Supplementary Information

Residential Solar PV Systems in the Carolinas: Opportunities and Outcomes

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This document contains twenty-four pages, ten tables, and seven figures.

1. The Duke Energy Carolina (DEC) and Duke Energy Progress (DEP) Balancing Authority Region

On July 2nd 2012, DEC and DEP merged, creating the largest regulated utility in the US encompassing most of North and South Carolina [1]. Today, DEC&DEP provides electric service to an approximately 3.93 million customers located over 58,000-square-miles of service areas in central and western North Carolina, northeastern and western South Carolina, a substantial portion of the coastal plain of North Carolina extending from the Piedmont to the Atlantic coast between the Pamlico River and the South Carolina border, and the lower Piedmont section of North Carolina. The company's power delivery system consists of approximately 169,348 miles of distribution lines and 19,344 miles of transmission lines directly connecting to all of the utilities that surround the DEC and DEP service areas. [2,3]. Figure S1 shows the territory now included in the DEC and DEP balancing authority regions [2]. Figure S2-a, and S2-b show the joint capacity mix and energy production by fuel type and technology for the DEC and PEC regions in 2015 [2]. The Figures show that nuclear generation accounts for 25% of the total generation capacity, and nuclear power is projected to provide 49% of the energy to the system [2].

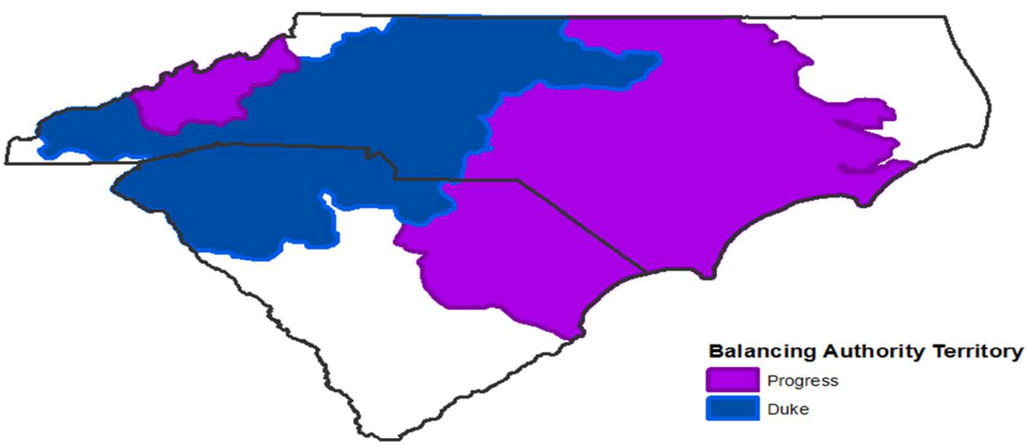
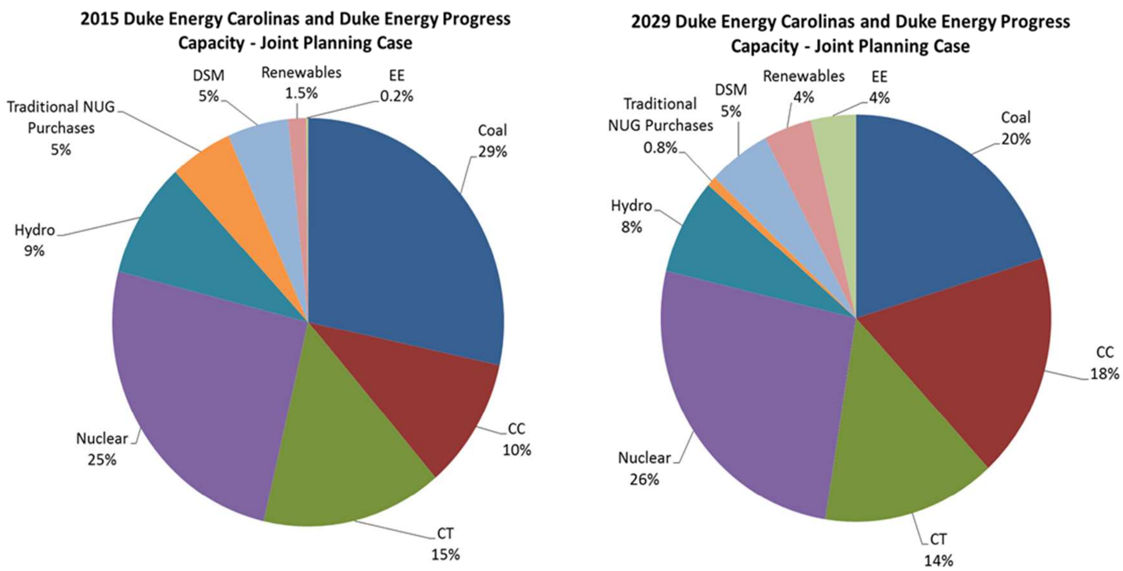
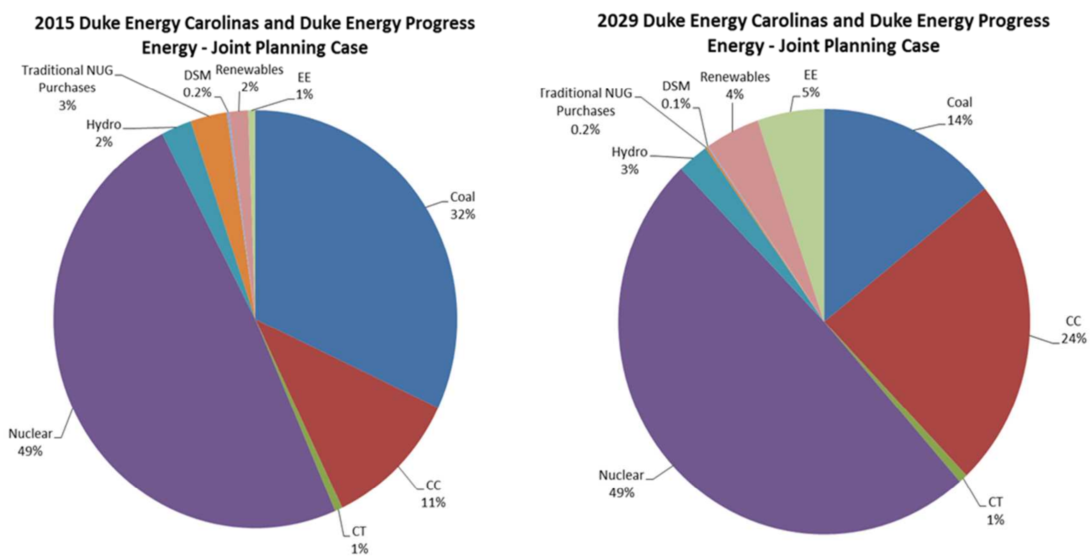


Figure S1. Duke Energy Carolinas and Duke Energy Progress Balancing Authority Regions. The Figure was generated by bringing the combined service map from [1] into ArcGIS and then tracing the regions to create a polygon region for each of the balancing authority areas.





S2-a

S2-b

Figure S2-a. DEC and DEP installed generation capacity by fuel type and technology in 2015 & 2029. Figure S2-b. Carolinas and Progress electricity generation by fuel type and technology in 2015 & 2029

2. Modeling Platform:

2.1. Power Generation Fleet

We look both at the present fleet and the most likely future fleet by developing two representative models for 2015 and 2025. The model of the current fleet includes all the coal, natural gas, hydro and nuclear power plants of DEC&DEP reported in [2,3], assuming the characteristics reported in the Emissions & Generation Resource Integrated Database (eGRID) [4]. The model for 2025 includes all of the new installations, and retirements described in the IRP for year 2025 [2,3].

2.2. Simulation of System Operations:

Four models are used in this analysis. The PV Production Model (PVM) simulates hourly data of PV generation for the year of study; the Solar Forecast Model (SFM) generates the day-ahead hourly forecasts of PV generation used by system operators to position generating units in a way that allows meeting systems' demand. Finally the Unit Commitment (UC) and Economic Dispatch (ED) models allow simulating operations of the power system. The inputs and outputs of these models and their usage for this analysis are summarized in Figure S3.

The Unit Commitment Model (UC) and real time economic dispatch (ED) models are optimization programs, commonly used by balancing authorities, to schedule and dispatch power generation in an electricity market [5]. The UC produces a schedule that commits the least cost generators to meet the system demand, or net-demand which is equal to the electrical demand of the system minus PV generation. The ED takes the commitment schedule output from the UC model and optimizes the system in real-time environment using actual load and PV generation. Distributed PV refers to PV systems installed on households in a net-metered configuration and thus entering the power system at the distribution level. This configuration essentially means that the grid "sees" the injection of PV power as a reduction in demand, and hence this study treats it as a component of net-demand (i.e. net-demand= demand- PV generation). Under this assumption PV solar generation cannot spilled/curtailed.

2.2.1. Unit Commitment Model (UC)

The UC is a mixed integer linear optimization program (MILP) which uses the system parameters (presented in Figure S3 and listed in detail in Table S1) to determine the hourly generation of each generator. A Bass Connections Project Team called Modeling Tools for Energy Systems Analysis (MOTESA) at Duke University originally built the UC model using IBM's ILOG CPLEX Optimization Studio. This model was modified in 2 specific ways for this analysis. First, constraints were added to the model to incorporate the unique properties of Hydro-Electric generators (described below). Next the simulation of the model was modified such that iterations were "nested" to incorporate and additional 8 hours to the day-ahead forecast. For example, a single iteration of the model optimizes over time intervals 1-32 but only records the output for intervals 1- 24. On the second iteration, the model optimizes over time intervals 25-56 and records the output for intervals 25-48. This modification was made to the model to avoid optimization result mismatches from one 24 hour period to the next due to limited foresight and is consistent with the "look-ahead" models that have been proposed and are under design of implementation in the U.S. Table S1 contains definitions for all the indices, parameters, and decision variables used in the UC.

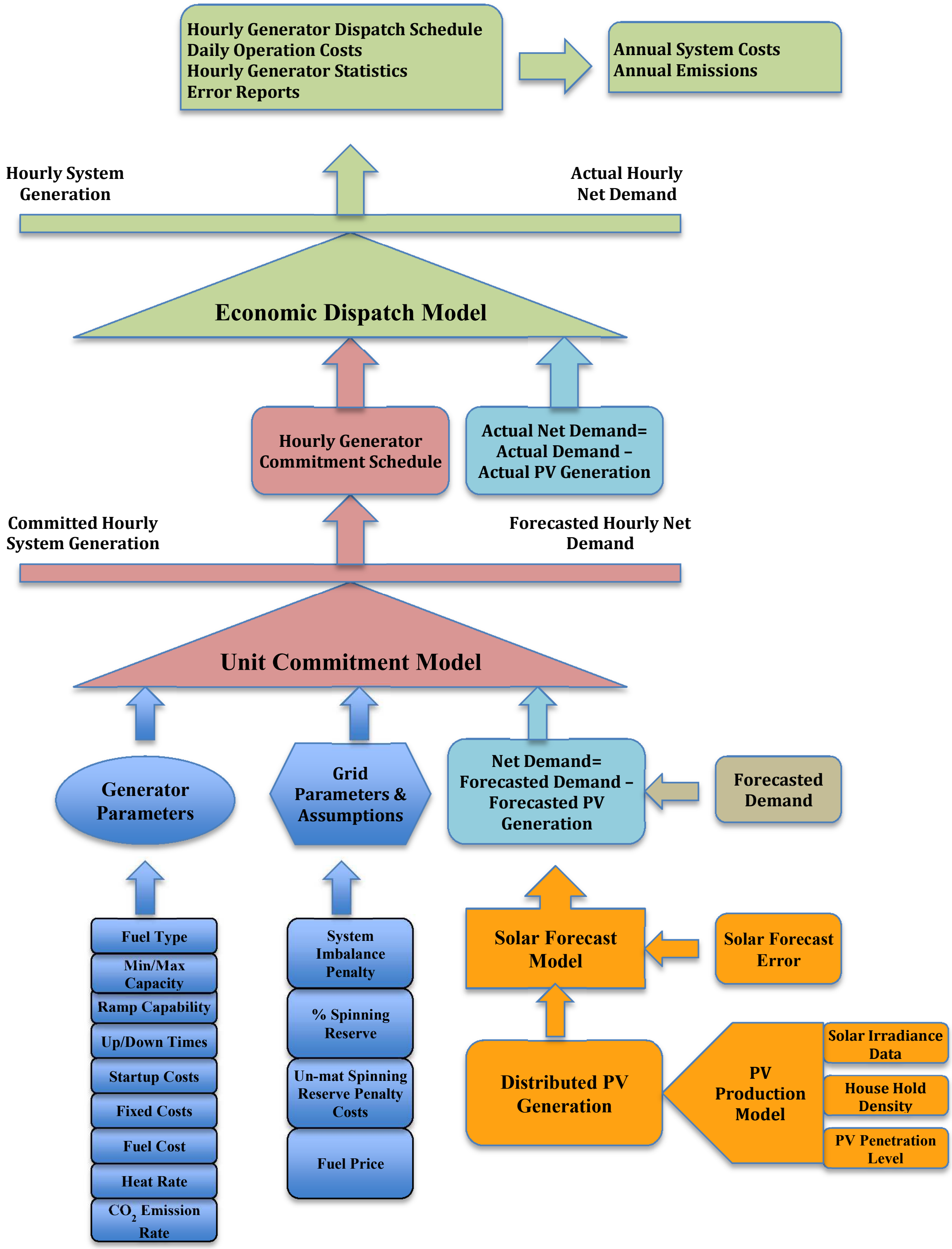


Figure S3. Modeling schematic. PV production model components are shown in orange, system parameters are shown in blue, the unit commitment model components are shown in red, and the economic dispatch model and the model outputs are shown in green.

Table S1. Unit Commitment Model Optimization indices, parameters, and decision variables.

Symbol	Description
Indices	
u	Dispatchable generator unit, $u \in 1..T$
t	Time interval hour, $t \in 0..T$
n	Time interval index used for minimum up and downtime requirements, $n \in t..T$
Parameters	
T	Number of intervals in time horizon
U	Number of dispatchable generators in the system
Demand	System demand in interval t [MW]
SpinReqt	Quantity of spinning reserves required in interval t [MW] equals 3%*load+5*PV Generation
UnderGenPen	System-wide under generation penalty [$/MWh]
SRScarcityPen	System-wide spinning reserve shortage penalty [$/MWh]
MCu:	Marginal Cost of operating dispatchable unit u [$/MWh]
SRCu	Cost of spinning reserves provided by unit u [$/MWh]
NLCu	No load cost (fixed operation cost) of operating unit u [$/interval]
StartCu	Cost of starting unit u [$]
Commitu,t	Commitment status of unit u in interval t (only a parameter in economic dispatch
MaxGenu	Maximum generation of unit u [MW]
MinGenu	Minimum generation of unit u [MW]
PosRampRateu	Maximum ramp-up rate of generator u [MW/minute]
NegRampRateu	Maximum ramp-down rate of generator u [MW/minute]
InitMinUpu	Number of intervals generator u must be up at the start of the optimization period
InitMinDownu	Number of intervals generator u must be down at the start of the optimization period due to its initial downtime [intervals]
MinUTu	Minimum uptime of unit u [intervals]
MinDTu	Minimum downtime of unit u [intervals]
InitMinUpu	Number of intervals generator u must be up at the start of the optimization period
Commit0u	Commitment status of unit u at end of previous time horizon [binary]
Gen0u	Generation level of unit u at end of previous time horizon [MW]
SR0u	Spinning reserve provided by unit u at end of previous time horizon [MW]
Decision Variables	
Genu,t:	Average power generation of unit u in interval t [MW]
SRu,t	Spinning reserve provided by unit u in interval t [MW]
Commitu,t:	Commitment status of unit u in interval t (only a decision variable in unit commitment models) [binary]
StartCostu,t	Startup cost of unit u in interval t [$]
OverGent	Surplus of generation over demand in interval t [MW]
UnderGent	Shortage of generation below demand in interval t [MW]
UnmetSRt	Shortage of spinning reserve below requirement in interval t [MW

Minimize the objective function z:

$$z = \sum_{t=1}^{T}\left(\sum_{u=1}^{U}(Gen_{u,t} \times MC_u + SR_{u,T} \times SRC_u + Commit_{u,t} \times NLC_u + StartCost_{u,t}) + OverGen_t \times OverGenPen + UnderGen_t \times UnderGenPen + UnmetSR_t \times SRScarcityPen\right)$$

Such that:

1. $Commit_{u,0} = Commit0_u \quad \forall u$
2. $Gen_{u,0} = Gen0_u \quad \forall u$
3. $SR_{u,0} = SR0_u \quad \forall u$
4. $\sum_{u=1}^{U} Gen_{u,t} + UnderGen_t - OverGen_t = FDemand_t \quad \forall\, t\, \in 1..T$
5. $\sum_{u=1}^{U} SR_{u,t} + UnmetSR_t \geq SpinReq_t \quad \forall\, t\, \in 1..T$
6. $StartCost_{u,t}\, \geq StartCost_{u,t} \times \left(Commit_{u,t} -\, Commit_{u,t-1}\,\right) \forall u, \forall\, t \in 1..T$
7. $Gen_{u,t} + SR_{u,t} \leq MaxGen_u \times Commit_{u,t} \quad \forall u, \forall t\, \in 1..T$
8. $Gen_{u,t} \geq MinGen_u \times Commit_{u,t} \quad \forall u, \forall t\, \in 1..T$
9. $Gen_{u,t} - Gen_{u,t-1}\, \leq PosRampRate_u \quad \forall u, \forall t\, \in 1..T$
10. $-Gen_{u,t} + Gen_{u,t-1}\, + SRes_{u,t-1} \leq NegRampRate_u \quad \forall u, \forall t\, \in 1..T$
11. $SRes_{u,t} \leq PosRampRate_u \quad \forall u, \forall t\, \in 1..T$
12. $\sum_{t=8}^{19}\left(Gen_{HYDRO,t} +\, SR_{HYDRO,t}\right) \leq MaxEnergy$
13. $\sum_{t=1}^{7}\left(Gen_{HYDRO,t} +\, SR_{HYDRO,t}\right) = 0$
14. $\sum_{t=20}^{32}\left(Gen_{HYDRO,t} +\, SR_{HYDRO,t}\right) = 0$
15. $\sum_{u=1}^{InitMinUp_u}\left(1 - Commit_{u,t}\right) = 0 \quad \forall\, u$
16. $\sum_{n=t}^{t+MinUT_u-1}\left(Commit_{u,n} \geq MinUT_u \times \left(Commit_{u,t} - Commit_{u,t-1}\right)\right) = 0 \quad \forall\, u, \forall t\, \in \{InitMinUp_u + 1, T - MinUT_u + 1\}$
17. $\sum_{n=t}^{T}\left(Commit_{u,n} - \left(Commit_{u,t} - Commit_{u,t-1}\right)\right) \geq 0 \quad \forall\, u, \forall t\, \in \{\, T - MinUT_u + 2, T\}$
18. $\sum_{u=1}^{InitMinDown_u}\left(Commit_{u,t}\right) = 0 \quad \forall\, u$
19. $\sum_{n=t}^{t+MinDT_u-1}\left((1 - Commit_{u,n}) \geq MinDT_u \times \left(Commit_{u,t-1} - Commit_{u,t}\right)\right) = 0 \quad \forall\, u, \forall t\, \in \{InitMinDown_u + 1, T - MinDT_u + 1\}$
20. $\sum_{n=t}^{T}\left((1 - Commit_{u,n}) - \left(Commit_{u,t-1} - Commit_{u,t}\right)\right) \geq 0 \quad \forall\, u, \forall t\, \in \{\, T - MinDT_u + 2, T\}$
21. $Gen_{u,t}, SR_{u,t}, StartCost_{u,t}, OverGen_t, UnderGen_t, UnmetSR_t \geq 0 \quad \forall u, t$

The objective function minimizes the total costs for running the generators (generation fuel costs, spinning reserve fuel costs, start-up costs, and fixed no load costs) as well as penalty costs (over-generation, under-generation, un-met spinning reserves) over a 32 hour time horizon subject to the constraints.

Constraints 1-3 are included to initialize the model and simulation. Constraint 4 ensures that generation always equals demand in each interval, and if it doesn't, it calculates the values of over or under generation to account for a penalty in the objective function. Constraint 5 ensures that spinning reserve requirements are met, and in case of a shortage, it calculates the amount of unmet reserves to account for a penalty in the objective function. Constraint 6 assigns a startup cost to the unit in the time interval in which the binary commitment variable switches from 0 to 1, indicating that the unit has turned on. Constraints 7 and 8 ensure that the maximum and minimum generation levels of committed generators are abided while constraints 9-11 ensure that the generators are operating within the limits of their positive and negative ramp rates. Constraints 12-14 are the additional constraints added specifically to address the energy limited nature of Hydro Electric plants. Constraint 12 limits the total energy that can be supplied by the hydro-electric generator during the hours of 8am to 7pm. This is needed because of the limited supply of water available to power the hydropower generators each day. The Max Energy constant was found by calculating the estimated daily hydro output, assuming that the annual percent of energy generation for the DEC and DEP region is around 2%. Constraints 13 and 14 restrict generation to only the peak hours of the day. Constraints 15-20 guarantee that generating units run in accordance with their minimum-up and minimum-down times. The initial minimum-up and -down time variables are calculated in a post-processing calculation at the end of each iteration and are carried over to the next time horizon during the simulation. Finally, constraint 21 makes all decision variables to be non-negative.

2.2.2. Economic Dispatch Model (ED)

The ED model is a linear program (LP) that uses the commitment schedule from UC and the actual load and PV generation to produce the optimal dispatch levels for each generator. The model's formulation is very similar to UC but it has two main differences. First, the unit commitment is an input to ED and no longer a decision variable; thus, "$Commit_{u,t}$" is omitted from the objective function and all related constraints are omitted too (i.e. equation 1, 15-20 of UC). Second, ED uses actual load and PV generation instead of the forecasted ones in UC and therefore term "$FDemand_t$" is replaced by "$ActualDemand_t$". Thus, the ED formulation can be written as follows:

Minimize the objective function z:

$$z = \sum_{t=1}^{T}\left(\sum_{u=1}^{U}(Gen_{u,t} \times MC_u + SR_{u,T} \times SRC_u) + OverGen_t \times OverGenPen + UnderGen_t \times UnderGenPen + UnmetSR_t \times SRScarcityPen\right)$$

Such that:

1. $Gen_{u,0} = Gen0_u \quad \forall u$
2. $SR_{u,0} = SR0_u \quad \forall u$
3. $\sum_{u=1}^{U} Gen_{u,t} + UnderGen_t - OverGen_t = ActualDemand_t \quad \forall\, t \in 1..T$
4. $\sum_{u=1}^{U} SR_{u,t} + UnmetSR_t \geq SpinReq_t \quad \forall\, t \in 1..T$
5. $Gen_{u,t} + SR_{u,t} \leq MaxGen_u \times Commit_{u,t} \quad \forall u, \forall t \in 1..T$
6. $Gen_{u,t} \geq MinGen_u \times Commit_{u,t} \quad \forall u, \forall t \in 1..T$
7. $Gen_{u,t} - Gen_{u,t-1} \leq PosRampRate_u \quad \forall u, \forall t \in 1..T$
8. $-Gen_{u,t} + Gen_{u,t-1} \leq NegRampRate_u \quad \forall u, \forall t \in 1..T$
9. $SRes_{u,t} \leq PosRampRate_u \quad \forall u, \forall t \in 1..T$
10. $\sum_{t=8}^{19}\left(Gen_{HYDRO,t} + SR_{HYDRO,t}\right) \leq MaxEnergy$
11. $\sum_{t=1}^{7}\left(Gen_{HYDRO,t} + SR_{HYDRO,t}\right) = 0$
12. $\sum_{t=20}^{32}\left(Gen_{HYDRO,t} + SR_{HYDRO,t}\right) = 0$
13. $Gen_{u,t}, SR_{u,t}, OverGen_t, UnderGen_t, UnmetSR_t \geq 0 \quad \forall u, t$

2.2.3. PV Production Model (PVM)

Solar irradiance, measured in Watts per square meter (W/m^2), is the main driver of PV production. Using GIS ArcMap, the 10km by 10km grid defined by the SUNY dataset was overlaid with a GIS shapefile containing household census data [6]. The number of homes contained within each of the SUNY gridded cells was aggregated. The resulting gridded data set showing the aggregated number of households in each cell is shown in Figure S4. The vast majority (71%) of US households in 2005 were classified as Single-Family Detached or Single-Family Attached [7]. For this study we assumed that 100% household units had the roof surface to accommodate a small PV system.

Using this new merged gridded data set, the PV production model determines the hourly output of each grid cell based on the number of households and the PV penetration level. The penetration level is defined as the percentage of total annual energy generated by the distributed PV systems relative to the total annual energy consumed within the system. To put this into perspective Table S2 describes the penetration level as a percentage of households with a 4kW PV system, which is made of 16, 3ft by 5ft PV modules rated at 250W each. All the cells in the area are then aggregated to find the total system-wide hourly PV production. The aggregate capacity of the PV systems can be varied to simulate different annual energy penetration levels.

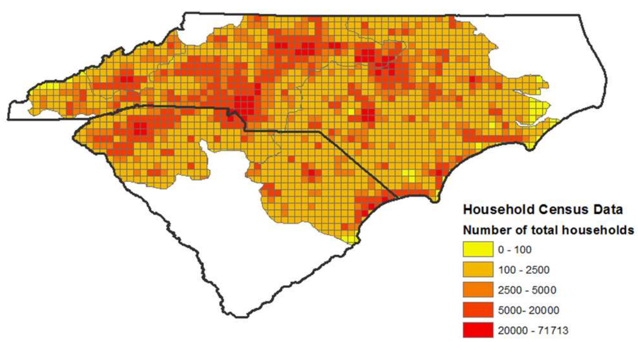


Figure S1. DEC and DEP regions showing household density contained within the 10 by 10km grids defined by the SUNY irradiance dataset. The figure was generated by using GIS ArcMap to overlay the 10km by 10km grid defined by the SUNY dataset with a GIS shapefile containing household census data [6]. The number of homes contained within each of the SUNY gridded cells was aggregated so the gridded data set would show the aggregated number of households in each cell.

Table S2. PV penetration levels in reference to residences with 4kW PV systems.

% Annual Energy Penetration in 2015	% Households with 4kW PV System	Total System MW of Name-Plate Rated PV Capacity
1.0%	6.6%	1,237
2.0%	13.2%	2,473
3.0%	19.8%	3,710
4.0%	26.4%	4,947
5.0%	33.0%	6,184
6.0%	39.6%	7,420
7.0%	46.2%	8,657
8.0%	52.8%	9,894
9.0%	59.4%	11,131
10.0%	66.0%	12,367
11.0%	72.6%	13,604
12.0%	79.2%	14,841
13.0%	85.8%	16,077
14.0%	92.4%	17,314

15.0%	98.9%	18,551

PV module nameplate capacity is rated at standard test conditions, 1000 W/m^2. Actual output is approximately proportional to the amount of irradiance hitting the tilted surface and affected by the module's temperature coefficient. The total system output is de-rated to 77%, based on the default value used in the PV Watts models, to account for loss factors such as soiling of the modules, wiring losses, inverter losses, module mismatch etc. [8]. Therefore PV generation, $GenPV$, measured in Watts can be estimated by equation S1,

$$GenPV = .77 \times pv_c \left(\frac{I_m}{1000\ {}^{W}/_{m^2}}\right) \times [1 - 0.005(T_c - 25°\mathrm{C})] \qquad \text{(S1)}$$

Where pv_c (W) is the nameplate PV capacity, I_m (W/m^2) is the direct irradiance hitting the tilted module surface, and T_c (°C) is the PV module's temperature which is estimated from ambient temperature T_q (°C), global solar irradiance (W/m^2), and wind speed (m/s) as follows [9]:

$$T_c = 0.943 \times T_a(°\mathrm{C}) + 0.028 \times GHI\ ({}^{W}/_{m^2}) - 1.528 \times WS({}^{m}/_{s}) + 4.3 \qquad \text{(S2)}$$

The following series of equations adapted from [10] are used to determine the direct irradiance hitting the tilted module surface based on the GHI and the position of the sun relative to the tilted module. This calculation was completed for each grid cell with a specific GHI level, longitude and latitude for each hour of the day throughout the year. Table S3 defines the variables and terms used in the following solar calculations.

Table S3. PV Production Model variables and definitions.

Symbol	Description	Definition	Units
GenPV	PV Generation	The amount of electricity produced from a PV system with rated capacity of pv_c at an irradiance level of I_m	W
I_m	Irradiance on tilted module surface	The portion of the GHI that is normal to the tilted module	W/m^2
pv_c	Name Plate PV Capacity [W]	The name plate capacity of the PV system at test conditions of 1000 W/m^2	W
GHI	Global Horizontal Irradiance	The total irradiance reaching a surface horizontal to the surface of the earth	W/m^2
θ_z	Solar Zenith Angle	The position of the sun's elevation relative to being directly overhead which is the compliment of the solar elevation angle	Degrees
Θ	Angle of Incidence	The angle between the sunlight rays incident to module and normal to the tilted module	Degrees
Β	Module Tilt Angle	The angle in which the module is tilted	Degrees
Γ	Module Azimuth Angle	The module orientation relative to 180 degree south.	Degrees
γ_s	Solar Azimuth Angle	The sun's orientation relative to 180 south	Degrees
Δ	Solar Declination Angle	The angle, which varies seasonally due to the earth's tilted axis, between the rays of the sun and the equatorial plane.	Degrees
L	Latitude		Degrees
DOY	Day of Year	The day of the year from 1 to 365	Days
HA	Hour Angle	Angular measurement of time	Degrees
X	Constant	A constant used in the equation of time	None
EoT	Equation of Time	A formula used to account for the earth's orbit and earth's tilt	None
Solar Time	Solar Time	The local time in terms of the position of the sun in terms of a 24 hour day (1440 mins) corrected for time zones	Hours

The direct irradiance normal to the tilted module surface can be estimated from the GHI as follows:

$$I_m = \frac{GHI}{cos\theta_z}\, cos\theta \qquad \text{(S3)}$$

where θ_z, the solar zenith angle, and θ, the angle of incidence, are defined by equation S4 and S5 as:

$$\theta = \ cos^{-1}\left(cos\theta_z cos\beta \ + sin\theta_z sin\beta cos(\gamma_s - \gamma)\right) \qquad \text{(S4)}$$

$$cos\theta_z = cosL\ cos\delta\ cosHA + sinL\ sin\delta \qquad \text{(S5)}$$

Where $L\ is\ the\ latitude\ of\ the\ gridded\ cell,$ β is the module tilt angle, γ is the module azimuth angle. We have chosen to set the module tilt angle β to 25 degrees to represent a module located on a tilted roof surface. The module azimuth angle γ is assumed to be 180 degrees or facing directly south which is the optimal orientation for solar exposure in the northern hemisphere. The solar azimuth angle γ_s , declination angle δ, and hour angle HA are calculated using equations S6-S11. The declination angle is determined by the Day of the year DOY.

$$\delta = 23.45°\ sin\left[\frac{DOY+284}{365} \times\ 360°\right] \qquad \text{(S6)}$$

The solar azimuth angle, γ_s , is calculated from the following equation:

$$cos\ \gamma_s\ = \frac{sin(90-\theta_z)sin\ L - sin\delta}{cos(90-\theta_z)cosL} \qquad \text{(S7)}$$

The hour angle is determined by equation S8, where solar time is a function of longitude, time zone, hour of the day, the Equation of Time (EoT), and a constant x determined by equations S9-S11.

$$HA = \frac{(Solar\ Time \times 60 - 720)}{4} \qquad \text{(S8)}$$

$$Solar\ Time = hour\ of\ day + \left(\frac{4\ \times (75 - Longitude) + EoT}{60}\right) \qquad \text{(S9)}$$

$$EoT = 9.87\ sin(2x) - 7.53\ cos(x) - 1.5\ sin(x) \qquad \text{(S10)}$$

$$x = 360\,\frac{(DOY-81)}{365} \qquad \text{(S11)}$$

The PV production is thus calculated for each gridded cell based on its unique hourly GHI, longitude and latitude. All the cells are added together to get the total hourly PV generation. This hourly PV generation is then subtracted from the demand to create the net-demand for the system.

2.2.4. Validation of PVM model using NREL's PVWatts System Model

We validated the PVM model by comparing its simulated annual PV generation with the output of NREL's PVWatts Model for four major cities within DEC and PEC assuming hourly solar resources and temperature data of NREL's typical meteorological year. The data of the typical meteorological year was generated by NREL based on satellite-derived data collected over the period 1998-2005. The design capacity of the rooftop PV panels is assumed to be 4 KW_{DC} at a 25-degree tilt and 180-degree orientation.

The annual solar generation comparisons shown in Table S4 indicate the outputs of the two models are very close. The highest discrepancy in PV generation for a year is observed for Raleigh, NC and it is less than 0.35%.

Table S4. PV Output Comaprison of NREL PVWatts Model and Constructed PVM Model

Model / Location	GHI (KWh/yr)	Avg. Temp. (°C)	NREL PV Watts Output (KWh/yr)	PVM Output (KWh/yr)	Difference %
Raleigh, NC	1,622.0	15.83	5,143.2	5,125.3	0.35
Charlotte, NC	1,661.5	16.55	5,257.2	5,249.2	0.15
Columbia, SC	1,693.0	17.71	5,271.3	5,276.6	-0.10
Greenville, SC	1,660.8	16.10	5,239.6	5249.3	-0.19

2.2.5. Solar Forecast Model (SFM)

In order to generate the day-ahead forecasts used as inputs to the day-ahead unit commitment model, we simulate first the day-ahead solar forecast error and add it to the PV Production simulated with the PVM. The day-ahead solar forecast error is generated with a method developed by the Pacific Northwest National Laboratory (PNNL) [11] and commonly used by other research groups and labs [12,13].

This method is based on observations that show that the accuracy of a day-ahead forecast depends on the clearness index (CI), which can be defined as the ratio of the hourly "actual" solar irradiance to the hourly "ideal" or "maximum" solar irradiance that would correspond to a clear sky. Table S5 shows the parameters used in this model.

Table S5. Solar PV forecast error model's parameters

Symbol	Description
CI (t)	Ratio of the hourly "actual" solar irradiance to the hourly "maximum" solar irradiance in interval t. Varies between 0 and 1
$P_{actual}(t)$	Actual power generation from solar PV in interval t [MW]
$P_{max}(t)$	Maximum possible power generation from solar PV in interval t [MW]
f(t)	Forecasted power generation in interval t [MW]
ε(t)	Forecast error in interval t [MW]
$\varepsilon_{min}(t)$	Minimum forecast error in interval t [MW]
$\varepsilon_{max}(t)$	Maximum forecast error in interval t [MW]
σ(t)	Standard deviation corresponding to CI in interval t

The forecast error for an hour t is defined as the difference between the actual generation $P_{actual}(t)$, and the forecast for that hour f(t):

$$\varepsilon(t) = P_{actual}(t) - f(t) \tag{S12}$$

The forecast f(t) is assumed to be bounded by the minimum possible generation $P_{min}(t)$ (assumed to be zero), and the maximum generation $P_{max}(t)$ which corresponds to the generation that could be obtained at any time t, when the sky is clear (i.e. CI = 1) as shown in S13:

$$P_{min}(t) \leq f(t) \leq P_{max}(t) \tag{S13}$$

Replacing S12 into S13 gives:

$P_{min}(t) \leq P_{actual}(t)\text{-}\varepsilon(t) \leq P_{max}(t)$ (S14)

Solving S14 for the minimum bounds for ε(t) gives:

$P_{actual}(t)\text{-}P_{max}(t) \leq \varepsilon(t) \leq \varepsilon_{max}(t)= P_{actual}(t)\text{-} P_{min}(t)$ (S15a)

As $P_{min}(t)$is assumed to be zero, S15a becomes:

$P_{actual}(t)\text{-}P_{max}(t) \leq \varepsilon(t) \leq P_{actual}(t)$ (S15b)

So the bounds of ε(t)are given by:

$\varepsilon_{min}(t)= P_{actual}(t)\text{-}P_{max}(t)$ (S15c)
$\varepsilon_{max}(t)= P_{actual}(t)$ (S15d)

During the night, ε(t) equals zero because there is no solar irradiance. During the day, ε(t) varies within a wide range depending on the time of the day and weather conditions. The PNNL study shows that the standard distribution of ε(t) can be described as a function of the CI.

In order to estimate the day-ahead forecast error for each hour of the year simulated, we took a year-long historical hourly time series (i.e. t=1,2,…8760) of solar production. We assumed the maximum possible generation varies by month so for each of the 12 months m and each of the 24 hours of the day h, we found a value = $P^{m,h}{}_{max}$. To find these values, for each month we followed steps 1-5:

1. For each of the 24 hours h, we found the maximum observed value for that hour within the month:
   $AbsoluteMaxP^{m,h} = max\{\ P^{m,d1,h},\ P^{m,d3,h},...\ P^{m,dD,h}\}$ where D is the number of days in month m

2. For each day we counted how many hours of the day had a generation below the maximum observed generation for that hour in the month:
   $NumHoursBelowMax^{d} = \sum_{i=1}^{24} I_i$ Where I is an indicator variable taking the value of 1 if the observation for that day for hour h is lower than $AbsoluteMaxP^{m,h}$and zero otherwise.

3. We chose the day d of the month with the minimum value for $NumHoursBelowMax^{d}$. In case of a tie between two or more days then we chose the day for which cumulative production (i.e. the sum of production for hours 1-24) was maximum. We called this day "The Clear Sky Day in Month m"

We assumed that the generation observed at each hour in The Clear Sky Day for Month m was the maximum generation for that hour in that month $P^{m,h}{}_{max}$. See table S6 below for the maximum solar irradiance values found in each month.

4. For each observation t we set $P_{max}(t)$ equal to the maximum observed during the same month for the same hour:
   $P_{max}(t) = P^{m,h}{}_{max}(t)$ where m and h are the month and hour corresponding to observation t
   Once we had the 12 sets (i.e. one for each month) of maximum hourly generation we:

5. We calculated the hourly average clearness for each observation in the time series dataset index as :

$$CI_t = \begin{Bmatrix} \frac{P_{actual,t}}{P\ max}\ if\ 0 \leq P_{actual,t} \leq Pmax \\ \\ 1\ otherwise \end{Bmatrix}, \quad \text{(S16)}$$

(Since it is possible that $P_{actual,t}$ may be > $Pmax$)

Table S6. Monthly maximum solar irradiance values (W/m^2)

Time	Jan	Feb	March	April	May	June	July	August	Sep.	Oct.	Nov.	Dec.
1:00	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2:00	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3:00	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4:00	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5:00	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6:00	0.0	0.0	0.0	0.3	2.7	8.7	2.0	1.1	0.0	0.0	0.0	0.0
7:00	0.0	0.0	3.9	132.1	184.8	183.4	126.5	115.3	51.9	2.6	0.0	0.0
8:00	4.1	75.2	223.4	333.0	383.6	380.8	304.5	283.9	239.8	162.3	101.2	2.8
9:00	154.3	283.8	432.3	537.8	578.9	559.7	496.5	474.1	432.6	351.6	282.7	196.3
10:00	283.2	460.5	621.8	720.2	747.9	727.3	660.6	649.1	615.2	519.0	448.1	348.7
11:00	406.1	607.4	769.6	855.5	882.6	870.0	804.7	776.0	753.9	645.6	574.1	466.4
12:00	505.0	707.5	862.9	947.6	961.0	943.3	899.1	853.6	841.7	713.8	640.3	533.6
13:00	538.2	742.7	897.7	975.1	972.0	919.9	929.6	894.8	866.4	719.2	644.3	543.2
14:00	514.6	718.7	853.6	918.3	916.6	884.8	888.4	860.8	813.9	663.0	584.5	490.4
15:00	442.3	626.5	736.3	802.9	817.6	798.9	784.3	773.4	706.7	544.1	466.0	381.4
16:00	321.5	474.9	575.5	638.0	673.9	652.0	633.9	632.3	555.6	375.9	302.9	231.2
17:00	170.8	278.4	387.7	434.7	492.4	483.9	458.2	455.4	367.8	184.1	116.0	63.7
18:00	19.1	86.2	174.5	218.2	290.5	293.5	258.7	262.1	170.1	15.9	0.5	0.0
19:00	0.0	0.0	9.3	41.4	98.6	116.7	88.5	85.4	12.5	0.0	0.0	0.0
20:00	0.0	0.0	0.0	0.0	0.5	3.6	0.7	0.1	0.0	0.0	0.0	0.0
21:00	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
22:00	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23:00	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
24:00	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

6. We assumed the forecast error for any particular hour t follows a truncated normal distribution with the bounds found in S15, with mean zero and standard deviation σ_t determined by the CI according to table S7 below. In this way the standard deviation for the forecast error of an hour t is a function of the CI for that hour (i.e. hours with a CI of less than 0.2 were assigned a standard deviation of 10% and so on).

Table S7. Standard deviation values corresponding to CI intervals

Clearness Index (CI)	Standard Deviation (σ)
0 < CI < 0.2	10%
0.2 < CI < 0.5	30%
0.5 < CI < 0.8	25%
0.8 < CI < 1.0	10%

7. The forecast error for the hour is generated as a random variable following a truncated normal distribution (TND) with mean zero and the standard deviation $\sigma_t = f(CIt)$ found in step 7. The limits

to truncate the normal distribution are given by the minimum (assumed to be zero) and the maximum value found in steps 1-5:

$\varepsilon_{min}(t) \sim TND\ (L,S,0,\sigma_t)$

8. The forecast PV generation for each hour t is generated as:

$f(t) = P_{actual}(t)-\varepsilon_{min}(t)\ (t)$

2.2.6. Generator operational parameters

The parameters used to describe the technical characteristics of the generation fleet considered in the UC/ED were obtained from multiple sources as summarized in Table S8.

Minimum run time, measured in hours, is defined by the minimum time that once started up, the generator must run before shutting down. Minimum down time is the amount of time that once turned off, the generator must remain off before starting back up. A FERC study shows estimates of minimum run/down times ranging over 24-4/12-5 hours for coal plants, 5-3/4-2 for combined cycle plants and 5-2/4-2 for gas combustion plants [14]. In this paper, the minimum run/down times for coal, natural gas combined cycle, and gas turbines respectively are set to 15/9, 4/3, and 2/2 which are the values for the majority of the generators considered in the FERC study. Nuclear plants are assumed to be running constantly and hydro-electric plants have a min run time of 1 hour and min down time of 1 hour which allows them to turn on and off as needed with no restraints [12](although there are other constraints limiting hydropower generation, as described in section 2.2.1).

Maximum ramp rates for coal-fired generators are assumed to be 85% of their rated maximum capacity per hour. This assumption is in agreement with the findings of an NREL study [15] and an Electric Power Research Institute (EPRI) study [16], based on information on the minimum operating load and cycling capabilities of 1,387 individual fossil units of different sizes, design and fuel. Study [16] found the ramping capability (MW/hour) for coal generators to be 80-90% of their rated maximum capacity. Natural Gas generator ramping capability was estimated in the range of 15-25 MW/Min which translates to 900-1500 MW/hour. Since all our generators are less than 900 MW, all natural gas generators have a ramping rate equal to their rated maximum capacity. All of these assumptions about plants ramping capabilities are also in agreement with the NREL study as seen in table S8.

The minimum economic capacity of a generator is the lowest generation level at which the generator can operate economically and is taken as an operating constraint in the UC/ED. We assume that minimum operating capacity for coal-fired power plants varies as a power of the nameplate capacity and hence estimate the parameters of a power law function from the FERC dataset [14] as shown in Figure S5. This trend line is used to calculate the minimum economic capacity of each generator based on its maximum capacity.

For gas-fired power plants the minimum operating capacity is set to be 25% of the design capacity consistent with the majority of the gas plants surveyed in the EPRI study [16].

To be consistent with the DEC and DEP generation expansion plan, it is assumed that nuclear generators and hydro-electric generators provide 49% and 2%, respectively, of total system energy generation. [2,3]

Table S8. Summary of all assumed operational parameters based on [4,14-16].

Parameters	Unit	Coal	NGCC	NGTT
Max capacity	MW	Name plate capacity		
Min economic generation	MW	Shown in figure S-5	25% of nameplate capacity	25% of nameplate capacity
Start-up heat rate	MMBtu/MW	16.5	2.0	3.5
Average heat rate	MMBtu/MW	Based on eGrid dataset		
Minimum down time	Hours	9	3	2
Minimum up time	Hours	15	4	2
Ramp rate	MW/Hr	85% of Max Cap	100% of Max Cap	100% of Max Cap
CO_2 emissions rate	Lb/MMBtu	Based on eGrid dataset		

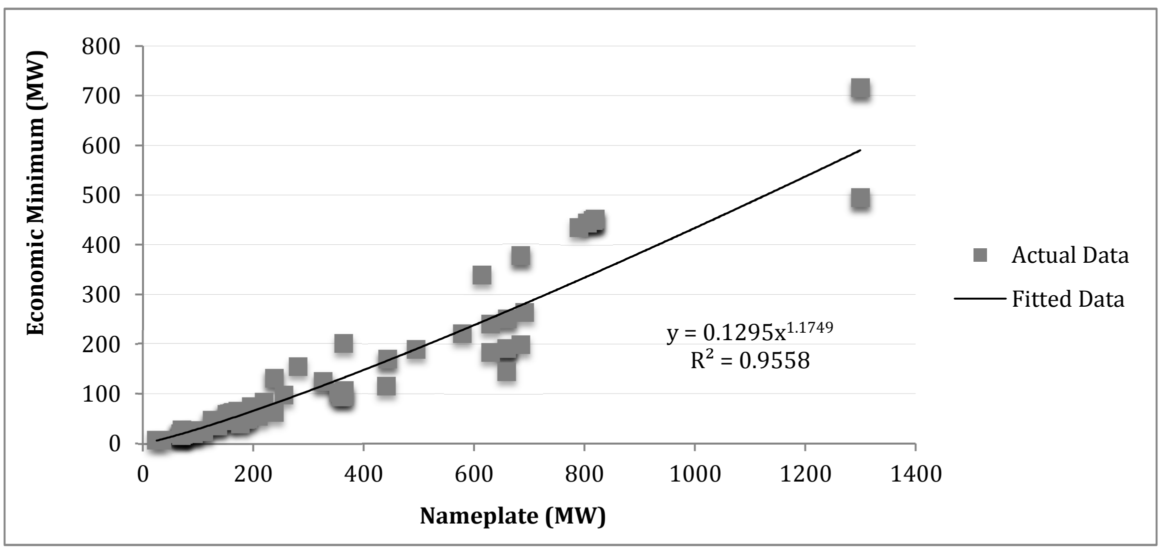


Figure S5. Trend line of the minimum economic capacity of coal-fired power plants

2.2.7. Generators cost parameters

The cost of producing electricity in our model includes fixed costs, start-up costs, and marginal fuel costs for generation and providing spinning reserves. Fixed costs represent the cost to maintain and operate the generators even when they are not producing electricity. This data was obtained from an E3 report [17] which provides an estimate of fixed costs by $/kW/year by generator type, also consistent with an NREL report [15]. Each time a generator is scheduled to start-up a cost is incurred due to the fuel and electricity needed to crank the generator motor. Start-up costs were obtained from a report that has been produced by Intertek APTECH for the National Renewable Energy Laboratory (NREL) and Western Electricity Coordinating Council (WECC) depending on prime mover, fuel type, and capacity [18]. These start-up costs are also consistent with those reported in the IEEE Power and Energy Magazine [19]. The start-up heat rates (i.e. the amount of fuel consumed during start-up) are 16.5, 2, and 3.5 MMBtu/MW for coal, gas combined cycle and gas combustion turbine, respectively [19]. Marginal fuel costs for coal and natural gas generators, when operating between the minimum and maximum power output, were determined by the generator average heat rate and the fuel source prices.

The dispatch of generators is highly affected by the price ratio of natural gas to coal. As described in the scenario analysis section of this paper, the 2015 coal and gas prices according to 2015 AEO are used to assess the system under 2015 conditions while three fuel prices for coal and natural gases are considered in the study to represent extreme and average price scenarios under 2025 conditions. For the Nuclear Power Plant (NPP), a production cost of \$24.4/MWh is assumed for 2015 [20] while \$28.6/MWh is assumed for year 2025 (assuming a 1.6% annual increase in fuel prices as observed in years 2010-2015). The marginal fuel costs for hydro-electric generators are assumed to be \$0.

2.3. Nuclear Power Plants Ramping Capability Assumptions

Nuclear Power Plants are usually operated at a constant electrical output to meet base electrical load (i.e., not as flexible-ramping generators). This is because of their low marginal costs and the corresponding fuel savings that can be achieved from displacing generation form coal or gas. However, in power systems where NPPs account for a significant share of generation, like in France where 75% of total electricity comes from nuclear powers, NPPs are required to operate as load-following generators using their Automatic Governor Controls (AGC) to increase or decrease power output as needed to meet the time-varying electrical demand and provide frequency control [21].

In systems with large penetration of intermittent sources of energy like wind and solar, operating NPPs as flexible generators may become a necessity. This is the case of the DEC and PEC system where net-demand would dip below the power production from base-load nuclear plants during the spring as energy demand would be low and PV production would be slightly high.

Although the experience of France suggests operating NPPs as flexible generators is entirely feasible from the technical and economic points of view, studies exploring this possibility for U.S. plants and specifically for the plants in the DEC DEP region do not exist. However, the survey conducted in the early 1980s by EPRI [16] revealed that 6 out of 54 nuclear units in the US reported load turndown operations.
Therefore, both flexible and inflexible modes of operation are considered in this study to find out the technical limits of PV penetration levels in DEC and PEC system under both operating conditions. Under the inflexible operation mode, NPPs are assumed to provide constant power at 87% capacity factor, consistent with actual values reported in eGrid data [4]. For the flexible operation mode, it is assumed that NPPs can operate in load following mode and ramp up and down between 70 and 100% of their rated capacity; however, they maintain the same annual share of nuclear power in the DEC & DEP electricity mix.

3. Start-up CO_2 Emissions & Abatement Costs Calculation

3.1 Startup CO_2 Emissions

The intermittency of PV generation implies that at increased levels of penetration the system will have more ramping, shut-downs and start-ups from conventional generators. Because start-ups require burning large amounts of fuel, they increase the system's CO_2 emissions and somewhat offset the benefits from PV. Figure S6 depicts the total annual CO_2 emissions from all plants' start-ups and also the number of start-ups for large coal plants (>500 MW). As PV penetration level increases, the numbers of start-ups of large coal plants increase and thus the total start-up related CO_2 emissions rise.

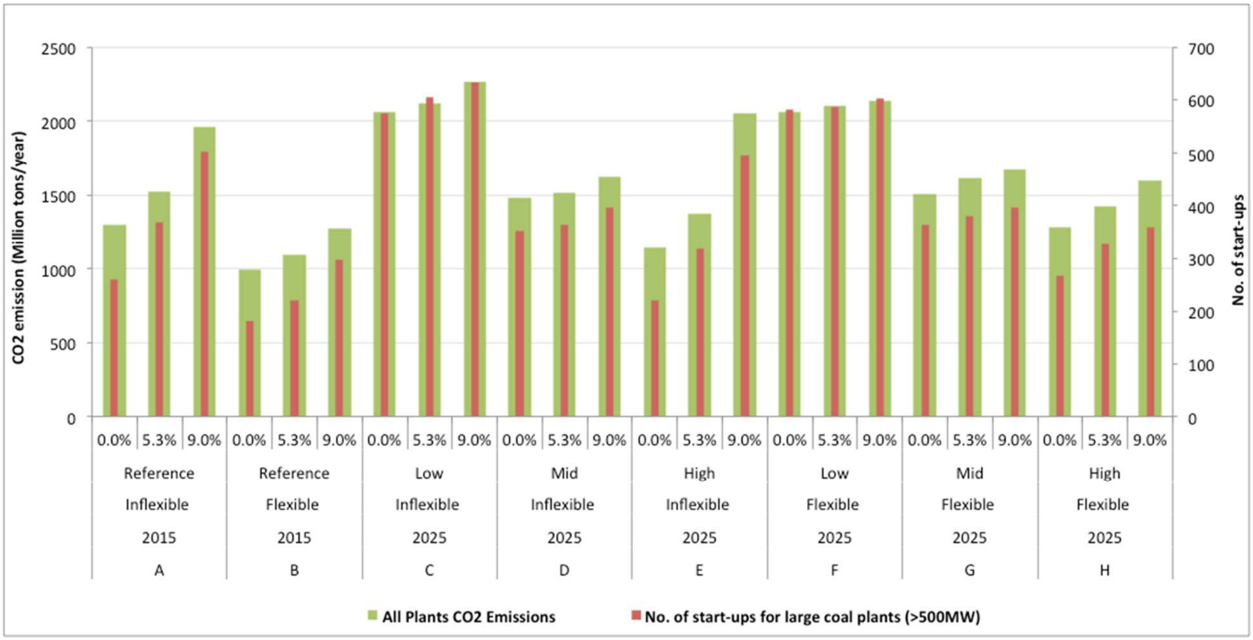


Figure S6. Total annual start-up CO_2 emissions and total number of start-ups for large coal plants for all scenarios

3.2 Calculation of CO_2 Abatement Costs

In all cases, CO_2 abatement cost is calculated as the change in system's costs divided by the changes in CO_2 emissions, where system's costs are equal to the costs of achieving the assumed PV installed capacity plus the fuel costs incurred to meet demand. The abatement cost formula can be written as follows:

$$CoA = \frac{SC_{PV} - SC_{base}}{CO_{2\,base} - CO_{2\,PV}} \qquad \text{(S17)}$$

where

SC_{PV} and SC_{base} are total system costs with and without PV system generation, respectively, and $CO_{2\,PV}$ and $CO_{2\,base}$ represent the total system's CO_2 emissions with and without PV system generation, respectively.

Figure S7 reports the cost of abatement of CO_2 emission under all considered PV penetration levels and fuel prices scenarios. Table S9 shows the CO_2 emissions for all scenarios presented in this paper.

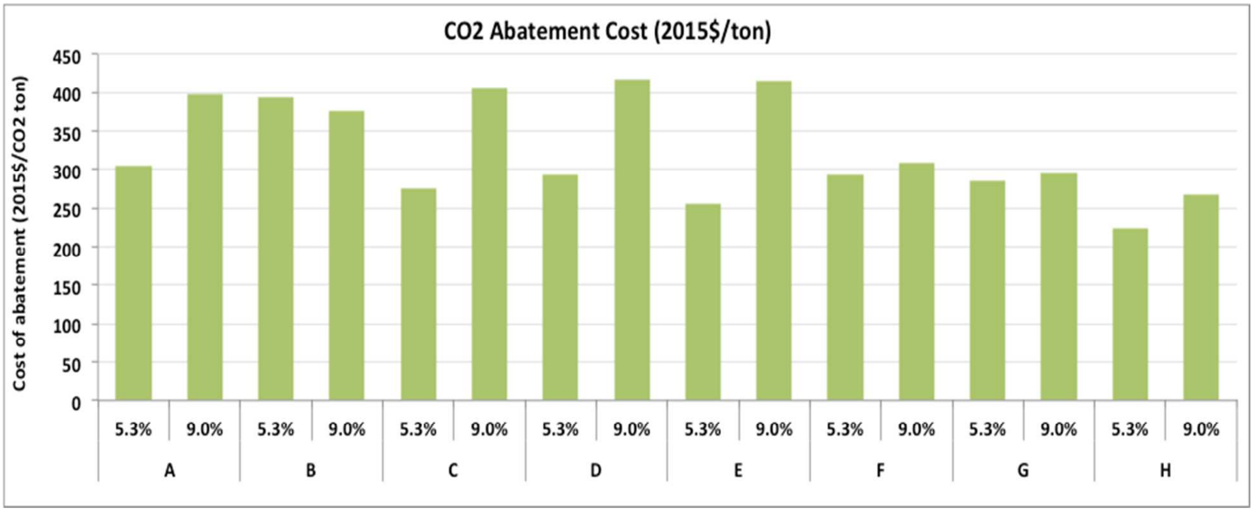


Figure S7. Cost of CO_2 abatement (CoA) under all scenarios

Table S9. CO_2 emissions under all scenarios

Scenario	Year	NPP Generation	Natural Gas Price	PV%	CO_2 emissions (ton/MWh)
A	2015	Inflexible	Reference	0.0%	0.47
				5.3%	0.41
				9.0%	0.37
B		Flexible	Reference	0.0%	0.46
				5.3%	0.41
				9.0%	0.38
C	2025	Inflexible	Low	0.0%	0.39
				5.3%	0.34
				9.0%	0.32
D		Inflexible	Mid	0.0%	0.42
				5.3%	0.37
				9.0%	0.35
E		Inflexible	High	0.0%	0.47
				5.3%	0.42
				9.0%	0.39
F		Flexible	Low	0.0%	0.40
				5.3%	0.35
				9.0%	0.33
G		Flexible	Mid	0.0%	0.43
				5.3%	0.38
				9.0%	0.35
H		Flexible	High	0.0%	0.48
				5.3%	0.42
				9.0%	0.40

3.3 Calculation of the Levelized Capital Cost of PV

The Levelized Cost of Electricity (LCOE) of PV-generated electricity in ¢/kWh is estimated using eq. (S18):

$$LCOE = \frac{CC_{annual} + O\&M_{annual}}{E_{annual}} \quad \text{(S18)}$$

where $O\&M_{annual}$ is the annual operational & maintenance cost –both fixed and variable costs, E_{annual} is is the annual electricity generation (MWh), and CC_{annual} is the total levelized capital cost ($).

CC_{annual} is obtained by multiplying the Capital Cost by the Fixed Charge Factor (FCF), which is used to annualize capital costs over the plant life. The FCF depends on the present value of the future yearly carrying charges equal to the sum of the book depreciation, deferred taxes, return on debt, return on equity, income taxes paid, and the ad valorem tax. It is given by equation S19 [22]:

$$FCF = \frac{\sum_{m=1}^{20} CC_m PV_m}{A_n} \quad \text{(S19)}$$

where CC_m is year by year carrying charges, PV_m is the present value factor of a future expense in a given year, and A_n is the annuity factor. The CC_m can be calculated as follows:

$$CC_m = D_b + t_{d,m} + RD_m + RE_m + t_{p,m} + a \;\; for\; m = 1, 2, \ldots, n \quad \text{(S20)}$$

where D_b is the book depreciation, $t_{d,m}$ is the tax preferences, $RD_m$is the return on debt in year m, RE_m is the return on equity in year m, $t_{p,m}$ is the taxes paid per year, a is the ad valorem tax r_{debt} and n is the plant life time. For the PV system considered in this paper, a Fixed Charge Factor (FCF) of 0.10 (excluding any Investment Tax Credits) is assumed, which corresponds to 50% equity and 50% debt with 6% interest rate, Federal tax rate 28%, State tax rate of 7 %, property tax rate of 0.9075% and an economic lifetime of 25 years. These assumptions are consistent with those made by the NC Sustainable Energy Association [23].

3.4 Fuel Prices Conversion Calculation

The fuel prices of coal and gas for the 2015 scenarios are reported as nominal prices in the AEO2015 report [24] and thus do not need to be converted to 2015$. The fuel prices in the 2025 base case are presented in 2013$ as well as in nominal values. So, coal and gas prices in 2013$ were converted to 2015$ by multiplying them by a conversion factor of 1.035 and 1.036, respectively. These conversion factors were calculated by dividing the nominal prices of coal and gas in 2015 by their corresponding 2013$ values.
Similarly, the coal and gas prices for the 2025 high and low cases were converted from 2012$ as reported in AEO2014 [25] to 2015$ values using conversion factors of 1.050 and 1.049, respectively.

4. Sensitivity of results to assumptions about orientation, material, and efficiency decay rates of PV Systems

The residential PV systems evaluated in this paper are assumed to be installed to face south in order to generate the maximum power. Also, the PV panels are assumed to be made of the standard polycrystalline silicon whose efficiency is 14-16% [8,26], with and annual efficiency decay of 0.5% [27]. Table S10 summarizes the sensitivity of results to varying assumptions of the PV systems, assuming scenario A with a 5.3% PV penetration level (i.e. 6.5 GW installed PV system). The values in each column indicate the changes on system's costs, CO_2 emissions, and Cost of CO_2 abatement (CoA), relative to the results obtained under baseline assumptions for PV panels' orientation and material. For instance, if all residential PV panels are positioned to face east instead of south, the annual power generation form the PV panels will decrease by 13.5%. Consequently, the DEC&PEC system's costs, emissions and CoA will increase by 1.3%, 1.8% and 18.3%, respectively. Likewise, if thin film modules are used instead of polycrystalline silicon modules, the DEC&PEC system's costs, emissions and CoA will increase by 1.9%, 0.8% and 9.9%, respectively. The reported system cost includes the generation costs from all generation units as well as the annualized PV costs.

Also, as mentioned in the manuscript, it is possible that the assumed compound efficiency decay rate of 0.5% per year may not reflect the conditions of the region, and hence the effect of higher annual performance degradation rates has been examined over the range of 0.2-1.0%. Results show that for each 0.1%/year increase in the efficiency decay rate, system costs, CO_2 emissions, and CoA increase anywhere in the ranges 0.4-0.9%, 1.0-1.8% and 1.4-2.8%, respectively. These results were obtained by simulating system's operations for each assumed compound decay rate in the range 0.2-1%. Accounting for the fact that, due to the performance degradation, the efficiency of a PV system decreases every year, would have required simulating the entire power system operations for 25 years (i.e. the lifetime of the PV system). For computational tractability, rather than simulating the power system for each of the 25 years of the PV systems' lifetime, we simulated system's operations only for one year, assuming an efficiency of the PV system equal to its average efficiency. The average efficiency of the PV panel over its lifetime was estimated by taking the average of annual efficiencies. For example, to simulate power system operations when the PV systems have a compound annual degradation rate of 1%, we simulate it assuming a degradation of 11.6% (i.e. the average of the 25 values of PV system's efficiency, estimated after compounding an annual decay rate of 1%).

Table S10 Summary of sensitivity analysis for scenario A with 5.3% penetration level

Description	Orientation				Module's Type		
	South	East	West	North	Poly-crystalline	Mono-crystalline	Thin-Film
Average annual peak power (MW)	4728	-8%	-10%	-25%	-	+3%	-3%
Average annual solar power (MWh)	8487476	-13.5%	-13.9%	-28%	-	+3%	-4.5%
System cost (1) ($/MWh)	42.48	+1.3%	+1.5%	+2.4%	-	+10.1%	+1.9%
Emissions (lb/MWh)	818	+1.8%	+2.0%	+3.5%	-	-0.3%	+0.8%
CoA ($/ton)	305	+18.3%	+19.9%	+42%	-	+15.5%	+9.9%

(i) System costs in this table include the levelized capital costs of the PV systems.

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