US-REGEN Unit Commitment Model Documentation

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ABSTRACT

The standard **U.S. R**egional **E**conomy, **G**reenhouse Gas, and **En**ergy (US-REGEN) electric sector model incorporates a relatively stylized representation of dispatch that excludes several operational constraints and unit-level detail. In recognition of these limitations, a stand-alone unit commitment version of US-REGEN has been developed to better understand the short-run costs and engineering challenges of operating the capacity mixes suggested by the full US-REGEN dynamic model. This unit commitment model investigates power system operations on an hourly level for each unit over an annual time horizon and includes constraints related to ramping, turndown limits, and startups, which are not traditionally captured in reduced-form representations of dispatch. Given the significance of transmission and trade as flexibility resources in electricity markets, a novel feature of the model is its endogenous treatment of imports and exports across regions. This report describes the unit commitment model, its capabilities, and its relation to the dynamic version of US-REGEN.

Keywords

Energy
Economy
Unit commitment
US-REGEN

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1
INTRODUCTION

In 2013, the Energy and Environmental Analysis Group at EPRI completed development of the **U.S. R**egional **E**conomy, **G**reenhouse Gas, and **En**ergy (US-REGEN) model (EPRI, 2014; Blanford, et al., 2014). This suite of energy-economic models connects a detailed representation of electric-sector investment and dispatch with a dynamic computable general equilibrium model of the economy while representing regional heterogeneity in resource endowments, costs, demand, and regulations. US-REGEN offers a snapshot of sub-regions in the contiguous United States and their linkages with each other. Figure 1-1 illustrates the model's default sub-regions. The different versions of the model can be used to investigate a wide range of energy and environmental questions related to technological, economic, and policy-relevant issues in the electric sector and beyond.

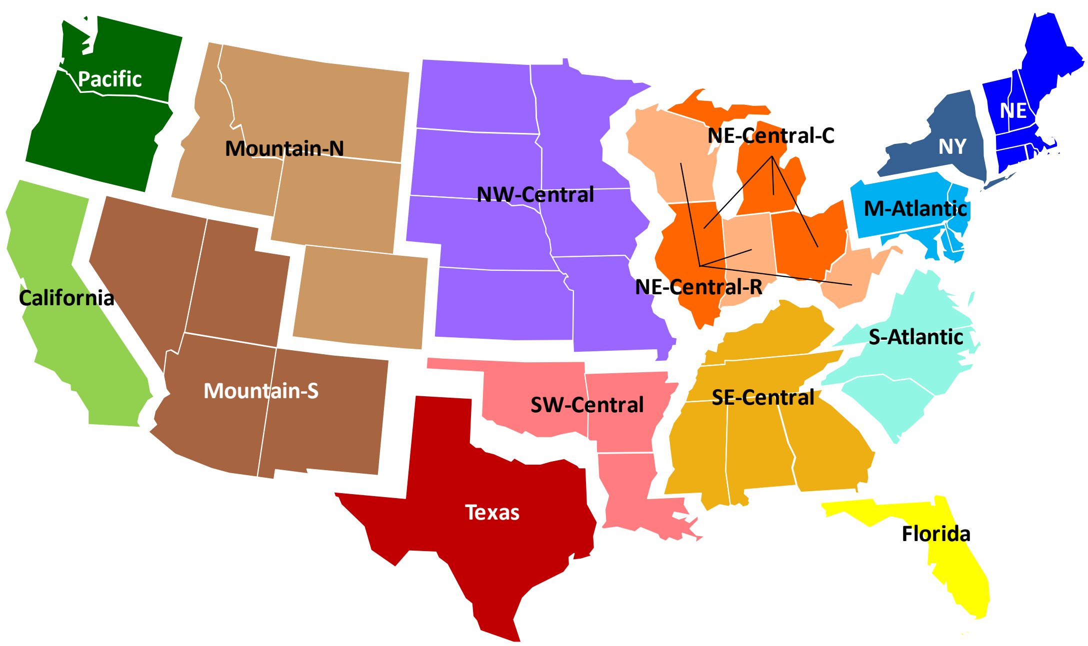

Figure 1-1
Regional Structure of US-REGEN Model

The original, dynamic US-REGEN electric model was formulated as an inter-temporal capacity expansion model, solving in five-year increments through 2050. As for all such models, the computational constraints inherent in solving for capacity and dispatch over long time horizons necessitate simplifications in other areas. In particular, the representation of dispatch is relatively stylized, ignoring many unit commitment and operational constraints.

While the dynamic version of US-REGEN has and continues to yield many insights, the continued penetration of intermittent generation into electric networks increases the importance of system balancing in the short-run, suggesting that quantifying system and unit-level flexibility impacts will be important for system operators, utilities, and policy-makers. Regulatory instruments (e.g., feed-in tariffs, production tax credits, investment tax credits, and renewable portfolio standards) have been introduced or proposed in many countries to incentivize the deployment of renewables. Such incentives are likely to become stronger as technological costs decrease and more stringent and comprehensive climate policies are adopted. All of these factors increase the importance of understanding the role of unit commitment constraints in capacity expansion scenarios.

Although there is significant uncertainty about when and how much new intermittent capacity will appear on the grid, there is a great deal of interest in understanding the potential impacts of this deployment on the existing fleet of generators, economic outcomes, and system reliability. Accurately quantifying the environmental and economic changes induced by intermittent renewable deployment requires detailed modeling of the interconnected electric power system. Recent reports indicate that integrating large amounts of variable generation onto the grid is technically feasible (e.g., IPCC, 2011); however, there are many engineering and economic challenges that could play decisive roles in the actual extent of deployment.

The unit commitment (UC) version of the **U.S. R**egional **E**conomy, **G**reenhouse Gas, and **En**ergy (US-REGEN) model was created to account for the important role of dispatch, temporal variability, and operational constraints in determining the flexibility needs and economic value of assets. UC models decide commitment and dispatch states for individual units, often with the objective of minimizing operating costs, while accounting for technical system constraints. These models represent chronological (i.e., hour-by-hour) power system operations, which are not traditionally captured in reduced-form representations of dispatch (especially in multi-decadal capacity planning models). Capturing these characteristics is critical to understanding the potential long-run impacts and economic implications of different capacity portfolios.

The UC framework complements the other capabilities of the US-REGEN model. The standard US-REGEN electric sector model incorporates a relatively stylized representation of dispatch that excludes several operational constraints and unit-level detail. In recognition of these limitations, the standalone UC model was developed to better understand the short-run costs and engineering challenges of operating the capacity mixes suggested by the full US-REGEN dynamic model.

The goal of these models is to integrate the capacity planning perspective with a unit commitment and economic dispatch one. This approach offers a more complete portrait of power system design and operation. Short-run dispatch modeling indicates the operational costs associated with flexibility, and the long-run investment perspective describes investments and the evolving capacity mix over a multi-decadal time horizon. This framework provides a test bed for assessing flexibility needs in the context of endogenous investments and regional heterogeneity in the composition of the generating fleet.

Based on these analysis needs, the US-REGEN suite of models can be run in different modes depending on the research questions and their level of detail:

- **Dynamic integrated model:** Solves a multi-regional dynamic general equilibrium model of the economy, iterating with a dynamic electric sector capacity expansion model (see below) with a high level of detail.
- **Dynamic electric sector only model:** Solves an inter-temporal capacity planning problem over a multi-decadal time horizon for the electric power sector with aggregated capacity

blocks and a simplified representation of dispatch. The perfect foresight (i.e., deterministic) framework simultaneously optimizes capacity investments and interregional transmission.[1]

- **Unit commitment model:** Given the capacity mix suggested by the electric sector model, minimizes total operating costs and determines the startup, shutdown, and operating schedule for every unit during each hour in a static year.

As suggested in Figure 1-2, there is a modeling tradeoff between operational detail (e.g., including higher temporal resolution) and computational complexity. Operational flexibility is rarely considered in capacity planning formulations due to the difficulty of including high-dimensional mixed-integer unit commitment constraints in large-scale optimization problems. However, capturing these dispatch characteristics is important in understanding flexibility needs and their subsequent impact on investment. Although an intertemporal planning model may ensure that capacity and energy needs are met, this condition is necessary but not sufficient to guarantee that flexibility requirements are simultaneously satisfied. The UC model provides a platform for assessing these flexibility demands in a setting with higher spatial and temporal granularity than the dynamic version of US-REGEN.

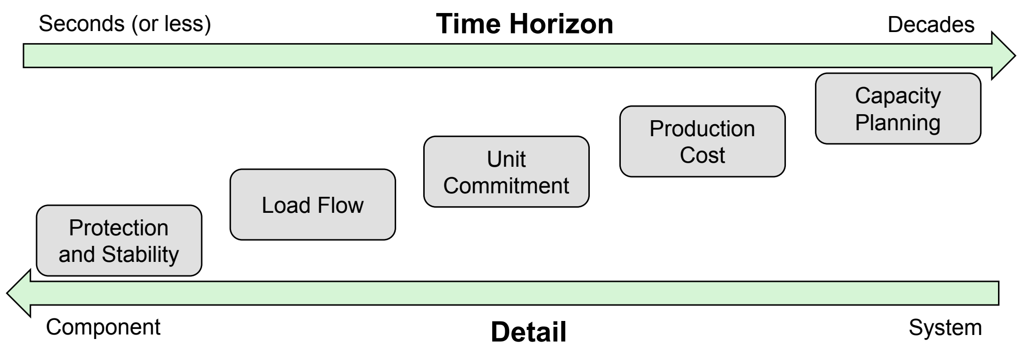

Figure 1-2
Examples of Power Sector Models

Unit commitment and economic dispatch can be thought of as operations sub-problems of capacity planning. However, most intertemporal capacity planning models ignore operating constraints and adopt a limited number of “representative” segments to model temporal variability. The simplifying assumption in formulations with non-sequential hours is that inter-segment constraints can be ignored. This assumption only holds in a restrictive domain for systems where generation flexibility matches the dynamics of net load. In contrast, the UC model’s hourly resolution captures a more complete spectrum of temporal variability of load and variable generation resources than representative segment approaches. These elements of simultaneity and chronological ordering are critical for representing the covariance of resources, trade, and UC constraints in a consistent framework.

Operational flexibility is rarely considered in capacity planning due to the computational complexity of including a high-dimensional mixed-integer UC model. Many models develop

[1] The costs incurred by producers in the optimization problem include investment costs associated with new generating capacity and inter-regional transmission, variable costs scaled by generation (primarily from fuel and variable operating and maintenance costs), and fixed operating and maintenance costs scaled by installed capacity.

capacity mixes with traditional planning models and test the resulting mix with production simulation models (e.g., NREL, 2010). The limited research to include UC details in generation planning suggests that their omission may materially alter the energy production and optimal capacity mix. Palmintier and Webster (2013) suggest that including operational dynamics is especially important in more stringent climate policy environments and when more variable generation is present.[2]

To preserve computational tractability while still incorporating cycling impacts and operational detail, these two versions of US-REGEN share data but run separately (i.e., do not iterate with each other), as Section 2.3 discusses. The solution of the dynamic electric sector model is used to populate the fleet composition for the UC model, which can then determine the operating schedule for each unit on an hourly basis. This soft-linking approach to connect capacity planning and higher-resolution dispatch models is a relatively new technique, which exploits the complementarities between models of different temporal resolutions (Deane, et al., 2012). This framework integrates flexible operations and key engineering limitations into the overall energy-economic analysis. Plant flexibility is represented through parameters like turndown limits (i.e., minimum stable generation), ramping limits, availability, and cycling-induced impacts.[3] Additionally, the UC model and its detailed representation of system operations can be used to improve the dynamic model (or other capacity planning models with greater spatial, temporal, or technical aggregation) to better account for flexibility needs and capabilities.

Given the significance of transmission and trade in influencing electricity market outcomes, a novel feature of the US-REGEN UC model is its endogenous treatment of imports and exports. Support for system balancing will likely come from many resources like fast-ramping capacity, adequate transmission, demand response, storage, and interregional ties. Trade can facilitate the exchange of electricity across regions during periods of surpluses or deficits, especially as intermittent resources comprise a greater fraction of generation and regional electricity markets become more tightly integrated. However, most UC models make simplifying assumptions about imports and exports, often assuming that future trade flows will mimic historical patterns. US-REGEN's integrated perspective models many regions at once to capture the increasingly interconnected landscape for system balancing. Cross-border flows are restricted by net transfer capacities, which are influenced by transmission investments in the dynamic model. As described in Section 2.3, US-REGEN has individual unit detail in the region of interest but aggregates units into capacity blocks for all other US regions. This formulation endogenously determines price-responsive trade positions and hourly market-clearing prices for each region.

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[2] Combustion turbines, in particular, seem to be critical providers of flexibility whose value is not captured in models with simplified dispatch dynamics, which biases capacity and generation values downward.

[3] Note how computational limitations mean that no single model is well-suited for addressing electric sector questions at all levels of resolution. The linked use of capacity planning and unit commitment models illustrated here demonstrate the insights from leveraging the respective strengths of both models.

2
UNIT COMMITMENT FORMULATION

2.1 Overview

The unit commitment (UC) and economic dispatch US-REGEN model determines the startup, shutdown, and operating schedule (including unit-specific output levels) for every unit during each hour of an annual time horizon. The model takes the perspective of a grid operator that minimizes total operating costs while meeting electricity demand and satisfying other system constraints. The model represents a wholesale electricity market where an operator uses a UC algorithm to order up generation based on bids from market participants and on perfect forecasts of electricity demand and renewable resources.

Combining economic dispatch with UC constraints results in a mixed-integer optimization problem with the objective of minimizing operating costs for all units in all regions. The four primary constituents of total operating costs are variable O&M costs, fuel costs (with output-dependent heat rates), startup costs, and shutdown costs. The UC model contains constraints like a load balance (market-clearing) condition for each region, maximum and minimum output levels for each unit, transmission constraints, optional operating reserve requirements, startup and shutdown logic for generators, minimum up and down times, and maximum ramp rates. UC-specific constraints describe the state dependence of system operations and linkages between variables across chronological periods, which are critical in understanding the engineering and economic implications of system operations.

UC models like US-REGEN can be viewed as deterministic production cost models that determine the cost of operating a particular power system given a set of system constraints. The problem of allocating demand across a fixed stock of available generators minimizes cost while simultaneously satisfying a variety of operational constraints. The UC version of US-REGEN is a deterministic hourly chronological UC and economic dispatch model. Other models (e.g., PLEXOS) can have subhourly detail, power flows,[4] or represent uncertainty (e.g., in security-constrained UC frameworks) for reliability modeling.

A novel feature of the US-REGEN UC model is its treatment of imports and exports. Trade may be an important flexibility resource to facilitate the exchange of electricity across regions during periods of surpluses or deficits. However, many existing UC models make simplifying assumptions about imports and exports, often assuming that future flows will match historical values. US-REGEN's integrated perspective models many regions at once to capture the increasingly interconnected landscape for system balancing. Transmission investments are made in the dynamic model and transferred to the UC framework, as discussed in Section 2.4.4.

[4] Power flow models typically represent one hour at a time and contain a much larger number of security and transmission constraints than the US-REGEN UC model.

2.2 Computational Difficulties

The combinatorial expansion of potential commitment states make the UC problem a computationally challenging one, especially as the number of generators and length of the horizon increase (let alone to incorporate a full UC problem in a multi-decadal capacity planning model). Integer variables for operation create a large combinatorial space of possible commitment states, which makes it difficult to find an optimal solution with large numbers of units in a region of interest. For instance, a simplified UC problem for a power system may have 100 generators with 2 possible commitment states (i.e., on and off), which would give rise to $2^{100} = 1.27 * 10^{30}$ configurations in each period. An annual run for this system with 8,760 hours would give rise to an even larger system.

However, numerical issues are important to overcome for year-long UC problems with large numbers of generators. Time horizon considerations are especially important so that models can capture the seasonal and diurnal variations for load, wind resources, and solar resources as well as the corners of their joint distribution across regions. The treatments of unit aggregation and geographical heterogeneity are significant, because modeling multiple regions simultaneously creates the possibility of investigating cross-border trade in the provision of flexibility. Most UC models limit the number of units in a region of interest and typically do not explicitly model commitment and dispatch decisions in neighboring regions, which means that endogenous trade cannot be investigated in detail. The remainder of this section describes how US-REGEN addresses these challenges to investigate annual runs for all US regions.

To make a UC model of the entire US computationally tractable, US-REGEN has individual unit detail in the region of interest but aggregates units into capacity blocks (with the same identifying characteristics as the dynamic model) for all other regions.[5] This assumption implies that unit-commitment-related constraints are not included outside of the region of interest. Runtimes are also reduced by introducing a minimum threshold on unit sizes for explicit inclusion in the UC model.[6] This formulation allows price-responsive imports and exports to and from adjacent regional markets and can determine location-specific market-clearing prices. The bilateral flows assume that traded electricity is a homogenous good and that trade is constrained by transmissions across (but not within) regions. Constraints in the UC model ensure that the power flows are consistent across regions on an hourly basis and are subject to trade-volume constraints (i.e., do not violate physical transmission constraints in the balancing area). The shadow price on the transmission-volume constraint equals the price differential between the trading regions less transmission charges.

US-REGEN overcomes challenges associated with combinatorial expansion of commitment states and accelerates UC computation by employing a rolling commitment horizon solving approach. This strategy links shorter optimization horizons (e.g., twelve one-month periods instead of an entire year) by rolling forward in specified increments with sufficient overlap to

[5] Economic decisions in other regions do not account for unit-commitment-related costs (e.g., costs associated with rapid ramping or startup), which means that model results likely understate engineering and economic challenges associated with flexible system operations in other regions.

[6] Units smaller than this threshold value are aggregated and dispatched according to their historical availability factors. After testing and calibration, a threshold of 40 MW was selected to reduce runtimes while not compromising solution quality.

avoid beginning and end effects. The model optimizes over both the simulation and look-ahead (i.e., overlap) periods. The use of rolling commitment horizons offers the capability of more easily parallelizing the problem in the time domain. Figure 2-3 illustrates this partitioned horizon approach with overlapping periods.

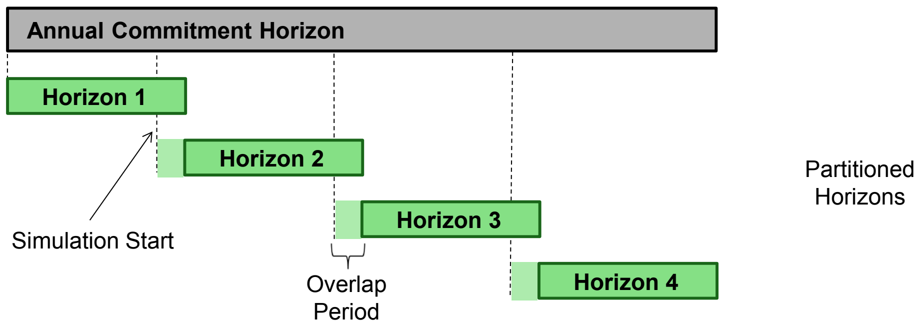

Figure 2-1
Diagram of Rolling Commitment Horizon Solving Approach

2.3 Assumptions

The primary decision variables in the model indicate the schedule of commitment, startup, and shutdown for each unit in each period. These binary UC variables prevent units from operating in the infeasible region (i.e., dispatched below the minimum feasible load) and give rise to the mixed-integer formulation of the UC optimization problem.

Fuel use characteristics and emissions are impacted by operating at output levels lower than their maximum rated outputs, which leads to a reduction in unit efficiency (i.e., increase in a unit's heat rate). The relationship between unit output and heat rate is poorly understood due to a lack of public data and systematic experiments under a range of operating conditions. EPRI (2011) is the first publication to quantify the effects of load following on heat rate. US-REGEN adopts the functional form based on this work and selects the heat rate penalties at minimum output for different capacity types based on consultations with literature and EPRI researchers.

The UC model currently reports the zonal wholesale price of electricity for each hour (i.e., time segment) in each region. This marginal price is based on the load-balance constraint dual variables, which enforce balancing between generation and load plus net exports (including line losses). The shadow price of this market-clearing constraint at optimality equals the change in the objective function value if the binding load constraint could be relaxed by one unit. Transactions across regions are driven by cost differentials that make it more economical to purchase electricity from neighboring areas (after accounting for trading costs) than to generate within the region owing to heterogeneity in supply- and demand-side conditions. Since market power is not represented (i.e., cost-minimization is assumed to obtain the market equilibrium), differences in the wholesale market-clearing prices across regions in equilibrium typically arise when transmission constraints are binding and prices cannot be equalized across regional markets. Transmission resource scarcities are more common in periods when excess generation from intermittent resources cannot be exported to other regions and must be spilled.

Unlike the dynamic US-REGEN model where similar units in a region are aggregated to facilitate computation, the UC model retains individual unit detail for most of the fleet in the region of interest. Operation-related decision variables are indexed over the set of all units in the US-REGEN region greater than 40 MW.[7] Units smaller than this threshold operate according to historical dispatch characteristics. Since intra-regional transmission is not modeled, variable generation resources across a model region are aggregated by their capacity types and dispatched as blocks. Wind and solar technologies can be curtailed during periods of overgeneration.

The upstream code for the UC model harmonizes data with the dynamic version of US-REGEN. However, transferring results of dynamic runs requires a few simplifying assumptions to downscale aggregate capacity block retirements and additions (which are decision variables for the dynamic model) into individual units for the UC model. For each capacity type in each region, new units are added with average sizes suggested by the NEMS Electricity Market Module (EIA, 2013) until the total capacity in the UC model equals the dynamic model. Retirements also loop over each capacity block in each region and remove units until the capacity in the two US-REGEN models converge. The model follows the decision rule of retiring the oldest units of a particular capacity type first.[8]

The UC version of US-REGEN also gives the option to allow capacity rentals in a given region. The actual peak load in some regions may not captured in the representative hours in the dynamic model. This gap occurs as a result of the hour selection process, which stresses the maximum load relative to variable generation output instead of the maximum itself (EPRI, 2014). To account for this discrepancy, the peak demand hours for the eastern and west interconnects were added to the extreme-spanning and clustering hours; however, these two hours may not capture the true peak in each region.

Capacity rentals in the UC model serve a role analogous to a backstop, whereby a high-cost representative technology is capable of supplying electricity to satisfy demand during peak hours and to prevent capacity shortfalls (in regions where the dynamic model does not build quite enough capacity to cover the year's maximum load hour). Thus, the ability to rent units ensures that capacity recommendations include sufficient flexibility to operate the system feasibility. For these runs, the only type of capacity that can be rented is a combustion turbine. The amount of additional capacity rented by the UC model is one way to measure the discrepancy between dispatch in the UC and dynamic models. During the small number of intra-annual segments that require capacity rentals to supply the last unit of generation, the shadow price of the market-clearing constraint will include this high rental cost. Thus, during a small fraction of hours in some regions, wholesale electricity prices will be at least an order of magnitude higher than the dispatch cost, which means that the average annual price reflects the complete long-run marginal cost of supply.

[7] The level of disaggregation for many model features can specified by the user for different applications through the modular upstream capabilities.

[8] If retiring the oldest unit would exceed the cumulative dynamic model retirements, then the UC model lowers the capacity of the oldest unit online.

2.4 Data Reconciliation and Model Calibration

2.4.1 Generator Characteristics

Data were obtained and compiled for each existing generating unit in the US. Many values are expressed on a unit-specific basis like minimum[9] and maximum capacities, rampup and rampdown limits, and fully-loaded heat rates. Other parameters take on capacity-block-specific values from their corresponding dynamic US-REGEN classes, including fuel prices (which vary by region and are based on dynamic runs), variable O&M costs, and availability factors for each segment. Other parameters are specified on a fuel-specific basis such as startup and shutdown costs, minimum up and down times, and the assumed heat rate penalty at minimum output levels. Unit-specific values are based on 2010 Form EIA-860 data (Annual Electric Generator Report).

For the dynamic model, decision variables are indexed by region and by capacity block type.[10] The values of performance attributes for blocks of existing capacity are calculated as the capacity-weighted average across units in that respective block. These capacity blocks are dispatched for each annual load "segment" (i.e., intra-annual period representing load and resource availability) without accounting for UC constraints. The temporal resolution for dispatch in the dynamic version of US-REGEN differs from the UC model in that only a select number of representative hours are included in the dynamic model instead of the complete set of 8,760 intra-annual hours, which is used in the UC model. Bilateral transfer capacity constrains power flows across regions for each segment but can be adjusted through transmission capacity investments in the dynamic model when such assets prove economically viable. For the optimality conditions to describe a competitive equilibrium outcome, capacity blocks are dispatched in each region in increasing order of marginal costs for a given segment but does not capture unit-commitment-related costs. This market-clearing requirement simulates the clearance of both energy and capacity markets.[11]

Data for the dynamic US-REGEN model come from a range of sources. Energy and fuel data are provided by the Energy Information Administration (EIA) of the U.S. Department of Energy.[12] The model uses cost and performance data from published and publicly available EPRI reports (Technical Assessment Guide 2009, Renewable Energy Technology Guide 2009), including 2011 updates from the EPRI Energy Technology Assessment Center.

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[9] Note that the minimum load as a percentage of the maximum capacity is determined at a capacity-block level.

[10] The dynamic model considers the following generator types when installing new capacity: Supercritical Pulverized Coal (SCPC) without Carbon Capture and Storage (CCS) with full environmental controls, Integrated Gasification Combined Cycle Coal (IGCC) with and without CCS (90% or 55% capture), Natural Gas Combined Cycle (NGCC) with and without CCS, Natural Gas Combustion Turbine, Dedicated Biomass, Nuclear, Hydroelectric, Geothermal, Wind (on-shore and off-shore), Solar Photovoltaic (central station and rooftop), and Concentrating Solar Power (CSP) (solar thermal).

[11] In the model's deterministic structure, constraining electricity generation to equal load in each segment is tantamount to the implicit stipulation that sufficient reserve and capacity investments occur to balance supply and demand in the peak segments. Thus, the reference version of the dynamic model does not explicitly incorporate auxiliary markets, though US-REGEN has the ability to incorporate spinning reserve or reliability (i.e., non-spinning) reserve constraints for applicable scenarios.

[12] The dynamic electric sector version of US-REGEN uses data from the EIA's 2014 Annual Energy Outlook (EIA, 2014) and adopts AEO 2014 values for the projected level of energy demand over time and reference energy prices.

Availability factors for existing capacity in the dynamic model are selected to account for average outages through a de-rating process. Most units operate at full capacity subject to dispatch for many hours of a typical year but must go offline for scheduled and unscheduled maintenance. However, planned downtime typically coincides with periods of lower demand, which means that a flat de-rating procedure would underestimate the availability of capacity during peak times. On the other extreme, not accounting for plant outages will overestimate availability, which is especially important for coal capacity. Since no hourly data for unit availability are publically available, the model uses EIA data for monthly generation totals by region. It is assumed that the monthly variability shape remains the same for each period of the model's time horizon. The availability factors implicitly include the calibrated base year (2010) reserve margins, since the calibration process does not distinguish between outages and units in reserve. Details of the dynamic model's calibration approach can be found in EPRI (2014).

2.4.2 Load

Synchronous historical hourly load data at the state level were derived from FERC Form 714 (Part III Schedule 2) reporting at the NERC region level, which are based on observed data from 2010. Hourly shapes are scaled to match electricity consumption as reported by the EIA for each state. The shape of wholesale power demand for each intra-annual hour in each region is assumed to have a static profile over time but is scaled by the exogenous trajectory of demand growth used in the dynamic model (based on the Annual Energy Outlook reference case). This hourly temporal granularity is important in characterizing emissions behavior due to the intraday nature of variable generation and its interaction with load.

2.4.3 Intermittent Renewable Resources

The spatial and temporal distributions of renewable energy resources and their associated costs are essential considerations in modeling these intermittent and uncertain[13] resources. In particular, models should capture positive and negative correlations between load, renewable resource variability, and uncertainty across adjacent regions given that resources are non-uniformly distributed in space and time. Representing periods of resource extremes is especially important in understanding capacity and generation needs across regions.

These considerations motivated US-REGEN's regional detail in describing the location of wind and solar resources relative to load centers (EPRI, 2014). The representation of intermittent renewable resources was informed by a collaboration with AWS Truepower to develop hourly data based on 1997–2010 meteorology. In order to preserve synchronicity, correlation, and variance, the output profiles from 2010 are used, as these values fall near the center of the distribution while exhibiting considerable variability. Wind output profiles were constructed by aggregating across 5,000 sites (accounting for protected and developed land) into eight onshore and one offshore wind classes based on resource quality. A similar screening and aggregation technique was applied to land and resource quality for central-station solar photovoltaic or concentrating solar power. Another dataset was created to estimate rooftop PV potential, and this profile was based on hourly data from 300 cities.

[13] Note that uncertainty is not captured in either the dynamic or unit commitment versions of US-REGEN.

The specific technological assumptions underlying these renewable resource profiles are discussed in greater detail in other US-REGEN documentation (EPRI, 2014; Blanford, et al., 2014). The dataset of hourly wind and solar output by resource class and state for the UC model are identical to the dynamic US-REGEN values.

Although the profiles for variable generation and load are critical factors in appropriately evaluating renewable investments, current computational capabilities cannot solve the full intertemporal optimization problem of capacity planning and dispatch for each time period, each region, and each technology in all 8,760 hours. In order to retain information about the temporal variability of wind, solar, and load, the dynamic version of US-REGEN employs an hour selection algorithm to select representative segments by stressing extremes of their joint distribution. The strategic selection algorithm (discussed in EPRI, 2014) reduces the intra-annual shape resolution by two orders of magnitude, using 86 segments to capture the joint temporal variability of renewable resources and load across all 15 model regions. The objective of the selection process is to maintain key characteristics of the disaggregated temporal data in the reduced form model through these strategically chosen segments.

In the UC model, renewables are treated as zero marginal cost generators. The hourly availability of intermittent resources depend both on the installed capacity and maximum available feed-in based on wind speeds and solar irradiation. Curtailment is available for wind and solar and is assumed to be costless.

2.4.4 Interregional Transmission

Accurately representing inter-region transmission is an important determinant in understanding how flexibility needs can be met in a given region and in the cost of their provision. The ability for a region to import or export power from or to neighboring regions to can provide balancing support during resource surpluses or deficits, marginal cost disparities, and unexpected system events. Such trade dynamics may lower grid integration costs, improve the competitive position of wind and solar, and require less backup than if regions were forced to balances resources with demand independently of each other. The model disaggregation and higher regional granularity of variable generation resource bases discussed in the previous section allow identification of higher quality resources, which makes areas potentially more competitive than average resources over a less disaggregated geographical area. Although increasing geographic diversity may mitigate the frequency of operational extremes, these opportunities can only be exploited through transmission builds that link diverse sites with load centers.

The dynamic and UC versions of US-REGEN model transmission capacity and flows between (but not within) regions. These inter-regional net transfer capacities do not explicitly represent a detailed transmission or distribution networks but do capture the grid-bound nature of transmission and indicate the size of the cross-border infrastructure. This “pipeline” approach models aggregate investments (in the dynamic model) and flows (in both models) but does not account for network effects or Kirchhoff’s laws like many security-constrained unit commitment models do. Data for existing inter-regional transmission capacity come from the IPM model (EPA, 2010) and are mapped to US-REGEN’s sub-regions.

In the UC model, the market-clearing conditions require generation and load plus net exports, including line losses, to balance in each time segment in each region. The complementary slackness optimization condition for trade suggests that, if the marginal unit in one region has a higher dispatch cost in a given segment than the marginal unit in a neighboring region (including an adjustment when loss factors are present), then transmission with the adjacent region would be fully utilized.

2.5 Caveats

The UC version of US-REGEN can be used to understand power system operations on an hourly level for each unit over an annual time horizon with constraints on ramping, turndown, and startups, which are not traditionally captured in reduced-form representations of dispatch. Given the significance of transmission and trade as flexibility resources in electricity markets, a novel feature of the model is its endogenous treatment of imports and exports across regions. When interpreting model outputs, it is important to be mindful of these capabilities as well as other assumptions in formulating and characterizing power system dispatch.

- **Deterministic structure:** The optimization formulation of the UC model implicitly assumes perfect information of forward-looking agents. The perfect foresight framework of the model means that some dynamics of system operations and values of certain assets may not be appropriately captured. For instance, studies have suggested that real-time pricing may be able to alleviate unforeseen forecast errors (in wind and demand) by responding to events quickly and provide a substitute for fast-ramping capabilities (Mills and Wiser, 2014). The UC model cannot capture the value associated with mitigating these deviations from day-ahead forecasts.
- **Hourly temporal resolution:** The temporal structure of the model omits impacts of subhourly variability and its associated operational difficulties. Again, these exclusions mean that US-REGEN is not a suitable testbed for answering detailed questions about ancillary services, storage, or forecast error when subhourly detail is critical.
- **Unit-level data for the region of interest only:** Although the UC model captures unit-level detail in a specified region for a given run, it aggregates units into capacity blocks for adjacent regions, which means that UC-related unit constraints are not applicable outside of the region of interest. This formulation allows price-responsive imports and exports to and from adjacent regional markets (unlike most other UC models, which treat these dynamics exogenously) but overstates the provision of flexibility from other regions and their ability to adjust dispatch rapidly.
- **Rolling commitment horizon:** Although the partitioned horizon approach enables year-long runs, not having one-shot annual runs makes interpretation of capacity rental challenging, difficult to enforce compliance for policies with annual requirements, and introduces potential fidelity issues with actual commitment decisions.
- **Exogenous demand:** The model currently assumes that price changes will not cause consumer demand to deviate from the reference profiles (i.e., assuming a zero price elasticity of demand). Although demand-side management could potentially play an important balancing role, price-responsive demand is not incorporated in the UC model.
- **Exogenous fuel prices:** Like electricity demand, the prices for fuels are based on outputs from the dynamic US-REGEN model (which are themselves based on the most recent AEO projections) and do not reflect intra-annual variation or price-responsiveness.
- **Infrastructure representation:** The representation of transmission expansion and flows offer aggregate pictures of electricity transfers across regions, which abstracts away from

many other transmission constraints out of computational necessity. Regional natural gas infrastructure is currently not represented in dynamic and UC versions of US-REGEN (either in terms of constraints on existing capacity or of new additions), though efforts are underway to include such dynamics in future versions of the model.

- **Limited representation of storage:** Although storage may prove to be an important flexibility resource to attenuate variability, the UC model only represents pumped hydro storage at existing capacities. In part, this omission is due to the lack of endogenous storage investments in the dynamic version of US-REGEN. It would be straightforward to incorporate other forms of large-scale storage with exogenous capacities and technical characteristics in future iterations of the model.

Note that, although the UC model will find feasible solutions for dispatching available resources to meet load constraints in all scenarios, the mathematical feasibility of such solutions is not necessarily sufficient to ensure on-the-ground feasibility given the caveats in this section.[14] Realizing these dispatch configurations may require processes and resources that are not included in the model due to computational tractability considerations. Additionally, the expansion of the choice set for balancing technologies (e.g., through large-scale storage or more flexibility dispatchable generators) can alter feasibility and lower operating costs. In total, assessments of model feasibility and conclusions therein are a function of model assumptions that are reasonable but uncertain, which make sensitivity analyses especially critical in understanding technical and economic feasibility and should temper interpretations of the feasibility (or infeasibility) based on modeling exercises alone.

[14] In terms of power system reliability, the UC model is better suited to addressing questions of adequacy than to security issues. Power system adequacy refers to whether the installed capacity and its composition can adequately meet demand, which the deterministic dynamic and UC models are design to assess at hourly resolutions. Power system security is related to its ability to weather the loss of supply components, which is considerably more challenging to represent without subhourly temporal resolution, increased geographical and system detail, and explicit consideration of uncertainty.

3 POSTPROCESSING TOOLS AND ANALYSIS

3.1 Overview

The outputs from unit commitment and economic dispatch models are often as voluminous and complex as the models themselves, making results challenging to interpret and insights time-consuming to extract. The curse of dimensionality applies as much to manipulating, interpreting, and presenting model results as to the multiplicative growth of the models themselves.

To alleviate this problem, the UC version of US-REGEN contains tools for graphical-user-interface-based postprocessing. Excel-based postprocessing in US-REGEN provides a platform for evaluating model results and for understanding flexibility and system operations. Flexibility is characterized and measured by defining and calculating key metrics. Examples of postprocessing capabilities and outputs are shown in Section 3.2. The model also creates output files to link to the InFLEXion flexibility screening and evaluation tool developed by EPRI researchers in Power Delivery and Utilization (EPRI, 2013a), as described in Section 3.3.

3.2 Graphical Postprocessing Tools

The UC version of US-REGEN provides a range of outputs for each run to assist in interpreting the results and understanding their implications for power system flexibility. These figures and tables are available through Excel, which provides a graphical user interface for postprocessing.

The most basic figures present dispatch stacks by technology type over time. The spreadsheets allow the user to view results for different scenarios, periods, and regions. In addition to segment-level outputs, annual totals for generation and transmission are also provided.

Figures 3-1 and 3-2 illustrate outputs using the Energy and Environmental Analysis (E&EA) reference scenario for Texas. Texas provides an interesting case study for flexibility, cycling, and integration issues given its wind resources and relatively isolated grid. Figure 3-1 shows the single-peaked diurnal load shape during the month of August, which is primarily driven by cooling demand. Dispatch in 2015 is characteristic of the current Texas fleet, as nuclear and coal are running at maximum availability and natural gas units are load following (and providing balancing support for variable wind generation). The negative correlation between wind and load leads the state to be a net exporter during off-peak hours and an importer during peak hours. Net annual trade positions for the 2015 model period are shown in Figure 3-2.

Other outputs allow users to examine startups counts, ramping behavior, and partial-load operations under wide range of conditions at different levels of aggregation.

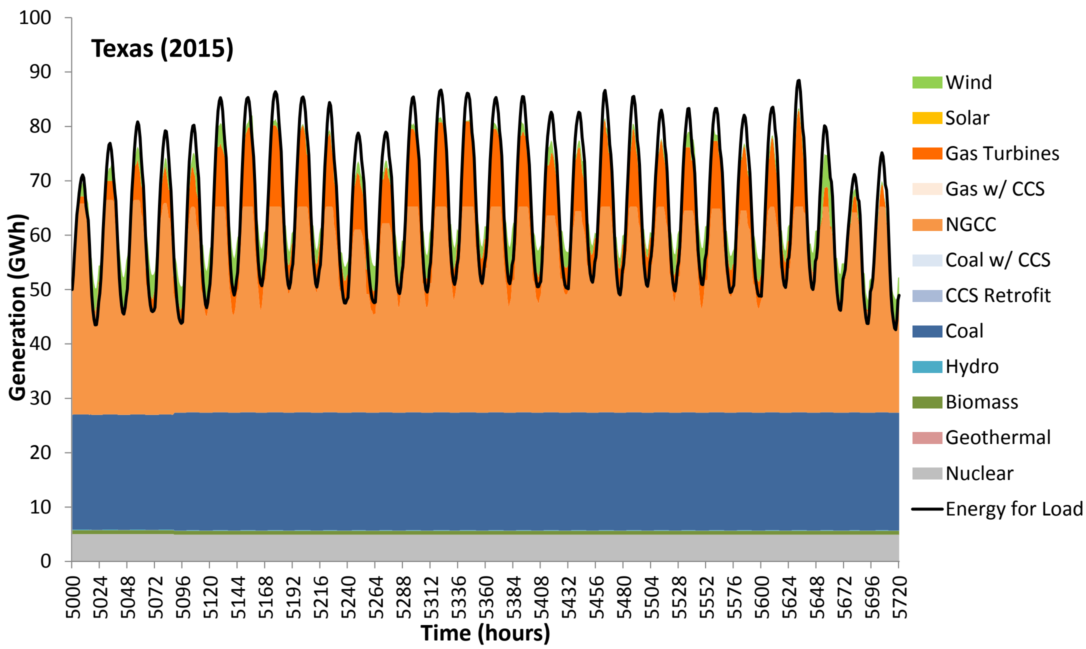


Figure 3-1
Dispatch by Technology (Texas, August 2015)

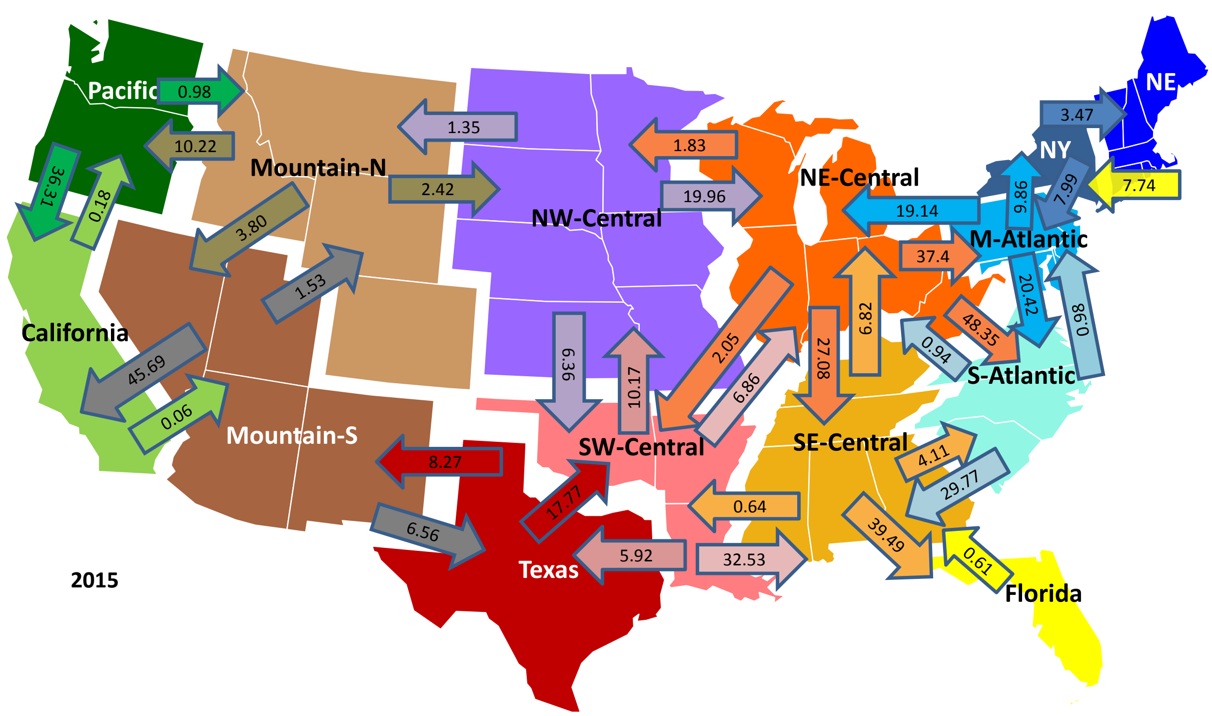


Figure 3-2
Annual Transmission Flows (TWh) in 2015

Under the E&EA reference scenario, wind capacity in Texas increases from 10 GW in 2015 to 92 GW by 2050. Coupled with 60 GW of rooftop solar, this intermittent capacity introduces greater variability and uncertainty to the power system and increases demand for flexibility.

Figure 3-3 compares the load duration curves and residual load duration curves for 2015 and 2050. The residual load duration curve represents the net load once variable generation is subtracted from demand in each hour and indicates the amount of load that must be met through dispatchable resources. The residual load duration curve is steeper in 2050 due to the greater deployment of wind and solar capacity as well as the accompanying temporal distribution of these intermittent resources relative to patterns of electricity demand. Additionally, the number of hours with negative residual load increases, with renewable generation exceeding load by over 50 GW in some hours. This operational regime is challenging due to the limited number of thermal generators online, which means that these units must start up quickly once needed. However, many high-load periods still remain, which suggests that conventional generators are still needed, especially during peak hours.

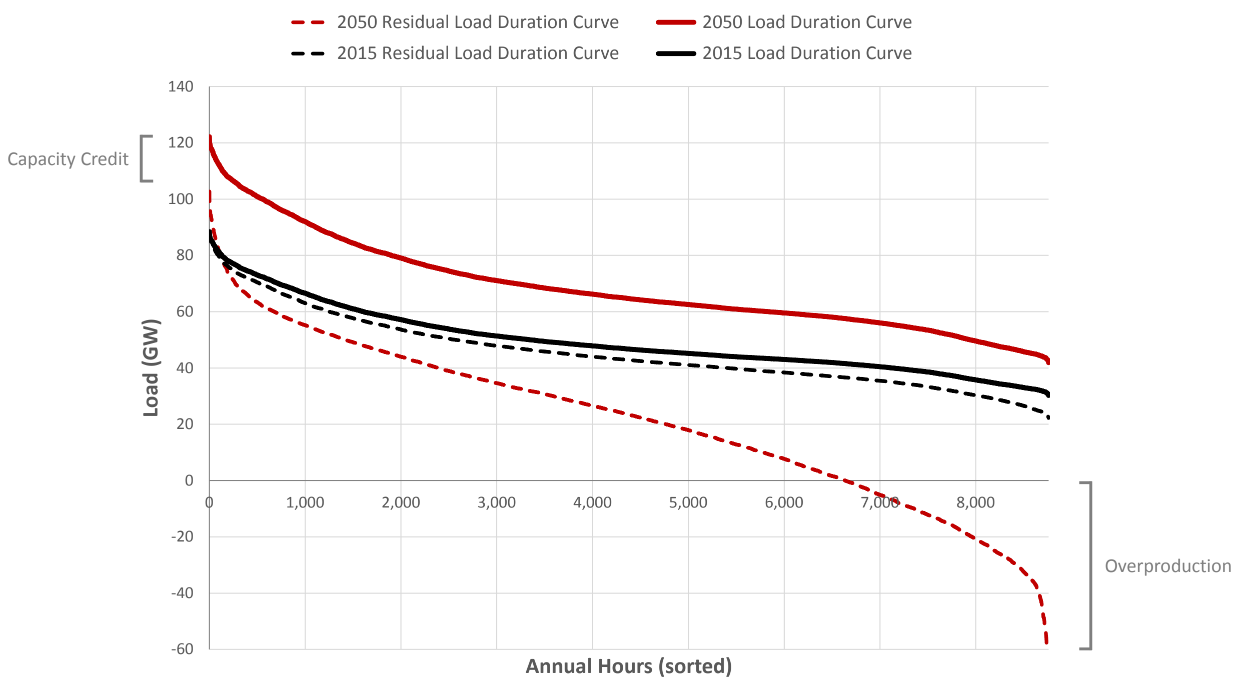
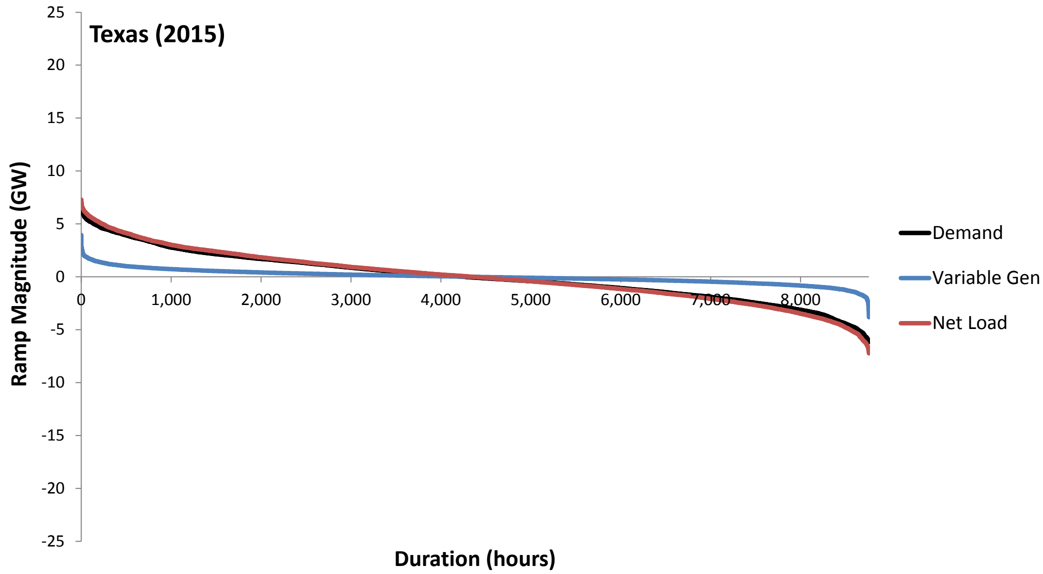


Figure 3-3
Load Duration Curve and Residual Load Duration Curve for Texas

Hourly ramping behavior and volatility can be visualized through ramp duration curves like Figure 3-4. These figures represent the ramping magnitude (i.e., hourly change in dispatch) that is exceeded for given number of hours. It provides information both on the ramping magnitude (vertical axis) and the frequency distribution (horizontal axis). Such figures can examine the variability of both load and variable generation simultaneously. The top panel illustrates how the 2015 variability of wind (blue) is lower than demand (black) due largely to the low installed wind capacity.



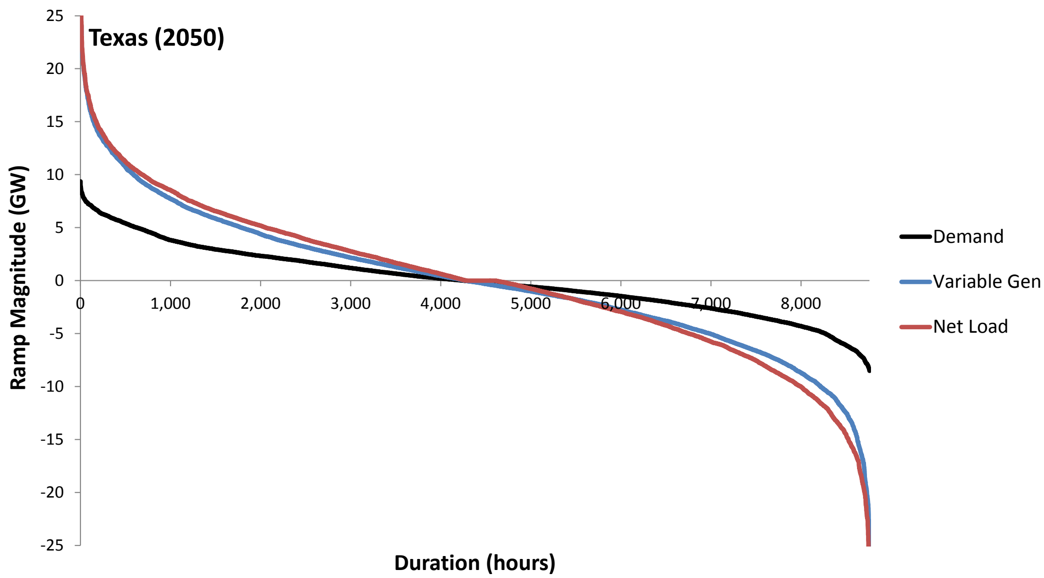


Figure 3-4
Ramp Duration Curves for Texas in 2015 (top) and 2050 (bottom)

The bottom panel in Figure 3-4 shows how ramp magnitudes increase by 2050, especially the duration and depth of variable generation ramps. When combined, the net load variability (red) is greater than either the demand or variable generation ramps. This effect is due in part to the negative correlation between wind and load (i.e., wind resources are least available during times when they are most needed to offset sudden increases in demand). Variable generation ramps (and not demand) are driving net load variability, since extreme hours increase with higher renewable shares for this case study. The separation of the net load and demand ramp duration curves indicates substantial demand for flexible operation from dispatchable resources. Overall, this example shows how greater integration of intermittent resources can increase flexibility demands of the power system. Although the integration of wind increases ramping needs in the Texas system in this scenario, it is not necessarily the case for all regions and all capacity mixes.

The postprocessing tools can characterize and measure flexibility through hourly ramp duration curves for different asset classes. In Figure 3-5, most of the load following for this region in 2050 comes from natural gas units and trade. Texas is primarily importing load-following capabilities when wind generation is low and exporting power when it is high. Transmission networks enable trade between neighboring regions and support system balancing. Without interconnections, load and generation must be balanced on a more localized basis, which (*ceteris paribus*) lowers flexibility and increases costs.

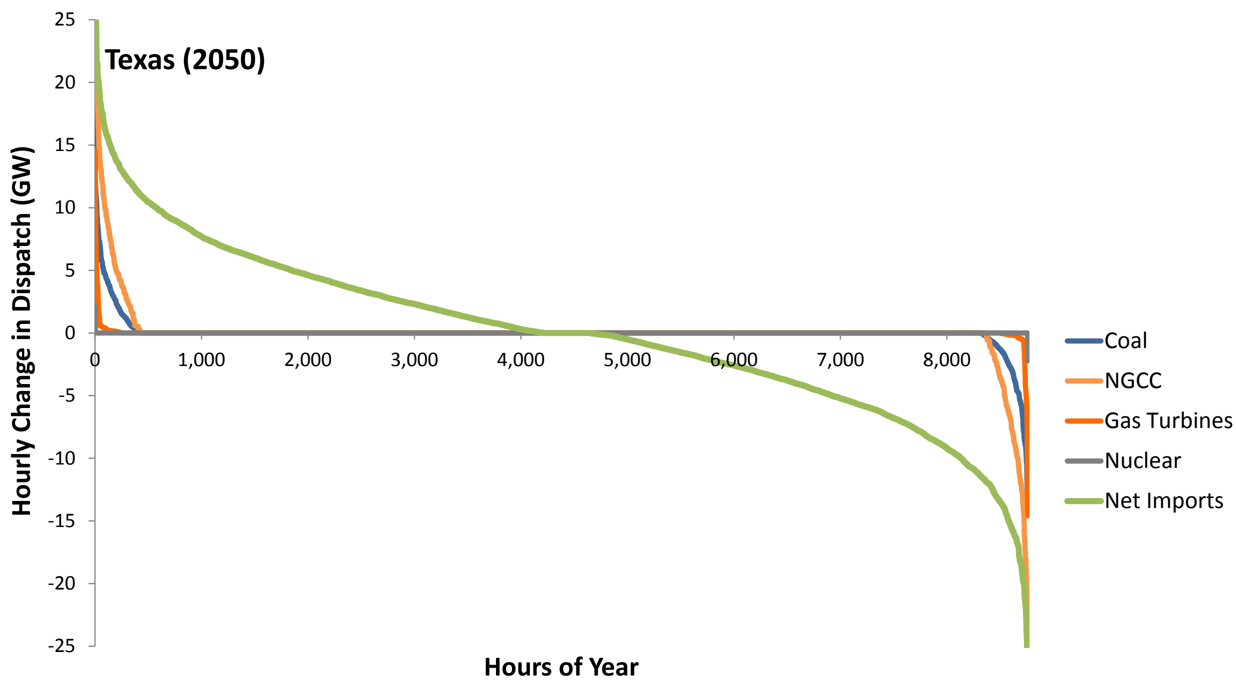


Figure 3-5
Resource Ramp Duration Curves for Texas in 2050

The value of transmission links with other regions is illustrated in the sorted price differential curves in Figure 3-6. These price differentials with neighboring regions equals the signed shadow price on the binding transmission constraint for a run where new transmission builds are prohibited (i.e., transmission is fixed to 2015 levels). These values indicate foregone opportunities for imports and exports that cannot be exploited and represent a crude approximation of the marginal economic value of transmission capability. For 2015 (solid lines), most hours exhibit price equalization across regions. However, for 2050 (dashed lines), prices differ significantly across geographical areas in the absence of trade, which is a reflection of the difficulties associated with system operation when exchanges across broader balancing areas are impeded owing to binding transmission constraints. This result reflects transmission network congestion with fluctuating renewables. These outputs illustrate how flexible operations challenges can be exacerbated by constraints that impact the provision of balancing support.

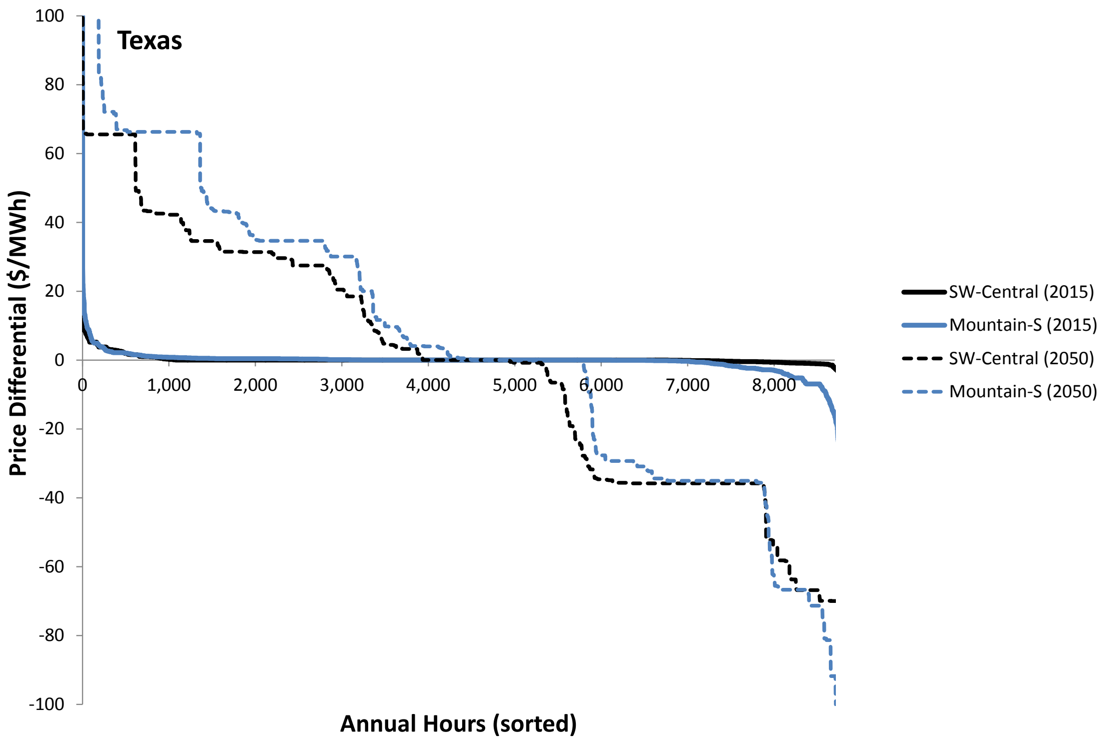


Figure 3-6
Sorted Price Differential Curves between Texas and Neighboring Regions

In addition to outputs reflecting flexibility needs and capabilities, the postprocessing tools also feature figures indicating the economic competitiveness of asset classes. Figure 3-7 presents weekly NGCC capacity factor heatmaps across all regions in the model. As more wind and solar capacity enters the grid, capacity factors for baseload and mid-load plants decrease as full-load hours simultaneously decrease. Increasing shares of wind and solar in a balancing area gradually displace baseload resources rather than peaking units. Like many regions, Texas NGCC generation decreases over time even though capacity increases, which is reflected in lower capacity factors.

2015

Week

Region	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
New England	0.9	0.9	0.8	0.8	0.9	0.9	0.9	0.8	0.8	0.8	0.7	0.7	0.7	0.7	0.7	0.7	0.6	0.6	0.5	0.6	0.8	0.8	0.7	0.7	0.8	0.8
New York	0.8	0.8	0.7	0.6	0.7	0.7	0.7	0.6	0.7	0.7	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.5	0.6	0.7	0.7	0.6	0.6	0.8	0.7
Mid-Atlantic	0.7	0.7	0.5	0.5	0.6	0.6	0.6	0.5	0.6	0.5	0.5	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.3	0.4	0.5	0.5	0.5	0.5	0.7	0.6
South Atlantic	1.0	1.0	0.9	0.9	1.0	1.0	1.0	0.9	1.0	0.9	0.8	0.7	0.7	0.6	0.6	0.6	0.6	0.7	0.6	0.7	0.8	0.8	0.8	0.9	0.9	0.9
Florida	0.5	0.7	0.2	0.2	0.2	0.3	0.4	0.2	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.5	0.5	0.5	0.6	0.6	0.6	0.7	0.7	0.7
East North Central (Regulated)	0.9	1.0	0.8	0.8	0.9	0.9	0.9	0.8	0.9	0.9	0.8	0.8	0.8	0.7	0.7	0.8	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.9	0.8
East North Central (Deregulated)	0.7	0.7	0.5	0.5	0.6	0.6	0.6	0.5	0.6	0.5	0.5	0.5	0.5	0.4	0.4	0.4	0.4	0.5	0.4	0.4	0.6	0.6	0.5	0.6	0.7	0.7
East South Central	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	0.9	0.9	0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	1.0	1.0	1.0
West North Central	0.5	0.4	0.3	0.3	0.4	0.4	0.4	0.3	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.4	0.4	0.3	0.4	0.6	0.5
West South Central	0.7	0.8	0.6	0.5	0.7	0.7	0.7	0.6	0.6	0.6	0.6	0.6	0.5	0.6	0.6	0.6	0.6	0.5	0.5	0.5	0.7	0.7	0.7	0.7	0.8	0.7
Texas	0.7	0.7	0.4	0.3	0.6	0.6	0.6	0.5	0.4	0.3	0.3	0.3	0.2	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.6	0.6	0.7	0.7	0.7
Mountain North (CO, ID, MT, WY)	0.6	0.6	0.5	0.5	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.2	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.1	0.1	0.2	0.3
Mountain South (AZ, NM, NV, UT)	0.6	0.7	0.6	0.6	0.5	0.4	0.4	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.5	0.4	0.5	0.5
Pacific	1.0	1.0	0.9	1.0	0.9	0.9	0.9	0.9	0.8	0.8	0.7	0.7	0.7	0.6	0.6	0.7	0.6	0.5	0.4	0.4	0.5	0.3	0.1	0.1	0.1	0.2
California	0.9	0.9	0.8	0.8	0.8	0.7	0.7	0.7	0.7	0.7	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.5	0.5	0.6	0.6	0.6	0.6	0.6	0.7	0.7

Region	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52
New England	0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.8	0.8	0.7	0.7	0.7	0.8	0.7	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.9	0.9	0.9	0.8
New York	0.8	0.9	0.9	0.8	0.8	0.8	0.8	0.7	0.7	0.7	0.6	0.7	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.7	0.8	0.7	0.7
Mid-Atlantic	0.6	0.7	0.8	0.8	0.7	0.7	0.6	0.6	0.6	0.5	0.5	0.5	0.5	0.4	0.5	0.4	0.4	0.4	0.5	0.4	0.4	0.5	0.6	0.7	0.7	0.5
South Atlantic	0.8	0.9	0.9	1.0	0.9	0.9	0.9	0.9	0.9	0.8	0.8	0.8	0.8	0.7	0.7	0.7	0.7	0.8	0.9	0.9	0.8	0.9	1.0	1.0	1.0	1.0
Florida	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.6	0.6	0.5	0.6	0.6	0.5	0.4	0.4	0.3	0.5	0.4	0.2	0.2	0.2	0.3	0.4	0.5	0.3	0.4
East North Central (Regulated)	0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.9	0.9	0.9	0.9
East North Central (Deregulated)	0.7	0.7	0.8	0.8	0.7	0.7	0.7	0.6	0.7	0.6	0.6	0.6	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.7	0.8	0.7	0.6
East South Central	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	1.0	1.0	0.9	1.0	1.0	1.0	1.0	1.0
West North Central	0.4	0.5	0.7	0.7	0.6	0.6	0.6	0.5	0.5	0.3	0.4	0.5	0.3	0.3	0.4	0.3	0.3	0.3	0.3	0.4	0.3	0.4	0.4	0.5	0.4	0.3
West South Central	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.7	0.6	0.7	0.7	0.6	0.6	0.6	0.6	0.6	0.6	0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Texas	0.6	0.7	0.8	0.7	0.8	0.8	0.8	0.8	0.7	0.6	0.7	0.6	0.5	0.4	0.5	0.5	0.5	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4
Mountain North (CO, ID, MT, WY)	0.2	0.3	0.3	0.3	0.4	0.3	0.4	0.3	0.3	0.3	0.4	0.3	0.4	0.3	0.3	0.3	0.2	0.2	0.2	0.3	0.3	0.3	0.2	0.2	0.2	0.2
Mountain South (AZ, NM, NV, UT)	0.5	0.6	0.7	0.6	0.6	0.5	0.6	0.6	0.5	0.5	0.5	0.5	0.6	0.5	0.5	0.5	0.4	0.4	0.4	0.4	0.5	0.4	0.3	0.3	0.3	0.3
Pacific	0.6	0.6	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.7	0.9	0.9	0.9	0.9	0.7	0.7	0.7	0.7
California	0.7	0.8	0.8	0.8	0.8	0.7	0.8	0.8	0.7	0.7	0.7	0.7	0.8	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.6	0.6	0.6	0.6

2050

Week

Region	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
New England	0.6	0.6	0.4	0.4	0.5	0.4	0.4	0.4	0.4	0.2	0.3	0.2	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.2	0.2	0.2	0.3	0.3
New York	0.9	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.6	0.8	0.5	0.6	0.5	0.5	0.5	0.6	0.5	0.4	0.5	0.6	0.6	0.5	0.6	0.7	0.7
Mid-Atlantic	0.6	0.6	0.4	0.4	0.6	0.4	0.4	0.3	0.3	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.2	0.2	0.1	0.2	0.3	0.3
South Atlantic	0.5	0.5	0.2	0.2	0.4	0.3	0.3	0.2	0.3	0.2	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.2	0.3	0.3	0.3
Florida	0.2	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.1	0.1
East North Central (Regulated)	0.9	0.8	0.7	0.5	0.9	0.8	0.8	0.8	0.9	0.6	0.5	0.2	0.2	0.2	0.3	0.5	0.2	0.2	0.2	0.5	0.7	0.6	0.4	0.7	0.6	0.6
East North Central (Deregulated)	0.7	0.6	0.5	0.3	0.7	0.6	0.6	0.6	0.5	0.2	0.3	0.1	0.1	0.0	0.1	0.2	0.1	0.0	0.0	0.1	0.4	0.4	0.2	0.5	0.5	0.5
East South Central	0.8	0.8	0.3	0.2	0.6	0.6	0.6	0.4	0.5	0.3	0.2	0.1	0.1	0.1	0.1	0.2	0.1	0.2	0.2	0.4	0.4	0.4	0.4	0.5	0.5	0.6
West North Central	0.2	0.2	0.0	0.0	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0
West South Central	0.8	0.8	0.6	0.3	0.8	0.8	0.7	0.7	0.6	0.2	0.4	0.2	0.1	0.1	0.1	0.6	0.2	0.2	0.2	0.6	0.5	0.6	0.6	0.6	0.7	0.8
Texas	0.2	0.2	0.0	0.0	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1
Mountain North (CO, ID, MT, WY)	0.4	0.4	0.2	0.1	0.4	0.3	0.3	0.2	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.1	0.2	0.2
Mountain South (AZ, NM, NV, UT)	0.3	0.5	0.2	0.2	0.4	0.3	0.3	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.3
Pacific	0.8	0.8	0.7	0.7	0.7	0.8	0.7	0.7	0.6	0.5	0.5	0.4	0.4	0.4	0.5	0.5	0.4	0.3	0.4	0.5	0.5	0.4	0.2	0.3	0.3	0.4
California	0.6	0.7	0.6	0.5	0.6	0.6	0.5	0.5	0.5	0.3	0.3	0.2	0.2	0.1	0.2	0.3	0.1	0.1	0.2	0.4	0.3	0.3	0.3	0.3	0.3	0.5

Region	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52
New England	0.5	0.5	0.5	0.4	0.5	0.4	0.4	0.3	0.4	0.3	0.2	0.2	0.3	0.2	0.1	0.2	0.2	0.2	0.3	0.2	0.2	0.3	0.4	0.5	0.5	0.4
New York	0.7	0.8	0.9	0.9	0.8	0.8	0.8	0.8	0.7	0.6	0.6	0.6	0.7	0.7	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.8	0.9	0.9	0.8
Mid-Atlantic	0.5	0.5	0.6	0.5	0.5	0.5	0.4	0.3	0.4	0.2	0.2	0.2	0.3	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.1	0.2	0.5	0.6	0.5	0.4
South Atlantic	0.3	0.4	0.4	0.5	0.4	0.4	0.4	0.3	0.3	0.2	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.4	0.5	0.4	0.4
Florida	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.0	0.1
East North Central (Regulated)	0.6	0.8	0.8	0.9	0.8	0.8	0.9	0.7	0.6	0.4	0.5	0.5	0.6	0.7	0.7	0.6	0.2	0.6	0.5	0.7	0.5	0.4	0.9	0.7	0.9	0.6
East North Central (Deregulated)	0.5	0.7	0.7	0.7	0.7	0.7	0.7	0.5	0.5	0.3	0.4	0.4	0.4	0.4	0.4	0.3	0.1	0.3	0.2	0.4	0.2	0.3	0.7	0.6	0.7	0.3
East South Central	0.5	0.7	0.6	0.7	0.7	0.8	0.8	0.7	0.5	0.4	0.5	0.4	0.4	0.3	0.4	0.3	0.3	0.2	0.3	0.3	0.2	0.3	0.6	0.6	0.5	0.5
West North Central	0.2	0.1	0.1	0.2	0.2	0.3	0.2	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.1	0.1
West South Central	0.7	0.9	0.8	0.9	0.9	0.9	0.9	0.9	0.6	0.6	0.8	0.6	0.8	0.6	0.7	0.6	0.4	0.3	0.3	0.5	0.3	0.4	0.6	0.6	0.7	0.6
Texas	0.2	0.2	0.1	0.2	0.2	0.3	0.3	0.3	0.1	0.1	0.1	0.0	0.1	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0
Mountain North (CO, ID, MT, WY)	0.3	0.3	0.3	0.5	0.5	0.4	0.3	0.2	0.1	0.1	0.1	0.1	0.1	0.0	0.1	0.1	0.0	0.0	0.1	0.0	0.0	0.0	0.2	0.3	0.3	0.1
Mountain South (AZ, NM, NV, UT)	0.3	0.4	0.3	0.4	0.3	0.3	0.5	0.4	0.1	0.2	0.2	0.1	0.3	0.1	0.2	0.1	0.0	0.1	0.1	0.1	0.1	0.1	0.2	0.1	0.2	0.1
Pacific	0.6	0.7	0.7	0.7	0.7	0.7	0.8	0.7	0.6	0.5	0.7	0.6	0.7	0.6	0.6	0.6	0.5	0.6	0.6	0.6	0.7	0.6	0.7	0.6	0.7	0.6
California	0.5	0.7	0.7	0.7	0.7	0.6	0.7	0.7	0.4	0.5	0.5	0.4	0.6	0.4	0.5	0.5	0.3	0.4	0.4	0.4	0.5	0.4	0.5	0.4	0.6	0.4

Figure 3-7
Capacity Factors for NGCC Units by Region and Week in 2015 and 2050

To provide more in-depth assessment of flexibility demand, we developed a metric and visualization tool to assess trends in flexibility needs spatially and temporally. The metric, called the "variability index," compares spatial and temporal resource variability across different scenarios. The variability index aggregates unit-level outputs to offer a fleet-level perspective on the magnitude of hourly variation relative to maximum generation.

By construction, this metric equals one during periods where resources have constant outputs (i.e., are not undergoing flexible operations) and equals zero during periods of extreme variability. We define this extreme flexibility regime as one in which an asset is ramped from its maximum available output to zero from one period to the next.[15] This index implicitly aggregates startups and ramps to offer a high-level metric for evaluating flexibility demands and their implied equipment stresses.

The variability index for a given capacity block ($i \in I$) at a specific time ($t \in T$) and region ($r \in R$) is defined by:

$$\gamma_{ir}(t) = 1 - \frac{1}{n(U_r)} \sum_{u \in U_r} \left[\frac{1}{n(S_t)} \sum_{s \in S_t} \frac{|\phi_u(s) - \phi_u(s-1)|}{\Phi_u(s)} \right]$$

where $u \in U_r$ represents individual units in region r, $n(A)$ denotes the cardinality of set A, $s \in S$ represents the set of all hours (and $S_t \subseteq S$ is a subset of hours in period t). The innermost summand represents the absolute value of the hourly change in output of a specific unit $\phi_u(s)$. This difference is normalized by the maximum output in hour s of that unit:

$$\Phi_u(s) = \alpha_u(t) \cdot \bar{P}_u$$

where $\alpha_u(t)$ represents the availability factor and $\bar{P}_u$ is the maximum unit capacity. For this analysis, the period of time t represents one week, which means that the hourly variability indices are averaged over the course of 168 consecutive hours. The equation assumes that the variability index for a capacity block (e.g., natural gas combined cycle units) equals the arithmetic mean of the values for individual units.

In order to aggregate the block variability index $\gamma_{ir}(t)$ into an aggregate measure of total variability $\Gamma_r(t)$, the postprocessing tools for the UC model allow user-defined weights w_i that can assign different levels of emphasize to represent the perceived heterogeneity in asset flexibility. Thus, the total variability index for a region is a weighted arithmetic mean of the block variability indices:

$$\Gamma_r(t) = \frac{1}{\sum_{i \in I} w_i} \sum_{i \in I} w_i \cdot \gamma_{ir}(t)$$

These values are then visualized in a heatmap of variability indices for a given scenario. Each cell is color coded based on the average hourly change in generation relative to the maximum in that region at that time. Mapping values to colors allows for visual inspection of large quantities

[15] Although this extreme variability is uncommon, it offers a reasonable theoretical bound for output variability that can be transparently defined and straightforwardly computed.

of data and facilitates comparison and identification of outliers/patterns. It can also focus on specific region, weeks, or individual technologies.

As illustrated in Figure 3-8, the potential for intermittent resources to increase residual load variability and flexibility requirements will likely lead to more widespread cycling (e.g., more starts, widely varying output levels, and significant ramping), especially when transmission investment is constrained. Given these projections of increased volatility, it will be important for models to include full chronological simulation and UC constraints explicitly.

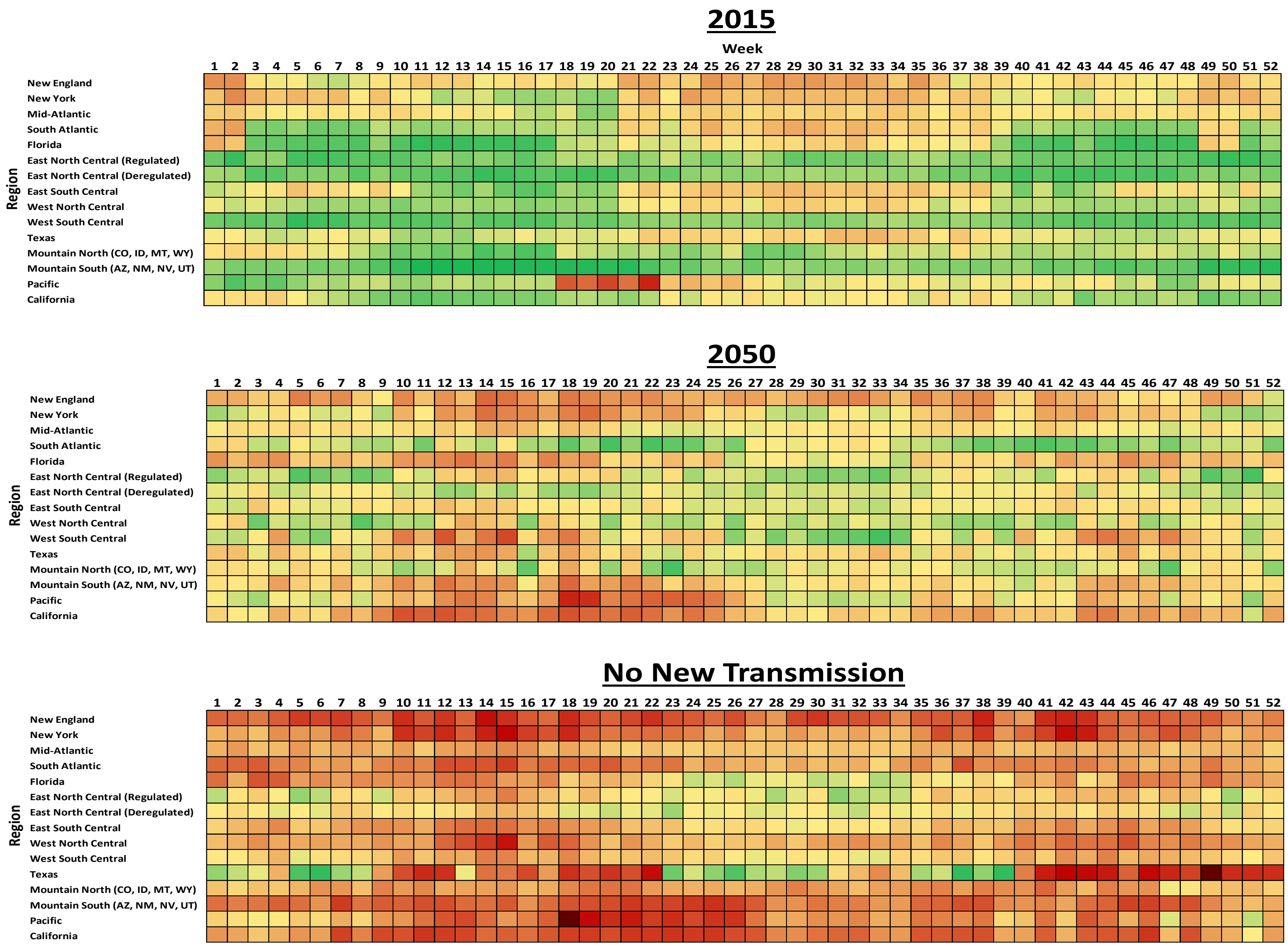


Figure 3-8
Variability Index Heatmaps by Region/Week in 2015, 2050, and without New Transmission in 2050

3.3 InFLEXion

In addition creating Excel-based postprocessing tools for US-REGEN, the UC version of US-REGEN creates output files to link to the InFLEXion flexibility screening and evaluation tool developed by EPRI researchers in Power Delivery and Utilization (EPRI, 2013a).

InFLEXion provides a multi-level platform for power system flexibility assessment. It is a powerful postprocessing tool to visualize UC outputs, quantify system flexibility metrics, and extract meaningful insights at allocable levels given the granularity of the data. By accounting for variability and chronology in demand, renewable generation, and resource characteristics and schedules, InFLEXion offers many sources of value:

- Short- and long-term planning aid to understand the impact of variability, ramping, and flexibility for balancing requirements
- Screening-level comparisons of the flexibility needs and capabilities of a given asset mix
- Flexibility metrics for understanding the magnitude and frequency of flexibility deficits

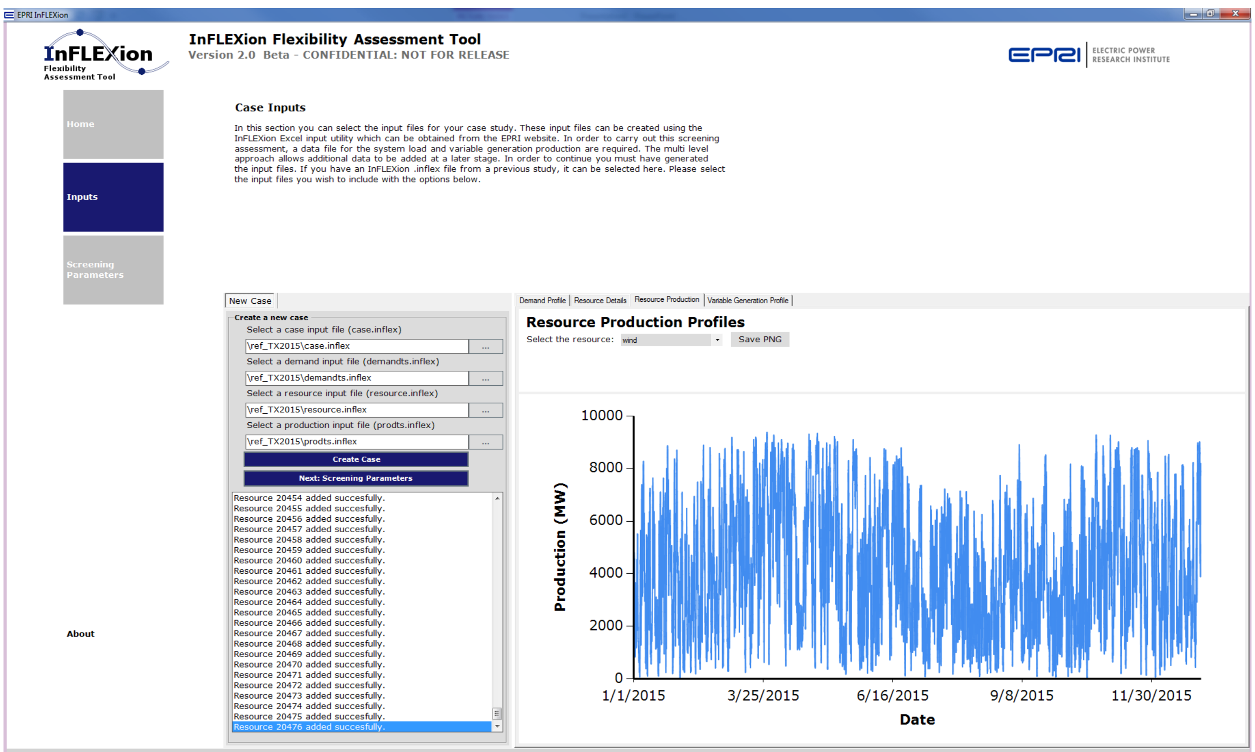


Figure 3-9
Screen Shot of the InFLEXion User Interface

The InFLEXion tool is used for this analysis to diagnose the ramping demand and flexibility adequacy metrics implied by the capacity mix from the dynamic and UC US-REGEN models. Using the simulated production time series from the UC version of US-REGEN in a given region of interest, InFLEXion provides assessments of flexibility at three levels:

1. **Variability analysis:** Using time-series outputs for demand and variable generation, InFLEXion calculates system ramping requirements like ramp duration curves, ranges of ramping, expected ramps at various output levels.
2. **Resource flexibility:** Using the Level 1 data along with input parameters from additional system resources, InFLEXion assesses the available flexibility of each resource over different time periods. This level is based only on resource parameters and not on implications from the UC model's commitment and dispatch decisions, which are explored in Level 3.
3. **System flexibility:** Using the previous data along with production time series for each resource in the network (i.e., all UC outputs), InFLEXion compares flexibility needs of the system with available flexibility of each generator. There are four flexibility metrics that account for system operational requirements.

More detailed information about InFLEXion can be found in the tool's user guide (EPRI, 2013a) and report on flexibility metrics (EPRI, 2013b).

A
DETAILED MATHEMATICAL FORMULATION

This appendix presents a detailed mathematical description of the UC model introduced in Section 2. The UC model is formulated as a mixed-integer optimization problem with the objective of minimizing all applicable costs for all units according to:

$$\min \sum_{s \in S} \sum_{r \in R} \sum_{u \in U_r} \left\{ \left[a_u + b_{u,s}(X_{u,s}) f_u \right] X_{u,s} + c_u I_{u,s}^{+} + d_u I_{u,s}^{-} \right\}$$

Sets and Indices

$s \in S$	time periods
$r \in R$	regions
$u \in U_r$	generating units in region *r*

Decision Variables

$X_{u,s}$	output level of unit *u* in period *s*
$I_{u,s}^{+}, I_{u,s}^{-}$	indicator variables for startup (+) and shutdown (-)

Parameters

a_u	fixed component of variable costs
$b_{u,s}(X_{u,s})$	heat rate (function of the output of unit *u* in *s*)
f_u	fuel costs
c_u, d_u	startup and shutdown costs (respectively)

The model includes the following constraints:

- Load balance (market-clearing condition)

$$\sum_{u \in U_r} X_{u,s} + \sum_{rr} t_{rr,r} E_{s,rr,r} \geq l_s \qquad \forall r, s$$

  where *rr* is the set of all regions excluding *r*, $t_{rr,r}$ is transmission penalty from region *rr* to *r*, $E_{s,rr,r}$ is the decision variable for net inter-regional imports from region *rr* to *r* in period *s*, and l_s is the net residual load, including transmission losses and variable generation (and storage losses).

- Maximum and minimum output for each generation unit

$$\underline{x}_u I_{u,s} \leq X_{u,s} \leq \overline{x}_u I_{u,s} \qquad \forall u, s$$

  where $I_{u,s}$ is the indicator variable for whether unit *u* is committed (i.e., online) in *s*, $\underline{x}_u$ is the minimum capacity of *u*, and $\overline{x}_u$ is the maximum capacity of *u*.

Table A-1
Minimum Load by Unit Type

Unit Type	Minimum (% Unit Rating)
Coal	50%
Natural Gas (Combustion Turbine)	45%
Existing NGCC	60%
New NGCC	40%

- Operating reserve requirements

$$\sum_{u \in U_r} \overline{x}_u I_{u,s} \geq l_s + h_s \qquad \forall s$$

where h_s is the reserve buffer.

- Startup and shutdown logic for generators

$$I^+_{u,s} + I^-_{u,s} = I_{u,s} - I_{u,s-1} \qquad \forall u, s$$

- Maximum rampup rate for generators

$$X_{u,s} - X_{u.s-1} \leq m^+_u \qquad \forall u, s$$

where m^+_u is the maximum rampup rate for unit *u*.

Table A-2
Ramp Up/Down Rate by Unit Type

Unit Type	Ramp Up/Down Limit (% Max/Hour)
Coal	50% / 60%
Oil	40% / 50%
Natural Gas	100% / 100%
Nuclear	30% / 30%

- Maximum rampdown rate for generators

$$X_{u,s} - X_{u.s-1} \leq m^-_u \qquad \forall u, s$$

where m^-_u is the maximum rampdown rate for unit *u*.

- Minimum up time for generators

$$\sum_{s=k}^{k+\underline{v}_u-1} I_{u,s} \geq \left(I_{u,k} - I_{u,k-1}\right)\underline{v}_u \qquad \forall u, k = p_u + 1, \ldots, s - \underline{v}_u + 1$$

where $\underline{v_u}$ is the minimum up time for unit *u*, and p_u is the number of periods that *u* must initially be online.

- Minimum down time for generators

$$\sum_{s=k}^{k+\underline{w_u}-1} I_{u,s} \geq \left(I_{u,k} - I_{u,k-1}\right)\underline{w_u} \qquad \forall u, k = q_u + 1, \dots, s - \underline{w_u} + 1$$

where $\underline{w_u}$ is the minimum up time for unit *u*, and q_u is the number of periods that *u* must initially by offline.

- Transmission flows

$$E_{s,r,rr} \leq \Xi_{r,rr} \qquad \forall s, r$$

where $\Xi_{r,rr}$ is the upper bound on net transfer capacity from region *r* to *rr*.

- Unit-level heat rate

$$b_{u,s}\left(X_{u,s}\right) = \frac{\pi_u^1}{X_{u,s}} + \pi_u^2$$

where π_u^1 and π_u^2 are calibrated, unit-specific parameters. The relationship between unit output and heat rate is poorly understood due to a lack of public data and systematic experiments under a range of operating conditions. EPRI (2011) is the first publication to quantify the effects of load following on heat rate. US-REGEN adopts the functional form based on this work and selects the heat rate penalties at minimum output for different capacity types based on consultations with literature and EPRI researchers. The heat rate at minimum output is the product of the heat rate at maximum output and the heat rate penalty in the table below.

Table A-3
Heat Rate Penalties by Unit Type

Unit Type	Heat Rate Penalty
Coal	1.1
Oil	1.2
Natural Gas	1.2
Nuclear	1.2

- Storage constraints
- Must-run constraints (optional)

B
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