Methodology Documentation for the Research Project "Rate Design and Distributed Energy Resource Integration: Impacts on the Environment and Distribution System Costs"

Description of methods utilized in a cross-organizational collaborative research project "Rate Design and Distributed Energy Resource Integration: Impacts on the Environment and Distribution System Costs" funded by the Sloan Foundation Grant G-2017-9829.

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Environmental Defense Fund, Massachusetts Institute of Technology Energy Initiative, the Institute for Policy Integrity at New York University School of Law, and Commonwealth Edison.

Contents

1. Framework Overview

The objective of this project is to identify the effectiveness of cost-reflective residential electricity tariffs on achieving desired social outcomes such as environmental benefits, increased adoption of Distributed Energy Resources (DERs), decreased system costs, fair distributional impacts, and more. This project is a Sloan Foundation-funded collaboration between researchers at Environmental Defense Fund (EDF), Massachusetts Institute of Technology Energy Initiative (MITEI), the Institute for Policy Integrity at New York University School of Law (Policy Integrity), and technical staff at Commonwealth Edison, a local electric utility in Illinois.

In this document, we detail the methodology employed for the project. The modeling framework used for this project is comprised of the following elements:

- *Demand Response and Distributed Resources Economics Model (DR-DRE) 2.0*: A tool that models distribution end-user decisions to invest in and operate DERs; originally developed by MIT.
- *Economic Dispatch Model (ED):* A tool that simulates the operation of power plants located within ComEd PJM area
- *Reference Network Model (RNM)*: An automated network planning tool; developed by IIT-Comillas.
- *OpenDSS:* Open source tools for simulating active distribution systems;

Through the collaboration, we have made major changes to the original DR-DRE and RNM models. First, we adapted the original DR-DRE and created DR-DRE 2.0, which includes a utility function for each end user. This allows us to more flexibly model preferences for load shapes. Second, we included gas- and electric- based technology alternatives for space heating, in addition to natural gas or diesel distributed generation (i.e. gensets). Third, we calibrated both models to the ComEd service territory in 2016, both to reflect observed loads, as well as to reflect the network composition.

2. Demand Response & Distributed Resources Economics Model (DR-DRE) 2.0

DR-DRE is a proprietary model originally developed and owned by MIT, and adapted in this project by adding a utility function (we refer to the adapted model as DR-DRE 2.0 to differentiate it from the original model). DRE optimizes the operation of a customer's on-site energy resources, including the purchases from the macro-grid in response to a set of prices and charges for energy services. The model incorporates solar PV, batteries, controllable loads, and the thermal storage properties of buildings/homes. This tool simulates the end user's load profiles taking into account DER adoption and operation, with the goal of minimizing the user's net electricity expenditure (i.e., any expenditure minus any DER-related revenues)

subject to model-specified technical constraints as well as a utility function that specifies the preferences for indoor temperature and load shifting.

In the original DR-DRE version, this utility function was missing and households' cost-minimizing responses to the electricity rate and tariff structure were - together with these technical constraints – instead determined by two disutility parameters (in the form of monetary penalties) for thermal and non-thermal load responses deviating from the baseline load profile. To address the limitations brought by these disutility parameters, we replaced the constraints related to these parameters with a household utility constraint based on a utility function that represents the household's preference for a comfortable indoor temperature as well as non-space heating electricity services. For more details on the utility function and how it was incorporated into DRE, see Bharatkumar et al. (2020).

The tariff, mostly derived from RNM's network costs calculation and electricity prices of the macro-grid, is passed into DR-DRE 2.0 such that the end user's bill depends on the specified tariff. Users can be presented with a variety of rate structures that can include energy ($/kWh), capacity ($/kW), and fixed components, or any combination thereof. Customers' decisions to adopt DERs, conserve, or shift consumption therefore depend on the relative prices and the associated welfare losses from changing consumption across the hours of the day. The model can also simulate the provision of different services by DERs, such as energy, operating reserves, firm capacity, and network services.

DR-DRE 2.0 is a mixed integer linear program written in the Julia/JuMP programming language, using IPOPT, a nonlinear solver. The model is designed to optimize a single end-user's consumption and/or production of electricity services through operational and investment decisions. The tool minimizes customer net expenses (revenues from DER operations minus any costs) given the underlying prices a customer faces, subject to a number of constraints.

The model's main constraints include:

- Customer utility function, to represent preferences for indoor temperature and load shapes (described in more detail in Section 7).
- Building thermal model constraints.
- Technical capacity and performance of DERs.

Main inputs include:

- DER technologies and characteristics: PV capacity and production data (location-specific PV Watts[1] production data scaled to PV capacity), battery characteristics (energy capacity, power capacity, charge and discharge efficiency, degradation).
- Building characteristics: non-thermal loads (e.g. lights, dishwasher, dryer), thermal loads (power rating of heat pump, water heater).

- Electricity tariffs: tariffs that feature energy prices, use-of-network charges, firm capacity prices/fixed charges.
- Weather data: hourly ambient temperature, insolation data.

Main outputs include:

- Customer purchases of electricity services from existing utility/retailer.
- Customer investment in DERs.
- Operating schedule of controllable DERs (battery, schedulable loads, and thermal storage).

See Huntington (2016) for a more complete description of DR-DRE's underlying equations, constraints, parameters, among others. In the following sections, we detail only the two main changes to the original DR-DRE model: the addition of space heating and distributed generation.

2.1. Space Heating

For the purpose of this project, we have included in the model the option for consumers to choose between an electric heat pump or a gas-fired furnace as alternatives for space heating based on the technical specifications of Table 1.

		Typical Heat Pump	Typical Gas Furnace
$\boldsymbol{pHVMax_h}$	(kW)	4.2	23.5
$\boldsymbol{pHVCOP_h}$	(p.u.)	2.52	0.92
$\boldsymbol{pHVCapEx_h}$	($)	5100	2610
$\boldsymbol{pHVO\&M_h}$	($/year)	234	441
$\boldsymbol{pHVLife_h}$	(years)	16	22
$\boldsymbol{pHPFuel_h}$		Electricity	Gas

Table 1: Heating systems technical specifications used in DR-DRE model[1]

Where,

$pHVMax_h$: Maximum heating capacity per heating equipment h [kW]

$pHVCOP_h$: Heating efficiency per equipment h (COP for heat pump, efficiency for furnace)

[1] Sources:
https://www.eia.gov/analysis/studies/buildings/equipcosts/pdf/appendix-a.pdf
https://www.eia.gov/environment/emissions/co2_vol_mass.php
https://accel.peoplesgasdelivery.com/home/gas_rates.aspx
https://studylib.net/doc/18832497/typical-charges-summary---residential
https://accel.peoplesgasdelivery.com/company/tariffs/info_hist.pdf

$pHVCapEx_h$: Heating system capital cost per heating equipment h [$]

$pHVO\&M_h$: Heating system annual fixed O&M per heating equipment h [$]

$pHVLife_h$: Heating system lifetime per heating equipment h [years]

$pHPFuel_h$: Heating system type of fuel per heating equipment h (electricity or natural gas)

In the model, the type of heating system to be adopted by the consumer will depend on the potential energy costs savings of a gas- versus an electric- based system, given their investment and fixed costs, operational expenditures and also thermal efficiencies.

Following the thermal model formulation in Huntington (2016), the internal gains are a function of the energy consumed by the heating or cooling systems and their efficiencies (Eq.1).

$$\sum_h^{HVACs} pHVCOP_h * vPowerHP_{t,h} - pCOP * vPowerAC_t = vIntGains_t \qquad \forall h,t \qquad (1)$$

Eq. 2 defines external losses as a function of the temperature difference between the outdoor and interior temperature and thermal resistance of the building.

$$vExtLosses_t = \frac{pOutdoorTemp_t - vTempInt_t}{pResistance} \qquad \forall t \qquad (2)$$

Finally, the thermal balance equation is given by Eq.3 which defines the indoor temperature as a function of the temperature in the previous hour plus changes due to internal gains and external losses.

$$vTempInt_t = vTempInt_{t-1} + \frac{vIntGains_{t-1} + vExtLosses_{t-1}}{pCapacitance} \qquad \forall t \qquad (3)$$

Focusing on the heating portion, $vPowerHP_{t,h}$ from Eq. 1 is the decision variable that determines the energy consumed by the user's heating system which cannot exceed the equipment heating capacity (Eq. 4).

$$0 \leq vPowerHP_{t,h} \leq pHVMax_h \qquad \forall h,t \qquad (4)$$

We have incorporated the binary variable $bHVType_h$ in the expressions that calculate the annualized cost of the heating system and annual fixed costs, in order to determine the heating technology to be adopted by the user --either an electric heat pump or a gas furnace (see Eqs.5-7).

$$\sum_h bHVType_h = 1 \qquad (5)$$

$$HV\_Annuity = \sum_h^{HVACs} pHVCapEx_h * bHVType_h * pAnnuity_h \qquad (6)$$

$$HV\_O\&MCost = \sum_h^{HVACs} pHVO\&M_h * bHVType_h \qquad (7)$$

The annualized cost of the heating system is then included in the overall annualized cost expression (Eq. 8).

$$DERAnnuity = Batt\_Annuity + PV\_Annuity + DG\_Annuity + HV\_Annuity \quad (8)$$

In the case of a furnace, the amount of gas consumed is given by Eq. 9. The thermal load is given by the gas used for space heating during winter and power used for space cooling during summer (Eqs.10-11).

$$vHVGas_t = \sum_h^{HVACs} vPowerHP_{t,h} \quad \forall t \quad (9)$$

$$vThermalLoadGas_t = vHVGas_t \quad \forall t \quad (10)$$

$$vThermalLoadEle_t = vPowerAC_t \quad \forall t \quad (11)$$

In the case of a heat pump, the amount of power consumed is given by Eq.12. The thermal load is given by the power used for space heating during winter and power used for space cooling during summer (Eq.13).

$$vHVEle_t = \sum_h^{HVACs} vPowerHP_{t,h} \quad \forall t \quad (12)$$

$$vThermalLoadEle_t = vHVEle_t + vPowerAC_t \quad \forall t \quad (13)$$

We then integrated the new variables and expressions into the model's balance equations (Eqs.14-16).

$$vPowerConsumed_t = vNonThermalLoadt_t + vThermalLoadEle_t + vBattCharge_t \; \forall t \quad (14)$$

$$vPowerProduced_t = vPVEnergy_t + vBattDischarge_t + \sum_c^{DGs} vDGEnergy_{t,c} \; \forall t \quad (15)$$

$$vPowerPurchased_t + vPowerProduced_t = vPowerConsumed_t + vPowerExport_t \; \forall t \quad (16)$$

We incorporated the gas or electricity consumption for heating purposes in the model's operational costs calculations, i.e. carbon costs if a CO2 price is included, energy costs due to electricity and/or natural gas usage, and electricity-only costs (Eqs.17-19)[2].

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[2] Emissions and related costs are calculated based on the following expressions:

$$vHVEmissionsCO2_t = \sum_h pHVCOP_h * vPowerHP_{t,h} * pHVGasCO2 \; \forall t$$
$$vHVEmissionsNOx_t = \sum_h pHVCOP_h * vPowerHP_{t,h} * pHVGasNOx \; \forall t$$
$$vHVEmissionsSO2_t = \sum_h pHVCOP_h * vPowerHP_{t,h} * pHVGasSO_2 \; \forall t$$

where,

$pHVGasCO2$: furnace CO2 emissions rate per kWh output metric ton/kWh
$pHVGasNOx$: furnace CO2 emissions rate per kWh output metric ton/kWh
$pHVGasSO_2$: furnace CO2 emissions rate per kWh output metric ton/kWh

$$HV\_CO_2Cost = \sum_t pCO2price * vHVEmissionsCO2_t \quad (17)$$

$$EnergyCost = \sum_t pBuyEle * vPowerPurchased_t + pBuyGas * vThermalLoadGas_t \quad (18)$$

$$EnergyCostwoGas = \sum_t pBuyEle * vPowerPurchased_t \quad (19)$$

Based on the above changes, we updated the expressions related to total costs and total revenue used DR-DRE 2.0's objective function (we highlight the new components related to space heating in Eqs.20-21).

$$TotalCost = pFixedCharge + \boldsymbol{EnergyCost} + \boldsymbol{DERAnnuity} + \boldsymbol{HV\_CO_2Cost} + \boldsymbol{HV\_O\&MCost} + vDGTotOperCost \quad (20)$$

$$TotalRevenue = \sum_t pSellEle_t * \left(vPowerExport_t - \sum_c vDGEnergy_{t,c}\right) \quad (21)$$

Finally, the objective function in DR-DRE 2.0 is given by the following expression in Eq.22.

$$Min\ (TotalCost - TotalRevenue) \quad (22)$$

Which is subject to the additional constraints that haven been added or updated for the purpose of the project – user' utility constraint, a user defined non-thermal cap during off-peak hours of the day, and constraint that limits potential electricity revenues from selling electricity back to the utility to be lower than electricity-only cost (Eqs.23-25).

$$\prod_t^T (vNonThermalLoadt_t - pMinLoad)^{a_t} - \sum_t^T b * (vTempInt_t - BlissPoint)^2 \geq \bar{u} \quad (23)$$

$$vNonThermalLoadt_t \leq pCapNonThermal_t \quad (24)$$

$$EnergyCostwoGas - TotalRevenue \geq 0 \quad (25)$$

2.2. Distributed Generation

Also, as part of this project, we have included into DR-DRE 2.0 the capability of modeling fossil-fired (natural gas or diesel) distributed energy resources (i.e. gensets). The potential for electric customers to adopt fossil fuel based DERs, especially given a change in electricity tariffs, is non-trivial and a concern to many utilities, and may cause an increase in emissions relative to the central grid. The technical specifications of this technology are shown in Table 2.

		Gas Genset
$\boldsymbol{pDGMax_c}$	(kW)	22
$\boldsymbol{pDGGasEff_c}$	(%)	19.6
$\boldsymbol{pDGCapEx_c}$	($/kW)	362
$\boldsymbol{pDGO\&M_c}$	($/kW)	12.2
$\boldsymbol{pDGLife_c}$	(years)	20
$\boldsymbol{pGasCO2}$	(Mton/kWh)	0.000922

$\boldsymbol{pGasSO2}$	(Mton/kWh)	0.000000004634
$\boldsymbol{pGasNOx}$	(Mton/kWh)	0.000017892
$\boldsymbol{pDGFuel_C}$		Gas

Table 2: Natural Gas genset technical specifications used in DR-DRE 2.0 model[3]

Where,

$pDGMax_c$: Maximum power capacity per DG equipment c [kW]

$pDGGasEff_c$: Electric efficiency per DG equipment c [%]

$pDGCapEx_c$: Capital cost per DG equipment c [$/kW]

$pDGO\&M_c$: Annual fixed O&M per DG equipment c [$/kW]

$pDGLife_c$: Lifetime per DG equipment c [years]

$pDGFuel_c$: Type of fuel per DG equipment c (Natural gas or Diesel)

$pGasCO2_c$: CO2 emission rate per kWh output per DG equipment c [Mton/kWh]

$pGasSO2_c$: SO2 emission rate per kWh output per DG equipment c [Mton/kWh]

$pGasNOx_c$: NOx emission rate per kWh output per DG equipment c [Mton/kWh]

In our model, the decision to adopt a DG unit will depend on the potential electricity costs savings for a consumer when considering total investment and fixed costs and operational (fuel) expenditures.

We have incorporated a binary variable $bDGType_c$ in the expression that decides to invest or not in a particular DG system (see Eqs. 26-27).

$$\sum_c bDGType_c = 1 \tag{26}$$

$$vDGInvest_c = pDGMax_c * bDGType_c \ \forall c \tag{27}$$

We annualize the cost of the DG system and include it in the overall annualized cost expression (Eqs. 28-29).

[3] Sources:
HomeAdvisor, Generac Generator Costs: https://www.homeadvisor.com/cost/electrical/install-a-generator/#generac2
EIA Carbon Dioxide Emissions Coefficients by Fuel: https://www.eia.gov/electricity/data/emissions/
Generac Residential & Small Business Generators:
http://www.generac.com/generaccorporate/media/library/content/brochure/residential-small-business-generators-brochure.pdf

$$DG\_Annuity = \sum_{c}^{DGs} pDGCapEx_c * vDGInvest_c * pAnnuity_c \quad (28)$$

$$DERAnnuity = Batt\_Annuity + PV\_Annuity + DG\_Annuity + HV\_Annuity \quad (29)$$

The amount of gas consumed is given by Eq.30.

$$vDGGas_t = \sum_{c}^{DGs} \frac{vDGEnergy_{t,c}}{pDGGasEff_c} \quad \forall t \quad (30)$$

Where $vDGEnergy_{t,c}$ is the amount of electricity generated by DG of type c given by Eq.31.

$$vDGEnergy_{t,c} \leq pDGMax_c * bDGType_c \quad \forall t \quad \forall c \quad (31)$$

We then integrated the new variables and expressions into DR-DRE 2.0's balance equations, paying particular attention to the electricity production from DGs (Eqs.32-33).

$$vPowerProduced_t = vPVEnergy_t + vBattDischarge_t + \sum_{c}^{DGs} \boldsymbol{vDGEnergy}_{t,c} \quad \forall t \quad (32)$$

$$vPowerConsumed_t + vPowerExport_t = vPowerPurchased_t + \boldsymbol{sPowerProduced}_t \quad \forall t \quad (33)$$

We calculate emissions based on the following expressions:

$$vDGEmissionsCO2_{t,c} = \sum_c vDGEnergy_{t,c} * pGasCO2_c \quad \forall t, c \quad (34)$$

$$vDGEmissionsNOx_{t,c} = \sum_c vDGEnergy_{t,c} * pGasNOx_c \quad \forall t, c \quad (35)$$

$$vDGEmissionsSO2_{t,c} = \sum_c vDGEnergy_{t,c} * pGasSO2_c \quad \forall t, c \quad (36)$$

Then, we incorporated DGs operational fuel and variable O&M costs given by gas or diesel fuel prices and variable O&M costs. In addition, we added a carbon cost in the case a CO2 price is included in the formulation (Eqs.37-40)

$$vDGFuelCost_t = pDGGasPrice_t * vDGGas_t + pDGOilPrice_t * vDGDiesel_t \quad \forall t \quad (37)$$

$$vDGO\&MCost_t = \sum_{c}^{DGs} pDGO\&M_c * vDGEnergy_c \quad \forall t \quad (38)$$

$$vDGCO2Cost_t = \sum_{c}^{DGs} pCO2price * vDGEmissionsCO2_{t,c} \quad \forall t \quad (39)$$

$$vDGTotOperCost = \sum_{t}^{T} (vDGFuelCost_t + vDGO\&MCost_t + vDGCO2Cost) \quad (40)$$

Finally, we updated the expressions related to total costs and total revenue used in DR-DRE 2.0's objective function. We added a constraint that limits any potential electricity revenue from selling electricity produced by DGs and also, we constrained revenues to be lower than total energy costs due to electricity usage (new components related to DG highlighted in Eqs.42-43).

$$TotalCost = pFixedCharge + EnergyCost + \boldsymbol{DERAnnuity} + HV\_CO_2Cost + HV\_O\&MCost + \boldsymbol{vDGTotOperCost} \quad (41)$$

$$TotalRevenue = \sum_t pSellEle_t * \left(vPowerExport_t - \sum_c \boldsymbol{vDGEnergy_{t,c}}\right) \quad (42)$$

$$EnergyCostwoGas - \boldsymbol{TotalRevenue} \geq 0 \quad (43)$$

3. Economic Dispatch (ED) Model

In order to estimate the environmental impacts of changes in load and DER deployment, we formulated a simple plant-level single-node hourly economic dispatch (ED) model that has a stylized representation of the wholesale electricity market of the portion of ComEd within the PJM system.

The ED model takes into consideration the main technological and economic parameters of those generation units belonging to the ComEd region as provided by SNL Energy for year 2016, including natural gas combustion turbines (CT) and combined cycle gas turbine (CCGT), nuclear units, steam turbine coal units, steam turbine gas units, internal combustion engines, and onshore-wind and utility scale solar systems. Table 3 shows the aggregated summer capacities per technology type installed by year 2016.

Technology	Installed Capacity (MW)	%
CT	7,325	32.8%
CCGT	1,809	8.1%
Nuclear	8,703	38.9%
Steam Turbine Coal	1,241	5.6%
Steam Turbine Gas	1,389	6.2%
Internal Combustion Engine	198	0.9%
Wind	1,658	7.4%
Solar	29	0.1%
Total	22,353	100%

Table 3: Installed capacity for selected region. Source: 2016 SNL Energy

For costs and technological parameters for each the power plants included in the model, we took information from the following sources:

- 2016 SNL Energy (ref?) for fuel, variable O&M and electric heat rates;
- 2016 EIA's Emissions[4] and 2016 SNL Energy (ref?) for CO2, NOx and SO2 emission rates by plant and corresponding region;

[4] EIA's Emissions by plant and region accessible at https://www.eia.gov/electricity/data/emissions/

- NREL's Regional Energy Deployment System technical report[5] for forced and planned outage rates and minimum technical load per type of technology.

In addition, we incorporated metered SNL Energy's hourly demand profiles based on Commonwealth Edison (CE) load zone as shown in Figure 1, where total demand for year 2016 accounted to 100TWh approximately.

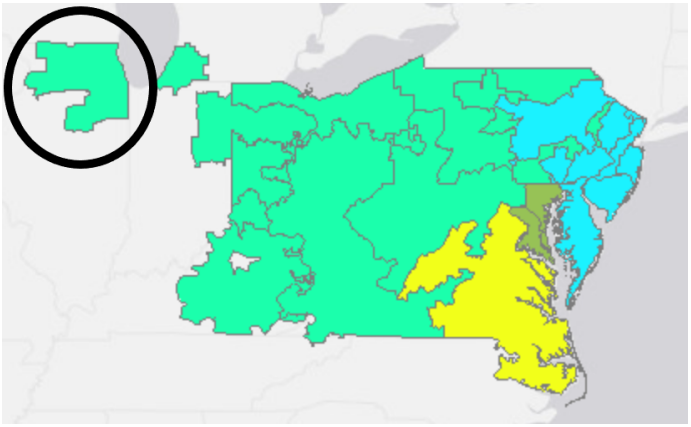

Figure 1: Commonwealth Edison load zone within PJM RTO control area

Also, we included renewable generation profiles for 2016 for wind and solar based on PJM's data management tool[6]. Each resource totaled about 4.4 and 0.04 TWh for 2016 respectively.

Our ED model incorporates imports from neighboring regions as a portion of the supply generated to meet demand will be imported. To calculate the marginal emission rates for trades, we converted the marginal fuel data provided by PJM Real-time Energy Market as provided by Monitoring Analytics[7] to marginal emission rates using the emission factors given by EPA's Emissions & Generation Resource Integrated Database[8] for year 2016. Finally, to value energy trade between ComEd and neighboring regions, we used historical real-time hourly prices for year 2016 as provided by PJM Data Miner tool[9] (see

[5] NREL's Regional Energy Deployment System (ReEDS) accessible at https://www.nrel.gov/docs/fy12osti/46534.pdf
[6] PJM's Data Miner 2 accessible at http://dataminer2.pjm.com/list
[7] Monitoring Analytics - Marginal Fuel Posting. Available at http://www.monitoringanalytics.com/data/marginal_fuel.shtml
[8] Emissions & Generation Resource Integrated Database (eGRID accessible at https://www.epa.gov/energy/emissions-generation-resource-integrated-database-egrid
[9] PJM's RTP accessible at http://dataminer2.pjm.com/feed/rt_hrl_lmps

Table 4).

Table 4: PJM's COMED node real-time price descriptive statistics

COMED Real-Time Hourly LMPs	($/MWh)
Max	246.947
Min	(51.125)
Simple average	26.067
Load weighted	27.66
Standard deviation	14.47

The ED model is formulated as an optimization problem that minimizes the total cost of scheduling generating power units over one-year time horizon, constrained to meeting zonal demand for electricity taking into account the presence of renewable resources while satisfying a number of technical and environmental constraints. Because of the limited information available at plant level, we did not consider short-term operational reserves nor start-up and shut-down decisions.

The objective function is given by the minimization of variable costs and emissions-related costs for all thermal plants t and energy trade over the sum of each hour h of the year:

$$\sum_h \left(\begin{array}{c} \sum_t \left(pVC_t * vQ_{h,t} + pCO2^{price} * pCO2_t^{rate} * vQ_{h,t} \right) * \frac{(1+losses)}{K_t} \\ + pRTP_h * \left(vTr_{imp_h} - vTr\_exp_h \right) * (1 + losses) \\ + pCO2^{price} * pCO2_h^{marginal} * \left(vTr_{imp_h} + vTr\_exp_h \right) * (1 + losses) \\ + pCENS * vEns_h \end{array} \right) \quad (44)$$

Decision variables are defined in the above expressions as follows:

$vQ_{h,t}$	Net power dispatched by generator t in hour h [MW]
vTr_imp_h	Trade imports with neighboring regions in hour h [MW]
vTr_exp_h	Trade exports with neighboring regions in hour h [MW]
$vRes_h$	Renewable energy sources generation (wind + solar) in hour h [MW]
$vResCur_h$	Renewable energy sources curtailment (wind + solar) in hour h [MW]
$vEns_h$	Non-served energy in hour h [MW]

Input parameters are defined as follow:

pVC_t	Variable cost (fuel and O&M) per generator t [$/MWh]
$pCO2^{price}$	CO2 price [$/ton]
$pCO2_t^{rate}$	CO2 emission rate per unit of output per generator t [ton/MWh]
$pCO2_h^{marginal}$	CO2 marginal emission rate in hour h [ton/MWh]
$pRTP_h$	Real-time price per hour h used to value imports and exports from ComEd [$/MWh]
losses	Network losses incurred by centralized power plants to supply demand at lower voltage levels [%]
K_t	Availability factor per generator t [p.u]
$pCENS$	Cost of non-served energy [$/MWh]

This objective function is subject to an energy demand balance at every hour of the year. We consider power produced by thermal plants, renewable resources, energy imported to and exported from neighboring regions, which has to be equal to the demand profile in hour h given by $pDEM_h$ (Eq.45).

$$\sum_t (vQ_{h,t}) + vRes_h + vTr\_imp_h + vEns_h = pDEM_h + vTr\_exp_h \quad \forall h \tag{45}$$

In addition, we added the possibility of renewable curtailment $vResCur_h$, determining the final amount of renewable generation $vRes_h$ during hour h (Eq.46)

$$vRes_h = pWIN_h + pSOL_h - vResCur_h \quad \forall h \tag{46}$$

Where,

$pWIN_h$	Wind generation profile per hour h [MW]
$pSOL_h$	Solar generation profile per hour h [MW]

The model includes minimum and maximum operational limits de-rated by the plant's availability factor (Eq.47).

$$K_t * pQ_t^{min} \leq vQ_{h,t} \leq K_t * pQ_t^{max} \quad \forall h, t \tag{47}$$

Where,

pQ_t^{min}	Minimum generation output of generation unit t [MW]

pQ_t^{max} Maximum generation output of generation unit t [MW]

Finally, we added a trade limit that constraint potential hourly imports from and exports to vTr_h neighboring regions where $pTrCap$ is the trading cap that was arbitrarily set to 4000MW (Eqs.48-49).

$$vTr\_imp_h \leq pTrCap \quad \forall h \tag{48}$$

$$vTr\_exp_h \leq pTrCap \quad \forall h \tag{49}$$

We also incorporated into the model a CO2 emissions constraint in case we wanted to explore cap limits in our scenarios, which we did not include as part of the project (Eq.50).

$$\sum_h \sum_t pCO2^{rate}{}_t * vQ_{h,t} \leq pCO2^{max} \tag{50}$$

Where, $pCO2^{max}$ is the annual CO2 emissions cap for the region in metric tons.

This simple model gives us the hourly scheduling of all the generating units as well as operational costs and hourly marginal prices for the system. In addition, we can determine the marginal generators for the system, and subsequently, the marginal emissions at each hour for 2016, our reference year. As seen in the formulation, we incorporated a carbon price in order to further assess environmental impacts. As we discuss later, we adopted two carbon prices at $44/ton (the central estimate of the Interagency Working Group's social cost of carbon at the 3% discount rate in 2016 dollars), and $25/ton on the low side. The adoption of these prices is expected to impact the dispatch order of the generators on the grid, leading to changes in marginal emissions and marginal wholesale prices.

Overall, the information from the ED model is used to link the operation of the wholesale market at the substation-level with the economic signals provided by marginal prices used in the construction of the retail tariffs given to the sample of consumers within the area being studied.

4. Reference Network Model (RNM)

The Reference Network Model (RNM)[10] is a large-scale regulatory tool where the objective is to build a reference network whose cost is indicative of the efficient cost required for building a network. It is important to note that this tool does not design the actual network of a given company, but rather a network that can be used as an efficient reference.

[10] The RNM was developed at IIT-Comillas in Madrid, Spain. For an in-depth description of the model, see https://www.iit.comillas.edu/technology-offer/rnm or Domingo et al. (2010).

RNM designs an electrical distribution network using a set of different types of geospatial information including buildings footprint, roads, and parcel usages of the service territory of interest. In addition, RNM uses an estimate of the power of every single customer and distributed energy resource (DER) and then it calculates the total costs associated with the network it has created (see e.g., Schmalensee 2015 for an application of RNM).

We benchmarked this built-up system to the ComEd network with input from ComEd engineers, helping ensure that the theoretically efficient RNM system (which may vary significantly from the actual distribution network, due to a variety of factors such as more stringent reliability requirements or non-optimal planning decisions) is a suitable reflection of reality. See Section 5.2 for more detail on our calibration approach.

5. Model Calibration

5.1. End-user calibration

We calibrate DR-DRE 2.0 to data in two ways. First, we utilize the hourly loads to estimate thermal and non-thermal loads. Second, we utilize the thermal and non-thermal loads as inputs into a utility function, and estimate parameters that define preferences for hourly consumption. Thermal and non-thermal loads are estimated with econometric techniques by analyzing the response to temperature controlling for different variables for each household of the AMI data sample. Further on, households' preferences need to meet the welfare constraint from the utility function. This process is described in greater detail in Bharatkumar et al (2020).

Furthermore, due to computational constraints, we cluster households into groups that are similar based on a number of different observable outcomes (including timing of peak demands, daily load variability over the year, total demands, etc.). The segmentation methodology or "clustering" employed several techniques including an unsupervised learning algorithm to find relevant groups of households within the entire sample. This allows us to estimate the model on a small group of clusters (45) rather than have to estimate the model for all the ComEd sample. Representative electric load profiles from each group were created, each representing differentiated patterns of electricity consumption. For more detail into this process, see Esparza et al (2020).

5.2. Network Model Calibration

The first set of results we obtained were based on a version of RNM that had been calibrated to European networks (Domingo et al., 2010), i.e., the equipment catalog specifies European standard voltage levels, and the resulting networks more closely emulate European distribution characteristics than U.S.

distribution characteristics. However, a better calibration was needed in order to have a synthetic network more closely representative of distribution systems found in the U.S.

Based on a version of RNM calibrated to U.S. networks (US-RNM) (refer to Palmintier et al. 2021; Postigo et al. 2020), we generated a network bounded to a subset of zip codes within the ComEd service territory, mainly comprised of residential neighborhoods with over 80% AMI adoption from the first month of the year. The geographical coverage area is depicted in **Error! Reference source not found.**, which corresponded to a cluster of about 60,000 households as detailed in Table 5.

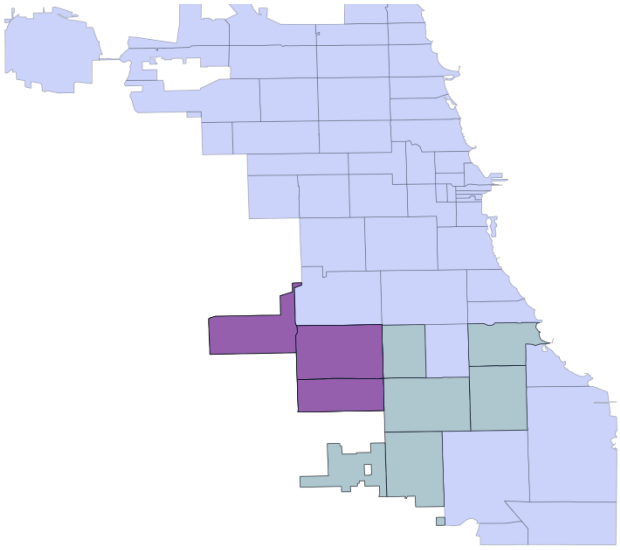

Figure 2: Selected three zip codes within Cook County, IL (purple polygons)

Zip codes	Sq mi	Sq km	Population	ComEd users
60629	6.81	17.63	113,916	33,593
60638	11.1	28.74	55,026	22,010
60652	5.02	13.00	40,959	13,769
	22.93	59.37	209,901	69,372

Table 5: Selected three zip codes within Cook County, IL. (Source: UnitedStatesZipCodes.org)

In addition to the selected zip codes, the US-RNM required a set of different types of geospatial information including buildings footprint, roads, and parcel usages. This information was either purchased[11] or downloaded from public repositories[12]. Building information needed to be adapted to

[11] Parcel data and Shapefiles of Cook County in Illinois were acquired especially for this project from https://reportallusa.com/

[12] Roads information was obtained for Illinois from download.geofabrik.de/north-america/us. Buildings footprints were obtained from https://data.cityofchicago.org/Buildings/Building-Footprints-current-/hz9b-7nh8/data#revert

include an estimated height of the buildings, which US-RNM requires to approximate building peak demand and annual electricity consumption. Based on this information, we generated a synthetic network for the three selected zip codes.

In order to understand the feasibility of the synthetic network regenerated by US-RNM, we performed a steady state power flow on the distribution system for peak load conditions using Electric Power Research Institute (EPRI)'s OpenDSS[13] with the goal of looking at US-RNM's results in terms of system's losses and voltage magnitudes across feeders. Results showed satisfactory metrics for voltage magnitudes within a +/-5% range, and active losses less than 5% as presented in Table 2 below.

Table 6: Load flow simulation results based on OpenDSS

Outputs		
Max pu. voltage	pu	1.028
Min pu. voltage	pu	0.94
Total Active Power	MW	214.204
Total Reactive Power	MVAr	34.1979
Total Active Losses	MW	6.5 (3.02%)
Total Reactive Losses	MVAr	9.0151

Additionally, to understand how representative the designed synthetic network was with respect to the particular ComEd distribution area, we compared several results including: length of electrical lines, number and size of substations and transformers installations, aerial and underground ratios, and continuity of supply indexes (SAIDI[14] and SAIFI[15]). Based on feedback from the utility company, results from US-RNM looked reasonable for the concession area being studied in terms of demand level, proportion of overhead and underground lines, and SAIFI (see Table 7-

Table 10).

Table 7: Demand and number of consumers

Type	Demand (kW)	Num. Points
Consumers LV	273,777	125,653
Consumers MV	57,834	32
Consumers HV	0	0
Total	331,611	125,685

Table 8: Length of overhead and underground lines

[13] EPRI's OpenDSS is a comprehensive electrical power system simulation tool primarily for electric utility power distribution systems. Details can be found at https://smartgrid.epri.com/SimulationTool.aspx

[14] System Average Interruption Duration Index (SAIDI) is the average outage duration for each customer served.

[15] System Average Interruption Frequency Index (SAIFI) the average number of interruptions that a customer would experience.

Voltage level	Overhead (km)	Underground (km)	% O	% U
Lines LV	724	1,176	38%	62%
Lines MV	639	518	55%	45%
Lines HV	38	8	83%	17%
Total	1,402	1,702		

Table 9: Length of lines per voltage level

Vnom (kV)	Number	Length (km)
Line 69	25	47
Line 12.5	17,939	1,157
Line 0.4	167,634	1,900

Table 10: Reliability indices for SAIDI and SAIFI

Number Dist. Transf and MV Cons.	SAIDI (hr)	SAIFI (number per customer)
17,862	4.63	0.52

However, one critical point was related to one of the voltage levels used in our simulations. While US-RNM uses 230kV, 69kV, 12.5kV and 0.4kV, ComEd uses 138kV level within its installations (a difficult parameter to change with the current version of RNM). Other discrepancies were related to: the number of MV/LV distribution transformers (too high in simulations), HV/MV substation costs (too low in simulations), SAIDI index (too high in simulations[16]). See

Table 10 and Table 11.

Type of equipment	Vnom1 (kV)	Vnom2 (kV)	Number	Investment cost ($)	Preventive maintenance ($/year)
Transmission Substation	230	69	3	0	0
HV/MV Substation	69	12.5	16	66,225,967	1,774,856
MV/LV Dist.Transf.	12.5	0.4	17814	91,680,375	2,457,034

Table 11: Substations and transformers results

RNM could be adjusted further to keep improving the already designed synthetic network. For example, in order to change the HV voltage level from 69kV (used in current simulations) to 138kV (used by ComEd), we should include information of equipment/components designed for that voltage level into the RNM catalog. However, that level of detail is very challenging to obtain.

[16] Based on feedback from the utility, SAIDI is close to one hour.

Finally, adjustments to the number of distribution transformers, reduction of the SAIDI index, and inclusion of substations with multiple transformers (not only one as currently used in RNM), would require modifications to the code of RNM to expand its current capabilities (something beyond the scope of the current project).

5.3. ED Model Calibration

To calibrate our ED model, we mostly focused on calibrating the operational results of the economic dispatch ED model to 2016 levels of observed demand and generation for the portion of PJM's service area being studied in this project. Since our region is just a portion with PJM area, we have added a simple representation for electricity imports and exports of the ComEd area with the rest of PJM. For the purpose of quantifying emissions, as explained in the methodology section, we added marginal emissions data based on the fuel types of marginal units in the PJM real-time energy market.

Table 12 and Table 13*Error! Reference source not found.* compare the aggregated model results to 2016 historical operation for ComEd territory based on the SNL Energy database. The tables compare annual production for the most relevant types of technology (MWh per year), capacity factor (CF), installed capacity (IC), and percentage of generation mix (% portfolio). As can be seen below, our model produces results that are quite consistent with the observed grid generation by different generator types.

Calibrated ED model	Annual Generation (MWh)	Capacity Factor (%)	Installed Capacity (MW)	% portfolio
Wind	4,414,245	30.4%	*1,658*	*4.3%*
Solar	43,838	17.3%	*29*	*0.0%*
Gas-CT	5,583,885	8.7%	7,325	*5.5%*
Gas-CC	9,046,150	57.1%	1,809	*8.8%*
Gas-ST	3,269,557	26.9%	1,389	*3.2%*
Internal Combustion	222,488	12.8%	198	*0.2%*
Coal-ST	6,865,749	63.1%	1,241	*6.7%*
Nuclear	72,945,696	95.7%	8,703	*71.2%*

Table 12: Economic dispatch model operational

SNL 2016	Annual Generation (MWh)	Capacity Factor (%)	Installed Capacity (MW)	% portfolio
Wind	4,414,245	32.2%	1,742	4.5%
Solar	43,838	16.5%	34	0.0%
Gas-CT	4,173,967	9.7%	7,325	4.3%
Gas-CC	8,193,389	49.0%	1,809	8.4%
Gas-ST	1,812,476	8.0%	1,389	1.9%
Internal Combustion	207,460	16.5%	198	0.2%

Coal-ST	4,132,612	47.5%	1,241	4.3%
Nuclear	74,037,490	95.4%	8,703	76.3%

Table 13: Historical operation for year 2016

In addition, we compared the marginal price estimated by the economic dispatch model (ED-MP) against the 2016 historical real-time locational marginal price for the ComEd area (COMED-RTP) (see Table 14).

		ED-MP	COMED-RTP
Max.	($/MWh)	209.47	246.95
Min.	($/MWh)	-52.66	-51.13
Simple Avg.	($/MWh)	25.76	26.07
Std.	($/MWh)	11.82	14.47
Corr.		0.88	

Table 14: Summary of descriptive statistics comparing marginal prices from ED model and historical 2016 data

Figure 3 and Figure 4 compares the model's hourly marginal price to the ComEd real-time hourly price for 2016. In average, both prices are quite similar in terms of magnitude and also peak, shoulder and off-peak hours during the day. Looking into more detail at a monthly level, we note that peak prices in both our model and the observed data occur during the same month of the year (July and August). The average prices are quite similar across the two datasets, and the observed maximum prices only exceed our modeled prices for a few hours of the year.

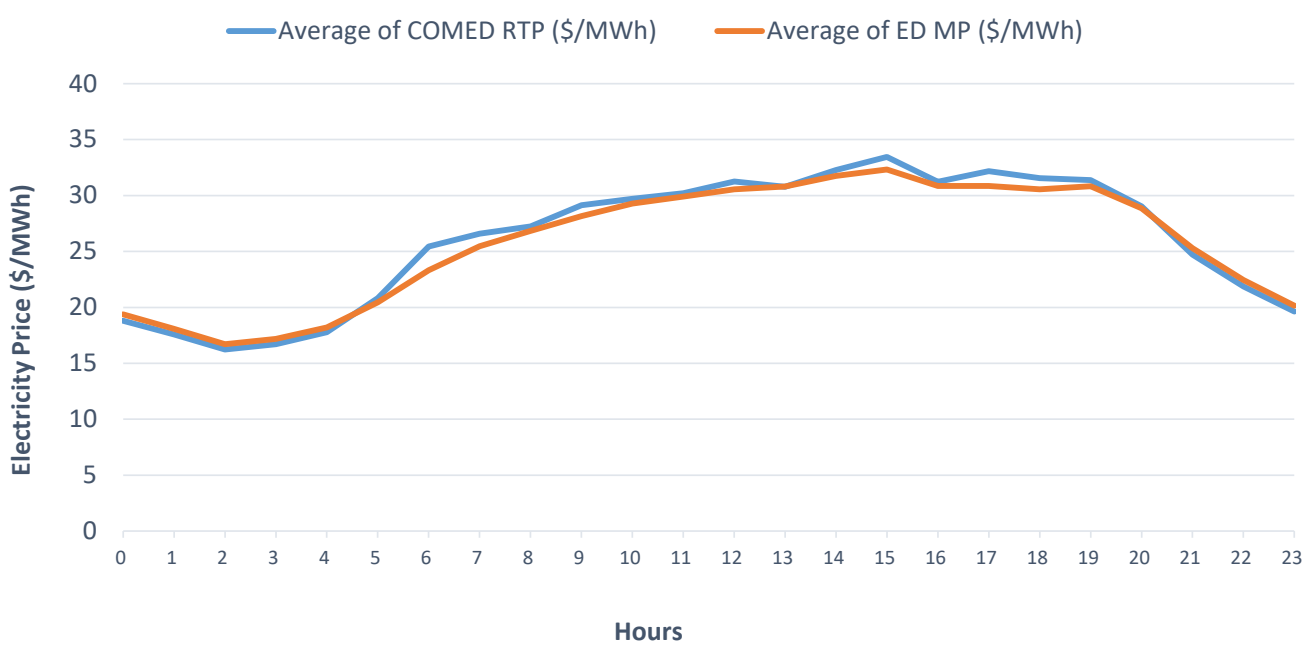

Figure 3: Comparison of average hourly marginal prices for the year, model results vs. real-time prices

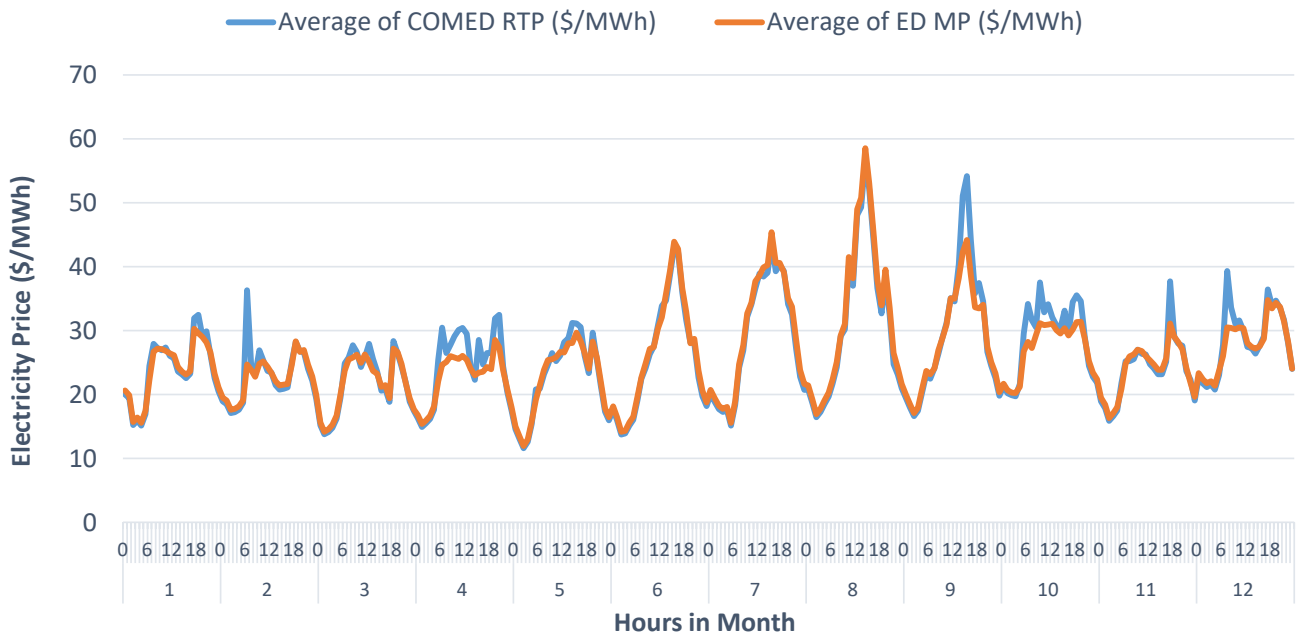

Figure 4: Figure 3: Comparison of average hourly marginal prices per month, model results vs. real-time prices

The dispatch model also outputs the hourly scheduling of all the generating units, categorized by technology type. Figure 5 shows an example of the hourly generation by technology for the month of January. The figure shows that the ED model does a good job of modeling baseload (nuclear, which is on consistently, and coal, which fluctuates very little) and ramping technologies (e.g., natural gas) -- which, as should be expected, fluctuate on par with intermittent technologies (specifically, wind, as there is little solar on the system). We also note the role of imports and exports from neighboring regions which also provide additional flexibility to the system.

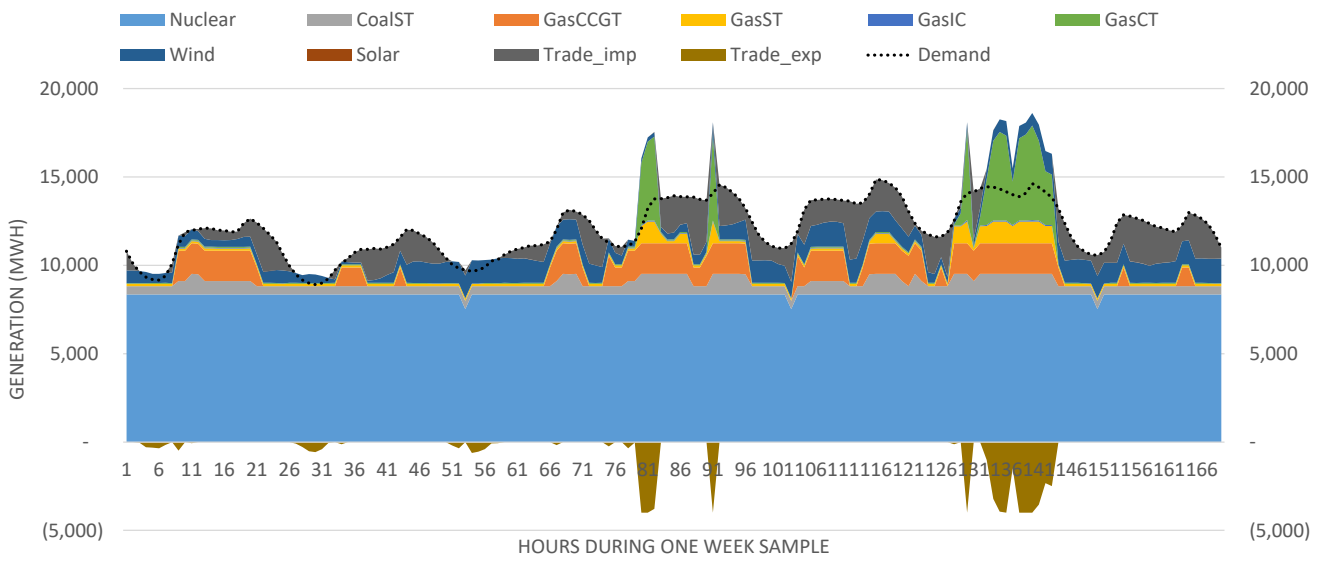

Figure 5: Hourly generation profiles produced by the ED model – January sample

Finally, a complete list of the annual aggregated results produced by the model such as prices, generation, energy trade, total and marginal emissions, and generation by fuel type is shown in Table 12 for our reference case.

Output	**Units**	**Value**
Average marginal price	$/MWh-yr	27.37
Annual generation	MWh-yr	102,391,608
Annual demand	MWh-yr	100,181,075
Annual net trade (imp-exp)	MWh-yr	(2,171,235)
Generation, wind	MWh-yr	4,414,245
Generation, solar	MWh-yr	43,838
Generation, gas-CT	MWh-yr	5,583,885
Generation, gas-CCGT	MWh-yr	9,046,150
Generation, gas-ST	MWh-yr	3,269,557
Generation, gas-IC	MWh-yr	222,488
Generation, coal-ST	MWh-yr	6,865,749
Generation, nuclear	MWh-yr	72,945,696
Annual trade+ (imp)	MWh-yr	5,556,213
Annual trade- (exp)	MWh-yr	(7,727,448)
Annual NOX emissions	Ton-yr	13,216
Annual SO2 emissions	Ton-yr	16,453
Annual CO2 emissions	Ton-yr	16,899,866
Annual CO2 emissions cost	$-yr	Eps

Annual NOX emissions from imports	Ton-yr	2,502
Annual SO2 emissions from imports	Ton-yr	3,394
Annual CO2 emissions from imports	Ton-yr	3,839,547
Annual NOX emissions from exports	Ton-yr	3,374
Annual SO2 emissions from exports	Ton-yr	4,574
Annual CO2 emissions from exports	Ton-yr	5,175,532
Annual marginal generation	MWh-yr	68,227
Annual marginal imports	MWh-yr	4,880,213
Annual marginal exports	MWh-yr	5,375,448
Annual marginal NOX emissions	Ton-yr	22
Annual marginal SO2 emissions	Ton-yr	34
Annual marginal CO2 emissions	Ton-yr	45,463
Annual marginal NOX emissions from imports	Ton-yr	2,195
Annual marginal SO2 emissions from imports	Ton-yr	2,980
Annual marginal CO2 emissions from imports	Ton-yr	3,366,285
Annual marginal NOX emissions from exports	Ton-yr	2,319
Annual marginal SO2 emissions from exports	Ton-yr	3,138
Annual marginal CO2 emissions from exports	Ton-yr	3,566,872

Table 15: ED model aggregated operational results for PJM ComEd territory

5.4. Building Thermal Components Calibration

DR-DRE 2.0 uses information about buildings, such as capacitance (C), resistance (R), time constant, and HVAC power rating, in order to generate a thermal load profile. Because the ComEd data are anonymized, we are unable to identify information about any specific customer's building or HVAC situation. Instead, we infer information regarding technical details by varying these parameters and choosing the set of parameters that results in a DR-DRE-simulated thermal load profile that best matches the predicted thermal loads for each end-user in terms of annual cooling load.

After running these calibrations, we find the following range of values across all customers:

Parameter	Min	Average	Max
Capacitance (kWh/deg C)	0.299	1.544	2.900
Resistance (deg C/kW)	3.448	9.112	33.490
Time Constant (hours)	10	10	10
Annual Cooling Load (kWh-yr)	176.27	867.02	1,605.89

6. References

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