Modernizing Transmission Planning

ESIG
ENERGY SYSTEMS
INTEGRATION GROUP

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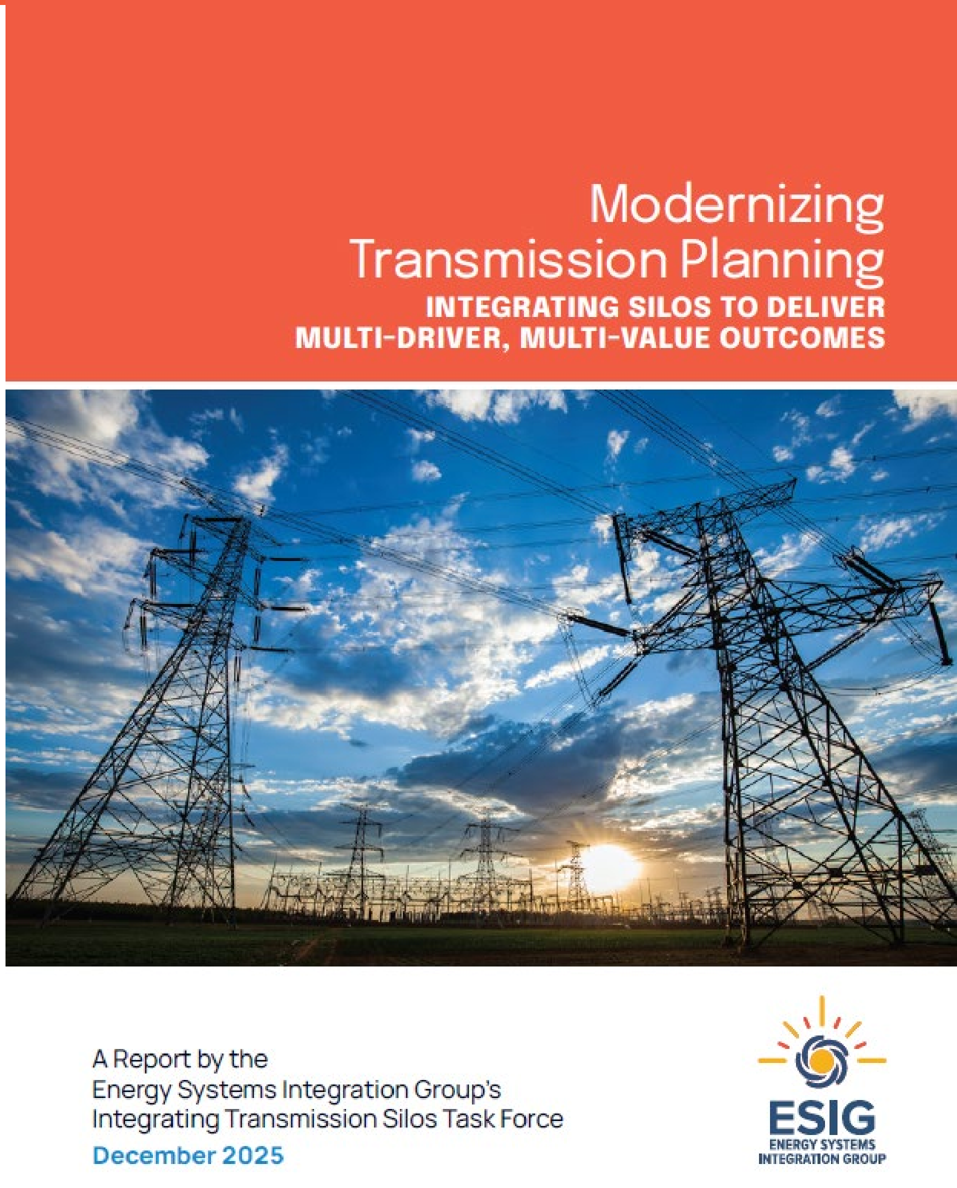
Introduction

Most regional planning **processes were designed for a grid that changed slowly and predictably**. They assumed steady load growth, gradual policy shifts, large central generating stations, and incremental reliability fixes. Today, **those conditions no longer hold**. Yet the planning studies—interconnection, economic planning, reliability, and public policy—**still run in separate silos,** each with its own calendar, workflows, tools, deliverables, and stakeholder track. The result is fragmented decision making and missed opportunities to address system needs more efficiently.

The Energy Systems Integration Group (ESIG) convened a task force including utility planners, system operators, developers, and other technical experts to examine **how planning processes can evolve**. The task force developed this report, which offers a **practical framework—integrate, broaden, deepen—that aligns with FERC Order 1920**. Drawing from experience in multiple regions, it shows how these principles are being applied and how they can be scaled to meet emerging needs.



Modernizing Transmission Planning

INTEGRATING SILOS TO DELIVER MULTI-DRIVER, MULTI-VALUE OUTCOMES

A Report by the
Energy Systems Integration Group's
Integrating Transmission Silos Task Force
December 2025

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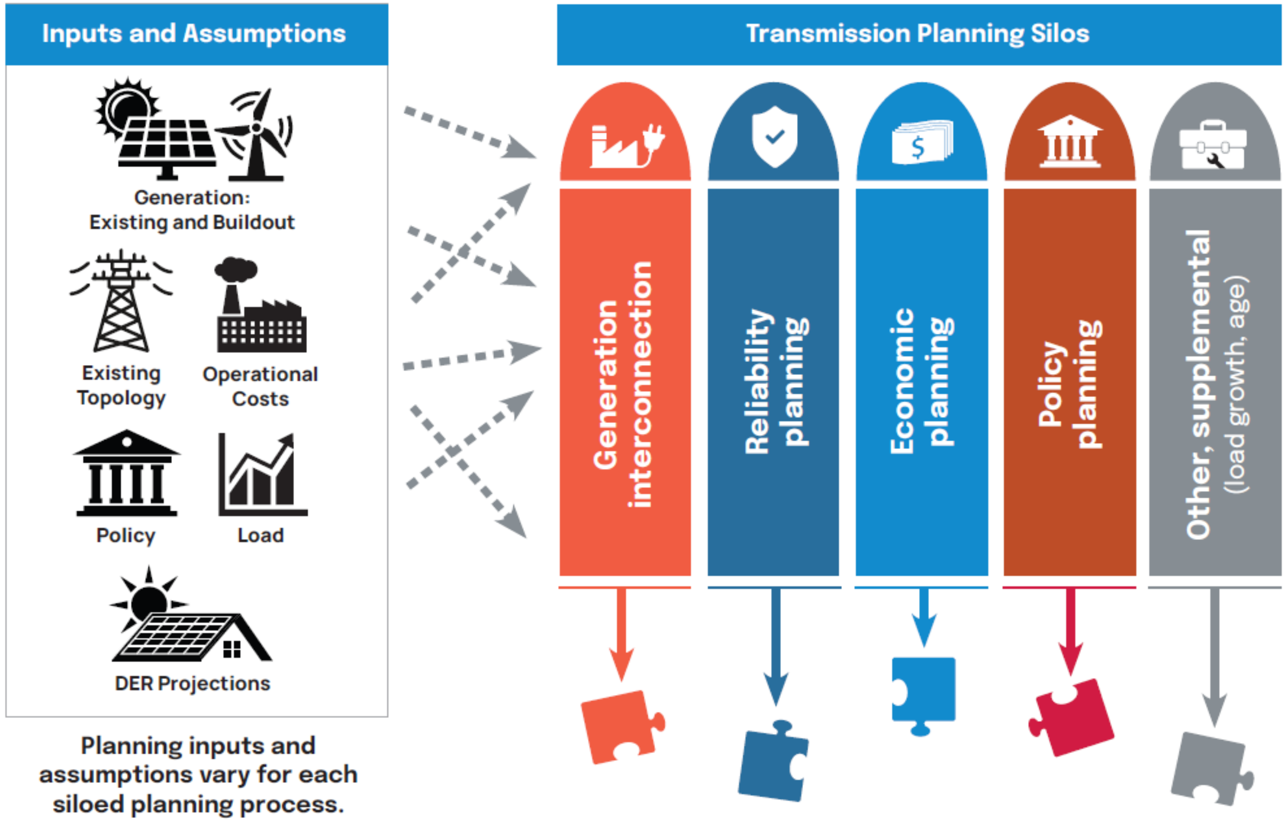
Today’s Planning Processes



Planning inputs and assumptions vary for each siloed planning process.

The result is disjointed, less efficient, single-driver transmission projects.

Attribute	Purpose	Project Output	Horizon	Assumptions	Study Type	Limitations
Generator interconnection	Processes queued generator requests	Request-focused upgrades	2–5 years	Queue-driven; assumes limited overlap	AC load flow, short-circuit, stability studies	Queue-specific; lacks system-wide coordination
Near-term reliability planning	Maintains NERC reliability compliance	Reliability upgrades (lines, transformers, voltage support)	5–10 years	Static load and supply forecast; conservative assumptions	Contingency analysis, thermal/stability checks	Narrow reliability focus; misses long-term trends
Economic/congestion planning	Alleviates market congestion and increases grid efficiency	Congestion relief upgrades (e.g., reconductoring, new lines)	2-10 years	Average forecasts; assumes current conditions	8,760-hour production-cost modeling, security-constrained unit commitment/security-constrained economic dispatch	Short-term congestion focus; ignores worst hours
Long-term scenario planning	Evaluates long-term futures under varied scenarios	Conceptual backbone projects, scenario-informed corridors	15–20 years or more	Scenario-based forecasts; includes policy sensitivity	Capacity expansion, production cost, and reliability	Often advisory only; has limited influence on near-term projects
Asset management/end-of-life planning	Replaces assets based on condition or risk assessments	Like-for-like replacements, equipment rebuilds	2–5 years	Asset health assessments; prioritizes maintaining current capabilities	Asset risk tools, condition databases	Often incentivizes in-kind replacement, which typically misses opportunity to right-size for future needs
Policy/public policy planning	Supports policy-driven buildouts (e.g., renewable portfolio standards, decarbonization goals)	Policy-driven transmission expansion/upgrades (e.g., renewable integration)	10–20 years	Policy mandates; assumes generation retirements	Scenario studies, policy overlays	Often siloed from economic and reliability processes

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Drivers for Change – Efficiency and Growing Investment

$20B

Congestion Costs

U.S. transmission congestion costs in 2022

130GW

Data Center Load

Projected data center electricity demand by 2030, doubling its share of national use

2,600GW

Queue Backlog

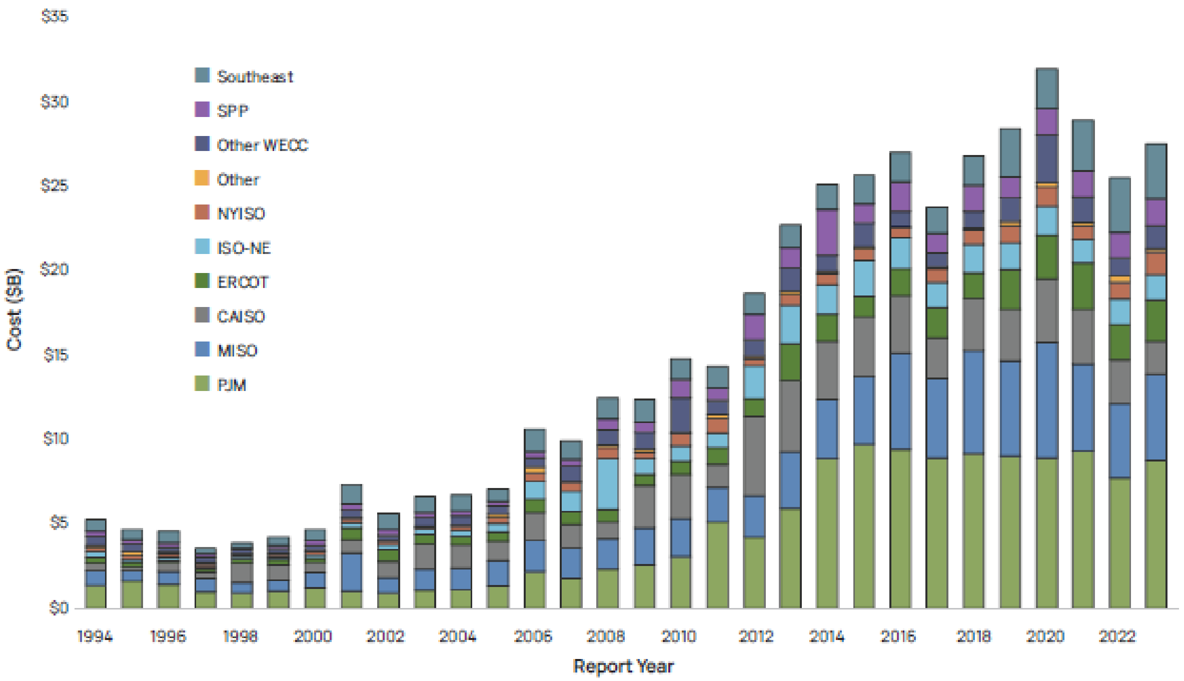
Generation and storage in interconnection queues at end of 2023; only ~14% reach operations

2x

Capacity Needed

DOE finds many regions must at least double transmission capacity by 2035

Total Utility-Reported Transmission Plant Additions Since 1994: Investment Is Rising, but Still Flowing Through Silos



Inflation-adjusted dollars spent on transmission facilities, as reported by utilities, have risen across all regions, with PJM, MISO, and CAISO accounting for the largest recent shares.

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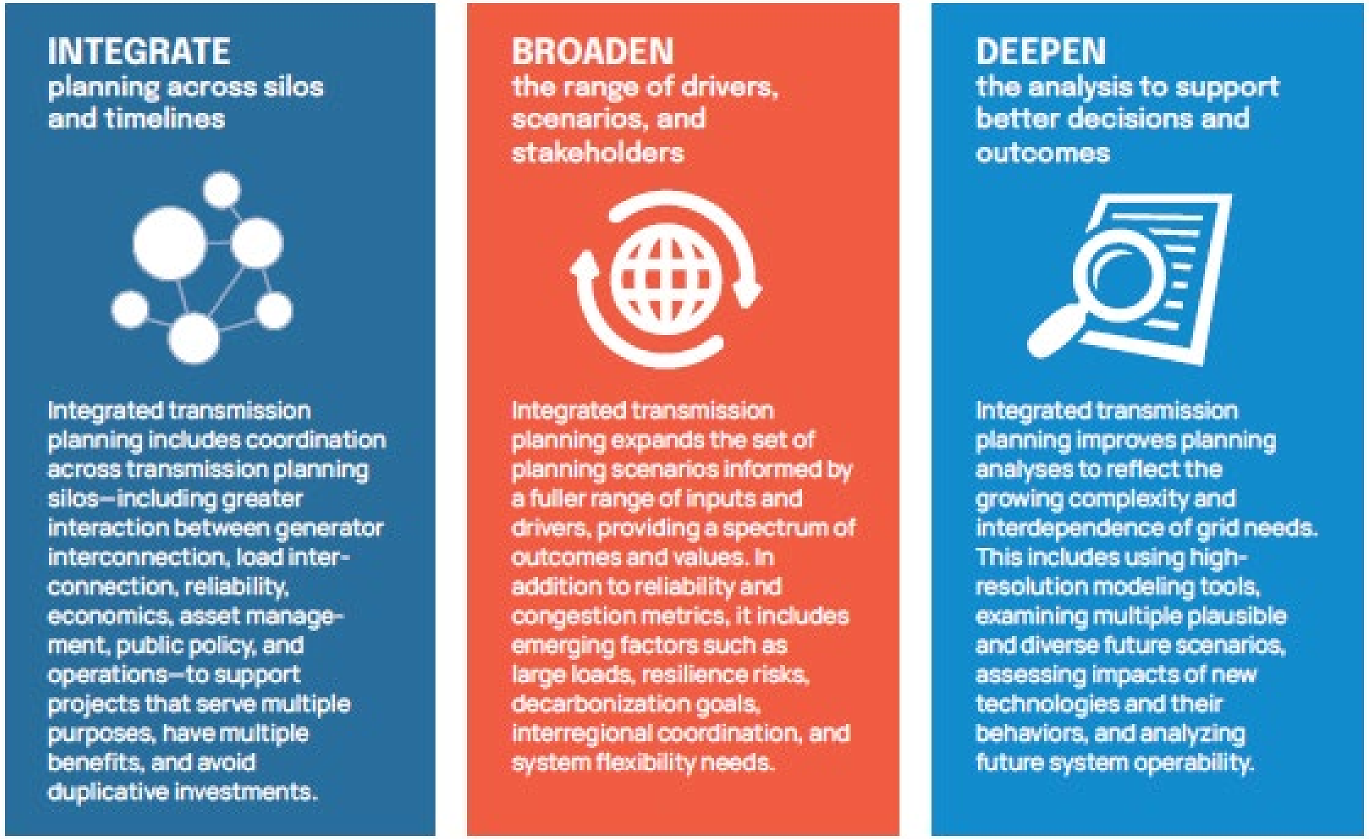
Framework for Evolving Transmission Planning



INTEGRATE
planning across silos and timelines

Integrated transmission planning includes coordination across transmission planning silos—including greater interaction between generator interconnection, load interconnection, reliability, economics, asset management, public policy, and operations—to support projects that serve multiple purposes, have multiple benefits, and avoid duplicative investments.

BROADEN
the range of drivers, scenarios, and stakeholders

Integrated transmission planning expands the set of planning scenarios informed by a fuller range of inputs and drivers, providing a spectrum of outcomes and values. In addition to reliability and congestion metrics, it includes emerging factors such as large loads, resilience risks, decarbonization goals, interregional coordination, and system flexibility needs.

DEEPEN
the analysis to support better decisions and outcomes

Integrated transmission planning improves planning analyses to reflect the growing complexity and interdependence of grid needs. This includes using high-resolution modeling tools, examining multiple plausible and diverse future scenarios, assessing impacts of new technologies and their behaviors, and analyzing future system operability.

Outcomes

- Studies that produce cost-effective multi-need portfolios coordinated based on common assumptions, benefits, and portfolio-level scoring
- Insights gained from a broad set of futures, allowing for the development of least-regrets and probability weighted plans, built with staging and optionality in mind.
- A steadier buildout of high-voltage and multi-benefit transmission lines combined with right-sized asset replacements to address long-term needs, reducing serial mitigations and rework
- Projects serving multiple purposes are more straightforward to justify
- Faster, more predictable interconnection of generators and loads
- Alignment with policy and resilience goals where extreme weather and supply mix considerations are directly incorporated into study processes and portfolio evaluations

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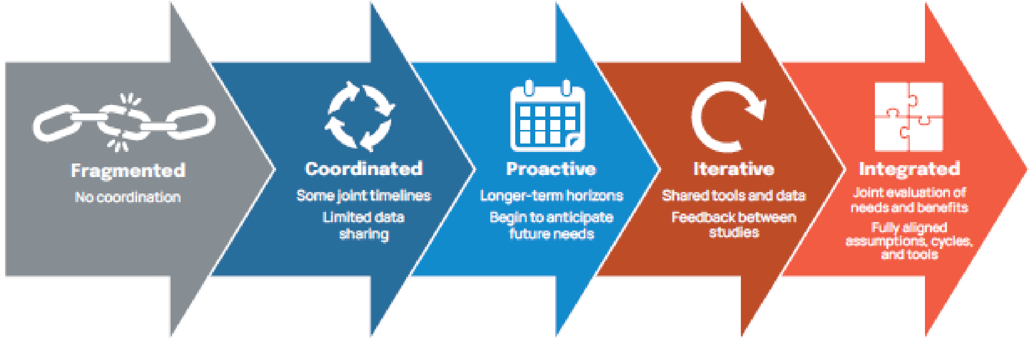
Integrate

- **Aligning study timelines** so outputs from one process feed directly into the next.
- **Sharing data and assumptions** across reliability, economic, policy, and interconnection studies.
- **Coordinating scenario development** so each function evaluates the same futures.
- **Carrying constraints and solutions forward** between study types so they can be refined and re-evaluated.
- **Restructuring institutional roles** so that planning teams are organized to collaborate across functions rather than operate in isolation.

Integration doesn't necessarily require a complete redesign. It is best viewed as a continuum of progress–small steps to align timelines, share assumptions, and coordinate solutions can significantly improve outcomes.



This continuum illustrates the progression from siloed to fully integrated planning. Each stage reflects deeper coordination across planning functions, more consistent use of inputs and tools, and stronger alignment with long-term system needs.

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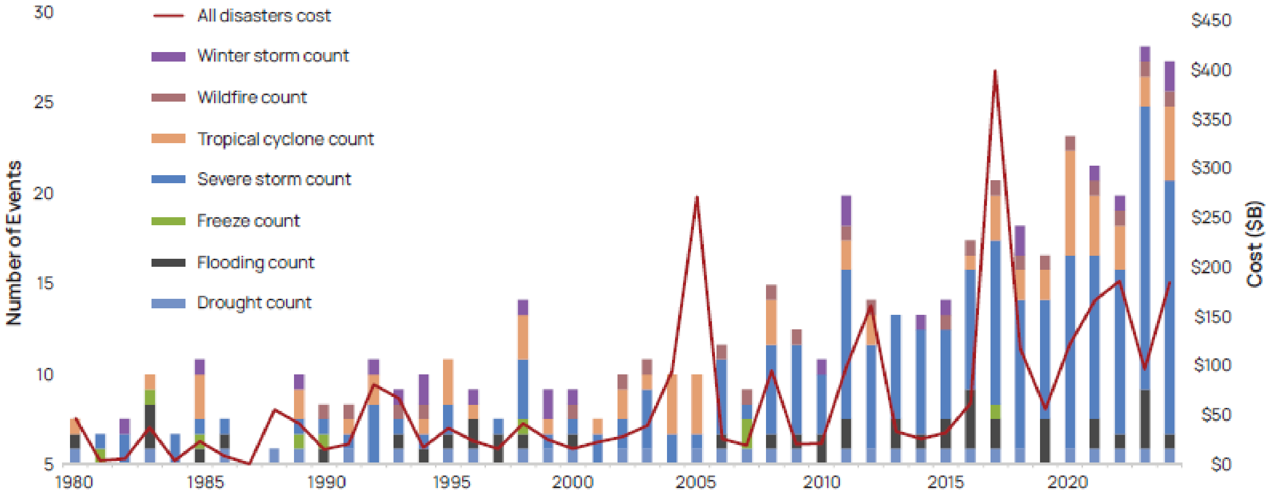
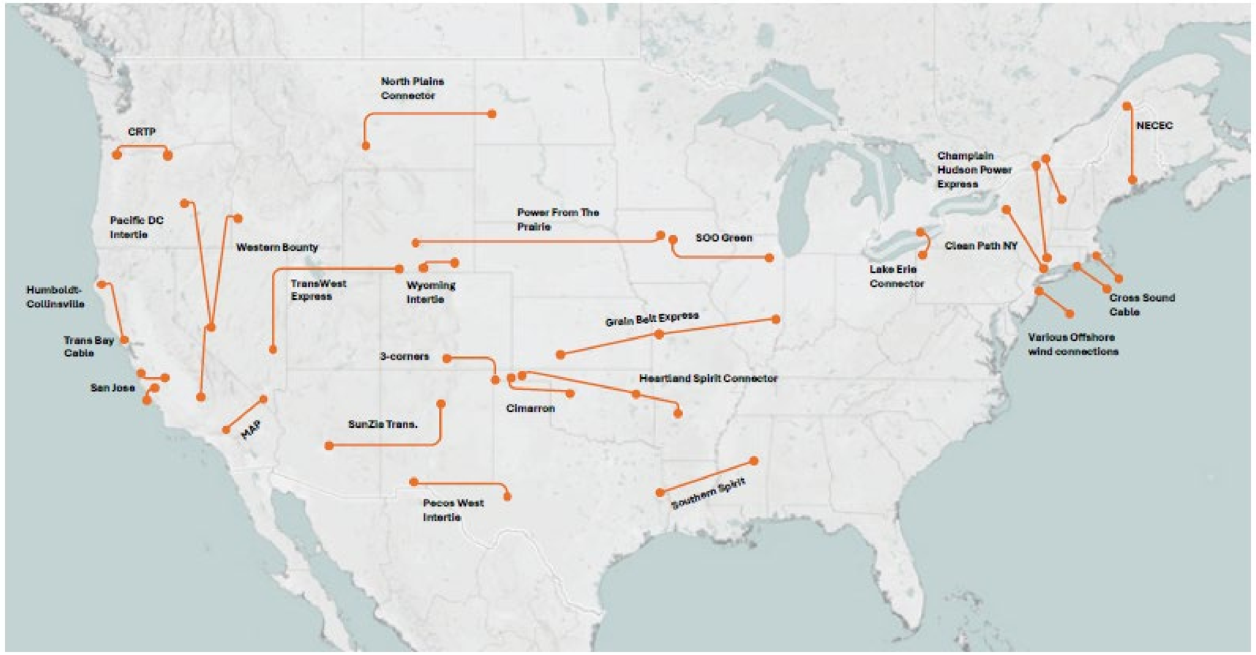
Broaden

United States Billion-Dollar Disaster Events, 1980 to 2024





- **Large Load Integration:** considering operational characteristics and technology uncertainty
- **Include Resource Adequacy as a Transmission Planning Driver:** Acknowledge the role transmission plays in supporting resource adequacy
- **Include/Prioritize Resilience as a Planning Driver:** Consider probalistic and determininstic approaches to studying system resilience
- **Improve Interregional and Multi-Jurisdictional Coordination:** Purposeful integration of multi-jurisdiction projects in planning cycles
- **Improve Policy Alignment and Scenario Diversity:** Incorporate policy consideration and sources of uncertainty in scenario development

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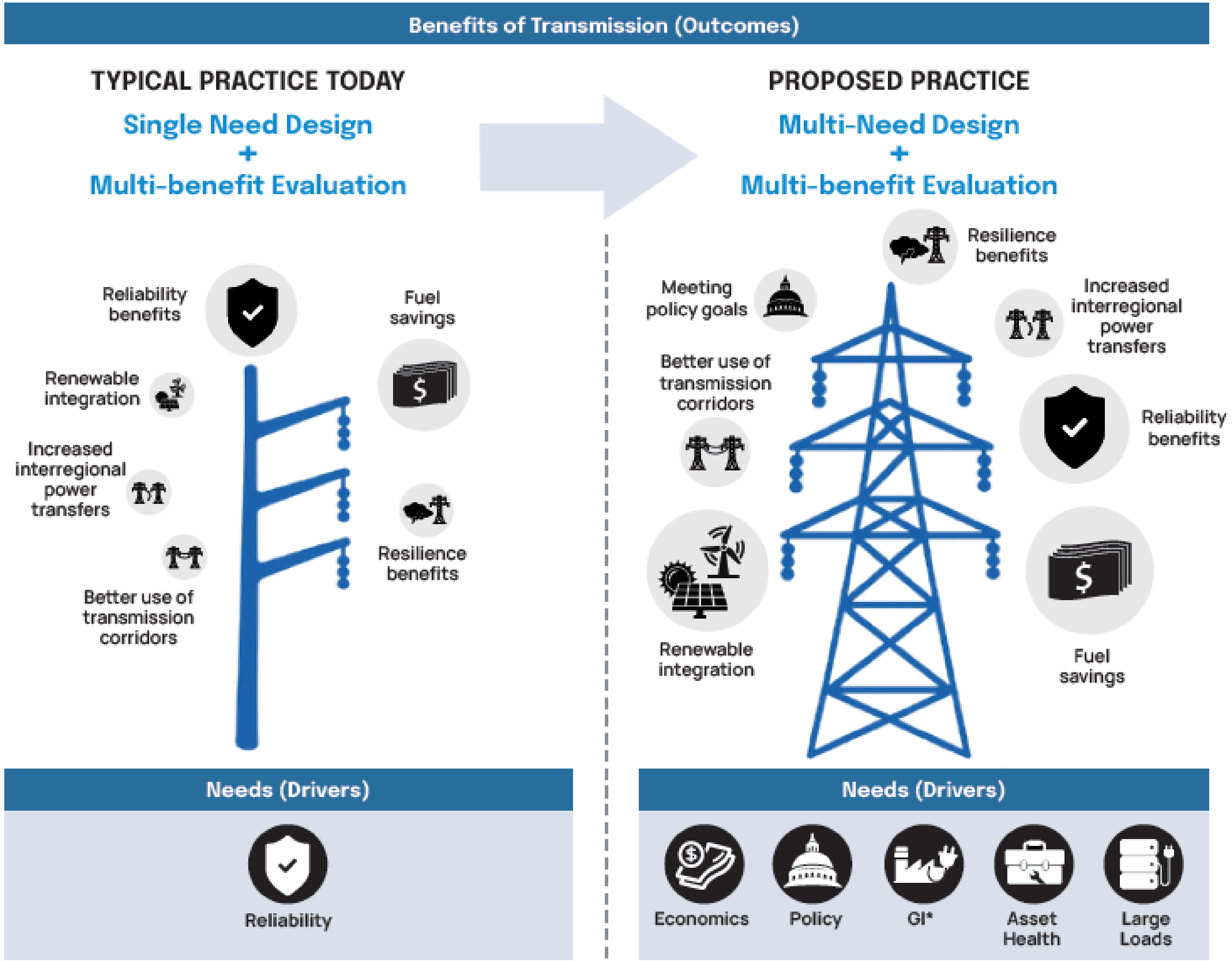
Deepen

- Expand and modernize benefit-cost frameworks with FERC Order 1920
- Do Multi-Need Planning: Design Projects with Purpose, Not Just Value
- Improve Modeling of Uncertainty and System Risk
- Increase Optionality: Building Flexibility into Transmission Investments
- Incorporate Operability into Transmission Planning

Multi-Need vs Single Need Projects



Benefits of Transmission (Outcomes)

TYPICAL PRACTICE TODAY

Single Need Design
+
Multi-benefit Evaluation

Reliability benefits

Fuel savings

Renewable integration

Increased interregional power transfers

Resilience benefits

Better use of transmission corridors

Needs (Drivers)

Reliability

PROPOSED PRACTICE

Multi-Need Design
+
Multi-benefit Evaluation

Resilience benefits

Meeting policy goals

Increased interregional power transfers

Better use of transmission corridors

Reliability benefits

Renewable integration

Fuel savings

Needs (Drivers)

Economics

Policy

GI*

Asset Health

Large Loads

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Principles of Scenario Planning and Optionality

Scenario Development and Evaluation

- Base scenario development on a core of common concepts, like public policies and demand growth, then expand associated assumptions to create a broad but overlapping set of scenarios
- Expand scenario libraries to include extreme weather, rapid electrification, technology cost swings, or delayed policy timelines
- Use least-regrets and probability-weighted approaches to evaluate project portfolios
- Stress-test project benefits under diverse futures, ensuring that portfolios are not overly dependent on any single outcome

Planning with Optionality

- Building to higher voltage or tower class (e.g., 500 kV design operated initially at 230 kV).
- Structuring rights-of-way use and agreements to support the addition of future circuits.
- Designing modular substations or expandable interconnection points.
- Staging project components to align with resource development or load growth, minimizing uncertainty impacts
- Specifying HVDC designs to include grid-forming, blackstart, STATCOM, and other beneficial capabilities.

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From Intent to Implementation

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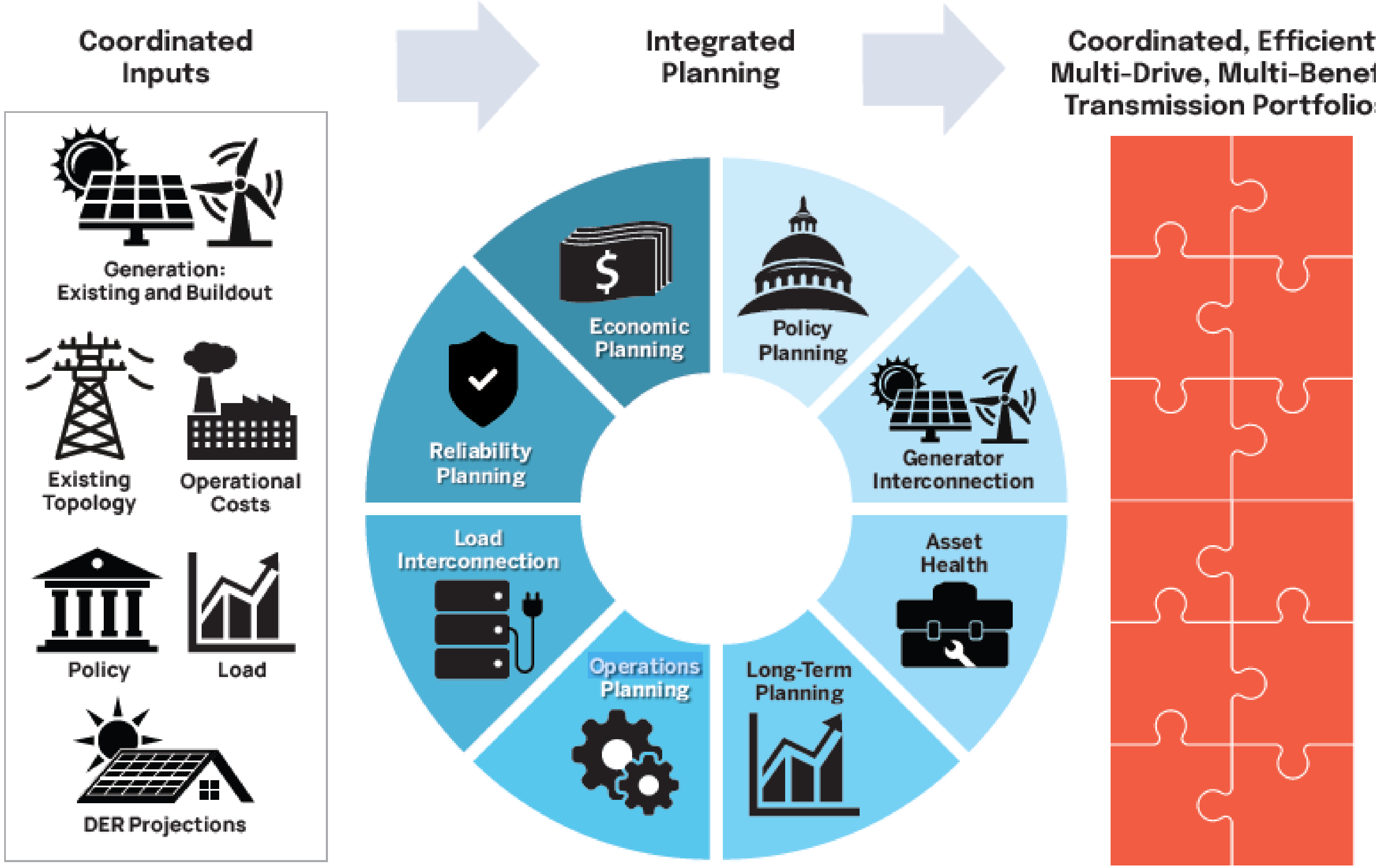
Integrated Multi-Need and Multi-Benefit Planning

From Siloed Inputs and Processes to Integrated, Multi-Benefit Transmission Planning



Coordinated Inputs

Generation: Existing and Buildout

Existing Topology

Operational Costs

Policy

Load

DER Projections

Integrated Planning

Economic Planning

Policy Planning

Generator Interconnection

Asset Health

Long-Term Planning

Operations Planning

Load Interconnection

Reliability Planning

Coordinated, Efficient Multi-Drive, Multi-Benef Transmission Portfolio

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Integration Priorities

Three Priority Integration Seems

1 Generator and Large Load Interconnection with Long-Term Planning

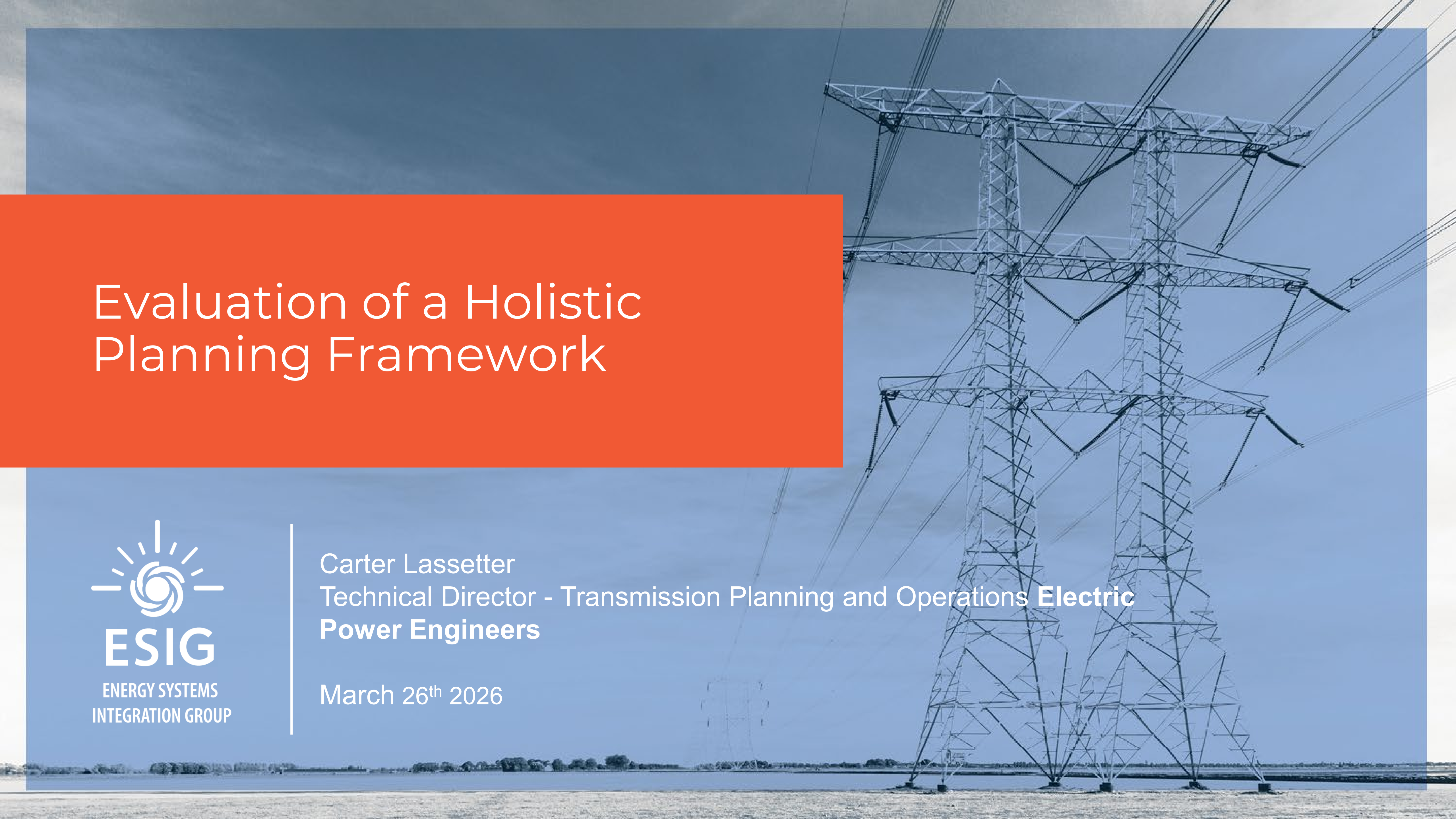
- Synchronize interconnection assumptions and study cycles with long-term regional planning. Bundle recurring bottlenecks into shared corridor upgrades.

2 Asset Replacement with Long-Term Planning

Tie asset-management programs to long-range planning so rebuilds meet future needs—not just like-for-like replacements. Make right-sizing the default.

3 Operations Planning with Planning

Design transmission for how the grid runs. Bring ramping, dynamics, and stability directly into long-range studies, not just as post-selection checks.



Evaluation of a Holistic Planning Framework

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Carter Lassetter
Technical Director - Transmission Planning and Operations **Electric Power Engineers**

March 26th 2026

Study Context

Problem Statement:

As grid complexity increases, the separation of generation interconnection studies and adjacent transmission planning creates growing risks of misaligned system needs, potential inefficient solutions, and challenges facilitating needed generation.

Example Industry Solution:

SPP has introduced the Consolidated Planning Process (CPP) which intends to merge the Definitive Interconnection System Impact Study (DISIS) alongside the Integrated Transmission Planning (ITP) process to facilitate an improved look at system needs by studying load and generation needs jointly.

Study Scope Overview

- Demonstrate how consolidating planning processes and aligning assumptions helps balance expected generation capacity with system needs to identify transmission requirements.
- Leverage available ITP models, create adjusted load profiles, and align an “appropriate” resource plan with serving said load.
- Compare against existing DISIS mechanisms and draw conclusions of consolidation effort.

Key Considerations

1. Combining planning processes to enable the joint study of load and generation allows for an opportunity to better optimize portfolio development.

2. With the development of the GRID-C mechanism (cost sharing between generation and load), generation will have a higher likelihood to interconnect in energy starved regions.

Background

Integrated Transmission Planning (ITP)

- SPP’s process to evaluate system needs based on a future look regarding expected generation and load growth.
- Performed on a yearly cadence, with the intention of developing an appropriate portfolio to maintain system reliability and rates.
- Upgrades are funded by loads.

Background

Definitive Interconnection System Impact Study (DISIS)

- Cluster based study process for generation that is performed in a three-phase process.
- Clusters are studied in a queue.
- Generation is studied by modifying latest developed ITP model series.
- Upgrades funded by interconnecting DISIS projects.

Sample DISIS Study Results

DISIS 2023 – Group 01

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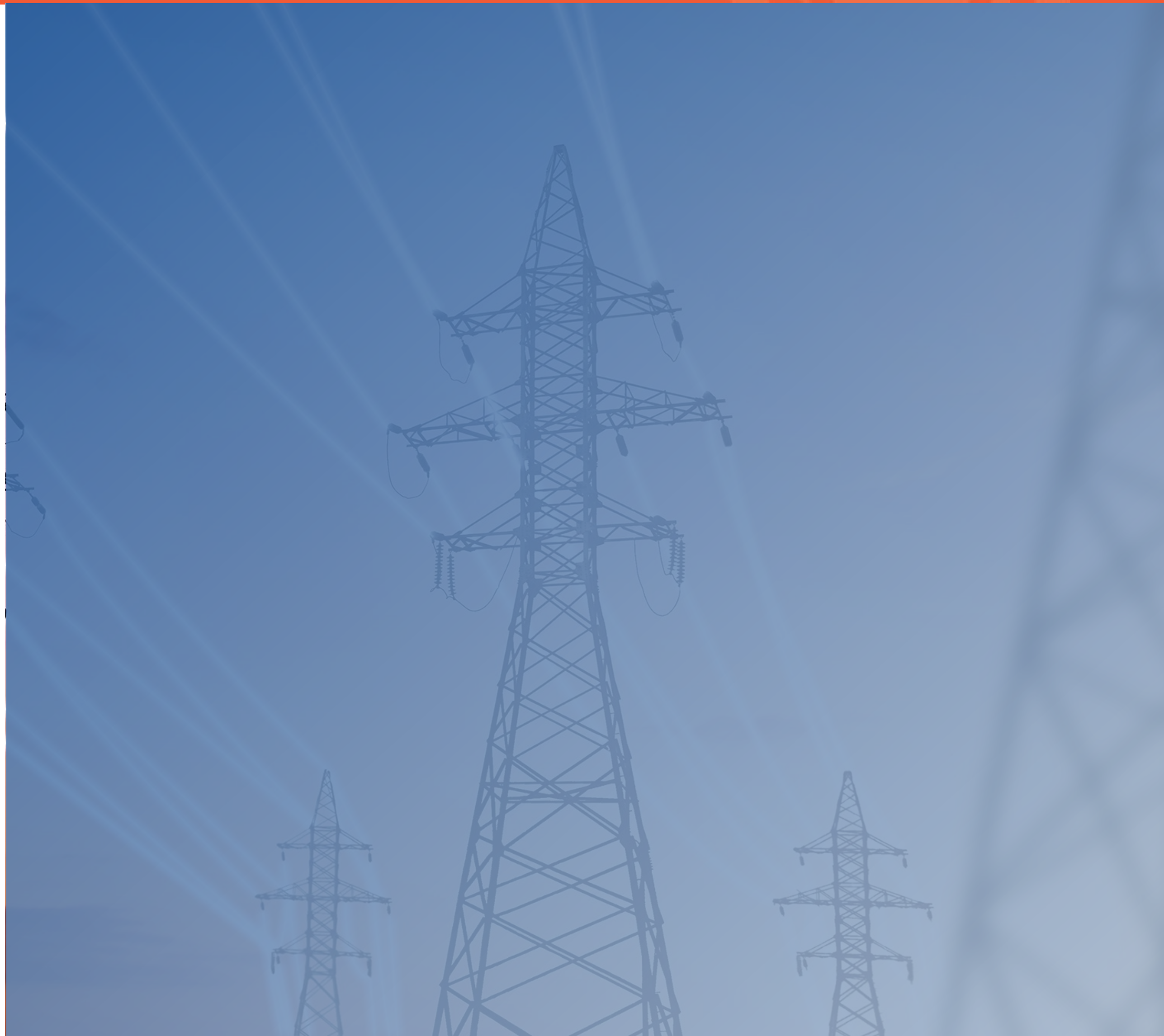
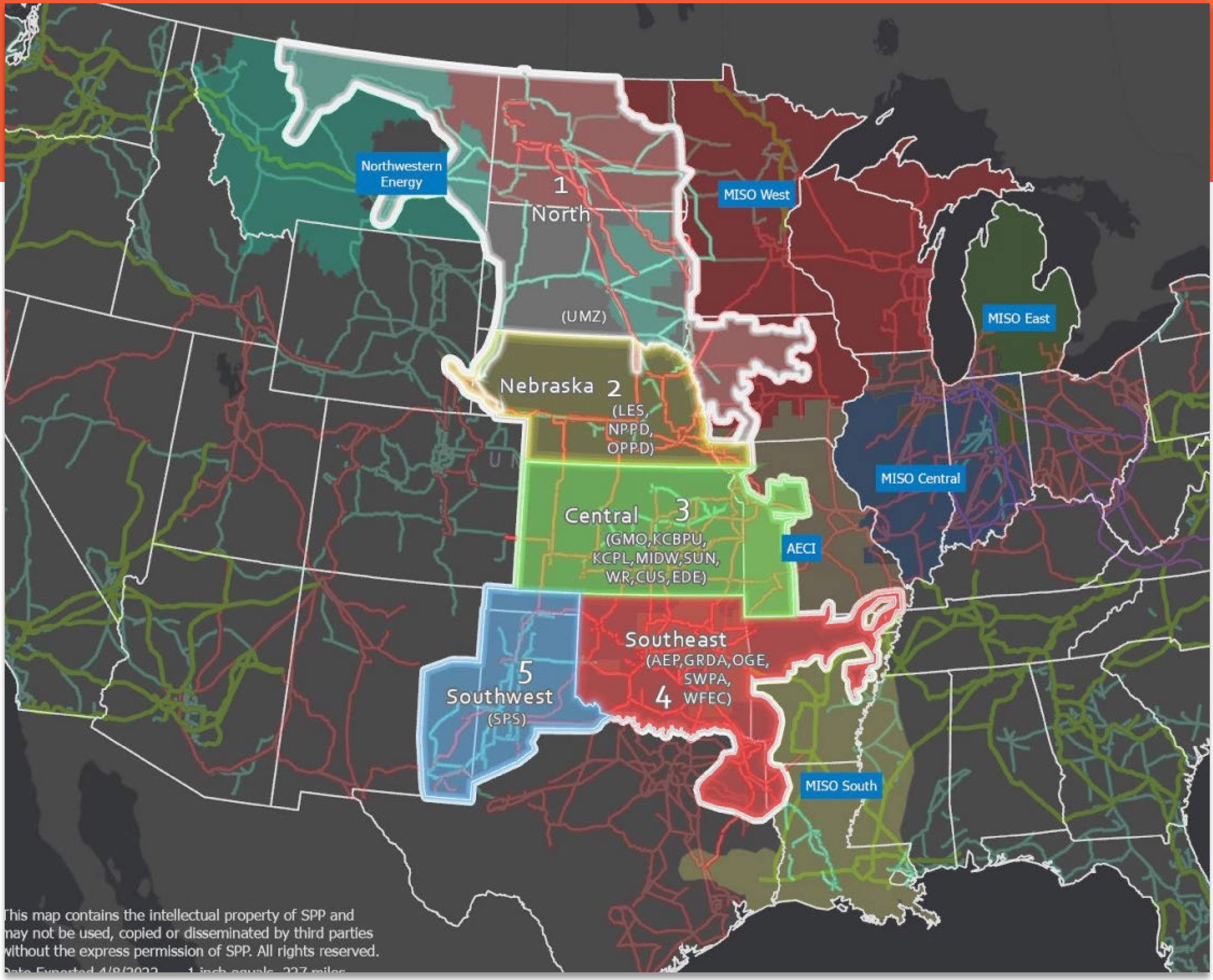
DISIS 2023 Group 01 - Projects

- **Starting Cluster Size:**
  24 Projects, ~5000 MW
- **Phase 2 Cluster Size:**
  5 Projects, 1225 MW
- **End Cluster Size:**
  0 Projects, 0 MW





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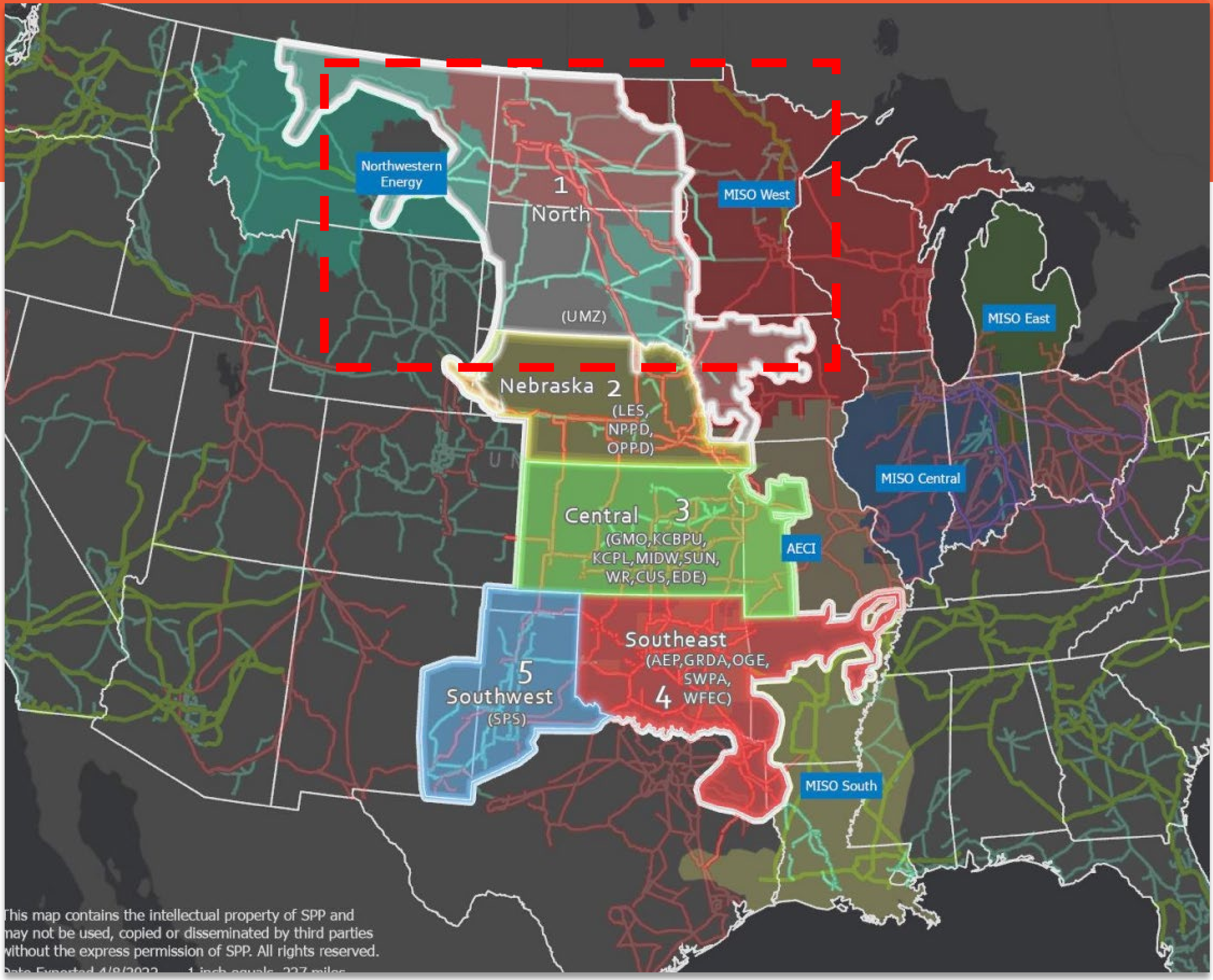

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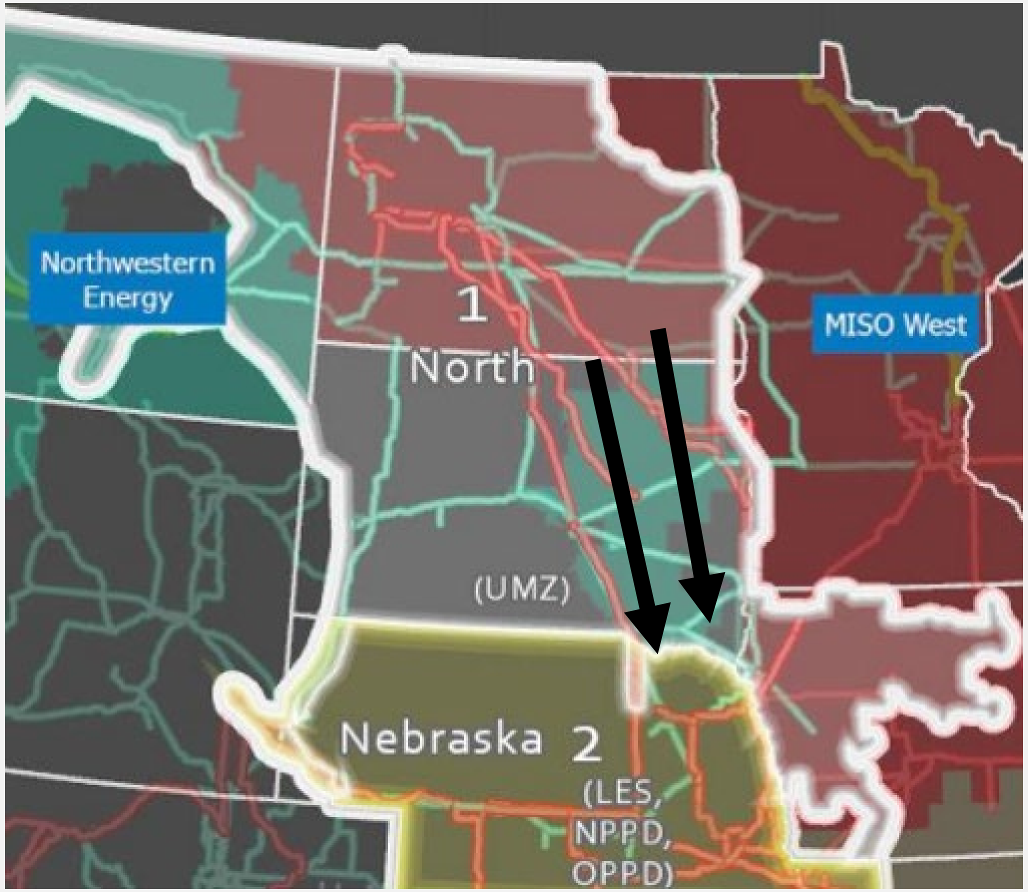
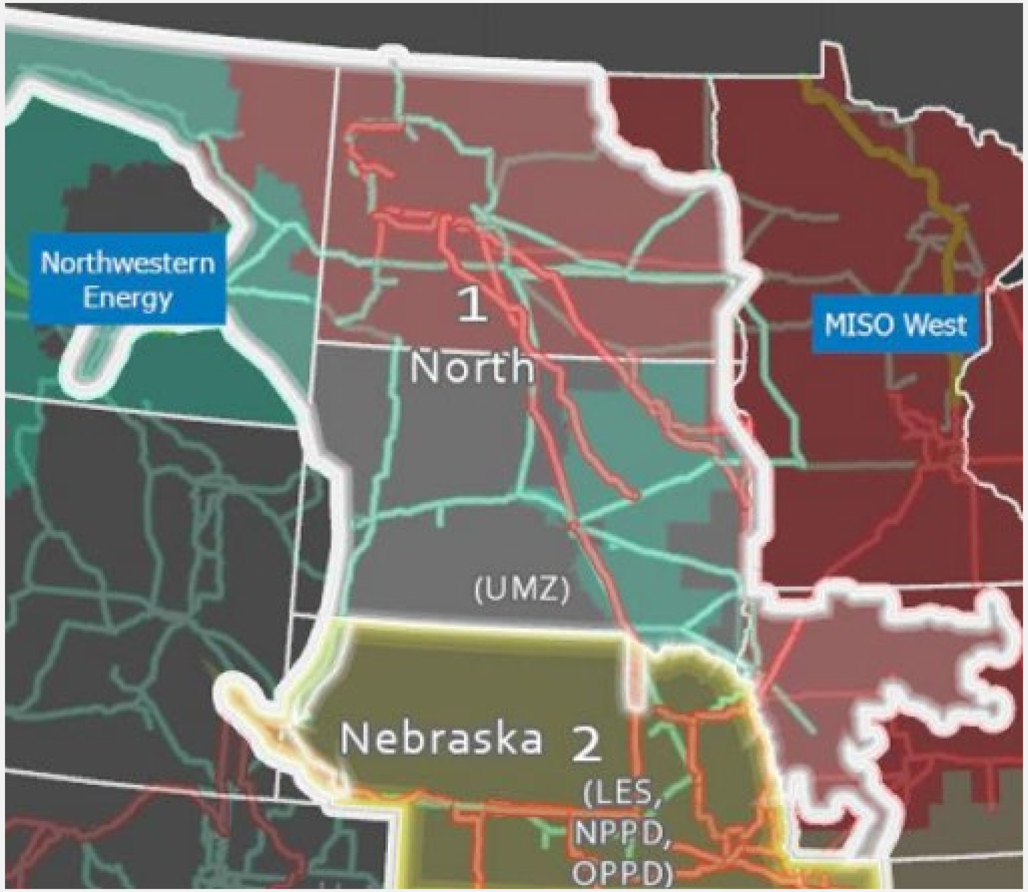
Date Exported 4/8/2022 1 inch equals 227 miles

North to South Flow



- Phase 1 DISIS 2023 G01 Projects influence large increase in transfers across long transmission paths.
- Significant rebuilds / new lines required across interface totaling > $400 Million.

Summary



- DISIS 2023 customers were tagged to significant upgrade costs, resulting in a full withdrawal of the cluster.
- Continual load growth and continual generation withdrawal could potentially lead to a situation where lack of generation exists in the North.
- Study process may sometimes result in large bottlenecks that cannot be resolved through the DISIS process and must eventually be fixed through ITP: “build and they will come”

Demonstrating Combined Planning Benefits

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Study Assumptions

1. This study focuses on loosely aligning with SPP’s current processes within the ITP and DISIS processes and the future CPP construct.
2. DISIS Fuel Based Dispatch (FBD) level is leveraged.
3. Dispatching methodology is maintained for DISIS projects.
4. Starting cases are altered with appropriate load forecast assumptions.
5. System violations are focused on large needs (such as 345 kV system issues or voltage collapse) resulting in large upgrade cost.

Study Models

Scenario	Sum Load (GW)	Sum Pgen (GW)	Sum Pmax (GW)	Winter Load (GW)	Winter Pgen (GW)	Winter Pmax (GW)	Light Load (GW)	Light Load Pgen (GW)	Light Load Pmax (GW)
Scenario 1	8.10	9.14	12.18	8.93	8.74	12.19	6.70	7.33	12.18
Scenario 2	8.10	13.34	17.60	8.93	12.72	17.62	6.70	9.10	17.60
Scenario 3	11.34	9.14	12.18	12.20	8.74	12.19	9.16	7.33	12.18
Scenario 4	11.34	13.34	17.60	12.20	12.72	17.62	9.16	9.10	17.60

- **Scenario 1:** Cases represent an ITP look (with headroom in G01 semi tapped out)
- **Scenario 2:** Cases represent DISIS look using Scenario 1 as starting point
- **Scenario 2 Sensitivity:** Scenario 2 CQ request placement modified in accordance to load requirements.
- **Scenario 3:** Cases represent an ITP look (with headroom tapped out)
- **Scenario 4:** Cases represent a merging of Scenario 3 with study generation from Scenario 2
- **Scenario 4 Sensitivity:** Scenario 4 CQ request placement modified in accordance to load requirements.

Scenario 1

Moderate Load Growth Model

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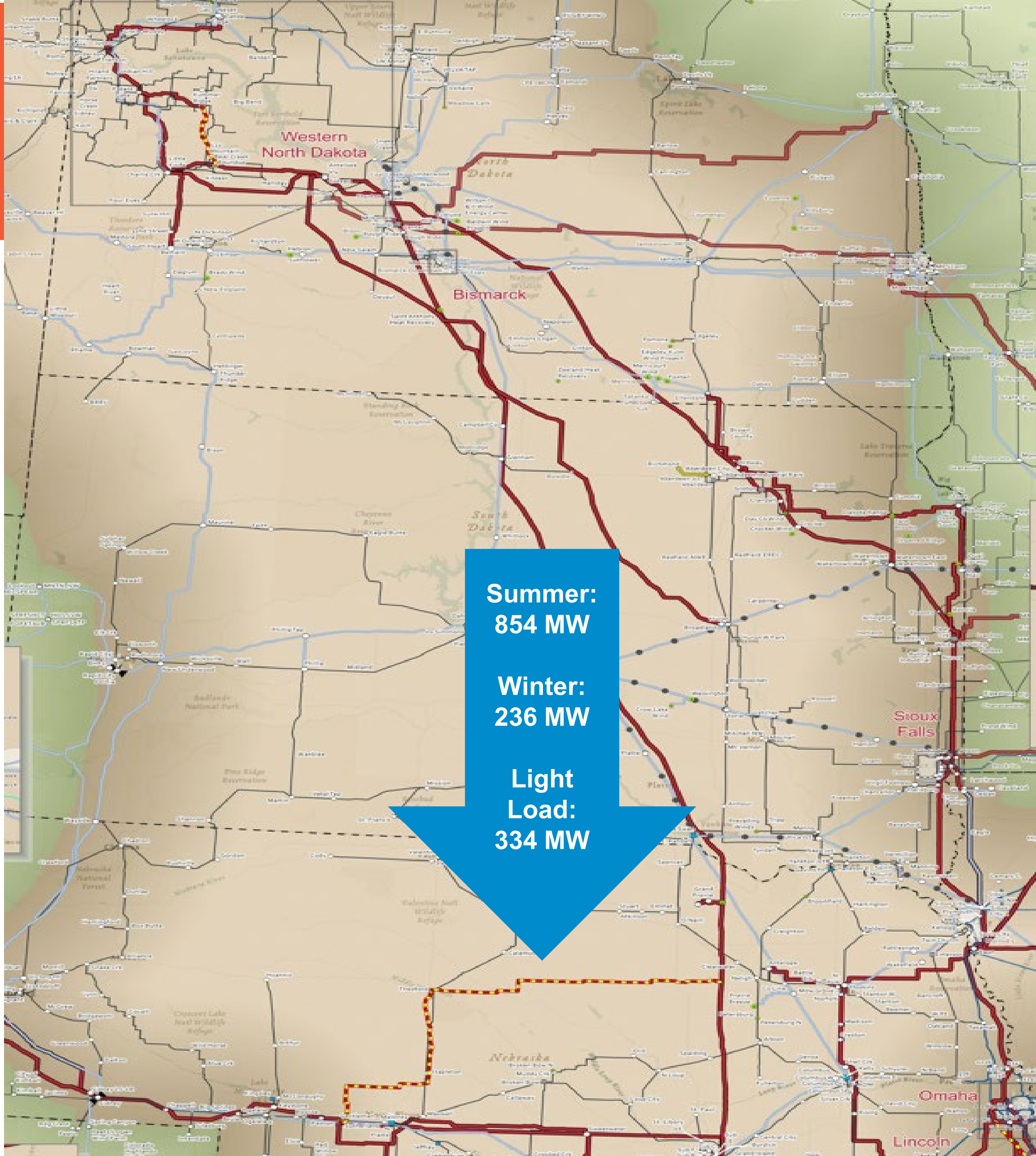
Scenario 1

- 25ITP Summer Peak, Winter Peak and Light Load Scenarios have load scaled in Group 01 to a moderate level such that most of local generation is dispatched.
- Available generation within Group 01 is utilized to serve the internal load of Group 01.
- This Scenario is used to demonstrate the state of Group 01 with adequate resource to meet the load.
- In this scenario Group 01 would act as an exporter in all scenarios.



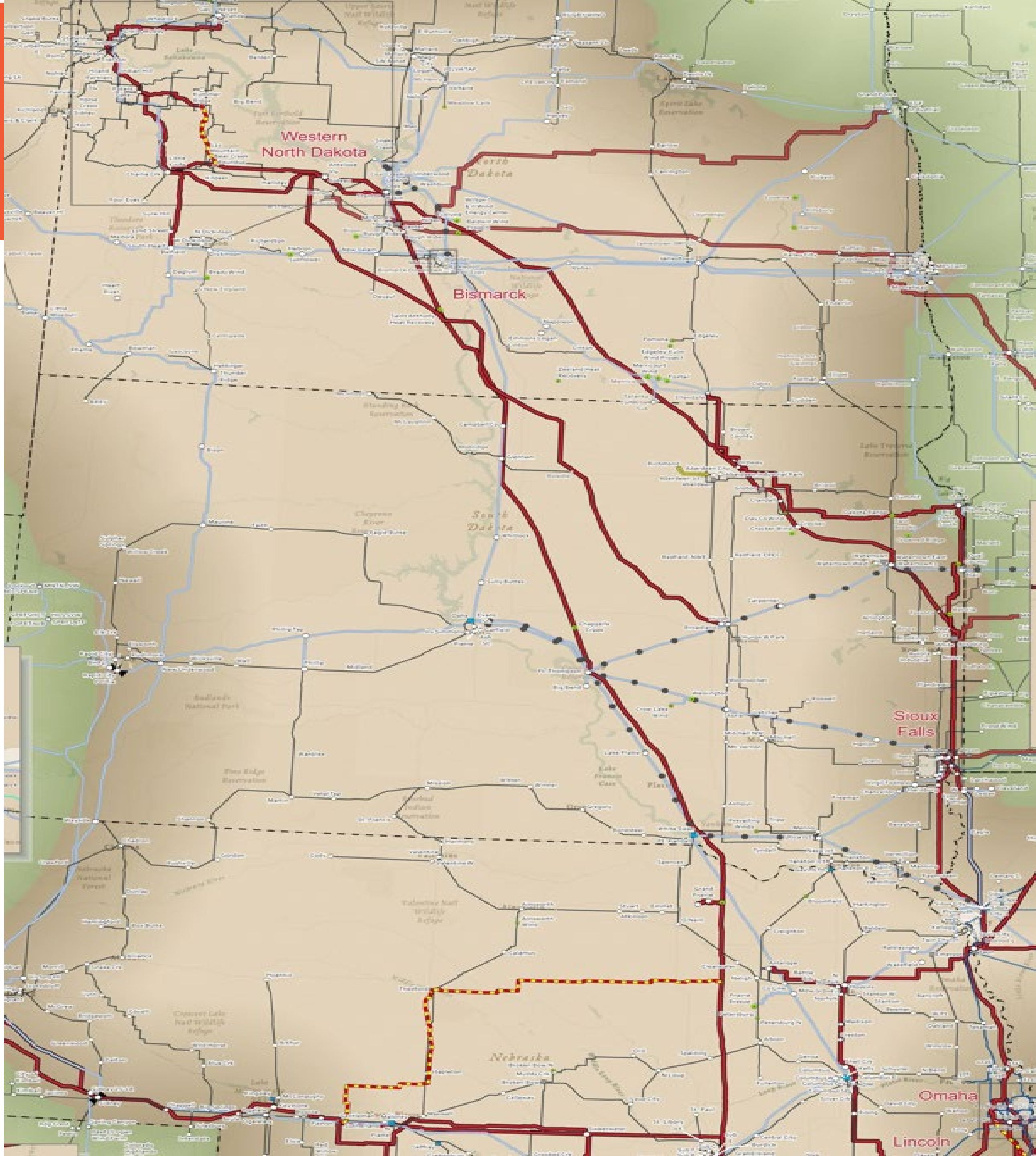
Summer: 854 MW

Winter: 236 MW

Light Load: 334 MW

Scenario 1

- Available generation within Group 01 is utilized to serve the internal load of Group 01.
- While local issues persist, no major issues are observed in the regional facilities.
- The results of contingency analysis demonstrate adequate infrastructure to support the export levels observed that remain similar to their ITP levels even after accounting for load growth.



Scenario 2

GI Impact on Moderate Load Growth

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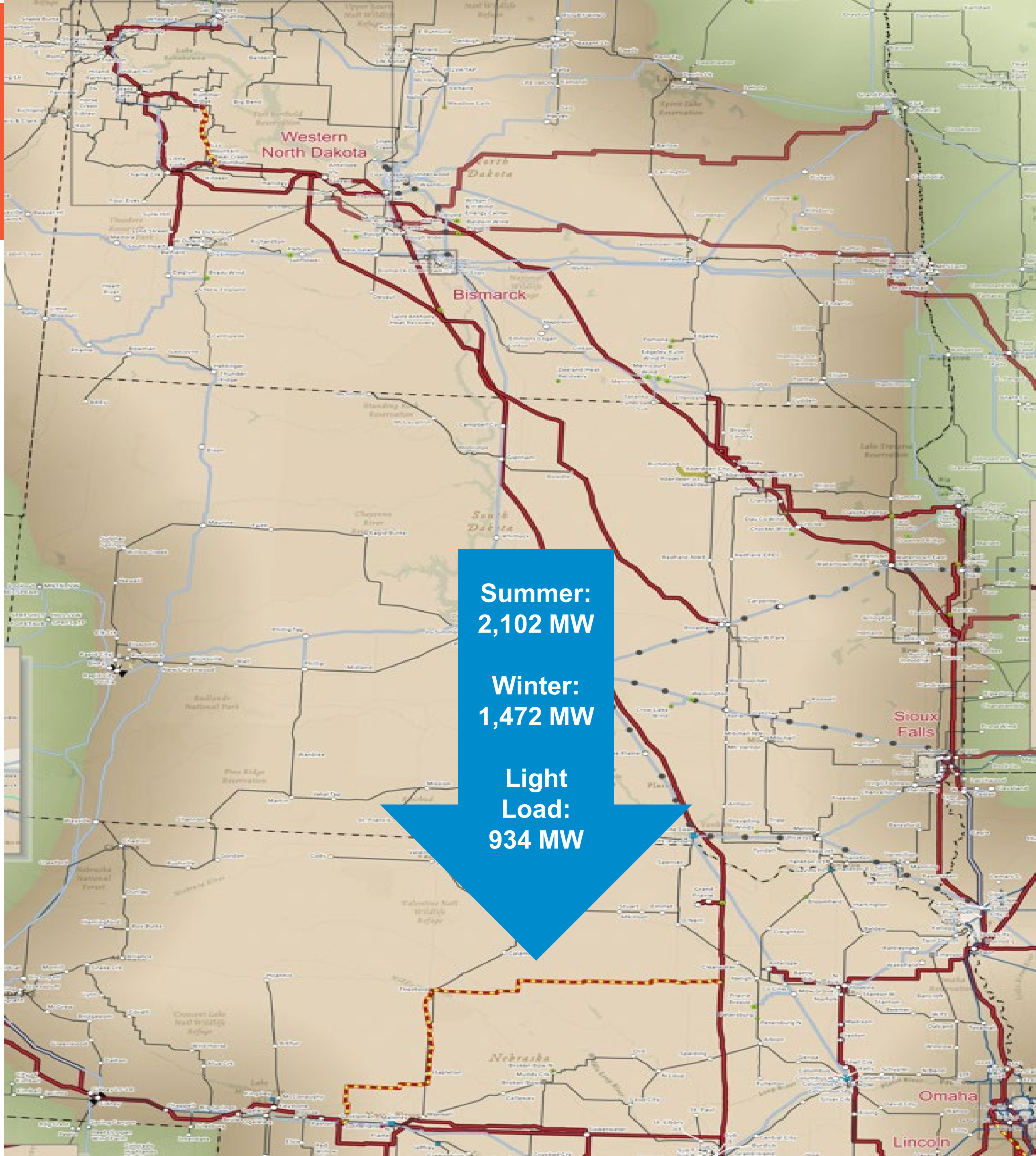
Scenario 2

- Scenario 2 keeps the load level equal to the increased load in Scenario 1.
- DISIS-2023-001 cluster requests within Group 01 are added and dispatched considering FBD requirements.
- No other requests from previous clusters are added to demonstrate the impact of a small addition within Group 01.
- The requests dispatched at 100% are sunk against the entirety of the SPP footprint based on the Load Ratio Share (LRS) of each transmission area.
- Group 01 exports are significantly increased.



Summer:
2,102 MW

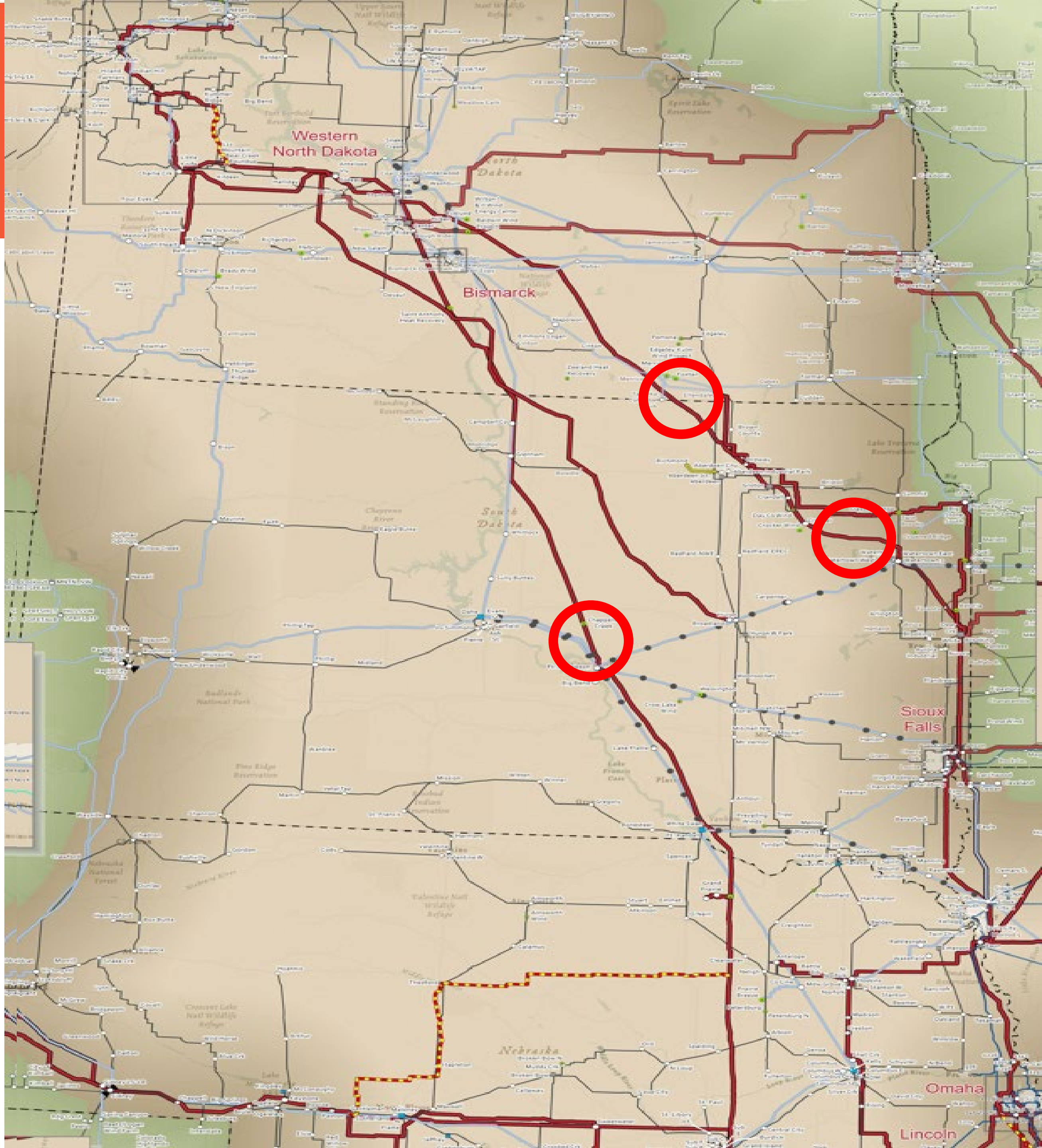
Winter:
1,472 MW

Light Load:
934 MW

Scenario 2

Contingency analysis shows some major overloads across the 345 kV network at the Groups 01 and 02 regional facilities consistent with DISIS observations.

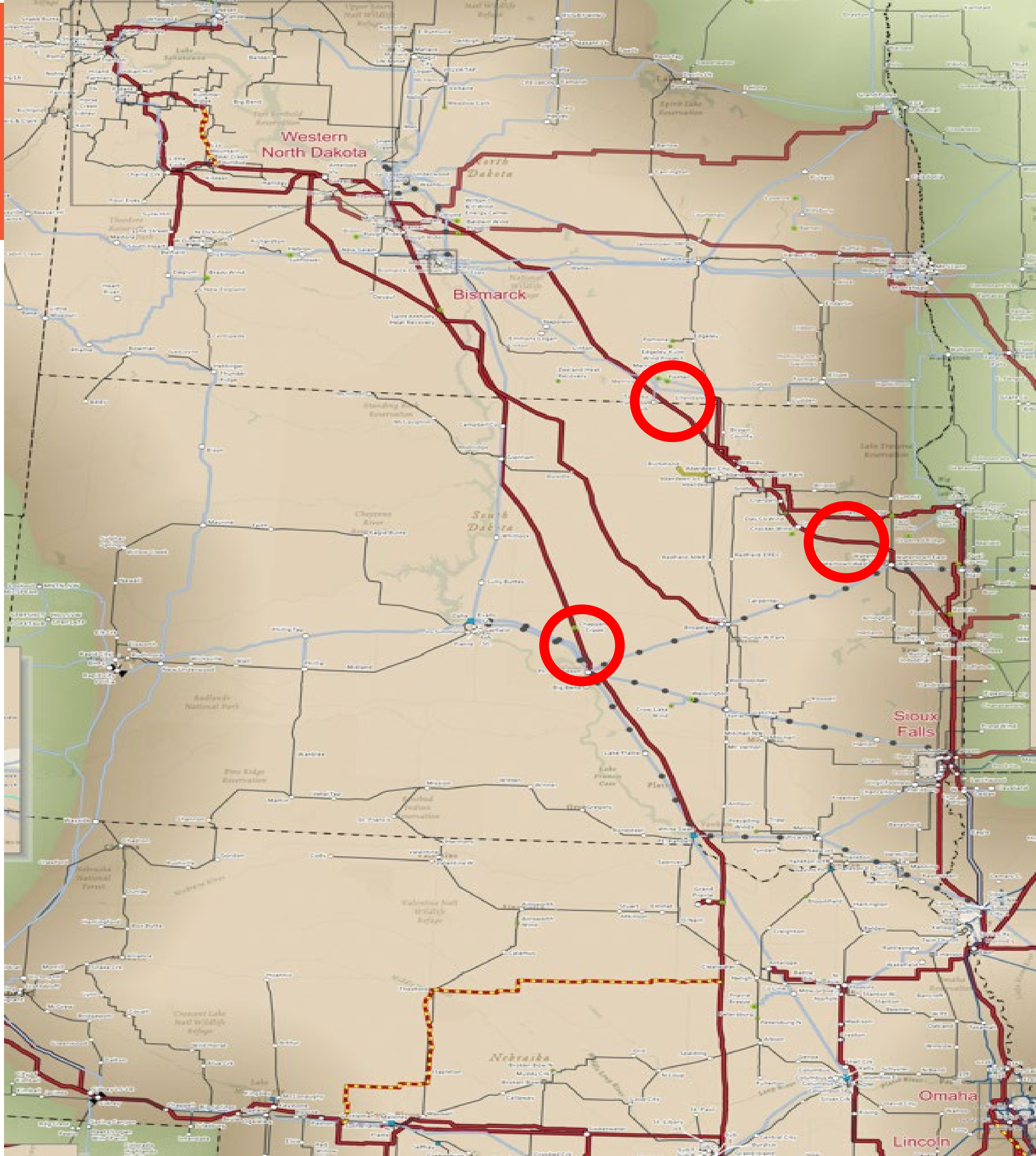
Monitored Facility	Summer Max Loading (%)	Winter Max Loading (%)	Light Load Max Loading(%)
640510 HOLT.CO3 345 652832 GRPRAR1-LNX3 345 1	141.15	89.62	92.78
652529 WATERTN3 345 659165 CROCKER_-BE3 345 1	143.53	102.63	92.08
652806 FTTHOM1-LNX3 345 659130 CHAPELLE-BE3 345 1	177.16 (P0: 143%)	113.16	116.18



Scenario 2 Sensitivity

- DISIS-2023- 001 Requests are placed strategically with 1.3 GW moved to Western North Dakota to meet load requirements.
- Contingency analysis still shows some major overloads across the 345 kV network at the Groups 01 and 02 regional facilities consistent with DISIS observations.

Monitored Facility	Summer Max Loading (%)	Winter Max Loading (%)	Light Load Max Loading(%)
640510 HOLT.CO3 345 652832 GRPRAR1-LNX3 345 1	140.63	84.68	47.26
652529 WATERTN3 345 659165 CROCKER_-BE3 345 1	141.15	97.19	63.67
652806 FTTHOM1-LNX3 345 659130 CHAPELLE-BE3 345 1	176.41	84.46	80.98



Scenario 3

High Load Growth

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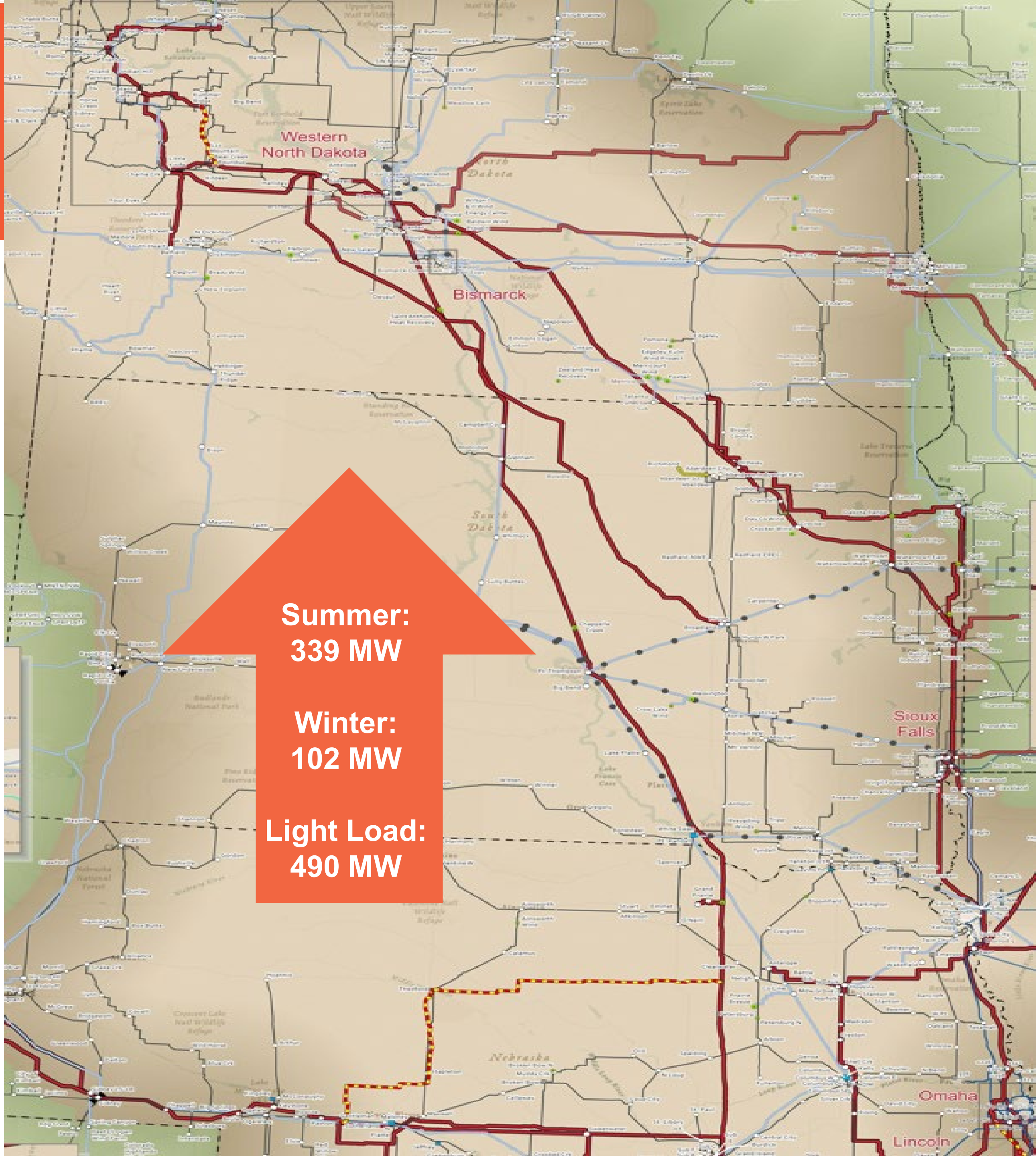
Scenario 3

- Scenario 3 increases the load in Group 01 from Scenario 1 without considering the queue requests.
- The load growth considered is meant to represent a future case with high load growth loosely mimicking the observations in 26ITP load profile.
- As available resources within Group 01 are semi-exhausted, external generation are used to serve the added load in Group 01.
- Group 01 becomes an importer.



Summer:
339 MW

Winter:
102 MW

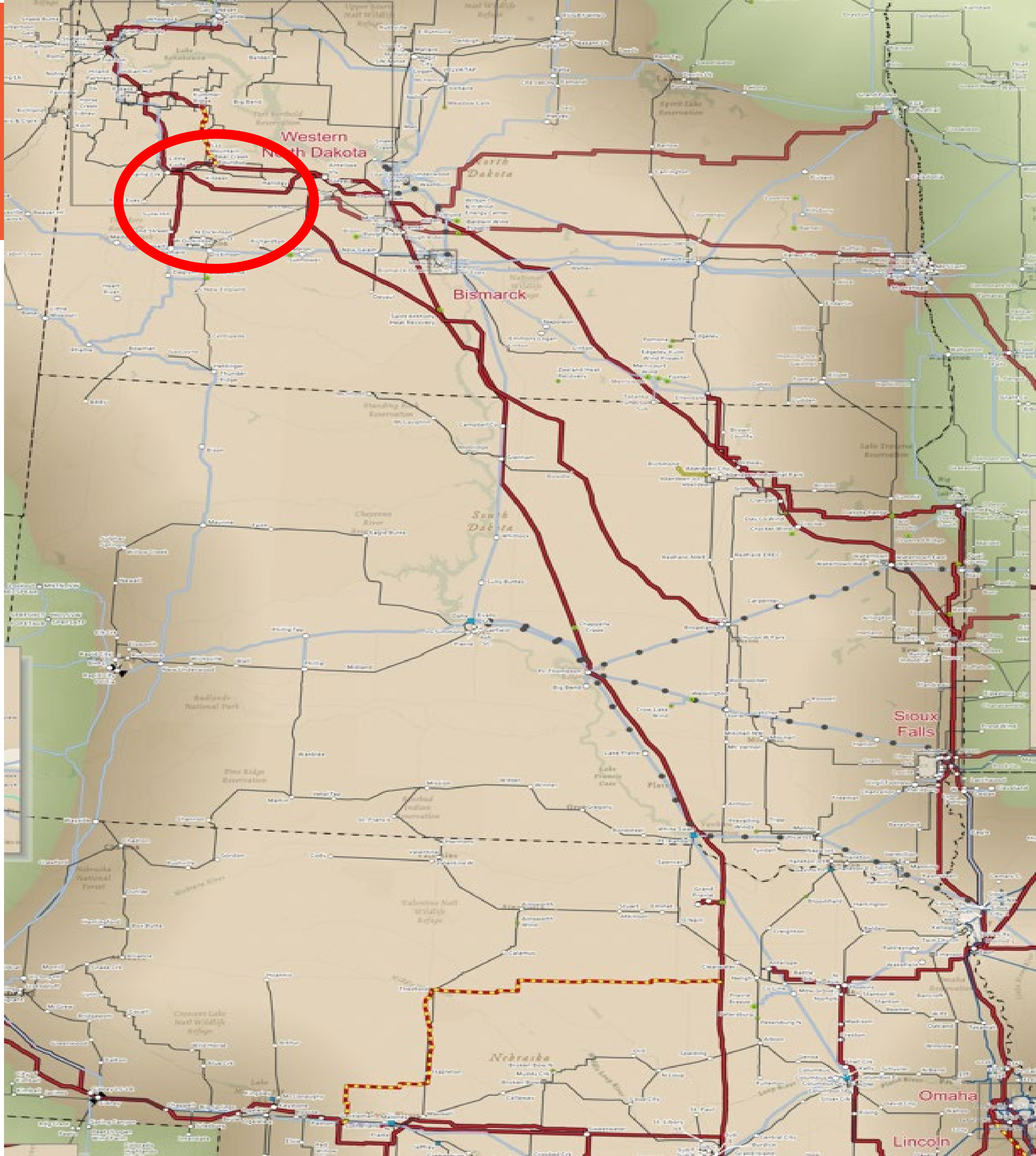
Light Load:
490 MW

Scenario 3

- Contingency analysis shows overloads across the 345 kV network within Group 01 in the far north.
- In the Winter Peak scenario this causes voltage breakdown due to large transfer from south to north.

Monitored Facility	Summer Max Loading (%)	Winter Max Loading (%)	Light Load Max Loading(%)
659101 ANTELOPE-BE3 345 659183 CHARL_CK-BE3 345 1	128.31	132.14*	100.74
659101 ANTELOPE-BE3 345 659384 ROUNDUP_-BE3 345 1	124.15	125.82*	102.22

*: DC Loading reported as non-convergence occurs.



Scenario 4

GI Impact when Coupled with High Load Growth

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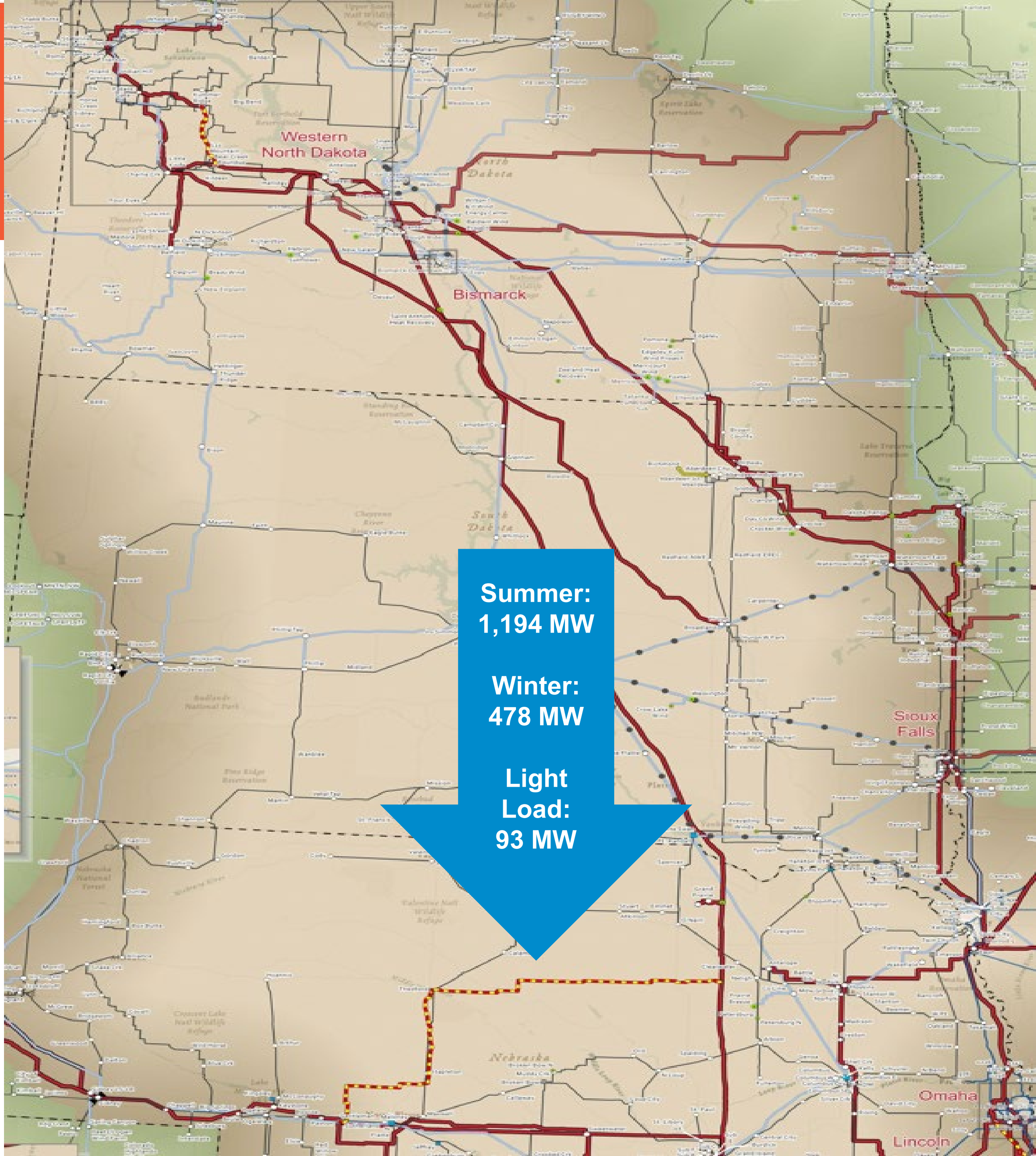
Scenario 4

- Scenario 4 leverages the same load levels from Scenario 3.
- Scenario 4 considers the same DISIS queue requests as in Scenario 2 to be added and dispatched accordingly.
- Similar to Scenario 2, the added dispatch of the cluster requests is sunk using the DISIS methodology and based on LRS to the entirety of SPP footprint.
- Group 01 extra capacity now serves internal load growth and changes the pattern to exporting from Group 01.
- The availability of local generation also maintains a better voltage profile throughout Group 01 avoiding low voltages in the northern region seen in the Winter Peak of Scenario 3.

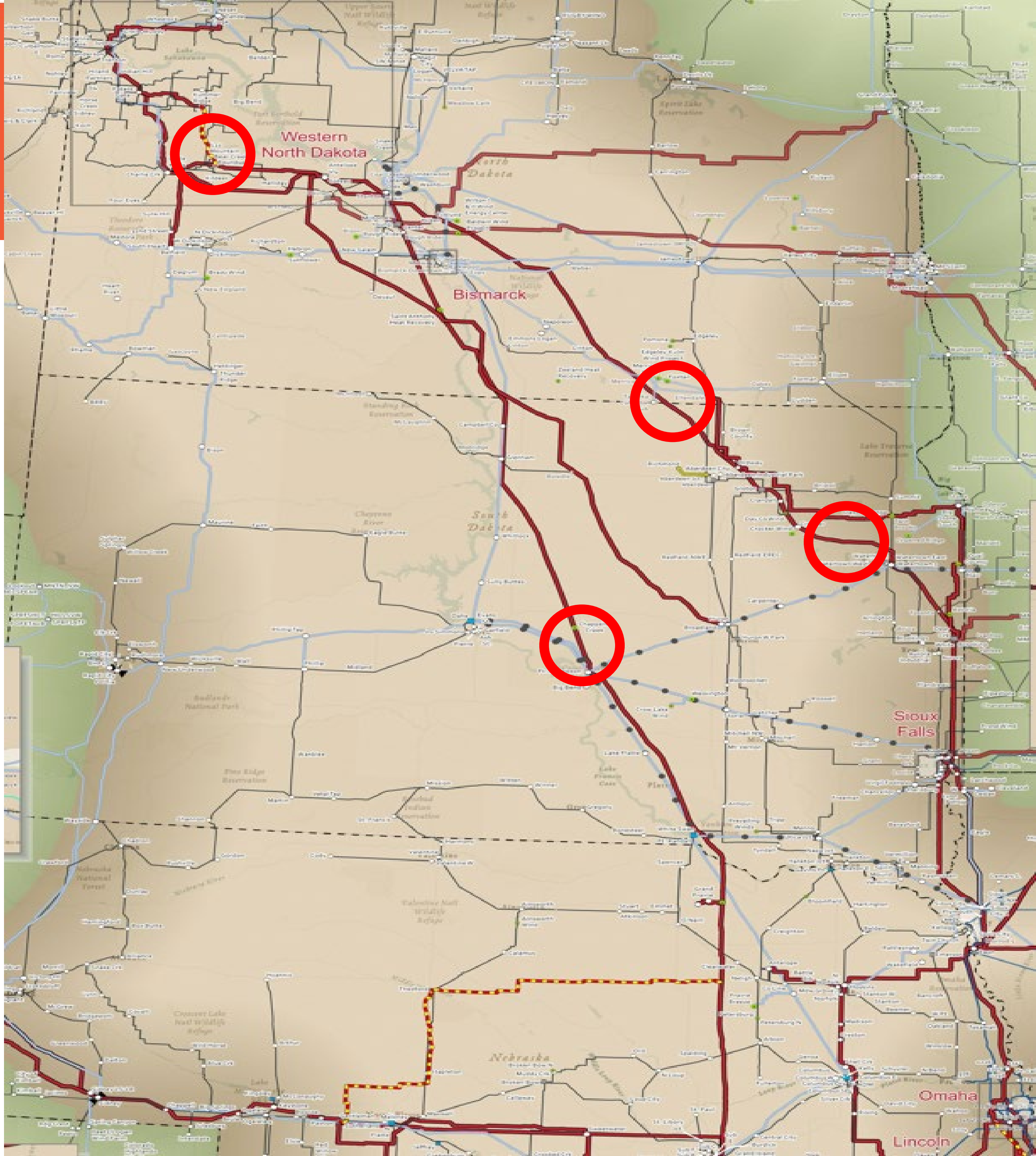


Scenario 4

Contingency analysis shows overloads, while reduced, still exist specially in the Western North Dakota region.

Monitored Facility	Summer Max Loading (%)	Winter Max Loading (%)	Light Load Max Loading(%)
640510 HOLT.CO3 345 652832 GRPRAR1-LNX3 345 1	99.56	57.61	63.93
652529 WATERTN3 345 659165 CROCKER_-BE3 345 1	100.4	86.45	77.43
652806 FTTHOM1-LNX3 345 659130 CHAPELLE-BE3 345 1	178.10*	108.66*	111.75*
659101 ANTELOPE-BE3 345 659183 CHARL_CK-BE3 345 1	102.10	125.41	106.35
659101 ANTELOPE-BE3 345 659384 ROUNDUP_-BE3 345 1	107.44	119.05	107.54

*: No P0 violations/violation occurs for smaller subset of contingencies due to location of DIS23 requests

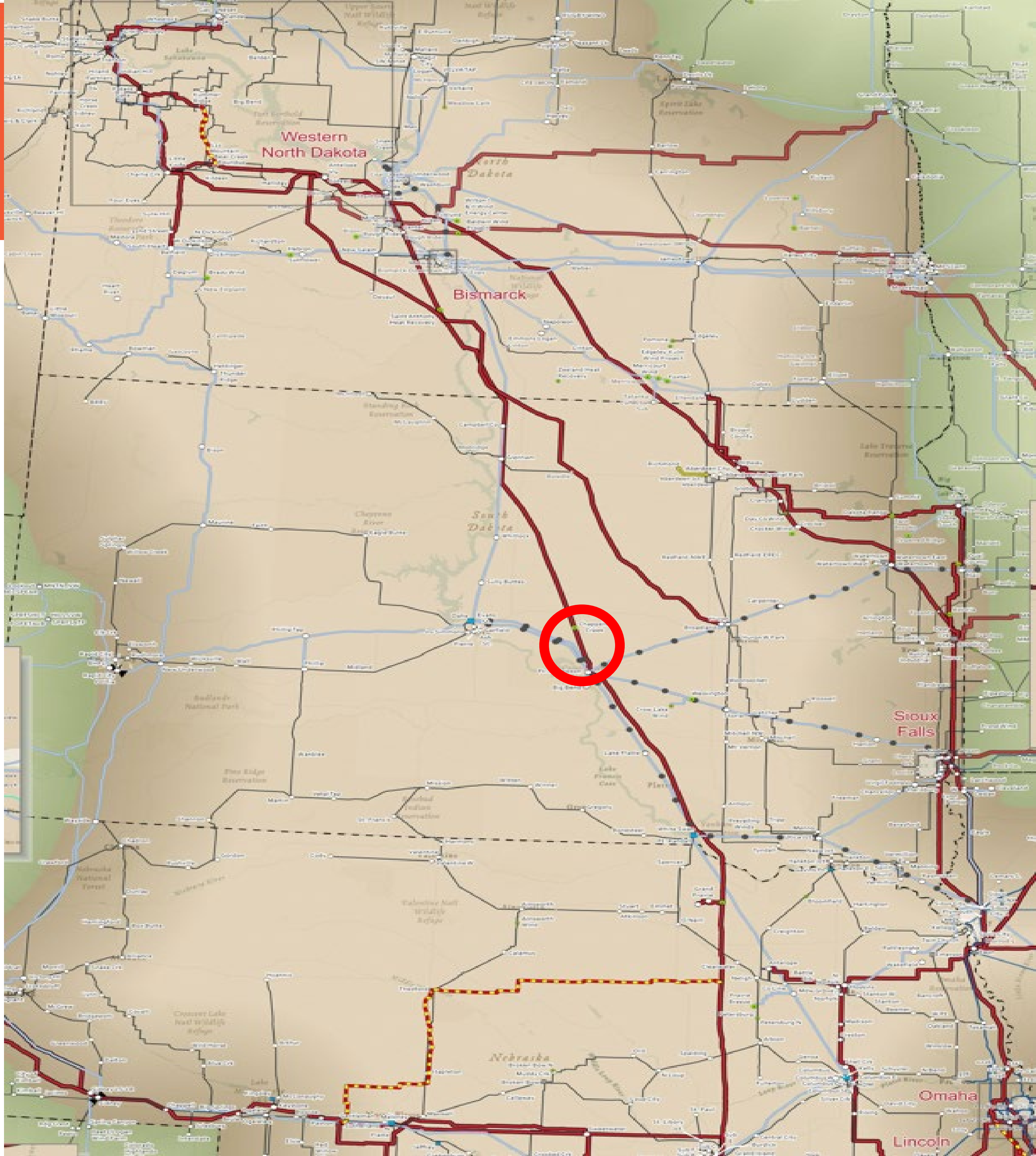


Scenario 4 Sensitivity

- Similar to Scenario 2 Sensitivity, CQ requests are placed strategically.
- Contingency analysis shows overloads reducing significantly compared to Scenario 2. Furthermore, issues due to import in Scenario 3 are resolved.

Monitored Facility	Summer Max Loading (%)	Winter Max Loading (%)	Light Load Max Loading(%)
640510 HOLT.CO3 345 652832 GRPRAR1-LNX3 345 1	89.57	47.26	62.07
652529 WATERTN3 345 659165 CROCKER_-BE3 345 1	97.64	63.67	63.64
652806 FTTHOM1-LNX3 345 659130 CHAPELLE-BE3 345 1	129.84*	80.98	95.99
659101 ANTELOPE-BE3 345 659183 CHARL_CK-BE3 345 1	<90	<90	<90
659101 ANTELOPE-BE3 345 659384 ROUNDUP_-BE3 345 1	71.05	96.09	91.05

*: No P0 violations/violation occurs for smaller subset of contingencies due to location of DIS23 requests



Results - Summarized

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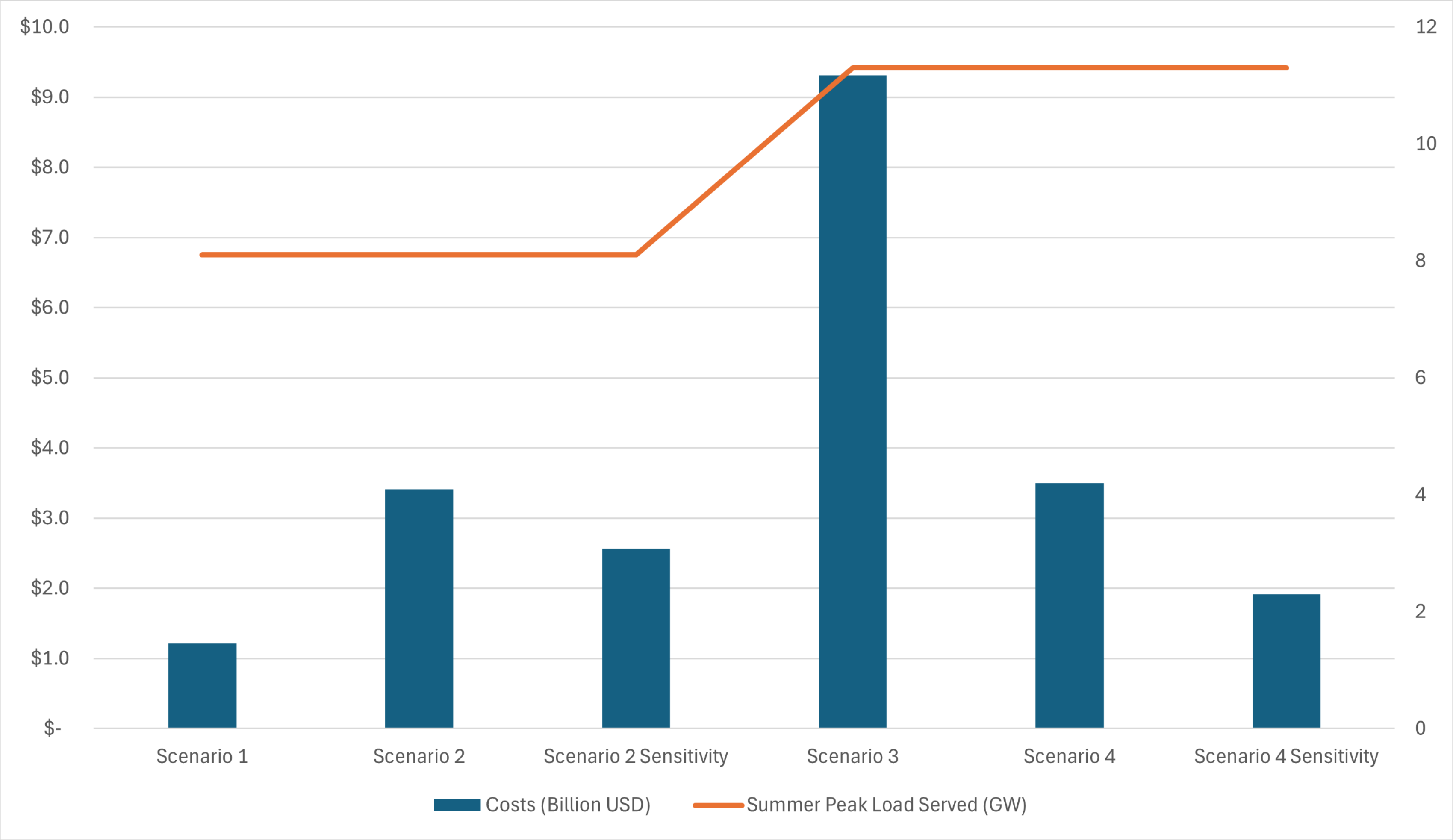
Study Results Overview

Scenario	Description of Issues	Major Overloaded Lines in Summer	Major Overloaded Lines in Winter	Major Overloaded Lines in Light Load	Representative Conceptual Cost (Billion USD)
Scenario 1	• Local issues • No major issues on the 345 kV infrastructure	N/A	N/A	N/A	**$1.2**
Scenario 2	• Overload of major lines near the regional buses between Group 01 and Group 02	• Ft. Thompson to Chappelle Creek 345 kV (Max 140%) • Watertown to Crocker 345 kV (Max 141%) • Holt to Grand Prairie 345 kV (Max 176%)	• Ft. Thompson to Chappelle Creek 345 kV (Max 140%) • Watertown to Crocker 345 kV (Max 141%)	• Ft. Thompson to Chappelle Creek 345 kV (Max 140%)	**$3.4**
Scenario 2 Sensitivity	• Overload of major lines near the regional buses between Group 01 and Group 02	• Ft. Thompson to Chappelle Creek 345 kV (Max 140%) • Watertown to Crocker 345 kV (Max 141%) • Holt to Grand Prairie 345 kV (Max 176%)	N/A	N/A	**$2.5**
Scenario 3	• Overload of major lines in the Western North Dakota Area • Voltage profile/collapse issues in Western North Dakota Issues	• Antelope Valley to Charlie Creek 345 kV (Max 128%) • Antelope Valley to Roundup 345 kV (Max 124%)	• Antelope Valley to Charlie Creek 345 kV (Max 132%) • Antelope Valley to Roundup 345 kV (Max 125%)	• Antelope Valley to Charlie Creek 345 kV (Max 100%) • Antelope Valley to Roundup 345 kV (Max 102%)	**$9.3**
Scenario 4	• Resolution of most regional transfer issues with only issues remaining due to the location of requests. • Thermal issues in Western North Dakota persist.	• Ft. Thompson to Chappelle Creek 345 kV (Max 178%) • Antelope Valley to Charlie Creek 345 kV (Max 102%) • Antelope Valley to Roundup 345 kV (Max 107%)	• Ft. Thompson to Chappelle Creek 345 kV (Max 108%) • Antelope Valley to Charlie Creek 345 kV (Max 125%) • Antelope Valley to Roundup 345 kV (Max 119%)	• Ft. Thompson to Chappelle Creek 345 kV (Max 111%) • Antelope Valley to Charlie Creek 345 kV (Max 106%) • Antelope Valley to Roundup 345 kV (Max 107%)	**$3.5**
Scenario 4 Sensitivity	• Resolution of most regional transfer issues with only issues remaining due to the location of requests. • Voltage and thermal issues in Western North Dakota resolved.	• Ft. Thompson to Chappelle Creek 345 kV (Max 129%)	N/A	N/A	**$1.9**

- Scenario 1: Cases represent an ITP look (with headroom in G01 semi tapped out)
- Scenario 2: Cases represent DISIS look using Scenario 1 as starting point
- Scenario 2 Sensitivity: Scenario 2 CQ request placement modified in accordance to load requirements.
- Scenario 3: Cases represent an ITP look (with headroom tapped out)
- Scenario 4: Cases represent a merging of Scenario 3 with study generation from Scenario 2
- Scenario 4 Sensitivity: Scenario 4 CQ request placement modified in accordance to load requirements.

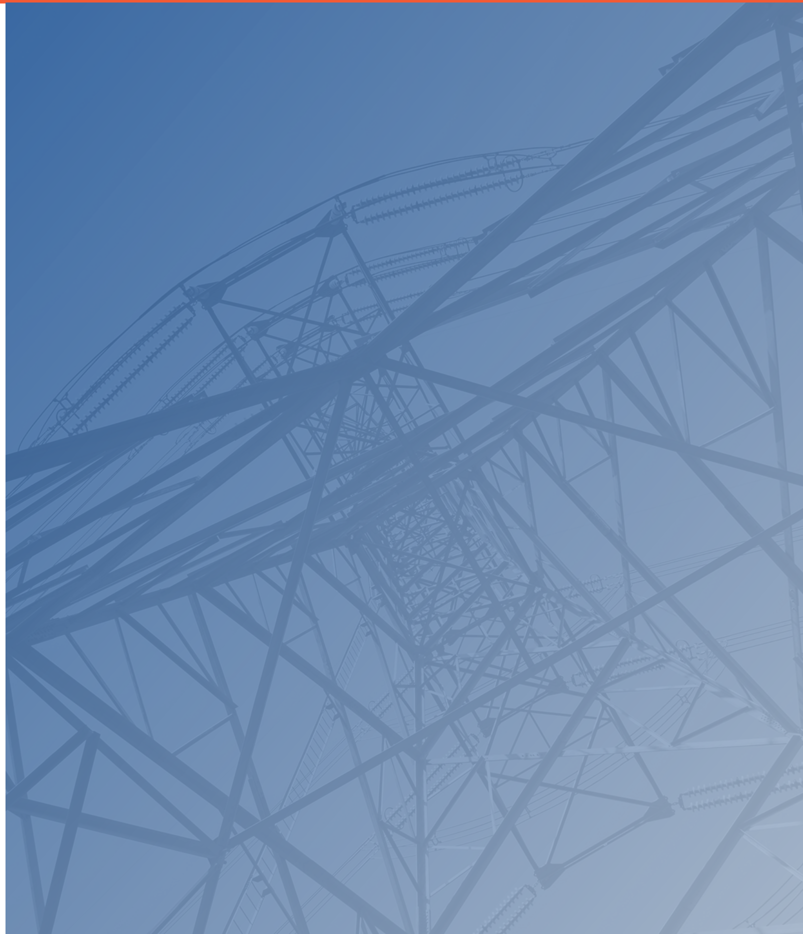
Study Results Overview



- Scenario 1: Cases represent an ITP look (with headroom in G01 semi tapped out)
- Scenario 2: Cases represent DISIS look using Scenario 1 as starting point
- Scenario 2 Sensitivity: Scenario 2 CQ request placement modified in accordance to load requirements.
- Scenario 3: Cases represent an ITP look (with headroom tapped out)
- Scenario 4: Cases represent a merging of Scenario 3 with study generation from Scenario 2
- Scenario 4 Sensitivity: Scenario 4 CQ request placement modified in accordance to load requirements.

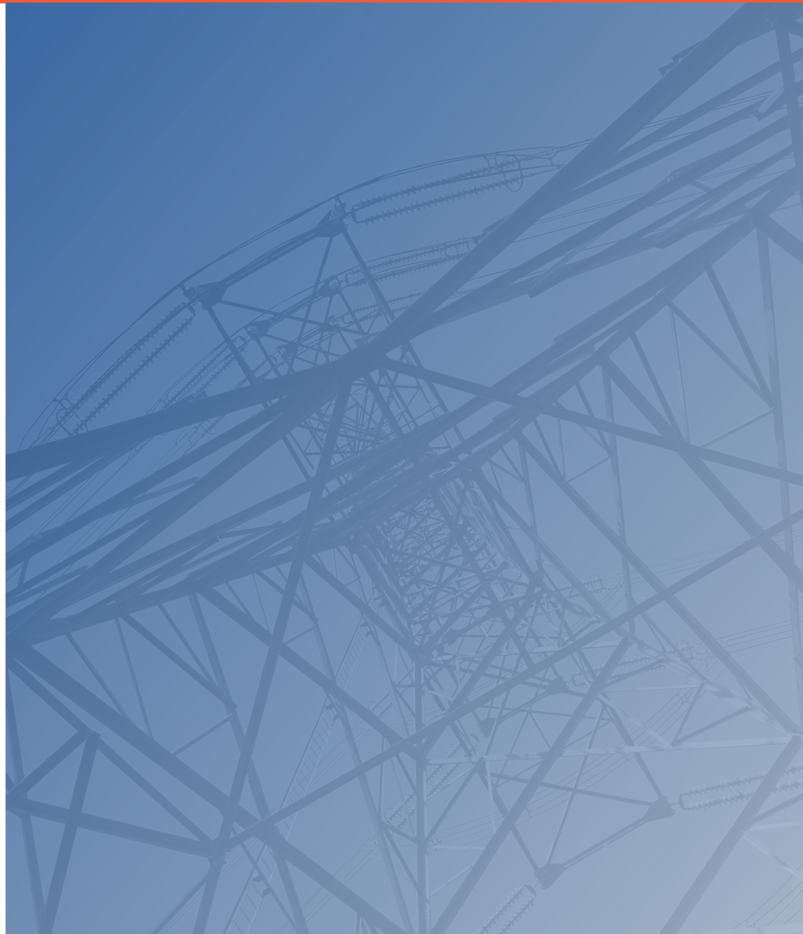
Results Take-Aways

- Like the DISIS 2023 cluster demonstrated, costs may be prohibitive when assigned to GI customers leading to high withdrawals.
- Portfolio costs identified in Scenario 3 are high without accompanying GI customer interconnections.
- Balancing load and generation growth provides improved costs as shown in Scenario 4.
- Further optimizing study generation sites (similar to SPP's Planned Interconnection Locations construct), as seen in Scenario 4 Sensitivity, allows even more opportunities for improved portfolios.



Summary

- Current study mechanisms can leverage out of date expectations of load forecasts which may impact true “needs.”
- Out of phase studying may result in generation needing to “catch up” to load growth which may result in missing out on needed generation interconnection.
- Consolidating generation and load studies together allows a better understanding of joint needs.



Key Considerations

1. Different study approaches can lead to different conclusions on how combined generation impacts the grid.

2. Studying load and generation together can reduce impacts, but results remain highly dependent on assumptions and the scale of load and generation growth.

3. SPP’s GRID-C framework enables cost sharing for major upgrades that were historically fully assigned to DISIS customers and then, in some instances, dropped due to withdrawals until ITP found the need.

4. SPP incorporates market-based levers (e.g., re-dispatch) to better align outcomes with system needs, potentially reducing export constraints and avoiding costly upgrades.

Q&A

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THANK YOU