Evaluating Impacts of the Inflation Reduction Act and Bipartisan Infrastructure Law on the U.S. Power System

Daniel C. Steinberg,[1] Maxwell Brown,[1] Ryan Wiser,[2] Paul Donohoo-Vallett,[3] Pieter Gagnon,[1] Anne Hamilton,[1] Matthew Mowers,[1] Caitlin Murphy,[1] and Ashreeta Prasana[1]

1 National Renewable Energy Laboratory
2 U.S. Department of Energy, on detail from Lawrence Berkeley National Laboratory
3 U.S. Department of Energy

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Executive Summary

The Inflation Reduction Act of 2022 (IRA) and the Infrastructure Investment and Jobs Act of 2021, commonly referred to as the Bipartisan Infrastructure Law (BIL), collectively represent the largest commitment of the U.S. Federal Government to invest in the modernization and decarbonization of the U.S. energy system. The Congressional Budget Office (CBO) estimates that total support for the broad range of climate and clean energy programs, tax credits, and other incentives authorized through the two laws will exceed $430 billion from 2022 through 2031 (CRS 2022; CBO 2021, 2022). While the climate and clean energy provisions are numerous and have the potential to impact all aspects of the U.S. energy system from fuel and electricity production to final consumption in industry, transportation, and buildings, the provisions relevant to the electricity sector—in particular the suite of tax credits for clean generation, storage, and carbon dioxide (CO_2) capture and storage—are expected to be some of the most consequential in terms of emissions reduction and clean energy deployment (Larsen et al. 2022; Jenkins, Mayfield, et al. 2022; Mahajan et al. 2022; Zhao et al. 2022).

In this report, we detail the methods and results of a study estimating the potential impacts of key provisions of IRA and BIL on the contiguous U.S. power sector from present day through 2030. The analysis employs an advanced power system planning model, the Regional Energy Deployment System (ReEDS), to evaluate how major provisions from both laws impact investment in and operation of utility-scale generation, storage, and transmission, and, in turn, how those changes impact power system costs, emissions, and climate and health damages. While not exhaustive in capturing every provision, the analysis estimates the possible scale of power sector impacts that could result from the modeled provisions in IRA and BIL.

The study is structured around two scenarios to evaluate the potential impacts of both laws on the power sector:

- ***No New Policy***: A counterfactual scenario that reflects all federal and state policies enacted as of September 2022, *with exception to IRA and BIL*. Load growth is assumed to be consistent with the Energy Information Administration's Annual Energy Outlook 2022 (AEO22) *Reference case* (EIA 2022a).
- ***IRA-BIL***: A scenario that reflects all federal and state policies enacted as of September 2022, *including* key IRA and BIL provisions, most notably the investment and production tax credits for zero-carbon emitting electricity generation and storage (ITC and PTC), the tax credit for CO_2 capture and storage (45Q), and the tax credit for existing nuclear plants. To account for the impacts of IRA and BIL on electrification, the scenario includes increased load growth from a scaled version of the *Medium Electrification* scenario from the Electrification Futures Study (Mai et al. 2018).

These scenarios are simulated across seven sets of assumptions with varying projected future electricity market conditions, including technology costs and performance, natural gas prices, and the degree of availability, feasibility, and cost of development of renewable resources, electricity transmission, and CO_2 pipeline, injection, and storage infrastructure. In addition, we simulate two sensitivities on the 'policy' treatment in which we vary key assumptions pertaining to the realized value of the clean electricity ITC and PTC: 1) the cost of monetization of tax credits, and 2) the level of bonus crediting realized by project developers.

We demonstrate that IRA and BIL have the collective potential to drive substantial growth in clean electricity by 2030, while reducing net-costs, mitigating climate change, and decreasing the human health impacts of power sector emissions. In addition, we show that while the IRA and BIL provisions modeled drive increased clean electricity and associated emissions reductions across all future conditions analyzed, if projected clean electricity technology cost and performance improvements are not realized and/or barriers to deployment of clean electricity or supporting infrastructure (such as transmission) are not mitigated, then the share of clean generation achieved and the associated emissions benefits realized may be substantively reduced.

Most notably, we find:

- ***Clean electricity shares***[1] ***could increase substantially with IRA and BIL, rising from 41% in 2022 to a range of 71%–90% of total generation by 2030,*** across the range of scenarios considering uncertainties in future technology costs, fuel prices, policy impacts, and deployment constraints. This represents a 25 to 38 percentage point increase relative to the *No New Policy* cases evaluated. This increase in clean generation is primarily driven by increased deployment and generation from wind and solar capacity, that, in aggregate,

[1] Included in the clean electricity share is generation from nuclear, fossil generation with carbon capture and storage (CCS), and renewable technologies, including wind, solar, hydroelectric, geothermal, landfill gas, and biomass.

Table A. Ranges in Deployment, Total Installed Capacity, and Generation Share for Select Technologies Across the Suite of IRA-BIL Scenarios and Sensitivities.

Technology Category	Cumulative Deployment, 2023–2030 [GW or TW-mi][a]	Average Deployment Rate, 2023–2030 [GW/yr or TW-mi/yr]	Installed Capacity, 2030 [GW or TW-mi]	Generation Share, 2030 [%]
Wind and Solar	350–750	44–93	600–1000	40%–62%
Fossil-CCS[b]	5–55	<1–7	5–55	1%–8%
Battery Storage	40–100	5–12	50–100	–
Transmission	18–35	2.2–4.4	–	–

[a]Generation and storage capacity and deployment rates are reported in GW and GW per year, while transmission capacity and the associated deployment rate is reported in TW-mi and TW-mi per year.
[b]CCS = carbon capture and storage

reaches 40% to 62% of total generation by 2030 with smaller contributions from fossil generation with carbon capture capacity, which reaches 1% to 8% of total generation by 2030. The increase in wind and solar generation is supported by both increases in battery storage deployment as well as expansion of long-distance transmission—the latter of which increases by 9% to 24% from 2022 installed capacity. Finally, existing nuclear capacity, with exception to announced retirements, is maintained across all *IRA-BIL* scenarios through 2030.

- ***Annual power sector CO_2 emissions could decline to 72%–91% below the 2005 level across the range of policy scenarios by 2030.*** This is equivalent to annual avoided emissions of 600 Mt CO_2 to 900 Mt CO_2 by 2030 relative to the *No New Policy* case, with cumulative (2023–2030) avoided emissions ranging from 2,700 MtCO_2 to 3,900 MtCO_2. These reductions in emissions, if achieved, are estimated to result in avoided climate damages reaching $160 billion–$230 billion per year by 2030.[2] Furthermore, avoided nitrogen oxide (NOx) and sulfur dioxide (SO_2) emissions—precursors to particulate matter formation—are estimated to reduce human health damages as much as $20 billion–$46 billion per year by 2030.[3]
- ***IRA and BIL are estimated to lead to a net decrease in total and average annual bulk power system costs (inclusive of tax credit value).*** IRA and BIL spur substantial increases in bulk power system investment, but those costs are more than offset by the combination of decreased fuel expenditures and the increased scope and value of tax credits and other programs. Across all policy cases evaluated, clean energy, storage, and transmission investment contribute to an increase in cumulative capital and non-fuel operating expenditures, but the combined value of tax credits and fuel savings lead to net decreases in power system costs of $8 billion to $25 billion annually by 2030 and $50 billion to $115 billion cumulatively, from 2023 to 2030. These cost reductions translate to approximately a $3 per MWh to $6 per MWh (5% to 13%) reduction in average annual bulk system costs by 2030.
- ***The rates of deployment of wind and solar technologies could grow rapidly with the average annual combined rate of deployment (2023–2030) ranging from 44 GW per year to 93 GW per year***—representing more than a doubling of the historical maximum annual deployment rate in many scenarios. Under cases that use reference technology and fuel price assumptions, annual average deployment from 2023 to 2030 ranges from 26 to 29 GW per year and 43 to 47 GW per year for wind and solar, respectively, representing a 50%–70% and a 135%–160% increase relative to the historical maximum annual deployment (2010–2022). Under scenarios with limited improvement in the cost and performance of clean energy technologies and/or lower price natural gas, more moderate capacity additions occur, with annual average deployment ranging from 18–25 GW per

[2]The avoided climate damages are estimated using the "preferred mean" estimate of the social cost of CO_2 (SC-CO_2) from Rennert et al. (2022).

[3]These estimates are calculated using three reduced complexity air quality models (AP2, EASIUR, and InMAP) that incorporate exposure-response functions to estimate health impacts. We report values that apply the response function from the Harvard Six-Cities study (Dockery et al. 1993; Lepeule et al. 2012). We report additional estimates based on exposure-response functions from the American Cancer Society (ACS) (Pope III et al. 2002; Krewski et al. 2009) in the main body of the report.

year and 19–36 GW per year for wind and solar, respectively. Finally, a scenario capturing a range of deployment barriers demonstrates the potential for more limited, but sustained deployment of wind (18 GW per year) while solar deployment shows robust increases (reaching 49 GW per year) given the reduced market share of other clean technologies under these scenarios, most notably wind and fossil-CCS technologies.

- ***Fossil generation with CCS could be economically deployed at levels reaching the tens of gigawatts if such technologies achieve projected cost and performance levels and the required supporting infrastructure is successfully developed.*** Across the suite of scenarios, fossil generation with CCS capacity ranges from approximately 5 GW to over 50 GW by 2030—an order of magnitude difference. This range indicates the high degree of uncertainty in the level of fossil-CCS deployment induced by IRA and BIL, and demonstrates the sensitivity to assumptions about technology development, and feasibility and cost of deploying supporting infrastructure, primarily CO_2 pipeline and storage infrastructure.
- ***Though IRA and BIL are found to drive increases in clean technology deployment under all cases evaluated, existing and developing barriers to deployment of clean technologies and supporting infrastructure could materially reduce the rate of clean electricity deployment and the associated benefits.*** Barriers to deployment, such as siting and permitting challenges, supply-chain constraints, and social acceptance of electricity infrastructure development, could significantly reduce the rate of clean electricity deployment. Evaluation of a stylized suite of concurrently-implemented deployment constraints,[4] including more limited renewable resource access, constrained transmission development, and increased costs of CO_2 transport and storage infrastructure demonstrated the potential for a 10 percentage point reduction in the clean generation share (relative to the Mid case) and a 24% reduction in cumulative avoided emissions 2023–2030.

[4]While this suite of constraints explores some aspects of current and developing deployment barriers, it does not comprehensively address all potential deployment barriers.

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1 Introduction and Background

Over the past two years, the U.S. Congress enacted two laws that could have far reaching implications for the nation's energy system—the Inflation Reduction Act of 2022 (IRA) and the Infrastructure Investment and Jobs Act of 2021, the latter of which is commonly known as the Bipartisan Infrastracture Law (BIL).[5] The laws collectively establish a broad suite of programs and financial incentives designed to reduce emissions of greenhouse gases and other harmful pollution, advance clean energy technology manufacturing and deployment, increase U.S. energy security, and mitigate systemic environmental justice issues while increasing the affordability of energy. The Congressional Budge Office (CBO) estimates that the climate and clean energy support authorized through the two bills will total more than $430 billion, cumulatively, from 2022 through 2031 (CRS 2022; CBO 2021, 2022), representing the largest commitment of the federal government to invest in the modernization and decarbonization of the U.S. energy system.

While IRA and BIL include provisions relevant to each sector of the U.S. energy economy,[6] the provisions related to the U.S. power system comprise a majority of the estimated climate and energy support. Early analysis of the laws has shown that these provisions are likely to be responsible for the largest share of greenhouse gas emissions reductions resulting from the full suite of IRA and BIL provisions (Jenkins, Mayfield, et al. 2022; Larsen et al. 2022; Mahajan et al. 2022; Zhao et al. 2022).

In this report, we detail the methods and results of an analysis of the potential impacts of key provisions of IRA and BIL on the U.S. power sector from present day through 2030. The analysis employs an advanced power system planning model, the Regional Energy Deployment System (ReEDS), to evaluate how major provisions from both laws impact investment in and operation of utility-scale clean generation, storage, and transmission, and, in turn, how those changes impact power system costs and emissions.

We demonstrate that the provisions analyzed have the potential to drive rapid growth in clean electricity deployment while reducing average electricity costs and lowering harmful pollution. While IRA and BIL are found to drive substantial increases in the clean share of generation and associated declines in emissions across scenarios explored, we also show that potential constraints on deployment driven by factors such as siting and permitting challenges, supply-chain constraints, social acceptance of energy infrastructure development, and/or limited technology cost and performance improvement have the potential to slow the rate of clean energy deployment and the associated benefits that could be realized.

This report builds on preliminary results discussed in the 2022 Standard Scenarios Report (Gagnon et al. 2022), but focuses on the implications through 2030 and provides additional detail on the deployment, emissions, and power system cost outcomes across a range of scenarios designed to evaluate key drivers of the potential impacts of IRA and BIL. While the energy system implications of IRA, and to a lesser degree, BIL, have been explored using other models (Jenkins, Mayfield, et al. 2022; Larsen et al. 2022; Roy, Burtraw, and Rennert 2022; Mahajan et al. 2022), all models are designed with different scopes (e.g., entire energy system versus power-system only) and different emphases and, therefore, have different strengths and weaknesses. As such, it is valuable, if not crucial, to evaluate the potential implications of policies using multiple models. The models used in this study are focused solely on the power system and were designed with high spatial and temporal resolution that jointly enable a detailed treatment of the unique aspects of renewable generation and storage, carbon dioxide transport and storage, and a high degree of fidelity in power system operation for a national-scale planning model.

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[5] H.R.5376 – 117th Congress (2021-2022): https://www.congress.gov/bill/117th-congress/house-bill/5376/text; H.R.3684 – 117th Congress (2021-2022): https://www.congress.gov/bill/117th-congress/house-bill/3684

[6] IRA and BIL together have provisions related to electricity generation and transmission, transportation and mobility, fuel and critical material production, buildings and energy efficiency, clean energy manufacturing, environmental and climate justice, sustainable agriculture and forestry, and climate research, among others. See CRS (2022) and Jenkins, Farbes, et al. (2022).

2 Methods

2.1 Overview and Scenario Structure

This analysis applies the ReEDS model to evaluate the potential impacts of key provisions of IRA and BIL on the evolution of the utility-scale power system in the contiguous Unites States. We simulate power system evolution under scenarios both with and without the suite of IRA and BIL provisions included (detailed in Section 2.3) and under a range of alternative future electricity market, infrastructure, and technology conditions. To account for changes in behind-the-meter solar adoption driven by IRA and BIL, we rely on projections from the Distributed Generation Market Demand Model (dGen).[7]

The analysis focuses on two core scenarios:

- ***No New Policy***: assumes federal and state policies enacted as of September 2022, with exception to BIL and IRA, and assumes load growth (0.7% increase per year compound annual growth (CAGR) 2023–2030) consistent with the Energy Information Administration's (EIA's) Annual Energy Outlook 2022 (AEO22) *Reference case* (EIA 2022a).
- ***IRA-BIL***: includes the IRA and BIL provisions as described below (Section 2.3) and, to account for the impacts of IRA and BIL on electrification, assumes increased load growth (1.1% CAGR 2022–2030) consistent with a scaled version of the *Moderate Electrification* scenario from the Electrification Futures Study (Mai et al. 2018).[8]

We evaluate the two core scenarios across seven sensitivities (Table 1), including a central or Mid case, to account for major sources of uncertainty including future cost and performance of clean generation and storage technologies, future natural gas prices, and future limitations on deployment related to potential supply-chain, regulatory, and/or social acceptance related constraints on deployment. Finally, we explore two policy sensitivities that vary assumptions about the realized value of the ITC and PTC tax incentives under IRA.

Although the Mid case represents a central reference scenario, it is not intended to be a prediction of the most likely outcome of the evolution of the power sector under IRA and BIL. Rather it represents a projection of the evolution of the power sector under a specific set of market, technology, and policy conditions. While the technology and fuel cost projections used in the Mid case (and other cases using the reference cost projections) do represent 'best guesses,' this scenario does not consider the full suite of drivers of investment decisions, in particular, those that are associated with behavior that deviate from least-cost optimization. As a result, the Mid case more closely represents the power system evolution that would occur if all economically optimal investment and retirement opportunities were executed.

While the ReEDS model includes a sophisticated representation of the U.S. power system, a variety of real-world constraints driven by institutional friction, market power, imperfect information, limited capital and labor liquidity, uncertainty, and human behavior, among others, would likely result in actual planning decisions deviating from those estimated by a national planning model.[9] We explore the implications of a set of key 'non-economic' drivers of system change in the Constrained sensitivity. This sensitivity attempts to capture the potential implications of regulatory or permitting challenges associated with renewable, transmission, and/or pipeline infrastructure development, the potential impacts of social opposition to energy infrastructure development, and limited inter-regional coordination between utilities and transmission operators; however, this sensitivity does not comprehensively capture all potential deployment barriers or their potential magnitude of stringency. We highlight both the Mid and the Constrained cases in the results given that they provide two projections of power system evolution that use central assumptions for fuel prices and technology costs and performance.

[7]For more information on dGen, see http://www.nrel.gov/analysis/dgen

[8]While we include a change in electricity load due to IRA-BIL, the demand impacts were not a focus of this study. There remains significant uncertainty in the realized impacts of IRA-BIL provisions on load growth, particularly at the sub-national level.

[9]Additional discussion of the limitations of the modeling approach is included in Section 2.4

Table 1. Scenario Structure and Definitions of Scenario Assumptions.

Sensitivity Type	Sensitivity	Abbrev.	Description
Mid case	Moderate cost and performance for all technologies, Reference natural gas price	Mid	• Cost and performance assumptions for all technologies except CCS-retrofits are from the 2022 Annual Technology Baseline (ATB) *Moderate* case; plant-level CCS-retrofit costs and performance impacts are from the EIA-NEMS model (EIA 2022b). • Power sector delivered fuel prices are from the AEO2022 *Reference* case
Technology cost and performance (C&P)	Advanced Renewable and Battery Technologies	AdvBRE	• Cost and performance assumptions for battery storage and renewable technologies are from the 2022 ATB *Advanced* case.
	Conservative Renewable and Battery Technologies	ConsBRE	• Cost and performance assumptions for battery storage and renewable technologies are from the 2022 ATB *Conservative* case.
	Advanced All Clean Technologies	AdvClean	• Cost and performance assumptions for battery storage, renewable, nuclear, and greenfield CCS technologies are from the 2022 ATB *Advanced* case; plant-level CCS-retrofit costs (from EIA-NEMS) assumed to decline from 2023 to 2030 at the same rates as the greenfield CCS technologies in the 2022 ATB.
Natural gas price	High natural gas price	HGP	• Power sector delivered natural gas prices are from the AEO2022 *Low Oil and Gas Resource* case
	Low natural gas price	LGP	• Power sector delivered natural gas prices are from the AEO2022 *High Oil and Gas Resource* case
Constrained deployment	Constrained	Constr.	• Reduced land area/resources available for renewable development (applies to wind, solar, geothermal, and bio) • New long-distance transmission builds restricted to the historical national average build rate (1.4 TW-mi per year) and to builds within transmission planning regions • Increased (2x) cost of CO_2 pipeline, injection, and storage infrastructure
Policy impacts	Low IRA Impact	LII	• Increased cost of monetization of tax credits: 10% to 15% for non-CCS techs and 7.5% to 11.25% for CCS techs • Eligible techs earn, on average, one-half of a bonus or 5% (decreased from 10%).
	High IRA Impact	HII	• Decreased cost of monetization of tax credits: 10% to 5% for non-CCS techs and 7.5% to 3.75% for CCS techs • Eligible techs earn, on average, one and one-half of a bonus or 15% (increased from 10%)

Notes: Both the *No New Policy* and *IRA-BIL* scenarios are simulated with all sensitivity assumptions listed here, with exception of the 'policy impacts' sensitivities which are only applied to the *IRA-BIL* cases. For each sensitivity, with exception to the differences noted in the "Description," assumptions are identical to the Mid case assumptions. Cost and performance projections for generation and storage technologies are from the National Renewable Energy Laboratory's Annual Technology Baseline (ATB) (NREL 2022), with exception to costs and performance impacts of plant-level CCS-retrofits which are from the EIA-NEMS model (EIA 2022b) and further modified for the *Advanced All Clean* scenario; fuel price projections are from EIA's 2022 Annual Energy Outlook (EIA 2022a). Consistent with the 2022 Standard Scenarios report (Gagnon et al. 2022) all scenarios include a near-term technology-neutral capital cost adjustment to reflect recent increases in costs associated with supply-chain constraints.

2.2 Model Description

ReEDS is an electricity system capacity expansion model of the contiguous United States that simulates the evolution of the utility-scale power system (Ho et al. 2021). The model projects the investment in, operation of, and retirement of utility-scale generation, transmission, and storage resources to meet load, grid operational requirements,[10] and all major federal and state environmental policies and regulations relevant to the power system.

The ReEDS model was designed to capture the unique aspects of renewable generation and storage technologies. This is achieved through a combination of high spatial and temporal resolution to capture variability in electricity load and renewable resource availability, explicit representation of power system operational constraints, and robust treatment of resource adequacy.[11] Furthermore, the most recent version of ReEDS[12] includes a spatially explicit representation of the potential for, costs of, and constraints on infrastructure for (CO_2) transport and storage (Irish et al. 2023) enabling a robust treatment of the costs and constraints associated with transport and geologic storage of captured CO_2. However, while ReEDS does include an explicit representation of the ability to develop and operate CO_2 transport and storage infrastructure, it does not capture potential shared use of such infrastructure by industrial (non-power) CCS facilities, nor does it represent the potential use and associated value of CO_2 for enhanced oil recovery.

The version of the model used here has been updated since the release of the 2022 Standard Scenarios report (Gagnon et al. 2022). The most relevant modification is an improvement to the representation of retrofits of existing fossil-fueled electricity generation facilities to include CCS equipment. While the previous version of ReEDS included a representation of the opportunity to retrofit existing natural gas and coal-fired generation facilities, it did not differentiate across existing units when specifying the costs of upgrading or the operational characteristics of an upgraded facility. Instead, uniform costs and operating impacts of retrofits were assumed. Applying uniform cost and performance assumptions does not capture the diversity in plant characteristics—including plant capacity, age, heat rate, emissions controls, and facility siting—and the associated implications for the costs and impacts of retrofitting. In contrast, the version of the model used in this report includes unit-specific estimates of the capital cost of retrofitting coal and natural gas facilities with carbon capture, as well as unit-specific impacts on the resulting (post-upgrade) facility's maximum operating capacity, heat rate, non-fuel operating costs, and fixed costs. The unit-level data for these characteristics comes from the National Energy Model System's (NEMS) Electricity Market Module (EIA 2022b).[13]

The scope of ReEDS is limited to the bulk power system; the model does not endogenously capture behind-the-meter adoption of generation or storage resources, such as photovoltaic and battery systems, nor does it capture costs or constraints associated with the distribution system. As such, to account for potential changes in adoption of behind-the-meter photovoltaic capacity driven by IRA and BIL, this analysis relied on a limited set of simulation results from the Distributed Generation Market Demand (dGen) model, a model of customer adoption of distributed resources.

2.3 Policy Implementation

IRA and BIL include numerous provisions directly relevant to investment in and/or operation of the electricity system, however many of those provisions are not feasible to represent within the structure of a long-term power system optimization model or are otherwise too small in magnitude to be resolved within a national-scale modeling framework. Thus, this analysis focuses on evaluating the implications of the key electricity sector incentives and programs authorized by IRA and BIL. Tax credit and associated provisions specifying transferability and direct pay options, as well as the extension and expansion of accelerated depreciation are explicitly represented within ReEDS. To account for the potential impacts of a select number of other IRA and BIL programs and provisions, we used

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[10] ReEDS explicitly represents the provision of five key electricity services that must be met to maintain grid adequacy: energy, firm capacity, and three types of operation reserves (regulation, contingency, and flexibility reserves).

[11] ReEDS ensures that any identified future system meets a minimum level of resource adequacy—a component of system reliability—in all regions and years over the projected investment pathway.

[12] https://www.nrel.gov/analysis/reeds/

[13] While the NEMS values provide a comprehensive source for plant-level retrofit costs and the impacts on operating performance, there exists substantial uncertainty around the future costs of fossil generation with CCS technologies, and in particular, the cost of retrofitting existing fossil generation facilities with CCS given the diversity in plant age, capacity, efficiency, existing emission controls, and siting, among other characteristics. Further research is needed to improve such cost and performance projections and we note that the CCS deployment ranges reported could change with improved projections and/or inclusion of a representation of non-power sector drivers of CCS infrastructure development.

a set of simple assumptions to estimate the impact of those programs and assumed that a portion of those impacts were additional to the deployment and associated generation identified by the ReEDS model. The analysis results presented in this paper reflect the combined impacts of the selected key tax- and non-tax provisions of IRA and BIL.

2.3.1 IRA Tax Credit Representation in ReEDS

Gagnon et al. (2022) provides an overview of the IRA implementation, but for accessibility, we reproduce that description here with additional detail on the implementation.

Four tax credit programs are explicitly represented in ReEDS:

- ***Production Tax Credit (PTC)*** for renewable and other zero-carbon generation: $26 per MWh[14] over 10-years of operation plus a bonus credit that, under our reference policy conditions, is assumed to start at an average rate of 5% ($1.3 per MWh) in 2023 and increase to 10% ($2.6 per MWh) by 2028 (see below for further information). The representation in ReEDS captures both the modification and extension of the existing PTC (§45) for renewable generation and the creation of the new technology-neutral emissions based PTC (§45Y), including the associated technology eligibility limitations.

- ***Investment Tax Credit (ITC)*** for renewable and other zero-carbon generation: 30% plus a bonus credit that, under our reference policy conditions, is assumed to start at an average rate of 5% (35% for the total value) in 2023 and increase to 10% (40% total value) by 2028. As with the PTC, the representation in ReEDS captures both the modification and extension of the existing ITC (§48) as well as the new technology-neutral ITC for zero-carbon generating and storage technologies (§48E).

- ***Captured CO_2 Incentive (45Q)*** for CO_2 captured and stored in geologic formations: $85 per tonne of CO_2 and for 12-years of operation of a generation facility with CCS.[15]

- ***Existing Nuclear Production Tax Credit (45U)*** for generation from existing nuclear facilities: $15 per MWh, but it is reduced if the market value of the electricity generated exceeds $25 per MWh. As a simplification, the market-adjusted value of 45U was not directly represented in ReEDS. Instead, we assume that 45U, in combination with the Civil Nuclear Credit program under BIL, is sufficient to maintain cost-recovery of existing nuclear plants and, thus, nuclear plants are not subject to economic-based retirement in ReEDS until 2033.

Wage and Apprenticeship Requirements

To qualify for the above levels of the PTC, ITC, and 45Q, new projects must demonstrate that wages for the labor force used to construct facilities are equal to or exceed prevailing wages and that a minimum share of work is executed by individuals from registered apprentice programs.[16] While such requirements could increase the capital costs for facilities, particularly if current markets allow for labor rates below prevailing wage thresholds, for simplicity, we assume that all new projects meet these requirements with negligible impact to project costs, and therefore all projects are eligible for the full value of the incentives. Further exploration of the potential costs associated with meeting these requirements is warranted.

Bonus Crediting

Projects eligible for the PTC and ITC are also eligible to claim up to two bonus credits if they meet specific domestic content requirements, and/or are located in an "energy community."[17] For projects electing the PTC, each bonus credit increases the PTC value by 10% or $2.6 per MWh. For projects electing the ITC each bonus credit increases the value by 10 percentage points (i.e. from 30% up to a maximum of 50%). Under our reference policy assumptions, projects on average achieve one-half of a credit in 2023, increasing to a full-credit by 2028. In reality, projects cannot receive one-half of a credit; rather, they can receive zero, one, or two credits. However, given likely diversity in the number of bonus credits achieved and that developers will strive to increase the domestic content of

[14] All values reported are in 2022$. Note that since the time of this analysis, IRS provided new guidance increasing the value of the incentive from $26 per MWh to $27.5 per MWh. See https://www.irs.gov/pub/irs-drop/a-22-23.pdf for further information.

[15] The dollar values for the 45Q incentive are nominal through 2026 and inflation adjusted after that

[16] For additional information refer to Federal Register/Vol. 87, No. 229/Wednesday, November 30, 2022/Notices: Prevailing Wage and Apprenticeship Initial Guidance Under Section 45(b)(6)(B)(ii).

[17] See Inflation Reduction Act of 2022, 1 U.S.C §13101(g) for detailed definitions, and for additional discussion see Raimi and Pesek (2022).

facilities over time to recoup the domestic content bonus, we make the simplifying assumption that, on a fleet-wide basis, the average crediting rate increases over a 5-year period and then remains flat. Note that the U.S. Department of Treasury has not yet published final guidance on the specific requirements for eligibility for the domestic content and energy community bonuses, creating uncertainty in the degree of difficulty in qualifying. The *LII* and *HII* sensitivities evaluate the potential implications of lower and higher rates of bonus crediting.

Accelerated Depreciation

Any technology that qualifies for the new technology-neutral PTC or ITC—all zero-carbon generation and storage technologies—also qualifies for 5-year accelerated depreciation for any project placed in service beginning in 2025. This is directly captured in ReEDS within the financing calculations. See Ho et al. (2021) for details on how accelerated depreciation is handled.

PTC versus ITC

The changes to the PTC and ITC authorized through IRA allow eligible projects to elect either the PTC or the ITC. While many factors can influence the difference in the value of the alternatives for a particular facility, generally the two largest drivers of the value are the capital cost and the capacity factor that the facility is expected to achieve. All else equal, increasing capital costs will increase the ITC value relative to the PTC, and increasing capacity factor will decrease the value of the ITC relative to the PTC. Given that there is generally more variation in capital costs and capacity factor across technology types (e.g., offshore wind versus solar photovoltaic [PV]) than within technologies (projects of the same type in different physical locations), the technology type will largely determine which incentive has a higher value. In ReEDS, this determination was made exogenously to the model. Onshore wind, utility-scale PV, and biopower are assumed to elect the PTC while offshore wind, CSP, geothermal, hydropower, nuclear, pumped storage, battery storage, and distributed PV are assumed to elect the ITC.

Cost of Monetizing Tax Credits

Across most eligible technologies, tax credit values are reduced by 10% under the assumption that monetizing the credits results in some loss of their value. Clean energy project developers often do not have sufficient tax liability to enable use of all tax credits available. Financing structures have therefore evolved to allow a tax equity investor to jointly finance a project and receive full or partial distributions of the associated tax credits. These structures bear some cost, and therefore the full value of the credit is not retained by the project developer. The value lost is referred to here as the 'monetization cost.' The 10% value assumed is less than the reduction in the value historically used in ReEDS for the non-refundable tax credits (the pre-IRA PTC, ITC, and 45Q) as the IRA-authorized transferability of credits will likely result in greater fluidity (and reduce monetization cost) of credits. CCS credits are reduced by a lower fraction, 7.5%, due to the additional allowance for direct pay for 45Q tax credits under IRA. The policy sensitivities vary these values, as described in Table 1.

PTC and ITC Phase-out

Under IRA, the PTC and ITC are triggered to begin a phase-out schedule in the year that electricity sector emissions fall below 25% of 2022 levels or in 2032, whichever is later. Given that this study evaluates near-term impacts of IRA and BIL (through 2030), this provision does not impact results.

2.3.2 Distributed PV Adoption

While this analysis focuses on evaluating the bulk power system implications of IRA and BIL, deployment of customer adopted, behind-the-meter, generation and storage resources impacts the overall level of capacity, energy, and operating reserves required to meet electricity load reliably. To account for changes in distributed PV adoption driven by IRA and BIL we executed a limited scenario analysis using the dGen model. The dGen model simulates customer adoption of distributed energy resources for residential, commercial, and industrial consumers based on the empirically parameterized characteristics of the population of consumers and the likelihood of adoption at alternative rates of return on investment.

In the dGen model, distributed PV was assumed to receive the ITC: the §25D clean energy credit for residential customers, and the §48 and §48E credit for commercial and industrial customers. For residential projects the ITC was assumed to be 30%. For commercial and industrial projects, the ITC was assumed to have a total value of 40%

(assuming eligibility for at least one of the 10 percentage point bonuses). These representations are simplifications, as there can be greater diversity in captured value depending on factors such as ownership type and tax status.

We simulated three different scenarios using the dGen model in which distributed PV costs were varied up and down relative to a mid-case representation. Cost assumptions for all three cases (mid, low, and high) are from the 2021 Annual Technology Baseline (ATB) where low cost corresponds to the ATB Advanced scenario, mid cost corresponds to the ATB Moderate scenario, and high cost corresponds to the ATB Conservative scenario. The dGen cost cases were paired with the corresponding technology cost and performance sensitivity in this study. Sensitivities capturing advanced or conservative renewable cost and performance projections—the *Advanced Renewable and Battery Technologies*, *Conservative Renewable and Battery Technologies*, and *Advanced All Clean Technologies*—were associated with the relevant dGen low or high cost case. All other sensitivities were paired with the dGen mid-case. All state-level distributed PV incentive programs, such as net-metering and net-billing, were assumed to remain in place over the time period analyzed.

IRA includes additional bonus credits for the ITA (up to 20 percentage points) for up to 1.8 GW per year for facilities (including but not limited to solar) that are placed in service or directly benefiting lower income and Tribal communities. IRA also contains a Greenhouse Gas Reduction Fund, administered by the U.S. Environmental Protection Agency (EPA) and expected to, in part, support low-income solar development. The dGen model runs used in this analysis did not have an explicit representation of the additional bonus credits or the Greenhouse Gas Reduction Fund. Instead, 0.9 GW per year (50% of the maximum total annual capacity allowed to receive the low-income community bonus) of distributed PV was added to the dGen projections through 2032. The estimate of 0.9 GW reflects the assumption that the bonus credit program limit will be achieved, but that some of the projects capturing the bonus credit and benefiting from the Greenhouse Gas Fund may not be additional (i.e., they would have occurred anyway even if the bonus credit were not available).

2.3.3 Analysis of Other Provisions

Separate from ReEDS, we also assessed the potential impacts of a number of other IRA and BIL loan, grant, and other programs on the power sector. Following the basic approach in DOE (2022), in these cases, we generally assumed that a large majority of the prospective impacts of these programs are captured in ReEDS results and cannot be separately evaluated outside that context. In effect, these programs are assumed to help facilitate achieving modeled outcomes—without them, the modeled outcomes may not be practically feasible. However, we also assumed that a smaller portion is additional to otherwise modeled outcomes, applying simplifying assumptions to broadly estimate the potential incremental impacts of these provisions on capacity additions and retirements, electricity supply, and CO2 emissions. Provisions analyzed in this way include numerous grant, loan, and demonstration programs, including programs to support rural utilities and communities, energy communities, and energy reinvestment.

Based on this simplified approach, in aggregate, these programs are assumed to contribute to the modeled ReEDS results, and to additionally deliver power sector CO2 reductions beyond those already estimated in ReEDS, of roughly 25 Mt per year by 2030 (approximately 3% of those otherwise estimated with ReEDS). This estimate is not a projection of the unique impact of these provisions, as those impacts are largely implicitly embedded in the ReEDS results, but instead intends to roughly capture a portion of that possible impact—that which may be additional to otherwise modeled outcomes. Related, note that many other BIL and IRA programs are not directly assessed, but are assumed to help support modeled outcomes by addressing deployment barriers, building-out delivery infrastructure and supply chains, and driving technology advancements. These include numerous transmission authorities; various supply-chain and workforce investments; multiple R&D, demonstration, and loan programs; and various other hard-to-model programs and policies.

2.4 Key Caveats

2.4.1 Modeling Caveats

ReEDS is a linear program designed to identify the suite of investments in and operations of the power system to minimize the cost of meeting load. As such, the model will "choose" any investment, retirement, or operational change that will lower overall costs subject to electricity system physical and environmental constraints. In economic terms, the model represents a near-perfect market for the supply of electricity—"near-perfect," instead of "perfect," because the model is sequentially solved without perfect foresight of future conditions and accounts for some aspects of market friction.

In reality, electricity markets are far from "perfect" markets. Institutional interests, imperfect information, market power, barriers to entry, supply-chain constraints, and human behavior, among other drivers lead to market distortions that can result in non-optimal decision making or simply a departure from otherwise least-cost outcomes. As such, rather than treating results from a given ReEDS scenario as a prediction of specific real-world outcomes, the results should be viewed as projections of the suite of investment and operational decisions that lead to the lowest costs of meeting load while ensuring that all other power system operational (e.g., operating reserve requirements, firm capacity or resource adequacy requirements) and environmental/policy (e.g., emissions caps, renewable portfolio standards) constraints are simultaneously met. That being said, some scenarios—such as the Constrained scenario in this study—are formulated to capture, albeit, stylistically, aspects of "non-economic" behavior that can shape outcomes in the power sector.

As noted above, ReEDS has a highly spatially and temporally resolved representation of the power system for a national-scale planning model. Despite this, more aggregate representations of some aspects of the power system are necessary to ensure computational tractability. In particular, like all national-level power system planning models, ReEDS does not model specific transmission rights-of-way with detailed AC power flow simulation. Rather, transmission investment and operation is represented "zonally," captured through a representation of the aggregate transmission capacity between ReEDS regions (134 balancing areas across the contiguous United States). In addition, ReEDS only captures the bulk or utility-scale aspects of the power sector. Distribution system and distributed connected resource (e.g. distributed PV and storage) investment, operation, and associated costs, as well as efficiency and demand response program costs and impacts are not considered endogenously.

2.4.2 Analysis Caveats

In addition to the general model caveats noted above, we highlight other caveats, more specifically related to this study, here. First, this study evaluates the potential impacts of IRA and BIL across a broad range of future conditions. However, we have not exhaustively evaluated all potential conditions. As such, the realized future conditions could be outside the range of those captured within the suite of scenarios analyzed here, leading to potential IRA and BIL impacts that are beyond the range of those identified in the results reported below.

Second, the model generally allows the investment in and operation of new electricity transmission and CO_2 pipeline and storage infrastructure required to support new generation facilities and meet the needs of growing demand. Given potential challenges in siting new transmission and pipeline infrastructure, we constrain near-term (through 2028) transmission builds in all cases, and do not allow new CO_2 pipeline deployment until 2028.[18] Furthermore, we explore the implications of continued limitations and increased costs of constructing new transmission and pipeline infrastructure in the Constrained case. However, deployment barriers and extended construction timelines for such infrastructure could certainly extend beyond what is captured in the Constrained case, and if so, would likely further reduce the deployment of clean generation sources. This remains an important area of for further research.

Third, with respect to the IRA and BIL provisions modeled, there remains uncertainty in how the final criteria determining the eligibility or value of IRA credits will be specified. Further guidance from the U.S. Department of the Treasury could result in substantial shifts in the realized value and scope of tax credits. Uncertainties regarding two such issues—eligibility for domestic content and energy community bonuses under the ITC and PTC—are explored to a degree in this study, however, others remain.

Finally, while the analysis captures a number of key power sector provisions from IRA and BIL, there are many provisions that will likely directly or indirectly impact power sector evolution. Of particular importance, we capture neither the tax credit for clean hydrogen production (§45V) nor the §45Q tax credit for direct air capture (DAC) and storage of CO_2. In addition, while we have accounted for an expected moderate increase in load associated with IRA and BIL electrification provisions, there is substantial uncertainty in how IRA and BIL provisions will ultimately impact load, as well as broader uncertainty in the evolution of key drivers of demand, electrification, and efficiency that interact with the IRA and BIL programs, including population changes, consumer preferences, technology change, economic growth, policy change, and utility efficiency and demand response program changes. Realized electricity consumption could be above or below the projected levels used in this study.

[18] ReEDS tracks when plants or infrastructure comes online rather than when they begin construction. This constraint therefore allows 2028 to be the first operational year of pipeline that was assumed to be under construction prior to 2028.

3 Results

3.1 Deployment and Generation

The *No New Policy* Mid- and Constrained cases show only modest changes in the capacity and generation mixes between 2023 and 2030. Under the Mid case, we observe moderate cumulative deployment of wind (54 GW), solar (125 GW), storage (10 GW), and natural gas (57 GW) capacity from 2023 through 2030 with associated increases in generation, while capacity and generation contributions from coal and oil-gas-steam (OGS) facilities decline—coal and OGS capacity decline 46 GW and 40 GW, respectively (Figure 1). Constraints on resource accessibility and deployment results in only limited impacts under the *No New Policy* scenario. The *No New Policy* Constrained case shows a 14 GW reduction in wind deployment by 2030, as compared to the Mid case, which is primarily offset by additional deployment and generation from solar and natural gas capacity. Technology cost and performance and fuel price sensitivities to the *No New Policy* case demonstrate trends consistent with the Mid case, but show variation in the level of deployment of wind, solar, and gas (Figure 2), the extremes of which are generally associated with the advanced and conservative technology cases. The annual average deployment rate under the *No New Policy* Mid case is 7 GW/yr for wind (5 GW/yr–15 GW/yr, across all cases), 16 GW/yr for solar technologies (12 GW/yr–26 GW/yr, across all cases), and 7 GW/yr for gas (4 GW/yr–8 GW/yr, across all cases).

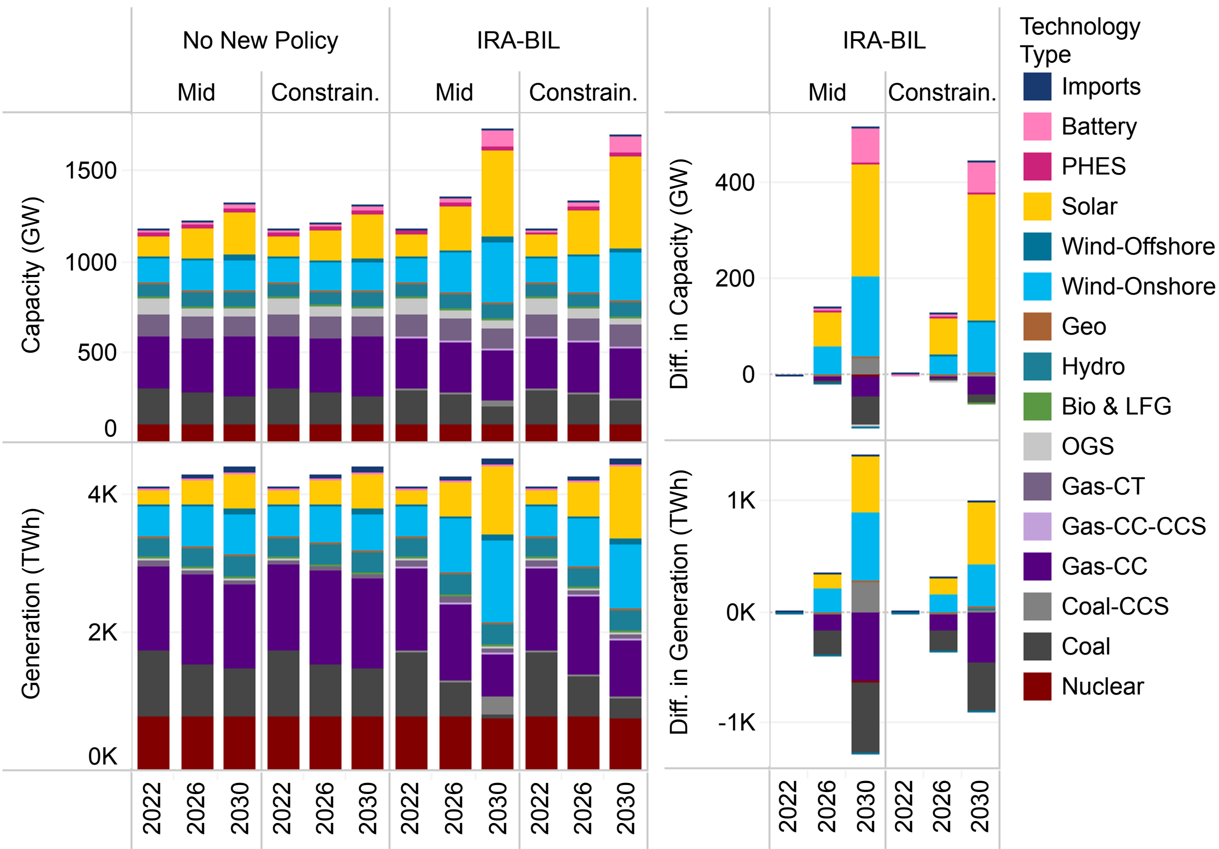

Figure 1. Left pane: capacity (top row) and generation (bottom row) 2022-2030 by technology in the Mid and Constrained *No New Policy* and *IRA-BIL* cases. Right pane: differences in capacity and generation in the *IRA-BIL* Mid and Constrained cases from the corresponding No New Policy case.

PHES=Pumped Hydroelectric Energy Storage; Geo=Geothermal; Hydro=Hydroelectric; Bio & LFG=Biopower and Landfill Gas; OGS=Oil Gas Steam; Gas-CT=Natural Gas Combustion Turbine; Gas-CC=Natural Gas Combined Cycle; CCS=Carbon Capture and Storage

IRA and BIL drive substantial increases in wind and solar deployment and generation. Cumulative deployment from 2023 to 2030 under the *IRA-BIL* Mid case totals 220 GW for wind (150 GW–320 GW across sensitivities) and over

360 GW of solar (150 GW–430 GW across sensitivities), representing average annual deployment rates of 45 GW per year and 27 GW per year for solar and wind, respectively. Associated with the deployment of wind and solar capacity is substantial deployment of battery storage, totaling 80 GW cumulatively from 2023 through 2030 in the Mid case and 40 GW–100 GW, across sensitivities. In addition, in the latter part of the decade, approximately 40 GW of existing fossil capacity is retrofit with CCS (5 GW–55 GW, across sensitivities). The deployment of fossil-CCS demonstrates the substantial value of the 45Q incentive for CCS projects, and the potential large implications for CCS deployment. Finally, although difficult to identify in Figures 1 and 2, capacity additions under all *IRA-BIL* cases include 1.4 GW of nuclear demonstration projects.[19]

Deployment barriers captured under the *IRA-BIL* Constrained case demonstrate a substantially larger impact on capacity and generation evolution than under the *No New Policy* case. New wind deployment falls from approximately 220 GW in the *IRA-BIL* Mid case to 150 GW in the Constrained case—a 70 GW decrease (32% reduction) in deployment by 2030. Similarly, new fossil-CCS builds decline from approximately 40 GW in the Mid case to 5 GW in the Constrained case. These results demonstrate the considerable impact that barriers or limitations to accessing wind resources and developing CO_2 transport and storage infrastructure could have on wind and CCS deployment. Reductions in deployment and generation from these two technologies are largely offset by increased generation from natural gas, coal, and solar technologies, the latter of which is deployed in greater quantities despite assumed reductions in the amount of land available for solar development.

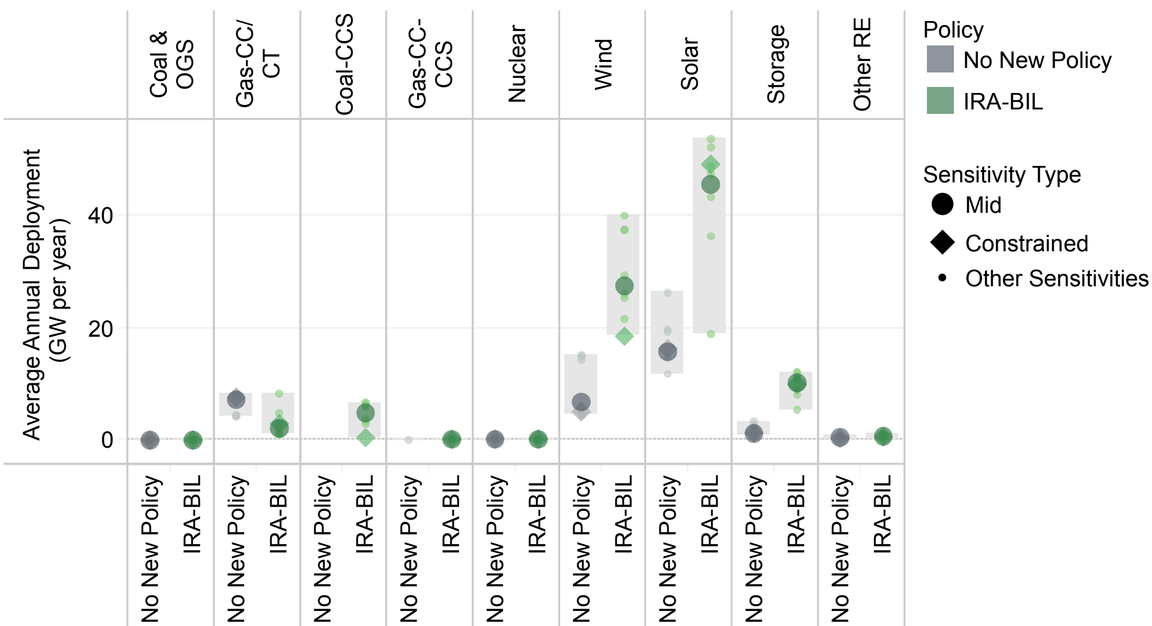

Figure 2. Ranges in average annual deployment (2023-2030) by technology category and scenario.

The light-grey shaded bars show the range of annual deployment observed within each scenario and across sensitivities. Shapes indicate the observed values for individual cases (scenario-sensitivity combination). Grey shaded shapes indicate values from the *No New Policy* cases and green shaded shapes indicate vales from the *IRA-BIL* cases. The large circle and diamond shapes show the Mid and Constrained sensitivities while the small circles indicate all other types of sensitivities, including the cost and performance, fuel price, and high/low IRA impact sensitivities.

The rapid deployment of wind and solar combined with the new deployment of fossil-CCS under the *IRA-BIL* scenarios leads to substantial shifts in the generation mix. Wind and solar technologies, in aggregate, reach 50% of total generation in 2030 under the Mid *IRA-BIL* scenario, while unabated fossil falls below 20%, and total clean[20] generation climbs to over 81%, up from approximately 41% in 2022 (Figure 3).

[19] All scenarios reflect the completion of the Vogtle units 3 and 4.

[20] "Clean" technologies here include all zero-CO_2 emitting generation—wind, solar, hydroelectric, geothermal, nuclear, biopower—as well as fossil technologies with CCS.

While the Constrained case has little implication for the clean and fossil shares of generation under the *No New Policy* scenario, under the Constrained *IRA-BIL* scenario, clean generation sources provide 71% of total generation—10 percentage points lower than in the Mid *IRA-BIL* scenario (81%). Additional sensitivities to the Mid case demonstrate that future technology cost and performance evolution and fuel prices can all substantially impact technology deployment and the clean share of generation. However, technology cost and performance assumptions and constrained deployment consistently have the largest impacts on the future generation mix across the suite of sensitivities evaluated.

Finally, the policy sensitivities explored, namely the assumed average PTC and ITC bonus crediting achieved and the cost of monetization of all tax credits, also impact levels of deployment, but to a lesser degree than the cost and performance or Constrained sensitivities.

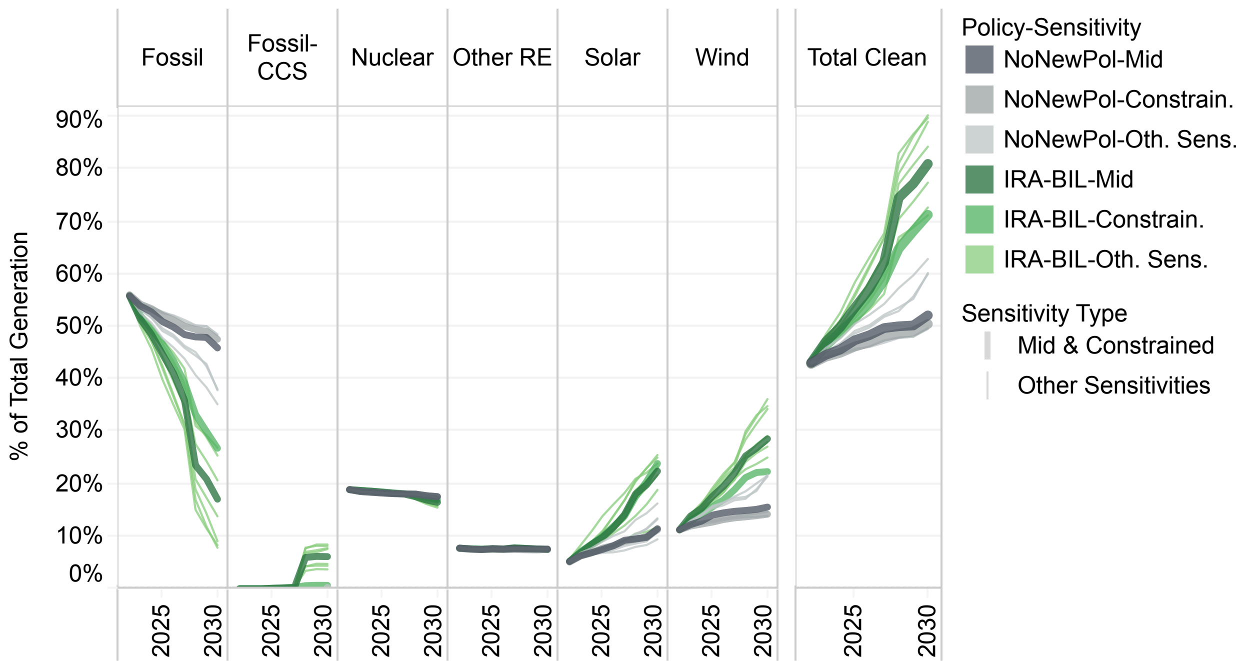

Figure 3. Share of total generation by technology category across all scenarios and sensitivities.

No New Policy cases are shown in grey and *IRA-BIL* cases are shown in green. Thick lines in the darkest shade show the Mid cases and thick lines in the lighter shade shows the Constrained cases. Thin lines in the lightest shade show all other sensitivities, including the cost and performance, the fuel price, and high/low IRA impact sensitivities.

3.2 Transmission

IRA and BIL contain several loan and grant programs to support new transmission infrastructure, which are not modeled here but are assumed to facilitate modeled outcomes. Although these programs are not directly modeled, we observe a substantial increase in transmission deployment across the IRA-BIL scenarios. Under the *IRA-BIL* Mid case, over 24 TW-miles of new long-distance transmission is deployed by 2030, a 16% increase in total installed capacity relative to today (Figure 4). This observed increase in transmission is largely driven by the increased deployment of wind (and solar) technologies in the *IRA-BIL* case. The additional transmission enables access to more remote, but high-quality renewable resources.

Under the Constrained case, in which new transmission is not allowed between 11 defined transmission regions[21] (but is allowed within a region) and total annual long-distance transmission additions are limited to the historical average annual build rate, total transmission growth falls to 12% by 2030, and we observe an associated response in wind deployment, which falls from 29% of generation in the Mid case to 22% in the Constrained case. Similarly,

[21] See Denholm et al. (2022) Figure B2 for map of regions.

sensitivities which show lower deployment of wind driven by changes in their projected costs also show lower reliance on new transmission. This suite of results demonstrates the value of transmission in achieving higher shares of clean generation, and, in particular, wind, and suggests that constraints and/or delays in developing new transmission could slow or reduce the level of clean electricity deployment achieved.

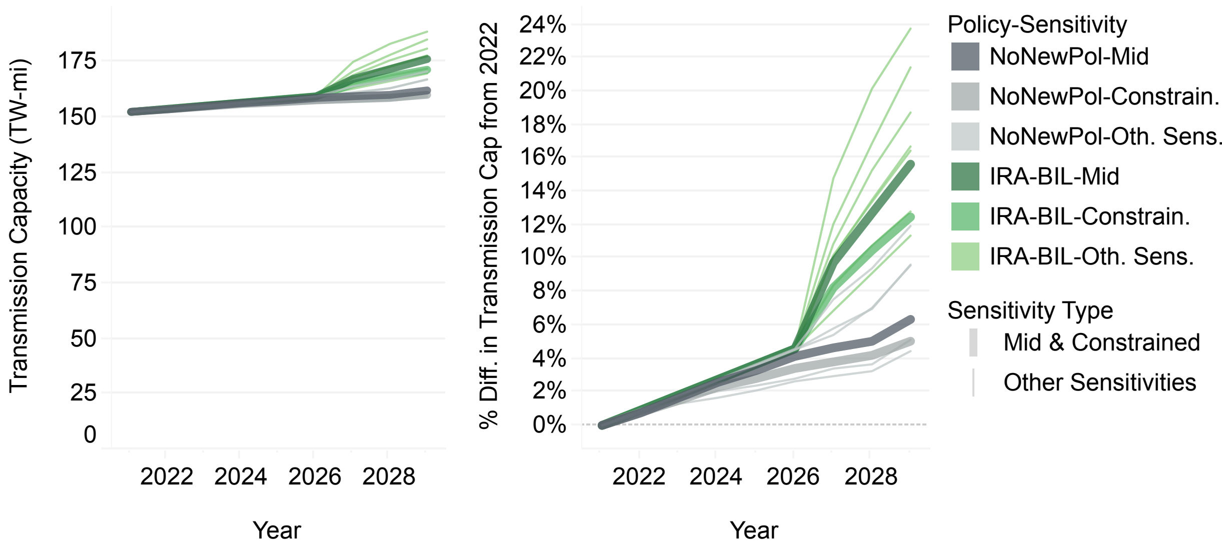

Figure 4. Transmission capacity (left) and percent change in transmission capacity from 2022 (right) across all scenarios and sensitivities.

3.3 Emissions

3.3.1 CO_2 Emissions

Power sector CO_2 emissions associated with combustion of fossil fuels decline under both the *No New Policy* and *IRA-BIL* scenarios, however, the rapid increase in clean generation under the *IRA-BIL* scenarios drives a corresponding increase in emissions reductions over the decade (Figure 5). By 2030, under the *IRA-BIL* Mid case, power sector CO_2 emissions fall to 390 Mt per year, equivalent to an 84% reduction in power sector CO_2 emissions from the 2005 level.

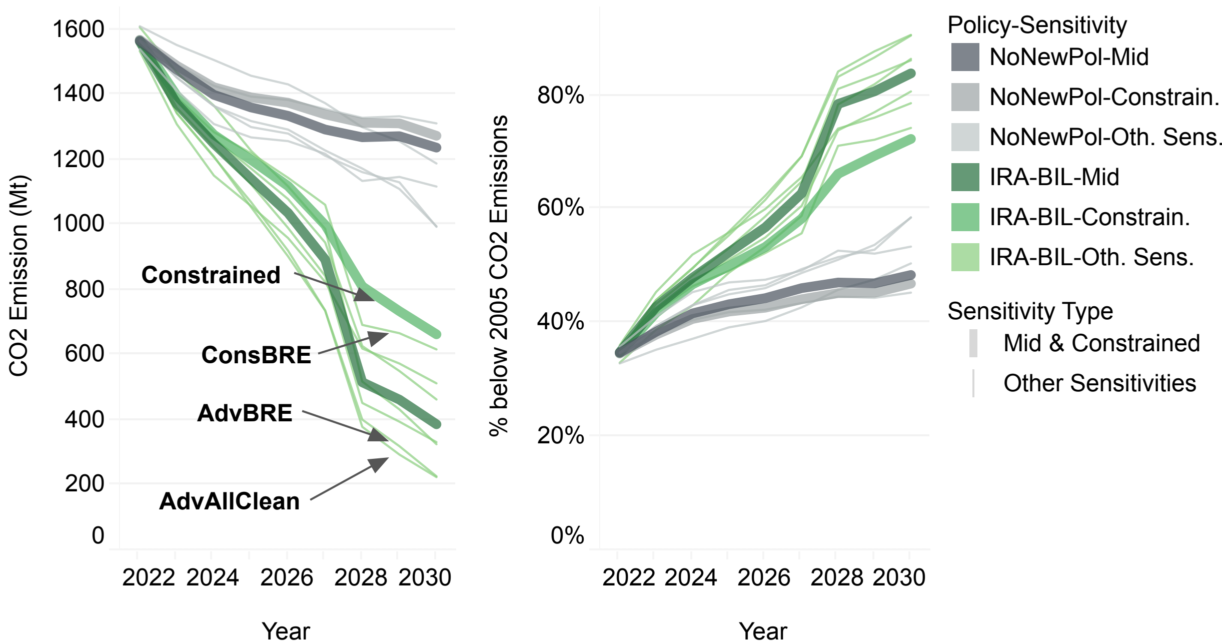

Figure 5. Projected power sector CO_2 emissions (left) and percent change in power sector CO_2 emissions below the 2005 level (right) across all scenarios and sensitivities.

Across the suite of *IRA-BIL* sensitivities, 2030 CO_2 emissions range from 230 Mt (91% below 2005) to 660 Mt (72% below 2005), primarily driven (at the extremes) by cost and performance assumptions and deployment constraints. Lower costs and higher performance of clean technologies lead to increased deployment and greater emissions reductions from displaced coal and natural gas. Deployment constraints lead to reduced wind and fossil-CCS deployment and the continued reliance on unabated fossil resources for a larger share of generation. It is under these latter conditions (constrained deployment) that we observe the highest level of emissions (and least emissions reductions) among the *IRA-BIL* cases.

Higher and lower natural gas price assumptions have less pronounced impacts on emissions, as changes in generation and associated emissions from natural gas capacity are generally offset by compensating changes in generation and emissions from coal capacity. Finally, assumed differences in the realized level of bonus crediting and the cost of monetization of tax credits also drive changes in emissions, mediated through their deployment effects, but the impacts are small relative to the technology cost and performance and constrained deployment sensitivities.

3.3.2 SO_2 and NOx Emissions

Under the *IRA-BIL* Mid case, annual SO_2 and NOx emissions fall from 1.2 Mt and 1.1 Mt to 0.31 Mt and 0.35 Mt, respectively, from 2022 to 2030, representing 60% and 57% reductions in these criteria pollutant emissions relative to the *No New Policy* case. Across the *IRA-BIL* sensitivities, reductions relative to the associated *No New Policy* case in 2030 range from 45% to 62% and 43% to 60% for SO_2 and NOx, respectively. The wide range of changes in SO_2 and NOx emissions observed across the sensitivities is driven primarily by the variation in the total share of fossil generation.

3.4 Bulk Electricity System Costs

Figure 6 shows changes in average annual bulk electricity system costs over time across scenarios and the percent change in average annual costs across each *IRA-BIL* scenario relative to the corresponding *No New Policy* case. Unless otherwise specified, all cost or value figures are reported in 2022$. "Bulk system costs" here includes all costs associated with investment, operations, and maintenance of utility-scale generation, transmission, and storage infrastructure, as well as the value (negative cost) of the PTC, ITC, and 45Q, but it does not include administrative costs, costs associated with distribution infrastructure, distribution connected storage or generation assets, or costs associated efficiency and demand response programs operated by utilities. The tax credit component of bulk system costs represents the value of tax credits to project developers. The values are, therefore, net of the assumed cost of monetization of the tax credits, and account for the reduced pre-tax revenue requirement for corporate income tax payments. As such, the reported tax credit values are not equivalent to estimates of tax credit expenditures that may not incorporate monetization and income tax effects.

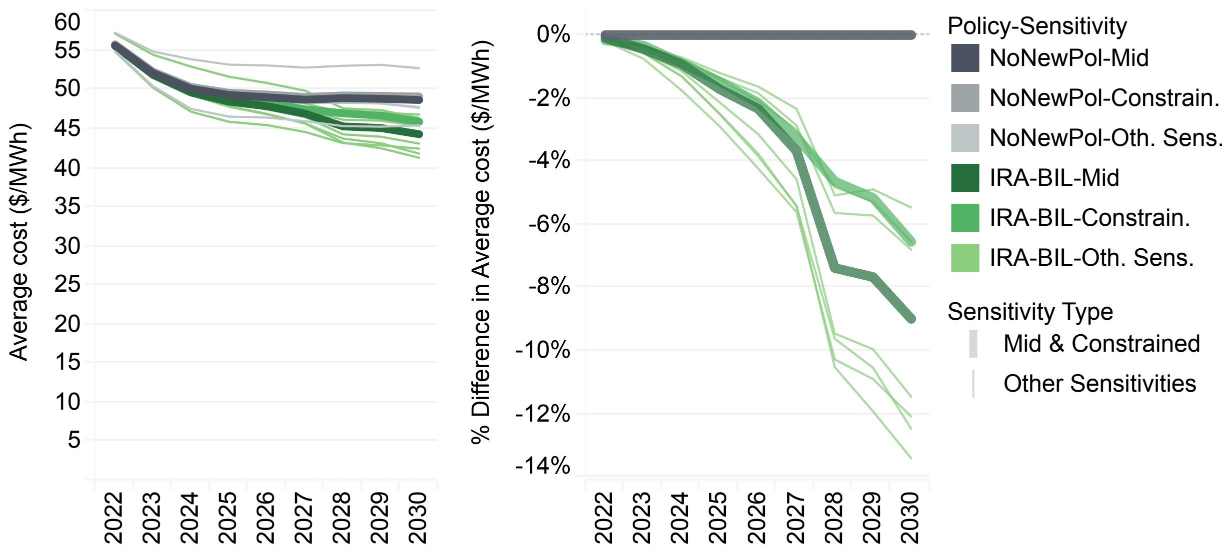

Figure 6. Average annualized bulk power system costs (left) and percent change in annualized cost (right) in all IRA-BIL scenarios relative to the corresponding *No New Policy* scenario.

Across all cases—both *No New Policy* and *IRA-BIL*—average costs decline (Figure 6) due to declining total debt, improvements in technology cost and performance, and growth in load that is largely met with lower cost energy resources (compared to the historical average), such as wind and solar. However, average costs under the *IRA-BIL* cases decline more rapidly. Under these cases, IRA and BIL induced investment in clean generation, storage, and transmission infrastructure drives increases in total capital and non-fuel operational expenditures, but these increases in expenditures are more than offset by decreases in fuel expenditures (resulting from reduced fossil generation) as well as the increased scope and value of tax credits (Figure 7). This leads to a net reduction in annual system costs of $16 billion by 2030 under the Mid case and a range of $8 billion to $25 billion across all sensitivities. Cumulatively, from 2023–2030, annual system costs are reduced by $50 billion to $115 billion (undiscounted) across all sensitivities. The present value of cumulative (2023–2030) system costs reductions using a 2% discount rate ranges from $46 billion to $105 billion.

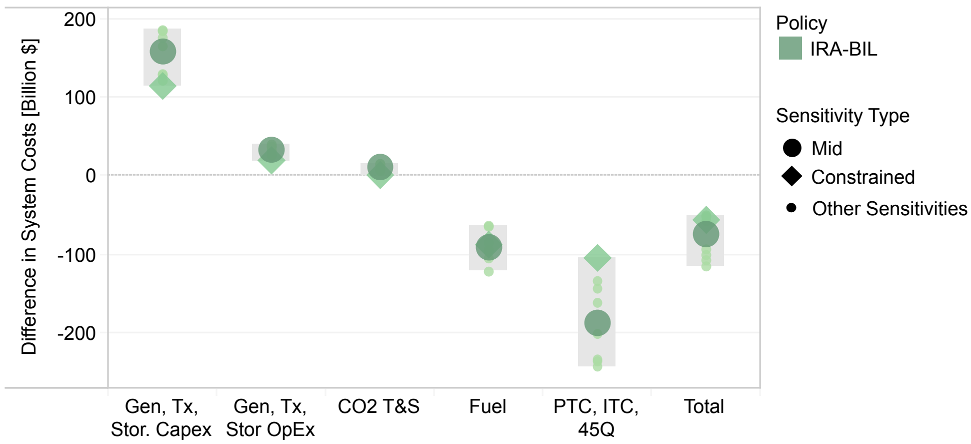

Figure 7. Ranges in the differences in cumulative bulk power system costs by category between the *IRA-BIL* cases and the corresponding *No New Policy* cases, 2023–2030. Positive values indicate higher costs in the *IRA-BIL* scenarios.

The categories reported are capital expenditures for generation, transmission, and storage (Gen, Tx, Stor. CapEx), non-fuel operational expenditures for generation, transmission, and storage (Gen, Tx, Stor. OpEx), total capital and operational expenditures for CO_2 transport and storage(CO_2 T&S), fuel expenditures (Fuel), and value of tax credits (PTC, ITC, 45Q). The far right bar shows the range in the net change in system cost, i.e. the sum of differences across all categories.

On an average cost basis, under the *IRA-BIL* Mid case, costs decline by approximately $4.3 per MWh by 2030 relative to the *No New Policy* case—equivalent to a 9% reduction. The overall range is from approximately a $2.7 per MWh (5%) decrease in the case with conservative cost and performance assumptions for renewable and storage technologies to a $6.3 per MWh (13%) decrease in the case with advanced cost and performance assumptions for all clean generation and storage technologies.

The resulting decrease in bulk system costs could lower retail rates by a similar absolute magnitude—i.e. $4.3 per MWh in the Mid case (assuming such savings are passed on to customers)—however the percent changes in retail rates would likely be lower as bulk system costs only make up a portion of total costs borne by customers.

3.5 Avoided Climate and Health Damages

3.5.1 Avoided Climate Damages

We estimate avoided climate damages by applying social cost of CO_2 (SC-CO_2) estimates from Rennert et al. (2022). Rennert et al. (2022) report values in 10-year increments beginning in 2020. Therefore, to estimate annual avoided damages for in each year evaluated in this study, we apply linearly interpolated SC-CO_2 values to emissions in each year based on the reported 2020 and 2030 values from Rennert et al. (2022). We calculate avoided damages using the "preferred mean" estimates of the SC-CO_2 which uses a 2% near-term discount rate. The preferred mean estimates for emissions in 2020 and 2030 are $185 per tonne CO_2 and $226 per tonne CO_2, respectively. In addition, we report more conservative damage estimates calculated using the mean SC-CO_2 based on a 3% discount rate ($80 per tonne in 2020 and $104 per tonne in 2030.[22]

The estimated annual avoided global climate damages grow to nearly $220 billion per year ($100 billion per year using the 3%-SC-CO_2 value) under the *IRA-BIL* Mid case with a range of $160 billion per year to $230 billion per year ($70 billion per year to $110 billion per year using the 3%-SC-CO_2) across sensitivities. Cumulative avoided climate damages (2023–2030) associated with the *IRA-BIL* scenarios are shown in Figure 8. Avoided cumulative damages in the Mid *IRA-BIL* case are $880 billion and $440 billion based on application of the preferred mean and 3% discount rate based SC-CO_2, respectively.[23] Across all sensitivity cases cumulative (2023–2030) avoided

[22] The SC-CO_2 values noted here are reported in 2020$ terms consistent with Rennert et al. (2022), but we report our resulting avoided damages in 2022$.

[23] Cumulative values are reported undiscounted. The present value of cumulative avoided damages using the 2% discount rate SC-CO_2 value and discounting at the same 2% discount rate yields a value of $780 billion.

damages range from \$670 billion to \$960 billion using the preferred mean SC-CO_2 value and \$300 billion to \$440 billion using the 3% discount rate based SC-CO_2.

Finally, the range of avoided climate damages (Figure 8) demonstrates that while all scenarios are associated with large climate benefits, alternative future market conditions could substantially reduce the climate benefits associated with the power sector IRA-BIL provisions. In particular, the Constrained case leads to 25% less avoided damages than those in the Mid case.

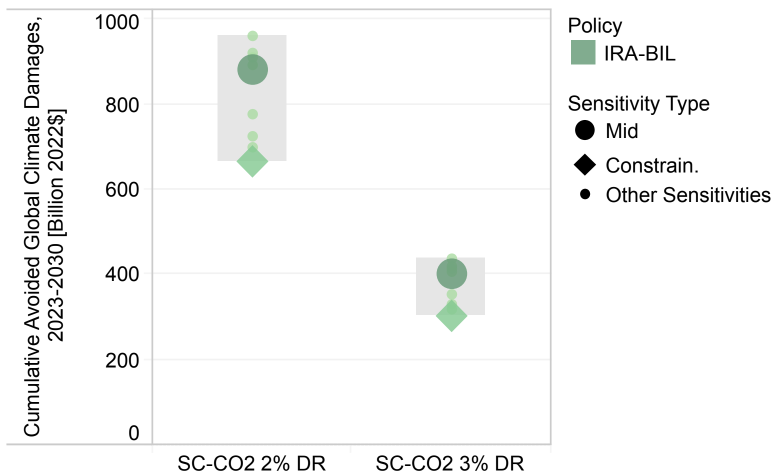

Figure 8. Estimated range in cumulative avoided global climate damages, 2023–2030, associated with reduced CO_2 emissions in the *IRA-BIL* cases.

The assumed SC-CO_2 values used to calculate the avoided damages are from Rennert et al. (2022). The left bar shows the range of avoided damages estimated using the "preferred mean" 2% near-term discount rate based SC-CO_2 of \$185 per tonne CO_2 in 2020, increasing to \$226 per tonne CO_2 in 2030. The right bar shows the range estimated using the 3% discount rate based SC-CO_2 of \$80 per tonne CO_2 in 2020, increasing to \$104 per tonne CO_2 in 2030.

3.5.2 Avoided Health Damages

Avoided health damages (avoided premature deaths) from reductions in sulfur dioxide (SO_2) and nitrogen oxides (NOx) emissions—precursors to particulate matter formation—are estimated using three reduced complexity air quality models (AP2, EASIUR, and InMAP). The air quality models track the dispersion and atmospheric chemistry of pollutants to estimate the change in exposure to particulate matter as a result of a change in emissions from a particular location. The models incorporate exposure-response functions developed from epidemiological studies to estimate the health impacts. In this study, we report the estimates based on application of the concentration response function from two widely referenced studies: the Harvard Six-Cities (H6C) study (Dockery et al. 1993; Lepeule et al. 2012) and the American Cancer Society (ACS) study (Pope III et al. 2002; Krewski et al. 2009). We report both given that the estimated mortality risk associated with an exposure to a given level of PM2.5 are about 2.5 times higher in the H6C study compared to ACS study. We translate mortality estimates into monetary value by applying a value of statistical life, using the U.S. Environmental Protection Agency's estimate of \$9.9 million in 2021\$ (EPA 2022). The range of values reported reflects both the range of precursor pollutant (NOx and SO_2) changes across the suite of IRA-BIL sensitivities as well as the range of estimates for particulate matter formation from each of the air quality models.[24]

Avoided SO_2 and NOx emissions under the range of *IRA-BIL* cases are estimated to reduce premature mortality by approximately 4,200 to 7,000 deaths, cumulatively, 2023–2030, using the ACS values and approximately 11,000 to 18,000, cumulatively based on the H6C study. These avoided deaths are estimated to lead to \$45 billion to \$76

[24] Additional information about the air quality models is provided at https://www.caces.us/data.

billion ($65 billion in the Mid case) in avoided health damages, cumulatively, 2023–2030, based on the ACS study, and $120 billion to $190 billion ($170 billion in the Mid case), cumulatively, based on the H6C study.[25]

[25]Cumulative values are reported undiscounted, in 2022$.

4 Conclusions

The results of this analysis demonstrate that IRA and BIL have the potential to drive transformative change in the U.S. power sector. Under the Mid case scenario explored, wind, solar, and storage deployment more than doubles historic maximum annual rates of deployment, clean electricity reaches over 80% of total generation by 2030, and emissions fall to 390 Mt CO_2 per year—over 80% below the 2005 CO_2 level. These potential emissions reductions are, in turn, estimated to lead to $880 billion worth of cumulative avoided climate damages (using the central 2%-discount rate SC-CO_2 value), while related reductions in criteria pollutants lead to an estimated $170 billion of cumulative avoided health damages.

Sensitivities structured to evaluate less favorable conditions for clean electricity deployment, including higher projected costs of clean electricity technologies and barriers to technology and infrastructure deployment, were shown to reduce the level of total clean electricity deployed. However, even in these cases, the IRA and BIL were still found to drive substantial increases in the clean electricity share, reaching over 70%, with power sector emissions falling to 72% below the 2005 level. Nonetheless, the lower rate of clean energy deployment in the deployment constrained and high clean cost cases highlights the potential value of continued research and development to drive advancements in clean electricity technologies as well as actions taken to mitigate existing and developing constraints on deployment of clean electricity, transmission, and pipeline and storage infrastructure.

Finally, while this suite of changes ultimately arise as a result of the overall increase in investment in clean electricity technologies, the increased capital expenditures (and non-fuel operating expenditures) are more than offset by a reduction in fuel expenditures associated with decreased fossil generation and increased value (and scope) of the tax credits. In aggregate, this leads to a net reduction in average bulk power system costs.

Irrespective of future market conditions we find that the IRA and BIL could spur substantial increases in clean technology investment in the U.S. power sector, driving down greenhouse gas emissions, all while lowering electricity costs. Fully realizing these modeled benefits will require action by all jurisdictions of U.S. government—federal, state, and local—the private sector, and civil society to support the beneficial deployment of clean energy technologies.

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