BEFORE THE COURT OF ADMINISTRATIVE HEARINGS

FOR THE

MINNESOTA PUBLIC UTILITIES COMMISSION

STATE OF MINNESOTA

In the Matter of the Petition of the City of Slayton for the Determination of Compensation for City Acquisition of Xcel Energy Electric Service Territory	MPUC Docket No. E-002, PT-7157/ SA-25-129 CAH Docket No. 25-2500-40870

REBUTTAL TESTIMONY OF MARK FRITSCH
ON BEHALF OF THE CITY OF SLAYTON

January 9, 2025

Exhibit ___

PUBLIC DOCUMENT

I. INTRODUCTION

Q. Mr. Fritsch, please state your full name and occupation.

A. My name is Mark Fritsch. I reside in Lake Elmo, Minnesota, and I am the Founder and President of Current Compass LLC, an energy industry consulting firm.

Q. On whose behalf are you giving this testimony?

A. I am testifying on behalf of the City of Slayton ("City").

Q. Please describe your educational and employment background.

A. I received a Bachelor of Science degree in Mechanical Engineering from the University of Minnesota in 1980. From 1980-2010, I was employed by Northern States Power Minnesota, now doing business as Xcel Energy. I held various positions during that time, including electric power plant manager and manager of electric maintenance and protection for Xcel substations and transmission systems located in its Minnesota service territory. In those positions, I was responsible for development and execution of both long- and short-term planning. Those planning periods included both fixed and variable costs for generation, substation and transmission assets, and related budgeting to adjust for needs as they arose from rate case outcomes and other contingencies. During my last two years at Xcel, I was director of regulatory projects. Among my duties in that position was to oversee the development and preparation for Xcel Minnesota's general rate cases. I used my expertise in management and planning of both generation and transmission assets in rate case development.[1]

Q. What did you do for employment after leaving Xcel?

A. I was hired by the City of Owatonna, Minnesota shortly after leaving Xcel and held the position of CEO/General Manager of Owatonna Public Utilities ("OPU") until 2018. OPU is

[1] Mark Fritsch Resume attached.

an electric, gas and water municipal utility serving customers within and near the city limits of Owatonna. Since 2018, I have been a consultant to municipal electric and gas utilities and founded Current Compass for that purpose. As a consultant, I have worked with Minnesota municipal utilities in advising and negotiating their agreements with cooperative and investor-owned utilities (IOUs), including Xcel, on municipal service territory acquisitions, as well as on other municipal utility issues.

Q. Have you ever testified before the Minnesota Public Utilities Commission (MPUC) or before other public utility commissions?

A. No, I have not.

Q. What have you done to prepare for your testimony in this case?

A. I have read the public and non-public direct testimony of all witnesses submitting direct testimony in this contested case. I have also reviewed exhibits and other documents produced by the City of Slayton and Xcel Energy for the subjects I will address in this testimony.

Q. What subjects do you address in this rebuttal testimony?

A. I address two subjects in rebuttal to Xcel's direct testimony. First, I respond to Xcel's method of analyzing avoided and not avoided cost submitted by Lisa Peterson. As discussed below, her testimony is a reversal of Xcel's recently stated acknowledgement that transmission costs are avoidable, as stated in a PowerPoint presentation that Xcel presented in connection with the Minnesota Municipal Utilities Association (MMUA) to provide Minnesota municipal electric utilities with Xcel's positions on net revenue loss. Further, I will show that Xcel has also acknowledged that fixed production-energy costs are also avoidable when Xcel has growth in sales. To that point, Xcel has testified to an anticipated "era" of sales growth in its current rate case.[2] Yet, in this case, Ms. Peterson testifies that all fixed production cost as unavoidable.[3]

Second, I discuss the additional relevant planning periods that Xcel employs for system planning purposes that are a five-year duration, or less, and were omitted by Xcel in describing its much lengthier, 20-year planning period in this case for use as the net lost revenue payment period. The only net revenue loss Xcel may experience with a Slayton acquisition is a loss of the Slayton load. In my experience at Xcel and OPU, small load loss adjustments, less than 1% of Xcel's total, can be adjusted very quickly without having an impact on current and future rates to customers. Slayton's loss is far less than 1% of Xcel's total Minnesota load.

AVOIDED COSTS

Q. Please describe your knowledge of and background to the Xcel PowerPoint presentation you reference as the first subject of your testimony.

A. My involvement with these Xcel presentations began in 2019 after I became a consultant to municipal utilities and was asked by MMUA to be its representative at such a meeting. Most or all Minnesota municipal utilities are members of MMUA. The first meeting and Xcel PowerPoint discussion I attended was presented on May 6, 2019, at Xcel's corporate headquarters. I was invited by Xcel as the representative for MMUA. I recall that Xcel employees Bridget Dockter, Michael Peppin, David Olson III, Mary Woolf, Jennifer Roesler, and Mara Ascherman, were in attendance. Xcel's 2019 PowerPoint materials were shared with me.[4] As I discussed with Xcel representatives at the meeting, I intended

[2] *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota*, MPUC Docket No. E-002/GR-24-320, Liberkowski Direct. Testimony ("Dir. Test.") at 4 (Nov. 1, 2024).
[3] Peterson Dir. Test., pp. 24, l. 11.
[4] Att. A: May 6, 2019 Xcel PowerPoint – MMUA and Xcel Energy "Service Territory - Annexations" ("2019 PPT"); Note pages 7-12 include April 2018 materials.

to use the PowerPoint for my presentation to municipal utility representatives at the upcoming MMUA annual conference in August 2019. The PowerPoint slides referenced MMUA's interest and included an "Annexation Form" to be filled out by the municipality seeking to acquire Xcel territory to be submitted to Xcel.[5]

Q. Did you present the Xcel subject matter from the May 2019 PowerPoint at the MMUA Conference?

A. Yes, I did. And in a separate conversation Xcel's previous Regional Vice President, Government and Community Relations, Greg Chamberlain, related to me Xcel's desire to inform municipalities of Xcel's position on lost revenue compensation.

Q. Did you attend any subsequent Xcel PowerPoint presentations on its lost revenue positions?

A. Yes. Xcel gave another presentation again in April 2021.[6] It was similar to its 2019 PowerPoint, but shorter. It maintained the 2019 chart showing the Xcel Cost Functions that it regarded as "Cost Avoided" or not. [7]

Q. Did Xcel maintain the same position on Cost Avoided categories from the 2019 to 2021 meetings?

A. Yes.

Q. When was your next meeting with Xcel to go over its PowerPoint presentation?

A. It was in March 2025. The PowerPoint was dated March 21.[8]

Q. Who attended that Xcel presentation?

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[5] *Id*., p. 2, 3, and 18.
[6] Att, B: April 2021 Xcel PowerPoint – "Service Territory Sale Pricing Assumptions" (Apr. 2021) ("2021 PPT").
[7] 2019 Xcel PPT, p. 10; and 2021 PPT, p. 4.
[8] Att. C: March 21, 2025 Xcel PowerPoint – "Service Territory Sale Pricing Assumptions" ("2025 PPT"); Note: Att. C has same May 6, 2019 cover and materials with March 21, 2025 materials from pp. 7-12..

A. I recall Lisa Peterson being the PowerPoint presenter, and Chris Barthol of Xcel was also in attendance. It was an online presentation and discussion using Microsoft Teams.

Q. Was this presentation for the same purpose of providing Xcel positions on compensation issues?

A. That has been my understanding since I first attended in 2019. Page 17 of the March 2025 PowerPoint states that Xcel believes a "more standardized information sharing process" can benefit both Xcel and "MMUA."[9] It also continued to include a municipal utility "Annexation Form" as a requested information sheet from cities for Xcel, as used in the May 2019 PowerPoint.[10]

Q. Did any positions of Xcel on lost revenue compensation change in the March 2025 materials?

A. Yes. Xcel changed its position on transmission costs and fixed production-energy related costs.[11] Ms. Peterson presented the PowerPoint in 2025 which states that Xcel recognized that transmission costs were avoidable. But she also noted that Xcel changed its position regarding fixed production-energy costs in municipal territory acquisitions, changing its position on these costs from avoidable in 2019 and 2021, to unavoidable in 2025.[12]

Withdrawn

Q.

A.

[9] Id. 2025 PPT, p. 17.
[10] Id. 2025 PPT, pp. 17-18..
[11] Att. A and C: 2019 PPT, p. 4; 2025 PPT, p. 10.
[12] Att. A, B, C: 2019 PPT, p. 4; 2021 PPT, p. 4; 2025 PPT, p. 10.

Withdrawn

Q.

A.

[13] Att. C: 2025 PPT, p. 10.

Withdrawn

Q.

A.

Q.

A.

[14] Att. A, C: 2019 PPT, p. 11; 2025 PPT, p. 11.
[15] Att. D: Withdrawn

Withdrawn

Q. Back to the PowerPoint presentations, do you agree with Xcel's stated view on all other avoided costs it identifies in its "Avoided Costs vs. Costs Not Avoided" charts?

A. As I stated, my primary disagreement with Xcel's 2019 PowerPoint was that transmission costs were avoidable. I also disagreed with Xcel's position that fixed production – capacity would not be avoidable, even when the capacity market had a positive value due to sales growth. I agreed with Xcel that fixed production – energy was avoidable when the excess capacity was coupled with sales growth.

Otherwise, the PowerPoint presentation slides from 2019-2025 reflected the same positions from Xcel that I observed in my experience as a city utility consultant. For example, in the PowerPoint's Xcel used the 10-year net lost revenue payment period, identified regularly used avoided-unavoided cost categories.

Q. Xcel identifies a 10-year lost revenue payment period in its PowerPoint materials. Yet it requests a 20-year lost revenue period in this contested case. In your public meetings with Xcel during this period, did Xcel representative ever suggest use of a 20-year payment period?

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[16] Att. E: Withdrawn
[17] *Id*.
[18] Att. F: Withdrawn

A. No, they did not. The request to double the length of the lost revenue payment from the 10 years used in all the Section 216B.44 cases brought before the MPUC for compensation decisions, was never mentioned by Xcel. As included in all the PowerPoint presentations, Xcel used a 10-year lost revenue payment period.[19]

Q. Are there other differences in how Xcel described its approach to compensation during this 2019-spring 2025 presentation and its testimony in this case?

A. Yes. Ms. Peterson presented the PowerPoint in 2025 and identified 75.84% avoided costs for residential using Xcel's public data from its most recent rate case.[20] Since 2019 Xcel's avoided costs for residential has been between 74.42 and 75.84 %.[21] In her direct testimony in this case, however, she states that only about 36% of Xcel's costs of serving residential Slayton customers are avoided.[22] Slayton is a mostly residential and non-demand customer base within its municipal limits.[23] Xcel's method analyzing avoided and not avoided costs during these PowerPoint presentations, however, was very similar to Mr. Berg's analysis, and the methods used by cities, cooperatives, and Xcel itself in my experience with Xcel on compensation due to net lost revenue.

Q. Did Ms. Peterson's direct testimony in this case use the same avoidable cost analysis used in the 2019 and 2025 PowerPoint presentations?

A. No, she did not. Xcel's avoided cost testimony through Ms. Peterson reverses Xcel's previously stated position from as recently as the March 2025 PowerPoint presentation.[24]

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[19] Att. A, B, C: 2019 PPT pp. 8, 12, 14; 2021 PPT p. 6; 2025 PPT pp.5, 12, 14.
[20] Att. C: 2025 PPT p.11.
[21] Att. A, B, C: 2019 PPT p. 11; 2021 PPT, p. 5; 2025 PPT, p. 5.
[22] Peterson Dir. Test., p.10 l. 20.
[23] Berg Dir. Test. p. 23 l. 3-4
[24] Att. C: 2025 PPT p.10.

Q. In sum, on what issues did Xcel change its position on avoided costs from 2019 to the March 2025 PowerPoint presentation?

A. As stated, its March 21, 2025 PowerPoint, Xcel incorporated the change in transmission costs to avoidable rather than unavoidable.[25] Xcel also stated in the 2025 presentation that fixed production – energy was unavoidable instead of avoidable due to Xcel's forecast of flat to declining electric sales. Xcel's testimony in its most recent rate case, however, notes that, "…[w]e sit on the cusp of a new era that may see substantial load growth, including from new facilities such as data centers and similar facilities."[26] With

Withdrawn

<u>LOST REVENUE PAYMENT PERIOD</u>

Q. You stated earlier in your testimony that the second topic would be Xcel's omission of shorter planning periods that are more relevant to the Slayton facts than the 20-year

[25] *Id*.
[26] MPUC Docket No. GR-24-320; Liberkowski Dir. Test. at 4.
[27] Att. D: Withdrawn
[28] Att. E: Withdrawn

planning period Xcel seeks in this case. Please describe these Xcel planning periods and explain their relevance to the lost revenue payment period appropriate in this case.

A. As a former Xcel employee with planning responsibilities, I became familiar with the numerous planning periods Xcel used and the subjects for which Xcel created internal planning periods. In my experience, longer planning periods were used for large changes in actual or forecasted load, infrastructure changes, and negative outcomes from rate cases. Xcel's Integrated Resource Plan (IRP), is an example of a long-term plan that is a "whole system view" and not relevant to small load changes such as the Slayton acquisition. In addition to the 20-year planning period Xcel proposes, Xcel performs much more near-term planning for capital investments, grid modernization, staffing and budgets.

Xcel's main near-term planning is guided by their Integrated Distribution Plan (IDP).[29] This plan is provided every biennial and focuses on the electric grid. It is designed to provide the PUC with Xcel's short and long-term distribution system plans, costs and benefits of specific investments, and a comprehensive analysis of customer cost and value. Xcel develops a 5-year capital budget for distribution as part of its IDP.[30] The 5-year capital plan includes system expansions, upgrades for capacity, reliability and power quality. It also includes age-related replacements and asset renewal and grid modernization. That

[29] *In the Matter of Xcel Energy's 2023 Integrated Distribution Plan*, MPU Docket No. E-002/M-23-452, Order Accepting 2023 Integrated Distribution Plan and Modifying Reporting Requirements (Sep 16, 2024 ("Xcel 2023 IDP")).
[30] Xcel 2023 IDP, p. 20-21.

plan has discretionary projects that can be delayed or cancelled. This gives Xcel a great tool when cost reductions are needed because of load loss or rate case impacts. Xcel's IDP, updated every 2-years and its integrated 5-year capital plan,

in my view, these five year IDP planning periods are more relevant than a 20-year planning period to the only unavoided cost Xcel truly has from a Slayton acquisition – the substation load attributable to Slayton.[31]

Further, Xcel does not directly relate its 30-year IRP planning period subjects to any specific fixed cost that will be left stranded and not earning the expected return if Slayton leaves the retail service territory.[32]

Further, Ms. Peterson's discussion of pole infrastructure useful lives is not relevant to Xcel's needed adjustment period to the loss of Slayton's load.[33] Under the Section 216B.45 factors, the city would be paying original cost minus depreciation for all of these infrastructure items. Their useful life, described by Ms. Peterson, becomes irrelevant with that payment, which provides full compensation for that infrastructure.

Q. Why are the Xcel planning periods you identify more appropriate for use due to the net loss of Slayton revenue?

[31] Berg Dir. Test., p. 28, l. 14-15.
[32] Sun Dir. Test., p. 2, l. 22 - p. 3, l. 2.
[33] Peterson Dir. Test., p. 13, l. 20-27; p. 14, l. 13-17.

A. The small loss of load due to Slayton does not affect any long-term Xcel planning. Use of the planning periods I listed above will allow Xcel to easily mitigate the loss of Slayton's load, without rate consequence to Xcel's numerous remaining ratepayers.

Q. The five-year planning or reporting periods you identify are much shorter than Xcel's proposed length of net revenue loss payment period. Do you have experience to justify such a short planning duration in this case?

A. Yes. In my work experience at Xcel, I was responsible for adjusting fixed costs by making cost control measures due to budget impacts from changes in loads, actual and projected revenue loss, and negative rate case outcomes. These included staffing, maintenance, operations, and capital project reductions. These measures I supervised were typically taken within a five-year timeline and adjusted through Xcel's yearly milestones, followed by an additional year(s) planning when necessary to fully adjust. We would track actuals to forecasts each month. As I stated above, Xcel has powerful adjustment capabilities as a large, publicly traded and vertically integrated IOU. These short planning and forecasting periods were required of all departments in Xcel. These shorter monthly and yearly planning periods were critical for our financial success. Each year we had earnings per share goals that could only be achieved through these shorter planning periods.

Q. Besides your work at Xcel Energy, do you have any other experience and expertise in planning or adjusting to mitigate load loss?

A. Yes, as CEO/General Manager of OPU. At OPU, we regarded load losses of 1% or less of our total load to allow a number of non-rate increase adjustments that could be made within a short time. With a 1% or less loss we would accomplish our non-rate adjustment by starting with our year end revenue for that loss and then determining what costs and expenditures we could delay and/or reduce each month thereafter. Typically, we could delay filling open positions and capital expenditures. We would also reduce travel, contract/consulting and overtime expenditures. If load growth exceeded that loss, OPU's monthly planning and year end forecasts would easily manage load loss within its first year. OPU has that adjustment and mitigation capability and it has only 13,000 meters compared to Xcel's 740,000 meters in its Minnesota service territory.

Q. What is your recommendation for a net lost revenue payment period in this case?

A. I agree with Mr. Berg's recommendation of a five-year payment period as more than reasonable time for Xcel to adjust to and mitigate the loss of the Slayton load at Xcel's substation.

Q. Does that conclude your rebuttal testimony?

A. Yes.

Attachment Description
Mark Fritsch Resume
Attachment A: May 6, 2019 Xcel PowerPoint – MMUA and Xcel Energy "Service Territory - Annexations"
Attachment B: April 2021 Xcel PowerPoint – "Service Territory Sale Pricing Assumptions" (Apr. 2021)
Attachment C: March 21, 2025 Xcel PowerPoint – "Service Territory Sale Pricing Assumptions"
Attachment D: Withdrawn
Attachment E: Withdrawn
Attachment F: Withdrawn

Mark J. Fritsch

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Professional History

Founder/President, Current Compass, Inc., 2010 – present

Offer Service Territory acquisition, leadership consulting, business start-up and subject matter expertise to municipal utilities.

CEO & General Manager, 2011-2018

Owatonna Public Utilities (OPU) — *Owatonna, MN*

Led a remarkable turnaround effort for a municipal gas, water and electric utilities facility by combining industry expertise with proven leadership strategies to achieve peak performance, national recognition for performance and value.

- Implemented strategic planning processes and communications programs on day one to align personnel and departments behind common goals, resulting in streamlined operations, reduced costs and lower rates
- Achieved goals for national excellence recognition with APPA's, Reliable Public Power Provider (RP3), Diamond Award (electrical business), and APGA's, System Operational Achievement Recognition (SOAR), the Silver Award for the natural gas business
- Worked with CFO, creating strategies to engage workforce and hold operating expenses at same level for years 1 – 5
- Guided the facility toward an accident free workplace within two years, and reduced controllable expenses by 20% in three years
- Leading development of new 5MW solar plant and 38 MW natural gas fired facility
- Worked closely with community leaders to repurpose a flooded power plant into an award winning $15M office complex, successfully preserving an iconic landmark by leveraging cost savings and FEMA funds: Top Projects of 2015
- Work with Owatonna Partners for Economic Development to attract new business with beneficial utility rate plans
- Partnered with Viracon, Inc. to create an energy plan that allowed the company to remain, saving 600+ jobs
- Worked with the city and Bushel Boy Farms to provide them utility services that reversed planned relocation and instead facilitated an expansion to 3-4 times their current size, saving jobs and increasing local employment
- Serve as the city's pro bono consultant, offering strategic planning, HR policies and practices, advice on interpersonal issues, host workshops with city council, mayor and city staff

Director, Regulatory Projects, 2008 – 2010

Xcel Energy — *Minneapolis, MN*

Conducted extensive research in a consultancy role representing the organization in regulatory processes for rates, riders and tariffs that guided critical issues and led to successful rate restructuring.

- Developed federal compliance programs including FERC and NERC for fossil and hydro plants
- Created strategies that resulted in a successful $250 million rate case

Director, Allen S. King Plant, 1999 – 2008

Xcel Energy — *Minneapolis, MN*

Established a vision and applied leadership and skilled negotiation to re-power a 600 MW base load supercritical coal fired plant.

- Extended plant life longer than anyone in the industry estimated for this type of unit , saving tens of millions annually
- Created strategy to secure $500M to repower the plant and gain overwhelming environmental community support
- Introduced "The Balanced Scorecard" approach resulting in more than $80M in cost savings over nine years
- Achieved best in class, U.S. performance for reliability and environmental performance
- Achieved accident free safety record in a challenging union workplace by building relationships

Director, Corporate University, 1994 – 1999

Xcel Energy — *Minneapolis, MN*

Transformed corporate training by establishing Chief Learning Officer role and developed innovative learning, based on recognized expertise; driving training, qualification and compliance for nuclear & conventional power facilities.

- Reduced training costs by 30% while improving impact using centralized management and decentralized delivery
- Changed company culture from managing to leading by designing and implementing leadership training, succession planning and performance monitoring programs as part of human resources
- Gained recognition as one of the top 50 corporate universities in the world
- Developed *Chief Learning Officer Exchange* that led to effective idea sharing, learning and application for effective leadership development across the corporation and recognition among top 50 corporate universities worldwide

Manager, Electric Maintenance and Protection, 1990 – 1994

Xcel Energy — *Minneapolis, MN*

Managed construction testing, reliability and maintenance of over 400 substations, with oversight of 150 union/ non-union staff.

- Achieved over 30% cost reduction and eliminated human-error-caused outages through process and reliability centered improvement programs
- Developed a profitable business services consulting group with sales to external companies

Superintendent, RDF Plants, 1987 – 1990

Xcel Energy — *Minneapolis, MN*

Managed the conversion and operations of two coal fired plants to refuse derived fuel (RDF) powered facilities, leveraging several 25 MW facilities toward reduced landfill waste and revenue generating energy.

- Reduced operations costs by 30% through union negotiations and process improvement efforts
- Increased production 19% using self-directed work teams, quality improvement processes and safety improvements

Education

Bachelor of Science, Mechanical Engineering, 1980 - University of Minnesota, Minneapolis, MN

Professional Certifications

- Minnesota Management Academy, U of M, Carlson School of Mgmt
- HR Executive Program, U of M, Carlson School of Mgmt
- Masters Forum, U of M, Carlson School of Management
- Principal Centered Leadership, Covey Leadership Center

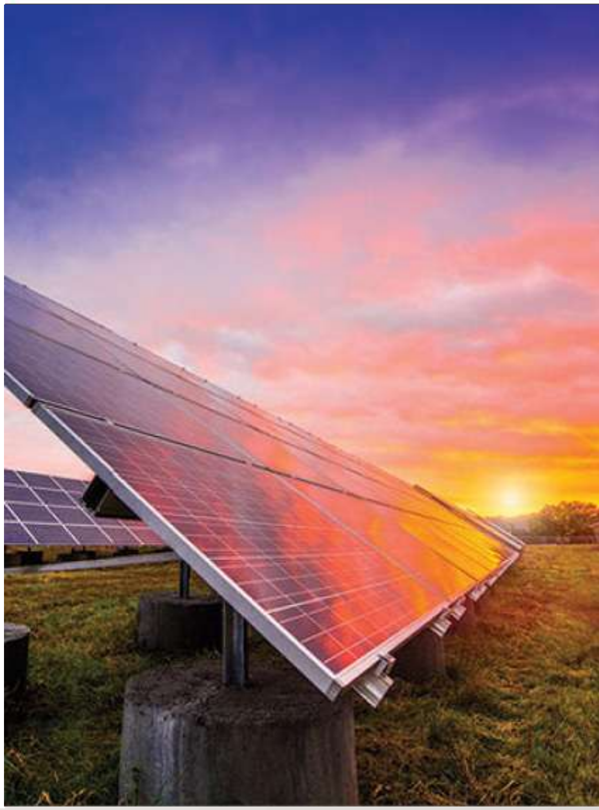
Awards/Affiliations

- Board Vice President, Southern Minnesota Municipal Power Agency (SMMPA), 2016
- President, Rotary of Owatonna, 2016
- Distinguished Service Award – Minnesota Municipal Utilities Association, 2016
- Board of Directors, Great River Greening – Past Chair
- Board of Directors, BestPrep – Past Chair
- President's Award for Safety – Xcel Energy, 2006
- Leader of Vision Award, BestPrep, 2005
- Governors Awards for Public Utility, Power Plant and Utility Safety, multiple awards
- Meals on Wheels, Volunteer and Volunteer of the Year Award Winner, 2007
- Boy Scout, Scoutmaster, 2007 – 2012

Service Territory - Annexations

MMUA and Xcel Energy

May 6, 2019



Agenda

- MMUA's Requested Review Items
- MN Statutory Requirements
- Scope of issue
- Response to Request(s) of contract conditions
- Information Request Template
- Next Steps

MMUA's Requested Review
Standardization of Annexation Process

1. Amount of compensation
   - Lost revenue calculation

2. Existing facility Price

3. Duration of payments

4. Expenses resulting from integration of facilities

5. Compensation
- Municipal owned and or developed territory compensation
- Rates for property and bare ground

6. How to handle interim service

7. Streamlined Settlement Processes

MN Statutory Requirements

216B.44 MUNICIPAL SERVICE TERRITORY EXTENSION.

After notice and hearing, the commission shall determine appropriate terms for an exchange, or in the event no appropriate properties can be exchanged, the commission shall fix and determine the appropriate value of the property within the annexed area, and the transfer shall be made as directed by the commission. In making that determination the commission shall consider the original cost of the property, less depreciation, loss of revenue to the utility formerly serving the area, expenses resulting from integration of facilities, and other appropriate factors.

Scope of Issue

- In the past 10 years, we have had:
  - 7 annexations. All have come to a mutually agreeable resolution.
  - 40 exception agreements, 4 have terminated.
- All of the agreements came to a mutually agreeable resolution and the volume is not high. This is not a significant issue for us.
- Responses to request(s) of contract conditions.
- Standardized information template would be useful for all parties.

1. Compensation Review

- Amount of Compensation (Lost Revenue)
- What do we take out of our gross revenues to get to our net lost revenues?
  - Illustrations are included in the presentation below.

Service Territory Sale Pricing Assumptions

April 2018

Slides (7-12)

Commission Accepted Net Revenue Loss Analysis - 5-Step Process

1. Calculate Gross Revenues the selling Utility will lose over a 10-year period.
2. Determine the costs the utility will no longer incur from not serving the customers.
3. Calculate net revenue loss for each year (Step 1 minus Step 2).
4. Calculate net present value of annual net revenue losses.
5. Territory sale must also include cost of impacted distribution facilities and any integration costs.

Assumptions

- Cost assumptions based on MN PUC order from Xcel's last Minnesota rate case (Docket No. E002/GR-15-826)
- Uses Class Cost of Service Study for Cost Analysis at Commission Ordered Cost and Revenue Levels
- All Costs are Functionalized
  - Fixed Production
  - Variable Production
  - Transmission
  - Etc.
- Costs Allocated to Customer Class using Commission Approved Allocation Methods

Avoided Costs vs. Costs Not Avoided

	Is Cost Avoided?	
Cost Function	**Yes**	**No**
Fixed Production: Capacity Related		**X**
Fixed Production: Energy Related	**X**	
Variable Production Costs (Fuel etc.)	**X**	
Transmission		**X**
Distribution Substations		**X**
Primary Distribution Lines	**X**	
Secondary Distribution Lines	**X**	
Customer-Related Costs	**X**	

PUC Ordered Revenue Requirement by Utility Function
Avoided vs. Costs Not Avoided

	Revenue Requirement ($000) by Customer Class and Utility Function				
Utility Function	**MN**	**Residential**	**Commercial not Demand Billed**	**Commercial & Industrial Demand Billed *****	**Lighting**
Fixed Production: Capacity Related	$408,768	$147,291	$13,385	**$248,092**	$0
Fixed Production: Energy Related	$237,915	$71,954	$7,316	**$157,753**	$892
Fuel & Purchased Power	$1,665,415	$486,817	$50,690	**$1,120,408**	$7,499
Transmission	$300,243	$107,938	$9,806	**$182,499**	$0
Distribution Substations	$84,907	$33,811	$2,694	**$47,863**	$539
Primary Distribution Lines	$103,964	$54,682	$3,061	**$45,689**	$532
Secondary Distribution Lines & Transformers	$31,053	$15,782	$1,057	**$14,103**	$110
Metering, Meter Reading & Billing	$317,795	$262,408	$19,888	**$13,670**	$21,828
Total Revenue Requirement	$3,150,060	$1,180,683	$107,898	**$1,830,078**	$31,401
Total Avoided Costs	**$2,356,142**	**$891,644**	**$82,013**	**$1,351,624**	**$30,862**
Total Costs NOT Avoided	**$793,918**	**$289,040**	**$25,885**	**$478,454**	**539**
% of Total Costs Avoided	**74.82%**	**75.52%**	**76.01%**	**73.86%**	**98.28%**

Customer Usage and Revenue Assumptions Required for Analysis

Data Requirements for Analysis:

- Has property been annexed by the city, if not, when?
- Timeline for development
- Date Electric Service will be required
- Size of Each Lot
- Number and Type of Customers
- Lot Zoning for Vacant Lots: Residential, Commercial, Industrial
  - Type of residential housing and types of businesses
- Customer usage assumptions
  - Customer Load
  - Load Factor
  - Business Operating Hours
  - Service Voltage
- Lost Revenues are Calculated for 10 Years after Electric Service Starts

2. Existing Facility Price

Spreadsheet is provided to City after valuation is complete

City of ??????- Annexation - Values of Existing Facilities

Notes: Utility distribution assets depreciated over 50 year life; Current Net Book Value + Removal Costs= Total Customer Cost

NUMBER	ADDRESS	TRANSFORMER #	TRANSFORMER DETAILS	UG or OH	Wire Footage	YEAR INSTALLED	Age (2018)	TRANSFORMER ORIGINAL COST	WIRE ORIGINAL COST	DEAD END ARM ORIGINAL COST	ARRESTOR ORIGINAL COST	CUTOUT ORIGINAL COST	ELBOW ORIGINAL COST	Labor, OH and Misc Materials	ORIGINAL TOTAL COST	TRANSFORMER NET BOOK VALUE (UNDEPRECIATED) (2018)	DEAD END ARM NET BOOK VALUE (UNDEPRECIATED) (2018)	ARRESTOR NET BOOK VALUE (UNDEPRECIATED) (2018)	CUTOUTS NET BOOK VALUE (UNDEPRECIATED) (2018)	ELBOWS NET BOOK VALUE (UNDEPRECIATED)	WIRE NET BOOK VALUE (UNDEPRECIATED) (2018)	LABOR, OH AND OTHER MISC. MATERIALS NET BOOK	TOTAL CURRENT NET BOOK VALUE	FACILITIES TO BE REMOVED	REMOVAL COST	TOTAL NET BOOK VALUE (UNDEPRECIATED) PLUS REMOVAL
1	101 16th Street NE	T1111111	300kva 12470v 120/208v 3 phase	UG/OH	540FT - #2 ACSR OH PRIMARY / 250FT - 1/0 PRIMARY UG 3PH	1991	27	$7,300.00	$92.00 + $1,328 = $1,420.00	$189.57	3 FOR A TOTAL OF $103.44	3 FOR A TOTAL OF $233.40	6 FOR A TOTAL OF $141.36	$9,814.81	$19,202.58	$3,358.00	$87.20	$47.58	$107.36	$63.41	$653.20	$4,516.44	$8,833.19	Nothing	$0.00	**$8,833.19**
2	101 16th Street NE	T2222222	1000kva 12470v 277/480v 3 phas	UG	430FT - 1/0 PRIMARY UG 3PH	1998	20	$14,357.00	$2,283.00		3 FOR A TOTAL OF $180.21		3 FOR A TOTAL OF $70.68	$8,416.18	$25,307.07	$8,614.20		$108.13		$42.41	$913.20	$5,506.31	$15,184.24	Wire and associated equipment on the pole	$1,333.24	**$16,517.48**
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TOTAL AMOUNT DUE																										**$29,686.00**

3/4. Duration of Payments & Expenses Resulting from Integration of Facilities

- This is covered in the Service Territory Agreement, see attached snip-its from the Agreements

Compensation. The Municipal will pay to Xcel Energy the following as compensation for the Annexed Service Territory Transfer area The net book value (original cost depreciated) of the service facilities in place within the annexation area and any integration or re-feed costs that may be necessary as compensation for the exclusive right to provide electric service to the Territory Transfer area through Annexation. The net book value will be calculated using the average property unit cost, net of customer constributions, and the year the unit of the property was initially purchased.

The Annual Payments for the Annexed Service Territory: For a period of 10 years starting on the Effective Date, the City shall pay Xcel Energy annually.

5. Compensation

- Municipal Owned and or Developed Territory Compensation
- Large Customer Acquisition Compensation
- Rates for Property with existing load and bare ground
    - As described earlier in the presentation, compensation for annexations follow the same general process, but taking into account the specifics of the circumstance.

6. Interim Service

- Handling Interim Service
  - If the property is clearly within City limits, we will allow interim service as long as we have agreement to compensation, by either
    - Adding a provision in the Compensation and Orderly Transfer Agreement or
    - Entering into a separate Exception Agreement that terminates when the Commission approves the Compensation and Orderly Transfer Agreement.
  - If the property is not within the City limits, then we will not agree to interim service until the property is annexed to the city, or until we have a signed Compensation and Orderly Transfer Agreement.

7. Streamlined Settlement Processes

- Based on a review of our current process, we believe it would be valuable to both the Company and MMUA if there were a more standardized information sharing process
- The template enclosed - see next page for visual- requests necessary information to smooth settlement process

Annexation Form

ANNEXATION FORM

Municipality **NAME OF MUNICIPALITY:**

MUNICIPALITY TO PROVIDE THE FOLLOWING INFORMATION TO THE UTILITY

Estimated land size to be annexed (acres):
Legal Description of the land to be annexed:
Please attach a map of the land to be annexed to this form, as it will be needed for a filing with the Minnesota Public Utilities Commission.
Is the land already annexed into City limits? Yes ☐ No ☐ If yes, and the land was annexed in the last 10 years, please provide the Order from the Minnesota Office of Administrative Hearings, Municipal Boundary Adjustment Unit, providing documentation of such annexation. If no, when will it be annexed?
Number of lots and size of each lot:
Are there existing Xcel Energy customers on this site? Yes ☐ No ☐
If yes, provide address(es): Repeat as needed. [Address] [City, State, Zip]

PROVIDE THE FOLLOWING INFORMATION FOR EACH LOT/CUSTOMER

Zoning for each lot: Residential ☐ Commercial ☐ Industrial ☐	
Load (per kW by lot/building):	
Customer Class: Residential ☐ Commercial & Industrial ☐	
Rate of the Customer: Firm ☐ Interruptible ☐	
Service Voltage (secondary, primary, etc):	
Estimated Load Factor: (Load factor = Est. kWh use for Month/(Est Peak Demand kW x Hours in the Month)	
Business Operating Hours Days per Week: Hours per Weekday: Hours per Weekend:	
Name(s) (for Business): Repeat as needed.	Type of business or industry: (retail w/ or w/o refrigeration; type of commercial; if industrial, type of industry, etc.)

Name(s) (for Residential Development): Repeat as needed.	Type of dwelling: (single family, duplex, apartment, etc.) If multi-family, number of units:
Developer Contact Information: [Name] [Address] [Phone Number]	
Provide copy of plat.	
Provide timeline of the development:	
Development start date:	
Estimated date when power will be needed for permanent service:	

Next Steps

Xcel Energy®

Service Territory Sale Pricing Assumptions

April 2021

Commission Accepted Net Revenue Loss Analysis - 5-Step Process

1. Calculate Gross Revenues the selling Utility will lose over a 10 year period

2. Determine the costs the utility will no longer incur from not serving the customers

3. Calculate net revenue loss for each year (Step 1 minus Step 2)

4. Calculate net present value of annual net revenue losses

5. Territory sale must also include cost of impacted distribution facilities and any integration costs

6. Compensation rates vary by customer class, kWh usage and revenues

Assumptions

- Cost assumptions based on MN PUC order from Xcel's last Minnesota rate case (Docket No. E002/GR-15-826)
- Uses Class Cost of Service Study for Cost Analysis at Commission Ordered Cost and Revenue Levels
- All Costs are Functionalized
  - Fixed Production
  - Variable Production
  - Transmission
  - Etc.
- Costs Allocated to Customer Class using Commission Approved Allocation Methods

Avoided Costs Vs Costs Not Avoided

	Is Cost Avoided?	
Cost Function	**Yes**	**No**
Fixed Production: Capacity Related		X
Fixed Production: Energy Related	X	
Variable Production Costs (Fuel etc.)	X	
Transmission		X
Distribution Substations		X
Primary Distribution Lines	X	
Secondary Distribution Lines	X	
Customer-Related Costs	X	

PUC Ordered Revenue Requirement by Utility Function

Avoided Costs Vs Costs not Avoided

Utility Function	MN	Residential	Commercial not Demand Billed	Commercial & Industrial Demand Billed ***	Lighting
Fixed Production: Capacity Related	$408,769	$147,291	$13,385	$248,093	$0
Fixed Production: Energy Related	$237,915	$71,954	$7,316	$157,753	$892
Fuel & Purchased Power	$1,665,419	$486,818	$50,690	$1,120,411	$7,499
Transmission	$300,244	$107,938	$9,806	$182,500	$0
Distribution Substations	$84,907	$33,811	$2,694	$47,863	$539
Primary Distribution Lines	$103,965	$54,682	$3,061	$45,689	$532
Secondary Distribution Lines & Transformers	$31,053	$15,782	$1,057	$14,103	$110
Metering, Meter Reading & Billing	$317,796	$262,409	$19,888	$13,671	$21,828
Total Revenue Requirement	$3,150,068	$1,180,685	$107,898	$1,830,083	$31,401
Total Avoided Costs	**$2,356,148**	**$891,645**	**$82,013**	**$1,351,628**	**$30,862**
Total Costs NOT Avoided	**$793,920**	**$289,040**	**$25,886**	**$478,455**	**$539**
% of Total Costs Avoided	**74.80%**	**75.52%**	**76.01%**	**73.86%**	**98.28%**

Calculation Details

- Customers' total billing quantities estimated based on 5 years of billing history
- Annual customer revenues calculated based on current Xcel rates and estimated billing quantities
- Lost Revenues = Gross Annual Revenues * (1 - % of Costs Avoided)
- Over the 10-year period assumes:
  - No change customers' billing quantities
  - Assumes a 2% annual increase in bills
  - Discounts the lost revenues over the 10-year period at Cost of Capital (6.45%)
- Lump-sum payment based on the net present value of lost revenues over the 10 period

Service Territory - Annexations

MMUA and Xcel Energy

May 6, 2019

Agenda

- MMUA’s Requested Review Items
- MN Statutory Requirements
- Scope of issue
- Response to Request(s) of contract conditions
- Information Request Template
- Next Steps

MMUA's Requested Review
Standardization of Annexation Process

1. Amount of compensation
   - Lost revenue calculation
2. Existing facility Price
3. Duration of payments
4. Expenses resulting from integration of facilities

5. Compensation
- Municipal owned and or developed territory compensation
- Rates for property and bare ground

6. How to handle interim service

7. Streamlined Settlement Processes

MN Statutory Requirements

216B.44 MUNICIPAL SERVICE TERRITORY EXTENSION.

After notice and hearing, the commission shall determine appropriate terms for an exchange, or in the event no appropriate properties can be exchanged, the commission shall fix and determine the appropriate value of the property within the annexed area, and the transfer shall be made as directed by the commission. In making that determination the commission shall consider the original cost of the property, less depreciation, loss of revenue to the utility formerly serving the area, expenses resulting from integration of facilities, and other appropriate factors.

Scope of Issue

- In the past 10 years, we have had:
  - 7 annexations. All have come to a mutually agreeable resolution.
  - 40 exception agreements, 4 have terminated.
- All of the agreements came to a mutually agreeable resolution and the volume is not high. This is not a significant issue for us.
- Responses to request(s) of contract conditions.
- Standardized information template would be useful for all parties.

1. Compensation Review

- Amount of Compensation (Lost Revenue)
- What do we take out of our gross revenues to get to our net lost revenues?
  - Illustrations are included in the presentation below.

Service Territory Sale Pricing Assumptions

March 2025

Slides (7-12)

Commission Accepted Net Revenue Loss Analysis - 5-Step Process

1. Calculate Gross Revenues the selling Utility will lose over a 10-year period.
2. Determine the costs the utility will no longer incur from not serving the customers.
3. Calculate net revenue loss for each year (Step 1 minus Step 2).
4. Calculate net present value of annual net revenue losses.
5. Territory sale must also include cost of impacted distribution facilities and any integration costs.

Assumptions

- Cost assumptions based on MN PUC order from Xcel's last Minnesota rate case (Docket No. E002/GR-21-630)
- Uses Class Cost of Service Study for Cost Analysis at Commission Ordered Cost and Revenue Levels
- All Costs are Functionalized
    - Fixed Production
    - Variable Production
    - Transmission
    - Etc.
- Costs Allocated to Customer Class using Commission Approved Allocation Methods

Avoided Costs vs. Costs Not Avoided

	Is Cost Avoided?	
Cost Function	**Yes**	**No**
Fixed Production: Capacity Related		X
Fixed Production: Energy Related		X
Variable Production Costs (Fuel etc.)	X	
Transmission	X	
Distribution Substations		X
Primary Distribution Lines	X	
Secondary Distribution Lines	X	
Customer-Related Costs	X	

PUC Ordered Revenue Requirement by Utility Function
Avoided vs. Costs Not Avoided

	Revenue Requirement ($000) by Customer Class and Utility Function				
Utility Function	**MN**	**Residential**	**Commercial Non-Demand**	**Commercial & Industrial Demand Billed *****	**Lighting**
Fixed Production: Energy Related	$379,238	$123,243	$11,068	**$243,755**	$1,172
Fixed Production: Capacity Related	$514,564	$203,145	$14,249	**$297,170**	$0
Fuel & Purchased Power	$1,692,348	$537,234	$49,816	**$1,099,312**	$5,986
Transmission	$398,439	$157,052	$11,011	**$230,376**	$0
Distribution Substations	$94,673	$39,078	$2,691	**$52,355**	$549
Primary Distribution Lines	$181,488	$92,424	$4,640	**$83,702**	$723
Secondary Distribution Lines & Transformers	$46,787	$25,089	$1,376	**$20,218**	$105
Metering, Meter Reading & Billing	$405,478	$335,540	$24,302	**$20,215**	$25,421
Total Revenue Requirement	$3,713,015	$1,512,806	$119,152	**$2,047,102**	$33,955
Total Avoided Costs	**$2,724,541**	**$1,147,340**	**$91,144**	**$1,453,822**	**$32,235**
Total Costs NOT Avoided	**$988,474**	**$365,467**	**$28,007**	**$593,280**	**$1,721**
% of Total Costs Avoided	**73.38%**	**75.84%**	**76.49%**	**71.02%**	**94.93%**

Customer Usage and Revenue Assumptions Required for Analysis

Data Requirements for Analysis:

- Has property been annexed by the city, if not, when?
- Timeline for development
- Date Electric Service will be required
- Size of Each Lot
- Number and Type of Customers
- Lot Zoning for Vacant Lots: Residential, Commercial, Industrial
  - Type of residential housing and types of businesses
- Customer usage assumptions
  - Customer Load
  - Load Factor
  - Business Operating Hours
  - Service Voltage
- Lost Revenues are Calculated for 10 Years after Electric Service Starts

2. Existing Facility Price

Xcel Energy

Spreadsheet is provided to City after valuation is complete

City of ??????- Annexation - Values of Existing Facilities

Notes: Utility distribution assets depreciated over 50 year life; Current Net Book Value + Removal Costs= Total Customer Cost

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Load (per kW by lot/building):	
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Rate of the Customer: Firm ☐ Interruptible ☐	
Service Voltage (secondary, primary, etc):	
Estimated Load Factor: (Load factor = Est. kWh use for Month/(Est Peak Demand kW x Hours in the Month)	
Business Operating Hours Days per Week: Hours per Weekday: Hours per Weekend:	
Name(s) (for Business): Repeat as needed.	Type of business or industry: (retail w/ or w/o refrigeration; type of commercial; if industrial, type of industry, etc.)

Name(s) (for Residential Development): Repeat as needed.	Type of dwelling: (single family, duplex, apartment, etc.) If multi-family, number of units:
Developer Contact Information: [Name] [Address] [Phone Number]	
Provide copy of plat.	
Provide timeline of the development:	
Development start date:	
Estimated date when power will be needed for permanent service:	

Next Steps

Xcel Energy®