3.1.1.5 Route Alternative A4

Route alternative A4 is 3.7 miles long and diverts from the applicants' proposed route near County Road 10, where it turns south for approximately 1.75 miles and then turns west for approximately 2 miles before rejoining the applicants' proposed route. Route alternative A4 does not include any transmission line ROW sharing, paralleling, or double-circuiting.

3.1.1.6 Alignment Alternative AA15

One alignment alternative is included in the Iron Range Substation region. Alignment Alternative AA15 would shift the applicants' proposed route from private property onto Itasca County tax forfeit lands. The AA15 alignment alternative is 0.4 mile long and shifts the alignment west of the applicants' proposed route south of County Road 436. Alignment alternative AA15 would require crossing over existing transmission infrastructure and then crossing back. Alignment alternative AA15 would parallel an existing transmission line ROW for its entire length.

3.1.2 Hill City to Little Pine Region

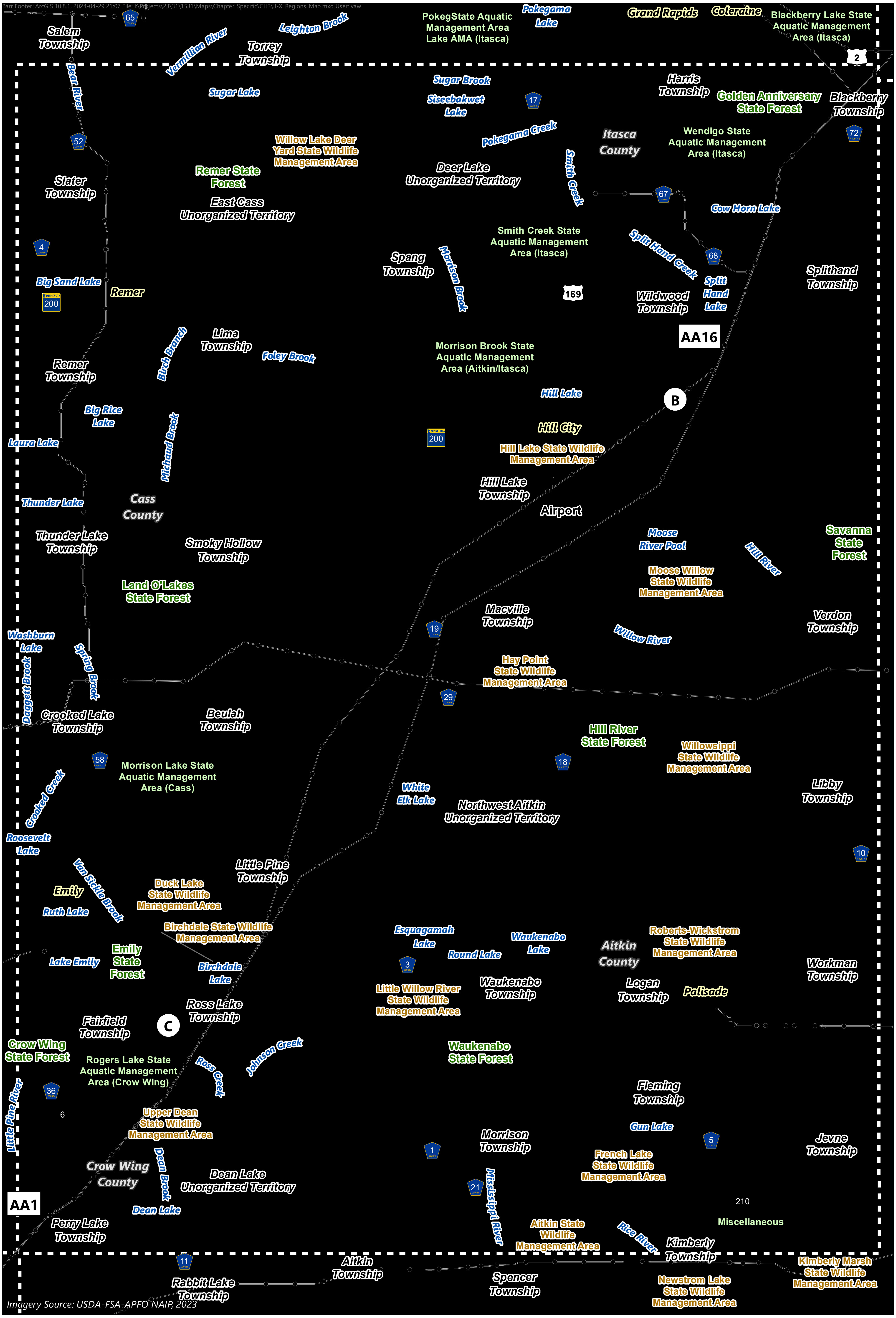
The Hill City to Little Pine region is in Aitkin, Cass, Crow Wing, and Itasca counties. The region includes the applicants' proposed route, two route alternatives (B and C) and three alignment alternatives (AA1, AA2, and AA16) (Map 3-3).

3.1.2.1 Applicants' Proposed Route – Hill City to Little Pine Region

The applicants' proposed route generally moves southwest through the Hill City to Little Pine region, following a portion of Minnesota Power's existing 230 kV line (92 Line). The applicants' proposed route begins at US Highway 2 where it moves southwest for approximately 4.75 miles, crossing the Mississippi River. The applicants' proposed route then moves more southerly as it crosses Danson Road, continuing for approximately 11.5 miles, where it then turns westerly north of Hill River State Forest and continues for 8.6 miles. The applicants' proposed route turns south and jogs east of an Enbridge pump station and continues along the 92 Line ROW for approximately 27 miles, where it crosses the Mississippi River at the southern end of the region.

3.1.2.2 Route Alternative B

Route alternative B is 26.4 miles long and shifts west from the applicants' proposed route to potentially reduce natural resource impacts. Route alternative B turns west 1.5 miles north of State Highway 200 and parallels an existing transmission line ROW for a majority of the route length. Route alternative B continues southwest crossing the Hill River Ditch, Willow River, Moose River, and East Lake, before rejoining to the applicants' proposed route approximately 0.8 miles south of County Road 1. A portion of route alternative B, in an area where it parallels an existing transmission line ROW, is adjacent to the Hill City/Quadna Mountain Airport. Specialty structures would be required near the Hill City/Quadna Mountain Airport to lower structure heights to less than 80 feet for approximately 0.5 to 1 mile. This lower height would be required to maintain airport clear-zone requirements.



Applicants' Proposed Route
Route Width
Route Alternative
Alignment Alternative
Route Alternative Width
Existing Transmission Line
PWI Waterway
PWI Basin
State Forest
Municipal Boundary
Region Boundary

Miles
0 1.5 3

Map 3-3

HILL CITY TO LITTLE PINE REGION
Northland Reliability Project

3.1.2.3 Route Alternative C

Route alternative C is 4.6 miles long and shifts west from the applicants' route. Route alternative C generally follows existing roads and disturbed corridors. This route turns west from the applicants' proposed route along Lens Road and then turns south to follow County Road 106 for 2.6 miles before rejoining the applicants' proposed route approximately 0.5 mile south of County Road 36. Route alternative C would cross an existing transmission line in two locations (once to cross over the existing transmission line and once to cross back). It would also require at least three heavy-angle structures to accommodate 90-degree and angled turns along the route. Route alternative C does not include any transmission line ROW sharing, paralleling, or double-circuiting.

3.1.2.4 Alignment Alternative AA1

Alignment alternative AA1 is 1.6 miles long and shifts west of the applicants' proposed route to avoid private property. This alternative crosses State Highway 6 further north than the applicants' proposed route and crosses Wood Road further northwest than the applicants' proposed route. Alignment alternative AA1 does not include any transmission line ROW sharing, paralleling, or double-circuiting. It would cross an existing transmission line in two locations (once to cross over the existing transmission line and once to cross back). It would also require at least two heavy-angle structures to accommodate proposed 90-degree and angled turns.

3.1.2.5 Alignment Alternative AA2

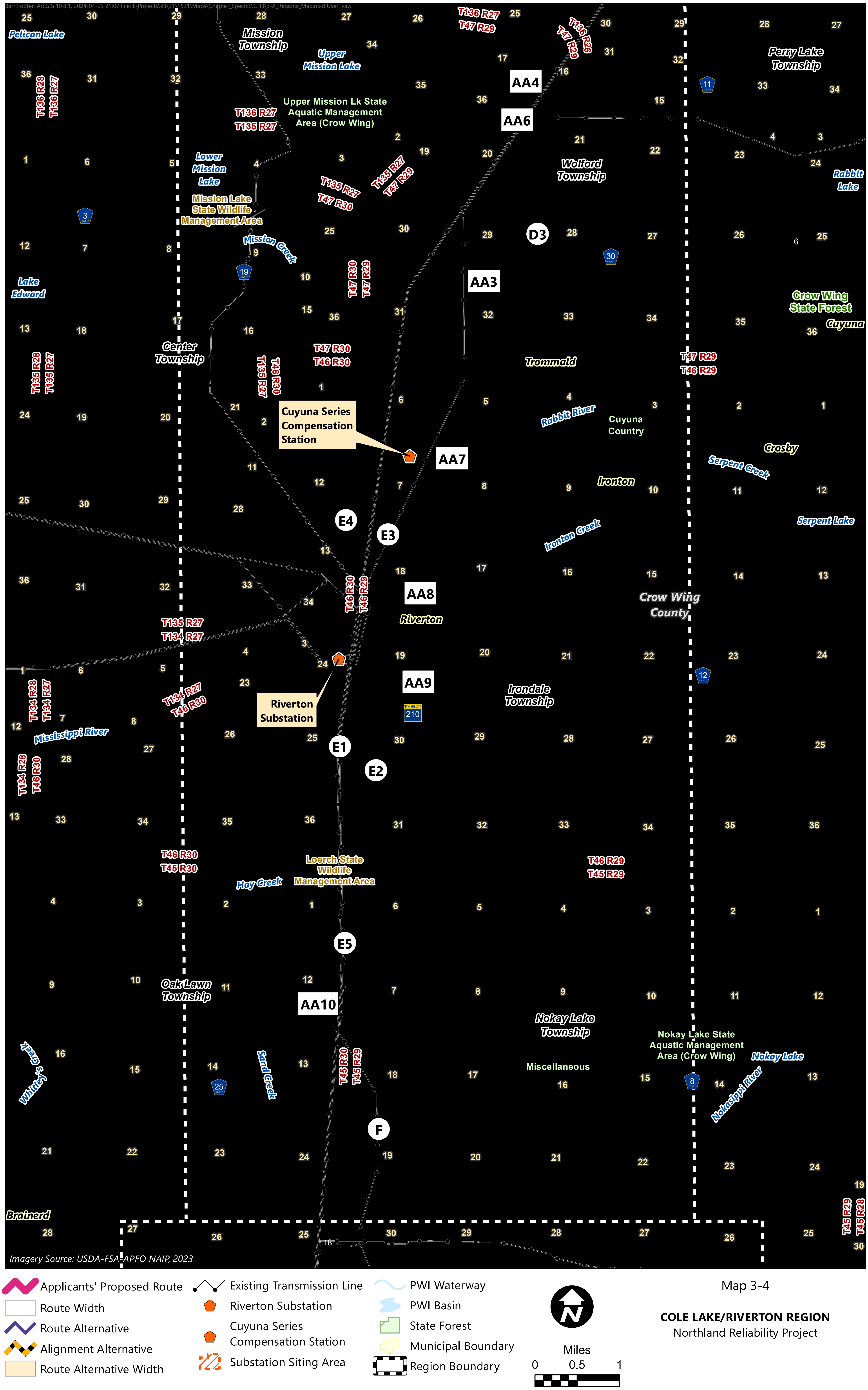
Alignment alternative AA2 is 0.6 mile long and shifts west of the applicants' proposed route to avoid private property. Alignment alternative AA2 crosses State Highway 6 further north than the applicants' proposed route and follows the highway south for approximately 0.2 miles before rejoining the applicants' proposed route. Alignment alternative AA2 does not include any transmission line ROW sharing, paralleling, or double-circuiting. It would cross an existing transmission line in two locations (once to cross over the existing transmission line and once to cross back). It would also require at least two heavy-angle structures to accommodate proposed 90-degree and angled turns.

3.1.2.6 Alignment Alternative AA16

Alignment alternative AA16 is 11 miles long and would entail double-circuiting two existing transmission lines in order to allow alignment alternative AA16 to utilize that existing ROW, to minimize potential impacts in the area. Alignment alternative AA16 is located west of the applicants' proposed route. Alignment alternative AA16 continues southwest for approximately 5.75 miles before rejoining the applicants' proposed route just south of the Itasca County and Aitkin County border.

3.1.3 Cole Lake-Riverton Region

The Cole Lake-Riverton region is located in the central portion of the project in Crow Wing County (Map 3-4). The Cole Lake-Riverton region contains the applicants' proposed route, eight route alternatives (D3, E1, E2, E3, E4, E5, F, and G) and seven alignment alternatives (AA3, AA4, AA6, AA7, AA8, AA9, and AA10). The five route alternatives labeled E1 through E5 offer route alternatives around the town of Riverton.



Map 3-4

COLE LAKE/RIVERTON REGION
Northland Reliability Project

3.1.3.1 Applicants’ Proposed Route – Cole Lake-Riverton Region

The applicants’ proposed route moves southwesterly through the Cole Lake region, beginning at the Mississippi River crossing and ending at the new Cuyuna Series Compensation Station. The route moves southwest for 0.75 mile along the 92 Line before deviating and turning southerly then westerly for 1 mile to avoid residences. It rejoins the 92 Line for approximately 3.75 miles where it crosses Miller Kae Road and South Black Bear Road before arriving at the new Cuyuna Series Compensation Station. As the applicants’ proposed route leaves the Cuyuna Series Compensation Station, it extends southeast for approximately 7.8 miles along new ROW, crossing the western portion of Hay Lake, before joining GRE’s 230 kV MR Line (MR Line). The route shares the MR Line ROW for approximately 2 miles then turns due east for 0.5 mile at the southern end of the region.

3.1.3.2 Route Alternative D3

Route alternative D3 is 3.3 miles long and is shifted east and south from the applicants’ proposed route in an effort to reduce potential impacts. Route alternative D3 diverges south from the applicants’ proposed route just south of County Road 11 and heads south for approximately 2 miles, and then turns west for 1.3 miles before rejoining with the applicants’ proposed route. Route alternative D3 does not include any ROW sharing, paralleling, or double-circuiting; however, it would cross one existing transmission line.

3.1.3.3 Alignment Alternative AA3

Alignment alternative AA3 involves double-circuiting two existing transmission lines, which would then allow placement of the project within existing transmission line ROW. Alternative AA3 is approximately 5 miles long and would terminate at the new Cuyuna Series Compensation Station.

3.1.3.4 Alignment Alternative AA4

Alignment alternative AA4 is a shorter version of AA3. Alignment alternative AA4 would double-circuit two existing transmission lines so that the project could be constructed within existing transmission line ROW. Alignment alternative AA4 is approximately 0.8 miles long.

3.1.3.5 Alignment Alternative AA6

Alignment alternative AA6 is 1 mile long; it would divert from the applicants’ proposed route north of River Road and head due south along Cole Lake Way for approximately 0.7 miles, then turn due west for 0.3 mile before rejoining the applicants’ proposed route. Alignment alternative AA6 does not include any ROW sharing, paralleling, or double-circuiting; however, it would cross one existing transmission line.

3.1.3.6 Route Alternative E1

Route alternative E1 is 7.2 miles long and diverts from the applicants’ proposed route north of Bluegill Road and heads southwest for approximately 7.2 miles before rejoining the applicants’ proposed route on Woodrow Road. Route alternative E1 was proposed to avoid impacts to the Cuyuna County State Recreation Area by using existing transmission line ROW. Route alternative E1 would double-circuit two existing transmission lines, which would then allow placement of the project route within existing transmission line ROW (Photo 3-1). Although this alternative would cross into a Wildlife Management Area (WMA), it would utilize existing transmission line ROW through this area. Route alternative E1 would require modifying existing transmission lines in the area and may also need a wider route width in certain areas.

Photo 3-1 View of Route Alternative E1 ROW from CR 159

3.1.3.7 Route Alternative E2

Route alternative E2 is 4.4 miles long and diverts from the applicants' proposed route just south of State Highway 210 where it heads southwest for 1.75 miles before turning due south for 2.6 miles and rejoining the applicants' proposed route. Where the line turns and heads south, route alternative E2 would share existing transmission line ROW for approximately 2.6 miles.

3.1.3.8 Route Alternative E3

Route alternative E3 is, for the most part, a shorter version of route alternative E1. It is 5.2 miles long and diverts from the applicants' proposed route north of Bluegill Road and heads southwest for approximately 4.2 miles, generally following route alternative E1. However, just south of State Highway 210, route alternative E3 would break away from route alternative E1 and turn southeast for 1 mile to rejoin the applicants' proposed route.

3.1.3.9 Route Alternative E4

Route alternative E4 is 11 miles long; it diverts from the applicants' proposed route 1 mile north of Miller Lake Road. It then heads southwest of the applicants' proposed route and west of the town of Riverton, where it begins a sinuous route edging west around Hay Lake, with two Mississippi River crossings. Route alternative E4 then heads due south for approximately 4.5 miles before rejoining the applicants' proposed route at Woodrow Road. Route alternative E4 would share existing transmission line ROW for approximately 8 of its 11 miles. Route alternative E4 would cross six existing transmission lines and would require at least two heavy-angle structures to accommodate 90-degree and angled turns along the route.

3.1.3.10 Route Alternative E5

Route alternative E5 is 8.1 miles long; it diverts from the applicants' proposed route approximately 0.7 mile north of Bluegill Road, heading west of the town of Riverton, around Hay Lake, and then south to rejoin the applicants' proposed route at Woodrow Road. This route was proposed as a shorter alternative to route alternative E4. It would share existing transmission line ROW for approximately 6.3 miles and would also cross the Mississippi River two times. Route alternative E5 would cross six existing transmission lines and would require at least two heavy-angle structures to accommodate 90-degree and angled turns along the route.

3.1.3.11 Route Alternative F

Route alternative F is 2.4 miles long and was proposed to reduce impacts to natural resources. Route alternative F diverts from the applicants' proposed route 0.25 mile south of Woodrow Road and continues traveling south for approximately 2.5 miles before rejoining the applicants' proposed route just north of State Highway 18. Route alternative F would parallel existing transmission line ROW for approximately 1.5 miles.

3.1.3.12 Route Alternative G

Route alternative G is 3.5 miles long and was proposed to avoid impacts to residential areas. Route alternative G would divert from the applicants' proposed route approximately 0.35 mile north of State Highway 18 and continue south for approximately 1.75 miles. From there, it would turn due east for approximately 1.15 miles and turn north for approximately 0.75 mile to rejoin the applicants' proposed route west of Burgwald Road. Route alternative G would parallel existing transmission line ROW for approximately 1.7 miles and would require at least one heavy angle structure to accommodate a 90-degree turn along the route.

3.1.3.13 Alignment Alternative AA7

Alignment alternative AA7 is 0.3 mile in length and diverts from the applicants' proposed route 0.7 mile north of Bluegill Road. Alignment alternative AA7 removes one angled turn from the applicants' proposed route, straightening the proposed transmission line ROW in this area. Alignment alternative AA7 does not include any transmission line ROW sharing, paralleling, or double-circuiting.

3.1.3.14 Alignment Alternative AA8

Alignment alternative AA8 is 1.5 miles long and diverts from the applicants' proposed route where it crosses County Road 128. Alignment alternative AA8 heads southwest along the east side of County Road 128 and then follows the east side of County Road 59 due south around the Cuyuna Recreational Area until it rejoins the applicants' proposed route just south of State Highway 210. Alignment alternative AA8 does not include any transmission line ROW sharing, paralleling, or double-circuiting.

3.1.3.15 Alignment Alternative AA9

Alignment alternative AA9 is 1.6 miles long and diverts from the applicants' route where it crosses County Road 128. Alignment alternative AA9 routes around the Cuyuna Recreation Area by heading southwest along the east side of County Road 128 for approximately 0.5 mile before following the west side of

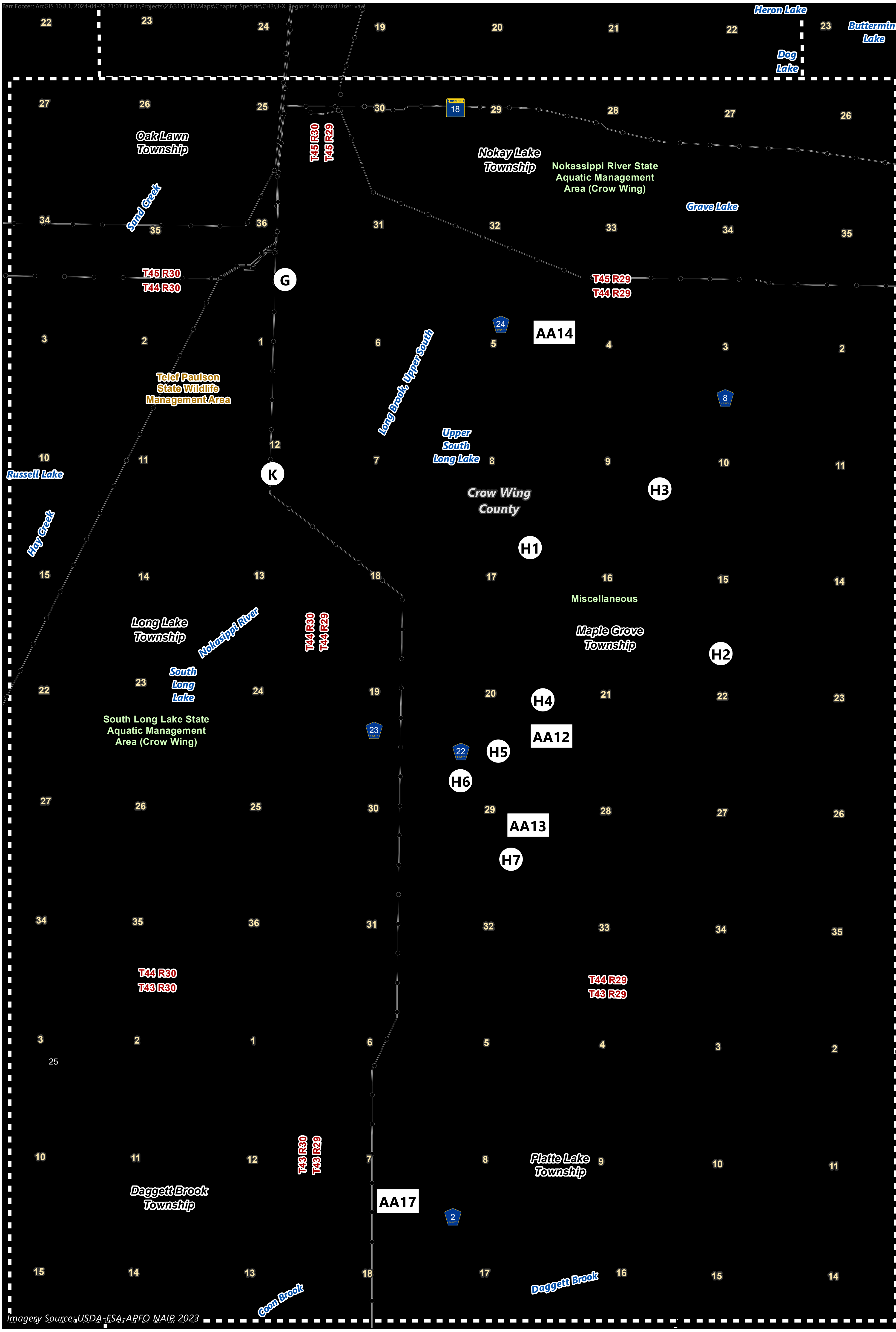
County Road 59 due south for approximately 1.1 miles until it rejoins the applicants' proposed route just south of State Highway 210. Alignment alternatives AA8 and AA9 present similar proposals; however, alignment alternative AA9 would share existing transmission line ROW.

3.1.3.16 Alignment Alternative AA10

Alignment alternative AA10 diverts from the applicants' proposed route approximately 0.1 mile north of Woodrow Road and runs parallel (but offset by 0.25 mile) to the applicants' proposed route for 0.75 mile, then turns due south for 0.25 mile where it rejoins the applicants' proposed route. Alignment alternative AA10 would share an existing transmission line ROW for approximately 0.25 mile.

3.1.4 Long Lake Region

The Long Lake region is located in the central portion of the project, south of the Riverton region (Map 3-5). The Long Lake region contains the applicants' proposed route, eight route alternatives (H1, H2, H3, H4, H5, H6, H7, and K), and four alignment alternatives (AA12, AA13, AA14, and AA17) (Map 3-5).



Applicants' Proposed Route
Route Width
Route Alternative
Alignment Alternative
Route Alternative Width
Existing Transmission Line
PWI Waterway
PWI Basin
Region Boundary

N

Feet

0 2,000 4,000

Map 3-5

LONG LAKE REGION

Northland Reliability Project

3.1.4.1 Applicants’ Proposed Route – Long Lake Region

The applicants’ proposed route moves generally southeast through the Long Lake region, paralleling GRE’s 69 kV RW Line (RW Line) for approximately 3 miles where it then turns south then west along a new ROW for 6.5 miles. The route then rejoins the MR line just east of County Road 23 and continues south for approximately 3.75 miles, paralleling the MR line this entire for this entire distance, to where the Long Lake region ends.

3.1.4.2 Route Alternative H1

Route alternative H1 is 6 miles long and diverts eastward of the applicants’ proposed route just north of County Road 24 and heads south for 2 miles around an Aquatic Management Area (AMA), along a portion of the applicants’ proposed route. Route alternative H1 then turns southwest for just under 2 miles before turning due south for 1.8 miles where it would parallel an existing transmission line ROW before rejoining the applicants’ proposed route south of County Road 22.

3.1.4.3 Route Alternative H2

Route alternative H2 is 8.2 miles long and routes around an AMA. This route alternative diverts due east from the applicants’ proposed route south of County Road 24 for approximately 1.25 miles before turning due south along County Road 8 for 1.75 miles. From there, route alternative H2 continues south along County Road 108 to County Road 22. Route alternative H2 then turns due west along County Road 22 for approximately 2.75 miles before turning south and paralleling an existing transmission line ROW where it proceeds for 0.5 mile to reconnect with the applicants’ proposed route. Route alternative H2 would require at least one heavy angle structure to accommodate a 90-degree turn in the route.

3.1.4.4 Route Alternative H3

Route alternative H3 is 2.6 miles long and was proposed to avoid private land enrolled in a state program. Route alternative H3 diverts from the applicants’ proposed route 0.75 mile north of Crust Road, where it progresses southeast for 0.8 mile before turning southwest for 1.75 miles before rejoining the applicants’ proposed route in an undeveloped area 1 mile north of County Road 22. Route alternative H3 does not include any transmission line ROW sharing, paralleling, or double-circuiting. It would also require at least one heavy angle structure to accommodate an angled turn in the route.

3.1.4.5 Route Alternative H4

Route alternative H4 is 2.1 miles long and was proposed to avoid private land by rerouting through tax-forfeited land. Route alternative H4 diverts southwest from the applicants’ proposed route 0.75 mile north of County Road 22. It would progress southwest for 2 miles before rejoining the applicants’ proposed route at the edge of an agricultural field southeast of the County Road 22 and County Road 23 intersection. Route alternative H4 does not include any transmission line ROW sharing, paralleling, or double-circuiting. It would also require at least one heavy angle structure to accommodate an angled turn in the route.

3.1.4.6 Route Alternative H5

Route alternative H5 is 2.4 miles long and was proposed to avoid private property and certain natural resources. This route alternative diverts from the applicants’ proposed route 0.75 mile north of County Road 22, where it turns west for 0.5 mile and then due south for 0.75 mile. It then runs west along County Road 22 for 0.5 mile before heading southwest for 0.75 mile where it then rejoins the applicants’ proposed route southwest of the County Road 22 and County Road 23 intersection. Route alternative H5 does not include any transmission line ROW sharing, paralleling, or double-circuiting. It would also require at least four heavy-angle structures to accommodate 90-degree and angled turns in the route.

3.1.4.7 Route Alternative H6

Route alternative H6 is 1.7 miles long and was proposed to cross less private property and natural resources. Route alternative H6 diverts from the applicants' proposed route where it crosses County Road 22 and heads due west along the road for 1 mile before it progresses southwest for 0.75 mile. It rejoins the applicants' proposed route southeast of the County Road 22 and County Road 23 intersection. Route alternative H6 does not include any transmission line ROW sharing, paralleling, or double-circuiting. It would also require at least three heavy-angle structures to accommodate angled turns in the route.

3.1.4.8 Route Alternative H7

Route alternative H7 is 2 miles long and was proposed to avoid private property and certain natural resources. This route alternative diverts from the applicants' proposed route 0.5 mile south of the County Road 22 crossing. Route alternative H7 turns southwest for 0.6 mile before heading due west for 1.4 miles where it rejoins the applicants' proposed route on the east side of County Road 23. Route alternative H7 does not include any transmission line ROW sharing or paralleling, or double-circuiting. It would also require at least one heavy angle structure to accommodate an angled turn in the route.

3.1.4.9 Route Alternative K

Route alternative K is 6.8 miles long and generally runs west of the applicants' proposed route. Route alternative K diverts from the applicants' proposed route 0.25 mile north of State Highway 18, where it runs due south for 3.5 miles before turning southeast for 1.4 miles. Route alternative K then progresses due south for 1.9 miles before rejoining the applicants' proposed route southeast of the County Road 22 and County Road 23 intersection. Route alternative K would share existing transmission line ROW for its entire length, including where the line would cross between South Long Lake and North Long Lake.

3.1.4.10 Alignment Alternative AA12

Alignment alternative AA12 is 1.1 miles long and was proposed to avoid private property. Alignment alternative AA12 is located approximately 0.25 mile east of the applicants' proposed alignment, near where the line crosses County Road 22. Alignment alternative AA12 does not include any transmission line ROW sharing, paralleling, or double-circuiting. It would also require at least two heavy-angle structures to accommodate an angled turn in the route.

3.1.4.11 Alignment Alternative AA13

Alignment alternative AA13 is 1.9 miles long and was proposed to avoid private property and certain natural resources. Alignment alternative AA13 diverts from the applicants' proposed alignment 0.5 mile south of County Road 22 and progresses southwest before heading due west for approximately 1.5 miles where it rejoins the applicants' proposed alignment east of County Road 23. Alignment alternative AA13 does not include any transmission line ROW sharing, paralleling, or double-circuiting. It would also require at least one heavy-angle structures to accommodate an angled turn in the route and cross one existing transmission line.

3.1.4.12 Alignment Alternative AA14

Alignment alternative AA14 is 0.6 mile long and diverts from the applicants' proposed alignment 0.35 mile south of County Road 24, where it progresses due south for 0.25 mile then turns southeast for 0.4 mile before rejoining the applicants' proposed alignment south of Schilling Road. Alignment alternative AA14 does not include any transmission line ROW sharing, paralleling, or double-circuiting.

3.1.4.13 Alignment Alternative AA17

Alignment alternative AA17 is 0.3 mile long and located where the applicants' proposed route crosses County Road 2. Alignment alternative AA17 is west of the applicants' proposed alignment. Alignment alternative AA17 does not include any transmission line ROW sharing or paralleling, or double-circuiting. It would also require at least two heavy-angle structures to accommodate angled turns in the route. Alignment alternative AA17 would also cross an existing transmission line in two locations (once to cross over the existing transmission line and once to cross back).

3.1.5 Morrison County Region

The Morrison County region is located in the south-central portion of the project (Map 3-6). This region crosses through Crow Wing, Morrison, and Benton County. This region contains the applicants' proposed route. It includes no route or alignment alternatives.

3.1.5.1 Applicants' Proposed Route – Morrison County Region

The applicants' proposed route moves south through the Morrison County region, paralleling the MR Line ROW through the entirety of the region, with multiple river and creek crossings. The route continues due south for approximately 36 miles to the southern end of the Morrison County region near 75th Street Northeast.

Map 3-6

MORRISON COUNTY REGION

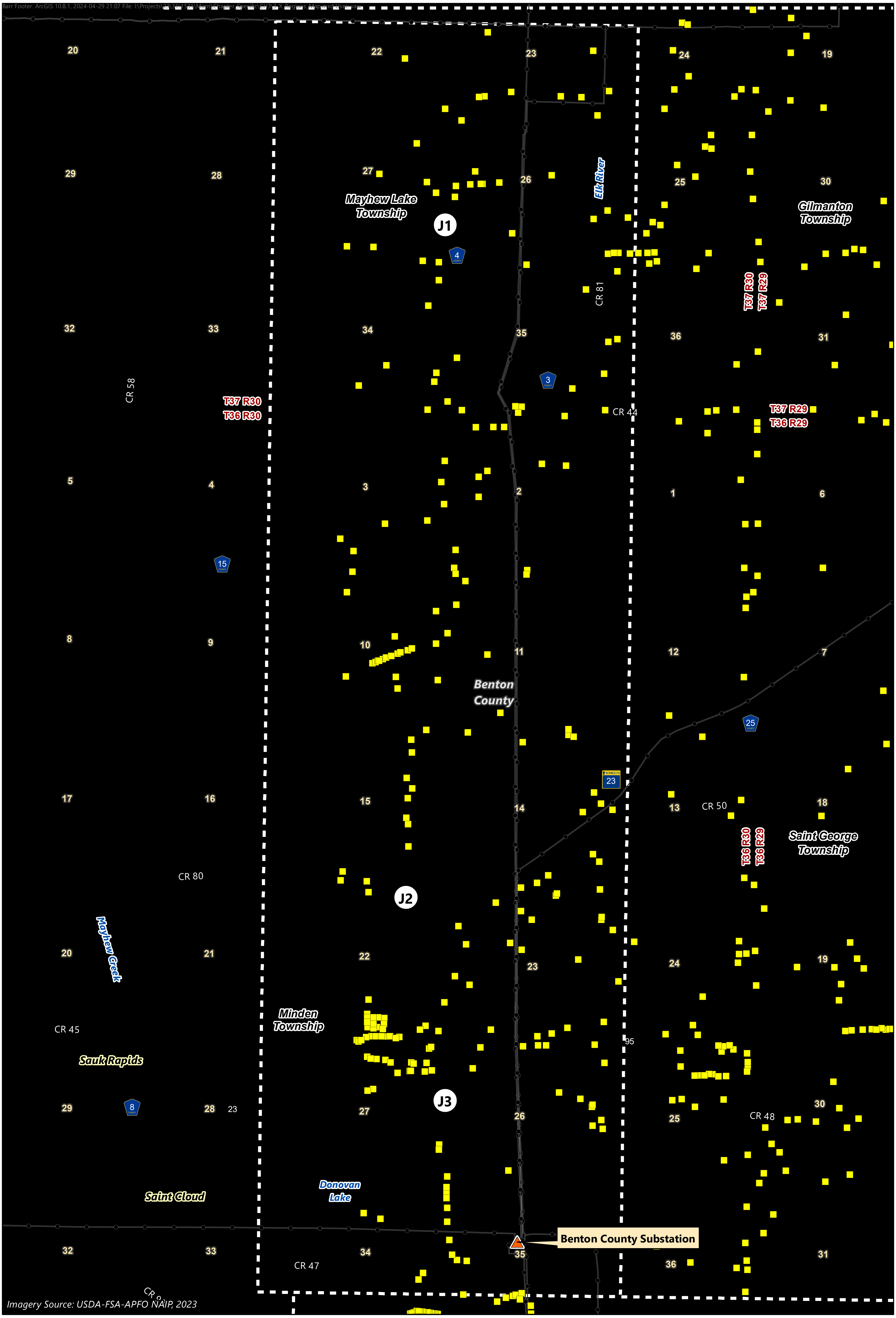
Northland Reliability Project

3.1.6 Benton County Elk River Region

The Benton County Elk River region is in the southern part of the project and contains the Benton County Substation at its the southern end (Map 3-7). The Benton County Elk River region contains the applicants' proposed route, and three route alternatives (J1, J2, J3) (Map 3-7). The J route alternatives have a route width of 0.5 mile to provide flexibility in identifying the optimal alignment through this area.

3.1.6.1 Applicants' Proposed Route – Benton County Elk River Region

The applicants' proposed route moves generally south throughout the Benton County Elk River region, paralleling the MR Line starting near 75th Street Northeast and ending at the Benton County Substation. This portion of the route is approximately 5 miles in length, crossing roads, agricultural fields, forested areas, and rivers. Although the applicants' proposed route parallels existing transmission lines, this route generally follows the Elk River. Due to the meandering nature of the Elk River, the applicants' proposed route would have multiple river crossings in addition to portions of the ROW being located in the river's 100-year floodplain.



Applicants' Proposed Route
Route Width
Route Alternative
Alignment Alternative
Route Alternative Width
Existing Transmission Line
Benton County Substation
Substation Siting Area
Residence
PWI Waterway
PWI Basin
Municipal Boundary
Region Boundary

Feet
0 1,500 3,000

Map 3-7

BENTON COUNTY ELK RIVER REGION

Northland Reliability Project

3.1.6.2 Route Alternative J1

Route alternative J1 is 5.1 miles long and diverts from the applicants' proposed route along 75th Street NE. Route alternative J1 heads west for 0.5 mile along 75th Street NE then turns due south along the west side of 55th Ave NE and then follows Golden Spike Road NE for 3.5 miles. Route alternative J1 then turns southeast for 1 mile along 55th Avenue NE and 35th Street NE before rejoining the applicants' proposed route. Route alternative J1 does not include any transmission line ROW sharing or paralleling, or double-circuiting but it was designed to parallel existing transportation rights-of-way. It would also require at least six heavy-angle structures to accommodate angled turns in the route.

3.1.6.3 Route Alternative J2

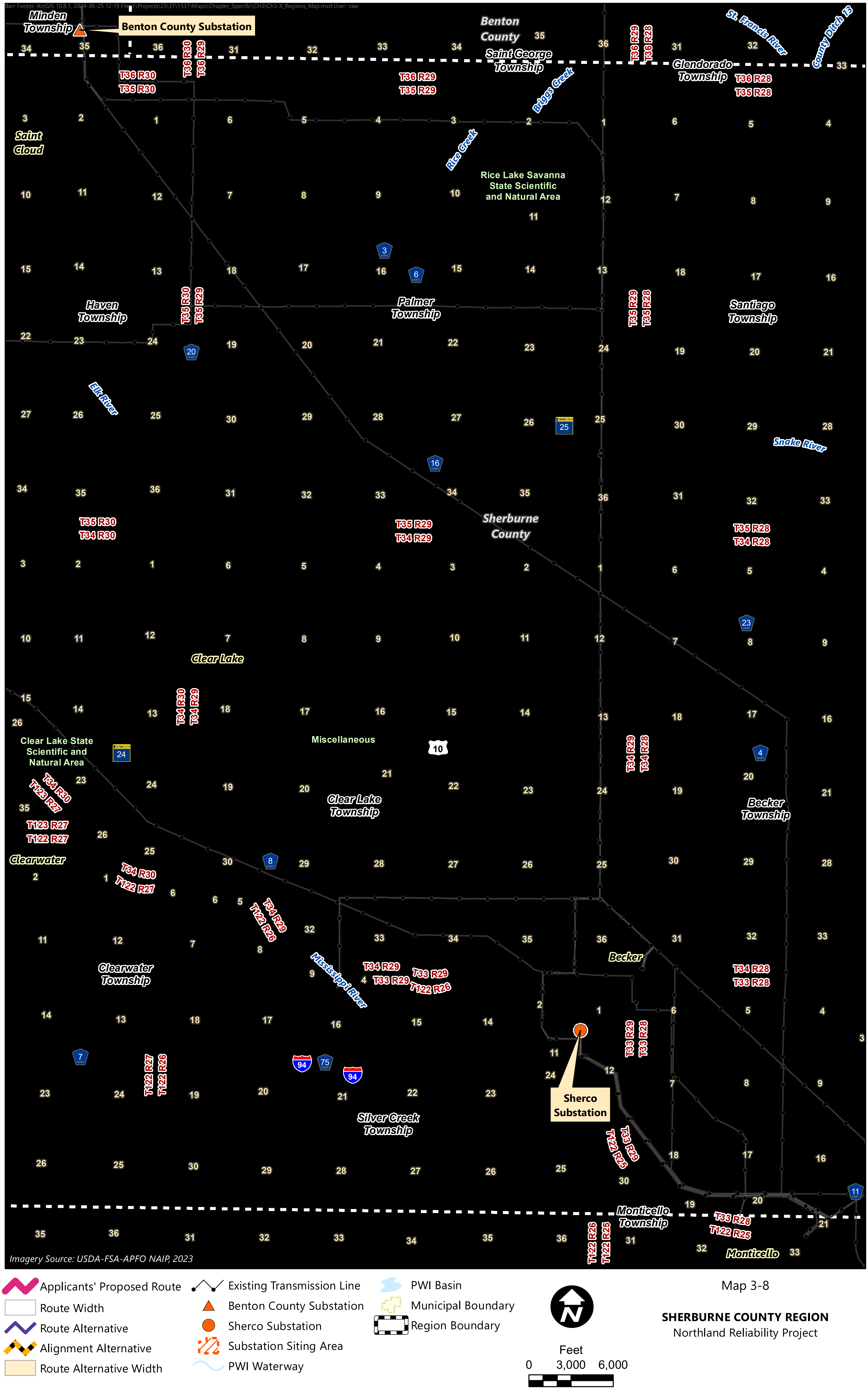
Route alternative J2 is 8.4 miles long and diverts from the applicants' proposed route along 75th Street NE. Route alternative J2 heads west for 0.5 mile along 75th Street NE then turns due south along the west side of 55th Avenue NE where it follows Golden Spike Road NE, 52nd Avenue NE, and 55th Avenue NE for approximately 7.5 miles before turning east for 0.5 mile to the Benton County Substation. This last 0.5-mile of the route alternative would parallel existing transmission line ROW; however, the remaining 7.9 miles of the route alternative does not include transmission line ROW sharing or paralleling, or double-circuiting. Route alternative J2 would also require at least six heavy-angle structures to accommodate angled turns along the route.

3.1.6.4 Route Alternative J3

Route alternative J3 is 2.7 miles long and diverts from the applicants' proposed route where it crosses Highway 23 NE. This route alternative heads southwest for approximately 0.75 mile before turning due south along 55th Avenue NE for approximately 1.4 miles where it then turns east for 0.5 mile to the Benton County Substation. Route alternative J3 would parallel an existing transportation ROW for the first 0.75-mile and would parallel existing transmission line ROW for the last 0.5-mile of the proposed route. Route alternative J3 would also require at least four heavy-angle structures to accommodate angled turns along the route.

3.1.7 Sherburne County Region

The Sherburne County region is the southernmost region of the project (Map 3-8). The majority of the region is contained within Sherburne County, but small portions also occur in Wright and Stearns Counties. This region starts at the Benton County Substation and ends south of Xcel Energy's new Big Oaks Substation. The Sherburne County Region includes two existing transmission lines owned by the applicants, and work occurring in this region would consist mainly of upgrades to these two lines. This region includes no route or alignment alternatives. The applicants' proposed route follows, and would replace, existing transmission lines, except for approximately 1.5 miles of proposed new transmission line that would connect to the future Big Oaks Substation (Map 3-8). The 1.5 miles of new transmission line would parallel an existing road.



Map 3-8

SHERBURNE COUNTY REGION
Northland Reliability Project

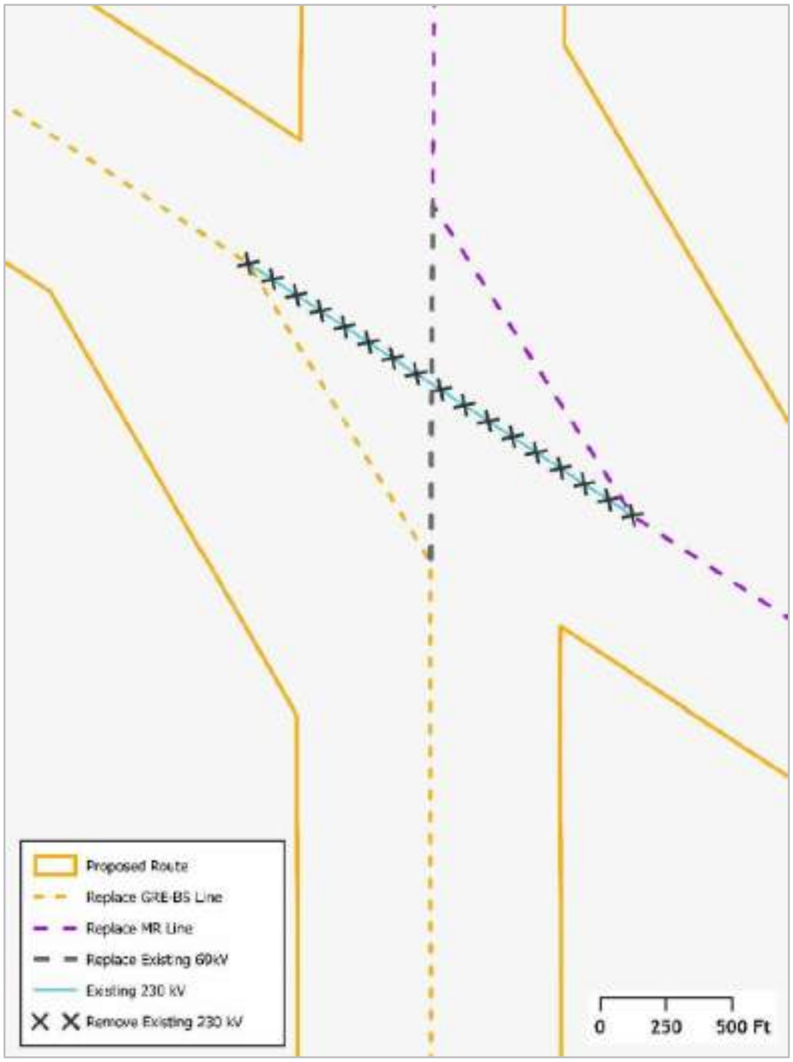
Within the Sherburne County region, GRE's existing 230 kV transmission line (MR Line) would be replaced with a new double-circuit 345 kV transmission line from the Benton County Substation to the new Xcel Energy Big Oaks Substation. The replacement would be within the existing MR Line ROW. The approximately 21.3-mile route that utilizes the MR Line exits the Benton County Substation and travels due east for approximately 7 miles, before turning southeasterly for the remaining portion of the line. The route deviates from the existing MR Line at 137th Street, where a new transmission line would be constructed parallel to 137th Street heading west for approximately 1.5 miles. The route then meets an existing transmission line ROW and travels south for the last mile along Sherburne Avenue, before ending at the new Big Oaks Substation.

GRE's existing 345 kV transmission Line (GRE-BS Line) would be replaced with new 345 kV transmission line structures from the Benton County Substation to Xcel Energy's existing Sherco Substation. The replacement would be within the existing GRE-BS Line ROW. This line would be constructed as a single-circuit 345 kV transmission line but on double-circuit capable structures, in order to accommodate a second 345 kV circuit in the future. The approximately 17.7-mile route departs from the Benton County Substation heading southeast until 125th Avenue where it then turns due south along the west side of the City of Becker and enters the Sherco Substation. Additionally, approximately ten-miles of the proposed 345 kV transmission line between the Benton County Substation and the Sherco Substation and the 345 kV transmission line between the Benton County Substation and the new Big Oaks Substation would be designed to carry a 115 kV circuit on triple-circuit structures. The existing GRE 69 kV EW Line would then be co-located on these structures, with the 69 kV line upgraded to a 115 kV circuit sometime in the future as a separate project.

3.1.7.1 Line Uncrossing

A portion of the work in the Sherburne County region also includes "uncrossing" two existing transmission lines. Currently, GRE's 230 kV MR Line and their 345 kV GRE-BS Line, which are both being replaced as part of the Project, cross over each other approximately 0.5 mile north of 82nd Street (i.e., the existing 345 kV GRE-BS Line traverses over the top of the existing 230 kV MR Line). Crossing transmission lines increases resiliency risk; should one of the lines fall it risks not only a fault (i.e., unexpected de-energization), but also taking down the other transmission line. In addition, performing maintenance at the crossing creates a safety risk, as under normal operating conditions one line must remain energized while work is occurring on the other line. The Project would rebuild these two transmission lines and reconfigure them such that the new lines would not cross. This work would also include rebuilding a 0.26-mile 69 kV connector segment that is located between the two transmission lines.

Figure 3-1 Uncrossing Detail



Source: reference (6)

3.2 Engineering and Design

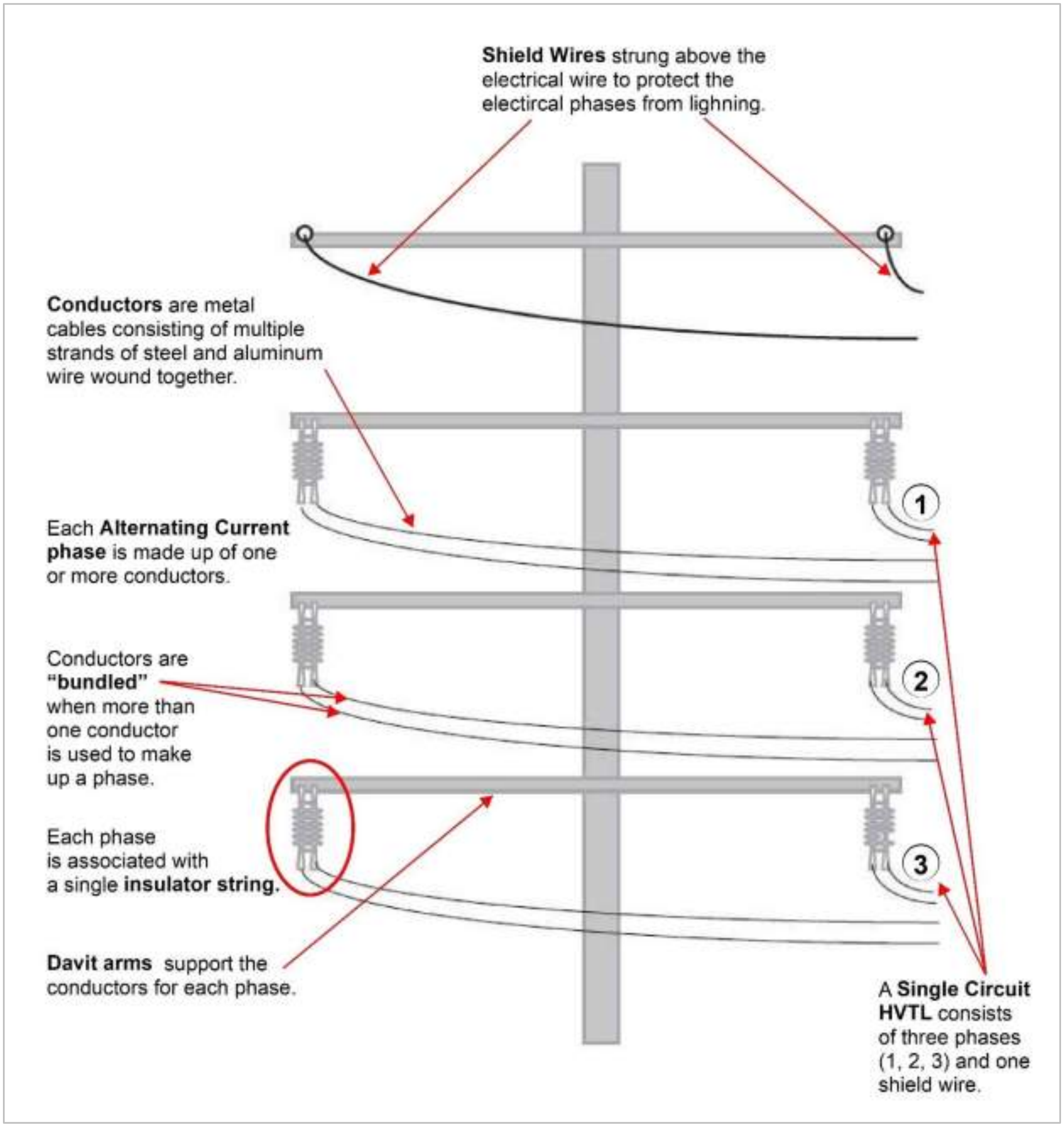
The applicants have proposed three structure types for the project allowing for several possible configurations, as well as double-circuiting with existing transmission lines. This Chapter describes the structures and configurations that may be used for the project.

3.2.1 Transmission Lines

Transmission line circuits consist of three phases, each phase at the end of a separate insulator and physically supported by a structure that holds it above ground. A phase consists of one or more conductors: single, double, or bundled. A typical conductor is a cable consisting of aluminum wires stranded around a core of steel wires. There may also be shield wires strung above the phases to prevent damage from lightning strikes.

Transmission lines are usually either single-circuit (carrying one three-phase conductor set) or double-circuit (carrying two three-phase conductor sets). The majority of the project is proposed as a double-circuit 345 kV line and would therefore be constructed on double-circuit capable structures (Figure 3-2). The project also includes two small sections of triple-circuit capable structures which are typically used in limited situations due to reliability, resiliency, cost, and safety implications. Triple-circuit structures were proposed by the applicants in specific areas to avoid a degradation in the reliability or maintainability of the transmission system.

Figure 3-2 Typical Double-Circuit Transmission Line



3.2.2 Structures

The project would be constructed primarily using double-circuit, 345 kV structures (Figure 3-3) consisting of tubular steel, self-weathering, monopole structures with V-string insulators. The benefits of this structure design include a reduced footprint and ROW needs due to the use of a monopole, allowing for vertically orienting the two circuits using V-string insulators to limit conductor blowout. Technical drawings and the dimensions of the transmission structures can be found in Appendix D.

Figure 3-3 Example Double-Circuit, Monopole 345 kV Structures with V-String Insulators

Portions of the project in the Sherburn County Region would be designed and constructed on triple-circuit capable structures with a 69 kV underbuild position to accommodate GRE’s existing 69 kV transmission line (EW Line). An underbuild places a smaller electric distribution line beneath a transmission line circuit on the same pole, reducing the need for additional structures. The 69 kV portion carried on the triple-circuit structures would be constructed to 115 kV standards but would not be capable of operating above 69 kV due to the remainder of the EW Line remaining at its existing 69 kV design capacity.

There may be various locations along the route where existing transmission lines would need to be realigned, relocated, reconfigured, or replaced. The structure types to be used at these locations include, but are not limited to, typical wood or steel construction and typical monopole or H-frame structures. Structure designs would be driven by an effort to minimize human and environmental impacts, to the extent practicable.

The double-circuit 345 kV structures would range in height from 130 to 170 feet, with spans of 800 to 1,000 feet between structures. A monopole structure is typically installed on a concrete foundation, while an H-frame structure can be installed on concrete foundations or embedded directly into the ground.

Table 3-1 provides a summary of the design features associated with structure types that may be used, reconfigured, or replaced for the project.

Table 3-1 Typical Structure Design Characteristics

Line Type	Structure Type	Structure Material	ROW Width (feet)	Structure Height (feet)	Foundation	Foundation Diameter (feet)	Average Structure Span (feet)
Double-Circuit 345/345 kV	Monopole	Steel	150	130-170	Concrete Pier	7-10	800-1,000
Single-Circuit 230 kV	H-frame	Wood	150	65-90	Direct Embed [1]	NA	700-900
Single-Circuit 115 kV	H-frame	Wood	100	60-80	Direct Embed	NA	600-800
Single-Circuit 69 kV Rebuild [2]	Monopole	Wood	100	60-80	Direct Embed	NA	300-500
Triple-Circuit 345/345/69 kV	Monopole	Steel	150	140-180	Concrete Pier	8-10	600-800

Note: The values in the table are typical values expected for the majority of tangent structures based on similar facilities. Actual values may vary.

1 Certain specialty or storm structures may be necessary. These structures may be concrete pier foundations instead of direct embed.

2 Single-circuit 69 kV transmission line will be replaced in Segment 2 of the project for a GRE line from West Becker Switch and West End Substation, and the new line will be built to 115 kV capable. There is approximately 1,345 feet of single-circuit 69 kV replacement to 115 kV capable within the uncrossing area between the Benton County Substation to Big Oaks Substation line (also known to as the MR Line) and the Benton County Substation to Sherco Substation line (also known as the GRE-BS Line). GRE's 69 kV EW Line easement width varies from 70 to 100 feet in width.

3.2.3 Conductors

The applicants are evaluating two different conductor types for the project: a horizontally bundled twisted pair-type aluminum conductor steel reinforced (T2-ACSR) type and a horizontally bundled aluminum conductor steel supported (ACSS) type. Both conductor types would be capable of carrying 3,000 amps.

Twisted-pair conductors may be used to minimize potential conductor movement caused by galloping. Galloping is the motion of conductors that can occur due to wind acting on conductors coated with a layer of ice or wet snow. Under certain wind conditions, the conductors can begin to move significantly, usually vertically. Significant galloping can lead to faults, as well as damage to hardware and structural components.

3.2.4 Associated Facilities

Associated facilities proposed for the project include the Iron Range 500 kV/345 kV substation expansion, the Cuyuna 345 kV Series Compensation Station, and the Benton County 345 kV substation expansion (Map 1-1).

The existing Iron Range 500 kV Substation would be expanded by approximately 15 acres on, property owned by Minnesota Power, to facilitate interconnection of the project at its northern endpoint. The 15-acre expansion is an estimate; the size, shape, and precise location may change per engineering design standards.

Minnesota Power's new Cuyuna Series Compensation Station would be located on Minnesota Power owned property approximately 2 miles north of the existing Riverton Substation. The Cuyuna Series Compensation Station would be 25 acres and include 345 kV series capacitor banks that are necessary for reliable operation and optimal performance of the project. Additionally, a portion of the site would be developed as a construction laydown yard and permanent material storage yard due to its location near the midpoint of the project.

The existing GRE Benton County Substation would be expanded by approximately 8.5 acres on property owned by GRE to facilitate interconnection of the project.

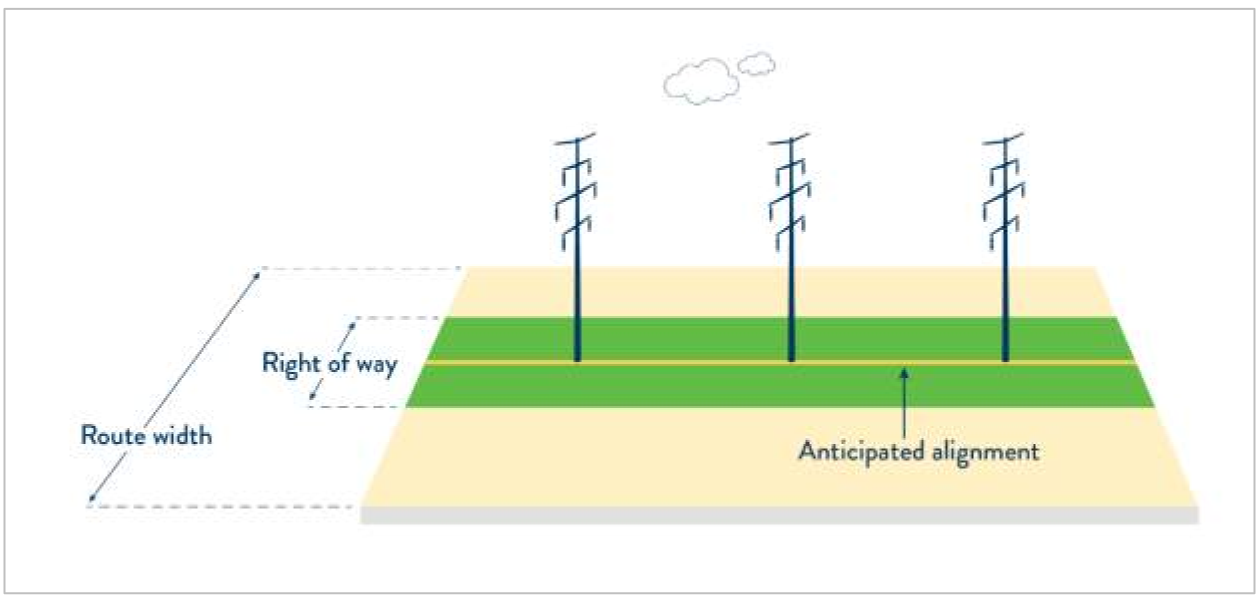
The substation modifications would be designed to allow future maintenance to be done with minimum impact on substation operation and provide necessary clearance from energized equipment to ensure safety.

The project would terminate at the new Big Oaks substation, which will be a 345 kV switching station located northwest of the Monticello Nuclear Generating Plant in Becker, Minnesota. The Big Oaks substation is being permitted and constructed as part of MISO LRTP Project #2, the Alexandria to Big Oaks 345 kV Transmission Project (PUC Docket Nos. ET10/TL-23-159 & E015/CN-22-538; OAH Docket No. 25-2500-39723).

3.3 Route Width, Right-of-Way, and Anticipated Alignment

When the Commission issues a route permit, it approves a route, a route width, and an anticipated alignment within that route width (Figure 3-4). The Commission may include conditions in a route permit. These conditions could address the route width or anticipated alignment in a specific area of the project, for example, requiring the alignment of a specific portion of the route to be north rather than south of a road or requiring that the route width be narrower in a certain area.

Figure 3-4 Route Width, Right-of-Way, and Anticipated Alignment Schematic



3.3.1 Route Width

The route width is typically larger than the actual ROW needed for the transmission line (Figure 3-4). This additional width provides flexibility in constructing the line yet is not of such extent that the placement of the line is undetermined. The route width allows the applicants to work with landowners to address their concerns and to address engineering issues that may arise after a permit is issued. The route width, in combination with the anticipated alignment, is intended to balance flexibility and predictability.

The transmission line must be constructed within the route designated by the Commission unless, after permit issuance, permission to proceed outside of the route is sought by the applicants and approved by the Commission (Minn. Rule 7850.4800).

In general, where the route follows or replaces an existing high-voltage transmission line, the applicants are requesting a route width of 500 feet on either side of the existing transmission line centerline for a total of a 1,000-foot route width. In areas where the route follows more than one existing transmission line, the route width requested is 500 feet from each outermost existing line (1,000 – 1,120 feet wide). In areas where the route uses new ROW, the applicants are requesting a route width of 1,500 feet on either side of the centerline for a total route width of 3,000 feet. The wider route width is requested to allow for flexibility to minimize impacts to resources and to work with landowners.

The applicants requested wider route widths in specific areas along the existing transmission line ROW, which include the following:

- Iron Range Substation region, South of the Iron Range Substation – the applicants request a route width of one mile to allow for flexibility in entering and exiting the substation in Sections 19 and 20 of Trout Lake Township in Itasca County.
- Hill City to Little Pine region, Minnesota Power's high-voltage direct current (HVDC) line – where the route crosses Minnesota Power's existing ±250 kV HVDC line in Section 31 of Macville Township in Aitkin County, the applicants request a route width of 4,400 feet. An Enbridge pump station and associated 230 kV tap line owned by GRE are located east of the 92 Line, and the route would need to cross over both the HVDC line and tap line. The applicants are requesting a wider route width in this area to provide flexibility to cross the HVDC line at mid-span, thus minimizing the height of the structures and to avoid the existing infrastructure in the area.
- Cole Lake region, River Road in Wolford Township – South of the Mississippi River near River Road and Cole Lake Way, northwest of Crosby in Section 21 of Wolford Township in Crow Wing County, Minnesota Power's 13 Line joins the 11 Line and 92 Line from the east. The applicants are requesting a route width of up to one mile (expanding to the east) on the east side of the existing lines to provide flexibility to avoid impacts to existing residences.
- Cole Lake region and Riverton region, Cuyuna Series Compensation Station – to allow for the siting of the new Cuyuna Series Compensation Station and flexibility in routing the project transmission lines into and out of the new substation in Sections 5, 6, 7, and 8 of Irondale Township in Crow Wing County, the applicants request a route width of 1.25 miles.
- Benton County Elk River region, Golden Spike Road – the applicants request that the route width be expanded to the east by 400 feet, to a total route width of 1,400 feet, to allow for routing the project to minimize impacts to residences located near the existing lines and in proximity to Elk

River and to allow for a more perpendicular crossing of Golden Spike Road in Section 2 of Minden Township in Benton County.

- Benton County Elk River region, North of the Benton County Substation – the applicants request a route width of 0.75 mile to allow for flexibility in entering and exiting the substation in Section 35 of Minden Township in Benton County.
- Sherburne County region, GRE-BS Line and MR Line Crossing – the applicants request a route width of 2,500 feet where the existing MR Line and GRE-BS Line cross in Section 1 in Becker Township in Sherburne County to allow for the uncrossing of those lines when they are rebuilt.
- Sherburne County region, North of County Road 23 SE – the applicants request a route width of 1,450 feet to potentially shift the existing centerline to minimize the crossing of an unnamed lake north of County Road 23 SE in Section 7 of Becker Township in Sherburne County.
- Sherburne County region, North of County Road 24 – the applicants request a route width of 1,850 feet to potentially shift the existing centerline to the east to minimize the crossing of an unnamed lake in Section 28 and 29 of Becker Township in Sherburne County.
- Sherburne County region, Big Oaks Substation – to ensure a sufficient area is identified to interconnect the project with the future Big Oaks Substation in Sections 7 and 18 of Becker Township in Sherburne County, the applicants request a route width of 4,960 feet.

3.3.2 Right-of-Way

A ROW is the specific area required for the safe construction and operation of the transmission line, where such safety is defined by the NESC and the NERC reliability standards. The ROW must be within the designated route and is the area for which the applicant obtains rights from private landowners to construct and operate the line.

Once the Commission issues a route permit, the applicants would conduct detailed survey and engineering work. Additionally, the applicants would contact landowners to gather information about their property and their concerns and discuss how the transmission line ROW might best proceed across the property. A transmission line ROW across private property is typically obtained by an easement agreement between the applicants and landowners.

The applicants have indicated that the project requires a 150-foot-wide ROW (75 feet on either side of the centerline). However, to the extent practicable, the new double circuit 345 kV transmission line would be co-located with existing high-voltage transmission lines or other ROWs, which would allow partial ROW sharing and would lessen the overall easement required for the project. In the Sherburne County Region, new transmission lines would generally follow the existing high-voltage transmission lines centerline, with the majority of the new lines utilizing the existing ROW, though exceptions exist in certain areas.

The applicants requested wider rights-of-way for a route alternative proposed in their scoping comments (Appendix E) – Route Alternative E1:

- A 215-foot ROW would be required for the portion of route alternative E1 from the Cuyuna Series Compensation Station to Little Rabbit Lake in order to accommodate double-circuiting the existing 230 kV transmission line into the existing ROW.

- An additional 80 feet of ROW west of the existing line in the portion of route alternative E1 starting south of Little Rabbit Lake and ending at the Riverton Substation would also be required.

- In the portion of route alternative E1 south of the Riverton Substation to the Highway 210 crossing, an additional 100 feet of ROW is required on the east side of the corridor, with the exception of the Highway 210 crossing realignment area.

- In the portion of route alternative E1 south of Highway 210 to where it would rejoin the applicants' proposed route, an additional 100 feet of ROW is needed to accommodate the double-circuit 345 kV line. This additional ROW would be located on the east side of the corridor for the first 1.4 miles and then shifts to the west side for the remaining 1.4 miles.

3.3.3 Anticipated Alignment

The anticipated alignment is the anticipated placement of the transmission line within the route and ROW, in essence, where the transmission line is anticipated to be built.

After coordinating with landowners and completing detailed engineering plans, the applicants would establish the final project alignment and designate pole placements. These final plans, known as "plans and profiles," must be provided to the Commission so that they can confirm that the applicants' plans are consistent with the route permit and all permit conditions prior to construction of the project. This confirmation ensures that the built project alignment is consistent with the anticipated alignment in the Commission's permit.

3.4 Construction and Maintenance Procedures

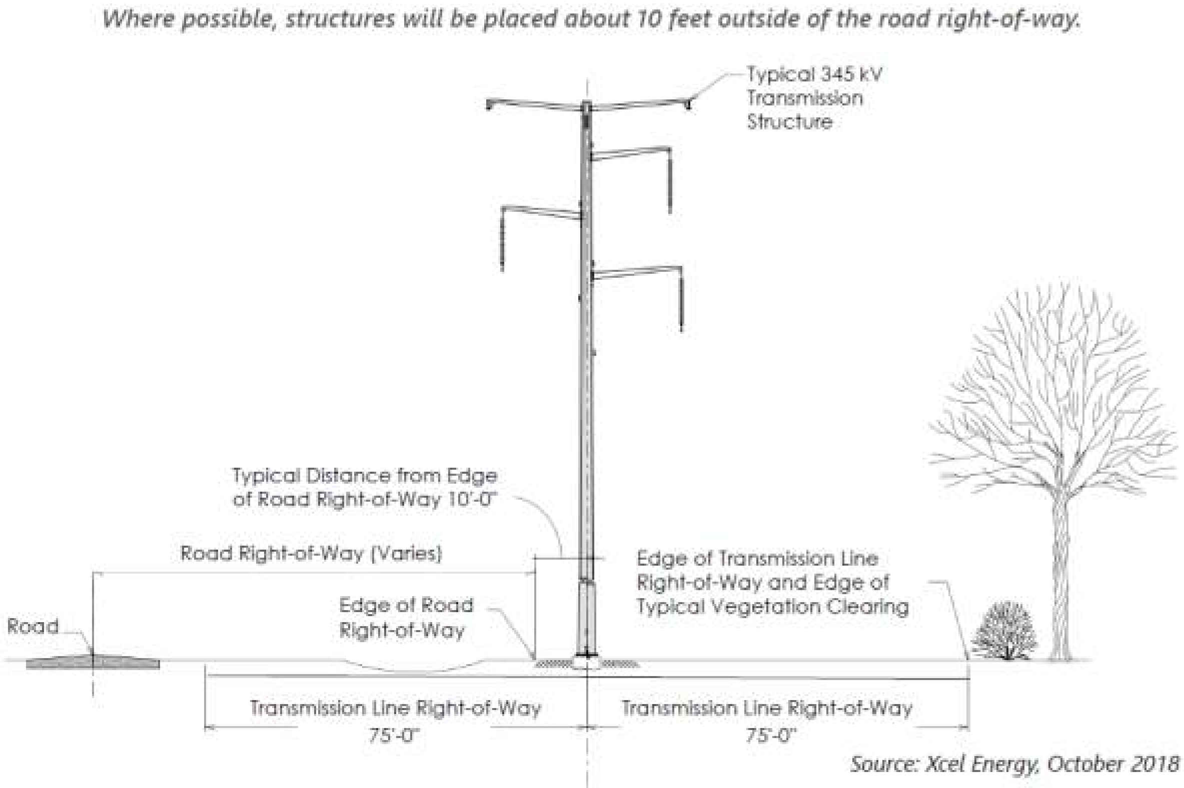
Construction of the project would not begin until all necessary federal, state, and local approvals have been obtained, easements have been acquired for ROW, and final plans and profiles have been approved by the Commission. The precise timing and order of ROW clearing and construction along the line would depend on the receipt of all necessary approvals for each line segment constructed, system loading issues, when existing transmission lines can be taken out of service for construction to proceed, and available workforce.

3.4.1 Right-of-Way Acquisition

For new 345 kV transmission lines, the applicants typically obtain ROW that is 150 feet wide (75 feet on each side of the transmission line centerline). Along the segment of the project from the Iron Range Substation to the Benton County Substation, the applicants would, where practicable, overlap the new 345 kV double-circuit transmission line ROW with existing high-voltage transmission ROWs for up to 30 to 40 feet. Along the segments of the project from the Benton County Substation to the new Big Oaks Substation and the Benton County Substation to Sherco Substation, the applicants do not anticipate it would be necessary to expand the existing ROW width. Instead, existing ROW is expected to adequately accommodate the project's ROW requirements, except near the Sherco Substation and the new Big Oaks Substation. New or modified ROW is anticipated near these two substations, and in limited circumstances where new easements may need to be acquired and/or existing easements amended to account for the project (the overall easement width would still measure 150 feet).

The final ROW width would vary depending on factors such as proximity to or overlap with public road ROWs (Figure 3-5), transmission line structure types, transmission line structure locations relative to existing or future improvements, etc. Modifications to the ROW width acquired and/or utilized would be made on a case-by-case basis.

Figure 3-5 Schematic of Structure Placement along Roadways



The applicants' proposed route largely follows existing high-voltage transmission line ROW; the applicants have existing easement rights for these existing lines. To accommodate the new construction and proposed rebuilds and reconfigurations when additional or different land rights are required, the applicants would work with landowners to either secure those new or amended easement rights.

One of the first steps in the construction process is to acquire an easement from each of the landowners along the permitted transmission line route. Prior to contacting these landowners, the applicants would conduct a title search to identify all persons and entities that have a recorded interest in the affected real estate. Once ownership has been determined, a ROW agent would contact each landowner to discuss where the structure(s) would be located on the property, as well as the easement boundaries. The proposed transmission line location could be staked with landowner permission.

The ROW agent would collect area land value data to determine the amount of just compensation to be paid for the rights to construct, operate, and maintain the transmission line in the easement. Based on this data, a fair market value offer would be developed, necessary documents to acquire the easement would be prepared, and an offer made to the landowner.

If a negotiated settlement could not be reached with a landowner, the applicants may acquire an easement by exercising the power of eminent domain pursuant to Minn. Statute 117. The process of exercising the power of eminent domain is called condemnation.

Before commencing condemnation, the applicants would provide the landowner with a copy of each appraisal it had obtained for the property interests to be acquired. To begin the formal condemnation process, the applicants would file a petition in the district court where the property is located and serve that petition on all owners of the property.

If the court grants the petition, a three-person condemnation commission would be appointed that would determine easement compensation. The commission would first schedule a viewing of each parcel identified in the petition. Next, the commission would schedule a valuation hearing where the applicants and landowner present testimony and evidence about the just compensation for acquiring the easement. The commission would then make an award of just compensation and file it with the court. The applicant and the landowner would both be bound by the award. At any point in this process, the case could be dismissed if the parties reach a settlement.

There may be instances where a landowner elects to require the applicants to purchase their entire property rather than acquiring only an easement for the transmission facilities. The landowner is granted this right under Minn. Statute 216E.12 This statute, sometimes referred to as the “Buy-the-Farm” statute, applies only to transmission lines with a voltage of 200 kV or more and to properties that meet certain other criteria; thus, this statute could apply to many of the properties crossed by 345 kV transmission lines where new easements are being acquired by the applicants.

Once a ROW is acquired, and prior to construction, the ROW agent would contact each landowner to discuss the construction schedule and requirements. For safe construction, special considerations may be needed for fences, crops, or livestock. Fences or livestock, for example, may need to be moved or temporary or permanent gates may need to be installed. In each case, the ROW agent would coordinate with the landowner, who would be compensated for any project-related construction damages.

3.4.2 Right-of-Way Access

The applicants would evaluate construction access opportunities by identifying existing transmission line easements, roads, or trails adjacent to the permitted route. Where feasible, the applicants indicate that they would limit access and construction activities to the ROW acquired for the project to minimize impacts to landowner and adjacent properties (reference (6)). In some situations, private field roads, trails, or farm fields may be used to gain access to construction areas. Where no current access is available, where existing access is inadequate, or when access requires incorporation of areas outside the ROW, permission from landowners would be obtained prior to using any of these areas to access the ROW for construction.

Improvements to existing access or construction of new access could be required to accommodate construction equipment. Where applicable, the applicants would obtain permits for new access from local road authorities. The applicants would also work with appropriate road authorities to ensure proper maintenance of roadways traversed by construction equipment.

3.4.3 Equipment and Staging Areas

Construction activities would require the use of many different types of equipment, including, but not limited to, tree removal equipment, mowers, cranes, backhoes, line trucks, drill rigs, dump trucks, front-end loaders, bulldozers, flatbed trucks, concrete trucks, helicopters, cranes, and various trailers for hauling equipment. Excavation equipment is often set on wheel or track-driven vehicles. Where possible, construction crews would use equipment that minimizes land impacts.

Construction staging areas would be required for the project and would be identified after a route is permitted. To the extent practicable, staging areas would be located on previously disturbed sites and would be used as receiving locations for delivery and storage of construction materials and equipment until they are needed for the project. Preferable staging areas would be large enough to lay down material and pre-assemble certain structural components or hardware. For staging areas outside the project ROW or not located on property owned by the applicants, rights to use these areas would be obtained individually from the affected property owner or agency.

3.4.4 Construction Process

Construction for the project would begin once all required approvals are obtained, property and ROWs are acquired, and final design is complete. Approximately 75-150 construction workers would be required to build the project, depending on sequencing and timing. Project construction would be comprised of two phases. The first phase would include tree clearing in the Iron Range Substation region, Hill City to Little Pine region, Cole Lake-Riverton region, Long Lake region, Morrison County region, and the Benton County Elk River region. In the Sherburne County region, the first phase would consist of removing the existing transmission lines. The applicants would carefully plan this work to maintain service to customers. The transmission lines in the Sherburne County Region would be taken out of service for construction and placed back into service sequentially so as not to have the two lines out at the same time.

The second construction phase would involve structure installation and stringing of conductor wire. The applicants would employ standard construction practices developed from experiences with past projects in addition to industry-specific BMPs. BMPs address ROW clearance, erecting transmission line structures, and stringing transmission lines.

Most project structures would require a drilled pier concrete foundation, which requires excavation of a hole to place the foundation (Photo 3-2). The size of the hole needed to place the foundation is approximately eight feet in diameter for a 345 kV double-circuit transmission structure foundation and 25 feet, or more, deep (Photo 3-3). An angle or dead-end structure may require a foundation of 12 feet or larger in diameter. The actual diameter and depth of the hole depend on structure design and soil conditions.

Photo 3-2 Drilling a Hole for a Structure Foundation

The diameter and depth of the hole depend on structure design and soil conditions
Source: reference (7)

Photo 3-3 Finished Structure Foundation

Structure foundations are typically 4 to 10 feet in diameter
Source: reference (7)

Once foundations are constructed, structures are moved from staging areas and delivered to the foundations. Structures are then lifted into place with a crane and bolted to the foundations (Photo 3-4). Insulators and other hardware are then attached. Once structures are in place, conductors are strung. The applicants would install the conductor wire by establishing stringing setup areas. These stringing setup areas are usually located every four miles along a project route, or as needed, and occupy an approximately 150-foot by 600-foot area. Conductor stringing operations require brief access to each structure to secure the conductor wire to the insulators and to install shield wire clamps once final sag is established. Where conductors cross streets, roads, or highways, temporary guard or clearance poles would be used to ensure that conductors do not obstruct or otherwise interfere with traffic. Conductor-marking devices such as bird flight diverters would be installed, as necessary, once conductors are in place.

Photo 3-4 Erecting Structure with a Crane

Structures are assembled before being lifted into place with a crane.
Source: reference (7)

Some soil conditions may require that construction mats be placed along the ROW or at a pole location to minimize soil disturbances. These mats can also be used to provide access across sensitive areas to minimize impacts such as soil compaction, rutting, or damage to plant species. When spanning sensitive areas is not feasible, one or more of the following practices may be required by the Commission’s route permit to minimize impacts:

- Constructing during frozen ground conditions.
- Using construction mats when winter construction is not possible and wetlands and other sensitive areas could be impacted.
- Avoiding equipment fueling and maintenance activities in or near environmentally sensitive areas.

- Implementing BMPs such as use of silt fences, bio logs, erosion-control blankets embedded with seeds, and other measures. These measures would be outlined in the Stormwater Pollution Prevention Plan (SWPPP) being developed by the applicants for the project.

3.4.5 Restoration and Cleanup Procedures

The applicants indicate that construction crews would attempt to minimize ground disturbance to the extent feasible; however, some disturbance is anticipated during the normal course of construction (reference (6)). The applicants indicate that once construction is completed in an area, disturbed areas would be restored to their original condition to the maximum extent feasible (reference (6)). In accordance with MPCA construction stormwater permit requirements, temporary restoration before the completion of construction in some areas along the ROW could be required.

Once construction is complete and restoration activities have commenced, the landowner would be contacted to discuss any damage that occurred due to project activities. If fences, drain tile, or other property have been damaged, the applicants note that they would repair the damages or provide the landowner reimbursement for repairs (reference (6)). In some cases, an outside contractor may be hired to restore the damaged property as near as practicable to its original condition.

Construction activities on agricultural land would be conducted in accordance with an AIMP approved by the MDA. The applicants indicate that farmers would be compensated for damage to crops resulting from construction (reference (6)). The damaged area would be measured, and yield would be determined in consultation with the farmer and paid at current market rates. The applicants would also make payments for future year crop loss from soil compaction. In addition, the applicants note that farmers would be compensated for their expense in deep ripping, which involves the use of equipment with strong, deep working tines that penetrate compacted soil to mechanically break up the soil in heavily compacted areas. If a farmer does not have access to deep-ripping equipment, the applicants indicate that they would provide this service (reference (6)).

It is anticipated that the ground-level vegetation disturbed or removed from the ROW would naturally reestablish to pre-construction conditions. In areas where soil compaction or other construction-related disturbances impair reestablishment, the applicants indicate that they would reseed these areas with seed free from noxious weeds to promote vegetation reestablishment (reference (6)). Vegetation that is consistent with substation site operation outside the fenced area would be allowed to reestablish naturally at substation sites.

3.4.6 Maintenance Procedures

The project would be designed and maintained in accordance with the NESC and the applicants' standards. In general, transmission lines boast exceptional reliability and lengthy estimated service lives often spanning decades, and seldom undergo complete retirement. This type of infrastructure has very few mechanical elements and is designed and constructed to withstand weather extremes typical of the region.

Transmission lines and substations are engineered to function for decades, demanding only moderate maintenance throughout their operational lifespan. The applicants would be responsible for the operation and maintenance of the project, performing aerial and ground inspections annually, addressing and correcting any deficiencies identified during these examinations. Applicant inspections would be limited to the ROW and to areas where obstructions or terrain may require off ROW access.

The ROW would be managed to control encroachment that may interfere with transmission line operation, including vegetation management activities. The applicants would perform vegetation management activities within the ROW, including mechanical clearing, hand clearing, and herbicide application.

A certain amount of maintenance would be required at substations to ensure proper operation within NESC and NERC standards. Transformers, circuit breakers, batteries, protective relays, and other equipment would need to be serviced periodically in accordance with the manufacturer's recommendations. The substation site must be kept free of vegetation, and adequate drainage must be maintained.

3.5 Project Costs

The total project cost is estimated to be between $970 million and $1.35 billion (based on 2022 dollars), depending on the route and design options selected (Table 3-2). If a route other than the applicants' proposed route is selected, or non-standard construction conditions are imposed, the applicants indicate that the project cost estimate may change (reference (6)). The costs associated with specific route and alignment alternatives are discussed in Chapters 6 and 7.

Table 3-2 Project Cost Estimate – Applicants' Proposed Route

Project Component	Low ($Millions) (2022$)	Mid ($Millions) (2022$)	High ($Millions) (2022$)
Iron Range 500 kV/345 kV Substation Expansion	$70.4	$95.0	$108.9
Iron Range – Cuyuna 345 kV Double-Circuit	$312.0	$368.1	$420.7
Cuyuna 345 kV Series Compensation Station	$80.0	$99.3	$113.9
Cuyuna – Benton County 345 kV Double-Circuit	$312.0	$336.6	$384.7
Benton County 345 kV Substation Expansion	$25.5	$31.4	$36.0
Benton County – Big Oaks 345 kV Double-Circuit	$97.6	$133.9	$153.0
Benton County – Sherco 345 kV Line	$72.4	$92.8	$106.1
Realignments and Reroutes	-	$17.0	$19.5
Asset Retirements	-	$8.5	$9.8
Project Cost Totals	$970	$1,182	$1,353

Project operation and maintenance costs would consist of three components: the new transmission lines; substation expansions; and new compensation station. Operation and maintenance costs for the new transmission lines would rely on controlling regrowth of vegetation within the ROW. The applicants estimate that this would cost approximately $7,500 per mile per year. Additional operation and maintenance costs associated with the transmission line would vary based on the location of the line, number of trees located along the ROW, age and condition of the line, voltage of the line, and other factors. The operation and maintenance costs for substation expansions would include inspections to maintain and repair equipment, compliance inspections, vegetation removal, and drainage maintenance. Minnesota Power's substation maintenance costs typically range from $50,000-$100,000 annually. GRE's substation maintenance costs typically range from $100,000-$200,000 annually. The Cuyuna Series

Compensation Station has more specialized equipment compared to a standard transmission substation and would require additional operation and maintenance, therefore the costs are anticipated to be approximately $175,000 annually.

3.6 Project Schedule

It is anticipated that the Commission will make decisions on the applicants' CN and route permit application in late 2024. Land acquisition would begin in spring 2025, with construction expected to begin in summer/fall 2025. The project is expected to be in service by June 2030.

4 Alternatives to the Proposed Project

The project is one possible solution to provide voltage support, improve system strength, and provide local sources of power delivery in northern and central Minnesota. This chapter evaluates alternatives to the project that may also address this problem. These alternatives are known as system alternatives. As described in Chapter 2, the Commission must determine whether the project is needed or if another project would be more appropriate for Minnesota. For example, a project that connects different endpoints (substations). This chapter discusses the following system alternatives:

- No-build Alternative
- Alternative Endpoints
- Upgrading Existing Facilities
- Generation and Non-Wire Alternatives
- Alternative Voltages
- Alternative Number, Size, and Type of Conductor
- Direct-Current (DC) Alternatives
- Underground Alternative

This chapter discusses whether these system alternatives are feasible (whether they can be engineered, designed, and constructed) and available (whether the alternative is readily obtainable and at the appropriate scale) and, if so, whether they can meet the project need (Chapter 1.1). Additionally, this chapter discusses the potential human and environmental impacts of the alternatives.

4.1 No-Build Alternative

Under the no-build alternative, the project would not be constructed, and all other electrical transmission facilities would remain as is. The no-build alternative is feasible and available but would not meet the need for the project.

The no-build alternative does not address reliability and stability issues in northern and central Minnesota. Reliability issues are highest in the winter months when the need for electricity is highest in northern Minnesota. Because the project was evaluated and optimized by MISO as part of a broader regional portfolio, the reliability risk implications also extend beyond Minnesota (reference (2)). The project is needed to maintain regional reliability as utilities and Minnesota add new clean energy resources and modify the way they use existing fossil-fuel plants (reference (2)). Thus, the no-build alternative does not meet the need for the project.

4.1.1 Human and Environmental Impacts

There would be no direct human or environmental impacts resulting from this alternative. The no-build alternative would avoid the potential impacts of the project, as they are described in Chapters 5 and 6.

4.2 Alternative Voltages

Under this alternative, the project need would be met by a transmission line of a different size (i.e., a line with a voltage other than 345 kV). The discussion here proceeds in two parts—first discussing voltages lower than 345 kV and then voltages greater than 345 kV.

In general, transmission lines with voltages other than 345 kV are feasible and available and could meet the need for the project, at least in part. Voltages less than 345 kV either do not meet the need for the project or do not meet the need as well as the proposed 345 kV line. Alternatives with voltages greater than 345 kV are anticipated to have greater costs and impacts than the project.

4.2.1 Lower Voltage Alternatives

There are two possible voltages lower than 345 kV that could be used for the project that would involve local transmission systems – 115 kV and/or 230 kV.

The voltage stability concerns mitigated by the project are caused by a potential outage of the Forbes – Chisago 500 kV Line. Any alternative would need to establish an electrically parallel path that would stay in service when the Forbes – Chisago 500 kV Line is lost. For any solution to be effective in mitigating these voltage stability concerns, the applicants' studies have found that the solution must have a similar electrical impedance to the Forbes – Chisago 500 kV Line.

To achieve the required electrical impedance and be able to accommodate the necessary power transfer levels, the applicants' analysis indicates multiple 230 kV or 115 kV lines (circuits) would be needed. A 230 kV alternative would require more than five individual circuits, while a 115 kV alternative would require more than 22 individual circuits. The increase in the total number of new transmission line rights-of-way for the 230 kV and 115 kV alternatives would create human and environmental impacts greater than those for the proposed project. Based on this analysis, lower voltages such as 230 kV and 115 kV could meet the need for the project but would have greater human and environmental impacts. Thus, they are not a more reasonable or prudent system alternative.

4.2.2 Higher Voltage Alternatives

There are two possible higher voltages that could be used for the project – 500 kV and 765 kV.

There are currently no 765 kV transmission lines in the MISO region north and west of Illinois. Because of this, expensive transformation would be required to interconnect with existing 500 kV and 345 kV systems at the Iron Range Substation and the Benton County Substation. Combined with the increased construction costs and ROW requirements for a higher voltage line, the total costs, impacts, and operational complexity would be substantially greater than those for a 345 kV line. The applicants assessed the current and future needs of the region and concluded that a double-circuit 345 kV line provides a greater degree of capacity, expandability, and long-term flexibility when compared to a 765 kV transmission line.

The applicants considered a 500 kV alternative to match the electrical impedance of the existing Forbes – Chisago 500 kV Line (described in Chapter 4.2.2). The Northern Minnesota Beyond Baseload Study (references (8); (9)) and MISO also considered a 500 kV alternative. In evaluating a single-circuit 500 kV alternative, the applicants found the proposed double-circuit 345 kV configuration has more benefits overall than a single-circuit 500 kV alternative. The 500 kV alternative has slightly lower losses and slightly higher incremental transfer capability, but it has a slightly higher cost with less redundancy and flexibility. Double-circuit 345 kV was selected for the project due to the redundancy benefits of the double-circuit configuration compared to a single-circuit alternative and the increased flexibility for future expansion and interconnection as the needs of the local and regional grid continue to evolve. Given similar performance and higher near-term cost, the applicants concluded that higher voltages such as 765 kV and 500 kV are not a more reasonable or prudent project alternative.

4.2.3 Human and Environmental Impacts

The types of human and environmental impacts from alternative voltage transmission lines would be similar to those of the project. Similarities would include aesthetic, agricultural, and natural resource impacts, with impact differences determined by rights-of-way, structure types, and associated facilities (e.g., transformers).

A lower voltage transmission line alternative would have substantially more human and environmental impacts than the proposed project due to the increase in number of circuits needed for a 230 kV or a 115 kV line. This increase in circuits would also increase the total number of new transmission line rights-of-way and would affect more properties along these rights-of-way.

Aesthetic and agricultural impacts have the potential to be greater with a 500 kV or 765 kV line. The lattice structures are more visible on the landscape and the structures have a much larger footprint. Though they may be in a smaller number of fields due to larger spans, the structure's impact on each field would be greater than a 345 kV structure.

4.3 Alternative Endpoints

It's possible that the project need could be met with substation endpoints other than the Iron Range and Benton County substations (i.e., alternative endpoints). The applicants' initial alternative endpoint analysis was combined with the evaluation of the 500 kV alternative voltage as part of the Northern Minnesota Beyond Baseload Study (references (8); (9)).

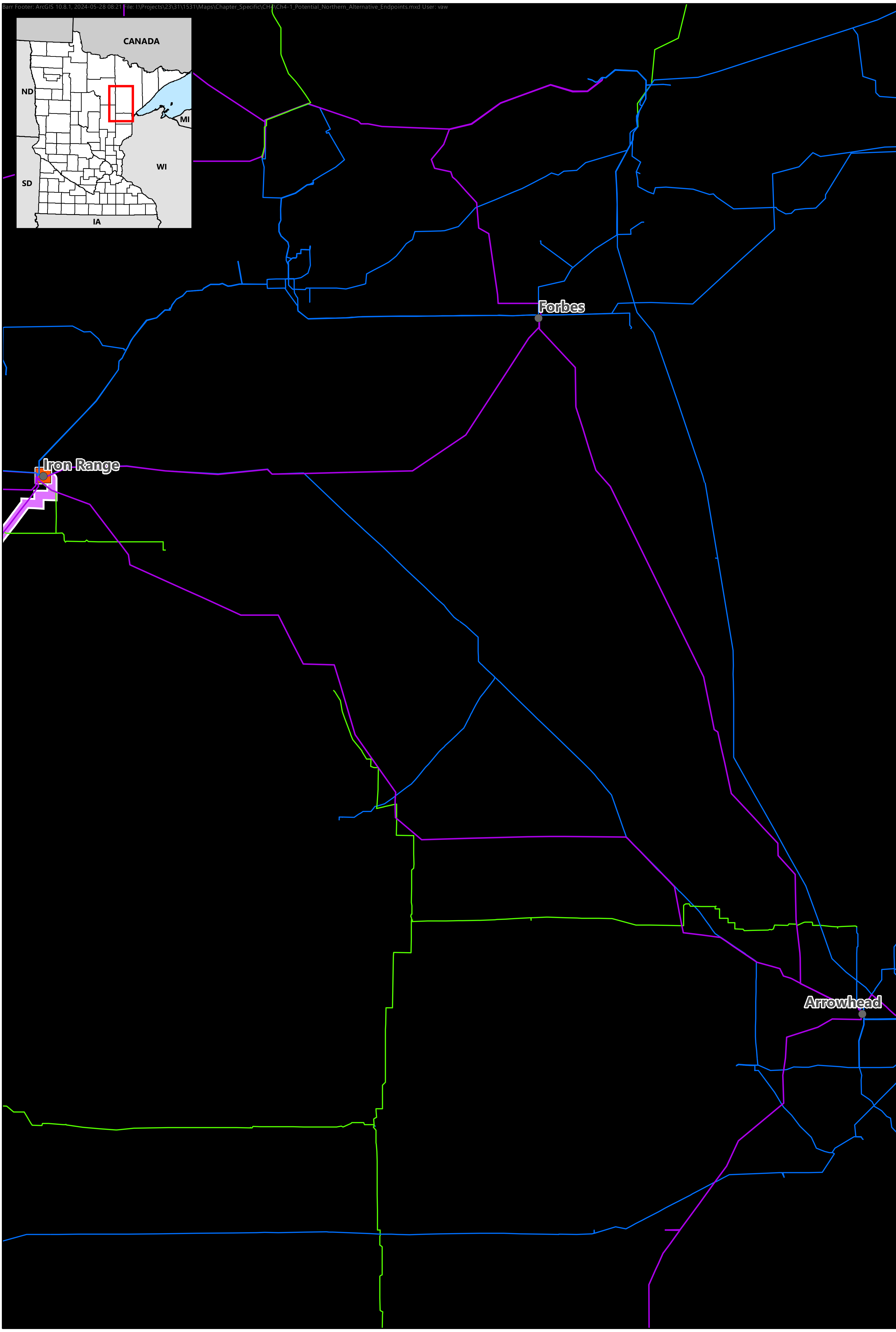
To be effective in mitigating voltage stability concerns, any alternative transmission solution must provide a new electrical connection parallel to the Forbes – Chisago 500 kV Line. This means that alternative endpoints must be situated similarly to the Forbes – Chisago 500 kV Line, with one end in northern Minnesota and the other end interconnecting to the existing 345 kV transmission backbone that connects to the Twin Cities area. This configuration is necessary to provide a low-impedance path for facilitating bulk regional transfers between northern Minnesota and central Minnesota. In Chapters 4.3.1 through 4.3.3, alternative endpoint evaluation is discussed in two parts: 1) alternative northern endpoints and 2) alternative southern endpoints.

4.3.1 Alternative Northern Endpoints

Alternatives for the project's northern endpoint are based on the assessment discussed in Chapter 4.2.1, where the analysis supports excluding lower voltage alternatives. As a result, all northern alternative endpoints must start at an existing 500 kV or 345 kV substation. This narrows the list of alternatives to three – the Forbes 500 kV Substation, the Arrowhead 345 kV Substation, and the Iron Range 500 kV Substation (Map 4-1).

The Forbes 500 kV Substation presents geographic diversity and single point of failure concerns. If a catastrophic event were to occur at the Forbes Substation, it would result in the loss of both the Forbes - Chisago 500 kV Line and the project if it connected at Forbes. Using this substation as the northern endpoint would not meet the basic reliability and resiliency needs. The Arrowhead 345 kV Substation would require construction of additional ties between the substation and the transmission system on the Iron Range to comprehensively address project needs. The Iron Range 500 kV Substation provides optimal transfers in both directions (south to north and north to south) while avoiding the geographic diversity concerns associated with the Forbes 500 kV Substation. An additional regional transmission interconnection at the Iron Range 500 kV Substation also improves the redundancy of transmission sources for bulk power delivery into the local northern Minnesota 230 kV system via the existing Iron Range 500 kV/230 kV transformer.

Northern Minnesota does not have any other substations that offer existing 345 kV or above infrastructure. The applicants concluded that the Iron Range 500 kV Substation is the only reasonable northern endpoint that would meet the needs of the project (reference (2)).



Applicants' Proposed Route
Iron Range Substation
Alternative Endpoint

Electric Transmission Line Voltage

69 kV
115 kV / 161 kV
230 kV
345 kV
400 kV

0 2 4 6
Miles

Map 4-1

POTENTIAL NORTHERN ALTERNATIVE ENDPOINTS

Northland Reliability Project

4.3.2 Alternative Southern Endpoints

There are several alternatives for the project's southern endpoint (Map 4-2). Based on the previous assessment ruling out lower voltage alternatives, all southern alternative endpoints must start at an existing 500 kV or 345 kV substation. Unlike the northern alternative endpoints, there is a broader geographic area to consider for southern alternative endpoints, as they simply need to connect into the existing 345 kV transmission system serving the Twin Cities. Potential southern alternative endpoints considered for the project are as follows:

- The Chisago 500 kV/345 kV Substation
- The Bison (Fargo) 345 kV Substation
- The Alexandria 345 kV Substation
- The Arrowhead 345 kV Substation
- The Monticello 345 kV Substation
- The Sherco 345 kV Substation
- The proposed Big Oaks 345 kV Substation
- The Benton County 345 kV Substation

The Chisago 500 kV/345 kV Substation alternative raises concerns about geographic diversity and single points of failure. This would result in failure to meet basic reliability and resiliency needs of the project (reference (6)).

The Bison (Fargo) 345 kV Substation, Alexandria 345 kV Substation, and Arrowhead 345 kV Substation all fail to resolve the basic voltage stability needs addressed by the project without additional modifications or improvements (reference (6)).

The Monticello 345 kV Substation alternative would require a new transmission line on new ROW to connect to the Benton County Substation. It would also require establishing a new Mississippi River crossing, developing two new 345 kV line terminals and large oil-filled shunt reactors to meet project needs. In view of all of these practical considerations, the applicants determined that the Monticello Substation is not a more reasonable or prudent alternative endpoint for the project (reference (6)).

The Sherco Substation was considered as a southern alternative endpoint for the project as either a direct connection from the Iron Range Substation or an extension from the Benton County Substation. Direct connection from the Iron Range Substation to the Sherco Substation would require a new transmission line on a new ROW from the Benton County Substation to the Sherco Substation, as opposed to replacing structures in existing transmission line rights-of-way. As a result, the applicants determined that establishing a direct connection from the Iron Range Substation to the Sherco Substation is not a more reasonable or prudent alternative for the project (reference (6)).

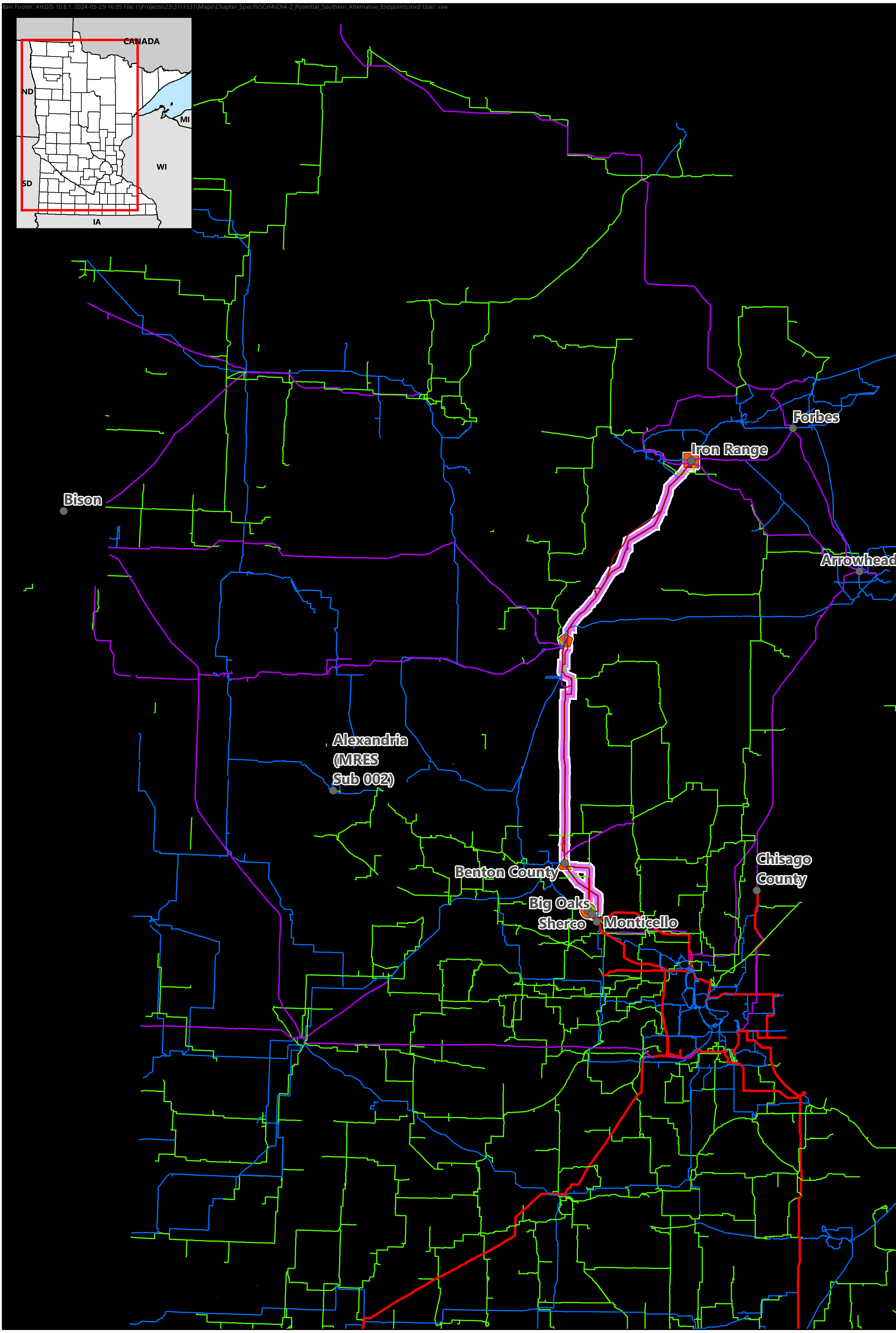
The Big Oaks 345 kV Substation is proposed as part of MISO LRTP Project #2, the Alexandria to Big Oaks 345 kV Transmission Project (PUC Docket Nos. ET10/TL-23-159 & E015/CN-22-538; OAH Docket No. 25-2500-39723). This alternative meets the need to provide additional outlet capability south of the Benton County Substation. Constructing a new double-circuit 345 kV line on existing transmission line

ROW from the Benton County Substation would strengthen the connection between the project and the Twin Cities area 345 kV backbone network. Therefore, the applicants concluded that the Big Oaks Substation was a reasonable southern alternative endpoint for the project after first interconnecting at the Benton County Substation (reference (6)).

The Benton County 345 kV Substation meets the project needs in four major areas: shunt reactor considerations; series compensated line considerations; practical routing and environmental considerations; and future flexibility. This alternative would shorten the length of the new 345 kV lines from the Iron Range Substation by approximately 20 miles compared to interconnecting directly at the Sherco Substation or Big Oaks Substation. The applicants determined that including the Benton County Substation interconnection with the project would provide added redundancy, improve resiliency, and increase local load-serving capacity to the St. Cloud area. The applicants concluded that including the interconnection to the Benton County Substation as part of the design of the southern endpoint was a reasonable and prudent option for the project (reference (6)).

4.3.3 Human and Environmental Impacts

The human and environmental impacts of the alternative endpoints vary. All the alternatives are 345 kV lines that proceed across predominantly agricultural landscapes. Assuming that many impacts could be mitigated through prudent routing, the differences in impacts would likely be related to the lengths of the lines. For example, relatively longer 345 kV lines would have relatively greater impacts. Ultimately the length of the project with the Benton County Substation endpoint is 20 miles shorter than the other alternatives. The lengths of the other 345 kV substation endpoint alternatives are similar to or longer than the project.



Applicants' Proposed Route
Benton County Substation
Iron Range Substation
Sherco Substation
Cuyuna Series Compensation Station
Other Substation

Electric Transmission Line Voltage
69 kV
115 kV / 161 kV
230 kV
345 kV
400 kV

N

0 10 20 30
Miles

Map 4-2

POTENTIAL SOUTHERN ALTERNATIVE ENDPOINTS
Northland Reliability Project

4.4 Upgrading Existing Facilities

Existing facility upgrades considered for the project included additional dynamic reactive power additions (assumed to be Static Synchronous Compensators [STATCOMs], which are fast-acting devices that can provide or absorb reactive current and regulate voltage at the point of connection to the power grid (reference (10)), additional capacitor banks, and rebuilding overloaded transmission lines to a higher capacity. These upgrades were considered because they address the primary project needs by resolving regional reliability constraints resulting from baseload generator fleet transition.

These upgrades were developed in an iterative fashion to resolve voltage stability and transmission line overload constraints that would follow with the hypothetical loss of the Forbes – Chisago 500 kV Line in the most limiting case.

Where the voltage stability limit was reached and a voltage collapse occurred, a STATCOM was placed at the place where the voltage collapse was the most severe to prevent the voltage collapse. Where "system intact" low voltages were identified, a capacitor bank was placed at the location to boost the voltage. Where transmission line overloads were identified, existing transmission lines were reconductored with a higher-capacity, lower-impedance conductor to mitigate the overload.

The resulting existing system upgrades alternative included 2,350 megavolt-ampere (MVAR) of new STATCOM additions across five separate sites, an additional 436 MVAR of new capacitor banks, and 435 miles of transmission line rebuilds on existing lines ranging from 69 kV to 230 kV. Upgrades would also be required at 35 different substations and on 18 individual transmission lines. Based on MISO's Transmission Cost Estimate Guide for MTEP23, the estimated cost for these upgrades to be at least $1.2 billion (reference (11)).

In addition to a higher cost than the project, the amounts of reactive resource additions needed to control voltage would create additional transmission system operational complexity. Heavy reliance on reactive resource additions also makes it challenging to anticipate voltage stability issues in real-time operations. In addition to operational complexities, constructability is another concern – it would require extended outages on 18 individual transmission lines as well as shorter outages at the 35 individual substations to integrate reactive resource additions.

Lastly, the existing facility upgrades described in Chapter 4.4.1 and 4.4.2 do not allow for future growth or expansion beyond the studied amount. Future load growth or additional changes on the system would continue to drive additional incremental upgrade needs for the foreseeable future as the clean energy transition continues. For all these reasons, the applicants concluded that upgrading existing facilities, including reactive resource additions and transmission line upgrades, is not a more reasonable or prudent alternative to the project (reference (6)).

4.4.1 Double-Circuiting and Other Engineering Considerations

Double-circuiting is the construction of two separate transmission circuits on the same structure. Placing two transmission circuits on common structures generally reduces ROW requirements, which potentially reduces human and environmental impacts. The project is already proposed as a double-circuit 345 kV line for the majority of its length.

As most of the project would be constructed adjacent to existing transmission lines, the applicants also considered triple-circuit structures to further reduce ROW requirements. Triple-circuiting is the construction of three transmission circuits on a common structure. Triple-circuiting is typically only used in limited applications due to reliability, resiliency, cost, and safety implications. Reliability standards established by NERC require that the planned transmission system be able to withstand potential contingencies – including the loss of a common structure. The triple-circuit system must be able to remain reliable if all three circuits were simultaneously lost. In addition, when considering triple-circuits with the existing system, there are economic implications as development not only requires larger and more expensive structures compared to a double- or single-circuit, but there are also increased costs and market impacts due to the removal of an existing transmission line (reference (6)).

Triple-circuit structures were evaluated as an alternative, including with the existing 230 kV lines that are adjacent to the project for most of its length. Triple-circuit 345 kV/345 kV/230 kV structures are not a feasible option for the project because simultaneous outages of the proposed double-circuit 345 kV line and the parallel 230 kV lines, either due to a common structure failure or due to maintenance on a common structure requiring an outage of all three circuits, creates unacceptable reliability risks for the system.

The applicants found triple-circuiting to be a feasible option for the project along approximately ten miles of 345 kV/345 kV/69 kV triple-circuit structures in the Sherburne County Region. This is a distinct circumstance compared to potentially triple-circuiting other areas of the project because the system configuration in this area can withstand the potential loss of a common tower and still meet reliability standards. Because the applicants' analysis found that triple-circuit in this specific circumstance would not degrade the reliability or maintainability of the transmission system, the applicants have proposed to triple-circuit this portion of the project.

The applicants also considered replacing existing facilities with the proposed double-circuit 345 kV line. The project in the Sherburne County Region would replace existing facilities to minimize the need for new ROW. In the northern portion of the project, the applicants considered replacing the existing 230 kV lines between the Iron Range Substation, Riverton Substation, Mud Lake Substation, and Benton County Substation with the proposed double-circuit 345 kV line. This alternative was not feasible because it would degrade the reliability of the underlying transmission system. The 230 kV system is needed to work in conjunction with the project to move energy from the project's endpoints to serve load along the route. If the existing 230 kV lines were replaced by the new double-circuit 345 kV line, additional substation facility expansions would be required at both the Riverton Substation and the Mud Lake Substation. The expansions would be necessary to maintain a reliable source of power delivery to the underlying 230 kV and 115 kV transmission system, which distributes power to the local area. These substation expansions would add to the cost of the project.

Additionally, without the existing parallel 230 kV lines, additional transmission system reinforcements may be necessary to provide capacity on the underlying system to facilitate transfers during planned or unplanned outages of the proposed double-circuit 345 kV line. Extended outages of the existing substations and 230 kV transmission lines would also potentially create reliability concerns during the multi-year construction timeframe for the project.

Finally, the applicants considered realigning portions of existing lines to create space for the project to minimize routing impacts and/or to avoid crossing existing transmission lines. Crossing high-voltage transmission lines increases resiliency risk, because if one of the lines fall it risks not only a fault (i.e., unexpected de-energization) but also taking down the other transmission line. In addition, performing maintenance at line crossings creates a safety risk, as under normal operating conditions one line must remain energized while work is occurring on the other line. To cross existing transmission lines, structure height of the line that is crossing the existing line must also be increased. For the new transmission line, the lowest conductor is driven by clearance to ground. When crossing over an existing line, the height of the lowest conductor is driven by clearance between it and the top of the tallest wire on the existing line. As a result, new towers that cross existing lines are taller than standard transmission lines, introducing additional concerns such as FAA height clearance restrictions and safety concerns (reference (12)). Therefore, where practical, new lines are designed to minimize crossing existing transmission lines.

Most of the northern portion of the project is routed adjacent to an existing 230 kV line. In certain places along the route, it was less impactful to route on the west side of the existing 230 kV line and in other places on the east side. To route the line to both minimize impacts and to avoid crossing the existing transmission line multiple times (creating reliability and safety risks), the project would realign placement of the existing transmission line. For example: the northern portion of the project is proposed to be routed on the east side of the existing 230 kV. To avoid having to cross the existing line to route on the west side for a portion of the project, the applicants propose to move the existing 230 kV to the west and construct the project within the route previously occupied by the 230 kV.

4.4.2 Human and Environmental Impacts

The potential human and environmental impacts of upgrading existing facilities would be limited to construction impacts related to replacing existing infrastructure, but in most cases this alternative does not meet project needs. The impacts of double and triple-circuiting would vary in the type and extent of impacts due to differences in structure heights and spans.

4.5 Generation and Non-Wire Alternatives

There are various generation and non-wire project alternatives, including new peaking generation, distributed generation, renewable generation, battery energy storage, demand-side management, and reactive resources. These alternatives must be able to resolve regional reliability constraints resulting from baseload generator fleet transition, specifically voltage stability and other related concerns. Comprehensive project alternatives should also support an increase in renewable energy. These needs are more complex to assess. Most alternatives were screened first according to their effectiveness, to address the underlying voltage stability issues.

To address the voltage stability issues, the operational characteristics of any generation or non-wires alternative must reduce transfer on the northern Minnesota (NOMN) Interface enough to prevent voltage collapse due to loss of the Forbes – Chisago 500 kV Line. Transfer levels can be reduced by either reducing load or increasing generation in northern Minnesota. A 10 percent stability margin must be maintained from the point of voltage collapse, according to typical voltage stability planning standards (Table K-1 in Appendix K of (reference (13)).

In the applicants' most recent analysis, the NOMN Interface, including the required stability margin, is 1,788 MW. With Minnesota Power's Boswell Energy Center (BEC) units offline, the NOMN Interface transfer level during the most limiting system conditions was calculated to be 2,562 MW using a 2031 Winter Peak model. To reduce NOMN Interface to within its voltage stability limit, total transfer on the interface would need to be reduced by 774 MW. Based on the distribution factors calculated from the power flow models, this is equivalent to about 980 MW of generation addition or load reduction in northern Minnesota (reference (6)).

4.5.1 Peaking Generation

The applicants' considered peaking generation as a project alternative. The peaking generation alternative would be dispatchable generation that is interconnected to the transmission system and is able to run continuously when called upon, most likely using natural gas as the fuel source. The applicants considered three general configurations for peaking generation. The first option would be to install several banks of small reciprocating internal combustion engine (RICE) generators throughout northern Minnesota, which would require 100 or more individual RICE units (estimated to cost $2.2 billion total) (reference (11)). The second option would be to install larger natural gas combustion turbine (CT) generators at a handful of locations in northern Minnesota, which would require three to five new CTs (estimated to cost approximately $850 million to 1.3 billion total) (reference (11)). The third configuration option would be to install a single large natural gas combined cycle (CC) generation plant at BEC or a similar location in northern Minnesota (estimated to cost a minimum of approximately $1.2 billion) (reference (11)).

The three solutions are feasible alternatives and would potentially bring additional benefits to the energy supply portfolio. However, they do not meet carbon dioxide (CO_2) emission reduction, renewable integration, or regional transfer capability needs addressed by the project (reference (6)). They also cannot directly provide the comprehensive regional benefits identified by MISO in the LRTP Tranche 1 Portfolio analysis (reference (6)). Additionally, none of these solutions is expected to be more cost effective than the project. Therefore, the addition of new fossil-fueled peaking generation is not a more reasonable and prudent alternative to the project.

4.5.2 Distributed Generation

The applicants considered distributed generation as a project alternative. Distributed generation, in this context, means dispatchable generation that is connected to the local distribution system and can run continuously when called upon, most likely on natural gas or other fossil fuels. Renewable distributed generation and battery energy storage are also possibilities. Fossil-fueled distributed generation has the same fundamental limitations as transmission-connected peaking generation discussed in Chapter 4.5.1, and likely at a greater cost due to the number of smaller generators in diverse locations that would be required. Fossil-fueled distributed generation also does not meet CO_2 emission reduction, renewable integration, or regional transfer capability needs addressed by the project. Therefore, the addition of new fossil-fueled distributed generators is not a more reasonable and prudent alternative to the project.

4.5.3 Renewable Generation

The applicants considered renewable generation, either solar or wind generation, as a project alternative. The renewable generation could be interconnected at a single location on the transmission system or at multiple locations on the transmission or distribution system. To adequately address voltage stability concerns in northern Minnesota, a renewable generation solution would need to be able to deliver 980 MW to reduce NOMN Interface loading to within its voltage stability limit. Therefore, to achieve 980 MW of instantaneous production, more than 980 MW gross capacity of each of these generation sources would need to be added.

Power from renewable generation also needs to be available when called upon in the amount required to mitigate the risk of a voltage collapse. Because renewable generation is dependent on natural events, such as sunlight or wind speed, and cannot be dispatched if those conditions are not met, neither wind nor solar generation alone is a feasible system alternative. As the major issue arises during winter peak conditions coincident with high northward transfers, 980 MW of generation delivered would be needed in the evening/nighttime hours, which negates solar energy output support. Wind energy output is unpredictable, sometimes decreasing during the evening hours of the day. Regardless of the magnitude installed, neither solar nor wind energy by itself can be relied upon to be available when needed to prevent the voltage stability issues addressed by the project (reference (6)).

4.5.4 Purchased Power

The applicants considered a purchased power alternative, where electrical power would be purchased from existing generation sources, rather than constructing a new generating facility. Purchased power is similar to power generation as discussed in Chapters 4.5.1, 4.5.2, and 4.5.3; however, with purchased power, the energy would come from what is currently available on the MISO grid as opposed to a specifically generated type of power. As detailed in the March 2024 MISO monthly operations report (reference (14)), 2024 energy fuel sources include 10 Terawatt hours (TWh) from coal generation, 19 TWh from hydro generation, 11 TWh from wind generation, 7 TWh from nuclear generation, 1 TWh from gas generation, and 1 TWh from solar generation. Purchased power has an increased cost risk because of the variability of the MISO market.

This alternative is feasible and available but does not meet project need. Purchased power would not connect Minnesota customers to the larger pool of renewable energy that is currently available in the Upper Midwest, because it would rely instead upon purchasing the power that is available on any given day from the MISO grid. This alternative would also not meet the project's need to create stable and reliable energy. Therefore, the use of purchased power is not a more reasonable and prudent project alternative.

4.5.5 Energy Storage

The applicants considered energy storage, both by itself and combined with new renewable generation, as a system alternative. The energy storage alternative would need a battery or some other energy storage technology capable of being charged and discharged when called upon for as long as there is sufficient energy available. To address voltage stability concerns and related thermal overloads for a single contingency, a significant amount of storage and reactive support is necessary. For shorter duration outages, eight-hour battery storage would be adequate. For longer duration outages (days), storage could be paired with solar to allow recharging of battery storage during daylight hours.

To provide adequate energy storage, a 7,840 MWh battery would be required. The CPLANET tool, created by the Electric Power Research Institute (EPRI), was used by the applicants to find optimal battery placement to address thermal overloads under varying conditions and address thermal issues as a proxy for voltage stability issues, since the two are closely tied in the project (reference (6)). The results indicated that 800 MW of 8-hour energy storage (6,400 MWh) would be required, split across five substations in northern Minnesota, eastern North Dakota, and Manitoba, to mitigate thermal concerns to an acceptable standard. To alleviate the remaining voltage violations, 500 MVAR of STATCOM 68 would be needed at five different substations throughout northern Minnesota and eastern North Dakota to maintain voltage stability.

The applicants also considered pairing the energy storage solution with new solar generation. If solar could produce the needed generation during daylight hours, energy storage could supply the needed generation outside of daylight hours. Because the primary concerns arise during winter nighttime hours with north flow transfer conditions, solar energy would have minimal benefit for addressing reliability issues in an eight-hour timeframe. Any longer-duration storage solutions would be significantly more costly to implement.

The applicants utilized the Department of Energy's 2022 Grid Energy Storage Technology Cost and Performance Assessment (reference (15)) to estimate the cost of the 6,400 MWh energy storage solution. A lithium-ion LFP energy storage solution with a rated instantaneous charge/discharge of 800 MW and an energy rating of 6,400 MWh would cost an estimated $2.1 to $2.5 billion. The additional STATCOMs required to maintain voltage stability would be an additional cost of $100 million (reference (16)). The total energy storage solution cost would be $2.2 to $2.6 billion, which is approximately two times the cost of the project.

This alternative solution would not mitigate issues to the same level as the project, and any combination of energy storage and STATCOM would be substantial in both size and cost. Therefore, the addition of new energy storage in northern Minnesota is not a more reasonable and prudent project alternative.

4.5.6 Demand Side Management and Conservation

The applicants considered demand-side management, which would consist of using less electricity or conserving electricity, as an alternative. Common examples include using LED light bulbs or high-efficiency air conditioners. Other examples include Xcel Energy's Saver's Switch program which cycles air conditioners on and off during times of peak electrical load (reference (6)). It would be assumed to encompass all forms of peak shaving programs, such as interruptible loads and dual fuel programs, as well as more general energy conservation programs, such as energy efficiency rebates. Although conservation programs would continue to be implemented in the project area to encourage efficient use of electricity, these programs are insufficient to reach the significant levels of load reduction (reference (6)). For these reasons, solutions involving demand-side management and conservation alone are not a more reasonable and prudent project alternative.

4.5.7 Reactive Power Additions

The applicants considered non-wire alternatives that would implement additional reactive power additions to support the area and prevent voltage collapse. Reactive power additions are transmission technologies capable of providing reactive power and voltage support to the system. This would be done using traditional electromechanical devices (switched capacitor banks and reactors), flexible alternating-current (AC) transmission system devices (static VAR compensators or STATCOMs), or synchronous condensers. Unlike generation or energy storage solutions, reactive power additions do not produce any active power (e.g., MWs) for consumption by end-use customers, meaning this alternative is not capable of directly reducing NOMN Interface transfer levels as discussed for other generation and non-wire alternatives. Instead, reactive power solutions enable increased interface transfer capability by providing voltage support where needed to prevent voltage collapse.

While a reactive power addition may contribute to resolving or reducing the severity of the northern Minnesota voltage stability issues, reactive power additions alone cannot satisfy any of the project needs. This is because transmission lines on the NOMN Interface and the underlying system become overloaded at higher NOMN Interface transfer levels than are achievable with reactive power (reference (6)). Additional existing system upgrades described in Chapter 4.4 would also be required. For these reasons, solutions involving only reactive power additions are not a more reasonable and prudent system alternatives.

4.5.8 Human and Environmental Impacts

Potential impacts associated with generation and non-wire alternatives would depend on the type of generation. The peaking generation, distributed generation, demand side management and conservation and reactive power additions would impact humans by not meeting the project's need to create stable and reliable energy. Renewable energy and energy storage would not generate the capacity needed to meet the project's needs. Wind farms create potential aesthetic and noise impacts. They also have the potential to impact birds and bats, which can be struck by rotating turbine blades. Natural gas plants (and other plants that use carbon-based fuels) create potential air impacts, including the emission of greenhouse gases (GHGs) and the exacerbation of global warming. Such plants also have potential aesthetic and noise impacts and may have impacts on water resources and associated natural resources. Impacts of solar farms include the temporary but long-term loss of land that could be used for other purposes (e.g., agriculture, as well as aesthetic impacts).

4.6 Alternative Number, Size, and Type of Conductor

Conductors used for the project are subject to change based on a conductor optimization study that would be completed during detailed project design. The applicants are considering two potential conductor configurations for the project: a horizontally bundled twisted pair-type aluminum conductor steel reinforced (T2-ACSR) type and a horizontally bundled aluminum conductor steel supported (ACSS) type. The T2-ACSR conductor generally has a higher capital cost than a typical ACSS conductor, but it is being considered specifically due to conductor galloping concerns identified on previous projects, which are caused by wind and ice loading conditions that are common in Minnesota.

Conductors are generally bundled together to optimize corona performance and cost effectiveness, particularly at 345 kV and above. While the conductor optimization study would consider single conductors, three-conductor bundles, and various sizes of conductors, it is expected these conductor configurations would not meet performance criteria. Single conductors are not expected to meet performance criteria for audible noise, electric fields, radio frequency interference, and they would result in higher losses. Three-conductor bundles are not expected to have significant technical or economic benefits from additional sub-conductors at 345 kV, particularly in view of the added cost and structural loading requirements from a three-conductor bundle.

Utilizing larger conductors can reduce transmission losses; however, this long-term savings must exceed the initial cost increase to be considered as a feasible alternative. Beyond the wire cost alone, larger wires translate to increased structural loading which results in higher structure costs. The conductor optimization study will be designed to pinpoint the most advantageous project conductor configuration(s). The analysis will entail comprehensive technical and economic factors, considering various conductor sizes and configurations in light of mechanical and electrical performance criteria, long-term losses, and initial capital costs.

4.6.1 Human and Environmental Impacts

Conductors are a required component of the project, and the optimal conductor configuration will be determined following completion of the conductor optimization study. The human and environmental impacts of the conductors would vary with the number of conductor bundles. Impacts could include noise, electric fields, and radio frequency interference; however, all of these impacts are anticipated to be minimal. Outside of these, impacts would be similar to those of the project.

4.7 Direct-Current Alternatives

HVDC lines are typically proposed for transmitting large amounts of electricity over long distances. HVDC line losses are significantly less over long distances than an AC line. HVDC lines require conversion stations at each delivery point because the DC power must be converted to AC power before it can be used by customers. A single converter station can be upwards of $400 million, not including the required DC line construction. HVDC lines are typically proposed for large regional transmission projects that involve hundreds of miles of new transmission line. HVDC becomes a cost-effective alternative to AC transmission when the total line length is greater than 350-400 miles (reference (6)).

Because the total length of the project is around 180 miles, HVDC would add significant costs to the project. The project is designed to support the underlying AC transmission system now and in the future by being interconnected to the Benton County Substation and being designed for a future interconnection at the Cuyuna Series Compensation Station. These connections to the underlying AC system would not be feasible with an HVDC solution. As a result, the applicants determined that there is no justification in terms of reliability, economy, or performance for an HVDC line (reference (6)).

4.7.1 Human and Environmental Impacts

An HVDC line transmission line would have human and environmental impacts similar to the proposed project.

4.8 Underground Alternative

Undergrounding is an alternative that is seldom used for high-voltage transmission lines like those proposed for the project. One of the primary reasons is that they are significantly more expensive than overhead lines. The construction cost of locating the entire length of the project's proposed transmission underground is estimated to be as much as 5 to 10 times greater per mile than if it were to be constructed overhead (reference (17)). The cost range depends on the design voltage, the type of underground cable required, the extent of underground obstructions like rock formations, the thermal capability of the soil, the number of river crossings, and other factors. This cost does not include the large reactors that would likely be required at each substation to counteract the large line charging currents present on underground high-voltage lines. In addition, there are increased line losses and additional maintenance expenses incurred throughout the useful life of an underground high-voltage transmission line. This would further increase the total additional cost of building an underground line instead of an overhead line.

Beyond initial costs, another important consideration of undergrounding high-voltage transmission lines is consistency with existing lines and standards. The applicants do not have any buried lines at voltages of 115 kV or above. The addition of underground transmission is outside the applicants' current standards and would require new installation and maintenance training, tooling, equipment, and new inventory to be carried for maintenance and critical spares. This would result in increased costs and possibly a reduction in inventory levels of other items, which then results in diminished maintenance and emergency restoration responsiveness and effectiveness.

Edison Electric Institute's study on the undergrounding of overhead power lines (reference (17)) examined six years of major storm events to determine what trends and impacts these events are having on the industry. They also looked at what type of reliability advantage undergrounding may provide to customers. Available reliability data indicates that underground electric infrastructure has only a slightly better reliability performance than overhead electric systems. Utility experience has shown that during a major outage event, the entire utility system is affected, not just the overhead system.

Underground lines can also be more challenging to operate and maintain. Overhead lines are typically subject to more frequent outages than underground cables, but service can usually be quickly restored by automatic reclosing of circuit breakers (reference (6)). Circuit breakers on underground lines are typically not reclosed until there is verification that a fault has not occurred on the underground cable. As a result, the smaller number of outages is typically offset by their increased duration. A faulted underground line takes much longer to restore because of the difficulty in locating the fault and accessing the site to make repairs. If the fault is due to a failure in the cable, the segment of failed cable must typically be replaced. This usually involves completely replacing the failed cable between two man-hole splice points, which are ordinarily located every 1,500 to 2,000 feet along the line. To replace failed cable, it must be possible to bring heavy equipment, including cable reels weighing 30,000 to 40,000 pounds, into the ROW during all seasons of the year. If the fault occurs in a wetland area where all-season roads are not maintained, restoration can be delayed due to the need to install wetland matting to gain access to the manholes involved in replacing the failed cable.

Due to the construction, maintenance, and cost drawbacks of high-voltage underground transmission lines, undergrounding is not a more reasonable and prudent project alternative (reference (6)).

4.8.1 Human and Environmental Impacts

A common argument in favor of implementing underground lines is that they will minimize the human and environmental impacts above ground. However, there are human and environmental impacts both during and after construction of an underground transmission line. During both underground and overhead transmission line construction, the ROW must be cleared of vegetation. For overhead transmission, excavation work is concentrated at the structure foundations; however, for underground transmission, excavation work would be needed along the entirety of the line, similar to a pipeline. This results in increased impact due to ground disturbance, especially in sensitive environmental areas. In addition, large areas for access roads capable of supporting heavy construction equipment, trenching activities, and cable installation are needed for underground transmission. After construction, the ROW needs to continue to be free of all woody vegetation to reduce soil moisture loss, because high-voltage underground conductors make use of soil moisture for conductor cooling, as well as to minimize potential for tree/shrub roots to conflict with the buried line. A permanent road must also be maintained along the ROW for maintenance and repair.

4.9 System Alternatives Summary

A comparison of how each of the system alternatives meet the need of the project, minimize human and environmental impacts, and meet the MISO-approved cost for the project in part or in whole are shown in Table 4-1 and Table 4-2.

The project’s northern end point, the Iron Range Substation, and the project’s southern end points, the Sherco and Big Oaks Substations, best meet project needs and come closest to meeting the MISO-approved cost for the project. The project has been routed next to existing transmission lines and would be upgraded to double-circuiting where possible. The applicants found triple-circuiting to be feasible along approximately 10 miles of 345 kV/345 kV/69 kV triple-circuit structures in Sherburne County and have proposed such.

Analysis by MISO and the applicants indicates that transmission lines with voltages less than 345 kV either do not meet the project need or do not meet the need as well. The 500 kV alternative has slightly lower losses and slightly higher incremental transfer capability, but it also comes at a slightly higher cost with less redundancy and flexibility; ultimately the 500 kV alternative does not meet the project need.

The no-build and demand side-management alternatives do not meet the project need. All of them are premised on not building the project. Not building the project would result in continued grid instability and reliability concerns. A combination of energy storage and renewable energy sources could meet part of the project need, but analyses by MISO and the applicants indicates that the magnitude of the size and cost would not meet the need as well as the project.

Undergrounding, while slightly more reliable than overhead transmission, would have a greater human and environmental impact on a project of this size. Undergrounding would increase project costs by five to 10 times.

Table 4-1 Guide to System Alternatives Summary Table

Consistency with System Alternative Characteristic	Color
Consistent	
Somewhat consistent or consistent in part	
Not consistent	

Table 4-2 Comparison of System Alternatives – Summary

System Alternative	Meets Stability and Reliability Needs	Costs Consist with MISO Analysis	Minimizes Human and Environmental Impacts	Summary
Northland Reliability Project	●	●	◒	The project increases voltage stability and reliability in northern and central Minnesota. Impacts would depend, in part, on the route and structures selected for the project.
No Build	○	Not applicable	●	The no-build alternative does not meet stability and reliability needs. It would have no direct human or environmental impacts.
Transmission Line Voltage < 345 kV	◒	○	○	Lower voltage transmission lines could meet the project need, but only with significant increase in structures, cost, and human and environmental impacts.
Transmission Line Voltage > 345 kV	●	◒	◒	Higher voltage transmission lines could meet the need for the project, with a higher costs and similar human and environmental impacts.
Alternative Endpoints	◒	◒	◒	Alternative endpoints introduce reliability concerns for the project. Their benefits are anticipated to be less than the project. Impacts would be similar, depending on the route selected for the project.
Upgrading Existing Facilities	◒	◒	◒	Upgrades to existing facilities would have operational complexities and constructability concerns, with a significant cost increase. The project is already proposed as a double circuit for most of its length.
Generation and Non-Wires	◒	○	◒	Generation and non-wire alternatives do not meet the project stability and reliability needs and generally have a significant cost increase. Renewable energy would meet project needs when combined with energy storage but would have a significant cost increase.
Alternative Number, Size and Type of Conductor	●	◒	◒	Alternative number, size and type of conductors could meet the project needs. There would be a significant cost increase, despite some long-term savings. Human and environmental impacts would be similar to the proposed project.
Direct-Current	○	○	○	Direct current alternatives would not be able to meet future transmission needs and would have significantly greater costs.
Underground	●	○	○	Undergrounding could meet project needs, but there would be a significant increase in cost. Human and environmental impacts would be more significant than the project.

5 Affected Environment, Potential Impacts, and Mitigation Measures

This chapter provides an overview of the human and environmental resources that could be affected by the project. It discusses the potential project impacts on these resources and the measures that could be used to avoid, minimize, and mitigate these impacts.

This chapter has two purposes. First, it provides the reader with a general understanding of the resources in the project area and the specific ways in which these resources could be impacted by the project. Second, it prepares the reader for Chapters 6 and 7, which discuss potential impacts relative to the routing alternatives for the project. Detailed tables summarizing the data used for impact analyses are included in Appendix F.

Project construction and operation would impact human and environmental resources. Some impacts would be short term and similar to those of any large construction project (e.g., noise, dust, soil disturbance). These impacts are fairly independent of the project route selected. They can be mitigated by measures common to most construction projects, for example, the use of erosion-control blankets and silt fencing.

Other impacts will exist for the life of the project and may include aesthetic impacts, impacts to agriculture, and impacts to natural resources. These long-term impacts are generally not well mitigated by construction measures, meaning these impacts do not flow from how the project is constructed but rather where it is located and its design. Long-term impacts can be mitigated through prudent route selection and project design.

5.1 Describing Potential Impacts and Mitigation

Chapters 5 and 6 of this EA analyze potential human and environmental impacts of the project on various resources. Understanding these impacts involves contextualizing their duration, size, intensity, and location. This form of contextual information serves as the basis for assessing the overall project impacts on resources.

- **Duration**—Impacts vary in length of time. Short-term impacts are temporary and generally associated with construction. Long-term impacts are associated with operation and usually end with decommissioning and reclamation. Permanent impacts extend beyond the decommissioning stage.
- **Size**—Impacts vary in size. To the extent possible, potential impacts are described quantitatively, for example, the number of impacted acres or the percentage of affected individuals in a population.
- **Intensity**—Impacts vary in the severity to which a resource is affected, in whatever context that impact occurs.
- **Location**—Impacts are location dependent. For example, common resources in one location might be uncommon in another.

Instead of assigning values based on resource significance, qualitative descriptors are employed. These descriptors provide a standardized language for comparing impact levels and characteristics of both the proposed and alternative routes. This approach offers the reader a clear, common understanding of potential route impacts that enhances the route comparison task. For this work, the qualitative descriptors are as follows:

- **Minimal**—Minimal impacts do not considerably alter an existing resource condition or function. Minimal impacts may, for some resources and at some locations, be noticeable to an average observer. These impacts generally affect common resources over the short term.

- **Moderate**—Moderate impacts alter an existing resource condition or function and are generally noticeable or predictable for the average observer. Effects may be spread out over a large area, making them difficult to observe, but can be estimated by modeling or other means. Moderate impacts may be long term or permanent to common resources but are generally short- to long-term for rare and unique resources.

- **Significant**—Significant impacts alter an existing resource condition or function to the extent that the resource is severely impaired or cannot function. Significant impacts are likely noticeable or predictable for the average observer. Effects may be spread out over a large area making them difficult to observe but can be estimated by modeling. Significant impacts can be of any duration and may affect common and rare and unique resources.

This EA also discusses ways to avoid, minimize, or mitigate specific impacts. These actions are collectively referred to as mitigation.

- **Avoid**—Avoiding an impact means that the impact is eliminated altogether by moving or not undertaking parts or all of a project.

- **Minimize**—Minimizing an impact means to limit its intensity by reducing the project size or moving a portion of the project from a given location.

- **Mitigate**—Impacts that cannot be avoided or minimized could be mitigated. Impacts can be mitigated by repairing, rehabilitating, or restoring the affected environment, or compensating for it by replacing or providing a substitute resource elsewhere.

5.1.1 Regions of Influence

Potential impacts to human and environmental resources are analyzed in this EA within specific regions of influence (ROI). The ROI for each resource is the geographic area within which the project may exert some influence. It is used in the EA as the basis for assessing the potential impacts to each resource as a result of the project. Regions of influence vary with the resource being analyzed and the potential impact (Table 5-1).

In this EA, the following ROI are used:

- **Seventy-five feet (ROW)**. A distance of 75 feet on each side of the anticipated alignment (150 feet total) is equivalent to the ROW for the project. ROW is used as the ROI for analyzing potential displacement impacts and impacts to land-based economies, the natural environment, and rare and unique natural species.

- **Five hundred feet (Route Width)**. A distance of 500 feet on each side of the anticipated alignment (1,000 feet total) is equivalent to the Route Width for the project. Route Width is used as the ROI for analyzing potential impacts to public health and safety as well as direct effects to archaeological and historic resources.

- **One thousand feet**. A distance of 1,000 feet (2,000 feet total) from the anticipated alignment for the project is used as the ROI for analyzing potential aesthetic and property value impacts, public utilities, and zoning and land use compatibility. Impacts may extend outside of the 1,000-foot distance but are anticipated to diminish relatively quickly such that potential impacts outside of this distance would be minimal.

- **One Mile**. A distance of 1 mile from the project is used as the ROI for analyzing potential impacts to archaeological and historic resources, rare and unique species, airports and airstrips, socioeconomics, and communities of environmental justice concerns (EJC).

- **Project Area**. The project area, defined generally as the civil townships through which the project passes, is used as the ROI for analyzing potential impacts to cultural values, land use, emergency services, air quality, and tourism and recreation. These are resources for which impacts may extend throughout communities in the project area.

Table 5-1 Regions of Influence

Type of Resource	Specific Resource/Potential Impact to Resource	Region of Influence (ROI)
Human Settlement	Displacement	ROW (150 feet)
Human Settlement	Aesthetics, Property Values, Electronic Interference, Zoning and Land Use Compatibility	2,000 feet
Human Settlement	Cultural Values	Project Area
Human Settlement	Socioeconomics/EJ	One Mile
Transportation and Public Services	Roadways/Railways	2,000 feet
Transportation and Public Services	Public Utilities	2,000 feet
Transportation and Public Services	Emergency Services	Project Area
Transportation and Public Services	Airports	One Mile
Public Health and Safety	Electric and Magnetic Fields, Implantable Medical Devices, Stray Voltage, Induced Voltage	Route Width (1,000 feet)
Public Health and Safety	Air Quality	Project Area
Land-Based Economies	Agriculture, Forestry, Mining	ROW (150 feet)
Land-Based Economies	Tourism and Recreation	Project Area
Archaeological and Historic Resources	Archaeological Resources; Historic Architectural Resources	One Mile, Route Width (1,000 feet)
Natural Environment	Water Resources	ROW (150 feet)
Natural Environment	Soils	ROW (150 feet)
Natural Environment	Vegetation and Wildlife	ROW (150 feet)
Natural Environment	Geology	ROW (150 feet)
Rare and Unique Natural Resources	Protected Species	One Mile
Rare and Unique Natural Resources	Sensitive Ecological Resources	ROW (150 feet)

5.2 Environmental Setting

The project is located in the east central part of Minnesota and traverses Itasca, Aitkin, Crow Wing, Cass, Morrison, Benton, and Sherburne counties. The project's general environmental setting consists of forest, agricultural land, water resources such as lakes, streams, rivers, and wetlands, low density and rural residential development, and commercial development. The closest cities to the project include Hill City, Riverton, Ironton, Harding, Lastrup, St. Cloud, and Becker. The most important land uses in the area include forestry, agriculture, and tourism.

The Minnesota DNR and the U.S. Forest Service (USFS) have developed an Ecological Classification System (ECS) for ecological mapping and landscape classification in Minnesota that is used to identify,