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Utility Sector Impacts of Reduced Electricity Demand: Updates to Methodology and Results

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Abstract

This report presents revisions to the methodology for estimating the utility sector impacts associated with electricity demand reductions, first published in our 2014 study [1]. The earlier report described how to calculate utility impact factors based on data from the Energy Information Agency's Annual Energy Outlook (AEO) projections of electricity supply and demand [8]. The 2014 methodology relied on data from the AEO Reference case, and side cases implementing demand-side policies with a substantial impact on total demand. Beginning in 2015, the AEO publication schedule was revised to limit the number of side cases published with each AEO, and no suitable demand-focused side cases have been released since 2014. Hence, this paper presents a generalization of the methodology that allows a uniform approach irrespective of the nature of the side cases published with the AEO.

The impact factors we calculate represent coefficients of variation between a unit reduction to site electricity demand and corresponding supply-side changes, including reductions to electric power generation and primary fuel consumption by fuel type, emissions of criteria pollutants (Hg, NO_x and SO_2) and greenhouse gases (CO_2, N_2O and CH_4), and total installed capacity by plant type. The impact factors are time-dependent, and also depend on the demand sector and end use. In this report, we apply the methodology to all AEO publications from 2014-2019, and all scenarios. We quantify the variation in factors across different side cases within each AEO, and across different AEO publications, and compare this to the variation due to changes in methodology.

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1 Introduction

Energy conservation and efficiency policies that reduce demand for electricity, relative to a no-policy scenario, will also have broader impacts on the electric utility industry. A reduction to electricity demand will lower total electricity generation, which in turn leads to reductions in the combustion of fossil fuels, emission of greenhouse gases (CO_2, CH_4 and N_2O), and emission of criteria pollutants (NO_x, SO_2 and Hg). Given that decisions about future investment in the electric grid are influenced by projections of demand growth, any change to projected demand will also lead to changes to the build-out of installed electric capacity, affecting both the total magnitude and the mix of generation types. These changes to electric system capacity, generation and emissions contribute to the overall societal costs and benefits of a policy, and are included in the policy impact analyses conducted for the U.S. Department of Energy (DOE) Appliance and Equipment Standards Program [3]. The DOE program has published energy conservation standards for dozens of equipment types over the last two decades, with aggregate program impacts estimated at several quads of primary energy per year [15].

The goal of this paper is to present a means of estimating the impacts of demand-side energy policy on the utility sector that is straightforward to implement, and that is consistent with the projections of electric utility sector characteristics produced by the DOE's Annual Energy Outlook (AEO) [8]. The AEO provides projections of energy market variables calculated with the National Energy Modeling System (NEMS) [4]. NEMS is a computational model of the coupled energy-economic system for the United States, which uses an econometric approach to project energy supply, demand, prices and other economic and demographic variables. Each edition of the AEO includes a Reference case that incorporates baseline assumptions about economic growth, the availability of fossil resources, technological development, and implementation of federal and state policies that are finalized at the time of publication. To analyze the effect of alternative assumptions, including policies under consideration but not yet implemented, the AEO also publishes a series of side cases. Each side case provides the same set of output variables as the Reference case, and so can be used to quantify the relative impact of the modeled policies or economic variations.

In previous work ([1], referred to here as the 2014 study), we developed a methodology to estimate the electric utility sector impacts of demand reduction, and summarized these in the form of time series of impact factors. An impact factor is defined as the net change to some electric system variable given a unit change in site electricity demand; hence, utility sector impacts can be estimated simply by multiplying the impact factor time series with a time series of expected site energy savings.[1] As will be reviewed in this paper, impact factors can be defined for a variety of sectors and end-uses, and include generation changes by fuel type, capacity changes by fuel and technology type, and emissions changes by pollutant type [1]. The approach estimates marginal changes to electric system quantities. A mathematical definition of marginal change is provided in the next section; intuitively, for a quantity q that depends on some variable x, a marginal change represent the incremental change to q given a small change in x.

For the electric system, we can distinguish between the dispatch margin and the construction margin. The dispatch margin refers to the fact that, given a small change in demand, there will be a corresponding small change in the dispatch of existing generation; this is the expected system response over short time-scales. The construction margin refers

[1] Site energy use or energy savings refers to values calculated at the point of use.

Name	Short Name	Description
High Economic Growth	High Growth	Higher growth rates for population and productivity
Low Economic Growth	Low Growth	Lower growth rates for population and productivity
High Oil Price	High Price	Assumes conditions under which global liquids demand is high and supply is low
Low Oil Price	Low Price	Assumes conditions under which global liquids demand is low and supply is high
High Oil and Gas Resource and Technology	High Resource	Recovery of unconventional oil and gas, and rate of technological improvement, are assumed to be 50% higher than in the Reference case
Low Oil and Gas Resource and Technology	Low Resource	Recovery of unconventional oil and gas, and rate of technological improvement, are assumed to be 50% lower than in the Reference case

Table 1: Name and brief description of the AEO side cases used in this analysis [8].

to the fact that, under a small change in demand that persists over a long period of time, there will be a corresponding small change in the way that new capacity is added to the system. As NEMS models both dispatch and construction, it includes both effects.

Within NEMS, the calculation proceeds in each annual time step by first building up the demand-side, in the form of a load duration curve, and then calculating the corresponding supply-side dispatch and potential new generation needed to meet demand [6]. Hence, the flow of information is from the demand-side to the supply-side. The approach developed in the 2014 study took advantage of the fact that the package of side cases published with AEO2014 included several with an exclusive focus on demand-side policies. These side cases were used to analyze the pattern of decrements to demand, relative to the AEO Reference case, and relate these to the pattern of decrements to supply side quantities. Specifically:

- Decrements to demand, organized into on-peak, shoulder and off-peak demand, are related directly to decrements to generation by fuel type;
- Decrements to generation by fuel type are related to decrements to fuel consumption;
- Decrements to fuel consumption are related to decrements to emissions;
- Decrements to generation by fuel type are related to decrements to installed capacity by technology type.

In 2015, EIA revised the AEO publication schedule so that a reduced set of side cases are published each year (listed in Table 1), with the larger set of policy side cases only released every other year. Since that time, the type of demand-side policy scenarios used in the 2014 study have not been available, necessitating some changes to the methodology. This paper presents the modified methodology, which can be used with whatever side cases are published in a given year. The principal difference from the 2014 study is in the way demand is related to generation fuel type, *i.e.*the first item in the list above. In the modified approach this step uses grid-average data rather than marginal data, because the side cases listed in Table 1 do not generally result in significant changes to demand. As marginal relationships between supply-side quantities can be calculated using any side case in which generation differs from the Reference case, the other steps in the calculation are similar to the 2014 study.

While there is some change in the calculated factors due to a change in methodology, it is also important to note that the impact factors vary from one AEO edition to the next due to changing assumptions about the future development of the electric grid. This is illustrated in Figures 1 and 2, which summarize the Reference case projections of generation by fuel type, and pollutant emissions, for the AEO editions 2014 to 2019. Both figures show time series data, with quantities presented as averages over five-year periods. The data are plotted starting with the period 2021-2025; for AEO 2014 to 2016 the projection period ends with the period 2036-2040, while for the later editions it ends with the period 2046-2050. Figure 1 shows that, beginning in AEO2016, there is a significant shift out of coal generation into natural gas and renewable sources. Although the time pattern varies, this shift persists through AEO2019; the magnitude of generation from renewable sources also increases over time and with each AEO.[2] These patterns have an obvious impact on the emissions that are plotted in Figure 2. Emissions of Hg are directly proportional to coal consumption; emissions of NO_x and SO_2 are dependent on fuel quality and combustion technology and show a less dramatic decrease with time.

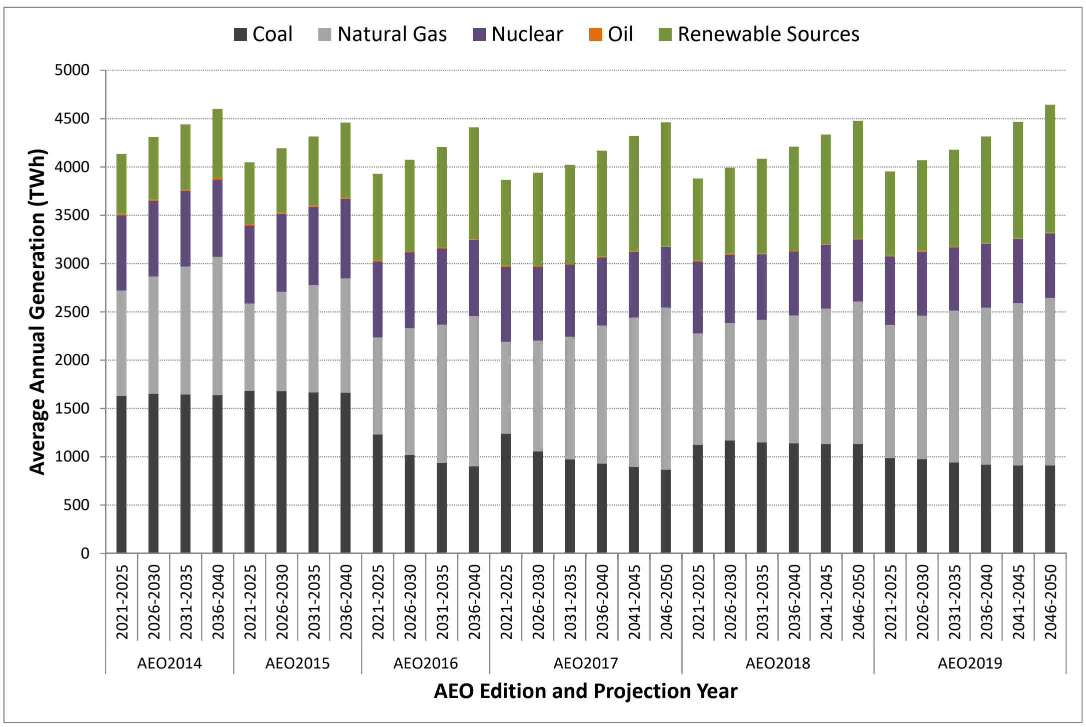

Figure 1: Average annual generation by fuel type, for the Reference case in each AEO edition. The data are shown averaged over five-year periods. For AEO2014-2016 the projection period ends in 2040.

The approach developed in this paper allows impact factors to be calculated for the AEO Reference case and for the other side cases included in the AEO publication. To explore the

[2]The decrease of coal use in AEO2016-17 is partly due to the Clean Power Plan, included in the Reference case for those two years. The Clean Power Plan was removed from the Reference case as of AEO2018 [13].

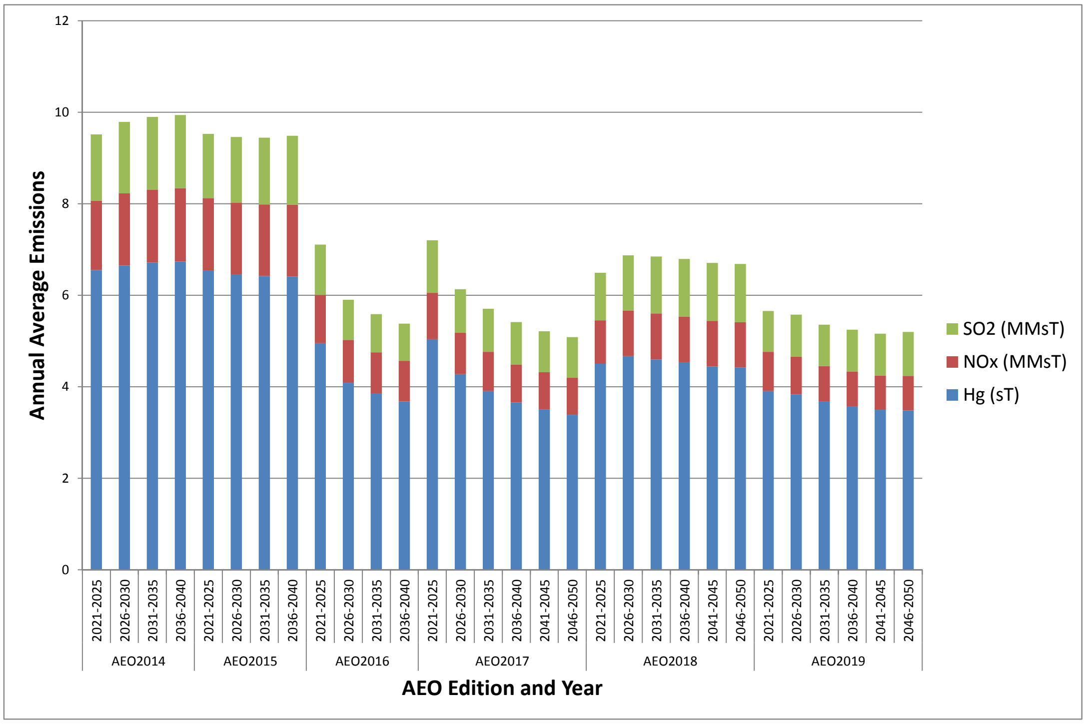

Figure 2: Average annual emissions by species, for the Reference case in each AEO edition. The data are shown averaged over five-year periods. The units for Hg emissions are short tons (sT); the units for NO_x and SO_2 are million short tons (MMsT).

variation in the reported quantities as a function of publication year, and the assumptions made in each side case, we calculate impact factors for all AEO publications from 2014-2019, and all scenarios. We also estimate the effect of the change in methodology by comparing impact factors calculated using the 2014 approach to those calculated by applying the current method to AEO2014 data. The results show that the level of variation due to methodology is of the same order of magnitude, or smaller, as that arising from changes in the AEO edition/side case.

The rest of this paper is organized as follows: in Section 2 we present the overall methodological approach; this discussion is self-contained so the reader does not need to be familiar with the 2014 study. We define the methods used to calculate supply-side impact factors, and to convert these to impact factors by sector and end-use. In Section 3 we discuss demand-side variables and define the methods used to link the time pattern of demand to generation by fuel type. In Section 4 we present the calculated impact factors and compare results for different AEO publications, side cases, and calculation methodologies. Section 5 presents our conclusions. The Appendix includes tables of impact factors for different AEO editions, and the full set of impact factors by sector and end-use for the AEO 2019 Reference case.

2 Approach

2.1 Equations

In this section we provide a mathematical definition of a marginal change, and discuss how the AEO data can be used to construct approximate marginal impact estimates. We also discuss the effect of computational noise on the calculations.

Broadly, let $F(x)$ be a function which depends on some variable x (and potentially other variables that we ignore here). For example, F could be generation and x could be demand. Under a change to the value of x,

$$x \to x + \delta x, \tag{1}$$

there will be a corresponding change in F

$$F(x) \to F(x + \delta x) \simeq F + \delta F, \tag{2}$$

where

$$\delta F = \frac{\partial F}{\partial x} \delta x. \tag{3}$$

The value of the derivative $\partial F / \partial x$ is defined as the marginal impact factor, *i.e.*it is a coefficient that relates changes in F to changes in x; this is the quantity we want to estimate. If it is not possible to estimate the derivative, an alternative approach is to simply ratio the quantities F and x:

$$\delta F \simeq \frac{F}{x} \delta x. \tag{4}$$

This is equivalent to assuming that the percent change in F is the same as the percent change in x. To distinguish this estimate from the marginal factor, we refer to it as a grid-average quantity.

The derivative in equation 3 is only defined for continuous data, whereas the data published with AEO are discrete. The methods described in [1], and in this paper, approximate the marginal impact by calculating ratios of differences (or deltas) as follows: We use the index K to label the different side cases published with AEO, with $K = 0$ corresponding to the Reference case, and F_K the value of F in case K. The delta for F is defined as

$$\Delta F_K = F_0 - F_K, \tag{5}$$

where

- K is the label for the side case,
- $K = 0$ is the label for the Reference case,
- F is some variable calculated by AEO, and
- ΔF is the discrete change, or delta, in F for side case K.

If the scenario modeled in case K includes significant demand reductions, and no other supply-side policies, then we can assume that the change to F is induced entirely by the change to demand. In the 2014 study, only side cases of this type were used in the estimation of impact factors, and marginal data were used in all steps of the calculation.

Since 2015, the AEO has not published the side cases that were used in the 2014 analysis. Hence, we develop a hybrid approach that combines marginal quantities for supply-side variables with a method that uses grid-average data to relate supply to demand. The only

Scenario	AEO2014	AEO2015	AEO2016	AEO2017	AEO2018	AEO2019
Best available technology	-12.3%					
High technology	-9.5%					
Low electricity demand	-16.6%					
Extended policies	-3.0%		-3.4%			
Energy efficiency			-0.4%			
High growth	6.5%	6.8%	6.5%	2.7%	2.6%	2.6%
High price	-0.6%	0.1%	-0.8%	0.6%	1.0%	0.8%
High resource	2.4%	3.2%	1.7%	1.0%	0.7%	1.1%
Low growth	-5.6%	-5.0%	-5.4%	-3.0%	-3.4%	-2.6%
Low price	0.3%	0.2%	-0.5%	-0.4%	-0.4%	-0.5%
Low resource	-2.2%		-2.1%	-1.7%	-1.1%	-1.2%

Table 2: Percent difference in total electricity demand, relative to the Reference case, for the side cases published with each AEO. The table includes three demand-side policy cases published only with AEO2014.

supply-side variables directly impacted by demand reductions are generation and installed capacity. Changes to fuel consumption and emissions are induced by the change to generation. For example, defining G as generation and as $Q(G)$ as fuel consumption, a change in generation δG induces a change in fuel use δQ through the relationship

$$\delta Q = \frac{\partial Q}{\partial G}\delta G. \tag{6}$$

The derivative $\partial Q/\partial G$ can be approximated by a ratio $\Delta Q_K/\Delta G_K$ for a broad range of side cases, that do not need to satisfy any particular conditions on demand.

In evaluating whether the data permit the estimation of marginal quantities, the most important factor is the noise introduced into the AEO by convergence error in the NEMS results. Within NEMS, individual modules for the supply sectors (Coal, Liquid Fuels, Electricity Markets, *etc.*) and demand sectors (Commercial, Industrial, Residential, and Transportation) are executed iteratively, and prices and quantities adjusted, until the model reaches an equilibrium where supply and demand balance. NEMS is a very large, complex model, so the achieved equilibrium is only approximate, and there are always small deviations in the supply-demand balance. These are random errors, referred to as convergence error, which vary in magnitude and sign across the different AEO side cases.

While the convergence error is small relative to grid-average quantities, when calculating differences (as in this analysis), the effect of convergence error can become significant. This is especially true for the early years of the projection period, when differences between the Reference and side cases are small. When the deltas are constructed, the convergence errors are added; depending on the signs of the errors and the magnitude of the deltas, the relative noise level can fluctuate greatly between variables and projection years. Incorporating the deltas into a ratio will generally amplify the relative noise, particularly if the error in the numerator is of the same sign as the delta, and in the denominator it is of opposite sign. Based on our review of the data in this and earlier reports [1, 2], we find that a relative difference of 5% is the minimum required to overcome convergence error, and arrive at reasonable marginal estimates based on the deltas. To evaluate the suitability of different side cases, we present in Table 2 the percent change in total electricity demand for all the cases published since 2015, and for three additional demand-side scenarios published only in

AEO2014. While the High and Low growth scenarios do sometimes meet the 5% threshold, this is not consistent across AEO editions. Moreover, these scenarios mix various supply- and demand-side effects, and so are not representative of how the utility sector responds to demand-side policies.

2.2 Variables of Interest

In this section we define the specific AEO variables for which we calculate marginal impact factors, as well as the dependent variables retained in the calculations.

AEO publishes, for each year in the projection period, electric sector power generation G (TWh) and power sector fuel consumption Q (Quads) by fuel type, denoted f. The ratio of the two defines the fuel-specific heat rate H:

$$H(f,y) = \frac{Q(f,y)}{G(f,y)} \tag{7}$$

where

- H is the heat rate (Quads/Twh),
- y is the projection year,
- f is a label for the fuel type,
- $G(f,y)$ is the total power-sector generation (TWh), and
- $Q(f,y)$ is the total power sector primary fuel consumption f (Quads).

For fossil fuels, H is defined from data; for nuclear and renewable sources, we follow AEO convention and assign a heat rate for accounting purposes. The nuclear heat rate is 0.0105 Quad/TWh and the rate for renewable sources is set equal to the grid-average for fossil fuels.

Emissions result from combustion, so emissions intensities are directly related to fuel consumption. AEO publishes the total mass M of pollutant emitted by the electric power sector, with units of million short tons (MMsT). Here these are converted to a fuel-specific emissions intensity B, with

$$B(f,s,y) = \frac{M(f,s,y)}{Q(f,y)} \tag{8}$$

where

- B is the fuel specific emissions intensity (MMsT/Quad),
- s is a label for the pollutant species, and
- $M(f,s,y)$ is the mass of pollutant s allocated to combustion of fuel f.

Emissions can be scaled to generation using the product $H(f,y)B(f,s,y)$. The AEO publishes data for CO_2, Hg, NO_x, and SO_2 only. For CH_4 and N_2O, we use the constant, fuel-specific emissions intensities published by the Environmental Protection Agency (EPA) [11].

The capacity types are defined somewhat differently from fuel types. The major capacity types reported in the AEO are coal, nuclear, renewable sources, natural gas combined-cycle, oil-and-gas steam, and combustion turbine/diesel.[3] The latter two types are less efficient,

[3] In this analysis we ignore niche capacity types such as distributed generation and pumped storage, which have very low market penetration, and don't vary between side cases.

Capacity Type	Code	Generation Fuel Type	Code
Coal	cl	Coal	cl
Natural Gas Combined-Cycle	ngcc	Natural Gas	ng
Nuclear	ur	Nuclear	ur
Peaking	pk	Oil (Petroleum Fuels)	pf
Renewables	rn	Renewables	rn

Table 3: List of capacity and fuel types, and short-hand codes used in plots.

single-cycle plants that are fired by either oil or natural gas, and are used primarily during peak-load hours. As in [1], here we combine these two single-cycle plant types into the *peaking* capacity category. For coal, nuclear, and renewable sources, there is a one-to-one relationship between the generation by fuel type and the installed capacity by plant type (*i.e.*, all coal is burned in coal plants, *etc.*), so we use the same code for fuel type and plant type. While the natural gas combined-cycle plants run exclusively on natural gas, not all natural gas generation can be attributed to this plant type. Because generation from natural gas and oil does not map directly onto a gas- or oil-burning capacity type, the codes for these plant types are different from the codes for the related fuel types. Table 3 provides a list of capacity types and associated fuel types.

Capacity and generation are related through a factor $C(p, y)$ with

$$C(p, y) = \frac{IC(p(f), y)}{G(f, y)} \tag{9}$$

where

- C is the capacity coefficient (GW/TWh),
- $p(f)$ is a label for the plant type associated to fuel type f, and
- $IC(p, y)$ is the total installed capacity in GW.

The fuel-specific heat rates, emissions intensities and capacity factors defined above use data for the whole grid, *i.e.*these are the grid-average values. To define marginal impact factors, we replace the quantities G, Q and M by differences between the reference case and side cases, and average over the side cases. The ratios estimated from marginal data are distinguished by using a hat (ˆ) on the variable.

Substituting, for example, ΔG for G and ΔQ for Q in equation 7, the marginal heat rate is

$$\hat{H}(f, y) = \frac{1}{N_{\text{SC}}} \sum_K \frac{\Delta Q_K(f, y)}{\Delta G_K(f, y)}, \tag{10}$$

where N_{SC} is the number of side cases used in the calculation. Marginal emissions intensities are written

$$\hat{B}(f, s, y) = \frac{1}{N_{\text{SC}}} \sum_K \frac{\Delta M_K(f, s, y)}{\Delta Q_K(f, y)}. \tag{11}$$

As discussed below in Section 4.1.3, we do not define marginal factors for capacity changes, instead using the grid-average values of equation 9.

End-Use	Commercial Code	Residential Code
Space Cooling	cl	cl
Cooking	co	co
Electric Clothes Dryers	–	ed
Freezers	–	fr
Space Heating	ht	ht
Lighting	lt	lt
Office equipment non-pc	on	–
Office equipment PC (Computers/Electronics)	op	–
Other	ot	ot
Refrigeration	re	re
Ventilation	vt	–
Water Heating	wh	wh

Table 4: List of end uses, and the end-use codes used in charts and tables.

2.3 Impact Factors

In this section we describe the final output of the calculation and how it relates to the supply-side factors defined above. The form of the output is the same as in [1] and [2]. We calculate time-dependent impact factors which, when multiplied by the site electricity savings, provide the estimated changes to generation, installed capacity, fuel use and emissions. The factors are calculated separately for the sectors and end uses listed in Table 4.[4]

End-use dependence enters the calculation through the end-use load shape, *i.e.*the time-varying profile of electricity consumption associated with a specific activity. In NEMS, the individual end-use loads are added together to determine the shape of the total hourly electric system load. The hourly system load is converted to a load duration curve, which defines the number of hours per year that the system load is at or above a given level [6]. The load duration curve is used to determine the expected annual hours of operation for different types of generation, which are categorized as base-load, peaking and intermediate. Base-load plants (coal and nuclear) have high capital costs and relatively low operating costs, and are therefore designed to run for as many hours as possible. Peaking plants are relatively cheap to build and may be expensive to operate, and so are used in hours where the system load is at its highest. The intermediate plants (natural gas and renewable sources) are used to follow moderate changes in load associated with predictable daily and seasonal patterns. Different end-use load shapes lead to differences in the mix of generation fuel type that serve each load. For example, space-cooling is a strongly peak-coincident end use, and refrigeration has a relatively flat load shape. Hence, we would expect the proportion of base-load generation to be larger for refrigeration than for cooling. The differences by end use in generation fuel mix in turn affect the heat rate and emissions for each end use.

We connect the end use to generation fuel mix using a set of weights $z(u, f, y)$, where u is a label for the combined sector and end use. Our method for calculating the weights z is explained in Section 3.2. The weights satisfy

$$\sum_f z(u, f, y) = 1. \tag{12}$$

[4]These are the end uses for which NEMS provides distinct load shapes[5, 7].

Given the weights, we define the marginal heat rate for end use u as

$$h(u,y) = \Gamma \sum_f z(u,f,y)\hat{H}(f,y). \tag{13}$$

This equation includes a factor Γ that accounts for transmission and distribution losses. The national average value of Γ in NEMS is equal to 1.0737. The factor h defines the decrease in power-sector fuel consumption of fuel f given a unit reduction in site electricity demand.

The heat rate is combined with the emissions intensity to define the emissions impact factors $m(u,s,y)$:

$$m(u,s,y) = \Gamma \sum_f z(u,f,y)\hat{H}(f,y)\hat{B}(s,f,y). \tag{14}$$

The factor m defines the decrease in power-sector emissions of species s given a unit reduction in site electricity demand.

The impact factors for capacity $c(u,p,y)$ are defined by:

$$c(u,p,y) = \Gamma \sum_f z(u,f,y)C(p(f),y). \tag{15}$$

To summarize, the notation is:

- u is the label for the combined sector/end use,
- f is the label for generation fuel type,
- p is the label for capacity plant type,
- s is the label for pollutant species,
- Γ is the transmission and distribution loss factor,
- $g(u,f,y)$ is the generation fuel-share weight,
- $h(u,y)$ is the end-use specific heat rate,
- $m(u,s,y)$ is the emissions impact factor, and
- $c(u,p,y)$ is the capacity impact factor.

3 Demand-side Data

Two datasets from AEO are used to characterize electricity use by sector and end use: time series of annual electricity consumption, and load-shape information packaged with the NEMS code.[5] The sectors/end uses for which we calculate impact factors are listed in Table 4; these are the only sectors/end uses for which NEMS defines a distinct load shape. For the industrial sector, the load shape is assumed to be the same as that for commercial/other. The annual energy consumption data include end uses that don't have an associated load shape; these are incorporated into totals for the *other* category.

[5] The load shape data are provided in an input file included with the NEMS code installation package, which can be obtained through the AEO website [4].

3.1 Load Shapes

The NEMS data describe an 8760-hour load shape for the full year, of the form $l(u, d, h)$, with

$$\sum_{d,h} l(u, d, h) = 1. \tag{16}$$

where

- u is the sector/end use,
- d is an index defining the day with $d = 1, \ldots 365$,
- h is the hour of day with $h = 1, \ldots 24$, and
- $l(u, d, h)$ is the load-shape profile constructed from the NEMS data.

The load shapes themselves don't depend on the scenario.

The hourly demand data are converted to demand by time-of-use period using the hours assignment shown in Table 5. The column headers represent the 24 hours ending at 1am, 2am *etc.*, and the rows represent the time-of-use periods. For each hour/period, the table entry is equal to 1 if that hour has been assigned to the given period and 0 otherwise. These assignments are used only for weekdays; following conventional practice, all weekend hours are assigned to off-peak. The assignment is also seasonal, with summer defined as the months of May through September, and winter as all other months. These assignments are consistent with the NEMS internal allocation rules [6].

Season/Period		Hour-Ending																							
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Summer	On-peak	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0
	Shoulder	0	0	0	0	0	0	1	1	1	0	0	0	0	0	0	0	0	1	1	1	0	0	0	0
	Off-peak	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1
Winter	On-peak	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Shoulder	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0
	Off-peak	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1

Table 5: Assignment of hours to time-of-use periods, by season. On-peak and shoulder hours occur only on weekdays.

The data in Table 5 define a filter ϕ that is equal to one if the hour is in period n, and equal to zero otherwise. This filter is used to define weights that allocate end-use demand to time-of-use periods:

$$w(u, n) = \sum_{d,h} l(u, d, h)\phi(d, h, n) \tag{17}$$

As every hour is allocated to just one period,

$$\sum_{n} w(u, n) = 1. \tag{18}$$

for each sector/end use u.

The values $w(u, n)$ provide a distribution of the electricity consumption associated with end use u over the three periods indexed by n. Because the load shapes don't depend on scenario, neither do the weights $w(u,n)$. Total demand by period is calculated by multiplying the annual end-use electricity consumption by the weights w:

$$\tilde{D}_K(n,y) = \sum_u w(u,n) D_K(u,y). \tag{19}$$

where $D_K(u,y)$ is total demand for sector/end use u in scenario K and year y and we use the tilde ($\tilde{D}_K$) to refer to the demand by time-of-use period. While total demand varies somewhat with AEO publications, there is very little variation in the assignment of electricity use to periods, as illustrated in Figure 3. The figure shows total demand allocated by period for the Reference case for AEO publications 2014-2019. The data are averaged over five-year periods, and the projection ends in 2040 for AEO2014-16, and in 2050 for AEO2017-19. Total demand in the period 2036-2040 decreases by about 9% between AEO2014 and AEO2019.

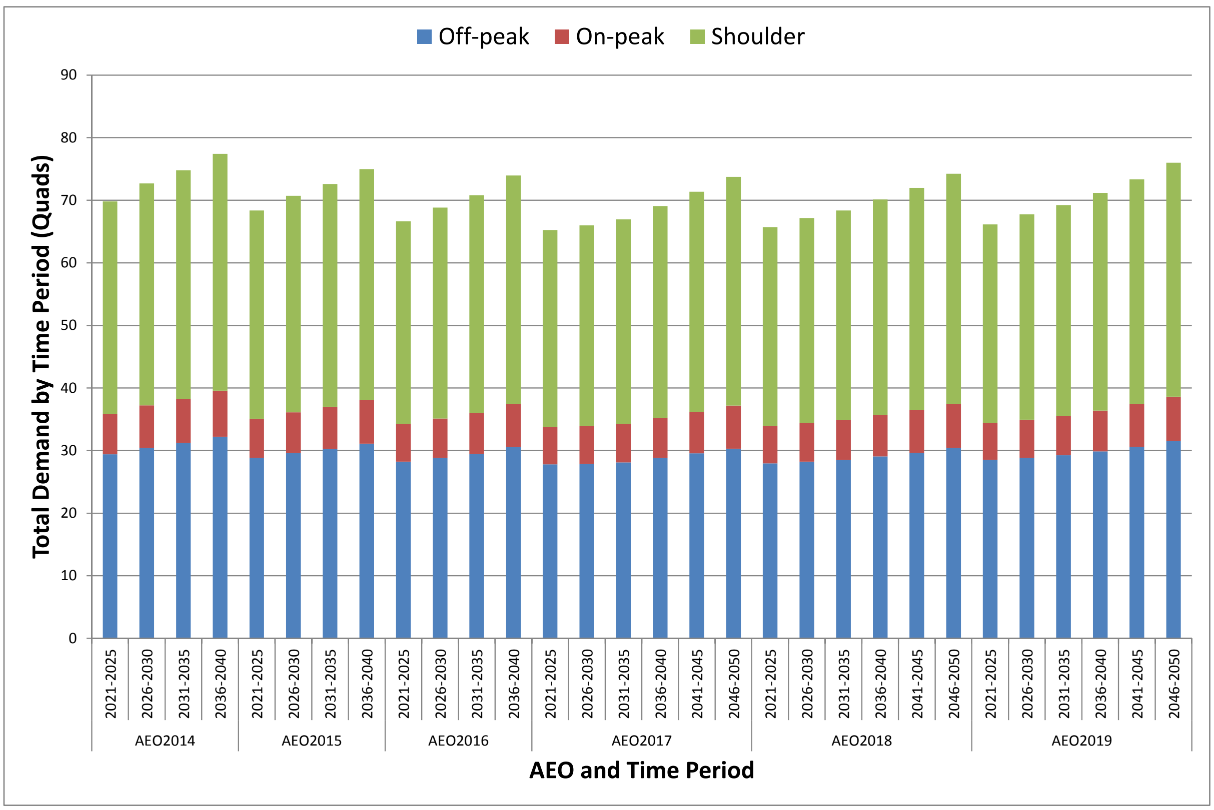

Figure 3: Sum of commercial, industrial and residential demand allocated to time-of-use periods for each AEO publication.

3.2 Linking Supply to Demand

In Section 2.3 we defined generation fuel-share weights $z(u,f,y)$ representing the fuel-share mix used to serve end use u. In this section we explain how these weights are calculated. The link is made by matching the generation by fuel type, with fuels classified as base-load, intermediate or peak generation, to the demand by time-of-use period.

This calculation uses grid-average data for generation fuel mix and demand by time-of-use period; as shown in Table 2, none of the side cases published for AEO2015-19 include demand-side scenarios that meet the 5% threshold for overcoming convergence error. We do, however, make an adjustment to the grid-average data in this calculation. This adjustment is based on the observation that, within AEO, the generation and installed capacity for nuclear power is approximately constant across all demand-side policy cases. In a review of the data for AEO2014-19, we find that the relative fuel share for the generation deltas is of the same order of magnitude as in the grid-average data, except for nuclear. For nuclear, the deltas are less than 2% (and zero in several cases) of the total change to generation; for comparison, the share of nuclear generation in the grid-average data ranges from 15-20%. The same is true for nuclear capacity; changes to installed capacity for nuclear power are either zero, or a small fraction of the grid-average value. This implies that, within NEMS, decisions about dispatch and construction of nuclear power are not affected by demand-side policies. Accordingly, in the calculation of z we exclude nuclear from total generation, and rescale so total generation in each year is equal to one. We also rescale total electricity demand to one, and then proceed with the allocation.

The allocation rules take the generation associated with a given fuel type, and allocate it to one of the three time-of-use periods, based on how different types of generation are dispatched.

1. All oil-fueled generation is allocated to serving on-peak demand.
2. As base-load generation is always on, generation from coal is allocated proportionally to all periods. [6]
3. For any remaining on-peak demand, we assume that 2/3 of this demand is served by natural gas and 1/3 by renewable sources.
4. The remaining natural gas and renewable generation are allocated to the shoulder and off-peak periods proportionally.

The result of this calculation is an intermediate set of weights $v_K(n, f, y)$ satisfying

$$\sum_f v_K(n, f, y) = 1. \tag{20}$$

These weights define the fraction of the load in time-of-use period n that is served by fuel type f. The weights depend on K because both the proportion of generation by fuel type and the proportion of demand by end use may vary with scenario.

The end use to period mapping, and the fuel-share weights for each period, are combined to define the end-use fuel-share weights:

$$z_K(u, f, y) = \sum_n w(u, n) v_K(n, f, y). \tag{21}$$

These weights are illustrated in Figures 4 and 5. Figure 4 shows the relative weight allocated to each fuel type for six representative end uses, comparing Reference case data across

[6] Allocated proportionally means that relative proportions are preserved; for example, in allocating coal, if the shares of unmet demand in on-peak, off-peak and shoulder periods are 0.2, 0.4 and 0.4, them 20% of coal generation is allocated to on-peak, 40% to off-peak, and 40% to shoulder.

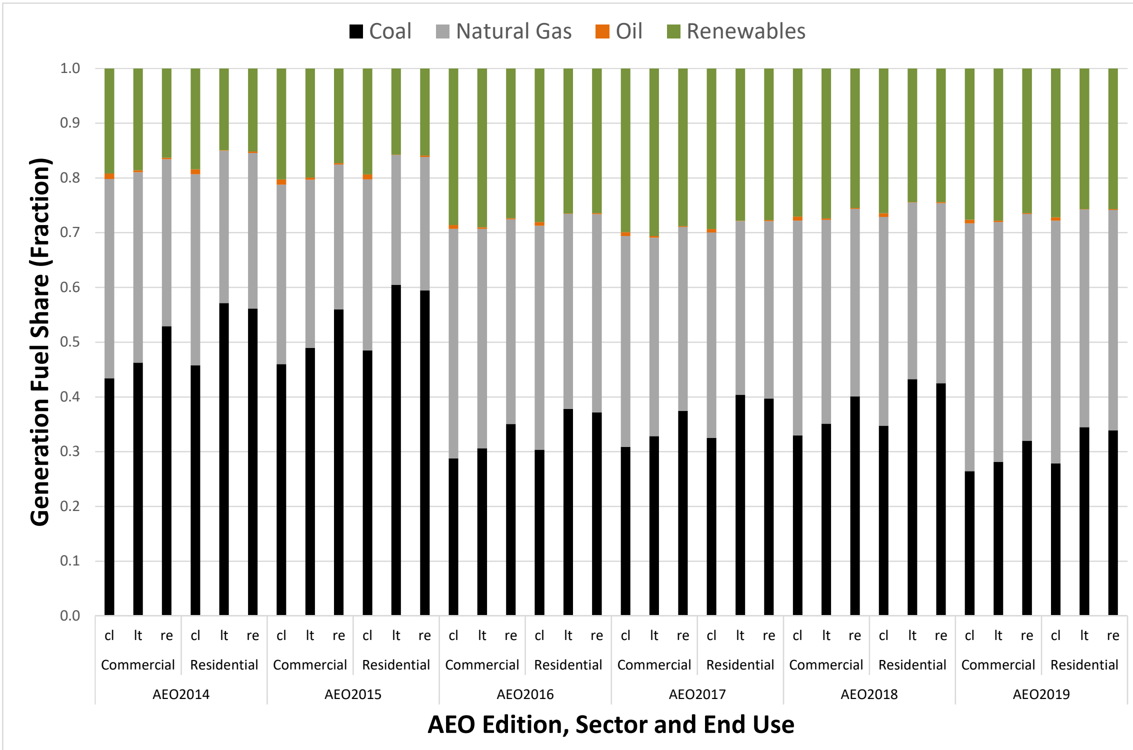

Figure 4: Relative weight allocated to each fuel type averaged over 2026-2030, for residential and commercial space-cooling (cl), lighting (lt) and refrigeration (re), and all AEO publications).

different AEO years. The end uses are space-cooling (cl), lighting (lt) and refrigeration (re) for the commercial and residential sectors, and the data plotted are averages for the years 2026-2030. Starting in AEO2016 the share of coal drops dramatically; this change persists, with some variation, through 2019. Figure 5 shows time series for all residential and commercial end uses, for the AEO2019 Reference case. The data here are averaged over ten-year periods, so each bar corresponds to one decade. The chart shows the share of coal continuing to drop, and largely being replaced by renewables, across all end uses. Both charts confirm that the proportion of coal is larger for flatter load shapes.

4 Results

In this section we present the results for inputs to the impact factor estimates as well as the impact factors themselves. We also discuss our methods for averaging and smoothing the estimated marginal heat rates and emissions intensities.

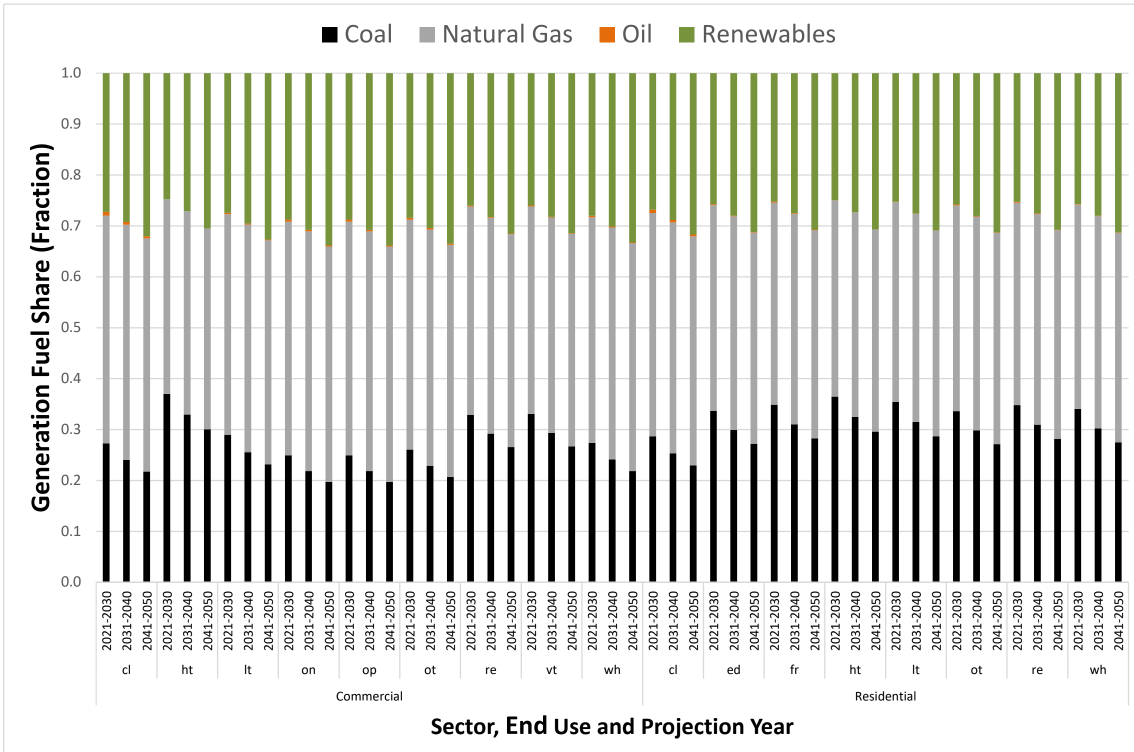

Figure 5: Time series of the relative weight allocated to each fuel type across all end uses in AEO2019. The data are averaged by decade.

4.1 Supply-Side Quantities

This section presents results of the calculations for capacity factors, heat rates, and emissions intensities. For the latter two variables, we compare the results calculated using marginal data to those based on grid-average data. Overall, marginal heat rates for natural gas and oil are smaller than the grid-average, while those for coal are approximately the same as the grid-average. For emissions there is no well-defined pattern; marginal intensities can be larger or smaller than grid-average, depending on the pollutant species, AEO edition, and projection year. The important point is that the marginal approach produces results that are reasonably consistent across AEO editions and scenarios, and so can be reliably used in calculating impact factors.

4.1.1 Marginal heat rate

As discussed in Section 2.1, convergence error leads to very noisy results for the calculated ratios of ΔG_K and ΔQ_K *etc.*Review of the data show that the High and Low Price, and High and Low Growth scenarios tend to give poor results, because the change in generation by fuel type is relatively small. Hence, in calculating marginal heat rates we rely on the Low

Species	Coal	Natural Gas	Oil
Hg	1.0	0.0	0.0
NO_x	1.0	0.3	1.0
SO_2	1.0	0.0	1.0

Table 6: Scaling factors used to disaggregate power-sector emissions of Hg, NO_x and SO_2 into emissions intensities by fuel type.

and High Resource cases. Figure 6 plots the generation changes to fossil fuels in these cases, again with the data averaged over five-year periods. The High Resource case shows primarily a displacement of coal use by natural gas; the pattern is similar for the Low Resource case, but with an increase to coal and decrease to natural gas. In percentage terms the differences range from $\pm 5\%$ to as much as $\pm 40\%$. While absolute changes to oil generation are too small to be clearly visible on this chart, they range from $\pm 5\%$ to $\pm 15\%$ in relative terms, large enough to give good results. To estimate the marginal heat rate, we use equation 10 for the High and Low Resource cases. We then apply a five-year moving average to further smooth the time series data. The calculated marginal heat rates are shown in Figure 7 for each AEO and fossil fuel type (open squares). For comparison, the figure also shows heat rates calculated using grid-average data (filled squares).

In NEMS, electric power capacity categories are further segregated by vintage, combustion technology, and efficiency [6]. These more detailed characteristics affect both heat rates and emissions. The policies and assumptions considered in a side case affect generation both through how it is dispatched, and over the longer term, through a change to the pattern of construction of new plants. Hence, newer plants are likely to be weighted more heavily in the marginal calculations, as these are the most affected by the scenario change. If newer plants are more efficient, then marginal heat rates should be lower, *i.e.*require less fuel to produce a unit of generation. This is generally what we find in the results. The data also show patterns of increase or decrease of heat rate with time. For natural gas, both the grid-average and the marginal heat rates decline over time with the same pattern, consistent across AEOs. This may reflect technology improvements to combined-cycle efficiencies that can be retrofit to existing plants. For coal there is little difference between marginal and grid-average heat rates, and little variation in time, reflecting the stability of coal-fired installed capacity in NEMS.

4.1.2 Marginal emissions intensities

As with heat rates, we base our calculation of marginal emissions intensities on deltas for the High and Low Resource scenarios. For CO_2, AEO publishes power sector emissions by fuel type, so $M_K(f,s,y)$ and $\Delta M_K(f,s,y)$ are available directly. For Hg, NO_x and SO_2, AEO publishes total power sector emissions but doesn't include a breakdown by fuel type. Here we use an algebraic approach to disaggregate emissions across fuel types. We define a factor $\beta(f,s)$ that scales the emissions intensity for natural gas and oil to that of coal. Based on a review of EPA data [14], our estimates for β are as given in Table 6.

Similar to equation 11 we define an emissions intensity for scenario K as

$$\hat{B}_K(f,s,y) = \frac{\Delta M_K(f,s,y)}{\Delta Q_K(f,y)}. \tag{22}$$

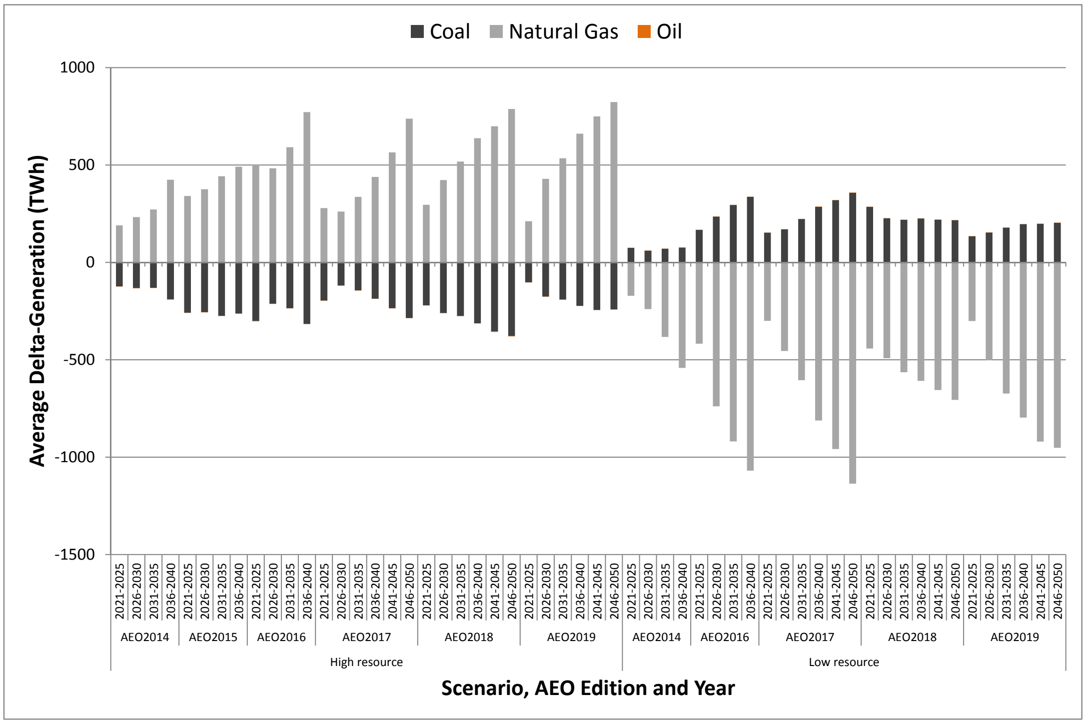

Figure 6: Changes to fossil generation, relative to the Reference case, for the High and Low Resource cases across AEO publications. The changes to oil generation are too small to be seen easily in the chart.

The total mass of pollutant species s is defined by

$$\Delta M_K(s,y) = \sum_f \Delta M_K(f,s,y) = \sum_f \Delta Q_K(f,y)\beta(f,s)\hat{B}_K(cl,s,y). \tag{23}$$

The value of $\Delta M_K(s,y)$ is known from the NEMS data, so we can define

$$\hat{B}_K(cl,s,y) = \frac{\Delta M_K(s,y)}{\sum_f \Delta Q_K(f,y)\beta(f,s)}, \tag{24}$$

and recover the other coefficients using

$$\hat{B}_K(f,s,y) = \beta(f,s)\hat{B}_K(cl,s,y). \tag{25}$$

The values $\hat{B}_K$ are then averaged over scenarios as in equation 11.

The calculated marginal emissions intensities for each fuel type are shown in Tables 7 and 8, which are included in Appendix A. The data are presented as averages over five-year periods. Table 7 provides values for coal and natural gas (the non-zero values for oil are the same as those for coal). The results for CO_2 emissions are almost constant both across time within each AEO, and across different AEO publications for a given time period. This makes

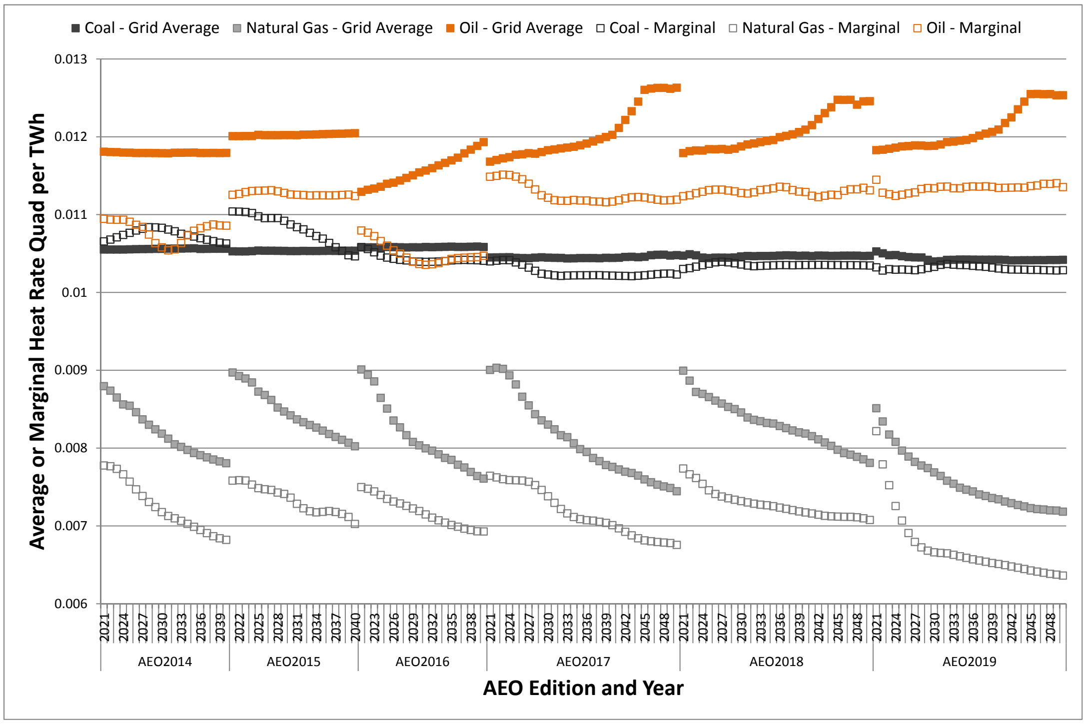

Figure 7: Fuel-specific heat rates calculated from grid-average data (filled squares) and deltas (open squares).

sense, as CO_2 emissions are determined by fuel heat content, which is almost constant. Emissions of Hg from coal combustion are alse fairly stable; variation across AEOs for a given time period is about ±5%, and within an AEO Hg emissions decrease slightly over time.

Emissions intensities for NO_x and SO_2 are sensitive both to combustion technology and fuel quality, and this sensitivity is evident in the larger variability both across years and publications. For coal, NO_x intensities vary between about 0.07 and 0.1 MMsT/Quad, with no consistent pattern across years or publications. The coal SO_2 intensities are higher in AEO2014 than in subsequent years; for AEO2015 and beyond the intensities vary between 0.07 and 1.1 MMsT/Quad; this is also the range of variation across years for AEO2019.

Table 8 shows data for coal only, comparing the values calculated using the marginal approach to those calculated based on grid-average data. There is almost no difference in the CO_2 values. For Hg the grid-average values tend to be lower, but this varies with AEO publication and the differences are not large. For NO_x, the grid-average values have little variation over time, and are lower than the marginal values by anywhere from 10% to 40%. AEO2016 and AEO2017 in particular have grid-average NO_x emissions that are 25%-40% lower than the marginal values. These editions of AEO included the CPP in the reference case, which accelerated the retirement of coal plants. The results here suggest that the more polluting plants are retired first, so these would be more heavily weighted in the marginal calculations. The pattern for SO_2 is more complicated. The grid-average intensities are substantially lower for AEO2014 and AEO2015, somewhat higher for AEO2018 and AEO2019, and vary between higher and lower over the projection period for AEO2016 and AEO2017. Sulfur emissions from coal are a function of coal quality as well as power plant technologies. AEO data on coal production show that the percentage of low-sulfur coal supply decreases from about 50% in AEO2014 to 42% in AEO2019. The low-sulfur percentage is approximately constant over time within each AEO publication. Hence, it is likely that variations in coal supply across AEO editions also contribute to the variation in SO_2 intensity.

4.1.3 Capacity coefficients

Equation 9 defines a coefficient that relates the change in generation to a change in installed capacity, with generation fuel types and capacity plant types matched as in Table 3. In our methodology, total peak capacity is scaled to the amount of oil-fired generation, and natural gas combined-cycle capacity is scaled to total natural gas generation. In previous work [1, 2] we used deltas in capacity to construct marginal capacity coefficients, but have found the coefficients estimated in that way to be especially susceptible to convergence error. This is not surprising, as capacity additions are fundamentally different from the other quantities modeled here, in that they always take place in discrete steps. In contrast, demand, generation, fuel use, and emissions vary continuously. This means that the derivative of capacity with respect to demand is mathematically undefined, even if the data were perfect. Capacity is added based on an internal decision model that is sensitive to small changes in utility revenues, so it is also possible to have a capacity addition appear across AEO cases, but shifted slightly in time. This leads to large variability in the ratios of ΔG and ΔC, which is primarily an artifact of the numerical method. Hence, in the current analysis we use grid-average data to define the capacity coefficient.

Our model estimates the impact of demand reductions on total peaking capacity, without distinguishing between oil- and natural gas-fired plants. It is possible to split the peaking category into these two fuel sub-types, using historical data available from EIA. The EIA Forms 860 and 923 [9, 10] provide fuel consumption by fuel type and total installed capacity by plant type for all active electric power plants in the US. Using these data, we calculate the percentage of installed single-cycle capacity that is oil- *vs.*natural-gas fired, which was about 14% in 2017. To project forward the relative peaking capacity shares, we assume that oil-fired capacity follows the same trend over time as oil-fired generation (the latter is available from the AEO data). The capacity split is plotted in Figure 8, which shows the sum of natural gas- and oil-fired peaking capacity. There is a trend across all AEOs of a slowly decreasing amount of oil-fired generation; in AEO2019, the oil-fired peaking percentage decreases from bout 10% in the period 2021-2025 to 5% in the period 2046-2050.

It is also possible to separate natural gas generation into single- and combined-cycle, using capacity factors calculated from the EIA data, as follows: The capacity factor η is defined as the average hourly plant output divided by the name-plate capacity:

$$\eta = \frac{\text{Generation (GWh)}}{8760 * \text{Capacity (GW)}}. \tag{26}$$

The factor 8760 is the number of hours in one year. The EIA data show that the capacity factor for gas-fired peaking plants is 1.86 times the capacity factor for oil-fired peaking plants. The capacity factor for oil-fired plants can be calculated from our estimate of oil-fired capacity and the AEO generation data for oil. We then use equation 26 to recover the natural-gas fired generation as the product of the capacity factor for gas-fired peak, times the estimated capacity for gas-fired peak, times the constant 8760. This calculation shows that natural gas-fired single-cycle plants represent 15-25% of all natural gas generation, with the percentage decreasing with AEOs and with time.

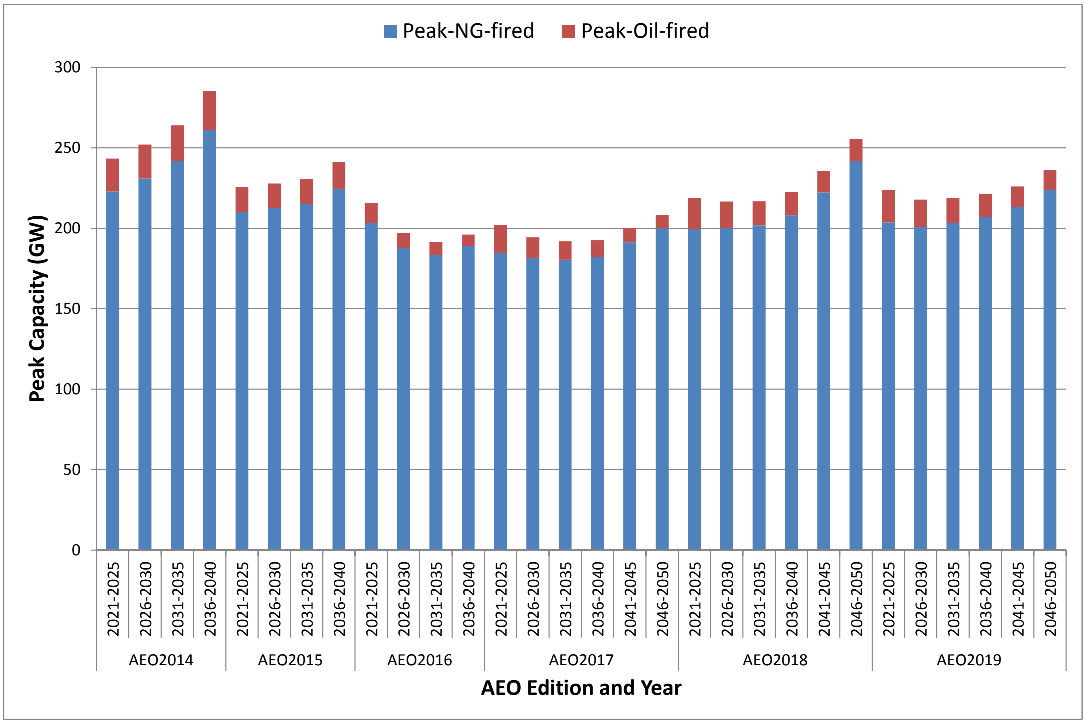

Figure 8: Separation of total peaking capacity into oil-fired and natural-gas fired.

Table 9 summarizes the results of this calculation for the Reference case. The capacity coefficients are defined by equation 9; capacity reductions in GW are estimated by multiplying a generation reduction in TWh by these coefficients. For simplicity, the NGCC coefficient predicts natural gas combined-cycle capacity based on total natural gas generation, not just the portion allocated to combined-cycle. The Peak coefficient predicts total peaking capacity based only on oil generation, while the Peak-oil and Peak-gas coefficients predict oil-fired/gas-fired capacity based on oil generation/natural gas single-cycle generation respectively. The total peaking capacity estimate doesn't depend on which method is used. The table also includes capacity factors as defined in equation 26 for each of the capacity types.

4.2 Impact Factors

Once the heat rates, emissions intensities and capacity coefficients have been calculated, these are combined with the end-use dependent fuel-share weights to provide the impact factors, as in equations 13, 14, and 15. The results obtained for AEO2019 are presented in

Tables 10 through 14, included in Appendix A. In general there is weak variation in the impact factor magnitudes as a function of end use; the most strongly varying factors are for NO_x and SO_2 emissions, which vary by approximately ±10% across end uses. The degree of variation across end use generally decreases in later years of the projection period.

4.2.1 Variability by AEO and scenario

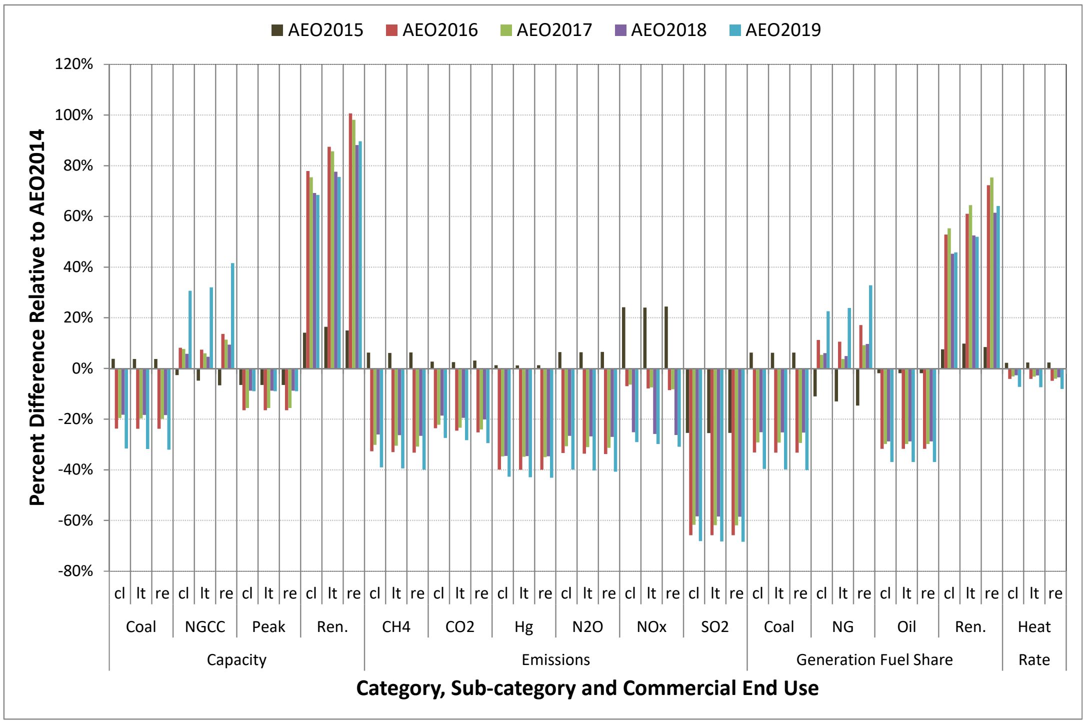

Figure 9: Percent difference in impact factors across AEO editions, relative to AEO2014, for the Reference case. The factors are averaged over the period 2021-2040, and plotted for three commercial end uses; space-cooling (cl), lighting (lt), and refrigeration (re).

Figure 9 quantifies the degree of variation in impact factors across the different AEO editions. The figure shows the percent difference in the impact factor, relative to values for AEO2014, for the Reference case for three commercial end uses: space-cooling (cl), lighting (lt) and refrigeration (re). The data in this plot are based on averages for the twenty-year period 2021-2040. The end uses were chosen as representative of peak-coincident, intermediate and flat end-use load shapes. The plot shows clearly the previously noted shift, starting with AEO2016, to scenarios with less coal, more renewables and more natural gas. Emissions go up slightly between AEO2014 and AEO2015, but then drop by 20-40% for AEO2016-2019. Relative differences between the AEO editions of 2016-2018 are smaller, with variation on the order of ± 10%. In AEO2019 there is a shift away from coal capacity and generation, primarily into natural gas.

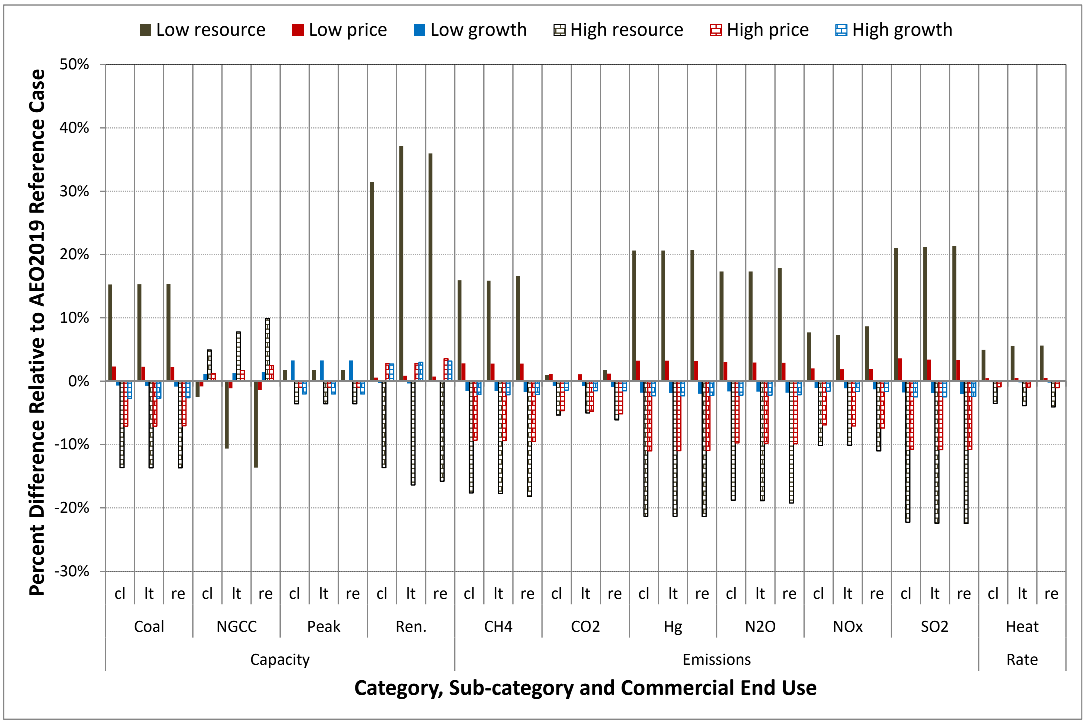

Figure 10: Percent difference in impact factors across side cases, relative to the Reference case, for AEO2019. The factors are averaged over the period 2021-2040, and plotted for three commercial end uses; space-cooling (cl), lighting (lt), and refrigeration (re).

The variation in impact factors due to the choice of scenario is shown in Figure 10. Here the percent difference in impact factors for AEO2019, relative to the Reference case, is plotted for the different side cases. The data are again averaged over the period 2021-2040 and plotted for commercial cooling, lighting, and refrigeration. As our method estimates marginal heat rates and emissions intensities by averaging over scenarios (see equations 10 and 11), the differences in the impact factors are entirely due to the different generation fuel mix in each AEO side case. Only the High and Low Resource cases show differences that exceed $\pm 10\%$.

The variations plotted in Figures 9 and 10 represent fundamental uncertainties about future technological, economic and regulatory developments that impact the grid. The AEO is not a prediction of the future; it provides a reasonable extrapolation of current trends, and uses the side cases to explore the sensitivity of the projection to specific assumptions, as described in Table 1. Our results suggest that, absent a major policy shift, the variability in impact factors due to these uncertainties is on the order of $\pm$ 10%.

4.2.2 Variability by methodology

In this section we evaluate the relative impact of changing the methodology from that outlined in the 2014 report [1] to the updated approach presented here. The comparison makes use of the three demand-side scenarios published in 2014 with a total demand reduction greater than 5% (Best Available Technology, High Technology, and Low Electricity Demand). The goal of the comparison is to quantify the effect of using deltas, rather than grid-average data, to calculate the fuel-share weights. For each of the three demand-side policy cases, we use the allocation method described in Section 3.2 to match the generation deltas by fuel type to the demand deltas by time-of-use period. (This calculation includes the changes to nuclear generation, primarily to illustrate how small they are.) Because each demand-side policy scenario affects a different set of end uses, the distribution of demand reductions by period will vary, which in turn affects the fuel-share weights. Figure 11 shows the end-use fuel-share weights, plotted as in Figure 4, for the three AEO2014 demand side cases and the Reference case. The plot compares the fuel-share weights calculated using deltas, to those calculated using the grid-average data. In all cases the proportion of coal is larger in the grid-average results than in the results based on deltas, but the difference depends on the scenario. The proportion of renewables is also larger in the grid-average results, and the proportion of natural gas may be larger or smaller. To obtain a single set of fuel-share weights to use in the analysis, we average results from the three demand side cases; this average is labelled *Deltas-Average* and compared to the Reference case at the far right of Figure 11.

The grid-average Reference case has a higher proportion of coal but a lower proportion of natural gas; this opposite tendency reduces somewhat the impact on emissions. The figure shows clearly that the proportion of nuclear on the margin is negligible. The effect that methodology has on the emissions impact factors is illustrated in Figure 12. The figure shows factors for residential and commercial cooling, lighting and refrigeration, averaged over the period 2021-2040. The factors based on fuel-share weights calculated from deltas are referred to as the *All Deltas Method*, while those based on fuel-share weights from grid-average data are labelled *Mixed Method*. In both cases we use the same supply-side heat rates and emissions intensities, presented in Section 4.1. The mixed method leads to somewhat higher emissions factors, but in most cases the difference is small. The largest effect is on Hg emissions, as these are directly related to the fraction of coal on the margin.

The level of variation due to methodology is of the same order of magnitude, or smaller, as that arising from changes in the scenario or AEO edition. We include this comparison to provide a quantitative perspective on how sensitive the impact factors are to the details of the methodological approach, but are not suggesting that the all-deltas method is more accurate than the mixed method. Figure 11 shows clearly that the fuel-share weights calculated using deltas are strongly dependent on the particular mix of policies included in a scenario. Arguably, with respect to long-term and broadly-based policies such as the DOE efficiency standards program [3], the mixed method may be more appropriate. Impacts of the DOE program are distributed across many end uses and years [15], and the set of end uses impacted in any given calendar year is essentially random. Under these circumstances, the grid-average fuel-share weights are a better estimator than those tied to a specific set of demand-side policies.

5 Conclusions

The broad goal of the utility impacts analysis is to provide a means of estimating the impacts of demand-side energy policy at the national scale that is easy to implement, and consistent with the projected development of the electricity sector published by AEO. This

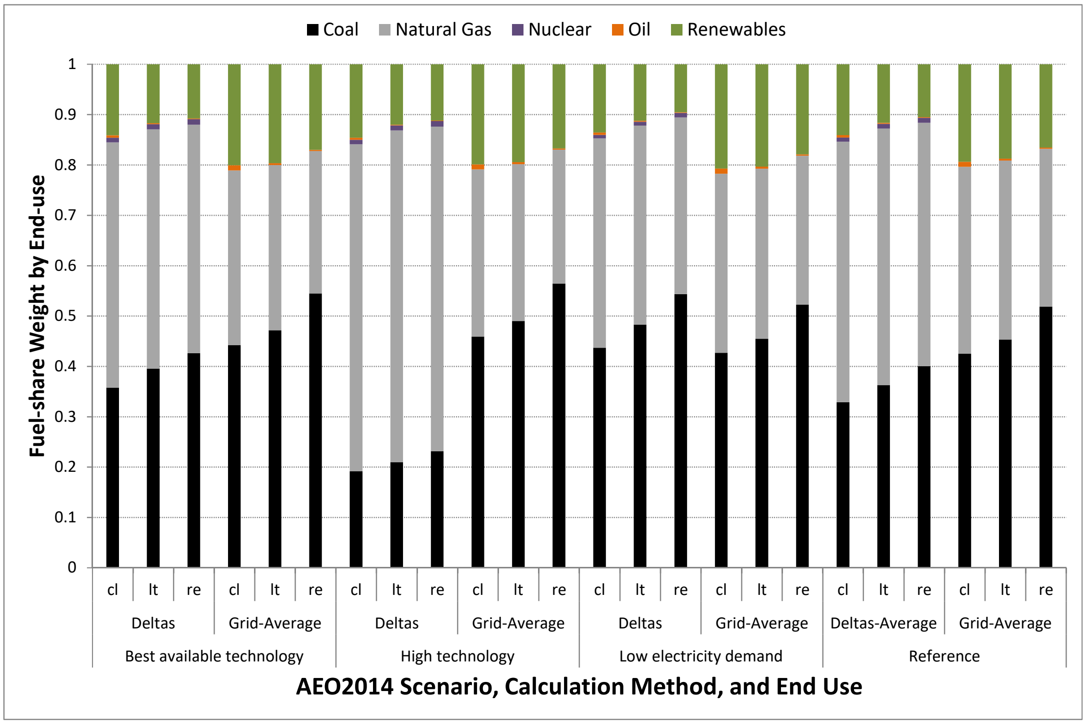

Figure 11: Fuel-share weights for AEO2014 demand-side scenarios for commercial cooling (cl), lighting (lt) and refrigeration (re). The plot compares weights calculated using deltas for generation and demand, to those calculated using grid-average data. For comparison to the Reference case, the Deltas-Average corresponds to the average across the three demand-side scenarios.

report presents a revised version of an earlier methodology [1]; the change in approach is necessitated by changes to the AEO publication schedule. Starting with AEO2015, the EIA publishes a full set of side cases every other year, and a restricted set of side cases annually (listed in Table 1). The 2014 methodology relied on the availability of side cases focused exclusively on demand-side policies, with a minimum impact on total demand of 5%. This paper presents a generalization of the approach that can be used with the restricted set of side cases published each year.

The approach relates supply-side quantities to the demand-side through fuel-share weights that define the fraction of end-use load served by each generation fuel type. The weights are combined with marginal supply-side data on fuel-specific heat rates, emissions intensities and capacity changes, to produce a set of time-dependent impact factors for each sector and end use. The impact factors relate a unit reduction to site electricity demand to the corresponding supply-side changes, specifically: reductions to electric power generation and primary fuel consumption by fuel type, emissions of criteria pollutants (Hg, NO_x and SO_2) and greenhouse gases (CO_2, N_2O and CH_4), and total installed capacity by plant type.

This report also looks at the variability in the calculated impact factors across different

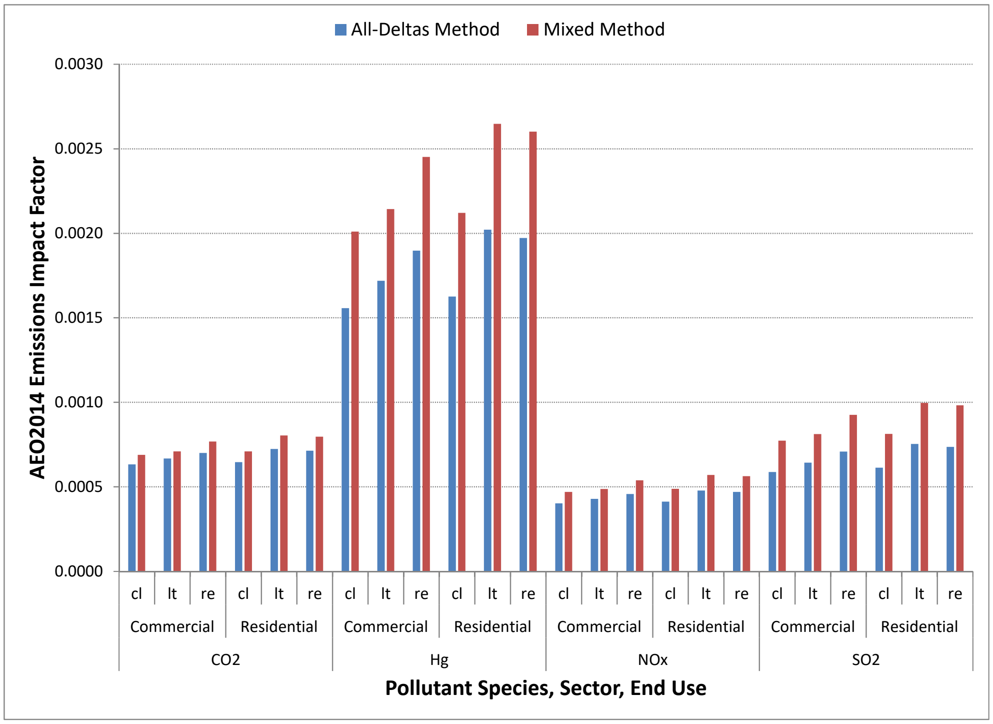

Figure 12: Emissions impact factors for AEO2014, for space cooling (cl), lighting (lt), and refrigeration (re), for the commercial and residential sectors. The plot compares factors calculated using deltas for both the supply-side data and fuel-share weights (All Deltas), to factors using deltas for the supply-side data and grid-average data for the fuel share weights.

editions of AEO from 2014 to 2019, and across different side cases. Uncertainties about future technological, economic and regulatory developments that impact the grid are inevitable. The AEO provides a reasonable extrapolation of trends that are current at the time of publication, and uses the side cases to explore the sensitivity of the projection to various assumptions. Our results suggest that, absent a major policy shift, the variability in impact factors due to changes in these assumptions is on the order of $\pm$ 10%. An example of a major policy shift occurs with AEO2016, which incorporated the Clean Power Plan [12] into the Reference case. This induced a large shift away from coal-fired generation, with corresponding impacts on emissions. While the Clean Power Plan was removed from the Reference case in AEO2018 [13], the AEO does not show a subsequent shift back into coal.

We also evaluate the variation in impact factors due to changes to the details of the methodological approach. We directly compare the method used in the 2014 study to the current approach, by using AEO2014 demand-side scenarios to quantify the effect of using deltas, rather than grid-average data, to calculate the fuel-share weights. The level of variation due to methodology is of the same order of magnitude, or smaller, as that arising from changes in the scenario or AEO edition. An advantage of the updated approach is that it is less sensitive to noise, and therefore less volatile under the changes that occur from one AEO to the next.

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A Detailed Tables

Pollutant	Period	Coal Marginal Emissions Intensity						Natural Gas Marginal Emissions Intensity					
		AEO2014	AEO2015	AEO2016	AEO2017	AEO2018	AEO2019	AEO2014	AEO2015	AEO2016	AEO2017	AEO2018	AEO2019
CO2 MMsT:Quad	2016-2020	104.4	103.9	104.5	105.6	105.0		58.4	58.3	58.5	58.5	58.5	
	2021-2025	104.4	104.7	105.2	105.0	105.2	105.3	58.5	58.4	58.5	58.5	58.5	58.5
	2026-2030	104.3	104.2	105.0	104.9	105.3	104.6	58.3	58.3	58.5	58.5	58.5	58.5
	2031-2035	104.2	104.2	104.7	105.0	105.1	104.5	58.2	57.8	58.5	58.5	58.5	58.5
	2036-2040	104.2	103.9	104.5	104.4	104.8	104.5	58.0	56.4	58.5	58.5	58.5	58.4
	2041-2045				104.5	104.7	104.4				58.5	58.5	58.4
	2046-2050				104.6	104.8	104.5				58.3	58.5	58.4
Hg sT:Quad	2016-2020	0.421	0.382	0.372	0.371	0.358							
	2021-2025	0.413	0.367	0.365	0.384	0.372	0.433						
	2026-2030	0.413	0.383	0.381	0.407	0.371	0.415						
	2031-2035	0.415	0.399	0.395	0.402	0.378	0.391						
	2036-2040	0.398	0.406	0.381	0.385	0.368	0.374						
	2041-2045				0.369	0.359	0.365						
	2046-2050				0.369	0.357	0.354						
Nox MMsT:Quad	2016-2020	0.078	0.101	0.092	0.096	0.080		0.023	0.030	0.028	0.029	0.024	
	2021-2025	0.076	0.095	0.098	0.097	0.081	0.114	0.023	0.029	0.030	0.029	0.024	0.034
	2026-2030	0.080	0.091	0.102	0.108	0.079	0.081	0.024	0.027	0.031	0.032	0.024	0.024
	2031-2035	0.082	0.094	0.107	0.107	0.073	0.070	0.024	0.028	0.032	0.032	0.022	0.021
	2036-2040	0.083	0.100	0.108	0.094	0.076	0.070	0.025	0.030	0.033	0.028	0.023	0.021
	2041-2045				0.088	0.066	0.071				0.027	0.020	0.021
	2046-2050				0.094	0.067	0.080				0.028	0.020	0.024
SO2 MMsT:Quad	2016-2020	0.125	0.109	0.089	0.098	0.080							
	2021-2025	0.140	0.105	0.076	0.101	0.081	0.067						
	2026-2030	0.160	0.110	0.082	0.088	0.087	0.092						
	2031-2035	0.160	0.101	0.083	0.071	0.092	0.088						
	2036-2040	0.157	0.113	0.086	0.081	0.096	0.094						
	2041-2045				0.085	0.102	0.096						
	2046-2050				0.088	0.098	0.105						

Table 7: Five-year average emissions intensities for coal and natural gas across all AEO publications.

Pollutant	Period	Coal Marginal Emissions Intensity						Coal Grid-Average Emissions Intensity					
		AEO2014	AEO2015	AEO2016	AEO2017	AEO2018	AEO2019	AEO2014	AEO2015	AEO2016	AEO2017	AEO2018	AEO2019
CO2 MMsT:Quad	2016-2020	104.4	103.9	104.5	105.6	105.0		104.7	104.7	104.6	104.8	104.7	
	2021-2025	104.4	104.7	105.2	105.0	105.2	105.3	104.7	104.8	104.6	104.8	104.7	104.7
	2026-2030	104.3	104.2	105.0	104.9	105.3	104.6	104.7	104.7	104.6	104.9	104.7	104.7
	2031-2035	104.2	104.2	104.7	105.0	105.1	104.5	104.6	104.6	104.4	104.7	104.6	104.7
	2036-2040	104.2	103.9	104.5	104.4	104.8	104.5	104.5	104.5	104.3	104.6	104.6	104.7
	2041-2045				104.5	104.7	104.4				104.5	104.5	104.7
	2046-2050				104.6	104.8	104.5				104.3	104.5	104.6
Hg sT:Quad	2016-2020	0.421	0.382	0.372	0.371	0.358		0.384	0.376	0.384	0.384	0.379	
	2021-2025	0.413	0.367	0.365	0.384	0.372	0.433	0.381	0.369	0.381	0.389	0.383	0.377
	2026-2030	0.413	0.383	0.381	0.407	0.371	0.415	0.381	0.365	0.379	0.387	0.382	0.377
	2031-2035	0.415	0.399	0.395	0.402	0.378	0.391	0.386	0.366	0.388	0.384	0.383	0.375
	2036-2040	0.398	0.406	0.381	0.385	0.368	0.374	0.389	0.365	0.385	0.377	0.380	0.373
	2041-2045				0.369	0.359	0.365				0.374	0.375	0.370
	2046-2050				0.369	0.357	0.354				0.373	0.373	0.367
Nox MMsT:Quad	2016-2020	0.078	0.101	0.092	0.096	0.080		0.075	0.078	0.068	0.067	0.066	
	2021-2025	0.076	0.095	0.098	0.097	0.081	0.114	0.075	0.078	0.067	0.065	0.064	0.062
	2026-2030	0.080	0.091	0.102	0.108	0.079	0.081	0.076	0.077	0.066	0.064	0.065	0.060
	2031-2035	0.082	0.094	0.107	0.107	0.073	0.070	0.077	0.076	0.067	0.064	0.066	0.058
	2036-2040	0.083	0.100	0.108	0.094	0.076	0.070	0.077	0.076	0.067	0.063	0.065	0.058
	2041-2045				0.088	0.066	0.071				0.063	0.065	0.057
	2046-2050				0.094	0.067	0.080				0.062	0.064	0.057
SO2 MMsT:Quad	2016-2020	0.125	0.109	0.089	0.098	0.080		0.080	0.080	0.086	0.085	0.085	
	2021-2025	0.140	0.105	0.076	0.101	0.081	0.067	0.083	0.078	0.084	0.088	0.087	0.085
	2026-2030	0.160	0.110	0.082	0.088	0.087	0.092	0.089	0.080	0.080	0.085	0.098	0.089
	2031-2035	0.160	0.101	0.083	0.071	0.092	0.088	0.090	0.082	0.084	0.092	0.103	0.092
	2036-2040	0.157	0.113	0.086	0.081	0.096	0.094	0.092	0.085	0.084	0.094	0.105	0.095
	2041-2045				0.085	0.102	0.096				0.095	0.106	0.096
	2046-2050				0.088	0.098	0.105				0.097	0.107	0.101

Table 8: Comparison of five-year average emissions intensities for coal, calculated based on marginal *vs.*grid-average data, for all AEO publications.

Plant	Period	Capacity Coefficients						Capacity Factors					
		AEO2014	AEO2015	AEO2016	AEO2017	AEO2018	AEO2019	AEO2014	AEO2015	AEO2016	AEO2017	AEO2018	AEO2019
Coal	2021-2025	0.158	0.153	0.163	0.170	0.187	0.204	0.721	0.744	0.700	0.671	0.613	0.563
	2026-2030	0.156	0.153	0.183	0.182	0.166	0.173	0.730	0.746	0.625	0.627	0.688	0.660
	2031-2035	0.157	0.154	0.188	0.182	0.167	0.166	0.727	0.741	0.606	0.626	0.683	0.686
	2036-2040	0.158	0.154	0.192	0.184	0.168	0.166	0.724	0.739	0.593	0.622	0.681	0.686
	2041-2045				0.184	0.169	0.166				0.621	0.677	0.686
	2046-2050				0.186	0.168	0.166				0.615	0.678	0.690
NGCC	2021-2025	0.222	0.257	0.248	0.254	0.229	0.223	0.515	0.444	0.463	0.450	0.500	0.513
	2026-2030	0.224	0.243	0.215	0.229	0.225	0.238	0.509	0.470	0.532	0.498	0.506	0.481
	2031-2035	0.231	0.246	0.214	0.229	0.227	0.248	0.493	0.464	0.533	0.498	0.502	0.460
	2036-2040	0.232	0.250	0.215	0.223	0.227	0.261	0.492	0.456	0.532	0.513	0.503	0.438
	2041-2045				0.219	0.229	0.271				0.522	0.499	0.421
	2046-2050				0.216	0.235	0.282				0.528	0.485	0.405
Peak	2021-2025	15.8	15.6	17.9	16.6	18.6	21.1	0.007	0.007	0.006	0.007	0.006	0.005
	2026-2030	16.4	16.0	19.8	20.2	21.1	23.6	0.007	0.007	0.006	0.006	0.005	0.005
	2031-2035	17.3	16.3	22.1	22.6	23.4	26.4	0.007	0.007	0.005	0.005	0.005	0.004
	2036-2040	18.3	16.7	25.7	24.7	25.2	28.6	0.006	0.007	0.004	0.005	0.005	0.004
	2041-2045				31.3	30.8	34.3				0.004	0.004	0.003
	2046-2050				36.4	36.1	38.6				0.003	0.003	0.003
Peak-Gas	2021-2025	0.713	0.573	0.546	0.754	0.873	1.015	0.160	0.199	0.209	0.151	0.131	0.112
	2026-2030	0.739	0.579	0.499	0.726	0.864	0.988	0.155	0.197	0.229	0.157	0.132	0.116
	2031-2035	0.774	0.586	0.485	0.717	0.865	0.992	0.148	0.195	0.235	0.159	0.132	0.115
	2036-2040	0.836	0.612	0.497	0.719	0.888	1.005	0.137	0.187	0.230	0.159	0.129	0.114
	2041-2045				0.748	0.940	1.025				0.153	0.121	0.111
	2046-2050				0.778	1.019	1.071				0.147	0.112	0.107
Peak-Oil	2021-2025	1.33	1.07	1.02	1.41	1.63	1.89	0.086	0.107	0.112	0.081	0.070	0.060
	2026-2030	1.38	1.08	0.93	1.35	1.61	1.84	0.083	0.106	0.123	0.084	0.071	0.062
	2031-2035	1.44	1.09	0.90	1.34	1.61	1.85	0.079	0.105	0.126	0.085	0.071	0.062
	2036-2040	1.56	1.14	0.93	1.34	1.66	1.87	0.073	0.100	0.123	0.085	0.069	0.061
	2041-2045				1.39	1.75	1.91				0.082	0.065	0.060
	2046-2050				1.45	1.90	2.00				0.079	0.060	0.057
Renewables	2021-2025	0.283	0.298	0.316	0.308	0.321	0.317	0.403	0.383	0.361	0.370	0.356	0.361
	2026-2030	0.275	0.293	0.314	0.306	0.317	0.316	0.415	0.390	0.363	0.373	0.360	0.361
	2031-2035	0.270	0.289	0.322	0.311	0.320	0.317	0.422	0.395	0.355	0.367	0.357	0.360
	2036-2040	0.272	0.287	0.328	0.317	0.324	0.321	0.420	0.397	0.348	0.360	0.353	0.356
	2041-2045				0.325	0.326	0.323				0.351	0.350	0.354
	2046-2050				0.329	0.330	0.325				0.347	0.346	0.352

Table 9: Five-year average apacity coefficients (equation 9), and capacity factors (equation 26), for all AEO publications.

Impact Factors for Marginal Heat Rates Quads/TWh

Commercial Sector	**2021-2025**	**2026-2030**	**2031-2035**	**2036-2040**	**2041-2045**	**2046-2050**
Space Cooling	9.54E-03	9.11E-03	9.02E-03	8.96E-03	8.90E-03	8.87E-03
Cooking	9.55E-03	9.12E-03	9.03E-03	8.98E-03	8.93E-03	8.91E-03
Space Heating	9.75E-03	9.37E-03	9.28E-03	9.22E-03	9.17E-03	9.15E-03
Lighting	9.58E-03	9.16E-03	9.07E-03	9.01E-03	8.96E-03	8.94E-03
Office Equipment (non-PC)	9.49E-03	9.05E-03	8.96E-03	8.91E-03	8.86E-03	8.84E-03
Office Equipment (PC)	9.49E-03	9.05E-03	8.96E-03	8.91E-03	8.86E-03	8.84E-03
Other Uses	9.52E-03	9.08E-03	8.99E-03	8.94E-03	8.89E-03	8.87E-03
Refrigeration	9.66E-03	9.26E-03	9.17E-03	9.11E-03	9.06E-03	9.04E-03
Ventilation	9.67E-03	9.27E-03	9.18E-03	9.12E-03	9.07E-03	9.04E-03
Water Heating	9.55E-03	9.12E-03	9.03E-03	8.97E-03	8.93E-03	8.91E-03
Residential Sector	**2021-2025**	**2026-2030**	**2031-2035**	**2036-2040**	**2041-2045**	**2046-2050**
Space Cooling	9.57E-03	9.15E-03	9.06E-03	8.99E-03	8.94E-03	8.91E-03
Cooking	9.66E-03	9.26E-03	9.17E-03	9.11E-03	9.06E-03	9.04E-03
Clothes Dryers	9.68E-03	9.28E-03	9.19E-03	9.13E-03	9.08E-03	9.06E-03
Freezers	9.70E-03	9.32E-03	9.23E-03	9.16E-03	9.11E-03	9.08E-03
Space Heating	9.74E-03	9.36E-03	9.27E-03	9.21E-03	9.16E-03	9.13E-03
Lighting	9.72E-03	9.33E-03	9.24E-03	9.18E-03	9.13E-03	9.11E-03
Other Uses	9.68E-03	9.28E-03	9.19E-03	9.13E-03	9.08E-03	9.06E-03
Refrigeration	9.70E-03	9.31E-03	9.22E-03	9.16E-03	9.11E-03	9.08E-03
Water Heating	9.69E-03	9.29E-03	9.20E-03	9.15E-03	9.09E-03	9.07E-03

Impact Factors for Marginal CO2 Emissions MMsT/TWh

Commercial Sector	**2021-2025**	**2026-2030**	**2031-2035**	**2036-2040**	**2041-2045**	**2046-2050**
Space Cooling	5.45E-01	5.04E-01	4.85E-01	4.64E-01	4.46E-01	4.32E-01
Cooking	5.41E-01	5.01E-01	4.82E-01	4.60E-01	4.42E-01	4.27E-01
Space Heating	6.21E-01	5.81E-01	5.60E-01	5.34E-01	5.14E-01	4.97E-01
Lighting	5.54E-01	5.14E-01	4.94E-01	4.72E-01	4.54E-01	4.38E-01
Office Equipment (non-PC)	5.20E-01	4.80E-01	4.61E-01	4.40E-01	4.23E-01	4.08E-01
Office Equipment (PC)	5.20E-01	4.80E-01	4.61E-01	4.40E-01	4.23E-01	4.08E-01
Other Uses	5.29E-01	4.89E-01	4.71E-01	4.49E-01	4.32E-01	4.16E-01
Refrigeration	5.87E-01	5.47E-01	5.27E-01	5.03E-01	4.84E-01	4.68E-01
Ventilation	5.88E-01	5.49E-01	5.28E-01	5.04E-01	4.85E-01	4.69E-01
Water Heating	5.40E-01	5.00E-01	4.81E-01	4.59E-01	4.41E-01	4.26E-01
Residential Sector	**2021-2025**	**2026-2030**	**2031-2035**	**2036-2040**	**2041-2045**	**2046-2050**
Space Cooling	5.57E-01	5.16E-01	4.97E-01	4.75E-01	4.57E-01	4.42E-01
Cooking	5.86E-01	5.46E-01	5.26E-01	5.02E-01	4.83E-01	4.67E-01
Clothes Dryers	5.94E-01	5.54E-01	5.34E-01	5.09E-01	4.90E-01	4.73E-01
Freezers	6.05E-01	5.65E-01	5.44E-01	5.20E-01	5.00E-01	4.83E-01
Space Heating	6.16E-01	5.77E-01	5.55E-01	5.30E-01	5.10E-01	4.93E-01
Lighting	6.08E-01	5.68E-01	5.47E-01	5.22E-01	5.02E-01	4.85E-01
Other Uses	5.93E-01	5.54E-01	5.33E-01	5.09E-01	4.89E-01	4.73E-01
Refrigeration	6.04E-01	5.65E-01	5.44E-01	5.19E-01	4.99E-01	4.83E-01
Water Heating	5.96E-01	5.57E-01	5.36E-01	5.11E-01	4.92E-01	4.75E-01

Table 10: Impact factors for AEO2019 Reference case, for heat rates and CO_2 emissions, by sector and end use.

Impact Factors for Marginal NOx Emissions MMsT/TWh

Commercial Sector	2021-2025	2026-2030	2031-2035	2036-2040	2041-2045	2046-2050
Space Cooling	4.90E-04	3.23E-04	2.67E-04	2.52E-04	2.47E-04	2.66E-04
Cooking	4.85E-04	3.21E-04	2.65E-04	2.50E-04	2.45E-04	2.63E-04
Space Heating	5.85E-04	3.91E-04	3.24E-04	3.06E-04	3.01E-04	3.24E-04
Lighting	5.01E-04	3.32E-04	2.74E-04	2.59E-04	2.54E-04	2.73E-04
Office Equipment (non-PC)	4.58E-04	3.02E-04	2.49E-04	2.35E-04	2.30E-04	2.47E-04
Office Equipment (PC)	4.58E-04	3.02E-04	2.49E-04	2.35E-04	2.30E-04	2.47E-04
Other Uses	4.70E-04	3.10E-04	2.56E-04	2.42E-04	2.37E-04	2.54E-04
Refrigeration	5.43E-04	3.61E-04	2.99E-04	2.82E-04	2.77E-04	2.98E-04
Ventilation	5.44E-04	3.62E-04	3.00E-04	2.83E-04	2.78E-04	2.99E-04
Water Heating	4.84E-04	3.20E-04	2.64E-04	2.49E-04	2.44E-04	2.62E-04
Residential Sector	**2021-2025**	**2026-2030**	**2031-2035**	**2036-2040**	**2041-2045**	**2046-2050**
Space Cooling	5.04E-04	3.34E-04	2.76E-04	2.60E-04	2.55E-04	2.75E-04
Cooking	5.41E-04	3.60E-04	2.99E-04	2.82E-04	2.76E-04	2.97E-04
Clothes Dryers	5.51E-04	3.67E-04	3.04E-04	2.87E-04	2.82E-04	3.03E-04
Freezers	5.65E-04	3.77E-04	3.12E-04	2.95E-04	2.89E-04	3.12E-04
Space Heating	5.79E-04	3.87E-04	3.21E-04	3.03E-04	2.97E-04	3.20E-04
Lighting	5.69E-04	3.80E-04	3.15E-04	2.97E-04	2.91E-04	3.14E-04
Other Uses	5.50E-04	3.67E-04	3.04E-04	2.87E-04	2.81E-04	3.03E-04
Refrigeration	5.64E-04	3.76E-04	3.12E-04	2.94E-04	2.89E-04	3.11E-04
Water Heating	5.54E-04	3.69E-04	3.06E-04	2.89E-04	2.83E-04	3.05E-04

Impact Factors for Marginal SO2 Emissions MMsT/TWh

Commercial Sector	2021-2025	2026-2030	2031-2035	2036-2040	2041-2045	2046-2050
Space Cooling	2.14E-04	2.76E-04	2.47E-04	2.47E-04	2.40E-04	2.52E-04
Cooking	2.12E-04	2.74E-04	2.46E-04	2.46E-04	2.39E-04	2.51E-04
Space Heating	2.81E-04	3.66E-04	3.31E-04	3.32E-04	3.24E-04	3.42E-04
Lighting	2.23E-04	2.88E-04	2.59E-04	2.59E-04	2.52E-04	2.65E-04
Office Equipment (non-PC)	1.94E-04	2.49E-04	2.23E-04	2.23E-04	2.16E-04	2.27E-04
Office Equipment (PC)	1.94E-04	2.49E-04	2.23E-04	2.23E-04	2.16E-04	2.27E-04
Other Uses	2.02E-04	2.60E-04	2.33E-04	2.33E-04	2.26E-04	2.37E-04
Refrigeration	2.52E-04	3.27E-04	2.94E-04	2.95E-04	2.88E-04	3.03E-04
Ventilation	2.53E-04	3.28E-04	2.96E-04	2.97E-04	2.89E-04	3.05E-04
Water Heating	2.11E-04	2.73E-04	2.45E-04	2.45E-04	2.38E-04	2.50E-04
Residential Sector	**2021-2025**	**2026-2030**	**2031-2035**	**2036-2040**	**2041-2045**	**2046-2050**
Space Cooling	2.24E-04	2.90E-04	2.60E-04	2.60E-04	2.52E-04	2.65E-04
Cooking	2.51E-04	3.26E-04	2.93E-04	2.94E-04	2.86E-04	3.02E-04
Clothes Dryers	2.57E-04	3.35E-04	3.02E-04	3.02E-04	2.95E-04	3.11E-04
Freezers	2.67E-04	3.47E-04	3.13E-04	3.14E-04	3.06E-04	3.23E-04
Space Heating	2.77E-04	3.61E-04	3.26E-04	3.27E-04	3.19E-04	3.37E-04
Lighting	2.69E-04	3.51E-04	3.16E-04	3.18E-04	3.10E-04	3.27E-04
Other Uses	2.57E-04	3.34E-04	3.01E-04	3.02E-04	2.94E-04	3.10E-04
Refrigeration	2.66E-04	3.46E-04	3.12E-04	3.13E-04	3.05E-04	3.22E-04
Water Heating	2.59E-04	3.38E-04	3.04E-04	3.05E-04	2.98E-04	3.14E-04

Table 11: Impact factors for AEO2019 Reference case, for NO_x and SO_2 emissions, by sector and end use.

Impact Factors for Marginal CH4 Emissions MMsT/TWh

Commercial Sector	2021-2025	2026-2030	2031-2035	2036-2040	2041-2045	2046-2050
Space Cooling	4.19E-05	3.94E-05	3.72E-05	3.51E-05	3.34E-05	3.21E-05
Cooking	4.21E-05	3.95E-05	3.73E-05	3.52E-05	3.35E-05	3.22E-05
Space Heating	5.42E-05	5.14E-05	4.88E-05	4.61E-05	4.40E-05	4.25E-05
Lighting	4.39E-05	4.13E-05	3.91E-05	3.68E-05	3.51E-05	3.38E-05
Office Equipment (non-PC)	3.88E-05	3.62E-05	3.42E-05	3.22E-05	3.06E-05	2.94E-05
Office Equipment (PC)	3.88E-05	3.62E-05	3.42E-05	3.22E-05	3.06E-05	2.94E-05
Other Uses	4.02E-05	3.76E-05	3.56E-05	3.35E-05	3.19E-05	3.06E-05
Refrigeration	4.90E-05	4.63E-05	4.39E-05	4.14E-05	3.95E-05	3.81E-05
Ventilation	4.92E-05	4.65E-05	4.41E-05	4.16E-05	3.97E-05	3.82E-05
Water Heating	4.19E-05	3.93E-05	3.72E-05	3.50E-05	3.33E-05	3.21E-05
Residential Sector	**2021-2025**	**2026-2030**	**2031-2035**	**2036-2040**	**2041-2045**	**2046-2050**
Space Cooling	4.37E-05	4.11E-05	3.89E-05	3.67E-05	3.50E-05	3.37E-05
Cooking	4.88E-05	4.61E-05	4.37E-05	4.12E-05	3.93E-05	3.79E-05
Clothes Dryers	5.00E-05	4.73E-05	4.48E-05	4.23E-05	4.04E-05	3.89E-05
Freezers	5.16E-05	4.89E-05	4.63E-05	4.37E-05	4.17E-05	4.02E-05
Space Heating	5.36E-05	5.08E-05	4.82E-05	4.55E-05	4.34E-05	4.19E-05
Lighting	5.22E-05	4.94E-05	4.69E-05	4.43E-05	4.23E-05	4.07E-05
Other Uses	4.99E-05	4.72E-05	4.47E-05	4.22E-05	4.03E-05	3.88E-05
Refrigeration	5.15E-05	4.88E-05	4.62E-05	4.37E-05	4.17E-05	4.02E-05
Water Heating	5.05E-05	4.77E-05	4.52E-05	4.27E-05	4.07E-05	3.93E-05

Impact Factors for Marginal Hg Emissions sT/TWh

Commercial Sector	2021-2025	2026-2030	2031-2035	2036-2040	2041-2045	2046-2050
Space Cooling	1.35E-03	1.22E-03	1.08E-03	9.67E-04	8.94E-04	8.33E-04
Cooking	1.36E-03	1.23E-03	1.08E-03	9.75E-04	9.02E-04	8.40E-04
Space Heating	1.82E-03	1.66E-03	1.47E-03	1.33E-03	1.23E-03	1.15E-03
Lighting	1.43E-03	1.29E-03	1.14E-03	1.03E-03	9.52E-04	8.88E-04
Office Equipment (non-PC)	1.23E-03	1.11E-03	9.79E-04	8.79E-04	8.12E-04	7.55E-04
Office Equipment (PC)	1.23E-03	1.11E-03	9.79E-04	8.79E-04	8.12E-04	7.55E-04
Other Uses	1.29E-03	1.16E-03	1.02E-03	9.20E-04	8.51E-04	7.92E-04
Refrigeration	1.62E-03	1.47E-03	1.31E-03	1.18E-03	1.09E-03	1.02E-03
Ventilation	1.63E-03	1.48E-03	1.31E-03	1.18E-03	1.10E-03	1.02E-03
Water Heating	1.35E-03	1.22E-03	1.08E-03	9.70E-04	8.97E-04	8.36E-04
Residential Sector	**2021-2025**	**2026-2030**	**2031-2035**	**2036-2040**	**2041-2045**	**2046-2050**
Space Cooling	1.41E-03	1.28E-03	1.13E-03	1.02E-03	9.43E-04	8.80E-04
Cooking	1.61E-03	1.46E-03	1.30E-03	1.17E-03	1.08E-03	1.01E-03
Clothes Dryers	1.66E-03	1.51E-03	1.34E-03	1.20E-03	1.12E-03	1.04E-03
Freezers	1.72E-03	1.56E-03	1.39E-03	1.25E-03	1.16E-03	1.08E-03
Space Heating	1.79E-03	1.63E-03	1.45E-03	1.31E-03	1.21E-03	1.14E-03
Lighting	1.74E-03	1.58E-03	1.41E-03	1.27E-03	1.18E-03	1.10E-03
Other Uses	1.65E-03	1.50E-03	1.33E-03	1.20E-03	1.11E-03	1.04E-03
Refrigeration	1.71E-03	1.56E-03	1.38E-03	1.25E-03	1.16E-03	1.08E-03
Water Heating	1.67E-03	1.52E-03	1.35E-03	1.22E-03	1.13E-03	1.06E-03

Table 12: Impact factors for AEO2019 Reference case, for CH_4 and Hg emissions, by sector and end use.

Impact Factors for Capacity Changes-Coal GW/TWh

Commercial Sector	2021-2025	2026-2030	2031-2035	2036-2040	2041-2045	2046-2050
Space Cooling	6.16E-02	4.92E-02	4.42E-02	4.16E-02	3.96E-02	3.79E-02
Cooking	6.22E-02	4.96E-02	4.46E-02	4.20E-02	3.99E-02	3.82E-02
Space Heating	8.32E-02	6.70E-02	6.05E-02	5.72E-02	5.46E-02	5.24E-02
Lighting	6.54E-02	5.23E-02	4.70E-02	4.43E-02	4.22E-02	4.04E-02
Office Equipment (non-PC)	5.65E-02	4.49E-02	4.03E-02	3.78E-02	3.60E-02	3.43E-02
Office Equipment (PC)	5.65E-02	4.49E-02	4.03E-02	3.78E-02	3.60E-02	3.43E-02
Other Uses	5.89E-02	4.69E-02	4.21E-02	3.96E-02	3.77E-02	3.60E-02
Refrigeration	7.41E-02	5.95E-02	5.37E-02	5.06E-02	4.83E-02	4.63E-02
Ventilation	7.45E-02	5.98E-02	5.39E-02	5.09E-02	4.85E-02	4.65E-02
Water Heating	6.19E-02	4.94E-02	4.44E-02	4.18E-02	3.97E-02	3.80E-02
Residential Sector	**2021-2025**	**2026-2030**	**2031-2035**	**2036-2040**	**2041-2045**	**2046-2050**
Space Cooling	6.47E-02	5.18E-02	4.66E-02	4.39E-02	4.18E-02	4.00E-02
Cooking	7.38E-02	5.92E-02	5.34E-02	5.04E-02	4.80E-02	4.61E-02
Clothes Dryers	7.59E-02	6.09E-02	5.50E-02	5.19E-02	4.95E-02	4.74E-02
Freezers	7.85E-02	6.32E-02	5.70E-02	5.38E-02	5.13E-02	4.93E-02
Space Heating	8.20E-02	6.60E-02	5.96E-02	5.63E-02	5.38E-02	5.16E-02
Lighting	7.97E-02	6.41E-02	5.79E-02	5.46E-02	5.21E-02	5.00E-02
Other Uses	7.57E-02	6.08E-02	5.49E-02	5.18E-02	4.94E-02	4.73E-02
Refrigeration	7.84E-02	6.30E-02	5.69E-02	5.37E-02	5.12E-02	4.92E-02
Water Heating	7.67E-02	6.16E-02	5.56E-02	5.25E-02	5.00E-02	4.80E-02

Impact Factors for Capacity Changes-NGCC GW/TWh

Commercial Sector	2021-2025	2026-2030	2031-2035	2036-2040	2041-2045	2046-2050
Space Cooling	1.06E-01	1.15E-01	1.23E-01	1.29E-01	1.34E-01	1.38E-01
Cooking	1.05E-01	1.14E-01	1.22E-01	1.27E-01	1.31E-01	1.34E-01
Space Heating	9.01E-02	9.89E-02	1.07E-01	1.12E-01	1.16E-01	1.18E-01
Lighting	1.02E-01	1.12E-01	1.20E-01	1.25E-01	1.29E-01	1.32E-01
Office Equipment (non-PC)	1.09E-01	1.18E-01	1.26E-01	1.31E-01	1.36E-01	1.39E-01
Office Equipment (PC)	1.09E-01	1.18E-01	1.26E-01	1.31E-01	1.36E-01	1.39E-01
Other Uses	1.07E-01	1.16E-01	1.24E-01	1.29E-01	1.34E-01	1.37E-01
Refrigeration	9.64E-02	1.06E-01	1.13E-01	1.19E-01	1.23E-01	1.26E-01
Ventilation	9.62E-02	1.05E-01	1.13E-01	1.18E-01	1.23E-01	1.25E-01
Water Heating	1.05E-01	1.14E-01	1.22E-01	1.27E-01	1.32E-01	1.34E-01
Residential Sector	**2021-2025**	**2026-2030**	**2031-2035**	**2036-2040**	**2041-2045**	**2046-2050**
Space Cooling	1.04E-01	1.13E-01	1.21E-01	1.27E-01	1.32E-01	1.35E-01
Cooking	9.67E-02	1.06E-01	1.14E-01	1.19E-01	1.23E-01	1.26E-01
Clothes Dryers	9.53E-02	1.04E-01	1.12E-01	1.17E-01	1.22E-01	1.24E-01
Freezers	9.35E-02	1.03E-01	1.10E-01	1.16E-01	1.20E-01	1.23E-01
Space Heating	9.09E-02	9.97E-02	1.07E-01	1.13E-01	1.17E-01	1.19E-01
Lighting	9.25E-02	1.01E-01	1.09E-01	1.14E-01	1.19E-01	1.21E-01
Other Uses	9.54E-02	1.04E-01	1.12E-01	1.17E-01	1.22E-01	1.24E-01
Refrigeration	9.36E-02	1.03E-01	1.10E-01	1.16E-01	1.20E-01	1.23E-01
Water Heating	9.46E-02	1.04E-01	1.11E-01	1.17E-01	1.21E-01	1.23E-01

Table 13: Impact factors for AEO2019 Reference case, for coal and natural gas combined-cycle capacity, by sector and end use.

Impact Factors for Capacity Changes-Peak GW/TWh

Commercial Sector	2021-2025	2026-2030	2031-2035	2036-2040	2041-2045	2046-2050
Space Cooling	1.79E-01	1.64E-01	1.57E-01	1.52E-01	1.48E-01	1.47E-01
Cooking	7.36E-02	6.74E-02	6.49E-02	6.27E-02	6.11E-02	6.06E-02
Space Heating	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Lighting	6.84E-02	6.25E-02	6.02E-02	5.82E-02	5.67E-02	5.62E-02
Office Equipment (non-PC)	1.00E-01	9.17E-02	8.83E-02	8.54E-02	8.32E-02	8.25E-02
Office Equipment (PC)	1.00E-01	9.17E-02	8.83E-02	8.54E-02	8.32E-02	8.25E-02
Other Uses	9.00E-02	8.23E-02	7.93E-02	7.67E-02	7.46E-02	7.40E-02
Refrigeration	4.49E-02	4.11E-02	3.96E-02	3.83E-02	3.73E-02	3.70E-02
Ventilation	4.25E-02	3.89E-02	3.75E-02	3.62E-02	3.53E-02	3.50E-02
Water Heating	7.02E-02	6.43E-02	6.19E-02	5.98E-02	5.82E-02	5.78E-02
Residential Sector	**2021-2025**	**2026-2030**	**2031-2035**	**2036-2040**	**2041-2045**	**2046-2050**
Space Cooling	1.65E-01	1.51E-01	1.45E-01	1.40E-01	1.36E-01	1.35E-01
Cooking	4.93E-02	4.51E-02	4.34E-02	4.20E-02	4.09E-02	4.05E-02
Clothes Dryers	4.34E-02	3.97E-02	3.82E-02	3.69E-02	3.60E-02	3.57E-02
Freezers	4.79E-02	4.38E-02	4.22E-02	4.08E-02	3.97E-02	3.94E-02
Space Heating	2.06E-03	1.88E-03	1.81E-03	1.75E-03	1.71E-03	1.69E-03
Lighting	1.57E-02	1.44E-02	1.39E-02	1.34E-02	1.31E-02	1.29E-02
Other Uses	4.10E-02	3.75E-02	3.61E-02	3.49E-02	3.40E-02	3.37E-02
Refrigeration	4.65E-02	4.25E-02	4.09E-02	3.96E-02	3.85E-02	3.82E-02
Water Heating	2.65E-02	2.43E-02	2.34E-02	2.26E-02	2.20E-02	2.18E-02

Impact Factors for Capacity Changes-Renewable Sources GW/TWh

Commercial Sector	2021-2025	2026-2030	2031-2035	2036-2040	2041-2045	2046-2050
Space Cooling	9.15E-02	9.39E-02	9.70E-02	1.03E-01	1.09E-01	1.14E-01
Cooking	9.38E-02	9.63E-02	9.94E-02	1.07E-01	1.12E-01	1.19E-01
Space Heating	8.28E-02	8.56E-02	8.92E-02	9.68E-02	1.03E-01	1.09E-01
Lighting	9.20E-02	9.45E-02	9.77E-02	1.05E-01	1.11E-01	1.17E-01
Office Equipment (non-PC)	9.66E-02	9.90E-02	1.02E-01	1.09E-01	1.15E-01	1.21E-01
Office Equipment (PC)	9.66E-02	9.90E-02	1.02E-01	1.09E-01	1.15E-01	1.21E-01
Other Uses	9.54E-02	9.78E-02	1.01E-01	1.08E-01	1.13E-01	1.20E-01
Refrigeration	8.72E-02	8.99E-02	9.33E-02	1.01E-01	1.06E-01	1.13E-01
Ventilation	8.71E-02	8.97E-02	9.31E-02	1.00E-01	1.06E-01	1.13E-01
Water Heating	9.40E-02	9.65E-02	9.96E-02	1.07E-01	1.12E-01	1.19E-01
Residential Sector	**2021-2025**	**2026-2030**	**2031-2035**	**2036-2040**	**2041-2045**	**2046-2050**
Space Cooling	8.99E-02	9.24E-02	9.55E-02	1.02E-01	1.07E-01	1.13E-01
Cooking	8.73E-02	9.00E-02	9.33E-02	1.01E-01	1.06E-01	1.13E-01
Clothes Dryers	8.62E-02	8.89E-02	9.23E-02	9.96E-02	1.05E-01	1.12E-01
Freezers	8.45E-02	8.72E-02	9.07E-02	9.79E-02	1.04E-01	1.10E-01
Space Heating	8.35E-02	8.62E-02	8.98E-02	9.74E-02	1.03E-01	1.10E-01
Lighting	8.46E-02	8.73E-02	9.08E-02	9.83E-02	1.04E-01	1.11E-01
Other Uses	8.64E-02	8.90E-02	9.25E-02	9.98E-02	1.06E-01	1.12E-01
Refrigeration	8.46E-02	8.73E-02	9.08E-02	9.81E-02	1.04E-01	1.10E-01
Water Heating	8.62E-02	8.88E-02	9.23E-02	9.97E-02	1.06E-01	1.12E-01

Table 14: Impact factors for AEO2019 Reference case, for peak and renewable capacity, by sector and end use.