RHODIUM GROUP

Assessing the Effect of Rising Temperatures

The Cost of Climate Change to the U.S. Power Sector

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About the Authors

Rhodium Group (RHG) combines policy experience, quantitative analysis and on-the-ground fieldwork to analyze disruptive global trends. Our independent research supports the investment management, strategic planning, and policy analysis needs of clients in the financial, corporate, non-profit and government sectors. RHG has offices in New York, California and Hong Kong, and associates in Washington, Singapore and New Delhi.

Kate Larsen is a Director at RHG and manages the firm's work on US and global climate change issues. Previously, Kate worked at the White House Council on Environmental Quality where she was Deputy Director for Energy and Climate Change. From 2007 to 2013, Kate worked in the Office of Climate Change at the US Department of State, serving as lead US negotiator on mitigation commitments and compliance in the UN climate negotiations. She was a primary architect of the first universal system for measurement, reporting, and verification of developed and developing country emissions and commitments under the UN, and continues to advise NASA and other organizations on greenhouse gas monitoring and accounting.

John Larsen is a Director at RHG and leads the firm's U.S. power-sector work. Previously, he worked for the U.S. Department of Energy's Office of Energy Policy and Systems Analysis, where he advised on electric power-sector policy design. Prior to working in government, he led federal and congressional policy analysis in the World Resources Institute's Climate and Energy Program. Mr. Larsen is a non-resident Senior Associate in the Energy and National Security Program at the Center for Strategic and International Studies and holds a bachelor's degree in environmental science from the University of Massachusetts at Amherst and a master's degree in urban and environmental policy and planning from Tufts University.

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This report builds on work developed by the Climate Impact Lab , a collaboration between the University of California Berkeley, the University of Chicago, Rutgers University and the Rhodium Group. The Climate Impact Lab leverages cutting-edge climate, economic, and data science to help decision-makers understand the risks climate change presents to our communities and our world.

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Executive Summary

Every day, the U.S. electric power sector responds to a range of weather conditions. As climate change begins to move these weather conditions—in particular temperature—outside the bounds of our historical experience, the electric power system becomes increasingly vulnerable to reduced performance and disruption. In this report we assess the risk of climate change to the U.S. electric power sector based on temperature-related shifts in energy demand and electric power generation over the next 25 years. Based on highly granular modeling of a range of climate futures, we assess the potential change in seasonal and daily temperatures for all counties across the United States and the impact on regional residential and commercial demand for space heating and cooling. When combined with temperature-induced penalties on thermal power generation efficiency and capacity, we are able to estimate the integrated effect of climate-related temperature change on electricity demand; the change in expected electric generation and capacity to meet that new demand; and changes to electricity expenditures and the total system-wide costs to the electric power sector from climate-induced temperature change. We find that:

By 2040, much of the continental United States is projected to experience warmer summers and a rise in the number of extreme-heat days (those with maximum temperatures over 95°F). The average American has historically experienced around two weeks each year of days over 95°F. With climate change under a high emissions scenario (i.e., RCP 8.5, explained in the "Climate Futures" section of this report) in 2040, that same person will *likely* (67% probability) experience three to six weeks (25-40 days) each year on average.[i] Much of Texas and the West South Central region can expect to experience two to three months of these extreme-heat days every year.

As a result, national residential and commercial electricity demand is projected to rise due to increased demand for space cooling. With unabated climate change, residential and commercial electricity demand will *likely* rise 3-9% above levels expected if historical climate conditions were to continue through 2040, with a 1-in-20 risk that demand rises over 12%. Across the Middle Atlantic – the region with the highest median jump in demand - we find *likely* increases of 4-15%, with a 1-in-20 risk of an over 20% increase in electricity demand across the region on average by 2040. Even under a low global greenhouse gas (GHG) emissions pathway (i.e. RCP 2.6, explained in the "Climate Futures" section), additional warming will *likely* increase residential and commercial electricity demand 2-7% nationwide by 2040. These changes are in addition to any other changes in electricity demand that may occcur from other market or socioeconomic developments between now and 2040.

Spending on residential and commercial electricity is also expected to rise, with a likely nationwide increase of 6-18% and a 1-in-20 chance that expenditures will rise over 23%. Customers in the Middle Atlantic, Mountain, and East North Central see the largest median rise in electricity expenditures.

To meet increasing demand for space cooling and offset supply-side losses due to temperature-related efficiency pentalities, total electricity generation will likely increase by 2-4% under RCP 8.5 when compared to a "historical climate" scenario (where temperatures remain at the 1981-2010 average through 2040). We project that most of this extra generation will consist of natural gas combined cycle (NGCC) and solar photovoltaics (PV) power plants, with combustion turbines contributing to meet peak loads.

Climate change will also require significant changes in the scale and type of new generation capacity that is brought online. To meet increasing system demands, total generating capacity is projected to increase 10-25% under RCP 8.5. Solar PV is one technology that increases in capacity relative to a historical climate scenario to meet system demands. However, fossil fuel-fired combustion turbine peaker plants could also see significant expansion relative to a historical climate scenario. Climate change under RCP 8.5 could lead to a more than doubling of combustion turbine capacity from today's levels by 2040. This situation will put upward pressure on electric power system-wide costs.

1. Introduction

From the wells and pipelines that supply oil and natural gas to fuel our cars and power plants to infrastructure that delivers electricity to power appliances in our homes and offices, American energy systems are extremely sensitive to seasonal and even daily changes in weather conditions. The U.S. electric power sector is particularly vulnerable. Over the course of the last few decades, rising temperatures and increasing frequency of extreme weather events like heat waves, intense precipitation events, and wildfires have revealed the vulnerability of our electric power system to a changing climate and the growing need to understand the potential magnitude of such risks going forward.[ii]

Over the course of the next few decades, continued climate change will only exacerbate the risks facing the U.S. electric power sector. Rising average and extreme temperatures, drought and increasingly scarce water resources, more frequent and intense storms, sea-level rise and flooding will all affect the cost and reliability of U.S. electric power supply. Most of the vulnerabilities and risks are unique to local and regional circumstances; fuel facilities and infrastructure along the Gulf Coast are particularly at risk from wind and storm surge damage by hurricanes, for example, while power plants and transmission lines in the Southwest are particularly at risk of extreme drought and more frequent wildfires.[iii]

Rising temperatures are the most widespread climate risk factor the U.S. electric power sector faces; few states will be immune to the effects. These risks come not just from extreme temperature spikes like heatwaves, but also from the more gradual warming of average temperatures that can shift patterns of energy use, as Americans turn increasingly to air conditioning to cope with warmer summers. Spikes in electricity demand during hot summer afternoons when the electric load is already at its peak can put a serious strain on critical energy infrastructure across the country. Under all plausible future scenarios, global climate change is expected to result in increasingly warmer average temperatures across the U.S. in the coming decades.[iv]

These changes will likely have a material effect on patterns of energy demand and supply as local conditions move away from the historical norms currently used for resource and infrastructure planning and investments. The more we understand about the range of potential risks rising temperatures pose to the U.S. energy system, the more effectively policymakers, energy industry officials, and planners can incorporate those risks into near- and long-term planning to enhance resilience and mitigate the factors that cause climate change.

In this report we assess the risk of climate-related changes in temperature to the U.S. electric power sector including impacts to energy demand and electric power generation over the next 25 years. Although there are myriad potential impacts of climate change on the U.S. power sector (including extreme precipitation events like hurricanes and associated flooding and impacts on water resources available for use in thermal cooling and hydropower generation) we focus exclusively on temperature-related impacts here because of our high confidence in our ability to project temperature extremes and the ability of our energy models to account for those impacts.[v,vi,vii]

In the first section of this report, we provide an overview of highly granular modeling of the range of climate futures the United States may face and the localized impact on average and extreme temperatures across the United States in the 2030-2049 timeframe. In the second section, we assess what these potential changes mean for regional residential and commercial energy demand. In the third section, we discuss the temperature-related impacts on thermal electric generation and the resulting effects on electric supply. Finally, in the fourth section, we assess the integrated effect of temperature-related demand and supply-side impacts from three potential climate futures on electric generation and capacity additions out to 2040, the effect on regional spending on electricity, and the total system-wide costs to the electric power sector from climate change.

2. A Changing Climate

Across the continental United States, Americans have been experiencing warmer than usual conditions over the past few decades. In all but two of the last 20 years, the annual average temperature was higher than the long-term average (1901-1960), and 12 of the last 14 summers have been hotter than average.[viii] As we demonstrate below, temperatures are expected to rise even further over the coming decades even under the most optimistic climate change scenarios. Understanding the distribution and magnitude of expected changes in seasonal and daily temperatures across the United States under future climate scenarios can help planners prepare for a range of potential impacts to the electric power sector.

To determine how projections of future temperatures may differ from conditions we know today, we assess local and regional temperatures across the United States using climate projections developed as part of the Coupled Model Intercomparison Project Phase 5 (CMIP5) with a suite of over 30 different global climate models. This suite of complex models has become the gold standard for use in global climate assessments (including by the Intergovernmental Panel on Climate Change (IPCC)'s Fifth Assessment Report (AR5) as well as for regional assessments, including the 3rd U.S. National Climate Assessment released in 2014).[ix] Major U.S.-based models participating in CMIP5 have been developed by teams led by the NASA Goddard Institute for Space Studies, the NOAA Geophysical Fluid Dynamics Laboratory, and the National Center for Atmospheric Research.

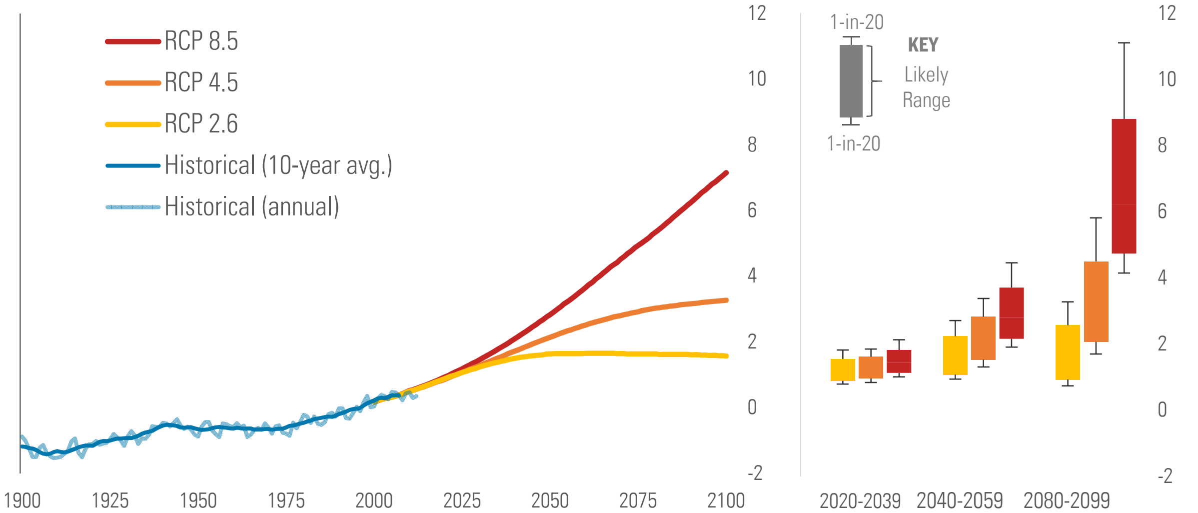
Uncertainty in the equilibrium climate sensitivity - the magnitude and timescale of the planet's response to a given change in radiative forcing - is a major contributor to overall uncertainty in projections of future climate change and its potential impacts. Many past climate impact assessments have focused only on the "best estimates" of climate sensitivity. To capture a broader range of potential outcomes, we use the Model for the Assessment of Greenhouse-gas Induced Climate Change (MAGICC), a commonly-employed simple climate model[x] that can emulate the results of more complex models and can be run hundreds of times to capture the spread in estimates of climate sensitivity and other key climate parameters. MAGICC's model parameters are calibrated against historical observations[xi,xii] and the IPCC's estimated distribution of climate sensitivity.[xiii]

To account for uncertainty surrounding global greenhouse gas (GHG) emissions pathways, we assess three potential climate futures termed "Representative Concentration Pathways" (RCPs). These pathways span a plausible range of future global atmospheric GHG concentrations and are associated with varying levels of climate change. At the high end of the range, RCP 8.5 represents a world where fossil fuels continue to power robust global economic growth, and this high GHG emissions pathway is consistent with a world that is absent climate policy by major emitting countries. At the low end of the range, RCP 2.6 reflects a future only achievable by aggressively reducing global emissions (even achieving net negative emissions by the last quarter of this century) through a rapid transition to low-carbon energy sources. The intermediate pathway (RCP 4.5) is consistent with a modest slowdown in global economic growth and/or a shift away from fossil fuels more gradual than in RCP 2.6. For comparative purposes, a "historical climate" scenario is also considered, in which average historical climate conditions (i.e., for the period from 1981-2010) continue through 2040.

Under all three future climate pathways, average global temperatures rise over the course of the century. By mid-century under RCP 8.5, global average temperature will *likely* (67% probability) rise between 2.2 and 3.7°F from historical levels (i.e., 1981-2010 average). Even under RCP 2.6, global average temperatures will *likely* increase by 1.1 to 2.2°F by mid-century. By the end of the century, the differences between future pathways are even larger (see Figure 1).

Figure I: Global average temperature projections under three future climate pathways

Change (°F) relative to 1981-2010 average, median projections (left), confidence intervals (right)

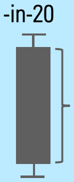


Source: Houser, T., S. M. Hsiang, R. E. Kopp, K. Larsen, M. Delgado, A. S. Jina, M. D. Mastrandrea, S. Mohan, R. Muir-Wood, D. J. Rasmussen, J. Rising, and P. Wilson. Economic Risks of Climate Change: An American Prospectus (New York: Columbia University Press, 2015), 24

TEXT BOX I: DEFINING LIKELYHOOD

In presenting our results we use the term "*likely*" to describe outcomes with a 67% probability of occurring within a stated range (corresponding to p-values of 16.7 and 83.3). For tail risks, we describe results as having a 1-in-20 chance of being above or below a stated threshold (corresponding with p-values of 5 and 95).

1-in-20 (5% chance outcome is above this value)



Likely Range (67% chance)

1-in-20 (5% chance outcome is below this value)

Because land warms faster than the oceans, the average land temperature increase across the continental United States over the 21st century will, *more likely than not*, be even greater than the global average, *likely* rising 1.9 to 3.5°F under RCP 2.6 and 2.6 to 5.8°F under RCP 8.5. This change is on top of the approximately 1.5°F of warming the United States has already experienced over the past century, with the majority of that warming (over 80%) occurring in the last 30 years.[xiv,xv]

For the remainder of the report, we present results for the continental United States for the 20-year period centered on the year 2040 (i.e., 2030-2049).[xvi] Using multi-decadal averages, rather than a single year, ensures that results are not excessively influenced by natural interannual variability. The year 2040 provides a reasonable time horizon for the type of energy infrastructure planning that can benefit from an assessment of potential climate impacts. To understand the potential change in temperature under a range of climate futures, we compare the 20-year average temperature projections to the 30-year historical reference period from 1981-2010, the years used to define "climate normal" by the National Climate Data Center.[xvii]

In addition to presenting results for a range of potential climate futures, we also address uncertainty by presenting not only the most likely (or median) outcomes but also the *likely* range of outcomes (with a 67% probability that the outcome will be within a specified range). We also present the tail risks – those outcomes less likely to occur but with much more extreme consequences – thresholds we define as having a 1-in-20 (or 5%) chance of being exceeded. This allows for planners to incorporate not only the most likely outcomes into their risk assessment, but also ensures that it is possible to take into account low-probability, high-consequence outcomes.

Figure 2: Average summer temperature (°F)

Historical average 1981-2010 and for a typical year from 2030-2049 under three climate pathways

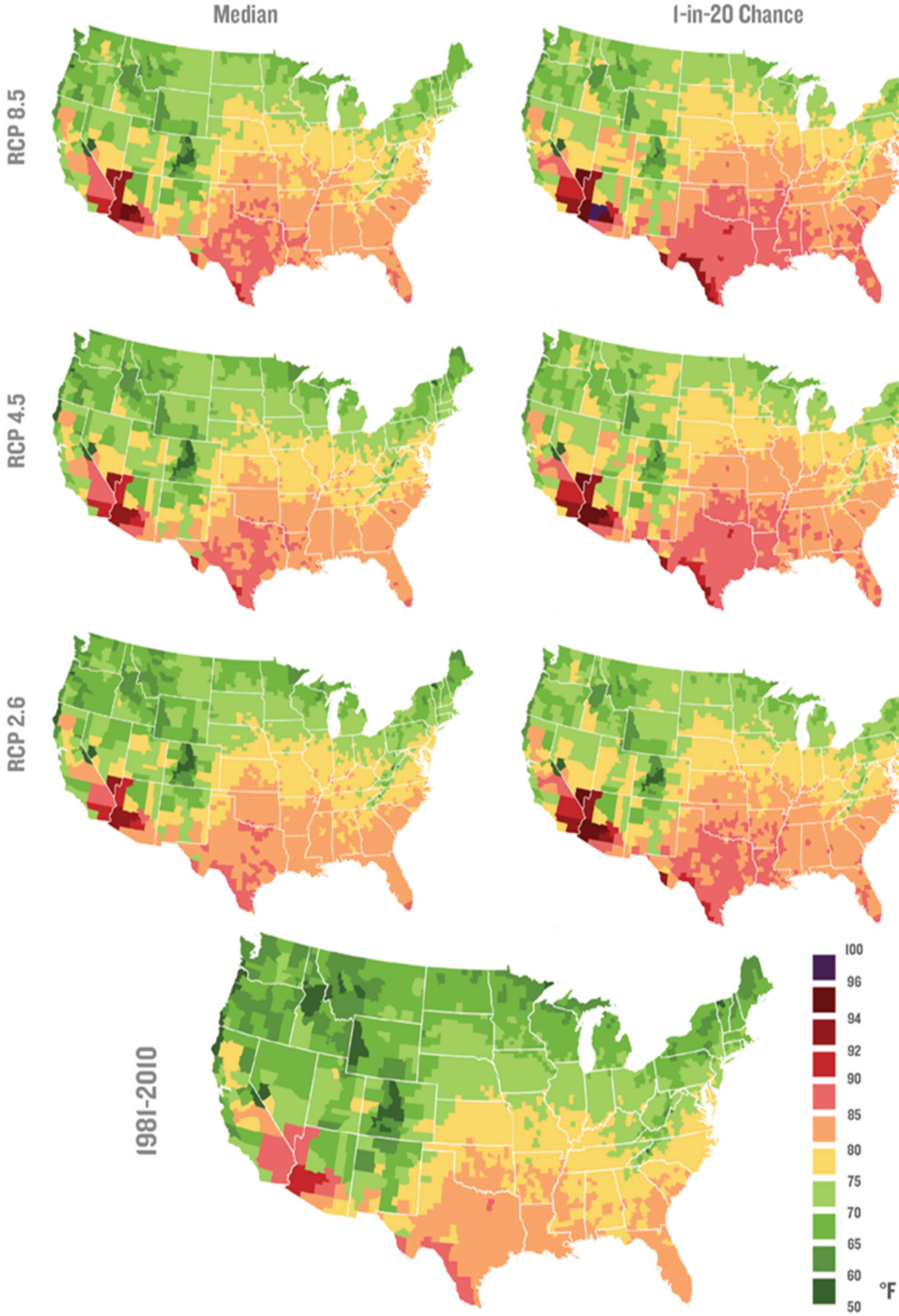


Figure 3: Extreme heat days (maximum temperature 95°F or greater) due to climate change

Average number of extreme heat days for an average year from 2030-2049

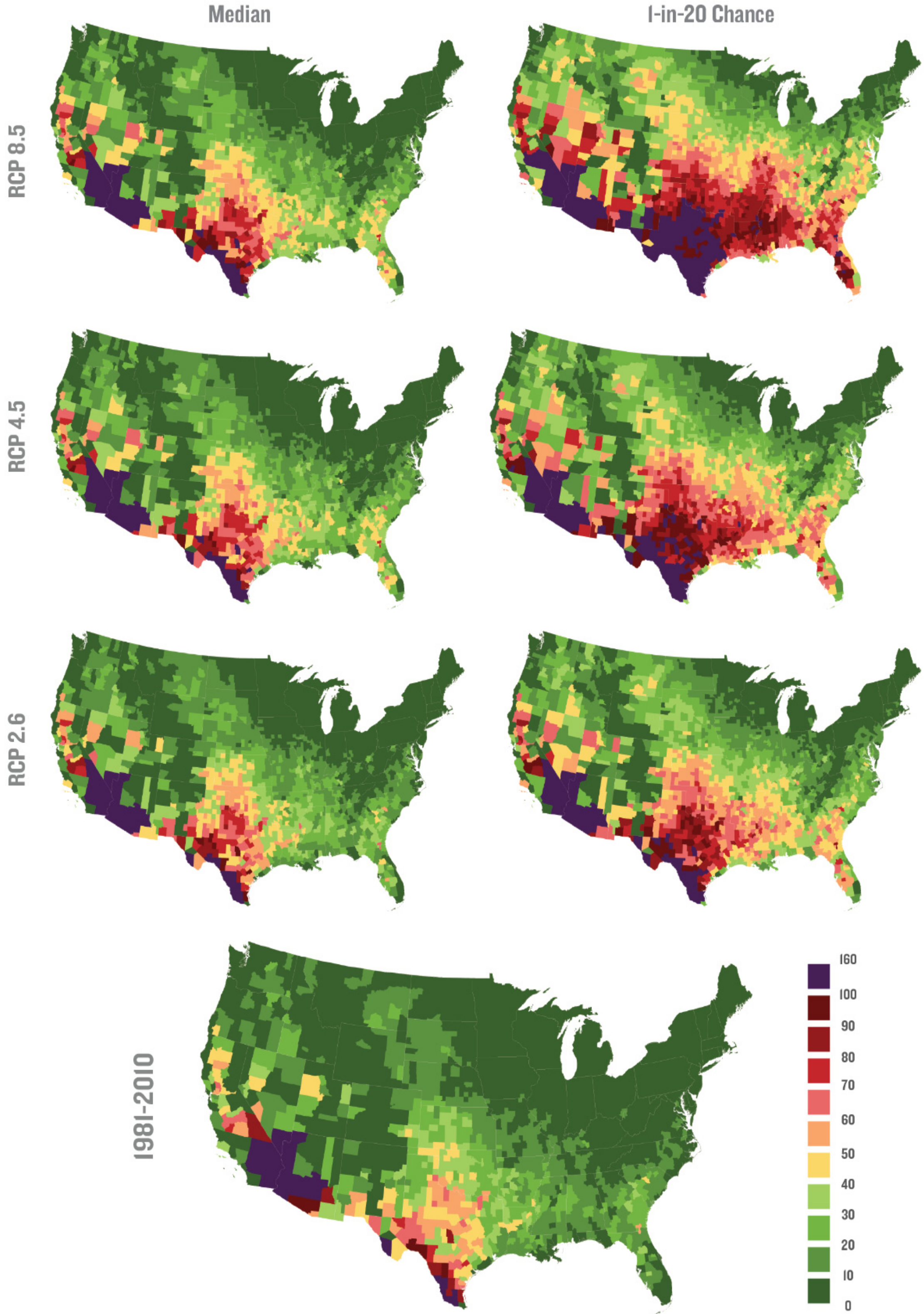
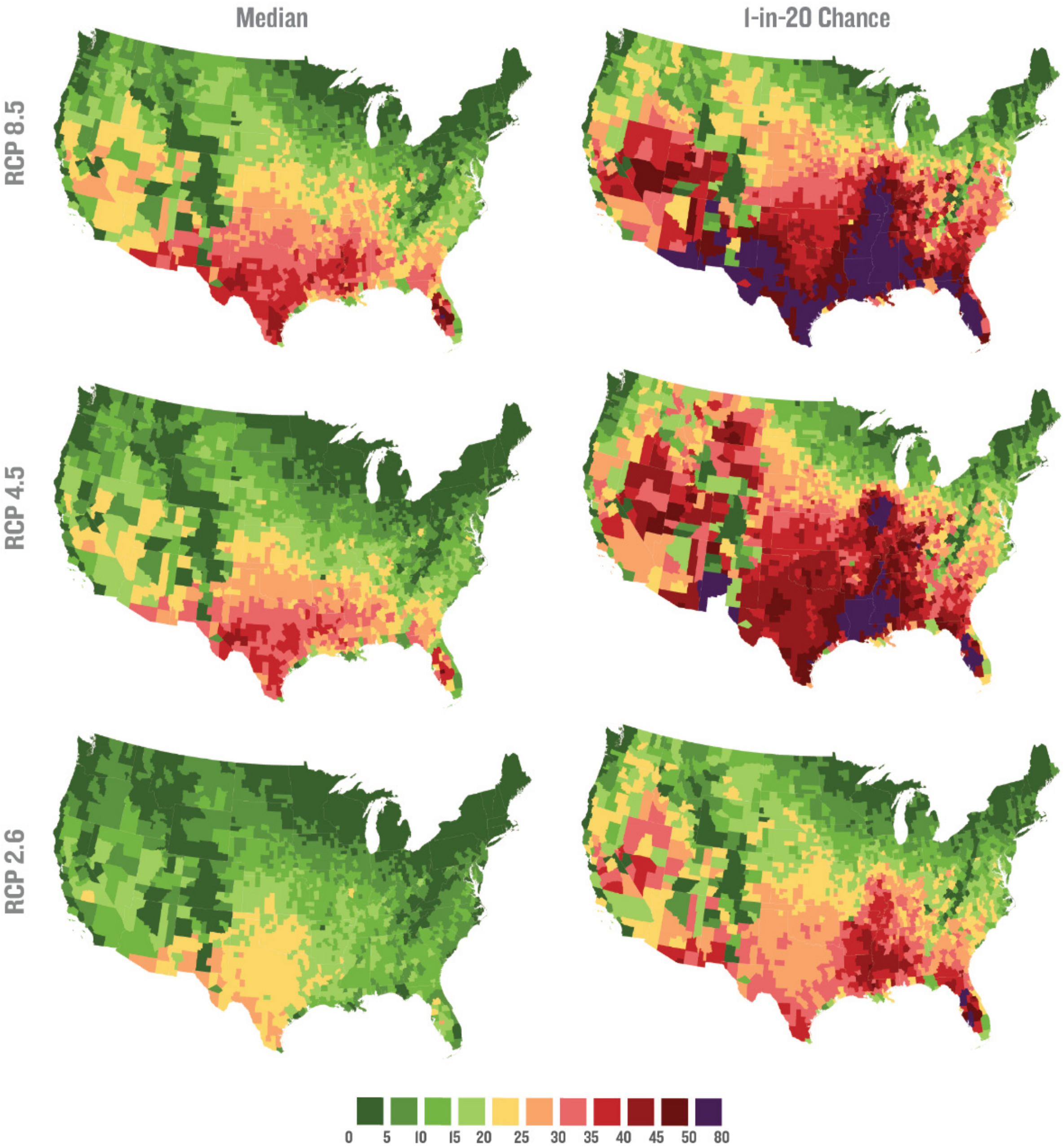


Figure 4: Change in extreme heat days (>95°F) due to climate change

Number of days in an average year from 2030-2049 compared to the historical average (1981-2010)



U.S. TEMPERATURE PROJECTIONS

With projected future climate change, much of the continental United States is projected to experience increasingly warmer summers over the course of the next century.[xviii] Between 1981 and 2010, the national average summer (June, July and August) temperature was around 75°F. With continued climate change by 2030-2049, summer average temperatures will *likely* rise an additional 2-5°F under RCP 8.5 (to an average of 77-80°F). Under an ambitious global GHG mitigation pathway (RCP 2.6), that rise is *likely* limited to 2-3°F (with a national summer average of 77-78°F). National averages, however, tend to mask much more dramatic local and regional changes in temperature. The South (defined as the East South Central, West South Central and Southern Atlantic Census regions) for example, will likely see a shift from historic average summer temperature of 75-85°F to averages in the 80-90°F range under RCP 8.5. The West South Central region (Texas, Louisiana, Arkansas and Oklahoma) is projected to see the greatest warming, with *likely* summer temperatures rising from a historical average of 82°F to 85-87°F by 2040 under RCP 8.5. Figure 2 provides a highly granular look at average summer temperatures by county across the United States for an average year from 2030-2049 under three climate pathways.

The United States is projected to also see a rise in the number of extreme heat days (those with maximum temperatures over 95°F). Over the past few decades, the average American experienced about two weeks (15 days) each year of 95°F or hotter days (Figures 3 and 4). By 2040, the average American will *likely* experience three to six weeks (25-40 days) each year on average under RCP 8.5. Much of Texas and the West South Central region can expect to experience two to three months of days topping 95°F (two to three times historic rates). A growing number of counties in southern Texas, Arizona and California will *likely* experience four months or more of days reaching 95°F or hotter each year on average.

There are similarly large projected changes in average winter temperatures and reduction in the number of extremely cold days across the continental United States. Northern states see the largest shift, with average winter temperatures *likely* rising 2.9 to 6.5°F in the Northeast by mid-century under RCP 8.5. Of the 25 states that currently have sub-freezing average winter temperatures, only six (Vermont, Maine, Wisconsin, Minnesota, North Dakota and Alaska) are still likely to do so under RCP 8.5 by the end of the century.

3. Impact on U.S. Energy Demand

Demand for heating and cooling, which accounts for roughly half of residential[xix] and a third of commercial energy use[xx], fluctuates hourly, daily, and seasonally in response to outdoor ambient temperatures. As summer temperatures rise, so does demand for electricity to power air conditioning, causing higher summer peak loads. Climate-driven changes in demand for space cooling can have an outsized impact on the electric power sector, forcing utilities to build additional capacity to meet higher peak demand.

Econometric studies have identified the incremental change in electricity consumed for each additional day at a specified temperature level using U.S. state-level annual electricity demand data over the past few decades.[xxi,xxii,xxiii] These analyses find that electricity consumption increases during both hot days and cold days when the average daily temperature deviates from 65°F. Incremental increases in daily temperature cause a larger shift in electricity consumption than incremental decreases in temperature, although both changes have substantial impacts on overall demand. These studies also find that in hotter locations that are more likely to have air conditioning widely installed, electricity demand increases more rapidly with temperature. This suggests that as Americans adapt to hotter climates, they install space cooling appliances and use air conditioning more heavily on hot days.

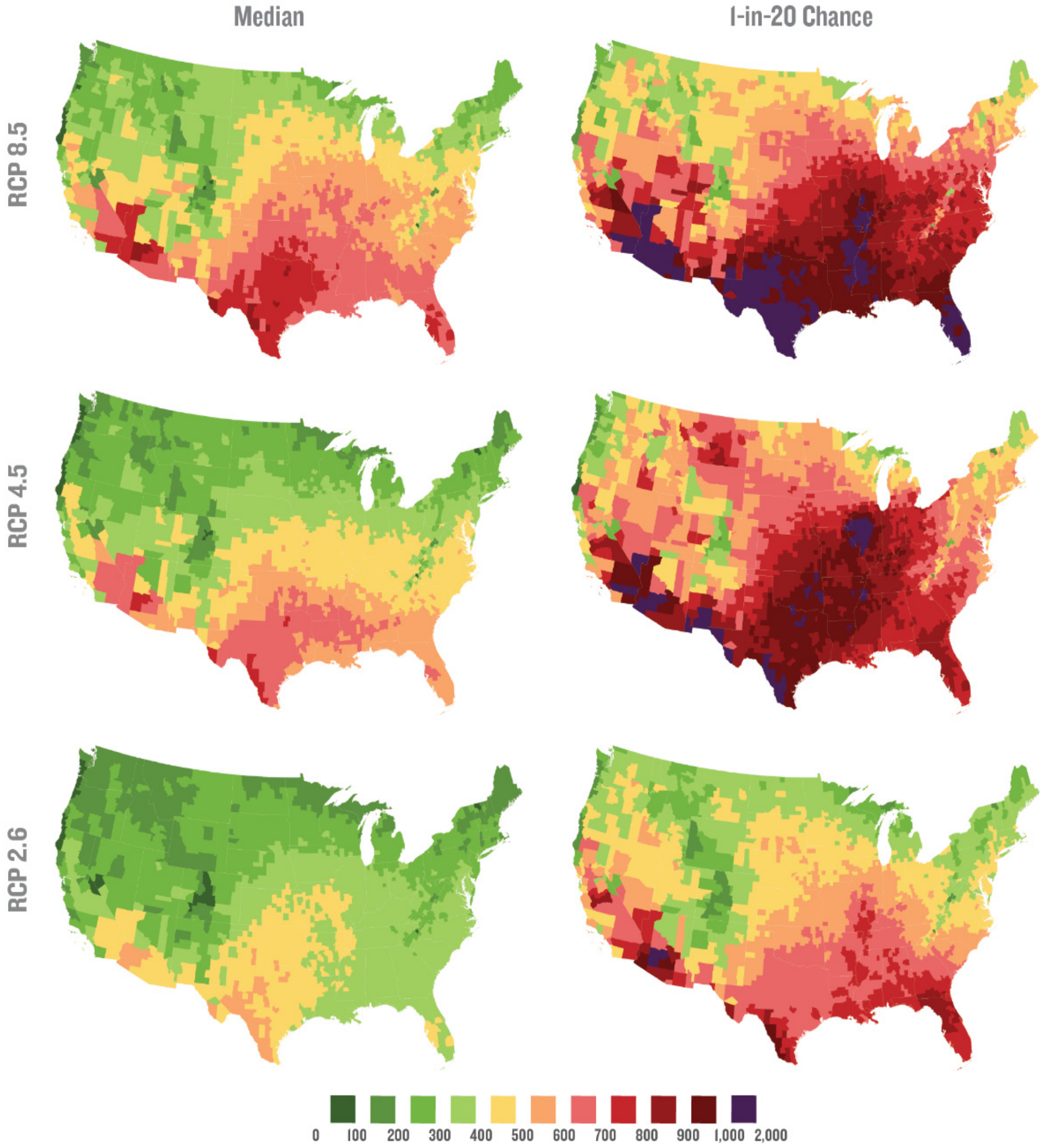
Rising temperatures also mean warmer winters, decreasing overall demand for heating.[xxiv] Because many households and businesses use natural gas or oil-fired boilers and furnaces for heating, rather than electricity, the result is a decline in natural gas and oil demand. As both winter and summer temperatures warm, regions that have traditionally experienced moderate climates may see a shift from predominantly heating demand to predominantly cooling demand; this could lead to a noticeable shift in net energy fuel demand.

To understand how future changes in temperature under our three climate pathways may impact U.S. energy demand in the 2040 timeframe, we translated projections of daily minimum and maximum temperatures into county-level projections of annual cooling degree days (CDDs) and heating degree days (HDDs). (See Technical Appendix for more detail.) CDDs and HDDs measure how hot or cold a location is relative to an average daily temperature of 65°F for each day over the course of a year. These metrics are used by the U.S. Department of Energy (DOE) Energy Information Administration (EIA) in modeling heating and cooling energy demand in their annual American Energy Outlook (AEO). In its projections, EIA uses state-level 30-year linear trends to develop HDD and CDD forecasts, which account for the observed trend of warmer winters and summers across the United States over the last 30 years.[xxv] In this report we provide an assessment of potential future CDDs and HDDs based not on historical patterns but on our localized climate projections for the years 2030-2049.

With rising summer average temperatures and increasing numbers of extreme heat days out to 2030-2049, we find a noticeable increase in CDDs across the United States even under the most optimistic climate pathway (Figure 5). Regions with already high levels of cooling demand can expect to see the highest increase in CDDs. Under RCP 8.5, most of the South and many parts of the Southwest can expect to see an increase of at least 600 CDDs each year on average. Nearly a fifth of U.S. counties can expect to see the number of CCDs jump by 50% or more (under the median RCP 8.5 outcome), with a 1-in-20 chance two-thirds of all U.S. counties will see an increase of 50% or more. Under this most extreme climate pathway, there is a 1-in-20 chance that much of Texas, Arizona, Florida, Texas, Louisiana, Alabama, Arkansas and Missouri will see an annual average jump of 1,000 CDDs or more. Even with more modest temperature changes under RCP 2.6, most U.S. counties will *likely* face a rise in CDDs of between 200 and 500 each year on average with a 1-in-20 risk that CDD increases will look like the more extreme RCP 8.5 median outcome.

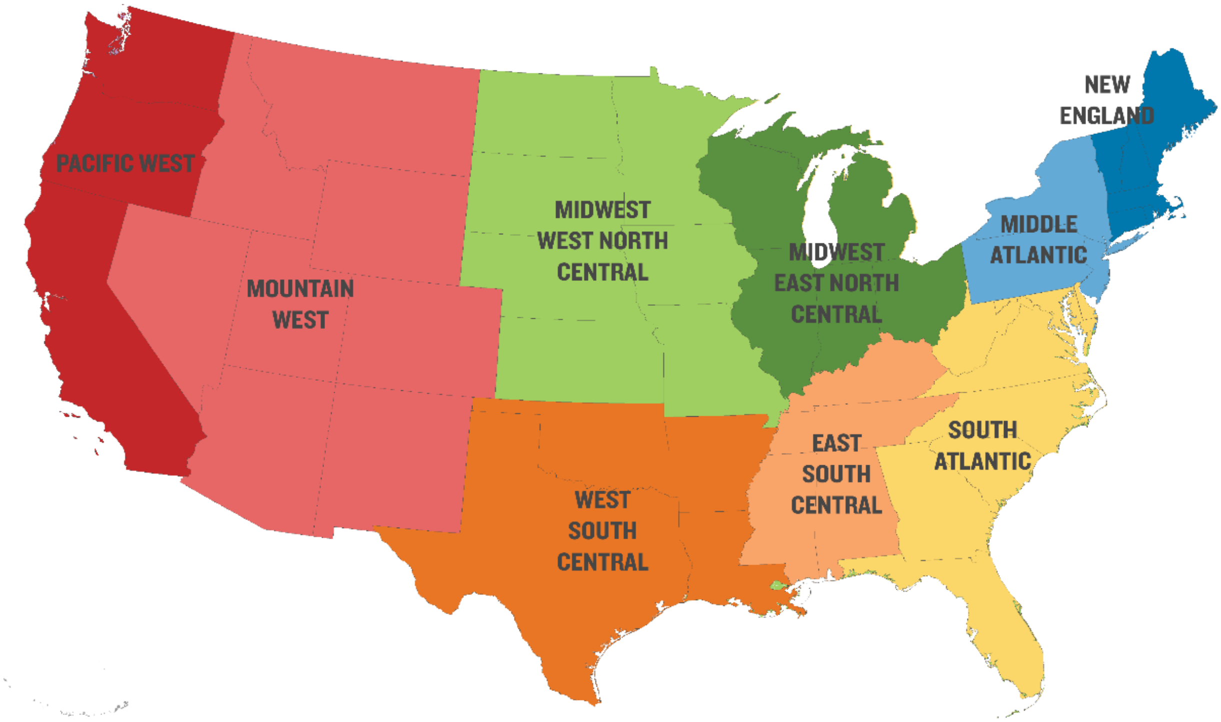
Figure 5: Change in Cooling Degree Days (CDDs) due to climate change

Change from historical average (1981-2010) for an average year from 2030-2049



To capture the effects of these climate-related temperature changes on regional U.S. energy demand and supply (and to capture the full fuel substitution and price implications of these interactive effects), we employ RHG-NEMS, a version of the EIA's National Energy Modeling System (NEMS)[xxvi] maintained by the Rhodium Group. (See the Technical Appendix for a complete description of the modeling approach used in this analysis.) Modeling temperature changes in NEMS provides a reasonable estimate of the relative change in demand, price, and costs given likely economic and energy system structures out to 2040.[xxvii] While our climate inputs have a county-level resolution, we report our results for changes in energy demand and expenditures by U.S. Census region (Figure 6).

Figure 6: U.S. Census Regions



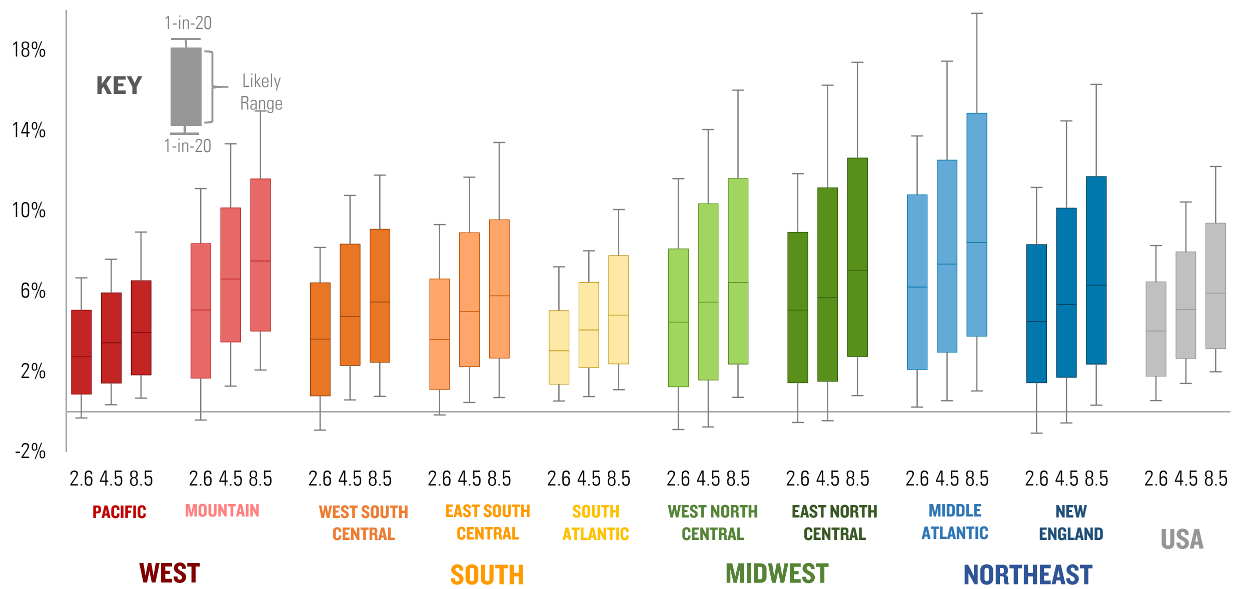
CLIMATE-RELATED TEMPERATURE IMPACTS ON REGIONAL ELECTRICITY DEMAND

Under all three climate pathways, residential and commercial electricity demand is projected to rise due to increased cooling demand in 2040. We isolate the climate-related temperature impacts from other drivers that are expected to affect the U.S. energy system (e.g., expected socio-economic changes, policy and price effects) by comparing our climate pathways to a scenario in which historical climate conditions (i.e., the 30-year average from 1981-2010) continue out to 2040, holding all other variables constant.

Under the most optimistic climate pathway (RCP 2.6), nation-wide residential and commercial electricity demand will *likely* increase 2-7% above rates expected if historical climate conditions were to continue by 2040. Under RCP 8.5, demand will *likely* rise 3-9%, with a 1-in-20 risk that demand will rise over 12% (the same tail risk under RCP 2.6 is an increase of only 8%). Regional impacts to electricity demand vary slightly from the national average, with more modest increases in the Pacific and South Atlantic states offset by much greater increases across the Midwest and Middle Atlantic regions (see Figure 7). These areas have historically experienced mostly moderate climates and are expected to turn increasingly to air conditioning as temperatures rise over the next couple of decades. Across the Middle Atlantic—the region with the highest median jump in demand—we find *likely* increases under RCP 8.5 of 4-15%, with a 1-in-20 risk of an over 20% in electricity demand across the region on average by 2040.

Figure 7: Change in residential and commercial electricity demand from climate change in 2040

Percent change by RCP relative to historical climate scenario (1981-2010 average)



CLIMATE-RELATED TEMPERATURE IMPACTS ON REGIONAL HEATING DEMAND

With rising winter average temperatures and a decline in the number of extremely cold days out to 2030-2049, we find a noticeable decrease in residential and commercial heating demand (measured as HDDs) across the United States (Figure 8). Northern regions with typically high levels of heating demand can expect to see the largest decline in HDDs. Under RCP 8.5, the entire northern half of the United States can expect to see a drop of 750-1,250 HDDs each year on average. Nearly half of all U.S. counties can expect to see the number of HDDs drop by 15-20% (under the median RCP 8.5 outcome), with a 1-in-20 chance that nearly all U.S. counties will see a decline in that range (with half of all counties experiencing a 25-30% decline). The tail risks (1-in-20 chance) for all climate pathways show an even more extreme drop in HDDs across the northern states, with reduction of over 1,500 HDDs across much of the Northeast, Midwest, Mountain West (in particular the Rockies) under RCP 8.5. Even with more modest temperature changes under RCP 2.6, the majority of U.S. counties see a *likely* decline in HDDs of between 250 and 750.

The primary impacts of the change in heating degree days will be experienced as changes in demand for natural gas, which fuels the majority of space heating in commercial and residential buildings across the United States. Under all three climate pathways, demand for natural gas for space heating are projected to decline as a result warmer winter temperatures in 2040. Under the most optimistic climate pathway (RCP 2.6), nation-wide residential and commercial natural gas heating demand will *likely* decrease 3.4-12% below the level that would be expected if historical climate conditions were to continue through 2040. Under RCP 8.5, demand will *likely* drop 6.0-16%, with a 1-in-20 chance that demand will decline by more than 19%. Impacts to natural gas heating demand are fairly uniform across regions, with only slight variation from the national average across climate pathways (Figure 9).

Figure 8: Change in Heating Degree Days (HDDs) due to climate change

Change from historical average (1981-2010) for average year from 2030-2049

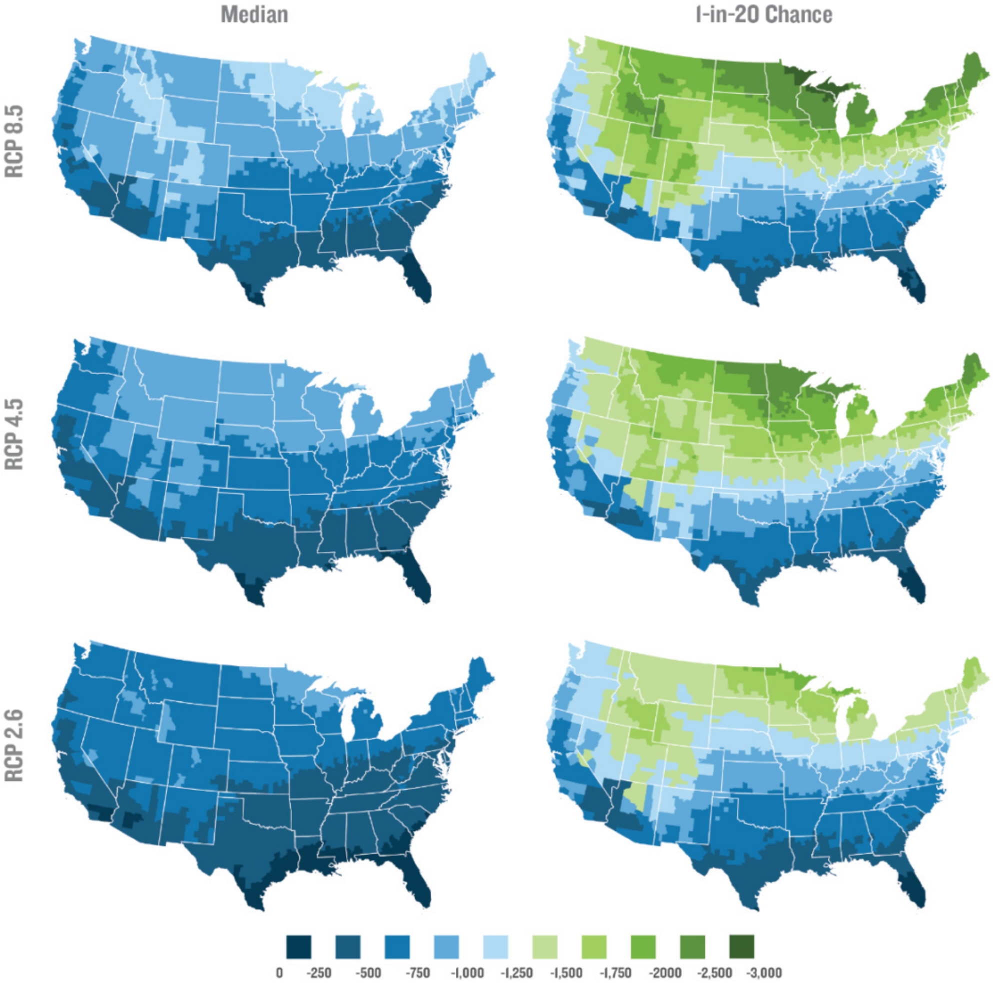
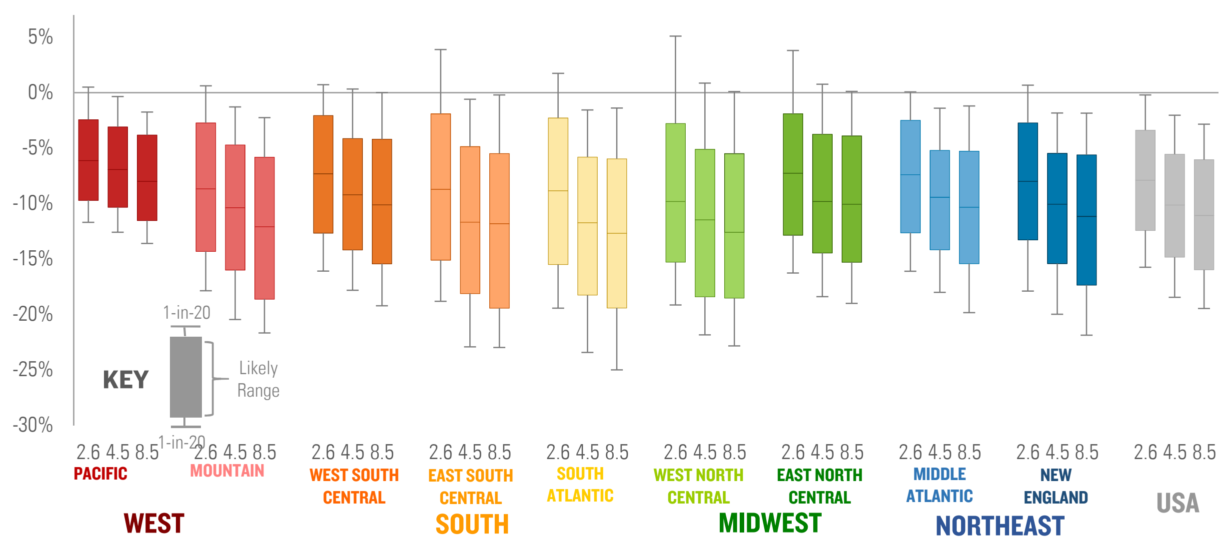


Figure 9: Change in residential and commercial natural gas heating demand from climate change

Percent change by RCP relative to historical climate scenario (1981-2010 average) in 2040



4. Energy System Implications

SUPPLY CAPACITY AND EFFICIENCY LOSS DUE TO TEMPERATURE CHANGE

Warmer temperatures affect not just the demand for heating and cooling but also the systems that supply the energy to power those services in American homes and businesses. The energy supply chain is long and complex, and as a result there are a number of points where climate-related temperature changes can interrupt or reduce the capacity of the U.S. energy infrastructure system to deliver electricity, heating, or transport fuels. In this report we focus on the impacts of temperature on the capacity and efficiency of thermal and combustion electric generation – the power plants that generated over 80% of American electricity in 2015.

Coal, natural gas combined cycle, oil, nuclear, and biomass power plants primarily produce electricity by boiling water and using steam to spin a turbine. This steam is then cooled, condensed back into liquid water, and reused. Higher ambient air temperatures both reduce the efficiency of this process and limit the maximum power that a plant can deliver. The magnitude of these temperature-related impacts depends on a number of plant- and site-specific factors and can be described in terms of so-called "damage functions." For example, studies of nuclear power sensitivity to high temperatures estimate that output losses are approximately 0.3% for every 1°F (0.5% for every 1°C) increase in air temperature.[xxviii] Natural gas combined cycle plants may see a reduction in electricity output by 0.3 to 0.5% for the same temperature increase.[xxix] For combined cycle plants with dry cooling, often more sensitive to warmer ambient temperatures, the reduction can be as large as 0.7%. Natural gas-fired combustion turbines are also sensitive to temperature, as hot air is less dense, requiring plant operators to decrease fuel injection on hot days to maintain the needed air-to-fuel ratio. These plants, which are often used for peaking and are therefore frequently used during the hottest times of the year, may see a 0.3 to 0.4% decline in electricity output for each 1°F (0.6 to 0.7% decline for each 1°C) increase in temperature.[xxx]

The total impact on the U.S. electricity supply cannot be modeled using the same simple plant-level damage functions described above. There are many complex interactions between temperature and supply that these isolated effects do not take into account, including demand changes, regulatory action (due to, e.g., high stream temperatures), and transmission and distribution constraints, among other factors. Therefore, we use the results of an empirical study[xxxi] of national supply and heat rate impacts in the form of damage functions developed by the National Renewable Energy Laboratory (NREL) for the Regional Energy Deployment System (ReEDS).[xxxii] The NREL study found that nationally, U.S. electricity generation capacity will decrease 2% for gas turbine engines and 0.6% for steam turbine generators under their reference scenario, and that heat rates will increase 0.2% for gas turbine engines and 0.4% for steam turbine generators by 2050. We use the damage functions derived from the NREL study in our integrated analysis presented below.

INTEGRATED ENERGY SYSTEM IMPACTS

When the effects of climate-related temperature impacts on energy demand and electricity supply are modeled, we can see the broader effects on electric generation and capacity, including integrated effects on costs and consumer spending. To understand the integrated system-wide effects, we model the simultaneous change in heating and cooling demand with the heat-related impacts on electric generation from thermal power plants using county-level temperature projections for the years 2030-2049 under three climate pathways. We compare these potential climate futures to a hypothetical world in which there is no climate change beyond recent historical levels (with temperatures remaining at the 1981-2010 average). Under all scenarios we assume all U.S. policy as of the end of 2015 remains in place, including all state and federal rules governing carbon emissions and all renewable electric generation goals and incentives.[xxxiii]

An unsurprising result of the combined increase in electric cooling demand with the heat-related efficiency penalty on thermal electric generation is that net electric generation increases to make up the shortfall. Nearly all of the load for cooling falls on the electric power system, while space heating is distributed among several fuel sources, the majority of which is met with natural gas (with much smaller contributions from electricity, heating oil, and biofuels). The large increase in electricity demand for cooling is offset only marginally by the relatively small portion of the decline in heating demand that is met with electric power. The overall net effect of warmer seasonal and extreme temperatures is an increase in electricity demand, particularly during peak periods. This shortfall, combined with the heat-related efficiency penalty to thermal generation, will require scaled up electric generation and additional capacity.

Under RCP 2.6, total U.S. electricity generation will *likely* increase by 1-3% above levels required under historical climate conditions in 2040. Under RCP 8.5, *likely* increases grow to 2-4% above the historical climate scenario. What is perhaps more interesting is the distribution of this generation growth among different types of power sources. Most of the additional growth is projected to be met by increased generation from natural gas combined cycle plants (NGCC) and solar, with combustion turbine peaker plants contributing to meet peak loads and maintain reserve margins (Figure 10). To maintain compliance with carbon emission limits set out under the Clean Power Plan (CPP) - which we assume is in place through 2030 and extended at 2030 levels through 2040 - some coal generation is projected to be displaced by natural gas.

Climate-driven increases in cooling demand increase electricity consumption during the hottest times of the day and hottest periods of the year, when electricity demand is already at its peak. Higher peak demand requires the construction of additional power generation capacity to ensure reliable electricity supply during peak hours (Figure 11). To meet increasing system demands under RCP 2.6, total generating capacity will likely increase by 4-18%. Under RCP 8.5, generation must increase 10-25% (median of 18%) relative to the historical climate scenario. Greater peak demand on increasingly hot summer days leads to a significant expansion of fossil-fired combustion turbine (CT) peaker plants relative to a historical climate scenario, as these facilities are the lowest-cost option to meet the increasing reserve margin requirement (with projected CT capacity increases of 95 GW under RCP 2.6 and 155 GW under RCP 8.5). An RCP 8.5 climate outcome could lead to a more than doubling of total CT capacity from 2015 levels (142 GW) by 2040. The remainder of the necessary additional capacity to meet projected demand comes primarily from solar, other fossil (oil and gas steam units and fossil equipped with carbon capture and storage) and NGCC units.[xxxiv]

Although the three climate futures differ considerably in terms of additional generation and capacity needs, total power sector CO_2 emission levels remain the same across all climate pathways. This is due to the emission limits imposed by the CPP. Economy-wide CO_2 emissions vary slightly across pathways depending on the change in natural gas demand in end-use sectors from climate change effects.

Figure 9: Change in national electric generation in 2040 by RCP scenario

Change by fuel type (TWh) in comparison to historical climate scenario (1981-2010) in 2040, median RCP outcomes

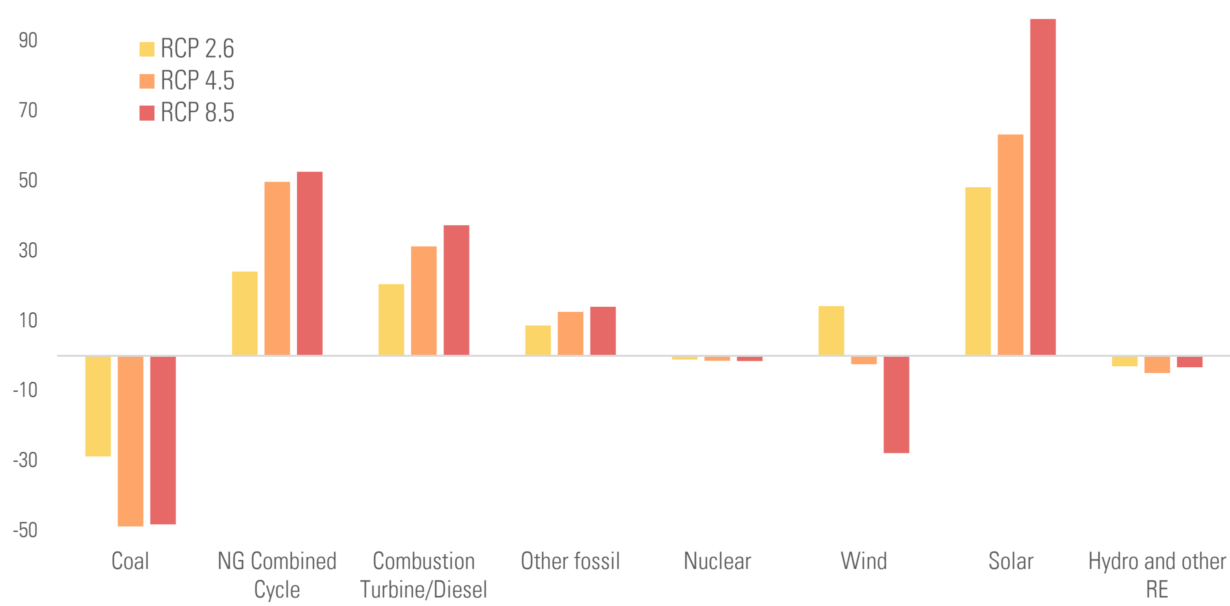


Figure 10: Change in national electric generating capacity in 2040 by RCP scenario

Change in capacity (GW) in comparison to historical climate scenario (1981-2010) by fuel type, median RCP outcomes

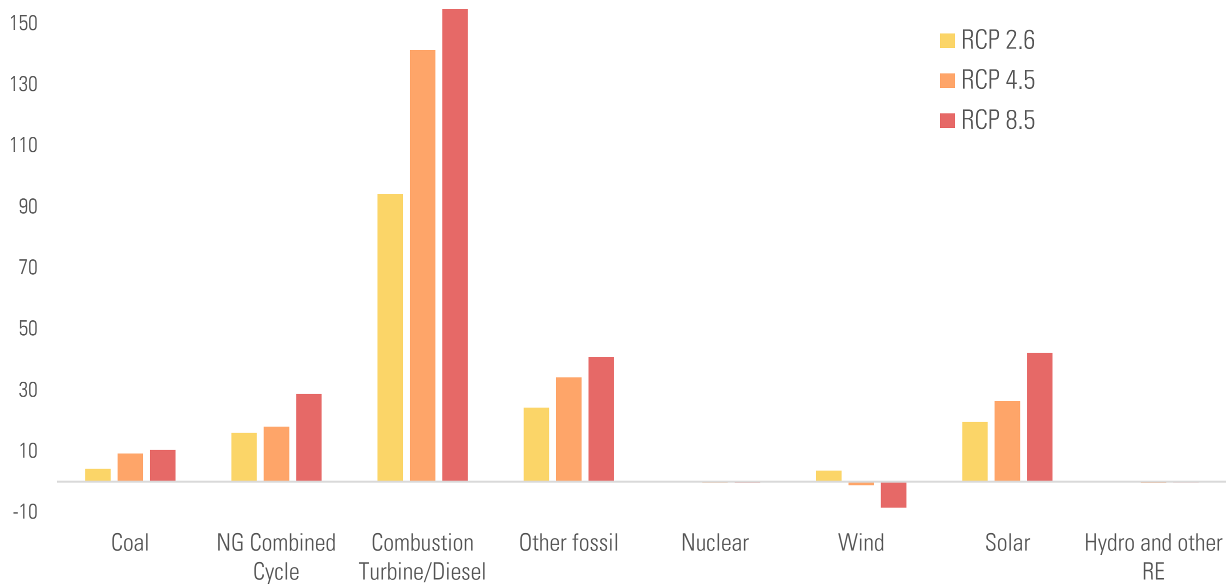
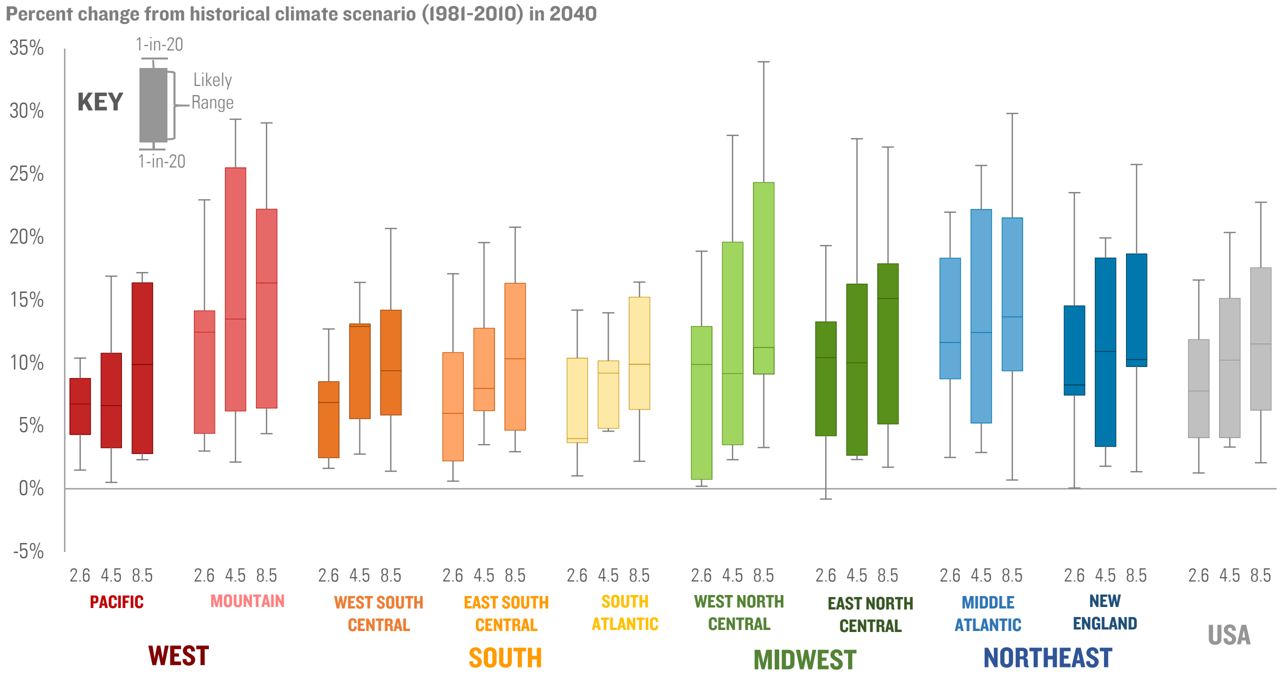


Figure 11: Change in residential and commercial electricity expenditures in 2040 from temperature rise by RCP scenario

Percent change from historical climate scenario (1981-2010) in 2040



The three climate pathways do result in different costs, however, both to consumers and across the electric power system as a whole. Rising demand for electric cooling during the hottest times of the day when electricity demand is already at its peak coincides with times when costs and electricity prices are at their highest. Projected capacity additions needed to meet additional peak demand would also contribute to rising costs. While most of the additional peaking capacity would only operate part of the time, the capital costs of new capacity additions as well as operating costs are passed on to electricity consumers.

As a result, total electricity expenditures by residential and commercial consumers are projected to rise under all climate pathways when compared to a future in which historical average climate continues out to 2040 (Figure 12). At the low end, under RCP 2.6, nationwide spending on residential and commercial electricity will *likely* rise 4-12%. At the high end, under RCP 8.5, total expenditures will *likely* grow 6-18%, with a 1-in-20 chance that total national electricity expenditures will rise over 23% compared to a historical climate scenario. The tail risk declines somewhat under RCP 2.6, but it remains significant, with a 1-in-20 chance that the increase will be 17% or greater. Customers in the Middle Atlantic, Mountain, and East North Central regions will see the largest median rise in electricity expenditures in 2040, especially under the higher climate change pathways. Customers in the West North Central region will see *likely* increases of 9-24% under RCP 8.5 (with a 1-in-20 chance of a 34% or greater jump when compared to historical climate conditions).

When we look at residential and commercial expenditures on total energy across the economy, we find that the decline in heating demand from warmer winters offsets some, but not all, of the growth in electricity expenditures to meet the rise in cooling demand. Under RCP 8.5, total energy expenditures will *likely* rise 1-3% on average across the United States by 2040 (with a 1-in-20 chance of a 4% increase or greater). As illustrated in Figure 13, regional results vary considerably.

Finally, to get a sense of the overall cost of the three potential climate futures, we look at the relative changes in total system-wide costs across the electric power sector (Figure 14). This includes all costs associated with expansion, operation and maintenance of the U.S. bulk power system, such as the cost of new capacity and transmission additions, any power plant retrofits, fixed and variable operations and maintenance, other capital additions, fuel, purchased power, and energy efficiency program costs. These values do not include any consumer equipment costs associated with the purchase of new appliances such as air conditioners. Nationwide under RCP 2.6, total system-wide costs in Net Present Value terms (NPV between 2016 and 2040 using a 5% discount rate; see Technical Appendix for further detail) will *likely* increase by $55-216 billion above similar costs under a historical climate scenario (a 2-8% increase). Under RCP 8.5, costs *likely* rise by $104-307 billion, an increase of 4-11% above historical climate levels, with a 1-in-20 chance that system-wide costs will increase by nearly $400 billion (an increase of 14%).

Figure 12: Change in total energy expenditures in 2040 by RCP scenario

Percent change from expenditures under historical climate scenario (1981-2010) in 2040

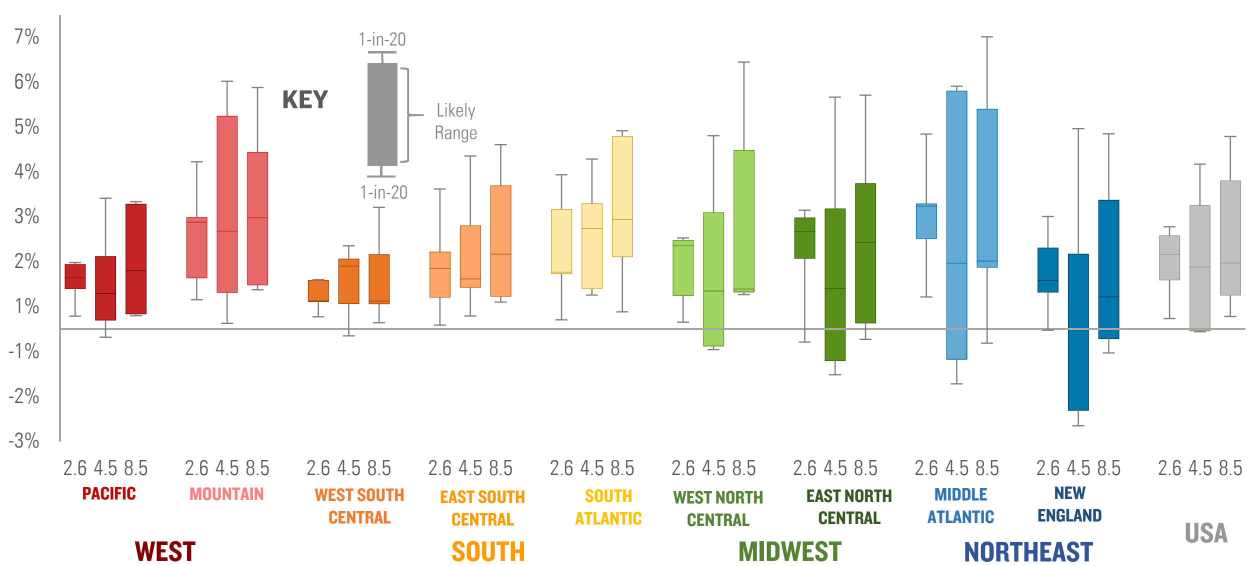
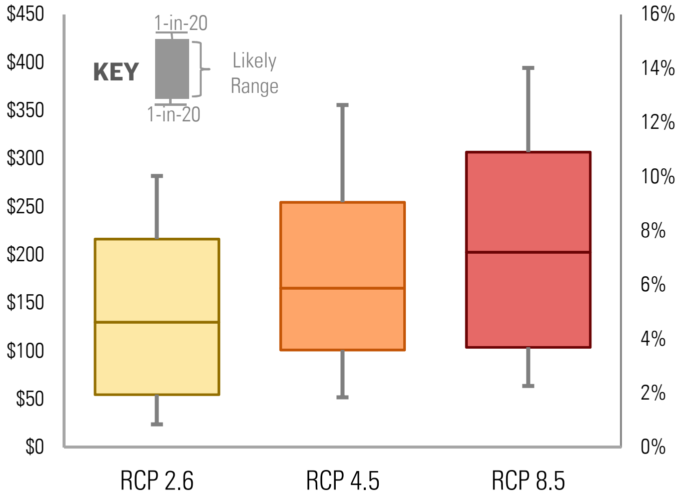


Figure 13: Climate-related resource costs to the power sector

Billion USD, 2016 NPV of 2016-2040 changes (left) and percent change (right) from historical climate scenario, 5% discount rate



TEXT BOX 2: US POWER SECTOR COSTS FROM UNMITIGATED CLIMATE CHANGE

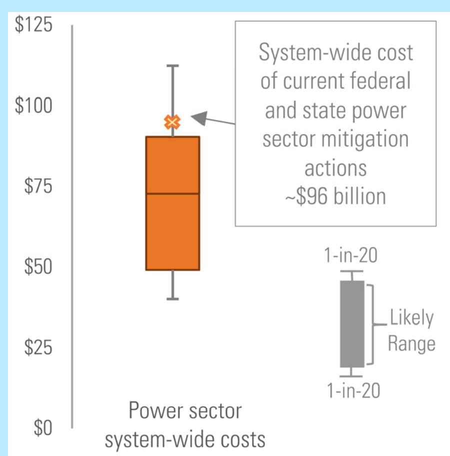
An estimation of the cost of climate change to the U.S. power sector would need to factor in the full range of potential climate-related impacts the power sector may experience. This includes those related not just to local temperature rise, but also extreme precipitation events, coastal storms, sea-level rise, and flooding, among many others. This analysis considers only a small portion of the total potential cost from climate change – the impact of temperature rise on residential and commercial electricity demand and the efficiency of thermal electric generation.

The cost of this narrow subset of impacts from "unmitigated" climate change to the U.S. power sector can be described as the difference in system-wide resource costs between our high GHG emissions climate scenario (RCP 8.5) and the aggressive global greenhouse gas mitigation scenario (RCP 2.6). We estimate that the net present value (NPV) of this difference will *likely* be $49-$90 billion between 2016 and 2040 (with a median value of $72 billion). There is a 1-in-20 chance that such costs will total $112 billion or more over the next 25 years.

The cost of this small sub-set of climate impacts to the U.S. power sector is roughly the same order of magnitude as the total system-wide costs of meeting current federal and state power sector mitigation policies (limited to only those costs associated with expansion, operation and maintenance of the U.S. bulk power system, such as the cost of new capacity and transmission additions, any power plant retrofits, fixed and variable operations and maintenance, other capital additions, fuel, purchased power and energy efficiency program costs), which we calculate at around $96 billion over that same period (see Technical Appendix for more detail). When the costs of other climate-related impacts to the sector are factored in, the total costs of unmitigated climate change are likely to far exceed the costs of mitigation from the sector.

Figure 14: Estimates of total US power system costs from climate-related temperature rise

Difference in cost between RCP 2.6 and 8.5, NPV of 2016-2040, 5% discount rate (2013 billion USD)



5. Conclusions

The warming trends the United States has experienced over the past few decades – and the growing impacts on electric demand for space cooling in American homes and offices – are here to stay. Rising average and extreme temperatures are expected to increase under all plausible climate change futures. For the electric power sector, these changes in climate are projected to require investments in additional generation capacity that will be able to meet higher peak electricity demand during increasingly hot summer afternoons and during heat waves. Targeted investments in cost-effective energy efficiency beyond what occurs in our scenarios as well as demand response could also help to mitigate cost impacts. The pace of warming can be reduced to some extent by aggressively mitigating global GHG emissions, but even if international efforts are successful in reigning in global GHG, a certain amount of temperature rise has already been locked in.

Planners are already beginning to acknowledge the need to update energy demand and supply forecasts with climate data that is consistent with recent warming trends. As we have shown here, incorporating the range of potential climate change scenarios provides better insight into conditions the U.S. electric power sector is most likely to experience over the next 25 years. While there remains significant uncertainty in the exact climate future that will come to pass, we do know with certainty that it will not look like the last 30 years. Electric power sector planning conducted today will need to take that reality into account or risk falling short of the necessary investments for meeting future demand.

While we have shown that rising temperatures associated with climate change will likely have a significant impact on the U.S. power sector, temperature is only one of myriad risks posed by climate change. This report did not attempt to assess or quantify risks to the U.S. power sector posed by droughts and the resulting changes in water availability, extreme precipitation events, flooding, or sea-level rise and storm surge from coastal storms, among many other impacts. Nor have we sought to capture the upstream risks of climate change to the infrastructure required to produce and deliver the fuels used to power U.S. electricity generation. A full accounting of this wide range of risks will require continued efforts to build out the empirical research on the effect of changing climatic conditions on all upstream and downstream components of the U.S. electric power system. As it becomes available, new empirical work can be incorporated into studies like this one, expanding on the set of impacts accounted for and broadening our understanding of the full costs of climate change to the U.S. power sector.

Technical Appendix

CLIMATE PROJECTIONS

Our climate projections are derived from the Surrogate Model-Mixed Ensemble (SMME) projections employed by Houser *et al.* in *the Economic Risks of Climate Change: An American Prospectus*.[xxxv] We use three scenarios based on the Representative Concentration Pathways (RCPs) developed by the Integrated Assessment Modeling Consortium (IAMC) and used in the Fifth Assessment Report (AR5) of the Intergovernmental Panel on Climate Change (IPCC). The three RCPs used in this study, RCPs 2.6, 4.5, and 8.5, span a plausible range of future atmospheric greenhouse-gas concentrations. The Houser *et al.* results provide spatially- and temporally-correlated distributions of county-level daily minimum, average, and maximum temperature from 1981 to 2099. To supplement the projections of minimum, average, and maximum temperature, we developed county-level projections of annual heating degree days (HDDs) and cooling degree days (CDDs)[xxxvi] using the max-min method.[xxxvii]

As described in Rasmussen et al. (2016)[xxxviii], the distributions of CDDs and HDDs are derived from projections available from the bias-corrected and spatially disaggregated (BCSD) archive derived from select CMIP5 models.[xxxix] Houser *et al.* used the distribution of changes in end-of-century global mean temperature projected by the MAGICC6 model[xl] in probabilistic mode to assign probability weights to these projections. This method gives a full probabilistic range of 1/8-degree-resolution projections of daily climate variables corresponding to 29, 43, and 44 global climate models and model surrogates for RCP 2.6, RCP 4.5, and RCP 8.5, respectively.

For this report, distributions of summer average temperature are the average across daily average temperatures in June, July, and August for all years in a given period. The historical period is defined as 1981-2010, and the projection period is defined as 2030-2049. We compute distributions of the number of days exceeding a given threshold temperature by counting the number of days in a given year above the threshold and then averaging this count across years within a period.

MODELING THE ENERGY SYSTEM

Our analysis of the temperature-related impacts of climate change on the U.S. energy system relies on RHG-NEMS, a version of the Energy Information Administration's (EIA) National Energy Modeling System (NEMS) maintained by Rhodium Group. EIA uses NEMS to produce their Annual Energy Outlook (AEO), which projects the production, conversion, consumption, trade, and price of energy in United States through 2040. NEMS is an energy-economic model that combines a detailed representation of the U.S. energy sector with a macroeconomic submodule provided by IHS Global Insight.

The version of RHG-NEMS used for this analysis follows DOE EPSA's Side Case, one of the cases that was used for analysis in the Quadrennial Energy Review (QER). The EPSA Side Case input assumptions are based on the final release of the 2015 Annual Energy Outlook (AEO 2015), with a few updates that reflect current and future technology cost and performance estimates, current policies, and current measures, including the Clean Power Plan and tax credit extensions for solar and wind passed by Congress in December 2015. In addition, cost and performance estimates for utility-scale solar and wind have been updated to reflect recent market trends and projections, and are consistent with what was ultimately used in AEO 2016. Carbon capture and storage (CCS) cost and performance estimates have also been updated to be consistent with the latest published information from the National Energy Technologies Laboratory. As with the AEO, the ESPA Side Case provides one possible scenario of energy sector demand, generation, and emissions from present day to 2040, and it does not include future policies that might be implemented or unforeseen technological progress or breakthroughs.

All modeling frameworks represent tradeoffs to ease model optimization which lead to varying results across platforms. Specifically, there is some temporal and spatial aggregation within NEMS that will impact the degree of wind and solar development and generation. The temporal resolution of NEMS is limited to nine time slices and resource curtailments are not modeled. Wind resource availability is an exogenous input based on the square kilometers available within four different wind classes per each individual Electricity Market Module

(EMM) region. Utility-scale solar resource availability are also inputs by EMM region.

NEMS is designed as a modular system with a module for each major source of energy supply, conversion activity and demand sector, as well as the international energy market and the U.S. economy. The integrating module acts as a control panel, executing other NEMS modules to ensure energy market equilibrium in each projection year. The solution methodology of the modeling system is based on the Gauss-Seidel algorithm. Under this approach, the model starts with an initial solution, energy quantities and prices, and then iteratively goes through each of the activated modules to arrive at a new solution. That solution becomes the new starting point and the above process repeats itself. The cycle repeats until the new solution is within the user-defined tolerance of the previous solution. Then the model has "converged," producing the final output.

MODEL DETAIL AND CLIMATE IN RHG-NEMS

In RHG-NEMS, energy consumption estimates of residential and commercial sectors are modeled using the Residential Demand Module (RDM) and Commercial Demand Module (CDM). The RDM projects energy demand by end-use service, fuel type, and Census division. Similarly, the CDM projects energy demand by end-use service and fuel type for eleven different categories of buildings in each Census division. Both modules use energy prices and macroeconomic projections from other RHG-NEMS modules to estimate energy demand based on extensive exogenous inputs including consumer behavior, appliance efficiency and choices, and government policies.

One of the exogenous factors affecting energy demand in NEMS is climate. Temperature is usually captured in the demand equations in terms of heating degree days (HDDs) and cooling degree days (CDDs). For instance, the demand for fuel to heat buildings depends on the HDDs, which is defined as the number of degrees that a day's average temperature is below a certain desired temperature or threshold (here we use the value set by NOAA – 65°F – and used by EIA in its AEO). It is expected that higher average temperatures will reduce space heating demand for residential and commercial buildings in winter and increase cooling demand in summer. Future climate is represented as annual HDDs and CDDs by Census region in both the RDM and CDM. To estimate changes in the energy system due to climate using RHG-NEMS, we aggregate county-level HDDs and CDDs up to Census regions using population-weighted averages. The modules incorporate the future change in heating demand (due to changes in HDDs) and cooling demand (due to changes in CDDs) to inform decisions about appliance purchases as well as total energy consumption. For further details see the RDM[xli] and CDM[xlii] documentations.

Electricity generation is handled in RHG-NEMS by the Electricity Market Module (EMM). The EMM is a detailed, bottom-up representation of the U.S. electricity system that predicts the electricity market response to changes in fuel prices, energy demand, production costs, and other variables on a plant-by-plant basis. The EMM retrieves electricity demand from the end-use sectoral modules in RHG-NEMS and solves for electricity capacity, generation, and prices using four integrated submodules – the Electricity Load and Demand (ELD) submodule, the Electricity Capacity Planning (ECP) submodule, the Electricity Fuel Dispatch (EFD) submodule and the Electricity Finance and Pricing (EFP) submodule. There are 22 electricity supply regions in the EMM, representing former NERC sub-region boundaries. The four submodules solve for each EMM region but regions can trade power per specified transmission links. A detailed description of EMM methodology can be found in the documentation for EIA's version of NEMS.[xliii]

INCORPORATING THE CLIMATE RESPONSE FOR THERMAL ELECTRIC GENERATION

For the impacts to energy supply, we use damage functions developed by the National Renewable Energy Laboratory (NREL) for the Regional Energy Deployment System (ReEDS).[xliv] The ReEDS temperature-related changes in power plant capacity and heat rate (the inverse of efficiency) are based on the results of Jaglom *et al.*[xlv] Fractional changes in summer capacity and heat rate are a linear function of changes in summer average temperature from 2010. Capacity and heat rate changes are specified by time slice (peak vs. off-peak). In this analysis, we assume that capacity and heat rate changes can be averaged across the day according to the number of hours in each time slice. This may underestimate the impact of climate change, as the load is higher during peak hours. We compute these fractional changes using our projections of county-level average summer temperature.

Because the EMM does not explicitly model the impact of climate-related changes in temperature electricity generation, we modified RHG-NEMS to input changes in summer capacity and heat rate for existing plants and for planned capacity additions at the plant level. Changes in capacity and heat rate for other planned and unplanned additions are applied at the EMM region level by plant type. To aggregate county-level annual capacity and heat rate impacts to the EMM region level, we need to know the spatial distribution of impacts within an EMM region, which is not provided by RHG-NEMS. County-level changes in capacity and heat rate are specified by plant type, and we aggregate these impacts to the EMM region level using one of three methods. Impacts to baseload fossil fuel plants are aggregated using the spatial distribution of existing fossil fuel capacity within an EMM region. Impacts to baseload nuclear plants are aggregated using the spatial distribution of existing nuclear capacity within an EMM region, or existing fossil fuel capacity if no nuclear power exists in that region. Finally, impacts to peaking plants (combustion turbines) are aggregated using the spatial distribution of 2012 population within an EMM region.[xlvi]

ENERGY SYSTEM IMPACTS

Our method translates daily temperature data into annual HDDs, CDDs, and supply and heat rate impacts. Because of this, we are able to capture the full range of annual impacts to the energy system for projection period, 2030-2049. Because annual weather variability is large relative to the year-on-year changes in average climate, we assume that any of these annual impacts are representative of the impacts that might occur in any year over this period.

Since RHG-NEMS is a simulation model, with outcomes in a given year being dependent on the results of the previous year's run, the changes to the energy system that might result from an impact in 2030 would be materially different from the changes that might result from an impact in 2040. To deal with this issue, for each impact variable we treat each of the 20 years of climate outcomes (between 2020 and 2039) as a separate and independent sample. To develop a scenario usable in NEMS, we linearly interpolate between the historical average (1981-2010) and the projected impact in 2040. Therefore, the number of independent simulations that are required to produce the full range of impacts are 580 for RCP 2.6, 860 for RCP 4.5, and 880 for RCP 8.5, with an additional 20 runs for the historical climate baseline. This allows us to simulate the full range of climate futures that might be observed in 2040 as well as the response of the energy system to those changes.

Due to the complexity and run time of the RHG-NEMS model, it is infeasible to simulate the full set of 2,340 climate outcomes with all modules activated. Instead, we estimate impacts to the energy system in two steps.

First, we use the RDM and CDM to estimate the distribution of national changes in total building energy demand over the full range of climate uncertainty for each RCP and the historical (1981-2010) period. Preliminary results showed energy demand impacts to be much greater in magnitude than the energy supply impacts, indicating that the distribution of impacts from energy demand changes alone would be representative of the distribution of impacts from both energy demand and energy supply changes. Since we only activated the RDM and CDM for this step, the distribution of changes in energy demand does not incorporate feedbacks from outside the these sectors such as changes in energy prices and the resulting rebound in energy demand. However, such interactive effects would be small compared to the initial impact, and ignoring those in this step allows us to more completely characterize the full distribution of demand-side impacts.

Second, we drew the full RHG-NEMS model runs from the critical points of the above distribution. Specifically, we selected the climate model run corresponding to the 5th, 16.7th, 50th, 83.3rd, and 95th percentiles of the distribution of changes in national energy demand for each RCP pathway, and included the joint set of HDD, CDD, capacity, and heat-rate impacts in the integrated run. In these full RHG-NEMS runs, we included both energy demand and energy supply impacts. In addition, we activated all model modules to incorporate energy prices and macroeconomic feedbacks. We report quantiles of market-wide outcomes such as changes in energy expenditures from results of these integrated runs.

While we believe that changes in national building energy demand estimated by the residential and commercial demand modules are a good predictor of the energy system that would be seen in the full integrated RHG-NEMS model, there is no guarantee that each quantile of the building energy demand model distribution would correspond to the same quantile in the distributions for each variable of interest in the full RHG-NEMS model. Therefore, we define these integrated results as representative runs corresponding to the critical points of the distribution of national building energy demand.

SYSTEM-WIDE COSTS

Estimates of system-wide costs are calculated as a net present value between 2016 and 2040 of the annual sums of capital commitments for all bulk power system cost components, including capacity additions, transmission capacity additions, power plant retrofits, fixed and variable operations and maintenance, capital additions, fuel, purchased power, and energy efficiency program costs. Distribution system and consumer costs of electrical equipment (such as air conditioners, heat pumps, etc.) are not included. All costs are presented in constant 2013 USD. The NPV was calculated using a 5% discount rate.

To estimate the costs of current federal and state actions that – intentionally or unintentionally – help to reduce CO_2 emissions from the power sector , we assume that all major U.S. power sector renewable goals, incentives and other CO_2 mitigation actions are inactive and/or do not take effect after 2015.[xlvii] This "no mitigation" scenario was developed to model a scenario in which U.S. emissions are as consistent as possible with a no climate policy global emissions pathway. The purpose of this run is to compare the estimated system costs from temperature-related climate impacts – one small subset of overall climate change costs – to the estimated system costs from lowering GHG emissions.

Endnotes

[i] See text box "Defining likelihood" for a description of how we define *likely* results.

[ii] US Department of Energy. US Energy Sector Vulnerabilities to Climate Change and Extreme Weather (2013). Available here.

[iii] US Department of Energy. Climate Change and the US Energy Sector: Regional Vulnerabilities and Resilience Solutions (2015). Available here.

[iv] US Global Change Research Program. Climate Change Impacts in the United States: The Third National Climate Assessment, Our Changing Climate. Walsh, J., Wuebbles, D., Hayhoe, K., Kossin, J., Kunkel, K., Stephens, G., Thorne, P., Vose, R., Wehner, M., Willis, J., Anderson, D., Doney, S., Feely, R., Hennon, P., Kharin, V., Knutson, T., Landerer, F., Lenton, T., Kennedy, J., and R. Somerville. (Washington DC, 2014).

[v] Our confidence in projecting future changes in extremes (including the direction and magnitude of changes) varies with the type of extreme, based on confidence in observed changes, and is thus more robust for regions where there is sufficient and high quality observational data. Temperature extremes, for example, are generally well simulated by current GCMs, though models have more difficulty simulating precipitation extremes. While projected changes in humidity are expected to also impact electricity demand for cooling, we do not take humidity into account in this analysis.

[vi] Intergovernmental Panel on Climate Change. A Special Report of Working Groups I and II, Managing the Risks of Extreme Events and Disasters to Advance Climate Change Adaptation, Changes in Climate Extremes and their Impacts on the Natural Physical Environment. Seneviratne, S. I., Nicholls, N., Easterling, D., Goodess, C. M., Kanae, S., Kossin, J., M. Reichstein, A. Sorteberg, C. Vera, & X. Zhang. (Cambridge, UK and New York, NY, USA: Cambridge University Press, 2012), 109-230.

[vii] Intergovernmental Panel on Climate Change. Contribution of Working Group I to the Fourth Assessment Report, Climate Change 2007: The Physical Science Basis, Climate Models and Their Evaluation. Randall, D. A., Wood, R. A., Bony, S., Colman, R., Fichefet, T., Fyfe, J., & Taylor, K. E. (Cambridge, UK and New York, NY, USA: Cambridge University Press, 2007), 589-662. http://www.ipcc.ch/pdf/assessment-report/ar4/wg1/ar4-wg1-chapter8.pdf.

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[ix] Climate projections for this analysis are based on modeling conducted for the *Economic Risks of Climate Change: An American Prospectus* (2015), available here. For a detailed methodology, see *The American Climate Prospectus* (2014) "Technical appendix: Physical climate projections," available here.

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[xxv] Projections of CDDs and HDDs used in EIA's AEO 2015 reference case relative to our projections vary by year and region. In general, EIA's CDDs lie below the median of our projected CDDs for RCP 2.6, and EIA's HDDs lie above the median of our projected HDDs for RCP 2.6.

[xxvi] More information on NEMS is available at http://www.eia.gov/oiaf/aeo/overview/.

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