Net Zero in Texas: The Role of the Electric Grid

Executive Summary

More people. More cars and trucks. More industry producing more products. Growth is at the heart of the future of Texas, offering opportunities for robust economic growth but also setting up a looming showdown as the state seeks to balance growth with efforts to achieve a net-zero carbon emission economy by 2050. A sustainable electric grid is fundamental to these aspirations, and the buzzword is “electrification.”

It will be a task of monumental proportions. Electric power touches every facet of life, from brewing your morning coffee to education, health care, and industry. Residential, commercial, and industrial customers increasingly say they want to buy decarbonized electricity. Many large corporations operating in the state have set net-zero goals, adding to the pressure. The power sector is the third largest source of greenhouse gas emissions in Texas, and it supplies power to all the other sectors that are trying to reduce their carbon emissions. That means powering the shift from internal combustion engines to electric vehicles, and the transition of furnaces, appliances, and industrial processes to electrification.

The rest of the economy won’t be able to achieve its own net-zero goals if the power sector cannot meet these expectations.

The Energy Information Administration, International Energy Agency, and Intergovernmental Panel on Climate Change have all recognized that decarbonizing the electric grid is critical to reaching national and international carbon emissions reduction goals. The federal government set a goal of achieving a net-zero grid by 2035 in acknowledgment of the grid’s importance to other efforts. But environmental sustainability is just one part of what is known as the Energy Trilemma – electricity must be reliable and affordable as well. Decarbonized electricity is only valuable if it is available when consumers need it, and if they can afford to pay the bills.

Texas produces and consumes more electricity than any other state, generating 473.5 million megawatt hours of power in 2020, and demand is expected to reach 564 million megawatt hours by 2050. The growth in demand while simultaneously decarbonizing the grid will require more delivery infrastructure and generation capacity to guarantee reliability as the electric grid transforms.

The Texas grid is unique among U.S. states, with more than 80% of the market served by a self-contained grid operated by ERCOT, the Electric Reliability Council of Texas. More than 80% of carbon emissions from electricity generation in Texas are also produced on the ERCOT grid, and the bulk of projected population growth over the next 30 years will occur in the region served by ERCOT. (Three other transmission organizations serve smaller swathes of Texas along with neighboring states.) ERCOT is ground zero in decarbonizing the Texas grid. And because ERCOT doesn't connect to any other state grids, meaning it can't buy electricity from elsewhere in the event of an outage, the solutions must be homegrown. For this paper, we assume the construct of the ERCOT system will remain unchanged.

Carbon emissions from the power sector have begun dropping steadily, if slowly, over the past 10 years, to 176.8 million metric tons of CO_2 in 2020 from 239.6 million metric tons in 2011. They will have to drop substantially more – an additional annual average reduction of 14.5 million metric tons to meet net-zero electricity production by 2035, and about 7.25 million metric tons a year to achieve net-zero by 2050.

The reduction over the past decade is in part a consequence of the growth of zero-emission wind and solar power, but nearly 90% of the carbon dioxide emissions reductions are a result of the transition from coal-fired generation that was replaced by natural gas-fired units. Coal-fired generation accounted for approximately 16% of power on the ERCOT grid in 2022, down by half from 32% in 2017. Natural gas makes up the largest share of generation, at about 42%.

And while the significance of the transition overall has been remarkable, the variability of the alternative forms of generation that have been introduced has created new challenges.

On average, about 26% of power on the ERCOT grid is wind-generated – Texas leads the nation in wind power installed capacity and is the 6th largest system of wind in the world. An additional 10% comes from nuclear power, and 6% from solar energy. Simply expanding those emission-free sources of generation won't solve the net-zero challenge, however, as any solution must also ensure adequate future capacity, reliability, and affordability. Wind and sunshine may be free sources of fuel, but new transmission lines and the cost of prematurely retiring fossil fuel-generating plants add significantly to the price tag. And those free sources of fuel still consume major amounts of resources and produce major amounts of waste. Consider that a 100-megawatt wind farm, producing enough electricity to power 75,000 homes, requires 30,000 tons of iron ore, 50,000 tons of concrete, and 900 tons of plastics, none of which are carbon neutral. A 100-megawatt solar installation requires half again as much of those resources. At projected rates of deployment in the U.S., by 2050 it is expected that the retirements of these wind and solar projects will create significant amounts of waste with few cost-effective options for recycling many components like wind turbine blades and plastics used for wind and solar.

Winter Storm Uri in 2021 offered a stark demonstration of the need for reliability, as all types of power generation failed, leading to a days-long blackout across much of the state blamed for hundreds of deaths and billions of dollars in damages. More than half of the state's natural gas supply was shut down due to power outages, frozen equipment, and frigid weather conditions. Some wind turbines also froze, reducing wind generation. Were it not for the generation from many of the coal-fired plants that are scheduled to be retired in the near future, longer-term outages would have resulted. Several bills pending before the Texas Legislature seek to address the reliability issue through commercial marketplace constructs to encourage dispatchable generation.

This white paper, part of a series on how Texas might achieve a net-zero economy by 2050, analyzes whether Texas can create a decarbonized grid by 2050 while maintaining reliability and affordability. Using a model-based analysis, we consider whether certain technologies provide comparative benefits on affordability and reliability – and if certain policies may encourage the incorporation of those technologies – by assessing five scenarios under which Texas might achieve a decarbonized electric grid. We also tried to assess the consequences, intended and unintended, of potential policies to ensure reducing emissions doesn't result in unexpected challenges, be that higher costs, reduced operating reserves, or something entirely unforeseen. We used the National Energy Modeling System used in the EIA's 2022 Energy Outlook scenarios to create the business-as-usual scenario, with the remaining scenarios designed as growth scenarios relative to the business-as-usual case. To complete the analysis, we used the Regional Energy Deployment System model produced by the National Renewable Energy Laboratory.

In short, a net-zero grid is possible, but holistically addressing not just emissions but also adequate capacity at a reasonable cost requires an all-of-the-above solution.

We found that a scenario built upon using all available generating sources – focused on retaining existing baseload resources, including coal and natural gas, coupled with carbon capture, utilization, and storage (CCUS), the addition of hydrogen and more restrained growth of renewable generation – would be the lowest-cost pathway to a net-zero grid by 2050.

Under this scenario, nameplate capacity, or the maximum rated generating output, would grow to 240 gigawatts, while CO_2 levels are reduced to negative due in part to CCUS used with natural gas combined cycle turbines. The total levelized cost between 2020-2050 would be $200.4 billion in 2020 dollars.

Other notable findings, addressed in more detail in the paper, include:

- Current projects under construction, under site review, or in the planning stages in ERCOT could add 54,644 megawatts of net nameplate generation to the grid, with 95% of that coming from renewables and batteries and the rest from natural gas generators. That's somewhat deceptive; wind and solar don't produce at the nameplate capacity, so the actual new generation available to the grid will be lower. In fact, on average as little as 15-40% of the planned nameplate capacity for wind and 50-80% of the planned nameplate capacity for solar may become available from the portion of these planned projects if constructed.
- Short-duration storage – ranging from 1-to-4 hours in duration – is growing, too. More than 8,000 megawatts of storage capacity have started construction or are the subject of an executed interconnection agreement. Another 61,850 megawatts are under study, with one-third planned to be co-located with wind, solar, or other generation and two-thirds planned as standalone storage projects. Many projects are capable of supplying power in only 1-to-4-hour increments, serving to help smooth the demand curve over a day and not as a backup source of power.

- Even under the business-as-usual scenario, generating capacity would continue to grow to 212 gigawatts, largely through increases in onshore wind and natural gas combined cycle turbines, and CO_2 emissions would fall to just below 56 million tons annually. That's 70% below 2019 levels but not net-zero. The total levelized cost between 2020-2050 would be $217.1 billion in 2020 dollars.
- In a scenario characterized by high use of renewables, battery storage, and hydrogen, with medium emphasis on natural gas and CCUS, nameplate capacity grows to 390 gigawatts, and CO_2 emissions are reduced to carbon negative levels due in part to using emissions-free energy to produce hydrogen and DAC to remove emissions from fossil generation sources. The total levelized cost between 2020-2050 would be $221 billion in 2020 dollars.
- A scenario built on high use of renewables and storage, with relatively low emphasis on other fuels and technologies including CCUS, would allow capacity to grow to 329 gigawatts while reducing carbon to negative levels using large amounts of hydrogen. The total levelized cost between 2020-2050 would be $244.7 billion in 2020 dollars.
- The use of CCUS would improve the reliability of the grid in future years, allowing it to add net-zero baseload generation capacity without additional emissions. A grid incorporating CCUS will also allow the grid to maintain higher reserve margins and operational flexibility, offering reliability under a variety of weather stressors.
- The federal Inflation Reduction Act provides incentives for a broad range of clean energy technologies, including an extension of the investment and production tax credit for wind and solar through 2024. The tax credits will then transition to clean electricity investment and production tax credits for a broad range of emissions-free technologies, including nuclear generation, hydrogen production with renewable energy, stand-alone storage projects, hydro, geothermal, wind, and solar. The credits will be available until 2032 or until emissions from U.S. electricity production is equal to or less than 25% of emissions from such production in 2022.
- The IRA also modifies the 45Q tax credit to encourage CCUS, raising the credit to $60/ton for utilizing carbon dioxide, $85/ton for permanently storing carbon dioxide in geologic storage, $130/ton for utilizing carbon dioxide captured using direct air capture (DAC) technology, and $180/ton for storing carbon dioxide captured using DAC.

Decisions made over the next few years about how to decarbonize the Texas grid will include both technical and geopolitical concerns, including the reality that solar technologies require substantial amounts of rare earth minerals. By some estimates, meeting all U.S. electricity demands with solar energy would require a 2000% increase in the use of rare earth minerals, most of which are currently sourced from China. Beyond these technical and geopolitical issues, the development of the commercial marketplace will be a key driver for investment and adoption.

A carbon-free grid, our research suggests, is a far more complex task than simply focusing on emissions. Reducing carbon emissions, while imperative, can't happen in a vacuum if we are to maintain our way of life, especially if we are to do so in ways that allow us to export solutions to the rest of the world.

Texas remains a focal point for innovation that can demonstrate, assist, and lead as an example of how the rest of the world can decarbonize. Scaling up wind and solar is unlikely to happen at a fast enough pace to help the world reach net-zero electricity within the next few decades. By using a wide range of technologies and fuel sources, however, a meaningful impact on emissions and the environment is possible.

Chapter 1: The Texas Electric Grid

At a basic level, the Texas electric grid is comprised of generators, transmission, and distribution entities. These entities operate to produce and deliver electricity through coordinated efforts overseen by transmission organizations. Within Texas, the transmission organizations include the Electric Reliability Council of Texas (ERCOT), El Paso Electric Co., Mid-Continent Independent System Operator (MISO), and Southwest Power Pool (SPP). Of these, the largest and arguably most important to Texas is ERCOT. This research assesses how different technologies might impact the ability of ERCOT and the entities operating within ERCOT to achieve a net-zero grid by 2050 and the resulting impacts on grid capacity, cost, reliability, and CO_2 emissions. Although there are other regional transmission organizations (RTOs) and independent system operators (ISOs), the focus of this research is on ERCOT because it is the largest RTO in the state and over 80% of emissions from Texas electric generators come from those in ERCOT (Figure 1).

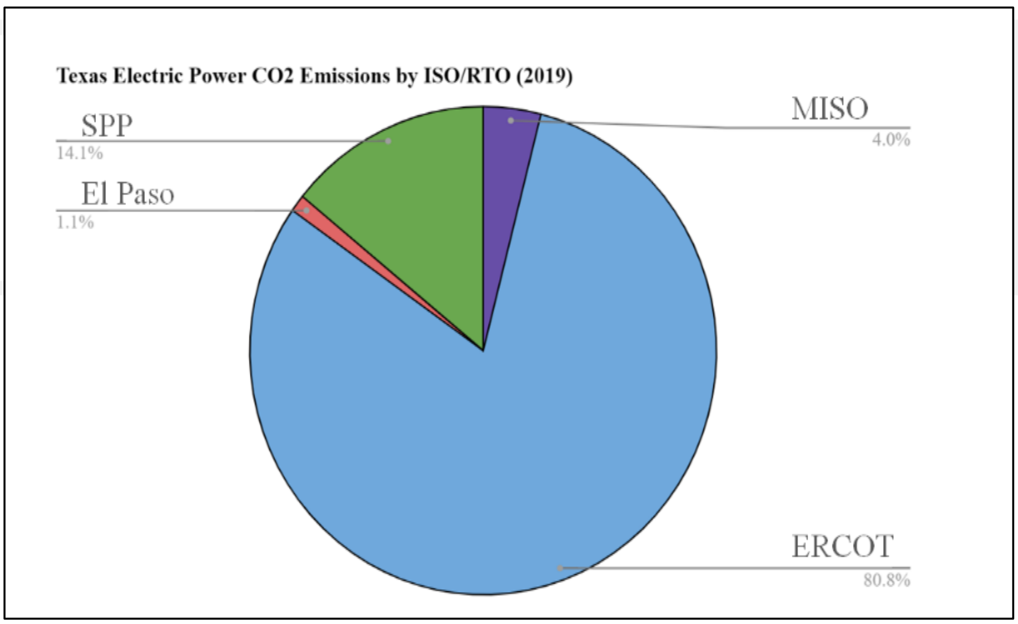

Figure 1. Texas Electric Power CO_2 Emissions by ISO/RTO as of 2019. Data source: U.S. EIA.

In addition to being the primary contributor to emissions and the largest RTO in Texas, ERCOT is an intrastate transmission organization, whereas El Paso Electric Co., SPP, and MISO operate in multiple states. The intrastate nature of ERCOT allows for Texas to unilaterally implement state-level changes that may encourage the further development and implementation of different generation technologies, a task that may be more difficult across multi-state RTOs/ISOs. Another reason for focusing on ERCOT is due to the projected growth in population and correspondingly, electricity demand. By 2050 the population of Texas is expected to grow significantly. Estimates of Texas's population in 2050 range from 31.2 million to 54.4 million people. We anticipate much of that growth will occur in the ERCOT service region, including the Austin, San Antonio, Dallas, and Houston metro areas, and therefore, will result in significant load growth in ERCOT, which will need to be met while still providing affordable, reliable, and zero-carbon electricity.

1.1 ERCOT

Texas’s grid is unique in that most Texans are served by a Regional Transmission Organization (RTO) not connected to other states. The RTO is maintained by the Electricity Council of Texas (ERCOT) through a variety of suggested parameters and internal policies. Additionally, the ERCOT market is largely deregulated in that owners of electric generation resources are typically not the same owners of transmission and distribution. Under ERCOT, Texas has maintained a deregulated energy market since 1995. Stakeholders in Texas’s grid include:

- Independent generators
- Power marketers
- Retail Electric providers
- Electric Utilities–both privately owned and municipally owned
- Transmission and distribution providers
- Cooperatives
- Consumers

ERCOT is overseen by the Public Utility Commission of Texas (PUCT), which is the government regulator for electric utilities and passes regulations controlling ERCOT operations.

1.1.1 Generation and Demand in ERCOT

Texas produces and consumes more electricity than any other state. In 2020, the state generated 473.515 million MWh. Texas also has the highest net summer capacity of any state with 128,947 MW of generation theoretically available. Within Texas, ERCOT has historically experienced peak system-wide demand during the summer months. Recently, ERCOT has also experienced several instances of demand exceeding expectations.

Prior to the summer of 2022, ERCOT projected that peak available load serving resources for summer 2022 totaled 91,392 MW. ERCOT also projected that the highest peak demand would total 77,733 MW, leaving a planning reserve margin of 14,075 MW or 22.8%. Figure 2 presents ERCOT's Long-Term Load forecast for the next ten years. It is based on forecasted economic data and historical weather from 2006 – 2020.

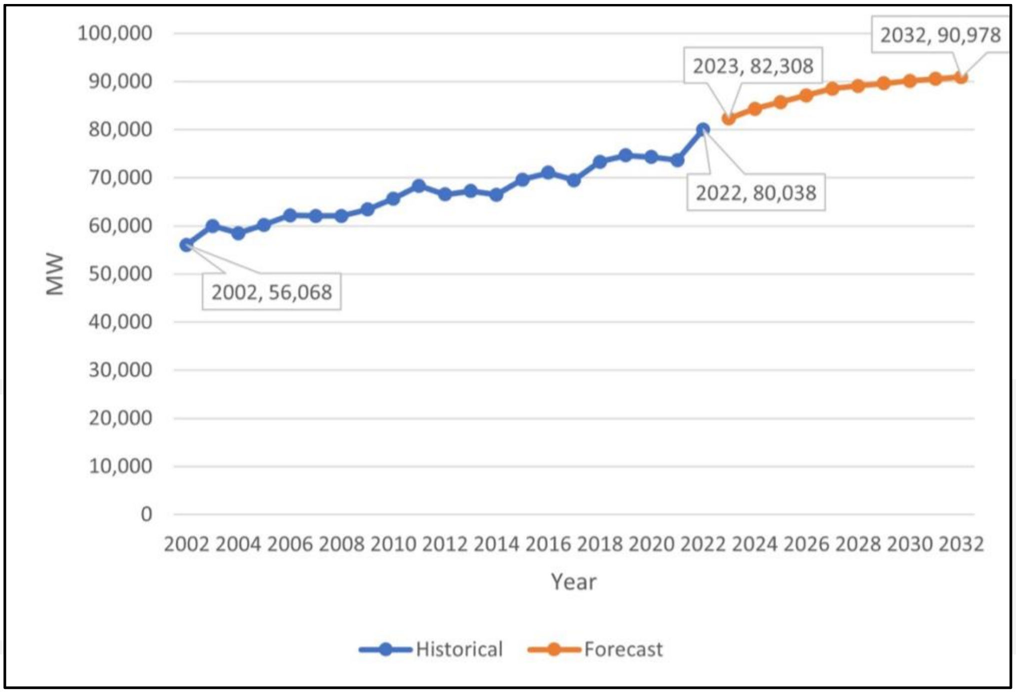

Figure 2. ERCOT projected summer peak demand. Data source: ERCOT.

However, actual demand in Texas repeatedly exceeded this projected demand in the summer of 2022, breaking record after record in July. On July 20, 2022, ERCOT set a record demand of 80,038 MW, exceeding the highest peak projection by 2,721 MW. Utilizing the average historical and projected growth rates from 2019-2032, the 2050 projected demand can be expected to reach 122,171 MW. The 2050 demand could reach 123,183 MW if 2020 and 2021 are excluded to account for demand reduction from COVID.

Since 2002, the forecasted peak summer demand has increased from 56,068 MW to 77,317 MW, an increase of 37.9%. (Figure 2). By 2031, the peak summer demand is projected to increase another 11.5%, to 86,233 MW. Based on the Summer 2022 record peak, which already surpassed the projected peak for 2031, and utilizing the same ERCOT projected growth of demand of 11.5% from 2022 through 2031, it is feasible that peak demand in 2031 may reach 96,149 MW or higher. Such an increase in demand exceeds the current projected peak resource capacity of 91,392 MW. Accordingly, not only must Texas focus on decarbonizing the current grid, but it must also plan for and invest in new generation and transmission capable of handling such growth.

Understanding how this ever-increasing demand is met requires an understanding of the generation sources supplying the electricity. Approximately 42% of electricity generated in ERCOT is produced using natural gas or natural gas combined cycle (natural gas-cc) plants. However, Texas is also leading the way in renewables. Texas produces 27% of all wind-generated electricity in the United States. Over time, a significant portion of the generation in ERCOT has come from wind, which now is the second largest source of generation. Table 1 shows the fuel mix for ERCOT for 2016 through August 2022.

Table 1. Sources of CO_2 emissions in ERCOT by generation type. All values are in percentage.

Year	Biomass	Coal	Gas	Gas-CC	Hydro	Nuclear	Other	Solar	Wind
2016	0.2	28.7	6.2	37.4	0.3	12.0	<0.1	0.2	15.1
2017	0.2	32.0	5.0	34.0	0.2	11.0	0.0	0.6	17.0
2018	0.2	25.0	6.0	38.0	0.2	11.0	0.0	0.9	19.0
2019	0.1	20.0	7.0	40.0	0.3	11.0	0.0	1.6	20.0
2020	<0.1	18.0	6.0	40.0	0.2	11.0	0.0	2.0	23.0
2021	0.1	19.0	7.0	35.0	0.1	10.0	<0.1	4.0	24.0
2022	0.1	16.0	7.0	35.0	<0.1	10.0	0.1	6.0	26.0

With more than half of electricity being generated by fossil fuels, ERCOT also contributes substantial emissions, although the emissions have been declining. In 2019, net direct CO_2 emissions from Texas power plants, including synchronized industrial and commercial generators, totaled 218 million metric tons. Emissions from the ERCOT balancing authority accounted for 1756 million metric tons or 81% of emissions from the power sector. In 2019, ERCOT produced 413 million MWh or about 85% of the electricity produced in the state. For every MWh produced, there were 426 kg of carbon dioxide emitted. The national average for 2019 was 418 kg/MWh. This places Texas 22nd among the states for emissions per MWh produced. Figure 3 shows electric power emissions for Texas from 2009 through 2019.

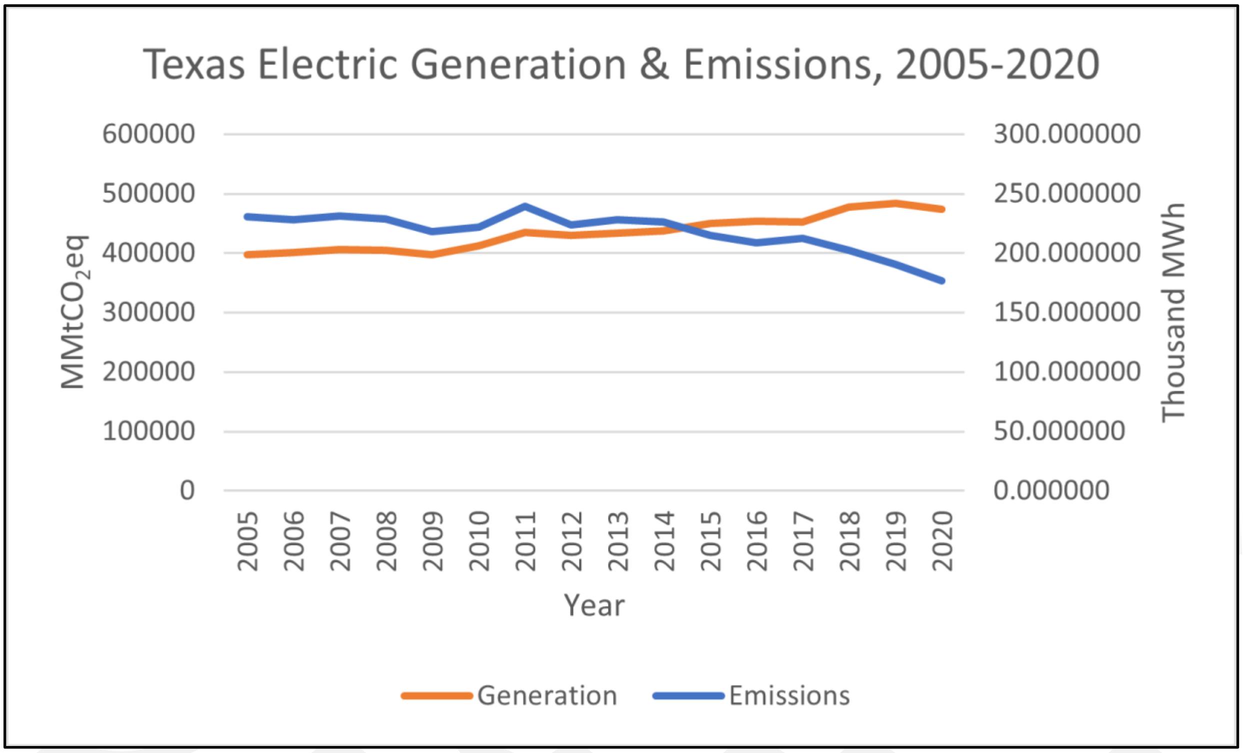

Figure 3. Electric Power Carbon Dioxide Emissions, All Fuels for Texas 2005-2020, Texas Net Generation, All Fuels for Texas 2005-2020. Data source: U.S.EIA, Federal Reserve Bank of St. Louis.

Considering this, along with the increasing demand and in turn generation (Figure 2), it becomes clear that state emissions attributable to electric power have decreased despite the increased demand. This is in part attributable to more solar and wind generation being installed in Texas as well as more efficient use of electricity through improved building, appliances, and practices which helps to decrease demand per user despite demand increasing overall. However, to meet current federal goals of net-zero electricity production in Texas by 2035, the state would need to reduce annual average emissions for power production by about 14.5 million metric tons per year. To achieve that same goal by 2050, the state would need to reduce average annual emissions by about 7.25 million metric tons per year.

1.2 Current Plans to Meet Future Demand

Currently proposed projects under site review or in planning stages, as well as those under construction in ERCOT with interconnection agreements in place, could bring an additional 54,644 MW of net nameplate generation capacity with 95% of that coming from a combined portfolio of renewables and batteries, and the remaining 5% is from natural gas power generators, both single-cycle combustion turbines and combined cycle. This brings a unique challenge as even with an increase in nameplate capacity, wind turbines are only, on average, able to produce between 15%-40% of their nameplate capacities, whereas solar power (photovoltaic), in Texas, can reach about 50%-80% reliability of net capacity. Increasing variable renewable energy (VRE) generation without increases in baseload generation which can supply electricity at any time of day raises concerns over reliability as demand increases.

To deal with this variability, generators in the state are building out storage. Over 8,000 MW of storage capacity has started or executed an interconnection agreement to be added to the grid. Another 61,850 MW are under study, with one-third of that storage capacity planned to be co-located with wind, solar, or other generation and two-thirds being stand-alone storage projects. Not all these storage projects will be built due to financial and transmission constraints, but a large build out of storage in ERCOT would certainly help to alleviate short-term reliability concerns from increasingly VRE penetration. The concern with storage is that many projects, given technological constraints, are capable of supplying power in 1-to-4-hour increments. Accordingly, storage is frequently thought of more as a technology to help smooth the demand curve over a day and not a backup source of power and not a solution to long-term reliability events like those experienced during Winter Storms in 2021.

1.3 Reliability Concerns

Reliability has been front of mind for Texans since the winter storm of 2021 that caused catastrophic blackouts. During that time, hundreds of people lost their lives, and billions of dollars in economic damages were caused as the grid shut down. That and similar events show that having baseload, reliable, and dispatchable power is of critical importance. Historically, this reliable and dispatchable electricity has come from coal or natural gas-fired power plants. Such plants can be brought online within minutes or hours to provide additional power at times when variable resources such as wind and solar are either not providing much energy due to weather or time of day or when demand exceeds capacity available.

However, during the Winter Storm, a confluence of events showed the vulnerability of ERCOT's reliability. There were problems with nearly all types of generation resources, including freezing well-heads and natural gas generation, freezing wind turbines, and even reports of frozen coal piles. The storm spurred reform to winterize critical supply infrastructure to avoid such an event from reoccurring. However, the concerns are still forefront for Texans and reliability remains a key concern. This focus on reliability has caused questions to be raised about whether it is prudent to further retire baseload dispatchable resources, whether they be coal, nuclear, or gas, and these same questions imply that there may be fundamental issues with solely relying on VREs to power the future grid.

As the United States moves towards decarbonizing the electric power industry, coal plants are increasingly being scheduled for retirement before the useful life of the plant has ended. The same is true in Texas. To date, this move towards early closures has been driven by market economics and federal policy around control of SOx and NOx emissions. As owners of these coal-fired generators increasingly move towards decarbonization, it is anticipated the current trend will continue or even accelerate. At the same time, methane and carbon dioxide emissions from gas-fired plants are requiring generation owners to assess whether it is prudent to buildout additional gas-fired power plants.

Further, early retirement of coal plants often brings undesirable short-term financial impacts to ratepayers. Plants under consideration for early retirement often have hundreds of millions of dollars of undepreciated value. In some states, utilities may apply to securitize this undepreciated amount through selling securitization bonds. These bonds are then paid by ratepayers over years for plants that are no longer used and useful because of the early retirement, putting the liability and loss squarely on the ratepayers rather than the utility.

In Texas and across the rest of the country, concerns have arisen about whether current plant retirements are outstripping the building of replacement capacity. If ERCOT's summer net capacity and demand projection hold steady next year, then the slated retirements will only reduce the reserve capacity by 650MW. Of the 14 planned closures, only one plant – Oklaunion – *partially* feeds into ERCOT's transmission grid. This increasing trend towards the retirement of coal-fired baseload power plants has many concerned that the ever-increasing buildout of renewables in the state will be unable to supply reliable power during events like the winter storm of 2021 or during summer peak demand. Accordingly, it becomes clear that nationwide, but particularly in Texas, any pathways toward decarbonization must also be affordable and reliable.

1.4 Current Texas Energy Policy Regarding Emissions

1.4.1 Renewable Portfolio Standards

The Texas government has taken regulatory steps to increase renewable generation on the grid, which has assisted in reducing greenhouse gas emissions per MWh produced. In 1999, Texas passed and implemented a renewable portfolio standard (RPS) system of energy production goals to reach. The goals were amended and updated in 2005 by HB20, which set a target of 10,000 MW of installed capacity by 2025. That goal was achieved in 2010. Today the ERCOT grid has 35,736 MW of nameplate wind capacity, 11,462 MW of nameplate solar capacity, and 1,732 MW of nameplate storage capacity. The success of renewables has been helped tremendously by state and federal incentives.

1.4.2 State Incentives for Renewables

In 1999, along with the passage of the RPS, Texas created a renewable energy certification (REC) system to encourage the purchase of renewable energy. A REC is created by producing one MWh of renewable energy. This certificate can then be sold, transferred, and purchased in a marketplace operated by ERCOT. To help create a marketplace for renewable electricity, retail electricity providers are assigned annual RPS requirements. These requirements are met by purchasing RECs from renewable generators and subsequently retiring RECs in compliance with ERCOT rules. RPS requirements are apportioned to retail providers based on their share of electricity sales within the state. The creation of the REC marketplace has driven the buildout of additional renewable facilities and has subsidized renewables growth by requiring the purchase of RECs to meet RPS requirements.

Texas has also incentivized investment in economic development projects through the passage of the Texas Economic Development Act in 2001. This provision provides school districts with the power to enter into agreements with entities making large, qualified investments in a community for a reduced property assessment over 10 years, which in turn reduces the entities' ad valorem tax obligation to the school district. The incentive is available for investments in manufacturing, research and development, clean coal projects, and advanced clean energy projects which include the capture of at least 50% of carbon dioxide emissions, renewable electric generation, electric generation using integrated gasification combined cycle technology, nuclear power generation, computing centers, and Texas priority projects.

The Texas Comptroller publishes a biannual report showing estimates of the status of the Chapter 313 program. The 2021 Summary Data showed that the program has resulted in 193 active manufacturing projects, four research and development projects, 210 wind renewable projects, and 102 non-wind renewable projects. Of note, although there are nine categories of projects that qualify for the tax reductions, only four categories are reported to have entered into agreements for such reductions, with a majority of those going to renewables developers. The Comptroller estimates that the program has resulted in $2.71 billion in total gross tax benefits to companies investing in renewables. The Chapter 313 program expired on December 31, 2022. However, projects entering into agreements before the deadline will be eligible to receive the reduced *ad valorem* taxes for the next 10 years.

Texas has also helped to incentivize renewable projects through the buildout of transmission from Competitive Renewable Energy Zones (CREZs) in the wind-rich Panhandle and West Texas to population centers in East Texas. Legislation mandating the construction of the lines was passed in 2005. Completion of the CREZ lines cost approximately $6.9 billion. This buildout of transmission enabled further projects to be built and connected to the ERCOT grid and while it is not a tax credit or abatement, it was a government-mandated project paid for by Texas ratepayers.

1.4.3 State Incentives for Clean Energy Projects

In 2009, the Texas Legislature passed franchise tax credits for clean energy projects. A clean energy project is a project with a capacity of at least 200 MW, capable of capturing and permanently sequestering carbon dioxide, and is fueled by coal, natural gas, or petroleum coke. To qualify for the tax credit, the project must be implemented with the construction of a new facility. To date, the Comptroller has not reported that any such tax credits have been awarded.

Chapter 312 of the Texas Tax Code allows local authorities to offer property tax abatements through a similar mechanism as Chapter 313. These tax abatements are available to renewable and non-renewable projects. Because these agreements are reported on an individual city and county basis, an analysis of the incentives provided is beyond the scope of this paper. However, reviewing the summary data from the Comptroller shows that many of the projects granted tax incentives under Chapter 312 in the energy industry are non-renewable energy projects.

1.4.4 Comparing Incentives for Different Generation Sources

A study[1] of the available incentives in Texas for varying sources of generation estimated that considering all available state incentives for Texas electricity generation, coal, natural gas, nuclear, wind, and solar all received some incentive. The study projected financial support for each fuel type on a $/MWh basis in 2019 as follows:

Table 2. State financial support for various sources of electric generators. Data source: University of Texas Energy Institute.

Fuel Type	Financial Support ($/MWh) in 2019
Coal	$0.52
Natural Gas	$1.25
Nuclear	$0.05
Wind (w/o CREZ)	$1.91
Wind (w/ CREZ)	$17.10
Solar	$10.60

For purposes of this research, we assume these incentives have not significantly changed since 2019 at the state level. However, as noted above, the Chapter 313 program ended on December 31, 2022. This will reduce the state-level incentives for wind and solar projects moving forward, but federal incentives will continue to incentivize renewable projects in the state.

1.5 Federal Energy Incentives

While this research aims to assess how ERCOT can achieve a net-zero grid by 2050, the federal government has set more ambitious goals to achieve a net-zero electric grid by 2035 and a net-zero economy by 2050. To assist utilities and RTOs meet such an ambitious goal, the federal government recently enacted the Inflation Reduction Act (IRA). The IRA provides incentives for a broad range of technologies, including an extension of the investment and production tax credit for wind and solar through 2024. The tax credits thereafter transition to clean electricity investment and production tax credits. These new tax credits, available at the start of 2025, apply to a broader range of emissions-free technologies. Technologies eligible for the credit include nuclear generation, hydrogen production with renewable energy, stand-alone storage projects, hydro, geothermal, wind, and solar, along with any other emissions-free form of electricity generation. The clean energy tax credits will be available until 2032 or until emissions from electricity production in the United States is equal to or less than 25% of emissions from such production in 2022. These credits will likely serve to ensure that increased renewable and storage projects are developed in Texas throughout the next decade or longer.

In addition to credits for renewable electric generation, the IRA also incentivizes carbon capture, utilization, and storage (CCUS) projects for coal, natural gas, and other hydrocarbon sources of electricity generation through modifications to the 45Q tax credit. This credit has been identified by some as a critical component in preserving baseload, dispatchable, low-emissions electricity. Prior research done by the National Petroleum Council, identified that to truly incentivize commercial-scale adoption of CCUS projects in the United States, the 45Q credit would need to be raised from $50/ton at the time of the report in 2019 to $110/ton. The IRA raised the 45Q credit to $60/ton for utilizing carbon dioxide (most current utilization is for enhanced oil recovery operations), $85/ton for permanently storing carbon dioxide in geologic storage, $130/ton for utilizing carbon dioxide captured using direct air capture (DAC) technology – which captures carbon dioxide from ambient air rather than a point source, and $180/ton for storing carbon dioxide captured using DAC. These new incentives, paired with the Texas clean energy franchise tax credits, may incentivize those currently operating or with plans to construct new generation facilities which utilize hydrocarbons as fuel to retrofit or include carbon capture technologies onto those plants.

Chapter 2: Methodology

2.1 Defining the Scenarios

Our analysis is based on five different scenarios for the growth of demand and capacity within ERCOT. Under each scenario, different technologies are expected to improve in cost and performance at varying rates and therefore can be expected to have varying availability to contribute to generation and capacity. These growth rates represent high growth rates for all technologies fueled by federal incentives. For new technologies that currently do not contribute capacity to the ERCOT grid, as well as for technologies like CCUS and other carbon dioxide removal (CDR) methods like direct air capture, we assumed that the state would incentivize deployment to reach a baseline capacity of 0.1 GW in 2025.

After 2025, these new technologies are assumed to begin improving due to existing government incentives, policies, and mandates like the production and investment tax credits, renewable portfolio standards, renewable energy credit trading program, and investment in Competitive Renewable Energy Zones. Such incentives have previously contributed to the substantial growth of onshore wind (Figure 4). We assume that the federal and state government will support, incentivize, and encourage the growth of pumped storage, hydrogen fuel cells, solar thermal, offshore wind, CCUS, and CDR in a similar manner to achieve state and national decarbonization goals, and therefore we assume a best-case scenario for technologies with broad state and federal support. These assumptions are based on the commitment within the Inflation Reduction Act to provide federal incentives over an extended period for these technologies as well as the number of investments and project announcements being made across Texas and the rest of the country.

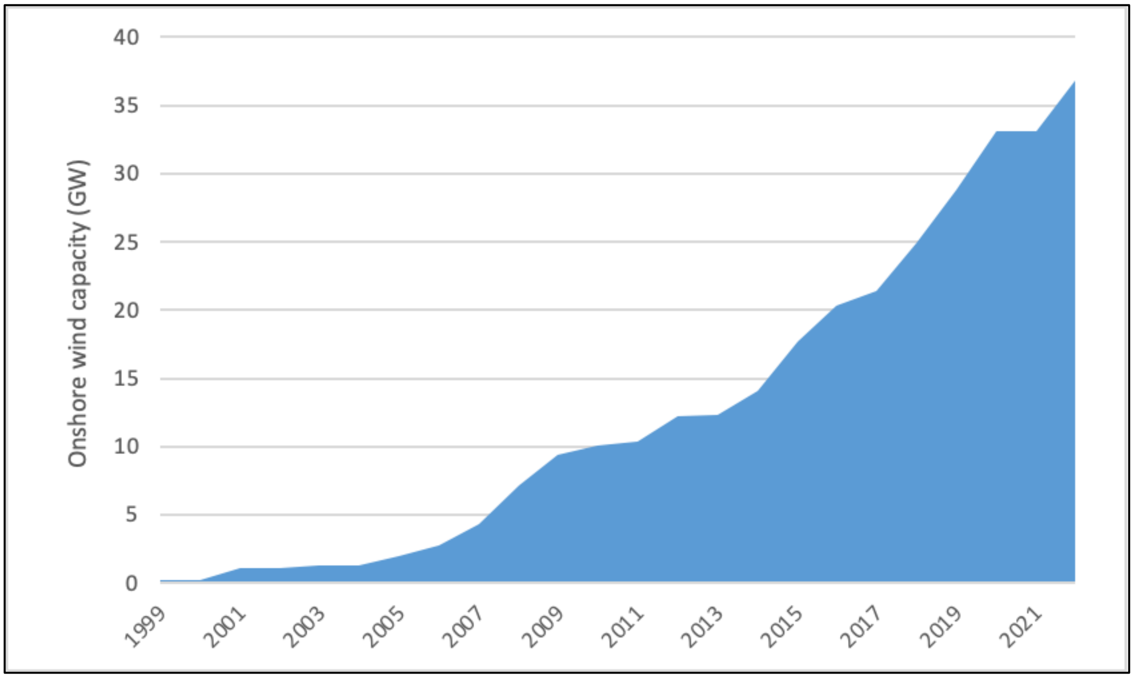

Figure 4. Capacity addition from onshore wind energy in Texas from 1999 to 2022. Data source: ERCOT.

We define our scenarios as Business as usual (BAU), High End-Use Electrification, Unconstrained Energy Supply (Scenario 2), High End-Use Electrification, Constrained Renewables and Storage (Scenario 3), High End-Use Electrification, Unconstrained Renewables and Storage (Scenario 4), and Low End-Use Electrification, Constrained Energy Supply (Scenario 5). The Business-as-Usual scenario is based on the National Energy Modeling System used in the U.S. EIA's 2022 Energy Outlook scenarios. The remaining scenarios were growth scenarios relative to the Business-as-Usual. For all scenarios, it was assumed that capacity additions of new technologies would become available beginning in 2026 and therefore the scenarios would begin to diverge from the base case at the growth rate outlined below in Table 3.

Table 3. Technology penetration and energy supply scenarios, year-on-year growth rates relative to the Business-as-Usual scenario of the U.S. EIA's 2022 Energy Outlook.

	Renewables	**Storage**	**Liquid fuels**	**CCUS**	**CDR**	**Biomass**	**Hydrogen**
Scenario 2	High	High	Medium	Medium	Medium to low	High	High
Scenario 3	Low to Medium	Low	High	High	High	High	High
Scenario 4	Highest	Highest	Low	Low	Low	Low	Low
Scenario 5	Lowest	Lowest	Highest	Highest	Highest	Medium	Medium

Assumptions made in formulating the scenarios are based on EIA predictions and current national energy policy. The variations in each scenario are intended to differentiate scenarios utilizing the historical growth trajectory of wind in Texas from 1999-2022. The business-as-usual baseline assumes growth consistent with historical wind generation growth and each additional scenario deviates from this baseline to account for varying degrees of growth above or below the historical wind growth rates. The decision to utilize the 1999-2022 growth rate of wind in Texas assumes that State and Federal incentives like those found in the Inflation Reduction Act and those used to support wind will likewise be used to support nascent technologies.

2.2 Assessment of Cost and Emissions for Each Scenario

After formulating the five scenarios for future growth given assumptions on technology improvement and implementation rates, we assessed (1) the cost of each scenario and (2) the associated emissions of each scenario. To complete this analysis, we used the Regional Energy Deployment System (ReEDS) model produced by the National Renewable Energy Laboratory (NREL).[2] The ReEDS model is a long-term capacity expansion and dispatch research model which can assess the cost, value, and technical characteristics of grid expansion. Given a set of assumptions, ReEDS models the impacts of a variety of technological and policy changes on the evolution and operation of generation, transmission, and demand-side technology.

To recreate the scenarios listed above, we restricted ReEDS to model only the ERCOT system. Further, we constrained transmission buildout to be intra-RTO only. This was done to evaluate specific technological impacts on ERCOT without interference with technological improvements made outside of ERCOT. To account for federal policy initiatives, we set a goal for each of our alternative scenarios to achieve the federal goal of having a net-zero grid in place by 2035. Finally, throughout all five scenarios, we assumed NREL's high demand scenario would apply given that in all five scenarios – including Business-as-Usual – we assume that Texas demand growth will continue to exceed the national average. Each scenario was solved sequentially, with decision-making in each modeled year based on static operating conditions for the subsequent 20 years. We then adjusted input variables in ReEDS to reflect the scenarios contemplated above. Details on how these parameters were changed can be seen in Appendix 1. ReEDS accounts for a multitude of constraints including reliability, reserve margins, fuel price, siting limitations, federal incentives, climate, and other variables. ReEDS solves for a grid optimized for reliability and cost, given inputs that are impacted by these constraints.

2.3 Assessing Reliability of the Two Lowest Cost Options

We then use the Electricity Systems Optimization (ESO) framework to assess the impact of deploying different technologies at varying rates on the ERCOT system in terms of cost and reliability – or ability to meet demand.[3] Namely two scenarios, technologies with CCS and without CCS, to give a magnified impact on CCS technology. The ESO framework is a mixed-integer linear optimization model, which was written and modeled in GAMS by researchers at the Imperial College of London. We utilized a GAMS license with the CPLEX solver to run the model. Data clustering of demand, cost, and renewables availability on an hourly basis was done in the Python environment. Details on how the data were clustered can be seen in Appendix A.

2.4 Assessing Lifecycle Emissions of the Least Cost Scenario

As a final step, we sought to quantify the lifecycle emissions of the least cost scenario. Lifecycle emissions analyses look at the cradle-to-grave life of the product or good and account for the emissions associated with the mining of materials, land use, water consumption, and transporting goods, emissions during the useful life of the asset, and finally the emissions associated with decommissioning that asset. Because the NREL and ESO models account for only emissions released during the operation of the generating source, we sought to quantify additional DAC or carbon removal that might be needed for the grid to truly become net-zero. To assess the CO_2

emissions for the entire lifecycle of an energy source in our least cost scenario – accounting for the upstream, operational, and downstream emissions – we used those emissions per kWh produced listed in Table 4.[4, 5]

Table 4. Lifecycle emissions from various energy sources. Data source: IPCC and UNECE.

Technology	**Abbreviation used**	**Emissions (Grams of CO_2 per kwh)**
Nuclear	nuclear	12
Coal	coal	820
Natural Gas CC	gas-cc	490
Natural Gas Combined CC CCS	gas-cc-ccs	170
Natural Gas Turbine	gas-ct	490
Diesel Steam Turbine	o-g-s	490
Hydropower	hydro	24
Landfill Gas	lfill-gas	593
Wind Power Onshore	wind-ons	11
Wind Power Offshore	wind-ofs	12
Utility Photo Voltaic	upv	48
Distributed Utility Photo Voltaic	dupv	48
Distributed Photo Voltaic	distpv	48
Rooftop Photo Voltaic	pvb	41
Battery Technology_2	battery_2	33
Battery Technology _4	battery_4	33
Battery Technology _6	battery_6	33
Battery Technology _8	battery_8	33
Battery Technology _10	battery_10	33
Pumped- Hydropower	pumped hydro	24
Steam Methane Reforming	smr	38
Direct Air Capture	dac	-294

Chapter 3: Results

3.1 ReEDS Capacity Expansion - BAU

ReEDS was used to assess optimized grid expansion. Capacity growth by technology through 2050 for the BAU scenario is shown in Figure 5. Additionally, the corresponding emissions from the capacity additions as modeled are shown by the red line in Figure 5.

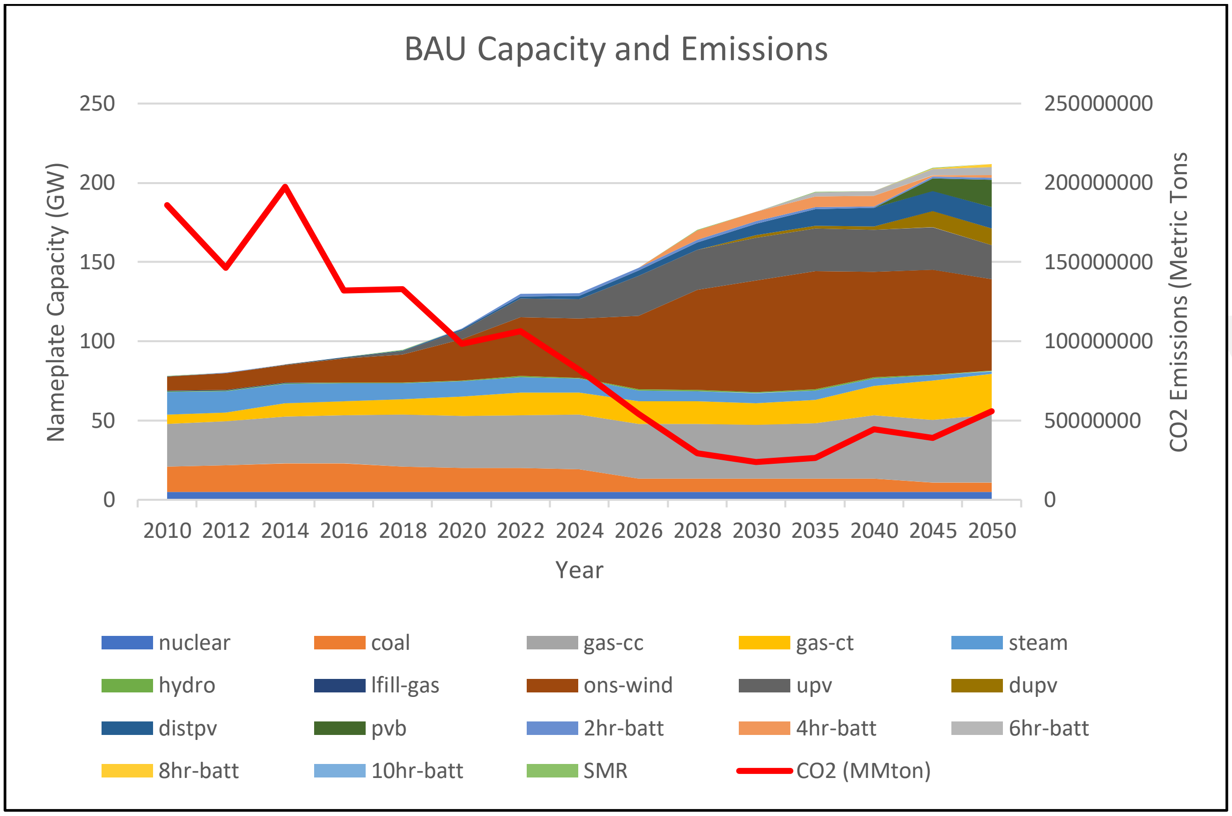

Figure 5. BAU capacity growth as modeled using ReEDS.

In the BAU scenario, nameplate capacity grows to 212 GW with the two largest sources of capacity being onshore wind and natural gas combined cycle turbines. CO_2 emissions are reduced to just below 56 million tons annually. This reduction represents a nearly 70% decrease from 2019 emissions levels but falls short of decarbonizing the grid by 2050.

3.2 ReEDS Capacity Expansion – Scenario 2

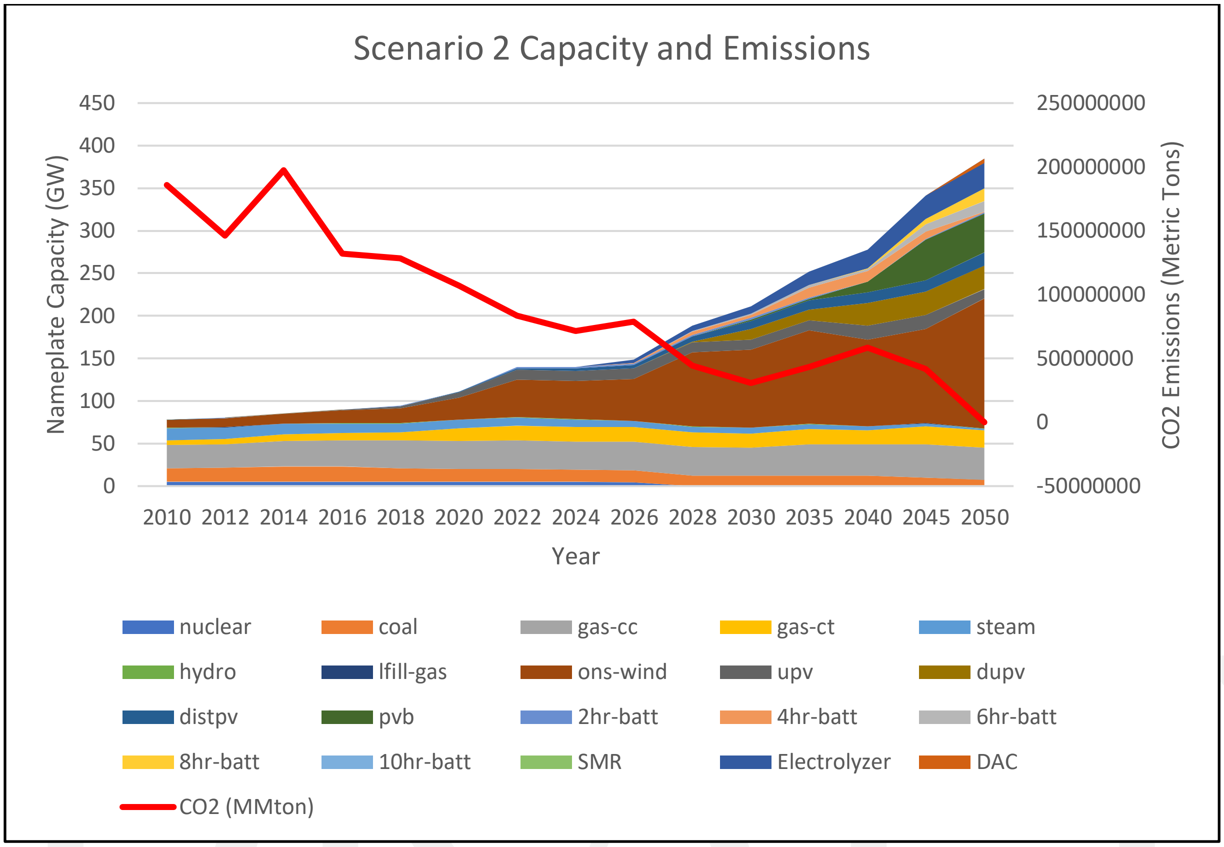

Figure 6. Scenario 2 capacity growth as modeled using ReEDS.

In Scenario 2, nameplate capacity grows to 390 GW, with the largest sources of capacity being onshore wind, solar, and batteries. CO_2 emissions are reduced to carbon-negative levels due in part to electrolyzers producing hydrogen and DAC playing a role in removing CO_2 emissions from fossil generation sources.

3.3 ReEDS Capacity Expansion – Scenario 3

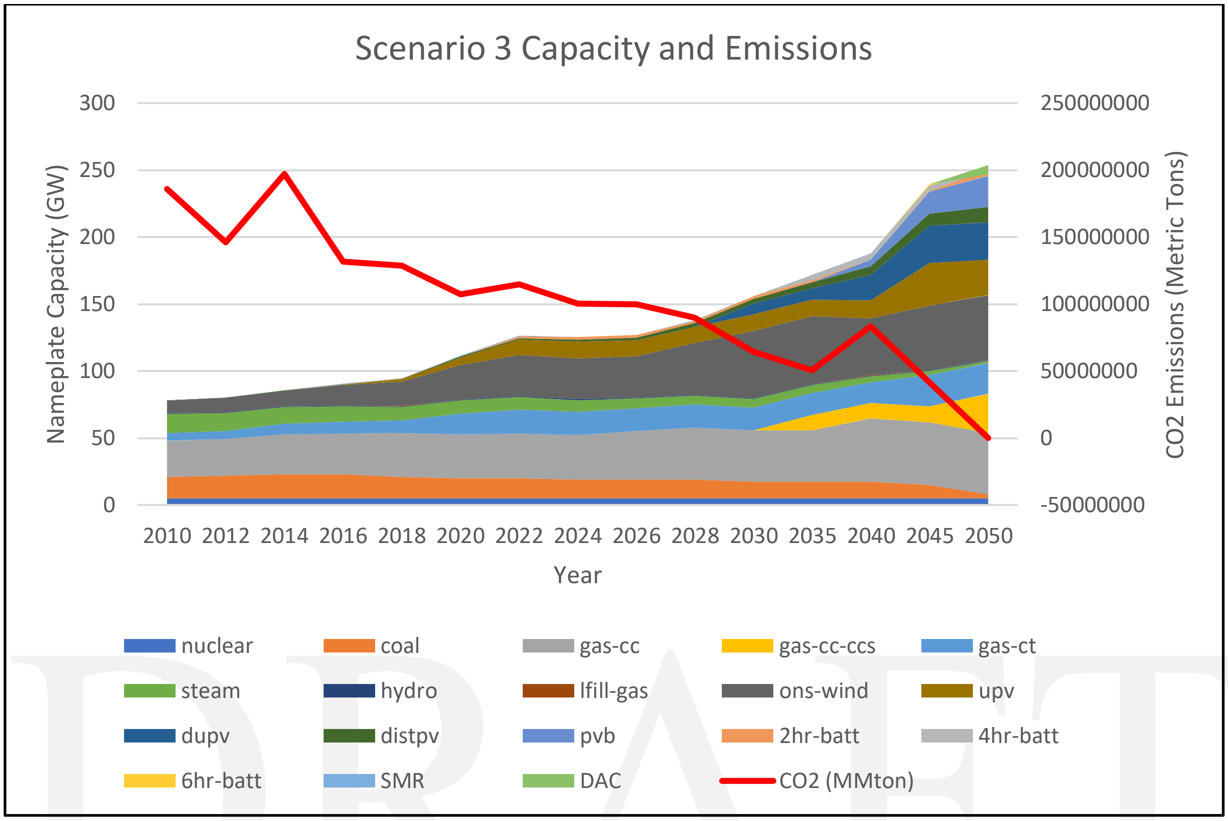

Figure 7. Scenario 3 capacity growth as modeled using ReEDS.

In Scenario 3, nameplate capacity grows to 260 GW with the largest sources of capacity being onshore wind, solar, natural gas combined cycle turbines, and natural gas combined cycle turbines with carbon capture. CO_2 emissions are reduced to carbon-negative levels due in part to carbon capture utilization and storage on natural gas generators and DAC playing a role in removing CO_2 emissions from fossil generation sources.

3.4 ReEDS Capacity Expansion – Scenario 4

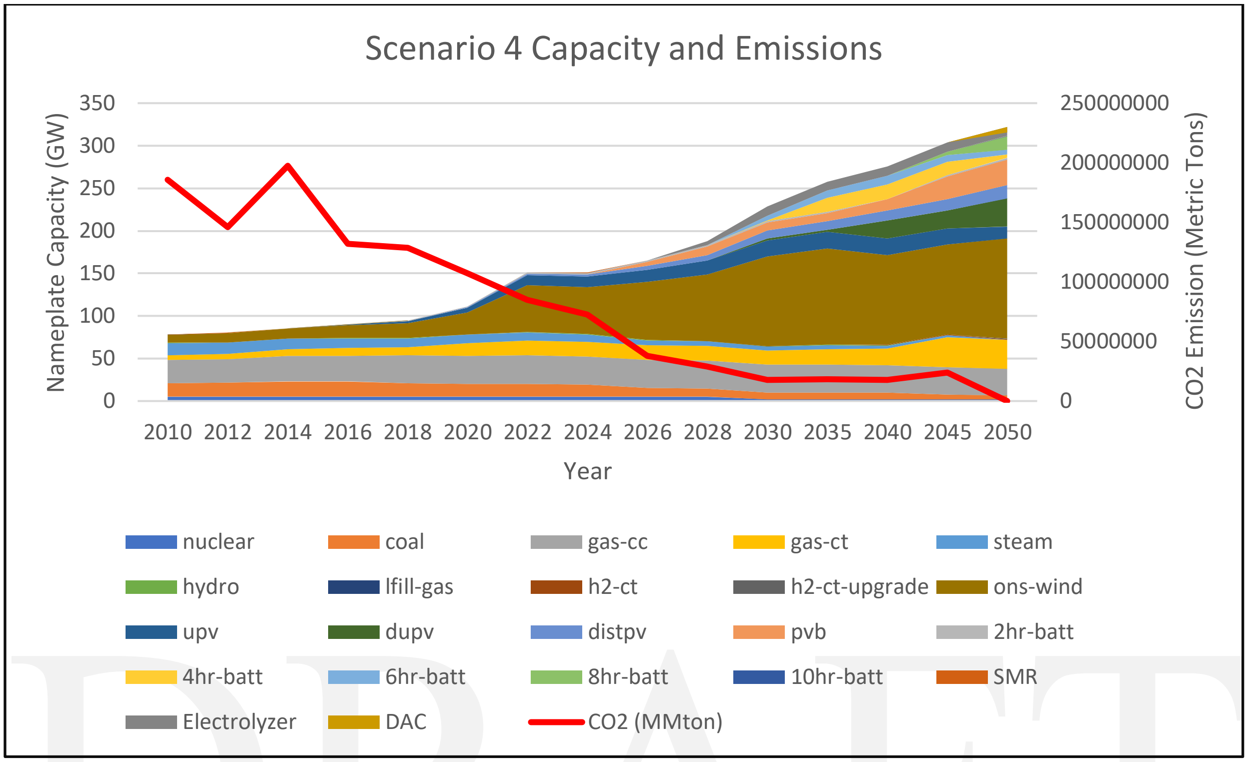

Figure 8. Scenario 4 capacity growth as modeled using ReEDS.

In Scenario 4, nameplate capacity grows to 329 GW with the largest sources of capacity being onshore wind and solar. CO_2 emissions are reduced to carbon-negative levels due in part to large amounts of hydrogen being produced and hydrogen-fueled turbines and retrofits meeting grid reliability needs.

3.5 ReEDS Capacity Expansion – Scenario 4

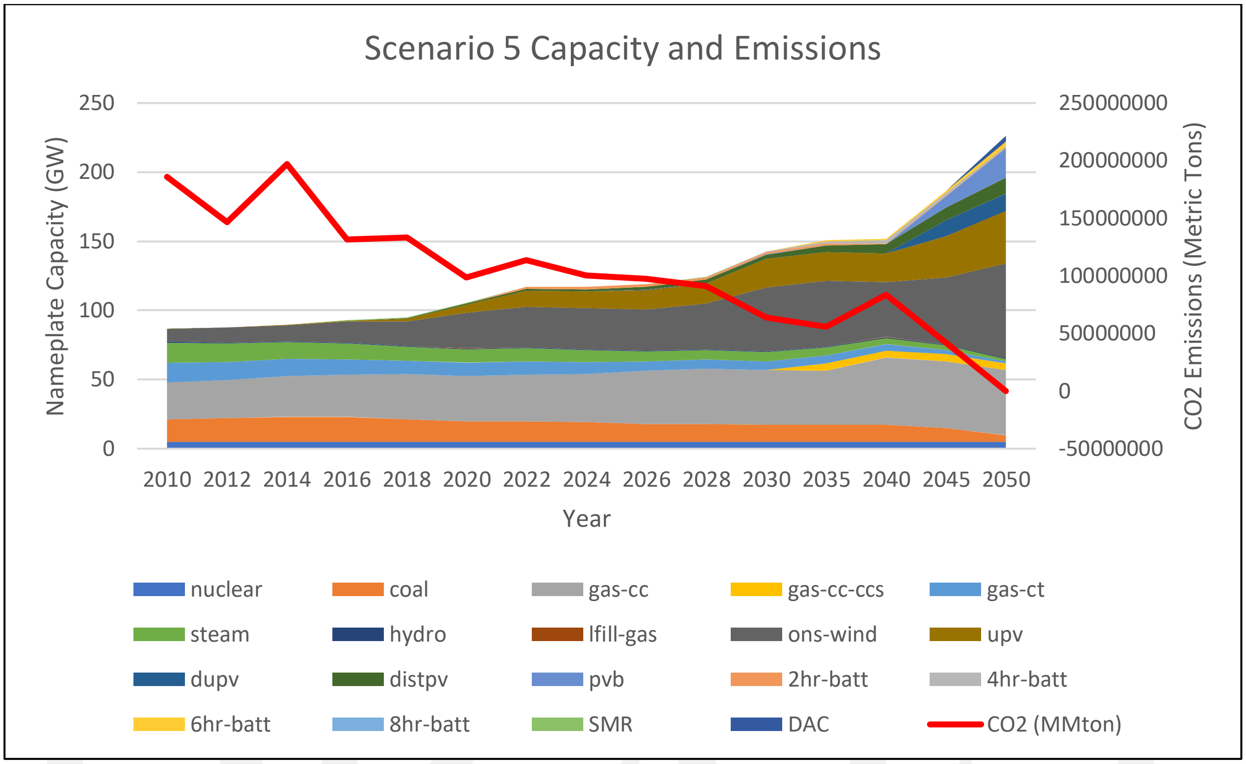

Figure 9. Scenario 5 capacity growth as modeled using ReEDS.

In Scenario 5, nameplate capacity grows to 240 GW with the largest sources of capacity being onshore wind and natural gas combined cycle turbines. CO_2 emissions are reduced to carbon-negative levels due in part to carbon capture and storage on natural gas combined cycle turbines and DAC.

3.6 Additional Results from ReEDs

In addition to solving for capacity contributions from a variety of technologies, ReEDS also provides the expected total system cost for each scenario. As shown in Table 5, the lowest cost pathway to achieving a net-zero grid is Scenario 5.

Table 5. Levelized System Cost from 2020-2050 in 2020 billion USD.

Cost category	BAU	Scenario 2	Scenario 3	Scenario 4	Scenario 5
Capital	87.0	113.0	81.0	124.4	62.2
PTC	(32.2)	(49.3)	(19.2)	(52.0)	(17.3)
O&M	101.4	112.8	106.0	115.6	96.9
Fuel	34.4	24.9	39.9	31.1	38.0
Transport	14.5	13.3	10.8	14.7	10.4
H_2 network	0.0	0.0	0.0	0.0	0.0
H_2 VOM	1.1	0.8	2.5	0.8	1.1
H_2 fuel	10.6	5.5	19.6	10.0	8.4
CO_2 capture	-	0.1	1.9	0.1	0.8
Total	**217.1**	**221.0**	**242.5**	**244.7**	**200.4**

3.7 ESO Capacity Expansion

In addition to analyzing which technologies might be needed to achieve a net-zero grid in ERCOT, we also sought to assess the reliability of the two lowest-cost scenarios achieving net-zero. To do this, we looked for differences between Scenario 5 and Scenario 2. These alternatives presented the least cost paths to achieve net-zero without significantly deviating from the affordability of the BAU scenario. Scenario 5 differs from Scenario 2 in that Scenario 5 requires CCS technologies to reach net-zero while Scenario 2 does not. Accordingly, we sought to determine if there were significant differences in reliability in a grid containing CCS versus a grid without CCS. The ESO model also provides a comparison of emissions and costs.

Previous work has suggested that utilizing CCS with existing baseload dispatchable resources like natural gas or coal-fired plants results in greater reliability.[6] In the previous work, the ESO model was used. For our purposes, we utilized the ESO model and used demand data from 2019 with a projected growth rate that follows closely to the previously described scenarios in conjunction with electrical pricing data and availability data for both wind and solar. The results for the technological mix are that of power output and associated emissions, as well as the cost of investment per technology on a five-year basis.

3.2.1 With CCS

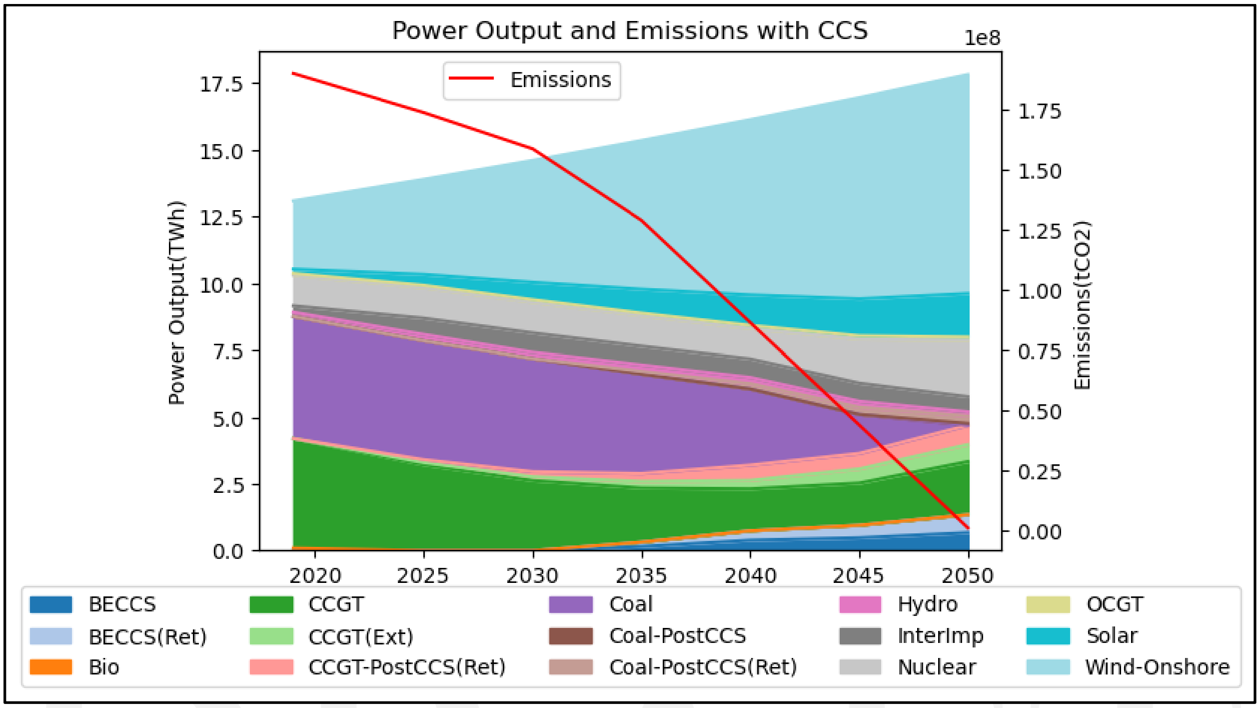

Figure 10. Shows power output from available technologies with CCS through the year 2050 and associated total emissions.

From Figure 10 wind energy contributes a large amount of energy to the grid, with coal and natural gas combined cycle following. There are small contributions from those technologies equipped with CCS adding to the overall grid capacity.

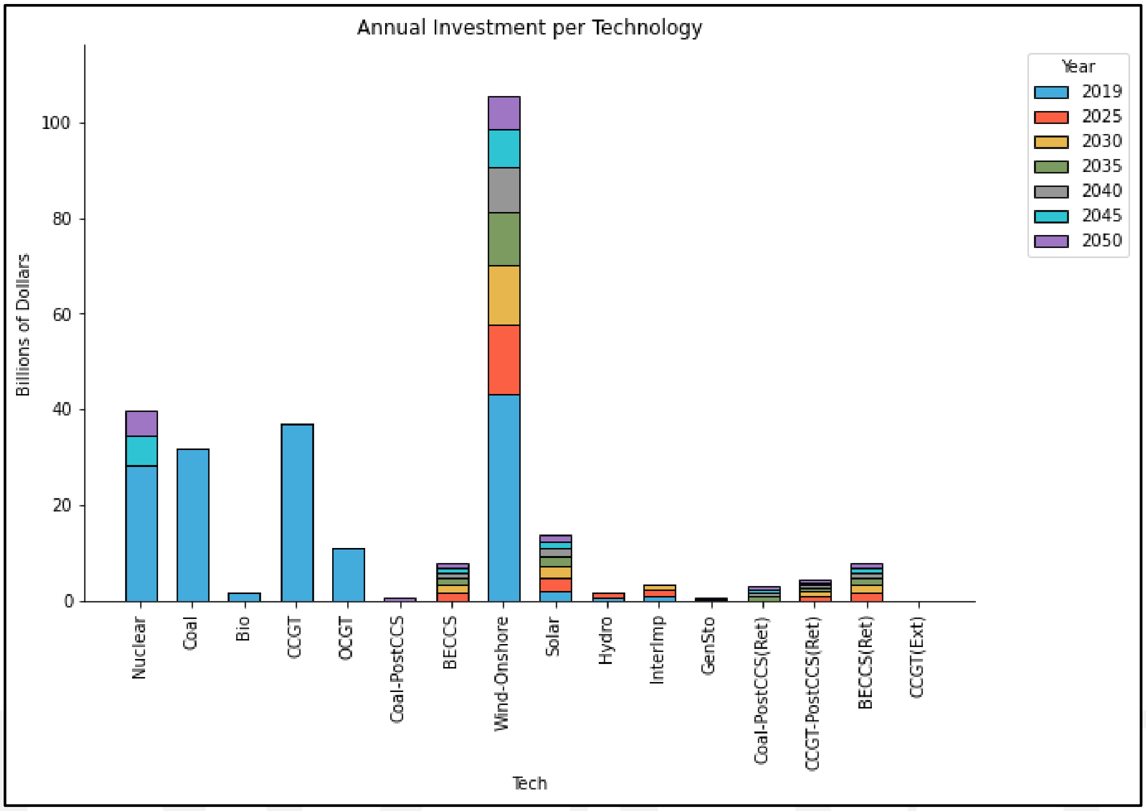

Figure 11. Quinquennial investment in billions USD.

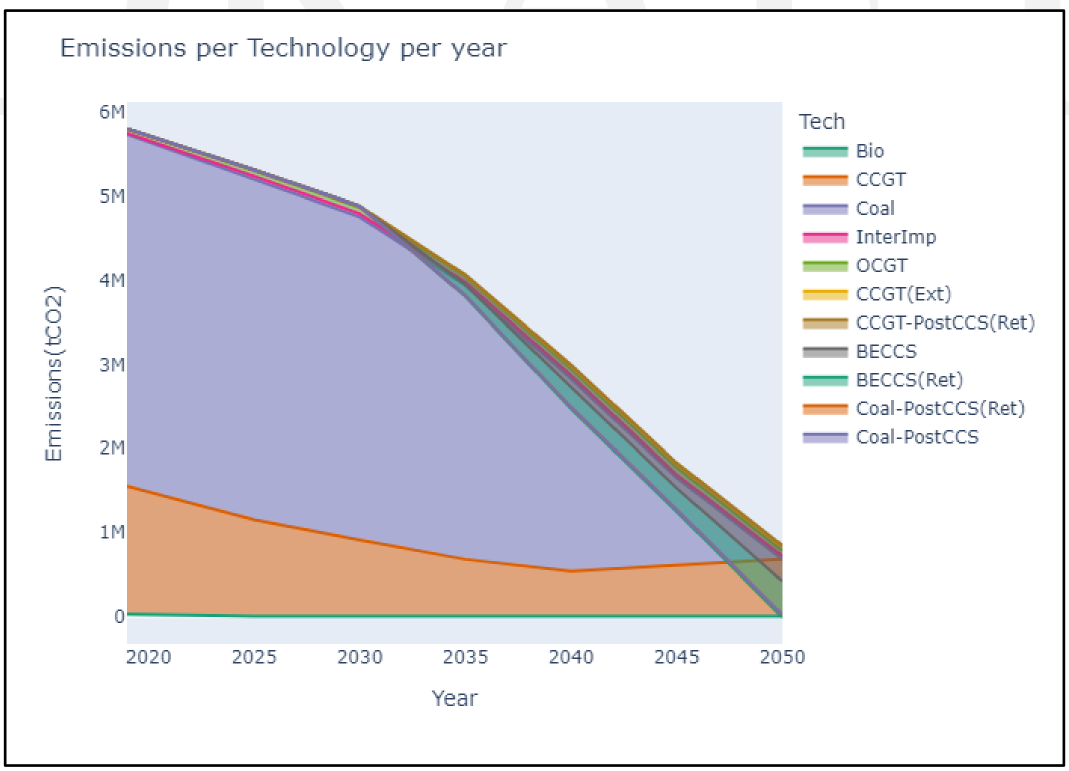

Figure 12. Emissions in tons of CO_2 per year.

3.2.2 Without CCS

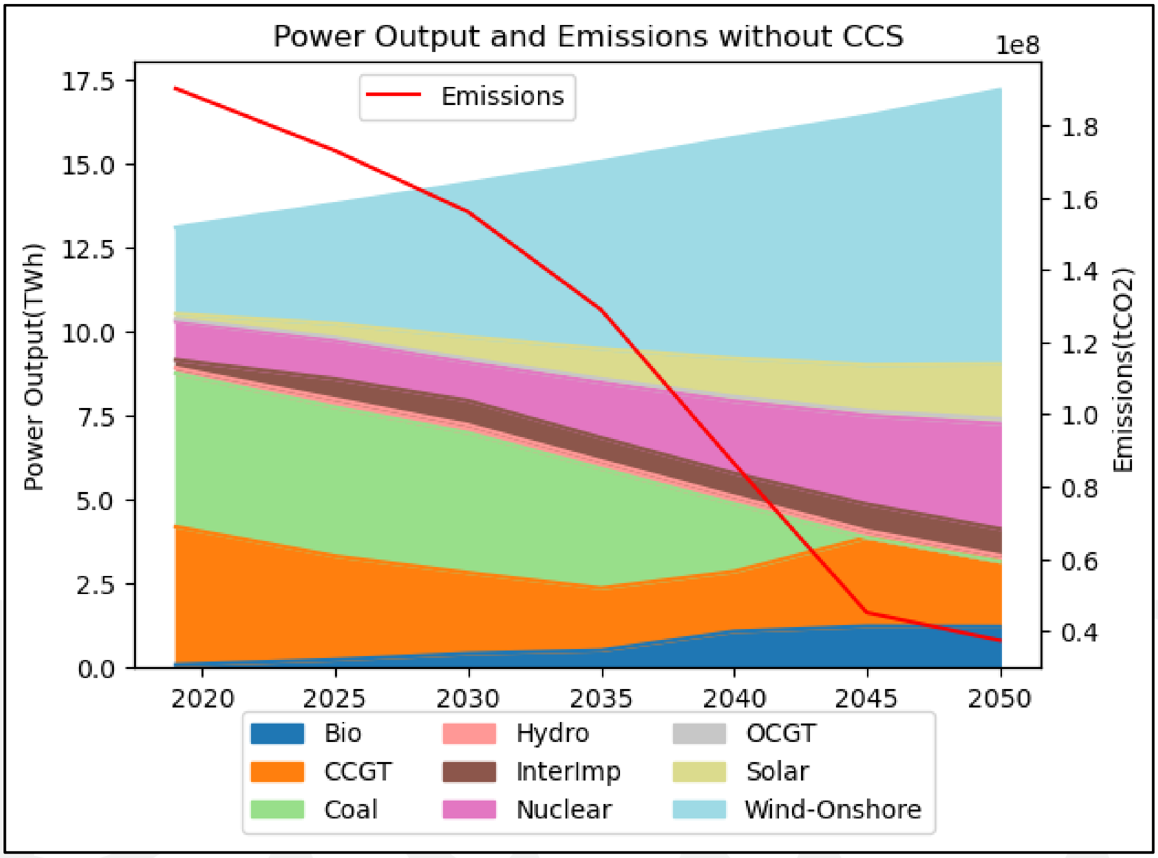

Figure 13. Power output from available technologies without CCS through the year 2050 and associated total emissions in tons of CO_2.

From Figure 13, onshore wind produces the most energy, with solar coming in second. This is an indication that the baseload capacity will be reduced. It is also noteworthy that emissions do not reach zero by 2050.

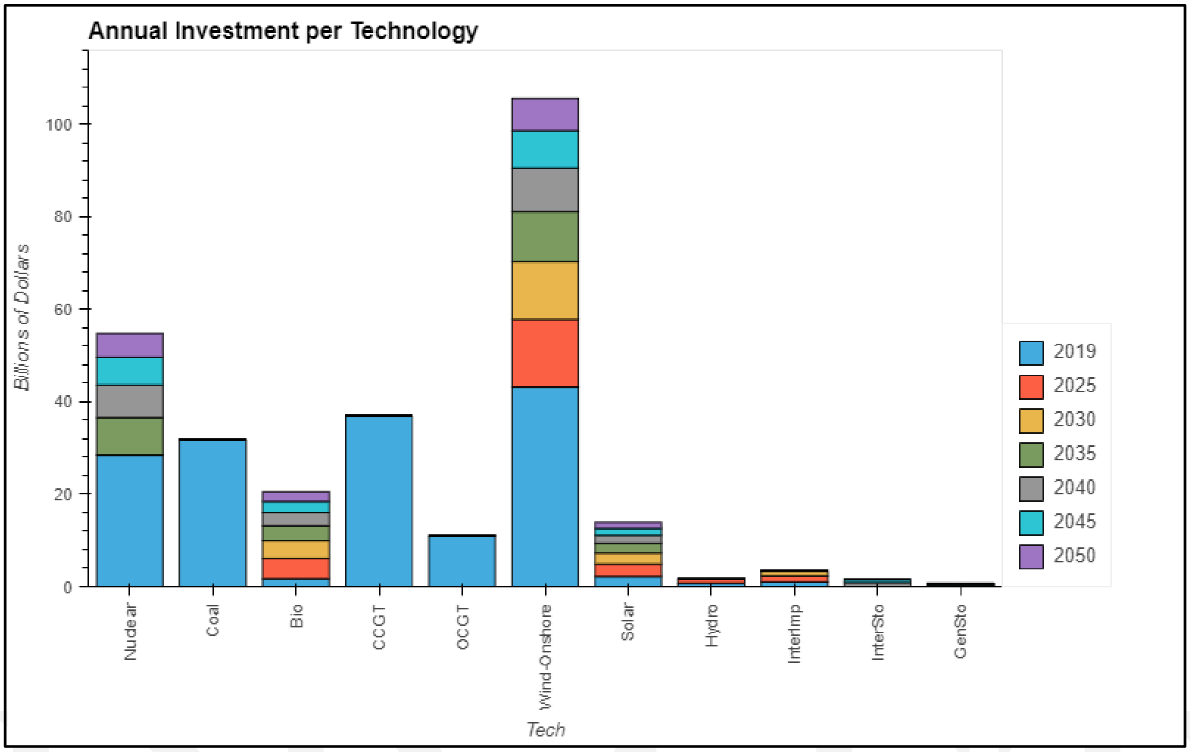

Figure 14. Quinquennial investment in billions USD.

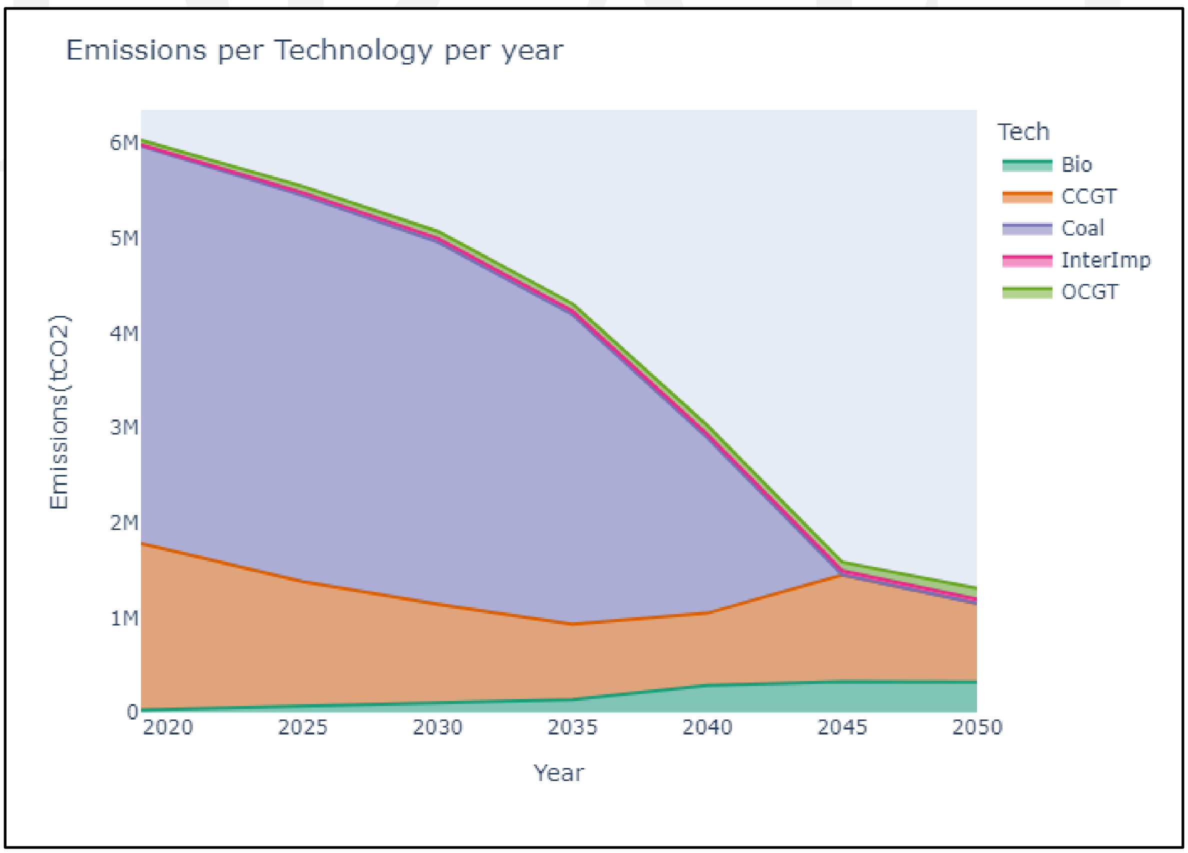

Figure 15. Emissions in tons of CO_2 per year.

3.3 Cost and Total Emissions Comparison

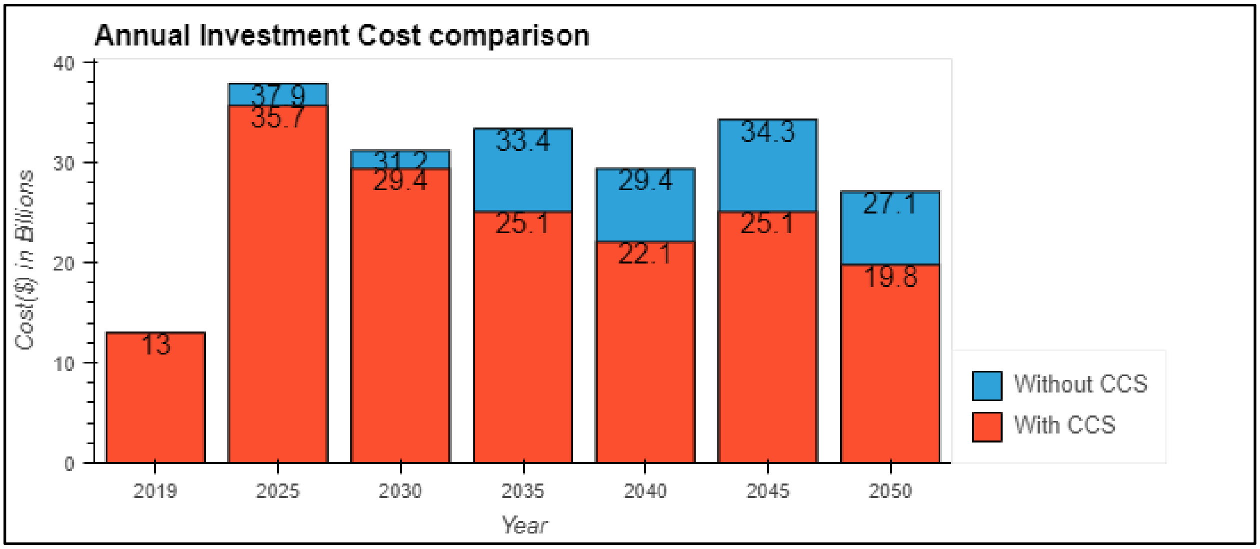

Figure 16. Comparison of investment needed for a grid with CCS versus a grid without CCS.

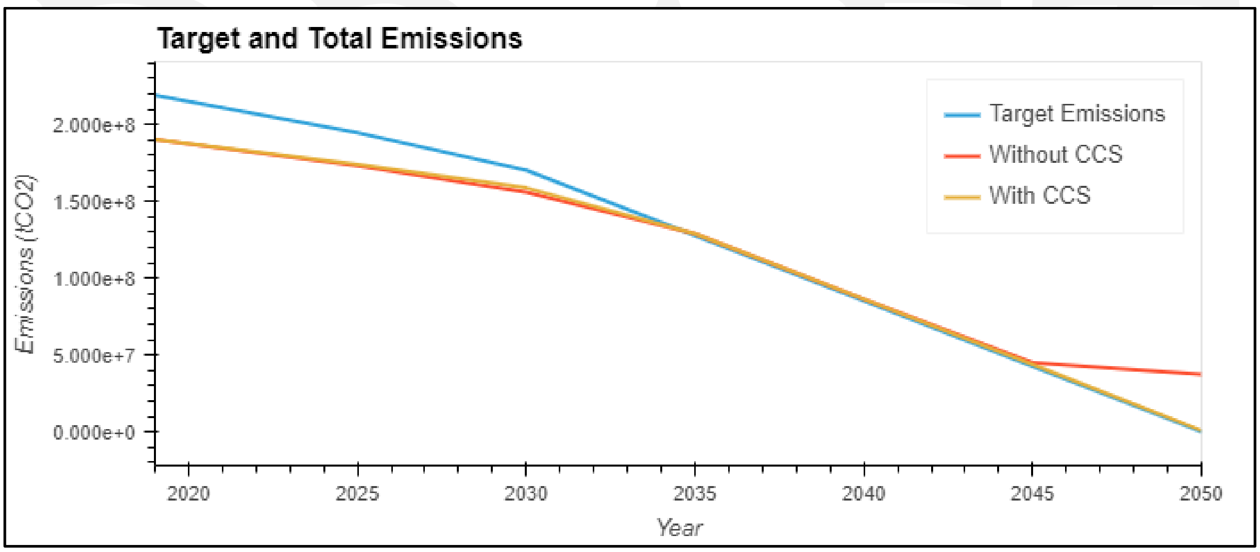

Figure 17. Comparison of emissions for a grid with CCS versus a grid without CCS.

Figures 16 and 17 suggest that the technology that will require the most investment will be onshore wind, for both scenarios. Figure 16 also shows the total quinquennial investment is higher without CCS technology than with CCS. Lastly, the decarbonization goal for the year 2050 is nearly met in the scenario with CCS technology but is not met without CCS. The graphs below show the total power output per cluster per hour overlaid with demand on the same timescale for both scenarios.

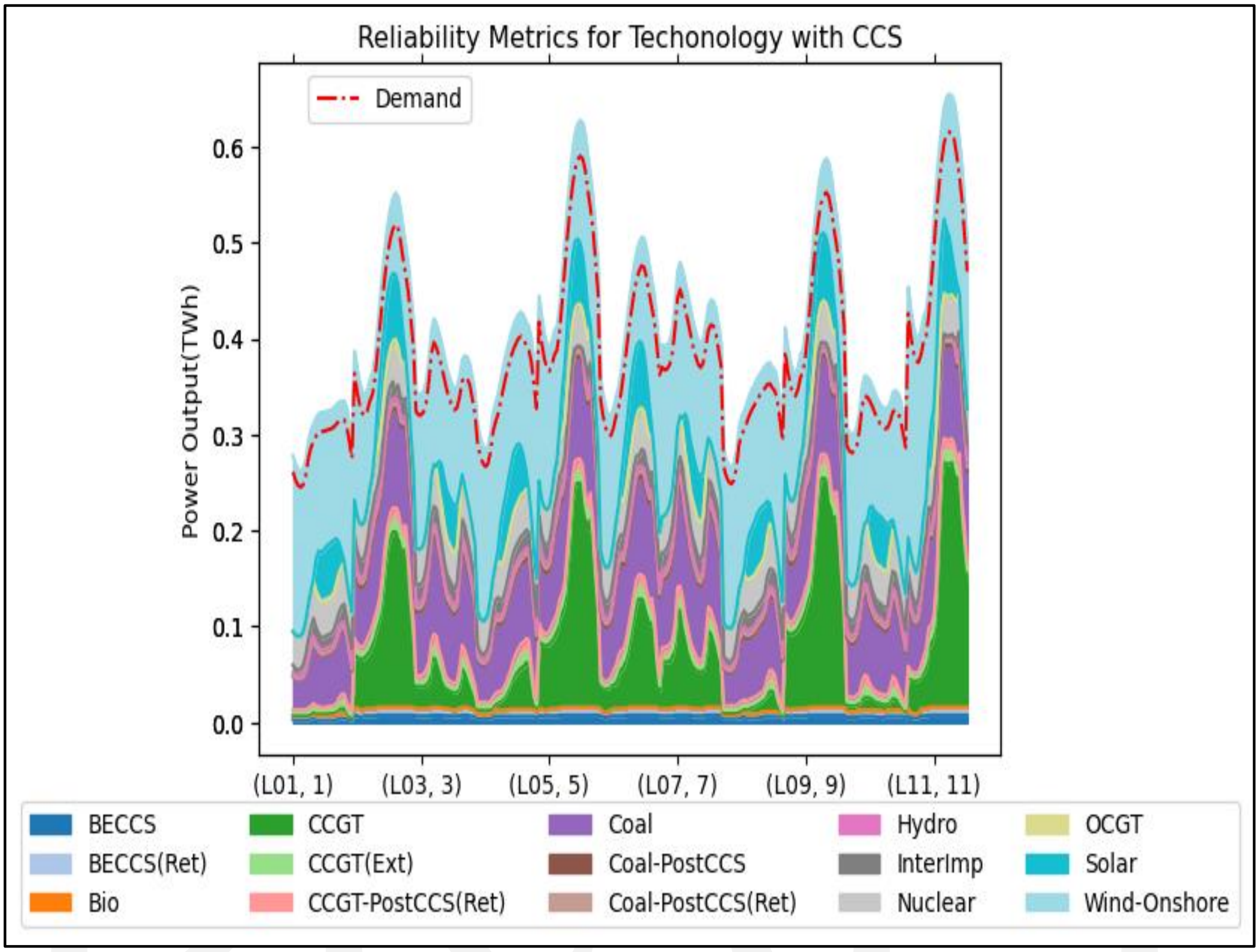

Figure 18. Power output (TWh) for each technology per cluster per hour overlaid with demand, for a grid with CCS. The red line indicates peak demand.

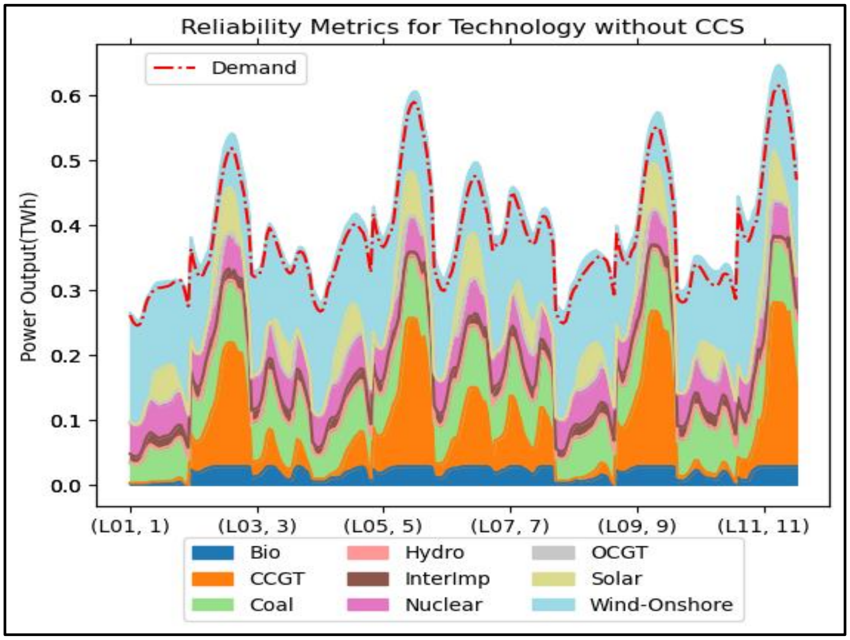

Figure 19. Power output (TWh) for each technology per cluster per hour overlaid with demand for a grid without CCS technology.

Figures 18 and 19 show that in both scenarios the technology mix can exceed demand through 2050, indicating that in each, the reliability of the grid is high.

3.4 Lifecycle Emissions of Scenario 5

To assess whether the negative emissions projected for 2050 in the least cost Scenario 5 account for the entire lifecycle emissions of given generation resources, we quantified the lifecycle emissions for all generation sources contained in Scenario 5. To do so, we first quantified the total generation projected by the ReEDs for each technology (Table 6).

Table 6. Total Power Generation in TWh by year and technology for Scenario 5.

Technology	2022	2023	2025	2030	2035	2040	2045	2050
Nuclear	39.6	39.6	39.6	39.6	39.6	39.6	39.6	39.6
Coal	45.6	26.5	7.1	6.6	6.6	6.6	5.2	2.5
Natural Gas CC	152.0	171.0	195.0	135.0	111.0	195.0	85.9	24.7
Natural Gas Combined CC CCS	0.0	0.0	0.0	0.0	38.2	11.2	35.4	35.1
Natural Gas Turbine	7.3	11.2	12.3	6.9	6.8	6.1	6.0	5.8
Diesel Steam Turbine	5.1	4.8	4.2	3.4	3.1	2.4	1.6	0.8
Hydropower	0.7	0.7	0.6	0.6	0.7	0.7	0.7	0.7
Landfill Gas	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Wind Power Onshore	94.6	97.2	103.0	173.0	184.0	158.0	196.0	264.0
Wind Power Offshore	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utility Photo Voltaic	29.5	30.3	33.3	52.9	51.1	49.3	74.1	95.9
Distributed Utility Photo Voltaic	0.0	0.0	0.0	0.0	0.0	0.0	34.0	35.4
Distributed Photo Voltaic	1.9	2.2	2.9	4.9	6.9	9.8	13.7	17.6
Rooftop Photo Voltaic	0.0	0.0	0.0	0.6	0.6	0.5	26.7	56.9
Battery Technology_2	-0.3	-0.3	-0.2	-0.3	-0.2	0.0	-0.1	-0.1
Battery Technology _4	0.0	0.0	0.0	-0.2	-0.2	-0.6	-0.5	-0.4
Battery Technology _6	0.0	0.0	0.0	0.0	-0.4	-0.2	-0.6	-2.7
Battery Technology _8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.2
Battery Technology _10	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped-Hydropower	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Steam Methane Reforming	0.0	0.0	-0.6	-1.2	-1.1	-1.0	-0.9	-0.8
Direct Air Capture	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-2.5

The values projected from the NREL model did not include generation totals for every year. Using linear interpolation methodology, the generation values were calculated for each year from 2022 to 2050 for each source.

The total CO_2 emissions are obtained as follows:

$$Net\ CO_2\ emissions = \ CO_2\ emissons\ per\ unit\ power * Total\ power\ units$$

where, 'CO_2 emissions per unit power' are presented in Table 4 and 'Total power units' in Table 6. Table 7 and Figure 21 highlight that although the emissions from the actual generation of electricity can be negative or decarbonized by 2050, the lifecycle emissions will not reach zero by 2050.

Table 7. Total CO_2 emissions in million tons.

Technology	**2022**	**2023**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
Nuclear	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Coal	37.4	21.7	5.9	5.4	5.4	5.4	4.3	2.1
Natural Gas CC	74.5	83.7	95.4	66.0	54.4	95.4	42.1	12.1
Natural Gas Combined CC CCS	0.0	0.0	0.0	0.0	6.5	1.9	6.0	6.0
Natural Gas Turbine	3.6	5.5	6.0	3.4	3.3	3.0	2.9	2.8
Diesel Steam Turbine	2.5	2.4	2.0	1.7	1.5	1.2	0.8	0.4
Hydropower	<0.1	<0.1	<0.1	<0.1	<0.1	<0.1	<0.1	<0.1
Landfill Gas	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Wind Power Onshore	1.0	1.0	1.1	1.9	2.0	1.7	2.2	2.9
Wind Power Offshore	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utility Photo Voltaic	1.4	1.5	1.6	2.5	2.5	2.4	3.6	4.6
Distributed Utility Photo Voltaic	<0.1	<0.1	<0.1	<0.1	<0.1	<0.1	1.6	1.7
Distributed Photo Voltaic	0.1	0.1	0.1	0.2	0.3	0.5	0.7	0.8
Rooftop Photo Voltaic	0.0	0.0	0.0	<0.1	<0.1	<0.1	1.1	2.3
Battery Technology_2	<0.1	<0.1	<0.1	<0.1	<0.1	<0.1	<0.1	<0.1
Battery Technology _4	0.0	0.0	0.0	<0.1	<0.1	<0.1	<0.1	<0.1
Battery Technology _6	0.0	0.0	0.0	0.0	<0.1	<0.1	<0.1	<0.1
Battery Technology _8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	<0.1
Battery Technology _10	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped- Hydropower	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Steam Methane Reforming	0.0	0.0	<0.1	<0.1	<0.1	<0.1	<0.1	<0.1
Direct Air Capture	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-7.3
Total CO_2	**121.2**	**116.6**	**112.8**	**81.8**	**76.6**	**112.2**	**66.0**	**29.2**

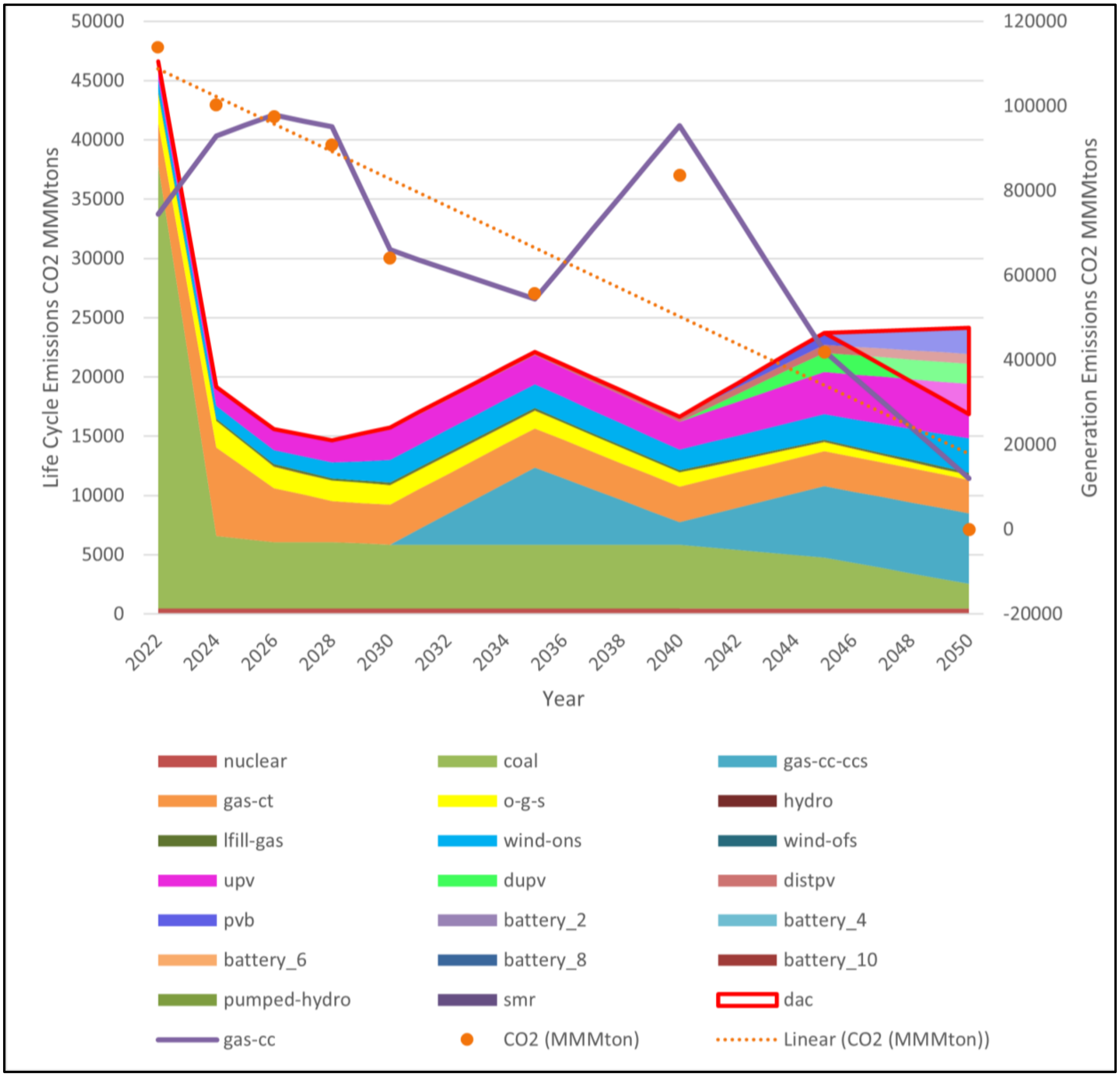

Figure 21. Total CO_2 emissions in million tons.

Chapter 4: Discussion and Implications

4.1 Technological Implications

From the ReEDs model, it is important to first note that the capacity contributions of any given technology in any given scenario are not predictions of how the ERCOT grid will progress from now through 2050. Rather, the results show optimized solutions given assumptions about demand, transmission, technology advancements, and pricing. What the results do show is that how certain technologies progress and the pathway that ERCOT takes in achieving any net-zero goals can have significant impacts on overall system cost.

As one might expect, fuel costs are the highest in Scenarios 3 and 4, where the growth of renewable penetration on the ERCOT system is constrained. However, transmission costs are also the lowest in Scenarios 3 and 4, likely because much of the renewable additions in the other scenarios would require incremental transmission buildout. Said differently, in future scenarios where renewable generation growth is largely unconstrained, transmission costs will be higher, but fuel costs will be lower as renewable generation pushes fossil resources from the generation mix.

The most significant difference in cost category between Scenario 5 and all other scenarios is that lower capital expenditures are needed in Scenario 5. This is likely due to Scenario 5 resulting in the fewest retirements of reliable baseload resources by 2050. Table 8 shows the retirements of baseload resources by fuel type per scenario.

Table 8. Planned future retirements from 2024-2050 by fuel type in each scenario.

Fuel Type	Business as Usual	Scenario 2	Scenario 3	Scenario 4	Scenario 5
Nuclear	0.0	2.5	0.0	1.5	0.0
Coal	3.8	2.4	3.2	4.1	2.8
Gas-CC	0.8	0.8	0.8	0.8	0.8
Gas-Ct	0.8	0.8	0.8	1.0	0.8
Steam	2.5	2.5	2.5	3.5	2.5
Total	7.9	8.9	7.3	10.9	7.0

Based on the results from ReEDS, Scenario 5 involves the smallest amount of retired capacity from baseload resources. In Scenario 5, no nuclear is retired before 2050. Additionally, while coal is retired, Scenario 5 calls for fewer retirements than all but Scenario 2. While this alone does not drive the difference seen in capital expenditures, it is part of the story. As more baseload resources are retired, we can expect that additional low-carbon alternatives will be needed to replace that capacity. This is particularly true when considering that in all scenarios demand is continually growing at a pace greater than the national average.

To further assess the differences in capital expenditures between Scenario 5 and all other scenarios, we considered annual capacity additions to (1) replace retiring baseload capacity and (2) meet the growing electricity demand. Table 6 shows the capacity additions required in each scenario.

Table 9. Total nameplate capacity additions from 2024-2050 for each scenario.

Scenario	**Total Nameplate Capacity Additions (GW)**
Business as Usual	48.5
Scenario 2	90.2
Scenario 3	50.7
Scenario 4	81.9
Scenario 5	46.1

Capacity additions in ReEDS are solved to meet growing demand while accounting for the variability of resources and the requirements to maintain regulatory and operating reserve margins on the grid. Given these requirements, ReEDS solves for the nameplate capacity needed to provide the actual output to meet demand. Accordingly, all scenarios in ReEDS have a certain level of reliability built into the model. It is likely Scenario 5 is the least-cost pathway to achieving a net-zero grid in ERCOT by 2050 because Scenario 5 involves (1) the fewest retirements of baseload resources, (2) the least amount of transmission buildout needed to connect renewable resources to load centers, and (3) the least amount of needed capacity additions to meet growing demand.

Given that Scenario 5 represents the least-cost pathway for ERCOT to reach net-zero by 2050, we look to which technologies enable that least-cost path to learn what technologies might be most important to assist in directing ERCOT towards traveling that path. First, it is clear from all the recommended scenarios that a broad array of technologies is needed to achieve any net-zero goals. Scenario 5 specifically utilizes nuclear, coal, natural gas combined cycle, natural gas combustion turbines, natural gas combined cycle with carbon capture and storage, steam from generators using oil, gas, diesel or some other fuel, hydropower, landfill gas, onshore wind, solar, batteries, pumped hydro and a small amount of offshore wind. Scenario 5 also experiences increased demand on the grid to power steam methane reformers to make hydrogen and direct air capture units.

The other scenarios are largely the same, with the caveat that some include small amounts of bioenergy with carbon capture and storage (BECCS), cofire, hydrogen-powered combustion turbines, and biofuels. Further, some scenarios call for some nuclear to be used in hydrogen production while others rely on hydrogen production from electrolyzers. The point of listing these resources found in the scenarios is not to dive into the nuances between each, but to point out that it is likely to take a broad array of technologies and each scenario relies on certain technologies not currently being used commercially. Accordingly, we believe certain steps may be taken at the state level to drive investment into developing and commercializing these technologies while allowing the marketplace to determine which technologies are best suited to achieve the state's goals.

From the ESO model, the results are not to be interpreted as predictions for the state of ERCOT's grid by the year 2050, rather they show trends, given a set of technologies and assumptions. These trends have implications on how technologies affect the state of the grid regarding overall power output, total system cost, and emissions.

As mentioned previously, we compared Scenario 5 and Scenario 2 for reliability. To do so, we compared grid expansion using the separate ESO model to assess whether a grid with CCS was more reliable than one without, which was a primary difference in the two least-cost options from the NREL model. Comparing a grid with CCS and one without, we observed that CCS plays an important role in reducing total system cost and allowing emissions to be reduced to nearly zero by 2050. The findings of lower costs with CCS are the same as those shown in the NREL model. However, in the NREL model, Scenario 2 and Scenario 5 each reached a net negative by 2050. In the ESO model, the grid without CCS did not achieve net zero by 2050. This is likely in part due to differences in the technologies each model considers in evaluating emissions. The NREL model assumes technologies like advanced photovoltaics and batteries that can discharge over longer times than currently available technologies.

However, the most important for our purpose is that the ESO model showed a grid with or without CCS could meet the reliability needs of the ERCOT grid in 2050. Despite significant differences in emissions and costs, both grids were able to meet demand reliably. With that being said, the dispatchable power output for the technologies including CCS is higher than for those without CCS. Accordingly, in the scenario where the grid of the future includes CCS, there is likely to be higher reserve margins and greater operational flexibility, which could allow ERCOT to avoid unforeseen events where demand cannot be met, as happened during 2021's Winter Storm Uri.

4.2 Policy Implications

Ensuring reliability while decarbonizing the grid is critical. In considering the problems experienced in the winter storm of 2021, some have begun to question whether it is prudent to retire existing baseload resources like nuclear, coal, or gas plants when ERCOT may already be subject to catastrophic blackouts.

Within the state, concerns over reliability without necessarily focusing on decarbonization took center stage during the 2023 legislative session. The concerns regarding reliability and protecting baseload power are best reflected in a suite of recent bills passed in the Texas Senate during the 2023 session. Senate Bills 6, 7, 1287, 2012, and 2014, all passed by the state Senate during the 88th Legislative session, propose sweeping changes that are meant to increase dispatchable generation or hinder renewable development[1]. SB 6 would require the state to hire companies to build 10,000 MW of natural gas-fired generators for use in emergencies. SB 7 would allow energy providers who can provide at least four hours of continuous service and could turn on within two hours to bid into a separate day-ahead market. SB 1287 would limit the amount paid for power producers interconnecting to ERCOT, aimed at shifting some interconnection costs to renewable generators who often locate further from load centers. SB 2012 would place parameters on the

[1] These measures had not yet been approved by the Texas House at the time of publication.

Public Utility Commission of Texas (PUCT) regarding the implementation of new market constructs discussed below. SB 2014 makes the purchase of RECs voluntary, again aimed at slowing the growth of renewables. Finally, SB 2015 would mandate that 50% of energy generation in ERCOT be dispatchable after January 1, 2024. The bill would make dispatchable energy credits available for sale if 55% of the projected generation after the effective date is not anticipated to be dispatchable. This suite of bills may improve reliability but will likely do little to abate emissions and may certainly result in higher emissions than ERCOT currently produces. Further, reducing emissions to net-zero under any scenario examined above seems unlikely if the suite of bills is signed into law without some reform to encourage technologies that can enable net-zero while also satisfying Texas law.

Complicating Texas' plans for additional baseload power, mostly from natural gas, is the Environmental Protection Agency's (EPA) new proposed rules regulating CO_2 emissions. The rule was published on May 8, 2023. The rule comes after the Supreme Court ruled last year that an Obama-era rule which would have mandated generation shifting was impermissible. The new rule addresses that ruling by focusing on the best system of emissions reduction technologies within the fence lines of existing power coal and natural gas-fired power plants. While the rule will most certainly be challenged in courts, it is uncertain whether those challenges will be successful this time. If the rule ultimately goes into effect, it will require many existing coal and natural gas facilities to make drastic changes to their operations. Coal plants subject to the rule will either be required to co-fire with natural gas or install CCUS technologies. Natural gas-fired plants will be required to either utilize hydrogen mixed fuels or install CCUS technologies.

While the Texas grid has incorporated a significant amount of renewable energy, notably wind power, to supply the state's energy needs. Such an undertaking was made possible due to the federal production tax credit, as well as the state RPS system. However, the above-outlined state policies may hinder further diversification and conflict with the new EPA proposed rules regarding emissions.

Diversification and evolution have allowed the Texas grid to meet demand with occasional interruption in an environmentally conscious manner. Current Texas and federal policies provide significant tax credits and subsidies aimed at expediting the energy transition. Tax incentives are now available for hydrogen, clean fuels, wind, solar, carbon capture, nuclear, batteries, and other technologies. The existence of these federal incentives is likely to mean market participants will continue to build wind, solar, and batteries in ERCOT at a rapid pace. This is due in large part to the maturity of these technologies, regardless of state policies looking to slow or limit growth.

Given the proposed EPA rule, we will begin to see additional hydrogen, carbon capture, nuclear, and clean fuels projects in the state. The number of these projects and their success should be carefully considered. Scenario 5 suggests there is merit to maintaining as much baseload power as possible. These technologies have the potential to assist in decarbonizing this baseload power. Accordingly, it may be in the long-term interest of Texas to help further incentivize those types of projects which will require a shift in policy and recognition of the benefits that those technologies can play in harmony with federal emissions rules. This can be achieved using past frameworks like property tax reductions, investment in infrastructure, and market standards that have proven successful in the state.

4.3 ERCOT Resilience and Policies to Encourage Scenario 5

Regardless of the uncertainty surrounding pending legislation and rules at the EPA, it is likely that many power generators will begin planning for compliance with the EPA rule. This will inevitably result in additional baseload plants being planned for early retirement. Scenario 5 of this research would suggest only retiring those assets when they reach the end of their useful life due to cost. Further, Scenario 5 suggests many of these assets can remain in service and the state can still achieve a net-zero grid by 2050 through utilizing technologies like carbon capture and storage and hydrogen as proposed by the EPA. In fact, the model does not assume early retirements and therefore – if followed – would alleviate concerns over retirements outpacing capacity additions and rate impacts. However, it is worth noting that this modeling assumption of no early retirements is unlikely to occur, as coal plants across the country are continually being scheduled for early retirements. This trend, combined with the proposed EPA rule, makes this assumption somewhat unrealistic. Despite this reality, the model assumes no earl early retirements across all scenarios and what appears to be a clear path towards decarbonizing the grid utilizing a broad range of technologies. The fact that early retirements will likely occur primarily impacts the timing of needed additions and potentially cost as technologies like CCUS and hydrogen are anticipated to be less expensive in the future than if needed today. This in turn may impact the overall cost of each Scenario to decarbonize but the added costs are likely similar across all scenarios and therefore the differences among the scenarios would remain largely the same.

Regardless of the uncertainty of how the recent state legislation and EPA rule proposal will impact Texas, it is clear from our analysis that careful planning and consideration are needed as the nation transitions to a zero-carbon power grid if states are to maintain affordability and reliability. To further encourage the technologies which enable the net-zero transition in all scenarios modeled, Texas could consider a new low-carbon portfolio standard. Such a standard could be modeled on the renewable portfolio standard and require transmission and distribution utilities to purchase a certain amount of low-carbon baseload electricity if it is available in the market. The same amendment could be made to SB 2015, resetting the standard from simply dispatchable generation to low-carbon dispatchable generation and providing credits and market incentives to encourage such technologies. Such a framework would help create a marketplace for power from these technologies, much like what was done to incentivize wind. Such a standard could also be complementary to and work in conjunction with whatever method the PUCT elects to improve reliability on the ERCOT grid. Currently, the PUCT is considering making market changes to ERCOT to improve reliability and is constrained by those requirements included in SB 2012.

As a part of that docket, the PUCT hired a consultant to evaluate various market design reforms which might be implemented to increase reliability while maintaining affordability. The consultant evaluated several market designs and ultimately recommended the PUCT implement a forward reliability market (FRM).[7] After reviewing the study and recommendation, PUCT staff is recommending the agency implement a performance credit mechanism (PCM).[8]

The two recommended market reforms include attributes that would address market reliability. The FRM establishes a reliability standard, much like the renewable standard. Additionally, the FRM creates a mandatory, centrally cleared forward market governed by ERCOT. The forward market administers reliability credits and clears the credits based on a sloped demand curve, with costs being assigned to load-serving entities (transmissions and distribution organizations) based on pro-rata consumption during a given year's hours of highest reliability risk.[9]

The PCM, favored by PUCT staff and likely to be the new standard, establishes a reliability standard and performance credits that generators commit to and must produce during the highest hours of reliability risk. The PCM also establishes a settlement process through which credits are awarded to generators based on their availability during those hours. Those credits can then be purchased by load-serving entities at a price determined by the demand curve. The PCM allows generators, which are generally separate from load-serving entities in ERCOT, to voluntarily trade credits, and generators must participate in the market to qualify for payment in the retrospective process.[10]

The PUCT's decision is focused on reliability while our recommendation focuses on achieving a sustainable grid. For the PUCT to consider low carbon resources as those that might qualify under the performance credit mechanism – would likely require direction from the Legislature. Because there is no clear answer as to where exactly all the low-carbon power would come from, transmission and distribution providers would only be required to purchase power to meet the standard as it became available. Further, because the ReEDS model suggests that in one scenario that achieving net-zero will take power from multiple sources including storage, gas plants with carbon capture, and renewables, it makes sense to make the low-carbon portfolio standard technology-neutral and to include storage as an eligible source if the stored power was similarly sourced from low-carbon generation. If this were the case, it would further make sense to ensure that only newly decarbonized power is available for purchase to meet that standard (*i.e.*, power from a new retrofit or a new plant).

Furthermore, the model does not suggest all gas turbines need to be replaced with those capable of being fueled by hydrogen, nor does it suggest that all those same turbines need to have carbon capture and storage capabilities. Rather, it suggests that over time, more renewables, batteries, and other technologies will naturally develop. These will largely help offset many of today's emissions. Additionally, direct air capture and BECCS are available as negative emissions technologies. Accordingly, a modest amount of capacity needs to come from low-carbon baseload resources.

For example, ReEDS suggests that in Scenario 5, a buildout of between 5 GW and 6 GW of capacity from natural gas combined cycle turbines with carbon capture and storage would be necessary. While this seems like a vast amount today, a low-carbon baseload portfolio standard might require 5 GW to 10 GW of capacity by 2040. Those targets are like those set for wind in the renewable portfolio standard and were easily surpassed by their target date.

Another component of such a standard may include further incentives for low-carbon baseload power in a form like the Competitive Renewable Energy Zones (CREZ) project for the necessary transport infrastructure. As additional low-carbon sources become available, there will be a need for additional electric transmission, hydrogen, and CO_2 transport infrastructure. The state could, for example, undertake a CO_2 pipeline feasibility study to be initiated by the Texas Legislature and carried out by relevant regulatory bodies like the Railroad Commission, Texas Commission on Environmental Quality, and the PUCT. The same could be done for hydrogen transport, additional transmission, and sourcing of biomass for biofuels or BECCS. Once the most cost-beneficial projects were identified, the state could invest in the necessary infrastructure to support the growing sector of low-carbon electricity generation.

The historical basis for this recommendation comes from a massive Texas Legislature-initiated electric infrastructure project—CREZ. In the 2000s, with its first renewable portfolio standard (RPS) in place, Texas was faced with a unique opportunity to grow the renewable energy sector. As wind generation ramped up, the largest issue facing this wind generation boom was how to build the transmission infrastructure so that the generation from turbines in the Panhandle and West Texas could power the population centers in the eastern and southern sections of the state without curtailment or lost load. In 2005, seeing the success of the first goals from the initial RPS, the Legislature moved to enact new goals, but more importantly, set up the RPS for success by issuing a directive to the PUCT to establish much-needed improvements to the transmission infrastructure. PUCT, working with ERCOT and non-governmental stakeholders including the public and transmission service providers, conducted research, and solicited feedback and proposals from interested stakeholders, and by 2014 over 11,000 megawatts of high-voltage transmission lines had been built to support the growing renewable energy industry. By seeing the need and initiating the project, the Texas Legislature was able to pave the way for Texas to be *the* leader in renewables without sacrificing the market structure. A similar project paving the way for low-carbon baseload power can be accomplished in this same way, and it all starts with a feasibility study.

Texas would not be the first state to initiate fact-finding of this sort. Wyoming, Illinois, North Dakota, and Iowa all have pipeline projects either being studied or planned and developed at this time with direction from state legislatures and agencies or federal regulatory agencies. Wyoming, for example, has a private-public partnership for the development of an enhanced oil recovery CO_2 pipeline and related CCUS projects which demonstrates that legislative led-initiatives are vital to demonstrate state commitment to carbon-reduction plans.

Finally, the Scenarios illustrate there is an apparent sustainability and cost tradeoff, where increasing sustainability with primarily wind and solar creates increased costs to maintain reliability, whereas investing in making dispatchable resources more sustainable, results in lower overall system costs. This realization is somewhat counterintuitive as many believe that most utility-scale renewable resources are less expensive today than fossil fuel alternatives. However, on a system level, which requires consideration of transmission, 24-hour reliability, and intermittency, it may be more cost-effective to make dispatchable resources more reliable while simultaneously building out renewables, particularly those that can readily integrate into the existing transmission and distribution grid and paired with storage.

To ensure that achieving a low-cost net-zero grid is possible, Texas could target the bottlenecks associated with R&D and technological innovation in hydrogen, storage, access to critical materials, and lifecycle concerns of the materials used in renewables. State intervention in these areas specifically makes sense, as private initiatives are likely to result in underinvestment and suboptimal outcomes as many of these technological innovations carry outsized risks that many corporations are unwilling to undertake. This intervention can come in the form of investing in research, state procurement of low-carbon goods and electricity even at a higher cost to provide a market for these emerging markets and providing additional tax incentives for companies investing in these technologies.

Regardless, of which path Texas chooses, and whether a path is set by EPA, our results indicate that a net-zero grid is possible in ERCOT. Importantly, such a grid, if carefully planned, may in fact cost as much or less than simply maintaining and growing the current grid through 2050. However, for that modeled scenario to become reality requires careful planning and thinking beyond simply what faces ERCOT today or the next couple of years. Adequate planning will require great foresight from the PUCT, ERCOT, and the Legislature to address the needs of the ERCOT grid for decades to come and ensure that transitions are made in a manner that maintains reliability and affordability. Further, it may require state incentives and investment in the technologies that will be needed to make a net-zero grid probable and affordable.

APPENDIX A

Table A1. Assumed growth rates to estimate emissions resulting from each scenario before recreating each scenario in the ReEDS model.

	High End-use Electrification, Unconstrained Energy Supply	**High End-use Electrification, Constrained Renewables, and storage**	**High End-use Electrification, Unconstrained Renewables, and storage**	**Low End-use Electrification, Constrained Energy Supply**
Coal	-2.70%	-2.30%	-3.00%	-1.70%
Oil and Natural Gas Steam	2.30%	2.70%	1.00%	3.00%
Combined Cycle	2.30%	2.70%	1.00%	3.00%
Combustion Turbine/Diesel	2.30%	2.70%	1.00%	3.00%
Nuclear Power	same as BAU	same as BAU	same as BAU	same as BAU
Pumped Storage	scenario adapted to wind base case	scenario adapted to wind + (-2.30%)	scenario adapted to wind + (3.00%)	scenario adapted to wind + (-2.70%)
Diurnal Storage	2.70%	1.0%	3.00%	0.70%
H_2 Fuel Cells	scenario adapted to wind base case	scenario adapted to wind base case	scenario adapted to wind + (-2.30%)	scenario adapted to wind + (-1.70%)
Conventional Hydroelectric Power	same as BAU	same as BAU	same as BAU	same as BAU
Geothermal	2.70%	1.00%	3.00%	0.70%
Municipal Waste	2.70%	0.03%	1.00%	0.70%
Wood and Other Biomass	2.70%	2.70%	1.00%	0.70%
Solar Thermal	scenario adapted to wind base case	scenario adapted to wind + (-2.00%)	scenario adapted to wind + (3.00%)	scenario adapted to wind + (-2.70%)
Solar Photovoltaic	2.70%	1.70%	3.00%	0.70%
Wind	2.70%	1.70%	3.00%	0.70%

Wind (Offshore)	scenario adapted to wind base case	scenario adapted to wind + (-2.00%)	scenario adapted to wind + (3.00%)	scenario adapted to wind + (-2.70%)
Distributed Generation	2.70%	1.70%	3.00%	0.70%
CCUS	scenario adapted to wind + (-1.70%)	scenario adapted to wind base case	scenario adapted to wind + (-2.30%)	scenario adapted to wind + (3.00%)
CDR	scenario adapted to wind + (-2.00%)	scenario adapted to wind base case	scenario adapted to wind + (-2.30%)	scenario adapted to wind + (3.00%)

Clustering Methodology

Currently, the input data for electricity power demand, wind and solar power production is segmented on an hourly basis. Hence, for a given year there would be 8,760 (365 days x 24 hours) data points for each input. To reduce the time-computational complexity, we use a clustering method to reduce the size of the input data.

We have used k-means clustering methodology where data points are grouped based on the distance from a cluster's centroid. We have grouped the data points into 11 clusters, and each cluster has a mean of all the data points in that cluster based on an hourly basis. Therefore, there would be a total of 264 (11 clusters * 24 hours). A weighting factor would be assigned to each cluster based on the number of data points grouped in days, in that cluster. Since the electricity demand derives from the power production and price, therefore the clustering was performed on-demand data, and then the corresponding power and price data are included in the same clusters. There are two scenarios for clustering. In the first scenario, all the demand data points are used for clustering into 11 clusters. In this case, the weighting factors for each cluster would depend upon the number of data points grouped in days in that cluster. In the second scenario, we isolate the day with peak demand and assign it to cluster number 11, hence its weighting factor would be one, since this cluster includes only one day. This gives a better representation of the peak demand. The remaining hourly data points corresponding to 364 days are then clustered into 10 clusters.

For example, the following plots present the 11 clusters for the second scenario. The thick lines represent the clusters, and the thin lines represent the data points for 24 hours over 365 days. There is a total of 264 cluster data points, which are identified by the marker points, with 24 cluster points corresponding to 24 hours of a day under each cluster. The dashed blue line represents the hourly mean of all cluster points.

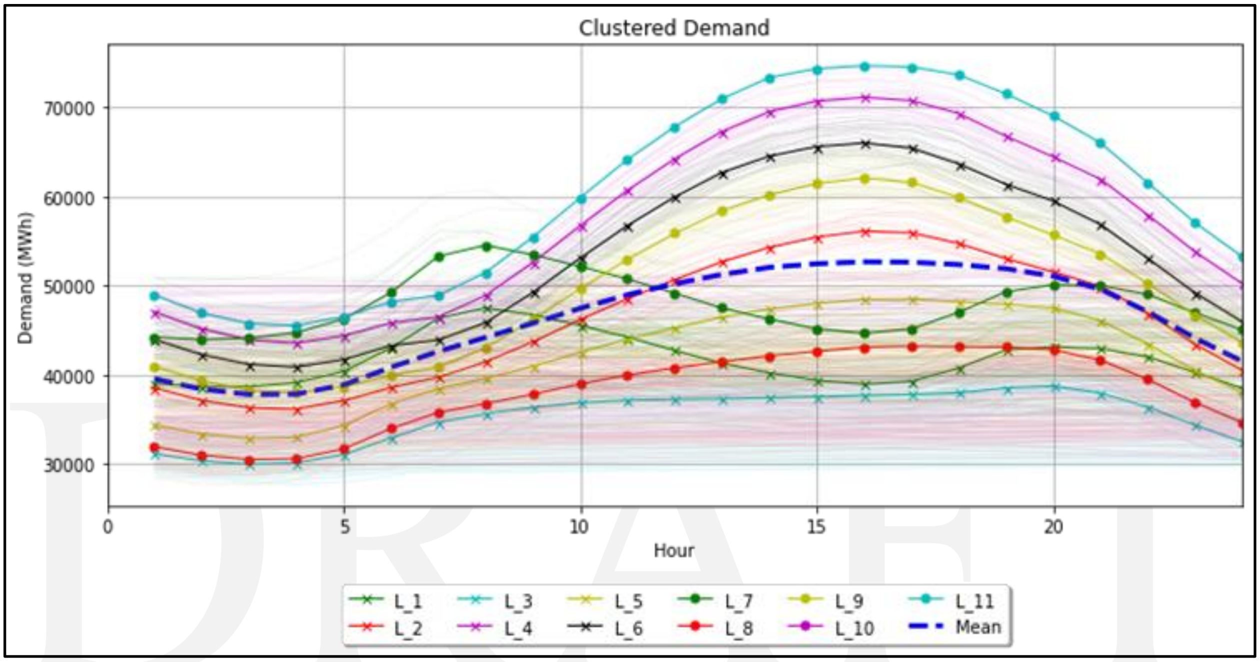

Figure A1. Clustering methodology for demand simulation, where the demand is measured in MWh.

Table A2. Cluster IDs and counts for clustering scenarios 1 and 2.

Cluster ID	Scenario 1 count	Scenario 2 count
L_1	42	31
L_2	39	25
L_3	18	71
L_4	28	31
L_5	23	24
L_6	44	38
L_7	68	12
L_8	18	42
L_9	7	51
L_10	31	39
L_11	47	1

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