Analytic Approaches for Projecting CO_2 Emissions from Affected EGUs: Electric Sector Models

TSD – Projecting EGU CO2 Emissions Performance: Mass-Based Goals and Plan Performance

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National-scale capacity expansion and dispatch planning models

Typical uses

National-scale electric capacity expansion models are typically used for long-term policy analysis forecasting over a period of decades. They are built with a focus on big-picture trends in energy use across large regions or the country as a whole, and capture only broad-scale information, such as changes in regional fuel mix, fuel consumption, emissions, and infrastructure expenditures (i.e. new generation and transmission). Such models can be used to review trends in emissions and energy sector structure under changing regulatory and economic conditions. This model type is used for regulatory policy analysis by EPA, as well as regional environmental regulatory entities. Currently, EPA employs a national-scale capacity expansion planning model, the Integrated Planning Model (IPM), used to examine the impacts and efficacy of environmental policies, such as emissions trading programs, regional transport rules, and boiler emissions reductions policies (such as the Mercury and Air Toxics Standard).[1] Planning and emissions targets for the Regional Greenhouse Gas Initiative (RGGI) are also modeled in IPM.[2] Utilities and electric system planners use national-scale capacity expansion models to forecast regional market electricity and capacity prices, as well as to estimate likely regional fuel uses and emissions. Recently, the Eastern Interconnect Planning Collaborative (EIPC), a utility and stakeholder process funded by US DOE, thoroughly modeled the costs and implications of a rigorous carbon emissions reduction scenario in the east using a national-scale capacity expansion model.[3] The US National Renewable Energy Laboratory (NREL) recently published the Renewable Electricity Futures Study, examining opportunities and costs of increasing renewable energy penetration in the US, and examining greenhouse gas emissions reductions from the resulting scenarios.[4]

Features

National-scale electric capacity expansion models have moderate spatial detail with broad scope, generally encompassing the entire country or interconnects (i.e. Eastern, Western, and ERCOT), subdivided into smaller areas, such as balancing authorities or control areas. For computational efficiency, these models generally model several representative hours of the year, or aggregate hours into representative bundles with similar demand (i.e. peak, shoulder, off-peak, superpeak, etc…) and/or likely generation characteristics. In these models, existing EGU are clustered into broad technology types, sometimes subdivided by vintage or emissions controls. These types of models focus on future capacity expansion decisions, seeking units that provide energy and capacity requirements while

[1] See http://www.epa.gov/powersectormodeling/BaseCasev513.html

[2] See, for example, http://www.rggi.org/docs/ProgramReview/February11/13_02_11_IPM.pdf

[3] See http://www.eipconline.com/

[4] Renewable Electricity Futures Study (Entire Report) National Renewable Energy Laboratory. (2012). Renewable Electricity Futures Study. Hand, M.M.;Baldwin, S.; DeMeo, E.; Reilly, J.M.; Mai, T.; Arent, D.; Porro, G.; Meshek, M.; Sandor, D. eds. 4 vols. NREL/TP-6A20-52409. Golden, CO: National Renewable Energy Laboratory. http://www.nrel.gov/analysis/re_futures/.

minimizing system bulk-energy costs, maintaining reliability criteria, and following other constraints, such as minimum build times, renewable energy availability, or emissions restrictions.

Application to emissions reduction approaches

Due to the binning of generation units into generic types, these models roughly captures outcomes from direct control strategies such as EGU efficiency improvements individual EGU fuel switching. The effects of additional energy efficiency, renewable energy, or fleet-wide fuel switching can be appropriately captured at a regional level, although this model is less appropriate for analyzing individual EGU decisions and outcomes. Unit-specific emissions limitations (i.e. permit limits), retrofit decisions and retirements can only approximated roughly in these models, because they do not include specific EGU characteristics. For the purposes of reviewing emissions reductions approaches, these models should be able to capture the non-economic retirements of existing assets.

- EGU efficiency improvements and/or fuel switching: Fleet-wide fuel switching can be appropriately captured at a regional level, although any changes to heat rates or fuel switching at applicable EGUs are normally completed manually prior to operation, as these models are not setup to optimize such modifications.
- Individual EGU emissions restrictions: As EGU are generally aggregated in these models, national scale models are not equipped to review individual EGU emissions restrictions.[5]
- Market-based emissions reductions:[6] National and regional scale models are able to capture economic tradeoffs between aggregate EGU categories (e.g. fuel and unit types), and thus can either capture the effect of emissions prices, or calculate emissions prices based on a regional or national emissions cap.
- EE/RE Programs: The effects of additional energy efficiency and/or renewable energy can be roughly captured at a regional level, although marginal changes due to demand reductions may be "blocky" in nature, affecting one aggregate class of unit at a time.

Discussion

National capacity expansion models can provide valuable trends and insights at the national and regional level capable of capturing the effects of broad multi-level policy decisions. Units are normally aggregated up to generic technology types and dispatched in a simplified manner ignoring or approximating factors such as ramp rates and variable heat rates. These models may also not distinguish a precise location for new emitting or non-emitting resources within a region or subregion, rendering it

[5] Individual unit emissions restrictions for units with a fixed (or nearly fixed) emissions rate are modeled similarly to energy-limited units (i.e. units that can only deliver a certain amount of energy over a period of time, such as hydrologic reservoirs). To model individual unit restrictions, models must co-optimize for least cost dispatch at all hours, as well as total energy availability for units with restrictions. Such modeling generally requires the review of tradeoffs between individual units to ensure that energy and capacity requirements are met at all hours while still meeting total emissions limits. This analysis is generally beyond the capability of models that aggregate units or hours.

[6] Market-based emissions reductions include direct emissions prices as well as the realized or opportunity cost of emissions credits realized from a trading program.

difficult to determine state vs. out-of-state impacts.[7] Finally, these models generally do not review utility-specific impacts.[8] Many of capacity expansion models require expertise to operate and interpret. Models of this class require multiple hours to solve. Many of the models used for this purpose are proprietary, with significant licensure fees (or are run on behalf of customers by the model owner) and detailed input data may be proprietary.

Utility-scale capacity expansion and dispatch planning models

Typical uses

While these models are similar in concept to national capacity expansion models, utility planning models are typically used for planning decisions (including new resource procurement and retirement or retrofit decisions) within a specific utility's territory, typically reviewing periods of up to two decades. Utility-scale capacity expansion models are an industry-standard, used regularly in state electricity regulatory proceedings. Within the electricity sector there is broad familiarity with these models at state level utility commissions. Multiple vertically integrated utilities use capacity expansion models to both conduct forward planning, as well as review the economics of specific retrofit decisions. Utilities that submit Integrated Resource Plans (IRP) typically a utility-scale capacity expansion model to examine long-term strategies and develop short-term action plans.[9] Utilities have experience using these models to examine carbon reduction strategies, as IRP scenarios may include greater penetrations of EE or RE, proxy emissions prices or trading, and/or hard emissions caps.

Features

Utility-scale planning models have high spatial detail with limited geographic scope, generally encompassing a utility service territory or a sub-regional scale. These models generally have better temporal resolution than the national-scale capacity expansion models, with each model year dispatched based on an annual hourly load duration curve.[10] Utility-scale capacity expansion models

[7] For example, even if a model respects state boundaries, within an electrically contiguous area, a new resource may be equally likely to be put in place on either side of a political boundary. State and other political boundaries are generally not meaningful in electric system modeling, except for state policies and constraints.

[8] Utility-specific impacts refer to changes that could be expected to affect customers or owners of particular utilities. These impacts include rate changes, or costs and/or revenues experienced by ratepayers or owners, or independent power producers. National and regional-scale models examine the electric sector as a whole and do not make distinctions with regards to utility ownership.

[9] See, for example: The Duke Energy Carolinas IRP (Annual Report), September 2012. http://www.energy.sc.gov/files/view/Duke_IRP 2012.pdf; PacifiCorp 2013 IRP (Vol 1), April 2013. http://www.pacificorp.com/es/irp.html; TVA IRP, March 2011. http://www.tva.gov/environment/reports/irp/archive/index.htm; Georgia Power Company 2013 IRP, January 31, 2013, http://facts.psc.state.ga.us/Public/GetDocument.aspx?ID=145981; 2011 Joint IRP of Louisville Gas and Electric and Kentucky Utilities Company, April 2011. http://psc.ky.gov/PSCSCF/2011%20cases/2011-00140/20110421_LG%26E-KU_IRP_Volume%20I.pdf; Great River Energy IRP, November 2012, http://www.greatriverenergy.com/makingelectricity/resourceplan/pdoc295631.pdf; Public Service Company of Oklahoma IRP, October 2012, http://occeweb.com/pu/PSO%202012%20IRP.pdf.

[10] Load duration curves typically represents a typical week for each month.

typically track individual units, where each EGU has specific operational characteristics. Models are designed to choose the optimal resource mix to meet an objective function (typically least cost on a present value basis), given a number of constraints.

Due to the additional spatial and temporal resolution of these models as compared to the national scale models, the number of technology options for capacity expansion is generally limited to a select subset to reduce the runtime of the model. This can be done through an outside-the-model screening analysis to pre-select the resources most likely to be economic in a planner's area of interest, or running the model iteratively to eliminate rarely chosen alternatives.

Application to emissions reduction approaches

Utility-scale planning models are commonly used to understand marginal capacity addition decisions for focused areas of interest (i.e. a specific utility's decisions). Individual EGU representation means that these models are reasonably suited to the review of both the operational margin as well as the build margin. They can determine how signals such as emissions prices would impact operational decisions, the acquisition of new units, and the retirement of existing assets on an economic basis. Similarly, These models are typically limited in scope to a few balancing areas, and thus may not represent measure impacts that occur outside the modeled region, or may unduly credit all measure impacts to that single balancing area. Most utilities are focused on their area of operation and as such focus their modeling efforts on that area, but it would be feasible for a state planning agency to model a wider spatial area.

The effects of additional energy efficiency, renewable energy, or fuel switching can be captured at the balancing area level, although such additions may have wider-ranging impacts beyond the study area of these models., These models can be sensitive to input assumptions, including commodity prices, new unit assumptions, existing unit cost assumptions, and restrictions on new unit selection. For the purposes of reviewing emissions reductions approaches, these models should be able to capture the non-economic retirements of existing assets.

- EGU efficiency improvements and/or fuel switching: These models explicitly track the EGU-specific and system implications of direct control strategies such as heat rate improvements or fuel switching.
- Individual EGU emissions restrictions: Utility-scale models may be able to review individual EGU emissions restrictions, depending on the capability of the specific model.
- Market-based emissions reductions: Utility -scale planning models are well equipped to capture the effect of emissions prices on individual EGU output.[11] These models can determine how signals such as emissions prices would impact operational decisions, the acquisition of new units, and the retirement of existing assets on an economic basis.
- EE/RE Programs: These models explicitly track the EGU-specific and system implications of EE/RE programs. The effects of additional EE/RE programs can be captured at the balancing area level, although such additions may have wider-ranging impacts beyond the study area of these models.

[11] Utility-scale models do not generally see changes that occur in EGU outside of the model's boundaries, and thus cannot estimate a regional or national emissions clearing price.

Discussion

The use of an hourly load duration curve for dispatch provides a more detailed dispatch than national models. Such a dispatch methodology combined with unit specificity allows for analysis of a wide range of emissions reduction approaches. The dispatch is still more limited than the chronological electricity simulation models discussed later, which can account for ramp rates, minimum downtime limitations, or specific outages. However, the added capacity expansion optimization benefits allow for broader changes in a utilities energy mix and more flexible long term analysis. Impacts beyond model scope are represented by generic market assumptions, and occur externally to the model; regional impacts are not represented. Depending on the number of future resource alternatives allowed, solution times can be long (hours to days). Most such models are proprietary software with significant licensure fees, and detailed input data may be proprietary and/or considered confidential business information (CBI) by utilities.

Electricity System Simulation Dispatch Models

Typical Uses

Simulation dispatch models are regularly used by utilities, grid operators, and independent power producers (IPP) for short term planning, ratemaking, dispatch decisions, and market intelligence. Simulation dispatch models are driven by economics and specifically account for operational constraints (e.g. ramp rates, heat input curves, and unit downtime for maintenance) and system restrictions, such as reserve requirements. These models do not optimize unit procurement or retirement, and thus are reasonably used to review only a few years forward.[12] Grid operators, including utilities and independent system operators (ISO) use similar models in near real-time to match demand against available generators and dispatch least cost EGU. EGU owners and operators run simulation models to assist in fuel procurement, forecast revenues and costs, and calculate the avoided costs for the procurement of EE[13] and RE from qualifying facilities. Other utilities use simulation dispatch models to forecast rates for ratemaking proceedings and other planning purposes.

Features

Electricity system simulation dispatch models (also called production cost models) utilize security constrained economic dispatch (SCED) algorithms to determine which EGU operate on an hourly (or shorter) basis to meet demand.[14] These models typically have a very broad spatial scope, generally

[12] Some planners use simulation dispatch models in conjunction with national or utility-scale capacity expansion planning models, where the capacity expansion model indicates the disposition of new and existing resources, and the simulation dispatch model is used to calculate operations for individual EGU. In this case, these models can be used in the same time horizon as the capacity expansion model (i.e. decades).

[13] For example, see Hornby, R., P. Chernick, D. White, et al., 2013. Avoided Energy Supply Costs in New England: 2013 Report. http://www.rieermc.ri.gov/documents/2013%20Evaluation%20Studies/AESC%20Report%20-%20With%20Appendices%20Attached.pdf

[14] The Energy Policy Act of 2005 (EPAct) §1234 defines economic dispatch as the "operation of generation facilities

covering multiple Regional Transmission Organization (RTO) regions, and often modeling entire interconnects (i.e. Western, Eastern and/or ERCOT). While individual units are modeled in detail, including fuel and variable costs and operational constraints, transmission is simplified to characterize thermal constraints between zones, which typically represent control areas or balancing authorities. Zones contain both load (demand) and EGU; dispatch and transmission are balanced to maintain reliability while providing least cost service on a variable cost basis. Some versions of these models operate at a "nodal" level, where transmission constraints between individual EGU or plants are modeled as well. Simulation dispatch models typically operate chronologically, modeling either all 8760 hours of the year, or typical weeks. These models contain substantially more detail about individual EGU than regional or national planning or capacity expansion models, including unit ramp rates, minimum outages, maintenance schedules, emissions and fuel use constraints, and often heat rate curves depicting expected efficiency changes at various levels of output. Many of these models are able to operate in a "stochastic" mode, allowing for random variations in unknown variables, such as forced outage schedules, fuel prices, and hourly demand.

Application to Emissions Reduction Approaches

Simulation dispatch models are well suited to evaluate system and individual EGU impacts, on an operational basis, related to either changes in demand, economic considerations that impact specific EGU, or operational constrains (such as emissions or operational limits). However, the build margin is not directly represented in this type of model. From this perspective, simulation dispatch models may be used to predict, over the near term,[15] how new EE or RE impacts fossil generators. These models are designed to review both expected changes in dispatch under baseline conditions, as well under different fuel price assumptions or emissions constraints.

- EGU efficiency improvements and/or fuel switching: Unlike capacity expansion models, simulation dispatch models will not choose economically optimal units to retrofit for improved heat rates or fuel switch, compared to other routes for emissions reductions. These models explicitly track the EGU-specific and system implications of direct control strategies such as heat rate improvements or fuel switching.[16]
- Individual EGU emissions restrictions: Most simulation dispatch models are equipped to review individual EGU emissions restrictions, depending on the capability of the specific model. Solving for large numbers of EGU with unit emissions restrictions may push the limits of some dispatch algorithms due to the requirement to co-optimize large numbers

to produce energy at the lowest cost to reliable serve consumers, recognizing any operational limits of generation and transmission facilities."

[15] "Near term" is reasonably a short number of years (i.e. 3-5), but may vary depending on changing economic considerations, such as rapidly changing fuel prices or unit additions/retirements.

[16] For example, fuel switching a boiler from coal to gas-fired generation will reduce the emissions rate of the EGU, but may increase the variable cost of the EGU, effectively decreasing its dispatch. To compensate for the loss of energy from this EGU, other EGU(s) will increase their output. Depending on that EGU's position in the loading order (i.e. it's relative economics) the energy requirement may be met by boilers with greater or lesser emissions rates. In aggregate, system emissions rates may change differently than the emissions from the EGU with an improved efficiency or changed fuel.

of EGU while meeting annual or sub-annual emissions limits.

- Market-based emissions reductions: Simulation dispatch models are well equipped to capture the effect of emissions prices on individual EGU output, and may be able to calculate a clearing price for emissions amongst the set of modeled EGU. These models can determine how signals such as emissions prices would impact operational decisions, but not the acquisition or retirement of EGU.
- EE/RE Programs: Simulation dispatch models are unit specific and fairly detailed and can predict which units will reduce generation (and subsequently emissions) when new EE or RE is introduced into a system. Long term penetrations of EE or RE may avoid new capacity or transmission, or allow existing generation to retire economically, system changes that would not be captured by a simulation dispatch model.

Discussion

Simulation dispatch models generally do not have capacity expansion capabilities, and thus are restricted to a review of the operational margin. Many of the models used for simulation dispatch purposes require expertise to operate and interpret. Solution times can be long (though generally less than a day). Most such models are proprietary software with significant licensure fees, and detailed input data may be proprietary and/or considered CBI by utilities. Some parties have asserted that the output from these models using utility information is also CBI.

Multi-Sector Models

Typical uses

Multi-sector models are typically used for examine broad-scale carbon markets and similar federal initiatives, including clean energy standards, carbon taxes, and renewable energy portfolio standards. They are used to review trends in emissions, expected broad-scale resource consumption, and energy sector structural changes under changing regulatory and economic conditions, and often review changes over a period of decades.

Features

Multi-sector models cover a broad range of energy sectors beyond electricity to better reflect demands and technology choice at the end-use. Such models have limited spatial detail with broad scope, generally encompassing the entire country subdivided into somewhere from one to thirty regions. Such models have much more limited temporal resolution and dispatch treatment, and units are aggregated to a few broad technology types. A key strength of this type of model is the ability to provides multi-sectoral feedback between resource consumption and price (i.e. tracking national fuel supplies and adjusting price to account for demand).

The range of national capacity expansion, utility planning, and chronological dispatched models discussed above all focus on properly characterizing the electric sector in order to answer sector-specific

questions. Multi-sector models attempt to include many other energy-consuming sectors of the economy in order to understand interactions between these sectors. Their more aggregate representation of the electricity sector may limit their use to providing input data for more specific analysis and to better understand variations in load that may result from changes outside the electricity sector.

Application to emissions reduction approaches

This type of model is best used to quickly understand the national-scale impacts resulting from simplified representations of potential policies with particular attention to new capacity expansion, changes in fuel prices, and other resource concerns. A reasonable use of outputs from this type of model would be useful as input to a more detailed analysis. For example, recent results from EIA's Annual Energy Outlook, produced with the NEMS model, could be used to provide fuel prices and load forecasts into a planning model.

- EGU efficiency improvements and/or fuel switching: These models are not well suited to address heat rate improvements, unit specific fuel switching, or unit specific emissions limitations in anything but a very simplified representation.
- Individual EGU emissions restrictions: As EGU are generally aggregated in these models, multi-sector models are not equipped to review individual EGU emissions restrictions.
- Market-based emissions reductions: Multi-sector models are able to capture economic tradeoffs between aggregate EGU categories (e.g. fuel and unit types) and even non-electric sector emissions sources, and thus can either capture the effect of emissions prices, or calculate emissions prices based on a regional or national emissions cap, including multi-sector caps.
- EE/RE Programs: The effects of additional energy efficiency and/or renewable energy can be roughly captured at a regional level, although marginal changes due to demand reductions may be very blocky in nature, affecting large blocks of units.

Discussion

These models provide a valuable tool in understanding the national energy system impacts of changes to the electricity sector, and as such can provide inputs based on internally consistent scenarios of multi-sector energy use to more detailed analyses. Their limited spatial and temporal detail combined with limited treatment of EGU technology types significantly limits their use in addressing unit specific emissions reduction approaches. Due to their level of spatial aggregation, these models cannot be used to represent output or outcomes in individual state impacts without significant simplifying assumptions. Furthermore, they typically do not represent utility structures or energy markets that would affect resource decisions at the state level.