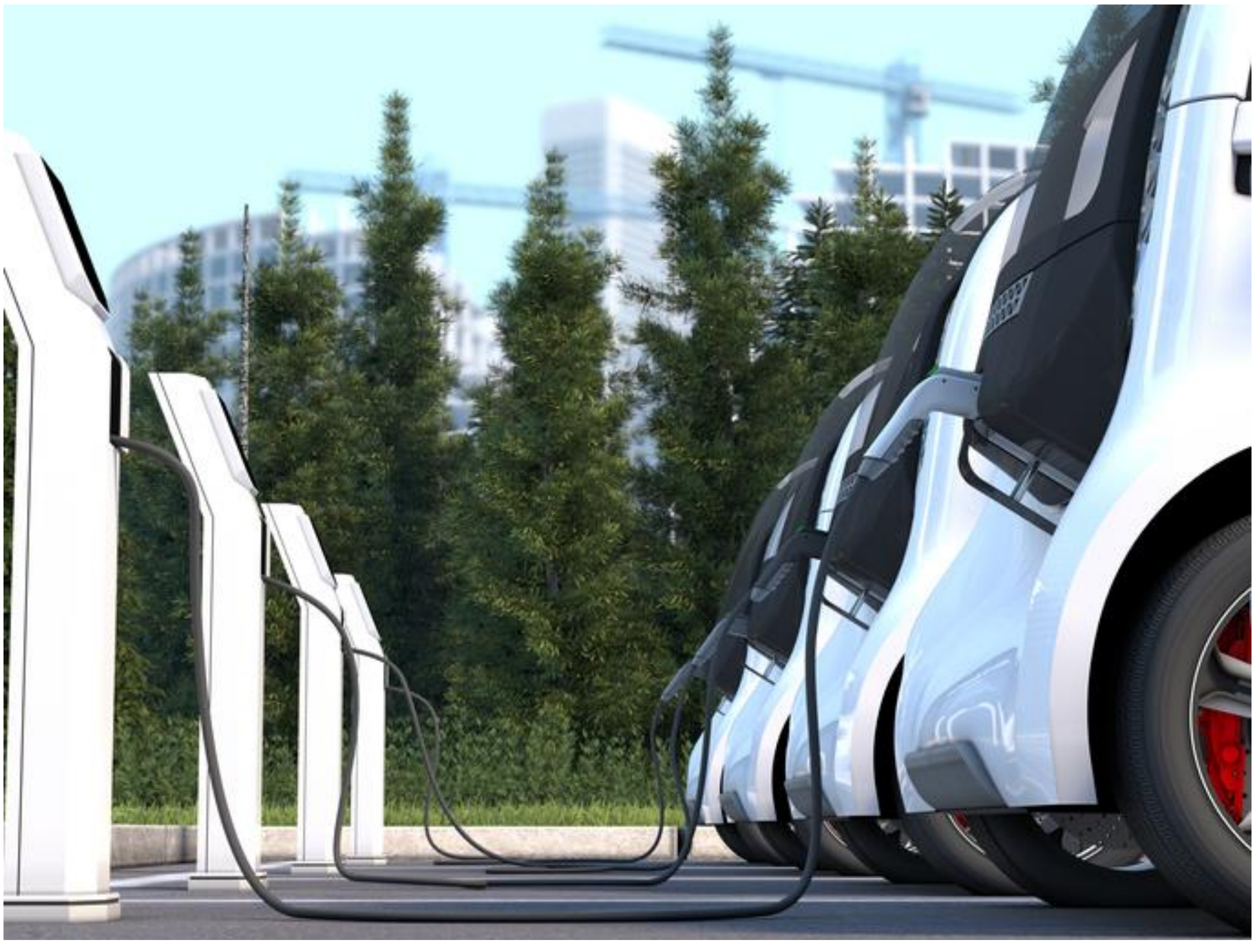
Long-Term Load Forecasting: Workshop Summary



September
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About the Energy Systems Integration Group

The Energy Systems Integration Group is a nonprofit organization that marshals the expertise of the electricity industry's technical community to support grid transformation and energy systems integration and operation. More information is available at https://www.esig.energy or info@esig.energy.

ESIG Publications Available Online

This workshop summary is available at https://www.esig.energy/event/2023-long-term-load-forecasting-workshop/. All ESIG publications can be found at https://www.esig.energy/reports-briefs.

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Overview

Utilities have always needed to create long-term load forecasts as foundational inputs that system planners used in resource planning, transmission planning, and distribution planning. Traditionally, this was fairly straightforward, incorporating changes in demand due to economic growth, population, and industry. Today, long-term load forecasting can be much more complex:

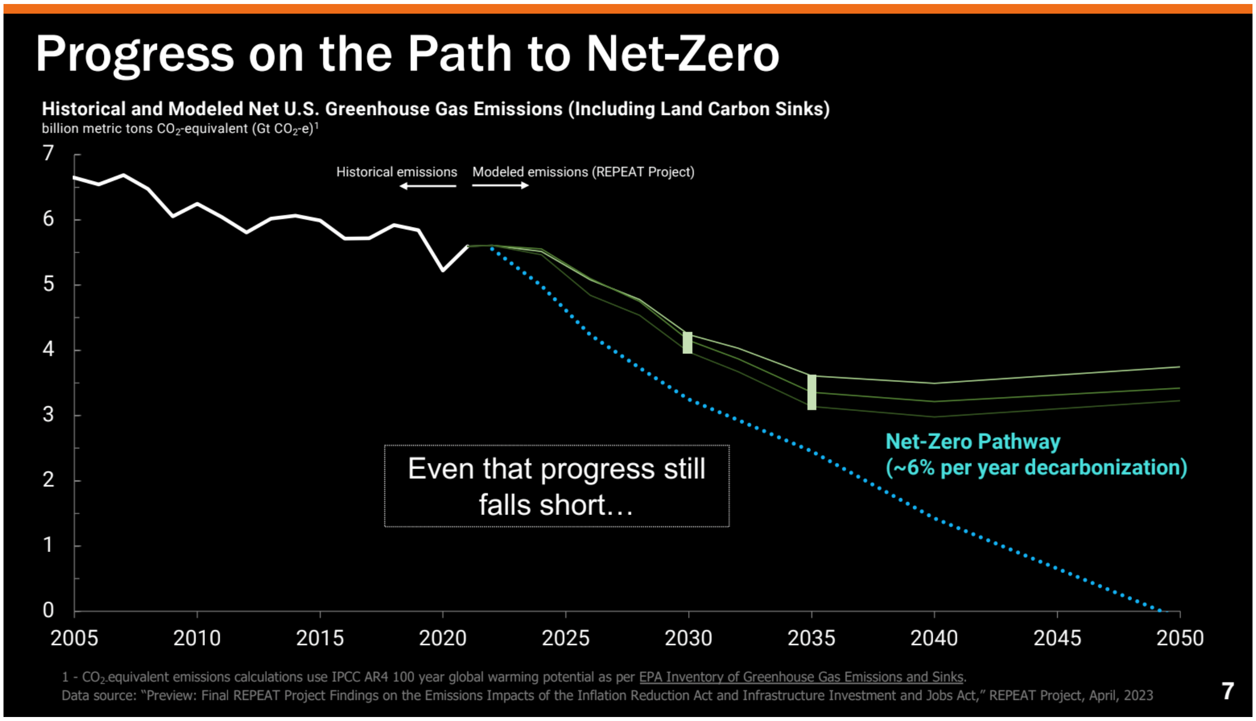
- Climate change impacts on weather can result in hotter, longer-duration, and more geographically widespread heat waves, and more extreme weather events that impact heating and cooling loads as well as generator performance.
- The electrification of buildings, transportation, and industry will increase total demand and make it more variable. Electrification may also cause peak demand periods to move from summer to winter in some regions.
- New, large loads such as hydrogen production, data centers, cryptocurrency, electrification of industrial heat, and ultra-fast vehicle charging stations will impact demand at all levels of the power system.
- Because loads are changing, especially with electrification, distribution planning will be especially impacted. Planners need more granular, distribution-level long-term load forecasts in order to assess needs on a more dynamic distribution system.

To address these needs of system planners, the Energy Systems Integration Group (ESIG) held a special topic workshop on long-term load forecasting during June 13-15, 2023. This was held in parallel with ESIG's annual workshop on markets and meteorology, which focuses on system operations and market design. The goal of the Long-Term Load Forecasting workshop was to survey the state of the art across these different sectors and impacts, and to understand gaps and needs in this area from system planners. Workshop presentations and videos can be found online. ESIG gratefully acknowledges funding from the Department of Energy and Lawrence Berkeley National Laboratory to support the organization of this workshop.

The Evolution of Load and Future Grid Needs

Jesse Jenkins of Princeton University opened the workshop with a discussion of grid needs to meet decarbonization goals, based on analysis from his REPEAT project, which analyzes policy impacts, and Princeton's Net-Zero America study, which examined net-zero emissions by 2050. He explained that the Inflation Reduction Act (IRA) and the Infrastructure Investment and Jobs Act (IIJA) have led to a dramatic shift in policy in the U.S such that the full financial might of the federal government is now aligned behind the clean energy transition. Clean energy is essentially "on sale." He showed how the U.S. has made emissions progress from 2005 to the present (Figure 1), and that the IRA and IIJA will accelerate decarbonization (shown in green), but falls short of the administration's goals (shown in blue).

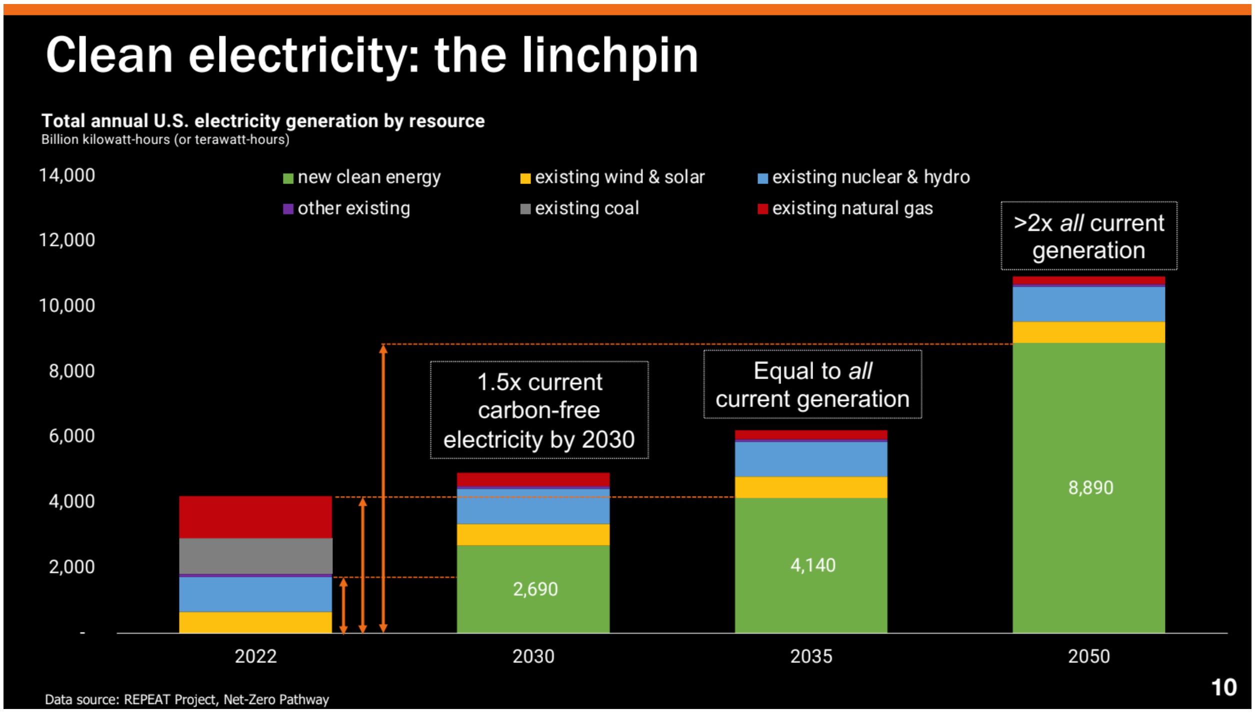
FIGURE 1



Source: Jesse Jenkins's presentation at the workshop.

Now that the financial incentives are in place, the challenge is how to build energy infrastructure at scale. The left-hand bar in Figure 2 shows today's electricity generation. By 2030 we expect to need 1.5 times our current carbon-free electricity generation, and by 2035 we expect to need as much *new* clean electricity generation as the total generation today. And then by 2050 we need do all that again because demand will be more than double what it is today. He explained that what this means for building clean energy infrastructure is that we need to double the peak rate of deployment of wind and solar through 2030, and that rate needs to grow to 3.5 times the peak rate of deployment from 2031 through 2035. Solar deployment may be on track, but wind is much slower than it needs to be.

FIGURE 2



Source: Jesse Jenkins's presentation at the workshop.

Transmission growth is critical to supporting clean energy, especially wind deployment, and Jesse finds that about 75,000 GW-miles of transmission will be needed. Transmission will need to expand at a rate of 2.3% annually between now and 2035, which is not too far off the transmission growth that occurred over the period 1978–1999, but which is nearly double the recent transmission growth during 2004–2016. He finds that if we fail to double transmission, we will lose half of the potential emissions reductions from the IRA.

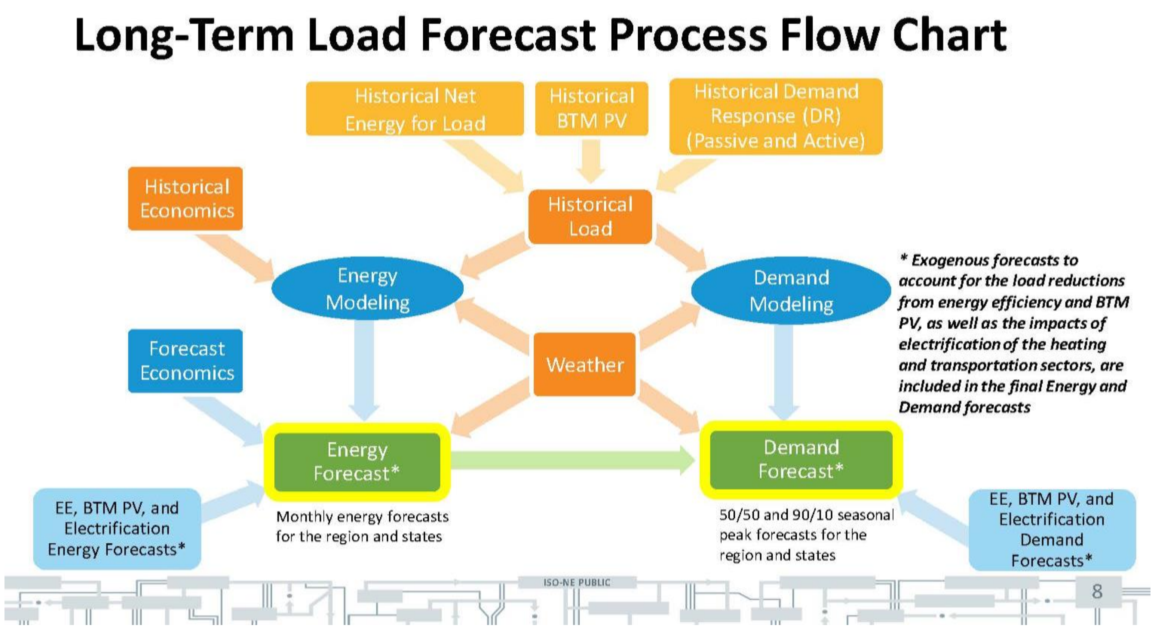
Electric vehicles (EVs) are starting to change the flat or declining load growth that many regions of the U.S. have experienced over the past couple of decades, and heat pumps may be the next technology to impact load growth. Unlocking demand flexibility will be key. EVs offer tremendous flexibility but will need to be incentivized in order to realize this. He discussed how these incentives need to be significant enough to be worth the time for customers to sign up.

Introduction to Long-Term Load Forecasting

Jon Black of Independent System Operator of New England (ISO-NE) discussed how long-term load forecasting is foundational to all planning studies and explained that what forecasters focus on is changing quickly. Whereas it was once seasonal peaks and annual energy, it is now becoming about much more granular load characteristics. Long-term load forecasts are vital to the foundational set of assumptions that inform the capacity market, transmission planning, economic studies and scenario analyses, generator interconnection, and long-term outage coordination.

ISO-NE currently develops a 10-year forecast each year, using statistical/econometric modeling. It begins by modeling the base load and adjusts those outputs using exogenous forecasts of energy efficiency measures, distributed energy resources (DERs) (especially distribution-connected solar), heating electrification, and transportation electrification. Its approach to forecasting has changed considerably over the past decade, moving beyond demand to include things like load-masking by DER photovoltaics (PV) (accounting for distribution-connected PV that is not telemetered, or does not participate in wholesale markets) and other emerging trends. A high-level summary of the whole process flow is shown in Figure 3.

FIGURE 3



Source: Jon Black's presentation at the workshop.

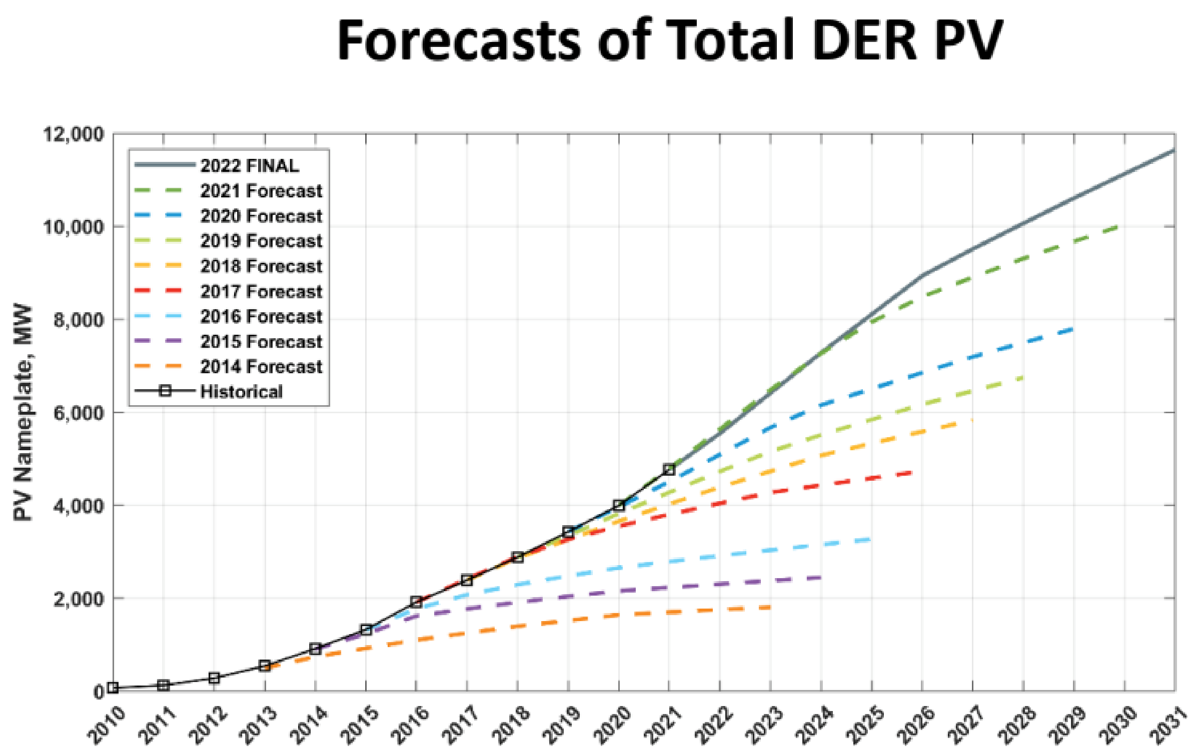
Demand forecasts are currently generated using daily peaks, although that may change.

To create probabilistic demand forecasts, ISO-NE leverages 30 years of historical weather and creates probability distributions for a three-day weighted temperature-humidity index. This index is a key input to summer system peak demand models. The most relevant points in its load distribution forecasts depend on the downstream use. For example, transmission planners generally use a 90/10 peak demand forecast, and some planners use discrete points in a distribution such as summer peak, winter peak, etc. Resource adequacy planners use probabilistic inputs, aiming to capture the load forecast uncertainty.

Heating electrification leverages the National Renewable Energy Laboratory's (NREL's) ResStock and ComStock datasets, and includes building stock characterization, heating pathways, adoption forecasting, and hourly demand modeling. Transportation electrification includes policy goals, the pace of EV adoption, and uncertainty. Profiles are weather-dependent and segregated by vehicle class. ISO-NE is forecasting 6 GW of extra heating and transportation demand in winter, and by the mid-2030s may become a winter-peaking system.

Forecasting of behind-the-meter PV (DER PV that does not participate in wholesale markets) has been based on a methodology that essentially looked at policy drivers. Figure 4 shows how this methodology could not keep up with DER PV adoption. Note that as one moves from the flat to the steep part of the S-curve of adoption, it can be hard to forecast accurately. Jon says that they need to move to a model-based methodology like NREL's [dGen]() or similar tools. In order to forecast for planning, but especially for operations, system operators need *data* on these systems; ISO-NE does not know how much PV is installed at a substation. Finally, the system needs significant amounts of clean energy, balancing resources, energy adequacy, and robust transmission, and these forecasts are foundational to a successful energy transition.

FIGURE 4



Source: Jon Black's presentation at the workshop.

Potential methodological improvements that ISO-NE is considering are:

- Integrating weather data that reflect future climate projections

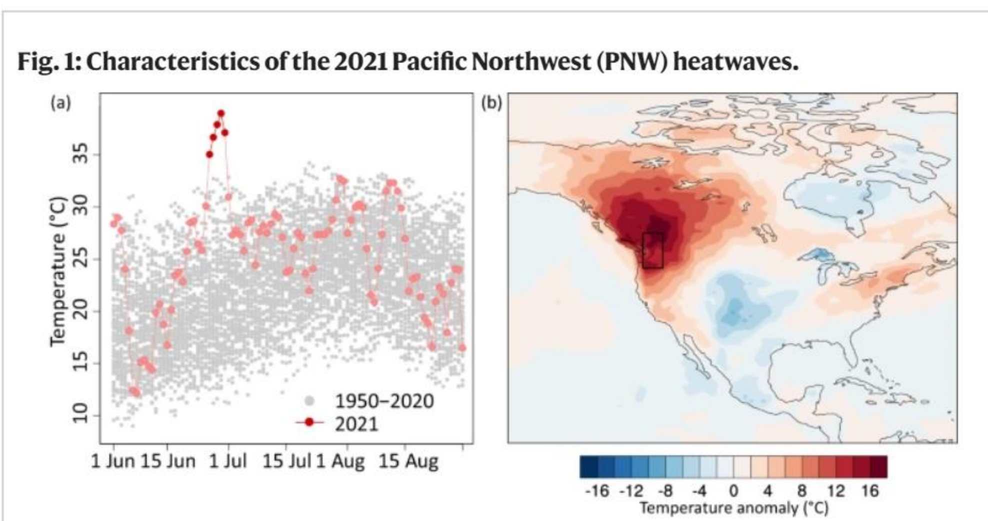
- Expanding DER forecasts, including potential increases in co-located and standalone DER storage
- Transitioning from daily peak to hourly modeling
- Extending the forecast horizon to 20 years or more
- Given that exogenous forecasts have been deterministic up to this point, developing additional probabilistic scenarios for these forecasts to quantify additional sources of uncertainty so that downstream users can factor in this uncertainty

Weather and Climate

The foundational input to creating load, solar, and wind datasets for system planning is weather data. Weather data representing historical years for the region being modeled has traditionally been used. For example, temperature and humidity time-series data can be used as inputs in models to determine heating and cooling loads for different classes of buildings.

While existing wind and solar plant output data can be used in planning, these are lacking for hypothetical wind and solar plants. For these, industry has developed methods to create time-series data based on historical weather, to synthesize hypothetical wind and solar plant output (Reanalysis, the National Solar Radiation Database, the WIND Toolkit). It is important that the load, wind, and solar data be time-synchronized to capture correlations (i.e., it would be unrealistic to use 2011 load data with 2012 wind data and 2013 solar data). However, historical weather data do not reflect how climate change will impact weather in the future. For example, **Laurent DuBus** of RTE pointed out how the June 2021 heat wave in the Pacific Northwest far eclipsed historical temperature variability (Figure 5).

FIGURE 5

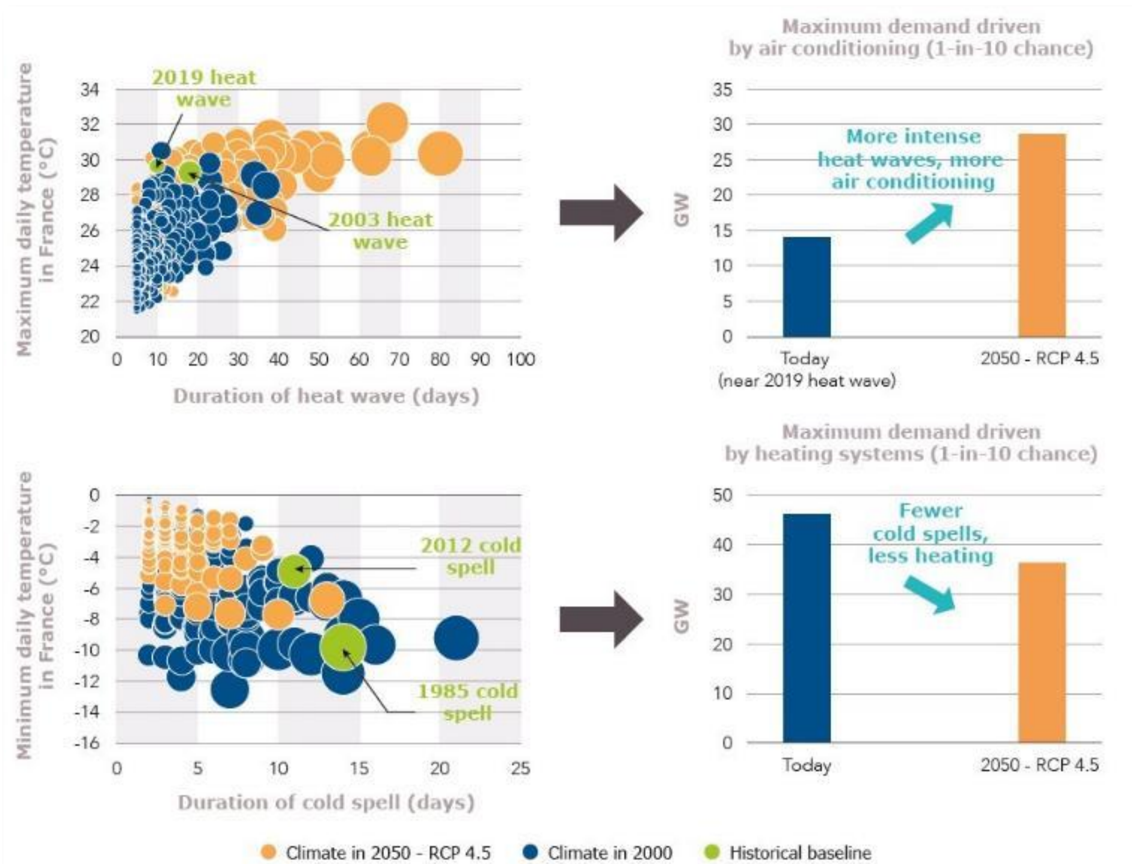


Source: E. M. Fischer, U. Beyerle, L. Bloin-Wibe, C. Gessner, V. Humphrey, F. Lehner, A. G. Pendergrass, S. Sippel, J. Zederand, and R. Knutti, "Storylines for Unprecedented Heatwaves Based on Ensemble Boosting," *Nature Communications* 14: 4643 (2023). https://doi.org/10.1038/s41467-023-40112-4, included in Laurent DuBus's presentation at the workshop.

Forward-looking weather datasets require significant modeling. Climate change impacts depend on greenhouse gas concentrations in the atmosphere. Representative concentration pathways (RCPs) are used in global climate models to help us understand climate change impacts on weather at different greenhouse gas concentrations, for example, RCP 4.5, which is an intermediate scenario, and RCP 8.5, which is a very high greenhouse gas scenario. Global climate model data for a particular future year and RCP is the starting point for a forward-looking weather dataset.

The weather and climate session included four methodologies for creating forward-looking weather datasets, and ultimately forward-looking load/solar/wind datasets. **Laurent DuBus** discussed the forward-looking weather datasets that RTE has created for its *Energy Pathways to 2050*, which models different future scenarios and is the first study of its kind to include climate change considerations. It used 200 years worth of hourly weather data, provided by Météo-France, the French National Meteorological Service, with over 37,000 grid points across Europe that represent the climate of the year 2000, the climate of the year 2050 under RCP 4.5, and the climate of the year 2050 under RCP 8.5. These data are the basis for long-term load forecasts, wind/solar/hydro output, and the availability of thermal generators. Figure 6 shows predictions for 2050 under RCP 4.5: heat waves are expected to become hotter and last longer, while cold waves will be milder and shorter. These changes significantly impact load through heating and cooling needs. Conversely, he finds that wind and solar power plant output is only marginally affected by climate change and is an order of magnitude less than the variability we see today—the bigger impact on their output is due to technology improvements.

FIGURE 6



Source: Laurent DuBus's presentation at the workshop.

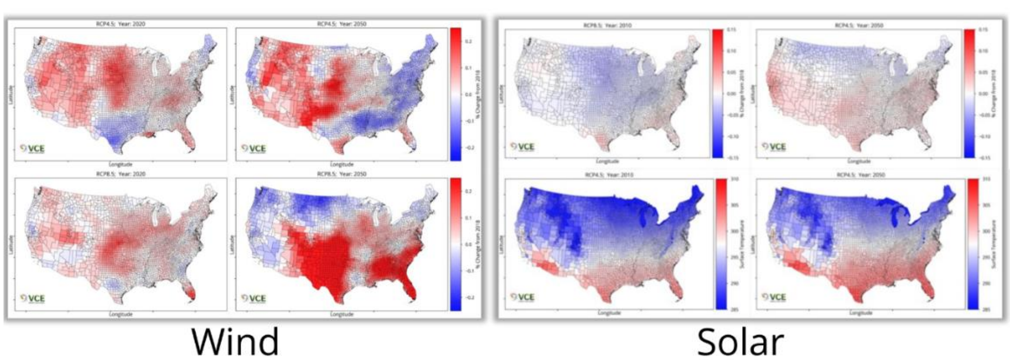
Erik Smith of the Electric Power Research Institute (EPRI) discussed a computationally light approach to synthesizing forward-looking weather datasets. The global climate model datasets provide a daily maximum temperature, minimum temperature, and mean temperature. Dynamically downscaling these data is expensive and computationally intensive, so one might undertake that for a few scenarios or few climate models but not for significant amounts of data. His approach instead leverages large amounts of historical hourly weather. He uses 72 historical years of ERA5 data for 1950–2021 and detrends the data so that only the natural variability remains (without the long-term temperature warming trend). He then applies this historical variability to the global climate model trends.

He uses five climate models and two emissions concentration scenarios, which creates 720 years of data to represent one future year. By synthesizing a year 720 times, this approach captures more extremes and tail events. Advantages include realistic variability and tail events and a preservation of the physical link between meteorological variables. Disadvantages are that it does not capture how climate change may change variability or tail events in the future.

Grant Buster of NREL presented Super-Resolution for Renewable Energy Resource Data with Climate Change Impacts (Sup3rCC), which uses a machine learning approach. The global climate model data have a 100 km spatial resolution. Grant takes high-resolution data from NREL's mesoscale datasets (WIND Toolkit and National Solar Radiation Database) and "coarsens" them to create low-resolution training data. Then, using generative machine learning, he can synthesize high-resolution output that is consistent over time and space. Initial data are available, and more years and emissions pathways are being synthesized. The data have been corrected, verified, and validated against other mesoscale datasets. Moderator Justin Sharp noted that it is important to validate the data against actual output because mesoscale data itself may not be accurate.

Chris Clack of Vibrant Clean Energy (now Pattern Energy) presented the data used in his WISDOM model. He "nudges" historical data using multi-model ensembles of climate data (the World Climate Research Programme's CMIP-5/6). The climate data go out to 2100. The historical data are the National Oceanic and Atmospheric Administration's (NOAA's) reanalysis data which go back to 1836. He uses NOAA's High-Resolution Rapid Refresh data for high resolution. The benefit of this approach is the high resolution data, but the downside is that, because it is based on historical data, similar to Erik's approach above, it does not yield more extreme weather. Chris mentioned that they actually saw the February 2021 cold event in Texas in their model, but it was so extreme that they thought it was a mistake. Figure 7 shows how wind and solar output changes under different carbon pathways for different years. He predicts that it will get windier in the south and southeast if carbon emissions get worse.

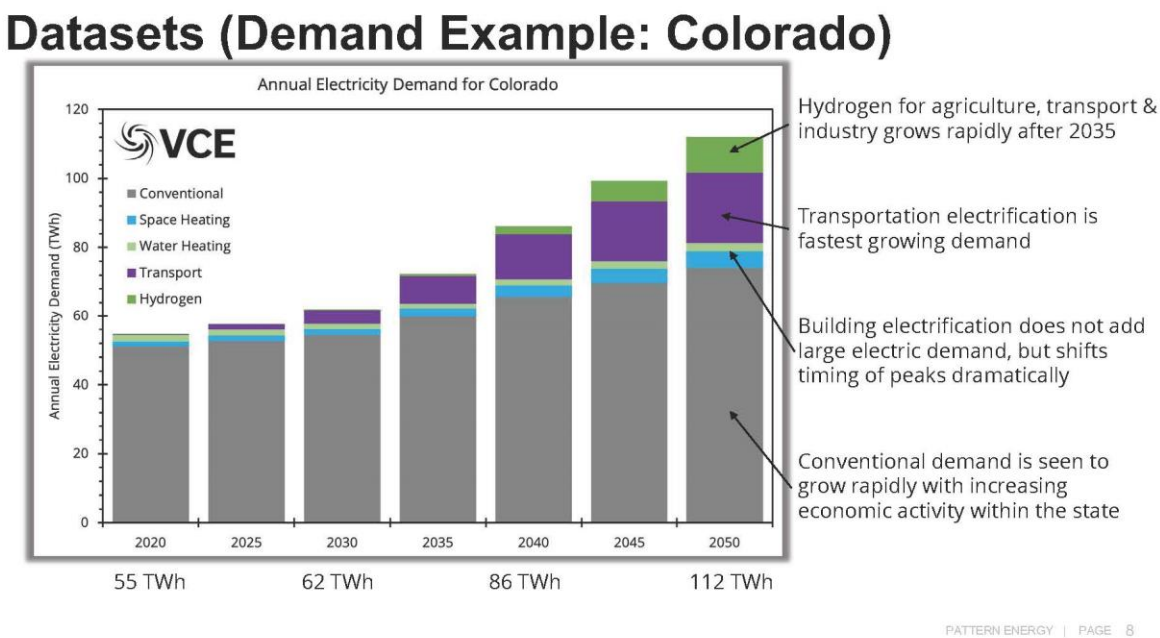
FIGURE 7



Source: Chris Clack's presentation at the workshop.

Chris predicts significant increases in demand as we move to a decarbonized future. Demand predictions for Colorado by sector are shown in Figure 8.

FIGURE 8

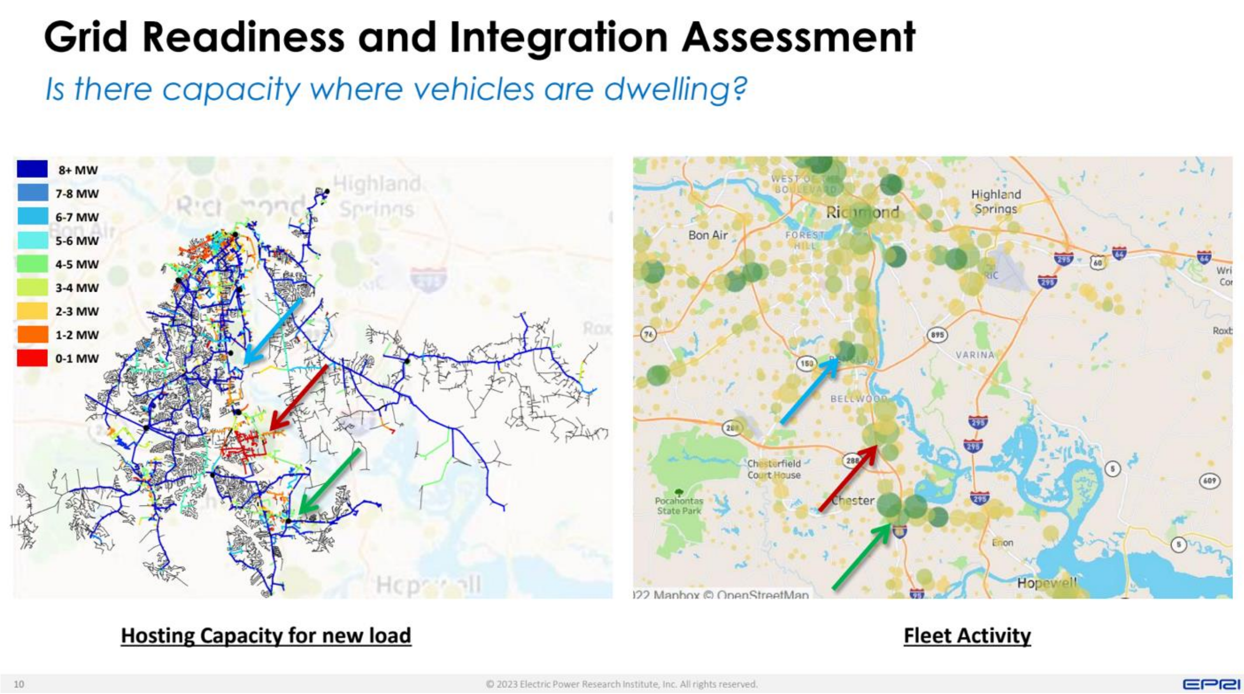


Source: Chris Clack's presentation at the workshop.

Electrification of Transportation

Jeremiah Deboever of EPRI has an ongoing collaborative project on medium-duty and heavy-duty fleet electrification. He finds that 85% of distribution planners indicate that EV charging will become a concern within the next five years. While 64% of vehicles are light-duty vehicles, he focuses on medium-duty and heavy-duty vehicles because they consume more kWh per mile, they have more regular patterns than light-duty vehicles, they may centrally charge, and fleet owners tend to buy them all at once as soon as they are economical. Planners need to understand a number of things about future fleets: where do they "live" and where do they charge, when do they electrify and when do they charge, how many vehicles are in a fleet and how many in one location? Using measured data from charging, and breaking patterns into "charge as soon as possible" and "charge as late as possible," Jeremiah can discern from the difference between these two patterns how much flexibility there is in charging. He is using these data in hosting capacity analyses on 1500 feeders with 15 distribution utilities to better understand grid readiness and fleet integration (Figure 9).

FIGURE 9

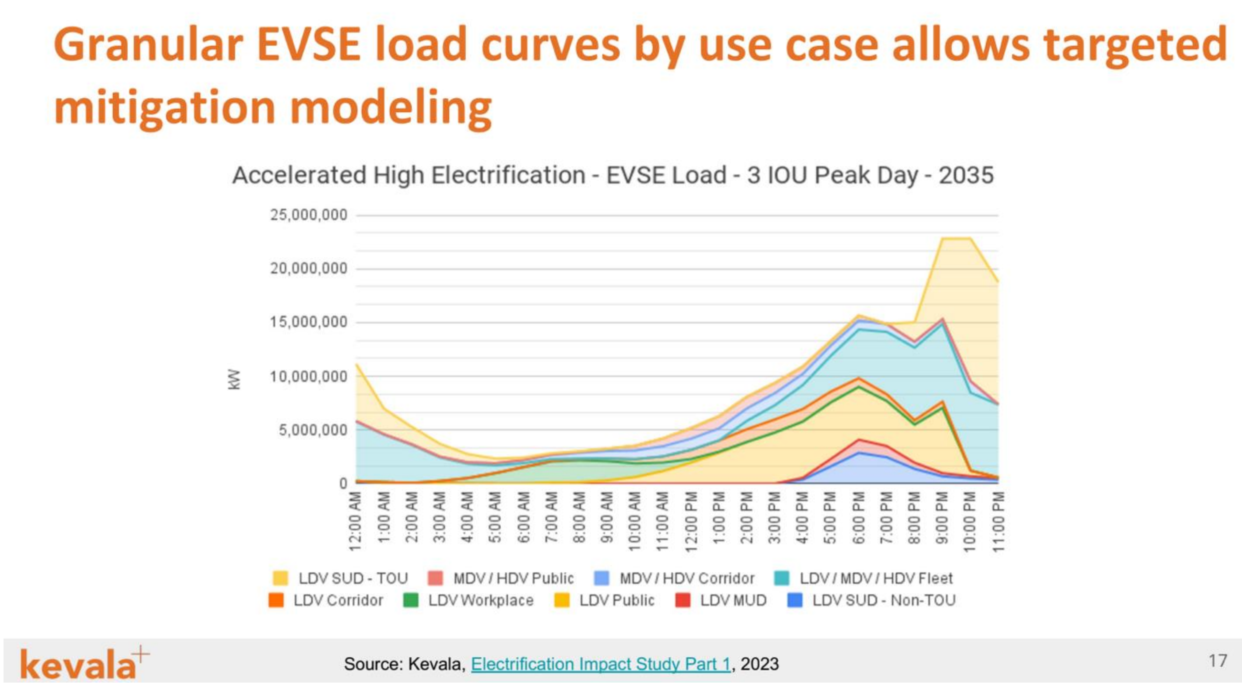


Source: Jeremiah Deboever’s presentation at the workshop.

Tim Pennington of Idaho National Laboratory discussed Caldera, their tool to model EV, grid, and DER interactions. Transportation models can simulate mobility and energy system models can simulate distribution systems and traditional loads, but Caldera can add the missing link to understanding EV charging effects and driving conditions. This agent-based modeling platform can predict system impacts based on EV models and EV supply equipment (chargers) models. He showed results of aggregated modeling of personal use EVs, of an extreme fast-charging station with energy storage to reduce demand charges, of price controls at extreme fast-charging stations, and various demand management strategies.

Troy Hodges of Kevala began by explaining that today utility interconnection processes cannot keep up with the current pace of EV charging station requests, and the next challenge is that distribution planning processes do not prepare grids for the coming wave of transportation electrification in the next 5 to 15 years. He presented phase 1 of their recent Electrification Impact Study for the California Public Utilities Commission, which first forecasted net loads for the 12 million premises at California’s investor-owned utilities. This included PV, batteries, EVs, and building electrification under different scenarios. They then identified current capacity from secondary transformers to sub-transmission feeder banks and determined additional capacity needs due to forecasted net loads. Finally, they examined locational costs, estimating unit costs to meet capacity needs, determining incremental capital investments to meet capacity needs, and quantifying revenue requirements and marginal costs by distribution asset. The average feeder sees incremental load equivalent to 40% of peak load just from EVs. At a high level, they found that $50 billion in traditional investments would be needed by 2035 if there was no mitigation, including substations, transformer banks, feeders, and service transformers. Figure 10 shows granular load by use case, which can be used to craft different mitigation strategies to manage demand.

FIGURE 10

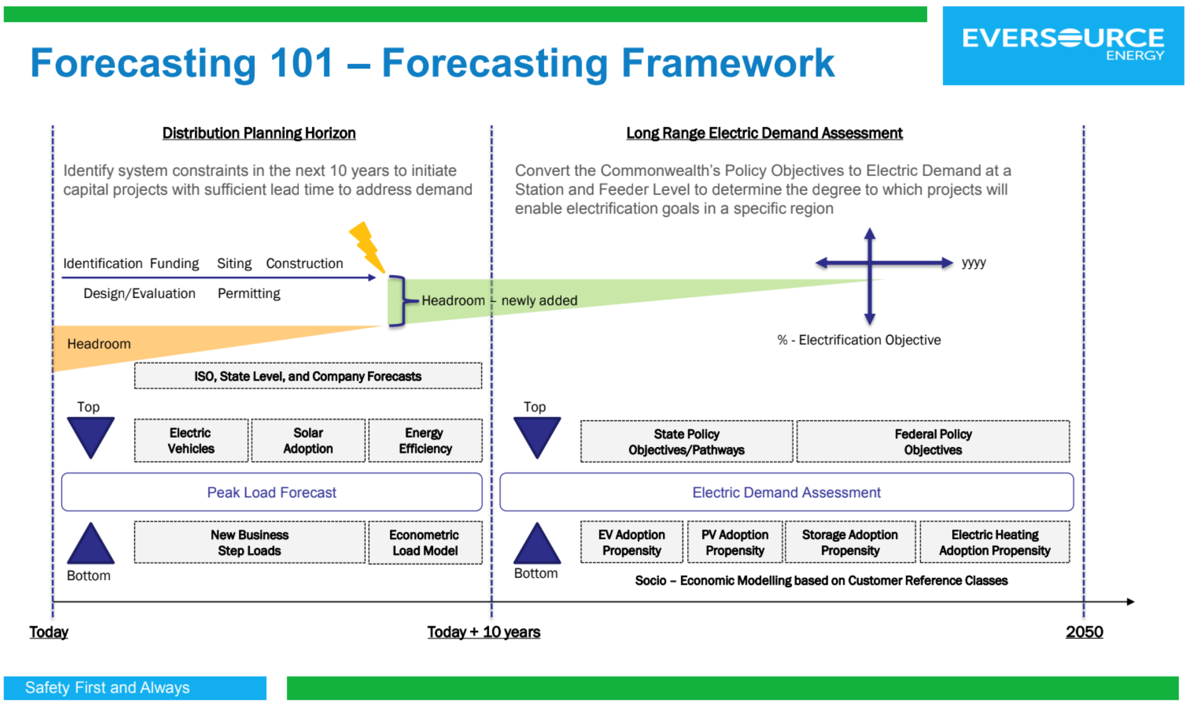


Source: Troy Hodges's presentation at the workshop.

Gerhard Walker of the utility Eversource explained that utilities must forecast because infrastructure can take years to plan, site, and build—over 10 years for transmission, 5 to 8 years for substations, weeks for distribution service upgrades, and 2 to 3 years for circuit redesigns). Larger projects take longer and need longer-range forecasts. Because bigger projects serve larger areas and because forecasts over larger areas are more accurate, this makes bigger projects more certain. In comparison, geographically granular forecasts have significant uncertainties. Figure 11 shows 10-year forecasts that they currently create in the distribution planning process as well as long-range electric demand assessments, which are a translation of policy objectives into load. They use long-range demand assessments to ensure that solutions from the distribution planning process are future-proof. They may not build everything needed for 2050 because they do not want to overbuild system, and so they strike a balance between the two. One way to future-proof is to build in a way that enables upgrades in the future, e.g., buy a little more property to allow for a larger transformer in the future.

Eversource purchases GPS tracking data on vehicle movement, which allows them to understand things like seasonal tourism needs. Gerhard discussed how they reduce needs to upgrade feeders with demand management and rate structures, and how they create circuit-level risk assessments. So, if a circuit is being upgraded and the risk assessment shows that it has a high level of innovator/early adopters, planners will do a 1+ installation, using the largest available conductor and pole mount/pad mount size to ensure they do not run into any issues.

FIGURE 11



Source: Gerhard Walker's presentation at the workshop.

Flexibility in Future Load

The flexibility session focused on customer response today, the grid's flexibility needs, and what kind of flexibility we can get from new large loads. **Tom Hines**, consultant to Arizona Public Service (APS), spoke about how 70% of APS customers are on time-of-use rates and how demand-side management was going to be a much larger resource in 2035. APS uses behavioral changes, direct dispatch, and rate responsiveness to drive customer load flexibility. They have over 120 MW of response from thermostat controls and up to 50 MW of commercial and industrial demand response today. They see 12% to 15% opt-out of events, but that is typically in the last 30 minutes of an event, which means they have already gotten the value from the event. APS was able to call four sequential events in August 2020 and got response within 2-3% of their forecast, which helped them avoid the rolling blackouts that the California Independent System Operator experienced. They are going to have improved day-ahead and real-time forecasts for their demand response soon. Finally, Tom described their approach to how they assess their demand response potential in their planning process.

Caitlin Murphy of NREL discussed the value of flexible loads from electrification using results from the Electrification Futures Study. They find that vehicle electrification dominates incremental growth in annual electricity demand and could lead to higher, sharper, more frequent peaks if left unmanaged. Electric space heating impacts the timing and magnitude of peak demand, with some regions moving to winter-peaking systems. Electrification drives a 58% increase in total installed capacity in 2050 from 2018 levels. By managing flexible loads, they found reduced capital and operating costs on the bulk power system, reduced renewable curtailment, reduced distribution investment costs, and increased DER hosting capacity on distribution systems.

Derek Stenclik of Telos Energy had a thought-provoking perspective on load flexibility. Load flexibility directly competes with battery storage, and because battery storage is already either mandated or planned in many areas, load flexibility may be too late to play a significant role on the bulk power system. While load flexibility can provide capacity contributions during summer stress events, he noted that electrification is pushing reliability risks to winter and that the stress events require longer-duration resources than many load flexibility resource are able to provide. He asserted that we should look for the right load flexibility and that it could include energy efficiency, meeting distribution system needs, multi-day load shifting, and large flexible loads.

Agee Springer of the Electric Reliability Council of Texas (ERCOT) runs ERCOT's Large Flexible Load Task Force. A large flexible load is considered to be one that can respond to wholesale prices or other grid conditions. Some of these register as load resources and provide ancillary services and/or participate in economic dispatch. Most large loads adjust consumption independent of direction from or coordination with ERCOT. Today, there are large loads such as data centers, cryptocurrency, and oil fields that request interconnection in months rather than years. In addition, some can ramp quickly: hundreds of MW in seconds to minutes. Ride-through is an issue to maintain reliability, and he spoke of a recent event in which 1600 MW of load tripped offline, causing frequency to spike. Other potential issues include large amounts of load MW that respond to price outside of economic dispatch from ERCOT: if the amount of load is large enough, it can cause prices to drop, which can lead to the load ramping up, which can cause price spikes, and the process repeats itself. This can lead to oscillations in generation and price, and potentially also frequency. ERCOT's Controllable Load Resource program addresses this issue by dispatching the loads.

Industrial Loads and Hydrogen

New industrial loads will likely have significant impact on the future power system. **Tom Hines** had mentioned Arizona's new Taiwan Semiconductor Manufacturing Company chip manufacturing plant, which will consume the equivalent of about one-fourth of APS's current load. **Dan Esposito** of Energy Innovation discussed hydrogen production and how federal incentives will impact how that load evolves. The biggest impact will come from the IRA's clean hydrogen production tax credit. Dan said that it is hard to overstate the size of this incentive. The IRA incentive of $3/kg is equivalent to $60/MWh, and the additional $1/kg current sale price of hydrogen yields a $80/MWh value. He noted that DOE's 2030 goal is 10 million metric tonnes of hydrogen production. If this all came from electrolysis, it would require about 12% of today's annual electricity consumption. Rules are still being decided at the Treasury Department. Dan modeled loose and stringent tax credit guidance. Under loose guidance, the electrolysis likely will not be flexible, will run as baseloaded production, and will run whenever prices are $80/MWh or lower. With stringent guidance, more renewable energy supply is incented, electrolyzers are incented to be flexible and to have hydrogen storage, and at low wholesale prices, electrolyzers are incented to soak up excess supply.

Patrick Leslie of Rondo discussed industrial heat batteries. Thirty-six percent of total world energy use is industrial; of that, three-fourths is to generate heat. He estimates 41 TWh of thermal storage to serve those needs, at a cost of $2 trillion. Rondo has created heat batteries by heating bricks at a high temperature. Their concept is that by using 70 MW of input power, from renewables, for example, they can charge 320 MWh of thermal storage that can produce 20 MW of thermal energy around the clock.

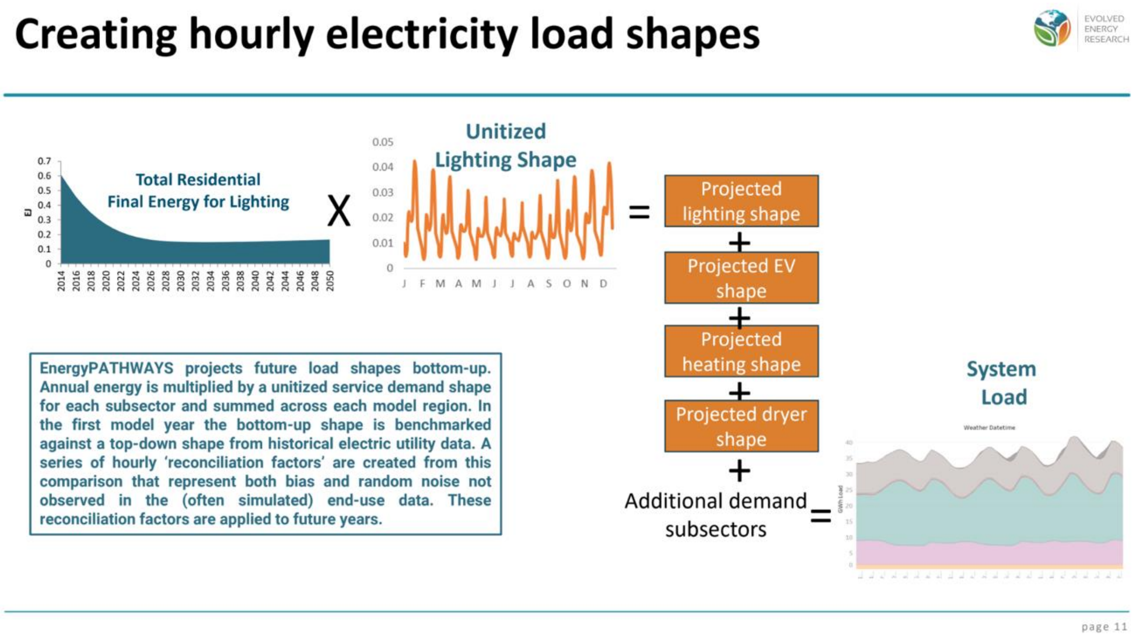
Carsten Baumann of Schneider Electric discussed data centers. He estimates 39 GW globally of new data center load in the next five years, which is a 360-fold increase of today's data center load. Today, data centers are on the order of 2% of electricity consumption. In the U.S., data center load is forecasted to grow 10% per year.[1] Data centers are getting bigger and designs are now exceeding 500 MW. There are regions today such as Ireland and Dominion Energy where one-fifth of the electricity goes to data centers. Carsten believes there is a lot of potential for flexibility, but it has not yet been demonstrated. About two-thirds of data center load goes to IT load, which is flat, and about one-third goes to cooling/mechanical loads, which could change due to changing ambient temperatures.

Electrification of Buildings

Jeff Deason of Lawrence Berkeley National Laboratory discussed how efficiency has a major impact on how building loads will evolve, even with electrification. **Ryan Jones** of Evolved Energy Research explained how forecasting and backcasting were both important tools to understand what might happen with expected customer behavior as well as inferring what customer adoption needs to be to meet future goals. Forecasting a reference might show 0.2% load growth while a backcast low-carbon scenario may see periods of 2 to 3% load growth. He thinks the IRA is likely to accelerate electrification by 5 to 10 years, but forecasts of impacts differ widely. He then explained his bottom-up approach to load forecasting (Figure 12). He uses a stock accounting model (Energy Pathways). For lighting, he projects service demand out to 2050 and incorporates stock turnover to yield final energy demand. He multiplies this by unitized shapes to create these load forecasts. He repeats this for other subsectors like EV, heating, dryers, etc. and builds up system load from these components. He notes that there are many uncertain factors that can have nonlinear impacts on peak load, including rates of electrification; building mass/insulation improvements; heat pump sizing, low temperature cut-out, backup heating, and technology improvement projections; spatial diversity factors; future climate change; and customer behavior.

[1] See https://www.mckinsey.com/industries/technology-media-and-telecommunications/our-insights/investing-in-the-rising-data-center-economy.

FIGURE 12

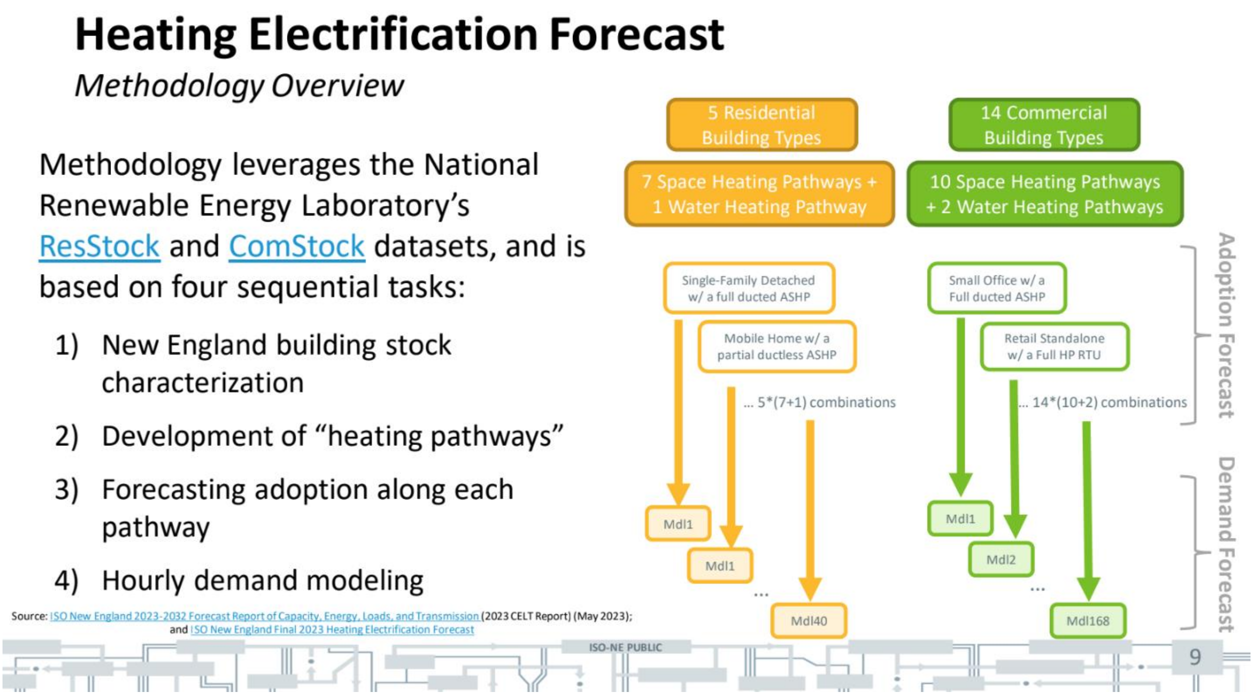


Source: Ryan Jones's presentation at the workshop.

Jon Black of ISO-NE focused on space and water heating electrification in buildings. Impacts are dominated by space heating. ISO-NE has forecasted electrification for four years now. They leverage NREL's ResStock and ComStock. They use 5 residential building types with 7 space heating pathways, and 14 commercial buildings types with 10 space heating pathways (Figure 13). They forecast adoption for each pathway and model hourly demand. Probabilistic modeling of adoption is guided by Bass diffusion models.

ISO-NE developed heating load relationships (for all building types) to outdoor temperature. Reference heat pumps were selected for each pathway. As heating is electrified, ISO-NE moves into a winter-peaking system, and this could be as early as 2031.

FIGURE 13



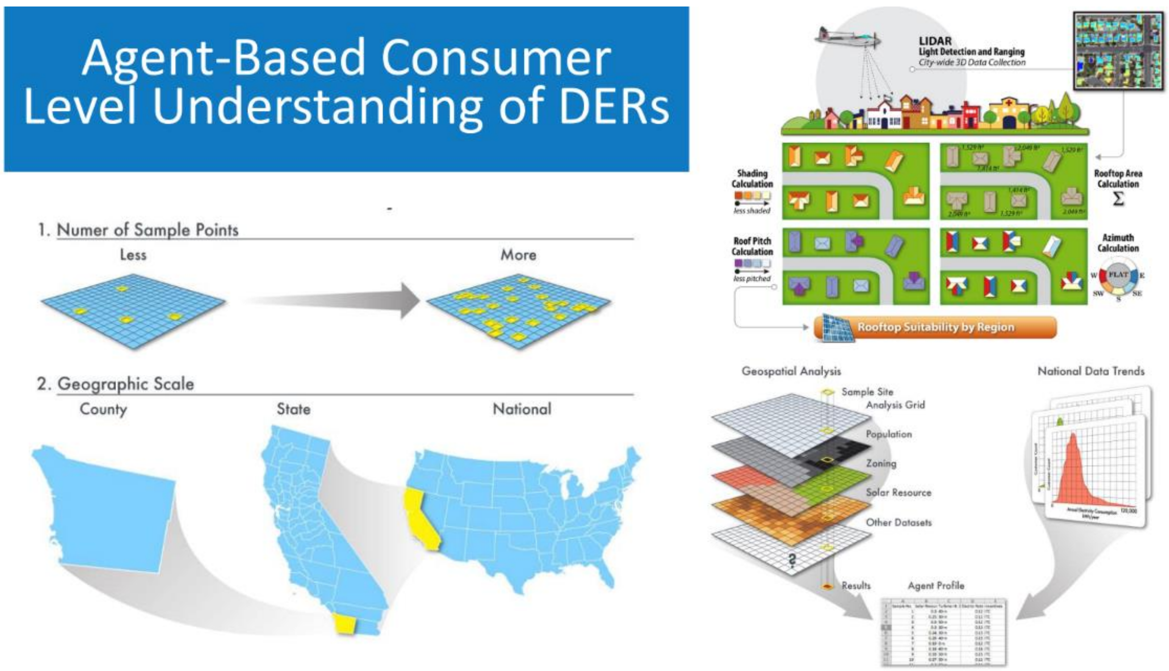
Source: Jon Black's presentation at the workshop.

Arthur Maniaci of the New York Independent System Operator (NYISO) discussed air source heat pumps in detail. At a certain point as temperature decreases, performance of the heat pump is not sufficient, and supplemental heat is necessary. This means that while the heat pump might only use 6 kW, at low temperatures, supplemental heat might add another 11 kW of heating load. The maximum size cold-climate heat pump in the residential sector is 5 tons. He showed a particular region in which supplemental heat is required for about 650 hours during the heating season. They found that square footage was a key criterion to analyze their building stock because for large premises, supplemental heat is needed from resistance heating or dual fuel gas.

Distributed Solar and Storage

Paritosh Das of NREL presented NREL's dGen agent-based approach to simulating consumer decision-making to forecast adoption of distributed solar, storage, wind, and geothermal by region and sector through 2050 (Figure 14). The framework for modeling DER adoption starts with the resource and physical potential and constraints, and then technical and land-use constraints, economics, and finally market aspects like policies, competition with other resources, and regulatory constraints. The agent-based nature of the decision-making process is calibrated through surveys and program data. Location-based attributes are used to represent heterogeneity of the population. This modeling approach was foundational to the inputs for NREL's LA100 study.

FIGURE 14



Source: Paritosh Das's presentation at the workshop.

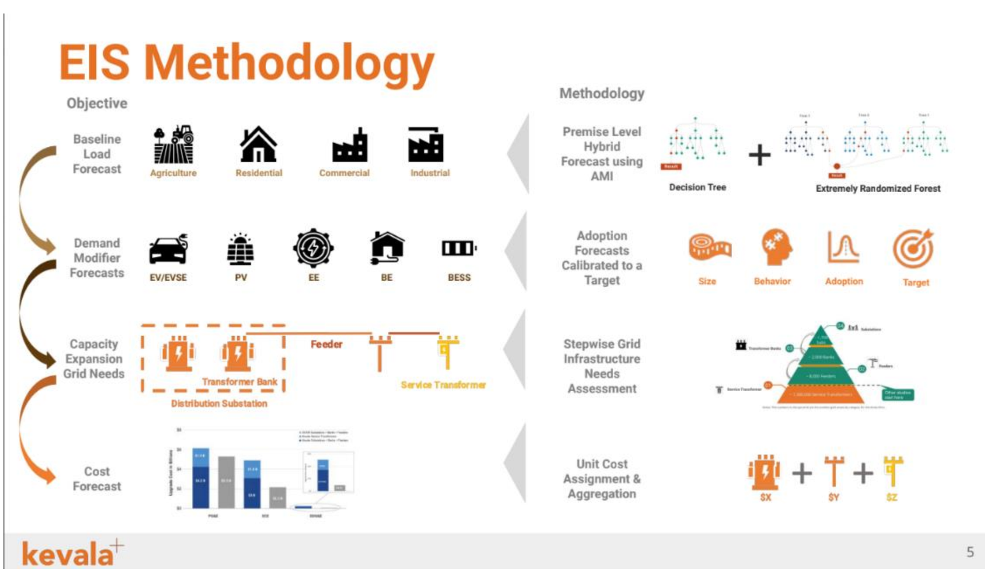
Fred Schaefer from Cadeo presented AdopDER, which is a site-level simulation model that estimates impacts for over 40 DERs at a temporally and spatially granular level. He starts with an adoption forecast that is calibrated to current adoption and uses the dGen diffusion model going forward. This is at the level of the service territory. To disaggregate this down to the household level, they use a propensity model that includes parameters like building type, income, rent vs. own, and neighborhood effects. To determine system size they use historical data and note that Google's Sunroof would be better, but is proprietary and not very scalable. Finally, NREL's PV Watts generates hourly output. Similar approaches can be used for non-residential solar. Storage tends to be added to solar rather than standalone, so an "attachment rate" is used to model those solar installations that include storage. Fred noted that there are so many assumptions that go into these models that defining confidence bands is difficult; he recommends defining and modeling different scenarios as a more realistic path forward.

Brittany Farrell of Clean Power Research explained their methodology for forecasting distributed solar/storage. She starts with historical adoption data to train their model. This includes data on system location, size, orientation, equipment specifications, and other external factors. Data come from utility interconnection records. If data are insufficient, she can also infer battery and PV adoption using advanced metering infrastructure (AMI) data from a customer. She then looks at adoption potential. A solar resource potential study can be undertaken to determine an upper bound of potential from rooftop systems. Then she needs to figure out how fast adoption will occur. A fast logistic regression tool can be run over many scenarios to look at adoption rates based on market penetration, costs, incentives, payback, and socioeconomic data. Similar to Fred, she uses an attachment rate for storage to determine adoption of solar/storage systems. Next, she disaggregates service territory adoption to more granular locations. This model is also trained using historical data. Finally, these individual systems' output can be aggregated to the circuit, feeder, or substation level.

Distribution System Planning

The distribution system planning panel session examined granular distribution forecasts, either disaggregated from the bulk power system level down to the distribution level or a bottom-up approach with premise-level forecasts. **Darrin Kinney** of Integral Analytics gave a high-level overview of the status of advanced DER forecasting and planning. DER scenario forecasting is a new and evolving discipline. He showed how their LoadSeer tool takes in macro-regional forecasts and resource plans, parcel-level end-use scoring/forecasts, geospatial data, and normalized base load shapes to produce forecast datasets that can be used in distribution load flows, capacity expansion, and production simulations, and visualization tools. **Julieta Giraldez** of Kevala discussed how both independent system operator and distribution planners are moving toward bottom-up forecasting and hourly weather-driven models. For their recent Electrification Impact Study, they used premise-level data to examine primary and secondary distribution upgrades from the service transformer all the way up the distribution system (Figure 15). She suggested this kind of modeling could extend all the way up to the bulk power system. They train a machine learning model on AMI data for each premise. The weather data are based on forward-looking climate data similar to those described in the first panel session. They used known load growth plus load growth based on Caltrans socio-economic forecasts including new adopters of technology. Similar to Ryan Jones's backcasting method, they used policy-driven DER targets and then aligned the top-down and bottom-up forecasts. Instead of assigning a pro rata share of the gross forecast to each feeder, they used the bottom-up data to identify the most probable locations for DERs. They looked at upgrade needs for service transformers, feeders, transformer banks, and substations. This baseline study looks at unmanaged EV charging and finds that about $50 billion of distribution upgrade costs will be needed by 2035.

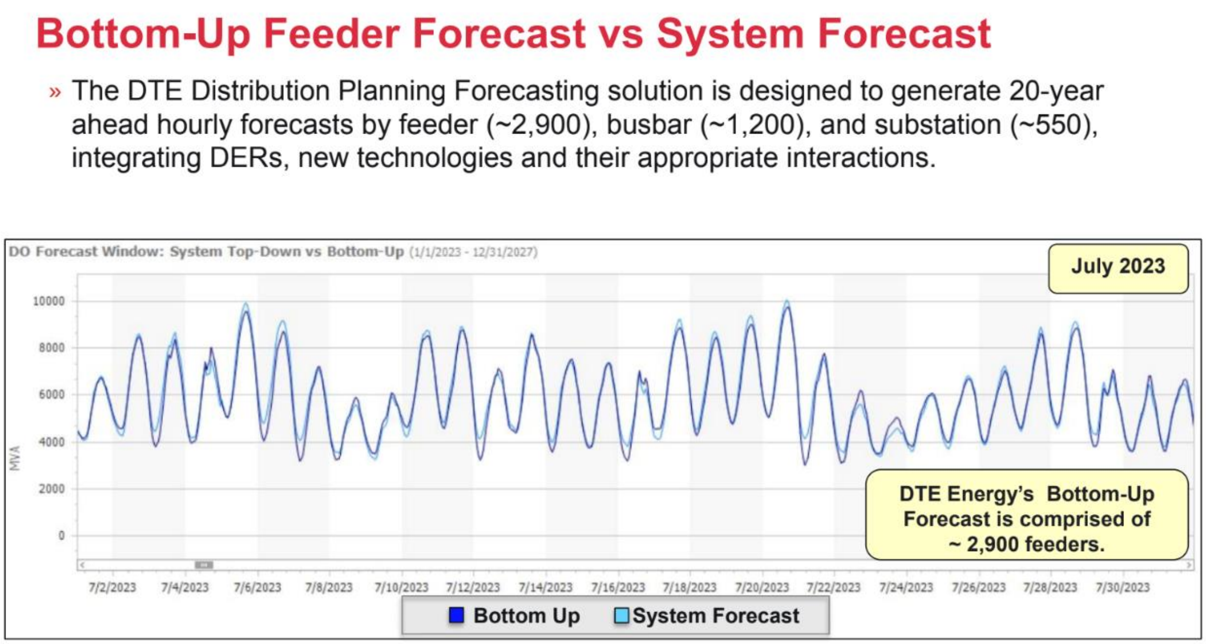
FIGURE 15



Source: Julieta Giraldez's presentation at the workshop.

Andy Sukenik of Itron discussed their approach to integrating top-level corporate forecasts with distribution planning forecasts. Figure 16 shows an example of their bottom-up feeder-level forecasts compared to the system-level forecasts for DTE Energy. To achieve this, he showed their model for a feeder's load as a function of temperature. A different model is created for each hour of the day to capture heat build-up in a building. These models can vary depending on whether the feeder serves residential or commercial customers. The median mean absolute percentage error across the 3,000 feeders in this study was 3.3%. They incorporate a climate change trend into extreme summer and winter weather. Because this can get into temperature ranges that have not been seen before, they extrapolate from their existing models how the extreme temperatures will impact load. Finally, Andy dove into EV load shapes for different use cases and how those impact different levels of the distribution system.

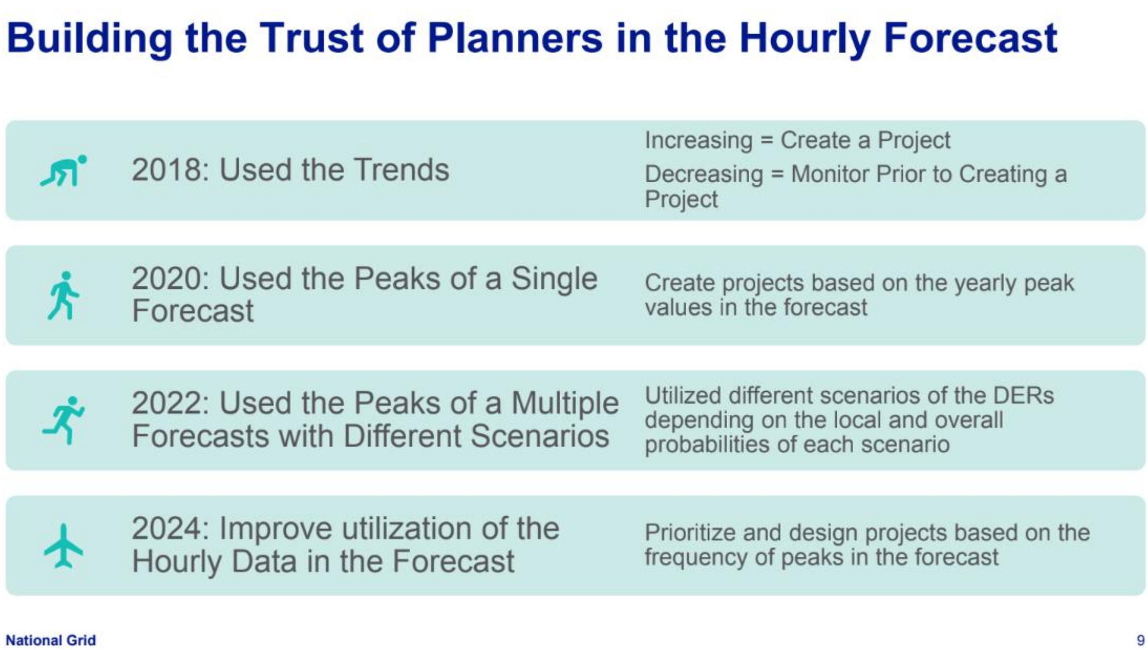
FIGURE 16



Source: Andy Sukenik's presentation at the workshop.

Ryan Hinkley of National Grid spoke about their distribution planning with feeder-level forecasts. They use a bottom-up and top-down approach, examining premise-level data and combining it with policy-driven targets and incentives. They base the forecasts on a 90/10 weather scenario (capturing 90% of weather events). They include low, base, and high levels for their DERs: energy efficiency, PV, EVs, storage, and heat pumps. Using historical loads, and these five DER types, they set up their scenarios (including fossil-free vision and full electrification). For each feeder, they forecast hourly data to 2050. This is built from data for each DER for each scenario. Between 2030 and 2035 they predict that peak demand will shift from summer to the winter. It takes time to build trust with the system planners in these hourly forecasts (Figure 17) Ryan showed a crawl, walk, run, fly approach to phasing in how the forecast is used. A robust panel discussion followed. One panelist noted a rate case during the summer of 2023 that was done using a 2020 grid needs assessment, and how we needed to update these forecasts and models frequently. Ryan mentioned that when National Grid upgrades a feeder, they build to their 2050 forecast to eliminate the possibility of having to revisit that feeder within the short term, but that they do not build until the need for an upgrade is triggered.

FIGURE 17

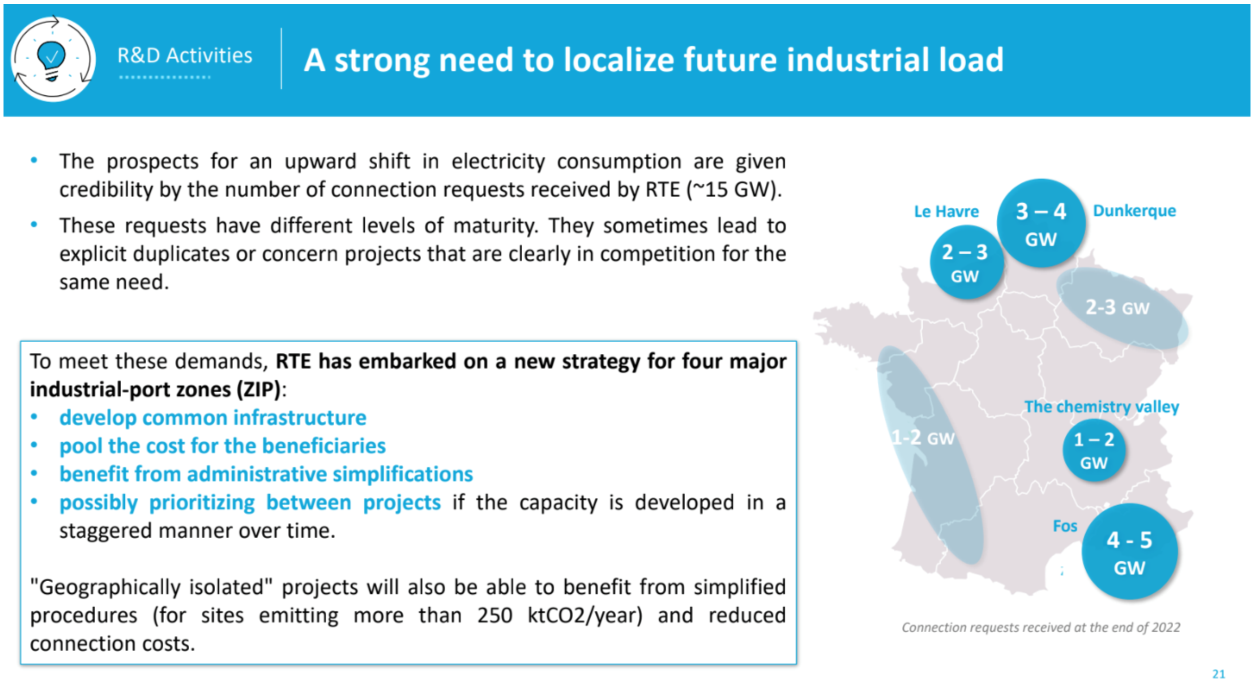


Source: Ryan Hinkley's presentation at the workshop.

Bringing It All Together

The last session focused on bringing all the components previously discussed together to undertake planning of different types at ISO/RTOs, and utilities. **Laurent DuBus** of RTE discussed their *Energy Pathways to 2050* report, which looks at various scenarios to reach carbon neutrality in France, and a 2030-2035 mid-term adequacy effort. This included different load levels based on electrification, efficiency, and increased manufacturing. Scenarios included examination of a successful effort, an effort that is a few years delayed in meeting targets, and an effort that is initially thwarted but stronger in later years. Load forecasting was broken down into sectors: transportation, digital (data centers), heating, and industry. They metered different sectors including submetering within facilities to understand consumption, and from this, they decomposed load curves for various end uses. An interesting finding from their work is the need to localize future industrial load (Figure 18). They have a large number of interconnection requests from load, about 15 GW, and have a new strategy for four major industrial-port zones to help manage this growth.

FIGURE 18

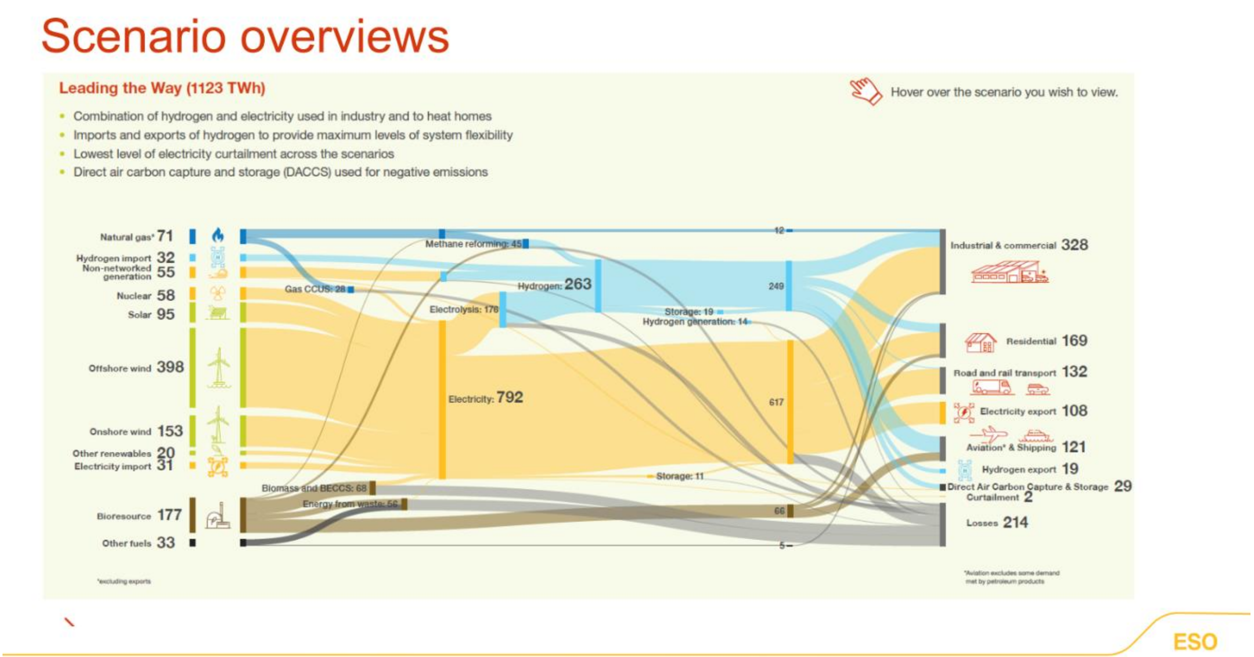


Source: Laurent DuBus's presentation at the workshop.

Sagar Depala of National Grid ESO discussed how they develop credible, bottom-up scenarios for Great Britain: Future Energy Scenarios. These are not probabilistic scenarios but rather represent the edges of uncertainty. National Grid ESO examines a consumer transformation future where consumers are willing to electrify and change behavior to enable flexibility, a system transformation future where hydrogen plays a key role, a leading-the-way future where consumers and the system both come together to transition the grid, and a falling-short future in which progress is much slower (Figure 19). They find that electricity demand increases in all scenarios but harnessing flexibility helps to smooth out peaks. Current high electricity prices in Europe have led to decreases in annual consumption that may last until electrification impacts drive load growth. But peak demand does not drop as much because consumers protect peak demand, the demand that matters most to them. They find a 0.4% and 2.2% forecast accuracy in the one-year-ahead and four-years-ahead time frames, respectively.

While the current stress periods on the system result from cold, dark days, they find that the future grid will be stressed on a low-supply day. Decarbonization of heat and industrial flexibility remain areas of uncertainty.

FIGURE 19

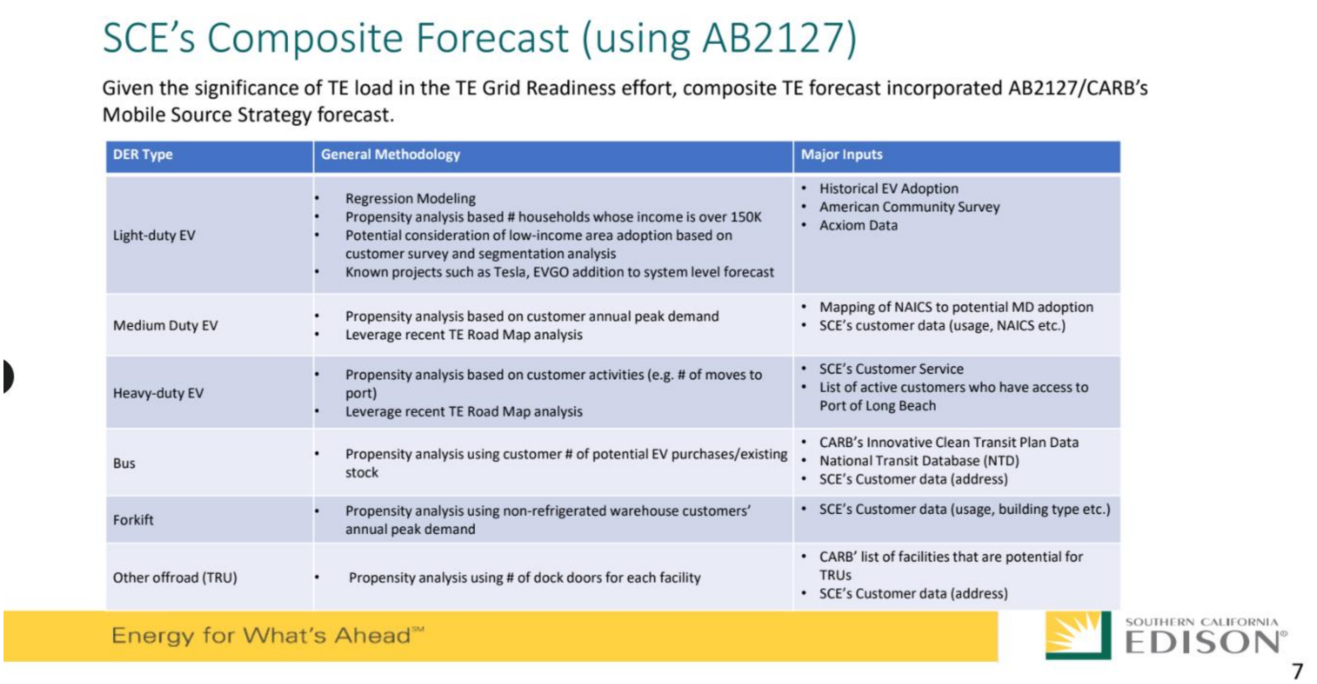


Source: Sagar Depala's presentation at the workshop.

Anupam Thatte of the Midcontinent Independent System Operator (MISO) presented MISO's Electrification Futures study. Three futures were defined with increasing levels of electrification, with a focus on EVs and other electrification including heat pumps, water heaters, dryers, industrial processes, and others. MISO is currently refreshing the MISO Futures, with significant new resources and additional retirements being incorporated. MISO's Regional Resource Assessment analyzes existing resources, planned resources, and forecasted demand and shows a gap starting in the 2027-2028 time period, where additional resources may be needed. Finally, the assessment shows that in 2041, MISO may experience a duck curve pattern in the winter.

Mark Esguerra of Southern California Edison stressed the importance of not using stale forecasts, because policy and other drivers change so quickly. While this may not have a big impact in the near-term, it does in the longer-term where diverging growth rates have a bigger impact. As part of its Transportation Electrification Grid Readiness, Southern California Edison incorporated supplemental demand forecasts from the Air Resources Board and customer-centric disaggregation approaches to identify locations of increased electrification, and identified long lead time projects for planning and proactive early action now (especially regarding land and permitting). (See Figures 20 and 21.) It also looked at key strategic areas and whether their physical potential for upgrades was sufficient, finding 20 substations that could be an issue. Port of Long Beach, as an example, is an important transportation corridor to consider, and its demand may increase by a factor of 10 to 20. The utility uses different methodologies and inputs to forecast adoption for different vehicle classes. It prioritized 10% to 15% of distribution assets for Transportation Electrification Grid Readiness assessment based on the transportation electrification forecast and available grid capacity. Over 90% of the selected locations are along major transportation corridor of near ports, and nearly 70% of the locations are in disadvantaged communities.

FIGURE 20



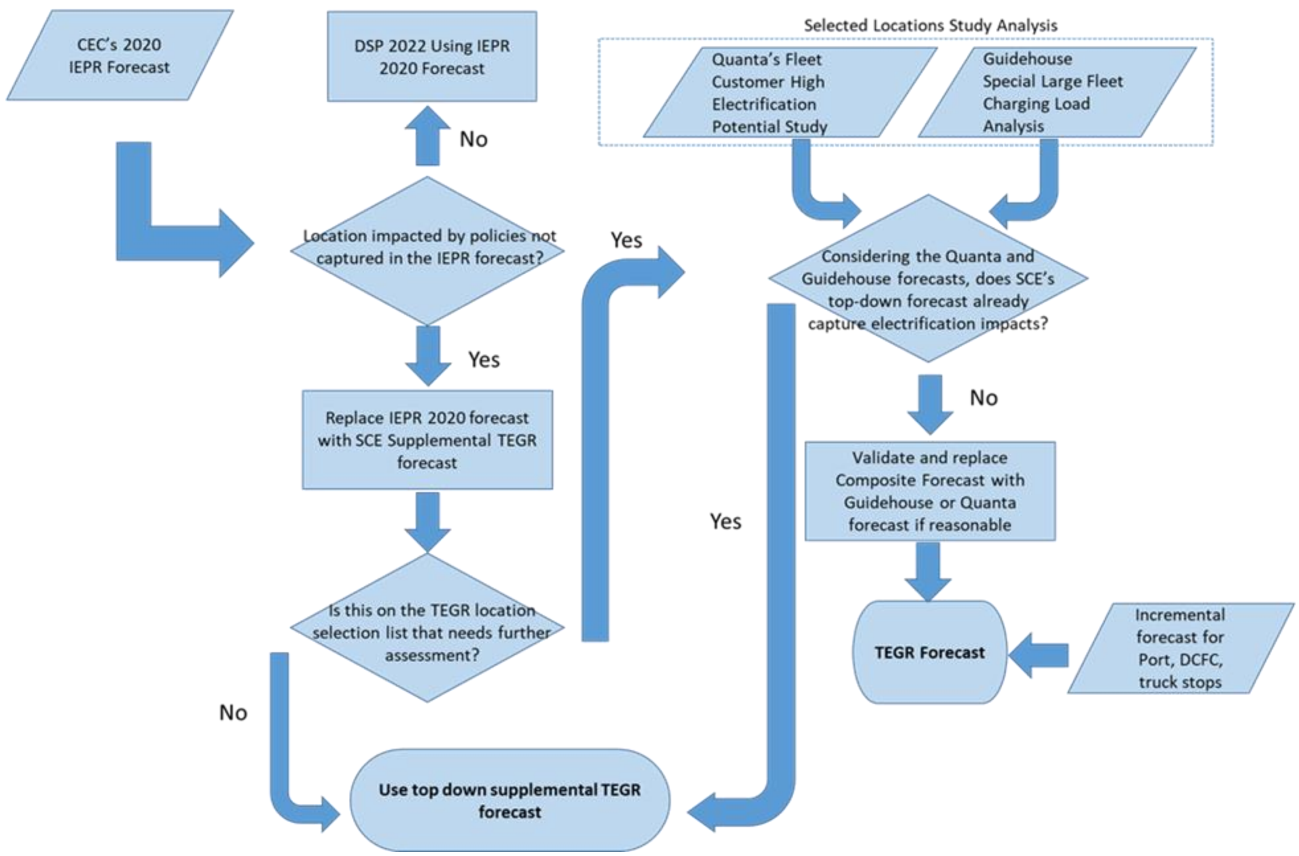
SCE's Composite Forecast (using AB2127)

Given the significance of TE load in the TE Grid Readiness effort, composite TE forecast incorporated AB2127/CARB's Mobile Source Strategy forecast.

DER Type	General Methodology	Major Inputs
Light-duty EV	• Regression Modeling • Propensity analysis based # households whose income is over 150K • Potential consideration of low-income area adoption based on customer survey and segmentation analysis • Known projects such as Tesla, EVGO addition to system level forecast	• Historical EV Adoption • American Community Survey • Acxiom Data
Medium Duty EV	• Propensity analysis based on customer annual peak demand • Leverage recent TE Road Map analysis	• Mapping of NAICS to potential MD adoption • SCE's customer data (usage, NAICS etc.)
Heavy-duty EV	• Propensity analysis based on customer activities (e.g. # of moves to port) • Leverage recent TE Road Map analysis	• SCE's Customer Service • List of active customers who have access to Port of Long Beach
Bus	• Propensity analysis using customer # of potential EV purchases/existing stock	• CARB's Innovative Clean Transit Plan Data • National Transit Database (NTD) • SCE's Customer data (address)
Forkift	• Propensity analysis using non-refrigerated warehouse customers' annual peak demand	• SCE's Customer data (usage, building type etc.)
Other offroad (TRU)	• Propensity analysis using # of dock doors for each facility	• CARB' list of facilities that are potential for TRUs • SCE's Customer data (address)

Source: Mark Esguerra's presentation at the workshop.

FIGURE 21



Source: Mark Esguerra's presentation at the workshop.

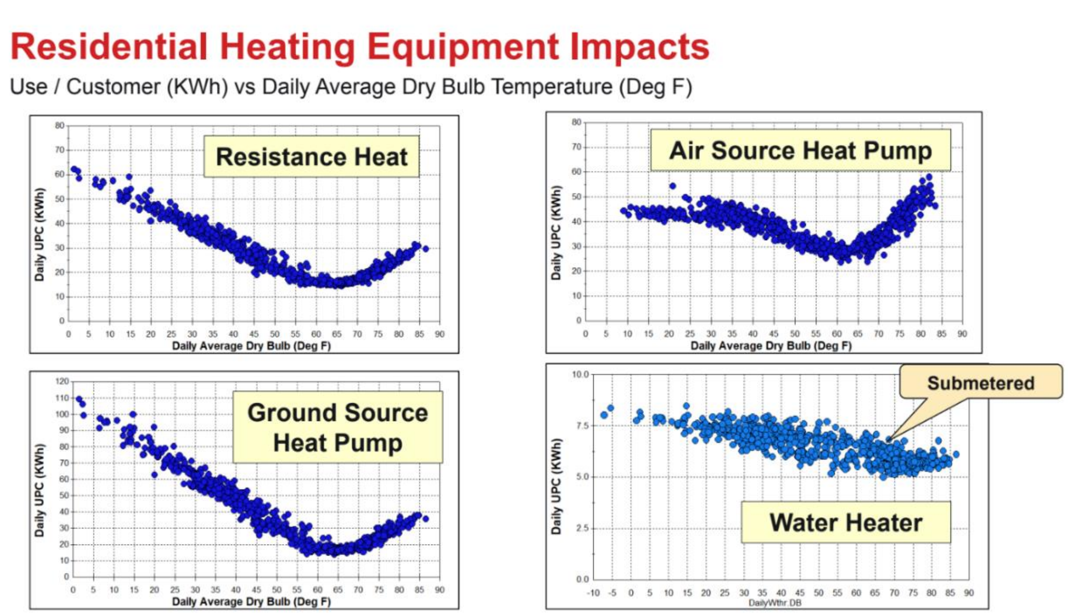
Ryan Jones of Evolved Energy Research explained key modeling considerations that they use with EnergyPATHWAYS, which creates the demand, and RIO, which is a capacity expansion model that is economy-wide and can incorporate sectoral coupling. He focused first on temporal resolution in capacity expansion models. If you are just using a load duration curve method, you do not get the chronology you need to model storage. Day/period sampling is good, but he finds that solutions do not stabilize until about 750 well-chosen time slices per year are used. Finally, hourly (8760) modeling is helpful, but computationally can limit one's ability to look across many years. He then addressed problematic approaches for resource adequacy. He discussed disadvantages to simply adding in thermal capacity to fix loss-of-load events, since that might not be the optimal resource solution. Some models identify super-peak time slices, but really it is net peak load we care about, not gross peak load. Finally, pre-calculated effective load-carrying capability surfaces can work for near-term modeling but are challenging, for example, as you shift from summer peak to winter peak.

Ryan dove into why sector coupling is so important using results from the Annual Decarbonization Perspective 2022. He compared a clean electricity, high electrification, and a zero-carbon economy scenario, all to meet 100% clean electricity by 2050. As you move from the clean electricity to the high electrification to the zero-carbon economy scenario, total load increases as you electrify and then also generate hydrogen to replace other fuels. The supply side becomes more renewables-dominant because hydrogen production provides flexibility. The zero-carbon economy scenario does not use gas with carbon capture and storage (CCS) because gas with CCS is competing for limited geological storage with other parts of the economy. (There is still lots of CCS, it's just not occurring in the power sector.) It is important to include exogenous load for hydrogen because hydrogen for electricity is actually the least economic use of hydrogen. Biomass mostly goes to hydrogen production or to make fuels—less is available for electricity. More than half of load in some regions is for hydrogen production, not for electricity end-uses.

Lastly, Ryan showed how distribution systems could be represented in capacity expansion models. For Pacific Gas and Electric (PGE), he ran an economy-wide decarbonization scenario using 15 feeder archetypes to represent 700 feeders in PGE. He found that feeders with low to medium utilization can absorb large amounts of additional growth and that those that are near the planning threshold (67%) are responsible for most of the avoided distribution capacity.

Andy Sukenik of Itron presented the statistically adjusted engineering modeling framework for load, including heating, cooling, other equipment, PV, and EVs. He then discussed how we might improve existing frameworks. Areas for improvement include calibrating with end use adoption and unit consumption, integrating behavioral impacts, integrating new technologies, and tracking sector-level forecasts daily using AMI data. For example, he discussed how AMI data showed how mobility was impacted by the pandemic, and how the Great Recession of 2008-2009 affected the load of a small number of people and how today's inflation affects the load of a large number of people. He also delved into the need to segment and dive into the details of load. Vermont, for example, incentivized heat pumps, which yielded an increase of saturation from 5% to 17% in four years. They found that the peak load in winter does not occur at extremely cold temperatures but rather at medium-cold temperatures, probably due to backup fuel use by air source heat pumps at very cold temperatures. Further segmentation into specific heating types shows this effect in Figure 22.

FIGURE 22



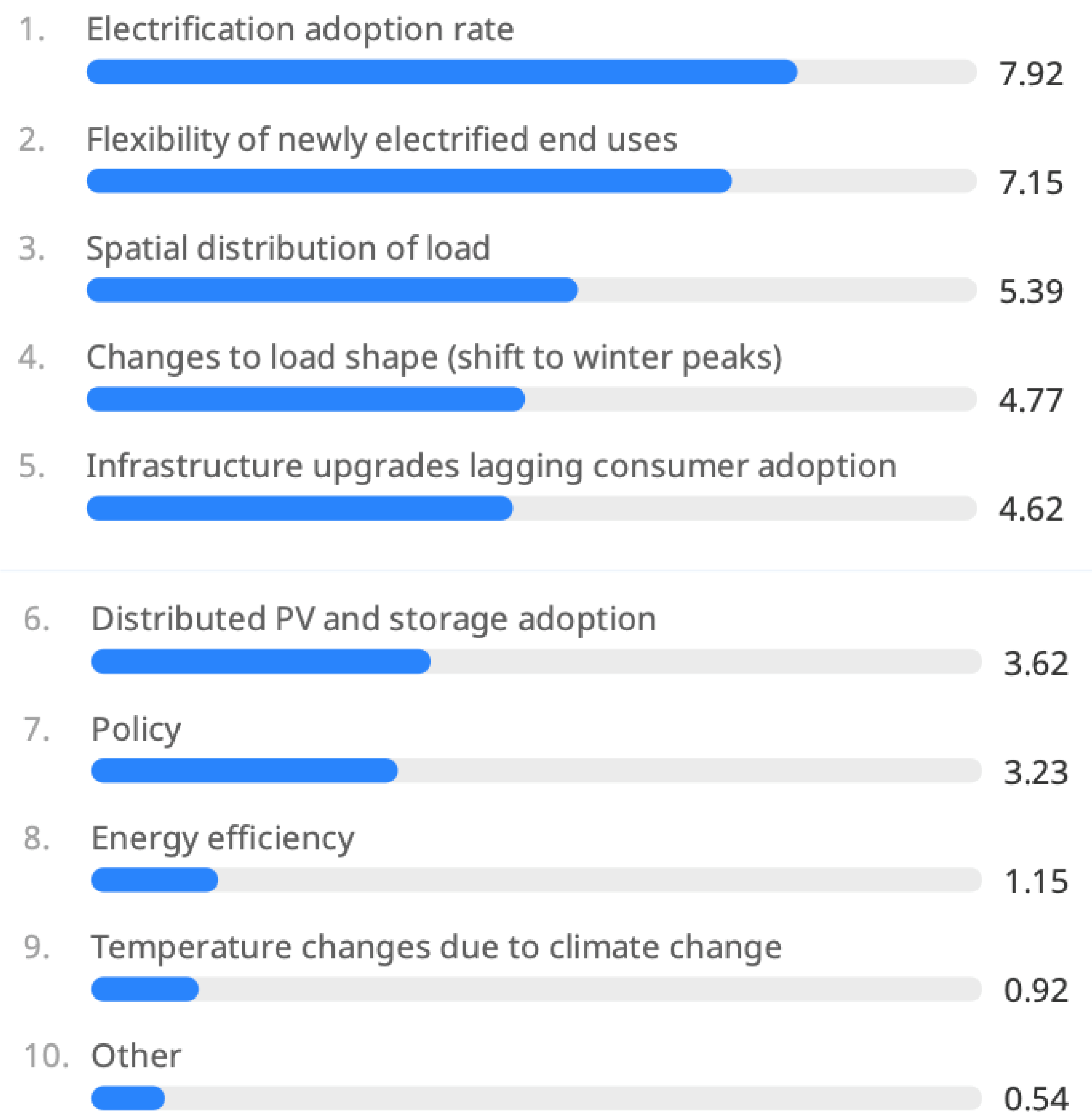
Source: Andy Sukenik's presentation at the workshop.

Key Takeaways

- It is difficult to keep up with the pace of policy changes and adoption trends. Forecasts get stale quickly. Forecasting during the steep part of an S-curve can be very challenging.
- Bottom-up forecasting is increasingly being used at a systems planning level.
- Forecast data need to be appropriate for the type of modeling or planning being conducted. Forecasters need to provide the right type of data and modelers need to understand the limitations of the forecast data they are given.
- Infrastructure upgrades lag consumer adoption of electrification significantly (e.g., transformer orders taking three years or more). Planners may need to consider “non-traditional” measures to compensate (demand management, DER battery storage to manage distribution system overloads, etc.).
- Modeling is improving our ability to understand the various forms of uncertainty in long-term load forecasting, but turning that into decision-making is still elusive.
- While there is agreement that we need demand flexibility, we still struggle with which services to focus on, how to access the flexibility, and whether planners/operators can depend on it.

At the end of the workshop, a couple of polls were taken, and the results are shown below. ESIG is launching a Long-Term Load Forecasting Task Force to continue these discussions and further dive into methodologies, best practices, data needs, and research gaps.

Rank the sources of long-term load forecasting uncertainty that most concern you. 013
(1/2)



What product would you like to see from the Task Force?
(1/2)

022

Description of the state-of-the-art and gaps of Long-Term Load Forecasting

59 %

Limited analysis on specific topic

0 %

Overview of sources of uncertainty

9 %

Deep dive on single source of uncertainty

0 %

Overview of uses of LT load forecasts and which details are important

23 %

slido

Multiple-choice poll

What product would you like to see from the Task Force?
(2/2)

022

Other

9 %

Long-Term Load Forecasting: Workshop Summary

This workshop summary is available at https://www.esig.energy/event/2023-long-term-load-forecasting-workshop/.

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To learn more about work being done in this area, please send an email to info@esig.energy.