In any case, the~~ The energy savings will count toward the 1.5 percent savings goal.

J. The energy savings, cost, and benefits of modifications to non-third-party projects will be included in the calculation of a utility's DSM incentive~~, but will not change the percent of net benefits awarded at different energy savings levels~~.

K. The costs of any mandated, non-third-party projects (e.g., the 2007 Next Generation Energy Act assessments, University of Minnesota Initiative for Renewable Energy and the Environment costs) shall be excluded from the calculation of ~~net benefits awarded at specific energy savings levels (calculated before the CIP year begins) and in the post-CIP year calculations of~~ net benefits and energy savings achieved and incentive awarded.

L. Costs, energy savings, and energy production from Electric Utility Infrastructure Projects (EUIC), solar installation, and biomethane purchases shall not be included in energy savings for DSM financial incentive purposes.

~~M. The Department shall file a recommendation with the Commission on the application of a net benefits cap for Minnesota Power's incentive by October 1, 2013. The recommendation should be filed in Docket No. E,G-999/CI-08-133.~~

~~N. No adjustment will be made at this time to the calibration of the incentive mechanism for utilities that have Commission-approved decoupling mechanisms.~~

O. The new shared savings DSM incentive shall be in operation for ~~the length of each utility's triennial CIP plan~~ 2017-2019.

P. ~~All utilities except Otter Tail Power and Minnesota Power shall make a compliance filing on or before February 1, 2013, integrating the Commission's decision into their individual incentive proposal. Otter Tail Power and Minnesota Power shall make their compliance filings on or before February 1, 2014. Thereafter, utilities shall file yearly incentive proposals on or before February 1 of each year.~~ Utilities may discontinue the annual February 1st compliance filing because a scale of net benefits will no longer be required since the Department's proposal sets percentages at certain savings thresholds and calibrates the mechanism to dollars per unit of energy.

C. Future Proceedings

It is important that examination and analysis of the financial incentive program continue. The Commission will therefore ask the Department to file its next CIP and DSM Financial Incentive Mechanisms Evaluation Report by July 1, 2019. In this report, the Department should recommend whether to continue the incentive program and, if so, how to improve it.

Finally, if and when it becomes appropriate to modify the Shared Savings DSM Financial Incentive Plan, the Commission delegates to the Executive Secretary the ability to set the schedule for a process to approve any modifications. The revised plan would apply to the 2020-2022 Triennial CIPs (due June 1, 2019).

ORDER

1. The Commission hereby revises its Shared Savings DSM Financial Incentive Plan with the modifications set forth below.

   A. For electric utilities, the plan is modified to do the following:

      1) Authorize financial incentives for a utility that achieves energy savings of at least 1.0 percent of the utility's retail sales.

      2) For a utility that achieves energy savings equal to 1.0 percent of retail sales, award the utility a share of the net benefits as set forth in Attachment A.

      3) For each additional 0.1 percent of energy savings the utility achieves, increase the net benefits awarded to the utility by an additional 0.75 percent until the utility achieves savings of 1.7 percent of retail sales.

      4) For savings levels of 1.7 percent and higher, award the utility a share of the net benefits equal to the Net Benefits Cap.

   B. For gas utilities, the plan is modified to do the following:

      1) Authorize financial incentives for a utility that achieves energy savings of at least 0.7 percent of the utility's retail sales.

      2) For a utility that achieves energy savings equal to 0.7 percent of retail sales, award the utility a share of the net benefits as set forth in Attachment A.

      3) For each additional 0.1 percent of energy savings the utility achieves, increase the net benefits awarded to the utility by an additional 0.75 percent until the utility achieves savings of 1.2 percent of retail sales.

      4) For savings levels of 1.2 percent and higher, award the utility a share of the net benefits equal to the Net Benefits Cap.

   C. For all utilities, set the following Net Benefit Caps:

      1) 13.5 percent in 2017,

      2) 12.0 percent in 2018, and

      3) 10.0 percent in 2019.

D. For all utilities, set the following Conservation Improvement Plan (CIP) Expenditure Caps:

1) 40 percent in 2017,

2) 35 percent in 2018, and

3) 30 percent in 2019.

2. The Commission retains certain provisions from the current Shared Savings DSM Financial Incentive Plan, with slight modifications, as follows:

A. CIP-exempt customers shall not be allocated costs for the new shared savings incentive. Sales to CIP-exempt customers shall not be included in the calculation of utility energy savings goals.

B. If a utility elects not to include a third-party CIP project, the utility cannot change its election until the beginning of subsequent years.

C. If a utility elects to include a third-party project, the project's net benefits and savings will be included in the calculation of the energy savings and will count toward the 1.5 percent savings goal.

D. The energy savings, cost, and benefits of modifications to non-third-party projects will be included in the calculation of a utility's DSM incentive.

E. The costs of any mandated, non-third-party projects (e.g., the 2007 Next Generation Energy Act assessments,[68] University of Minnesota Initiative for Renewable Energy and the Environment costs[69]) shall be excluded from the calculation of net benefits and energy savings achieved and incentive awarded.

F. Costs, energy savings, and energy production related to Electric Utility Infrastructure Costs,[70] solar installation,[71] and biomethane purchases[72] shall not be included in energy savings for DSM financial incentive purposes.

3. The new Shared Savings DSM Incentive Plan shall be in effect for 2017-2019.

4. Utilities may discontinue the annual February 1 compliance filing because a scale of net benefits will no longer be required since the Department's proposal sets percentages at certain savings thresholds and calibrates the mechanism to dollars per unit of energy.

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[68] *See* 2007 Laws, art. 2.
[69] *Id*., § 3, subd. 6.
[70] Minn. Stat. § 216B.1636.
[71] Minn. Stat. § 216B.241, subd. 5a.
[72] *Id*., subd. 5b.

5. Regarding the next CIP evaluation report and review of the approved new shared savings formula:

   A. The Department shall submit its next evaluation report on CIP and the Shared Savings DSM Financial Incentive Plan by July 1, 2019.

   B. The Commission delegates to the Executive Secretary the ability to set the schedule for a process to approve any modifications to the Shared Savings DSM Financial Incentive Plan for application to the 2020-2022 Triennial CIPs (due June 1, 2019).

6. This order shall become effective immediately.

BY ORDER OF THE COMMISSION

Daniel P. Wolf
Executive Secretary

This document can be made available in alternative formats (i.e., large print or audio tape) by calling 651.296.0406 (voice). Persons with hearing or speech disabilities may call us through Minnesota Relay at 1.800.627.3529 or by dialing 711.

ATTACHMENT A

INCREMENTAL INCENTIVES

The level of net benefits a utility accrues for achieving the threshold level of savings equals:

*Net Benefit Cap – 0.75 % * (Energy Savings Benchmark + 0.2 % – threshold) / 0.1 %*

(*Underline identifies threshold savings level required for trigger awards; Double-underline identifies Net Benefits Cap*.)

	Electric Investor Owned Utilities			Natural Gas Investor Owned Utilities		
Achievement Level (percent of retail sales avoided)	**2017 Percent of Net Benefits Awards**	**2018 Percent of Net Benefits Awards**	**2019 Percent of Net Benefits Awards**	**2017 Percent of Net Benefits Awards**	**2018 Percent of Net Benefits Awards**	**2019 Percent of Net Benefits Awards**
0.0%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
0.1%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
0.2%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
0.3%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
0.4%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
0.5%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
0.6%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
0.7%	0.00%	0.00%	0.00%	9.75%	8.25%	6.25%
0.8%	0.00%	0.00%	0.00%	10.50%	9.00%	7.00%
0.9%	0.00%	0.00%	0.00%	11.25%	9.75%	7.75%
1.0%	8.25%	6.75%	4.75%	12.00%	10.50%	8.50%
1.1%	9.00%	7.50%	5.50%	12.75%	11.25%	9.25%
1.2%	9.75%	8.25%	6.25%	13.50%	12.00%	10.00%
1.3%	10.50%	9.00%	7.00%	13.50%	12.00%	10.00%
1.4%	11.25%	9.75%	7.75%	13.50%	12.00%	10.00%
1.5%	12.00%	10.50%	8.50%	13.50%	12.00%	10.00%
1.6%	12.75%	11.25%	9.25%	13.50%	12.00%	10.00%
1.7%	13.50%	12.00%	10.00%	13.50%	12.00%	10.00%
1.8%	13.50%	12.00%	10.00%	13.50%	12.00%	10.00%
1.9%	13.50%	12.00%	10.00%	13.50%	12.00%	10.00%
2.0%	13.50%	12.00%	10.00%	13.50%	12.00%	10.00%

Source: Department Reply Comments, at 18 (Table 4) and 20 (Table 5) (February 18, 2016).

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
Reply Comments

Docket No. E017/M-19-256

Dated this **26th** day of **July 2019**

/s/Sharon Ferguson

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