Modeling the Effects of Flexible Interconnection on Solar Integration: A Case Study

Prepared for: FERC Innovations and Efficiencies in Generator Interconnection Staff-Led Workshop

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Tyler H. Norris

Ryan Watts, P.E.

Duke University

Acknowledgements and Disclaimer

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About the Authors

Tyler H. Norris is a J.B. Duke Fellow and PhD student at Duke University's Nicholas School of the Environment in the GRACE Lab. His current research focuses on grid interconnection and its relationship to electric power markets, with an emphasis on market and regulatory analysis and techno-economic modeling, building on professional roles in utility-scale power project development, electricity market analysis, and USDOE technology-to-market programs.

Ryan Watts is a transmission planning engineer and licensed professional electrical engineer in the state of Nevada. Watts previously managed Transmission Planning at NV Energy, a public utility serving 2.4 million electric customers across Nevada, where his responsibilities included overseeing and conducting FERC interconnection and transmission service studies, supporting NERC compliance, and ensuring compliance with FERC policy. He is currently the Director of Grid Integration Engineering at Cypress Creek Renewables.

Table of Contents

Executive Summary

Takeaway

Treating solar as a more flexible, curtailable resource in generator interconnection studies has the potential to avoid significant costs related to network upgrades and accelerate generator additions, while maintaining reliability.

Study Results

Power flow modeling produced the following results when solar generators were treated as energy-only resources instead of capacity resources, in the context of a recent interconnection cluster study:

- Avoided 75% of identified overloads, representing 27 separate transmission elements;
- Saved 72% of network upgrade costs related to thermal power flow overloads; and
- Reduced capacity-weighted costs by $112 per kW of studied solar generation capacity.

Additional Opportunities

The analysis suggests that improving energy-only interconnection service among some US transmission providers could provide material benefits. Additional cost savings may also be possible with the following steps:

- Transmission elements are rated at the maximum weather adjusted capability of the equipment, and at emergency ratings where applicable;
- Modern grid enhancing technologies are adopted and reflected in interconnection studies to enable higher real-time current carrying capability limits; and
- Energy-only interconnection studies adopt treatment similar to system operators like NYISO, CAISO, or ERCOT.

Background: Research Motivation

Potential Solutions

In April 2024, the U.S. Department of Energy released the agency's first Transmission Interconnection Roadmap. The roadmap contained several solutions related to flexible interconnection service, including:

- <u>Solution 2.5</u>: Create new and better use existing fast-track options for interconnection, such as surplus interconnection service, generation replacement service, and energy-only interconnection service.
- <u>Solution 3.2</u>: Ensure that generators have the option to elect energy-only interconnection and be re-dispatched rather than paying for network upgrades.
- <u>Solution 3.3</u>: Explore and evaluate potential options for delinking the interconnection process and network upgrade investments to increase up-front interconnection cost certainty.

Research Gap

There is limited existing research on the potential benefits and reliability implications of flexible interconnection options. To address this gap, we conducted a power flow simulation comparing the results of inflexible and flexible interconnection service for solar generators.

U.S. DEPARTMENT OF ENERGY

Transmission Interconnection Roadmap

Transforming Bulk Transmission Interconnection by 2035

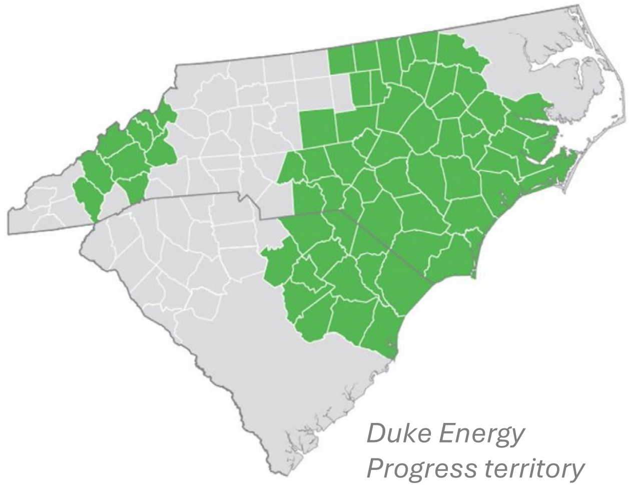
April 2024

https://www.energy.gov/articles/doe-releases-first-ever-roadmap-accelerate-connecting-more-clean-energy-projects-nations

Background: Duke Cluster Study

Selection of Real-World Interconnection Study for Re-simulation

- To assess potential benefits of flexible interconnection service, we considered recent cluster studies that could be replicated and re-simulated using alternative assumptions.
- We selected Duke Energy Progress' (DEP) 2023 Resource Solicitation Cluster (RSC) Phase 1 study released in April 2024, conducted for DEP's annual solar procurement.
- The DEP RSC study offered a uniquely instructive case study, because it isolates the interaction of utility-scale solar projects with prevailing interconnection study methods.



Duke Energy Progress territory

Summary of Key Inputs and Assumptions for Duke Study

- Resources: 24 separate solar/solar-plus-storage generator interconnection requests (1,858 MW)
- Study type: Thermal power flow. The Phase 1 study did not include stability or short circuit analysis.
- Load cases: 2027 summer and 2027/28 winter.
- Interconnection service: 100% Network Resource Interconnection Service (see more pg. 8)
- Capacity value: DEP assigns near-zero capacity value (Effective Load Carrying Capability, ELCC) to solar.
- Curtailment: DEP does not consider the ability to redispatch/curtail solar in summer peak hours to mitigate transmission overloads.

Background: Duke Cluster Study

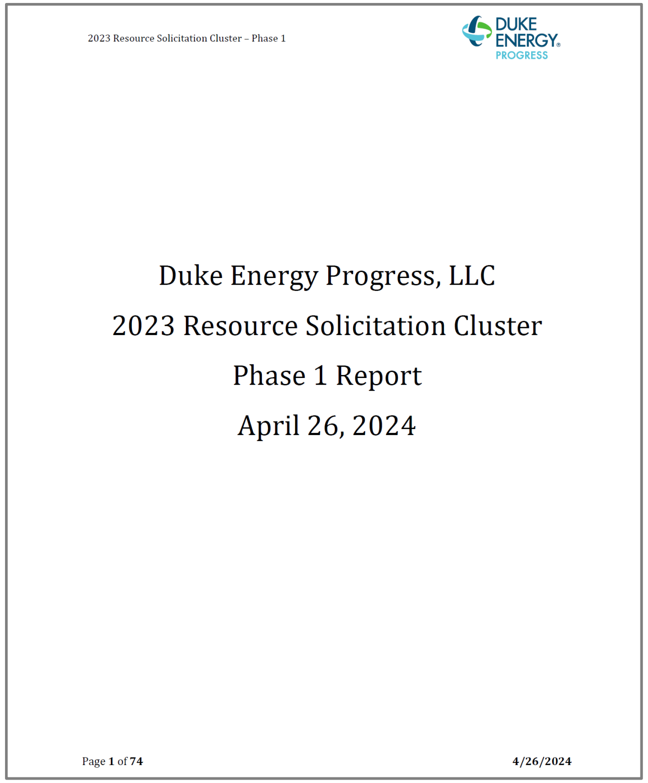
Results of Duke Cluster Study

Network Update Costs

- The DEP RSC Phase 1 study identified $470 million in network upgrades, or approximately $250 per kW of solar nameplate capacity.
- $350 million of these were thermal power flow related upgrades, with the remainder attributed to POI and telecommunication upgrades.
- The average network upgrade cost per project was $20 million. Nearly 70% of projects were allocated at least $10 million, and 33% were allocated at least $20 million.

Upgrade Timeline

- The average time estimated for completion of such upgrades by DEP was 4.5 years following the execution of an interconnection agreement, ranging up to 7 years.



2023 Resource Solicitation Cluster – Phase 1

DUKE ENERGY. PROGRESS

Duke Energy Progress, LLC

2023 Resource Solicitation Cluster

Phase 1 Report

April 26, 2024

Page 1 of 74 4/26/2024

Source: Duke Energy Progress, LLC. 2023 Resource Solicitation Cluster Phase 1 Report. April 26, 2024. https://www.oasis.oati.com/woa/docs/CPL/CPLdocs/2023_DEP_Resource_Solicitation_Cluster_(Phase_1)_Study_Report.pdf

Background: NRIS vs. ERIS

Definitions

Per FERC guidance, transmission providers are required to offer at least two interconnection services to FERC jurisdictional interconnection customers: Network Resource Interconnection Service (NRIS) and Energy Resource Interconnection Service (ERIS).[1] Whereas NRIS is required to be designated as a capacity resource, ERIS is ineligible for capacity designation.[2] NRIS subjects interconnection requests to more rigorous reliability analysis and thus generally entails higher network upgrade costs.

Solar NRIS vs. ERIS in Duke Energy Progress

DEP assigns near-zero capacity value (ELCC) to new solar generators, primarily due to the utility's winter-peaking system and its approach to ELCC accreditation. However, DEP requires all projects bidding into its annual solar procurement program to be fully deliverable and subject to NRIS, and it does not provide ERIS as an option to state jurisdictional interconnection requests.[1] In effect, generators without deliverability value are being studied for deliverability, making those generators more likely to trigger network upgrades than if they were studied as ERIS. This study aims to illuminate the impact of this requirement for interconnection studies and network upgrade costs.

NRIS vs. ERIS study assumptions

NRIS requests are generally subject to all contingency types defined in NERC Reliability Standard TPL-001 (P1-P7) and various stress cases. In contrast, treatment of ERIS requests by transmission providers varies widely. This study adopts DEP's proposed approach for studying energy-only provisional interconnection service requests under contingency types P1 and P2.1 (zero DFAX threshold).[3] This standard for ERIS is more rigorous than some transmission providers, and if treatment was adopted similar to that of NYISO, CAISO, or ERCOT, network upgrade costs for ERIS would be expected to be lower.

1. Norris, T. H. 2023. Beyond FERC Order 2023: Considerations on Deep Interconnection Reform. NI PB 23-04. Durham, NC: Nicholas Institute for Energy, Environment & Sustainability, Duke University.
2. Exceptions exist in MISO/SPP for ERIS generators which separately procure firm transmission service.
3. DEC, DEP, & DEF Provisional Service Filings Update. April 19, 2024. Slide 11: http://www.oasis.oati.com/woa/docs/CPL/CPLdocs/4.19.24_DEC_DEF_DEP_Provisional_Service_Filings_Update_Meeting_Presentation.pdf

Methodology

Summary: We replicated DEP's study results using DEP's data and assumptions, and then compared the results against a re-simulation assuming flexible energy-only interconnection service (ERIS).

Model: We used PowerGem's Transmission Adequacy & Reliability Assessment (TARA) software, a steady-state power flow simulation tool widely used by U.S. transmission providers, including most RTO/ISOs.

Data: We relied on the DEP RSC 2023 Phase 1 power flow models posted by DEP in May 2024 and did not modify any generator dispatch or load assumptions, and strictly utilized DEP-provided contingency and monitor files. 100% of the modeling data used to perform the analysis was DEP-provided; our analysis focused on applying DEP-data to understand how the RSC study results would have changed under a different study methodology using the same power flow modeling data.

Modeled scenarios:

- <u>Baseline Scenario: NRIS</u>: To replicate DEP's study and establish a baseline for comparison, we first modeled a scenario using equivalent contingencies and generation cases used by DEP for the RSC study.
- <u>Flexible Scenario: ERIS</u>: To assess the impact of flexible interconnection service, we then modeled a scenario applying the same contingency types proposed by DEP for energy-only provisional interconnection service (TPL-001 P1, P2.1), applied against all generation cases assessed by DEP, excluding the cases used by Duke for NRIS P3 analysis. All other inputs and assumptions were equivalent.

Cost estimation: We used DEP's estimates for the cost of each identified network upgrade, as specified in the RSC study. We only report an overload as mitigated if it is fully avoided based on the identified overload threshold, and only if it appears in the list of overloads in DEP's RSC study.

Sensitivities: We ran several sensitivities to assess the impact of certain assumptions, each of which is discussed in more detail following the primary results.

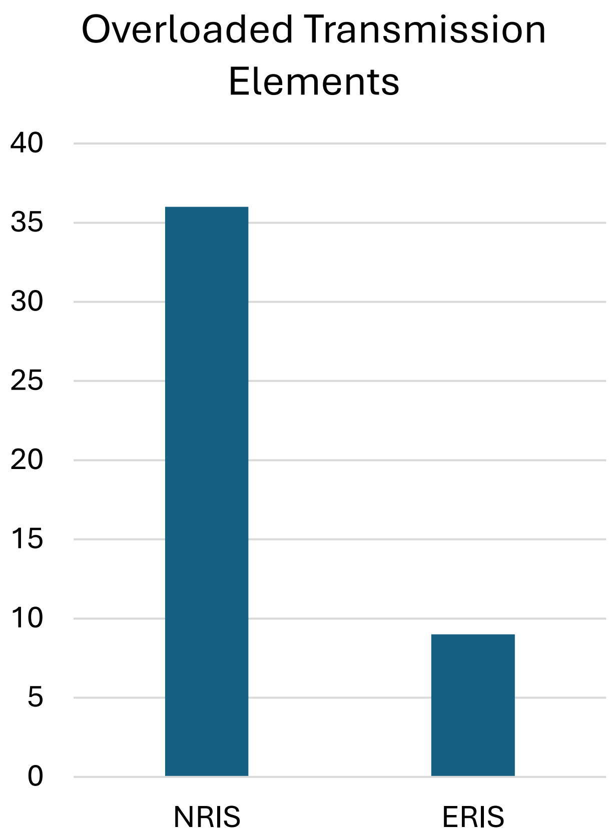
Paired storage: For the solar generators with paired storage, we did not treat them differently under the Baseline Scenario or Flexible Scenario as compared to the solar-only generators.

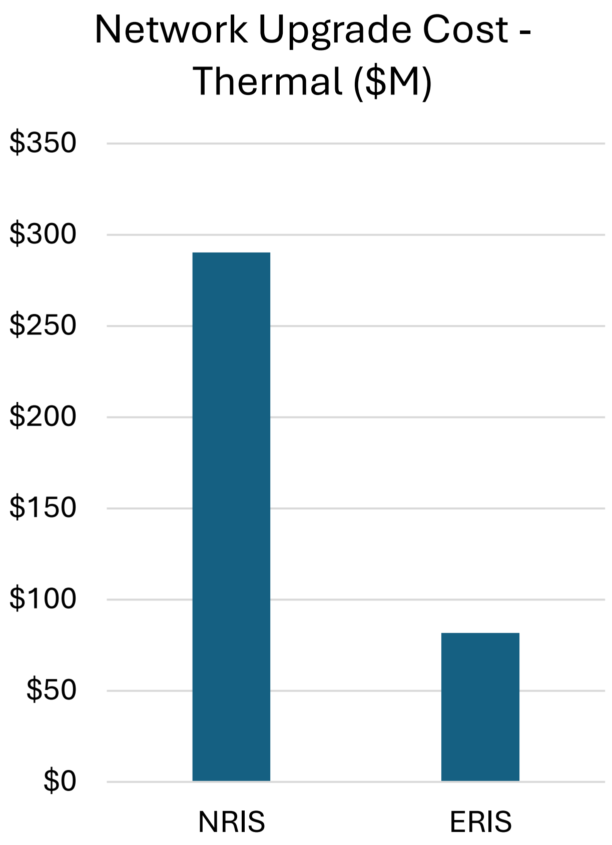
Results

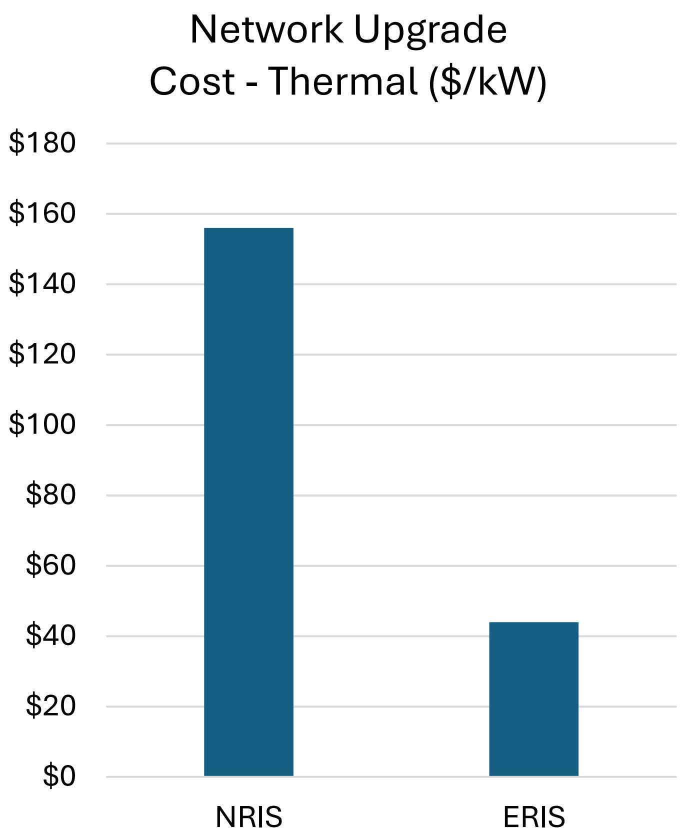
	Baseline Scenario: NRIS	Flexible Scenario: ERIS
Description	Reflects DEP's inputs and assumptions used to study the solar generators as NRIS, including all TPL-001 contingency types (P1-P7), including P3.	All inputs and assumptions were held fixed, except for the applied contingencies, which were updated to reflect DEP's proposed approach for studying energy-only provisional interconnection service (TPL-001 contingency types P1, P2.1).
Overloads	36 overloaded transmission elements*	9 overloaded transmission elements
Costs	$290 million in thermal network upgrades ($156/kW)*	$82 million in thermal network upgrades ($44/kW) *
Notes	Results reflect the deliverability test required by DEP based on local generation stress cases, which DEP refers to as "county stressed" or "county max" cases.	Results reflect the economic dispatch generation case provided by DEP, reflecting the ability to curtail ERIS generators with real-time congestion management.

* Based on DEP's cost estimate for each network upgrade required to mitigate each respective overload

Results


Overloaded Transmission Elements
40
35
30
25
20
15
10
5
0
NRIS
ERIS


Network Upgrade Cost - Thermal ($M)
$350
$300
$250
$200
$150
$100
$50
$0
NRIS
ERIS


Network Upgrade Cost - Thermal ($/kW)
$180
$160
$140
$120
$100
$80
$60
$40
$20
$0
NRIS
ERIS

Sensitivities

We ran three sets of sensitivities to assess the impact of key assumptions:

- **Sensitivity #1**: Impact of overload thresholds
- **Sensitivity #2**: Impact of local stressed conditions
- **Sensitivity #3**: Impact of generator out of service (P3)

Sensitivity #1: Overload Threshold

Summary: We simulated the impact of using different loading thresholds for triggering network upgrades. In addition to DEP's 95% threshold, we simulated a threshold of 100%, 105%, and 110% to represent theoretical increases in weather adjusted equipment ratings, optimization of Duke's current facility rating methodology to improve equipment capability, and/or utilization of grid enhancing technologies.

Background:

- The current carrying capability of transmission elements (e.g. transmission lines, transformers) varies based on a variety of conditions. The rated limit of each element is based on several assumptions and safety standards, including overhead clearance for transmission lines (i.e. lines physically sag under higher current loading).
- To identify overloads in interconnection studies, DEP uses a threshold below the rated current carrying capability of the elements on its transmission system. Specifically, DEP uses a threshold of 95%, meaning that DEP requires a network upgrade when elements are loaded at or above 95% of each element's rated loading limit. This approach differs compared to many transmission providers, which often use a threshold of 100%.
- DEP does not publish its facility rating methodology and declined a request to provide one under CEII protection, therefore, it is not possible to evaluate DEP's method for determining its transmission element ratings to explore potential improvements. DEP generally does not utilize Short Term Emergency (STE) ratings that are common with other transmission providers to increase equipment capability during contingency events.
- Modern grid enhancing technologies (GETs) can enable higher current carrying capabilities for certain transmission elements, offering the potential for interconnection studies to use higher element ratings, avoid overloads, and reduce required transmission investment.

Sensitivity #1: Overload Threshold

Results:

	Baseline Scenario: NRIS			Flexible Scenario: ERIS		
Threshold	Number of Overloaded Elements	Count of Repeat Overloads (>1)	Cost ($M)	Number of Overloaded Elements	Count of Repeat Overloads (>1)	Cost ($M)
95%	36	8	$ 290.3	9	n/a	$81.6
100%	27	8	$ 252.6	8	n/a	$69.6
105%	17	6	$ 158.9	8	n/a	$69.6
110%	15	5	$ 138.3	8	n/a	$69.6

Discussion:

- For the NRIS scenario, the threshold has a significant impact on the number of identified overloads, particularly at 100% and 105%. Specifically, if a 105% threshold is attainable with optimized element ratings and/or GETs, 45% of thermal network upgrade costs are avoided compared to DEP's existing threshold (95%).
- For the ERIS scenario, a 100% overload threshold saves 15% of costs compared to a 95% overload threshold. The threshold is less impactful thereafter, due to the fact that utilization of ERIS already avoids a significant portion of overloads.
- If a more restrictive 95% threshold was used for NRIS compared to a less restrictive 100% threshold for ERIS, the ERIS cost savings compared to NRIS expand from 72% to 76% of total NRIS costs.

Sensitivity #2: Local Stress Cases

Summary: We simulated the impact of using strictly the economic generation dispatch case, rather than subjecting the projects to the full suite of cases required by DEP based on local generation stress cases.

Background:

- To assess the deliverability of generator interconnection requests, transmission providers often test local generator stress cases, in which electrically proximate generators within certain pockets of the system (including existing installed generators) are ramped up beyond their economic dispatch levels. In some cases, these proximate generators may be assumed to dispatch at their maximum potential output.
- DEP runs a large number of such local generation stress cases, which it refers to as "county max" or "county stressed" conditions. DEP states that these cases entail maximum output of local generators for each case, however, it isn't documented which generators are included in each "county stressed" case or how realistic these system conditions are.
- Substantial latitude appears to exist in the assumptions that transmission providers use for these local generation stress cases.

Sensitivity #2: Local Stress Cases

Results:

	Baseline Scenario: NRIS		Flexible Scenario: ERIS	
	Local Stress Cases	Economic Dispatch Case	Local Stress Cases	Economic Dispatch Case
Number of Overloads	36	13	20	9
Cost	$ 290.3	$138.9	$168.4	$81.6

Note: results reflect DEP's 95% overload threshold

Discussion:

- DEP's local stress conditions appear to have greater impact on overloads and associated costs than any other single assumption in our study, driving approximately half of all identified network upgrade costs.
- Local stress tests are common for NRIS deliverability assessments, however, these results suggest that stakeholders may benefit from additional information regarding the specific assumptions used by some transmission providers.
- Although local stress conditions are generally not appropriate to apply against ERIS, if they are applied, these results suggest similarly large impacts, underscoring the need to confirm details of transmission providers' ERIS treatment.

Sensitivity #3: Generator Out of Service (P3)

Summary: We simulated the cost impact of the generator out of service contingency (TPL-001 P3) separately from the rest of the contingency types used for NRIS (P1, P2, P4-P7).

Background:

- The P3 contingency is simulation of a loss of a generator unit, followed by System Adjustments that may include "Transmission changes and re-dispatch of generation," followed by loss of another transmission element.
- The P3 contingency type may be applied by DEP in a way that creates unnecessary system stress by not utilizing the flexibility within the TPL-001 standard to mitigate issues through System Adjustments. Specifically, DEP assumes a uniform scaling of all area generators to replace the lost generation during the System Adjustment period. Whether intentional or not, this study process does not seek to minimize system stress and may lead to overloads and transmission investment that could be avoided with targeted redispatch.
- DEP could instead choose to redispatch the system to within its reliability limits to the extent that's economical, avoiding overloads and resulting transmission investment. DEP's assumption that all area generators will be scaled uniformly is a simplified method of simulating P3 contingencies and does not represent a targeted approach that seeks to minimize transmission investment. This change of methodology can be done within the current "System Adjustments" period defined by TPL while maintaining reliability and compliance.

Sensitivity #3: Generator Out of Service (P3)

Results:

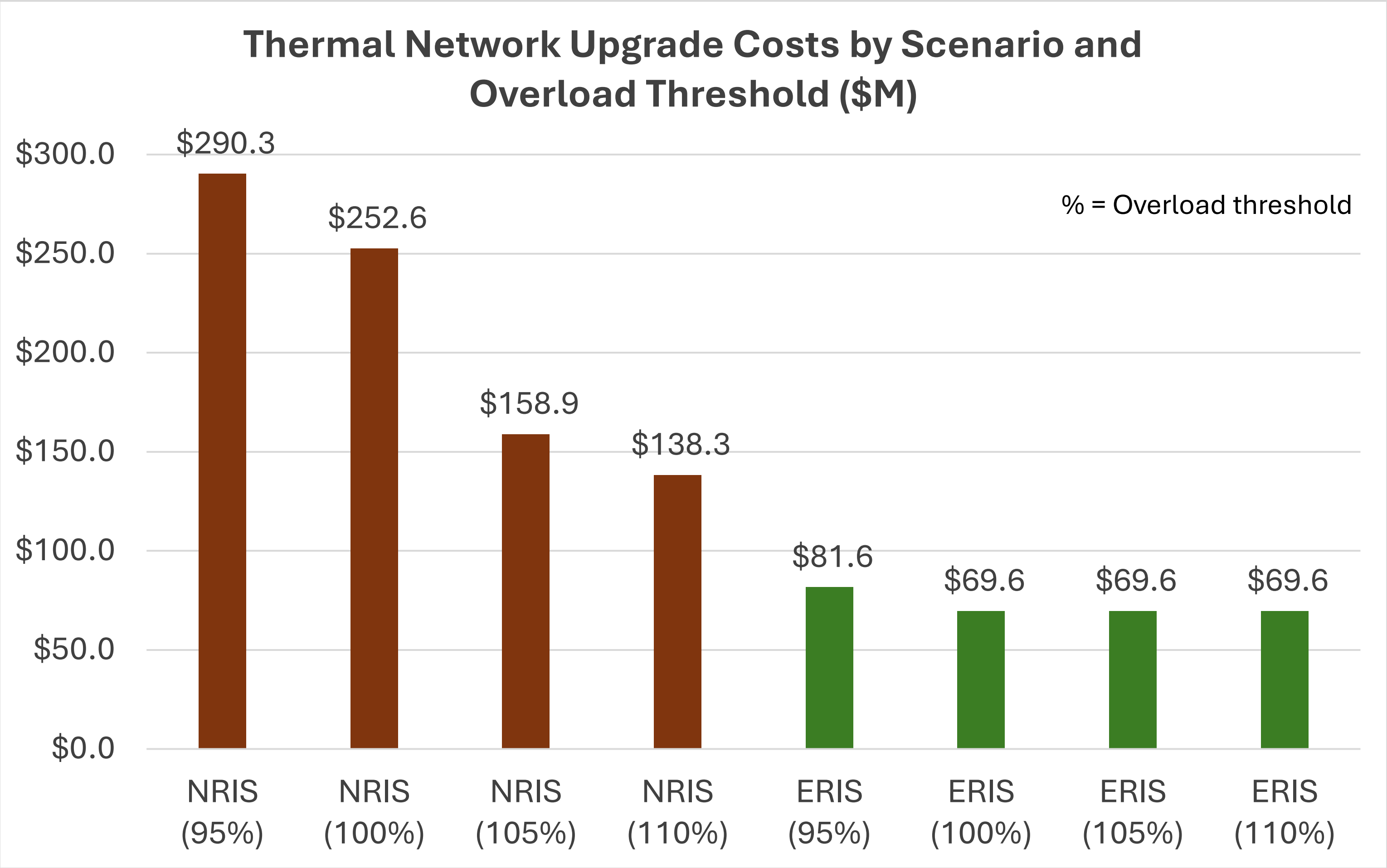
	NRIS excluding P3 Contingency			NRIS including P3 Contingency			Incremental Impact of P3		
Overload Threshold	Count of Overloads	Repeat Overloads (>1)	Cost	Count of Overloads	Repeat Overloads (>1)	Cost	Count of Overloads	Repeat Overloads (>1)	Cost
95%	34	17	$282.0	36	26	$ 290.3	2	9	$8.28
100%	25	13	$215.3	27	23	$ 252.6	2	10	$37.4
105%	17	11	$158.9	17	15	$ 158.9	0	4	$0
110%	15	11	$138.3	15	13	$ 138.3	0	2	$0

Note: results reflect DEP's local stress conditions

Discussion:

- In terms of overload count and cost in the context of DEP's RSC study, the P3 contingency can have significant impacts at certain thresholds and not in others. At an overload threshold of 100%, the P3 contingency is responsible for driving 15% of total thermal network upgrades.
- The impact of the P3 contingency is especially apparent with respect to the prevalence of the identified overloads, resulting in significantly more repeat overloads across the hundreds of simulated case-contingency pairs.

Summary of Results and Sensitivities



Appendix

Limitations

The results in this report reflect a good faith attempt to most accurately model the DEP 2023 RSC Phase 1 study under varying study methodologies to understand the impacts of specific changes of assumptions, and these results are unofficial by nature. Best efforts were made to rely on matching naming attributes, power flow results, and other available information to cross reference overloads between data sets. Some limitations of this study include the following:

- Most of DEP's study results could be replicated with a high level of confidence, but some overloads could not be reproduced based on DEP's provided inputs and assumptions, specifically P3 overloads, for unclear reasons. Of 44 relevant overloads, 36 were fully replicated; 4 were near-replicated, with slight differences in loading values; and 4 could not be replicated. These specific overloads were excluded from the analysis in this report to limit uncertainty.
- Naming conventions between DEP power flow models and the RSC are necessarily different at times due to character limitations in power flow software and the need to simplify results into a readable format within the RSC.
- Contingency analysis with TARA reported some overloads not identified in the RSC as requiring mitigation. These overloads were ignored and assumed to be outside the scope of the RSC, so only overloads that were both identified within the RSC and replicated with a high degree of confidence were included within this report.
- As previously noted, DEP's RSC study did not include stability or short circuit analysis. Similarly, this report did not seek to perform a stability or short circuit analysis.

Supplementary Analysis Opportunities

Areas for supplementary analysis include, but are not limited to:

Curtailment analysis

The impacts to curtailment of these alternative scenarios could be further investigated as part of a nodal production cost modeling run across ERIS vs. NRIS transmission upgrade scenarios to assess the impact of additional transmission investment required for NRIS service. This would help form a wholistic view on the value of transmission investment to avoid potential curtailment and estimate which mix of generating resources and transmission investment would result in the least cost delivered energy to consumers.

Contingency Sensitivities

Transmission providers often apply different sets of contingencies and loading impact thresholds (i.e. transfer distribution factors, DFAX) to ERIS in interconnection studies. Each of these assumptions could be simulated to compare against the assumptions used in this study, to inform considerations regarding an optimized approach to ERIS studies.

Paired storage

To account for paired battery energy storage systems (BESS), hybrid solar generators simulated as ERIS could be studied such that the BESS nameplate capacity is simulated as NRIS, to reflect its contribution as a capacity resource.

GRACE Lab

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Our research

Our research explores, assesses, and proposes technological, policy, and market approaches to contribute to the pursuit of environmental sustainability, affordability, reliability, and justice in the energy sector.

Primary research areas

- Characterizing sources of uncertainty that increase power systems' financial and reliability risk and designing risk management tools and strategies.
- Examining the attributes and characteristics of different electric power technologies and the possibilities and advantages of designing flexible policy mechanisms that consider the decision-making process and real options valued by those regulated.
- Assessing the economic, environmental, and reliability potential of renewable energy, storage, and emissions control technologies -- mainly related to their operational flexibility (e.g., use of different fuels, varying power output levels), the uncertainty that affects their outcomes, and the implications for the systems where they are integrated.

GRACE Lab is led by Dr. Dalia Patino-Echeverri, Gendell Family Associate Professor

https://sites.nicholas.duke.edu/daliapatinoecheverri