Cost Minimization of Generation, Storage, and New Loads, Comparing Costs with and without Externalities

Lance Noel^{1,2,*}, Joseph F. Brodie¹, Willett Kempton¹, Cristina L. Archer¹, Cory Budischak³

Abstract: The goal of this research is to understand the economics of anticipated large-scale changes in the electric system. 86 million different combinations of renewable generation (wind and solar), natural gas, and three storage types (hydrogen storage, electric vehicles equipped with vehicle-to-grid (V2G) technology, and building heat) are modeled within the PJM Interconnection. The corresponding electric systems are then operated and constrained to meet the load every hour over four years. The total cost of each energy system is calculated, both with and without externalities, to find the least cost energy systems.

Using today's costs of conventional and renewable electricity and without adding any externalities, the cost-minimum system includes no renewable generation, but does include EVs. When externalities are included, however, the most cost-effective system covers 50% of the electric load with renewable energy and runs reliably without need for either new conventional generation or purpose-built storage.

The three novel energy policy implications of this research are: (1) using today's cost of renewable electricity and estimates of externalities, it is cost effective to implement 240 GW of renewable electricity to meet 50% of the total electric load; (2) there is limited need to construct new natural gas power plants, especially from a system-wide perspective; and (3) existing coal plants may still be useful to the energy system, and instead of being retired, should be repurposed to occasionally provide generation.

Keywords: renewable energy; electric vehicles; externalities; vehicle-to-grid; energy modeling; renewable integration

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Nomenclature

Cap _{MW/MWh}	Capital Cost per MW/MWh	CG	Conventional Generation
EH	Electric Heat	EL	Electric Load
ES	Energy Storage	ESRB	Energy Storage Range Buffer
EV	Electric Vehicle	FOM	Fixed Operation & Maintenance Cost
Gen _k	Average Annual Generation for Generation Type k	GHG	Greenhouse Gas
GIS	Geographic Information System	H	Health Externality Cost
H ₂	Hydrogen Storage	HL	Heat Load
HP	Heat Pump	HS	Heat Storage
ICE	Internal Combustion Engine	ITC	Investment Tax Credit
LCOE	Levelized Cost of Energy	LMP	Local Marginal Prices
METSTAT	Meteorological-Statistical Model	MW _k	Installed Power Capacity for Generation Type k
MWh _k	Installed Storage Capacity for Generation Type k	NGH	Natural Gas Heaters
O&M	Operation and Maintenance	PTC	Production Tax Credit
PUC	Public Utility Commission	PV	Photovoltaic
r	Discount Rate	RG	Renewable Generation
RHTS	Resistive Heating with Thermal Storage	RPS	Renewable Portfolio Standard
RREEOM	Regional Renewable Electricity Optimization Model	RTO	Regional Transmission Organization
SCC	Social Cost of Carbon	SoC	State-of-charge
SOFC	Solid Oxide Fuel Cell	V2G	Vehicle-to-grid
VOM	Variable Operation & Maintenance Cost	WRF	Wind Research & Forecasting Model

1. Introduction

Large reductions in CO₂ emissions may require shifting from fossil fuels to electric power for light vehicles and building heat, while also generating increasing fractions of electricity from fluctuating renewable sources. Previous papers have investigated the plausibility and benefits of large-scale renewable energy

penetration. Jacobson and Delucchi (1) investigated the possibility of powering the entire world's energy demand by wind, water and solar power and concluded that, although significant investments would be required, it is plausible for wind, water, and solar to power the world's energy demand, given resource capacity and physical and material constraints. .

Focusing on the U.S. electric system, Arent et al. investigated the feasibility of large-scale renewable, finding that there are substantial benefits (without calculating the costs) of reaching 80% renewable (2) Likewise, Mai et al. calculate a pathway to 80% renewable by 2050, finding a 30% increased cost compared to current generation cost (not including externalities) (3). Another model, SWITCH, has been used to study how the US Western generation mix would change with carbon pricing (4), also finding 80% reduction in carbon emissions by 2050. Finally, a recent study (5) compares new wind and solar generation, and hypothesizes a future national electricity market, continent-wide transmission, and balancing over a national grid, finding a 80% renewable national grid in 2030 will cost the same as average electricity costs in 2012. Two previous studies based on the model used in this analysis (6) (7) compared fixed proportions of renewables via one price metric, and found that a significant percentage of hours could be covered with renewable energy, and that, at expected future costs, more than 90% of hours could be covered by renewable energy at a cost lower than current prices

Rather than fixing the target fraction of renewable energy, this study models a large U.S. electric system (now 165 GW generation, with 85 GW_a average load), iterating to create 85,766,121 possible variants of generation, storage and new loads, then running each through 4 years of hourly operation. Building on previous literature, the costs and benefits of each of these possible energy systems are evaluated to find those that minimize the net present cost to society. An innovative aspect of this approach is that the optimal fraction of renewable energy generation is therefore an outcome, not a constraint.

For perspective, the cost minimization calculations in this article are not a reflection of current decision-making. In the United States, decisions regarding electricity systems are reviewed and approved by state public utility commissions (PUCs), which minimize only the market cost of electricity, ignoring the health and environmental external costs. Outside the PUC evaluation, other state or Federal agencies use regulatory mechanisms to reduce pollution. The model here provides a common metric to compare the minimization of only internal costs versus the minimization of all costs to society. The model does not project future population nor continuing declines in the cost of renewable generation. Rather than predicting a least-cost future, one can think of this analysis as answering the question: "If policies had been minimizing social cost, what would the energy system look like today?" Or, looking forward, the results could be a guide to the energy system if external costs are incorporated into the price of fuels.

This article models four types of new generation—land-based wind, offshore wind, solar photovoltaics (PV), and natural gas. The model also includes two new types of load (i.e., the conversion of vehicles and building heat to electricity), along with the benefits and costs of such fuel switching; secular load growth is not modeled. For possible new storage, the model includes hydrogen as purpose-built storage and two other forms of inherent end-use storage, vehicle-to-grid (V2G) electric vehicles (EVs), and electric heat storage (EH),

with the latter two becoming available only as their associated loads do as well. Because the model includes transportation and heating sectors, most of the calculations consider changes in the societal cost of *energy* including displacing vehicle and heating fuels, not just electricity (some cost-minima change when both are included). Electricity, transport and building heat represent more than two thirds of carbon emissions in the U.S. (8) and have commercially ready renewable alternatives. The model, based on (6), is constrained to meet electric and heating load each hour. It models a real electric grid, the PJM Interconnection, a large US regional transmission organization (RTO), using hourly load, weather, and solar data for years 2010 through 2013.

Compared to previous studies, the work presented in this article contributes to the literature in in three novel ways. First, the model integrates electricity, storage, transportation and heating systems. In contrast, previous models only focused on the electricity system, and often ignored EVs and EH, with even fewer including V2G and heat storage. Secondly, this study models over 86 million different combinations of energy systems, compared to previous studies that reported the characteristics of one to several energy systems, allowing for comparisons across different types of energy systems. The iterative nature of the model can more precisely estimate the marginal cost of increasing renewable share of electric load and, at the same time, capture the various technological pathways of reaching a certain percentage of renewable. Lastly, this work is unique to analyze the costs of each energy system both with and without externalities and to explore the differences in the cost-minimum systems and their renewable penetration. In sum, this research analyzes a currently-existing market, adds new types of load, storage and generation, and compares cost-optima with and without externality costs. The methods are described in the Methodology and in the Supplemental Section.

2. Methodology

This study utilizes and modifies the Regional Renewable Electricity Economic Optimization Model (RREEOM), developed by Budischak et al. (6). The Supplemental Section describes the improvements to RREEOM's economic calculations and modeling. This study attempts to incorporate more comprehensive economic costs than original version of the model, but also makes some simplifications, see section 2.2.1 below for full discussion of assumptions. Compared with more typical economic models, this model lacks valuation of consumer preferences, the increasing marginal cost of implementation, and price elasticity. Geographically, RREEOM's data is exclusively within the PJM territory; the article does not model power transfers to and from other RTO regions, nor does the model consider deployment time constraints. Instead, the purpose of this work is to show the implications of monetizing externalities on the development of renewable energy within a large region.

2.1 Model Inputs

The model represents three main energy- and carbon-producing sectors: electricity generation and storage; light-duty vehicles, and building heat. For each sector, the model requires two types of inputs. First, the cost of each technology, which consists of capital costs, operation and maintenance (O&M), and externalities. Second, in order to determine how much of each resource is needed, the hourly load and resource capacity of each technology (e.g. how much load hourly; how much wind and sun hourly) is similarly required. In overview, the model generates all possible combinations of each generation, storage, and new

111 load; each combination is called an “energy system”. Then the model runs each energy system for four years
112 to determine how load is met by generation and storage, given yearly variations in wind and solar production.
113 The method for calculating the inputs for each of the sectors is discussed next in broad terms, while the
114 Supplemental Section gives more details.

115 2.1.1 Costs

116 To calculate costs, electricity production was disaggregated into six generation types: offshore wind,
117 land-based wind, solar, nuclear, natural gas, and coal. Offshore wind, land-based wind, solar, and natural gas
118 were modeled as potential new capacity installations. The model does not include new nuclear and coal power
119 plants as these are much more costly than new natural gas plants (9), and currently few or none of these are
120 planned for new generation capacity in PJM. This is a reasonable simplification because, in fact, of the nearly
121 60 GW of new generation planned in PJM over the next ten years, over 95% is either wind or natural gas (10).
122 There are no nuclear plants on queue in the PJM territory, and planned new coal generation is about 1% of
123 total PJM capacity (10). In the model, whenever renewable generation, plus storage, fails to meet the load, the
124 difference is met by today’s PJM conventional generation (see Figure 1 below). Coal, natural gas and nuclear
125 together make up 89% of today’s PJM power capacity and 95% of annual energy generation (11). Thus, while
126 the total PJM electricity capacity is 186 GW, and includes wind, solar, pumped hydro, and oil, for the purposes
127 of simplified modeling, the model’s current generation includes only nuclear, coal, and natural gas, a total
128 capacity of 165 GW. The model also ignores current renewable generation, which comprised less than 2% of
129 annual electric energy, and less than 1 GW of power capacity (10) during the modeled years. Economically, the
130 model assumes that the existing PJM system does not have any capital costs, and only operating costs are
131 considered. To model new generation and storage, the capital costs are based on 2013 estimated costs (12)
132 (9), inclusive of transmission and interconnection costs. Wind is modeled to increase in capital cost as the
133 lower cost sites are used up first, both for land-based and offshore wind.

134 Operation and maintenance (O&M) costs were included for both existing and new installations and
135 were divided into fixed (FOM) and variable (VOM) costs. FOM includes O&M costs not associated with
136 operating hours, such as scheduled maintenance, while VOM increases with greater utilization of the power
137 plant, for example, component wear, and notably consumable materials such as fuel. Estimated FOM and
138 VOM costs for each generation type were drawn from EIA (9) (13) (14).

139 Two categories of external cost were included: health and climate change. Health externalities were
140 based on health impact studies per type of generation, drawn from three studies (15) (16) (17). Climate
141 externalities use lifecycle GHG emission rates for each generation type (18), converted to cost using two
142 Federal calculations: an “average” and “realistic worst case” social cost of carbon (SCC) estimates (19), SCC1
143 and SCC2 in the model.

144 Secondly, storage was divided into two types: hydrogen storage (H_2) and V2G-capable electric vehicles.
145 Purpose-built batteries were found by Budischak et al. (6) to not be cost-competitive and therefore are not
146 modeled here. For H_2 storage, it was assumed that an electrolyzer would generate H_2 in an aboveground
147 storage tank, and associated fuel cells would convert the H_2 back to electricity. Capital costs and conversion

losses associated with H₂ were based on a solid oxide fuel cell (SOFC), an electrolyzer, and a steel tank (20). On the other hand, estimating the capital cost of V2G was more complex. V2G is low-cost because it uses storage and grid connections purchased for the electric vehicle's primary purpose, transportation. A secondary purpose, electricity storage, is accomplished by adding control equipment, at minimal capital cost. Currently, most people are not choosing to buy an electric vehicle, therefore, the model calculates the added capital costs for V2G based on surveyed willingness-to-pay for an electric vehicle, with the assumption that an incentive would be required to get people to buy an EV in the first place. The needed incentives were based on a stated preference survey (21), compared to the average cost of a gasoline vehicle (22); this is added to the cost of EV purchase, reflecting the cost of adding this load and storage resource. This difference was then converted into the cost per kWh of added battery capacity. Unlike previous models, the willingness to pay for an electric vehicle in this model is heterogeneous across the population—system-wide, that means that more is paid for each additional marginal kWh of V2G storage as more EVs are added. For further details, see the Supplemental Section.

H₂ storage uses no fuel, and its VOM electrical input cost is accounted for in round trip losses, not in input electricity; an additional FOM cost is based on the literature (23). For V2G storage, VOM and FOM costs are calculated in the context of the displacement of internal combustion engine (ICE) vehicles, which have been found to be more expensive to maintain. However, given the lack of data regarding EV FOM, the model conservatively assumes that there is no net change regarding FOM of EVs. On the other hand, EV VOM incurs a cost by adding load to the grid, but also a benefit in that gasoline consumption is displaced. Both of these are estimated from average miles driven per year, gasoline efficiency (24), and the current cost of gasoline, with federal and state taxes removed (25). These savings are calculated as a benefit per megawatt-hour (MWh) of EV capacity per year, thus effectively a benefit of adding V2G storage. Similarly, the externalities associated with EVs were calculated as the health benefits from reduced gasoline consumption (26) and climate change mitigation benefits (27) (19). Likewise, the cost of replacing batteries due to degradation, based on estimated future battery pack prices (28), is also included in EV VOM. Unlike EVs for V2G storage, H₂ storage does not directly cause any externalities, nor does it directly displace any significant externalities.

For large scale renewable penetration, recent models show that the most cost-effective electrical systems will be configured so that generation exceeds load during certain hours, which for wind, would be more likely to occur in the winter (6) (29). It has been proposed that this excess generation can be used for heat (7) (6). The model assumes a hybrid system comprising of a heat pump (HP) and resistive heating with thermal energy storage (RHTS), both with their own benefit; HP provides high efficiency while RHTS has low capital costs and allows compact, long-term heat storage (due to much higher temperature) (7). Similarly to V2G storage, increased penetration of EH would displace natural gas heaters (NGH), which comprise about 75% of all non-EHs in PJM (30). The capital cost of each technology is based on (7). The FOM of an HP/RHTS hybrid system is less than the FOM cost of a NGH system, implying a FOM savings as HP/RHTS penetration increases (7). Meanwhile, the model includes the sole added component of VOM for heating as the fuel cost of natural gas. While EH will add to load, it will also displace natural gas consumption, thus, the VOM cost is based on natural gas fuel savings (31). Likewise, the externalities are based on the reduction of health damages due to natural gas combustion (32)(33), and reduction of climate change emissions (34), (19).

2.1.2 Resource Assessment and Production

A resource assessment for PJM is required in order to set the maximum capacity of each new generation and storage resource in the model. The resource maximum is used to set an upper limit for iterating through possible electrical systems, as the model builds each type of generation from zero to the maximum capacity. Production is computed hourly, and compared to load for each hour over a four-year period, from 2010 to 2013. The resource maximum for new natural gas generation and H₂ storage has no natural limit as they are man-made. Thus, based on preliminary model runs, their maximum resource limit was set well above what would be cost effective.

Land-based wind capacity was determined based on state-by-state data, using a report of potential wind capacity in each state, given sufficient wind speeds and exclusion areas (35). Since some states are not entirely within PJM, these state numbers were adjusted to reflect wind capacity within PJM's territory (36). These calculations yield a total 201 GW capacity within PJM territory. Moreover, to account for spatial variability, the model assigns areas into one of three capacity factor ranges (see the Supplemental Section) and utilizes the windiest areas first. Next, the hourly capacity factors, i.e. the ratio of the actual production over the maximum capacity are calculated based on four years of actual hourly wind generation data in PJM from 2010 to 2013, obtained as part of a joint UD-PJM project (37). Because the vast majority of wind turbines operating during these four years have a smaller rotor diameter than wind turbines being installed today (38) (39), and because the model seeks to accurately reflect today's technology, the capacity factors were accordingly adjusted to reflect current turbine technology and practices. See the Supplemental Section. After this adjustment, the average capacity factor across all of PJM would have been 0.351 if today's larger rotor diameter wind turbines had been deployed. Hourly land-based wind generation was obtained as the product of the hourly adjusted capacity factor by the total capacity.

Rooftop solar capacity was also determined on a statewide basis (40). To determine the proportion of states only partially covered by the PJM territory, Geographic Information System (GIS) data were used to find the relative household density within the PJM service area of each of these states (41), and compared to the GIS solar capacity (42), (40), resulting in a maximum capacity of 96 GW in the PJM territory. Hourly solar data were gathered from all the locations within NREL's Meteorological-Statistical (METSTAT) solar model that would fall under PJM jurisdiction. At each location, the solar radiance was modeled in watt-hours per square meter (Wh/m²) based on the METSTAT model (43). This was converted into an hourly capacity factor by dividing modeled radiance by 1,000 Wh/m², the ideal solar radiance for maximum capacity, and then multiplying by 0.80 to account for losses, resulting in an average capacity factor over the four years of 0.134. Since solar capacity did not change significantly across the PJM territory, this same capacity factor was used in all PJM locations, and the same solar capacity was aggregated and treated as a single solar plant.

For offshore wind, the maximum capacity in PJM was based on areas that were available for offshore wind development adjacent to the PJM states, from Virginia to New Jersey, with exclusion areas removed (37). Based on this work, 78 GW of offshore wind could be developed and connected to the PJM area. This capacity was divided into two areas in this study, based on water depth, with the deeper areas requiring greater capital costs, primarily due to increased foundation costs and associated financing (44). Hourly generation of offshore

225 wind over the four years was determined using the Weather Research & Forecasting (WRF) model. From
226 hourly wind speeds and the power curve of a model turbine (the REpower 5MW) the production of offshore
227 wind power minus losses was calculated. As a benchmark, the average capacity factor over the four years was
228 0.424.

229 The maximum V2G capacity is based on total motor vehicle registration within the PJM territory (45)
230 (41). The number of vehicles was multiplied by average battery capacity per car (21) to obtain the maximum
231 potential V2G storage capacity in PJM of 1,950 GWh. Likewise it was assumed that for every EV there would
232 be, on average, a 10 kW bidirectional charger (some smaller; others larger), resulting in a maximum power
233 capacity of 521 GW. From the perspective of the model, the total capacity of V2G is treated as one single
234 aggregate battery. This battery was constrained each hour by three conditions: first, it must never go below its
235 range buffer for unexpected trips of 20% state-of-charge (SoC); second, its capacity is limited by the amount of
236 time the vehicle is being driven and thus disconnected from the charger, decreasing the capacity on average by
237 7% (46); and third, the aggregate battery “loses” energy for driving, approximated as if it were a leakage rate at
238 0.86% of its maximum kWh capacity each hour.

239 Lastly, the maximum heating capacity “resource” is based on the maximum heat load, as calculated by
240 (7). The authors also calculated the hourly heating load over the four years. For each electrical system, heat
241 storage is filled at times of excess electricity and emptied as needed for building heat (see Figure 1 below).

242 2.2 Description of the RREEOM Model v. 2.0

243 The model is based on RREEOM (6), though significantly modified. The original RREEOM was
244 constrained to meet hourly electrical load from renewable generation, storage, and back-up thermal
245 generation, in the least costly mix possible. To capture the range of possible energy systems, Budischak et al.
246 (6) created 1.6 billion different possible electricity systems, with 70 different possible values for each of the five
247 input variables. The present model modifies several key aspects, including the incorporation of EV driving
248 behavior, minimum SoC, driving load, thermal load from heat demand, and the possibility of new natural gas
249 development. Because these additions factorially increase the number of combinations, the updated RREEOM
250 steps through 21, rather than 70, increments of possible values for each of the six input variables (solar, land-
251 based wind, offshore wind, H₂, V2G, and EH). This creates $21^6 = 85,766,121$ (86 million) combinations of new
252 generation, storage, electric vehicles and electric heating.

253 The model iteratively creates each energy system, then compares that system’s renewable electricity
254 generation for each hour to the hourly electricity load within PJM from 2010 to 2013 (47), 35,064 hours in
255 total. During those four years, the maximum actual PJM electrical load was 158 GW, and the average hourly
256 load was 86 GW_a. Furthermore, the model also keeps track of the hourly heat load (7), which had a maximum
257 of 180 GW_t with an average of 52 GW_t.

258 When testing each energy system during the four years, if renewable generation at a given hour is less
259 than the combined electric and thermal load, the model will use all available storage to meet those loads. Any
260 remaining load will be met by generation from the current PJM system (as a simplification, only current
261 thermal plants), dispatched according to lowest hourly cost, and as constrained by estimated ramp rates. If

262 there is still more load, the model will then construct and then use as many new natural gas generators as
 263 needed. In the Supplemental Section, the assumption that building new natural gas is more expensive than
 264 using existing generation is tested, and it is concluded that it is cheaper to dispatch the current PJM system
 265 first, justifying the above-described simplified algorithm. Conversely, if renewable generation at a given hour
 266 exceeds electricity load, it will then be used to meet heat load via heat pumps. If there is remaining excess
 267 renewable generation, it will be put into electric storage, if any excess remains after that, it is put into high
 268 temperature heat storage via electric resistance. If excess generation still remains, it will be spilled. It should
 269 be noted that the spilled excess generation in practice would likely be sold in inter-regional markets, but this is
 270 outside the scope of the current model; as a consequence, the model underestimates the value of excess
 271 generation. The logical operation of the model is illustrated in Figure 1.

272
 273 Figure 1. RREEOM Hourly Flow Chart
 274

2.2.1 Model Assumptions

The model makes several simplifying assumptions. The model assumes that there is perfect transmission (the “copper plate” assumption). It assumes that no energy will be imported or exported to other connected TSOs; ignores reserve requirements, within-hourly fluctuations of load and generation, retirements of existing power plants, and does not include the possibility of demand-side management. Demand-side management, including demand-response and energy efficiency, were not included so as not to rely on assumptions of the amount and cost of demand-side management; as well, their omission makes interpretation of the results more direct. In reality, demand-side management will be useful and cost-effective for matching generation to load in the actual implementation of renewable generation, but this is outside the scope of this paper.

These simplifications are also discussed in Budischak, et al., (6) at 62-63. They allow the model to show what an electricity system would look like and how it could work with various penetrations of renewable energy; it is not intended to model sub-hourly dispatch decisions. Furthermore, with large amounts of storage, over- and under-generation due to ramp rates, within-hour fluctuations of load, and reserve requirements would be addressed by dispatch of quick storage which is plentiful for other reasons in all the low-cost systems (48).

One important implication of the model's large increase in load from today, yet not allowing export from the wind-rich Great Plains, is that limited and increasingly expensive wind within PJM is used. By contrast, Budischak et al. (6) assumed that wind generation could be drawn from outside the then-PJM footprint, resulting in three findings quite different from the present study: it was cost-effective to build 90% renewables (with externalities included), building 99% renewables, although more costly, required much less conventional generation than seen here, and storage was both normally full and utilized much more than here.

Likewise, similar to the previous model (6), this model aggregates and simplifies the spatial aspects of the electricity grid, connecting all generation and load. While this oversimplifies the balancing challenges of renewable electricity integration, there is also an abundance of quick storage geographically dispersed present in the low-cost systems. The computationally-intensive spatial consideration of the electricity grid is outside the scope of the work presented here, and should be developed in future work. Relatedly, another implication concerns the model's simplifying assumption of uniform prices within the entire PJM area, whereas in fact, "Locational Marginal Prices" (LMPs) are higher in PJM's East and North, and wind energy costs are much less in the Great Plains, to the West of PJM. Thus, some additional thermal generation might be built in areas with higher LMPs, and offshore wind and solar would be more competitive in the Northeast, than shown in the results based on PJM average costs. Further, the low-cost onshore wind capacity would not be limited to 201 GW, implying cost-effective results at higher renewable penetration.

2.2.2 Cost Calculation of the Model Output

The model calculates the cost for each system in net present value over a 25-year lifespan, using a 3% discount rate (a social discount rate, appropriate to show the cost to society) (49). Note that the model uses

net present value rather than the more conventional metric of cost, levelized cost of energy (LCOE) in cents/kWh; either works equally well to find minimum cost systems. These costs are calculated based on the inputs, as previously discussed. The model calculates the cost as if these hypothetical energy systems are built in the beginning of each run, and thus underestimates the build-out constraints and lower costs due to learning curves of renewable energy deployment. The purpose of this paper is not to show how or at what pace to develop energy systems, but rather what energy system the nation would have developed, if minimizing total social costs. One novelty of the analysis is the ability to vary the extent to which externalities affect cost minimization, allowing for policy comparisons. As noted, costs for each energy system are calculated for four different cost metrics, varying by the addition of external costs. For each cost metric, the least-cost system is found as one minimizes Equation 1 below.

Equation 1. 25 Year Net Present Cost Calculation

$$Cost = MW_k * Cap_{MW_k} + MWh_k * Cap_{MWh_k} + \sum_{i=1}^{25} \frac{MW_{i,k} * FOM_k + Gen_{i,k} * (VOM_k + H_k + SCC_k)}{(1+r)^i}$$

Where all symbols are defined in the Nomenclature Table, for generation type k for year i

3. Results

3.1 Minimum-cost electric systems

The costs for each of the 85,766,121 energy systems were calculated using four cost metrics: market cost without any externalities (“Market”), then market cost plus health externalities (labelled “M+Health”), then adding to those an “Average Case” social cost of carbon (the “M+H+SCC1” cost), and alternatively substituting for SCC1, a “Realistic Worst Case” social cost of carbon (19) (“M+H+SCC2”). Table 1 shows the power capacity and energy production mix for each minimum cost solution, based on each of the four cost metrics. For example, using the M+Health cost metric to pick the lowest cost of the 86 million energy systems, the minimum-cost system has 4.8 GW of solar capacity and 121 GW of wind, no new electric heat but 235 GW of new EV, while retaining 156 GW conventional generation, for a total of 282 GW generation capacity (compared to 165 GW today). This capacity produces 101 GW_a to meet load (compared to 86 GW_a today), the greater capacity and generation needed due to additional EV load.

Table 1. Power Capacity, Electricity Produced, storage, and new loads in each the four Minimum-cost Energy Systems.

	Power Capacity in GW (now 165 GW)				Electric Energy Produced in GW _a (now 86 GW _a)			
	<i>Market cost</i>	<i>M+ Health</i>	<i>M+H+SC C1</i>	<i>M+H+SC C2</i>	<i>Market cost</i>	<i>M+ Health</i>	<i>M+H+SC C1</i>	<i>M+H+SC C2</i>
Generation								

Solar PV	0	4.8	33.9	77.4	0	0.7	4.54	10.4
Land Based Wind	0	121	191.6	201.7	0	41	58	61.1
Offshore Wind	0	0	0	19.5	0	0	0	8.25
Conventional Generation	181	156	153.5	159.5	111	59	50	43
<i>Sum of generation</i>	181	282	379.0	458	111	101	113	123
Storage	<i>Capacity (GW)</i>				<i>Discharged to grid (GW_a)</i>			
V2G EVs	235	235	365	417	0	0.65	2.1	3.2
H ₂ Storage	0	0	0	0	0	0	0	0
New Loads	<i>Load power capacity (GW)</i>				<i>Load energy consumed (GW_a)</i>			
EV charging	235	235	365	417	7.6	7.6	11.8	13.4
Electric Heat (of 180 GW; 52 GW _a)	180	0	126	180	52	0	37	52

339

340 Several trends are seen across Table 1. Generally, as more external costs are considered, systems with
341 more renewable energy are picked as least expensive, conventional generation capacity declines modestly, and
342 conventional production declines substantially. Examining each minimum-cost system (each column), first,
343 selecting by market cost only, the minimum-cost system builds no renewable electricity. This result conveys
344 that without monetizing externalities (and without existing tax credits), it is not cost effective to build GW-scale
345 renewable generation. Thus, the model with Market-cost optimization approximately replicates current
346 decisions by utilities and PUCs, which until recently built only minimal amounts of renewables. The market
347 cost-only metric does develop substantial EH and EVs. Thus, while fuel saving alone does not incentivize
348 renewable electricity, it does incentivize the implementation of EVs and EH.

349 In contrast, the M+Health metric selects 121 GW of land-based wind and 4.8 GW of solar PV, together
350 producing 42 GW_a of electricity, about half of electricity consumption. Implicit in this jump up is that there is a
351 threshold effect for renewable electricity, where a great deal is built above a certain price of conventional
352 generation, but none below that price. Though this energy system develops large amounts of renewable
353 energy, almost all goes directly to load; only 1.8% of generation is spilled, thus there is insufficient excess
354 generation to economically power EH and little need for storage.

355 M+H+SCC1 almost doubles renewable capacity to 220 GW, and accelerates fuel switching, converting
356 70% of all NGH's to EH and 70% of all ICE vehicles to EVs. Note that these more complete externality costs lead
357 to a system with renewable generation capacity that is substantially larger than load, thus there are more
358 hours of excess production than with Market or M+Health alone, effectively lowering the cost of electricity for

359 EV and EH. This combined effect illustrates the value of modeling renewable generation each hour along with
360 new flexible loads.

361 Figure 2 shows the interaction among renewable generation, electric and heat storage, and
362 conventional generation in the M+H+SCC1 minimum-cost energy system over each hour of the four modeled
363 years. Renewable generation ranges from 2.9 to 179 GW and conventional generation is required throughout
364 the four years for both electric and heating loads. Heat storage is recharged only when excess generation and
365 lower loads occurs, and only 0.8% of the total annual heat load is met via heat storage.

366

367 *Figure 2. Hourly Generation and Storage State-of-Charge for the Minimized Energy System under the*
 368 *M+H+SCC1 metric a) Renewable Electricity Generation, b) Energy in Electrical Storage, c) Dispatched*
 369 *Conventional Generation Used to Meet Electrical Load (excluding heating), d) Energy in Heat Storage, e)*
 370 *Dispatched Conventional Generation Used to Meet Heat Load*

371

372 Finally, M+H+SCC2 is dominated by 299 GW of renewable capacity, as well as converting 100% of
373 buildings to EH and 80% of all vehicles to EVs. M+H+SCC2 is the only system to implement any offshore wind,
374 and also the only to build the maximum amount of land-based wind, 201 GW. Because electric load has
375 increased from EVs and EHs, despite 299 GW of renewable electricity, this energy system requires 159.5 GW of
376 conventional electricity capacity.

377 Across all four minimum-cost energy systems there are several consistent trends. Each requires
378 substantial conventional generation capacity. Despite new loads in all systems, all minimum-cost energy
379 systems (except the Market energy system) require less conventional capacity and less conventional energy
380 generation than the current PJM grid. None of the minimum-cost energy systems that include externalities
381 require the construction of any new conventional generation, despite new load and hundreds of GWs of
382 renewable electricity capacity. Moreover, the average energy used from conventional generation decreases as
383 externalities are monetized, though only down to a lowest of 43 GW_a. Correspondingly, none of the minimum-
384 cost energy systems implement any hydrogen storage, and use very limited amounts of V2G storage to meet
385 load. That is, it is cheaper to utilize the current legacy generation of PJM and storage inherent in EVs and EH
386 when renewable generation is insufficient rather than to build extra storage or new conventional generation.

387 Table 2 shows the cost of implementing each of the four minimum-cost electricity grids incrementally
388 to today's cost. These additional costs are calculated for the four cost metrics for each minimized grid for the
389 point of comparison. One way to read Table 2 is if the "Market" column (columns are how the minimum cost
390 system is picked) and the market row (the metric that calculates row's cost), this intersection being the method
391 and metric of PUCs today - the cost of electricity is close to today's actual wholesale price - just 1.3 ¢/kWh
392 higher. However, society actually has to pay these external costs, so, continuing down the column, the actual
393 cost to society is 5.7 to 10.9 ¢/kWh above today's wholesale price. Conversely, using the lowest cost electric
394 system under M+H+SCC2 (the right most column), the social cost is the cheapest—an additional 7.7 ¢/kWh
395 (lowest number on bottom row). Yet from a PUC perspective (i.e., only considering market costs, that is, only
396 reading the top row) the M+H+SCC2 system would not be least expensive, it would add 5.4 cents per kWh.

397 While storage is used only at limited times (Fig. 2), it still plays an important cost-reducing role.
398 Excluding all forms of electrochemical storage, the M+H+SCC1 cost-minimized energy system would only
399 construct 175 GW of renewable electricity (51 GW less than the central results), and cost \$230 billion more
400 than the central results, which utilize 365 GW and 1,369 GWh V2G storage capacity, costing \$742 billion to
401 implement. To replace V2G with the same capacity of purpose-built hydrogen storage, however, it would cost
402 society an additional \$416 billion. To the extent storage reduces the cost of the energy system, V2G is a cost-
403 optimum way of providing storage.

404

405 *Table 2. Additional electric Cost per kWh of each Minimum-Cost Energy System (in cents per kWh added to*
406 *today's market price). Columns are the cost metric used to pick the minimum cost system. Rows describe which*
407 *costs are included in the ¢/kWh figures in that row. External cost savings of load shifts from fuel to electricity*

408 are included in picking the minimum cost system (columns) but not in the calculation of electricity cost
409 increments (rows).

		Metric used to choose minimum-cost system			
		Market Cost	M+Health	M+H+SCC1	M+H+SCC2
Metric for electricity cost increment (¢/kWh)	Market Cost	1.3¹	4.2	4.7	5.4
	M +Health	5.7 ²	6.4	6.2 ²	6.5
	M +H +SCC1	7.6	7.2	6.8	6.9
	M +H +SCC 2	10.9	8.6	7.8	7.7

1. This electricity cost is higher than today's grid (despite no added renewable electricity) because the total load has increased due to higher levels of EVs and EHs.
2. Note that two electric cost increments (marked with note 2) are unexpectedly cheaper per kWh than the diagonals, due to the fact that these cost increments include the cost of new generation but not the externality savings from EV and HV fuel switch from fuels to electricity.

410

411 Trends across Energy Systems

412 Next the costs of all energy systems modelled are compared. Figure 3 compares the costs of all energy
413 systems (not only minimum-cost ones) across increasing amounts of load covered by renewables. The figure
414 also illustrates that the maximum amount of renewables, regardless of cost, was 92.6%. This maximum is
415 lower than the 99.9% calculated in Budischak, et al. (6) due to today's larger PJM territory, new loads from EVs
416 and EH, and the limitation on wind capacity—all of which led to a low wind production to load ratio.

417 Whereas Figure 3a shows the costs for *all* energy systems, 3b shows only the cost-minimized systems
418 at each renewable percentage, the two lines distinguishing cost indexes (Market versus M+H+SCC1). The low
419 points of each line in Figure 3b correspond to the single selected electric systems of Table 1, that is, the
420 minimum cost system includes near-zero renewables if the cost-minimum is picked by market cost only, but
421 renewables cover 50% of load for M+H+SCC1 (see the corresponding energy columns of Table 1). The
422 M+H+SCC1 curve is very flat—for example to move from the 50% cost minimum to 70% renewables, it costs
423 only 2.3% more. By contrast, the market cost curve rises monotonically with more renewables. Both curves
424 become exponentially more expensive to about 90% renewables, because PJM renewable resources are more
425 scarce, in poorer resource areas, thus more expensive, given the restriction to locate them within PJM territory
426 only. This exponential increase highlights the limitation of the model; in reality, if PJM were to aim for more
427 than 85% renewable in the near-term, other techniques would be utilized, such as demand-response,
428 importing wind from the Midwest, efforts to increase energy efficiency, or building other, less common types
429 of renewable electricity.

430

431 a)

432

433 *b)*

434

Figure 3. Comparing energy systems by Renewable Share of Load (x-axis) to Net Present Cost (y-axis) Cost is given both as market (no externalities) and as M+H+SCC1. a) Cost of every Energy System at each percentage of load covered by Renewables. b) Minimum Cost Energy System at Each Percentage of Load covered by Renewables

As another view of cost-minima, Figure 4 shows how land-based wind versus solar (the two most utilized renewables) affect cost, assuming zero implementation of other technologies. Figure 4a shows Market cost (via color) and 4b shows M+H+SCC1 cost (note, 4a and 4b use different color scales but both use red for highest cost). In 4a, the lowest cost region is the extreme lower left, with any increases in solar or wind increasing cost, and highest costs at the upper right maxima. Figure 4b, measuring by M+H+SCC1 shows that from the origin, increasing either solar or wind reduces cost. Wind has a much larger effect--if wind is held at zero, no amount of solar alone significantly reduces the cost. Conversely, if half the wind resource is built (120 GW), cost is dramatically reduced and much solar can be built without increasing cost. The general shape of 4a versus 4b has a lesson in the "optics" of renewables -- if one only considers market cost, it appears that anything more than small amounts (~10%) of renewables quickly increases costs, whereas the true cost as in 4b, is substantially higher if large amounts of wind are not built; adding solar causes a very small but non-zero reduction in social cost.

455 Figure 4. The Relative Impact on net present cost ($\$ \times 10^{12}$) of energy systems, comparing all combinations of
 456 land-based wind and solar. a) Market with cost metric shown by color. b) M+H+SCC1 with cost metric shown
 457 by color.

458

459 **4. Sensitivity Analyses**

460 Beginning from the central results shown in Figure 2, four alternative cost inputs were substituted to
 461 determine how much input assumptions affected the results (additional sensitivity analyses are in the
 462 Supplemental Section). Table 3 summarizes the resulting minimum-cost systems based on both Market and
 463 M+H+SCC1 cost metrics.

464 *Table 3. Comparison Of Alternative Assumptions on Power Capacity Mixes (in GW)*

	Solar	Offshore Wind	Land-based Wind	V2G	Hydrogen	Total Conventional (now 165)	New Natural gas generation	Electric Heat
Maximum Resource Capacity	97	77.5	201	521	∞	∞	∞	180
<i>Central Results</i>								
Market	0	0	0	235	0	180	17	180
M+H+SCC1	33.9	0	191	365	0	153.5	0	126
<i>7% Disc. Rate</i>								
Market	0	0	0	104	0	162	0	0
M+H+SCC1	0	0	101	156.5	0	148	0	36
<i>2030 Cap. Costs</i>								
Market	0	0	0	496	0	191	26	180
M+H+SCC1	53	19	201	496	0	154	0	144
<i>With PTC/ITC</i>								
Market	0	0	20	231	0	171	6	180
M+H+SCC1	77	0	201	365	0	153	0	153
<i>2030 Cap + PTC</i>								
Market	0	0	20	496	0	180	15	180
M+H+SCC1	72.5	27	201	496	0	165	0	180

465

466 The first sensitivity analysis was to change the discount rate from a social discount rate (3%) to a
 467 commercial discount rate (7%). The discount rate is used to convert future costs and benefits to their present
 468 value. In comparison to the central results, using a higher discount rate leads to a minimum-cost energy
 469 system with 120 GW less renewable electricity with M+H+SCC1, and 150-200 GW less of V2G (in both M and

470 M+H+SSC1). This happens because renewable electricity and transport generally have higher upfront costs yet
471 the future benefits of fuel savings and future damage reduction are less valuable with a higher discount rate.

472 The second sensitivity analysis uses 2030 capital costs for new technologies, based on the mean of
473 published estimates for the future capital costs of solar (50) (51) (52) (3) (53) (54), land-based wind (50) (51)
474 (55) (3) (56), offshore wind (50) (57) (55) (3), and EV lithium ion batteries (58) (59) (60) (61)(Fuel cost increases
475 in 2030 were not included). The minimum-cost energy system without externalities differs only in having
476 substantially more EVs, due to substantially lower battery costs. These results, taken together with the central
477 results finding large-scale EV adoption to be cost-effective, and imply that the barrier to EV implementation in
478 the near future will not be the cost of technology, but rather consumer willingness to drive EVs. If the model is
479 correctly capturing consumer preferences, social aspects of EVs should be the focus of any EV incentive. Unlike
480 EVs, renewables may require market mechanisms such as monetizing externalities or direct renewable policies,
481 as this sensitivity analysis suggests that reduced technology costs alone may not encourage renewable energy
482 development to the socially-optimal level. This finding seems more pessimistic than current conditions in the
483 U.S. Great Plains (outside PJM), where current costs of wind are below cost of conventional generation, and
484 where wind is approximately half of new generation (39).

485 The U.S. Production Tax Credit (PTC) and the Investment Tax Credit (ITC), are current incentives for
486 renewable electricity development. However, the model finds that the PTC and ITC alone lead to only 20 GW
487 of renewable generation at market cost, versus almost 280 GW if pricing includes external costs. While the PTC
488 and ITC would encourage some renewable electricity, without the monetization of externalities, like 2030
489 capital costs, it is not enough to encourage similar amounts of renewable electricity as would including
490 externalities. Adding the PTC and ITC to the 2030 capital costs reduction (last row in Table 3) also does not
491 produce substantially more renewable development, again showing that including externalities is the most
492 powerful incentive.

493 **5. Conclusions**

494 These conclusions address system operation and three policy observations. The scenario with highest
495 renewables (458 GW capacity and 123 GW_a production) and high new loads (597 GW new plug capacity and
496 65.4 GW_a average load), works as a reliable system and provides assured power despite weather fluctuations.
497 This least cost system (M+H+SCC2) builds out more renewables than needed to meet current types of loads,
498 with excess going into both EV and EH, and some periods of generation deficit supplied by discharge from EV.
499 A notable finding is that this system is reliable without either new generation or purpose-built storage, while
500 noting the model's spatial simplification, especially in regards to transmission and balancing. The high stability
501 without any purpose-built storage suggests that, if land-based wind were not limited to the PJM footprint, the
502 model may have found that the least-cost system would have had substantially more renewables, as did (6).

503 As the first policy-related conclusion, using today's costs plus externalities, it is cost-effective both to
504 implement 240 GW of renewable electricity capacity to meet 50% of total electric load, and to convert 70% of
505 building heat to electricity and 70% of light vehicles to EVs. In the current policy environment, PSC and
506 business decisions are based only on market cost—separate environmental policies, such as a “Renewable

507 Portfolio Standard” (RPS), mandate a minimum amount of renewables. Current RPSes in PJM states require an
508 average 18% by 2023 (62). --In contrast, the model finds that 50% is the PJM cost-optimum. These results
509 would support policies such as far more ambitious RPS targets in a shorter time frame than today’s, or a more
510 complete accounting of costs in societal decisions.

511 Secondly, the results indicate that with 50% renewable energy, there is limited or no need to construct
512 either new power plants or purpose-built storage. Although one commonly reads in the media that these are
513 necessary for even modest percentages of renewables, the hourly model results show that there is always
514 sufficient power and that it is substantially cheaper, to use the current legacy generation of PJM along with the
515 storage inherent in new fuel replacement technologies (EV and EH) to absorb excess generation and to fill in
516 generation lulls. New natural gas generation may play a local, supplementary role in PJM’s future, such as
517 decreasing transmission congestion. However, the results suggest that actually building the 41 GW of new
518 natural gas plants that are currently in PJM’s generation queue (10) is not needed and is not cost-effective to
519 society.

520 Thirdly, the model finds that existing conventional thermal plants can still be useful in an external-cost
521 optimized energy system. Conventional plants provide much less electricity, running at only 0.33 capacity
522 factor under M+H+CCS1 versus 0.61 under market costs only. Nevertheless, their existing power capacity
523 appears useful in a high-renewables system, to fill in long wind lulls that would strain storage. For example,
524 PJM is currently planning the retirement of over 20 GW of coal through 2019 (10) based on production cost
525 and emissions; it may be desirable to evaluate retirements not only on the current metric weighted toward
526 operating cost, but to also retain some plants picked for low standby costs, maintaining them for occasional
527 use as reserves.

528

529

530

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