GeoVision Analysis Supporting Task Force Report: Impacts

The Employment Opportunities, Water Impacts, Emission Reductions, and Air Quality Improvements of Achieving High Penetrations of Geothermal Power in the United States

Dev Millstein,[2] James McCall,[1] Jordan Macknick,[1] Scott Nicholson,[1] David Keyser,[1] Seongeun Jeong,[2] and Garvin Heath[1]

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Foreword

This report describes research and analysis performed in support of the U.S. Department of Energy Geothermal Technologies Office for its Geothermal Vision Study. A summary of the study is captured in DOE's report, *GeoVision: Harnessing the Heat Beneath Our Feet* (DOE 2019) and included ground-breaking, detailed research on geothermal technologies. The study projects and quantifies the future electric and nonelectric deployment potentials of these geothermal technologies within a range of scenarios in addition to their impacts on U.S. jobs, the economy, and environment. Coordinated by the U.S. Department of Energy Geothermal Technologies Office, the Geothermal Vision Study development relied on collecting, modeling, and analyzing robust data sets through seven national laboratory partners that were organized into eight technical task force groups. These task forces and their respective principal leading national laboratory are listed in Table F-1. The table also provides a guide to the final research documents produced by each *GeoVision* task force. In most cases, these were prepared as laboratory reports, and they are referenced accordingly. Consult these external reports for detailed discussions of the topics contained within, which form the basis of the *GeoVision* analysis.

Table F-1. Guide to Technical Research Documents Providing the Basis of the *GeoVision* Analysis

***GeoVision* Task Force**	**Lead National Laboratory**	**Report Number/Citation**
Exploration and Confirmation	Lawrence Berkeley National Laboratory	LBNL-2001120 (Doughty et al. 2018)
Potential to Penetration	National Renewable Energy Laboratory	NREL/TP-6A20-71833 (Augustine et al. 2019)
Thermal Applications: Direct Use	National Renewable Energy Laboratory	NREL/TP-6A20-71715 (McCabe et al. 2019)
Thermal Applications: Geothermal Heat Pumps	Oak Ridge National Laboratory	ORNL/TM-2019/502 (Liu et al. 2019)
Reservoir Maintenance and Development	Sandia National Laboratories	SAND2017-9977 (Lowry et al. 2017)
Hybrid Systems	Idaho National Laboratory	INL/EXT-17-42891 (Wendt et al. 2018)
Institutional Market Barriers	National Renewable Energy Laboratory	NREL/PR-6A20-71641 (Young et al. 2019)
Social and Environmental Impacts (this report)	Lawrence Berkeley National Laboratory	NREL/TP-6A20-71933 (Millstein et al. 2019)

Acknowledgments

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List of Acronyms

AEO	Annual Energy Outlook
ANL	Argonne National Laboratory
AP2	Air Pollution Emission Experiments and Policy
AP-42	Compilation of Air Pollutant Emission Factors
BAU	Business as Usual
Btu	British thermal unit
CARB	California Air Resources Board
CH_4	methane
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
CPP	Clean Power Plan
CSAPR	Cross-State Air Pollution Rule
dGeo	Distributed Geothermal Market Demand Model
DOE	U.S. Department of Energy
DU	direct use
EASIUR	Estimating Air pollution Social Impact Using Regression
EGS	enhanced geothermal system
EIA	U.S. Energy Information Administration
EPA	U.S. Environmental Protection Agency
FTE	full-time equivalent
GHG	greenhouse gas
GHP	geothermal heat pump
GREET	Argonne National Laboratory's Greenhouse gases, Regulated Emissions, and Energy use in Transportation
GW	gigawatt
IMPLAN	Impact Analysis for Planning
I-O	input-output
IPCC	Intergovernmental Panel on Climate Change
IRT	Improved Regulatory Timeline
TI	Technology Improvement
JEDI	Jobs and Economic Development Impact
kWh	kilowatt-hour
LCA	Life Cycle Assessment
MATS	Mercury and Air Toxics Standards
MMT	million metric tons
MMT CO_2e	million metric tons of carbon dioxide equivalent
MWh	megawatt-hour
MW_t	megawatt thermal
N_2O	nitrous oxide
NO_x	nitrogen oxides
NREL	National Renewable Energy Laboratory
O&M	operation and maintenance
PCA	power control area
$PM_{2.5}$	fine particulate matter
ReEDS	Regional Energy Deployment System

scf	standard cubic feet
SO_2	sulfur dioxide
SO_x	sulfur oxide
TMT	thousand metric tons
VOC	volatile organic compound
VSL	value of statistical life

Executive Summary

The U.S. Department of Energy (DOE) *GeoVision: Harnessing the Heat Beneath Our Feet* report (*GeoVision* [DOE 2019]) seeks to identify growth potential within the geothermal electric power sector and the geothermal heating and cooling sector. The *GeoVision* report identifies resource potential; necessary and advantageous technology advancement targets; market and structural barriers limiting deployment; and the potential deployment and external benefits of overcoming the identified barriers and technology needs. This Impacts Task Force Report focuses on the potential external benefits of future growth in the geothermal electric power and geothermal heating and cooling sectors that would be facilitated by meeting the targets for technological improvement and by easing market and structural barriers. The report calculates benefits based on forecasts of the current geothermal electric power and geothermal heat pump (GHP) sectors, and the broader electricity generation and building heating and cooling sectors that cover the present day out to 2050. Additionally, a brief section describes potential benefits that could be realized from the expansion of geothermal direct-use district heating systems.

This report focuses on the creation of new job opportunities within the geothermal sectors, along with a suite of environmental benefits linked to water usage, air pollution, and greenhouse gas (GHG) emissions that may occur under expanded geothermal deployment scenarios. These expanded deployment scenarios could be achieved if technological targets and barrier reduction targets are met; thus, the results described here represent the benefits of achieving the *GeoVision*. The primary expanded deployment scenario for electric sector geothermal technology is called the 'Technology Improvement' (TI) scenario, and the primary expanded scenario for the GHP sector is called the 'Breakthrough' scenario. Deploying new geothermal resources, and the impact of such deployment on the rest of the power sector and on heating and air-conditioning demand within buildings, is determined through using National Renewable Energy Laboratory's (NREL's) Regional Energy Deployment System (ReEDS) electric sector capacity expansion model and the Distributed Geothermal Market Demand Model (dGeo). For each of the benefit categories, we take the modeled output from ReEDS and dGeo and apply additional tools as necessary to assess potential benefits in physical and, where feasible, monetary terms. We qualify the study results where appropriate and highlight areas of uncertainty not otherwise explicitly addressed in our analysis.

As summarized below, we find that achieving the *GeoVision* scenarios can provide benefits to the United States, especially with respect to gross job creation, air quality improvements, and GHG emission reductions.

Employment Opportunities

Achieving the TI scenario leads to developing a robust geothermal power industry, focused on the development of enhanced geothermal system (EGS) opportunities. This industry, combined with traditional hydrothermal power development, supports peak employment of 262,000 "gross" full-time jobs[1] in 2048, in addition to the level expected under a Business-as-Usual

[1] "gross" full-time jobs represent the geothermal industry jobs created to support deployment in the TI scenario, referenced to the BAU scenario. It is the difference in employment levels between the two scenarios. This estimate does not account for job changes in other sectors of the economy, which would represent "net" jobs.

(BAU) scenario. This level of employment would be roughly 45 times larger than current employment within the geothermal power sector. Operation and maintenance (O&M) jobs to support this industry peak at 6,000 in 2050 and provide long-term local employment benefits for communities near power plants. Total investment in this sector will reach $220 billion, cumulatively, by 2050. Outside of the electric sector, the expansion of the GHP industry under the Breakthrough scenario would support an additional 36,300 "gross" jobs at the peak year of GHP activity in 2043. Under the Breakthrough scenario, growth in the GHP industry will rely on $112 billion of investment, cumulatively, through 2050. Together, growth within the geothermal electric power sector and GHP sector present the opportunity to develop two new industries that are geographically complementary to each other that create jobs across the country, but with most job impacts occurring in the Western or mid-Atlantic regions of the United States.

Water Impacts

In this report, the water use required by centralized geothermal electricity generating plants was examined. Water impacts of distributed GHPs are presumed to be minimal and not examined here. Water usage within the U.S. power sector can be described in two manners: (1) water withdrawals, where water is removed and then returned to its source (often at a higher temperature) and (2) water consumption, where water is removed from a source and either evaporated or injected into the ground (not returned). Achieving the TI scenario slightly reduces systemwide power-sector water withdrawals by 23 billion gallons per year in 2050 (a reduction of 0.3%), relative to BAU. Despite lower quantities of water being withdrawn, systemwide water consumption under the TI scenario is increased by approximately 40 billion gallons per year in 2050 (an increase of 4%), relative to BAU. Thus, the significant growth described in the *GeoVision* does not create significant additional demands on freshwater resources from within the power sector on a national scale. Importantly, geothermal technologies can use nonfreshwater resources, such as municipal wastewater and brackish groundwater, because water is not needed for cooling but rather to maintain reservoir pressure. A scenario was developed to test the potential for geothermal growth under a situation where geothermal power was limited to locations at which it could cost-effectively rely only on nonfreshwater resources. Under this scenario, geothermal deployment is reduced by 11% (6.5 gigawatts [GW]) relative to the TI scenario, meaning the availability of freshwater sources does not significantly limit the potential for geothermal growth if the cost, technical, and regulatory targets of the TI scenario are met. These results assume EGS technologies are all dry-cooled binary systems. If EGS technologies are assumed to be wet-cooled flash systems, however, power-sector withdrawals and consumption would increase by 11% and 71%, respectively, compared with the TI scenario, and geothermal deployment would be reduced by 6% (3.5 GW).

Air Pollution Benefits

Within the electric sector, achieving the TI scenario reduces cumulative emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_x), and fine particulate matter ($PM_{2.5}$) by 1%—or 279,000, 417,000, and 54,000 metric tons (t), respectively—relative to the BAU scenario. These emission reductions are concentrated in the time period between 2030 and 2050. These reductions could produce $13 billion of net present value benefits to the United States in the form of lower future health and environmental damages based on central estimates, which is equivalent to a levelized benefit of geothermal of 0.5 cents per kilowatt-hour ((¢/kWh)-geothermal. Across the full set of methods considered, total monetary benefits span $6 billion (0.2¢/kWh-geothermal) to $23 billion (0.8¢/kWh-geothermal). These benefits derive, in large measure, from a reduction in premature mortality from sulfate particles from SO_2 emissions—achieving the TI scenario reduces premature mortalities by 2,200–5,100 based on methods developed at the U.S. Environmental Protection Agency (EPA). Outside of the electric sector, the expansion of the GHP industry under the Breakthrough scenario reduces cumulative building heating emissions of SO_2, NO_x, and $PM_{2.5}$ by an additional 232,000, 711,000, and 57,000 t, respectively, providing $28 billion–$61 billion of value based on avoiding up to 8,700 premature mortalities.

Greenhouse Gas Reductions

In the *GeoVision*, geothermal electricity production and direct use both provide significant reductions to national GHG emissions. Geothermal electricity production in the TI scenario, particularly from EGS systems, offsets higher emitting generation sources, saving a cumulative total of 516 million metric tons of carbon dioxide equivalent (MMT CO_2e) from 2015 to 2050, on a life cycle basis and relative to a BAU scenario. This represents 0.7% of total cumulative GHG emissions from total U.S. electricity production during this time period. By the end of the study period, the GHG emissions avoided annually are roughly equal to the annual emissions of 6 million cars. Outside of the electric sector, GHP installations in the Breakthrough scenario offset a cumulative total of 1,281 MMT CO_2e, representing an 8.3% reduction to on-site emissions from buildings relative to a scenario that holds GHP installations constant at 2012 deployment levels. By the end of the study period, 90 MMT CO_2e, of annual emissions are avoided from GHP deployment, equivalent to removing almost 20 million cars from the road.

Limitations

It is important to note that the impacts described earlier are sensitive to the particular deployment scenarios envisioned within this study. Also, the impacts are sensitive to the location of geothermal deployment and the set of assumptions about the overall electricity and building air-conditioning and heating sectors. The set of benefits quantified here is by no means comprehensive, although it represents some of the major potential benefits that could be realized from geothermal power development. Some potential benefits not included in this analysis are water quality, land-use, and wildlife impacts.

Although not addressed here, decision-makers will naturally wish to compare the benefits reported here to any potential costs or risks introduced by adding high levels of geothermal power and GHP to their regions. Although the present work might inform policy decisions, it does not intend to suggest any specific type of policy. The costs and benefits of increased geothermal power and GHP deployment will be affected by the policy and market mechanisms used to influence that development; therefore, this analysis quantifies the general magnitude of gross employment, environmental, and health benefits only. Moreover, although the analysis presented in this report suggests a significant possible role for geothermal energy in delivering the described benefits, previous research shows that achieving those benefits in the most cost-effective way might be best supported by a policy framework that directly addresses key market failures and unpriced externalities rather than solely using technology- or sector-specific incentives.

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1 Introduction

The *GeoVision* describes a future in which technological improvements, reduced costs, decreased regulatory burdens, and other factors lead to a dramatic increase of geothermal resources for electricity generation and for directly heating and cooling buildings. If the *GeoVision* is achieved it will benefit various stakeholders within the geothermal electricity and heating and cooling sectors. However, this is an important question to investigate: Beyond direct impacts to the geothermal industry, will achieving the *GeoVision* provide substantial benefits to the country? In this report, we attempt to evaluate that question by quantifying a set of impacts of achieving the *GeoVision*. In the *GeoVision*, the expanded use of geothermal power leads to the development of a new industrial ecosystem, a cleaner electricity system, and reduced in-building fuel combustion. Thus, we estimate the gross job creation, water usage benefits, air quality and public health benefits, and greenhouse gas (GHG) emission benefits created by realization of the *GeoVision*. This set of benefits covers many, but not all, of the important impacts created by this *GeoVision*.

Within this report, we estimate benefits from geothermal electricity generation separately from those of the GHP sector. In each case, we find the benefits of achieving a certain level of deployment over a baseline scenario. For example, we report reduced electric sector air pollution emissions from an improved deployment scenario, and we calculate those reductions by subtracting the emissions found under the baseline scenario from those under the improved deployment scenario. In other words, we only count as benefits the changes that occur beyond the relevant baseline scenario. These benefits can be thought of as a consequence of achieving the *GeoVision*, and thus give a partial estimate of the value of achieving the *GeoVision*.

For the electric sector, we compare two different improved deployment scenarios to a Business-as-Usual (BAU) scenario. Under the BAU scenario, there is relatively low growth in geothermal electricity generation out to 2050. The two improved deployment scenarios are the Improved Regulatory Timeline (IRT) scenario and the Technology Improvement (TI) scenario. These scenarios have progressively more favorable conditions for geothermal deployment, so the TI scenario, for example, includes the assumptions of the IRT scenario along with the improved technology assumptions. Above, the terminology of “achieving the *GeoVision*” was used, and that means specifically achieving the TI scenario within the electric sector. Table 1 contains brief descriptions of the various scenarios; additional details can be found in Augustine et al. (2019).

For the GHP sector, we compare three deployment scenarios to a baseline scenario in which GHP installations are held constant at 2012 deployment levels. The benefits calculated in this case can be thought of as the benefits of all future growth in GHP deployment under each deployment scenario. The three GHP deployment scenarios are the Navigant Low scenario, the NREL Optimistic scenario, and the Breakthrough scenario. Compared with the NREL Optimistic scenario, the Navigant Low scenario has a lower assumed customer adoption rate of GHP technologies. The Breakthrough scenario includes the higher customer adoption rate and also technology improvements that reduce overall system cost. In the case of the GHP sector, achieving the Breakthrough scenario is what is meant by “achieving the *GeoVision*.”

The primary modeling tools used in this analysis are the Regional Energy Deployment System (ReEDS [Short et al. 2011]) model for the electric sector and the Distributed Geothermal Market

Demand Model (dGeo) for the GHP sector. Further details about the scenarios and the modeling tools used to develop the scenarios can be found in Gleason et al. (2017), Sigrin et al. (2016), Eurek et al. (2016), McCabe et al. (2019), Liu et al. (2019), Young et al. (2019), Augustine et al. (2019), and Doughty et al. (2018). The rest of this report is structured by benefit category (i.e., jobs, water, air pollution, GHG), with each section including introductory and methodological materials along with results. A final section includes an overview of a set of brief case studies of the impacts of geothermal direct-use district heating applications. Please also see the supplements for additional details related to both methodology and results.

Table 1. Scenario Matrix

A brief description is provided here; for details, see Augustine et al. (2019) and Liu et al. (2019).

	Abbreviation	Main Characteristics
Electric sector		
Business-as-Usual	BAU	Low level of expanded hydrothermal resources over time
Improved Regulatory Timeline	IRT	Some increased deployment of hydrothermal resources relative to BAU through regulatory reforms
Technology Improvement	TI	Includes all the assumptions of IRT but adds technology improvements such that significant deployment of enhanced geothermal system occurs
GHP Sector		
Baseline 2012 deployment	—	For comparison purposes, includes all GHP deployment up through 2012
Navigant Low	—	dGeo deployment forecast based on Navigant adoption rates*
NREL Optimistic	—	dGeo deployment forecast based on NREL adoption rates* (similar to historical adoption rate of photovoltaics and higher than the Navigant rate)
Breakthrough	—	Includes technology cost reductions and the NREL Optimistic adoption rates (This scenario has the largest amount GHP deployment.)

* Adoption rate is related to the rate at which consumers adopt dGeo given a certain payback period; see Gleason et al. (2017).

2 Workforce and Economic Development Impacts

Summary

Achieving the TI scenario leads to the development of a robust geothermal power industry, focused on development of enhanced geothermal system (EGS) opportunities. This industry, combined with traditional hydrothermal power development, supports peak employment of 262,000 "gross" full-time jobs in 2048, which represents the increased employment level needed to move from deployment levels in the BAU scenario to the TI scenario. This level of employment would be roughly 45 times larger than current employment within the geothermal power sector. Operation and maintenance (O&M) jobs to support this industry peak at 6,000 in 2050. Total investment in this sector will reach $220 billion cumulatively by 2050. Outside of the electric sector, the expansion of the GHP industry under the Breakthrough scenario would support an additional 36,660 "gross" jobs at the peak year of GHP activity in 2044. Under the Breakthrough scenario, growth in the GHP industry will rely on $112 billion of investment cumulatively through 2050. Together, growth within the geothermal electric power sector and GHP sector present the opportunity to develop two new industries that are geographically complementary to each other and create jobs across the country, but with most job impacts occurring in the Western or mid-Atlantic regions of the United States.

2.1 Introduction

To achieve the *GeoVision*, the geothermal workforce needs to expand to construct and operate new power plants. Drillers, geoscientists, and drilling services contractors will be needed to explore for and exploit new geothermal resources. Mechanical and electrical construction contractors will be needed to install power plant components. Geothermal supply chain manufacturers will be needed to manufacture turbines and other power plant equipment. Heating, ventilating, and air conditioning contractors and construction contractors will be needed to install heat exchanger loops and heat pumps for GHP deployment. Local O&M contractors will be needed to reliably and safely operate these units. This workforce, in turn, will support additional jobs in communities through purchases at restaurants, grocery stores, retail outlets, and so on. Increased employment creates opportunities for local economic development, as do other local impacts associated with geothermal-related manufacturing and deployment, such as property taxes and land lease payments. Several past studies have looked at economic impacts of geothermal plants in the United States, e.g., the U.S. Department of Energy (DOE) (DOE 2004; Peterson at al. 2005; Jennejohn 2010; Battocletti and Glassley 2013; and Matek and Gawell 2014).

This section looks at employment impacts for achieving the *GeoVision* scenarios. Analysis of employment impacts can help identify economic development opportunities and help governments, businesses, and communities identify opportunity spaces for geothermal deployment. Although future impacts are uncertain based on many economic, technical, political, and international variables, our modeling efforts estimate economic impacts from increased geothermal employment based on current knowledge and assumptions.

This section will look at "gross" job impacts from geothermal deployment compared with current BAU scenarios. These gross job impacts represent total employment needed to fulfill increased deployment numbers, but do not represent the impact of this employment on other workforces. As geothermal competes with other generation resources (coal, natural gas, wind, solar, and so on), increased geothermal generation will displace other generation sources and impact employment levels within other generation technology sectors. As geothermal deployment increases, the geothermal power sector may also impact the oil and gas sector through collaboration and competition related to drilling expertise and equipment. For example, geothermal may provide jobs for oil and gas workers during decreased oil price periods when rig utilization rates and employment are lower, and vice versa. However, assessing the impacts of geothermal deployment on employment levels within other energy generation technology sectors (or other sectors of the economy) is beyond the scope of our modeling.

2.2 Methods

2.2.1 Input-Output Modeling

Impact estimates of geothermal capacity expansion and operation come from two input-output (I-O) models: the Geothermal Jobs and Economic Development Impact (JEDI) model and the Economic Impact Analysis for Planning (IMPLAN) model. Both use the same underlying economic data provided by IMPLAN. JEDI is customized to estimate electricity capacity expansion and operation while IMPLAN is generalized and used to estimate impacts from GHP and direct-use development.

JEDI splits results into two phases: construction and O&M. The construction phase is for the equivalent of 1 year and is inherently temporary. For example, a construction project that supports 600 jobs would support 300 jobs annually, on average, if the project took 2 years. If the same project took 3 years it would support an annual average of 200 jobs. JEDI assumes that jobs are created in the year of expenditure and do not consider project cycle lifetimes. The O&M phase is ongoing. This is assumed to be constant through the life of a project. If 200 O&M jobs were supported in 2030, for example, and a project had an expected life of 30 years, then the same 200 jobs would be expected to be supported in 2050.

JEDI reports job estimates in three categories: on-site, supply chain, and induced. On-site estimates are the most direct impacts of a particular project. During construction, on-site jobs include the workers who are actively involved in designing and building a project, such as rig workers and engineers. Jobs related to project supply chains include people employed in companies that supply raw materials, or professional service providers such as accountants, lawyers, contracted designers, and manufacturers. Induced employment is supported by the expenditures of on-site and supply chain workers. If an on-site worker, for example, spent money earned from geothermal activity at a grocery store, then the additional employment required at that grocer would be considered induced employment.

IMPLAN divides employment impacts into direct, indirect, and induced categories. Direct impacts arise in industries directly affected by project expenditures. In this case, if a developer spends money on manufactured products such as pipelines, these manufacturing impacts would be considered direct. This is not the case with JEDI, which would move these to supply chain. Thus, within IMPLAN, direct impacts are a result of project expenditures themselves, not the number of workers who are physically located at a project site. Indirect impacts are based on expenditures that support direct impacts. The IMPLAN definition is somewhat narrower than the

JEDI supply chain definition in that JEDI moves impacts such as manufacturing to supply chain. Induced impacts are the same in both models.

IMPLAN results are not split out into construction and O&M. In general, results are reported as job years. A job year is the equivalent of one full-time equivalent (FTE) job for 1 year. A person who works for 40 years works 40 FTE job years.

2.2.2 Additional Methodological Notes and Possible Related Limitations

The JEDI model uses the IMPLAN I-O model to calculate economic impacts. Although such models are well-established in economics and the economics literature (Miller and Blair 2009), these models only calculate the total or gross employment requirements needed for given expenditures. This means that these impacts do not consider displaced economic activity from the given geothermal deployment, such as alternative energy investments (coal, natural gas, wind, and so on). I-O modeling also does not account for current and future workforce projections. Further, results do not consider structural changes in the economy in the future. Structural changes in the economy could be driven by changes in prices, taxes, or the preferences of consumers and producers.

I-O models such as JEDI assume that businesses within an economy produce using the same ratios of inputs to their output (revenue) in every time period, starting in 2014 and continuing to 2050. These do not assume technological changes or productivity growth that could lead to companies substituting one input for another or consumers choosing different goods on the basis of prices or changing preferences.

Finally, I-O models assume that all inputs will be available in any quantity, regardless of feasibility. However, the deployment scenarios within ReEDS do not incorporate these limitations. Similarly, JEDI estimates do not assume project feasibility or profitability. Also, economic impacts caused by changes in electricity prices because of increased geothermal deployment are not included within our modeling efforts.

2.3 Results

2.3.1 Electric Sector Employment Impacts

Increased employment opportunities are presented here as the increase in jobs found within each deployment scenario compared with the BAU scenario. Achieving the TI scenario leads to large increases in employment opportunities within the geothermal power sector. In contrast, employment impacts under the IRT scenario are much smaller in the later analysis years (see Figure 1).[2] Peak employment impacts in the TI scenario occur in 2048 with 262,000 gross on-site, supply chain, induced, and O&M jobs needed to support the build-out in ReEDS. As of 2017, geothermal jobs were around 6,000 (DOE 2017); thus, the industry will need to grow roughly 45 times over to meet these employment needs. Roughly $220 billion will need to be invested from 2015 to 2050 to support this geothermal deployment and the associated job growth in the TI scenario. Breakout of jobs by on-site, supply chain, induced, and O&M jobs is shown in

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[2] JEDI result data tables are located in Supplement A.

Figure 2 for the TI scenario compared with BAU. O&M jobs provide continual employment and peak at 6,000 in 2050.

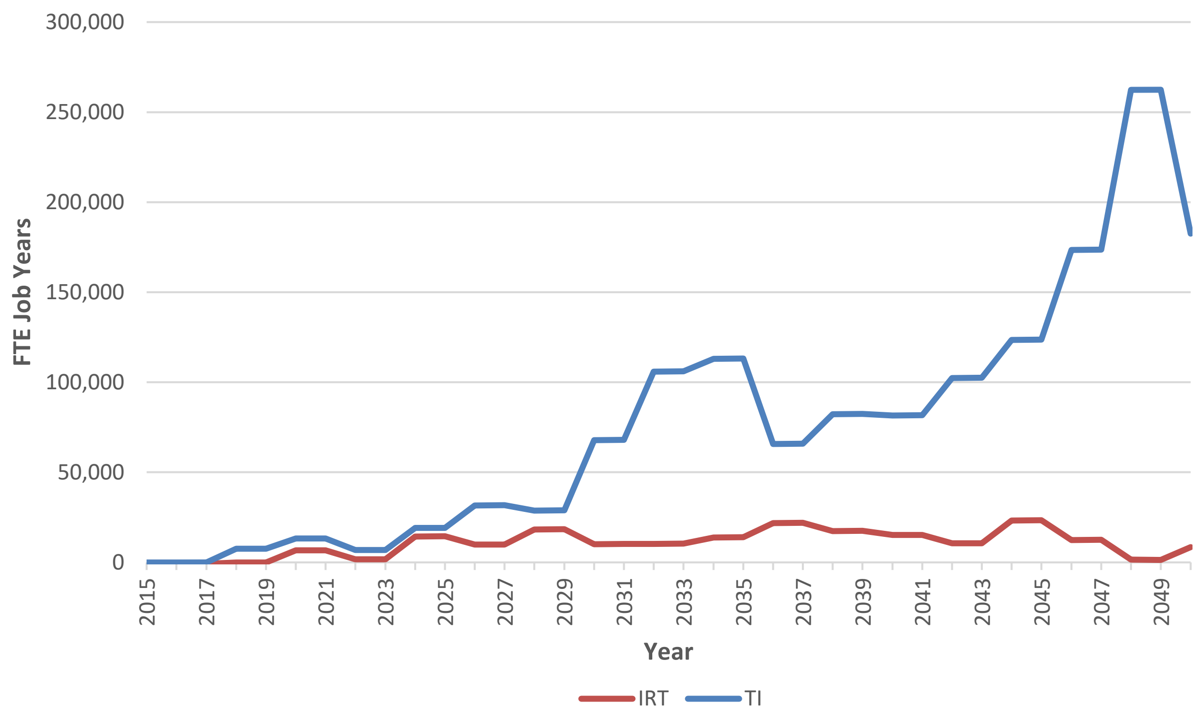


Figure 1. Electric sector annual employment impacts by scenario compared with the BAU scenario (from 2015 to 2050)

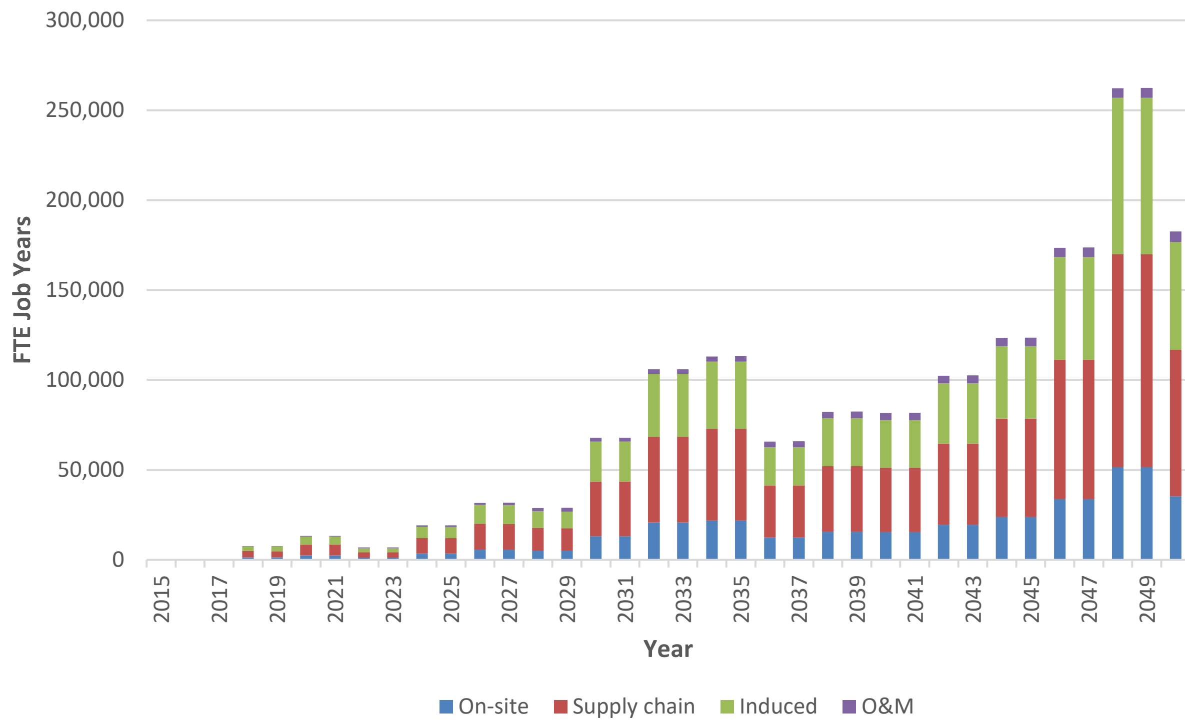
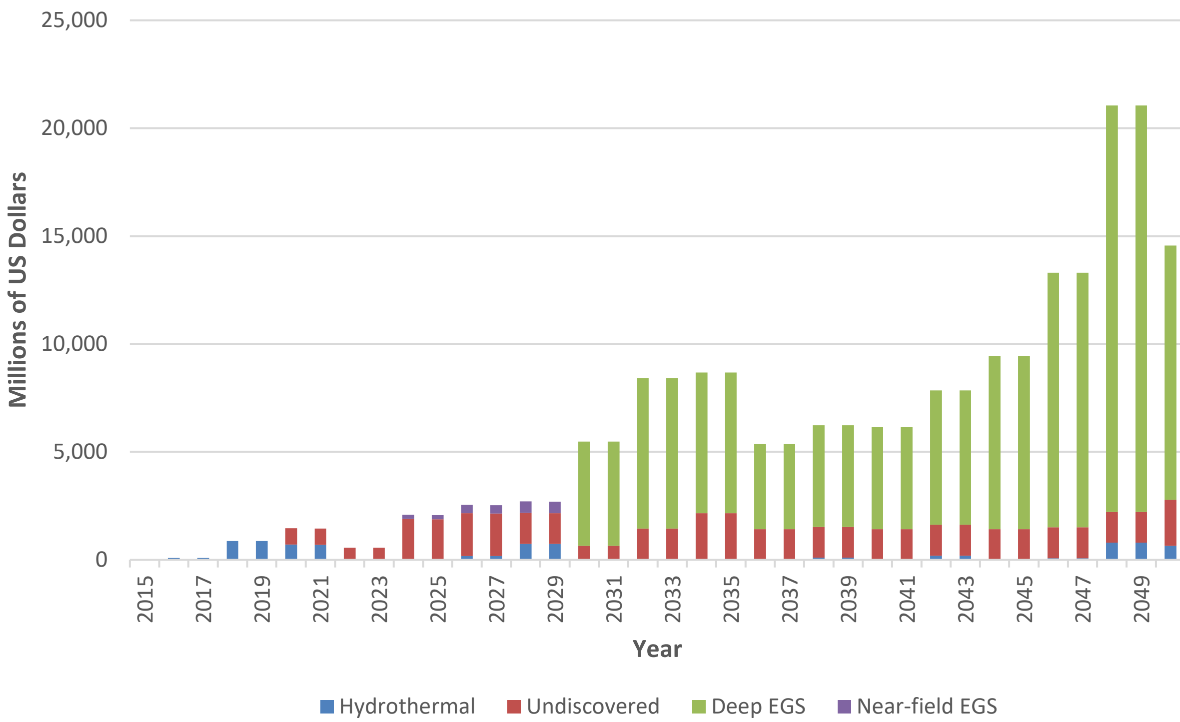


Figure 2. Annual on-site, supply chain, induced, and O&M jobs for the TI scenario compared with the BAU scenario (from 2015 to 2050)

The employment peak in 2048 is dependent on technology breakthroughs and cost reductions for EGS technologies according to modeling. In the TI scenario, most of the job creation comes from deep EGS power plants, which are deployed starting in 2030. Figure 3 shows the total expenditures by technology type. As employment is directly related to expenditures, this graph represents a proxy for the jobs created by technology type. The relatively low FTE seen in years 2038–2041 is tied to the expansion rate of EGS deployment. EGS deployment increased in years 2030–2050, but EGS deployment increased at a slower rate in years 2036–2042 than surrounding years, leading to relatively smaller employment gains in years 2038–2041.

Electric sector deployment is mainly limited to the western United States, but there is some deployment in the Appalachians (mainly in West Virginia) and southern U.S. region. Cumulative expenditures from 2015 to 2050 by state are shown in Table 2.



Note: These are absolute expenditures; they are not relative to the BAU scenario.

Figure 3. Expenditures by technology type (from 2015 to 2050), TI scenario

Table 2. Cumulative Expenditures by State in Millions of Dollars from 2015 to 2050

State	Cumulative Expenditures (millions of dollars)	State	Cumulative Expenditures (millions of dollars)
California	$79,851	Colorado	$3,008
West Virginia	$27,030	Montana	$976
Oregon	$26,495	Texas	$222
Idaho	$21,838	Wyoming	$208
Nevada	$17,310	Pennsylvania	$110
Utah	$14,914	Virginia	$51
Arizona	$13,754	Mississippi	$30
New Mexico	$13,339	Louisiana	$17
		Total	$219,152

Note: These are absolute expenditures; they are not relative to the BAU scenario.

2.3.2 Geothermal Heat Pump Sector Employment Impacts

Figure 4 shows the employment levels needed to support the three GHP deployment scenarios. The highest employment needed occurs in the Breakthrough scenario, which includes optimistic adoption rates from the NREL Optimistic scenario and cost reductions. The gross direct, indirect, induced, and O&M[3] jobs for the Breakthrough scenario are shown in Figure 5. Peak employment occurs in 2044 with 36,660 jobs needed to build out deployment based on roughly $112 billion in cumulative investment through 2050.

All deployment and cost numbers come directly from dGeo. The breakout of costs by economic sector can be found in Supplement A. Note that O&M jobs are estimated from the percentage of total expenditures as IMPLAN does not break out these specific jobs, as in JEDI.

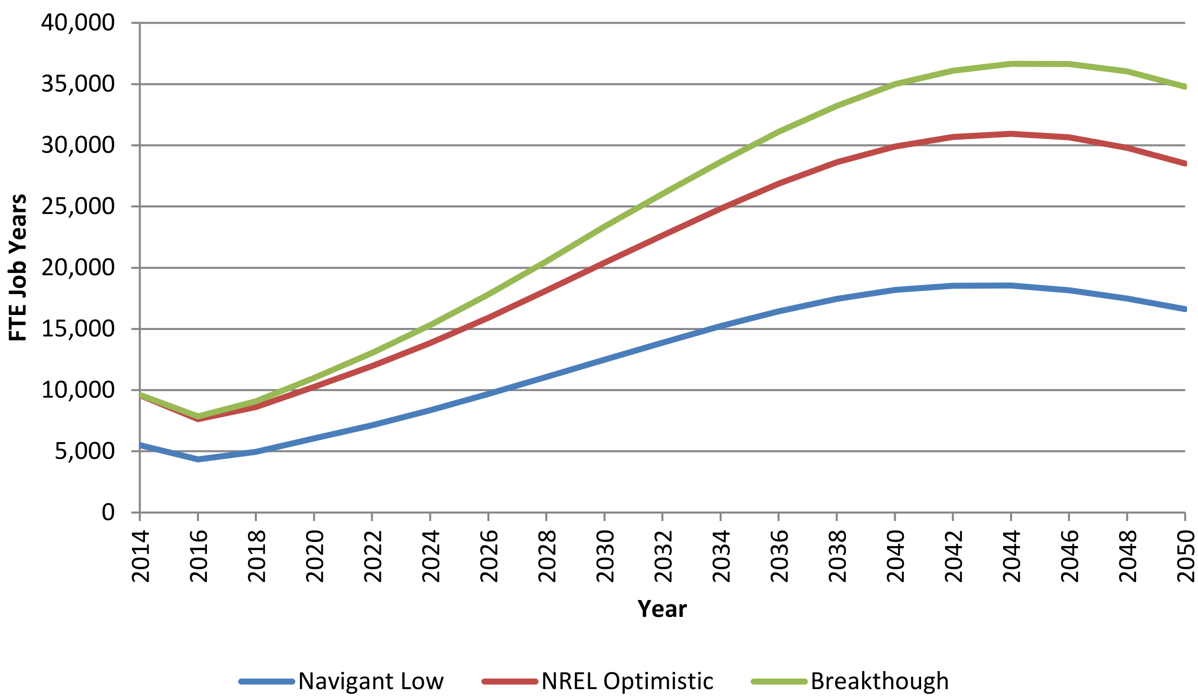


Figure 4. Total GHP annual employment impacts by scenario

[3] Note that JEDI and IMPLAN each categorize job families differently even though the same economic multipliers are used. The ratio of direct to nondirect jobs will be different because of this categorization, but the total employment created will be similar.

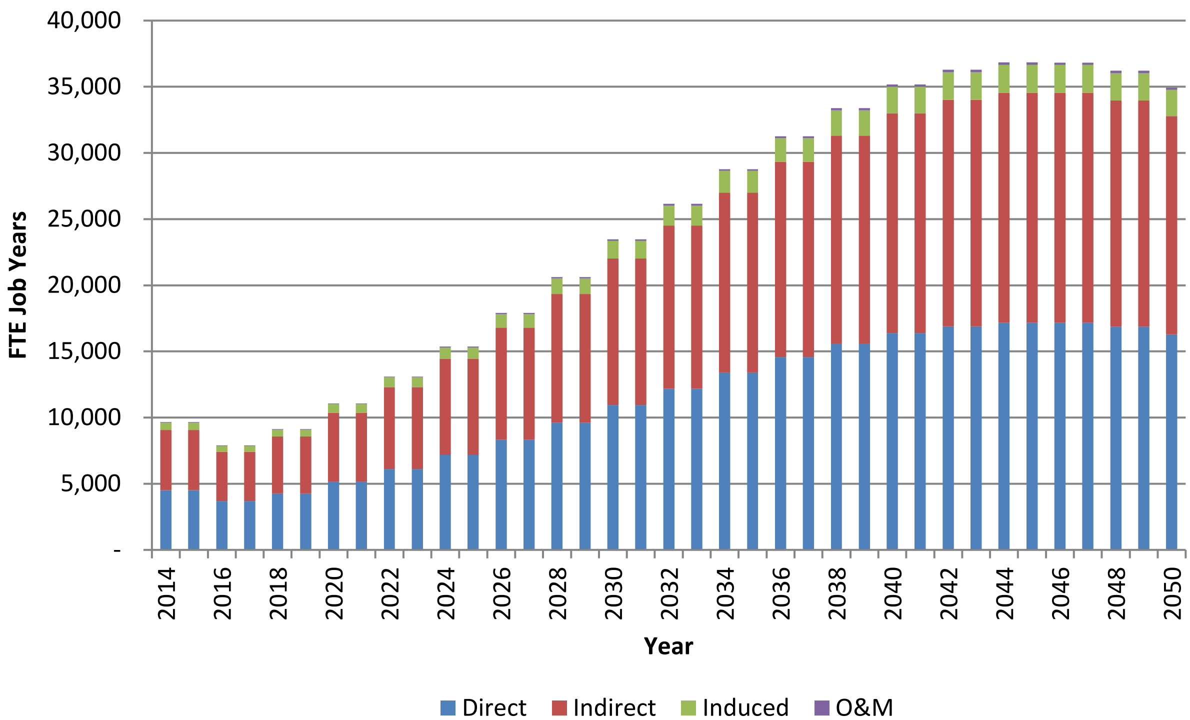


Figure 5. GHP annual employment for the Breakthrough scenario (2014–2050)

Figure 6 shows the geographic distributions of spending in the years 2030 and 2050. Most of the expenditures in 2030 are in Texas and the mid-Atlantic region. This is geographically complementary to electric sector deployment, which occurs mainly in the Western United States. Combined electric sector and GHP economic impacts will be more geographically diverse, when compared with each sector.

GHP expenditures grow from $2.9 billion in 2030 to $4.3 billion in 2050, with peak expenditures coinciding with peak employment in 2043. Changes in expenditures mainly occur in six states from 2030 to 2050; 43% of changes occur in New Jersey, New York, California, Massachusetts, Michigan, and North Carolina (ranked in order of highest to lowest change).

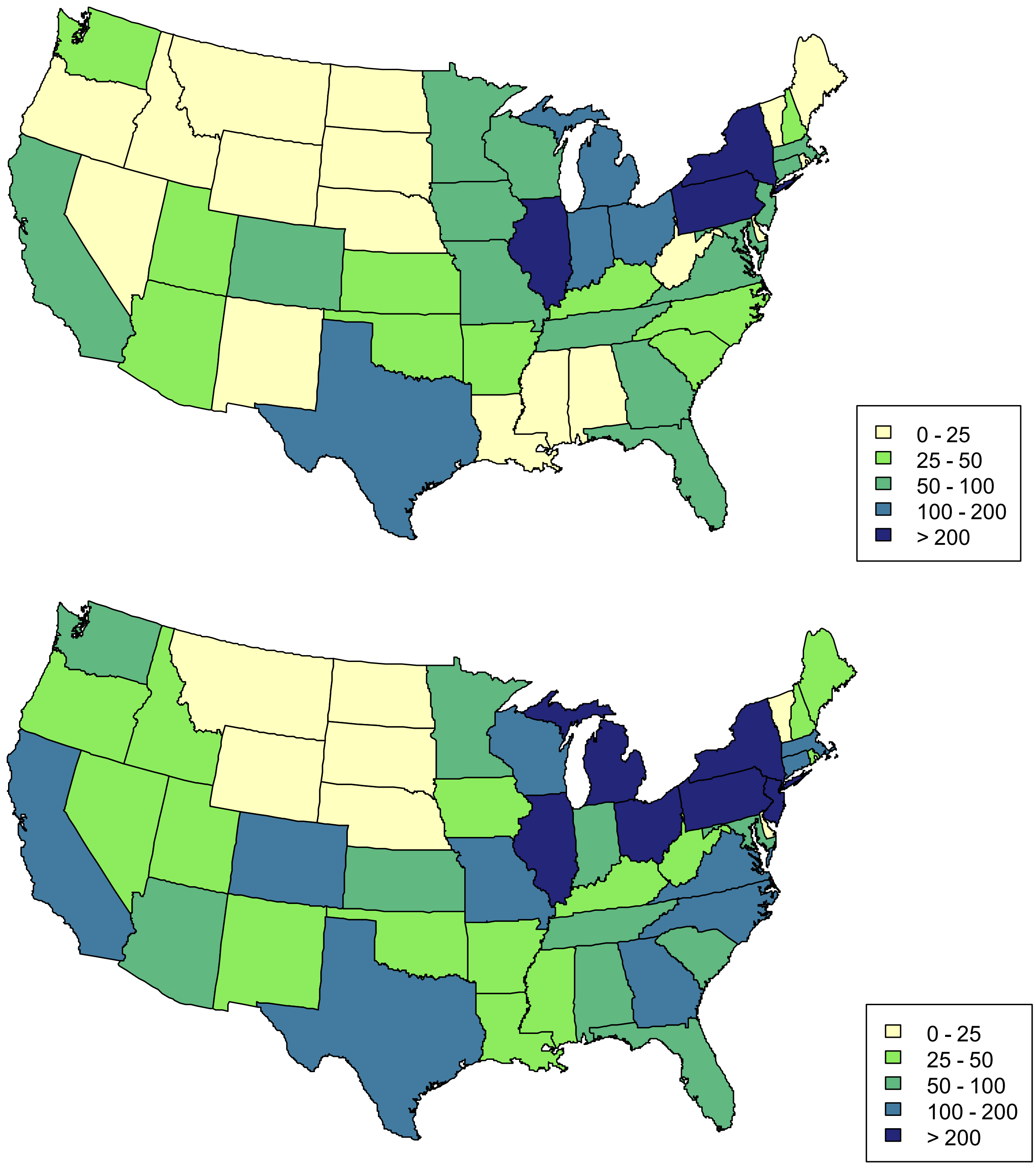


Figure 6. GHP expenditures in 2030 (top) and 2050 (bottom) by state, in millions of dollars

2.3.2.1 Local Operation and Maintenance Benefits

Many of the main employment impacts from the electric sector and GHP come from on-site construction jobs and supply chain manufacturing jobs. Most of these jobs will last over the lifetime of construction (1–3 years) and will be short-term in nature. Young et al. (2019) compares short-term and long-term job impacts for geothermal, wind, solar, and natural gas power plants. On a generation basis, geothermal creates the second most short-term construction jobs, with solar creating the most, as shown in the figure below. However, when looking at long-term O&M jobs, geothermal creates the most employment. These O&M jobs are mainly filled by local workers, and most of the wages are spent locally within the community.

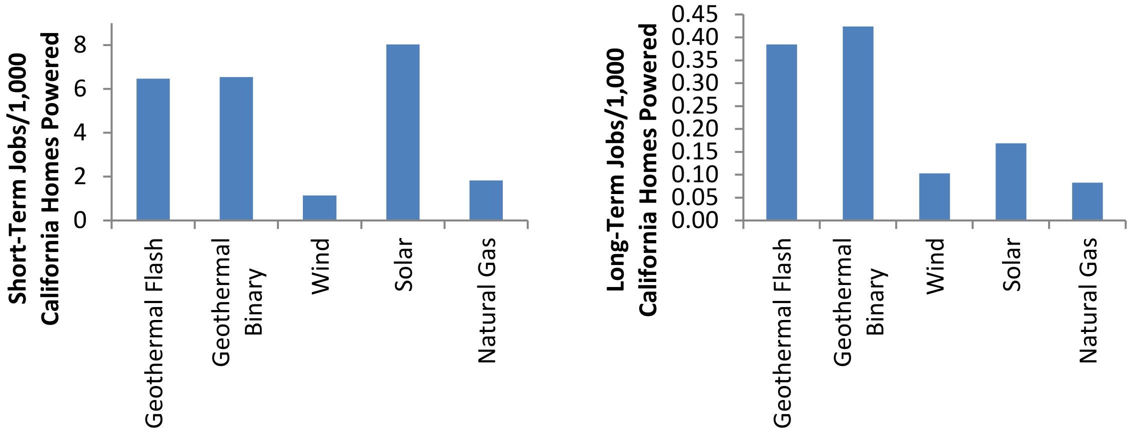


Figure 7. Short-term (left) and long-term (right) job creation comparison for geothermal, solar, wind, and natural gas generation technologies by generation

2.4 Concluding Remarks

Achieving the *GeoVision* will result in increased employment, wages, and economic output within the geothermal electricity and GHP sectors. On-site construction jobs will be created in local areas around deployment, but supply chain and induced jobs will be created on a national scale. Combining geographic trends of geothermal development in the electric and GHP sectors shows benefits in many states across the United States, but particularly in the Western and mid-Atlantic regions of the country. To achieve the vision, employment within the geothermal electric sector combined with the GHP industry (roughly 300,000 combined jobs in 2048) will need to grow to be roughly equal to or greater than the current number of people employed within the oil and gas extraction industry (BLS 2017).

3 Water Use Impacts

Summary

Achieving the *GeoVision* TI scenario slightly reduces systemwide power-sector water withdrawals by 23 billion gallons per year in 2050 (a reduction of 0.3%), relative to BAU. Despite lower quantities of water being withdrawn, systemwide water consumption under the TI scenario is increased by approximately 40 billion gal per year in 2050 (an increase of 4%), relative to BAU. Thus, the significant growth described in the *GeoVision* does not create significant additional demands on freshwater from within the power sector on a national scale. Importantly, geothermal technologies can make use of nonfreshwater resources such as municipal wastewater and brackish groundwater, as water is not needed for cooling but rather to maintain reservoir pressure. A scenario was developed to test the potential for geothermal growth under a situation where geothermal power was limited to locations at which it could cost-effectively rely solely on nonfreshwater resources. Under this scenario, geothermal deployment is reduced by 11% (6.5 gigawatts [GW]) relative to the TI scenario, meaning the availability of freshwater sources does not significantly limit the potential for geothermal growth if the cost, technical, and regulatory targets of the TI scenario are met. These results assume EGS technologies are all dry-cooled binary systems. If EGS technologies are assumed to be wet-cooled flash systems, however, power-sector withdrawals and consumption would increase by 11% and 71%, respectively, compared with the TI scenario, and geothermal deployment would be reduced by 6% (3.5 GW).

3.1 Introduction

The electric power sector (here referring to all generation types, not only geothermal) relies on readily available supplies of water for reliable operations. Most water requirements are for thermal plant cooling, but all life cycle stages of energy production require water. Although energy supply can also affect water resources through changes in water quality and temperature, water use is typically categorized into two metrics: withdrawal and consumption. Withdrawals are defined as the amount of water removed or diverted from a water source for use, while consumption is the amount of water evaporated, transpired, and incorporated into products or crops or otherwise removed from the immediate water environment (Kenny et al. 2009). The U.S. power sector is the largest withdrawer of water in the nation, at 38% of total withdrawals (Maupin et al. 2014). Its share of consumption is much lower, around 3% nationally, but can be regionally important (Solley et al. 1998). Water availability can impact the electric sector in multiple ways, including influencing new capacity decisions (Averyt et al. 2011; Macknick et al. 2015) and power plant operations and reliability (DOE 2013; Rogers et al. 2013; McCall et al. 2016; Macknick et al. 2016). In turn, the power sector affects water avalability and quality for other competing uses. Moreover, future uncertainties around water availability and temperature, including those associated with climate change, may exacerbate vulnerabilities and water-related costs in the power sector (Cohen et al. 2014; DOE 2013; Melillo et al. 2014).

Prior studies have evaluated the impact of a range of U.S. electric sector futures on water demands (see Arent et al. 2014; Chandel et al. 2011; Clemmer et al. 2013; DOE 2015; Macknick and Sattler et al. 2012; Roy et al. 2012; Tidwell et al. 2013; van Vliet et al. 2012). Many renewable energy technologies have low operational (see 3.2 Methods) and life cycle (see Macknick, Newmark et al. 2012; Meldrum et al. 2013) water use compared with fossil and nuclear technologies. As a result, prior work generally finds that future scenarios designed to meet carbon-reduction goals also result in water savings, particularly when renewable-based pathways are envisioned (Clemmer et al. 2013; Macknick and Sattler et al. 2012).

Geothermal technologies can have multiple configurations and cooling systems that are dependent upon reservoir characteristics, but many configurations have lower water requirements than conventional thermal generation, such as coal, nuclear, and natural gas technologies. Given the expected deployment of low-water geothermal technologies, achieving the *GeoVision* could reduce power-sector water use in many regions. Some states have already proposed measures to reduce the water intensity of the electricity produced in their states, and the U.S. Environmental Protection Agency (EPA) has invoked the Clean Water Act to propose various measures to limit the impacts of thermal power plant cooling on aquatic habitats (EPA 2011). To the extent that geothermal deployment can reduce power-sector water demands, it might also reduce the cost of meeting future policies intended to manage water use. In this section, we calculate the water withdrawal and consumption impacts of achieving the *GeoVision*, both nationally and regionally, and discuss the possible benefits of the resulting reduced water demands.

3.2 Methods

This section presents the approach used to determine potential operational water withdrawal and consumption impacts associated with achieving the *GeoVision*. In the following Results sections, systemwide water impacts are quantified by taking the difference between a deployment scenario (e.g., the TI scenario) and the BAU scenario. Results are presented on a national and state basis—regional impacts are essential because water resources are managed locally, and water is not easily transferred across basins.

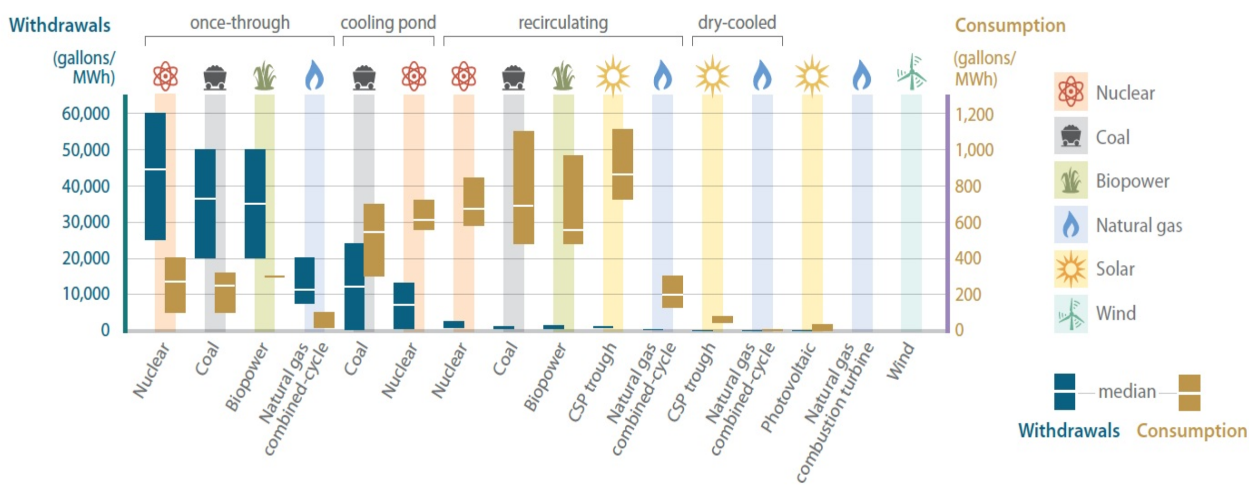
ReEDS was used to compute power-sector water withdrawal and consumption in the *GeoVision* TI and BAU scenarios. ReEDS incorporates the cost, performance, and water-use characteristics of different generation technology and cooling-system combinations and considers water availability as a limiting condition for any new power plant construction (Macknick et al. 2015; Schroeder et al. 2014). Cooling systems for thermal power plants implemented in ReEDS fall into four categories: once through, pond, recirculating, and dry cooling.[4]

Consistent with prior studies and proposed EPA regulations, our analysis does not allow new power plants in ReEDS to employ once-through cooling technologies (Macknick and Sattler et al. 2012; Tidwell et al. 2013). The basic approach used here has been applied in multiple studies evaluating the national and regional water impacts of the U.S. electric sector (see Clemmer et al. 2013; DOE 2015; Macknick and Sattler et al. 2012; Macknick et al. 2015; and Rogers et al. 2013).

Our analysis focuses exclusively on operational water-use requirements. These requirements can vary greatly depending on fuel type, power plant type, and cooling system, and many renewable

[4] Cooling systems for the existing fleet are assigned to ReEDS balancing-area generating capacity based on an analysis of individual electric-generating units aggregated at the ReEDS balancing-authority level, as described elsewhere [Averyt et al. (2013); UCS (2012)].

energy technologies have relatively low operational water withdrawal and consumption intensities (Averyt et al. 2011; see Figure 8). We focus on operational water requirements for power generators, as these operational requirements are orders of magnitude greater than upstream water requirements (e.g., fuel production and manufacturing) for all energy technologies. Exceptions are photovoltaics and wind, which have minimal or zero operational water requirements (Meldrum et al. 2013). Thermal power plants—including coal, natural gas, and nuclear—using once-through cooling withdraw far more water for every megawatt-hour of electricity generated than do plants using recirculating cooling systems. For water consumption, however, once-through cooling has lower demands than recirculating systems. Dry cooling can be used to reduce both water withdrawal and consumption for thermal plants, including geothermal technologies, but can have varying cost and efficiency penalties (EPA 2009).

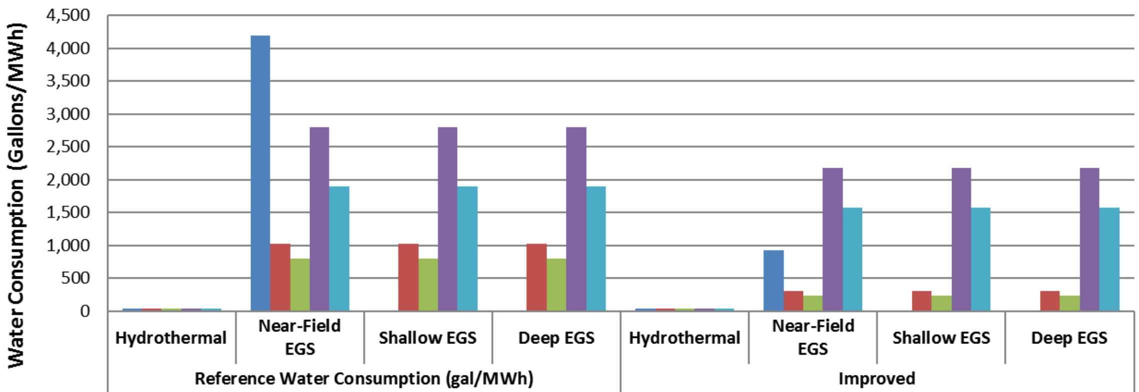


Note: CSP = concentrating solar power

Figure 8. Operational water withdrawal and consumption requirements by generation technology and cooling system

Source: Averyt et al. (2011)

Geothermal technologies' use of water is highly dependent upon technology configuration, the cooling system, and reservoir temperature (see Figure 9). Hydrothermal resources can be transformed via binary or flash configurations that can be air-cooled or that can use reservoir fluids for cooling, do not require water for reservoir stimulation, have minimal or zero subsurface reservoir losses, and only require operational water for noncooling process and hotel needs (Schroeder et al. 2014). Hydrothermal exploitation can have lower water requirements than traditional thermal power generation sources. EGS resources, however, require operational water for a variety of processes. EGS power generation projects require continuous injection of fluids to maintain volume and pressure as belowground reservoir losses are estimated to range from 1% to 10% (Schroeder et al. 2014). EGS flash systems also generally require a recirculating cooling system, which can substantially increase water requirements. As reservoir temperatures increase, smaller total flow rates are needed to generate the same amount of energy, which leads to lower belowground fluid loss and lower water requirements for cooling. For the purposes of this study, all EGS technologies were assumed to be operated in a binary, air-cooled configuration, resulting in water withdrawal and consumption rates that are comparable to natural gas combined-cycle technologies utilizing recirculating cooling systems.



	Reference Water Consumption (gal/MWh)				Improved			
	Hydrothermal	Near-Field EGS	Shallow EGS	Deep EGS	Hydrothermal	Near-Field EGS	Shallow EGS	Deep EGS
Binary < 125 C	41	4,200			41	920		
Binary 125-160 C	41	1,020	1,020	1,020	41	300	300	300
Binary 160-190 C	41	800	800	800	41	230	230	230
Flash 190-300C	41	2,800	2,800	2,800	41	2,180	2,180	2,180
Flash 300+ C	41	1,900	1,900	1,900	41	1,570	1,570	1,570

Note: MWh = megawatt hour

Figure 9. Operational water withdrawal and consumption requirements for geothermal technologies

Source: Schroeder et al. 2014

Although the core *GeoVision* scenarios assume all new EGS capacity in a dry-cooled binary configuration, we performed a sensitivity analysis to assess variations in water use and geothermal deployment resulting from EGS in a wet-cooled flash configuration. In this sensitivity analysis, new EGS capacity is built with water requirements approximately 10 times the rate of dry-cooled binary systems.

To capture the ability of geothermal technologies to utilize alternative nonfreshwater resources, such as municipal wastewater and brackish water, we performed a sensitivity analysis where new geothermal technology capacity was not allowed to use freshwater resources. We considered the resulting changes in water use and geothermal deployment that result from these restrictions.

3.2.1 Additional Methodological Notes and Possible Related Limitations

This analysis does not estimate full life cycle water uses, including upstream processes such as construction, manufacturing, and fuel supply. Including these requirements could have a minor impact on water usage results from the *GeoVision*, but associating upstream water uses to regions is challenging. Moreover, prior work has demonstrated that thermoelectric water withdrawals and consumption during plant operations are orders of magnitude greater than the demands from other life cycle stages (Meldrum et al. 2013).

Power-sector water use will be affected by various possible changes in the electric sector, such as coal-plant retirements, new combined-cycle natural gas plant construction, and the increased use of dry cooling. These changes, in turn, may be driven in part by future uncertain water policies, and they could affect the estimated water savings under the *GeoVision*. Additionally, although water resource impacts are described regionally at the state level, there can be considerable variation in water resource availability and impacts within a given state. Evaluating water impacts on a smaller watershed level could partially address this limitation.

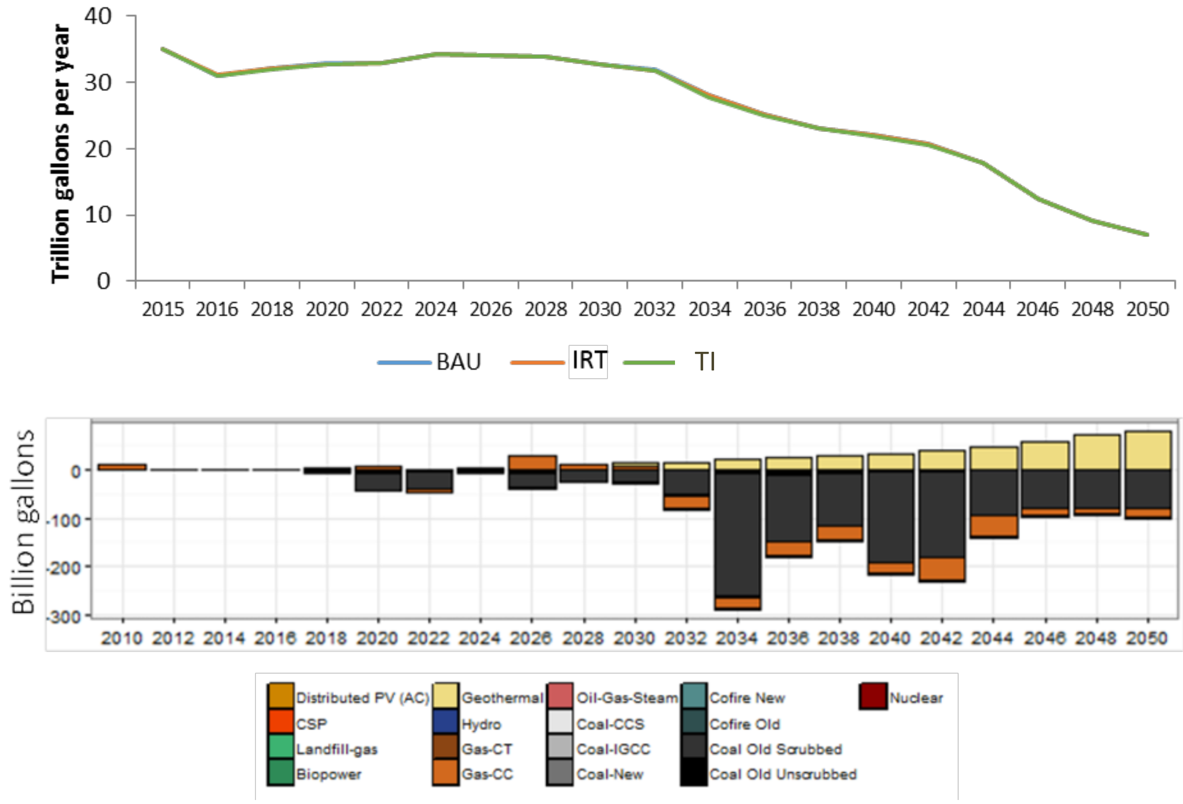
Finally, the benefits of water-use reductions are not quantified in monetary terms owing to challenges associated with quantifying the value of water resource services (DOE 2015).

3.3 Results

Achieving the *GeoVision* reduces national power-sector water withdrawals when compared with the BAU scenario but leads to some increases in regional and national water consumption.[5]

Figure 10 shows the decline in annual power-sector water withdrawals for the *GeoVision* BAU, IRT, and TI scenarios from 2015 to 2050, as well as the fuel-specific differences in water withdrawals for the BAU and TI scenarios. On a national level, withdrawals decline substantially over time under both scenarios, largely owing to the retirement and reduced operations of once-through cooling thermal facilities and the assumed replacement of those plants with newer, less water-intensive generation and cooling technologies. In the BAU scenario, once-through cooling plants are largely replaced by new thermal plants using recirculating cooling as well as solar and wind power capacity. In the TI scenario, water-intensive coal plants are also replaced by geothermal technologies, primarily after 2030. As a result, TI scenario national power-sector withdrawals are 0.3% (23 billion gal) lower than BAU withdrawals in 2050; 23 billion gal represents the annual water usage of approximately 150,000 U.S. households. Cumulative water withdrawal savings from 2015 to 2050 total 2.7 trillion gal. TI scenario water withdrawals are 80% lower in 2050 than they are in 2015. By 2050, geothermal technologies account for 1.1% of power-sector water withdrawals compared with 8.5% of generation.

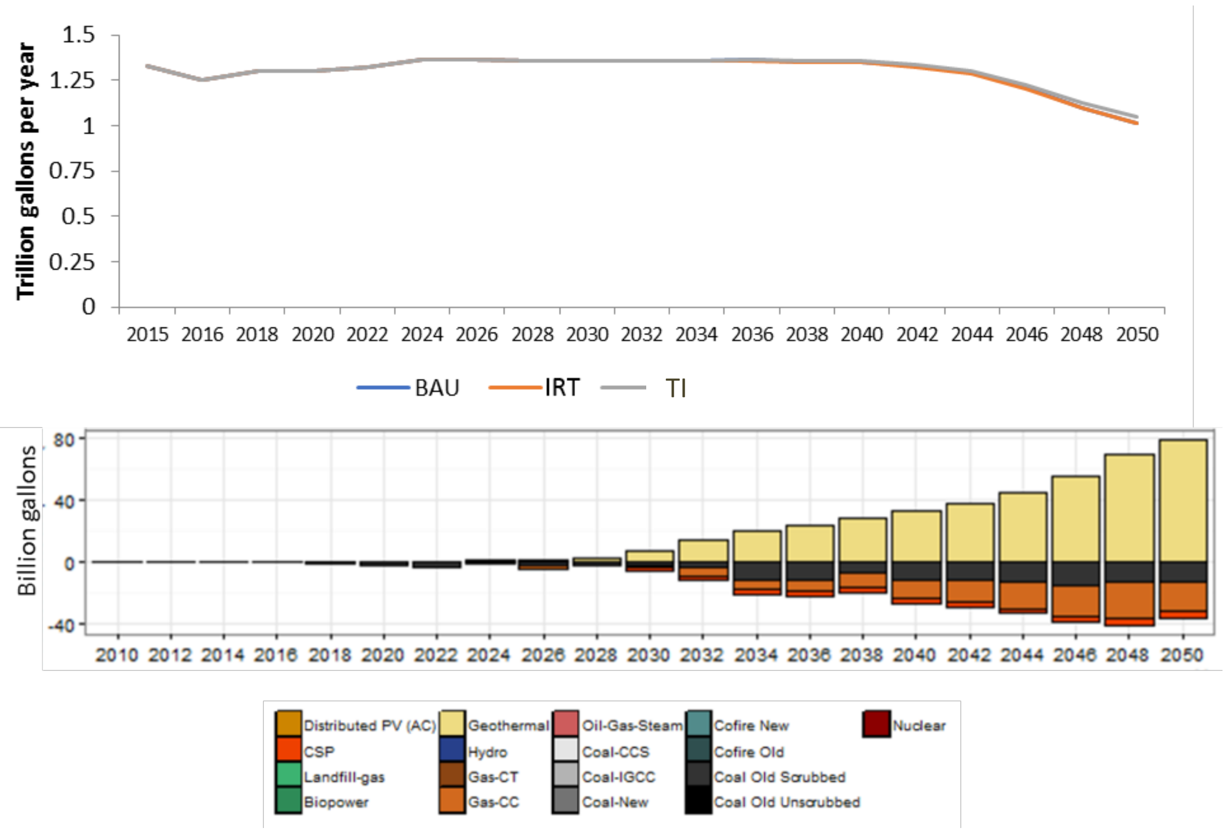
[5] The terms “withdrawal” and “consumption” are defined in the first paragraph of the introduction.



Note: PV = photovoltaic; AC = alternating current; CSP = concentrating solar power; CT = combustion turbine; CC = combined cycle; CCS = carbon capture and storage; IGCC = integrated gasification combined cycle; cofire = biomass-fossil cofiring

Figure 10. Power-sector water withdrawal impacts of *GeoVision* scenarios from 2015 to 2050 (top), and annual differences between TI and BAU scenarios by fuel type from 2015 to 2050 (bottom)

Figure 11 shows the change in annual power-sector water consumption for the *GeoVision* BAU, IRT, and TI scenarios from 2015 to 2050, as well as the fuel-specific differences in water consumption for the BAU and TI scenarios. National power-sector water consumption declines over time in these scenarios, but to a lesser extent than water withdrawals. Consumption is slightly higher in the TI scenario in later years. The increase to water consumption within the TI scenario becomes noticeable beginning in 2030, coincident with the increased deployment of EGS power plants. Overall, national power-sector consumption is 4% (40 billion gal) higher in 2050 for the TI scenario compared with the BAU scenario; 40 billion gal represents the annual water usage of approximately 300,000 U.S. households. In comparison to 2015 values, TI scenario consumption is 21% lower in 2050. By 2050, geothermal technologies account for 7.6% of power-sector water consumption compared with 8.5% of generation.



Note: PV = photovoltaic; AC = alternating current; CSP = concentrating solar power; CT = combustion turbine; CC = combined cycle; CCS = carbon capture and storage; IGCC = integrated gasification combined cycle; cofire = biomass-fossil cofiring

Figure 11. Power-sector consumption impacts of *GeoVision* scenarios from 2015 to 2050 (top), and annual differences between TI and BAU scenarios by fuel type from 2015 to 2050 (bottom)

Water withdrawal and consumption impacts under the TI scenario are not uniform throughout the continental United States (Figure 12). Focusing first on withdrawal, by 2050, 22 of 48 states have lower withdrawals in the TI scenario than in the BAU scenario, a reflection of both where geothermal capacity is deployed and the specific type of capacity that is offset by such deployment. There are important reductions in water withdrawals in Southern California, Arizona, and Texas, with some increases in water withdrawals in Northern California, Utah, and New Mexico. For water consumption, by 2050, 19 of 48 states have lower consumption in the TI scenario than in the BAU scenario. Many regions that showed decreases in withdrawals also show decreases in consumption, yet in some cases, regions with decreases in water withdrawals show increases in water consumption. This tradeoff of withdrawals for consumption can be explained by the different withdrawal and consumption rates of generation sources in these regions.

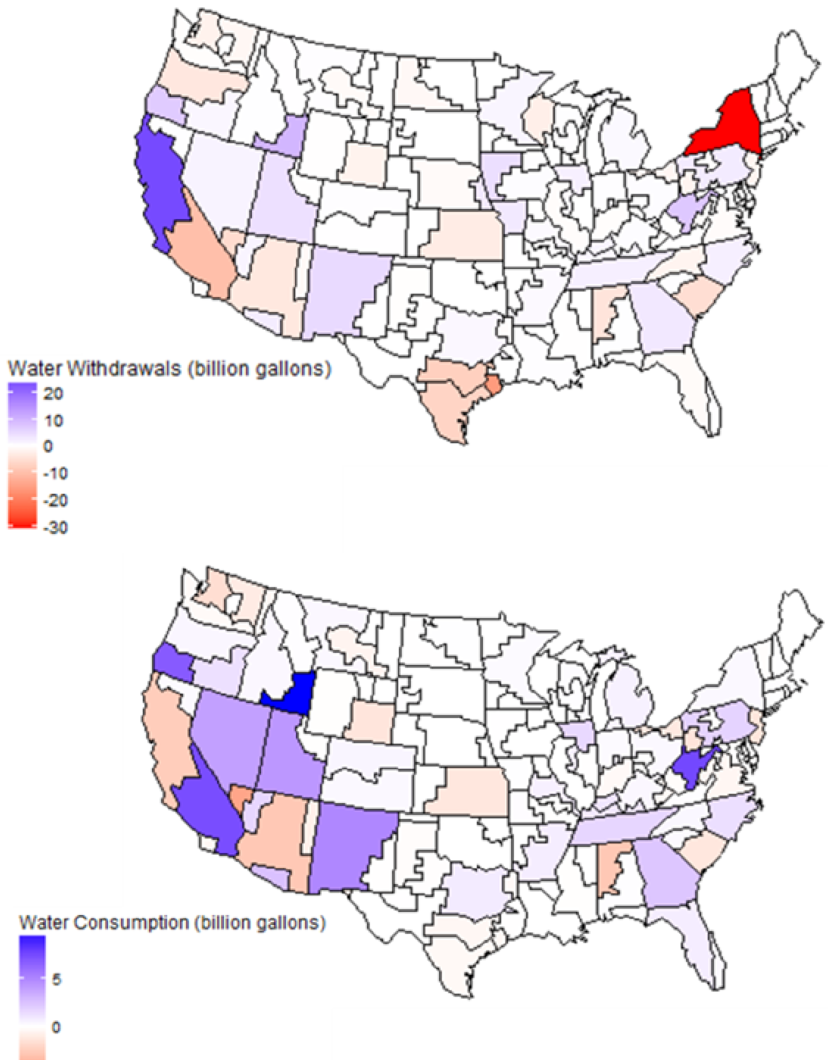
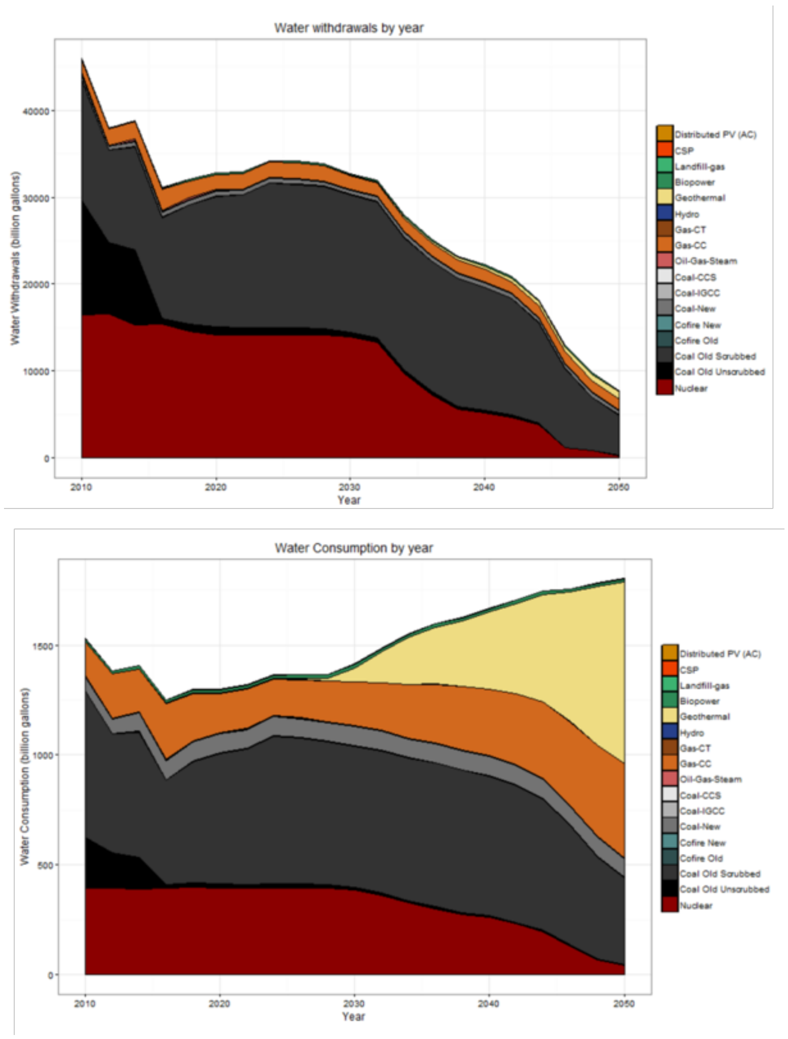


Figure 12. 2050 changes in water withdrawals (top) and water consumption (bottom) in the TI scenario relative to BAU

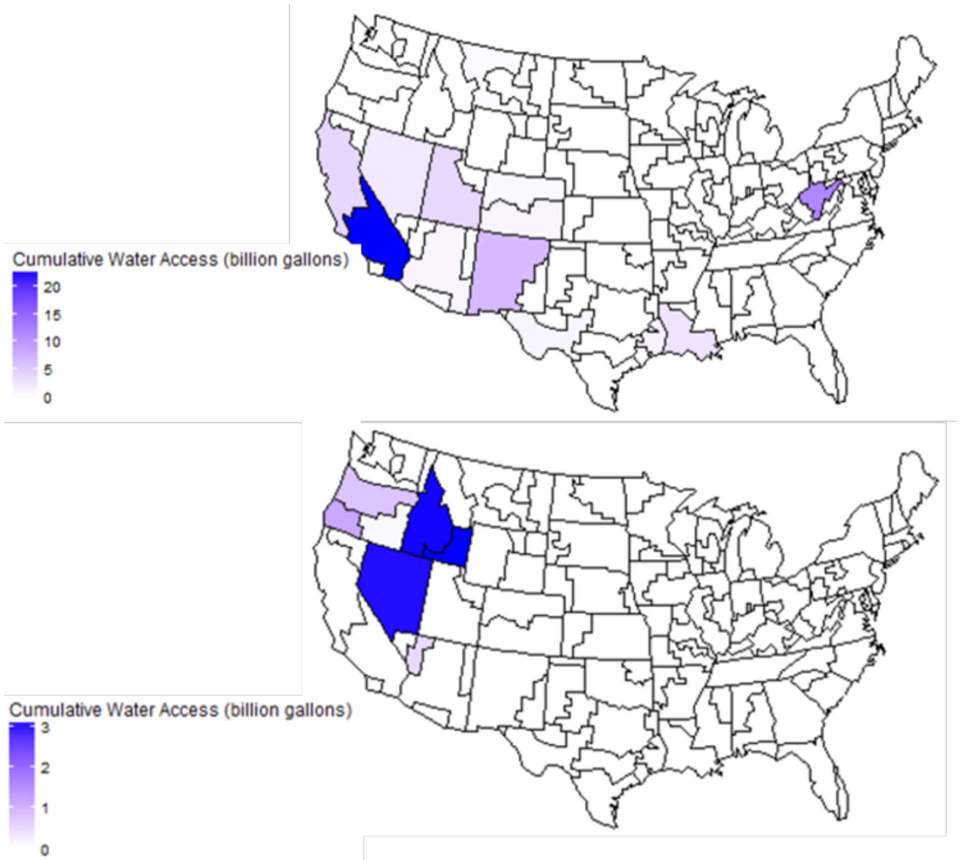
The water consumption and withdrawal impacts previously described assume that all new EGS plants are deployed in a dry-cooled binary configuration. To evaluate how results might change if different configurations were deployed, we considered a scenario in which new EGS capacity is built in a wet-cooled flash configuration. As shown in Figure 13, the relative impact of this scenario on water withdrawals is minor. National withdrawals are 11% higher in the EGS-flash sensitivity scenario than in the TI scenario, but withdrawals are still lower than they are in 2015. For water consumption, deploying wet-cooled flash EGS technologies can lead to substantially higher water consumption (71%) than the TI scenario. Water consumption in 2050 is higher in the EGS-flash sensitivity scenario than it is in 2015. Water withdrawal and consumption increases are primarily concentrated in states with geothermal deployment. Because of water availability constraints in the EGS-flash sensitivity scenario, geothermal deployment is reduced by 6% (3.5 GW) compared with the TI scenario.



Note: PV = photovoltaic; AC = alternating current; CSP = concentrating solar power; CT = combustion turbine; CC = combined cycle; CCS = carbon capture and storage; IGCC = integrated gasification combined cycle; cofire = biomass-fossil cofiring

Figure 13. Water withdrawal (top) and consumption (bottom) trends from 2015 to 2050 in the EGS-flash sensitivity scenario

A major benefit of geothermal technologies is their ability to utilize nonfreshwater resources for operations. To evaluate the deployment and water use impacts of an alternative case of freshwater availability, we undertook a sensitivity study where all new power plants can only utilize nonfreshwater resources. These restrictions led to a slight reduction in geothermal deployment (6.5 GW) by 2050 compared with the TI scenario, with much larger reductions in coal (23 GW) and natural gas (11 GW) technology deployment. This suggests that geothermal technologies can be more flexible than other thermal technologies in utilizing alternative water resources. Importantly, desirable geothermal resources are often in close proximity to brackish groundwater and municipal wastewater resources that can be utilized in geothermal power plants. Figure 14 highlights areas where municipal wastewater and brackish groundwater resources increase in the limited freshwater availability sensitivity scenario compared with the TI scenario. Increases in the use of alternative water sources correspond primarily to areas with high geothermal deployment. Municipal wastewater resources are used at a much higher rate than brackish groundwater resources, partly because of the groundwater pumping costs of utilizing brackish water resources.



(Note the different scaling between panels.)

Figure 14. Cumulative increases in the utilization of municipal wastewater (top) and brackish groundwater (bottom) resources from 2015 to 2050 in the limited freshwater availability scenario

The ability of geothermal energy to reduce water withdrawals and consumption in certain locations can offer economic and environmental benefits, especially in regions where water is scarce. By reducing electric-sector water use, geothermal energy can reduce the vulnerability of the electricity supply to the availability or temperature of water, potentially avoiding electric-sector reliability events and/or the effects of reduced thermal plant efficiencies—concerns that might otherwise grow as the climate changes (DOE 2013). Additionally, increased geothermal deployment can free up water for other productive purposes (e.g., agricultural, industrial, or municipal use) or to strengthen local ecosystems (e.g., benefiting wildlife owing to greater water availability, lack of temperature change, and so on). Finally, geothermal deployment might help reduce the cost of future national or state policies intended to limit electric-sector water use.

Quantifying in monetary terms the societal value of water-use reductions is difficult, however, because no standardized methodology for doing this exists in the literature. One potential approach is to consider geothermal deployment as avoiding the *possible* need to otherwise employ thermal power plants with lower water use or to site power plants where water is available and less costly. ReEDS already includes the cost and performance characteristics of different cooling technologies as well as the availability and cost of water supply in its optimization; these costs and considerations are embedded in the results presented earlier. However, if water becomes scarcer in the future and/or if water policy becomes stricter, then additional costs might be incurred. In such an instance, a possible upper limit of the incremental cost of water-use reductions associated with conventional thermal generation can be estimated by comparing the cost of traditional wet cooling with the cost of dry cooling. Dry cooling adds capital expense to thermal plants and reduces plant efficiencies. The total cost increase of dry cooling for coal generation has been estimated at 0.32–0.64¢/kWh (Zhai and Rubin 2010). For natural gas combined-cycle plants, Maulbetsch and DiFilippo (2006) estimate an "effective cost" of saved water at $3.80–$6.80 per 1,000 gal, corresponding to approximately 0.06–0.17¢/kWh (DOE 2015). These estimated incremental costs for dry cooling are relatively small, and they likely set an upper limit on the water-related cost savings of geothermal energy or any other power technology intended, in part, to reduce water use.[6]

3.4 Concluding Remarks

In the case of water usage, achieving the *GeoVision* will not significantly alter the water needs of the electricity system. Although, under the TI scenario, there is some reduction to systemwide water withdrawals, water consumption increases by a small amount (<1% decrease to withdrawals and a 4% increase to consumption, nationally). The main driver of this result is the assumptions related to subsurface water loss and the assumed binary, air cooled, configuration for EGS plants. Of particular note, however, is the potential to support almost all of the geothermal growth found in the TI scenario using only alternative nonfreshwater resources, indicating that geothermal power growth could be supported even under conditions where access to freshwater resources was restricted.

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[6] The actual benefits, in terms of cost savings, would be lower than these figures for a few reasons. First, many regions of the country are not facing water scarcity, so the economic benefits of reduced water use are geographically limited. Second, to the extent that geothermal offsets more electricity supply (kilowatt-hours) than electricity capacity (kilowatts), it may not be able to offset the full capital and operating cost of less water-intensive cooling technologies. Third, to date, few plants have been required or chosen to implement dry cooling; alternative, lower-cost means of obtaining and/or reducing water have predominated, including simply locating plants where water is available. Alternative water resources, such as municipal wastewater or shallow brackish groundwater, could also be more cost-effective than dry cooling in some regions (Tidwell et al. 2014). These lower-cost methods of reducing water use are likely to dominate for the foreseeable future. Because of these complicating factors, a separable monetary benefit of the *GeoVision* in terms of reduced water use is not estimated.

4 Air Pollution Reductions

Summary

Within the electric sector, achieving the TI scenario reduces cumulative emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_x), and fine particulate matter ($PM_{2.5}$) by 1%, or 279,000, 417,000, and 54,000 metric tons (t), respectively, relative to the BAU scenario. These emission reductions are concentrated in the time period between 2030 and 2050. These reductions could produce $13 billion of net present value benefits to the United States in the form of lower future health and environmental damages based on central estimates, which is equivalent to a levelized benefit of geothermal of 0.5¢/kWh-geothermal. Across the full set of methods considered, total monetary benefits span $6 billion (0.2¢/kWh-geothermal) to $23 billion (0.8¢/kWh-geothermal). These benefits derive, in large measure, from a reduction in premature mortality from sulfate particles from SO_2 emissions—achieving the TI scenario reduces premature mortalities by 2,200–5,100 based on methods developed at the EPA. Outside of the electric sector, and cumulatively from 2015 to 2050, the expansion of the GHP industry under the Breakthrough scenario reduces building heating emissions of SO_2, NO_x, and $PM_{2.5}$ by an additional 232,000, 711,000, and 57,000 t, respectively, equivalent to two to three times the total single year SO_2 and NO_x emissions from all residential combustion sources and one-fifth of a single year of $PM_{2.5}$ residential emissions. These GHP sector emission reductions provide $28 billion–$61 billion of value based on avoiding up to 8,700 premature mortalities.

4.1 Introduction

Combusting fuels to generate electricity or heat produces air pollutants that harm human health and cause environmental damage (NRC 2010). Epidemiological studies have shown a causal association between increased mortality and morbidity and chronic exposure to air pollution, specifically exposure to $PM_{2.5}$ (for examples of the association with mortality, see Dockery et al. 1993; Krewski et al. 2009; and Lepeule et al. 2012). Chronic exposure to elevated ozone levels is also associated with increased mortality and morbidity (for examples of the association with mortality, see Bell et al. 2004 and Levy et al. 2005). Combustion-based electricity and heat generation can contribute to elevated $PM_{2.5}$ levels through two pathways: through direct emissions of $PM_{2.5}$ and through emissions of gases that undergo chemical reactions in the atmosphere and transform to $PM_{2.5}$, including SO_2 and NO_x. SO_2 is transformed to sulfate particles in the atmosphere, and NO_x can undergo transformation to particulate nitrate under certain conditions. Combustion-based power plants and combustion-based building heating also contribute to ground-level ozone through emissions of NO_x, which, in combination with volatile organic compounds (VOC), can contribute to ozone formation.

Outdoor air pollution has a large impact both globally and in the United States. Lim et al. (2012), for example, report that more than 3 million premature deaths occur globally each year from outdoor particulate air pollution and that outdoor particulate air pollution is the 14th leading modifiable risk factor for deaths in North America. Although all energy sources have environmental impacts, most renewable energy sources—including geothermal electricity generation and GHPs—have little or no direct air pollution emissions and also low life cycle air pollution emissions (IPCC 2011; Ricci 2010; Turconi et al. 2013; Matek 2013). Therefore, achieving the *GeoVision*, specifically the TI scenario within the electric sector and the Breakthrough scenario within the GHP sector, promises to reduce air pollution emissions.

In the United States, recent studies have evaluated the potential air quality and public health benefits of reducing combustion-based electricity generation. For example, Driscoll et al. (2015) found that policies aimed at reducing power-sector CO_2 emissions would also reduce $PM_{2.5}$ and ozone, preventing as many as 3,500 premature mortalities in 2020. Siler-Evans et al. (2013) value the health and environmental benefits of displaced conventional generation from new solar and wind power at 1¢/kWh to 10¢/kWh, with the range largely reflecting locational differences; Buonocore et al. (2015) build on this work by further exploring how benefits vary by location and technology. Millstein et al. (2017) estimate that the value of health and climate benefits from wind and solar generation from 2007 to 2015 and across the continental United States is equal to $88 billion (based on their central estimate). The following analysis aims to apply these techniques to exploring the potential air quality and health benefits of geothermal power and its potential expansion under the *GeoVision*. In this section, we calculate those potential emissions reductions and present the associated public health and environmental benefits both in the form of health indicators and in monetary terms.

4.2 Methods

A brief description of the methods used to develop benefit estimates is presented in this section; additional details are included in Supplement B.

4.2.1 Electric Sector Modeling

To value the potential air quality benefits of achieving the TI scenario, we estimate the reductions in emissions of SO_2, NO_x, and $PM_{2.5}$ from 2015 to 2050 in the TI and IRT scenarios relative to the BAU scenario. We then quantify the public health and environmental benefits of those changes in emissions in the form of reduced mortality and morbidity, and we translate them into monetary terms (in 2015 dollars). Given uncertainty in pollutant transport, transformation, and exposure, as well as uncertainty in the human response to ambient $PM_{2.5}$ and ozone, we use multiple established methods to quantify the health and environmental outcomes and monetary benefits of the emissions changes. Our overall approach is similar to that which DOE has used to evaluate the expansion of wind and solar power (Wiser et al. 2016a; Wiser et al. 2016b; Millstein et al. 2017), and it is broadly consistent with methods used in Buonocore et al. (2015); Cullen (2013); Driscoll et al. (2015); EPA (2015); Fann et al. (2012); Valentino et al. (2012); NRC (2010); McCubbin and Sovacool (2013); and Siler-Evans et al. (2013).

We start with ReEDS-estimated, power-sector combustion-related SO_2 and NO_x emissions in the TI, IRT and BAU scenarios. We then estimate power-sector $PM_{2.5}$ emissions as a function of ReEDS generation by power plant type and location. Incorporated in these estimates are assumptions about power-sector regulations that apply to emissions of SO_2, NO_x, and/or $PM_{2.5}$, such as the Mercury and Air Toxics Standards (MATS) and the Cross-State Air Pollution Rule (CSAPR).

4.2.2 Geothermal Heat Pump Modeling

We quantify the GHP benefits that occur from reducing on-site fuel use and from reducing electricity demand. In the case of GHP, reductions to on-site fuel use, as opposed to reductions to electricity demand, provides the majority of the benefits and is the primary focus of the analysis. Fuels that are reduced by GHP include natural gas, fuel oil, and propane, and we determine the associated reduction to emissions of SO_2, NO_x, and $PM_{2.5}$ based on the fuel type and type of heating equipment that is offset by GHP installation. We estimate potential benefits based on the difference between three GHP development scenarios (the Navigant Low, NREL Optimistic, and Breakthrough scenarios) and a 2012 installed baseline.

The reduction to electricity demand that accompanies the GHP development scenarios was not included within the ReEDS scenarios. Thus, we have no direct model outputs that describe the impact on emissions of the GHP electricity demand changes. We instead rely on average, state-level, emission rates from ReEDS developed in the TI scenario. These average emission factors (e.g., kilogram SO_2 per megawatt-hour [MWh] of total fossil generation by state) produce a rough estimate of the avoided emission benefits. As mentioned previously, however, the large majority of the GHP benefits comes from the avoidance of on-site fuel use; thus, we do not try to refine our estimate of GHP electricity benefits further.

We calculate the public health benefits of those changes in emissions in the form of reduced mortality and monetized values. To address uncertainty in estimated potential benefits, we use a similar approach to that of the electric sector and apply multiple methods to quantify the health and environmental benefits from the reduced emissions.

4.2.3 Air Quality and Health Impact Models

For both the electric and GHP sectors, we calculate—based on emissions changes—a range of health and environmental benefits, including total monetary value and reduced mortality. For the electric sector, we also include estimates of reduced morbidity. Each air quality and health impact model we use accounts for pollutant transport and chemical transformation as well as population exposure and response. For quantifying the electric sector benefits, we use: (1) the Air Pollution Emission Experiments and Policy (AP2, formerly APEEP) analysis model (described in Muller 2014 and Muller et al. 2011) and (2) the EPA benefit-per-ton methodology developed for the Clean Power Plan (CPP) (EPA 2015). The CPP approach includes two estimates of the health impacts to span the uncertainty in the underlying epidemiological studies. Henceforth, we refer to the two outputs from the CPP approach as “EPA low” and “EPA high.” The high and low classifications correspond to differences only between the underlying health impact functions employed by the EPA, and the EPA does not favor either of its estimates over the other. We take the simple average of all three benefit estimates as the central value.

For quantifying the GHP fuel use sector benefits, we use: (1) a state-specific health impact model (PENN model) (Penn et al. 2017) and (2) the Estimating Air pollution Social Impact Using Regression (EASIUR) model (Heo et al. 2016). For the PENN model, we calculated mortality reductions by state and converted them to monetized benefits. For the EASIUR model, we calculated two estimates of the social benefits of GHP to incorporate the uncertainty related to the underlying epidemiological studies. We refer to the two estimates from the EASIUR model as “EASIUR low” and “EASIUR high.” For the GHP impacts on the electric sector, we use the same models as discussed previously, AP2, EPA high, and EPA low for the monetized benefit calculation and EPA high and EPA low for mortality benefits. One important assumption across all methods used is the monetary value of preventing a premature mortality, or the value of statistical life (VSL). Consistent with the broader literature, all use a VSL of approximately $6 million (in 2000 dollars).

4.2.4 Additional Methodological Notes and Possible Related Limitations

Our focus is on a subset of air emissions impacts: SO_2, NO_x, and $PM_{2.5}$. Environmental impacts that we do not evaluate include heavy metal releases, radiological releases, waste products, and land-use impacts associated with power and upstream fuel production, as well as noise, aesthetics, and others. We only consider emissions from power plant operations, and so do not assess upstream and downstream life cycle impacts. Additionally, our air emissions reduction estimates are inherently uncertain, in part owing to the impact of uncertain policy and market factors on those reductions. We also do not consider the possible erosion of the air quality benefits because of the increased cycling, ramping, and part loading required of fossil generators in electric systems with higher penetrations of variable renewable generation. Literature suggests that this omission will not alter dramatically the basic results reported here (Oates and Jaramillo 2013; Valentino et al. 2012; Lew et al. 2013; GE Energy Consulting 2014).

Our methodology presumes that MATS is maintained or replaced with a similar regulation such that SO_2 and NO_x cap-and-trade programs, such as CSAPR, are essentially nonbinding over time. Otherwise, the benefits of achieving the TI scenario should arguably be valued at allowance prices to reflect savings in the cost of complying with the cap (Siler-Evans et al. 2013). Our methodology also assumes that the CPP is not implemented. Under a trading system such as the CPP, air quality improvements over time would be seen under all scenarios, including the BAU scenario. It is unlikely that there would be additional improvements to air quality under the TI scenario if the CPP was in effect.

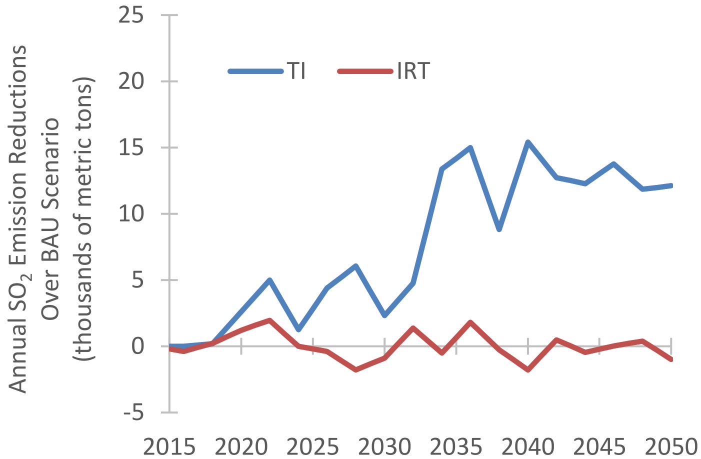
Estimates of the health and environmental benefits associated with emissions reductions are inherently uncertain. We reflect some—but not all—of those uncertainties by calculating benefits using two approaches leading to three different estimates for both the electric sector and the GHP sector.

4.3 Results

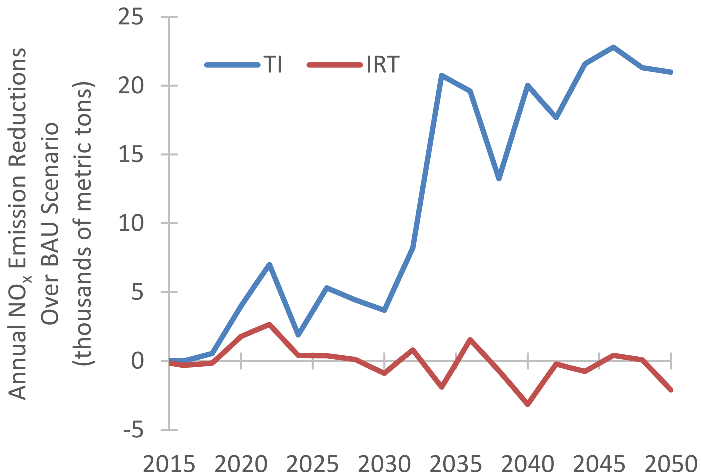
4.3.1 Electric sector

Within the electric sector, achieving the TI scenario reduces 2015 to 2050 cumulative emissions of SO_2, NO_x, and $PM_{2.5}$ 279,000, 417,000, and 54,000 t, respectively, relative to the BAU scenario. These reductions represent about 1% of total emissions in each category and are concentrated in the time period between 2030 and 2050. Figure 15 shows emissions changes over time, with the most prominent feature being the increase to emission reductions beginning near 2030 associated with the development of EGS resources. Emission benefits from the IRT scenario are marginal, but benefits from the TI scenario are significant.

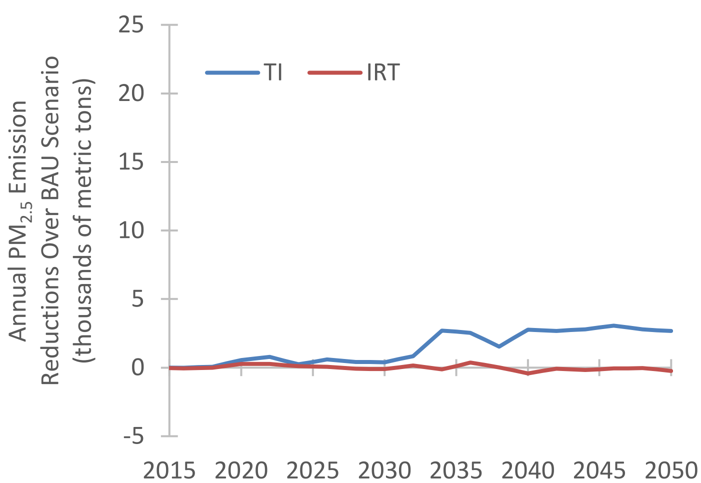
(a)



(b)



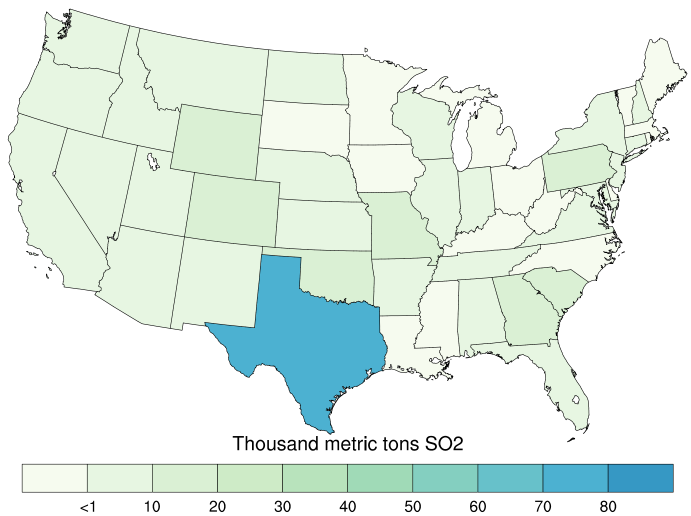
(c)



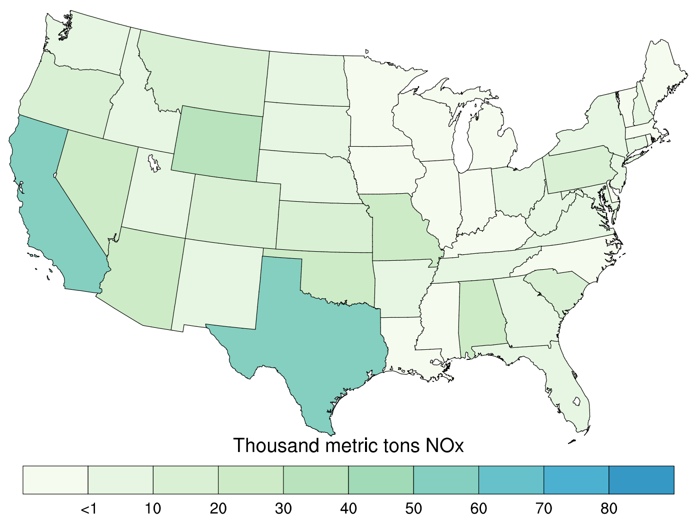
Note: Positive values indicate a reduction to emissions

Figure 15. Power-sector annual emission benefits of the TI and IRT scenarios versus the BAU scenario

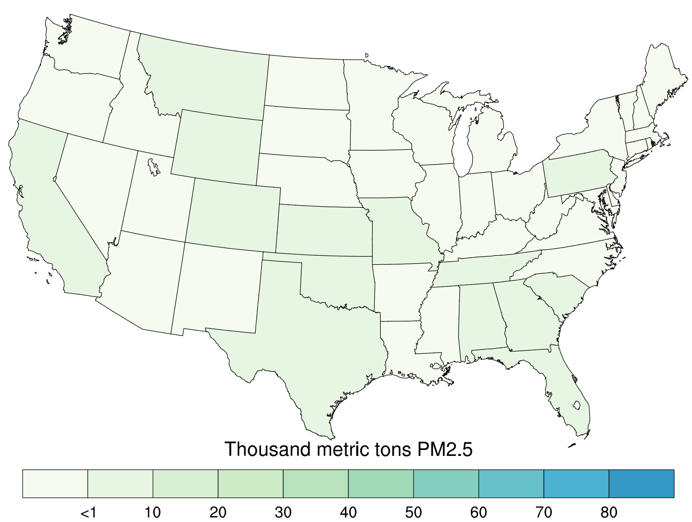
(a)



(b)



(c)



Note: (a) SO_2, (b) NO_x, and (c) $PM_{2.5}$

Figure 16. Cumulative electric sector emission reductions by state, from 2015 to 2050, (TI relative to BAU) in thousand metric tons (TMT)

As shown in Figure 16, SO_2 emission benefits are concentrated in Texas, with a lower level of emission benefits spread across many other states. Important NO_x emission benefits are found across many states, including, Texas, California, Alabama, and a number of states across the western half of the county. Emissions of direct $PM_{2.5}$ emissions from the power sector are lower than emissions of gaseous NO_x and SO_2, and thus direct $PM_{2.5}$ emission benefits are lower as well. The location of emission benefits is driven both by the location of the geothermal deployment and the types and emission rates of the power plants offset by those deployments.

These emissions reductions lead to improved air quality and health outcomes across the continental United States. Specifically, total U.S. health and environmental benefits from the TI scenario fall in the range of $6 billion–$23 billion on a discounted, present-value basis, depending on the method used to quantify those benefits. The average central estimate is $13 billion, which is equivalent to a levelized benefit of geothermal of 0.5¢/kWh-geothermal; the total range is 0.2–0.8 ¢/kWh-geothermal (Figure 17). The range of benefits estimates reflects uncertainties in how to value emissions reductions. All of the valuation estimates are based on emissions reductions that occur from 2015 to 2050; any emissions reductions after 2050 are not considered in our analysis.

Most of the health benefits come from avoided premature mortality, again primarily associated with reduced chronic exposure to ambient $PM_{2.5}$ (largely derived from the transformation of SO_2 to sulfate and NO_x to nitrate particles). Based on the EPA approach, achieving the TI scenario prevents 2,200–5,100 premature mortalities in total from 2015 to 2050. Achieving the TI scenario also would result in numerous forms of avoided morbidity outcomes (Table 3), including 2,800 hospital admissions for respiratory and cardiovascular symptoms, 210,000 lost workdays, and 276,200 missed school days.

Table 3. Electric Sector Emissions Reductions, Monetized Benefits, and Mortality and Morbidity Benefits from 2015 to 2050 for the TI Scenario

Impacts	SO_2	NO_x	$PM_{2.5}$	Total
Emissions Reductions				
TI scenario air pollution reductions (millions metric tons [MMT])	0.3	0.4	0.1	—
Total Monetized Benefits (Present Value)				
EPA low benefits (billions of dollars [2015])	6	2	1	10
EPA high benefits (billions of dollars [2015])	14	7	3	23
AP2 benefits (billions of dollars [2015])	4	1	1	6
EPA Total Mortality Reductions				
EPA low mortality reductions (count)	1,300	500	300	2,100
EPA high mortality reductions (count)	3,100	1,400	600	5,000
EPA Morbidity Reductions from Primary and Secondary $PM_{2.5}$ Impacts				
Emergency department visits for asthma (all ages)	200	100	100	400
Acute bronchitis (ages 8–12)	1,800	500	300	2,600
Lower respiratory symptoms (ages 7–14)	23,000	6,700	4,400	34,100
Upper respiratory symptoms (asthmatics ages 9–11)	35,900	9,700	6,300	51,900
Minor restricted-activity days (ages 18–65)	872,000	225,000	160,300	1,257,300
Lost workdays (ages 18–65)	144,400	39,400	26,200	210,000
Asthma exacerbation (ages 6–18)	79,900	24,300	14,900	119,100
Hospital admissions, respiratory (all ages)	400	100	100	600
Hospital admissions, cardiovascular (ages >18)	500	100	100	700
Nonfatal heart attacks (Peters et al. 2001)	1,600	400	300	2,300
Nonfatal heart attacks (pooled estimates, four studies)	200	—	—	200
EPA Morbidity Reductions from NO_x: Ozone Impacts				
Hospital admissions, respiratory (ages >65)	—	1,000	—	1,000
Hospital admissions, respiratory (ages <2)	—	400	—	400
Emergency room visits, respiratory (all ages)	—	400	—	400
Acute respiratory symptoms (ages 18–65)	—	853,700	—	853,700
Lost school days	—	276,200	—	276,200

Note: Scenario relative to the BAU scenario
All values accumulated from 2015 to 2050, and all monetized benefits are discounted at 3% (mortality and morbidity values are simply accumulated over the time period. EPA dollar benefits include mortality and morbidity estimates from primary and secondary $PM_{2.5}$ effects from SO_2, NO_x, and direct $PM_{2.5}$ emissions and ozone benefits from reduced NO_x emissions during the ozone season (May–September). AP2 dollar benefits include mortality and morbidity estimates from primary and secondary $PM_{2.5}$ effects from SO_2, NO_x, and direct $PM_{2.5}$ emissions and ozone benefits from reduced NO_x emissions during the ozone season (May–September). AP2 benefits also include environmental effects such as loss of visibility and crop damage. Both AP2 and EPA monetary benefit estimates are dominated by mortality benefits.

4.3.2 Geothermal Heat Pump Fuel Use Sector

We find GHP can reduce on-site fuel use of natural gas, fuel oil, and propane. We discuss GHP impacts on the electric sector in a following section. The reduction to on-site fuel use that occurs from achieving the Breakthrough scenario reduces cumulative emissions, from 2015 to 2050, of SO_2, NO_x, and $PM_{2.5}$ by 232,000, 711,000, and 57,000 t, respectively, relative to the 2012 current installed capacity. These emission reductions are equivalent to two to three times the total single year SO_2 and NO_x emissions from all residential combustion sources and one-fifth of a single year of $PM_{2.5}$ residential emissions (EPA 2016). Figure 17 shows the annual emission benefits of the Navigant Low, NREL Optimistic, and Breakthrough scenarios by pollutant. The emission reduction increases gradually over time. In the case of GHP, significant benefits are found even in the scenario with the least deployment, the Navigant Low scenario, with the additional deployment in the NREL Optimistic and Breakthrough scenarios adding some additional benefits.

Figure 18 shows cumulative (from 2015 to 2050) emission reductions for the GHP fuel use sector by state based on the Breakthrough scenario. SO_2 emission benefits are concentrated in the Midwest region where GHP offsets residential fuel oil use. We note that SO_2 benefits are sensitive to heating oil sulfur content regulations, and thus we find low SO_2 benefits in the Northeast region where strict SO_2 limits have been enacted for heating oil. NO_x emission benefits are concentrated in several states in the eastern Midwest and Northeast regions including Illinois and New York. The spatial distribution of $PM_{2.5}$ emission reductions is similar to that of NO_x emissions, showing large emission reductions in the eastern Midwest and Northeast regions. $PM_{2.5}$ emission reductions from the GHP fuel use sector are significantly lower than those of NO_x and SO_2 (Figure 18). As discussed in this section, however, social and health benefits from $PM_{2.5}$ are comparable to or higher than those of SO_2 and NO_x (see Table 4) depending on the health impact model. The spatial distribution of emission benefits is driven by both the location of the geothermal resources, specifically the proximity to dense population areas, and the type of fuel and equipment offset by those resources.

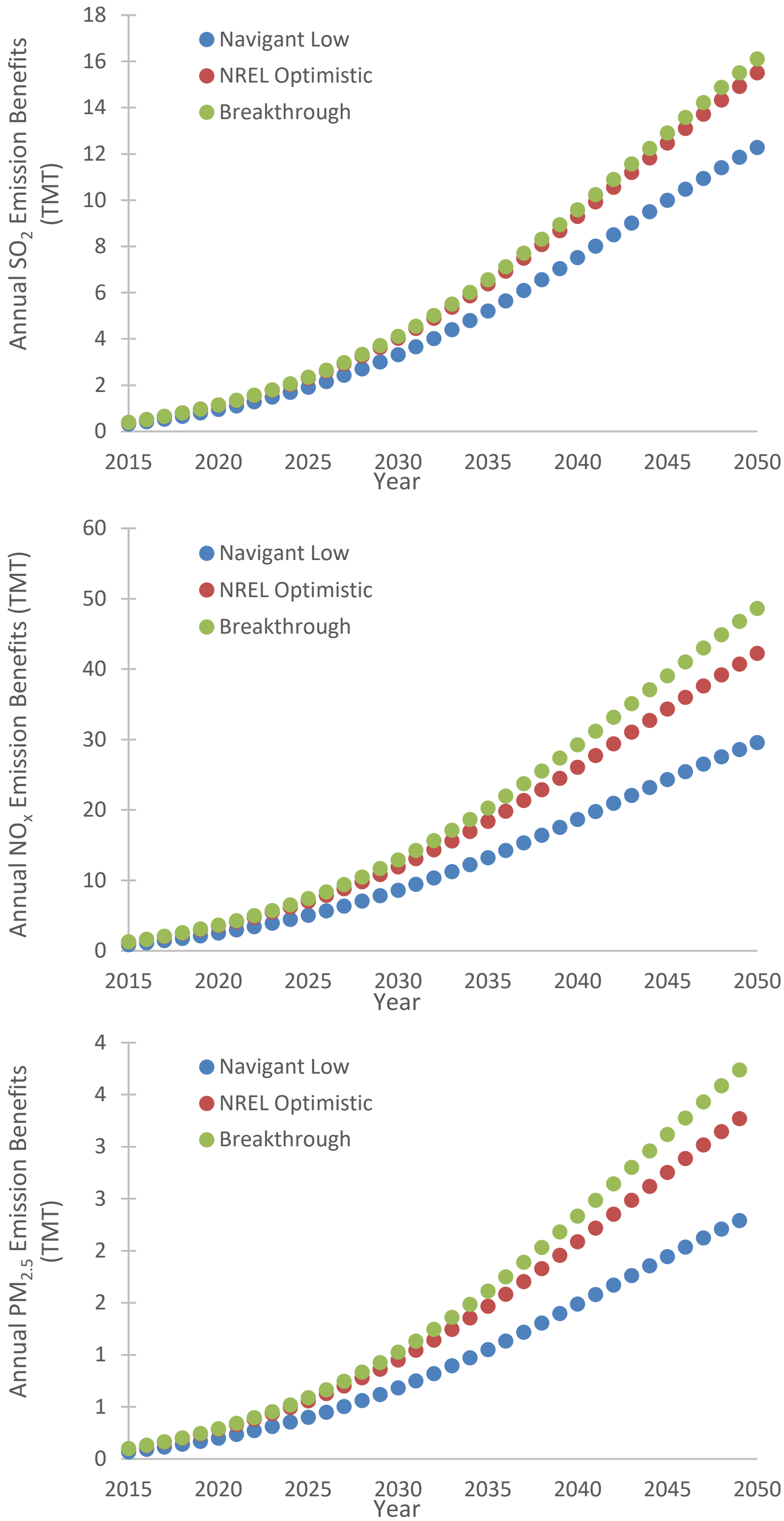
We use these emission reductions to estimate the air pollution-related health benefits across the continental United States. The cumulative present value of air pollution benefits under the Breakthrough scenario is equal to \$27 billion–\$61 billion depending on the method used to quantify those benefits (Figure 19). Note that all of the valuation estimates in Figure 19 are based on emissions reductions that occur from 2015 to 2050. The Navigant Low scenario generates approximately 70% of the value relative to the Breakthrough scenario. Based on the EASIUR high model for the Breakthrough scenario, we estimate that 17%, 37%, and 46% of the monetary benefits are derived from reducing SO_2, NO_x, and $PM_{2.5}$, respectively (see Table 4). The range of benefits estimates reflects the spread of valuation estimates produced by the air quality and health models.

We estimate the number of avoided premature mortalities using the PENN model (Penn et al. 2017). The estimates from the PENN model are based on avoided premature mortality because of reduced exposure to $PM_{2.5}$ and ozone but do not consider other avoided impacts. Achieving the Breakthrough scenario prevents cumulative (from 2015 to 2050) premature mortalities of 2,700, 3,200, and 2,800 for SO_2, NO_x, and $PM_{2.5}$, respectively, yielding a total mortality reduction of 8,700 (Table 4).

(a)

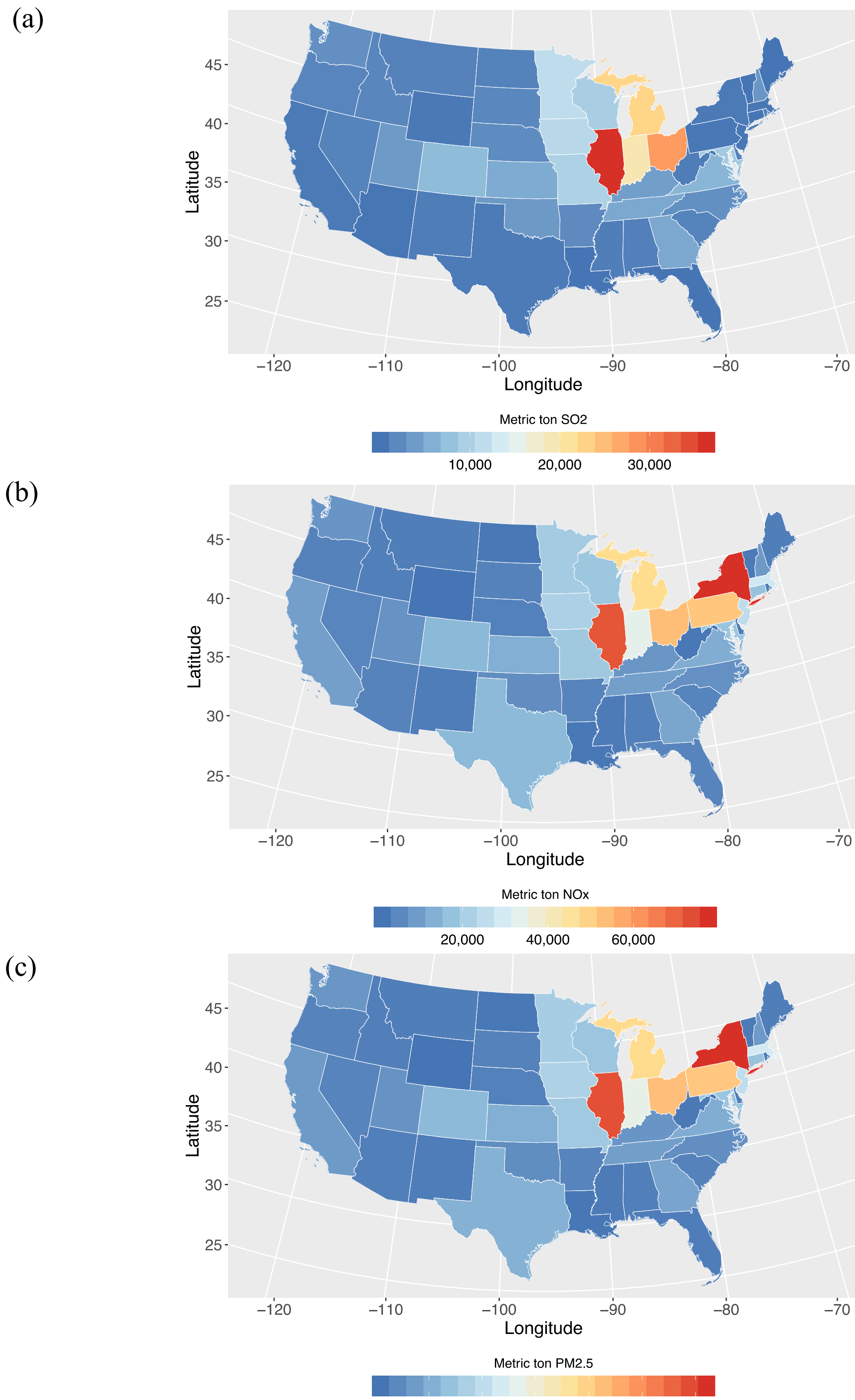
(b)

(c)



Breakthrough scenarios: (a) SO_2, (b) NO_x, and (c) $PM_{2.5}$

Figure 17. GHP fuel use sector annual emission benefits of the Navigant Low, NREL Optimistic, and Breakthrough scenarios



(a) SO_2, (b) NO_x, and (c) $PM_{2.5}$

Figure 18. Cumulative, from 2015 to 2050, GHP fuel use sector emission reductions by state (Breakthrough scenario over 2012 installed capacity) in TMT

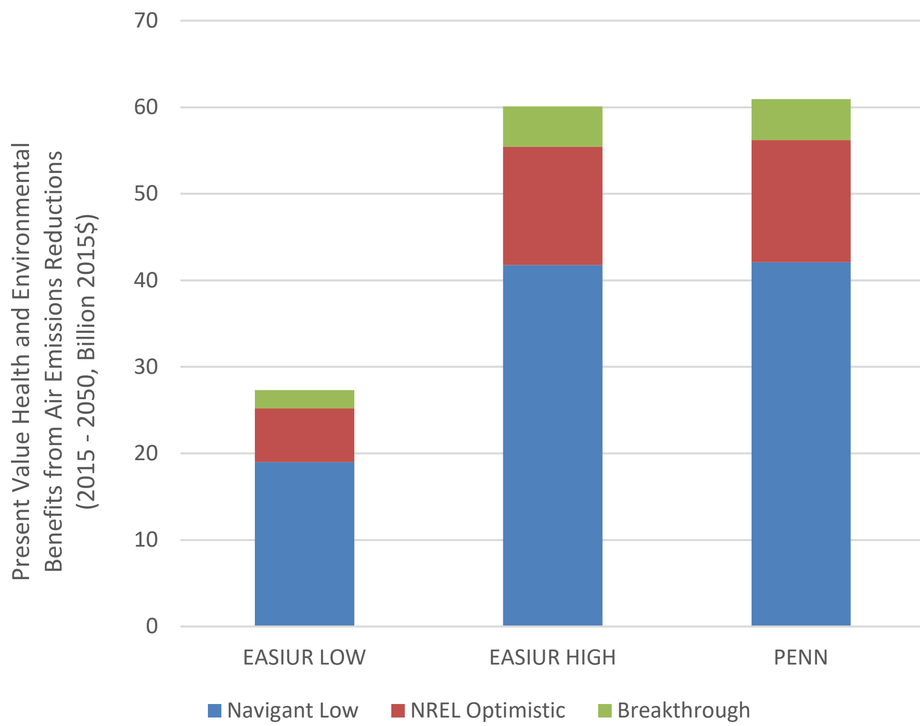


Figure 19. Present value health and environmental benefits from air emissions reductions (from 2015 to 2050, in billions of dollars [2015])

Table 4. Summary of Emissions Reductions, Monetized Benefits, and Mortality Benefits for the Geothermal Heat Pump Fuel Use Sector from 2015 to 2050 (Breakthrough Scenario)

Impacts	SO_2	NO_x	$PM_{2.5}$	Total
Emission Reductions				
Breakthrough scenario air pollution reductions (TMT)	232	711	57	—
Total Monetized Benefits (Present Value)				
EASIUR low benefits (billions of dollars [2015])	5	10	13	28
EASIUR high benefits (billions of dollars [2015])	10	22	28	60
PENN benefits (billions of dollars [2015])	19	22	20	61
Total Mortality Reduction				
PENN mortality reductions (count)	2,700	3,200	2,800	8,700

All values accumulated from 2015 to 2050 from the Breakthrough scenario. All monetized benefits are discounted at 3%, however the mortality values are simply accumulated over the time period. EASIUR benefits are based on avoided premature mortality because of reduced exposure to $PM_{2.5}$ but do not account for avoided morbidity or other air pollution damages. PENN estimates are based on avoided premature mortality as a result of reduced exposure to $PM_{2.5}$ and ozone but also do not account for other avoided impacts.

4.3.3 Geothermal Heat Pump Impacts to Electricity Demand

GHP systems can offset not only on-site fuel use associated with heating but can also offset on-site electricity use for both heating and cooling. GHP systems do require electricity to pump cooling and heating fluids and run fans. Results from dGeo indicated that in some locations, GHP systems increased total electricity demand, but in most locations, GHP systems reduced both on-site fuel use and electricity use. We quantify the impacts from GHP on electricity demand. Under the Breakthrough scenario, 2015 to 2050 cumulative emissions of SO_2, NO_x, and $PM_{2.5}$ are reduced by 43,000, 57,000, and 8,000 t, respectively, relative to the 2012 current installed capacity (see Table 5).

We find that these emission reductions would provide \$2.3 billion–\$6.7 billion (central average of \$4 billion) of health benefits across the continental United States (see Table 5). The range of benefits here reflects the spread of estimates across the air quality and health impact models used to quantify those benefits. All of the valuation estimates in Table 3 are based on emissions reductions that occur from 2015 to 2050. The monetized benefits from reduction in SO_2 emissions are higher than those of NO_x and $PM_{2.5}$ across the models, which is consistent with the result of the electric sector shown in Table 1. Table 3 also shows estimates of the health benefits from avoided premature mortality using two EPA models and the AP2 model (see Section 4.2 Methods for additional descriptions of these models). Achieving the Breakthrough scenario prevents total cumulative (from 2015 to 2050) premature mortalities of 280 and 670 for the EPA low and high models, respectively (Table 5). In both models, SO_2 accounts for approximately 70% of the total mortality reduction, yielding a dominant impact on the health benefits. As discussed in the previous Methods section, the estimates of the emission impacts from changes to electricity demand because of GHP deployment contain additional uncertainty relative to the estimates of the GHP on-site fuel use benefits. Because these benefits are relatively small compared with the on-site fuel benefits, we do not attempt to refine these estimates.

Table 5. Summary of Emissions Reductions, Monetized Benefits, and Mortality Benefits from Geothermal Heat Pump Electricity Demand Reduction from 2015 to 2050 (Breakthrough Scenario)

Impacts	SO_2	NO_x	$PM_{2.5}$	Total
Emission Reduction				
Breakthrough scenario air pollution reductions (TMT)	43	57	8	—
Total Monetized Benefits (Present Value)				
AP2 (billions of dollars [2015])	1.3	0.5	0.5	2.3
EPA high (billions of dollars [2015])	4.5	1.4	0.8	6.7
EPA low (billions of dollars [2015])	2.0	0.4	0.4	2.8
Total Mortality Reduction				
EPA high (count)	460	120	90	670
EPA low (count)	200	40	40	280

4.4 Concluding Remarks

Achieving the *GeoVision* will result in significant improvements to air quality and public health, including the avoidance of 2,200–5,100 premature mortalities from electric sector deployment of geothermal technologies and the avoidance of up to 8,700 premature mortalities from deployment of GHP technologies. Of note is that although the *GeoVision* showed significant benefits in both the electric sector and the GHP sector, the benefits from GHP found under the Breakthrough scenario for the GHP sector are even larger than the benefits from geothermal electricity generation found under the TI scenario. One reason for the relatively large GHP benefits is that emissions avoided by GHP are collocated with urban populations while emissions from power plants are often located far from dense population regions and are always released from elevated stacks (lessening the impact on the local population).

5 Greenhouse Gas Emission Reductions

Summary

In the *GeoVision*, geothermal electricity production and GHP deployments both provide significant reductions to national GHG emissions. Geothermal electricity production in the TI scenario, particularly from EGS systems, offsets higher emitting generation sources, saving a cumulative total of 516 million metric tons of carbon dioxide equivalent (MMT CO_2e) from 2015 to 2050, on a life cycle basis and relative to a BAU scenario. This represents 0.7% of total cumulative GHG emissions from the electric sector during this time period. By the end of the study period, the GHG emissions avoided annually are roughly equal to the annual emissions of 6 million cars. Outside of the electric sector, GHP installations in the Breakthrough scenario offset a total of 1,281 MMT CO_2e, representing an 8.3% reduction to on-site emissions from buildings relative to a scenario that holds GHP installations constant at 2012 deployment levels. By the end of the study period, 90 MMT CO_2e of annual emissions are avoided from GHP deployment, equivalent to removing almost 20 million cars from the road.

5.1 Introduction

Geothermal power can help address concerns about climate change by reducing emissions of GHG from the electricity and thermal power sectors. Geothermal electricity generation produces relatively low levels of life cycle GHG emissions in comparison to other electricity generation technologies. GHPs can reduce the on-site combustion of fuels for heating, providing efficiency gains and shifting some heating energy usage toward the electric sector, potentially utilizing renewable or other low emission resources.

This section estimates the potential GHG reductions associated with the geothermal deployment scenarios developed for the electric and the residential and commercial building heating and cooling sectors on both a direct combustion and life cycle basis. In the electric sector, *GeoVision*'s IRT and TI scenarios are compared with the BAU scenario. In the residential and commercial building heating and cooling sector, deployment of GHPs modeled in dGeo under the Navigant Low, NREL Optimistic, and Breakthrough scenarios is compared with a scenario assuming no additional adoption beyond a 2012 baseline.

5.2 Methods

Estimation of GHG emissions displacement resulting from geothermal adoption in the electric sector and the commercial and residential heating and cooling sector was conducted using scenarios developed for NREL's ReEDS model and NREL's dGeo model, respectively. For this study, both direct (combustion) displaced emissions and life cycle displaced emissions were estimated. The emissions factors themselves are derived from emissions of three GHGs: carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O). Please see Supplement C for a detailed description of methodology and emission rates.

5.2.1 Electric Sector

The ReEDS model directly estimates CO_2 emissions from electricity generation and accounts for both direct and indirect sources. The emissions factors embedded in the ReEDS model come from NREL's Life Cycle Assessment (LCA) Harmonization Project (Heath and Mann 2012).

Direct (combustion) emissions are those attributed to the specific process of combusting fossil fuels to produce electricity. Indirect emissions can be classified into three categories. The most significant group is noncombustion emissions, which come from all other fuel-related operations besides combustion, including fuel cycle emissions.[7] These noncombustion emissions are calculated per unit of *generation*, so the middle year of each 2-year ReEDS interval is interpolated as the average of the adjacent years. The other two sources of indirect emissions are the upstream and downstream sources. Upstream emissions result from materials manufacturing and plant construction, while downstream emissions are those resulting from plant decommissioning. Both of these sources are calculated per unit of *capacity*, so to avoid double counting in the aggregate, the middle year of each 2-year ReEDS interval is interpolated by equally dividing each modeled year's upstream and downstream emissions between the modeled year and the subsequent middle year.

Though they tend to be significantly lower (per unit of generation) than emissions from fossil fuel generation (Sullivan et al. 2010), there are nonnegligible life cycle GHG emissions from geothermal electricity generation. To more precisely quantify these emissions using the latest available data from published literature, an exhaustive screening study was conducted to determine median emissions factors for EGS binary, hydrothermal binary, and hydrothermal flash geothermal technology (Eberle et al. 2017). These emissions factors were then embedded within the ReEDS model's combustion and life cycle emissions calculation framework. A summary of the emissions factors reported in this geothermal technology LCA screening study is presented in Figure 20.

[7] Fuel cycle emissions include those from resource extraction, processing, and delivery.

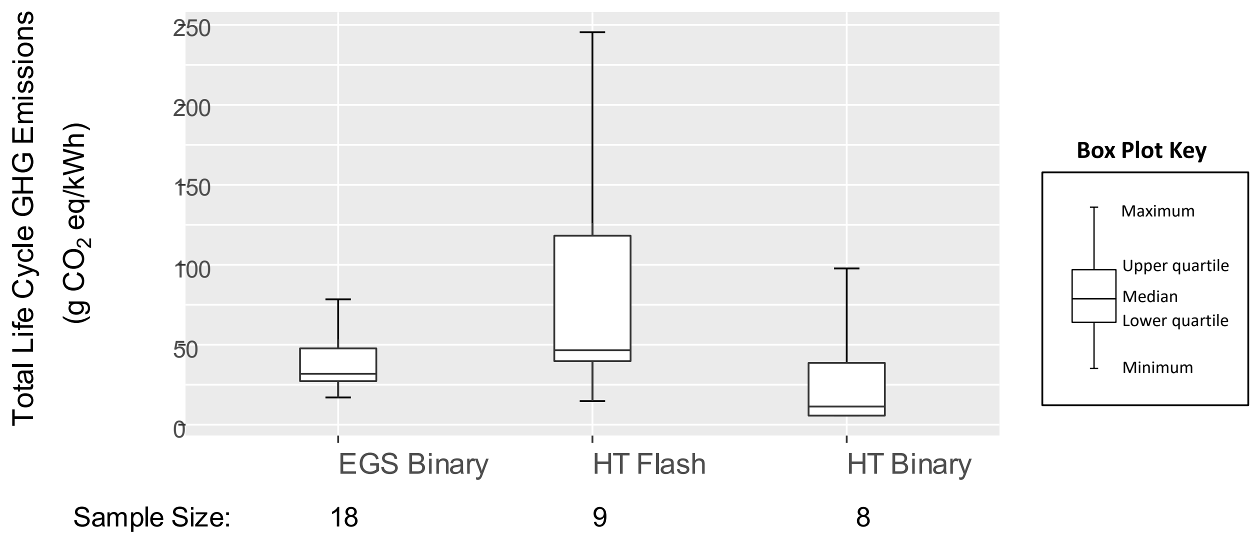


Figure 20. Life cycle GHG for three types of geothermal electricity: EGS binary, hydrothermal flash, and hydrothermal binary

Sample size refers to the number of estimates forming the box plot summary statistics for each technology.
Source: Eberle et al. 2017

5.2.2 Geothermal Heat Pump

Emissions displacement resulting from the adoption of GHP technology in commercial and residential buildings is determined from the dGeo outputs by comparing the modeled baseline fuel requirements[8] with the amount of electricity required for adopters of GHP. To calculate the cumulative CO_2 equivalent emissions displaced by GHP adoption for a given dGeo scenario year, the differences between an agent's baseline and GHP energy requirements for each fuel type, multiplied by the corresponding fuel-specific emission factor, are summed. These quantities are then scaled by the number of GHP adopters for each agent in the model year. Finally, all agents' displaced emissions are combined to get the emissions displacement for a single year. To arrive at a cumulative total for the 2015–2050 period, this aggregation is repeated for every modeled year,[9] interpolating the middle year's displaced emissions. The full aggregation of displaced GHP emissions is presented in this equation:

$$\begin{aligned}&\mathit{Cumulative\ Displaced\ GHP\ Emissions}\ (MMTCO_2e)\\&=\sum_{t=2015}^{2050}\sum_{i=1}^{n}\sum_{j=1}^{6}\left(a_{i,t}\right)*\left(b_{i,j}-g_{i,j,t}\right)*f_{i,j,t}\end{aligned}$$

where
$a_{i,t}$ = the number of GHP-adopting buildings for representative agent i in year t
n = the number of agents at the desired level of aggregation (state or national)

[8] dGeo models six fuel types: natural gas, electricity, propane, fuel oil, district hot water, and district steam.
[9] dGeo, like ReEDS, has a 2 year time step.

$b_{i,j}$ = the baseline requirement of fuel j per agent i building
$g_{i,j,t}$ = the GHP adopters' requirement for fuel j per building in agent i in year t
$f_{i,j,t}$ = the emissions factor associated with one of the six displaceable baseline fuels used by agent i in year t.

$f_{i,j,t}$ is a constant for each fuel type except electricity; the emissions factor for electricity varies both geographically and temporally to match the local generation mix at the power control area (PCA) level. Baseline heating requirements remain fixed over time for each agent in the dGeo GHP model, while the GHP adopters' required electricity amounts may change over time.

5.2.3 Additional Methodological Notes and Possible Related Limitations

Several additional aspects of the methodology, and possible related limitations, deserve note. First, our GHG emissions-reduction estimates are inherently uncertain, in part owing to the impact of uncertain policy and market factors on those reductions. Specifically, electric sector emission policies are based on current active regulations, thus while MATS and CSAPR are included in the modeling, the CPP is not. Additional regional policies designed to limit CO_2 emissions are also not included. Moreover, life cycle emissions are based on median (and static, not affected by future decarbonization trends) literature estimates. Second, we do not consider the possible erosion or enhancement of the GHG benefits because of the increase or decrease of cycling, ramping, and part loading required of fossil generators in electric systems with higher penetrations of geothermal energy. This omission, however, will not meaningfully bias our results, because the available literature clearly demonstrates that this impact is small. For example, see Lew et al. (2013).

5.3 Results

5.3.1 Electric Sector

Both the IRT scenario and TI scenario show reduced fossil electricity generation leading to reduced fossil fuel-based carbon emissions in the electric sector. Figure 21 shows annual combustion-related carbon emissions (left panel) and annual life cycle GHG emissions (right panel) for the BAU, IRT, and TI scenarios.

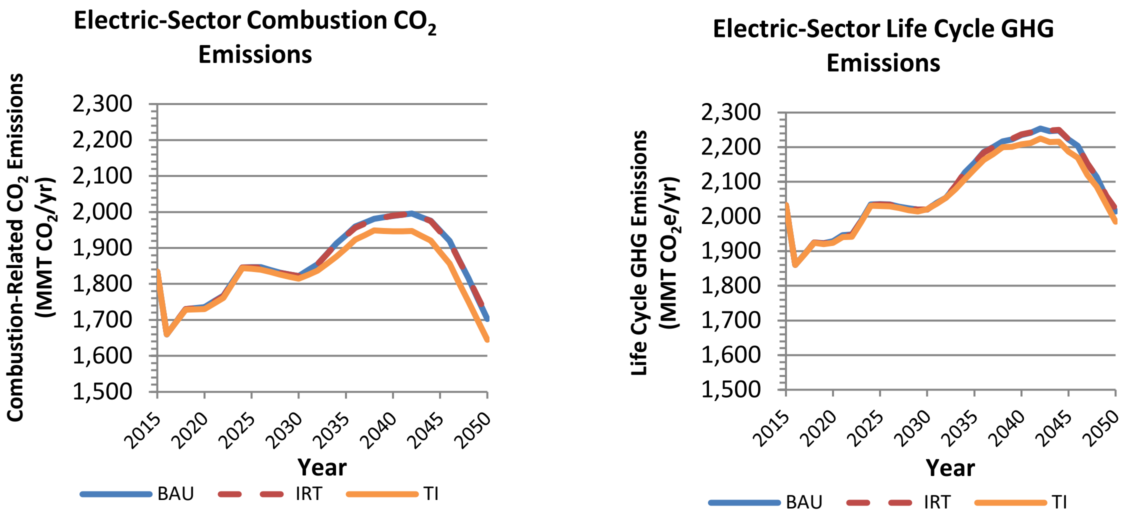


Figure 21. Electric-sector GHG emissions in the BAU, IRT, and TI scenarios

The TI scenario is estimated to reduce combustion emissions in the electric sector relative to the BAU scenario: 5 MMT CO_2 in 2020 (0.3%), 7 MMT CO_2 in 2030 (0.4%), and 58 MMT CO_2 in 2050 (3.4%).[10] Cumulative combustion emissions from 2015 to 2050 are reduced by 954 MMT CO_2 (1.2%). By contrast, cumulative combustion emissions reductions in the IRT scenario are smaller in magnitude, at 18 MMT CO_2 (< 0.1%).

The estimates of combustion-related emissions in the left panel of Figure 21, however, do not consider several potentially important effects. First, only CO_2 emissions are considered while other potent GHGs are ignored, an omission that may be particularly important for methane released in coal mining, oil production, and natural gas production and transport. Second, and related, only emissions from the combustion of fossil energy are counted, while emissions from upstream fuel extraction and processing are disregarded.[11] Finally, a focus on combustion-only emissions means that the GHG emissions from equipment manufacturing and construction, O&M activities, and plant decommissioning are not considered. A more comprehensive evaluation requires that GHG emissions across the full life cycle of each technology be evaluated with LCA procedures, and the results of this assessment are presented in the right panel of

[10] Unless otherwise noted, all reported values related to CO_2 or GHG emissions are in units of metric tons (i.e., tonne) of CO_2 or CO_2e.

[11] GHG emissions associated with securing and transporting fuel are applicable not only to fossil fuels such as coal and natural gas but also to nuclear (uranium).

Figure 21.[12] An extensive review and analysis of previously published LCAs on electricity generation technologies was conducted through the LCA Harmonization Project.[13]

As of 2017, emissions estimates from the LCA Harmonization Project are now embedded within the ReEDS model, enabling ReEDS to directly calculate noncombustion, upstream, and downstream emissions in addition to combustion emissions. For the *GeoVision* analysis, the life cycle emissions estimates collected by the LCA Harmonization Project were augmented by an assessment of additional geothermal LCA literature, published through February 2017 (Ghafghazi et al. 2011). Based on this comprehensive literature assessment, the median life cycle GHG emission values for EGS binary, hydrothermal binary, and hydrothermal flash geothermal technologies were updated within the ReEDS model and used in the calculation of the geothermal electric sector life cycle emissions.

When considering the full life cycle, Figure 21 (right panel) shows that the TI scenario reduces GHG emissions in the electric sector relative to the BAU scenario by 5 MMT CO_2e (0.2%) in 2020, -2 MMT CO_2e (-0.1%) in 2030, and 30 MMT CO_2e (1.5%) in 2050. Cumulative life cycle GHG emissions are reduced by 516 MMT CO_2e (0.7%) from 2015 to 2050. The GHG emissions avoided annually by 2050 are roughly equal to the annual emissions of 6.4 million cars.[14]

As shown in the top panel of Figure 22, noncombustion and upstream GHG emissions in the TI scenario are greater than in the BAU scenario, resulting in negative GHG displacement for both of these categories. Greater indirect[15] emissions in the TI scenario compared with the BAU scenario are mainly because of deep EGS flash plant construction. Total life cycle emissions displacement in the TI scenario is smaller in magnitude than the combustion-only emissions displacement in the TI scenario. Figure 22 (bottom panel) indicates that the cumulative life cycle GHG emissions in the IRT scenario are essentially equivalent to emissions in the BAU scenario, (specifically they are 8 MMT CO_2e [<0.1%] higher than the BAU scenario).

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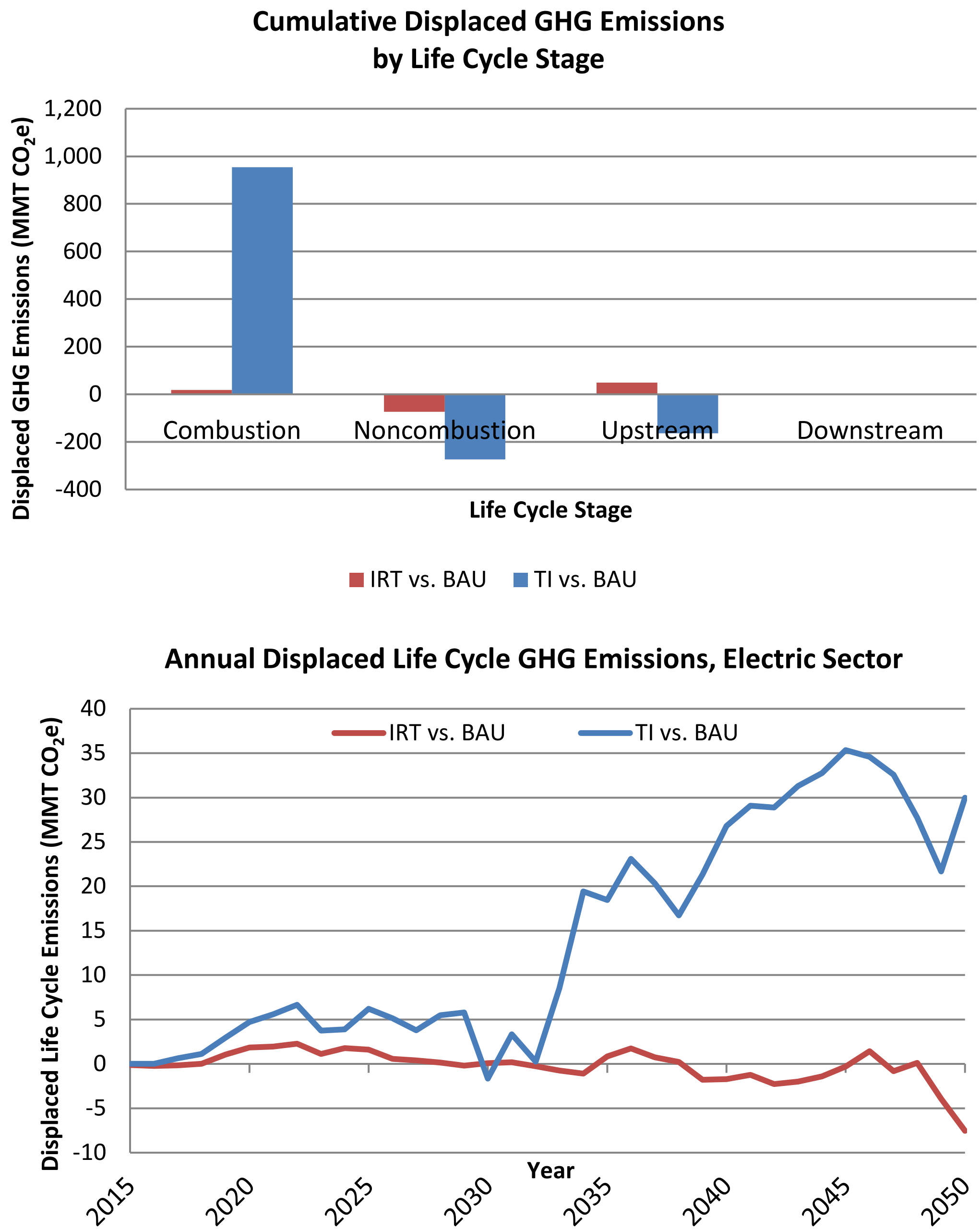
[12] A full LCA considers upstream emissions, ongoing combustion and noncombustion emissions, and downstream emissions. Upstream and downstream emissions include emissions resulting from raw materials extraction, materials manufacturing, component manufacturing, transportation from the manufacturing facility to the construction site, on-site construction, project decommissioning, disassembly, transportation to the waste site, and ultimate disposal and/or recycling of the equipment and other site material.

[13] https://www.nrel.gov/analysis/life-cycle-assessment.html

[14] Assuming a typical passenger vehicle emits about 4.7 t of CO_2 per year, based on the assumption of a fuel economy of about 21.6 miles per gallon and 11,400 miles of travel per year. Thus, this represents recent typical conditions for the United States.

[15] Indirect emissions are defined as the sum of emissions from all life cycle stages except for direct combustion. This includes upstream (including construction), noncombustion, and downstream emissions.



The height of the annual displacement plot (bottom panel) equals the total displacement for the TI scenario compared with the BAU scenario.

Figure 22. Cumulative displaced GHG emissions in the electric sector by life cycle emission type (top panel) and annual life cycle GHG emissions displacement in the electric sector (bottom panel)

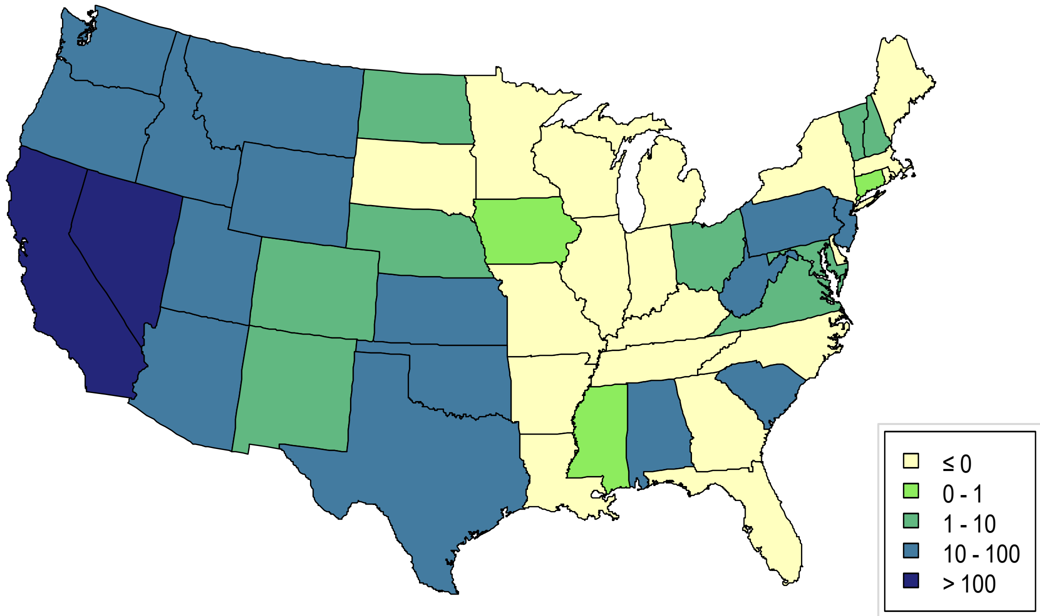


Figure 23. State-level cumulative 2015–2050 combustion-related CO_2 reductions in the electric sector for the TI scenario relative to the BAU scenario

For the TI scenario, Figure 23 shows that cumulative combustion CO_2 emissions reductions are concentrated in the West. In California and Nevada, high levels of geothermal deployment, combined with reductions in electricity generation primarily from natural gas, result in the two highest state-level, cumulative combustion CO_2 emissions displacement totals, at 320 MMT and 130 MMT, respectively. A clustering of emissions reductions is also observed in the mid-Atlantic region because of the deployment of deep EGS in West Virginia. The noncombustion, life cycle impacts are not assigned to regions (and so are not included in Figure 23) because of the challenges of estimating the location of upstream and downstream emissions.

5.3.2 Geothermal Heat Pumps

The Breakthrough scenario shows reduced fossil energy consumption for heating and cooling in the residential and commercial buildings markets from GHP adoption leading to reduced fossil fuel-based carbon emissions beyond those in the electric sector.

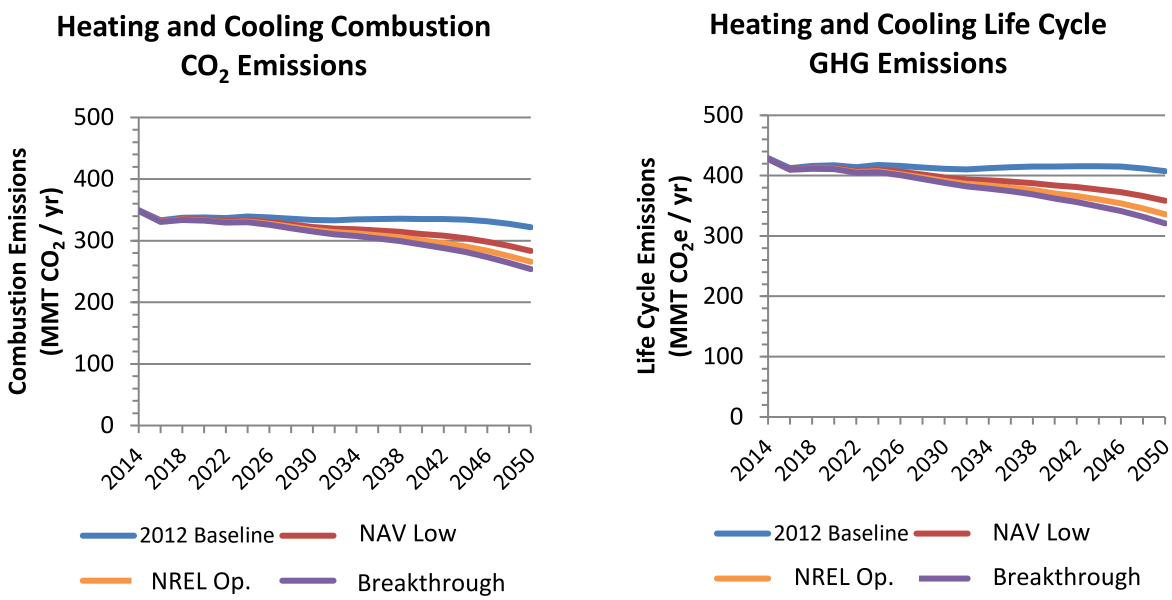


Figure 24. Commercial and residential building heating and cooling sector GHG emissions considering GHP deployment in the 2012 baseline scenario as compared with the Navigant Low Scenario (NAV Low) scenario, NREL Optimistic scenario (NREL Op.), and Breakthrough scenario

Common residential and commercial heating and cooling systems, such as furnaces, portable space heaters, window/wall air conditioners, and central air systems, are the technologies displaced by GHP. The displaced fuels used by these technologies include natural gas, fuel oil, propane, electricity, district steam, and district hot water. Figure 24 shows the annual combustion-related carbon emissions (left panel) and annual life cycle emissions (right panel) for the Breakthrough scenario, the Navigant Low scenario, and the NREL Optimistic scenario and a 2012 GHP-baseline scenario.

The left panel of Figure 24 shows that the Breakthrough scenario is estimated to reduce annual direct combustion CO_2 emissions in the residential and commercial building heating and cooling sector relative to the 2012 baseline scenario: 5.4 MMT CO_2 (1.6%) in 2020, 19 MMT CO_2 (5.7%) in 2030, and 68 MMT CO_2 (21%) in 2050. Cumulative combustion emissions from 2015 to 2050 in the Breakthrough scenario are 1,014 MMT CO_2 (8.2%) lower than in the 2012 baseline scenario, whereas the NREL Optimistic scenario and Navigant Low scenario show relatively smaller reductions, at 848 MMT CO_2 (6.8%) and 593 MMT CO_2 (4.8%), respectively.

As in Figure 22, which summarizes electric sector emissions reductions, the left panel of Figure 24 only includes combustion-related CO_2 emissions reductions. Unlike Figure 22, the right panel of Figure 24 includes life cycle emissions associated with the displaced fossil fuels and electricity required for GHP operation only; it does not include construction and decommissioning life cycle emissions from the GHP technology.

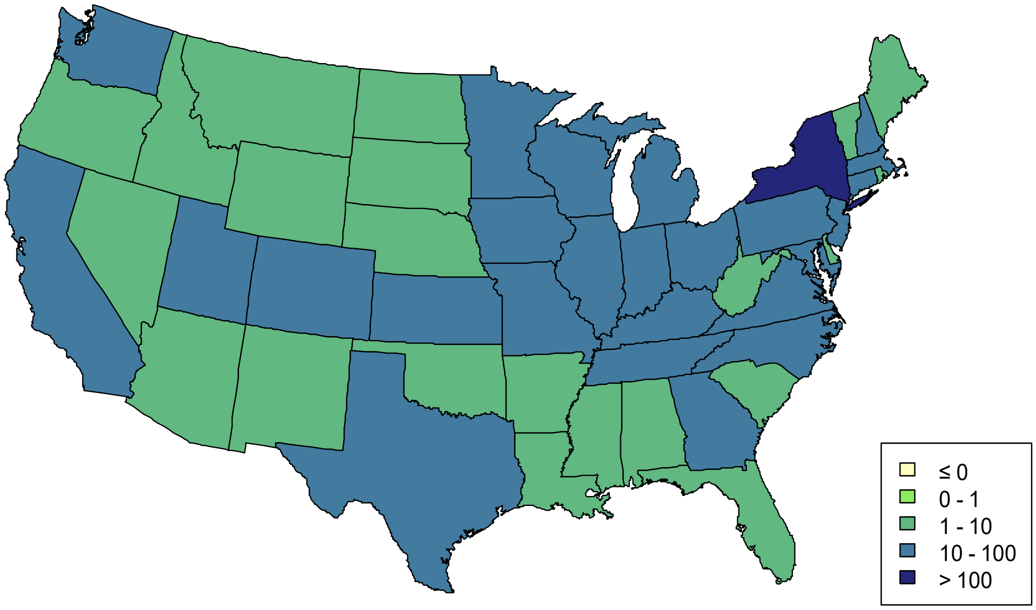


Figure 25. State-level cumulative 2015–2050 combustion-related CO_2 reductions based on GHP deployment in the residential and commercial building heating and cooling sector for the Breakthrough scenario relative to the constant 2012 baseline scenario

Although the omission of GHP construction and dismantling likely leads to an overestimate of the GHG displacement in the Breakthrough scenario, the magnitude of overestimation is judged small because GHG emissions from these omitted life cycle stages are small compared with those associated with the electricity consumed during GHP operation, which are in turn small compared with emissions from combustion-based technologies (Ghafghazi et al. 2011). GHG emission factors for displaced fuels were obtained from Argonne National Laboratory's Greenhouse gases, Regulated Emissions, and Energy use in Transportation (GREET) Model (ANL 2016) and the U.S. Energy Information Administration's Annual Energy Outlook (AEO) 2016 (EIA 2016).[16] (For more information about the GHP greenhouse gas emissions calculation methodology, please see Supplement C).

When considering the full life cycle, Figure 24 (right panel) shows that the Breakthrough scenario is estimated to reduce GHG emissions in the heating and cooling sector relative to the 2012 baseline scenario: 6.7 MMT CO_2e (1.6%) in 2020, 24 MMT CO_2e (5.8%) in 2030, and 87 MMT CO_2e (21%) in 2050. The GHG emissions avoided annually by 2050 are roughly equal to the annual emissions of 20 million cars.

Cumulative life cycle GHG emissions from 2015 to 2050 in the Breakthrough scenario are 1,281 MMT CO_2e (8.3%) lower than in the 2012 baseline scenario, whereas the NREL Optimistic scenario and Navigant Low scenario show relatively smaller reductions, at

[16] Combustion emissions factors for natural gas, propane, and district steam/hot water were obtained from GREET, and the combustion emissions factor for fuel oil was obtained from the U.S. Energy Information Administration (2016). Indirect emissions factors for natural gas, propane, fuel oil, and district steam/hot water were all obtained from GREET. Geographically and temporally specific combustion and indirect emissions factors for electricity were obtained directly from ReEDS.

1,077 MMT CO_2e (7.0%) and 753 MMT CO_2e (4.9%), respectively. Life cycle GHG reductions are larger in absolute terms than combustion-only CO_2 reductions. Displacement of natural gas and fuel oil accounts for the majority of GHG displacement in the GHP sector.

As shown in Figure 25, cumulative combustion emissions reductions are more evenly distributed throughout the continental United States for GHP deployment than for electric sector geothermal deployment, yet with somewhat higher amounts in the mid-Atlantic, Midwest, and Great Lakes regions. This is expected because electric sector resources are concentrated in the western United States while GHP resources are available throughout the country.

Figure 26 shows that GHG emissions displacement is dominated by the displacement of natural gas[17] and fuel oil, accounting for a combined 80% of annual displaced emissions. This is not surprising; natural gas and fuel oil are the first and third most commonly used main space heating fuels in the United States, according to the 2015 Residential Energy Consumption Survey (EIA 2016). The second most used main space heating fuel, electricity, does not exhibit significant GHG emissions displacement[18] because GHPs require electricity to operate. Displacement of propane, the fourth most used main space heating fuel in the United States (just behind fuel oil), is moderate, at about 10% of annual emissions reductions. Emissions reductions attributable to the displacement of district steam and district hot water are negligible.

[17] Displacement of natural gas alone accounts for about 60% of the GHG emissions displacement in this sector, on both an annual and cumulative basis.
[18] Displacement of electricity accounts for about 8% of the total displaced GHG emissions in this sector, on both an annual and cumulative basis.

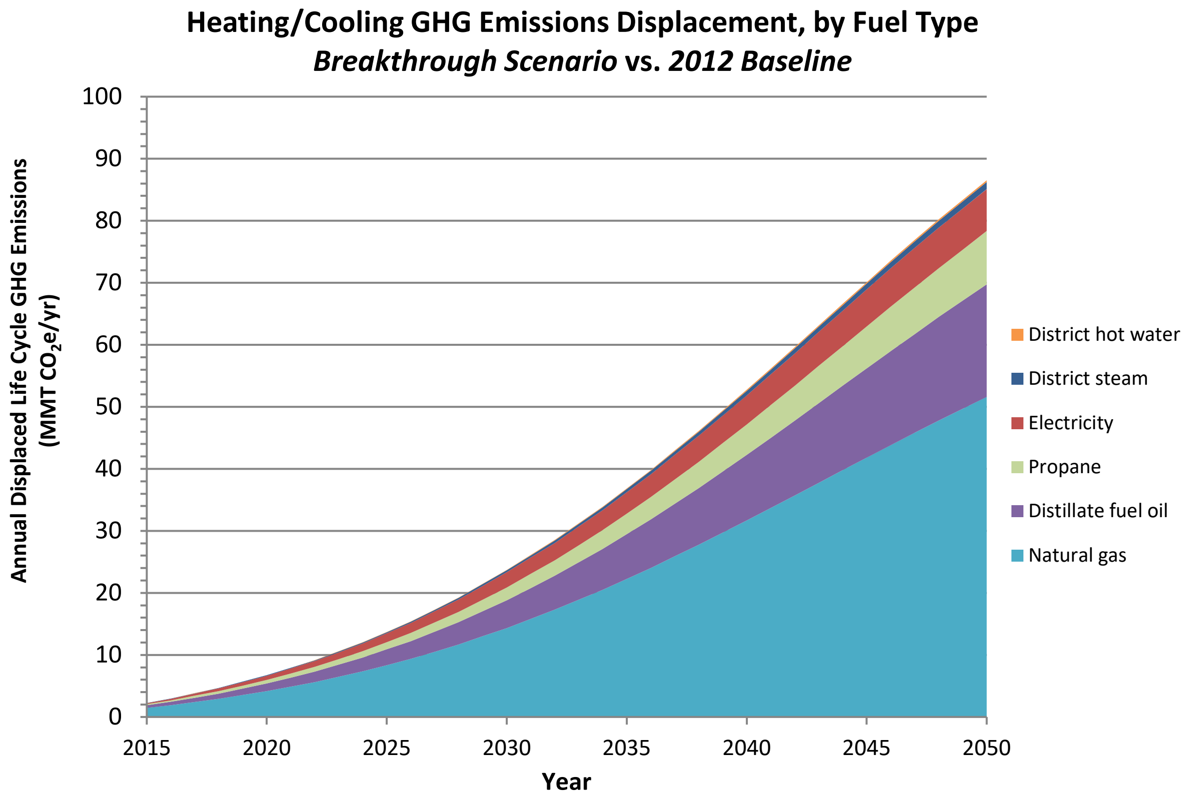
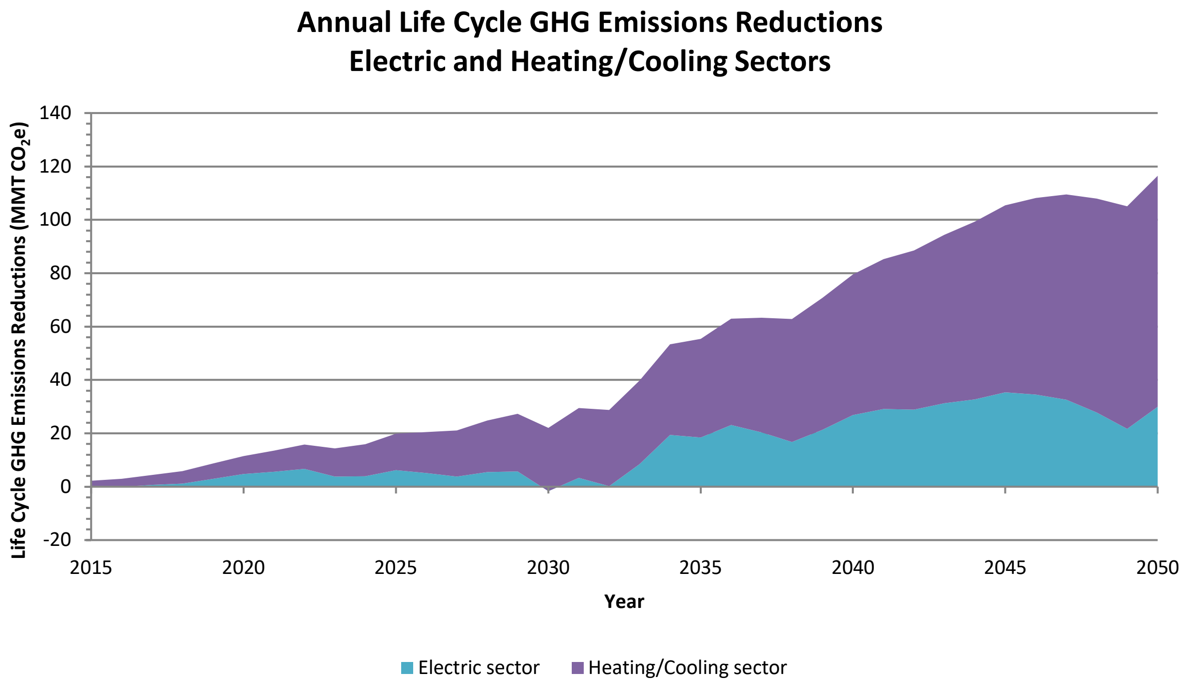


Figure 26. Life cycle GHG emissions by displaced fuel type

5.4 Concluding Remarks

Geothermal deployment in the U.S. electric sector and the residential and commercial building heating and cooling sector, as modeled in the ReEDS TI and dGeo Breakthrough scenarios respectively, yields cumulative life cycle GHG emissions reductions through 2050 of 516 MMT CO_2e and 1,281 MMT CO_2e relative to the respective model baselines. As shown in Figure 27, the rate of emissions reductions (on an annual basis) increases from 2015 through 2050, reaching a combined annual reduction of 117 MMT CO_2e per year by 2050. These reductions are significant and, by 2050, the emission reductions are equivalent to removing roughly 26 million cars from the road.



Note: Electric sector GHG displacement is for the ReEDS TI scenario relative to the BAU scenario, and residential and commercial building heating and cooling GHG displacement is for the dGeo Breakthrough scenario relative to the constant 2012 baseline scenario.

Figure 27. Annual life cycle GHG emissions displacement in the electric and heating/cooling sectors

6 Direct-Use Impacts

Summary

A case study of seven representative hydrothermal direct-use heating systems and seven representative EGS direct-use systems shows that direct-use systems can provide significant job opportunities while providing air quality and climate benefits. The size of direct-use systems sampled here can range from approximately 5 megawatt thermal (MW_t) to around 55 MW_t and can serve up to tens of thousands of buildings. If 50–100 direct-use systems were developed each year, this could annually provide about 10,000 jobs while reducing emissions and preventing dozens of premature mortalities related to exposure to air pollution. This rate of development is feasible given the economic potential. However, deployment would depend on the feasibility and preference of developing EGS resources for direct-use purposes, and thus development on this level would likely not begin until 2030.

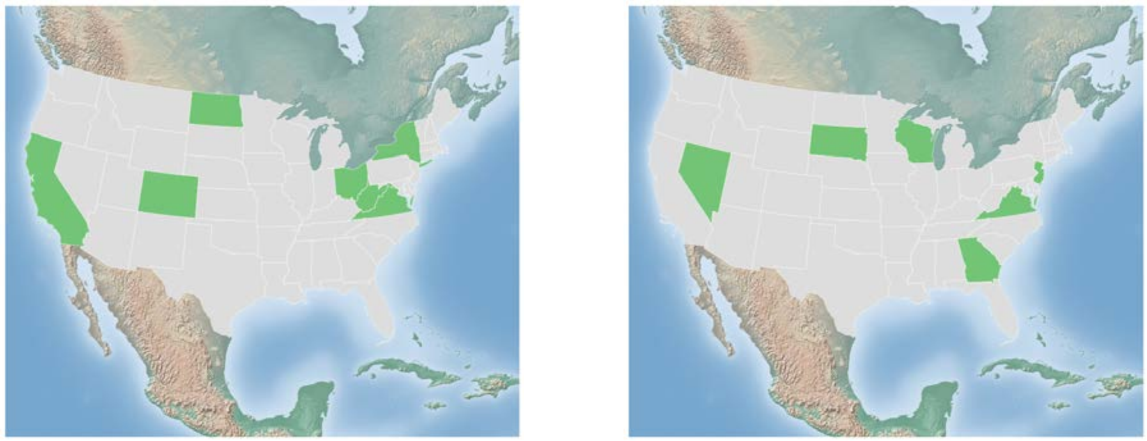
6.1 Introduction

Direct use of geothermal resources for district heating is different from GHP systems in that underground heat reservoirs are tapped to provide heating for many, sometimes thousands of, buildings. The dGeo model was used to calculate the economic possibility of expanded use of direct-use geothermal resources for district heating. dGeo develops deployment scenarios based on a three-step process. First, the technical availability of a resource is calculated across all locations. Second, economic potential of deployment is calculated, which is based on the feasibility of using a resource (i.e., revenues from a renewable resource exceed the costs of development) at each location. Finally, the likelihood of deployment of such a resource in any particular year and location is calculated based on consumer acceptance and market adoption rates of economic feasible sites. This last calculation is called the market potential, and in the direct-use case, and unlike the GHP case, the market potential is poorly constrained because of the limited data and experience with direct use in the United States. This means that, although a large potential expansion of direct-use systems can be envisioned as feasible, precise expansion scenarios (such as the Breakthrough scenario for GHP) were not developed for direct-use systems. Therefore, instead of estimating the impacts of a full expansion scenario, we quantify the impacts of a limited number of representative systems and use those results to qualitatively describe the impacts of larger direct-use expansion. We choose representative systems from two direct-use economic potential scenarios, a BAU scenario and a TI scenario which uses the same cost and technology improvement assumptions for developing the direct-use reservoir as the electricity sector TI scenario (see McCabe et al. [2019] for direct-use scenario details).

6.2 Methods

We quantify the impacts on job opportunities, fuel use, electricity demand, and air pollutant and GHG emissions for a set of representative systems within the two direct-use scenarios: BAU and TI. Representative plants are chosen based on the median levelized cost of heating of all plants in a particular region (Figure 28). We analyze direct-use systems across the four U.S. census regions within the continental United States. For the direct-use case studies, specific instances of direct-use plant construction were selected from the full set of modeled direct-use systems. The direct-use plants that had the median levelized cost of heating value within each combination of region (Northeast, Midwest, South, and West) and technology type (hydrothermal and EGS) were selected as case studies.[19]

(a) (b)



(a) BAU scenario and (b) TI scenario

Figure 28. States chosen for the representative direct-use systems based on the median levelized cost of heat in each region

The methods for assessing impacts of each representative system were adapted from the methods developed to assess the impact of the GHP *GeoVision* scenarios. The method descriptions within the prior impact analysis sections contain details about the approaches that were applied to direct use. For example, direct-use job opportunities are estimated based on the use of the IMPLAN model, following the approach described for the GHP sector. For air quality, emission factors that were developed and applied to the fuel use and equipment within the context of the dGeo model for GHP were applied to the dGeo outputs in the context of direct use as well. Because direct-use systems face variable demand but utilize a relatively constant heat resource, many direct-use systems contain a peaking boiler. Emissions of air pollutants and GHGs from the peaking boiler were accounted for, and emission benefits described account for the total difference between a region's emissions with and without a direct-use plant deployed. Specifically, to estimate GHG emissions, the baseline[20] heating emissions of all modeled dGeo agents within each newly constructed direct-use plant's PCA were aggregated and compared with the aggregate emissions from dGeo's calculated mix of adopting and nonadopting agents in each direct-use plant's PCA. The differences are estimates of the local life cycle GHG emissions displacements resulting from each direct-use plant's construction.

6.3 Results and Discussion

The direct-use case study shows that benefits vary widely based on the type and size of system, system location, and the type of fuel use that is avoided. Despite this variation, it is clear that significant national level benefits could potentially be achieved with the widespread adoption of direct-use systems. The magnitude of these benefits would depend on the adoption rates and

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[19] No plant was selected for the Northeast/hydrothermal combination, because there were no hydrothermal direct-use plants deployed in the Northeast region in either dGeo scenario.

[20] Here, "baseline" refers to the heating emissions in a scenario without direct-use adoption.

market acceptance of direct-use systems. Thus, a detailed quantification of these benefits would require further research. For the remainder of this section, we review the specific benefits of the direct-use case study systems and then put these benefits in some context given the potential size of the economically viable market for direct-use systems.

The size of the hydrothermal direct-use systems ranges from 4 MW_t to 21 MW_t of name-plate capacity, and the range of buildings these direct-use systems serve is 51 to 2,041. In general, the direct-use systems that serve thousands of buildings are serving both a smaller number of large commercial properties and a larger number of small residential properties. The size of the EGS direct-use systems ranges from 14 MW_t to 55 MW_t of name-plate capacity, and the range of buildings these systems serve is 1,070–19,538. These ranges include systems from both the BAU and TI scenarios. In general, the EGS systems are larger than the hydrothermal systems. Also, in most— but not all—cases, the TI scenario systems are larger than the BAU scenario systems. Table 5 shows details related to all the individual system sizes.

Investment and associated employment benefits are a function of the system size but vary widely by location and system type. The total investment for each of the case study systems ranges from $12 million to $44 million. This investment leads to roughly 100–200 full-time jobs created during the construction phase across all the types of systems. A small number of jobs per system would be required on an ongoing basis for maintenance. Thus, to create 10,000 jobs per year within the direct-use sector, 50–100 systems would need to be developed each year. This level of development, approximately 5 gigawatt thermal per year, is a small fraction of the total economic potential projected to be feasible for development starting in 2030 when it is assumed EGS systems become feasible. In general, on a per-system basis, EGS systems provide slightly greater job opportunities than the hydrothermal systems, with some of that difference being related simply to system size and the need for reservoir stimulation. The technical and economic potential is much larger for EGS than hydrothermal systems. Thus, significant job growth at a national level would depend on EGS feasibility. However, hydrothermal direct-use systems may provide important employment benefits at regional or local levels. Details for the individual systems can be seen in Table 6.

There is large variation in the magnitude of air quality benefits provided by direct-use systems. The magnitude of the air quality benefits is driven by the type of fuel and energy offset by the direct-use system, which is in turn determined by the region. The direct-use systems that provide significant air quality benefits offset local combustion—specifically, combustion of fuel oil. Some direct-use systems primarily offset electricity usage, and those systems provide relatively low air quality benefits. The EGS direct-use systems all provide significant air quality benefits, with most systems reducing roughly one instance of premature mortality every three years. One of the systems, which offsets significant use of fuel oil, reduces roughly seven premature mortalities per year. However, there is wider variation, and therefore higher uncertainty, between the health impact models for this particular location compared with other locations. The hydrothermal direct-use systems provide comparatively low air quality benefits. Details related to system level air quality benefits can be seen in Table 7.

GHG emissions are reduced by direct-use systems (see Table 8). As in the previous impact categories, the benefits vary by plant but are strongest for EGS plants. Most EGS direct-use systems reduce life cycle CO_2 emissions by 30–100 TMT per year. Large benefits are seen in both the BAU scenario and the TI scenario.

6.4 Concluding Remarks

We have reported that individual direct-use systems can create new local job opportunities while providing air quality and GHG emission benefits. The key to deriving large-scale benefits is the development of many direct-use systems each year, necessitating the development of EGS resources. Interestingly, although the BAU scenario versus TI scenario assumptions make a significant difference in the total economic potential available for deployment, benefits on a per system basis from BAU and TI systems are relatively consistent across the impact categories. We do see large differences in benefits between EGS and hydrothermal plants. In fact, much of the large-scale potential benefits that could be derived from direct-use systems rely on the ability to develop EGS direct-use systems. Without a specific deployment scenario, we are unable to estimate the scope of the total potential benefits. However, the development of 50–100 direct-use systems per year could annually provide approximately 10,000 jobs while reducing emissions and preventing dozens of premature mortalities related to exposure to air pollution.

Table 6. Summary of Size and Energy Characteristics, Investment, and Job Creation for Direct-Use Systems in the Business-as-Usual and Technology Improvement Scenarios

Scenario	Year	Region	State	Resource Type	Name-Plate Capacity (MW_t)	On-Site Fuel Energy Reduction (MWh)	On-Site Electricity Energy Reduction (MWh)	On-Site Fuel Energy Demand (MWh)–Peaking Boiler	Number of Buildings	Expenditures (thousands of dollars)	FTE Jobs
BAU	2016	Midwest	ND	HT	6	0	2,106	246	273	25,049	144
BAU	2016	South	VA	HT	8	90	7,985	242	61	25,352	146
BAU	2026	West	CA	HT	9	40	9,626	183	119	12,356	71
BAU	2038	South	WV	EGS	20	20,591	0	306	1,170	30,751	177
BAU	2040	Northeast	NY	EGS	28	206,241	48,980	577	8,627	31,685	182
BAU	2046	West	CO	EGS	14	485,317	75,506	333	19,538	28,269	163
BAU	2046	Midwest	OH	EGS	19	173,851	98,229	261	12,934	36,666	211
TI	2016	Midwest	SD	HT	4	0	3,748	87	924	13,202	74
TI	2016	South	VA	HT	7	75	7,511	138	51	20,223	114
TI	2026	West	CA	HT	21	54,804	40,780	183	2,041	24,045	135
TI	2030	Northeast	NJ	EGS	27	211,363	37,454	290	8,553	22,310	126
TI	2038	Midwest	WI	EGS	28	132,721	22,996	248	6,198	28,022	158
TI	2042	West	NV	EGS	55	445,417	47,589	476	17,210	44,900	253
TI	2046	South	GA	EGS	28	135,479	173,472	276	19,440	19,941	112

Note: HT = hydrothermal

Table 7. Summary of Air Quality Benefits for Direct-Use Systems in the Business-as-Usual and Technology Improvement Scenarios (Includes Monetized and Mortality Benefits)

				Fuel Use			Electricity				
					Monetary Benefits (thousands of dollars [2015])		Monetary Benefits (thousands of dollars [2015])			Mortality Reduction (count)	
Scenario	Year	Region	Resource Type	Mortality Reduction (count)	EASIUR Low	PENN	AP2	EPA High	EPA Low	EPA High	EPA Low
BAU	2016	Midwest	HT	0	-	-	57	210	84	0.02	0.01
BAU	2016	South	HT	0	0	1	186	530	222	0.06	0.02
BAU	2026	West	HT	0	0	0	22	148	62	0.02	0.01
BAU	2038	South	EGS	0.04	45	297	0	0	0	0	0
BAU	2040	Northeast	EGS	0.54	3,380	3,781	117	367	145	0.03	0.01
BAU	2046	West	EGS	0.17	1,732	1,072	1,662	1,941	754	0.2	0.08
BAU	2046	Midwest	EGS	7.2	2,586	45,593	2,362	5,915	2,533	0.59	0.25
TI	2016	Midwest	HT	0	-	-	84	417	159	0.04	0.02
TI	2016	South	HT	0	0	1	175	499	209	0.05	0.02
TI	2026	West	HT	0.08	254	660	140	210	81	0.02	0.01
TI	2030	Northeast	EGS	0.47	5,762	3,883	710	1,021	425	0.1	0.04
TI	2038	Midwest	EGS	0.13	1,620	975	490	1,436	613	0.14	0.06
TI	2042	West	EGS	0.61	1,561	4,086	308	499	192	0.05	0.02
TI	2046	South	EGS	0.22	892	1,373	2,007	6,905	2,988	0.69	0.29

Note: HT = hydrothermal

Table 8. Summary of Greenhouse Gas Benefits for Direct-Use Systems in the Business-as-Usual and Technology Improvement Scenarios

Region	Resource Type	BAU Combustion CO_2 Offset (TMT CO_2e)	BAU Life Cycle CO_2e Offset (TMT CO_2e)	TI Combustion CO_2 Offset (TMT CO_2e)	TI Life Cycle CO_2e Offset (TMT CO_2e)
Midwest	HT	1	1	1	1
South	HT	2	3	2	3
West	HT	1	1	16	19
Northeast	EGS	33	42	33	41
Midwest	EGS	37	46	25	30
South	EGS	3	3	55	65
West	EGS	80	100	65	85

Note: HT = hydrothermal

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Supplement A: Jobs and Economic Development Impact and Economic Impact Analysis for Planning Model Validation

Calculating economics of achieving the *GeoVision* rely on the use of two models: (1) the Geothermal Jobs and Economic Development Impact (JEDI) spreadsheet tool developed by the National Renewable Energy Laboratory (NREL) and (2) the Economic Impact Analysis for Planning (IMPLAN) modeling software developed by MIG Inc. The JEDI tool was used to calculate employment impacts for the electric sector, and IMPLAN was used for geothermal heat pump (GHP) and geothermal direct-use plants. Both tools utilize input-output (I-O) methodology that calculates economic impacts of expenditures in different economic sectors.

I-O models estimate how expenditures from one sector of the economy interact with other sectors of the economy. Economic sectors are interdependent with one another and require inputs from other economic sectors to function. For example, construction of geothermal power plants will require steel, which will require input from the iron ore and smelting sectors of the economy. Both JEDI and IMPLAN model how increased expenditures in geothermal technologies will increase demand in other related sectors. For more information on I-O model methodology, see Miller and Blair (2009).

Jobs and Economic Development Impact Modeling—Electric Sector

JEDI allows the user to calculate economic impacts for individual geothermal projects. Default cost, local content percentages, and I-O multipliers are included with the model, but users can update these individual numbers for specific project costs. Each JEDI tool was validated by industry and economic experts for the individual technologies, along with comparison to observed employment trends (Billman and Keyser 2013).

All cost and deployment inputs into the JEDI model come directly from Regional Energy Deployment System (ReEDS) outputs. No default cost numbers were changed in the JEDI geothermal model, except for those explicitly called for in ReEDS.

Jobs and Economic Development Impact Results

Jobs from JEDI are split up into on-site construction, short-term jobs and into operation and maintenance (O&M), long-term jobs. On-site construction jobs will be supported over the construction phase of project development, typically 1–5 years. O&M jobs will be supported over the life of the project and can last roughly 25–30 years. JEDI calculates jobs and economic impact for three categories: on-site, supply chain, and induced jobs (see Table A-1).

Table A-1. Breakout of Jobs and Economic Development Impact Job Classifications

On-Site	Supply Chain	Induced
Power plant construction crews Drillers Well stimulation crews Management Environmental Road construction Operators/maintenance contractors Power line construction Legal and siting	Geothermal turbine manufacturers Piping manufacturers Trucking and vehicle equipment manufacturers Support businesses—financers, bankers Utilities Tooling and equipment suppliers	Jobs and earnings that support spending from the project—including, but not limited to: Daycare providers Rental incomes Grocery store clerks Retail workers

Local Content Percentages

JEDI default local content percentages were used for economic modeling listed in Table A-2. Local content percentages can vary by state in the model and the applicable states for the model are listed. Note that some labor items were left out because local content percentages were unknown or zero.

Table A-2. Jobs and Economic Development Impact Default Local Content Percentages Used for Economic Modeling

	Local Content Percentage	Applicable States
Permitting		
Environmental analysis	75%	California, Nevada, Utah, Colorado
Environmental impact assessment	75%	California, Nevada, Utah, Colorado
Exploration (Predrilling)		
Geologist	100%	California, Colorado, Utah, Nevada, Idaho, Oregon, Texas, New Mexico
Geophysicist	100%	California, Colorado, Utah, Nevada, Texas
Geochemist	100%	California, Colorado, Utah, Nevada, Texas
Other geo scientists	100%	California, Colorado, Utah, Nevada, Texas
Field crew	100%	California, Colorado, Utah, Nevada, Texas
Management/administrative	100%	California, Colorado, Utah, Nevada, Texas
Exploration equipment, tests, surveys	100%	California, Colorado, Utah, Nevada, Texas
Exploration Drilling		
Geologist	100%	California, Colorado, Utah, Nevada, Idaho, Oregon, Texas, New Mexico
Mud engineer(s)	100%	California, Colorado, Utah, Nevada, Texas, New Mexico
Drilling fluids–mud	100%	California, Colorado, Utah, Nevada, Texas, New Mexico
Directional engineer and motorman	100%	California, Colorado, Utah, Nevada, Texas, New Mexico
Direction tools and services	100%	California, Colorado, Utah, Nevada, Texas, New Mexico
Drilling engineering	100%	California, Colorado, Utah, Nevada, Texas, New Mexico
Drill rig rate	100%	California, Colorado, Utah, Nevada, Texas, New Mexico
Drill hands–labor	100%	California, Colorado, Utah, Nevada, Texas, New Mexico
Management/administrative		
Site construction	100%	All
Material costs–cement and casing	100%	All
Move services and equipment	100%	All

Location maintenance	100%	All
Fuel	100%	All
Camp	100%	All
Production Drilling		
Geologist	100%	California, Colorado, Utah, Nevada, Idaho, Oregon, Texas, New Mexico
Mud engineer(s)	100%	California, Colorado, Utah, Nevada, Texas, New Mexico
Drilling fluids–mud	100%	California, Colorado, Utah, Nevada, Texas, New Mexico
Directional engineer and motorman	100%	California, Colorado, Utah, Nevada, Texas, New Mexico
Direction tools and services	100%	California, Colorado, Utah, Nevada, Texas, New Mexico
Drilling engineering	100%	California, Colorado, Utah, Nevada, Texas, New Mexico
Drill rig rate	100%	California, Colorado, Utah, Nevada, Texas, New Mexico
Drill hands–labor	100%	California, Colorado, Utah, Nevada, Texas, New Mexico
Site construction	100%	All
Material costs–cement and casing	100%	All
Move services and equipment	100%	All
Location maintenance	100%	All
Fuel	100%	All
Camp	100%	All
Well Stimulation		
Reservoir engineer	100%	California, Colorado, Utah, Nevada, Idaho, Oregon, Texas, New Mexico
Geologist	100%	California, Colorado, Utah, Nevada, Idaho, Oregon, Texas, New Mexico
Geophysicist	100%	California, Colorado, Utah, Nevada, Texas
Drill rig	100%	California, Colorado, Utah, Nevada, Texas, New Mexico
Drill hands–labor	100%	California, Colorado, Utah, Nevada, Texas, New Mexico
Materials (proppant, water)	100%	All
Fuel	100%	All
Injection testing	100%	California, Texas

Mobilization/demobilization	100%	All
Water	100%	All
Downhole logging	100%	California, Texas, Colorado
Flash Plant–Power Plant Costs		
Labor		
Engineering–design	100%	California, Nevada, Idaho, Colorado, Utah
Laborers	100%	All
Mechanical	100%	All
Electrical	100%	All
Binary Plant Equipment		
Turbines, generators	0%	
Air-cooled condenser	100%	Texas, Nevada, California
Well field pumps	100%	Texas, Nevada, California
Geothermal fluid heat exchangers	100%	Texas, Nevada, California
Flash Plant Equipment		
Turbine generator cost	0%	
Flash vessels	100%	Texas, Nevada, California
Cooling tower cost	100%	Texas, Nevada, California
Condenser cost	100%	Texas, Nevada, California
Pump cost	100%	Texas, Nevada, California
Noncondensable gas removal system	100%	Texas, Nevada, California
Hydrogen sulfide removal system	100%	Texas, Nevada, California
Flash Plant Operation and Maintenance Costs		
Labor Costs		
Field labor	100%	All
Plant labor	100%	All

Economic Impact Analysis for Planning Modeling—Geothermal Heat Pump Sector

The JEDI tool was not used to estimate GHP impacts, because the JEDI tool was not created for GHP deployment, and GHP technology is too different from electric sector power plants for modification of the existing tool. IMPLAN is considered an economic industry standard for performing I-O modeling.

For the GHP sector, expenditures came from the Distributed Geothermal Market Demand Model (dGeo) that is described in detail earlier in this report. dGeo results only reported total expenditures needed for deployment and did not include an economic breakout by sector needed for entry into IMPLAN. Individual sectors are dependent on some economic sector more than others, which will result in different levels of indirect jobs for the same expenditure. However, total job creation (direct, indirect, and induced) is more highly dependent on the level of expenditures than the economic sector that expenditure is applied to (i.e., the same expenditure in two different IMPLAN sectors will yield roughly the same employment levels).

For IMPLAN modeling, the following percentage breakout comes from Battocletti and Glassley (2013). A breakout of employment by job type is shown on Page 3 of Battocletti and Glassley (2013). Job makeup percentages were calculated for each job type and applied to IMPLAN economic sectors. The North American Industry Classification System code assigned for each job type was called out in Battocletti and Glassley (2013); this code was used to determine the applicable IMPLAN sectors. The total expenditures from dGeo were allocated according to Table A-3.

Table A-3. Distributed Geothermal Market Demand Model Cost Breakout by Impact Analysis for Planning Sector

IMPLAN Sector Description	IMPLAN Number	Cost Allocation
Electric power transmission and distribution	49	0.66%
Maintenance and repair construction of residential structures	63	20.96%
Air conditioning, refrigeration, and warm air heating equipment manufacturing	277	38.67%
Wholesale trade	395	22.03%
Internet publishing and broadcasting and web search portals	432	0.02%
Architectural, engineering, and related services	449	17.37%
Marketing research and all other miscellaneous professional, scientific, and technical services	460	0.28%

Source: Adapted from Battocletti and Glassley (2013)

O&M spending was not included in the dGeo for residential installations, but there were some costs for commercial systems. All of these O&M costs were included in the model in the "Maintenance and repair construction of residential structures" IMPLAN economic sector.

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Supplement B: Air Pollution

Fine Particulate Matter Emission Estimates

Fine particulate matter ($PM_{2.5}$) emission estimates are developed for both scenarios as the product of Regional Energy Deployment System (ReEDS) generation outputs (megawatt-hours [MWh] by generation type and vintage) and average emission rates (grams per MWh by generation type). Average $PM_{2.5}$ emissions rates (reported by Argonne National Laboratory [Cai et al. 2012; Cai et al. 2013) are differentiated by generation type (coal, gas, or oil) and U.S. state. Additionally, $PM_{2.5}$ emission factors are adjusted over time to comply with scheduled $PM_{2.5}$ Mercury and Air Toxics Standards (MATS) limits for existing plants (for more details, see Appendix L of the *Wind Vision* report [DOE 2015]).

Air Quality Regulations

Although the Cross-State Air Pollution Rule (CSAPR) is represented in ReEDS, it is essentially nonbinding owing to the sulfur dioxide (SO_2) reductions required for MATS and the long-term substitution of natural gas and other generation sources for coal power generation. We assume that MATS or something like MATS will remain as an active regulation. Supporting this assumption to a significant degree, the effect of MATS has already been seen through actual and announced coal plant retirements. Absent one or both of these regulations, future absolute air pollution emissions would likely be higher than those estimated by ReEDS; however, it is uncertain how the absence of one or both of these regulations might impact estimated *avoided* emissions. For example, without both MATS and CSAPR, geothermal power might displace generation with high emission rates, thereby increasing the estimated benefits of the *GeoVision*. However, absent only MATS, the CSAPR pollution caps would likely be binding, and geothermal power might therefore have little physical benefit in avoiding SO_2 or nitrogen oxides (NO_x) emissions (but would have benefits in reducing compliance costs).

Health Impact Models

Benefits calculated by Air Pollution Emission Experiments and Policy (AP2) and the U.S. Environmental Protection Agency (EPA) Clean Power Plan (CPP) differ in a number of respects. For example, the AP2 model accounts for not only mortality and morbidity but also air pollution-induced reductions in timber and agriculture yields, visibility reductions, accelerated materials degradation, and reductions in recreation services; the benefits calculated with the EPA CPP benefit-per-ton approach only include mortality and morbidity. Both the EPA CPP benefit-per-ton approach, the AP2, and the PENN model include the benefits from primary and secondary particulate reductions and from ozone reductions, while Estimating Air pollution Social Impact Using Regression (EASIUR) includes benefits from only $PM_{2.5}$ exposure.

EPA low and EASIUR low are based on research summarized in Krewski et al. (2009), whereas EPA high and EASIUR high are based on research presented in Lepeule et al. (2012). EPA low and high ozone impacts are based on work by Bell et al. (2004) and Levy et al. (2005). Both sets (low and high) of epidemiology research have different strengths and weakness, and one is not favored over the other. The PENN model presents one central impact estimate based on an average of the high and low epidemiological relationships.

The AP2 model contains monetized benefit-per-ton estimates based on emissions in 2008, so damages from AP2 are scaled over time based on census population projections (U.S. Census Bureau 2012) and per capita income growth projections used by U.S. Energy Information Administration (EIA) (EIA 2014), using an elasticity of the value of statistical life (VSL) to income growth consistent with the National Research Council (NRC 2010). A similar approach is taken for the extrapolation of EASIUR and PENN models. EPA benefit-per-ton values are developed for each year within each of three large regions by linearly extrapolating the EPA's provided benefit-per-ton values. In this manner, there is implicit representation of the population and income growth assumptions incorporated in the EPA's analysis. The 2015–2025 benefit-per-ton values are based on the linear trend established by the EPA's 2020 and 2025 values. The 2026–2050 benefit-per-ton values are based on the linear trend established by the EPA's 2025 and 2030 values. The same process is used for the EPA's health incidence-per-ton (mortality and morbidity outcomes) estimates.

Emission Estimates for Geothermal Heat Pump and Direct-Use Sector

Emission reductions from the geothermal heat pump (GHP) and direct-use fuel use sector are estimated by applying the emission factor for each fuel type to energy reductions from the adoption of the GHP and direct-use systems simulated in the Distributed Geothermal Market Demand Model (dGeo). As described in the main text, we focus on potential emission reductions from the avoidance of the use of fuels such as natural gas, distillate fuel oil, and propane. We use emission factors in the EPA's Compilation of Air Pollutant Emission Factors (AP-42) documents (EPA 1995) compiled for air pollutants by source, except for a few cases (e.g., sulfur oxide [SO_x] for distillate fuel oil). The emission factors used in our analysis are provided in Table B-1–Table B-4 by fuel type (for natural gas, two tables are provided). Except for the NO_x emission factors for natural gas combustion, a single emission factor is used for each combination of fuel types and pollutants following the EPA's simplified emission factors. For natural gas, the EPA provides NO_x emission factors for four different groups depending on the combustor type, and we apply these different emission factors to the equipment in the dGeo, taking into account the equipment type (Table B-1). The emissions factors are provided in units of weight per unit consumption (e.g., pound per cubic feet), and we converted the original values in these units to energy units to be applied to the energy reductions estimated from dGeo (see Table B-1–Table B-4). The original energy reductions from GHP and direct use simulated in dGeo are aggregated by U.S. county. Thus, we apply derived emission factors to energy reductions at the county level and further aggregate to state and national levels for summary.

Table B-1. Emissions Factors[§] for Nitrogen Oxide Emissions from Natural Gas Combustion

Equipment*	dGeo Sector	lb/10^6 scf[‡]
Built-in room heater	Residential[¶]	94
Central warm air furnace	Residential	94
Furnaces that heat air directly[&]	Commercial	178
Packaged heating units[#]	Commercial	61
Cooking stove	Residential	94
Floor or wall pipeless furnace	Residential	94
Steam or hot water system	Residential	94
Boilers inside the building	Commercial	61
Portable kerosene heaters	Residential	94
Fireplace	Residential	94
Heat pump	Residential	94
Individual room heat pump for heating	Commercial	61
Individual space heaters	Commercial	61
Other equipment	Residential	94
Other heating equipment	Commercial	61
Packaged unit heat pump for heating[#]	Commercial	61
Split system heat pump for heating	Commercial	61
Storage water heater	Residential	94
One or more centralized	Commercial	61
One or more point of use	Commercial	61
Other	Commercial	61
Both types of water heaters	Commercial	61
Tankless water heater	Residential	94

[§]Emission factors are based on the EPA's AP-42 (EPA 1995, AP-42, Fifth Edition Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources, Office of Air Quality Planning and Standards), available at https://www3.epa.gov/ttn/chief/ap42/ch01/index.html (accessed April 2017).
*This represents equipment types used in the dGeo.
[‡]This represents pounds per million standard cubic feet; 1 scf is assumed to be 1,032 British thermal unit (Btu). See https://www.eia.gov/energyexplained/index.cfm?page=about_energy_units; the conversion factor of natural gas volume to heat content from EIA may change after periodic updates.
[¶]The EPA's residential furnace emission factors are used for all residential equipment types from dGeo.
[&]This represents the average emission factor for the EPA's large wall-fired boilers with heat input greater than 100 10^6 Btu. Other commercial equipment types in dGeo use emission factors for the EPA's small boiler types.
[#]Packaged units generally have heat input levels less than 100 10^6 Btu per hour (EPA 1995); thus, we use the average emission factor for the small-boilers category from the EPA.

Table B-2. Emissions Factors† for Sulfur Oxide and Particulate Matter Emissions from Natural Gas Combustion

Pollutant	Equipment*	lb/10^6 scf‡
SO_x§	All	0.6
PM#	All	7.6

†Emission factors are based on the EPA's AP-42 (EPA 1995), available at https://www3.epa.gov/ttn/chief/ap42/ch01/index.html.
*For SO_x and particulate matter (PM), we apply a single emission factor available from the EPA to all equipment types.
‡1 scf is assumed to be 1,032 Btu. See https://www.eia.gov/energyexplained/index.cfm?page=about_energy_units; the conversion factor of natural gas volume to heat content from EIA may change after periodic updates.
§This is in units of SO_2.
#This represents total PM (condensable plus filterable).

Table B-3. Emissions Factors from Distillate Fuel Oil Combustion

Pollutant	Equipment*	lb/10^3 gal#
NO_x†	All	20
SO_x‡	All	36
PM†	All	2

†Emission factors are based on the EPA's AP-42 (EPA 1995), available at https://www3.epa.gov/ttn/chief/ap42/ch01/index.html.
*A single emission factor for each pollutant is applied to all equipment types as in the SO_x and PM emissions from natural gas combustion.
‡Based on California Air Resources Board's (CARB's) Emission Inventory Document, available at https://www.arb.ca.gov/ei/areasrc/fullpdf/full7-3.pdf. We use CARB's emission factor for SO_x emission because EPA's emission factor for SO_x requires additional information on weight percentage of sulfur in the oil. CARB assumes that distillate fuel oil has 0.25% of sulfur by weight. The EPA's emission factor (EPA 1995) for distillate oil is 142 lb/10^3 gallon (gal) before applying the sulfur weight percentage. This is essentially the same as that of CARB when applying the 0.25% (i.e., $142 \times 0.25 \approx 36$).
#To convert to energy units, heat contents of 140×10^6 Btu/10^3 gal are used (EPA 1995).

Table B-4. Emissions Factors from Propane Combustion

Pollutant	Equipment*	lb/10^3 gal#
NO_x†	All	13
SO_x‡	All	0.014
PM†	All	0.7

†Emission factors are based on the EPA's AP-42 (EPA 1995), available at https://www3.epa.gov/ttn/chief/ap42/ch01/index.html.
*A single emission factor for each pollutant is applied to all equipment types.
‡As in distillate fuel oil, the SO_x emission factor is based on CARB's Emission Inventory Document, available at https://www.arb.ca.gov/ei/areasrc/fullpdf/full7-3.pdf.
#To convert to energy units, heat contents of 91.5×10^6 Btu/10^3 gal are used (EPA 1995).

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Supplement C: Greenhouse Gas Emission Reductions

Emission Factors

For this study, both direct (combustion) displaced emissions and life cycle displaced emissions were estimated. The emissions factors themselves are derived from emissions of three greenhouse gases (GHGs): carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O). To combine these emissions into a single quantitative estimate, the global warming potentials of the latter two gases relative to CO_2—as reported in the Intergovernmental Panel on Climate Change's (IPCC's) Fifth Assessment Report (AR5) (IPCC 2014)—were used. In this section, the methodology and assumptions used in determining the emissions factors are discussed in more detail, on a fuel-by-fuel basis.

Electricity

Emissions factors for electricity vary depending on the fuel used to generate it. Because different regions employ different generating fuel mixes, and generating mixes will change over time, the emissions factors for electricity energy displacement will depend on both location and year. The Regional Energy Deployment System (ReEDS) model provides estimates of generation mix by ReEDS power control area (PCA) regions and computes both combustion and noncombustion CO_2 emissions per generated kilowatt in each PCA region, at each 2-year time step interval from 2015 to 2050. Because the Distributed Geothermal Market Demand Model (dGeo) assigns a ReEDS-consistent PCA to each agent, these same PCA-specific emissions factors can be applied to electricity displaced in the residential and commercial building heating and cooling sector. The end result is a more accurate and detailed accounting of electricity emissions displacement than would be possible using broader national- or state-level average generation emissions factors. Although this does allow the assignment of displaced combustion emissions to individual PCA regions (which can then be aggregated to the state level), noncombustion, life cycle impacts are not assigned to regions because of the challenges of estimating the location of upstream emissions.[21]

Emissions Factors from Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation Model

Argonne National Laboratory's Greenhouse gases, Regulated Emissions, and Energy use in Transportation (GREET[22]) Model (ANL 2016) was consulted wherever possible to obtain GHG emissions factors for fuels besides electricity. Although GREET was designed with transportation technology analysis in mind, it also includes emission factors for stationary combustion, as well as the fuel life cycle. Because emissions values in GREET are reported in grams per 10^6 British thermal unit (Btu) of fuel *burned*, assumptions about displaced equipment efficiency are avoided.

[21] This caveat applies to all fuels, not just electricity.
[22] The specific version of GREET used for the GHG analysis is GREET v.1_2016.

Natural Gas

The natural gas combustion and life cycle emissions factors were obtained from GREET, using the model's values for a gas-fed, small industrial boiler.

Propane

The propane emissions factors were also obtained from GREET, using the model's values for a liquified petroleum gas-fueled commercial boiler. One of the developers of GREET at Argonne National Laboratory (ANL) confirmed that propane and liquified petroleum gas are synonymous in this context (J. Han, personal communication, Jan. 25, 2017).

Distillate Fuel Oil

The distillate fuel oil emissions factors were obtained from GREET and the U.S. Energy Information Administration's (EIA's) Annual Energy Outlook (AEO) 2016 (EIA 2016). GREET does not currently include an emissions factor for fuel oil, so AEO 2016 was consulted for the combustion emissions factor. However, AEO 2016 does not report life cycle emissions factors, so GREET's life cycle emissions values for conventional diesel were used as a close approximation for fuel oil's life cycle emissions. The diesel refining and transportation steps of the diesel life cycle were included, while final diesel distribution and storage steps were excluded, because fuel oil and diesel vary in the way they are delivered to their final end-use destinations (the former via pipeline, the latter typically via truck).

District Steam and District Hot Water

In accordance with the dGeo, the combustion and noncombustion fuel used in both district steam and district hot water equipment is assumed to be natural gas. The emission factors are again derived from the GREET model, using the assumptions for larger utility/industrial boiler equipment instead of the smaller natural gas boiler assumed for natural gas itself. District heating equipment, serving the greater heating demand of multiple buildings, is assumed to be larger than the natural gas boilers employed for single buildings. This assumption turns out to be relatively insignificant; the differences between the natural gas and district steam/hot water emissions factors in Table C-1 are less than 0.5%.

Table C-1. Combustion and Life Cycle Greenhouse Gas Emission Factors for Geothermal Heat Pump Sector Fuel Offsets

Direct (Combustion)

Fuel	CO_2 (g/10^6 Btu)	CH_4 (g/10^6 Btu)	N_2O (g/10^6 Btu)	Total (gCO_2e/kWh)	Source
Natural gas	5.94E+04	—	—	2.03E+02	GREET
Propane	6.80E+04	—	—	2.32E+02	GREET
Distillate fuel oil	7.32E+04	—	—	2.50E+02	AEO 2016
District steam/hot water	5.94E+04	—	—	2.03E+02	GREET

Indirect (Noncombustion)

Fuel	CO_2 (g/10^6 Btu)	CH_4 (g/10^6 Btu)	N_2O (g/10^6 Btu)	Total (gCO_2e/kWh)	Source
Natural gas	6.78E+03	2.90E+02	1.77E+00	5.45E+01	GREET
Propane	1.64E+04	1.77E+02	5.09E+00	7.86E+01	GREET
Distillate fuel oil	1.41E+04	1.75E+02	2.60E-01	6.63E+01	GREET
District steam/hot water	6.78E+03	2.90E+02	2.17E+00	5.48E+01	GREET

Total Life Cycle (Combustion Plus Noncombustion)

Fuel	CO_2 (g/10^6 Btu)	CH_4 (g/10^6 Btu)	N_2O (g/10^6 Btu)	Total (gCO_2e/kWh)	Source
Natural gas	6.61E+04	2.90E+02	1.77E+00	2.57E+02	GREET
Propane	8.44E+04	1.77E+02	5.09E+00	3.11E+02	GREET
Distillate fuel oil	8.72E+04	1.75E+02	2.60E-01	3.16E+02	AEO 2016, GREET
District steam/hot water	6.61E+04	2.90E+02	2.17E+00	2.57E+02	GREET

Note: gCO_2e/kWh = grams of carbon dioxide equivalent per kilowatt hour

Supplement C References

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