NPCC Distributed Energy Resources/Variable Energy Resources Forum

October 13, 2022, 9:00 a.m. – 12:00 p.m. EDT WebEx Meeting

Dial-In: 415-655-0003 (USA) / 416-915-6530 (Canada)
Guest Code: 24343720867
Password: Yq2eMFM655* (97236366 from phone)
WebEx Link

Day Two NPCC Regional Standards Committee Meeting – DER VER Forum:

October 13, 2022, 9:00 a.m. – 12:00 p.m. (all times EDT)

11.0 Distributed Energy Resources (DER) Variable Energy Resources (VER) Forum Topics

11.1 Welcome and Safety Message: Gerry Dunbar, NPCC Director Reliability Standards and Criteria (9:00 am - 9:05 am)
11.2 Antitrust Compliance Guidelines, Public Notice, and Meeting Protocols: Ruida Shu, NPCC Manager of Reliability Standards (9:05 am – 9:10 am)
11.3 NPCC VER/DER Outreach Efforts: Gerry Dunbar, NPCC Director Reliability Standards and Criteria (9:10 am – 9:15 am)
11.4 Operational Challenges of DER Integration at the Transmission-Distribution Interface – John Penaranda, Grid Operations Manager, Hydro One Networks (9:15 am – 9:55 am)
11.5 Planning New England's Transmission Grid for 2040 and 2050 – Daniel Schwarting, Manager, Transmission Planning, ISO-New England (9:55 am – 10:35 am)

Break (10:35 am – 10:40 am)

11.6 Leveraging Existing Planning Process to Prepare for the Energy Transition – Megan Lund, Manager – Transmission Planning Southwest & East, Independent Electricity System Operator (10:40 am – 11:20 am)
11.7 Transmission, a Key Enabler of the Energy Transition – Charlie Smith, Executive Director, Energy Systems Integration Group (11:20 am – 12:00 pm)
11.8 Closing – Gerry Dunbar

Northeast Power Coordinating Council, Inc. (NPCC)

Antitrust Compliance Guidelines

It is NPCC's policy and practice to obey the antitrust laws and to avoid all conduct that unreasonably restrains competition. The antitrust laws make it important that meeting participants avoid discussion of topics that could result in charges of anti-competitive behavior, including: restraint of trade and conspiracies to monopolize, unfair or deceptive business acts or practices, price discrimination, division of markets, allocation of production, imposition of boycotts, exclusive dealing arrangements, and any other activity that unreasonably restrains competition.

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- Their company's prices for products or services, or prices charged by their competitors;
- Costs, discounts, terms of sale, profit margins or anything else that might affect prices;
- The resale prices their customers should charge for products they sell them;
- Allocating markets, customers, territories or products with their competitors;
- Limiting production;
- Whether or not to deal with any company; and
- Any competitively sensitive information concerning their company or a competitor.

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Public Announcement

RSC and DER/VER Forum Meetings, WebEx, and Conference calls:
Participants are reminded that this meeting, WebEx, and conference call are public. The access number was posted on the NPCC website and widely distributed. Speakers on the call should keep in mind that the listening audience may include members of the press and representatives of various governmental authorities, in addition to the expected participation by industry stakeholders.

Meeting Logistics

Participants will be muted upon entry, and you are encouraged to use the "Chat" feature of the WebEx if you wish to ask a question. The questions will be answered by the presenter at the end of each presentation. NPCC DER/VER Forum will be recorded, the recording and meeting material will be posted on the DER Forum section of the NPCC website.

Thank you for your cooperation.

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NPCC 2022 Outreach Activity

Gerry Dunbar

Director Reliability Standards and Criteria

October 13, 2022

NPCC, Inc.

NPCC 2022 – 2025 Strategic Plan

Strategic Focus Area

Reliably Integrate Resources Brought Forward by Decarbonization Objectives

- DER/VER Forums
  - May 2022 --- Electric Vehicle Charging
  - August 2022 --- Building Electrification
  - October 13, 2022 --- Transmission Integration
- NPCC DER/VER Guidance Document
  - Revisions Posted for Comment

Operational Challenges of DER Integration at the Transmission/Distribution Interface

NPCC DER/VER Forum

John Penaranda/October 13, 2022

Agenda:

Operational Challenges of DER Integration at Tx/Dx Interface

- Ontario Drivers: Decarbonization, Electrification/Energy Transition
- About Hydro One
- Tx/Dx Interface: Sub-transmission
- DER Modelling and Forecasting R&D
- Alarm Management System
- DER Integration Challenges/Opportunities: Operating
- Q & A

Ontario Drivers

Decarbonization – Canada's gov. energy policy targets:

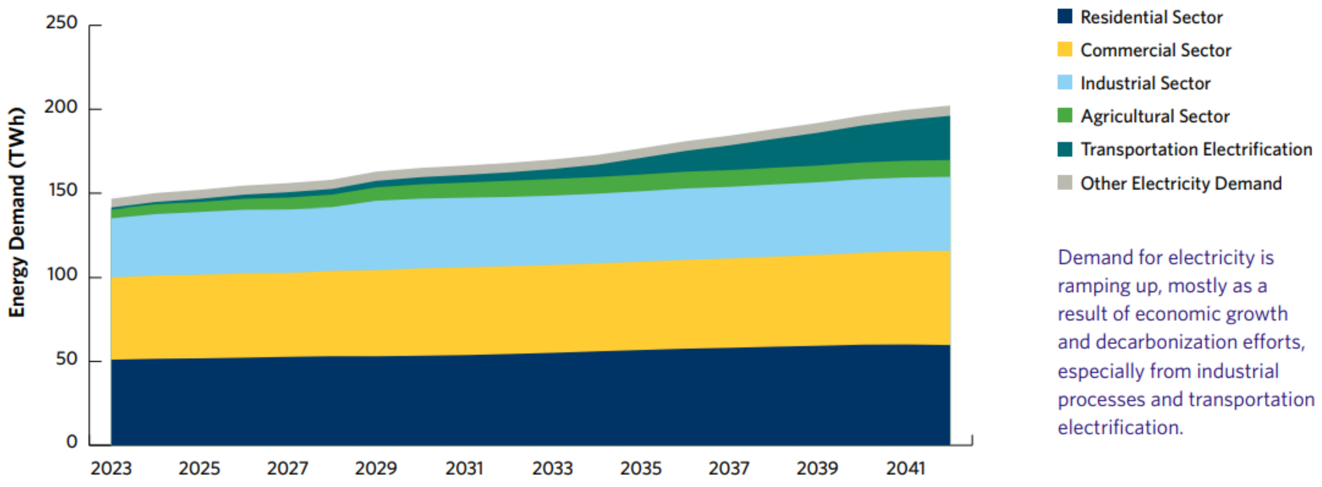
- By 2030, power indigenous remote & rural communities with clean reliable energy
- By 2035, produce ~100% of electricity from non-emitting sources and 100% of light-duty vehicles sales must be ZEVs (zero emission vehicles).
- By 2040, establish leading hydrogen & full cell technology cluster
- End goal, by 2050 achieve net zero emissions

Energy Transition/Electrification – IESO identified drivers:

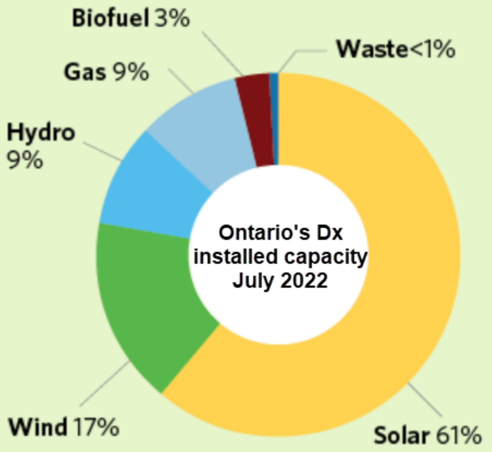
- EV (electric vehicles) becoming mobile energy storage units. EV grid infrastructure
- Electric Arc Furnaces (steel ind.) transitioning from blast fossil fuel furnaces to electric arc furnaces.
- Building Space and Water Heating (residential/commercial) shifting from natural gas to electric heating.
- Public Transportation systems (fleet - TTC, train - Metrolinx, ferry – OPG/MTO)

Ontario Outlook

Long-term demand forecast (by sector)



Demand for electricity is ramping up, mostly as a result of economic growth and decarbonization efforts, especially from industrial processes and transportation electrification.

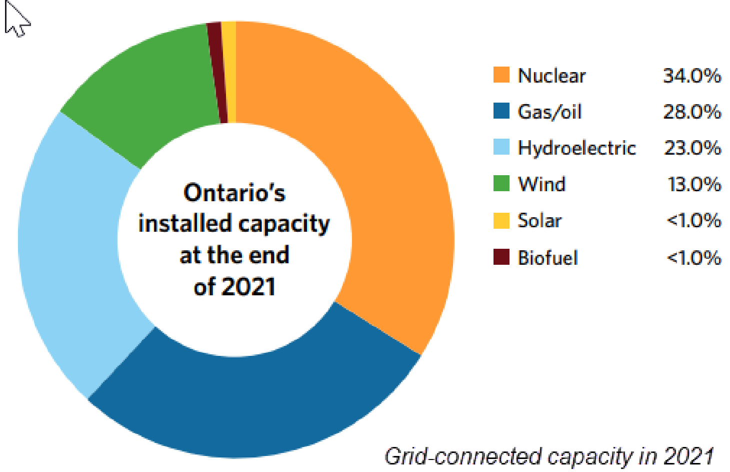


Solar	2,171 MW or 61%
Wind	591 MW or 17%
Hydro	333 MW or 9%
Gas	320 MW or 9%
Biofuel	110 MW or 3%
Waste	24 MW or <1%

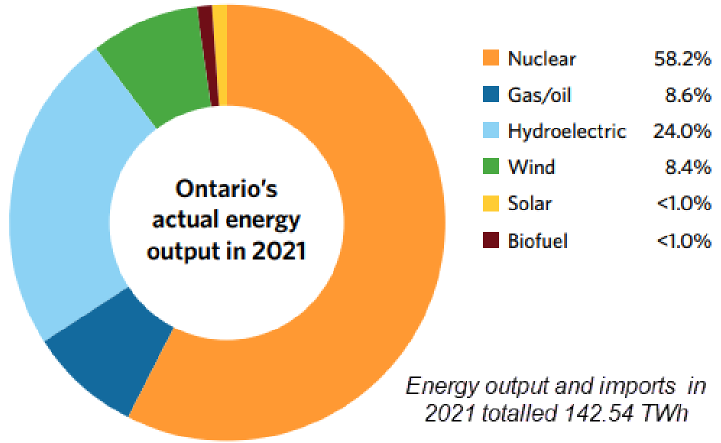
Total Dx Grid-connected capacity in July-2022 totalled 3,549 MW

Distribution-Connected Capacity as of July 2022 (Source: Progress Report on Contracted Electricity Supply)

Ontario Capacity and Energy Output in 2021



*Grid-connected capacity in 2021 totalled 38,079 MW**



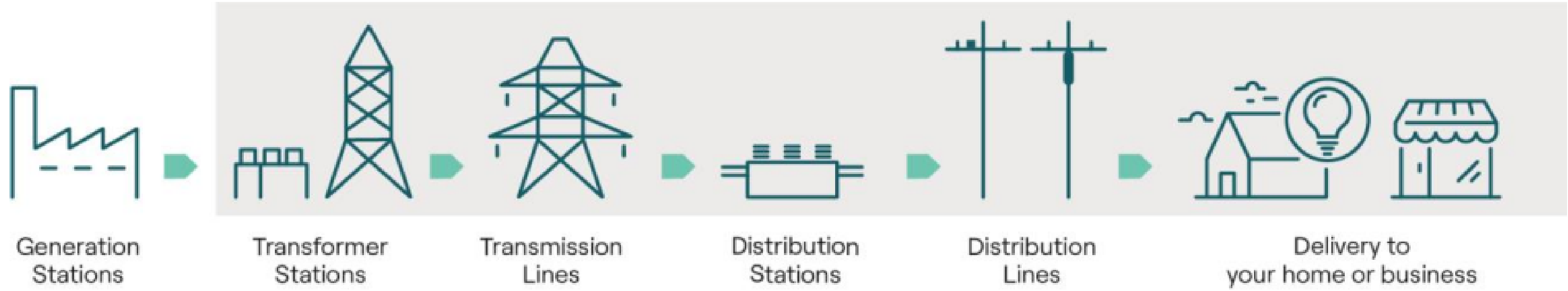
Energy output and imports in 2021 totalled 142.54 TWh

Source: IESO Corporate Strategy (2022–2027)

About Hydro One

	Transmission Segment	Distribution Segment
Customers	57 local distribution companies and 85 large industrial customers connected directly to the transmission network.	~1.5M residential and business customers located mostly in rural areas covering approximately 75% of the geographic area of the province.
Assets	306 transmission stations and approximately 30,000 circuit kilometres of high voltage lines.	~125,000 circuit kilometres of low-voltage distribution lines and approximately 1,000 distribution and regulating stations.
2022 Expected Rate Base[1]	$14.5 billion	$9.2 billion
Allowed ROE (2022)	8.52%	9.00%
Annual Capital Program[2]	~$1,170 - ~$1,700 million[3]	~$670 - ~$1,200[3]

Hydro One's Role in the Ontario Electric Power System



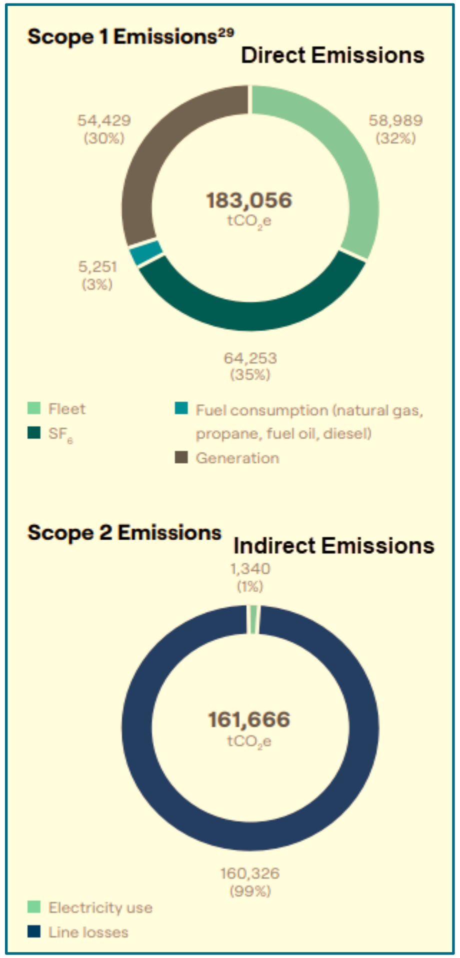
Hydro One Decarbonization Commitment

Hydro One Climate Change Mitigation Goals

- We plan to convert 50% of our fleet of sedans and SUVs to EVs or hybrids by 2025, and 100% by 2030.
- By 2030, we target an interim emissions reduction of 30%.
- By 2050, achieve net-zero GHG emissions.

2021 Climate Change Mitigation Performance

- We reduced our GHG emissions by 9% compared to our 2018 baseline.
- We converted approximately 14% of our fleet of sedans and SUVs to Evs or hybrid, (slower pace due to ongoing supply chain disruptions, global shortage of vehicle computer chips)



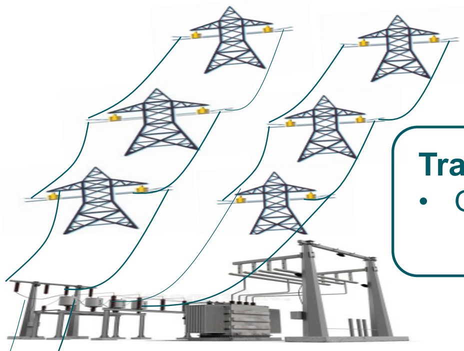
Low-Carbon Energy Mix Ontario's electricity sources are largely carbon-free – **Hydro One** transmits and distributes electricity ~ 96% carbon emission-free and our GHG emissions are ~ 0.2% of Ontario's total GHG emissions

Hydro One Sub-Transmission

Transmission System Operator

- Coordinates & operates the Tx System
- IESO visibility into Dx System is limited

IESO Controlled Grid



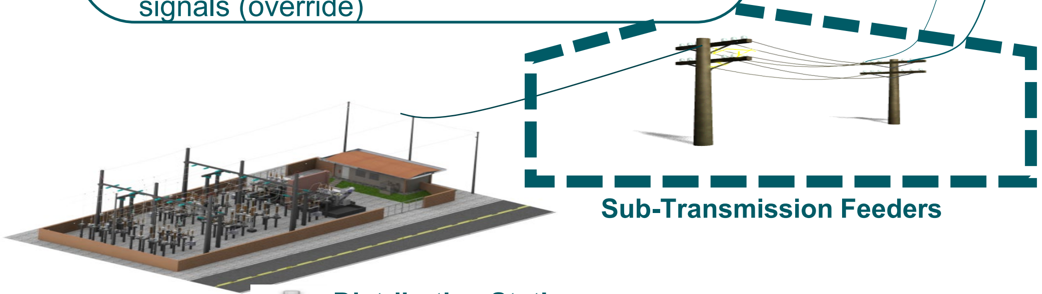
Sub-Transmitter (HONI)

- Owns assets and operates Sub-Tx system
- IESO and LDCs do not have visibility into this Sub-Tx system
- This system is often reconfigured
- This system is exposed to significant thermal and voltage constraints.
- Sub-Tx system can distort IESO market signals (override)

Transmitter (HONI)

- Owns assets and Manages Tx system

Transmission Station

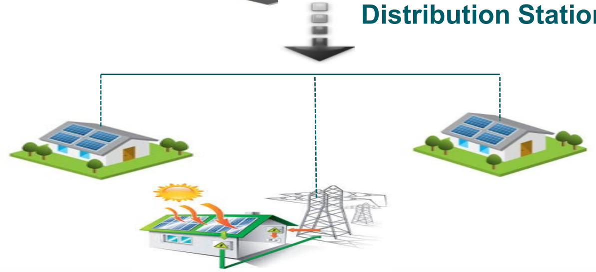


Sub-Transmission Feeders

Distribution Station

Distributor (LDC)

- All 57 LDC's are connected to HONI's Tx and Sub-Tx System.
- There are many hybrid feeders that contain both HONI assets and LDC assets.
- Hydro One is also the largest Distributor and operates 47% of all Dx grid in Ontario.

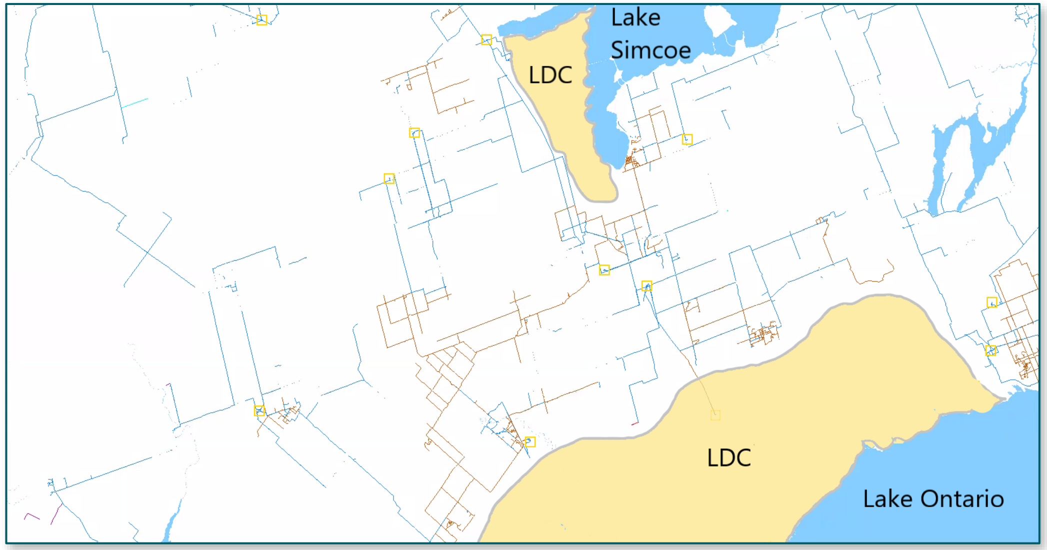


DERs, Aggregators & Customers

- Customers use power from the system and DERs,
- In future market scenarios could bid their DERs, alone or aggregated, into the IESO markets.

Hydro One Sub-Transmission

- Ontario's Dx system is **unique** compared to most other provinces or states.
- Hydro One leverages a 'Sub-Tx' system to convey high voltage power across large geographic regions far from Tx stations to LDCs and large customers.
- The Sub-Tx system is impacted by changes in demand and/or power injection from DERs, directly connected customers and the Tx system.



GTA map showing Sub-Tx feeders (blue and orange lines)

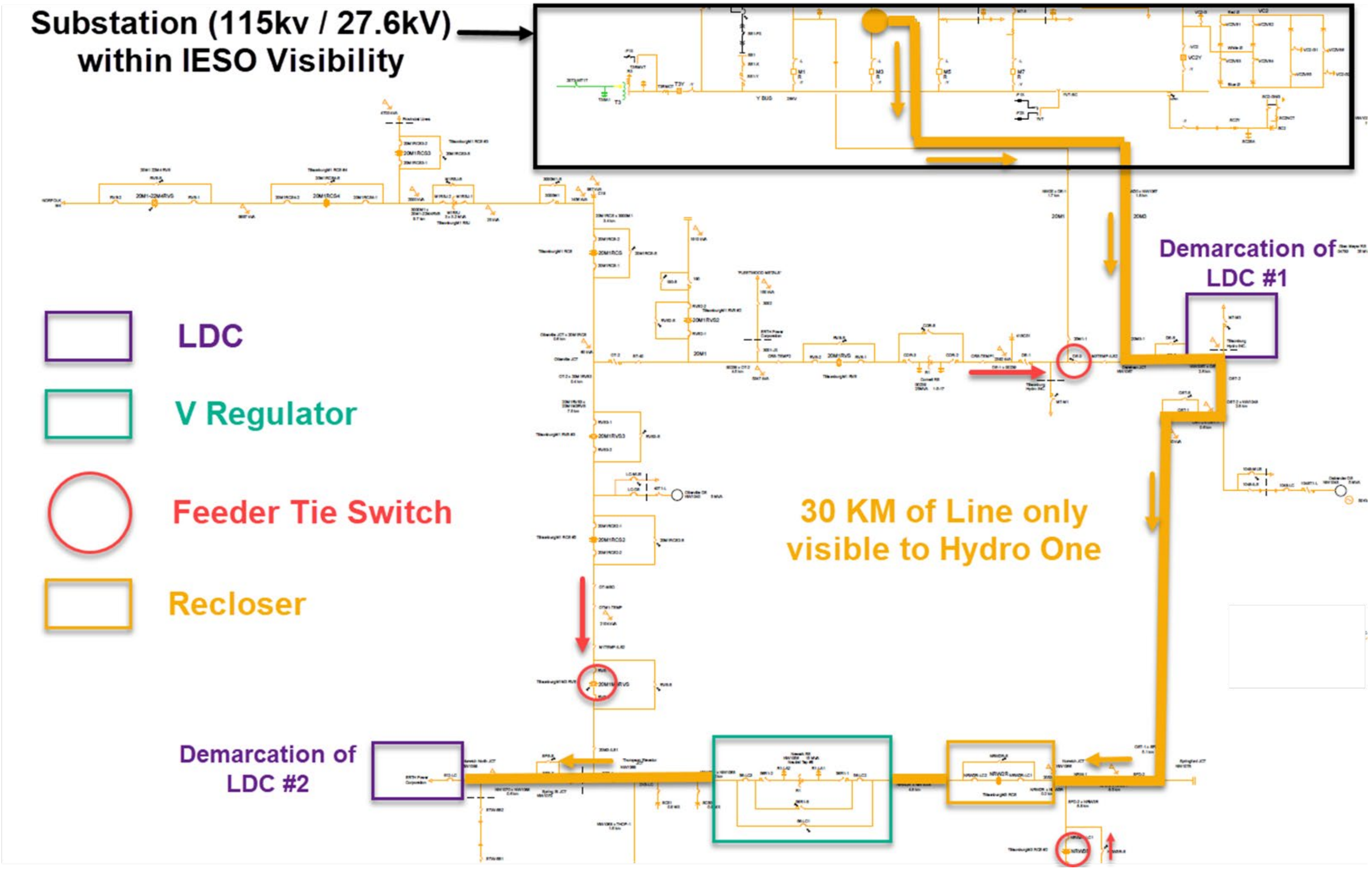
Properties of the Sub-Tx system

- ❖ 3 or 4 Wire Systems
- ❖ 1-30MVA Customers
- ❖ Thermal Constraints
- ❖ LDC Substations
- ❖ Up to 75km of Line
- ❖ Reconfigurable
- ❖ <10MW DER's
- ❖ Voltage constraints
- ❖ Distribution Automation

Relevance of the Sub-Tx system

- The Sub-Tx is not static, it is often reconfigured due to maintenance
- Both the LDC's and IESO are unaware of these reconfigurations.
- Sudden changes in the Sub-Tx system (e.g. feeder reconfiguration) can determine new operating conditions impacting pre-dispatch, other connected customers, DERs, sub-Tx assets and distorting market signals (override)

Hydro One Sub-Transmission



6.2 Switching

The Customer must comply with **The Code** when performing switching operations which impact load transfers or parallels.

6.3 Outage Planning

OGCC Operating Planning shall be notified of all transfers involving customer load and/or generation supplied from Hydro One owned stations to ensure that the transfer won't have adverse effects on the distribution system.

Feeder with Hydro One Customers

- ***Load and/or Generation Transfers:*** OGCC Operating Planning is accountable for assessing transfers on distribution feeders that have embedded generation and/or load customers connected to them.

Feeder without Hydro One Customers

- ***Load Transfers:*** If the customer's load is being transferred to an alternate customer supply feeder (i.e. back to back), the customer is accountable for the assessment of the transfer, and the customer shall formally advise the OGCC Operating Planning regarding acceptance of the transfer.

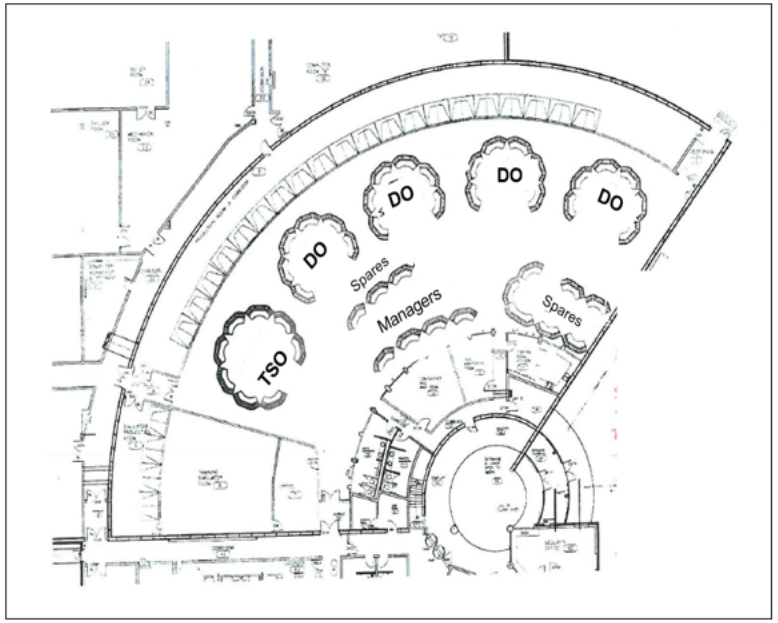
- ***Generation Transfers:*** If embedded generation is connected to a customer's section of feeder or to a feeder shared with Hydro One, the customer shall be accountable assessing the generation transfer and shall formally advise the OGCC Operating Planning regarding acceptance of the transfer.

Example of Normal Operations Section in Tx Connection Agreement

Hydro One System Operations Vision

DxM DISTRIBUTION MODERNIZATION

OGCC – Control Room Layout



DISTRIBUTION OPERATOR

DMS DUTIES

DMS Operations

- Smart Switches (self-healing configurations)
- Remote Load Break Switches (RLBS)
- Reclosers
  - Vipers
  - M-Class and F-Class
- Feeder transfer studies
  - Sectionalizing
- Temporary relay settings
- Distance to faults
- Controlling Authority
  - HVDSs and LVDSs
    - Automated
    - Not Automated
  - F-Class devices outside of TSs
- Work Protection
  - Mainly self-administered from Dx Lines
- Operating/Monitoring/Responding to and studying the impact of Distributed Energy Resources (DERs)

Distribution

Distribution Operator Supervisor

Distribution Operator

Distribution Operating Planning Supervisor

Distribution Operating Planner

Alarm Management System - EPRI

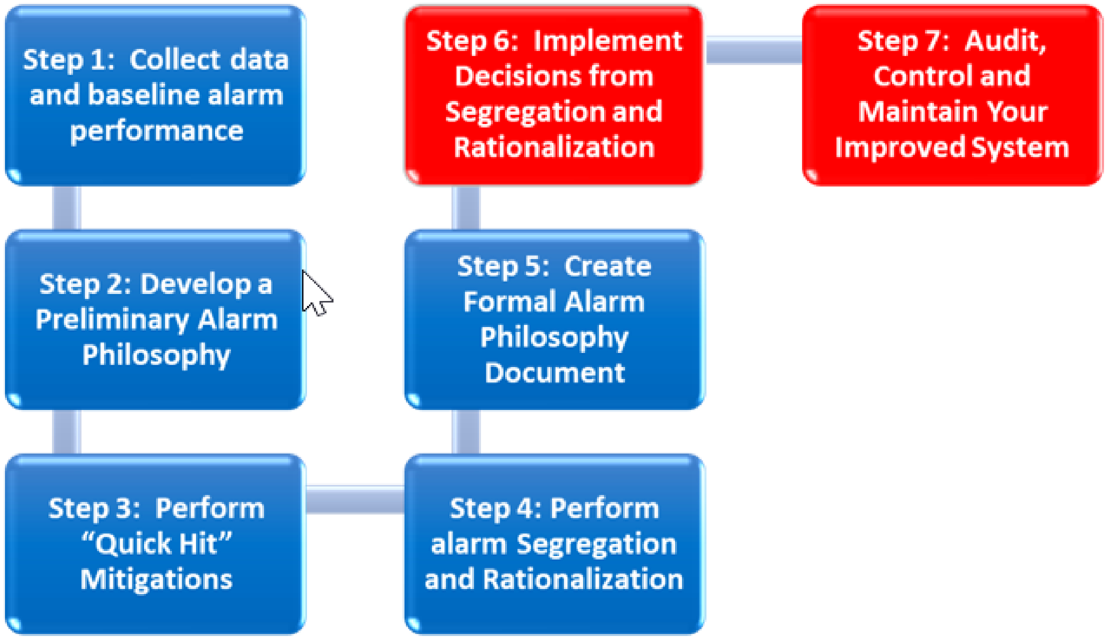
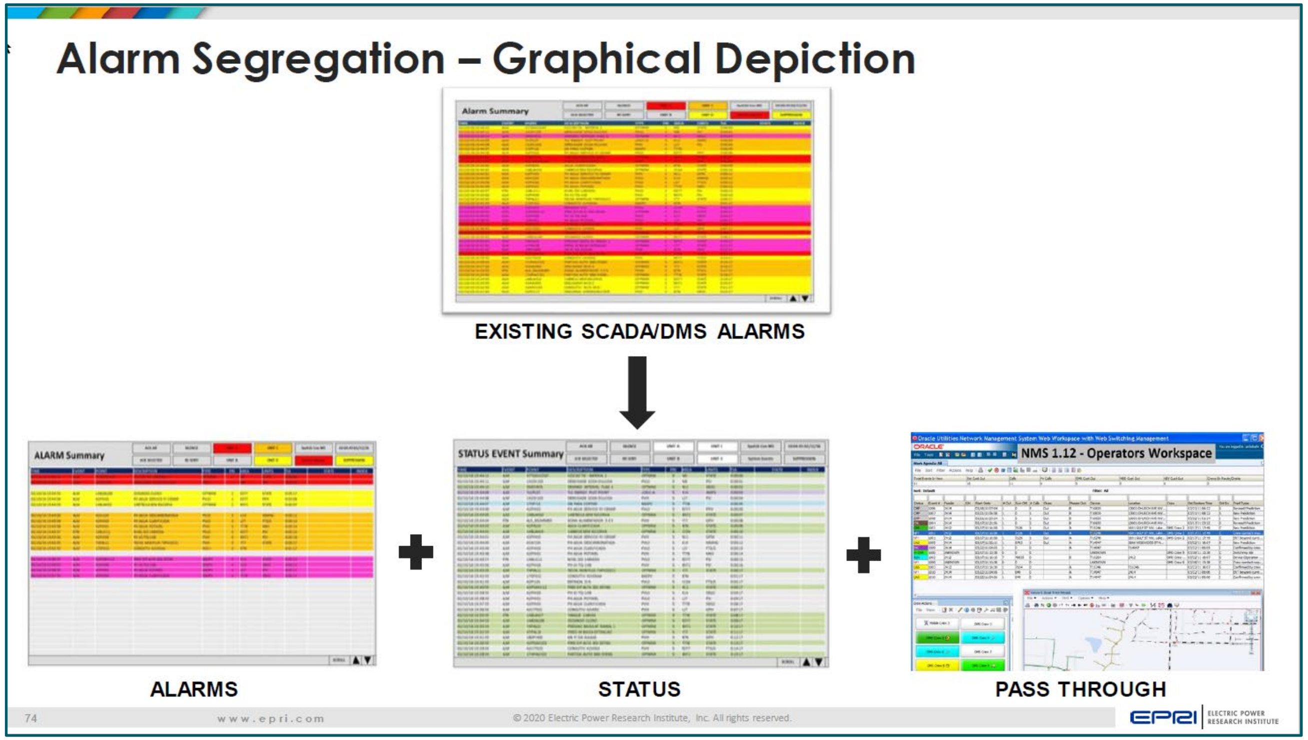


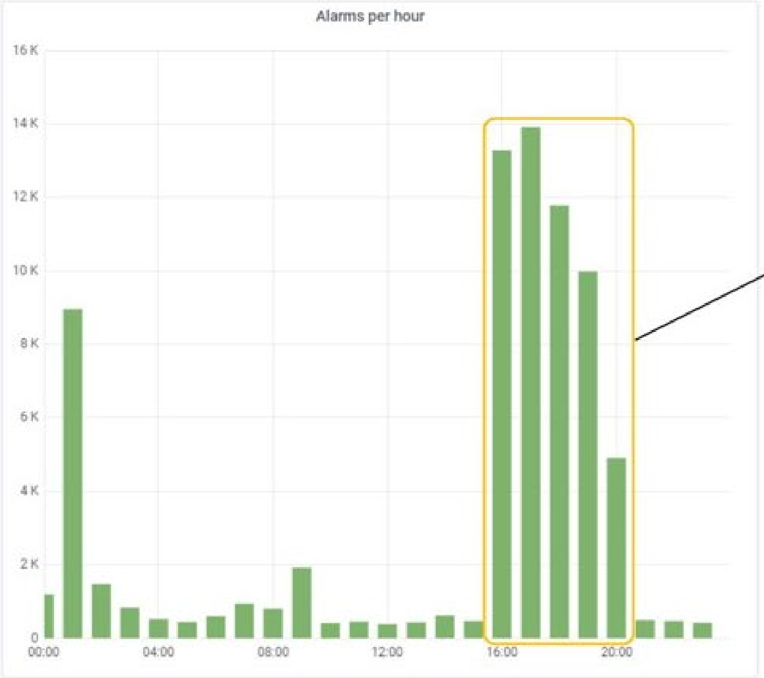
Figure 1 - Alarm Management Process Flow Chart



Alarm Management System - EPRI

DMS Bad Actors

8/4 4:00-9:00PM



Top frequent

ORILLIA TS Load break device Disconnect:Loss of A.C NORMAL	11333
ORILLIA TS Load break device Disconnect:Trouble/Minor Error NORMAL	11333
ORILLIA TS Load break device Disconnect:Trouble/Minor Error ALARM	11333
ORILLIA TS Load break device Disconnect:Loss of A.C ALARM	11333
ALMONTE TS Load break device Disconnect:Loss of A.C NORMAL	1497
ALMONTE TS Load break device Disconnect:Trouble/Minor Error NORMAL	1497
ALMONTE TS Load break device Disconnect:Loss of A.C ALARM	1497
ALMONTE TS Load break device Disconnect:Trouble/Minor Error ALARM	1497
Command:Poll for Data aborted - Connection closed	582
F45041_9M6-RLBS1_CONN connect timeout (60 secs) exceeded - disconnecting	291

Load break device: Disconnect Trouble/Loss of AC

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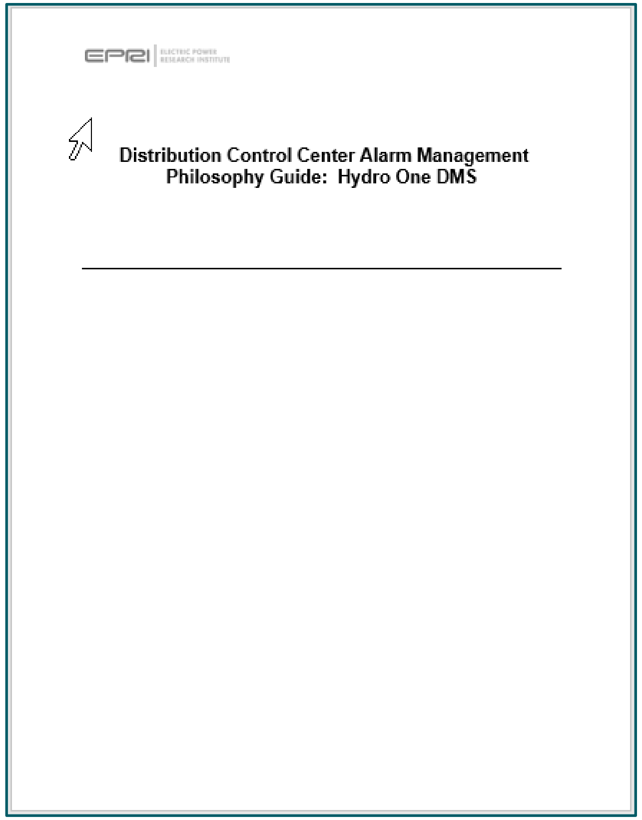
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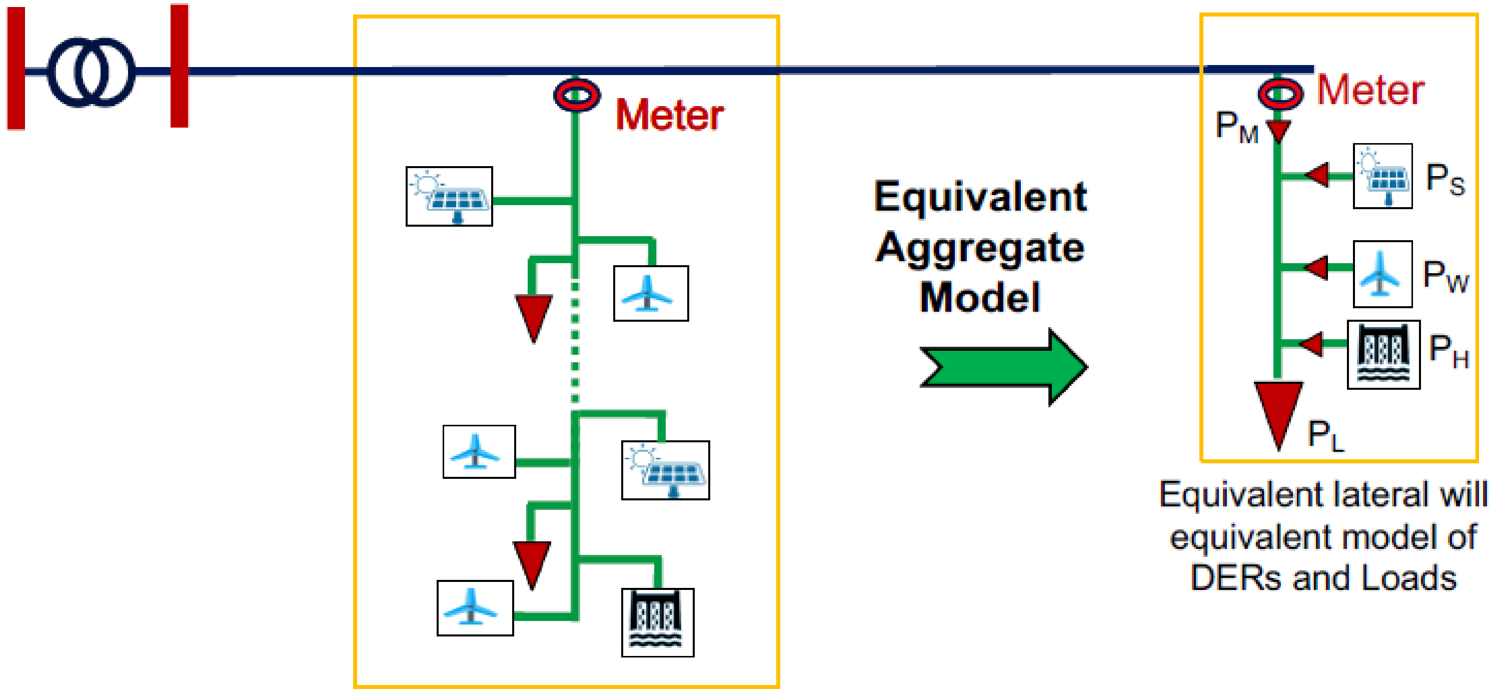
Distribution Control Center Alarm Management Philosophy Guide: Hydro One DMS

EPRI Dx Alarm Management Philosophy

DER Forecasting and Modelling – TMU

Approach – High resolution short-term DER forecast



Lateral with large number of DERs and Loads

Equivalent lateral will equivalent model of DERs and Loads

Toronto Metropolitan University Centre for Urban Energy

Project Overview

4 Research Activities

1. DER Forecasting
2. DER Modeling – Steady State Domain
3. DER Modeling – Transient and Dynamic Domain
4. Distribution System Operator (DSO) Models

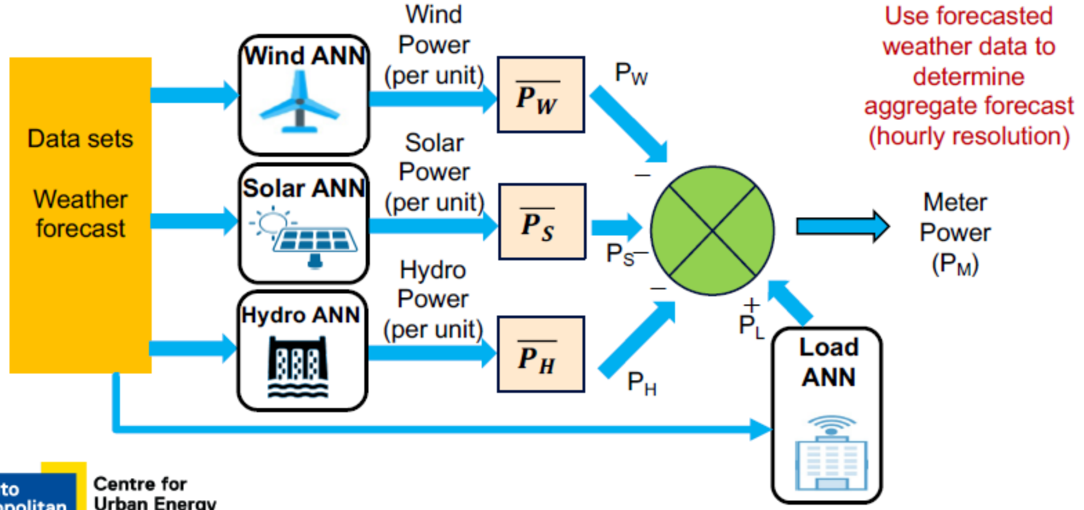
Ryerson University Centre for Urban Energy

TMU DER Forecasting and Modeling Project.

DER Forecasting and Modelling – TMU

hydro One

Architecture – High resolution short-term DER forecast
Step #4 – Operational Software (Trained ANNs)



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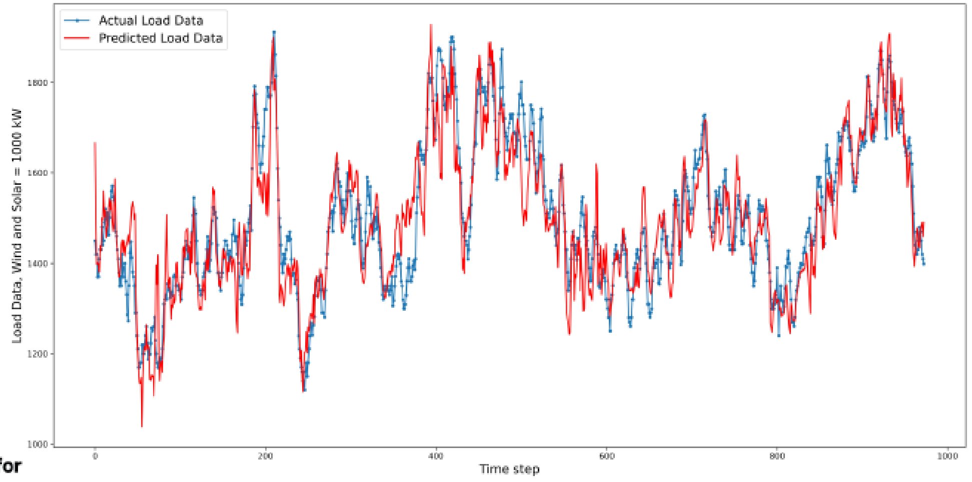
Architecture Step 3: Aggregate Load ANN Model #2
Forecasted Load power data

Considering all the input features, 50 Epochs

The predicted Load data is based on the predicted combination (the red one in the Error tables)

Sample of the predicted power meter versus the actual power meter data is shown in this Figure for the case of 100% penetration of DERs.



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DER Forecasting Results for 100% DER penetration - error RMSE = 3.78096%

DER Integration Challenges/Opportunities

- Adoption of evolving Dx Modernization technologies: CFCI,FLISR, smart recloser, adaptive protection settings, DERMS
- Co-existence with old legacy DER that are part of the Dx grid, but might not follow IEEE-1547
- Changes in the HONI Technical Interconnection Requirements (TIR) v. 2013 [in collaboration with EPRI]
- Operational criteria for managing microgrids and sustained “islanding” operation
- Assess Interaction with other Tx/Dx system protection such as UFLS, rotational load shedding, voltage reduction at Tx stations (incl. Load Rejection from RAS)

- Timely DER Integration training and development of Operating staff (including training the trainers)
- Acknowledge Dx operator expertise role to manage storms, or large system events
- Identification of the new roles/competences of the Control Room Dx Operators & Supervisors.

- Pencil out Dx Market regulatory framework and performance. New market participants: DSO, DER aggregators
- Knowledge transfer out from of DER pilot projects or sandboxes into effective Dx system solutions

- Common knowledge platforms between North American utilities, R&D, and the industry to share DER integration “lessons learned”.

Thank you!

For more information, please contact us at John.Penaranda@HydroOne.com

ISO New England's Planning Initiatives to Support the Transmission Grid in 2040 and 2050

Dan Schwarting, P.E.

MANAGER | TRANSMISSION PLANNING

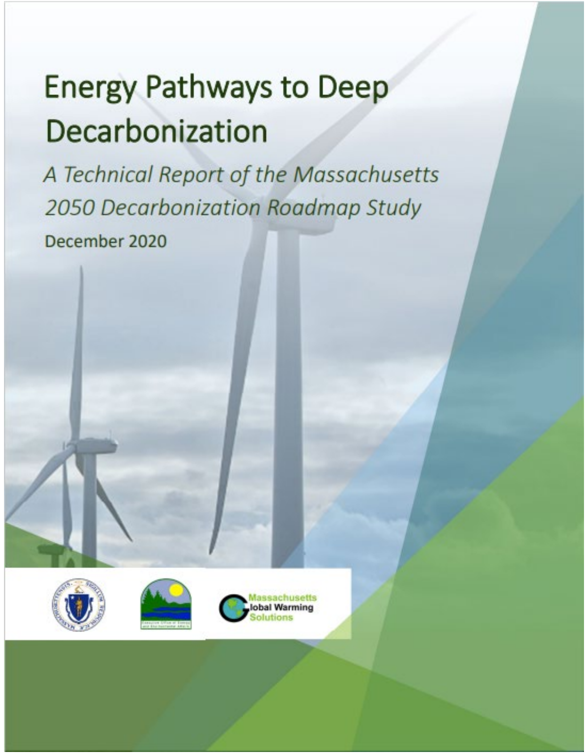
New England’s Long-Term Outlook on the Energy Transition

- Many of New England’s states have ambitious goals for clean energy and emissions reductions
- **How will New England’s electric transmission grid contribute to meeting these goals?**
- ISO New England’s typical transmission plans look 10 years into the future – **how will the system evolve over 20-30 years?**

≥80% by 2050	**Economy-wide greenhouse gas reductions: MA, CT, ME, RI, and VT (mostly below 1990 levels)**
Net-Zero by 2050 80% by 2050	MA emissions req’t MA clean energy standard
90% by 2050	VT renewable energy req’t
100% by 2050 Carbon-Neutral by 2045	ME renewable energy goal ME emissions req’t
100% by 2040	CT zero-carbon electricity req’t
100% by 2030	RI renewable energy req’t

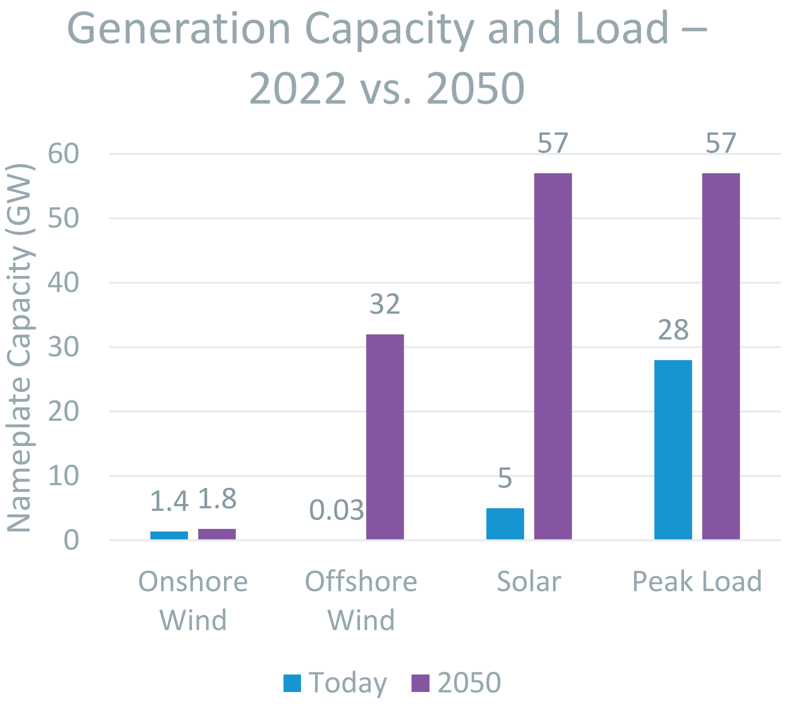
Source of Study Input Assumptions

- "Energy Pathways to Deep Decarbonization" study identified a number of pathways to a zero-carbon-emission economy
  - Study commissioned by Massachusetts in 2019-2020
- The "All Options" pathway was chosen by the New England States Committee on Electricity (NESCOE) as a basis for further study work by ISO-NE



Details of the "All Options" Pathway

- Development of significant new renewable generation capacity
- Retirement of all existing coal and oil generation
  - Some natural gas units retained, with decreased capacity factor
- Transportation and heating electrification
- New transmission to Quebec and New York



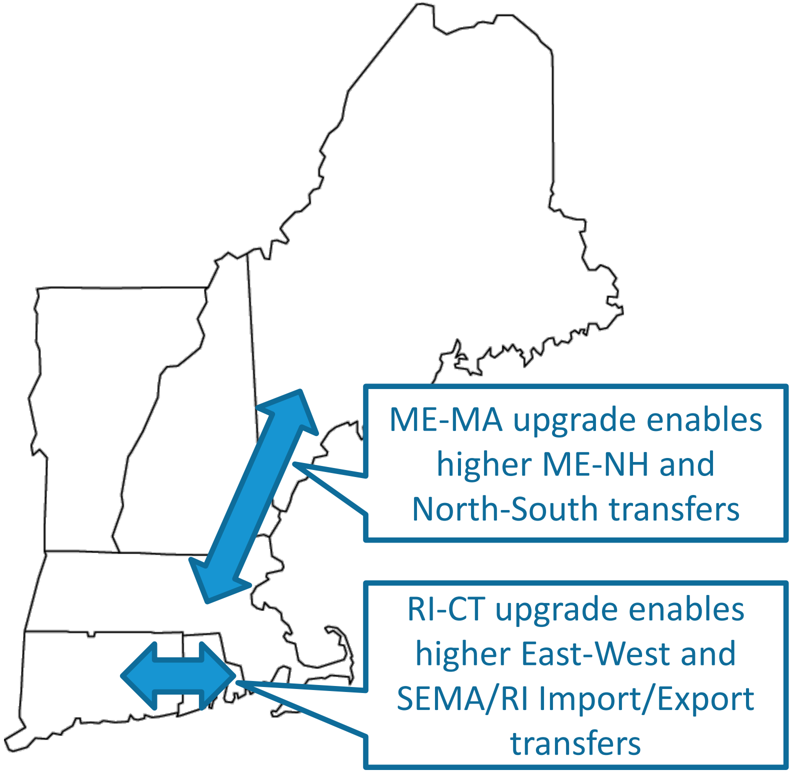
Source: Energy Pathways to Deep Decarbonization; load recast to a 2019 weather year as described in a June 2021 Planning Advisory Committee presentation

Future Grid Reliability Study Phase I

- The Future Grid Reliability Study (FGRS) Phase I was performed in 2021-2022 as the ISO-NE 2021 Economic Study
- 8760-hour-per-year analysis of various scenarios in 2040
- Examined production cost, emissions, ancillary services, and high-level transmission system constraints
  - Transmission system modeled with a pipe-and-bubble approach, with key interface constraints within and outside of New England modeled
- FGRS Scenario 3 was based on the "All Options" pathway

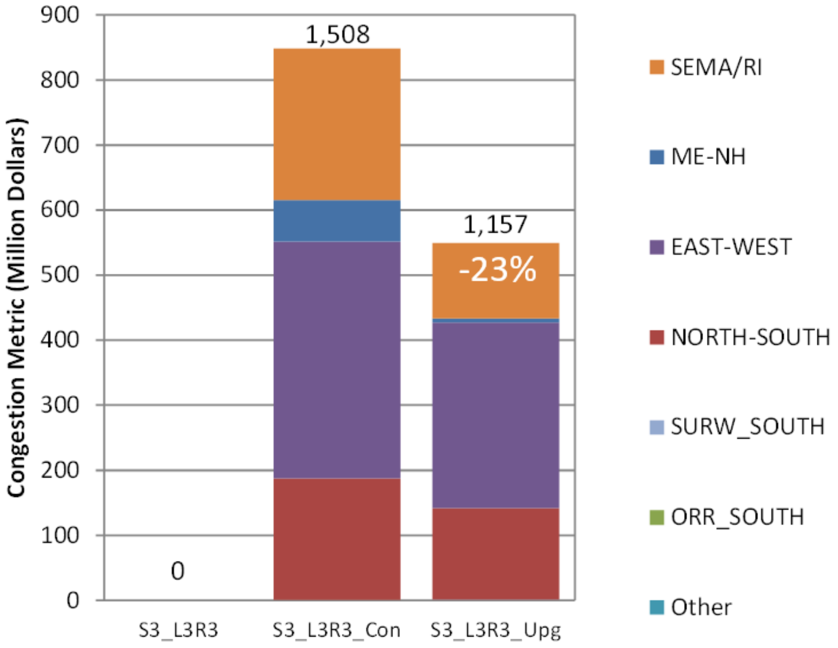
FGRS: High-Level Transmission Analysis

- Unconstrained simulation showed flow above transfer limits on some interfaces for 30-40% of the hours in 2040 in FGRS Scenario 3
- Two high-level transmission upgrades added to the model
  - 500 MW increase from Maine to Central/Northeast Massachusetts
  - 500 MW increase from Rhode Island to Connecticut



FGRS: Key Transmission Findings

- 500 MW upgrades (≤ 25% of interface capacity) led to substantial reduction in congestion
  - 25% reduction in congested hours on North-South
  - 35% reduction in congested hours on SEMA/RI Export
- Production cost analysis showed a 23% reduction in congestion costs



2050 Transmission Study: Background

- At the request of the New England states, ISO-NE also began the 2050 Transmission Study in late 2021 to analyze the transmission system in more detail
- Input assumptions based on the "All Options" Pathway
- Key questions to be answered include:
  - Where will the transmission system be deficient in serving load in 2035, 2040, and 2050?
  - What conceptual transmission upgrades could resolve these deficiencies?
  - Approximately how much will these upgrades cost?

2050 Transmission Study: Snapshots Examined

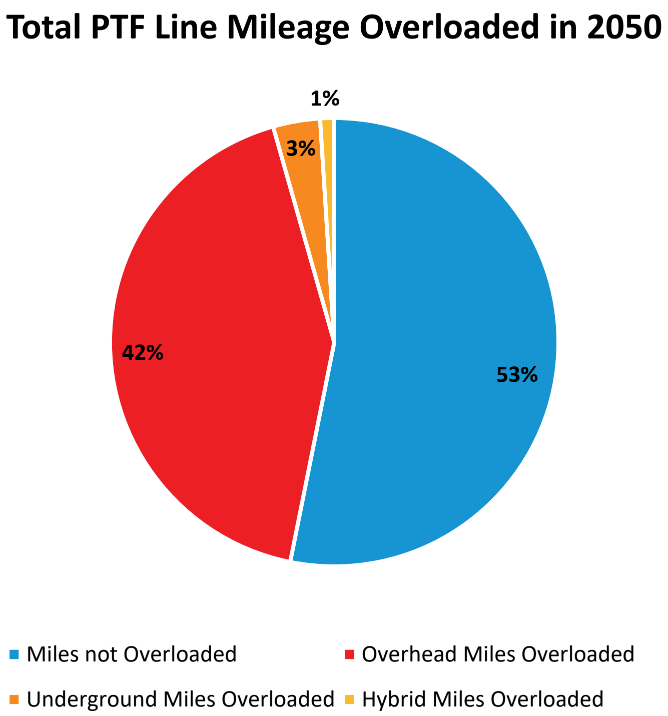
- The 2050 study examines 12 specific snapshots in time
- Focus is on load-serving capability during peak hours, rather than year-round renewable deliverability
- "DC power flow" analysis only: no consideration of voltage or transient stability performance

Power Consumption* by Snapshot (MW)				
Year	Summer Daytime	Summer Evening A (Overall)	Summer Evening B (Northern NE)	Winter Evening
2035	29,375	26,749	25,741	35,116
2040	32,447	32,968	31,968	43,046
2050	40,004	38,601	38,492	56,997

New England is summer-peaking today, but **winter-peaking by 2035** in the "All Options" Pathway.

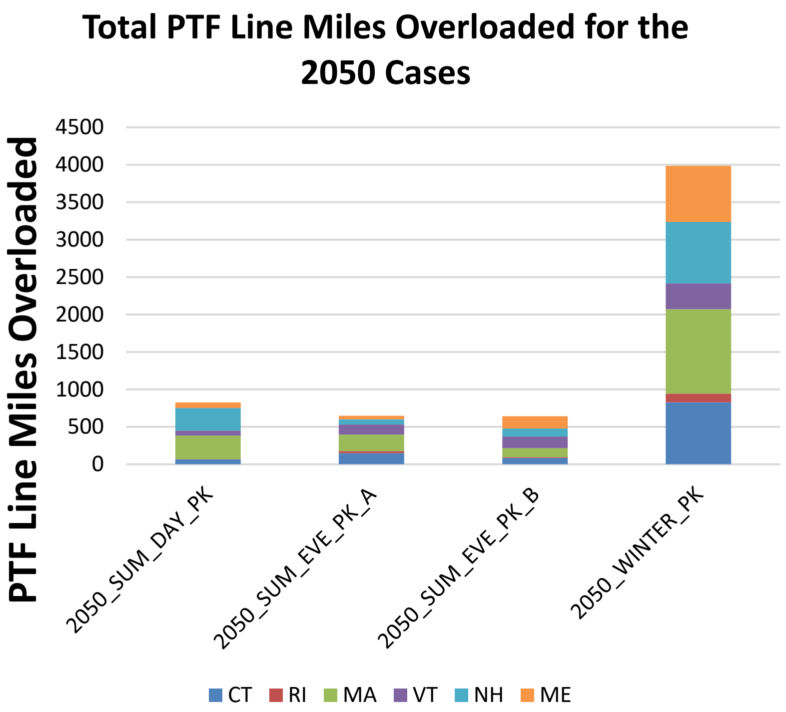
* Includes distribution losses and reductions due to energy efficiency. Does not include transmission losses or reductions due to distributed solar installations.

Percentage of Line Mileage Overloaded in 2050



- Approximately half of the total Pool Transmission Facility (PTF) line miles in New England (~4,200 miles out of ~9,000 miles) are overloaded in 2050
- Approximately 90 PTF transformers (of about 150 total) are also overloaded in 2050

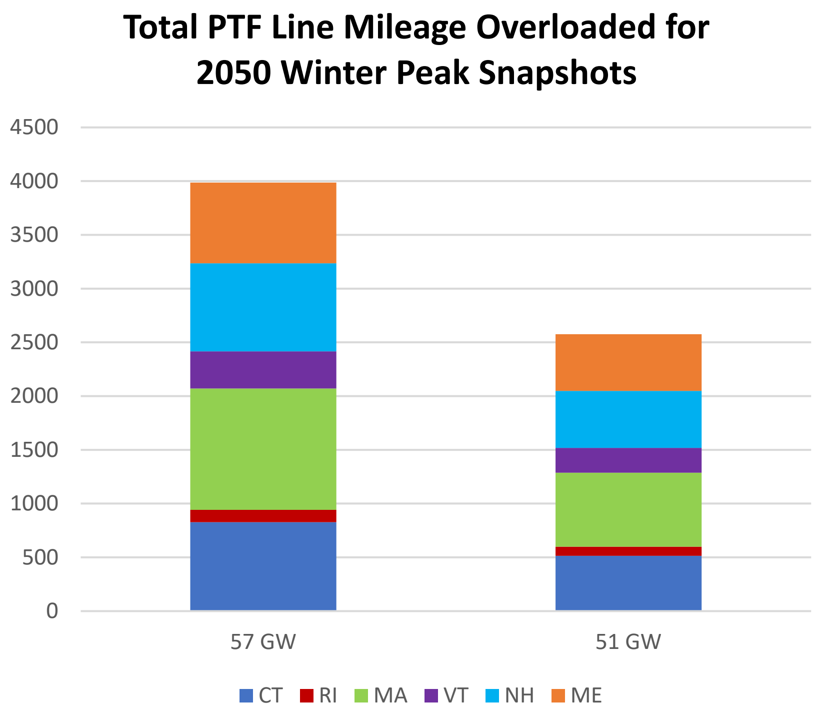
2050 Results by Snapshot



- In 2050, the vast majority of overloads occur in the Winter Evening Peak due to electrified heating
- Overloads spread throughout all six New England states
  - New Hampshire and Maine have relatively high amounts due to high North-South transfers driven by new resource assumptions

Sensitivity Analyses

- Sensitivity analysis was performed to determine relationship between peak load and overloaded mileage
- Reducing winter peak loads significantly reduces transmission concerns
  - A ~10% reduction in load causes roughly a 35% reduction in overloaded transmission miles
  - Assumes that decreased load is offset by decreased northern New England generation



2050 Transmission Study: Key Takeaways So Far

- Under the conditions studied:
  - Winter peak is a major driver of transmission concerns in the long term
  - Generator interconnection locations are critical
    - Interconnecting in southern New England rather than northern New England tends to reduce transmission needs
  - Additional 345/115 kV transformer capacity is required
    - Serving peak load from remote renewable resources requires long-distance transmission at high voltage, and then transformation to reach local substations
    - Generator interconnections directly to the 115 kV network may help, but often require upgrades on the 115 kV system instead
  - Outside of dense urban areas, many concerns can be resolved through incremental upgrades (rebuilding/reconductoring existing lines)

2050 Transmission Study: Ongoing Analysis

- Solution development is expected to continue throughout late 2022 and early 2023
  - Begin with “primary solution set,” and then address intermediate years and the original 57 GW winter peak
  - Includes development of order-of-magnitude cost estimates for solution components
- Final 2050 Transmission Study report expected in 2023

Primary Set

- Solutions to address 2050 reduced Winter Peak (51 GW) and Summer Peak snapshots

2035 & 2040

- Subsets of primary solution set to fully address needs in 2035 and 2040

57 GW Winter

- Additional solutions to fully address original 2050 Winter Peak (57 GW load)

Supporting the Transmission Grid for 2040 and 2050

- Transmission upgrades can reduce renewable curtailment and congestion
- Winter peak is a major driver of transmission concerns in the long term
- Reducing winter peak loads significantly reduces transmission concerns
- Generator interconnection locations are critical

Questions?

THURSDAY, OCTOBER 13, 2022

Leveraging Existing Planning Processes to Prepare for the Energy Transition

Megan Lund, Manager – Transmission Planning, Southwest & East

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About the IESO

Operate Ontario’s province-wide electricity system on a 24/7 basis

Support innovation and emerging technologies

Oversee the electricity market, driving competition to maintain affordability

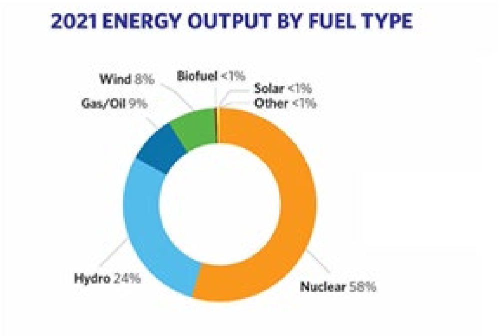
Work closely with communities to explore sustainable options

Plan for Ontario’s future energy needs

Enable province-wide energy conservation

Key Electricity Trends in Ontario

- Demand for electricity is on the rise
- Existing and new resources will be required to maintain reliability
- Technological evolution is leading to more decentralized grid
- Interest in decarbonization continues to grow
- Nuclear refurbishments and retirements are contributing to new supply needs



FUTURE

Exploring pathways to **decarbonization**

Expanded opportunities for **energy storage**

Local energy projects that contribute to the provincial grid

Potential for increased **energy efficiency**

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Exploring Pathways to Decarbonization

- The IESO is developing achievable pathways to decarbonizing our sector, considering factors such as system reliability, cost and timelines.
- Study will consider a potential increase in resources like energy storage, imports and energy efficiency.
- Potential electrification forecasts showing demand could double or triple.
- Continue to work with provincial and federal governments to ensure our focus aligns with environmental policy objectives.

Levels of Electricity Planning

IESO Accountabilities

Bulk System Planning

- Electricity transfers across the Province
- Transfers across the interties
- System resource adequacy
- Relieving congestion, eliminating inefficiencies, enabling the market – where economic
- Incorporation of large generation

Regional Planning

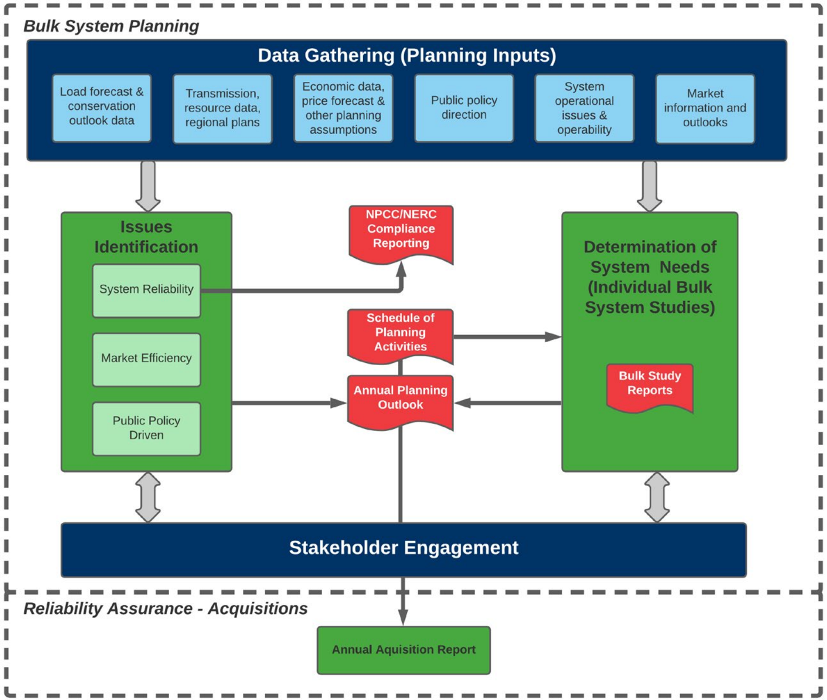
- Local deliverability
- Load security and restoration
- Customer connection facilities; load supply stations
- Energy efficiency and local generation resources

Distribution Planning

- Load supply stations
- Distribution facilities (under 50 kV)
- Distribution connected generation, demand side resources/efficiency

Overview of the Bulk System Planning Process

- Data gathering happens continuously to maintain the inputs for doing planning studies
- Issues Identification comprises the annual assessments to identify potential resource adequacy and bulk transmission system issues
- A Schedule of Planning Activities is a roadmap of anticipated Bulk System Studies
- Bulk System Studies are focused, solutions-oriented studies done per the Schedule of Planning Activities
- The APO summarizes the system needs identified via Issues Identification and Bulk System Studies



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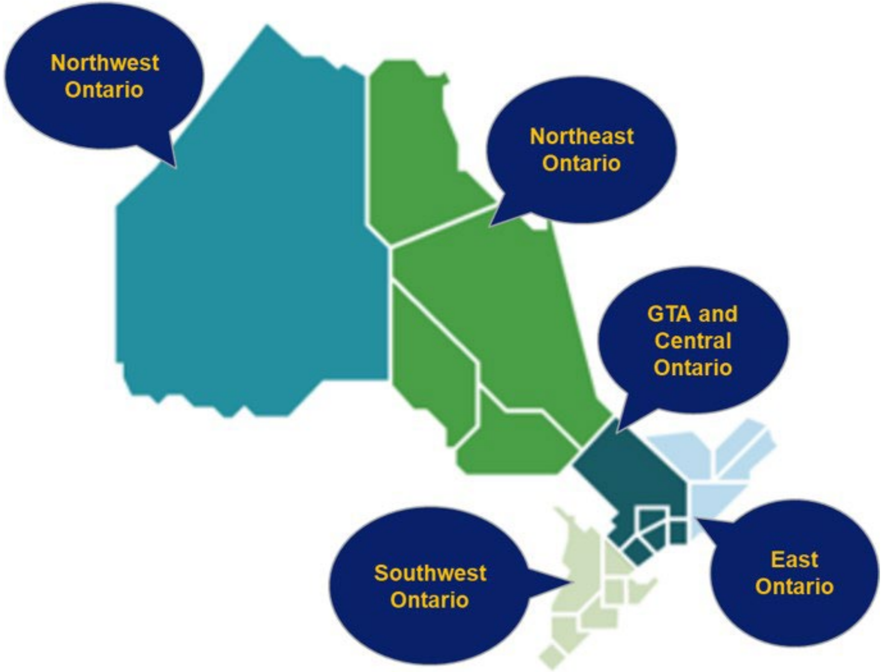
Overview of Regional Planning

- 21 electricity planning regions
- Based on electricity infrastructure boundaries
- Planning based on each region's unique needs and characteristics
- Each region goes through a formal planning process at least once every 5 years
- Undertaken by a technical working group which includes the IESO, transmitter(s) and distributor(s)



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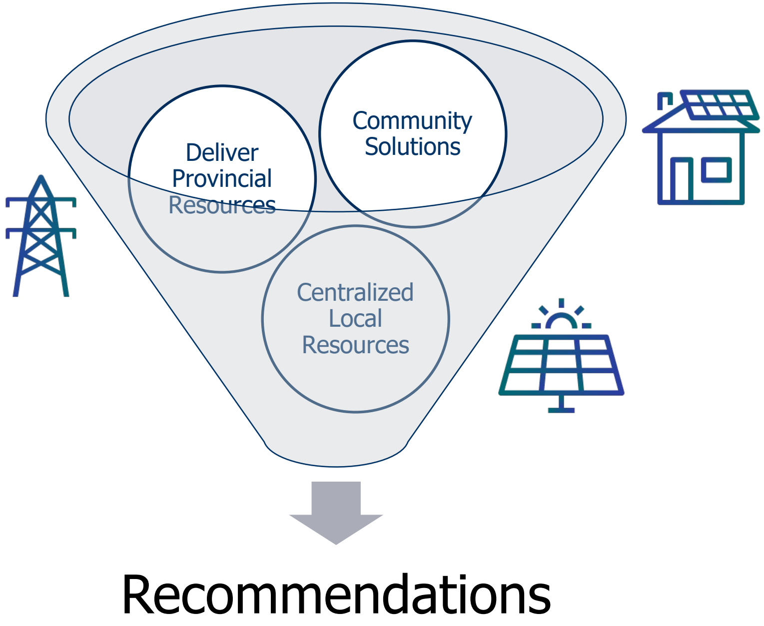
Integrated Regional Resource Plans

- Following a high level need screen, if comprehensive planning is required an IESO led Integrated Regional Resource Plan is launched
- The plan studies electricity demand over a 20 year outlook and assesses the current electricity supply infrastructure to ensure it will be sufficient to meet needs
- Both “wires” and resource options are evaluated to meet the needs
- Recommendations are made to initiate any infrastructure needed in the near- to medium-term, depending on lead time



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Increasing Uncertainty in Key Planning Inputs

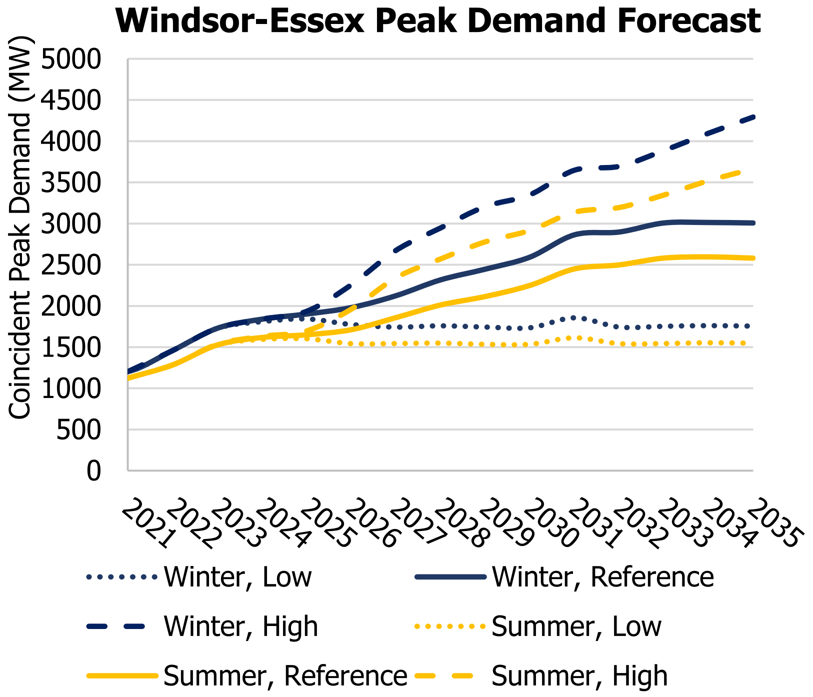
Load Forecast

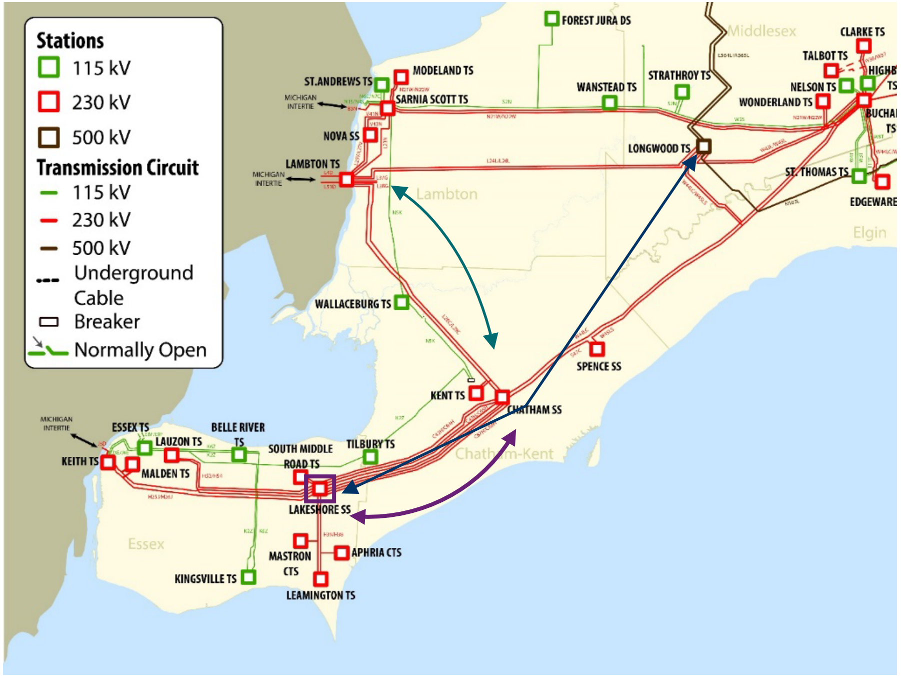
Local Generation

Option Costs & Lead Time

Bulk Planning Case Study: West of London/Windsor-Essex (Southwestern Ontario)

West of London & Windsor Essex Bulk System Plans





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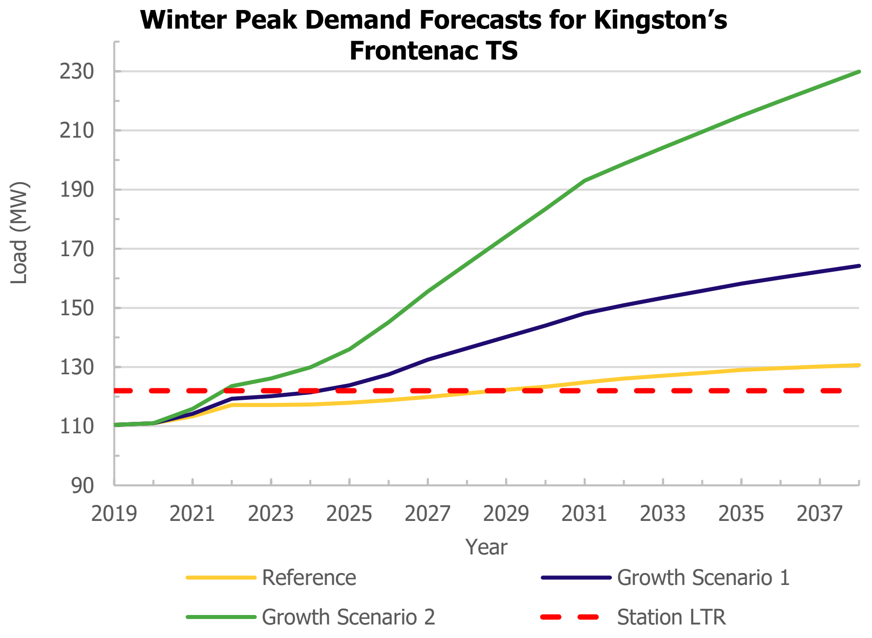
Factors Considered for Long-term Recommendation

	Enhanced with 230 kV	Enhanced with 500 kV	Neutral
Cost	x		
Ability to meet future demand		x	
Land use – transmission corridor	x		
Land use – stations		x	
Resiliency		x	
Deliverability of existing resources			x
Reliability during outages	x		
Operational flexibility		x	
Interchange with Michigan			x
Transmission losses		x	
Community preferences	?	?	?
Other factors?	?	?	?

Regional Planning Case Study: Peterborough to Kingston IRRP (City of Kingston, Ontario)

City of Kingston – Reflecting the Community's Needs



Success comes from working together

✓Close collaboration between the distributor and the municipality

✓Strong relationships between the distributor and their large customers, leveraged to understand their future plans to meet policy goals

✓Active engagement from municipality and customers in both public webinars and targeted outreach throughout the regional planning process

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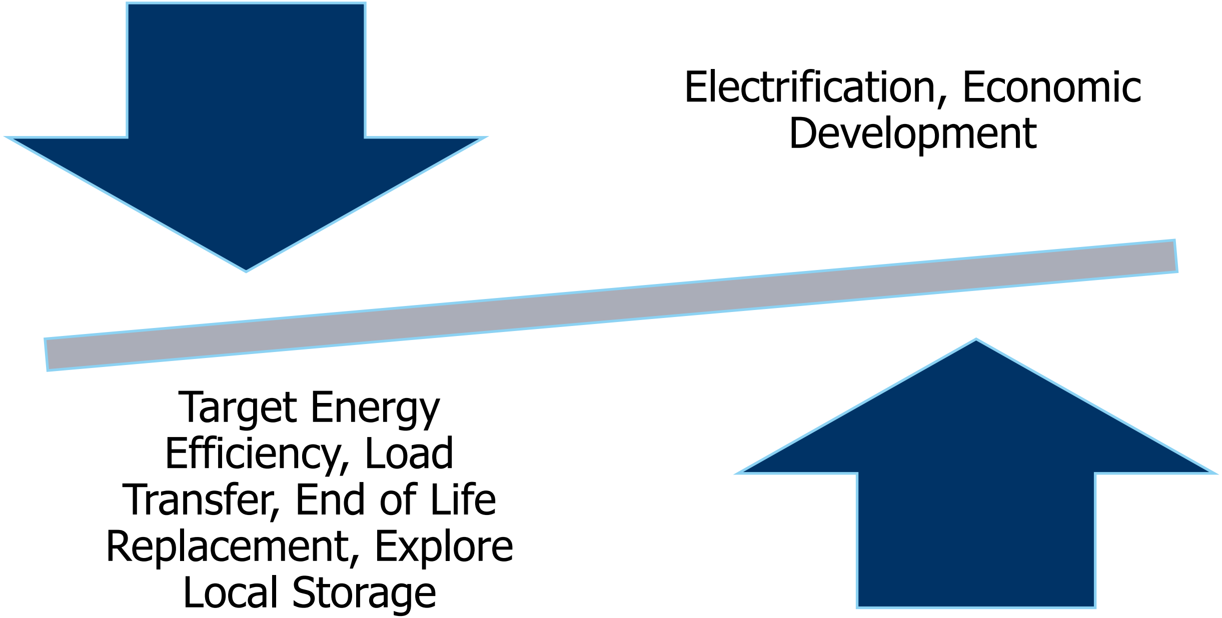
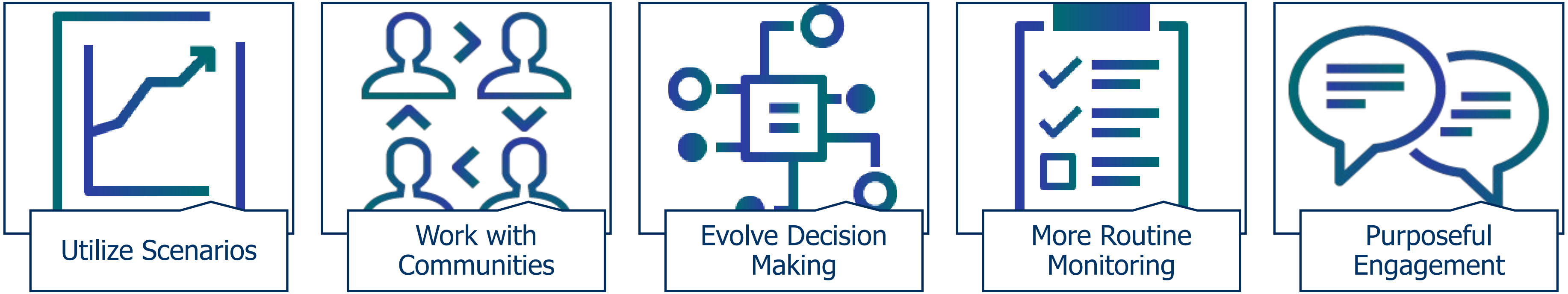
Integrated Solutions to Manage Mid-term Uncertainty



- ❑ Frequent monitoring
- ❑ Distributor and Transmitter to trigger station development work when needed

Takeaways on Opportunities to Progress in the Near-term with Existing Planning Processes

While a “process” can be viewed as constraining, there are opportunities to leverage our day-to-day planning activities by being open to change and thoughtful in our approaches



Thank You

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Transmission - A Key Enabler

NPCC Workshop

October 13, 2022

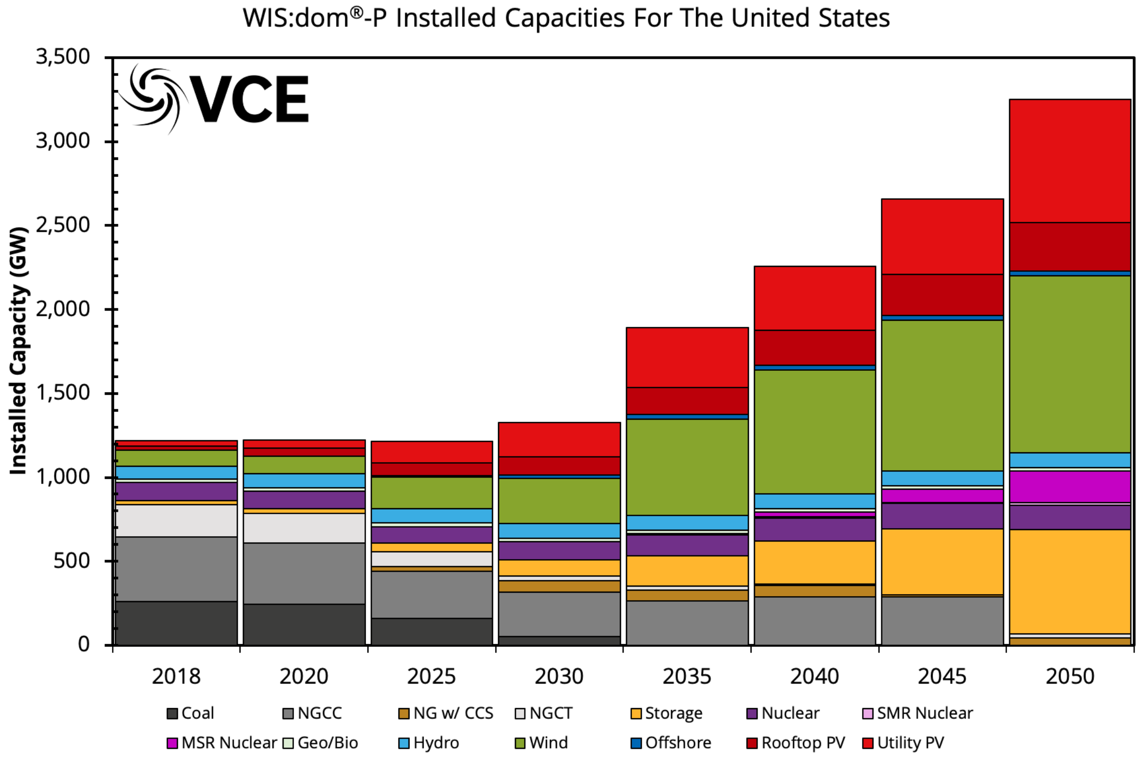
J. Charles Smith, Executive Director, ESIG

ESIG

ENERGY SYSTEMS INTEGRATION GROUP

Wind and solar generation must grow exponentially

- We may need 1 TW or more of new wind and PV capacity to reach 100% clean electricity goals (that's 5x current wind/PV capacity)
- Decarbonizing the entire US energy economy may require twice that.

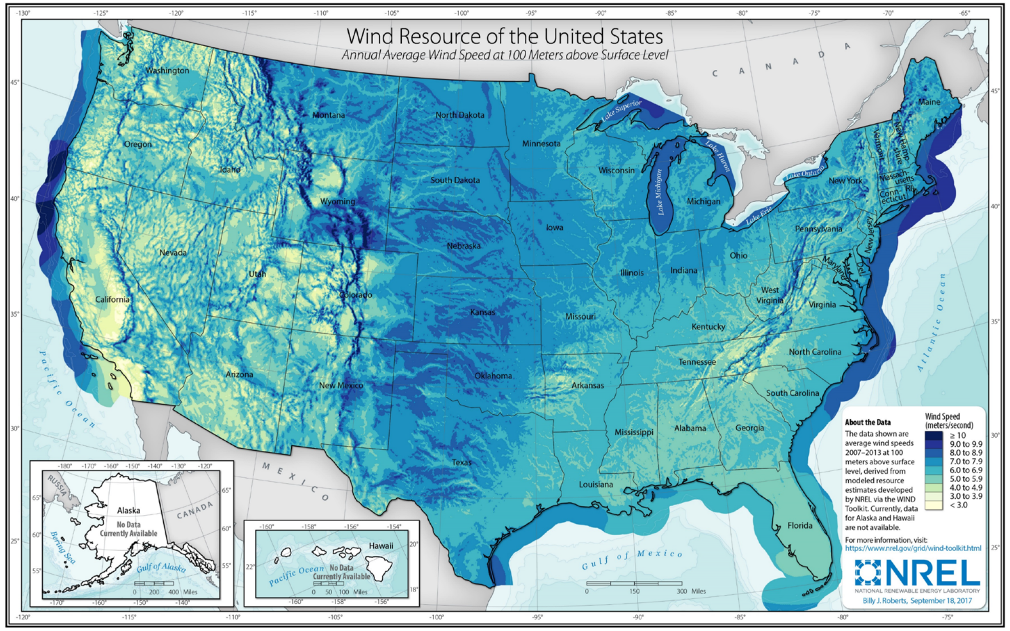


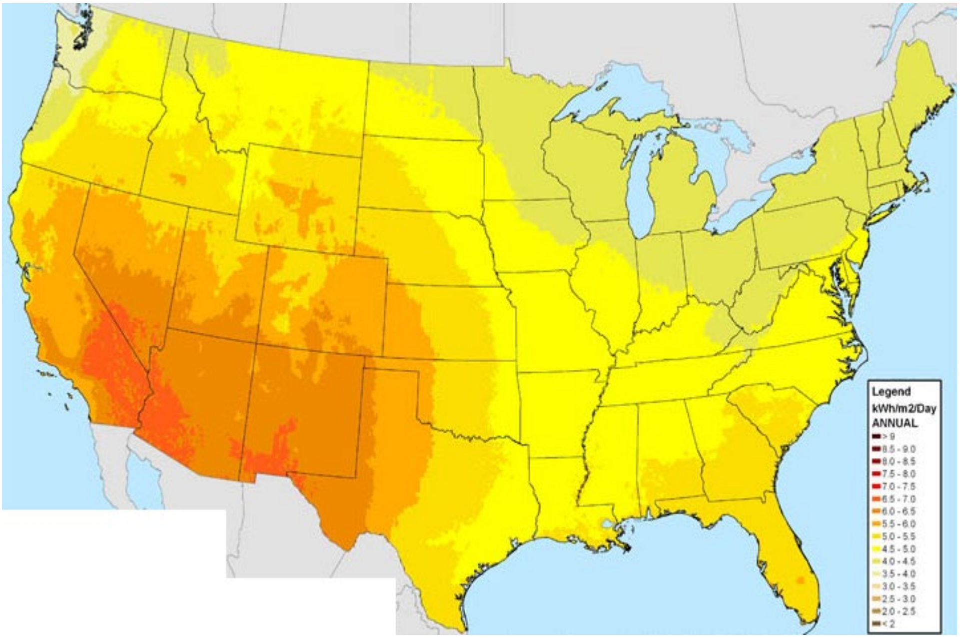
MISO RIIA 100% buildout [MW]			
	DPV	UPV	wind
MISO	32,190	67,975	129,647
SPP	8,139	14,700	41,750
TVA	40,174	85,275	7,300
SERC	85,119	180,825	15,250
PJM	41,174	93,100	185,600
NYISO	8,483	19,675	31,600
Total	**215,279**	**461,550**	**411,147**

Source: MISO RIIA Study, Preliminary results from VCE's ZeroByFifty Study

Transmission and Renewable Energy
Inescapable physical properties

1. Best wind and solar far from load. 88% in 15 central states.
2. Regional exchange allows system balancing with higher penetration
3. Transmission supports weak parts of grid as generators retire, system inertia declines

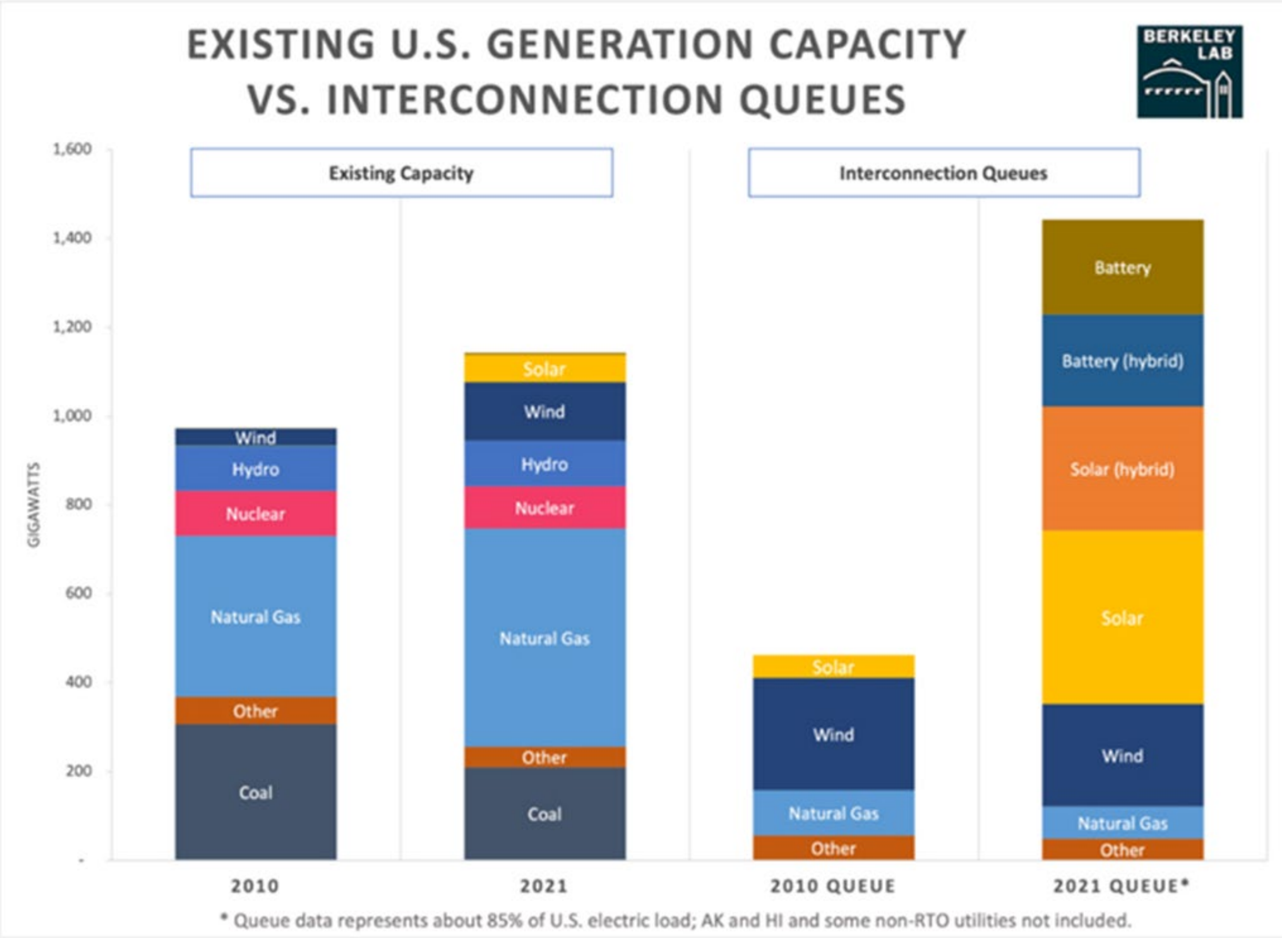




NREL Wind (left, 100m height) and Solar (right) Resource Maps

https://windexchange.energy.gov/maps-data/319 , https://www.nrel.gov/gis/images/map_pv_us_annual10km_dec2008.jpg

Generating Capacity and Queues – Then and Now



Source: Lawrence Berkeley National Laboratory

Figure 1: Existing U.S. capacity (2010 and 2021) compared to interconnection queue capacity (2010 and 2021).

We evaluated a number of studies

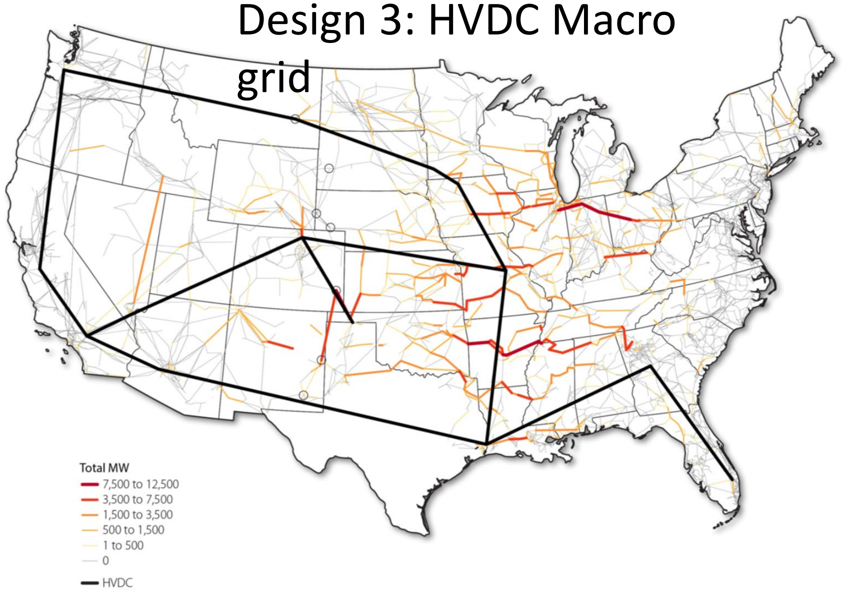
Study	Region	Renewable Capacity	Clean Energy Level(s)	Annual Electricity Demand	Target Year
The 2035 Report	United States	1,100 GW (wind and solar)	90% clean electricity	4,500 TWh	2035
Electrification Futures Study	United States and Canada	600 GW (wind) 1,000 GW (solar)	23% to 75% renewable energy	7,000 TWh	2050
Interconnections Seam Study	United States (except Texas) and Canada	600-900 GW (wind and solar)	63% to 95% carbon free electricity	4,900 TWh	2038
MIT study	United States	1,200 GW (wind) 1,100 GW (solar)	100% clean electricity	5,000 TWh	2040
Renewable Integration Impact Assessment	United States - Eastern Interconnection	411 GW (wind) 677 GW (solar)	Up to 100% clean electricity for the eastern interconnection	2018 demand	N/A
ZeroByFifty	United States	1,100 GW (wind) 1,000 GW (solar)	100% clean energy	9,000 TWh	2050

A network of cross-country transmission is critical to minimizing cost

Interconnections Seam Study

- What's the value of interconnecting the east and west?
- Crossing the seam allows you to build the solar in the west and the wind in the east and share
- 50% renewables case: macro grid adds \$19B to transmission costs but saves \$48B (generation capacity, O&M and emissions), for a benefit/cost ratio of 2.5
- 85% renewables case (95% clean electricity): macro grid builds 40GW transfers across seam with a benefit/cost ratio of 2.9

Design 3: HVDC Macro grid

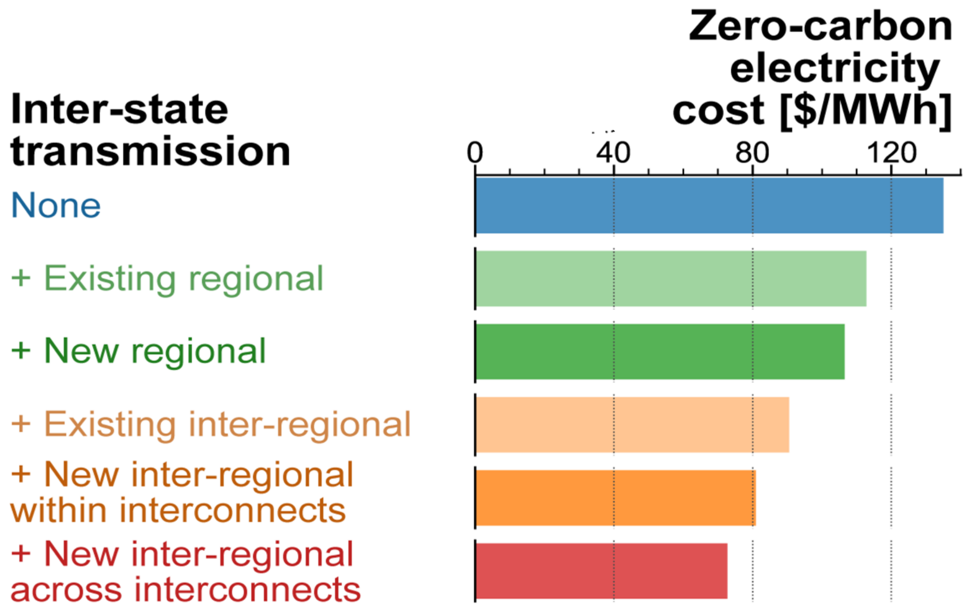


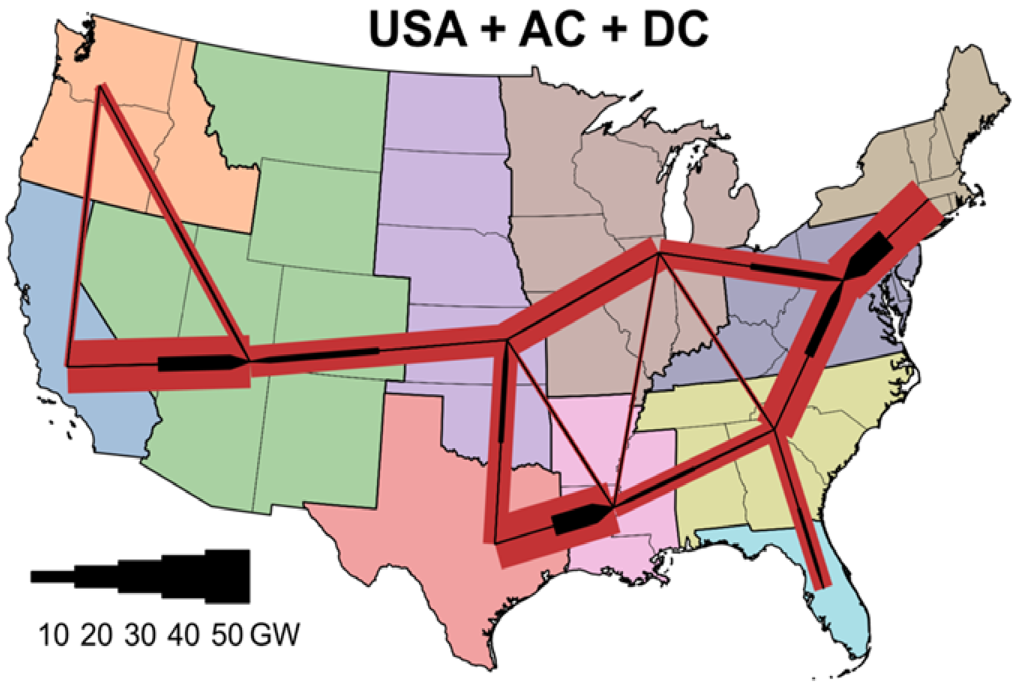
50% Renewables case	BAU across seams	HVDC Macro grid	
Objective function	**Design 1**	**Design 3**	**Delta**
Line investment (B$)	61.21	80.10	18.89
Generation investment (B$)	704.03	700.51	-3.52
Operation and maintenance (B$)	1336.36	1300.70	-35.66
Emission cost (B$)	171.10	162.50	-8.60
35-yr B/C ratio	-	-	2.52

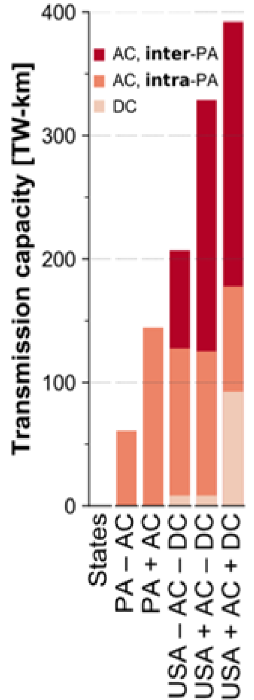
https://www.nrel.gov/analysis/seams.html

MIT Study - Value of Transmission for Decarbonization

- What is the value of coordination within regions, between regions and nationally?
- Co-optimized capacity expansion and dispatch model with 7 years of hourly weather
- Least-cost plan results in nearly double today's transmission system (in MW-miles) with 40 GW transfers between east and west and 70 GW between ERCOT and east
- Finds that an "every state for itself" approach has a levelized capital and O&M cost of \$135/MWh and that this cost can be reduced by 46% (to \$73/MWh) with inter-regional coordination and transmission expansion



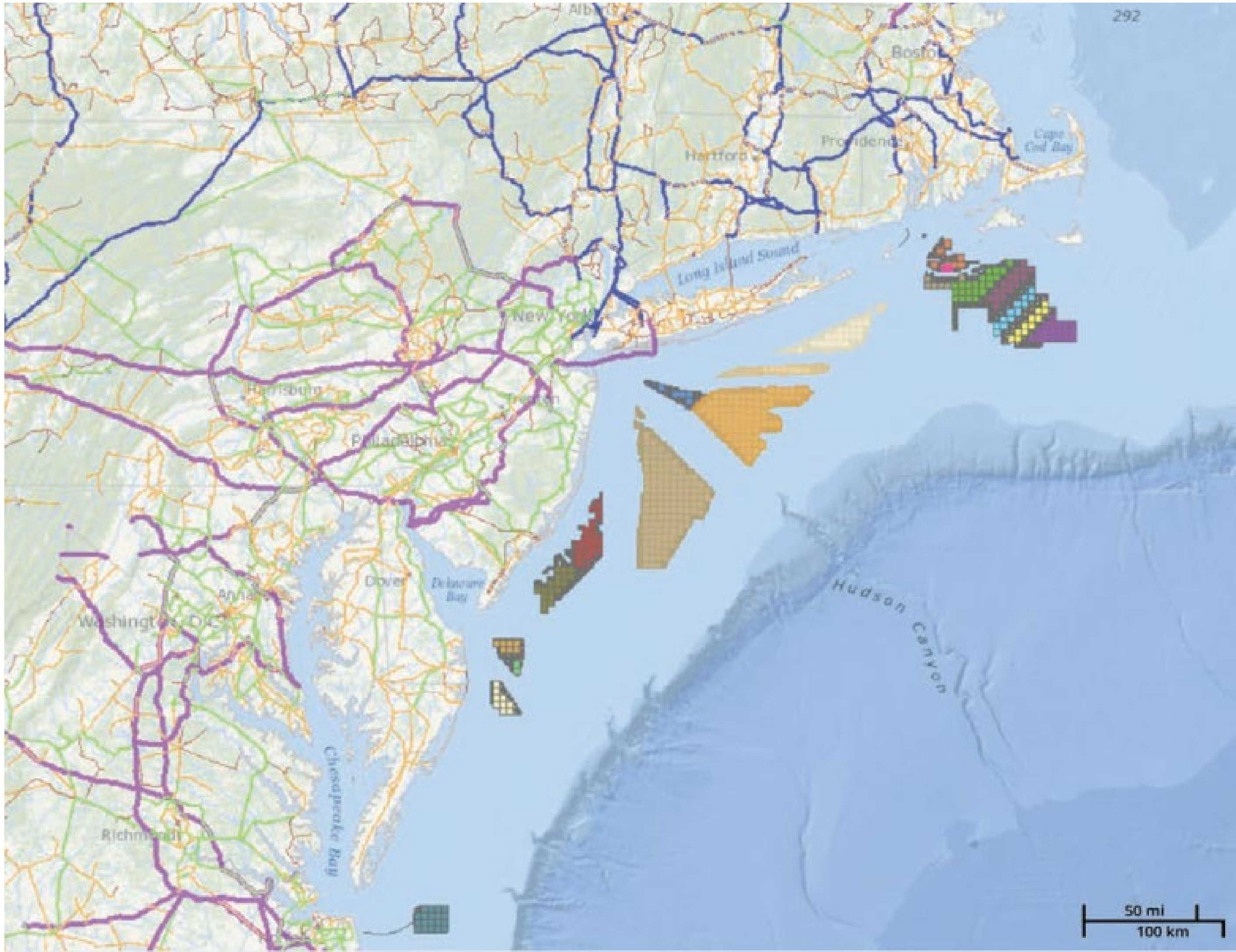




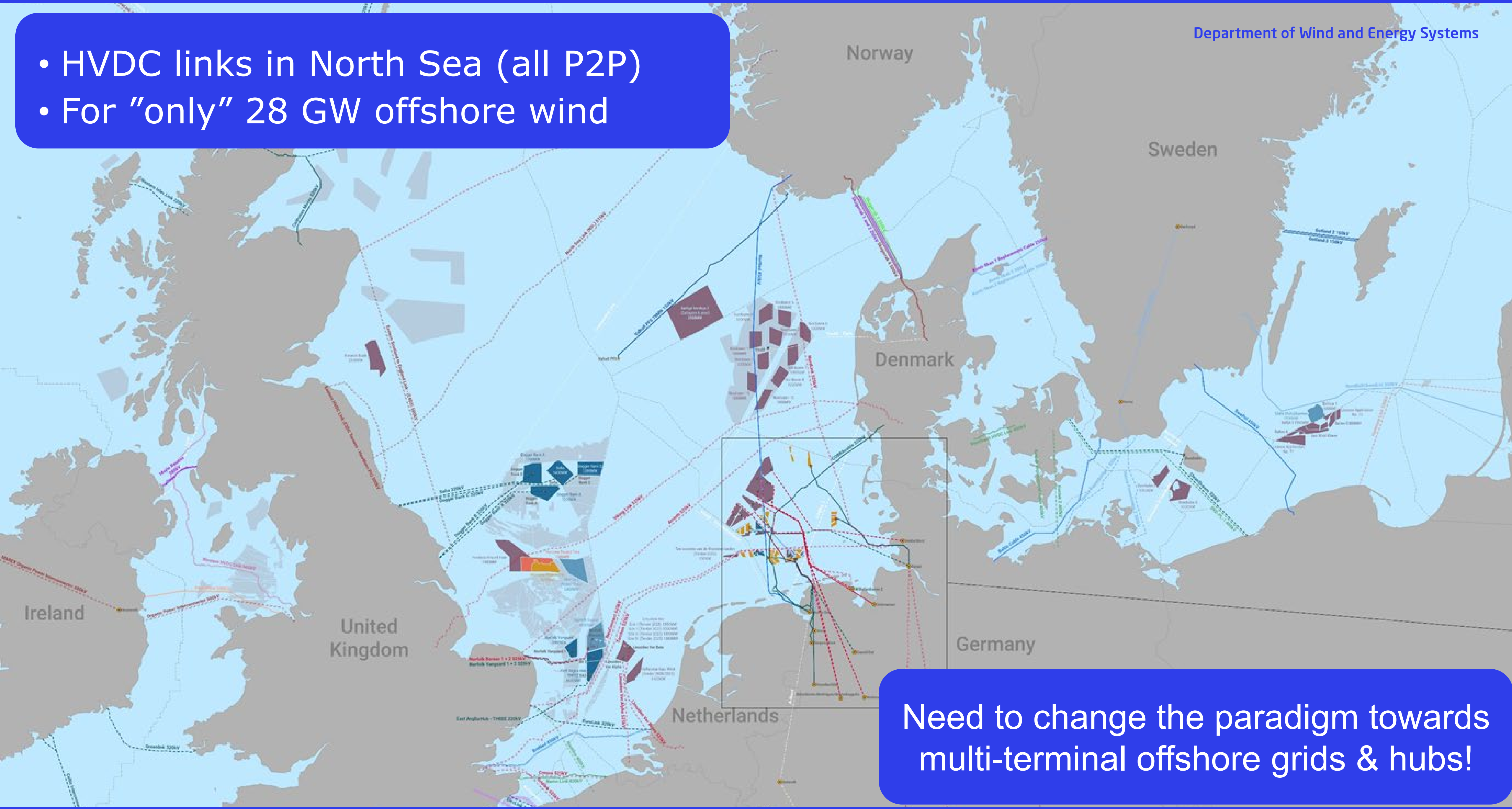
https://doi.org/10.1016/j.joule.2020.11.013

Offshore too!

- 30 GW in state plans
- Over 100 GW if the Northeast states decarbonize
- Provides diversity along West Coast as well
- High capacity value
- Transmission needed to efficiently access



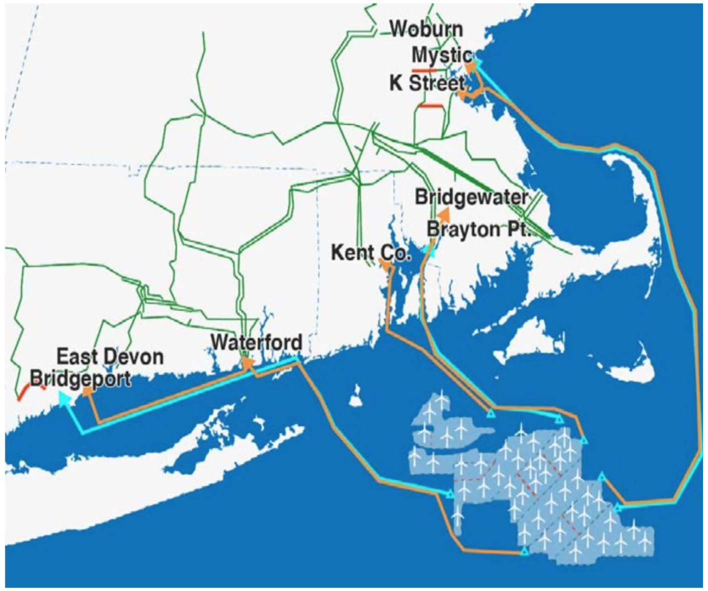
- HVDC links in North Sea (all P2P)
- For ”only” 28 GW offshore wind



Need to change the paradigm towards multi-terminal offshore grids & hubs!

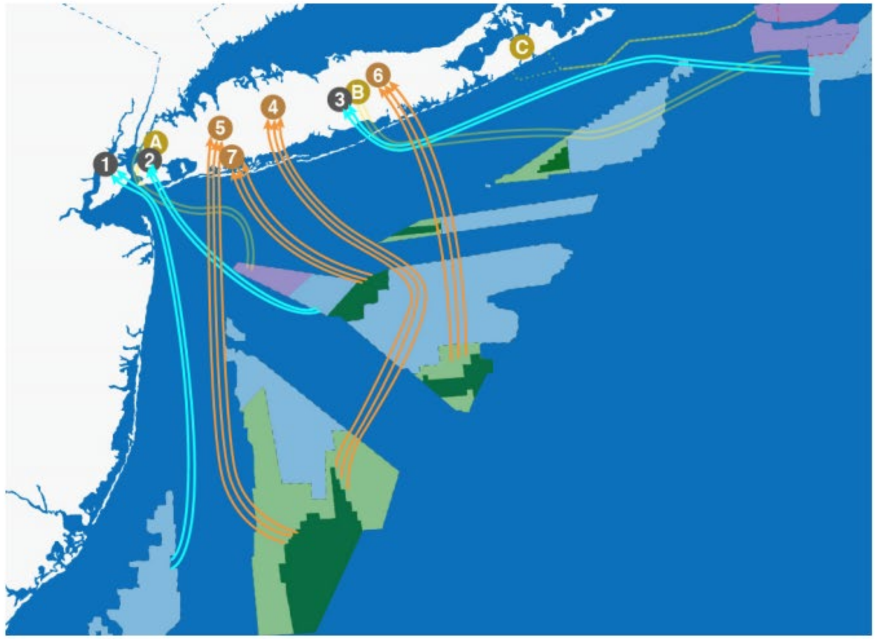
Anbaric/Brattle offshore wind studies

- ISO-NE: Proactive, planned approach saves $1B in onshore upgrades
  - HVDC grid design to enable 8.6 GW of wind without requiring major onshore grid updates
- In NYISO, it would save $500M
  - 9 GW of offshore wind

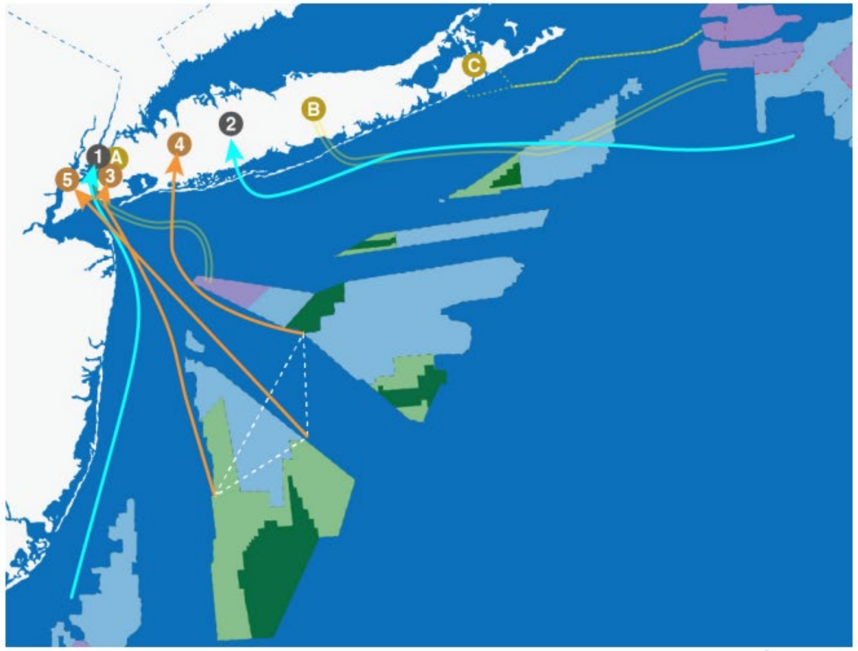


https://newengland.anbaric.com/wp-content/uploads/2020/07/Brattle_Group_Offshore_Tranmission_in_New-England_5.13.20-FULL-REPORT.pdf
http://ny.anbaric.com/wp-content/uploads/2020/08/2020-08-05-New-York-Offshore-Transmission-Final-2.pdf

GLL Offshore Transmission Scenario

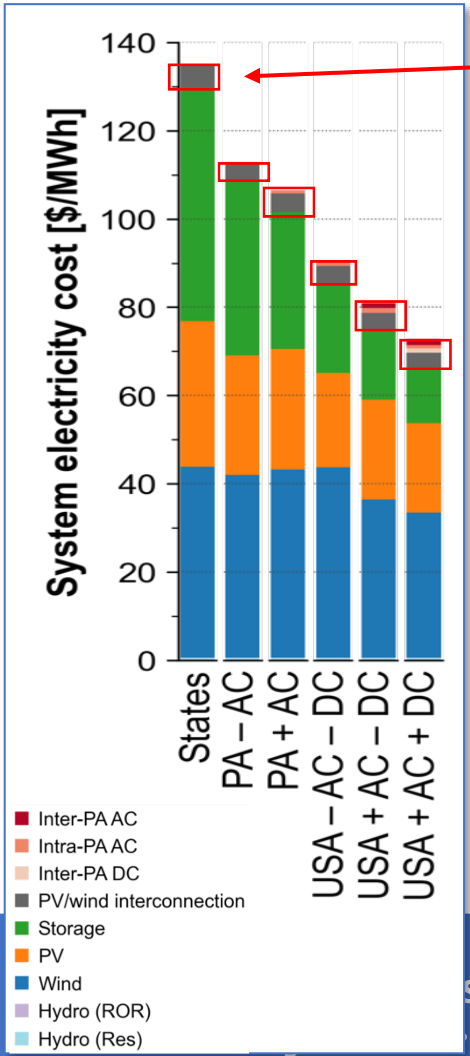


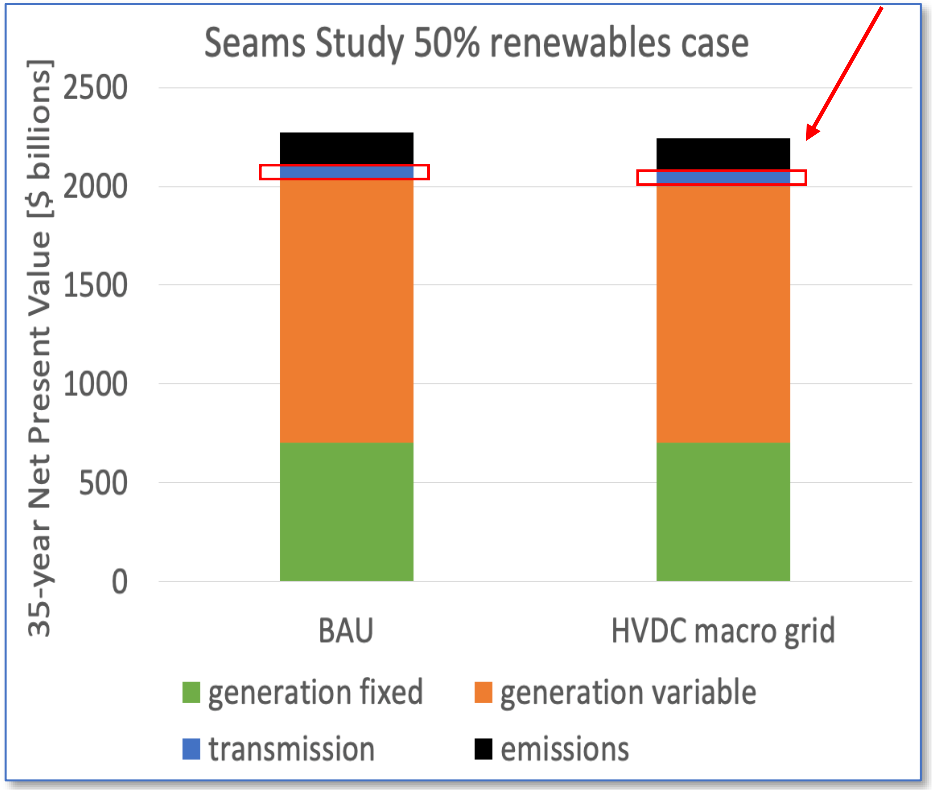
Planned Offshore Transmission Scenario

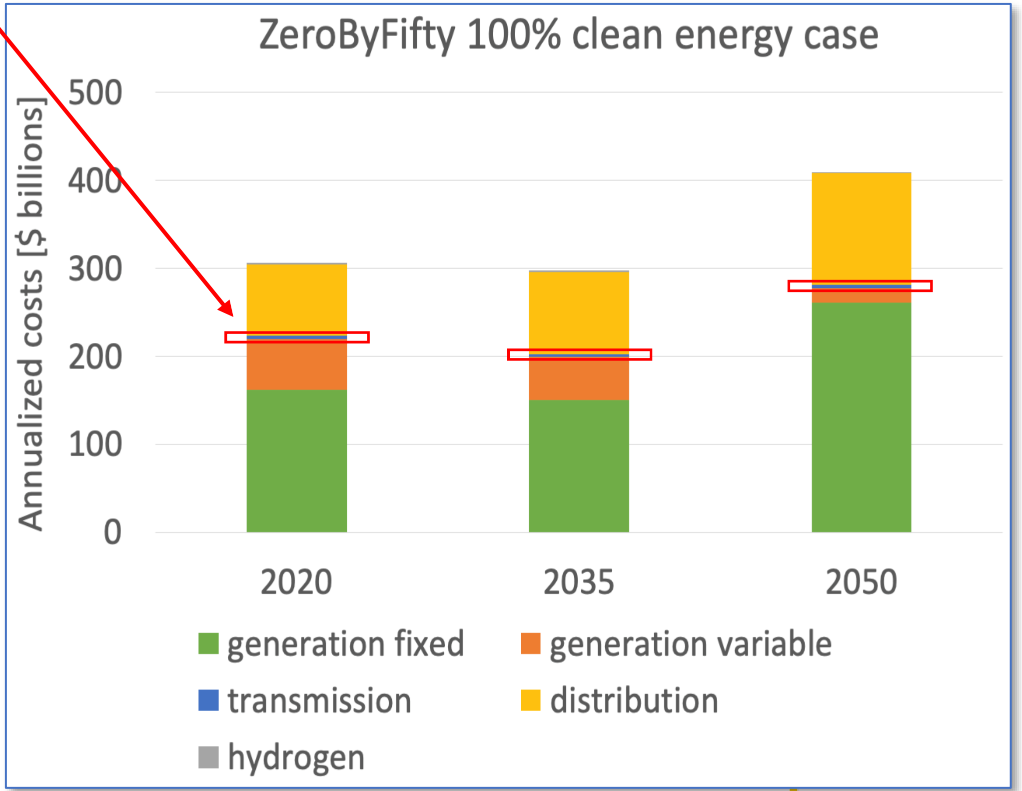


Transmission costs are tiny compared to other clean resources/infrastructure

TRANSMISSION COSTS







s Integration Group

of Energy Systems Integration and Operations

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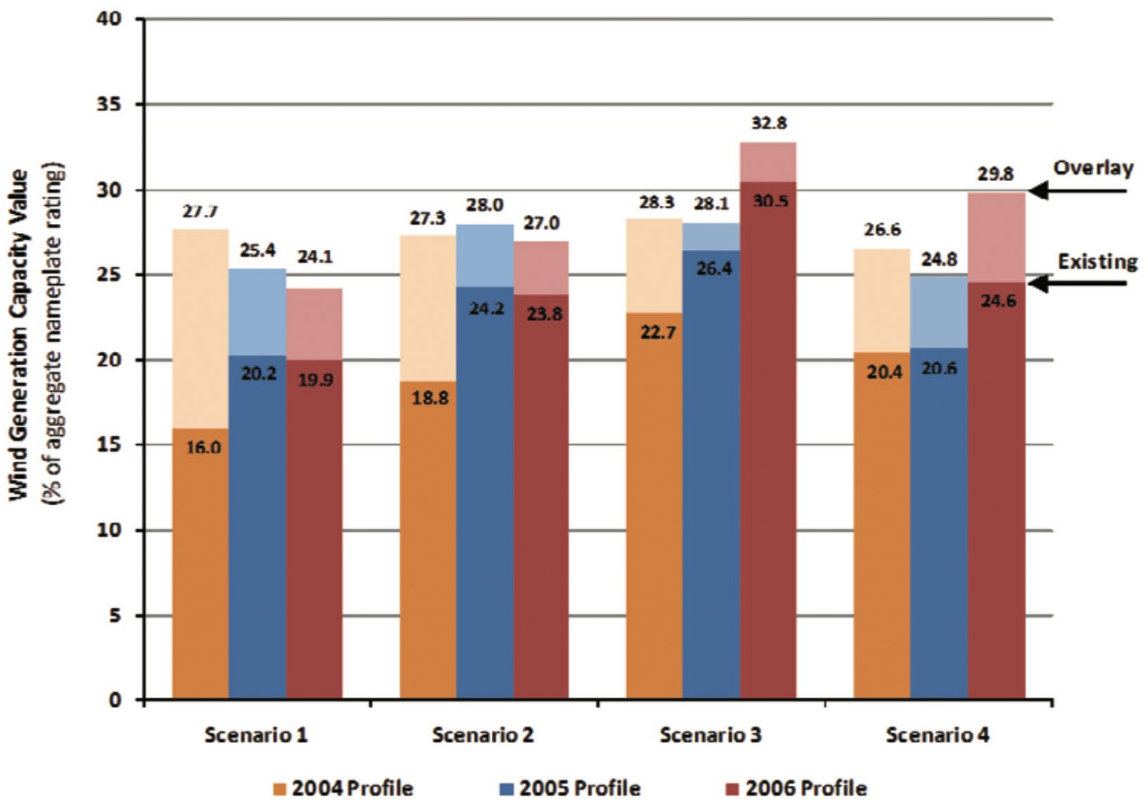
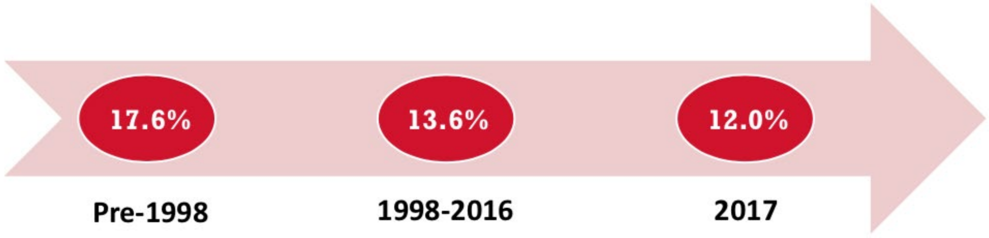
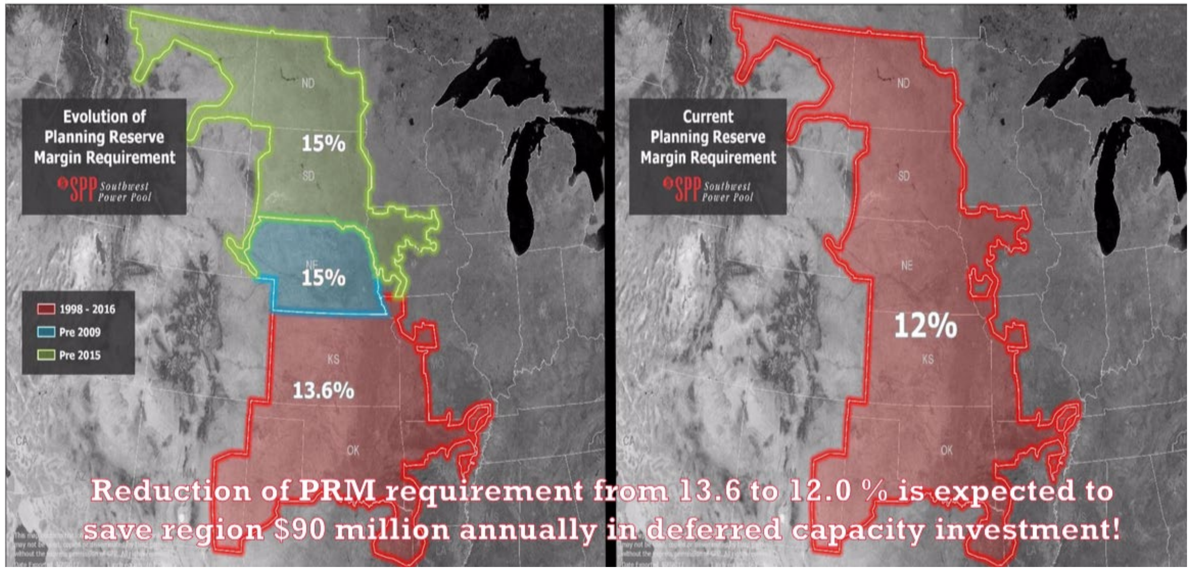
Brown and Botterud, 2020; NREL Interconnection Seams study; Preliminary results from VCE's ZeroBy

Transmission is not just about delivering resources to load

Transmission contributes to resource adequacy







Transmission smooths all time scales of weather variability

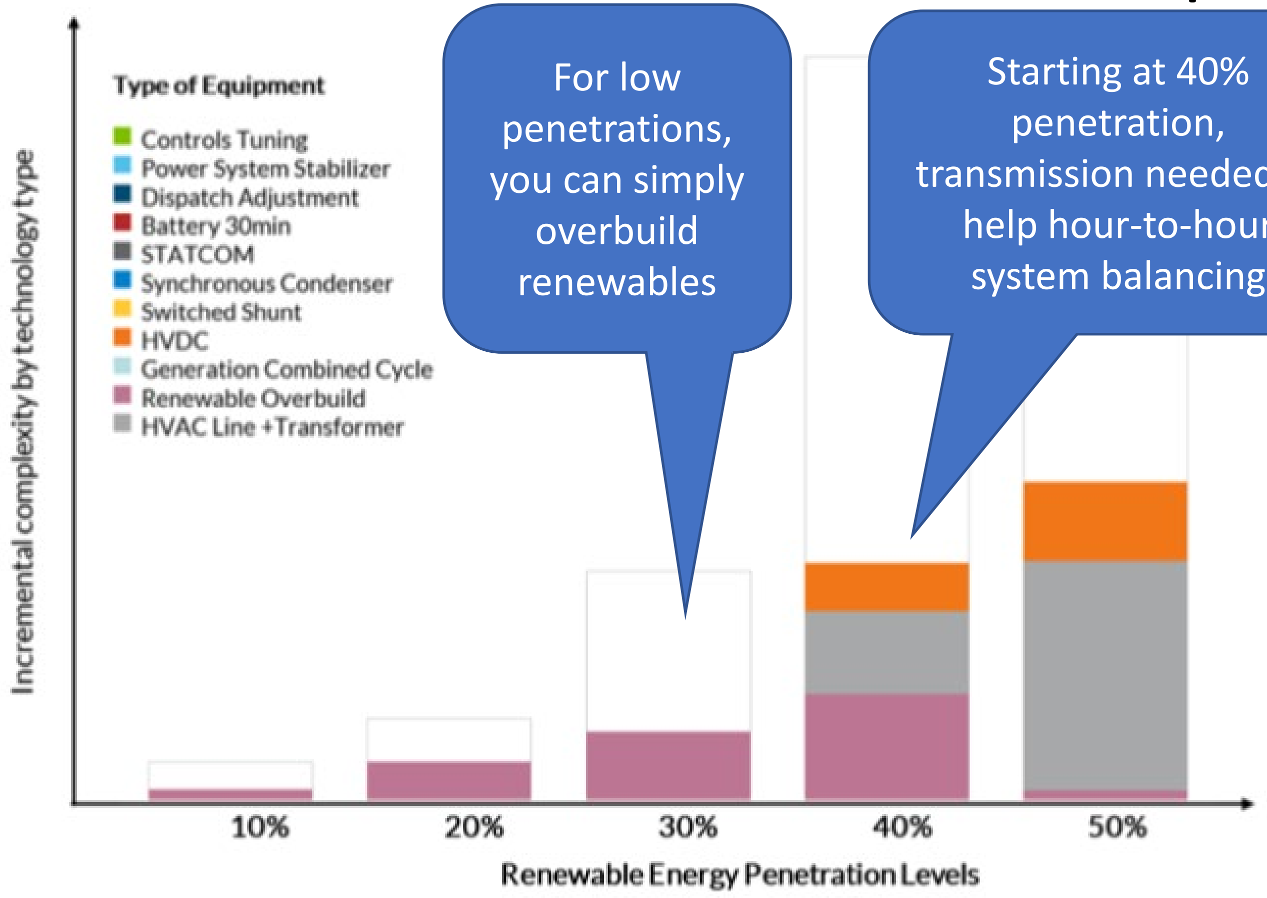
Source: Enernex, EWITS, NREL/SR-550-47078, 2010; L. Nickell, SPP, CREPC Spring meeting, 2017

Energy Systems Integration Group

Charting the Future of Energy Systems Integration and Operations

ESIG

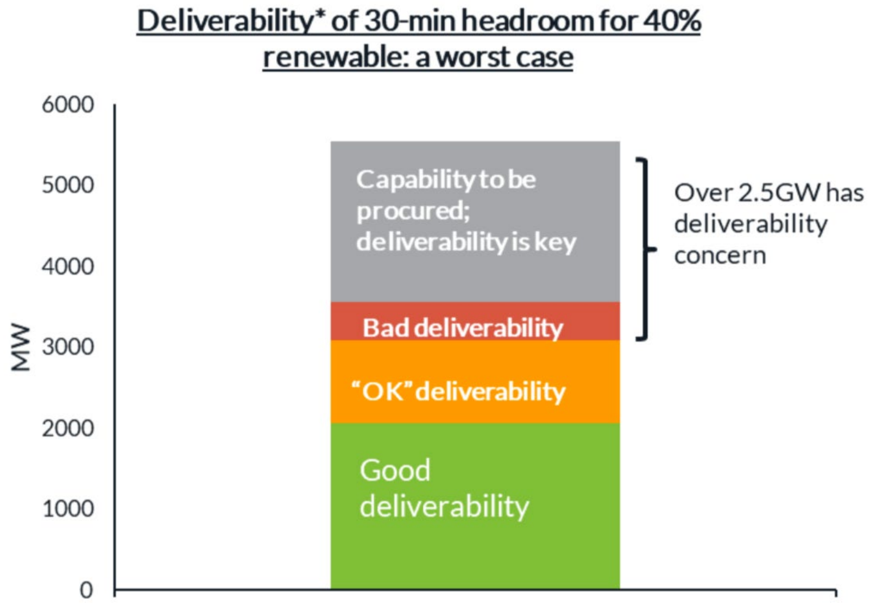
Transmission needed to help system balancing



For low penetrations, you can simply overbuild renewables

Starting at 40% penetration, transmission needed to help hour-to-hour system balancing

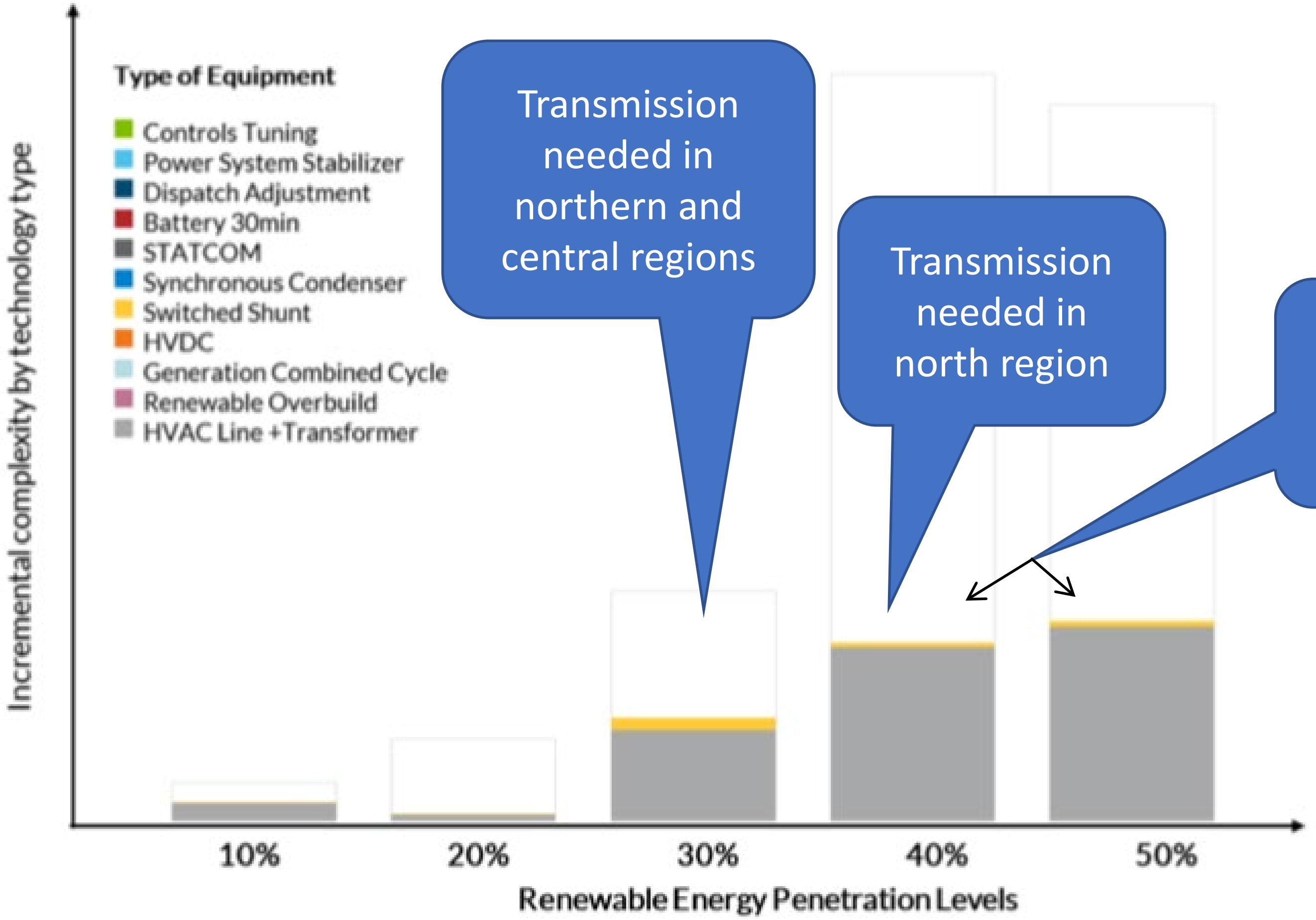
Transmission needed to deliver ancillary services



Transmission is critical to maximizing flexibility

https://cdn.misoenergy.org/RIIA%20Summary%20Report520051.pdf

Transmission needed for steady-state reliability



Transmission needed in northern and central regions

Transmission needed in north region

Higher voltage transmission solutions needed

https://cdn.misoenergy.org/RIIA%20Summary%20Report520051.pdf

Figure UC-10: Steady state solutions - incremental complexity by technology for each renewable penetration milestone

Transmission infrastructure needed for dynamic stability

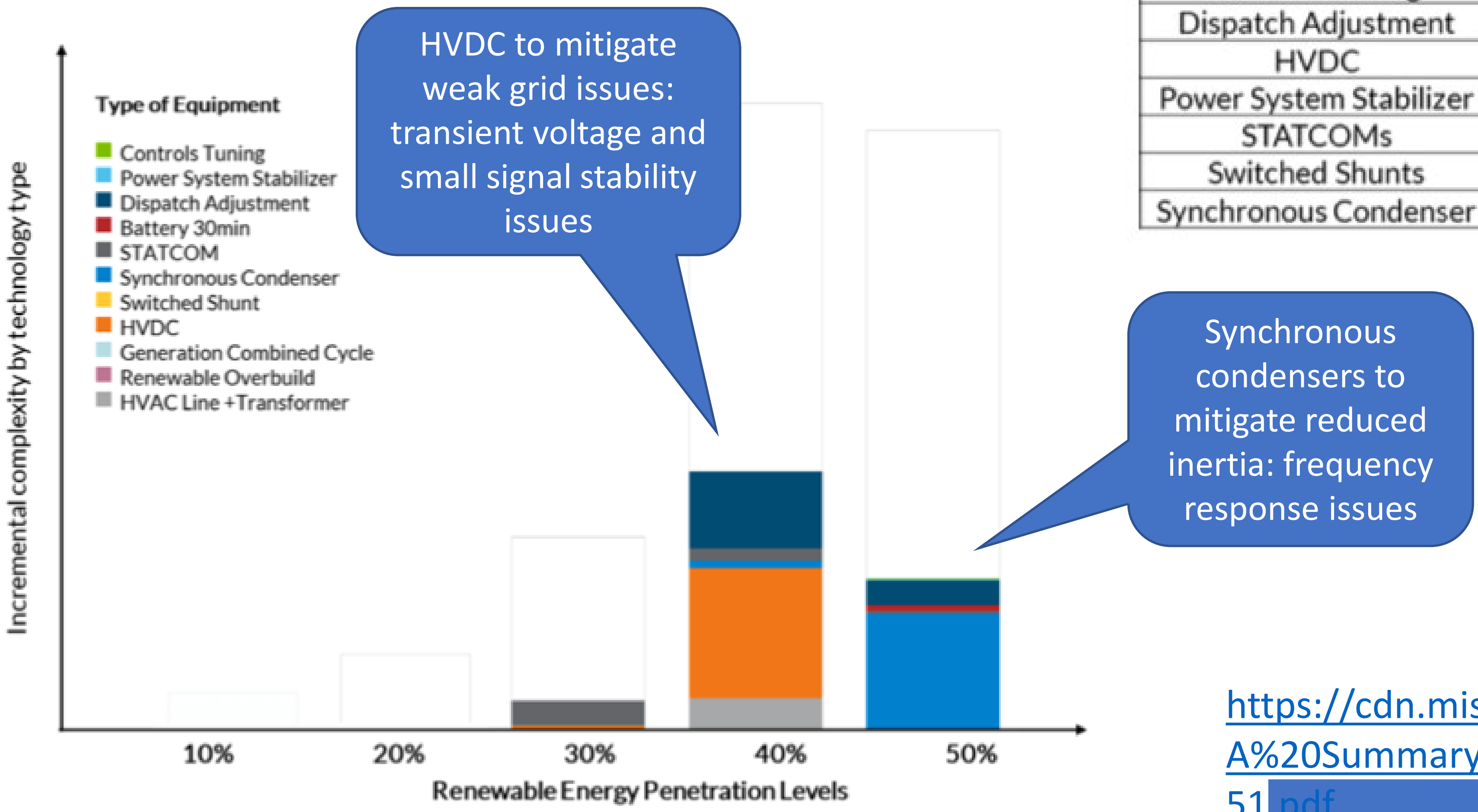


Figure UC-12: Dynamic stability solutions - incremental complexity by technology for each renewable penetration milestone

# of equipment per milestone	MISO + Eastern Interconnect			
	30%	40%	50%	Total
Batteries (30min)	-	-	1,233	1,233
Controls Tuning	-	-	1,787	1,787
Dispatch Adjustment	-	169	60	229
HVDC	1	4	-	5
Power System Stabilizer	-	-	109	109
STATCOMs	47	31	23	101
Switched Shunts	-	-	1	1
Synchronous Condenser	5	14	248	267

https://cdn.misoenergy.org/RIIA%20Summary%20Report520051.pdf

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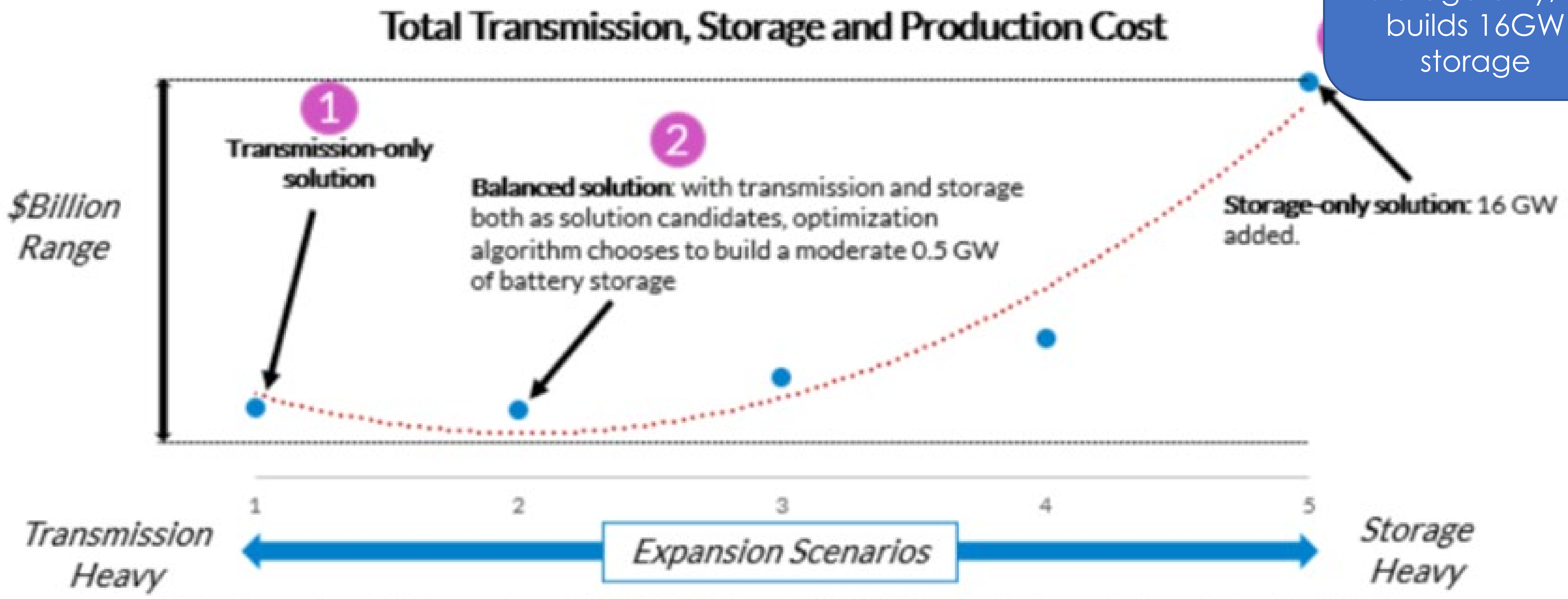
Storage-only solutions can be more expensive and may not address all the issues

If you allow the model to optimize size of storage only, it builds 16GW storage

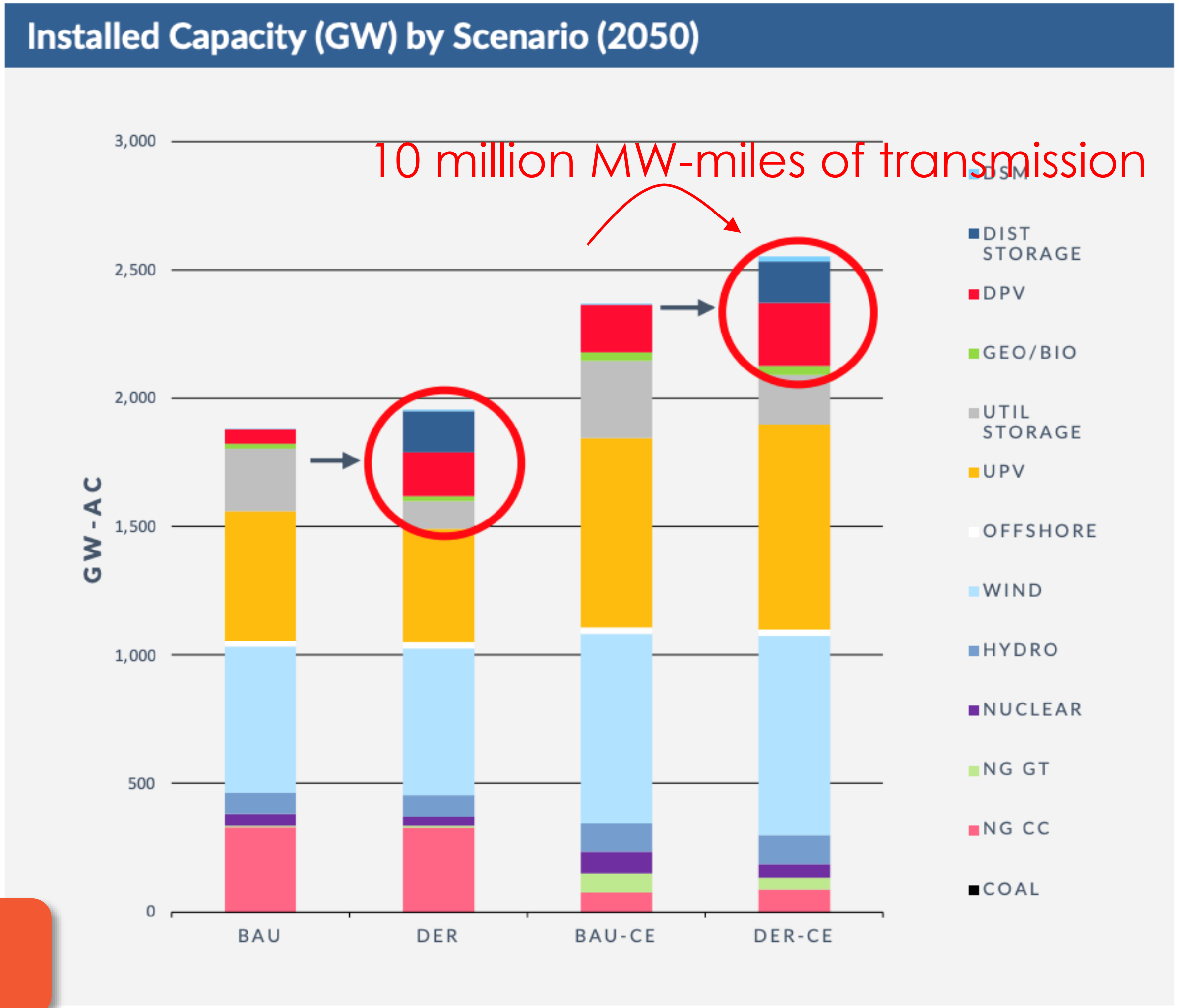


Note: Expansion simulation performed for 40% milestone with all 30% and prior transmission solutions included.

https://cdn.misoenergy.org/RIIA%20Summary%20Report520051.pdf

You may need transmission even with high levels of DERs

- Optimizing G, T&D saves money vs not including distribution in optimization
- Benefits are even bigger if you have clean energy goals - save $473B by optimizing G, T&D
- Optimizing G, T&D builds more DERs and also builds more transmission



https://www.vibrantcleanenergy.com/wp-content/uploads/2020/12/WhyDERs_TR_Final.pdf

Managing distribution will be critical as we electrify

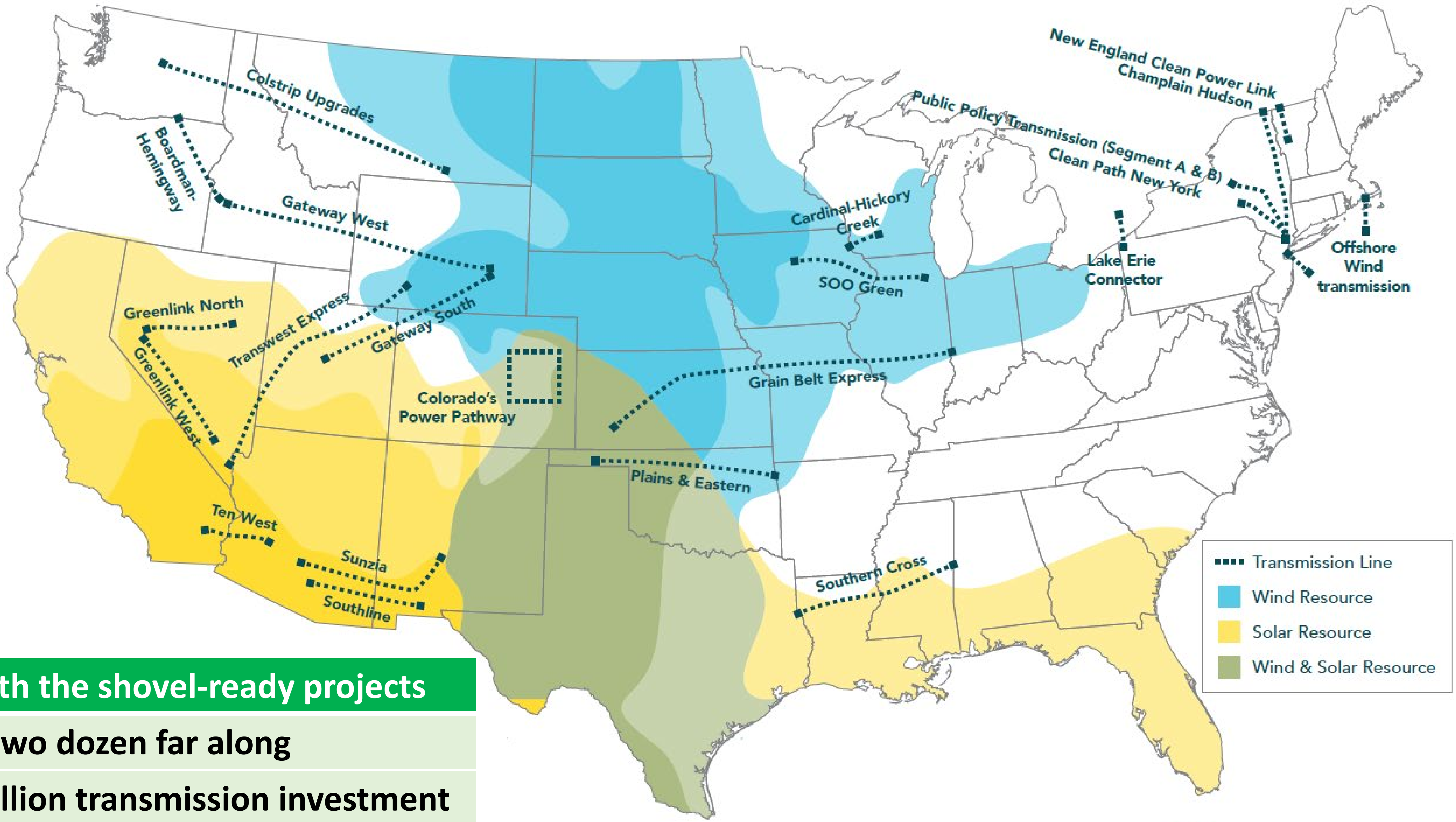
A National Approach to Transmission

If you want to go to the moon you need a space program.

If you want to decarbonize the economy you need a transmission plan.

National Planning Process

- Conduct regular, on-going planning activities
- Include comprehensive engineering and economic analysis
- Leverage national and regional capabilities
- Include regional planners, utilities, and governments
- Result in the construction of multi-regional transmission



Start with the shovel-ready projects

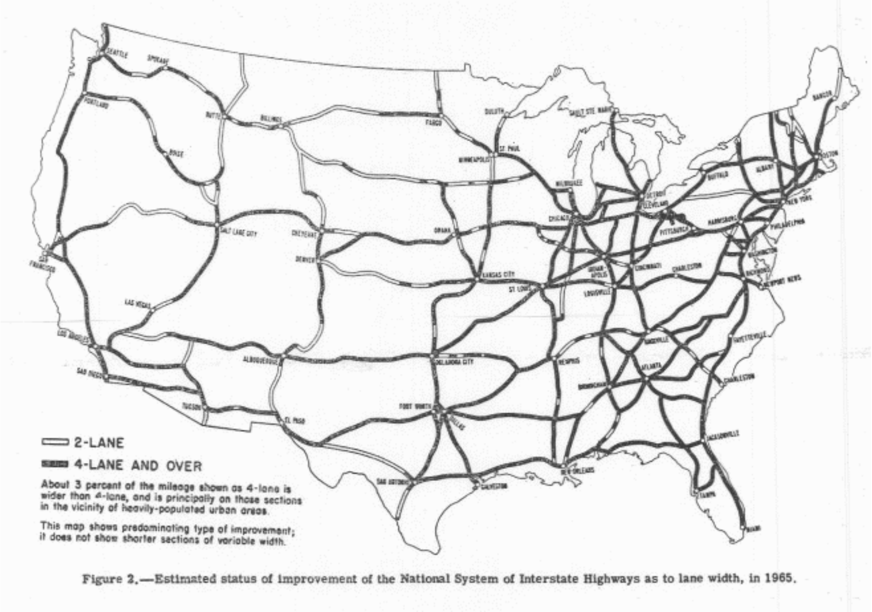
Nearly two dozen far along

$33.3 billion transmission investment

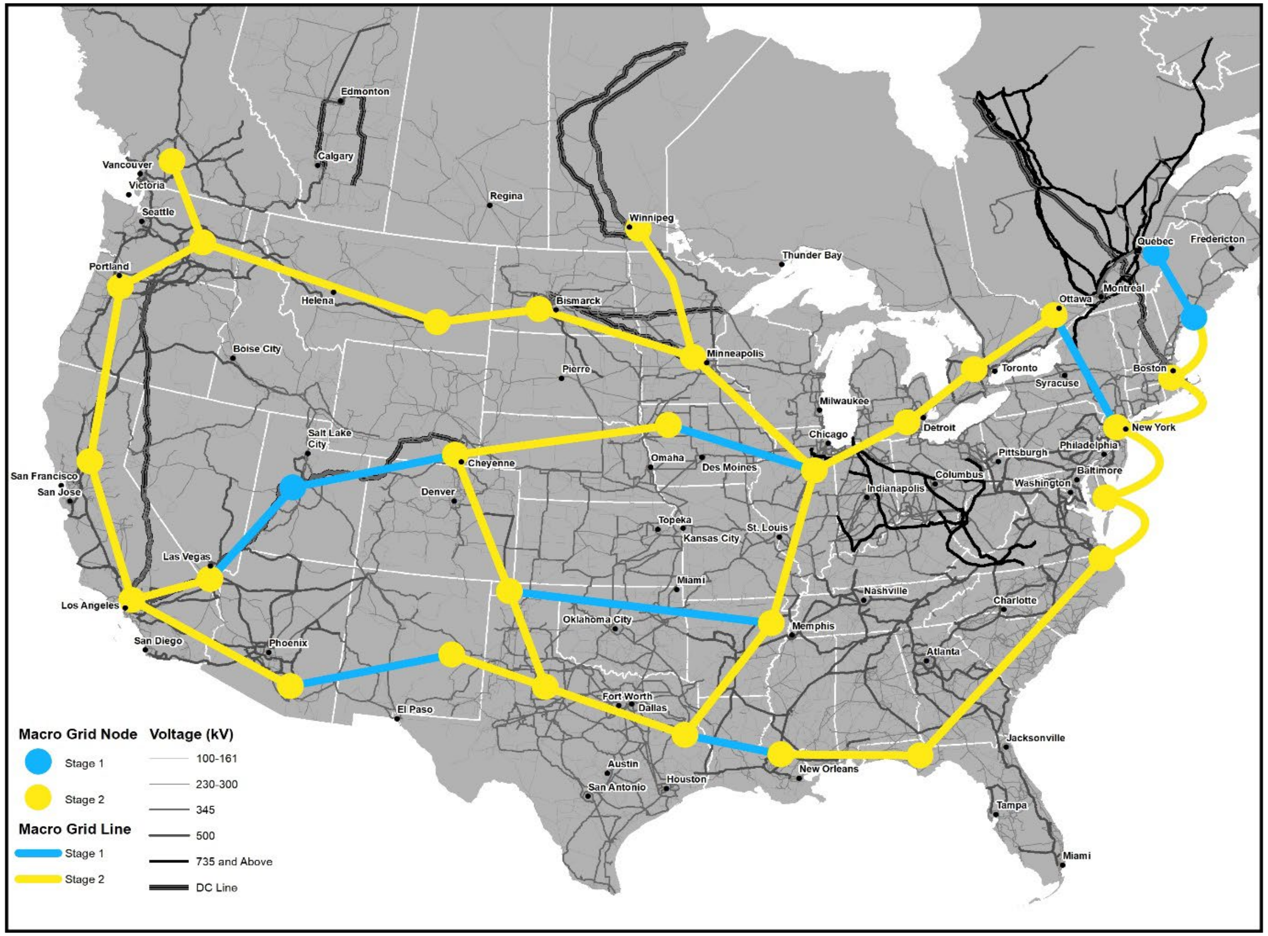
60,000 MW new renewable capacity

Design a national macro grid

Build in stages and start planning now



Original US Highway Map



https://www.esig.energy/transmission-planning-for-100-clean-electricity/

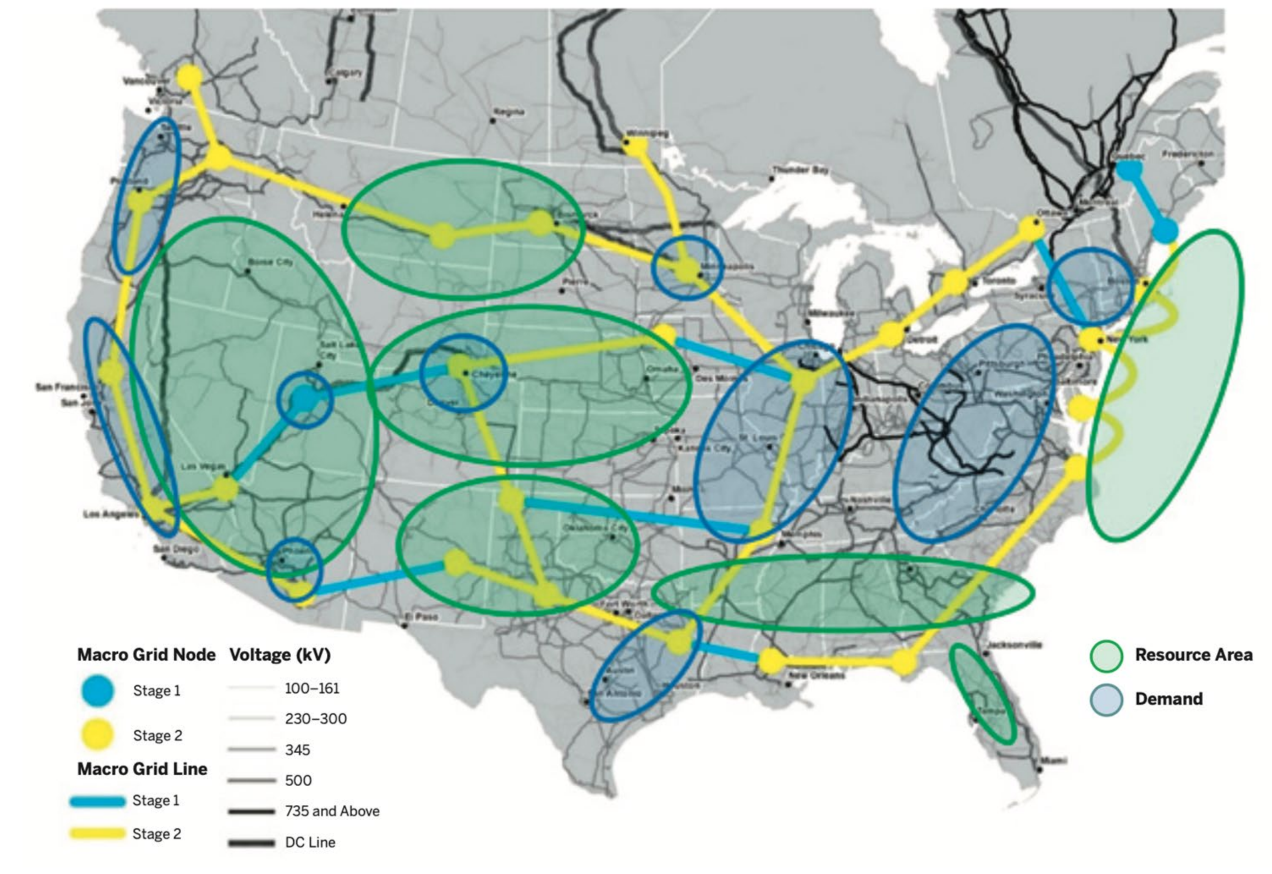
Energy Systems Integration Group

Charting the Future of Energy Systems Integration and Operations

ESIG

Why Not Conventional Transmission Expansion?

- Transmission fills three buckets of needs:
  - Connecting resource zones to loads to provide energy and ancillary services
  - Connecting diversity for resource adequacy and resilience benefits
  - Reliability for steady-state and dynamic stability
- A fundamental transformation of the grid for the fundamental transformation of the resource mix is needed.
  - Incrementalism likely won't achieve this.
  - Top-down 'optimizations' can show us the end game and improve bottom-up efforts.
  - Macrogrid design would be based on sound transmission planning principles but may require some new approaches.
  - HVDC allows for controllability to coordinate across regional system operators
  - VSC-HVDC supports stability with high levels of inverter-based resources
  - HVDC allows for long distances transfers at low cost with limited right-of-way

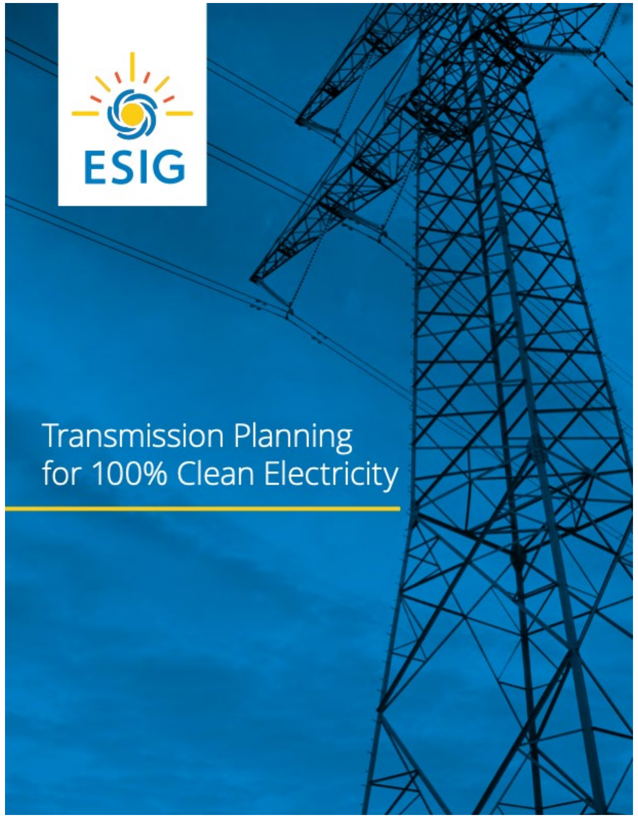


Source: Energy Systems Integration Group.

ESIG Recommendations

1. Create a national transmission planning authority that conducts ongoing national transmission planning
2. Identify renewable energy zones
3. Work collaboratively with the regional transmission planning processes

Get Started Now!



- Transmission Planning for 100% Clean Electricity https://www.esig.energy/wp-content/uploads/2021/02/Transmission-Planning-White-Paper.pdf
- Multi-Value Transmission Planning for a Clean Energy Future https://www.esig.energy/wp-content/uploads/2022/07/ESIG-Multi-Value-Transmission-Planning-report-2022a.pdf
- Design Study Requirements for a US Macrogrid https://www.esig.energy/wp-content/uploads/2022/02/ESIG-Design-Studies-for-US-Macrogrid-2022.pdf
- Proactive Planning for Generator Interconnection – report to be published https://www.esig.energy/event/webinar-proactive-planning-for-generator-interconnection-a-case-study-of-spp-and-miso/

THANK YOU

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NPCC 2022 Outreach Activity

Gerry Dunbar

Director Reliability Standards and Criteria

October 13, 2022

NPCC, Inc.

NPCC 2022 – 2025 Strategic Plan

Strategic Focus Area

Reliably Integrate Resources Brought Forward by Decarbonization Objectives

- NPCC DER/VER Forums
  - 2023 Forums TBD

- NPCC DER/VER Guidance Document
  - Revisions Posted for Comment

NPCC 2022 Activity

Comments/Suggestions:

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NPCC 2022 Corporate Goals

NPCC DER/VER Guidance Document