Capacity Expansion Modeling for Transmission Planning:

Summary of an ESIG Workshop

Energy Systems Integration Group

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About ESIG

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.

ESIG Publications Available Online

This workshop summary and the accompanying materials are available at https://www.esig.energy/capacity-expansion-modeling-for-transmission-planning/. All ESIG publications can be found at https://www.esig.energy/reports-briefs.

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To learn more about the topics discussed in this workshop summary or for more information about the Energy Systems Integration Group, please send an email to info@esig.energy.

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Purpose of the Workshop

The Energy Systems Integration Group, sponsored by the U.S. Department of Energy, held a workshop on October 24, 2022, to review the capabilities of capacity expansion modeling tools that are currently available and how they can be incorporated in transmission planning. Proactive transmission planning will be a major factor in successfully decarbonizing the economy, and capacity expansion models can be leveraged to guide the development of proactive transmission projects. The need to model transmission expansion alongside generation expansion requires that the value of transmission is accurately represented in the models.

To this end, model vendors, planners, and industry experts were brought together to explore two key questions on integrating transmission planning and capacity expansion models:

- What are today's modeling tool capabilities and how do they relate to transmission planning?
- What do transmission planners need so that capacity expansion modeling can be an effective first step in transmission planning?

Materials were distributed to participants ahead of the workshop and included a model capability grading rubric (Appendix A), a model capabilities summary table (Appendix B), and videos describing the models and their features.

This summary reviews discussions at the workshop about the current state of transmission planning and capacity expansion modeling integration; directs readers to resources for more widespread implementation of these tools in transmission planning; and includes two appendices, the workshop modeling tool summary table and a grading rubric for assessing tool capabilities.

Modeling Tool Capabilities Today

As we move toward a power system with higher wind and solar resources, it becomes increasingly important to consider generation and transmission expansion as an integrated process. However, for many utilities and independent system operators, transmission planning and generation planning are still separate, siloed processes today.

Capacity expansion models are traditionally used by utilities to optimize generation expansion in order to meet demand in the future at least cost (of capital and operations). If the planning process is integrated, once generation portfolios are developed, downstream planning processes may identify additional transmission needs and provide more detailed analysis. However, planners are only beginning to integrate generation and transmission planning in a single planning framework, with even fewer using capacity expansion modeling to guide generation and transmission planning in a single process.

One speaker, who described himself as a user of multiple tools, remarked that the pre-recorded videos demonstrated how far capacity expansion models have come in the last decade. For example, all models can purportedly co-optimize generation and transmission, and many go beyond this to include ancillary services and storage. Some model other energy sectors including hydrogen, transportation, heating, and even representations of the demand side. Many models can represent transmission with different voltage levels or line types with appropriate losses, costs, and length limits, and one can endogenously design an HVDC macrogrid using different types of HVDC technology.

Approaches to Integrating Transmission Expansion Planning

Workshop participants discussed how integrating generation and transmission expansion planning using these models can be done in a variety of ways. Several tools can co-optimize generation and transmission investments, while others integrate the two processes by running transmission expansion using sensitivity cases (that is, additional scenarios) within the capacity expansion model.

Representing the transmission system in the models is usually done as a zonal transfer model (i.e., "pipe and bubble" model), which aggregates nodal transmission topology, improving model runtime and performance, at the expense of model fidelity. This representation provides insight to transmission planners on which zonal interfaces are a high priority for additional studies to determine specific portfolios of beneficial transmission projects (for example, between regions like the Independent System Operator of New England (ISO-NE) and the New York Independent System Operator (NYISO), or between internal zones like Zones J and K in NYISO). Using a zonal representation has some tradeoffs; it limits the detail of transmission expansion options that can be selected in the capacity expansion model, which are typically evaluated as linear increases in transfer capabilities between zones.

Full DC optimal power flow models and nodal transmission representation is also available using current modeling tools, but this approach is typically only done for production cost simulations after a generation portfolio is identified, rather than integrated into the expansion planning model itself. The implementation of these nodal tools for capacity expansion is still at an early stage and faces difficulties in incorporating detailed system data while maintaining model tractability, and this is a major reason why zonal representation is still preferred among planners. A few presentations at the workshop discussed a hybrid zonal/nodal approach, which both generation and transmission planning groups may find promising, as it incorporates operational power flow constraints in the nodal data but allows for simplified transmission expansion between zones in the zonal dataset, which improves model runtime and performance.

Capacity expansion planning today is broadly used as a scenario-based tool to model future generation and transmission needs across many load growth, decarbonization, and economic futures. In using this approach, planners are attempting to identify the least-cost plans that satisfy their planning constraints, typically defined by a planning reserve margin, which accredits generation and demand-response resources based on their ability to meet peak demand needs during hours of high risk to shed load. Many of the modeling tools available are also able to include generation and transmission investment signals that go beyond the planning reserve margin, such as energy deficiencies, scarcity pricing, public policy goals, and measures of resilience. Given the range of planning criteria available for models to co-optimize around, it is important that investments selected by the model, such as transmission expansion, are traceable to system needs, such as meeting reliability planning criteria or relieving transmission congestion. This ensures that planners understand what need is met with the investments and whether the investments available for the model to select are accounting for the entire value of the resource. This is especially true as capacity expansion and transmission planning are integrated and diverse resource types with different benefits are available to be selected.

But while the modeling capabilities are available, many of the hurdles to efficiently planning for a decarbonized future exist as social and institutional barriers. Some workshop participants noted the importance of reflecting the benefits of an integrated planning framework and understanding the complementary nature of generation and transmission in the regulatory structure within which planners operate.

Guiding Principles Discussed

Workshop participants discussed the following guiding principles to aid planners in implementing capacity expansion modeling for generation and transmission planning:

- Optimal expansion planning is a powerful tool for identifying sites where generation and transmission development are cost-optimal and can guide additional studies.
- Capacity expansion planning must not be siloed from transmission, operations, and reliability.
- Transmission expansion can be an investment decision available to the model and co-optimized alongside generation and storage.
- Downstream production cost modeling, resource adequacy modeling, and power flow analysis of an expansion planning portfolio is required to assess operational constraints and portfolio performance. No one tool can evaluate all areas simultaneously.
- Better modeling is important to accurately represent the range of benefits provided by different resources, but there also exist institutional, regulatory, and social hurdles to bringing about more proactive transmission planning.

A Sampling of Participants' Thoughts and Questions About Linking Capacity Expansion and Transmission Planning

After the workshop, comments and questions from workshop participants were gathered and are provided here to illustrate how some experts in power system planning are thinking about capacity expansion and transmission planning. These points highlight questions and concerns that must be addressed to resolve the second major question of the workshop, what do transmission planners need to use capacity expansion modeling in an effective way?

- "Models will be as resilient as the constraints provided to them," meaning that planners must learn how to incorporate resilience stressors into their modeling scenarios.
- "Linkage between [capacity expansion] models and other models is critically important," with particular emphasis on the need to translate zonal capacity expansion models into nodal ones for further analysis.
- "[Capacity expansion] outcomes depend on operations, operations depend on planning, planning depends on simulations of future outcomes. The planning world must re-incorporate operational constraints into expansion models."
- "There is a gap between capacity expansion modeling and planners' actual implementation of these portfolios."
- "Several other studies [show] that high-capacity, low capacity factor, emissions-free resources (for example, emissions-free peakers) tend to be favored among capacity expansion models to meet reserve margins in high-renewable scenarios."
- "Regional models [only] with primary neighbors may be precluding benefits from transmission connections with regions farther away."
- "Power flow does not work the way a pipe and bubble model works."

- "Does transmission have an effective load-carrying capability (ELCC)?" And more generally, is the role of transmission in ensuring an adequate system represented in the models? Non-generating resources, like transmission, contribute to reliability, and accounting for their contribution to all planning criteria improves accuracy for co-optimized generation and transmission plans.

Three Major Needs Identified

Three categories stood out during the workshop that participants felt were high priority for implementing capacity expansion modeling in transmission planning.

Planning Inputs

If capacity expansion modeling is to be an effective screening tool for identifying optimal transmission projects, multiple scenarios must be assessed that can show the range of benefits that transmission projects can provide. As those who have been involved in an integrated resource plan process with capacity expansion models can attest, the inputs are a source of significant contention among stakeholders. Because of limited time and computational resources, model scenarios and input data must be down-selected to include only the most important parameters. Further developments of capacity expansion models should work to be able to include more parameters to broaden the range of system futures that planners can assess while maintaining model tractability. Due to existing limitations, planners must remember that the limited set of scenarios assessed can preclude unknown optimal portfolios from being selected. An iterative approach is needed whereby model inputs and system constraints can be updated based on information from downstream models to avoid overreliance on assumptions around future demand and operational needs.

Of particular importance is incorporating resilience scenarios/events within long-term planning. There is growing concern around community resilience in the face of extreme events and the unknown intensity of future events driven by climate change. Some panelists even recommended incorporating severe storms, such as hurricanes, into expansion planning at frequencies likely to occur due to climate change. While a balance must be struck between the level of risk society is willing accept and the cost of solutions to mitigate that risk, such studies would begin by exploring portfolios optimized to meet these system needs. Many workshop participants believed that planners should begin explicitly incorporating resilience consideration in their future scenarios, including capacity expansion models, noting that if planning does not adequately adapt to changing risks, investments may become stranded or misaligned with community needs.

As the energy transition progresses, inverter-based resources will be deployed in increasing amounts, potentially leading to operational constraints as a limiting factor. It is under these conditions that capacity expansion modeling attempts to forecast future investment needs based on reliability and economic planning criteria. Some workshop participants stated that some level of detail on operational constraints, both for generation and transmission, is important to ensure that expansion portfolios reflect realistic conditions and that resources that contribute to operational reliability, such as transmission or grid-forming inverters, are fully valued across their range of benefits.

Planning Integration

Workshop participants also discussed how planning processes can be integrated across generation and transmission planning groups, enabling planners to realize the benefits of proactively planning for the energy transition challenges that lie ahead while planning for a range of possible futures. A main benefit that capacity expansion modeling provides to system planners is the high-level generation and transmission portfolios required for future system needs. However, the portfolios do not mean anything if they are not adequately linked to downstream analyses. Linkage enables planners to assess how each portfolio operates, which is needed to validate portfolios as economically and operationally sufficient.

As a first step, participants discussed how capacity expansion modeling tools can be used for transmission and generation expansion within a single planning framework. The process could be iterative, where, if downstream analyses (for example, transmission and resource adequacy studies) show infeasibilities or inefficiencies, the capacity expansion model can be refreshed to reflect actual operational constraints. In practice, this will serve to validate how future lower-carbon and higher-renewable-energy systems can be resource adequate, and identify additional system needs that may be required to realize this future.

Although the adoption of capacity expansion tools for transmission planning is still fairly new, the industry is starting to realize the benefits of enhancing transmission planning with these tools. Planners that are lagging have industry leaders they can follow and move out of their pilot phases and into implementation. Participants noted that siloed planning departments can be integrated in order to plan better and smarter for the future.

Downstream Analysis

Lastly, workshop participants discussed the importance of robust modeling linkages between capacity expansion modeling and downstream analysis. By necessity, most capacity expansion models use simplifications of the actual nodal system, turning it into a zonal model. Depending on the market structure in which planners are participating, mapping zonal expansion results to the nodal system may be a required step for additional analyses. If a planning framework is more integrated and includes power flow analyses of the expansion plans, nodal mapping is a requirement.

Regardless of the system representation, it is critical to link capacity expansion results into production cost, resource adequacy, and power flow models. Standardization of communication between capacity expansion, production cost, power flow, and resource adequacy models can ensure that planning is capturing the full range of benefits for future investments. If tools are not adequately set up to assess the multiple values of different resources (such as the resource adequacy benefits of transmission), then the expansion portfolios created are less informative and less useful in the real world.

Participants considered it important to share best practices for linking multi-domain model results and zonal/nodal expansion portfolios for onboarding more planners to use capacity expansion modeling for integrating generation and transmission planning.

Moving Forward

By using the guiding principles outlined above, planners can better integrate generation and transmission planning to meet the energy transition challenge. Workshop participants made it clear that they believe planners will benefit from integrating these systems to proactively plan transmission for a more resilient, economic, and decarbonized grid. As a first step, participants should leverage connections made during the workshop and start sharing their best practices for capacity expansion modeling, identifying and addressing user needs, and integrating capacity and transmission planning. Much of the work called for at the workshop is already being done by first movers in the industry, and many lessons learned from their planning frameworks and modeling perspectives were shared during the workshop and are summarized here as well, but continuing these conversations following the workshop is important for spreading these best practices across the industry.

The materials collected prior to the workshop and the presentations given contain abundant information about how this work is being done, and these can be found at https://www.esig.energy/capacity-expansion-modeling-for-transmission-planning/. This summary includes two appendices: Appendix A is a grading rubric on "good, better, and best" capabilities in eight categories of model attributes, and Appendix B lists the capabilities of existing models as described in our survey of developers.

Appendix A: Model Capability Grading Rubric

Category	Good	Better	Best
Geographic Scope and Timescales	• Pre-defined sub-regions (national or ISO/RTO) with minimal user customization.	• Flexible pre-defined sub-regions which can be aggregated or decomposed based on user preference.	• Fully customizable sub-regions by users. • Nodal representation of regions available.
Spatial and Temporal VRE Data	• Single weather year 8,760 profile for VRE generation profiles. • Generation profiles based on large aggregated grids representing regions, not specific sites.	• Many 8,760 weather year profiles used for VRE generation. • Aggregation or individual resource siting.	• Many decades of weather year data to capture broad variations in VRE generation. • Diversity of resource siting captured using individual resource sites. • Existing or future transmission requirements data for VRE incorporated or definable.
Integration with Other Models	• Capacity expansion output requires processing or reformatting to be used as input into separate models.	• Capacity expansion output is readily available and formatted for use as input into other PCM, RA or transmission models.	• Production cost simulations, resource adequacy and transmission power flow analysis can be integrated with expansion planning process in an iterative fashion.
Co-optimizations	• Energy • Capacity	• Energy • Capacity • Transmission • Ancillary services • Fuel supply • Market and environmental policies	• Includes all of the “better” options. • Can include resource operating constraints and economic price signals (scarcity). • Granular assessment of transmission expansion for greenfield, brownfield, or individual upgrades. • Stochastic risk analysis (e.g., fuel constraints).
Capacity Adequacy	• Planning reserve margin targets. • Capacity value uses ELCC curves.	• Planning reserve margin targets. • Capacity value uses ELCC curves that may be dynamic in the model to represent multi-dimensional dependency of capacity value, such as for solar energy with higher penetration of battery storage. • Economic price signals (scarcity prices, A/S needs, transmission congestion, etc.).	• Production cost and/or resource adequacy analysis informs validity of investment decisions. • Portfolio effects of resources captured in capacity analysis. • Capacity performance across all resource types based on outage and resource availability (weather variability, fuel supply, etc.).
Energy Adequacy and Chronological Dispatch	• Load duration curve with limited or no linking between intervals or chronology.	• 24-hour chronological dispatch over representative time slices. • Timeseries sampling and clustering to maintain peaks and load and renewable correlations.	• 8,760 chronological dispatch. • Representative time slices with 24-hour dispatch which can be varied by stochastic sampling of renewable and load profiles over the study horizon. • Allows for energy-only resources to be built.
Transmission Representation	• Transport model (pipe and bubble). • Can define transfer limits between zones.	• Transport model. • Transfer limits and different voltage or transmission types (AC/DC). • Losses and economic costs of transmission utilization.	• Transport or nodal model that can utilize DC optimal power flow (OPF) in capacity expansion. • Granular transmission system components or portfolios represented. • Sub-zonal transmission or project specific transmission needs identifiable.
Transmission Investment	• Transmission investments are not selected by the model but can be evaluated using sensitivity cases.	• Transmission investments co-optimized with resource expansion in each zone. • $/mile, Capex and cost recovery requirements describe costs. • Distinction between AC/DC lines and voltages based on cost and losses only.	• Investment costs and benefits consider multiple selection criteria, such as voltage, AC/DC, emissions reductions, resource adequacy benefits, production cost savings. • Investment options are available at granular system level (reconductoring, new transformers up to greenfield lines). • Can be used to pinpoint specific system locations for upgrades using nodal representation or screen for high priority zonal interface upgrades.

Appendix B: Capacity Expansion Modeling Tool Capability Summary Table

<table>
<tr><th>Model</th><th>Geographic Scope and Timescales</th><th>Spatial and Temporal Data</th><th>Integration with Other Grid Models</th></tr>
<tr><td>NREL ReEDS</td><td>• National-scale with 134 regions available. Can aggregate regions.
• Typically, multi-decadal timescales.</td><td>• Model uses a single representation of load and renewable production profiles for solve years.
• Profiles can be based on several weather years of load and production data to capture correlations.
• Sites can be binned into resource classes and sub-categorized by interconnection costs.
• Individual sites can also be represented.</td><td>• Tools available to pass ReEDS output to production cost models and resource adequacy models.
    • Production Cost: PLEXOS & SIIP, RA: Probabilistic Resource Adequacy Suite
• No capability to directly pass data back from PCM and RA models into ReEDS.
• Integrated with Distributed Generation (dGen) model for rooftop PV.</td></tr>
<tr><td>EPRI US REGEN</td><td>• National-scale with flexible sub-regional detail down to state or NY zonal level.
• Default 16 sub-regions.
• Typically, multi-decadal with 5-year timesteps through 2050.</td><td rowspan="7">• Model uses a single representation of load and renewable production profiles for solve years.

• Profiles can be based on several weather years of load and production data to capture correlations.

• Profiles can be regional or site specific.</td><td>• Electric sector and end-use demand simulation.
• Non-electric fuels and fuel production.
• Models converge on energy price and quantities available.
• Temperature changes due to climate change are represented in the end-use demand model.
• Tools available to pass REGEN output to production cost models.</td></tr>
<tr><td>Optimal Capacity Expansion Planning Model v2</td><td>• National/multi-national and adaptive to other geographies.
• Typically, multi-decadal timescales.</td><td>• Can be interfaced with other tools like production cost modeling and resource adequacy.
• Other models are not directly integrated with this tool.</td></tr>
<tr><td>EnCompass v6.2</td><td>• Single or multiple ISO/RTO.
• National scale for climate impact plans.
• Typically, multi-decadal timescales.</td><td>• Can be run for production cost simulation, resource adequacy and DC optimal power flow runs.
• Expansion not directly integrated with other results, but the same database can be used.</td></tr>
<tr><td>CGT-Plan (Expansion Planning Modeling System (EPMS))</td><td rowspan="4">• Typically, single or multiple ISO/RTO.

• Typically, multi-decadal timescales.</td><td>• Iterative analysis between EPMS and CGT-Plan expansion output which uses expansion results in production cost models, then modifies expansion plan constraints and re-runs.
• Plans to include resource adequacy assessment within the larger EPMS system.</td></tr>
<tr><td>RESOLVE v2.0 (beta)</td><td>• Can be run for capacity expansion or production cost modeling.
• E3 co-develops Pathways (decarbonization model) and RECAP (resource adequacy model), but these are not directly integrated tools with RESOLVE.</td></tr>
<tr><td>Aurora v14.2</td><td>• Can be run for production cost simulation, resource adequacy and DC optimal power flow runs.
• Expansion not directly integrated with other results, but the same database can be used.</td></tr>
<tr><td>PLEXOS v9.1</td><td>• Can be run for production cost simulation, DC optimal power flow and resource adequacy.
• Can model gas, water, hydrogen and generic commodity markets.
• Expansion not directly integrated with PCM and RA results, but the same database can be used.</td></tr>
<tr><td>Power System Optimizer 3.1 / ENELYTIX</td><td>• Typically, single or multiple ISO/RTO and multiple interconnections.
• Typically, multi-decadal timescales.</td><td>• Model uses a single representation of load and renewable production profiles for solve years.
• Profiles can be based on several weather years of load and production data to capture correlations.
• Profiles can be regional or site-specific.
• User controlled flexible stochastics.</td><td>• Can be run for production cost simulation, DC optimal power flow and resource adequacy.
• Can model adjacent energy infrastructure and Power-to-X/X-to-X. (e.g., methane, hydrogen, water, and heat needs in the economy).
• Roundtrip analysis of expansion with production costing (PCM) and resource adequacy (RA) simulations using the same database.</td></tr>
</table>

Model	Capacity Adequacy	Energy Adequacy and Chronological Dispatch
NREL ReEDS	• Constant seasonal PRM by region taken from NERC long-term reliability assessment. • Dispatchable resources use summer/winter capacities. • Hydropower uses seasonal ratings. • VRE and storage use a capacity factor approximation solved every two years based on net load correlation for 2007-2013 weather year 8,760 dispatch to re-evaluate VRE ELCCs.	• 17 time slices, four daily periods for each season and one afternoon summer peak. • Time slices use average profiles for load and VRE generation. • Between each pair of solve years using a single weather year 8,760 load and renewable profile to determine average and marginal curtailment of VRE and transmission and storage ability to reduce VRE curtailment.
EPRI US REGEN	• Default PRM is set to 7% above peak net load by sub-region. PRM must be met by dispatchable resources within the region. • Capacity credit by resource is based on correlation between resource generation and load from the 8,760 weather year profile used and endogenous to the model.	• Typically, 120 representative hours are created for each 5-year period and energy adequacy is evaluated for each sub-region. • Dispatch is computed for representative hours and weighted by hours represented by the segment. • Energy storage uses a system state approach based on Worgin et al. (IEEE, 2016). • Alternatively, can use a 1 year 8,760 hour static equilibrium approach which allows for fully endogenous storage investments when looking at years further out.
Optimal Capacity Expansion Planning Model v2	• Evaluates 8,760 hourly load profiles against VRE generation, storage charging/discharging and other generation assets. • 8,760 representation captures low wind and solar days.	• 8,760 chronological supply-demand balance considering ramping constraints of different technologies. • Investment decisions are made annually or every five years (can hybridize investment periods).

EnCompass v6.2	• PRM targets using three-point demand curve (min, target, max) for regions or sub-regions.
	• Capacity enforcement can be tailored to annual, month, season, etc.
	• Resources contribute to PRM based on firm capacity contribution (ELCC curves).
	• Demand resources assumed to target peak reduction.
		• Representative periods use average profiles and chronological dispatch within the periods.
		    • Type 1 week uses 7 representative days each month.
		    • Type 2 on-peak/off-peak uses 2 days per month.
		• Timesteps can also be aggregated within periods to provide detail in profiles where needed (e.g., high detail in morning and peak and less midday/overnight)
		• Ending conditions (e.g., storage charge) target beginning conditions for energy limited resources.
		• Demand and VRE profiles are adjusted to maintain peak, peak hour, min load and total energy.

CGT-Plan (Expansion Planning Modeling System EPMS)	• Uses PRM and capacity value inputs by region modeled.
	• Sharing capacity between regions is allowed with deliverability of shared capacity enforced under a 115% of peak load condition.
		• Periods are modeled non-chronologically using time-slices (or "blocks").
		• Typically, 15-20 blocks per year are used to represent the three seasons and several periods of unique interest (e.g., regional peaks).
		    • Least-cost dispatch is modeled for every block.
		• Storage and demand reduction is modeled using adjoining blocks by season.
		    • Charging (discharging) in block *k* is discharged (charged) in block *k+1*.

RESOLVE v2.0 (beta)	• Typically uses PRM and capacity value inputs (net qualifying capacities/ELCC). • Has been used with alternative capacity adequacy approaches (e.g., Hawaiian Electric Energy Reserve Margin). • Sub-zonal transmission investment heuristic trigger helps determine if enough transmission is available at peaks to meet peak resource production.	• Typically uses a representative day approach for dispatch. • Ex) 37 representative days with 24-hour resolution. • Energy only resources can be selected which ignores the need for transmission capacity to be available during peak periods (employed in California Public Utility Commission IRP).
Aurora v14.2	• Uses PRM and capacity value inputs. • Price signals from inadequate capacity provide additional economic incentive to build resources. • Firm capacity input directly by user or determined dynamically as resources are added to the system (ELCC curve).	• Chronological dispatch or load duration curve methodologies available. • Dispatch can be sampled into chunks of hours by days of week or weeks of the year.
PLEXOS v9.1	• Uses PRM and capacity value inputs. • Can incorporate ELCC curves. Economic signals from scarcity, A/S, transmission congestion and natural gas scarcity provide additional incentives for build decisions.	• Three chronology options are available to use depending on system needs. • Fitted, sampled and partial (derivative of load duration curves). • Recommended using fitted or sampled chronology for renewable, storage and demand response modeling.
Power System Optimizer 3.1 / ENELYTIX	• Uses PRM and capacity value inputs. • Also considers reliability and economic constraints (transmission congestion, fuel scarcity, etc.) as drivers for investment decisions. • Firm capacity input directly or determined dynamically as resources are added to the system (ELCC curves).	• Both load duration curves , 8,760 chronological, and representative periods methods are available. • Chronological 8,760 data can be used and aggregated into time slices or time step chunks. • Intertemporal constraints such as storage state of charge targets, fuel constraints, emissions, resource availability are maintained between aggregated time steps.

Model	Co-optimizations	Transmission Representation	Transmission Investment
NREL ReEDS	• Generation, transmission, storage and reserves for bulk power system.	• Power Transfer Distribution Factor transport model between 134 zones. • Representative paths for new transmission based on land slopes and terrain types to identify lowest cost route. • Spur lines connecting VRE sites uses cost adders. Bulk transmission is greenfield single-circuit 500 kV lines. • AC vs. DC lines differ on cost and losses.	• Investments in interzonal capacity expansion based on $/MW-mile costs. • HVDC lines can be modeled as multi-terminal for VSC DC converter stations to allow an HVDC macro grid. • Uses geospatial analysis to account for siting and other land use challenges to transmission expansion to estimate effective distances between zones.
EPRI US REGEN	• Generation, transmission, storage and reserves for bulk power system. • Fuel production/conversion, gas/CO2/H2 pipeline expansions and flows. • Also includes 8,760 hour end-use demand module which is run in iteration with the energy production model to convergence.	• Pipe and bubble transport model. • Intra-zonal transmission upgrades represented with cost adders. • Different voltages or line types evaluated based on costs, losses, lifetime and length limits.	• Every five-year timestep additional transmission between zones evaluated in cost minimization objective. • Costs are based on high voltage AC lines in a $/GW-mile metrics developed by EPRI.
Optimal Capacity Expansion Planning Model v2	• Generation, transmission, storage, and reserves for bulk power system • Adjacent energy infrastructure (e.g., hydrogen production, transport and storage).	• Pipe and bubble transport model. • Different voltages or line types evaluated based on costs, losses, lifetime and length limits.	• Transmission investments based on technology parameters on a cost per MW and cost per MW-km basis.
EnCompass v6.2	• Generation, transmission, storage and reserves, and environmental policies for bulk power system.	• Pipe and bubble transport model with bi-directional limits, losses, tariffs, and flowgates. • Nodal representation is possible with DC power flow which use load and generation shift factors.	• Transmission upgrades available for selection by the model along with resource expansion. • Capital costs and recovery requirements dictate project economics and selection.
CGT-Plan (Expansion Planning Modeling System EPMS)	• Generation, transmission, storage and DERs. • DERs are modeled using a single three-segment, three-bus feeder at each load bus. • Each feeder bus represents rooftop solar, microturbines, energy efficiency and DR which can be selected.	• Characterized as a DC power flow nodal model.	• Transmission investments are represented by expanding line limits, with impedance unchanged. • Investments are also made at the voltage level of the existing line using a cost per MW-mile as a function of voltage level. • New transmission links are modeled as existing zero-capacity circuits.
RESOLVE v2.0 (beta)	• Generation, transmission, storage and reserves for bulk power system. • Includes electrolyzer operations.	• Pipe and bubble transport model with bi-directional MW ratings. • Interface limits can be defined for single or multiple lines and vary over model hours/years.	• The model selects transmission upgrades based on a levelized $/MW-year cost based on capex and financing assumptions. • Sub-zonal transmission upgrade costs triggered by combinations of zonal resource investments to be selected by the model. • Based on heuristics for VRE levels and transmission needs developed by E3.
Aurora v14.2	• Generation, transmission, storage and reserves for bulk power system.	• Pipe and bubble transport model for capacity expansion. • Different voltages or line types evaluated based on costs, losses, lifetime and length limits.	• Transmission investments are represented using sensitivity cases, not selected by the model.
PLEXOS v9.1	• Generation, transmission, storage and reserves for bulk power system. • Adjacent energy infrastructure (e.g., hydrogen, natural gas, heat, water).	• Pipe and bubble transport model for regional zonal configurations. Different voltages or line types evaluated based on costs, losses, lifetime and length limits. • Offers roundtrip integration with Siemens PSS/E power flow software for production cost simulation.	• Investments can be assessed using sensitivity cases or by allowing the model to select transmission upgrades based on cost information and recovery requirements. • Individual transmission component (e.g., reconductoring) upgrades can be represented and selected if nodal representation is used.
Power System Optimizer 3.1 / ENELYTIX	• Generation, transmission, storage and reserves for bulk power system. • Adjacent energy infrastructure, fuel networks, fuel storage and fuel supply and conversions. (methane, hydrogen, heat, water) • Co-optimized expansion of generation, transmission, storage (including impact of duration (MWh vs MW), fuel systems (including	• Pipe and bubble transport model, nodal or hybrid zonal/nodal with bi-directional limits, losses, tariffs and flowgates. • Nodal representation with DC power flow for both Generation and Transmission Expansion Options • Different voltages or line types evaluated based on costs, losses, lifetime and length limits.	• Transmission investments are available for selection by the model based on fixed and variable costs, system constraints, and greenfield vs brownfield. • Full parameterization of transmission investments on par with generation expansion. • Full security-constrained power flow identifies impacts on adjacent facilities and need for concurrent upgrades / installations. • Multiple facilities with different costs and constraints can be evaluated and constrained based on other investments • Individual transmission component (e.g., reconductoring) upgrades can be represented

Model	Model Availability and Base Datasets	Runtime and Performance	Documentation
NREL ReEDS	• Open access but requires a GAMS license and CPLEX license (or open-source solver). • Processed data available with model, raw base data is from public sources.	• A single run with default settings takes <12 hours on 16 GB RAM laptop. • Full-year chronological dispatch or individual site resolution for wind require high-memory or HPC clusters. • Runtimes are 2 days or more.	• Docs: https://www.nrel.gov/docs/fy21osti/78195.pdf • Access: https://www.nrel.gov/analysis/reeds/request-access.html
EPRI US REGEN	• Available through the Electric Power Research Institute. • Development of open-source version is in progress.	• Typical model is for 2015-2050, using 120 time segments for each 5-year timestep and default 16 sub-regions takes ~30 minutes with 128 GB, 6 thread HPC. • 1 year 8,760 hour model takes ~2 hours with HPC.	Docs: https://us-regen-docs.epri.com/
Optimal Capacity Expansion Planning Model v2	• Commercial availability TBD.	• Ex) European energy system model with 70 zones, 8,760 hours per year, 2022-2050, 5-year investment decisions solves in 10-12 hours with HPC. • Reducing slices to every second hour, third day and 12th week (or other combination) allows 32 GB laptops to solve.	• Docs: Not publicly available • Reference provided: https://www.sciencedirect.com/science/article/abs/pii/S0360544221006277
EnCompass v6.2	• License by Anchor Power Solutions. Partnership with Horizons Energy provides National Database (NDB) for licensees. • Data available for 78 markets within NERC. Generation, zonal transmission, fuel prices, load, and A/S forecast data. • Nodal datasets are available for Eastern Interconnect, WECC, and ERCOT.	• Horizons Energy 30-year NERC expansion uses typical on-peak/off-peak 2-days per month and hourly aggregation and runs in ~8 hours. • Annual production cost models take ~1.6 hours per year. • Single large RTO (e.g., MISO), 30-yr expansion ~1 hour expansion and 45 min per year for PCM. • Recommended min 4 cores, 32 GB of RAM with 4 simultaneous 8,760 runs.	• Docs: Not publicly available • Website: https://anchor-power.com/encompass-power-planning-software/
CGT-Plan (Expansion Planning Modeling System EPMS)	• Model is research-grade and users commission developer (Iowa State University) to run.	• Model runtime and performance is dependent on model size and model reduction software used. • Typically, runtimes are 1-6 hours using 300-400 bus models on an Intel-Xeon Linux server having 252 GB RAM and 32 CPUs at 2.70 GHz.	• Inquiries should be directed to James McCalley at jdm@iastate.edu.
RESOLVE v2.0 (beta)	• Users typically commission E3 to develop and run the model. Input datasets offered upon client request. • Open-source license available end of 2022. • No built-in data provided with the model.	• Typically, generation resources, balancing areas are aggregated, and time series sampled to improve runtime. • Runtimes range from minutes to several hours based on aggregations, scope, and timescale.	• California Public Utility Commission Public Release Version: https://files.cpuc.ca.gov/energy/modeling/2021%20PSP%20RESOLVE%20Package.zip
Aurora v14.2	• Licensed by Energy Exemplar. • Data available from Energy Exemplar for resources, load, existing generation and transmission in the United States and Canada. • Capacity expansion futures from Energy Exemplar are also available.	• Model timestep chunks, day/week selection, and size drive the computing and runtime needs. • Some users implement non-standard hardware such as gaming laptops, desktops, or larger virtual machines. • WECC zonal data with out-of-the-box configuration can run standard 25-year expansion in several hours.	• Docs: Not publicly available • Website: https://www.energyexemplar.com/aurora
PLEXOS v9.1	• Licensed by Energy Exemplar. • Data available for 50+ countries. Zonal Electric and Nodal Electric available for U.S., Canada and New Zealand. Fundamental natural gas models also available. • PLEXOS user published datasets, such as Pan-European snapshot or PLEXOS World.	• Provides PLEXOS Cloud platform for scalable cloud computing environment to fit model needs. • WECC zonal data with out-of-the-box configuration can run standard 25-year expansion in several hours.	• Docs: Not publicly available • Website: https://www.energyexemplar.com/plexos
Power System Optimizer 3.1	• Licensed either for PSO engine (standalone) or through ENELYTIX cloud-based platform. • Data available from ENELYTIX for existing generation, load and transmission (zonal or nodal). • Datasets cover North America, Europe, and other select locations.	• Model runtime and performance dependent on size and resolution of the model. • RTO-scale multi-decade expansion models typically solve between tens of minutes to several hours. • ENELYTIX cloud-based service allows for scalable computing environment to fit user needs.	• Docs: Not publicly available • Website: https://www.enelytix.com/home/pso