MINNESOTA
PUBLIC UTILITIES COMMISSION

Staff Briefing Papers

Meeting Date	April 19, 2018	Agenda Item **4
Company	All electric utilities	
Docket No.	**E999/CI-07-1199** **E999/DI-17-53** **In the Matter of Establishing an Updated 2016 Estimate of the Costs of Future Carbon Dioxide Regulation on Electricity Generation under Minn. Stat. §216H.06**	
Issues	What values should the Commission adopt as the likely range of costs for future CO_2 regulation on electricity generation? In what year should the values begin to be applied?	
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✓ **Relevant Documents**	**Date**
Agencies (DOC/MPCA), *Request for Comments*	August 22, 2017
Clean Energy Organizations, *Comments* (Docket No. 17-53 only)	September 22, 2017
Minnesota Large Industrial Group, *Comments*	September 22, 2017
Minnesota Power, *Comments*	September 22, 2017
Otter Tail Power, *Comments*	September 22, 2017
Xcel Energy, *Comments* (Docket No. 17-53 only)	September 22, 2017

Relevant Documents	**Date**
Union of Concerned Scientists, *Correction to CEO Filing* (Docket No. 17-53 only)	September 26, 2017
Agencies, *Analysis and Recommendations*	January 19, 2018
Clean Energy Organizations, *Comments*	February 15, 2018
Minnesota Large Industrial Group, *Comments*	February 16, 2018
Great River Energy, *Comments* (Docket No. 07-1199 only)	February 19, 2018
Otter Tail Power, *Comments*	February 19, 2018
Xcel Energy, *Comments*	February 19, 2018
Minnesota Power, *Comments*	February 20, 2018
Agencies (DOC/MPCA), *Correction*	February 28, 2018
Agencies (DOC/MPCA), *Reply Comments*	March 5, 2018
Clean Energy Organizations, *Reply Comments*	March 5, 2018
Minnesota Large Industrial Group, Reply Comments	March 5, 2018
Minnesota Power, *Reply Comments*	March 5, 2018
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Xcel Energy, *Reply Comments*	March 5, 2018

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I. Statement of the Issues

What values should the Commission adopt as the likely range of costs for future CO_2 regulation on electricity generation? In what year should the values begin to be applied?

II. Background

Minnesota Statute § 216H.06 requires the Commission to establish and regularly update an estimate of the likely range of costs of future carbon dioxide (CO_2) regulation on electricity generation:

> **216H.06 EMISSIONS CONSIDERATION IN RESOURCE PLANNING.**
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> By January 1, 2008, the Public Utilities Commission shall establish an estimate of the likely range of costs of future carbon dioxide regulation on electricity generation. The estimate, which may be made in a commission order, must be used in all electricity generation resource acquisition proceedings. The estimates, and annual updates, must be made following informal proceedings conducted by the commissioners of commerce and pollution control that allow interested parties to submit comments.

Importantly, the range of CO_2 regulatory costs under consideration in this case are separate to the Commission's recently updated environmental externality values, which measure the *social* impact of CO_2 emissions. The CO_2 values the Commission is directed to establish in this docket are estimates of *regulatory* costs incurred to comply with anticipated environmental policy.

To avoid double counting CO_2-priced emissions, a utility need not apply the CO_2 externality values in any year in which the regulatory costs are applied. The Commission's direction and rationale was set forth in its December 21, 2007 *Order Establishing Estimate of Future Carbon Dioxide Regulation Costs* (the December 2007 Order):

> In estimating costs associated with CO_2 emissions for the purpose of analyzing electricity generation resources, a utility need not apply CO_2 externality costs derived pursuant to § 216B.2422, subdivision 3, to CO_2 emitted in any year to which the utility applies the CO_2 regulation costs derived pursuant to Minnesota Statutes § 216H.06.[1]
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> …
>
> While the calculation of externality values under § 216B.2422 is not directly comparable to the estimate of regulatory costs under § 216H.06, they both reflect steps to account for the burdens that CO_2 emissions impose on third parties. When a utility calculates the cost of emitting another ton of CO_2 in any given year, therefore, it would be

[1] *In the Matter of Establishing an Estimate of the Costs of Future Carbon Dioxide Regulation on Electricity Generation Under Minnesota Statutes § 216H.06*, Commission Docket No. E-999/CI-07-1199, ORDER ESTABLISHING ESTIMATE OF FUTURE CARBON DIOXIDE REGULATION COSTS, at 11 (December 21, 2007) ("December 2007 Order").

inappropriate to use both the CO_2 externality value and the CO_2 regulatory cost estimate. But utilities should continue to apply the Commission's CO_2 externality values otherwise.[2]

The statute also directs the Department of Commerce and Minnesota Pollution Control Agency ("the Agencies") to seek comment from parties and prepare a report for the Commission recommending a range of regulatory cost estimates.

On August 22, 2017, the Agencies requested comments on the following issues:

1. What approaches could be used within the next few months to develop updated regulatory cost value ranges for CO_2 emissions?

2. If existing carbon trading markets are used as a reference, should only markets located in the U.S./North America be considered or should all global values be considered?

3. Given the United States Supreme Court's stay of the Clean Power Plan implementation and the United States Environmental Protection Agency's (USEPA) stated intention to replace the Clean Power Plan as well as other considerations, what is a reasonable date (year) in which utilities can be expected to incur regulatory CO_2 emission costs?

4. Is there a basis for the Commission to re-assess its decision to apply only the regulatory cost value or the externality value, but not both, to emissions in a given planning year? If so, please provide the basis.

5. If there is a basis for the Commission to re-assess how the regulatory cost value and the externality value ranges are applied, what options should the Commission consider?

Note that the Agencies specifically requested comment on whether the Commission should re-assess its decision to apply only the regulatory cost value or the externality value, but not both, to emissions in a given planning year. It is a departure from past requests for comment for the Agencies to ask this question; however, in light of the Commission's recent update to its environmental externality values, staff believes it is a reasonable question to ask. But staff would also note that the Commission does not need to take action on this issue, nor should the Commission feel compelled to address it simply because it was raised.

After taking comment, the Agencies filed their "Analysis and Recommendations" with the Commission on January 19, 2018.

On January 23, 2018, the Commission issued a notice setting initial and reply comment periods to allow parties the opportunity to address the Agencies' report and make recommendations.

[2] December 2007 Order, at 4.

III. Agencies' Analysis and Recommendations

Recommended Range

The Commission's August 5, 2016 *Order Establishing 2016 and 2017 Estimate of Future Carbon Dioxide Regulation Costs* maintained its estimate of the range of likely costs of carbon dioxide regulation at between $9 and $34 per short ton of CO_2. Furthermore, the Commission required that utilities shall begin applying the above range of CO_2 values as of 2022.

The Agencies recommend that the Commission establish the range of likely costs of CO_2 regulation at $5 to $25 per ton of CO_2 emitted, with a postponement of the effective date to 2025 and beyond. In other words, the Agencies concluded that the current range of $9 to $34 per ton of CO_2 is too high.

According to the Agencies, "recent developments in the carbon market may no longer support the current range of $9 to $34 per ton of CO_2."[3] The Agencies referenced the fact that U.S. carbon markets, the Regional Greenhouse Gas Initiative (RGGI) and California, "have recently seen declines in their auction prices to less than three dollars per ton CO_2e for RGGI (June 2017) and 14 dollars per ton CO_2e for California (May 2017)."[4]

In addition, the Agencies considered a range produced by Synapse Energy Economics in March 2016, which projected carbon prices beginning in 2022 with a range of $15 to $25 per ton of CO_2, increasing gradually in each subsequent year. The Agencies recommend the high end of the Synapse range to be adopted as the high end of the Commission's range.

The Agencies believe a blend of existing U.S. carbon market prices and third-party national CO_2 price forecast information, both of which are publicly available resources, are reasonable estimates to use in utility resource planning.

In response to the Agencies' request for comment, some parties recommended the updated values should be based on third-party vendor forecast data; the Agencies did not necessarily disagree with this approach, but noted it could be costly to continue to rely on third-party vendors. As such, the Agencies used the Synapse forecast, which is free and publicly available.

The Agencies acknowledged that, since the Synapse forecast was produced prior to the most recent federal regulatory developments, it might be higher than costs likely to be incurred. However, Synapse has indicated that it intends to produce a new forecast within the next few months to reflect current and future expected carbon emissions regulation. Thus, the Agencies might revise this range in future recommendations.

Date of Application

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[3] Agencies, Analysis and Recommendations, at 3.

[4] *Id*.

Regarding the date of application, the Agencies recommend an effective date of 2025 to reflect the EPA's proposed repeal of the Clean Power Plan, as well as possible legal challenges. (Staff note: In the Clean Power Plan, while the final compliance year is 2030, there is an interim compliance date of 2022, which is followed by a phased-in "glide path" of emissions reductions through 2030.) According to the report, "the Agencies anticipate that the earliest electric utilities will be required by federal regulations to reduce their CO_2 emissions is starting in 2025, and potentially even later."[5]

Regulatory Costs and Externality Costs

The Agencies recommend the Commission not alter the accepted practice of applying the externality cost values only until the regulatory cost values become effective. In its Analysis and Recommendations, the Agencies responded to the Clean Energy Organizations' (CEO) recommendation to use externality costs in all planning years:

> CEO indicated that "our understanding of the damages of climate change and the Commission's recently updated externality values together warrant a new approach to utility planning for reducing carbon emissions." The CEO offered two options: (1) apply only the externality values in all planning years, or (2) continue to assume regulatory costs begin to be incurred in 2022, applying the regulatory cost range established according to the Synapse carbon pricing forecast.
>
> The Agencies note that Minnesota Statutes § 216H.06 states, "The estimate ... must be used in all electricity generation resource acquisition proceedings." Additionally, Minnesota Statutes § 216B.2422, subdivision 3, states "… A utility shall use the values established by the commission … when evaluating and selecting resource options in all proceedings before the commission, including resource plan …." Therefore, it appears that the CEO's first option would not comply with statutory requirements of Minnesota Statutes § 216H.06 because only the externality value ranges established under Minnesota Statutes § 216B.2422, subdivision 3, would be used. The second option offered by the CEO is not a methodological change in how the two cost ranges are currently applied.[6]

Further, the Agencies cited the Commission's December 2007 Order, in which the Commission determined it would be inappropriate to use both types of costs, particularly since both reflect the burdens imposed on third parties.

The Agencies acknowledged, though, that "utilities have interpreted the Commission's guidance in different ways," but nevertheless, "an accepted practice has been to apply the externality value range in the years prior to the year in which the Commission has determined

[5] *Id*., at 4.

[6] *Id*., at 6.

that the regulatory cost value range should start being applied, with only the regulatory cost value range applied in the remaining years of the planning period."[7]

Duration of Update

While not discussed until reply comments, the Agencies did not oppose Otter Tail Power's recommendation that the Commission-adopted range for 2018 should also apply in 2019. (Staff does not oppose Otter Tail's recommendation, either, and therefore will not discuss it any further in the "Staff Analysis" section of the briefing paper.) The Agencies referenced the Commission's previous, August 5, 2016 Order in this matter, which also addressed the duration of update issue:

> The Commission finds that it makes sense at this point to establish CO_2 regulatory costs for both 2016 and 2017. Calendar year 2016 is more than half over, and there is no evidence of any events on the horizon likely to change regulatory costs before the end of the next calendar year. Given the workloads and resource constraints facing the Department and the MPCA—and given their belief that CO_2 regulatory costs are unlikely to change in 2017—it is both reasonable and responsible not to require these agencies to conduct proceedings to recommend new carbon-regulation costs for calendar year 2017.[8]

IV. Party Comments

A. Clean Energy Organizations

The Clean Energy Organizations (CEO) do not support the Agencies' recommended range or date of application. Instead, CEO recommends the Commission maintain its 2022 applicability date and establish the range set forth in Table 3 of CEO's February 15, 2018, shown below. These values are conceptually consistent with the Agencies' recommended low end of the range, in that they are based on existing carbon markets. However, unlike the Agencies, CEO recommended using forward-looking values, not recent auction prices. In addition, CEO included an additional trading program, the Western Climate Initiative (WCI).[9]

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[7] Agencies, Analysis and Recommendations, at 6.

[8] Docket No. 07-1199, Commission order (August 5, 2016), at 5.

[9] The Western Climate Initiative is a collaboration among California, Ontario, and Québec.

Table 3

Recommended CO_2 regulatory value range			
	Low	Midpoint	High
2022	$12.56	$27.21	$41.86
2023	$13.39	$29.00	$44.61
2024	$14.28	$30.91	$47.55
2025	$15.22	$32.95	$50.67
2026	$16.23	$35.12	$54.01
2027	$17.31	$37.44	$57.57
2028	$18.45	$39.91	$61.36
2029	$19.67	$42.54	$65.40
2030	$20.98	$45.34	$69.71

CEO additionally recommends the Commission establish an escalation rate of 5% above the rate of inflation, which is reflected in Table 3 by the annual increase in values. The rationale for this is that both RGGI and WCI escalate their price floors and ceilings at roughly the same rate. RGGI's price floors and ceilings escalate at a fixed 7% per year, and WCI escalates at 5% above inflation, which totals 7% when combined with the Federal Reserve's target inflation rate of 2%.[10]

CEO also asks the Commission memorialize in its order that the regulatory cost value must be incorporated into the reference or base case of all modeling by all utilities in all resource acquisition and planning proceedings. (Staff notes that some utilities do this already; however, it is not a uniform requirement.) CEO's main argument for this is, if the Commission determines the range reflects costs utilities and ratepayers are expected to incur, these costs should be included into a base or reference case just like any other cost that is expected to be incurred.

Regarding the relationship of regulatory cost values and externality cost values, CEO does not recommend these costs be added together. However, there will be years in which the externality cost is higher than the regulatory cost value. In these instances, CEO recommends an approach it refers to as the "incremental externality" methodology, to be added to the lower regulatory cost. The purpose of the incremental externality would be twofold: it would avoid double counting, while still internalizing the full cost to society.

An example of this approach is shown in Table 5 of CEO's February 15, 2018 comments. Notice that in 2022, when the regulatory cost would take effect, the CO_2 price drops from $43.46/ton to $21.50/ton (the midpoint of the Commission's current range). A $21.50/ton CO_2 price fails to capture the full societal cost; however, the *sum* of the regulatory cost and the incremental externality would capture the social damage:

[10] CEO comments (February 15, 2018), at 10.

Table 5

	2020	2021	2022	2023	2024
CO_2 regulatory cost (midpoint)	$0.00	$0.00	$21.50/ton	$21.50/ton	$21.50/ton
CO_2 externality cost (high)	$42.46/ton	$43.36/ton	$22.76/ton	$23.66/ton	$24.56/ton

According to CEO, "Without an additional adjustment, the market failure will remain, and the regulatory cost value alone will no longer be sufficient to determine the societally optimal level of CO_2 emissions."[11]

The Commission has established a new externality cost range for CO_2 of $8.64 to $40.66/ton in 2018. This means that when the low CO_2 externality cost is used, CEO's proposed regulatory costs will often internalize the externality. CEO will further accept the current practice of switching to the regulatory cost, but only if the damage to society is accounted for.[12]

Finally, CEO recommends the Commission provide guidance to all utilities to bring uniformity and consistency to resource acquisition and planning proceedings. It is problematic, in CEO's view, for different utilities to take different approaches. CEO recommends that the Commission order all utilities in all proceedings to provide the following:

1. A base or reference case that embeds the midpoint of the regulatory value;
2. a sensitivity run using the low regulatory value;
3. a sensitivity run using the high regulatory value;
4. a sensitivity on the reference case (i.e., with the midpoint regulatory value) using the low externality value; and
5. a sensitivity on the reference case (i.e., with the midpoint regulatory value) using the high externality value.

Noted Flaws in the Agencies' Recommended Range

CEO disagrees with the Agencies' recommended range for several reasons. First, CEO submits that the Agencies did not rely on the best evidence of likely **future** regulatory costs, which is a requirement of the statute. Minn. Stat. § 216H.02 requires "an estimate of the likely range of costs of **future** carbon dioxide regulation" (emphasis added). The Agencies claimed its $5 per ton end of the range is reasonable in part because carbon markets "have recently seen declines" in the price of allowances.[13] In CEO's view, recent declines in auction prices are immaterial to what costs utilities will pay to emit CO_2 in the 2020s and beyond.

Table 2 of CEO's February 15, 2018 comments provides future price floors and ceilings in the RGGI and WCI carbon markets.[14] According to CEO, the range proposed by the Agencies is not supported by the very markets that they have looked to for justification.

[11] CEO comments (February 15, 2018), at 14.

[12] *Id.*

[13] Agencies' Analysis and Recommendations (January 19, 2018) at 3.

[14] Staff notes that it is disputed whether these are actually price floors and ceilings. This issue will be discussed

Table 2

RGGI and WCI price floors and ceilings				
	Price floor		Price ceiling	
	RGGI	WCI	RGGI	WCI
2022	$6.42	$18.69	$13.91	$69.80
2023	$6.87	$19.91	$14.88	$74.34
2024	$7.35	$21.20	$15.92	$79.17
2025	$7.86	$22.58	$17.03	$84.32
2026	$8.41	$24.05	$18.22	$89.80
2027	$9.00	$25.61	$19.50	$95.64
2028	$9.63	$27.27	$20.87	$101.85
2029	$10.30	$29.05	$22.33	$108.47
2030	$11.02	$30.94	$23.89	$115.52

Notice that the low and high values in Table 3 on page 8 of the briefing paper are averages of the RGGI and WCI price floors and ceilings in Table 2 above.

Second, CEO does not believe the Agencies establish a sufficient basis for a 2025 effective year. CEO acknowledges the uncertainty regarding the EPA Clean Power Plan; however, "the fact remains that the Clean Air Act requires federal action on greenhouse gases."[15,16] In addition, on December 28, 2017, the Trump Administration issued an Advance Notice of Proposed Rulemaking to solicit comments on the regulation it intends to adopt to replace the Clean Power Plan, so CO_2 regulation could be in place much sooner than 2025.

Third, CEO suggests that the Agencies failed to consider all forms of carbon regulation, policy, or pricing that could have a more immediate effect. For instance, CEO noted the MPCA could adopt rules to join a carbon market, state or federal legislation could be passed, and so forth, such that it is not reasonable to assume it will take until 2025 for some entity to address CO_2 regulation.

B. Minnesota Large Industrial Group

The Minnesota Large Industrial Group (MLIG) is a consortium of large industrial end-users of electricity in Minnesota spanning multiple utilities and functioning to represent large industrial interests before regulatory and legislative bodies.[17]

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later in the briefing paper.

[15] *Massachusetts v. EPA*, 549 U.S. 497 (2007).

[16] CEO comments (February 15, 2018), at 4.

[17] MLIG is composed of the following companies: ArcelorMittal USA (Minorca Mine); Blandin Paper Company; Boise Paper, a Packaging Corporation of America company, formerly known as Boise, Inc.; Enbridge Energy, Limited Partnership; Gerdau Ameristeel US Inc. (St. Paul facility); Hibbing Taconite Company; Mesabi Nugget Delaware, LLC; Sappi Cloquet, LLC; United States Steel Corporation (Keetac and Minntac Mine); United Taconite, LLC; USG

MLIG requests the Commission continue to follow its long-standing precedent by confirming, as the Agencies recommend, that either the externality value of CO_2 under Minn. Stat. § 216B.2422 applies or the regulatory value under Minn. Stat. § 216H.06 applies, but not both.

MLIG expressed concern that applying both the environmental cost values and the regulatory cost values for CO_2 emissions to resource planning could result in costs greater than $75/ton. MLIG does not believe it would be prudent or fair to accept such a high value without further discussion and analysis in a contested case proceeding.

The Agencies noted in its Request for Comment that "the electricity generation sector appears to be on track" to meet the State greenhouse gas reduction goals.[18] According to the MPCA, CO_2 emissions from the electric sector decreased by approximately 17% over the 2005 to 2014 timeframe,[19] and it is important to acknowledge this "on track" progress in updating the values.

Finally, the MLIG recommends the Commission postpone application of the currently established regulatory costs associated with CO_2 emissions until 2035. A 2035 effective date would be outside a utility planning period for integrated resource plans (IRP) filed within the next two years, which would allow application of the newly established externality costs associated with CO_2 emissions. Given the substantial uncertainty regarding CO_2 regulation, the Clean Power Plan in particular, a 2035 effective date provides both stakeholders and the Commission the opportunity to observe changes in both the market and regulatory landscape.

C. Minnesota Power

Minnesota Power (MP) supports averaging data from several vendors to anticipate the cost of future CO_2 regulation. Using different independent forecasts, instead of favoring a single vendor, improves the credibility that the full range reflects likely costs of CO_2 regulation. In addition, including independent forecasts has the benefit of being updatable; as third-party vendors revise their forecasts, so too can the Commission update the likely costs future CO_2 regulation as required by statute.

The Agencies asked parties to comment on which carbon markets should be used if trading programs are to be used as a reference. MP responded, "Only markets in the U.S./North America should be considered because the U.S./North America markets best represent the cost to reduce carbon within the region."[20]

Regarding the effective year, based on proprietary industry resources, as well as the MP's anticipated lead-time required for implementation of a federal regulation for CO_2, MP believes 2026 or later is appropriate to use in resource planning and acquisition. However, in its reply

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Interiors, LLC (Cloquet and Red Wing facilities); and Verso Corporation.

[18] Agencies Request, at 3.

[19] https://www.pca.state.mn.us/greenhouse-gas-emissions-data

[20] MP comments (September 22, 2017), at 1.

comments, MP supported Commission approval of the Agencies' recommended values and start date of 2025. This is not to say MP changed its position—MP noted that it "continues to support using third-party vendor forecast data that Minnesota utilities use for resource planning purposes."[21] But the Agencies' recommendations are acceptable, in MP's view.

D. Otter Tail Power

Otter Tail supports the Agencies' recommendations, agreeing that reducing the range of the likely costs of CO_2 results to $5 to $25 per ton, with a midpoint of $15 per ton, is more reasonable in today's regulatory environment.

Further, Otter Tail finds the Agencies' recommended effective date of 2025 is acceptable, although Otter Tail believes that an effective date of 2028 may be more realistic. The most recent forecast from consulting firm, Wood Makenzie, assumes that regulatory CO_2 emission costs will not begin until 2028.

Otter Tail is supportive of the Agencies' recommendation that there should be "no change to the way the value ranges established under Minn. Stat. §§ 216B.2422 and 216H.06 are applied." Otter Tail also recommends that the Commission adopt the new range and start date for both 2018 and 2019 instead of for just one year.

Finally, Otter Tail recommends that only U.S. markets and forecasts should be considered. Widely varying national energy policies and economic strength in other nations make irrelevant those costs when attempting to determine what should be applied in Minnesota. The best comparisons, in Otter Tail's view, might even be regional, for example, MISO-North.

E. Xcel Energy

Xcel initially proposed a regulatory cost range of $5 to $12, based on the average of the two North American carbon trading markets, RGGI and California/Québec (WCI), over the past two years of CO_2 allowance auctions. Xcel also proposed a 2025 start date to apply these values to reflect a three-year delay from the now-stayed Clean Power Plan (CPP) interim target. The Company summarized its position as follows:

> In summary, we believe we are in a period of particularly significant uncertainty around carbon regulation that makes it difficult to approximate potential future regulatory costs – or the point at which they may take effect. We believe however, the current regulatory cost range of $9 to $34 applied starting in 2022 may no longer be reasonable. If the Commission were to base its regulatory cost range on the North American carbon trading markets, the range would be in the area of approximately $5 to $12. We believe a start year of 2025 may be reasonable, given the current uncertainty around the CPP or its replacement. With respect to the intersection of regulatory costs and externalities values, we believe that the principles that underlie the Commission's determination that regulatory costs and

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[21] MP reply comments (March 5, 2018), at 1.

> externality values should not be applied additively remain the same – and therefore, the Commission should preserve that foundational concept.[22]

Xcel agreed with the Agencies that the Synapse forecast might be a high estimate of likely regulatory costs; however, Xcel can support establishing the range at $5 to $25 in the current uncertain environment, and updating it as the regulatory landscape becomes clearer.

Regarding the consideration of more localized estimates, Xcel noted that state- or regional- (MISO) focused studies "would not be useful to consider as a basis for the Commission's CO_2 regulatory cost range at present. EPA has proposed to repeal the CPP, and it is unclear what regulatory approach will replace it."[23]

Xcel emphasized that the Commission should not change the way utilities currently model the two types of costs. Xcel responded to CEO's incremental externality approach, stating, "it is not merely 'common practice' not to apply both externality and regulatory values in a given year; it is a Commission order."[24] Table 1 reflects how the Agencies' recommendations, if adopted, would be applied under the Commission's current practice:

Table 1: Application of Regulatory Cost and Externalities Values – Reference Case

	Pre-Regulatory Cost Period (years prior to 2025)		Regulatory Cost Period (2025 and beyond)	
	Regulatory Cost	Externality Value	Regulatory Cost	Externality Value
Reference Case	None	Low	Midpoint of Agencies' range	None

Xcel then explained that it is important to differentiate between the Reference Case (or base case) and the purpose and usefulness of sensitivities. In terms of base assumptions, Xcel believes utilities should continue to apply externalities values up to the point at which regulatory costs are expected, as shown above in Table 1.

The purpose of a *sensitivity* analysis, on the other hand, is to develop a reasonable range of possible outcomes to test the robustness of the Reference Case.

Xcel applied the following principles in selecting the most reasonable CO_2 sensitivities:

1) A broad range of sensitivities maximizes decisional value;

2) Sensitivities that are very close to the Reference Case provide little added value; and

3) The overall number of sensitivities should be reasonable, considering there will also be sensitivities for many other variables and input assumptions.[25]

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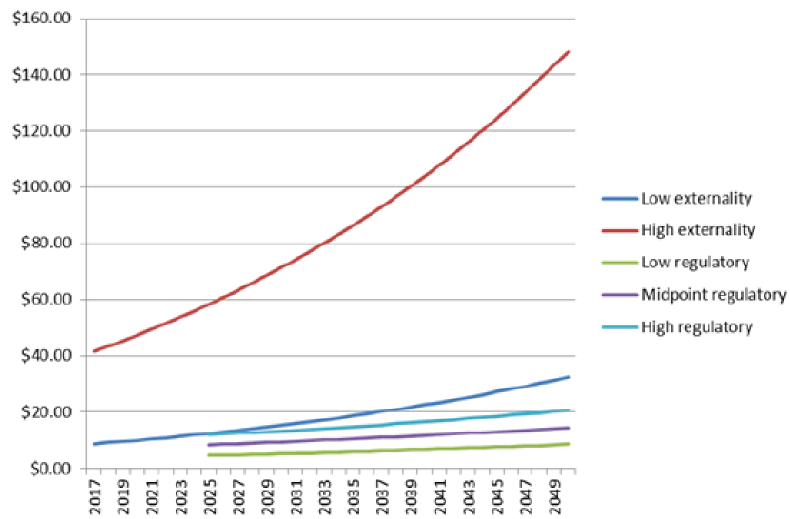
[22] Xcel comments (September 22, 2017), at 2.

[23] Xcel reply comments (March 5, 2018), at 4.

[24] Xcel reply comments (March 5, 2018), at 7.

[25] Xcel comments (February 19, 2018), at 5.

As mentioned above, Xcel ultimately agreed to accept the Agencies' recommendations, but prior to that it had recommended a range of $5 to $12 per ton. To illustrate the lack of decisional value in modeling all regulatory costs and externality costs, Xcel provided a figure including: 1) low externality; 2) high externality; 3) low regulatory; 4) midpoint regulatory; and 5) high regulatory.



Xcel believes the single highest CO_2 cost and the single lowest CO_2 cost would provide the greatest informational value, without regard to whether it is a regulatory cost or externality. This is "because it would likely represent the widest range for decision-making purposes – and, unlike the other options, it would also subsume the full regulatory cost range and the full range of externalities values."[26]

This is not the only option Xcel presents, however. What Xcel suggests above is the third of three options provided in its comments. In full, Xcel provides the following options for the Commission's consideration:

1) Option #1: the high and low externality values for each respective year;

2) Option #2: the high and low of the regulatory cost range that the Commission establishes; or

3) Option #3: the single highest CO_2 cost/value and the single lowest CO_2 cost/value low, without regard to whether it is a regulatory cost or externality value. *(Xcel's preferred option.)*

Xcel's proposed sensitivities changed somewhat in response to the Commission's January 3, 2018 Order in the externalities case. In the externalities case, the Commission required that utilities must evaluate a scenario that includes *no* externality costs:

[26] Xcel comments (September 22, 2017), at 9.

> Combining the higher discount rate with the shorter time horizon generates the lowest practicable estimate of CO_2 costs. Combining the lower discount rate with the longer time horizon generates the highest practicable estimate. By considering resource plans prepared with these costs—along with a scenario that excludes consideration of externality costs—the Commission will gain insight into the magnitude of the CO_2-related stakes in any resource choice.[27]

Table 2 of Xcel's February 19, 2018 comments reflect this requirement (Sensitivity 3). Overall, Xcel now proposes the following sensitivities, which would be in addition to the Reference Case shown in Table 1 above. It shows the low/low sensitivity and the high/high, as described above. Xcel also added a fourth option it does *not* recommend:

Table 2: Application of Regulatory Cost and Externalities Values – Sensitivities

	Pre-Regulatory Cost Period (years prior to 2025)		Regulatory Cost Period (2025 and beyond)	
	Regulatory Cost	Externality Value	Regulatory Cost	Externality Value
Sensitivity 1 (high externality)	None	High	None	High
Sensitivity 2 (low)	None	Low	Low end of Agencies' range	None
Sensitivity 3 (zero)[8]	None	None	None	None
Optional Sensitivity 4 (not recommended)	*None*	*High*	*High*	*None*

F. Great River Energy

On February 19, 2018, Great River Energy (GRE) filed limited comments supporting the Agencies' recommendations. Like others, GRE opposed the CEO "incremental externality" approach, characterizing it as a form of double counting that is inconsistent with past Commission orders.

V. Reply Comments

Most of the parties' reply comments were focused on criticizing the CEO's recommendations. The Agencies and Xcel noted that the price floors and price ceilings to which CEO refers are not actually price floors or ceilings at all; they are regulatory trigger points specific to a particular trading program's market design. According to the Agencies, CEO's proposed values are only "tools for the regulators to influence the allowance market should the actual prices go too high or too low."[28] According to Xcel, the floors and ceilings "are legislative mechanisms – in essence political compromises – incorporated into the design of the programs." Xcel explains how this works in RGGI:

> In the 2017 RGGI Model Rule, the price ceiling (termed CO_2 Cost Containment Reserve Trigger Price) is a price that if reached, triggers the release of additional

[27] Docket No. CI-14-643, Commission order (January 3, 2018), at 32.

[28] Agencies reply comments (March 5, 2018), at 3.

> allowances from the CO_2 Cost Containment Reserve – a pool of allowances additional to regular allowance budgets – to increase allowance supply and bring prices back down. This ceiling is not an expected price, but rather a safety valve mechanism to prevent allowances from becoming too expensive. The price floor (CO_2 Emissions Containment Reserve Trigger Price) works the opposite: if allowance price bids at RGGI auctions do not reach this price, allowances are withheld to decrease supply and cause prices to rise. This floor is likewise not an expected price, but rather a mechanism to reduce allowance supply and force additional emission reductions.[29]

Parties further criticized CEO's incremental externality approach, arguing it is overly complex and inappropriately deviates from the Commission's prior orders. Some specific comments include:

- MLIG: "Such a change would be a significant shift in how these costs are used in resource planning and most commenters in this proceeding have expressed concerns about this concept or skepticism about the need for such a change.[30] … [B]ecause both sets of values are expressed as ranges, there would be multiple potential combinations of values to evaluate in multiple modeling runs. The result would be added complexity to an already long and involved process.[31]

- MP: "These [regulatory cost] values reflect regulation imposed on the utility and are intended to incentivize utilities to take corrective action to lower their carbon profile. With that in mind, it makes sense that utilities would get credit for actions taken to offset the potential regulatory penalty associated with emitting CO_2 while not being subject to externality values considerations that seek to overlay burdens beyond that chosen by policy makers when establishing CO_2 regulations."[32]

- OTP: "The issue of how to apply the regulatory cost and the externality cost need not and should not be addressed in this proceeding."[33]

- Xcel: "The CEO's rationale that the relationship should change because one is now higher than the other in not supported by any Commission determination to date."[34]

Xcel further argued that, to achieve the result the CEO seek, it would be easier to run a sensitivity using the high CO_2 externality value in all planning years, which Xcel proposed in its Option 3 (the highest and lowest of the full suite of externality and regulatory costs).

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[29] Xcel reply comments (March 5, 2018), at 4.

[30] MLIG reply comments (March 5, 2018), at 2.

[31] *Id*., at 3.

[32] Minnesota Power reply comments (March 5, 2018) at 4.

[33] Otter Tail reply comments (March 5, 2018) at 2.

[34] Xcel reply comments (March 5, 2018), at 6-7.

The Agencies opposed all three of Xcel's methodological options. The Agencies would not object to a utility conducting the modeling runs in Options 1 and 2, but the differences between the two runs in Option 1 and the two runs in Option 2 may not be significant enough to warrant the extra time and effort. However, the Agencies noted that Xcel's Option 1 would not comply with § 216H.06, since it would not factor in regulatory costs.[35]

As to Xcel's Option 3, the Agencies believe mixing the cost ranges is not theoretically sound. The cost of future carbon regulation is modeled as an internal cost (on an *ex ante* basis), and therefore impacts the resources the model selects to be added or retired. In contrast, the externality value range is applied on an *ex post* basis once the model selects the resource package, and therefore impacts the estimated cost of the various resource portfolios, but does not influence which resources the model selects to include in the portfolios.[36]

No party agreed with CEO's recommendation to require a uniform methodology. As the Agencies explained, "it is not necessary for the Commission to prescribe specific sensitivities or alter the existing guidance … what matters is that a complete and well-thought-out analysis of a reasonable range of possible outcomes."[37] MP recommends "that the Commission grants flexibility in choosing the appropriate regulatory cost to include in a base scenario (or 'Future') that best represents the current outlook for CO_2 regulation."[38]

CEO, in defense of its incremental externality methodology, disputed the characterization of its proposal that it is "double counting." CEO explained:

> for years in which the regulatory cost is lower than the externality cost, only the incremental externality amount (i.e. the difference between the externality and regulatory values) would be applied as an externality cost. Because we would only apply the incremental externality cost, there would be no "double counting."[39]

There is a fundamental difference between CEO and the parties on this very important point about internalizing the social damage. Perhaps this can best be explained by comparing an excerpt of GRE's comments to CEO's comments.

- GRE: "The cost of federal regulation to reduce CO_2 emissions as outlined by the future regulatory cost of CO_2 represents the potential costs by which utilities would comply with future requirements levied at the federal level. **This would internalize the external societal costs of CO_2 emissions at a level as determined by the regulation this value**

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[35] Agencies Analysis and Recommendations (January 19, 2018), at 6-7.

[36] *Id*., at 7.

[37] Agencies reply comments (March 5, 2018) at 7.

[38] MP reply comments (March 5, 2018), at 3.

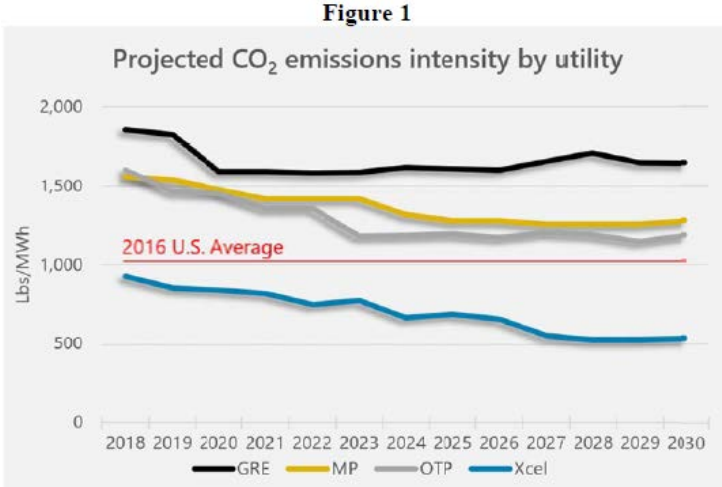
[39] CEO reply comments, at 1.

represents, therefore rendering additional externality values unnecessary as proposed by the CEOs."[40] (Emphasis added by staff.)

- CEO: "Since the Commission has updated its estimate of externality costs for CO_2, however, the interaction between regulatory and externality costs has become more complex. When the regulatory cost value is lower than the externality cost, the regulatory cost no longer fully internalizes the externalities."[41]

CEO also contends that Minnesota utilities are, in general, very carbon-intensive, and therefore are relatively vulnerable to a national carbon pricing system. CEO acknowledges that, while Xcel projects significant CO_2 emissions reductions, the same is not true for GRE, MP, and Otter Tail, all of whom expect to continue emitting substantial amounts of CO_2 throughout the next decade. This is illustrated in Figure 1 of CEO's reply comments, comparing the carbon intensity of GRE, MP, Otter Tail, and Xcel to the national average carbon intensity:

Figure 1



The figure above suggests Minnesota ratepayers are vulnerable to billions of dollars of CO_2 regulation risk.

In the end, the following table shows that most parties support the Agencies' recommendations, although some note that they still that support recommends they made in prior comments:

[40] GRE comments (February 19, 2018), at 2.

[41] CEO reply comments (March 5, 2018), at 2.

Party	Supportive of the Agencies' Recommendations
CEO	No
GRE	Yes
MLIG	Yes for the values; No for effective year (recommends 2035)
MP	Agreeable, but still prefers vendor forecasts
OTP	Yes, but prefers a 2028 effective year
Xcel	Initially no, but Xcel can accept them, given regulatory uncertainty

VI. Staff Analysis

The Commission's task, pursuant to Minn. Stat. § 216H.06, is that it "shall establish an estimate of the **likely** range of costs of future carbon dioxide regulation on electricity generation."[42] (Emphasis added by staff.) Unlike the environmental externalities docket, the purpose of this docket is not to quantify societal damage, but to insulate ratepayers from future costs they are predicted to bear in order for utilities to comply with environmental regulation. Therefore, staff's primary focus in the sections that follow are with regard to what is (a) likely and (b) applicable to Minnesota ratepayers.

The term "likely" has at least two different interpretations, not mutually exclusive from one another. The first interpretation is whether it is "likely" that CO_2 regulation will exist at all. If it is, it is reasonable to assume there will be *some* cost to CO_2 regulation, but estimates will be highly uncertain, and the appropriate treatment for uncertainty is very policy-driven.

A second aspect of "likely" is how Minnesota utilities will be affected, which requires an evaluation of a specific policy design. It would be advantageous, from a modeling perspective, to have some policy framework from which to derive a range of costs, for example, by assuming a known emissions constraints or a per ton tax. But that is not the case here, and as such, it is important to consider the fact that there is no CO_2 regulation at this time with which Minnesota utilities filing resource plans need to comply.

The Agencies' report and party comments discuss cap and trade frameworks, like RGGI and the WCI, but the details of those frameworks are completely undefined as they pertain to Minnesota utilities—e.g. how Minnesota would functionally exist in such a market. There are also references to the EPA Clean Power Plan, but the Clean Power Plan, even in light of its uncertainty at the judicial and federal levels, has several sub-issues related to allowance allocation, intrastate versus interstate trading, who is regulated, and so forth, all of which could significantly impact the likely cost. Absent these details, making any assumptions at either the high or low end about what every ton will cost Minnesota ratepayers is a very daunting task.

With this being said, the issue of uncertainty is not new—in fact, the Commission has addressed it in prior orders since the inception of this docket in 2007. As one example, the Commission

[42] Minn. Stat. § 216H.06

made the determination in its December 2007 Order that the existence of uncertainty is not an adequate justification for a \$0 CO_2 value:

> The Commission acknowledges that all forecasts entail a degree of doubt. This fact, however, is only tangentially relevant to the Commission's decision. The future is uncertain. The need to plan for the future is not. The degree of uncertainty regarding future CO_2 regulation and future technology makes the task of estimating regulatory costs more difficult; it does not make the task any less necessary. And it certainly does not lead the Commission to conclude that the most likely estimate of CO_2 costs is effectively \$0.[43]

But there are several important differences between today and 2007, and staff will address these in greater detail in later sections. Some important factors to consider include: 1) investments already made in CO_2 reductions; 2) the cost-competitiveness of renewable energy; and 3) the Commission's updated environmental externality values. While some are confident in the first aspect of likelihood—that CO_2 regulation will likely exist at some point—this expectation, by itself, does not provide any clarity with respect to a clear policy framework from which likely costs can be derived.

A. Minnesota's Compliance with EPA Clean Power Plan

There have been arguments put forward by the parties that the uncertainty in the fate of the EPA's Clean Power Plan should factor into the Commission's range, date of application, and regulatory scope of compliance. Xcel, for example, noted:

> EPA has proposed to repeal the CPP [Clean Power Plan], and it is unclear what regulatory approach will replace it. Regardless, few expect the CPP to be enacted in the form finalized in October 2015 and modeled by the organizations mentioned in the footnote. We therefore do not recommend state or regional CO_2 pricing based on the CPP.[44]

Xcel raises a fair point, but staff does not agree completely with Xcel for two main reasons.

First, as noted, Xcel supports the use of the Synapse forecast, but not state or regional pricing based on the CPP. But according to the Synapse report, the basis for the forecast was in large part the Clean Power Plan. Synapse discussed the foundation for its forecast, and it noted that compliance costs could be lower as neighboring states find mutually beneficial outcomes:

> Synapse has developed Low, Mid, and High case forecasts for CO_2 prices from 2022 to 2050. These forecasts reflect our best understanding of Clean Power Plan compliance costs, as well as future expected costs to meet science-based emissions targets. We believe it is highly likely that neighboring states with large

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[43] Commission order (December 21, 2007), at 5.

[44] Xcel comments (February 19, 2018), at 5.

> disparities in mitigation costs will work together to their mutual benefit to reduce overall compliance costs.[45]

Second, there was a substantial amount of analysis done in recent years pertaining to Minnesota's cost of compliance with the EPA Clean Power Plan, and staff will discuss that in the next section. In short, several studies found that Minnesota was well-positioned to cost-effectively comply with the final version of the Clean Power Plan. However, Xcel recommends the Commission ignore these studies.[46]

Staff's underlying concern is the logical flow of Xcel's argument. The Clean Power Plan included a state-specific emissions limit with a 2030 compliance year (and a 2022 interim target). Several studies identified that the State of Minnesota could exceed allowance-based targets at little, if any, net cost. Since that time, the Clean Power Plan has been stayed by the U.S. Supreme Court and is facing repeal by the Trump Administration. What Xcel is now arguing is that, in light of greater uncertainty and what appears to be a regression in U.S. climate policy, the Commission should disregard state-specific CPP analyses and assume instead a national forecast—still based on the CPP—that assumes Xcel and other utilities will pay up to $25 per ton for carbon emissions.

Some may argue that the Final Rule of the EPA Clean Power Plan, issued in October 2015, has limited applicability at this point. However, it should be noted that both the low and high bound of the Agencies' recommendation are based on, or price in, the EPA Clean Power Plan to some extent. This is because carbon markets and industry forecasts over the past few years have basically been operating under the assumption that the Clean Power Plan would be the nation's CO_2 regulation. As a result, RGGI auction prices—the basis of the low bound—have seen great volatility in recent years. The high bound—based on a Synapse forecast—was largely based on a range of national CPP compliance estimates. Thus, it is simply not possible to simultaneously ignore the CPP while basing the updated CO_2 regulatory costs on RGGI prices and a Synapse forecast, because the CPP is embedded within each bound.

The newly injected uncertainty raises policy considerations over the appropriate geographic regulatory scope—state, regional, or national. At the low end, the Agencies recommend a regional scope (the Northeast), but the high end reflects a national scope. Xcel's initial proposal was also regional, accounting for RGGI (Northeast) at the low end and California at the high end. So it not entirely consistent, either, to argue solely in favor of a national compliance estimate, since there is no national carbon market.

Despite the focus on the implementation of the EPA's rule that was finalized then stayed, staff believes the Clean Power Plan, conceptually, remains a reasonable proxy for hypothetical CO_2 regulation. First, it is the most recent national policy the Commission has available to it, unlike various cap-and-trade bills that have been used a basis to set values in previous iterations of this docket (e.g. Waxman-Markey). Second, its design and objective was to reduce national

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[45] Synapse report, at 6.

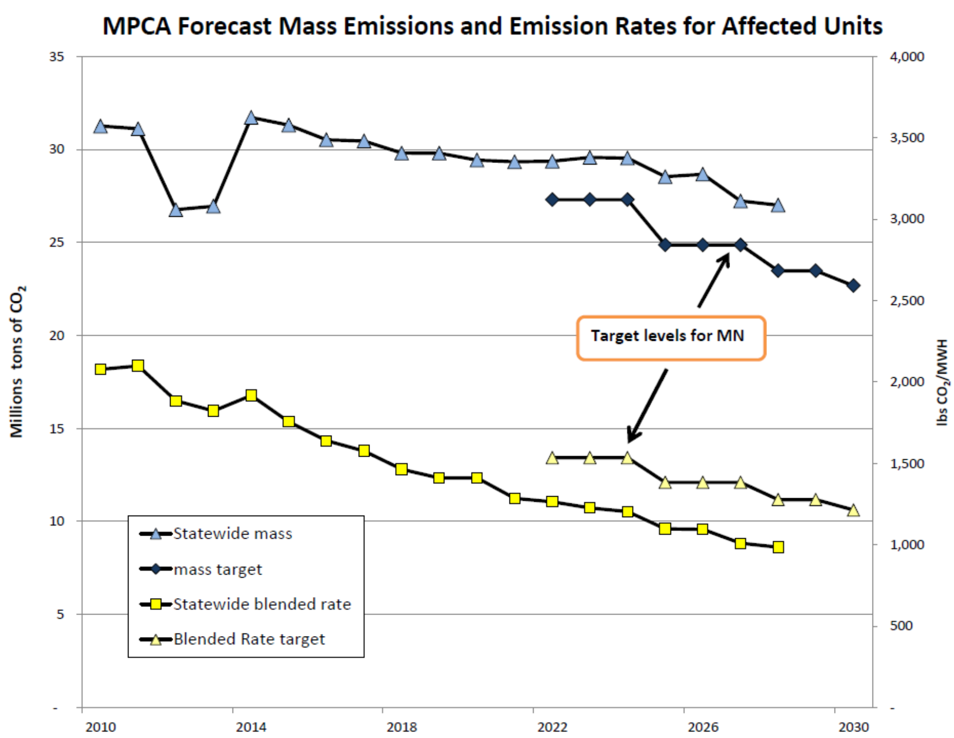
[46] Xcel comments (February 19, 2018), at 9.

CO_2 emissions by roughly 30 percent below a baseline year, while giving flexibility to states on how to comply. This seems to be a reasonable outline of future CO_2 policy. Third, and most importantly, there was substantial analysis conducted specific to Minnesota and its possible compliance pathways, which is something that has not been done before at that level of depth for previous considerations of the Commission's range.

1. MPCA EPA Stakeholder Collaborative

In 2014, the Minnesota Pollution Control Agency (MPCA) started a process to solicit stakeholder input in response to the Clean Power Plan Proposed Rule. That process evolved significantly over the course of two years, and workgroup meetings ranged from more general discussion sessions to presentations of very detailed analyses. Documents from many of these discussions are on the PCA website.

As an example, one analysis showed that, after taking into account generation and emissions from regulated facilities and comparing them to utility annual reports and resource plans, Minnesota is well-positioned, as a state, to comply with the CPP under an allowance-based or carbon-intensity (rate-based) framework. This is illustrated by the figure below (which does not incorporate the Sherco 1 and 2 retirement):[47]



[47] Minnesota Pollution Control Agency, Compliance Projections (December 11, 2015), Accessed online at https://www.pca.state.mn.us/sites/default/files/aq-rule2-22b.pdf

At a March 31, 2016 Technical Workshop, national allowance prices and Minnesota's compliance position were discussed in presentations by the Union of Concerned Scientists (UCS) and Center for Clean Air Policy (CCAP).

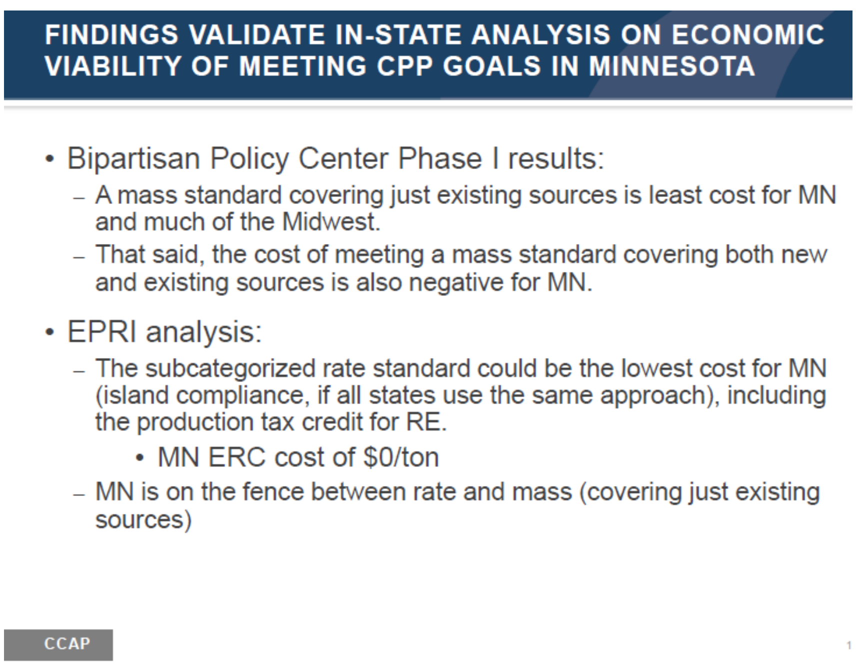
According to the UCS presentation:[48]

- Under the Reference Case, national carbon prices range from \$8 to \$13/ton, with an average of about \$11/ton from 2022 to 2030;
- Under the Full Trading Case, national carbon prices range from \$7 - \$11/ton, but average about \$10/ton; and
- Under the Clean Path Case, national carbon allowance prices carbon allowance average \$8/ton and range \$5-\$10/ton.

UCS also modeled Minnesota's compliance cost and assumed the Commission approved Xcel's IRP and proposed Sherco retirement. According to UCS, under this scenario:

- Minnesota's Clean Power Plan targets are exceeded by 2024;
- Electricity expenditures are reduced in every year, saving more than \$745 million by 2030 compared to the Reference Case; and
- Typical Residential electricity bills are 7 percent lower in 2030.

According to the CCAP presentation, a Bipartisan Policy Center found that the cost for meeting the Clean Power Plan under a mass (allowance) based approach is negative for Minnesota. An EPRI analysis found that under an "ERC Cost" (emissions reduction credit) approach, Minnesota's ERC Cost is \$0.



[48] Presentations accessed online at https://www.pca.state.mn.us/sites/default/files/aq-rule2-22f.pdf

2. Case Study: Xcel Energy 2016-2030 Resource Plan

Attachment H of Xcel's January 29, 2016 *Supplement to Resource Plan* was a preliminary assessment of Xcel's net allowance position under the Clean Power Plan. In brief, Xcel estimated potential revenues from CO_2 allowances and credits in future CO_2 markets, and Xcel projected its proposed resource plan would exceed requirements as set forth by EPA:

> Although our Current Preferred Plan is not primarily driven by the CPP [Clean Power Plan], we believe this plan will not only achieve, but likely exceed, the CO_2 reductions that could be required of the Company under Minnesota's CPP State Plan. As a result, the Current Preferred Plan may generate excess reductions in the form of CO_2 allowances (if Minnesota's plan is mass-based) or Emission Rate Credits (if the plan is rate-based), which under the CPP would be tradable to the owners of other CPP-regulated units within the state or in other states.[49]

Xcel projected a wide range of revenues for CPP compliance, depending on the policy details and allowance prices. Xcel projected a range of excess revenues as low as $31 million (Scenario 2 at $9/ton) to as high as $853 million (Scenario 1 at $34/ton), as shown by the table below:[50]

Table 1: Value of allowances, in excess of compliance needs, under two State Plan scenarios (hundreds of million dollars, undiscounted, over 2022 to 2030)

Allowance Price	Scenario 1	Scenario 2	Difference
$9/ton	$226	$31	$194
$21.50/ton	$540	$75	$465
$34/ton	$853	$119	$735

For this docket, however, Xcel argues *against* basing the Commission's CO_2 regulatory costs on the state or regional assessments of the Clean Power Plan.

3. PUC Notice Request for Information from Utilities Filing IRPs

Utility resource plans have continually shown declining CO_2 emissions. To illustrate this, the Commission's January 13, 2018 *Notice Seeking Comment* requested utilities who responded to the Agencies' Request for Comment to provide historical and forecasted CO_2 emissions. Specifically, the Notice asked utilities to provide their total emissions reductions and carbon intensity (CO_2/MWh), using an average of 2010-2012 operations as a baseline,[51] and provide forward-looking projections under each utility's most recently approved IRP.

Note that the Clean Power Plan, in its form as of October 2015, would require the State of Minnesota to cut its CO_2 intensity to 1,213 pounds (lbs) of CO_2 per MWh.

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[49] Docket No. 15-21, *In the Matter of Xcel Energy's 2016-2030 Integrated Resource Plan*, Attachment H (January 29, 2016), at 1.

[50] Id. at 7.

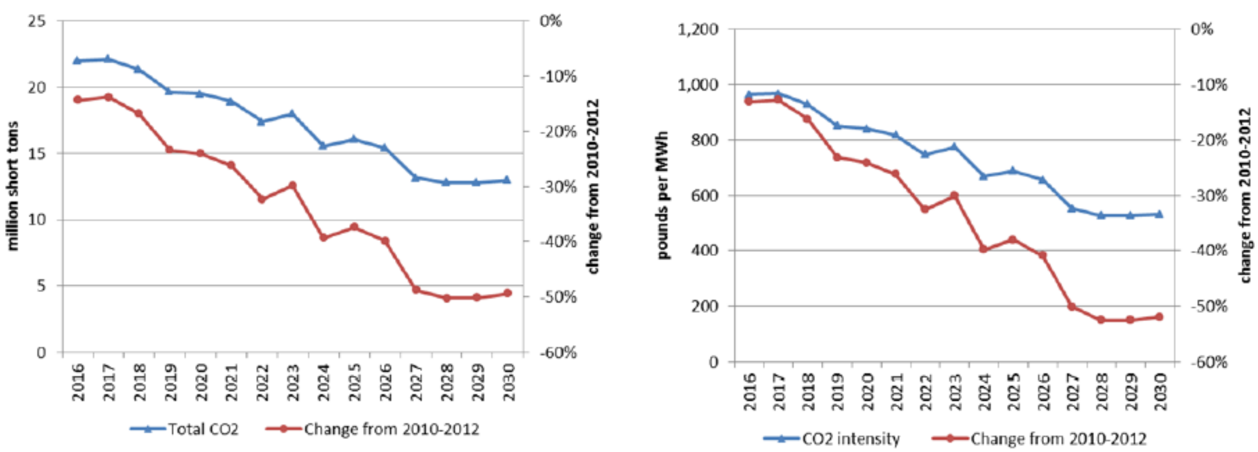
[51] Staff chose this baseline year to align it with the Final Rule of the Clean Power Plan and Xcel's IRP.

MP and Otter Tail provided tables of CO_2 reductions by total emissions and intensity, while Xcel provided a figure. MP and Otter Tail provided the following information:

Utility	CO_2-intensity (2010-2012), lbs/MWh	CO_2-intensity (final IRP year), lbs/MWh	% change
MP	2,060	1,280	**-37.86%**
OTP	1,861	1,156	**-37.88%**

Xcel expects to reduce its carbon intensity to roughly 500 lbs/MWh, reflecting a reduction of more than 50% relative to its 2010-2012 average. Xcel's projection does *not* include its full 1,550 MW of approved new wind (since this amount is higher than what the IRP envisioned).

Figure 2: Total CO_2 Emissions (left) and CO_2 Intensity (right) Relative to 2010-2012 under Xcel Energy's Upper Midwest Resource Plan for 2016-2030



Another issue to consider is jurisdiction. Recall that in Figure 1 of CEO's reply comments—shown on page 18 of the briefing paper—CEO displayed the average CO_2 intensity in the U.S. relative to GRE, MP, Otter Tail, and Xcel. This, CEO argues, shows Minnesota utilities' exposure to CO_2 price risk. CEO also argues that the MPCA could exercise its authority under Minn. Stat. § 116.07, subd. 2(a) to take steps to join a carbon market, like RGGI or WCI. It should be noted that the power plants that elevate GRE's and Otter Tail's CO_2 intensity are outside MPCA's jurisdiction. If Minnesota became a RGGI state, for instance, GRE's 1,100 MW coal-fired Coal Creek Station in North Dakota and Otter Tail's coal-fired Coyote Station and Big Stone, located in North and South Dakota, respectively, could not be MPCA-regulated sources.

The Commission's December 2007 Order emphasized the "need to plan for the future."[52] While staff is *not at all* suggesting it is time for the Commission discard the CO_2 regulatory costs, utilities' historical and planned investments demonstrates that planning for the future is and has been underway, and State energy policy sets forth directives and guidance across several statutes that will continue CO_2 abatement efforts. Furthermore, the remarkable drop in the cost of renewable energy suggests this course of carbon reduction is not set to reverse

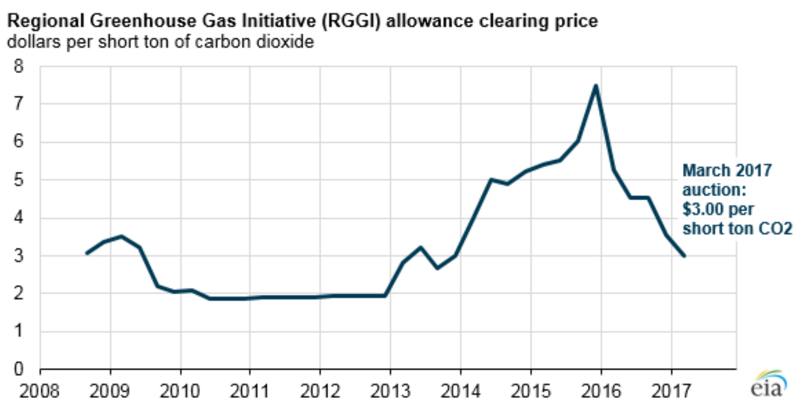
[52] Commission Order (December 21, 2007), at 5.

anytime soon. One could say, then, that in 2007 the Legislature viewed Minnesota's CO_2 position in a different way than it might today. With all of these factors taken together, when examining the potential for and implications of a national carbon pricing program, it is not unreasonable for the Commission to take historical reductions and the present landscape into account.

B. Carbon Markets (the Agencies' low bound)

The Agencies recommend a low bound of $5/short ton to reflect the "average of recent RGGI prices."[53] In this section, staff will discuss some issues pertaining to applying permit prices in an unrelated carbon market to set likely costs assumed to be incurred by Minnesota ratepayers. (CEO recommends the Commission also use prices from the Western Climate Initiative, but in this section staff will mostly discuss RGGI.)

Below is a figure of historical RGGI prices, [54] which staff believes confirms that $5/short ton is a reasonable reflection of RGGI prices:



Source: U.S. Energy Information Administration, based on Regional Greenhouse Gas Initiative

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Xcel agreed with the Agencies that it may be reasonable to use CO_2 allowance prices in existing carbon markets, but partly on the basis that "there is no obvious alternative."[55]

Otter Tail also agreed that existing carbon markets "should be a consideration when setting a range of CO_2 allowance costs,"[56] but only U.S. carbon markets should be considered.

MP did not object to using carbon markets, but noted that only U.S./North American carbon markets should be considered.

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[53] Agencies report, at 4.

[54] EIA https://www.eia.gov/todayinenergy/detail.php?id=31432

[55] Xcel comments (September 22, 2017), at 5.

[56] Otter Tail comments (September 22, 2017), at 2.

The volatility of RGGI auction prices, as illustrated by the figure above, largely involves market forces entirely unique to that cap-and-trade system involving nine participating states, which challenges the reasonableness of using RGGI prices as a reasonable proxy for Minnesota. For example, what explains the spike in allowance prices in January 2013 was RGGI's announcement to reduce its cap on CO_2 emissions by 45%, to be imposed in 2014. Prices later spiked in August 2015 after EPA's release of the proposed Clean Power Plan; in that year, bids were submitted for more than three times the total number of RGGI allowances offered.[57] In 2016 and 2017, RGGI auction prices fell dramatically as a result of the U.S. Supreme Court's decision to stay the implementation of the EPA Clean Power Plan, leading to a March 2017 auction clearing price of $3.00/short ton.

The Agencies observed that RGGI allowance prices have been lower than the Commission's current range, which justifies reducing the current low bound; however, staff would add that there is also a question of relevance. In addition to the historical volatility illustrated and described above, in August 2017, RGGI announced it will propose an additional 30% cap reduction by the year 2030, relative to 2020 levels. One might expect this will lead to higher allowance clearing prices in subsequent auctions, but at the same time, one might also ask why this is relevant to Minnesota utilities' **likely** CO_2 regulatory compliance costs.

There is no direct connection between RGGI allowance prices and Minnesota generators' price of electricity, and 216H.06 plainly states that the Commission shall estimate "the likely range of costs of future carbon dioxide regulation on electricity generation." As staff will explain later, it is even difficult to estimate how the price of RGGI allowances impacts the price of electricity in RGGI-participating states.

CEO acknowledged this comparison of RGGI to Minnesota in its comments, stating that "market conditions in any region will not accurately reflect market conditions if a cap-and-trade system existed in Minnesota or the U.S."[58] So if the Commission is to use RGGI prices as the basis for CO_2 regulation in Minnesota, it is, at a minimum, important to consider the context of RGGI as well as how allowances should be incorporated into a capacity expansion model.

1. Context

The Agencies, while recommending that carbon markets are reasonable proxies for CO_2 regulation, noted that "carbon market costs are current costs and **do not reflect likely future values**."[59] (Emphasis added by staff.) CEO responded to this, recommending that "the Commission can improve on the Agencies' approach of setting the regulatory cost values based on existing carbon pricing programs in the U.S. by setting the range according to the price floors and ceilings in these programs for the relevant future years."[60] The Agencies replied back that the CEO's values are not actually price floors or ceilings.

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[57] EIA https://www.eia.gov/todayinenergy/detail.php?id=31432

[58] CEO comments (September 22, 2017), at 5.

[59] Agencies report, at 4.

[60] CEO comments (February 15, 2018), at 7.

The price floor and price ceiling proposed by CEO reflect the "ECR" (Emissions Containment Reserve) and "CCR" (Cost Containment Reserve) components of RGGI. In short, the ECR is a mechanism that withholds allowances from circulation to secure additional emissions reductions if prices fall below trigger prices; the ECR will only trigger if emission reduction costs are lower than projected. The CCR is a quantity of allowances held in reserve, made available for sale if allowance prices exceed predefined price levels. The table below[61] shows the ECR and CCR (in the red box), and these values are included in Table 2 of CEO's comments:

	Base Cap	Bank Adjustment	Adjusted Cap	CCR Trigger Price ($)	ECR Trigger Price ($)	CCR Size	ECR Size
2020	78,175,215	21,891,408	56,283,807	$10.77	N/A	10,000,000	N/A
2021	75,147,784	TBD	TBD	$13.00	$6.00	7,514,778	6,845,333
2022	72,872,784	TBD	TBD	$13.91	$6.42	7,287,278	6,637,900
2023	70,597,784	TBD	TBD	$14.88	$6.87	7,059,778	6,430,464
2024	68,322,784	TBD	TBD	$15.92	$7.35	6,832,278	6,223,030
2025	66,047,784	TBD	TBD	$17.03	$7.86	6,604,778	6,015,597
2026	63,772,784	N/A	63,772,784	$18.22	$8.41	6,377,278	5,808,163
2027	61,497,784	N/A	61,497,784	$19.50	$9.00	6,149,778	5,600,727
2028	59,222,784	N/A	59,222,784	$20.87	$9.63	5,922,278	5,393,293
2029	56,947,784	N/A	56,947,784	$22.33	$10.30	5,694,778	5,185,859
2030	54,672,784	N/A	54,672,784	$23.89	$11.02	5,467,278	4,978,425

The ECR is a supply mechanism, not a price control mechanism, and as such, having the ECR in place does not appear to prevent prices from dropping below the trigger price. Also, notice from the table above that the CCR size (the quantity of allowances held in reserve) is confined to only 10% of the cap. It is also worth noting that the ECR and CCR are intended to address certain problems confronting that particular market, such as surplus allowances, excessive banking, and lower-than-expected prices. This means that not only are the CCR and ECR unreflective of a forecast of future auctions, but surplus allowances and banking are program characteristics totally unrelated to the State of Minnesota.

Similar issues exist in the Western Climate Initiative. According to a December 2017 report from Energy Innovation:

> Recently released data show that oversupply reached a new maximum in 2016, which supports the conclusion that WCI oversupply has grown … Because unused allowances, the tradable emissions permits at the core of the program, can be saved and used later, this oversupply will very likely be banked. Banked allowances enable higher emissions than would otherwise occur by effectively raising future cap levels above those established by regulation.[62]

With this being said, returning to the figure showing the recent market volatility of RGGI auction prices, on page 26 of the briefing paper, in late-2015 prices spiked to almost $8/ton

[61] https://www.rggi.org/sites/default/files/Uploads/Program-Review/12-19-2017/Principles_Accompanying_Model_Rule.pdf

[62] Energy Innovation, "Oversupply Grows in the Western Climate Initiatve Carbon Market" (December 2017), http://energyinnovation.org/wp-content/uploads/2018/02/WCI-oversupply-grows-February-update.pdf

when the market was anticipating the Clean Power Plan would be implemented. Only after the Supreme Court stay and prospect of repeal by the Trump Administration did the market price crash. It makes more sense to consider (to the extent they should be considered at all) allowance prices at points in time when the market assumed federal regulation, not when it didn't. In other words, if the working assumption is that carbon will be a nationally regulated pollutant, and if it is further determined that the recent history of RGGI prices is a reasonable proxy for future values, then CEO's RGGI values—setting aside whether they are actually floors or ceilings—might be more accurate than the Agencies' values. This is because the Agencies' values, reflecting "recent developments," only apply to the market correcting for a waning probability of regulation, rather than an increasing probability.

Regardless, staff repeats that the larger issue is that § 216H.06 directs the Commission to determine the likely effect of CO_2 regulation on electric generation. And again, oversupply and banking in the two U.S. carbon markets, which several argue are reasonable proxies, involve market forces completely separate from Minnesota electric generation. Unless the MPCA has plans to join an existing carbon market—and staff has no reason to believe that it does—it is questionable whether these markets, and therefore their prices, are at all applicable to Minnesota's resource planning process.

2. Modeling Allowance Prices

Methodology

Resource plans model and rank expansion plans with and without CO_2 regulatory costs imposed. Utilities have different ways of doing this, but in general, emission rates for thermal generation units are an input modeled as tons or pounds per MMBTU of fuel consumed for energy production, which is then multiplied by the CO_2 regulatory cost. The effect of carbon pricing is that the dispatch order changes, with the costlier units operating less, but still operating. Otherwise more expensive units can be added to the model or displace CO_2-emitting generation, but this may come at a premium relative to the No-CO_2 case. In the end, what this means is that the least-cost expansion plan under a No-CO_2 case is always less expensive than the least-cost expansion plan in the With-CO_2 case.

Thus, as it appears in resource planning today, CO_2 regulation looks inherently detrimental financially, in that the No-CO_2 scenarios are far less expensive. And maybe, for some, CO_2 regulation will always be viewed in this way. MP, for example, keeps the practice of referring to the CO_2 regulatory cost value as a "penalty." However, staff is not convinced that if a state, region, or nation enacts CO_2 regulation, it will necessarily be financially detrimental.

The externalities case is different because pollution necessarily produces social damages. But strategically participating in carbon markets does not have to impose a financial "penalty," as it were. Depending on the program design, cap-and-trade could have strategic financial value. This is evidenced by the fact that when an actual carbon policy—the Clean Power Plan—was considered in Xcel's 2015 IRP, it generated hundreds of millions of dollars in revenue for the Company.

Historical and planned carbon abatement measures, as well as Minnesota utilities' position in a potentially carbon-regulated environment, could be something the Commission and utilities could take into account in resource planning. Minnesota Power, for example, states, "it makes sense that utilities would get credit for actions taken to offset the potential regulatory penalty associated with emitting CO_2."[63] MP raises a good point, but the problem is that MP makes this argument to oppose CEO's recommendation to use an incremental externality when the externality exceeds the regulatory cost. What MP could have argued instead is whether or to what extent it will have to pay a "penalty" at all, and what historical investments could mean in terms of future value. In other words, MP conflates externalities with regulatory costs and argues that a relatively lower permit price serves merely to offset the financial harm imposed by the externality.

If a direct tax on carbon is implemented, historical achievements would not matter (because regardless of the system, each emission of CO_2 would be priced). However, where the Agencies and the parties (except CEO) stand today is the assumption that it is likely Minnesota utilities will engage in a cap-and-trade system by 2025. Xcel, for example, argued that because existing programs and regulatory proposals that came nearest to being enacted reflected cap-and-trade systems, "it seems more supportable at present to use cap and trade as the basis."[64]

What Xcel has not explained, though, is how its recommendation would function any differently than a carbon tax in a capacity expansion model. If, hypothetically, Xcel participated in RGGI, it is not apparent how it would do so in a way that is at all consistent with how parties recommend RGGI prices be used in this proceeding.

For instance, Xcel, while critical of CEO's recommendation to consider a CO_2 tax, prefers an approach that would function in an economic model in essentially the same way as a tax, in that the CO_2 price "could cause the dispatch of a unit to fall sufficiently that a utility would decide it has become uneconomic and propose retirement of that unit."[65]

If Xcel participated in RGGI, the State of Minnesota would implement the program through its own regulation, which includes emissions caps (or budgets) that are equal to shares of a region-wide cap. Virtually all allowances are sold through auctions, but to the extent more allowances are obtained than needed, or if CO_2 emissions are reduced, excess allowances can be sold and used as a source of revenue.

In addition, while it is true that RGGI auctions the majority of allowances, rather than the more common approach of freely allocating some or all of them, a central tenet of RGGI is that RGGI states are required to use a minimum of 25% of their auction proceeds for a "consumer benefit or strategic energy purpose." This greatly offsets the actual cost of RGGI participation.

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[63] MP reply comments (March 5, 2018), at 4.

[64] Xcel reply comments (March 5, 2018), at 6.

[65] Xcel comments (February 19, 2018), at 8.

If two completely different policy designs are mechanically indistinguishable in a capacity expansion model, and if the Commission likewise favors a cap-and-trade system, it might be necessary to explore how to impose a cap and, possibly, how to bank emissions allowances to take historical abatement measures into account. Ideally, the modeling should reveal how CO_2-mitigating measure could make a utility better off financially, not inherently worse off.

If the permit price of an unrelated market is to be used in this case, at a minimum there should be some assumption about the amount of allowances available to the utility, as well as how those allowances can be used. It is staff's understanding that Minnesota utilities either are in the process of procuring, or have procured, the license for a new capacity expansion model. New modeling software has the capability to combine emission limits with capital project optimization, allow for over-compliance in early years to offset tighter limits in later years, and include banking logic to optimally utilize emission allowances. Thus, in the future, utilities should be able to put forward a plan that maximizes the financial value of participating in whatever market it assumes, but in a more realistic, sophisticated way. Staff acknowledges this could be challenging, especially if complicated techniques like banking are included, but at least this would have the effect of reflecting actual participation in carbon markets.

The core issue is that if the Commission adopts the Agencies' recommendations, it could be interpreted to mean that it accepts the likelihood of a cap-and-trade system. This is because neither RGGI nor the Synapse forecast are based on a carbon tax; both include a system of allowance prices.[66] Xcel in particular—because it argued in favor of cap-and-trade over taxes—should be able to explain how a modeling exercise would consider the Agencies' range and a CO_2 tax as distinctly different policy designs.

Xcel observed about RGGI and WCI, "The fact that allowance prices in both programs have remained low reflects that it has been relatively affordable to reduce CO_2 emissions and achieve compliance."[67] Xcel attributes low allowance prices in part to "policy design mechanisms." But incorporating only the permit price disregards why those allowance prices are able to stay low. One could argue that these details are embedded in price assumption, but the auction price, by itself, lacks other central components of these markets, like being a net seller, proceed re-distribution, and how generators participate in the wholesale market.

Comparison to RGGI

In RGGI, a CO_2 allowance represents an authorization to emit one short ton of CO_2 from a regulated source, as issued by a participating state. Allowances can be acquired by purchasing them at regional auctions or through secondary markets.

The current RGGI cap declines 2.5% each year until 2020. The RGGI cap for years 2014-2020 is shown by the table below:

[66] In fact, Synapse noted in its report, "While some advocates have claimed that a tax is administratively simpler and reduces bureaucratic, regulatory, and compliance costs, a common aversion to new taxes has meant that no carbon tax proposals have received substantial support in recent policy debate."

[67] Xcel reply comments (March 5, 2018), at 5.

Year	RGGI Cap (Allowances)	% Change
2014	91,000,000	-
2015	88,725,000	-2.5%
2016	86,506,875	-2.5%
2017	84,344,203	-2.5%
2018	82,235,598	-2.5%
2019	80,179,708	-2.5%
2020	78,175,215	-2.5%
Total (2014-20)	-12,824,785	-14.1%

Below, staff shows the total annual tons of CO_2 emitted from MP, Otter Tail, and Xcel, through 2025—the year in which the RGGI permit price would go into effect. As shown, through 2025, utilities expect to reduce emissions in an amount that is roughly consistent with RGGI's 2.5% annual cap reduction from 2014-2020 (on a per annum basis, utilities' reductions are sometimes higher and sometimes lower):[68]

Year	Minnesota Power (tons)	% Change
2010-2012	11,128,692	-
2018	9,467,750	-14.9%
2019	9,377,720	-1.4%
2020	9,070,157	-3.3%
2021	8,725,532	-3.8%
2022	8,831,038	1.2%
2023	8,820,850	-0.1%
2024	8,284,597	-6.1%
2025	7,967,182	-3.8%
Total (2018-25)	-1,500,568	-15.9%

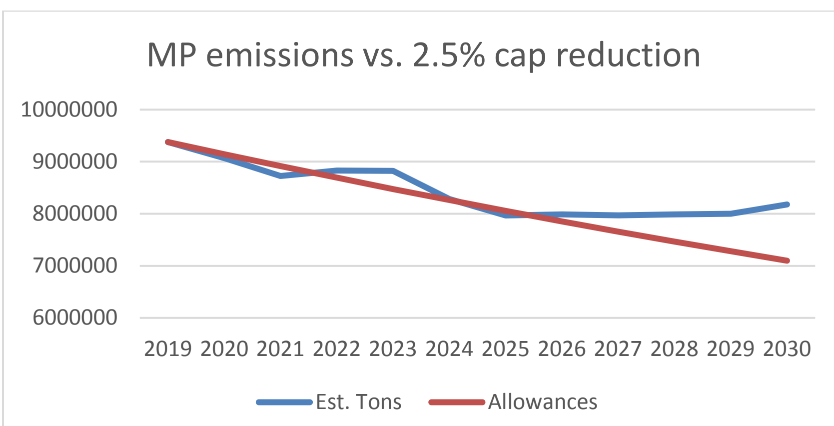
Year	Otter Tail (tons)	% Change
2010-2012	4,100,000	-
2018	4,060,000	-1.0%
2019	3,990,000	-1.7%
2020	3,740,000	-6.3%
2021	3,820,000	2.1%
2022	3,400,000	-11.0%
2023	3,480,000	2.4%
2024	3,560,000	2.3%
2025	3,560,000	0%
Total (2018-25)	-500,000	-12.3%

[68] Unlike MP and Otter Tail, Xcel did not provide annual tons in tables; thus, the values in the Xcel tables reflect what staff could ascertain from Xcel's Figure 2.

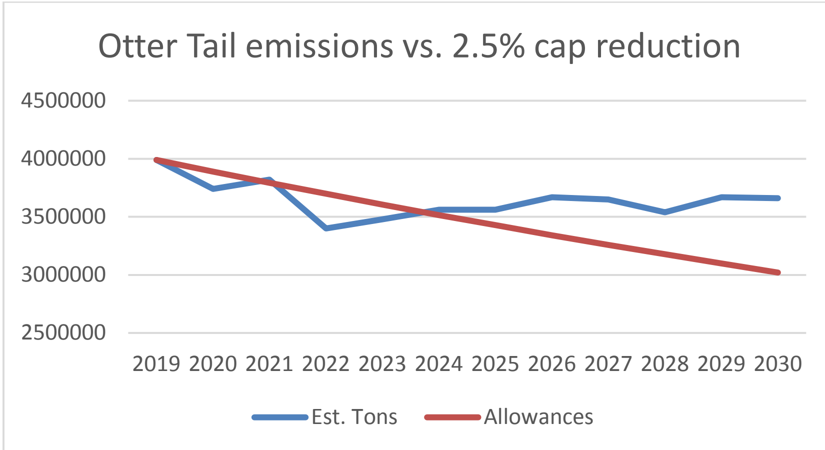
Year	Xcel (tons)	% Change
2017	22,000,000	-
2018	21,500,000	-2.3%
2019	19,900,000	-7.4%
2020	19,800,000	-0.5%
2021	19,000,000	-4.0%
2022	17,500,000	-7.9%
2023	18,000,000	2.9%
2024	15,500,000	-13.9%
2025	16,000,000	3.2%
Total (2017-25)	-6,000,000	-27.3%

If cap-and-trade requirements are to be incorporated into resource planning, then utilities should be able to model their systems in a manner consistent with the way a cap-and-trade system actually operates. As staff understands the Agencies' recommendation, all CO_2 emissions have an associated permit price, which means a utility must pay to emit every unit of CO_2 in the model. Referring to the tables above, in a hypothetical control period, all IOUs would outpace the cap reduction at certain intervals.

Staff offers a decision option whereby utilities' emissions will be capped at the level of CO_2 emissions in the first IRP planning year. This cap will be reduced by 2.5% in each subsequent year thereafter.[69] Utilities need only pay the Agencies' permit price, which is effective in 2025, for emissions that exceed that cap. (This would be akin to a free allowance distribution system, to avoid getting into the weeds of RGGI program design.) If utilities are under the cap, they may accrue financial revenues from selling allowances. For Otter Tail and Minnesota Power, the baseline cost of compliance could be inferred by the following figures, showing projected emissions (in blue) with a 2.5% reduction to their first IRP planning year (in red):

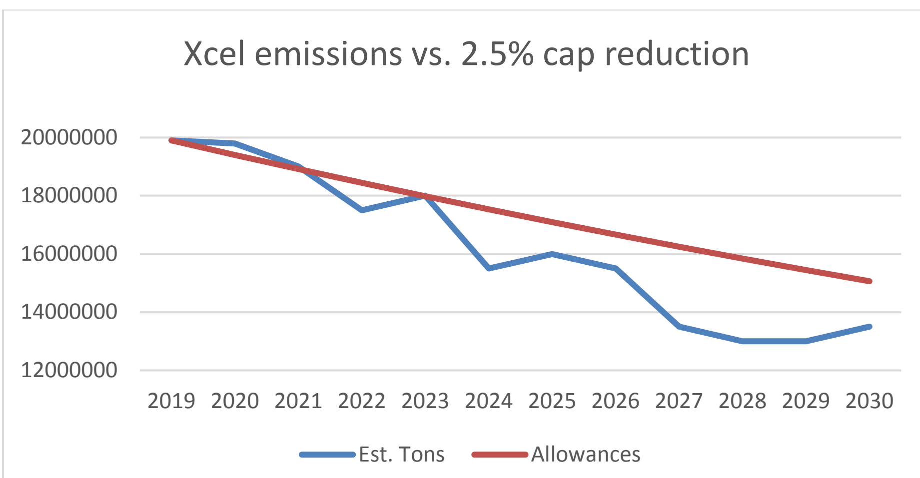


[69] Staff notes that if this approach is seriously considered, staff believes it is prudent to consider a less than 2.5% cap reduction, or a delayed start date for the annual reduction, to account for historical CO_2 reduction measures.



A simplistic way of viewing the cost of compliance under this approach is that the cost of compliance would equal the emissions over the cap multiplied by the permit price. However, if banking could be assumed, and utilities can test ways of getting under the cap, utilities may be able to derive financial value from further reducing carbon emissions. The purpose of this exercise is twofold: first, it would reflect an actual cap-and-trade system, and second, it might dispense with the view that CO_2 regulation is always financially detrimental.

One obvious problem with this approach is it is utility-specific, whereas enforcement authority in RGGI governed by each state participating in the program. Second, under a utility-specific approach, Xcel would never pay anything (assuming free allowance allocation). Under the same approach used for MP and Otter Tail, Xcel's position would look like this:



Third, if all emissions reduction in Minnesota from the three IOUs were combined, the total reductions could outpace the RGGI states, at least in the near- to intermediate-term, making the State a net seller of allowances on the whole. Thus, the Commission could find that assuming a carbon-regulated environment could only be favorable for Xcel in particular and likely Minnesota as a whole, might defeat the purpose of the statute.

Even assuming a gradually reducing cap will be inherently limited, primarily because there is no entity with whom to trade allowances. Each IOU in Minnesota will encounter unique challenges and opportunities in a carbon market. Xcel, for example, has a substantial amount of flexible natural gas and wind on its system already, as well as a relatively low load factor, which means it has less of a need for baseload power. This is unlike Minnesota Power, which has a high load factor, as well as almost no natural gas and no replacement, currently, for its two remaining coal units, Boswell 3 and 4. But staff is concerned about treating a permit price as a tax—the emissions rate (lbs/MMBTU) times the permit price ($/ton)—as far as the economic model is concerned.

In addition, it is important not to overprice CO_2 such that it leads to inefficient market outcomes. For example, sending the wrong CO_2 price signal could overbuild wind if the CO_2 price is so high that a capacity expansion model selects wind only to ramp down highly expensive, CO_2-intensive coal. In a carbon market with tradable allowances, the most economically efficient outcome could be that, rather than building new wind units, Xcel just trades with Minnesota Power. This result is, in part, why the same Clean Power Plan studies staff cites but Xcel recommends not to use found that Minnesota is relatively well-positioned to meet the requirements of the EPA Clean Power Plan. In any case, if the Agencies and parties all agree that it is more likely than not utilities will be in a cap-and-trade system in 2025, it is imperative to construct that universe realistically.

Compliance Costs in RGGI

Lastly, Minn. Stat. § 216H.06 directs the Commission to base the range on the impact to the costs of electricity generation. In a carbon-constrained environment, a permit price is not necessarily equivalent to the impact to the price of electricity. In RGGI, for example, a study by Acadia Center found:

> Comparing retail electricity prices from 2008 (before RGGI's launch) to 2015 shows that prices have dropped by 3.4% across the region. While RGGI's direct impact on electricity prices (and other trends described in this report) is difficult to isolate from other factors, it is evident that the program has not caused electricity prices to increase above 2008 levels.[70]

There is also the interaction with the wholesale market to consider. For instance, in a carbon-constrained environment, the order of unit dispatch will change to some degree, but the net effect in the market is difficult to quantify. This is because resources that emit less carbon than the price-setting marginal resource will be rewarded by an energy price that increases more than their own emissions costs; further, low-emitting resources that generate in times and places with the highest marginal emissions rates will be rewarded the most. A report by Analysis Group discussed this issue in a RGGI context:

> In the near term, while all owners of emitting resources recover all of their costs to operate – including the cost of CO_2 allowances – the net effect of the program

[70] Acadia Center, "Regional Greenhouse Gas Initiative Status Report" (July 2016), att 4. Accessed online at http://acadiacenter.org/wp-content/uploads/2016/07/Acadia_Center_2016_RGGI_Report-Measuring_Success_FINAL_08092016.pdf

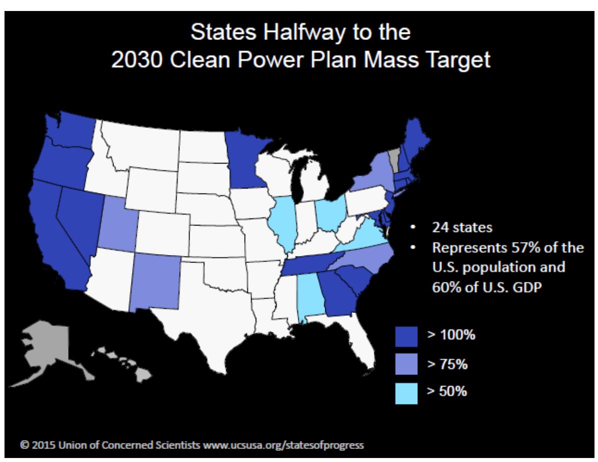
> can reduce profits for owners of plants with relatively high carbon emissions (e.g., coal-fired power plants). On the other hand, owners of zero-carbon generating sources (e.g., nuclear, wind, solar, hydro) get the benefit of being paid higher market prices that reflect CO_2 allowance costs, without having to buy allowances.[71]

As mentioned above, a core feature of RGGI is to raise funds that are reinvested in energy efficiency and renewable energy, and funds are also used to mitigate the impact of the program on wholesale electricity prices and consumer electricity costs. According to an analysis from NRDC, RGGI states could earn $3.2 billion more for their state clean energy programs by selecting the tightest emissions cap under consideration.[72]

So to the extent carbon markets are incorporated into this proceeding, it is insufficient to look at only the allowance price; it is just as important is to consider the context of that market and know the level of allowances so to be able to replicate it in a capacity expansion model. At a minimum, parties advocating for using carbon markets as a proxy price should be able to explain how resource planning can incorporate specific aspects of program design. Otherwise, all of the advantages of historical investments in CO_2 reduction by Minnesota utilities, as well as cap-and-trade systems generally, are effectively ignored.

C. Synapse Forecast (the Agencies' high bound)

In the "MPCA EPA Stakeholder Collaborative" section of this briefing paper, staff discussed the Union of Concerned Scientists' (UCS) analysis of the Clean Power Plan, which found that Minnesota could exceed its compliance targets by 2024. Moreover, the slide below shows that Minnesota was one of only a handful of states (in dark blue) positioned to exceed the mass-based allowance target (and excess allowances means a financial benefit):



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[71] Analysis Group, "The Economic Impacts of the Regional Greenhouse Gas Initiative on Nine Northeast and Mid-Atlantic States," (July 14, 2015), http://www.analysisgroup.com/uploadedfiles/content/insights/publishing/analysis_group_rggi_report_july_2015.pdf

[72] Natural Resource Defense Council, "Tighter Pollution Cap Could Get RGGI States $3.2B Extra" (July 31, 2017), https://www.nrdc.org/experts/jackson-morris/tighter-pollution-cap-could-get-rggi-states-32b-extra

Notably, Synapse used the same model as UCS—the ReEDS (Regional Energy Deployment System) model—to develop its compliance cost estimates. The difference is that UCS produced a state-by-state analysis, whereas Synapse did not. Synapse also ran the model based on EPA's Proposed Rule, not the Final Rule, which in some ways benefitted states like Minnesota.[73]

1. Synapse's Range

As described in the Agencies' report, the Synapse forecast "projects carbon prices beginning in 2022 with a range of $15 to $25 per ton of CO_2, and increasing gradually in each subsequent year."[74] The Agencies recommend that the high end of the Commission's range should incorporate the high end of the Synapse range. Staff suggests the Commission consider whether to instead use the *low* end of the Synapse range ($15/ton) as the *high* end of the Commission's range.

It is important to know what the high end of the Synapse forecast actually represents. Synapse developed Low, Mid, and High case forecasts for CO_2 prices from 2022 to 2050. Synapse discusses the Low, Mid, and High scenarios on page 3 of its report:

> Beginning in 2022, we expect Clean Power Plan compliance will put economic pressure on carbon-emitting power plants throughout the United States. We assume smooth allowance trading among large groups of states. **The Clean Power Plan is followed later by a more stringent federal policy in the Mid and High cases**. The CO_2 prices presented here are forecasts of "effective" prices of CO_2 which may or may not take the form of market-based allowances.[75] (Emphasis added by staff.)

In other words, embedded within the $25 per ton value is *another* assumption that there will be an additional, more stringent federal policy on top of the Clean Power Plan. As Synapse explains, the High case reflects an aggressive, international effort to combat climate change:

> New regulations may mandate that electric-sector emissions are reduced to 90 percent or more below 2005 levels by 2050 … Other factors that may increase the cost of achieving emissions goals include: greater restrictions on the use of offsets; restricted availability or high cost of technology alternatives such as nuclear, biomass, and carbon capture and sequestration; and more aggressive international actions (thereby resulting in fewer inexpensive international offsets available for purchase by U.S. emitters).[76]

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[73] See Footnote 39 of the Synapse report.

[74] Agencies, Analysis and Recommendations, at 3.

[75] Synapse report (March 2016), at 3.

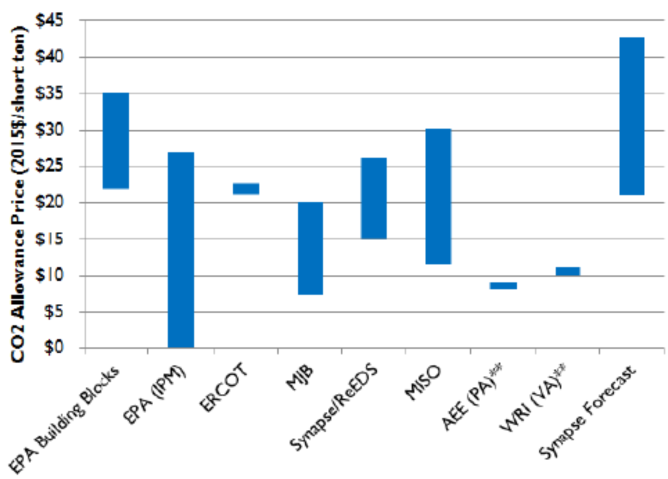
[76] Synapse report (March 2016), at 4.

Staff is concerned that, at this time, Synapse's High case extends far beyond what will be applicable to Minnesota utilities in their forthcoming resource plans. Besides, pursuant to Subdivision 2c. of Minn. Stat. § 216B.2422 (the resource planning statute), utilities must outline a plan to meet the State's greenhouse gas emission reduction goals established in Minn. Stat. § 216H.02, subdivision 1,[77] so this ambition for aggressive action is already required by the Legislature. As such, the Commission could set the low end of the range at $5 per ton to reflect RGGI allowance prices and $15 per ton to reflect the Low case of the Synapse forecast.

2. Synapse's Forecast Compared to Other Estimates

The Synapse report compared its own forecast to others that likewise estimated the cost of the Clean Power Plan at state, regional, and national levels. This is summarized in Figure 6 of the Synapse report, shown below.

Figure 6: Summary of Clean Power Plan study CO_2 price estimates for 2030 (2015 dollars/short ton)



Source: Synapse Energy Economics, Inc. 2016.

There are two particularly noteworthy studies from Figure 6 above, the MISO Study and the MJB (M.J. Bradley & Associates) Study.

MISO Report

MISO was very clear in its report and stakeholder discussions that its findings "are **not** recommendations for complying with the Clean Power Plan." The report also made clear that its intention was not to conduct a resource planning-type analysis. MISO stated, "Resource expansion was not optimized for [Clean Power Plan] compliance as part of this study, but rather was input into each scenario."[78] So it can already be inferred that, by not optimizing the expansion plan, which is a role for the states, compliance cost estimates are probably high.

[77] Minn. Stat. § 216H.02, subdivision 1 states, "It is the goal of the state to reduce statewide greenhouse gas emissions across all sectors producing those emissions to a level at least 15 percent below 2005 levels by 2015, to a level at least 30 percent below 2005 levels by 2025, and to a level at least 80 percent below 2005 levels by 2050."

[78] MISO, "MISO's Analysis of EPA's Final Clean Power Plan Study Report" (July 2016), Accessed online at https://cdn.misoenergy.org/20160720%20PAC%20Item%2002a%20Clean%20Power%20Plan%20Study%20Report8

MISO's analysis found that flexibility in compliance options leads to lower compliance costs. In particular, "individual states and regions derive different benefits from pursuing different options, but working together as a region allows each state to share this diversity in a way that benefits the entire region."[79] Thus, if trading is assumed, one can also expect lower overall compliance costs.

Furthermore, MISO found that "compliance costs are found to vary greatly with the price of natural gas along with the economic and technical potential of both renewable and energy efficiency deployment."[80] Staff will discuss the cost of renewable energy and the price of natural gas later, but for now, it is important to keep in mind that MISO found that these two factors are major drivers of compliance costs.

MJB (M.J. Bradley & Associates) Study

As shown in Figure 6 of the Synapse Report, MJB estimated a compliance cost range of about $7-20 per ton. What is noteworthy about this result is the timing of the publication. Synapse used MJB's estimate from January 2016, but MJB published an updated modeling analysis of the Clean Power Plan in June 2016.

According to MJB, "The updated study reflects several assumption changes from our January report, including the extension of the renewable energy tax credits for wind and solar."[81]

For the June 2016 Report, MJB ran ten scenarios—two reference cases and evaluating eight alternative Clean Power Plan scenarios. Four model runs assumed mass-based, nationwide trading (except California), and projected national allowance prices are shown below:[82]

Allowance Prices **(2012$/ton)**

Code	Assumptions	2025	2030
MB03	Existing + New, National, Current EE	$0.00	$6.05
MB04	Existing + New, National, 1% EE	$0.00	$2.97
MB05	Existing + New, National, 2% EE	$0.00	$0.00
MB07	Existing Only, National, Current EE	$0.00	$4.14

Again, extending the PTC had the effect of substantially lowering allowance prices, which is consistent with what MISO found: the price of renewable energy is a major driver of compliance costs.

9646.pdf

[79] *Id*.

[80] *Id*.

[81] M.J. Bradley & Associates, EPA's Clean Power Plan: Summary of IPM Modeling Results With ITC/PTC Extension, Accessed online at http://www.mjbradley.com/sites/default/files/MJBA_CPP_IPM_Report_III_2016-06-01_final_0.pdf

[82] *Id*., Slide 13.

3. Factors Influencing Cost of Compliance

The basic question to answer when establishing a likely range of compliance costs is what carbon regulation would mean in terms of (1) the change to a utility's resource plan and (2) what the costs for the replacement resources might be. Since policy-driven investments in carbon reductions would almost certainly mean additional or accelerated renewable energy procurement, any compliance cost estimate would necessarily be correlated to the cost of renewable energy, which is consistent with prior studies.

As the Commission is well-aware, the market price of wind and solar energy have fallen precipitously, to historically low levels, since Minn. Stat. § 216H.06 was enacted in 2007. Moreover, emerging technologies such as energy storage and grid modernization will continue to be explored and optimized in utility systems regardless of CO_2 regulation.

In December 2017, Xcel filed with its Colorado regulators an All-Source Solicitation of Bids as part of its 2016 Colorado IRP process. Below is Attachment A of that 2017 All-Source Request for Proposals (RFP), showing that Xcel received 430 bids for over 111,960 MW of capacity, with the median price for renewable energy between $18-$36/MWh. This was a result Xcel characterized as "unprecedented."[83]

RFP Responses by Technology

Generation Technology	# of Bids	Bid MW	# of Projects	Project MW	Median Bid Price or Equivalent	Pricing Units
Combustion Turbine/IC Engines	30	7,141	13	2,466	$ 4.80	$/kW-mo
Combustion Turbine with Battery Storage	7	804	3	476	6.20	$/kW-mo
Gas-Fired Combined Cycles	2	451	2	451	[redacted]	$/kW-mo
Stand-alone Battery Storage	28	2,143	21	1,614	11.30	$/kW-mo
Compressed Air Energy Storage	1	317	1	317	[redacted]	$/kW-mo
Wind	96	42,278	42	17,380	$ 18.10	$/MWh
Wind and Solar	5	2,612	4	2,162	19.90	$/MWh
Wind with Battery Storage	11	5,700	8	5,097	21.00	$/MWh
Solar (PV)	152	29,710	75	13,435	29.50	$/MWh
Wind and Solar and Battery Storage	7	4,048	7	4,048	30.60	$/MWh
Solar (PV) with Battery Storage	87	16,725	59	10,813	36.00	$/MWh
IC Engine with Solar	1	5	1	5	[redacted]	$/MWh
Waste Heat	2	21	1	11	[redacted]	$/MWh
Biomass	1	9	1	9	[redacted]	$/MWh
Total	430	111,963	238	58,283		

Staff agrees with Otter Tail's comment that "CO_2 emissions are declining rapidly in this industry. However, these reductions are being driven by economics, not by federal and state legislation or regulation."[84] In all of the studies discussed above, the cost and availability of renewable energy and the price of natural gas drove the cost of compliance. Both of these options available to electric utilities have experienced significant price declines.

In addition to Xcel's RFP showing the decline in renewable energy, according to the Energy Information Administration's (EIA) 2018 Annual Energy Outlook (AEO2018), Henry Hub natural gas prices are expected to remain in the $3-$4 per MMBTU for the next decade. Furthermore,

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[83] Xcel Energy, Colorado Public Utilities Commission Proceeding No. 16A-0396E, 2017 Solicitation Report, December 28, 2017, https://www.documentcloud.org/documents/4340162-Xcel-Solicitation-Report.html

[84] Otter Tail comments (September 22, 2017), at 4.

AEO2018's forecast for natural gas prices was 14% lower on average through 2050 than in EIA's AEO2017 forecast. Synapse used "AEO 2015 natural gas prices, which rise from $5.30 per million BTU in 2022 to $5.93 per million."[85] This means that Synapse assumed natural gas prices roughly 50-75% higher than today's projected near-term market price.

Taking together the current state of the markets for renewable energy and natural gas, one might question why a $25 per ton impact on electric generation will befall Minnesota ratepayers in a carbon-regulated environment. The industry trend is that carbon-intensive generation is becoming increasingly uneconomic even in the absence of CO_2 regulation.

According to the Synapse report, "Synapse's CO_2 price forecast reflects our expert judgment that near-term regulatory measures to reduce greenhouse gas emissions, coupled with longer-term legislation passed by Congress to reach science-based emissions targets, will result in significant pressure to decarbonize the electric power sector. Key assumptions of our forecast include:

- Near-term climate policy actions reflect a regulatory approach, for example, under Sections 111(b) and 111(d) of the Clean Air Act.
- A federal program establishes targets more stringent than the Clean Power Plan.
- Future federal legislation sets a price on emissions through a cap-and-trade policy or a carbon tax will likely be prompted by one or more of the following factors:
  - New technological opportunities that lower the cost of carbon mitigation;
  - Lower gas prices that reduce the costs of potential policies;
  - A continuation of executive actions taken by the President that spur demand for congressional action;
  - The inability of executive actions to meet long-term emissions goals;
  - A Supreme Court decision making it possible for states to sue companies within their boundaries that own high-carbon-emitting resources, and creating a financial incentive for energy companies to act; and
  - Mounting public outcry in response to increasingly compelling evidence of human-driven climate change."[86]

[85] Synapse report (March 2016), at 28.

[86] Synapse report (March 2016), at 2.

The Commission can consider these same factors to determine whether the Synapse range is reasonable, too high, or too low, as well as what adjustments might be needed to reflect likely costs in Minnesota.

D. Relationship of CO_2 Regulatory Costs to CO_2 Externality Costs

The Agencies noted in its reply comments, "Except for the CEO, all commenters agreed that … the environmental cost values be applied in the years prior to the years in which the cost of future carbon dioxide regulation values are applied."[87] The Agencies also concluded that applying the externality values in all planning years would not comply with statutory requirements of Minnesota Statutes § 216H.06.[88]

As might be expected, it can be problematic and confusing to toggle between externality and regulatory costs. One reason is because, as Xcel noted, "the values established under the two Statutes are intended to represent different things."[89] Second, as the Agencies observed, "utilities have interpreted the Commission's guidance in different ways."[90]

Additionally, complexities arise strictly out of modeling technique. As the Agencies noted, "carbon regulation is modeled as an internal cost (on an ex ante basis), and therefore impacts the resources the model selects to be added or retired. In contrast, the externality value range is applied on an ex post basis once the model selects the resource package, and therefore impacts the estimated cost of the various resource portfolios, but **does not influence which resources the model selects to include in the portfolios**."[91] (Emphasis added by staff.)

Xcel agreed that only regulatory costs are internalized and therefore affect the dispatch order; however, Xcel added that externality cost values "affect the PVSC ranking of different potential plans – causing a plan with more fossil resources to have a higher PVSC relative to a plan with fewer fossil resources, all else being equal. Therefore, both CO_2 Regulatory Costs and CO_2 Externality Values **may impact resource selection**, additions/retirements, the PVSC ranking of portfolios, and the Commission's ultimate decision on the optimal plan."[92] (Emphasis added by staff.)

These two comments, while seemingly very different, may in practice land in a similar place, in that the final *ranking* of least-cost resource plans is what is important. Nonetheless, it is important the Commission has clarity on this issue. For instance, if in half of the planning period the dispatch order changes (regulatory costs) and in the other half the dispatch order

[87] Agencies reply (March 5, 2018), at 6.

[88] Agencies, Analysis and Recommendations, at 6.

[89] Xcel comments (September 22, 2017), at 4.

[90] Agencies, Analysis and Recommendations, at 6.

[91] Agencies, Analysis and Recommendations, at 7.

[92] Xcel comments (February 19, 2018), at 8.

does not change and costs are imposed *ex post* (externalities), this could be a basis to keep these two types of costs separate.

At the very least, staff believes it is important the Commission is aware of the disagreement between Xcel and the Agencies, if not solely to assess the theoretically validity of Xcel's Option 3. The Agencies claim, "As to Xcel's option 3, mixing the cost ranges is not theoretically sound."[93] Xcel, on the other hand, proposes that "running *Sensitivities* in the Regulatory Cost period as we propose (at the lowest CO_2 cost/value and the highest CO_2 cost/value), regardless of whether these represent Regulatory Costs or Externalities Values is practical, efficient, and will provide greater decisional value for the Commission and stakeholders."[94]

Below, staff presents and responds to some additional arguments raised on this issue.

- Otter Tail: "While an extensive proceeding addressing the Federal Social Cost of Carbon and criteria pollutants was recently concluded before the Commission, there was no evidence in that proceeding that supported applying both the regulatory cost value <u>and</u> an externality value."

Otter Tail is correct that the externalities docket did not address issues pertaining to modeling CO_2 regulatory costs. Otter Tail is also correct that applying both the regulatory cost value <u>and</u> an externality value was not an issue raised in that case. (In fact, because the externality values were derived from specific economic framing assumptions, adding costs to the externality values would actually deviate from the best available estimates.)

However, less clear is whether the updated methodology and, in turn, the updated estimates actually demands that externalities should be applied in all planning years, although not in the same sensitivity as the regulatory costs.

First, to step back and define what the social cost of carbon (SCC) is, it is important to note that the SCC is not a single value; it represents the mean of 150,000 modeled observations *per emissions year*[95] and across three discount rates.

The prior approach, in contrast, took an estimate of long-term global societal costs and divided it by an estimated amount of long-term CO_2 emissions (i.e., the average ton approach). The framework, methodology, data, and models used to update the environmental externalities under the SCC framework were far more sophisticated and specific than what the Commission previously used.

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[93] Agencies, Analysis and Recommendations, at 7.

[94] Xcel comments (February 19, 2018), at 7.

[95] The federal government's SCC estimates were separate model runs for years 2020, 2030, 2040, and 2050. The Commission, with modifying some of the economic framing assumptions, employed the same basic framework and connected the emissions years by a linear interpolation.

The Commission's December 2007 Order determined that the regulatory costs and externality costs "both reflect steps to account for the burdens that CO_2 emissions impose on third parties."[96] This implies a satisfaction with approximation, but the updated externality values were derived from several specific areas of technical expertise combined with numerous policy decisions. Thus, at this juncture, the Commission might prefer more precision with regard to each type of cost.

Second, how the Commission views damages to society has also changed, at least analytically. For example, externality costs will now include emissions years through 2050 and employ a last ton marginal damage approach, which means accounting for the fact that incremental emissions are increasingly damaging over time.

With these considerations in mind, while staff does not disagree with Otter Tail, what is new is (1) the specificity of the various assumptions that calculate the externality costs and (2) the incorporation of increasing costs to society as a result of accumulating CO_2 emissions in the atmosphere.

The fact that a $5-$25 range remains fixed departs from the Commission's last ton approach for estimating social damages in the externalities case. If the CO_2 regulatory cost values stay fixed, the regulatory costs cannot possibly internalize the social damage, because the Commission has already determined that incremental CO_2 emissions are increasingly damaging over time. Therefore, staff would argue that *not* applying the externalities in all planning years would be inconsistent with the Commission's findings and approved methodology.

- Minnesota Power: "Once a CO_2 regulation is implemented, it will account for the impact of CO_2 emissions when making resource planning decisions."

By definition, an externality occurs whenever there is an impact imposed on a third party. As previously stated, the social cost of carbon is an estimate of the present discounted value of the damage caused by an *incremental increase* in CO_2 emissions in a particular emissions year. If Boswell 4, for example, continues to operate even if MP is in compliance with future CO_2 regulation, this does not mean CO_2 emissions from Boswell 4 cease to be externalities; the facility will still create an incremental increase in CO_2 emissions and therefore will still impact society.

The Commission recognized this distinction in its January 3, 2018 Order updating externality costs. For example, previously, the value for sulfur dioxide (SO_2) was set at $0 per ton after 2000 due to the existence of a federal SO_2 allowance trading program.[97] The Commission revised that approach in updated externality values, setting median SO_2 costs at $6,159 per ton (Rural), $8,245 per ton (Metro Fringe), and $10,439 per ton (Urban). In other words, the Commission looked to the damage to society irrespective of whether a pollutant was regulated.

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[96] Commission order, "In the Matter of Establishing an Estimate of the Costs of Future Carbon Dioxide Regulation on Electricity Generation Under Minnesota Statutes § 216H.06" (December 21, 2007), at 4.

[97] Docket No. 93-583, *Order Establishing Environmental Cost Values* (January 3, 1997), at 20.

Parties will probably argue about this in future proceedings, but the existence of a possible future CO_2 allowance program is irrelevant to the social damage an incremental unit of CO_2 emissions will produce.

With this being said, staff agrees with the parties that not adding the two types of CO_2 costs is a reasonable thing to do. The Commission could avoid duplicate accounting if the CO_2 regulatory costs are confined to their own scenarios. If the Commission takes this approach, then a CO_2 regulatory cost scenario would not consider environmental externalities, which is arguably beneficial to the analysis, as it would be clear that separating them would delineate between what are, in Xcel's words, "different things."

It could also be a practical and proactive measure to separate the regulatory and externality costs simply for the fact that the updated externality costs are now much higher than they were previously. It is not wild to imagine that if externality costs are turned off, or reduced to a lower regulatory cost, parties will repeatedly issue discovery requests asking utilities to conduct modeling runs that evaluate the Commission's externality values for all planning years.

The Agencies addressed this, too, noting, "To the extent a participant anticipates that a particular sensitivity run will provide value, the participant should provide it, or request that it be provided."[98] As staff sees it, it makes sense to address it now rather than over and over again in future proceedings.

- Xcel Energy: "Modeling each of the data points would be administratively complex, and some of the values will 'cluster' within the range, so the differences may not be meaningful for decision-making purposes."

In staff's view, Xcel's concerns about administrative complexity and clustering are greatly overstated. For one, Xcel's own 2015 resource plan was even more complex than the standard practice. In its 2015 IRP, Xcel modeled the follow CO_2 sensitivities: (1) Base (the $21.50/ton midpoint); (2) Zero CO_2; (3) Low CO_2; (4) High CO_2; (5) Late-Low CO_2; and (6) Social Cost of Carbon.[99]

The Commission could mitigate administrative complexity by removing the requirement to use the midpoint of the range. If the Commission adopts a tighter range, and since the statute only requires a high and low bound, staff believes it would be most appropriate to discard the midpoint first, especially if that value is fairly close to another estimate.

Second, staff questions whether some are making the regulatory costs versus externality costs issue harder than it needs to be. Staff agrees with Xcel that an externality sensitivity can be run on its own, but staff disagrees with Xcel that this needs to be confined to the high externality scenario in order to avoid "clustering."

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[98] Agencies reply comments (March 5, 2018), at 7.

[99] Docket 15-21, *In the Matter of Xcel Energy's 2016-2030 Integrated Resource Plan*, January 29, 2016 Supplement, Attachment B, Page 17 of 17.

Considering the Commission's externality values and the Agencies' recommended regulatory cost values in 2025, a series of scenarios could look like this:

Scenario	2025
#1: Reference Case	$0
#2: Agencies, Low	$5
#3: Externalities, Low	10.07
#4: Agencies, High	$25
#5: Externalities, High	$46.96

The values above are not clustered, as Xcel claims. It does not appear they would be administratively complex to evaluate, as Xcel also claims. As separate scenarios, they would not be double counted, as Minnesota Power claims. And, as separate scenarios, there would not be one part of the planning period whereby the dispatch order is changed and another part where it is not. Also, there is nothing that conflicts with statute, as the Agencies claim. Finally, it would eliminate the need for a midpoint.

Moreover, Xcel's recommendation, in staff's view, actually strengthens the argument for keeping the two types of costs separate. Xcel's proposal would, in its own words, set CO_2 values "without regard to whether it is a regulatory cost or externality value."[100]

The externality costs at each end of the range are not arbitrary; they are estimates carefully derived from the consideration of very specific, complex, and technical issues. The low end of the range represents "the global damage of the last (marginal) short ton emitted, calculated through the year 2100, with a 5.0% discount rate."[101] The upper bound represents "the global damage of the last (marginal) short ton emitted, calculated through the year 2300, with a 3.0% discount rate."[102] Clearly, the Commission took each end of this range quite seriously. Using a regulatory cost in place of an externality cost simply because they are in a similar vicinity ignores the reasons why each externality value was established in the first place.

Staff can understand that Xcel is trying to be pragmatic, and perhaps staff's difference of opinion with Xcel on this point mostly has to do with priorities and objectives. Xcel's recommendation appears to prioritize price sensitivity, or in its words, "decisional value." From a utility costs perspective, this makes sense, as the CO_2 range is a measure of risk management. The Agencies agreed with Xcel on this point, noting, "what matters is that a complete and well-thought-out analysis of 'a reasonable range of possible outcomes' is crucial to resource acquisition and planning decisions."[103]

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[100] Xcel comments (September 22, 2017), at 9.

[101] Commission order, *In the Matter of the Further Investigation into Environmental and Socioeconomic Costs*, MINN. PUB. UTIL. COMM'N, E-999/CI-14-643.

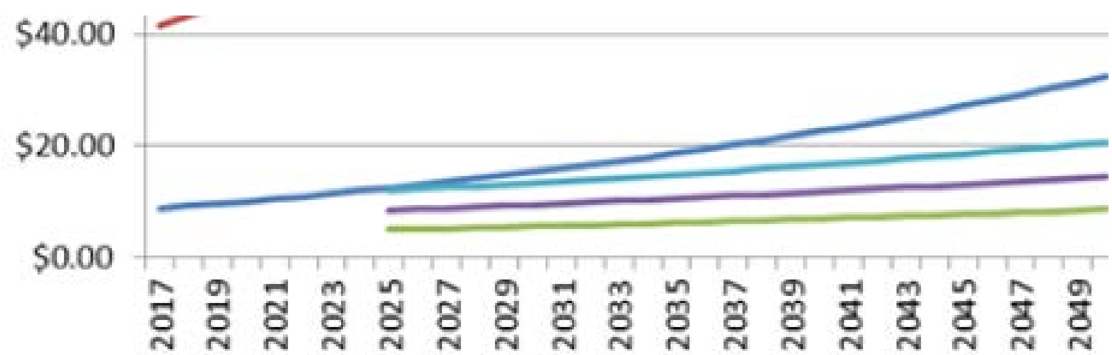
[102] *Id*.

[103] Agencies reply comments (March 5, 2018), at 7.

Staff does not agree "decisional value" should be the objective; the point is to use the best available estimate based on the best available science to account for the social damage caused by the pollution utilities emit. This is the very essence of a public interest determination. Therefore, staff agrees with CEO that the social damage should be taken into account because that is what best reflects the statutory intent of having environmental externalities to begin with. Even if staff might not respond to this problem in the same way as CEO—i.e., the incremental externality approach—staff agrees with the CEO's underlying premise, which is to "ensure that the externality costs of CO_2 are fully internalized."[104]

Finally, staff will address the figure on page 9 of Xcel's September 22, 2017 comments, which shows all externality and regulatory costs (with the midpoint). The same figure is shown on page 14 of the briefing paper. Note that the range includes Xcel's original $5-$12 per ton range, not the Agencies $5-$25 per ton Xcel ultimately accepts.

The figure Xcel uses is a classic example of visually misleading the reader via the y-axis. As it appears in Xcel's comments, there is one line in red (high externality) that is very high up on the chart, then four values that appear close together. (Xcel calls this clustered.) Here are the four so-called clustered values, with the high externality data point removed so that the y-axis can better reflect the differentiations in the estimates:



Using *this* representation, the reader might find there could be interesting decisional value by adopting the full range. After all, expansion plans can be quite sensitive to CO_2 pricing, especially for carbon-intensive utilities. Removing the purple line (the midpoint of the regulatory cost range) would even further space out the estimates. The point is, without actually evaluating a proposed resource plan, staff cannot say one way or another what effect each value will have on an expansion plan. But staff *is* confident that Xcel cannot either.

In Figure 1 of Xcel's February 19, 2018 comments, Xcel displays similar information, only with the Agencies' recommended values. In that chart, Xcel basically lays a heavy blue line representing the midpoint of the regulatory cost range over the line showing the Low end of the externality range. Xcel notes both values "would provide nearly identical results,[105] so the Commission should pick the midpoint of the regulatory cost range.

[104] CEO comments (February 15, 2018), at 15.

[105] Xcel comments (February 19, 2018), at 6.

If staff had to pick between the two, staff would prefer a vetted, scientifically defensible estimate that is required by statute over a midpoint, which has no association to statute, between two questionably accurate values. Furthermore, Xcel's claim that they would provide nearly identical results is vague, as the Agencies and Xcel both agreed that Strategist treats the costs differently; the Commission might wish to verify with Xcel that applying the same value *ex ante* versus *ex post* yields the same modeling result. (The Agencies indicate the different methods of applying costs matter a great deal.) In addition, as explained previously, staff believes a $5-$15 per ton range is more appropriate, because the $25 per ton is based on a Synapse High case that assumes very aggressive efforts to combat climate change; using a $15 per ton upper bound, the midpoint would not be the same as the Low externalities value.

- Agencies: "apply[ing] only the externality values in all planning years would not comply with statutory requirements of Minnesota Statutes § 216H.06."

There is nothing in Minn. Stat. § 216H.06 that prevents externality values from being included in all planning years. And certainly the Legislature did not intend for § 216H.06 to replace the environmental externalities statute. The environmental externalities statute very clearly requires that utilities "shall use the [externality] values established by the commission … in all proceedings before the commission."[106]

But there is a broader issue here tying back to statutory intent. Consider, for example, that Xcel Energy's next resource plan will be filed in February 2019. Xcel's next IRP will address the fate of the Allen S. King Generating Station and replacement resources for its Prairie Island and Monticello nuclear units. It is hard to believe that the spirit of the law would indicate that externality cost values should be turned off in 2025, at the very time when those values would be most informative to the Commission's ability to make a public interest determination.

E. Effective Year

There are at least three ways to consider the effective year: 1) the date in which a particular policy might become law (CEO); 2) whether assumptions should be made about how much time to allow for a policy to be implemented (MP); or 3) when utilities will begin to incur net costs to comply with CO_2 regulation (Agencies).

CEO argued in support of 2022 by reasoning "there is little record support for determining that it will take state and federal regulators and lawmakers until 2025 to **establish** a regulatory price on CO_2 emissions."[107] (Emphasis added by staff.) Establishing a price and implementing one are two different things.

MP argued the Commission should assume a lead-time, noting, "Based on proprietary industry resources, as well as **the anticipated lead-time required for implementation** of a federal

[106] Minnesota Statutes § 216B.2422, subdivision 3.

[107] CEO comments (Feb 15, 2018) at 8.

regulation for CO_2, application of a CO_2 regulation is not anticipated before 2026." (Emphasis added by staff.) This assumes passing a law, then allowing utilities to prepare for compliance.

The Agencies recommended 2025 as a year when "utilities can expect to **incur costs** to regulate CO_2 emissions."[108] (Emphasis added by staff.) This refers to taking actionable steps that would be more expensive than without the policy in place.

Xcel's comments reflected those of the Agencies. Xcel noted, "The planning year when the regulatory cost range must be applied has likewise been based on the first compliance year of anticipated CO_2 regulation – the year utilities and their customers are expected to incur compliance costs … When the range was last updated, the Commission chose 2022 based on the first compliance year of the CPP."[109]

Staff notes that "first compliance year" and "expected to incur costs" could be two different things. In its last resource plan, for example, Xcel "projected to reduce CO_2 potentially beyond what the State Plan requires of the Company [and] may put the Company in the position of being a net allowance or ERC seller, after the Company has surrendered sufficient allowances or ERCs to bring its own units into compliance."[110] Thus, Xcel can be in a compliance year without incurring any additional costs.

Below is a table of all parties' initially proposed effective dates to begin applying CO_2 regulatory costs (of note, MP and Otter Tail agreed to the Agencies' and Xcel's 2025 effective year):

Party	Proposed Effective Year
Agencies	2025
Clean Energy Orgs.	2022
Minnesota Power	2026
MLIG	2035
Otter Tail Power	2028
Xcel Energy	2025

If the Commission separates the externalities costs and the regulatory costs into different scenarios, then staff has no recommendation for the effective date, in part because providing one would imply some opinion about the future that staff does not have.

If, on the other hand, the Commission continues past precedent, or finds there is no basis for changing how resource plans consider both CO_2 regulatory and externality costs, then staff believes the MLIG's recommendation to use a **2035** effective date is the most reasonable.

108 Agencies reply comments (March 5, 2018), at 6.

109 Xcel comments (September 22, 2017), at 3.

110 Xcel Energy, Docket No. 15-21, In the Matter of Xcel Energy's 2016-2030 Integrated Resource Plan, Attachment H, Page 3 of 11.

Several parties, including the Agencies, cited the Commission's December 2007 Order that determined both ranges "reflect steps to account for the burdens that CO_2 emissions impose on third parties."[111]

"Burdens on third parties" is an important phrase here. A regulatory cost is a rate impact. An externality is an impact to a third party. Therefore, if no change is to be made, the Commission's environmental externality values are better, more scientifically defensible estimates to capture this imposition of costs to society, and there is no existing policy framework from which to reliably verify future regulatory rate impacts.

A second reason why a delayed effective year could be preferable is that, in the absence of a known policy framework, environmental externalities are a reasonable proxy. If utilities continue to plan at the social optimum of pollution, one could reasonably expect that it will be unlikely that actual CO_2 regulation will require more carbon-constraining resource plans than a CO_2-internalized resource plan would.

Finally, one advantage that the regulatory costs proceeding has over the externalities case, at least from a procedural standpoint, is that the § 216H.06 requires annual updates. Therefore, any changes in future policy should be relatively easy to incorporate. While the history of this proceeding shows that past orders largely dictate future ones, there is no decision the Commission can make at this time that will necessarily prevent future Commissions from taking a different action.

F. Legislation and Likelihood

The Commission does not need 100% certainty that a regulation will be in place before establishing regulatory cost values; in fact, such a guarantee would be a vast departure from past precedent. However, there is a line—which is not at all clear—that separates the world of possibilities from actual likelihood.

In the environmental externalities case, the physical science component had a very clear meaning of the term "likely": the Intergovernmental Panel on Climate Change (IPCC) addressed uncertainty probabilistically, with a quantified likelihood from *exceptionally unlikely* to *virtually certain*. "Likely," as used by the IPCC, meant that the likelihood of an outcome had a 66% or greater probability of occurrence.

In this case, there is no probabilistic framework from which to assess the likelihood of a policy outcome; it is almost entirely some combination of judgment and predictions about the future. Therefore, in some ways, likelihood rests entirely on how the Commission decides to draw the line between possibilities and likelihood.

Staff acknowledges the limitations of its analysis, too, which has referred to (1) the fact that there is no CO_2 regulation in place at present; (2) the fact that Minnesota utilities have made significant investments in CO_2 mitigation; (3) an opinion that the Clean Power Plan is still a

[111] December 2007 Order at 3.

reasonable proxy for CO_2 regulation; and (4) using the updated environmental externalities as an appropriate stand-in policy. Admittedly, this is a narrow view, and all four points could ultimately be proven totally wrong if or when a CO_2 regulation is in place.

However, in the Commission's own subjective assessment of likelihood, it could be better-served by considering specifics rather than generalities. For example, Xcel projects that it will 63% carbon-free by 2030, which could be a more helpful fact that referring to Minnesota's leadership on CO_2 reduction generally. Also, the Commission may simply ask MPCA whether it has any plans to join RGGI or another carbon market, rather than considering the agency's boundaries of authority.

CEO points out that "there were six bills introduced in the 113th Congress that would have imposed some type of carbon pricing program," and "in 2017 a coalition of prominent Republicans proposed "The Conservative Case For Carbon Dividends."[112] From this, CEO concludes that "the CEO's recommended range is supported by other indicators of the likely regulatory costs of CO_2 emissions."[113]

The introduction of legislative proposals is a questionable indicator of likelihood. While six bills were introduced in the 113th Congress in support of carbon pricing, six proposals were also brought forward in the 113th Congress in opposition to carbon pricing. Moreover, six similar proposals of opposition were introduced in the 114th Congress, and one more was proposed to prohibit the use of the social cost of carbon in any rulemaking.[114] With regard to the "Conservative Case for Carbon Dividends," this plan would include a phase-out of "the EPA's regulatory authority over carbon dioxide emissions … including an outright repeal of the Clean Power Plan."[115]

It is true that it has long been the practice over the course of this docket to consider federal legislation and rulemaking to provide a basis for setting regulatory cost values. Therefore, CEO's argument definitely has merit. However, Minnesota utilities have never been so well-positioned for a carbon-regulated future, and as such, the Commission may have more risk tolerance for the vulnerability that CEO claims Minnesota ratepayers are subjected to. And now that the Commission's environmental externalities values have been updated, the wait-and-see approach MLIG recommends seems less "risky" than it might have in the past.

Throughout this proceeding, there has been an underlying presumption that CO_2 regulation, if implemented, will reflect a serious effort to ambitiously confront climate change. But what if it doesn't? What if CO_2 regulation is implemented, but it is so ineffective or impractical such that there is no cost or no clear solution? Should the Commission neglect a carbon regulation that has been implemented but requires no action in favor of an aggressive one that is hypothetical?

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[112] CEO comments (February 15, 2018), at 9.

[113] CEO comments (February 15, 2018), at 10.

[114] https://priceoncarbon.org/business-society/history-of-federal-legislation/

[115] Climate Leadership Council, "The Conservative Case for Carbon Dividends," Accessed online at https://www.clcouncil.org/wp-content/uploads/2017/02/TheConservativeCaseforCarbonDividends.pdf

Staff raises this issue because CEO noted, "the Trump Administration, while noticing its intent to repeal the Clean Power Plan, also issued, on December 28, 2017, an Advance Notice of Proposed Rulemaking to solicit comments on the regulation it intends to adopt to replace the Clean Power Plan. This suggests federal regulations may be in place sooner than the Agencies project."[116]

The Agencies submitted comments to EPA on the Advance Notice of Proposed Rulemaking on February 26, 2018. In its letter, the Agencies identified a number of problematic challenges with EPA's new interpretation of best system of emission reduction (BSER). Particularly, the Agencies were concerned about EPA's identification of Heat Rate Improvements (HRI) as the BSER, noting that the MPUC has already required Minnesota utilities to adopt cost-effective HRI measures.

The breadth of the Agencies' comments in the federal rulemaking docket have limited applicability here. The point is that even if the Clean Power Plan is replaced with a regulation that requires actions which Minnesota utilities have already done, it would still represent the federal government's regulation of carbon dioxide. The statutory language of § 216H.06 carries no presumption of how aggressive CO_2 regulation might be. Thus, if the Trump Administration replaces the Clean Power Plan, no matter what it looks like, it should be, in staff's view, the policy framework from which CO_2 regulatory costs are derived (at least at one end of the range). It might not be unreasonable, then, to account for the possibility that CO_2 regulation could perhaps not be overly onerous.

As a final note, Xcel stated in its reply comments, "The Agencies propose a broad range of CO_2 regulatory costs, on the rationale that the landscape for CO_2 regulation is highly uncertain at this time. We agree."[117]

Staff remains unconvinced that the appropriate treatment for uncertainty in this case is broadening the range. What "broadening the range" really means in this context is to establish likely CO_2 values that are increasingly greater than zero, which, in turn, means increasing the regulatory cost to be used in resource planning.

Again, staff does not understand why a stay by the U.S. Supreme Court and potential repeal by the Trump Administration means that the Commission should prepare for higher costs than envisioned before from various Clean Power Plan studies conducted for the State of Minnesota, when at the time it was presumed that the Final Rule would become implemented *and* that it would be cost-effective for the State.

Staff does, however, believe a $5-$15 per ton range is fair, provided that the economic model appropriately captures the mechanics of and participation in a cap-and-trade system, which is the basis for each end of the Agencies' recommended range.

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[116] CEO comments (February 15, 2018), at 4-5.

[117] Xcel reply comments (March 5, 2018), at 2.

VII. Decision Options

Likely Range of Costs

1. Establish the range of likely costs of CO_2 regulation at:
    a. \$5 to \$25 per short ton *(Agencies—based on RGGI and Synapse High)*

    b. \$5 to \$15 per short ton *(Staff-variant of Agencies recommendation—based on RGGI and Synapse Low)*

    c. \$5 to \$12 per short ton *(Xcel, 9/19/17—based on RGGI and California/Québec)*

2. Establish the regulatory cost values based on the RGGI and WCI trading programs by calculating the low value as the average of the programs' floor prices and the high value as the average of the programs' ceiling prices. The values are set out in Table 3 of CEO's comments. *(CEO)*

Table 3

Recommended CO_2 regulatory value range			
	Low	Midpoint	High
2022	\$12.56	\$27.21	\$41.86
2023	\$13.39	\$29.00	\$44.61
2024	\$14.28	\$30.91	\$47.55
2025	\$15.22	\$32.95	\$50.67
2026	\$16.23	\$35.12	\$54.01
2027	\$17.31	\$37.44	\$57.57
2028	\$18.45	\$39.91	\$61.36
2029	\$19.67	\$42.54	\$65.40
2030	\$20.98	\$45.34	\$69.71

    a. Establish an escalation rate for the chosen values at 5% above the rate of inflation. *(CEO)*

Effective Year

3. Utilities shall begin applying the above range of CO_2 values in their resource planning and resource acquisition proceedings as of:
    a. 2022 *(CEO)*;
    b. 2025 *(Agencies, Xcel)*;
    c. 2026 *(Minnesota Power)*;
    d. 2028 *(Otter Tail Power)*; or
    e. 2035 *(Minnesota Large Industrial Group)*

4. The range of regulatory cost values and effective year shall be applied for a two-year time period covering both 2018 and 2019. *(Otter Tail, MLIG, Agencies)*

Methodological changes

5. Make no change to the way the value ranges established under Minn. Stat. §§ 216B.2422 and 216H.06 are applied. *(Agencies, MLIG, MP, OTP, Xcel)*[118]

6. Externality costs in excess of regulatory costs must be included when assessing the societal costs of a resource package or plan, as set out in example Tables 3 and 4 of CEO's 2/15/18 comments. *(CEO)*

7. The utilities' total system CO_2 emissions in the first year of its integrated resource planning period shall establish a cap on a utility's CO_2 emissions. The cap will reduce by 2.5% in each subsequent year of the planning period. Utilities need only pay the CO_2 price, which will become effective in 2025, for emissions that exceed its cap. Utilities may bank allowances to offset emissions in later years. If utilities are under the cap, emissions (allowances) may be sold at the Commission's CO_2 cost value. *(Staff option)*

Scenarios and Sensitivities

8. Grant utilities flexibility in determining the appropriate value range to be used in a base scenario. *(Minnesota Power)*[119]

9. The regulatory cost value must be incorporated into the reference or base case of all modeling by all utilities in all resource acquisition and planning proceedings. *(CEO)*

10. All utilities in all resource planning proceedings shall provide:
    - A base or reference case that embeds the midpoint of the regulatory value;
    - A sensitivity run using the low regulatory value;
    - A sensitivity run using the high regulatory value;
    - A sensitivity on the reference case (i.e., with the midpoint regulatory value) using the low externality value; and
    - A sensitivity on the reference case (i.e., with the midpoint regulatory value) using the high externality value. *(CEO)*

11. In the sensitivity analysis, utilities need only consider the single highest CO_2 cost/value and the single lowest CO_2 cost/value low, without regard to whether it is a regulatory cost or externality value. *(Xcel)*

12. The Commission does not require that utilities evaluate the midpoint of the range. *(Staff option)*

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[118] Staff note: If the Commission wishes to make no methodological changes, it can skip Options 4-6.

[119] Staff note: If the Commission prefers Option 7, it might be cleaner to skip Options 7-9.