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RIPS Writeup

**Introduction**

Climate change threatens all parts of the U.S. electric power system, from electricity generation to distribution.22 Of particular interest here is thermal electricity generation, which generates roughly 90% of the electricity in the U.S.65 and could be affected by climate change through several pathways.66 Decreased water availability and increased water temperatures could reduce the capacity and efficiency of thermal units that use once-through cooling.24 Additionally, increased air temperature and humidity could reduce the capacity and efficiency of thermal units that use re-circulating cooling.66 Increased air temperature could also reduce the capacity and efficiency of gas turbines.26

Several studies have projected generator-specific reductions in generator capacity and efficiency under climate change.24,26,66,67 For instance, van Vliet et al. (2012)24 found summertime average useable capacities of 61 thermal plants in the eastern U.S. could decrease by up to 16% by 2060. Furthermore, significant (>50%) and extreme (>90%) capacity reductions could occur 1.4 and 2.8 times more frequently, respectively.24 However, none of these studies have translated their findings to the system level, a necessary step to understand how climate change may affect cost and reliability of the power system as a whole. For instance, large reductions in generators’ capacities in a region would pose a greater threat to system reliability if they were coincidental across the fleet than if they were not. Thus, this chapter will examine how generator-specific capacity and efficiency reductions under climate change could affect system-level cost and reliability. Given that planning could mitigate some or all of these capacity and efficiency reductions, this chapter will also assess the cost and reliability trade-offs in planning and operating the power system under generation constraints caused by climate change.

**Methods**

Figure 4 summarizes my proposed research approach.In order to capture the potential effects of climate change on the cost and reliability of the electric power system, I will use a unit commitment and economic dispatch (UCED) model. The UCED model will determine hourly generation for a given year by each generator that minimizes variable electricity generation costs under detailed system- and unit-level constraints. To assess trade-offs between planning and operations under climate change, I will couple the UCED model with a capacity expansion (CE) model, which will forecast generator additions to the fleet while minimizing capital and variable electricity generation costs under several system- and unit-level constraints. Appendix D provides the full formulations of the CE and UCED models, which I will build in the General Algebraic Modeling System.64

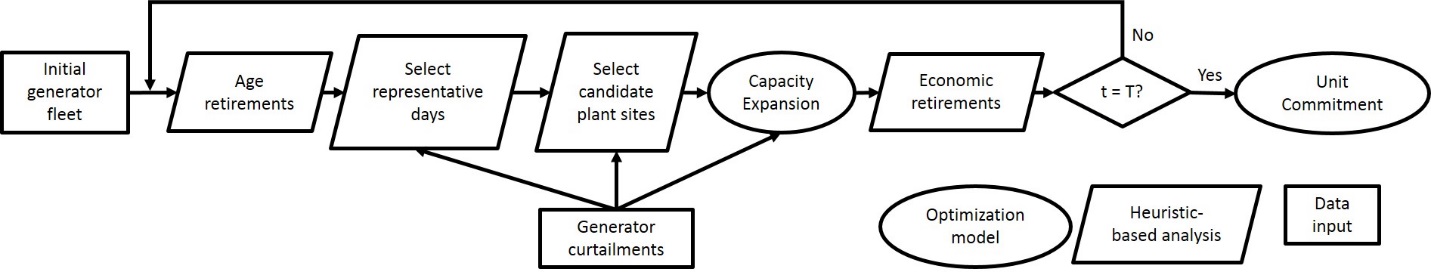


Figure 4: Proposed modeling approach to estimate the effect of climate change-induced efficiency and capacity reductions on power system planning and operations. “Unit Commitment” refers to a unit commitment and economic dispatch model.

The UCED and CE models used here will be modified versions of those used in Chapter 4. To account for the effects of climate change on future power system planning and operations, both models will include spatially- and temporally-differentiated capacity and efficiency reductions at new and existing units, as detailed below. While not the focus of this research, both models will also capture the effect of climate change on future electricity demand using regressions developed by a colleague. In addition, the UCED model used here will not include electricity storage; will procure bi-directional regulation reserves, as in most U.S. power systems, rather than separate up and down regulation reserves; and will not co-optimize for energy and reserves, as SERC does not run a co-optimized market. The CE model used here, to offset the computational complexity of including spatially- and temporally-differentiated capacity and efficiency reductions for existing and new units, will not include unit commitment constraints. Also, since the UCED model runs only after the final CE run in this chapter rather than after each CE run as in Chapter 4, I will only limit economic-based retirements to maintain the planning reserve margin after the final CE run here.

I will utilize this modeling framework in a study design that compares outcomes among four scenarios: accounting for climate change in planning (the CE model) and operations (the UCED model), planning but not operations, operations but not planning, and neither planning nor operations. This design allows me to assess, among other questions, how accounting versus not accounting for climate change during planning will affect system reliability during operations under climate change. To test the sensitivity of my results to the magnitude of effects from climate change, I will repeat this study design under different climate change trajectories.

In order to capture the effects of climate change, I will conduct my study in 2050 in the SERC Reliability Corporation footprint. As mentioned above, the CE and UCED models will include spatially- and temporally-differentiated capacity and efficiency reductions at new and existing units. To estimate these reductions, I will use two datasets that colleagues will develop: (1) regressions that relate the capacity and efficiency of different plant types to water availability and temperature and air temperature, pressure, and humidity; and (2) forecasts of spatially- and temporally-specific water and air data under different climate change trajectories. Since existing generators have known locations and plant types, I will estimate future capacity and efficiency reductions for each existing generator by applying the regression for each generator’s plant type to the future air and water data at each generator’s location. New generators, however, could be built in many locations, each of which would have different future air and water conditions and, consequently, different future capacity and efficiency reductions. By inputting to the CE model multiple possible build locations for each potential new generator and corresponding future capacity and efficiency reductions for each location, the CE model will optimize not only for the number and type of generators to build, but also where to build those generators.

Due to computational limitations, the CE model cannot consider every potential new generator site across the SERC region. Instead, from the full set of possible new generator sites, I will use heuristics to select a subset of potential new generator sites for each potential new generator and pass those subsets into the CE model. One such heuristic will select the site with the greatest total annual reduction in capacity for each potential new generator, calculated by summing daily capacity reductions over the period of analysis. Other illustrative heuristics will select the sites for each potential new generator with the least total annual reduction in capacity and the greatest capacity reduction coincident with peak net demand.

**MODEL FORMULATION**

This appendix provides the full formulation for the capacity expansion and unit commitment and economic dispatch models used in Chapter 5.

**D.1 CAPACITY EXPANSION FORMULATION**

In order to capture the effects of climate change on electric power system planning, this capacity expansion (CE) model accounts for spatially- and temporally-differentiated reductions in capacity and efficiency due to future air and water conditions under climate change. These reductions are included for potential new and existing generators. Based on these reductions, the CE model not only optimizes the type and number of generators to build, but also where to build those generators.

Table 3: Variables, parameters, and sets used in CE formulation.

|  |  |
| --- | --- |
| **Variable** | **Definition** |
| nc,l | Number of new generators built of plant type c |
| pc,l,t | Electricity generation by all new generators of plant type c at location l and time t (MWh) |
| pi,t | Electricity generation by each existing generator i at time t (MWh) |
|  |  |
| **Parameter** | **Definition** |
|  | Capacity factor of renewable plant type cr at time t |
| CRFc | Capital recovery factor of plant type c |
| Dc | Lifetime of plant type c (year) |
|  | Annual CO2 emission cap (ton) |
|  | CO2 emission rate of plant type c (ton/MMBtu) |
|  | CO2 emission rate for generator i (ton/MMBtu) |
| FCc | Fuel cost of plant type c ($/MMBtu) |
| FCi | Fuel cost for generator i ($/MMBtu) |
| FOMc | Annual fixed operation and maintenance costs of plant type c ($/MW) |
| HRc,l,t | Heat rate of plant type c at location l and time t (MMBtu/MWh) |
| HRi,t | Heat rate for generator i at time t (MMBtu/MWh) |
| M | Planning reserve margin as fraction of demand |
| OCc,t | Operating cost of plant type c at time t ($/MWh) |
| OCi,t | Operating cost of generator i at time t ($/MWh) |
| OCCc | Overnight capital cost of plant type c ($/MW) |
| PtD | Electricity demand at time t (MWh) |
| PcNAMEPLATE | Nameplate electricity generation capacity of plant type c (MWh) |
| Pc,l,tMAX | Maximum electricity generation capacity, accounting for deratings, of plant type c at location l at time t (MWh) |
| Pi,tMAX | Maximum electricity generation capacity of generator i at time t (MWh) |
| PtMAX,SOLAR | Maximum electricity generation by all existing solar generators at time t (MWh) |
| PtMAX,WIND | Maximum electricity generation by all existing wind generators at time t (MWh) |
| Q | Discount rate |
| VOMc | Variable operation and maintenance costs of plant type c ($/MWh) |
| VOMi | Variable operation and maintenance costs of generator i ($/MWh) |
| Wb | Scaling factor from number of representative hours included in CE model for time block b to number of total hours in time block b |
|  |  |
| **Set** | **Definition** |
| b | Time blocks (special blocks plus four seasons); bB |
| c | Potential new plant types; cC |
| cr | Potential new renewable plant types; subset of C |
| ct | Potential new thermal plant types; subset of C |
| i | Existing generators in fleet; iI |
| io | Existing solar generators in fleet; subset of I |
| iw | Existing wind generators in fleet; subset of I |
| l | Possible build locations for new generators; lL |
| t | Time indices in optimization horizon; tT |
| tb | Time indices in time block b; subset of T |
| tp | Time index of peak demand; subset of T |

**Objective Function**

The capacity expansion model minimizes total annual cost (*TC*), or the sum of fixed and variable electricity generation costs:

where *c*, *b*, *t*, and *i* index potential new plant types, time blocks, time, and existing generators, respectively; *n* = the number of new generators built; *PNAMEPLATE* = nameplate capacity [MW]; *FOM* = fixed operation and maintenance (O&M) costs [$/MW/year]; *OCC* = overnight capital cost [$/MW]; *CRF* = capital recovery factor; *W* = scaling factor from representative to total hours in time block; *p* = electricity generation [MWh]; and *OC* = operational cost [$/MWh]. Operating costs (*OC*) for new and existing generators equal:

where *VOM* = variable O&M costs [$/MWh], *HR* = heat rate [MMBtu/MWh], and *FC* = fuel cost [$/MMBtu]. *CRF* is defined as:

where *Q* = discount rate and *D* = plant lifetime.

**System Generation and Capacity Constraints**

Electricity generation must equal demand (*PD*[MWh]):

Additionally, sufficient capacity must exist to meet the planning reserve margin:

where *ct* and *cr* index new thermal and renewable plant types, respectively; *iw* and *io* index existing wind and solar generators, respectively; *M* = a fraction of peak demand; *PMAX* = maximum derated capacity [MW]; *CF* = capacity factor; *PMAX,SOLAR* = maximum aggregate generation by existing solar generators [MWh]; and *PMAX,WIND* = maximum aggregate generation by existing wind generators [MWh].

**Generation Constraints**

Electricity generation by existing generators must be less than their maximum derated capacity:

Generation by all existing wind and solar units must also be less than aggregate generation profiles:

Electricity generation by new thermal generators must be less than the maximum derated capacity times the number of new generators built:

Electricity generation by new renewable generators is constrained by capacity factors:

**Annual CO2 Emissions Limit**

Total CO2 emissions from new and existing generators cannot exceed the annual CO2 emission cap ( [ton]):

where = CO2 emission rate [ton/MMBtu].

**D.2 UNIT COMMITMENT AND ECONOMIC DISPATCH FORMULATION**

In order to capture the effect of climate change on power system operations, this unit commitment and economic dispatch (UCED) model accounts for spatially- and temporally-differentiated capacity and efficiency reductions due to future air and water conditions under climate change.

Table 4: Variables, parameters, and sets used in UCED formulation.

|  |  |
| --- | --- |
| **Variable** | **Definition** |
| gi,t | Electricity generation above minimum stable load by generator i at time t (MWh) |
| nset | Non-served energy at time t (MWh) |
| pi,t | Electricity generation by generator i at time t (MWh) |
| ri,t | Bi-directional regulation reserves provided by generator i at time t (MWh) |
| si,t | Spinning reserves provided by generator i at time t (MW) |
| ui,t | Binary variable indicating on/off state of generator i at time t, where 1 indicates on {0,1} |
| vi,t | Binary variable indicating generator i turns on at time t {0,1} |
| wi,t | Binary variable indicating generator i turns off at time t {0,1} |
|  |  |
| **Parameter** | **Definition** |
| CNSE | Cost of non-served energy ($/MWh) |
|  | CO2 emission rate for generator i (ton/MMBtu) |
|  | CO2 emission cost ($/ton) |
| FCi | Fuel cost for generator i ($/MMBtu) |
| Gi | Electricity generation above minimum load by generator i in last hour of prior optimization period (MWh) |
| HRi,t | Heat rate for generator i at time t (MMBtu/MWh) |
| K | Number of hours before which a generator can turn on in the current optimization horizon, based on when it shut off in the last optimization period and its MDT |
| MDTi | Minimum down time for generator i, which indicates the number of hours that must elapse before a generator can turn on once it shuts off (hours) |
| OCi,t | Operating cost of generator i at time t ($/MWh) |
| Pi | Electricity generation by generator i in the last period of the prior optimization horizon (MWh) |
| PtD | Electricity demand at time t (MWh) |
| Pi,tMAX | Maximum electricity generation capacity of generator i at time t (MWh) |
| PtMAX,SOLAR | Maximum electricity generation by all solar generators at time t (MWh) |
| PtMAX,WIND | Maximum electricity generation by all wind generators at time t (MWh) |
| PiMIN | Minimum stable load of generator i (MWh) |
| Rt | Required bi-directional regulation reserves at time t (MWh) |
| REi | Generator eligible (1) or not (0) to provide regulation reserves |
| RR | Scalar that translates hourly ramp limit to ramp limit over regulation reserve timeframe |
| RS | Scalar that translates hourly ramp limit to ramp limit over spinning reserve timeframe |
| RLi | Hourly ramp limit of generator i (MWh) |
| St | Required spinning reserves at time t (MWh) |
| SEi | Generator eligible (1) or not (0) to provide spinning reserves |
| SUi | Start-up cost for generator i ($) |
| Ui | On/off state of generator i in the last period of the prior optimization horizon {0,1} |
| VOMi | Variable operation and maintenance cost of generator i ($/MWh) |
|  |  |
| **Set** | **Definition** |
| i | Generators in fleet; iI |
| io | Solar generators in fleet; subset of I |
| iw | Wind generators in fleet; subset of I |
| t | Time indices in optimization horizon; tT |

**Objective Function**

The UCED model minimizes total operational costs (*TC*), or the sum of electricity generation, start-up, and non-served energy costs:

where *i* and *t* index generators and time, respectively; *p* = electricity generation [MWh]; *OC* = operating cost [$/MWh]; *v* = binary variable indicating the generator turns on; *SU* = start-up costs [$]; *nse* = non-served energy [MWh]; and *CNSE* = cost of non-served energy [$/MWh]. Operating costs (*OC*) equal:

where *HR* = heat rate [MMBtu/MWh]; *FC* = fuel cost [$/MMBtu]; = CO2 emission rate [ton/MMBtu]; = CO2 emission cost [$/ton]; and *VOM* = variable operation and maintenance [$/MWh].

**System-wide Electricity Demand and Reserve Requirement Constraints**

Electricity generation plus non-served energy must equal system-wide demand (*PD* [MWh]) in each time period:

Provided spinning (*s* [MWh]) and regulation (*r* [MWh]) reserves must equal or exceed required spinning (*S* [MWh]) and regulation (*R* [MWh]) reserves, respectively, in each time period:

Given the large penetration of wind power in our scenarios, we set hourly spinning reserve requirements equal to 3% of maximum daily load plus 5% of hourly wind generation.1,2 Regulation reserve requirements are the subject of ongoing research.

**Generator-Specific Generation and Reserve Constraints**

Electricity generation is represented by two variables, total generation (*p* [MWh]) and generation above minimum stable load (*g* [MWh]):3

where *PMIN* = minimum stable load [MWh] and *u* = binary variable indicating the generator is on (1) or off (0). Combined electricity generation by wind (*Iw*) and solar (*Io*) generators must be less than or equal to aggregate wind (*PMAX,WIND*[MWh]) and solar (*PMAX,SOLAR* [MWh]) generation profiles:

Electricity generation plus provided regulation and spinning reserves cannot exceed maximum capacity:

Note that wind and solar cannot provide reserves. Provided regulation reserves cannot exceed electricity generation above minimum stable load:

Generators must be online and eligible to provide regulation and spinning reserves, and cannot provide reserves in excess of their ramp limit over the reserve timeframe:

where *SE* = binary indicator of whether generator can provide spinning reserves; *RE* = binary indicator of whether generator can provide regulation reserves; *RL* = hourly ramp limit [MWh]; *RS* = scalar that translates hourly ramp limit to ramp limit over spinning reserve timeframe; and *RR* = scalar that translates hourly ramp limit to ramp limit over regulation reserve timeframe.

**Ramp Constraints**

Up and down ramp constraints limit changes in electricity generation above minimum stable load plus provided spinning and regulation reserves:

In the first time period, electricity generation above minimum stable load in the prior period equals generation above minimum stable load from the final hour of the last optimization horizon (*G* [MWh]):

In the first UC run, *Gi* equals zero for all generators.

**Unit Commitment Constraints**

Whether a generator is on or off depends on turn on and turn off decisions:

where *w* = binary variable indicating the generator turns off. In the first period, the commitment state in the prior period equals the commitment state in the last period of the prior UC run [*U*]:

In the first UC run, *Ui,t* is set to zero for all generators. Generators also cannot turn on until they reach their minimum down time (*MDT* [hours]):

To account for shut downs in the prior optimization window, carried hours of minimum down time from the prior UC run (*K*) are enforced:

**D.3 REFERENCES**

(1) Oates, D. L.; Jaramillo, P. Production cost and air emissions impacts of coal cycling in power systems with large-scale wind penetration. *Environ. Res. Lett.* **2013**, *8* (2), 24022.

(2) Lew, D. *Western Wind and Solar Integration Study*; 2010.

(3) Morales-españa, G.; Member, S.; Latorre, J. M.; Ramos, A. Tight and Compact MILP Formulation of Start-Up and Shut-Down Ramping in Unit Commitment. *IEEE Trans. Power Syst.* **2013**, *28* (2), 1288–1296.