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Ky. Public Service Commission

Thank you for the opportunity to address the VALUE of ROOFTOP SOLAR GENERATED ELECTRICITY.

As compared to non-renewable sources, Solar generated electric power is essentially a non-polluting source of energy. Its economic value goes far beyond our current electric bill.

As a nonpolluting source, Rooftop solar generated electricity HAS SIGNIFICANT ECONOMIC benefits. These economic - benefits are well documented and quantified. This should be reflected in the dollar VALUE associated with rooftop generated electric power.

Benefits of SOLAR include significantly reduced Health Care costs and costs related to Environmental Pollution from non-renewable sources.

. Fossil fuel electric generation has health care costs conservatively estimated at $100/per person/year in Kentucky*. These costs are associated with widespread diseases related to particulate air pollution from fossil fuel generated electricity, such as Black Lung Disease affecting thousands of miners, and respiratory/cardiovascular diseases impacting the general population.

Solar generated electricity does not have mitigation costs related to fossil fuel extraction and combustion, which result in significant long term water, soil, and air pollution. Examples include mitigation costs of billions of dollars to contain toxic coal combustion residues, and reclamation of abandoned mining areas which have long term negative environmental impact.

Several studies, like those published by the Harvard School of Public Health, show costs related to Health and Environmental damage, from fossil fuel generated electricity, add at least 10 cents per kilowatt hour to our electric bill*.

The Public Service Commission should consider the economic benefits of Rooftop Solar generated electricity when placing value on its generation. Rooftop solar generators should be COMPENSATED for the FULL VALUE OF energy produced. The FULL VALUE of rooftop solar includes external avoided costs, such as costs related to pollution by fossil fuel electric generation sources.

By doing so, the PSC will not be abandoning the values of BETTER HEALTH AND CLEAN ENVIRONMENT which BENEFITS ALL KENTUCKIANS.

- *Attachments: Bibliography Information sources/documentation. Full text copies are open source documents

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RESEARCH ARTICLE

An Analysis of Costs and Health Co-Benefits for a U.S. Power Plant Carbon Standard

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Abstract

Reducing carbon dioxide (CO_2) emissions from power plants can have important "co-benefits" for public health by reducing emissions of air pollutants. Here, we examine the costs and health co-benefits, in monetary terms, for a policy that resembles the U.S. Environmental Protection Agency's Clean Power Plan. We then examine the spatial distribution of the co-benefits and costs, and the implications of a range of cost assumptions in the implementation year of 2020. Nationwide, the total health co-benefits were \$29 billion 2010 USD (95% CI: \$2.3 to \$68 billion), and net co-benefits under our central cost case were \$12 billion (95% CI: -\$15 billion to \$51 billion). Net co-benefits for this case in the implementation year were positive in 10 of the 14 regions studied. The results for our central case suggest that all but one region should experience positive net benefits within 5 years after implementation.

Introduction

In June 2014, the U.S. Environmental Protection Agency (EPA) proposed draft standards for carbon dioxide (CO_2) emissions from existing power plants–the Clean Power Plan–which were finalized in August 2015[1]. Fossil fuel-fired power plants make up 31% of U.S. greenhouse gas (GHG) emissions, largely CO_2, and by 2030, the final version of the Clean Power Plan would reduce CO_2 emissions by 32% below 2005 levels[1]. Reducing CO_2 emissions from power plants can have public health "co-benefits" by simultaneously decreasing sulfur dioxide (SO_2), nitrogen oxides (NO_x), and primary fine particulate matter ($PM_{2.5}$) emissions, resulting in lower ambient air concentrations of $PM_{2.5}$ and ozone [1–5], and can be an important part of policy decision-making. Driscoll et al. (2015) examined three different scenarios that were available in 2014 for a U.S. Federal standard for CO_2 emissions from power plants, and simulated the air quality and health co-benefits of these different policy scenarios[2]. Of the three analyzed in Driscoll *et al.* [2], the policy that most resembled the final U.S. Clean Power Plan had the greatest health co-benefits.

the authors of this paper are below. The study design; collection, analysis, and interpretation of data; writing of the paper; and decision to submit for publication was solely conducted by the authors.

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Despite the fact that health co-benefits generally represent the largest share of near-term economic benefits associated with climate change mitigation[6,7], few studies have examined both the magnitude and the spatial distribution of costs and co-benefits of such actions. Economic analysis of the Clean Power Plan has thus far considered only partial equilibrium effects [8,9], thereby excluding hidden costs from implicit taxes on factors of production and hidden benefits associated with improved labor productivity from air quality improvements. The U.S. EPA Regulatory Impact Analysis for the Clean Power Plan estimated the partial equilibrium total national costs and benefits, but not in a spatially explicit manner[10,11]. Here, we build on the analysis of air quality and health co-benefits in Driscoll et al.[2] by estimating and mapping co-benefits and costs for 14 power supply regions under the policy scenario that most closely resembles the U.S. Clean Power Plan. We use three different energy efficiency cost cases and a simulated implementation year of 2020. In doing so, we answer the following questions: (1) how do the magnitude of costs and co-benefits change under varying assumptions; (2) how are the costs and co-benefits spatially distributed; and (3) what can we infer about relationship between costs and co-benefits of the policy over time?

Materials and Methods

Estimation of Health Co-Benefits

The methods used to estimate the health co-benefits in terms of the number of cases are described in detail in Driscoll et al. (2015)[2] and summarized here. The Integrated Planning Model (IPM)[12], a dynamic power sector production cost linear optimization model of the North American power grid, was used to simulate the power sector response to the carbon standard, and to estimate emissions of CO_2, SO_2, NO_x, and directly emitted $PM_{2.5}$ from 2,417 fossil fuel-fired power plants in the U.S. under a "business-as-usual" (BAU) reference scenario based on the U.S. Energy Information Administration 2013 Annual Energy Outlook [13] and a moderately stringent but highly flexible policy scenario, available in 2014, that resembles the final Clean Power Plan, using 2020 as an implementation year. This policy scenario allows for the use of different compliance mechanisms, including demand-side energy efficiency, efficiency and heat rate upgrades to power plants, power plants co-firing with lower-carbon fuels, electrical grid dispatch to lower-carbon generation, and trading of emissions within and between states. The resulting emissions estimates from the IPM model for this scenario were inputted into the Community Multiscale Air Quality (CMAQ) model v4.7.1[14], using the 12 km x 12 km grid for the continental U.S., to simulate the concentration of $PM_{2.5}$ and ozone under this scenario, and under BAU. The results of the CMAQ runs were input to BenMAP CE v.1.1[15], a Geographic Information System (GIS) model designed to calculate health impacts of air pollution, air quality management scenarios, and other applications. We used BenMAP to estimate the number of cases and distribution of co-benefits for six health outcomes based on the difference between the policy scenario and BAU (Table 1). The health co-benefits in this analysis are conservative and do not include possible benefits from reducing other health effects, such as asthma[16], stroke[17], and autism[18]; benefits associated with decreased emissions of hazardous air pollutants (e.g., mercury)[19]; pediatric benefits[16]; or the direct health benefits of climate change mitigation[20,21]. We use the valuation module in BenMAP CE v1.1[15] with default methods and values to estimate the economic value of the co-benefits at county, power region, and national scales[22–24]. Details on the health impact functions and valuation methods are available in S1 and S2 Tables.

Estimation of Costs

We use the IPM output to develop three partial equilibrium cost cases to compare with the partial equilibrium co-benefit estimates. The IPM runs were designed to simulate the electricity

FORMAS Human Cooperation to Manage Natural Resources through Resources for the Future. No known U.S. EPA funding. 5) Charles Driscoll – co-author, Syracuse University. Funding for this work was provided by subaward on grant from Hewlett Foundation to Harvard University. Prior U.S. EPA funded project on modeling climate change effects on watersheds through Syracuse University. Current U.S. EPA grant on land use and air quality through Syracuse University and Resources for the Future. Member of U.S. EPA Clean Air Scientific Advisory Committee (a federal advisory committee) – review board for secondary NOx and SO2 standards. Member of Advisory Board for National Research Council Board of Environmental Studies and Toxicology. Member of Advisory Board for Hubbard Brook Research Foundation. This did not alter the authors' adherence to PLOS ONE policies on sharing data and materials.

sector response to constraints on CO_2 emissions by improving the operation of existing facilities, substituting to lower emitting technologies, and by investing in demand-side energy efficiency. The policy scenario we examine assumes that incentives are created for programmatic funding of energy efficiency. At the assumed cost and level of funding, energy efficiency contributes most of the mitigation that is achieved in the policy scenario we analyze[2].

Our measure of costs includes capital, operations and maintenance for generation and investments in energy efficiency and assumes a default real interest rate of 4.77% for all expenditures. The electricity system costs in the implementation year under the policy scenario reflect the difference from BAU in the annualized costs of investments made between the announcement of the policy and the implementation year, plus changes in operations and maintenance in the implementation year. The costs for capital and operations and maintenance are the same in each of the three cost cases because generation is the same. Uncertainty arises in how to account for the costs of energy efficiency, and we explore three options.

There are two main components to the costs of energy efficiency investments. The first, program spending, includes 18% for administration and 82% for investment and is incurred by the utility or some other entity. This cost is recovered through a charge on electricity bills. The second, participant cost (i.e. the matching contribution of the residential, industrial or commercial property owner where the energy efficiency investment occurs) we assume to be equal to the program investment of 82% of and additional to the total program costs. In our central cost case we assume the programmatic energy efficiency investment costs are annualized while participant costs are incurred in the present year ("overnight"). The lower bound cost case assumes that both program and participant costs after 2013 are annualized. The upper bound cost case is an extreme case that assumes that both program and participant costs are incurred overnight.

Net Co-Benefit Calculation

We calculate annual net co-benefits in the implementation year as the difference between the value of co-benefits for the central estimate and 95% confidence intervals and costs for the three cases. Investments in energy efficiency in the policy scenarios begin to ramp up in 2013 providing accrued measures in place that contribute to reduced demand in the implementation year 2020. Hence the associated air quality benefits are not strictly due to investments in 2020. On the other hand, investments that year yield air quality co-benefits in the future. We report net co-benefits as a snapshot, comparing the co-benefits with investment costs in 2020, not counting the benefits that will continue to flow.

To reveal the spatial distribution of net co-benefits, we compare estimated costs with the value of health co-benefits by power supply region. For this analysis we use approximate state

Table 1. Health co-benefits of moderately stringent, highly flexible carbon standards by health endpoint for the central estimate and 95% confidence intervals. Estimates are rounded to two significant figures. Monetized values are in 2010 USD.

Health endpoint	Source of Concentration-Response Function:	Health co-benefits (# of cases) (95% CIs)	Health co-benefits (million 2010 USD) (95% CIs)
Mortality, All Cause	Roman et al.[25]	3,200 (680–5,600)	$26,000 ($1,900–$63,000)
Mortality, All Cause	Jerrett et al.[26]	300 (100–500)	$2,500 ($300–$5,700)
Hospital Admission, All Respiratory	Ji et al.[27]	410 (150–680)	$13 ($4.7–$22)
Hospital Admission, All Cardiovascular (except heart attacks)	Levy[28] Zanobetti[29] Pooled	330 (230–440)	$13 ($8.7–$17)
Hospital Admission, All Respiratory	Levy[28] Zanobetti[29] Pooled	280 (150–420)	$9.1 ($4.7–$13)
Acute Myocardial Infarction, Nonfatal	Mustafic et al.[30]	220 (130–310)	$20 ($11–$27)
	Total		**$29,000 ($2,300–$68,000)**

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boundaries for the 14 IPM power supply regions. Additionally, to calculate the time it would take for health co-benefits to equal the program costs for an investment in the implementation year, we sum the annual co-benefits from our central cost case over time and compare this with the costs in the implementation year plus the remaining annual payments for subsequent years (without discounting) for that portion of costs that is not recovered overnight.

Results and Discussion

Magnitude of Co-benefits and Costs

The national total of the monetized health co-benefits in the implementation year 2020 is $29 billion 2010 USD (95% CI: $2.3 to $68 billion)(Table 1). Most of this value (99.8%) is associated with avoided mortality due to decreases in $PM_{2.5}$ and ozone (Table 1); the remainder is derived from morbidity effects. Results below are in 2010 USD, unless otherwise noted.

Under the central cost case, the total cost in the implementation year is $17 billion. The estimated cost under the lower cost case in which all costs are annualized is -$450 million. Negative costs in the implementation year occur in this case because the program-driven expenditures on energy efficiency are spread out over time but yield immediate savings in generation-related costs. The savings continue in future years, so the negative costs apply for each year in the program. The estimate for the upper case in which all costs occur overnight is $39 billion. The higher costs in this case are due to the upfront loading of all energy efficiency costs.

The net co-benefits for the central estimate for health co-benefits and central cost case is $12 billion (95% CI: -$15 billion to $51 billion). Positive net co-benefits indicate that the value of the health co-benefits are greater than the costs of the policy scenario, without taking into account additional health benefits, ecosystem benefits (e.g., visibility, crop and tree productivity)[31], or climate change benefits. The net co-benefit under the lower cost case is $30 billion (95% CI: $2.7 billion to $69 billion). The net co-benefit under the upper cost case is -$10 billion (95% CI: -$37 billion to $29 billion); in this case the health co-benefits are less than the costs of the policy in that year.

Spatial Distribution of Co-benefits and Costs

All counties of the continental U.S. receive annual co-benefits under the policy scenario in 2020 (Figs 1 and 2). Most counties gain at least $1 million in annual co-benefits, using our central estimate, and co-benefits are highest in the Northeast and Southwest U.S. (Figs 1 and 2). Health co-benefits per capita are greatest in Mid-Atlantic, Ohio River Valley, and South-Central regions of the U.S. (areas within the IPM regions PJME, PJMC, MISO, SERCC, SERCD, and ERCOT), with nearly every individual in these regions gaining at least $100 of co-benefits per year under the central estimate (Fig 2).

Central estimates of the annual co-benefits in the implementation year for each of the 14 IPM regions range from $5.6 billion in the Midwest (MISO and SERCG) to $57 million in the Pacific Northwest (PNW) (Table 2). The greatest health co-benefits occur in areas that have historically had a large amount of electricity generation from coal and are characterized by relatively poor air quality prior to 2020, and therefore receive large improvements in air quality under this scenario.

Costs in 2020 for the IPM regions range from $7.8 billion for the Midwest (MISO and SERCG) under the upper cost case to $-1.6 billion for the central mid-Atlantic region (PJMC) under the lower cost case (Table 2). Regions with high baseline emissions and large projected emissions reductions tend to have the highest costs–MISO, SERCG, PJME, and OTHERWEST. Generally, the Mid-Atlantic (PJMC), the Southeast (SERCC and SERCSE), the Southern Power Pool (SPP) and New York (NYISO) had lower costs.

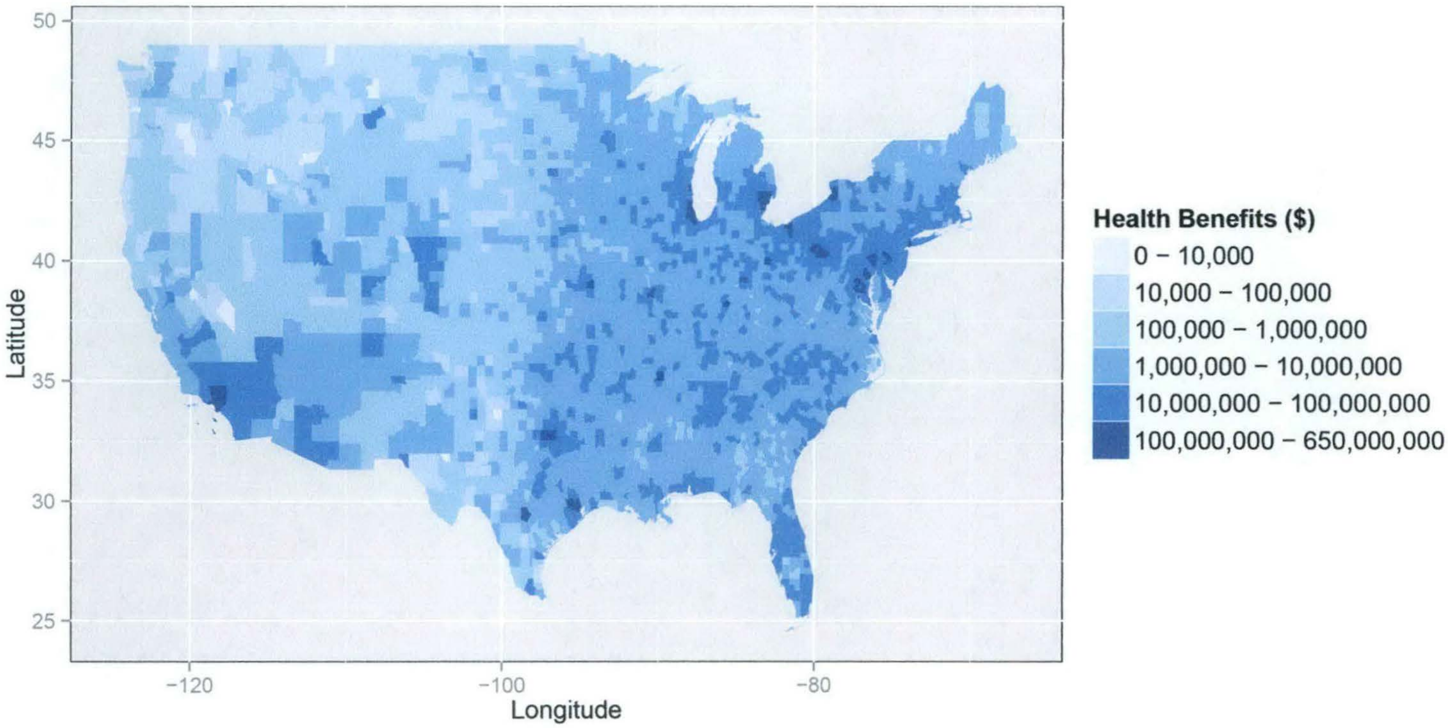

Fig 1. Total annual co-benefits of moderately stringent, highly flexible carbon standards in 2020 (2010 USD).

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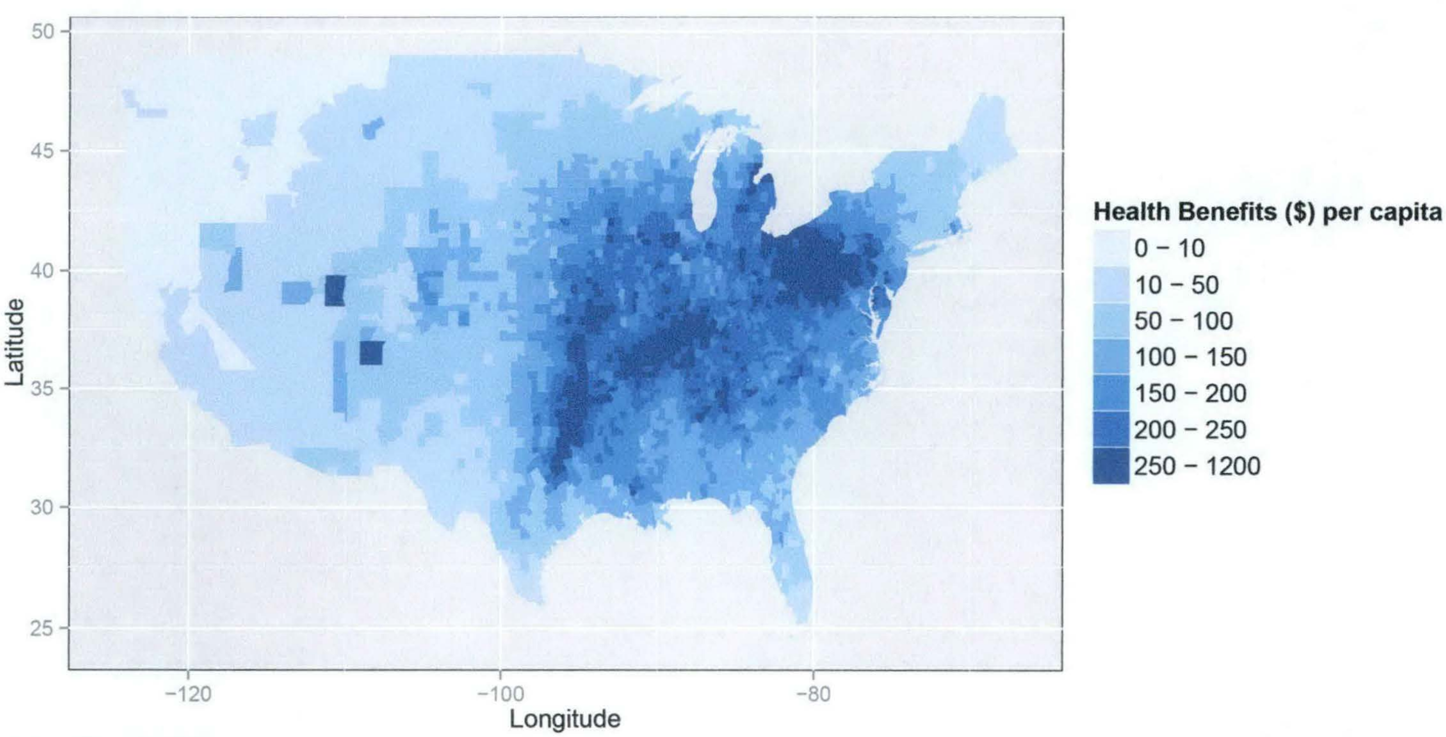

Fig 2. Annual co-benefits per capita for 18 to 99 year-olds under moderately stringent, highly flexible carbon standards in 2020 (2010 USD).

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Table 2. Monetized value of annual co-benefits, costs, and net co-benefits by cost case for U.S. and IPM regions in 2020 (million 2010 USD). All values are calculated and then rounded to two significant figures, so net co-benefits may not sum perfectly.

			Lower cost case: All Costs Annualized		Central cost case: Annualized Program Costs, Overnight Consumer Costs		Upper cost case: All Costs Overnight	
IPM Region	**States**	**Health Co-benefits (95% CI)**	**Cost**	**Net Co-Benefits (95% CI)**	**Cost**	**Net Co-Benefits (95% CI)**	**Cost**	**Net Co-Benefits (95% CI)**
US	All lower 48 states	29,000 (2,300–68,000)	-450	30,000 (2,700–69,000)	17,000	12,000 (-15,000–51,000)	39,000	-10,000 (-37,000–29,000)
CALIFORNIA	CA	480 (37–1,100)	360	110 (-330–760)	1,400	-960 (-1,400–310)	2,700	-2,300 (-2,700–1,600)
ERCOT	TX	1,900 (150–4,500)	170	1,800 (-14–4,400)	1,800	100 (-1,700–2,700)	3,800	-1,900 (-3,700–690)
FRCC	FL	900 (71–2,100)	-140	1,000 (210–2,300)	960	-56 (-880–1,200)	2,300	-1,400 (-2,200–170)
ISONE	ME, VT, NH, MA, CT, RI	880 (69–2,100)	220	660 (-150–1,900)	690	190 (-630–1,400)	1,300	-390 (-1,200–810)
MISO and SERCG	IN, MI, IL, WI, IA, MN, SD, ND	5,600 (440–13,000)	140	5,500 (290–13,000)	3,600	2,100 (-3,100–9,700)	7,800	-2,100 (-7,300–5,500)
NYISO	NY	1,600 (120–3,700)	110	1,400 (5.7–3,600)	610	950 (-490–3,100)	1,200	350 (-1,100–2,500)
OTHERWEST	WY, NV, UT, CO, AZ, NM	970 (80–2,300)	740	220 (-660–1,500)	1,800	-820 (-1,700–480)	3,100	-2,100 (-3,000–800)
PJMC	OH, PA, WV	5,400 (420–13,000)	-1,600	7,100 (2,100–14,000)	310	5,100 (110–13,000)	2,700	2,700 (-2,300–10,000)
PJME	NJ, DE, MD, VA	3,000 (230–7,000)	890	2,100 (-660–6,100)	2,500	440 (-2,300–4,500)	4,500	-1,500 (-4,300–2,500)
PNW	WA, ID, MT, OR	57 (4.8–130)	320	-260 (-320–190)	980	-920 (-970—850)	1,800	-1,700 (-1,800—1,600)
SERCC	NC, SC, GA, AL	1,700 (130–4,000)	-930	2,600 (1,100–4,900)	-26	1,700 (160–4,000)	1,100	610 (-950–2,900)
SERCD	AR, LA, MS	1,300 (100–3,000)	-120	1,400 (220–3,100)	790	490 (-690–2,200)	1,900	-620 (-1,800–1,100)
SERCSE		3,300 (260–7,700)	-570	3,900 (830–8,300)	1,500	1,800 (-1,200–6,200)	4,000	-760 (-3,800–3,700)
SPP	NE, KS, MO, OK	2,000 (160–4,700)	11	2,000 (150–4,700)	450	1,600 (-290–4,300)	990	1,000 (-830–3,700)

doi:10.1371/journal.pone.0156308.t002

Using the central estimates for health co-benefits, the regional net co-benefits (i.e. value of co-benefits minus costs) in 2020 range from a high of $7.1 billion in the central mid-Atlantic (PJMC) region under the lower cost case to a low of $-2.3 billion in California under the upper cost case (Table 2, Fig 3). The results show that under the central cost case the 2020 net co-benefits are positive in 10 out of 14 regions (Table 2, Fig 3). For the lower cost case, the 2020 net co-benefits are positive in 13 regions of 14 regions (Table 2, Fig 3). Notably, even in the upper cost case, there are positive net co-benefits in 2020 in four out of 14 regions (Table 2, Fig 3 and S1 Fig). Further, co-benefits continue to accumulate over time, and so do costs in the central and low cost case. On an undiscounted basis for co-benefits, using our central cost case, the value of annual health co-benefits outweigh costs in FRCC in less than 2 years, they outweigh costs in OTHERWEST in less than 3 years, and they outweigh costs in California within 5 years of the implementation year. However, the co-benefits do not outweigh costs in the Pacific Northwest within the program period. Notably, this payback period is based on the limited health co-benefits included here and does not incorporate future avoided costs from CO_2 reductions.

Uncertainty in Co-benefits and Costs

The health co-benefits from the policy scenario analyzed here represent just a subset of the total health co-benefits that would be expected due to reductions in $PM_{2.5}$, ozone, and other air pollutants. Specifically, we did not include co-benefits of avoided asthma[16], stroke[17], autism[18], and other health endpoints[16,32]. We also relied on large cohort studies that do not include impacts to people younger than 18 years. Finally, we did not include the benefits associated with lower emissions of air toxics, such as mercury, cadmium, carbon monoxide, and polycyclic aromatic hydrocarbons[19], and assumed that all particle types had the same toxicity[28].

The co-benefit estimates do not include the direct health benefits due to the mitigation of climate change, such as fewer heat-related illnesses[33] or a deterioration of air quality associated with climate change[20]. In addition, known benefits to natural resources, such as

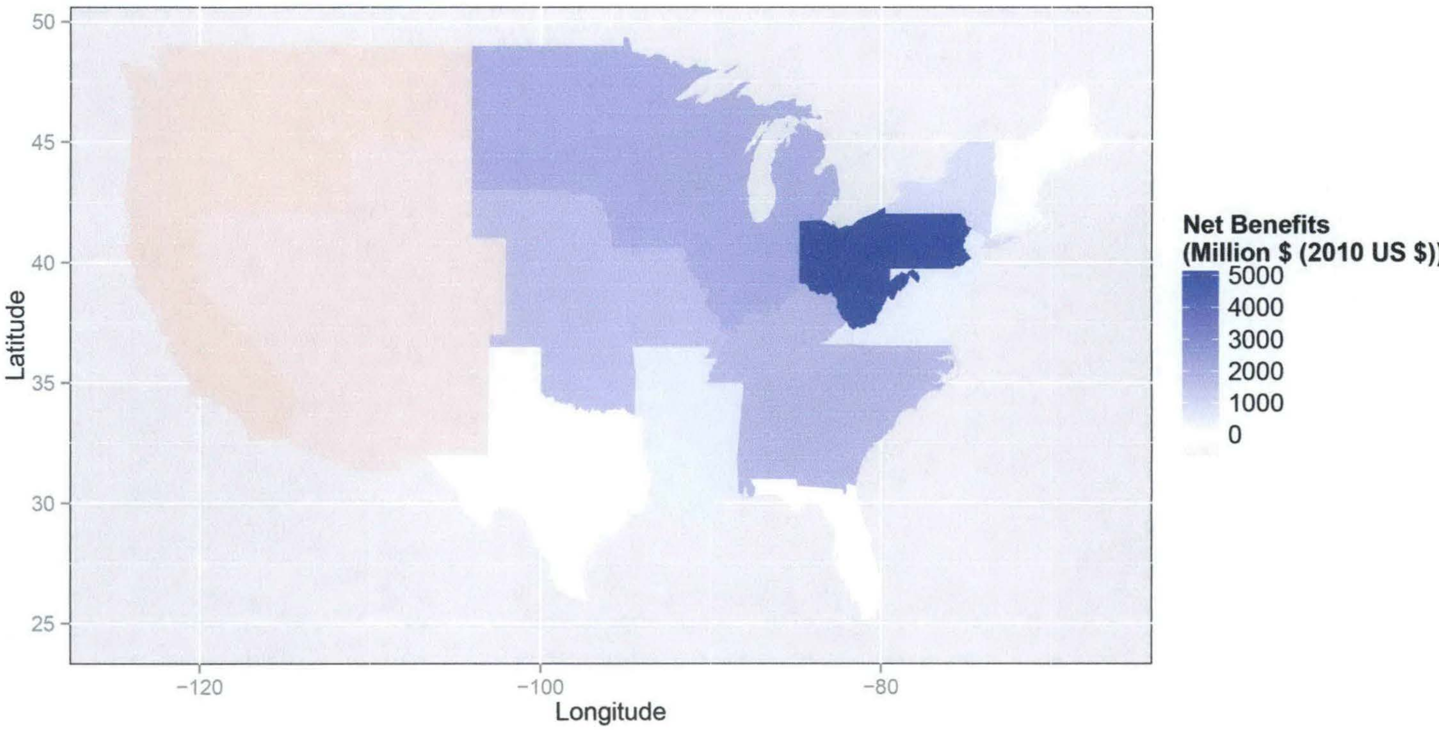

Fig 3. Net benefits by IPM Region for a moderately stringent, highly flexible carbon standard in 2020 (2010 USD) using central estimates for both cost and health co-benefits.

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visibility improvements[34] and increased crop[35] and timber productivity [31,36]associated with lower ozone are not included.

The valuation of climate benefits is less advanced than the valuation of health co-benefits, but the literature is developing rapidly. The U.S. government has identified a central case value of $40 (2010 USD) of benefits in 2020 per short ton of CO_2 emissions reduction, accounting for benefits that accrue domestically and internationally[37]. The moderately stringent, highly flexible policy scenario we evaluate results in reductions of 531.2 million short tons[2], which is approximately equivalent to $21.2 billion in direct climate benefits, using the U.S. regulatory social cost of carbon[38]. Therefore, the total estimated benefits for the scenario total approximately $50 billion per year in 2020 when both the estimated health co-benefits and social cost of carbon are included. This may be a conservative estimate for the value of climate damages since this value is lower than many recently published values for the social cost of carbon[39–41]. However, the implications of other values for the social cost of carbon can be explored by linearly scaling[39–41]. This result is consistent with previous co-benefit studies on policies affecting electricity generation[7,8,10,11,42–44].

The three cost cases presented here demonstrate that economic assumptions strongly influence net benefit results. Most of the range in net benefits, holding health co-benefits constant at the central estimate, is attributable to how the cost of energy efficiency is handled. Therefore, it is important to consider the plausibility of each cost case. A substantial literature critically questions whether and why potentially cost-effective opportunities for energy efficiency investments may go unrealized[45–48]. Nonetheless, empirical evidence from many programs suggests program spending on energy efficiency may have negative costs, even before considering environmental benefits[49,50]. In some cases investments in energy efficiency can actually reduce total system costs, even after accounting for the participant cost.

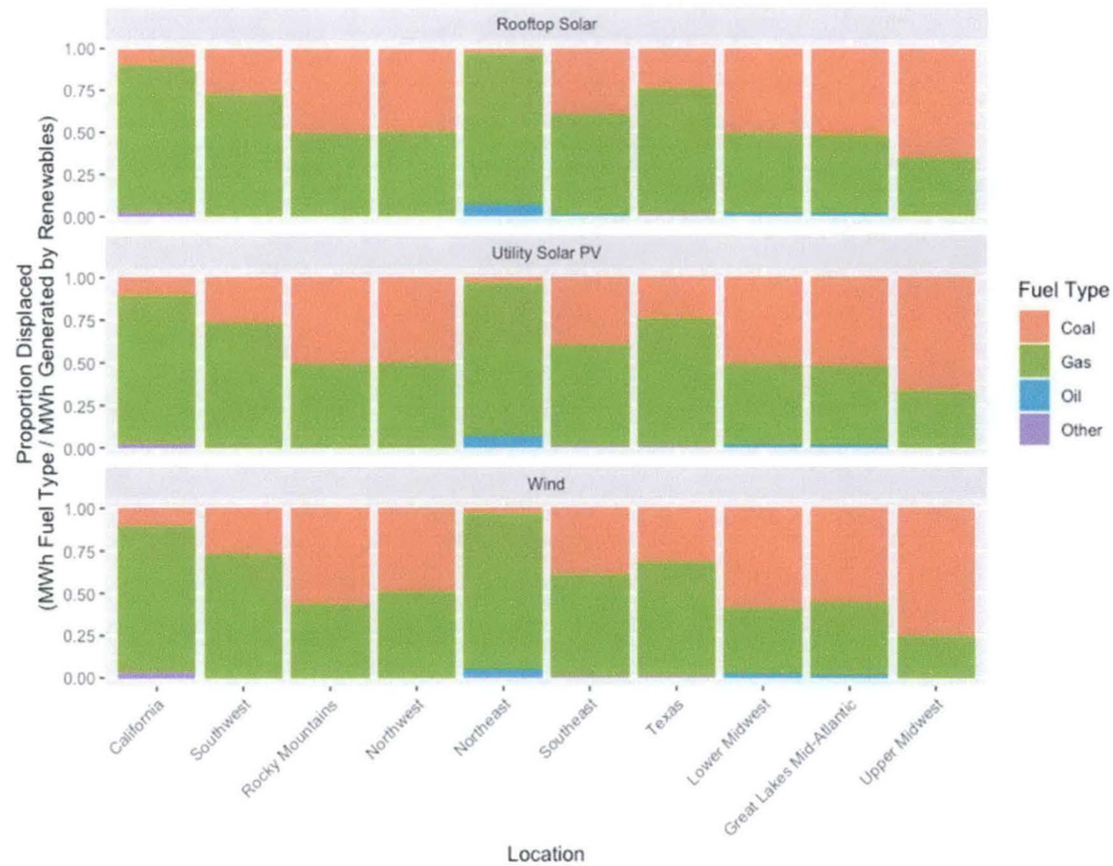

Figure 4. Proportions of plant primary fuel types displaced, by location and renewable energy type (MWh/MWh).

Great Lakes and Upper Midwest are still first and second, but the Northeast moves to third (figures 5(b) and S6).

Variation in benefits between different regions and types of RE can be explained by differences in primary fuel types displaced, emissions displaced, and benefits per emission reduction. Coal and gas were the predominant primary fuel types displaced; small amounts of oil were displaced in the Northeast, the Lower Midwest, and the Great Lakes; and small amounts of other fuel types (this can include waste-derived fuel and waste gases) were displaced in California and the Great Lakes (figure 4). The highest amounts of coal were displaced in the Great Lakes, Upper Midwest, Lower Midwest and Rocky Mountains (figure 4). These regions also generally tended to have higher climate and health benefits, but with varying contributions from each emission type (figure 6).

Valuing reduced methane leakage from gas usage using the Shindell *et al* social cost estimate [36] increased the total benefits per MWh of RE by a mean of ~36% (range: 17%–66%); using our low estimate, the total benefits per MWh increased by a mean of ~11% (range: 5%–19%) [20]. Comparing just the contribution of methane leaks to the total benefits of reducing gas consumption increased the benefits of reducing gas consumption by ~71% (range: 43%–methane increased the benefits of reducing gas consumption by 21% (range: 13%–25%).

Regions with high amounts of CO_2 emissions avoided with RE deployment generally have much lower costs per ton of CO_2 reduced (figure 7). Wind and utility-scale solar PV have fairly similar costs per MWh, so have fairly low cost per ton of CO_2 reduced. Costs per ton of CO_2 reduced for rooftop solar are much higher, reflecting a higher cost per MWh of rooftop solar [38]. Wind and utility solar PV have lower costs per ton of CO_2 reduced in the Upper Midwest, Lower Midwest, Rocky Mountains, and the Great Lakes. When the health benefits of RE are subtracted from the cost, the cost drop substantially. This also rearranges the ranking somewhat—the Upper Midwest, Great Lakes, Upper Midwest, and Southeast then get the lowest cost per ton of CO_2 avoided (figure 7).

Discussion

Here, we developed EPSTEIN 2.0, and used it to estimate the climate and health benefits for RE in 10 grid regions across the US for different sizes and types of RE deployment in each region. Benefits scaled roughly linearly with the size of the RE project deployed, and differences between regions were much

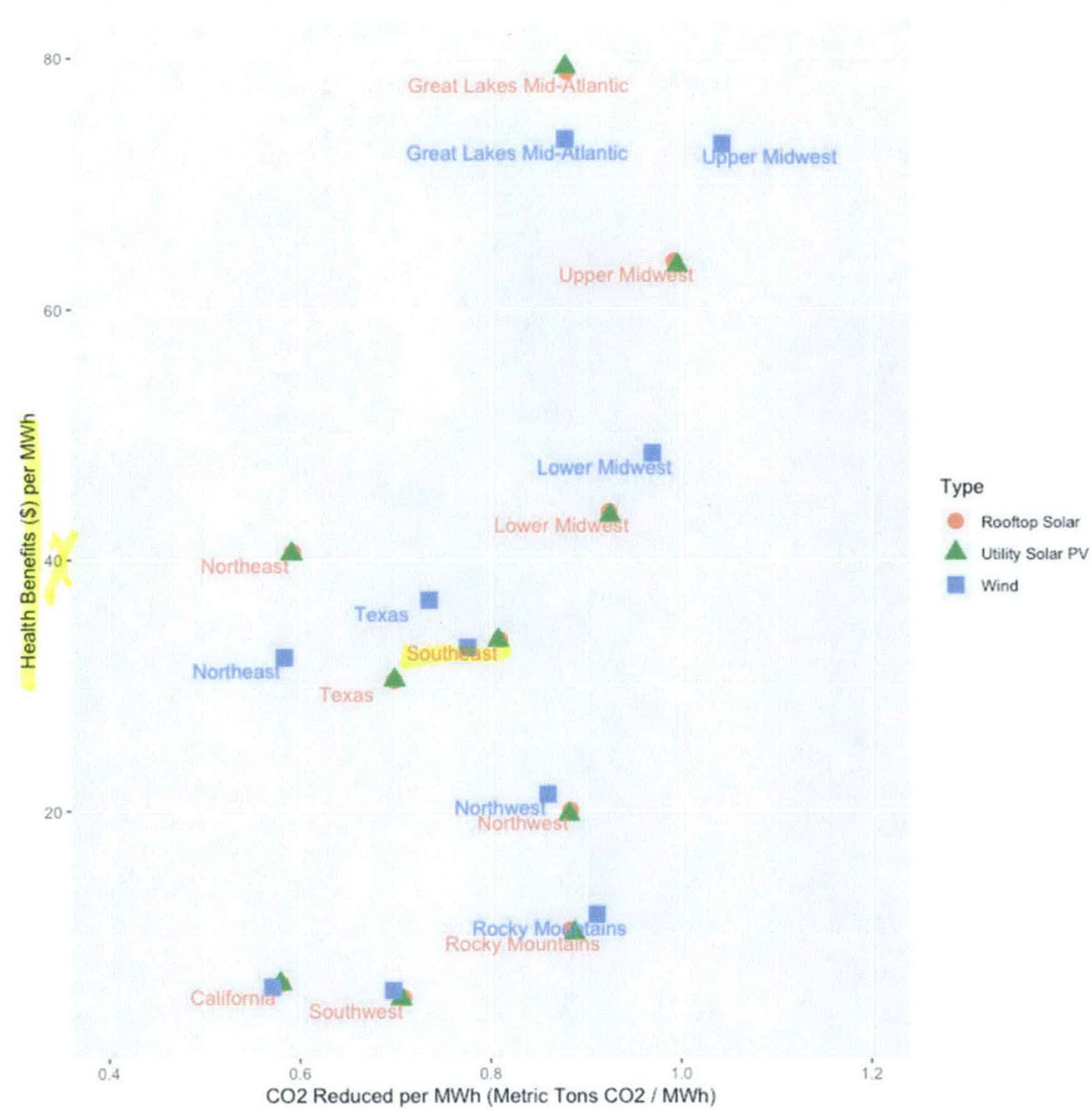

Figure 5. (a) Health benefits and CO_2 emissions reductions, by region and renewable energy type. Points for rooftop solar and utility solar PV overlap. Not all points are labeled to prevent over-plotting. (b) CO_2 reductions and health benefits per ton of CO_2 reduced, by region and renewable energy type. Points for rooftop solar and utility solar PV overlap. Not all points are labeled to prevent over-plotting.

Deploying RE has benefits to both climate and health everywhere in the US, and the magnitude of each depends on the fuel types reduced, emissions reductions, and benefits of emissions reductions. Benefits vary by location and are quite sensitive to different parameter values. The Great Lakes and the Upper Midwest generally have the highest benefits, followed by the Lower Midwest, largely due to coal displacement and the populations downwind. The Northwest and Rocky Mountains have high climate benefits, largely due to coal displacement. The Northeast has fairly high health benefits per ton of CO_2 reduced, largely driven by reduced use of gas and oil in a region with high population density.

Variations in benefits reflects differences in the primary fuel types of plants displaced, emissions reduced, and health benefits of those emissions reduc- higher benefits than the Great Lakes. However, for both types of solar, the Great Lakes has higher benefits than the Upper Midwest, largely driven by SO_2 reductions (figure 3(c)). This difference in SO_2 reductions from solar largely results from differences in displacement of coal and other fuels (figure 6). This reflects coal in the Great Lakes having higher impacts per MWh than coal in the Upper Midwest (figure S7), largely due to higher emissions rates from plants displaced in the Great Lakes (figure S8).

The results here are similar to results of studies focused on other regions [9–11, 13, 14], and to a historical reconstruction of the benefits of RE [12]. However, there are some differences between studies using more sophisticated electrical dispatch modeling. One study focused on offshore wind found that the benefits of wind did not scale linearly with the amount of capa-

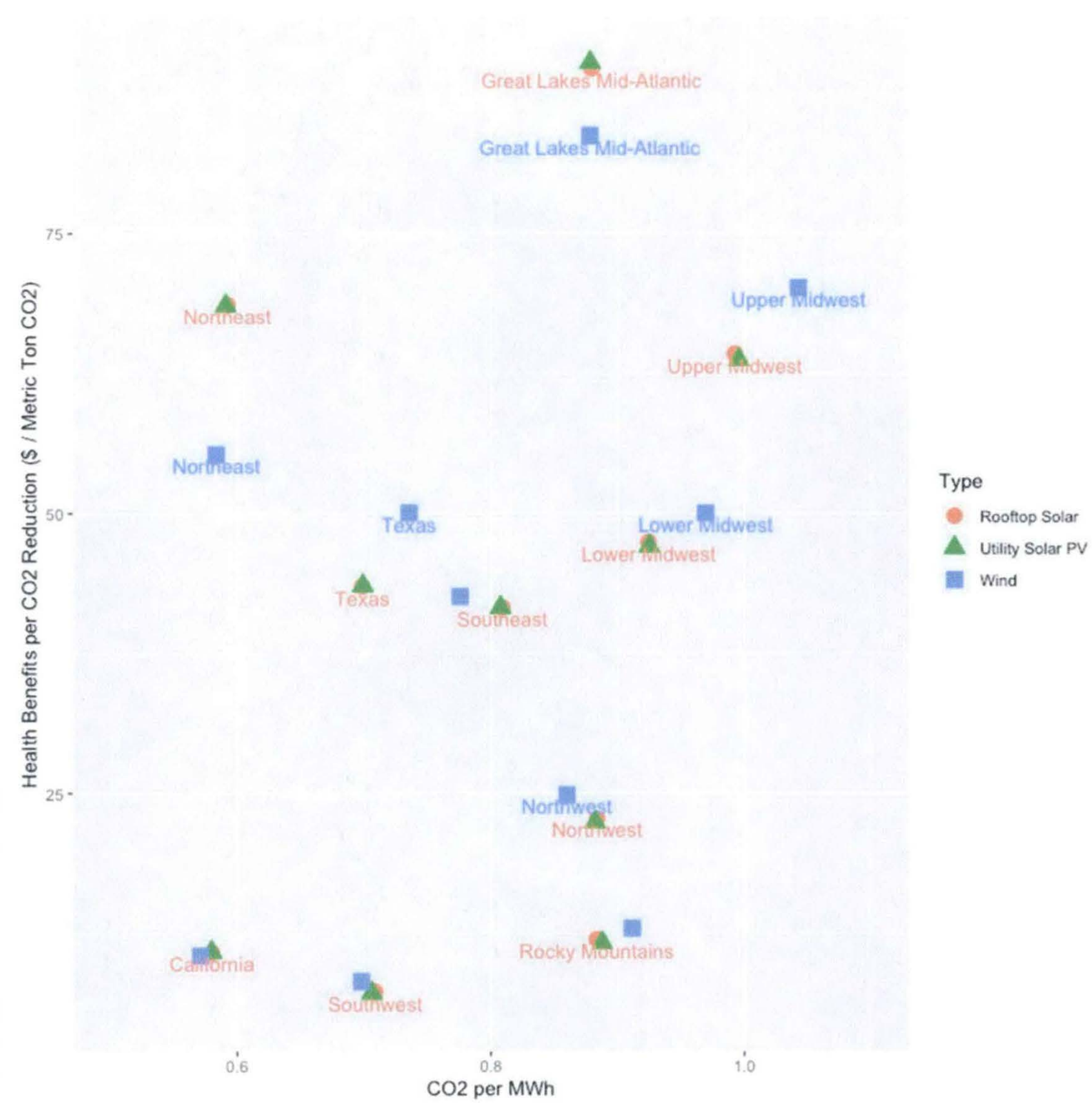

Figure 5. (Continued.)

model being better able to capture plant specific responses to offshore wind going into operation, resulting in non-linearities at grid-scale. A study focusing in detail on the PJM Interconnection, which substantially overlaps with the Great Lakes/Mid-Atlantic region in AVERT, and using 2012 as a simulation year, did find that different locations of RE deployment within the same region had substantially different benefits [9]. This demonstrates advantages of the more sophisticated electrical dispatch modeling and of using higher resolution data on available wind and solar resources, since the results here did not match this previous study in locations where solar had a lower capacity factor.

There are a number of limitations with EPSTEIN 2.0. AVERT does not capture the degree of detail that other electrical grid models can capture, including plant upgrades and retirements, changes in response from changes in fuel prices, transmission upgrades, changes, changes due to fuel mixing, and other factors that may make historical responses not represent the present [9]. AVERT may also miss grid dynamics that more elaborate electrical dispatch modeling captures, resulting in some uncertainty in responses in individual plants. EASIUR does not capture ozone or morbidity endpoints due to either $PM_{2.5}$ or ozone, therefore underestimates total benefits. This model assigns emissions reductions and consequent benefits to plant primary fuel type, rather than literal fuel displaced. Therefore, it does not disaggregate benefits of reduced fuels in plants that use multiple fuel types. The model framework also does not capture benefits across the life cycle of reduced coal or gas consumption. Health impacts of coal mining can make up a substantial portion of the total impacts of coal [39–41]. Health impacts related to proximity to natural gas wells were not included here [42–44]. Assessing the impacts of stack emissions from power plants,

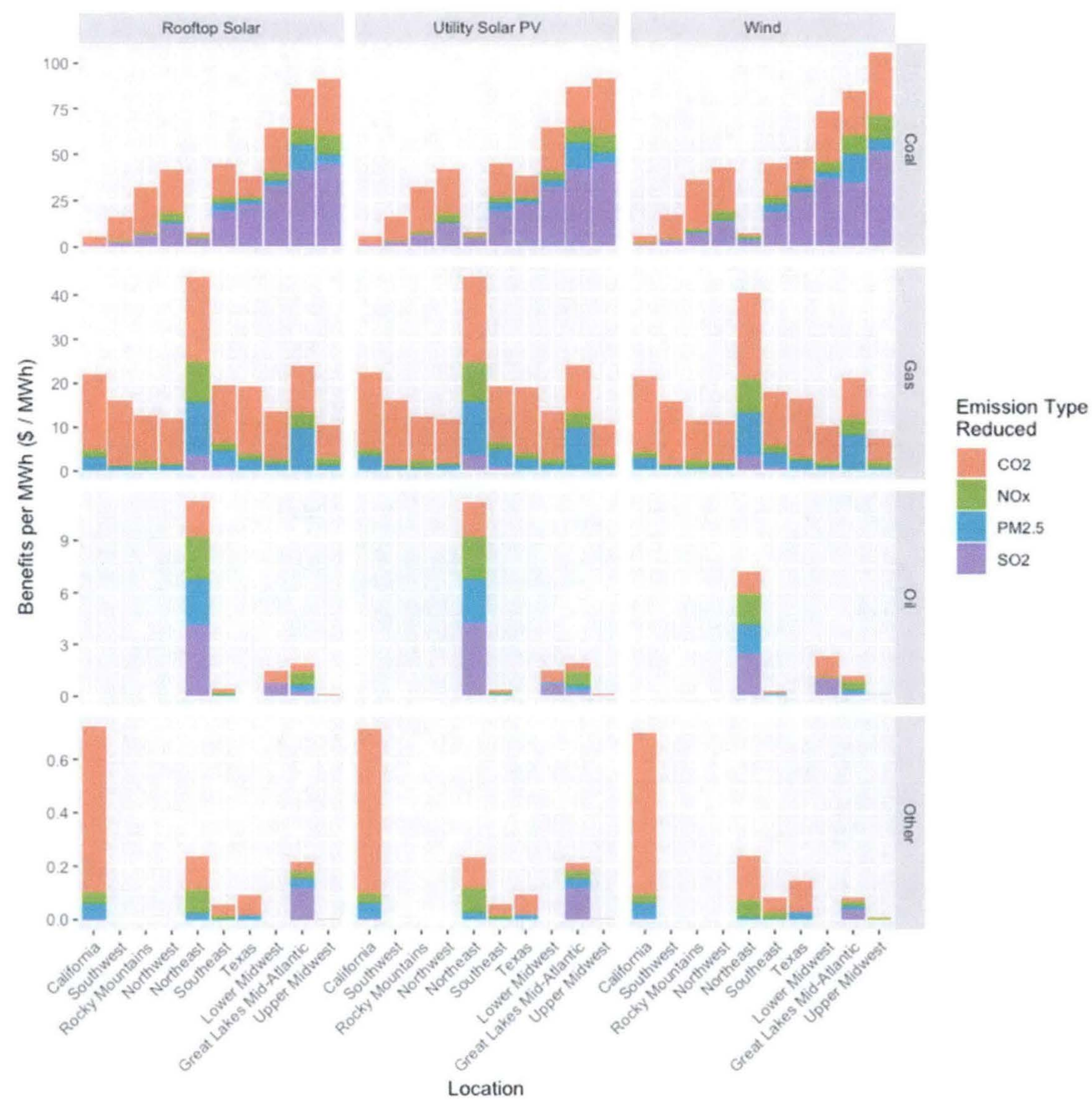

Figure 6. Benefits per MWh by primary fuel type displaced by location and renewable energy type.

the total benefits from RE, by omitting the benefits of reducing consumption of fossil fuels. Our results indicate that including methane leakage in the natural gas supply chain alone can increase benefits by 36%.

Including carbon emissions reductions and health benefits in RE planning

Deploying RE in different locations can have substantially different benefits, and the cost per ton of CO_2 avoided varies substantially depending on the location where RE is installed (figure 7). While health benefits of RE deployment tend to be high in areas that also have high CO_2 reduction potential, there can be tradeoffs between CO_2 reductions and health benefits.

For example, deploying RE in the Rocky Mountains has roughly the same CO_2 reduction potential as the Great Lakes, but much lower health benefits (figures 5(a) and S5). Comparing strictly in terms of cost per ton of CO_2 reduced, deploying wind and utility-scale solar PV anywhere in the US is more cost sequestration (CCS) (figure 7) [45]. Deploying wind and utility-scale solar PV in many regions of the country is also more cost effective than installing CCS on a coal-fired power plant (figure 7) [38].

Health benefits can be important part of benefit cost assessments of carbon mitigation. For example, deploying wind or utility-scale solar PV in all regions of the country, except the Southwest and California, is more cost effective than installing CCS on a coal-fired power plant when including health benefits (figure 7). Wind and utility scale solar deployed anywhere, along with rooftop solar in the Upper Midwest and the Great Lakes, are more cost effective at reducing CO_2 than deploying live air CCS when health is included (figure 7).

Our model results, along with CO_2 reduction cost-effectiveness, do not represent full benefit-cost analyses of individual projects. Ideally, a full benefit-cost analysis for an individual project would include: site specific generation profiles and detailed electrical dis-

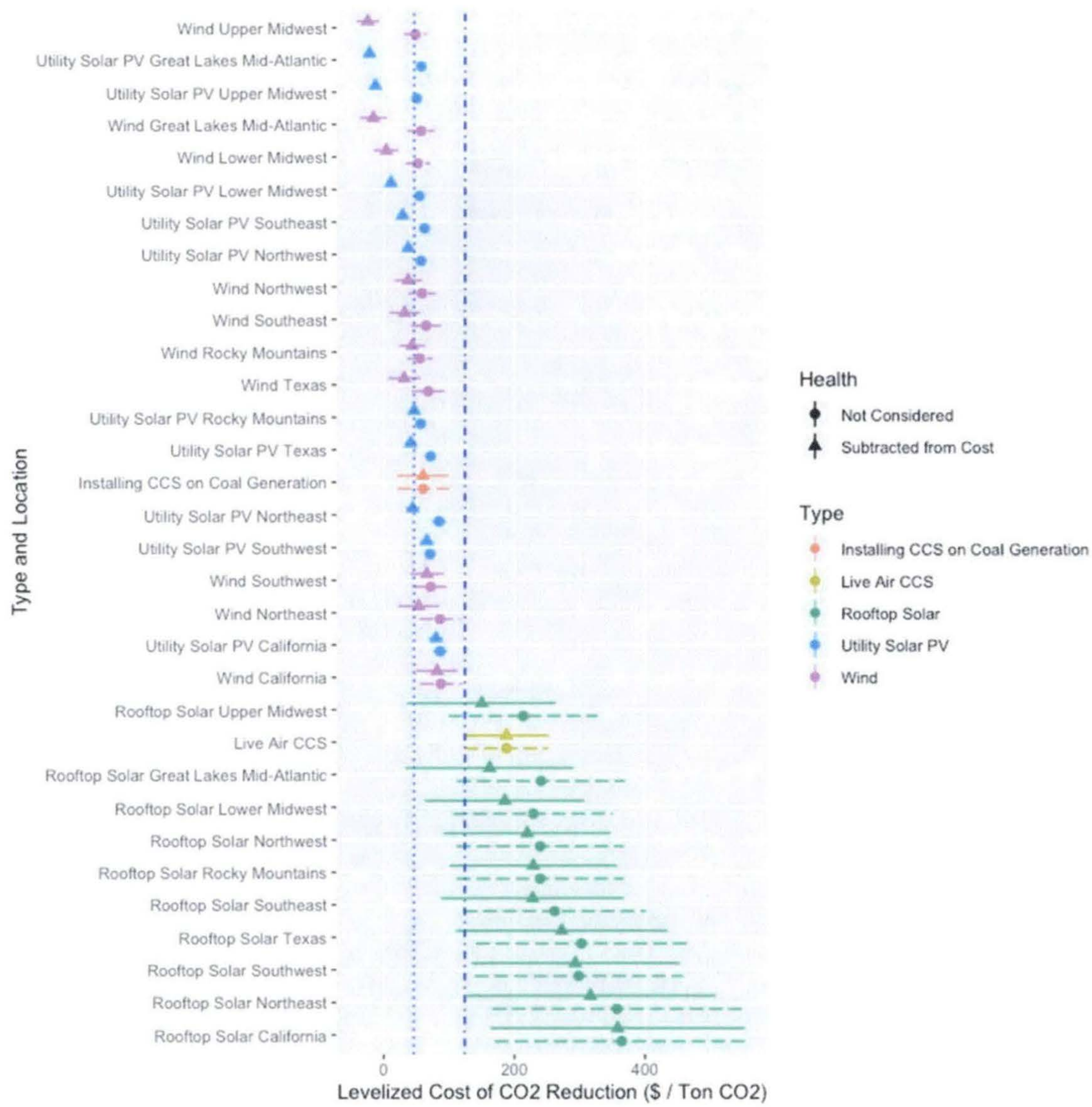

Figure 7. Ranked cost of reducing or removing CO_2 per ton, based on low and high levelized cost of energy for each renewable energy type [38], with and without health benefits subtracted from cost. Illustrative costs of live air carbon capture and sequestration (LA CCS) [45], and coal with carbon capture sequestration [61] are added for comparison. The thinly dashed line marks a social cost of carbon of $41.80 per metric ton, and the thick and thin dashed line marks a social cost of carbon of $112.2 per metric ton.

impacts of emissions changes from coal with CCS [39, 46, 47]; full life cycle impacts for fossil fuel use changes, including increases in the case of coal with CCS [39, 48–50]; impacts of captured CO_2, especially if it is used for enhanced oil recovery [45, 51]; electricity price effects [52, 53], and impacts from RE manufacture and installation [54–57].

This model framework and information can be useful for governments, RE developers, and investors for developing RE deployment strategies that maximize both CO_2 reductions and health benefits. It can also be used to estimate CO_2 reductions from renewable energy credits (RECs), power purchase agreements (PPAs), and increases in renewable portfolio standards (RPS). It allows governments to evaluate the health benefits of RPS increases and allows for REC and PPA purchasers to evaluate their CO_2 reductions and health benefits. This or RECs in the US better understand the environmental benefits of different options. With this framework, siting or purchasing decisions could be based on health benefits, CO_2 emission avoided, or a mixture of the two. Estimates of the CO_2 reductions from a PPA or a REC could allow for these to be purchased as a form of carbon offset and could even be used to create health impact offsets.

Our results show that RE deployment is a cost-effective method to reduce CO_2 emissions, and that health benefits can be an important component of the full benefits of RE projects. We show that with the current electrical grid, in most locations, RE deployment is more cost effective at reducing CO_2 emissions than live air CCS or coal with CCS. Cost effectiveness varies substantially by region where the RE type is deployed but varies less between type of RE. We also demonstrate that health impacts and benefits of these different CO_2

impacts, costs, and benefits of a given project. The sensitivity to methane leakage from the gas system indicates that life cycle considerations could be important. Our work demonstrates that assessing health benefits can be included in evaluating RE deployment, and possibly other types of climate policies as well [58]. Information on health benefits is often quite informative to the public discussion and to decision-making and can be useful in both building political support for climate policies and ensuring that they are healthy and just [9, 59, 60].

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Any data that support the findings of this study are included within the article.

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The power plant carbon standards policy scenario evaluated here will deliver a relatively consistent stream of health co-benefits over time, compared to no carbon standard, but the estimated stream of costs varies over time depending on economic assumptions. The model assumes spending on energy efficiency begins in 2013 and increases through 2025. The co-benefits of this spending accrue for many years after the investment is made, so the net co-benefits are not yet at their maximum level in 2020. Therefore, the comparison of co-benefits with costs in 2020 represents lower net benefits than what we would expect when the program is fully implemented in 2030.

This analysis is based on a reference case from the year 2013 based on the 2013 Annual Energy Outlook[13] and a 2014 policy case. Since that time, energy demand, renewable energy penetration, renewable energy and efficiency costs, and projections have changed, and the Clean Power Plan has also been finalized. While this may limit the ability of the scenario here to represent the final version of the Clean Power Plan, we expect the relationships between benefits and costs, and the geographical trends to remain similar. Finally, the results we present here are only partial equilibrium estimates of costs and air quality co-benefits. Additional costs and benefits that would be identified in a general equilibrium framework could be substantial but may be offsetting in the balancing of costs and co-benefits [51].

Policy Implications

We found that for a moderately stringent, highly flexible policy scenario similar to the final U. S. Clean Power Plan, the monetized value of health co-benefits alone exceed estimated costs for the U.S. by $17 billion per year in 2020. When the social cost of carbon is included, the benefits increase from $29 billion to $50 billion with national net benefits of $38 billion per year in 2020. The central cost case assumes annualized program costs and overnight consumer participant costs for energy efficiency.

We also found that the estimated costs of a policy scenario for power plant carbon standards that is similar to the Clean Power Plan vary substantially across regions and under different economic assumptions. At a regional scale, the monetized value of the health co-benefits exceed costs in ten of 14 power regions in 2020 in the central estimate of health co-benefits and the central cost case. Further, annual co-benefits in excess of costs continue to accumulate after the implementation year. Consequently even in the high cost case, where only four power regions have positive co-benefits in the implementation year undiscounted co-benefits will exceed costs within six years for all regions except the Pacific Northwest. Therefore, even after accounting for uncertainty for cost recovery we anticipate that the value of health co-benefits will exceed costs under the central cost case in all but one of the power regions in the U.S. by the time the standards are fully implemented in 2030.

As this and other studies demonstrate, the health co-benefits gained from air quality improvements associated with climate mitigation policies can be large, widespread, and occur nearly immediately once emissions reductions are realized [2,44,52]. As such, health co-benefits can offset costs and provide an important additional motivation for policies that target greenhouse gas emissions, including the U.S. Federal Clean Power Plan.

Supporting Information

S1 Fig. Monetized value of net co-benefits under three different cost cases and the central estimate of health co-benefits for 14 power regions (2010 USD) in the year 2020. S1a Fig represents the lower cost case; S1b represents the central cost case; S1c represents the upper cost case.
(EPS)

S1 Table. Health Impact Functions.
(DOCX)

S2 Table. Cost per case in U.S. (2010 USD).
(DOCX)

Author Contributions

Conceived and designed the experiments: KFL CTD DB JJB. Analyzed the data: JJB KFL DB SS CTD. Contributed reagents/materials/analysis tools: SS JJB DB. Wrote the paper: JJB KFL DB SS CTD.

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Climate and health benefits of increasing renewable energy deployment in the United States*

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Abstract

The type, size, and location of renewable energy (RE) deployment dramatically affects benefits to climate and health. Here, we develop a ten-region model to assess the magnitude of health and climate benefits across the US We then use this model to assess the benefits of deploying varying capacities of wind, utility-scale solar photovoltaics (PV), and rooftop solar PV in different regions in the US—a total of 284 different scenarios. Total benefits ranged from $2.2 trillion for 3000 MW of wind in the Upper Midwest to $4.2 million for 100 MW of wind in California. Total benefits and highest cost effectiveness for CO_2 reduction were generally highest for RE deployment in the Upper Midwest and Great Lakes and Mid-Atlantic US and lowest in California. Health was a substantial portion of total benefits in nearly all regions of the US Benefits were sensitive to methane leakage throughout the gas supply chain.

Introduction

Use of fossil fuels contributes to climate change and health impacts of air pollution [1–5]. Electricity generation is a major source of CO_2, one of the main greenhouse gases (GHGs) driving climate change. Electricity is also a major source of air pollutants that harm health—sulfur dioxide (SO_2), nitrogen oxides (NO_x), and fine particulate matter ($PM_{2.5}$) [6]. In 2017, electricity generation was responsible for 1,941.4 million metric tons (MMT), or 29.5% of GHG emissions in the United States [7]. In 2014, US electrical generation was also responsible for 68% of SO_2 emissions, 12% of NO_x emissions, and 3.4% of primary $PM_{2.5}$ emissions [6]. Emissions from electricity generation were responsible for 31 000 excess deaths in the US in 2010 [5]. Deploying renewable energy (RE) generation is one of many strategies that can reduce reliance on fossil fuels, prevent emissions of GHGs, and reduce the health burden and other environmental impacts of electricity generation [8–11].

The climate and health benefits of the growth in RE has been assessed historically [12], marginal benefits of incremental increases have been assessed for past years [13], and the benefits of either specific project types or projects in specific regions has been assessed [9, 10, 12, 14, 15]. To build on this, we evaluate a series of RE projects at different sizes and across all regions of the US for the year 2017, using consistent methods to estimate benefits, and using health benefit modeling that incorporates seasonal differences in health impacts of emissions.

To do this, we developed the Environmental Policy Simulation Tool for Electrical Grid Interventions, v2.0, (EPSTEIN 2.0), a model to estimate health and climate benefits of RE projects, throughout the US EPSTEIN 2.0 builds on EPSTEIN 1.0, which was geographically limited to the Mid-Atlantic US [9]. We use EPSTEIN 2.0 to simulate the benefits of wind, utility scale solar PV, and rooftop solar PV, deployed at a variety of sizes, in 10 different regions of the US (figure S1), and evaluate and rank different RE types and locations in terms of health benefits, CO_2 avoided, and

* Strategic deployment of #wind and #solar can maximize carbon reductions and health gains.

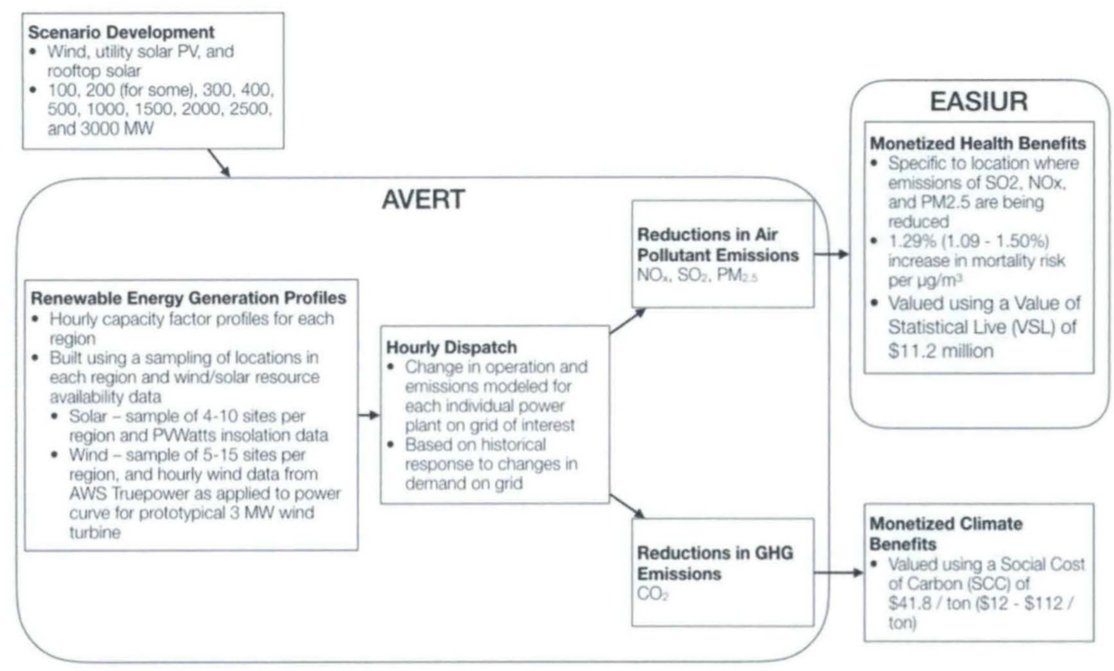


Figure 1. Study design schematic showing model component linkages.

cost per ton of CO_2 avoided with and without health benefits included.

Methods

Similar to EPSTEIN 1.0 [9], EPSTEIN 2.0 is an electrical grid model simulating how RE deployment affects operation of other power plants on the grid and their CO_2, NO_x, SO_2, and $PM_{2.5}$, emissions. This is linked to a public health impact assessment model for NO_x, SO_2, and $PM_{2.5}$ emissions, and a method to value the impact of GHG emissions [16, 17]. For the electrical grid model, EPSTEIN 2.0 uses the Avoided Emissions and Generation Tool (AVERT), an intermediate-complexity electrical grid simulation model produced by the US Environmental Protection Agency (EPA) [18]. To value the benefits of reduced CO_2 emissions, EPSTEIN 2.0 uses the US regulatory social cost of carbon (SCC) [19, 20]; to value the health benefits of reduced SO_2, NO_x, and $PM_{2.5}$ emissions, EPSTEIN 2.0 uses a reduced complexity health benefits assessment model, Estimating Air Pollution Social Impacts Using Regression (EASIUR) [16, 21, 22]. In all cases, dollar values from valuation methods are expressed in 2017 USD (figure 1).

We developed a series of scenarios (table S1, figure 1), modeling the effects of increasing wind, utility solar PV, or rooftop solar PV in the year 2017. We used increments of 100, 300, 400, 500, 1000, 1500, 2000, 2500, and 3000 MW in each region of the US, with some regions having an additional run at 200 MW, and ran each scenario individually. We then rank the different location and energy type combinations and calculate health benefits per CO_2 reduction for each region and energy type. We decompose benefits of each scenario by displaced plant primary fuel type, emissions, and benefits per MWh of RE generated. We also assess the sensitivity of results to methane leakage from the natural gas system. Each component of the model and the other analyses are described below.

AVERT electrical grid model

AVERT is an intermediate complexity electrical grid model, designed to estimate the benefits of increased RE deployment and energy efficiency [18]. It uses historical hourly power plant generation and emissions data for each individual power plant to predict the response of individual power plants to changes in electrical demand for a given year, based on the performance (emissions rates, pollutant control status, boiler status, permitting, and other applicable policies) of each individual plant in that year [18]. AVERT splits the continental US into ten regions, corresponding to the major electrical grid regions (figure S1). We use prototypical capacity profiles from within AVERT for renewables in each region developed from wind and insolation data on a sampling of sites in each region [18, 23–25]. AVERT is less complex than more sophisticated electrical grid models that use grid economics, production cost, and operational and transmission constraints to simulate power plant behavior [18]; however, more sophisticated models are often proprietary and computationally intensive [18]. We compare output from AVERT to previous work using Ventyx/PROSYM, a complex economic

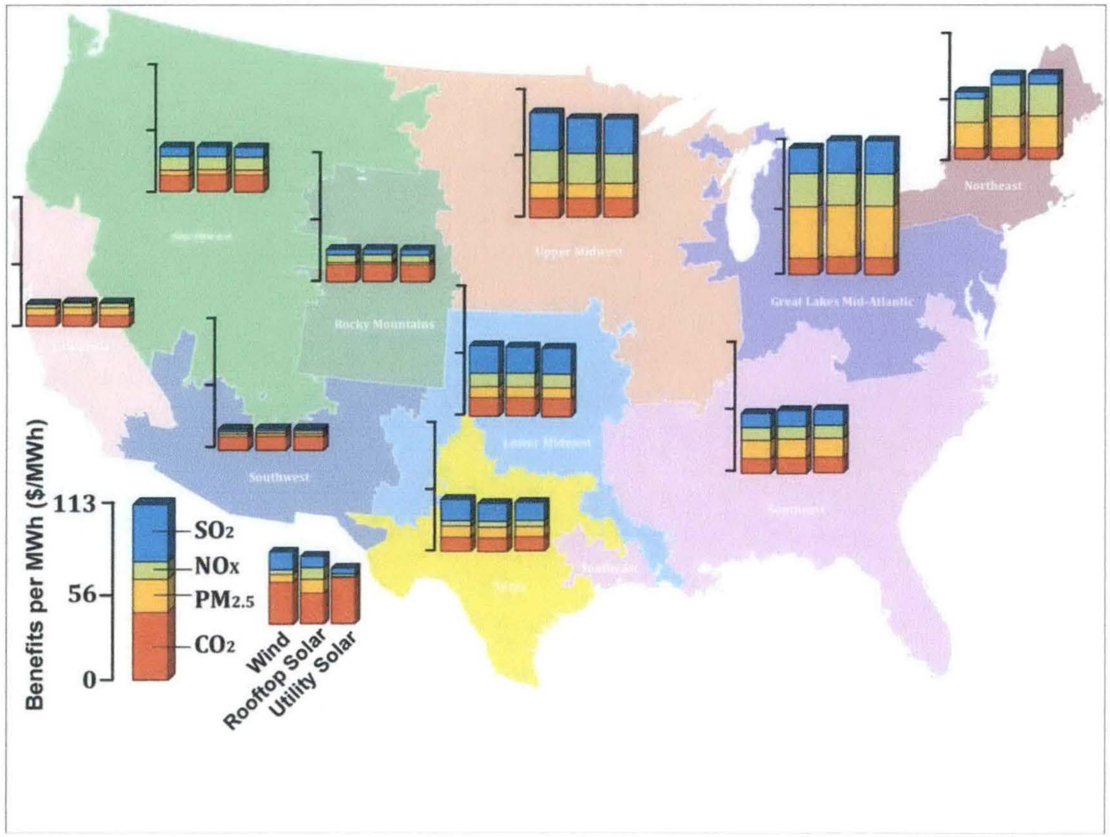


Figure 2. Benefits per MWh of renewable energy deployed for each electrical grid region in the US Benefits are shown for wind, rooftop solar, and utility solar PV, and broken down by pollutant type displaced.

The output from AVERT includes changes in generation, fuel consumption, and emissions of CO_2, NO_x, SO_2, and $PM_{2.5}$, on both annual and monthly timescales, for each plant on the grid where RE is deployed. In about half of the regions, the high capacity scenarios resulted in displacement of more than 15% of fossil generation, a threshold within AVERT where results may have decreased reliability (table S1). To compare results from EPSTEIN 2.0 to results from EPSTEIN 1.0, we perform one run with 500 MW of wind and one with 500 MW of utility solar PV for 2012, the model year for the EPSTEIN 1.0 simulations [9].

Estimating benefits of emissions reductions

EPSTEIN 2.0 estimates benefits from reducing CO_2 emissions using the SCC [20]. The SCC is derived from impact assessment models that capture, in monetary terms, the impact of emitting one extra ton of CO_2 [20]. The SCC captures some health impacts of climate change, agricultural productivity impacts, property damage, and impacts on ecosystem services [20]. Our main SCC estimate is \$41.80/short ton CO_2, \$112/short ton CO_2 (high impact scenario, 3% discount rate) is our high SCC estimate, and a low of \$12/short ton [20].

We use EASIUR to estimate the total benefits of health benefits occurring outside the region where emissions reductions are occurring [16, 21, 22]. Details of EASIUR are available elsewhere, [16, 21, 22], but briefly, EASIUR is constructed from a series of 100 runs using the Comprehensive Air Quality Model with Extensions (CAMx), a complex atmospheric chemistry, fate, and transport model. These runs simulate the impact of an additional ton of emitted pollutant in a location on $PM_{2.5}$ levels in all areas downwind. This model output was then used to create a generalized model for air quality impacts, population exposure, and health impacts, using US Census and Centers for Disease Control data from the Benefits Mapping and Analysis Program (BenMAP), and existing literature on health impacts of $PM_{2.5}$ [16, 21, 22, 26, 27]. EASIUR provides monetized estimates of health impacts of emissions occurring on a 36 km $\times$ 36 km grid at three different heights, both averaged throughout the year and seasonally. We primarily use the seasonal values of from EASIUR linked to monthly output from AVERT, but compare these results to those obtained using the annual average values from EASIUR.

We adjust the direct output from EASIUR to reflect a concentration-response curve with a slope of 1.29% (95% CI: 1.09–1.50), from a meta-analysis of 53 studies of the relationship between mortality risk and

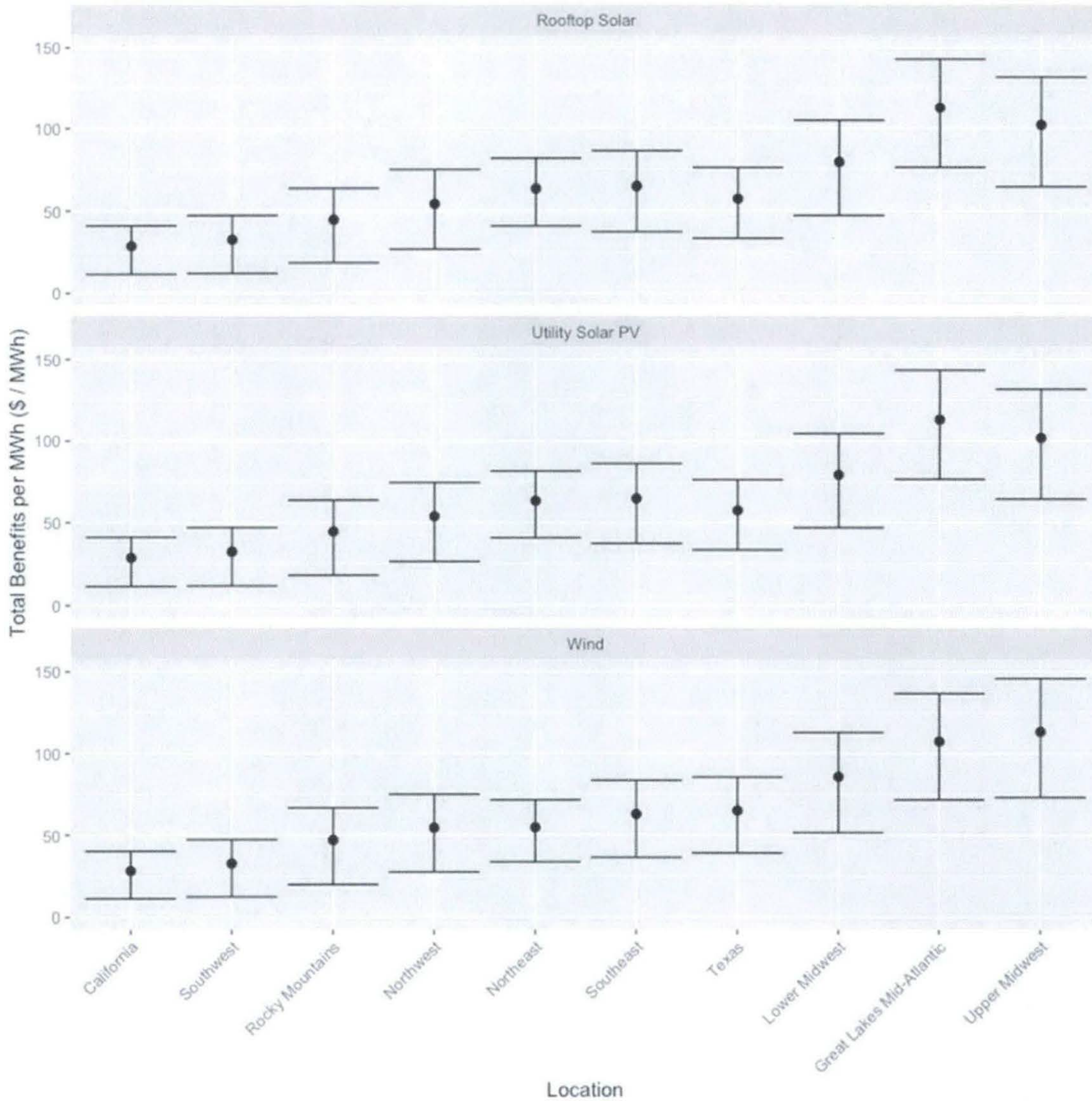


Figure 3. (a) Mid (point), and high and low (whiskers) estimates of total benefits per MWh for each RE type and location. Middle estimates are represented by points, with low and high represented by error bars. (b) Mid (point), and high and low (whiskers) estimates of health and climate benefits per MWh for each RE type and location. Middle estimates are represented by points, with low and high represented by error bars. (c) Mid (point), and high and low (whiskers) estimates of benefits per MWh for each RE type and location, for CO_2, NO_x, SO_2, and $PM_{2.5}$ emissions reduced. Middle estimates are represented by points, with low and high represented by error bars.

mortality risk are valued using the value of statistical life (VSL), an estimate of willingness to pay for reduced mortality risk [29, 30]. The VSL is commonly used in regulatory impact analyses, and in environmental health policy research to value health benefits from reducing air pollution [9, 10, 12, 31, 32]. Here, we use a VSL of $11.2 million, corresponding to the central estimate of the VSL, adjusted for inflation and income growth [29, 30]. We then present these results in terms of benefits per MWh and health benefits per ton of CO_2 reduced. We also rank each type and location in terms of cost per ton of CO_2 reduced, with and without health benefits.

To examine what drives variability in benefits between different scenarios, we break the model results into its component parts—grouping scenarios of benefits per MWh generated. For each region and RE type combination, we examine primary fuel types of the plants displaced, emissions displaced, and benefits across regions and RE types.

We also examine the sensitivity of these results to methane leakage, assuming that leakage rate scales linearly with gas consumed—an approach common in attributional life cycle assessment [33]. We estimate methane leakage rate from the fossil gas supply chain using an estimated 2.3% leakage in the gas transmission system [34], and a methane loss rate from power plants of 0.26%, the middle of the range of estimated leakage rates from power plants [35]. We estimate the mass of methane leaked using a heating value of 1037 Btu/ft^3, a density of 0.05 lb/ft^3, and gas with a 95% methane content. We value the cost of this

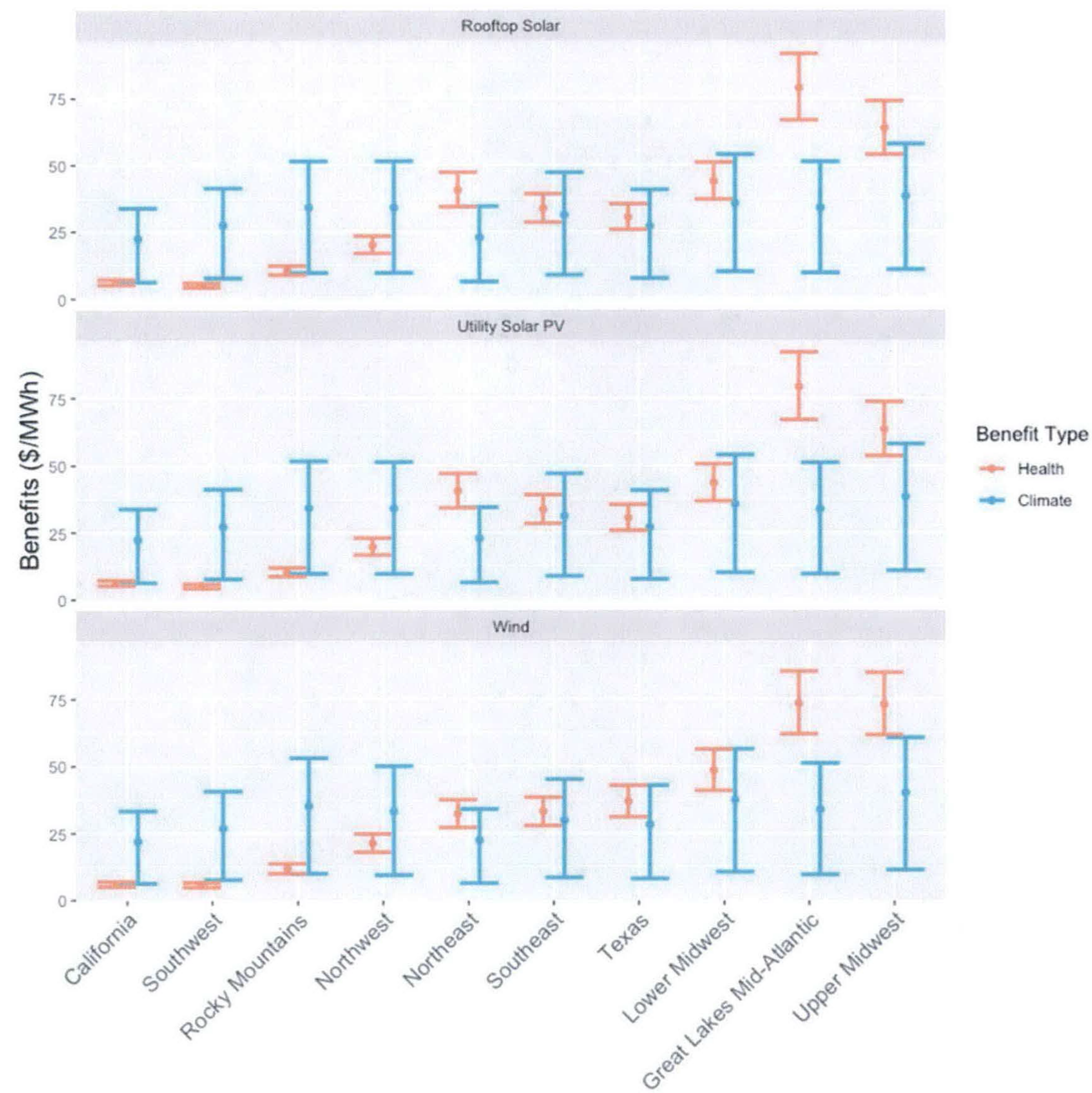


Figure 3. (Continued.)

($1296/metric ton, after adjusting for inflation) [20], and a separate estimate that includes health impacts ($4404/metric ton, after adjusting for inflation) [36].

Results

Health and climate benefits of RE

The total benefits of RE varied dramatically across scenarios—with central estimates ranging from $4.2 million for 100 MW of wind in California, to $1.2 trillion in benefits from installing 3000 MW of wind in the Upper Midwest. Across all parameter choices and scenarios, the benefits ranged from $1.7 million for installing 100 MW of wind in California, to $2.2 trillion for 3000 MW of wind in the Upper Midwest, using high values for the effects of $PM_{2.5}$ on mortality, and the highest value of the SCC. Incorporation of season had modest effect on the benefits estimates—generally increasing benefits for wind and decreasing rate of benefits generated per MWh of renewable electricity generated were quite similar within each region and RE type (figures S3 and S4). This indicates that, as modeled by EPSTEIN 2.0, the relationship between RE generated and social benefits is essentially linear, for each region and each RE type. Since this rate is essentially linear, we use the benefits rates per MWh of RE to examine trends between RE types and regions, along with the drivers behind this variation. We use the mid-range values for the SCC, VSL, and the estimate of the relationship between annual average $PM_{2.5}$ exposure and increased mortality risks throughout, unless otherwise stated.

The total benefits per MWh varied by a factor of 4 between regions and RE types, ranging from $28 per MWh for Wind in California, to $113 per MWh for wind in the Upper Midwest and Utility Solar PV in the Great Lakes. Within a given region, the benefits per MWh of different RE types were fairly similar (figures 2, 3, and S5). For both solar PV types, the

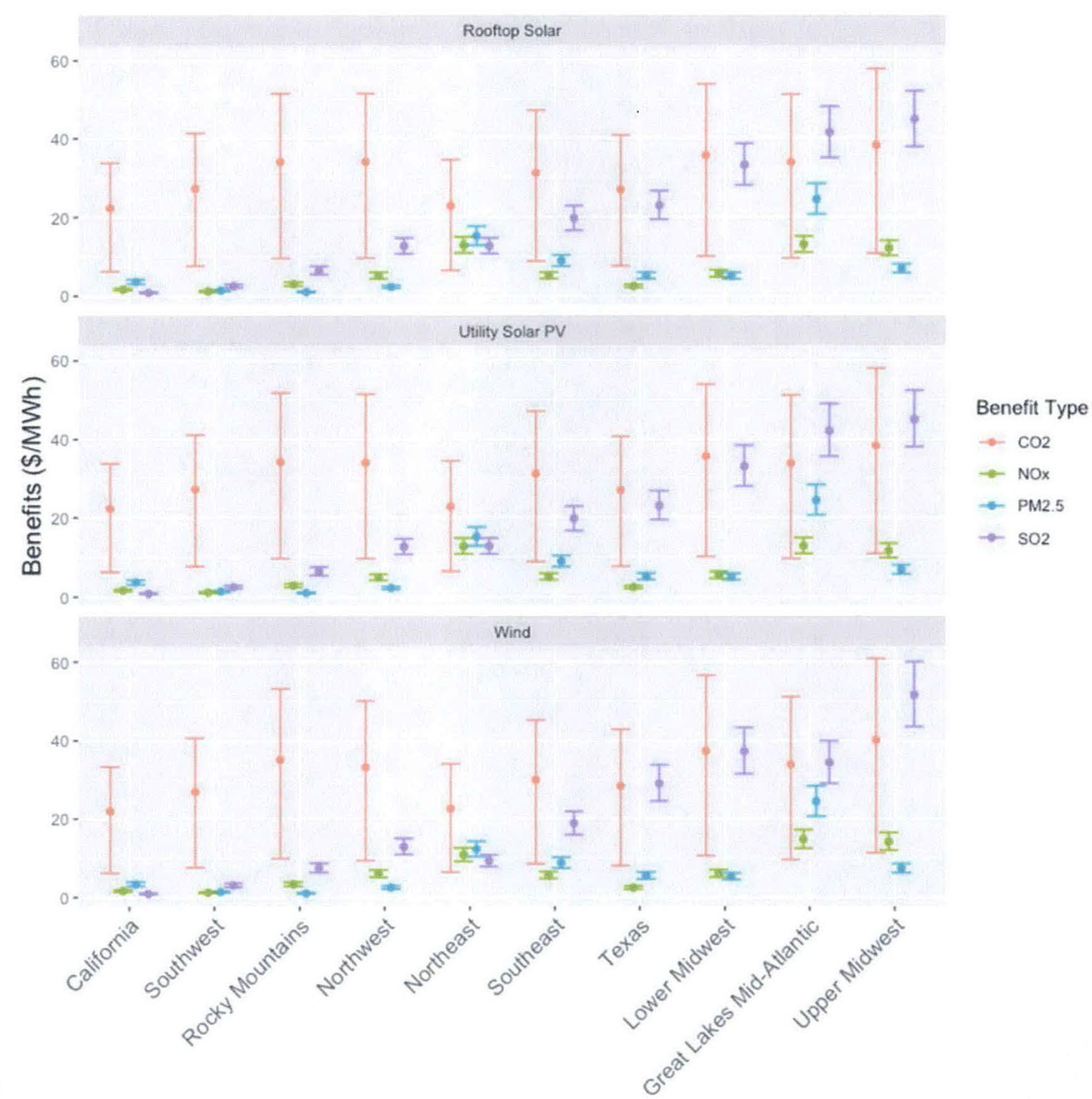


Figure 3. (Continued.)

throughout) had the highest benefits per MWh, followed by the Upper Midwest, and then the Lower Midwest (figures 2 and 3). The lowest three were California, followed by the Southwest, and then the Rocky Mountains (figures 2 and 3). For wind, the highest three were the Upper Midwest, followed by the Great Lakes, and then the Lower Midwest; the lowest three were California, the Southwest, and the Rocky Mountains (figures 2 and 3). For 2012 in the Great Lakes region, the total benefits per MWh hour were roughly double that of our 2017 analyses (table S2). This is largely driven by 2017 having much lower benefits from SO_2 reductions compared to 2012, reflecting RE displacing proportionately more gas and less coal in 2017 than in 2012.

Health benefits vary much more than climate benefits (figure 3). Regions in the eastern half of the US generally had higher health benefits and higher total benefits than regions in the western half. Regions with a higher proportion of coal displaced tended to have These trends were fairly consistent across RE types, but the trends and the exact ranking of regions are somewhat sensitive to parameter choice.

Deployment of RE to optimize climate and health benefits

Separating the health benefits from the climate benefits reveals a ranking of regions and RE types, agnostic to different values of health and climate benefits—basically providing the 'efficiency frontier' of health and climate benefits (figures 5(a) and (b)) [37]. The majority of variation is between regions; the benefits per MWh of different RE types generally cluster by region (figures 5(a) and (b)). RE deployment has the greatest CO_2 reductions in the Upper Midwest, closely followed by the Lower Midwest (figures 5(a) and (b)). The highest health benefits from deploying more RE occur in the Great Lakes, followed by the Upper Midwest, and then the Lower Midwest (figure 5(a)). Examining health benefits per CO_2 reduction instead

Health effects of coal

From SourceWatch

There are a number of negative **health effects of coal** that occur through its mining, preparation, combustion, waste storage, and transport. Negative health effects from coal use within the U.S. include:[1]

- Reduction in life expectancy (particulates, sulfur dioxide, ozone, heavy metals, benzene, radionuclides, etc.)
- Respiratory hospital admissions (particulates, ozone, sulfur dioxide)
- Black lung from coal dust
- Congestive heart failure (particulates and carbon monoxide)
- Non-fatal cancer, osteroporosia, ataxia, renal dysfunction (benzene, radionuclides, heavy metals, etc.)
- Chronic bronchitis, asthma attacks, etc. (particulates, ozone)
- Loss of IQ from air and water pollution and nervous system damage (mercury)
- Degradation and soiling of buildings that can effect human health (sulfur dioxide, acid deposition, particulates)
- Global warming (carbon dioxide, methane, nitrous oxide)
- Ecosystem loss and degradation, with negative effects on health and quality of life.

coalSwarm

This article is part of the Coal Issues portal on SourceWatch, a project of CoalSwarm (http://coalswarm.org/) and the Center for Media and Democracy (http://www.prwatch.org/). See here for help on adding material to CoalSwarm.

Coal 101: What's Wrong with Coal?

Coal 101: What's Wrong with Coal?

Contents

Coal Mining

Health effects from coal mining include:

- the release of methane (CH_4), a potent greenhouse gas estimated to account for 18% of the overall global warming effect triggered by human activities (CO_2 is estimated to contribute 50%).[2]
- the release of carbon monoxide (CO) from explosives, which pollutes the air and poses a health risk for mine workers.[3]
- coal dust and coal particles stirred up during the mining process, as well as the soot released during coal transport, which can cause severe and potentially deadly respiratory problems.[3]
- drastic alteration of the landscape, particularly with mountaintop removal, which can render an area unfit for other purposes, even after coal mine reclamation. The clearing of trees, plants, and topsoil from mining areas destroys forests and natural wildlife habitats. It also promotes soil erosion and flooding, and stirs up dust pollution that can lead to respiratory problems in nearby communities.[3]

- water pollution from acid mine run off and coal sludge.[3]

As of June 2010, no national limits exist on air pollution from coal mines. On June 17, 2010, in a petition presented to Environmental Protection Agency Administrator Lisa Jackson, a coalition of environmental groups called for new controls over coal mine air pollution. The petition states that coal mines should be held to the Clean Air Act standards in force for gravel mines, coal-fired power plants, coal processing plants, and other sources. The petition also calls on Jackson to adopt strict limits on other dangerous air pollutants released from coal mines, including methane, as well as particulate matter, nitrogen oxide gases, and volatile organic compounds — all toxic air pollutants under the Clean Air Act.[4]

Coal Mining Hazards

Chronic exposure to coal dust can lead to black lung disease, or pneumoconiosis, which took the lives of 10,000 miners worldwide over the last decade.[5] Rates of black lung are on the rise, and have almost doubled in the last 10 years. The US National Institute for Occupational Safety and Health (NIOSH) reported that close to 9 percent of miners with 25 years or more experience tested positive for black lung in 2005-2006, compared with 4 percent in the late 1990s.[6]

Miners can also suffer other serious, long-term respiratory ailments: industrial bronchitis is very common among coal workers. In nonsmokers (who are less prone to develop bronchitis than smokers), studies of coal miners have shown a 16%[7] to 17%[8] incidence of industrial bronchitis.

Miners are also at risk of injury and fatality from coal mining disasters, such as the Upper Big Branch mine disaster that occurred on April 5, 2010 at Massey Energy's Upper Big Branch Mine at Montcoal in Raleigh County, West Virginia. Twenty-nine miners were killed.[9]

Mountaintop Removal

In mountaintop removal mining, most common in the Appalachian region of the U.S., mountaintops are literally blown off to reach coal seams, with the waste products deposited into valleys below, causing permanent damage to the landscape and the local ecosystem. According to the Sierra Club, this practice has "damaged or destroyed approximately 1,200 miles of streams, disrupted drinking water supplies, flooded communities, eliminated forests, and destroyed wildlife habitat. Coal companies have created at least 6,800 fills to hold their mining wastes, and the government estimates that if this mining continues unabated in Appalachia it will destroy 1.4 million acres of land by 2020."[3]

Coal Combustion

Coal is the least efficient of the fossil fuels in terms of the amount of energy gained vs. CO2 released. Burning it also releases numerous toxic chemicals and particulates, which can exact a cost on a country's population in terms of reduced life expectancy and increased health costs [10].

Coal combustion releases nitrogen oxides, sulfur dioxide, particulate matter (PM), mercury, and dozens of other substances known to be hazardous to human health. [11]

Coal-fired power plants that sell electricity to the grid produce more hazardous air pollution in the U.S. than any other industrial pollution sources. According to the report details, over 386,000 tons of air pollutants are emitted from over 400 plants in the U.S. per year. Interestingly, while most of the power plants are located in the Midwest and Southeast, the entire nation is threatened by their toxic emissions. An ALA graph shows that while pollutants such as acid gases stay in the local area, metals such as lead and arsenic travel beyond state lines, and fine particulate matter has a global impact. Particle pollution from power plants is estimated to kill approximately 13,000 people a year [12]

According to the Union of Concerned Scientists, in an average year, a typical coal plant (500 megawatts) generates the following amounts of air pollutants:[13]

- 3.7 million tons of carbon dioxide (CO_2), an amount equivalent to chopping down 161 million trees. CO_2 pollution is the principal human cause of global warming and climate change.
- 10,000 tons of sulfur dioxide (SO_2), which causes acid rain and forms small airborne particles that can cause lung damage, heart disease, and other illnesses.
- 10,200 tons of nitrogen oxide (NOx), equivalent to half a million late-model cars. NOx leads to formation of smog, which inflames lung tissue and increases susceptibility to respiratory illness.
- 500 tons of small airborne particles (particulate matter), which can cause bronchitis, reductions in lung function, increased hospital and emergency room admissions, and premature death.[14]
- 220 tons of hydrocarbons, which contribute to smog formation.
- 720 tons of carbon monoxide (CO), which causes headaches and places additional stress on people with heart disease.
- 170 pounds of mercury. 1/70th of a teaspoon of mercury deposited in a 25-acre lake can make the fish unsafe to eat. Mercury also causes learning disabilities, brain damage, and neurological disorders.[15]
- 225 pounds of arsenic, which leads to cancer in 1 out of 100 people who drink water containing 50 parts per billion.
- 114 pounds of lead, 4 pounds of cadmium, and other toxic heavy metals. These toxic metals can accumulate in human and animal tissue and cause serious health problems, including mental retardation, developmental disorders, and damage to the nervous system.[16]

Coal ash, the hazardous waste that remains after coal is burned, can also contain: chromium, which can cause stomach ulcers, anemia, and stomach and lung cancers; selenium, which in excess can cause impaired vision or paralysis; and boron, which can cause eye, nose, and throat irritation, or in large amounts damage to testes, intestines, liver, kidney, and brain. All effects can eventually lead to death. [17]

Aging coal plants "grandfathered" in after passage of the Clean Air Act have been particularly linked to large quantities of harmful emissions.[18][19]

Emissions from coal power plants in Europe contribute significantly to the burden of disease from environmental pollution. The brand-new figures published in this report show that European Union-wide impacts amount to more than 18,200 premature deaths, about 8,500 new cases of chronic bronchitis, and over 4 million lost working days each year. The economic costs of the health impacts from coal combustion in Europe are estimated at up to €42.8 billion per year. Adding emissions from coal power plants in Croatia, Serbia and Turkey, the figures for mortality increase to 23,300 premature deaths, or 250,600 life years lost, while the total costs are up to €54.7 billion annually.These costs are mainly associated with respiratory and cardiovascular conditions, which are two important groups of leading chronic diseases in Europe [20].

Physical Effects

A November 2009 report on the effects of coal by the Physicians for Social Responsibility (http://www.psr.org/resources/coals-assault-on-human-health.html) (PSR) found that coal combustion affects not only the human respiratory system, but also the cardiovascular and nervous system.[21]

Respiratory Effects

- Premature death: according to a 2004 report by the Clean Air Task Force (http://www.catf.us/publications/view/24), fine particulates from power plants result in nearly 24,000 annual deaths, with 14 years lost on average for each death.[22]
- Coal combustion contributes to smog through the release of oxides of nitrogen, which react with volatile organic compounds in the presence of sunlight to produce ground-level ozone, the primary ingredient in smog. Air pollutants such as nitrogen dioxide (NO 2) and fine particulate matter adversely affect lung development.[21]
- Air pollution triggers attacks of asthma, which now affects more than 9% of all U.S. children, who are particularly susceptible to the development of pollution-related asthma attacks. There are now tens of thousands of hospital visits and asthma attacks each year.[21]
- Coal pollutants also plays a role in the development of chronic obstructive pulmonary disease (COPD), a lung disease characterized by permanent narrowing of airways.[21]
- Exposures to ozone and PM are also correlated with the development of and mortality from lung cancer, the leading cancer killer in both men and women.[21]

Cardiovascular Effects

- Air pollution is known to negatively impact cardiovascular health. The mechanisms have not been definitively identified, but studies in both animals and humans suggest they are the same as those for respiratory disease: pulmonary inflammation and oxidative stress. Pollutants produced by coal combustion can lead to cardiovascular disease, such as artery blockages leading to heart attacks, and tissue death and heart damage due to oxygen deprivation. It is estimated that soot pollution from power plants contributes to 38,200 non-fatal heart attacks each year.[22]
- Recent research suggests that nitrogen oxides and PM2.5, along with other pollutants, are associated with hospital admissions for potentially fatal cardiac rhythm disturbances. Cities with high NO 2 concentrations have death rates four times higher than those with low NO 2 concentrations, suggesting a potential correlation.[21]
- There are also cardiovascular effects from long-term air pollution exposure. Exposure to chronic air pollution over many years increases cardiovascular mortality, a correlation that remains significant even while controlling for other risk factors like smoking. Conversely, long-term improvements in air pollution reduce mortality rates: reductions in PM2.5 concentration in 51 metropolitan areas, due to the Clean Air Act, were correlated with significant increases in life expectancy.[21]
- A 2012 *Journal of the American Medical Association* article (http://jama.ama-assn.org/content/307/7/713.short) looked at 34 studies comparing the risk of suffering a heart attack at various levels of inhaling industrial and traffic-related air pollutants including carbon monoxide, nitrogen dioxide, and particulate matter. The researchers conclude that: "All the main air pollutants, with the exception of ozone, were significantly associated with a near-term increase in [heart attack] risk."

Nervous System Effects

- According to the PSR report, the nervous system is also a target for coal pollution's health effects, as the same mechanisms thought to mediate the effect of air pollutants on coronary arteries also apply to the arteries that nourish the brain. These include stimulation of the inflammatory response and oxidative stress, which can lead to stroke and other cerebral vascular disease.[21]
- Several studies have shown a correlation between coal-related air pollutants and stroke. In Medicare patients, ambient levels of PM2.5 have been correlated with cerebrovascular disease, and PM10 with hospital admission for ischemic stroke, which accounts for eighty-seven percent of all strokes.[21]
- Coal contains trace amounts of mercury that, when burned, enter the environment and can act on the nervous system to cause loss of intellectual capacity. Coal-fired power plants are responsible for approximately one-third of all mercury emissions attributable to human activity. Researchers have estimated that between 300,000 and 630,000 children are born in the U.S. each year with blood mercury levels high enough to impair performance on neurodevelopmental tests and cause lifelong loss of intelligence.[21]

Researchers from Harvard University's School of Public Health found that pregnant women exposed to high levels of diesel particulates or mercury were twice as likely to have an autistic child compared with peers in low-pollution areas. The findings were published in a 2013 issue of Environmental Health Perspectives, and is the largest U.S. study to examine the ties between air pollution and autism.[23]

Climate change

Coal-fired power plants are responsible for one-third of America's carbon dioxide (CO2) emissions—about the same amount as all transportation sources (cars, SUVs, trucks, buses, planes, ships, and trains) combined.[24] A 1000 megawatt (MW) coal-fired power plant produces approximately the same amount of global warming as 1.2 million cars.[25]

SO2 emissions have roughly paralleled the increase in coal consumption, reflecting heavy coal burning and inadequate sulfur control measures. Coal burning, the primary source of China's high SO2 emissions, accounts for more than three quarters of the country's commercial energy needs, compared with 17 percent in Japan and a world average of 27 percent [20]. China's consumption of raw coal increased annually by 2 percent between 1989 and 1993. Meanwhile, SO2 emissions increased by more than 20 percent and TSP increased by approximately 10 percent. The country is expected to burn 1.5 billion metric tons of coal annually by the year 2000, up from 0.99 billion metric tons in 1990. Without even more dramatic measures to control emissions than are currently in place, the deterioration of air quality seems inevitable [26].

Health costs from climate change

A November 2011 analysis published in the journal *Health Affairs* by NRDC scientists estimated that climate change-related events in the United States during the last decade added up to health costs exceeding $14 billion dollars and over 760,000 interactions with the health care system. The analysis looked at cases in six specific categories in the U.S. occurring between 2002 through 2009, including: Florida hurricanes, North Dakota floods, California heat waves and wild fires, nationwide ozone air pollution, and Louisiana West Nile virus outbreaks. The group of events resulted in an estimated 1,689 premature deaths, 8,992 hospitalizations, 21,113 emergency room visits, and 734,398 outpatient visits, totaling over 760,000 encounters with the health care system.[27]

Coal Waste

Coal sludge from mining and coal ash from combustion are stored throughout the U.S. in coal waste sites. As of October 2010, coal waste is not regulated by the federal government, even though *New York Times* analysis of EPA data found power plants are the nation's biggest producer of toxic waste, surpassing industries like plastic, paint manufacturing, and chemical plants.[28]

Coal Sludge

After mining, coal is crushed and washed to remove the surrounding soil and rock. Coal sludge, also known as slurry, is the liquid coal waste produced by mining activities. The washing process generates huge amounts of liquid waste. Another form of liquid coal waste is acidic mine runoff, as sulfuric acid forms when coal is exposed to air and water. Each year coal preparation creates waste water containing an estimated 13 tons of mercury, 3236 tons of arsenic, 189 tons of beryllium, 251 tons of cadmium, and 2754 tons of nickel, and 1098 tons of selenium. The mining process also produces millions of tons of solid coal waste each year from dredging up land and its natural elements, including heavy metals.[11] Coal companies usually dispose of sludge by constructing dams from the solid mining refuse to store the liquid waste. These impoundments are often located in valleys near their coal processing plants, and are at risk from breaking open and spilling onto residential areas (see *Coal waste Spills* below), or leaching into and contaminating groundwater supplies.[29]

Coal Ash and Toxic Waste

Burning coal produces airborne compounds, known as fly ash and bottom ash (collectively referred to as coal ash), which can contain large quantities of heavy metals that settle or wash out of the atmosphere into oceans, streams, and land.[30][11] The amount of fly ash is going up: in 2006, coal plants in the United States produced almost 72 million tons, up 50 percent since 1993.[13]

The large quantities of toxic metals in coal ash include lead, mercury, nickel, tin, cadmium, antimony, and arsenic, as well as radio isotopes of thorium and strontium.[11] Small amounts of heavy metals can be necessary for health, but too much may cause acute or chronic toxicity (poisoning). Many of the heavy metals released in the mining and burning of coal are environmentally and biologically toxic elements, stored in federally unregulated coal waste sites.[30]

Sulfur dioxide scrubbers also create coal waste. The flue-gas desulfurization (FGD) process creates a wet solid residue containing calcium sulfite ($CaSO_3$) and calcium sulfate ($CaSO_4$). Often dry material such as fly ash is added to stabilize the sludge for transport and landfill storage.[31]

A power plant that operates for 40 years will leave behind 9.6 million tons of toxic waste.[11] This coal waste constitutes the nation's second largest waste stream after municipal solid waste.[32]

Soil and Water Pollution

Most often coal waste is disposed of in landfills or "surface impoundments," which are lined with compacted clay soil, a plastic sheet, or both. As rain filters through the toxic ash pits year after year, the toxic metals are leached out and pushed downward by gravity towards the lining and the soil below. An EPA study found that all liners eventually degrade, crack or tear, meaning that all landfills eventually leak and release their toxins into the local environment.[33][34] In a best case scenario, the EPA study determined that a 10-acre landfill would leak 0.2 to 10 gallons per day, or between 730 and 36,500 gallons over a ten-year period, an amount guaranteed to infiltrate the drinking water supply.[33]

In January 2009, an Associate Press study found that 156 coal-fired power plants store ash in surface ponds similar to one that ruptured at Kingston Fossil Plant. The states with the most storage in coal ash in ponds are Indiana, Ohio, Kentucky, Georgia and Alabama. The AP's analysis found that in 2005, 721 power plants generating at least 100 MW of electricity produced 95.8 million tons of coal ash, about 20 percent of which - or almost 20 million tons - ended up in surface ponds. The rest of the ash winds up in landfills or is sold for other uses.[35]

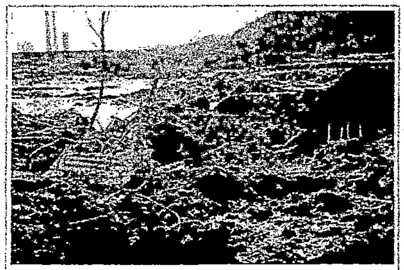
In October 2009, Appalachian Voices released an analysis of monitoring data from coal waste ponds at 13 coal plants in North Carolina. The study revealed that all of them are contaminating ground water with toxic pollutants, in some cases with over 350 times the allowable levels according to state standards. The contaminants include the toxic metals arsenic, cadmium, chromium, and lead, which can cause cancer and neurological disorders. The study was based on data submitted by Duke Energy and Progress Energy to state regulators.[36]

High hazard coal ash dumps

In response to demands from environmentalists as well as Senator Barbara Boxer (D-California), chair of the Senate Committee on the Environment and Public Works, the EPA made public its list of 44 "high hazard potential" coal waste dumps. The rating applies to sites at which a dam failure would most likely cause loss of human life, but does not include an assessment of the likelihood of such an event. The list includes sites in 10 states, including 12 in North Carolina, 9 in Arizona, 6 in Kentucky, 6 in Ohio, and 4 in West Virginia. Eleven of the sites belong to American Electric Power, 10 to Duke Energy. No Tennessee Valley Authority sites were included on the list. EPA relied on self-reporting by utilities to rank the facilities, and TVA classied all of its dump sites - including Kingston Fossil Plant - as "low hazard."[37]

Coal Waste "Spills"

On December 22, 2008, a retention pond wall collapsed at TVA's Kingston plant in Harriman, TN, releasing a combination of water and fly ash that flooded 12 homes, spilled into nearby Watts Bar Lake, contaminated the Emory River, and caused a train wreck. Officials said 4 to 6 feet of material escaped from the pond to cover an estimated 400 acres of adjacent land. A train bringing coal to the plant became stuck when it was unable to stop before reaching the flooded tracks.[38] Hundreds of fish were floating dead downstream from the plant.[39] Water tests showed elevated levels of lead and thallium.[40]


TVA ash spill in Harriman, TN on December 25, 2008. Photo courtesy of United Mountain Defense.

Originally TVA estimated that 1.7 million cubic yards of waste had burst through the storage facility. Company officials said the pond had contained a total of about 2.6 million cubic yards of sludge. However, the company revised its estimates on December 26, when it released an aerial survey showing that 5.4 million cubic yards (1.09 billion gallons) of fly ash was released from the storage facility.[39] Several days later, the estimate was increased to over 1 billion gallons spilled.[41] The TVA spill was 100 times larger than the Exxon Valdez spill in Alaska, which released 10.9 million gallons of crude oil.[42] Cleanup was expected to take weeks and cost tens of millions of dollars.[43]

Drinking water contaminated with hexavalent chromium from coal may cause cancer

A report released by EarthJustice and the Sierra Club in early February 2011 stated that there are many health threats associated a toxic cancer-causing chemical found in coal ash waste called hexavalent chromium. The report specifically cited 29 sites in 17 states where the contamination was found. The information was gathered from existing EPA data on coal ash and included locations in Alabama, Arkansas, Delaware, Florida, Illinois, Indiana, Minnesota, Massachusetts, North Carolina, North Dakota, Nevada, Ohio, Oklahoma, Pennsylvania, Tennessee, Virgina and Wisconsin.

As a press release about the report read:

> Hexavalent chromium first made headlines after Erin Brockovich sued Pacific Gas & Electric because of poisoned drinking water from hexavalent chromium. Now new information indicates that the chemical has readily leaked from coal ash sites across the U.S. This is likely the tip of the iceberg because most coal ash dump sites are not adequately monitored.[44]

Coal Transport

18% of hard coal production is traded on the world coal market.[45] In 2007, the United States exported almost 60 million tons of coal.[46]

Raw Video: Oil Leak Threatens Great Barrier Reef

Coal is often transported via trucks, railroads, and large cargo ships, which release air pollution such as soot and can lead to accidents. On April 3, 2010, Chinese-owned bulk coal carrier named Shen Neng 1 rammed into the Great Barrier Reef in Australia, the planet's largest coral reef and selected as a World Heritage Site in 1981. The fuel oil is a byproduct of oil production that is used by many cargo ships because it is cheap, but also full of contaminants and very gooey, making it dangerous for animals and hard to clean up. A light aircraft was seen spraying a chemical dispersant on the spilled oil. [47]

The Australian Transport Safety Bureau said it would be conducting a full investigation of the incident.[47] The Chinese freighter was in a no-shipping zone, and the owners of the ship could face a fine of $1 million if found to have violated Australia's shipping laws. It is possible that the Captain was attempting to make his voyage shorter by taking a short cut through the reef. Critics say commercial ships are supposed to be monitored by Australian authorities, but the monitoring is weak. The Australian group World Wide Fund for Nature (Australia) claims the Chinese company that owns the ship, Shenzhen Energy, a subsidiary of the COSCO Group, has had three similar incidents occur during the past four years.[48]

Health costs from US coal plants

2010 Clean Air Task Force Report

A 2010 report from the Clean Air Task Force, *The Toll From Coal* (http://www.catf.us/resources/publications/files/The_Toll_from_Coal.pdf) found that, in the United States, particle pollution from existing coal power plants is expected to cause some 13,200 premature deaths in 2010, as well as 9,700 additional hospitalizations and 20,000 heart attacks.[49]

Estimated mortality figures for 2010 have Pennsylvania leading the nation with 1,359 premature deaths, 1,016 people admitted to the hospital, and 2,298 additional heart attacks. Ohio comes in second with 1,221 additional premature deaths; New York takes third with 945 dead from coal pollution. Per capita, the figures change slightly: West Virginia is first in the nation, with an estimated 14.7 coal-related deaths per 100,000 adults. Pennsylvania and Ohio tie for second, with 13.9; Kentucky comes in third at 12.6.[49]

The report found that the total monetized value of these adverse health impacts amounts to more than $100 billion per year. This burden is not distributed evenly across the population. Adverse impacts are especially severe for the elderly, children, and those with respiratory disease. In addition, the poor, minority groups, and people who live in areas downwind of multiple power plants are likely to be disproportionately exposed to the health risks and costs of fine particle pollution.[49]

In the previous version of this study, done in 2004 (http://www.catf.us/resources/publications/view/24), it was estimated that coal pollution would caused about 24,000 premature deaths annually. The authors cited EPA action in 2005 under the Clean Air Interstate Rule (CAIR) as resulting in the declining mortality figures. Though CAIR was struck down in Federal court in 2008, the pollution reduction requirements remain in effect until a replacement is established. In making their projections, the authors of the study assume similarly stringent requirements will be in place for the remainder of 2010.[49]

Even with much decreased numbers, the report says sulfur dioxide and nitrogen oxide emissions from coal power plants will "continue to take a significant toll on the health and longevity of millions of Americans." Overall, the report says "among all industrial sources of air pollution, none poses greater risks to human health and the environment than coal-fired power plants."[49]

2011 Harvard report: external costs of coal up to $500 billion annually

A Feb. 2011 report, "Mining Coal, Mounting Costs: the Life Cycle Consequences of Coal," (http://onlinelibrary.wiley.com/doi/10.1111/j.1749-6632.2010.05890.x/pdf) led by associate director of the Center for Health and the Global Environment at Harvard Medical School Dr. Paul Epstein, found that accounting for the full costs of coal would double or triple its price. The study, which was released in the *Annals of the New York Academy of Sciences,* tallied the economic, health and environmental costs associated with each stage in the life cycle of coal – extraction, transportation, processing, and combustion - and estimated those costs, which are borne by the public at large, to be between $175 billion and $500 billion dollars annually.[50]

In terms of human health, the report estimated $74.6 billion a year in public health burdens in Appalachian communities, with a majority of the impact resulting from increased healthcare costs, injury and death. Air pollutants from combustion accounted for $187.5 billion, mercury impacts as much as $29.3 billion, and climate contributions from combustion between $61.7 and $205.8 billion. The study discussed a number of other impacts that are not easily quantified, including effects of heavy metal toxins and carcinogens released into water supplies as part of coal mining and processing; the death and injury of workers mining coal; and the social impacts in mining communities.[50]

Table 1: Estimates of external costs of coal in cents/kWh of electricity (2008 US$)[51]

Type of impact	Low	Best	High
Land disturbance	0.00	0.01	0.34
Methane emissions from mines	0.03	0.08	0.34
Public health burden in Appalachia	4.36	4.36	4.36
Fatalities due to coal transport	0.09	0.09	0.09
Air pollutants from combustion	3.23	9.31	9.31
Lost productivity from mercury emissions	0.01	0.10	0.48
Excess mental retardation from mercury emissions	0.00	0.02	0.19
Excess cardiovascular disease from mercury emissions	0.01	0.21	1.05
Climate damage from combustion emissions of CO_2 and N_2O	1.02	3.06	10.20
Climate damage from combustion emissions of black carbon	0.00	0.00	0.01
Subsidies	0.16	0.16	0.27
Abandoned mine lands	0.44	0.44	0.44
Total	9.36	17.84	26.89

The study concluded:

> "Our comprehensive review finds that the best estimate for the total economically quantifiable costs, based on a conservative weighting of many of the study findings, amount to some $345.3 billion, adding close to 17.8¢/kWh of electricity generated from coal. The low estimate is $175 billion, or over 9¢/kWh, while the true monetizable costs could be as much as the upper bounds of $523.3 billion, adding close to 26.89¢/kWh. These and the more difficult to quantify externalities are borne by the general public." The average residential price of electricity at the time of the report is 12¢/kWh.[50]

Skeptical Science (http://www.skepticalscience.com/true-cost-of-coal-power.html) notes that when the coal externalities of the study are included in coal's price, it increases the levalized costs to approximately 28 cents per kWh, which is more than the 2009 U.S. Energy Information Administration cost of hydroelectric, wind (onshore and offshore), geothermal, biomass, nuclear, natural gas, and solar photovoltaics, and is on par with solar thermal, although the costs of solar thermal are falling.[52]

The study noted that its estimates did not include the full cost of coal:[50]

> "Still these figures do not represent the full societal and environmental burden of coal. In quantifying the damages, we have omitted the impacts of toxic chemicals and heavy metals on ecological systems and diverse plants and animals; some ill-health endpoints (morbidity) aside from mortality related to air pollutants released through coal combustion that are still not captured; the direct risks and hazards posed by coal sludge, coal slurry, and coal waste impoundments; the full contributions of nitrogen deposition to eutrophication of fresh and coastal sea water; the prolonged impacts of acid rain and acid mine drainage; many of the long-term impacts on the physical and mental health of those living in coal-field regions and nearby MTR sites; some of the health impacts and climate forcing due to increased tropospheric ozone formation; and the full assessment of impacts due to an increasingly unstable climate."[50]

Resources

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- External costs of coal
- Climate impacts of coal plants
- Health costs of coal plants
- Mercury and coal
- Sulfur dioxide and coal
- Global warming
- Environmental impacts of coal
- Air pollution from coal-fired power plants
- Coal waste
- Coal sludge

- Fly ash
- Heavy metals and coal

External resources

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Data show spike in black lung disease

12/66 BC-DAILY NEWS

MORGANTOWN, W.Va. (AP) — New data show many more coal miners across Appalachia suffering from the most serious form of black lung disease than federal regulators previously reported.

National Public Radio reported Friday that its investigation shows cases 10 times more prevalent, with data from 11 black lung clinics in Virginia, West Virginia, Pennsylvania and Ohio showing 962 cases so far this decade. Some clinics had incomplete records and others declined to provide data about their "complicated" black lung cases.

On Thursday, the National Institute for Occupational Safety and Health said that 60 current and former miners – from Pike, Floyd, Letcher and Knott counties in Kentucky – were diagnosed with progressive massive fibrosis, the most severe form of black lung, between January 2015 and last August. Those stricken struggle to breathe.

"The current numbers are unprecedented by any historical standard," NIOSH epidemiologist Scott Laney said. "We had not seen cases of this magnitude ever before in history in central Appalachia."

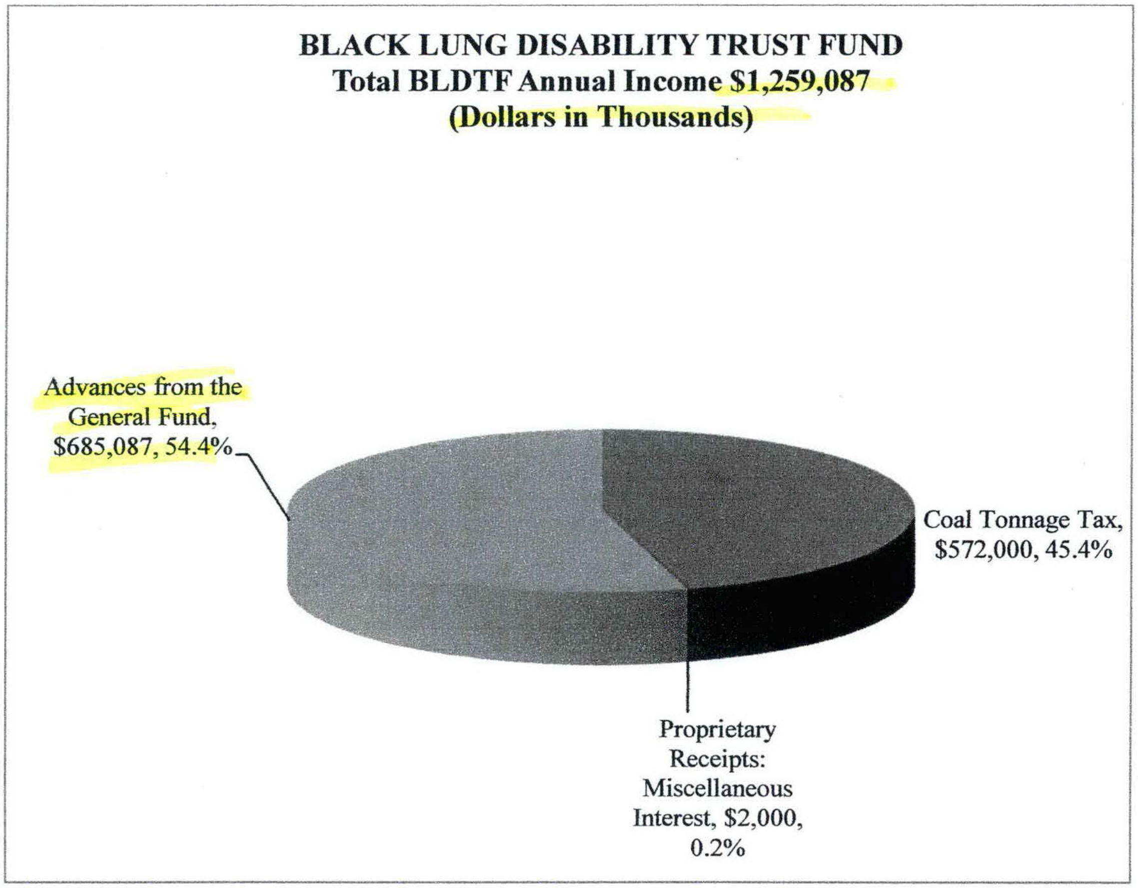
In the last three years, 644 cases of complicated black lung were diagnosed at Stone Mountain Health Services with clinics in three Virginia communities. That's six times the NIOSH national count in nearly half the time.

FY 2015

CONGRESSIONAL BUDGET JUSTIFICATION

BLACK LUNG DISABILITY TRUST FUND

BLACK LUNG DISABILITY TRUST FUND



BLACK LUNG DISABILITY TRUST FUND

DETAILED WORKLOAD AND PERFORMANCE					
		FY 2015 Enacted		FY 2016 Enacted	FY 2017 Request
		Target	Result	Target	Target
Black Lung Disability Trust Fund					
Strategic Goal 4 - Secure retirement, health, and other employee benefits and, for those not working, provide income security					
Strategic Objective 4.1 - Provide income support when work is impossible or unavailable and facilitate return to work					
BLDTF WL 1	Claims Received	7,300	6,818	7,400[r]	8,000[e]
BLDTF WL 2	Trust Fund Beneficiaries	17,580	13,064	16,000[r]	15,600[e]
BLDTF WL 3	Beneficiaries Paid by Responsible Operators	4,370	4,889	5,200[r]	5,200[e]
BLDTF WL 4	Medical benefits only recipients	1,100	731	700[r]	700[e]

Legend: (r) Revised (e) Estimate (base) Baseline -- Not Applicable TBD - To Be Determined [p] - Projection

Sub Menu

Fish Consumption Advisories

The Kentucky Departments for Environmental Protection, Health Services and Fish and Wildlife Resources jointly issue a fish consumption advisory to the public when fish are found contaminated. Trace contaminants such as polychlorinated biphenyls (PCBs) and mercury are found in some fish in Kentucky. An advisory cautions people about potential health problems that may result from eating fish caught from a particular area. An advisory does not ban eating fish; it is a guide to reduce your risk. This guide provides information on how often fish may be safely eaten. Most fish are healthy to eat and are an excellent source of low-fat protein. To answer basic questions about fish consumption advisories, Kentucky Division of Water has prepared an FAQ that can be found here: **Frequently Asked Questions about Fish Consumption Advisories**

A new method for reporting the fish consumption advisories has been adopted. Consumption rates for specific fish have been developed based on a meal of 1/2 pound of fish (before cooking) eaten by a 150-pound individual. Following these guidelines and spacing your meals of those fish species will limit your health risks by reducing your total exposure.

A sensitive population category exists for women of childbearing age, children 6 years of age or younger, pregnant and nursing women and women who plan to become pregnant. Those individuals who consume fish from the Ohio River should follow the sensitive population consumption advisories.

Risks from eating contaminated fish can be reduced by the following:

- ...fillet the fish, remove the skin and trim all fat
- ...do not eat fish eggs
- ...broil, grill or bake the fillets instead of frying or microwaving
- ...do not eat or reuse juices or fats that cook out of the fish.

Fish consumption advisories are in effect for the following:

1. **Statewide:** All Kentucky waters are under an advisory for mercury. Women of childbearing age and children 6 years of age or younger should eat no more than six meals per year of predatory fish, no more than one meal per month of panfish and bottom feeding fish and no more than 1 meal per week of fish in the "other fish" category. The general population should eat no more than one meal per month of predatory fish and no more than one meal per week of panfish and bottom feeding fish. There is no advisory for the general population for fish in the "other fish" category.

   Predatory fish include black bass (smallmouth, largemouth and spotted), white bass, striped bass, hybrid striped bass, sauger, saugeye, walleye, muskellunge, flathead and blue catfish, yellow bass, bowfin, chain pickerel and all gars.

Panfish include bluegill, crappie, rock bass as well as green, longear and redear sunfish.

Bottom feeder fish include the bullheads, buffalo species, channel catfish, common carp, redhorse species, shovelnose sturgeon, drum, creek chub as well as the white suckers, spotted suckers, northern hogsuckers and carpsuckers.

Other fish include asian carp, trout species, minnows, etc.

This is not an emergency, as organic mercury can occur naturally in the environment and does not affect swimmers, skiers or boaters. Fish can accumulate these low levels of mercury by eating plankton and other small aquatic creatures.

2. **Drakes Creek:** Fish should not be consumed from dam on W. Fork at Franklin, Ky. downstream to confluence with Barren River. This includes all species and sizes. (PCB)
3. **Fish Lake:** Ballard Wildlife Management Area, Fish Lake, is an approximately 30-acre natural lake in Ballard County. This advisory is considered to be lake-wide from the headwaters of the lake to the outflow of Shawnee Creek.

   Advisory for Fish Lake:

Fish Group	General Population	Sensitive Population	Contaminant(s)
Bottom Feeders	1 meal/month	6 meals/year	Mercury

4. **Fishtrap Lake:** Fishtrap Lake is approximately 1100 acres and impounds the Levisa Fork River in Pike County, KY.

   Advisory boundaries:

   This advisory will include the Levisa Fork River from the KY/VA Stateline to the dam on Fishtrap Lake. A similar fish consumption advisory has been issued by VA for a portion of the Levisa fork river in their state.

   Advisory for Fishtrap Lake:

Fish Group	General Population	Sensitive Population	Contaminant (s)
Bottom Feeders and White Bass	1 meal/month	6 meals/year	PCB
Predatory Fish	1 meal/week	1 meal/month	PCB

5. **Green River Lake:** Green River Lake is approximately 8,210 acres and impounds Robinson Creek and the Green River in Taylor and Adair counties.

Fish Group	General Population	Sensitive Population	Contaminant(s)

TENNESSEE VALLEY AUTHORITY

HOME ABOUT TVA ENERGY ENVIRONMENT RIVER MANAGEMENT ECONOMIC DEVELOPMENT NEWS & ISSUES

Key Topic

Coal Combustion Products

TVA is phasing out wet storage of ash and gypsum at its coal-fired power plants and installing state-of-the-art dry storage systems.

The transition from wet to dry storage will make TVA an industry leader in managing coal combustion products.

Background
Following the ash spill at Kingston Fossil Plant in December 2008, TVA has developed a comprehensive plan for managing coal combustion products so no similar event ever occurs again at a TVA site.

Important points

- After the Kingston spill, TVA commissioned Stantec Consulting to inspect, evaluate and recommend improvements for combustion product management at all 11 TVA fossil plants.
- In August 2009, the TVA Board of Directors approved a plan to end wet storage of coal ash and gypsum with a goal of making TVA's storage facilities the safest, most modern, and most thoroughly inspected in the industry.
- TVA plans to convert all wet ash and gypsum storage to dry storage, and to eliminate any storage impoundment's federally classified high-risk potential to people and property if the impoundment failed.
- The plan, subject to environmental reviews and regulatory approvals, calls for building ash and gypsum dewatering facilities, permitting and constructing new dry storage landfills and closing existing ash and gypsum ponds.
- The plan is expected to cost $1.5 billion to $2 billion over an eight- to 10-year period.

Other information

- All 11 TVA coal-burning plants now use wet bottom-ash systems, and these will be converted to dry systems.
- The six TVA coal-burning plants that use wet fly-ash handling systems are: Allen, Gallatin, Johnsonville and Kingston in Tennessee; Widows Creek in Alabama, and Paradise in Kentucky.
- The first conversion to dry fly-ash storage will be at Kingston Fossil Plant. It should be complete in late 2011.
- In the last decade, TVA has beneficially reused more than 29 million tons of coal combustion products. TVA is evaluating a number of market, economic and regulatory issues that will provide the basis for identifying and setting specific targets for increasing the diversion of these materials.

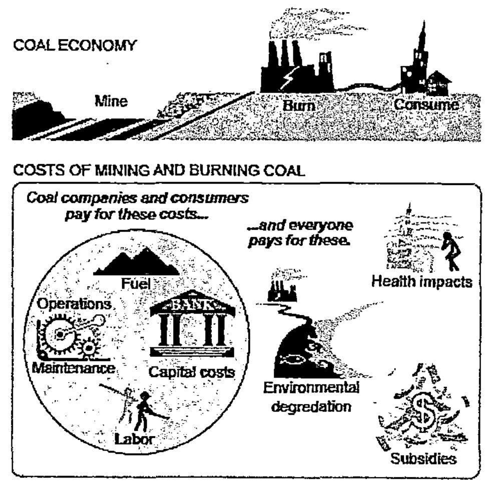
The True Cost of Coal

Last Modified: 12th September 2013

To the electricity customer, coal is relatively cheap. But missing from the sticker price are coal's major impacts on ecosystems, human health, and our economy.

- People are sickened by pollution from coal fired power plants, shortening their lives and burdening the health care system with costly care.
- Fish are poisoned when coal mines dump waste into streams, starving their predators, depriving subsistence fishermen, and straining stocks that support commercial fisheries.
- Future generations will be heavily impacted by global warming from the carbon dioxide that burning coal spews into the air.
- As taxpayers we pay to subsidize coal use and clean up its aftermath.

Collectively, these are known as **"externalized costs"** , because they are not paid by those directly involved in the buying and selling that sets the market price (the coal mining companies, the coal-using power plants, or their electricity customers). Coal has many externalized costs, therefore its market price doesn't reflect its **"True Cost."** Although it appears to be cheap to the buyer, it is much more expensive to society as a whole. For a more detailed discussion of True Cost, see our article **here**.



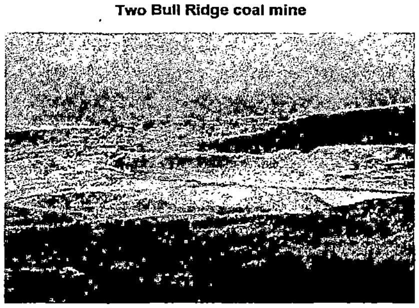
True Cost of Coal: Not all costs of coal are reflected in the price of electricity.

Worldwide these externalized costs were estimated to exceed $450 billion in 2007 . We estimated total economic value of coal in that year to be $210 billion, less than half of the externalized costs. To make this estimate we assumed that the 2007 **US open market price of ~$30 per ton** was representative of the world open market and multiplied this by the world coal consumption in 2007 of about 7 billion tons.

Similarly, in 2009 the National Resource Council **calculated** that the total hidden costs of coal combustion in the United States had exceeded $62 billion in 2005. In 2010, a **detailed economic analysis** of the costs of downwind pollution (primarily from coal plants) concluded that each dollar spent on airborne pollution controls saved $50-100 in annual costs downwind. Another study, **released in Feburary 2011** , estimated that the true cost of coal was up to $500 billion annually in the United States alone. This study further calculated that if all the externalized costs of coal were accounted for, it would at almost 18 cents/kWh to the price of coal. Yet another study, **also released in February 2011** , looked in detail at the benefits of increased electricity generation versus the much larger detrimental effects of coal consumption. A **detailed report** on the true cost of energy released in May 2011 calculated the true cost of coal to be 170% of the retail price. **An analysis** in August 2011 found the external damages caused by coal combustion to be about twice the "value added" of the commodity. A **2013 report** on surface mountaintop mining calculated that to meet US coal annual demand from mountaintop mining would require the destruction of 310 square miles of mountains.

Habitat Destruction

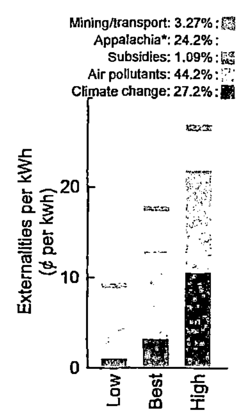
Two Bull Ridge coal mine



This is the most active of the Usibelli coal mines.

Most **coal mining** in the U.S. is surface mining, which includes strip mining and mountaintop removal. In surface mines, the original ecosystem at the mine site is destroyed in the process of removing the coal. Coal companies are required to plant vegetation to **reclaim the site after mining**, restoring the original ecosystem may be difficult, particularly in wetlands areas. Mining destroys fish and wildlife habitat, which has rippling effects not only on their populations, but on the human residents that rely on them.

Beyond the footprint of the mine itself, coal mining impacts surrounding lands, discharging mine runoff into nearby waterways and sending coal dust across the landscape. Coal dust particles and discharged sediment from coal mining can reduce life expectancy of fish, damage their immune systems, and suffocate fish eggs.



Pollution and Health Impacts

Mining and burning coal releases a number of toxic pollutants, some of which remain behind as solid waste, and some of which are released into the atmosphere. These pollutants are responsible for a large number of illnesses and premature deaths, both to people directly involved in the industry and people worldwide.

Coal combustion wastes (CCW) include ash, sludge, and boiler slag left over from burning coal to make electricity. These wastes (120 million tons/year in the US) concentrate toxins such as arsenic, mercury, chromium, cadmium, uranium and thorium. In addition, these wastes create an expensive storage problem **"in perpetuity"**. Coal combustion emissions released into the atmosphere contain nitrous oxides which are responsible for

CCW disposal in Fairbanks

UAF disposal site for CCW
source: Russ Maddox (2010). Copyright held by photographer.

industrial and urban smog, sulfur dioxide which is the primary reactive agent behind acid rain, **mercury** which accumulates in the food chain, and large amounts of carbon dioxide which is the most important greenhouse gas contributing to climate change. Coal mining itself also releases significant amounts of methane, another extremely potent greenhouse gas. Coal mining is responsible for **over 25%** (2.1 MB)of the energy-related methane emissions in the US.

Coal dust in mines and near storage and **transport facilities** contributes to serious respiratory illnesses such as asthma and **Pneumoconiosis** (black lung). Solid combustion wastes such as fly ash pollute groundwater near storage facilities, contaminating individual and community water supplies.

Airborne pollutants have a larger footprint. Despite air pollution regulations, toxic emissions (soot, sulfur dioxide, nitrous oxides) from coal-fired power plants are estimated to be responsible for thousands of deaths due to lung disease each year in the US and Canada. A **government study** in Ontario found that the coal-fired plants in that province alone were responsible for an average annual total of about 660 premature deaths, 920 hospital admissions, 1090 emergency room visits, and 331,000 minor illness.

Coal-fired power plants are a major source of atmospheric **mercury**, which accumulates in the food chain and can damage the developing nervous systems of human fetuses, as well as leading to reduced immune function, weight loss, reduced reproduction rate, mental defects and other neurological problems.

Economics

All of the impacts of coal have an economic cost, from the jobs lost by fishermen downstream of a coal mine, to the health care costs of the people sickened by coal-fired power plant pollution, to the cost of cleaning up spills of toxic coal waste.

Some of the simplest economic costs of coal come in the form of subsidies and tax breaks which are not reflected in the market price of coal (for example the estimated $4.6 billion in **coal-related subsidies** in the 2009 stimulus package). Coal mining and combustion projects require major investments, and the risks and costs of those investments are often passed on to taxpayers via infrastructure subsidies and loan guarantees. An extreme example of this is the **Healy Clean Coal Plant (HCCP)**, which has cost the State of Alaska and the Federal Government nearly $300 million since the mid 1990's yet is not producing power in return. Similarly, **a recent study in Kentucky** determined that the government spends $115 million more on subsidies for the coal industry in the state than it receives in taxes or other benefits. We **have calculated** that coal pays only 5% of it's market value to the state of Alaska, even though the nominal rates are much higher.

Healy Clean Coal Plant (HCCP)

The HCCP plant near Usibelli coal mine

Taxpayers also pay the costs of cleaning up environmental disasters caused by the coal industry. Cleanup of the recent **coal ash spill in Tennessee** is estimated to cost up to $1 billion, not including **pending litigation** . Now that the cleanup at this site has been **taken over by the EPA** under the Superfund law, most of this cost will be borne by the US taxpayer.

The health impacts of coal pollution have enormous economic costs, through health care costs and lost productivity. The Ontario government study estimated these costs as billions of dollars within Ontario alone. A similar recent **study in West Virginia** found that the cost associated with premature death due to coal mining was five times greater than all measurable economic benefits from the mining. Interestingly **a recent study** in Illinois found that coal mining in the state resulted in a net cost to the state of almost $20 million, **without even including any externalities.**

Other industries depend on the ecosystems coal mining destroys. This economic impact on industries such as recreational fishing, commercial fishing, and tourism is particularly relevant in Alaska. Almost **55,000 direct jobs** (full time equivalent basis, FTE) are closely linked to the health of Alaska's ecosystems. These jobs make up more than a quarter of Alaskan FTE employment and produce almost $2.6 billion of income for Alaska workers. These 55,000 ecosystem-dependent jobs dwarf the 350 estimated jobs that would be created by a project such as the **Chuitna Coal strip mine**.

Negative effects on the economy lead to worse health in the population, which has an impact on health care costs, compounding the economic impact. Some people have used this to argue that **coal has additional benefits** to society. The argument is that coal provides cheap electricity, which is a boon to the economy, therefore health is improved, and health care costs are lowered. While this additional health effect should indeed be considered, it should be applied **after** the economic impacts discussed above. Once the costs of pollution, global warming, and habitat destruction are added to the benefits of cheap electricity, the economic impact of coal is no longer positive, and this additional health effect only makes it even more costly.

*See our related articles on **True Cost** and **True Cost of Electricty Generation**.*

Further Reading

- Greenpeace-commissioned study to quantify the externalized costs of coal worldwide in 2007
- Hidden Costs of Energy: Unpriced Consequences of Energy Production and Use (National Resource Council, 2009)
- Coal's assault on human health (Physicians for Social Responsibility, 2009)
- "Estimating the Global Public Health Implications of Electricity and Coal Consumption" (2011). Published in Environmental Health Perspectives.
- Report: The Hidden Cost of Harmful Pollution to Downwind Employers and Businesses (2010). Prepared by the Clean Air Council
- Environmental Accounting for Pollution in the United States Economy(2011).

The Health Care Burden of Fossil Fuels

A special online-only addition to September 2011's Graphic Science

By Mark Fischetti | August 31, 2011

Burning fossil fuels releases significant quantities of carbon dioxide, aggravating climate change. Although it gets less attention these days, combustion also emits volumes of pollutants, which can cause a variety of illnesses. The most extensive consequences across the U.S. are noted below.

— Mark Fischetti

SEE ALSO:
Mind: The Best Way to Nap | Sustainability: **139 Countries Could Get All of their Power from Renewable Sources** | Tech: **Anonymous's Cyber War with ISIS Could Compromise Terrorism Intelligence** | The Sciences: **Ears: Do Their Design, Size and Shape Matter?**

U.S. Health Burden Caused by Particulate Pollution from Fossil-Fueled Power Plants

Illness	Mean Number of Cases
Asthma (hospital admissions)	3,020
Pneumonia (hospital admissions)	4,040
Asthma (emergency room visits)	7,160
Cardiovascular ills (hospital admissions)	9,720
Chronic bronchitis	18,600
Premature deaths	30,100
Acute bronchitis	59,000
Asthma attacks	603,000
Lower respiratory ills	630,000
Upper respiratory ills	679,000
Lost workdays	5.13 million
Minor restricted-activity days	26.3 million

» Read more about 'The Human Cost of Energy' in the September 2011 issue of *Scientific American*.

Mortality in Appalachian Coal Mining Regions: The Value of Statistical Life Lost

MICHAEL HENDRYX, PHD[a]
MELISSA M. AHERN, PHD[b]

SYNOPSIS

Objectives. We examined elevated mortality rates in Appalachian coal mining areas for 1979–2005, and estimated the corresponding value of statistical life (VSL) lost relative to the economic benefits of the coal mining industry.

Methods. We compared age-adjusted mortality rates and socioeconomic conditions across four county groups: Appalachia with high levels of coal mining, Appalachia with lower mining levels, Appalachia without coal mining, and other counties in the nation. We converted mortality estimates to VSL estimates and compared the results with the economic contribution of coal mining. We also conducted a discount analysis to estimate current benefits relative to future mortality costs.

Results. The heaviest coal mining areas of Appalachia had the poorest socioeconomic conditions. Before adjusting for covariates, the number of excess annual age-adjusted deaths in coal mining areas ranged from 3,975 to 10,923, depending on years studied and comparison group. Corresponding VSL estimates ranged from \$18.563 billion to \$84.544 billion, with a point estimate of \$50.010 billion, greater than the \$8.088 billion economic contribution of coal mining. After adjusting for covariates, the number of excess annual deaths in mining areas ranged from 1,736 to 2,889, and VSL costs continued to exceed the benefits of mining. Discounting VSL costs into the future resulted in excess costs relative to benefits in seven of eight conditions, with a point estimate of \$41.846 billion.

Conclusions. Research priorities to reduce Appalachian health disparities should focus on reducing disparities in the coalfields. The human cost of the Appalachian coal mining economy outweighs its economic benefits.

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EPA United States Environmental Protection Agency

http://www3.epa.gov/mats/whereyoulive/ky.html

Mercury and Air Toxics Standards (MATS)

Mercury and Air Toxics Standards in Kentucky

EPA's new Mercury and Air Toxics Standards (MATS) - the first ever national limits on mercury and other toxic emissions from power plants -- will improve people's health by requiring power plants that contribute to air pollution in Kentucky to use widely available, proven pollution control technologies to protect families from pollutants like mercury, arsenic, chromium, nickel and acid gases.

These new standards will prevent up to 210 premature deaths in Kentucky while creating up to $1.8 billion in health benefits in 2016.

Additional Information

- Map of utilities covered by this rule
- EPA's Cross-State Air Pollution Rule (CSAPR)

More about MATS

- The Mercury and Air Toxics Standards will save thousands of lives and provide important health protections to the most vulnerable, like children and older Americans. The standards will slash toxic emissions nationwide and prevent as many as 11,000 premature deaths, 4,700 heart attacks, and 130,000 asthma attacks each year.
- These achievable standards comply with a law that has been in place for nearly two decades. To develop these standards, EPA worked extensively with a broad array of stakeholders, including the public, environmental and health groups and industry, receiving over 900,000 public comments which helped inform the final standard.
- Until now there were no national limits on emissions of mercury and other air toxics from power plants. Toxic air pollutants like mercury -- a neurotoxin -- can damage children's developing brains, reducing their IQ and their ability to learn.
- These standards will put an end to 20 years of industry uncertainty and level the playing field for power plants across the country - over half of which are already using widely available pollution control technology and are forced to compete with facilities that have taken advantage of loopholes, or with aging plants, often 40 years old or older, that have never been updated with modern pollution controls.

Please see the following technical documents for more information about the benefits for MATS.

- Regulatory Impact Analysis for MATS (PDF) (510pp, 8.3MB)

Last updated on Thursday, November 19, 2015

Mercury and Air Toxics Standards (MATS)

Cleaner Power Plants

On this page:

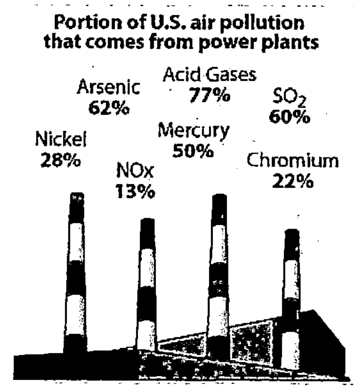
- Controls to Meet Limits are Widely Available
- Setting Emissions Limits for Toxic Air Pollutants
- Power Plants Have Time to Meet the Standards
- Reliable Energy

Power Plants

- View a map of U.S. power plant locations

On December 16, 2011, the Environmental Protection Agency (EPA) finalized the first ever national standards to reduce mercury and other toxic air pollution from coal and oil-fired power plants. More than 20 years after the 1990 Clean Air Act Amendments, some power plants still do not control emissions of toxic pollutants, even though pollution control technology is widely available.

There are about **1,400** coal and oil-fired electric generating units (EGUs) at **600** power plants covered by these standards. They emit harmful pollutants including mercury, non-mercury metallic toxics, acid gases, and organic air toxics including dioxin.



Power plants are currently the dominant emitters of mercury (**50 percent**), acid gases (over **75 percent**) and many toxic metals (**20-60 percent**) in the United States.

While newer, and a significant percentage of older power plants already control their emissions of mercury, heavy metals, and acid gases, approximately **40 percent** of the current EGUs still do not have advanced pollution control equipment.

The other big sources of mercury have already reduced their emissions.

In 1990, three industry sectors made up approximately **two-thirds** of total U.S. mercury emissions: medical waste incinerators, municipal waste combustors, and power plants. The first two of these sectors have been subject to emissions standards for years and as a result have reduced their mercury emissions by more than **95 percent**. In addition, mercury standards for industries such as cement production, steel manufacturing and many others have reduced mercury emissions from these sources.

Sources of Mercury Emissions in the U.S.

Industrial Category	1990 Emissions tons per year (tpy)	2005 Emissions (tpy)	Percent Reduction
Power Plants	59	53	10%
Municipal Waste Combustors	57	2	96%
Medical Waste Incinerators	51	1	98%

Table 2.5
.29 tons

The final rule establishes power plant emission standards for mercury, acid gases, and non-mercury metallic toxic pollutants which will result in: preventing about **90 percent** of the mercury in coal burned in power plants being emitted to the air; reducing **88 percent** of acid gas emissions from power plants; and reducing **41 percent** of sulfur dioxide emissions from power plants beyond the reductions expected from the Cross State Air Pollution Rule.

Controls to Meet Limits are Widely Available

The Mercury and Air Toxics Standards provide regulatory certainty for power plants. Additionally, these standards level the playing field so that all plants will have to limit their emissions of mercury as newer plants already do.

Use of widely-available controls will reduce harmful air toxics and help modernize the aging fleet of power plants, many of which are over 50 years old.

Widely-available control technologies that reduce mercury and other air toxics

Pollutant Addressed	Existing Control Technologies to Address Toxic Pollutants
Mercury	Selective Catalytic Reduction (SCR)with Flue-gas Desulfurization (FGD), Activated Carbon Injection (ACI), ACI with Fabric Filter (FF) or Electrostatic Precipitators (ESP)
Non-mercury metals	FF, ESP
Dioxins & furans	Work Practice Standard (inspection, adjustment, and/or maintenance and repairs to ensure optimal combustion)
Acid gases	FGD, Dry Sorbent Injection (DSI), DSI with FF or ESP
Sulfur dioxide	FGD, DSI

EGU - Electric Generating Units
TSD - tech support document
SAB - Science Advisory Board

Setting Emissions Limits for Toxic Air Pollutants

The MATS sets standards for all Hazardous Air Pollutants (HAPs) emitted by coal- and oil-fired EGUs with a capacity of 25 megawatts or greater. These are called national emission standards for hazardous air pollutants (NESHAP), also known as maximum achievable control technology (MACT) standards. Coal- and/or oil-fired electric utilities emit many of the 187 hazardous air pollutants listed in the Clean Air Act.

Emissions standards set under the toxics program are federal air pollution limits that individual facilities must meet by a set date. MACT for new sources must be at least as stringent as the emission reduction achieved by the best performing similar source. Existing source MACT standards must be at least as stringent as the emission reductions achieved by the average of the top 12 percent best controlled sources. These standards must address all hazardous air pollutants emitted at a source category.

Setting a MACT standard is a two step process:

1. The "MACT floor" is established based on what is currently achieved by sources – costs may not be considered.
2. EPA may regulate "beyond the floor" where justified – costs and other issues must be considered.

Power Plants Have Time to Meet the Standards

Existing sources generally will have up to 4 years if they need it to comply with MATS.

- This includes the 3 years provided to all sources by the Clean Air Act. EPAs analysis continues to demonstrate that this will be sufficient time for most, if not all, sources to comply.
- Under the Clean Air Act, state permitting authorities can also grant an additional year as needed for technology installation. EPA expects this option to be broadly available.

EPA is also providing a pathway for reliability critical units to obtain a schedule with up to an additional year to achieve compliance. This pathway is described in a separate enforcement policy document. The EPA believes there will be few, if any situations, in which this pathway will be needed.

In the unlikely event that there are other situations where sources cannot come into compliance on a timely basis, consistent with its longstanding historical practice under the Clean Air Act, the EPA will address individual circumstances on a case-by-case basis, at the appropriate time, to determine the appropriate response and resolution.

Reliable Energy

In EPA's 40 year history, the Clean Air Act has not impacted power companies' ability to keep the lights on in communities across the United States. EPA's analysis shows that the MATS rule and the Cross State Air Pollution Rule will not adversely affect resource adequacy in any region of the country. More information is available in EPA's resource adequacy analysis (PDF) (9pp, 418k).

A number of other analyses have reached conclusions consistent with EPA's, including a report from the Department of Energy (PDF).

Last updated on Thursday, November 19, 2015

report:
EPA-452/R-11-011
Regulatory Impact
analysis for
The Final Mercury &
Air toxics Standards
Dec 2011

Andy McDonald
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[redacted]

November 13, 2019

Kentucky Public Service Commission
211 Sower Boulevard, Post Office Box 615
Frankfort, Kentucky, 40602-0615

Public Comments Regarding PSC Case Number 2019-00256

Dear Commissioners,

My name is Andy McDonald. I am a resident of Franklin County and a customer of Kentucky Utilities. Thank you for opening this proceeding to receive public input regarding the implementation of changes to Kentucky's net metering policies.

My wife and I operate a small organic farm and sell produce at the local farmers market. In 2011 we began net metering with a 1.1 kilowatt PV system, which supplied 100% of the net annual electricity needs for our home and farm. In 2017, as our electricity needs increased, we expanded our solar array to 2 kilowatts. In 2018 we bought a used electric car and we are planning to add another 2 kilowatts to bring our home and business back to net-zero.

Away from the farm I work for the company Earth Tools, where I develop and consult on solar energy projects. Earth Tools also sells and services agricultural equipment throughout North America and has 16 employees in Owen County. Earth Tools is a net metering customer of Owen Electric Co-op, using a 23 kilowatt PV system to meet most of our annual electricity needs and keep our electricity bills low.

Net metering has been an effective and simple program enabling my family, our farm, and the company I work for to enjoy low, predictable, and stable energy bills. Thanks to net metering and solar energy, we don't worry about our electric bills. We also care about the environment and the health of the people of Kentucky. It's important to us that we can contribute to making Kentucky a healthier place to live by investing in solar energy. Net metering has made this possible.

We want other people and businesses to have the opportunity to benefit from solar energy, and for these opportunities to be available throughout Kentucky. The decisions you make implementing the Net Metering Act of 2019 will determine whether Kentuckians will continue to have access to affordable solar energy or whether the door will close on this opportunity in Kentucky.

I have been actively engaged with net metering policy since Kentucky's initial law was passed in 2004. In 2008 I participated in the passage of the updated net metering law and the development of Kentucky's Interconnection and Net Metering Guidelines. Based on this experience I have filed detailed written comments and ask the Commission to give attention to those comments.

Net metering has been a foundational policy enabling the growth of a solar PV industry in the United States and here in Kentucky. It has the virtues of being simple, clear, predictable, and consistent, qualities that have been supported by the state's Interconnection and Net Metering Guidelines, which established uniform policies and procedures across all regulated utilities in Kentucky. The predictability of net metering has enabled customers to make long-term financial investments in PV systems, with very reliable returns on investment. This has enabled solar businesses to grow and develop a market for this technology.

Net metering has the additional virtue of being a very low-cost policy to implement. It requires no taxpayer investment and has a negligible financial impact on utilities and ratepayers. Analysis of Kentucky utility data shows that the financial impact of net metering on residential ratepayers is less than 1 cent per month, even before accounting for the benefits it provides.[1] (Please refer to the written testimony of Karl Rabago for more details on this analysis.)

As a policy which has been essential for people who want to produce their own power, to control their long-term energy costs, and to protect themselves against future rate increases; and as a policy which is central to the success of Kentucky's small solar businesses, I am very concerned with how the Net Metering Act will be implemented by the PSC. There is the risk of ending a policy that works well in order to solve a problem which does not exist; and of spending more money to "fix the problem" than is gained by the "solution."

I therefore urge the Commission to establish an open process for investigating this issue in its full complexity before accepting any utility rate cases to implement changes to net metering. The value of solar has been studied extensively in many parts of the United States and merits careful consideration in the Kentucky context. While each utility has unique characteristics, there are a host of common issues relevant to all utilities regarding the benefit/cost analysis of

[1] See Comments submitted by Karl Rabago on behalf of MACED and KFTC in KY PSC Case No. 2019-00256, p. 37-38. Rabago's analysis of data reported to the US Energy Information Administration shows that in 2018, net metering may have cost Kentucky utilities about $75,000, before accounting for any benefits of net metering. This amounts to less than one cent per month per average ratepayer.

distributed generation. A single initial administrative case to investigate these issues and establish a common methodology for determining the value of net metering would be the most efficient use of Commission, ratepayer, and stakeholder resources. This would help to prevent the creation of a mix of policies and approaches unique to different utilities, which would be detrimental to ratepayers interested in using solar energy and the businesses that serve them.

Thank you again for your attention. I have several additional comments to share with the Commission, which I will submit along with a copy of these comments.

Sincerely,

Andy McDonald

Additional Comments

The following points are in response to comments submitted to this proceeding by utility representatives.

The Safety of Rooftop Solar

One of the comments submitted by utilities expressed concerns about the safety of rooftop solar. Net metering customers adhere to strict electrical code requirements, as required by Kentucky's Interconnection and Net Metering Guidelines (2009, p.6). The National Electric Code 2017 that has been adopted in Kentucky requires "module level rapid shutdown" for solar PV to within one foot of the solar panel array horizon. This means that every wire conductor that is outside of one foot from any solar module in a system installed today can be safely de-energized within 30 seconds, even when system is shutdown from the ground.

Safety was one of the reasons cited to support passage of net metering legislation in 2004. Providing net metering created a process for ensuring the safe installation of residential solar systems, as the Net Metering and Interconnection Guidelines sets standards and allows utilities to hold solar customers responsible. Net metering policy adds safety and does not reduce it.

If any utilities claim there are costs imposed by net metering related to safety, they should present evidence to support these claims and they should be evaluated within the context of a comprehensive benefit/cost analysis.

The Fallacy of Claiming that Net Metering Causes the Poor to Subsidize the Rich

In their public comments for this case, Kentucky Power repeated the common talking point that net metering results in low-income customers subsidizing wealthy solar customers. First, this argument assumes cross-subsidization is occurring without presenting evidence. A comprehensive benefit/cost analysis of distributed generation is needed before one can assert that a cross-subsidy exists and numerous studies across the United States have found that distributed generation has value which often exceeds the retail rate. Furthermore, the analysis of Kentucky utility data cited previously shows that, even without considering the benefits of distributed generation, net metering has added less than one cent per month to the average customer's bill. Is it worth the Commission's time to address a "subsidy" of such a negligible magnitude?

Secondly, net metering customers come from all walks of life and economic circumstances. The argument that net metering results in low-income people subsidizing the wealthy is a cynical political argument intended to undermine popular support for net metering. The fact is that net metering provides lower- and middle-income families a means to reduce their utility bills and achieve greater financial stability. People's Self-Help Housing in Lewis County illustrates this. They have built 17 homes for low-income families in their Ever Green development using solar panels and net metering. Reducing and stabilizing their energy bills was a key strategy for helping families afford these homes.

"PSHH set a goal of cutting electricity usage in half for our new homes starting with Ever Green," said Dave Kreher, executive director of PSHH, which has built 357 energy efficient new homes for low-income households in Lewis County since 1982. "We couldn't control rate hikes, but we could cut electric usage through solar panels and net metering."

The utilities and their allies used this misleading argument about the poor subsidizing rich solar customers to build support for passing SB100. Ironically, the "remedies" they have proposed would greatly reduce the economic value of net metering, making solar even less accessible to low-income families.

My name is Sister Joetta Venneman, and I am here representing the Sisters of Charity of Nazareth, an international community of Catholic sisters who have lived and ministered in Nelson County and around the world for over 200 years.

Our mission states that we are committed to work for justice, the poor, and to care for Earth. We now consider Earth one of the poor, and have taken steps to do our part to reverse the trend of planetary destruction. We made a commitment to reduce our greenhouse gas emissions to zero by 2047. Why? We notice that the planet is warming, increasing catastrophic storm events. We have ministries in disaster relief and have been to Houston, New Orleans, and West Point, KY, where we've seen first hand how these storms impact people's lives.

In order to lower the greenhouse gas emissions that impact the warming of the planet, we have installed solar panels, with hopes to do more. Residential solar is part of the solution needed to reduce these natural disasters. At a time when we should be encouraging more people to invest in rooftop solar, local utility companies appear to be "bullying" regular citizens out of the market, even when we are nowhere near being a threat to their market share. As solar customers, we are less than 1 percent in KY.

This is where you, the public service commission, come in. We are asking you to conduct an objective, transparent, comprehensive study as other state public service commissions have done. We ask you to examine the facts of how residential solar helps or hurts the utility companies and residential solar customers financially. Compare documented costs and benefits, and please, count up the full-cost benefits that solar energy provides to the state, including cleaner air, lowering of asthma rates in children, reducing dependence on imported fuels, and economic development.

We are so glad that the Public Service Commission exists to protect consumers from utility monopolies.

Thank you for your service.

November 13, 2019

My name is Carrie Ray, I live in Lexington and I work for the Mountain Association for Community Economic Development, or MACED, in Berea. I work with small businesses, non-profits, and local governments to lower their utility bills with energy efficiency and renewable energy. This is not the first time I've been here to advocate on behalf of our small business and nonprofit clients, who are typically forgotten in discussions of energy policy and regulations. While impacts on residential ratepayers and industrial customers are important, small businesses and nonprofits form the backbone of our communities and economy, and we should not ignore them.

In their comments on this issue, the Kentucky Chamber of Commerce states, "Every dollar a business spends on utility bills is a dollar not spent on payroll, business expansion, or philanthropic activities. While energy costs are a part of doing business in any state, outdated energy policy should not force companies to pay more than they have to." I have zero argument with this. It's entirely true, and it's why in the last year alone we have seen a 129% increase in the number of Appalachian small businesses, non-profits, and local governments interested in pursuing rooftop solar as a way to keep their doors open. The Chamber and the utilities have provided no evidence that net metering has made any type of impact on rates, but Kentucky Power's small commercial customers have faced a 214% increase in their demand charge in the past two years, while also assessing this charge on more of its customers. Kentucky Utilities has raised their General Service rates by 23% over the last five years, and their Power Service demand charge has gone up about 50%. Solar is not a luxury for Hemphill Community Center, or SouthDown Farm, or many of the other clients we serve. It's a way to continue to provide services to their community, to employ people, to simply be able to afford to pay their skyrocketing utility bills. The Chamber is right, money spent on utility bills doesn't get spent in other, better, more productive ways. That's why we need to preserve the net metering arrangement as it stands.

The Chamber also purports, again without providing any evidence, that net metering causes manufacturing businesses to have higher rates, and that this harms the economy as Kentucky is dependent on manufacturing. As an aside, I would point out that economic development is an externality, despite repeated insistence that the PSC isn't concerned with externalities. But my main point is that this is comparing apples to oranges. Manufacturing rates have actually gone *down* in recent years in the case of Kentucky Utilities and Kentucky Power. Demand charges have gone up, but this is precisely an area in which distributed solar could help to reduce these charges, not increase them. And once again, while we shouldn't dismiss the importance that our manufacturing industry has on our state, we should also not dismiss the importance of the local grocery store, the community center, the library, or the hardware store that is looking to net-metered solar to keep their lights on.

If we are concerned about the externality of economic development, which this PSC has stated they are, then let's look at how rooftop solar has impacted our clients in Appalachian Kentucky, a region whose economy we all know is struggling. In the past two years, MACED has helped facilitate 10 rooftop solar installations for small businesses, local governments, and non-profits. We currently have 17 additional projects in our pipeline. All told, this accounts for nearly $1.7 million of investment into solar projects, with annual savings of over $90,000 in utility bills for these enterprises. That's a lot of dollars to spend on payroll, business expansion, and philanthropic activities. The vast majority of these projects were installed by Kentucky solar installers, employing Kentuckians, paying Kentucky taxes.

And here's the kicker. All these projects total 750KW of solar capacity – which is 0.0005% of Kentucky Power's generation capacity. Of course, MACED doesn't know of every solar installation happening, and we're not talking about residential solar either. But we could install all of these projects 20 times over before hitting the 1% cap on distributed solar that already exists in the legislation.

Changing the current net metering arrangement is unnecessary. It's not raising anyone's rates. It's not burdensome to the grid. But it is providing residents, non-profits, local governments, and businesses a way to get out from under crippling utility bills and invest that money into their communities or their bottom line. Utilities have made major investments in their own solar farms – which is worth applauding – but they are simultaneously trying to keep individuals and businesses from making the same type of investment. Our utilities aren't stupid – they can see that the future is in renewables. But instead of innovating and adapting like many other utilities around the country, they are clinging desperately to an outdated business model and trying to get you, the Public Service Commission, to back them up on it.

Rooftop solar is a boon for the struggling economy of eastern Kentucky. One-to-one net metering is essential to keeping this momentum going. Please do not cut the feet out from under us.

Carrie Ray
Energy Programs Coordinator

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MACED
Mountain Association for Community Economic Development

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October 13, 2019

Public Service Commission
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Reference: Case No. 2019-00256

The language of SB100, passed by the KY General Assembly in 2019, instructs the PSC to

(9)(2) ...develop interconnection and net metering guidelines for all retail electric suppliers operating in the Commonwealth... meet[ing] the requirements of KRS 278.466***(7)***[(6)].

And further that
(3) *A retail electric supplier serving an eligible customer-generator shall compensate that customer for all electricity produced by the customer's eligible electric generating facility that flows to the retail electric supplier, as measured by the standard kilowatt-hour metering prescribed in subsection (2) of this section. The rate to be used for such compensation shall be set by the commission using the ratemaking processes under this chapter during a proceeding initiated by a retail electric supplier or generation and transmission cooperative...*
(5) ...each retail electric supplier shall be entitled to implement rates to recover from its eligible customer-generators all costs necessary to serve its eligible customer-generators, including but not limited to fixed and demand-based costs...

To do this well and fairly for all stakeholders, the PSC must consider the benefits to the electric grid and Kentucky society from small 'customer-generators,' and the distributed generation they provide, as well as possible costs to the individual electric utilities from such distributed generation which is provided at no investment cost to the "retail electric suppliers", aka electric utilities.

Electric utilities argue that they have fixed costs, and the only cost to them that is reduced by 'customer-generators' is the variable instantaneous cost of generating electricity at 60 Hertz and standard voltages, which they present as mostly the cost of fossil fuel for operating the generating plants. This formulation is largely nonsense, because all costs associated with the operation of electric grid are variable over the planning period of <u>20 years</u> which is used in the Integrated Resource Planning process. Generation equipment, transmission equipment, distribution equipment, emission control equipment, and coal ash landfills all need maintenance, overhaul, and/or replacement during a 20 year timeframe.

But solar photovoltaic panels are typically expected to last <u>40 years</u>, substantially longer than most parts of the electric grid and the equipment operated by utility companies. (PV modules are warranted by their manufacturers to last at least 25 years). To proclaim that the output of solar systems is to be considered a <u>variable cost</u> when they have a life expectancy of 40 years, but the fabric filters in the pulse-jet particulate filtering systems at KY coal power plants are a fixed cost, when we know they are expected to fail within a timespan of hours after a defined number of pulses - this labeling seems like just ridiculous politicians spin.

The author is aware of 18 expert studies of the question "What value should be given to the electricity produced by distributed generation such as rooftop solar systems?"

Multiple states, from California through Missouri and up to Maine, have performed these 'value of solar' studies that show that non-Distributed Generation ratepayers (*i.e.*, those not participating in net metering) actually benefit from net metering of solar customers, because "[w]hen you do the math correctly, the data shows that the benefits provided by local rooftop solar equal, or exceed, the costs to the utility or to other customers," as studies distilled by the Solar Energy Industries Association has demonstrated.[1] Indeed, the 2016 meta-survey published by Environment America Research & Policy Center of 16 recent analyses of the question across the country found that thirteen studies out of the group of 16 determined that the value of distributed solar energy generation was worth more than the average residential retail electricity rate in Kentucky at the time the analysis was conducted. These included independent and PSC-commissioned studies, while the three of the analyses surveyed which found value of solar to be less than the KY retail rate were commissioned by electric utilities.[2] In 12 independent or PSC commissioned analyses, the values computed as the fair value provided by distributed solar ranged from $11.60/kwh (CPR-Utah) to $33.60/kwh (Maine).

In another example, Daymark Energy Advisors' study for Maryland PSC, in April, 2018 estimated distributed solar's value to be between approximately $0.31/kWh and $0.41/kwh.[3]

A large part of the difference between utility funded studies and independent or PSC studies is due to what benefits are considered. Evaluation of the cost and benefits of net metering and distributed generation should include the full range of benefits that net metering and distributed generation provide to the utility, ratepayers, and society. The benefits which distributed generation solar offers to the energy grid, and to Kentucky's wider society, include avoided energy costs, reduced line losses, avoided investment in new capacity, reduced financial risks from volatile fuel sources, increased grid resiliency, environmental and social benefits, reduced public health threats, and job creation and economic development. The PSC should consider all these benefits when determining the value of solar and distributed generation.

The PSC can find further detailed examination of these topics in the 2014 paper by the National Renewable Energy Laboratory, *Methods for Analyzing the Benefits and Costs of Distributed Photovoltaic Generation to the U.S. Electric Utility System.*[4]

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[1] Solar Energy Industries Association, *Net Metering Facts*, available at https://www.seia.org/research-resources/net-metering-facts (referencing California, Nevada, and Maine, *inter alia*).

[2] Lindsey Hallock, Frontier Group & Rob Sargent, Environment America Research & Policy Center, *Shining Rewards: The Value of Rooftop Solar Power for Consumers and Society* (October 2016), available at: https://environmentamerica.org/reports/ame/shining-rewards

[3] http://www.psc.state.md.us/wp-content/uploads/MD-Costs-and-Benefits-of-Solar-Draft-for-stakeholder-review.pdf

Adjudication by the PSC will only produce a result which optimizes Kentucky's economic growth and most vibrant economy if the full range of benefits enumerated above for all customers and Kentucky citizens are fully considered, and brought in to the calculations in a quantitative way. It will be a mistake, and basically unfair, to only consider very short-term costs to electricity retailers for providing electricity to 'customer-generators' without considering the longer term savings from avoided generation investment costs, the broad environmental and social benefits, the improved public heath, and the economic development benefits that increased use of distributed solar generation can bring.

The argument by electric utilities that solar customers do not contribute fairly to the costs of the grid is flawed. It seems to use the same logic as "A customer who goes on vacation is a cost to the utility, because they don't pay as much that month." A study by the US Department of Energy concluded in 2017 that distributed solar would have a negligible impact on rates until solar reaches 10% or more of a utility's peak demand (Galen, Department of Energy, 2017). In Kentucky, we are quite far from that 10% mark–substantially under 1% of Kentucky's electric energy mix currently comes from distributed solar.

Further, the existing cap on the growth of net metering already limits any potential impacts of net metering. The current statute says net metering stops when 'customer-generators' have a nameplate capacity of 1% of peak demand. This cap on growth of net metering is a clear limit to any rate impacts net metering could potentially have.

Also, complicating the regulatory process could become a real cost for solar customers and businesses. The cost of implementing a more complex administrative process for administering net metering should be considered within the scope of this issue. Currently, administering net metering is simple and low-cost, for the utility and customer, and the existing simple, rules are well understood. The PSC should consider the cost of a new administrative system which involves litigating the issue in recurring, complex, rate cases for every KY utility, as compared to the negligible overall impact net metering has proven to currently have on ratepayers.

Thank you for considering these comments.

Yours truly,

Wallace McMullen
Chair
Kentucky Solar Energy Society

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Louisville, KY 40216

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[4] Paul Denholm, et al., National Renewable Energy Laboratory, *Methods for Analyzing the Benefits and Costs of Distributed Photovoltaic Generation to the U.S. Electric Utility System* (Sept. 2014), available at: https://www.nrel.gov/docs/fy14osti/62447.pdf

Clean Energy Credit Union &
John Fredrick

Join the 2019 Louisville Solar Tour!

Saturday, October 5, 2019

Other Side

LOUISVILLE SOLAR TOUR

SOLAR OVER LOUISVILLE

Josh Fredrick, Installer

The Louisville Solar Tour offers you a chance to see examples of Louisville families and businesses harnessing free energy from the sun to generate electricity, warm and cool their homes and buildings, charge electric cars—and to slash their utility bills.

10 AM — Kickoff gathering at U of L **Speed School's Ernst Hall, Room 103,** on Eastern Parkway just east of 3rd St. Several parking lots nearby, and served by TARC routes 29 and 4. The keynote speaker will be **Adam Edelen**, co-developer of Kentucky's largest solar installation. Other experts will follow with more tips, including financing options. The 'Introduction to Solar Technology' kickoff is free and open to the public.

11 AM — Bus tour, departing from Ernst Hall. Tour will visit homes, churches and businesses featuring a range of solar installations. The bus tour is limited to 40 participants, and costs $15 per person. Project owners and/or installers will be present at site locations for explanations and Q&A.

3 PM — Solar Celebration at solar-powered **Apocalypse Brew Works**, 1612 Mellwood Avenue for socializing and info tables. Food trucks and refreshments will be available for purchase. Bus tour participants will have the option of ending their tour there, or going back to the starting point.

You can register to take the Tour and get more details at
http://www.kyses.org/louisvillesolartour2019,
the website of the Kentucky Solar Energy Society,
or phone Wallace McMullen at 502-271-7045.

This event will be one of hundreds across the US as part of the 24th Annual National Solar Tour of the American Solar Energy Society to demonstrate practical and economic solar solutions, and to encourage community conversations addressing the growing need for clean energy.

Earth & Spirit Center

The Kentucky Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort
KY 40602-0615

Case No. 2019-00256

November 12, 2019

Following comments to the Public Service Commission are for its consideration of the broad issues of implementation of the "Net Metering Act" as they apply to individual utilities.

Net metering is the difference between the dollar value of excess distributed energy generation by a customer-generator that is fed back to the electric grid over a billing period at prices established by the Commission through the ratemaking process (the compensation rate); and the dollar value of all electricity consumed by the same customer-generator over the same billing period that is priced under retail electric utility's tariff rate. This compensation rate is established for each retail electric-utility during a ratemaking proceeding initiated by the electric utility.

Following comments covers two key areas:

1. According to the Energy Information Administration: "Kentucky has both utility-scale (1 megawatt or larger) and distributed (customer-sited, small-scale) solar power generation facilities, which together accounted for 0.1% of the state's electricity generation in 2018".
   https://www.eia.gov/state/analysis.php?sid=KY#92

   With reference to findings in the report from Lawrence Berkeley National Laboratory, funded by Office of Energy Efficiency and Renewable Energy of the U.S. Department of Energy: "For the vast majority of states and utilities, the effect of distributed solar on retail electricity prices will likely remain negligible for the foreseeable future. At currant penetration levels (0.4% of total U.S. retail electricity sales), distributed solar likely entails no more than a 0.03 cent/kWh long-run increase in U.S. average retail electricity prices, and far smaller than that for most utilities. Even at projected penetration levels in 2030, distributed solar would likely yield no more than roughly a 0.2 cent/kWh (in 2015 dollar) increase in U.S. average retail electricity prices, and less than 0.1 cent/kWh increase in most states, where distributed solar penetration is projected to remain below 1% of electricity sales."
   https://emp.lbl.gov/sites/all/files/lbnl-1007060-es.pdf

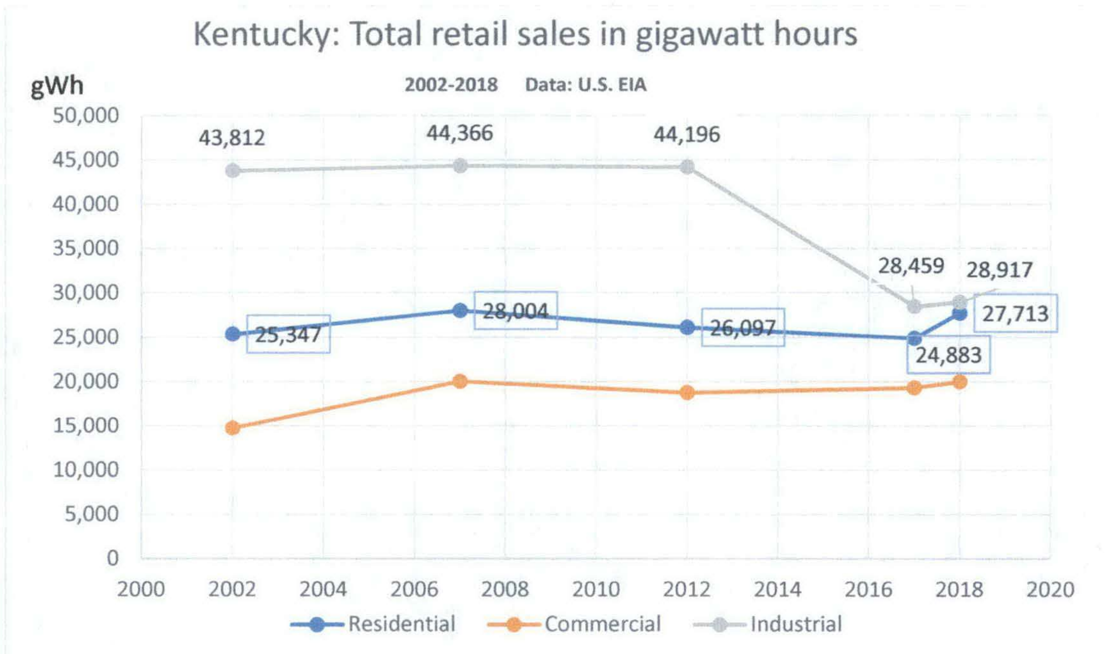
   Kentucky's Office of Energy Policy and Kentucky Solar Energy Industries Association estimate that Kentucky's distributed solar generation is not more than half of the state's total 0.1% solar electricity generation, or around 0.05%.
   It's estimated, that with the present version of net-metering (phasing out December 31, 2019), it'll take around 10 years for the state to reach 1% of the state's electricity generation.

   Conclusion: Solar customer-generated electricity in Kentucky is in its infancy, around 0.05% of total electricity generation, the 45th lowest in the Country. According to detailed National studies under the U.S. Department of Energy, at this level, the effect of customer-generated electricity on retail electricity prices will likely remain negligible for the foreseeable future.

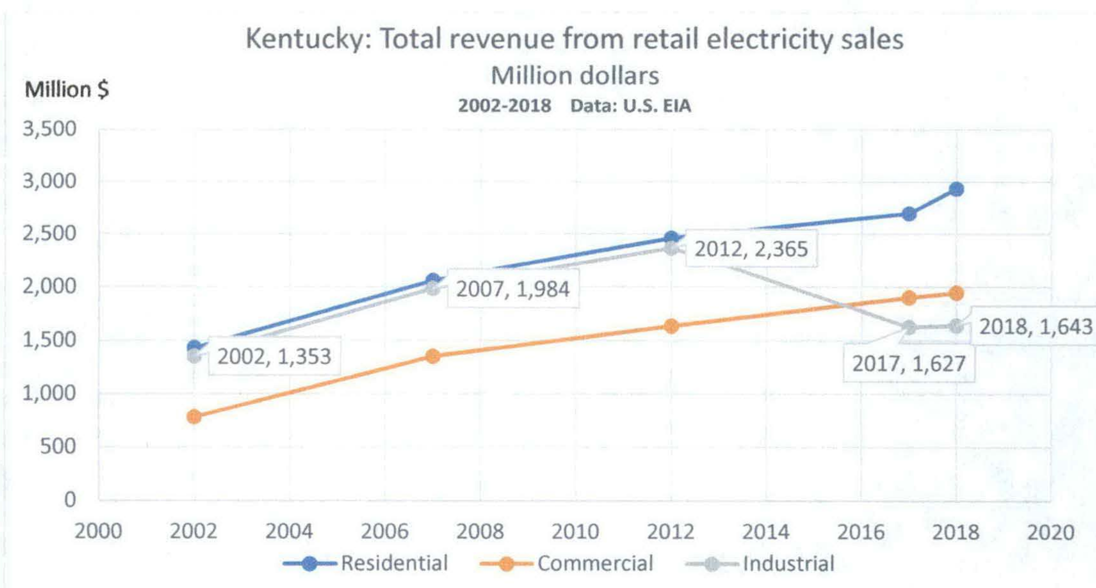
   Customer-generated electricity is distributed generation. This is electricity plus service added.

2. Following is of great concern to ratepayers as they might fear higher rates in future as electric utility retail sales to industrial customers plummeted from 2012 to 2017 and are likely to affect the electric utilities overall ability to stay competitive. Kentucky could change from a low-cost to a high-cost electricity provider.

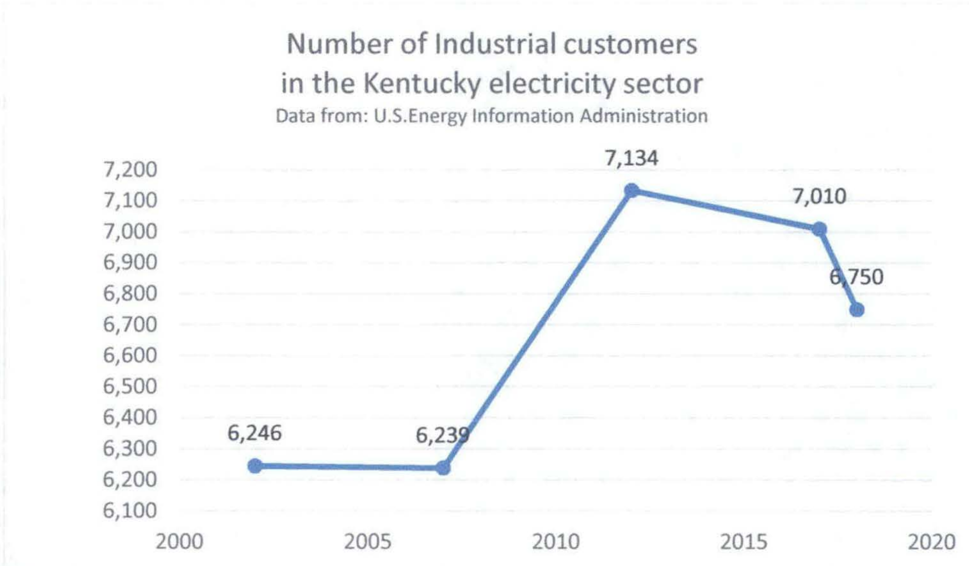
   a. Total retail sales to Industrial customers in gigawatt hours dropped from 44,196 in 2012 to 28,459 in 2017, a 36% drop. The 21 Rural Electric Cooperatives (REC) retail sales went down from 12,131 gigawatt hours in 2012 to 9,986 in 2017. A good 17% drop.



   b. Total retail revenue industry sales plummeted $738 million over the 5-year period from $2,365 million in 2012 to $1,627million in 2017. The 21 RECs' lost $167 million in retail revenue.



c. Total number of industrial customers keeps going down. This customer group used to be the biggest and about the size of residential and commercial customers together. Looking at figures for 2018, industrial customers keep shrinking.



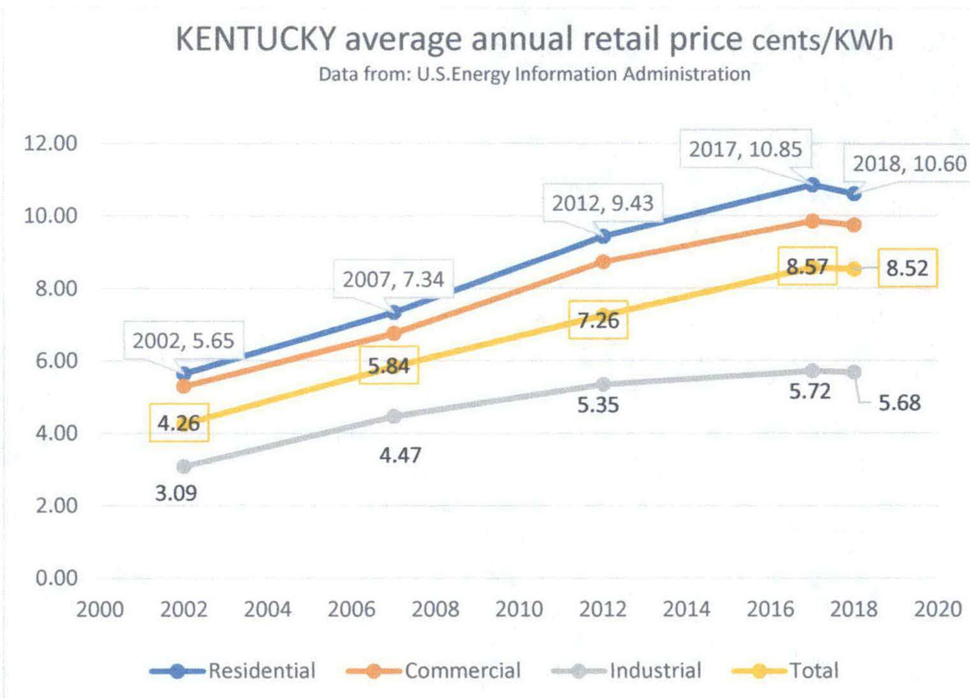
d. With such a significant loss in revenue and at the same time underutilized power production, this might affect future capital expenditures and the electric utilities ability to pay back debt and ability to attract new investment. This is part of the revenue requirement formula going into the ratemaking calculation and could affect rates to go up over the next years.

e. The utilities' intangible value is also part of the revenue requirement formula going into the ratemaking calculation. This is likely to go down. Stockholders of Investor-owned utilities are being denied the very profitable performance of companies like NextEra energy, Terraform Power and other power companies, that focus on renewable energy.
By not providing renewable energy in timely manner for Industrial customers, the utilities have become uncompetitive. It's very clear from below, that renewable energy companies stock value like NextEra Energy far surpasses companies like Duke Energy.

f. All electric utilities will need to be able to attract investors, based on progressive business conduct. Losing a huge chunk of its core customer business would be judged poor business performance and informed investors might turn away, also affecting rates.

g. In 2017-2018, the electric utilities seemingly tried to compensate for their lost sale to Industry customers by lowering energy retail price for the first time since 2002, encouraging existing customers to use more electricity. All groups used slightly more between 2017-2018 as shown in the table under point 1.a.

Lowering the retail price to residential customers from 10.85 to 10.60 cents/kWh seems like a contradiction of their long-standing claim, that roof-top solar customers (customer-generators) are causing a shift in cost to regular ratepayers.



Conclusion: Electric utilities have lost major industry customers who are turning to renewable energy resources. This is causing an underutilized generation capacity on coal-powered plants and they'll have difficulties paying down debt. Higher wholesale prices are to be expected in future.

Lost revenue leaves utilities with impaired capital and their overall ability to stay competitive is at risk without investments in renewables. Their ability to attract needed investments for this transition is declining because of more debt and less revenue.

Following is brought to the Commission's attention

Ratepayers have reasons for great concern:

- Despite the growing market demand for zero-carbon generation utilities, avoiding expanding and transitioning into renewables in timely manner, has left the state and its' ratepayers in a vulnerable position.
- Losing revenue leaves the utilities with impaired capital.
- Utilities can't have debt – but ratepayers have debt.
- Utilities ability to maintain the distribution infrastructure is weakened.
- Utilities in Kentucky will have difficulties to attract much needed investment.
- More companies and corporations are looking to invest in states with plans for and providing zero-carbon generation as more and more companies are setting zero-carbon energy goals. Kentucky is missing out welcoming new companies invest in the state.
- Rates are likely to go up, as there is a declining demand for coal generated power. Kentucky might go from a low-cost to a high-cost energy state.
- Many states are realizing how distributed generation is a contributor not a competitor and are upgrading the grid to effectively use surplus distributed electricity to boost grid efficiency and grid resilience.
- In a time where renewable energy will become the dominating resource for electricity, grid-infrastructure will need further expansion and investments. Distributed generation will be an aid in this added structure.

Utility rates are required to be fair, just and reasonable.
Utility service is required to be adequate, efficient and reasonable.
Kentucky and it's ratepayers will benefit from setting the compensation rate to equal the retail price.

Many thanks for your consideration.
Yours sincerely,

Kris O'Daniel
647 Beechland Road
Springfield, KY 40069

https://www.eia.gov/state/analysis.php?sid=KY#92

https://emp.lbl.gov/sites/all/files/lbnl-1007060-es.pdf

https://www.eia.gov/state/print.php?sid=KY

www.eia.gov/electricity/data.php#sales

psc.ky.gov/PSC_WebNet/ListLibrary.aspx?typ=STAT

https://www.eia.gov/state/analysis.php?sid=KY#92

https://www.utilitydive.com/news/northeastern-utilities-aim-to-crush-and-flatten-system-peaks-as-ders-boos/562944/

KENTUCKIANS FOR THE COMMONWEALTH

P.O. Box 1450 • London, KY 40743
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Action for Justice

Process

Over the past decade, KFTC members have hosted hundreds of public conversations about what a Just Transition means and requires. One important lesson we've learned along the way is that "In times of transition, process matters. It really matters."

As SB 100 was passing, you commissioners wrote a letter to the Kentucky General Assembly, assuring our legislators that you had "broad authority to consider... evidence of the quantifiable benefits and costs of a net-metered system." We ask you now to stand by that commitment you made, and to truly consider a comprehensive cost-benefit analysis of the impact of net metering as you decide on this rate case.

Given that meta-analyses of state-specific value of solar studies[3] have shown that net metering more often than not provides a net benefit to ratepayers, it is imperative that the PSC examine the benefits of grid-tied solar, rather than just the costs as SB 100 instructs. This analysis should be grounded in verifiable data, in the inclusion of *all* relevant stakeholders, and in the involvement of objective and trusted third-party evaluation of methodologies and data.

Many of our more technical comments towards how the PSC should structure its cost-benefit analysis are captured in the comments of Karl Rábago, the expert witness we have commissioned alongside our friends at the Mountain Association for Community Economic Development. We refer the Commission to these notes for more precise guidance about what to consider ~~into~~ in the ratemaking process.

A second, crucial component of a fair, transparent process is the inclusion of all voices in the process. The PSC should and must support the right of all entities to intervene in future PSC rate cases, including rate cases regarding solar net metering. The 2018 case of the PSC disallowing advocates of low-income and environmental groups from intervening in a rate case was unprecedented and mistaken. The AG's office is unable to provide the same perspective as these advocates in a rate case, and it should be the right of all relevant parties who can speak to a rate's impact to participate in the process.

Beyond that, the PSC should ensure that the process for both intervention and public feedback is accessible, through the provision of adequate time and opportunity for comment periods, opportunities for regionally-based public hearings outside of Frankfort, and equal weight given to both email and paper comments in future public comment periods.

[3] ICF (20 18) Review of Recent Cost-Benefit Studies Related to Net Metering and Distributed Solar, and Weissman and Fanshaw (2016) Shining Rewards: The value of rooftop solar for consumers and society.

KENTUCKIANS FOR THE COMMONWEALTH
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Action for Justice

Oral Comments on PSC Case Number 2019-00256

Person One:

Dear Commissioners,

We are Kentuckians. Our grassroots organization, Kentuckians For The Commonwealth, represents thousands of people living across the state. KFTC is a community of people inspired by a vision and working for a brighter future for all people, no matter our skin color, gender, or how much money we have. We believe a just and inclusive transition to a clean energy economy is possible in Kentucky, and that process must begin now.

In 2016 our organization began shaping a people's energy plan for Kentucky. Over 18 months, we directly engaged more than 1,200 Kentuckians in conversations about our energy future and consulted energy experts about how to make a Just Transition possible. Together we wrote a plan that would produce more jobs and lower electricity bills, and reduce greenhouse gas pollution from Kentucky's power sector by 40% over 15 years. In our ambitious plan, we had a vision to strengthen Kentucky's limited solar policies, and that Kentucky's installed distributed solar energy capacity would grow, under the auspices of one-to-one net metering, from 17.6 MW to 613 MW between 2016 and 2032. (Read the full plan at EmpowerKentucky.org.)

But in 2019, our elected officials moved us in the wrong direction and chose to scrap one-to-one net metering altogether–leaving the future of distributed solar in our state uncertain and precarious. It's worth noting that utilities spent $204,557 on utility lobbying in 2018[1], and $327,050 in PAC contributions to 2018 legislative candidates[2] to push their bill through.

The responsibility now lies with the Public Service Commission to set a new rate for new grid-tied renewables at each utility. In our monopoly utility system, the PSC plays the necessary role of regulating (the investor owned utilities and cooperatives) and offering careful scrutiny over ratemaking–with an eye towards just, reasonable, and fair rates.

As the Kentucky Public Service Commission contemplates how to implement the 2019 Net Metering Act, we urge you to live up to your mission by prioritizing process, fairness, and impact. I will speak about the process piece of this case.

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[1] https://www.kentucky.com/opinion/editorials/article208215114.html

[2] https://www.courier-journal.com/story/news/politics/2019/02/25/kentucky-solar-industry-pac-donations-controversial-net-metering-bill/2948705002/

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Energy Efficient ENTERPRISES

Nov 13, 2019

PSC Public Comments

Before legislation passed in 2004 establishing net metering policy. Back in 2001, I participating in the first net metered solar system installation in KY. A 20 something panel 2-1/2 kW system (still operating today) installed at a nonprofit office building in rural Rockcastle county and interconnected with Kentucky Utilities. We asked KU if they would consider offering net metering. They were hugely supportive and filed with this body a pilot program (Case filing 2001-00303). Things seem to be a little different now.

In March 14, 2002 Order, the PSC approved that pilot (10 kW residential and 25 kW commercial), but did find some issues. I recall one issue being the ability of LG&E and KU to record the amount of power delivered to the customer, the amount of power received from the customer, and the time period during which the power was either delivered or received. I thought it was extreme overkill, but KU continued to be supportive and installed time-of-day metering capturing flows in both directions. To me we were making a simple capital improvement to our facility equivalent in reduced electricity consumption, that we would acheive from fuel switching our electric water heater out to a natural gas water heater.

In that Order, the issue of fixed cost recovery was brought up. The PSC stated at the time, "For customers served under tariffs with demand rates, the utility is still able to recover its investment in fixed costs through a separate demand charge." With that perspective, I urge this body to keep the kWh one-for-one netting in place for customers participating in tariffs that include a separate demand charge. Given that many retail electric providers now how optional residential demand services this could simplify your work by striking out any and all rate classes with separate demand charges from allocating a change to the one-to-one policy.

I still, almost 20 years later, have real trouble with this cost recovery argument. Net Metered customer-generators, unlike Qualified Facilities have no way to cash out their excess generation. They use it or lose it (i.e. freely given to their retail electricity provider as a parting gift when they change address and close their account). This forces system sizes to be commensurate with annual use and no larger.

Additionally, the Final Net Metering-Interconnection Guidelines that came out of PSC Administrative Case 2008-0169 addressed aspect utilities raised concerning cost-recovery. In those very detailed 23 page Guidelines, is included (condition 2—generation capacity will not exceed transformer nameplate rating on shared secondary and condition 1—on a distribution circuit, the aggregated generation on that circuit, including the proposed will not exceed 15 percent of the Line Section's most recent annual one hour load). This is huge and was included and agreed upon to avoid utility costs associated with distributed net metering output getting to a point of potentially backfeeding a substation. No net metered generation ever sees transmission infrastructure. It only interacts with the local distribution circuit. From the substation point of view, someone installing solar panels has the same effect as insulating their house and downsizing their air conditioner capacity. From the substation view net metering is an energy efficiency measure. It would not surprise me if 90 percent of solar net metered installation delivery to grid in this state is satisfying an electric load within a structure within line-of-site of that generation.

I believe through collaboration, we can bring the greatest benefit both to customer-generators and retail electric providers. Technology, including smart advanced inverters, battery and module level control has improved substantially since the 2009 issued interconnection guidelines. I urge this body to open up another administrative case to bring those benefits to the table before moving forward with rate changes to the one-to-one policy. Benefits available today include sophisticated monitoring and communication of the grid status, the ability to receive offsite operation instructions, and the capability to make autonomous decisions to maintain grid stability and reliability.

- *Capability of "riding through" minor disturbances to frequency or voltage:* Advanced inverters can direct a distributed generation system to stay online during relatively short, minor frequency or voltage disturbances.
- *Capability to inject or absorb electricity into or from the grid:* Variability in the power output from distributed generation can make it difficult for grid operators to keep frequency and voltage levels within the required range. The capability of advanced inverters to feed electricity into or take electricity from the grid can help maintain system stability by keeping voltage and frequency level within specified limits.
- *Capability to provide a "soft start" after power outages:* Staggering the timing of the reconnection of distributed generation to the grid after an outage can help avoid spikes in active power being fed into the grid, limiting the risk of triggering another grid disturbance.

Another concern I have is what happens when upgrades are necessary to those grandfathered until 2045. Our office needed a new roof recently. We had the 27-kW array dropped and replaced as part of that process. Unfortunately, two modules broke while in shipment to offsite storage. The 308-W modules, not being manufactured anymore, had to be replaced and were replaced with larger 360-W modules. I urge this body to not get into what constitutes a new install versus what is maintenance on an old install. Simplest method to do that is to consider anyone grandfathered in to be eligible to make changes to their system without risk of losing their grandfather one-to-one status.

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MACED
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Joshua Bills
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Teri Faragher
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[redacted]

November 12, 2019

Comments to the Public Service Commission:

Thank you for holding public hearings. It seems reasonable that, as the PSC, you would hear from the public. But I know that there are corporations with a vested interest who would prefer that you didn't, and I appreciate that you lived up to your title.

The issues you are currently wrestling with are much larger than Kentucky and certainly much larger than anyone in this room or any utility company represented here today. But the manner in which they are resolved will affect our lives and determine how we are perceived by future generations, how we are judged based on our choices, more than any other issue confronting us.

My husband and I installed solar panels in 2013 and we believe it is one of the best decisions we ever made. We are not wealthy, though we are comfortable and relatively secure on fixed incomes. We made the decision because we wanted to become part of the solution rather than part of the problem. We primarily heated with wood and propane backup until 2013, when we installed solar panels and switched to geothermal HVAC.

In the six years since, we have viewed our relationship with KU as a partnership. We pay our monthly service fee to KU for use and maintenance of the grid and we generate power that helps them avoid the cost of creating new energy capacity while increasing grid resiliency, creating jobs and reducing environmental impact. It is a win-win situation. And though it might be a little off topic, I do have to note that the KU employees who serve our region are absolutely top of the line. They are knowledgeable, efficient and courteous and one of the top reasons I value and hope we can continue our partnership with KU.

I would say the same of the independent renewable energy experts I have met. It has been encouraging to watch Kentucky's solar industry and jobs in renewable energy grow as the technologies have developed, improved and become more affordable. The renewable energy experts in this room are the people who are going to inform Kentucky's economic development in energy in the future. It would benefit the utility companies to partner with them rather than hinder them. And it would benefit all of us if the utility companies, the PSC and KY's independent renewable energy companies placed the common good of our citizens where it should be... above profit. It is the common good of Kentuckians that should drive all decisions related to energy policy. We particularly depend on you, the PSC, to safeguard the public good and see that it does.

The transition to renewable energy is not a question of "if" but a question of "when." And the sooner we make that transition the better chance we have of leaving an inhabitable planet for our children, grandchildren and great grandchildren.

There is no question that we have to embrace renewable energies if we want our planet to survive. I'm sure that as whale oil was replaced by coal, those with a vested interest in whale oil opposed this transition, and fought hard with many of the same arguments used today to hang on to fossil fuels. But it is time for us to hang up our harpoons and to develop policies that support and promote renewable energies. We can't waste any more precious time allowing "whale oil salesmen" to delay this transition from reliance on fossil fuels to clean energy sources.

Thank you for your time.

Teri Faragher

Case # 2019-00256

Joetta Prost, 1600 Southcross Dr., Hebron KY / Boone County,

We are customers of Owen, & when we installed our rooftop solar in Sept. 2018, Owen Staff said we were one of about 20 of their 60,000 Owen Customers — which highlights the small rate of penetration at this time.

Each month our panels send me a report (via an app called Enphase) that tells me how much electricity we have generated — for example: 678 KWh. The report also the amount of carbon offset that resulted from our rooftop panels — 1,266 lbs. in my last report And then it also tells me that we have offset the equivalent of 15 trees! Now we have a big back yard & recently planted 10 trees, but that's all the space we have! Each month our rooftop has the impact of 10-15 trees!

Like others here today, I am concerned about the future for our next generation. I hope that you, like me, believe that global climate change is real & that fossil fuels contribute to the world's climate crisis.

→

And I hope that you, like me, believe that Kentucky should be & can be a leader in addressing this crisis for future generations? If so, Then you will want to support renewable, reliable, clean energy — and rooftop solar is part of the solution that should be supported & encouraged. My 15 trees a month should matter to you! Please take action to support rooftop solar. Thank you.

[illegible signature] PhD

2019-
PSC Comments – Case 00256

I have been a net-metering customer since 2016.

The rate of compensation for net-metering customers is the charge you have been given. Here are a few thoughts on what that means to me. The Value of Solar has been asked, and answered before by various PSCs and PUCs. Let's take a realistic low end as somewhat below the retail price of standard electricity. The highest estimate I have seen is almost $0.20/kWh over retail electric rates. All the range between these two extremes is used. This tells me that PSCs and PUCs will determine a VoS similarly to how they value renewable energy. I suspect you will do the same.

You have said that you are constrained by legislation. You are experts at word-smithing and will use your skills for whatever you decide. If you decide to not value the policy, societal and environmental benefits of renewable energy, that is a decision too.

But you are not the only group putting a value on renewable energy. The Solar Share program of LGE/KU comes to mind. Its first phase is fully subscribed and they are working on subscriptions for the second phase, despite it being a very bad financial deal that just gets worse the more shares you buy. I never thought they would get this far. Are these subscribers crazy or stupid? I know some of these folk and they are neither crazy nor stupid. They have made their value judgement and concluded that doing what they can to avoid excessively burdening average or below average income people, increased insurance rates, drowned islands and coastlands, species loss, polluted air, etc., makes this a *good* deal.

The utilities have added another whine to their complaints about net-metering. They are now trying to devalue the energy that net-metering customers put on the grid by saying that net-metering customers do not have to meet all the reliability, safety, and other standards that they do. True enough, but they made a safety and reliability deal along with a universal coverage deal as part of the trade for regulated monopoly status. Besides, they have no qualms about taking my poorly papered excess electron, jumbling it with their improved pedigree electrons and selling the lot of them to my neighbors for full retail price (the laws of physics say this is what actually happens). I hope we can all stop posturing and tell the truth.

Jack Morris
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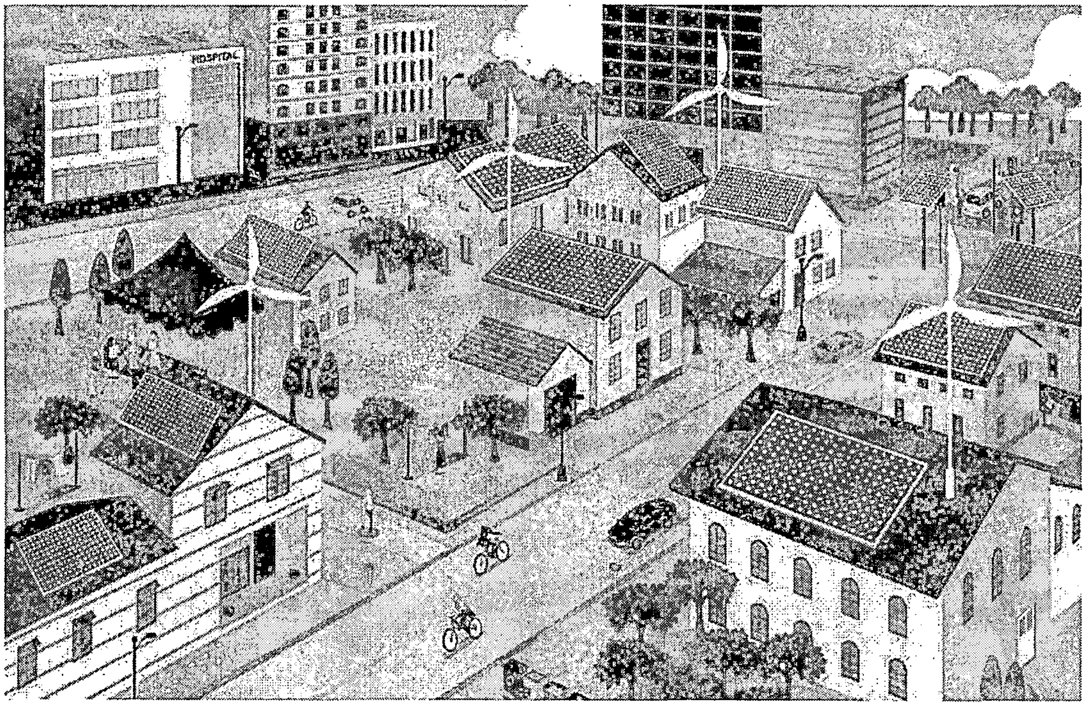

Review of State Net Energy Metering and Successor Rate Designs

Tom Stanton

Principal Researcher for Energy and Environment

National Regulatory Research Institute

nrri

Acknowledgments

First, I want to thank Jamie Barber, Georgia PSC staff member and Chair of the NARUC Staff Subcommittee on Rate Design, for her valuable assistance in helping to shape this project. Ms. Barber is co-author of the state reviews presented in the Appendix, and consulted with me about this project.

Several more colleagues deserve special credit for helping me complete this project. I wish to thank especially members of the NARUC Staff Subcommittee on Rate Design, who participated in webinars in March and August 2018, where the themes of this project were the topics of conversation. Similarly, NRRI hosted a webinar on these topics in March 2018 and I wish to thank all of the participants for their contributions.

Autumn Proudlove and the staff at the North Carolina Clean Energy Technology Center shared a wealth of related information from their *50 States of Solar, 50 States of Grid Modernization, and 50 States of Electric Vehicles* quarterly reports series, and helped answer many questions along the way.

Important ideas that helped shape this report were contributed by: Hon. Matt Schuerger, Commissioner, and staff member Susan McKenzie, from the Minnesota PUC; Julie Baldwin and Daniel Blair from the Michigan PSC staff; Sandra Hart from New York PSC staff; and Jake Marren, Vermont PUC staff.

Jamie Barber of Georgia PSC staff, Anita Castledine and Karen Olesky of Nevada PUC staff, Briana Kobar of VoteSolar, Jim Lazar of the Regulatory Assistance Project, Autumn Proudlove of the North Carolina Clean Energy Technology Center, Dr. Carl Pechman, Director of NRRI, Dr. Sherry Lichtenberg, NRRI Principal Researcher, Jennifer Murphy, NARUC's Director of Energy Policy and Senior Counsel, and Wally Nixon of Arkansas PSC staff all reviewed a draft of this report and provided extensive support, helping to identify omissions, and providing editorial guidance helping to clarify many issues. I thank them all for their time and effort in completing those reviews.

Any remaining errors or omissions are my own doing. As always, I invite readers to notify me if they notice anything that needs correcting, and I welcome ideas about future research projects.

—Tom Stanton, Principal Researcher, Energy and Environment

nrri

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List of Figures and Tables

List of Acronyms Used

DER – Distributed Energy Resources

DG – Distributed Generation

IRP – Integrated Resource Plan

kW, kWh – kilowatt, kilowatt-hour

MW, MWh – megawatt, megawatt-hour

LCOE – Life-cycle Cost of Energy

NEB – Net Energy Billing

NEG – Net Excess Generation

NEM – Net Energy Metering

PPA – Power Purchase Agreement

PSC – Public Service Commission

PUC – Public Utility Commission

PV – Photovoltaic

REC – Renewable Energy Certificate

T&D – Transmission and Distribution

TOU – Time-of-Use

VDER – Value of Distributed Energy Resources

VOS – Value of Solar

Review of State Net Energy Metering and Successor Rate Designs

Executive Summary

The objective of this paper is to summarize actions now being taken in many states to change rate designs for distributed energy resources (DER) on the customer side of the meter. Net energy metering (NEM) has been the most common rate design used for customers with small-scale generators that provide what is sometimes known as self-service power. Recently, there has been considerable interest in finding alternatives to net metering by legislatures and public utility commissions (PUCs), with some related deliberations underway or recently concluded in at least 48 states and the District of Columbia. These actions sometimes arise from preexisting legislative or regulatory requirements that trigger reviews when the total installed NEM system capacity or energy production, either for individual utilities or statewide, reaches a predetermined threshold. In other cases, regulatory reviews have been requested by utility companies through proposals to replace net-metering with other alternatives.

Alternative proposals to supplant net metering include rate designs with various combinations of: (a) compensating for energy delivered to the grid at a price other than the retail service rate; (b) increasing fixed charges and sometimes also minimum bills; (c) time-varying rates; and (d) adding demand-charges to bills for customers who did not previously have them. Several states have considered creating a separate rate class for customers with distributed generation (DG), whereas others have made provisions for utility ownership of DG under specific circumstances. Another important factor included in this review is the treatment of customers who entered into NEM arrangements under previous rate designs. There is often some provision for grandfathering, allowing customers to continue operating under a previous rate design for some period after the new rate becomes effective.

In some jurisdictions, the proposed or adopted changes affect all residential and small commercial customers, whereas in others the changes apply only to NEM customers. In some jurisdictions, NEM or successor rate designs also apply to customers participating in variations of aggregated, neighborhood, or virtual net metering, which often also includes participants in community-solar projects. The rates for community solar participants are often somewhat different from customers with on-site DG, but they are sometimes considered part of the same overall tariff.

This NRRI briefing paper includes reviews of changes to NEM or DG program rate designs. The changes resulted from either new legislation that directs state commissions to make changes, or changes that state public utility regulatory commission have already adopted, or both.

The review encompasses legislative changes that have occurred since 2014 and regulatory changes that took effect by mid-2018 or earlier. It draws from and expands upon information provided in the North Carolina Clean Energy Technology Center's *50 States of Solar* series; particularly, the *4th Quarter Report and Annual Summary for 2017* (2018a) and *Q1 and Q2 2018 Update Reports* (2018b and 2018c).

Table 1 provides a summary of recent changes to NEM rate designs that are already effective for one or more utility companies in those states listed.

Table E-1: Policy Types Already Adopted by States

Policy Types	Vertically Integrated States	Restructured States
NEM 2.0 or NEM Successor Tariff[1]	AZ, CA, HI, ID, IN, LA, MI, NV, UT, VT	CT, DC, MA, ME, NY
Changing credit rates for excess generation	AZ, CA, GA, HI, IN, KS, LA, MT, NC, NH, NV, SC, UT, WI	ME, NY, OH, TX
Increasing (decreasing) customer fixed-charges[2]	AL, AK, AR, AZ, (CO), FL, HI, ID, IN, KS, KY, MI, MN, MO, ND, NM, NV, OK, SC, SD, TN, WA, WI, WV	(CT), DC, DE, MA, NH, NJ, (NY), OH, PA, RI, TX
Assigning demand-charges or stand-by charges	AL, AR, AZ, CA, KS, NC, NM, SC, UT	MA, NH
Creating a separate customer class for DG	IA, ID, KS, MT, NV	TX
Providing for third-party or utility-owned DG	AZ, FL, GA, LA, MO, NC, NM, SC, UT, VA, VT	DC, NY, RI, TX
Adding provisions for community solar[3]	CA, CO, HI, MN, NC, OR, VA, VT, WA	CT, DC, DE, IL, MA, MD, ME, NH, NJ, NY, RI

Source: NCSU CETC *50 States of Solar* report series, 2015 through 2018.

1 See Figure 2, p. 12.

2 In these instances, the decisions result from specific regulatory commission orders and affect individual utility companies.

3 See Figure 4, p. 37. Several states have provisions for community solar programs that treat participants as virtual or remote net metering customers. Listed here are those states where legislation provides for community solar programs. Many more states have one or more active community solar projects, but as yet have no statewide law or rules: Most often, those projects were proposed by individual utility companies and approved by state regulatory commissions (or, for those utilities that are not state regulated, were approved by their municipal or cooperative regulatory bodies). See Stanton and Kline 2016.

Organization of Paper

Part I introduces the subject matter of this report and includes four sections.

The first section briefly describes the major drivers that are causing policy makers and utilities to focus attention on this topic and the second section provides observations about the implications of those drivers for possible changes in rate design. The third section reviews one of the major decisions regarding rate designs for DER, which is whether rates should be based primarily on estimates of the value that the resources produce and provide to the utility system or to society at large, or if it is better to base rates on the costs of the DER systems.

The last section of Part I introduces the eight major types of state actions that are included in this review:

- Net metering replacement or successor tariffs, sometimes called "NEM 2.0";
- Comprehensive reviews of different rate designs for customers with DG;
- Changing the rates for net excess generation (NEG) or for all energy delivered to the utility grid;
- Increasing monthly fixed charges for residential and small commercial customers;
- Adding demand charges or standby charges to rates that previously had none;
- Treating customers with DG as a new customer class;
- Providing for third-party and/or utility ownership of DG; and
- Enabling community solar projects.

Part II summarizes the changes taking place in the nineteen states that are actively updating or replacing NEM tariffs and rules. This part of the paper focuses on the period from 2015 through the first half of 2018. In addition, summaries of actions are presented for two states where NEM was never fully implemented, but similar policy changes are being considered.

Part III reviews additional related actions that are ongoing in many states. Those include:

- Comprehensive reviews of rate designs for customers both with and without self-service power, underway in 14 states;
- Commission decisions in 34 states, affecting about 125 utility companies, changing fixed charges for small customers (mostly increases, but recently a few decreases, too);
- Eleven states have added system-capacity based demand charges, as-used demand charges, flat grid-access fees, or standby charges for customers with DG;
- Six states have taken actions toward treating customers with distributed generation as a separate class for ratemaking purposes;
- Third-party ownership of customer-sited DG, as approved in 34 states, and utility ownership approved in seven states, with decisions pending in four more; and
- Legislative or regulatory actions in 20 states, enabling community solar projects, and many additional states approving specific utility-run community solar projects.

Part IV presents conclusions and recommendations, which are shaped by four primary observations:

(1) There is no consensus about which rate designs are most suitable for updating or replacing retail NEM;

(2) Differences in the existing markets and rates of growth for NEM and DER technologies, and differences in electric utility industry structure, should help inform policy makers about the kinds of rate design changes that are most appropriate for each jurisdiction; and,

(3) In the near term, at least some related actions are underway in almost every state, as shown in Table E-1, so it is important for all interested parties to observe how those actions are affecting markets for NEM and more generally for DER.

Many important questions remain, for continuing research and analysis of the changes presently underway, including:

- How do NEM rate changes affect the rate of adoption of DG or even broader DER technologies? Are the markets for DG and DER still in the earliest stages of consumer adoption, or are some technologies already starting into emerge into uninhibited market growth?
- How big are the potential markets for community solar? What kind of offerings work best for low- and middle-income participants?
- In states that create a separate rate class for DG customers, what can we learn about the class usage patterns? How similar they are to non-DG customers? And, how do the class usage patterns affect utility costs of service?
- Are studies of the value of solar, the value of DER, and utility costs of service measuring the right benefits and costs? Are they measuring all of them? Finally, are the measuring methods valid and reliable?
- Are there marked differences in DG markets between jurisdictions allowing versus prohibiting third-party ownership? If yes, what are those differences?
- In jurisdictions with utility-led programs, utility ownership, or both, what happens to market growth rates? And, what happens to competition?
- If the policy approaches are different in vertically integrated and restructured states, how are they different?

An Appendix provides additional descriptions of related actions in ten representative states, five with vertically integrated and five with restructured electric utility industry structures. The states reviewed in this appendix have each engaged in more than one of the actions included in the review completed for this project. The five vertically integrated states are Arizona, Georgia, Hawaii, Minnesota, and Vermont. The five restructured states/jurisdictions are the District of Columbia, Illinois, New Hampshire, New York, and Texas. The appendix is available for downloading from the NRRI website, at http://nrri.org/download/appendix-nem-policies.

I. Introduction

The purpose for this report is to summarize recent changes in rate designs applied to net energy metering (NEM) and other tariffs that apply to distributed generation (DG). It is based on reviews of state legislation, recent decisions by state public utility commissions (PUCs), and to a lesser extent, on open dockets and utility company tariffs complying with commission decisions.[1,2,3] This updates an earlier NRRI report addressing similar topics (Stanton, 2015).

The eight major types of rate design approaches and policy changes included in this review are listed in Table 1. It provides information for states with vertically integrated industry structures (listed in rows without shading) and restructured utilities (listed in rows with blue-shading) that have already taken actions to enact those changes by mid-2018 or earlier.[4] Almost every state listed in Table 1 has engaged in one or more actions related to these kinds of changes.

The vast majority of utility regulatory jurisdictions have either statewide programs or individual utilities that offer some version of what is variously called NEM or similar programs typically referred to as net energy billing. The federal Energy Policy Act of 2005 (EPAct 2005) amended the Public Utility Regulatory Policies Act (PURPA), to include the following standard that states are required to consider, but not required to adopt:

> Each electric utility shall make available upon request net metering service to any electric consumer that the electric utility serves. For purposes of this paragraph, "net metering service" means service to an electric consumer under which electric energy generated by that electric consumer from an eligible on-site generating facility and delivered to the local distribution facilities may be used to offset electric energy provided by the electric utility to the electric consumer during the applicable billing period (16 U.S.C. 2621(d)(11)). State PUCs and non-state-regulated utilities were directed to consider the adoption of this net metering standard by August 2008 (Flores-Espino 2015, p. 4).

1 This report is based on a snapshot at one point in time. Many of the actions discussed in this report remain under review and changes are taking place rapidly. The intent is to provide a broad view, characterize the types of changes that are being considered, and summarize decisions that have been made to date. Readers aware of any needed corrections, additions, or deletions are invited to contact Mr. Stanton, at NRRI. Please email tstanton at nrri dot org.

2 This review includes information about nearly all of the 50 states, plus the District of Columbia. Throughout the report, the word "state" is used to refer to any of the 51 jurisdictions.

3 This review does not include tariffs for merchant power plants, meaning facilities that are in the business of generating and selling electricity. Rather, it focuses on DG used by a customer, primarily to offset their own use of electricity that would otherwise be purchased from a regulated utility or competitive electricity supply company.

4 For a map showing restructured states, see U.S. Energy Information Administration, *Electricity retail choice states, 2010*, at https://www.eia.gov/todayinenergy/detail.php?id=6250. However, note that this source includes among restructured states both Oregon and Michigan, though electricity retail choice is restricted in those two states: In Oregon only large non-residential customers are eligible for "direct access" service (OARD Chapter 860-038: Direct Access Regulation) and Michigan restricts what it calls "Electricity Choice" to not more than 10 percent of each utility's annual sales (MCL 460.10a). Because the competitive offerings in those states are so limited, in this document Oregon and Michigan are listed as vertically integrated.

Table 1: DER Policy Types Recently Adopted by States

Policy Types	Vertically Integrated States / **Restructured States**
NEM 2.0 or NEM Successor Tariff[1]	AZ, CA, HI, ID, IN, LA, MI, NV, UT, VT
	CT, DC, MA, ME, NY
Changing credit rates for excess generation	AZ, CA, GA, HI, IN, KS, LA, MT, NC, NH, NV, SC, UT, WI
	ME, NY, OH, TX
Increasing (decreasing) customer fixed-charges[2]	AL, AK, AR, AZ, (CO), FL, HI, ID, IN, KS, KY, MI, MN, MO, ND, NM, NV, OK, SC, SD, TN, WA, WI, WV
	(CT), DC, DE, MA, NH, NJ, (NY), OH, PA, RI, TX
Assigning demand-charges or stand-by charges	AL, AR, AZ, CA, KS, NC, NM, SC, UT
	MA, NH
Creating a separate customer class for DG	IA, ID, KS, MT, NV
	TX
Providing for third-party or utility-owned DG	AZ, FL, GA, LA, MO, NC, NM, SC, UT, VA, VT
	DC, NY, RI, TX
Adding provisions for community solar[3]	CA, CO, HI, MN, NC, OR, VA, VT, WA
	CT, DC, DE, IL, MA, MD, ME, NH, NJ, NY, RI

Source: NCSU CETC *50 States of Solar* report series, 2015 through 2018.

[1] See Figure 2, p. 12.

[2] In these instances, the decisions result from specific regulatory commission orders and affect individual utility companies.

[3] See Figure 4, p. 37. Several states have provisions for community solar programs that treat participants as virtual or remote net metering customers. Listed here are those states where legislation provides for community solar programs. Many more states have one or more active community solar projects, but as yet have no statewide law or rules: Most often, those projects were proposed by individual utility companies and approved by state regulatory commissions (or, for those utilities that are not state regulated, were approved by their municipal or cooperative regulatory bodies). See Stanton and Kline 2016.

By 2015, 43 states and the District of Columbia had NEM programs for at least some of their regulated utility companies.[5] NEM was "arguably the most widespread state distributed solar policy in the country" (NCSU-CETC 2016, p. 13).

The major impetus for actions to replace NEM is the concern that NEM customers could drive their utility bills so low that they would not be making their fair contribution to utility fixed cost recovery. A 2013 report from the Edison Electric Institute raised concerns about "disruptive challenges" and "game changers" for the electric industry, from a combination of factors including the rapid and increasing growth of distributed generation, especially solar photovoltaic systems, as well as the flat or slow-growth of energy sales, and rate designs where most fixed costs are recovered through volumetric charges (Kind 2013). That report proposed several changes in policy, including:

- Ending subsidies for distributed solar;
- Instituting higher fixed charges;
- Increasing charges for interconnection, for utilities managing increasing variability in supply and demand, and for backup supply;

5 Some state laws and rules apply to all electric utilities, but others apply only to state-regulated utilities and sometimes to additional, specifically identified non-state-regulated utilities. Non-state-regulated utilities often offer NEM or NEB programs as directed by their own boards of directors.

- Revising NEM programs to treat credits as utility "purchases at a market-derived price"; and
- Considering exit fees for partial requirements and "fully departing" customers, "to recognize the portion of investment deemed stranded as customers depart."

Many utilities and some other interested parties subsequently described NEM as a program that was inherently causing cross-subsidies to be paid by non-participating customers to participating customers. Because the vast majority of NEM customers use solar photovoltaic systems, and markets for those systems were growing rapidly in some jurisdictions, such factors led to widespread perceptions that NEM programs, originally intended to support nascent markets for marginally cost-effective solar PV, have served their purpose and the time has come to replace them with cost-based or value-based tariffs.

The logic supporting alternatives to retail compensation for NEM is that those customers who are supplying some of their own power by self-generating are still making extensive use of the existing utility grid in two very important ways: (1) as a sink for excess generation whenever their usage of electricity is less than the output of their on-site generator; and (2) for receiving supplemental energy whenever their local usage is greater than the production of their on-site generator. A reverse argument, however, is that exports from NEM customers are a service that the customer provides to the utility system, and the regulatory treatment should appropriately compensate NEM customers for the services they are producing and delivering.

Advanced metering can account for those times when excess power is being delivered, either in small intervals by meters capable of recording the outflow of electricity from the generator into the grid (or from the generator in excess of the customer's usage during the same time interval), or by netting outflow in excess of inflow over the course of a billing period.

In a traditional NEM tariff, the credit for excess generation delivered to the grid is equal to the full retail price that the same customer pays for energy purchases from the grid. Whether NEM results in a subsidy for distributed solar is a complex question, which cannot be answered without detailed analysis, utility by utility. To this end, many states have engaged in studies of the long-term benefits and costs of distributed solar. A majority of these studies find that NEM results in a net benefit, at least at the levels of participation in the present time and near future. (Muro and Saha 2016; RMI 2013; Darghouth, Barbose, et al. 2014).

In any case, increasing numbers of state public utility regulators have adopted multi-tier rate structures for self-generators, where the rate for excess energy delivered to the grid is different from the rate charged for the energy the same customer receives from the grid. These new rates for exported energy differ by jurisdiction, based on variations of (a) a calculation of the value of the energy delivered to the grid, particularly for solar energy (referred to as a VOS rate), or (b) a commission-approved "avoided cost" to the utility, which is most often derived from the wholesale price of energy that the utility would otherwise have to generate itself or purchase in a wholesale market.

In states with open markets that reveal wholesale power prices, a supply rate can be used as the credit proxy. That can help simplify calculating the credit amount, although even then it can be difficult to reach any consensus on exactly how to do so. For example, should the credit rates include both capacity and energy costs bundled into an average rate at all hours, or should the credit be differentiated by the prices at the specific times energy is delivered? And, how should transmission charges and line-losses be included in such calculations, if at all?

A. Implications for rate design

The time pressure associated with such changes depends, in large part, on how fast DER options are spreading and how much those changes affect utility revenues. Table 2 presents a high-level summary of a range of different conditions of existing DER markets. It is intended to present a preliminary picture of how the depicted differences might relate to different parties' perceptions of the time pressure for making policy changes.

Table 2 names three market types, based on their general market conditions as described in the second row and as characterized by the general benefit/cost comparisons shown in the third row. Readers can think of markets for solar PV, especially, as gradually having moved from left to right as equipment has improved in conversion efficiency, reliability, and durability while also declining in cost (Woodhouse, Jones-Albertus, et al. 2016). The same general trends in learning-curve improvements hold true for most manufactured products (Rogers 2003).

In the earliest stages, the market for solar PV could be termed "uneconomic," because systems were high-priced, such that participating customers would receive only modest returns on investment and payback periods were lengthy. By and large, that meant that the early customers were either true believers or innovators—the few who might not care so much about financial returns, but might be motivated by their interest in solar power and self-reliance, or their status among their peers as innovators. Eventually, however, the performance of solar PV equipment improved and costs declined, partly as a consequence of its policy driven adoption, which often included the impacts of multiple government support policies promoting solar, such as grants, loans, and tax incentives. In concert with those changes, some jurisdictions moved into the pre-economic and eventually grid-competitive positions shown in the final column of the table.

Table 2: Preliminary Model of Different DER Market Conditions

Market Model Name	Price Support	Transitional	Price-competitive
General market condition	Uneconomic	Pre-economic	Grid-competitive
B/C ratio[1]	B < C, slow if ever ROI	B ≈ C, modest ROI or payback under optimistic scenarios	B > C, patient ROI, reasonable payback under many scenarios
LCOE to VDER comparison	LCOE > VDER	LCOE= VDER	LCOE < VDER
Other relevant support policy impacts	Low	Medium	High
Types of adopters[2]	True believers, Innovators	Early adopters	Early majority
Market share for DER[3]	~1% or fewer customers	~1 to 2.5%	>2.5%
DG, NEM growth rates[4] (customers or capacity)	< 1/3 per year	1/3–2/3 per year	Annual doubling or more
Trend in total utility sales levels	Growing or flat	Growing, flat, or declining	Flat or declining
Time pressure for regulatory actions	Low	Medium	High

Source: Author's construct based on Taylor, McLaren, et al. 2015 (NREL/TP-6A20-62361) and adapted from Rogers 2003, *Diffusion of Innovations, Fifth Edition.*

1 The benefit/cost (B/C) ratio takes into account utility rates and includes as benefits available support policies, like financial incentives, plus any other costs DER can avoid.

2 Adopter types from Rogers 2003.

3 Market share characterizations shown are the author's construct based on Rogers 2003 and observations of NEM growth reported by U.S. Energy Information Administration.

4 DG, NEM growth rates depicted here are the author's construct, based on personal observations and published solar market data. Depending on the purpose for analysis, growth rates might be measured in terms of cumulative capacity or numbers of customers.

Table 2 also describes market conditions in general terms of the relationship between the lifecycle cost of energy (LCOE) and the value of DER (VDER). The LCOE from any new DER measure represents an estimate of the productivity of the measure, compared to the cost to implement and maintain the measure over its useful lifetime. Analysis can also be used to compare VDER to the embedded costs for the pre-existing utility infrastructure. The benefit/cost information can be quite similar, depending on what benefits and costs are included in analysis. LCOE/VDER analysis can be used to explore two different perspectives: (1) the investor perspective comparing cost to value; and (2) the utility or social perspective, which looks at LCOE in terms of the embedded costs in the pre-existing utility system that are reflected in current and predicted future rates. In considering VDER, it is important to recognize that VDER will often decline over time as the cumulative production from those resources increases: The DER resources supplant marginal utility supplies, but as DER supplies increase, the marginal benefits gradually approach the average cost (Darghouth, Barbose, et al. 2014). Generally, this means that the value of the early, small numbers of DER measures is greater, perhaps equal to or possibly even exceeding current retail prices, but as the deployment numbers expand, the VDER will eventually converge toward the average wholesale prices.

There would presumably be strong causal links among the market conditions shown in Table 2, including: (a) each general market condition, including the financial viability of self-generation and the relationship between LCOE and VDER, based in part on the effects of "other relevant support policies"; (b) the types of adopters attracted; (c) the achievable market share, and, (d) annual growth rates as measured by either cumulative capacity or numbers of customers.

The trend in total utility sales can be thought of as an independent variable. Sales lost to self-generators represent only one of many relevant factors in rate-setting and revenue recovery. In the early market stages those losses have a relatively small influence on total utility sales. Similarly, various parties' perceptions of the time pressure for regulatory actions can be affected by many factors, and those perceptions could diverge widely among different interested parties and policy makers.

In addition to measures of DER equipment cost and performance, there can be other features of state policy and regulatory landscapes that support or hinder DER adoption (Stanton 2015, pp. 21, 23). Hledik and Lazar conclude that multiple influences shape "the role for policymakers and state regulators." Important among those influences would be the existing: (a) state policy guidance about utility regulatory support of DERs; (b) the scope of non-regulatory state support programs; (c) industry structure and determinations about regulated utility responsibility for power supply, including utility ownership; and, (d) rates of DER deployment. Hledik and Lazar state:

> In jurisdictions with rapid deployment and vertically integrated utilities, there is likely a need for more rapid movement toward some sort of discrete pricing for the distribution services needed by and provided by DERs. Regions with slow deployment may be able to learn from experiences in fast-deploying jurisdictions... before adopting policies and pricing frameworks (Hledik and Lazar 2016, p. 8).

Hledik and Lazar assume a future with widespread adoption of DER, and review four different approaches towards packaging and pricing grid services, both for the services that the utility provides to its customers and for the services that DER might provide to the utility. The four approaches include:

(1) granular retail rates, where each service is "discretely priced... [and] [e]ach price is calculated so that expected sales will generate the overall revenue requirement determined by the regulator;"

(2) retail buy/sell arrangements, where "[c]ustomers pay retail prices for all services delivered by the utility system [and] they are paid separately for any discrete services they supply to the grid;"

(3) procurement model, where "[t]hird-party aggregators maintain the direct business relationship with DER customers, pricing services on a competitive basis;" and,

(4) DER-specific retail rates, where, "[c]ustomers with DERs pay separate tariffs for service, based on the unique service characteristics of their requirements [and] [s]tandardized credits are calculated for services provided by DER customers... ."

Hledik and Lazar review rate design options based on five major criteria: (1) economic efficiency; (2) equity/fairness; (3) customer satisfaction; (4) utility revenue stability; and (5) customer price/bill stability. They compare the alternatives from the utility perspective, and from the perspectives of both participating and non-participating consumers (Hledik and Lazar 2016, pp. 32-34).

As the NARUC *Manual on Distributed Energy Resources Rate Design and Compensation* explains, it is important for jurisdictions to determine the level and pace of adoption of DERs before deciding what, if any, policy reforms are needed. There are different impacts on each utility system that result from increases in the numbers and types of interoperated DERs. Before taking any reform actions, policymakers should request and review data, analyses, and studies for their own jurisdictions. Policy reforms that are rushed and not well thought out can have unintended consequences, including creating volatile business conditions of boom and bust cycles for DER businesses. It is necessary to understand how current policies and their associated growth rates in DER adoption are affecting: (a) utility system costs and revenues; (b) DER business models; and, (c) the costs and benefits that accrue to different DER technologies and services. Once those factors are well understood, policy makers can consider changes in rate designs, along with any changes in other support policies (*Manual* 2016, p. 59).

B. Value-based or cost-based rates for distributed resources?

Changes to NEM tariffs are often premised on whether rates for self-generation are more appropriately based on estimates of value or cost. Initially, NEM was largely understood to be an administratively simple, rough-justice approach that was acceptable at a time when markets for solar PV and other DG were uneconomic. In many of the initial decisions about NEM, policy makers assumed that the retail rate was a close-enough proxy for the value of solar or value of DG, and the total numbers of participating customers and kilowatt hours being credited at the retail price were relatively small: The product of the close-proxy rate, representing a rough approximation of the avoided cost of utility generation or purchases that would otherwise be needed if NEM generators did not export some energy to the grid. When NEM was just getting started, the small number of participating customers multiplied by the small quantity of energy each would deliver to the grid, meant that any error associated with under- or over-estimating the true value would be small. Barbose (2017) explores "the potential effects of distributed solar on retail electricity prices," and on utility revenues. That study models the effects on both the utility cost of service and retail electricity prices, at both the relatively low participation levels in most jurisdictions today, and at much higher projected future participation levels, when as many as 5, 10, 15, or 20 percent of all eligible customers might participate.

Now that some markets are shifting into the new status of transitional or price competitive, and larger numbers of customers are demonstrating their interest in obtaining and using DG and other DER, policy makers are demonstrating much greater interest in alternative rate structures and in establishing credit rates that accurately reflect benefits and costs.

At the heart of decisions about DER rate design are fundamental determinations about the expected value of distributed resources and decisions about whether to design rates based on value, cost, or some mix of the two. This has led many states to engage in studies to determine the VOS or VDER through studies. There are already roughly two dozen completed studies in over one dozen states (RMI 2013; Taylor, McLaren et al. 2015). Interestingly, there is little consistency in the findings from those studies to date. The studies have not all included the same list of potential benefits or costs, nor have they all used the same measurement methods. Thus, the resulting values range widely, from as little as 4¢/kWh to as much as 30¢/kWh, with a mean value of 16¢/kWh (RMI 2013).

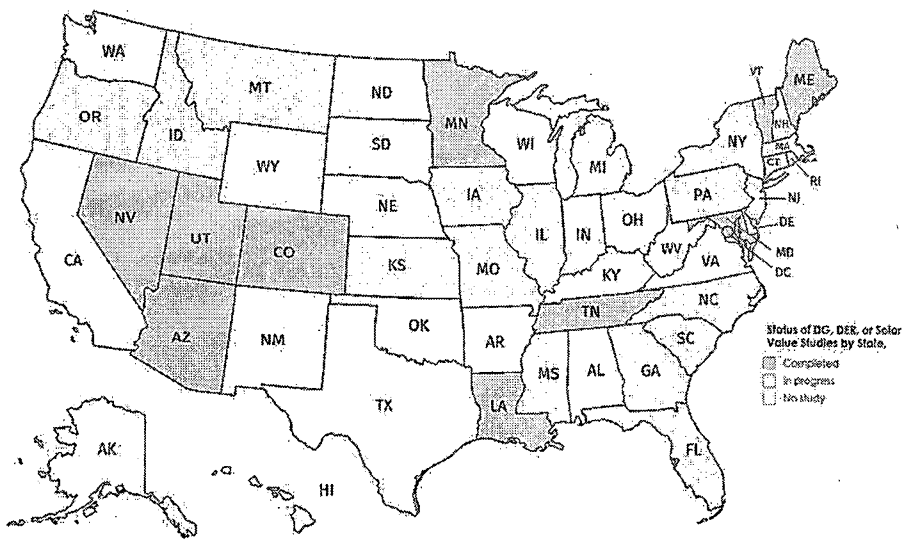
Figure 1 shows the 11 states that have recently completed value-based studies, along with 18 other states that have proceedings in progress for completing value-based studies. States are included in Figure 1 if they have studies recently directed by state legislatures or regulators. The map does not include several other states where individual utility companies or other interested parties completed studies; many such studies have been completed by academic researchers, hired consultants, and utility companies. Several states are forming stakeholder groups to provide input and decision-making about study parameters and methods. In Figure 1, states are marked as pending even if one or more value-based studies has been completed for that state, as long as a study requested by state regulators is not yet completed.

At present, there is no "one size fits all" system for completing these studies. Fundamental differences of opinions remain among different interested parties about both the identification of benefit and cost categories to be included, and the appropriate methods and time horizons to use for estimating what those benefits and costs might be. Different states even use different names for some of the same benefit and cost categories (NCSU-CETC 2018b, p. 27).

Another important parameter is the time-period of study, as many benefit and cost values are different in the short term as opposed to long term, and uncertainty increases the farther into the future studies try to predict. In addition, different cost and benefit components change over time, in response to different causes. Similar to other utility future modeling exercises, value studies can model a variety of scenarios and sensitivities. Examples include variations in fossil fuel supply costs; future global climate change policies; and the rate of DER market adoption (Bradford and Hoskins 2013; RMI 2013; Taylor, McLaren et al. 2015; Whited et al. 2017).

Several states are beginning to investigate benefits and costs in more detail, looking at seasonal and daily variations in the price of grid electricity, at locational value, and studying combinations of multiple DER technologies, most notably combining on-site generation with energy storage.

Figure 1: Map of States with Completed and In-Progress Value-Based Studies (2014–3rd Quarter 2018)



Source: NCSU-CETC, 2016-2018e, *50 States of Solar* report series.

These value-studies can serve multiple purposes, not just rate setting. VOS or VDER can be calculated and used as a point of reference to see how current estimates relate to wholesale avoided costs or retail prices, and to understand how current and near-term future DER costs compare to the calculated values, with and without various financial incentives and other policy supports. One consistency that does emerge from several of these studies to date is a recognition that distributed resources are generally more valuable than bulk power in the wholesale market, due mainly to cost savings because of reduced transmission and distribution system losses, and often adding some estimated value for environmental benefits. But, several studies have also concluded that distributed resources are less valuable than the full retail rate.

Another purpose for VOS or VDER studies is to apply prices derived from them to some, but not all, participants in DER programs. For example, New York is applying VDER prices to large DG generators, and Minnesota is applying them to community solar participants, but neither state is applying VDER prices to customers participating in other aspects of NEM or DG programs.

A few states have decided that studies should focus on embedded costs rather than value. The Kansas Corporation Commission has directed that compensation rates should be cost-based and not include any unquantifiable values, an approach also being considered in North Carolina and Louisiana. The 2017 North Carolina law, HB 589, G.S. 62-126.7, states specifically that both costs and benefits have to be considered. State commissions in South Carolina and Utah have also directed utilities to complete cost-of-service studies for DG customers prior to making any further changes to the existing NEM programs.

C. Types of policy decisions in this review

This review covers eight major kinds of proposals or decisions adopted by either state legislatures, public utility commissions, or both. Most of these actions took place between 2015 through the third quarter of 2018, although a few predated 2015. In addition, this report includes some discussion about activities slated for completion in late 2018 or after.

The actions reviewed here include state legislation and state regulatory commission orders addressing:

- Net metering replacement or successor tariffs, sometimes called "NEM 2.0";
- Comprehensive reviews of rate designs for customers with or without distributed generation;
- Changing the rates for net excess generation (NEG) or for all energy delivered to the utility grid;
- Increasing monthly fixed charges for residential and small commercial customers;
- Adding demand charges or standby charges to rates that previously had none;
- Treating customers with distributed generation as a new customer class;
- Providing for third-party and/or utility ownership of distributed generation; and
- Enabling community solar projects.

Several states are also considering or have adopted) time-varying or time-of-use (TOU) rates. The same TOU rates can be applied in both directions, to charges and credits, or different TOU rates can apply to retail sales versus customer export to the grid. That policy is related to and can be combined with several of the eight policies reviewed for this report.

II. Early Actions on Net Energy Metering Successor Tariffs

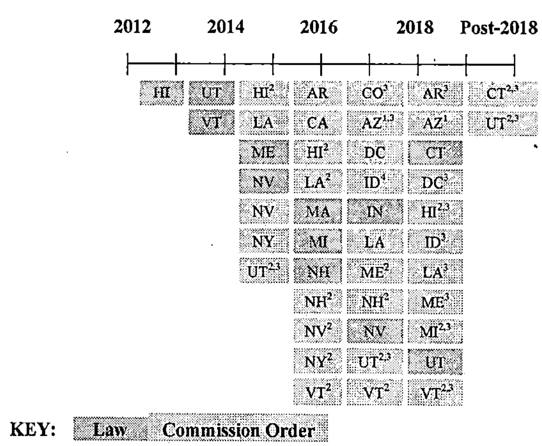
In several states, one or more of these actions has been adopted in response to a legislative or regulatory directive to review NEM, sometimes with the explicit intention of establishing a new approach to billing and crediting customers with on-site generation. Those successor tariffs are sometimes called "NEM 2.0," but they often change the rate structure in ways that differ from the definition of NEM, as that term is typically defined:

> Net metering "compensates a customer for excess generation [with] credits for exported energy deducted" from the amount charged for electricity purchased from the utility during a billing period, and compensation "at the retail rate" at least as long as the credit for excess generation is not greater than the bill for the customer's usage during the billing period. If excess generation exceeds the customer's usage during the billing period, some credit amount other than the retail rate can apply, but the compensation mechanism would still be called net metering (NCSU CETC 2017, p. 16).

A few states have already moved far down the path toward finalizing decisions about replacements for NEM, including Arizona, California, Hawaii, Massachusetts, and Vermont. Several additional states have made decisions about ending previous NEM programs, although decisions about replacement tariffs are still pending. These include Connecticut, Idaho, Indiana, Louisiana, Maine, Michigan, New Hampshire, New York, and Utah. The process for investigating and deciding on an NEM alternative is also underway in Arkansas, although there has not yet been a decision about whether or when to end the previous NEM program.

Figure 2 provides a timeline of both legislative and regulatory actions geared towards developing NEM successor tariffs. As Figure 2 illustrates, the process of developing NEM successor tariffs is typically sequential, with the legislature triggering actions in most states, followed by one or more Commission actions. In two states, Nevada and Utah, the legislature made two rounds of changes during the time frame depicted. From Figure 2 and from the state descriptions that follow, it is clear that these procedures are tending to be time consuming and often contentious. It often takes as long as a few years to complete these actions; indeed, almost every state that has been engaged in these efforts still has commission decisions pending regarding particular implementation details.

Figure 2: Timeline of States Adopting NEM Successor Tariffs



Notes: [1] Indicates a decision affecting only one or more individual utility companies.
[2] Indicates additional state legislative or regulatory actions, subsequent to the enabling laws or rules.
[3] Indicates pending regulatory decisions.
[4] Idaho does not have statewide NEM legislation. The Idaho PUC has directed individual regulated utility companies to file NEM tariffs.

Source: Author's construct.

SIDEBAR 1: DEFINITIONS

Most jurisdictions refer to these programs as NEM, but there are many subtle differences in program designs that can result in at least some blurring of distinctions.[a] Therefore, some researchers are proposing standard definitions for these kinds of tariffs. North Carolina State University Clean Energy Technology Center researchers (2017, p. 16; box 2) propose definitions for net metering and net billing. In addition, several states have considered or adopted a "buy all, sell all" rate, and one state, Michigan, is considering a variation called an "inflow/outflow" rate. Those basic rate designs can be described as follows:

- **Net metering** "compensates a customer for excess generation [with] credits for exported energy deducted" from the amount charged for electricity purchased from the utility during a billing period, and compensation "at the retail rate" at least as long as the credit for excess generation is not greater than the bill for the customer's usage during the billing period. If excess generation exceeds the customer's usage during the billing period, some credit amount other than the retail rate can apply, but the compensation mechanism would still be called net metering (NCSU CETC 2017, p. 16).
- **Net billing** compensates a customer for excess generation using a rate other than the retail rate for consumption, after netting production and consumption over intervals shorter than the billing period (e.g., 15-minute or 1-hour intervals). "The rate for compensation varies by state and utility. It is usually lower than the retail rate, but is often higher than the monthly average rates paid in the wholesale electricity market." And, similar to net metering, the customers can use their on-site generation to meet their own on-site needs, which effectively reduces grid-supplied electricity that would otherwise be purchased at the full retail rate (NCSU CETC 2017, p. 16).
- **Buy-all, sell-all** rates have participating customers purchase all of their service from their utility company, usually at the same retail rate that would apply if the customer did not have on-site generation; however, some specific charges might apply only to customers with on-site generation. Then, all of the energy generated by a participating customer is separately metered during each billing period, and that output is credited at a commission-approved price. Buy-all, sell-all rates treat all on-site production the same, regardless whether the energy is consumed on-site or exported to the grid. Some programs require all of the output to be delivered to the grid, not behind the customer's meter, but that is a policy decision, rather than an essential factor.
- **Inflow/outflow** rates are a variation of net billing. This approach was proposed in Michigan by Public Service Commission (PSC) Staff and was then adopted in principle by the Michigan PSC (April 18, 2018 Order in Case No. 18383). Michigan legislation in 2016 called for developing a new, "cost-based" tariff for distributed generation, to replace Michigan's preexisting NEM program.[b] Similar to a buy-all, sell-all or net billing rate options, in the inflow/outflow tariff framework, customers pays the standard retail price for all energy delivered through their meter, called inflow, just as other customers who have no on-site generation. When a customer's generator produces electricity that is consumed on-site, the customer avoids purchasing that energy at the regular retail rate. Then, all exported energy during a billing period, called outflow, is metered and a commission-approved rate other than retail will be applied to that energy. The preliminary Michigan PSC staff proposal was to credit outflow at the Commission-approved PURPA avoided-cost rate established for each utility. With the inflow/outflow method, on-site usage of on-site generation is treated as a simple reduction in use, equivalent to other reductions in usage due to energy conservation or efficiency improvements.

a For example, North Carolina Clean Energy Technology Center researchers note: "Maine calls its system 'Net Energy Billing' though it fits the standard definition of net metering, and Mississippi calls its new system 'Net Metering' even though it more closely resembles net billing" (January 2017, p. 43).

b See https://www.michigan.gov/mpsc/0,4639,7-159-80741_80743-406256--,00.html.

A. State actions to change existing NEM tariffs and program rules

To date, major actions to make changes to NEM tariffs and program rules have been undertaken in 19 states and the District of Columbia. Those actions include:

ARIZONA[6] – In a January 2017 Order in Docket No. E-00000J-14-0023, the Arizona Corporation Commission decided to end retail rate net metering and begin crediting customers at an avoided cost rate for solar energy injected into the grid. Customers will be credited at the retail rate for energy generated and used onsite. For power above their own needs, customers will be paid an avoided cost rate, based on the 5-year running average price of utility-scale solar, including both power purchase agreements (PPAs) and utility self-built solar systems, plus an additional amount to represent avoided transmission and distribution (T&D) capacity and line-losses. The credit rates are to be determined in rate cases for each of the state's three investor-owned utility companies. In addition, the Commission has determined that rooftop solar customers shall be treated as a separate class for ratemaking.

Arizona's existing net metering rules are codified in A.A.C. R-14-2-2301 through 2308. In a November 2017 Order in Docket No. E-00000J-14-0023 (p. 4) the Commission directs staff "to gather comments and hold workshops as necessary to develop a proposed Net Metering and Export Rate [and] develop draft rules for Commission consideration." Revisions are currently being considered in Docket No. RE-00000A-17-0260.

ARKANSAS – Act 827 of 2015 directs the state's PSC "to ensure net metering rates, terms, and conditions are appropriate to recover the full utility costs of serving net metering customers, net of any quantifiable benefits." A Commissioner Order is pending in Docket No. 16-027-R. Briefs and Reply Briefs have been filed.

Companion Docket No. 16-028-U was expanded in December 2017 to investigate and address broadly defined DER issues, and a recent Order No. 10 directs the participating parties to file comments on procedural issues, including how multiple substantive issues and sub-issues involving grid modernization and power sector transformation should be organized and addressed by stakeholders and the Commission. The Commission expects to engage a facilitator by the end of 2018 to assist the Commission and the parties with organizing, hosting, and addressing issues in workshops, working groups, and technical conferences over the next two years or more.

CALIFORNIA – The generic rulemaking proceeding for developing net energy metering successor tariffs in California is Docket No. R1407002. One successor tariff was adopted in Decision 16-01-044 January 28, 2016.

In California, net metering was initiated by 1995 legislation, and subsequently amended multiple times. A Commission order in 2008 added virtual net metering for multi-family affordable solar housing and it was further expanded in 2011. Aggregated net metering was authorized by 2012 legislation. In 2013 a new law, AB327, directs the Commission to develop a successor tariff "based on the costs and benefits of the renewable electrical generation facility [and ensuring] that the total benefits of the standard contract or tariff to all customers and the electrical system are approximately equal to the total costs" (see Decision 16-01-044, pp. 12-16).

The NEM successor tariff, among other details, provides for: minimum bills; non-residential NEM customers paying fixed charges applicable to their customer class; NEM customers paying non-bypassable charges on all kWh of inflow during each metered time interval; residential customers taking service under any TOU rate available to them; and the successor tariff calls for maintaining and updating both virtual net metering and net metering aggregation (Decision 16-01-044, pp. 2-5).

6 See also Appendix, p. A-2.

A second phase of this docket has been established, for developing alternatives for "residential customers in disadvantaged communities, and… consumer protection and evaluation measures for the NEM successor tariff (Decision 16-01-044, p. 5). Decision 17-12-005 in December 2017 modified virtual net metering to facilitate pairing eligible generation with energy storage. Tariff alternatives for disadvantaged communities were issued in a June 2018 Decision 18-06-027.

COLORADO – The Commission opened Docket No. 17M-0694E in 2018 to review its rules regarding electric resource planning (ERP), Colorado's Renewable Energy Standard (RES), and Enabling New Technology Integration. A March 2018 Colorado law, SB 18-009 (CRS 40-2-130), states:

> Colorado's consumers of electricity have a right to install, interconnect, and use energy storage systems on their property without the burden of unnecessary restrictions or regulations and without unfair or discriminatory rates or fees (CRS 40-2-130(1)(b)(II)).

Docket No. 17-M-0694E is considering proposals for amending: (a) existing rules to accommodate energy storage, to include non-wire alternatives and to take into account any and all demand-side resources in ERP; (b) distribution system planning; (c) interconnection rules; (d) PURPA implementation; (e) net energy metering; and (f) provisions for including low-income customers in community solar gardens.

CONNECTICUT – Public Act No. 18-50, passed in May 2018, broadly addresses Connecticut's Energy Future. It includes provisions for updating the Connecticut renewable portfolio standard, which is now set to grow annually from 21 percent after January 1, 2018, until reaching 44 percent on January 1, 2030. In addition, the law directs the Public Utilities Regulatory Authority (PURA) to develop program requirements and tariff proposals for shared clean energy facilities.

The new law initiates the process of replacing net metering with either buy-all sell-all or net billing options, and directs PURA to establish the new rates. Existing net metering customers are grandfathered until year-end 2039.

DISTRICT OF COLUMBIA[7] – In Formal Case 1130 (FC1130), the PSC proposes amendments to the District's net metering rules, renewable energy portfolio standard, electricity quality of service standards, small generator interconnection rules, and more. Amendments to the District's net metering rule include new definitions for customer generator; backup generation; energy storage and microgrids; and revised definitions for cogeneration facilities, combined heat and power facilities, demand response, and distributed energy resource.

An RM-9 Working Group is being assembled to consider NEM and interconnection rules, including rules affecting community renewable energy facilities (CREFs).

HAWAII[8] – Net metering successor tariffs were first approved by the Hawaii PUC in October 2015, and were revised in an October 2017 Order in Docket No. 2014-0192. Participating customers can choose a customer-self-supply option with no credits for grid export, or one of two additional tariff options: (1) "smart export" for solar plus storage systems; or, (2) "controllable grid-supply" with advanced inverter functions enabled and subject to utility control. Compensation for energy exports under both options is set below the retail rate. In a June 2018 Order No. 35563 in Docket No. 2014-0192, the PUC approved Hawaiian Electric Companies' smart export tariff and invited comments on the Companies' proposed controllable grid supply tariffs.

7 See also Appendix, p. A-14.

8 See also Appendix, p. A-2.

IDAHO – In a May 2018 Order No. 34046 in Case No. IPC-E-17-13, the Idaho PUC discontinued Idaho Power Company's previous net energy metering rate, and started the process of introducing a successor tariff. The Commission determined that "use [of] the grid to both import and export energy" should be treated as a separate class for assigning both costs and benefits. This Order starts the process of creating a separate rate class, but "does not change rates, rate design, or the current compensation credit structure for on-site generation customers."

The Commission directed the Company to file tariff advice regarding advanced inverter capabilities under IEEE Standards 1547-2018, and to initiate a new docket "to study the costs and benefits of net metering on Idaho Power's system, proper rates and rate design, ... [and] compensation for net excess energy... ." The Commission also directed the Company "to undertake a comprehensive customer fixed-cost analysis to determine the proper methodology and 'spread' of fixed costs... ." The Company is also directed to "file a study... exploring fixed-cost recovery in basic charges and other rate design options prior to its next general rate case."

In a September 2018 Final Reconsideration Order No. 34147, the Commission states that it is "open to the possibility" that non-exporting customers might be removed from the Company's net metering schedules. The Commission directs, "a non-export option should be studied for feasibility and vetted for safety and operational concerns by the Company and interested stakeholders in the forthcoming docket." The Order does, however, direct that "for now," non-exporting DG customers would be considered in the same separate customer class as exporting DG customers (Order, p. 16).

ILLINOIS – Illinois started updating NEM rules in 2015, in Illinois Commerce Commission (ICC or Commission) Docket No. 15-0273. The Commission's November 12, 2015, Order in Docket No. 15-0273 outlines the changes in NEM rules. Some of the changes respond to updated legislative directives and others result from workshops conducted with electricity providers (see April 26, 2016, Order in Docket No. 15-0273, p. 1).

Effective in June 2017, new legislation titled the *Future Energy Jobs Act* (S.B. 2814), directed Illinois utilities to allow meter aggregation "for properties owned or leased by multiple customers, individual units within single buildings that are owned or leased by multiple customers (e.g., apartments or offices), and community renewables projects." The law established community renewable energy programs, and created a "Solar for All" program promoting community solar options for low-income customers. The same law also created a solar set-aside within the state's renewable portfolio standard (RPS), setting quotas for RECs from different kinds of projects including: new wind; PV projects, with separate quotas for distributed, utility scale, and brownfield redevelopment projects. The Illinois community renewable generation program created by the Act in §1-10, is not only for solar PV systems but can also support "community projects powered by wind, solar thermal, biodiesel, crops and untreated and unadulterated organic waste biomass, tree waste, and hydropower that does not involve new construction or significant expansion of hydropower dams."

In March 2017, the ICC opened a broad, grid modernization proceeding known as NextGrid. NextGrid working groups are focused in part on DER topics, including VDER, DER grid integration, environmental impacts of DER, ratemaking, which includes both time-varying rates and VDER, and distribution system planning.

INDIANA – Indiana Act No. 309 of 2017 triggers a transition to a net billing arrangement to replace net metering. "Indiana will close net metering to new customers by July 2022 or when the state's 1.5% aggregate cap is reached; new customers entering net metering arrangements before this date are grandfathered until July 2032 only." "Indiana will begin to credit customers at 1.25 times the avoided cost rate in July 2022 or once the 1.5% aggregate cap is reached, whichever occurs first." The legislation defines avoided cost as "the average marginal price of electricity paid by the electricity supplier during the most recent calendar year." Indiana utilities are directed to file proposed avoided cost rates, not later than March 1, 2021, and "may request... recovery of energy delivery costs attributable to serving customers that produce distributed generation."

LOUISIANA – In December 2015, the Louisiana PSC opened Docket No. R-33929, to modify net metering rules and consider changes to solar policies. The Commission's General Order No. 12-8-2016 adopted revised rules. Utilities were directed to file updated tariffs within 30 days from the effective date of the new rules. The new net metering tariff provides for net excess generation to be compensated at the utility's Commission-approved avoided cost rate; however, the Commission indicates it may also approve, on a utility-specific basis, "alternative avoided cost rates such as seasonally differentiated avoided cost rates or average avoided cost rates that reflect upward adjustments for avoided line losses and daytime, on peak generation."

In Phase II of this proceeding, the PSC "is reviewing additional changes to its NEM Rules intended to address on-going concerns and have general applicability to all small-scale DG technologies." The Commission issued its *Phase II Notice of Proposed Modified Rules and Request for Comments* in November 2017, and directed parties to file comments by December 29, 2017. A decision is pending.

MAINE – In 2015, the Maine legislature adopted a Resolve, which states in part, "[I]t is in the public interest to develop an alternative to net energy billing that fairly and transparently allocates the costs and benefits of distributed generation to all customers, allows participation by all customers and creates a sustainable platform for future growth of distributed generation to the benefit of all ratepayers." The legislature overrode Governor Paul LePage's veto, to pass this resolution, which directs the Maine Public Utilities Commission to convene a stakeholder group to develop an alternative to net metering. This action was in response to a 2015 report prepared by Strategen Consulting for the Maine Office of the Public Advocate (OPA), titled *A Ratepayer Focused Strategy for Distributed Solar in Maine*.

The Maine PUC opened Docket No. 2015-00218, for this stakeholder process, which culminated in a January 30, 2016 *Report to the Legislature*. As stated in that *Report* (p. 7), "The stakeholders reached substantial agreement on a large number of important aspects of a market-based solar development policy and on some aspects of an alternative to [net energy billing] [but,] there was no stakeholder consensus on an overall solar program."

In September 2016, the PUC opened rulemaking Docket No. 2016-00222. In its Notice of Rulemaking, the Commission stated its intention to gradually reduce the percentage of kilowatt hours that customers could net against transmission and distribution charges, reducing the number by 10 percent per year starting with customers who begin net energy billing in 2017, until "after the year 2025, there would be no netting of the T&D bill" (September 14, 2016 Notice of Proposed Rulemaking, p. 5). The Rule would also increase the eligible facility size from 660 kW to 1MW, and allow for and include provisions governing community-based net energy billing.

In a March 2017 Order, the Commission adopted amendments to the rule, which moves to a buy-all, sell-all framework including a gradual phase-down of the credit rate. The Commission subsequently issued a December 2017 Order in Docket No. 2017-00308, temporarily waiving the revised rule's implementation schedule "to provide stakeholders further opportunity to resolve all outstanding technical issues." Central Maine Power and Emera Maine filed revised net energy billing tariffs in Dockets Nos. 2018-00037 and 2018-00038, respectively. In a March 2018 Order in both Dockets, the Commission rejected the Companies' proposed terms and conditions, and directed the companies to refile, reflecting the Commission's decisions in that Order. The Companies' revised tariffs were then filed and approved, in March and April 2018.

In the Commission's most recent action on the NEB program, an August 2018 Order in Docket No. 2018-0037 directs the Commission Staff to establish a "Rapid Response Process (RRP) to settle disputes over NEB metering costs" and to work with the utilities and solar installers "to explore the feasibility of utilizing inverters that include revenue grade meters and other relevant emerging technologies to reduce the costs to install a meter to measure the gross output of an NEB facility" (Order, pp. 1, 5).

MASSACHUSETTS – The Massachusetts legislature passed a new law in 2016, "to provide... for the continued support of solar power generation and a transition to a stable and equitable solar market at a reasonable cost to ratepayers." That law provided that once the installed capacity of solar net metering in Massachusetts reached 1,600 MW_{dc} (direct current), credits for excess energy would decline to a value known as "market net metering credits" (Acts 2016, Chapter 75, §4b). Those credits would be reduced for residential and commercial customers, compared to credits accruing to municipalities or other government agencies. In general, the credits would be based on the distribution company's default service charge, plus distribution, transmission, and transition charges, all per kWh (Chapter 75, §3). Residential and commercial customer credits would be set at 60 percent of that product, whereas municipalities and government agencies would be entitled to the full amount. Massachusetts calls this net metering replacement its "Solar Massachusetts Renewable Target (SMART) Program." Details about the program are found in the Code of Massachusetts Regulations, 225 CMR 20.[9]

The legislation, in Chapter 75, §11, directs the Commission to promulgate rules for the SMART Program that will, among other things: (a) promote the orderly transition to a stable and self-sustaining solar market at a reasonable cost to ratepayers; (b) rely on market-based mechanisms or price signals as much as possible to set incentive levels; (c) minimize direct and indirect program costs and barriers; (d) encourage solar generation where it can provide benefits to the distribution system; and (e) promote investor confidence through long-term incentive revenue certainty and market stability. The legislation also explicitly supports community-shared solar facilities, solar for the benefit of low-income customers, and solar for municipal and other government facilities.

The Department of Public Utilities (DPU) issued an Order in Docket No. 17-140-A on September 26, 2018, that implements the SMART program. Massachusetts utilities were directed to file new tariffs in compliance with the Order, by October 15, 2018. The Order (p. 72) addresses data collection and monitoring for the SMART program, and indicates the Commission will direct changes to the program if necessary to achieve the legislated goals.

The program calls for compensation rates to be set for blocks of capacity for each distribution company, and to decline by four percent as each block of capacity is filled. Extra credits called compensation rate adders will be available based on: (a) the location of solar generators (e.g., building mounted, floating, on brownfields, or landfills); (b) off-takers for the solar energy, such as solar projects for community-shared, low-income, or public entities; (c) systems co-located with energy storage; and (d) systems using two-axis solar tracking. In addition, the program includes provisions for subtracting from the base compensation level for systems located on greenfield properties (225 CMR 20.7).

Also, in Docket 17-146, the Massachusetts DPU is investigating "the eligibility of energy storage systems to net meter... and the participation of certain net metering facilities in the Forward Capacity Market... ." In its initial Order, the Commission asked parties to respond to a series of questions about both issues (October 3, 2017 Order in D.P.U. 17-146).

MICHIGAN – Public Act 341 of 2016 (MCL 460.1173) directs the Michigan PSC (MPSC) to establish a new DG tariff, to replace the previous net metering program based on 2008 legislation. The new law specifically calls for the Commission to "conduct a study on an appropriate tariff reflecting an equitable cost of service for utility revenue requirements for customers who participate in a net metering program or distributed generation program... ."

A February 2018 MPSC Staff Report recommended that the successor to NEM should be an inflow/outflow billing mechanism, with retail rates paid for on-site consumption delivered by the utility, retail rate offsets for on-site production used on-site, and another rate paid for grid exports. In its April 18, 2018, Order in Case No. U-18383

9 See also the Massachusetts DPO press release on the SMART Program Order, at https://www.mass.gov/news/department-of-public-utilities-issues-order-to-continue-solar-development, and Massachusetts Department of Energy Resources (DOER) information on the SMART Program, at https://www.mass.gov/solar-massachusetts-renewable-target-smart.

(p. 18), the Commission "requires the rate-regulated utilities to file the inflow/outflow tariff in their next post-June 1, 2018 rate case... [but] will also permit a rate-regulated utility to file an alternative DG tariff if desired, to enable a thorough evaluation of all viable DG tariff options."

Detroit Edison's rate case, in Docket No. U-20162, is the first following that Commission Order. Detroit Edison proposes in Rider 18 that DG customers pay the full retail price for electricity inflow, and that outflow would be credited at the company's monthly average real-time locational marginal price for energy. The company also proposes instituting a monthly "system access charge" for DG customers, based on the installed nameplate capacity (see Gearino 2018).

Upper Peninsula Power Company is the second Michigan utility, in Docket No. U-20276, filing proposed tariffs for DG customers, following the Commission Order. The utility's proposal is to charge the full retail rate for inflow, and credit outflows according to the power supply charge for the relevant rate class. The power supply charge represents an average annual value for energy only. The company also proposes that outflow credits could not be used to offset non-energy customer charges. And, the utility proposes that all new DG customers would pay a system access charge based on DG system capacity, but the company did not specify the amount of that charge.

NEVADA – New state legislation passed in June 2015 revised net metering provisions (SB374, NRS 774.773 et seq.). Nevada's net metering law initially passed in 1997, and was amended in 2001, 2005, 2007, 2011, 2013, 2015, and 2017. The 2015 amendments (SB374) revised the cap on cumulative capacity for utilities to offer net metering, required utilities to submit tariffs by July 31, 2015, and directed the Commission to review and approve or disapprove of the tariffs by December 31, 2015.

In Dockets Nos. 15-07041 and 15-07042 the PUC of Nevada took action to end net metering and replace it with net billing. The initial decision by the PUC did not grandfather pre-existing net metering customers, but instead moved them to the new tariffs. However, in September 2016, in an approved settlement agreement in Dockets Nos. 16-07028 and 16-07029, grandfathering would be allowed for 20 years.

In February 2016, the Commission issued a Modified Final Order on net metering tariffs for Nevada Energy Companies in Dockets Nos. 15-07041 and 15-07042. In that order, the Commission determined that non-NEM customers were subsidizing NEM customers by an average amount per residential customer of $471 to $623 per year. The Commission stated, "[T]he Legislature expressly prohibited the Commission from adopting rates that unreasonably promote NEM and authorized the Commission to avoid, reduce, or eliminate an unreasonable shifting of costs from NEM ratepayers to non-NEM ratepayers" (Order, p. 167).

The Modified Final Order created separate rate classes for NEM customers and the basic service charge was increased to include additional distribution costs, compared to non-NEM tariff rates. Additionally, net metering was replaced by net billing, in which NEM customers would get a credit for all excess energy delivered to the grid after hourly netting. The credit was based on the long-term avoided energy cost with an adder for avoided distribution line losses.

The Modified Final Order set up a process for a gradual transition to cost-based rates (for both the increased basic service charge and the reduced credit for excess energy) for all NEM customers. The order established a 12-year process for a gradual transition to cost-based rates for all NEM customers, with changes occurring in five steps that each would increase prices and reduce net excess energy credits by 2028. By 2028, NEM customer billing would include fixed charges comprised of customer and distribution costs from the most current cost-of-service study, resulting in an increase in the basic service charge compared to non-NEM customers, of as much as about $25 to $30 per month. The Commission stated:

> A 12-year timeframe for all NEM customers to date represents an approximately $100 million subsidy that non-NEM ratepayers will have to pay to cover the costs to serve NEM ratepayers that are not recovered from NEM ratepayers during the transition period (Order, pp. 160-161).

The Commission also directed NV Energy to include a separate line item titled "net energy metering subsidy" on non-NEM customer electric bills until the transition is completed on January 1, 2028 (Order, p. 162).

In December 2016, in Docket No. 16-06006, the PUC called for: (a) restoring retail rate net metering in Sierra Pacific Power's territory; (b) authorizing up to 6MW of new net metering using full retail rates, until the new general rates would be set by the start of 2020; (c) grandfathering new NEM customers through November 2036; and (d) retaining a separate rate class for NEM customer-generators (Order, p. 56). A stipulation in that Docket covered all aspects of Sierra's rate case except net metering. A hearing was held regarding the NEM portion of rate design and the Commission, through its order, restored retail rate net metering.

Legislative amendments in 2017 (AB405) provide for net metering for small customers (not more than 25 kW), beginning with credits based on 95 percent of the full retail rate that the customer would have otherwise paid for energy when excess energy was delivered to the utility, and then decreasing in percentage terms for new customers as small-net-metering capacity is added in 80MW blocks, until the credit reaches 75 percent of the full retail rate. The bill also directs the PUC to report to the legislature about the impact of net metering by June 30, 2020, and biennially thereafter. Among other things, the reports are to include calculations showing: (a) if net metering has an impact on rates; (b) the amount of rate increase or decrease, if applicable; and (c) data used to determine the rate impacts, including avoided generation capacity, avoided transmission capacity, avoided system upgrades, and the impacts on utility capital expenditures (Act 405, §28.5).

That law also created a Renewable Energy Bill of Rights for Nevada residents. The Bill of Rights provides, in part, that customer-generators have the right to:

1. Generate, consume, and export renewable energy and reduce his or her use of electricity that is obtained from the grid;
2. Use technology to store energy at his or her residence;
3. Receive "fair credit for any energy exported to the grid"; and
4. Belong to the same existing broad rate class as if in the absence of a net metering system, without any different fees and charges.

On September 1, 2017, in Docket No. 17-07026, the PUC approved tariffs pursuant to AB405. Separate rate classes for NEM customers were eliminated and monthly net metering was restored, with net excess energy delivered to the grid credited at the amount determined by the percentage of retail rates established by AB 405. On March 14, 2018, the PUC approved a stipulation regarding TOU rates pursuant to AB 405.

NEW HAMPSHIRE[10] – In a 2016 law, the New Hampshire legislature directed the state Public Utility Commission "to develop a new alternative net metering tariff or tariffs" (Order No. 26029, p. 2). The stated purpose of the legislation is "to continue 'reasonable opportunities for electric customers to invest in and interconnect customer-generator facilities and receive fair compensation…while ensuring costs and benefits are fairly and transparently allocated among all customers.'" (Order No. 26029, pp. 70-71). The legislation specified eight factors for

10 See also Appendix, p. A-19.

Commission consideration, including: (1) costs and benefits of customer-generation facilities; (2) avoidance of unjust and unreasonable cost-shifting; (3) rate effects on all customers; (4) alternative rate structures including time-based tariffs; (5) limitations on the amount of eligible generating capacity; (6) the size of facilities eligible for net metering; (7) timely recovery of utility lost revenues, using a lost-revenue adjustment mechanism; and (8) utility administrative processes required for the new tariff implementation (Order No. 26029, pp. 68-70).

The Commission adopted an interim alternative NEM tariff in December 2016 in Order No. 25972, and a successor tariff in June 2017 in Order No. 26029. The Commission states the successor tariff is "in effect for a period of years while further data is collected and analyzed, pilot programs are implemented, and a distributed energy resource (DER) valuation study is conducted" (Order No. 26029, p. 2). In its order, the Commission directs parties to develop and propose for implementation four pilot projects, including: (1) a time-of-use pilot; (2) a program using monetary bill credits "to make the benefits of solar DG system ownership available to low and moderate income customers"; (3) a real-time pricing pilot; and (4) at least one non-wire alternative pilot program in each utility service territory (Order No. 26029, pp. 62-64, 72).

In addition to those actions, New Hampshire is one of six jurisdictions participating in a U.S. Department of Energy supported *Multistate Initiative to Develop Solar in Locations that Provide Benefits to the Grid*. That project is a collaborative effort among several states and the Clean Energy States Alliance, with support from the National Renewable Energy Laboratory.

NEW YORK[11] – A March 2017 New York PSC Order in Case No. 15-02703 directed regulated utilities to file new tariffs "implementing the transition from net energy metering (NEM) to a Value of Distributed Energy Resources (VDER) Phase One Tariff... to become effective on April 1, 2017" (Order, p. 151). The Commission established a temporary Phase One NEM mechanism for service during an interim time period until the Commission implements a "Value Stack" (Order, p. 23). Utilities were directed to develop "locationally-granular prices to reflect the full value to their distribution systems from DER additions" (Order, pp. 19, 155). The Order also set levels for each regulated utility, for capacity to be provided by community distributed generation projects (Order, p. 154). The Commission endorsed a time frame calling for developing a Phase Two VDER methodology and presenting a report on that work, with recommendations to the Commission, by the end of 2018 (Order, pp. 137, 150).

In September 2017, the New York PSC issued another order in the same Docket No. 15-E-0751, implementing VDER tariffs, including the methodology for determining the "Value Stack." The regulated utilities were directed to file new tariffs to become effective on November 1, 2017. The Commission stated, in part:

> Phase Two will include, at a minimum, the following topics: (1) inclusion of DER projects in VDER tariffs on a technology-neutral basis; (2) development of methods to provide equal compensation for reduced consumption and injected generation; (3) a framework for the development and consideration of grid access charges, nonbypassable fees, or other methods to mitigate costs imposed on non-participants; (4) potential changes to default rate design and development of optional rates for VDER participants; (5) improvements and modifications to the Value Stack, including components related to the bulk system, distribution system and societal values; and, (6) transitioning of mass market projects to VDER (Order, p. 137).

Phase Two proceedings began in June 2017 with the formation of stakeholder working groups. Phase Two proceedings are taking place in Docket No. 15-E-0751 and three related Dockets: No. 17-01276, In the Matter of the Value of Distributed Energy Resources Working Group Regarding Value Stack; No. 17-01277, In the Matter of the Value of Distributed Energy Resources Working Group Regarding Rate Design; and No. 17-01278, In the Matter of the Value of Distributed Energy Resources Working Group Regarding Low and Moderate Income. In July 2018, New York PSC Staff issued reports summarizing comments received from interested parties and "suggesting improvements to the VDER tariff."

11 See also Appendix, p. A-23.

UTAH – The Utah legislature, in 2014, added a provision to the state's utility code chapter on net metering, UC 54-15-105, which directs the Public Service Commission to: "(1) determine... whether costs that the electrical corporation or other customers will incur from a net metering program will exceed the benefits of the net metering program, or whether the benefits of the net metering program will exceed the costs; and (2) determine a just and reasonable charge, credit, or ratemaking structure, including new or existing tariffs, in light of the costs and benefits."

The Commission opened Docket No. 14-035-114 in August 2014, regarding the Investigation of the Costs and Benefits of PacifiCorp's [Rocky Mountain Power's] Net Metering Program.[12] In that case, the Commission issued a November 2015 Order which "establishes an analytical framework for assessing the costs and benefits of net metering" (Order, p. 3). In response to that Order, Rocky Mountain Power (RMP) filed requested Cost of Service studies in November 2016. The November 2016 filings also included a proposed tariff to replace net metering, which would include a net billing mechanism with reduced export credit rates, demand charges, and increased fixed charges for small net metering customers.

In September 2017, the Commission issued an Order Approving Settlement Stipulation, which creates a limited-time "Transition Program" to replace net metering for the time being, pending a decision "to determine the compensation for exported power" and then establish a new tariff (Order, pp. 5-6). The settlement parties agreed that RMP would file an application to open a proceeding for determining the appropriate Export Credit rate, and support a schedule for completing that proceeding and establishing the rate, within no more than three years. RMP also agreed "to facilitate a workshop to discuss the type and scope of data expected to be considered in the proceeding" (Order, p. 20).

The proceeding to establish new export credit rates is Docket No. 17-035-61. The Commission issued a Phase I Order in Docket No. 17-035-61, in May 2018. The order instructs RMP to continue load research studies, gathering data from samples of residential and commercial customers for up to 12 months, beginning in the 2019 calendar year.

A 2018 Utah law, S.B. 141, repeals the state's existing net metering provisions on January 1, 2036. RMP's net metering tariff was amended in April 2018 to indicate the December 31, 2035 termination date.

VERMONT[13] – In Act 99 of 2014, the General Assembly directed the Vermont PUC to design a revised net-metering program.[14] A proposed rule was published in October 2016, and a final rule was adopted, effective July 1, 2017. Related documents are indexed on a PUC web page, *Revised Net-Metering Program Pursuant to Act 99*.

The final rule, Rule 5.100, allows pre-existing net metering customers to be grand-fathered for 10 years, and sets up a net metering program where export credits are based on a "blended residential rate" (Rule 5.127). Net metering customers can also receive credit adjustors, plus or minus, depending on REC ownership (whether retained by the customer-generator or transferred to the electric company), and whether systems are installed on "appropriate and beneficial" sites (Rule 5.127).

In Vermont, net metering applications are submitted to the Commission, and the Commission determines whether to grant a Certificate of Public Good, which is required before net metering commences. As part of that review, the Commission checks site plans for compatibility and consistency with state and local land use regulations and aesthetics. The rule also includes provisions for group net metering (Rule 5.130). Rule 5.128 directs the Commission to engage in biennial updates, for the review of REC adjustors, siting adjustors, the statewide blended residential

12 Rocky Mountain Power is the only investor-owned utility operating in the State of Utah.

13 See also Appendix, p. A-11.

14 Previously, Vermont PUC was known as the Vermont Public Service Board. The name was changed, effective July 1, 2017. See https://puc.vermont.gov/news/name-change-public-utility-commission.

rate, and eligibility criteria for four different categories of NEM. The first biennial update is in Docket No. 18-006-INV, where the Commission issued its Order on May 1, 2018. Green Mountain Power submitted net metering tariff revisions on May 15, 2018, in Docket 18-1356-TF. The Commission approved revisions in a June 29, 2018 Order. The definitions for "preferred site" for NEM are being reviewed in Docket No. 17-5202-PET. A July 20, 2018 Commission Memorandum summarizes results from a workshop and sets a schedule for the next steps in the process.

VIRGINIA – The Virginia General Assembly, in 2018 SB 966, initiated many changes to electric utility regulation. Among the many topics addressed in this *Grid Transformation and Security Act* are:

- Exempting electricity storage companies from the definition of "public utility";
- Increasing the capacity of utility-constructed solar and wind generation facilities from 50 to 5,000 MW, including rooftop solar installations of not less than 50kW capacity;
- Authorizing utilities to petition the State Corporation Commission (SCC) for a predeclaration of prudence for a solar or wind project;
- Requiring each electric utility, in its integrated resource plan, to evaluate long-term electric distribution grid planning and proposed electric distribution grid transformation projects and develop a long-term plan for energy efficiency measures to accomplish policy goals of reduction in customer bills, reduction in emissions, and reduction in carbon intensity;
- Directing the SCC to conduct pilot programs for deploying battery storage;
- Requiring electric utilities to investigate potential improvements to NEM programs; and
- Requiring the SCC to submit reports to the legislature after each triennial review proceeding, describing and quantifying the electric utility investments in solar and wind projects and in electric distribution grid transformation projects.

Virginia electric utility, Dominion Energy, hired a consultant to "facilitate a stakeholder engagement process," focusing on four major topics raised in the new Act. The consultant report (Meridian Institute 2018) was submitted to the utility in September 2018. The report focused on four major topics raised in the new *Act*:

- Potential improvements to net metering programs;
- Potential improvements to community solar pilot programs;
- Expanding options for customers with corporate clean energy procurement targets; and,
- Impediments to the siting of new renewable energy projects.

B. Related actions in two additional states

In addition to the nineteen states discussed above, significant actions are also underway in one state that had never adopted NEM, Georgia, and in another, Mississippi, that only recently established an NEM program. Those actions are briefly described here.

GEORGIA[15] – A 2001 Georgia law, O.C.G.A. § 46-3-50, includes basic provisions for cogeneration and distributed generation, including net metering. The Georgia Cogeneration and Distributed Generation Act of 2001 allows, but does not require, net metering. Customers can choose a net metering arrangement or can opt to enter into a buy-all, sell-all relationship. (DSIRE-USA, 2015).

15 See also Appendix, p. A-4.

In August 2016 in Docket No. 20161, the Georgia PSC accepted a settlement agreement for Georgia Power's integrated resource plan. The order accepting that agreement directed Georgia Power to work with PSC Staff and a developer to propose a pilot project for a one megawatt solar installation in the right-of-way of a Georgia Interstate highway, and for Georgia Power and PSC staff to "work collaboratively to finalize a three megawatt community solar project to be brought before the Commission for approval (Order, p. 12). The approved settlement agreement also included provisions for a Renewable Energy Development Initiative (REDI), in which Georgia Power is using competitive solicitations to procure renewable energy, including 150 MW of DG and 1,050 MW of utility-scale resources. The order also approves a renewable cost benefit (RCB) framework to be used in evaluating bids for renewable energy supply.

The Commission has issued several additional orders in this same docket, including:

- December 2016 Order Approving Joint Recommendation Regarding the Renewable Cost Benefit Framework;
- June 2017 Order Approving Georgia Power Company's Community Solar Program and Related Tariff;
- June 2017 Order Approving the Application of the RCB Framework to Behind the Meter Solar Technologies and the Request to Adjust the REDI DG Program Schedule; and
- August 2017 Order Approving Renewable Energy Development Initiative Commercial and Industrial Program.

Georgia Power is filing quarterly status reports in this docket and the Commission has also issued orders regarding specific solar projects. An initial VOS study is complete; Georgia identified nine distributed generation cost components providing a net benefit, six components providing a cost, and two components providing either a cost or a benefit.

MISSISSIPPI – In December 2010, the Mississippi PSC opened Docket 2011-AD-2 to investigate establishing and implementing net metering and interconnection standards for Mississippi. A 2014 Mississippi VOS study concluded that VOS was positive under all but one of the scenarios and sensitivities studied. A net billing law passed in 2015, and the Commission established rules in 2016. The Mississippi program calls for net billing, with compensation based on the utility's wholesale electricity rate, plus an incentive of 2.5¢/kWh to reflect the value of distributed energy. In addition, the rule directs Entergy and Mississippi Power to credit an additional 2¢/kWh to the first 1,000 low-income customers who install NEM solar projects.

The Mississippi PSC had initially required the state's electric cooperatives to provide NEM. However, a new law enacted in 2016, HB 1139 (Miss. Code Ann. § 77-5-235), authorizes the PSC to require cooperatives to adopt NEM programs, but also states that the PSC may not establish the level of compensation or credits for these programs.

In addition, the Mississippi PSC is presently considering an application from Entergy Mississippi, in Docket No. 2018-UA-133, which includes a proposal for the utility to offer a new *Smart Energy Services Program*, in which one of the services the utility could provide to residential customers would be distributed solar PV systems.

III. Inventory of Related State Regulatory Actions

In addition to the specific actions that states have undertaken to update or replace NEM programs, many other related actions have been taken that affect DG. We summarize these actions briefly here.[16] They include:

- Comprehensively reviewing utility rate designs, not only NEM or DG rates;
- Changing fixed charges, minimum bills, or both;
- Adding demand or standby charges;
- Making TOU rates optional or mandatory for new DER customers;
- Establishing a separate customer class;
- Ruling on third-party or utility-owned DG; and,
- Adding community solar provisions.

In some cases, these actions would apply only to NEM customers or customers with distributed generation, whereas in other cases they might apply to all residential and small commercial customers. For example, many utilities have proposed changes to fixed charges for all small customers; some have proposed demand charges only for NEM customers; and of course stand-by charges would apply only to customers using on-site generation. In addition, some utilities have proposed establishing a separate rate class for NEM customers or for all customers with DG. Some of these actions apply only to new NEM customers, with pre-existing customers grandfathered for some time under the NEM program rates that were in effect at the time the customers were initially accepted into the program.

At last count:

- Comprehensive reviews of rate designs for customers both with and without self-service power are underway in 14 states;
- Commission decisions have been made in at least 34 states, affecting about 125 utility companies, changing fixed charges for small customers (mostly increases including a few large increases, but recently a few decreases, too);
- Eleven states have added system-capacity based demand charges, as-used demand charges, flat grid-access fees, or standby charges for customers with distributed generation;
- Six states have taken actions towards treating customers with distributed generation as a separate class for ratemaking purposes;
- Third-party ownership of DG is approved in 34 states, and utility ownership is approved in seven states, with decisions pending in four others; and,
- Twenty states have taken legislative or regulatory actions to enable community solar projects, and many additional states have approved specific utility-run community solar projects.

Table 3 indicates which actions have been taken in recent years on a state-by-state basis. Table 3 does not include additional related actions taken by non-state-regulated utilities. As Table 3 shows, one or more of these actions has been taken in almost every state, and 17 states have undertaken three or more of the six actions.

16 Unless otherwise noted, the information presented in this Inventory comes from the *50 States of Solar* quarterly report series, for calendar years 2015 through 2017 and through the first three quarters of 2018, published by North Carolina State University, Clean Energy Technology Center (NCSU-CETC). The reports can be found at https://nccleantech.ncsu.edu/our-work/policy/the-50-states-reports/. Table 3 does not include related actions taken by non-state regulated utilities, but those actions taken by the country's larger publicly owned and self-regulated utilities are included in the NCSU-CETC reports.

Table 3: States with Recent Laws and Completed Regulatory Proceedings, by Policy Type (years enacted)

State[1]	Comprehensively reviewing utility rate designs	Increasing (decreasing) fixed charges	Adding demand, standby, or grid-access charges	Establishing a separate customer class	Ruling on third-party or utility-owned DG	Adding community solar provisions
Alabama		2016	2013			
Alaska		2017				
Arizona		2015	2016, 17,[2] 18		2015, 16, 17	
Arkansas	2017	2017	2017[3]			
California	2015		2016			2015, 18
Colorado		2015, 16, (18)				2015
Connecticut	2016, 17	(2018)				2015
Delaware		2017				2015
District of Columbia	2017	2016, 17			2018	2016,[4] 17
Florida	2017	2017			2018	
Georgia	2016[5], 17[5]				2015	
Hawaii		2015				2015, 17
Idaho		2015, 16		2017		
Illinois	2017					2016, 17, 18
Indiana		2016				
Iowa				2017		
Kansas		2015	2018	2017		
Kentucky		2015, 17				
Louisiana					2016, 17	
Maine						2015, 17
Maryland						2015
Massachusetts		2016, 17, 18	2016, 18, 18			2015, 17
Michigan[6]		2015, 17				
Minnesota	2018	2015, 17				2013, 15,16, 17
Mississippi[7]						
Missouri	2017, 18	2015, 17			2016	
Montana	2018			**2017**		
Nebraska[8]						
Nevada		2015, 16[2], (17)		2015		
New Hampshire		2017	2017[3]			2015, 17
New Jersey		2016, 17				2018
New Mexico		2015, 16, 18	2016, 17		2015, 16, 17	

[1,2,3,4,5,6,7,8] See Table Notes at the end of the table.

Table 3 (continued): States with Recent Laws and Completed Regulatory Proceedings, by Policy Type (years enacted)

State[1]	Comprehensively reviewing utility rate designs	Increasing (de-creasing) fixed charges	Adding demand, standby, or grid-access charges	Establishing a separate customer class	Ruling on third-party or utility-owned DG	Adding community solar provisions
New York	2014	2015, 16, (18)			2015, 17	2015, 17
North Carolina		2017	2016, 17		2017, 18	2017, 17
North Dakota		2017, 18				
Ohio	2018	2018				
Oklahoma		2015, 17				
Oregon[6]		2015				2015
Pennsylvania	2017	2015, 17				
Rhode Island	2018	2016, 18			2016, 16	2016, 16
South Carolina[8]		2015, 16, 17	2017[2]		2015	
South Dakota		2015, 16				
Tennessee		2016				
Texas		2016, 17		2017	2016	
Utah			2017[3]		2016	
Vermont						2013, 15, 16, 17
Virginia					2017	2017, 18
Washington						2015, 17, 18
West Virginia		2015				
Wisconsin		2015, 16, 17				
Wyoming						

Source: NCSU CETC *50 States of Solar Reports,* 2015 through third quarter 2018. https://nccleantech.ncsu.edu/the-50-states-reports/

[1] Jurisdictions that have restructured electric industries, so that generation service is a competitive business and customers are able to choose their generation service provider from among multiple competitive suppliers, are identified by rows shaded in blue.

[2] This is a voluntary demand rate for new NEM customers, who can decide whether to opt in.

[3] These states enacted new tariffs as successors to NEM programs. Rules vary about the rate treatment for customers that were already participating in pre-existing NEM programs, prior to when the new programs were adopted. The term commonly applied to those situations is called "grandfathering," meaning that the customers with pre-existing NEM relationships with their providers are allowed to continue under that program until some predetermined term, date, or capacity limit is reached.

[4] Actions implemented through legislation are indicated in **bold, dark-red ink**. All other actions are the result of state regulatory commission orders or other state executive branch actions.

[5] The Georgia PSC, in Docket No. 39372 and Docket No. 40161, is reviewing Georgia Power Company rates for utility-scale and distributed renewable energy resources, not all rate designs.

[6] Michigan and Oregon are two states that are mostly vertically integrated, but do have some competitive generation services. In Oregon only large non-residential customers are eligible for what is termed "direct access" service (Oregon Administrative Rules Database – OARD Chapter 860-038: Direct Access Regulation) and Michigan restricts what it calls "Electricity Choice" to not more than 10 percent of each utility's annual sales (MCL 460.10a).

[7] Legislation in 2014 initiated NEM in South Carolina (SC Code Title 58, Chapter 40), as did a Commission Order in Mississippi (in a December 3, 2015 Order in Docket No. 2011-AD-2).

[8] Nebraska has only publicly owned electric distribution utilities, which are not state regulated. The State PSC regulates high-voltage electric transmission lines.

A. Comprehensive reviews of utility rate designs

As shown in Table 3, 11 states have engaged in comprehensive reviews of all utility rates, not just rates for DG. This reflects in part the many different factors affecting utility sales and revenues, the many different state policies toward different DER technologies, and the rapid changes of those technologies, including technical capabilities for DER technologies to produce and deliver utility system benefits.

In several of those states, the comprehensive rate design reviews are just one component of broad grid-modernization proceedings. Rate reviews typically include considerations of potential changes related to time and possibly location-varying rates, and the emergence of multiple cost-effective energy storage technologies. (See NCSU-CETC *50 States of Grid Modernization* quarterly report series, 2017–2018).

Rate design studies have been completed in New Hampshire and Rhode Island. The New Hampshire report considers, among other things, customer charges, demand charges, time-varying rates for both transmission and distribution, locational pricing, and potential roles for advanced metering functionalities. It also includes a list of principles to guide rate design (pp. 13-16). The Rhode Island report is broader in content but more preliminary, characterized as a Phase I report. It includes proposals for studying and developing rate designs for time-varying rates, electric vehicles, and beneficial electrification.

In Missouri, a 2017 Staff Report proposes stakeholder workshops to explore modified rate design proposals (pp. 13-14), and a 2018 Staff Report includes recommendations about "rate design to enhance DER" (p. 3, 50-53).

As part of its PowerForward initiative, Ohio, held a multi-day fact-finding "Phase 3" hearing with a major focus on ratemaking. In its PowerForward Roadmap, the Ohio Commission notes its desire to implement performance-based ratemaking and its intention to evaluate and address the utility "throughput incentive." The Commission also notes that distribution utilities should propose time-of-use rates for standard service offer customers (Roadmap, pp. 26-30, 35).

A Pennsylvania Utility Commission May 2018 Order in Docket No. M-2015-2518883 includes a policy statement with a list of considerations the Commission intends to employ when considering rate proposals, and describes examples of the kinds of rates electric distribution companies "may propose," including: critical-peak pricing or other demand-based rates; a critical peak volumetric price or average demand component for some distribution costs, and volumetric on-peak and off-peak rate recovery for other distribution costs; and other optional rate designs, possibly including locational pricing.

Stakeholder processes addressing rate reforms are also underway in Minnesota (Docket No. 15-662) and Montana. Dockets that include a specific focus on rate design are also ongoing in New Mexico, New York, and West Virginia (NCSU-CETC 2018d, pp. 32-34, 38).

B. Increasing fixed charges

Going back to 2014, over 125 utility companies have requested fixed charge increases, and by mid-2018 state commissions had acted on almost exactly 100 of those requests. Utilities requested fixed charge increases ranging from as little as roughly a dollar or two per month (in 25 cases), three to six dollars per month (in 40 cases), more than six to ten dollars per month (in 25 cases), and more than 10 dollars per month (in 10 cases). Regarding the cases decided by mid-2018:

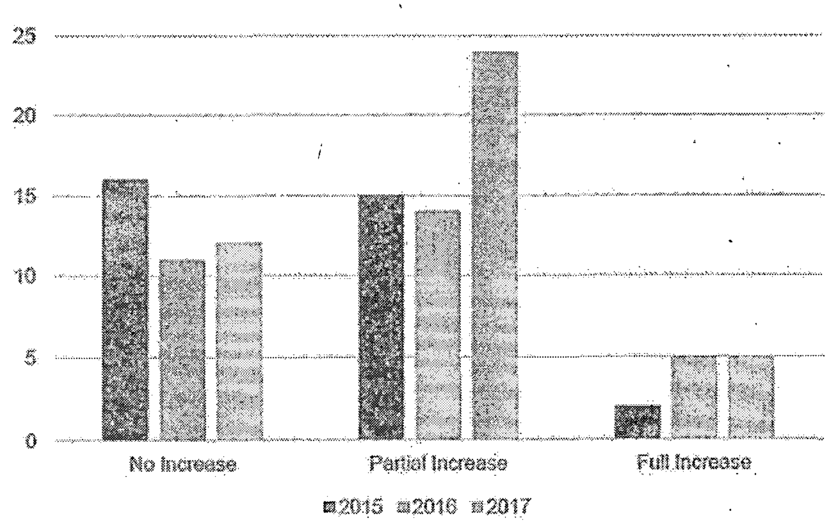
- Regulators rejected just over two dozen of the requests and utilities withdrew two others;
- Of the requests rejected, six resulted from partial or full settlement agreements;
- In a bit more than half of all the requests, the regulators approved a partial increase in the fixed charge, less than what the utility had requested;

- Of the partial increases approved, the previous fixed charge increased by: less than $1 per month for 15 decisions; another 15 ranged from $1 to less than $2; 16 ranged from $2 to $3.50; and only four raised the previous fixed charges by $5 or more per month; and,
- In about a dozen cases, the utility's requested increase was approved in full.

Figure 3 presents a summary of commission decisions on fixed charges for calendar years 2015, 2016, and 2017. Although this small sample of 100 decisions might not indicate any particular trends, the changes could reflect a growing willingness on the part of state commissions to grant at least partial increases. The trend could also be related to utilities tempering their requests based on perceptions of what they believe their state commission might accept. A new development, in 2018, has been state commissions deciding to reduce fixed charges, as happened in Colorado, Connecticut, and New York, in each case reducing the level of distribution costs included in the fixed charges.[17] Fixed charges are limited to specific components of customer-related costs, by statute in Connecticut (12 CA 499, Chapter 283§16-243bb) and California (AB 327 of 2013) and by a state administrative rule in Iowa (IAC 199–20.10(2)).

Looking at the cases decided from 2014 through 2017, where utilities had requested increases in fixed charges, there were nine states where four or more cases were decided. Pennsylvania had ten such decisions, Wisconsin had seven, and New York and Missouri had six each. Five such cases were decided in New Mexico and five in Kentucky, plus four each in Indiana, Michigan, and Texas. Together, these nine states represent 53 decisions in the past four years, just a little more than half of the total cases decided in all states. Just over 30 decisions were in vertically integrated states and the other 20 in the restructured states of New York, Pennsylvania, and Texas. Although the total number of cases decided is too small to support any definitive statistical analysis, a few patterns do appear. For example, six of those nine states have vertically integrated utility structures. Two of those cases were dismissed and one was withdrawn. Of the others, partial increases were approved in fifteen of the cases, the full increases requested by the utilities in six cases, and no increase was approved in the other eight cases. Where increases were granted, the new fixed charges range from a low of slightly less than $12 per month to a high of $21 per month.

Figure 3: Results of IOU Residential Fixed Charge Decisions, 2015–2017



Note: This chart excludes decisions made by state utility regulators to increase residential fixed charges. These decisions are included in Figure 12.

Source: NCSU-CETC *50 States of Solar: 2017* Policy Review and Q4 2017 Quarterly Report, January 2018, p. 33.

17 All of the data reported here, unless otherwise cited, were collected by NCSU CETC for the *50 States of Solar* report series, 2015-2018.

The review of these early decisions reflects what can be thought of as a kind of Goldilocks question, where utilities apply for monthly fixed-charge increases and state regulators ultimately decide what is too big, too small, or just right.

One important aspect of those decisions is how much the proposals deviate from existing rates. Whited et al. (2017, p. 24) report on fixed charges for customers in 43 major U.S. cities. That review, based on 2016 data, shows that fixed charges ranged from a low of $4 per month in Cleveland to a high of nearly $20 per month in Sacramento: Eight of the cities had fixed charges of $6 or less per month; 21 cities had charges more than $6 and up to $10 per month; five more cities had charges greater than $10 and up to $15 per month; and five others had charges more than $15 per month. As these authors point out, adding two dollars a month in Cleveland would mean a 50 percent increase, but adding the same dollar amount in Sacramento would represent only a 10 percent increase. None of the requested increases in fixed charges were approved in New York; one case was settled and five others were decided by Commission order. In Pennsylvania, partial increases were approved in nine out of ten commission orders, and the tenth case was settled with no increase. The maximum monthly increases approved in Pennsylvania were all less than $2.25. In Texas, one case was dismissed with no increase to the fixed charge, two others in 2015 and 2016 were decided, each with a monthly increase of $1.90, and then in 2017 one of the same utilities requested an additional $1 per month increase and the Commission approved an increase of $0.50 per month.

A second type of fixed charge might apply only to customers with DG or even more narrowly only to customers with PV generators. Those are commonly called "grid access charges," and they can be set on a per-kW basis, similar to a demand charge but in this case a fixed charge that is added to the monthly bills of only particular customer-generators. The per-kW charges can be set based on the installed capacity of the DG system, or can be determined by measuring demand to determine a maximum flow of power in either direction, inflow or outflow.

C. Adding demand or standby charges to small-customer rates

Decisions about demand or standby charges have been reached in 15 states: Arizona; California; District of Columbia; Kansas; Montana; Nevada; New Hampshire; New Mexico; North Carolina; Oklahoma; South Carolina; South Dakota; Tennessee; Texas; and Utah. The most common type is a demand charge based on the nameplate capacity of installed DG, usually called a grid-access fee.

The Kansas Commission approved Westar Energy's proposed mandatory residential demand charge for distributed generation customers in late September 2018. That decision follows a 2017 Commission order finding that additional fees for customer-generators are acceptable. The approved charge will be determined by a customer's peak demand during system peak hours, and will vary seasonally.

In Massachusetts, the Commission approved a demand charge in early 2018, but that decision was later overturned by newly passed state legislation. The new law does not disallow demand charges, though; it only establishes new requirements for their design.

The New Mexico Public Regulatory Commission ended a standby charge for Xcel Energy customers, but the Commission has also indicated it plans to open a rulemaking to address standby charges.

D. Community solar provisions

At least 19 states and the District of Columbia have taken either legislative or regulatory commission actions to establish community-based solar programs, and all but three of those 20 jurisdictions already have working projects. In addition to those jurisdictions, one or more individual utilities in 23 more states have already developed their own community solar programs or projects, and have sought and received approval from their regulators. **Figure 4** shows the timeline of state actions establishing community solar.

Many of these programs are treated as what is called "virtual" or "remote" net metering, with bill credits accruing monthly for each participating customer according to each customer's share of the total output of a community solar project, with virtual net metering rules approved by the state Commission.

Part of the impetus for community solar programs is extending solar access opportunities to customers who would not otherwise be able to install their own systems. For example, renters and residents of multi-family buildings might not be able to install solar PV systems on their properties. Many states are also working on techniques for including low- and middle-income customers in community solar programs (Stanton and Kline, 2016).

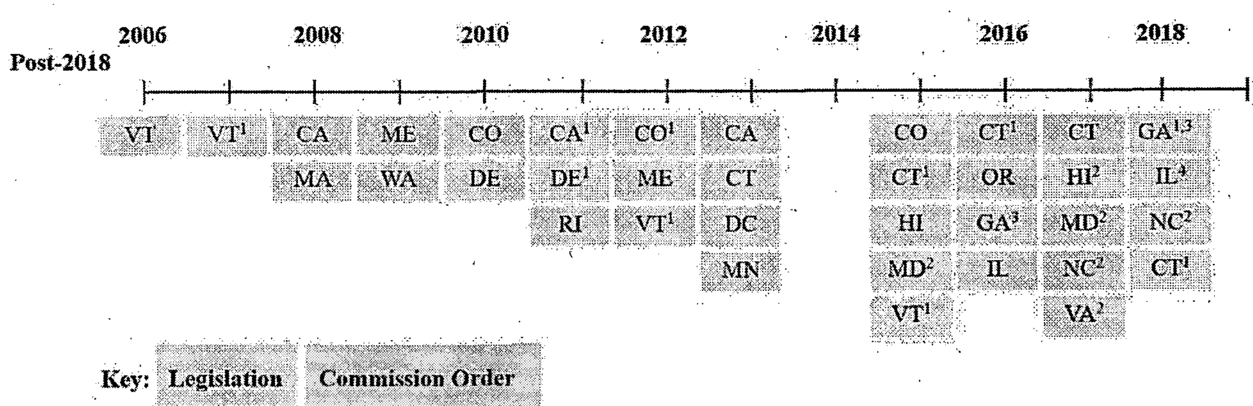
SIDEBAR 2: WHAT'S THE DIFFERENCE BETWEEN A "SALE" AND AN "EXCHANGE" OF ENERGY?

The Internal Revenue Service, by individual letter rulings, has acknowledged that when customer benefits constitute a simple exchange of energy like individual net metering, with the bill credits subject to annual caps closely related to the customer's annual energy usage, the benefits do not have to be included in calculating gross income.

Depending on the design details of NEM replacement and community solar programs, it is possible that payments from a utility for purchasing energy could be construed as income for the participating customer, subject to taxation as income, as opposed to an exchange of energy that is not taxed.

With several states considering a move to buy-all, sell-all rates for at least some self-generators, it will be important to know what specific rate design details might cause federal or state tax authorities to treat the revenues as a sale to the utility, subject to taxation as income.

Figure 4: Timeline of States Adopting Community Solar Programs



Notes: [1] Indicates additional state legislative or regulatory actions, subsequent to the enabling laws or rules.
[2] Indicates a pilot program.
[3] Indicates a decision affecting only one utility company.
[4] Indicates pending regulatory decisions.

Source: Authors' construct based on Stanton and Kline 2016.

E. Creating a separate rate class for customers using DG

Actions taken in several states could create a separate rate class for customers with DG. As shown in Table 3, that topic is being addressed in states in the Midwest (Iowa and Kansas), Northwest (Idaho, Montana, Oregon, and Washington), and Southwest (Nevada). In Montana, the legislature authorizes regulators to approve a separate rate class for DG customers, but the Commission has not yet determined whether to establish a separate class. In Kansas, an approved stipulated agreement in a Westar rate case allows for a separate DG class.

In some other states where legislators or regulators have not yet considered any statewide action on this issue, at least one utility company has sought regulatory approval for creating a separate rate class for DG customers. Such requests received commission approvals in Idaho and Texas, but commissions denied similar proposals in Colorado, Iowa and New Mexico. A court ruling also denied a utility request in Wisconsin (NCSU-CETC 2016-2018).

The effect of establishing a separate rate class for DG customers varies substantially, depending on the cost allocation methodology a state employs. Many states use the Basic Customer method to determine customer-related costs, including in fixed charges only costs quite directly associated with metering, billing, and collection.[18] Other states use a minimum-system or zero-intercept method, which assigns a share of distribution-circuit and transformer costs on a per-customer basis; that method will have a more significant impact on DG customers.

F. Third-party ownership rules for DG resources

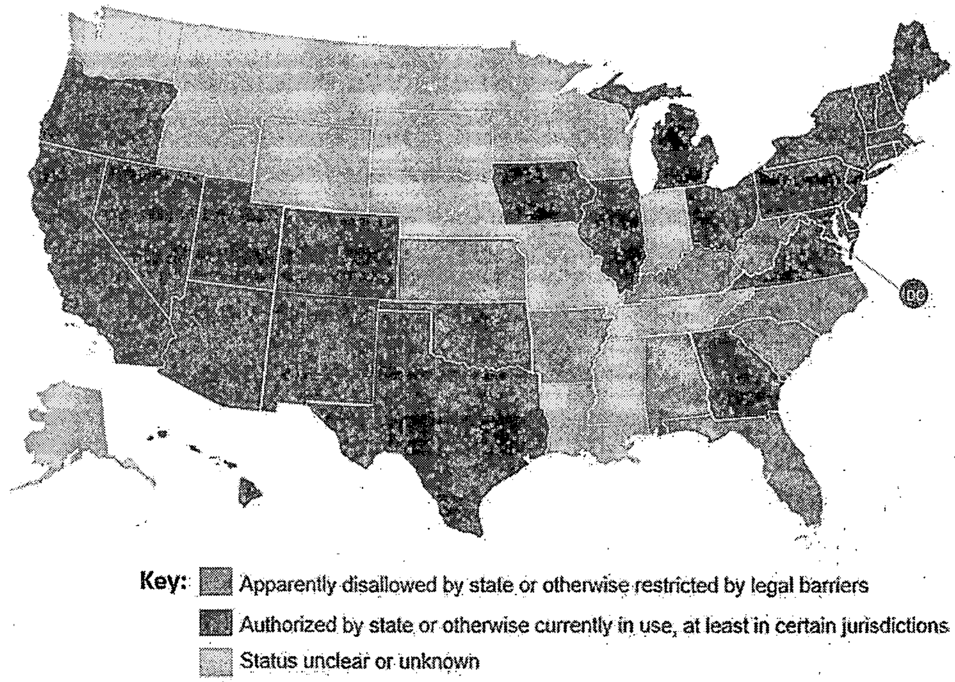
Since 2015, eight states have taken actions on whether third parties shall be eligible to own and operate DG resources installed behind the meter in customer facilities. They include Arizona, Georgia, Louisiana, Missouri, New Mexico, North Carolina, Oklahoma, and Texas. As shown in **Figure 5**, third-party ownership of customer-sited DG is presently allowed in at least 27 states and the District of Columbia, but in 15 states the status of third-party ownership for providing self-service power is still unclear. At last count, eight states had laws or rules in place that prohibit third-party ownership (NCSU-CETC 2018e).

The barrier preventing third party ownership is typically found in state laws that declare that regulated utility companies are the only entities that can sell electricity to end-use customers. Third parties can produce electricity as a merchant function, and can then sell the electricity into a wholesale market or directly to a utility company under a PPA, but the laws and rules for producing and delivering wholesale power are different from those affecting retail sales. In some jurisdictions, it could be legal for a third party to sell or lease a solar-PV system to a retail consumer, while it is not legal for the third party to enter into a contract for the sale of electricity to the same customer through a PPA. This might appear to be a subtle distinction, but there are important ramifications for accounting and tax treatment that make both solar developers and particular customers prefer one approach instead of another (Bolinger and Holt 2015; Burger and Luke 2017).

18 For example, the Washington Commission recently ruled:

> We determine that neither [the utility's] proposal to increase basic charges for residential customers, nor Staff's recommendations to add a minimum bill to basic charges and establishing seasonal rates, should be adopted. We are not persuaded on the basis of the current record that transformer costs should be recovered in basic charges, or through a minimum bill. We have never approved such a proposal and continue to believe these costs are not customer-related costs as that term is generally understood. Transformer costs should be recovered as distribution charges subject to [the Company's] electric decoupling mechanism, which adequately protects the Company's recovery of its fixed costs. (Dockets UE-170033 and UG-170034, at Paragraph 355)

Figure 5: Map of State Status on Third-Party Ownership of Self-Service Generation



Source: NCSU-CETC, 2018e, *The 50 States of Solar: Q3 2018 Update.*

SIDEBAR 3:
SHOULD SCHOOLS BE A SEPARATE RATE CLASS?

A decision by the California PUC directs San Diego Gas & Electric Company to develop a "schools-only rate . . . considering schools as a rate class" separate from other commercial and industrial customers, including "appropriate rate design for net energy metering and non-net-energy metering members of this class" (Decision 17-08-030, ¶ 36 on p. 93).

The reasoning is that school facilities typically have non-coincident peaks, and large portions of school electrical usage are generally "off-hour" and "off-season."

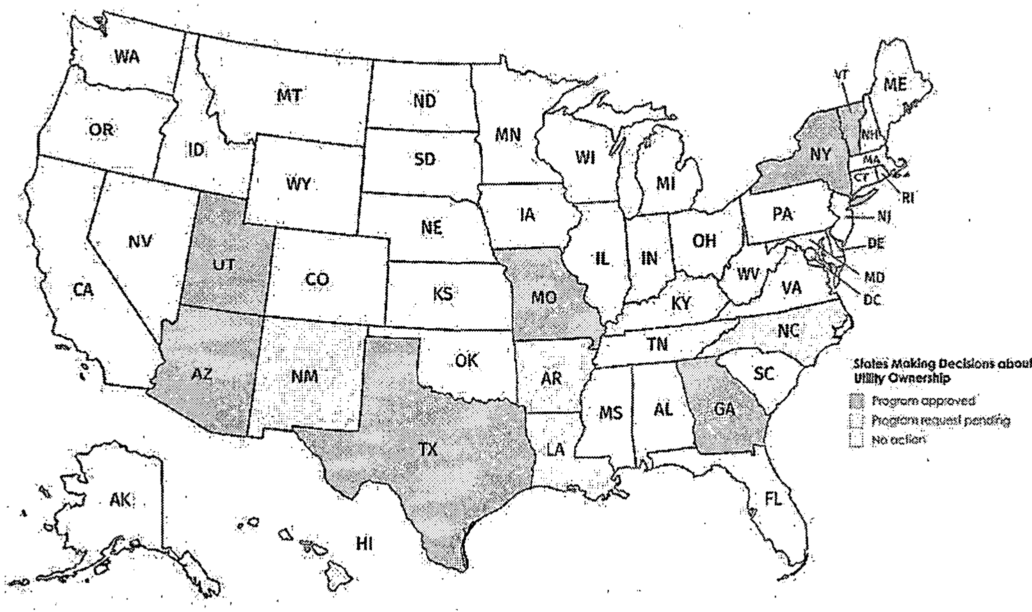
Commissions in several states are grappling with the question whether DG customers have usage patterns that are so different from other customers that it could be appropriate to consider them as a separate rate class. In a similar vein, though, there could be many other subsets of customers with usage patterns that diverge far from broad class averages. So, a relevant question is how different must usage patterns be, in order to warrant separation of rate classes.

G. Utility-led programs for customer-sited DG

In a utility-led rooftop solar program, a utility typically pays the upfront cost of a solar installation located at a customer site and compensates customers for hosting the system through a special DG rate, a flat monthly payment, or through another type of incentive. **Figure 6** shows, highlighted in green, the states that took action on rooftop solar programs led by regulated utility companies, in 2015 through 2018. States that are highlighted in yellow are currently considering proposals for utility-led programs.

Among the states highlighted, only New York and Texas have restructured electric utility industries. In Georgia, the program offer is through an unregulated utility-affiliate. In almost every instance, state commissions are treating these as pilot programs, which are limited in scope (e.g., in terms of numbers of participating customers, utility costs eligible for rate recovery, or both), and subject to monitoring and evaluation to determine costs and benefits, and the extent to which benefits accrue to non-participating customers (NCSU-CETC 2016-2018).

Figure 6: Map of States Authorizing Utility-Led Rooftop Solar Programs, 2014-2018



Source: NCSU-CETC, *50 States of Solar* report series, 2015-2018.

SIDEBAR 4:
WHAT'S THE DIFFERENCE BETWEEN A "SALE" OR "LEASE" OF AN ELECTRICITY GENERATING SYSTEM

Laws in some states differentiate between a sale or lease of an electricity generating system itself: Some state laws state that only a regulated utility can sell electricity, so it could be legal for a customer to purchase what is essentially an appliance that generates electricity, but not legal for the same customer to enter into a PPA to purchase electricity. Figure 5, on page 37, shows the current status of this issue in the states.

In May 2018, the Florida PSC approved a request for declaratory ruling, which allows one solar installer to employ a "residential solar equipment lease" without that constituting a "sale of electricity," nor deeming the solar company as a "public utility" under Florida law. The North Carolina Utilities Commission adopted leasing rules in January 2018 in Docket No. E-100 Sub 156, pursuant to a new law (HB 589, G.S. 62-126.7) that passed in 2017. In Wisconsin, the PSC declined to open Docket No. 9300-DR-102 in a December 2017 Order stating "the petition for declaratory ruling raises significant public policy considerations that are best left for the Legislature's determination rather than for the Commission's . . . ." (Order, p. 11).

IV. Conclusions

The issues reviewed in this paper are dynamic and challenging. As outlined here and in the series of quarterly reports from the North Carolina State University Clean Energy Technology Center (2015-2018), the interested parties in nearly all states, including state regulatory commissions and staff, are devoting much time and attention to decisions about updating NEM rates or developing NEM successor tariffs. As one observer explains, "In the search for the right successor tariff, stakeholders face the challenge of balancing uncertain costs and benefits with the right mix of detail and flexibility in a new kind of rate" (Trabish 2018).

Many parties have characterized the current situation as a war-like conflict that is inherently a zero-sum game. It has been described as "reflecting a combative 'all or nothing' approach"—in zero-sum, win-lose terms, as if utilities are on one side and DG proponents on another, waging "battles" or engaged in a "showdown" over what could be an "existential threat" to utilities (Hess 2016; Leslie 2017; Smith and MacGill 2016, pp. 354-355; Stanton 2015, pp. 4-5, 9-11). Observers might think of this as what policy makers call a "wicked" problem, which is one characterized by diverse viewpoints reflecting conflicting value frameworks, and fundamental disagreements about both ends and means, which make the problem "inherently resistant to a clear definition and an agreed solution" (Head and Alford 2013, pp. 712-714).

Much uncertainty remains about both means and ends: There is little consistency among states about exactly what policy changes to make to update or replace traditional NEM programs. In fact, it is safe to say that each of the major topics reviewed in this report deserves its own future study:

- How do NEM rate changes affect the rate of adoption of DG or even broader DER technologies? Are the markets for DG and DER still in the earliest stages of consumer adoption, or are some technologies already starting to emerge into uninhibited market growth?
- How big are the potential markets for community solar? What kind of offerings work best for low- and middle-income participants?
- In states that create a separate rate class for DG customers, what can we learn about the class usage patterns? How similar are they to non-DG customers? How do the class usage patterns affect utility costs of service?
- Are studies of VOS, VDER, and utility costs of service measuring the right benefits and costs? Are they measuring all of them? And are the measuring methods valid and reliable?
- Are there marked differences in DG markets between jurisdictions allowing versus prohibiting third-party ownership? If yes, what are those differences?
- In jurisdictions with utility-led programs, utility ownership, or both, what happens to market growth rates? And, what happens to competition?
- If the policy approaches are different in vertically integrated and restructured states, how are they different?

In any case, all interested parties can observe what happens over time to NEM and DG markets and utility financial stability in each state that implements these kinds of changes, and hopefully all can start discerning what works best under what circumstances. As one observer points out, the situation is likely to get even more complicated, and quickly, as more and more DER technologies come into play (Peskoe 2016). Already service providers are offering multiple DER options, including demand-response, on-site thermal and electrical storage, energy management systems with load management capabilities, electric vehicles with vehicle-to-grid capabilities, and more. Peskoe observes:

> PV is not the only decentralized technology or service that has disruptive potential— a combination of several complementary technologies and services is more likely to transform the electricity industry than a single technology... (Peskoe 2016, pp. 102-103).

Leslie explains that solar PV is perhaps "the vanguard of DERs," that could, in combination with other DER, upend the traditional electric utility business model and further says,

> DERs . . . include not just rooftop solar, but wind power, batteries, electric vehicles, smart meters, smart water heaters, smart thermostats, on and on. They promise not just emission-free, fuel-less electricity, but far greater energy efficiency, thus reducing consumer costs and environmental damage. Their expanding use increasingly will determine how the grid functions (Leslie 2017).

Similarly, Smith and MacGill note that the electric utility industry could already be on a technological and economic trajectory in which DER combines in new ways to serve consumer wants and needs. They foresee the possibility of "Schumpeter's 'creative destruction' view of innovation meeting Schumacher's 'small is beautiful' and 'appropriate technology' philosophy," such that increasing numbers of consumers could start to view electricity from the traditional grid as an "inferior good," at least for certain purposes (Smith and MacGill 2016, pp. 349, 354).

In this context, it could be helpful for policy makers and interested parties alike to think of the present challenges surrounding NEM 2.0 and successor tariffs as just one piece in a much larger puzzle. Additional pieces are already becoming visible, through many states' interests in what is generally becoming known as grid modernization, including comprehensive rate reforms, as well as through changes to utility business models, major updates to integrated resource planning and distribution system planning to incorporate DER, advancing non-wire alternatives, enabling microgrids, and more. In the not-too-distant future, attention could shift from what are just and reasonable tariff arrangements for individual customers with on-site generation, to how DER ensembles can produce multiple benefits for multiple customers, the utility system as a whole, and society at large. A question worth exploring, sooner rather than later, is: What kinds of policy changes might be needed to enable that technological evolution, and how do the policy changes for individual customers relate to and combine with the similar kinds of policies designed to affect groups of customers?

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Appendix

Summaries of Recent State Actions on Net Energy Metering Policies in Five Vertically Integrated and Five Restructured States

by

Co-Authors

Jamie Barber, Energy Efficiency and Renewable Energy Manager, Georgia PSC and Chair of NARUC Staff Subcommittee on Rate Design

and

Tom Stanton, Principal Researcher, Energy and Environment National Regulatory Research Institute

The Appendix is available for download from http://nrri.org/download/appendix-nem-policies.

nrri

PSC Case Number 2019-00256

Laura J. Cole
1511 Thames Drive
Lexington, KY 40517

Net metered customer's credit for solar energy should be valued at the same rate the utility charges for electric power.

We need renewable energy use to grow quickly over the next decade. This includes solar energy generated by the utilities and energy generated by customers.

Please don't let Kentucky be left out of the growth in good solar energy jobs. We need to move forward and be a leader at this pivotal time for human civilization.

Laura J Cole
November 13, 2019

Public Service Commission
211 Sower Boulevard, Post Office Box 615
Frankfort, KY 40602
RE: Comments on PSC Case Number 2019-00256 November 13, 2019

Thank you for listening today to comments from members of the public related to the implementation of SB 100 (case number 2019-00256). I previously submitted written comments in October; the comments below are a supplement to my earlier comments.

The PSC's tasks and responsibilities are profound. Electric utilities provide an essential public service that no one can live without. Also, our utilities are monopolies, not controlled by competitive market forces. Thus the PSC must regulate our utilities to ensure that the public interest is served and must stand in for market forces. The decisions on compensation for self-generated energy fed to the grid will impact how well our energy system serves the public interest and reflects a competitive market system.

Along with others today, I urge the PSC to collect comprehensive Kentucky-based data on the benefits, as well as costs, of net-metered solar energy. There are numerous short and long term benefits (1). For example, solar panels generate energy during times of peak system demand, on summer afternoons when demand is high. This reduces the need to operate expensive peaker plants, and reduces line loss and wear and tear on grid infrastructure during pre-peak and peak periods. Solar generation also reduces the need to build new infrastructure to meet peak demand. Thus distributed solar reduces system and customer costs.

Beyond such direct system benefits of rooftop solar, I want to argue that larger public benefits such as the reduction in environmental and health costs should be considered in PSC analyses. Cost-benefit analyses in other states have quantified the avoided costs of carbon and other avoided environmental costs that come with net-metered roof-top solar (ibid). (And they have quantified these separately from environmental compliance costs). In its own analysis, the PSC should likewise quantify and use these avoided costs.

Some have argued that the environment and health are outside the scope of the PSC, and that rates are an unsuitable place to address societal costs. Given that the PSC is responsible for protecting the public interest and safety as these relate to the energy system, this is not justified. Externalities are costs that must be borne by someone. While some externalities may have been reasonably neglected in the past, they can now no longer be ignored. Scientific consensus shows that climate change and the dangers of fossil fuel use are such externalities. Over 90% of climate scientists now agree that human-caused global warming is happening, with fossil fuel use being a primary driver (2). Most significantly, climate change and environmental degradation do not simply sit along side other public concerns. Rather they are deeply intertwined with our heath, our economy, our lifestyle, our national security, and the welfare of our children and grandchildren. For example, fossil fuel pollutants directly endanger our health, their effect on climate change further endangers our health, and high temperatures further enhance the negative effects of pollutants (3). A fuel source that endangers our health and generates climate change represents an energy system threat to safety and the public welfare.

With this in mind, the PSC should set rates that encourage rather than discourage efficient use of fossil fuels, and that encourage alternative energy sources. Currently, Kentucky ranks 38th among states for energy efficiency policies, and also ranks poorly in state support for solar. For example, Kentucky allows no virtual net metering, no 3rd party ownership, and has no renewable portfolio standard. Our existing net metering policy is the one positive step Kentucky has taken, and the compensation in this policy should be maintained. Kentucky needs rate structures that promote energy efficiency and distributed energy generation (4).

Economic development is an externality that has been considered in past PSC rate decisions. We must recognize that climate, health, and the environment are deeply intertwined with the economy and economic development. For example, improving the health of our workforce can raise profit margins through reduced absenteeism and insurance costs. And state renewable policies can affect company decisions to locate in Kentucky. Businesses are increasingly responding to citizens', employees' and investors' concerns about climate change and a healthy environment. Businesses not only want renewable energy for their operations, but also, they may seek locations with strong solar policies in order to attract employees who value clean air and water for their families (5).

Kentucky's distributed solar, still in its infancy, has the potential to be one of our key alternatives to fossil fuels. At stake with SB100 is the contraction or the expansion of this protection of our health, safety, environment, and economy.

Also at stake are equitable access to the economic benefits of rooftop solar, and consumer choice. Existing Kentucky evidence, even without considering the benefits of solar, shows miniscule cost shifting to non-solar customers (6). Thus, a substantial reduction in compensation for energy fed into the grid would unfairly penalize people who choose solar energy, and prevent lower income customers from access to this resource.

Finally, as stated earlier, since our utilities are monopolies, the PSC must stand in for absent market forces. The advent of self-generation offers the potential for some free market choice in Kentucky. The PSC should protect that choice. If rooftop solar becomes out of reach due to pressure from utilities, and if solar businesses do not survive, then the choice for distributed solar disappears. Polling evidence shows that Kentuckians, like other Americans, are deeply concerned about climate change and pollution and support pro-solar policies (7). For example, 59% of Kentuckians believe global warming will harm future generations, 67% support regulating fossil fuel as a pollutant, and a large percent support pro-solar policies such as tax rebates for solar panels (79%) and funding for research into renewables (79%). This suggests that greenhouse gas avoidance has market value, and that in a competitive free market many customers would choose safe, clean energy. We need the PSC to make sure that monopoly utilities do not abuse their power. Rates should not be used as an anti-competitive tool.

Sincerely,

Cathryn Clement

Catherine Clement
212 Preston Ave.,
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[redacted]

Endnotes

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www.climatecommunication.yale.edu/visualizations-data/ycom-us/ (see Kentucky data)