Decarbonisation scenarios of the U.S. electricity system and their costs

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Article

Keywords: decarbonising electricity, climate change mitigation, carbon, CO2

Posted Date: April 9th, 2021

DOI: https://doi.org/10.21203/rs.3.rs-337451/v1

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Abstract

Decarbonising electricity is crucial for climate change mitigation, while understanding its economic implications has been a challenge. Previous analyses primarily rely on levelised cost or single-year optimization, which fail to account for the complex spatiotemporal dynamics of capacity expansion and dispatch decisions. Here, we present a regionally resolved national model that considers such dynamics and quantifies the cost of decarbonising the U.S. electricity system under a set of possible scenarios. The result shows that, compared to a business-as-usual scenario, reducing 80% CO_2 emission by 2050 relative to 2005 level would incur, depending on the scenarios, \$220~\$490 billion additional costs (present value in 2020 US\$, equivalent to ¢0.15~¢0.34 kWh^{-1}) to the electric sector during 2020–2050, with regional costs ranging -¢0.08~¢0.51 kWh^{-1}. When compared with the mitigated CO_2, these additional costs equal to \$10 and \$37 per tCO_2 reduced, which are well below the social cost of carbon in the literature.

Main

Decarbonisation of the electricity system is crucial for climate change mitigation. To achieve the 2 °C climate target of Paris Agreement, the electric power sector needs to rapidly reduce its greenhouse gas (GHG) emissions to nearly zero by mid-century[1–4].

Literature confirms the technical feasibility of decarbonising the electricity system to a large extent, or even 100%, of variable renewable energy (VRE). However, a stark difference in views persists as to the cost of such a transition. Some studies have shown that high penetration of VRE can substantially increase average cost of electricity[5–10], as additional investments are needed for reserve capacity and storage[11]. Other studies found that such a transition will lower the average cost of electricity, due to the declining prices of photovoltaics (PV), wind turbines, and electricity storage systems[12–17].

Previous studies on the cost of decarbonising electricity are, however, based on the simulations for one year or a few continuous years[5–7,14–17]. As these studies only provide a snapshot of possible future electricity system, they offer limited insights on the dynamics of the system and associated costs along the transition. In addition, previous studies tend to focus on a single region or an entire nation without distinguishing sub-regions, limiting the ability to capture key spatiotemporal dimensions of electricity systems such as transmission capacity and dispatchability.

Furthermore, previous studies often estimate the system-wide levelised cost of electricity (LCOE)[14–16], which are calculated by averaging technology LCOEs weighed by annual generation mix. The modelling approach used in these studies only simulates future electricity mix based on supply-demand balance, but it does not model the capacity expansion, so these studies do not correctly quantify capital investments of the electricity system. In addition, the use of static capacity factors and the lack of a temporal dimension in LCOE calculations fail to capture the system-level costs due to adjustments in actual electricity dispatch and investments in reserve capacity and transmission[11,18,19].

In this study, we incorporate the future projections of electricity demand and technology costs into a recursive optimization model. The model simulates the least-cost capacity expansion and dispatch of the contiguous U.S. electricity system for each two-year period from 2020 to 2050 using the output of

the previous two-year period as an input to subsequent two-year period. The estimated system cost includes both capital and operational costs, which depend on installed capacity and generation output, respectively at each two-year period. The model captures spatiotemporal variability of electricity capacity and generation by maintaining supply-demand balance and operational reliability for 17 intra-annual time slices across 134 balancing areas.

To represent a wide range of future electricity pathways, we adopt four electricity scenarios from a previous study[20], and further evaluate their cost implications during 2020–2050. BAU (Business-as-usual) scenario assumes the reference projections of electricity demand, technology and fuel costs derived from Annual Energy Outlook (AEO) and annual technology baseline (ATB 2016) by the National Renewable Energy Laboratory (NREL)[21,22]; COAL scenario assumes no retirement of coal power plant before 2050 and lower coal fuel prices; NUC (Nuclear) and REN (Renewable) scenarios both assume 80% CO_2 emission reduction by 2050 relative to 2005, but differs in lifetimes of nuclear plants (NUC scenario assumes all nuclear units remain in service for 80 years) and cost projections for solar and wind technologies (NUC scenario uses ATB high cost projections for wind and solar, while REN scenario uses ATB reference cost projections for solar and wind) to favour nuclear and renewable resources respectively. Although the four electricity scenarios are developed under different technology and fuel costs, we postprocess the model output costs to align with their reference projections in our cost calculation to ensure fair comparisons among scenarios (See Methods). The cost results are expressed as 2020 US dollar following the Consumer Price Index inflation calculation[23].

Sensitivities on the adopted electricity scenarios also consider the climate-water impacts on electricity capacity expansion and dispatch by incorporating outputs of climate, hydrological, and thermoelectric power production models. Therefore, we quantify the cost of electricity system using climate projections from five global climate models (GCMs) under four representative concentration pathways (RCPs) [RCP 2.6, RCP 4.5, RCP 6.0, and RCP 8.5]. In addition, two different modelling approaches are used for assessing the climate-water impacts. The one-way approach represents a single-direction application of climate and water resource data in electricity system modelling. The iteration approach,

on the other hand, incorporates a feedback mechanism between electricity generation and climate-water constraints through iteration between models, so it estimates more viable electricity generation projections that achieve grid reliability thresholds and also reflects the adaptation of electricity system to the climate-water impacts[20] (See Methods). These scenarios provide a rich data set to assess the incremental effects of climate change on cost calculations.

Average capacity, generation, and CO_2 emission in 2020 and 2050

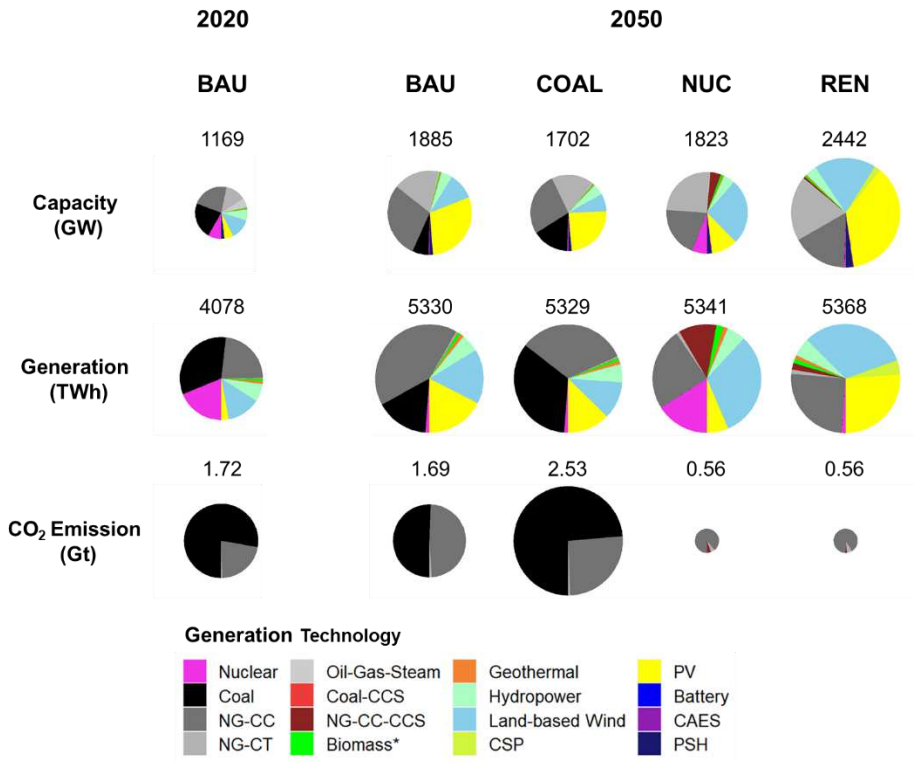

Fig. 1 | Average capacity, generation, and CO_2 emission of the U.S. electricity system in 2020 and 2050. The results of capacity, generation, and CO_2 emission presented here are averaged across the 21 climate scenarios (5 GCMs × 4 RCPs under one-way approach and one RCP 8.5 under iteration approach) due to their minor differences. The capacity numbers of different scenarios include both electricity generation and storage technologies. Electricity generation and storage technologies abbreviations include: CAES: compressed-air energy storage; Coal-CCS: Coal with carbon capture and storage; CSP: Concentrated solar power; NG-CC: Natural gas combined cycle; NG-CC-CCS: Natural gas combined cycle with carbon capture and storage; NG-CT: Natural gas combustion turbine, PSH: Pumped-storage hydropower; PV: Photovoltaic; Biomass* includes Biomass, Municipal Solid Waste and Landfill Gas; Battery: Sodium-sulphur flow battery (12-MW, 7.2-hour). The exact values of capacity, generation, and CO_2 emission at 2020 and 2050 can be found in Supplementary table 1-3. The annual new-installed capacity, total capacity, generation, and CO_2 emission from 2020 to 2050 (even years) can be found in Supplementary Fig. 1-2.

The evolution of installed capacities and generation mixes under the four electricity scenarios (average across climate scenarios) explains the underlying cost structures. Under REN scenario, 80% reduction in annual CO_2 emission is achieved by almost quintupling the combined capacity of VRE sources (photovoltaic, concentrated solar power, land-based wind, hydropower, geothermal, and biomass) from 307 GW in 2020 to 1,495 GW in 2050. In contrast, nuclear, oil-gas-steam, and coal capacities decline substantially, as capacity retires while no new capacity is built for these technologies. To reach the same carbon reduction target, the combined capacity of VRE sources under NUC scenario is more than doubled from 307 GW in 2020 to 775 GW, contributing 43% of the total generation capacity in 2050. Other low-carbon sources, such as nuclear (108 GW) and natural gas combined cycle with carbon capture and storage (NG-CC-CCS) (76 GW), together also account for 10% of total generation capacity in 2050. Annual CO_2 emissions from the contiguous U.S. electricity system increase from 1.7Gt to 2.5 Gt over the course of 30 years under COAL scenario, mainly due to the stable coal (262 GW to 266 GW) and increasing natural gas capacities (407 GW to 753 GW) from 2020 to 2050. The combined capacity of VRE sources is only 638 GW in 2050 under COAL scenario, which is lowest among the four scenarios (Fig. 1).

Total electricity generation increases by about 30% between 2020 and 2050 for all scenarios because they use the same AEO electricity demand growth scenario. Under REN scenario, VRE sources provide as much as 70% of electricity generation in 2050 (3,780 TWh), growing up from 25% in 2020. As for NUC scenario, VREs take about 44% of the annual generation (2,521 TWh) in 2050, with other major low-carbon sources (nuclear and NG-CC-CCS) contributing 27% (1,449 TWh). The generation mix in 2050 under COAL scenario is still fossil-dominated, as coal and natural gas both take about one third (1,829 TWh and 1,770 TWh, respectively) of the annual generation, and VREs and nuclear together account for the last one third (Fig. 1).

Cost dynamics of electricity system

The annual costs under the four electricity scenarios (average across climate scenarios) reflect temporal dynamics that are determined by the annual capacity expansion and dispatch of the electricity system. Such dynamics also affect the order of annual costs under the four electricity scenarios. The

cumulative costs sum annual costs from the starting year to the target year, but they do not always follow the same order as displayed by annual costs. Our results show that, as the electricity system develops under the four electricity scenarios, the cumulative costs start to diverge and follow a consistent order (NUC > REN > BAU > COAL) after around 2030. By 2050, the cumulative costs over the 30 years reach $7,700 billion, $7,600 billion, $6,600 billion, $6,000 billion for NUC, REN, BAU, and COAL scenarios, respectively (Fig. 2a). However, the annual costs in the same year show a different order: REN has the highest annual cost ($310 billion) in 2050, followed by BAU ($300 billion), NUC ($260 billion), and COAL ($250 billion) scenarios (Fig 2b). The difference of orders in cumulative and annual costs indicate the inadequacy of single-year cost estimates in representing the long-term development of electricity system. Instead, the total cost incurred by the electricity system across the whole transition period should be applied in the cost comparison of different electricity scenarios.

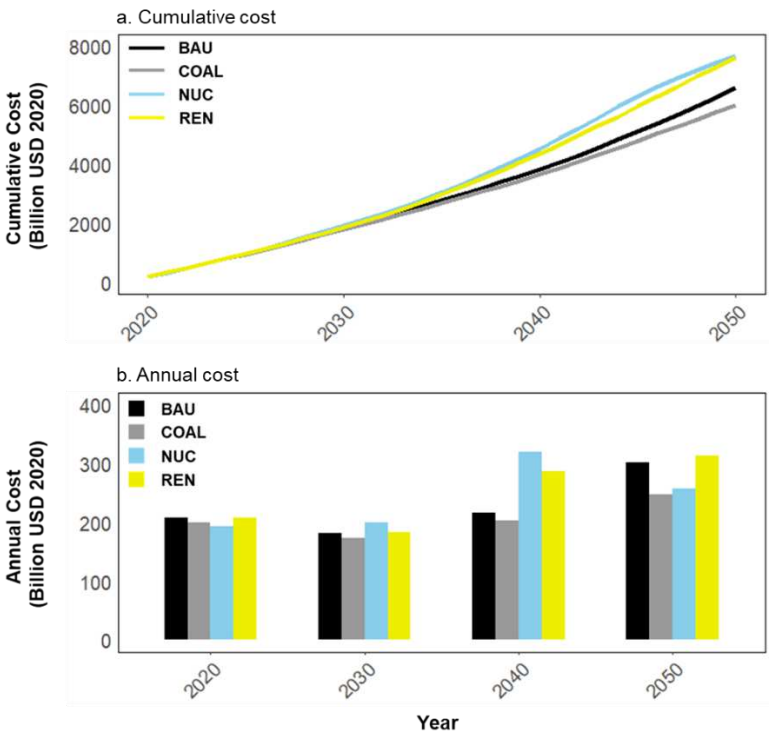

Fig. 2 | Cumulative cost (a) and annual cost (b) of the U.S. electricity system under BAU, COAL, NUC and REN scenarios. The cumulative cost (averaged across climate scenarios) at each year is the sum of annual costs of the current and all previous years (starting from 2020). The annual cost (averaged across climate scenarios) is the sum of capital cost, fixed operational and maintenance (FOM) cost, variable operational and maintenance (VOM) cost, and fuel cost across all generation, storage and transmission technologies incurred at each year. The annual costs of four representative years (2020, 2030, 2040, and 2050) are presented in the figure. Both cumulative cost and annual cost neither take any social discount rates into account nor include any externality costs, such as costs from emissions. The annual cost of each generation, storage, and transmission technology from 2020 to 2050 under the four scenarios are presented in Supplementary Fig. 3-5.

Total cost of electricity system from 2020 to 2050

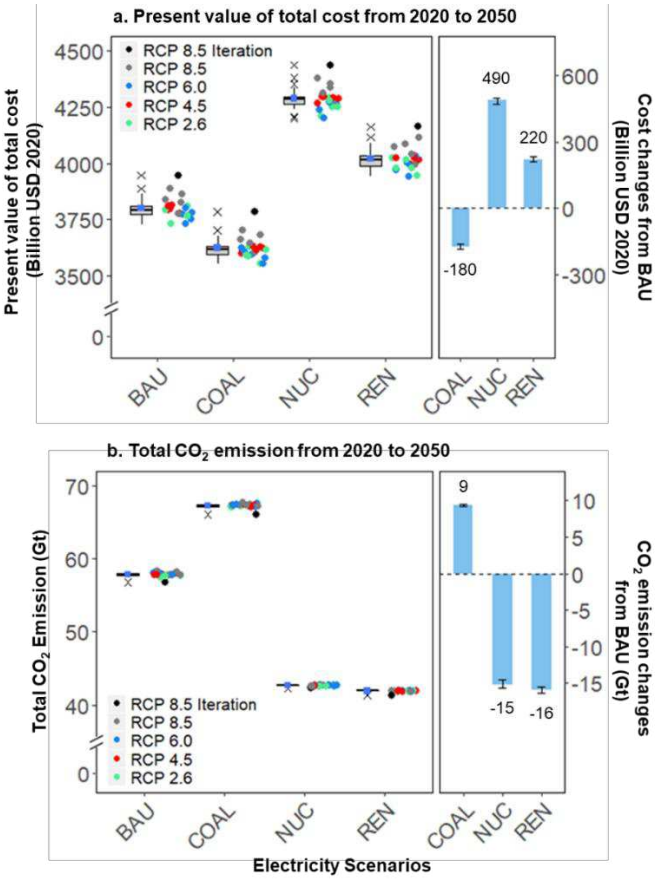

Fig. 3 | Present value of total cost (a) and CO_2 emission (b) of the U.S. electricity system from 2020 to 2050 under four electricity scenarios. The broad panels of each figure represent the present value of total cost (a) and total CO_2 emission (b) under the four electricity scenarios, and the range of each box represents the total costs/total CO_2 emission estimated based on different climate scenarios, which are also shown by the scatter points next to it. The square blue point in the box represents the mean. Different colours of the scatter points represent different RCP scenarios. RCP 2.6, RCP 4.5, RCP 6.0, and RCP 8.5 are results of the one-way approach. Each colour includes five points under each electricity scenario, representing the variability of the five GCM outputs. The RCP 8.5 Iteration is result of the iteration approach, and it has only one point under each electricity scenario, representing the average across five GCM outputs. The right narrow panels represent the changes of costs and CO_2 emissions of COAL, NUC, and REN scenarios from BAU scenario. The error bars in the right narrow panels show the ranges of maximum and minimum values, and the number of each bar represents the average value.

We calculate the present value (3% social discount rate (SDR)) of annual costs from 2020 to 2050 and sum them up to obtain the present value of total cost from 2020 to 2050 for all scenarios (See Methods). The results (average across climate scenarios) show that the BAU scenario incurs a total cost

$3,800 billion and a total CO_2 emission of 58 billion metric tons (Gt) between 2020 and 2050. Compared to BAU scenario, NUC and REN scenarios have higher total costs, which are $4,300 billion and $4,000 billion, respectively, but they both only emit around 42 Gt CO_2, saving a total 15–16 Gt CO_2 over the course of 30 years. COAL scenario has a lower total cost ($3,630 billion) than BAU scenario, while generating 67 Gt CO_2 emissions (Fig. 3).

Under climate change, higher RCP scenarios tend to increase total cost of the U.S. electricity system by < ±3.0% compared to the mean (Fig. 3). The impacts of climate change on the total cost of electricity system is materialized mainly through their effects on electricity demand, because higher average temperature tends to increase cooling demand. This effect is especially impactful during the summer. The climate impacts also affect the generation efficiency of thermal power plants, because under the climate-water constraints, thermal power plants will be operated under the derated efficiency level in order to meet the safety and environmental regulations[20], although such effects are found to be relatively small.

We further break down the average cost changes into technology-specific components (Fig. 4). The capital, fuel, and OM costs of NG-CC are $330 billion lower in COAL than in BAU, and VREs sources, such as PV and land-based wind, also have lower costs in COAL scenario. The savings more than negate the additional costs from coal electricity ($260 billion) resulting in $180 billion net reduction in cost (Fig. 4a). Under NUC scenario, nuclear and land-based wind electricity displace much of the electricity supply from coal power plants, saving as much as $320 billion from coal by 2050, while that alone does not negate additional costs, most notably from land wind ($350 billion) leading to $490 total additional costs (Fig. 4b). Under REN scenario, cost savings are materialized mainly from fossil fuels, such as coal (-$290 billion) and NG-CC (-$53 billion), while additional costs are needed for land wind ($240 billion), PV ($150 billion) and other sources result in net $220 billion additional cost compared to BAU (Fig. 4c).

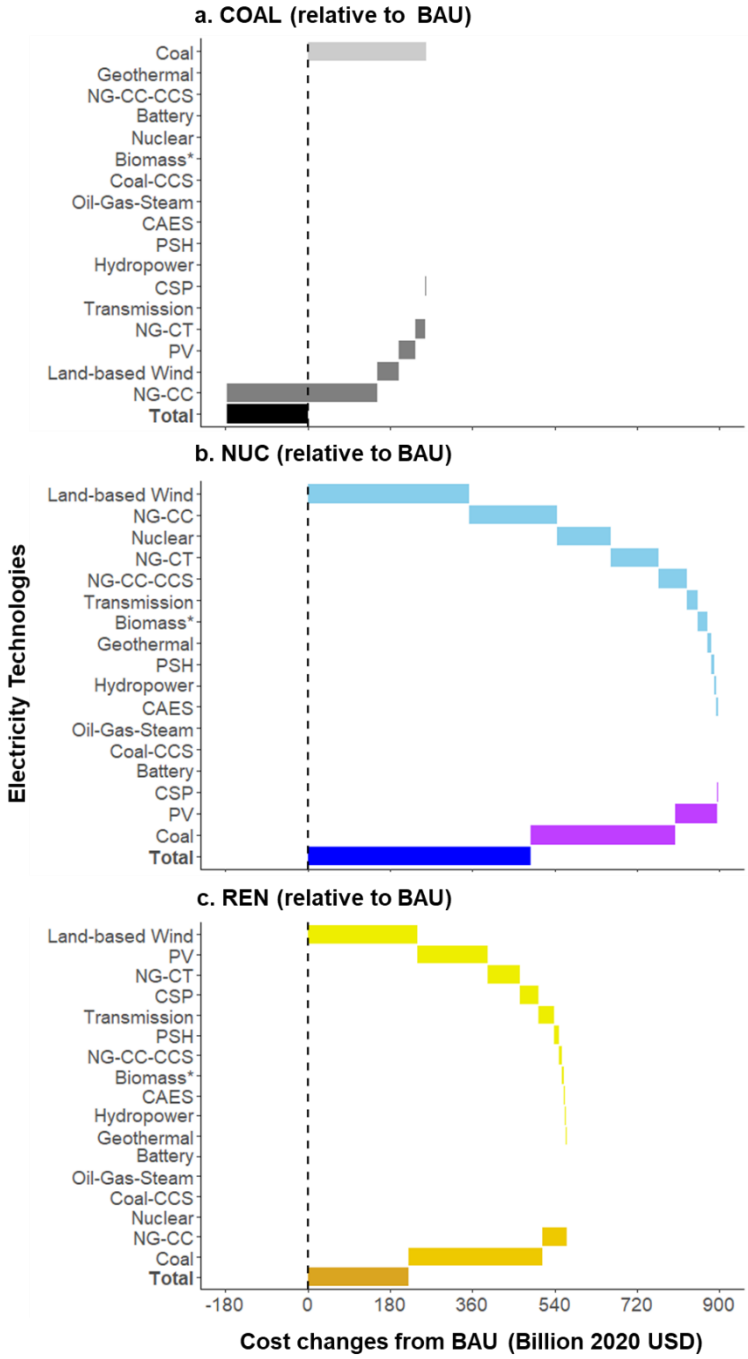

Fig. 4 | The contribution of various generation and transmission technologies to the cost changes (average across climate scenarios) of COAL, NUC, and REN scenarios from BAU scenario. The contribution to the cost changes by cost types can be found in Supplementary Fig. 6.

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Regional variability of electricity cost

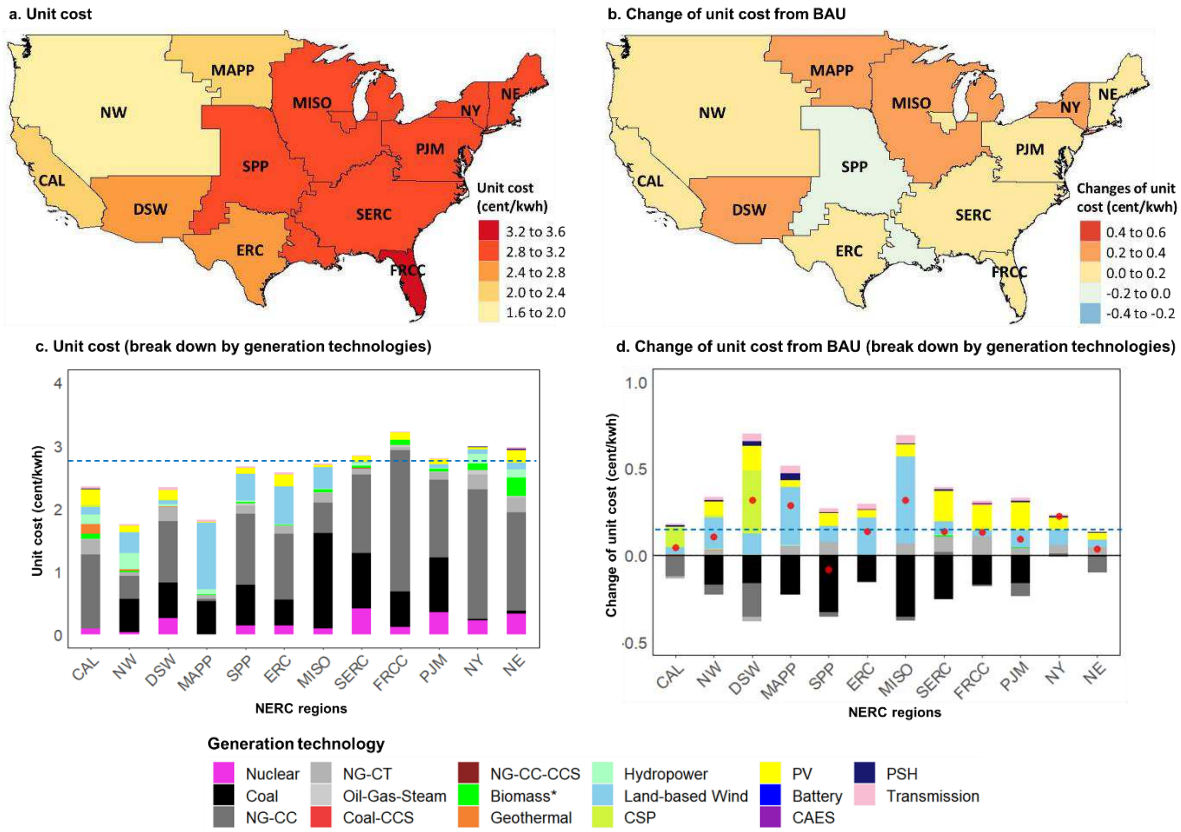

Fig. 5 | The average unit costs of electricity (a, c) under REN scenario and their changes relative to BAU scenario (b, d) at 12 North American Electric Reliability Corporation (NERC) regions across the U.S. The map plots (a, b) show the costs at different regions, and the bar plots (c, d) show the contribution of different technologies to the costs. The dash lines in the bar plots show the average values at the national level. The red dot in plot (d) shows the net additional unit cost at different NERC regions. NERC region: NE = New England; NY = New York; PJM = Pennsylvania-New Jersey-Maryland (covers Mid-Atlantic region); SERC = South-eastern Electric Reliability Council; FRCC = Florida Reliability Coordinating Council; MISO = Midcontinent Independent System Operator; MAPP = Mid-Continent Area Power Pool; SPP = Southwest Power Pool; ERC (ERCOT) = Electric Reliability Council of Texas; DSW = Southwest; NW = Northwest; CAL = California. The cost only includes the capital, FOM, VOM, and fuel cost of the electricity system, but it does not consider the electricity import and export among different NERC regions, therefore the revenue and payment associated with electricity import and export are not included in the cost presented here. The results of BAU, NUC, and COAL scenarios are presented in Supplementary Fig. 7 – Supplementary Fig. 14.

The average unit costs of electricity are calculated by dividing the present value of total cost by the total generation (across 2020–2050, all averaged across climate scenarios), and they show regional variability across 12 North-American Electricity Reliability Corporation (NERC) regions in the contiguous U.S. (See Methods). Under the REN scenario, average national unit cost of electricity (across 30 years) is 2.8 cent/kWh, with a variation between 1.9 cent/kWh in Northwest (NW) to 3.4 cent/kWh in

Florida Reliability Coordinating Council (FRCC). In general, the eastern regions, such as New England (NE, 3.0 cent/kWh), New York (NY, 3.0 cent/kWh), Pennsylvania-New Jersey-Maryland (PJM, 2.9 cent/kWh), South-eastern Electric Reliability Council (SERC, 3.0 cent/kWh), and FRCC (3.4 cent/kWh), have higher unit costs than regions in the central and western U.S., such as Southwest (DSW, 2.5 cent/kWh), Northwest (NW, 1.9 cent/kWh), California (CAL, 2.4 cent/kWh), and MAPP = Mid-Continent Area Power Pool (MAPP, 2.0 cent/kWh). This is mainly because eastern regions have higher reliance on the fossil fuel resources, such as NG-CC and coal, for the electricity generation, which incurred higher fuel costs, causing higher overall unit costs in these regions (Fig. 5a, Fig. 5c, Supplementary Fig. 15).

Compared to BAU scenario, REN scenario reduces fuel cost for almost all regions (except for NY), but the incurs higher capital investments due to the new instalment of various renewable capacities. Therefore, almost all regions have net additional unit costs (0.04 cent/kWh in NE to 0.32 cent/kWh in DSW) under REN scenario, except for the Southwest Power Pool (SPP), which saves 0.08 cent/kWh relative to BAU scenario. We also observed the regional variability of investment in low-carbon sources across the NERC regions. For example, the southwestern regions (CA and DSW) will invest mostly in the solar electricity, especially the CSP, which can be attributed to the abundant solar resources in these regions. For central regions, such as MAPP, Midcontinent Independent System Operator (MISO) and Electric Reliability Council of Texas (ERC), the investment in wind electricity dominate the additional unit costs, which also correspond to the high-quality wind resources in those regions (Fig. 5b, Fig. 5d, Supplementary Fig. 16).

CO_2 abatement cost of low-carbon electricity pathways

Compared to BAU scenario, NUC and REN scenarios will incur higher total costs but reduce CO_2 emission over the course of 30 years, so we calculated the CO_2 abatement cost by dividing the present value of total additional costs (with four SDRs at 2%, 3%, 5% and 7%) of NUC and REN scenarios by their CO_2 emission savings compared to BAU scenario, and this metric represents the average cost of reducing 1 metric ton (t) CO_2 by pursuing these low-carbon electricity pathways. The CO_2 abatement costs, depending on the SDRs, ranges from \$18–\$37/t CO_2 for the NUC scenario and \$10–\$15/t CO_2

182 for the REN scenario. According to the social cost of carbon (SC-CO_2) estimated by U.S. EPA, the av-
183 erage SC-CO_2 ranges from \$15 to \$33/t CO_2 under 5% SDR from 2020 to 2050, and this range will
184 increase to \$79 to \$121/t CO_2 with 2.5% SDR[24]. In comparison, the CO_2 abatement costs under NUC
185 and REN scenarios are lower than the reported SC-CO_2 ranges, except for that of NUC scenario under
186 5% SDR, which falls in the middle of the SC-CO_2 range (Fig. 6a).

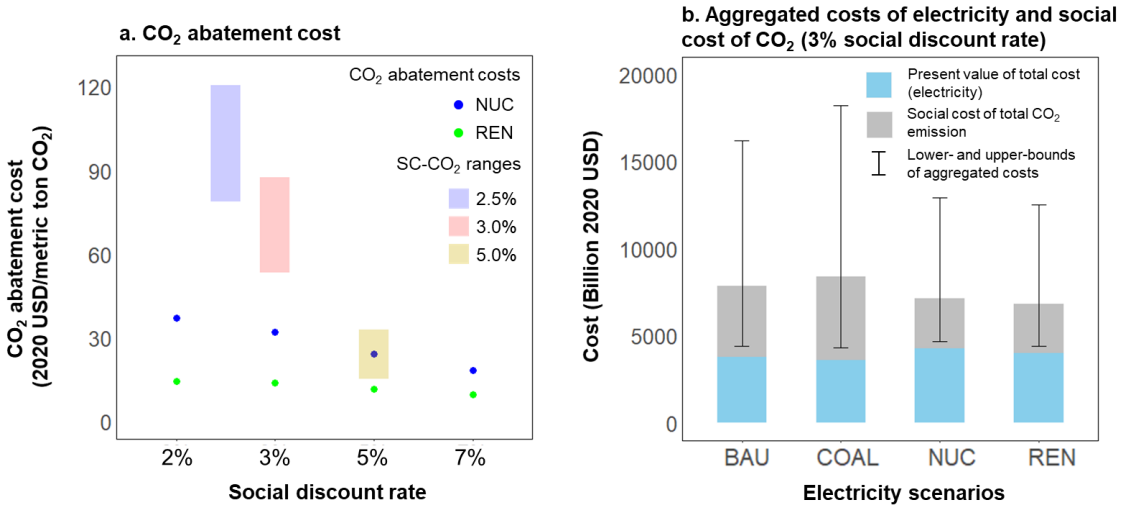

Fig. 6 | The CO_2 abatement cost under NUC and REN scenarios (a) and aggregated cost of electricity and social cost of CO_2 under four electricity scenarios (b). In Fig. 6a, the dots represent the CO_2 abatement costs (averaged across climate scenairos due to negligible differences) of NUC and REN scenarios under different SDRs (2.0%, 3.0%, 5.0%, and 7.0%). The three horizontal bands represent the average SC-CO_2 estimated by U.S. EPA under different SDRs (2.5%, 3.0% and 5.0%). The lower bound of each band represents the average SC-CO_2 in 2020, and upper bound represents the average SC-CO_2 in 2050. The SC-CO_2 was originally estimated based on 2007 US\$, and we converted them to 2020 US\$. In Fig. 6b, both present value of total cost (electricity) and social cost of total CO_2 emission are calculated based on 3% SDR. The pink bars represent the social cost of total CO_2 emission calculated based on average SC-CO_2 (at 3% SDR). The error bars reflect the uncertainty range of SC-CO_2 (at 3% SDR). The lower and upper bounds of error bars represent the aggregated cost results calculated based on 5th and 95th percentile SC-CO_2 (at 3% SDR), respectively.

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188 Furthermore, we multiply annual SC-CO_2 by annual CO_2 emissions and sum them up across 2020–
189 2050 to obtain the social cost of total CO_2 emission over the course of 30 years. The results show that
190 COAL scenario incurs the highest social cost of total CO_2 emission at \$4,890 billion (based on average
191 SC-CO_2 at 3% SDR), followed by BAU (\$4,060 billion), NUC (\$2,840 billion), and REN (\$2,800 bil-
192 lion) scenarios. By aggregating the present value of total costs (electricity) and social costs of total

CO_2 emission, the results suggest that, despite the higher total costs of electricity, NUC and REN scenarios have lower aggregated costs due to their lower CO_2 emissions compared to BAU and COAL scenarios (Fig. 6b).

Discussion

In our study, we have shown that achieving 80% of carbon reduction in the U.S. electricity system by 2050 incurs $220–$490 billion additional costs over a 30-year period under a set of scenarios that transition towards different sources of low-carbon electricity.

Our conclusion, in some degree, contradicts with a few other studies which claim that an U.S. energy system relying exclusively on wind, water and solar (100% WWS) will have lower electricity cost than the business-as-usual scenario[14–16]. First, these studies mainly compare the average unit costs of electricity under different scenarios at a single target year (2050). It is reasonable that a 100% WWS energy system has lower average unit cost of electricity than its business-as-usual counterpart in the year when such a system is available, as these studies shows that the 100% WWS system has no fuel cost and reduces curtailment by deploying storage technologies and creating flexible loads. However, the decarbonisation of electricity system is a long-term process featured by the cumulative instalment of low-carbon sources and retirement of fossil-based sources. The annual system cost depends on annual capacity expansion and dispatch, which are influenced by technology cost projection, capacity and generation requirement, and policy assumption. Our study shows that the annual costs under four electricity scenarios in 2050 show different orders compared to those of cumulative costs over the course of 30 years. Therefore, the cost comparison of different electricity scenarios should be based on their cost metrics that covers the whole transition period, instead of the single-year cost estimation, which only captures a snapshot of the transition period.

Second, the previous studies estimated the unit cost of electricity in 2050 by averaging technology LCOEs weighed by the 2050 generation mixes. Such a cost estimation does not correctly characterise the capital investment which should be determined by the installed new capacity. In our study, we applied the least-cost optimization model to estimate the costs of electricity system, which, depending on

the cost types, are determined by capacity (capital cost and fixed operational and maintenance cost) and generation (variable operational and maintenance cost and fuel cost), respectively. Therefore, compared to LCOE, our cost estimation is a better metric to capture the costs incurred by annual capacity expansion and dispatch of the electricity system.

Although our study shows decarbonising the U.S. electricity system incurs additional costs relative to the BAU scenario, they are lower than the social cost of carbon in the literature, indicating that the benefits of avoiding potential climate damage outweighs the abatement cost of decarbonising the electricity system. In addition, the low-carbon transition of electricity system is also shown to reduce health costs (by cutting air pollution) and create more jobs opportunities[15,16]. Therefore, the overall social benefits highlight the significance of decarbonising the U.S. electricity sector.

Furthermore, we also find that the average unit cost of electricity varies across different regions in the U.S. Under NUC and REN scenarios, the eastern regions have higher reliance on the fossil fuel sources, leading to higher unit cost of electricity compared to central and western regions. The additional unit cost (relative to BAU) also ranges from -0.08 cent/kWh (cost saving) to 0.51 cent/kWh across different regions, with the expenditures also varying among different technologies. For example, under the REN scenario, the additional costs in southwestern regions mostly comes from the solar electricity, while the investment in wind electricity dominates the additional costs in the central regions. Such regional heterogeneity of electricity cost provides valuable guidance for implementing regional specific policies to support the low-carbon electricity with the consideration of regional resource and technology availabilities.

Limitations

In this study, NUC and REN scenarios have about 450 GW of NG-CT as peak load generator in 2050, while the total storage capacities (PSH, CAES, and battery) are less than 60 GW, because the cost assumptions of storage technologies (Overnight capital cost of PSH is $3,500/kW and remains constant over time, and overnight capital cost of sodium-sulphur flow battery is assumed to be $3425/kW in

2010 and declines at 0.5% per year[25,26]) are higher than that of NG-CT (overnight capital cost decreases from $850/kw to $740/kw during the studied period[22]). Recent studies have shown that the costs of wind, solar and Li-on battery have been declining substantially to the extent that the combination of renewables with battery storage has become cost competitive to the natural gas peaker plants[27,28], so more up-to-date cost data of battery storage technologies need to be used to evaluate the role of storage technologies in future electricity system.

Our results also show that, at the national level, the climate impact has a relatively minor effect on the total cost of the U.S. electricity system compared to the effect of different electricity scenarios, as the total costs under different climate scenarios only change from their averages by less than ±3.0%. In this study, climate change affects the electricity system mainly through increasing the load and reducing the efficiency of thermal power plants. However, several studies have revealed that the climate induced changes in temperature, wind and cloud pattern, and water resources availability can also affect the operation of solar[29], wind[30], and hydropower[31]. These effects should be incorporated into future studies to examine the climate impacts on the operation and costs of electricity system, especially when VREs are at high penetration level. Also, the climate impacts on electricity system is only modelled until 2050 in this study, while it is expected that global surface temperature and its associated impacts on nature and human systems will become more significant after 2050[1], so evaluating the effects of severer climate scenarios or even extreme climate events on a electricity system is also important for understanding the grid reliability under climate change.

Methods

The electricity optimization model

The Regional Energy Deployment System (ReEDS) model is a capacity expansion and dispatch model for electric power sector of the contiguous U.S. By incorporating grid reliability requirements, technology resource constraints, and policy constraints, the model determines the least-cost mix of technologies that meets regional electricity demand requirements. The cost minimization is performed recursively and sequentially by solving a linear program for each two-year period from 2010 to 2050. ReEDS serves load and maintains operational reliability in 17 time-slices within each model year, which includes four seasons (Spring, Summer, Fall, and Winter), and each season has a representative day with four chronological time-slices (overnight, morning, afternoon, and evening), and the 17_{th} time-slice is a "summer peak" representing the top 40 hours of summer load (Supplementary Table. 4). In the continuous U.S., ReEDS simulates the generating capacity and balances supply and demand in 134 model balancing areas (BAs), allowing the model to capture the geospatial complexity of resources and technology availability across the country[32].

In this study, the ReEDS model is applied to estimate the capacity expansion, electricity generation, electricity costs, and CO_2 emission in the continuous U.S. The costs include capital cost, fixed and variable operational and maintenance (FOM and VOM) costs, and fuel cost. ReEDS simulates results for the even years of the studied period, and we calculated the results of the odd years by taking the average between the two closest even years to get the completed result for each single year.

The electricity scenarios

The four electricity scenarios we considered in this study were adopted from a previous paper[20] with their assumptions showing as follows:

BAU (Business as usual) scenario: Assuming the reference projections of electricity demand, technology and fuel costs derived from AEO 2016 and 2016 NREL Annual Technology Baseline (ATB)[21,22].

COAL scenario: 1. Using almost the same reference projections of electricity demand, technology and fuel costs as in BAU scenarios except for fuel cost of coal generation, for which we used the AEO

2016 low coal fuel cost projection to allow coal power plant to be more cost-competitive for electricity generation; 2. Assuming no coal-based power plant retirement by 2050.

NUC (Nuclear) scenario: 1. Using almost the same reference projections of electricity demand, technology and fuel costs as in BAU scenarios except for costs of solar and wind, for which we assumed ATB 2016 high cost projections for solar and wind so that their development will be suppressed and the nuclear power plant will be more cost-competitive for electricity generation; 2. Assuming 80% carbon dioxide (CO_2) emission reduction by 2050 relative to 2005; 3. Assuming lifetime extension of nuclear power plant to 80 years for all units.

REN (Renewable) scenario: 1. Using the same reference projections of electricity demand, technology and fuel costs as in BAU scenarios; 2. Assuming 80% carbon dioxide (CO_2) emission reduction by 2050 relative to 2005.

In order to represent a wide range of potential electricity pathways in the future, the NUC and COAL scenarios were created based on different cost assumptions compared to those used in BAU and REN scenarios (Technology cost projection data for developing the four scenarios can be found in Supplementary Information—Technology Cost Projection Data.xlsx). In the total cost calculation, we adjusted the cost projections of the NUC (high cost projections for solar and wind) and COAL (low coal fuel cost projection) scenarios by converting them to their reference projections in order to ensure fair cost comparisons among the four electricity scenarios, but the capacity, generation and CO_2 emission that were simulated under the NUC and COAL scenarios (using their original cost assumptions) remains the same.

The climate scenarios

To incorporate the climate effect, a one-way and a iteration modelling approaches were applied to examine the effect of climate and water impacts on the electricity system development (Supplementary Fig. 17)[20]. In the one-way approach, 20 sets of climate data were developed using five global climate model (GCMs) [GFDL-ESM2M, HadGEM2-ES, IPSL-CM5A-LR, MIROC-ESM-CHEM, and NorESM1-M] under four representative concentration pathways (RCP) [RCP 2.6, RCP 4.5, RCP 6.0, and RCP 8.5]. The climate data were then used to derive the heating and cooling degree-day, which

can be further applied to adjust the future electricity demand, transmission, as well as the heat-rate and capacity of thermal power plants. The climate data also informed the water balance model (WBM) to project water availability for cooling and operations, which are then used as the water withdraw constraint in the ReEDS. During the ReEDS simulation, the four electricity scenarios mentioned previously were also incorporated, together with the climate inputs, to estimate the future capacity and generation portfolio of the U.S. across a total 80 climate-electric scenarios (5 GCM × 4 RCP × 4 electricity scenarios).

As for the iteration approach, the ReEDS is firstly executed to produce electricity expansion projection at balancing authority level only accounting for the climate impacts on electricity demand and transmission. The ReEDS outputs of electricity capacity and generation, together with climate data, were used in the Water Balance Model and Thermoelectric Power and Thermal Pollution Model (WBM-TP2M) to simulates climate-water impacts on electricity capacity and generation by calculating the adjusted available capacity (AAC) for thermal power plants at plant level[33]. The AAC represents the available capacity of a power plant as a percentage to its nameplate capacity by considering the efficiency and generation losses due to the changes in air temperature, humidity, and river temperature and flow. Then, the results from ReEDS and WBM-TP2M are compared and evaluated based on a feasibility check, which requires the ReEDS output to meet a 14% reserve margin threshold requirement. If this requirement is stratified, the ReEDS output is considered reliable and feasible, otherwise the AAC from the WBM-TP2M needs to be applied to ReEDS to generate new electricity expansion projections. This iteration continues until a feasible solution is found. Compared to the one-way approach, the iteration approach can capture the climate impacts at each thermal power plant (while the one-way approach only reflects the balancing authority level). Moreover, the iteration approach also shows a feedback mechanism between the climate impacts and the electricity system, and it allows the electricity system to gradually adapt to the climate impacts through multiple rounds of feasibility check and adjustment. The iteration approach is only conducted for the RCP 8.5 with the five GCMs given it longer computational time compared to the one-way approach. Ultimately, the iteration approach was examined for 20 climate-electric scenarios (5 GCM × 1 RCP × 4 electricity scenarios). Given the

model capability, this study only considered the climate impacts on thermal power plants, while the climate impacts on hydropower, wind, solar were assumed to be static.

Present value calculation

The ReEDS simulated the annual cost every two years based on least cost optimization from 2020 to 2050. The annual cost includes capital cost, FOM cost, VOM cost, and fuel cost for generation, storage, and transmission technologies. We converted the cost outputs from ReEDS (expressed as $2004) to 2020 US dollar (2020$) following the Consumer Price Index inflation calculation from U.S. Bureau of Labour Statistics[23].

The cost outputs from ReEDS do not consider the time value of the investment, so we calculated the present value of costs incurred during 2020 to 2050 for the U.S. electricity system following the method described in 2018 ReEDS documentation[32]. The initial (base) year t_0 is 2020, and the final year t_f is 2050. We also considered a wide range of discount rates d, which are 2%, 3%, 5%, and 7%, to represent both private and social discount rate. The economic lifetime n, which is defined as the number of years that the capital investment will be paid off, is assumed to be 20 years.

The annual capital cost at year *t* $C_{cap,t}$ represents the total unannualized cost for building the new capacity of each year. For the annual capital cost incurred during 2020 to 2031, because they will be paid off before the 2050, given the 20-year economic lifetime. The total present value of capital cost during 2020 to 2031 $PV_{Cap\ 2020\ to\ 2031}$ is calculated as follow:

$$PV_{Cap\ 2020-2031} = \sum_{t=2020}^{2031} C_{cap,t} \times \frac{1}{(1+d)^{t-t_0}}$$

For the annual capital cost incurred during 2032 to 2050, we scale the cost at each year to account for the proportion of the cost that will be paid before 2050 by adding a scaling factor S_t. The total present value of capital cost during 2032 to 2050 $PV_{Cap\ 2032\ to\ 2050}$ is calculated as follow:

$$PV_{Cap\ 2032-2050} = \sum_{t=2032}^{2050} C_{cap,t} \times S_t \times \frac{1}{(1+d)^{t-t_0}}$$

The scale factor S_t is defined as the ratio of the capital recovery factor for the full economic lifetime n to the capital recovery factor for the number of years that the annual capital investment of a specific year t will be paid before 2050. The scale factor and capital recovery factor are calculated as follow:

$$S_t = \frac{CRF(d,n)}{CRF(d,t_f+1-t)}$$

$$CRF(d,n) = \frac{d}{1-\frac{1}{(1+d)^n})}$$

The other cost components, such as FOM, VOM, and fuel costs, are assumed to be paid off in the year when they are incurred. In the present value calculation, they were all considered as operational cost $C_{Op,t}$ and discounted as follow:

$$PV_{Op\ 2020-2050} = \sum_{t=2020}^{2050} C_{Op,t} \times \frac{1}{(1+d)^{t-t_0}}$$

The present value of total cost of the U.S. electricity system from 2020 to 2050 $PV_{Total\ cost,2020-2050}$ is calculated by summing up the present value of capital cost and operational cost:

$$PV_{Total\ cost,2020-2050} = PV_{Cap,2020-2031} + PV_{Cap,2032-2050} + PV_{Op\ 2020-2050}$$

Geographical analysis

In the cost comparison among the 12 NERC regions. We calculated the unit cost and change of unit cost from BAU scenario for the 12 NERC regions. The unit cost is calculated by dividing the present value of total 30-year cost by the total 30-year generation (all averaged across climate scenarios), which represents an average unit cost of electricity over the 30 years. The change of unit cost from BAU scenario was calculated by dividing the present value total 30-year cost changes of the three electricity scenarios (COAL, NUC and REN) relative to BAU scenario by their corresponding total 30-year generation, which indicates the cost change per unit electricity generation for the each region to transition from BAU scenario to COAL, NUC and REN scenario respectively. The geographical boundaries of the NERC regions were adopted from the ReEDS model database[32,20].

CO_2 abatement cost

Given the fact that NUC and REN will have higher total costs but lower CO_2 emissions compared to BAU scenario, we developed the CO_2 abatement cost (with four SDRs at 2%, 3%, 5% and 7%) to quantify the cost of decarbonising the U.S. electricity system in the context of CO_2 mitigation. This metric represents the average cost of reducing 1 metric ton CO_2 emission by pursuing the low-carbon electricity pathways. The CO_2 abatement cost for NUC and REN scenarios are shown as follows:

$$CO_2\ Abatement\ Cost_{NUC} = \frac{Present\ value\ of\ total\ 30\ year\ cost_{NUC} - Present\ value\ of\ total\ 30\ year\ cost_{BAU}}{Total\ 30\ year\ CO_2\ emission_{BAU} - Total\ 30\ year\ CO_2\ emission_{NUC}}$$

$$CO_2\ Abatement\ Cost_{REN} = \frac{Present\ value\ of\ total\ 30\ year\ cost_{REN} - Present\ value\ of\ total\ 30\ year\ cost_{BAU}}{Total\ 30\ year\ CO_2\ emission_{BAU} - Total\ 30\ year\ CO_2\ emission_{REN}}$$

Competing interests

The authors declare no competing financial interests.

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Figures

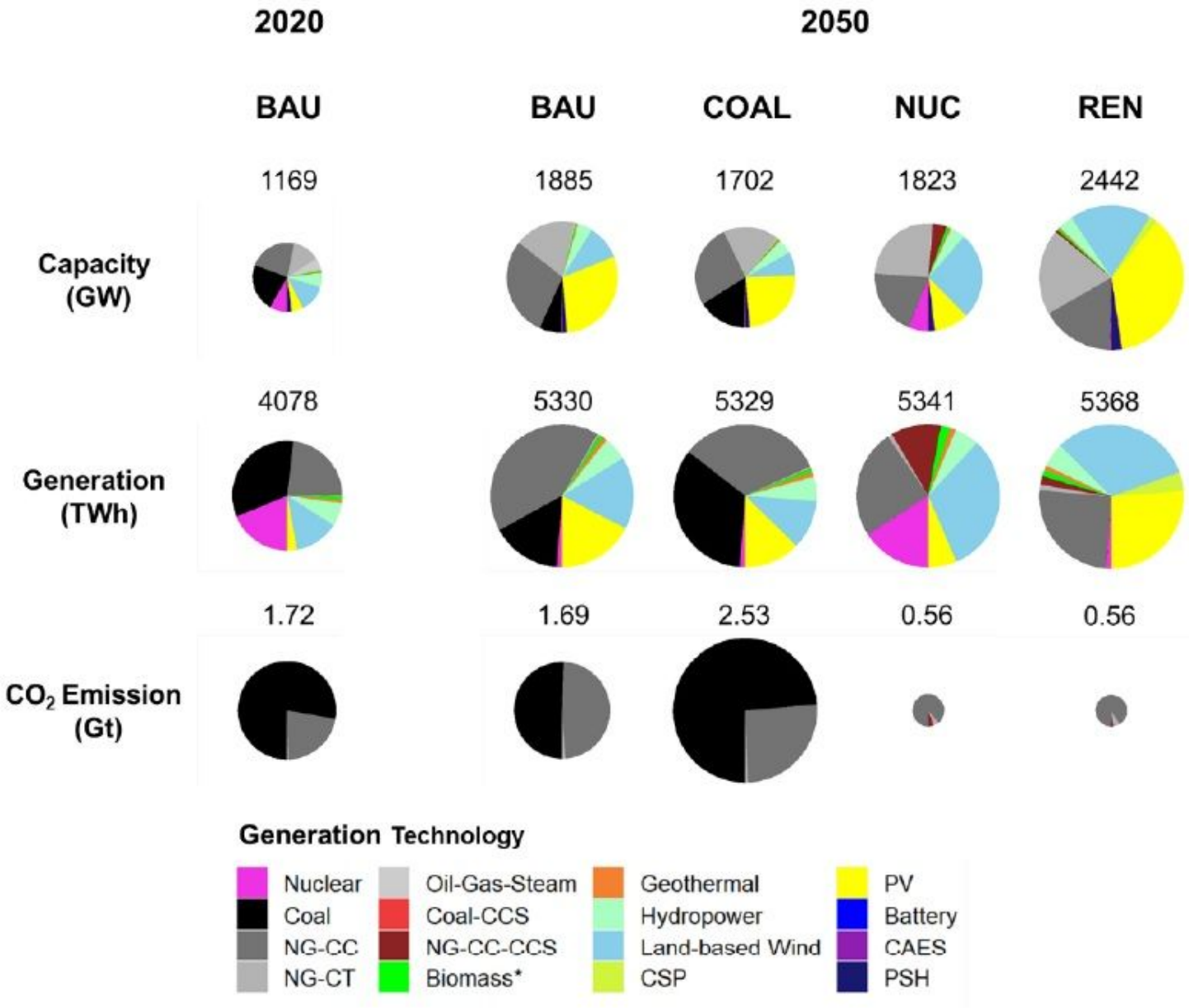

Figure 1

Average capacity, generation, and CO2 emission of the U.S. electricity system in 2020 and 2050. The results of capacity, generation, and CO2 emission presented here are averaged across the 21 climate scenarios (5 GCMs × 4 RCPs under one-way approach and one RCP 8.5 under iteration ap-proach) due to their minor differences. The capacity numbers of different scenarios include both elec-tricity generation and storage technologies. Electricity generation and storage technologies abbrevia-tions include: CAES: compressed-air energy storage; Coal-CCS: Coal with carbon capture and stor-age; CSP: Concentrated solar power; NG-CC: Natural gas combined cycle; NG-CC-CCS: Natural gas combined cycle with carbon capture and storage; NG-CT: Natural gas combustion turbine, PSH: Pumped-storage hydropower; PV:

Photovoltaic; Biomass* includes Biomass, Municipal Solid Waste and Landfill Gas; Battery: Sodium-sulphur flow battery (12-MW, 7.2-hour). The exact values of ca-pacity, generation, and CO2 emission at 2020 and 2050 can be found in Supplementary table 1-3. The annual new-installed capacity, total capacity, generation, and CO2 emission from 2020 to 2050 (even years) can be found in Supplementary Fig. 1-2.

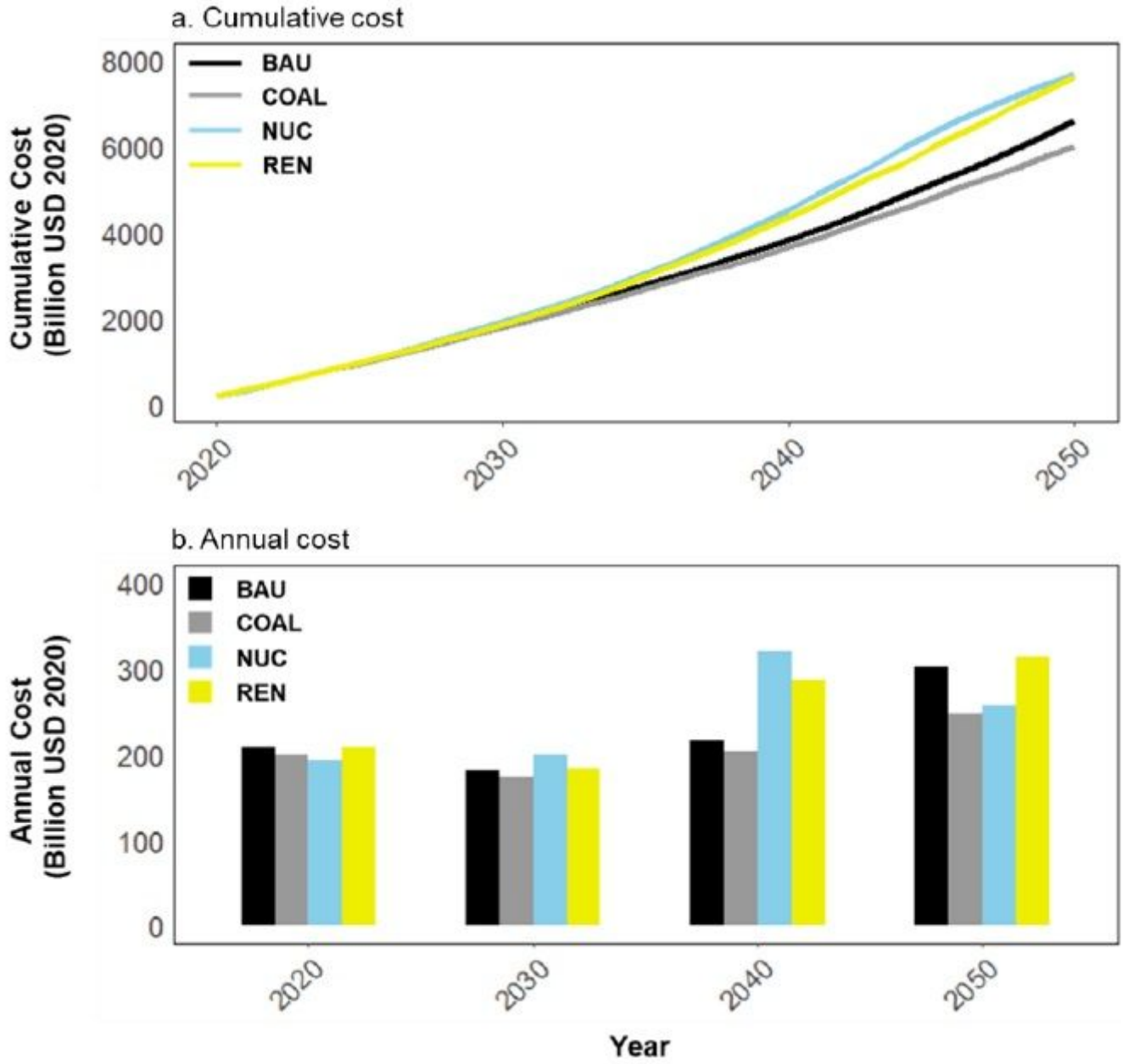

Figure 2

Cumulative cost (a) and annual cost (b) of the U.S. electricity system under BAU, COAL, NUC and REN scenarios. The cumulative cost (averaged across climate scenarios) at each year is the sum of annual costs of the current and all previous years (starting from 2020). The an-nual cost (averaged across climate scenarios) is the sum of capital cost, fixed operational and maintenance (FOM) cost, variable

operational and maintenance (VOM) cost, and fuel cost across all generation, storage and transmission technologies incurred at each year. The annual costs of four representative years (2020, 2030, 2040, and 2050) are presented in the figure. Both cumulative cost and annual cost neither take any social discount rates into account nor include any externality costs, such as costs from emissions. The annual cost of each generation, storage, and transmission technol-ogy from 2020 to 2050 under the four scenarios are presented in Supplementary Fig. 3-5.

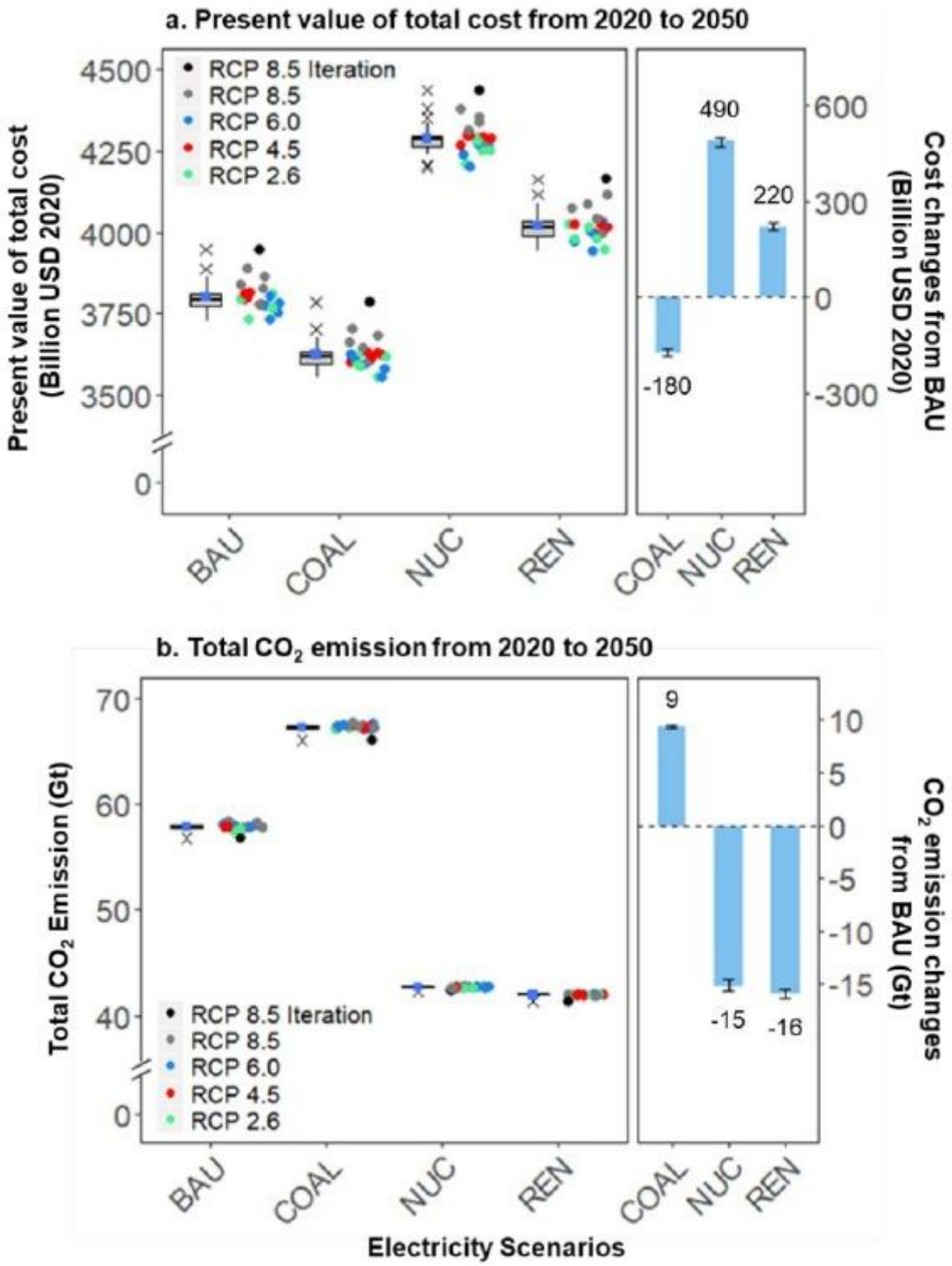

Figure 3

Present value of total cost (a) and CO2 emission (b) of the U.S. electricity system from 2020 to 2050 under four electricity scenarios. The broad panels of each figure represent the pre-sent value of total cost (a) and total CO2 emission (b) under the four electricity scenarios, and the range of each box represents the total costs/total CO2 emission estimated based on different climate scenarios, which are also shown by the scatter points next to it. The square blue point in the box rep-resents the mean. Different colours of the scatter points represent different RCP scenarios. RCP 2.6, RCP 4.5, RCP 6.0, and RCP 8.5 are results of the one-way approach. Each colour includes five points under each electricity scenario, representing the variability of the five GCM outputs. The RCP 8.5 Iteration is result of the iteration approach, and it has only one point under each electricity scenario, representing the average across five GCM outputs. The right narrow panels represent the changes of costs and CO2 emissions of COAL, NUC, and REN scenarios from BAU scenario. The error bars in the right narrow panels show the ranges of maximum and minimum values, and the number of each bar represents the average value.

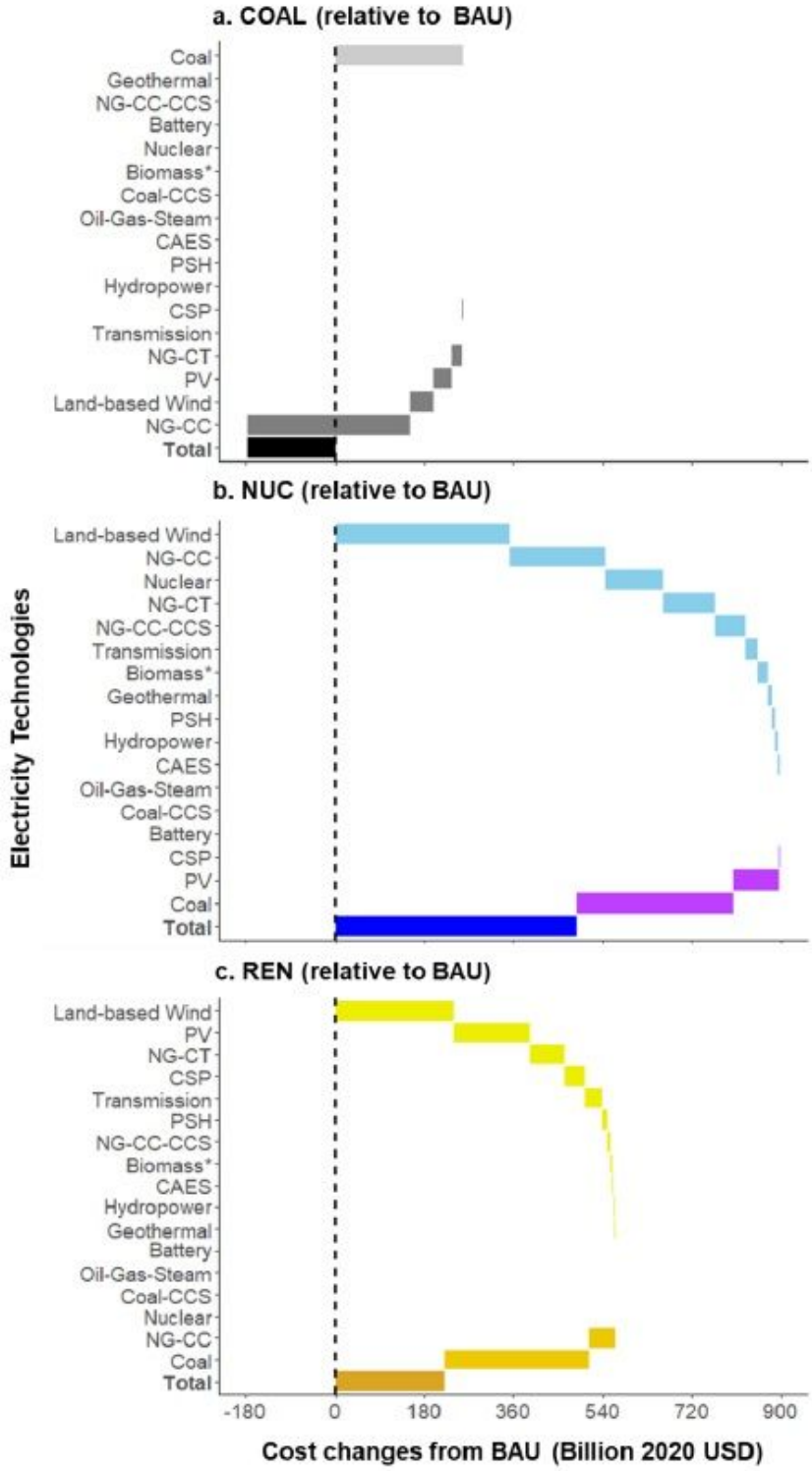

Figure 4

The contribution of various generation and transmission technologies to the cost changes (average across climate scenarios) of COAL, NUC, and REN scenarios from BAU scenario. The contribution to the cost changes by cost types can be found in Supplementary Fig. 6.

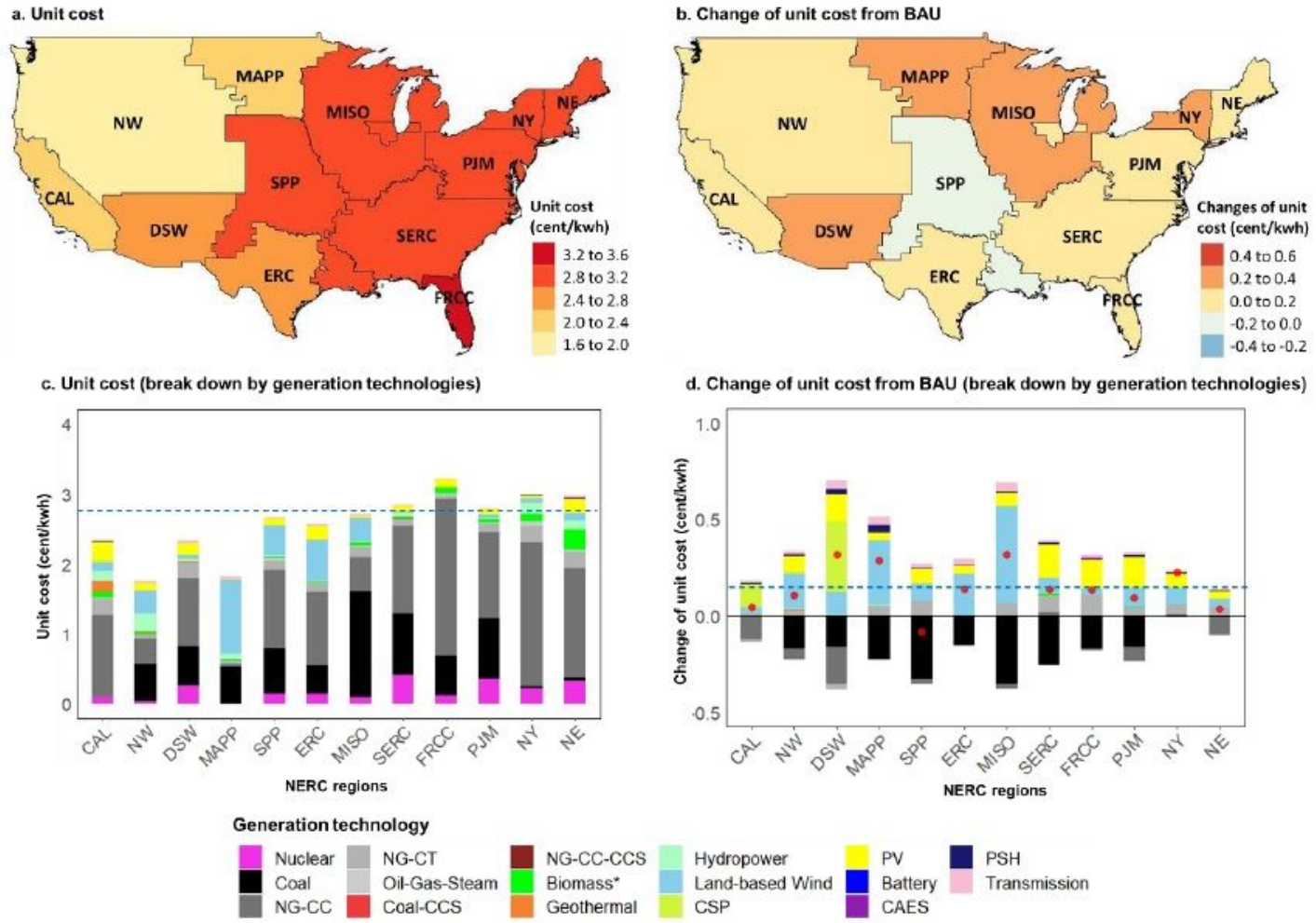

Figure 5

The average unit costs of electricity (a, c) under REN scenario and their changes rela-tive to BAU scenario (b, d) at 12 North American Electric Reliability Corporation (NERC) re-gions across the U.S. The map plots (a, b) show the costs at different regions, and the bar plots (c, d) show the contribution of different technologies to the costs. The dash lines in the bar plots show the average values at the national level. The red dot in plot (d) shows the net additional unit cost at different NERC regions. NERC region: NE = New England; NY = New York; PJM = Pennsylvania-New Jersey-Maryland (covers Mid-Atlantic region); SERC = South-eastern Electric Reliability Council; FRCC = Florida Reliability Coordinating Council; MISO = Midcontinent Independent System Operator; MAPP = Mid-Continent Area Power Pool; SPP = Southwest Power Pool; ERC (ERCOT) = Electric Reliability Council of Texas; DSW = Southwest; NW = Northwest; CAL = California. The cost only includes the capital, FOM, VOM, and fuel cost of the electricity system, but it does not consider the electricity import and export among different NERC regions, therefore the revenue and payment associated with electricity import and export are not included in the cost presented here. The results of BAU, NUC, and COAL scenarios are presented in Supplementary Fig. 7 – Supplementary Fig. 14.

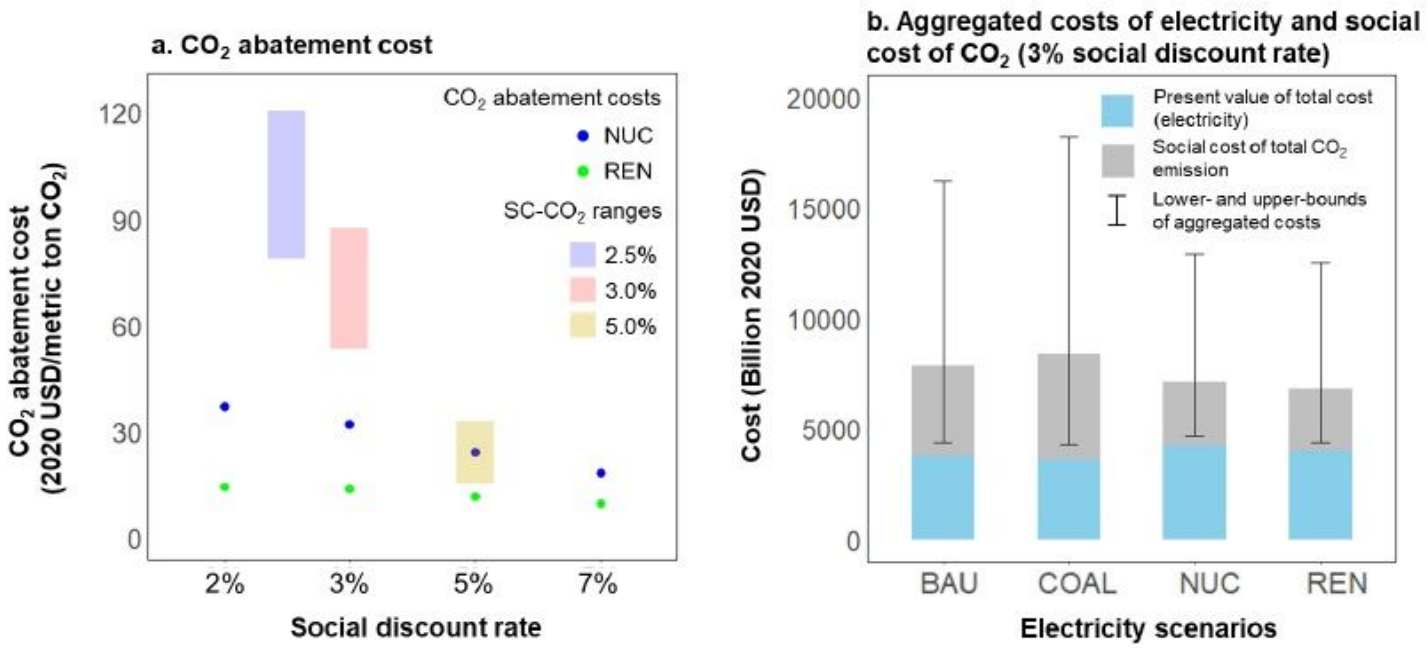

Figure 6

The CO2 abatement cost under NUC and REN scenarios (a) and aggregated cost of electricity and social cost of CO2 under four electricity scenarios (b). In Fig. 6a, the dots represent the CO2 abatement costs (averaged across climate scenairos due to negligible differences) of NUC and REN scenarios under different SDRs (2.0%, 3.0%, 5.0%, and 7.0%). The three hori-zontal bands represent the average SC-CO2 estimated by U.S. EPA under different SDRs (2.5%, 3.0% and 5.0%). The lower bound of each band represents the average SC-CO2 in 2020, and upper bound represents the average SC-CO2 in 2050. The SC-CO2 was originally estimated based on 2007 US$, and we converted them to 2020 US$. In Fig. 6b, both present value of total cost (electricity) and social cost of total CO2 emission are calculated based on 3% SDR. The pink bars represent the social cost of total CO2 emission calculated based on average SC-CO2 (at 3% SDR). The error bars reflect the uncertainty range of SC-CO2 (at 3% SDR). The lower and upper bounds of error bars represent the aggregated cost results calculated based on 5th and 95th percentile SC-CO2 (at 3% SDR), respectively.

Supplementary Files

This is a list of supplementary files associated with this preprint. Click to download.

- 2.SupplementaryInformationResults.docx
- 3.SupplementaryInformationData.xlsx