Integrated Planning for New England

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Training for New England Conference of Public Utility Commissioners

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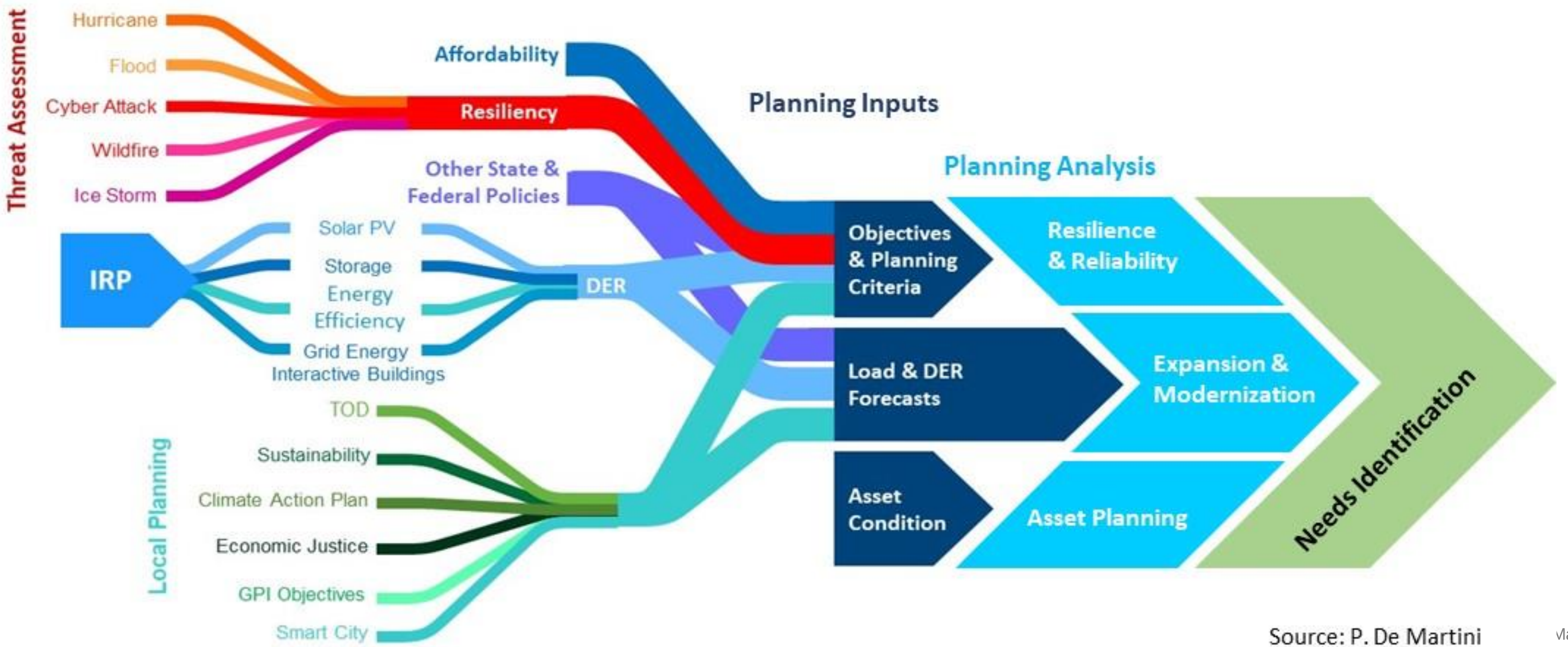
Topics for Discussion

- ► Overview of Integrated System Planning - Key Elements
- ► Focus on Areas for Alignment Across Resource, Transmission & Distribution Planning
- ► Deeper Look at Forecasting Load, Resources and Climate Impacts

The process framework for integrated system planning provided here should not be considered a prescriptive approach. Rather, it is most useful as a guide that provides a set of considerations regarding specific processes and methods that may serve the unique circumstances and objectives of individual jurisdictions and utilities.

Integrated System Planning

System planning is increasingly dependent upon Integrated Resource Planning (IRP)/bulk power use of distributed energy resources (DER) and local sustainability and resilience plans.



Source: P. De Martini

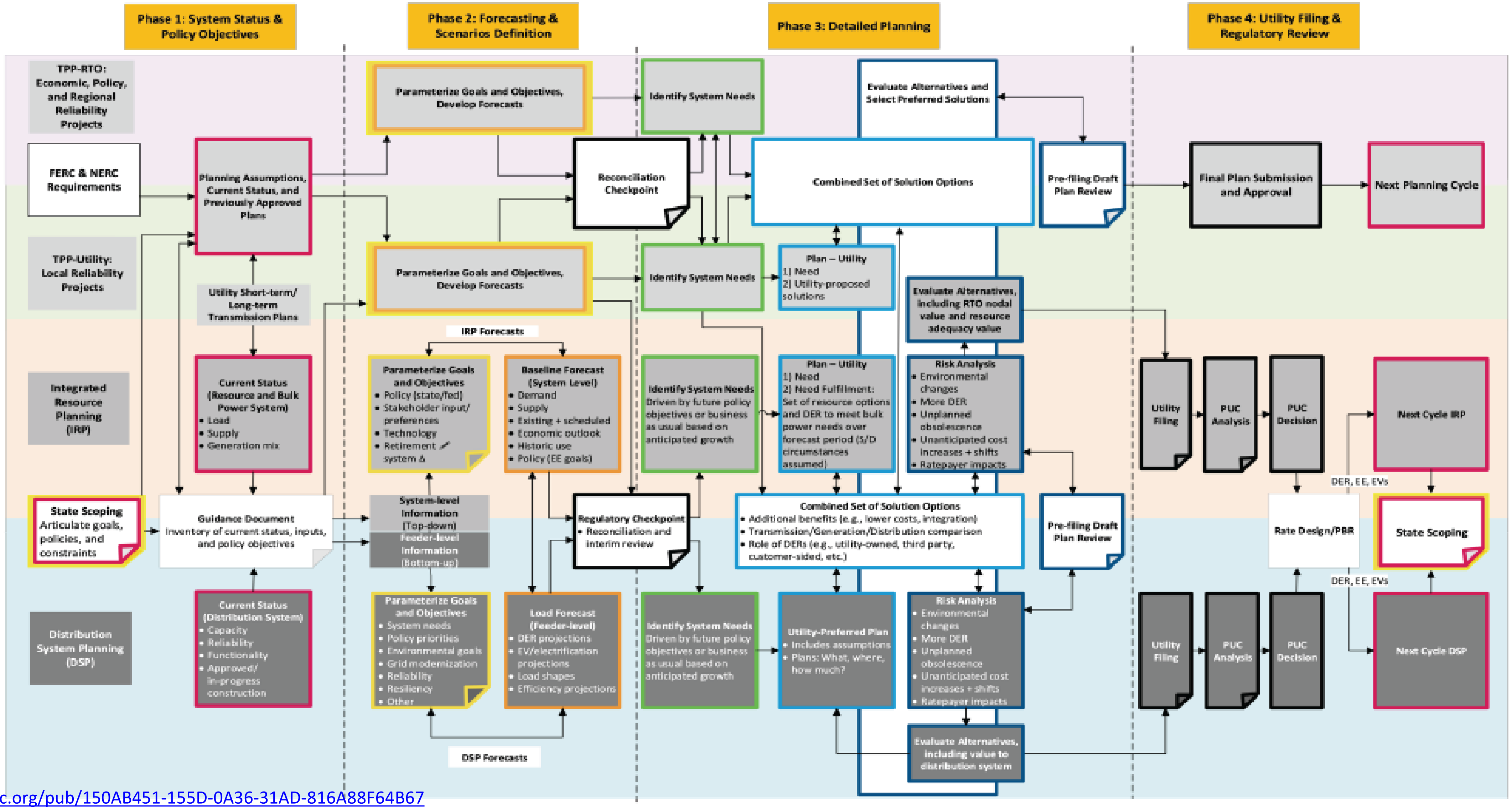
Integrated System Planning

Conceptually the elements can fit into a logical, aligned sequence.

Source: Hawaiian Electric

Integrated System Planning Multi-Entity Example

However, in practice there is significant complexity when integrating multiple processes and entities operating on different planning cycles.



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Integrated System Planning

Phase 1. Planning Objectives & System Status
Phase 2. Forecasting & Scenarios Definition
Phase 3. Detailed Planning
Phase 4. Utility Filing & Regulatory Review

- A fully integrated system planning process for any New England state would be a highly complex undertaking, if at all possible.
- However, it is possible to identify key points in the respective resource, transmission and distribution planning processes to ensure:
  - Consistent inputs and assumptions
  - Transparency regarding respective processes and key points of interdependency/alignment
  - Consistent consideration of operating criteria and conditions (e.g., weather)
  - Optimization of solutions to potentially address a greater set of needs
- There are opportunities for state commissions to consider the interdependencies of various dockets that inform and/or are informed by integrated system planning.

Phase 1. Policy Objectives & System Status

Policy Objectives

- **An objective is a desired outcome with an associated timing and/or performance criteria.**
- For example, objectives may include (a) specific customer, policy, and/or business outcomes and (b) associated timing and/or performance requirements. Objectives inform what is needed, by when, and guide the subsequent steps in the process.

System Status

- **Assessment of the current asset condition and operational performance of a system is essential to determine compliance with planning criteria and service standards.**
- Assessment includes determining the current condition of grid assets, asset loading, asset utilization, and feeder and substation reliability. These assessments are done in relation to standards and operational performance criteria.
- Determining asset condition requires effective data on distribution infrastructure, including relative age, current condition, and stress conditions experienced (e.g., faults and overloads), among other aspects.

Policy Objectives & Criteria Shape Integrated System Planning

Environmental Issues / Other Constraining Factors in Resource Planning

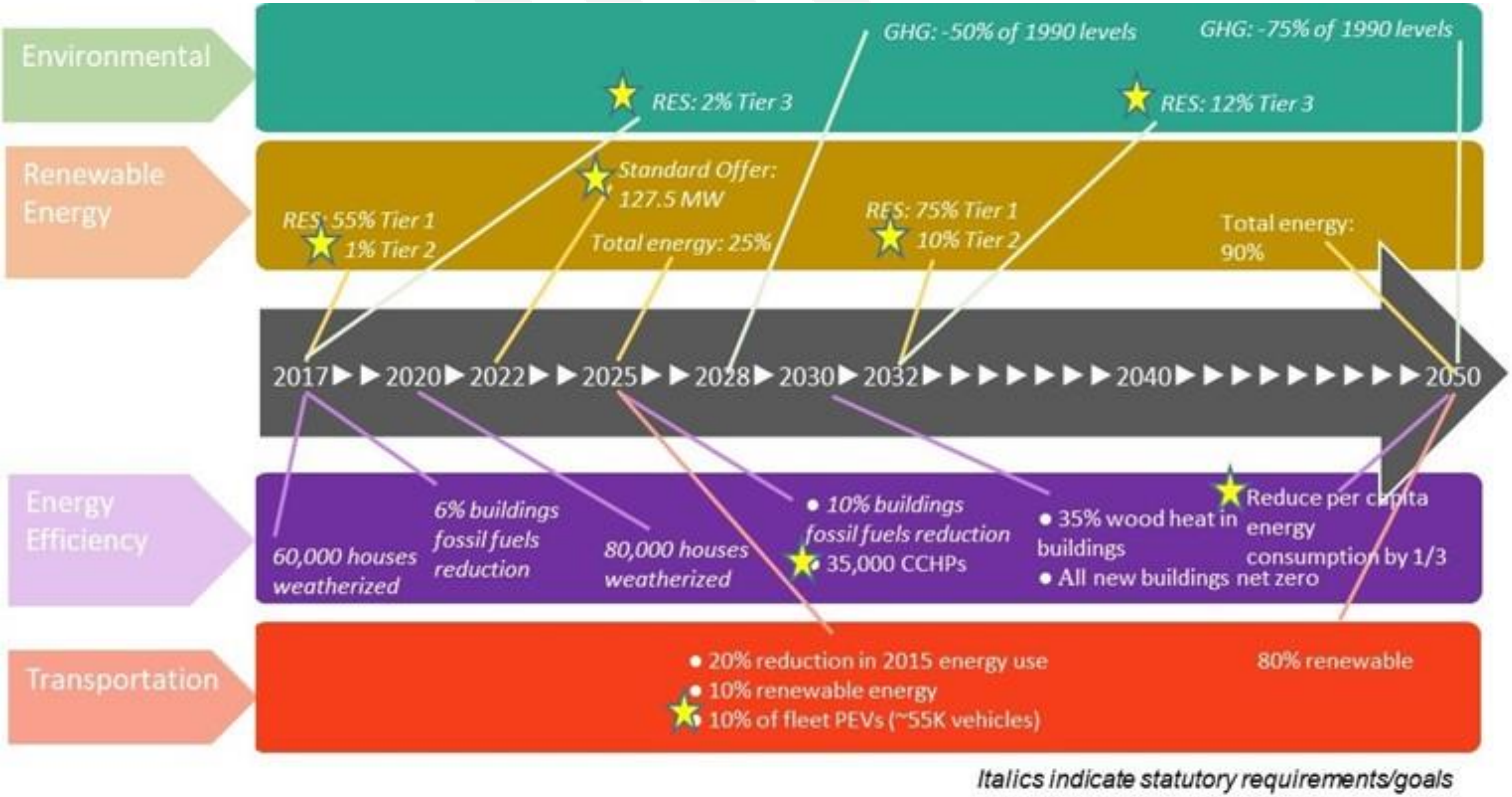
- Federal and state air quality and water usage laws and regulations
- Other federal regulations – FERC, NERC
- Other state requirement — e.g., energy efficiency, solar photovoltaics (PV), targets for other DERs
- Existing generation fleet
  - Age
  - O&M costs
  - Upgrade or life extension costs
- Transmission / distribution constraints
- Fuel supply constraints

New England Planning should be driven by state climate mitigation & adaptation

- Rhode Island: Net zero 2050 (80% below 1990 by 2040; 45% by 2030) – 2021 Act on Climate
- Maine: 80% renewable by 2030; 100% by 2050 – LD 1494 (2019)
- Connecticut: 45% below 1990 economy-wide levels by 2030; 80% by 2050 (P.A. 08-98)
- Massachusetts: 85% (of 1990 level) economy-wide by 2050 – Senate No. 9 (2021)
- Vermont: 80% below 1990 GHG emissions by 2050 – Act 253 of 2020
- New Hampshire: unofficial 80% target by 2050 from 2009 Climate Action Plan

Vermont Example (c. 2019)

State policy goals inform system planning objectives.



Phase 2. Forecasting

- **Load & DER forecasts: Distribution planning requires a closer examination of the potential changes to load and DERs at the level of a substation, feeder, and in some cases sections of a feeder.**
  - System forecasts of DER adoption and use inform the development of more “bottom-up” granular locational forecasts that are applicable to the specific distribution planning areas under assessment. The aggregate results are typically compared with system-level projections.
  - Ideally, the granular distribution forecasts in aggregate comport with the system-level forecasts.

- **Climate Forecasts: Policymakers and planners need to understand changes in local weather to assess grid risks.**
  - Climate is a description of a long-run average over a large area, and weather is the realization of climate in a small geographic and time scale.
  - “Downscaling” is required to transform low-resolution environmental information into high-resolution spatial and temporal scales to assess grid infrastructure impacts.

Phase 2. Scenario Development

Scenarios generally address specific policy questions, or a range of plausible physical or operational constraints or changes in the existing system.

- In New England, scenarios may include several policy choices or constraints:
  - Transmission constraints or elimination of transmission constraints
  - Availability or lack of availability of specific types of resources (onshore wind, offshore wind, imports)
  - Higher or lower levels of behind-the-meter (BTM) generation, numbers of electric vehicles (EVs), or levels of electrification of currently fossil-fueled end uses
  - Seeking life extension for the Millstone or Seabrook facilities, or other major generating facility (alternatively, making a policy choice to prevent the premature retirement of facilities)
  - Early retirement of natural gas and other fossil fuel plants
- Climate change impacts should also be included.

Phase 3. Detailed Planning

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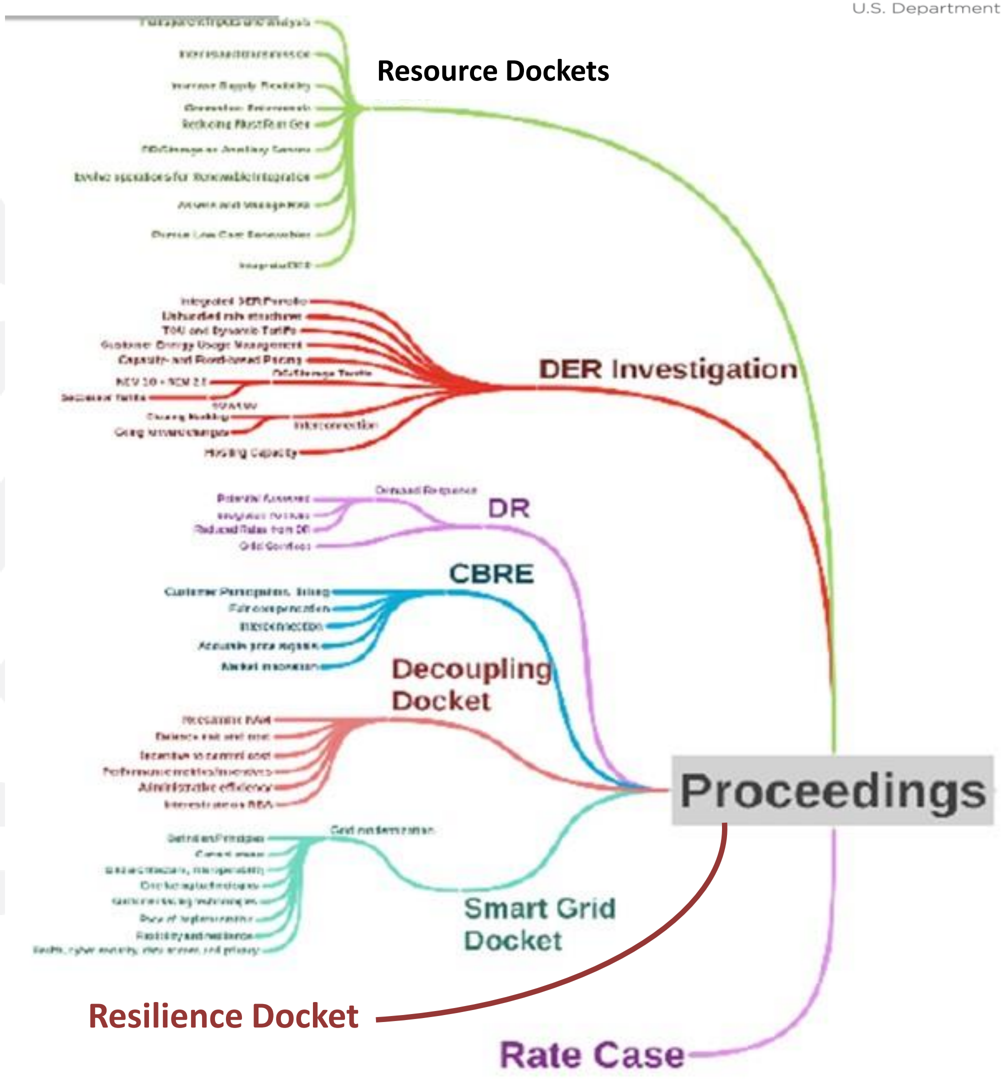
- **Grid engineering analyses** **are based on the laws of physics that ultimately dictate the physical operation of the electric system.**
  - These analyses inform grid needs identification and changes, upgrades and solutions that may be needed.
- **Grid needs** **identification involves identifying specific substations and circuits where planning criteria are already violated, or forecasted to become violated over the planning period.**
- **Solution Identification:** **Identify utility, customer, and third-party solutions that address multiple planning objectives to provide the greatest relative value.**
  - **This step is a key opportunity to identify solutions that address more than one need, including needs across resource, transmission and distribution planning.**
- **Long & Short Term Planning:** **Requires taking a holistic view to address both normal conditions and resilience needs to optimize solution expenditures equitably.**

Phase 4. Utility Filing & Regulatory Review

- Planning integration considerations include the interdependency of typically separate commission dockets in relation to planning steps and timing.

- Opportunities for state commissions to consider the interdependencies of various dockets that inform or are informed by integrated system planning.

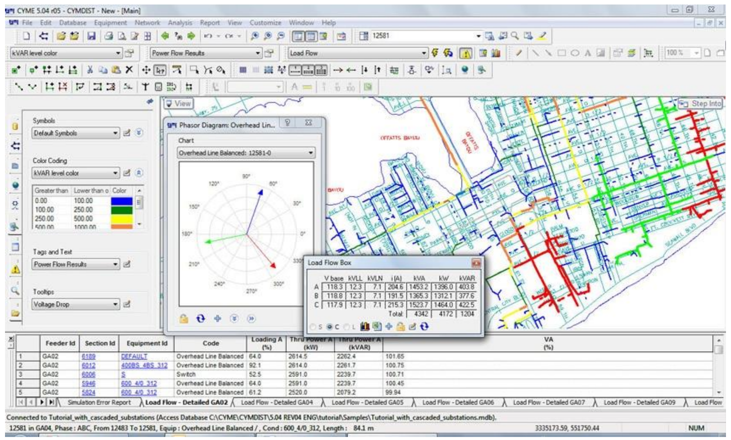


Takeaways on Key Elements of Integrated System Planning

- Integrating system planning processes is aspirational, but may not be practical writ large.
- However, key interdependent aspects of resource, transmission and distribution planning are ripe for alignment:
  - Planning Objectives and Criteria
  - Load, Resource, and Climate Forecasts and Assumptions
  - Grid Needs and Solution Evaluation
- Identifying regulatory docket interdependencies can enhance system planning and outcomes.

Load Forecasting – Current Best Practices

- **Load Forecast** advanced practices are granular load forecasts
  - Granular in time – Forecasts for all 365 days x 24 hours = 8,760 hours per year
    - Feeds into advanced modeling of resources
  - Granular in space – Forecasts at the circuit and transformer level
- A diverse set of tools are used to create these forecasts
  - LoadSEER
  - CYMEDIST
  - SYNERGI
  - GridLab-D
  - Econometric models
  - Probabilistic forecasting techniques
  - End-use models
- Judgement and company projections can form basis of forecasts



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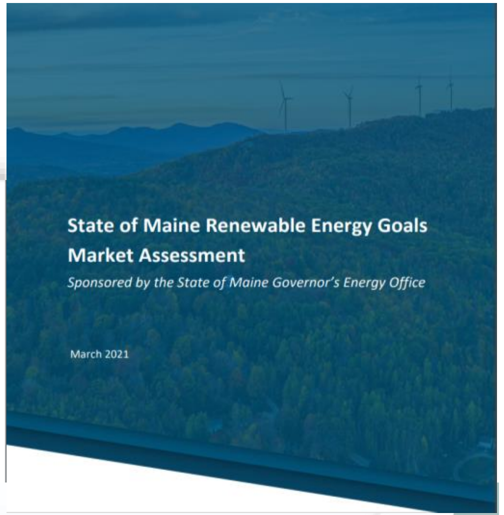
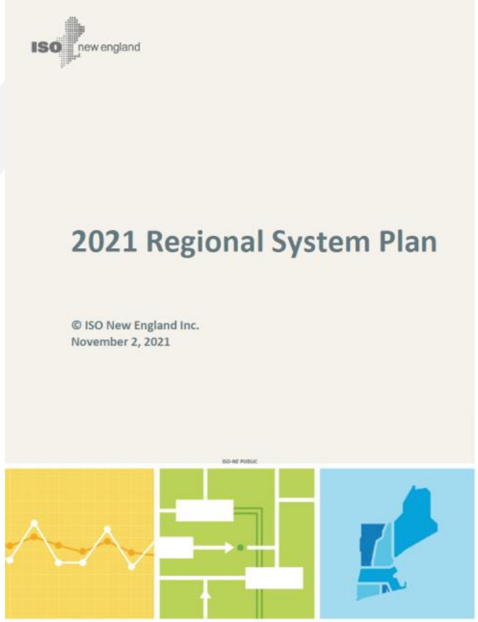
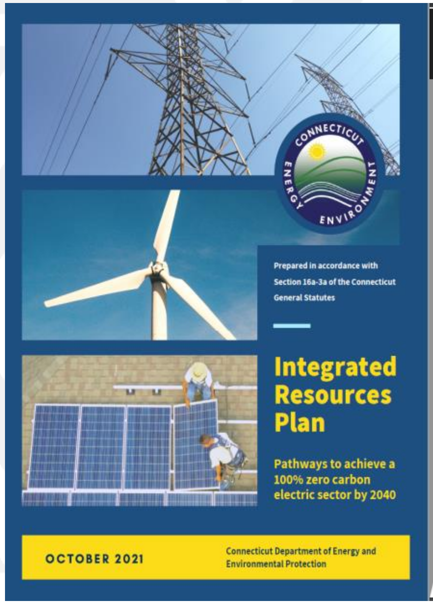
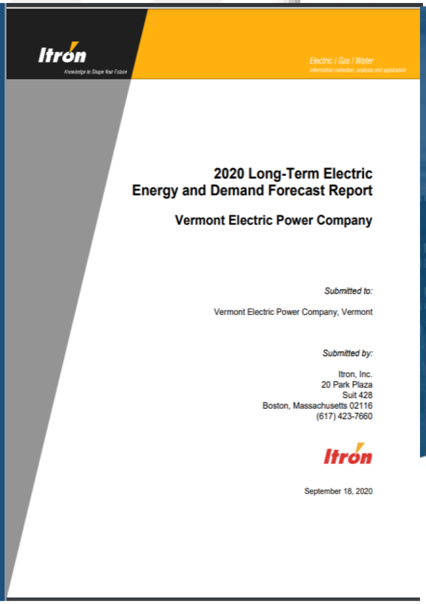
Load Forecasting in Current New England Resource Plans

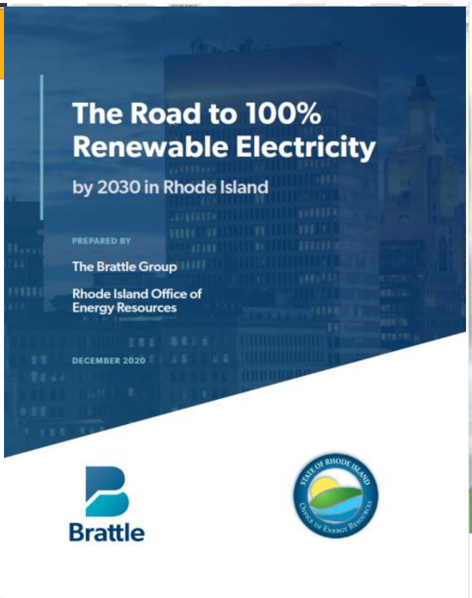
- New England states' resource plans documentation of load and DER forecasts:
  - Mix of econometric and end-use models
  - Several plans included granular load forecasts
  - Several plans included granular DER forecasts
  - ISO-NE's forecast underlies some plans' projections

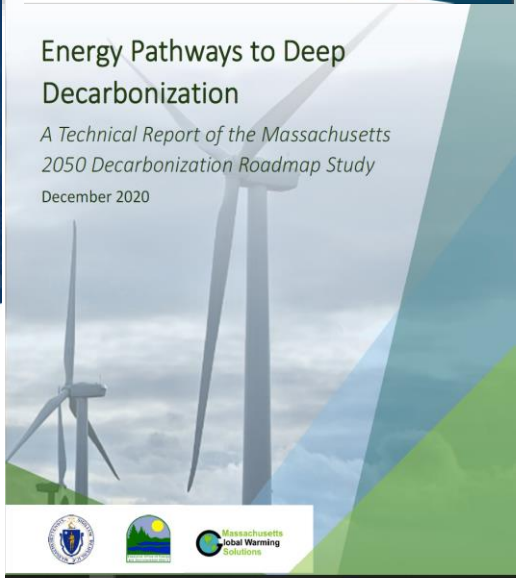








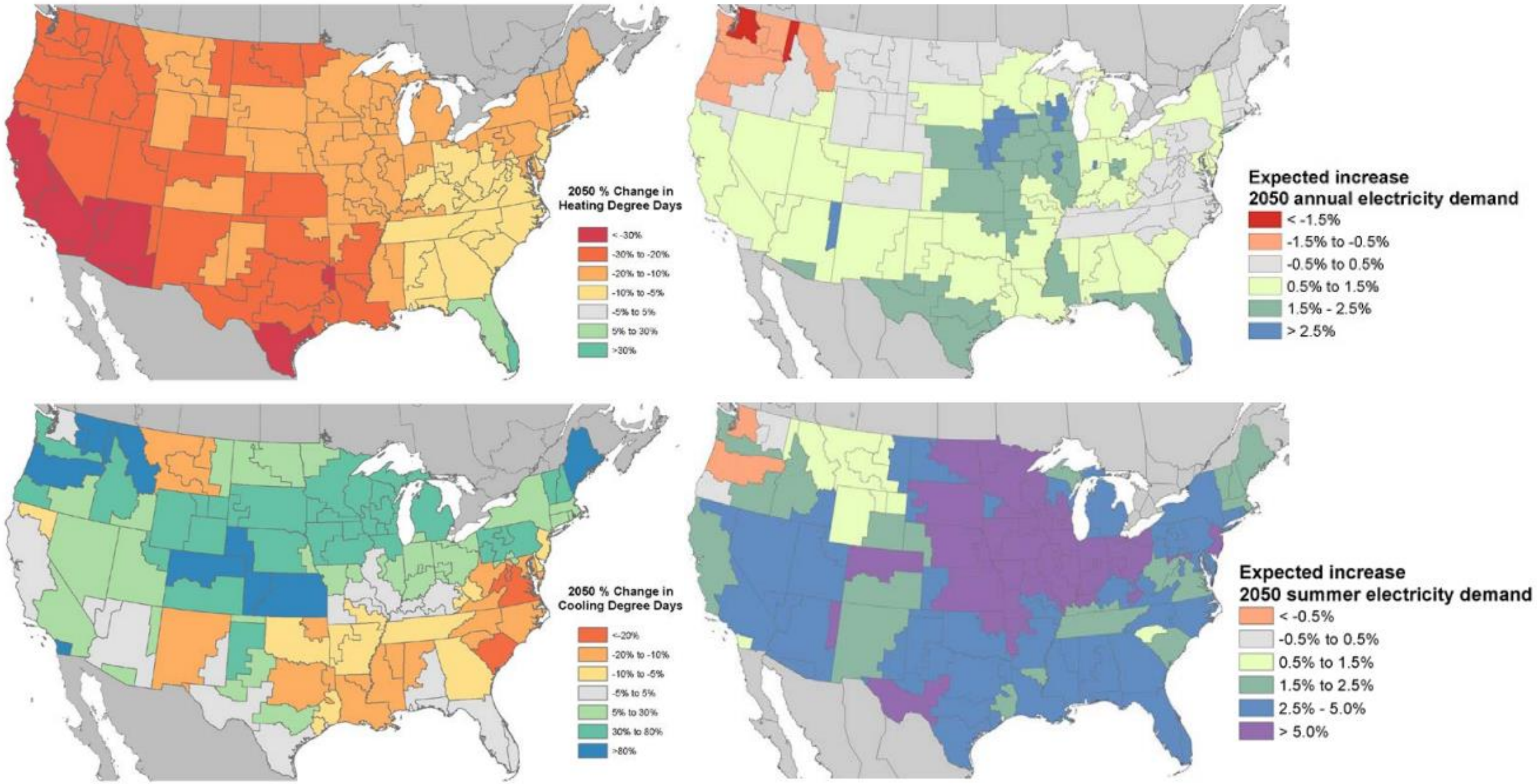




New Challenges for Load Forecasting – Climate Change

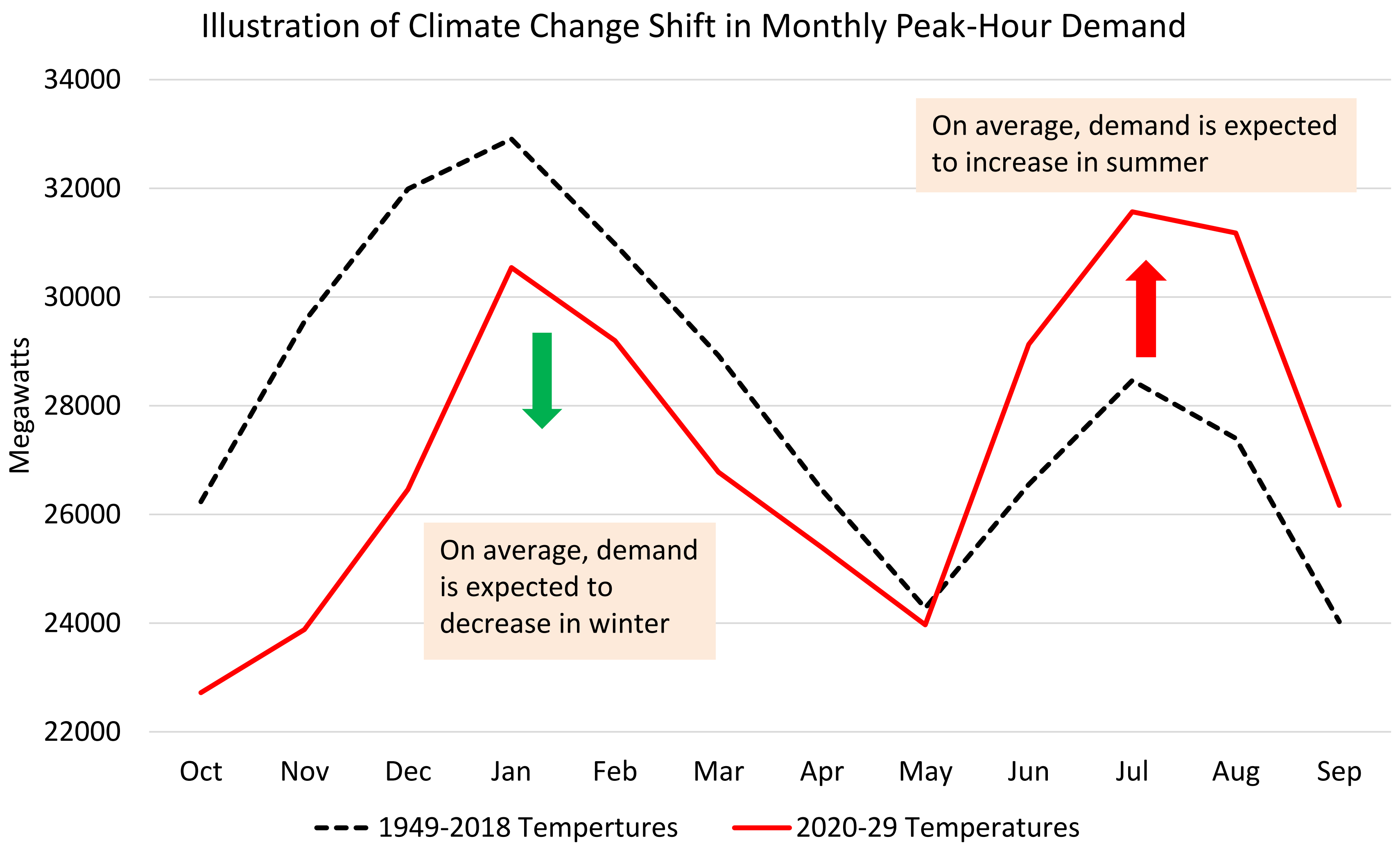
- Impact of climate change
  - Temperature increase
  - Precipitation patterns
  - River flows and hydro electric generation
- Load forecasting
  - Demand
  - Peak load
- Example studies
  - Demand projection [1]
  - Peak load forecasting [2]

Load Projection in 2050 [1]



[1] P. Sullivan, J. Colman, and E. Kalendra, *"Predicting the Response of Electricity Load to Climate Change,"* NREL Technical Report, NREL/TP-6A20-64297, 2015.
[2] D. Burilloa, M. V. Chester, S. Pincetl, E. D. Fournier, and J. Reyna, "Forecasting Peak Electricity Demand for Los Angeles Considering Higher Air Temperatures Due to Climate Change," *Applied Energy* 236 (15): Feb. 2019.

NW Power Plan Example – Downscaled Climate Data (Rather than Historic Data) Shifts System Peak



Dashed line represents monthly average peak-hour demand based on historic temperatures from 1949-2018.

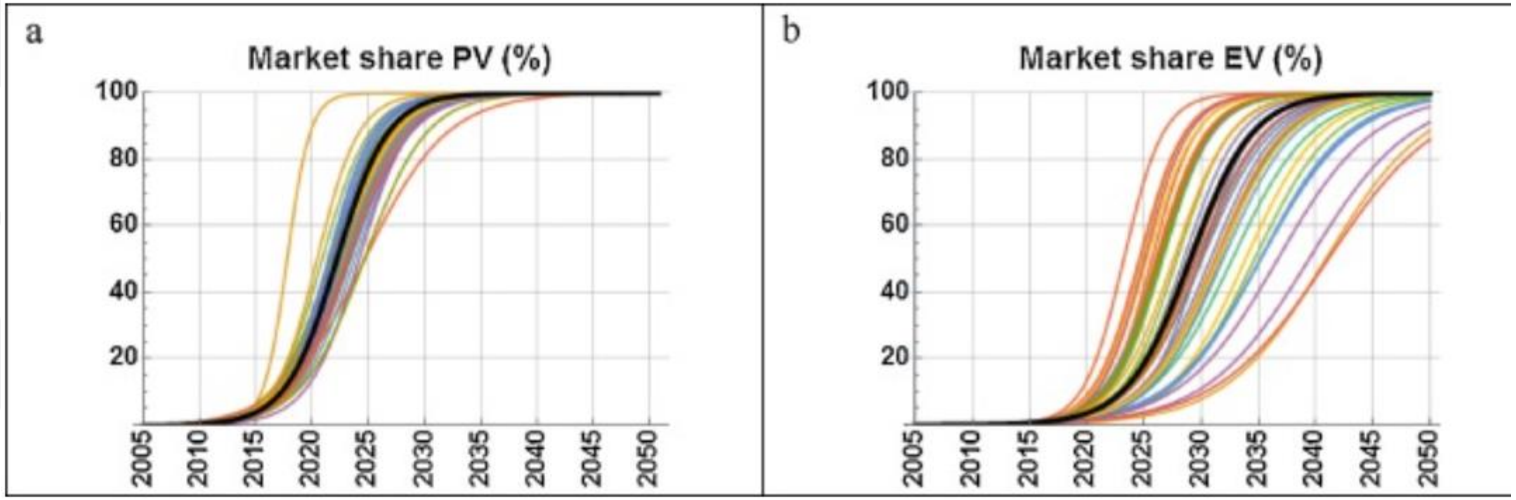
Solid line represents monthly average peak-hour demand based on forecasted climate change temperatures for 2020-29.

[1] Because this chart was created in 2019, historic temperatures (and therefore demand forecasts) for that year were not available.

From John Fazio, Northwest Power and Conservation Council, November 2021, [Presentation to the National Council on Electricity Policy](#).

Current Forecasting Best Practices (1)

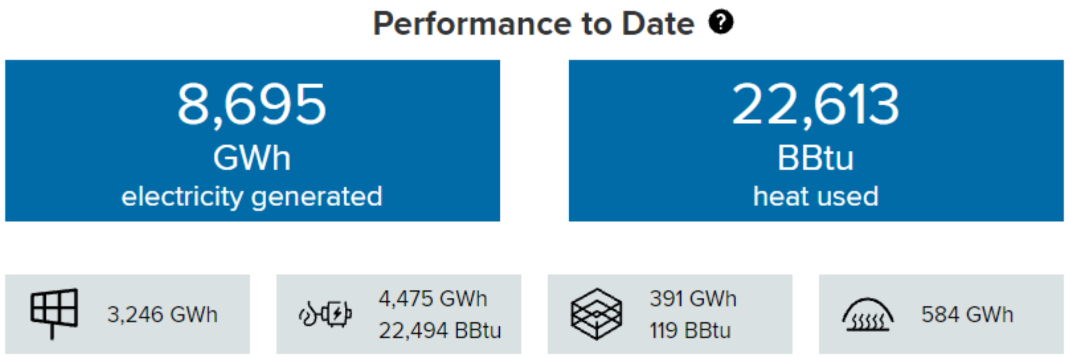
- **DER forecasts**
  - Some utilities use **econometric methods** to analyze the historical relationship between DER adoption and other economics variables to forecast future adoption.
  - Some utilities forecast DER adoption by fitting innovation diffusion curves to historical data, typically using the **Bass diffusion model.**
    - Requires a sufficient history of adoption
    - Not always feasible for DERs in nascent stage or those experiencing truly disruptive innovation
    - Bass diffusion optimizes three parameters (P - innovators, Q - imitators, and M – potential adopters) to explain monthly adoption patterns
  - Utilities can use tools such as **Gridlab-D, WattPlan Grid**, and **LoadSEER.**



Source: van der Kam et al. 2018

Current Forecasting Best Practices (2)

- **DER forecasts, cont.**
  - Some utilities start with top-down, system-wide DER forecasts that they disaggregate between substations.
  - California's [Distribution Forecasting Working Group Final Report] describes three classes of disaggregation techniques:
    - **Proportional allocation** - Disaggregates the DER forecast to circuits based on utility data for the circuit (load, energy, or number of customers)
    - **Propensity models** - Base disaggregation on customer characteristics that are used to compute a propensity score. Propensity models could be estimated using ZIP code data, where models relate historical adoption to customer characteristics in each ZIP code
    - **Adoption models** - Use a bottom-up adoption forecast based on observed adoption patterns and estimated adoption model parameters; includes S-Curve/Bass Diffusion Models
  - Utilities with granular data can predict where customers have a higher propensity for DER adoption based on characteristics such as energy use, weather, number of customers, and geographic location.
- For example, NYISO is relying on the NYSERDA DER database as an interim source for its forecasts. The database includes DER locations across the state, aggregate DER data, and current and past performance data from New York DER projects.



Current Forecasting Best Practices (3)

- **EV forecasts**
  - Utilities using best practices forecast customers' propensity to adopt EVs with **propensity models** (using regression techniques or machine learning to identify key variables correlated with customer adoption) or **Bass diffusion models** (to fit diffusion curves) at a granular (ZIP code) level based on characteristics such as energy use, weather, number of customers, and geographic location.
  - EVs are then allocated to the circuit level based on factors such as load, energy, or number of customers.
  - Other tools are also being explored, including transportation modeling to simulate EV charging behaviors using **POLARIS** (Planning and Operations Language for Agent-based Regional Integrated Simulation), an agent-based model developed by Argonne National Laboratory.
  - Hawaiian Electric Integrated Grid Planning example:
    - Integral Analytics developed the EV forecast adoption model by combining macro-level Bass Diffusion models with geospatial customer-level, agent-based models through its proprietary load forecasting tool, LoadSEER.
    - Total number of vehicles was segmented into charging profile segments. Hourly changing profiles were developed using charging station telemetry, load research, and AMI data.
    - Hourly load modeling and statistical sampling were used to develop a core set of EV charging profiles
  - Some utilities are working with Electric Vehicle Supply Equipment companies to develop EV load profiles for various EV charging use cases.

System Level vs. Distribution Level Forecasts

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Resource planning is usually at system level

- Loads forecasted at a system level
- Generation meeting load at the system or other high aggregation level — e.g., state level
- BTM generation included in IRPs often at an aggregated system level
  - Distribution system and BTM generation tend to be areas of low visibility
  - Load forecasting models (listed earlier) can help with visibility

Integrated planning is at multiple levels

- A significant portion of new generation is connecting to the distribution system.
- To encourage more new generation to connect requires knowledge – where there is available capacity and where there are bottlenecks.
- Distribution-level data needed to assess:
  - What is happening BTM – PV, EV, and electrification
  - What is happening BTM is uneven for many reasons, but equity concerns are better addressed if spatial disaggregation is improved.
- Some of the load forecasting tools help provide spatial visibility.

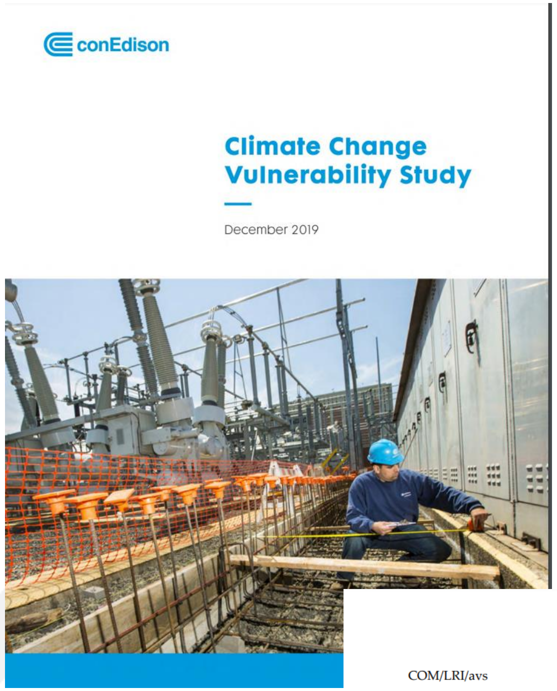
Advanced Forecasting Example – National Grid

- Since 2018, National Grid has generated and published 8,760-hour feeder level forecasts.
- Forecasts are used for local area planning assessments and non-wires alternative evaluations.
- A Marginal Avoided Distribution Capacity study is used to quantify the value of DER in targeted locations.
- In-house modeling combined with **GridLAB-D**™, an open-source, simulation-based modeling environment that enables detailed power flow solutions, generates 8,760 load profiles for every feeder.
- High-performance cloud computing, such as Amazon Web Services, improves the overall computational process.
- EV charging behaviors of both residential and non-residential customers are simulated using the **POLARIS** model.
- Annual peak load forecasts incorporate projected economic and demographic impacts and anticipated technological advances and policy objectives.
- Future enhancements will incorporate probabilistic forecasting techniques.

https://jointutilitiesofny.org/sites/default/files/NG_2020_DSIP.pdf

Intersection of Integrated Planning and Resilience

- Distribution utilities are also beginning to plan for resilience to climate impacts, which affect planning resources and infrastructure funding.
- Con Edison's study is often cited as the gold standard for assessing and addressing climate vulnerabilities.
- The California PUC has ordered utilities to develop similar plans.
- Florida's Storm Hardening Plans and PSE&G's Energy Strong offer examples of utilities planning to address tropical storm and other intense storm impacts.
- The State of Maine issued a climate vulnerability assessment that is related and potentially instructive.



COM/LRI/avs Date of Issuance 9/3/2020

Decision 20-08-046 August 27, 2020

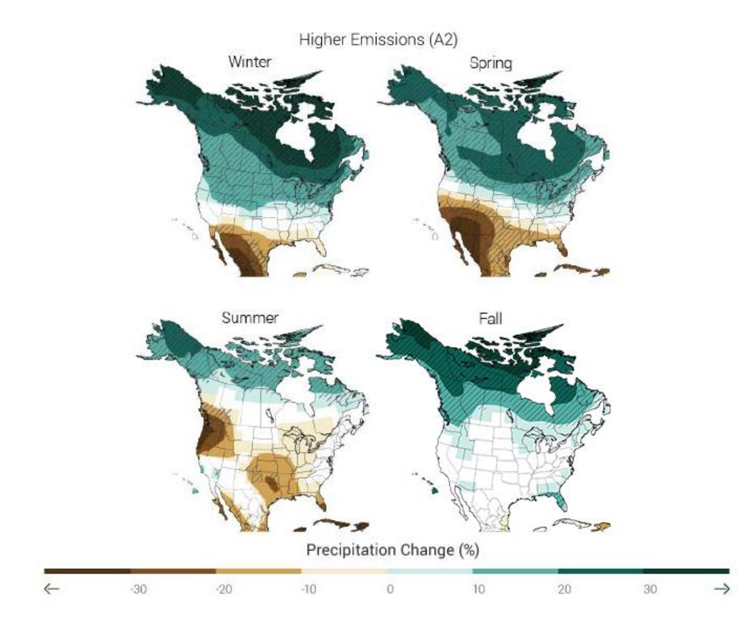
BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Consider Strategies and Guidance for Climate Change Adaptation.	Rulemaking 18-04-019

DECISION ON ENERGY UTILITY CLIMATE CHANGE VULNERABILITY ASSESSMENTS AND CLIMATE ADAPTATION IN DISADVANTAGED COMMUNITIES (PHASE 1, TOPICS 4 AND 5)

Intersection: Climate Projections and Integrated Planning, Plus Resilience

- Best-practice resource plans investigate the impact of climate change on resource availability (and loads)
  - Large thermal generation uses water for cooling
  - Higher incoming water temperatures can lead to reduced efficiency and curtailments, or make it harder to meet effluent requirements
  - Climate change can affect seasonal hydroelectric generation.



Maps show percent change in precipitation in each season for the higher emissions case in the 2071–2099 time period compared to 1970–1999. Source: [The Third National Climate Assessment](#).

- Some examples:
  - [TVA's 2019 IRP](#) noted the potential for additional cooling capacity costs or deration of thermal plants.
  - [Southwestern Public Service's 2018 IRP](#) studied groundwater availability for cooling a coal plant, leading to a change in running the plant for peaking operation only.
  - Pacific Northwest projecting changes in operation of hydro system
    - [2021 Northwest Power and Conservation Council's 8th Power Plan](#) studied impacts of changes in Columbia River power output on the region's summer loss of load probability
    - [Tacoma Power's 2020 IRP](#) studied impacts on wholesale purchases due to potentially changed Columbia River power output

Limitations

- **Data**
  - A main limitation to forecasting granular DER adoption is the need for granular data.
  - Some utilities that have not yet implemented these forecasts cite the need for enhanced capabilities to collect and monitor granular data (such as from Advanced Metering Infrastructure, which will provide greater temporal and geospatial granularity).
  - Other utilities note that data quality for substations and circuit locations has been a barrier to more granular load forecasting.
    - Example: "Historically, data quality for substations and circuit locations has been a barrier to their use for more granular load forecasting due to lack of metering, meter data gaps, and abnormal system operations or configurations. This step required extensive use of data analytics to identify and remove load transfers, outages, data gaps, and data recording errors. Load transfers were of particular importance since they can be confused with load decreases or growth." Central Hudson Gas & Electric Corporation's 2020 DSIP report
- **Need for enhanced probabilistic forecasting techniques**
  - Another often mentioned limitation to advancing forecasting practices is the need for enhanced probabilistic forecasting techniques for variabilities in weather, economic growth, proliferation of DER, etc.—which can all impact load.

Takeaways on Distribution and Integrated Planning

- ► Distribution planning historically focused on:
  - ■ Operating safely – utility workers & general public
  - ■ Meeting customer power needs
  - ■ Meeting customer power quality needs
  - ■ Meeting customer reliability needs
- ► Cost – service for a fair and reasonable cost
- ► All of these focuses remain valid! But now:
  - ■ Generation also at distribution voltages
  - ■ Planning processes include new feedback loops
  - ■ Planning goal – extract value from customers' DERs
- ► Climate variability is increasingly straining the system
  - ■ Assessing climate vulnerabilities
  - ■ Planning to harden the system

Projected Increases in the Number of Days over 90°F

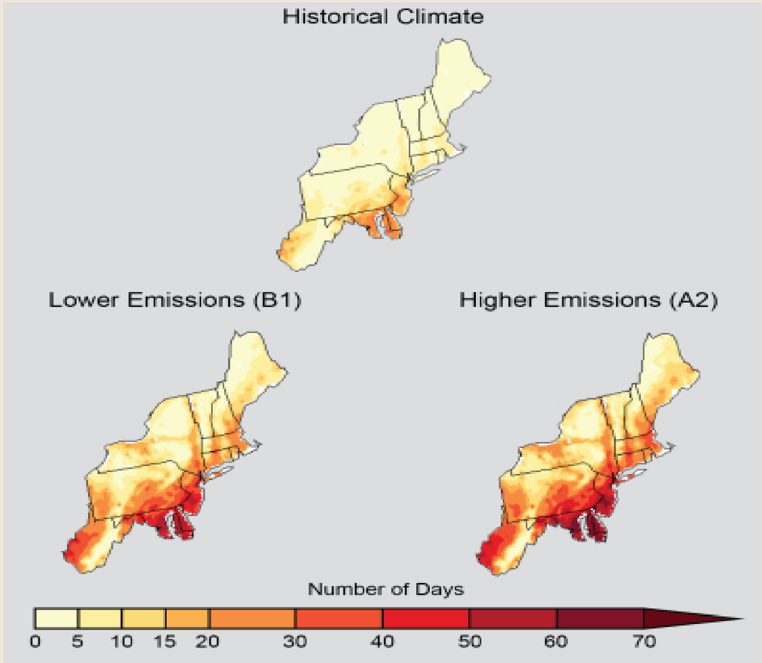


Figure 16.2. Projected number of days per year with a maximum temperature greater than 90°F averaged between 2041 and 2070, compared to 1971-2000 (Historical Climate), assuming continued increases in global emissions (A2) and substantial reductions in future emissions (B1). (Figure source: NOAA NCDC / CICS-NC).

Source: Horton, R., G. Yohe, W. Easterling, R. Kates, M. Ruth, E. Sussman, A. Whelchel, D. Wolfe, and F. Lipschultz, 2014: Ch. 16: Northeast. Climate Change Impacts in the United States: The Third National Climate Assessment, J. M. Melillo, Terese (T.C.) Richmond, and G. W. Yohe, Eds., U.S. Global Change Research Program, 16-1-nn.

Questions Public Utility Commissions Can Ask

- What models are being used?
  - How does the utility forecast DER adoption?
  - How does the utility quantify the impact of DER adoption?
  - Are models derived from proven theoretical methods?
- What are the modeling inputs?
  - What forecasts are utilities using as inputs to other forecasting models and how were those developed?
  - Are potential climate change impacts to forecasts being considered and, if so, how?
  - Are the assumptions reasonable?
    - Are the assumptions objective (based on objective data, for example) or subjective (based on expert opinion, for example)?
    - Are assumptions valid (do parameter estimates align with those found in existing research, for example)?
  - Are proper methods and data used?
    - Are methods disclosed?
    - Are they understandable?
    - Is the data reliable and valid?
    - What kind of data limitations exist?
    - Is the data readily accessible?

DER Integration into Wholesale Markets

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Training Webinars on Electricity System Planning
for New England Conference of Public Utility Commissioners
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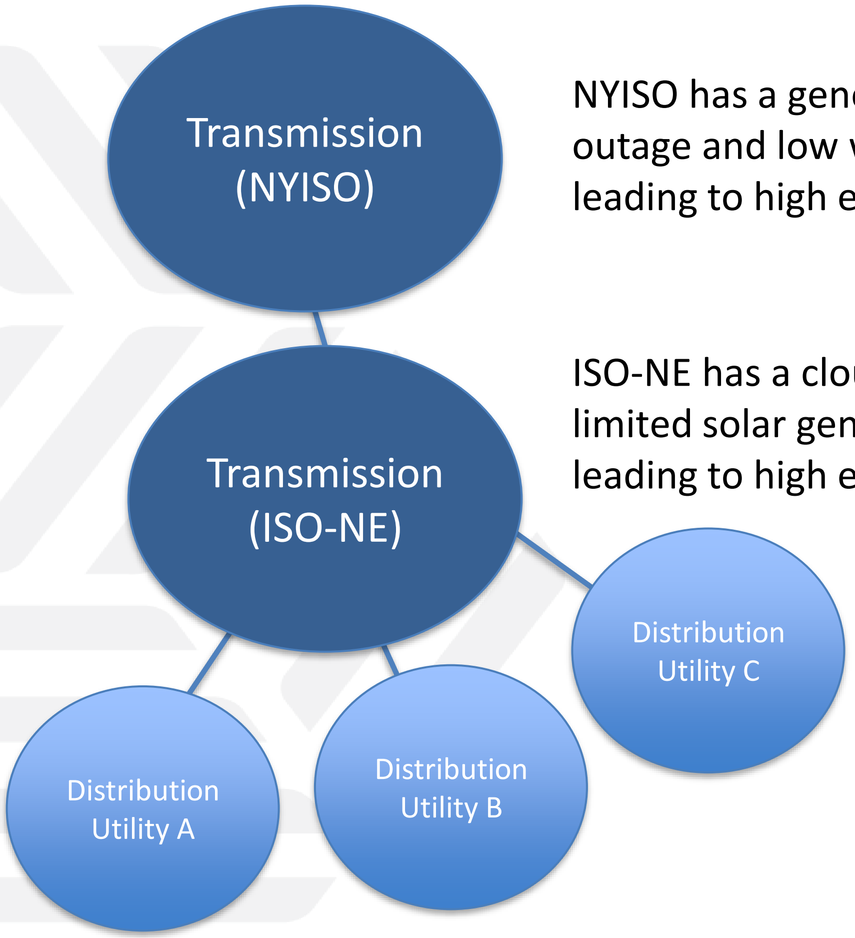
This presentation was funded by the U.S. Department of Energy's Grid Modernization Laboratory Consortium.

Overview

- Background: Distributed energy resource (DER) integration into wholesale markets
- Barriers to DER integration
- Nearer-term priorities for DER integration
- Longer-term priorities for DER integration
- Key considerations for public utility commissions
- Questions public utility commissions can ask

Background: What is DER integration and why is it important? (1)

- “DER integration” refers to the integration of DER into distribution system operations and wholesale markets and operations, enabling closer coordination between distribution (D) and transmission (T) system planning and operations.
- Better T-D coordination will reduce required electricity system investment and operating costs.
- DER integration covers a wide range of areas: DER interconnection, T&D planning, data access and communication, distribution system operations, utility regulation and tariffs, and wholesale markets.



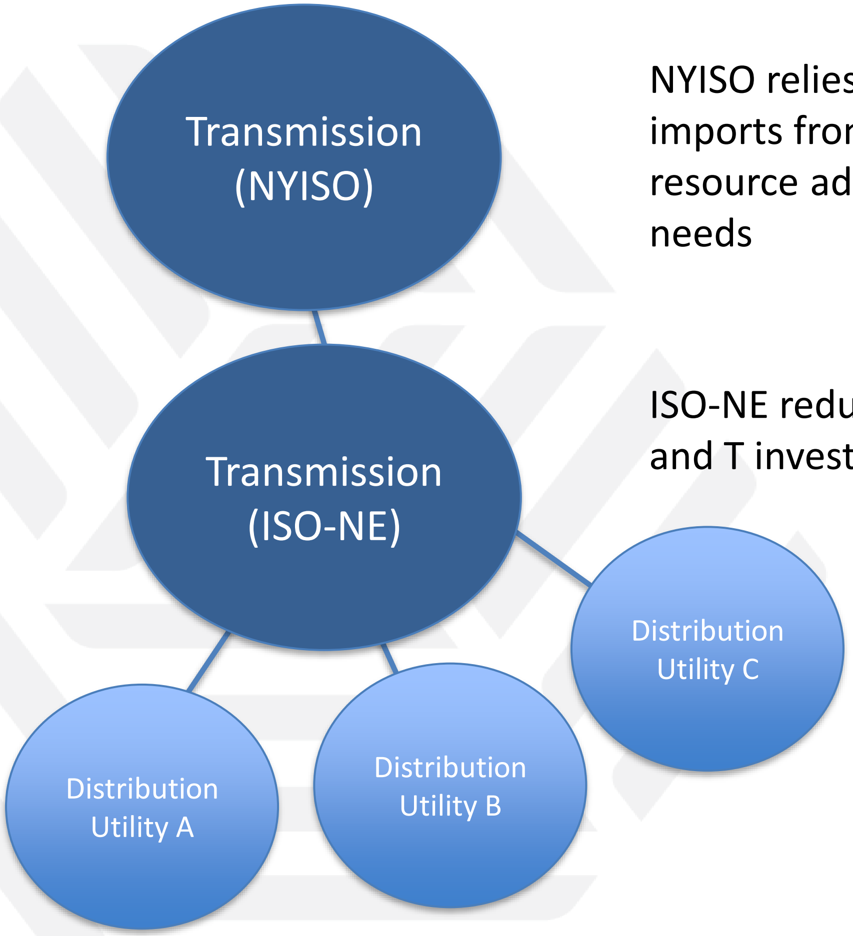
NYISO has a generator outage and low wind, leading to high energy prices

ISO-NE has a cloudy day with limited solar generation, leading to high energy prices

Coordinated T-D operations example

Distribution customers with storage shift discharging to system peak hours, and customers with responsive load reduce output (e.g., EVs charge as little as possible).

Background: What is DER integration and why is it important? (2)



NYISO relies more on imports from ISO-NE to meet resource adequacy (RA) needs

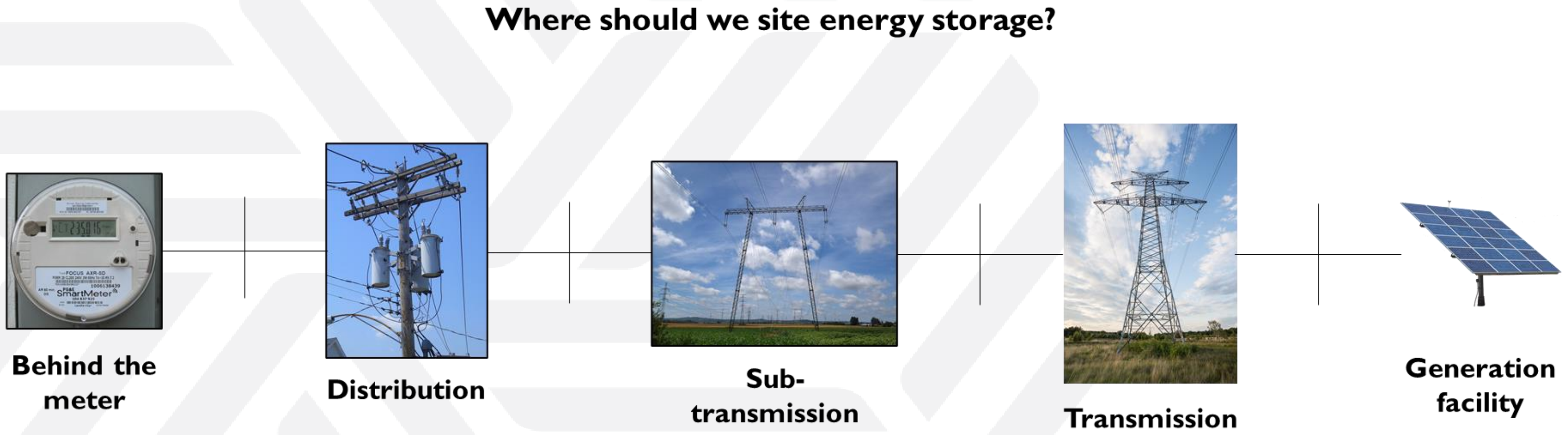
ISO-NE reduces total RA need and T investments

Coordinated T-D operations example

Distribution customers invest in a significant amount of distributed generation, distributed storage, and load management that is coincident with ISO-NE and NYISO peak demands.

Background: Storage placement illustrates why DER integration is important

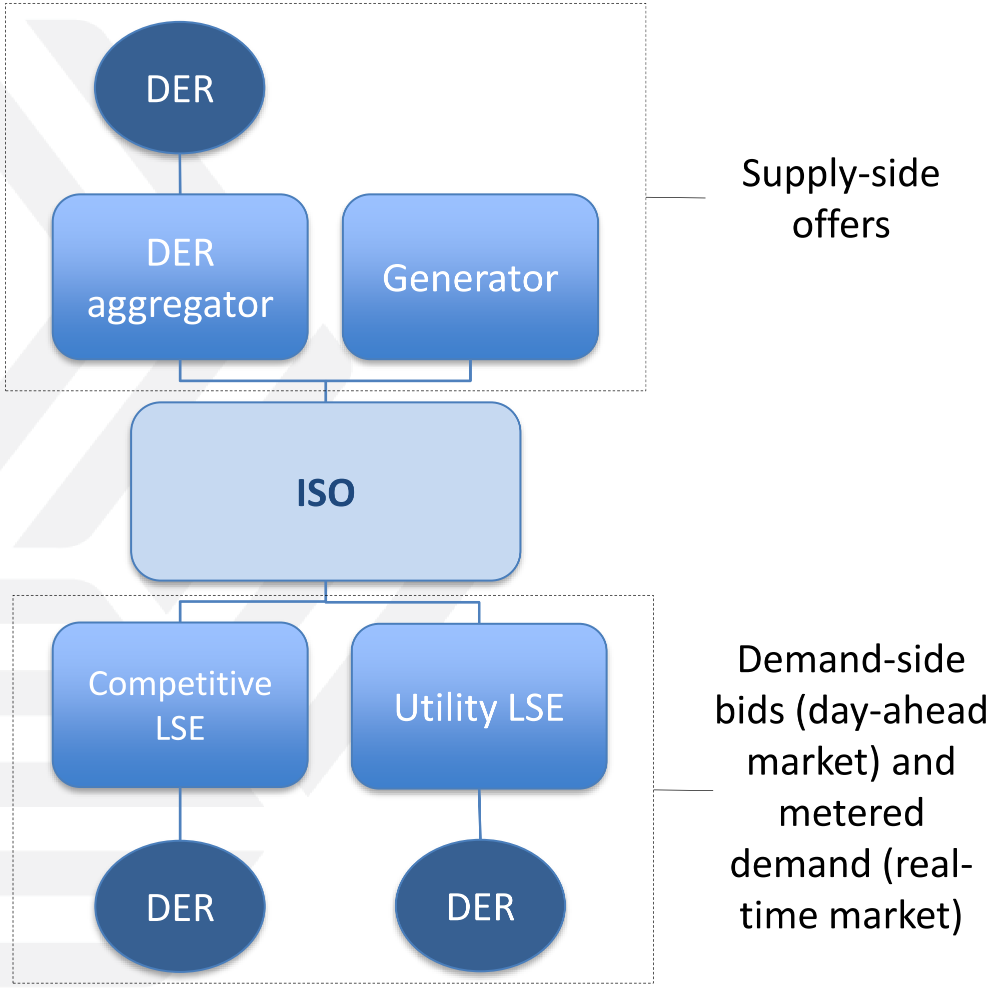
- Better coordination between D and T systems can resolve the question of how much storage should be optimally located in different parts of the electric grid, based on where it has the most value for the lowest cost.



- From a regulator's perspective, it's important to think about "value and cost to whom"?

Background: Approaches to DER participation in wholesale markets

- Under FERC Order 2222, DER can participate on the supply side individually or through aggregation by making offers directly into ISO markets.
  - ISO directly settles with DER owner or aggregator
- DER can also participate in ISO markets on the demand side through LSE demand bids or metered demand.
  - ISO settles with LSE, DER offsets LSE ISO charges, and LSE settles with DER owner or aggregator.



Key elements in DER integration

Distribution Interconnection
Utility assesses DER impacts on D system, determines whether D upgrades will be needed

Distribution Planning
Utility pre-emptively builds D infrastructure, determines upgrades that will be triggered through interconnection and how DER will be operated

Distribution Operations and Markets
Utility ensures D reliability, may operate DER to avoid reliability violations (and in the future potentially to minimize D costs subject to D security constraints)

Wholesale Markets
ISO ensures T reliability, operates markets for RA, day-ahead/real-time energy and ancillary services

Utility Regulation and Tariffs
State regulators determine utility incentive framework and approve tariffs and rates

Barriers to DER integration (1)

- **DER interconnection**
  - *Interconnection standards* – Many states have yet to adopt and implement IEEE 1547-2018 (focused on smart inverters and voltage support).
  - *Process enhancement and standardization* – Coordination among states is limited in terms of distribution interconnection enhancements (timelines, technical requirements, upgrade cost allocation).
  - *Interconnection costs* – Cost allocation methods are in flux. States are still at an early stage in allowing DER to avoid D upgrades in exchange for limiting generation or being curtailed in some hours (“flexible interconnection”).
- **Distribution planning**
  - *T-D planning coordination* – D utilities and ISOs have limited coordination on load/DER forecasts and engineering studies.
  - *Regional resource planning coordination* – Coordination is limited among ISOs, state PUCs and energy offices, utilities, generators, and DER developers on scenarios for regional resource development.

Barriers to DER integration (2)

- **Distribution operations**
  - *DER overrides* – Most utilities do not yet have processes for overriding ISO dispatch of DER aggregators, including outage communication capabilities.
  - *DSO functionality and grid investments* – There is a lack of clarity over future monitoring, communications, and dispatch/control needs and investment requirements.
- **Utility regulation and tariffs**
  - *Utility incentives* – Utilities may not have incentives to maximize the value of DER.
  - *DER tariffs* – Many utilities do not have time-varying, market-based tariffs for customers that can shift load and have behind-the-meter generation.
- **Wholesale markets**
  - *Demand participation* – Opportunities for intraday participation in ISO markets through demand bids are limited.
- **State-federal jurisdiction**
  - *Overlapping jurisdiction* – Federal-state jurisdiction over distribution interconnection, planning, operations, and markets remains unclear in some cases.

Nearer-term priorities

- **DER interconnection**
  - Adopting and implementing IEEE 1547-2018
  - Investing in interconnection process improvements, with some amount of regional or national standardization
  - Allowing static export limits for distributed generation paired with storage*
- **Distribution planning**
  - Coordinating DER/load forecasting for T-D systems; undertaking "what if" regional resource scenario analysis through regional fora
- **DER operations**
  - Developing transparent, non-discriminatory approaches to DER overrides that can evolve into more active distribution operations over time
  - Beginning to consider future models for distribution system operations and mapping out needed investments over time
- **Utility regulation and tariffs**
  - Exploring incremental improvements to utility performance incentives and time-of-use-based tariffs for DER customers
- **State-federal jurisdiction**
  - Establishing a FERC-state working group on distribution jurisdiction

* See, for instance, *Use of Operating Agreements and Energy Storage to Reduce Photovoltaic Interconnection Costs*, https://eta-publications.lbl.gov/sites/default/files/80556.pdf

Longer-term priorities

- **DER interconnection**
  - Implementing more flexible approaches to interconnection of DER and EV loads, eventually allowing dynamic curtailment (dispatch) of DER
- **Distribution planning**
  - Developing new planning criteria for D investments (e.g., moving toward a reliability, economic, policy framework like the T system)
- **DER operations**
  - Right-sizing the sophistication of utility distribution operations (e.g., how actively do DSOs need to manage D systems?)
- **Utility regulation and tariffs**
  - Creating open access rules for the distribution system
  - Developing multi-part tariffs for DER customers, with more sophisticated time-varying distribution rates
  - Developing future utility business models (e.g., balancing cost recovery and economic bypass of grid charges)
- **Wholesale markets**
  - Allowing intraday demand bids and locational marginal pricing settlement for loads

Key considerations for public utility commissions

- *Starting from fundamentals* – Taking a bottom-up approach to problem solving, being clear about terms and concepts (e.g., be careful with the term “DER”), and developing a working framework of options for future distribution operations and markets
- *Focusing on least-regrets* – In the near term, focusing resources on incremental, least-regrets changes that build on existing institutions
- *Keeping a long-term perspective* – Starting to think about solutions to longer-term challenges, creating a vision for future distribution system operations and markets, and developing a long-term plan that prioritizes areas to tackle over time
- *Working together* – Participating in regional/national fora and learning from other jurisdictions

Questions public utility commissions can ask

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- Where are nearer-term gaps in current distribution interconnection, distribution planning and T-D planning coordination, distribution operations, and utility DER tariffs?
- How can nearer-term gaps be most effectively and efficiently addressed, while laying the foundations for a transition to future distribution system operations and markets?
- What is the longer-term vision for future distribution system operations and the role (and business model) of the distribution utility?
- Where would clearer state-federal jurisdiction be most helpful in the nearer and longer term?
- Where are opportunities for public utility commissions to work together on DER integration, and what balance between regional (e.g., NECPUC) or national (e.g., via NARUC) fora would provide the most helpful venue for collaboration?

Resources for more information

- Energy Systems Integration Group (ESIG), 2022, *DER Integration into Wholesale Markets and Operations*, https://www.esig.energy/wp-content/uploads/2022/01/ESIG-DER-Integration-Wholesale-Markets-2022.pdf
- Advanced Energy Economy (AEE) and GridLab, 2022, *Removing Barriers to DER Participation in Wholesale Markets*, https://gridlab.org/wp-content/uploads/2022/01/eLab-Accelerator-DER-Wholesale-Markets.pdf
- Advanced Energy Economy (AEE) and GridLab, 2022, *FERC Order 2222 Implementation: Preparing the Distribution System for DER Participation in Wholesale Markets*, https://gridlab.org/wp-content/uploads/2022/01/AEE-GridLab-FERC-O.2222-Campaign-Final-Report.pdf

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