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November 17, 2016

VIA U. S. AND ELECTRONIC MAIL

Mr. Darrell Nitschke, Executive Secretary
North Dakota Public Service Commission, Dept. 0480
600 East Blvd.
Bismarck, North Dakota 58505

RE: NSP MINOT LOAD SERVING PROJECT
CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY
(CASE NO. PU-16-644)

Dear Mr. Nitschke:

On November 2, 2016, the North Dakota Public Service Commission held an Informal Hearing in the above captioned case. Northern States Power Company appreciated the opportunity to provide information regarding our proposed Minot load serving project.

During the Informal Hearing, the Commission requested that the Company provide information regarding a number of issues of interest, and not all directly related to the Minot project. We are pleased to provide the following response to the various topics:

Status of Stanton Agreement with Great River Energy (GRE)
The Stanton Displacement Agreement between the Company and Great River Energy (GRE) has been in effect since 1964. Pursuant to this agreement, generation of up to 188 MW of delivery capacity from GRE's Stanton Plant in North Dakota is used primarily to serve NSP loads in North Dakota located in the GRE and Otter Tail Power local balancing authority areas. On a reciprocal basis, 188 MW of generation from our fleet is allocated for GRE loads in Minnesota. This innovative swap arrangement was put in place to so that GRE would not have to build a transmission line from the Stanton Station plant to their loads in Minnesota, and NSP would not have to build a transmission line from our fleet to serve North Dakota loads.

However, since the Agreement was signed in 1964, additional transmission capability has been developed in Minnesota and North Dakota by the Company, GRE and other (Midcontinent Independent System Operator (MISO) members. Due to this build-out of the regional transmission grid and the establishment of the open access MISO market, we do

not believe closure of the Stanton Plant in May 2017 will adversely impact our ability to serve our North Dakota customers.

We note that the retirement of a generating plant within the MISO footprint is subject to MISO approval. It is our understanding that GRE has filed their request to retire the Stanton Plant through a MISO proceeding known as the "Attachment Y" process. It may also be worth noting that within the context of NSP's integrated system and the operation of MISO's open transmission network, the generation of energy from one specific power plant does not directly serve the electrical load in the immediate area. Rather, all generation injects into the electric grid and all loads withdraws from the grid. Thus, from a reliability standpoint, there is little significance electrically in the retirement of the Stanton Plant since other generators are still injecting sufficient energy into the system and there is sufficient transmission capacity to deliver electric service to Minot and Grand Forks.

Magic City Substation Land Acquisition and Use

While North Dakota statute prohibits corporations and limited liability companies from owning or leasing land used for farming or ranching, and from engaging in the business of farming or ranching, there is an industrial and business purpose exception. Specifically, a corporation not engaged in the business of farming or ranching may own or lease land used for farming or ranching when the land is necessary for "the siting of buildings, plants, facilities, industrial parks, or similar business or industrial purposes of the corporation". (N.D.C.C. § 10-06.1-07). The Company currently anticipates purchasing land sufficient for the substation as well as future expansion, and we are evaluating plans for the use of the buffer areas around the substation/associated equipment.

Southwest Power Pool (SPP) Interconnections and Potential for SPP Charges

NSP and Basin Electric Power Cooperative (BEPC) will both have sufficient capability from their respective regional transmission organizations (RTOs) – i.e., MISO and SPP – to serve their own loads without requiring the purchase of transmission service from the other RTO. NSP will have full access to MISO transmission via the connection from the proposed Magic City Substation to the McHenry Substation, which in turn connects to the wider MISO transmission system. Conversely, BEPC will have access to the SPP transmission system through the Western Area Power Administration's (WAPA) Garrison – Mallard 115 kV line and its 115 kV line coming into its Logan Substation from the west. See Attachment A for a map showing the lines and substations.

The Commission has raised a concern that NSP may be facing potential SPP charges in conjunction with the Minot project, similar to Otter Tail Power. However, NSP is not in the same position as Otter Tail Power due to the fact that our Minot load can be directly and fully served by MISO's bulk electric system. Therefore, we will not need to purchase transmission service from SPP or otherwise be subject to any SPP charges.

Cost Sharing for the Minot Load Serving Project

In order to reliably serve our load in Minot into the future, NSP needs to construct the proposed Magic City Substation and new 230 kV transmission line connecting the substation to GRE's McHenry Substation. As such, under Attachment FF of the MISO Tariff, baseline reliability projects are paid for by the Transmission Owner developing such projects. In this case, the cost of the Minot load serving project is paid by NSP as the Transmission Owner constructing the project.

For many years the Minot area electric load requirements have been jointly served by transmission facilities owned by NSP, BEPC, and the Western Area Power Administration (WAPA). Currently, two of the three transmission lines delivering electricity to serve loads in the Minot area are owned by BEPC and WAPA, and the third transmission line is owned by NSP. The addition of the new 230 kV transmission line from the McHenry Substation to the new Magic City Substation proposed by the Company will bring a fourth transmission option to the Minot area. In effect, this will help maintain a balance between electric transmission sources provided by the Company, BEPC, and WAPA in terms of serving the collective loads in the Minot area.

The Company's proposed Minot load serving project has been collaboratively designed to support the transmission system of the entire area. By working closely with BEPC and WAPA to plan the Minot area transmission system, the Company and the other utility entities can establish separately the transmission infrastructure necessary to serve our respective loads while also interconnecting the transmission facilities in the Minot area to each other to increase overall reliability. Thus, if one entity's transmission elements trip, other transmission facilities will still be available to serve the area load. BEPC and WAPA have historically made significant investments in the Minot area transmission grid. The Company's Minot load serving project represents a timely opportunity for NSP to help maintain reliable service to the Minot area.

We note that NSP reliability is materially improved by BEPC's decision to interconnect their Logan to Mallard 115 kV line to the Company's proposed Magic City Substation. BEPC has other assets in the area that it could utilize to ensure it can independently serve their electric loads without use of NSPM's proposed substation assets. For example, BEPC could route its Garrison – Mallard 115 kV line into their Logan Substation (See Attachment A). The cost of routing their line into either the Logan Substation or the new Magic City Substation would be roughly the same. If BEPC were required to pay for part of the Magic City Substation, it is likely that BEPC would look for options other than interconnecting with us. This would mean that NSP would lose the reliability benefit of having the BEPC interconnection. These are the types of "mutual reliance" projects that utilities in the area are always looking for to maintain reliable service to our respective customers.

Events that Can Cause Low Voltage and Thermal Overload Conditions

Please see Attachment B, taken from our CPCN application, for a listing of the various contingencies identified in the Load Study that would result in low voltage or thermal

overload conditions. These tables indicate the severity of the impact on the voltage and loading levels of each scenario.

Installing a Combustion Turbine Near the Minot Area Load

A combustion turbine (CT) is most likely to be the least cost alternative to the Minot area load serving project, but there are drawbacks to such an approach. First, the Company estimates the cost to install a 73 MW combustion turbine (CT) in the Minot area would be about $123 million in 2018 dollars, compared to the estimated $49 million for the transmission and substation solution proposed by the Company. The CT cost estimate does not include any natural gas supply infrastructure requirements, nor does it include any transmission upgrade costs that may be assigned to the generator through the MISO generation interconnection process. Second, a CT is not cost-effective during non-peak conditions and it would not be dispatched by MISO due to its higher cost. Thus, a significantly lower cost transmission solution is a far better approach to addressing the emerging transmission needs in the Minot area than a generation solution.

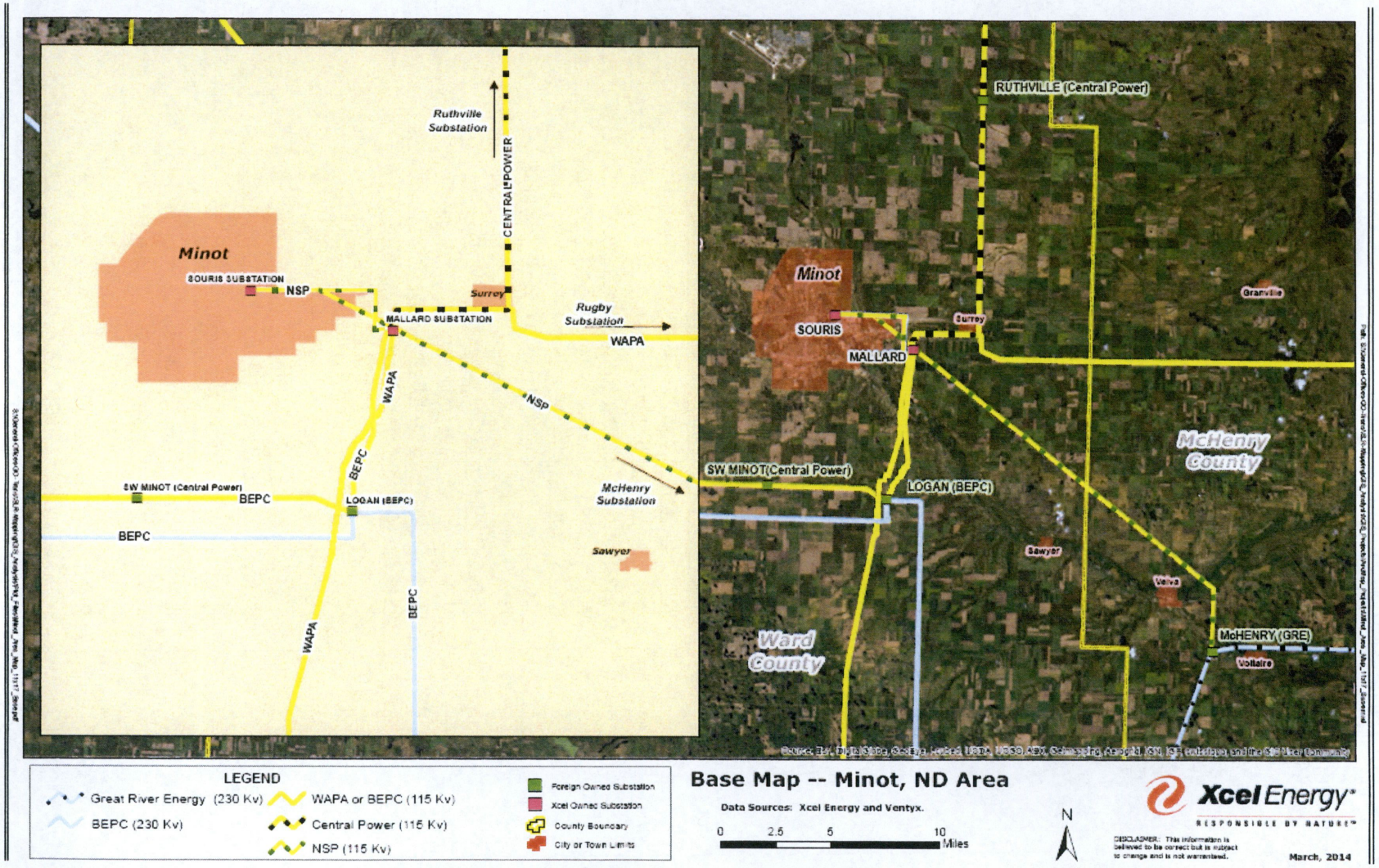
Please do not hesitate to contact me if you have any additional questions or concerns regarding this additional information.

Sincerely,

/S/

David H. Sederquist
Sr. Regulatory Consultant

Base Existing System Map



Base Model Contingency Analysis

A contingency analysis was also conducted for the study area. The table below shows the category B voltage violation results for the current transmission system in the Minot Area.

Minot Area Category B Flagged Voltage Issues

2024 Winter Peak Model with North Transfers

UNDERVOLTAGE Substation	Voltage	Voltage Drop	Contingency
Souris 115 kV	94.58		System Intact
	86.44	8.13	Loss of Souris to Mallard 115 kV
	80.66	13.91	Loss of Mallard to Logan 115 kV
	87.99	6.58	Loss of McHenry 230/115 kV Transformer
	89.07	5.51	Loss of Leland Olds to Logan 230 kV
	86.2	8.38	Loss of Logan 230/115 kV Transformer
	89.07	5.51	Loss of Souris – Velva – McHenry 115 kV
Mallard 115 kV	94.86		System Intact
	80.18	14.68	Loss of Mallard to Logan 115 kV
	89.54	5.32	Loss of McHenry 230/115 kV Transformer
	90.83	4.03	Loss of Balta to Rugby 230 kV
	90.66	4.2	Loss of Rugby 230/115 kV Transformer
	89.09	5.77	Loss of Leland Olds to Logan 230 kV
	86.06	8.8	Loss of Logan 230/115 kV Transformer
	90.69	4.17	Loss of Souris – Velva – McHenry 115 kV
Velva Tap 115 kV	98.88		System Intact
	94.15	4.73	Loss of Souris to Mallard 115 kV
	90.79	8.1	Loss of Mallard to Logan 115 kV
	88.38	10.51	Loss of McHenry 230/115 kV Transformer
	94	4.88	Loss of Logan 230/115 kV Transformer
Logan 230 kV	96.66		System Intact
	94.48	2.18	Loss of Mallard to Nelson 115 kV
	93.95	2.72	Loss of McHenry 230/115 kV Transformer
	94.54	2.12	Loss of Balta to Rugby 230 kV
	94.54	2.13	Loss of Rugby 230/115 kV Transformer
	94.51	2.16	Loss of Nelson to Max 115 kV
	91.15	5.51	Loss of Leland Olds to Logan 230 kV
	94.47	2.19	Loss of Souris – Velva – McHenry 115 kV
Logan 115 kV	96.23		System Intact
	93.53	2.7	Loss of Mallard to Nelson 115 kV
	92.11	4.12	Loss of McHenry 230/115 kV Transformer
	93.07	3.16	Loss of Balta to Rugby 230 kV
	92.99	3.24	Loss of Rugby 230/115 kV Transformer
	90.52	5.7	Loss of Leland Olds to Logan 230 kV
	87.08	9.15	Loss of Logan 230/115 kV Transformer
	92.97	3.26	Loss of Souris – Velva – McHenry 115 kV
Ruthville 115 kV	92.54		System Intact
	76.6	15.94	Loss of Mallard to Logan 115 kV

	86.84	5.7	Loss of McHenry 230/115 kV Transformer
	88.22	4.32	Loss of Balta to Rugby 230 kV
	88.04	4.5	Loss of Rugby 230/115 kV Transformer
	86.35	6.19	Loss of Leland Olds to Logan 230 kV
	83.07	9.48	Loss of Logan 230/115 kV Transformer
	88.07	4.47	Loss of Souris – Velva – McHenry 115 kV
SW Minot 115 kV	95.33		System Intact
	91.4	3.92	Loss of McHenry 230/115 kV Transformer
	92.35	2.97	Loss of Balta to Rugby 230 kV
	92.26	3.07	Loss of Rugby 230/115 kV Transformer
	89.69	5.64	Loss of Leland Olds to Logan 230 kV
	87	8.33	Loss of Logan 230/115 kV Transformer
	85.81	9.52	Loss of Logan to SW Minot 115 kV
	92.25	3.07	Loss of Souris – Velva – McHenry 115 kV

There are several category B contingencies that result in voltage violations for NSP's and the I/S buses. The loss of the Logan – Mallard 115 kV line, in particular, results in severely low voltages at NSP's Mallard and Souris substations. The same contingency results in the Ruthville substation approaching .75 p.u. voltage. This contingency removes the strongest source serving the Minot area load. The remaining Garrison-Max-Mallard and McHenry-Souris 115 kV lines are unable to maintain acceptable voltages. In general, contingencies involving one of the three sources into this area results in low voltage violations. A new source is needed to maintain acceptable voltages in the Minot area.

The following table shows the category B thermal violations. Most of the flagged thermal violations are on the 115 kV system serving the Minot load. Losing one of the 115 kV line in the Minot area tends to overload the other lines serving the Minot load. This is an indication that new 115 kV points of injection may be needed to offload existing 115 kV lines.

Minot Area Category B Flagged Thermal Issues

2024 Winter Peak Model with North Transfers

Circuit Element	MVA Rating	Loading Percent	Contingency
Mallard to Logan 115 kV	159.3	81.5	System Intact
		100.7	Loss of Souris to Velva Tap 115 kV
		117.7	Loss of Mallard to Nelson 115 kV
		100.5	Loss of Velva Tap to McHenry 115 kV
		103.3	Loss of McHenry to Coal Creek Tap 230 kV
		100	Loss of McHenry 230/115 kV Transformer
		100.3	Loss of Balta to Rugby 230 kV
		117.7	Loss of Nelson to Max 115 kV
		119.5	Loss of Garrison to Max 115 kV
		100.7	Loss of Souris – Velva – McHenry 115 kV
McHenry to Velva Tap 115 kV	119.5	41.1	System Intact
		102.3	Loss of Souris to Mallard 115 kV
		101.4	Loss of Mallard to Logan 115 kV

McHenry 230/115 kV Transformer	84.0	114.6	System Intact
		160.4	Loss of Souris to Mallard 115 kV
		178.7	Loss of Mallard to Logan 115 kV
		159.3	Loss of McHenry to Balta 230 kV
		188.2	Loss of Balta to Rugby 230 kV
		154.7	Loss of Rugby 230/115 kV Transformer
		145.4	Loss of Garrison to Voltaire 115 kV
		157.8	Loss of Leland Olds to Logan 230 kV
		165	Loss of Logan 230/115 kV Transformer
Garrison to Voltaire 115 kV	109.0	77.2	System Intact
		102.3	Loss of McHenry to Coal Creek Tap 230 kV
Logan 230/115 kV Transformer	200.0	101.4	System Intact
		113	Loss of Souris to Velva Tap 115 kV
		124.6	Loss of Mallard to Nelson 115 kV
		112.9	Loss of Velva Tap to McHenry 115 kV
		116.2	Loss of McHenry to Coal Creek 230 kV
		112.9	Loss of Balta to Rugby 230 kV
		124.6	Loss of Nelson to Max 115 kV
		125.8	Loss of Garrison to Max 115 kV
		115.9	Loss of Logan to Blaisdell 230 kV
		113	Loss of Souris – Velva – McHenry 115 kV

5.2: Bulk Option Analysis

The full analysis of the base transmission system shown above as well as previous studies indicates the need for an additional high voltage source into the Minot area. Three potential solutions were considered for this analysis. The first step was to screen the potential solutions to determine which option demonstrated the best performance. Other considerations, such as costs and constructability were considered in determination of the overall best solution. The options as laid out in section 4.4 of the report include:

Option 1: Joint NSP and Integrated System solution

Option 2: NSP solution

Option 3: Integrated System solution.

Minot Area Load Serving Bus Voltages (System Intact)

2024 Winter Peak Model with North Transfers

	Option 1	Option 2	Option 3
Logan 230 kV bus	0.984	0.995	0.995
McHenry 230 kV bus	0.992	1.007	0.999
Ward County 230 kV bus	0.984	1.006	N/A
Mallard 115 kV bus	0.982	0.999	0.978
Ruthville 115 kV bus	0.968	0.986	0.957