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NREL is a national laboratory of the U.S. Department of Energy, Office of Energy Efficiency & Renewable Energy, operated by the Alliance for Sustainable Energy, LLC.

Technical Report
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Abstract

Recent and anticipated trends indicate that renewable resources, particularly wind and solar energy, will provide a growing contribution to the U.S. and global power systems in the coming decades. These resources are variable and uncertain by nature, and their impacts on system expansion and operation need to be properly accounted for in electric system models. To this end, we introduce a new capacity expansion model, the Resource Planning Model (RPM), with high spatial and temporal resolution that can be used for mid- and long-term scenario planning of regional power systems. RPM endogenously and dynamically considers grid integration of renewable resources, including transmission and interconnection availability and costs, renewable resource limits and output characteristics, and dispatch options for conventional generators, in its optimal generator and transmission decision-making. As an hourly chronological model with a highly discretized regional structure, RPM provides a framework where various future scenarios can be explored while ensuring that the scenarios include many aspects of grid reliability. Although the structure of RPM was designed to be adaptable to any geographic region, here we describe an initial version of the model adapted for the power system in Colorado.

We present example scenario results from this first version of RPM, including an example of a 30%-by-2020 renewable electricity penetration scenario. Under the assumptions used, the preliminary scenario analysis demonstrates that wind technologies are the dominant contributors to this 30%-by-2020 renewable electricity scenario and that renewable generation largely displaces natural gas. This displacement results in annual carbon dioxide (CO_2) emission reductions of approximately 12%. We find that under the least-cost deployment solution from the model, new wind capacity is largely deployed in the north-central and southeastern regions of Colorado and utility-scale solar capacity is largely deployed in the Front Range urban corridor, along with northwestern and south-central Colorado regions. Finally, we observe changes to fossil generation dispatch, particularly with regard to greater power plant ramping and cycling of natural gas combined cycle and coal power plants. In addition to presenting these initial findings, this report provides a detailed documentation of RPM as a new analytic tool for regional power system planning and dispatch.

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1 Introduction

In this report, we introduce a new transparent regional capacity expansion model with high spatio-temporal resolution and detailed representation of dispatch. The development of this model, referred to as the Resource Planning Model (RPM), is motivated by the lack of a tool in the public domain that can be used to characterize optimal regional deployment of resources with detailed dispatch modeling. In particular, RPM is designed to evaluate scenarios of renewable technology deployment to meet renewable portfolio standard (RPS) and emission-reduction goals, and to project possible deployment levels for various projections of future technology and fuel prices.

The model co-optimizes transmission, generation, and storage options. It considers major grid operation constraints within its purview as a capacity expansion model. More specifically, detailed operational constraints in RPM are used to inform the capacity expansion decisions, i.e., the degree to which generation dispatch, ramping, cycling, value of storage, and value of peak coincidence affect the amount and location of renewable deployment is inherent within the model. The methodologies for treating renewable technologies in RPM can help improve commercial models or capacity expansion models with greater geographic scope and more limited spatio-temporal resolution. Finally, RPM is designed with a flexible structure to enable research into how investment decisions may be affected by the choice of model time periods, particularly with high levels of renewable penetration.

The Resource Planning Model is developed to inform policymakers, academic researchers, and electric utility planners. In particular, RPM is a regional capacity expansion model with spatio-temporal resolution and grid operational aspects that approach those of long-term planning tools used by utility planners, but with data and model details that are publicly available. Although the structure of RPM was designed to be adaptable to any geographic region and any hourly or multiple hour time resolution, here we describe the first version of the model adapted for the power system in Colorado and henceforth referred to as the RPM-CO model.

A wide range of power sector models is used by various researchers to evaluate energy policies. Although we do not attempt here to provide a comprehensive review of all models used in the literature, we provide a brief overview of related models and model types and a description of their differences with RPM.

Examples of public sector models that have been used to examine various energy policies include the U.S. Energy Information Administration's (EIA's) National Energy Modeling System (NEMS) model[1] and Brookhaven National Laboratory's MARKet ALlocation (MARKAL) model (Loulou et al. 2004). NEMS and MARKAL model the entire U.S. economy, including all energy sectors and, for this reason, have coarse representations of the electricity sector.[2] In particular, NEMS models the power system using 9 time slices per year (three seasons with three diurnal periods) and 22 electricity generation regions covering the entire contiguous United States. MARKAL includes 12 time slices per year (three seasons with four diurnal periods) and 10 regions. The resolution of these models requires many simplifications, including

[1] Documentation for NEMS can be found at www.eia.gov/analysis/model-documentation.cfm.
[2] Multiple versions of MARKAL exist with various geographic scopes. The discussion in this report refers to the versions used in the cited references.

approximations of grid operations and aggregation of individual generating units into generalized technology categories. Nonetheless, these simplifications are generally adequate to provide insights for long-term national scenario analyses, including evaluations of national energy policies (EIA 2011, EIA 2012, Alfstad 2008, Mignone et al. 2012).

Compared with their economy-wide counterparts, electric sector-only capacity expansion models can afford to represent the power sector with greater resolution. Examples of such models include NREL's Regional Energy Deployment System[3] (ReEDS) model (Short et al. 2011) and the University of California, Berkeley's SWITCH model,[4] which have coarser spatio-temporal resolution. ReEDS is an electric sector-only model that includes 17 time slices per year (four seasons with four diurnal periods and one peak time slice) and 134 balancing areas[5] in the contiguous United States. SWITCH has greater temporal resolution with 144 model hours (12 months X 2 representative days per month X 6 representative hours per day). The geographic scope of SWITCH is limited to the Western Electricity Coordinating Council (WECC), which is divided into 50 model regions. These models have been used to examine implications of various energy policy options, particularly those related to the electric sector (Logan et al. 2009; Mignone et al. 2012; Nelson et al. 2012). The detailed grid representation in these types of model has become increasingly necessary with recent historical and potential trends in the power sector, particularly with increasing renewable technology deployment. ReEDS has also been used to evaluate technical grid integration challenges of renewable generation technologies (DOE 2012; Mai et al. 2012).[6]

Although ReEDS and SWITCH were developed to capture many of the major grid integration challenges of future expansion scenarios, their large geographic scopes, technology aggregations, and other necessary simplifications limit their applicability for regional utility or service area planning. For example, ReEDS and SWITCH represent Colorado with two and four regions,[7] respectively, which is likely insufficient to inform generation siting and planning for the local utilities within Colorado.

Because utilities typically use internal or proprietary tools for long-term capacity planning, we are unable to easily evaluate them or compare them with public or academic models.[8] However, we believe these models generally lack certain important characteristics. We identify some of these deficiencies here. These tools typically do not simultaneously co-optimize transmission and generation. In addition, renewable technologies and their integration challenges and opportunities are not dynamically treated in these tools. For example, the contributions from variable (wind and solar photovoltaics) generators for planning reserves may be exogenously considered even though they may vary depending on the penetration level and the locations where they are deployed. More generally, the overall options for grid flexibility, including

[3] Documentation for ReEDS can be found at www.nrel.gov/analysis/reeds.
[4] Documentation for the SWITCH model can be found at rael.berkeley.edu/sites/default/files/SWITCH_Model_Documentation_December_2011.pdf.
[5] ReEDS also includes 356 wind and CSP resource regions.
[6] These technical studies also relied on commercial production cost models described below.
[7] ReEDS includes 13 wind and CSP resource regions within Colorado and 2 "balancing areas" where all other technologies and load are treated.
[8] Mills and Wiser (2012b) reviews methods and models used in utility planning and procurement processes, with a focus on solar valuation.

changes to how plants are dispatched, may not be fully represented when renewable integration is considered in the models.

Utility planners and system operators also use production cost models to inform their generation and transmission planning.[9] Examples of production cost models include PLEXOS (CAISO 2010), GridView (Feng et al. 2002), and GE MAPS (GE Energy 2010). As with the utility planning tools described above, this suite of commercial models are also often proprietary. Commercial production cost models are security-constrained unit-commitment (SCUC) and security-constrained economic dispatch (SCED) models that typically model the hourly or subhourly operation of all individual generator units in the model system for a given period. They typically represent energy transfers through DC optimal powerflow models. Although the size of the model system can range widely, the number of model generators, load buses, and transmission lines can exceed ten thousand. Although the level of operational detail contained in these models far exceeds the models described above, this suite of models is not designed to directly address the capacity expansion problem. In short, production cost models have detailed representation of system dispatch but rely on other models or tools for the generation capacity and transmission available for dispatch. Capacity expansion models and production cost models can be used in tandem for planning purposes, but this process may require several iterations to identify optimal generation portfolios.

Section 2 provides a brief description of the model with more details provided in the appendix. Section 3 describes the input data used in the models. Section 4 provides a sample of model outputs based on preliminary scenario analysis conducted. We list conclusions and next steps in Section 5.

2 Brief Model Description

This section provides a qualitative description of RPM-CO. We provide a more complete listing of the major model sets, parameters, variables, and equations in the appendix.

2.1 General Model Framework

RPM-CO is a mixed-integer linear program that minimizes overall system cost, including capital costs, operations and maintenance (O&M) costs, fuel costs, and start-up costs during each optimization period. The objective function (see the appendix) includes annual operating costs (fuel and variable O&M) and annual fixed costs (amortized cost of capital assets including generation and transmission infrastructure resources, and fixed O&M). All costs and input data are user-defined, and we describe sample data inputs in Section 3. As in many other electric sector optimization models, cost optimization is subject to several constraints to characterize power plant operation, transmission dispatch, grid reliability, and capacity expansion. We qualitatively describe model constraints here, and we provide more-detailed descriptions, including constraint equations, in the appendix.

RPM-CO is a sequential optimization model with five optimization periods separated by five years from 2010 to 2030. Sequential optimization allows non-linear calculations to be made

[9] Other models with greater detail than the ones described here are also used, and they include AC transmission, voltage stability, and other models. We consider these models to be outside the long-term planning domain.

between optimizations. These calculations are necessary to update parameters, including capacity value of wind and solar technologies, for the next linear optimization period. In addition, the five-year separation provides an appropriate planning timeframe for many generation-types[10].

We represent all major commercial generation technologies in RPM-CO, including: two types of pulverized coal, three types of natural gas combined cycle (NG-CC), three types of natural gas combustion turbines (NG-CT), oil and gas steam (OGS), nuclear, biopower, geothermal, hydropower, five classes of onshore wind, and utility-scale fixed-tilt (PV-fixed) and 1-axis tracking photovoltaics (PV-track). The multiple types of fossil technologies reflect the range of efficiencies and emission controls that are present in the existing fleet of fossil generators in Colorado. Differentiation between fossil types is based on plant size and is described in Section 3. The main parameters that characterize each generation technology include nameplate capacity, heat rate, fuel type and costs, O&M costs, outage rates, start-up costs, minimum generation levels, and minimum on and off periods. In addition, generation profiles for wind and solar technologies are also exogenously defined, as are limits to hydropower dispatch. For new technology options, cost and performance projections and minimum plant sizes are considered in the model. The technologies currently considered in RPM-CO are motivated by the existing system and recent and anticipated trends in deployment. The flexible model structure of RPM allows for the inclusion of additional technologies.

2.2 Model Spatial and Temporal Resolution

One of the distinguishing features of RPM-CO is the high spatial resolution of the model. Figure 1 shows the 27 regions within Colorado and the 4 boundary regions representing Wyoming (two regions), Utah, and New Mexico.[11] The Colorado regions are based on aggregations of one or more counties, where aggregations were guided by the spatial distributions of load, existing large generators, and renewable resources. The combination of multiple regions, multiple fossil technologies, and the mixed-integer programming structure of RPM-CO allow it to model large individual fossil power plants. For example, in the current implementation, the largest coal (>250 megawatts (MW)) and NG-CC (>250 MW) technology types (see Section 3.2) represent individual existing power plants.[12] By modeling individual plants, as opposed to aggregations of plants, the dispatch characteristics for each plant can be accurately represented in the model. In addition, power plant retirements can be assessed at the individual plant level.

[10] We do not model construction lead times explicitly; new power plants are immediately available for dispatch during the same year that they are built. Technology-specific fixed charge rates (see Section 2.3.2) are based on differing construction periods for different technology types.
[11] Nebraska, Kansas, and Oklahoma also neighbor Colorado; however, they are excluded from the model because they are not in WECC. Limited capacity of DC lines connecting Colorado to the Eastern Interconnection exist; however, these are ignored in RPM-CO.
[12] Several power plants consist of multiple generating units and these are treated in aggregate. This aggregate treatment of individual units effectively lowers the operational flexibility of modeled generation resources.

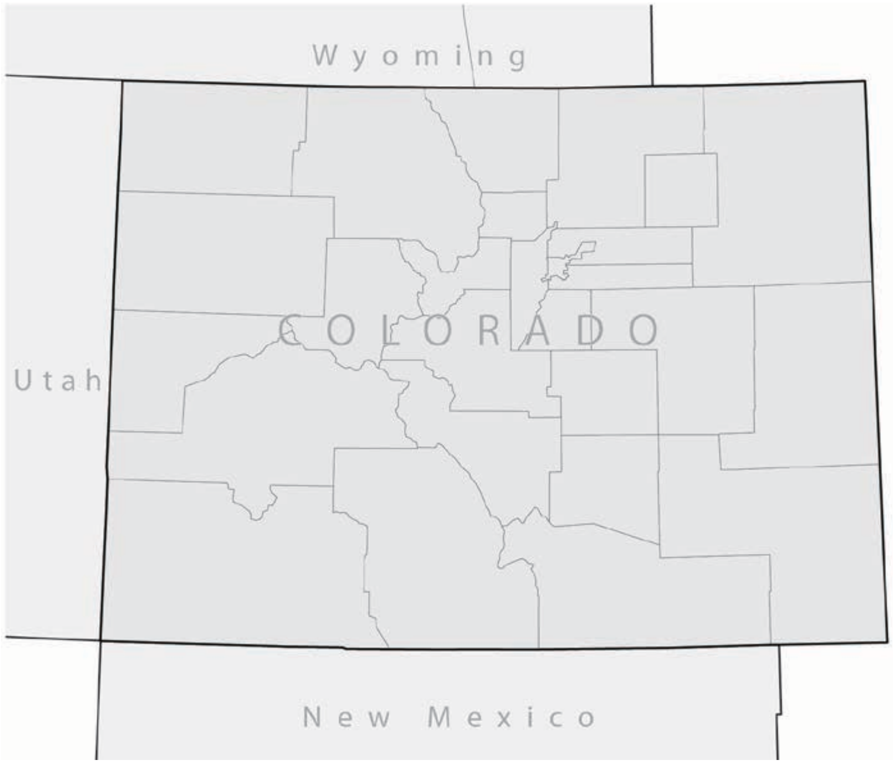

Figure 1. Regions included in RPM-CO

The highly discretized regional structure of the model also allows us to more accurately represent the locational differences in renewable resource quality. Figure 2 shows the model regions overlaid with PV resource quality and Figure 3 shows wind resource quality for Colorado and surrounding regions. The data sources for renewable resources are described in Section 3. In addition, high spatial resolution allows us to model transmission limits within Colorado (and between Colorado and neighboring states) to better identify locations with *accessible* high quality renewable resources. The model inherently considers the limits and costs of transmission between resource regions in its capacity expansion optimization.

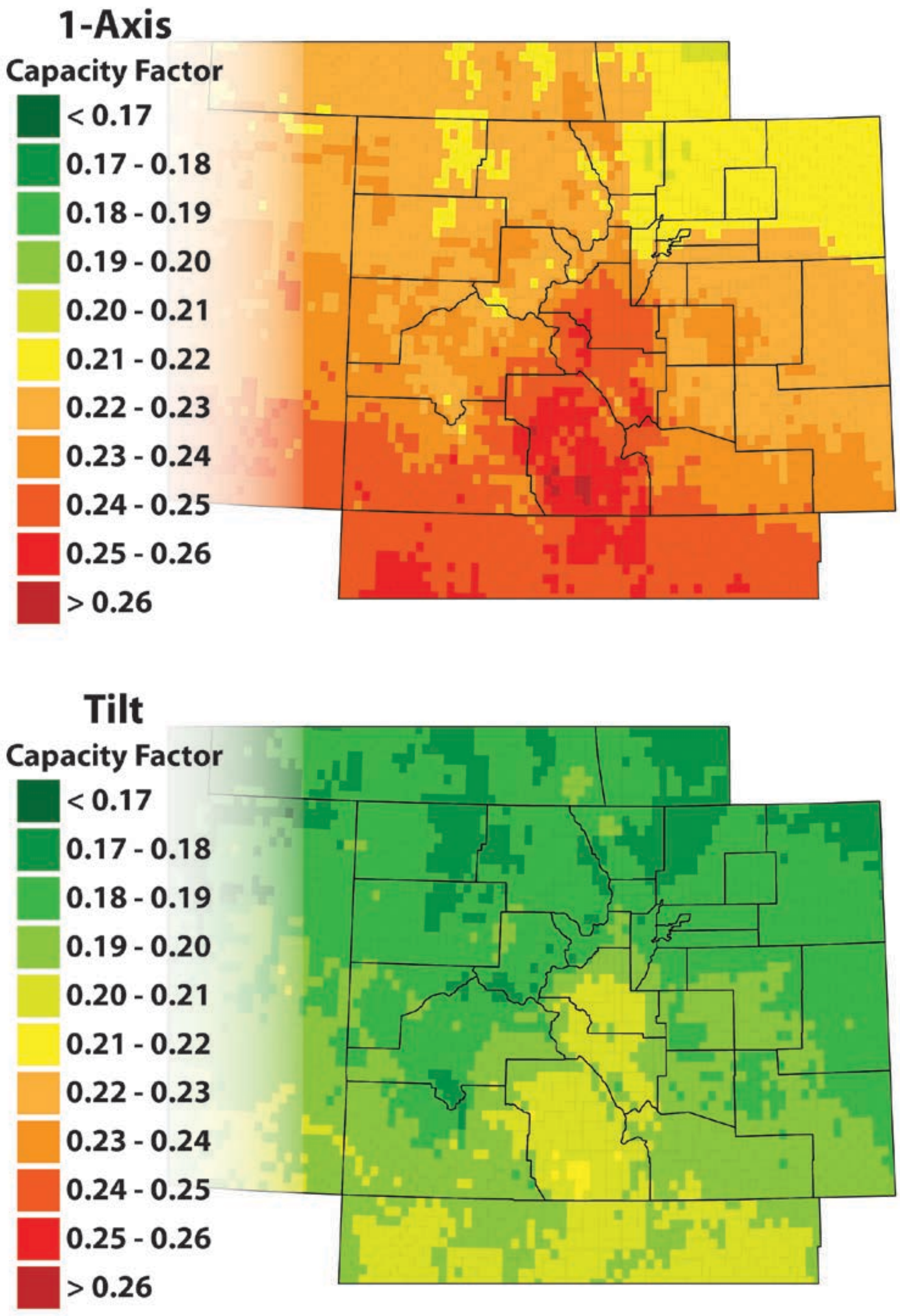

Figure 2. Photovoltaic resource quality by model region and technology type: 1-Axis tracking (top) and Fixed-tilt (bottom)

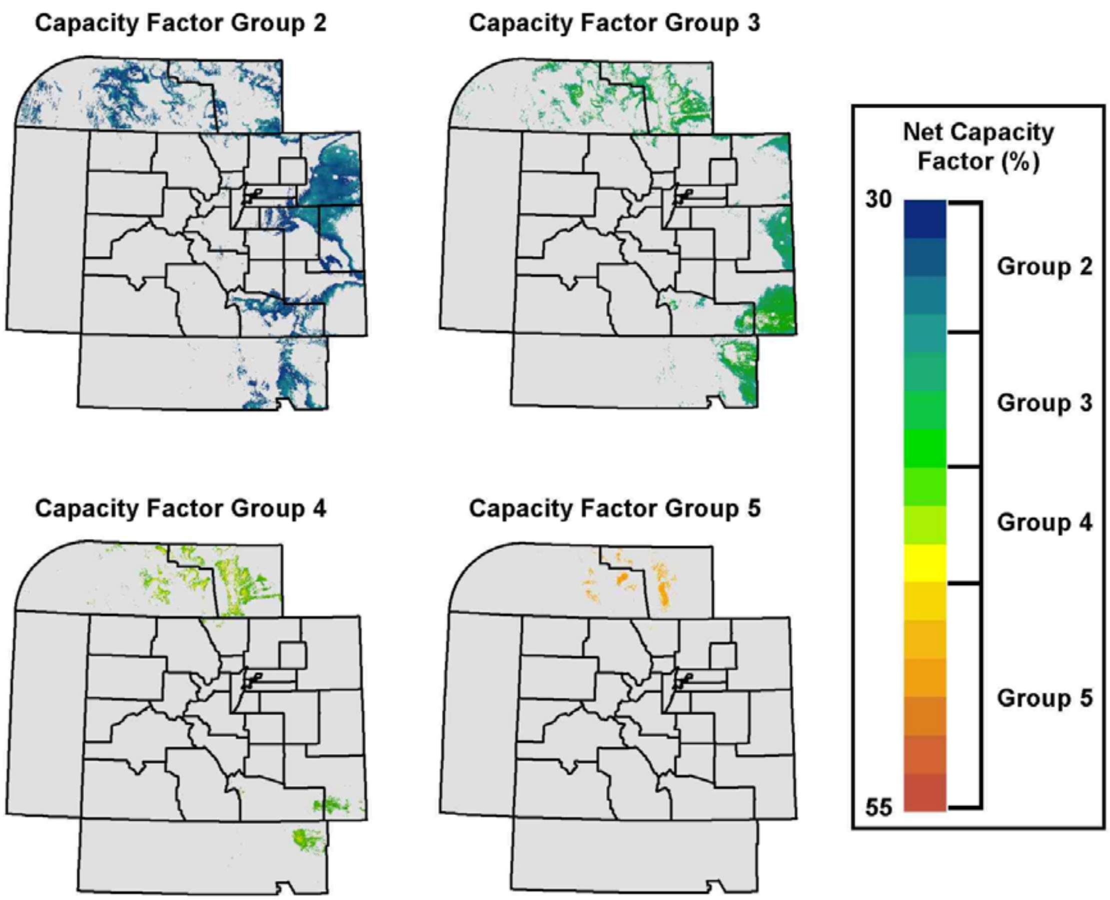

Figure 3. Wind resource by capacity factor group and model region

RPM-CO is an hourly chronological model. Because meteorological conditions play the primary role in determining (1) electricity demand, (2) wind speeds, and (3) solar PV output, the input hourly data rely on the data from the same year for all three. In the current implementation, data for 2005 are used (see Section 3). Certain parameters (e.g., capacity value) rely on the full vector of 8,760 hours. The dispatch modeling within the optimization relies on a subset of these hours. In particular, we divide the year into four seasons (summer, fall, winter, spring) and represent each season with a set of user-selected consecutive days. Although any number of days can be modeled, runtime and other constraints limit our analyses to one week of dispatch per season; however, we typically limit our model runs to four days per season (see Section 3.6).

The chronological nature of the model enables it to capture plant cycling limits and costs, and minimum on and off periods.[13] Thus, the choice of model days or hours can affect overall model results related to dispatch and capacity expansion. In particular, intra- and inter-day variations in load, wind, and solar are present throughout the year, and these variations change with renewable

[13] Ramp rate limits can also be represented in the model; however, these limits are generally not binding under hourly time steps. For this reason, they are currently not modeled in RPM for fossil units. Ramping limits would be necessary for subhourly modeling.

penetration levels.[14] Section 3 describes some preliminary analysis we have conducted to select the representative model days. However, more work is needed to evaluate how the selection of model days impacts overall modeling results. RPM-CO provides a framework in which these types of research questions can be answered.

2.3 Qualitative Model Description

We designed many of the model equations and variables in RPM-CO based loosely on a combination of the ReEDS model (Short et al. 2011) and a dispatch model by Sioshansi and Denholm (2010). The primary decision variables in RPM-CO include capacity expansion variables as well as detailed dispatch variables. The equations in the model are designed to capture both of these aspects while maintaining the linearity of the problem. The major model equations and variables are qualitatively described in this section. A more complete list of model equations and variables is provided in the appendix.

2.3.1 Model Decision Variables

We categorize the model decision variables into the following: generation, transmission, and storage. Each of these categories is subdivided into capacity expansion and dispatch, and solved concurrently. For generator variables, the model decides the types and sizes of generators to build in each model region (capacity expansion), concurrently with the hourly dispatch status for each existing generator, start-up/shut-down events, spinning reserve provisions, and non-spinning reserve provisions (dispatch). For transmission variables, the model decides the sizes and locations of new transmission capacity to build (capacity expansion), concurrently with the hourly power flow between regions (dispatch). For storage variables, the model decides the types and sizes of storage resources to build in each region (capacity expansion), while solving for the hourly charging, discharging and spinning reserve provisions (dispatch).

Included in the decision variables listed above is a subset of binary decision variables that serve two major functions. The first functional group of binary variables helps enforce minimum plant size requirements for new generator capacity expansion of large fossil and nuclear technologies to capture the economies of scale relevant for these plant types. With these variables, the model captures the value of modularity of certain technologies over others. The second functional group of binary variables helps enforce operation constraints of existing generators, including minimum generation requirements, minimum on and off periods, start-up and shut-down event logic, and the ability of a generator to provide energy and reserves. With these variables, the model captures the on or off status of plants and whether or not a plant start-up or shut-down event has occurred.

Note that the second functional group of binary decision variables applies only to existing capacity. More stringent operational limits are applied to new capacity for certain technology types. In particular, all new coal, NG-CC, and nuclear plants are required to operate above their minimum generation points for all model hours, whereas existing plants of the same type only operate above their minimum generation points if the plant is up and running. These stringent operational limits on new capacity is relaxed during the next five-year optimization period as the

[14] For each set of days chosen, we scale the overall load, wind, and solar profiles so that the overall energy required (for load) and energy available (for wind and solar) matches that of the seasonal average. This is necessary to capture the annual plant economics for capacity expansion decision-making.

"new" capacity is rolled into the "existing" capacity representation during the next solve. This different treatment of "new" versus "existing" capacity is necessary to maintain linearity in the problem[15]. However, it also loosely represents the fact that newer and more efficient large plants are likely to be dispatched prior to inefficient plants and are therefore less likely to be cycled.

2.3.2 Objective Function

The objective function of RPM-CO represents the one-year cost of all new capital investments[16] and the annual cost to operate the model system. Capital investments include the cost of new generation, storage, grid interconnection, and transmission capacity. Operational costs include fixed and variable O&M costs, fuel costs, start-up costs, and shut-down costs. Other costs, including a carbon price, can also be included in the objective function. The model minimizes this objective function during each solve subject to the constraints described in Section 2.3.3.

2.3.3 Model Constraints

Major constraints in RPM-CO include load balance, planning and operating reserve requirements, renewable resource limits, exogenously defined wind and solar generation profiles, thermal power plant constraints, transmission constraints, and policy constraints.

2.3.3.1 Load Balance Constraints

The load balance constraint requires that for each of the 31 model regions and each hour, generation within the region and power imports into the region exactly equals the sum of the local demand, exports out of the region, and curtailments. Curtailment by region is a variable in the model. Power imports include an estimate of transmission losses from the source regions. In addition, because RPM-CO does not explicitly represent the distribution network and any losses within the distribution network, the demand that must be met represents the bus-bar demand, which is assumed to be 4% higher than the end-use electricity demand (CEC 2011).

2.3.3.2 Planning Reserve Constraints

Planning reserve requirements ensure sufficient firm capacity is available to at least exceed the peak demand by a reserve margin. The required reserve margin for the Rocky Mountain Power Pool region is set by the North American Electric Reliability Corporation (NERC) to be 12.5% (NERC 2011). We model the Rocky Mountain Power Pool to include all Colorado regions and the two Wyoming regions. For dispatchable generators (i.e., all generator types excluding wind and solar PV), full nameplate capacity is counted toward the planning reserve requirement, i.e., the capacity value of these plants is one. Variable generators, including solar PV and wind, have a lower capacity value that is endogenously calculated between optimization periods.

Capacity values for PV and wind can be estimated in several ways (Milligan and Porter 2006; Madaeni et al. 2012; Mills and Wiser 2012a). Here, we use a simplified net-load approach.

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[15] Since "new" capacity is a decision variable, it cannot be combined with other decision variables, including the binary decision variables used to represent start-up and shut-down events, while maintain model linearity. This is not an issue for "existing" capacity since generation resources become parameters and not a decision variables after they are built.

[16] More precisely, the overnight capital cost is multiplied by technology-specific fixed charge rate. For the preliminary scenario analysis presented in Section 4, fixed charge rates ranging from 0.10 to 0.15 are used based on financing assumptions from (Mai et al. 2012). The objective function is defined in the appendix.

Separate capacity value estimates are calculated for existing installed variable generators and potential new installations. In particular, the capacity value of total existing wind and solar capacity is estimated by the ratio of the difference between the peak load and net peak load to the installed nameplate capacity. Net load is defined as the load minus wind and solar PV generation. Marginal capacity values are applied to potential new installation and are calculated for each region and technology separately.[17] The marginal capacity value of each technology in each region is estimated as the ratio of the reduction in net peak load to an assumed increment of new nameplate capacity. The contribution to the capacity reserve requirement for wind and solar PV is reduced accordingly, based on the estimated capacity values for all new and existing variable generators. All else being equal (e.g. capacity factor, access to transmission, etc), the optimization routine would deploy variable generation technologies in regions with the highest capacity values. In general, capacity value declines with increasing renewable penetration level, particularly if the deployment is concentrated in small spatial regions. This representation of planning reserves and capacity value allows RPM-CO to endogenously value geospatial and technological diversity. In addition, the capacity value calculations are dynamic and they depend on the specific deployment and load scenario modeled.

2.3.3.3 Operating Reserve Constraints

Operating reserve constraints ensure sufficient contingency and frequency regulation reserves are available for each model hour in RPM-CO. Requirements for operating reserves are imposed for two balancing authorities within the model system: Public Service Company of Colorado (PSCO) and Western Area Colorado Missouri (WACM).[18] For each balancing authority, contingency reserve requirements at each hour are based on the maximum between 6% of the hourly demand and an absolute contingency requirement based on the single largest contingency within the system (i.e., the 810-MW Comanche Generating Station coal plant).[19] At least half of the contingency reserves are required to be spinning reserves. In addition, we require additional spinning reserves (1% of demand) to be available during each hour to represent frequency regulation reserves. RPM-CO provides a framework for increasing operating reserve requirements with increasing renewable energy penetration levels; however, that is not considered in the preliminary scenario analysis. Future work will focus on quantifying the potential need for additional reserves, and how to model them in dispatch models.

2.3.3.4 Renewable Resource Limits and Wind and Solar Generation Profiles

Based on the resource data described in Section 3, the model also limits deployment and output characteristics of wind, solar, and hydropower technologies.

In particular, wind supply curves are calculated for each model region and five wind power classes[20] to (1) limit the amount of wind capacity that could be installed based on the available

[17] For wind, a distinct capacity value is calculated for each wind power class in each region.
[18] Each model region in Colorado is associated with one of these two balancing authorities; however, the generators and load within the region boundaries do not perfectly align with actual boundaries for the PSCO and WACM service areas. Modeled operating reserves requirements were based on current requirements in PSCO and WACM, but may not capture the full set of reserve requirements.
[19] We require PSCO to hold at least 451 MW of contingency reserves and WACM to hold at least 359 MW of contingency reserves.
[20] Five wind power classes are defined based on average wind generation characteristics from AWS Truepower (AWS 2012), as described in Section 3.3.

land area and resource quality, and (2) incorporate grid interconnection costs (which depend on the proximity to, and availability of, the regional transmission infrastructure) for new wind installations. Furthermore, we apply regional hourly wind and PV generation profiles. For PV, we use distinct profiles for fixed-tilt and 1-axis tracking systems based on results from NREL's System Advisor Model (see Section 3). Due to the large solar resource and less restrictive siting challenges (relative to wind), we do not characterize regional PV resource limits, or additional grid interconnection costs in the model.[21]

We currently do not allow new builds for other renewable technologies, including biopower, geothermal, or hydropower; however, RPM-CO can be easily modified to include these options. We limit hydropower dispatch with maximum and minimum hourly generation constraints, hourly ramping constraints and a seasonal energy constraint. These limits are derived from historical hydropower generation, and they loosely represent water and other stream-flow constraints. Constraints to biopower and geothermal dispatch are characterized in a similar manner as other thermal power plants.

2.3.3.5 Thermal Power Plant Constraints

Unlike wind and solar generation, thermal power plant dispatch is endogenously determined within the optimization routine. However, modeled thermal power plant dispatch is constrained based on the physical flexibility of the technology types. Plant flexibility is modeled based on parameters that characterize each technology type, including minimum generation points, ramp rates, start-up and shut-down issues, minimum on and off times and outage rates.

We apply multiple constraints to thermal power plant dispatch to help inform the flexibility limits (and options) for future deployment scenarios, particularly for those scenarios with higher levels of renewable penetration. The major constraints to thermal power plant dispatch consider generator capacity allocation, minimum generation requirements, and start-up and shut-down event logic. Many of these constraints require binary variables as described in Section 2.3.1 as well as in the appendix.

Generator capacity allocation constraints limit the sum of thermal power plant generation and the amount of capacity allocated to provide operating reserves to be less than the nameplate capacity of the plant for each hour. The ability to provide spinning and non-spinning reserves depends on the state of the plant. Specifically, only plants that are on, synchronized, and generating electricity can provide spinning reserves if they have sufficient available capacity to provide reserves. The ability to provide different services also depends on technology type. For example, we allow NG-CT plants to provide non-spin (or quick-start) reserves when they are not generating because of their ability to start quickly from a cold start. However, we limit the ability of all other technology types to provide such services.

Minimum generation requirements ensure that generators must either produce at a technology-specific minimum level or be shut down by the model. New coal, NG-CC, and nuclear plants are required to operate at or above their minimum generation level during the model period in which

[21] A base grid interconnection cost is applied to all technologies, including PV.

they are built, whereas existing generators are constrained to operate at or above their minimum generation levels only if the plant is up and running.

Start-up and shut-down event logic constraints govern plant transitions from generating to idle, and vice versa, as well as minimum on and off periods, which are technology-specific. Plant start-up costs are also characterized in the model based on Lew et al. (2012), and they capture the relative economics of cycling in the dispatch (and expansion) decision-making of the model.

2.3.3.6 Transmission Constraints

We model transmission in RPM-CO based on a simple transport model. In other words, full flow control is allowed within the model along each transmission path and power flow is only constrained by the line capacity. Figure 4 shows the model representation of the existing transmission network based on the assumptions described in Section 3. New transmission lines are allowed within the model as well; however, these new lines are restricted to neighboring regions or locations where current connections exist.[22] Future work will improve the simple transport model to more accurately reflect electric flow in the system.

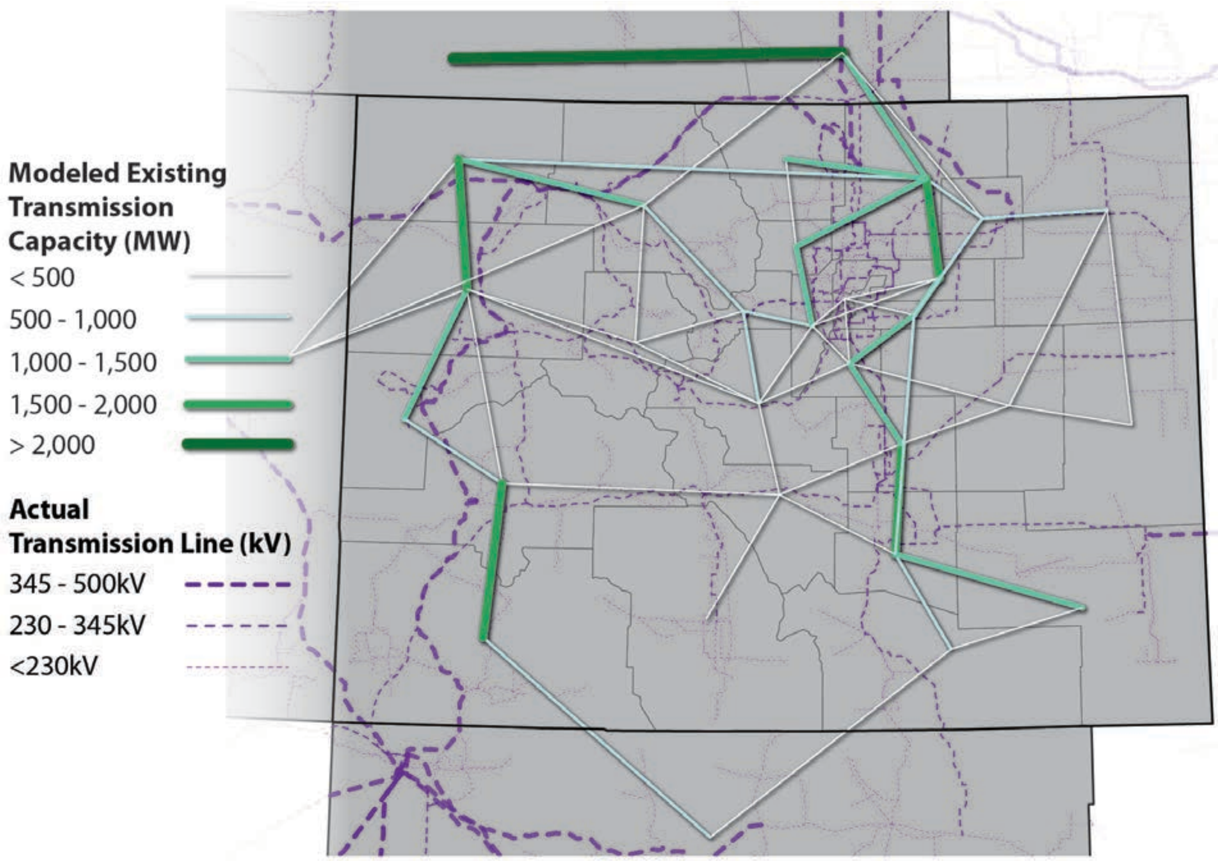

Figure 4. Transmission representation in RPM-CO

kV = kilovolt

[22] For the preliminary scenario analysis described in Section 4, we disallowed any new transmission capacity for simplicity.

Inter-state transfer capacities are defined using data from the WECC Loads and Resources Subcommittee. Intra-state transfer capacities were estimated using existing transmission line spatial data from Ventyx Velocity Suite (Ventyx 2012) and geographic information systems (GIS) analysis. Though the spatial data are detailed, they lack the existing capacity of each line. The voltage and length of each line is used to translate to capacity using the approximate power carrying capability of an uncompensated AC transmission line (National Regulatory Research Institute 1987). Defining the existing transfer network relied on GIS, by first determining the start and end vertices of each transmission line and then associating them with a region, producing region pairings. Capacities of regions with multiple pairings are aggregated producing distinct transfer capacities.

RPM-CO is designed to evaluate long-term planning scenarios for a small area; however, this area is electrically connected to a larger synchronous grid (WECC). For this reason, treatment of the boundary conditions can play a significant role in overall model results. Currently, we assume hard boundary conditions around the model system, which includes Colorado and parts of three surrounding states. Inter-state transfer of power within this model system is treated in a similar manner as intra-state transfers. In other words, we allow transfer of power between model regions based on the simple transmission treatment described above, irrespective of the state to which the source and destination regions belong. Future work will be needed to evaluate different boundary conditions and their effect on model results.

2.3.3.7 Policy Constraints

Options for policy-related constraints are available in RPM-CO and include renewable portfolio standards (RPS) and annual emission limits. The RPS in Colorado imposes an annual requirement for renewable generation. Current legislation[23] dictates that 30% of electricity sales must come from renewable resources by 2020. The legislation includes an in-state multiplier of 1.25 for in-state renewable generation. In addition, there is a 3%-by-2020 solar rooftop PV requirement. Any of these parameters can be changed to model different RPS scenarios. RPM-CO tracks power sector emissions for CO_2, sulfur dioxide (SO_2), nitrogen oxides (NO_x), and mercury (Hg), and constraints can be applied to limit the annual emissions of any of these pollutants.

[23] See www.dsireusa.org.

3 Model Inputs

The Resource Planning Model is a tool for exploring efficient development of electricity generation and transmission resources for a wide range of market dynamics, including different technology and fuel costs, generator retirement schedules, RPS, emissions constraints, and so on. RPM was designed to allow users to set key market parameters and simulate a diverse range of electric sector growth scenarios. In this section, we describe several model inputs chosen in the preliminary scenario analysis (Section 4) to demonstrate model functionality. Both the input parameters and preliminary scenario analysis results are intended to highlight model capabilities; they should not be interpreted as projections of future technology costs, market trends, or renewable and conventional market potential.

3.1 Electricity Demand

We characterize electricity demand for each model region using hourly electricity demand profiles for 2005 from the Ventyx Velocity Suite (Ventyx 2012). Electricity demand in Ventyx is characterized for "transmission zones," which are larger than model regions considered (six in Colorado, and nine in the full study region, including Wyoming, Utah, and New Mexico). To associate transmission zones with more spatially resolved model regions, we assume that electricity demand scales directly with population. We use LandScan nighttime population data (ORNL 2012) with approximately 1-kilometer (km) x 1-km resolution to calculate population-weighted scaling factors, and we use these to associate Ventyx demand to model regions. This methodology is applied to the Colorado study region, but it could be adapted to any U.S. region.

We focus on 2005 electricity demand data because 2005 is the most recent year with coincident hourly wind and solar generation data (Section 3.3), and electricity demand data. RPM is designed to simulate capacity expansion from 2010 to 2030, and we scale 2005 electricity demand to approximate total 2010 demand, while maintaining 2005 hourly demand profiles. Electricity demand is assumed to increase additionally from 2010 through 2030 by 1% per year, based loosely on *AEO 2011* (EIA 2011). For all years, we assume that the temporal shape of hourly electricity demand remains unchanged (represented by 2005 data), and we scale hourly electricity demand to be consistent with annual growth rate assumptions.

RPM provides a framework for exploring the impact of varying hourly load profiles, which could result from several factors, including wide-scale adoption of electric vehicles, smart grid appliances, and so on. Efficient capacity expansion under different, and potentially uncertain, demand profiles will be the focus of subsequent research.

3.2 Conventional Generation Resources

Plant-specific generator characteristics are calculated using three datasets: Ventyx Velocity Suite (Ventyx 2012), the Environmental Protection Agency's (EPA's) National Electric Energy Data System (NEEDS) (EPA 2010) and Form EIA-923 (EIA 2010a) for generator capacity[24]; and EPA's Continuous Emission Monitoring System (CEMS)[25] (EPA 2012b) for plant-specific operating characteristics. We use a statistical characterization of hourly CEMS data from 2008

[24] Several data sources archive generator characteristics for some, but not all, of the generators within the study region. Three data sources were used to develop a complete data set of generator capacity and plant characteristics.
[25] See www.epa.gov/ttn/emc/cem.html.

(Lew et al. 2012) to inform plant-specific heat rates, minimum generation levels, ramping and cycling characteristics, and emissions levels for generation resources within the study region. Similarly, we obtained oil and gas steam (OGS) generator characteristics from the Ventyx Velocity Suite. We associate each generator with a model region, and we use a capacity-weighted average of plant-level generation characteristics to represent existing generators within each model region. 2010 generation capacity is listed for each state in Table 1.

Table 1. Existing Generation Capacity in 2010 by State (MW)

	Colorado	Wyoming	Utah	New Mexico
Coal	5,702[b]	6,262[c]	4,771[c]	3,970[c]
Natural Gas—Combined Cycle	2,579[b]	-[c]	1,195[c]	-[c]
Natural Gas—Combustion Turbine	2,350[b]	68[c]	390[c]	574[c]
Oil / Gas Steam[a]	184	6	25	2
Hydropower[a]	680	306	281	85
Wind[a]	1,306	1,415	224	292
Utility PV[a]	85	-	-	54
CSP[a]	-	-	-	-
Biopower[a]	13	-	9	6
Geothermal[a]	3	-	44	-
Pumped-Hydropower Storage[a]	563	0	-	-
Total	13,465	8,057	6,938	4,983

[a] Ventyx 2012
[b] EIA 2010a
[c] EPA 2010

RPM uses a mixed-integer optimization structure that deploys discrete plants with specific sizes, heat rates, minimum generation characteristics, and emission rates. In the preliminary scenario analysis (Section 4), we allow only new natural gas generation resources (CCs and CTs) to be developed, consistent with recent trends and industry projections for the Colorado study region (GEO 2010).

Currently, RPM does not endogenously model the decision to retire electric generating capacity. However, the model exogenously considers planned retirement and fuel conversion activities based on Xcel Energy's pathway to meet emission requirements defined in Colorado's Clean Air, Clean Jobs Act (PUC Colorado 2010). This emission reduction pathway includes retiring 596 MW of the existing coal capacity, converting 463 MW of coal to natural gas[26], and implementing emissions controls to 742 MW of coal capacity[27]. Table 2 summarizes the expected timeline for these actions. Additionally, Xcel Energy has plans to install 569 MW of natural gas combined cycle capacity at the Cherokee site (Denver, Colorado) in 2015 to supplement the retired coal generation. These 569 MW are exogenously forced into RPM as new combined cycle construction in 2015.

[26] The 463 MW of fuel conversions from coal to natural gas are exogenously forced into RPM based on scheduled retirements of coal capacity, and the development of new combined cycle generation capacity.
[27] Included in the 596 MW of retirements are 551 MW of coal capacity that will be decommissioned and a 45-MW coal plant that will be converted to a synchronous condenser. The retirements and fuel conversions are modeled in RPM; however, we currently do not model emission control retrofits in RPM.

Table 2. Summary of Xcel Energy's Pathway to Meeting the Emissions Requirements of the Clean Air Clean Jobs Act (PUC Colorado 2010)

Coal Unit	Capacity (MW)	Action	Completion Date (Estimated)
Cherokee 1	107	Retirement	2011
Cherokee 2	106	Retirement	2011
Cherokee 3	152	Retirement	2015
Cherokee 4	352	Conversion To Natural Gas	2017
Arapahoe 3	45	Retirement[a]	2013
Arapahoe 4	111	Conversion To Natural Gas	2014
Valmont 5	186	Retirement	2017
Hayden 1	139	Emissions Controls	2015
Hayden 2	98	Emissions Controls	2016
Pawnee	505	Emissions Controls	2014

[a] Arapahoe 3 will be converted to a synchronous condenser by decoupling the turbine from the generator. Synchronous generators do not provide real power, but they regulate reactive power for system stability. Although the turbine and generator can be recoupled whereby restoring the synchronous generating capabilities, as we do not model reactive power in RPM, we simply assume that the 45 MW of generating capacity are no longer available at Arapahoe 3.

3.3 Renewable Resources and Technologies

We obtained the characteristics of existing renewable energy resources (i.e., installed by 2010) from the Ventyx Velocity Suite. In this section, we describe the methodology used to simulate hourly generation profiles for wind and solar resources, and generation constraints for semi-dispatchable renewable resources such as hydropower (run-of-river and pumped storage), geothermal, and biopower generators.

Wind Resources

We use two data sources to characterize wind generation characteristics at high temporal resolution (3Tier 2010) and high spatial resolution (AWS Truepower 2012). First, we simulate hourly wind generation profiles for each model region and five wind groups (defined based on annual average wind capacity factors; see Table 3), and these hourly profiles are used to capture the different temporal generation patterns for wind resources with different capacity factors.[28] To do this, we use detailed simulations of wind generation at specific locations for 2005 (3Tier 2010). These potential wind generation sites were chosen for the Western Wind and Solar Integration Study (GE Energy 2010); we use site locations to associate each site with a model region. We then characterize "aggregate" hourly wind generation profiles for each wind group by averaging the hourly generation from six wind sites within each of the five wind groups. This results in 30 wind sites for each model region. If model regions do not have a sufficient number of wind sites within each group to satisfy the selection criteria, we use the closest unselected wind sites from nearby regions to approximate hourly generation patterns. We use "aggregate" wind generation profiles from six wind sites to represent the inherent smoothing of variable wind

[28] Capacity factors represent the amount of electricity generated over a given period divided by the amount of electricity that could have been produced if the generator produced electricity at nameplate capacity for the full period. For example, if a 1-MW wind turbine generates 8 megawatt-hour (MWh) of electricity over the course of one day, it would have a capacity factor equal to 8 MWh/24MWh or 33% for that day.

generation by developing wind resources in spatially dispersed locations. This methodology may underestimate the frequency and magnitude of wind ramping at low levels of wind penetration and overestimate ramping at higher levels of penetration.

Next, we calculate wind resource supply curves for the five wind groups in each model region. The resource supply curves represent the marginal cost of developing new wind resources per unit of additional capacity developed, based on the quality of undeveloped wind resources and access to existing transmission resources. We characterize the amount of new wind capacity that could be developed in each model region and wind group, using AWS Truepower (AWS 2012) simulations of wind gross capacity factors (based on simulated 80 meter wind velocities from 2003 to 2010) at 200-meter x 200-meter horizontal spatial resolution.[29] We then filter this dataset to remove land area deemed unsuitable for wind development, such as urban areas, developed land, protected areas (local, state and national parks), and slopes greater than 20% (Lopez et al. 2012). We convert the remaining land area into wind capacity by assuming that 5 MW of wind capacity could be sited on one square kilometer of land (DOE EERE 2008). Lastly, we estimate the potential need for, and cost of, new transmission and interconnection resources to develop each potential wind location based on the proximity of each location to existing transmission corridors and the dynamic utilization of these transmission resources.[30] This results in 155 wind resource supply curves (5 wind groups for 31 model regions) that represent the incremental cost of developing an additional unit of wind capacity. Model regions frequently do not have any resources associated with a given wind group (Figure 3), and the wind resource supply curves will show zero capacity.

Table 3. Wind Net Capacity Factors (%) Associated with each Wind Group[a]

Capacity Factor	Group 1	Group 2	Group 3	Group 4	Group 5
Mean Annual Capacity Factor (%)	28	33	38	42	48
Range in Annual Capacity Factors (%)	25–31	31–36	36–41	41–46	>46

[a] Wind resource characterizations from AWS Truepower (AWS 2012), based on simulated 80-m wind speeds from 2003 to 2010 and proprietary relationships between wind speed and generation profiles (wind power curves).

Photovoltaics Resources

We simulate hourly PV generation profiles for two utility-scale[31] PV technologies: (1) fixed mount PV systems that are south-facing with a 25-degree tilt, based on a common utility-scale system orientation (Ong et al. 2012), and (2) 1-axis tracking PV systems that are mounted flat (no tilt) and rotate from east-to-west with a maximum tracking angle of ±45 degrees.[32] Hourly PV generation profiles are calculated for fixed and tracking PV systems at 10-km x 10-km resolution using the PVWatts module (Marion et al. 2001) in System Advisor Model (SAM).[33] We simulate PV generation for 2005 using hourly solar radiation data from the National Solar

[29] We assume an 85% availability factor to convert gross capacity factor to net capacity factor. The model uses net capacity factor to account for outages and other effects that limit availability of wind power plants.
[30] Short et al. 2011 describes the same methodology used in the ReEDS model.
[31] The RPM framework characterizes optimal capacity expansion of wholesale generation technologies, and does not characterize the potential evolution of distributed generation technologies like rooftop photovoltaics.
[32] This orientation was chosen to represent flat-mounted, ganged tracking systems that are common for large utility-scale PV projects in the United States (Ong et al. 2012)
[33] See sam.nrel.gov.

Radiation Database (NREL 2007), meteorological data from the North American Regional Reanalysis (Mesinger et al. 2006), and an 85% derate factor (based on inverter losses, panel soiling, system wiring, and module mismatch).

We characterize aggregate hourly PV generation profiles for each system type and model region using three steps: (1) identify the 10 resource areas (10-km x 10-km) with the highest PV capacity factors in each model region; (2) remove the 3 resource areas with the highest PV capacity factors to conservatively estimate PV resources in areas that could be developed; and (3) use the remaining seven resource areas to calculate aggregate hourly generation profiles for each model region. We use aggregate PV generation profiles to estimate the impact of developing spatially dispersed solar resources.

We do not calculate transmission-based resource supply curves for PV as we do for wind. This is because solar resources are very large compared to the amount deployed in the model (Lopez et al. 2012), and there is less spatial diversity within the resource (Figures 2 and 3). Based on this, we assume that solar resources will be developed near existing transmission corridors for the levels of PV penetration explored in the preliminary scenario analysis. We apply the same grid interconnection cost for PV as other non-wind generation types.

3.3.1 Hydropower Resources

A significant amount of hydropower capacity—680 MW—exists in the Colorado study region (Ventyx Velocity Suite). We characterize hydropower generation using hourly generation profiles from specific hydropower units within the study region[34] (WECC 2012a) to statistically represent dispatch characteristics. From these data, we calibrate hydropower dispatch using three operational constraints: (1) minimum and maximum hydropower generation, determined for each season; (2) total seasonal hydropower generation; and (3) hourly ramp rate limits (±15%). The first two constraints are informed by the hourly hydropower generation data, but the last constraint is developed to limit the dispatchability of these resources.[35]

Colorado also has 563 MW of pumped-storage hydropower resources (Ventyx Velocity Suite). Pumped-storage hydropower units store electrical energy by pumping water from a low- to high-elevation reservoir, and then later re-generate electricity, subject to about a 20% energy loss, by sending water back down to the low-elevation reservoir. We allow the model to economically dispatch these storage resources. In the current implementation, we do not explicitly model energy storage (megawatt-hours [MWh]) levels for the pumped-storage hydropower plants. However, we require a balance between the total energy discharged and the amount charged minus efficiency losses over each season.

[34] Hydropower data were available from 2006, while other system characteristics (hourly electricity demand, PV generation, and wind generation) are based on 2005. It is important to match hourly electricity generation with demand to characterize the optimal dispatch of conventional generators to integrate renewable. However, we assume that hydropower resources are somewhat dispatchable, and we use the hourly generation statistics to calibrate basic generation characteristics. For this purpose, it is not as important to match generation years for hydropower as it is for wind and solar.

[35] There are large ranges of hydropower resource types and dispatch characteristics. Defining general operational constraints to approximate both historical generation characteristics and potential future dispatch strategies can be challenging. We use this constraint to limit hydropower ramping to conservatively estimate the dispatchability of hydropower resources.

In the preliminary model simulations described in Section 4, we did not allow new hydropower or pumped-storage hydropower resources to be developed. However, we do allow hydropower resources (and pumped-storage hydropower) to be dispatched differently, within the operational constraints described above, to add flexibility to the electric sector. Additionally, RPM provides a framework for evaluating the economic deployment of new hydropower resources and we anticipate using the model in this capacity in future work.

3.3.2 Geothermal, Biopower, and Other Renewable Resources

Limited deployment of geothermal (3 MW) and biopower (13 MW) capacity has occurred in the Colorado study region (Ventyx Velocity Suite). Geothermal plants are modeled as dispatchable generators, and they are dispatched as baseload generation because they have no fuel costs. Biopower resources are similarly modeled as dispatchable resources, and they will also generate as baseload units if biomass feedstock costs are lower than the costs of other fuels in a given scenario. In the preliminary model analysis, we did not allow new geothermal or biopower capacity to be developed; however, the economic development and dispatch of these technologies could be explored within the RPM framework.

3.4 Electricity Imports and Exports

One challenge in optimizing capacity expansion for distinct regions within an electricity interconnect is characterizing electricity imports and exports between the study region and boundary areas. In the preliminary scenario analysis, we approximate current and future imports and exports using historical power flows from WECC transmission path data (WECC 2012b). Colorado has historically exported electricity to Utah (WECC path 30), imported electricity from Wyoming (WECC path 36), and either imported or exported a small amount of electricity to New Mexico (WECC path 31). We calibrate seasonal import and export constraints using hourly power flow between regions from 2009, which is the most recent year with power-flow data (WECC 2012b). Based on these data, we constrain seasonal imports into Colorado to less than 10.3% to 12.4% of electricity demand (depending on the season), and we limit seasonal exports to less than 2.0% to 5.1% of demand. No other restrictions or costs are placed on inter-state energy transfers. Future works is needed to better account for power transfers across regions. In the preliminary model runs, we find that the electricity import constraint is frequently binding, but the export constraint is typically not binding, as discussed in Section 4.

RPM can be used to explore optimal capacity expansion in scenarios with very different electricity import/export dynamics, which can be essential to efficiently integrating large amounts of renewable electricity (DOE 2012, Mai et al. 2012). To do this, electricity generation and demand in boundary regions must be modeled in appropriate detail. We intend to expand the representation of boundary regions in future work to explore interregional power-flow dynamics.

3.5 Selection of Model Days

The RPM framework is unique in that it combines multi-year capacity expansion with hourly dispatch dynamics. Given the computationally intensive nature of capacity expansion models,[36] simulating dispatch for all hours of the year would require very long model run times. Instead, we select several representative days from each season to run. In the preliminary scenario analysis (Section 4), we simulate hourly dispatch for 17 days per year, including four consecutive days (Sunday-Wednesday) for each calendar season and one peak electricity demand day to ensure sufficient generation/transmission capacity. This represents 408 dispatch hours,[37] with chronological dispatch within each season.

We choose a representative week for each season by finding a period that is most representative of "typical" seasonal electricity demand, using 3 steps: (1) we calculate seasonal average electricity demand for each day of the week at hourly resolution[38]; (2) we then calculate the root-mean-square error (RMSE) difference between hourly electricity demand for each week and the seasonally averaged electricity demand; and (3) we choose the week with the lowest RMSE deviation from mean electricity demand for each season. We then choose four consecutive days (Sunday-Wednesday) from this representative week to model.

After identifying representative weeks for each season, we scale electricity demand, and solar and wind generation profiles, to ensure that the scaled four-day electricity demand and generation represent total seasonal load, and wind and solar generation.[39] This scaling is necessary to properly capture plant economics for the capacity expansion decision-making. By minimizing the deviation between weekly and seasonal electricity demand, we choose days that require the least amount of scaling to represent total seasonal electricity demand, but these weeks may require more scaling to represent seasonal wind and solar generation than other weeks that could have been chosen.

The methodology for choosing representative times to characterize the value of variable (wind and solar) and dispatchable resources in capacity expansion models is an area of active research. We have designed the RPM framework to be run at various time resolutions (hourly to multiple hour temporal resolution) and to use different methodologies for choosing representative days. We explored a few different methods for choosing representative days while developing the model, including minimizing the RMSE deviation between daily and seasonal mean wind and

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[36] Capacity expansion problems are computationally intensive because of the large number of combinations of generation resources that could be developed, including: different types and sizes of generation capacity, different generator locations, trade-offs between adding new generation or transmission capacity, among others. This limits the spatial and temporal resolution of capacity expansion models.

[37] The number of optimization periods equals (4 days/season * 4 seasons + 1 peak day) * 24 hours/day = 408 hours.

[38] This is to capture different electricity use trends for weekdays versus weekends.

[39] For example, if a season has 90 days, we calculate the following scaling factor, *C,* to apply to hourly PV generation:

$$C = \frac{\textit{Seasonal PV Generation}}{\left(\frac{90}{4}\right)\textit{Model PV Generation}}.$$

We calculate similar scaling factors for electricity demand and wind generation.

solar generation profiles. However, we have not systematically assessed how these different selection methods would impact capacity expansion decisions. Developing optimal methods for selecting representative periods will be the focus of future work.

3.6 Cost Assumptions for Generation Technologies and Fuels

The cost of electricity generated by different technologies is driven by several factors including capital costs, fuel prices, O&M costs, planned and forced outage rates, emissions costs in various policy scenarios, and other factors. Future capital costs and fuel costs are inherently uncertain, and RPM allows users to set these prices to facilitate scenario analysis. The cost projections used here are intended to demonstrate model capabilities and features, and they do not represent forecasts of future price and performance potential.

Table 4 outlines the capital cost assumptions used in the preliminary scenario analysis in Section 4. All conventional and renewable technology prices are based on Black and Veatch, Inc. (2012), and they represent a relatively conservative projection of future price and performance improvements for all technologies. Other cost and performance factors, including technology-specific O&M costs, can be found in Black and Veatch (2012). Fixed charge rates are also assumed to differ by technology and are based on the financing and lifetime assumptions from Mai et al. (2012). Here and elsewhere in this report, all technology and system costs are shown in 2010 US dollars (2010$).

Table 4. Price Projections (2010$/Watt[a]) for Electricity Generating Technologies

Technology	2010	2015	2020	2025	2030
Coal	2.94	2.94	2.94	2.94	2.94
Natural Gas—Combined Cycle	1.25	1.25	1.25	1.25	1.25
Natural Gas—Combustion Turbine	0.66	0.66	0.66	0.66	0.66
Wind—All Wind Classes	2.01	2.01	2.01	2.01	2.01
PV—Fixed Tilt	2.88	2.59	2.45	2.32	2.22
PV—1-xis Tracking	3.98	2.66	2.55	2.45	2.35

[a] All prices are converted from 2009 to 2010 US dollars using the consumer price index (www.bls.gov/data/inflation_calculator.htm).

Table 5 shows the fuel price projections used in the preliminary scenario analysis, and are based on the AEO 2011 reference scenario (EIA 2011). As with other system characteristics, these prices are intended only to demonstrate model capabilities, and RPM provides a framework for exploring the impact of various future price scenarios on capacity expansion and dispatch.

Table 5. Fuel Price Projections (2010$/MMBTU[a])

	2010	2015	2020	2025	2030
Coal	2.30	2.14	2.19	2.28	2.36
Natural Gas	5.15	4.75	5.09	5.85	6.31
Biomass	5.08	5.08	5.08	5.08	5.08

[a] All prices are converted from 2009 to 2010 US dollars using the consumer price index (www.bls.gov/data/inflation_calculator.htm).

Table 6 summarizes the assumed operating characteristics for new fossil generators developed by the model. RPM uses mixed-integer optimization, allowing generation units of distinct sizes to be built. In the preliminary model scenarios, we assume minimum generator sizes for coal and natural gas resources, as shown in Table 6, along with technology-specific operational characteristics (heat rates, emissions rates, and minimum generation) from Black and Veatch (2012). For fossil generators built before 2010, we use historical plant operation from the EPA CEMS data (EPA 2012, Lew et al. 2012) to inform plant-specific heat rates, emission rates and minimum generation levels. These are included as capacity-weighted operating characteristics for each generator type in all model regions. For fossil generators built after 2010, we estimate NO_x emission rates using average emission rates from existing Colorado generators based on the EPA CEMS data, and we estimate CO_2, SO_2 and mercury emission rates based on national averages used in the ReEDS model (Short et al. 2011).[40]

Table 7 summarizes additional operating characteristics assumed for existing fossil generation resources. These include the planned and forced outage rates (Black and Veatch 2012), the maximum amount of capacity that can be used for spinning reserves, as well as the time and costs associated with starting up and shutting down fossil generators (Lew et al. 2012).

Table 6. Assumed Characteristics for New Thermal Generators

	Minimum Size (MW)	Heat Rate (MMBTU/MWh)	CO_2 Rate (metric tons/MMBTU)	NO_x Rate (short tons/MMBTU)	SO_2 Rate (short tons/MMBTU)	Minimum Generation (% of nameplate)
Coal	606	9.4	9.3E-02	1.4E-04	3.1E-05	40%
NG CC	580	6.7	5.4E-02	3.6E-06	1.7E-06	50%
NG CT	211	10.4	5.4E-02	1.7E-05	4.9E-06	50%

Table 7. Operating Characteristics for Thermal Generators

	Forced Outage Rate (%)	Planned Outage Rate (%)	Maximum Spinning Fraction (% of total)	Fixed Start-Up Cost ($/MW)	Start-Up Fuel Usage (MMBTU/MW)	Minimum On Time (hr)	Minimum Off Time (hr)
Coal	6%	10%	10%	129	14.5	12	12
NG CC	4%	3%	10%	79	0.24	4	4
NG CT	3%	5%	50%	34	1.53	0	0

[40] NO_x and SO_2 emissions rates depend on site-dependent generator characteristics, combustion controls and post-combustion controls. We estimate NO_x and SO_2 emissions rates for new generators based on historical averages which may may overestimate future emissions. However, these emissions factors can be modified in different scenarios to explore the regional costs of complying with future regulation standards, such as the EPA New Source Performance Standards (NSPS).

4 Sample Model Results

To demonstrate the RPM capabilities, we explore two capacity expansion scenarios in the Colorado study region: (1) a 30% renewable portfolio standard (RPS) to be met by 2020 and sustained for all subsequent periods applied to Colorado (referred to as "30% RE" throughout), and (2) a Baseline scenario with no RPS requirement (referred to as "Baseline" throughout). The first scenario is similar to the current Colorado RPS[41], with a few modifications.[42] We do include a 3% solar carve-out[43] to the 30% RPS, similar to the current Colorado RPS. For years preceding 2020, we apply intermediate RPS targets based on linearly scaling from current RE penetration to the 30% target by 2020. The Baseline scenario is identical in all ways except that it does not include a RPS requirement or the solar carve-out.

The amount and location of wind and solar deployment is sensitive to several assumptions, including renewable energy targets and new and existing transmission capacity. RPM provides a framework for exploring the impact of these and other factors on the deployment of renewable and fossil-based generators. The scenarios explored here are intended to demonstrate model capabilities and should not be interpreted as projections of future market trends, technology costs, or renewable and conventional market potential. In addition, these scenarios are not intended to represent a policy analysis of the existing Colorado RPS.

4.1 Electric Sector Evolution

Figure 5 shows the progression in annual Colorado generation in terawatt-hours (TWh) and net-imports of electricity from surrounding states (including Wyoming, Utah and New Mexico), and Figure 6 shows generation fractions for each technology in 2010 and 2030. Colorado end-use electricity demand is assumed to increase from about 60 to 73 TWh from 2010 to 2030. This increase in demand is met by increased wind, solar and natural gas generation in the 30% RE scenario, and almost entirely by increased natural gas generation in the Baseline scenario.

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[41] See www.dsireusa.org.

[42] The modeled RPS was used to explore the costs and benefits of reaching 30% renewable energy generation in Colorado, and it differs from the existing CO RPS in several key ways, including: (1) we apply the renewable requirement to all Colorado electricity demand, not just the demand served by investor owned utilities; (2) we constrain the RPS to be met with renewable resources developed within Colorado state boundaries, and we do not consider interstate trading of renewable electricity credits; (3) we remove the 1.25 multiplier for renewable energy generated within Colorado; (4) we model the 3% solar carve-out to apply to all Colorado electricity demand and require the carve-out to be met by utility-scale PV; and (5) we allow existing hydropower generation to contribute to the RPS requirement.

[43] The modeled solar carve-out requires 3% of electricity demand in Colorado to be generated by solar technologies by 2020, and the 3% generation level to be maintained after 2020 as electricity demand increases. Since RPM-CO does not include a representation of rooftop PV markets, we require the 3% solar carve-out to be met by utility-scale PV projects.

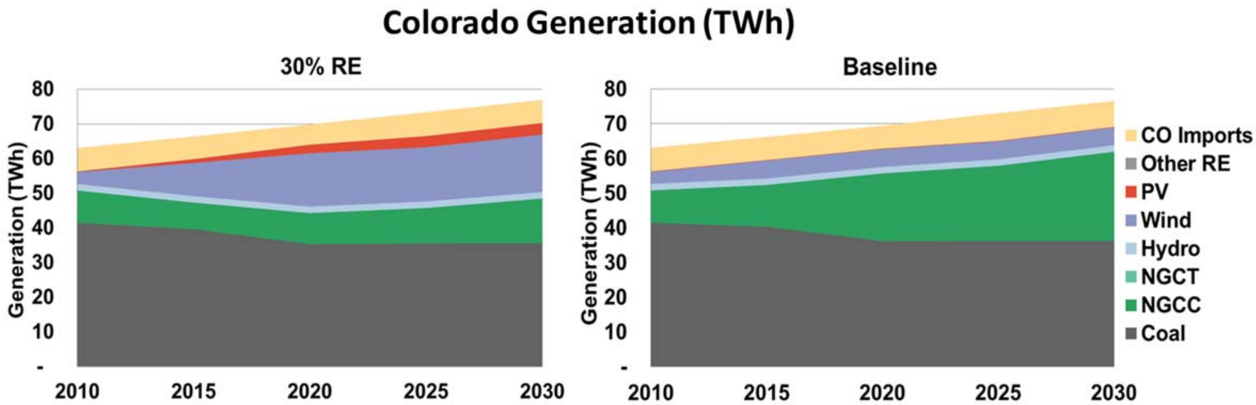

Figure 5. Growth in electricity generation (TWh) for the 30% RE scenario and the Baseline scenario

Figure 6 shows the fractional breakdown of modeled 2010 and 2030 electricity generation from different technologies. In the Baseline scenario, no new wind or solar capacity is developed after 2015,[44] and the relative generation fractions of wind and solar decrease based on increasing electricity demand. In the 30% RE scenario, wind increases from 5.5% of electricity generation in 2010 to about 22% by 2030, and solar generation increases from 0.23% to about 4.3%. The 30% RE scenario included a 3% solar carve-out, and we see additional PV capacity developed to reach the renewables target. The renewable energy fraction is stipulated to meet 30% of end-use electricity *demand*, but based on energy losses in the transmission and distribution systems,[45] we model the renewables target as reaching 28.3% of total electricity *generation*.

Figures 5 and 6 show natural gas combined cycle (CC) generation increases in both scenarios, from 14.9% in 2010 to about 16.8% in the 30% RE scenario and 33.6% in the Baseline scenario. We find that natural gas combustion turbine (CT) generation increases slightly, and that existing CT capacity is sufficient to meet these small increases. Coal generation is projected to decrease in both scenarios, from about 65.9% in 2010 to 46.4% by 2030 in the 30% RE scenario and 47.5% by 2030 for the Baseline scenario. Coal generation declines over the study period as coal capacity is retired based on planned retirement schedules (Section 3.2), and because the model is constrained to restrict new coal development in these scenarios.[46]

[44] We exogenously force 497 MW of new wind builds in the 2015 optimization to account for historical wind capacity additions between 2010 and 2012.
[45] We do not explicitly model the distribution system; we simply assume 4% distribution losses (CEC 2011).
[46] New coal capacity is limited in the sample model results to limit the model from exogenously retiring and then re-building coal generation resources.

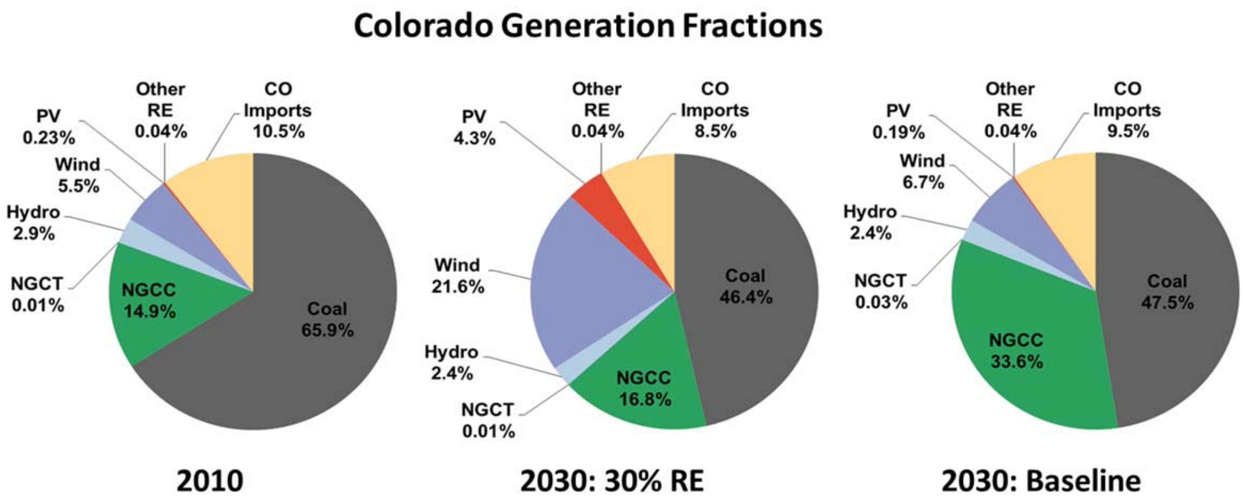

Figure 6. Electricity generation fractions for 2010 and for the 2030 30% RE scenario and Baseline scenario

Figure 7 compares 2010 Colorado in-state generation fractions from the RPM model with historical generation data from EIA form 923 (EIA 2010b). Electricity demand and generation capacity are calibrated for 2010 using historical data (see Section 3), but the RPM model determines optimal dispatch for all years.[47] The EIA data does not include generators less than 1 MW, and only captures about 90% of in-state CO generators and electricity demand,[48] however, the comparison suggests that the RPM optimal dispatch algorithm is largely in line with the historical data. The RPM model shows a larger fraction of in-state coal generation, as compared to historical trends, and a correspondingly smaller natural gas generation fraction. Reasons for these differences may include differences in plant- or utility-specific fuel price contracts, congestion issues that RPM does not capture, as well as various real-world dispatch considerations such as additional regional reserve requirements that are not captured within the least-cost dispatch algorithm. Further work is needed to understand differences between model dispatch and historical data.

[47] The Comanche 3 coal unit came online mid-year of 2010, therefore, we only allow it to generate electricity or provide reserve services during the summer and fall model seasons for the 2010 model year.

[48] EIA form 923 contains generation data for some, but not all, U.S. electric service providers. As such, the generation fractions in Figure 7 represent a subset of the generation resources and end-use demand included in the RPM model.

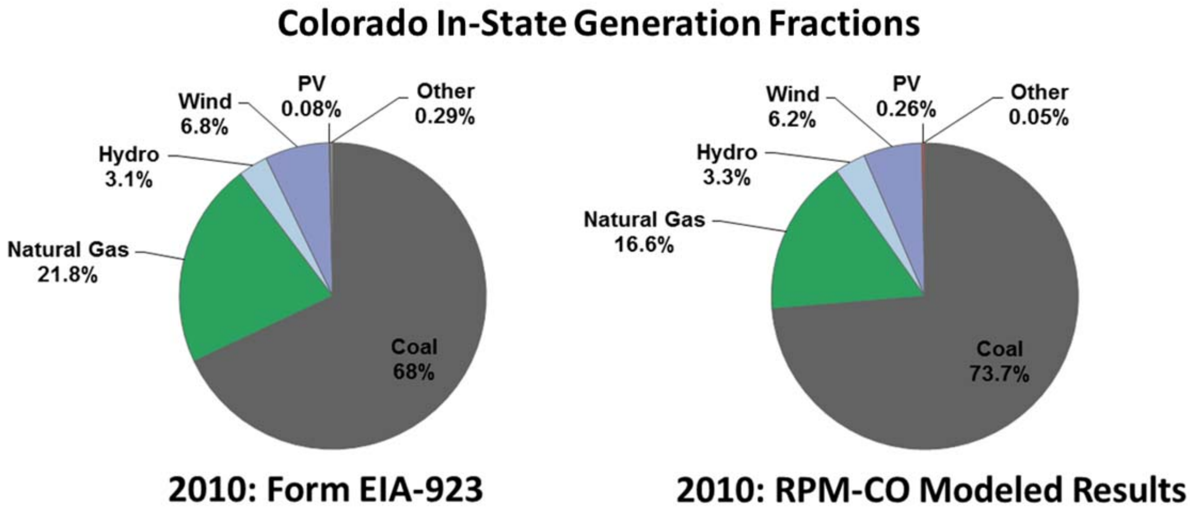

Figure 7. Electricity generation fractions for Colorado in-state generation in 2010 for historical data and modeled results

Note: The 2010 generation fractions in Figure 7 represent the relative contribution from each generation technology to total in-state generation in Colorado. Figure 7 differs from Figure 6 which represents the contribution from each generation technology to serving Colorado electricity demand, which is met using a combination of in-state generation and electricity imports.

Figure 8 shows the development of new generation capacity within the Colorado study region, for both the 30% RE scenario and the Baseline scenario. In the 30% RE scenario, 3,632 MW of new wind capacity and 1,722 MW of solar capacity are developed to meet the renewables target. In the Baseline scenario, no new wind or solar capacity is developed after 2015 in the absence of a renewables target. In both scenarios, new natural gas generators are developed to meet increasing electricity demand and replace retired coal generators. In sum, new natural gas capacity totals 2,428 MW by 2030 in the 30% RE scenario and 3,426 MW in the Baseline scenario. Planned coal retirements and fuel conversion to natural gas (Section 3.2) decrease coal capacity from 5,702 MW in 2010 to 4,648 MW by 2020. We assume that no new geothermal or biopower resources will be developed, and their contribution to Colorado generation capacity remains marginal (represented by the “Other RE” category). Table 8 summarizes 2010 and 2030 capacity and generation shown in Figures 6–8.

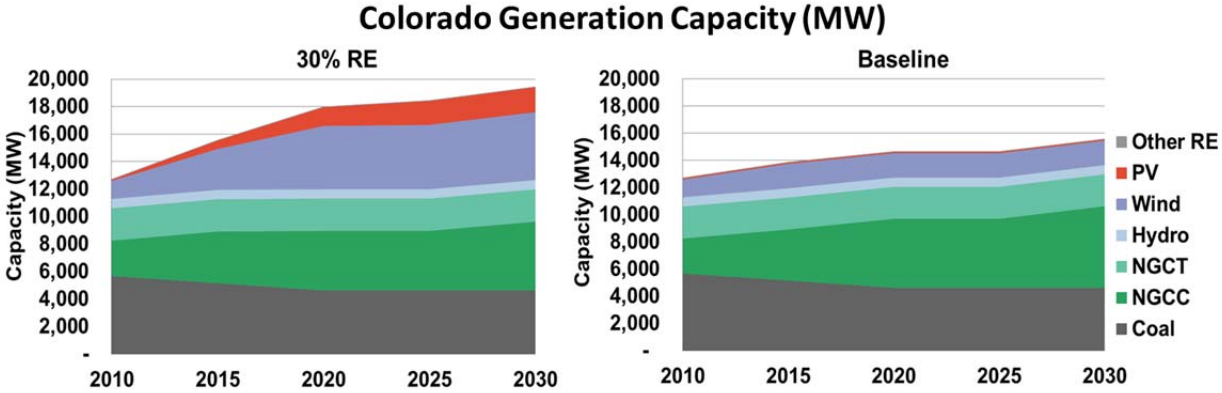

Figure 8. Growth in generation capacity (MW) for the 30% RE scenario and the Baseline scenario without an RPS

Table 8. Colorado Electricity Generation Capacity (MW) and Annual Generated Energy (TWh) for the 30% RE and Baseline Scenarios

Technology	**Capacity (MW)**			**Generation (TWh / % total generation)[a]**		
	2010	***2030 30% RE***	***2030 Baseline***	***2010***	***2030 30% RE***	***2030 Baseline***
Coal	5,702	4,648	4,648	41.5 / 65.9%	35.7 / 46.4%	36.3 / 47.5%
Natural Gas–CC	2,579	5,008	6,005	9.36 / 14.9%	12.9 / 16.8%	25.7 / 33.6%
Natural Gas–CT	2,350	2,350	2,350	<1 / <1%	<1 / <1%	<1 / <1%
Oil / Gas Steam	184	184	184	<1 / <1%	<1 / <1%	<1 / <1%
Hydropower	680	680	680	1.85 / 2.93%	1.85 / 2.4%	1.85 / 2.42%
Wind	1,306	4,938	1,803	3.48 / 5.52%	16.6 / 21.6%	5.14 / 6.72%
Photovoltaics	85	1,807	85	<1 / <1%	3.33 / 4.33%	<1 / <1%
Other RE	16	16	16	<1 / <1%	<1 / <1%	<1 / <1%
Electricity Imports	-	-	-	6.59 / 10.5%	6.5 / 8.45%	7.3 / 9.55%

[a] The RPS target is based on the fraction of end-use electricity demand, which is about 4% less than total generation because of transmission and distribution losses. As such, the fraction of total generation from renewable electricity is slightly less than 30% in the RPS scenario.

Figure 9 shows the geographic location of modeled wind, solar, natural gas (CC and CT), and coal generators deployed in the 30% RE scenario by 2030; and Figure 10 similarly shows modeled deployment in the Baseline scenario by 2030. After 2015, no new wind and solar resources are developed in the Baseline scenario, and the 2030 geographic distribution represents systems built by 2015. Also, both scenarios use the same coal retirement and fuel conversion schedule (Section 3.2) and do not allow new coal generation to be built.

Figures 9 and 10 show that new wind resources are developed in several regions to meet the 30% RE target. Strong development is modeled in southeastern and north-central Colorado, corresponding to regions with Class 4 wind resources (Figure 3) and proximity to existing transmission capacity. Solar resources are primarily developed in central, southern (San Luis Valley) and northwestern Colorado, which correspond to regions with access to good solar resources (Figure 2) and access to existing transmission capacity. PV is also deployed in and around load centers in the Front Range, by Denver, Colorado Springs, and Fort Collins. In the preliminary scenario analysis, we do not allow new transmission resources to be developed, and the modeled deployment of wind and solar projects are based, in part, on using existing transmission capacity.

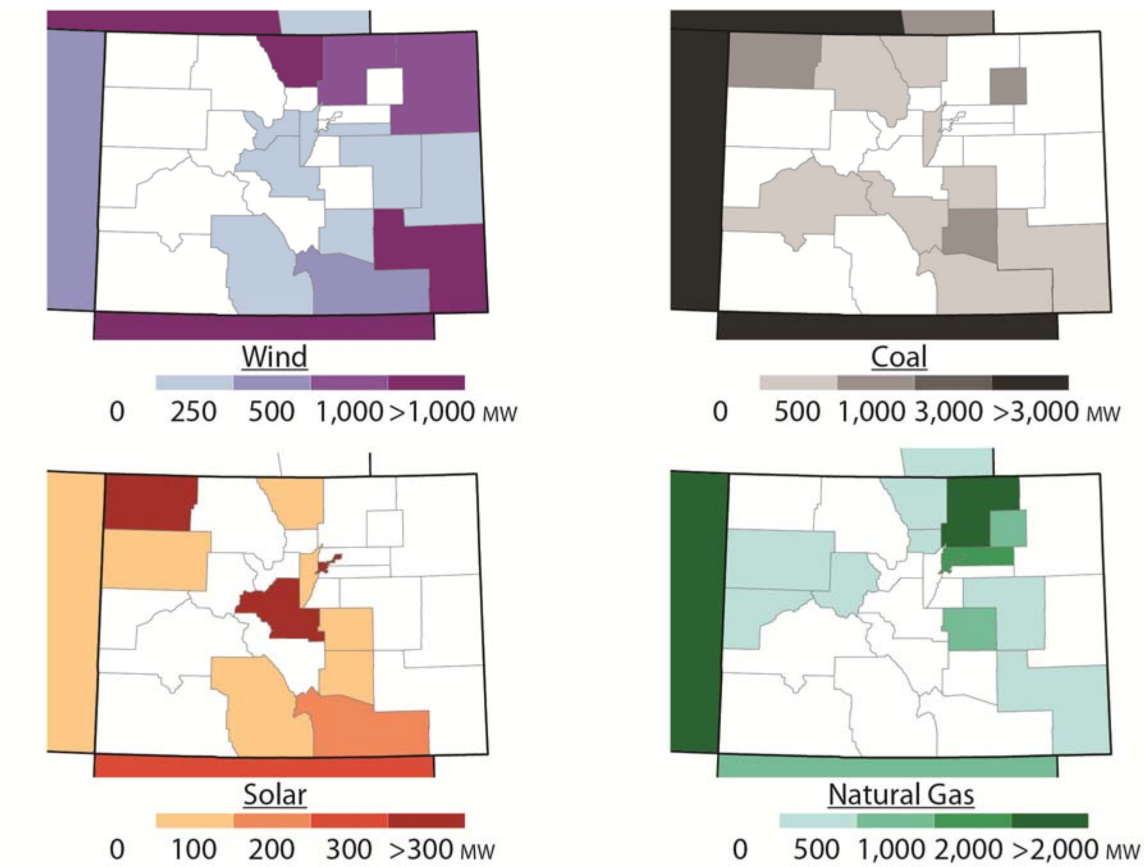

Figure 9. Modeled deployment in the 30% RE scenario

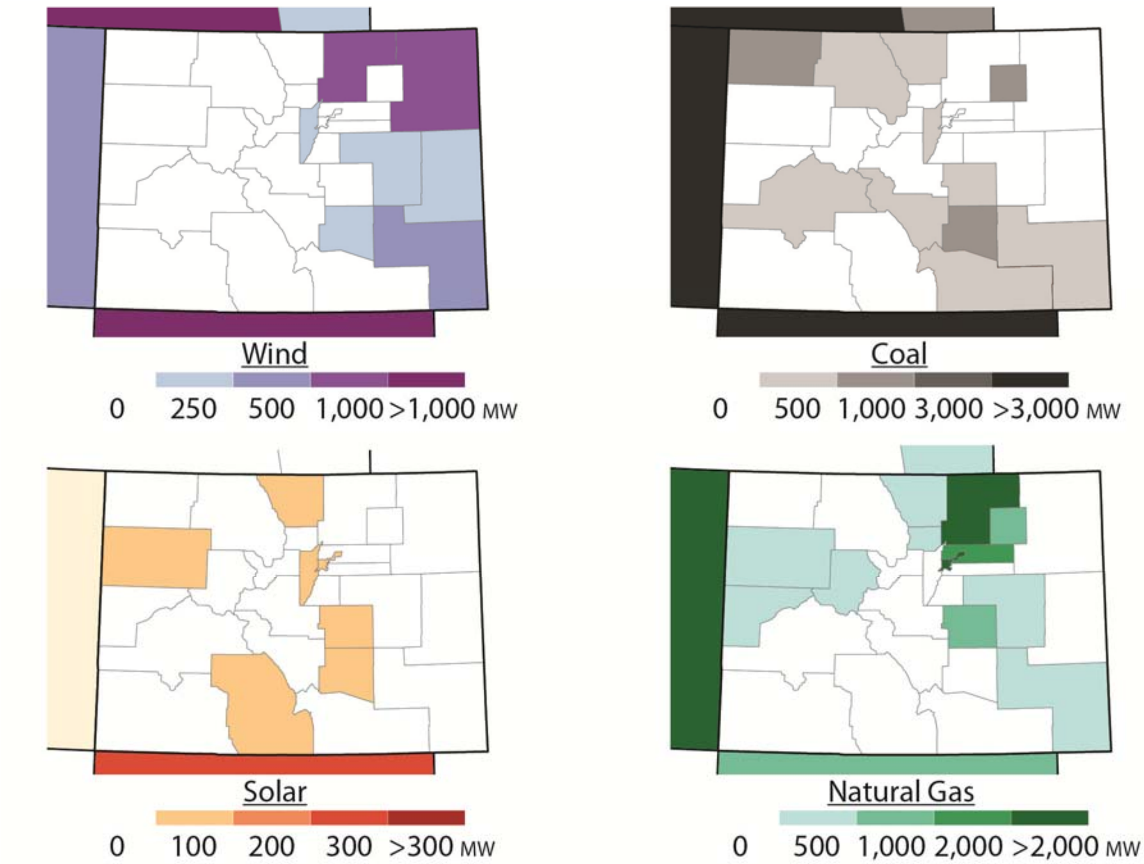

Figure 10. Modeled deployment in the Baseline scenario

Figures 9 and 10 show the geographic location of natural gas generators built in the 30% RE and Baseline scenarios. Colorado had more than 2,300 MW of CT capacity by 2010, and RPM optimizes the Colorado system without additional CT builds in either scenario by 2030. This is a direct result that the planning reserve constraint is not found to be binding under any scenario or year. One reason for this is that the Rocky Mountain Power Pool region (to which Colorado and Wyoming belong) currently exceeds the NERC-directed 12.5% capacity reserve margin requirement and continues to exceed this requirement based on our load growth and retirement assumptions.

We do find significant new CC capacity built in both the 30% RE scenario (2,428 MW by 2030) and the Baseline scenario (3,426 MW by 2030). Combined cycle capacity is primarily deployed near load centers in the Front Range urban corridor in both scenarios, including a large amount of new capacity near Denver in the Baseline scenario that is not seen in the 30% RE scenario because of a combination of locally sited PV capacity and remotely sited wind and PV projects.

Figures 11–13 show the optimal hourly dispatch of generation resources within Colorado for 2010 and the 2030 30% RE scenario. In all seasons, coal generators are run as baseload resources but are ramped down during hours when natural gas CCs reach minimum generation limits. Natural gas CTs, CCs, and hydropower resources are used to provide operational flexibility to follow variations in electricity demand, and wind and solar generation. Since we only apply *seasonal* constraints to imports from out of state, they are also used as an additional source of flexibility. Further work is needed to improve the constraints on inter-regional power transfers.

Figure 11 shows the dispatch of electricity generation resources during four representative days (Sunday-Wednesday) during summer. In 2010, summer afternoon electricity demand is met using natural gas CCs, pumped-hydropower storage, and electricity imports. In the 2030 30% RE scenario, wind generation is relatively consistent during all hours, and PV generates strongly midday with natural gas and pumped storage ramping up to meet strong afternoon and evening load. In the 2030 Baseline scenario, natural gas CCs generate much more significantly and provide the majority of load following.

Figure 12 shows a similar dispatch of generation resources for four days in spring. Spring dispatch profiles are primarily different to summer dispatch characteristics because electricity demand is significantly lower (peaking at about 9,500 MW rather than 12,000 MW in summer in 2030), while both wind and solar generation are relatively high. This leads to significantly less natural gas CC generation in all scenarios and a small amount of coal ramping. We do not find significant curtailment in any season or model scenario.

Lastly, Figure 13 shows model dispatch for one day in mid-July with the highest electricity demand. Electricity demand peaks at about 11,500 MW in 2010, and is projected to peak at about 14,000 MW in 2030. As with during other times of year, ramping is provided by gas CCs, CTs, and pumped-hydropower storage (as shown by the difference between solid and dashed black lines). In the 30% RE scenario, wind generates most strongly during the night and morning preceding peak demand. PV generation peaks during the middle of the day and begins to decline during the early afternoon peak hours. Wind and PV primarily displace natural gas CC generation on the peak day and shift the timing of natural gas ramping from midday to the afternoon and early evening. Wind and PV generation do not significantly decrease the amount of natural gas CT capacity dispatched to meet peak demand. All scenarios show a small amount of coal ramping in the early morning before the peak based on the assumed minimum generation limits for natural gas CC units.

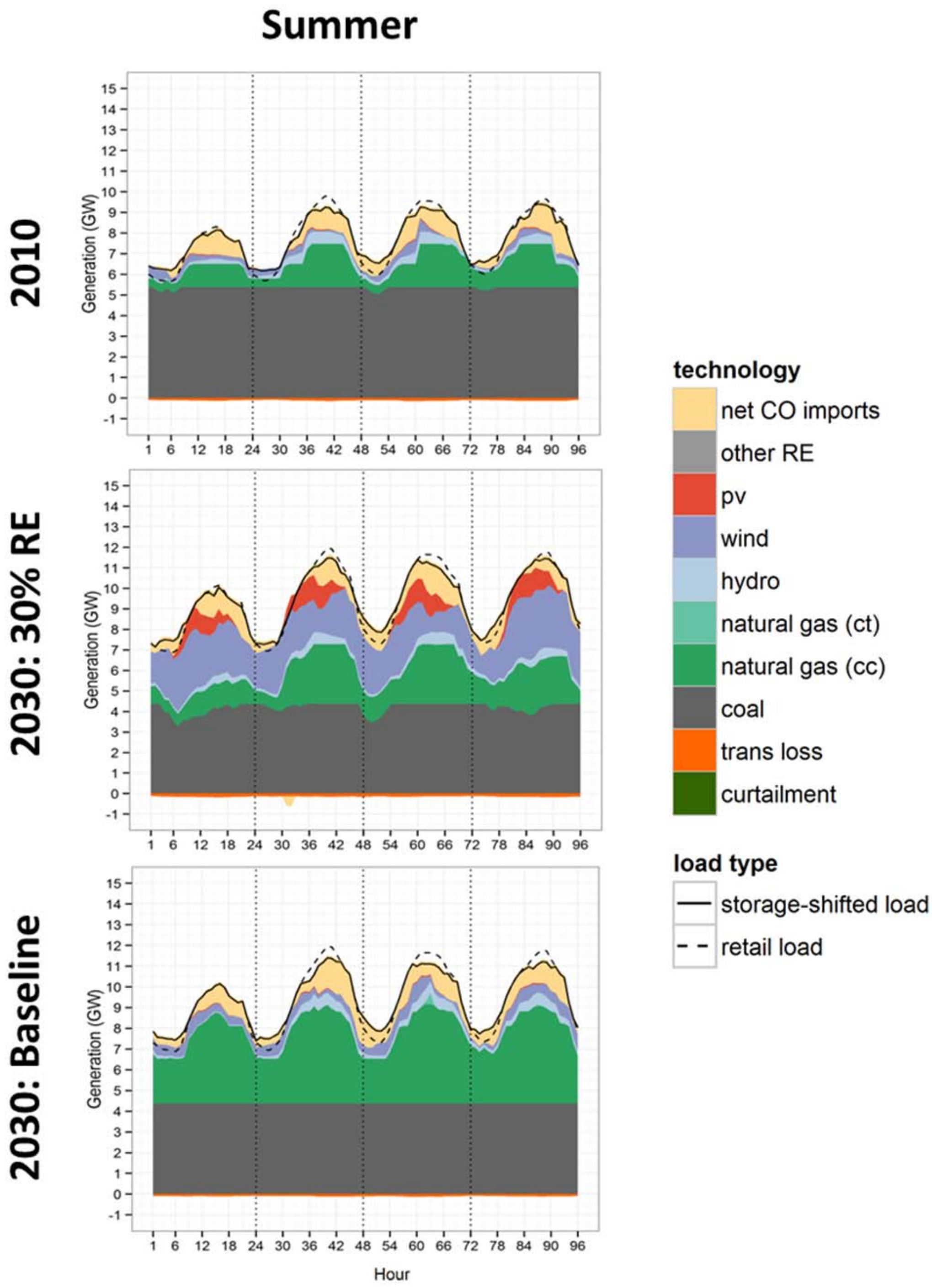

Figure 11. Electric sector dispatch for four days (Sunday-Wednesday) in summer for 2010 and the 30% RE and Baseline scenarios

Pumped-hydropower storage charging is shown during times when the retail load (dashed line) is below the storage-shifted load (solid line) during the night, and vice-versa for storage discharging during the day.

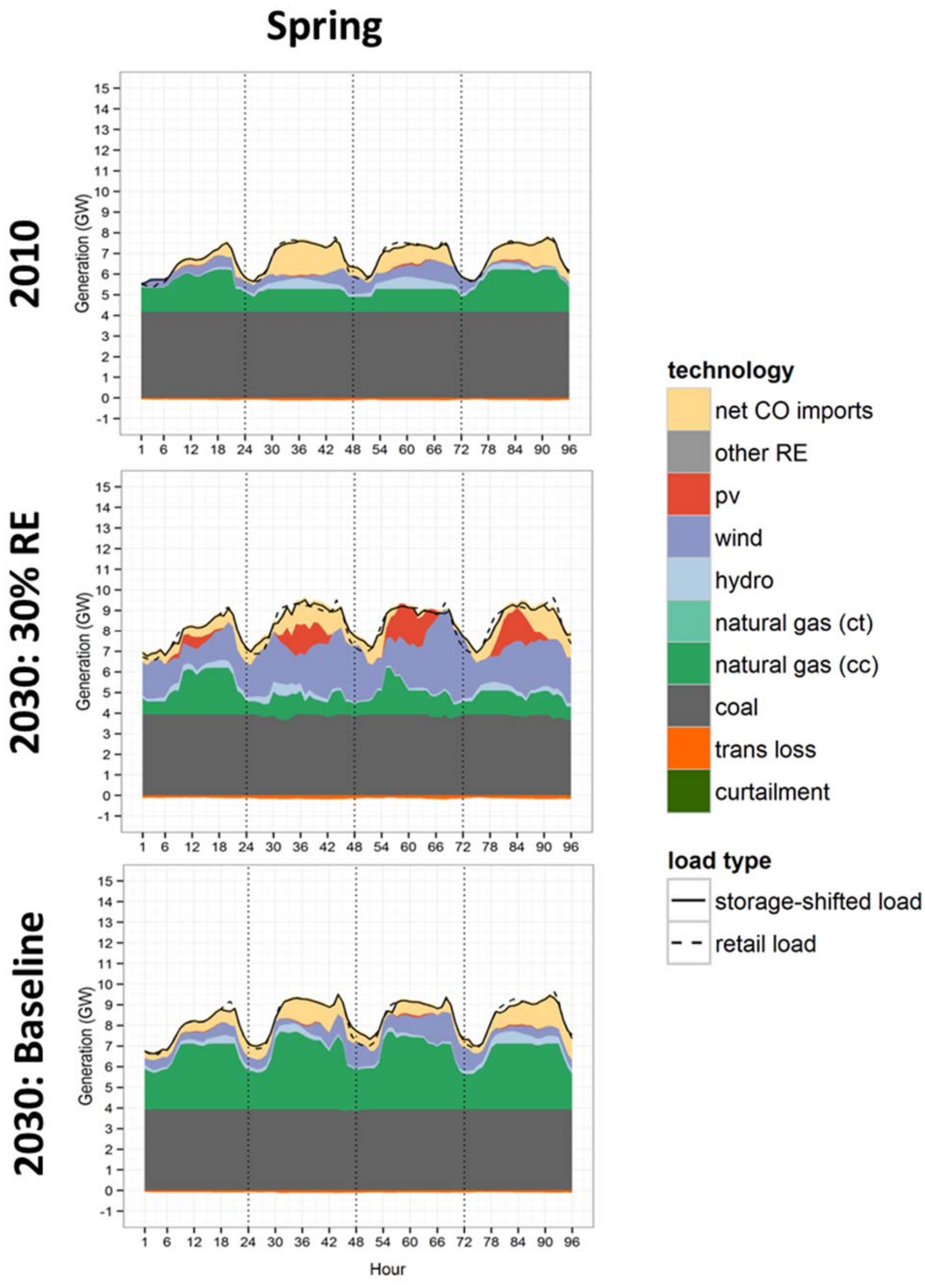

Figure 12. Electric sector dispatch for four days in spring (Sunday-Wednesday)

Pumped-hydropower storage charging is shown during times when the retail load (dashed line) is below the storage-shifted load (solid line) during the night, and vice-versa for storage discharging during the day.

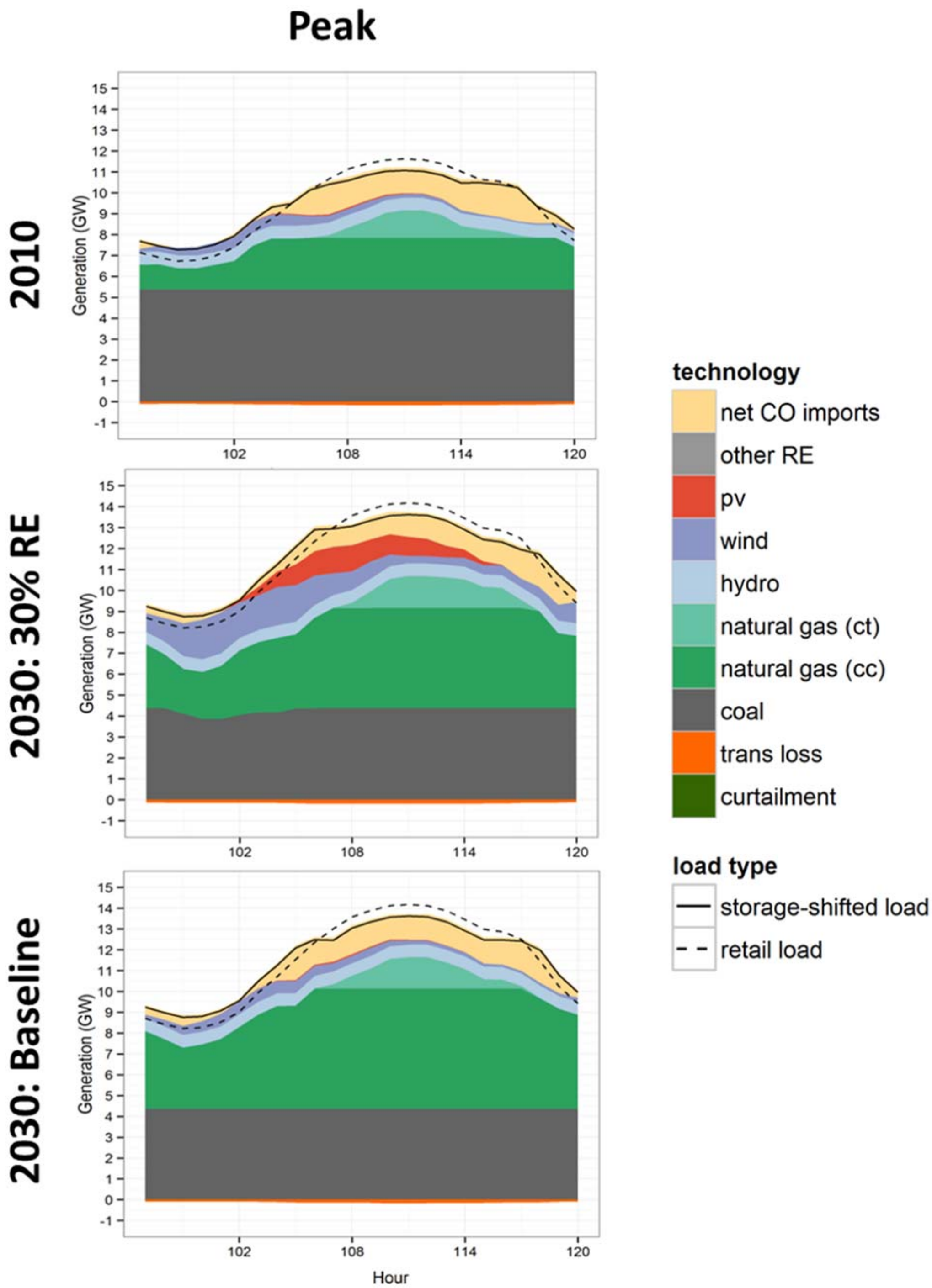

Figure 13. Electric sector dispatch for one day with the peak electricity demand for the year

Pumped-hydropower storage charging is shown during times when the retail load (dashed line) is below the storage-shifted load (solid line) during the night, and vice-versa for storage discharging during the day.

4.2 Electric Sector Emissions and Costs

RPM is designed to characterize electric sector costs, emissions rates, transmission utilization, and other parameters for various deployment scenarios. In doing so, RPM can be used as a tool by policymakers to understand the costs and benefits associated with various policy scenarios, such as the potential costs and impacts on emissions associated of reaching a RPS target.

Figure 14 shows the electric sector emissions[49] of CO_2, NO_x, and SO_2 for the 30% RE scenario and the Baseline scenario. Emissions decrease significantly in all scenarios from 2010 to 2020 based on assumed coal retirements (Section 3.2). In the 30% RE scenario, electric sector carbon emissions decrease 12% below the Baseline scenario. Carbon reductions (12%) are less than the increase in renewable generation (about 12% to 28% of CO generation) because renewable electricity primarily offsets natural gas CC generation, which has lower carbon emission rates, per unit of generated electricity, than coal generation. The 30% RE scenario also reduces electric-sector NO_x emissions (2%–3% below the Baseline scenario for 2020–2030) and SO_2 emissions (1%–2% below the Baseline), but by far less than the RE generation fraction because RE primarily displaces natural gas CC generation and not coal generation. SO_2 emissions are reduced more significantly from 2010 to 2020 than NO_x because SO_2 are primarily emitted by coal generation, while NO_x are emitted by all fossil generators.

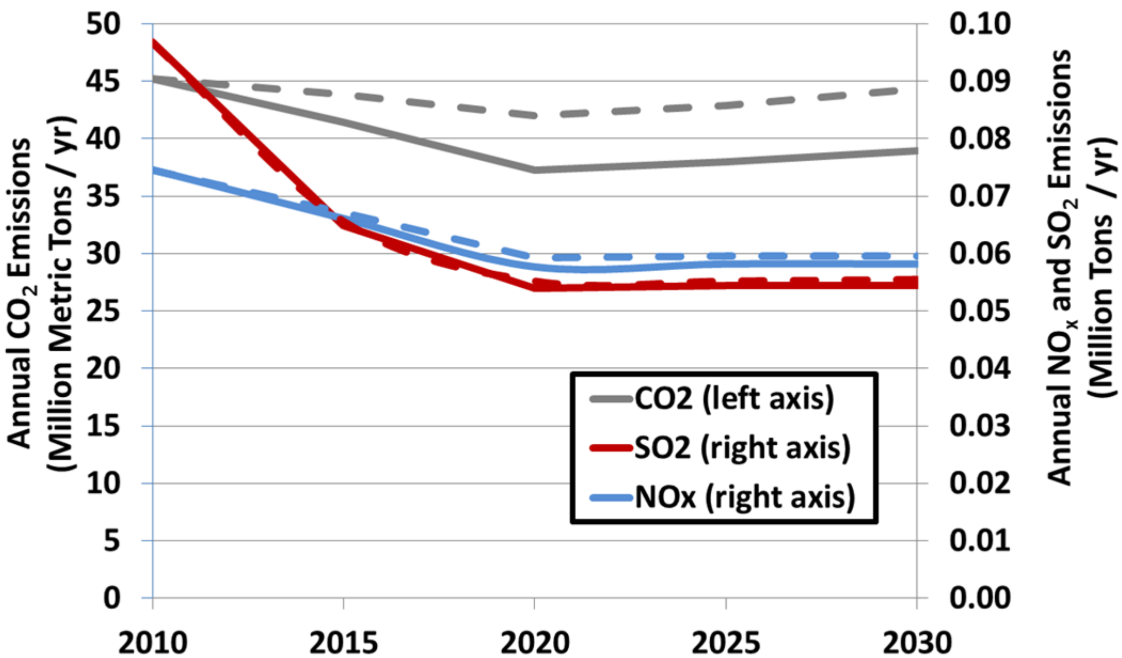

Figure 14. Annual electric sector emissions in the Colorado study region for the 30% RE scenario (solid lines) and the Baseline scenario (dashed lines)

[49] Emissions rates were calculated using average historical emissions factors (Colorado average for NO_x and national averages for CO_2 and SO_2). As such, the emissions in Figure 14 represent possible emissions trends based on the evolution of the Colorado electric sector, but may not represent actual electric sector emissions for any given year.

Figure 15 shows the net present value (NPV) of the 2010 through 2030 costs of developing and operating the generation resources in the 30% RE and Baseline scenarios. NPVs are calculated by linearly interpolating annual capital and operating costs between the five-year model intervals and discounting at a 3% discount rate (real dollars).[50] Capital costs are assumed to be paid over a 20-year loan term extending beyond the model's time horizon at a uniform fixed charge rate, based on those used in Mai et al. (2012).

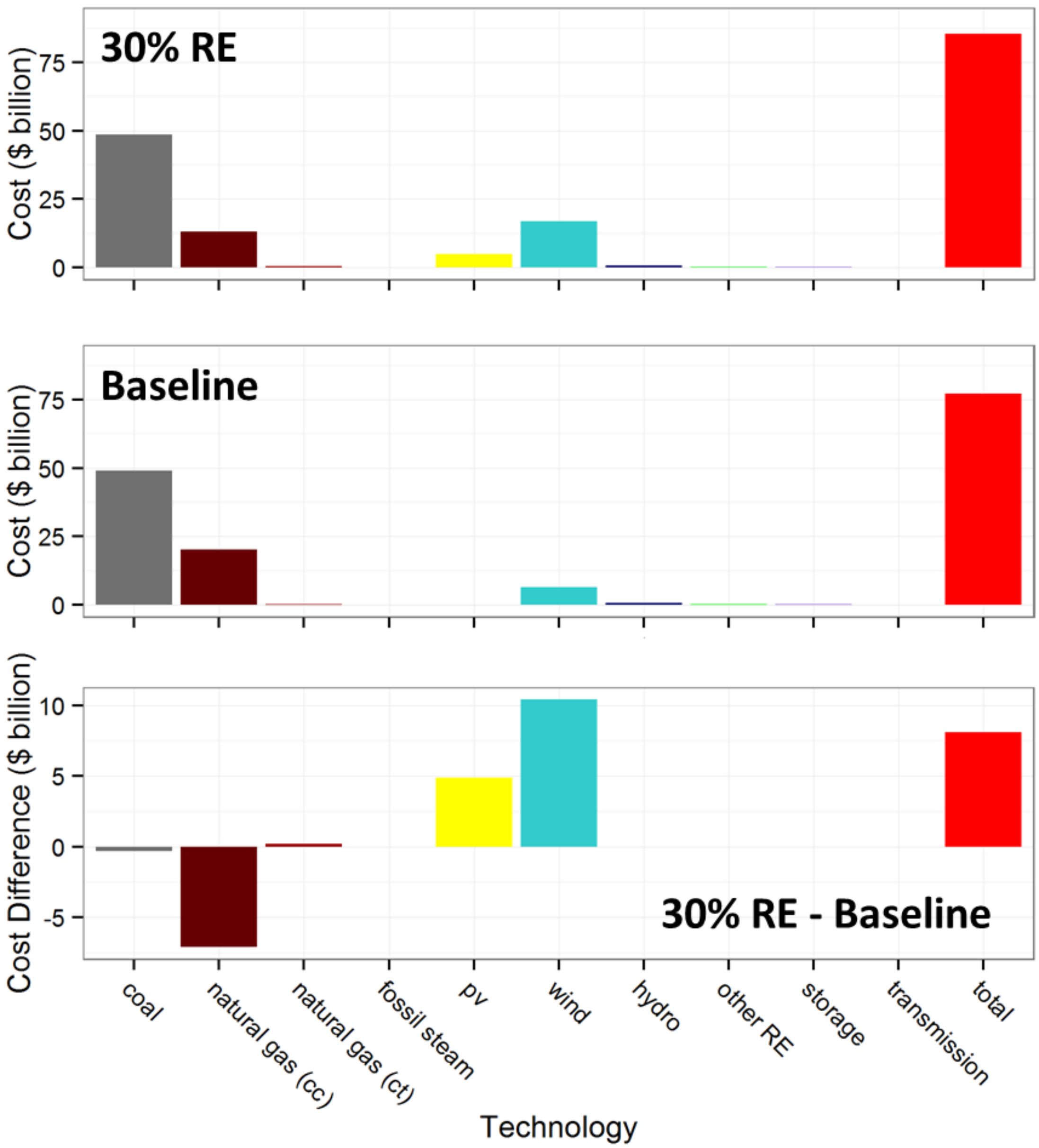

Figure 15. Net present value of the 2010–2030 costs of developing and operating generation resources in the 30% RE scenario and the Baseline scenario

[50] Representing a social discount rate.

Figure 15 shows that discounted electric sector costs vary from about $77.3 to 85.4 billion dollars for the Colorado study region from 2010–2030. The primary difference between the 30% RE scenario and the Baseline scenario is the significant deployment of wind and solar capacity. This additional capacity costs an additional $15.3 billion dollars but offset about $7.1 billion dollars in building and operating natural gas CC resources. In total, we find that the modeled 30% RE scenario cost an additional $8.1 billion dollars for the 2010–2030 period. The cost results presented here strongly depend on assumed fossil fuel and capital costs and sensitivity analyses are needed to bound the cost implications represented here. We find that the cost of reaching the modeled 30% RE scenario represents about a 0.82 cents/kWh average increase in electricity costs,[51] based on the cost assumptions listed in Section 3.6.[52]

5 Conclusions and Future Work

In this report, we present a new capacity expansion model, the Resource Planning Model (RPM) that uniquely combines hourly dispatch with multi-year generator and transmission planning. The high resolution of the model allows it to represent the flexibility limits of a power system in its capacity expansion decision-making, including physical limits on thermal generator dispatch, coincidence of variable generation and load, hourly transmission availability and congestion, and reserve requirements. RPM is ideally suited for regional electric system planning with increasing levels of variable generation as it considers the simultaneous and chronological hourly variations in load, wind, and solar resources across a geospatial region. It can be used to explore a variety of future scenarios with varying levels of renewable deployment and evaluate the emissions and cost impacts of such scenarios, while ensuring many aspects of power resource adequacy across all scenarios.

In addition, RPM provides a framework to answer questions that are of interest to the modeling and analysis communities. RPM can be used to research the selection of optimal "representative" model time slices and the importance of time resolution in reduced-form models. The flexible model structure of RPM also enables us to evaluate the impacts on deployment and dispatch of simplifications to a representative physical system. RPM provides a test-bed to explore how representations of boundary conditions on a small region within a larger electric system impact results. These and related research areas would be of value to the broader energy modeling community.

We present preliminary scenario analysis results for an initial version of RPM representing the power system in Colorado. These preliminary results indicate that achieving 30% renewable electricity by 2020 and sustained through 2030 is possible for this system and would result in 12% reduction in annual CO_2 emissions. The increased renewable capacity and reduced fossil capacity and fuel use result in a 10% increase in NPV costs over 20 years (2010-2030, 3% real discount rate). Most of the new renewable capacity is comprised of wind capacity, located in

[51] Total electric sector costs were related to a variable cost per kWh by linearly interpolating annual load projections between 2010 and 2030, and discounting at a 3% (real) rate (same as used in the NPV calculation). This resulted in 995.1 million MWh for 2010 to 2030. The possible increase in electricity prices ($/kWh) was calculated by dividing the additional cost of reaching the 30% RE target by the discounted electricity demand.

[52] The future costs of each model scenario, and cost differences between scenarios, are highly dependent on several assumptions, including future fuel prices, technology-specific price and performance characteristics, and other system parameters. We plan to explore these sensitivities in future work.

north-central and southeastern Colorado. New solar PV capacity is also observed and is found to be located in south-central and northwestern Colorado and the Front Range urban corridor. RPM finds that electricity supply-demand balance (and reserve provision) is possible with this level of renewables, even without new inter-regional transmission capacity, through greater fossil power plant ramping and cycling. More research is needed to confirm these results.

Future work will focus on improving the boundary-condition representations of the focus region. A more accurate representation of boundary regions could help improve our estimate of emission reductions that renewable technologies provide and allow for more realistic conditions for power plant dispatch in Colorado. Another area of model improvement is in the transmission representation, such as through DC optimal power-flow methods. We also plan to include representation of demand-side options, such as demand response or distributed generation, in RPM. Future research with the model will focus on the sensitivity of model results to the selection of model days and hours. We plan to work with various stakeholders to improve the model representations in the areas described.

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Appendix. Model Formulation

This appendix describes the formulation of RPM-CO, which was written in the General Algebraic Modeling System (GAMS) platform. All major sets, parameters, variables, and equations are listed and defined.

Indices

- ***bin*** *: wind supply curve bin*
- ***c*** *: wind power class*
- ***d*** *: dispatch period*
- ***h,h'*** *: hour*
- ***n,p*** *: region*
- ***pol*** *: pollutant type*
- ***q*** *: electricity generating technology*
- ***st*** *: storage technology*

Model Data Sets

Temporal Sets

- $\boldsymbol{D}$ *: set of dispatch periods {summer, fall, winter, spring, peak}*
- $\boldsymbol{NONPEAK} \subset \boldsymbol{D}$ *: set of nonpeak dispatch periods where **NONPEAK** is a proper subset of **D** {summer, fall, winter, spring}*
- $\boldsymbol{H_d}$ *: set of hours for each dispatch period **d***

Spatial Sets

- $\boldsymbol{N}$ *: set of all regions {1..31}*
- $\boldsymbol{CO} \subset \boldsymbol{N}$ *: set of Colorado regions where **CO** is a proper subset of **N** {1..27}*
- $\boldsymbol{NONCO} \subset \boldsymbol{N}$ *: set of non-Colorado regions where **NONCO** is a proper subset of **N** {28..31}*
- $\boldsymbol{PSCO} \subset \boldsymbol{N}$ *: set of PSCO regions where **PSCO** is a proper subset of **N***
- $\boldsymbol{WACM} \subset \boldsymbol{N}$ *: set of WACM regions where **WACM** is a proper subset of **N***
- $\boldsymbol{WY} \subset \boldsymbol{N}$ *: set of Wyoming regions where **WY** is a proper subset of **N***
- $\boldsymbol{TCONNECT}$ *: set of all arcs **(n,p)** that connect regions **n** and **p***

Technology Sets

- $\boldsymbol{Q}$ *: set of all electricity generating technologies*
- $\boldsymbol{DG} \subset \boldsymbol{Q}$ *: set of distributed generation technologies where **DG** is a proper subset of **Q***
- $\boldsymbol{DISPATCH} \subset \boldsymbol{Q}$ *: set of dispatchable technologies where **DISPATCH** is a proper subset of **Q***
- $\boldsymbol{HYDRO} \subset \boldsymbol{Q}$ *: set of hydro-based technologies where **HYDRO** is a proper subset of **Q***
- $\boldsymbol{NONMOD} \subset \boldsymbol{Q}$ *: set of generating technologies that are non-modular[53] where **NONMOD** is a proper subset of **Q***
- $\boldsymbol{NONSPIN} \subset \boldsymbol{Q}$ *: set of generating technologies that can provide non-spinning reserves where **NONSPIN** is a proper subset of **Q***

[53] *Non-modular refers to plants that must be built in bulk capacity, such as nuclear, coal and natural gas.*

- $\boldsymbol{PV} \subset \boldsymbol{Q}$ *: set of photovoltaic-based technologies where* ***PV*** *is a proper subset of* ***Q***
- $\boldsymbol{RE} \subset \boldsymbol{Q}$ *: set of renewable energy technologies where* ***RE*** *is a proper subset of* ***Q*** *{wind, fixed-axis pv, 1-axis pv, hydropower, geothermal, biopower}*
- $\boldsymbol{SPIN} \subset \boldsymbol{Q}$ *: set of generating technologies that can provide spinning reserves where* ***SPIN*** *is a proper subset of* ***Q***
- $\boldsymbol{THERMAL} \subset \boldsymbol{Q}$ *: set of thermal technologies where* ***THERMAL*** *is a proper subset of* ***Q***
- $\boldsymbol{VG} \subset \boldsymbol{Q}$ *: set of variable generation technologies where* ***VG*** *is a proper subset of* ***Q*** *{wind, fixed-axis pv, 1-axis pv}*
- $\boldsymbol{WIND} \subset \boldsymbol{Q}$ *: set of wind-based technologies where* ***WIND*** *is a proper subset of* ***Q***
- $\boldsymbol{ST}$ *: set of storage technologies*

Wind Technology Sets

- $\boldsymbol{B}$ *: set of wind supply curve bins. Five (5) bins define the wind resource supply curves.*
- $\boldsymbol{C}$ *: set of wind classes. There are five (5) wind power classes.*

Emissions Data Sets

- $\boldsymbol{POL}$ *: set of emissions types {CO_2, SO_2, NO_x, Hg}*
- $\boldsymbol{CO2} \subset \boldsymbol{POL}$ *: set of carbon dioxide emissions types where* ***CO2*** *is a proper subset of* ***POL*** *{CO2}*

Model Parameters

Generation Technology Cost Data

- $capcost_q$ *--\$ per MW-- overnight capital cost for technology* ***q***
- fcr_q *--unitless-- fixed charge rate for technology* ***q***
- $fomN_q$ *--\$ per MW-year-- fixed O&M costs for new plant technology* ***q***
- $fomO_{n,q}$ *--\$ per MW-year-- fixed O&M costs for region* ***n*** *and existing technology* ***q***
- $fuelprice_q$ *--\$ per MMBtu-- fuel price for technology* ***q***
- $regmult_{n,q}$ *--unitless-- overnight capital cost multiplier for region* ***n*** *and technology* ***q***
- $shutdowncost_q$ *--\$ per MW-- cost per shutdown for thermal generator* ***q***
- $startupcost_q$ *--\$ per MW-- cost per startup for thermal generator* ***q***
- $vomN_q$ *--\$ per MWh-- variable O&M costs for new plant technology* ***q***
- $vomO_{n,q}$ *--\$ per MWh-- variable O&M costs for region* ***n*** *and existing technology* ***q***

Generation Technology Performance Data

- $capacityO_{n,q}$ *--MW-- installed capacity for region* ***n*** *and technology* ***q***
- $capacityWO_{c,n}$ *--MW-- installed wind capacity for wind power class* ***c*** *and region* ***n***
- $cf_{d,h,n,q}$ *--unitless-- PV profile during dispatch period* ***d****, hour* ***h****, in region* ***n***
- $cfprofileW_{c,d,h,n}$ *--unitless-- normalization factor for the wind power profile by power class* ***c****, dispatch period* ***d****, hour* ***h****, in region* ***n***
- $cfWN_c$ *--unitless-- annual capacity factor for wind power class* ***c***
- $cfWO_{c,n}$ *--unitless-- annual capacity factor for existing wind power class* ***c*** *in region* ***n***
- fo_q *--unitless-- forced outage rate for thermal generator* ***q***
- $heatrateN_q$ *--MMBtu per MWh-- heat rate for new thermal generator* ***q***
- $heatrateO_{n,q}$ *--MMBtu per MWh-- heat rate for region* ***n*** *and existing thermal generator* ***q***

- *$hydromaxcf_{d,n}$ --unitless-- maximum run-of-river hydropower capacity factor during dispatch period **d**, in region **n***
- *$hydromaxgen_{d,n}$ --MWh-- maximum seasonal generation for run-of-river hydropower during dispatch period **d**, in region **n***
- *$hydromincf_{d,n}$ --unitless-- minimum run-of-river hydropower capacity factor during dispatch period **d**, in region **n***
- *$maxplantsize_q$ --MW-- maximum plant size for new thermal generator **q***
- *$mingenN_q$ --unitless-- minimum generation level for new thermal generator **q***
- *$mingenO_{n,q}$ --unitless-- minimum generation level in region **n** for existing thermal generator **q***
- *$minoff_q$ --hours-- minimum off time for thermal generator **q***
- *$minon_q$ --hours-- minimum on time for thermal generator **q***
- *$minplantsize_q$ --MW-- minimum plant size for new thermal generator **q***
- *$po_{d,q}$ --unitless-- planned outage rate during dispatch period **d** thermal generator **q***
- *$spinfrac_q$ --unitless-- fraction of nameplate that can contribute to spinning reserves for technology **q** based on 10 min ramp rates*

Storage Technology Cost Data

- *$stcapcost_{st}$ --\$ per MW-- overnight capital costs for storage technology **st***
- *$stfcr_{st}$ --unitless-- fixed charge rate for storage technology **st***
- *$stfomN_{st}$ --\$ per MW-year-- fixed O&M costs for new storage technology **st***
- *$stfomO_{n,st}$ --\$ per MW-year-- fixed O&M costs for existing storage technology **st***
- *$stfuelprice_{st}$ --\$ per MMBtu-- fuel prices for storage technology **st***
- *$stvomN_{st}$ --\$ per MWh-- variable O&M costs for storage technology **st***
- *$stvomO_{n,st}$ --\$ per MWh-- variable O&M costs in region **n** for storage technology **st***

Storage Technology Performance Data

- *$stcapacityO_{n,st}$ --MW-- installed storage capacity for region **n** and existing storage technology **st***
- *$stfo_{st}$ --unitless-- forced outage rate for storage technology **st***
- *$stheatrateN_{st}$ --MMBtu per MWh-- heat rate for new storage technology **st***
- *$stheatrateO_{n,st}$ --MMBtu per MWh-- heat rate for region **n** and existing storage technology **st***
- *$stmaxplantsize_{st}$ --MW-- maximum size for new storage technology **st***
- *$stminplantsize_{st}$ --MW-- minimize size for new storage technology **st***
- *$stpo_{d,st}$ --unitless-- planned outage rate during dispatch period **d** for storage technology **st***
- *$strte_{st}$ --unitless-- round trip efficiency for storage technology **st***
- *$stsupply_{n,st}$ --MW-- available storage resource for region **n** and existing storage technology **st***

Grid Interconnection Data

- *$gridconnect_q$ --\$ per MW-- grid interconnection costs for generator **q***
- *$stgridconnect_{st}$ --\$ per MW-- grid interconnection costs for storage technology **st***

- *windbinO$_{bin,c,n}$ --MW-- wind resources already installed for each wind supply curve bin **bin**, wind power class **c**, in region **n***
- *windgridconnect$_{bin,c,n}$ --\$ per MW-- grid interconnection costs for wind supply curve bin **bin**, wind power class **c**, in region **n***
- *windsupply$_{bin,c,n}$ --MW-- wind resource available for each wind supply curve bin **bin**, wind power class **c**, in region **n***

Transmission Data

- *distance$_{n,p}$ --miles-- distance between region **n** and **p***
- *max_exports$_{d}$ --MWh-- maximum energy flows exported out of Colorado in dispatch period **d***
- *max_imports$_{d}$ --MWh-- maximum energy flows imported into Colorado in dispatch period **d***
- *tcapacityO$_{n,p}$ --MW-- existing transfer capacity between region **n** and **p***
- *tcapcost --\$ per MW-mile-- new transmission costs*
- *tfcr --unitless-- fixed charge rate for transmission*
- *tloss --% per mile-- fractional transmission losses per mile*

Policy Data

- *2010_nonCO_ReGen --MWh-- total generation from renewables outside of Colorado in 2010*
- *dgfrac --unitless-- fraction of generation from distributed generation (i.e., fixed-axis pv)*
- *emissioncap$_{pol}$ --tons-- emission cap by pollutant **pol***
- *instate_mult --unitless-- multiplier for in-state generation to meet the RPS*
- *pollutefactor$_{pol,q}$ --tons per MMBtu-- emission factor for pollutant **pol** and technology **q***
- *rpsfrac --unitless-- fraction of annual generation from renewables*
- *stpollutefactor$_{pol,st}$ --tons per MMBtu-- emission factor for pollutant **pol** and storage technology **st***

Reserves Data

- *cvN$_{n,q}$ --unitless-- marginal capacity value for pv in region **n** (fixed tilt is separate from 1 axis tracking)*
- *cvO --unitless-- average capacity value of all variable generation capacity {wind and pv}*
- *cvWN$_{c,n}$ --unitless-- marginal capacity value for wind of power class **c** in region **n***
- *orspin_psco$_{d,h}$ --MW-- spinning reserve requirement for PSCO during dispatch period **d**, in hour **h***
- *orspin_wacm$_{d,h}$ --MW-- spinning reserve requirement for WACM during dispatch period **d**, in hour **h***
- *ortot_psco$_{d,h}$ --MW-- total reserve requirement for PSCO during dispatch period **d**, in hour **h***
- *ortot_wacm$_{d,h}$ --MW-- total reserve requirement for WACM during dispatch period **d**, in hour **h***
- *reservemargin --unitless-- reserve margin requirement for planning reserves*

Load Data

- *distributionloss -- unitless-- fractional losses in the distribution network (5%)*

- *$load_{d,h,n}$ --unitless-- demand during dispatch period **d**, in hour **h**, of region **n***
- *$season\_scale_d$ --unitless-- ratio of days per season to days per week for dispatch period **d** (used to scale the selected week days to a full season)*

Complex Sets

- $\overline{H}_{d,h,q}: \max\left\{ord(h) - minon_q\,, |H_d| - \left(minon_q - ord(h)\right)\right\} \leq ord(h') \leq ord(h)$
$$\ni\ h' \in H_d\,, h \in H_d, q \in THERMAL$$

  *Set of valid time periods in dispatch period **d**, hour **h** of thermal technology **q** where each element of the set, i.e., **h'**, is greater than the maximum of (**h – $minon_q$**) and **(the cardinality of set H_d) – ($minon_q$ – h)** and where **h'** is less than **h**. Simplified, the elements of the set include all hours from **h-$minon_q$** to **h** with time wrapping considered.[54] $\overline{H}_{d,h,q}$ is the set of consecutive time periods that are used to enforce minimum on periods.*

- $\underline{H}_{d,h,q}: \max\left\{ord(h) - minoff_q\,, |H_d| - \left(minoff_q - ord(h)\right)\right\} \leq ord(h') \leq ord(h)$
$$\ni\ h' \in H_d\,, h \in H_d, q \in THERMAL$$

  *Set of valid time periods in dispatch period **d**, hour **h** of thermal technology **q** where each element of the set, i.e., **h'**, is greater than the maximum of (**h – $minoff_q$**) and **(the cardinality of set H_d) – ($minoff_q$ – h)** and where **h'** is less than **h.** Simplified, the elements of the set include all hours from **h-$minoff_q$** to **h** with time wrapping considered. $\underline{H}_{d,h,q}$ is the set of consecutive time periods that are used to enforce minimum off periods.*

Variables

Binary Variables

- *$Shutdown_{d,h,n,q}$: 1 if existing thermal technology **q** is shutdown during dispatch period **d**, in hour **h**, in region **n**; 0 otherwise*
- *$Startup_{d,h,n,q}$: 1 if existing thermal technology **q** is started up during dispatch period **d**, in hour **h**, in region **n**; 0 otherwise*
- *$StUnitN_{n,st}$: 1 if storage technology **st** is built in region **n**; 0 otherwise*
- *$UnitN_{n,q}$: 1 if non-modular technology **q** is built in region **n**; 0 otherwise*
- *$Up_{d,h,n,q}$: 1 if existing thermal technology **q** is on during dispatch period **d**, in hour **h**, in region **n**; 0 otherwise*

Generation Variables

- *$CapacityN_{n,q}$ --MW-- new generating capacity of technology **q** in region **n***
- *$CapacityWN_{c,n}$ --MW-- new wind generating capacity of wind power class **c** in region **n***
- *$Curtailment_{d,h,n}$ --MW-- amount of power curtailed during dispatch period **d**, hour **h**, in region **n***
- *$GenerationN_{d,h,n,q}$ --MW-- generation from new technology **q** during dispatch period **d**, in hour **h**, in region **n***

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[54] *As an example of time wrapping, let $h \in H_d \in \{1..10\}$. If $h = 1$, then $h\text{-}1 = 10$.*

- $GenerationO_{d,h,n,q}$ *--MW-- generation from existing technology* ***q*** *during dispatch period* ***d****, in hour* ***h****, in region* ***n***
- $NonspincapN_{d,h,n,q}$ *--MW-- non-spinning capacity reserved from new technology* ***q*** *during dispatch period* ***d****, in hour* ***h****, in region* ***n***
- $NonspincapO_{d,h,n,q}$ *--MW-- non-spinning capacity reserved from existing technology* ***q*** *during dispatch period* ***d****, in hour* ***h****, in region* ***n***
- $SpincapN_{d,h,n,q}$ *--MW-- spinning capacity reserved from new technology* ***q*** *during dispatch period* ***d****, in hour* ***h****, in region* ***n***
- $SpincapO_{d,h,n,q}$ *--MW-- spinning capacity reserved from existing technology* ***q*** *during dispatch period* ***d****, in hour* ***h****, in region* ***n***
- $WindBinN_{bin,c,n}$ *--MW-- new wind resources installed for each wind supply curve bin* ***bin****, wind power class* ***c****, in region* ***n***

Transmission Variables

- $TCapacityN_{n,p}$ *--MW-- new transfer capacity between region* ***n*** *and* ***p***
- $TFlow_{d,h,n,p}$ *--MW-- power transferred during dispatch period* ***d****, in hour* ***h*** *between region* ***n*** *and* ***p***

Storage Variables

- $StCapacityN_{n,st}$ *--MW-- new storage capacity of storage technology* ***st*** *in region* ***n***
- $StChargeN_{d,h,n,st}$ *--MW-- amount charging for new storage capacity during dispatch period* ***d****, in hour* ***h****, in region n from storage technology* ***st***
- $StChargeO_{d,h,n,st}$ *--MW-- amount charging for existing storage during dispatch period* ***d****, in hour* ***h****, in region* ***n*** *from storage technology* ***st***
- $StGenerationN_{d,h,n,st}$ *--MW-- generation from new storage capacity during dispatch period* ***d****, in hour* ***h****, in region* ***n*** *from storage technology* ***st***
- $StGenerationO_{d,h,n,st}$ *--MW-- generation from existing storage capacity during dispatch period* ***d****, in hour* ***h****, in region* ***n*** *from storage technology* ***st***
- $StSpincapN_{d,h,n,st}$ *--MW-- spinning capacity reserved during dispatch period* ***d****, in hour* ***h****, in region* ***n*** *from storage technology* ***st***
- $StSpincapO_{d,h,n,st}$ *--MW-- spinning capacity reserved during dispatch period* ***d****, in hour* ***h****, in region* ***n*** *from storage technology* ***st***

Objective Function

The objective function minimizes the annualized system cost. This annual system cost includes the annualized capital cost, grid connection cost, fixed and variable O&M cost, fuel cost, start-up[55] and shut-down costs and emission costs for conventional and storage technologies.

$$Minimize\ Total\ Annual\ Cost$$

Total capital, grid connection, and fixed O&M costs for all new technologies and all regions

$$\sum_{\substack{n \in N,\\ q \in Q}} CapacityN_{n,q} * \left(fcr_q * \left(regmult_{n,q} * capcost_q + \ gridconnect_q\right) + \ fomN_q\right)$$

[55] Startup costs include costs associated with the fuel requirement for plant startups.

+ Total grid connection cost for new wind used from all resource supply curve bin, all wind power classes, and all regions

$$+ \sum_{\substack{bin\in B,\\ c\in C,\\ n\in N,\\ q\in WIND}} WindBinN_{bin,c,n} * windgridconnect_{bin,c,n} * fcr_q$$

+ Total fuel and variable O&M costs for all new and existing technologies in all hours of all dispatch periods and all regions

$$+ \sum_{\substack{d\in D,\\ h\in H_d,\\ n\in N,\\ q\in Q}} GenerationN_{d,h,n,q} * season\_scale_d * (vomN_q + heatrateN_q * fuelprice_q)$$

$$+ \sum_{\substack{d\in D,\\ h\in H_d,\\ n\in N,\\ q\in Q}} GenerationO_{d,h,n,q} * season\_scale_d * (vomO_{n,q} + heatrateO_{n,q} * fuelprice_q)$$

+ Total storage capital, grid connection, and fixed O&M costs for all storage technologies in all regions

$$+ \sum_{\substack{n\in N,\\ st\in ST}} StCapacityN_{n,st} * (stfcr_{st} * (stcapcost_{st} + stgridconnect_{st}) + stfomN_{st})$$

+ Total storage fuel and variable O&M costs for all new and existing storage technologies in all hours of all dispatch periods and all regions

$$+ \sum_{\substack{d\in D,\\ h\in H_d,\\ n\in N,\\ st\in ST}} StGenerationN_{d,h,n,st} * season\_scale_d * (stvomN_{st} + stheatrateN_{st} * stfuelprice_{st})$$

$$+ \sum_{\substack{d\in D,\\ h\in H_d,\\ n\in N,\\ st\in ST}} StGenerationO_{d,h,n,st} * season\_scale_d * (stvomO_{n,st} + stheatrateO_{n,st} * stfuelprice_{st})$$

+ Total new transmission line costs

$$+ \sum_{\substack{n\in N,\\ p\in N \ni\\ (n,p)\in TCONNECT}} TCapacityN_{n,p} * distance_{n,p} * tcapcost * tfcr$$

+ Total start-up and shut-down costs for all existing thermal technologies in all hours of all dispatch periods and all regions

$$+ \sum_{\substack{d\in D,\\ h\in H_d,\\ n\in N,\\ q\in THERMAL}} Startup_{d,h,n,q} * startupcost_q * capacityO_{n,q} * season\_scale_d$$

$$+ \sum_{\substack{d \in D, \\ h \in H_d, \\ n \in N, \\ q \in THERMAL}} Shutdown_{d,h,n,q} * shutdowncost_q * capacityO_{n,q} * season\_scale_d$$

+ Total cost of carbon for all new and existing technologies in all hours of all dispatch periods and all regions

$$+ \sum_{\substack{d \in D, \\ h \in H_d, \\ n \in N, \\ q \in Q, \\ pol \in CO2}} (GenerationN_{d,h,n,q} * heatrateN_q * season\_scale_d * pollutefactor_{pol,q}) * carbon\_price$$

$$+ \sum_{\substack{d \in D, \\ h \in H_d, \\ n \in N, \\ q \in Q, \\ pol \in CO2}} (GenerationO_{d,h,n,q} * heatrateO_{n,q} * season\_scale_d * pollutefactor_{pol,q}) * carbon\_price$$

Constraints

Load Constraints

The load constraints ensure that generation less curtailments plus net power imports is equal to load in each region and time period.

load_balance$_{d,h,n}$

Total generation from all technologies

$$\sum_{q \in Q} (GenerationN_{d,h,n,q} + GenerationO_{d,h,n,q})$$

+ Total discharge from all storage technologies

$$+ \sum_{st \in ST} (StGenerationN_{d,h,n,st} + StGenerationO_{d,h,n,st})$$

*+ Total imports into region **n** minus transmission line losses*

$$+ \sum_{\substack{p \in N \ni \\ (n,p) \in TCONNECT}} TFlow_{d,h,p,n} * (1 - tloss * distance_{n,p})$$

*= load in that region, plus total charge into all storage technologies, plus total exports out of region **n** + curtailments in region **n***

$$= load_{d,h,n} + \sum_{st \in ST} (StChargeN_{d,h,n,st} + StChargeO_{d,h,n,st}) + \sum_{\substack{p \in N \ni \\ (n,p) \in TCONNECT}} (TFlow_{d,h,n,p})$$

$$+ Curtailment_{d,h,n}$$

*These constraints hold for every hour **h** in each dispatch period **d** and for all regions **n**.*

$$\forall\, d \in D, h \in H_d, n \in N$$

Transmission Constraints

The transmission constraints ensure that transmission line flows do not exceed the transmission line capacity between two regions in each time period.

transfer_limit$_{d,h,n,p}$

*Power flowing from region **n** to region **p** must be less than the total transmission line capacity from **n** to **p**. These constraints hold for every hour **h** in each dispatch period **d** and for all regions **n** and **p** where **n** and **p** are grid connected.*

$$TFlow_{d,h,n,p} \leq TCapacityN_{n,p} + TCapacityN_{p,n} + tcapacityO_{n,p}$$
$$\forall\, d \in D, h \in H_d, n \in N, p \in N \ni (n,p) \in TCONNECT$$

CO_import_limit$_{d,h,n,p}$

*Total transmission into Colorado in each dispatch period **d** must be less than the dispatch period import limits**.** These constraints hold for every dispatch period **d**.*

$$\sum_{\substack{h \in H_d \\ n \in NONCO \\ p \in CO \ni \\ (n,p) \in TCONNECT}} TFlow_{d,h,n,p} * season\_scale_d \leq max\_import_d \quad \forall\, d \in D$$

CO_export_limit$_{d,h,n,p}$

*Total transmission flows out of Colorado in each dispatch period **d** must be less than the dispatch period export limits**.** These constraints hold for every dispatch period **d**.*

$$\sum_{\substack{h \in H_d \\ n \in CO \\ p \in NONCO \ni \\ (n,p) \in TCONNECT}} TFlow_{d,h,n,p} * season\_scale_d \leq max\_export_d \quad \forall\, d \in D$$

Long-Term Planning Reserve Constraints

The following constraints ensure that sufficient infrastructure exists to meet long-term planning and operating reserve requirements.

planning_reserves$_{d,h}$

The North American Electric Reliability Corporation requires a 12.5% reserve margin for the Rocky Mountain Power Area (RMPA), which includes Colorado and Wyoming regions. Therefore, the total firm capacity in the RMPA must be exceed the peak demand in the RMPA by 12.5%.

Total capacity of all dispatchable generators in CO and WY

$$\sum_{\substack{q \in DISPATCH \\ n \in CO \,\cup\, n \in WY}} \left(CapacityN_{n,q} + capacityO_{n,q}\right)$$

+ Total capacity value of existing variable generators in CO and WY

$$+ \sum_{\substack{q \in VG \\ n \in CO \,\cup\, n \in WY}} capacityO_{n,q} * cvO$$

+ Total capacity value of new wind in CO and WY

$$+ \sum_{\substack{c \in C \\ n \in CO \cup n \in WY}} CapacityWN_{c,n} * cvWN_{c,n}$$

+ Total capacity value of new PV in CO and WY

$$+ \sum_{\substack{q \in PV \\ n \in CO \cup n \in WY}} CapacityN_{n,q} * cvN_{n,q}$$

+ Total capacity of all storage units in CO and WY

$$+ \sum_{\substack{st \in ST \\ n \in CO \cup n \in WY}} \left(StCapacityN_{n,st} + stcapacityO_{n,st}\right)$$

≥ Reserve margin requirement for CO and WY

$$\geq \sum_{n \in CO \cup n \in WY} load_{d,h,n} * (1 + reservemargin)$$

*These constraints hold for every hour **h** in each dispatch period **d**.*

$$\forall\, d \in D, h \in H_d$$

Operating Reserve Constraints

For both PSCO and WACM,[56] contingency reserve requirements in each hour are based on the maximum between 6% of the hourly demand and an absolute contingency requirement based on the single largest contingency within the system (i.e., 451 MW for PSCO and 359 for WACM). At least half of the contingency reserves are required to be spinning reserves. In addition, we require additional spinning reserves (1% of demand) to be available during each hour to represent frequency regulation reserves.

$tot\_or\_requirement\_psco_{d,h}$

Total spin capacity in PSCO

$$\sum_{\substack{q \in SPIN \\ n \in PSCO}} \left(SpinCapN_{d,h,n,q} + SpinCapO_{d,h,n,q}\right)$$

+ Total non-spin capacity in PSCO

$$+ \sum_{\substack{q \in NONSPIN \\ n \in PSCO}} \left(NonspinCapN_{d,h,n,q} + NonspinCapO_{d,h,n,q}\right)$$

+Total storage spin capacity in PSCO

$$+ \sum_{\substack{st \in ST \\ n \in PSCO}} \left(StSpinCapN_{d,h,n,st} + StSpinCapO_{d,h,n,st}\right)$$

*≥ Total operating reserve requirement for PSCO, i.e., contingency reserve (max{0.06*$load_{psco}$, 451}) + frequency reserve (0.01*$load_{psco}$).*

$$\geq ortot\_psco_{d,h}$$

[56] Each model region within Colorado is associated with one of these two balancing authorities; however, the generators and load within the region boundaries do not perfectly align with actual boundaries for the PSCO and WACM service areas. We also associate the two Wyoming regions with the WACM balancing authority.

*These constraints hold for every hour **h** in each dispatch period **d.***

$$\forall\ d \in D, h \in H_d$$

spin_or_requirement_psco$_{d,h}$

Total spin capacity in PSCO

$$\sum_{\substack{q \in SPIN \\ n \in PSCO}} \left(SpinCapN_{d,h,n,q} + SpinCapO_{d,h,n,q}\right)$$

+Total storage spin capacity in PSCO

$$+ \sum_{\substack{st \in ST \\ n \in PSCO}} \left(StSpinCapN_{d,h,n,st} + StSpinCapO_{d,h,n,st}\right)$$

*≥ Total spinning operating reserve requirement for PSCO, i.e., half of contingency reserve (0.5*max{0.06*load$_{psco}$,451}) + frequency reserve (0.01*load$_{psco}$).*

$$\geq orspin\_psco_{d,h}$$

*These constraints hold for every hour **h** in each dispatch period **d.***

$$\forall\ d \in D, h \in H_d$$

tot_or_requirement_wacm$_{d,h}$

Total spin capacity in WACM

$$\sum_{\substack{q \in SPIN \\ n \in WACM}} \left(SpinCapN_{d,h,n,q} + SpinCapO_{d,h,n,q}\right)$$

+ Total non-spin capacity in WACM

$$+ \sum_{\substack{q \in NONSPIN \\ n \in WACM}} \left(NonspinCapN_{d,h,n,q} + NonspinCapO_{d,h,n,q}\right)$$

+Total storage spin capacity in WACM

$$+ \sum_{\substack{st \in ST \\ n \in WACM}} \left(StSpinCapN_{d,h,n,st} + StSpinCapO_{d,h,n,st}\right)$$

*≥ Total operating reserve requirement for WACM, i.e., contingency reserve (max{0.06*load$_{wacm}$, 359}) + frequency reserve (0.01*load$_{wacm}$).*

$$\geq ortot\_wacm_{d,h}$$

*These constraints hold for every hour **h** in each dispatch period **d.***

$$\forall\ d \in D, h \in H_d$$

spin_or_requirement_wacm$_{d,h}$

Total spin capacity in WACM

$$\sum_{\substack{q \in SPIN \\ n \in WACM}} \left(SpinCapN_{d,h,n,q} + SpinCapO_{d,h,n,q}\right)$$

+Total storage spin capacity in WACM

$$+ \sum_{\substack{st \in ST \\ n \in WACM}} \left(StSpinCapN_{d,h,n,st} + StSpinCapO_{d,h,n,st}\right)$$

*≥ Total spinning reserve requirement for WACM, i.e., half of contingency reserve (0.5*max{0.06*load$_{wacm}$, 359}) + frequency reserve (0.01*load$_{wacm}$).*

$$\geq orspin\_wacm_{d,h}$$

*These constraints hold for every hour **h** in each dispatch period **d.***

$$\forall\ d \in D, h \in H_d$$

Wind Constraints

The wind constraints track wind resource supply curve usage and resource limits as well as enforce wind generation levels. Wind generation follows an hourly profile.

wind_resource$_{c,n}$

Total new and existing wind capacity builds of wind power class **c** in region **n** must be less than the total wind resource supply for wind power class **c** in region **n**. These constraints hold for every wind power class **c** and every region **n.**

$$CapacityWN_{c,n} + capacityWO_{c,n} \leq \sum_{bin \in B} windsupply_{bin,c,n} \quad \forall\ c \in C, n \in N$$

wind_interconnection$_{c,n}$

Total new wind resource usage for wind power class **c** in region **n** must be equal to the new wind capacity builds for wind power class **c** in region **n**. These constraints hold for every wind power class **c** and every region **n.**

$$\sum_{bin\ \in B} WindBinN_{bin,c,n} = CapacityWN_{c,n} \quad \forall\ c \in C, n \in N$$

wind_interconnection2$_{bin,c,n}$

Total new and existing wind resource usage for wind supply curve bin **bin** of wind power class **c** in region **n** must be less than or equal to the wind resource supply in supply curve bin **bin** of wind power class **c** in region **n**. These constraints hold for all wind supply curve bins **bin** every wind class **c** and every region **n.**

$$WindBinN_{bin,c,n} + windbinO_{bin,c,n} \leq windsupply_{bin,c,n} \quad \forall\ bin \in B, c \in C, n \in N$$

wind_capacity_new$_{n,q}$

New wind capacity in region **n** must be equal to the total new wind capacity from all wind power classes **c.** These constraints hold for every region **n.**

$$CapacityN_{n,q} = \sum_{c \in C} CapacityWN_{c,n} \quad \forall\ n \in N, q\ \in WIND$$

wind_generation_new$_{d,h,n}$

Generation from new wind in hour **h** of dispatch period **d** in region **n** must be equal to the total new wind generation from all wind classes **c** in hour **h** of dispatch period **d** in region **n**. Wind generation is defined by a seasonal/diurnal profile specific to each wind power class and region. These constraints hold for every hour **h** in each dispatch period **d** in every region **n.**

$$GenerationN_{d,h,n,q} = \sum_{c \in C} CapacityWN_{c,n} * cfWN_c * cfprofileW_{c,d,h,n}$$

$$\forall\ d \in D, h \in H_d, n \in N, q \in WIND$$

wind_generation_old$_{d,h,n}$

Generation from existing wind in hour **h** of dispatch period **d** in region **n** must be equal to the total existing wind generation from all wind classes **c** in hour **h** of dispatch period **d** in region **n**. Wind generation is defined by a seasonal/diurnal profile specific to each wind power class and region. These constraints hold for every hour **h** in each dispatch period **d** in every region **n.**

$$GenerationO_{d,h,n,q} = \sum_{c \in C} capacityWO_{c,n} * cfWO_{c,n} * cfprofileW_{c,d,h,n}$$
$$\forall\, d \in D, h \in H_d, n \in N, q \in WIND$$

PV Constraints

PV constraints enforce generation levels according to hourly profiles.

pv_generation_new$_{d,h,n,q}$

Generation from new PV in hour **h** of dispatch period **d** in region **n** must be equal to new PV capacity in region **n** times the seasonal/diurnal capacity factor for new PV in hour **h** of dispatch period **d** in region **n**. These constraints hold for each PV technology **q,** for every hour **h** in each dispatch period **d** in every region **n.**

$$GenerationN_{d,h,n,q} = CapacityN_{n,q} * cf_{d,h,n,q} \quad \forall\, d \in D, h \in H_d, n \in N, q \in PV$$

pv_generation_old$_{d,h,n,q}$

Generation from existing PV in hour **h** of dispatch period **d** in region **n** must be equal to existing PV capacity in region **n** times the seasonal/diurnal capacity factor for existing PV in hour **h** of dispatch period **d** in region **n**. These constraints hold for each PV technology **q,** for every hour **h** in each dispatch period **d** in every region **n.**

$$GenerationO_{d,h,n,q} = capacityO_{n,q} * cf_{d,h,n,q} \quad \forall\, d \in D, h \in H_d, n \in N, q \in PV$$

Hydropower Constraints

The hydropower constraints enforce minimum and maximum generation in each hour as well as seasonal generation limits for hydropower. Note that **HYDRO** exists in **DISPATCH**. Therefore, hydropower generation is also constrained with the "**DispTech_capacity_bound**" suite of constraints for **DISPATCH** technologies (below).

We do not allow new capacity expansion of run-of-river hydropower, so constraints on new run-of-river hydropower generation are not included here. Furthermore, the model does not include any reservoir hydropower capacity. Therefore, we have excluded the reservoir hydropower constraints here.

hydro_generation_ror$_{d,n,q}$

Total generation from existing run-of-river hydropower generation for dispatch period **d** in region **n** must be less than or equal to the maximum allowed generation for dispatch period **d** in region **n**. Seasonal generation limits are based on historical data. These constraints hold for every non-peak dispatch period **d** in every region **n.**

$$\sum_{h \in H_d} GenerationO_{d,h,n,q} * season\_scale_d \leq hydromaxgen_{d,n}$$
$$\forall\, d \in NONPEAK, n \in N, q \in HYDRO$$

hydro_gen_min_max_ror$_{d,h,n,q}$

Generation from existing run-of-river hydropower in hour **h** of dispatch period **d** in region **n** must be between the minimum and maximum allowed generation for any hour **h** of dispatch period **d** in region **n**. These constraints hold for every hour **h** in each non-peak dispatch period **d** in every region **n.**

$$capacityO_{n,q} * hydromincf_{d,n} \leq GenerationO_{d,h,n,q} \leq capacityO_{n,q} * hydromaxcf_{d,n}$$
$$\forall\, d \in D, h \in H_d, n \in N, q \in HYDRO$$

hydro_ramp_ror$_{d,h,n,q}$

Generation from existing run-of-river hydropower in hour **h** of dispatch period **d** in region **n** cannot ramp up or down more than the hydropower ramping rate with respect to the generation in hour **h-1**. These constraints hold for every hour **h** in each non-peak dispatch period **d** in every region **n.**

$$GenerationO_{d,h-1,n,q} - GenerationO_{d,h,n,q} \leq hydroramp * GenerationO_{d,h,n,q}$$
$$-GenerationO_{d,h-1,n,q} + GenerationO_{d,h,n,q} \leq hydroramp * GenerationO_{d,h,n,q}$$
$$\forall\, d \in D, h \in H_d, n \in N, q \in HYDRO$$

Required Plant Size Constraints

The following constraints enforce a size range for new capacity builds of certain technologies.

minimum_maximum_build$_{n,q}$

New plant capacity of non-modular technology **q** in region **n** must be between the minimum and maximum non-modular plant sizes for technology **q**. These constraints hold for every region **n** and every non-modular technology **q.**

$$UnitN_{n,q} * minplantsize_q \leq CapacityN_{n,q} \leq UnitN_{n,q} * maxplantsize_q$$
$$\forall\, n \in N, q \in NONMOD$$

Generation Capacity and Operating Reserve Capacity Constraints

The following operation constraints enforce how generating capacity can be allocated to help meet load and system reliability. Generators can provide combinations energy, spinning reserves and non-spinning reserves. Only thermal generators can provide spinning reserves and non-spinning reserves.

ThermTech_capacity_bound_new_energy_spin$_{d,h,n,q}$

New generation and spin capacity for thermal technology **q** in hour **h** of dispatch period **d** in region **n** must be less than the new capacity for thermal technology **q** in region **n**. Because all elements of **THERMAL** exist in **DISPATCH**, these constraints are not as tight as the **"DispTech_capacity_bound_new_energy_spin_nonspin"** constraints for **DISPATCH** technologies (below). These constraints hold for every hour **h** in each dispatch period **d** in every region **n** and for all thermal technologies **q.**

$$GenerationN_{d,h,n,q} + SpinCapN_{d,h,n,q} \leq CapacityN_{n,q}$$
$$\forall\, d \in D, h \in H_d, n \in N, q \in THERMAL$$

ThermTech_capacity_bound_old_energy_spin$_{d,h,n,q}$

Existing generation and spin capacity for thermal technology **q** in hour **h** of dispatch period **d** in region **n** must be less than the existing capacity for thermal technology **q** in region **n**. Note that these constraints require that a thermal plant is 'up' to provide energy and spinning reserves. These constraints hold for every hour **h** in each dispatch period **d** in every region **n** and for all thermal technologies **q.**

$$GenerationO_{d,h,n,q} + SpinCapO_{d,h,n,q} \leq Up_{d,h,n,q} * capacityO_{n,q}$$
$$\forall\, d \in D, h \in H_d, n \in N, q \in THERMAL$$

DispTech_capacity_bound_new_energy$_{d,h,n,q}$

New generation for thermal technology **q** in hour **h** of dispatch period **d** in region **n** must be less than the new capacity for thermal technology **q** in region **n** derated by forced and planned outages. These constraints hold for every hour **h** in each dispatch period **d** in every region **n** and for all dispatchable technologies **q.**

$$GenerationN_{d,h,n,q} \leq CapacityN_{n,q} * \left(1 - fo_q\right) * \left(1 - po_{d,q}\right)$$
$$\forall\, d \in D, h \in H_d, n \in N, q \in DISPATCH$$

DispTech_capacity_bound_old_energy$_{d,h,n,q}$

Existing generation for thermal technology **q** in hour **h** of dispatch period **d** in region **n** must be less than the existing capacity for thermal technology **q** in region **n** derated by forced and planned outages. Even though all elements of **THERMAL** exists in **DISPATCH**, thermal technologies do not need capacityO multiplied by 'Up' in these constraints. The requirement that thermal generators must be 'up' to produce energy is embedded in the "**ThermTech_capacity_bound_old_energy_spin"** constraints (above). These constraints hold for every hour **h** in each dispatch period **d** in every region **n** and for all dispatchable technologies **q.**

$$GenerationO_{d,h,n,q} \leq capacityO_{n,q} * \left(1 - fo_q\right) * \left(1 - po_{d,q}\right)$$
$$\forall\, d \in D, h \in H_d, n \in N, q \in DISPATCH$$

DispTech_capacity_bound_new_energy_spin_nonspin$_{d,h,n,q}$

New generation, spin capacity and non-spin capacity for dispatch technology **q** in hour **h** of dispatch period **d** in region **n** must be less than the new capacity for dispatch technology **q** in region **n**. Because all elements of **THERMAL** exist in **DISPATCH**, these constraints are tighter than the **"ThermTech_capacity_bound_new_energy_spin"** constraints for **THERMAL** technologies (above). These constraints hold for every hour **h** in each dispatch period **d** in every region **n** and for all dispatchable technologies **q.**

$$GenerationN_{d,h,n,q} + SpinCapN_{d,h,n,q} + NonspinCapN_{d,h,n,q} \leq CapacityN_{n,q}$$
$$\forall\, d \in D, h \in H_d, n \in N, q \in DISPATCH$$

DispTech_capacity_bound_old_energy_spin_nonspin$_{d,h,n,q}$

Existing generation, spin capacity and non-spin capacity for dispatch technology **q** in hour **h** of dispatch period **d** in region **n** must be less than the existing capacity for dispatch technology **q** in region **n**. Even though all elements of **THERMAL** exist in **DISPATCH**, thermal technologies do not need capacityO multiplied by 'Up' in these constraints. The requirement that thermal generators must be 'up' to produce energy and provide spinning reserves is embedded in the

"**ThermTech_capacity_bound_old_energy_spin**" constraints (above). These constraints hold for every hour **h** in each dispatch period **d** in every region **n** and for all dispatchable technologies **q.**

$$GenerationO_{d,h,n,q} + SpinCapO_{d,h,n,q} + NonspinCapO_{d,h,n,q} \leq capacityO_{n,q}$$
$$\forall\ d \in D, h \in H_d, n \in N, q \in\ DISPATCH$$

SpinTech_capacity_bound_new_spin$_{d,h,n,q}$

New spin capacity for technology **q** in hour **h** of dispatch period **d** in region **n** must be less than the maximum allowed spin capacity for new spin technology **q** in region **n**. These constraints hold for every hour **h** in each dispatch period **d** in every region **n** and for all spin technologies **q.**

$$SpinCapN_{d,h,n,q}\ \leq\ CapacityN_{n,q} * spinfrac_q$$
$$\forall\ d \in D, h \in H_d, n \in N, q \in\ SPIN$$

SpinTech_capacity_bound_old_spin$_{d,h,n,q}$

Existing spin capacity for technology **q** in hour **h** of dispatch period **d** in region **n** must be less than the maximum allowed spin capacity for existing spin technology **q** in region **n**. Even though all elements of **SPIN** exists in **THERMAL**, thermal technologies that can provide spin do not need capacityO multiplied by 'Up' in these constraints. The requirement that thermal generators must be 'up' to provide spinning reserves is embedded in the "**ThermTech_capacity_bound_old_energy_spin**" constraints (above). These constraints hold for every hour **h** in each dispatch period **d** in every region **n** and for all spin technologies **q.**

$$SpinCapO_{d,h,n,q}\ \leq\ capacityO_{n,q} * spinfrac_q$$
$$\forall\ d \in D, h \in H_d, n \in N, q \in\ SPIN$$

Minimum Generation for Thermal Plants

minimum_generation_new$_{d,h,n,q}$

New generation for technology **q** in hour **h** of dispatch period **d** in region **n** must be greater than or equal to the minimum generation requirement for new plants of technology **q** in region **n**. These constraints hold for every hour **h** in each dispatch period **d** in every region **n** and for all thermal technologies **q.**

$$GenerationN_{d,h,n,q}\ \geq\ CapacityN_{n,q}\ *\ mingenN_q$$
$$\forall\ d \in D, h \in H_d, n \in N, q \in\ THERMAL$$

minimum_generation_old$_{d,h,n,q}$

Existing generation for technology **q** in hour **h** of dispatch period **d** in region **n** must be greater than or equal to the minimum generation requirement for existing plants of technology **q** in region **n** if the existing plant is 'up'. These constraints hold for every hour **h** in each dispatch period **d** in every region **n** and for all thermal technologies **q.**

$$GenerationO_{d,h,n,q}\ \geq\ Up_{d,h,n,q} * capacityO_{n,q}\ *\ mingenO_{n,q}$$
$$\forall\ d \in D, h \in H_d, n \in N, q \in\ THERMAL$$

Thermal Plant Start-up and Shut-down Constraints

The following start-up and shut-down constraints provide the logic for thermal generator start-up and shut-down operations in each time period.

minimum_on$_{d,h,n,q}$

If a plant of thermal technology **q** is up in hour **h**, the plant could have started up in at most one hour from **h-minon** to **h** (with time wrapping considered).[57]**.** If a plant is not up in hour **h**, the plant cannot have started up in any hour from **h-minon** to **h** (with time wrapping considered)**.** These constraints hold for every hour **h** in each dispatch period **d** in every region **n** and for all thermal technologies **q.**

$$\sum_{h' \in \overline{H}_{d,h,q}} Startup_{d,h',n,q} \quad \leq \quad Up_{d,h,n,q}$$
$$\forall\, d \in D, h \in H_d, n \in N, q \in \; THERMAL$$

minimum_off$_{d,h,n,q}$

If a plant of thermal technology **q** is up in hour **h**, the plant cannot have shut down in any hour from **h-minon** to **h** (with time wrapping considered)**.** If a plant is not up in hour **h**, the plant could have shut down in at most one hour from **h-minon** to **h** (with time wrapping considered)**.** These constraints hold for every hour **h** in each dispatch period **d** in every region **n** and for all thermal technologies **q.**

$$\sum_{h' \in \underline{H}_{d,h,q}} Shutdown_{d,h',n,q} \quad \leq \quad 1 - Up_{d,h,n,q}$$
$$\forall\, d \in D, h \in H_d, n \in N, q \in \; THERMAL$$

startup_transition$_{d,h,n,q}$

If a plant of thermal technology **q** starts up in hour **h**, the plant must be up in **h**, having previously not been up in **h-1** (with time wrapping considered). These constraints hold for every hour **h** in each dispatch period **d** in every region **n** and for all thermal technologies **q.**

$$Startup_{d,h,n,q} \geq Up_{d,h,n,q} - \; Up_{d,h-1,n,q} \quad \forall\, d \in D, h \in H_d, n \in N, q \in \; THERMAL$$

shutdown_transition$_{d,h,n,q}$

If a plant of thermal technology **q** shuts down in hour **h**, the plant must not be up in **h**, having previously been up in **h-1** (with time wrapping considered). These constraints hold for every hour **h** in each dispatch period **d** in every region **n** and for all thermal technologies **q.**

$$Shutdown_{d,h,n,q} \geq Up_{d,h-1,n,q} - \; Up_{d,h,n,q} \quad \forall\, d \in D, h \in H_d, n \in N, q \in \; THERMAL$$

startup_transition2$_{d,h,n,q}$

If a plant of thermal technology **q** starts up in hour **h**, the plant cannot have been up in **h-1** (with time wrapping considered). These constraints hold for every hour **h** in each dispatch period **d** in every region **n** and for all thermal technologies **q.**

$$Startup_{d,h,n,q} \leq 1 - Up_{d,h-1,n,q} \quad \forall\, d \in D, h \in H_d, n \in N, q \in \; THERMAL$$

[57] *As an example of time wrapping, let $h \in H_d \in \{1..10\}$. If $h = 1$, then $h\text{-}1 = 10$.*

startup_transition2$_{d,h,n,q}$

If a plant of thermal technology **q** shuts down in hour **h**, the plant must have been up in **h-1** (with time wrapping considered). These constraints hold for every hour **h** in each dispatch period **d** in every region **n** and for all thermal technologies **q.**

$$Shutdown_{d,h,n,q} \leq Up_{d,h-1,n,q} \quad \forall\, d \in D, h \in H_d, n \in N, q \in \ THERMAL$$

Storage Build Constraints

The storage build constraints track storage resource supply curve usage and enforce a size range for new storage capacity builds.

storage_resource$_{n,st}$

Total new and existing storage capacity in region **n** of storage technology **st** must be less than the storage supply in region **n** of storage technology **st**. These constraints hold for every region **n** and for all storage technologies **st.**

$$StCapacityN_{n,st} \ + \ stcapacityO_{n,st} \leq \ stsupply_{n,st} \quad \forall\, n \in N, st \in ST$$

storage_minimum_maximum_build$_{n,st}$

New storage capacity in region **n** of storage technology **st** must be between the minimum and maximum storage size for storage technology **st**. These constraints hold for every region **n** and for all storage technologies **st.**

$$StUnitN_{n,st} * stminplantsize_{st} \ \leq StCapacityN_{n,st} \ \leq \ StUnitN_{n,st} * stmaxplantsize_{st}$$
$$\forall\, n \in N, st \in ST$$

Storage Operations Constraints

The storage operation constraints define the round trip efficiency for a storage plant and how storage capacity can be allocated to help meet load and contribute to system reliability.

storage_balance_new$_{d,n,st}$

The ratio of the total new storage generation to total new storage charging for all hours in dispatch period **d** of storage technology **st** must be equal to the round trip efficiency of storage technology **st**. These constraints hold for every dispatch period **d** every region **n** and for all storage technologies **st**.

$$\sum_{h \in H_d} StGenerationN_{d,h,n,st} = \sum_{h \in H_d} StChargeN_{d,h,n,st} * \ strte_{st} \quad \forall\, d \in D, n \in N, st \in ST$$

storage_balance_old$_{d,n,st}$

The ratio of the total existing storage generation to total exiting storage charge for all hours in dispatch period **d** of storage technology **st** must be equal to the round trip efficiency of storage technology **st**. These constraints hold for every dispatch period **d** every region **n** and for all storage technologies **st**.

$$\sum_{h \in H_d} StGenerationO_{d,h,n,st} = \sum_{h \in H_d} StChargeO_{d,h,n,st} * \ strte_{st} \quad \forall\, d \in D, n \in N, st \in ST$$

storage_capacity_bound_new$_{d,h,n,st}$

New storage generation and new storage charging in hour **h** of dispatch period **d**, in region **n** for storage technology s**t** must be less than the new storage capacity in region **n** for storage technology **st** derated by forced and planned outages. These constraints hold for every hour **h** in each dispatch period **d** in every region **n** and for all storage technologies **st.**

$$StGenerationN_{d,h,n,st} + StChargeN_{d,h,n,st} \leq StCapacityN_{n,st} * (1 - stfo_{st}) * (1 - stpo_{d,st}) \quad \forall\, d \in D, h \in H_d, n \in N, st \in ST$$

storage_capacity_bound_old$_{d,h,n,st}$

Existing storage generation and existing storage charging in hour **h** of dispatch period **d**, in region **n** for storage technology s**t** must be less than the existing storage capacity in region **n** for storage technology **st** derated by forced and planned outages. These constraints hold for every hour **h** in each dispatch period **d** in every region **n** and for all storage technologies **st.**

$$StGenerationO_{d,h,n,st} + StChargeO_{d,h,n,st} \leq stcapacityO_{n,st} * (1 - stfo_{st}) * (1 - stpo_{d,st}) \quad \forall\, d \in D, h \in H_d, n \in N, st \in ST$$

storage_spin_bound_new$_{d,h,n,st}$

New storage spin capacity in hour **h** of dispatch period **d**, in region **n** for storage technology s**t** must be less than or equal to the new storage capacity that is not used for storage generation or storage charging in hour **h** of dispatch period **d**, in region **n** for storage technology s**t**. These constraints hold for every hour **h** in each dispatch period **d** in every region **n** and for all storage technologies **st.**

$$StSpinCapN_{d,h,n,st} \leq StCapacityN_{n,st} - StGenerationN(d,h,n,st) - StChargeN_{d,h,n,st} \quad \forall\, d \in D, h \in H_d, n \in N, st \in ST$$

storage_spin_bound_old$_{d,h,n,st}$

Existing storage spin capacity in hour **h** of dispatch period **d**, in region **n** for storage technology s**t** must be less than or equal to the existing storage capacity that is not used for storage generation or storage charging in hour **h** of dispatch period **d**, in region **n** for storage technology s**t**. These constraints hold for every hour **h** in each dispatch period **d** in every region **n** and for all storage technologies **st.**

$$StSpinCapO_{d,h,n,st} \leq stcapacityO_{n,st} - StGenerationO(d,h,n,st) - StChargeO_{d,h,n,st} \quad \forall\, d \in D, h \in H_d, n \in N, st \in ST$$

Policy Constraints

Policy constraints enforce annual renewable portfolio standard and emission requirements.

state_rps

Total annual renewable Colorado generation – Total Colorado curtailments

$$\sum_{\substack{d\in D,\\ h\in H_{d},\\ n\in CO,\\ q\in RE}} \left(GenerationN_{d,h,n,q} + GenerationO_{d,h,n,q}\right) * season\_scale_d$$

$$- \sum_{\substack{d\in D,\\ h\in H_{d},\\ n\in CO}} Curtailment_{d,h,n} * season\_scale_d$$

≥ *rps fraction * total annual end-use demand in Colorado*

$$\geq rpsfrac * \sum_{\substack{d\in D,\\ h\in H_{d},\\ n\in CO_n}} \frac{1}{1 + distributionloss} * load_{d,h,n} * season\_scale_d$$

dg_carveout

Total annual distributed generation in Colorado must be greater than or equal to the distributed generation requirement (i.e., distributed generation fraction times the annual end-use demand in Colorado).

$$\sum_{\substack{d\in D,\\ h\in H_{d},\\ n\in CO,\\ q\in DG}} \left(GenerationN_{d,h,n,q} + GenerationO_{d,h,n,q}\right) * season\_scale_d$$

$$\geq dgfrac * \sum_{\substack{d\in D,\\ h\in H_{d},\\ n\in CO}} \frac{1}{1 + distributionloss} * load_{d,h,n} * season\_scale_d$$

emission_limit$_{pol}$

Total annual emissions of pollutant type **pol** emitted from all technologies **q** and all storage technologies **st** must be less than or equal to the emissions cap for pollutant type **pol**. These constraints hold for every pollutant **pol.**

$$\sum_{\substack{d\in D,\\ h\in H_{d},\\ n\in N,\\ q\in Q}} \left(GenerationN_{d,h,n,q} * heatrateN_q\right) * season\_scale_d * pollutefactor_{pol,q}$$

$$+ \sum_{\substack{d\in D,\\ h\in H_{d},\\ n\in N,\\ q\in Q}} \left(GenerationO_{d,h,n,q} * heatrateO_{n,q}\right) * season\_scale_d * pollutefactor_{pol,q}$$

$$+ \sum_{\substack{d\in D,\\ h\in H_{d},\\ n\in N,\\ st\in ST}} \left(StGenerationN_{d,h,n,st} * stheatrateN_{st}\right) * season\_scale_d * stpollutefactor_{pol,st}$$

$$+ \sum_{\substack{d \in D,\\ h \in H_{d,}\\ n \in N,\\ st \in ST}} \left(StGenerationO_{d,h,n,st} * stheatrateO_{n,st}\right) * season\_scale_d * stpollutefactor_{pol,st}$$

$$\leq emissioncap_{pol} \quad \forall\, pol \ \in POL$$

Binary and Non-Negativity Constraints

$UnitN_{n,q}$, $StUnitN_{n,st}$, $Up_{d,h,n,q}$, $Startup_{d,h,n,q}$, $Shutdown_{d,h,n,q} \in \{0,1\}$
All other variables ≥ 0