



Transmission Planning and CapX2020

**Building trust to
build regional
transmission
systems**

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HUMPHREY SCHOOL
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Transmission Planning and CapX2020

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April 2016

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List of Acronyms

ALJ – Administrative Law Judge

BTU – British Thermal Unit

CapX2020 – Capacity Expansion by the year 2020

CCC – Certificate of Corridor Compatibility

CMA – Construction Management Agreement

CPA – Cooperative Power Association

CPCN – Certificate of Public Convenience and Necessity

CON – Certificate of Need

DNR – Department of Natural Resources

DOE – Department of Energy

EIS – Environmental Impact Statement

EPA – Environmental Protection Agency

ER – Environmental Review

EQC – Environmental Quality Board

FERC – Federal Energy Regulatory Commission

GRE – Great River Energy

IOU – Investor-owned utility

ISO – Independent System Operator

kV – kilovolt

MAPP - Mid-Continent Area Power Pool

MW – megawatt

MISO – Midcontinent Independent System Operator

MRES – Missouri River Energy Services

MTEP – MISO Transmission Expansion Planning

MVP – multi-value project

NERC – North American Electric Reliability Corporation

NIETC – National Interest Electric Transmission Corridors

OES – Office of Energy Security

OMA – Operations and Maintenance Agreement

OTP – Otter Tail Power Company

PM – Project Management

PMO – Project Management Office

PPA – Project participation Agreement

PSC – Public Service Commission

PUC – Public Utilities Commission

REA – Rural Electrification Administration

REC – Rural Electric Cooperative

RES – Renewable Energy Standard

ROW – Right of Way

RPU – Rochester Public Utility

RUS- Rural Utility Service

RTO – Regional Transmission Organization

SMMPA – Southern Minnesota Municipal Power Agency

TCEA – Transmission Capacity Exchange Agreement

TDU – Transmission Dependent Utility

UPA – United Power Association

USDA – United States Department of Agriculture

USFWS – United States Fish and Wildlife Services

WPPI Energy – Wisconsin Public Power Inc.

Executive Summary

This report tells the story of how CapX2020, a group of 11 utilities that serve load in several Upper Midwest states, worked together to plan, develop, and build \$2.1 billion worth of new high-voltage transmission lines spanning nearly 800 miles in Minnesota, Wisconsin, North Dakota, and South Dakota. These coordinated efforts were at the forefront of changing energy system planning in the United States, and have ushered in a new era of multi-state transmission planning and development that is re-shaping the electric power industry.

In 1999, the Federal Energy Regulatory Commission (FERC) issued Order 2000, which required utilities and states to create regional transmission plans. This was a departure from standard industry practice: previously, pairs of utilities had partnered to build single lines connecting them. However, collaborative regional planning requires more coordination and trust because it involves many more stakeholders. For instance, there was significant regulatory risk because state policymakers and utilities were figuring out how to navigate the changing rules and regulations. The CapX2020 partnership was the first instance of a large group of utilities working collaboratively to address the transmission needs of an entire region.

In the early 2000s, the electricity transmission infrastructure of the Upper Midwest needed to be upgraded. The aging grid was struggling with reliability issues and having difficulty supporting growing electricity demands. At the same time, new renewable energy generators, predominantly wind, were connecting to the grid to meet state-level Renewable Portfolio Standards (now known as Renewable Energy Standards). The last new high-voltage transmission in the Upper Midwest was built in the late 1970s, and some of those additions had been fraught with controversy.

The CapX2020 group (short for “Capacity Expansion Needed by 2020”) was formed in 2004 to build the necessary high-voltage transmission lines. CapX2020 achieved success by building a strong coalition of 11 utilities that had the resources to finance and manage large-scale projects, and the political influence to ally with a broad range of stakeholders to change laws and influence regulations. The relationships the CapX2020 group cultivated coevolved with their work, allowing each utility to: (1) understand the challenge they faced of working together to build high-voltage transmission, (2) work with each other to develop a process through technical studies and engagement with industry stakeholders, and (3) make decisions about which rules of conduct were the most significant through governance and project agreements. CapX2020 developed a shared vision and aligned around a common goal, created a win-win situation for all participants, fostered deep relationships, developed a system of group governance to operationalize their work, and engaged with stakeholders with openness and transparency. These aspects parallel Kania and Kramer’s Collective Impact Theory, which states the commitment of a group of important actors from different sectors to a common agenda enables them to work together to solve a specific social problem (Kania & Kramer, 2011).

Regional planning that took heroic efforts from the CapX2020 group has become easier as markets and regulations have matured. The group came together to collectively identify risks, mitigate them ahead of time, and develop a realistic approach to upgrading the high-voltage transmission system in the Upper Midwest. The CapX2020 project created an organization that

will continue to exist for decades to operate and maintain the transmission lines, and may collaborate in a similar capacity on projects in the future. It also created an example that other utilities can and should emulate as they cooperate on regional projects. To this end, CapX2020 accomplished several remarkable feats and simultaneously mundane activities that changed how transmission planning is done in the Midwest and United States:

- They performed technical studies necessary to show that new high-voltage transmission lines were needed.
- They changed laws and regulations in Minnesota in 2005 to enable the suite of projects to move forward.
- They engaged to an unparalleled degree with landowners, town, city, and county administrators, state utility Commissioners, legislatures, and regulators throughout the planning process to bring a new era of transparency and civic engagement to transmission planning, citing, and construction of new high-voltage transmission lines.
- They planned and managed projects with unprecedented levels of regulatory, logistic, and financial complexity.

The five sections of this report are organized as follows:

Section 1 describes the current transmission system in the United States and the Upper Midwest and outlines the decade-long process of building new high-voltage transmission lines. This section also reviews the contentious history of transmission development in Minnesota, especially the events of the late 1970s that have influenced how utilities and policy makers approached new development.

Section 2 outlines the work of the CapX2020 group between 2004 and 2007. It describes how the CapX2020 group was formed, determined its collective goals, performed coordinated technical studies, engaged with a wide variety of stakeholders, and changed Minnesota regulations that govern transmission planning to enable the projects to move forward.

Section 3 describes the roles that regulators, state agencies, and the public played in the development and approval of the new CapX2020 high-voltage transmission lines.

Section 4 examines how CapX2020 constructed the new lines. It examines both the internal organizational and project management structure of CapX2020, and discusses the challenges of coordinating the simultaneous construction of five distinct projects.

Section 5 explores the legacy of CapX2020 by examining what the new transmission lines mean for the future of energy system planning, how they support new regional energy generation and the critical role of public engagement for stakeholders and public buy-in for new high-voltage transmission lines.

To create this report, we reviewed over 100 documents including technical studies, government reports and laws, newspapers, and websites about the CapX2020 project and supplemented this archival research with 32 interviews with individuals who were directly involved in the CapX2020 project. Our discussions with utility employees, state and federal utility regulatory commissioners, industry representatives, lawyers, and landowners helped us better understand the social processes involved in creating and implementing CapX2020. We transcribed over 50 hours of participant interviews resulting in over 400 pages of documentation

(see Appendix B). The investigation of this report was developed collaboratively with electricity industry practitioners to fact check and to gain a deeper understanding of localized knowledge that influenced the CapX2020 initiative.

Energy industry professionals and policymakers will find this report valuable because it describes the evolution of processes for coordinated development, permitting, and construction of multiple new high-voltage transmission lines. Given the new federal and state policy and regulatory demands, understanding how change is happening in practice can strengthen the processes utilities, regulators and policymakers engage in to create the next-generation energy system. Policymakers and the general public will find this report valuable because it makes transparent the decisions and processes in building critical societal infrastructure like high-voltage transmission lines and discusses how the public can become engaged and involved.

1. How the Current Transmission System Works

Planning and building the U.S. high-voltage transmission system has been a challenge for decades. Increasingly coordinated electric system operation, development of new renewable generation far from traditional load centers, and changes in industry operation have led to increasing challenges in planning, building and allocating costs for this critical infrastructure.

This report examines a critical innovation in high-voltage system planning in the United States and documents an important policy success. We provide a detailed case study of CapX2020 and examine how this group of utilities in four states first came together and how their experience changed transmission planning in North America. Their planning process foundational for the coordinated transmission planning in the 15-state Midcontinent Independent System Operator (MISO) region. The careful work by the CapX2020 group provided an important new model for coordinated regional transmission planning in the United States.

In this section we provide background on the high-voltage transmission network in the United States and in the Upper Midwest. We lay out the historical challenges in building transmission lines and examine the regulatory processes and capital and operational considerations shaping the planning and construction of new lines.

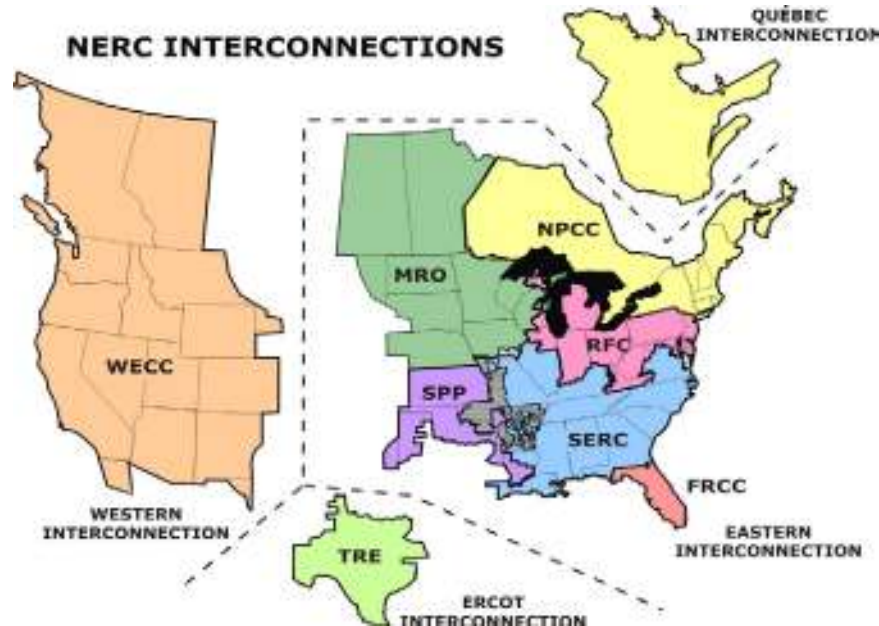
1.1 The United States High-Voltage Transmission Network

Transmission lines are the backbone of the electric grid infrastructure in the United States, and are the critical link between power plants that generate electricity and customers who need electric power for their homes, businesses, and lives. Electricity flows from power plants, through transformers and high-voltage transmission lines to substations, through lower-voltage distribution network lines, and then finally to the end-use customers. Electric power supply and demand must be balanced across the entire grid to maintain the reliability of the entire system. However, the flow of power within the grid is limited by the capacities and arrangements of individual transmission lines. The electric power system is operated to provide reliable service without exceeding the limits of individual components, and it is designed to maintain reliable service even during contingencies such as the failure of a transmission line or power plant. Grid planners and operators work to develop new transmission lines that enhance reliability and minimize cost and the risk of overloading sections of the system.

In the United States the transmission network is broken up into three synchronous grids, or interconnections: the Eastern Interconnection, the Western Interconnection, and the ERCOT interconnection (Figure 1). These Interconnections operate independently of each other, with minimal transfers of electricity between them. Interconnections are further sub-divided into Balancing Authorities, each of which was originally intended to be self-sufficient in electrical generation. In practice, many balancing areas import and export power to and from neighboring areas. Balancing Authorities were created to allow for regional coordination and planning to improve system reliability at a lower cost. The Balancing Authorities follow operational standards established by the North American Electric Reliability Corporation (NERC) with federal oversight provided by FERC. Before the creation of Balancing Authorities, individual

electric utilities planned and operated their generation, transmission and distribution networks independently within their exclusive service territories. The retail rates utilities charged to their customers were set by state regulators (Borenstein & Bushnell, 2015).

Figure 1: NERC interconnections



Source: nerc.org interconnections map (NERC, 2015)

In the late 1990s, the federal government and state governments passed laws deregulating (also called “restructuring”) the electric power system to allow entities other than utilities to generate and sell power. This was a major change in the way electricity was generated and sold. Between 1995 and 2002, 19 states restructured their electricity markets to allow for competition from non-utility generators. FERC issued two important orders in 1996 to foster competition. Order 888 required unbundling and the separation of markets, which made public utilities that own, control, or operate transmission facilities allow open access on their lines to other power producers on the same terms and rates that it gives its own generation (FERC, 1996b). This Order changed transmission system planning and ordered that it be conducted separately and in a nondiscriminatory manner. It also required transmission network planning and development to meet the needs of the regional market participants, rather than the needs of an individual utility or a particular type of generation. It addressed transmission open access and began to make the electric system more competitive. Order 889 established the rules and standards governing market information to encourage the creation of electricity system markets (FERC, 1996a). FERC issued Order 2000 in 1999, to allow the creation of non-compulsory Regional Transmission Organizations (RTOs) that would encourage transmission-owning utilities to coordinate system planning, operations, and the creation of electricity markets (FERC, 1999). Today, over 70 percent of U.S. electric power is planned, operated and sold in RTO markets.

In the Upper Midwest, MISO was created as a not-for-profit, member-based organization to operate the regional transmission network and wholesale energy market. The MISO footprint is larger than the 4-state Upper Midwest region that is the focus of this report: it currently includes 15 states and Canadian provinces and stretches from Manitoba, Canada to the Gulf of Mexico

(Figure 2). Most of the MISO states—with the exception of Illinois—remain traditionally regulated. Utilities participate in MISO to coordinate system planning, and ensure system reliability.

Figure 2: The MISO footprint



Source: MISO Corporate Fact Sheet (MISO, 2015)

The shift to wholesale electricity markets and the ability of new power producers to participate in electric markets had the unintentional consequence of exacerbating transmission system planning problems. Historical challenges of proving the reliability and cost effectiveness of new transmission builds were made even more difficult in multi-state markets where the clear beneficiaries of transmission line additions were difficult to evaluate.

In 2002, investment in transmission lagged behind investment in new power generation, and utilities were struggling to keep up with growth in demand. A Department of Energy (DOE) study in the same year found that transmission capacity was expected to increase by 6% nationally, in the same period electricity demand (in MW) was expected to increase by 20% (US Department of Energy, 2002). According to a 2005 FERC proposed rulemaking, the amount of power delivered to the system had doubled while transmission investment had declined, resulting in decreasing transmission capacity, increasing system congestion and potentially compromised system reliability (FERC, 2005). While transmission planning historically occurred at the state level, the Energy Policy Act of 2005 broadened the federal government's role: it expanded FERC's authority to supplement state-level siting efforts and encourage more transmission planning and authorized the DOE to establish "National Interest Electric Transmission Corridors"(NIETC) (FERC, 2006). While the Department of Energy worked hard in 2006 to identify Critical Congestion Areas across the nation and established national corridors in 2007,

court challenges essentially waylaid NIETC development and stalled the federal role in coordinated transmission planning (Klass & Wilson, 2012).

1.2 The Upper Midwest Transmission System

The transmission grid of the Upper Midwest has over 50,000 miles of lines that are part of the Eastern Interconnection, with each state having a slightly different grid design.¹ Parts of the Upper Midwest transmission system have become congested under normal power flow conditions, which impacts reliability of service and affects system costs. Additionally, many of the lines were built decades ago and need to be refurbished. The support structures are corroding and cracking and their foundations are deteriorating. Failure to address aging infrastructure in a timely manner has the potential to cause outages and disrupt reliable service.

In Minnesota, the high-voltage transmission system is comprised mostly of 230-kV and 345-kV lines (Minnesota Electric Transmission Planning). The state's system was designed to deliver power from large centralized coal, nuclear, and later natural gas generation plants to the major electric load centers in the Twin Cities, Duluth, Rochester, and St. Cloud, and link utilities and the rest of the grid within the state and region to ensure reliability.

In Wisconsin, the electricity generally flows from northwest to southeast. Western Wisconsin is connected by high-voltage lines of 161 and 345-kV, while southeastern Wisconsin predominantly uses 345-kV lines that connect into Illinois (Public Service Commission of Wisconsin, 2013).

In North and South Dakota vast, sparsely populated landscapes require long distance high-voltage power lines to export electricity to load centers in other states to the east and west. Both North and South Dakota have strong wind resources and North Dakota also has low-BTU lignite coal resources that it wants to continue to use. New high-voltage transmission lines are needed to support the Dakotas' ability to export electricity to neighboring states.

Until the CapX2020 projects, regional utilities in Minnesota and neighboring states had not cooperated on extensive regional transmission planning. This is not to say that the utilities did not have a history of working together. Historically on joint high-voltage transmission projects, one utility would discretely own part of the facility and a different utility would discretely own the other part. One utility would build one end, the other utility would build the other, and they would meet at the middle or at a substation. They had always jointly permitted projects, but the CapX2020 projects were the first where each utility owned a percentage of the whole line, with one construction manager leading the work. Furthermore, many utility employees and politicians remembered the socially and politically contentious Minnesota transmission expansion of the 1970s and were anxious to not repeat past mistakes, discussed further at the end of section one and in section 3 of this report. However, growing demand spurred utilities in Minnesota and surrounding states to build new transmission.

¹ Calculating the exact number of high-voltage transmission lines per state is difficult. Defining what qualifies as a "high-voltage" line differs from state to state, and even between utilities within a single state. For example, some utilities consider >161-kV high-voltage, while others classifying high-voltage lines as >230-kV. The 50,000 miles mentioned here is a conservative estimate, and refers to lines \geq 161-kV as high-voltage.

1.3 Building Transmission Lines

Planning, permitting, routing and building transmission lines are a time consuming and expensive process. While new wind, solar or natural gas generators can usually be sited and constructed in one to five years, the siting and construction of high-voltage transmission lines routinely take upwards of a decade. This section outlines this process.

1.3.1 Jurisdictional Authority and Investment in Electricity Markets

Both the states and the federal government exercise jurisdiction over transmission line planning and construction. Historically, vertically integrated utilities finance, own, and operate their own generation and transmission facilities, often partnering with neighboring utilities under bilateral agreements to supplement their generation capacity.² The transfer of electricity occurred within the territories of the partnered utilities, and only benefitted customers in those two utilities. With the creation of RTOs described in section 1.1, some transmission planning efforts became centralized and subject to federal jurisdiction, but approvals for each specific line still rest with state Public Utilities Commissions (PUCs).

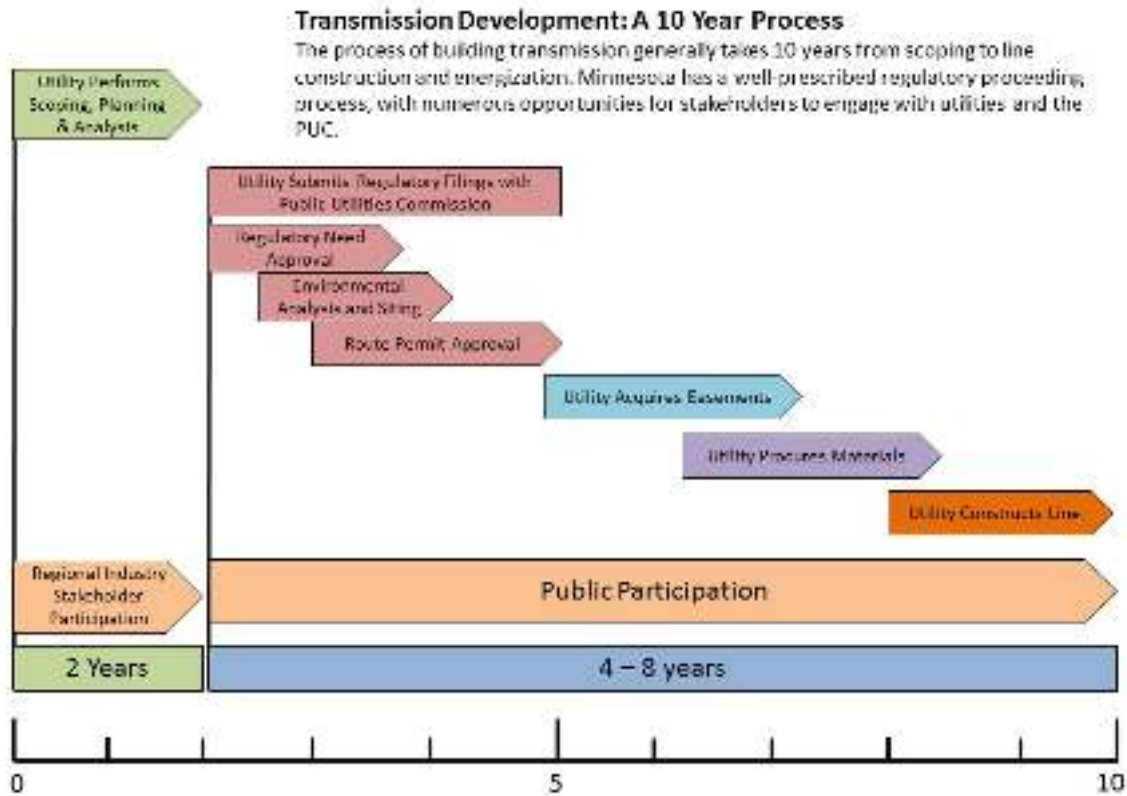
1.3.2 The Process of Building High-Voltage Transmission

Siting and construction of a transmission line can take 10 years. This process varies from state to state, but generally follows the same progression (Figure 3):

1. Scoping
2. Regulatory filings
3. Easements
4. Materials procurement
5. Construction and energization

² It is important to note that most of the Upper Midwest is traditionally regulated, with the exception of Illinois, which deregulated its market in the late 1990's.

Figure 3: The process of developing high-voltage transmission lines



The first phase of transmission development is project scoping, which includes the planning, and analysis performed by utilities, and can take up to two years. Transmission planners evaluate both their own system and the broader regional conditions. They estimate future loads and evaluate pending generation interconnections to create generation plans that identify system retrofits, enhancements and additions necessary to ensure safe and reliable system performance. Planners also identify annual maintenance activities to maintain and improve reliability. The resulting plans must meet NERC reliability standards.

Once a utility has a plan, the projects in traditionally regulated states must receive approvals from state PUCs to ensure cost recovery.³ When a utility wishes to build new high-voltage transmission facilities, the state PUC examines the utility's filing to establish the need for the project. The PUC also reviews the proposed routing of the transmission line. In most cases, the common applications require some variation of a Certificate of Need (CON) and Route Permit. A CON determines if the proposed transmission lines are necessary and serve a purpose, as well as determining the appropriate size, configuration, and timeframe needed to complete the project. A Route Permit specifies the path which a line will follow. Together with local and federal oversight, state Public Utility Commissions serve as the regulatory authority, a neutral party to determine if projects fit the needs of the state and the region. The issues a PUC can consider

³ The governing body that regulates the rates and services of a public utility is known as a Public Utilities Commission (PUC) or Public Service Commission (PSC). In the case of CapX2020 projects, Minnesota and South Dakota are regulated by their state's PUC, while North Dakota and Wisconsin are regulated by their state's PSC.

when evaluating the need of a line are often statutorily determined and have historically focused on issues surrounding system reliability and ensuring low system costs. Approving transmission lines to help utilities to meet state policy goals like renewable portfolio standards are more recent. Flowcharts showing the Certificate of Need and Route Permitting processes in Minnesota can be found in Appendix F. The process of receiving regulatory approval can take up to three years from the time the first CON application is submitted to final route approval from the PUC.

Once a route permit application is approved, utilities may begin negotiating with landowners to acquire easements for construction. In order to construct, operate, and maintain a transmission line, the utility acquires the land as an easement within a set distance of the project centerline. For example a 345-kV line typically requires an easement 150 feet wide. The strip of land the transmission line is on is referred to as the Right-of-Way (ROW); an easement is the right to use property that the utility does not own.

The easement procurement stage can often last several years for large projects. Acquiring the necessary rights can be very time consuming. If a landowner and the utility cannot agree on the easement or payment, the utility will pursue a process called condemnation, in which a judge and panel of impartial individuals decide whether the easement is needed, and its value. In Minnesota, a landowner may request that the utility purchase the entire property, using a 1970s provision of eminent domain law entitled “Buy the Farm” (mn"Eminent Domain Powers; Power of Condemnation," 1977).

The materials procurement and construction of a line often overlaps with the easement stage. It can take up to a year to obtain materials necessary to construct new transmission lines, such as concrete, pole structures, and conductors. To acquire materials for the CapX2020 projects, the construction management project team issues a request for proposals, and contractors place bids. Some firms supplying materials for transmission projects were relatively small and other larger firms were already running near capacity, with many struggling to supply the quantities of materials on the schedule that the CapX2020 projects required. The CapX2020 utilities faced a similar difficulty with labor: they struggled to find enough experienced labor, from design engineers to lineworkers because no large transmission projects had been built in the Upper Midwest in 30 years, and the market was tight nationwide with construction workers moving between projects and geographic areas.

At the same time the materials are being procured, construction crews prepare for work by identifying staging areas along the transmission route. Many utilities use regional and local construction companies to secure materials and labor, as it is more cost-efficient than contracting with larger national companies and is seen as supporting local economies. For example, local suppliers provide concrete, as concrete must be used within 2 hours of being mixed. Once materials suppliers along project routes are identified, and local drivers are contracted to deliver concrete to each pole location for foundation work, construction of the power line begins.

Depending on the route, scope and size of the line, construction can take up to two years or more to complete. Once a newly constructed line is connected to the transmission grid it is tested for safety and reliability before it is energized as part of the high-voltage electric system.

A detailed description of the decade-long process, including a review of the permitting process for the four states encompassing the CapX2020 projects, is given in Appendix E.

1.3.3 Capital and Operational Costs of Transmission

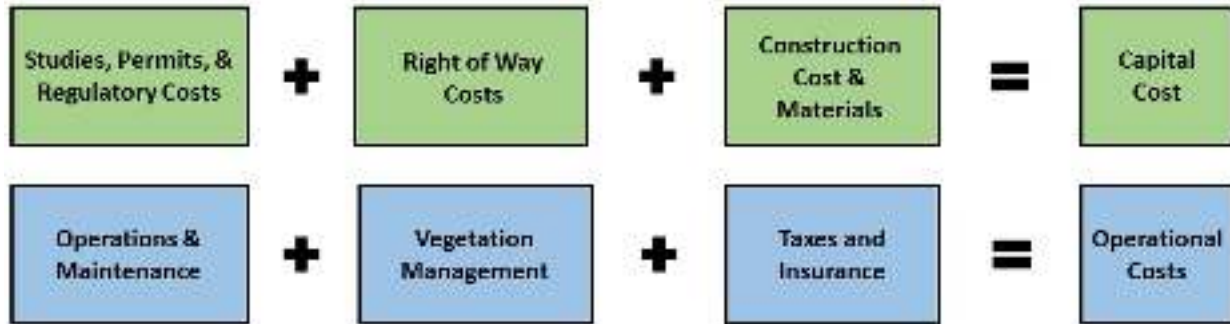
Transmission lines are expensive to build but inexpensive to operate. Depending on the size, location, and design of the line, transmission capital costs can range from \$150,000 to more than \$2 million per mile (Brown & Sedano, 2004).⁴ Capital costs are found in the regulatory and permitting steps, right-of-way land acquisitions, materials, substations, and construction costs, as shown in Figure 4. The largest portion of the capital cost is typically from materials, substation, and construction costs. Transmission line design specifics such as the structure types and right-of-way width also impact capital costs.

The route that the transmission line follows also influences its costs. The geography of the land creates unique challenges for each project that can impact costs. The Upper Midwest is a relatively inexpensive region for building transmission because it is generally flat and not densely populated. Construction in urban areas is more expensive than rural areas because more landowners in densely populated areas mean that more right-of-way easements must be acquired. Crossing rivers, sensitive environmental areas, or difficult terrain also increases the costs. For example, the CapX2020 Hampton-Rochester-La Crosse line crosses the Mississippi River and is subject to more environmental controls and higher construction costs (see Section 4.3.4 and Appendix J for more detail). The cost of regulatory oversight also varies between states and regions. Some utility personnel interviewed for this report believed that Minnesota has one of the most stringent regulatory environments in the United States. It is not uncommon to make adjustments to the details of the project to meet environmental requirements, community needs, or landowner demands.

Operational costs for transmission lines are generally low and equal only about three percent annually of a line's capital cost. These costs include general maintenance, vegetation management, taxes, and insurance costs (Silverstein, 2011). These costs cover foreseen and unforeseen events, such as component failures and weather events. For example, pole structures are sensitive to climate and are susceptible to corrosion and deterioration. Long-term vegetation management along the line right-of-way prevents disruptions in service from tree-induced line failures. The highest operational costs come in the form of taxes paid by the utility to cities and counties, the details of which vary from state to state. In Stearns County, Minnesota, the completed CapX2020 Fargo-St. Cloud-Monticello project helps make Xcel Energy the counties top property tax payer. In 2015, the utility will pay a total of \$4.16 million on 138 parcels in Stearns County alone (Stearns & County, 2015).

⁴ This range reflects projected capital costs of new transmission lines in the early 2000s. More current estimates put capital costs near \$2.5 million per mile. Both estimates do not include any costs associated with substations.

Figure 4: Capital and operational costs of high-voltage transmission



Source: Adapted from Silverstein, 2011.

1.4 The History of the High-Voltage Transmission System in Minnesota

Before the group of CapX2020 projects, the last major build-out of transmission projects in the Upper Midwest occurred in the middle and late 1970s. There were a number of lines built at the time, but the most controversial project came about when two rural electric cooperatives, Cooperative Power Association (CPA) and United Power Association (UPA) partnered to build 430 miles of transmission lines to connect a new electric generation station at the coal mine in Underwood, North Dakota to the Twin Cities suburbs. Many rural Minnesotans opposed the high-voltage transmission line that crossed farmland from central North Dakota to the Twin Cities. Landowners were convinced the line would negatively affect their land and its value, and that it would only benefit residents of larger cities. Rural residents also opposed the line because they felt decisions were made to favor corporate farm and corporate utility interests but did not consider their needs ("Minnesota Powerline Oral History Project," 1977-1979). The farmer-led revolt escalated to acts of civil disobedience, peaking in 1978 when a resistance group known as the "bolt-weevils" attempted to sabotage the project by using tractors, manure spreaders, and ammonia sprayers to disrupt operations and tore down 14 transmission towers, some of which were toppled after the line was energized. The vandalism mostly came to an end when ownership of the line was temporarily ceded to the Rural Electrification Administration (REA), a federal agency, which invoked involvement of the Federal Bureau of Investigation. Between 1976 and 1978, 120 people were arrested in connection with the protests, four people were convicted of criminal counts, and one person was convicted of felony charges (Casper & Wellstone, 1981). Despite the public push-back, the project was completed, and the dispute between rural landowners and the utilities involved became known as the "CU Project Controversy".⁵ Paul Wellstone, former Minnesotan Senator and political activist, wrote a book in 1981 with Barry Casper called *Powerline: The first battle of America's Energy War*, which described the farmer-led revolt.

⁵ "CU" is a combination of the two line owners' names: Cooperative Power Association and United Power Association.

In 1977, the Minnesota legislature responded to the CU Project Controversy with an update to eminent domain law called the Buy the Farm ("Eminent Domain Powers; Power of Condemnation," 1977). One of the authors of the law, Gene Merriam, recalled that, "It was the most contentious atmosphere in rural Minnesota that I'd ever witnessed. [...] The perception was that the legislature had to deal with it" (Teigen, 2014). The updated law required utilities to propose at least two possible routes for new transmission lines with voltages of 230-kV or higher, and increased public involvement in the siting process. The law also allowed property owners affected by a high-voltage line to force a utility company to buy an entire property, not just the land needed for the easements ("Eminent Domain Powers; Power of Condemnation," 1977). The provision, known as 'Buy the Farm,' was an attempt to balance the power of landowners and utilities. Critics felt the vaguely worded provision lacked detail about how the process was supposed to work and believed the law did not go far enough to protect landowners. The law remained unused and untested for almost 35 years, as utilities focused on developing lower voltage projects. Minnesota's eminent domain law was amended in 2006, during the planning stage of CapX2020, to increase condemnation payments to landowners by requiring utilities to compensate owners for appraisals, loss of an ongoing business, relocation costs, and attorney's fees ("Eminent Domain Powers; Power of Condemnation," 2006).

The tumultuous events from the 1970s resonate strongly in the current Minnesota energy debates. When the CapX2020 group began communicating with residents on affected routes, many rural landowners and the utilities who remembered those events were apprehensive that the new lines would bring the same contentious issues to the forefront. CapX2020 took the historical event into consideration as they began to move forward, with many members of the group reading Wellstone and Casper's book *Powerline*. Priti Patel, former Co-Director of the CapX2020 group, but who has since moved on to a position as Regional Executive of the North Region with MISO recalls,

"Many of us were wired to think, 'How do we make sure this goes well?' Reading that book helped us understand where the problems were, and where we could make sure that we created a strategy and an education and communication policy that could make this go better. It was a mentality." (Patel, 2015)

2. CapX2020

2.1 The Creation of the CapX2020 Group

2.1.1 Genesis

In the summer of 2004, Will Kaul, Vice President of Transmission for Great River Energy (GRE), began conversations to address transmission infrastructure needs with his counterparts at the largest Minnesota transmission-owning utilities. GRE, Minnesota Power, Otter Tail Power Company, and Xcel Energy began discussions that summer, with Missouri River Energy Services (MRES) subsequently joining the group. Ray Wahle of MRES recalls the phone call he received that started it all:

“I received a phone call from two gentlemen – Rod Scheel from Otter Tail Power and Tom Ferguson of MN Power. They called me and stated that they were thinking about transmission expansion in the region. They described the overall concept, which was nowhere near what it would become. Obviously there were no projects defined. They said, ‘We need to do something. We don’t know what it is. We’re starting this, would you like to participate?’ And of course, I looked at that as an opportunity—you never want to say no right off the bat. You at least want to find out more about it. So I said, ‘Sure, we’ll participate.’ From that point forward, the project just started going, and things just snowballed from there. So that’s how MRES got involved in CapX initially. A simple phone call with an invite to a meeting.” (Wahle, 2016)

The utilities joined together to create CapX2020, aiming to build new high-voltage transmission lines needed to meet the current and evolving electricity needs of Minnesota and the region.⁶ The original people involved in the discussions dubbed themselves the Vision Team, and sensed that the opportunity was ripe for a broad stakeholder coalition to support transmission investment. Each utility was concerned about the inadequacy of the transmission system to maintain reliability and support the development of renewable energy. The initial Vision Team was comprised of six members from the original five participating utilities (Table 1):

Table 1: Original CapX2020 Vision Team

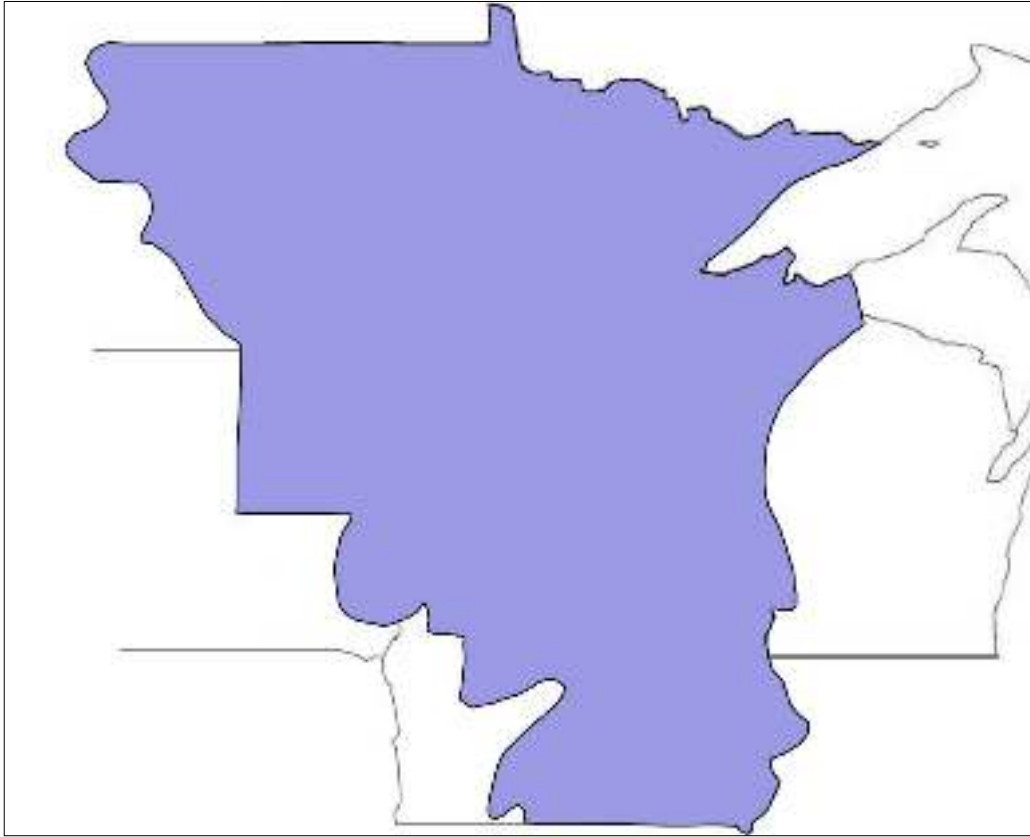
<u>Original Vision Team</u>
Will Kaul, Vice President, Transmission, Great River Energy
Tom Ferguson, Vice President, Power Delivery and Transmission, Minnesota Power
Raymond J. Wahle, Director, Power Supply & Operations, Missouri River Energy Services
Rod Scheel, Vice President, Asset Management, Otter Tail Power Company
Doug Jaeger, Vice President, Transmission, Safety & Technical Training, Xcel Energy
Don Jones, Director, Transmission Asset Management, Xcel Energy

Source: CapX2020 Interim Report, 2004

In these early stages, other investor-owned utilities (IOUs), cooperatives, and municipal utilities were watching the new group’s initiative with interest, but had not yet joined as participants. The Vision Team decided that the Initiative’s study region would encompass the service territories of electric utilities that have load-serving responsibilities for Minnesota consumers, shown in Figure 6 below.

⁶ Although CapX2020 projects and members span four states in the Upper Midwest, 90% of the project line length is in Minnesota.

Figure 5: CapX2020 study region



Source: CapX2020 Interim Report, 2004

One of the first entities to join the project was Otter Tail Power, which has a service territory that extends from central North Dakota, down through western South Dakota, and extends east to Bemidji, Minnesota. A prior technical study identified challenges maintaining reliability and managing load in the area, which encompasses the Red River Valley in Minnesota.

Southern Minnesota Municipal Power Agency (SMMPA), a municipal joint-action agency and eventual CapX2020 participant, has member utilities located throughout the state, mostly in south central Minnesota. As the CapX2020 discussions were beginning, they were getting most of their wind power from a 100 MW wind farm near Dexter, Minnesota. Dave Geschwind, Executive Director and CEO of SMMPA recalled the system challenges they were facing:

“When that wind farm was first developed, it was in a transmission constrained area, so the market prices, in many cases, would go negative because you couldn’t get the wind out. There would be times when the output would have to be curtailed because there was too much.” (Geschwind, 2016)

He went on to note that the addition of greater transmission assets in the state and region would increase the ability for utilities to meet the renewable resource obligations because there would be less constraint on the system.

Moving further east, Dairyland Power is a rural electric cooperative that serves the farmlands and hinterlands of western Wisconsin, southeastern Minnesota, northeastern Iowa, and one small area in Illinois. Approximately 80 percent of Dairyland’s generation mix is from coal, which

they have been working to diversify. One of the biggest barriers they had been facing was transmission congestion, as the Mississippi River was a major congestion point between the wind rich areas to the west (the Dakotas, Minnesota, and Iowa) and the load centers to the east. Ben Porath, Vice President of Power Delivery for Dairyland has been with the company since 2003, and explained,

“Our small system happens to sit basically up and down the Mississippi river, and transmission congestion has been a huge problem for us. We buy most of the energy that our consumers use, so when there’s congestion created at the Mississippi river, we’re paying a higher price to serve our customers over here in Wisconsin. Projects like CapX [would] help reduce the congestion impact, and we could buy energy on a more economic basis.” (Porath, 2016)

WPPI Energy, a municipal joint-action agency serving members in Wisconsin, Michigan, and Iowa, was experiencing the same challenges. Projects like CapX2020 would help reduce the congestion impact and would enable more renewable energy development, allowing utilities to diversify their generation portfolios.

The Vision Team saw the benefits of working with neighboring utilities because each was experiencing similar challenges in ensuring reliable service in their areas. Their service areas overlapped, resulting in common challenges. They also recognized that transmission projects needed to address those challenges were bigger than any one utility could handle on its own. If they were going to solve the problem, they would have to work together. Teresa Mogensen, Senior Vice President of Transmission at Xcel Energy, explained why it made sense to work together:

“It was important to deal with it as a group because it was an area-focus, a regional focus. Not any single utility by itself. We found the needs that were emerging and that were in front of us, and we saw that worsening as we modeled the future. We had needs for supporting the energy policy direction of our set of states, and were working to figure out how to incorporate renewable energy into the mix. We had local area reliability needs, we had community support needs...a fully array of needs, and our philosophy was to find the most efficient mix of projects to meet the full array of needs in front of us. Part of that willingness means, ‘I win and I let you win too.’ Xcel Energy could say, ‘Well, I could do it all myself, I’ve got enough money.’ If we wanted to do that, to say we’re the big dog...well, maybe we could, but it doesn’t really make sense to do that. We asked ourselves, does it help the cause long term? Does it allow for us to meet our collective goals? Does it just bring about a bunch of future fights? If you look at these things with a logical business perspective, in my mind, it makes logical business sense to work together.” (Mogensen, 2016)

Furthermore, each utility understood the difficulties of building new high-voltage transmission lines. Jim Hoecker, former Chairman of FERC stated,

“If you want to build a transmission line, it’s extremely difficult. Particularly if you are going across multiple service territories, across state lines, or across a region or between regions. Then you’ve got some real issues. You’re dealing with multiplicity of regulators with different criteria, different regulatory cultures, different legal mandates, and it can get messy.” (Hoecker, 2015)

Partnering together would alleviate some of the pressures that are inherent in the permitting and approval processes in multiple states.

2.1.2 Uncertainties

Despite the emerging consensus about the need to address transmission infrastructure issues and a recognition of common challenges, utility investors still had many concerns, and the IOUs were reticent about making transmission investments. The Vision Team recognized they had a number of audiences they had to sell the project to, including their own companies. Within the group, questions of uncertainty and risk were circulating:

- What would the energy markets that MISO was setting up look like?⁷
- When someone interconnects to a system, how would they be charged, and how do they gain access?
- What would state renewable energy standards be, and what would be needed to meet them?
- How would the projects be permitted in Minnesota?
- How would the group allocate the costs of the projects?
- How would the utilities recover their costs of investment?

To address the uncertainties, the group recognized they needed to: (1) understand the evolving energy markets (2) advocate for regulatory reform (3) determine internal governance of the project and (4) establish management structures.

First and foremost, regulatory reforms were needed that would make it possible for the projects to be successful and for the IOUs to consider high-voltage transmission a good investment. For a traditional vertically-integrated IOU like Xcel Energy, transmission accounts for about seven percent of their overall revenue, and they were initially apprehensive about entering in a rate case for such a small percentage of their assets.⁸ More importantly, there was a long lag time between when an IOU would spend money on transmission project construction and when they would recover costs through electricity rates. With high-voltage transmission projects like those of CapX2020, there might be a five-year period where utilities are investing resources during planning and construction and when they would submit a rate case to start recovering costs. This lag was cited by utility interviewees as one of the main reasons why utilities were not investing in transmission.

Municipally-owned utilities and rural energy cooperatives do not have rate cases and are not affected by formula rates, but they wanted to make sure that the IOUs were motivated to participate in the project, as a large portion of the investment would come from them. Therefore, to all involved, regulatory reform was the most important policy matter that needed to be addressed for the vision of CapX2020 to move forward.

⁷ See section 1.1 and Appendix D for more details about the evolution of energy markets in the United States.

⁸ Rates and ratemaking is the formal regulatory process by which public utilities set the prices they will charge consumers. Ratemaking is typically carried out through rate cases before a PUC, and serves as one of the primary instruments of government regulation of public utilities.

Tony Clark, Commissioner on the Federal Energy Regulatory Commission (FERC) explained that there was a confluence of events in the early 2000s that encouraged investment in transmission:

“FERC has an awful lot to do with regard to cost recovery and the returns on equity that transmission lines are allowed to recover, and terms and conditions under which generators connect with the lines. FERC had been working to try and find ways to encourage transmission development where it’s needed and where it’s a low cost solution for all customers. Coming out of the Energy Policy Act of 2005, Congress had a quite clear statement of intent that it wanted the Commission to look at ways it could encourage transmission development across the country, understanding that there had been a historical lack of adequate transmission lines. A lot of it relates to the fact that the electricity industry came up as a very regional industry. So you had basically siloed off utilities that were serving just a particular region, but weren’t terribly interconnected with their peers. That worked well enough for many decades, but when you started looking at things like renewables, like other geographically distant forms of power that could be brought in, that were the low-cost way to meet consumer needs, but weren’t facilitated because of the balkanization of the grid.” (Clark, 2015)

2.1.3 Moving Forward in 2004

The Vision Team knew the transmission infrastructure in the Upper Midwest needed to be upgraded regardless of the uncertainties facing the electric industry. CapX2020 members recognized that they had to deliver reliable service to their customers and keep energy costs low and reasonable. Terry Grove, Co-Executive Director of CapX2020 and Director of Regional Transmission Development at Great River Energy recalled,

“We all serve load. These aren’t hedge funds or something – we aren’t here just to make money. We all have operated in these areas almost since the inception of centrally distributed electricity, so we have a bond. We can’t just leave, and we aren’t selling out. In GRE’s case, we’re governed by people from those areas. We can’t make a mess more than we need to with stakeholders. We say we live there, but the people who govern us actually live in the areas where the lines are, and are very protective of those areas.” (Grove, 2015)

After much discussion, the group started with the premise that it was necessary to move forward with project planning and not become bogged down with how their vision would be implemented. They knew the only way they could do that was to come together, become comfortable with uncertainties and move ahead with the understanding that specific details about ownership, cost allocation, and the permitting process would be worked out as the projects progressed. This was a bold move. No coordinated project of this scale had ever been attempted in the country and there was no certainty that this group could succeed. To move forward, the Vision Team defined their mission for the upcoming years (CapX 2020, 2004):

1. Create a joint vision of required transmission infrastructure investments needed to meet growing demand for electricity in Minnesota and the region.
2. Work to create a regulatory environment that allows these projects to be developed in a timely, efficient manner, consistent with the public interest.

The group took incremental steps in the first few months. They recognized that everyone had their own goals and objectives, but they all understood that if they worked together with an industry-wide perspective to address the broader system needs, they could come up with a plan they could all support. Ray Wahle elaborated on how the group moved forward in the early stages of development in the CapX2020 initiative:

“It reminds me of the old Chinese proverb: If you’re going to take a thousand-mile trip, you should start by sitting down and putting on your shoes. So really, that’s what we did. We sat down, we put on our shoes, and then we started walking. And as we started walking, we built momentum.” (Wahle, 2016)

Tim Rogelstad added,

“It began as an innocuous meeting to discuss opportunities. I don’t think anybody that day realized where it would ultimately lead us.” (Rogelstad, 2016)

To fulfill their mission, the newly formed CapX2020 group embarked on a series of technical studies to quantify and bound their needs, and began discussions with stakeholders, legislators, and regulators to enact the reforms needed to support the transmission projects.

2.2 2004 CapX2020 Interim Report

2.2.1 Meeting Mission Goal 1: Creating a Joint Vision through Technical Studies

In December of 2004, six months after the group formed, the Vision Team released an Interim Report presenting the group’s work to date, which described their planning efforts and introduced the CapX2020 technical studies underway (CapX 2020, 2004). The Interim Report laid out the CapX2020 planning scope, and described a plan for two technical studies to be completed within the following year: the Vision Study and the Red River Valley Study. The group acknowledged that the technical study work was a necessary component of showing the value of the projects because a more visionary approach was required, necessitating a broader look at the entire region as opposed to individual local areas of the system. The purpose of the Interim Report was to demonstrate the significant need for new transmission investment to their customers, policymakers, and regulators. It also served to inform other industry stakeholders of their study efforts, and to begin the public dialogue about transmission issues in the region. Planners from the participating utilities came together to understand what had been studied in the past to inform how they would move forward. The group built on ongoing sub-regional studies conducted by participating utilities like Xcel Energy for the Red River Valley and the Rochester, MN-La Crosse, WI area. Additionally, discussions with wind developers and resource planners shed light on the need for transmission to meet renewable energy standards.

The 2004 Interim Report introduced the Vision Study, a larger technical study already underway that was funded and conducted by the CapX2020 group to address their first goal. The Vision Study included in-depth engineering analysis, the objective of which was to outline necessary infrastructure improvements to meet future system needs under a variety of possible scenarios, regardless of the location of new generation facilities. Gordon Pietsch, Director of Transmission Planning and Operations for Great River Energy explained,

“We developed a study process that focused on looking at those various solutions and figuring out if they worked together - could they work together, both short-term and long-term – under various scenarios of load growth and generation dispatch patterns.” (Pietsch, 2015)

The group believed this study would identify the next major investments needed to strengthen the transmission backbone of the region and ensure the system was capable of providing reliable energy while accommodating future growth.

A separate study – the Red River Valley Study – initiated by Xcel Energy in 2000 before CapX2020 formed, was to be expanded to include components of the Vision Study’s findings within the context of the Red River Valley. It examined near-term transmission needs to address reliability issues in west-central Minnesota (Excel Engineering, 2006). Tim Rogelstad explained how updating the study would support the group’s work going forward:

“One of the first things we did as a group was refresh the Red River Valley Study. We wanted a study that would help support our business decision to move forward and our perspective as we move into siting and certificate of need types of applications.” (Rogelstad, 2016)

The study built upon analysis that highlighted the most vulnerable areas within the study region that were facing reliability issues. The study predicted that by 2007, low voltages and potentially voltage collapse could occur during winter peak conditions. Terry Grove of GRE noted,

“In some areas there was just a deficiency of transmission that for reasons that just grew up with the system. There was no tie from northwest Minnesota to northeast Minnesota, which became the Bemidji project. If you look at a map, people might ask why we didn’t build in certain areas, and the answer was that they could get by without it. But some places like Bemidji have grown huge amounts. There were gaps that couldn’t be plugged with Band-Aids.” (Grove, 2015)

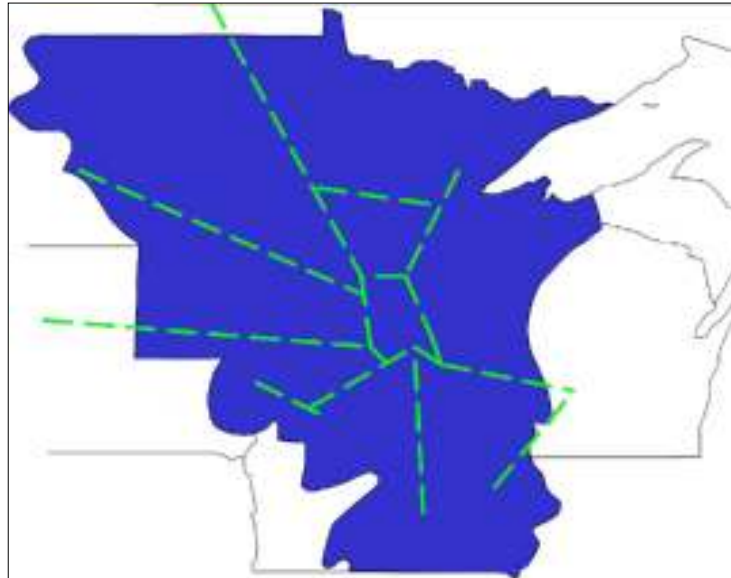
The CapX2020 group had the foresight to support continued work on the Red River Valley study, knowing that once completed it would provide a better understanding of the needs in the area as well as support a Certificate of Need application for projects in the study area in the future.⁹

The preliminary results of the Vision Study discussed in the Interim Report showed that the transmission system as it was in 2004 would not support the forecasted need for new generation facilities to meet projected customer demand. Even under the most optimistic scenarios with all major transmission lines and equipment in service, significant line and equipment overloads would occur by 2020. The study found that if a line or facility needed to be removed from service because of storm damage or routine maintenance, more overloads would occur. The transmission improvements the group would propose focused on high-voltage solutions of 345-kV or higher that best addressed the numerous load growth and generation scenarios explored in their technical studies. When placed over a map of the Upper Midwest, the scenarios looked like

⁹ The Red River Valley Study served as a technical reference used to inform the Certificate of Need application for the CapX2020 Bemidji to Grand Rapids 230-kV project.

a “broken window”, and served as a tangible visual the group would use to introduce their vision to stakeholders (Figure 6).

Figure 6: CapX2020 “broken window” conceptual transmission map



Source: CapX2020 Interim Report, 2004

2.2.2 Meeting Mission Goal 2: Organizing a Coalition

At the same time the technical studies were underway, the group worked towards accomplishing their second goal of creating an environment that allowed projects to be developed in a timely and efficient manner by reviewing state processes. To do this, the group reached out to renewable energy developers and advocates, regulators at the Minnesota Public Utilities Commission, and Minnesota legislators. From very early on, the group was committed to open dialog with stakeholders to accomplish significant regulatory reforms necessary to support transmission infrastructure expansion. Michael Noble, CEO of Fresh Energy, a leading organization in Minnesota on clean energy issues, recalls,

“We were already allied on the idea that we needed transmission. He [Will Kaul] saw it from the point of view of the electric companies, and I saw it from the point of view of the public interest in wind energy. We both had the same basic view that we needed infrastructure to support wind. We’ve had plenty of things we disagreed about, but you might as well agree on the things you do, and try to see if you can’t get those things done.” (Noble, 2015)

Armed with their preliminary study findings and the “broken window” conceptual map, the group identified regulatory changes that would enable the investments they felt were necessary for the region. They started by reviewing approaches to certification of need and cost recovery, while also evaluating industry structure, routing, and jurisdictional issues identified during the group’s preliminary meetings. They benefited from the support of renewable energy advocates, particularly from the wind industry. Beth Soholt, Executive Director of Wind on the Wires recalled,

“When we started working on transmission for wind energy almost 15 years ago, transmission was truly the glass ceiling for wind development. There was simply not enough transmission capacity to deliver the thousands of megawatts of new wind power that was envisioned for the Midwest. Not enough farm-to-market road to deliver the clean energy crop.” (Soholt, 2015)

Mike Gregerson from the Great Plains Institute added,

“Great Plains Institute’s goal is to advance clean energy in the Midwest. Whether that is solar, or wind, or biofuels, energy efficiency is a part of that. A large piece of that in the Upper Midwest, because of our footprint and the way the load centers are laid out, is that we need a lot of transmission to make that work.” (Gregerson, 2015)

The group took their initial findings and stakeholder support to the Minnesota PUC and state policymakers, and began to introduce their vision for transmission expansion in Minnesota and the region. Because of those meetings, the PUC was engaged from the very beginning in the planning process. The staff knew how the CapX2020 group’s planning process worked, and how the projects came to be. Tim Rogelstad of Otter Tail Power explained,

“I think it was critical to collaborative transparency that we engaged with regulators as we were conducting the study, rather than conducting the study and then sending it to them. I think it gets back to early engagement in the planning process. They knew our rationale and could make a judgment as to the benefit that they would have.” (Rogelstad, 2016)

The “broken window” vision that CapX2020 envisioned in their scenario planning process showing that new transmission was urgently needed to maintain reliability resonated with the Minnesota PUC, and the CapX2020 group was encouraged by state officials to continue their work.

2.3 2005 CapX2020 Vision Study

The CapX2020 Vision Study Technical Update, completed in May of 2005 by an eight-member technical team from the CapX2020 group, met the first part of CapX2020’s mission of creating a joint vision of required transmission infrastructure investments needed to meet growing demand for electricity in Minnesota and the region (CapX 2020, 2005).

The group used a scenario planning process to help deal with the uncertainties of alternate futures. They studied high growth and low growth scenarios, as well as alternative locations for new generation.¹⁰ Their objective was to determine a plan that would be robust under most, if not all futures— a “no-regrets” approach. Gordon Pietsch member of the technical team on the Vision Study recalls the group’s approach:

¹⁰ The study process of identifying pockets of generation that could expand to meet anticipated future load growth known as scenario planning was developed by the CapX2020 technical team. The method was later adopted by MISO as it worked to address regional planning as mandated by FERC Order 2000.

“Back then, MISO was still developing their planning processes. We had experience in the planning process, being former members of the MAPP [Mid-Continent Area Power Pool] organization in doing regional transmission planning, so we took it upon ourselves to develop what we thought was a short-term plan and a vision for transmission expansion within what we deemed the CapX footprint. We brought the planners together to understand what had been studied in the past...We took those needs into consideration and tried to figure out if all of those plans worked together. MISO staff was just starting to gain some experience in regional transmission planning. Many came from local utilities or graduated from school recently, so they brought a lot of expertise, but not a lot of history of how the transmission system had evolved. While they were doing that, and they were trying to solve the problems as best they could, we saw an opportunity to step in and help.” (Pietsch, 2015)

Their approach was to not just plan for their own small regions, but rather look at the larger region to see what would fit into a bigger mix.

The technical team also incorporated data and feedback from wind developers and organizations like Wind on the Wires, which works on wind power, state-level wind energy policy, and transmission issues in the Midwest. Beth Soholt, recalled the process of sharing information:

“One of the first things we did was look at a regional plan for wind build out. We worked early on to find the best wind zones, to aggregate information from wind developers, to work in the MISO process to feed good information in—to give them something constructive to work with.”

Sharing this information with utility transmission planners was critical to incorporating wind into the system.

“Wind was new in the early 2000s, and the utilities didn’t have experience operating wind on their system. We worked on things that they as a utility needed from a reliability standpoint, but we integrated the public policy piece, and I think that is one of the key things that sets Wind on the Wires apart. We not only challenged them, but we brought information to the table.” (Soholt, 2015)

The study began by considering two potential scenarios for growth in electricity demand: one with high growth and one with low growth. Based on these load projections, the technical team developed three generation scenarios, each including a build out of 2,400 MW of wind energy. The purpose of using multiple generation scenarios was to determine what transmission lines could connect to the various generation projects and still be useful under all three scenarios. Generation scenarios included a North/West bias, a Minnesota bias, and an Eastern bias, described in Table 1. Tim Rogelstad elaborated about how the group approached scenario modeling:

“A great accomplishment of the CapX group was this idea of looking at scenarios. Any study relies on assumptions. We came up with a set of scenarios based on different assumptions, and from that we defined where all the studies intersected, and those were the projects on which we focused.” (Rogelstad, 2016)

Table 2: CapX2020 scenario planning

CapX2020 Scenario Planning		
Scenario	Focus	Description
Growth in Electricity Demand	Base	Anticipated a load growth of 2.49% annually from 2009-2020, for an increase of 6,300 MW ¹¹
	Slow/Sensitivity	Slower load growth of about two-thirds of the projected growth in electricity demand, for an increase of about 4,500 MW
Generation	North/West bias	New generation modeled more heavily based on importing generation into Minnesota from Manitoba, North Dakota, South Dakota, and Iowa
	Minnesota bias	New generation modeled more heavily on a Minnesota-centric generation mix
	Eastern bias	New generation modeled more heavily based on importing generation into Minnesota from Wisconsin and Iowa

Source: CapX2020 Vision Study, 2005.

The technical team did a preliminary model of the three generation scenarios for the year 2020 that included no new transmission facilities. They found that without new transmission facilities to serve the projected load growth and new generation, a significant number of overloads would occur on the lines in the system. They also found potential violations of NERC criteria, such as low voltages and thermally overloaded facilities that would occur if a single transmission element was lost. Therefore, the study included generation scenarios that incorporated resources from several of the surrounding regions together with the 2,400 MW of renewable energy sufficient to address Minnesota's Renewable Energy Standard (RES).¹²

Using inputs obtained from independent power producers, wind developers, utility resource planning staff, and information solicited from the MISO generation interconnection queue, the technical team created scenarios for potential locations of new electric generating plants or wind farms.¹³ They combined the information gathered to form potential generation development

¹¹ This was based on load projections for utilities with customers in MN, published by the Mid-Continent Area Power Pool (MAPP) in the *2004 MAPP Load and Capability Report*. It is important to note that given losses that occur when transmitting electricity, electric service to generation stations, and planning reserve margins of 15% to ensure reliability, a load growth of 6,300 MW would require over 8,000 MW of new generation.

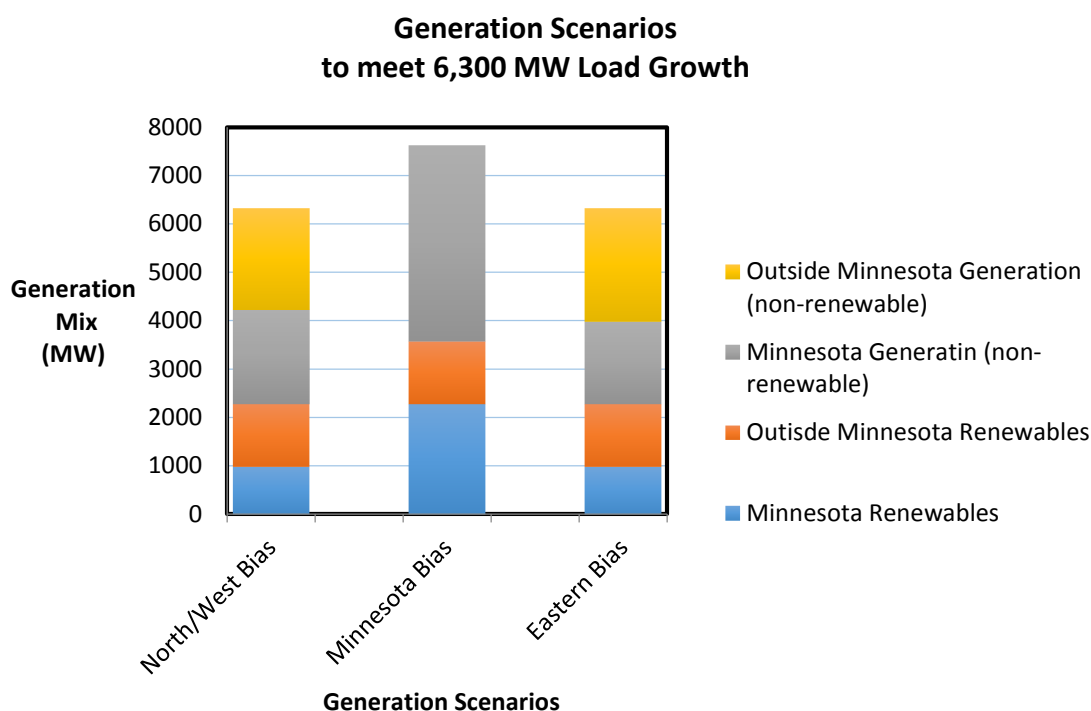
¹² See Appendix C: Timeline, years 2001, 2003, and 2007 for more information about Minn. Stat. §21B.1691, Minnesota Renewable Energy Standard.

¹³ They learned that the Upper Midwest had the potential to build wind farms capable of generating between 50,000 and 100,000 MW of power if given a large enough load footprint and transmission infrastructure to support it. They

nodes independent of fuel type, which they used in the modeling process to supply load increases selected in the two load-growth scenarios. The technical team looked at planning requirements necessary for participating utilities to meet the Minnesota RES, addressed issues related to relieving transmission congestion, and focused specifically on high-voltage solutions that best addressed the three generation scenarios. Each generation scenario reflected the potential generation development that might influence electric power flows on the regional grid, and thus indicated the size and location of new transmission infrastructure needed to deliver the new generation to its end-users.

The technical team modeled three different generation resource mixes, including renewable wind energy from inside and outside Minnesota, as well as other generation resources from inside and outside the state (Figure 7).

Figure 7: Generation scenarios studied in the CapX2020 Vision Study



Data Source: CapX2020 Technical Update

To test the effects of slower-than-projected demand growth, the CapX2020 technical team performed a sensitivity analysis for reduced load level to evaluate which facility additions were necessary. To model a 4,500 MW load level, the 6,300 MW load model used in scenario one was scaled down uniformly in each control area by a factor of two-thirds. The generation total was

also learned that the technology of wind turbines had rapidly advanced in the past decade. They are now taller, their rotors are bigger, they operate much better at low wind speeds and high wind speeds, and most importantly they can be managed directly by the system operation center so they do not have to be curtailed or turned off as much. Having the ability to look at localized wind patterns in real time allows system operators to better integrate wind into the transmission system at large, balancing the wind energy delivered to the grid leading to better overall efficiency and less wasted energy.

also reduced by scaling down each generator by a factor of two-thirds. For both the Minnesota-bias and North/West-bias sensitivity scenarios, it was determined that a majority of the facilities identified were still necessary despite a reduced load. In the Eastern-bias sensitivity scenario, it was clear that relief of existing facilities was needed between the Dakotas and Minnesota, though further study was necessary to justify some of the recommended transmission lines.

2.3.1 Vision Study Results and Next Steps

The CapX2020 technical team found that although the existing system was adequate to meet the reliability needs of customers in 2005, the study region would experience numerous transmission overloads, outages, and voltage problems if no additions were made by 2020. These results solidified the group's belief that they urgently needed to build new transmission, and that they needed to work together to make those investments feasible. The Vision Team wanted to find transmission projects that passed all the sensitivity tests, which would form a transmission backbone that would serve the region for the next 50 years and beyond. They selected lines identified as necessary by at least two of the three generation scenarios as the cornerstone of the CapX2020 Vision Plan. The team found the most overlap in transmission alternatives for the Minnesota and North/West generation bias scenarios. They estimated 1,620 miles of 345-kV common transmission lines were needed, at an estimated cost of \$1.215 billion. Results from analysis of the Eastern-bias scenario produced tremendously different results. Only two common 345-kV transmission facilities were pinpointed, and the group determined additional analysis was needed.

Transmission corridors were identified based on how frequently they were found necessary during the scenario assessment. The technical team also had the foresight to select corridors that could support additional generation and transmission projects in the future. Ray Wahle looked back on the group's approach and recalled,

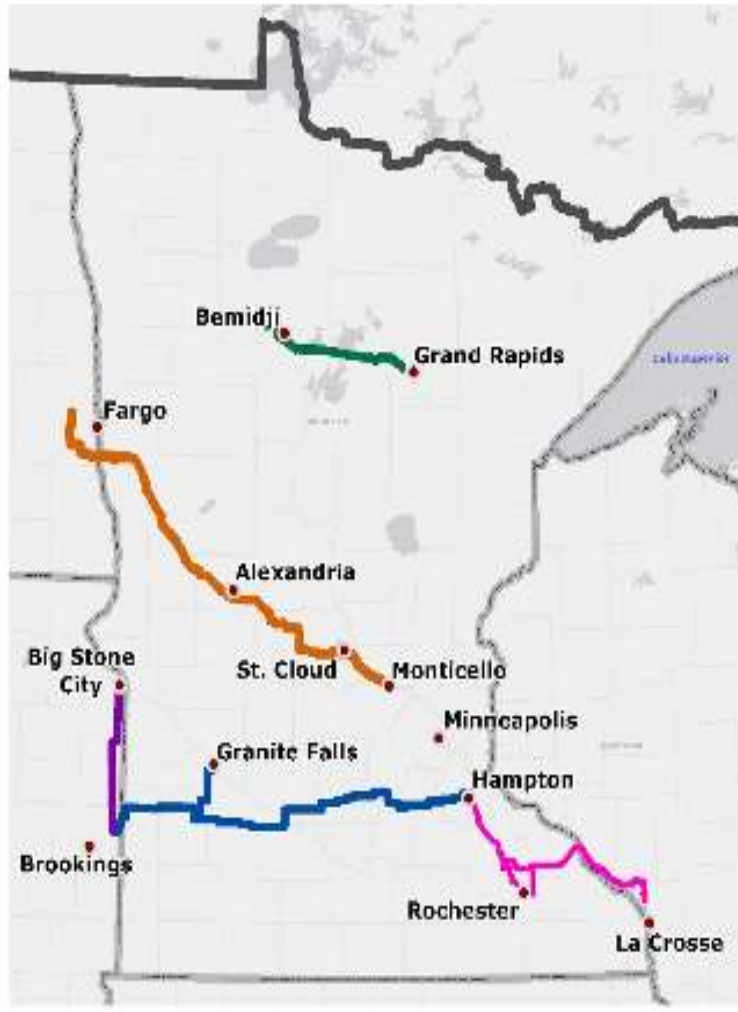
"We went through all the different types of scenarios, and interestingly enough, several projects always showed up in the studies. You always need this project, or you always need that project. If you had different scenarios, like if you had it weighted to the west, there might be a different line versus to the east. But you still had the basic CapX projects that worked and were needed. So we said, 'Okay. Since these transmission lines are always needed – and we looked at a broad variety of scenarios – those are the ones we should start with. And then as time marches on, if you see how generation is developing, say in the Dakotas, you might need some additional facilities in the Dakotas, but the backbone has now been put in and is operating.' That was the process. It took quite a unique study approach to come up with what the CapX facilities should be." (Wahle, 2016)

With this strategy, the group identified five projects totaling around 800 miles of new high-voltage transmission lines that met the current and future needs of the region (Figure 8).

None of the associated substations, generation interconnection facilities, or underlying lower-voltage (below 161-kV) transmission system infrastructure were explored in the Vision Study. Later, as the specific projects were developed, there were opportunities for CapX2020 to address local problems. The technical team identified problems on the lower-voltage transmission system and incorporated solutions into the CapX2020 projects themselves because they realized that while the 345-kV lines were solving problems, they were also creating new ones that would need

to be addressed. Additionally, none of the associated substation, generation, or interconnection facility costs were determined in the Vision Study.

Figure 8: CapX2020 Phase 1 project names and routes



Source: www.CapX2020.com

Project Names¹⁴

Bemidji-Grand Rapids 230-kV Project

Big Stone South-Brookings County 345-kV Project

Brookings County-Hampton 345-kV Project

Fargo-St. Cloud-Monticello 345-kV

Hampton-Rochester-La Crosse 345-kV Project

2.4 CapX2020 Engagement with the Minnesota Legislature

The CapX2020 group understood that their success depended upon changes in Minnesota legislation, so they engaged directly with policymakers. The technical studies the CapX2020

¹⁴ There were four projects (Bemidji-Grand Rapids, Brookings County-Hampton, Fargo-St. Cloud-Monticello, and Hampton-Rochester-La Crosse) were referred to as Group 1 projects. The Big Stone South-Brookings County project was added to the suite of projects in December 2011 when it was named a MISO Multi-Value Project.

group compiled provided empirical evidence that new high-voltage transmission lines were needed in Minnesota and the Upper Midwest and informed the CapX2020 group's approach to engaging with industry stakeholders. Although the need was clear, building new high-voltage transmission was difficult for utilities because it was difficult for them to recover their costs through electricity rates and obtain permits. The CapX2020 group lobbied the Minnesota legislature to ease some of those difficulties. In doing so, the group built upon the coalition formed during work on the Interim Report and Vision Study.

Historically, utilities tended to engage with other utilities and regulatory agencies when proposing a new project by way of exchanging technical studies and documentation to ensure that proposed project would not have adverse effects on the existing system and met NERC grid connection standards. More recently, the utility industry in Minnesota saw a paradigm shift regarding how utilities in the state approach transmission planning. Minnesota passed legislation in 2003 that created the Minnesota (MN) Transmission Owners group that required utilities to coordinate planning efforts and create opportunities for public participation in an effort to create a more transparent planning process. David Boyd, Vice President of Government and Regulatory Affairs at MISO, was a Commissioner with the Minnesota PUC during the late-2000s and recalled,

“Minnesota has - and other states would be smart to try this - we have a law that requires the transmission owners to do a biennial transmission plan. They file a report with the Commission that identifies where they see congestion and transmission issues, and propose potential solutions. I think they can use that filing if they choose to do so as a petition for a need permit. The point is that it gives the state and regulators kind of a two year window into where people like Xcel Energy and the CapX partners see the pinch points and what they might have in mind to fix it. It also means that the transmission owners, in some loose way, were already organized into a working or workable body. I think that loose familiarity and the fact that document exists probably helped seed the whole CapX partnership. It's a very unique partnership, and powerful coalition that they built trying to look very broadly at the state's transmission needs.” (Boyd, 2015)

Tim Rogelstad of Otter Tail Power and past Chair of the MN Transmission Owners group noted the difference between that group and the CapX2020 initiative:

“The MN Transmission Owners group was more of a technical-based group focused on complying with the law. The CapX group was the leadership that was necessary to advance plans forward. I think the engineers did a great job of identifying the problems and needs. You can study things to death, but to really have the leadership to move projects forward – that's what was different with respect to CapX.” (Rogelstad, 2016)

The CapX2020 work engaged with a wider range of stakeholders than in the past. Now state regulators, state agencies, and environmental groups representing a variety of different perspectives were actively contributing to changing state rules on transmission investment. Will Kaul of Great River Energy recalled working with stakeholders like Beth Soholt from Wind on the Wires, Bill Grant representing the Izaak Walton League, staff from the Department of Commerce, the Public Utility Commission, and the state regulators themselves like Representative Ellen Anderson (then Chair of the Senate Energy Committee), to negotiate the

changes and updates to the language of Minnesota's energy laws. The CapX2020 group held meetings with industry stakeholders between 2004 and 2005 at the capital in St. Paul, Minnesota to work through the challenges that impeded transmission investment and to craft new language for an energy bill they hoped to pass. Will Kaul remembered,

"It started with concept, then it went into drafting [the language of the bill]. I was involved with a number of those meetings, and my recollection was that the same people were there every time, at each step of the way, for each issue. It was a bunch of people who were firmly like-minded. We had a shared objective which was to get all this transmission built. And we had some divergent interests. They wanted to build for renewable energy, we wanted to build for renewable energy and reliability and other reasons. But we all had a common shared interest in getting it built." (Kaul, 2015)

The group recognized they had a common interest in building high-voltage transmission, allowing the varied group of stakeholders to collaborate. But as Will Kaul noted, within the group specific objectives, desires, and agendas varied. Michael Noble, Executive Director at Fresh Energy elaborated further,

"We didn't win every advocate over to our side. We have people we admire who still to this day think we shouldn't do it, and we shouldn't have high-voltage transmission structures across the landscape; that it's too damaging and harmful to the landscape and disruptive to communities. We've had good friends that have been upset with us, but we think it was the principled thing to do." (Noble, 2015)

At the end of the day, the CapX2020 group proposed a bill that would resolve uncertainties around investment recovery, the transmission business model, and the Certificate of Need and route permitting process.

2.4.1 The 2005 Minnesota Omnibus Energy Bill

The most important provisions to the investor-owned utility members of the CapX2020 group in the proposed bill were changes to transmission cost adjustment. Leading up to the 2005 legislation, investors were reluctant to put resources into new transmission lines because it took years before the investment paid off. The proposed bill allowed utilities to collect in 'real time' the costs as they are incurred on construction work in progress, as opposed to deferring them until the facility came into service ("Omnibus Energy Bill of 2005," 2005). Those details of Article 1 of the 2005 Omnibus Energy Bill changed investment in high-voltage transmission from least favored to most favored investment in the eyes of IOUs. Forward-looking construction work in progress formula rates enable utilities to recover costs associated with construction immediately, rather than at the end of the project. Utilities could attach a rider to their rates for transmission investments approved by the MN PUC to cover the costs they expected to incur from the project. The change would help to fund a project as it went along, reducing the need to borrow money, creating the financial assurance the IOUs were looking for. It also would reduce the overall cost of building a project because there would be less interest accrued during construction.

Article 1 of the 2005 legislation directly improved the circumstances of the IOUs as participants in a transmission development project, but did little to directly support project participants who were municipal and cooperative utilities because cost recovery on capital

investments differs between IOUs, municipals and cooperatives. Municipals and joint-action agencies are owned by the cities they serve and the customers of the municipals through the town or their utility, and a cooperative is owned by its customers. Tim Noeldner from WPPI Energy, a joint-action agency which serves municipal entities, explained further,

“Where that comes into play is that we finance projects differently than an IOU. We issue revenue bonds, which is really a pledge of the revenues that we receive from our members. We don’t have shareholders, we don’t have investors.”
(Noeldner, 2016)

Ray Wahle of MRES, a second joint action agency CapX2020 participant pointed out,

“We are structured differently, have a different financing method, and a different way that we get cost recovery than Xcel, Otter Tail, and Minnesota Power. The legislation did not help us directly. How it helped us indirectly is that it helped Xcel, Otter Tail, and Minnesota Power, which meant that they were fully supportive of CapX. If the legislation had not passed, I don’t know if the IOUs would have joined in the CapX effort.” (Wahle, 2016)

Had the legislation failed to pass and the IOUs not joined the initiative, the remaining utilities might not have had the resources in terms of people and capital to build the identified projects. The fact that the municipal utilities and cooperatives were able to see the benefit of passing investment recovery legislation to the whole group even though it did not directly impact them was a testament to their ability to support each other in the early stages of working towards their goal of upgrading the transmission system. Chris Fleege of MN Power recalled,

“Our companies have a long history of supporting each other. I don’t know if it is the “Minnesota nice” or whatever, everybody recognized the same issue. If we’re going to build large regional backbone transmission, it’s going to take more than individuals to do that, and it was a collective process.” (Fleege, 2016)

Critics of this change argued that the burden to fund high-voltage transmission falls on the ratepayers because the cost is passed onto them through rate changes. Proponents said the change would be beneficial for ratepayers because it would reduce overall project costs, which in turn would reduce the financial burden placed on consumers. In the short-run, consumers would start paying for projects sooner than they would otherwise, but in the long-run total costs would be lower as a result of change in formula rates.¹⁵ Removing this hurdle provided incentives for utilities to undertake the needed investments.

Article 1 of the 2005 Omnibus Energy Bill also included a provision that would allow utilities to transfer their transmission lines to a separate company under jurisdiction of FERC, known as a TransCo ("Omnibus Energy Bill of 2005," 2005). The goal of this provision was to allow for quicker cost recovery for upgrading the transmission system, to reduce investors' reluctance to invest in transmission projects, and permit municipal utilities, power agencies, and

¹⁵ Transmission costs generally make up 7 to 10% of a customer's bill. In that case, Xcel Energy customers could expect an incremental increase to around \$2 per month at the peak of construction in 2013 and 2014. In December of 2011, the Brookings County-Hampton and Big Stone South-Brookings County projects were approved as multi-value projects by MISO, meaning project costs will be allocated to all utility customers throughout the Midwest in MISO's footprint.

joint ventures to transfer ownership or control of transmission assets to transmission companies. The transfer of such assets are subject to MN PUC review, which must find that the transfer: (1) is consistent with the public interest, (2) facilitates the development of transmission infrastructure necessary to ensure reliability, (3) encourages development of renewable resources, (4) accommodates energy transfer between states, (5) protects Minnesota ratepayers against subsidization of wholesale transactions through retail rates, and (6) ensures that the state retain jurisdiction over the transferring utility ("Omnibus Energy Bill of 2005," 2005).

In the early 2000s, Xcel Energy had attempted to form a TransCo called TRANSLink, but received pushback from regulators who said Xcel Energy did not have the authority to create a TransCo under Minnesota state law. The new legislation would make it legal for utilities to consolidate their assets into a TransCo, and at the time the CapX2020 group had considered using a TransCo business model moving forward. Priti Patel noted,

"For the regulated IOUs, the concept of a TransCo means quite a bit of work with the regulator to help the regulator understand, 'What does that TransCo mean? What does it mean to the base business of that regulated utility? Who is going to operate it? Who are the employees? Is this going to take away resources from the base business?' There's a lot to it, and at the time, I surmise that the CapX2020 group thought, 'Instead of trying to get the political buy-in to get that going, what if we agree by contract?' There are so many legal implications, tax implications, regulatory implications – not just for the regulated IOUs, but for everybody. So, for many reasons, I think the TransCo may be a great idea today, but at the time, to make movement, it was probably better for them [CapX2020] to work together and to show regulators, legislators, and the region that they could get this done without having to take that other step." (Patel, 2015)

The idea of a TransCo also posed challenges to the municipality members, like SMMPA.

"I think the financing part of that would be a potential big hurdle for us to do a TransCo because the tax-exempt financing that we [SMMPA] use basically prohibits assets that are financed with tax exempt financing from being used for a private good. And arguably a TransCo could start to look like a private good, depending on how it's structured. That would prohibit tax-exempt financing, which would potentially create refinancing obligations on our part, which is a complicated mess." (Geschwind, 2016)

Instead of forming a TransCo and staffing it with its own people, the CapX2020 group formed a partnership that they would later formalize with Participation and Project Agreements. This not only helped manage overall costs, it more deeply integrated the project into each company's business.

The final key provision to the CapX2020 group of the 2005 Omnibus Energy Bill was Article 3, which shifted control over power plants location and transmission line siting from the Environmental Quality Board (EQC) to the Public Utilities Commission ("Omnibus Energy Bill of 2005," 2005). This gave the PUC the authority over both the CON and the route permitting process. It also allowed for CON and route permit applications to be filed simultaneously. This proposed change would bolster state agency coordination by requiring the Department of Commerce, in consultation with other state agencies, to provide technical expertise, staff resources, and other assistance with respect to siting and routing decisions to the Minnesota

PUC.¹⁶ The CON and route permitting process can take up to five years to complete without application overlap, and the provision would significantly reduce that timeframe. It also added the flexibility for utility applicants to select a permitting process that best suited each project. At an event commemorating the energization of the CapX2020 Brookings County-Hampton and Fargo-St. Cloud-Monticello 345-kV lines at the substation in St. Cloud, Minnesota, Teresa Mogensen noted,

“The regulatory process is long, but it’s a fair one that gives every stakeholder an opportunity to be heard, and that’s really important to us.” (Mogensen, 2015)

In his interview for this report, Terry Grove added,

“The state process is wonderful. The ability to either show need and then route, or do them simultaneously, or to have a hybrid where they overlap...that’s perfect. No situations are the same. If you said your only option was to do need and route together, you can get some very complicated politics where those questions get tangled up to the degree that can’t be untangled. I think our story was always solid on need, and on routing our story was always pretty flexible. Our mantra was that we wanted to prove a functional need, and we were willing to listen to regulators and key stakeholders about how we did that. I wouldn’t say that they all agreed, but the state was excellent in running the process, running it on time, and giving people their say.” (Grove, 2015)

CapX2020 would later use the newfound flexibility afforded by the 2005 legislation in the Minnesota state permitting process to submit one CON application for three of the 345-kV projects: (1) Fargo-St. Cloud-Monticello (2) Brookings County-Hampton, and (3) Hampton-Rochester-La Crosse. Showing the need for the three lines was similar in that they were the same voltage and used the same technical studies. David Boyd explained how from the perspective of the PUC, the three-in-one application lent itself to administrative efficiency:

“I don’t think it was a contentious decision to treat them as one. Essentially, the applicants argued that the degree to which the permit application covers the whole state and the extent to which they would be talking about the same statutory list of need requirements meant that they would almost be filing the same record and would end up filing three very very similar documents. For administrative efficiency, it was reasonable to take the need issue up as one. If it was contentious, it was probably be contentious to those who might oppose the projects. I could imagine that someone who didn’t like the concept would prefer to have four opportunities to argue against need rather than one large opportunity. However, doing routing in any larger bite would be unworkable. Getting the permits and the right kind of local meetings generating alternatives and the things that are in the statutes would have been impossible.” (Boyd, 2015)

¹⁶ For example, Article 3 also required an applicant for a siting and routing permit for high-voltage transmission lines to notify the Commissioner of Agriculture to participate and advise the PUC as to whether to grant the permit, which encourages and facilitates participation from other state agencies in the transmission permitting processes. Article 3 would also permit applications for a certificate of need for a large energy facility and an application for a site or route permit to be filed at the same time prior to construction, and would allow for a joint hearing for both applications.

Terry Grove further discussed the groups' rationale behind wrapping the need of three projects into one permit application:

"We did this so we weren't confusing people by saying, 'Can we re-jigger this line so we don't need that one?' By the time you would have had all those stories out there, especially if they were time-skewed, you'd have something that I think almost nobody could understand. It would look like your story is changing every day. People would see conspiracies that really didn't exist. I think bringing them together with a solid story – that was an innovation that worked out well. And, credit again to the stakeholders and regulators who were willing to listen to it."

Will Kaul added,

"We didn't do just one project at a time. That would be death by a thousand cuts for the public, for the utilities, and for regulators. So we came in with a portfolio of projects and we did something that was never done in Minnesota, which was bring \$2 billion dollars' worth of transmission expansion in a single regulatory filing." (Kaul, 2015)

There were two other provisions of note in the 2005 Omnibus Energy Bill. Article 2 authorized the Community-Based Energy Development Tariff, established to optimize local, regional, and state benefits from wind energy development, and to facilitate the construction of high-voltage transmission that supports renewable resources ("Omnibus Energy Bill of 2005," 2005). This provision gives priority to certificate of need applications for proposed lines that are necessary to support renewable resources (2005). In Article 11, the legislation addresses eminent domain landowner compensation issues by requiring the Legislative Electric Energy Task Force to convene a working group to research alternative methods of landowner compensation ("Omnibus Energy Bill of 2005," 2005). This working group was to make recommendations on changes to the certification and routing processes for high-voltage transmission lines.¹⁷

Governor Pawlenty signed the Omnibus Energy Bill into law on May 25th, 2005, encouraging utilities to build transmission lines and boost local investment in wind energy ("Omnibus Energy Bill of 2005," 2005). In retrospect, it was remarkable how quickly the CapX2020 group was able to negotiate their desired regulatory reforms, as they only began working on the issues in April of 2004. Ray Wahle of MRES had some thoughts on how the group was able to advocate for and get the legislation passed so quickly:

"The reason that happened is because we had identified the legislative challenges as one of the early problems. When you're talking about 11 utilities, you've got a lot of talent. And we – meaning the CapX partners – spent a lot of time in St. Paul explaining to the legislature what we needed, why we needed it, and how passing it would help solve the problem. It was a great effort by a lot of people. I wouldn't say it was easy, but we got organized and convinced people. We had a great story. I think we still have a great story." (Wahle, 2016)

¹⁷ The group was to report their findings to the MN PUC by January of 2006, however the report was never filed. The Minnesota Legislative Research Library, in charge of tracking mandated reports, contacted the Task Force twice in 2006 and again in February of 2007 for the report, but never got a response.

By the end of the legislative session in 2005, they had changed Minnesota law, achieving the reforms they sought, and had added another piece of the puzzle towards moving the projects forward. The IOUs could now successfully pitch the idea of investing in the projects to their respective companies. Absent that, there would have most likely been a long delay in the projects ability to move forward in a timely way. Tim Rogelstad of Otter Tail Power remembers the importance of the passage of the legislation:

“We saw the power of collaboration when we were able to bring forward that proposal with the support of the electric cooperatives and the municipal power groups. I commend the folks who aren’t regulated by the PUC but recognized that it was important for us as IOUs to have that certainty to be able to proceed forward.” (Rogelstad, 2016)

Once the bill was law, the Minnesota PUC called on the CapX2020 group to submit a CON application, as they had done such a good job selling the need for the projects within the state. But before they could do that, they needed to take the final step to commit to the projects. Will Kaul pointed out,

“It was kind of like the dog that’s chasing the car, and he caught up to it, and then what do you do? Once the bill was passed we had the Chair of the PUC saying to us, ‘Get that certificate of need in here soon!’ It was right after the East Coast blackout.¹⁸ We did a great job of selling this thing, and they were getting impatient.” (Kaul, 2015)

The group was looking at a decades-long commitment to a capital investment project that would cost billions of dollars. Utilities needed to raise the money, speak with their rating agencies, and justify the CapX2020 projects against other capital requirements they had. Furthermore, the group still needed to address internal questions of how the investment would be divided between the group of participants. More than two years after the bill passed, the group was finally prepared to submit their first Certificate of Need applications in Minnesota for four projects packaged into one regulatory filing.

2.5 CapX2020 Governance Agreements

2.5.1 Participation Agreement

The CapX2020 group was cohesive from the beginning, and referred to themselves as a “faith-based organization” in that they were able to move forward based on collaboration, trust, and taking prudent risks. This was exemplified by the fact that the group moved forward in 2004 to conduct expensive technical studies, even though they did not know how project costs would be determined or allocated.

¹⁸ The Northeast blackout of 2003 was a widespread power outage that occurred throughout parts of the Northeastern and Midwestern United States and Ontario on August 14, 2003, caused by a tree induced line failure and a faulty alarm system. All told, 50 million people lost power for up to two days in one of the biggest blackouts in North American history.

“Trust is actually the greatest lubricator I’ve ever seen in business. It’s a very efficient way to conduct business and we don’t have to spend a lot of time and money on lawyers, and we don’t have to spend a lot of time and money double checking each other. We were really able to move ahead on a handshake, and that made things go real smooth.” (Kaul, 2015)

Coordination of a group of diverse utilities required a measured approach, taking into consideration the various sizes and business structures of each participating member. Priti Patel explained,

“They were trying to prop up how we could get these varied owners together to start figuring out how to put words to paper. Things like rules and responsibilities, duties and obligations. You think it’s easy, but it’s not. You’ve got all these owners – some of who’ve worked well, some that trust each other, some who’ve had horrible business histories. Big players, small players. All kinds of politics. At the core, what came through was that when something needed to get done, that group got it done.” (Patel, 2015)

There were certain core issues the group agreed upon, and they worked forward from there. They recognized that because of the regional operation of the transmission grid in Minnesota and neighboring states, the work could only be successfully performed if a collaborative approach was taken. The utilities agreed they needed to coalesce to facilitate the collaborative planning and coordination of a number of potential projects as proposed by the Vision Study. However, given the loosely structured CapX2020 umbrella organization, there needed to be some type of formal organizational structure to support the projects, so they developed a document that would come to be known as their Participation Agreement. Dave Geschwind recalled,

“We got so far down the path with that informal approach – and it worked well – but I think we all recognized that when we were all going to show up with our millions and millions of dollars of investment that we couldn’t do that based on faith. At some point that has to be turned into agreements that are going to define how these relationships are going to be structured – because these projects and the agreements are going to outlive many of us.” (Geschwind, 2016)

It took from 2006 to 2008 to set up the overall umbrella agreements of how the CapX2020 participating members would work together.

A team of senior leaders – one representative from each participating utility – along with their legal representatives, developed the overall direction and strategy for the CapX2020 project group, and served as the liaison between the group and the utility for which they worked. Tim Rogelstad described why it took so long for the group to develop the Participation Agreement:

“We had 11 utilities involved in the negotiations of these agreements. It can be hard to negotiate a two-party agreement, let alone 11. The process was a huge undertaking, but all parties shared a willingness to work together. It took time, but given the involvement of 11 entities, each with potentially different interests and needs, we were able to get that done and actually work. It was quite an accomplishment.” (Rogelstad, 2016)

The Participation Agreement addressed issues of project governance, construction management, business risk, and insurance, while accommodating 11 utilities of all sizes and

business models. Ben Porath of Dairyland Power recalled what it was like to be on the working group that developed the group's formal agreement:

“It was a multi-year process to set up the overall umbrella agreement of how this would all work. Overall it was very painful to be actually on the working group because there was so much work and it was so voluminous. But stepping back and looking at it from a higher level, it was a very unique opportunity for the utilities. We did something here in CapX and the Upper Midwest that I don’t think has been done anywhere else in North America where the major IOUs – the big utilities – got together with the smaller municipal and cooperatives, all sat down in the same room, and developed a transmission build out jointly and cooperatively. We were happy to have had an opportunity to be at the table and work on that, even though it was very painful.” (Porath, 2016)

Using a national project counsel firm to mediate negotiations, the utilities identified their organization's interests and perceived project risks, and created a set of template project agreements to achieve consistency and efficiency. Managing negotiations between 11 utilities with different backgrounds and business structures was key to pushing the talks along. Tim Rogelstad looked back and remembered,

“A key attribute was having a third-party legal counsel that wasn’t representing any one party, could drive decisions, and facilitate agreement discussions. Without a third-party to force resolve of an issue, it would have been a disaster. That was clearly a best practice.” (Rogelstad, 2016)

The Participation Agreement was far more complex than the agreements the utilities were familiar with drafting, but Tim Rogelstad pointed out why they were necessary:

“The world certainly has changed, and the complexity and security that you need when you undertake spending over two billion dollars has too. Agreements are important and complex, and it will be interesting to see how that plays out.” (Rogelstad, 2016)

The complex Participation Agreement covered salaries of workers who were working full-time on the CapX2020 initiative, study costs, and other costs associated with project development and communications. Member utilities dedicated staff to the CapX2020 organization that would govern the project development and regulatory documentation required for state agency permits, explained further in section four. Co-executive directors from Great River Energy and Xcel Energy managed the overall operations, and support staff from the participating utilities assisted in committee work.¹⁹

Because of the different sizes and business structures of the utilities, and because each of the projects would present its own unique set of challenges, a key question the group had to answer was how votes would be counted within the Vision Team. Ultimately, the group agreed upon three levels of voting, depending on the issue (CapX 2020, 2007):

¹⁹ Committees included, but were not limited to: regulatory, transmission planning, project management office, standards, communications and public outreach, project agreements, right-of-way acquisitions, and government affairs.

- *Level One:* All actions of the Vision Team must receive the affirmative vote of at least a majority of the representatives of the Vision Team present at any meeting.
- *Level Two:* An affirmative vote of at least 60 percent of the Vision Team, regardless of the number in attendance at any meeting, is required. Actions include the appointment or termination of CapX2020 staff, approval of costs and budgets, approval of studies and potential projects, and approval of future agreements.
- *Level Three:* An affirmative vote of 75 percent of the Vision Team is needed to approve the termination of the Participation Agreement.

The voting structure was broken down in such a way that the group could identify which matters required which voting level, ensuring that in no case can a single owner unilaterally exercise control over the project. It was a way to compromise rather than having one way to approach governance for whatever came up. Some things needed unanimous decisions, and other things did not. In a less collaborative setting, one might postulate that the larger players would have muscled their way into having unilateral control because they might have felt entitled to that position based on size, but that was not the case with the CapX2020 group. Ben Porath remembered how even as one of the smallest entities, Dairyland Power, was treated as an equal:

“It’s never good to be the smallest player in the room and have your interests or concerns run over by others that can veto you at a whim, or take their interests into account over yours. The fact that we set up these sophisticated voting rights so that small players actually had the right to have our voice heard if we had a really concerning issue was very important to us, so we really appreciated that.”
(Porath, 2016)

The CapX2020 group felt that through the formal, contractual Participation Agreement that they were able to create sustainable long-term relationships that would be able to withstand speed bumps encountered along the way.

While CapX2020 came together in 2004, the formal Participation Agreement was completed in 2007, and was signed shortly thereafter by the participating members, all of whom own and operate transmission facilities in the Upper Midwest and serve Minnesota load (Table 3).

Table 3: CapX2020 participating members

CapX2020 Participating Members		
Utility	Type of Operator	Utility Footprint
Central Minnesota Municipal Power Agency	Municipal Joint Action Agency	South central Minnesota
Dairyland Power Cooperative	Cooperative Utility	25 members and 17 municipal customers in Western Wisconsin, southeastern Minnesota, northwestern Iowa, and northwestern Illinois
Great River Energy	Cooperative Utility	28 member cooperatives in Minnesota and Wisconsin

Minnesota Power	Investor-Owned Utility	Northeastern Minnesota
Minnkota Power Cooperative	Cooperative Utility	11 member-owned distribution cooperatives in eastern North Dakota and northwestern Minnesota
Missouri River Energy Services	Municipal Joint Action Agency	61 member municipalities in Iowa, Minnesota, North Dakota, and South Dakota
Otter Tail Power Company	Investor-Owned Utility	Central and eastern North Dakota, western Minnesota, and northeastern South Dakota
Rochester Public Utilities	Municipal Utility	Rochester, Minnesota
Southern Minnesota Municipal Power Agency	Municipal Joint Action Agency	18 non-profit, municipally owned member utilities located throughout the state, most in south central Minnesota.
WPPI Energy	Municipal Joint Action Agency	51 locally owned electric utilities in Wisconsin, Michigan, and Iowa
Xcel Energy	Investor-Owned Utility	Minnesota, Wisconsin, North Dakota, South Dakota, Colorado, New Mexico, and Texas

2.5.2 Determining Cost Allocation: The Poker Chip Exercise

Around the same time that the Participation Agreement was completed in 2008, the group needed to determine to what degree each utility would invest in each project. At this time, the group had identified the Group One projects through the Vision Study, and had rough estimations of the various project costs. Without knowing the levels of utility investment or participation, there was still uncertainty looming around each project. To resolve this, the utilities participated in what is known as the poker chip exercise. In this exercise, each utility representative was allocated a set amount of “poker chips” that reflected a percentage of the load-ratio share of the system peak. For example, on the hottest day of the year, Xcel Energy may serve 50 percent of the system load, Great River Energy may serve 15 percent, Minnesota Power may serve eight percent, and so on. The percentages that participants used was not published, and was most likely agreed upon through a series of negotiations between the participants.²⁰

In the day-long activity, participants set their “poker chips” on the projects they were interested in working on. Each participant distributed their chips to the proposed projects based on the objectives of the utility they represented, and each participant had different drivers as to what made certain projects more appealing to them. For example, Ray Wahle remembered that

²⁰ It is also unclear as to how the group defined “system load,” as the service areas were not uniform. Allocation amounts described in this paragraph are estimates used to explain and clarify how the activity took place.

MRES had predetermined the projects and the amounts they wanted to invest before starting the meeting:

“When we started that exercise, MRES wanted to be in two projects. We wanted to be in Fargo, and we wanted to be in Brookings because those two projects run through our member areas. And we had determined about how much we wanted to invest in the whole overall project. The way it turned out, we basically got in the projects at the levels we wanted to. And when everyone else laid their chips down, it turned out that we all ended up where we needed to be. Everyone walked away satisfied with the way they were invested, in which projects and the amount of investment.” (Wahle, 2016)

In general, most participants were interested in projects that affected their service area. Terry Grove of GRE noted,

“Most people didn’t want to invest in a single line, they wanted some diversity. However, if you were a smaller entity in a local area, it makes sense for them to put their chips on one project.” (Grove, 2015)

Chris Fleege of MN Power added,

“The five utilities that settled in to each project had local stakes, generally. So you really did have people close to the risks who thought about what would happen if this were to go poorly, or how they could do it in such a way that we could mitigate it beforehand.” (Fleege, 2016)

As was mentioned earlier, each utility had its own strategy to project investment. Ben Porath described Dairyland Power’s approach:

“In our project, Dairyland turned out to be an 11 percent owner of the Hampton-Rochester-La Crosse 345-kV line. We have a lot of customer demand around the Rochester and La Crosse areas and in between, so we could really tie the exercise into that we are about 10 percent of the load in the region. We tied our poker chips to our load, and it was good for us that way. It really was a tie-in from the old traditional way of load-ratio share and load impact more than a poker game, but it was fun to participate in the exercise.” (Porath, 2016)

After each utility had an opportunity to make known what projects they wanted to be in and at what level of investment, they found that they needed to do a bit of rearranging. Dave Geschwind, Executive Director and CEO of SMMPA recalled,

“That was an interesting meeting in that now, for the first time – to continue the card analogy – everyone was able to lay their cards on the table and say, ‘Here are the projects, and I am up for investing in X percent of that project.’ And then once you can see all that for the first time with all of your peers, then people could start to put some friendly pressure on others.” (Geschwind, 2016)

For example, at one point a project had six or seven potential owners. The group worked through various ways to appease everyone by suggesting that certain utilities take their percentage from the overloaded project and invest a higher percentage in one of the other projects they were interested in. After some re-arranging of the poker chips, the investment landscape was established and an important source of project uncertainty had been largely resolved (figure 9).

Most everyone interviewed for this report who attended the meeting recalled how smooth the day went:

“With some iterations of that, the chips were distributed, and almost by coincidence, we got five owners on each line. It’s a good number, as it gets a lot more complicated as you get more owners. Everybody at the time got the positions they wanted.” (Grove, 2015)

“I mean, when people laid their chips down, we were very close in terms of having the right amount of money for each of the projects. It was surprisingly close, and with just a little bit of juggling, we were there.” (Wahle, 2016)

This is not to say that concessions were not made. Going into the day, SMMPA was interested in participating in both the Brookings County-Hampton and the Hampton-Rochester-La Crosse projects, but ultimately ended up only in the Hampton-Rochester-La Crosse project. Rick Hettwer of SMMPA explained,

“We put in for 20 percent of the Brookings project and 80 percent in La Crosse, then it went back and forth with the different people....what projects they wanted to participate in, and so forth. The group tried to narrow it down to five participants in each project because they thought more than five might be too much to manage in each project. Ultimately, we ended up 100 percent on the La Crosse project.” (Hettwer, 2016)

That the group was able to tackle the tricky question of allocating billions of dollars in a single day with an innovative exercise speaks to the deep social capital and trust the CapX2020 members developed with each other. Terry Grove elaborated,

“When you don’t know how you were going to get your money, it was hard to build enthusiasm, and in some projects people wanted to be in one place, and we had too much [money] or too little in others. I think that illustrates the strength of CapX – people heard each other out, and moved off from their initial thoughts, and we worked out ownership.” (Grove, 2015)

It is important to note the role that timing played in the outcome of the poker chip exercise. Legislation passed just a few years prior, in 2005, changing investment in transmission to a favorable venture in Minnesota, but at the time MISO was still in the initial stages of developing their “value based planning” approach for the region that included a progressive approach of cost recovery in which transmission project costs are socialized throughout the entire MISO region.

“When we started the CapX2020 initiative, people didn’t want to invest in transmission. Part of the reason is because historically any investment that you made in transmission all went to your customers. When you negotiated transmission projects, you wanted to minimize your investment because that meant your customers would pay less. During the CapX period, MISO was in the process of developing regional cost allocation, but at the time we didn’t know how the poker chip exercise would play out. Had the poker chip exercise been done after MISO had figured out the cost allocation, it would have been a much different game.” (Rogelstad, 2016)

When the CapX2020 technical team was working on the Vision Study, they were primarily worried about reliability, and less so on consumer economics. Starting in 2006, MISO built off of the CapX2020 approach and shifted the MISO regional objective from minimizing investment to minimizing customer bills while meeting the reliability needs of the system and meeting state, regional, and federal policy goals. From this work came the Multi-Value Project (MVP) Portfolio, a suite of 17 projects that consider reliability and economic and public policy drivers in transmission development that provides benefits in excess of costs throughout the MISO footprint. Both the Brookings County-Hampton 345-kV and Big Stone South-Brookings County 345-kV lines were designated MVPs. However, the projects were not designated MVPs until December of 2011, more than two years after the poker chip exercise.

Figure 9: Project participation percentage of development costs and election rights

Schedule of Participation Percentage of Development Costs and Election Rights by Project At the end of the poker chip exercise, each project had five participating utilities to share the cost and responsibility of getting the project built.	Fargo - St. Cloud	
	Great River Energy	25.0%
	Minnesota Power	14.7%
	Missouri River Energy Services	11.0%
	Otter Tail Power	13.2%
	Xcel Energy	<u>36.1%</u>
		100%
St. Cloud-Monticello		
Great River Energy	25.0%	
Minnesota Power	14.7%	
Missouri River Energy Services	11.0%	
Otter Tail	13.2%	
Xcel Energy	<u>36.1%</u>	
		100%
Brookings County - Hampton		
Central MN Municipal Power Agency	2.2%	
Great River Energy	16.5%	
Missouri River Energy Services	5.1%	
Otter Tail Power	4.1%	
Xcel Energy	<u>72.1%</u>	
		100%
Bemidji - Grand Rapids		
Great River Energy	13.0%	
Minnesota Power	9.3%	
Minnkota Power	31.5%	
Otter Tail Power	20.0%	
Xcel Energy	<u>26.2%</u>	
		100%
Hampton - Rochester - La Crosse		
Dairyland Power Cooperative	11.0%	
Southern MN Municipal Power Agency	13.0%	
Rochester Public Utilities	9.0%	
WPPI Energy	3.0%	
Xcel Energy	<u>64.0%</u>	
		100%

Source: CapX2020 Project Route Permit Applications

2.5.3 Project Agreements

After the participating members signed the Participation Agreement and after the poker chip exercise identified which utilities would be working on each project along with investment amounts, the individual project groups signed Project Agreements. Each project included five CapX2020 member participants, with one utility taking lead as Development Manager and

Construction Manager per project.²¹ Specific details about each project can be found in Appendices F-J. Even though the Project Agreements could not be signed until after the poker chip exercise identified who would participate in each project, the group drafted agreement templates. Rick Hettwer recalled moving from working on the Participation Agreement to the Project Agreements:

“Once we got through the Participation Agreements for the CapX organization, we went through the Project Development Agreements, and we tried to come up with a generic development agreement that each of the sub-projects could come off of. That, again, was challenging with 11 participants.” (Hettwer, 2016)

Members participated jointly in the negotiation and drafting of each Project Agreement, which defined ownership, construction, operations and maintenance arrangements. The following agreements were executed for each project: a Project Participation Agreement (PPA), a Construction Management Agreement (CMA), a Transmission Capacity Exchange Agreement (TCEA), and an Operations and Maintenance Agreement (OMA).

The PPA governs the rights and obligations of the Project Owners, as funders of the construction of the project facilities and owners of the completed and energized facilities. The agreement sets up a management committee under which each owner has a representative. All decisions about constructing, equipping, designing, operating, maintaining, and administering the project are made by the Project Owners acting through the Management Committee. Like in the Participation Agreement, there are three levels of voting depending on the issue, and in no case can a single owner unilaterally exercise control over the project.

The CMA governs the rights and obligations of the Project Owners and Construction Managers during construction. The CMAs for each project were adapted from the template agreement to be project-specific, based on the scope of the project and the unique group of owners. The Construction Manager had full responsibility for the final engineering and design, material procurement, contracting, and construction project management throughout the energization of the project facilities. The CMA terminates once the construction process is complete.

Additionally, Project Owners established a TCEA to align their rights to the capacity of the line in the event there is no longer a RTO authority like MISO. In that event, the PPA would grant each Project Owner the right to “use the capacity and associated transfer capability for the line for all purposes associated with the transmission of electric energy and data for electric utility communications, in proportion to the Project Owner’s Percentage Interest.” Lastly, once the project facilities have been placed into service, the OMA assigns responsibility for operation, maintenance, NERC compliance, as well as assigning cost allocation for those services to the Project Owners based on their Asset Ownership Percentage.

Many of the CapX2020 participants saw the contract as a backstop, and something that was necessary from a practical standpoint. At the same time, it is important to note that the

²¹ Each project had five CapX2020 member participants with the exception of the Big Stone South – Brookings County, South Dakota line. In this instance unique to the CapX2020 projects, only Xcel Energy and Otter Tail Power were participating utilities. Great River Energy, Otter Tail Power, and Xcel Energy served as Project Managers. Details of the project can be found in Appendix H.

Participation Agreement and subsequent Project Agreements will be in place for up to five decades or longer - long past the careers of those who were involved in setting them up. The CapX2020 group that sat at the table to negotiate these agreements were all colleagues who have worked together for years.

“We could do things on a handshake deal because we know each other, but you turn over two or three generations from now with people that don’t know why we did the things we’re doing, why we got together to do them, or how we did things collaboratively. The Agreements will be a good framework for people to work together in the future, and really understand what we did and why we did it.”
(Porath, 2016)

By the time the Project Agreements were signed around 2009 and 2010, the CapX2020 group was five or six years into their effort, having spent a large amount of money while knowing up until the point of signature, the initiative could still have broken apart. The group truly was operating as a “faith-based” organization, and succeeding.

“Signing the Project Agreements solidified the commercial arrangements and commitments we were making to each other. But up until that point, it was truly faith.” (Rogelstad, 2016)

3. Public Engagement

3.1 The CapX2020 Approach to Public Engagement

Acquiring the necessary CON and route permits can take three years or more, giving the CapX2020 group ample time to engage with the public and landowners. The CapX2020 group was intentional with their strategy of early engagement with stakeholders and the public, and much of the push for openness and public involvement in the process was influenced by lessons the industry learned from the CU Project Controversy of the late 1970s, as chronicled in Paul Wellstone and Barry Casper’s book *Powerlines* (Casper & Wellstone, 1981) and explained in Section 1.4. Most of the CapX2020 Vision Team read the book when the group formed. It helped them understand the issues they might face, and how they could create a strategy for education and communication that would make things go better this time. Will Kaul, who started his career with a cooperative utility in 1978, recalled the tensions of the past:

“People felt very wronged in the process and they were so committed that they were cutting down towers while they were energized. They were risking their lives. So my promise to myself was never on my watch will we have something like this, and I think all of the other utilities felt the same way.” (Kaul, 2015)

The sentiment was echoed by the Minnesota PUC and its Commissioners. David Boyd explained,

“Anything that I did at the Commission that involved peoples land is a very very personal exercise, and you have to understand that and not be cavalier about these kinds of things. In Minnesota the last big buildout came with toppling of

powerlines, and it was a result of a poor process and lack of communication. You can't make that mistake again, and they knew that. (Boyd, 2015)

The group recognized the potential for great controversy and recognized that they would face the same issues encountered in the CU Project Controversy if they didn't handle these projects differently.

That is not to say, however, that the CapX2020 projects were free of opposition. There were certain factions of the public who were opposed to the projects for a variety of reasons. The No CapX2020 was a group led by Carol Overland of Minnesota and believed that the projects were not needed but rather served the purpose of transmitting energy generated from coal in the Dakotas through Minnesota to points to the east. Save Our Unique Lands (SOUL) of Wisconsin questioned the cost effectiveness and projected benefits of the utility proposals, believing that comparable investments in energy efficiency and local power would deliver equivalent or greater benefits to communities. Allen Gleckner, Senior Policy Associate at Fresh Energy recounted,

"I think there is a NIMBY (Not In My Backyard) faction there, a NIMBY drive to that opposition. I think a lot of folks were thinking, 'Wait, I don't want a transmission line going through here,' and they found that group and latched on to those arguments. Then they started saying, 'Not only do we not want this here, but why do we need it in the first place?' So, they were really pushing arguments about how we should use distributed generation and energy efficiency instead." (Gleckner, 2015)

Critics from No CapX2020 contended that there was not enough opportunity for the public to be involved in the determination of need for the projects during the CON process. However, from a utility standpoint, the process of determining need for a high-voltage transmission project is more technical than other aspects of the route citing process. Engineers run load flow studies and planners work to predict various generation futures. Technical studies like the Vision Study consider energy consumption trends, the retirement of coal plants and the addition of renewable generation in response to changing state and federal regulations, and the overall management of system reliability needs when they decide to propose a new project. One of the requirements in any CON application is that the applicant use a number of prescribed methods to demonstrate that the proposed facilities are in the best interest of the state's citizens, and that there is not a more prudent and reasonable way than the proposed project to meet the project's stated goals. Furthermore, Commissioners at the PUC and employees at the Department of Natural Resources (DNR) are charged with taking public interest into consideration when making their decisions, as it is written into their process. Moreover, there are four instances in the multi-step process where public input is accepted. Appendix E has a flowchart of the CON process, highlighting the four instances before the PUC makes its ruling.

In an initiative as large as the CapX2020 that spans four states and over 800 miles, organized opposition groups and people who do not agree with the projects were inevitable. The CapX2020 group continuously demonstrated a willingness and desire to solicit feedback and incorporate that feedback into their decision making processes. Their objective was to minimize the impacts on people as best they could by informing, teaching, and getting people involved early. Tim Rogelstad recalled the group's approach:

"Our goal was to engage early and get everything out on the table, so that we could make informed decisions." (Rogelstad, 2016)

3.2 Engaging with Landowners to Determine Project Routes

In Minnesota, there are a handful of times during the permitting process when the public is invited to participate, as can be seen in the CON and route permit process charts found in Appendix F. CapX2020 went beyond those requirements by hosting open houses and working directly with landowners to develop project routes. CapX2020 took the approach of meeting early and often with stakeholders to learn about and understand their perspectives in informal settings, rather than meeting them and hearing their grievances for the first time at a formal public hearing. Mark Nisbet, Xcel Energy's Principle Manager in North Dakota, noted that the group went far beyond what was required, holding meetings "anytime anyone wanted one." They started the public engagement process well before they set the routes. Will Kaul from GRE said,

"We took our time, communicating with communities, with thought leaders, newspaper editors all around the state. We spent two years basically building a political foundation for these projects. We didn't want to meet affected landowners for the first time at a public hearing. We wanted to meet them at a coffee shop or at an open house – a place where they were free to ask questions, learn about what we were doing, learn about why we were doing it – and that turned out to be very effective. We literally had hundreds and hundreds of meetings with anybody who would listen." (Nisbet, 2015)

Once the 2007 Vision Study had identified the project corridors, the CapX2020 group mailed over 70,000 invitations to public meetings that served to inform residents of the proposed routes. In the fall of 2007 alone, CapX2020 held over 25 open houses that were attended by over 2,000 people.

One of the purposes of public engagement was to make the case to the public that these projects were necessary and beneficial to the communities affected, as well as to educate the public on the technical aspects of the projects. Gordon Pietsch noted,

"We hadn't done anything in the state for many decades, so people weren't familiar with big transmission projects. It was an opportunity for us to educate people, answer questions about what we saw as a need, and describe those as best we could from an engineering standpoint so that the public could understand that." (Pietsch, 2015)

Early on in the route siting process, corridors where a line might go were identified. These preliminary corridors were larger than the final corridors would be (they could be 12 miles wide and a hundred miles long), and served to identify landowners who may be affected by a final corridor designation and who should be engaged. Open houses allowed the opportunity for these landowners to give the project managers input on the proposed corridors and provide important information for project managers to factor in while determining project routes. Chris Fleege recalled,

*"Local people **do** know where lines should go, or where they would recommend. I mean, nobody ultimately really wants it in their backyard, but they all have some*

real thoughts of definitely where not to go, for all sorts of reasons.” (Fleege, 2016)

Local landowners provided information about irrigation system plans, airports, future development, and other things that the utilities needed to consider.

The CapX2020 group was making the case that the projects were necessary for reliability purposes, but also that the lines would allow for load growth and enable more renewable generation to connect to the system. Mike Gregerson noted one of the challenges in educating the public about the wind potential of the region is the fact that the most wind found is not always near population centers:

“There had to be a lot of work done to get people to understand that, and then to be supportive of building, which some people view as beautiful, and some people view as ugly. But they’re large, very high transmission lines that, for some people – including environmental groups – say, ‘My lights are on, things are okay, why do you want to do this?’ So there’s that immediate suspicion that the utilities and MISO are doing this just to make money, and we really don’t need it, and if we do, more distributed generation will make everything okay. The problem with that is the level of wind development that we’re capable of doing in the Upper Midwest is enormous. We have 13,000 MW already built and operating in the Midwest, and there’s going to be another 13,000 MW, which will then meet most of the (Midwestern) states mandates. We have the potential to build between 50,000 and 100,000 MW. All the DOE studies that they’ve done basically say that if you can get the transmission built, and have a large enough load footprint, we can have 5-6 times the amount of wind we have now.” (Gregerson, 2015)

The CapX2020 group emphasized how new renewable generation factored into the purpose of the lines because they felt that it was a benefit from the projects that the public would be receptive to.

The CapX2020 group also benefited from working with their coalition partners instead of one entity attempting to get complete public buy-in by themselves. Having the broader group introduce the portfolio of projects was effective in showing local populations that it was not just Xcel Energy or GRE customers that would benefit, but that the projects were beneficial to everyone. Ben Porath explained the importance of Dairyland Power’s involvement in the Hampton-Rochester-La Crosse project:

“By having us in the project along with Xcel Energy, it gave Xcel Energy another resource to help deal with some of the landowners that were already Dairyland customers, already Dairyland landowners. We already had the easements and the right-of-way. We knew these folks. We could help at times if it was necessary to deal with landowners to help smooth things out and get things going. It was 100 percent important that Dairyland was directly involved in the project.” (Porath, 2016)

The smaller entities were able to leverage their local relationships as the projects moved forward. Although they were not the project managers, the municipal and cooperative CapX2020 members were able to bring people to the table and provide their perspective in a way that the IOUs could not. For example, the municipal members could relate to other municipal utilities

and their customers along the route even if they did not participate in the CapX2020 initiative. Tim Noeldner of WPPI Energy, a municipal entity in Wisconsin elaborated,

“Sometimes you’ll run into customers or interveners that say, ‘The only reason why you guys want to build this line is so that you can enrich the pockets of your shareholders and it’s all going to go flowing past to Chicago anyway, so what good is this for us?’ When this happens, we can step up and say, ‘Hey, we [WPPI Energy] are not-for-profit. We’re after this for our customers just like Xcel Energy is. And it’s pretty hard to accuse us of lining the pockets of our shareholders because we don’t have any!’” (Noeldner, 2016)

Terry Grove added,

“Our power came from when we were out in local areas. We had the municipal utility manager, the staff or CEO or directors of a cooperative, the investor-owned area relations representative – those are the people that live there, and those are the people that are trusted, and they are explaining to their neighbors why this is a good deal, and why their entity benefits. If you had the converse of that, of people out shooting at each other’s projects, that would be terrible.” (Grove, 2015)

In 2008-2009, CapX2020 project managers organized a series of routing work groups for community involvement. These work groups were meetings of small groups of community representatives who discussed individual projects with local government officials, representatives from agriculture, state and federal agencies, and environmental groups. The CapX2020 group made sure that representatives of the local utility or cooperative attended meetings because of the credibility that they brought.

Over the course of the meetings, the work groups helped identify and confirm some of the criteria used in proposing routes, evaluated local routing issues, and provided feedback on the proposed routes. This input helped refine the project corridors and informed the next round of open houses CapX2020 hosted. This iterative process allowed project managers to be responsive to the specific needs of a community affected by the new transmission lines. In addition to public meetings, CapX2020 targeted local governments by giving presentations to city councils, and county commissioners and administrators, and boards.

The utilities that were named Project Managers (Xcel Energy, GRE, and Otter Tail Power) led the outreach efforts for their individual projects. Each group took a strategic approach to landowner engagement by being consistent with their messaging.

“Xcel Energy ran the open houses and determined how they would be staffed, and I think that was very important. They wanted mostly the same people to go to all the open houses so that there was always a consistent story that people could understand. And, the people who were there from Xcel Energy or GRE could really understand what the issues were that were brought up by landowners. The project groups had uniformity or consistency in coverage so they knew what was going on.” (Wahle, 2016)

Intentionally sending the same staff members to the open houses ensured that local points would be heard and nothing was missed.

3.3 Evolution of Engagement

As work progressed and project routes were refined, CapX2020 continued to send out thousands of direct-mailers to landowners in project corridors and used newspaper ads and coverage on radio and television to announce public meetings, open houses, and presentations. The group invited public officials, state agency representatives, and PUC representatives to join utility representatives at meetings so that a diversity of perspectives were made available to landowners and the public. The CapX2020 group also mailed monthly and quarterly newsletters to residents along project corridors.

The CapX2020 members felt that engaging the public did not significantly reduce the amount of time it took to get the projects permitted, but it resulted in routes that were more acceptable to people affected by the lines. It's hard to assess whether the public engagement reduced the opposition to this project, but it did not face the level or intensity of opposition that transmission projects experienced in the CU Project Controversy in the late 1970s. Mike Gregerson recalled,

"The amount of work, and effort, and time...it's been 11 years. It's a very painstaking, careful process. And if you go through all of the public meetings, and engagement of regulators, and utility people that you need to do to get it done right, it's a lot of work, and it takes a lot of time. It's a lot of meetings, and in some cases, some parts you have to do over, because maybe the idea you had for a route – overall, people didn't like it. So the process of getting that done, number one, is really hard, and it takes a real collaboration by everybody. And it's a process that is ongoing. You don't meet with a state legislator, or a Commissioner, or an energy policy person once and everything's fine. You need to keep coming back because the regional grid continues to evolve." (Gregerson, 2015)

Looking back on what they learned over the course of the almost decade-long permitting and construction process, members of the CapX2020 group firmly believe that the developed strategy, engaging with landowners early and often, is one that they will continue to use on projects in the future. Chris Fleege of MN Power noted how the CapX2020 approach will serve as a template of how to do public engagement in the future for large transmission projects:

"People want to know what's happening, especially if it's going to impact them. Ultimately, there are a lot of ways to do that, and we've become much more effective in doing that. We've learned a lot from each other, because quite frankly, even Xcel Energy hadn't built large transmission outside of the metro area for some time...I think it speaks to the pre-planning and having the best minds of the business out of all the utilities come together to collectively develop a realistic approach. Identifying the risks, and mitigating them ahead of time. Having that large group coming together, I think we got the best product." (Fleege, 2016)

4. Construction and CapX2020 Project Management

Each of the four Group One CapX2020 projects was led by one utility, named Project Manager. With four projects running concurrently, the CapX2020 group's intention was to balance overall resources while selecting a lead utility capable of managing project work. The CapX2020 group selected the lead utilities from the subset of utilities that had the experience and resources to manage these projects.²² Xcel Energy took the lead on two projects: The Fargo-St. Cloud-Monticello 345-kV line, and the Hampton-Rochester-La Crosse 345-kV line. Great River Energy led the Brookings County-Hampton 345-kV line, and Otter Tail Power managed the Bemidji-Grand Rapids 230-kV line.

The decision of who led which project came down to experience and size of project work. Tim Rogelstad recalled how the decision was made for Otter Tail Power to lead the Bemidji-Grand Rapids project:

“The Bemidji-Grand Rapids line was a fraction of the size of the Fargo-St. Cloud-Monticello line, so that clearly was part of it. We didn’t have experience building a double-circuit 345-kV facility. The 230-kV line between Bemidji and Grand Rapids was best suited for our skills.” (Rogelstad, 2016)

This collaborative management approach was different from the administration of previous joint projects as the CapX2020 initiative was the first time that these utilities worked together as “tenants in common,” in which they all owned a percentage of the line from end-to-end. In the past, each project member would discretely own part of a line. For example, a utility would build one end, and another would build the other, with the lines ultimately meeting in the middle or at a substation. While utilities had jointly permitted projects in the past, this was the first time project work was combined with one utility serving as Project Manager to oversee the work.

The CapX2020 leadership created a Project Management Office (PMO) to facilitate cross-project, cross-team collaboration and capture best practices from these joint activities to serve as a model for future work (Kaul, 2010). On its face, the contractual structure of the CapX2020 group was based on a project-by-project basis and did not directly foster cross-project collaboration; however, it was the PMO that acted as the glue to bind the Vision Team and the 11 participant utilities in the execution of projects. The CapX2020 group saw opportunities in a number areas in which the PMO could work to achieve positive outcomes and benefits (Kaul, 2010), which can be summarized as:

1. Decrease overall implementation costs by coordinating procurement and distribution of supplies and materials.
2. Provide leverage to and support for the individual Project Managers (PM) and PMO Steering Committee representatives by facilitating communication and regular meetings.

²² MN Power was in the process of finishing construction work on a 345-kV line connecting Duluth, MN to Wausau, WI. As a result, they did not take a Project Manager role in the CapX2020 projects they participated in.

3. Prioritize and allocate CapX2020 project resources.
4. Eliminate redundancies through identification of overlapping project scopes and resource needs.
5. Coordinate dependencies across the portfolio of related projects.
6. Assist the CapX2020 Project Managers to remain on-schedule and on-budget through early identification of issues and deployment of targeted resolutions.

Teresa Mogensen summarized the approach,

“Our overall philosophy was minimizing cost, making sure we addressed all requirements associated with permits and schedules and everything else, and doing it in a way that teed up information to the right people at the right time.”
(Mogensen, 2016)

The PMO brought significant benefits by facilitating cross-project collaboration. For example, later projects benefitted from the experiences of earlier projects, and the PMO was able to shift resources between projects to meet pressing needs. Looking back on how the PMO helped matters run smoothly, Tim Rogelstad observed:

“The notion of the PMO office and a few other things led to some best practices. When the Bemidji-Grand Rapids project was complete, we did an extensive best-practice analysis. We brought in almost everyone involved with the project, including the outside resources consultants, environmental firms, design firms, and construction firms, to say, ‘Okay, we’re done. As we look back, what went really well, what didn’t go so well, and how would we have done it differently?’ And today we’re carrying those things forward.” (Rogelstad, 2016)

The CapX2020 leadership deliberately designed the PMO to ensure alignment with the Project Managers. Both groups were in-step with the strategic needs of the organization in mind, broadly pursuing the same agenda, even though at the day-to-day activity level PMs and the PMO were tackling different objectives. The PMO provided project-specific delivery support and advisory services while maintaining cross-project, cross-team collaboration. It managed major program challenges, optimized the use of shared organizational resources, and managed the overall risks, opportunities, and interdependencies among project groups.

It is always difficult to estimate the cost of a large, complex project and to keep it on schedule. The combination of a broad range of experiences and expertise along with a well-defined organizational structure gave the CapX2020 group the stability it needed to keep project work on time and on budget. Ray Wahle credited the group’s success on having aligned goals:

“I don’t know if it was so much the Participation or Project Agreements themselves, but rather the fact that we had a very good organizational structure. Everybody knew what we wanted to get accomplished, and everybody wanted to get it accomplished and not let your partner down. It drove people to pay attention to what was going on and to really perform well.” (Wahle, 2016).

Together, the PMs and PMO worked together to keep the CapX2020 projects on time, and on schedule. Clair Moeller of MISO recalled,

“The thing that has made my life easiest is that their estimates were accurate. It really helps. The fact that they were that proficient at estimating accurately,

timely, predictably, they were able to show the rest of the community it just work—that every project doesn’t over-run 200 percent. The technical skills they showed dramatically helped the momentum towards transmission investment, because they showed that it can be done. That is a really important element of what they’ve been able to do.” (Moeller, 2015)

4.1 Internal Project Management

Managing the execution of \$2.1 billion worth of transmission infrastructure build-out within the timeframe of about six years is a difficult task. At a dedication event of the Brookings County-Hampton and Fargo-St. Cloud-Monticello 345-kV lines in St. Cloud in 2015, Teresa Mogensen noted that \$1.3 billion was invested between the two projects:

“That [\$1.3 billion investment] is a significant investment in our public infrastructure. If we compare our CapX2020 lines to another big project—the Vikings stadium—that’s a billion dollar investment, too, that will host 10 NFL games a year.²³ Our CapX2020 lines, on the other hand, are going to be delivering electricity every second of every day from now until hopefully a long long time to come.” (Mogensen, 2015)

Leveraging the collective experiences of the 11 participating utilities was the foundation of the CapX2020 initiative. Together, the utilities possessed deep subject matter expertise across each phase of developing and constructing a high-voltage transmission project. Graham Arntzen, project management consultant with Pioneer Management Consulting said,

“People say, ‘Its poles and holes and wire, it should be easy!’ but it is far more difficult than that.” (Arntzen, 2015)

Each utility approached the projects differently based on their experiences and their particular service territory perspectives, and as a result each utility learned from one another and built upon their expertise in subsequent projects. Developing five major transmission projects, including the Big Stone South-Brookings County project, with significant schedule overlap introduces a great deal of complexity but also presents a great opportunity to collaborate and deliver on economies of scale and execution efficiencies.

The PMO identified the need for a program integrated schedule, and each project had an individual project schedule. The PMs, with support from the PMO, defined a common work breakdown structure and maintained a program-level schedule. This enabled the team to identify peaks and valleys in the execution of the work. The team smoothed work spikes to better fit with the supplier’s production capacity and available contractor labor. Finding the amount of labor necessary for construction proved to be a challenge. Many of the lineworkers who worked on the last major infrastructure build-out in the 1970s had retired, forcing some construction work to occur sequentially instead of in parallel. This challenge was anticipated, and PMs factored in

²³ A new football stadium under construction in Minneapolis, MN will serve as the home of the Minnesota Vikings. Reports in 2015 estimated the overall budget to be around \$1.06 billion.

enough contingency into the project so that logistical challenges such as this did not impact the overall schedule.

“Instead of doing work in parallel, we were doing it sequentially. That’s why I don’t think it really impacted the budget. It was always budgeted, it just couldn’t be done at the same time when you really got down to the nitty-gritty of it. There just weren’t enough line workers, materials, and equipment in the world to do as much as we all wanted to do at the same time. (Porath, 2016)

Managing suppliers, materials, and labor started years before construction began on the individual projects. The familiar adage of “measure twice, cut once” illustrates the importance of planning for a project of this scope and complexity. Decisions were made about construction timelines, materials, suppliers, and labor up to two years prior to the start of construction.

Figure 10: Construction crew pouring cement into a foundation



One important role the PMO played was to manage competing needs of individual projects, particularly for time-sensitive activities. For example, in 2013 alone, the Brookings County – Hampton Project poured more than 62,000 cubic yards of locally purchased concrete, at a cost of \$5.6 million (CapX 2020, 2013). The photograph in Figure 10 shows the scale of the concrete work for a spread foundation from the Mississippi River crossing. Local suppliers are necessary in concrete, as it must be used within two hours of being mixed. Suppliers along project routes were identified well ahead of time, and local drivers delivered concrete to each pole location for foundation work, yet there were instances when deliveries were reallocated from one construction site to another to apply the resources to the highest priority needs.

These resource shifts could be sensitive between project teams, as the utility responsible for managing an individual project was responsible for delivering on time and on budget. Incurring additional risk for the good of the overall portfolio of projects required a thoughtful management process. This is where the PMO and the group culture of collaboration as an overarching objective of the CapX2020 program demonstrated tremendous value. Fact-based analysis with detailed documentation and clear presentation of risks was foundational to the management and decision making processes. The project teams, the CapX2020 leadership team, along with



The Challenges of Construction

Some of the poles built in wetlands or other unstable soils required reinforced concrete foundations up to 12 feet in diameter and 65 feet deep, which required at least 25 truckloads of concrete. The huge volume of excavated soil then needed to be disposed of without leading to negative environmental impacts.

support of the PMO were able to strike a balance to ensure that all CapX2020 projects were successful.

“Different projects were going at different rates, and to the extent that we encountered something and figured out a way to deal with it in one of the projects, we wanted to take that best practice and make sure we brought it into the common pool of knowledge and carried it forward.” (Mogensen, 2016)

From the perspective of developing and sharing best practices, techniques, and knowledge, all the CapX2020 entities benefited from having worked through this process together.

4.2 Managing Construction Costs

It is common for construction projects to be late and overrun project budgets. The \$2.1 billion CapX2020 projects are on track to come in on time and on budget.

4.2.1 Line Design

With an effort as large as the CapX2020 expansion, many engineers were involved in project design. Engineers first performed the

detailed design of the line, including foundations and pole structures. These design decisions determined a significant portion of the cost of the line. The engineers and PMs then reviewed the construction processes to identify obstacles before the beginning of construction with the aim of preventing errors, delays, and cost overruns.

The CapX2020 group used innovative technologies during the construction process. For example, construction crews used helicopters at times to string transmission conductors (wire) from structure to structure. For example, during the summer of 2011 a helicopter was used to pull wire and install spacers and bird diverters on the 28-mile line being built along Interstate 94 northwest of Minneapolis. Helicopters were also used to set structures, string the line, and to install interphase spacers to help prevent damage caused by weather or by lines swinging too close to each other in high winds. Implosive connectors were used to splice transmission conductor joints (Figure 13), a method wherein a detonation implosively crimps the connectors around the cables, which results in a stronger connection and is a process less prone to error than traditional splicing techniques.

Figure 11: Implosive connector blast on a dead-end structure



4.2.2 Procurement of Materials and Labor

The size of the combined CapX2020 projects gave the group significant buying power. Suppliers and contractors were eager to secure work on the CapX2020 projects. Ensuring the projects had sufficient resources at the right time required a rigorous and disciplined sourcing approach that again leveraged the strong capabilities of the CapX2020 utilities.

The volume of services and materials needed to build the program of projects had to be clearly understood and presented to the marketplace. The PMO worked with the three Project Managing utilities' supply chain organizations to understand demand requirements and market supply. For example, Ray Wahle from MRES recalled an instance of collaboration during substation work on the Fargo-St. Cloud-Monticello project. Xcel Energy was responsible for the construction of the Fargo substation, and MRES was charged with constructing the Alexandria substation. Xcel Energy placed a bid to procure a reactor, and since two were needed for this project, MRES piggybacked on the contract:

“That’s one of the ways we worked together in terms of getting the equipment. Rather than us duplicate work, whoever they [Xcel Energy] bought their reactor from, we just went to the manufacture and said, “me too, we’ll sign the same contract.”” (Wahle, 2016)

For perspective, the cost of building a substation is significantly more expensive than other parts of line construction because of the extra materials and equipment needed. The Alexandria substation cost about \$25 million, or about 25 percent of MRES’s investment in all of the CapX2020 projects.

An integrated schedule was used to define how much of each material was required and when it was needed to keep the project on schedule. The PMO team performed due diligence reviews with service providers, material suppliers and construction contractors through a Request for Information. These reviews helped the team identify a short list of providers, suppliers and

contractors that would participate in ongoing Request for Proposals in the coming years. A clear demand picture and a well understood supply base were critical in ensuring the projects could be delivered on time and on budget. In one example, the team identified a significant risk in working with a particular supplier. This supplier communicated that they could provide a certain material for all CapX2020 projects, but the due diligence review demonstrated that with their current factory capacity, supplying all the projects would have been impossible. The PMO tried to award contracts to a mix of national, regional, and local companies in order to mitigate risk but favor local companies when feasible.

Careful contract review was critical to ensuring suppliers could deliver what they promised, but it was contract management that kept the projects on budget. The PMO monitored every transaction closely. Graham Arntzen, who worked in the PMO, noted,

“If you’re going to spend \$640 million dollars [on the Fargo project], you’re going to manage that \$640 million dollars. We chase both large and small transactions, and we chase hard.”(Arntzen, 2015)

The PMO supported the project cost controls function which includes forecasting project expenses, ensuring the team is managing to the scope and budget, and tracking the specifics of individual transactions in support of contract administration. This disciplined approach was crucial to keeping the CapX2020 projects on budget. Spending on construction approached \$60 million per month through the end of 2013 (CapX 2020, 2013). The PMs and PMO maintained control of project costs through detailed reporting, detailed financial management tools, and cross-functional meetings to keep a clear picture of the cost performance of the projects.

4.3 Construction Timing

4.3.1 Managing Construction Timing and Easements

One of the biggest challenges in managing the construction of a high-voltage transmission line is coordinating the acquisition of easements with the timing of construction. Easements give the utility the right to cross and use land for the purpose of constructing and maintaining the line. In a more traditional single-utility project, the legal counsel for project work would review a utility’s standard easement document to ensure compliance with state law. In the case of CapX2020, each of the 11 utilities had input on the language of the easement document used. Together they developed a base easement document that all parties could agree upon, yet each utility had a slightly different opinion on what easement rights should be acquired. Steve Quam, an eminent-domain lawyer with Fredrikson and Byron who worked on the CapX2020 projects recalls,

“All of the siting and land rights representatives from each of the 11 partners came together and discussed if we could have a uniform easement that could be used on the project. I was charged with synthesizing all 11 ideas and putting them into an easement document that would be used first for voluntary negotiations, and then second if we were forced to condemn property, it would be the rights we would acquire through the legal process.” (Quam, 2016)

The group developed a document that was flexible enough to work across the range of property types and jurisdictions the CapX2020 projects encompassed.

Figure 12: Hampton-Rochester-La Crosse line construction across the USFWS Upper Mississippi Wildlife Refuge in southeastern Minnesota.



The sequence of events on large projects are time sensitive, especially CapX2020 as it was comprised of four almost simultaneous projects across the state. Real estate acquisition teams that negotiated easements with landowners worked ahead of the construction crews. The acquisition teams generally preferred to acquire a significant percentage of easements before construction began because it is the most convenient and cost efficient for the construction crews to work sequentially through a project. Moving large construction equipment to a new spot on a line to skip over property without an easement could cost upwards of \$100,000. For a few of the CapX2020 projects, line length determined whether construction began before all of the easements for the route had been acquired. On shorter lines, crews waited until all the easements were acquired. On some of the longer segments, waiting was not an option. For example, construction began on those parcels where easements had been acquired along the 110-mile long Phase 3 of the Monticello-St. Cloud-Fargo line after all state permits were issued and some, but not all, of the easements had been acquired. Steve Quam remembered some of the challenges of managing the acquisition of easements while meeting other project demands and noted the importance of doing a lot of front-end work:

“The more front end time we had, the more successful we were. It’s difficult to manage, because you don’t know how many people are going to sign, you don’t know how many parcels are going to go into condemnation. And the more parcels you have, the more work there is, then time gets crunched and it becomes more difficult to meet all the demands that exist for a project of this magnitude.”
(Quam, 2016)

Just as construction crews encountered logistical challenges of finding qualified lineworkers, the easement and land acquisition teams encountered challenges. Project work was spread throughout the state, and most of the CapX2020 projects gained permitting approval from the PUC and could begin construction and acquiring easements between 2011 and 2013. This

translated to a logistical challenge of ensuring that the professionals required to acquire easements were organized early on.

In the easement agreements, CapX2020 negotiated right-of-way corridors 75-250 feet wide for the transmission lines. However, there were times CapX2020 crews needed more than that allotted space during construction when they needed to access land adjacent to the defined easement corridor to temporarily place poles, rebar, and other construction materials until they were used. Igor Lenzner, eminent-domain attorney with Rinke Noonan who represented and consulted with hundreds of affected landowners, remembers the challenges early on in the construction process:

“If I’m the property owner, I want to confine and define their rights as much as possible. In Stearns County, since we were the first to have hearings, one of the very first hearings we had CapX had not yet confined the access and temporary construction. So we went to the Commissioners saying, ‘Hey, this undefined easement is worse than a defined easement.’ It’s worse impact than value (landowner compensation) because we don’t know what its impact on the whole property.” (Lenzner, 2015)

Critics said the language of the CapX2020 easements that defined access to the land was too vague. Landowners wanted to know the exact areas included outside of the easement corridor, but the utilities wanted as broad rights as possible. Some landowners wanted to know where on their property construction crews would access the easement corridor, what equipment would be transported, how it would be transported, and how much space would be needed to accommodate it.

However, the CapX2020 group had a different approach for how best to deal with access. In general, the route a transmission line follows is linear, but sometimes access to the easement was not feasible under the specific conditions unique to a particular property. Where some landowners saw lack of definition in the easement document as problematic, the CapX2020 group saw flexibility for both parties:

“It gives the utilities the right to essentially do what makes sense. If there’s a road, you use it. If there’s not, you find the most reasonable way there.” (Steve Quam, 2016)

Furthermore, it was not always clear to the project teams when they might need more space than the typical 150-foot easement during construction, so the easements they used provided the utilities flexibility to accommodate unforeseen events. While the construction crews and utilities did not want to trespass, it was important for them to have access to the property when they needed it. It is also important to note the implications of having a flexible easement on future development on a property. Steve Quam recalled,

“The question is, do you have a blanket easement or a broader easement that allows you to do what is reasonable under all circumstances, or do you define an easement and then the landowner is forced to develop around your access. If you have an easement that is subject to the right to develop, they [the property owner] develops and we have to move. If we define it first, then they have to develop around us. So, arguably what was done is certainly broad, but it provides the landowner with more flexibility in the future.” (Quam, 2016)

When the “blanket easement” was not sufficient to satisfy a landowner, the CapX2020 group would further define easement areas.

Ultimately, with a portfolio of projects as large as CapX2020, most landowners were satisfied and that the process was fair. The culture of collaboration found in the Vision Team and the Project Management Office trickled down, permeating across the entire project, including the land acquisition and legal counsel teams. The legal system is generally adversarial, yet the legal teams that represented both CapX2020 and the affected landowners worked together to find a reasonable result that was fair to all parties.

“There were so many open issues that could have been contested, and a lot were brought to court for resolution, but there would have been a lot more. [Had we not worked together] it would have been, in general, more difficult process for all involved.” (Quam, 2016)

Most of the time, the CapX2020 legal team and lawyers representing landowners and other stakeholders were able to work together on fair terms and resolve issues in a manner acceptable to all parties.

4.3.2 Weather

Second only to the challenges that arose with managing landowners and easements were the challenges of managing construction schedules affected by inclement weather.

Teresa Mogensen remembers,

“In constructing the nearly 500 miles of line in three states, the men and women who built these projects faced many challenges. From high winds and freezing temperatures to record rainfalls, they met each and every challenge. (Mogensen, 2015)

Cold winters slowed construction and high winds, rain, and flooding added a set of unique challenges for PMs to manage. Some of weather challenges were self-imposed, while others came as a result of appeasing state and federal agency requests. Much of the construction was intentionally done in the wintertime to minimize the effects on farmers who had given them access to their land through easements and to allow crews to work in the wetland and other environmentally sensitive areas while the ground was frozen.

Figure 13: Helicopter line work in wintertime



4.3.3 Coordinating with State and Federal Agencies

Each project interacted with multiple state, federal, and tribal agencies during permitting and construction, including the Minnesota Department of Natural Resources (DNR), the U.S. Fish and Wildlife Service (USFWS), the Rural Utility Service (RUS), and the Army Corps of Engineers, to name a few. CapX2020 Project Managers had to coordinate construction schedules to meet the requirements of those agencies. For example, the Minnesota DNR would request that

the construction of a line segment not occur during nesting season of an endangered bird, or that crews clear a corridor during a particular time of year so as to not disturb a specific species. This was a challenge for Project Managers because they were already dealing with landowner requests, their own construction crew issues, and permitting requirements from other state agencies. Jamie Schrenzel, State Principal Energy Planner with the Minnesota DNR remarked,

“The utilities, of course, have to think of all different sorts of factors, and so does the PUC. All sorts of different factors, like relationships with landowners, economic factors, as well as natural resource concerns, and permitting timelines. At the DNR, we are focused on either our permit requirements or our general jurisdiction over wildlife.” (Schrenzel, 2015)

The timelines of the CapX2020 group and the requirements from state and federal agencies did not always align. Sometimes the utilities and state or federal agencies were not in agreement over recommendations. To its credit, the CapX2020 group was quick to communicate with the involved agency to resolve conflicts when they arose. Jamie Schrenzel went on to state,

“There are certainly sometimes tensions because people are coming from different perspectives, and different points of view. However, the CapX utilities are very collaborative, and they do a lot of early coordination.” (Schrenzel, 2015)

4.3.4 Mississippi River Crossing

The Hampton-Rochester-La Crosse project crosses state lines, and to do so it needed to traverse the Mississippi River, which was the biggest construction challenge of the project. For this part of the project alone, the CapX2020 group cooperated and coordinated with the US Department of Agriculture, the US Army Corps of Engineers, the USFWS, as well as the Wisconsin and Minnesota DNRs.

Before construction could begin, a federal Environmental Impact Statement (EIS) was required for the Mississippi crossing because of the federal management of the Upper Mississippi River National Wildlife and Fish Refuge by the USFWS. The EIS had to be filed with a lead federal agency to manage the federal EIS process. Dairyland Power is a borrower from the RUS, a department of the US Department of Agriculture, allowing Dairyland to make a unique contribution to the project work. The RUS managed the process, but the USFWS had jurisdiction. Ben Porath explained,

“It happens that since we borrow from the federal government, and you need a lead federal agency to help manage the federal EIS process, we were able to leverage our involvement through RUS to be the lead federal agency. It was the first time that something like that had been done in a joint-utility process basis on a transmission line, so although it took a while, we developed a really good process for getting the federal EIS done, which was kind of the final link in the chain to get the major project permits in place.” (Porath, 2016)

Determining a route while managing state and federal agency expectations proved to be a logistical challenge. During the planning phase, there were multiple routes to get to the river on one side in Minnesota, and multiple routes to get away from the river on the other side in Wisconsin. There was a lot of discussion between line engineers from the utilities and the state and federal agencies involved to determine the best place to cross the river and line design.

USFWS had two main concerns: the height of the structure and how much tree-clearing needed to be done, both of which impacted migratory birds. The DNR encouraged the group to look at a variety of locations for the crossing, and even suggested that the line be routed under the river because the area is an important flyway for birds. This proved to be very technologically challenging and expensive, and because there was an existing line in the area, the agencies determined the location at Alma to be the best site option. In the end, both groups compromised to find a solution. Part of the agreement was removing the existing line, built in 1965 by Dairyland Power Cooperative, and replace it with a triple-circuit configuration.²⁴ The size and shape of the towers for the crossing was also the product of compromise. Instead of building tall and skinny, the line was designed to be low and flat to avoid migratory bird impacts. This iterative communication was key to finding the most feasible location to cross, as this process was imbedded in the state permitting process. Ben Porath explained,

“I think CapX probably set the gold standard of how you would build a Mississippi River crossing... We have future growth built into the Mississippi River [because the lines are double-circuit 345-kV capable], so we don’t have to come back at a future date if we need that additional capacity. I hope when we build between Dubuque, IA and Madison, WI that we have the same long-term vision, and that we don’t just build what is needed today, but build something that is future-capable. Precedent was being set, and precedent can be used on future projects.” (Porath, 2016)

Construction crews dealt with a unique set of challenges, from building on an island to dealing with an early winter and extreme cold. That island and a nearby peninsula were only accessible by water, which meant all equipment, materials, and labor had to be delivered by barge or boat. Over 3,280 cubic yards of concrete was needed to build the pole foundations on the island. On one day in particular, 100 cement trucks were ferried to the island by barge, two trucks at a time. To add to the difficulty, at the time of construction there was a shortage of cement, according to local news reports. The project manager was able to work with the supplier to make sure that the CapX2020 project was given priority for concrete because they were in a race with the weather to deliver the materials before the river froze over.

The foundations used on the island were different than what was typically used inland because the soil was very unstable. They used pile-cap foundations, comprised of 362 16-inch steel pipe piles in a grid, with some driven into the soil as deep as 130 feet. Helicopters were selected as the best way to string wire and attach other line components between the two sides of the river.

²⁴ The Mississippi crossing now includes one double-circuit 345-kV line, one midsize 161-kV line, and one low-voltage 69-kV line.

Figure 14: Barges were used to ferry equipment, materials, and labor to an island on the Mississippi River.



5. Discussion and Conclusion

5.1 Characteristics That Made the CapX2020 Partnership Successful

As of Spring 2016, the CapX2020 group is on track to complete five new high-voltage transmission lines. Spanning nearly 800 miles at a cost of \$2.1 billion, all projects are on time and on budget. That alone is a significant achievement. It is even more impressive given that the last large high-voltage transmission line projects in Minnesota were built in the 1970s. Kent Larson, Executive Vice President and Group President of Operations at Xcel Energy noted,

“This thing started more than 10 years ago. If you think about a project of this size and magnitude and complexity, you could think of a lot of reasons for it not to happen. It’s easy to kill a project, but it’s much more difficult to make it happen, and this group came together and made it happen.” (Larson, 2015)

This was a significant accomplishment to the utilities and regulators involved, yet it went almost completely unnoticed by the general public except for the people whose backyards the lines went through. Al Juhnke, former State Agriculture and Energy Advisor to Minnesota Senator Al Franken noted,

“As far as public pizzazz and excitement goes, transmission projects rank just above sewer and water, and just behind road overlay projects. So, you know, the public doesn’t see this going on.” (Juhnke, 2015)

CapX2020 achieved success by building a strong coalition of 11 utilities that had the resources to finance and manage large-scale projects, and the political influence to ally with a broad range of stakeholders to change laws and influence regulations. The relationships the CapX2020 group cultivated coevolved with their work, allowing each utility to: (1) understand the challenge they faced of working together to build high-voltage transmission, (2) work with each other to develop a process through technical studies and engagement with industry stakeholders, and (3)

make decisions about which rules of conduct were the most significant through governance and project agreements.

Specifically, five key characteristics led to the group's success:

1. Common goals
2. Creating a win-win situation
3. Building relationships
4. Group governance
5. Transparency and open communication

These aspects parallel Kania and Kramer's Collective Impact Theory, which states the commitment of a group of important actors from different sectors to a common agenda can work together to solve a specific social problem (Kania & Kramer, 2011). Public utilities furnish the everyday necessity of reliable electricity to the public at large, operating at arm's length from government. As such, they have a duty and responsibility to figure out what kind of infrastructure is needed to support the array of needs that they are chartered to serve, and proceed in a way that is timely. The CapX2020 partnership and work exemplifies collective impact theory because, "At its core, collective impact is about creating and implementing coordinated strategy among aligned stakeholders" (Kania & Kramer, 2013). This framework offers a template to utilities for building a successful coalition to collaborate on large projects.

Characteristic 1: Common Goals

The CapX2020 group was successful because the participating utilities developed a shared vision for change. Their vision included a common understanding of the problem and a joint approach to solving it through agreed-upon actions. In Kania and Kramer's framework, collective action takes place around shared understanding about the purpose of an initiative, the relationships that utilities and stakeholders in the field have with each other, and the rules and regulations that govern legitimate action.

The need to address system reliability was greater than what any utility could handle on its own. The CapX2020 group recognized it would have been difficult for any of them – even Xcel Energy – to finance and obtain permits to build the lines alone, and that they needed to work together. Mike Gregerson of Great Plains Institute and the Midwestern Governors Association observed,

"If they would have tried it individually or on their own they could have possibly not gotten it done, or had some projects turned down...By working together, CapX2020 presented a much stronger picture to MISO and the states that they were in that this was a good idea, and even though it was a lot of money, there was a believability to the work that they did." (Gregerson, 2015)

Had the utilities approached the need to build new high-voltage transmission individually, system upgrades would have been installed piecemeal and the regional benefits that the CapX2020 projects brought would not have been realized. North Dakota Public Service Commissioner Brian Kalk pointed out,

"If you're going to try to build 345-kV lines of this size and scope, maybe Xcel Energy could do it alone. Maybe. But without some of the smaller cooperatives involved, they could never build a line like this. What you'd end up having instead of one transmission line they could all work with, you would have a hodge-podge

system of transmission lines in different areas...I think the best way to do transmission planning is this way, because then the cost can be shared by others, as well as doing more efficient planning.” (Kalk, 2015)

The utilities did not agree on everything over the more than 15 years they worked together, but having a common goal facilitated their ability to compromise so they could create a united front. Ray Wahle added,

“Everybody had their own goals, their own objectives going in, but I think from an industry-wide perspective we all understood that we needed to do something. When we first started out, we didn’t quite know what that something was. We needed transmission infrastructure. We had certain problems facing us: the RES, load growth, and reliability. I think when we came together as CapX partners, we did have a shared goal in terms of trying to solve these problems. I think that helped a lot in terms of us coming together as a group and being able to find a solution to our shared goal and problems. I think we started off on a very solid footing because of that, and everybody was on the same page.” (Wahle, 2016)

In addition to the reliability needs, CapX2020 participants shared the need to meet state renewable energy standards. They recognized that new high-voltage transmission also helped reduce the cost of complying with those requirements.

Characteristic 2: Creating a Win-Win Situation

The CapX2020 group recognized that they could only achieve their shared vision by cooperating with each other. This cooperation took two important forms. First, utilities sometimes made efforts that had little direct benefit to themselves, but benefitted the group as a whole. Second, group members or the group as a whole sometimes made decisions benefitting individual utilities in order to help them justify their participation in the CapX2020 project.

“Part of the willingness to collaborate means, ‘I win and I let you win too.’ That’s the attitude that you need to make it successful, because if the attitude is, ‘I only win if everybody else loses,’ then you’re not going to have a coalition like CapX; it’s not going to work. I think that’s an important thing, and it gets to the personal level that’s needed to advocate for this within the companies, and then the companies themselves, that they are willing to allow for that. Sometimes either the personal character or the company character isn’t going to line up with that, and you’re going to have trouble holding something together. It’s all those factors that are coming together, along with a willingness to maintain that relationship and see that value. Being able to say, ‘Yeah, I could get 100, but I’m going to get 50 instead because it makes sense for the long haul.’” (Mogensen, 2016)

As Tim Noeldner from WPPI Energy explained, the group was able to work past their differences to align their interests:

“Coopetition is a cross between collaboration and competition. Sometimes you compete with each other, and sometimes you cooperate with each other, but the objective is to make it so that everybody does better overall. Make the pie bigger instead of take somebody else’s piece of the pie away. This project has reminded me a lot of that work. You try and do the right thing, and then sort out the details about who’s going to own what percentage and what section, and have the

confidence in the other players that we will be able to get to something that makes sense.” (Noeldner, 2016)

Throughout the course of project planning and gaining permitting approvals, there were examples of how each utility helped one another. In 2005, key legislation was passed in Minnesota that enabled the projects to move forward by allowing earlier cost recovery for IOUs. This legislation was shaped and endorsed by the CapX2020 group and its coalition of stakeholders, though not all would directly benefit from this change. The group was able to see the power of collaboration when they were able to propose the bill and have the support of the electric cooperatives as well as the municipal power groups. Tim Rogelstad noted,

“I commend the folks who aren’t regulated by the PUC but recognized that it was important for us as IOUs to have that certainty to be able to proceed forward.” (Rogelstad, 2016)

When the CapX2020 group encountered a roadblock, they were able to make it a group issue, not just an individual issue. They took a “what’s good for the goose is good for the gander” attitude, and despite any differences the group had on the surface, they were able to work through them together.

The IOUs reciprocated by respecting the role of the smaller utilities during the development stages of the group’s work. In the grand scheme of the overall need for transmission, the municipal utilities and rural electric cooperatives (REC) that participated in the CapX2020 initiative were relatively small players. Ben Porath from Dairyland Power quipped,

“One of the jokes in the coop world is, ‘We have all the territory, but none of the customers.’ We don’t have the wherewithal to take on a major transmission project on our own. We need to work on a regional basis with the other regional utilities.” (Porath, 2016)

Generally known as Transmission-Dependent Utilities (TDU), municipal utilities and RECs rely upon transmission services owned or operated by another – often larger – utility for the energy needed to serve its customers. In general, a transmission owning utility owns and operates the high-voltage network of transmission lines to which the TDU interconnects their lower-voltage network of distribution lines. Rural electric cooperatives and municipal joint action agencies have members spread across expansive footprints. MRES, for example, serves 60 communities in four states. A TDU often does not have the technical or financial capacity to build high-voltage transmission line projects, and it would be infeasible for them to build transmission to each individual community they serve.

For a TDU like WPPI Energy, participating in the CapX2020 projects provided an opportunity to grow their capacity. Because of WPPI Energy’s ownership share of the Hampton-Rochester-La Crosse CapX2020 project, they qualified to become a transmission owning member of MISO (they were approved by the MISO board in December of 2015). Tim Noeldner explained the chicken-and-egg challenge smaller groups like WPPI Energy face:

“MISO has a tariff, which is a rate schedule, and it is the way we will recover our investment and return on the CapX transmission project. That’s how Xcel and GRE and all of the other owners of CapX will recover their investment. The challenge for WPPI Energy was that we couldn’t become a MISO transmission owner until we owned transmission, but we couldn’t get certainty of cost recovery

until we were MISO transmission owners. So, we first applied to become a transmission owner back in 2008 with MISO, and they said come back when you own some transmission, so we did when the line went in service.” (Noeldner, 2016)

The CapX2020 group advocated on behalf of the small utilities in the same way that the small utilities advocated in the legislature on behalf of legislation that primarily benefitted the large IOUs. Tim Rogelstad continued by explaining how there were many examples of how the group supported each other:

“When MISO approved the Fargo project, MRES was not a member. So when they wanted to be an owner, MISO was saying they would not give them regional cost allocation. That is when CapX as a group said, ‘Hey that’s not right. They were part of the planning process. It’s just the timing of their membership was different than the rest of us and, therefore, they should be allowed.’ Fortunately, they were, but I think that’s an example of where some of the other utilities stepped up to help a particular utility.” (Rogelstad, 2016)

The ability to support each other on a variety of issues speaks to the collaborative approach of the group, which allowed for large and small entities to work on a more equal playing field. The approach allowed each utility to leverage their expertise and relationships that had already been cultivated. Developing a win-win situation was a show of good faith that further strengthened the relationships the utilities had with each other.

Characteristic 3: Building Relationships

The social compacts established during a project like CapX2020 both constrain and enable what can be accomplished in the course of project work.

Utilities in Minnesota and the Upper Midwest had a history of working together, but the CapX2020 project was a much larger effort because of the amount of transmission that was being built, the amount of capital that was needed, and the scope of the regulatory process that the group went through to get the projects permitted. From this perspective, Ray Wahle recalled,

“I think our organizations got to know each other a lot better because we had to deal with everybody almost on a daily basis, and at a lot more levels of the organization. The people within the organizations became much more known to each other because by nature of the depth and breadth of the projects, you’re getting to know a lot more people. I’m sure I met new people through the process, but we had talked to lots of other companies in the past. I think it was much more frequent contact, much more in-depth contact, so you’re really finding out a lot more about people and what they’re trying to accomplish.” (Wahle, 2016)

There are innumerable examples that show the depth and breadth of the relationships that were cultivated over the course of 15 plus years the group has been working on the CapX2020 initiative together, many of which are discussed throughout this report. Developing the details of the Participation Agreement and Project Agreement templates alone took three years of negotiation and work. Monthly project check-ins resulted in consistency across all participants and ensured efforts remained aligned while keeping participants accountable. Teresa Mogensen added,

“Just like a marriage, times aren’t always smooth when you’re working together on something or trying to come together on something. You have to have a level of trust, that you have both good motivations and that you’re trying to get somewhere together, and that you can work through whatever bumps that you’re going to have together. There has to be a certain amount of trust and willingness to align with each other and hold that coalition together through the inevitable bumps and bruises and problems and other things that are going to come.”
(Mogensen, 2016)

All the CapX2020 participants interviewed for this report agreed that the members truly felt a deep level of trust with one another. They called themselves a “faith-based” organization – not in the religious sense – but rather in that they felt “comfortable being uncomfortable” with each other. They built on and strengthened their existing relationships as they developed confidence in each other. Eventually, they had to formalize their agreements for logistical reasons of managing \$2.1 billion of investment.

Characteristic 4: Group Governance

Through formal Participation and Project agreements, the CapX2020 group established a governance structure to withstand the contractual obligations that come with projects of this size and duration. It is important to note the amount of time the group dedicated to negotiating the Participation Agreement and establishing a voting structure, yet the procedures for handling disagreements have not yet been needed. Priti Patel noted,

“We spent so much time on that, and at the end of the day, in nearly every project management meeting I was in, it was generally consensus. It was so rare that a vote happened where someone voted against something or on the other side of a majority vote. If it did happen, it was because we had a political reason where we had to document it that way. What it showed me, is that at the end of the day, everybody wanted to make sure everyone was happy with everything that was going on.” (Patel, 2016)

Creating and maintaining collective action requires a dedicated staff with specific skills to coordinate participating organizations and agencies. The culture of collaboration and cooperation that the CapX2020 group fostered directly shaped how they would operationalize their work. This meant that instead of one utility dictating how the entire project would go, they relied on the expertise each utility brought to the table. The Vision Team, Project Management Office (PMO), and Project teams were able to allocate resources and maintain staff. To manage the large amount of work and procurement of all the materials and services needed, the CapX2020 group consolidated some of the project work under guidance from the PMO.

“We had governance for working with the partners through the Vision Team, and then we had a PMO set up to look for economies of scale, to set up good processes for teeing up information for all the project reporting, for working with our contractors, for establishing certain standards, for managing safety, and all of the million different facets that go into executing a large construction project over many many miles. The focus was on finding efficiencies and finding a good, positive way to manage it that let us do all those things as economically as we could.” (Mogensen, 2016)

The real test of the application of the parameters set forth through the agreements will truly come into play in the future. Dave Geschwind and Rick Hettwer from SMMPA considered when in the future the Agreements would be tested, and offered up a few examples. Dave began,

“When the next round of capital is needed to add a second circuit or do something to maintain that line, that’s when these voting procedures might be trotted out and tested for the first time. You might have different appetites for investing in the second circuit. Maybe some of the current participants aren’t going to want to be a part of that, and maybe others will. So, I don’t think we’ve seen the test yet of the governance structure of the documents.” (Geschwind, 2016)

Rick added,

“I think our first test coming up is going to be people who want to interconnect to the facilities, how the interconnection process is going to work, and who owns what during the interconnection process. Stuff like that. What’s nice about it is that if an issue comes up, they will address them through the agreements.” (Hettwer, 2016)

In addition to providing a necessary legal framework, the Participation Agreement and the Project Agreement documents set participants up for productive and mutually beneficial transactions surrounding how the CapX2020 group would operationalize their work.

Characteristic 5: Transparency, Open Communication, & Early Engagement

Knowing that a project’s success is shaped by the political context within which that project operates, the CapX2020 group took to heart the controversy from the 70s, and it shaped their communications approach. Instead of operating in isolation, the group made it a point to engage with stakeholders early and often. The strategy of getting out and meeting with as many different stakeholders as possible in as many places as possible was part of the CapX2020 approach to hear and understand diverse stakeholder perspectives.

Transmission is fundamentally a local issue in that poles are placed in somebody’s field, in front of their business, or in their backyard. In each of the four states where CapX2020 built transmission lines, robust public interaction along with a responsive regulatory process sensitive to public concerns enabled the CapX2020 projects to be successful. Mike Gregerson explained,

“The route permit is an area that gets real personal real fast, because at the end of the day you’re approving a project that goes over somebody’s land. You’re approving a project that somebody gets to look at for the rest of their lives.” (Gregerson, 2015)

Constant and open communication is needed across the many stakeholders to build trust, assure mutual objectives, and create common motivation. CapX2020 developed structures and processes to engage with stakeholders to keep them informed and engaged. In addition to facilitating the project for the CapX2020 group, this was also important from the perspective of state regulators. David Boyd explained,

“We’ve had proceedings where we’ve had people come in and say, ‘I’m an impacted landowner, and I don’t like that this powerline is going to be on my land. But the state is part of a reasonable process that I understood. I know I

didn't prevail, but I respect the process.' Now, that doesn't happen every day, but when it does, you realize that the way you do things is important. That the people that you have out in the field who are conducting hearings and gathering information and communicating is really important. With CapX, it's a matter of the way they organized themselves, and how they chose to present themselves, and how they chose to incorporate comments from multiple parties into one series of coherent papers that went forth in the hearing process and then to the state Commission." (Boyd, 2015)

The CapX2020 partners took a strategic and intentional approach to engaging with stakeholders by listening, incorporating their perspectives, and communicating with them as decisions were made as the projects progressed.

From the very beginning when the group started their collaboration in 2004, leaders from the Vision Team like Will Kaul engaged with thought leaders, and built a constituency that had environmentalists, regulators, legislators, utilities, and industry representatives. This led to the inclusion of perspectives not traditionally solicited during the early stages of project planning to the benefit of the CapX2020 project ambitions. As project work progressed and route corridors were identified, the CapX2020 communications teams within each project launched public outreach efforts that rivaled or surpassed what had been done in the past. The group took their time, communicating with communities, thought leaders, and local governments by way of over 100,000 direct mailers, 100's of open houses and local presentations, and newspaper ads. They also reached out to all media outlets in the project areas to generate news coverage to complement the direct mailer, which was the group's main way of reaching out to landowners. These actions were voluntary, as the group was motivated to sidestep the fractious events in the 70s, and they went far beyond what is required by the PUC during the determination of need and route permitting processes. CapX2020 had an intentional strategy of engaging early and often with stakeholders and the public, and it is an approach all interviewed participants pointed to as a technique they will use in the future:

*"Going forward this is **absolutely** our approach that we are taking on all projects. We treat all projects this way, as far as getting information out there and starting engagement early, partly because of the good outcomes we had with doing it in CapX; especially when you are involving people's property, their town, and their philosophies. To the extent that people want to be involved, we want to facilitate that involvement and we think that the time investment and financial investment in doing so really pays dividends in the later portions of the project by shortening time in some of the permitting processes or resulting in less money spent negatively in fighting over things. Rather, we can spend that in aligning things the best we can with the interests of all the stakeholders involved." (Mogensen, 2016)*

5.2 Locational and Temporal Factors that Enabled CapX2020's Success

The approach the CapX2020 group used sets the standard for how to collaborate on large-scale, multi-state, multi-jurisdictional infrastructure transmission projects. However, certain factors that contributed to the project's success were *temporal* and not replicable. Specific conditions shaped the economic and regulatory environment in the early 2000s.

One of the most important temporal factors was the climate around transmission investment in the early 2000s. First, the passage of the 2005 Omnibus Energy Bill in Minnesota shifted investment in transmission projects from the least enticing capital investment to most enticing to investors. The CapX2020 member utilities, together with their coalition, successfully lobbied the Minnesota state legislature and PUC for favorable regulations for transmission development. They persuaded the state legislature to include provisions in that bill that allowed utilities to begin recovering project costs before construction was complete, and made the process of permitting transmission lines more efficient and flexible.

"It took transmission from the least-favored investment to the most favored investment." (Kaul, 2015)

Without that cost-recovery provision in the 2005 law, many of the CapX2020 lines probably would not have been built.

Second, as the CapX2020 group was conducting its planning work, the regional transmission organization, MISO, was still developing its planning processes, now known as MTEP. Gordon Pietsch explained,

"MISO was just sort of getting their legs, and just starting to understand the planning process. They were encumbered with a lot of generators wanting to interconnect to the system – just overwhelmed with the number of interconnections being requested. They were developing business practices, trying to address the influx of those types of things. Their staff was just starting to gain some experience in regional transmission planning. Many came from local utilities or graduated from school recently, so they brought a lot of expertise, but not a lot of history of how the transmission system had evolved. The tariffs were still evolving, so we didn't know how our projects were going to get paid for." (Pietsch, 2015)

Out of the MTEP process evolved planning efforts to find a regional transmission solution that provides value across the region while meeting local energy and reliability needs, known as the Multi Value Project (MVP) Portfolio. A project can be given MVP status for meeting a certain set of criteria which makes it eligible to be financed by all MISO member utilities in the 15 MISO states and Manitoba, Canada. The MVPs will expand and enhance the region's transmission system, reduce congestion, provide access to affordable energy sources, and meet public policy requirements including renewable energy mandates. Two CapX2020 projects were designated MVPs, however they were not announced until 2011, more than three years after the CapX2020 group allocated line ownership through the poker chip exercise (see Section 2.5.2). Tim Rogelstad explained how investment strategies have shifted over the past two decades:

“One of the challenges utilities face today is that transmission has become much more competitive. Historically, you wanted to minimize your transmission investment. Now, I would venture a guess that every utility, or almost every utility, would be interested in trying to maximize their transmission investment—certainly the projects that are regionally cost shared.” (Rogelstad, 2016)

Third, the utilities in Minnesota and the Upper Midwest had a history of working together. They had not collaborated to the same extent as they did through the CapX2020 initiative, but they worked on joint projects with the encouragement of the state planning processes. Legislation in 2003 established the MN Transmission Owners group to create a more transparent transmission planning process and encourage cooperation between utilities. Furthermore, many of the utilities had a predisposition to collaborate because of the intertwined nature of the system and overlapping service territories that is not found throughout the country. Dave Geschwind explained,

“If you go to other parts of the country, this sort of cooperation does not exist. Almost the opposite, where you have large IOUs that maybe control most of the transmission in an area and who are trying to keep others from investing in the system. They aren’t looking for co-ownership; they want to own all of the transmission. But that’s not the environment we have up here, and I think that’s a good thing.” (Geschwind, 2016)

The way that utilities collaborate in the Upper Midwest is different from what is experienced across the country. Tony Clark said,

“It’s a bit of a different dynamic in MISO where you have such a concentration of vertically integrated utilities and strong state Commissions that continue to have all of their regulatory authority over the utilities. It’s a different dynamic in other regions of the country where they’ve unbundled, and you have different types of companies operating.” (Clark, 2015)

Some other regions of the country with different utility structures and histories of cooperation between utilities may have more difficulty replicating the success of the CapX2020 project. However, other states can create legislation to incentivize transmission development like Minnesota did and other ISOs and RTOs have developed regional transmission planning processes like MISO. Equally important, multi-utility projects can replicate the organizational and operational best practices that made the CapX2020 project successful.

5.3 The Legacy of CapX2020: Enabling Future Projects and Replicability

CapX2020 has made it easier for utilities in Minnesota and the Upper Midwest to work together. They set an example of how differently structured utilities (IOU, municipal, cooperative; large and small) can collaborate on large-scale infrastructure projects. Much of this approach can serve as a template and can be replicated. The CapX2020 group has a model of cooperation and successful project execution to work from, which makes it easier for members to

work together in the future. Many participants from the group talked about examples that illustrate the benefits of their collaboration. Teresa Mogensen explained,

“The success of the CapX group supports working together on similar things, or exploring things in perhaps a different way than we might have done before CapX2020 because we have built relationships, we have built a precedent of success, and we see value that has come from that collective that was not there before.” (Mogensen, 2016)

As utilities respond to current and future state and federal mandates that call for the increase of renewable generation and the retirement of carbon-heavy generators, the CapX2020 transmission lines will serve as a resource for interconnecting new wind projects and other generators in the region. In particular, the CapX2020 lines facilitate the transfer of wind from the wind-rich west to the populated areas to the east. Tony Clark explained,

“Anytime you have more transmission it’s going to increase the potential for more export capabilities from a resource-rich region.” (Clark, 2015)

Jim Hoecker, who served as the FERC Chairman from 1997-2001 elaborated further,

“The wholesale power market is becoming more highly integrated. We are spending between 10 and 20 billion dollars annually to strengthen the grid, to upgrade it, to replace aging facilities...and we’ve got a ways to go. We’ve got a lot more money to spend to have a real world class transmission network. There are some bright spots. ATC in Wisconsin saved that state from some real major reliability catastrophes. CapX has managed to reinforce the grid in Minnesota in ways that will aide reliability, but I think it will also give roads in Minnesota and to the east access to some of the best high quality renewable resources on the continent. That kind of integration is critical moving forward. Resource diversity gets rid of congestion which gives people access to lower cost generation, it reduces emissions, and when it comes to doing the Clean Power Plan, which in my view is one of the major regulatory things we’re going to see in the near future, it really makes the implementation of those changes infinitely easier. A lot of the country isn’t going to be as lucky as that.” (Hoecker, 2015)

The need to address system reliability was so great in the region that some utilities have seen immediate benefits of the CapX2020 lines. Ben Porath explained how the new lines alleviate some of the pressure Dairyland Power was facing in their service area:

“Things were getting hairy here over the years. Between Dairyland and Xcel, we’d built out a 161-kV transmission network back in the 1950s-1970s, and we’ve been relying on that transmission system for 50, 60 years. [...]. But as customer load, demand, and the areas grew, it became very difficult to manage outages. In the La Crosse area, for example, there were four 161-kV lines that served the area: three owned by Dairyland, one owned by Xcel. All of those lines were very much needed at all times to serve the La Crosse area, especially in the summer and winter. To try and schedule service outages or outages to rebuild the lines without a new source in the area was becoming more difficult every year. By having the CapX line now in service, we can already see the operational benefits of it. We can take other lines out of service for maintenance now. We can

withstand an outage due to a storm better than we could have historically.”
(Porath, 2016)

Other utilities are incorporating lessons learned from CapX2020 into the way they operate. Tim Rogelstad of Otter Tail Power gave an example,

“We’re preparing to file our resource plan in June of this year [2016]. We’re holding stakeholder meetings. What’s unique about these meetings is that we’re holding them before any analysis. Rather than engaging with stakeholders after we’ve received the results, we’re doing it up front. That’s a takeaway that we learned from the CapX process.” (Rogelstad, 2016)

The five characteristics that made CapX2020 success – informed by Kania and Kramer’s Collective Impact Theory and described in more detail in Section 5.1 – offer a guide to best practices that any utility or project can follow. With visionary leaders, these characteristics are not temporal and transcend a specific time and place. Even when utilities are not trying to solve a multi-state or multi-region problem, there are opportunities to apply many of the same best practices developed through CapX2020 to smaller projects as well. FERC Commissioner Tony Clark shared his thoughts:

“I don’t see why it couldn’t be replicable. It is a little different in that we are in a somewhat different time, post FERC Order 1000. Understanding that what made CapX2020 really work was that it was a reliability project, with reliability first that was driving the projects at play. And then in addition to that you had a group of states that were still monopoly, vertically-integrated, state-regulated, state-investor owned utility regulated states – although you do have some public power in there that are outside of that jurisdiction. But the big movers and shakers in CapX2020 tended to be the larger, investor-owned public utilities, all state regulated.” (Clark, 2015)

It is important not to discount the differences that exist between regional independent system operators, as the co-mingling of public and private utilities is found more often in the Upper Midwest than it is in other regions of the country. David Boyd, former Minnesota PUC Commissioner further explained,

“To understand why CapX2020 was successful, you really have to know the whole history of the region, its culture, and how it has evolved. For example, at the time this started North Dakota didn’t really have a wind industry to speak of, and I think some people were wary of whether someone was trying to pull a fast one on them. The lignite industry remains an important industry up there, and there were some who were worried that new lines would secretly cut the legs out from under it. But as they started talking and could see the options, and had more conversations that they could build on...it takes a while to realize that is not necessarily what is going on here. You’ve got to be proactive, thinking about what it takes in a new world to have a grid that is reliable and economical that serves all purposes. It’s the relationship aspect that needs to be replicated from the CapX partners to the states, the state regulators, the businesses involved, and the people paying the bills. It’s not a small matter.” (Boyd, 2015)

The sharing of best practices among participants supports innovation. Within the CapX2020 initiative, all the utilities benefited from having worked through the process together, creating a collective base of knowledge, techniques, and perspective that allowed them to evolve together as the work progressed. The CapX2020 project brought together the best minds from the Upper Midwest region during the planning process, working to pass legislation, and executing project work. The more people that were brought in, the broader the group's knowledge base became. Scholars have documented how "shared beliefs and values reduce uncertainty, operating as a cognitive framework that provides a means of sensemaking, often in light of what is understood about the past." (Sandfort, 2016). Ray Wahle explained how the group was able to reap the benefits of the collective group:

"You never learn anything from doing it right, you only learn from your mistakes. Unfortunately, that's the way it is. I'm never going to live long enough to make all the mistakes there are to make, so it's always good to find out what mistakes somebody else has made so we don't have to repeat them." (Wahle, 2016)

The group came together to collectively identify risks, mitigate them ahead of time, and develop a realistic approach to upgrading the high-voltage transmission system in the Upper Midwest. The CapX2020 project created an organization that will continue to operate for decades as they operate and maintain the transmission lines, and may collaborate in a similar capacity on projects in the future. It also created an example that other utilities can and should emulate as they cooperate on regional projects.

5.4 Conclusion

The CapX2020 project operated in the midst of a paradigm shift in the electricity industry.

The CapX2020 group upgraded the transmission backbone of the Upper Midwest through a series of simultaneously remarkable feats and mundane activities. In the early 2000s after three decades without any new high-voltage transmission development, the region was becoming desperate for additional capacity. Existing transmission lines were becoming congested as load grew and new renewable generators were installed to meet state RESs. FERC Order 2000 encouraged regional transmission planning through the establishment of ISOs, which were established to coordinate, control, and monitor the operation of the electrical grid. These factors created the necessary, but not sufficient conditions to encourage a regional transmission planning partnerships. However, no regional groups had emerged to plan new transmission in the five years between FERC Order 2000 and the initiation of CapX2020. It took visionary leaders *and* leadership to create the CapX2020 group to address the barriers that prevented a group of utilities to address regional transmission needs together.

CapX2020 was at the vanguard of regional transmission planning.

The time was ripe for action and the right actors came together in Minnesota and beyond with the social capital needed to form durable, long-lasting relationships. CapX2020 participants felt their working relationships, personal connections, and the comradery they developed were vital to seeing the project through to the end. The collaboration parallels the collective impact theory in that five key characteristics lead to the group's success. They developed a shared vision and aligned around a common goal, created a win-win situation for all participants, fostered deep

relationships, developed system of group governance to operationalize their work, and engaged with stakeholders with openness and transparency. Regional planning that took heroic efforts from the CapX2020 group has become easier as markets and regulations have matured.

As changes to the electricity industry continue, this culture of collaboration will be the new normal, and utilities will need to follow suit to remain competitive in the world of transmission development.

Over time, processes and coordinating structures become institutionalized, no longer seen as “new” but simply part of the way work is accomplished. As ISOs continue to develop their markets, as the effects of FERC Orders are felt, and as new legislation is implemented, coordinated transmission planning will continue to become the new normal, and utilities will need to follow suit to remain competitive in the world of transmission development.

The work of the CapX2020 group set a precedent for the way coordinated development, permitting, and construction of new high-voltage transmission lines should be done. As multi-state transmission planning becomes increasingly common, it will serve as a successful example that other regional groups can follow.

Appendices

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Appendix B: List of Interviewees

Name	Job Title	Company	Interview Date
Mark Alhstrom	CEO	Windlogics	July 9, 2015
Graham Arntzen	Engagement Lead	Pioneer Project Services	June 9, 2015
David Boyd	Vice President of Government and Regulatory Affairs	Midcontinent Independent System Operator	July 24, 2015
Tony Clark	Commissioner	Federal Energy Regulatory Commission	July 16, 2015
Chris Fleege	Vice President, Transmission and Distribution	Minnesota Power	January 22, 2016
Dave Geschwind	Executive Director and CEO	Southern Minnesota Municipal Power Agency	January 27, 2016
Allen Gleckner	Senior Policy Associate	Fresh Energy	June 16, 2015
Mike Gregerson	Program Consultant	Great Plains Institute	June 1, 2015
Terry Grove	Co-Executive Director CapX2020 & Director Regional Transmission Development	Great River Energy	June 8, 2015
Rick Hettwer	Manager of Power Delivery	Southern Minnesota Municipal Power Agency	January 27, 2016
Jim Hoecker	Counsel and Advisor	WIRES	August 24, 2015
Brian Kalk	Commissioner	North Dakota Public Service Commission	June 18, 2015
Will Kaul	Vice President, Transmission	Great River Energy	June 19, 2015
Igor Lenzner	Attorney	Rinke Noonan	June 11, 2015

Clair Moeller	Executive Vice President	Midcontinent Independent System Operator	July 9, 2015
Teresa Mogensen	Senior Vice President of Transmission	Xcel Energy	February 15, 2016
Mark Nisbet	Principal Manager, North Dakota	Xcel Energy	June 19, 2015
Michael Noble	CEO	Fresh Energy	June 16, 2015
Tim Noeldner	Vice President of Rates & Special Projects	WPPI Energy	January 20, 2016
Carol Overland	Attorney	No CapX2020	August 7, 2015
Priti Patel	Regional Executive, North Region	Midcontinent Independent System Operator	July 30, 2015
Gordon Pietsch	Director, Transmission Planning and Operations	Great River Energy	June 19, 2015
Ben Porath	Vice President of Power Delivery	Dairyland Power Cooperative	March 2, 2016
Steve Quam	Eminent Domain Lawyer	Fredrikson & Byron, P.A.	March 9, 2016
Greg Rislov	Commission Advisor	South Dakota Public Utilities Commission	June 23, 2015
Tim Rogelstad	President	Otter Tail Power Company	February 10, 2016
Jamie Schrenzel	State Principal Energy Planner	Minnesota Department of Natural Resources	July 10, 2015
Louise Segroves	Environmental Specialist	Barr Engineering	August 6, 2015
Beth Soholt	Executive Director	Wind on the Wires	June 30, 2015
Mark Thein	Chairperson	Oronoco Township Board	July 31, 2015
John Wachtler	Vice President	Barr Engineering	August 6, 2015

Ray Wahle	Director of Power Supply and Operations	Missouri River Energy Services	January 29, 2016
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Appendix C: Timeline

Periods

1960-1992: The Traditional System

1992-2004: The Lead-Up to CapX2020

2004-2007: CapX2020, The Early Years

2007-2014: CapX2020 Permitting and Construction Years

1960's

- High voltage transmission facilities (230-kV or higher) built in MN. The backbone of the bulk electric system, moving electricity from power plants to load centers. Designed to maintain reliability even when faced with various contingencies that arise due to weather or other factors that temporarily may remove a particular transmission facility from service.

1970's

- Majority of high voltage transmission facilities built in the 70's
- CU Project Controversy: Starting around 1975 and continuing through 1979, a farmer-led revolt against the building of a high-voltage transmission line from the coal fields of central North Dakota to the Twin Cities known as the CU Project Controversy.
- In 1977 the first Buy the Farm legislation regarding eminent domain was passed adding protections to landowners. The updated law required utilities to propose at least two possible routes for new transmission lines with voltages of 230-kV or higher, and increased public involvement in the siting process.

1987

- Unit 3 at the Sherco power plant begins operations. Since 1987, only shorter, lower-voltage transmission lines have been built, typically to meet local, load-serving needs.

1992

- Congress deregulated the wholesale electric power supply industry, making generation a competitive market while still regulating transmission facilities.

1996

- FERC Order 888: the functional separation of transmission from generation to ensure equal access to the grid. Mandated that electric utilities offer “open access” to their transmission system. Upshot was that generation and transmission planning must be performed in a nondiscriminatory manner—transmission planning and development must be prepared to meet the needs of all regional market participants rather than just those of the individual utility or specific generation resource type.

2001

- Minnesota Legislature enacts the Minnesota Renewable Energy Objective (REO), contained in Minn. Stat. §21B.1691. As originally enacted, the Statute required electric

utilities to “make a good faith effort” to obtain 10% of their Minnesota retail energy sales from eligible energy resources by 2015, and to obtain 0.5% of their renewable energy from biomass technologies.

2002

- MISO begins operations February 1, 2002, and is now the RTO for utilities in large parts of the Midwest and Upper Midwest. Initial work was to develop rules and systems for users to follow in conducting grid operations in accordance with NERC standards. It operates with stakeholder input and participation under FERC directions. MISO controls access to and use of the grid for wholesale transactions for its member companies. Most of MN’s transmission system now is operated under the oversight of the MISO umbrella organization.

2003

- Minnesota Legislature amends the Minnesota REO, requiring the Minnesota Public Utilities Commission (PUC) to supervise and facilitate utilities’ good faith efforts to meet their REO obligations.
- Minnesota Statutes § 216B.2425 establishes the Minnesota Transmission Owners group requiring any utility that owns or operates electric transmission lines in Minnesota to submit a transmission projects report to the Minnesota PUC.

2004

- GRE, MN Power, Otter Tail Power Co, and Xcel Energy jointly formed CapX2020 in the summer of 2004.
 - MRES subsequently joined the effort, and other IOU’s, cooperatives, and municipal utilities followed
- December 2004: interim report calling for studies
 - CapX2020 undertook two technical studies on major transmission facilities needs in MN: the Vision Study and the Red River Valley Study, both expected to be complete in May 2005.
- Began reviewing state processes to determine whether they are able to support development of the required transmission infrastructure in a timely, efficient manner, consistent with the public interest
 - Reviewed approaches to certification and cost recovery, while also evaluating industry structure, routing, and jurisdictional issues.
- Began dialogue with policymakers and stakeholders regarding the CapX2020 studies and state process issues
- Outreach to other transmission providers to share information and collaborate on solutions

2005

- May 2005: Vision Study complete
- May 2005: MN Omnibus Energy Bill signed by Governor Pawlenty

2006

- February 2006: Red River Valley Study complete

2007

- January 1, 2007: Participation Agreement completed and published. 11 utilities were named in the document as participants.
- Minnesota Legislature adopts a Renewable Energy Standard (RES), an update to Minn. Stat. §21B.1691 - Renewable Energy Objective, which was amended to establish a Renewable Energy Standard with specified mandated renewable energy goals beginning in 2010.
- Three 345-kV Projects (Fargo-St. Cloud-Monticello, Brookings County-Hampton, and Hampton-Rochester-La Crosse: MN CON application filed August 16, 2007

2008

- Bemidji-Grand Rapids 230-kV Project: CON application filed March 17, 2008
- Bemidji-Grand Rapids 230-kV Project: Route Permit application filed December 29, 2008
- Brookings County-Hampton 345-kV Project: MN Route Permit application filed December 29, 2008

2009

- Monticello-St. Cloud 345-kV Project: Route Permit application filed April 8, 2009
- Three 345-kV Project group CON granted May 22, 2009
- Bemidji-Grand Rapids 230-kV Project: CON granted July 9, 2009
- Fargo-St. Cloud 345-kV Project: MN Route Permit application filed October 1, 2009

2010

- Monticello-St. Cloud 345-kV Project: Route Permit granted July 8, 2010
 - Final EIS issued March, 2010
- Brookings County-Hampton 345-kV Project: MN Route Permit granted July 15, 2010
 - Final EIS issued January 26, 2010
- Fargo-St. Cloud 345-kV Project: ND CPCN application filed October 11, 2010
- Bemidji-Grand Rapids 230-kV Project: Route Permit granted October 28, 2010
 - Final EIS issued September 2, 2010
- Monticello-St. Cloud 345-kV Project: Construction began fall 2010
- Brookings County-Hampton 345-kV Project: SD Facility Permit filed November 22, 2010 (SD PUC must issue a facilities permit before a transmission line can be constructed)
- Hampton-Rochester-La Crosse 345-kV Project: MN Route Permit application filed January 19, 2010

2011

- Fargo-St. Cloud 345-kV Project: MN Route Permit granted June 10, 2011
 - Final EIS issued January 7, 2011

- Brookings County-Hampton 345-kV Project: SD Facility Permit granted June 14, 2011
- Brookings County-Hampton 345-kV Project: MISO granted the project MVP status on June 16, 2011
- Bemidji-Grand Rapids 230-kV Project: Construction begins August 2011
- Monticello-St. Cloud 345-kV Project: Construction complete and line energized December 21, 2011
- Hampton-Rochester-La Crosse 345-kV Project: WI CPCN filed January 3, 2011
- Fargo-St. Cloud 345-kV Project: ND CPCN (joint corridor compatibility and route permit application) granted January 12, 2011

2012

- Hampton-Rochester-La Crosse 345-kV Project: MN Route Permit granted April 12, 2012
 - Final MN EIS issued August 21, 2011
- Hampton-Rochester-La Crosse 345-kV Project: WI CPCN approved May 10, 2012
 - Final WI EIS issued January 2012
- Brookings County-Hampton 345-kV Project: Construction began May, 2012
- Bemidji-Grand Rapids 230-kV Project: Construction complete and line energized in autumn 2012
- Fargo-St. Cloud 345-kV Project: Construction began January 2012

2013

- Big Stone South-Brookings County 345-kV Project: SD Facilities Permit application filed June 4, 2013

2014

- Big Stone South-Brookings County 345-kV Project: SD PUC approved Facility Permit February 18, 2014

2015

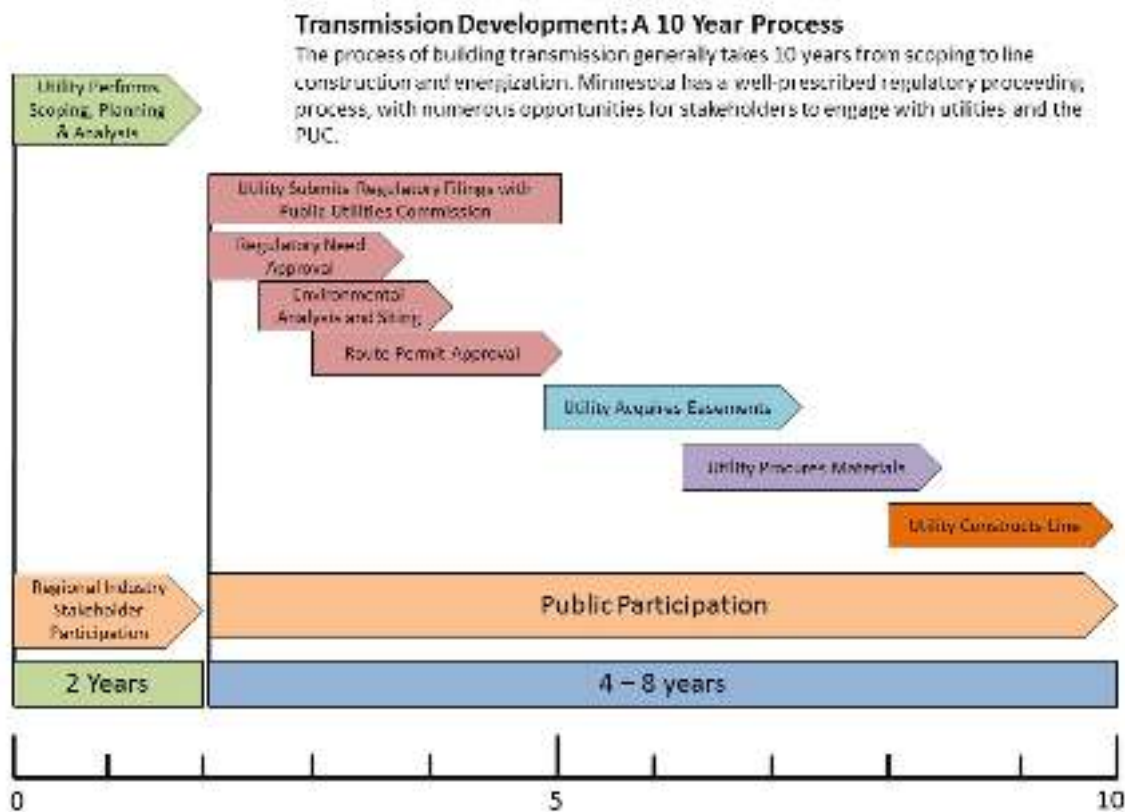
- Brookings County-Hampton 345-kV Project: Construction complete and project energized, early 2015
- Fargo-St. Cloud 345-kV Project: Construction complete and project energized May, 2015
- President Barak Obama and the EPA propose the Clean Power Plan, a policy aimed at combating anthropogenic climate change.

Beyond

- Big Stone South-Brookings County 345-kV Project: construction expected to start in late 2015 with a target in-service date of 2017

Appendix D: The Process of Building Transmission

The process of building a transmission line can take about 10 years, start to finish. This process varies from state to state, but generally follows the same progression, as described in the figure below: (1) Scoping, (2) Regulatory filings, (3) Easements, (4) Materials procurement, (5) Construction and energization.



Scoping

Transmission planners continually evaluate the transmission plans to address future loads, generation interconnections both to serve the loads of the utility it works for, as well as looking at the broader regional perspective to identify system additions or enhancements that need to be made to ensure system performance. Planners have a principle responsibility of ensuring the safety and reliability of the transmission system for the benefit of its customers, and focus on identifying maintenance activities that need to be performed on an annual basis to maintain and improve reliability, as well as document their compliance to the various NERC standards. Using modeling, planners evaluate alternatives by simulating the operation and performance of the transmission system under various scenarios. To perform technical analysis for the CapX2020

projects, planners used Power Technology's PSS/E program, and a contingency program that uses IPLAN programming language within PSS/E, developed by Great River Energy.²⁵ Planners examine options ranging from upgrading an existing line to a higher voltage to proposing a new transmission line. Planning in the Upper Midwest is coordinated by the Mid-Continent Area Power Pool (MAPP), a voluntary association of electric utilities and other electric industry participants, as well as at MISO. Additionally, in Minnesota, all electric utilities authorized to do business in Minnesota are required to file an annual data report to the Department of Commerce, which is used to identify emerging energy trends based on supply and demand.²⁶ Planners then work with neighboring utilities and stakeholders to identify preferred upgrades or alternatives, while also taking into consideration cost, environmental, and social impacts.

Regulatory Filings

Prior to line construction, projects must receive major approvals from their Public Utilities Commissions (PUC).²⁷ When a utility wishes to build new high voltage transmission facilities, states must first establish need for the project as well as determine the routing of the transmission line. In most cases, the common applications require some variation of a Certificate of Need (CON) and Route Permit. A CON determines if the proposed transmission lines are necessary and serve a purpose, as well as determining the appropriate size, configuration, and timeframe needed to complete the project. A Route Permit specifies where the line is to be routed. Together with local and federal oversight, state Commissions serve as the neutral parties in determining if projects fit the needs of the state and the region. Flowcharts which identify the Certificate of Need and Route Permitting processes in Minnesota can be found in Appendix E.

Minnesota and North Dakota have similar filing processes in that both have separated the CON and Route Permitting process into multiple steps. In Minnesota, a utility provides notice of intent to file an application to the potentially affected persons of the project. The applicant then submits their CON application to the PUC, and from there the Commission appoints an Administrative Law Judge (ALJ) to preside over public hearings in which anyone can attend and provide comments. Notice for these hearings are published in local newspapers prior to the start of hearings. After gathering written comments, oral testimony, and listening to the expressed opinions concerning the utility's proposal, the ALJ submits a report summarizing the hearing process and makes recommendations to the PUC. Additionally, the Department of Commerce, Office of Energy Security (OES) prepares an Environmental Report (ER), examining the land use and natural resource considerations associated with the project. It is here that issues of size, type, and project timing are reviewed. The Route Permit application is filed with the PUC, and is followed by a series of public meetings conducted by an ALJ in which comments, opinions, and supporting evidence on where the proposed line should be located and how potential impacts of the line should be addressed. Simultaneously, the OES prepares an Environmental Impact Statement (EIS). The OES accepts comments and updates the EIS throughout the Route Permit

²⁵ CapX2020 Technical Update: Identifying Minnesota's Electric Infrastructure Needs

²⁶ Minnesota Department of Commerce. Electric Utility Annual Reporting: Rule 7610.

²⁷ The governing body that regulates the rates and services of a public utility is known as a Public Utilities Commission (PUC) or Public Service Commission (PSC). In the case of CapX2020 projects, Minnesota and South Dakota are served by their state's PUC, while North Dakota and Wisconsin are served by their state's PSC.

process until preparing a final EIS that is submitted to the PUC. Ultimately, the PUC considers the recommendations from the ALJ, the EIS, and from public comments before making its final ruling of approval. The process in North Dakota is similar, yet lacks the environmental oversight from the Department of Commerce in Minnesota. When a utility wants to construct a transmission facility in North Dakota, they must first inform the PSC with a Letter of Intent. Following that, three applications must be approved before high voltage transmission can be built: (1) Certificate of Public Convenience and Necessity (CPCN), (2) Certificate of Corridor Compatibility (CCC), and (3) Route Permit. The CCC and Route permit examine related issues and can be thought of as two parts of one process.

South Dakota and Wisconsin have similar filing processes in that both combine determination of need and routing into one step. In South Dakota, the PUC reviews project applications and, if approved, grants an order for a permit for location, construction, and operation of the proposed project. The PUC considers the applications compliance with relevant laws, the potential to impact the environment, and social and economic conditions in the proposed project area, and the health, safety, and welfare of nearby residents. Like South Dakota, the determination of need and routing for a high voltage transmission line are combined in Wisconsin. The PSC reviews project applications and, if approved, grants a CPCN. When reviewing a transmission project, the Commission considers alternative plans to address the need and alternative locations or routes, as well as need, engineering, economics, safety, reliability, individual hardships, and environmental factors. In all cases, before federal agencies grant loans or issue permits for transmission lines, the applicants must comply with requirements of the National Environmental Review Act. Together, the determination of need and the establishment of a projects route application process takes about 3 years, regardless of state.

State	Regulatory Applications	Laws, Statutes, Rules, etc.	Description
Minnesota			The MN PUC must grant two permits before high voltage transmission facilities can be built. The Department of Commerce, Office of Energy Security prepares an Environmental Report during the need process, and an Environmental Impact Statement is written during routing.
	Certificate of Need	MN Statutes 21B.243 and MN Rules 7849, 7829, 7849.0010-0110, and 1405	
	Route Permit	MN Statute 216E.02	
North Dakota			The ND PSC must grant three permits before high voltage transmission facilities can be built. The Certificate of Corridor Compatibility and Route Permit
	Certificate of Public Convenience and Necessity	ND Century Code Chapter 49-03	

	Certificate of Corridor Compatibility	ND Century Code Chapter 49-22	proceedings examine related issues.
	Route Permit	ND Century Code Chapter 49-22	
South Dakota			The SD PUC must grant one Facility permit that issues decisions on need and routing for high voltage transmission facilities
	Facilities Permit	SD codified law Chapter 49-41B	
Wisconsin			The WI PSC must grant one Certificate of Public Convenience and Necessity, combining the determination of need and routing into one process.
	Certificate of Public Convenience and Necessity	WI Statutes §1.12 (6), 186.491 and 30.025, and WI Administrative Code Chapters PSC 2, 4, 111, and 112	

Easements

Once a route permit application is approved, utilities may begin negotiating with landowners to acquire easements for construction. In order to construct, operate, and maintain a transmission line, land is acquired as an easement within a set distance of the project centerline, typically up to 150 feet wide for projects that support 345-kV lines. The strip of land the transmission line is on is referred to as the Right-of-Way (ROW), while an easement is what the utility purchases for the right to use the property, where the legal title to the underlying land is retained by the original owner.

The transmission line owner will make an offer to each individual landowner based on “fair market value”. This varies by county because each county has a unique set of land sales data, agricultural statistics, and other considerations that determine the fair market value. Landowners have the option to take a one-time payment, or, as in Minnesota, can elect to spread the payment out over a period of time (most take the one-time payment). The landowner continues to pay property taxes on the right-of-way, however in some states like Minnesota, the state provides a property tax credit to landowners. Landowners are still able to use the acquired land for most purposes as allowed under the terms of the easement. The landowner can continue to be used as it was before, so long as it doesn’t interfere with construction, operation, or maintenance of the line. In agricultural areas, land within the right-of-way may be used for crop production and pasture. In more developed areas, there are a number of acceptable uses of the land with written permission from the utility, including lawn extensions, underground utilities, curbs and gutters. For the wellbeing of the transmission line, effective vegetation management in the ROW is crucial to maintaining operations. Electrical lines sag lower as they carry more electricity, in hotter temperatures, and when ice builds up on them. Outages occur when line owners do not

maintain vegetation management. Many times, outages and accidents occur when sagging lines contact trees.

The easement stage often carries over into materials procurement and construction of a line, depending on the negotiation process with landowners, and can take up to a year or more to amass. If a landowner and the utility cannot agree on the easement or payment, the utility will pursue a process called condemnation, a process that varies from state to state, under which a judge and panel of impartial individuals decide whether the easement is needed, and its value. In Minnesota, a landowner may request that the utility purchase the entire property, utilizing a 1970's law title Buy the Farm, discussed further towards the end of this section.

Materials Procurements

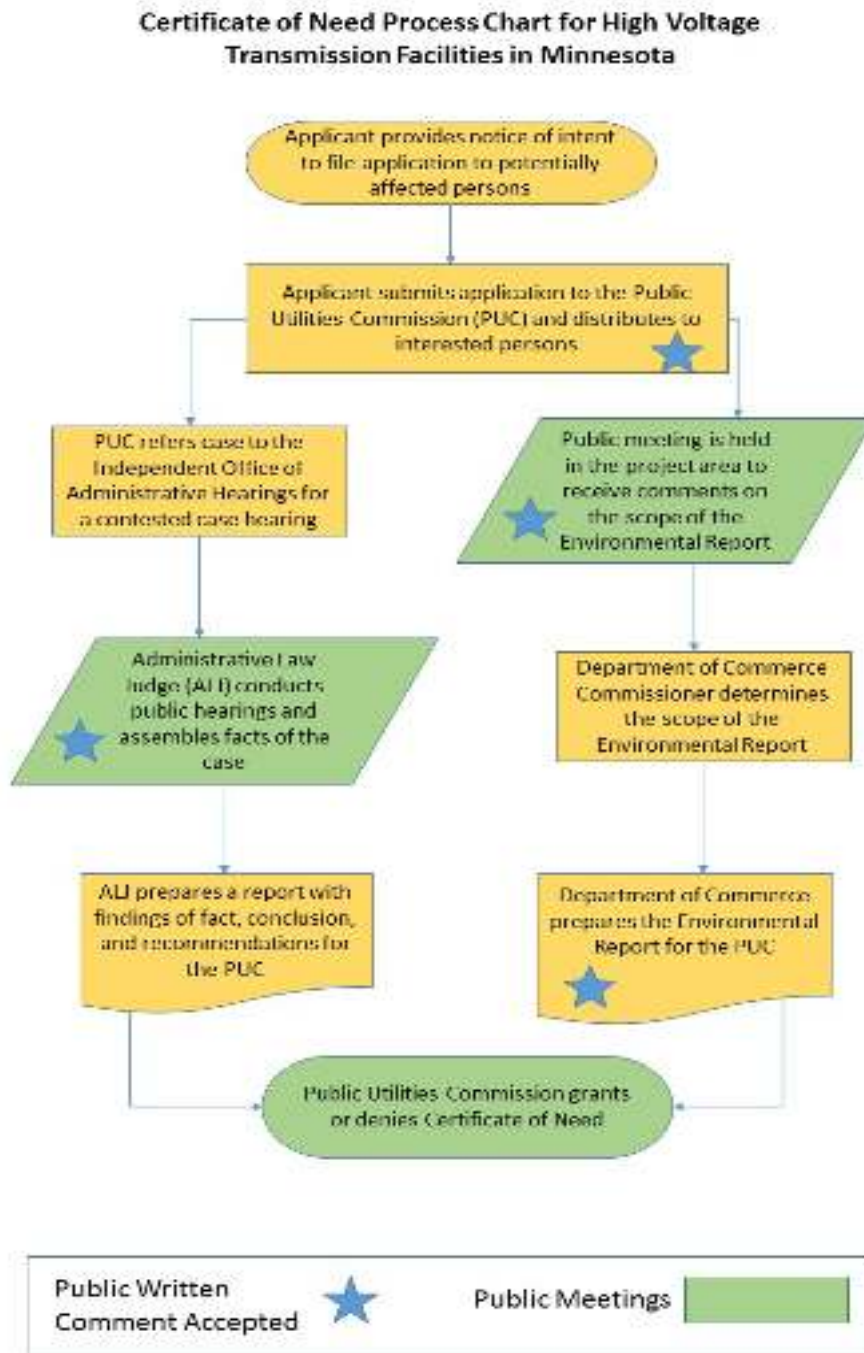
Materials like concrete, transmission line towers, and conductors and wires can take up to a year to obtain. The industry for transmission line materials needed for construction is traditionally small, as large construction projects had not been undertaken in over 30 years prior to the CapX2020 build-out. To acquire materials, the construction management project team issues a request for proposals, and contractors place bids.

At the same time, construction crews prepare for construction by identifying staging areas. Many firms utilize regional and local construction companies to secure materials and labor, as it is more cost-efficient than looking further out, and to support local economies. For example, local suppliers are key to providing concrete, as concrete must be used within two hours of being mixed. Suppliers along project routes are identified, and local drivers deliver concrete to each pole location for foundation work.

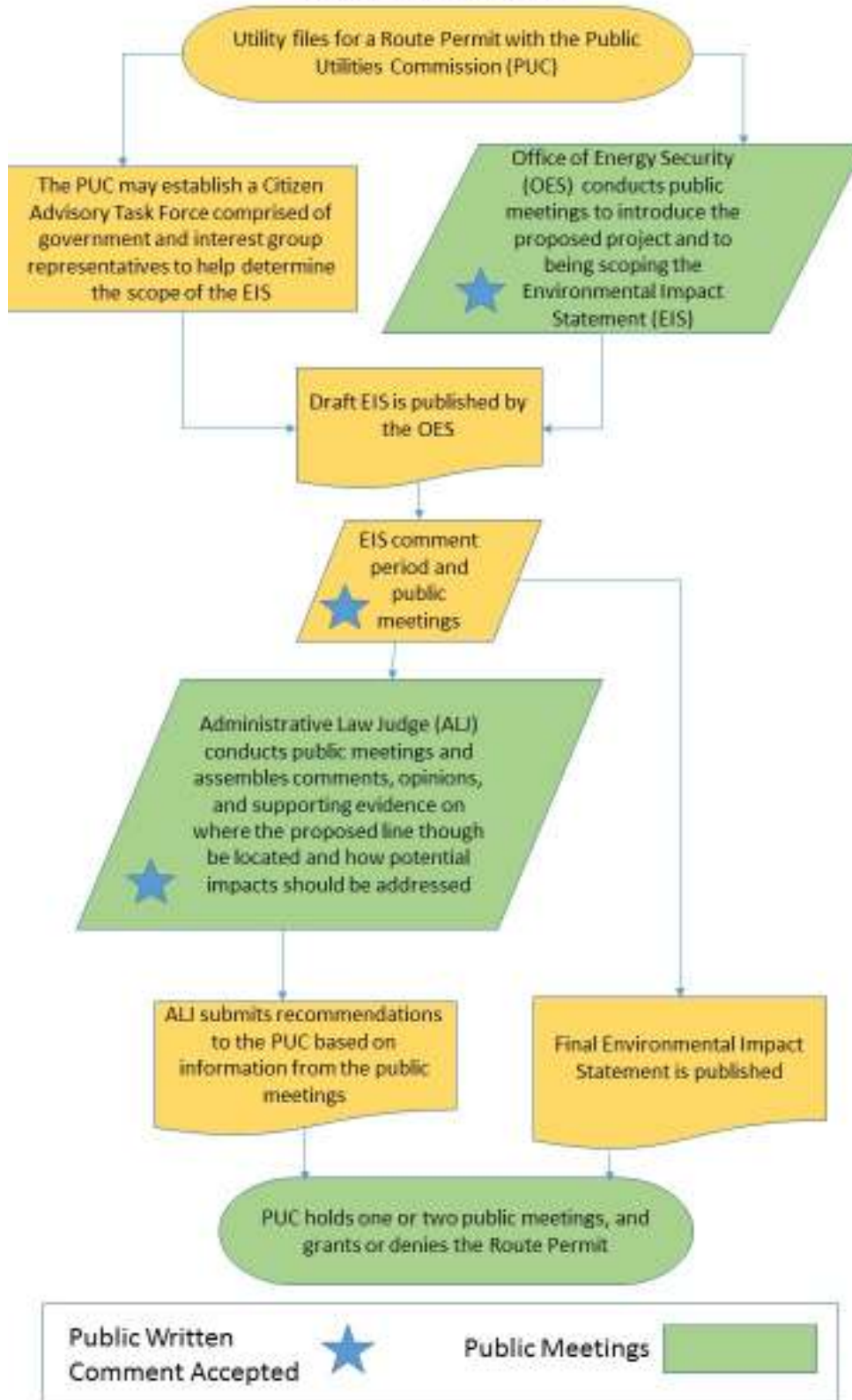
Construction and Energization

Depending on the scope and size of the line, construction can take up to two years or more to complete. Once a newly constructed line is connected to the transmission grid and tested for safety and reliability, it is energized to deliver electricity. Much of the timeframe of project construction and energization is dependent upon the steps taken prior to the construction process.

Appendix E: Certificate of Need and Route Permit Process Charts for High-Voltage Transmission Facilities in Minnesota



Route Permit Process Chart for High Voltage Transmission Facilities in Minnesota



Appendix F: Bemidji-Grand Rapids 230-kV Line Project Fact Sheet

BEMIDJI – GRAND RAPIDS 230-KV TRANSMISSION LINE

Project Overview and Need

The Bemidji-Grand Rapids 230-kV transmission line was fully energized in September of 2012 to improve reliability for the Red River Valley, Bemidji, Grand Rapids, and north central Minnesota. The single circuit line connects the Wilton substation near Bemidji, Minnesota and the Boswell Substation in Grand Rapids, Minnesota.

Project Permitting

The Minnesota Public Utilities Commission (PUC) must grant two approvals before construction - a Certificate of Need and a Route Permit. A Certificate of Need application was applied for in March of 2008, and granted in July of 2009. A Route Permit application was filed in June of 2008, and approved in November of 2010.

Minnkota Power Cooperative, a partner in the Bemidji-Grand Rapids Project, sought financing from Rural Utilities Service (RUS) for a portion of the investment. RUS, a federal financing agency within the U.S. Department of Agriculture, provides direct loans, loan guarantees, and grants to cooperatives for rural electric system projects. The RUS, in order to provide financing, is required to conduct an

Environmental Impact Statement, which it did jointly with the Minnesota Department of Commerce, Division of Energy Management (formerly the Office of Energy Security). RUS issued its record of decision November 23, 2011.

The project also received all major permits required from the U.S. Army Corps of Engineers, the U.S. Forest Service (to cross Chippewa National Forest), and the U.S. Fish and Wildlife Service, as well as from Minnesota's Department of Natural Resources, the Pollution Control Agency, the Department of Transportation, and various local government units.

Permitting Schedule

- Certificate of Need application – filed March 17, 2008
 - MN PUC approval – July 9, 2009
- Route Permit application – filed June 4, 2008
 - Judge's recommendation – issued September 20, 2010
 - MN PUC written order – issued November 5, 2010
- EIS scoping decision – issued April 2, 2009
- Revised EIS scoping decision – issued February 11, 2010
- Draft EIS – issued February 23, 2010

- Final EIS – issued September 2, 2010



Steel H-Frame Structures

Crews began clearing right-of-way in January 2011, working east from Cass Lake to the Boswell substation. Setting structures began in July 2011, and by the end of January 2012, about half of the line's 535 structures were set. Also in January 2012, installation started of conductor and shield wire using a helicopter and implosive splicing in the eastern part of the line. The eastern segment of the line was energized in August 2012 and the western segment was energized in September 2012.

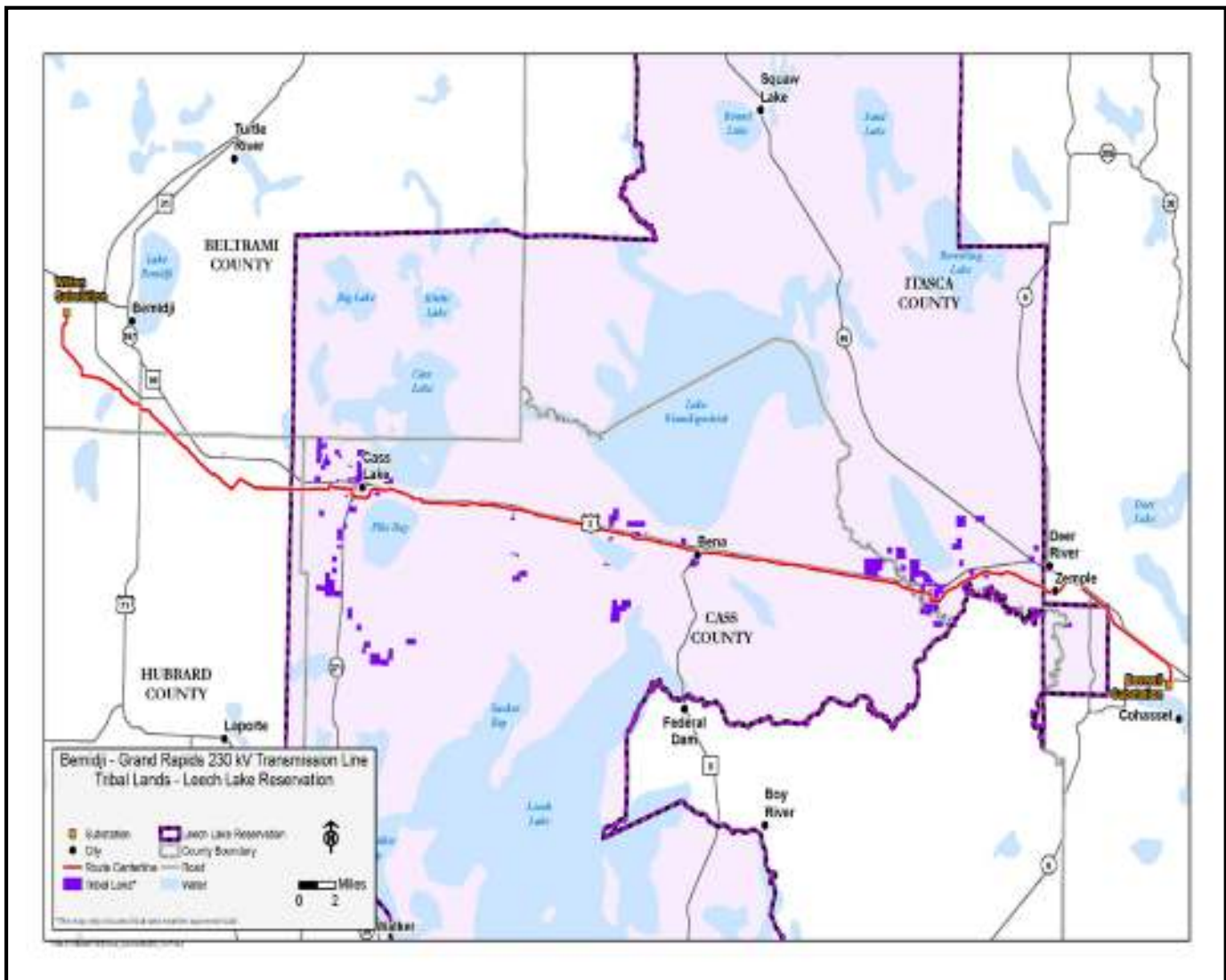
Participation Percentage of Development Costs and Election Rights

1. Great River Energy: 13.0%
2. Minnesota Power: 9.3%
3. Minnkota Power: 31.5%
4. Otter Tail Power: 20.0% (Project Manager)
5. Xcel Energy: 26.2%

Construction

In two years' time, the Bemidji-Grand Rapids project team constructed 70 miles of new transmission infrastructure and expanded substations on-time and on-budget. The project includes steel H-frame structures between 70 and 90 feet tall, and steel single-pole structures between 95 and 115 feet tall. The right-of-way is 125 feet wide in most places.

Bemidji – Grand Rapids Project Route Map



Appendix G: Big Stone South-Brookings County 345-kV Line Project Fact Sheet

BIG STONE SOUTH – BROOKINGS COUNTY 345-KV TRANSMISSION LINE

Project overview

The Big Stone South-Brookings County project is a 70 mile, 345-kV transmission line between a new Big Stone South Substation near Big Stone City, S.D., and the Brookings County Substation near Brookings, S.D. Xcel Energy and Otter Tail Power Company are joint owners and CapX2020 partners on the estimated \$225 million transmission line, and Xcel Energy is the construction manager. This project is different than the other CapX2020 projects because there are only two participating utilities, instead of five. Construction began in the fall of 2015, and is expected to be complete in 2017.

Project Need

Once constructed, the Big Stone South-Brookings County project will serve as a backbone for the eastern border of South Dakota. U.S. South Dakota Senator John Thune sees the new line as an opportunity for South Dakota to become a leader in wind development. “South Dakota needs to be at the crossroads of the energy renaissance of this country. The additional capacity is going to be the superhighway - the new roadway - for all kinds of wind energy.”²⁸ Since South Dakota’s ability to generate power is greater

than its ability to consume, the new transmission capacity gives generation in South Dakota access to energy markets where demand is high such as population centers to the east like the Twin Cities in Minnesota. Just as corn needs railroad tracks and trains to move their product to market, wind needs transmission lines.

The Big Stone South-Brookings County project is one of 16 multi-value projects (MVPs) approved by the Midcontinent Independent System Operator (MISO) and state regulatory agencies. The new tariff determined by MISO enables projects that meet certain criteria to be financed by all MISO member utilities in 12 states including Manitoba. The MVPs will expand and enhance the region’s transmission system, reduce congestion, provide access to affordable energy sources, and meet public policy requirements, including renewable energy mandates.

“Producing and delivering electricity as reliably, affordably, and environmentally responsibly as possible is at the core of our work-and this project supports those objectives,” said Tim Rogelstad, President of Otter Tail Power Company in a press

²⁸ Senator John Thune, speech, Big Stone Construction kick off ceremony.

release.²⁹ New transmission is an enabler for lower cost generation sources like wind, and allows the flexibility to use other generation sources.

Percentage of Line Ownership and Cost Allocation

Sometimes simpler is better, which was exactly the case in the Big Stone South - Brookings County transmission line project. Originally, the project was going to have a number of investors in it. However, Xcel Energy owns the Brookings County substation, the southern project terminus, and Otter Tail Power owns the Big Stone South substation, the northern project terminus. Technically, those two utilities and only those two utilities had a right to invest in the line. The CapX2020 partners evaluated allocating project costs while following the law and still maintaining the CapX2020 partnerships. During negotiations with CapX2020 partners, Xcel Energy offered the participants in the Brookings County-Hampton 345-kV project a share of the Big Stone South - Brookings County project. In the end, the CapX2020 group took that cost share and put it into the Brookings County - Hampton project, while leaving the Big Stone South - Brookings County project to Otter Tail Power and Xcel Energy.

Regulatory Process

The South Dakota regulatory process requires a Facility Permit from the South

Dakota Public Utilities Commission (SD PUC).

Two Facility Permits were required for the Big Stone South-Brookings County project. A Facility Permit was granted to Otter Tail Power Company in January of 2007 for approximately 35 miles from Big Stone City to just north of Gary, S.D. The SD PUC granted a Facility Permit to Xcel Energy and Otter Tail Power in February 2014 for an additional 42 miles from just north of Gary to the existing Brookings County substation. As part of the project permit process, Xcel Energy and Otter Tail Power recertified the 2007 Facility Permit to both partners.

Percentage of Line Ownership			
Utility	Transmission Lines	Brookings Substation	Big Stone South Substation
Otter Tail Power	50%	0%	100%
Xcel Energy	50%	100%	0%

²⁹ “CapX2020 utilities receive Facility Permit for South Dakota transmission line project.” CapX2020 press release, February 18, 2014.

Wind Potential in South Dakota

Northern States Power Company Principal Manager for South Dakota, Jim Wilcox said, “The Big Stone South-Brookings County project will expand electric infrastructure and utilize wind resources from South Dakota to support renewable energy development, as well as support the local economy and job growth.”³⁰ The economic benefits to the state and region do not end after construction, as the new transmission line has the potential to serve as a catalyst for wind development. The MISO interconnection queue has seen an uptick in requests since 2014, with the potential of an additional 950 MW of wind generation (if approved) in South Dakota alone.

- Conductor Installation: July 2016 - October 2017
- In-service date: Fall 2017
- Final Restoration: September 2017 - November 2017

Construction

The Big Stone South-Brookings County project includes 371 structures, about 33,000 cubic yards of concrete, and about 2 million feet of conductor wire.

Estimated Construction Schedule

- Vegetation Removal: August 2015 - November 2015
- Site Access/Road improvements: August 2015 - November 2015 and May 2016 - July 2016
- Foundation Construction: November 2015 - October 2016
- Structure Erection: June 2016 - September 2017

³⁰ “CapX2020 utilities receive Facility Permit for South Dakota transmission line project.” CapX2020 press release, February 18, 2014.

Big Stone South – Brookings County Project Route Map



Appendix H: Brookings County-Hampton 345-kV Line Project Fact Sheet

BROOKINGS COUNTY – HAMPTON 345-KV TRANSMISSION LINE

Project Overview

The Brookings County-Hampton project is the longest of the CapX2020 projects at a length of 250 miles, and is a double circuit 345-kV transmission line built between the Brookings County substation near Brookings, South Dakota, and the Hampton substation south of the Twin Cities in Hampton, Minnesota. The line is comprised primarily of single pole structures attached to concrete foundations, spaced about five per mile. Construction began in April 2012, and the line was placed in service on March 26, 2015.

The Brookings County-Hampton 345-kV Project is one of 16 multi-value projects (MVPs) approved by the Midcontinent Independent System Operator (MISO) and state regulatory agencies. The new tariff determined by MISO enables projects that meet certain criteria to be financed by all MISO member utilities in 12 states including Manitoba. The MVPs will expand and enhance the region's transmission system, reduce congestion, provide access to affordable energy sources, and meet public policy requirements, including renewable energy mandates.

Project Need



Public Meeting discussing the line route

The Brookings County-Hampton project will help meet projected electric growth in southern and western Minnesota, and the growing areas south of the Twin Cities metro area, particularly Scott and Dakota counties where population has more than doubled since the last major transmission upgrade. Additionally, Minnesota has one of the nation's most aggressive renewable energy standards, requiring 25% of electricity to come from renewable sources like wind (30% for Xcel Energy). The Brookings County-Hampton project connects the central part of the Buffalo Ridge in Minnesota, one of the nation's windiest areas, to the Twin Cities.

Project Route

The final route, determined after a lengthy regulatory process by the Minnesota Public Utilities Commission (MN PUC), was

Working with Federal Agencies

In late October 2010, a letter from the U.S. Fish and Wildlife Service (USFWS) proposed that a study be done on eagle winter habitat use and availability of the Minnesota River Valley and Silver Lake area. The letter also reversed the USFWS' prior opinion on the Minnesota River crossing at Belle Plaine. The agency worked with the CapX2020 utilities to determine at what location the line should cross the Minnesota River, and was ultimately approved by the MN PUC.

developed over the course of several years and with the input of thousands of landowners, stakeholders, state, and local officials. CapX2020 held several rounds of open houses and working groups to identify potential areas for the eventual route. Utilities provided two routes in the Route Permit application as required by law, and additional routes were proposed by members of the public during regulatory proceedings.

Project Permitting

This line required permit approval from both Minnesota and South Dakota. The CapX2020 utilities were granted a Certificate of Need (CN) from the Minnesota Public Utilities Commission (MN PUC) on May 22, 2009. A Route Permit was granted from the MN PUC on February 3, 2011

The South Dakota regulatory process requires a Facility Permit from the South Dakota Public Utilities Commission (SD PUC). The SD PUC granted a Facility Permit on June 14, 2011.

Permitting Schedule

In Minnesota:

- Certificate of Need application - filed August 16, 2007
 - MN PUC approval - May 22, 2009
- Route Permit Application - filed December 29, 2008
 - Judge's recommendation - issued April 22, 2010
 - MN PUC approval - issued July 15, 2010
 - MN PUC written order - issued September 14, 2010
 - Judge's recommendation - issued December 22, 2010
 - MN PUC written order for remanded route segment - issued March 1, 2011
- EIS scoping decision - issued June 30, 2009
- Draft EIS - issued October 20, 2009
- Final EIS - issued January 26, 2010

In South Dakota:

- Facility permit application - filed November 22, 2010
 - SD PUC approval - granted June 14, 2011

Participation Percentage of Development Costs and Election Rights

1. Central Minnesota Municipal Power: 2.2%
2. Great River Energy: 16.5% (Project Manager)
3. Missouri River Energy Services: 5.1%
4. Otter Tail Power: 4.1%
5. Xcel Energy: 72.1%

Construction

Because the line was so large, it was broken down into six segments during construction:

1. Cedar Mountain Substation in Renville County, MN to Helena Substation in Scott County, MN: Construction of the 72-mile segment began in April 2012 and was completed in September 2012. A 4-miles 115-kV connection with the Franklin Substation was built as part of this segment, and was placed in service March 2014.
2. Cedar Mountain Substation in Renville County, MN to Lyon County Substation east of Marshall, MN: Construction of the 50-mile segment began in spring 2013 and was completed late 2013. The line was placed in service March 2014.
3. Helena Substation in Scott County, MN to Chub Lake Substation in Scott County, MN just east of I-35: Construction of the 20-mile segment began in July 2013 and

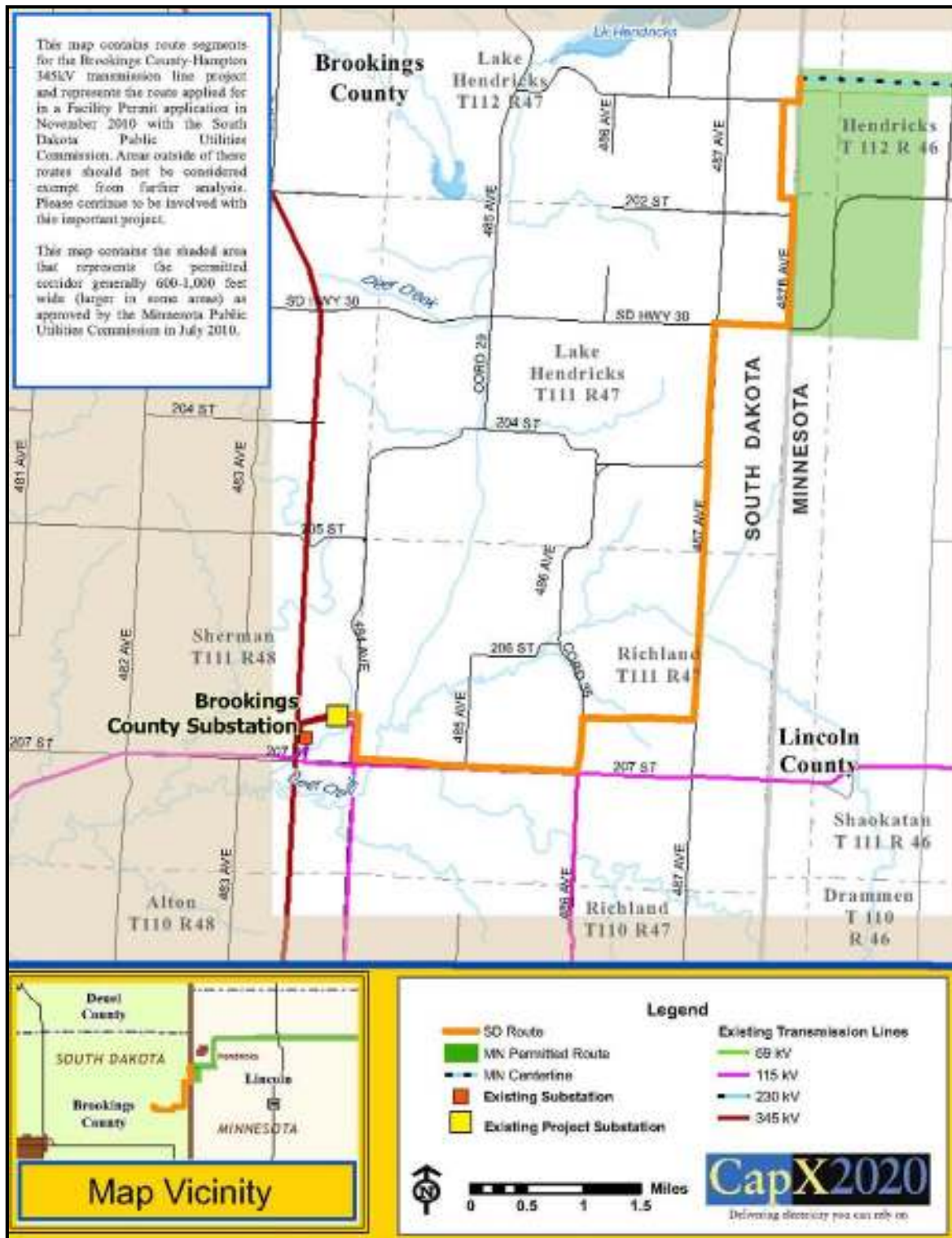
was completed in spring 2014. The line was placed in service April 2014, and restoration was completed in late June 2014.

4. Chub lake Substation in Scott County, MN to Hampton Substation in Dakota County, MN: Construction of the 18-mile segment began in autumn 2013 and was completed and placed in service April 2014, with restoration completed in late June 2014.
5. Lyon County Substation east of Marshall, MN to Brookings County Substation northeast of Brookings, South Dakota: Construction of the 58-mile segment began in late 2013 and was placed in service March 31, 2014.
6. Lyon County Substation east of Marshall, MN to the Hazel Creek and Minnesota Valley Substations near Granite Falls in Yellow Medicine County, MN: Construction of the 30-mile segments began in early 2014. The line was placed in service March 2015.

Brookings County – Hampton Project Route Map, Minnesota Segment



Brookings County – Hampton Project Route Map, South Dakota Segment



Appendix I: Fargo-St. Cloud-Monticello 345-kV Line Project Fact Sheet

FARGO – ST. CLOUD – MONTICELLO 345-KV TRANSMISSION LINE

Project Overview

Construction of the Fargo-St. Cloud-Monticello 345-kV transmission line started in 2010 and the line was fully energized in April, 2015. The project is the second largest of the CapX2020 projects at 240 miles long, and was separated into three phases to better manage permitting and construction schedules. The Monticello-St. Cloud 345-kV Project is Phase One of the longer contiguous segment. The Fargo-St. Cloud 345-kV Project make up Phases Two and Three of the line.

Phase One was energized and placed into service on December 21, 2011. The 28-mile line starts at the Monticello Nuclear Generating Plant and heads west generally paralleling Interstate 94 to the new Quarry Substation northwest of St. Cloud, Minnesota. It is double circuit capable, and constructed primarily of single pole steel structures. Phase Two between Fargo, ND and St. Cloud, MN was completed in August of 2014, and the entire line was fully energized at the completion of Phase Three in April of 2015.

Project Need

The last major upgrade to the project region's electric transmission infrastructure took place more than 30 years ago. Since

then, the population has grown, home sizes have nearly doubled, and appliance and electronic device usage have increased significantly. The new transmission lines were built in phases and are designed to meet the electricity growth in the Fargo, Alexandria, and St. Cloud areas, improve regional reliability, and add capacity for future generation, including tapping into vast wind energy resources in western Minnesota and the Dakotas.

Permitting Process: Phase I: Monticello - St. Cloud Project

This segment of the line needed two approvals from the Minnesota Public Utilities Commission before construction - a Certificate of Need and a Route Permit. The CapX2020 utilities were granted a Certificate of Need from the Minnesota PUC on May 22, 2009 for all three 345-kV projects, including this line. A route permit application was filed on April 8th, 2009 and approved in July of 2010.

Permitting Process: Phase II & III: Fargo - St. Cloud Project



**Helicopter at work installing
spacers near Monticello, MN.**

This segment of the line needed two approvals from the Minnesota Public Utilities Commission before construction - a Certificate of Need and a Route Permit. The CapX2020 utilities were granted a Certificate of Need from the MN PUC on May 22, 2009. A route permit application was filed October 1, 2009 and approved in June of 2011.

The North Dakota Public Service Commission (ND PSC) granted a Certificate of Public Convenience and Necessity in January 2011. A joint Certificate of Corridor Compatibility and Route Permit application was filed October 3, 2011 with the ND PSC and approved on September 12, 2012.

Participation Percentage of Development Costs and Election Rights

Project agreements for the Monticello - St. Cloud Project and the Fargo - St. Cloud Project were combined into one agreement between the five participating CapX2020 utilities.

1. Great River Energy: 25.0%
2. Minnesota Power: 14.7%
3. Missouri River Energy Services: 11.0%
4. Otter Tail Power: 13.2%
5. Xcel Energy: 36.1% (Project Manager)

Working with State Agencies

A unique agreement between MN DOT and CapX2020 provided interstate access to construction crews for a foundation construction and structure erection site west of Alexandria on I-94 near the Lake Latoka rest area. This access avoided the removal of approximately 40,000 square feet of wooded areas from a landowner's lake front property, and the movement for more than 4 weeks of heavy equipment and large trucks through a residential neighborhood.

During construction of the line, CapX2020 placed advertisements at area gas stations, rest areas, and in newspapers to inform local residents as well as motorists about the construction, and that it is illegal and unsafe to stop or slow down on the highway.



**Substation on the Fargo-St.
Cloud-Monticello Line**

Construction

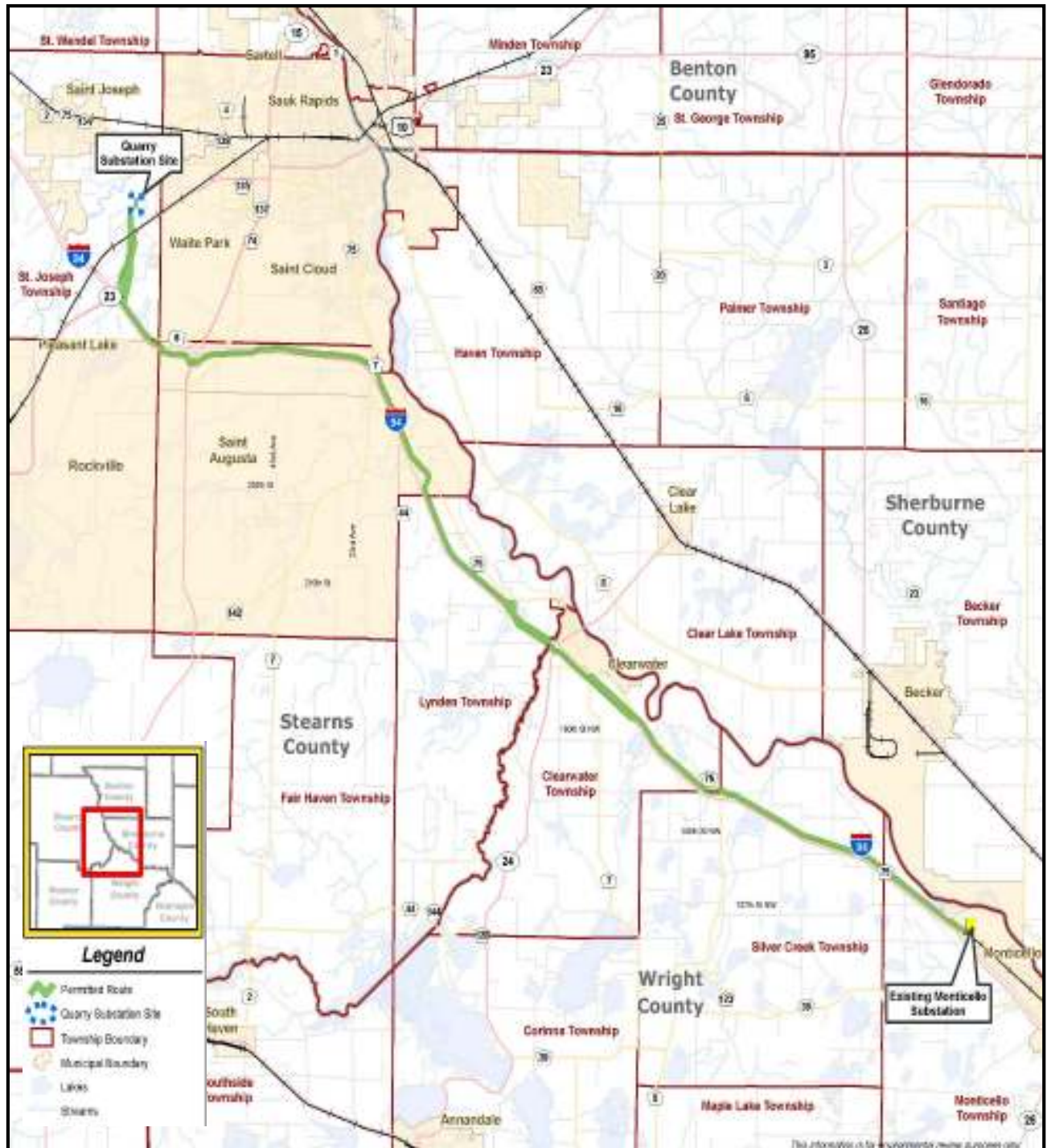
A massive amount of materials was needed to construct the three segments that make up the Fargo-St. Cloud-Monticello Project.

Because of the enormity of the line, construction began on Monticello-St. Cloud segment before the Fargo-St. Cloud segment had been fully permitted by either Minnesota or North Dakota.

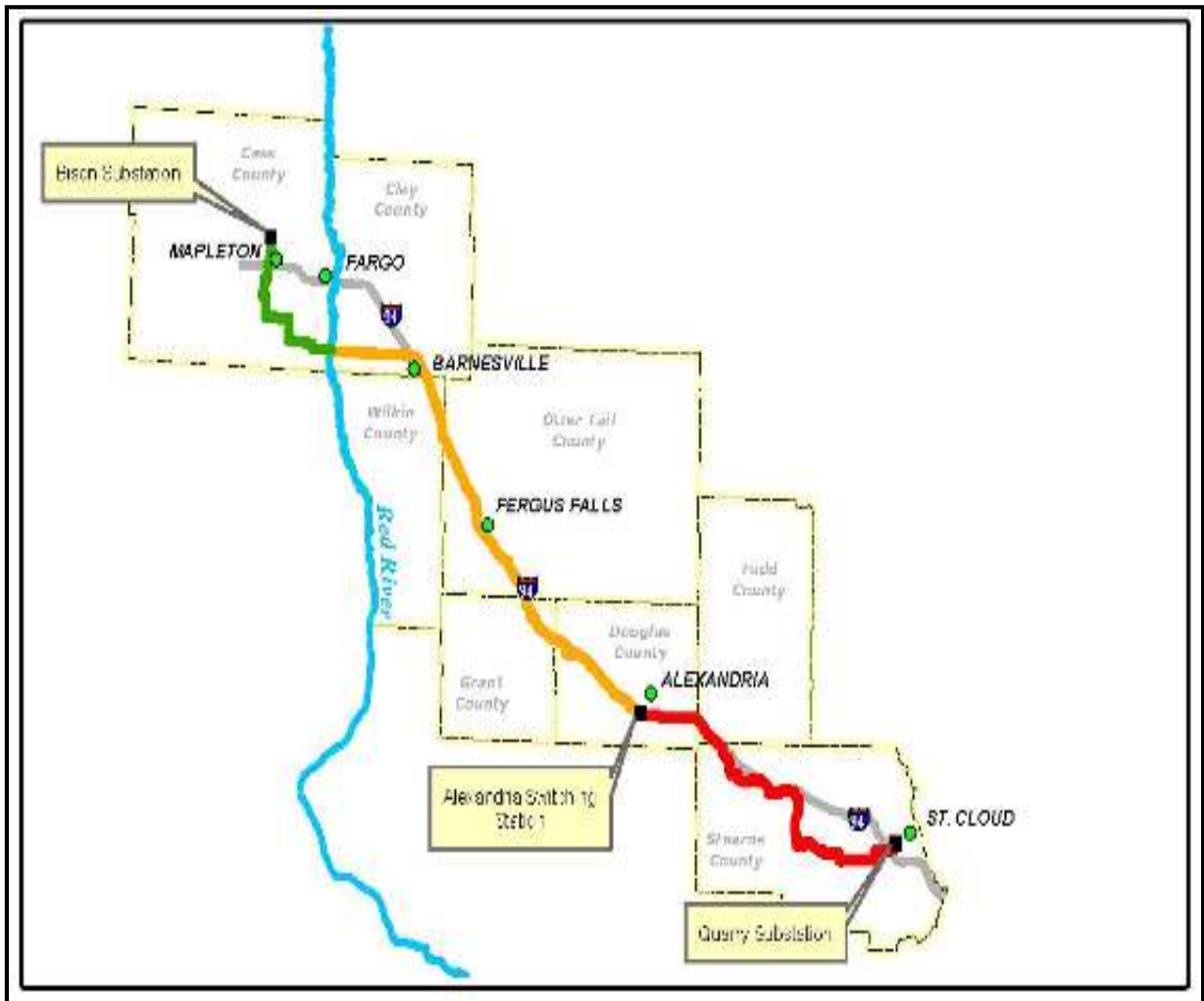
Two new substations were built for the project in St. Cloud, Minnesota and Mapleton, North Dakota. Terminals were added at two other substations.

Over 13,000 polymer mats were used to provide off-road access to construction crews to the location of poles to reduce land compaction. Additionally, helicopters were used for setting up the structures, stringing, and attaching components, including 2,200 interphase spacer units.

Monticello – St. Cloud Project Route Map



Fargo – St. Cloud Project Route Map



Appendix J: Hampton-Rochester-La Crosse 345-kV Line Project Fact Sheet

HAMPTON – ROCHESTER – LA CROSSE 345-KV TRANSMISSION LINE

Project Overview

Construction on the Hampton-Rochester-La Crosse 345-kV transmission line started north of Rochester in early 2013 and is expected to be complete in 2016.

In August 2015, a 90-mile, 345-kV segment of the project was energized, including 50 miles in Wisconsin between Alma and the new Briggs Road substation near Holmen and 40 miles in Minnesota between the new North Rochester substation near Pine Island and the Mississippi River. The final 345-kV segment, a 36-mile double circuit capable 345-kV line between the new Hampton substation near Hampton Minnesota, and the North Rochester substation near Pine Island is scheduled for completion in 2016.

A new 161-kV line between the North Rochester substation and the existing Northern Hills substation in northwest Rochester was energized in May 2014. A second 161-kV line between the North Rochester substation and the existing Chester substation in northeast Rochester is expected to be complete and energized in late 2015. The lower voltage 161-kV lines were not part of the initial plan for the line, however, the new 345-kV line provided an opportunity for the CapX2020 group to address a more local transmission issue in the area of the line.

Gordon Pietsch, Director of Transmission Planning and Operations for Great River Energy said, “We recognized that while the 345 lines were solving problems, they were also creating some problems that we needed to address as well.” The addition of the lower voltage lines was the result of a holistic planning approach, addressing both the regional as well as localized issues on project routes.

Single pole steel structures for the 345-kV line are being used to reduce land impacts. Structures are between 140 and 170 feet tall and will be spaced 800 to 1,000 feet apart with a 150-foot right-of-way. Structures for the 161-kV lines are between 70 and 125 feet tall and are spaced 400 to 650 feet apart, with a typical right-of-way of 80 feet.

Permitting Process

This line requires permit approval from both Minnesota and Wisconsin. The CapX2020 utilities were granted a Certificate of Need (CN) from the Minnesota Public Utilities Commission (MN PUC) on May 22, 2009 for all three 345-kV projects. The CapX2020 utilities filed a Route Permit application with the MN PUC on January 19, 2010, and received approval in April of 2012. A Route Permit for the smaller 161-kV line, an off-shoot of the main 345-kV line, was filed with the MN PUC in September of 2011, and approved a year later in 2012.

The Wisconsin regulatory process combines need and routing into one permit which certifies the project need and designates a route. A Certificate of Public Convenience and necessity (CPCN) was filed with the Public Service Commission of Wisconsin (WPSC) and the Wisconsin Department of Natural Resources in December of 2010 and approved in May of 2012.

Permitting Schedule

Minnesota Permitting

- Certificate of need application - filed August 16, 2007
 - MN PUC approval - May 22, 2009
- Route Permit application - filed January 19, 2010
 - Judge's recommendation - issued February 8, 2012
 - MN PUC approval - April 12, 2012
- MN EIS scoping decision - issued August 6, 2010
- MN Draft EIS - issued March 21, 2011
- MN Final EIS - issued August 31, 2011

Wisconsin Permitting

- CPCN application - filed January 3, 2011
 - PSCW approval - issued May 10, 2012
- Draft WI EIS - issued November 2011
- Final WI EIS - issued January 2012

Participation Percentage of

Development Cost and Election Rights

1. Rochester Public Utilities: 9%
2. Dairyland Power Cooperative: 11%
3. Southern Minnesota Municipal Power Agency: 13%
4. WPPI Energy: 3%
5. Xcel Energy: 64% (Project Manager)



Construction crews pouring cement into a spread foundation as part of the Mississippi River crossing work

Construction: Crossing the Mississippi

The Hampton-Rochester-La Crosse project crosses state lines, and to do so it needed to traverse the Mississippi River, which was the biggest construction challenge of the project. The line crosses the Minnesota-Wisconsin border just south of Alma, WI, a city with a population of less than 1,000. For this part of the project alone, the CapX2020 group cooperated and coordinated with the US Department of Agriculture, the US Army Corp of Engineers, the US fish and Wildlife Service, and the Wisconsin and Minnesota Departments of Natural Resources (DNR).



Barges were used to ferry equipment, materials, and labor to an island on the Mississippi River.

Construction crews dealt with a unique set of challenges, from building on an island, to dealing with an early winter and extreme cold. The construction process included building on an island and a peninsula only accessible by boat or barge. All equipment, materials, and labor had to be delivered by barge or boat. Over 3,280 cubic yards of concrete was needed to build the pole foundations on the island. On one day in particular, 100 cement trucks were ferried to the island, two trucks by barge at a time. To add to the difficulty, at the time of construction there was a shortage of concrete, according to local news reports.³¹ The project manager was able to work with the supplier to make sure that the CapX2020 project was given priority for concrete because they were in a race with the weather to deliver the materials before the river froze over.

The foundations used on the island were different than what was typically used inland because the soil was very unstable. They used

Working with State and Federal Agencies

The US Fish and Wildlife had two concerns: the height of the structure and how much tree-clearing needed to be done. Both groups compromised to find a solution. Part of the agreement was removing the existing line, built in 1965 by Dairyland Power Cooperative, and replace it with a triple-circuit configuration.

The DNR encouraged the group to look at a variety of locations for the crossing, and even suggested that the line be routed under the river because the area is an important flyway for birds. This proved to be very technologically challenging and expensive, and because there was an existing line in the area, the agencies determined the location at Alma to be the best site option.

³¹ Carlson, Heather J. "Icy water, eagles factor into CapX2020 river crossing." 11/21/2014. Rochester, MN PostBulletin.com. Accessed at <http://www.postbulletin.com/news/local/icy-water->

[eagles-factor-into-capx-river-crossing/article_39c3b4e0-1b4f-5287-9e6c-b6f1eae8c6bc.html](http://www.postbulletin.com/news/local/icy-water-eagles-factor-into-capx-river-crossing/article_39c3b4e0-1b4f-5287-9e6c-b6f1eae8c6bc.html)

pile-cap foundations, comprised of 362 16-inch steel pipe piles in a grid, with some driven into the soil as deep as 130 feet.

The Mississippi crossing now includes one double-circuit 345-kV line, one midsize 161-kV line, and one low-voltage 69-kV line.

Helicopters were used to string wire and other line components between the two sides of the river, and towards the end of construction, helicopters were the only way to access the island because the river was completely frozen.

Hampton – Rochester – La Crosse Project Route Map

