Interregional Transmission Operational Coordination (IRTOC) Workshop

Grid Deployment Office (GDO)
National Renewable Energy Laboratory (NREL)

June 11 – 12, 2024

Webinar and Federal Advisory Committee Act (FACA) Notice

- None of the information presented herein is legal binding.
- The context included in this presentation is intended for informational purposes only relating to the Interregional Transmission Operation Coordination (IRTOC) Project.
- The purpose of today's meeting is to ask your input regarding IRTOC topics. To that end, it would be most helpful to us if, based on your personal experience, you provide us with your individual advice, information, or facts regarding this topic. The objective of this session is not to obtain any group position or consensus. Rather, NREL and GDO are seeking as much input as possible from all individuals at this meeting. To most effectively use our limited time, please refrain from passing judgement on another participant's recommendations or advice and instead concentrate on your individual experiences.

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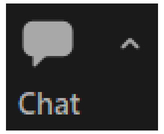
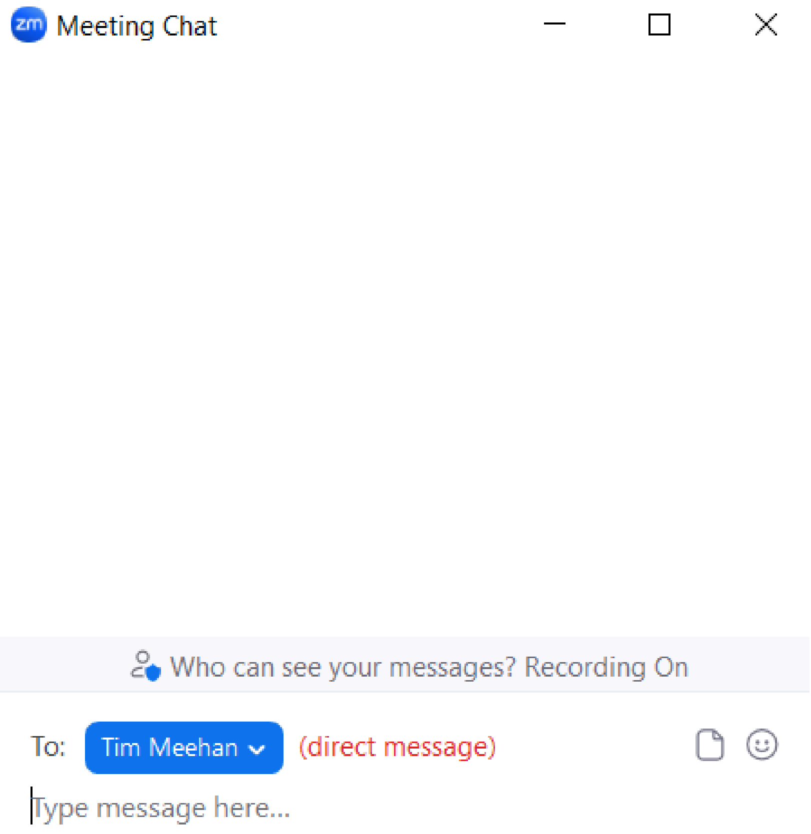
Housekeeping

Technical Issues?

If you have technical questions – please either directly message the host, Tim Meehan, or send and email to timothy.meehan@nrel.gov





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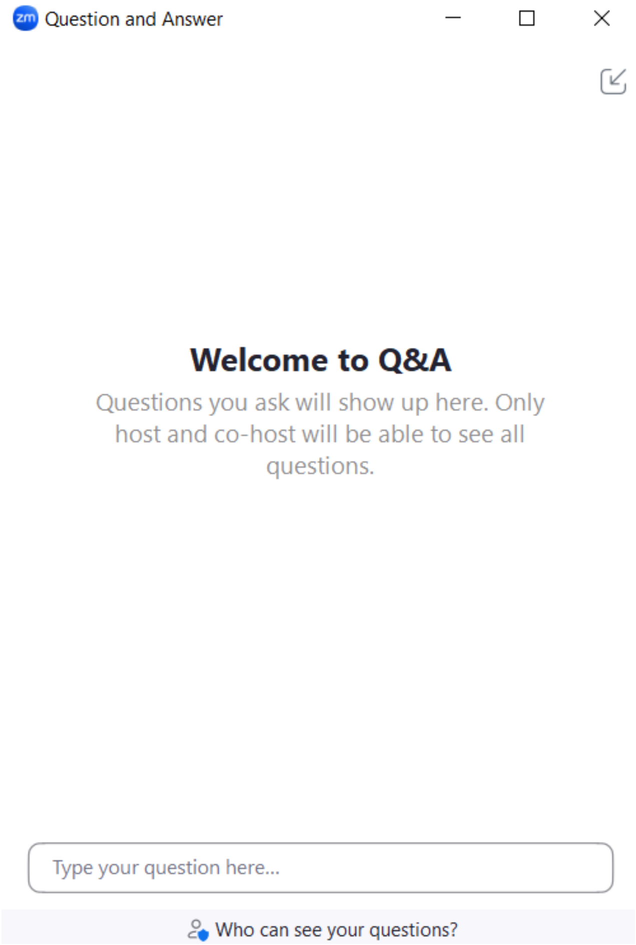
Questions

Please use the Q&A function to ask questions during the presentations.



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Agenda

Day 1 – June 11

- Welcome and Kickoff
- North American Experience Sharing
- European Experience on Multi-Region Market Coupling
- Interregional Coordination: Background and Framing

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Jeffery Dennis

Deputy Director, Transmission Division
Grid Deployment Office,
U.S. Department of Energy

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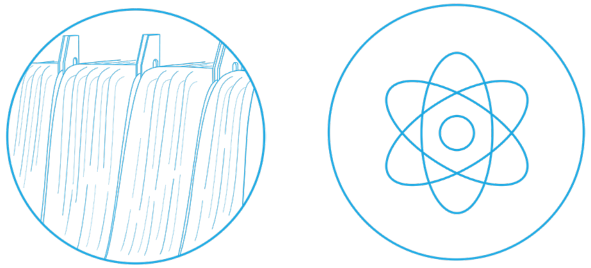
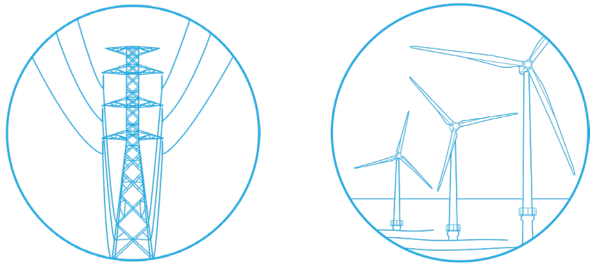
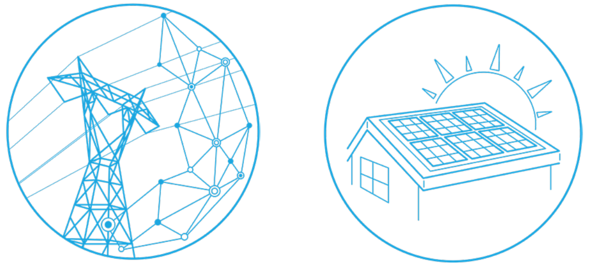
GDO Mission and Goals



Ensure **resource adequacy** by supporting **critical generation sources** and expanding and enhancing **electricity markets**.



Catalyze the development of new and upgraded **high-capacity electric transmission lines** and an improved **distribution system** nationwide.



Prevent **outages** and enhance the **resilience** of the electric grid.

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National Transmission Planning Study (NTP Study)

- Joint project with the National Renewable Energy Laboratory (NREL) and Pacific Northwest National Laboratory (PNNL)
- Comprehensive, multi-scenario analysis of long-term transmission needs ***and*** potential solutions to those needs
- **Objectives:**
  - Identify **interregional and national strategies** to accelerate cost-effective **decarbonization** while maintaining system reliability
  - Inform regional and interregional transmission planning processes, particularly by **engaging stakeholders** in dialogue
  - Identify **viable and efficient** transmission options that will provide broad-scale benefits to electric customers
- Final results will be shared published in a written report later in 2024

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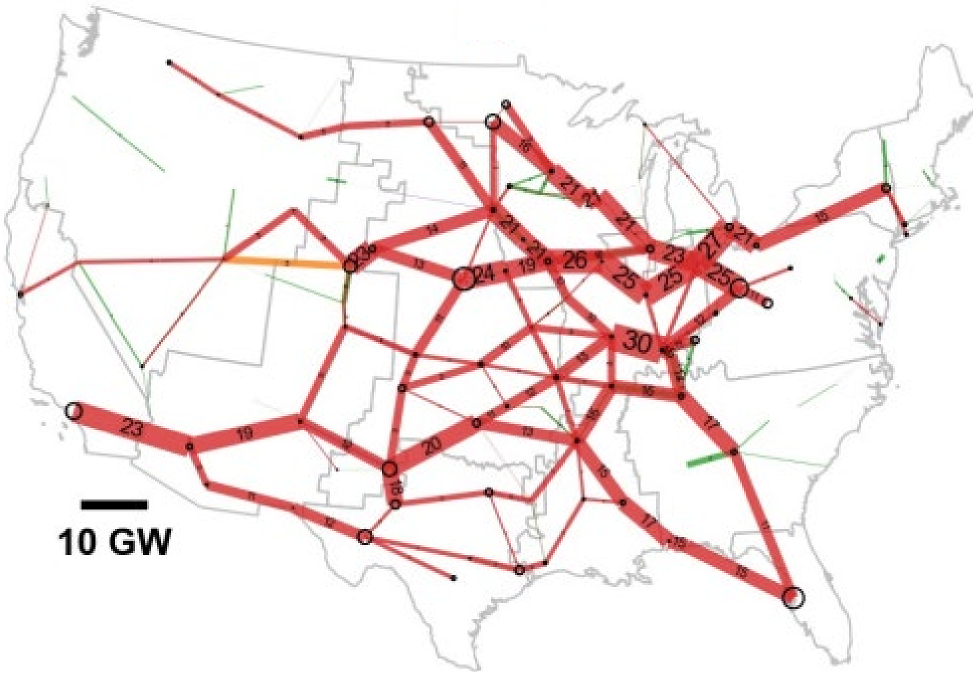
What is Interregional Transmission Operational Coordination?

The NTP Study and other studies show that the transmission grid will need to **expand interregionally, creating large transfers of power across regions**, assuming improved and enhanced planning and operational coordination among entities

- Neighboring market systems have agreements, such as **Joint Operating Agreements, to manage the flow of power** across regional transmission boundaries
- Market and operating barriers and inefficiencies can pose **both reliability and market risks, leaving benefits unrealized**
- Current market and operating practices **need to be updated** to manage the changing grid



Illustrative Only

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Objectives and Components

The IRTOC project aims to:

- Answer emerging questions about how a grid with more interregional connections and transfers of power can be operated reliably and efficiently
- Improve market-to-market congestion management processes, prices, operating reserve deliverability, and long-distance HVDC transmission line optimization

To meet these goals, this workshop aims to:

- Learn from experts in industry
- Solicit feedback from stakeholders on our methods and approach

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Agenda

Day 2 – June 12

- Welcome and Recap of Day 1
- National Transmission Planning Study Overview
- Post-Transmission
- IRTOC Software Development and Case Studies
- Open Discussion

Seams Optimization and Management

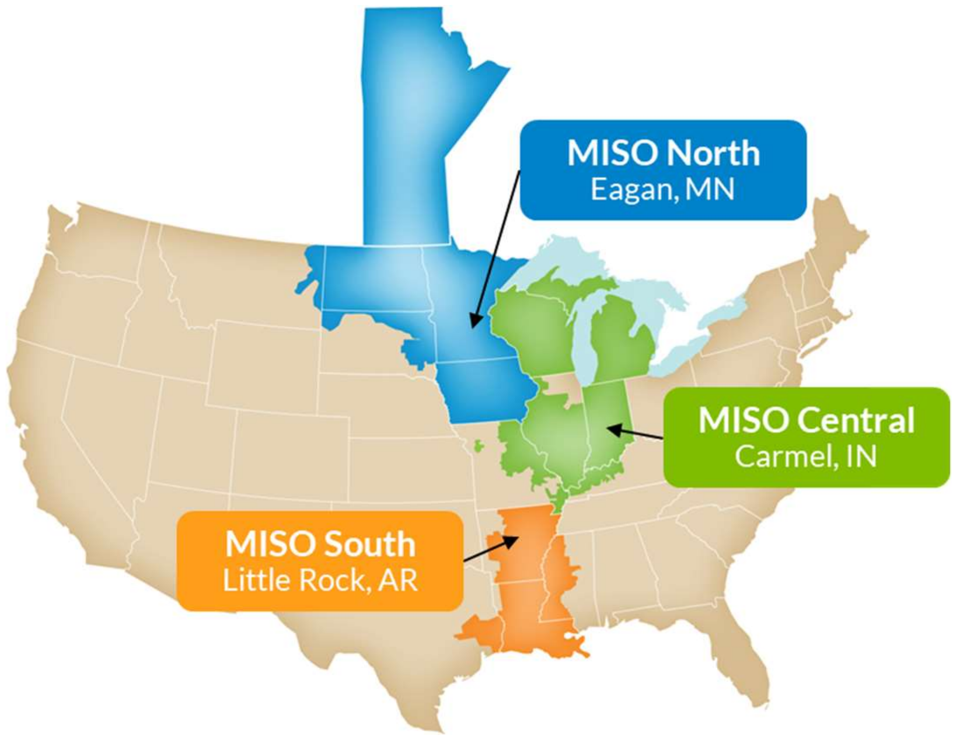
Timothy Aliff

MISO -Senior Director, Market Administration

Executive Summary

- Midcontinent Independent System Operator (MISO) is an independent, not-for-profit organization that delivers safe, cost-effective electric power across 15 U.S. states and the Canadian province of Manitoba.
- MISO works with our seams partners to manage congestion through Seams coordination using many complex tools, processes, high levels or coordination and collaboration
- MISO has unique agreements with each of our seam's partners for how we coordinate our seams, because of varying priorities, objectives and ideas of fairness which causes challenges
- Increased efforts to create more standardization will be needed as the energy transition continues

MISO Overview



MISO's reliability footprint and regional control center locations

MISO KEY FACTS

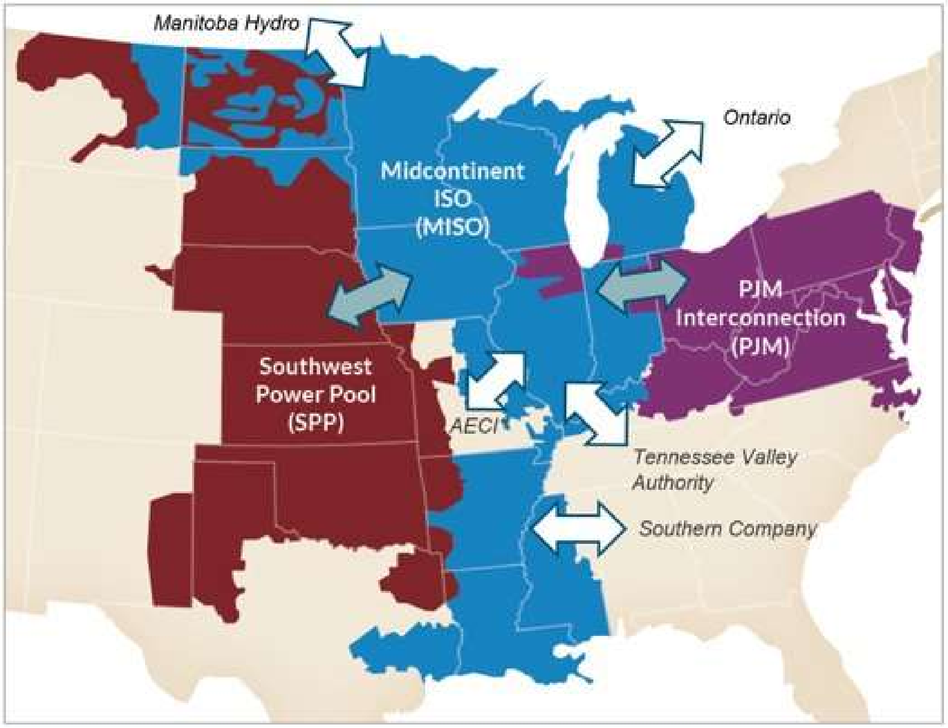
Area Served	15 U.S. States and Manitoba, Canada
Population Served	45 Million
Transmission Line	75,000 Miles
Generating Units*	> 2,900
Record Demand	127.1 GW 7/20/2011
Wind Peak	25.6 GW 1/12/2024
Solar Peak	4.5 GW 2/19/2024
Members	54 Transmission Owners
	143 Non-transmission Owners
Market Participants	> 500
Market Transactions	> $40 billion
Carbon Reduction	Approximately 32% since 2014

MISO seams processes are complex and require significant coordination and cooperation with our seam's partners

- All entities within the Eastern Interconnect must constantly be aware of how our actions impact one another
- MISO coordinates with seams partners daily- managing a simple congestion issue or more extreme scenarios where we are helping maintain the reliability of our neighbors
- Our Seams coordination focuses on utilizing our markets in unison to address congestion

MISO’s Seams team manages and utilizes many processes that can sometimes be unique for each seams partner

- **Flowgate Management**
  - Addition of New Flowgates/Changes
  - On Call Responsibility
- **Congestion Management Process**
  - Market-to-Market Process
  - Market Flows
  - Allocations/Firm Flow Entitlement/Tags (Network Native Load)
  - Market-to-Market Settlements
  - Interchange Distribution Calculator- Transmission Loading Relief
- **Available Flowgate Capability**
  - Used for Sale of Transmission Service
  - NERC Standards
  - Available Flowgate Capability Model Building
  - TRM & CBM Study
  - PI/CI Rule Study
  - First Contingency Incremental Transfer Capability Study
  - Annual Flowgate Review
- **Others**
  - Transmission Participation Matrix
  - WebSDX
  - EMS/IDC Model Updates



Where our service territory interconnects with other grid operators, effective seams coordination ensures efficient energy flows

While our neighbors create agreements with us and one another to standardize the Seams process, each company has different priorities, objectives and ideas of what is fair

The grid continues to evolve, presenting new challenges where some areas have faster pace of renewable integration and less base load generation

- Resource fleet evolution will result in an increase in congestion, uncertainty, and system complexity
- Higher levels of coordination and new processes will be required as the location of new resources shifts
  - Additional resources will change congestion and potentially increase congestion
  - This will result in more market-to-market reviews and resettlements to ensure equity across Seams and that more money will be exchanged between the market entities.
- Operators will need additional ways to relieve congestion, meaning they'll need additional flowgates to manage congestion internally and across seams

Future needs suggest that RTOs and ISOs should standardize and reduce one-off agreements

NAESB – WEQ-008
Transmission Loading Relief Standard

- The Business Practice Standard NAESB WEQ-008 defines the requirements for Transmission Loading Relief (TLR)
- These requirements provide consistent application of relief
- Market and Non-Market Flows treated equally

Parallel Flow Visualization

- Calculation method that helps improve wide-area view of MISO Reliability Coordinators
- Consistent and equitable
- During periods of congestion, assignment of relief obligations are more representative of those actually contributing to the congestion

Standardization leads to improved equity

Questions?

JUNE 11-12, 2024, NREL INTERREGIONAL TRANSMISSION OPERATIONAL COORDINATION WORKSHOP

Inter-Regional Interchange Scheduling Coordination

Feng Zhao

FZHAO@ISO-NE.COM

MANAGER, MARKETS AND OPTIMIZATION

ADVANCED TECHNOLOGY AND SOLUTIONS (ATS)

Outline

- Background
- Summary of Coordinated Transaction Scheduling (CTS) design
- Performance of CTS design
- Alternative inter-regional coordination designs
- Key Takeaways

Background

- The goal is to improve the efficiency of inter-regional electricity trades between ISO New England and New York ISO
- In 2011, stakeholders discussed two options of improvement: Tie Optimization and Coordinated Transaction Scheduling (CTS)
- CTS was launched by the two ISOs on December 15, 2015
- The Market Monitoring Unit (MMU) evaluated the CTS performance after first and second years of implementation

Summary of CTS Design: Inefficiency Causes

- Three causes of inefficient interchange scheduling:
  - *Latency*: System conditions and LMPs may change between when tie is scheduled and when power flows
  - *Non-economic clearing*: ISOs evaluate tie schedule requests without economic coordination, producing inefficient schedules
  - *Transaction costs*: Fees and charges levied by each ISO on external transactions serve as a disincentive to engage in trade, impeding price convergence, and raising total system costs

*See more details in ISO-NE's Coordinated Transactions Scheduling (CTS) Training

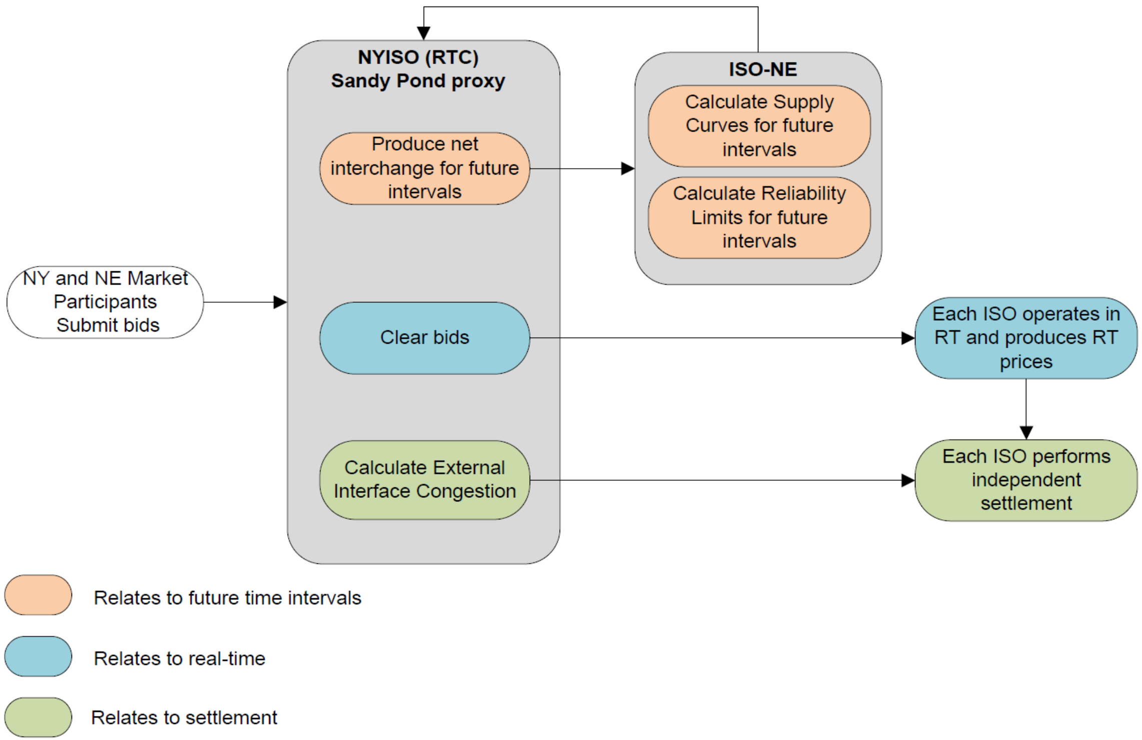
Summary of CTS Design: Features

- CTS features
  - More frequent scheduling of every 15 minutes;
  - New external transaction format of interface bid;
  - Coordinated economic clearing; and
  - Elimination of fees and charges for interface bids
- Implemented on NY Northern interface

Summary of CTS Design: ISO Roles

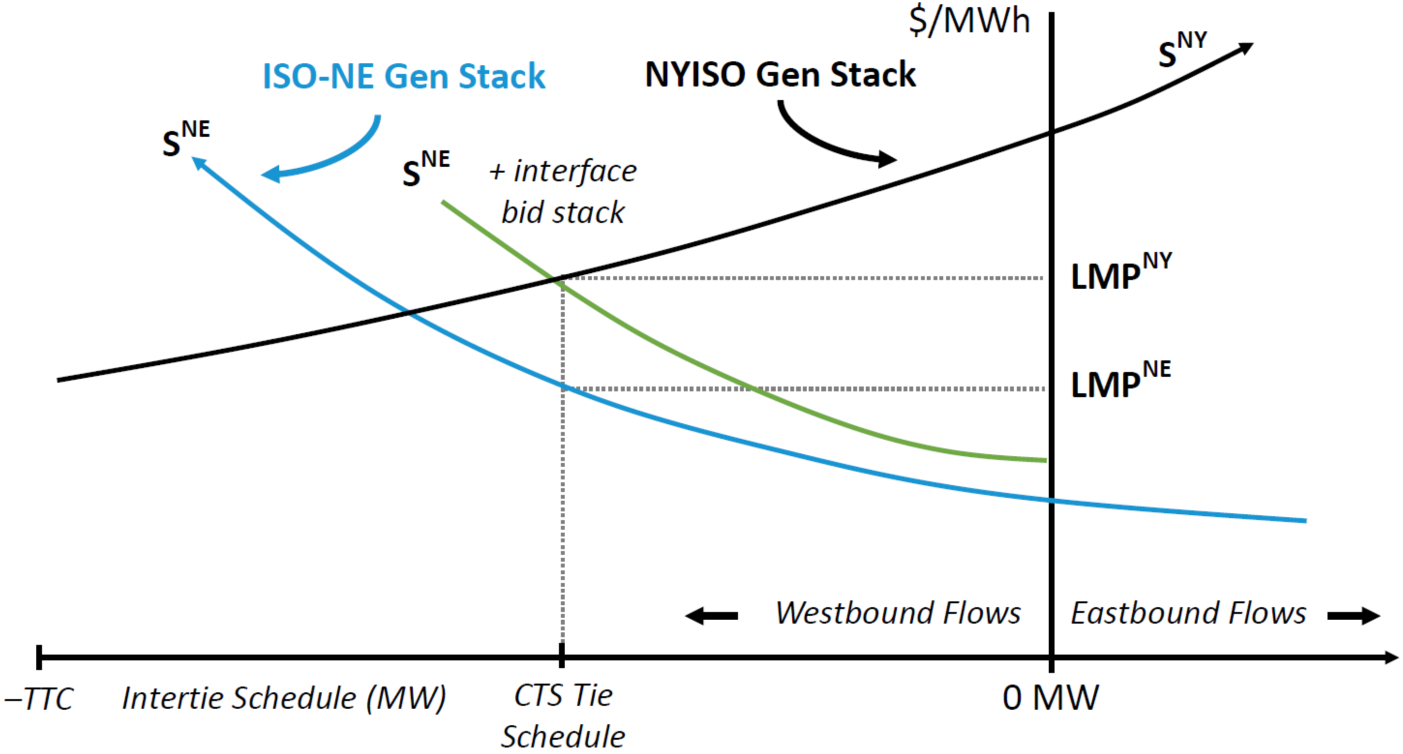
- NE (*Receiving ISO*) calculates *supply curves* at its proxy bus and provides them to NYISO every 15 minutes; these curves represent forecasted NE prices at different interchange levels
- NY (*Scheduling ISO)* models CTS bids and ISO-NE forecasted supply curves at the proxy bus into its real-time dispatch to optimize the interchange level

Summary of CTS Design: CTS Processes



RTC = Real-time commitment

Summary of CTS Design: Illustrative example



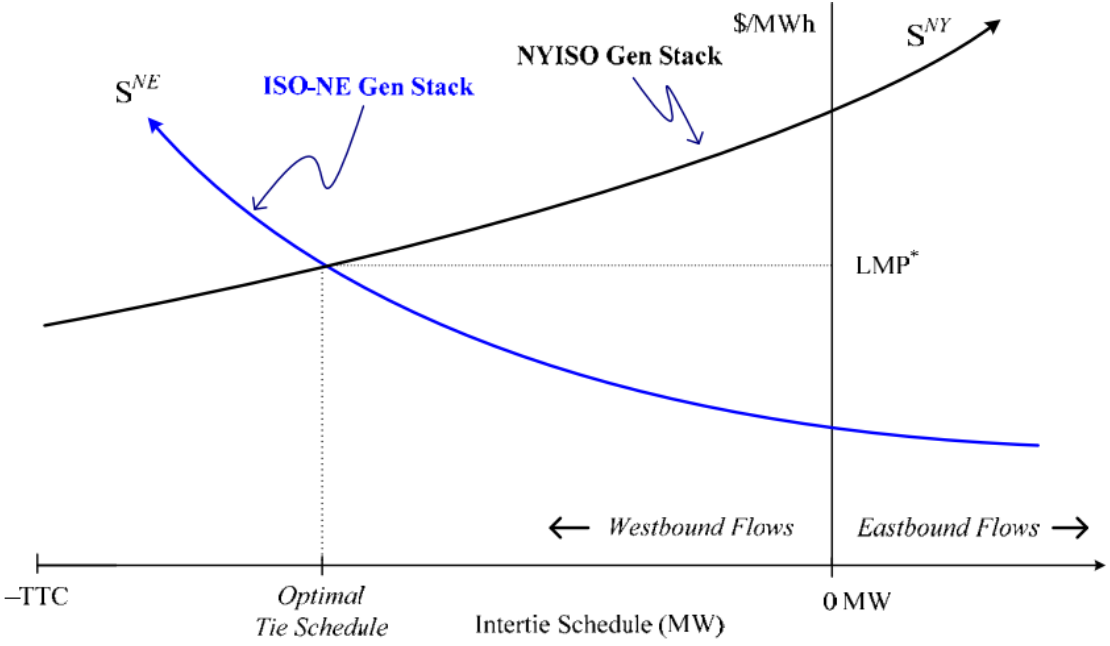
Performance of CTS Design: Production Cost Measure

- ISO-NE tariff requires MMU to evaluate CTS performance after 1st and 2nd years of implementation
  - Production cost is used to measure the CTS performance
  - MMU studies showed CTS improved from $2.0M of production cost savings in 2016 to $4.8M in 2017, compared to pre-CTS
  - MMU also compared CTS to *Tie Optimization* (CTS with infinite interface bids of zero price) and *Optimal Interchange* (Tie Optimization without latency), and found
    - Tie Optimization would increase production costs by $0.4 million largely because of forecast errors, and Optimal Interchange would reduce regional bid production costs by $5.3 million (compared to CTS) in Year 2 (similar to the Year 1 results)

*See more details in Potomac's second year Evaluation of CTS

Alternative Design: Tie Optimization

- In the ISOs' Inter-Regional Interchange Scheduling (IRIS) white paper ([link]()), *Tie Optimization* (TO) was presented as an alternative design



The difference between TO and CTS is whether or not the interface bids are used for scheduling

Bi-level Formulation of Tie Optimization

- Tie Optimization can be formulated as a bi-level optimization for the joint-dispatch problem with proxy-bus model:

Joint-dispatch problem with proxy-bus

$$Min_{\{g_{NY}, g_{NE}, I\}} \; Cost_{NY}(g_{NY}) + Cost_{NE}(g_{NE})$$

s.t. (1) $1^T \cdot g_{NY} + I = 1^T \cdot d_{NY}$

(2) $SF_{NY}^{l} \cdot (g_{NY} - d_{NY}) + SF_{NY,proxy}^{l} \cdot I \leq \bar{T}_{NY}^{l}$

(3) $\underline{I} \leq I \leq \bar{I}$

(4) $1^T \cdot g_{NE} - I = 1^T \cdot d_{NE}$

(5) $SF_{NE}^{l} \cdot (g_{NE} - d_{NE}) - SF_{NE,proxy}^{l} \cdot I \leq \bar{T}_{NE}^{l}$

Proxy injection/ withdrawal

Bi-level optimization

NE supply cost

$$Min_{\{g_{NY}, I\}} \; Cost_{NY}(g_{NY}) + f_{NE}(I)$$

s.t. (1)-(3) and

$$f_{NE}(I) = Min_{\{g_{NE}\}} \; Cost_{NE}(g_{NE})$$

s.t. (4)-(5)

Parametric optimization

The joint-dispatch problem is decomposed into NY & NE subproblems under the proxy-bus model

Alternative Design: Marginal Equivalent

- Both tie Optimization and CTS are built on the interchange proxy-bus model, i.e., the net interchange is modeled as injection or withdrawal at the proxy bus
  - This model approximation may introduce inefficiency under network congestions
  - Both approaches would schedule the interchange prior to the real-time dispatch, inducing latency
- A *Marginal Equivalent* approach was developed to allow more accurate network models and to enable coordination between two regions' real-time dispatch processes (Presentation, Paper)

Marginal Equivalent Algorithm (MEA)

- The idea is to coordinate neighboring regions' real-time dispatch processes through exchanging key information of marginal units and binding constraints
- The convergence of MEA is akin to the Simplex method
  - Guaranteed convergence to the optimal joint-dispatch solution in a finite number of iterations
  - Fast convergence observed in testing
  - Non-iterative implementation for simplicity may still produce major efficiency improvements with frequent real-time dispatch runs

Decomposition View of MEA

- Applying MEA to the joint-dispatch problem (without proxy-bus approximation) decomposes the problem into two coordinated dispatch subproblems of NE and NY
  - Each region's dispatch subproblem solves its own dispatch variables and constraints, plus additional variables of the other region's marginal units and additional binding constraints of the other region

Key Takeaways

- CTS implemented between NE and NY has improved the interchange scheduling efficiency
- Latency and proxy-bus approximation hinder CTS from achieving the fully efficient join-dispatch solution
- Alternative coordination schemes of TO and MEA are discussed

JUNE 11 2024

Interconnected Operation and Real-Time Congestion Management

Matt Vos
Control Room Supervisor

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IESO's role in Ontario

- IESO is the RC, BA and TOP for the province of Ontario
- We facilitate the wholesale electricity market and direct the operation of the IESO controlled grid (ICG)
- IESO is renewing Ontario's electricity market design, new market goes live May 1, 2025
- Ontario has 22 tie-lines with 5 different areas
- Ontario has no synchronous tie-lines with Quebec

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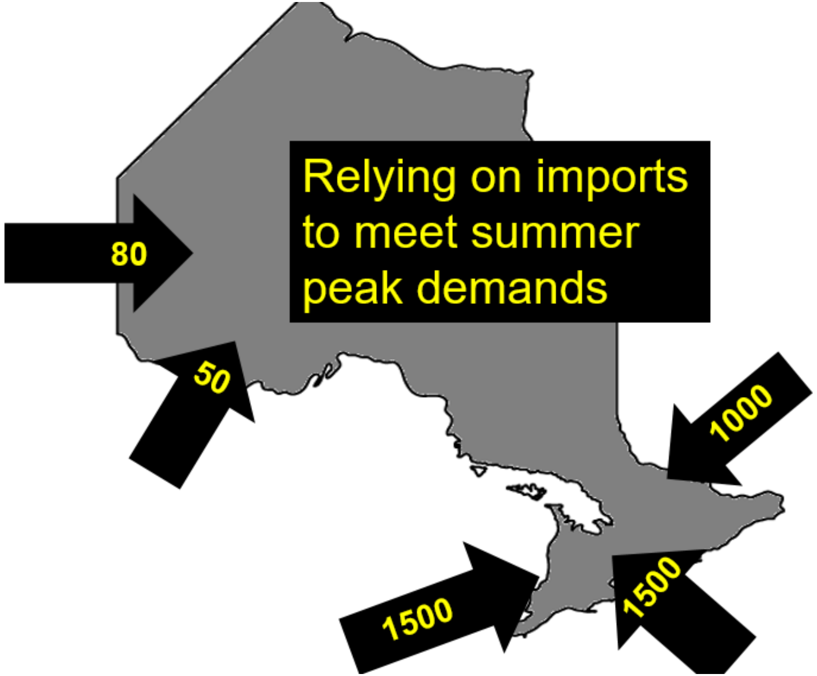
Benefits of Interconnected Operation

- Ontario set our peak demand in August 2006 at 27,000 MW
- In the early 2000's, Ontario was experiencing capacity shortfalls and relied on our neighbours for energy
- Ontario was consistently importing ~4000 MW during peak demand periods



Downtown Toronto Flooding – July 8, 2013

Downtown Toronto recorded 5 inches of rain in less than 2hrs

This is more than the average rainfall for the entire month of July

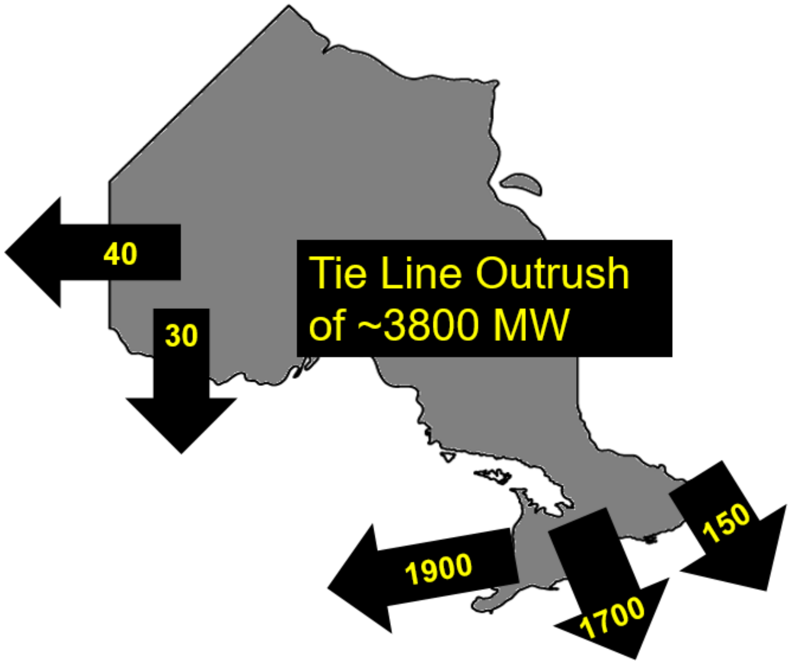
4000 MW load loss

The rain flooded relay buildings in several critical 230kV stations in Toronto

The flooding resulted in the loss of 25 230kV circuits and 4000MW of load

Impact of Load Loss

- The loss of ~4000MW of load resulted in an outrush on the tie-lines of ~3800MW
- IESO took immediate action to reduce our load/generation balance (ACE) back within normal limits
- The interconnection helped absorb the impacts of the large load loss
- Generators in the interconnection limited the system frequency increase that an islanded system would have experienced with such a significant load loss



Simultaneous Activation Reserve (SAR) – July 22, 2019

- IESO lost x4 500 MW nuclear units in 2min due to an unexpected cooling water issue
- IESO utilized the SAR program to restore our load/generation balance and received 1000 MW of support from our neighbours
- SAR is shared by all NPCC members (HQ does not participate) + PJM
- All BA's individually maintain but jointly activate 10min OR following a reportable event (>500 MW gen loss) or stress system conditions

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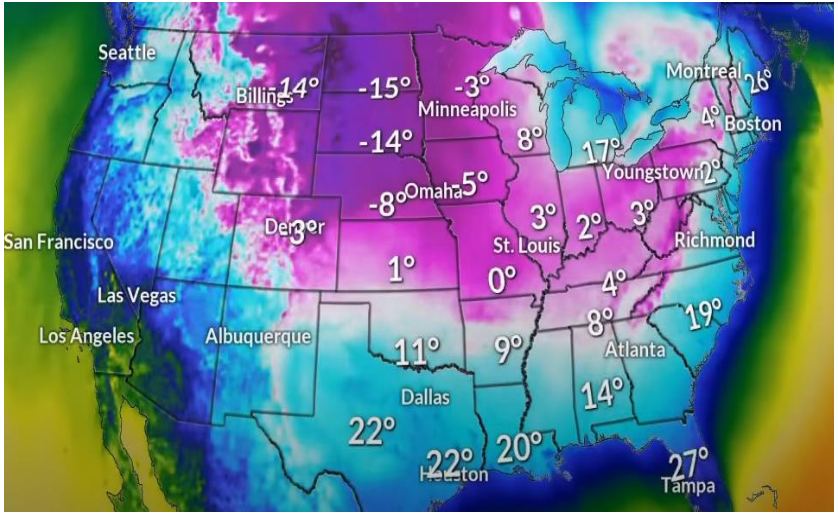
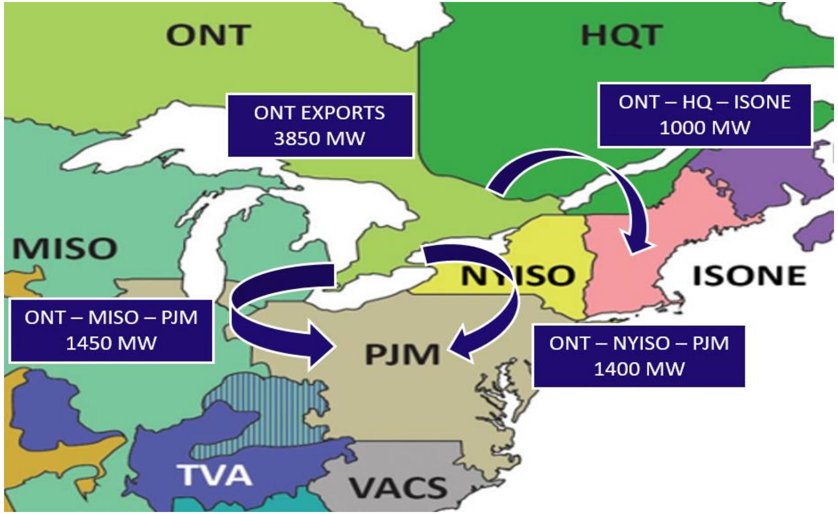
Winter Storm Elliot – December 24, 2022



Elliot brought a deep freeze to most of North America during Christmas 2022



Interties helped provide support to areas hit hardest by the storm

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Interconnected Operation and Congestion

- There are significant benefits to interconnected operation
- Interconnected operation can lead to unscheduled loop flows in certain areas of the power system
- The most common loop flows observed in the northeast part of the Eastern Interconnection is Lake Erie Circulation (LEC)
- LEC impacts MISO, IESO, NYISO and PJM

What is Lake Erie Circulation (LEC)?

- Electricity doesn't always follow the scheduled path and will always take the path of least resistance
- LEC is caused by generation/load patterns and interchange schedules within IESO, MISO, PJM and NYISO
- LEC can range from 200 MW – 2000 MW
- Was a significant issue for all areas until the Ontario-Michigan PARS were placed I/S in 2012

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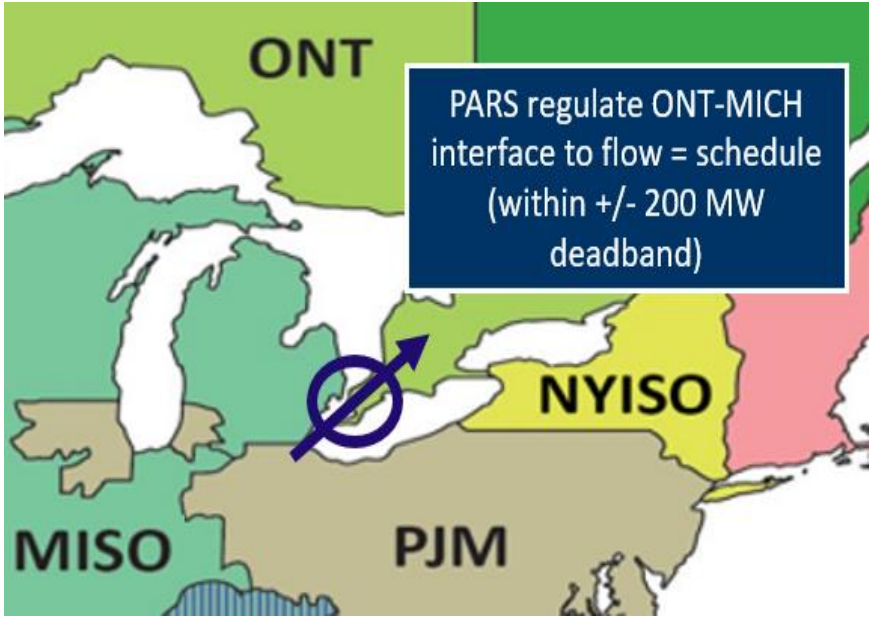
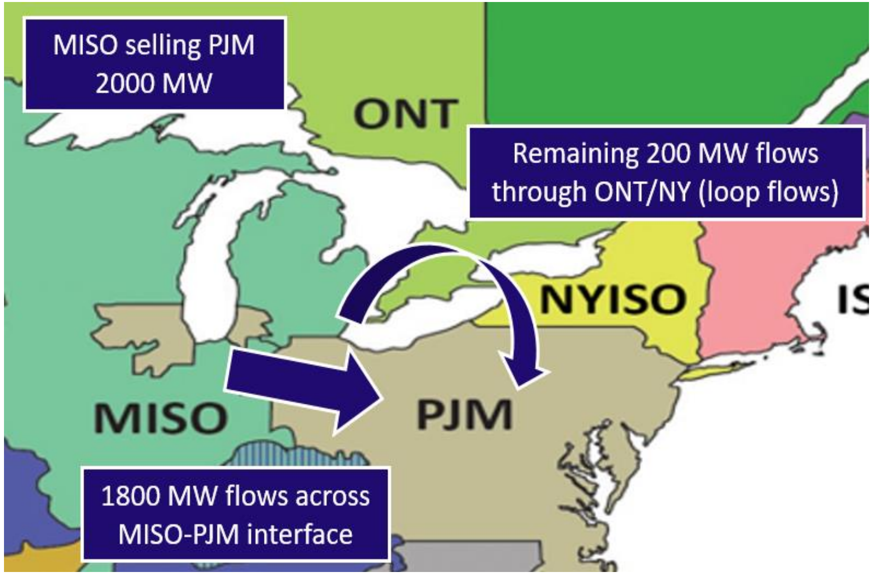
Ontario – Michigan Phase Angle Regulators (PARS)

- Project first introduced in 1998, PARS not placed I/S until 2012
- Equipment and regulatory issues delayed the I/S date
- Each of the four ONT-MICH tie-lines has a series PAR
- Before the PARS, the interface was in regulate mode 43% of the time
- After the PARS, the interface was in regulate mode 95.5% of the time



Using the IDC to Manage Congestion

- The remaining 4.5% of the time, the PARS have no more tap room to control the interface and the interface is declared in 'non-regulate'
- If these loops flows causing an area to overload a flowgate, operators can use the IDC to help identify who is contributing to the congestion
- Operators have the ability to issue 'Transmission Loading Relief' (TLR) within the IDC to issue transaction curtailments/generation re-dispatch to areas outside of their footprint to help relieve congestion



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IDC Summary

- IDC was first created in 1998 when areas were deregulating
- Tool was revamped in 2022 to utilize more real-time system telemetry and produce more accurate results
- Revamp took time… not easy creating uniform curtailment rules that apply to all BA’s in the eastern interconnection
- IDC remains an effective tool but still has some limitations:
  - IDC isn’t forward looking, looks at current/next hour
  - Looks at 1 hour increments (a lot can change on the system in 1hr)
  - Remains a reliability based tool, doesn’t contain detailed market information

Summary

- Eastern Interconnection provides significant benefits during real-time operation
- Provides reliability benefits and allow for more efficient market results
- Will become even more important as areas continue to integrate more energy limited resources into their supply mix
- Industry will continue working on ways to enhance real-time congestion management tools

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Power markets in Europe

Pietro Rabassi, Executive Vice President, Nord Pool

EU presentations on NREL IRTOC workshop

online, 11 June 2024

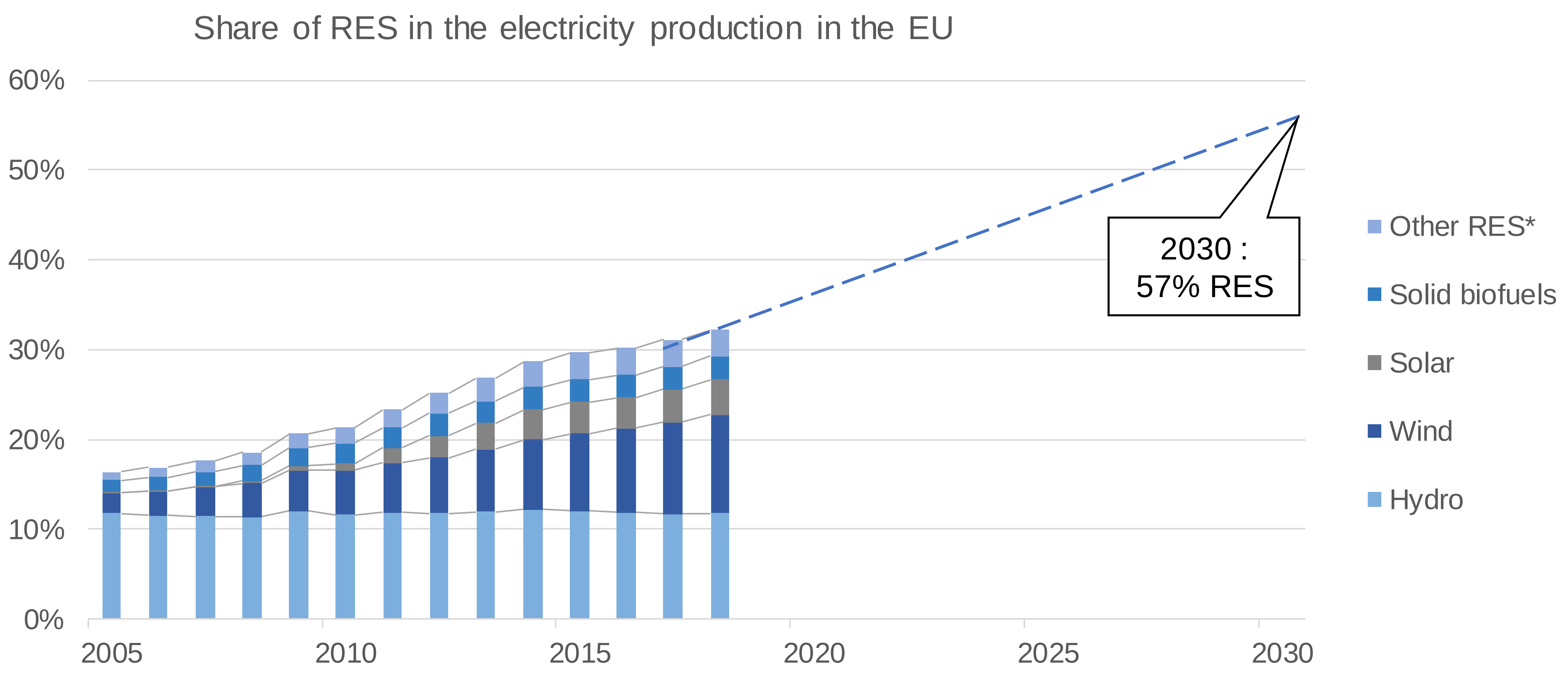
At a glance

- Nord Pool offers day-ahead and intraday trading, clearing and settlement services
- ~ 400 customers from 20 countries trade on Nord Pool's markets
- Operates in 16 European countries under our license and in 4 European countries as a service provider
- Nord Pool Consulting / Nord Pool Academy
- ~150 employees, 36 nationalities, offices in Oslo, Stockholm, Helsinki, London, Berlin, Brussels and Tallinn

1030 TWh
day-ahead

74 TWh
intraday

~400
customers



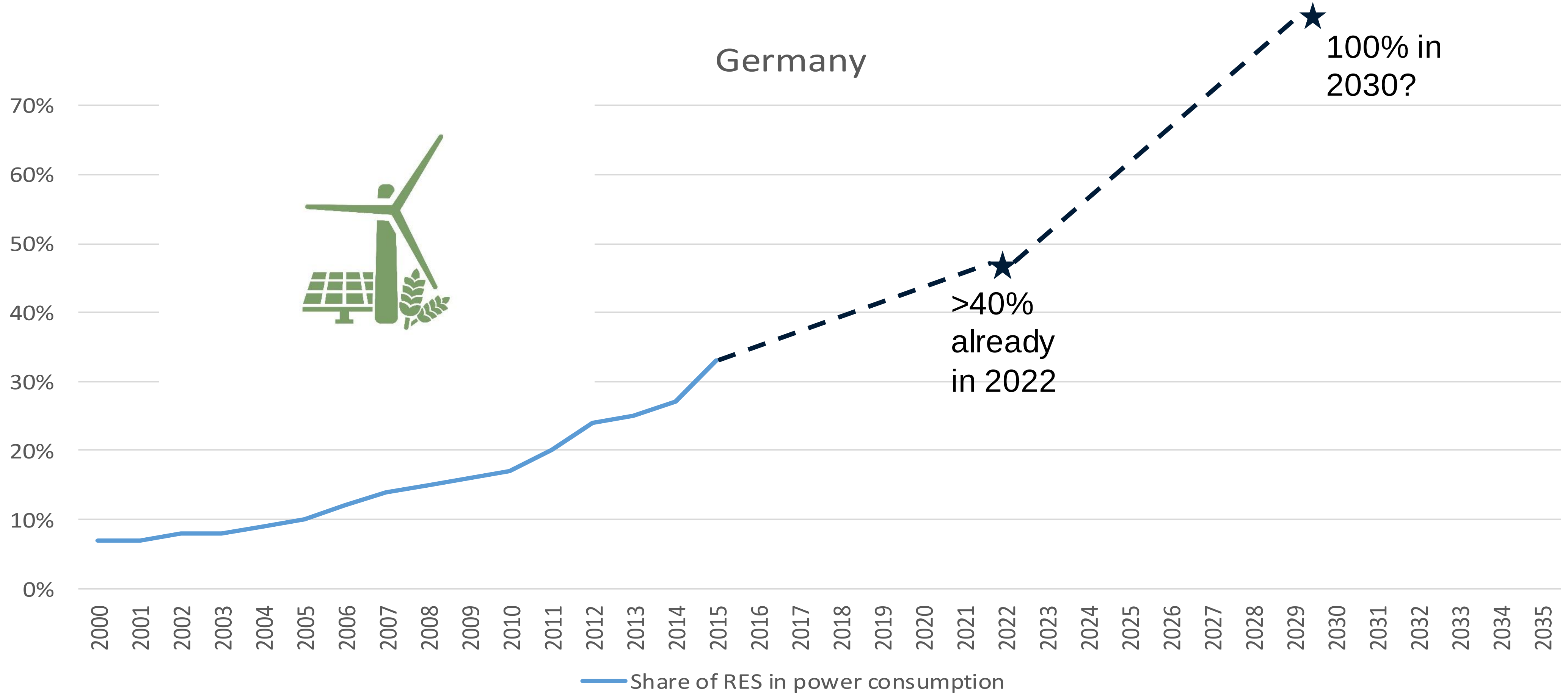
RES (especially iRES) have been and will be increasing their share across Europe (EU-28)…

EU targets by 2030 : 57% RES, ~ 30% iRES

*Electricity generation from gaseous and liquid biofuels, renewable municipal waste, geothermal, and tide, wave & ocean

Source : https://ec.europa.eu/eurostat/web/energy/data/shares

NORD POOL



…and a similar pattern applies to Germany—one main driver

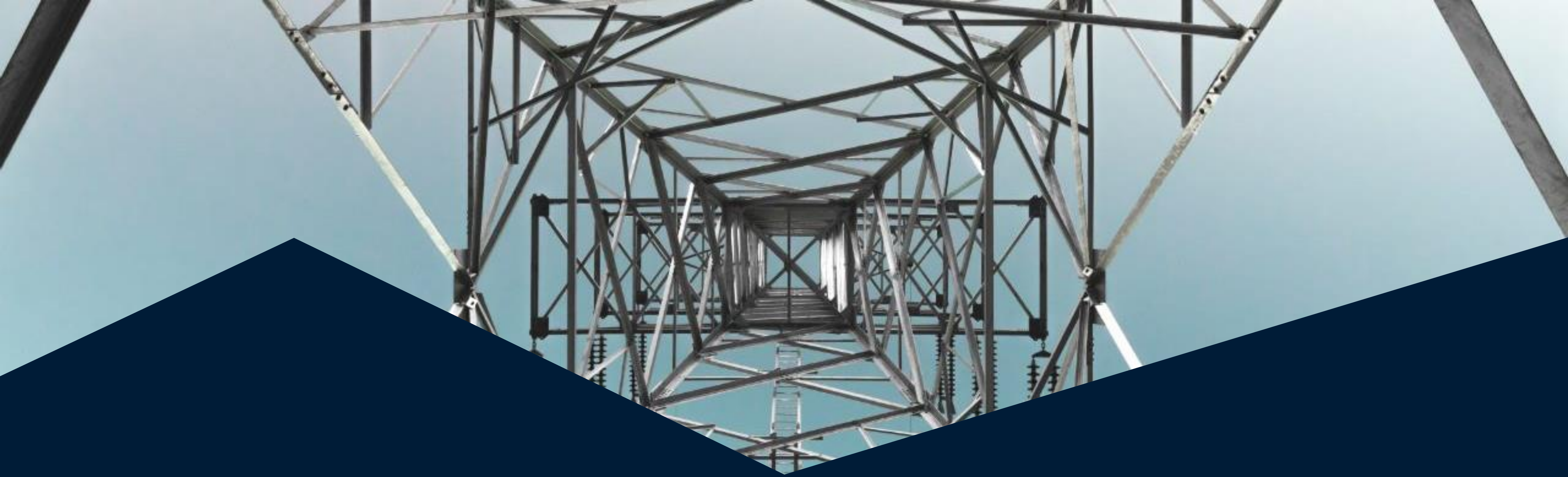
Source : Agora Energiewende (2021)

NORD POOL

The 6 current trends in European power market

- More trading close to delivery
- More APIs (algorithmic trading)
- Cost cutting
- Decentralized markets
- Flat-fee pricing
- Changing and new business models

NORD
POOL



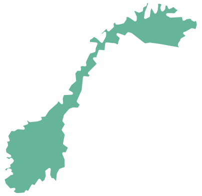
3. A more integrated European power market benefits our customers and the end consumer

- XBID (continuous trading)
- IDAs
- New cables
- Decentralized markets
- MRC/PCR (Day-Ahead auction)

NORD POOL

NORD POOL

NORD POOL WAS THE BEGINNING OF AN INTEGRATED EUROPEAN POWER MARKET



1991
Norwegian power market deregulated

1993
The Norwegian power exchange is established as 'Statnett Marked'

1996
Norway and Sweden join, this is the world's first international power market – called **Nord Pool**

1998
Finland joins Nord Pool

1999
The first international intraday market is established (Sweden and Finland)

2000
The Nordic market becomes fully integrated as Denmark joins

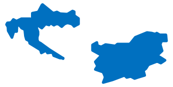
2010
UK and Estonia join Nord Pool

2013
Baltic completed – Lithuania and Latvia join Nord Pool

2014
North-western European power markets are coupled through the Price Coupling of Regions (**PCR**) project

2015
Nord Pool appointed **NEMO** in 15 countries

2016
Together with **IBEX** Nord Pool opens the Bulgarian power market - and with **Cropex** the Croatian power market



2018
European intraday market go-live

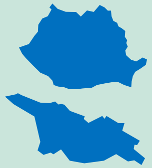
2019
Nord Pool opens day-ahead markets in Germany, Luxembourg, France, Austria, Belgium and The Netherlands

2020
Euronext acquires Nord Pool

Nord Pool opens **intraday** market in **Poland**

2021
Day-ahead trading in Poland is Launched

2023
Nord Pool celebrates 30 year of powering the market



2023
BRM and Genex – planning to open open the Romanian and Georgian power markets

A more integrated European power market benefits our customers and end consumers (~30 BEUR per year)…

so will more competition in power markets across Europe

- Real competition to the benefit of wholesale market participants and hence of end consumers
- Market participants own the Order Books

NORD POOL

Multi-NEMO* Arrangements

* Nominated Electricity Market Operator

Multi-NEMO arrangements (MNA)

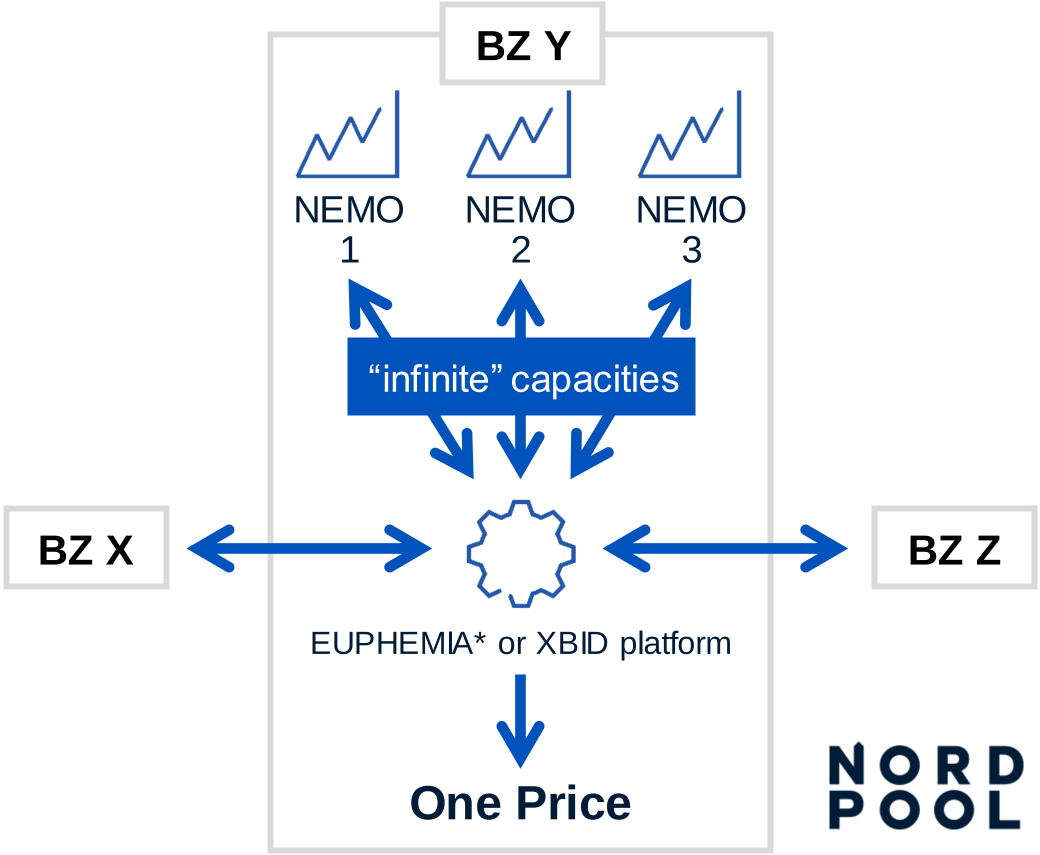
- MNAs stem from the 2015 European CACM (Capacity Allocation & Congestion Management) Regulation.
- MNAs are a legal framework that allow multiple power exchanges to operate in the same Bidding Zone (BZ).

One price / shared liquidity

Trade matching between buyers and sellers from different power exchanges assures one day-ahead price or access to the same Intraday liquidity.

EUPHEMIA algorithm

- New version of EUPHEMIA algorithm with cross-matching between power exchanges in same bidding zones
- New topology which allows several NEMO trading hubs (NTH) within a single bidding zone.



*) EUPHEMIA algorithm: flow-based patch where applicable

ENERGY TRANSITION: THE ROLE OF THE MARKET

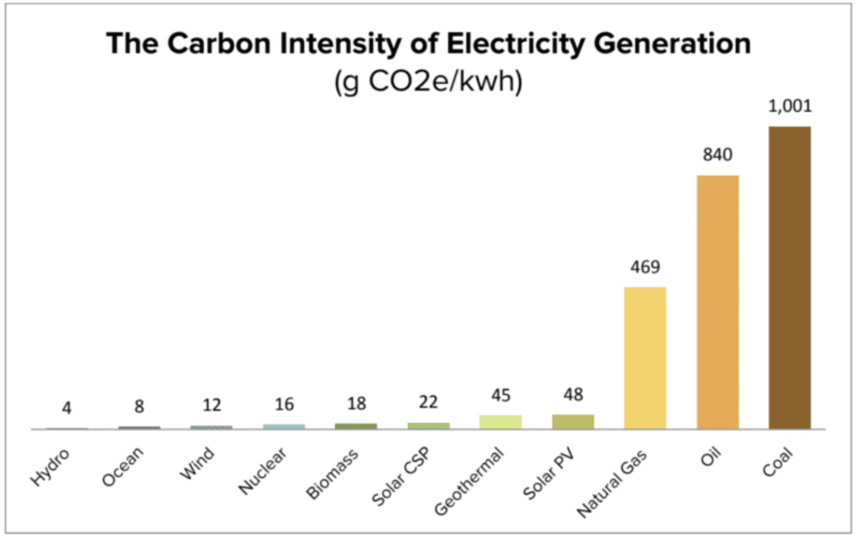
HOW THE CURRENT EUROPEAN MARKET DELIVERS DECARBONIZATION?

1. The merit-order promotes carbon-free electricity production
2. Marginal pricing is an incentive to carbon-free generation
3. Efficient use of interconnectors favors carbon-free generation
4. Intraday allows renewable assets to be managed on a 24/7 basis
5. Price transparency empowers consumer demand-response

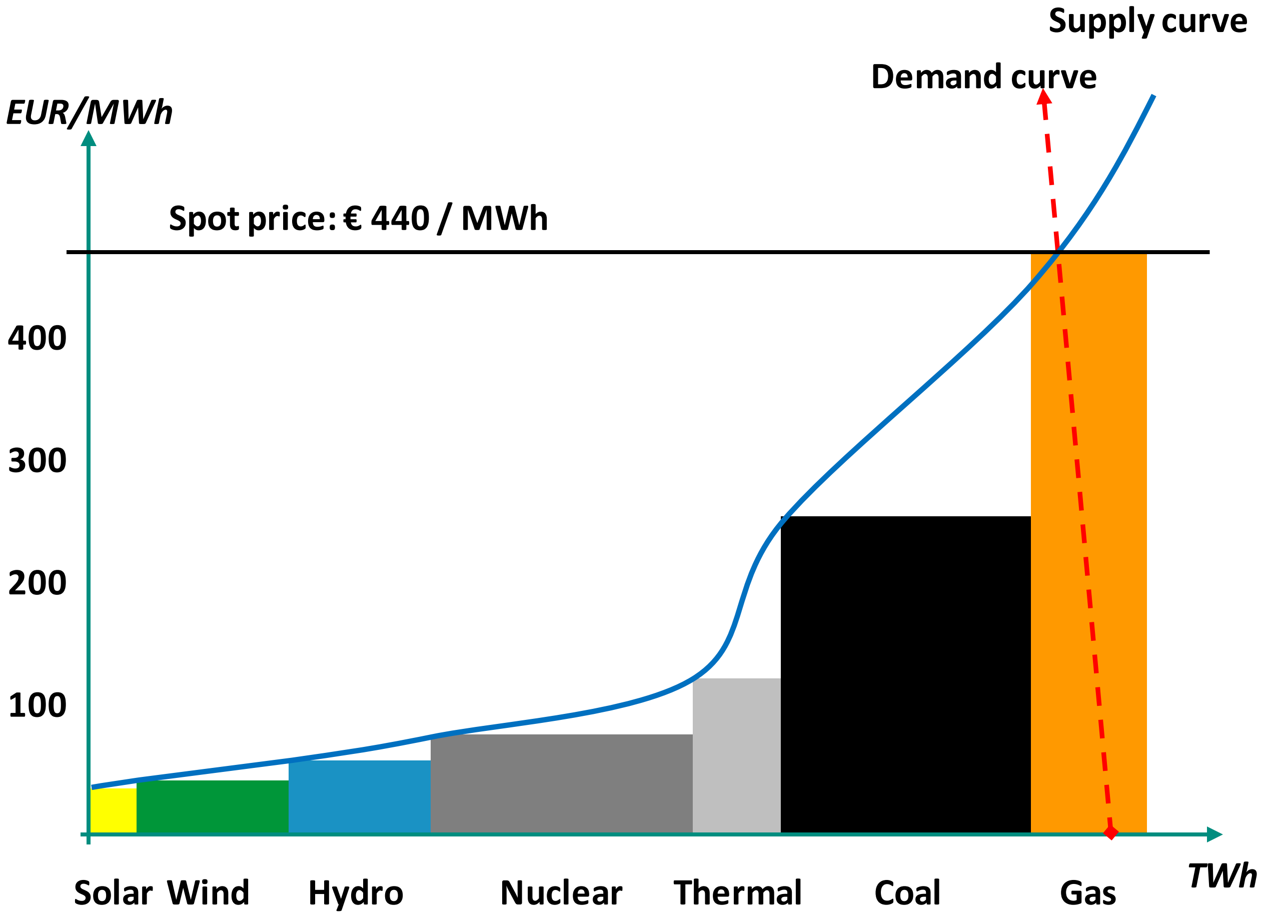
1

The merit-order promotes carbon-free electricity production

- The merit-order plays a crucial role in decarbonising the mix
- Power plants are dispatched by order of marginal costs, to meet demand
- Power plants with the lowest marginal costs are renewables and nuclear: they have therefore the priority
- They are also the ones with the lowest carbon intensity



Source: Adapted from IPCC special Report on Renewable Energy Sources and Climate Change Mitigation.



1

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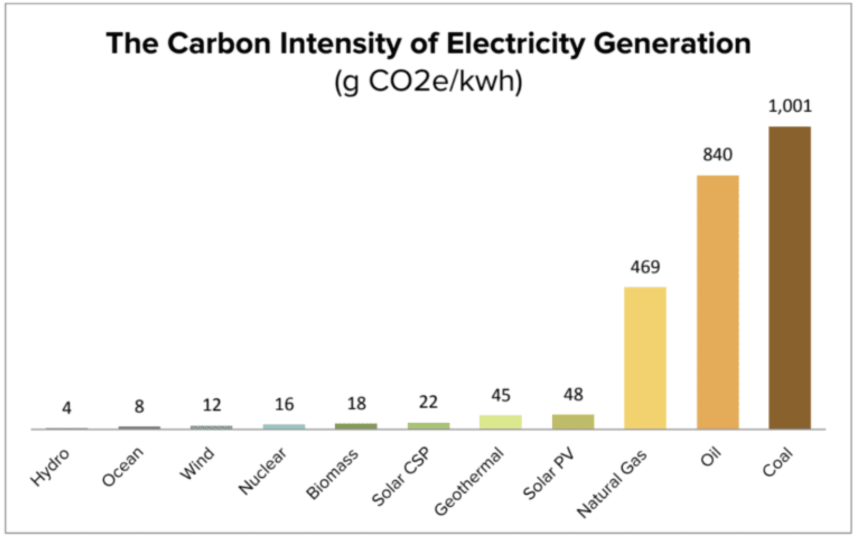

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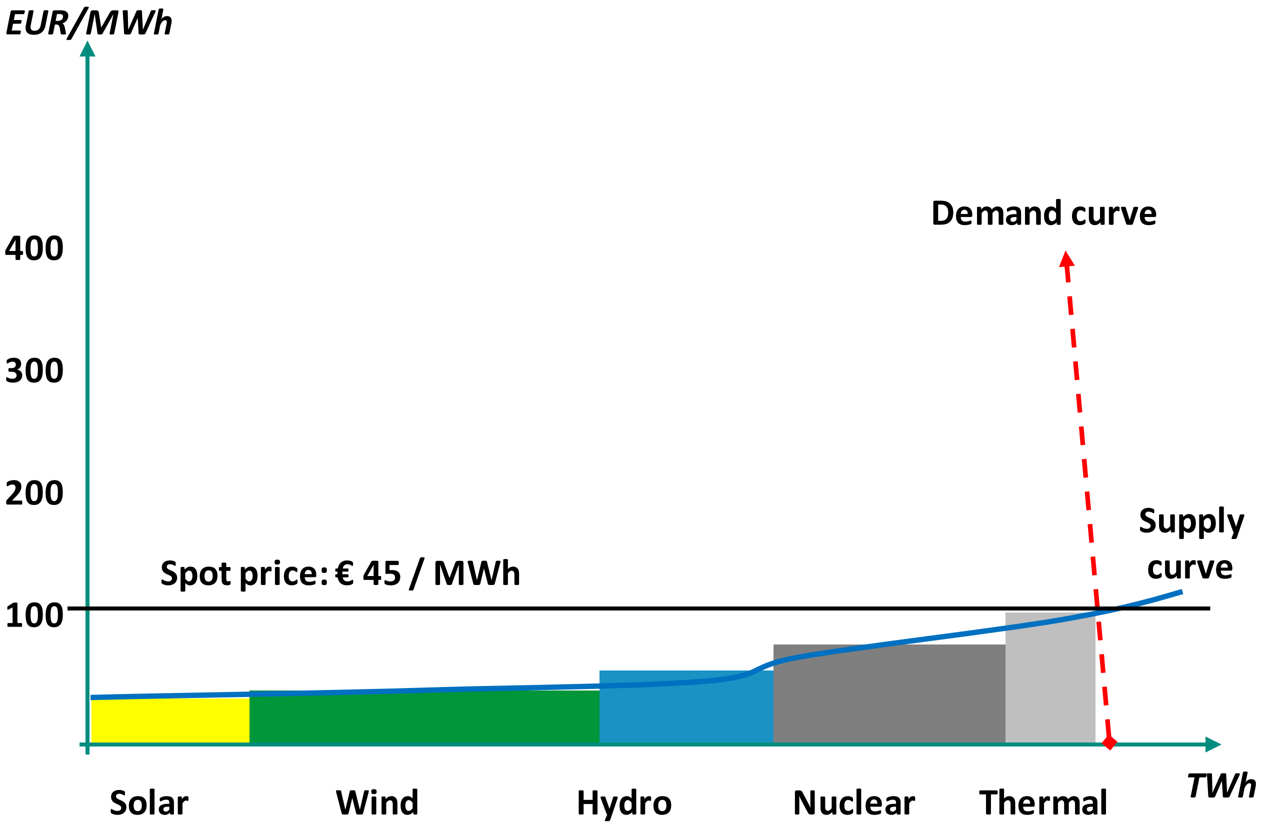
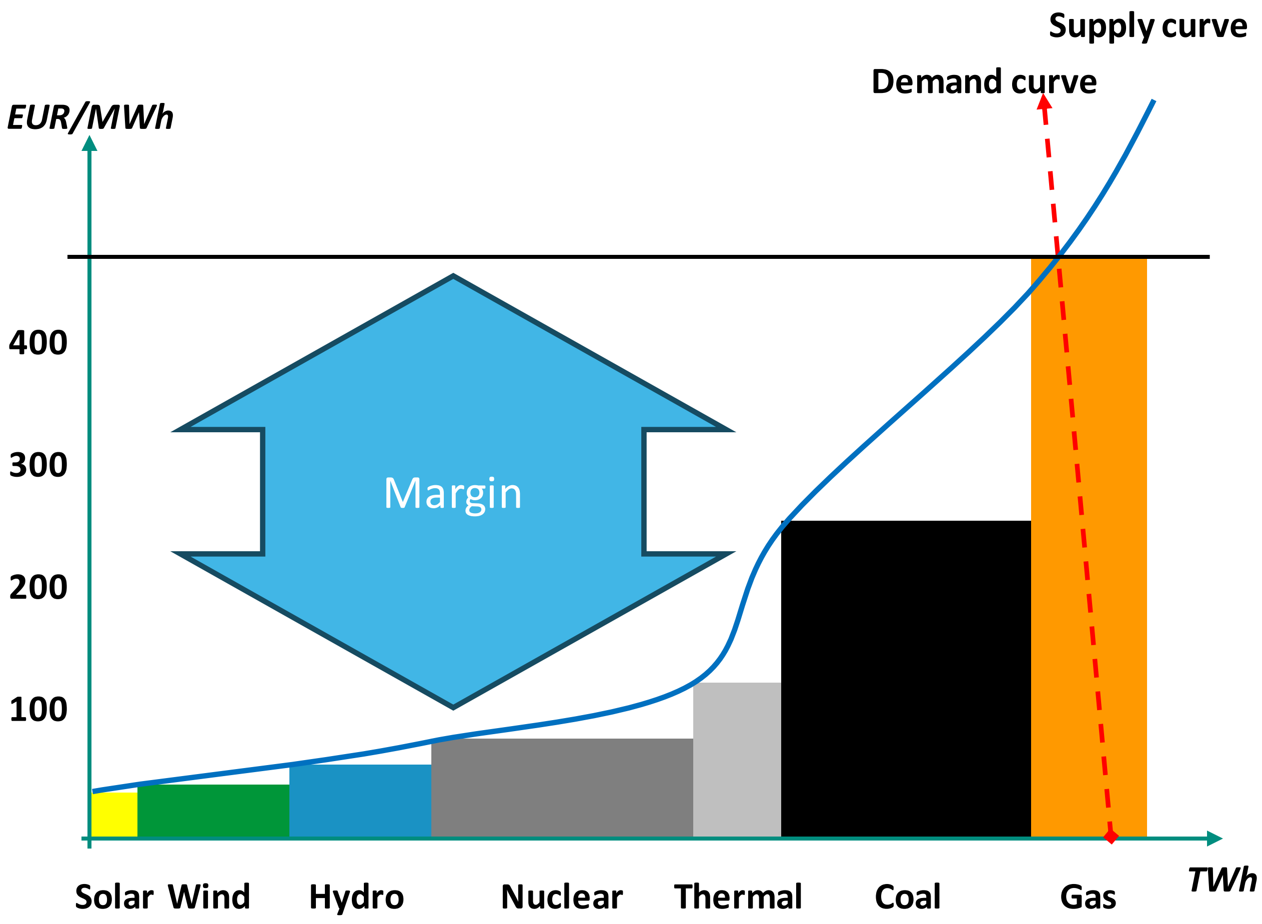


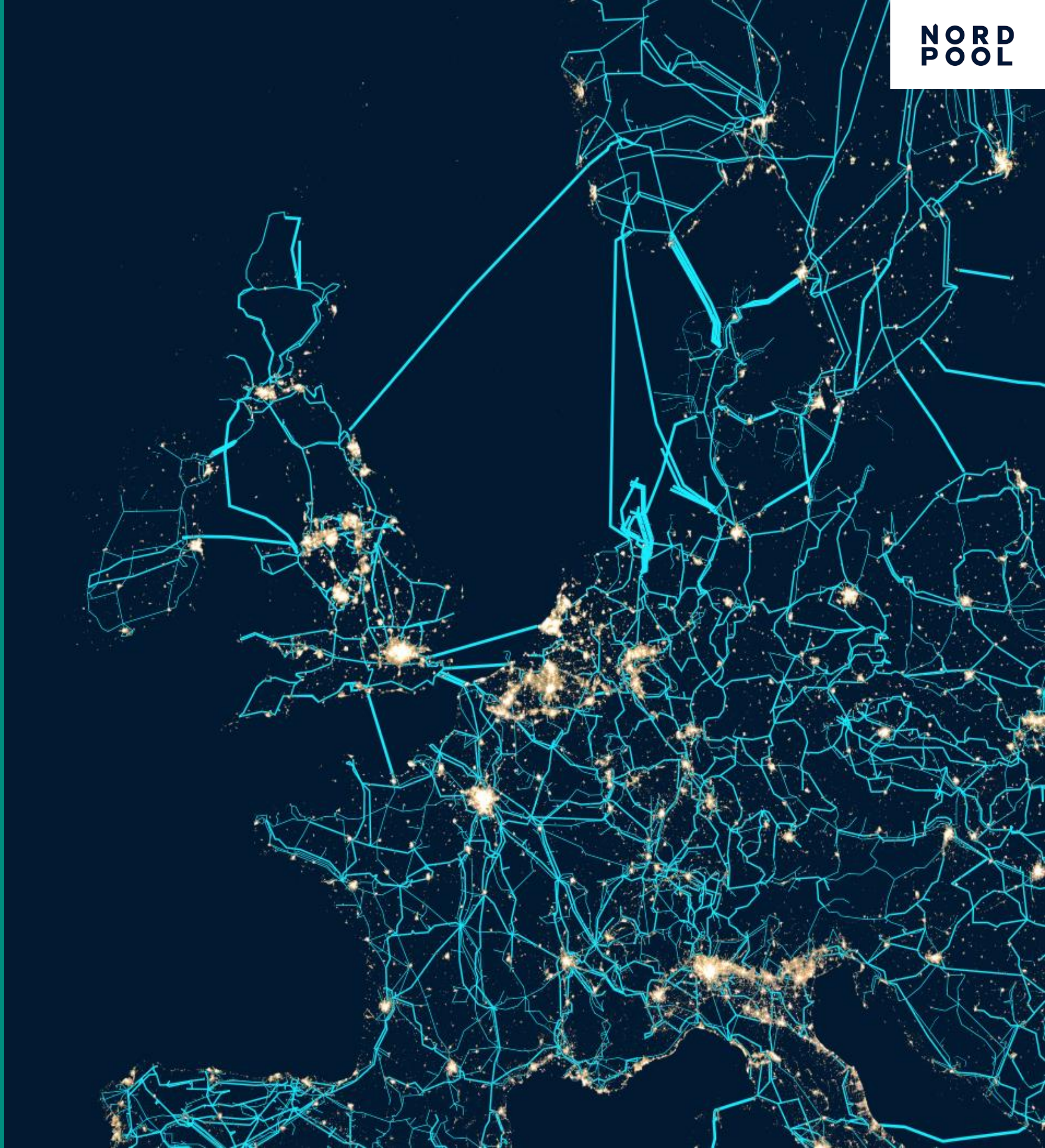
2 Marginal pricing is an incentive to carbon-free generation

- Nord Pool's market model incentivises producers to bid on the market at their marginal cost
- Marginal pricing allows low-marginal cost/low carbon intensive plants to earn more money by producing more thanks to the infra-marginal rent
- This mechanism encourages the expansion of carbon-free electricity and reduces the need for conventional, polluting power sources



3 Efficient use of interconnectors favors carbon-free generation

- Nord Pool enables cross-border trading through implicit allocation of capacities between countries on a European basis
- This mechanism ensures that electricity is supplied from the most cost-competitive and sustainable sources to meet the demand
- Even if this source is on the other side of the border
- We therefore maximise the use of carbon-free electricity across borders depending on weather conditions: a deficit of wind in some part of Europe can be compensated with a surplus in some other part



NORD POOL

4 Intraday allows renewable assets to be managed on a 24/7 basis

- Intraday is a continuous market, open 24/7, enabling renewables to balance their commercial position, closer to the actual delivery of electricity
- It allows them to use the latest available weather forecast into account
- At Nord Pool, we run the most stable, reliable and performant intraday system in Europe and are heavily investing in technology to fit market participants needs
- This brings confidence to market participants: they can rely on us to hedge weather and production fluctuations

NORD POOL

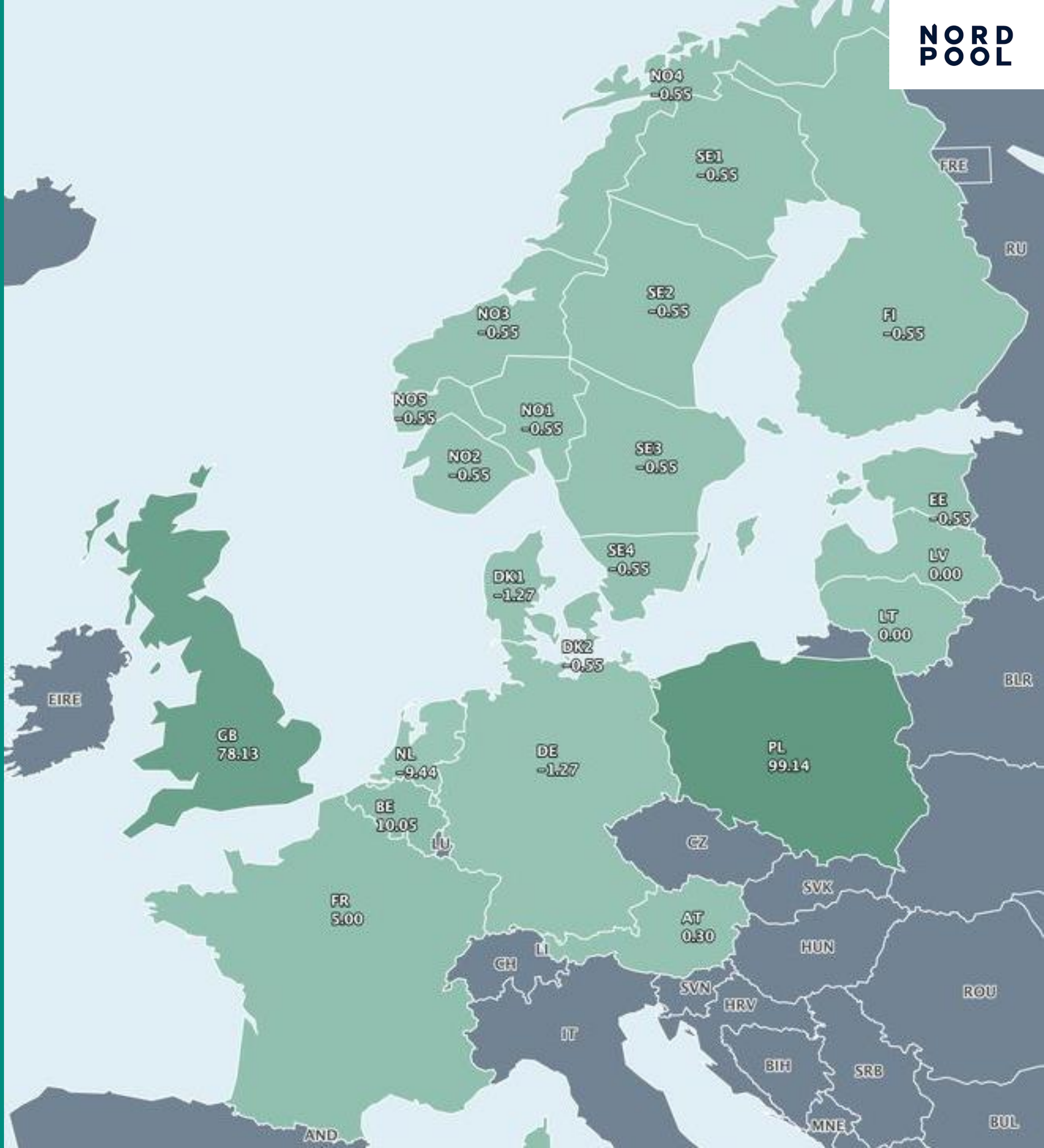
Year-on-year cumulative traded volumes on Nord Pool intraday

Q1-2023-Q1-2024

+100% in all Nord Pool markets

5 Price transparency empowers consumers demand-response

- Nord Pool has a key role in price transparency: we provide data and price signals to a wide and diverse audience
- A high price signal often signals the use of carbon-intensive power plants: therefore, a consumer has therefore both an economic and ecologic interest to consume power when prices are low
- The market empowers consumers to drive behavioural changes and help them optimise their consumption
- Digitalisation and technology make it possible: smart meters, smart devices receive live data directly from Nord Pool, for monitoring and active load management



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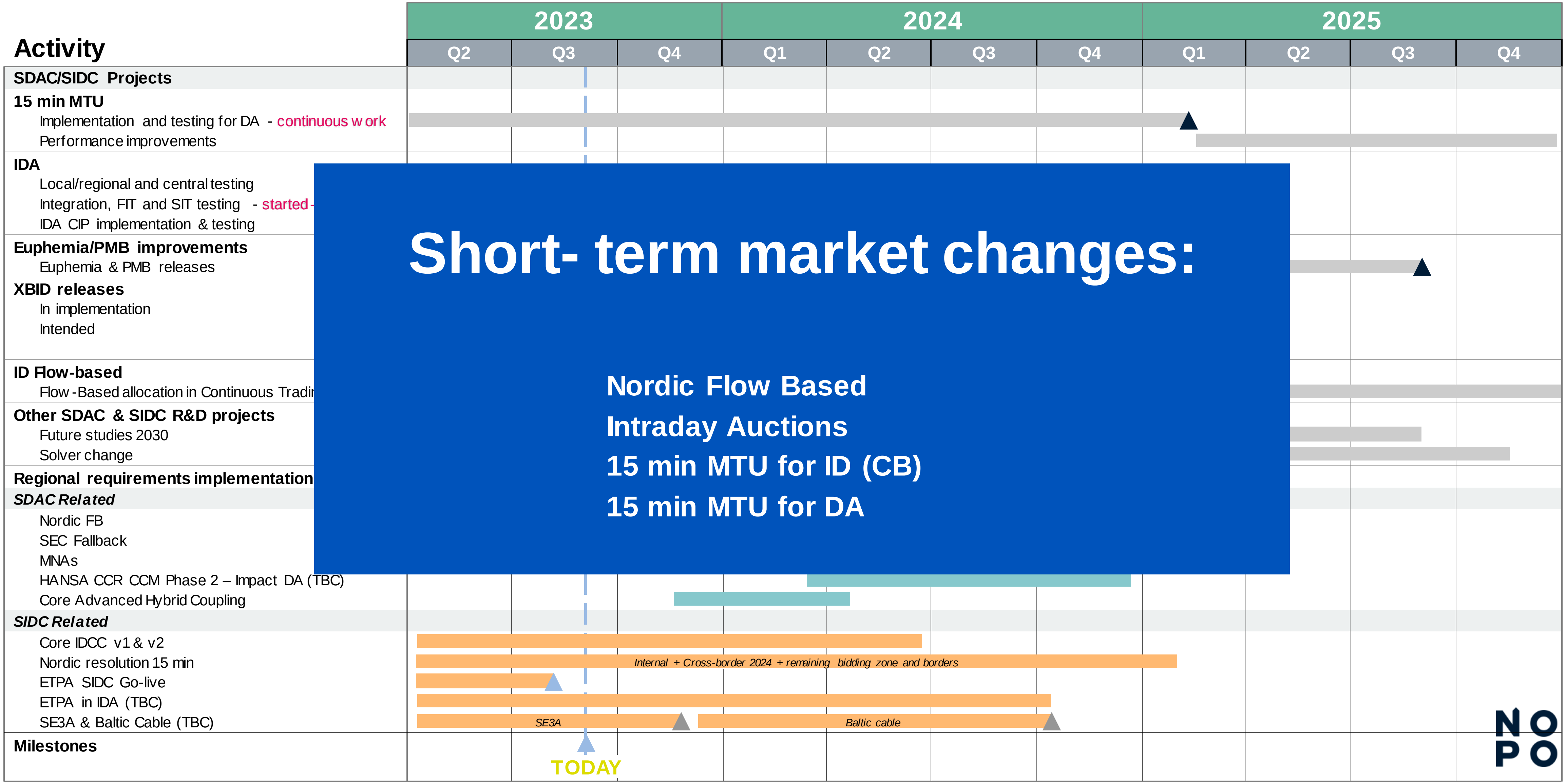
FUTURE POWER MARKET DESIGN

European integration strategy: more integrated but complex?



Short- term market changes:

Nordic Flow Based
Intraday Auctions
15 min MTU for ID (CB)
15 min MTU for DA

LONG-TERM ELECTRICITY MARKET DESIGN (EMD) REVIEW CAN IMPACT EFFICIENT MARKET FUNCTIONING

NORD POOL

2022

Emergency Measures

- EU member states and Norway introduced 439 regulatory measures at national level, of which 7% directly targeted wholesale markets
- In total 646 bill. EUR were earmarked for these emergency measures, of which 265 bill. EUR by Germany alone
- Temporary measures supposed to be ended by 2023, or 2024 the latest
- All measures applied after the price signal

2023-2024

Electricity Market Design Review

- Spot market is not broken
- SoB
- Changes to power derivatives market for price hedging
- CfD's to attract and accelerate RES project investments
- PPAs more widely available
- Energy efficiency requirements
- Capacity markets
- CACM 2.0 (Single Legal Entity)

2025-2028

Electricity Market Design Review 2.0

- Commission mandates a more thorough review of both short-term and long-term power market design
- Merit-order evaluation
- Nodal pricing evaluations
- Bidding Zone review

Where is the Electricity Market Design reform standing?

- EP vote (11 April); Council and publication to follow
- Main changes affecting the electricity markets are:
  - Single Legal Entity (Arts. 7.1 and 59.1 of Electricity Reg.)
  - Shared Order Books
    - Day-Ahead
    - Intraday
  - Unit-based bidding (Art. 7.2 point ca)
  - Peak shaving products (Art. 7a)
  - Regional Virtual Trading Hubs (Art. 9)
  - Capacity mechanisms (Arts. 21, 22, 64 and 69)
  - Electricity price crisis (Art. 66a)

NORD POOL

Questions and suggestions?

DANKE!
GRAZIE!
THANK YOU!
MERCI!
BEDANKT!
TAKK!
Dziękuję!

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NORD POOL

Pietro is Executive Vice President Europe at Nord Pool and, acting as General Manager for this region, he is responsible for overseeing and expanding Nord Pool's presence across Europe and creating greater value for its customers and other stakeholders.

Pietro has a professional background in international business, and the public and academic sectors, particularly relevant to the energy and power sector and to his role at Nord Pool.

He has studied engineering at Politecnico di Milano and Alta Scuola Politecnica in Italy and at Ecole Polytechnique in France, economics at Milan University and pursued postgraduate business and government studies at Harvard University in the USA.

Born into an Italian-Greek family and grown up in Italy close to Austria and Slovenia, Pietro has lived in 10 countries so far. You may address him in English, German, French, Italian or Greek (you can try some Spanish, Dutch and Russian, too).

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Effectiveness and Technical Challenges of Zonal Market Clearing for Congestion Management

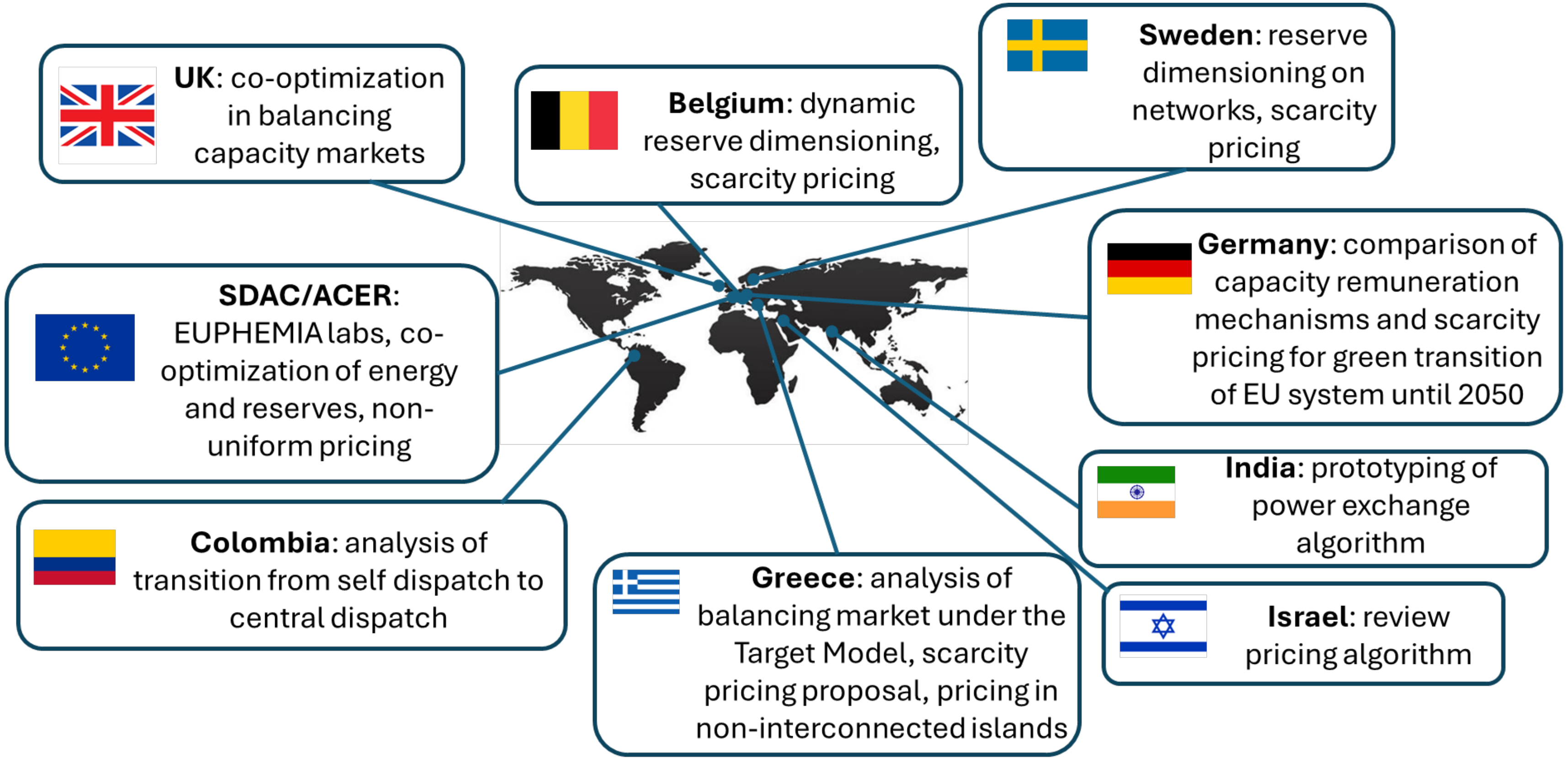
Anthony Papavasiliou, NTUA, Greece

June 11, 2024

NREL Inter-Regional Transmission Operational Coordination workshop

Our team

- Assistant professor (2022-2024), department of Electrical and Computer Engineering, National Technical University of Athens, Greece
- Formerly associate professor (2013-2022), Center for Operations Research, UCLouvain, Belgium
- Our team (currently consisting of eight PhDs and post-docs in UCLouvain and NTUA) conducts research on operations research, electricity market design and power system operations under the ICEBERG ERC Starting Grant



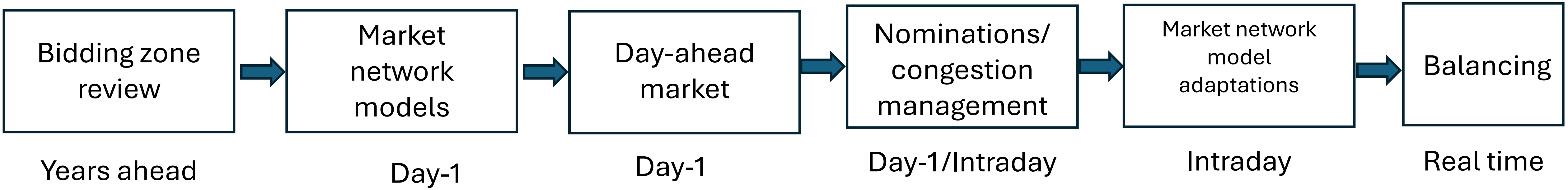
Zonal pricing in Europe

The European market integration project

- The European system installed capacity amounts to nearly 1000 GW
- Annual day-ahead traded volumes in the European market [1]: 1683.30 TWh
- Three major timeframes of energy trading:
  - **Day-ahead market** (Single Day-Ahead Coupling, SDAC)
  - **Intraday market** (Single Intraday Coupling, SIDC)
  - **Balancing**
    - Imbalance netting (International Grid Control Cooperation, IGCC)
    - Automatic frequency restoration reserve (Platform for the International Coordination of Automated Frequency Restoration and Stable System Operation, PICASSO)
    - Manual frequency restoration reserve (Manually Activated Reserves Initiative, MARI)
- An important legal mechanism for implementing an integrated market is EU-wide regulation, e.g.
  - Capacity Allocation and Congestion Management (CACM) regulation [2]
  - Electricity Balancing Guideline (EBGL) [3]
  - System Operation Guideline (SOGL) [4]
  - Electricity Regulation [5]

Salient features of congestion management in the European market

- Portfolio based (more on this later)
- Zonal market models throughout (day-ahead, intraday and real time)
- The process of setting up the European zonal system has various time steps
  - Long term: **bidding zone configuration**
  - Before day-ahead market: computation of market network models
  - **Day-ahead market**
  - Post day-ahead market: **nominations** and **congestion management** actions
  - Intraday and real-time adjustments to market network models
  - Cross-border **balancing**



Bidding zone configuration

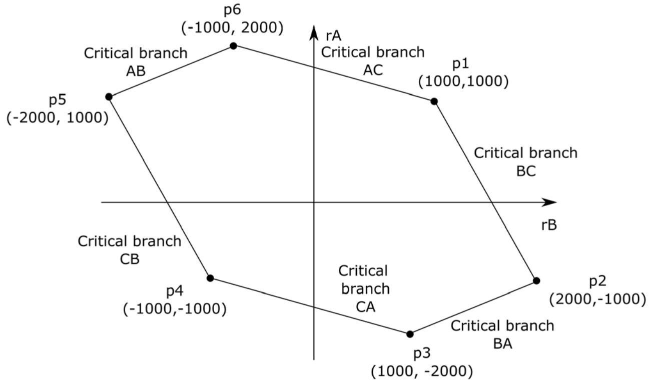
- The **bidding zone review** is the (politically difficult) process of deciding on which physical nodes are attributed to which zones
- Undertaken by Agency for the Cooperation of Energy Regulators (ACER) which is an agency of the European Union
- Takes place infrequently
  - Legal basis: articles 32-34 of CACM [2], article 14 of the Electricity Regulation [5]
  - In practice: once in 2018 (no outcome/inadequate), one ongoing

Computation of day-ahead market network models

- Two principal network models used in the day-ahead market-clearing model

- **Transportation model** (flows on lines assumed to be directly controllable)
  - Need to estimate **available transmission capacities** (ATCs)

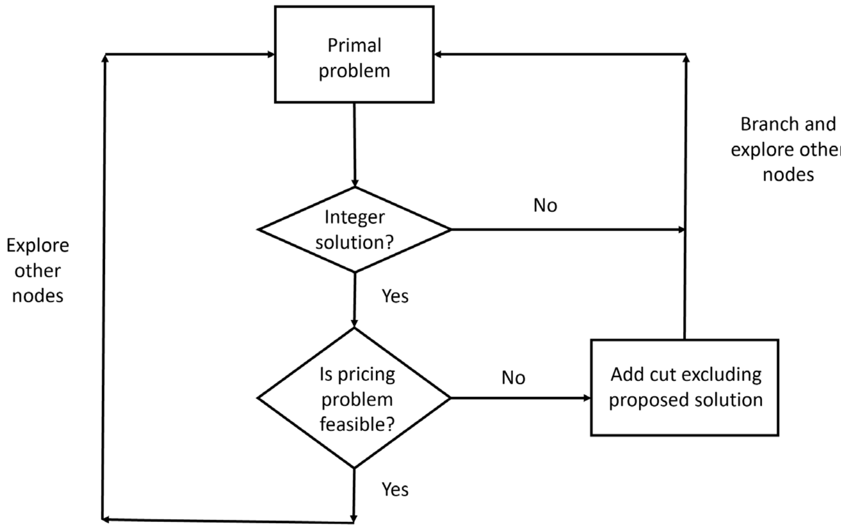
- **Flow-based model** (zonal approximation of PTDFs)
  - Need to estimate, for every critical network element (including contingencies)
    - Zonal power transfer distribution factors (PTDFs)
      - Using a base case
      - Using **generation shift keys** (GSKs)
    - **Remaining available margins** (RAMs)
  - The resulting flow-based polytopes are published daily in JAO (https://www.jao.eu/)
    - Anonymity of actual network elements is maintained



The computation of a flow-based polytope requires estimating RAM for a critical network element as well as zonal PTDFs. This is not easy, and approximations are inevitable. Source: [6].

Day-ahead market

- Day-ahead market is cleared by **EUPHEMIA**, which is a UCLouvain success story (N-SIDE spinoff has developed algorithmic backbone)
- Energy-network co-optimization (but no reserves, more on this later)
- Prices in bidding zones account for network constraints (ATC-based and flow-based)



The EUPHEMIA algorithm flow [6].

Nominations and congestion management

- After the day-ahead energy market clears, and portfolio owners know their commercial positions in the day-ahead energy and reserve markets, they can disaggregate their portfolio positions to unit-specific schedules
- These schedules are called **nominations** and are communicated to TSOs after day-ahead energy market clearing
- TSOs check if nominations are compatible with physical network constraints, and if not they resort to **redispatch**
  - Redispatch typically occurs within a bidding zone, and involves INC-DEC adjustments to restore network feasibility
  - These INC-DEC adjustments are typically paid as bid, though each national TSO has the freedom to define the specifics of this process nationally
  - The INC-DEC bids are settled at either cost-based estimates or market-based offers
  - Market-based offers entail clear **INC-DEC gaming opportunities** (which have been exploited in EU member states)

The license plates of Shmuel Oren's old Lexus.

Network model adaptations and balancing

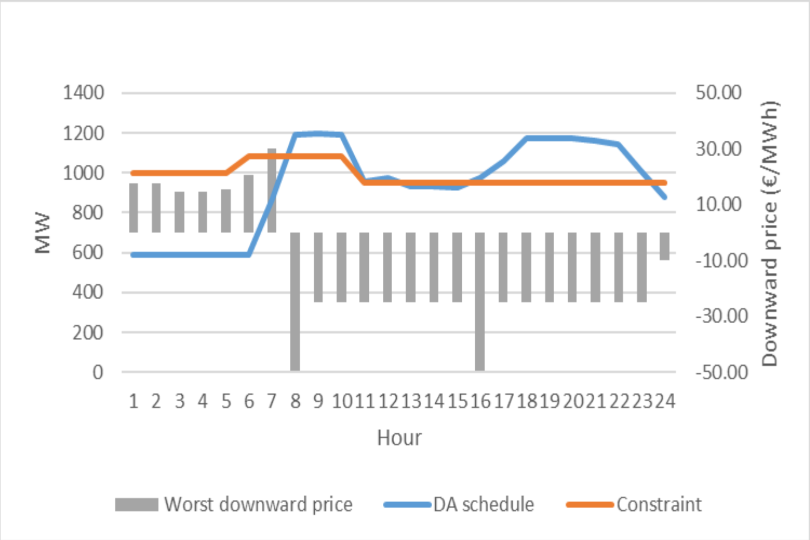
- As we approach real time, we enter the domain of the intraday market and balancing platforms
- The intraday market consists of:
  - An intraday auction
  - Continuous intraday trading up to less than an hour before real time
- The network model used in balancing is transportation-based, and the ATCs are adapted to the use of the system approaching real time
- Zonal network modeling can threaten system security in real time [6], **bid filtering** has been a measure for coping with this challenge

Simulated bid filtering results from August 23, 2021. Bids are sorted horizontally, according to price, and grouped by their bidding zone (NO1 through 5) and direction (up/down).

Source: Norwegian TSO Statnett (https://datascience.statnett.no/2022/01/20/using-data-to-handle-intra-zonal-constraints-in-the-upcoming-balancing-market/).

Zonal challenges

- Numerous challenges with zonal pricing are documented in the literature
- Short-term inefficiencies related to unit commitment [8, 9]
  - Inefficient commitment of units in Germany
  - Inefficiency estimates in line with massive German redispatch cost (order of billion €/year)
- Long-term inefficiencies related to generation capacity investment/retirement [10]
- INC-DEC gaming [11]
- Threatening operational security in real time [7]



Textbook INC-DEC gaming in a European member state in November 2020 – March 2021

The nodal-zonal debate in Europe

Criticisms of nodal pricing

Criticisms	**Counter-arguments**
Institutional compatibility: • Exchange of sensitive information about national infrastructure • Keeping low energy cost for some consumers	The fact that some consumers prefer to pay a low price for energy does not mean that neighbors should bear transmission costs
Implementation complexity: • Technological complexity • Portfolio offers	• Implementation in the US proves that it is technologically feasible • Unit-based offers allow for better scheduling and market monitoring

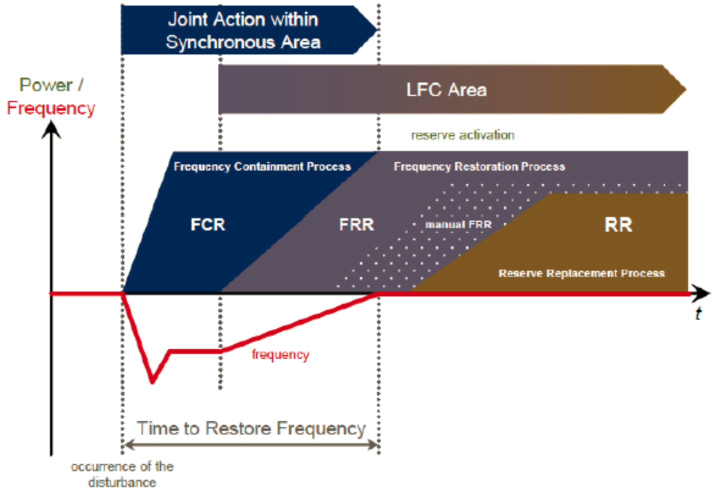
Criticisms of nodal pricing (II)

Criticisms	**Counter-arguments**
Market power: geographic splitting of the market leads to firms with a dominant position	All designs are exposed to manipulation due to market power, ignoring physical constraints of the network does not render a firm less able to exert market power
Cash transfers: zonal pricing achieves the same result with lower cash flows between market agents	But it does not achieve the same result if market participants deviate from truthful bidding
Non-intuitive price behavior	The behavior of prices is due to physical laws that cannot be ignored
Risk management and liquidity: too many pairs of nodes, difficult to hedge against transmission price differences between any pair of locations	Contract networks

Reserves

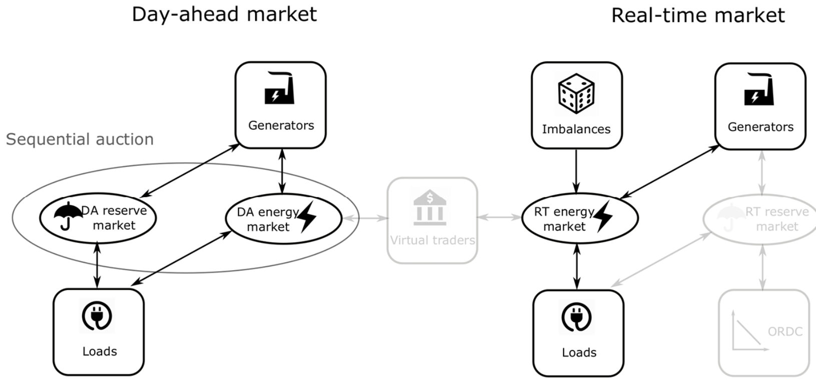
Reserve markets in Europe

- Although day-ahead energy markets in Europe are integrated, day-ahead reserve markets are not
- The day-ahead energy markets are operated by power exchanges, the day-ahead reserve markets are operated by TSOs
- Each national TSO can design day-ahead/forward reserve markets as they see fit
  - Although there is a push by legislation (article 40 of EBGL [3]) to integrate the day-ahead trading of reserve with the day-ahead trading of energy
  - Our team is actually conducting a study on quantifying the short-term benefits from such a move, which can be in the order of 1 billion €/year for the entire European continent (depending on specific assumptions)
  - Day-ahead reserve markets are often conducted before day-ahead energy markets
  - As part of the push for integration, it is becoming increasingly important to standardize definitions of reserves in Europe, with the predominant products being:
    - **Frequency containment reserve**: automatically controlled
    - **Automatic frequency restoration reserve** (upward/downward): automatically controlled, setpoint changes every 4 seconds
    - **Manual frequency restoration reserve** (upward/downward): manually controlled, full activation time within a few minutes
    - **Restoration reserve**: full activation time within multiple minutes



Reserve markets and scarcity pricing

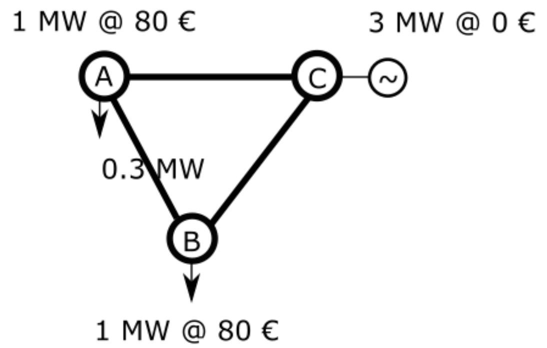
- Although day-ahead reserve markets are not integrated, the activated energy is integrated in Europe through the EU balancing platforms (e.g. MARI/PICASSO)
- But we have "forgotten" to put in place a real-time market for reserve in Europe [12]!
- This complicates scarcity pricing based on operating reserve demand curves



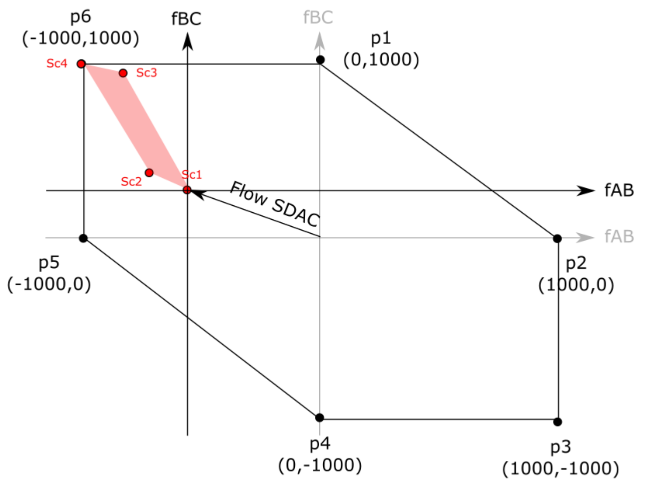
Although we have day-ahead reserve markets in Europe, we have forgotten to put in place a real-time market for reserve [12]!

Reserve deliverability

- The discussion on integrating energy and reserve in European day-ahead reserve market has raised an interesting computational challenge referred to as the **deterministic requirement**
- The deterministic requirement is the requirement of being able to deliver reserve that has been traded in the day-ahead, no matter the pattern of TSO energy activations in real time
- Computationally intractable, but can be approximated through an approach based on inscribing boxes in polyhedra [14]
- Computational viability of this approach demonstrated by prototyping within EUPHEMIA [15]



How much reserve should we allocate in this market? Source: [13]



Geometric representation of the computationally hard deterministic requirement. Source: [13]

Thank you

Questions?

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Interregional Coordination Background and Framing

Yonghong Chen
NREL Grid Planning and Analysis Center

Interregional Transmission Operational Coordination (IRTOC) Workshop

June 11, 2024

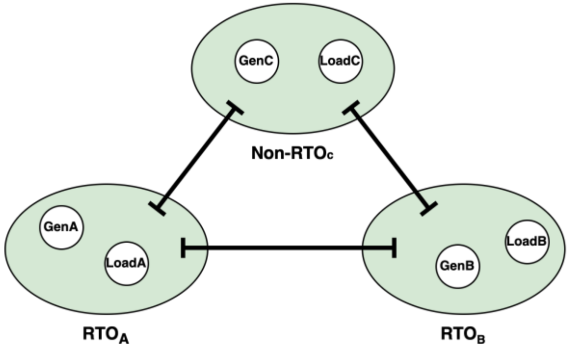
NOTICE
This presentation includes preliminary results and should not be cited or distributed

Background

Existing interregional coordination examples in North America

1) Coordinated Transaction Scheduling / Interchange Optimization
2) Congestion management
   - Market to market coordination (M2M) under Joint operating agreements (JOAs)
   - NERC Transmission Loading Relief (TLR)
3) Reserve sharing group

- **Coordination mostly happens in real time, with significant opportunities for improvement**
- **Limited coordination in operational forward processes**



Future transmission expansion

- National Transmission Planning (NTP) Study
- Off-shore wind studies

Interregional Extra High Voltage AC (EHVAC) and HVDC to support renewable integration

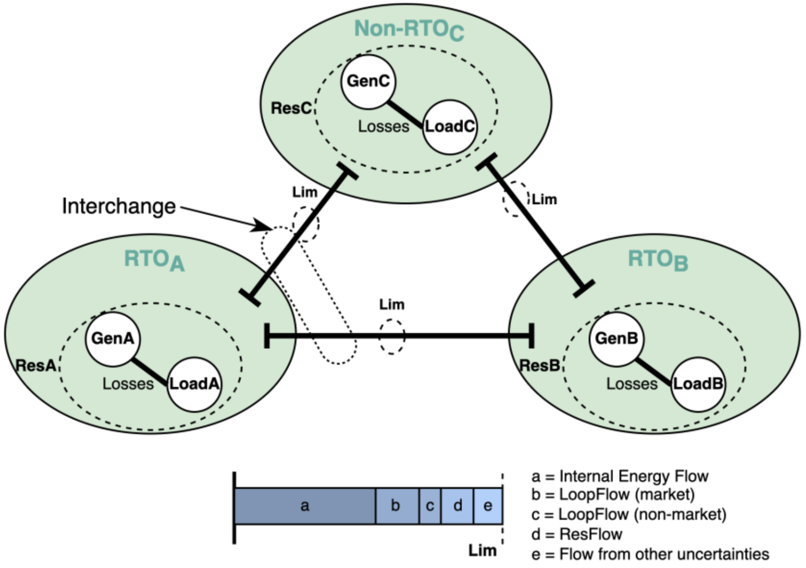
Interregional Transmission Operational Coordination (IRTOC)

- Focusing on interregional congestion management but also open to other areas of coordination.
- **Values and needs for coordination in operational forward processes**
- **Real time M2M congestion management challenges**
- **Intra- and inter-regional HVDC optimization**
- **Intra- and inter-regional reserve deliverability**

Two main functions in operations

- **Balancing authority (BA): power balance**
  - Gen + Interchange = Load + Losses
  - Reserve ≥ ReserveRequirement

- **Reliability coordination (RC): congestion management***
  - Flow from Energy: a+b+c ≤ Limit
  - Flow with reserve and margin: a+b+c+d+e≤ Limit



Example methods to manage various components:

1	Interchange optimization, coordinated transaction scheduling, etc.
a	Security constrained unit commitment and economic dispatch
b	Market to market (M2M) coordination on congestion relief with external RTOs
c	NERC transmission loading relief (TLR)
d and e	Transmission reliability margin (TRM), e.g., 2%

** RC is also responsible for other reliability services such as managing voltage and reactive power*

Interregional Coordination

- How can existing coordination processes across markets be improved to enhance system reliability and economic efficiency?
- How can coordination across multiple regions be optimized after building interregional transmission to achieve maximum benefits?

Levels of coordination

Many possible combinations

Single RTO: global optimization within the footprint

System wide constraints	Co-optimized constraints	Locational Marginal Pricing component
Power balance	*Gen1+Gen2=Load1+Load2*	*Marginal energy component (MEC)*
Transmission constraint (energy flow)	*EnergyFlow1+EnergyFlow2≤Limit*	*Transmission constraint shadow prices drive marginal congestion component (MCC)*
Reserve requirement	*Res1 + Res2 ≥ ResRequirement*	*Marginal prices for systemwide reserve requirement*
Transmission constraint (energy+ reserve flow)	*EnergyFlow1 + EnergyFlow2 + ResFlow1 + ResFlow2 ≤Limit*	*Marginal congestion component for reserve deliverability (MISO, CAISO zonal or nodal reserve prices)*

One RTO with two sub-areas 1 and 2 assuming lossless

Red: variables *Black: parameters*

Clearing without explicit coordination: two-RTO example

System wide constraints	Individual clearing	Implications
Power balance	*GenA+NSIA=LoadA* *GenB+NSIB=LoadB*	*MECA and MECB may not be equal* • *Traders may schedule transactions to arbitrage* • *NSI: net scheduled interchange (out of market)*
Transmission constraint (energy flow)	*EnergyFlowA+loopflow≤Limit*	• *Only monitoring RTO manages congestion* • *Loop flow from external areas is estimated (difficult)*
Reserve requirement	*ResA ≥ ResRequirementA* *ResB ≥ ResRequirementB*	• *Reserves are procured separately* • *Reserve products may be different*
Transmission constraint (energy+ reserve flow)	*EnergyFlowA+ResFlowA+ loopflow + TRM ≤Limit*	• *Only monitoring RTO manages congestion* • *Add TRM or other manual adjustment as buffers for uncertainty*

Two RTOs A and B assuming lossless
Red: variables *Black: parameters*

Current status: limited coordination

System wide constraints	Individual clearing with limited coordination	Mechanism
Power balance	*GenA+NSIA=LoadA* *GenB+NSIB=LoadB*	• *Coordinated transaction scheduling* • *Interchange optimization*
Transmission constraint (energy flow)	*EnergyFlowA+loopflowA≤Limit* *EnergyFlowB+loopflowB≤Limit*	• *M2M JOA congestion management*
Reserve requirement	*ResA ≥ ResRequirementA* *ResB ≥ ResRequirementB*	• *Reserve sharing group for contingency reserve (usually static ratio allocation)*
Transmission constraint (energy+ reserve flow)	*Mostly not coordinated*	

Two RTOs A and B assuming lossless
Red: variables *Black: parameters*
Blue: components with coordination mechanism

Possible coordination configurations

Coordination configurations	c0	c1	c2	c3	c4	c5	c6	c7	c8	c9	c10	c11
Power balance	0	1	0	1	0	1	0	1	0	1	0	1
Transmission constraint (energy flow)	0	0	1	1	0	0	1	1	1	1	1	1
Reserve requirement	0	0	0	0	1	1	1	1	0	0	1	1
Transmission constraint (energy+ reserve flow)	0	0	0	0	0	0	0	0	1	1	1	1

Interchange optimization

M2M JOA

MISO energy market 2005-2009

Full multi-area coupling (e.g., EIM, Coordinated multi-RTO scheduling)

0: no coordination 1: with coordination

EIM: energy imbalance market – may be extended to enforce all constraints under c11

Summary of the mathematical models

Fully coordinated ← No coordination

System wide constraints	Co-optimized multi-area coupling	Individual clearing with certain levels of coordination	Individual clearing without explicit coordination
Power balance	GenA+GenB=LoadA+LoadB	GenA+NSIA=LoadA GenB+NSIB=LoadB **Interchange optimization**	GenA+NSIA=LoadA GenB+NSIB=LoadB
Transmission constraint (energy flow)	EnergyFlowA+EnergyFlowB ≤Limit	EnergyFlowA+loopflowA≤Limit EnergyFlowB+loopflowB≤Limit **M2M congestion management energy flow**	EnergyFlowA+loopflow≤Limit **On monitoring RTO**
Reserve requirement	ResA + ResB ≥ ResRequirement	ResA ≥ ResRequirementA ResB ≥ ResRequirementB **Reserve sharing group for contingency reserve**	ResA ≥ ResRequirementA ResB ≥ ResRequirementB
Transmission constraint (energy+ reserve flow)	EnergyFlowA + EnergyFlowB + ResFlowA + ResFlowB ≤Limit	EnergyFlowA+ResFlowA+loopflowA≤Limit EnergyFlowB+ResFlowB+loopflowB≤Limit **M2M congestion management considering reserve deliverability**	EnergyFlowA+ResFlowA+loopflow ≤Limit **On monitoring RTO**

Red: variables *Black: parameters*
Blue: components with coordination mechanism

Key issues to address

Issue 1:
Impact from different coordination configurations at different operational stages

Research area 1:
1.1 Develop benchmark optimal mathematical models for each configuration
1.2 Multi-stage simulation with the flexibility to study different configurations
1.3 Consistent ways to measure economic and reliability impacts

Issue 2:
Strategies to address computational complexity and challenges to create new business structures

Research area 2:
2.1 Approximation methods, e.g.,
- *Distributed coordination under current structure versus adding a new layer for global coupling*
- *Reasonable simplification on mathematical models for multi-area coupling*

2.2 Business and technical complexity analysis

1.1 Benchmark model example: M2M JOA c2

Coordination configurations	c2	Individual clearing	Co-optimized constraints	
Power balance	**0**	*GenA+NSIA=LoadA* *GenB+NSIB=LoadB*		*Two power balance equations*
Transmission constraint (energy flow)	**1**		*EnergyFlowA+ EnergyFlowB ≤Limit*	*Jointly optimized energy flow*
Reserve requirement	**0**	*ResA ≥ ResRequirementA* *ResB ≥ ResRequirementB*		*Two separate reserve requirements, may have different reserve products*
Transmission constraint (energy+ reserve flow)	**0**	*EnergyFlowA+ResFlowA+ loopflow + TRM ≤Limit*		*Reserve flow impact is only considered in the monitoring RTO A, mostly not enforced in today's markets.*

This mathematical model requires inputs from both regions.

- One entity may clear two markets together to achieve the most effective congestion management. **This is the best outcome that M2M JOA can achieve.**
- The distributed solution approach is used in existing M2M JOA process. The two RTOs exchanges shadow prices of the same transmission energy flow constraint trying to achieve flow and price convergence.

1.2 Different coordination models across multi-stage of operations

	Europe		US RTOs	
	Coupling	**Clearing Model**	**Coupling**	**Clearing Model**
Day ahead (DA)	Multi-region	Zonal aggregation	Limited	Nodal within each RTO
Intra-day	Multi-region	Zonal aggregation	Limited	Nodal within each RTO
Real time (RT)		Zonal aggregation	Some level of coordination on interchange and/or congestion management	Nodal within each RTO
Pros	>900GW coupling to optimize transferring across EU		Each RTO (up to ~180GW) achieves high efficiency on power balance, congestion management and reserve procurement	
Cons	Congestion management challenges with zonal clearing		Expanding nodal clearing to multi-RTO has jurisdictional and computational challenges	

1.2 Sienna Decomposition to study multi-stage multi-region operational coordination

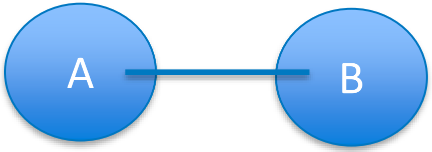


Illustration of energy only congestion management coordination across two RTOs

DA	**C0: No control of inter-regional congestion**	GenA+NSIA=LoadA GenB+NSIB=LoadB
	C2 Benchmark: best M2M outcome	GenA+NSIA=LoadA GenB+NSIB=LoadB EnergyFlowA+EnergyFlowB≤Limit
	C0 MRTO control (status quo)	GenA+NSIA=LoadA GenB+NSIB=LoadB EnergyFlowA+loopflow≤Limit **On monitoring RTO**
	C3 Multi-RTO coupling	GenA+GenB=LoadA+LoadB EnergyFlowA+EnergyFlowB≤Limit

Potential simplified models: zonal (EU), linear programming relaxation, etc.

Intra-day

RT	**C0: No control of inter-regional congestion**	$GenA + NSIA = LoadA$ $GenB + NSIB = LoadB$ **Calculate SE flow after clearing**
	C0 MRTO control (status quo)	$GenA + NSIA = LoadA$ $GenB + NSIB = LoadB$ $EnergyFlowA + loopflow \leq Limit\ (MRTO)$ **Calculate SE flow after clearing**
	C2 Multi-RTO real time M2M control lack of coordination	$GenA(t+1) + NSIA = LoadA$ $GenB(t+1) + NSIB = LoadB$ $EnergyFlowA(t+1) + loopflowA(t) \leq Limit$ $EnergyFlowB(t+1) + loopflowB(t) \leq Limit$
	C2 Distributed control through shadow price exchanges (C2D)	$GenA(t+1) + NSIA = LoadA$ $GenB(t+1) + NSIB = LoadB$ $EnergyFlowA(t+1) + EstLoopA(t+1) \leq Limit$ $EnergyFlowB(t+1) + EstLoopB(t+1) \leq Limit$
	C2 Marginal equivalent (C2M)	$GenA(t+1) + NSIA = LoadA$ $GenB(t+1) + NSIB = LoadB$ $EnergyFlowA(t+1) + loopflowA(t) + \Delta\, EnergyFlowB\_marginal(t+1) \leq Limit$ $EnergyFlowB(t+1) + loopflowB(t) + \Delta\, EnergyFlowA\_marginal(t+1) \leq Limit$
	C2 Benchmark: best M2M outcome (C2B)	$GenA + NSIA = LoadA$ $GenB + NSIB = LoadB$ $EnergyFlowA + EnergyFlowB \leq Limit$

Distributed coordination

Global coupling on congestion management

1.3 Consistent ways to measure economic and reliability impacts

Day Ahead Ci

Commitment plan CMi

↓

Real Time Cj

Energy and reserve dispatch plan DPj

……

Day Ahead Ck

Commitment plan CMk

↓

Real Time Cm

Energy and reserve dispatch plan DPm

↓

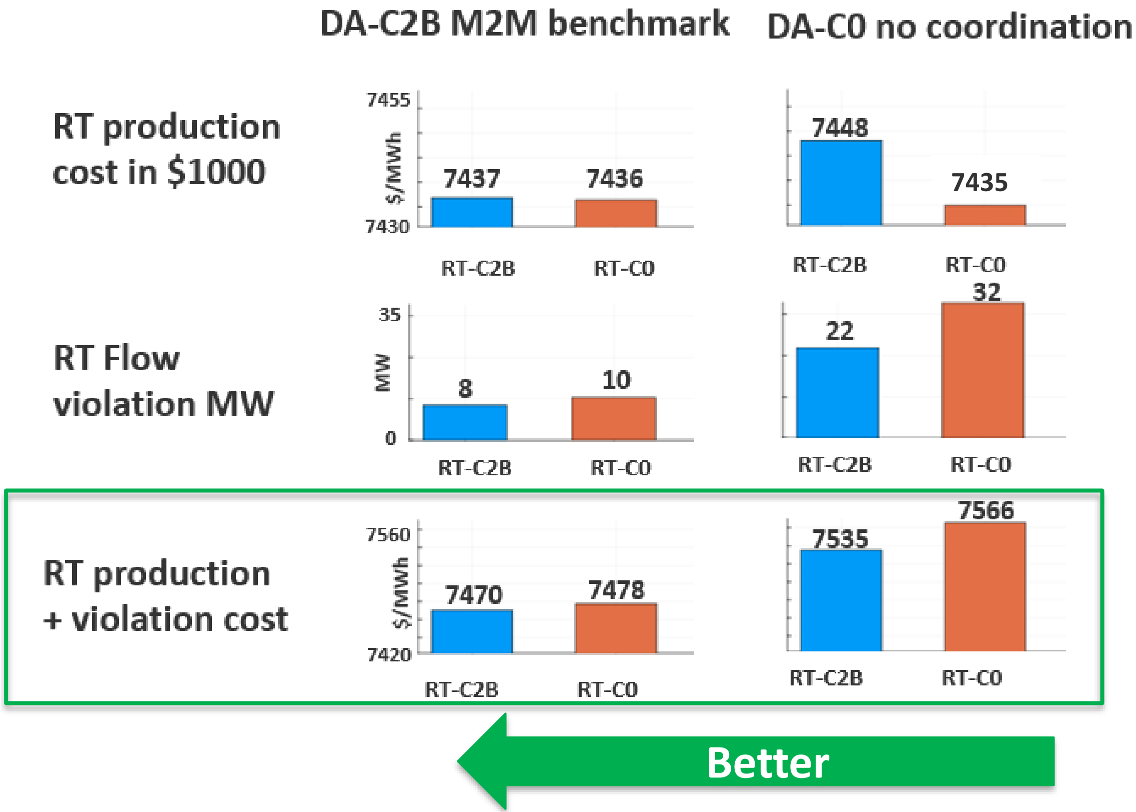
Emulation of actual system under Cm and DP

Real time simulation

- Production cost from CM and DP
- Violation cost from reserve shortage, pre-contingency flow violations, post-contingency flow violation, etc.

1.3 Illustration on 2xRTS-96Bus system on M2M coordination

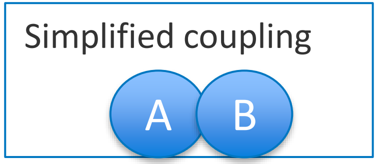
Preliminary results and should not be cited or distributed



- ***No coordination in DA: higher RT production cost & higher RT flow violation***
- ***RT M2M coordination can reduce production cost and flow violation. The impact is less than DA coordination.***

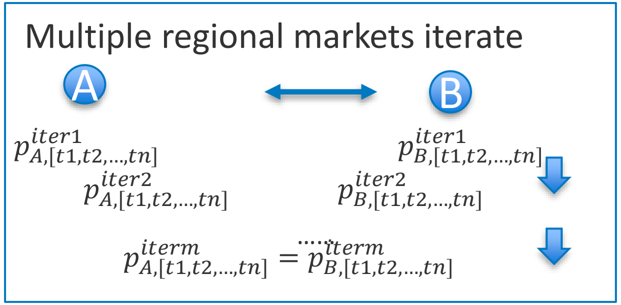
2.1 Approximation with simplified model or solution method

Forward operational process: simplified coupling or iterative multi-regional clearing



Single large model
Require simplifications to overcome computational challenges

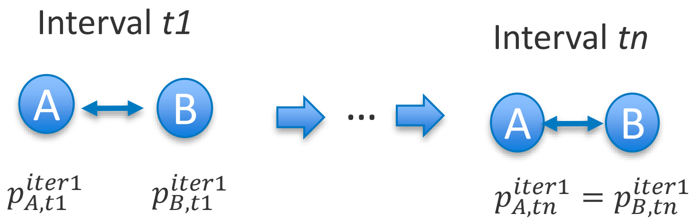
Or



Iterations on multiple regional market clearing: convergence & solving time challenges

$p_{A,\cdot}^{\cdot}, p_{B,\cdot}^{\cdot}$: *solution on joint variables from A and B respectively*

Real time: convergence across the rolling clearing process



Existing M2M approach:
- ***Each RTO performs single run for each interval***
- ***Two RTOs exchange information and achieve convergence in multiple intervals***

Needs to develop enhanced and new algorithms for:
- ***Better convergence***
- ***Large number of M2M constraints***
- ***More than two regions***

Framing the interregional coordination study

- Build study framework in Sienna
  - Multi-region
  - Multi-stage
  - Multi-configuration on coordination methods
  - Real time emulation to consistently measure economic and reliability impacts

- Analysis on complexity, efficiency and reliability
  - Develop benchmark models
  - Simplification of single large coupling model
  - Convergence of distributed methods on solving multiple regional models iteratively

- IRTOC project: focus on congestion management (C2 and C8)

Q&A

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NREL Transforming ENERGY

National Transmission Planning (NTP) Study

David Palchak

June 12, 2024

NOTICE
This presentation includes preliminary results and should not be cited or distributed

Objectives of the study

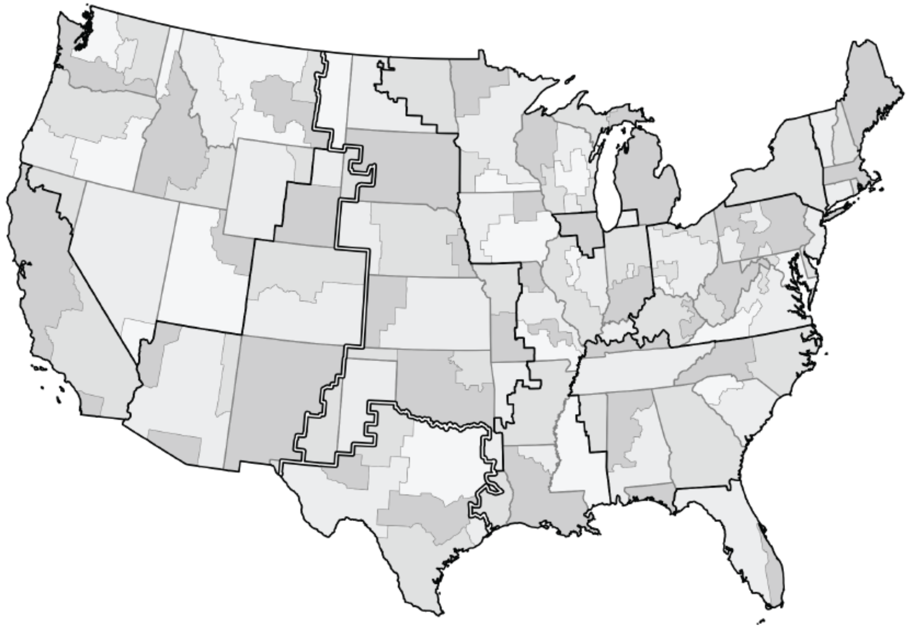
Better understand the role, value, and opportunities for transmission across the U.S.

Identify interregional and national strategies to accelerate cost-effective decarbonization while maintaining system reliability

Inform regional and interregional transmission planning processes, particularly by engaging stakeholders in dialogue

Develop methods for national-scale transmission planning that are applicable for industry

Multimodel analysis for a low-cost, reliable transmission system of the future



Zonal Resolution

Long-Term Scenarios through 2050

- Capacity Expansion
- Economic Analysis
- Resource Adequacy

Nodal Resolution

2035 Transmission Portfolios

- Production Cost
- Power Flow
- Stress Analysis

Scenario Framework: Transmission Expansion Paradigms

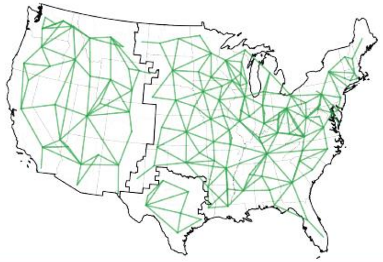
Reference Transmission Framework

Limited (Lim)

- No new interregional transmission
- Total annual transmission expansion limited to recent observed maximum

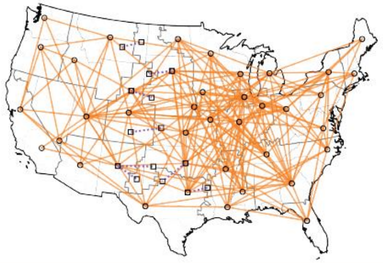
Accelerated Transmission Framework

Alternating Current (AC)



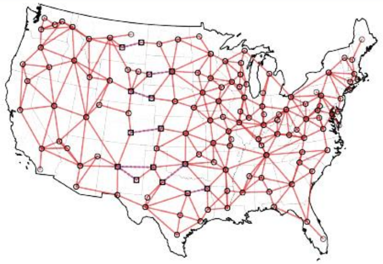
- Expansion allowed within interconnections
- No new DC connections

Point-to-Point (P2P)



- Expansion allowed across the country
- Includes long-distance point-to-point HVDC options

Multi-Terminal (MT)

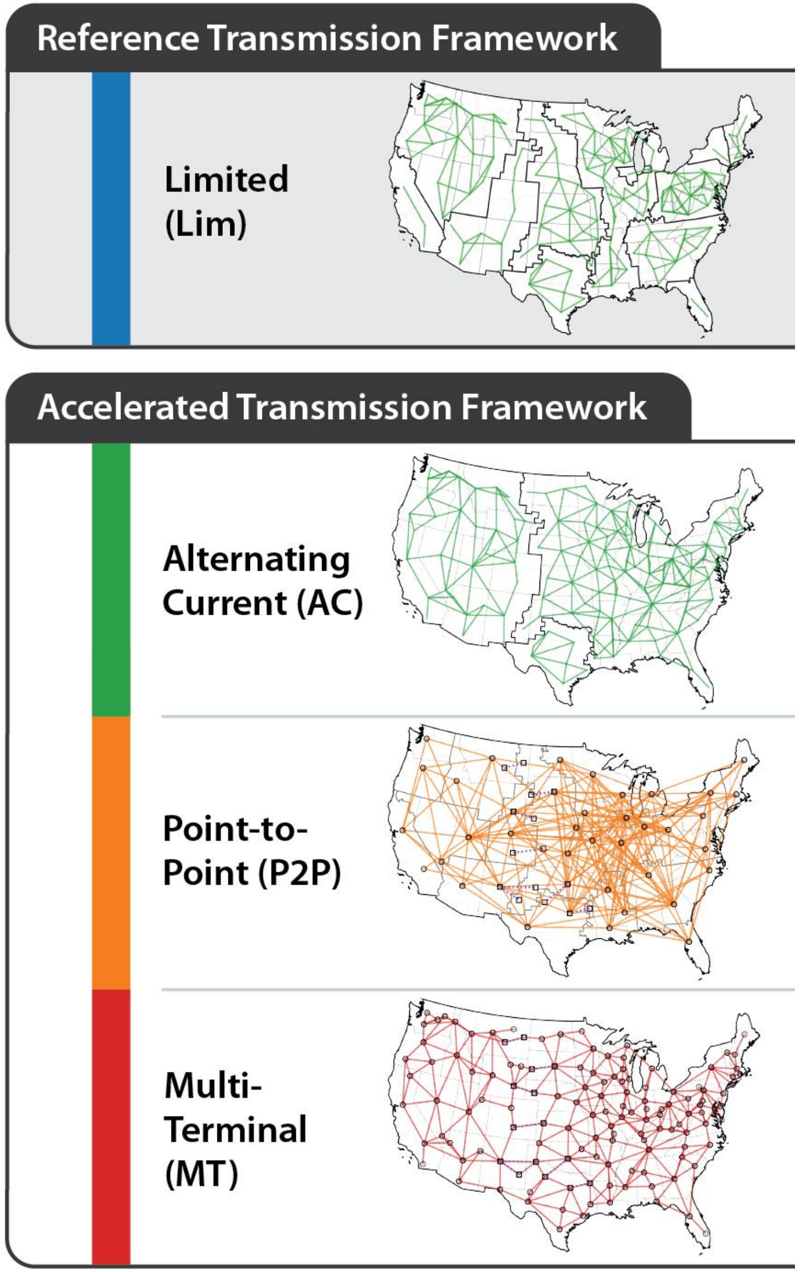


- Expansion allowed across the country
- Includes multi-terminal HVDC options between neighboring zones

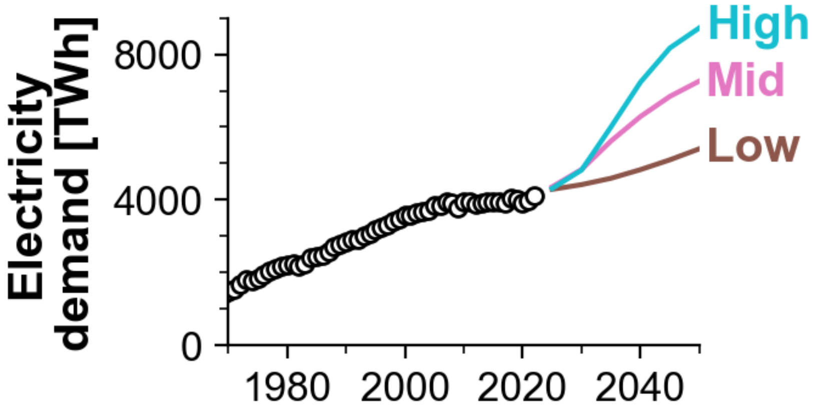
Scenario Framework:

Transmission
×
Demand
×
Emissions Targets

36 core scenarios



× 3 Demand Growth

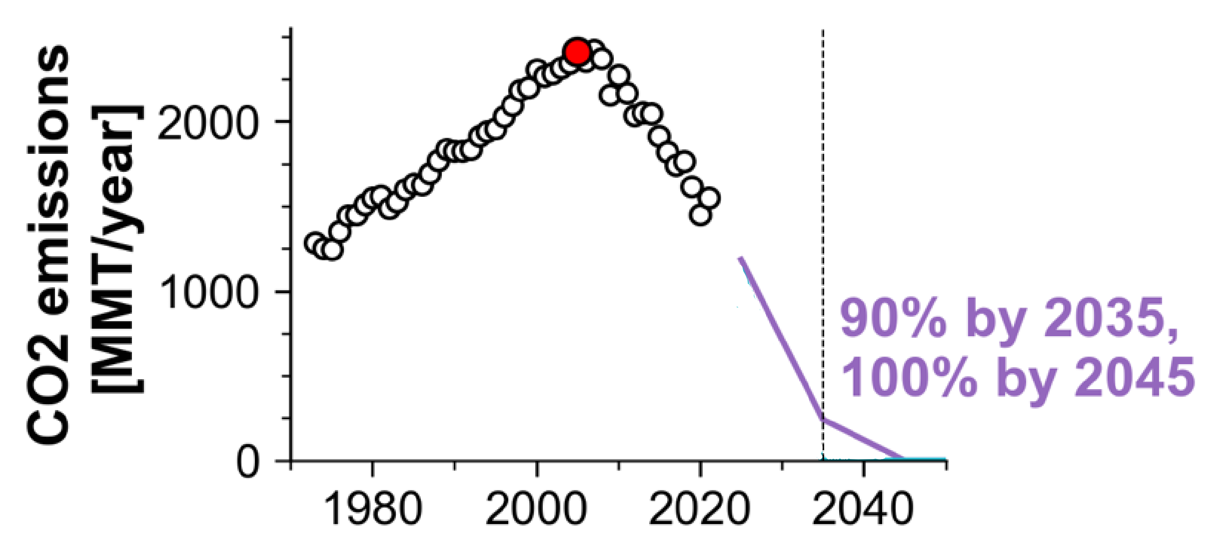


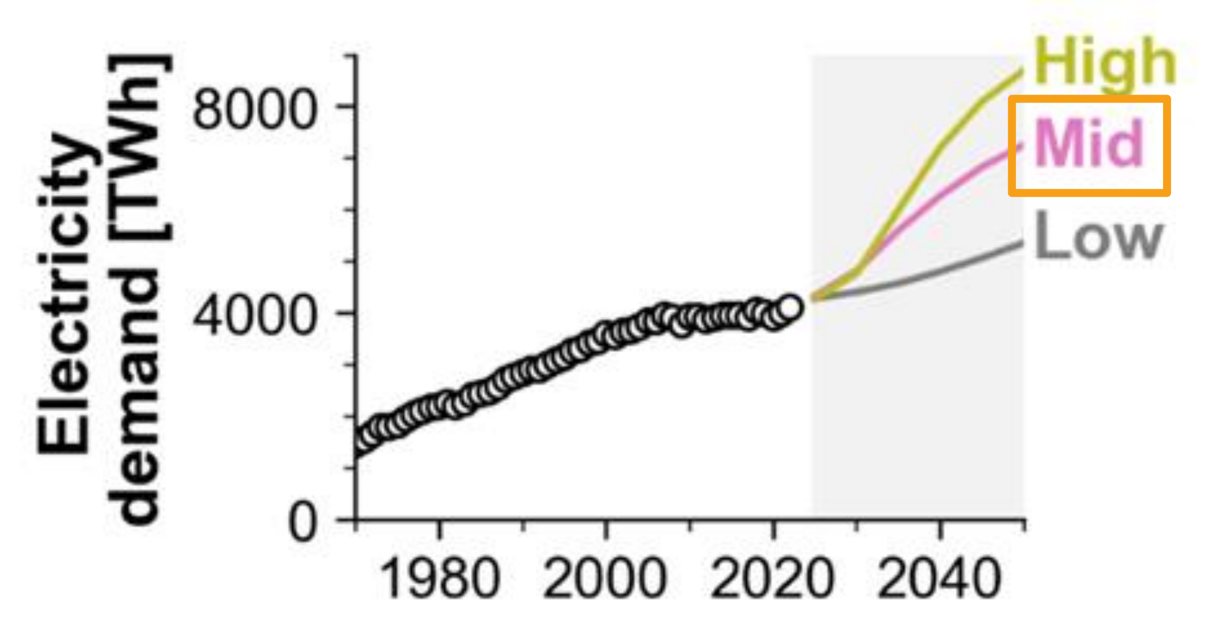
× 3 Emissions Targets
Current policies
90% CO_2 reduction by 2035
100% by 2035

Goal is to understand role of transmission across many possible futures

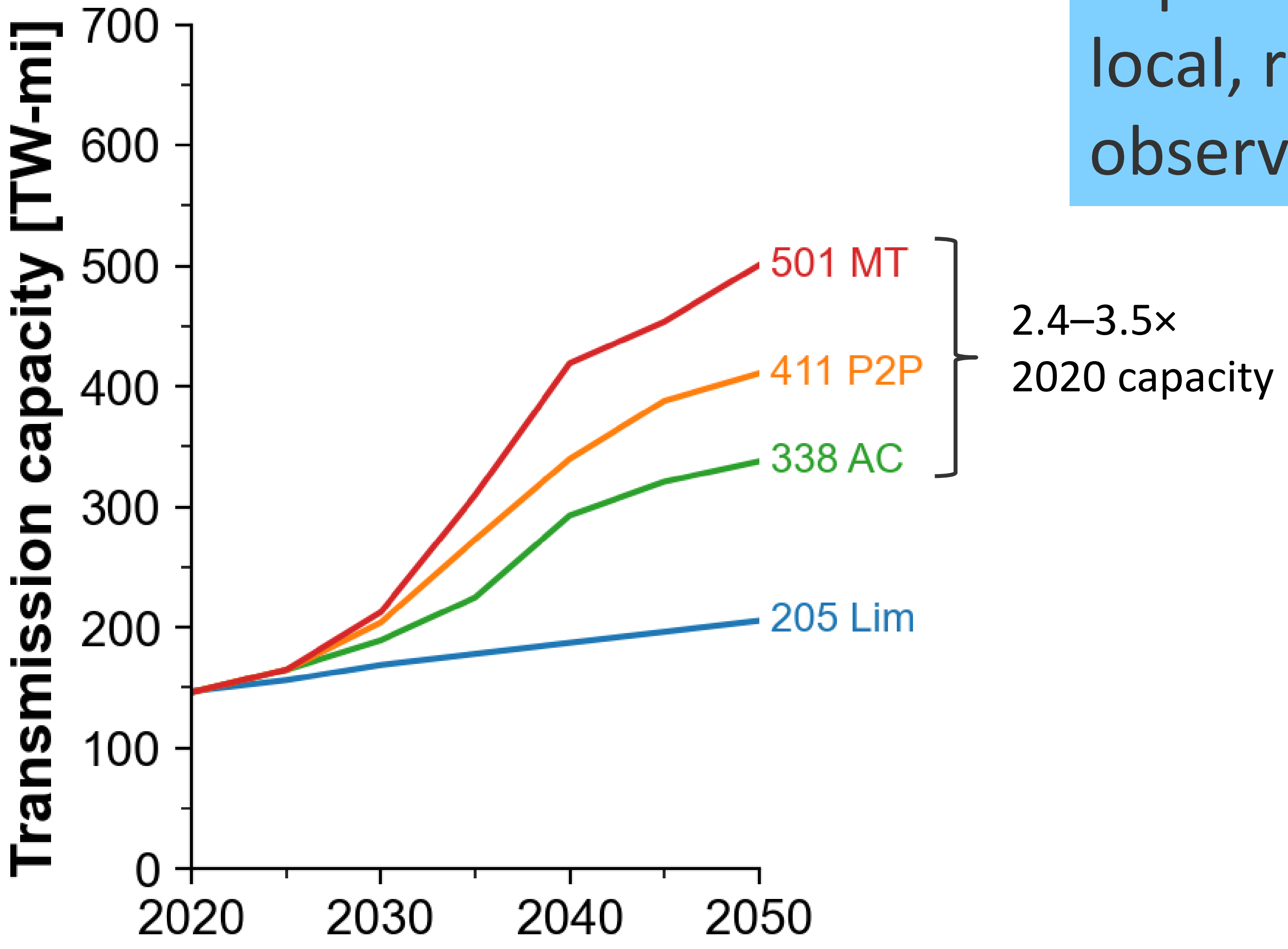
90% by 2035, 100% by 2045

Central decarbonization scenario





Rapid and significant growth in new transmission capacity occurs under the decarbonization scenarios



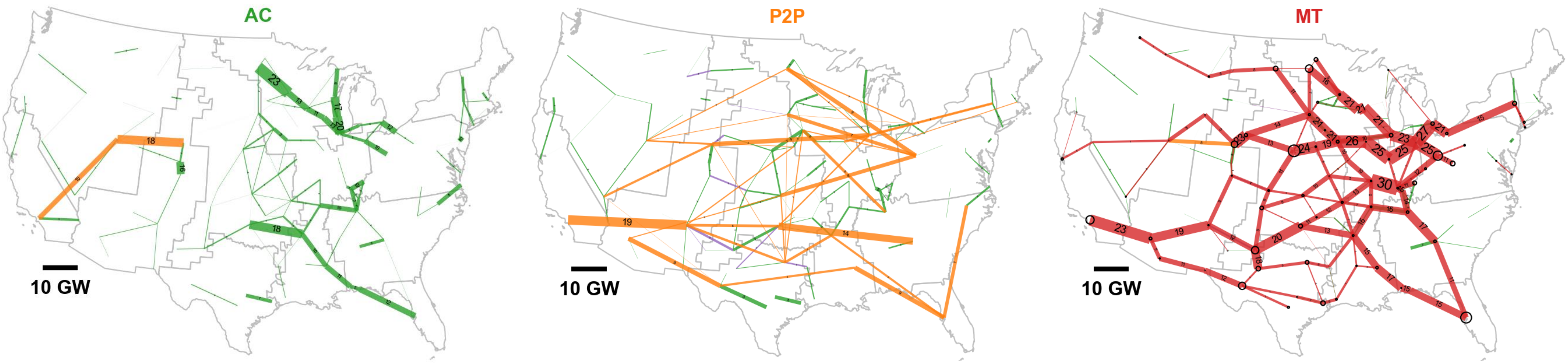
Expansion of **all types** of transmission—local, regional, and interregional—is observed under low-carbon futures

Transmission additions under the **HVDC** scenarios are greater than under the **AC** ones

Interim results
Do not distribute

90% by 2035, mid demand

Transmission is added in **all regions**, but expansion is particularly pronounced around the **central wind belt**

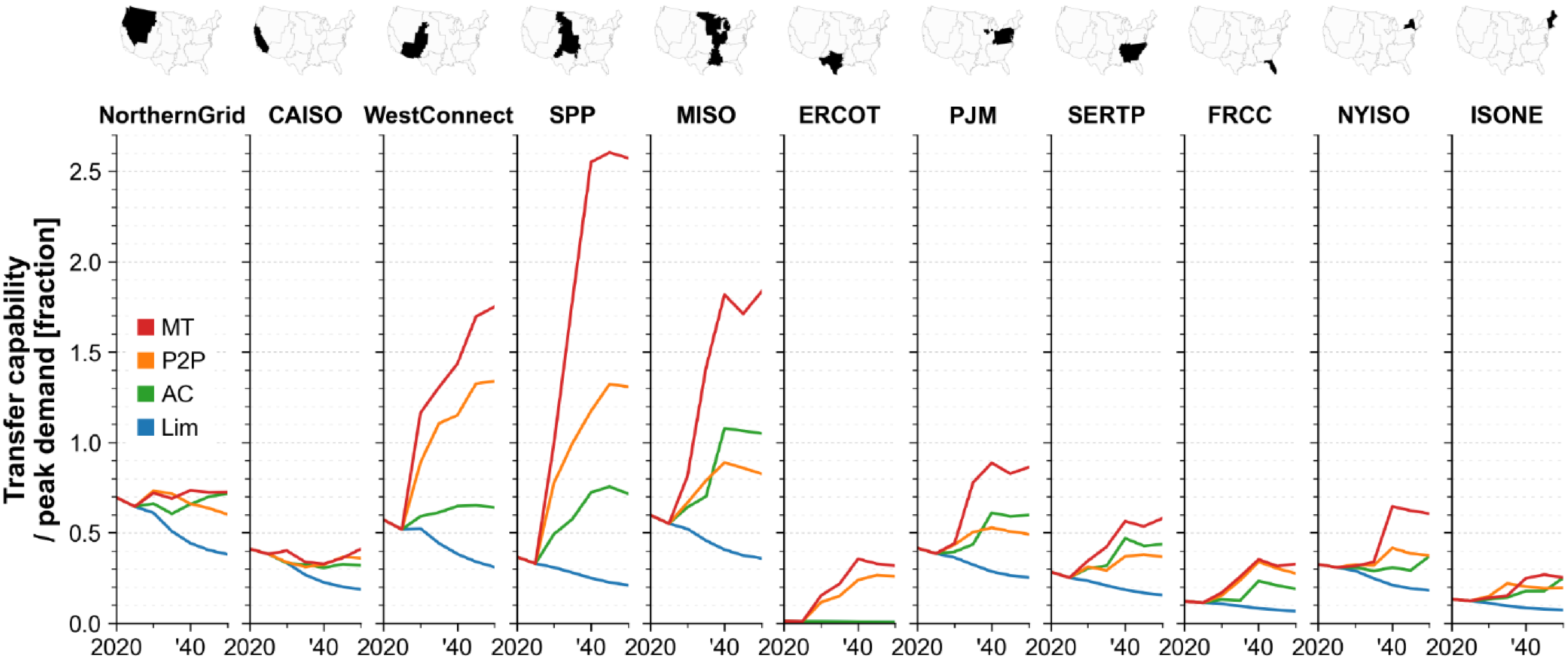


Additions from 2020-2050

Interim results
Do not distribute

90% by 2035, mid demand

Interregional transfer capacity increases substantially in many regions, especially in HVDC scenarios



Interim results
Do not distribute

90% by 2035, mid demand

Why is there so much transmission built?

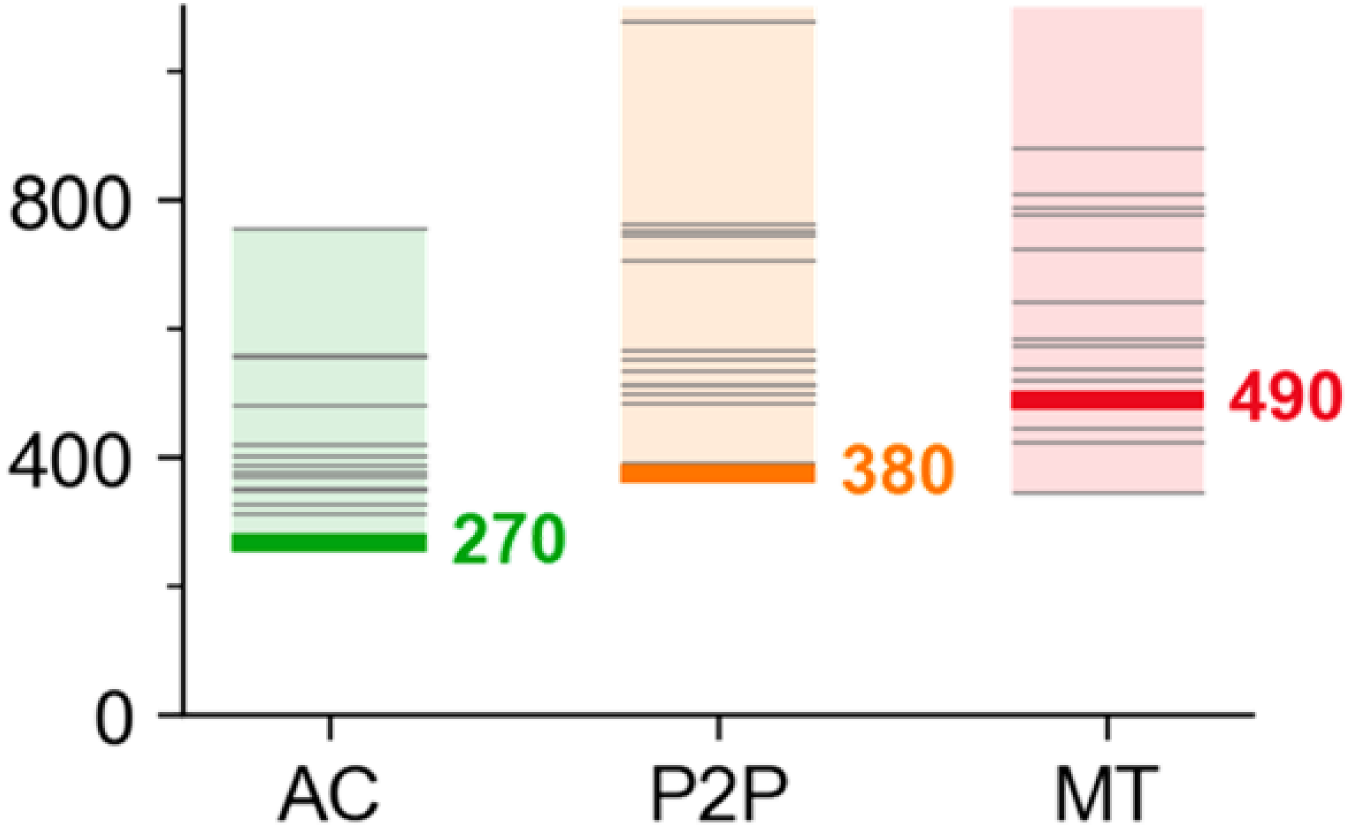
Approximately $1.60 to $1.80 is saved for every dollar spent on transmission

Interim results
Do not distribute

90% by 2035, mid demand

System cost savings from transmission expansion [$billion]

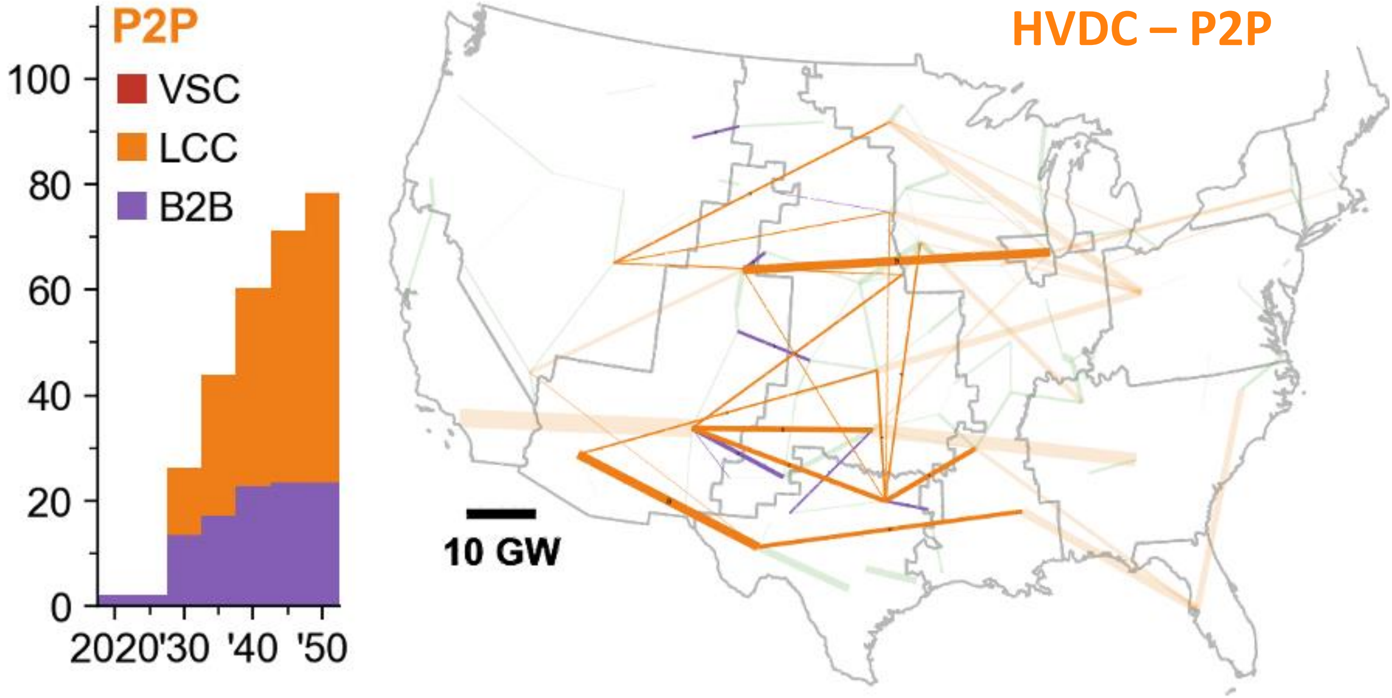
Core scenarios **highlighted**, sensitivities in gray

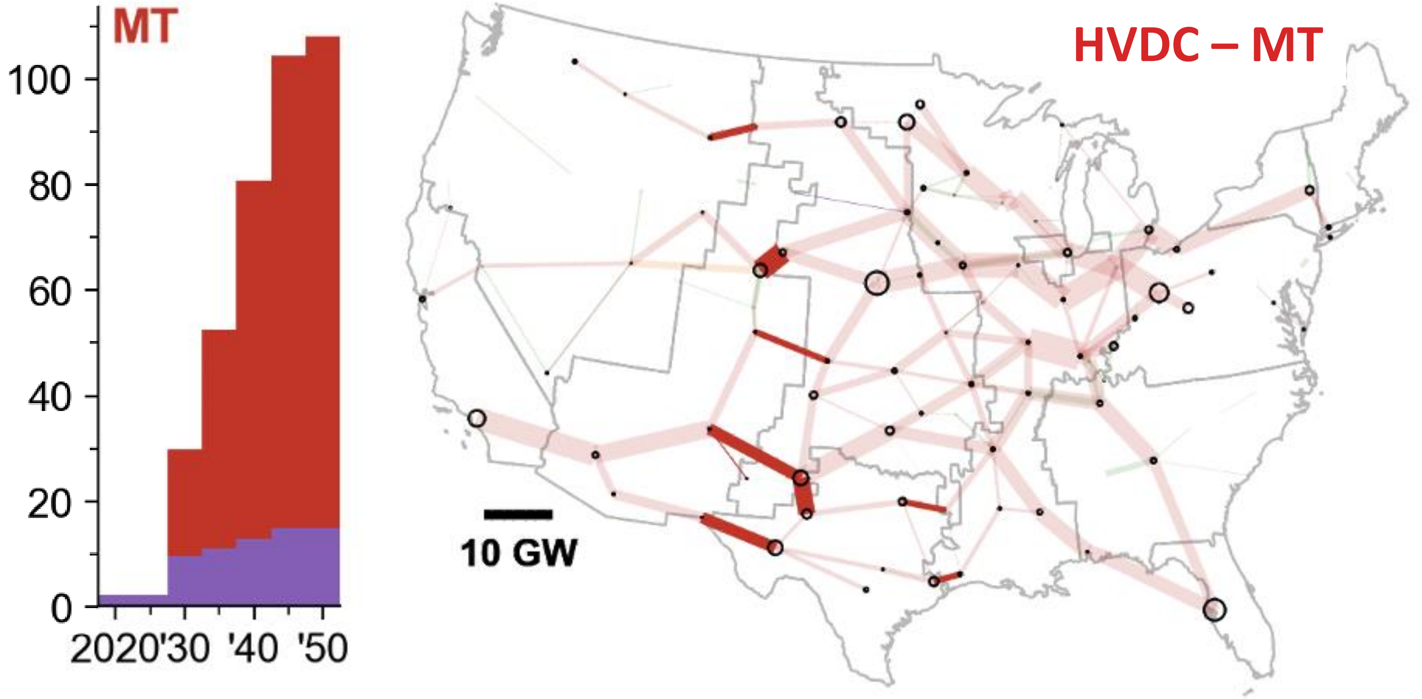


Represents savings compared to Limited

When allowed, transmission capacity expands significantly between the interconnections

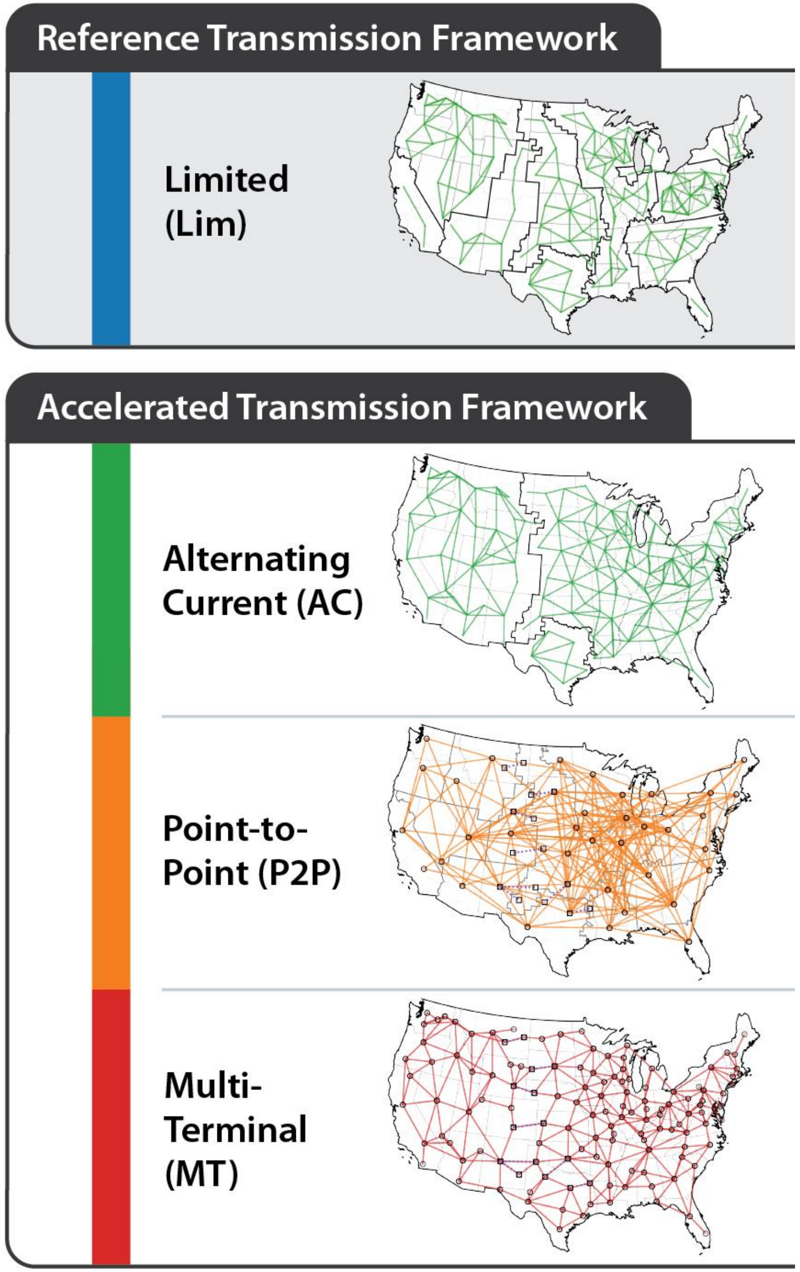
~35-50 times the current seam-crossing capacity





Interim results
Do not distribute

Scenario Framework: Transmission Expansion Paradigms



× 3 Demand Growth

× 3 Emissions Targets

× 15 Sensitivities

Sensitivity
PV + battery low cost
Wind low cost
Electrolyzer low cost
+Nuclear SMR +DAC
No interface expansion limit
Transmission cost 2x
No resource adequacy sharing
Siting limited for PV and wind
CCS high cost
Many challenges
No H2
No CCS
No H2 or CCS
No H2 or new nuclear
Climate

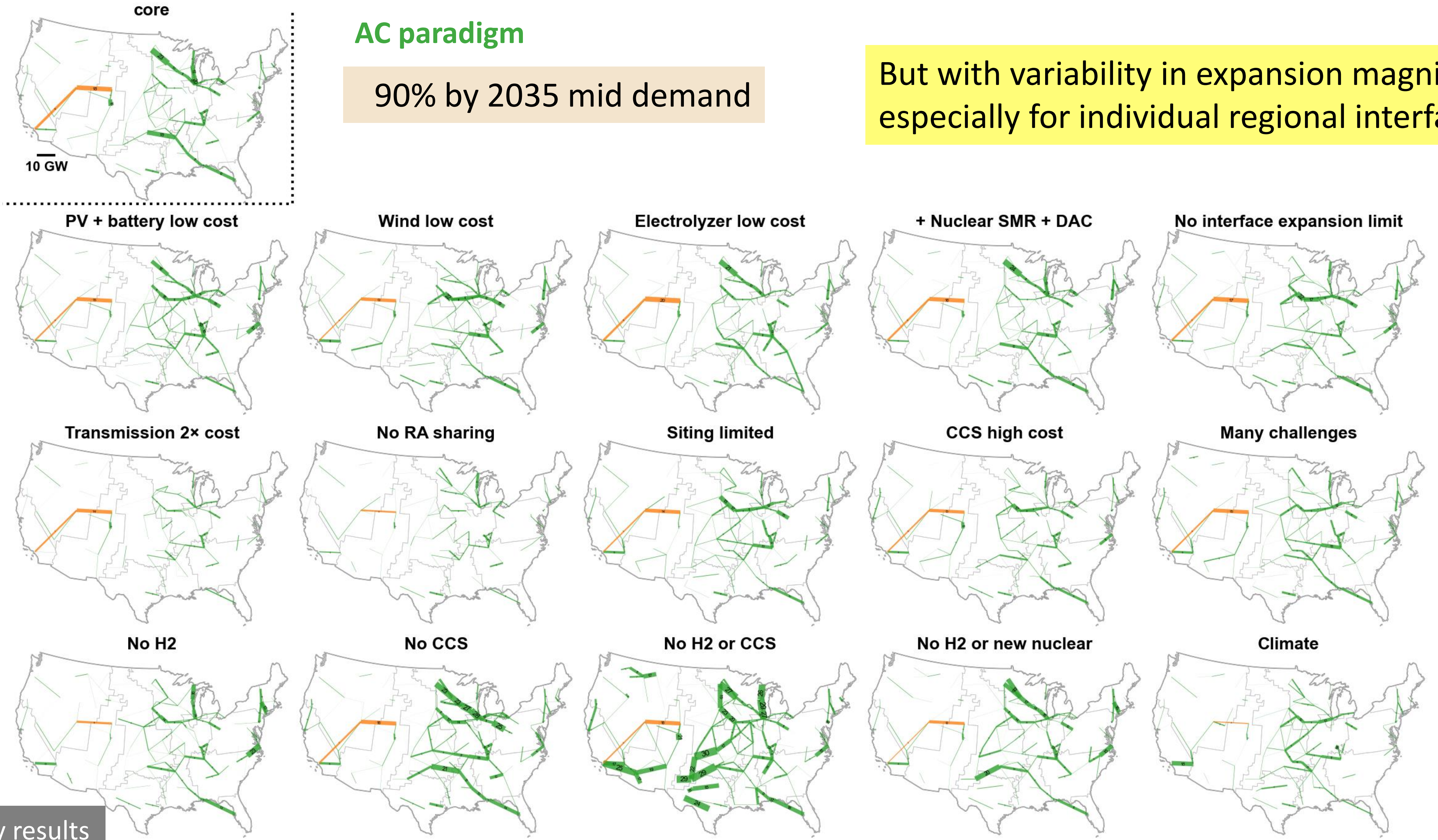
**sensitivities modeled for 90x2035, Mid Demand only*

Spatial distribution of transmission expansion is robust across many possible futures

AC paradigm

90% by 2035 mid demand

But with variability in expansion magnitude—especially for individual regional interfaces

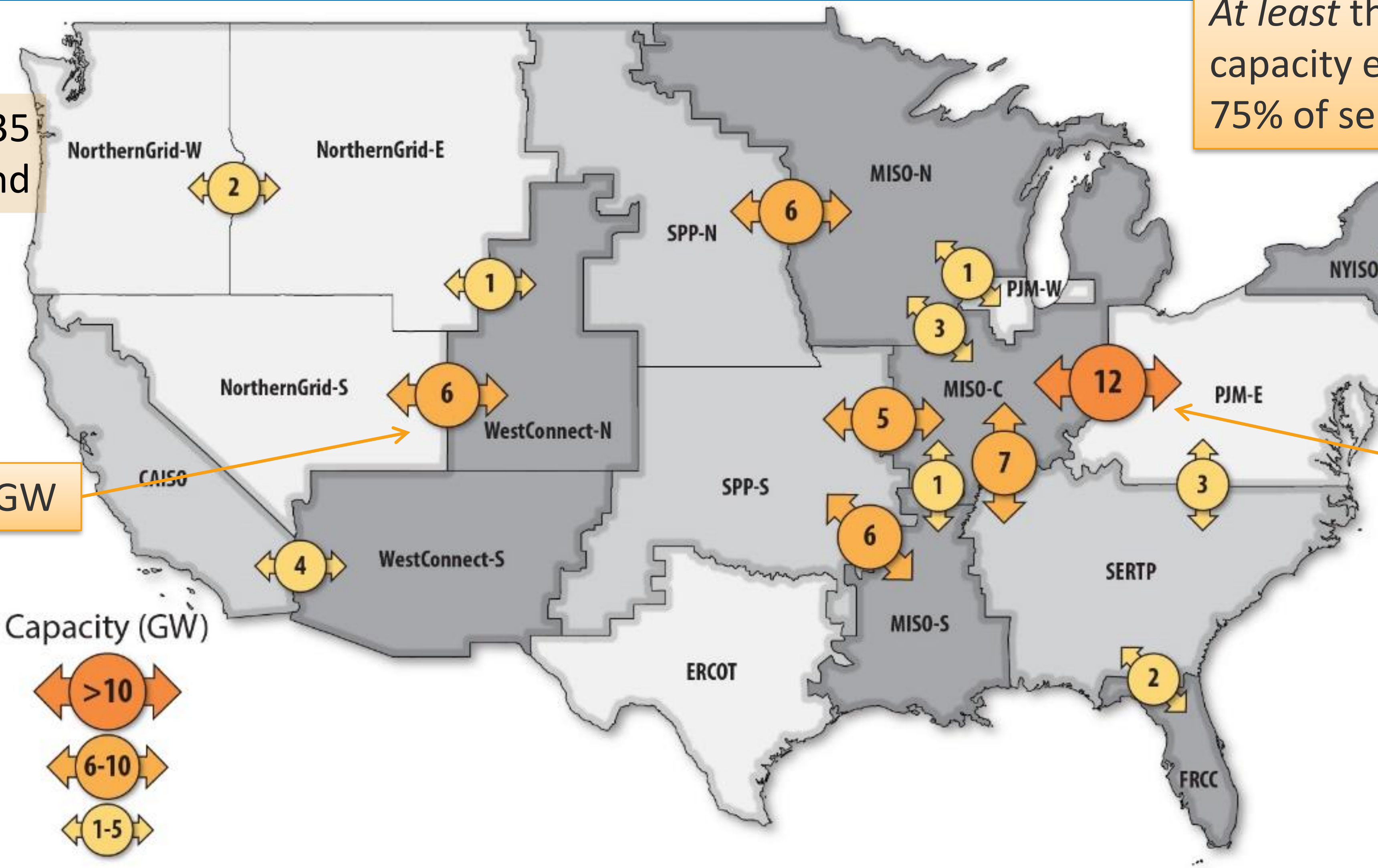


Preliminary results

HOT: new interregional transfer capacity robustly developed by 2035 (AC paradigm)

At least this much transmission capacity expansion is present in 75% of sensitivities

90% by 2035 mid demand



Preliminary results

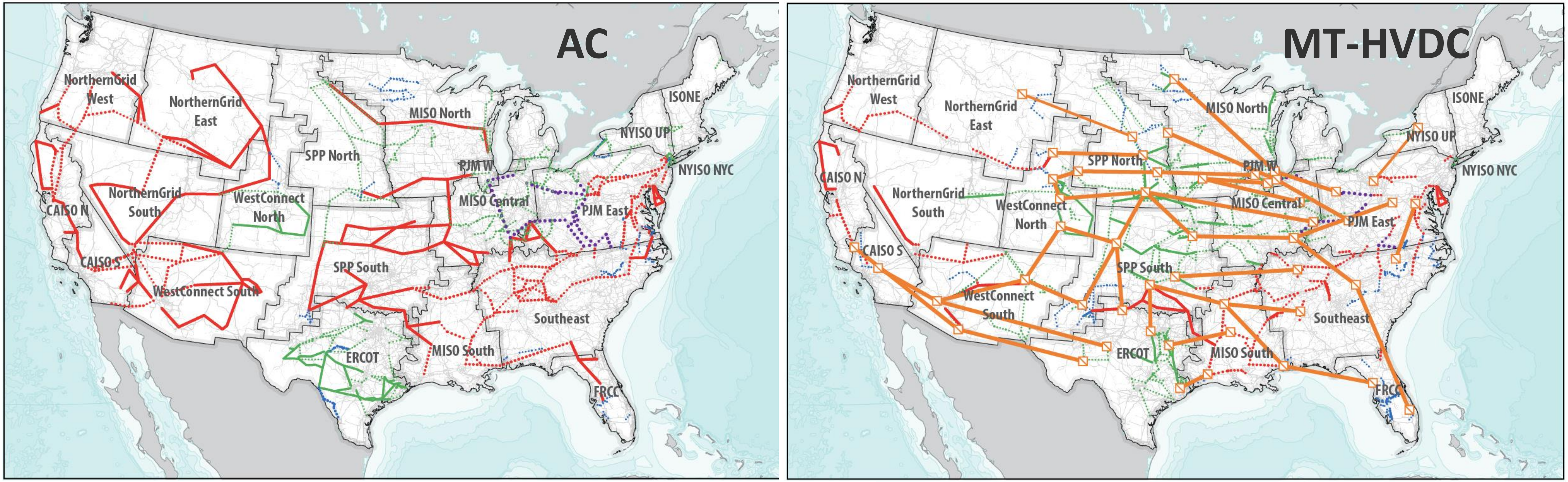
25th percentile capacity; > 1 GW expansions

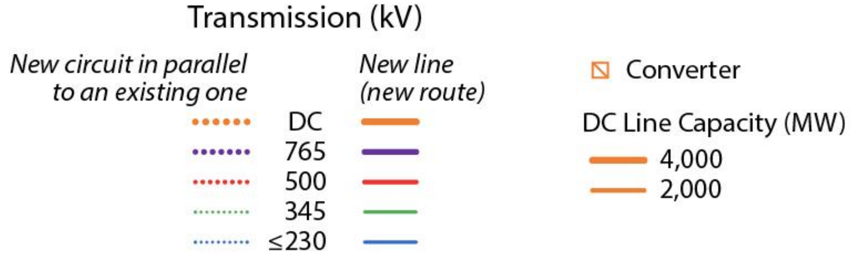
Nodal scenarios

- 3 scenarios (intractable to have all 100 scenarios network models)
- Detailed transmission planning
- Analysis of grid operations

Transmission portfolios require detailed engineering

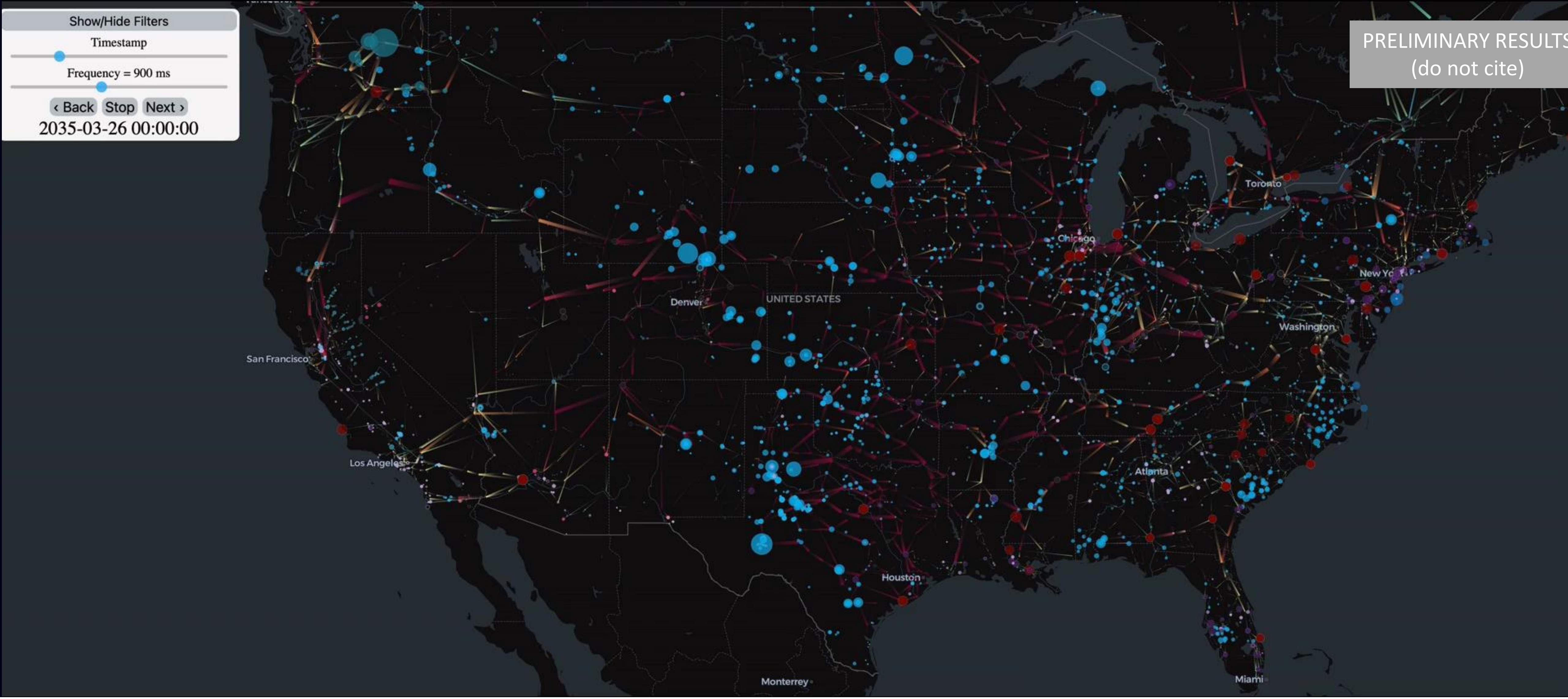
2035 nodal implementations that meets 90% by 3025 scenario requirements





NOTE: Only new transmission installed after 2020 is highlighted.

Detailed power system modeling to examine engineering challenges, hourly operations, and validate that systems are implementable



- Wind
- Solar
- Hydro
- Nuclear
- Gas
- Coal

2-day snapshot
(AC Scenario)
(March 2035)

Transmission line loading

Less loaded — More loaded

Key Findings Summary

- Rapid and significant transmission expansion results in lower cost systems
- HVDC scenarios build the most transmission capacity and results in the lowest cost systems
- Common transmission opportunities exist across a large range of future scenarios
- Detailed modeling validate that transformative transmission portfolios are implementable and support a highly decarbonized power sector

Thank you

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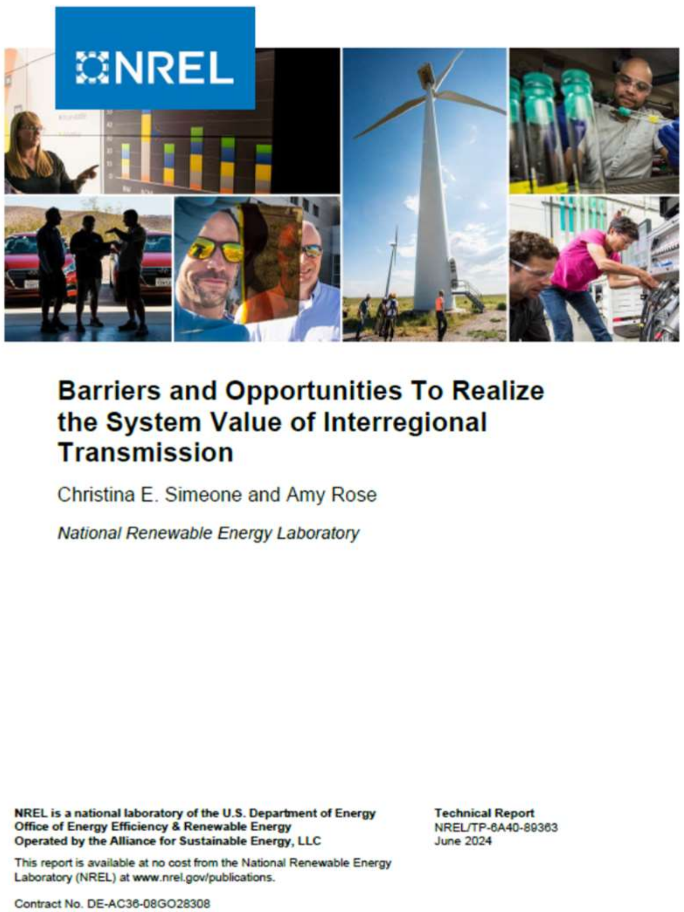
Transforming ENERGY


Barriers and Opportunities To Realize the System Value of Interregional Transmission

Christina E. Simeone and Amy Rose

National Renewable Energy Laboratory

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Technical Report
NREL/TP-6A40-89363
June 2024

"Barriers and Opportunities to Realize the System Value of Interregional Transmission"

(Simeone & Rose, June 2024)

Christina E. Simeone, PhD
Senior Transmission Planner
Grid Planning and Analysis Center

https://www.nrel.gov/docs/fy24osti/89363.pdf

Introduction

IRTx =
Interregional Transmission

- **Motivation**: Why might IRTx benefits identified in planning models be different than benefits observed in practice?
- **Transmission Benefits:** Adjusted production cost savings, others.
- **Limitations:** This report focuses on historical data and issues with existing IRTx, not potential future issues.
- **Potential Symptoms of Inefficiencies**: uneconomic flows, high price differentials, underutilized capacity, lack of transparency.

Barriers and Opportunities Between Non-Market and Hybrid Areas

- **Relying upon bilateral trading** may lead to inefficient use of generation and transmission resources to meet system needs.
- **Imperfect congestion management** between nonmarket and hybrid regions can pose reliability risks and reduce the efficient use of IRTx to meet demand at lowest cost.
- Inconsistent **available transfer capacity (ATC)** values posted at seams can result in underutilized or oversubscribed transmission lines.
- Regional practices to **prioritize market transactions**, even during emergency conditions, can reduce system reliability.

Nonmarket and Hybrid Actions

- Implement coordinated scheduling and operations platforms or consolidation
- Pursue joint congestion management programs and reevaluate qualified paths for congestion management
- Develop consistent methods to calculate available transfer capacity
- Update processes to prioritize system reliability in scheduling market and wheeling transactions

Barriers and Opportunities Between Market Areas

- Uncertain price forecasting, high transaction fees, and other issues have limited the ability of **coordinated transaction scheduling (CTS) systems** to efficiently use IRTx.
- **Inefficient market-to-market congestion management practices** such as outdated flow limits or inaccurate modeling can result in inefficient transmission use and excessive congestion balancing costs.
- **Issues with interface pricing** can lead to operational inefficiencies such as loop flows, economic inefficiencies such as redundant charges, and opportunities for market manipulation through sham scheduling.
- **Available merchant HVDC line capacity** is not often made available to market operators for co-optimization in wholesale markets.

Market Actions

- Eliminate fees and improve price forecasting for coordinated transaction scheduling or move toward intertie optimization
- Update corridor flow limits, automate procedures, and align assumptions for congestion management programs
- Revise interface pricing methods and validate interregional transactions
- Integrate operational control of merchant HVDC lines with regional market operations

Barriers and Opportunities Common to All Areas

- In addition to other factors, **deliverability uncertainty** may discourage resource adequacy sharing through IRTx.
- The **inability to anticipate, operationally adjust, and solve** for **atypical constraints** that may occur from abnormal flows during large transfer events may unnecessarily limit the value of IRTx.
- **Internal transmission system constraints** may inhibit large power transfers from IRTx, leading to reliability concerns.

Common Actions

- Develop a framework for resource adequacy sharing among regions
- Support joint studies to identify transfer needs during extreme events and develop operational procedures to mitigate issues
- Evaluate internal transmission system ability to accommodate large power transfers as the underlying generation mix changes

Transformative Actions and Final Thoughts

Transformative Actions

- Conduct long-range, nationwide interregional transmission planning
- Implement interconnection-wide intertie optimization
- Establish a national system operator and planner to coordinate national network planning, scheduling, and resource adequacy functions

Final Thoughts

- Implementing any solution option may be technically complex and may impact power system stakeholders in different ways.
- This report does not fully explore these technical issues or complex stakeholder dynamics.

Thank you! Christina.Simeone@nrel.gov

Overview of Interregional Transmission Operational Coordination (IRTOC)

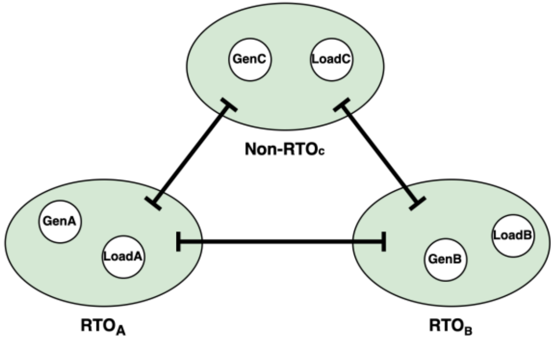
Yonghong Chen
NREL Grid Planning and Analysis Center

Inter-regional Transmission Operational Coordination (IRTOC) Workshop
June 12, 2024

NOTICE
This presentation includes preliminary results and should not be cited or distributed

IRTOC Background

- Focus on interregional market to market (M2M) congestion management but also open to other aspects of interregional coordination
  - **Real time M2M congestion management challenges**
  - **Values and needs for coordination in operational forward processes**
  - **Intra- and inter-regional HVDC optimization**
  - **Intra- and inter-regional reserve deliverability**



Focus areas

Market to Market (M2M) congestion management on EHVAC lines

1a. Enhanced real-time coordination methods to improve flow and price convergence.

1b. Coordination among more than two entities.

1c. M2M coordination in operational forward processes (day-ahead and intra-day).

HVDC optimization (intra- and inter-regional)

- **Intraregional HVDC**

2a. Energy and ancillary services co-optimization on intraregional HVDC scheduling.

- **Interregional HVDC**

2b. Interregional HVDC coordination.

2c. Coordination in operational forward process

Ancillary service deliverability (intra- and inter-regional)

3a. Identify transmission constraints to be included in market clearing.

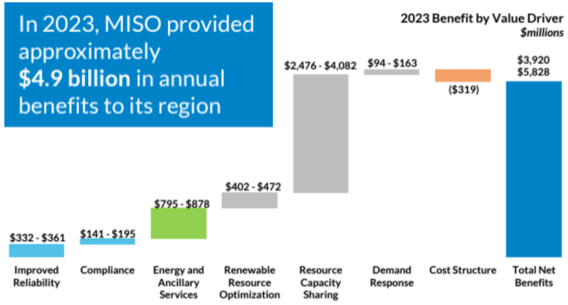
3b. Identify the contingency scenarios for post-reserve deployment constraints.

3c. Interregional transmission coordination considering energy and reserve deliverability

Single RTO Co-optimized electricity market: global optimization

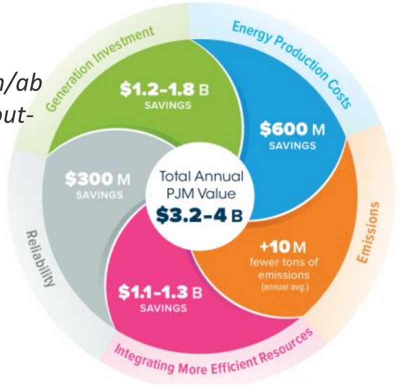
- Significant benefit through co-optimization
  - Energy and reserve scheduling
  - Congestion management

System wide constraints	Co-optimized
Power balance	GenA+GenB=LoadA+LoadB
Transmission constraint (energy flow)	EnergyFlowA+EnergyFlowB≤Limit
Reserve requirement	ResA + ResB ≥ ResRequirement
Transmission constraint (energy+ reserve flow)	EnergyFlowA + EnergyFlowB + ResFlowA + ResFlowB ≤Limit



https://www.misoenergy.org/meet-miso/MISO_Strategy/miso-value-proposition/

https://www.pjm.com/about-pjm/~/media/about-pjm/pjm-value-proposition.ashx



IRTOC multi-RTO congestion management coordination study

Coordination configurations	c0	c1	c2	c3	c4	c5	c6	c7	c8	c9	c10	c11
Power balance	0	1	0	1	0	1	0	1	0	1	0	1
Transmission constraint (energy flow)	0	0	1	1	0	0	1	1	1	1	1	1
Reserve requirement	0	0	0	0	1	1	1	1	0	0	1	1
Transmission constraint (energy+ reserve flow)	0	0	0	0	0	0	0	0	1	1	1	1

M2M JOA (c2)

IRTOC (c2, c8)

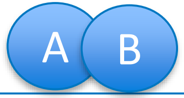
Full multi-area coupling (e.g., EIM, Coordinated multi-RTO scheduling) (c11)

0: no coordination   1: with coordination

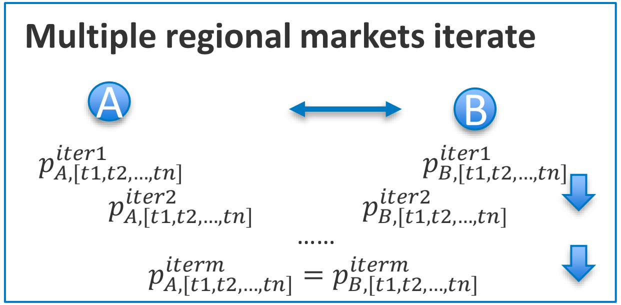
EIM: energy imbalance market – may be extended to enforce all constraints under c11

Solution methods – operational forward processes (day ahead, intra-day)

Simplified coupling



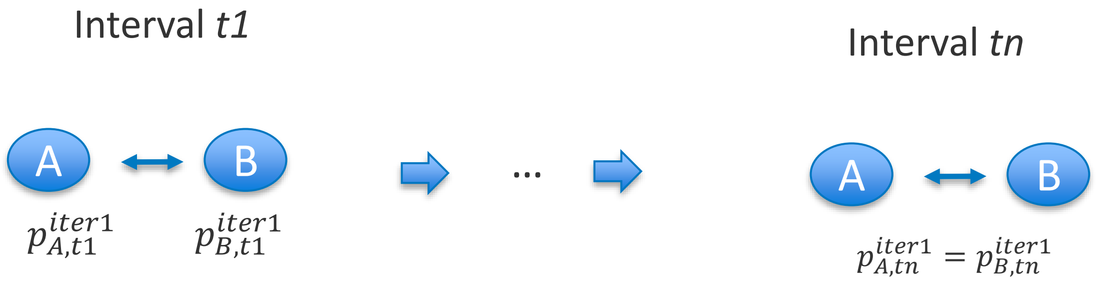
- **Single large model that can solve with optimal interregional transfer in one run (benchmark model)**
- Requires an entity to run multi-RTO coupling market clearing
- Multi-region full nodal model may have computational challenges. Simplification may be required.



$p_{A,\cdot}^{\cdot}, p_{B,\cdot}^{\cdot}$: *solution on joint variables from A and B respectively*

- No need to form new entities. Existing RTOs exchange information to achieve convergence through multiple iterations
- However, convergence with interregional EHVAC and HVDC in day ahead and intraday can be very challenge
- *Not plan to study under this project*

Solution methods – real time rolling market clearing



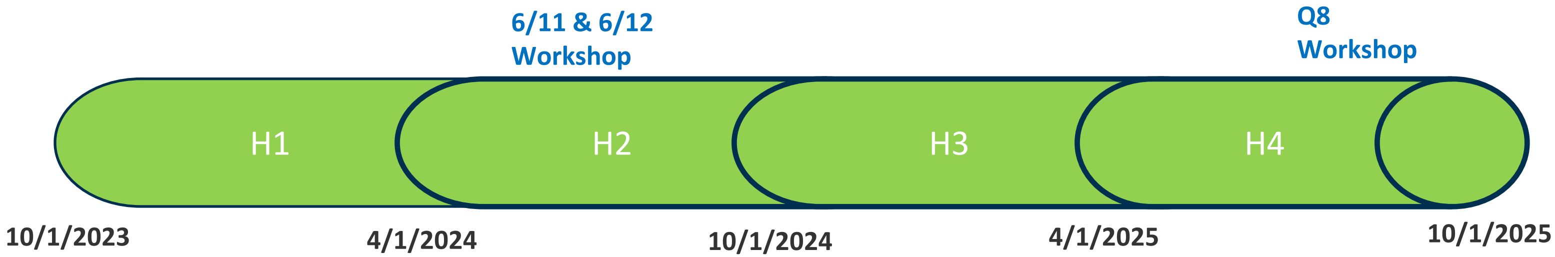
Existing M2M approach:

- Each RTO performs single run for each interval
- Two RTOs exchange information as inputs to the next interval
- Achieve convergence in multiple intervals

Needs to develop enhanced and new algorithms for:

- Better convergence
- Large number of M2M constraints
- More than two regions

Scope and timeline



Sienna development	• Sienna decomposition	Multi-stage & rolling coordination Energy+Reserve (locational nodal reserve)	Computation for large system	
Coordination structures and algorithms	• Real time M2M energy flow • Energy + reserve flow • HVDC energy flow	• Multi-stage coordination • Energy + reserve +HVDC		
Case study	• 5-bus • 96-bus	NTP Study on two regions (e.g., MISO+SPP) multi-stage energy flow coordination (EHVAC)	NTP Study on two regions multi-stage energy+reserve flow coordination (EHVAC)	NTP Study on two regions multi-stage energy+reserve flow coordination HVDC

Market to Market (M2M) congestion management on EHVAC lines

1a. Real-time coordination methods to address flow and price oscillation.

1b. Coordination among more than two entities.

1c. M2M coordination in the forward process (day-ahead and intra-day).

HVDC optimization (intra- and inter-regional)

- **Intraregional HVDC**

2a. Energy and ancillary services co-optimization on intraregional HVDC scheduling.

- **Interregional HVDC**

2b. Interregional HVDC coordination.

2c. Coordination in forward process

1a and 1b: Real time coordination methods to address flow and price oscillation

- Energy only M2M benchmark formulation is solved to get M2M optimal flow and shadow price
- **Research focus**: develop real time distributed coordination algorithms to achieve transmission constraint (energy flow) convergence

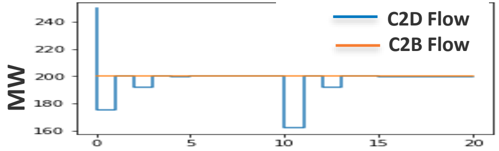
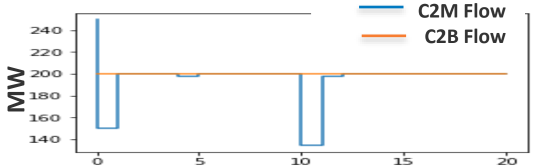
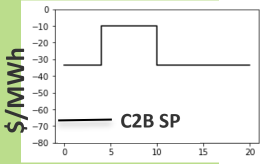
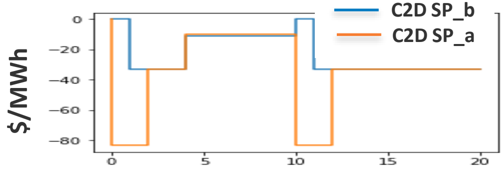
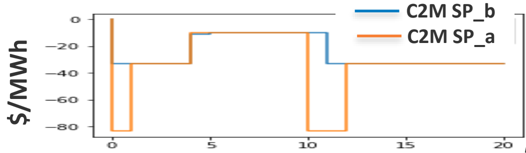
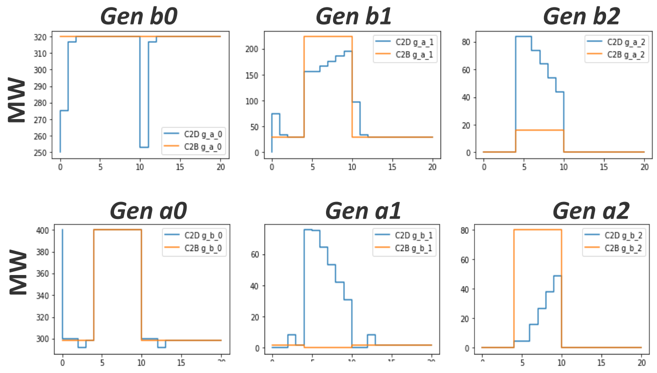
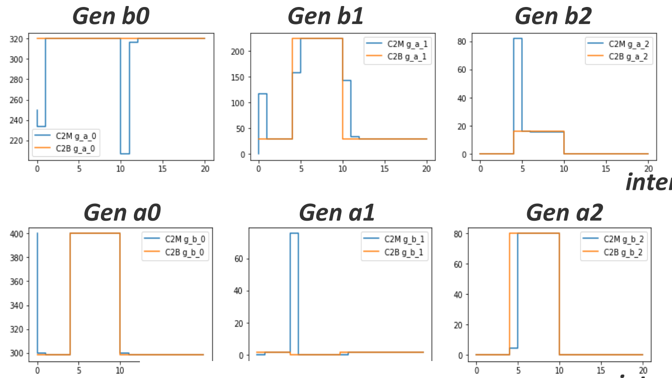
C2 Benchmark: best possible M2M outcome (C2B)	$GenA + NSIA = LoadA$ $GenB + NSIB = LoadB$ $EnergyFlowA + EnergyFlowB \leq Limit$

C2 Distributed control through shadow price exchanges (C2D)	$GenA(t+1) + NSIA = LoadA$ $GenB(t+1) + NSIB = LoadB$ $EnergyFlowA(t+1) + EstLoopA(t+1) \leq Limit$ $EnergyFlowB(t+1) + EstLoopB(t+1) \leq Limit$ Shadow prices from t are used to price $EstLoopA(t+1)$ and $EstLoopB(t+1)$ in the objectives.
C2 Marginal equivalent (C2M)	$GenA(t+1) + NSIA = LoadA$ $GenB(t+1) + NSIB = LoadB$ $EnergyFlowA(t+1) + loopflowA(t)$ $+ \Delta\, EnergyFlowB\_marginal(t+1) \leq Limit$ $EnergyFlowB(t+1) + loopflowB(t)$ $+ \Delta\, EnergyFlowA\_marginal(t+1) \leq Limit$ Marginal units from neighbor areas are incorporated to reflect potential reliefs from neighbors.

Real time coordination algorithm development

C2 Distributed control (C2D)	C2 Marginal equivalent (C2M)
• Exchange shadow prices (a) • Estimate loop flow from the neighbor RTO (b) • Incorporate (a) and (b) in optimization in the next interval to drive convergence	• Exchange marginal units • Incorporate marginal units from neighbor RTOs to reflect potential reliefs from neighbors
• Information exchange is minimum and similar to M2M implementation for MISO-PJM and MISO-SPP • Promising in addressing existing M2M convergence issues	• Better convergence
• Convergence may be slow	• Identify and exchange marginal units • Challenges to extend to energy+reserve, especially when two RTOs have different reserve products
Tested on two RTOs each with 5-bus Tested on two RTOs each with 96-bus Tested on four RTOs each with 5-bus	Tested on two RTOs each with 5-bus Tested on four RTOs each with 5-bus
TBD: Test on larger system	TBD: Test on larger system

Real time coordinated algorithm development (*Cont.*)

	C2 Distributed control (C2D)	C2 Marginal equivalent (C2M)
Flow converges		
Shadow price (SP)Converges 		
Generation dispatch convergences		

1c and 2c: M2M coordination in the forward process

DA Determines commitment	C0: No control of inter-regional congestion	GenA+NSIA=LoadA GenB+NSIB=LoadB
	C2B Benchmark: best possible M2M outcome	GenA+NSIA=LoadA GenB+NSIB=LoadB EnergyFlowA+EnergyFlowB≤Limit
	C01 MRTO control (status quo)	GenA+NSIA=LoadA GenB+NSIB=LoadB EnergyFlowA+loopflow≤Limit Only monitoring RTO
	C2S: Multi-RTO simplified coupling	GenA+NSIA=LoadA GenB+NSIB=LoadB EnergyFlowA+EnergyFlowB≤Limit **Solving LP relaxation to determine** i) HVDC schedule HVDC_Schedule ii) EHVAC allocation LimitA, LimitB

C2 both sides control based on allocation from the coupling	GenA+NSIA=LoadA GenB+NSIB=LoadB EnergyFlowA≤**LimitA** EnergyFlowB≤**LimitB** **HVDCFlow=HVDC_Schedule**

2a: intra- and inter-regional HVDC control

- Intraregional HVDC energy schedule optimization
  - Added to security constrained unit commitment (SCUC) and economic dispatch (SCED)
  - Including losses can cause interesting issues
    - Separate project to investigate losses under high renewable penetration

2b: inter-regional HVDC control

Inter-regional HVDC only for congestion management	Inter-regional HVDC for both interchange optimization and congestion management
Total interchanges are determined by transactions.	Total interchanges are determined by transactions plus interregional HVDC dispatch.
Interregional HVDC schedule are adjusted to relieve EHVAC congestions	Interregional HVDC schedule can impact both interchange transaction and congestion management
$GenA + NSIA = LoadA$ $GenB + NSIB = LoadB$ $EnergyFlowA + EnergyFlowB + EnergFlow\_HVDC\_schedule \leq Limit$	$GenA + NSIA + HVDC\_Schedule = LoadA$ $GenB + NSIB - HVDC\_Schedule = LoadB$ $EnergyFlowA + EnergyFlowB + EnergFlow\_HVDC\_schedule \leq Limit$
Preliminary conclusion	
• HVDC can be optimized by one region • EHVAC M2M congestion management can drive HVDC re-dispatch to manage congestion	• Tied to interchange optimization and with more open issues (e.g., settlement between two RTOs) • Need market coupling or more complicated algorithms to drive optimal HVDC schedule

Multi-stage with HVDC

DA Determines commitment	DA-C2B Benchmark:	GenA+NSIA=LoadA GenB+NSIB=LoadB EnergyFlowA+EnergyFlowB≤Limit
	DA-C0 MRTO control (status quo)	GenA+NSIA=LoadA GenB+NSIB=LoadB EnergyFlowA+loopflow≤Limit Only monitoring RTO
	DA-C2S: Multi-RTO simplified coupling prior to individual clearing	GenA+NSIA=LoadA GenB+NSIB=LoadB EnergyFlowA+EnergyFlowB≤Limit **Solving LP relaxation to determine** i) HVDC schedule *HS* ii) EHVAC allocation LimitA, LimitB
		GenA+NSIA=LoadA GenB+NSIB=LoadB EnergyFlowA**≤LimitA** EnergyFlowB≤**LimitB** **HVDCFlow=HS**

	RT-C2B Benchmark: best possible M2M outcome	$GenA + NSIA = LoadA$ $GenB + NSIB = LoadB$ $EnergyFlowA + EnergyFlowB \leq Limit$
	RT-C0 MRTO control (status quo)	$GenA + NSIA = LoadA$ $GenB + NSIB = LoadB$ $EnergyFlowA + loopflow \leq Limit\ (MRTO)$ **Calculate SE flow after clearing**
	RT-C2D Distributed control through shadow price exchanges	$GenA(t+1) + NSIA = LoadA$ $GenB(t+1) + NSIB = LoadB$ $EnergyFlowA(t+1) + EstLoopA(t+1) \leq Limit$ $EnergyFlowB(t+1) + EstLoopB(t+1) \leq Limit$
	RT-C2M Marginal equivalent	$GenA(t+1) + NSIA = LoadA$ $GenB(t+1) + NSIB = LoadB$ $EnergyFlowA(t+1) + loopflowA(t) + \Delta\ EnergyFlowB\_marginal(t+1) \leq Limit$ $EnergyFlowB(t+1) + loopflowB(t) + \Delta\ EnergyFlowA\_marginal(t+1) \leq Limit$

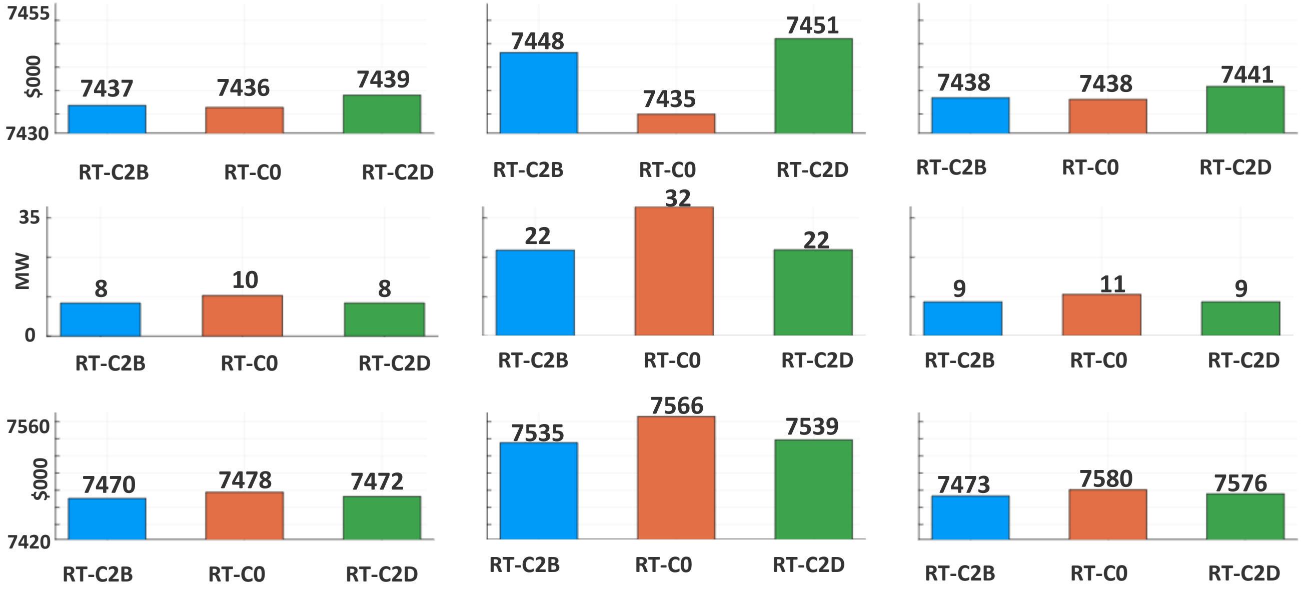
RT M2M coordination can reduce production cost and flow violation. The impact is less than DA coordination.

No coordination in DA: higher RT production cost & higher RT flow violation

Simplified DA coordination: Similar production cost and RT flow as the benchmark

2x RTS-96bus with HVDC

	DA-C2B M2M benchmark	DA-C0 no coordination	DA-C2S simplified coupling prior to individual clearing
RT production cost in $1000			
RT Flow violation MW			
RT production + violation cost			



Preliminary results and should not be cited or distributed

Ancillary service deliverability (intra- and inter-regional)

3a. Identify transmission constraints to be included in market clearing.

3b. Identify the contingency scenarios for post-reserve deployment constraints.

3c. Interregional transmission coordination considering energy and reserve deliverability

3a and 3b: Identify transmission constraints and contingency scenarios

System wide constraints	Co-optimized	Individual clearing without coordination
		GenA+NSIA=LoadA GenB+NSIB=LoadB
Transmission constraint (energy flow)	EnergyFlowA+EnergyFlowB≤Limit	
Reserve requirement		ResA ≥ ResRequirementA ResB ≥ ResRequirementB
Transmission constraint (energy+ reserve flow)	EnergyFlowA + EnergyFlowB + ResFlowA(Ai) ≤Limit EnergyFlowA + EnergyFlowB + ResFlowB(Bi) ≤Limit ResFlowA(Ai)= Flow_event(Ai) + Flow_ReserveDeployment(Ai) ResFlowB(Bi)= Flow_event(Bi) + Flow_ReserveDeployment(Bi) Ai: events in A, Bi: events in B	

Research focus: to identify

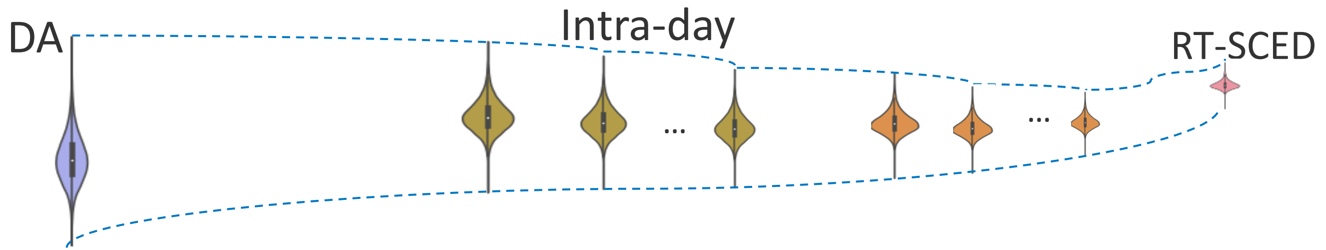
i) Relevant transmission constraints

ii) Relevant events: Static / dynamic, gen outage / renewable drop / HVDC schedule

3c: Interregional transmission coordination considering energy and reserve deliverability

- Pre-event EnergyFlowA and EnergyFlowB can be adjusted down to ensure reserve deliverability
- Each region can independently procure reserves with different reserve products
- Real time M2M convergence can be challenging on pre-event energy flow, post event energy+reserve flow and prices
- Optimize HVDC considering reserve deliverability

The impact of uncertainty on multi-stage coordination



Day-ahead and intra-day coordination:

- Better commitment and reduce real time dispatch cost and congestion
- Intra-day coordination may have more value with increasing uncertainties

Real time M2M coordination:

- Is required even with day-ahead and intra-day coupling
- Congestion management across multiple regions with multiple constraints can be challenging

Multi-stage uncertainty data for future portfolio is difficult to generate:

- IRTOC will focus on developing coordination methods and evaluation framework
- Using reasonable estimation of uncertainties at different stages

IRTOC focus areas

- Build study framework in Sienna focusing on multi-region and multi-stage congestion management
  - Real time emulation to consistently measure economic and reliability impacts
  - Intra- and inter-regional HVDC
  - Intra- and inter-regional reserve deliverability

- Analysis on complexity, efficiency and reliability
  - Develop benchmark models
  - Simplification of single large coupling model
  - Convergence of distributed methods on solving multiple regional models iteratively

Q&A

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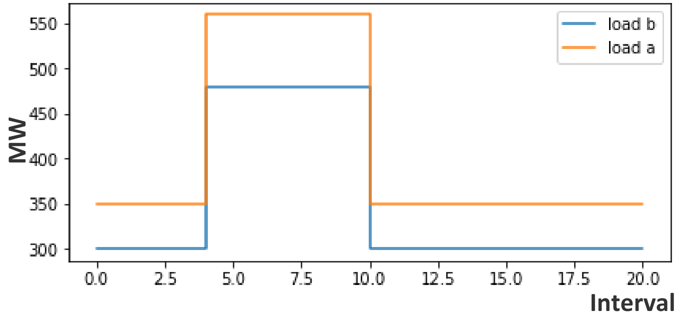
NREL Transforming ENERGY

Appendix – small two-region system



	Region a			Region b		
	a0	a1	a2	b0	b1	b2
Max limit Pmax (MW)	320	1000	300	400	800	100
Marginal cost ($/MWh)	10	60	50	0	40	30
Sensitivity	0.2	-0.4	0.6	0.5	-0.7	0.2

IRTOC mathematical formulations

- Real time M2M coordinated congestion management (1)(2)(3)(4)
- Benchmark model (1)(2)(3B)(4B)

System wide constraints	Co-optimized single RTO		Individual clearing with certain levels of coordination	Individual clearing without explicit coordination
Power balance				GenA+NSIA=LoadA (1) GenB+NSIB=LoadB
Transmission constraint (energy flow)	**Benchmark (3B)** EnergyFlowA+EnergyFlowB ≤Limit	⬅	EnergyFlowA+loopflowA≤Limit (3) EnergyFlowB+loopflowB≤Limit **M2M congestion management**	
Reserve requirement				ResA ≥ ResRequirementA (2) ResB ≥ ResRequirementB
Transmission constraint (energy+ reserve flow)	**Benchmark (4B)** EnergyFlowA + EnergyFlowB + ResFlowA + ResFlowB ≤Limit	⬅	EnergyFlowA+ResFlowA+loopflowA≤Limit **(4)** EnergyFlowB+ResFlowB+loopflowB≤Limit **M2M congestion management with reserve deliverability**	

NREL
Transforming ENERGY

Sienna

NOVEL POWER SYSTEMS SIMULATIONS FOR A DECARBONIZED GRID

José Daniel Lara PhD

Photo from iStock-627281636

Open-source ecosystem for power system modeling, simulation and optimization

Sienna's three core applications use combinations of packages in the Julia Programming Language

Sienna\Data

Efficient intake and use of energy systems input data

Developed to support modeling with large shares of renewable energy technologies

Sienna\Ops

Simulation of system scheduling, including sequential problems for production cost modeling

Sienna\Dyn

Simulation of power system dynamic response to disturbances and contingencies

Formerly known as SIIP

https://github.com/NREL-Sienna

MODEL LIMITED CHOICE

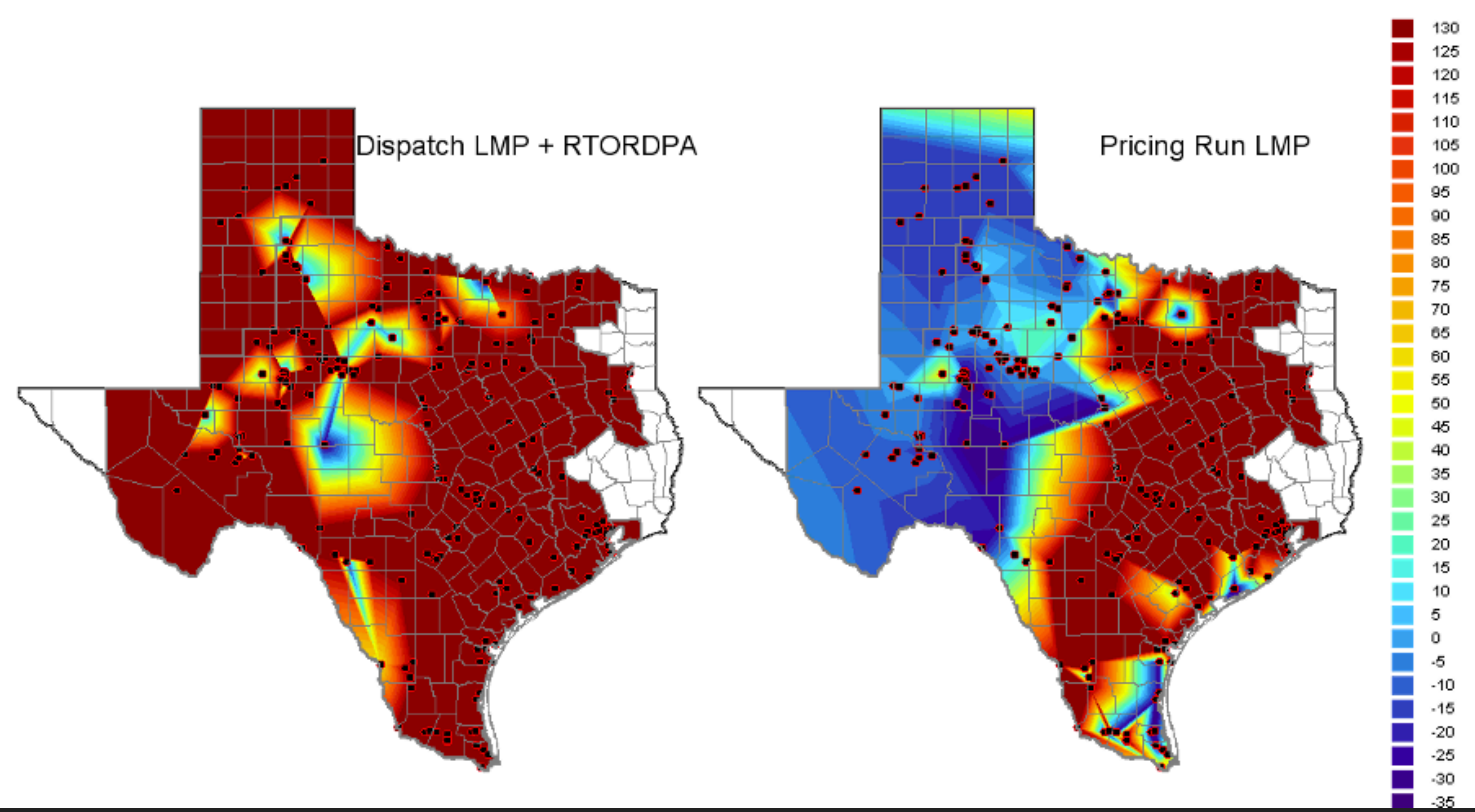
Structural exclusion of certain forms of simulation and analysis

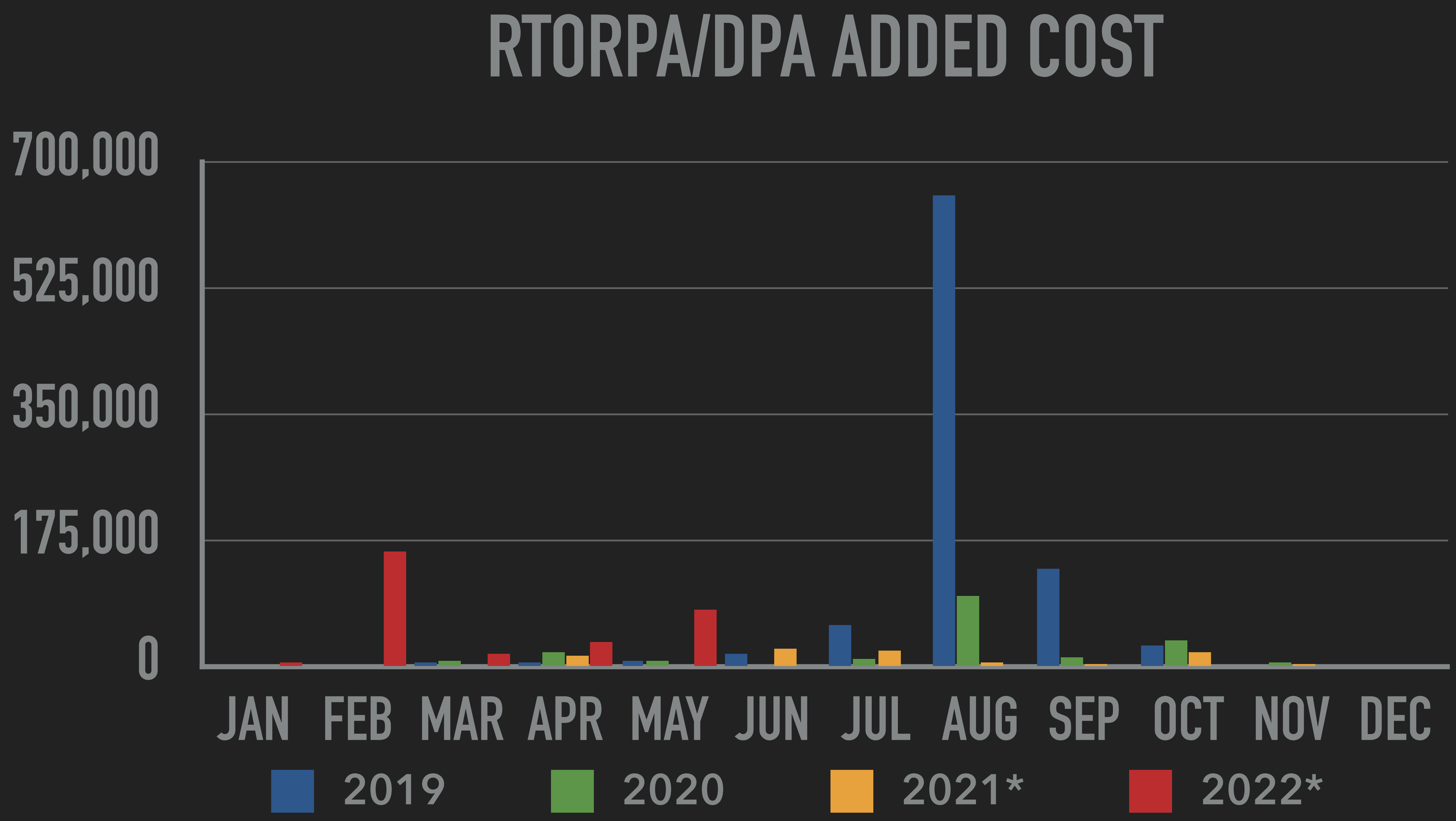
&

Formulation limitations due to restrictions in underlying models or data availability

EXAMPLE OF OPERATIONAL CHALLENGES

- Current operation simulation tools rarely capture more than two of the decision stages in a market simulation operation. Typically, these stages are: UC - ED.
- Existing tools can't evaluate low resolution operational decisions that have significant effects on costs like reserve deployments.
- Academic tools without careful software development can't scale the analysis, and tend to be limited to one-off studies and abandoned.



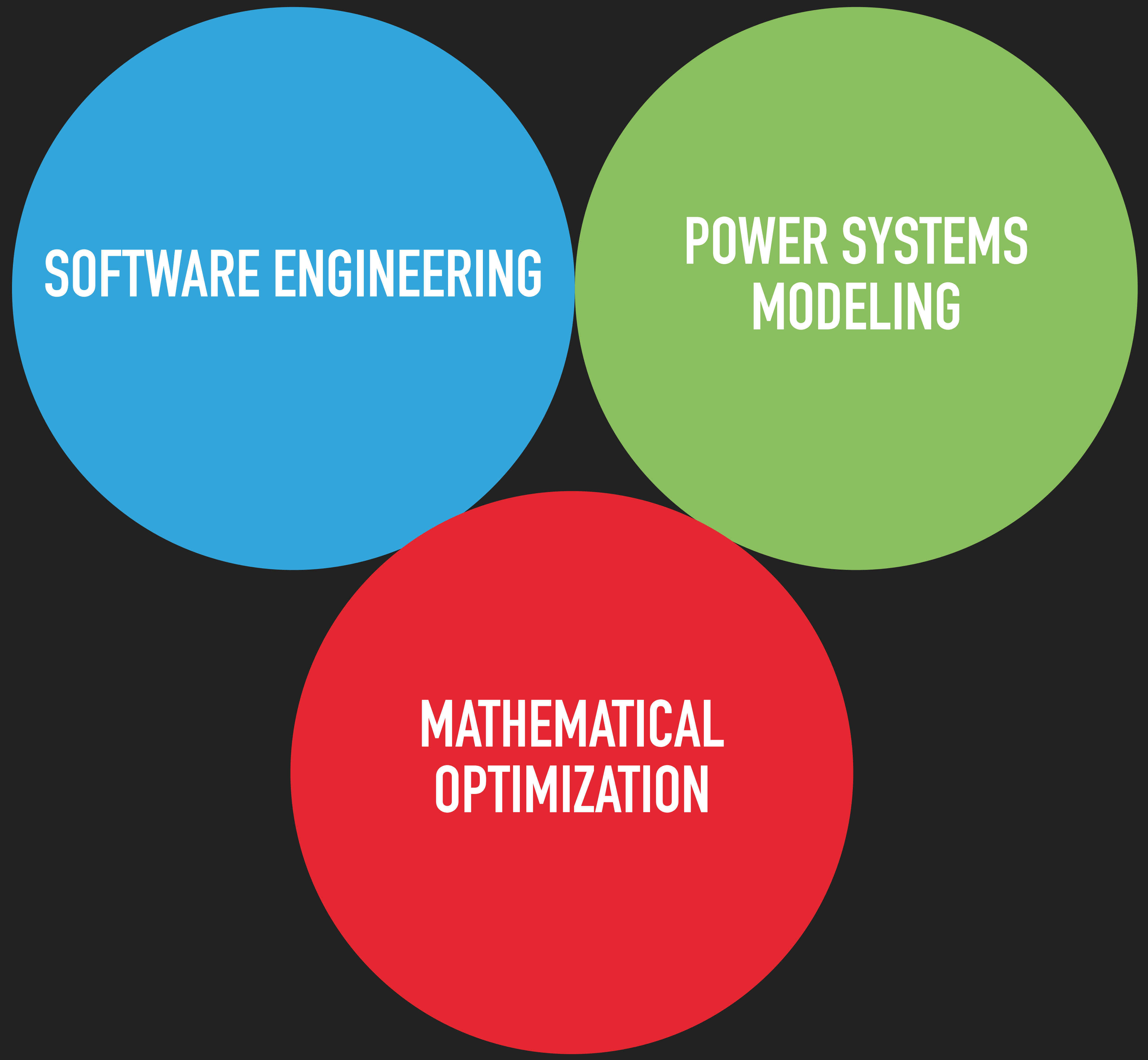


POWERSIMULATIONS.JL

DEVELOPING A NEXT-GENERATION OPERATIONS SIMULATOR FOR INTERCONNECTED SYSTEMS

CONTRIBUTIONS

- Understand the source of the limitation in existing operational simulation tools.
- Develop a configurable n-stage simulation platform to address the existing limitations.
- Implement software infrastructure for scalability.
- Enable open-source and reproducible scientific explorations.



FORMULATING AN OPERATIONS MODEL

BUILDING OPERATIONS PROBLEMS

$$
\begin{aligned}
f^k(\cdot) = \min_{\vec{u}_t^k} \quad & C_{f_k}(\vec{u}_t^k) \\
\text{s.t.} \quad & H_{f_k}^D(\vec{u}_t, \vec{u}_{t-1}, \vec{x}_{t-1}, \vec{\rho}_t, \Phi^k|t) \leq 0 \\
& H_{f_k}^B(\vec{u}_t, \vec{u}_{t-1}, \vec{x}_{t-1}, \vec{\rho}_t, \Phi^k|t) \leq 0 \\
& H_{f_k}^N(\vec{u}_t, \vec{u}_{t-1}, \vec{x}_{t-1}, \vec{\rho}_t, \Phi^k|t) = 0 \\
& H_{f_k}^S(\vec{u}_t, \vec{u}_{t-1}, \vec{x}_{t-1}, \vec{\rho}_t, \Phi^k|t) \leq 0 \\
& H_{f_k}^F(\vec{u}_t, \vec{u}_{t-1}, \vec{x}_{t-1}, \vec{\rho}_t, \Phi^k|t) \leq 0
\end{aligned}
$$

Cost Function: Linear, Polynomial, Piece-wise Linear.

Device and Branch Level Model: Generator Limits, Storage Capacity, Branch Power Flow.

Network Model: Copper plate model or nodal flow balance.

Services Model: Reserves, Area Exchanges, Reactive Power Control Areas.

Feedforward Model: Reserves Commitments, Area Exchanges, Reactive Power Control Areas.

BUILDING OPERATIONS PROBLEMS

$$f^k(\cdot) = \min_{\vec{u}_t^k} \quad C_{f_k}(\vec{u}_t^k)$$

$$\text{s.t.} \quad H_{f_k}^D(\vec{u}_t, \vec{u}_{t-1}, \vec{x}_{t-1}, \vec{\rho}_t, \Phi^k|t) \leq 0$$

$$H_{f_k}^B(\vec{u}_t, \vec{u}_{t-1}, \vec{x}_{t-1}, \vec{\rho}_t, \Phi^k|t) \leq 0$$

$$H_{f_k}^N(\vec{u}_t, \vec{u}_{t-1}, \vec{x}_{t-1}, \vec{\rho}_t, \Phi^k|t) = 0$$

$$H_{f_k}^S(\vec{u}_t, \vec{u}_{t-1}, \vec{x}_{t-1}, \vec{\rho}_t, \Phi^k|t) \leq 0$$

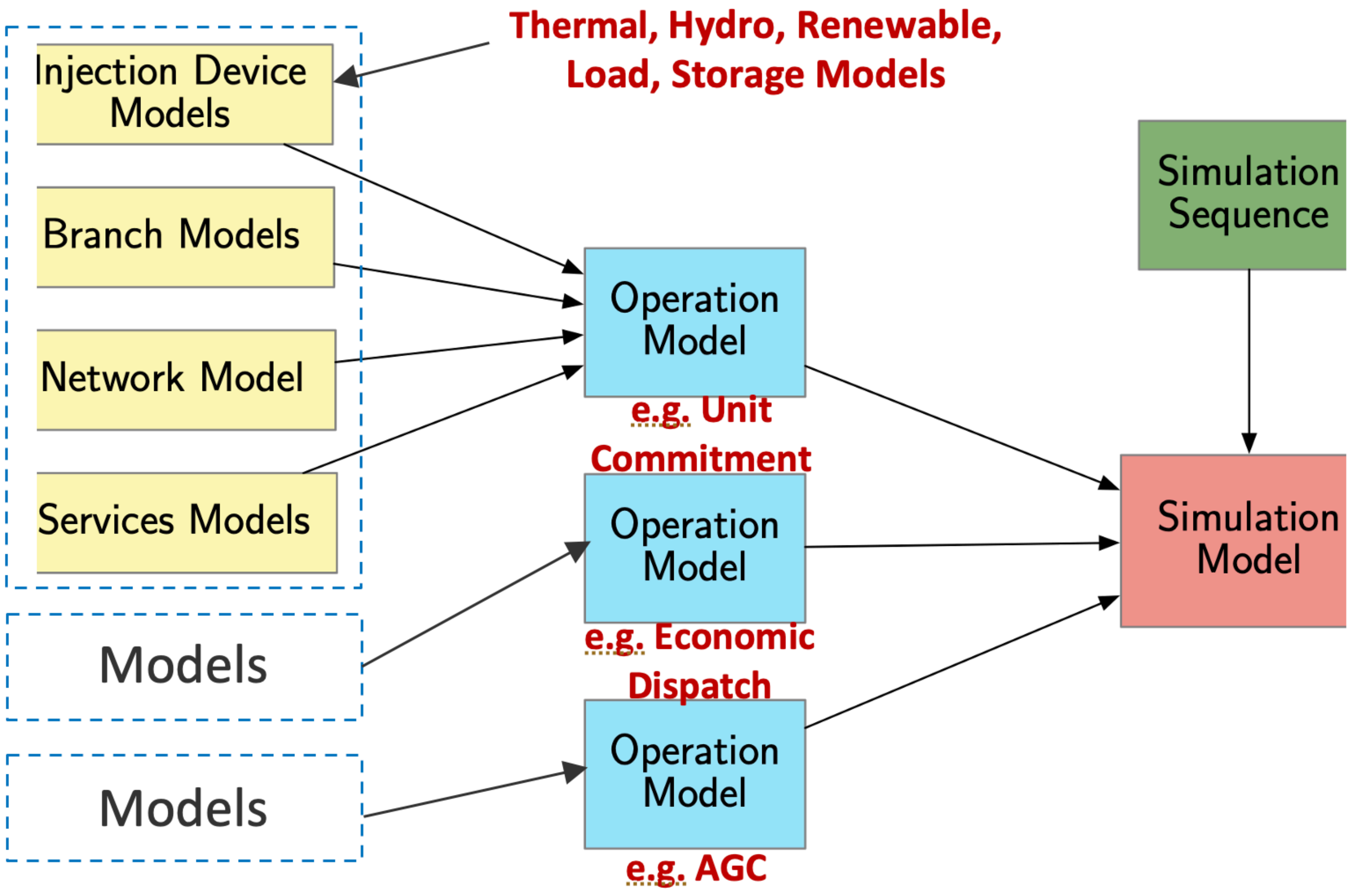
$$H_{f_k}^F(\vec{u}_t, \vec{u}_{t-1}, \vec{x}_{t-1}, \vec{\rho}_t, \Phi^k|t) \leq 0$$

```
NetworkModel(StandardPTDFModel, use_slacks=true, PTDF=PTDF(sys_rts_da))

set_device_model!(template_uc, ThermalMultiStart, ThermalCompactUnitCommitment)
set_device_model!(template_uc, ThermalStandard, ThermalCompactUnitCommitment)
set_device_model!(template_uc, RenewableDispatch, RenewableFullDispatch)
set_device_model!(template_uc, PowerLoad, StaticPowerLoad)
set_device_model!(template_uc, Line, StaticBranch,)
set_device_model!(template_uc, Transformer2W, StaticBranchUnbounded)
set_device_model!(template_uc, TapTransformer, StaticBranchUnbounded)
set_device_model!(template_uc, HydroDispatch, FixedOutput)
set_device_model!(template_uc, HydroEnergyReservoir, HydroDispatchRunOfRiver)
set_device_model!(template, GenericBattery, BookKeepingwReservation)
set_service_model!(template_uc, ServiceModel(VariableReserve{ReserveUp}, RangeReserve))
set_service_model!(template_uc, ServiceModel(VariableReserve{ReserveDown}, RangeReserve))
```

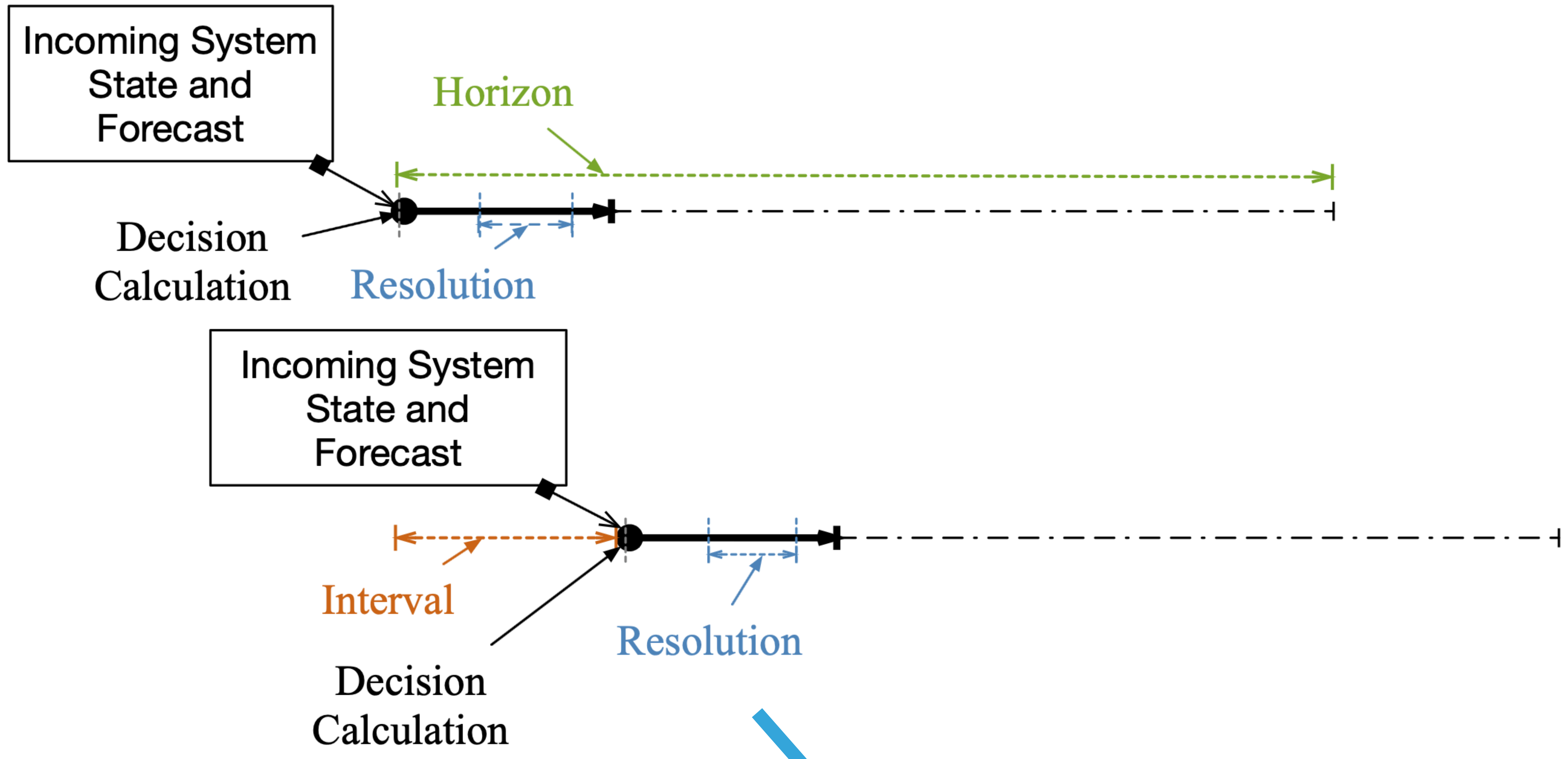
CUSTOMIZATION OF THE UNDERLYING SIMULATION

- Employ a tree-type structure to store the optimization models and related information.
- Define the sequence of solution separately from the problem definitions.
- Support problem level customization of the solution technique and details.

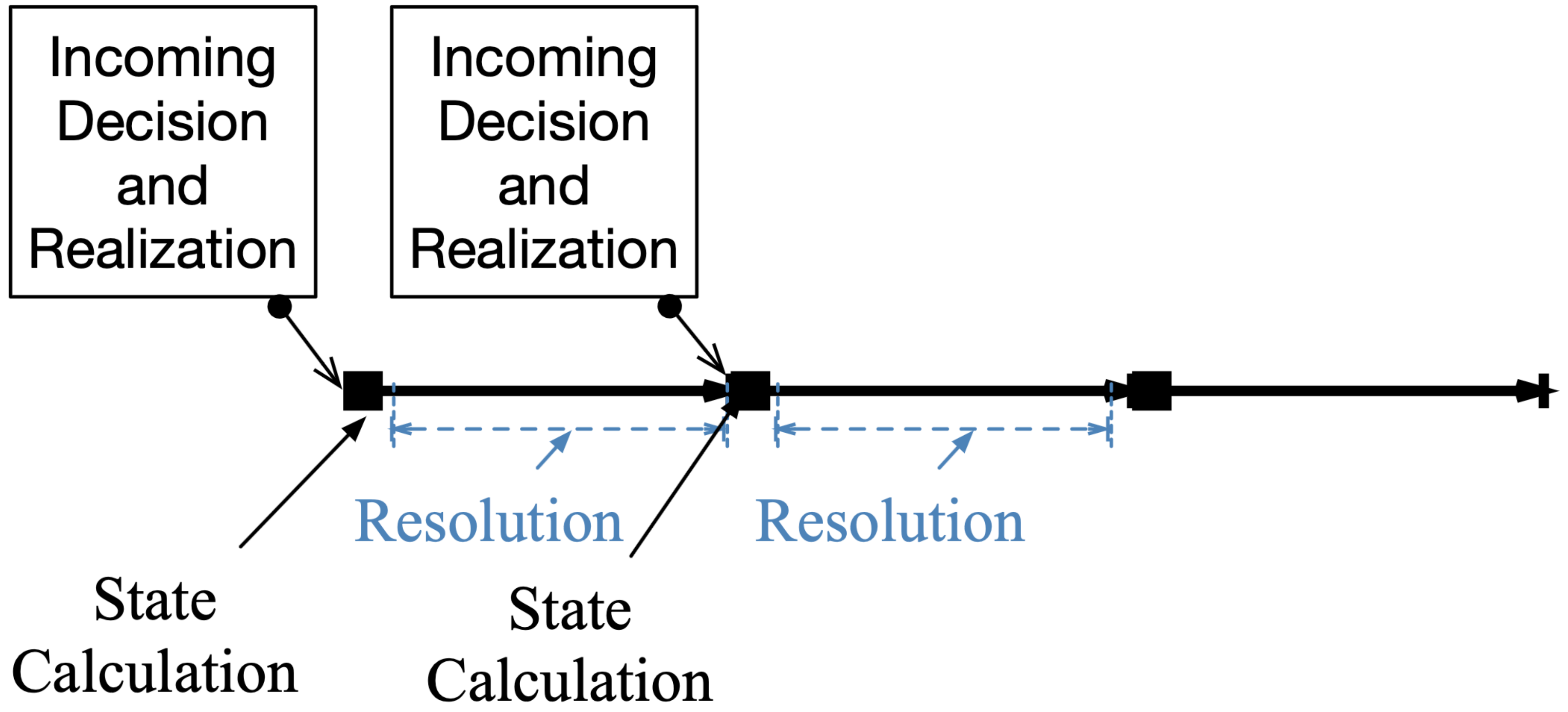


FORMALIZING SIMULATING OPERATIONS

DECISION MODEL



EMULATION MODEL

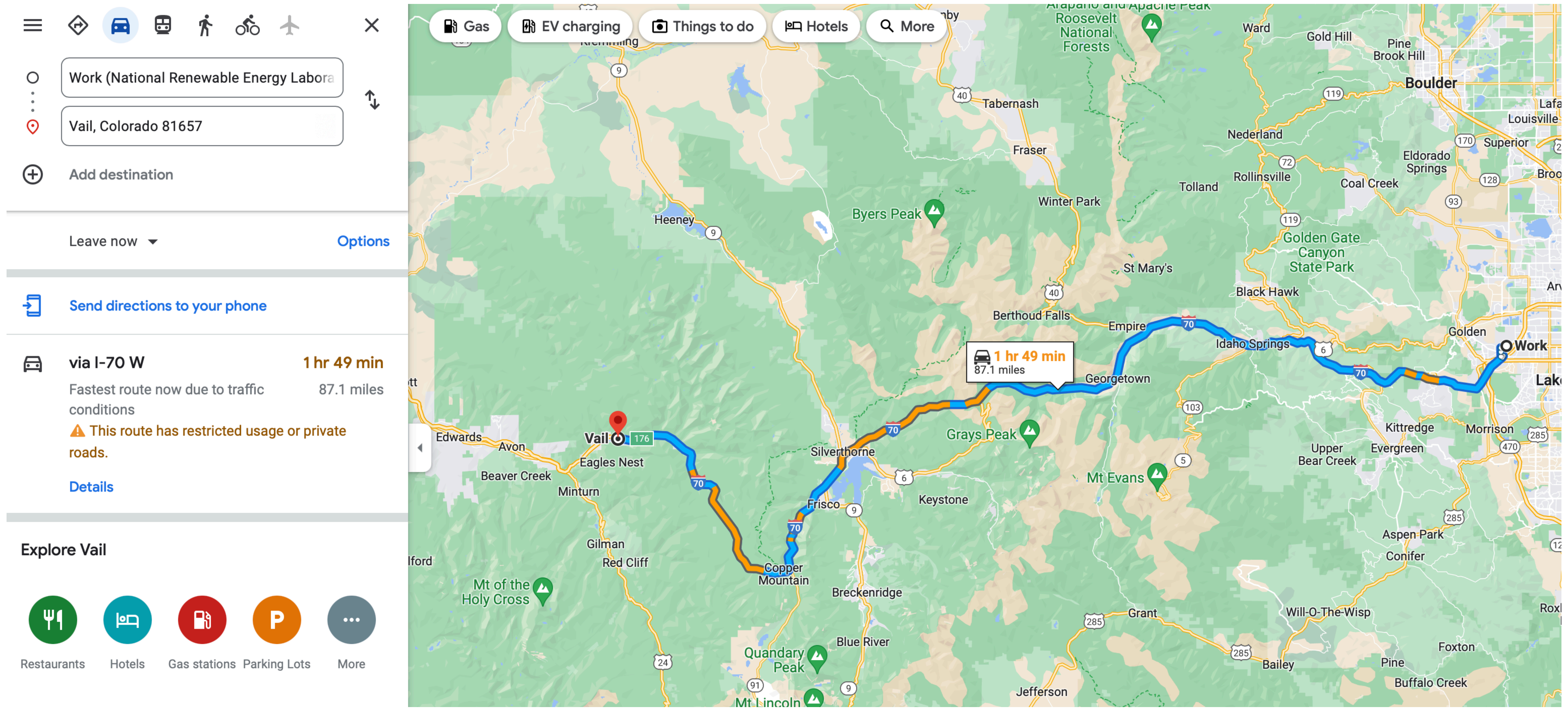


$$\vec{u}_t = F_t(\vec{x}_{t-1}, \vec{u}_{t-1}, \vec{\rho}_t, \Phi | t), \quad \vec{u}_{t_0} = \vec{u}_0$$

$$G_t(\vec{x}_t, \vec{x}_{t-1}, \vec{u}_t, \vec{\psi}_t) = 0, \quad \vec{x}_{t_0} = \vec{x}_0$$

EVERYDAY ANALOGOUS PROCESS

DECISION MODEL



EMULATION MODEL

SIMULATION SOLUTION STRATEGY

- If the optimization problem is formulated carefully, the inputs that change over the course of a simulation can be placed on the RHS of the linear constraints.
- Solvers can update Vector `b` without requiring re-instantiation of the whole problem as long as Matrix `A` doesn't require updates (i.e., no refactorization of `A`).
- An incumbent solution also speeds up finding the solution for the next step.

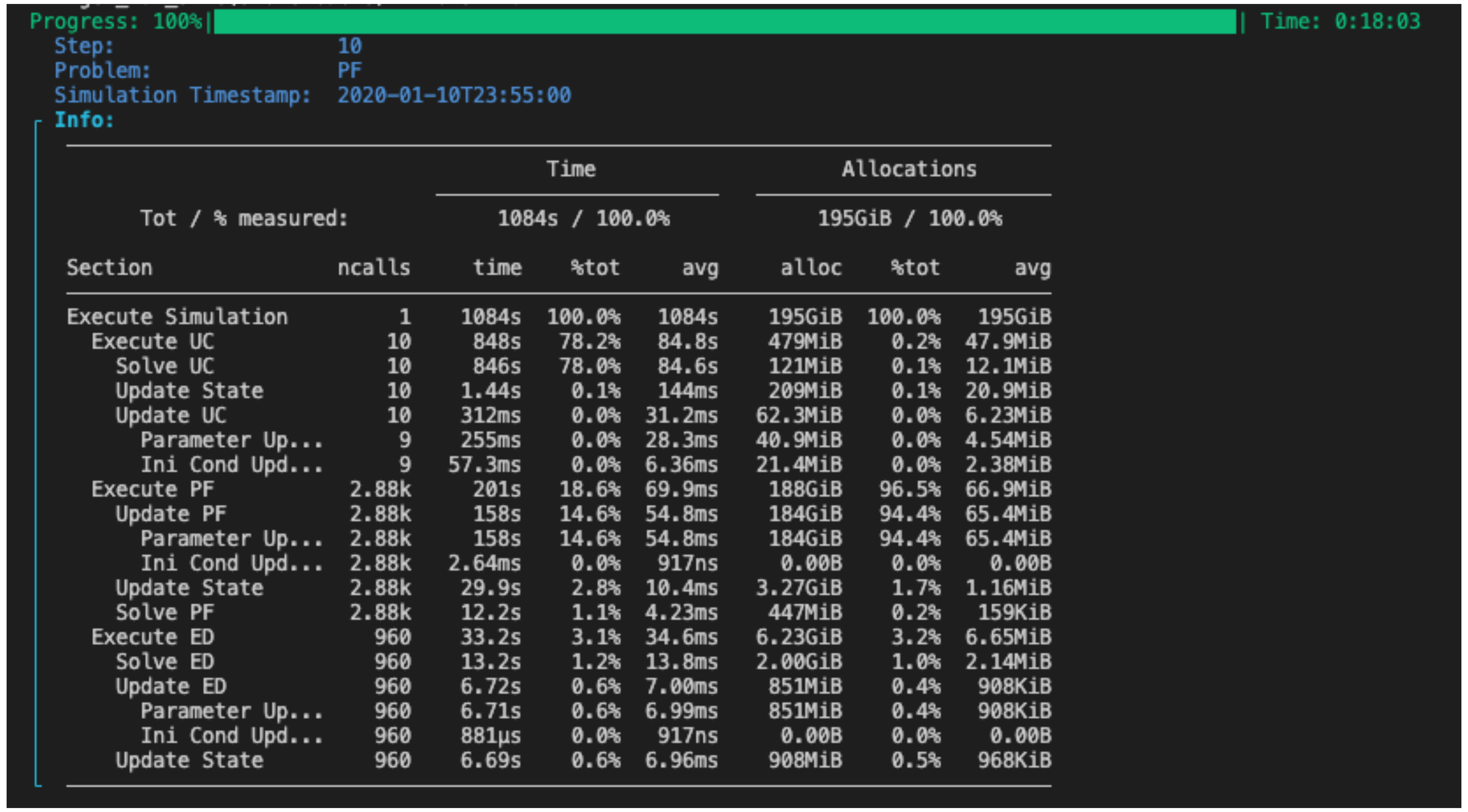
$$\begin{aligned} \min_{x} \quad & C(x) \\ \text{s.t.} \quad & \boxed{A}x \leq \boxed{b} \\ & H(x) \leq 0 \end{aligned}$$

THE VALUE OF AVOIDING REBUILDS A SMALL SAMPLE CASE

By keeping the problem in memory there are two major computational savings:

1. Building the optimization problem (creating constraints, variables, etc)
2. Finding the initial point in the simplex method and refactoring the base of the LP problem.

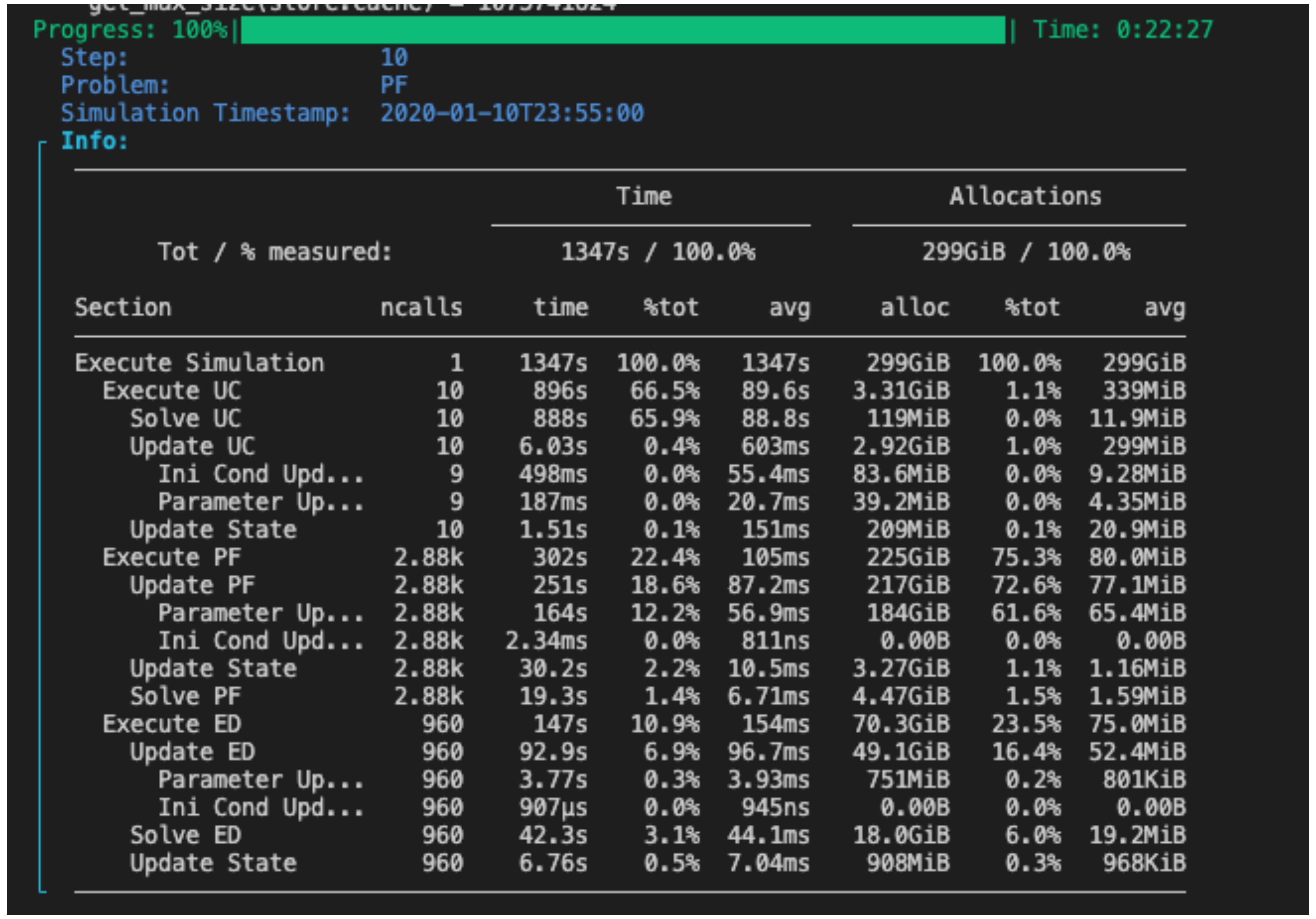
In memory update of ED decision model



Progress: 100% Time: 0:18:03
Step: 10
Problem: PF
Simulation Timestamp: 2020-01-10T23:55:00
Info:

		Time			Allocations		
Tot / % measured:		1084s / 100.0%			195GiB / 100.0%		
Section	ncalls	time	%tot	avg	alloc	%tot	avg
Execute Simulation	1	1084s	100.0%	1084s	195GiB	100.0%	195GiB
Execute UC	10	848s	78.2%	84.8s	479MiB	0.2%	47.9MiB
Solve UC	10	846s	78.0%	84.6s	121MiB	0.1%	12.1MiB
Update State	10	1.44s	0.1%	144ms	209MiB	0.1%	20.9MiB
Update UC	10	312ms	0.0%	31.2ms	62.3MiB	0.0%	6.23MiB
Parameter Up...	9	255ms	0.0%	28.3ms	40.9MiB	0.0%	4.54MiB
Ini Cond Upd...	9	57.3ms	0.0%	6.36ms	21.4MiB	0.0%	2.38MiB
Execute PF	2.88k	201s	18.6%	69.9ms	188GiB	96.5%	66.9MiB
Update PF	2.88k	158s	14.6%	54.8ms	184GiB	94.4%	65.4MiB
Parameter Up...	2.88k	158s	14.6%	54.8ms	184GiB	94.4%	65.4MiB
Ini Cond Upd...	2.88k	2.64ms	0.0%	917ns	0.00B	0.0%	0.00B
Update State	2.88k	29.9s	2.8%	10.4ms	3.27GiB	1.7%	1.16MiB
Solve PF	2.88k	12.2s	1.1%	4.23ms	447MiB	0.2%	159KiB
Execute ED	960	33.2s	3.1%	34.6ms	6.23GiB	3.2%	6.65MiB
Solve ED	960	13.2s	1.2%	13.8ms	2.00GiB	1.0%	2.14MiB
Update ED	960	6.72s	0.6%	7.00ms	851MiB	0.4%	908KiB
Parameter Up...	960	6.71s	0.6%	6.99ms	851MiB	0.4%	908KiB
Ini Cond Upd...	960	881µs	0.0%	917ns	0.00B	0.0%	0.00B
Update State	960	6.69s	0.6%	6.96ms	908MiB	0.5%	968KiB

Rebuild Models

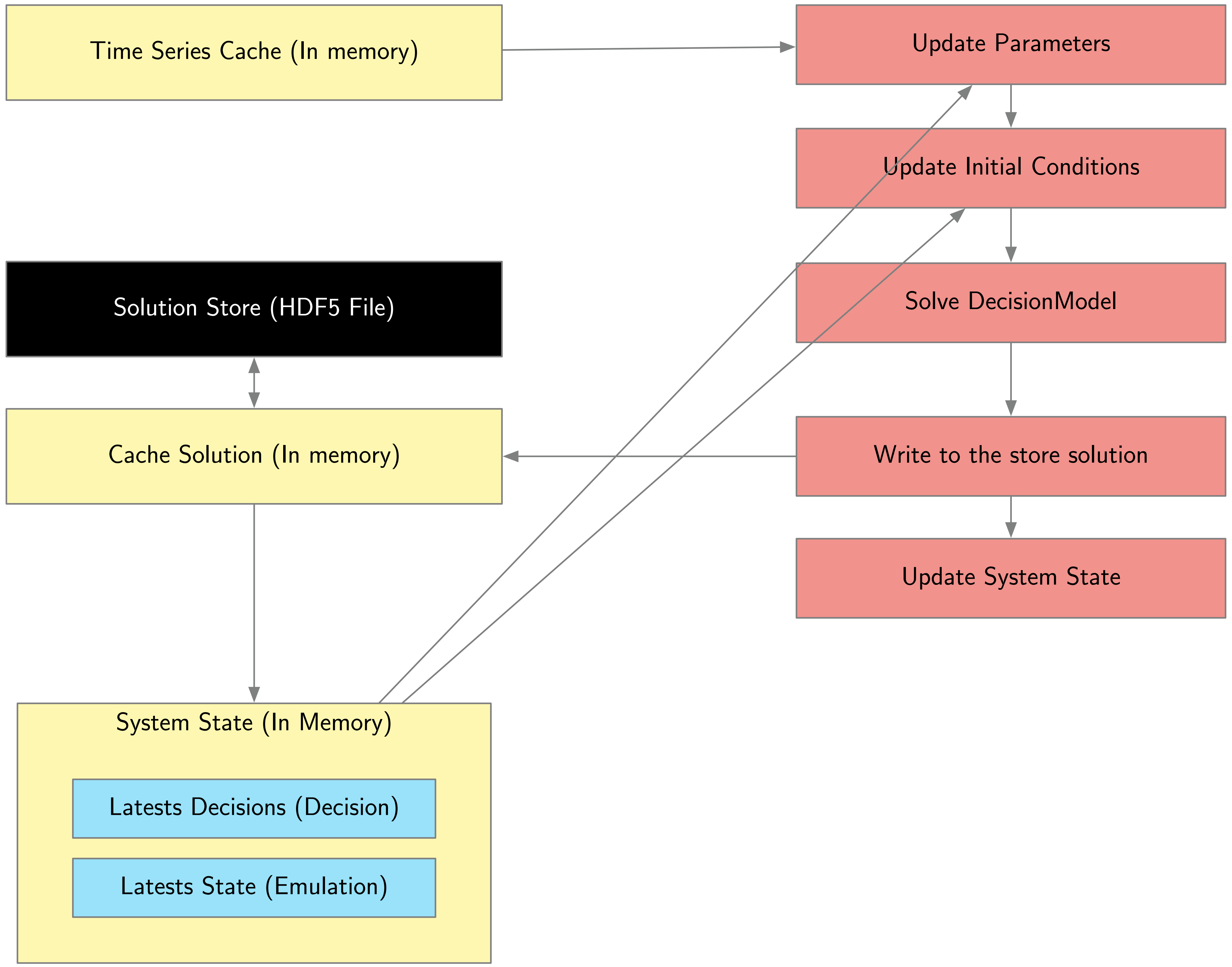


Progress: 100% Time: 0:22:27
Step: 10
Problem: PF
Simulation Timestamp: 2020-01-10T23:55:00
Info:

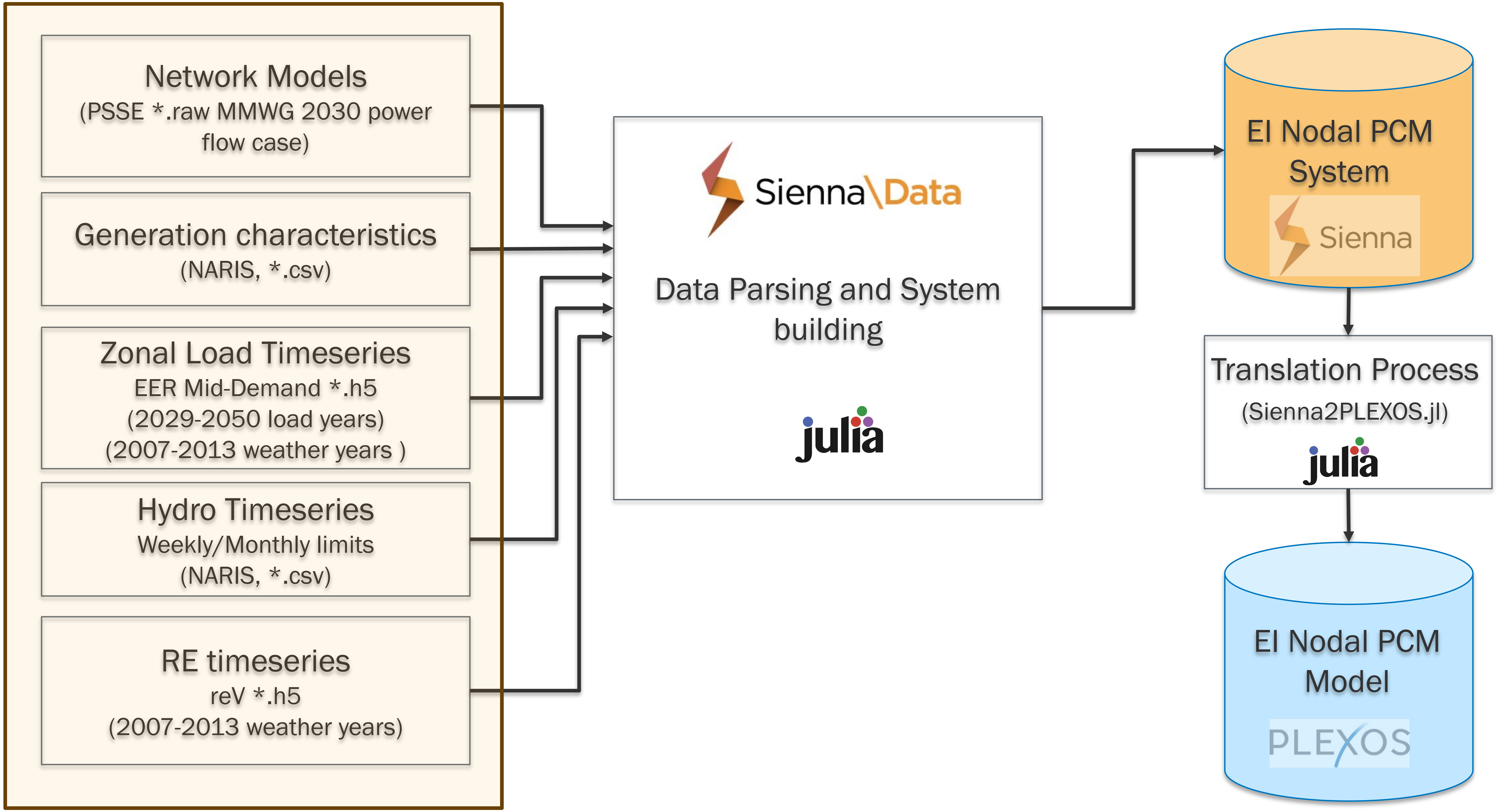
		Time			Allocations		
Tot / % measured:		1347s / 100.0%			299GiB / 100.0%		
Section	ncalls	time	%tot	avg	alloc	%tot	avg
Execute Simulation	1	1347s	100.0%	1347s	299GiB	100.0%	299GiB
Execute UC	10	896s	66.5%	89.6s	3.31GiB	1.1%	339MiB
Solve UC	10	888s	65.9%	88.8s	119MiB	0.0%	11.9MiB
Update UC	10	6.03s	0.4%	603ms	2.92GiB	1.0%	299MiB
Ini Cond Upd...	9	498ms	0.0%	55.4ms	83.6MiB	0.0%	9.28MiB
Parameter Up...	9	187ms	0.0%	20.7ms	39.2MiB	0.0%	4.35MiB
Update State	10	1.51s	0.1%	151ms	209MiB	0.1%	20.9MiB
Execute PF	2.88k	302s	22.4%	105ms	225GiB	75.3%	80.0MiB
Update PF	2.88k	251s	18.6%	87.2ms	217GiB	72.6%	77.1MiB
Parameter Up...	2.88k	164s	12.2%	56.9ms	184GiB	61.6%	65.4MiB
Ini Cond Upd...	2.88k	2.34ms	0.0%	811ns	0.00B	0.0%	0.00B
Update State	2.88k	30.2s	2.2%	10.5ms	3.27GiB	1.1%	1.16MiB
Solve PF	2.88k	19.3s	1.4%	6.71ms	4.47GiB	1.5%	1.59MiB
Execute ED	960	147s	10.9%	154ms	70.3GiB	23.5%	75.0MiB
Update ED	960	92.9s	6.9%	96.7ms	49.1GiB	16.4%	52.4MiB
Parameter Up...	960	3.77s	0.3%	3.93ms	751MiB	0.2%	801KiB
Ini Cond Upd...	960	907µs	0.0%	945ns	0.00B	0.0%	0.00B
Solve ED	960	42.3s	3.1%	44.1ms	18.0GiB	6.0%	19.2MiB
Update State	960	6.76s	0.5%	7.04ms	908MiB	0.3%	968KiB

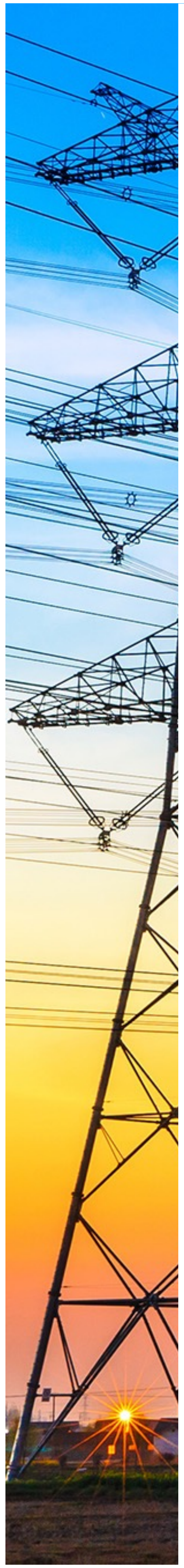
SOLVE MODEL FOR MULTI-STAGE SIMULATIONS

- The simulation has a store for the solution of each stage of the decision making problem.
- The simulator keeps track of the latest value of the decision variables and the system variables in a given state.
- An incumbent solution also speeds up finding the solution for the next step.
- Information written to disk is not retrieved back for the purpose of modeling. I.e., no write-read of LP files for every run.



Dataset Building Process



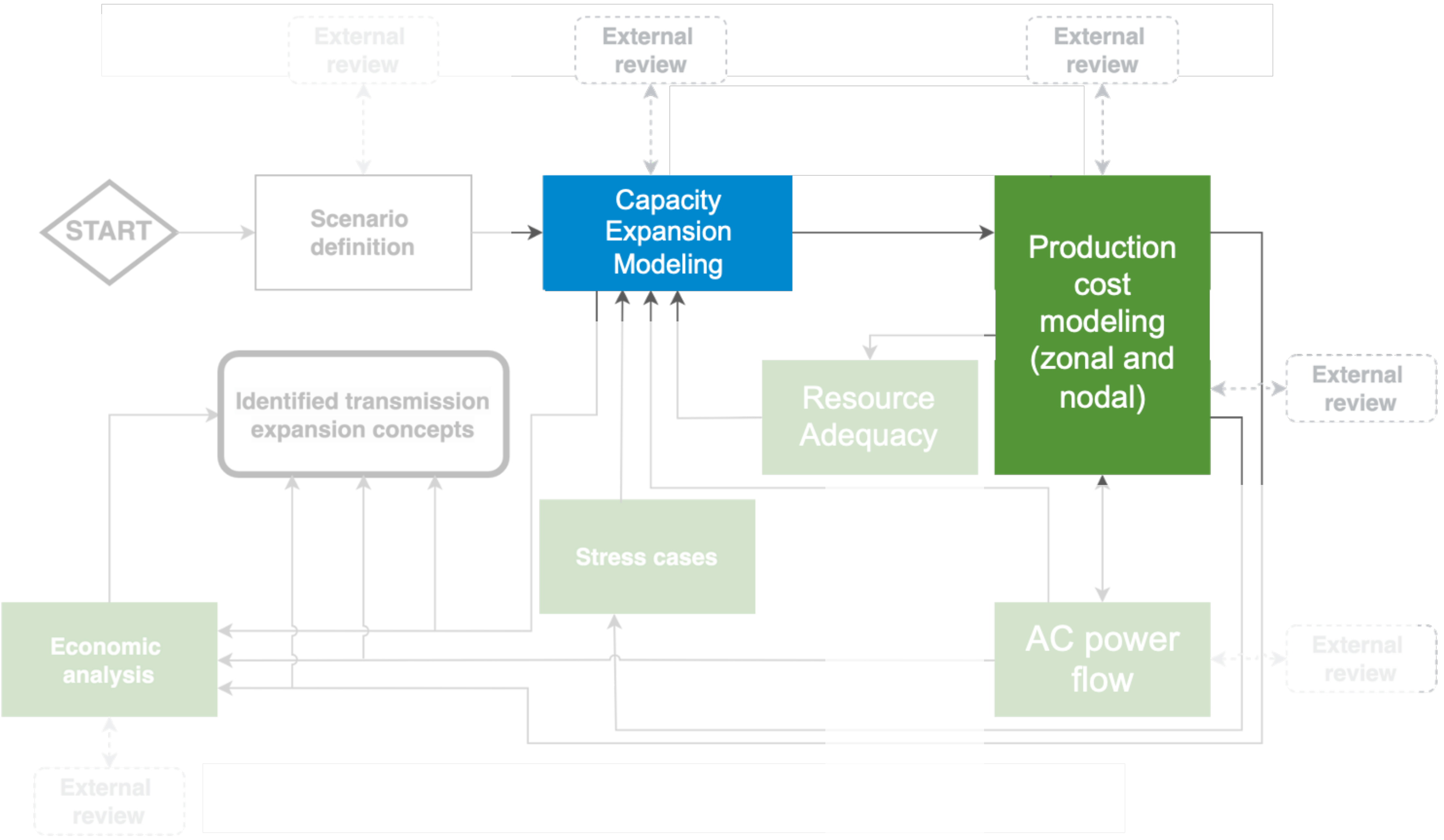


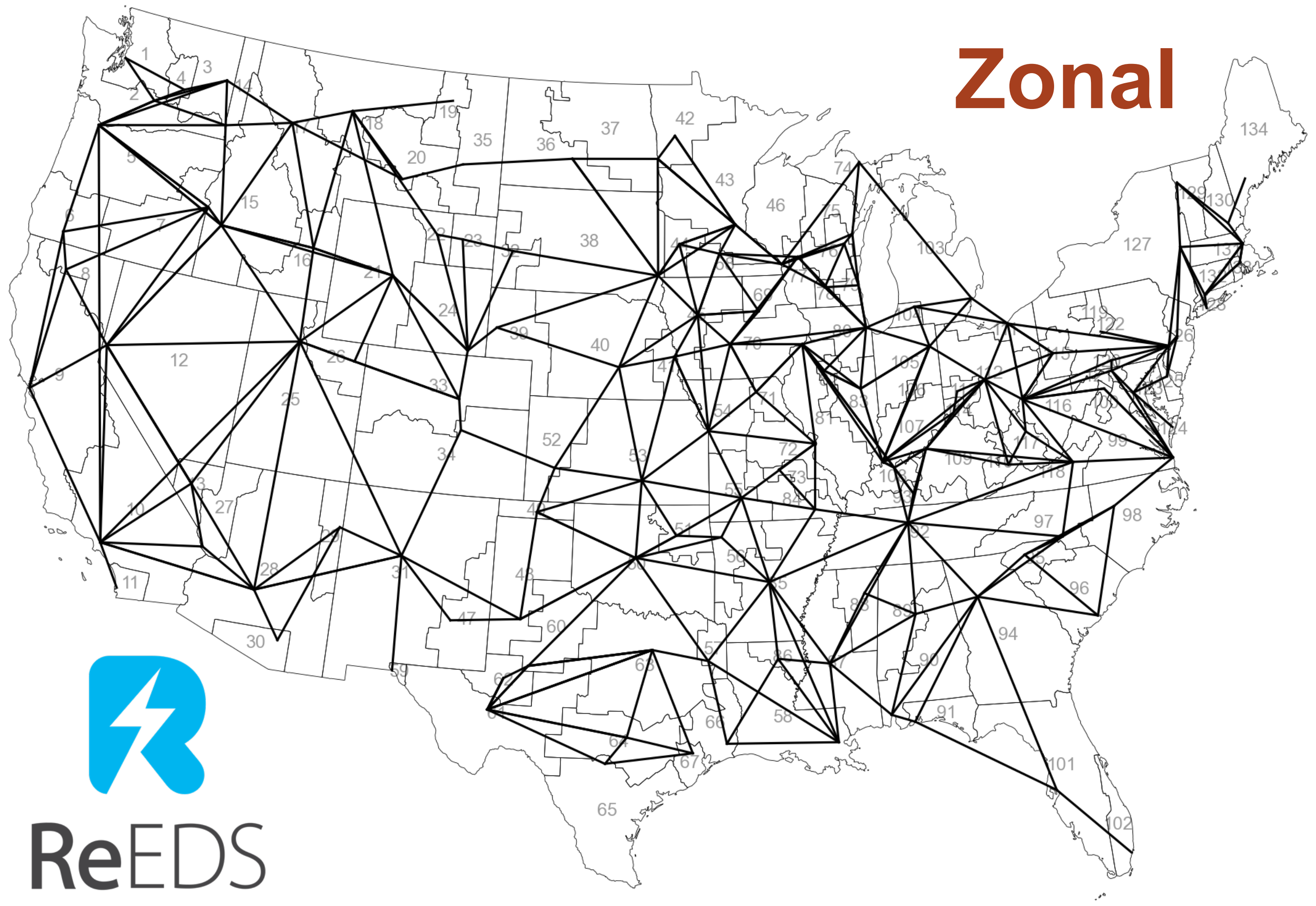
Use Case:
National Transmission Planning Study

(https://www.energy.gov/gdo/national-transmission-planning-study)

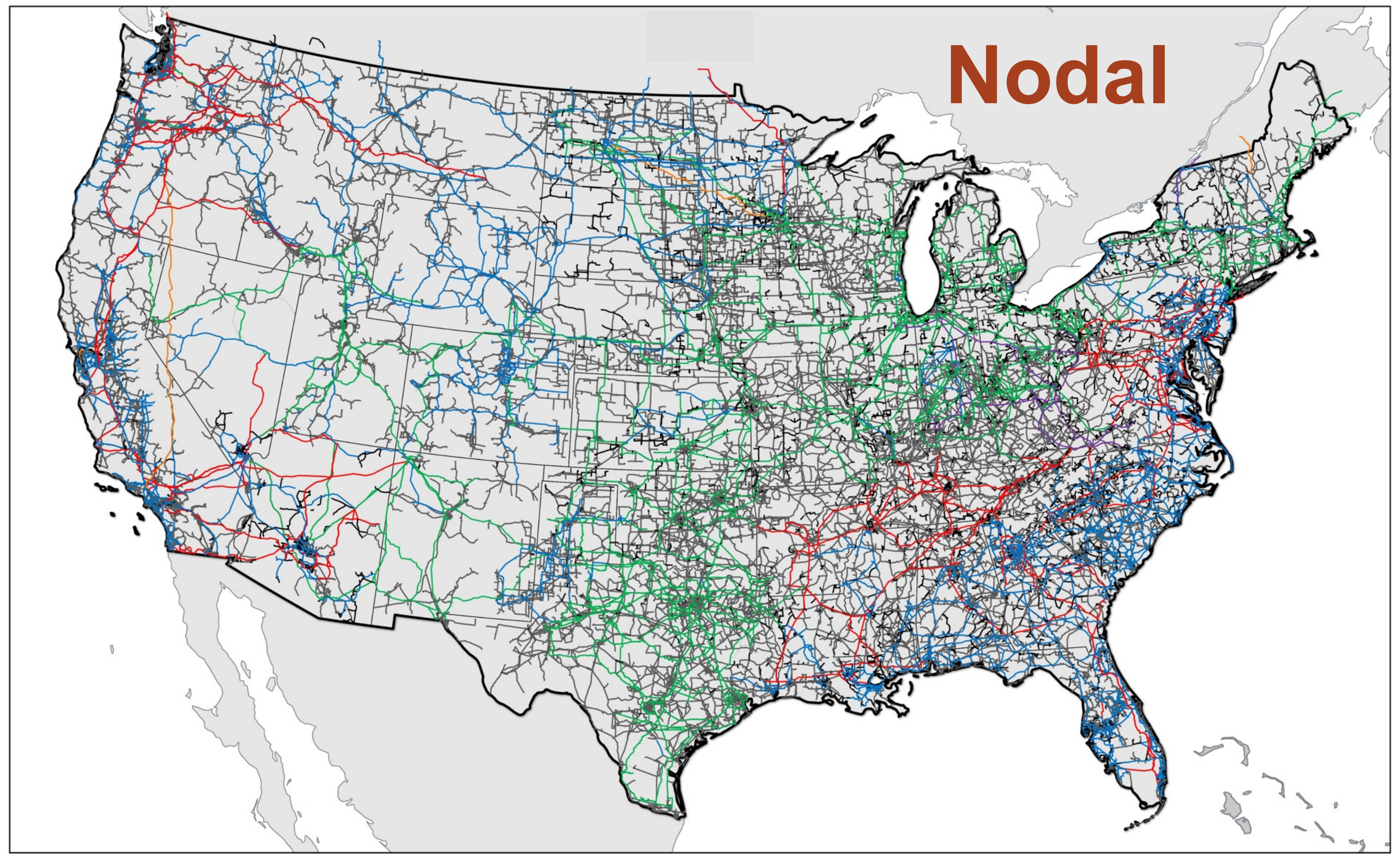
Objectives

- Identify interregional and national strategies to accelerate cost-effective decarbonization while maintaining system reliability
- Inform regional and interregional transmission planning processes, particularly by engaging stakeholders in dialogue
- Results help inform future DOE funding for transmission infrastructure support





ReEDS



Sienna\Data

Efficient intake and use of energy systems input data

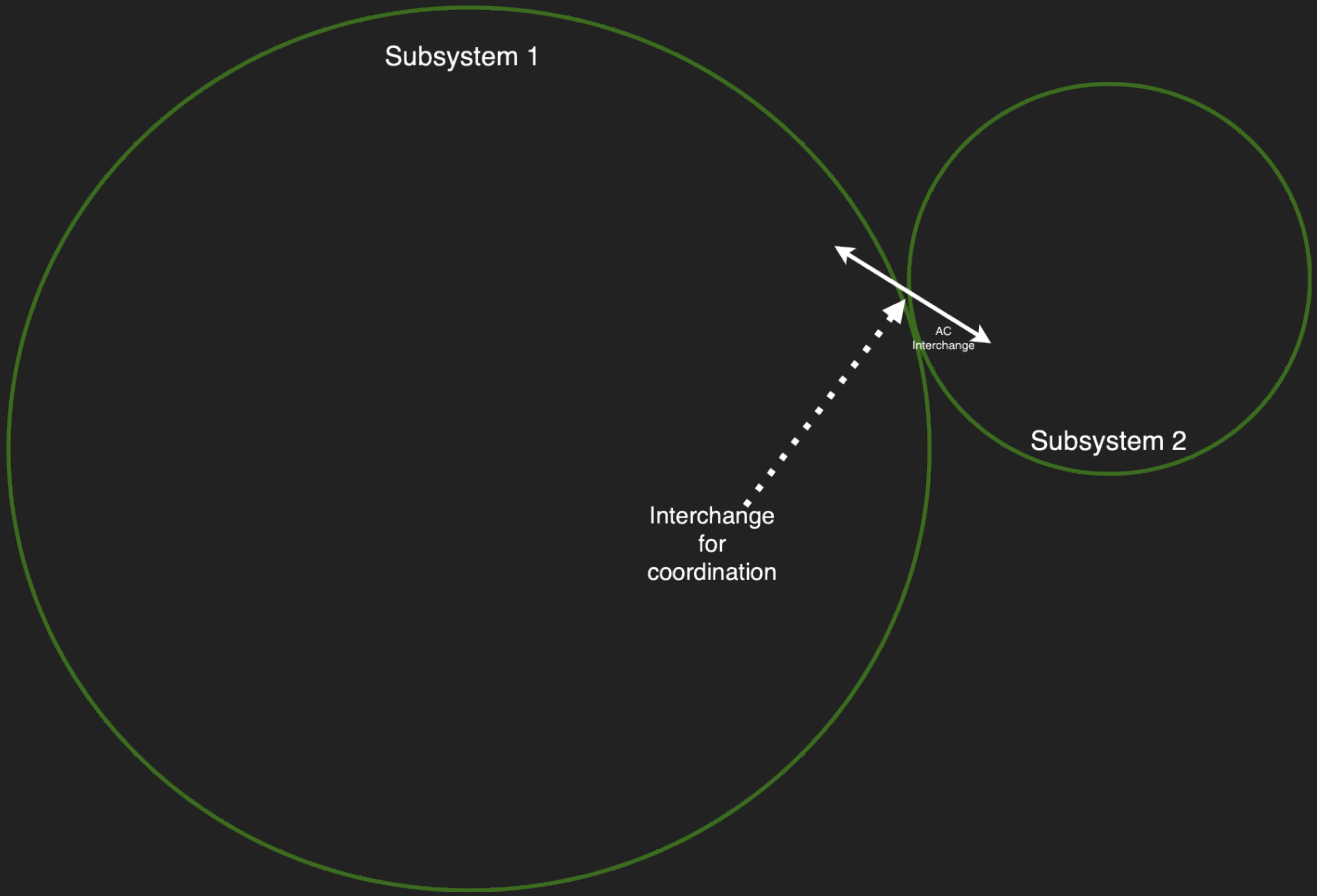
Sienna\Ops

Simulation of system scheduling, including sequential problems for production cost modeling

DEVELOPMENTS FOR M2M SIMULATION ON LARGE SCALE NETWORKS

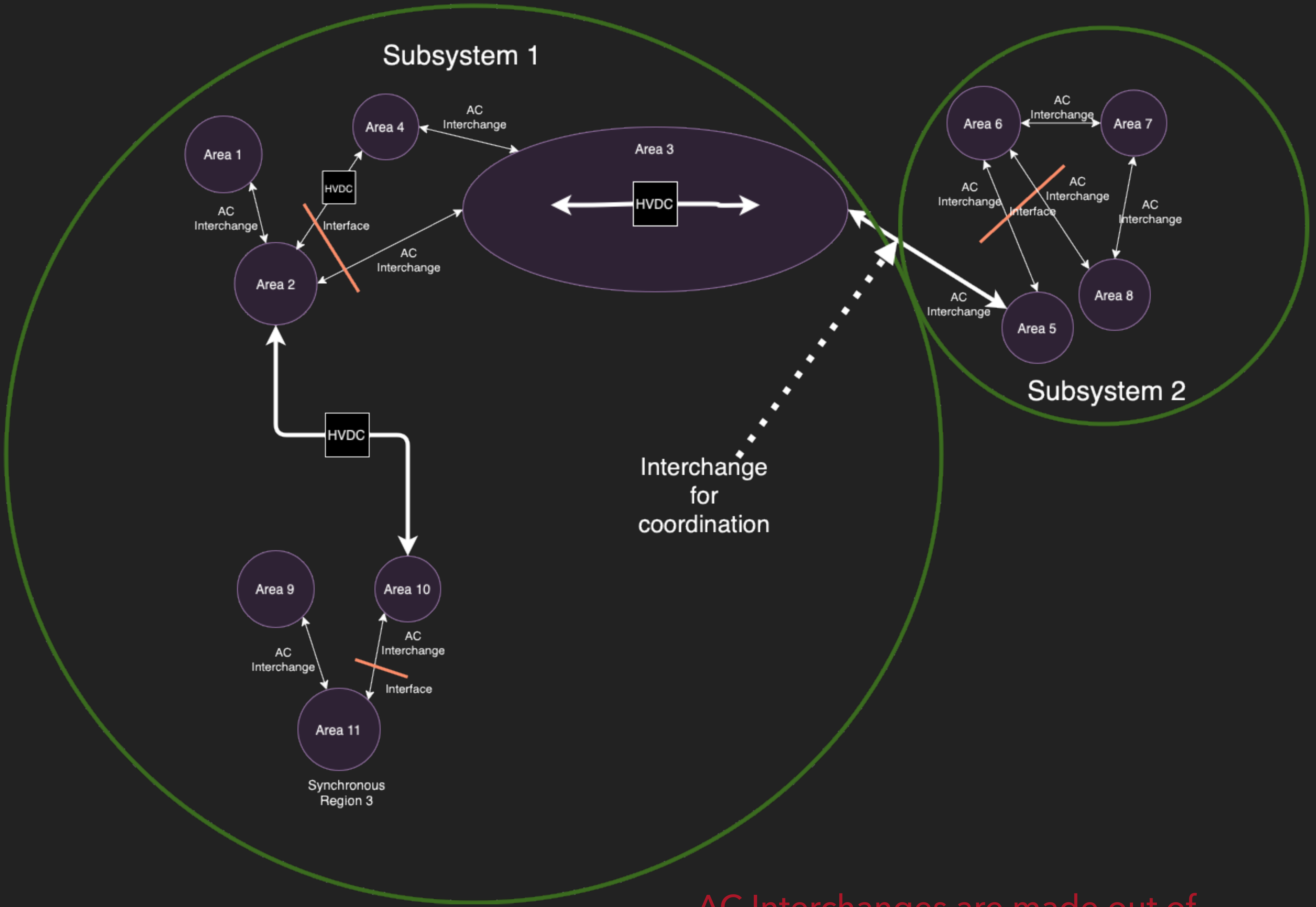
2-SUBSYSTEMS

- We define two Subsystems in an interconnected area that share an interchange.
- The objective is to develop a modeling/simulation platform to assess different techniques to coordinate over this interconnection efficiently.
- Several works have looked at this problem; however, these have not considered other topological challenges



2-SUBSYSTEMS, MULTIPLE AREAS

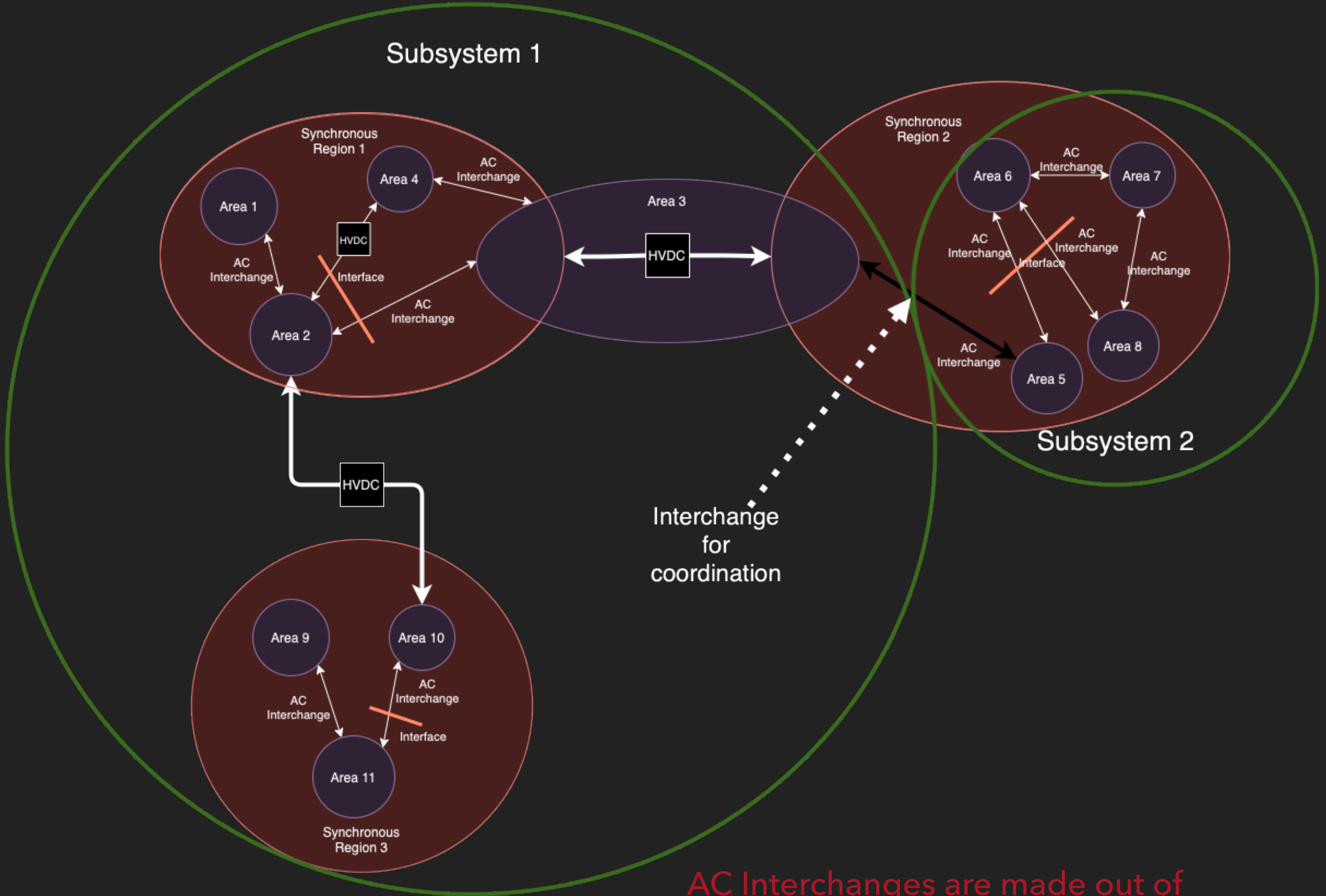
- Each subsystem is composed of several areas for balancing power.
- These areas might be connected by other interchanges internal to the subsystems. The interchanges can be in AC or via HVDC.
- Each subsystem also defines interfaces which might coincide with the interchanges or contain several



AC Interchanges are made out of multiple AC lines

2-SUBSYSTEMS, MULTIPLE AREAS, MULTIPLE SYNCHRONOUS REGIONS

- The areas are split across synchronous regions connected via HVDC.
- Modeling the synchronous regions adequately matters such that the PTDF assumptions are correct and the line flows are estimated correctly.
- The combination of balancing areas, regions and systems makes the problem complex to build and simulate



AC Interchanges are made out of multiple AC lines

MODEL FORMULATION – SETS

$\mathcal{B}$	System Buses
$\mathcal{R}$	Synchronous Regions
$\mathcal{A}$	Balancing Areas
$\mathcal{L}$	AC Lines
$\mathcal{H}$	Two Terminal HVDC Lines
$\mathcal{E} := \{e \in \mathrm{C}(\mathcal{A}, 2)\}$	Inter-area exchanges
$\mathcal{I}$	Transmission interfaces
$\mathcal{G}$	Generators
$\mathcal{X}$	Feasibility Set
$\mathcal{T} := \{1, \ldots, T\}$	Time steps

MODEL FORMULATION – INDEXING

b_r	bus in synchronous region $r \in \mathcal{R}$
b_a	bus in area $a \in \mathcal{A}$
$\mathcal{G}_r$	Subset of generators in region $r \in \mathcal{R}$
$\mathcal{G}_a$	Subset of generators in area $a \in \mathcal{A}$
$\mathcal{B}_r$	Subset of buses in region $r \in \mathcal{R}$
$\mathcal{B}_a$	Subset of buses in area $a \in \mathcal{A}$
$\mathcal{H}_i$	Subset of two Terminal HVDC assigned to interface $i \in \mathcal{I}$
$\mathcal{L}_i$	Subset of AC Line assigned to interface $i \in \mathcal{I}$
$h_{b\rightarrow}$	From bus Two Terminal HVDC Line $h \in \mathcal{H}$
$h_{b\leftarrow}$	To bus Two Terminal HVDC Line $h \in \mathcal{H}$
$h_{r\rightarrow}$	From region Two Terminal HVDC Line $h \in \mathcal{H}$
$h_{r\leftarrow}$	To region Two Terminal HVDC Line $h \in \mathcal{H}$
$h_{a\rightarrow}$	From area Two Terminal HVDC Line $h \in \mathcal{H}$
$h_{a\leftarrow}$	To area Two Terminal HVDC Line $h \in \mathcal{H}$
$l_{b\rightarrow}$	From bus Line $l \in \mathcal{L}$
$l_{b\leftarrow}$	To bus Line $l \in \mathcal{L}$
$l_{a\rightarrow}$	From area Line $l \in \mathcal{L}$
$l_{a\leftarrow}$	To area Line $l \in \mathcal{L}$
$e_{a\rightarrow}$	From area Inter-area exchange $e \in \mathcal{E}$
$e_{a\leftarrow}$	To area Inter-area exchange $e \in \mathcal{E}$

MODEL FORMULATION – PARAMETERS

$\boldsymbol{PTDF}^r$	PTDF subnetwork $n \in \mathcal{R}$
$D_{b,t}$	Net demand at bus b time t
P_g^{max}	Generator Max Power Output
F_l^{max}	AC line max rating normal operation
F_l^{max}	Two-terminal HVDC max flow normal operation
F_i^{max}	Max Flow Transmission Interface
F_i^{min}	Min Flow Transmission Interface
$F_e^{max,\leftarrow}$	Max Flow from-to Inter-area exchange
$F_e^{max,\rightarrow}$	Max Flow to-from Inter-area exchange

MODEL FORMULATION – VARIABLES & EXPRESSIONS

$$p_{g,t} \in [0, P_g^{max}]$$ Generator Power Output

$$f_{h,t} \in [-F_h^{max}, F_h^{max}]$$ HVDC Line flow

$$f_{e,t} \in [-F_e^{max,\rightarrow}, F_e^{max,\leftarrow}]$$ Inter-area exchange flow

$$i_{b,t} := D_{b,t} - \sum_{g \in \mathcal{G}_b} p_{g,t} + \sum_{\{h \in \mathcal{H} | h_{b\leftarrow} = b\}} f_{h,t} - \sum_{\{h \in \mathcal{H} | h_{b\rightarrow} = b\}} f_{h,t}$$ Net Injection at bus b at time t

$$f_{l,t} := \sum_{l \in \mathcal{L}_r, b \in \mathcal{B}_r} \boldsymbol{PTDF}^r_{l,b} i_{b,t}$$ Power flow over branch l in region r at time t

MODEL FORMULATION –CONSTRAINTS

$$\min_{\boldsymbol{p}, \boldsymbol{f}_h, \boldsymbol{f}_e} \sum_{t\in\mathcal{T}, g\in\mathcal{G}} \mathrm{O}_g(p_{g,t})$$

s.t.

$$p_{g,t} \in \mathcal{X}_g \quad \forall g \in \mathcal{G},\ \forall t \in \mathcal{T}$$
$$f_{l,t} \in \mathcal{X}_l \quad \forall l \in \mathcal{L},\ \forall t \in \mathcal{T}$$
$$f_{h,t} \in \mathcal{X}_h \quad \forall h \in \mathcal{H},\ \forall t \in \mathcal{T}$$
$$f_{e,t} \in \mathcal{X}_h \quad \forall e \in \mathcal{E},\ \forall t \in \mathcal{T}$$

| Feasibility sets for the different model components

$$\sum_{g\in\mathcal{G}_r} p_{g,t} + \sum_{\{h\in\mathcal{H}|h_{b\leftarrow}\in r\}} f_{h,t} - \sum_{\{h\in\mathcal{H}|h_{b\rightarrow}\in\mathcal{B}_r\}} f_{h,t} = \sum_{b\in\mathcal{B}_r} D_b \ \forall r \in \mathcal{R},\ \forall t \in \mathcal{T}$$

| Synchronous Region Power Balance

$$\sum_{g\in\mathcal{G}_a} p_{g,t} + \sum_{\{E\in\mathcal{E}|e_{a\leftarrow}=a\}} f_{e,t} - \sum_{\{e\in\mathcal{E}|e_{a\rightarrow}=a\}} f_{e,t} = \sum_{b\in\mathcal{B}_a} D_b \ \forall a \in \mathcal{A},\ \forall t \in \mathcal{T}$$

| Area Power Balance

$$\sum_{\{l\in\mathcal{L}|l_{a\rightarrow}=e_{a\rightarrow}\wedge l_{a\leftarrow}=e_{a\leftarrow}\}} f_{l,t} - \sum_{\{l\in\mathcal{L}|l_{a\rightarrow}=e_{a\leftarrow}\wedge l_{a\rightarrow}=e_{a\leftarrow}\}} f_{l,t} + \sum_{\{h\in\mathcal{H}|h_{a\rightarrow}=e_{a\rightarrow}\wedge h_{a\leftarrow}=e_{a\leftarrow}\}} f_{h,t} - \sum_{\{h\in\mathcal{H}|h_{a\rightarrow}=e_{a\leftarrow}\wedge h_{a\rightarrow}=e_{a\leftarrow}\}} f_{h,t} \leq f_{e,t} \quad \forall e \in \mathcal{E},\ t \in \mathcal{T}$$

| Area Exchange Upper Bound

$$\sum_{\{l\in\mathcal{L}|l_{a\rightarrow}=e_{a\rightarrow}\wedge l_{a\leftarrow}=e_{a\leftarrow}\}} f_{l,t} - \sum_{\{l\in\mathcal{L}|l_{a\rightarrow}=e_{a\leftarrow}\wedge l_{a\rightarrow}=e_{a\leftarrow}\}} f_{l,t} + \sum_{\{h\in\mathcal{H}|h_{a\rightarrow}=e_{a\rightarrow}\wedge h_{a\leftarrow}=e_{a\leftarrow}\}} f_{h,t} - \sum_{\{h\in\mathcal{H}|h_{a\rightarrow}=e_{a\leftarrow}\wedge h_{a\rightarrow}=e_{a\leftarrow}\}} f_{h,t} \geq f_{e,t} \quad \forall e \in \mathcal{E},\ t \in \mathcal{T}$$

| Area Exchange Lower Bound

$$\sum_{l\in\mathcal{L}_i} f_{l,t} + \sum_{h\in\mathcal{H}_i} f_{h,t} \leq F_i^{max} \quad \forall i \in \mathcal{I},\ t \in \mathcal{T}$$

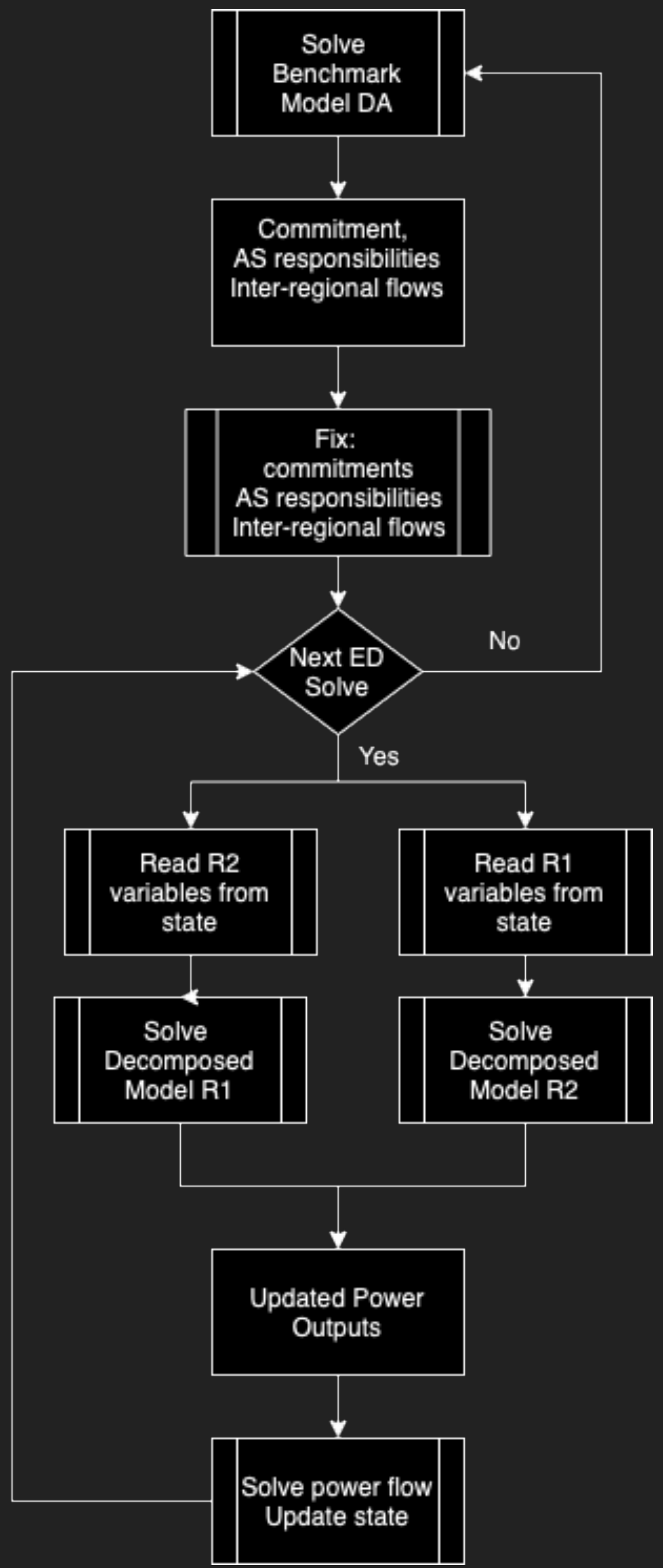
| Interface Upper Bound

$$\sum_{l\in\mathcal{L}_i} f_{l,t} + \sum_{h\in\mathcal{H}_i} f_{h,t} \geq F_i^{min} \quad \forall i \in \mathcal{I},\ t \in \mathcal{T}$$

| Interface Lower Bound

SIMULATION IMPLEMENTATION - WORK IN PROGRESS

- The simulation workflow takes advantage of the emulator concept to implement the equivalent of the state estimator.
- At each time step in the ED all the variables from the emulator are available to the decomposed model by subsystem. It includes potentially duals from the other subsystem's problem.
- Solving these problems at scale requires several stability tricks:
    - Reduce radial branches in the PTDF and sparsity the matrices
    - Use Ward equivalents to reduce the number of branches from the neighboring region each subproblem needs to solve for
    - Parallelize the build and solve of each decomposed problem



Sienna Index

6,000+	Downloads
25	Packages
12,968,279	Lines of code
22,000	Commits
694	Github stars
203	Forks
16	Publications
25	Contributors
200	Datasets
20	Project usages
1,000,000+	HPC simulation hours

Thank You!

Sienna

Interregional Transmission Operational Coordination (IRTOC)

Case Study: National Transmission Planning Study

Jarrad **WRIGHT** (jarrad.wright@nrel.gov)

NREL Grid Planning and Analysis Center

Inter-regional Transmission Operational Coordination (IRTOC) Workshop

June 12, 2024

Crawling… walking… running

IRTOC multi-RTO congestion management coordination study

Coordination configurations	c0	c1	c2	c3	c4	c5	c6	c7	c8	c9	c10	c11
Power balance	0	1	0	1	0	1	0	1	0	1	0	1
Transmission constraint (energy flow)	0	0	1	1	0	0	1	1	1	1	1	1
Reserve requirement	0	0	0	0	1	1	1	1	0	0	1	1
Transmission constraint (energy+ reserve flow)	0	0	0	0	0	0	0	0	1	1	1	1

Interchange optimization

M2M JOA

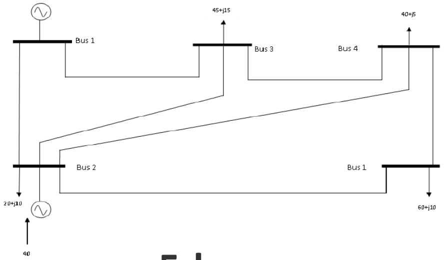
IRTOC

Full multi-area coupling (e.g., EIM, Coordinated multi-RTO scheduling)

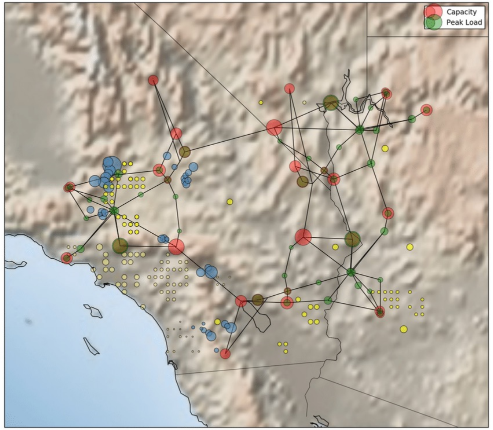
0: no coordination   1: with coordination

EIM: energy imbalance market – may be extended to enforce all constraints under c11

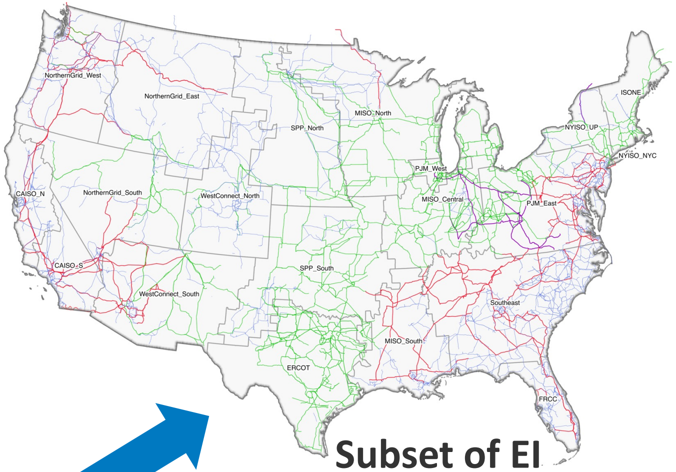
Increasingly testing methods and tools with larger models



5-bus



96-bus RTS (x2)



Subset of EI

(1000s-10000s of busses)

Intermediary step before large-scale?

Consistent evaluation of economic and reliability impacts:

- **Complexity** (tractability)
- **Efficiency** (prod. cost)
- **Reliability** (shortages, flow violations)

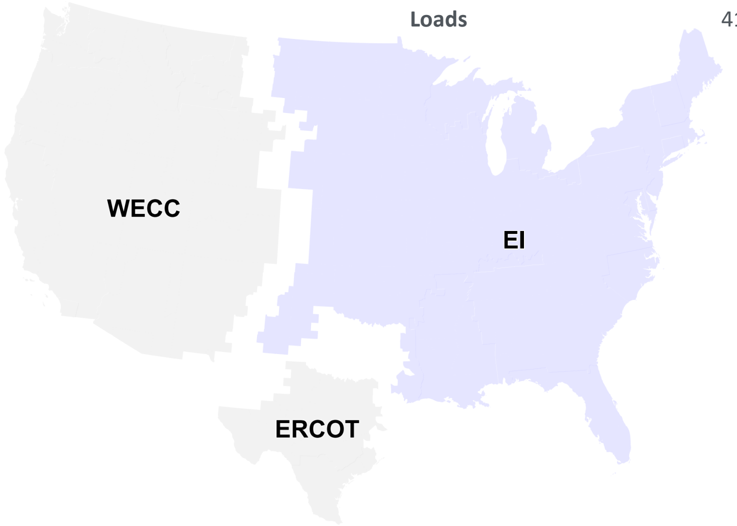
Summary of nodal PCM problem characterization (from NTP)

Overview

- Temporal resolution: Hourly
- Steps: 7 (1 week), 52 weeks (parallel)
- Horizon: 24 hours
- Overlap: 48 hours

CONUS	Stage 1	Stage 2 and 3
Generation capacity	Thermal (UC)	Thermal (UC)
Interface bounds (existing)	Monitored (Unbounded) (261 interfaces) (~1200 branches)	As in Stage 1
Interface bounds (scenarios)	Bounded (36 interfaces) (~1.0-1.2k branches)	Bounded (36 interfaces) (~1.0-1.2k branches)
Branch bounds	Unbounded	Bounded (add. ~250 branches) (most > 230 kV)
Solve times	~2-4 hours	~18-30 hours

Buses	95.9k
Lines & trafos	120k
Generators/storage	8k
Loads	41k



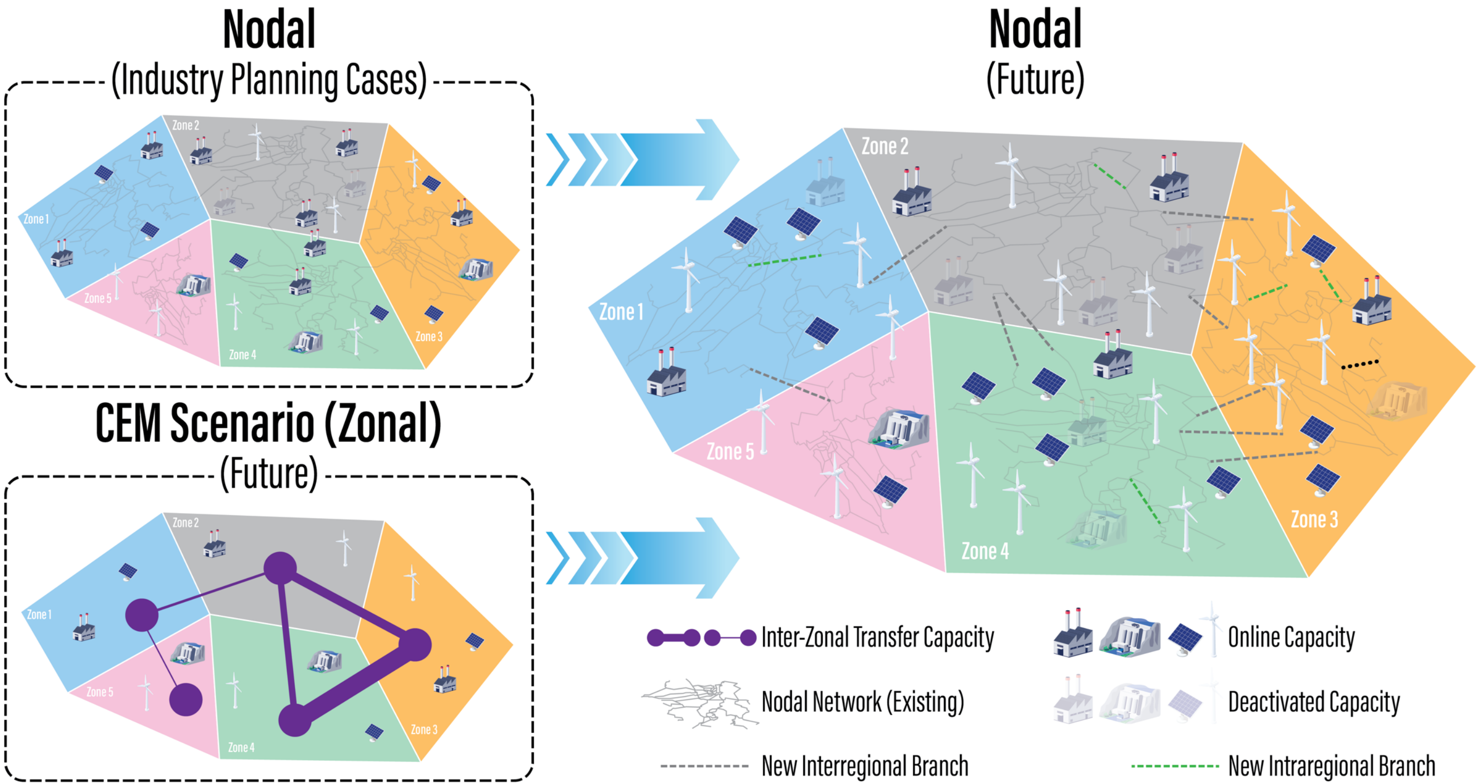
- Global co-optimization (energy & reserves)
- Perfect-foresight (DA, hourly)

DRAFT RESULTS

Sources: National Transmission Planning Study, 2024 (forthcoming)

NTP nodal scenarios

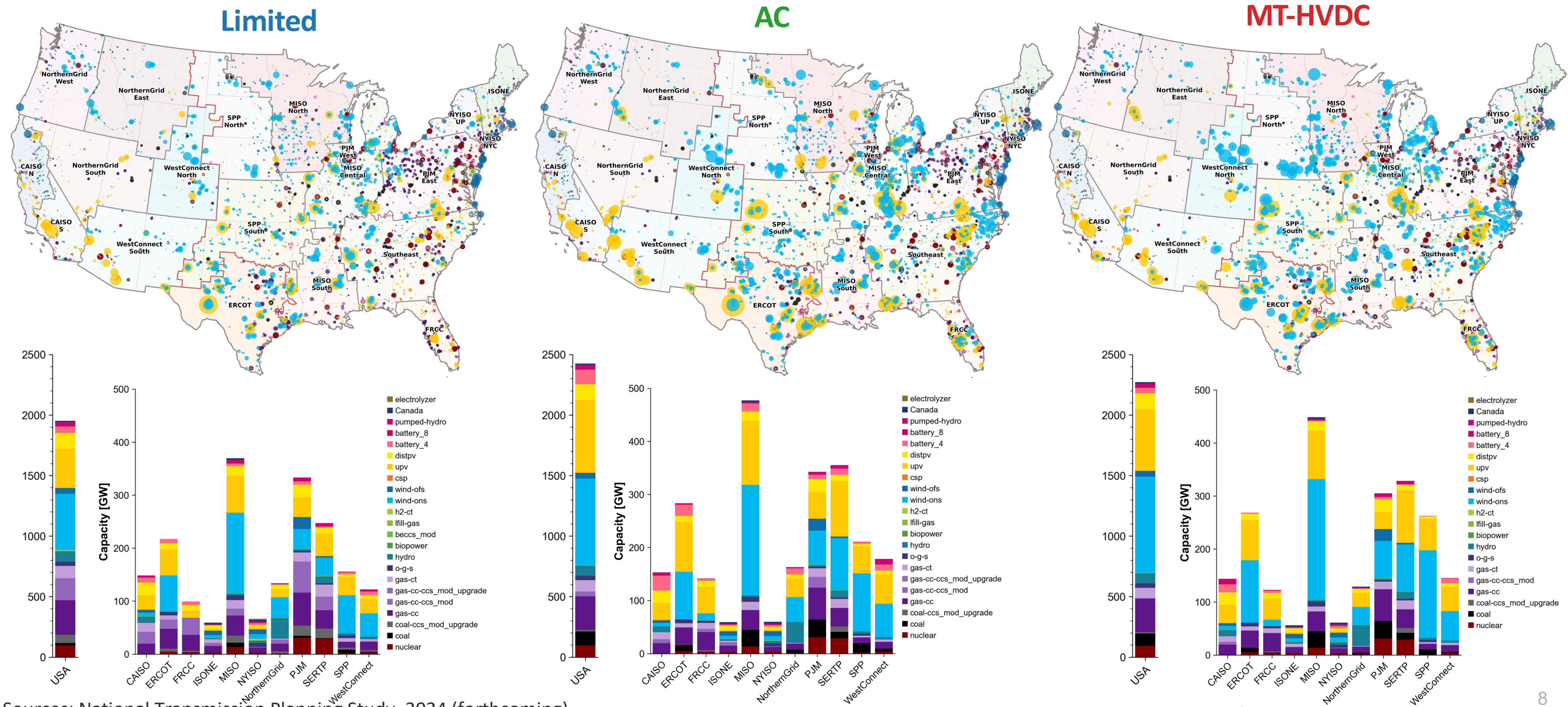
Zonal to Nodal Translation



Sources: National Transmission Planning Study, 2024 (forthcoming)

Results of disaggregation

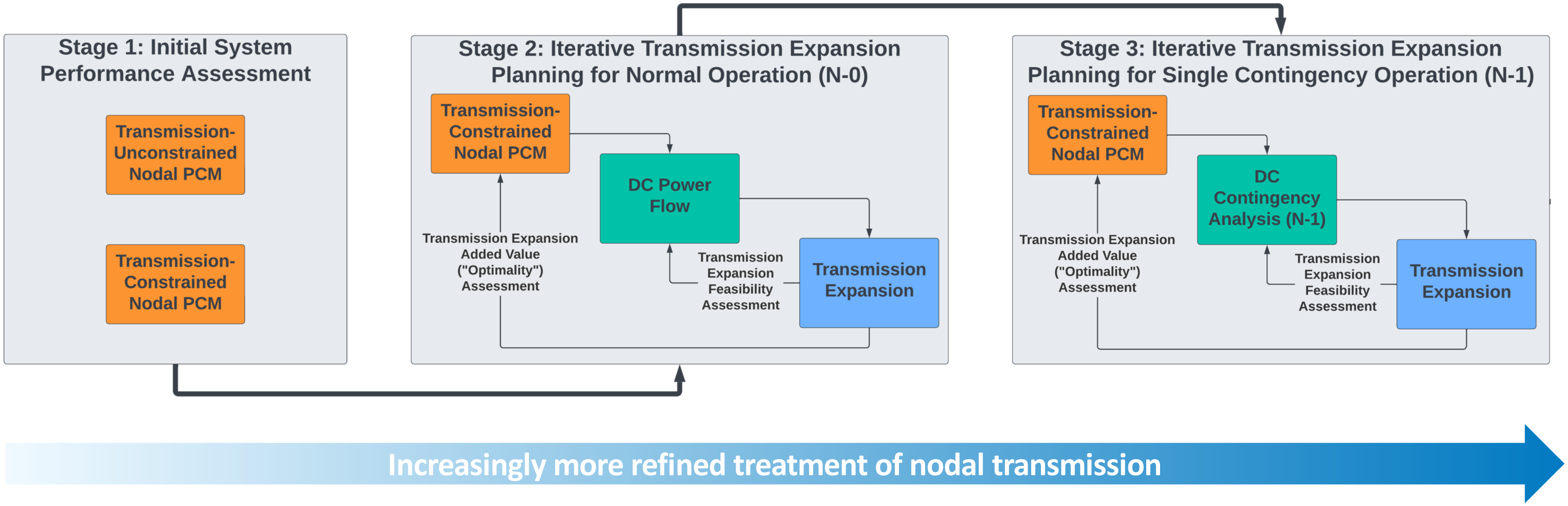
Interconnecting all generation and storage resources onto network nodes



Sources: National Transmission Planning Study, 2024 (forthcoming)

*Each dot represents a nodal injection

Iterative Transmission Expansion Planning Approach

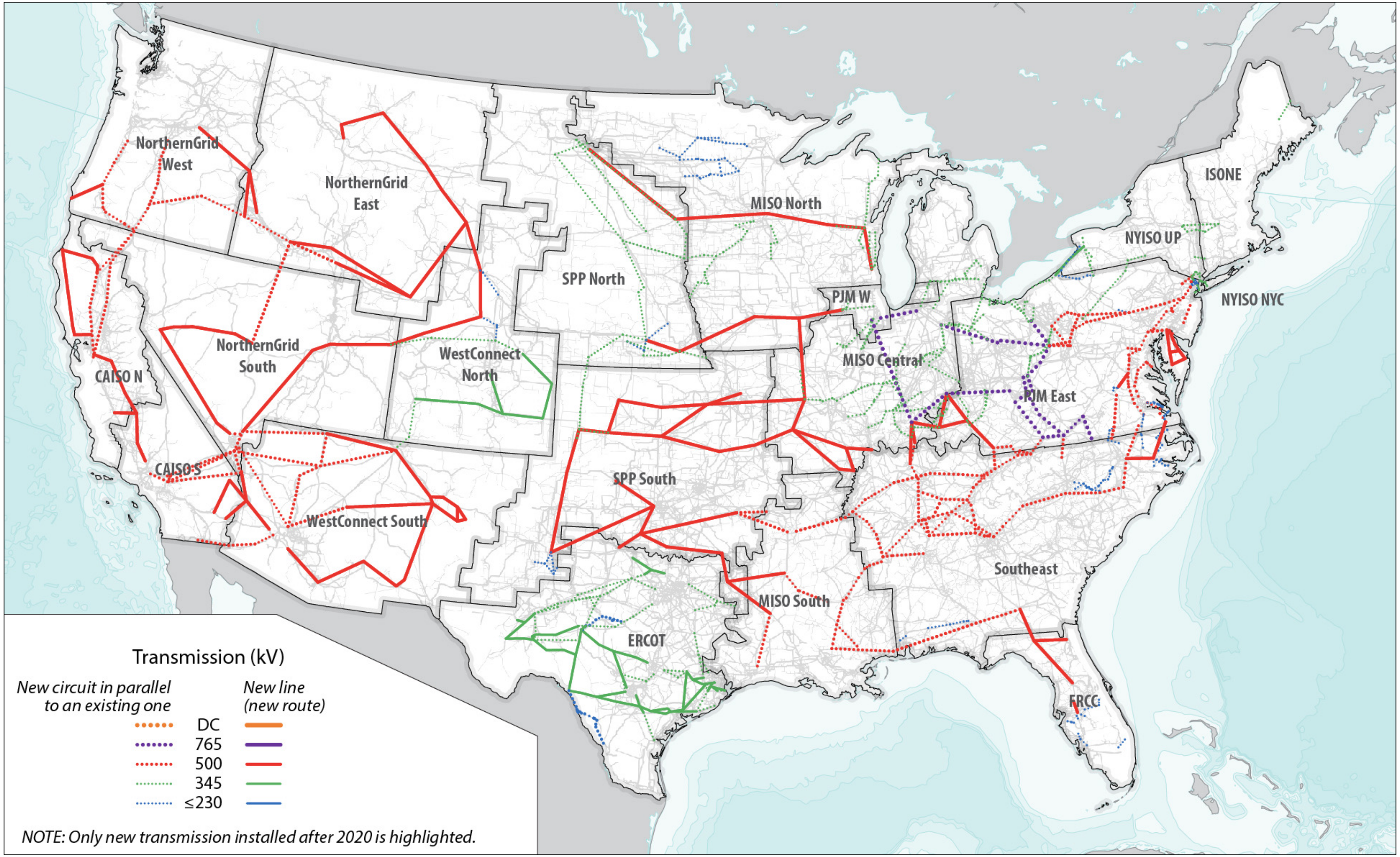


NOTE: Transition between steps involves the selection of appropriate operating conditions (snapshots of representative hours from nodal PCM simulations) over which transmission expansion planning is undertaken (this is further described later and is in a process of continuing improvement).

Sources: National Transmission Planning Study, 2024 (forthcoming)

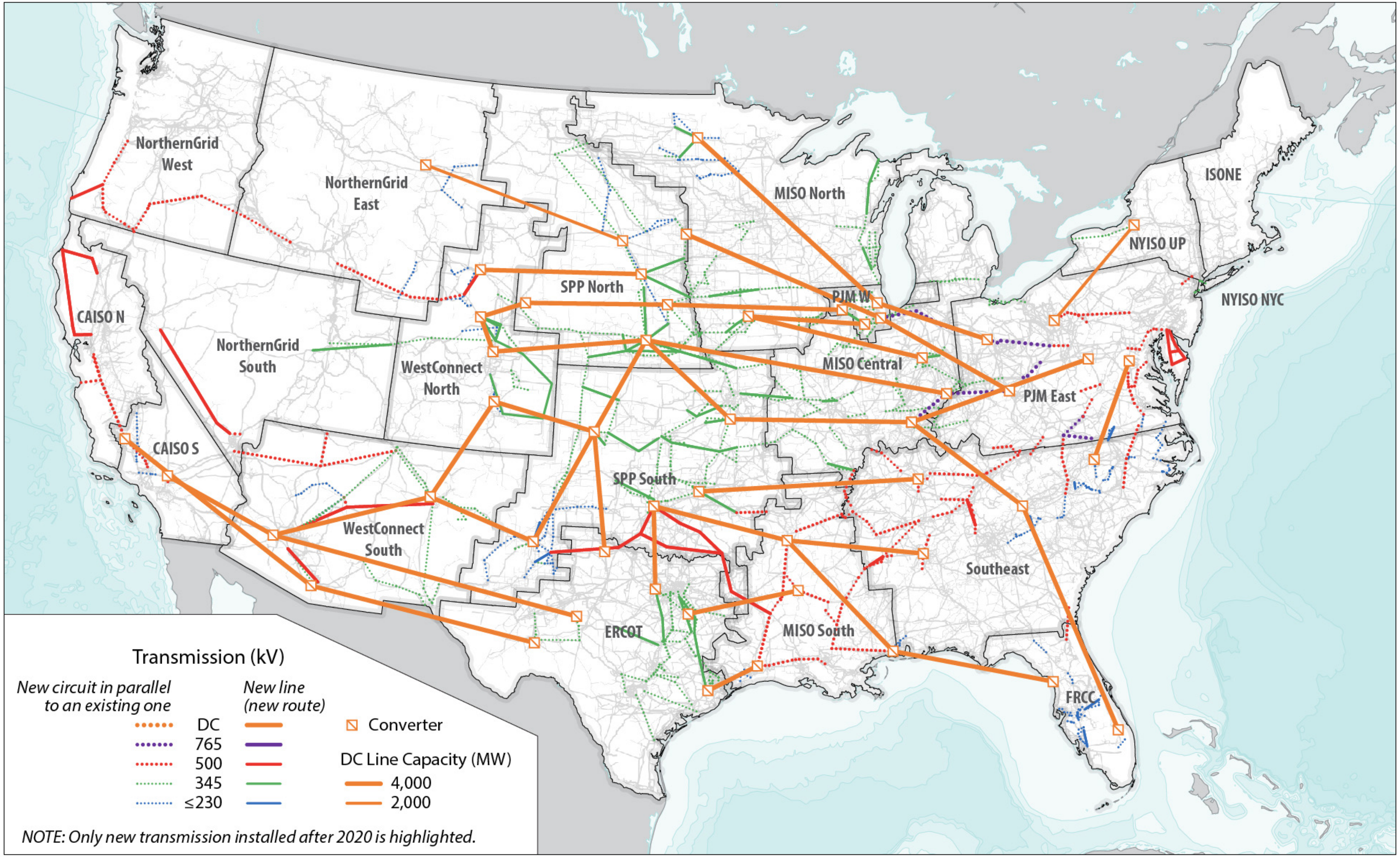
NTP nodal solutions

AC Transmission Expansion (2035, nodal)



Sources: National Transmission Planning Study, 2024 (forthcoming)

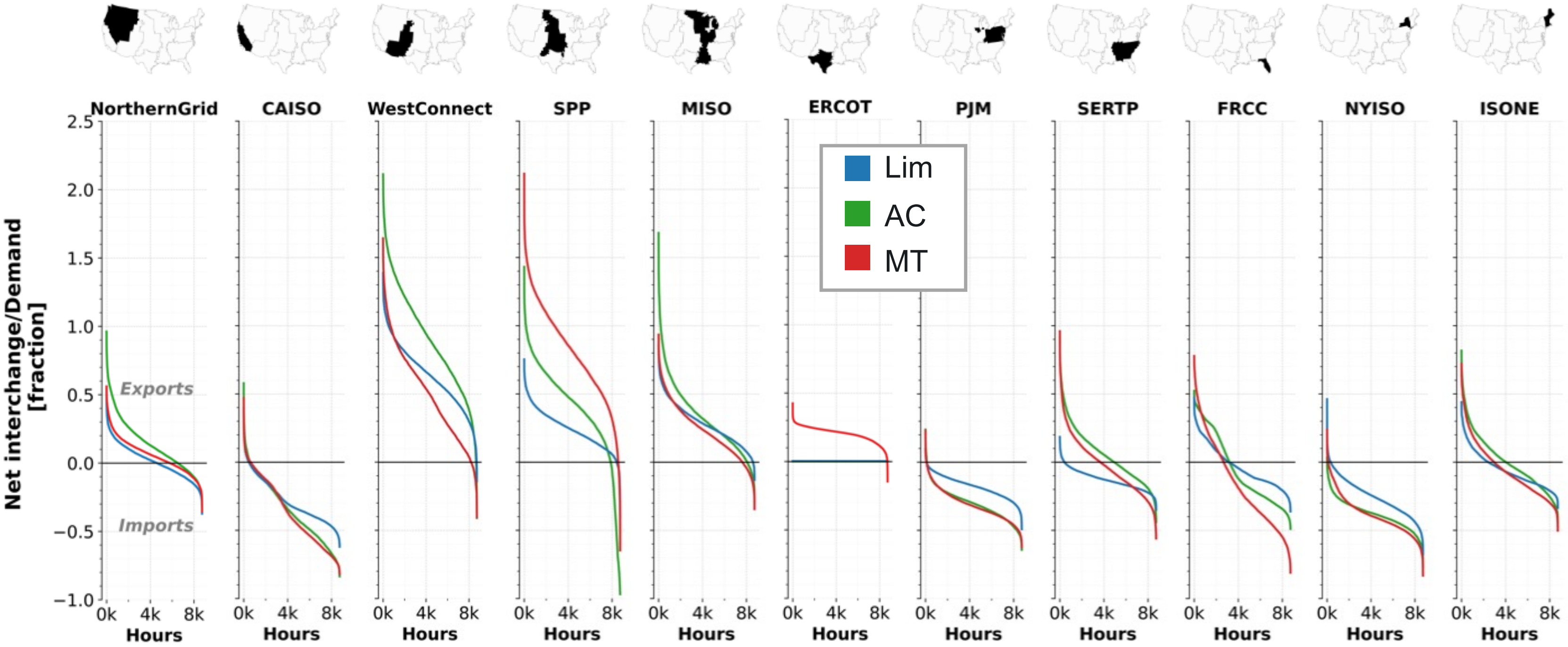
MT-HVDC Transmission Expansion
Overview (CONUS, 2035)



DRAFT RESULTS

Sources: National Transmission Planning Study, 2024 (forthcoming)

Increased inter-regional transfers demands improved inter-regional co-ordination



DRAFT RESULTS

Sources: National Transmission Planning Study, 2024 (forthcoming)

Some takeaways from NTP relevant for IRTOC

- Opportunities and challenges for ISOs/RTOs on inter-regional co-ordination with high-levels of decarbonization
  - HVAC and embedded HVDC work in tandem to improve contingency performance
  - Expanded inter-regional transmission is expected to require new operational frameworks to deal with new technology configurations (multi-terminal and meshed HVDC)

- In AC and MT-HVDC scenarios - more variation on interregional interfaces
  - Some regions become big importers/exporters, some are balanced annually (still import/export)
  - Very different operating regimes (solar/wind variability)
  - Larger swings diurnally (driven by solar PV and storage)

- Larger absolute power exchanges
  - Relative to Limited intra-regional expansion, long-distance and large power transfers
  - Increased number of inter-regional tie-lines
  - Potential for new voltage overlays (EHV) e.g. 345 kV => 500 kV or 765 kV, HVDC

- NTP inter-regional scenarios could be useful starting points for further assessment of multi-stage and multi-region operations

DRAFT RESULTS

Sources: National Transmission Planning Study, 2024 (forthcoming)

Further IRTOC developments

Further building on inter-regional operations in IRTOC

- **Geographical focus**
  - Region: Subset of the Eastern Interconnection e.g. SPP – MISO, MISO – PJM

- **Benchmark** expected (large-scale implementation)
  - Choose an appropriate NTP scenario
  - Global co-optimization (energy & reserves), perfect-foresight (DA, hourly) i.e. c7 configuration (CONUS-wide)
    - ✓ Potential basis to derive sub-regional interchanges & reserve requirements for IRTOC (c2 and c8)

- **Large-scale** implementation of coordination configurations
  - Multi-region and multi-stage at-scale
  - Implementing coordination configurations (c2 and c8)
    - ✓ Anticipate computational challenges
    - ✓ Anticipate convergence challenges on distributed algorithms to coordinate large number of constraints
  - Small number of constraints initially to develop the framework and generate insights
  - Framework can then be utilized for future computational and algorithm development
  - Smaller sub-system to focus on two-terminal HVDC (anticipate complexity of MT-HVDC and meshed-HVDC)
  - Imperfect foresight (forecast uncertainty – aim to use reasonable estimates)

Thank you

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