MODELLING THE ELECTRICITY AND HEAT PRODUCTION SECTOR IN LINE WITH TÜRKİYE’S NET ZERO EMISSIONS TARGET

TÜRKİYE'NİN NET SIFIR EMİSYON HEDEFİ DOĞRULTUSUNDA ELEKTRİK VE ISI ÜRETİM SEKTÖRÜNÜN MODELLENMESİ

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To my daughter Ece ÇALIKOĞLU

ABSTRACT

MODELLING THE ELECTRICITY AND HEAT PRODUCTION SECTOR IN LINE WITH TÜRKİYE'S NET ZERO EMISSIONS TARGET

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Doctor of Philosophy, Department of Environmental Engineering

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Various international agreements and mechanisms are established to mitigate climate change by setting targets to reduce greenhouse gas emissions. Türkiye plans to reduce greenhouse gas emissions by 41% from the Business as Usual level in 2030 and set its net zero target. Thus, reducing the emissions of the electricity and heat production sector, primarily driven by fossil fuels, will help achieve its emission target. This study aims to provide a pathway for designing the Turkish electricity and heat production sector and its policy reflection to achieve a net zero emissions target for 2053. Türkiye's electricity sector is analyzed based on five scenarios with different emission pathways between 2021 and 2053. The model results show a substantial increase in installed capacity, generation and cumulative investment costs to achieve the net zero target in the two scenarios, dominantly using nuclear power plants and fossil power plants with carbon capture and storage. Although the increment in installed capacity has a similar level in a third net zero emissions scenario, which integrates more wind and solar energy investments with the help of energy storage technologies, with these two scenarios, the cost of generation and cumulative investment costs are smaller than in these scenarios. An additional investment between 340 and 391 billion USD is necessary to achieve the net zero emissions target over business as usual between 2020 and 2053. It is calculated that 19-23% of the additional investment costs over business as usual level can be covered by carbon revenues. On the other hand, a minor increase in generation cost, emissions and installed capacity is expected when an emission reduction of 40% from the Business as Usual level is estimated. These results reveal the need for significant changes in its energy policies to pave the way for substantial investment in renewable and nuclear energy, battery storage installations, and power plants with carbon capture and storage to achieve the net zero target.

Keywords: Electricity sector modelling, Net zero target, LEAP software, GHG emissions, Climate change

ÖZET

TÜRKİYE'NİN NET SIFIR EMİSYON HEDEFİ DOĞRULTUSUNDA ELEKTRİK VE ISI ÜRETİM SEKTÖRÜNÜN MODELLENMESİ

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Sera gazı emisyonlarını azaltmak için hedefler belirleyerek iklim değişikliğini azaltmak için çeşitli uluslararası anlaşmalar ve mekanizmalar oluşturulmuştur. Türkiye, 2030'da sera gazı emisyonlarını referans senaryoya göre %41 oranında azaltmayı ve net sıfır hedefini belirlemeyi planlamaktadır. Bu nedenle, ağırlıklı olarak fosil yakıtlara dayalı olan elektrik ve ısı üretim sektörü emisyonlarının azaltılması, emisyon hedefine ulaşılmasına yardımcı olacaktır. Bu çalışma, 2053 için net sıfır emisyon hedefine ulaşmak için Türkiye elektrik ve ısı üretim sektörünün ve bunun politika yansımasının tasarlanması için bir yol göstermeyi amaçlamaktadır. Türkiye'nin elektrik sektörü, 2021 ile 2053 yılları arasında farklı emisyon patikalarına sahip beş senaryoya göre analiz edilmektedir. Model sonuçları, ağırlıklı olarak nükleer enerji ve karbon yakalama ve depolamalı fosil yakıtlı enerji santrallerinin kullanıldığı iki senaryoda net sıfır hedefine ulaşmak için kurulu güç, elektrik üretim maliyetleri ve kümülatif yatırım maliyetlerinde muazzam bir artış olacağını göstermektedir. Enerji depolama teknolojilerinin yardımıyla daha fazla rüzgar ve güneş enerjisi yatırımını entegre eden üçüncü bir net sıfır emisyon senaryosunda kurulu güçteki artış benzer bir düzeye sahip olsa da, bu iki senaryodakine göre elektrik üretim maliyetleri ve kümülatif yatırım maliyetleri daha düşüktür. 2020 ile 2053 yılları arasında net sıfır emisyon hedefine ulaşmak için referans senaryoya kıyasla 340 ila 391 milyar ABD Doları arasında değişen bir ek yatırım gerekmektedir. Karbon gelirleri ile referans senaryoya ek yatırım maliyetlerinin %19-23'ünün karşılanabileceği hesaplanmaktadır. Öte yandan, referans senaryoya göre %40'lık bir emisyon azaltımı düşünüldüğünde, üretim maliyetinde, emisyonlarda ve kurulu güçte ufak bir artış beklenmektedir. Bu sonuçlar, net sıfır hedefine ulaşmak için yenilenebilir ve nükleer enerjiye, batarya depolama kurulumlarına ve karbon yakalama ve depolamaya sahip elektrik santrallerine önemli yatırımların önünü açmak için enerji politikalarında önemli değişikliklere ihtiyaç duyulduğunu ortaya koymaktadır.

Anahtar Kelimeler: Elektrik sektörü modellemesi, Net sıfır hedefi, LEAP yazılımı, Sera gazı emisyonları, İklim değişikliği

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Ümit ÇALIKOĞLU
July 2023, Ankara

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LIST OF SYMBOLS AND ABBREVIATIONS

Symbols

η	Thermal Efficiency

Abbreviations

BAU	Business as Usual
BEPA	Biomass Energy Potential Atlas
BUENAS	Bottom-Up Energy Analysis System
CBAM	Carbon Border Adjustment Mechanism
CBDR-RC	Common but Differentiated Responsibilities and Respective Capabilities
CC	Carbon Cost
CCS	Carbon Capture and Storage
COP	Conference of the Parties
CP	Carbon Pricing
EF	Emission Factor
EFOM	Energy Flow Optimisation Model
EGD	European Green Deal
EHP	Electricity and Heat Production
EIA	Energy Information Administration
EST	Energy System for Türkiye
ETSAP	Energy Technology System Analysis Programme
EU	European Union
GAMS	General Algebraic Modeling System
GCPR	Generation Capacity Projection Report
GEM-E3	General Equilibrium Model for Energy-Economy-Environment

GHG	Greenhouse Gas
IEA	International Energy Agency
INDC	Intended Nationally Determined Contribution
IPCC	International Panel on Climate Change
IRENA	International Renewable Energy Agency
IRA	Inflation Reduction Act
LEAP	Low Emissions Analysis Platform
LULUCF	Land Use, Land Use Change and Forestry
MAED	Model for Analysis of Energy Demand
MENR	Ministry of Energy and Natural Resources
MIT	Mitigation
NDC	Nationally Determined Contributions
NEEAP	National Energy Efficiency Action Plan
NEMO	Next Energy Modeling system for Optimization
NEMP	National Energy and Mining Policy
NET	Net Zero Emissions
NGCC	Natural Gas Combined Cycle
NIA	National Impact Analysis
NIR	National Greenhouse Gas Inventory Report
NREL	National Renewable Energy Laboratory
O&M	Operation and Maintenance
PA	Paris Agreement
PAMS	Policy Analysis Modelling System
PRIMES	Price-Induced Market Equilibrium System
RES	Renewable Energy Sources
RNZP	Resilient and Net Zero Pathway

TIMES	The Integrated MARKAL-EFOM System
TSO	Transmission System Operator
UNCED	United Nations Conference on Environment and Development
UNECE	United Nations Economic Commission for Europe
UNFCCC	United Nations Framework Convention on Climate Change
USD	US Dollars
VEDA	Versatile Data Analyst
WEPA	Wind Energy Potential Atlas

1. INTRODUCTION

This part presents a general overview of the electricity and heat production (EHP) sector in terms of electricity generation, installed capacity, and greenhouse gas (GHG) emission, the history and current situation of the climate change negotiation processes and efforts to combat climate change, especially net zero emission targets from the perspective of Türkiye and the world. The current problem, the study's objective, scope, and structure have also been presented in this section.

1.1. General Information

In this sub-section EHP sector of Türkiye has been intensely examined in terms of legislation, action plans, modelling studies, electricity generation, installed capacity, and GHG emission; information on international agreements on climate change, climate change pledges of the countries, primarily net zero emission has been shared.

1.1.1. Overview of the Electricity and Heat Production Sector

Rapid economic growth, increase in population, industrialization and urbanization increase Türkiye's energy demand continuously, increasing the need for imported fuels. Ultimately, the current account deficit is increased.

The fact that the need for imported fuels is high and this need is increasing in line with the growing energy demand poses a threat, especially in terms of energy supply security. In this context, the National Energy and Mining Policy, announced in 2017, constitutes supply security, indigenization and foreseeable market [1].

Raising the utilization of RES, which contributes to reducing foreign dependency in the energy sector and combating climate change by reducing greenhouse gas emissions, stands out as one of the most effective tools.

As can be seen from Figure 1.1 and Figure 1.2, a 173% increase in power generation and a 252% increase in installed capacity occurred in the last 20 years [2]. In particular, with the Renewable Energy Law published in 2005, installation investments in renewable resources other than hydraulics, such as wind, solar, geothermal, and biomass, started to be used. These investments gradually gained momentum over the years. The YEKDEM mechanism, a feed-in tariff system, has contributed the most. Another vital contribution to the investments in this field comes with the application of Renewable Energy Source Zones, the first competition of which was held in 2017.

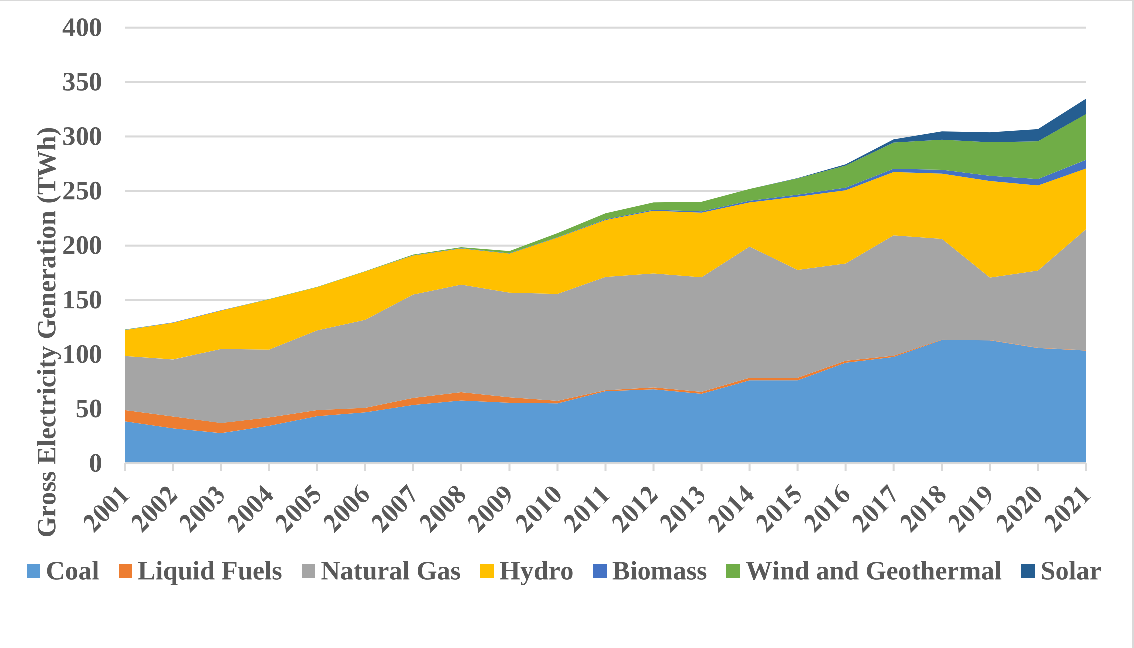


Figure 1.1. Gross electricity generation by sources between 2001 and 2021 (TWh) [2]

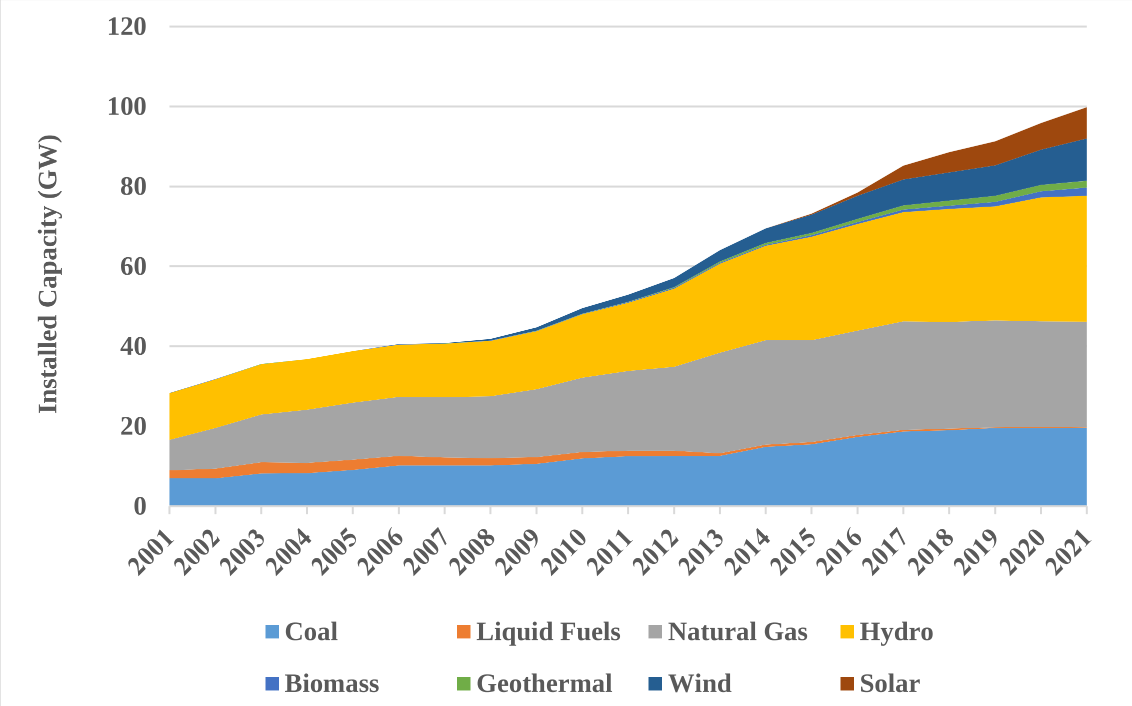


Figure 1.2. Installed power capacity by sources between 2001 and 2021 (TWh) [2]

With its RES investments, which have accelerated in recent years, Türkiye surpassed the United Kingdom and rose to 5th place in Europe and 12th in the world. Türkiye ranks 7th for each wind and solar power installed capacity in Europe. The Geothermal installed power capacity of Türkiye ranks first in Europe and 4th in the world. Türkiye has significant hydro potential, and Türkiye's hydropower installed capacity ranks 2nd in Europe and 8th in the world [3]. Despite the enormous development in RES investments in recent years, 64% of electricity generation and 46% of installed power capacity still belong to fossil fuels. Electricity generation and installed power capacity percent shares of Türkiye by sources in 2021 are given in Figure 1.3 and Figure 1.4, respectively [2].

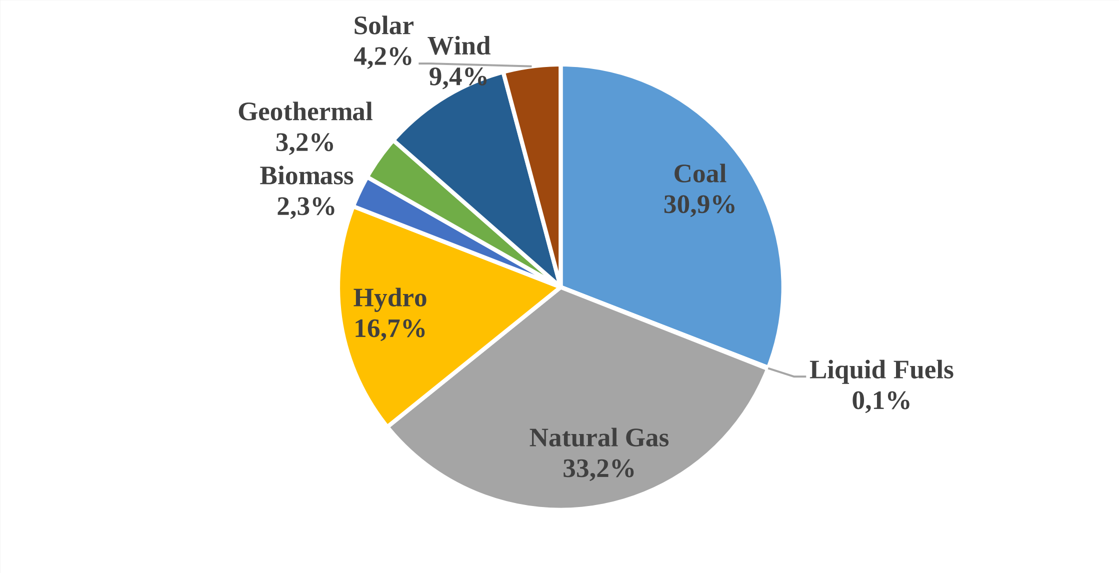


Figure 1.3. Electricity generation percent shares by sources in 2021 [2]

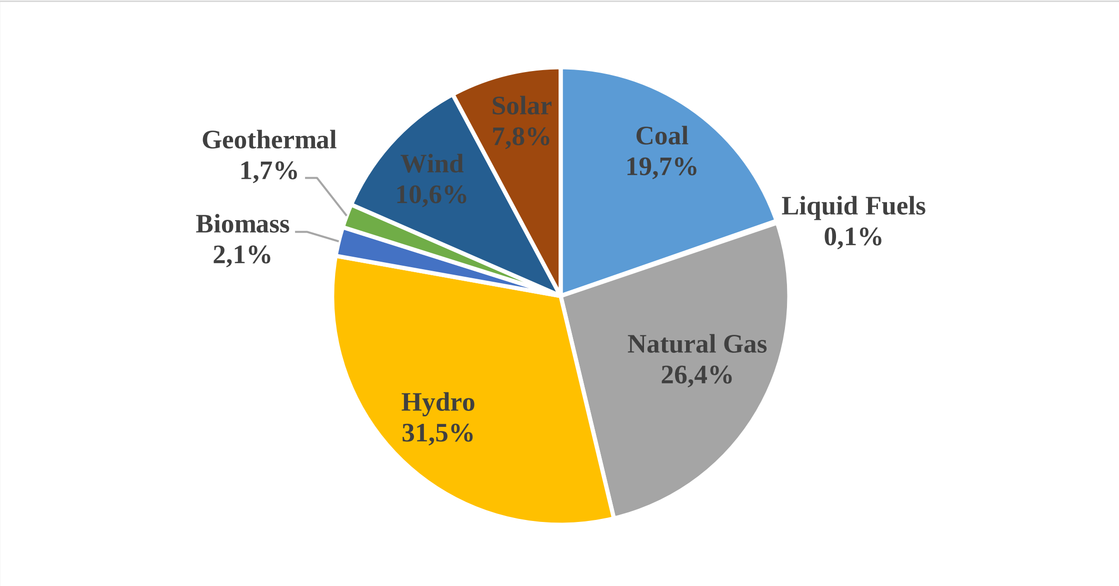


Figure 1.4. Installed power capacity percent shares by sources in 2021 [2]

In 2021, natural gas had the highest share in electricity production in Türkiye, with 33.2%, while the source with the highest share in installed power capacity was hydro, with 31.5%. The total share of non-hydro renewable resources in electricity generation is 19%, and the total share of these sources in installed power capacity is 22.2%. The share of coal in electricity generation and installed power capacity is 30.9% and 19.7%, respectively [2].

Although, Türkiye had many attempts to put nuclear power plants into operation, no nuclear power plant has been established in Türkiye until now. Currently, Türkiye plans to deploy nuclear power stations to limit the consumption of imported fossil fuels for electricity production. Akkuyu Nuclear Power Plant, Türkiye's prospective first nuclear power plant, is under construction. Türkiye plans to establish two or more power plants except Akkuyu Nuclear Power Plant [1].

The industry sector has the most significant share of Türkiye's net electricity consumption, equaling 47.5% in 2021. The commercial sector follows the industry sector with 25.5% and the residential sector with 21.6%. Because of that, electric cars have not reached a notable amount in Türkiye yet. The transport sector equals to %0.6 of the total net electricity consumption. The distribution of net electricity consumption of Türkiye by sectors in 2021 is given in Figure 1.5 [4].

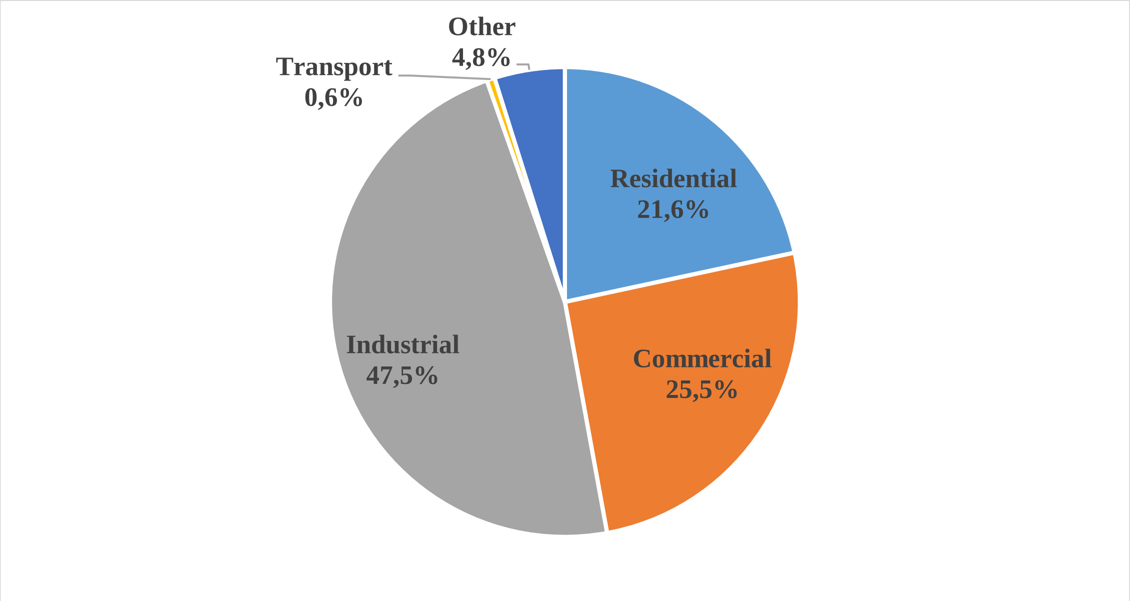


Figure 1.5. Net electricity consumption by sectors in 2021 [4]

According to the Electricity Market Law No. 6446, the Ministry of Energy and Natural Resources (MENR) publishes the "*Turkish Electric Energy Demand Projection Report*" every two years, including the demand estimated for the next 20 years. Türkiye’s electricity demand projections reveal a 94% increase in demand between 2020 and 2040 for the reference demand scenario [5]. Substantive investments in the power sector are needed to overcome this increment [1]. While ensuring this, providing decarbonization in the power sector is another crucial issue.

The Eleventh Development Plan (2019-2023) has significant policy targets for the electricity sector. According to the plan, achieving 219.5 TWh of electricity generation from domestic resources has been targeted until 2023. Related to this target, increasing the RES share of electricity production to 38.8 has also been targeted. Another target related to the power sector is decreasing natural gas share in electricity production from 29.85% to 20.7% [6].

According to Türkiye’s National Energy and Mining Policy, announced in 2017, Türkiye has targeted to commission 10 GW each of solar and wind power installed capacity until 2027 [1].

The National Energy Efficiency Action Plan (NEEAP) is another significant plan for the Turkish energy sector. The plan involves a 14% decrease in primary energy consumption and 66.6 million tons of CO_2 emission reduction with 55 actions under six thematic areas in 2017-2023. In the scope of NEAAP, 6.4 billion USD were invested in energy efficiency, resulting in cumulative energy savings of 1.6 billion USD in 2017-2021. The studies for preparing the 2nd NEEAP, which covers the 2024-2030 period, have been started by the MENR. It is foreseen that the preparation studies of the 2nd NEEAP will be completed by the third quarter of 2023 [7].

The MENR published the National Energy Plan of Türkiye on December 2022, according to article 20 of the Electricity Market Law numbered 6446. The main aim of this plan is to estimate the energy supply and demand in accordance with Türkiye's net zero emissions target. The plan includes all the details regarding the power plants to be commissioned and the production amount by resources [8].

Results of the modeling study established for this plan reveal that maximization of solar and wind power has a crucial role in reaching the GHG emission goals of Türkiye. Per the plan, in primary energy consumption, the share of RES increases from 16.7% to 23.7%, and the share of nuclear energy increases from zero to 5.9% in 2035. Wind and solar power installed capacities reach 29.6 and 52.9, respectively [8].

Integrating intermittent renewable installations like wind and solar power plants into the grid increases the need for flexibility in the system. The plan presents solutions to meet the need for flexibility. These are battery storage, electrolyzers, and demand side participation. While the battery storage capacity is projected to reach 7.5 GW, the projected values for electrolyzers and demand-side participation are 5 GW and 1.7 GW by 2035. The energy intensity, which decreased by 25% in the 2000-2020 period, is projected to be a 51% decrease in the 2000-2035 period. In 2053, the share of hydrogen in the natural gas mixture in terms of energy equivalent is projected to reach 12%, and the share of synthetic methane to 30% in 2053 [8].

According to the plan, the power mix has not included fossil power plants with carbon capture and storage (CCS) due to their high investment costs until 2053. Instead, the electricity production of coal power plants will continue to decrease until 2053. However, this does not mean they will retire before their economic life. They will contribute to system flexibility as reserve capacity [8].

The hydrogen Technology Strategy and Roadmap of Türkiye was announced on January 2023. This roadmap aims to establish a nationally guided research, technology development support and application program for the local development of hydrogen technologies and to define a strategic action plan. According to the roadmap, reducing the production cost of renewable hydrogen below 2.4 USD/kg H_2 by 2035 and under 1.2 USD/kg H_2 by 2053, and ensuring reaching the electrolyzer capacity to 2 GW in 2030, 5 GW in 2035, and 70 GW in 2053 have been targeted [9].

In 2021, Türkiye's total GHG emissions accounted for 564.4 Mt CO_2-eq, according to National Inventory Report (NIR). The EHP sector has the biggest share in GHG emissions of Türkiye, which is responsible for 26.5% of total GHG emissions with 149.4 Mt CO_2-eq. GHG emissions from this sector increased 100% in the last 20 years. EHP sector GHG emissions of Türkiye between 2001 and 2021 are given in Figure 1.6. GHG emissions of the sector have fluctuations in some years. In other words, although emissions are increasing, they may decrease in some years. The change in the GHG emission distribution trend is mainly due to the annual changes in the electricity generation resource distributions. For example, a decrease in emissions can be observed when hydroelectric power plants produce more than the previous year and when natural gas power plants produce more and coal-based power plants produce less power than the previous year [10].

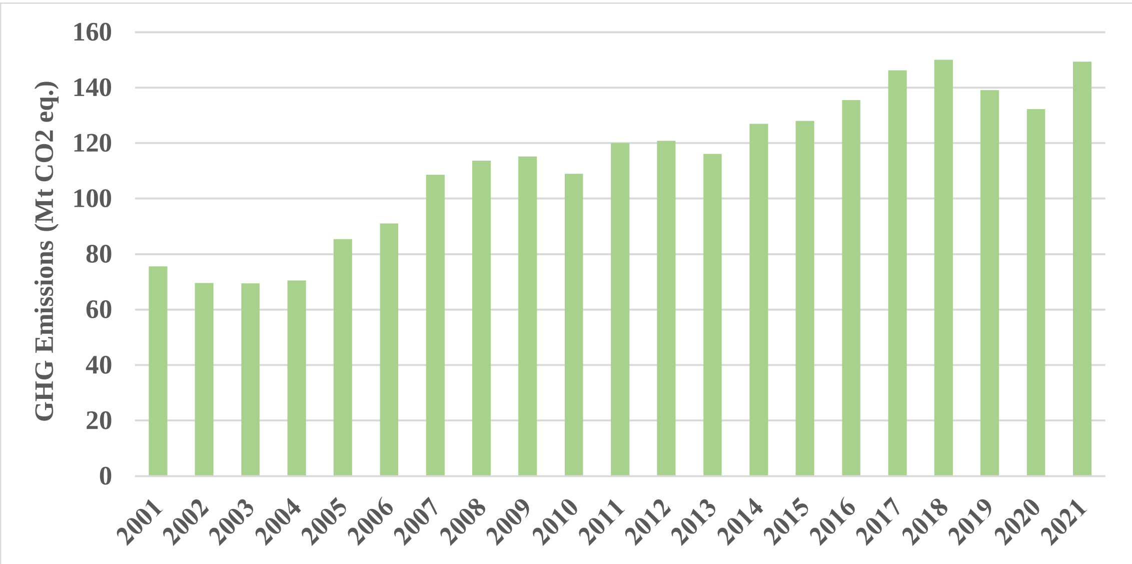


Figure 1.6. EHP sector GHG emissions of Türkiye between 2001 and 2021 [10]

1.1.2. Climate Change Negotiations

Climate change is a significant global issue that may have irreversible effects if the necessary measures are not taken. International climate negotiations are carried out under the United Nations Framework Convention on Climate Change (UNFCCC). UNFCCC is the first and most crucial measure to alleviate the effects of climate change induced by anthropogenic activity. Governments started to sign it during the United Nations

Conference on Environment and Development (UNCED), organized in Rio de Janeiro in 1992. In addition to 196 countries, the European Union (EU) is a party to the Convention, which became operational on March 21, 1994. Türkiye ratified the Convention on May 24, 2004 [11].

The UNFCCC urged the Parties to cut their emissions of GHG emissions, work together on science and technology, and safeguard their GHG sinks. To limit GHG emissions, the Convention is built on the idea of "*common but differentiated responsibilities and respective capabilities (CBDR-RC)*", considering each country's unique circumstances and development priorities [11].

In the UNFCCC negotiations, Türkiye has a special situation. In this regard, Türkiye is the only state by Annex I whose "*special conditions*" were approved by the Conference of the Parties resolutions and does not have a transition economy [11].

Considering the historical responsibility, level of economic development, technological accumulation, human development index, sensitive country position and similar indicators, there are resolutions (26/CP.7, 1/CP.16, 2/CP.17, 1/CP.18 ve 21/CP.20) of the Conference of the Parties stating that Türkiye is in an unique position among other Annex-I countries due to its special circumstances. However, it is an Annex-I country [11].

The Kyoto Protocol, the first implementation agreement of the UNFCCC, was accepted in 1997 and became effective in 2005. The Protocol has two commitment periods. First period containing the years between 2008 and 2012, the countries included in the Annex-I list of the Convention have an obligation to reduce their total emissions by a minimum of 5% compared to 1990. To achieve this goal, calculated GHG emission reduction or restriction requirements have been defined individually for Annex-I parties to the Convention. These obligations are included in the Annex-B list of the Kyoto Protocol [12].

The second period of the Kyoto Protocol involves the years 2013-2020. It has been determined that the parties on the Annex-B list will decrease their emissions by a minimum of 18% in 2020 compared to the 1990 level, which differs from the first period - the second period entered into force on December 31, 2020. Instead, the second period was only procedurally accepted due to the beginning of the Paris Agreement (PA), which ordered the post-2020 climate regime [12].

In 2009, Türkiye joined the Protocol as a party. Türkiye was not included in the Annex-B list of the Kyoto Protocol, which set quantitative requirements for GHG emission reduction or limitation, because it had not ratified the UNFCCC when the Protocol was approved in 1997. Due to this, Türkiye has not made a quantitative commitment to restrict or reduce its GHG emissions under the Kyoto Protocol [12].

The PA was adopted during the UNFCCC 21st Conference of the Parties (COP 21), which took place in Paris in 2015. It is a crucial milestone for the climate change efforts after 2020. All governments on a worldwide scale agreed to cut GHG emissions for the first time at COP 21. The condition of at least 55 parties ratifying the deal, which as of October 5 2016, accounted for 55% of worldwide GHG emissions, was met, and the accord came into force on November 4 2016 [13].

The PA intends to strengthen global socioeconomic resistance against the risk posed by climate change in the post-2020 period. The PA's long-term objective is to restrict the rise in global temperature to no more than 2°C, ideally 1.5°C, above pre-industrial levels. This objective necessitates steadily reducing fossil fuel use and a tendency towards renewable energy. Renewable energy is crucial in contributing to carbon-neutral electricity production among mitigation options [14].

The PA is according to categorizing developed and developing countries to combat global warming and the accepting that each country takes responsibility according to the idea of CBDR-RC [13].

The PA encourages developed countries to sustain their absolute emission reduction objectives while encouraging developing countries to raise their own emission reduction goals and adopt new, more ambitious goals that will eventually cover the entire economy, depending on their unique national circumstances [13].

On September 20, 2015, Türkiye declared her Intended Nationally Determined Contribution (INDC) up to a 21% decrease from the business as usual (BAU) level by 2030. Afterwards, the PA was signed on April 22, 2016. The PA was adopted by Presidential Decree on October 7 2021, and deposited with the UN Secretariat on October 11, 2021. Moreover, a net zero emission target for 2053 was declared by President Erdogan [13].

In this context, studies for preparing Türkiye's NDC and Türkiye's Long-Term Climate Change Strategy and Action Plan have been initiated within the scope of the "Updating Türkiye's NDC and Long-Term Climate Change Strategy Project". In February 2022, the Climate Council was held to determine the policies and responsible institutions for different sectors and to create a roadmap in accordance with the 2053 net zero emissions target and green development policy. The Climate Council took a total of 217 recommendations. In addition, studies for preparing the Climate Change Law have been initiated. It is thought that the most important part of the law is the planned emission trading system [13, 14].

The PA Work Program (Rulebook), which covers considerations on implementing the PA, was finalized at COP 26, hosted by the United Kingdom on 31 October-13 November 2021. In other words, the PA, which regulates the post-2020 climate regime, has been functional [13].

The COP 27 was held on 6-18 November 2022 in Sharm-el Sheikh, Egypt. Within the scope of COP 27, decisions were taken on important issues such as the Loss and Damage Mechanism and financing of adaptation to climate change [13].

At the Ministerial Session held on 15-16 November 2022 within the scope of COP 27, the Minister of Environment, Urbanization and Climate Change announced that the NDC was updated. According to this, GHG emissions will be reduced from the BAU level by 41% by 2030, which was 21% in the previous NDC, and emissions will reach a peak at the latest by 2038 [13].

1.1.3. Net Zero Emission Targets

The special report on global warming of 1.5 ºC of the International Panel on Climate Change (IPCC) was published in 2019. According to the report, limiting temperature increase to 1.5 °C indicates achieving net zero emissions globally by about 2050 and significant decrease in emissions other than CO_2, particularly methane [17]. Thus, the mitigation efforts should be increased since various studies show that existing commitments correspond to an average temperature increase of 2.6 °C [18].

Global emission has reached record levels without implying peaking. Therefore, the leaders of all governments were called to the Climate Action Summit, which was organized in New York on September 23 2019, to share their solid, realistic plans to improve their NDCs by 2020 consistent with reducing GHG emissions by 45 per cent over the next decade and achieving to net zero emissions by 2050 by UN Secretary-General António Guterres [19].

In the period after António Guterres's call, countries, cities, businesses and other institutions were committed to getting to net-zero emissions. As of November 2022, about 140 countries, involving the major emitters like China, the United States, India and the European Union, announced their pledges or consideration of net-zero targets. The GHG emissions of these countries reflect nearly 90% of the total global emissions [19,20].

Over 3000 companies and financial organizations have signed the Science-Based Goals Initiative to cut emissions in accordance with scientific studies. Also pledging to take ambitious, immediate action to reduce worldwide emissions by half by 2030 are more than 400 financial institutions, 1000 educational institutions, and more than 1000 cities joining the Race to Zero [21].

Indeed, the most important and first step came from the EU. The European Green Deal (EGD), which envisions transforming Europe into the world's first carbon neutral continent by 2050, was announced on December 11, 2019. It is aimed to cut emissions by a minimum of 55% by 2030, compared to the reference year 1990 [22]. In addition, the EU’s RES and energy efficiency targets have been revised. According to new targets, a renewable ratio of the EU's energy mix will be 40%, and final and primary energy consumption will be reduced by 36% and 39% by 2030.

Moreover, GHG emissions from cars and vans will be reduced by 55% and 50% by 2030 [23]. EU reached a political agreement on implementing a new tool called "Carbon Border Adjustment Mechanism" (CBAM) on December 13, 2022. CBAM stands out as one of the most significant policy tools of the EGD. The CBAM is intended to contribute to the EU's climate-neutral goals and to equalize the terms of carbon pricing between EU and non-EU exporters, thereby encouraging partner countries to decarbonize their generation processes [24].

EU is Türkiye's most important trading partner due to the Customs Union. EU takes a 41% share of Türkiye's total exports with 93 billion US dollars (USD) in 2021 and ranks first in total exports [25]. When possible impacts of the EU's CBAM are considered, Türkiye needs to develop policies to avoid affecting the trade volume with the EU. The policies it will develop in this direction will also significantly contribute to combating climate change globally. Consequently, Türkiye can contribute considerably to combating climate change and taking a vital position in the changing world trade system with the help of a net zero emission target.

Countries from all over the world announced their net zero emission target for various years. However, most of the targets have been determined for 2050. Countries like the US, UK, Japan, South Korea, Brazil, Norway, New Zealand, and South Africa have announced their net zero emission target for 2050. Some countries' net zero emission targets have been designated earlier than 2050. These countries are Uruguay (2030), Finland (2035), Austria (2040), Iceland (2040), Germany (2045), and Sweden (2045). Bhutan and Suriname have already achieved their net zero emission target. On the other hand, China, Kazakhstan, and Ukraine's targets are for 2060; Türkiye's target is for 2053 [26].

A significant step other than the net zero emission target of the USA is the Inflation Reduction Act (IRA), which President Biden passed into law on August 16, 2022. This is the most significant action done by Congress in the history of the US concerning clean energy and climate change. By 2030, the IRA aims to reduce GHG in economic emissions by 40% under 2005 levels, while 370 billion USD will be invested to decrease energy prices for citizens and small enterprises, mobilize private investment for clean energy projects in the whole country, strengthen supply chains, create fair jobs and new opportunities for workers [27].

1.2. Current Problem

According to the United States Energy Information Administration's (EIA) International Energy Outlook 2019 [28], global electricity production will achieve around 45 trillion kWh by 2050, nearly 17 trillion kWh more than the 2021 level [29]. This projection shows a substantial increment in global electricity demand, creating a significant challenge to reduce global emissions since this sector is responsible for 42% of global CO_2 emissions [30]. Based on International Energy Agency's (IEA) Stated Policies Scenario, current commitments and measures on climate change are not aligned with the PA to hold the increase in global average temperature to "well below 2 °C and pursue efforts to limit it to 1.5°C" [31].

Türkiye's electricity demand projections reveal increasing demand of up to 109% between 2020 and 2040 [5], following the 161% increase in power generation in the last 20 years [2]. The EHP sector's emissions account for 26.5% of Türkiye's total GHG emissions, which increased by 102% in the last 20 years [10]. Thus, these figures show that it will be difficult for Türkiye to meet its climate change targets if fossil fuel consumption trends continue in this sector.

Governments must announce more ambitious strategies to achieve their emission reduction goals. Consequently, they should set carbon-neutral targets, especially for the EHP sector [32]. Decreasing GHG emissions from the EHP sector has a significant role for Türkiye in combating climate change. Clean energy technologies like RES, energy efficiency, Carbon Capture, Utilization and Storage, and battery storage may be important actors in reaching carbon-neutral targets of Türkiye for the EHP sector. On the other hand, the critical role of other sectors, which accounts for 73.5% of the total 564.4 Mt CO_2-eq GHG emissions excluding land use, land use change and forestry (LULUCF), cannot be ignored in achieving net zero emissions targets [10]. Since these sectors also include hard-to-abate sectors such as steel, cement and chemicals, achieving the target is challenging for emerging economies like Türkiye. Low-carbon roadmap preparation studies for these sectors are being carried out in Türkiye.

1.3. Objective of the Study

Although Türkiye has made significant breakthroughs in the use of RES in the electricity sector, it is a country that still uses substantial amounts of fossil fuels in this sector. For this reason, Türkiye, like other countries that set a net zero target, must make significant breakthroughs, especially in the electricity sector, to achieve a net zero emission target. As can be seen from previous energy and, specifically, the power sector modelling studies reaching long-term net zero and low carbon targets have been addressed many times in various studies. However, these studies for the power sector do not include technological developments such as power plants with CCS, battery storage, technology costs that vary by year, and carbon pricing.

This study aims;

- to fill the gap in the literature by adding these details to the modelling of the EHP sector,

- to find a cost-effective pathway to achieve the net zero emission target from the EHP sector perspective,
- to reveal policy implications in the energy sector needed to reach regarded climate change target.

To achieve these aims, below are the set objectives for this study:

- including various technological developments in the EHP sector and analyzing their effects,
- developing five different scenarios, three of which are net zero emissions scenarios focusing on various technologies,
- analyzing the current and projected dynamics of the energy sector based on the data of authorized public institutions and international organizations.

The major contribution of this study is that the model developed is versatile in integrating various technological developments of the EHP sector to achieve the net zero emission target.

1.4. Scope of the Study

The model developed in this study is vital for analyzing the EHP sector for the net zero emission target in a country like Türkiye, where electricity consumption is increasing significantly due to the emerging economy. This study investigated which energy investments in the power sector should be realized to reach the 2053 net zero target. With the help of the Low Emissions Analysis Platform (LEAP), Türkiye's EHP sector emissions, a quarter of the total GHG emissions of Türkiye [33], are modelled between 2021 and 2053 in accordance with Türkiye's net zero carbon target for 2053. Five scenarios with different pathways, namely, the Business as Usual (BAU) Scenario, Mitigation (MIT) Scenario, Net Zero Emissions-1 (NET-1) Scenario, Net Zero Emissions-2 (NET-2) Scenario, and Net Zero Emissions-3 (NET-3) Scenario were analyzed using the developed LEAP Model. This study does not include costs in the supply chain of electricity generation technologies, licensing and land costs of power generation facilities, and technology development costs.

1.5. Structure of the Study

The first part of the study presents information on the EHP sector and GHG emissions, the current situation related to combating climate change in the world and Türkiye, the current problem, objectives, and the scope of the study. The second section involves information about energy modelling tools and previous studies. The third section includes details of the data-gathering methodology of the modelling study. The study results and discussion are given in the fourth section, and the conclusions and recommendations are presented in the last section.

2. MODELLING OF THE ENERGY SECTOR

Energy modeling programs are widely used to determine energy policies, GHG mitigation pledges, investment plans, the cost of energy systems, and the environmental impact of energy systems worldwide. Various energy modeling software is used to answer the objectives mentioned. Many studies have been conducted with energy models generally used to project GHG emissions of energy systems. These are divided into three groups according to methodologies: simulation, optimization or equilibrium models. In addition, they consist of top-down and bottom-up models according to approaches.

2.1. Software Used in Energy Sector Modeling

Energy modeling tools are widely used to estimate future energy supply and demand at the national or regional level. Often they are used exploratory, assuming certain changes in boundary conditions, for instance, the growth of economic activity, demography, or energy prices in the world. Energy models are also used for simulating technology like renewable energy investments and policy adoptions such as energy efficiency influencing supply and demand in the future [34]. Models of energy and electricity are typically created to address an issue or provide a solution. They have four purposes: power system analysis tools, operation decision support, investment decision support, and scenario are identified [35].

In general, top-down and bottom-up approaches are used in energy modeling. Bottom-up models, frequently known as the engineering approach, are founded on thorough technological explanations of the energy system. Top-down models, on the other hand, adhere to the economic viewpoint and take macroeconomic relations and long-term developments into account [36].

Penetration into the market and associated alterations of the cost of a policy or new energy technology with a certain level of technical feature can be simulated by bottom-up models. Nevertheless, they can't estimate the net effects or cost of structural, economic or employment for society. Environmentally conscious scientists, governments, and NGOs frequently cite the results of these models to explain the viability of significant changes to the energy system, mainly in the context of crucial and wide changes in the primarily fossil-fueled energy systems in nearly all countries [34].

Instead, top-down models can estimate energy supply and demand in the future for individual sectors, as well as the effects on employment, economic growth, and international trade. Nevertheless, because they rely too heavily on changes in energy prices and financial policies, they cannot fully characterize the progress of particular technologies or sectoral programs and related changes in energy demand, associated emissions and investments [34].

Energy and electricity models' methodologies usually consist of three major categories: simulation, optimization or equilibrium models [35].

As the name suggests, simulation models simulate an energy system according to certain equations and properties. These group of model are generally bottom-up models which involves details of energy systems in a technical way. Simulation models make it possible to assess various system topologies and the outcomes and innovations of various situations. An example of a model in which electricity market participants are modelled as agents with various strategies and actions is an agent-based simulation. This approach is widely applied to predicting potential energy demand and associated GHG emissions in the final energy sectors. Policy Analysis Modelling System (PAMS), National Impact Analysis (NIA), Bottom-Up Energy Analysis System (BUENAS), Model for Analysis of Energy Demand (MAED), and LEAP are examples of these simulation models [35].

Optimization models optimize a given quantity. This quantity is generally related to system operation or expenditure while modelling the energy systems, although some models can optimize many aspects instantaneously. Most optimization models employ a linear programming strategy with an objective function that is either maximized or minimized, depending on restrictions like balancing supply and demand in the grid. The number of power plants or wind turbines that can be built can be increased using mixed-integer linear programming, which enables those factors to be integral [35]. MARKAL and TIMES models, which is a type of MARKAL model, are typical examples of optimization models [34].

The energy market is modeled as a component of the economy as a whole in equilibrium models, which then examine how it interacts with the rest of the economy. As a result, these models are also used to evaluate the impact of various economic strategies. General equilibrium models, also known as computable general equilibrium models, consider the whole economy. Endogenously, they assess the balance of all economies and describe basic economic indicators such as gross domestic product. Partial equilibrium models are concerned with balancing a single market, the electricity or energy market, while ignoring the remainder of the economy [35]. General Equilibrium Model for Energy-Economy-Environment (GEM-E3) and PRIMES can be examples of equilibrium models [37].

In this section, information about Price-Induced Market Equilibrium System (PRIMES), The Integrated MARKAL-EFOM System (TIMES), and the Low Emissions Analysis Platform (LEAP), which are energy modeling programs that are frequently preferred and have important competencies, are given. Further, these software are compared, and the reason for choosing the LEAP program in this study is explained.

2.1.1. PRIMES

PRIMES is software for modelling the energy system, widely used in European Commission's Impact Assessment studies. The model is used to forecast energy demand and supply, GHG emissions, the grid's fuel mix, and costs such as maintenance and operation [38–40]. It simulates market equilibrium for energy supply and demand by determining the equilibrium pricing for each energy source in the EU countries. The model has been used for tax policy and carbon trading analyses, and it also contains a thorough depiction of energy technology [40]. Energy demand and supply, market prices, GHG emissions, investments, energy technology development, and cost projections between 2015 and 2050 are delivered by PRIMES [38].

PRIMES is a partial equilibrium model for the EU that includes member state specifics [37]. With a time horizon of 2050, the model gives complete estimates of energy supply and demand, market pricing, costs and investments for the whole energy system and associated emissions. In a forward-looking framework, PRIMES models different market equilibria and customer reactions. It's a hybrid model that blends micro-and macroeconomic dynamics with technology and technical detail. The PRIMES system includes top-down behavioural modelling dynamics and engineering bottom-up modelling features, managing dynamics under various anticipatory assumptions, and tracking technology vintages across all sectors. The PRIMES model comprises numerous sub-modules (for example, biomass demand and transportation demand and supply) [39].

The projections in the PRIMES Model include detailed energy balances, the configuration of demand by sector, power system and fuel supply, technology use and its investments, detailed cost types, if applicable, and emissions. It enables the assessment of the impacts of specific energy and environmental policies implemented at the country level or EU regarding price signals, for instance, taxes, subsidies, carbon pricing, renewable energy, and energy efficiency supports [41].

There are various limitations to the PRIMES model. It is not an econometric model, and unless connected to a macroeconomic model like GEM-E3, it cannot do closed-circuit analysis on the energy economy. PRIMES has not had detailed resolution as models used to simulate system operations such as power, gas and refinery. Despite its wealth of sectoral disaggregation, PRIMES has limitations owing to the idea of a representative customer per sector, which does not adequately reflect the variability of consumer kinds and sizes. Except for power and natural gas grid infrastructure, which is effectively described in the model, PRIMES lacks spatial information and representation and does not entirely capture problems concerning energy and fuel distribution retail infrastructure [41].

2.1.2. TIMES

As a bottom-up optimization model, TIMES is built on the General Algebraic Modeling System (GAMS) by the Energy Technology System Analysis Programme (ETSAP) [42]. The TIMES model is an advanced and integrated form of MARKAL and the Energy Flow Optimisation Model (EFOM) with additional functionalities and flexibilities. The TIMES model needs other user interfaces to handle data input and present the results in a user-friendly manner. Generally, VEDA (Versatile Data Analyst) -FE is used for handling the data, while VEDA-BE is used to read results and incorporates the user interface VEDA [43].

The TIMES model, which presents significant technology options, uses least-cost optimization for the long term with the intra-annual time resolution in hours. Although TIMES is typically used to analyze the overall energy sector, it can also be used to analyze a single sector, such as the power sector [44].

The TIMES model simulates transformation scenarios with a mixed-integer linear optimization problem depending on a primary objective function and further constraints for dynamic energy systems [42]. TIMES is an excellent predictive linear programming model generator that calculates a dynamic intertemporal partial equilibrium in integrated energy markets [45]. Throughout the numerous sectors and geographical areas, supply, refinery, production, trade and storage of energy products are modelled. Emissions can be linked with emission factors corresponding to unit energy products produced or consumed for energy commodities or processes [46].

TIMES model can be used for country or regional scale for energy systems, which offers a technology-rich base for determining energy system behaviour for a long-term or multi-period time interval. The model is generally conducted to estimate the whole energy sector, nevertheless may also be conducted to examine in detail a single sector, such as the power sector [44].

The flexibility of TIMES in cases where it is possible to split the year into several time slots with changed optional lengths is one of the most advantages of TIMES over other programs. TIMES also makes it probable to have different decomposition levels for different sectors and the choice of investing in blocks [47]. TIMES is a perfect program for simulating scenarios and an ideal tool for forecasting inquiry [48].

Because TIMES uses an optimization algorithm and has a wide technology and commodity base, the number of periods should be considered because they significantly impact the model's processing complexity [47]. To fulfil the demand side, TIMES needs the full range of processes as a supply of primary fuels throughout the transformation technologies [48]. In the model, the net electricity demand profiles are not entered externally but are estimated internally to optimally supply energy demand for all sectors [45].

2.1.3. LEAP

LEAP is a modelling software that estimates energy consumption, production, and resource use across various economic sectors for different scenarios. It also enables calculating GHG emissions not only for energy but also for non-energy sectors. It allows for top-down macroeconomic modelling simulations of the power sector and medium- to long-term capacity extension plans [49].

The approach is intended to aid energy planners and decision-makers in identifying and quantifying future energy demand patterns, the difficulties that come with them, and the potential effects of various policies [50]. It measures the energy demand for each year by multiplying the activity data with the energy intensity of all consumers. The forecast of activity growth rates or energy intensity is exogenous data for LEAP. The end-use-driven strategy is used in the demand program [51].

LEAP offers a large-scale database including a collection of technical features, environmental impacts, and costs for various energy technologies derived from various sources. The Stockholm Environment Institute in Boston developed the model [52].

The LEAP modelling software combines demand with energy technology on the supply side. It gives system implications such as technological power generation, resource consumption, power system costs, and global warming potential. Furthermore, the scenario manager makes it easier to compare various power generation technologies in the medium to long term, allowing for economic and environmental effect assessments [52].

The LEAP Model's many benefits include developing energy forecasting systems according to historical data on the energy sector, creating and analyzing multiple long-term scenarios, and comparing findings with those of other nations that similarly utilize the LEAP model. This benchmarking aids in determining which energy policies have the most impact on energy conservation, emission reduction, or other factors [53]. LEAP is particularly effective for forecasting the demand for energy and estimating GHG emissions, depending on the research's demands [49].

The primary constraints of LEAP software were the search and identification of the data necessary to generate the investigation scenarios. This is not a model of a specific energy system; instead, it is an instrument that may be used to build various energy models with individual data structures [49]. LEAP provides year-generation profiles rather than hourly generation data. As a result, no relationships between weather patterns affecting renewable power generation and demand load curves can be included [52].

2.1.4. Selection of Modeling Software

LEAP model was chosen to modelling of EHP sector of Türkiye. With the help of the LEAP model, a pathway has been explored to achieve a net zero emissions target for the EHP sector.

The main reason for choosing the LEAP model is that it enables the estimation of GHG emissions according to technologies invested for the power sector and provides the least-cost optimization using the Next Energy Modeling system for Optimization (NEMO) attachment. Estimating optimal power sector investments and electricity generation mix is easy by inputting GHG emission constraint data. One of the LEAP model's biggest advantages is allowing the demand projection to be entered into the system exogenously.

2.2. Previous Studies

Modelling programs such as PRIMES, TIMES, and the LEAP for long-term net zero and low carbon targets are widely used worldwide. In the study of Vrontisi et al., the respective EU members' emission trends in the scope of a well below 2 °C global GHG emission target were discussed, and the macroeconomic effects on the economy of the EU member states were projected by PRIMES Model [39]. In the study of Huang et al., a 14-region Global TIMES model was used to determine the effects of technology usage on the electricity production mix and CO_2 emission pathways to 2050 [54]. In the study of Nieves et al., Colombia's energy demand and GHG emissions analysis were estimated using the LEAP model for the 2015-2030 and 2030-2050 periods [49].

Chaube et al. used a single-region model in TIMES to simulate possible pathways to achieve 2030 and 2050 emission reduction goals for the power sector in Japan. Results of the modelling study reveal that a hybrid method consisting of nuclear energy and green hydrogen produced from renewable energy-sourced electrolysis is cost-efficient and offers decreasing emissions in the long run without sacrificing the security of supply. In contrast to natural gas with CCS, which plays a limited role in meeting emission reduction goals in the study, nuclear, wind, solar, and green hydrogen have a crucial role in reducing GHG emissions among technology options. The study shows that coal and oil must be phased out by 2030 [46].

Musonye et al. have assessed Kenya's electricity supply sector according to three electricity demand scenarios to analyze GHG emission reduction between 2020 and 2045 using TIMES. In the scenario which implements an emission trading system, renewable sources were utilized much more than in the BAU scenario. However, increasing the portion of RES under the scenario, including carbon capture, increased electricity costs while decreasing GHG emissions [55].

In the study of Amorim et al., TIMES was used to build Portugal's low-carbon roadmap by 2050. The modelling results reveal that modelling Portugal in an isolated manner reduces investment efficiency and may cause insufficient investments and inadequate use of RES in the long run. On the contrary, modelling Portugal with the interconnected system can significantly influence the structure of a renewable power system and improve investment effectiveness while reducing costs and risk [47].

The paper of Haiges et al. offers an investigation of the long-term electricity production scenarios for Malaysia by the TIMES model. The findings demonstrated that Malaysia has enough RES to provide the estimated future power demand by 2050, and fossil resources can be substituted entirely with electricity produced from hydropower and RES [48].

Capros et al. expanded the used PRIMES energy model to explore paths towards EU climate neutrality by 2050 and 2070 and examine effects on energy production, supply, and costs. Scenarios used in the PRIMES model include baseline scenario, scenarios with 80% or more GHG emission reductions, and climate-neutral scenarios. They argued that the existing legislation on the EU environment and energy package for 2030 is inadequate to guarantee carbon neutrality by 2050. They also claim that the alteration between the carbon reduction scenario of 80% and the carbon-neutral scenario cannot be linked without disrupting solutions [56].

Fragkos et al. [38] presented an evaluation of the application to the PA by the EU INDC based on the PRIMES energy model and the GEM-E3 model. EU goals were qualitatively explored and quantitatively evaluated until 2050 based on the simulation results of a Reference and an Alternate decarbonization scenario. The Reference scenario assumes that existing policies are maintained and all energy and environment policies are fully implemented by 2012. The decarbonization scenario considers the EU's INDC and long-term climate policy objectives. In 2030, GHG emissions from the electricity generation industry are expected to fall by 57% from 2005 levels, while in 2050, the loss would be 98%, implying a nearly carbon-free power supply sector. Compared to the Reference scenario, the EU INDC decreased by 30.2 Gt. of GHG emissions from 2015 to 2050.

In the study of Vrontisi et al., the particular EU28 emission reduction scenarios in the scope of a well below 2 °C global GHG emission target were discussed, and the macroeconomic effects for the EU28 economy were projected by taking into account different stages of climate ambition for main non-EU GHG emitting countries. In this study, PRIMES Model and the GEM-E3 were used together. The European Commission has commonly employed PRIMES and GEM-3 models in Impact Assessment studies. According to modelling results, as environment and energy policies are already in force in the reference scenario, EU28 GHG emissions are expected to separate from economic development continuously. In the PRIMES and GEM-E3 Reference scenarios, EU28 GHG emissions dropped by 34% in about 2050 relative to 2015. The EU28 well below 2 °C scenario's emission trend in 2050 indicates a drop in GHG emissions of 61 percent under reference levels and 74 percent under 2015 emissions [39].

Capros et al. performed the PRIMES model to respond to the Impact Assessment of the "*Clean Energy for all Europeans*" package of the European Commission. The obligatory commitments suggested or reaffirmed in the policy package are due in 2030 in a decarbonization context; the model applies to 2050. They have identified solid bottom-up policy measures in place of market-based approaches like carbon pricing, RES and efficiency values, and ETS used to reach the objectives. The model shows that electricity consumption almost does not increase in all scenarios in the mid-term due to the ambitious policies on energy efficiency. On the electricity production side, the most significant development is the growing diffusion of RES in the generation mix, with variable RES capability more than doubling in 2030 relative to 2015 levels and quadrupling by 2050 [57].

LEAP is a widely used model for the low-carbon energy transition. In the study of McPherson and Karney, the effects of a newly enacted law promoting wind energy on the electricity sector were examined using LEAP modelling [52]. In the study conducted by Huang et al., an energy supply and demand assessment in Taiwan was conducted using LEAP. In the scenario where the three existing nuclear power plants are estimated to retire, higher CO_2 emissions have been achieved than in the baseline scenario [53].

Yetano Roche et al. identified and assessed the paths to meet Nigeria's 2030 renewables and mitigation targets in the electricity sector with LEAP. In the ambitious scenario in terms of climate change, the model results show that Nigeria can fulfil its targets and GHG emission pledges and partially meet its renewable energy goals [58].

In the study of Rivera-González et al., the Ecuadorian power sector was assessed with LEAP, and the power supply and demand from 2018 to 2040 were estimated. In light of the modelling findings, the scenario focusing on RES-based electricity production could decrease the average GHG emissions, generation costs, and fossil fuel consumption by 11.72%, 9.78%, and 15.95%, respectively, relative to the baseline scenario. The main reason for these reductions is substituting oil-fired electricity generation stations with RES-based and natural gas combined cycle (NGCC) power plants [59].

In the study conducted by Zhao et al., per capita GDP, energy demand, energy system, and CO_2 emissions were used as indicators to estimate the stage of low-carbon development. The base, low-carbon, and limited low-carbon scenarios were considered in the LEAP model to simulate China's low-carbon development stage in 2050. The scenario involving low-emission investments makes an ambitious assumption on maximizing energy systems, including the creation and use of hydropower, development and utilization of alternative energy sources, and growth of nuclear energy and wind. The model results show a 19% reduction in emissions compared to the base scenario [60].

In Türkiye, a few modelling studies have been carried out in the energy sector for academic purposes and policy implications. Selçuklu et al. used an uncertainty information integrated optimization algorithm as part of the Pareto concept to model the electricity generation portfolio of Türkiye between 2012 and 2027. According to modelling results, natural gas and RES, primarily hydro and wind, stand out as the options with the lowest emissions and the most cost-effective electricity generation. Instead, nuclear investments planned by the government significantly increase costs while reducing emissions [61].

The World Bank Group published the Country Climate and Development Report for Türkiye in June 2022. The results of the report are based on the Computable General Equilibrium model. Sectoral roadmaps for various sectors were presented between 2022 and 2040. Based on the results of the scenario designed for net zero emissions, the electricity sector emissions will be substantially decreased by 2040, notwithstanding a growth in demand from the electrification of demand sectors. The investment needs increase while operational and fuel costs decrease compared to the baseline scenario because of the RES investments. Decommissioning of coal plants and mines also burdens the energy system more [62].

Türkiye's National Energy Plan, published in December 2022, presents the projections for the energy sector until 2035 based on the Energy System for Türkiye (EST) model. In light of the modelling findings, the portion of RES, which was 52% of the installed capacity in 2020, will reach 65% by 2035. The most important actors are wind and solar power plants. Forecasts for the years 2035 and 2053 are also included in the results. Until 2053, due to their high investment costs, the optimization model does not include fossil power plants with carbon capture and storage (CCS) in the power mix. Instead, the electricity production of coal power plants will continue to decrease until 2053. However, this does not mean they will retire before their economic life. They will contribute to system flexibility as reserve capacity [8].

2.3. Closing Remarks

This section included modelling studies used in the energy and power sectors, and PRIMES, TIMES, and LEAP energy modelling programs were examined in detail. The advantages and disadvantages of these programs are presented, and the reason for choosing the LEAP model is justified.

The previous studies section details studies dealing with similar issues to this study. As well as studies from abroad, academic studies and policy implications in Türkiye are included.

Energy modelling studies, particularly those focusing on the power sector, achieving long-term net zero and low carbon targets, have been discussed numerous times in various research. However, these estimates for the power industry omit technological advancements like power plants with CCS, battery storage technologies, varying technology costs by year, and carbon price. This work seeks to close a gap in the literature by including these specifics in modelling the EHP sector.

3. METHODOLOGY AND THE DATA SOURCES

In this study, using the LEAP model, the methodology was designed to analyze the effect of different GHG emission reduction targets on investments, technological choices, resource utilization, and fuel distribution. The energy resources to be invested and/or given up, the number of additional investments needed, ways to respond to the increasing electricity demand with carbon-neutral resources without threatening the security of supply, and the cost of these policy instruments were analyzed. This section explains data gathering, model development and sensitivity analysis, and scenario development sections in detail.

3.1. Data Gathering

Relevant data were obtained from national public institutions and various international organizations related to the energy sector to develop the model. These include technical data on power systems, cost data such as fuel, capital, and operating and maintenance cost, and emission factor data. The data used in the model other than those given in this section are available in APPENDIX 1.

3.1.1. Power System Data

In the power system data part, detailed information on the electricity sector, including consumption, historical generation and the installed capacity by fuel type, was obtained from TEIAS [2] and entered into the LEAP model's current accounts.

3.1.1.1. Electricity Consumption

Parallel to Türkiye has emerging economy, electricity consumption has increased regularly in the present years. As seen in Table 3.1, gross electricity consumption increased from 56.8 TWh to 306.1 TWh between 1990 and 2020 [2]. The aforementioned historical data has been entered into the existing accounts of the LEAP model.

Table 3.1. Gross electricity consumption in Türkiye (1990-2020, TWh) [2]

Year	Electricity Consumption (TWh)	Year	Electricity Consumption (TWh)	Year	Electricity Consumption (TWh)
1990	56.8	**2001**	126.9	**2011**	230.3
1991	60.5	**2002**	132.6	**2012**	242.4
1992	67.2	**2003**	141.2	**2013**	246.4
1993	73.4	**2004**	150.0	**2014**	257.2
1994	77.8	**2005**	160.8	**2015**	265.7
1995	85.6	**2006**	174.6	**2016**	279.3
1996	94.8	**2007**	190.0	**2017**	296.7
1997	105.5	**2008**	198.1	**2018**	304.2
1998	114.0	**2009**	194.1	**2019**	303.3
1999	118.5	**2010**	210.4	**2020**	306.1
2000	128.3				

3.1.1.2. Exogenous Capacity

Türkiye's total installed power capacity increased from 16.3 GW to 95.9 GW between 1990 and 2020 [2]. In other words, total installed capacity has increased six-fold in the last three decades. As shown in Table 3.2, resource diversity has increased with the increase in power plant investments based on renewable energy sources other than hydro since the mid-2000s. Historical installed power data from the TEIAS has been entered into the existing accounts of the LEAP model.

Table 3.2. Türkiye’s installed power capacity by sources (1990-2020, MW) [2]

Year	Hard Coal	Lignite	Liquid Fuels	Natural Gas	Hydro	Geothermal	Wind	Solar	Biomass
1990	332	4874	1748	2582	6764	18	0	0	0
1991	353	5041	1737	2937	7114	18	0	0	10
1992	353	5405	1530	3019	8379	18	0	0	14
1993	353	5609	1536	3127	9682	18	0	0	14
1994	353	5819	1542	3251	9865	18	0	0	14
1995	326	6048	1353	3333	9863	18	0	0	14
1996	341	6048	1388	3506	9935	18	0	0	14
1997	335	6048	1409	3966	10103	18	0	0	14
1998	335	6214	1532	4918	10307	18	9	0	22
1999	335	6352	1542	7303	10537	18	9	0	24
2000	480	6509	1586	7454	11175	18	19	0	24
2001	480	6511	2000	7609	11673	18	19	0	24
2002	480	6503	2400	10158	12241	18	19	0	28
2003	1800	6439	2733	11975	12579	15	19	0	28
2004	1845	6451	2569	13252	12645	15	19	0	28
2005	1986	7131	2506	14245	12906	15	20	0	35
2006	1986	8211	2397	14786	13063	23	59	0	41
2007	1986	8211	2000	15031	13395	23	146	0	43
2008	1986	8205	1819	15526	13829	30	364	0	60
2009	2391	8199	1699	16963	14553	77	792	0	87
2010	3751	8199	1593	18628	15831	94	1320	0	107
2011	4351	8199	1300	19955	17137	114	1729	0	126
2012	4383	8193	1286	20997	19609	162	2261	0	169
2013	4383	8223	616	25191	22289	311	2760	0	235
2014	6533	8281	595	26094	23643	405	3630	40	299
2015	6825	8696	523	25489	25868	624	4503	249	370
2016	8229	9126	445	26115	26681	821	5751	833	496
2017	9576	9129	380	27199	27273	1064	6516	3421	642
2018	9576	9456	371	26687	28291	1283	7005	5063	819
2019	9604	9966	189	26733	28503	1515	7591	5995	1171
2020	9624	9989	189	26489	30984	1613	8832	6667	1503

3.1.1.3. Historical Generation

Türkiye's historical electricity production data between 1990 and 2020 was obtained from TEIAS and entered into the LEAP model's current accounts. As shown in Table 3.3, Historical electricity generation data has a similar trend with the installed power data, and total electricity production increased from 57.5 TWh to 306.7 TWh between 1990 and 2020 [2].

Table 3.3. Electricity generation by sources in Türkiye (1990-2020, GWh) [2]

Year	Hard Coal	Lignite	Liquid Fuels	Natural Gas	Hydro	Geothermal	Wind	Solar	Biomass
1990	0.6	19.6	3.9	10.2	23.1	0.1	0.0	0.0	0.0
1991	1.0	20.6	3.3	12.6	22.7	0.1	0.0	0.0	0.0
1992	1.8	22.8	5.3	10.8	26.6	0.1	0.0	0.0	0.0
1993	1.8	22.0	5.2	10.8	34.0	0.1	0.0	0.0	0.1
1994	2.0	26.3	5.5	13.8	30.6	0.1	0.0	0.0	0.1
1995	2.2	25.8	5.8	16.6	35.5	0.1	0.0	0.0	0.2
1996	2.6	27.8	6.5	17.2	40.5	0.1	0.0	0.0	0.2
1997	3.3	30.6	7.2	22.1	39.8	0.1	0.0	0.0	0.3
1998	3.0	32.7	7.9	24.8	42.2	0.1	0.0	0.0	0.3
1999	3.1	33.9	8.1	36.3	34.7	0.1	0.0	0.0	0.2
2000	3.8	34.4	9.3	46.2	30.9	0.1	0.0	0.0	0.2
2001	4.0	34.4	10.4	49.5	24.0	0.1	0.1	0.0	0.2
2002	4.1	28.1	10.7	52.5	33.7	0.1	0.0	0.0	0.2
2003	8.7	23.6	9.2	63.5	35.3	0.1	0.1	0.0	0.1
2004	12.0	22.4	7.7	62.2	46.1	0.1	0.1	0.0	0.1
2005	13.2	29.9	5.5	73.4	39.6	0.1	0.1	0.0	0.1
2006	14.2	32.4	4.3	80.7	44.2	0.1	0.1	0.0	0.2
2007	15.1	38.3	6.5	95.0	35.9	0.2	0.4	0.0	0.2
2008	15.9	41.9	7.5	98.7	33.3	0.2	0.8	0.0	0.2
2009	16.6	39.1	4.8	96.1	36.0	0.4	1.5	0.0	0.3
2010	19.1	35.9	2.2	98.1	51.8	0.7	2.9	0.0	0.5
2011	27.3	38.9	0.9	104.0	52.3	0.7	4.7	0.0	0.5
2012	33.3	34.7	1.6	104.5	57.9	0.9	5.9	0.0	0.7
2013	33.5	30.3	1.7	105.1	59.4	1.4	7.6	0.0	1.2
2014	39.6	36.6	2.1	120.6	40.6	2.4	8.5	0.0	1.4
2015	44.8	31.3	2.2	99.2	67.1	3.4	11.7	0.2	1.8
2016	53.7	38.6	1.9	89.2	67.2	4.8	15.5	1.0	2.4
2017	56.8	40.7	1.2	110.5	58.2	6.1	17.9	2.9	3.0
2018	68.2	45.1	0.3	92.5	59.9	7.4	19.9	7.8	3.6
2019	66.0	46.9	0.3	57.3	88.8	9.0	21.7	9.2	4.6
2020	67.9	37.9	0.3	70.9	78.1	10.0	24.8	11.0	5.7

3.1.1.4. Energy Load Shape

The hourly real-time electricity consumption data of 2019 were obtained from the EPIAS transparency platform [63] to determine the system energy load shape. Because of the eliminating the impact of the COVID-19 Pandemic, 2019 was chosen instead of 2020. A year was divided into 48-time slices for two seasons and 24 hours in the LEAP program. Then hourly real-time electricity consumption data were entered into the current accounts of the LEAP model. The energy load shape is given in Table 3.4.

Table 3.4. Energy load shape (Percentage of annual energy)

Time Slice	Hours	Cumulative Hours	Average Value (%)
Wet: Hour 1	153	153	1.74
Wet: Hour 2	153	306	1.66
Wet: Hour 3	153	459	1.60
Wet: Hour 4	153	612	1.56
Wet: Hour 5	153	765	1.53
Wet: Hour 6	153	918	1.49
Wet: Hour 7	153	1071	1.46
Wet: Hour 8	153	1224	1.52
Wet: Hour 9	153	1377	1.71
Wet: Hour 10	153	1530	1.83
Wet: Hour 11	153	1683	1.87
Wet: Hour 12	153	1836	1.91
Wet: Hour 13	153	1989	1.86
Wet: Hour 14	153	2142	1.89
Wet: Hour 15	153	2295	1.95
Wet: Hour 16	153	2448	1.95
Wet: Hour 17	153	2601	1.96
Wet: Hour 18	153	2754	1.95
Wet: Hour 19	153	2907	1.93
Wet: Hour 20	153	3060	1.95
Wet: Hour 21	153	3213	1.98
Wet: Hour 22	153	3366	1.96
Wet: Hour 23	153	3519	1.91
Wet: Hour 24	153	3672	1.83
Dry: Hour 1	212	3884	2.23
Dry: Hour 2	212	4096	2.11
Dry: Hour 3	212	4308	2.03
Dry: Hour 4	212	4520	1.98
Dry: Hour 5	212	4732	1.97
Dry: Hour 6	212	4944	1.99
Dry: Hour 7	212	5156	2.04
Dry: Hour 8	212	5368	2.14
Dry: Hour 9	212	5580	2.38
Dry: Hour 10	212	5792	2.51
Dry: Hour 11	212	6004	2.54
Dry: Hour 12	212	6216	2.56
Dry: Hour 13	212	6428	2.46
Dry: Hour 14	212	6640	2.47
Dry: Hour 15	212	6852	2.51
Dry: Hour 16	212	7064	2.52
Dry: Hour 17	212	7276	2.56
Dry: Hour 18	212	7488	2.62
Dry: Hour 19	212	7700	2.66
Dry: Hour 20	212	7912	2.67
Dry: Hour 21	212	8124	2.63
Dry: Hour 22	212	8336	2.56
Dry: Hour 23	212	8548	2.48
Dry: Hour 24	212	8760	2.38

3.1.1.5. Process Efficiencies

The default efficiencies for grid-connected power plants were obtained from various sources, and the sectoral experience was taken into account, as given in Table 3.5.

Table 3.5. Process efficiencies of power plants (%)

Source	Process Efficiency (%)
Nuclear	35 [64]
Geothermal	12 [65]
Biomass	40 [66]
Hard Coal	40 [66]
Lignite	31 [66]
Natural Gas	55 [66]
Liquid Fuels	45 [66]

There is a certain decrease in process efficiencies in power plants with CCS. Efficiency reduction rates for coal thermal and natural gas power plants were obtained from the related studies as 10.8% [67] and 13.4% [68], respectively. The process efficiencies of plants with CCS calculated in line with these rates are given in Table 3.6.

Table 3.6. Process efficiencies of power plants with CCS (%)

Source	Process Efficiency (%)
Hard Coal with CCS	36
Lignite with CCS	28
Natural Gas with CCS	48

3.1.1.6. Resource Import, Export, and Reserves

This part of the study presents detailed information on the electricity sector, including resource imports and exports, and base year reserves. These data are entered into the LEAP model’s current accounts.

Natural gas imports and exports data were obtained from EMRA Natural Gas Sectoral Reports and entered into the current accounts of the LEAP model [69,70].

Legal companies with export licenses can export domestic or imported natural gas to the countries listed on the license. Natural gas exports started in 2007 when BOTAŞ exported natural gas to Greece. As of December 2019, Aygaz Company began to export LNG to Bulgaria [69,70].

Natural gas, which started to be used in the 1970s and whose usage rate and fields are increasing due to the advantages it has in parallel with the increase in energy demand, has made natural gas imports compulsory for Türkiye as the domestic reserves and production amounts remain at minimal levels to meet the current and potential use. Table 3.7 shows annual natural gas imports and exports [69,70].

Table 3.7. Natural gas imports and exports by years (Sm^3) [69,70]

Years	**Imports (Sm^3)**	**Exports (Sm^3)**
2005	26,571.0	0.0
2006	30,221.0	0.0
2007	35,842.0	30.8
2008	37,350.0	435.8
2009	35,856.0	708.5
2010	38,036.0	648.6
2011	43,874.0	714.0
2012	45,922.0	611.0
2013	45,269.0	682.0
2014	49,262.0	632.6
2015	48,427.0	623.9
2016	46,352.2	674.7
2017	55,250.0	630.7
2018	50,282.1	673.3
2019	45,211.5	762.7
2020	48,125.5	577.5

Coal bituminous imports and exports data were obtained from Turkstat and entered into the current accounts of the LEAP model. Coal imports, which started in deficient amounts in Türkiye before the 1980s, increased to over 10 million tons in the 1990s and over 15 million tons in the 2000s. Two thousand twenty imports are 39.38 million tons [71]. Coal exports are meagre compared to imports. Coal imports and exports data by year are given in Table 3.8 [72].

Table 3.8. Coal bituminous imports and exports by years (thousand tons) [72]

Years	Imports (th. tons)	Exports (th. tons)
2000	13,242	3
2001	6,294	1
2002	13,683	2
2003	16,004	1
2004	16,130	2
2005	16,667	15
2006	20,026	7
2007	22,417	4
2008	18,861	57
2009	20,033	2
2010	21,211	39
2011	22,828	2
2012	28,608	2
2013	26,192	12
2014	29,355	63
2015	33,782	151
2016	36,093	62
2017	39,299	94
2018	38,044	105
2019	37,963	48
2020	39,902	137

Natural gas reserve data were obtained from the Petroleum statistics table of the General Directorate of Mining and Petroleum Affairs. Lignite and coal bituminous reserve data were obtained from the Turkish Coal Enterprises' Coal Sector Report. Then, these values have been entered into the current accounts of the LEAP model. The amount of original natural gas available in Türkiye is 26.6 billion m^3. On the other hand, the recoverable natural gas is 20 billion m^3 [73].

As a result of intensive coal exploration activities initiated in 2005 by MTA in line with the policy of using domestic resources in energy, the lignite reserves of Türkiye, which was 8.3 billion tons, reached 19.32 billion tons as of the end of 2019 [71]. Türkiye's most crucial hard coal resources are in and around Zonguldak. The hard coal resource is 1.52 billion tons, 736 million tons of which is visible [71].

The annual yield of wind, geothermal, and biomass energy resources were obtained from the MENR, and the annual yield of hydro resources was obtained from the Turkish Electromechanic Industries Corporation’s websites. The annual yield of solar energy is assumed as unlimited. Türkiye's theoretical hydroelectric potential is 433 billion kWh/year, its technical potential is 216 billion kWh/year, and its technical and economic potential is 160 thousand GWh/year [74].

According to the Biomass Energy Potential Atlas (BEPA) data prepared by MENR to estimate the biomass energy potential, waste's total economic energy equivalent is around 3.9 MTOE/year [75].

According to the Wind Energy Potential Atlas (WEPA) prepared by MENR, Türkiye's wind energy potential has been estimated as 48,000 MW [76]. The annual yield was 135 thousand GWh using this installed power capacity and assuming the capacity factor for wind power plants as 0.32.

The probable geothermal heat potential of Türkiye is estimated as 31500 MWt, and the potential for electricity generation as 2000 MWe [77]. The annual yield was found to be 14 thousand GWh using this installed power capacity and assuming the capacity factor for geothermal power plants as 0.8.

3.1.2. Cost Data

This part of the study presents detailed information on the electricity sector’s costs, including fuel, capital, operation and maintenance, and carbon costs.

3.1.2.1. Fuel Cost

The costs of natural gas and hard coal have been obtained from IEA and World Bank. Especially for the years affected by the global energy crisis World Bank’s near-term fuel prices forecasts have been based on. Interpolation was applied for other years using IEA World Energy Outlook data with 10-year intervals and World Bank data [31,78]. Lignite price series have been assumed as one-third of hard coal prices. Nuclear fuel cost has been obtained from World Nuclear Energy Association [79]. Fuel costs by year are listed in Table 3.9.

Table 3.9. Costs of fuels between 2030 and 2053 (Adopted from [31,78,79])

Years	Hard Coal USD/tone	Lignite USD/tone	Natural gas (USD/Sm^3)	Nuclear (US cent/kWh)
2010	109	36	0.33	0.33
2011	104	35	0.31	0.33
2012	99	33	0.29	0.33
2013	95	32	0.27	0.33
2014	90	30	0.24	0.33
2015	85	28	0.22	0.33
2016	80	27	0.20	0.33
2017	75	25	0.18	0.33
2018	71	24	0.16	0.33
2019	66	22	0.14	0.33
2020	61	20	0.12	0.33
2021	138	46	0.60	0.33
2022	250	83	1.27	0.33
2023	170	57	0.93	0.33
2024	155	52	0.83	0.33
2025	140	47	0.74	0.33
2026	125	42	0.65	0.33
2027	111	37	0.56	0.33
2028	96	32	0.47	0.33
2029	82	27	0.38	0.33
2030	67	22	0.29	0.33
2031	67	22	0.29	0.33
2032	67	22	0.29	0.33
2033	66	22	0.29	0.33
2034	66	22	0.29	0.33
2035	66	22	0.29	0.33
2036	66	22	0.29	0.33
2037	66	22	0.30	0.33
2038	65	22	0.30	0.33
2039	65	22	0.30	0.33
2040	65	22	0.30	0.33
2041	65	22	0.30	0.33
2042	65	22	0.30	0.33
2043	64	21	0.30	0.33
2044	64	21	0.30	0.33
2045	64	21	0.30	0.33
2046	64	21	0.31	0.33
2047	64	21	0.31	0.33
2048	63	21	0.31	0.33
2049	63	21	0.31	0.33
2050	63	21	0.31	0.33
2051	63	21	0.31	0.33
2052	63	21	0.31	0.33
2053	62	21	0.31	0.33

3.1.2.2. Capital Cost

Power plant capital costs were obtained from national and international sources such as EIA [80], IEA [31] and International Renewable Energy Agency (IRENA) [81]. Renewable energy-based power plant costs have declined considerably over the previous decade due to constantly improving technology, economies of scale, competitive supply chains, and enhanced developer skills [81]. Capital cost data of different electricity generation technologies were obtained from various international organizations' reports. The capital cost data of battery storage has been obtained from the LEAP Software's "Time Slice Demo" named case study, which is compatible with the report of the National Renewable Energy Laboratory (NREL) [82]. Capital costs by technology types are listed in Table 3.10.

Table 3.10. Capital costs by technology types

Technology	**Cost, thousand USD/MW**	**Ref.**
Liquid Fuels	709	[80]
Natural Gas	780	[31]
Natural Gas with CCS	2 570	[80]
Lignite	1 400	[31]
Lignite with CCS	5 980	[80]
Hard Coal	1 400	[31]
Hard Coal with CCS	5 980	[80]
Hydro	1 870	[81]
Solar	827	[81]
Wind	1 446	[81]
Biomass	4 078	[80]
Geothermal	2 772	[80]
Nuclear	6 336	[80]
Battery Storage	1 484	[83]

Wind and solar energy generation technologies have recently seen remarkable cost reductions [84]. The reductions in the capital costs of renewable energy technologies are expected to continue due to the ongoing innovations in these technologies [85]. To reflect this situation, periodically varying capital costs for these electricity generation technologies have been obtained from various sources. The decreasing trend exists for battery storage installations too. Varying capital costs of RES-based technologies and battery storage are listed in Table 3.11.

Table 3.11. Varying capital costs of RES-based technologies and battery storage

Technology	Cost, thousand USD/MW		
	2020	**2030**	**2050**
Solar	827 [81]	530 [31]	380 [31]
Wind	1 446 [81]	1 410 [31]	1 340 [31]
Geothermal	2 772 [80]	2 434 [86]	1 254 [86]
Battery storage	**2020**		**2050**
	1 484 [82,83]		608 [82,83]

3.1.2.3. Operation and Maintenance Cost

Similar to capital cost data, various electricity generation technologies' fixed and variable operation and maintenance costs were obtained from several international organizations' reports. The fixed and variable operation and maintenance (O&M) costs by technology types are listed in Table 3.12.

Table 3.12. Fixed and variable O&M costs by technology types

Technology	Fixed O&M Cost, USD/MW	Variable O&M Cost, USD/MWh
Liquid Fuels	7 040 [31]	4.52 [31]
Natural Gas	14 170 [31]	2.56 [31]
Natural Gas with CCS	27 740 [31]	5.87 [31]
Lignite	40 790 [31]	4.52 [31]
Lignite with CCS	59 850 [31]	11.03 [31]
Hard Coal	40 790 [31]	4.52 [31]
Hard Coal with CCS	59 850 [31]	11.03 [31]
Hydro	40 000 [81]	1.40 [31]
Solar	10 000 [81]	0.00 [31]
Wind	33 000 [81]	0.00 [31]
Biomass	126 360 [31]	5.00 [81]
Geothermal	115 000 [81]	1.17 [31]
Nuclear	122 260 [31]	2.38 [31]
Battery storage	37 000 (2020) 15 000 (2050) [83]	0.00 [83]

Carbon pricing (CP) is a mitigation tool applied in many countries as a carbon tax, emission trading system, or both. These mechanisms are at the core of mitigation scenarios compatible with 1.5 °C pathways [17]. It is aimed to decrease the use of fossil fuels and promote the use of RES and energy efficiency applications. For this reason, CP was also considered, especially in the NET-1 Scenario, the NET-2 Scenario, and the NET-3 Scenario. When the EHP sector is included in the CP to be applied, the carbon cost (CC) burden will be imposed on the power plant operators using fossil fuels. The following calculations were made to determine this burden. CC per unit of power generation has been calculated according to Eq. 1.

$$CC = \frac{EF \times 3.6 \times 10^{-3} \times CP}{\eta} \tag{1}$$

where *CC* is the carbon cost (USD/MWh), *EF* is the emission factor (tons CO_2/TJ), *CP* is the carbon price (USD/tons CO_2), and η is the thermal efficiency of the plant. *CP* values were assumed to increase over the years. *CC* values by technology and years are given in Table 3.13.

Table 3.13. CC values by technology types and years

Technology	$\boldsymbol{\eta}$	***EF*, ton CO_2/TJ**	***CP*, USD/ton CO_2**			***CC*, USD/MWh**		
			2025	**2035**	**2053**	**2025**	**2035**	**2053**
Lignite	0.31	106.62	10	25	50	12.38	30.95	61.91
Hard coal	0.40	94.58	10	25	50	8.51	21.28	42.56
Natural gas	0.55	55.50	10	25	50	3.63	9.08	18.16
Liquid fuels	0.45	76.97	10	25	50	6.16	15.39	30.79

CCs were added to the variable O&M costs and entered into the model only for the NET-1 Scenario, the NET-2 Scenario and the NET-3 Scenario. The operation and maintenance variable costs by technology types to which CPs are added are listed in Table 3.14.

Table 3.14. CC added variable O&M costs by technology types

Technology	**CC Added Variable O&M Costs, USD/MWh**		
	2025	**2035**	**2053**
Lignite	16.90	35.47	66.43
Hard coal	13.03	25.80	47.08
Natural gas	6.19	11.64	20.72
Liquid fuels	10.68	19.91	35.31

3.1.3. Emission Factor Data

Türkiye's country-specific CO_2 emission factors are calculated every year within the scope of the Turkish NIR [33]. The elemental analyses of Turkish lignite, sub-bituminous, and other bituminous coals are obtained from coal-fired power plants to determine the carbon content of fuels. The oxidation rate of solid fuels is estimated using the mass percentage of carbon in ash-slag analysis. The same procedure is applied to determine residual fuel oil characteristics [33]. Gas chromatography analyses of Petroleum Pipeline Company (BOTAŞ) are used for volumetric fractions of gas concentrations. Then, the carbon mass of each gas compound is calculated. Measured CO concentrations in the stack gas are used to find the mass percentage of the unoxidized carbon and the oxidation rate [33].

Türkiye's country-specific CO_2 emission factors of fuels were obtained from the most current Turkish NIR. Using country-specific data rather than default data is important to ensure that emission calculations in the model reflect the country's characteristics. As in the Turkish NIR, the default data were used for the other greenhouse gases, CH_4 and N_2O. The CO_2 emission factors by fuels used in the model are given in Table 3.15 [33].

Table 3.15. CO_2 emission factors by fuels [33]

Fuel	**CO_2 Emission Factor, ton/TJ**
Residual Fuel Oil	76.97
Diesel Oil	72.28
Natural Gas	55.50
Lignite	106.62
Hard Coal	94.58

Power plants with CCS capture around 90% of the CO_2 from flue gas [87]. According to this rate, CO_2 emission factors for CCS power plants were calculated as presented in Table 3.16.

Table 3.16. CO_2 emission factors of CCS power plants by fuels

Fuel	CO_2 Emission Factor, ton/TJ
Natural Gas with CCS	5.6
Lignite with CCS	10.7
Hard Coal with CCS	9.5

3.1.4. Demand Data

The demand projection data between 2020 and 2040 has been obtained from the most current and available Turkish Electric Energy Demand Projection Report. Energy System for Türkiye (EST) was used for demand estimation in this report. Population, GDP, fuel prices, fuel and resource potential, energy system components, time-based efficiency increases and cost changes, power plant internal consumption and network losses, the widespread use of electric vehicles, and other trends in the global energy sector are the main factors considered in the EST model. In the EST model, three scenarios, namely low, middle, and high, were developed based on the economic growth rate predictions. The electricity demand estimates based on the scenarios are presented in Table 3.17, and annual average demand increment ratios are given in Table 3.18 [5].

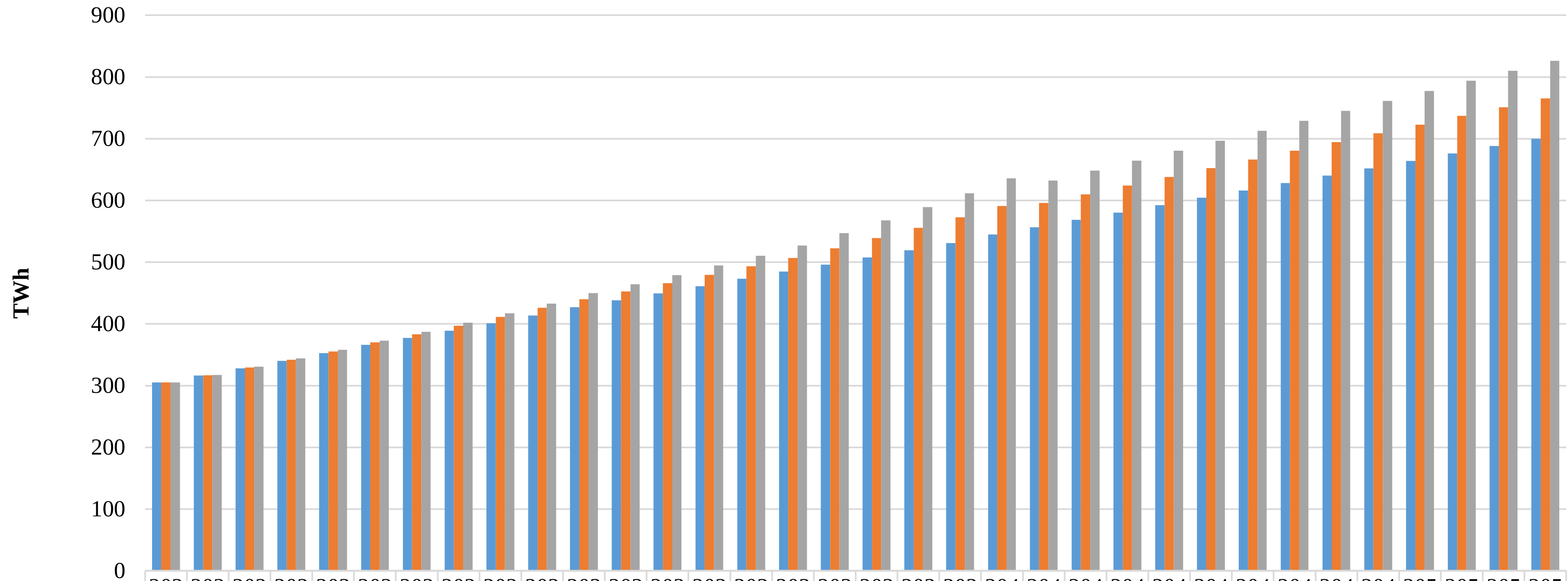
Table 3.17. EST Model electricity demand estimates between 2020 and 2040 (TWh) [5]

	Electricity Demand Estimates, TWh				
	2020	2025	2030	2035	2040
Scenario 1	305	366	427	485	545
Scenario 2	305	370	440	507	591
Scenario 3	305	373	450	527	636

Table 3.18. Annual average demand increment ratios between 2020 and 2040 (%) [5]

	2020-2025	2025-2030	2030-2035	2035-2040
Scenario 1	3.7%	3.1%	2.6%	2.3%
Scenario 2	3.9%	3.6%	2.9%	3.1%
Scenario 3	4.1%	3.8%	3.2%	3.8%

Within the scope of this thesis study, the estimates between 2020 and 2040 in the Turkish Electric Energy Demand Projection Report were extended until 2053. The trend function in Microsoft Excel 2013 software [88] was used for the extension process. In addition, with the help of the 5-year demand growth rates, the demand values of the intermediate years have been determined. The demand estimates between 2020 and 2053 based on three scenarios are presented in Figure 3.1.



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Scenario 1	305	316	328	340	353	366	377	389	401	414	427	438	449	461	473	485	496	508
Scenario 2	305	317	329	342	355	370	383	397	411	426	440	453	466	479	493	507	523	539
Scenario 3	305	318	331	344	358	373	387	402	417	433	450	464	479	495	510	527	547	568

	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053
Scenario 1	519	531	545	556	568	580	592	604	616	628	640	652	664	676	688	700
Scenario 2	556	573	591	596	610	624	638	652	666	681	695	709	723	737	751	765
Scenario 3	589	612	636	632	648	665	681	697	713	729	745	761	778	794	810	826

Figure 3.1. Extended electricity demand series (2020-2053, TWh)

3.2. Model Development and Sensitivity Analysis

The model consists of four modules: Effects, Transformation, Demand, and Resources. The Effects Module was used to determine GHG emission constraints, which are used primarily for optimization calculations. External data entry is provided to the Demand Module. All technical data and costs related to electricity generation and grid were entered into the Transformation Module. All relevant data on reserves, imports, and exports of resources were entered into the Resources Module.

Sensitivity analysis was performed to reveal the reaction in the model results to the changes in the inputs entered into the model. A 10% increase and a 10% decrease in natural gas fuel prices as input parameters in the BAU Scenario were analyzed for sensitivity analysis.

3.3. Scenario Development

In this study, the LEAP model has been used for energy system modelling. Five scenarios were developed to analyze various EHP conditions. These are BAU, MIT, NET-1, NET-2 and NET-3 Scenario. Optimization has been run for all scenarios, and the NEMO has been used as an optimization tool. Details for the optimization tool are given in APPENDIX 2. Major assumptions of the scenarios are given in Table 3.19.

Table 3.19. Major assumptions of the scenarios

Scenario Characteristics		BAU	MIT	NET-1	NET-2	NET-3
Carbon Constraints		No	40% reduction from BAU by 2053	Net Zero	Net Zero	Net Zero
Optimization		Yes	Yes	Yes	Yes	Yes
Maximum Annual Endogenous Capacity Addition	Solar	1000 MW	1500 MW	3000 MW	3000 MW	3500-8000 MW
	Wind	1000 MW	1500 MW	3000 MW	3000 MW	4000-8000 MW
	Nuclear	0 MW	0 MW	2400 MW	4800 MW	0 MW
Carbon Pricing		No	No	Yes	Yes	Yes
Power Plants with CCS		No	No	Yes	No	No
Battery Storage		No	No	No	No	Yes
Demand		Low	Low	High	High	High

3.3.1. BAU Scenario

Current plans and policies have been included in BAU Scenario. MENR Strategic Plan (2019-2023) [89], National Energy and Mining Policy (NEMP) [90], Türkiye's NDC document [91], Transmission System Operator (TSO) Generation Capacity Projection Report (GCPR) (2021-2025) [92] were used to establish the exogenous capacity values in BAU Scenario. Exogenous capacity includes planned and committed capacity expansions, retirements, and existing installed capacity [83].

Scenario 1, with the additional power capacity data in the GCPR, was used for the power stations between 2021 and 2025, except for the solar, wind, and nuclear power plants [92]. The capacity data for wind energy in the MENR Strategic Plan between 2021 and 2023 were used [89]. An additional 1000 MW of wind energy installed capacity was added annually between 2024 and 2027 based on the data given in the NEMP [90]. Wind power installed capacity is expected to reach 20 GW by 2030, according to Türkiye's NDC [91]. The capacity data presented in the MENR Strategic Plan was used for solar energy between 2021 and 2023 [89]. An additional solar energy capacity of 1000 MW was entered for each year between 2024 and 2027, based on the information gathered from the NEMP [90]. For nuclear energy, between 2021 and 2025, Scenario 1, with the additional power capacity data in the GCPR [92], was used. The GCPR includes the first three units of the Akkuyu Nuclear Power Plant, each having a 1200 MW installed capacity. The 4th and last unit of the Akkuyu Nuclear Power Plant was assumed to be commissioned in 2026. In the BAU Scenario, no additional nuclear capacity was foreseen except for the Akkuyu nuclear power plant. As stated above, exogenous capacity values were entered into the model manually, while endogenous capacity values were estimated by optimization. Exogenous capacity values are obtained for each power plant based on fuel type for specific periods. These specific periods are determined based on the official policy documents such as NEMP, GCPR, MENR Strategic Plan and NDC. In addition, the periods of the endogenous capacity additions are designed based on the regarding exogenous capacity addition periods. Thus, the investments in years other than those included in policy documents are determined by optimization. Capacity additions by year have been given Table 3.20.

Table 3.20. Capacity Additions (MW) – BAU Scenario

Source	**Exogenous Capacity Additions, MW**	**Maximum Endogenous Capacity Additions, MW**	
Period	**2020-2025**	**2021-2025**	**2026-2053**
Natural Gas	86.7	0	1000
Hydro	2401.1	0	500
Lignite	1291.0	0	1000
Hard Coal	1350.0	0	1000
Biomass	790.5	0	150
Geothermal	482.5	0	100
Liquid Fuels	8.7	0	0
Period	**2020-2045**	**2021-2045**	**2046-2053**
Nuclear	4800.0	0	0
Period	**2020-2027**	**2021-2027**	**2028-2053**
Solar	7332.6	0	1000
Period	**2020-2030**	**2021-2030**	**2031-2053**
Wind	11167.6	0	1000

Scenario 2 of the extended electricity demand series (2020-2053) given in Section 3.1.4 was used for electricity demand. According to Scenario 2 of the electricity demand series, electricity demand will reach 765 TWh in 2053.

3.3.2. MIT Scenario

The MIT Scenario is developed based on a 40 percent reduction in EHP sector CO_2 emissions from the BAU level by 2053. Renewable energy investments were the most critical mitigation in the emission reduction scenarios. Renewable energy investments also stand out as a cost-effective option [93].

According to a 40 percent reduction, annual emission constraints have been quantified. Firstly, the emission constraint in 2053 for the MIT Scenario, which is 60% of the estimated emissions in 2053 in the BAU scenario, was calculated. After that, 1990-2020 and 2053 CO_2 emission estimation data were entered into Microsoft Excel Program, and the polynomial CO_2 emission constraint pathway formula was estimated in Excel as Eq. 2.

$$EC_t = -\,0.0276 \times (t - 1990)^2 + 4.65 \times (t - 1990) + 18.154 \tag{2}$$

where *ECt* is the emission constraint (million tons CO_2) in the MIT Scenario, and *t* is the year.

The pathway of emission constraints of the MIT Scenario is given in Figure 3.2.

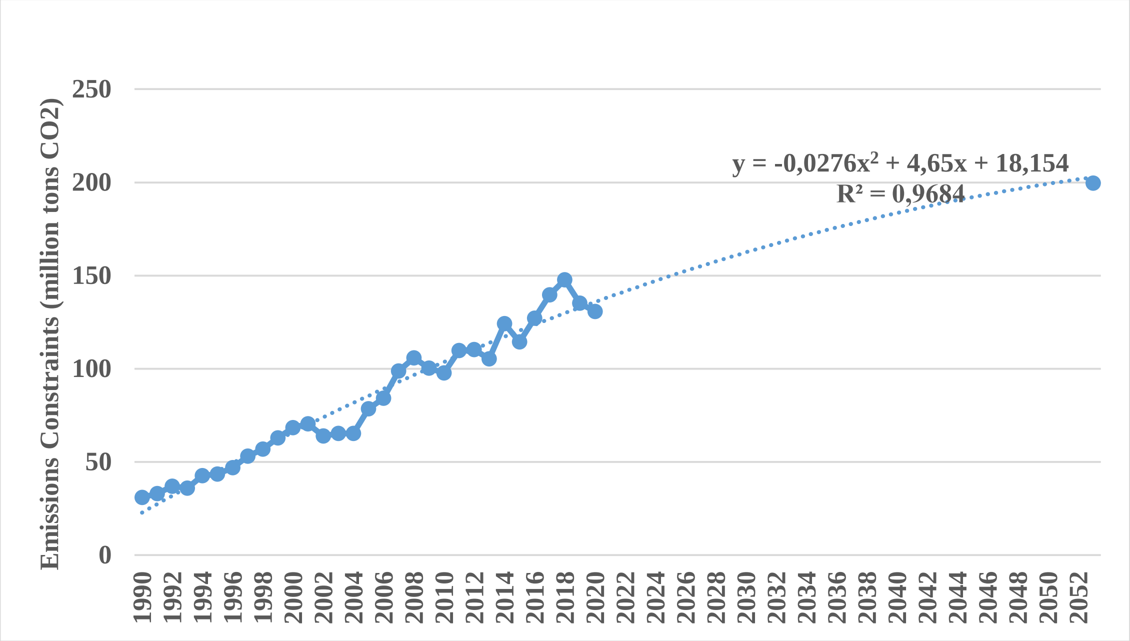


Figure 3.2. The pathway of emission constraints of the MIT Scenario (million tons CO_2)

After estimating emission constraints between 2021 and 2053, these values were entered into the model's Effect Branch for least-cost optimization.

For exogenous capacities in MIT Scenario, the same values were taken as with BAU Scenario, except for nuclear energy. For nuclear energy, between 2021 and 2025, Scenario 1 additional power capacity data in the GCPR [92] were used. The GCPR includes the first three units of the Akkuyu Nuclear Power Plant, each with a 1200 MW installed capacity. The 4th and last unit of the Akkuyu Nuclear Power Plant was assumed to be commissioned in 2026. Other nuclear power plants in Türkiye that are subject to commissioning in the future are Sinop and Igneada nuclear power plants. Sinop Nuclear Power plant will have four units with an 1120 MW installed capacity. The period of commissioning of the Sinop Nuclear Power Plant is assumed to be between 2030 and 2035.

Igneada Nuclear Power Plant will be built to have four units with 1100 MW of installed capacity. The commissioning period of the Igneada Nuclear Power Plant is assumed to be between 2040 and 2045. No additional nuclear capacity was foreseen for the years between 2046 and 2053. Like in the BAU Scenario, the endogenous capacity values are also estimated by optimization in the MIT Scenario. Capacity additions by year are presented in Table 3.21.

Table 3.21. Capacity Additions (MW) – MIT Scenario

Source	**Exogenous Capacity Additions, MW**	**Maximum Endogenous Capacity Additions, MW**	
Period	**2020-2025**	**2021-2025**	**2026-2053**
Natural Gas	86.7	0	1000
Hydro	2401.1	0	500
Lignite	1291.0	0	1000
Hard Coal	1350.0	0	1000
Biomass	790.5	0	150
Geothermal	482.5	0	100
Liquid Fuels	8.7	0	0
Period	**2020-2045**	**2021-2045**	**2046-2053**
Nuclear	13680.0	0	0
Period	**2020-2027**	**2021-2027**	**2028-2053**
Solar	7332.6	0	1500
Period	**2020-2030**	**2021-2030**	**2031-2053**
Wind	11167.6	0	1500

Scenario 2 of the extended electricity demand series (2020-2053) presented in Section 3.1.4 was used for electricity demand. According to Scenario 2 of the electricity demand series, electricity demand will reach 765 TWh in 2053.

3.3.3. NET-1 Scenario

The NET-1 Scenario is developed based on achieving net zero emissions in EHP sector GHG emissions in 2053. The NET-1 Scenario was designed to compensate for EHP sector GHG emissions with land use, land use change and forestry (LULUCF) emissions.

Türkiye's most recent NIR Report shows that LULUCF emissions were -56.95 million tons of CO_2-eq in 2020 [33]. These emissions are assumed to double and reach 113.9

million tons of CO_2-eq in 2053. Since EHP sector CO_2 emissions correspond to 31.6% of the total emissions of Türkiye [33], this sector's emissions at the same percentage are expected to be neutralized by LULUCF emissions in 2053. For this reason, this percentage was multiplied by the LULUCF emissions in 2053 to find the EHP sector emissions in 2053. After that, 1990-2020 and 2053 CO_2 emissions data were entered into Microsoft Excel Program [88], and the polynomial CO_2 emission constraint pathway formula was estimated with Excel as Eq. 3.

$$EC_t = -0.0968 \times (t - 1990)^2 + 6.7692 \times (t - 1990) + 7.3408 \qquad (3)$$

where ECt is the emission constraint (million tons CO_2) in the regarded year in the NET-1 Scenario, and t is regarded year.

The pathway of emission constraints of the NET-1 Scenario is given in Figure 3.3.

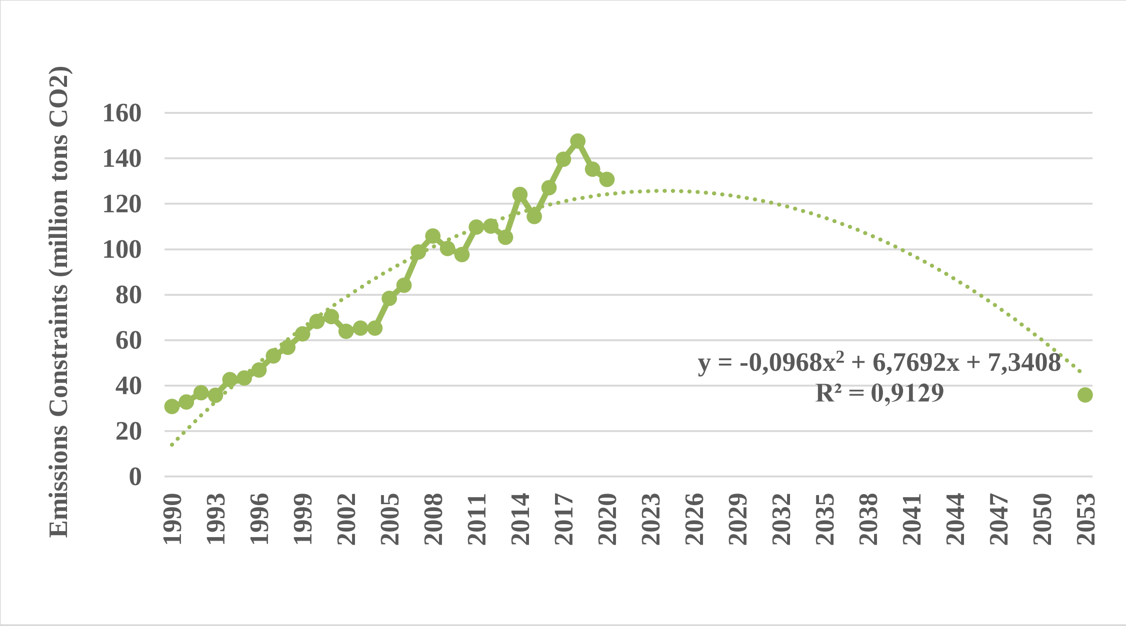


Figure 3.3. The pathway of emission constraints of the NET-1 Scenario (million tons CO_2)

After estimating emission constraints between 2021 and 2053, these values were entered into the model's Effect Branch for the least-cost optimization.

The same values were taken for exogenous capacities in the NET-1 Scenario, as with MIT Scenario. Unlike the MIT Scenario, power plants with CCS are also included in the optimization. The competitiveness of fossil power plants with CCS is highly dependent on CO_2 prices. This technology can compete with other options when high CO_2 prices exist [94]. As stated in 3.1.2.3, the other important change is that the carbon price is also considered in this scenario. Like in the other two scenarios, the endogenous capacity values are also estimated by optimization in the NET-1 Scenario. Capacity additions by year have been given in Table 3.22.

Table 3.22. Capacity Additions (MW) – NET-1 Scenario

Source	**Exogenous Capacity Additions, MW**	**Maximum Endogenous Capacity Additions, MW**	
Period	**2020-2025**	**2021-2025**	**2026-2053**
Natural Gas	86.7	0	1000
Hydro	2401.1	0	500
Lignite	1291.0	0	1000
Hard Coal	1350.0	0	1000
Biomass	790.5	0	150
Geothermal	482.5	0	100
Liquid Fuels	8.7	0	0
Period	**2020-2045**	**2021-2045**	**2046-2053**
Nuclear	13680.0	0	2400
Period	**2020-2027**	**2021-2027**	**2028-2053**
Solar	7332.6	0	3000
Period	**2020-2030**	**2021-2030**	**2031-2053**
Wind	11167.6	0	3000
Period	**2020-2029**	**2021-2029**	**2030-2053**
Natural Gas with CCS	0	0	500
Lignite with CCS	0	0	500
Hard Coal with CCS	0	0	500

The NET-1 Scenario requires more electricity on the demand side. The electrification is expected to increase to reach net zero emissions. According to the IEA, the share of electricity in total energy consumption is expected to be about 50% to reach the net zero target at the global level by 2050. Thus, electricity consumption will increase by more than two and a half times in 2050 compared to today [32]. This is because electricity has a direct electrification role in decarbonizing end-uses and producing electricity-derived fuels such as hydrogen [95]. Electrolyzers, electric vehicles and the wide use of electricity in the industry are the main reasons for increasing electrification. Therefore, electricity demand is assumed to be 1.5 times higher than the other two scenarios in the last scenario year. However, demands are assumed to be the same in all scenarios until 2030 since it is assumed that the progress in hydrogen generation and electric vehicles will occur mainly after 2030.

Firstly, according to 1.5 times higher demand, the electricity demand of the last scenario year (2053) has been calculated by multiplying the low electricity demand in 2053 in BAU and MIT scenarios with 1.5. After that, 2020-2030 low electricity demand and 2053 high electricity demand data were entered into Microsoft Excel Program, and the exponential formula of the high electricity demand pathway was estimated with Excel as Eq. 4.

$$ED_{Ht} = 289.68 \times e^{0.0401\times(t-2020)} \tag{4}$$

where ED_{Ht} is high electricity demand (TWh) in the regarded year in the NET-1 Scenario, and t is regarded year.

The pathway of the electricity demand of the NET-1 Scenario is given in Figure 3.4.

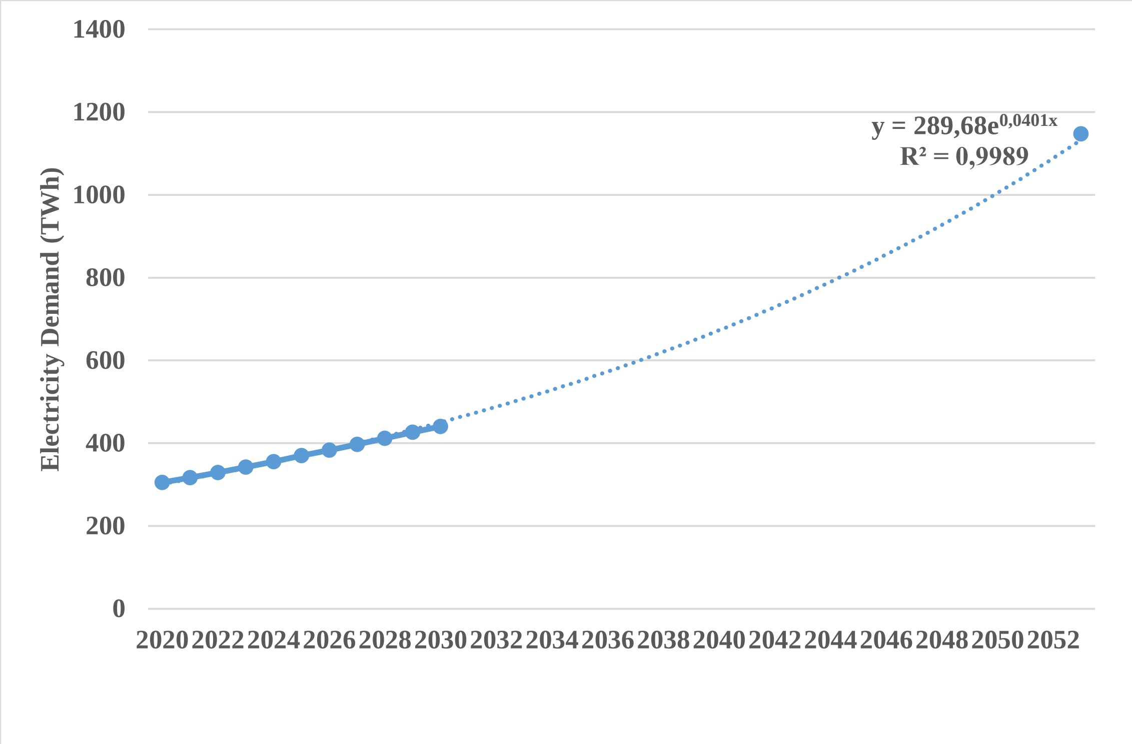


Figure 3.4 The pathway of electricity demand of the NET-1 Scenario (2020-2053)

3.3.4. NET-2 Scenario

The NET-2 Scenario is developed based on achieving net zero emissions in EHP sector GHG emissions in 2053 as in the NET-1 Scenario. Like in the NET-1 Scenario, the NET-2 Scenario was designed to compensate for EHP sector GHG emissions with land use, land use change and forestry (LULUCF) emissions. Because of that, the same pathway of emission constraints with the NET-1 Scenario was taken in the NET-2 Scenario. Then, these emission constraints between 2021 and 2053, these values were entered into the model's Effect Branch for the least-cost optimization.

The same values were taken for exogenous capacities in the NET-2 Scenario, as with the NET-1 and the MIT scenarios. The main difference between the NET-2 and the NET-1 scenarios is that the NET-2 Scenario does not include fossil power plants with CCS. This scenario also considers the carbon price, like in the NET-1 Scenario. Like in the other scenarios, the endogenous capacity values are also estimated by optimization in the NET-1 Scenario. Since fossil power plants with CCS were not integrated into the scenario, to compensate for the increasing demand, the maximum endogenous capacity addition of nuclear power plants and natural gas power plants was increased to 4800 MW and 1200 MW, respectively. These amounts were 2400 MW and 1000 MW in the NET-1 Scenario. Capacity additions by year have been given in Table 3.23.

Table 3.23. Capacity Additions (MW) – NET-2 Scenario

Source	**Exogenous Capacity Additions, MW**	**Maximum Endogenous Capacity Additions, MW**	
Period	**2020-2025**	**2021-2025**	**2026-2053**
Natural Gas	86.7	0	1200
Hydro	2401.1	0	500
Lignite	1291.0	0	1000
Hard Coal	1350.0	0	1000
Biomass	790.5	0	150
Geothermal	482.5	0	100
Liquid Fuels	8.7	0	0
Period	**2020-2045**	**2021-2045**	**2046-2053**
Nuclear	13680.0	0	4800
Period	**2020-2027**	**2021-2027**	**2028-2053**
Solar	7332.6	0	3000
Period	**2020-2030**	**2021-2030**	**2031-2053**
Wind	11167.6	0	3000

Since the electrification is expected to increase to reach net zero emissions, the NET-2 Scenario requires more electricity on the demand side, like in the NET-1 Scenario. Thus, electricity demand is assumed to be 1.5 times higher than the BAU and MIT scenarios in the last scenario year. In other words, the electricity demand estimated in the NET-1 Scenario was also used in the NET-2 Scenario.

3.3.5. NET-3 Scenario

The NET-3 Scenario is developed based on achieving net zero emissions in EHP sector GHG emissions in 2053 as in other net zero emissions scenarios. Like other net zero emissions scenarios, the NET-3 Scenario was designed to compensate for EHP sector GHG emissions with land use, land use change and forestry (LULUCF) emissions. Thus, the same pathway of emission constraints with other net zero emissions scenarios was taken in the NET-3 Scenario. After that, these emission constraints between 2021 and 2053, these values were entered into the model's Effect Branch for the least-cost optimization.

The same values except for nuclear power plants were taken for exogenous capacities in the NET-3 Scenario, as with the NET-1, the NET-2 and the MIT scenarios. Only the Akkuyu Nuclear Power Plant accounted for exogenous capacities such as nuclear power capacity. The other main differences between other net zero emission scenarios are that the NET-3 Scenario does not include fossil power plants with CCS and endogenous capacity addition for nuclear power plants and includes battery storage. The carbon price is also considered in this scenario, just like in other net zero emissions scenarios. Like in the other scenarios, the endogenous capacity values are also estimated by optimization in other net zero emissions scenarios. Since fossil power plants with CCS were not integrated and endogenous capacity addition for nuclear power plants was not included in the scenario, to compensate for the increasing demand, maximum endogenous capacity addition for wind and solar power plants was gradually increased to 9000 MW and for natural gas power plants were increased to 2000 MW. To realize such a substantial amount of wind and solar energy investments, battery storage installations have been allowed for the power system. Capacity additions by year have been given in Table 3.24.

Table 3.24. Capacity Additions (MW) – NET-3 Scenario

Source	**Exogenous Capacity Additions, MW**	**Maximum Endogenous Capacity Additions, MW**		
Period	**2020-2025**	**2021-2025**	**2026-2053**	
Natural Gas	86.7	0	2000	
Hydro	2401.1	0	500	
Lignite	1291.0	0	1000	
Hard Coal	1350.0	0	1000	
Biomass	790.5	0	150	
Geothermal	482.5	0	100	
Liquid Fuels	8.7	0	0	
Period	**2020-2045**	**2021-2045**	**2046-2053**	
Nuclear	4800.0	0	0	
Period	**2020-2027**	**2021-2027**	**2028-2045**	**2045-2053**
Solar	7332.6	0	3500	8000
Period	**2020-2030**	**2021-2030**	**2031-2045**	**2046-2053**
Wind	11167.6	0	4000	8000
Period	**2020-2053**	**2021-2025**	**2026-2045**	**2046-2053**
Battery Storage	0	0	5000	15000

Since the electrification is expected to increase to reach net zero emissions, the NET-3 Scenario requires more electricity on the demand side like in other net zero emissions scenarios. Thus, electricity demand is assumed to be 1.5 times higher than the BAU and MIT scenarios in the last scenario year. In other words, the electricity demand estimated in the NET-1 Scenario was also used in the NET-3 Scenario.

In addition, to analyze to impact of higher carbon prices converging the EU carbon prices, the model was tested by higher carbon prices for the NET-3 Scenario. Carbon prices were determined as 100 USD/ton CO_2, 150 USD/ton CO_2, and 200 USD/ton CO_2 for 2025, 2035, and 2053, respectively.

3.4. Closing Remarks

This section covers data gathering, model development and sensitivity analysis, and scenario development sections. Data used to establish the modeling study is given in this section. These data are generally obtained from energy-related public institutions in Türkiye and international organizations. These data are historical data and projected data for the future. A broad spectrum of technological, environmental and economic data has been used. Different scenario assumptions have been preferred in scenario development according to the ambitious level of the scenarios and mitigation technology options.

While there is no emission constraint in the BAU Scenario, there is a 40% reduction from the BAU level by 2053 in the MIT Scenario. On the other hand, the emission constraints of three NET Scenarios were determined in line with the net zero emission target. Solar and wind energy maximum capacity additions are generally increasing with the ambitious level of the scenarios. However, with the help of battery storage integration of the NET-3 Scenario, solar and wind energy maximum capacity additions are more than the other two NET Scenarios. While thermal power plants with CCS are included in the NET-1 Scenario assumptions, nuclear power plants are dominant as a mitigation tool in the NET-2 Scenario. The NET-3 Scenario is a net zero emissions scenario where nuclear capacity is limited and solar and wind investments dominate with the help of battery storage technologies. Carbon pricing has also been used only in net zero emissions scenarios. Also, higher electricity demand is assumed in net zero emissions scenarios, given that electrification will increase to reach net zero emissions and electrolyser capacity for hydrogen production is taken into account.

4. RESULTS AND DISCUSSION

In this section, the study's results according to five different scenarios are given in three dimensions: technology choices, economic analysis, and environmental analysis. In technology choices, projection results are revealed according to installed power capacity and electricity generation by sources. The cost of electricity generation and the investment cost of the scenarios are given in the economic analysis. The environmental analysis involves emission pathways between 2020 and 2053 according to scenarios and power generation GHG intensities. In addition to the results, this section covers policy analysis. The study results have been discussed from a policy perspective, and suggestions for energy policies have been expressed.

4.1. Study Results

This section discusses the modelling results under three headings: technology choices, economic analysis and environmental analysis for the BAU, MIT, NET-1, NET-2 and NET-3 Scenarios. In the technology choices section, the installed capacities and electricity generation estimates; in the economic analysis section, the cost of electricity generation and investment cost estimates; and in the environmental analysis section, the GHG emission pathways are presented and compared based on the developed scenarios. The results other than the modeling results in this section are given in APPENDIX 3.

4.1.1. Technology Choices

The model results show that the total installed capacity, 96 GW in 2020, reaches 204 GW, 223 GW, 342 GW, 353 GW and 491 GW for the BAU, MIT, NET-1, NET-2 and NET-3 scenarios, respectively, in 2053. The increase in electricity demand, especially with the increase in electrification, caused the installed capacity to be higher in 2053 for net zero emissions scenarios than other scenarios. Installed capacity by fuel and technology sources between 2020 and 2053 for each scenario are given in Figure 4.1, Figure 4.2, Figure 4.3, Figure 4.4 and Figure 4.5.

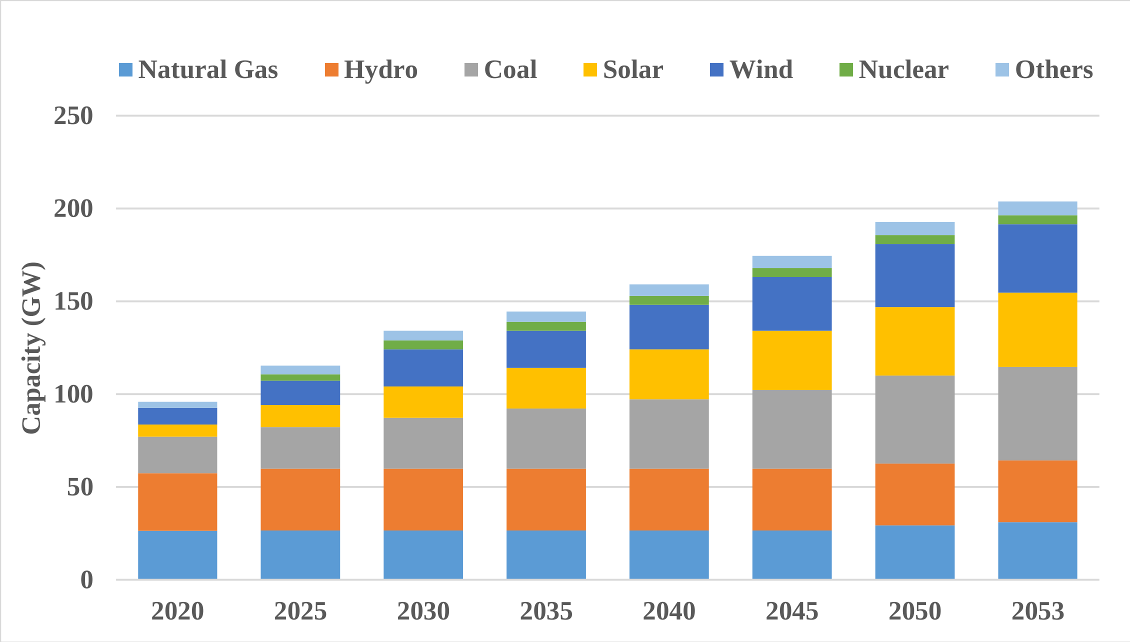


Figure 4.1. Installed capacity by fuel and technology sources – the BAU Scenario (2020-2053, GW)

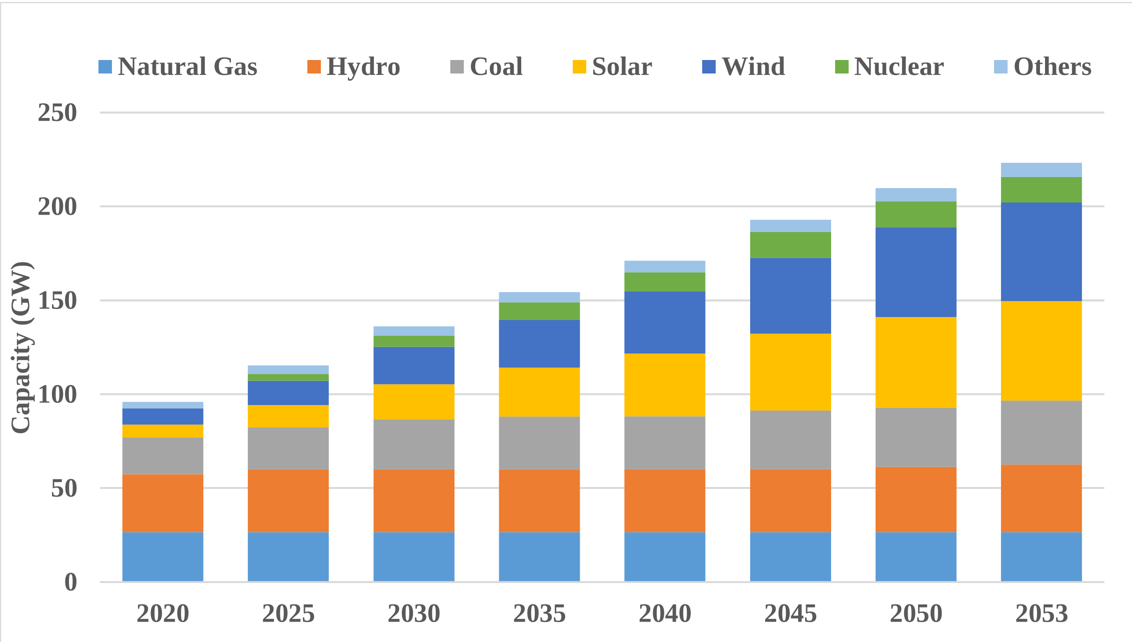


Figure 4.2. Installed capacity by fuel and technology sources – the MIT Scenario (2020-2053, GW)

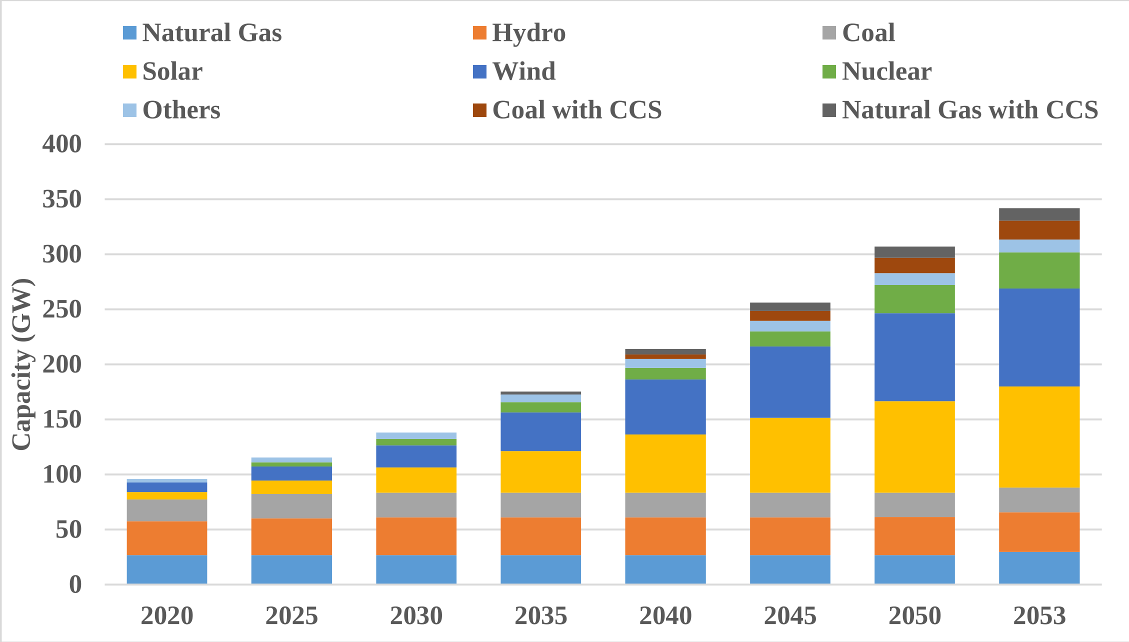


Figure 4.3. Installed capacity by fuel and technology sources – the NET-1 Scenario (2020-2053, GW)

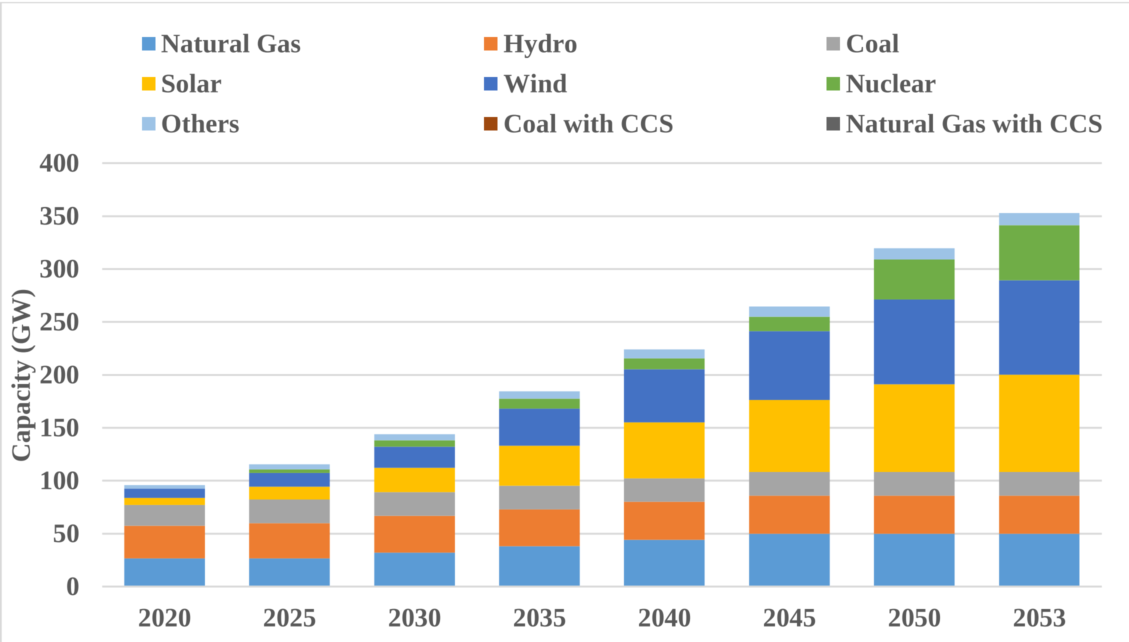


Figure 4.4. Installed capacity by fuel and technology sources – the NET-2 Scenario (2020-2053, GW)

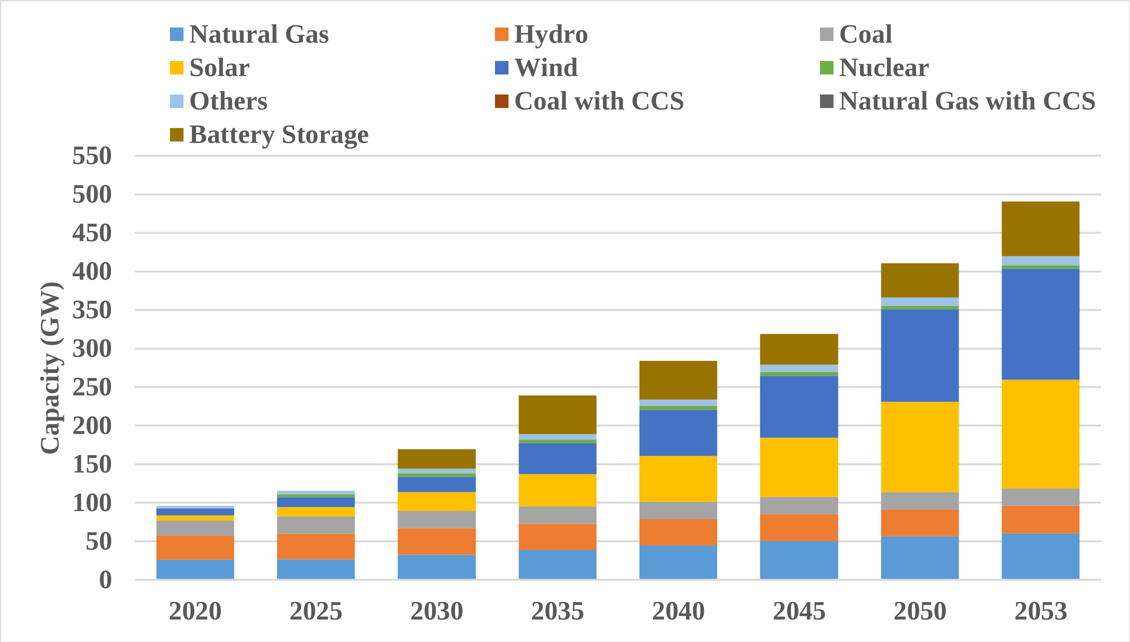


Figure 4.5. Installed capacity by fuel and technology sources – the NET-3 Scenario (2020-2053, GW)

Percent ratios of low-carbon electricity generation technologies included in the analyses change with the scenario assumptions. With the increase in net zero target ambition, the trend towards GHG emission-neutral technologies such as CCS, battery storage, renewable, and nuclear increases with optimization. In the MIT scenario, the emission constraint was provided by increasing the investments in renewable energy and nuclear energy power plants with respect to the BAU Scenario. In the NET-1 Scenario, the increased demand is supplied by fossil fuel power plants with CCS and renewable and nuclear energy-fueled plants. In the NET-2 Scenario, the increased demand is met by renewable and nuclear energy-fueled plants. Since fossil power plants with CCS have not been included in scenario assumptions of the NET-2 Scenario, demand is met by more nuclear power plants than in the NET-1 Scenario. Similar to our model results, RES and nuclear-based power plant installed capacities were expected to increase in Türkiye's National Energy Plan. However, due to high costs, the electricity generation mix did not include power plants with CCS [8]. In the NET-3 Scenario, demand is dominated by RES-based power plants, thanks to the battery storage installations. On the other hand, nuclear-based power plants do not have a notable role.

While the percentage of fossil-fueled power plant installed capacity in 2053 is 40% for the BAU Scenario, it is only 15% for the NET-1 Scenario. The same ratio has a low amount in the NET-2 Scenario at 21%, but a little higher than the NET-1 Scenario because the natural gas plants compensate for the absence of the fossil power plants with CCS. Similarly, the percentage of fossil-fueled power plant installed capacity in 2053 is 20% for the NET-3 Scenario. Still, in this case, fossil power plants with CCS were replaced with much more RES-based power plants than the NET-2 Scenario. A similar trend related to decreasing in fossil-fueled power plants was seen in the Sustainable Power Generation System Scenario conducted by Rivera-González et al., where the existing oil-fired power plants were replaced with RES-based and NGCC power plants [59].

In the NET-1 Scenario, 67% of installed capacity belongs to renewable power plants, while 8% belongs to fossil power plants with CCS. The total installed capacity of nuclear power plants reaches about 33 GW for the NET-1 Scenario. In the NET-2 Scenario, the total installed capacity of nuclear power plants was estimated as 52 GW for 2053. However, such a large amount of nuclear power plant installed capacity may cause difficulty in choosing suitable plant sites. In the NET-3, Scenario 79% of the total installed capacity belongs to RES-based power plants, and only 1% of the total amount belongs to nuclear power plants in 2053. The increase in RES-based power plants was made possible by battery storage systems. Percent ratios of installed capacity categories by scenarios in 2053 are given in Figure 4.6.

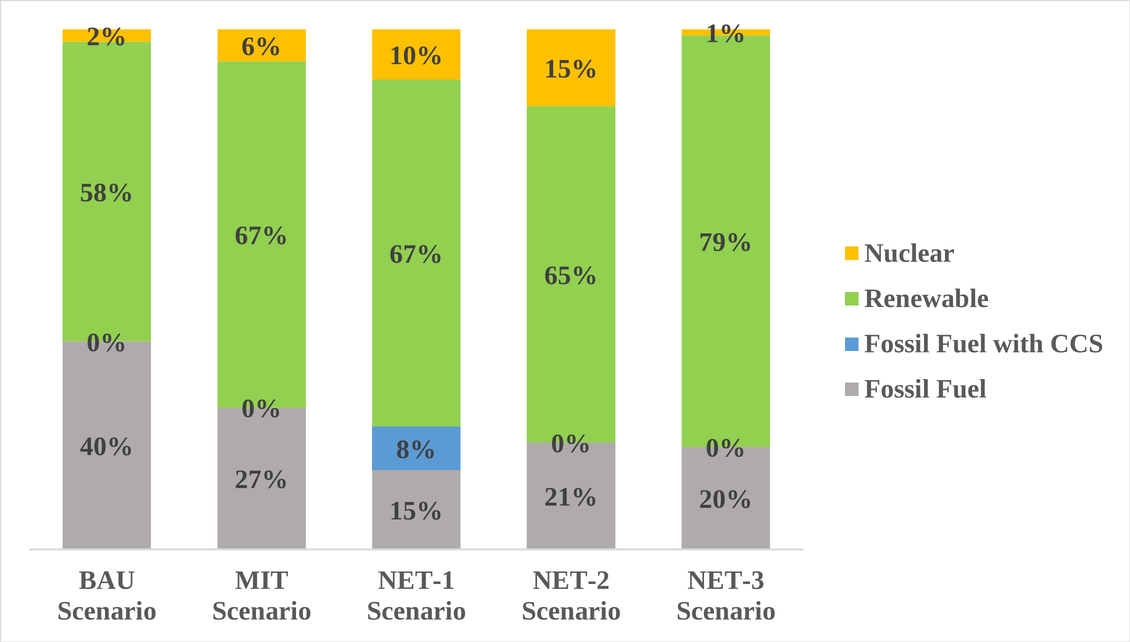


Figure 4.6. Percent ratios of installed capacity categories by scenarios in 2053

According to the modelling results, the total electricity generation, which was 307 TWh in 2020, reaches 765 TWh for the BAU and MIT scenarios in 2053. Because of the high electricity demand assumption in NET-1, NET-2, and NET-3 scenarios makes the total electricity demand reach 1088 TWh. Achieving net zero emissions requires a significant increase in electrification and electricity-derived fuels such as hydrogen [95]. World Bank Group's Country Climate and Development Report for Türkiye also includes increasing electrification in the Resilient and Net Zero Pathway (RNZP) scenario [62]. Electricity generation by fuel sources and technologies between 2020 and 2053 for each scenario are given in Figure 4.7, Figure 4.8, Figure 4.9, Figure 4.10 and Figure 4.11.

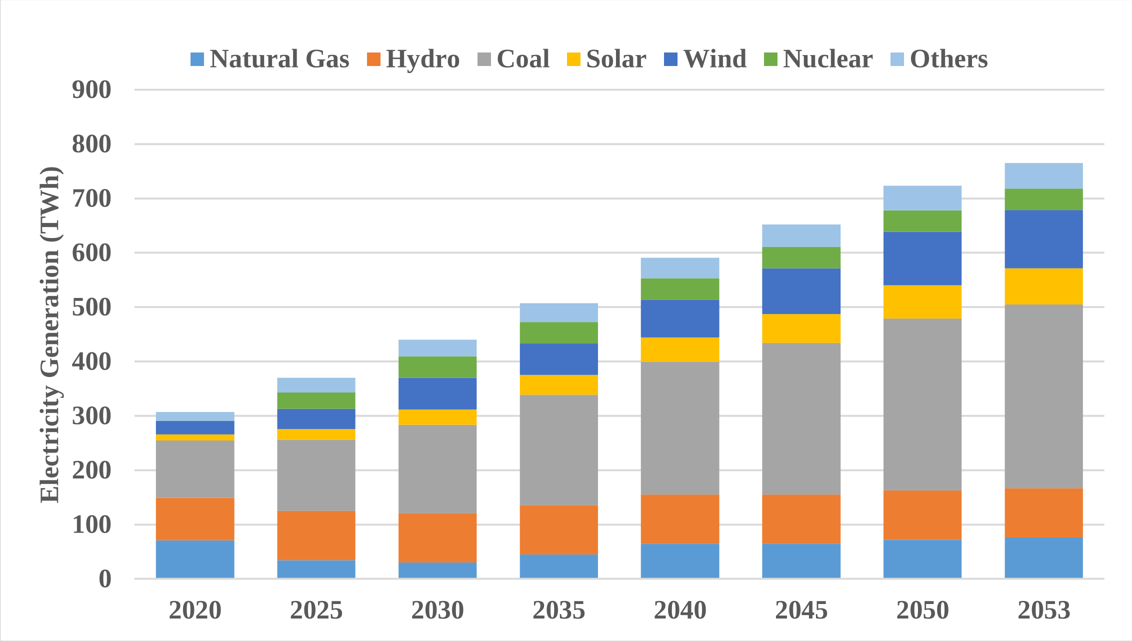


Figure 4.7. Electricity generation by fuel sources and technologies – the BAU Scenario (2020-2053, TWh)

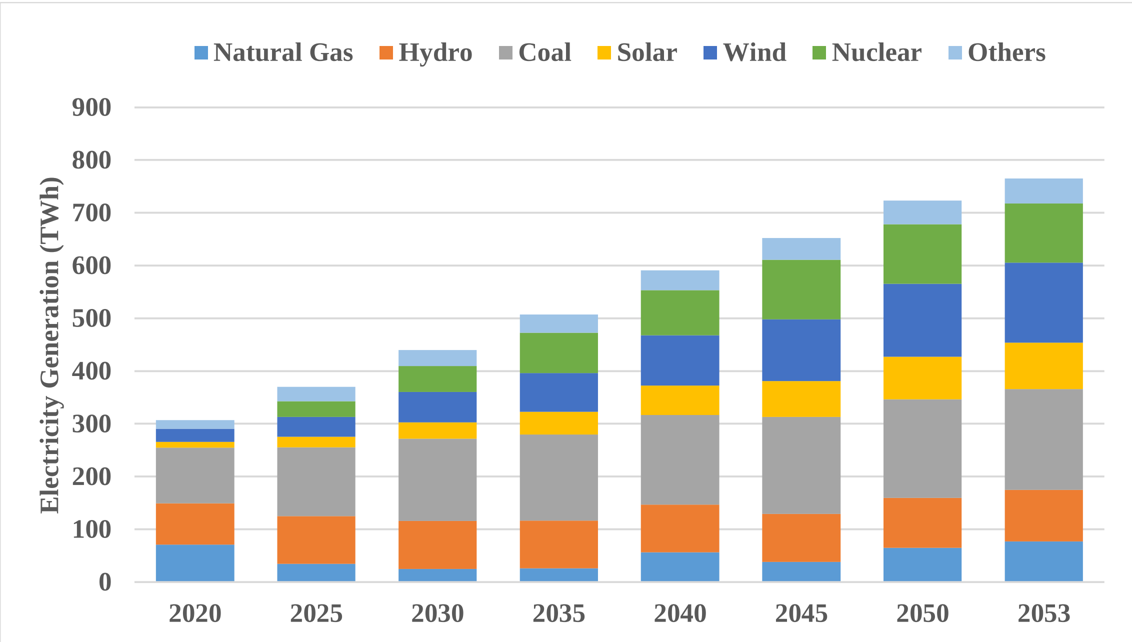


Figure 4.8. Electricity generation by fuel sources and technologies – the MIT Scenario (2020-2053, TWh)

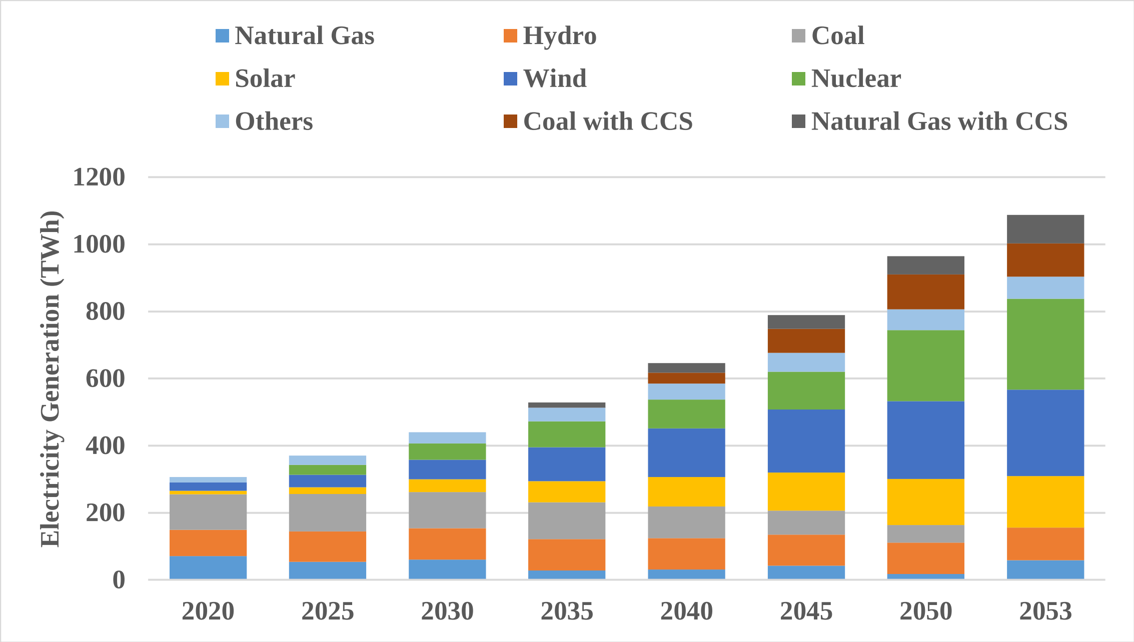


Figure 4.9. Electricity generation by fuel sources and technologies – the NET-1 Scenario (2020-2053, TWh)

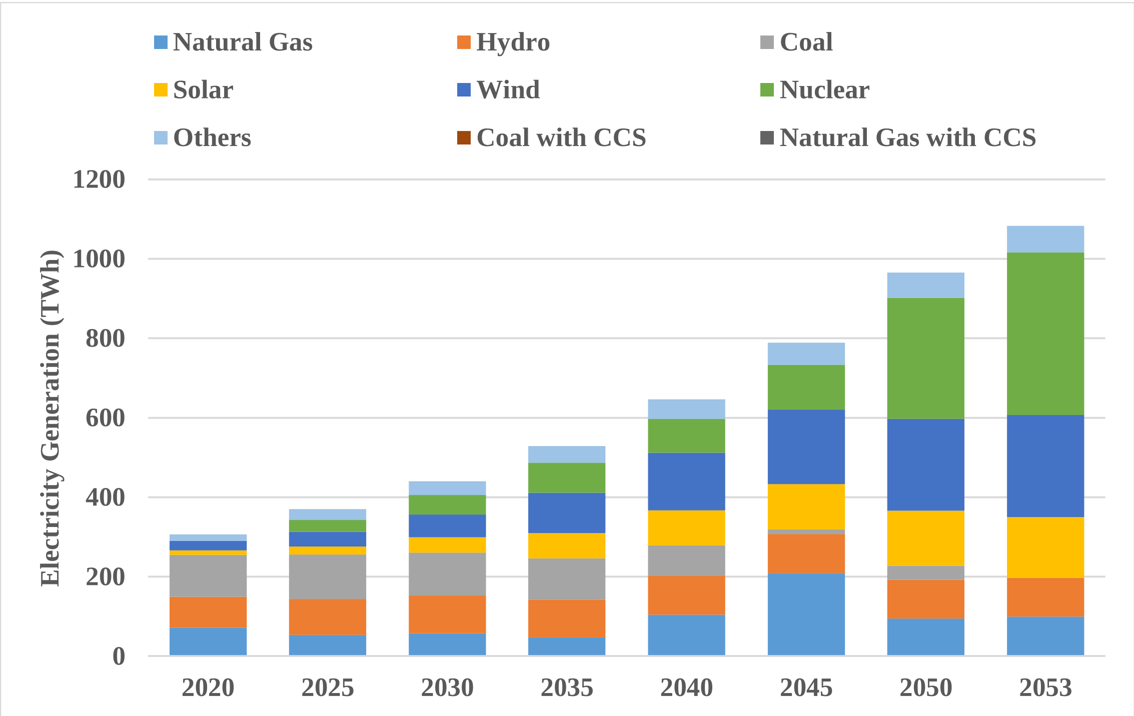


Figure 4.10. Electricity generation by fuel sources and technologies – the NET-2 Scenario (2020-2053, TWh)

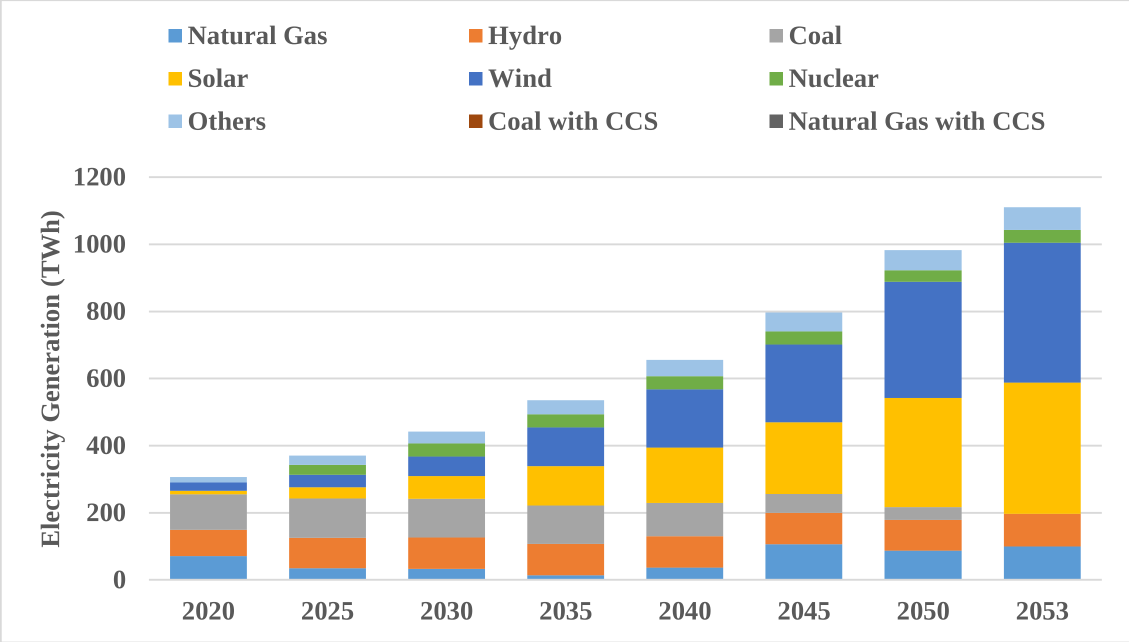


Figure 4.11. Electricity generation by fuel sources and technologies – the NET-3 Scenario (2020-2053, TWh)

Percent ratios of low carbon electricity generation increase at ambition levels similar to the trends seen for the installed capacity estimates. In the MIT Scenario, the emission constraint was provided by increasing the electricity generation of the renewable and nuclear energy power plants with respect to the BAU Scenario. In the NET-1 scenario, this situation is provided by the fossil fuel power plants with CCS and renewable and nuclear energy-fueled power plants, as seen in the installed capacity estimates. In the NET-2 Scenario, the emission constraint was provided by renewable and nuclear energy-fueled plants. Since fossil power plants with CCS have not been included in scenario assumptions of the NET-2 Scenario, the emission constraint and the demand was provided by more nuclear power plants than in the NET-1 Scenario. In the NET-3 Scenario, this situation was met dominantly by RES-based power plants and a small amount of nuclear power plants. While the percentage of fossil fuels in power generation is 54% for the BAU Scenario, it decreased dramatically to 5%, 9% and 9% for the NET-1 Scenario, the NET-2 Scenario, and the NET-3 Scenario, respectively, in 2053. However, this does not mean phasing out fossil-fueled power stations.

When the NET-3 Scenario is tested using the EU Carbon prices, coal power plants almost do not contribute to the electricity generation mix starting from 2030 because of the drastically increasing cost of generation. Electricity generation from coal power stations is replaced mainly by natural gas power plants.

Similarly, the electricity production of coal power plants continues to decrease until 2053 without the phasing-out of these power stations in the Türkiye's National Energy Plan [8]. The main advantage is that they will contribute to system flexibility as the reserve capacity. On the other hand, the phasing-out of coal power plants in the World Bank Group's study [62] and the replacement of existing oil-fired power plants exist in the study of Rivera-González et al. [59]. In the NET-1 Scenario, 53% of power generation belongs to renewable power plants, while 25% belongs to nuclear power plants, and 17% to fossil power plants with CCS. In the NET-2 Scenario, 53% of power generation is renewable, while 38% is nuclear. In the NET-3 Scenario, 88% of the power generation belongs to RES-based power plants. Battery storage installations have an important role in reaching this percentage. Similarly, the low-carbon scenario of the study of Zhao et al. also utilizes alternative energy sources, such as nuclear energy and wind [60]. Percent ratios of generation categories by scenarios in 2053 are given in Figure 4.12.

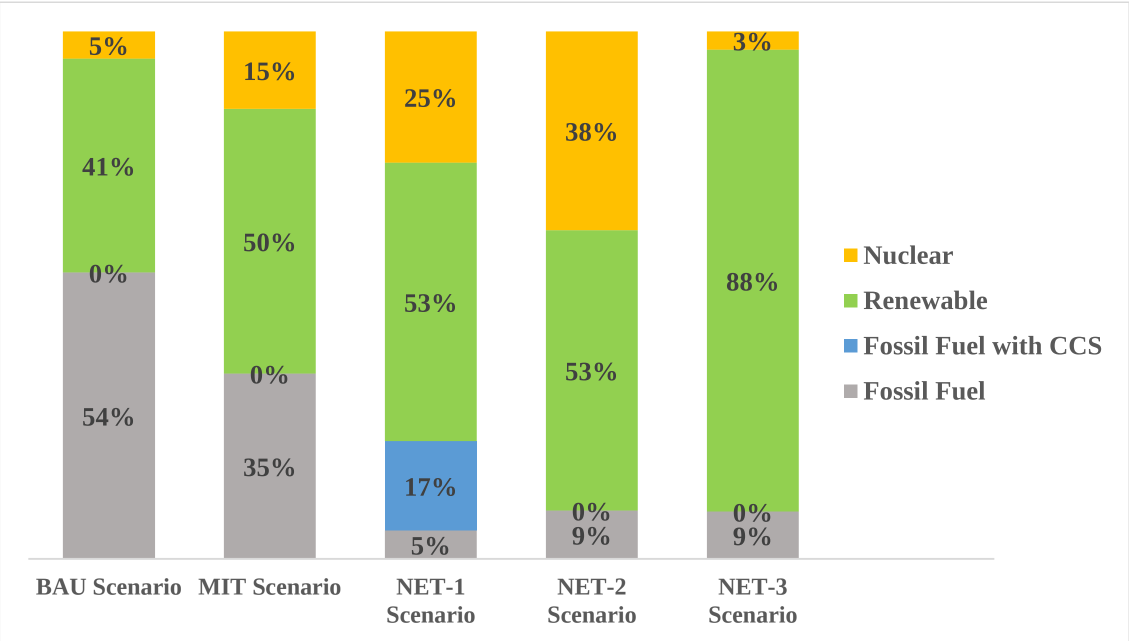


Figure 4.12. Percent ratios of generation categories by scenarios in 2053

4.1.2. Economic Analysis

The cost of power generation differs based on the technologies and fuel types. The generation costs for net zero emission scenarios are higher than in the other two scenarios. While the reason for this situation for the NET-1 Scenario is mainly due to using costly power plants with CCS and high electricity generation to meet high electricity demand, for the NET-2 Scenario is mainly due to more nuclear power plant and RES installed capacity. In the NET-3 Scenario, the production cost increment mainly comes from new RES-based power plant installations to meet increasing demand when providing emission constraints. The high costs of power plants with CCS are also addressed in Türkiye's National Energy Plan [8]. The optimization analyses did not use power plants with CCS in the power mix by 2053 because of the high costs. Still, CCS can find its place in net zero plans where fossil fuels continue to be used, despite the cost disadvantage and technical barriers compared to RES [96]. The generation costs of the MIT and BAU Scenarios follow the net zero emissions scenarios. The total generation costs of BAU, MIT, NET-1, NET-2, and NET-3 scenarios were estimated as 31 billion USD, 34 billion USD, 65 billion USD, 62 billion USD and 51 billion USD, respectively, in 2053. The costs of generation based on cost categories between 2020 and 2053 are presented in Figure 4.13, Figure 4.14, Figure 4.15, Figure 4.16 and Figure 4.17 for the scenarios.

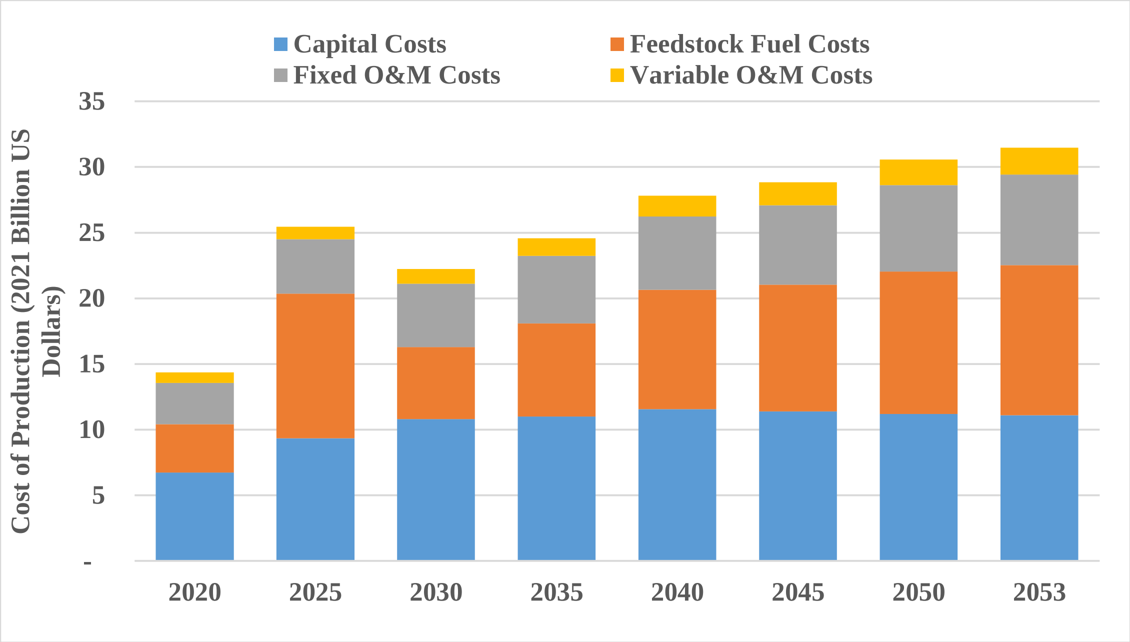


Figure 4.13. Cost of generation by cost categories – the BAU Scenario (2020-2053, 2021 Billion USD)

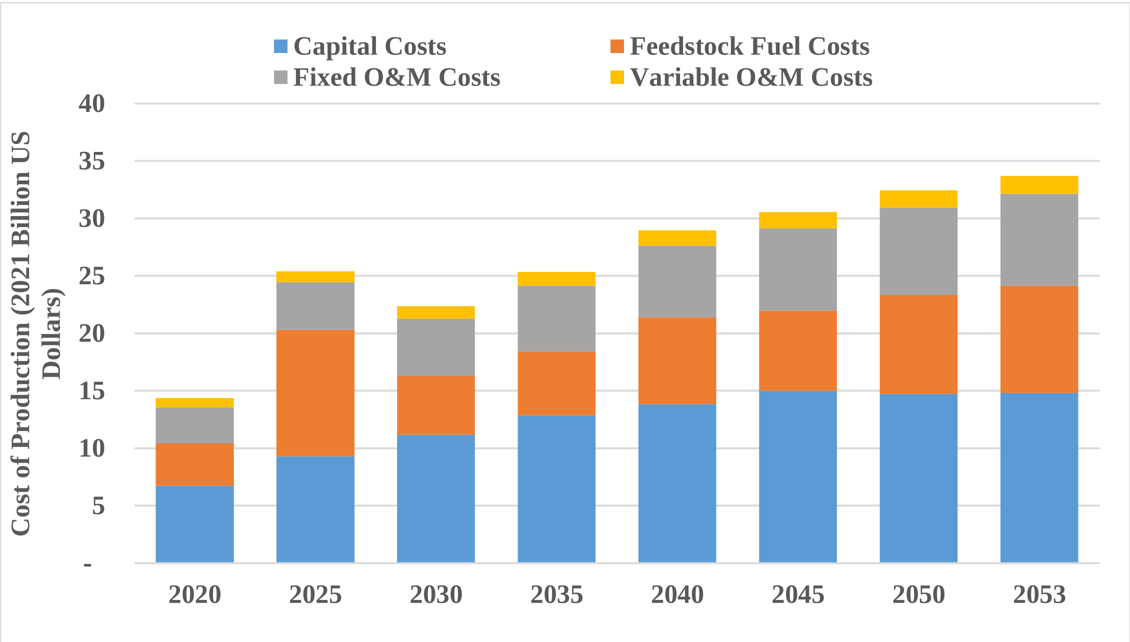


Figure 4.14. Cost of generation by cost categories – the MIT Scenario (2020-2053, 2021 Billion USD)

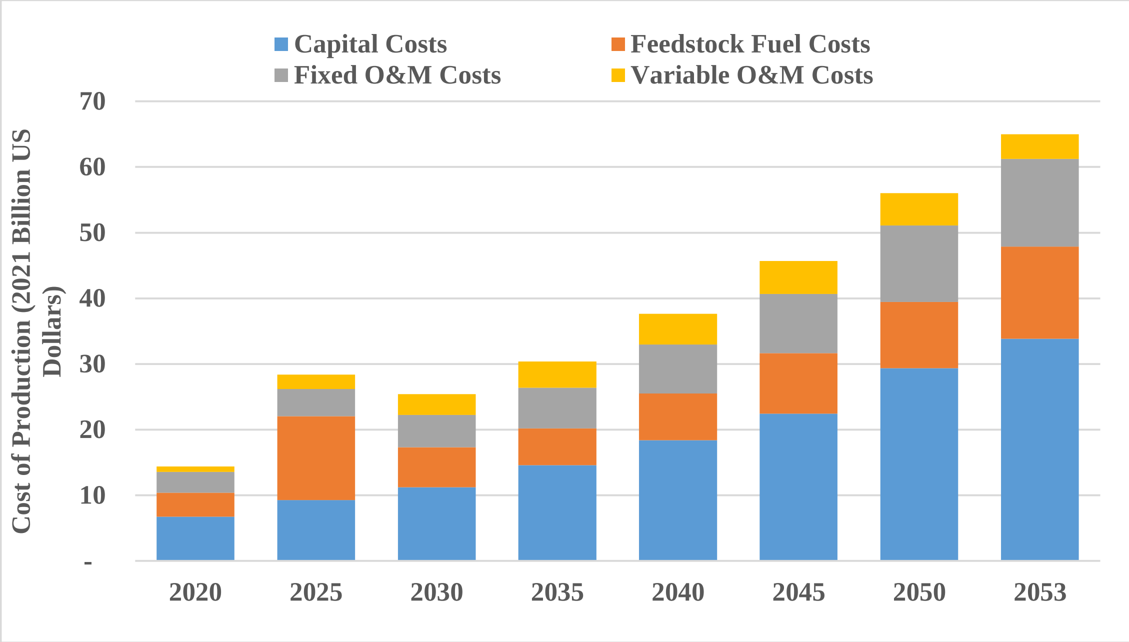


Figure 4.15. Cost of generation by cost categories – the NET-1 Scenario (2020-2053, 2021 Billion USD)

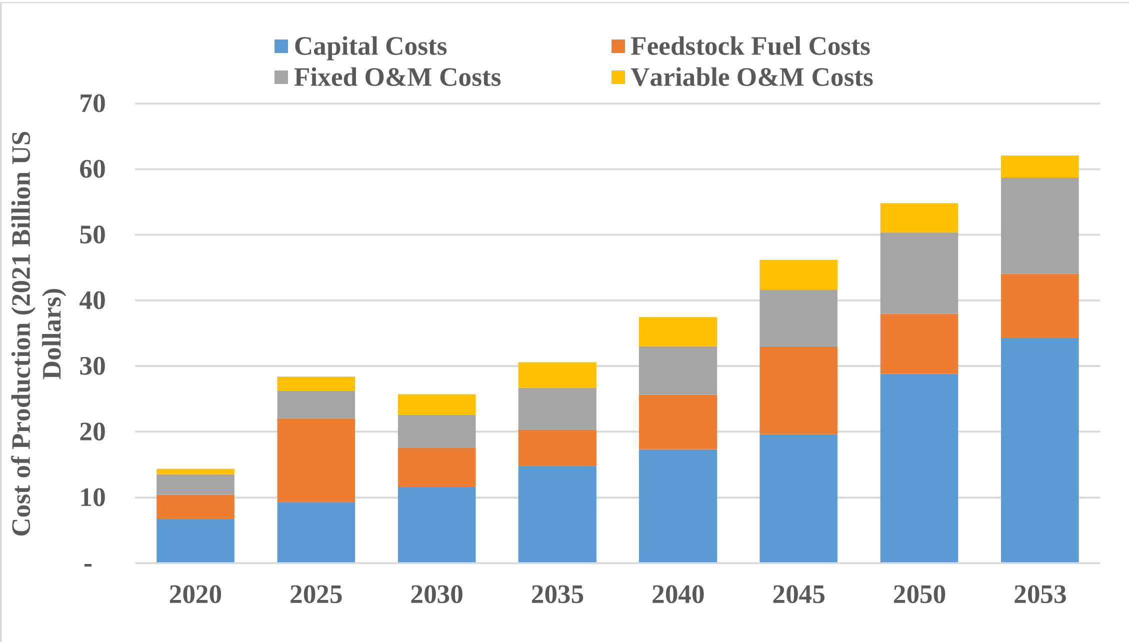


Figure 4.16. Cost of generation by cost categories – the NET-2 Scenario (2020-2053, 2021 Billion USD)

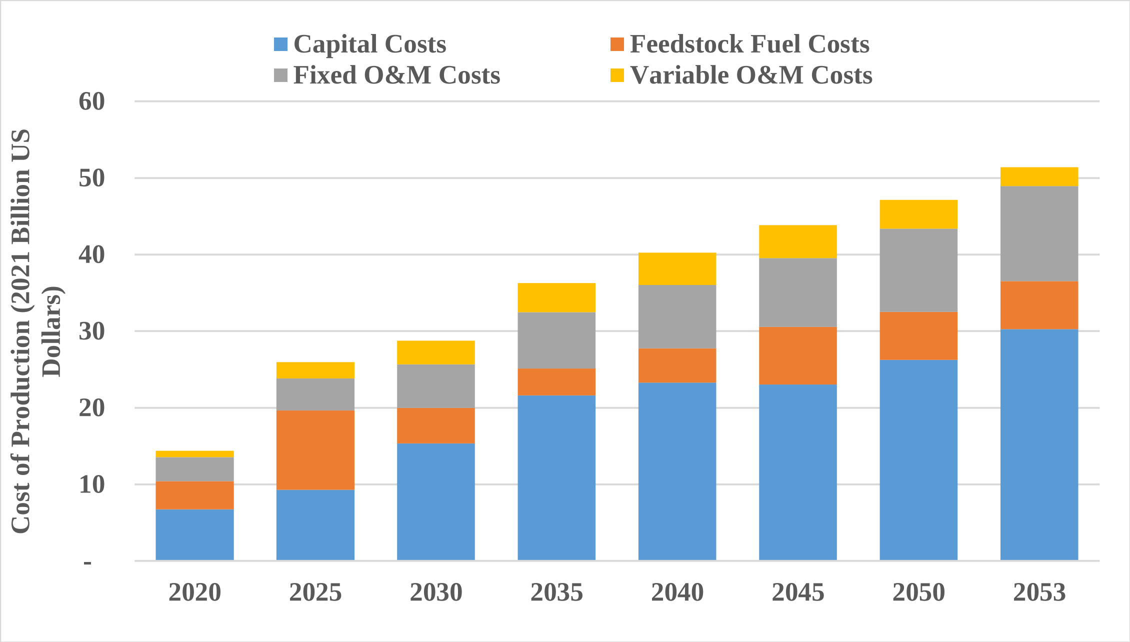


Figure 4.17. Cost of generation by cost categories – the NET-3 Scenario (2020-2053, 2021 Billion USD)

The unit cost of generation provides the generation costs independent of the size of the generation quantity. As expected, the NET-1 Scenario resulted in the highest unit generation cost of 59.8 USD/MWh in 2053, followed by the NET-2 Scenario with 57.4 USD/MWh, the NET-3 Scenario with 46.3 USD/MWh, the MIT Scenario with 44.0 USD/MWh and the BAU Scenario with 41.1 USD/MWh. When the EU carbon prices are entered into the NET-3 Scenario, the unit cost of generation increases from 46.3 USD/MWh to 51.2 USD/MWh in 2053. This means that higher carbon prices are increasing the cost of generation significantly. Despite this, the value is lower than other net zero emission scenarios.

On the other hand, significant shifts have occurred between cost categories in 2053. Transitioning to low-carbon generation technologies has increased capital costs for the MIT, NET-1, NET-2 and NET-3 scenarios. The NET-3 Scenario has the lowest fuel cost among other scenarios. The main reason is that the NET-3 Scenario has the highest electricity generation from renewable energy among all scenarios. Likewise, the investment demands increase in the Country Climate and Development Report for Türkiye's [62] RNZP scenario. At the same time, operational and fuel costs decrease compared to the baseline scenario because of the high amount of renewable energy investments. While fixed O&M costs were close to each other in the scenarios, variable O&M costs are higher for the NET-1 Scenario and the NET-2 Scenario than others due to the consideration of carbon pricing and having more nuclear power investments than other scenarios or having CCS (the NET-1 Scenario) investments.

Unit carbon cost for the NET-1 Scenario is estimated as 1.0 USD/MWh. When this unit carbon cost is subtracted from the variable O&M cost for the NET Scenario (3.5 USD/MWh), the variable O&M cost for the NET Scenario becomes almost equal to the variable O&M cost for the BAU Scenario. While RES investments reduce the variable O&M costs in the NET Scenario, CCS investments have the opposite effect. This is how the equalization of variable O&M costs of the BAU and the NET-1 scenarios can be explained. On the other hand, variable O&M costs without carbon costs are just 1.4 USD/MWh and 0.6 USD/MWh for the NET-2 Scenario and the NET-3 Scenario, respectively. Because these scenarios do not include fossil power plants with CCS, especially in the NET-3 Scenario, RES is used dominantly with the help of energy storage systems. While the unit carbon cost for the NET-3 Scenario is estimated as 1.6 USD/MWh, this value reaches 6.5 USD/MWh if EU carbon prices are used. By ensuring that carbon revenues are returned to green investments, such as RES and CCS, these investments will be supported on a market-based. Carbon revenues refer to the revenues collected within the scope of carbon allowances auctions in the emissions trading system. Certain facilities that emit GHG emissions are obliged to purchase carbon allowances from the auction mechanism in parallel to their GHG emissions. Introducing nuclear power and CCS investments explains the increase in fixed O&M costs at certain rates parallel with the scenarios' ambition levels. The unit cost of generation by cost categories and scenarios in 2053 are given in Table 4.1 and are presented between 2020 and 2053 in Figure 4.18.

Table 4.1. Unit cost of generation by cost categories and scenarios in 2053, USD/MWh

Cost Categories	**BAU Scenario**	**MIT Scenario**	**NET-1 Scenario**	**NET-2 Scenario**	**NET-3 Scenario**
Capital Costs	14.5	19.4	31.1	31.7	27.9
Feedstock Fuel Costs	14.9	12.2	12.9	9.0	4.9
Fixed O&M Costs	9.0	10.4	12.3	13.5	11.3
Variable O&M Costs	2.7	2.0	3.5	3.1	2.2
Carbon Costs	-	-	1.0	1.7	1.6
Variable O&M Costs w/o Carbon Costs	2.7	2.0	2.5	1.4	0.6
Total	**41.1**	**44.0**	**59.8**	**57.4**	**46.3**

As seen from Figure 4.18, while the unit cost of generation pathways of the BAU and MIT scenarios are quite close, the costs are noticeably higher for the NET-1 and NET-2 scenarios. The NET-3 Scenario has a moderate level among these scenarios. Conversely, in the study of Rivera-González et al., the Sustainable Power Generation System Scenario's generation cost is 9.78% lower than the BAU scenario [59]. This is because of replacing existing oil-fired power plants with RES-based and NGCC power plants. According to the modelling results of the study of Selçuklu et al., within the lowest emission options, natural gas, hydro and wind come to the fore as the most cost-effective options, while nuclear power is increasing generation costs [61]. A similar situation is observed in this study as well. For instance, while the unit cost of generation of wind power plants in 2053 is 38 USD/MWh, it is 91 USD/MWh for nuclear power plants. The fuel costs increased dramatically after 2020 because of the global energy crisis after Covid-19 Pandemic and Russian-Ukrainian War. The reflection of this situation also can be seen in Figure 4.18.

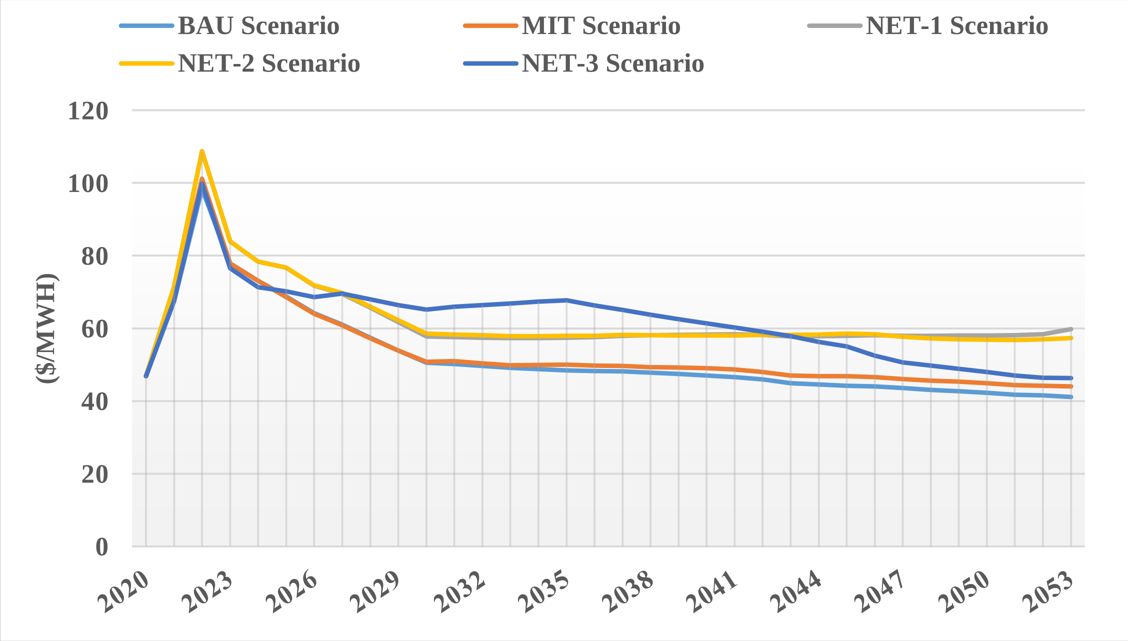


Figure 4.18. Unit cost of generation by scenarios between 2020 and 2053 (USD/MWh)

According to modelling results, the cumulative investment cost between 2021 and 2053 is 147 billion USD for the BAU Scenario. The cumulative investment cost of the MIT Scenario is 61 billion USD higher than the BAU Scenario, the difference between the cumulative costs of the NET-1 Scenario and the BAU Scenario is 385 Billion USD, the difference between the cumulative costs of the NET-2 Scenario and the BAU Scenario is 391 Billion USD, and the difference between the cumulative costs of the NET-3 Scenario and the BAU Scenario is 340 Billion USD. The increase is mainly due to the renewable and nuclear power plant investments for the MIT Scenario. Consequently, the investments of the power plants with CCS are responsible for the increment in the NET-1 Scenario. The model results showed a carbon revenue of 73 billion USD is expected between 2025 and 2053 for the NET-1 Scenario. Carbon revenue for the NET-2 and the NET-3 scenarios was estimated as 79 billion USD for the same period. This value achieves 242 billion USD, when EU carbon prices are taken into account for the NET-3 Scenario. With the return of this amount to support green investments such as RES and CCS, 19% of the additional costs of the NET-1 Scenario, which has an additional investment cost of 385 billion USD over the BAU scenario, can be covered. Hence, there is a strong link between carbon prices and the feasibility of CCS technologies [97].

In addition, 20% of the additional costs of the NET-2 Scenario and 23% of the additional costs of the NET-3 Scenario can be covered by carbon revenues. If EU carbon prices are used in the NET-3 Scenario, 71% of the additional costs can be met by carbon revenues. However, the increasing effect of high carbon prices on the unit cost of power generation should not be ignored. The World Bank Group model results also reveal that investment needs to increase for ambitious scenarios [62]. According to the study of Zhai et al., the cost increase is inevitable in systems where power plants with CCS are used intensively [14]. As stated, power plants with CCS were not integrated into the power system by 2053 in the Türkiye's National Energy Plan [8] because of their high investment costs. The cumulative investment cost difference between the NET-2 and BAU scenarios is mainly from the nuclear and RES-based power plants. Some amount of the cumulative investment cost of fossil power plants in the NET-1 Scenario was replaced with the cumulative investment cost of additional nuclear power plants in the NET-2 Scenario. Investment costs between 2020 and 2053 in the NET-3 Scenario are lower than other net zero emission scenarios. Because in this scenario, nuclear power plants and fossil power plants with CCS, which are relatively expensive technologies, were replaced with RES-based power plants. Although these large numbers of RES-based power plants were realized with battery storage investments, investment costs remained below other net zero emissions scenarios despite the added battery investments. The cumulative and yearly average investment costs between 2020 and 2053 are given in Table 4.2. The percent share of cost categories of cumulative investment costs by scenarios between 2020 and 2053 are presented in Figure 4.19.

Table 4.2. Cumulative and yearly average investment costs (2020-2053) (2021 billion USD)

	Investment Costs				
	BAU Scenario	**MIT Scenario**	**NET-1 Scenario**	**NET-2 Scenario**	**NET-3 Scenario**
Total	147	208	532	538	487
Yearly Average	4.5	6.3	16.1	16.3	14.8

	Additional Investment Costs			
	MIT vs BAU	**NET-1 vs BAU**	**NET-2 vs BAU**	**NET-3 vs BAU**
Total	61	385	391	340
Yearly Average	1.8	11.7	11.8	10.3

As can be seen in Figure 4.19, the technologies with the highest shares in cumulative investment costs were coal and wind for the BAU Scenario, nuclear and wind for the MIT Scenario, nuclear, wind and coal with CCS for the NET-1 Scenario, nuclear for the NET-2 Scenario, and wind and battery storage for the NET-3 Scenario. The study of Selçuklu et al. also highlighted the high costs of nuclear power plant investments [61].

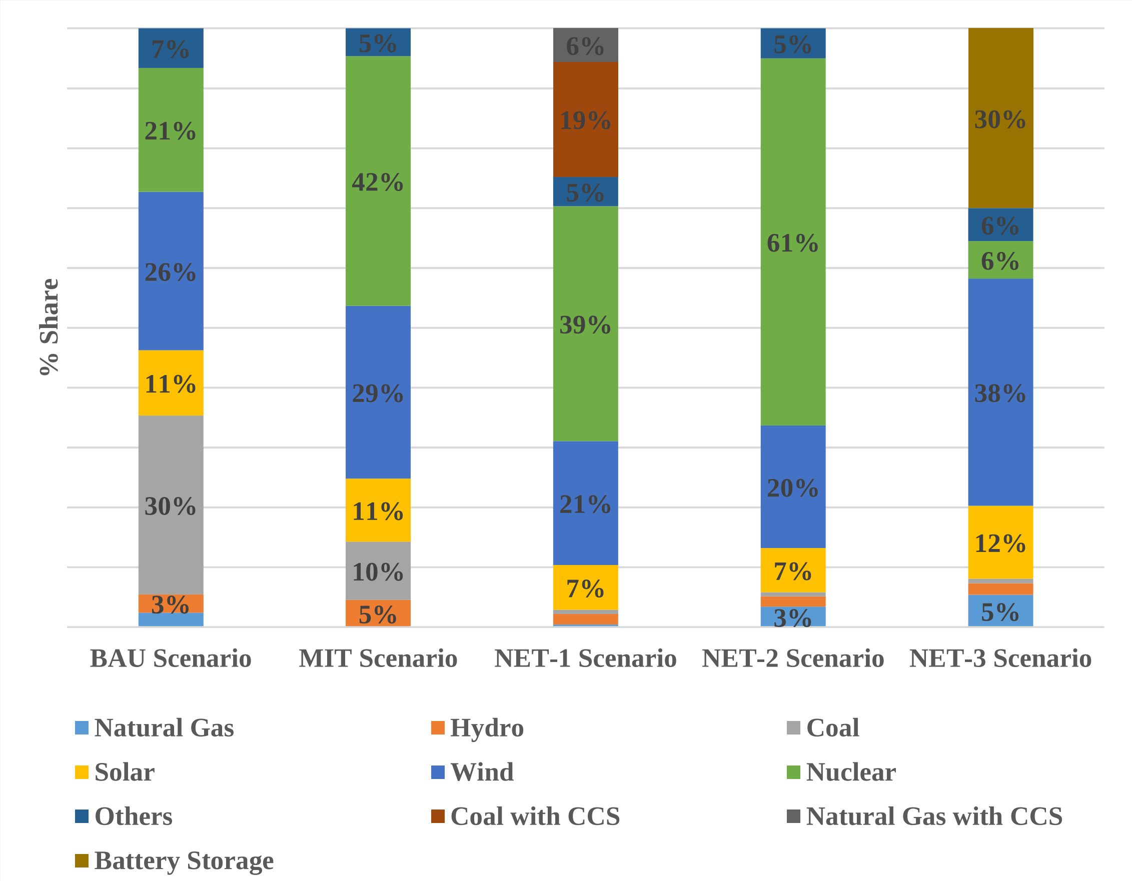


Figure 4.19. Percent share of cost categories of cumulative investment costs by scenarios (2020-2053)

4.1.3. Environmental Analysis

The modelling results show that the GHG emissions of the BAU Scenario increased more than 1.5 times in 2053 compared to 2020 and reached 334 million tons of CO_2-eq. The GHG emissions of the BAU Scenario are mainly from coal-fueled power plants. The MIT Scenario GHG emissions are expected to reach 200 million tons of CO_2-eq in 2053, which means a 53% increase with respect to 2020 emissions. Coal power plant emissions are a dominant part of the MIT Scenario GHG emissions like the BAU Scenario, and the remaining emissions are from natural gas power plants. According to modelling results, GHG emissions of the NET-1 Scenario, the NET-2 Scenario, and the NET-3 Scenario are estimated as 37 million tons of CO_2-eq, 36 million tons of CO_2-eq and 36 million tons of CO_2-eq, respectively. As stated in Section 3.3.3, LULUCF emissions will compensate for this value to reach the net zero target. Unlike the BAU and MIT scenarios, the NET-1

Scenario emissions in 2053 mostly came from natural gas and coal power plants with CCS.

On the other hand, all of the NET-2 Scenario and NET-3 Scenario emissions are from natural gas power plants. In the MIT and NET-2 scenarios, the emission constraint was achieved by increasing the investments in renewable energy and nuclear energy power plants with respect to the BAU Scenario; this was achieved by fossil fuel power plants with CCS, renewable energy and nuclear energy-fueled plants for the NET-1 scenario. On the other hand, in the NET-3 scenario, the emission constraint was achieved by substantially increasing the investments in renewable energy power plants with the help of battery storage units concerning the BAU Scenario.

In the study of Rivera-González et al., GHG emission decreases with replacing existing oil-fired power plants with RES-based and NGCC power plants in the Sustainable Power Generation System Scenario [59]. In Zhao et al. study, emission reduction is provided by increasing hydropower, nuclear energy and wind [60]. According to the modelling results of Selçuklu et al., natural gas, hydro, nuclear, and wind are the lowest emissions options [61]. While it was mentioned that renewable energy and nuclear investments would play an important role in Türkiye's net zero target in Türkiye's National Energy Plan [8], thermal power plants with CCS were not preferred due to their high costs. In this study, in addition to renewable energy and nuclear investments in the NET-1 Scenario, thermal power plants with CCS play an essential role in providing net zero emissions.

On the other hand, net zero emissions have been achieved without fossil power plants with CCS in the NET-2 Scenario. However, the available land required for such a large number of nuclear power plant investments remains a significant question mark. In the NET-3 scenario, RES-based power plants have a critical role in achieving the net zero emissions target. With the help of battery storage units, more renewable investments have taken place than other net zero emissions scenarios. The GHG emissions by fuel and technology types for each scenario between 2020 and 2053 are given in Figure 4.20, Figure 4.21, Figure 4.22, Figure 4.23 and Figure 4.24.

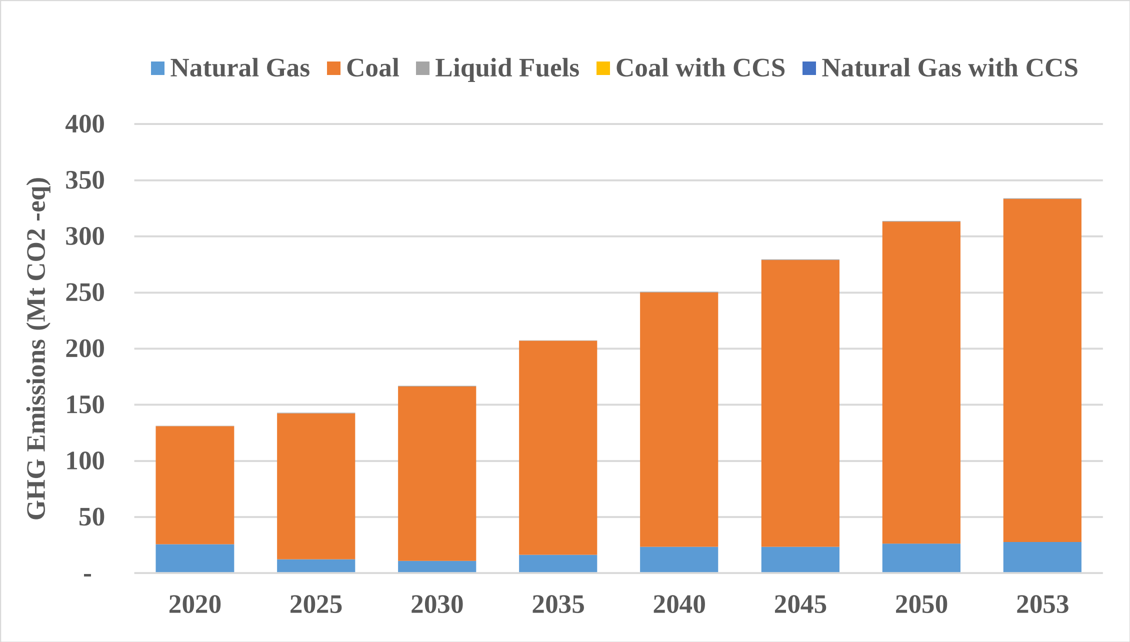


Figure 4.20. GHG emissions by fuel and technology types – the BAU Scenario (2020-2053, Mt CO_2-eq)

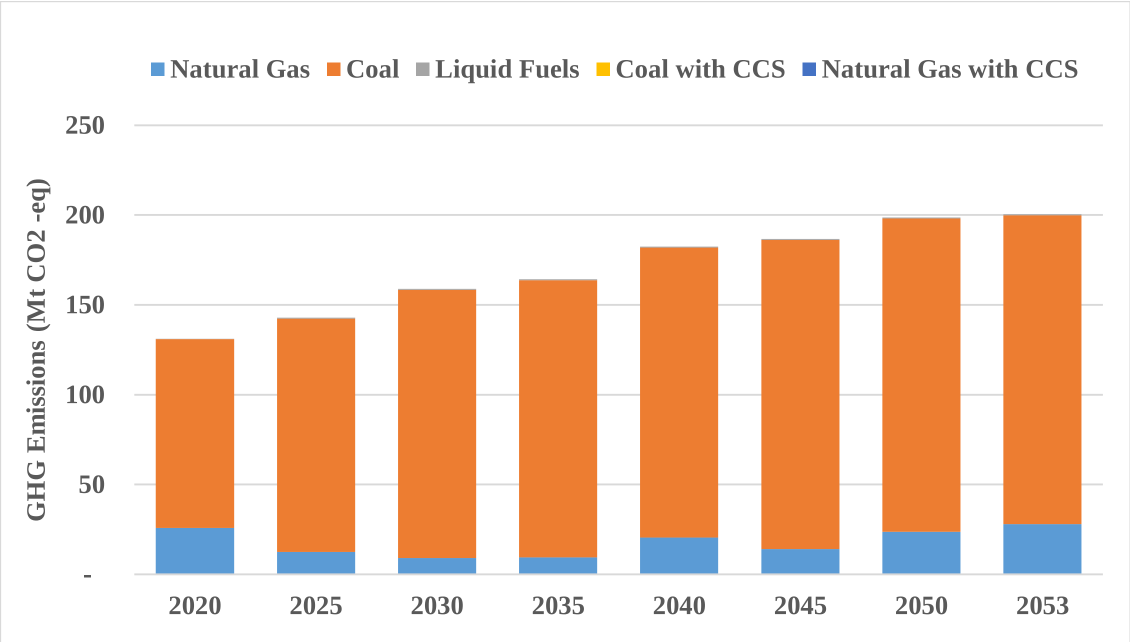


Figure 4.21. GHG emissions by fuel and technology types – the MIT Scenario (2020-2053, Mt CO_2-eq)

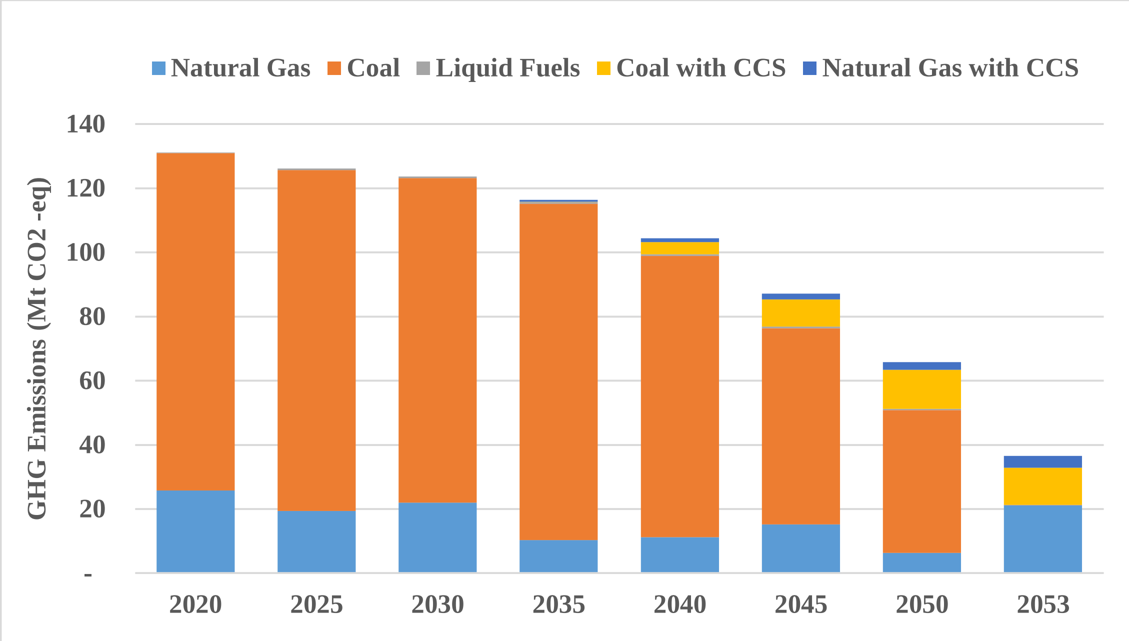


Figure 4.22. GHG emissions by fuel and technology types – the NET-1 Scenario (2020-2053, Mt CO_2-eq)

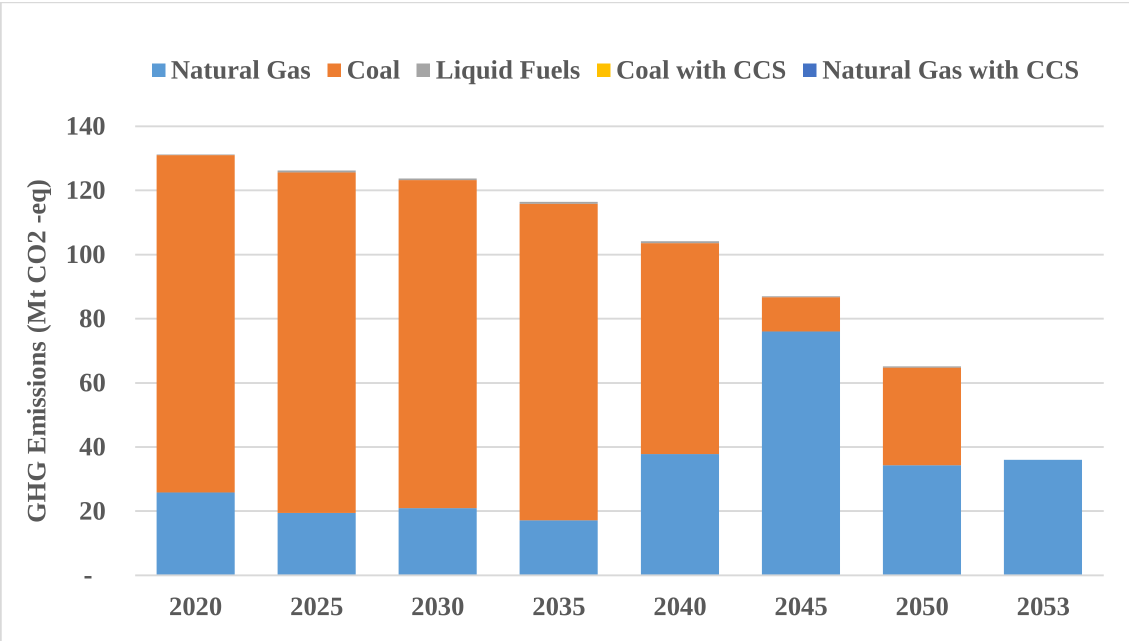


Figure 4.23. GHG emissions by fuel and technology types – the NET-2 Scenario (2020-2053, Mt CO_2-eq)

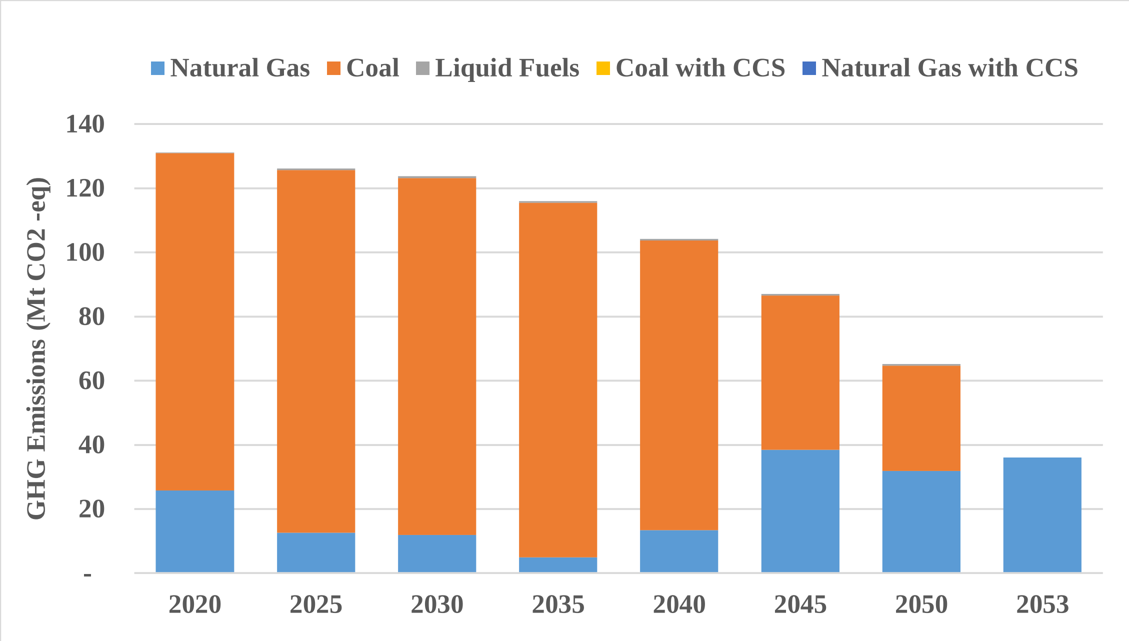


Figure 4.24. GHG emissions by fuel and technology types – the NET-3 Scenario (2020-2053, Mt CO_2-eq)

The GHG emissions per unit of power generation decrease as the emission constraints determined for the mitigation scenarios increase. The power generation GHG intensity determined as 0.45 tons of CO_2-eq/MWh for the BAU Scenario decreases to 0.03 tons of CO_2-eq/MWh for the NET-1, the NET-2, and NET-3 Scenario in 2053, as presented in Table 4.3.

Table 4.3. Power generation GHG intensities by scenarios in 2053

Scenario Name	**BAU Scenario**	**MIT Scenario**	**NET-1 Scenario**	**NET-2 Scenario**	**NET-3 Scenario**
Power generation GHG intensities (tons of CO_2-eq/MWh)	0.44	0.26	0.03	0.03	0.03

The distributions of total GHG emissions by scenarios between 1990 and 2053 are given in Figure 4.25. The MIT Scenario GHG emissions trend deviates from the BAU scenario and follows a lower emission pathway, especially after 2027. On the other hand, the NET-1, the NET-2 and the NET-3 Scenario show a sharp and steady decline to reach net zero emissions.

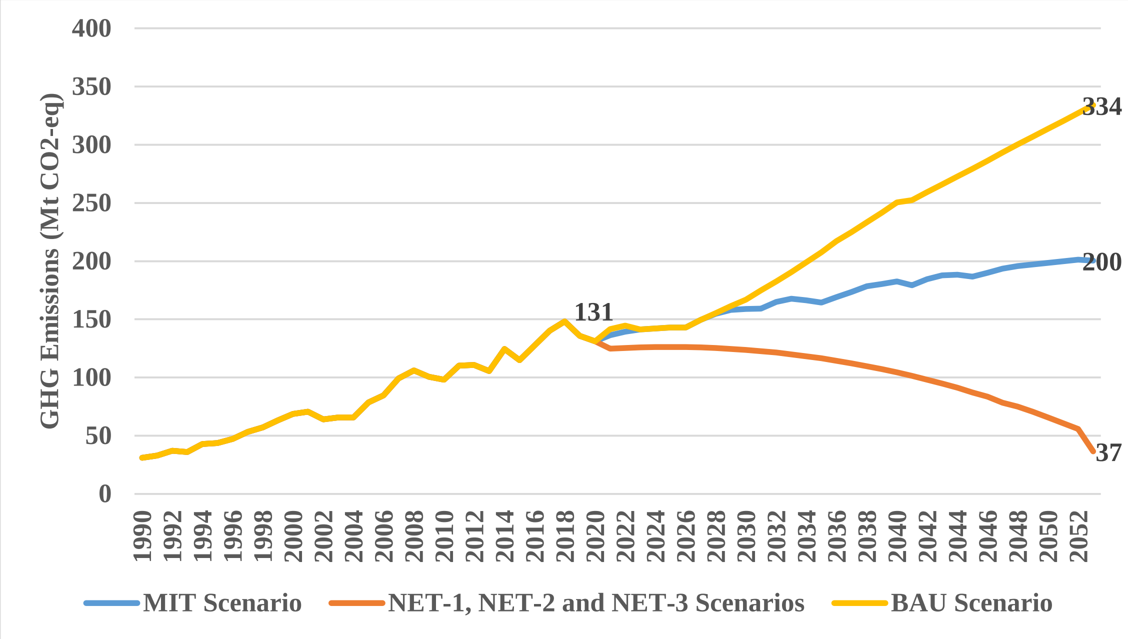


Figure 4.25. Total GHG emissions by scenarios (1990-2053, Mt CO_2-eq)

A total of 1.5 billion tons of CO_2 is estimated to be captured by carbon capture systems in fossil power plants with CCS by 2053. This amount equals 819 billion Sm^3 in volume, which exhibits vast geographic storage requirements. Okandan et al.'s study indicates that the Dodan field in Türkiye is a natural CO_2 reservoir presenting 7 billion Sm^3 suitable reservoir for geological sequestration. In addition, deep saline aquifers and salt caverns of the soda mines are other possible storage sites [98]. A United Nations Economic Commission for Europe (UNECE) study states that Türkiye has 210 million tons of CO_2 storage capacity for advanced enhanced oil recovery. This value has been reached by analyzing CO_2 storage opportunities in existing oil fields using certain assumptions and methodological principles [99], and it is equal to almost 14% of the total CO_2 captured by 2053, estimated by this study. Although Türkiye's CO_2 storage potential is low compared to the estimated amount that can be captured, more detailed storage potential investigations may change this situation.

Currently, most of the studies on storage potential are estimated without physical reservoir characterization, revealing high uncertainty on ultimate potential [100]. Koelbl et al. stated that regional CO_2 storage capacity was not a limiting factor for deploying CCS until 2050. In another study by Keppo and van der Zwaan, CCS deployment by 2100 was very limited due to capacity constraints, while the early deployment of CCS by 2050 was again mostly unaffected. In geographies where the most extensive research on regional carbon storage estimates has been conducted, the local availability of storage resources will not constrain CCS. Storage availability is highly uncertain for regions except for North America, Europe and Brazil. There will likely be a few places where local storage availability will be a limiting factor [100]. In addition, it is important to better understand how regional CO_2 storage capacity changes with use and how this capacity can change over time [103]. As a result, further studies are inevitable to determine whether Türkiye's regional carbon storage capacity will be a constraint. In fact, according to many studies, the limiting factor is injection rate rather than regional storage capacity [104–106]. In addition, plans for utilizing captured CO_2 and cooperation with neighbouring countries for storage will be other significant solution tools, even though CO_2 utilization's role in combating climate change is much smaller than CO_2 storage. This provides cost-effective options for reducing CO_2 emissions and can be profitable in some cases [103].

4.1.4. Sensitivity Analysis

In the sensitivity analysis as an input parameter, the natural gas price was used. It was aimed to analyze how the model responds to 10% natural gas price changes in certain output parameters. Output parameters consist of electricity generation of natural gas power plants, installed capacity of natural gas power plants, GHG emissions, and cost of production. This analysis was performed for the BAU Scenario in 2053. Percentage changes in output parameters according to 10% changes in input parameters are given in Table 4.4. "SA+10%" and "SA-10%" refer to sensitivity analysis results for a 10% increase and a 10% decrease in input parameters, respectively.

Table 4.4. Sensitivity analysis results

Input Parameter	**Output Parameters**	**SA+10%**	**SA-10%**
Natural Gas Price (USD/Sm^3)	Electricity Generation of Natural Gas Power Plants (TWh)	-8,0%	+5,6%
	Installed Capacity of Natural Gas Power Plants (GW)	-5,3%	+3,5%
	GHG Emissions (CO_2-eq)	-1,4%	+0,9%
	Cost of Production (Billion USD)	+0,7%	-1,0%

Electricity generation of natural gas power plants decreased by 8% in 2053 when natural gas prices increased by 10% during the modeling period. When the same parameter is decreased by 10%, an increase of 5.6% is observed in the generation. The sensitivity analysis shows that there is a trade-off between wind and natural gas power plants. The least-cost optimization model shifts the generation to wind power plants when natural gas prices rise and vice versa. A similar situation is observed in the installed power, and natural gas power plant investments may shift to wind power plants when fuel prices rise and vice versa. However, the sensitivity here is lower than in electricity generation. With the increase in natural gas prices, replacing natural gas power plants with a certain amount of wind power plants in electricity generation reduces GHG emissions. However, since natural gas is not the only emission source, its effect is limited to 1.4%.

On the other hand, when natural gas prices decrease by 10%, emissions increase by 0.9%. Due to the nature of the least-cost optimization model, the cost of production increases when natural gas prices increase. However, the effect is 0.7% as many sources are included in the production mix. When natural gas prices decrease by 10%, cost of production decreases by 1%.

4.2. Policy Analysis

As a significant global problem, climate change may permanently impact the environment if the required measures are not taken. Based on the current research, the existing climate targets are insufficient to limit the global temperature to the desired level. Therefore, governments need to be more ambitious with climate targets. Consequently, governments should develop their net zero emissions targets to limit the global temperature increase to the desired level. Perhaps the most comprehensive of these is the European Green Deal. The Carbon Border Adjustment Mechanism is planned to be implemented in line with European Green Deal. It will deeply affect the economies of many countries, including Türkiye.

Türkiye has also declared its net zero emissions target. Türkiye can contribute substantially to the fight against climate change and take a crucial role in the changing global trade system with the aid of a net zero emissions target. Despite achieving considerable advances in renewable energy-based technologies, Türkiye is a country that still heavily relies on fossil fuels in the EHP sector. If fossil fuel consumption trends continue, it will be difficult for Türkiye to meet its climate change targets. Due to this, Türkiye, like other countries with a net zero emissions target, must take significant steps, particularly in the EHP sector, to meet its goal.

This study examines which energy investments in the EHP sector should be made to achieve the 2053 net zero target. An energy modelling software, LEAP, is used to model emissions of this sector between 2021 and 2053 with five scenarios. Current plans and policies have been included in the Business as Usual Scenario. The Mitigation Scenario is developed based on a 40 percent reduction in EHP sector CO_2 emissions from the business as usual by 2053. The Net Zero Emissions-1 Scenario, the Net Zero Emissions-2 Scenario, and the Net Zero Emissions-3 Scenario are developed based on achieving net zero emissions in 2053. The primary contribution of this work is constructing a flexible energy model to incorporate various technological developments in the EHP sector to reach the net zero emission target. In a country has emerging economy like Türkiye, where energy consumption is rising considerably, this model is essential for simulating this sector for the net zero emission target.

The model results reveal a substantial increase in installed capacity, cost of generation and cumulative investment costs for the Net Zero Emissions-1 Scenario and the Net Zero Emissions-2 Scenario due to the significant increase in electrification. In other words, achieving net zero emissions by 2053 will significantly burden the Turkish economy. At this point, in the name of climate justice, access to climate finance is crucial not to harm the growth and development of Türkiye, which has an emerging economy. Although the increment in installed capacity has a similar level in Net Zero Emissions-3 Scenario with other net zero emissions scenarios, the cost of generation and cumulative investment costs are smaller than in these scenarios. The main reason for this situation is that capital costs of renewable energy and battery storage installations are lower than nuclear power plants and fossil fuel-based power plants with carbon capture and storage with the help of decreasing prices over the years. In addition, a similar situation exists for feedstock fuel costs and variable and fixed operation and maintenance costs. The difference between the Business as Usual Scenario and the Mitigation Scenario is relatively small in terms of cost of generation, emission and installed capacity. This means that lower costs in the Mitigation Scenario can significantly reduce emissions. However, it will not be sufficient for the net zero emissions target.

While the emission constraint in the Mitigation Scenario was provided by increasing investments in renewable and nuclear energy power plants, increased demand is met in net zero emissions scenarios by these plants and by adding fossil fuel power plants with carbon capture and storage, much more nuclear capacity or battery storage.

While fossil fuels share accounts for 54% of power generation in the Business as Usual Scenario, it accounts for only 5% in the Net Zero Emissions-1 Scenario and 9% in the other two net zero emissions scenarios in 2053. However, this does not imply the phasing out of fossil-fuel power plants before their economic lifetime. They will contribute to system flexibility as reserve capacity.

The switch to low-carbon generation technology has raised capital costs in the Mitigation and Net Zero Emissions scenarios. Among the alternatives, the Net Zero Emissions-3 Scenario has the cheapest fuel cost due to generating higher electricity from renewable energy sources than other scenarios. Although the scenarios' fixed operation and maintenance costs were close, the Net Zero Emissions-1 Scenario and the Net Zero Emissions-2 Scenario's variable operation and maintenance costs are greater than the Business as Usual Scenario and the Mitigation Scenario because carbon price is considered. On the other hand, the variable operation and maintenance costs level in the Net Zero Emissions-3 Scenario is smaller than other net zero emissions scenarios because of the substantial amount of renewable energy installations.

The cumulative investment costs of the Net Zero Emissions-1 Scenario and the Net Zero Emissions-2 Scenario are relatively high compared to other scenarios. This difference mainly comes from the power plants' carbon capture and storage investments for the Net

Zero Emissions-1 Scenario and the additional nuclear capacity for Net Zero Emissions-2 Scenario. Returning carbon revenues to green investments such as CCS and RES can extinguish these high costs. It is estimated that 19-23% of the additional investment costs can be covered this way. These are followed by the Net Zero Emissions-3 Scenario. This scenario has limited nuclear power plant investment and no fossil power plants with carbon capture and storage. Instead of these installations, the scenario has substantial solar and wind energy investments and battery storage installation. These technologies' capital costs are decreasing yearly because of the relatively low costs of cumulative investments in the Net Zero Emissions-3 Scenario. Compared to the Business as Usual Scenario, a somewhat limited increase in the cumulative investment costs in the Mitigation Scenario comes from renewable energy and nuclear energy investments.

The Business as Usual Scenario's greenhouse gas emissions grew more than 1.5 times in 2053 compared to 2020, totalling 343 million tons of CO_2-eq. The Business as Usual Scenario's primary source of greenhouse gas emissions is coal-fired power stations. In the Mitigation Scenario, greenhouse gas emissions will rise by 53% from 2020 to 200 million tons of CO_2-eq in 2053. Like the Business as Usual Scenario, the coal power plants have the largest share in greenhouse gas emissions in the Mitigation Scenario and are followed by natural gas power plants. The Net Zero Emissions-1 Scenario, the Net Zero Emissions-2 Scenario and the Net Zero Emissions-3 Scenario's greenhouse gas emissions are calculated to be 37 million tons of CO_2-eq, 36 million tons of CO_2-eq, and 36 million tons of CO_2-eq. With the help of carbon sinks, emissions reaching the net zero target are provided.

To contribute to the global efforts to combat the effects of climate change, it is crucial for Türkiye set a net zero emission target for 2053. While reaching this target, decarbonising the EHP sector, which corresponds to one-fourth of the total greenhouse gas emissions of 2020, is important. These efforts would also contribute to Türkiye's trade relations with the European Union by implementing the Carbon Border Adjustment Mechanism.

The results of this study, in which Türkiye's EHP sector is modelled within the scope of the net zero emission target, reveal the requirements for substantial investments in renewable energy, battery storage, nuclear energy and power plants with carbon capture and storage to achieve these targets. A massive nuclear capacity increase is required if fossil power plants with carbon capture and storage and battery storage investments for more renewable energy investments are not included in the production mix while achieving the net zero emissions target. Given these results, Türkiye needs to make significant changes in its energy policies. Policy instruments will be required to further the momentum that Türkiye has already achieved in the field of renewable energy. On-site production should be encouraged more, and regulations should be put forward to strengthen the grid infrastructure to establish renewable energy investments revealed by the model results. Considering nuclear power plants, between 33 and 52 GW installed capacity plants seem difficult to provide suitable land for conventional plants. At this point, small modular reactors have the potential to provide some flexibility to the electricity sector. However, at this stage the advantages of the small modular reactors have not been completely proven and this requires time. Since small modular reactors are a new subject, relevant legislative studies and licensing issues should be clarified by regulatory authorities. In addition, the model results reveal a need for fossil fuel power plants with carbon capture and storage; however, using these costly technologies is difficult for emerging economies like Türkiye to reach the net zero target with increasing electricity demand. At this point, it would be beneficial for Türkiye to follow the developments in cost reduction for these technologies, which can also be achieved by using domestic resources in the future. Another critical constraint for carbon capture and storage is the storage site requirement. Presented available storage sites for carbon storage are not sufficient to store the captured carbon projected in this study. Therefore, discovering more possible storage sites, regional cooperation with neighbouring countries for storage and planning for capturing carbon utilization is needed. There has not been a study on physical reservoir characterization related to carbon dioxide storage in Türkiye, and the uncertainty regarding the storage potential is quite high. Studies to be carried out in this direction to eliminate the uncertainty may make CCS feasible for Türkiye. Parasitic loading of carbon capture systems is another disadvantage of this application. In addition, it will also be necessary to maximize the renewable energy source potential. As a solution, activities and regulations for energy storage will come to the fore.

4.3. Closing Remarks

In this section, the results of the study according to scenarios and policy analysis has been given. The study's findings have been reviewed from a policy perspective, and recommendations for energy policies have been made.

The model results reveal a significant increase in installed capacity, cost of generation, and cumulative investment costs for the Net Zero Emissions-1 Scenario and the Net Zero Emissions-2 Scenario. Even though the installed capacity increase is similar to other net zero emissions scenarios, the cost of generation and cumulative investment costs are lower in the Net Zero Emissions-3 Scenario. The main reason is that thanks to falling prices over time, the capital costs of renewable energy and battery storage installations are cheaper than those of nuclear power plants and fossil fuel-based power plants with carbon capture and storage.

In terms of cost of generation, emissions, and installed capacity, the difference between the Business as Usual Scenario and the Mitigation Scenario is rather minimal. This indicates that in the Mitigation Scenario, lower prices can significantly reduce emissions. However, it will not be enough to meet the net zero emissions aim.

The study's findings, which were based on a simulation of Türkiye's EHP sector within the framework of the net zero emission target, show that significant investments in renewable energy, battery storage, nuclear energy, and power plants with carbon capture and storage are necessary to meet these goals. Carbon capture and storage and nuclear power plants have some constraints related to available storage areas and land for installation and environmental concerns. With the activities and regulations to integrate energy storage installations into the electricity grid will come to the fore.

5. CONCLUSION AND RECOMMENDATIONS

Numerous research has been conducted on energy modeling studies, particularly those concentrating on the power sector and achieving long-term net zero and decarbonization targets. However, these projections for the power sector do not include technological developments like power plants with CCS, energy storage technologies, varying technology costs by year, and carbon pricing. This study aims to fill a gap in the literature by adding these details in modeling the electricity and heat production sector.

Different scenario assumptions have been used depending on the ambitiousness of the scenarios and available mitigation technology options while developing scenarios in LEAP modeling software. The data used in the modeling study have been obtained from energy-related public institutions in Türkiye and international organizations. These are related to the technology choices, environmental factors and costs.

In contrast to the BAU Scenario, which has no emission restrictions, the MIT Scenario has a 40% reduction from the BAU level by 2053. On the other hand, net zero emissions scenarios’ constraints were established in accordance with the goal of net zero emissions. Maximum capacity additions for solar and wind energy are generally increasing with the amount of ambition of the scenarios. However, with the addition of battery storage in the NET-3 Scenario, solar and wind energy maximum capacity additions are more than in the other two NET Scenarios. While thermal power plants with CCS are included in the NET-1 scenario assumptions, nuclear power plants dominate as a mitigating instrument in the NET-2 scenario. The NET-3 Scenario is a net zero emissions scenario in which nuclear power is limited and solar and wind investments dominate thanks to battery storage technologies. The carbon price has also been implemented only in scenarios with net zero emissions scenarios. In addition, increased electricity demand is assumed in net zero emissions scenarios, given that electrification would increase to achieve net zero emissions and electrolyser capacity for hydrogen production is considered.

The Net Zero Emissions-1 Scenario and the Net Zero Emissions-2 Scenario both show a considerable increase in installed capacity, cost of generation, and cumulative investment expenses. The Net Zero Emissions-3 Scenario has lower generation costs and cumulative investment costs, even if the increase in installed capacity is similar to that in other net zero emissions scenarios. The main factor is that compared to nuclear power plants and fossil fuel-based power plants with carbon capture and storage, the capital costs of renewable energy and battery storage systems are lower. This is because prices have been lowering over time.

The difference between the Business as Usual Scenario and the Mitigation Scenario is fairly small regarding generation costs, emissions, and installed capacity. This reveals that lower prices in the Mitigation Scenario than in net zero emission scenarios can significantly reduce emissions. On the other hand, it will not be sufficient to achieve the goal of net zero emissions.

The results of the studies, which were based on a modeling of Türkiye's electricity and heat production sector within the context of the net zero emission target, demonstrate the importance of making significant investments in renewable energy, battery storage, nuclear energy, and power plants with carbon capture and storage to achieve these objectives. Nuclear power plants and carbon capture and storage have some limits regarding the available storage area, land for installation, and environmental concerns. On the other hand, The Net Zero Emissions-3, where solar and wind energy installations can be installed more thanks to battery storage, emerges as the most suitable option for investment and generation costs among the net zero emissions scenarios. However, due to the limited lifetime of battery storage equipment, there are difficulties associated with this approach, such as the necessity of recycling and reuse of batteries at the end of their lifetime. In addition, negative aspects of upstream emissions and resource consumption in production processes should be considered. Energy storage installation integration will become more prominent with the activities and regulations accompanying it.

The major outcomes of this study can be summarized below:

- Renewable energy sources, nuclear energy power plants, battery storage systems, and fossil power plants with carbon capture and storage are crucial in achieving the net zero emissions target from the perspective of the electricity and heat production sector.

- Unabated fossil power plants' share in total electricity generation decreases by under 10% to achieve the net zero target.
- An additional investment between 340 and 391 billion USD is required for the net zero emissions target over business-as-usual conditions between 2020 and 2053.
- Carbon revenues are estimated to cover 19-23% of the additional investment costs. This means that a portion of green investments, such as renewable energy technologies, battery storage systems, and carbon capture and storage technology, can be covered in this way.
- The net zero emissions target requires a power generation greenhouse gas intensity of 0.03 tons of CO_2-eq/MWh in 2053.
- Boosting renewable energy sources and using battery storage systems for electricity grid flexibility is the cheapest option to reach the net zero emissions target from the perspective of the electricity and heat production sector.
- Considering the fossil power plants with carbon capture and storage to reach the net zero emissions target, it is estimated that a total of 1.5 billion tons of geographic CO_2 storage area is needed by 2053.
- Detailed physical characterisation studies for carbon storage areas are significant to integrate the carbon capture and storage technologies to Türkiye’s green transition plans target related to the net zero emissions target.

In line with the results obtained from this study, the following policy implications can be made:

- Türkiye needs to make significant changes in its energy policies and measures to realize substantial investments in renewable energy, battery storage, nuclear energy and power plants with carbon capture and storage to achieve net zero emissions targets.
- To integrate a substantial amount of renewable energy installations in line with the modelling results, reinforcement of the grid infrastructure and increasing flexibility with new policies and measures related to demand-side response and energy storage investments are crucial.

- New incentive mechanisms and simplifying the procedures are required to increase on-site renewable energy production.
- To benefit more from nuclear energy as a carbon neutral technology, developing support schemes for small modular reactors would help achieve the net zero emissions target.
- Preparing roadmaps and strategies regarding critical raw materials used in low-carbon energy technologies is crucial to decreasing foreign dependency.
- A legislative framework for the geographic storage of carbon dioxide should be developed, and detailed technical studies should reveal storage potential.
- To support low carbon technologies in line with the net zero emissions target with a market-based mechanism establishing an emission trading system will be beneficial.

For the future work, the following can be implemented:

- Studies that will reveal the demand for additional renewable energy power plants to produce green hydrogen would be beneficial as a crucial element for decarbonizing sectors that are hard to abate and electrify.
- Conducting a modelling study using different carbon prices to converge the net zero emissions target with a market-based approach and without taking carbon constraints can be suggested to estimate Türkiye's carbon prices in line with the net zero emissions target.
- The carbon intensity pathway of the electricity grid, in line with the net zero emission target, can be analyzed in terms of its impact on the sectors' market shares under the Carbon Border Adjustment Mechanism.
- A modelling study considering the bioenergy carbon capture and storage and direct air capture technologies, which have significant mitigation potential due to their negative emission behaviour, can be recommended for further studies.
- Modelling study focusing on deploying small modular reactors in line with the net zero emission target would be valuable.
- Since the 2021 land use, land-use change, and forestry emissions have decreased by 17% compared to 2020, it will be beneficial to carry out studies by considering this decrease in future studies.

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APPENDICES

APPENDIX 1 – Other Data Used in the Model

Table A.1. Exogenous capacity by fuel and technology sources – the BAU Scenario (2020-2053, GW)

	Natural Gas	Hydro	Coal	Solar	Wind	Nuclear	Others	Coal with CCS	Natural Gas with CCS	Total
2020	0.0	2480.9	42.6	672.2	1241.2	0.0	430.8	0.0	0.0	**4867.7**
2021	86.7	704.1	1405.0	1082.6	800.6	0.0	860.6	0.0	0.0	**4939.6**
2022	0.0	0.0	0.0	750.0	1000.0	0.0	258.5	0.0	0.0	**2008.5**
2023	0.0	349.0	36.0	1500.0	1250.0	1200.0	142.6	0.0	0.0	**4477.6**
2024	0.0	674.0	500.0	1000.0	117.0	1200.0	10.0	0.0	0.0	**3501.0**
2025	0.0	674.0	700.0	1000.0	1000.0	1200.0	10.0	0.0	0.0	**4584.0**
2026	0.0	0.0	0.0	1000.0	1000.0	1200.0	0.0	0.0	0.0	**3200.0**
2027	0.0	0.0	0.0	1000.0	1000.0	0.0	0.0	0.0	0.0	**2000.0**
2028	0.0	0.0	0.0	0.0	1500.0	0.0	0.0	0.0	0.0	**1500.0**
2029	0.0	0.0	0.0	0.0	1750.0	0.0	0.0	0.0	0.0	**1750.0**
2030	0.0	0.0	0.0	0.0	1750.0	0.0	0.0	0.0	0.0	**1750.0**
2031	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2032	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2033	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2034	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2035	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2036	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2037	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2038	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2039	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2040	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2041	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2042	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2043	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2044	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2045	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2046	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2047	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2048	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2049	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2050	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2051	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2052	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2053	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**

Table A.2. Exogenous capacity by fuel and technology sources – the MIT Scenario (2020-2053, GW)

	Natural Gas	Hydro	Coal	Solar	Wind	Nuclear	Others	Coal with CCS	Natural Gas with CCS	Total
2020	0.0	2480.9	42.6	672.2	1241.2	0.0	430.8	0.0	0.0	**4867.7**
2021	86.7	704.1	1405.0	1082.6	800.6	0.0	860.6	0.0	0.0	**4939.6**
2022	0.0	0.0	0.0	750.0	1000.0	0.0	258.5	0.0	0.0	**2008.5**
2023	0.0	349.0	36.0	1500.0	1250.0	1200.0	142.6	0.0	0.0	**4477.6**
2024	0.0	674.0	500.0	1000.0	117.0	1200.0	10.0	0.0	0.0	**3501.0**
2025	0.0	674.0	700.0	1000.0	1000.0	1200.0	10.0	0.0	0.0	**4584.0**
2026	0.0	0.0	0.0	1000.0	1000.0	1200.0	0.0	0.0	0.0	**3200.0**
2027	0.0	0.0	0.0	1000.0	1000.0	0.0	0.0	0.0	0.0	**2000.0**
2028	0.0	0.0	0.0	0.0	1500.0	0.0	0.0	0.0	0.0	**1500.0**
2029	0.0	0.0	0.0	0.0	1750.0	0.0	0.0	0.0	0.0	**1750.0**
2030	0.0	0.0	0.0	0.0	1750.0	1120.0	0.0	0.0	0.0	**2870.0**
2031	0.0	0.0	0.0	0.0	0.0	1120.0	0.0	0.0	0.0	**1120.0**
2032	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2033	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2034	0.0	0.0	0.0	0.0	0.0	1120.0	0.0	0.0	0.0	**1120.0**
2035	0.0	0.0	0.0	0.0	0.0	1120.0	0.0	0.0	0.0	**1120.0**
2036	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2037	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2038	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2039	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2040	0.0	0.0	0.0	0.0	0.0	1100.0	0.0	0.0	0.0	**1100.0**
2041	0.0	0.0	0.0	0.0	0.0	1100.0	0.0	0.0	0.0	**1100.0**
2042	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2043	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2044	0.0	0.0	0.0	0.0	0.0	1100.0	0.0	0.0	0.0	**1100.0**
2045	0.0	0.0	0.0	0.0	0.0	1100.0	0.0	0.0	0.0	**1100.0**
2046	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2047	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2048	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2049	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2050	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2051	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2052	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2053	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**

Table A.3. Exogenous capacity by fuel and technology sources – the NET-1 Scenario (2020-2053, GW)

	Natural Gas	Hydro	Coal	Solar	Wind	Nuclear	Others	Coal with CCS	Natural Gas with CCS	Total
2020	0.0	2480.9	42.6	672.2	1241.2	0.0	430.8	0.0	0.0	**4867.7**
2021	86.7	704.1	1405.0	1082.6	800.6	0.0	860.6	0.0	0.0	**4939.6**
2022	0.0	0.0	0.0	750.0	1000.0	0.0	258.5	0.0	0.0	**2008.5**
2023	0.0	349.0	36.0	1500.0	1250.0	1200.0	142.6	0.0	0.0	**4477.6**
2024	0.0	674.0	500.0	1000.0	117.0	1200.0	10.0	0.0	0.0	**3501.0**
2025	0.0	674.0	700.0	1000.0	1000.0	1200.0	10.0	0.0	0.0	**4584.0**
2026	0.0	0.0	0.0	1000.0	1000.0	1200.0	0.0	0.0	0.0	**3200.0**
2027	0.0	0.0	0.0	1000.0	1000.0	0.0	0.0	0.0	0.0	**2000.0**
2028	0.0	0.0	0.0	0.0	1500.0	0.0	0.0	0.0	0.0	**1500.0**
2029	0.0	0.0	0.0	0.0	1750.0	0.0	0.0	0.0	0.0	**1750.0**
2030	0.0	0.0	0.0	0.0	1750.0	1120.0	0.0	0.0	0.0	**2870.0**
2031	0.0	0.0	0.0	0.0	0.0	1120.0	0.0	0.0	0.0	**1120.0**
2032	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2033	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2034	0.0	0.0	0.0	0.0	0.0	1120.0	0.0	0.0	0.0	**1120.0**
2035	0.0	0.0	0.0	0.0	0.0	1120.0	0.0	0.0	0.0	**1120.0**
2036	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2037	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2038	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2039	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2040	0.0	0.0	0.0	0.0	0.0	1100.0	0.0	0.0	0.0	**1100.0**
2041	0.0	0.0	0.0	0.0	0.0	1100.0	0.0	0.0	0.0	**1100.0**
2042	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2043	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2044	0.0	0.0	0.0	0.0	0.0	1100.0	0.0	0.0	0.0	**1100.0**
2045	0.0	0.0	0.0	0.0	0.0	1100.0	0.0	0.0	0.0	**1100.0**
2046	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2047	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2048	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2049	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2050	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2051	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2052	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2053	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**

Table A.4. Exogenous capacity by fuel and technology sources – the NET-2 Scenario (2020-2053, GW)

	Natural Gas	Hydro	Coal	Solar	Wind	Nuclear	Others	Coal with CCS	Natural Gas with CCS	Total
2020	0.0	2480.9	42.6	672.2	1241.2	0.0	430.8	0.0	0.0	**4867.7**
2021	86.7	704.1	1405.0	1082.6	800.6	0.0	860.6	0.0	0.0	**4939.6**
2022	0.0	0.0	0.0	750.0	1000.0	0.0	258.5	0.0	0.0	**2008.5**
2023	0.0	349.0	36.0	1500.0	1250.0	1200.0	142.6	0.0	0.0	**4477.6**
2024	0.0	674.0	500.0	1000.0	117.0	1200.0	10.0	0.0	0.0	**3501.0**
2025	0.0	674.0	700.0	1000.0	1000.0	1200.0	10.0	0.0	0.0	**4584.0**
2026	0.0	0.0	0.0	1000.0	1000.0	1200.0	0.0	0.0	0.0	**3200.0**
2027	0.0	0.0	0.0	1000.0	1000.0	0.0	0.0	0.0	0.0	**2000.0**
2028	0.0	0.0	0.0	0.0	1500.0	0.0	0.0	0.0	0.0	**1500.0**
2029	0.0	0.0	0.0	0.0	1750.0	0.0	0.0	0.0	0.0	**1750.0**
2030	0.0	0.0	0.0	0.0	1750.0	1120.0	0.0	0.0	0.0	**2870.0**
2031	0.0	0.0	0.0	0.0	0.0	1120.0	0.0	0.0	0.0	**1120.0**
2032	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2033	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2034	0.0	0.0	0.0	0.0	0.0	1120.0	0.0	0.0	0.0	**1120.0**
2035	0.0	0.0	0.0	0.0	0.0	1120.0	0.0	0.0	0.0	**1120.0**
2036	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2037	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2038	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2039	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2040	0.0	0.0	0.0	0.0	0.0	1100.0	0.0	0.0	0.0	**1100.0**
2041	0.0	0.0	0.0	0.0	0.0	1100.0	0.0	0.0	0.0	**1100.0**
2042	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2043	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2044	0.0	0.0	0.0	0.0	0.0	1100.0	0.0	0.0	0.0	**1100.0**
2045	0.0	0.0	0.0	0.0	0.0	1100.0	0.0	0.0	0.0	**1100.0**
2046	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2047	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2048	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2049	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2050	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2051	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2052	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2053	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**

Table A.5. Exogenous capacity by fuel and technology sources – the NET-3 Scenario (2020-2053, GW)

	Natural Gas	Hydro	Coal	Solar	Wind	Nuclear	Others	Coal with CCS	Natural Gas with CCS	Total
2020	0.0	2480.9	42.6	672.2	1241.2	0.0	430.8	0.0	0.0	**4867.7**
2021	86.7	704.1	1405.0	1082.6	800.6	0.0	860.6	0.0	0.0	**4939.6**
2022	0.0	0.0	0.0	750.0	1000.0	0.0	258.5	0.0	0.0	**2008.5**
2023	0.0	349.0	36.0	1500.0	1250.0	1200.0	142.6	0.0	0.0	**4477.6**
2024	0.0	674.0	500.0	1000.0	117.0	1200.0	10.0	0.0	0.0	**3501.0**
2025	0.0	674.0	700.0	1000.0	1000.0	1200.0	10.0	0.0	0.0	**4584.0**
2026	0.0	0.0	0.0	1000.0	1000.0	1200.0	0.0	0.0	0.0	**3200.0**
2027	0.0	0.0	0.0	1000.0	1000.0	0.0	0.0	0.0	0.0	**2000.0**
2028	0.0	0.0	0.0	0.0	1500.0	0.0	0.0	0.0	0.0	**1500.0**
2029	0.0	0.0	0.0	0.0	1750.0	0.0	0.0	0.0	0.0	**1750.0**
2030	0.0	0.0	0.0	0.0	1750.0	0.0	0.0	0.0	0.0	**1750.0**
2031	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2032	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2033	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2034	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2035	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2036	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2037	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2038	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2039	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2040	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2041	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2042	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2043	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2044	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2045	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2046	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2047	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2048	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2049	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2050	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2051	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2052	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
2053	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**

Table A.6. Maximum availability by fuel and technology sources (%)

Fuel and Technology Sources	%
Liquid Fuels	50
Natural Gas	60
Natural Gas with CCS	90
Hydro	31
Lignite	55
Lignite with CCS	90
Imported Coal and Hard Coal	87
Imported Coal and Hard Coal with CCS	90
Solar	Yearly Shape (Solar)
Wind	33
Biomass	57
Geothermal	81
Nuclear	94

Table A.7. Availability shape for solar energy (% of annual energy)

Time Slice	Hours	Cumulative Hours	Average Value (%)
Wet: Hour 1	153	153	0.00
Wet: Hour 2	153	306	0.00
Wet: Hour 3	153	459	0.00
Wet: Hour 4	153	612	0.00
Wet: Hour 5	153	765	0.00
Wet: Hour 6	153	918	0.00
Wet: Hour 7	153	1071	0.00
Wet: Hour 8	153	1224	1.10
Wet: Hour 9	153	1377	2.76
Wet: Hour 10	153	1530	3.86
Wet: Hour 11	153	1683	4.96
Wet: Hour 12	153	1836	5.52
Wet: Hour 13	153	1989	5.52
Wet: Hour 14	153	2142	5.52
Wet: Hour 15	153	2295	4.96
Wet: Hour 16	153	2448	3.86
Wet: Hour 17	153	2601	2.76
Wet: Hour 18	153	2754	1.10
Wet: Hour 19	153	2907	0.00
Wet: Hour 20	153	3060	0.00
Wet: Hour 21	153	3213	0.00
Wet: Hour 22	153	3366	0.00
Wet: Hour 23	153	3519	0.00
Wet: Hour 24	153	3672	0.00
Dry: Hour 1	212	3884	0.00
Dry: Hour 2	212	4096	0.00
Dry: Hour 3	212	4308	0.00
Dry: Hour 4	212	4520	0.00
Dry: Hour 5	212	4732	0.00
Dry: Hour 6	212	4944	0.00
Dry: Hour 7	212	5156	0.00
Dry: Hour 8	212	5368	1.53
Dry: Hour 9	212	5580	3.82
Dry: Hour 10	212	5792	5.35
Dry: Hour 11	212	6004	6.88
Dry: Hour 12	212	6216	7.64
Dry: Hour 13	212	6428	7.64
Dry: Hour 14	212	6640	7.64
Dry: Hour 15	212	6852	6.88
Dry: Hour 16	212	7064	5.35
Dry: Hour 17	212	7276	3.82
Dry: Hour 18	212	7488	1.53
Dry: Hour 19	212	7700	0.00
Dry: Hour 20	212	7912	0.00
Dry: Hour 21	212	8124	0.00
Dry: Hour 22	212	8336	0.00
Dry: Hour 23	212	8548	0.00
Dry: Hour 24	212	8760	0.00

Table A.8. Emission constraints by scenarios (2021-2053) (million ton CO_2)

	MIT Scenario	NET-1 Scenario	NET-2 Scenario	NET-3 Scenario
2021	136.2	124.2	124.2	124.2
2022	139.2	124.8	124.8	124.8
2023	142.2	125.3	125.3	125.3
2024	145.0	125.6	125.6	125.6
2025	147.9	125.7	125.7	125.7
2026	150.7	125.6	125.6	125.6
2027	153.4	125.3	125.3	125.3
2028	156.1	124.8	124.8	124.8
2029	158.7	124.1	124.1	124.1
2030	161.3	123.2	123.2	123.2
2031	163.9	122.2	122.2	122.2
2032	166.3	120.9	120.9	120.9
2033	168.8	119.4	119.4	119.4
2034	171.2	117.8	117.8	117.8
2035	173.5	115.9	115.9	115.9
2036	175.8	113.9	113.9	113.9
2037	178.0	111.7	111.7	111.7
2038	180.2	109.2	109.2	109.2
2039	182.3	106.6	106.6	106.6
2040	184.4	103.8	103.8	103.8
2041	186.5	100.8	100.8	100.8
2042	188.4	97.6	97.6	97.6
2043	190.4	94.2	94.2	94.2
2044	192.3	90.6	90.6	90.6
2045	194.1	86.8	86.8	86.8
2046	195.9	82.9	82.9	82.9
2047	197.6	78.7	78.7	78.7
2048	199.3	74.3	74.3	74.3
2049	200.9	69.8	69.8	69.8
2050	202.5	65.0	65.0	65.0
2051	204.0	60.1	60.1	60.1
2052	205.5	54.9	54.9	54.9
2053	205.1	36.0	36.0	36.0

APPENDIX 2 – NEMO Optimization Modeling Tool

NEMO is a high-performance, open-source modeling tool for energy system optimization. NEMO can be used as a stand-alone tool, but it is intended to be used in conjunction with the LEAP as a user interface. Many users will find it convenient to use NEMO through LEAP [107].

NEMO models an energy system with perfect foresight using least-cost optimization. This optimization basically implies that it aims to meet energy and power demands throughout time at the lowest possible cost. The cost minimization function operates on discounted costs and simultaneously covers all modeled time periods. Investment expenses, fixed and variable operation and maintenance costs, and carbon costs for various energy system components can be covered by minimized costs. The objective function for least-cost optimization is given in Eq. 5.

$$LCE = min\left\{\sum_{y}\left[\frac{1}{(1+d)^{y-y_b}}\sum_{TT}\left[ACT + FC \times C_{TT,y} + OC \times \sum_{t} PG_{TT,y,t}\right]\right]\right\} \tag{5}$$

where *LCE* is the least-cost electricity generation, *y* is the year, y_b is the base year, *d* is the discount rate, *TT* is the technology type of power plant, *ACT* is the annualized capital costs, *FC* is the fixed costs, *C* is the capacity, *OC* is the operational costs, *PG* is the power generation, and *t* is time.

In this modelling study, fixed operation and maintenance costs are included in the fixed cost. In contrast, variable operating and maintenance costs, fuel costs and carbon costs are included in the operational costs.

NEMO can be used to represent a whole energy system or specific components of a system, such as electricity supply and demand. All NEMO scenarios are driven by some exogenously determined demands, but how these are defined is up to you. For example, needs can be defined for fuels or for energy services delivered by fuel-consuming devices.

Because NEMO is not a partial-equilibrium model, it lacks an endogenous demand response to energy supply prices.

NEMO stands out with its important benefits such as enabling least-cost optimization of energy supply and demand, modeling of energy storage, modeling of emissions and emission constraints, and modeling of renewable energy targets.

APPENDIX 3 – Modelling Results

Table A.9. Installed capacity by fuel and technology sources – the BAU Scenario (2020-2053, GW)

	Natural Gas	Hydro	Coal	Solar	Wind	Nuclear	Others	Coal with CCS	Natural Gas with CCS	Battery Storage	Total
2020	26.5	31.0	19.6	6.7	8.8	0.0	3.3	0.0	0.0	0.0	**95.9**
2021	26.6	31.7	21.0	7.8	9.6	0.0	4.2	0.0	0.0	0.0	**100.8**
2022	26.6	31.7	21.0	8.5	10.6	0.0	4.4	0.0	0.0	0.0	**102.8**
2023	26.6	32.0	21.1	10.0	11.9	1.2	4.6	0.0	0.0	0.0	**107.3**
2024	26.6	32.7	21.6	11.0	12.0	2.4	4.6	0.0	0.0	0.0	**110.8**
2025	26.6	33.4	22.3	12.0	13.0	3.6	4.6	0.0	0.0	0.0	**115.4**
2026	26.6	33.4	23.3	13.0	14.0	4.8	4.7	0.0	0.0	0.0	**119.7**
2027	26.6	33.4	24.3	14.0	15.0	4.8	4.8	0.0	0.0	0.0	**122.8**
2028	26.6	33.4	25.3	15.0	16.5	4.8	4.9	0.0	0.0	0.0	**126.4**
2029	26.6	33.4	26.3	16.0	18.3	4.8	5.0	0.0	0.0	0.0	**130.3**
2030	26.6	33.4	27.3	17.0	20.0	4.8	5.1	0.0	0.0	0.0	**134.1**
2031	26.6	33.4	28.3	18.0	20.0	4.8	5.2	0.0	0.0	0.0	**136.2**
2032	26.6	33.4	29.3	19.0	20.0	4.8	5.3	0.0	0.0	0.0	**138.3**
2033	26.6	33.4	30.3	20.0	20.0	4.8	5.4	0.0	0.0	0.0	**140.4**
2034	26.6	33.4	31.3	21.0	20.0	4.8	5.5	0.0	0.0	0.0	**142.5**
2035	26.6	33.4	32.3	22.0	20.0	4.8	5.6	0.0	0.0	0.0	**144.6**
2036	26.6	33.4	33.3	23.0	20.0	4.8	5.7	0.0	0.0	0.0	**146.7**
2037	26.6	33.4	34.3	24.0	21.0	4.8	5.8	0.0	0.0	0.0	**149.8**
2038	26.6	33.4	35.3	25.0	22.0	4.8	5.9	0.0	0.0	0.0	**152.9**
2039	26.6	33.4	36.3	26.0	23.0	4.8	6.0	0.0	0.0	0.0	**156.0**
2040	26.6	33.4	37.3	27.0	24.0	4.8	6.1	0.0	0.0	0.0	**159.1**
2041	26.6	33.4	38.3	28.0	25.0	4.8	6.2	0.0	0.0	0.0	**162.2**
2042	26.6	33.4	39.3	29.0	26.0	4.8	6.3	0.0	0.0	0.0	**165.3**
2043	26.6	33.4	40.3	30.0	27.0	4.8	6.4	0.0	0.0	0.0	**168.4**
2044	26.6	33.4	41.3	31.0	28.0	4.8	6.5	0.0	0.0	0.0	**171.5**
2045	26.6	33.4	42.3	32.0	29.0	4.8	6.6	0.0	0.0	0.0	**174.6**
2046	26.9	33.4	43.3	33.0	30.0	4.8	6.7	0.0	0.0	0.0	**178.0**
2047	27.6	33.4	44.3	34.0	31.0	4.8	6.8	0.0	0.0	0.0	**181.9**
2048	28.2	33.4	45.3	35.0	32.0	4.8	6.9	0.0	0.0	0.0	**185.5**
2049	28.8	33.4	46.3	36.0	33.0	4.8	7.0	0.0	0.0	0.0	**189.2**
2050	29.3	33.4	47.3	37.0	34.0	4.8	7.1	0.0	0.0	0.0	**192.9**
2051	29.9	33.4	48.3	38.0	35.0	4.8	7.2	0.0	0.0	0.0	**196.5**
2052	30.5	33.4	49.3	39.0	36.0	4.8	7.3	0.0	0.0	0.0	**200.2**
2053	31.0	33.4	50.3	40.0	37.0	4.8	7.4	0.0	0.0	0.0	**203.8**

Table A.10. Installed capacity by fuel and technology sources – the MIT Scenario (2020-2053, GW)

	Natural Gas	Hydro	Coal	Solar	Wind	Nuclear	Others	Coal with CCS	Natural Gas with CCS	Battery Storage	Total
2020	26.5	31.0	19.6	6.7	8.8	-	3.3	0.0	0.0	0.0	**95.9**
2021	26.6	31.7	21.0	7.8	9.6	-	4.2	0.0	0.0	0.0	**100.8**
2022	26.6	31.7	21.0	8.5	10.6	-	4.4	0.0	0.0	0.0	**102.8**
2023	26.6	32.0	21.1	10.0	11.9	1.2	4.6	0.0	0.0	0.0	**107.3**
2024	26.6	32.7	21.6	11.0	12.0	2.4	4.6	0.0	0.0	0.0	**110.8**
2025	26.6	33.4	22.3	12.0	13.0	3.6	4.6	0.0	0.0	0.0	**115.4**
2026	26.6	33.4	23.3	13.0	14.0	4.8	4.7	0.0	0.0	0.0	**119.7**
2027	26.6	33.4	24.3	14.0	15.0	4.8	4.8	0.0	0.0	0.0	**122.8**
2028	26.6	33.4	25.3	15.5	16.5	4.8	4.9	0.0	0.0	0.0	**126.9**
2029	26.6	33.4	25.8	17.0	18.3	4.8	5.0	0.0	0.0	0.0	**130.8**
2030	26.6	33.4	26.8	18.5	20.0	5.9	5.1	0.0	0.0	0.0	**136.2**
2031	26.6	33.4	27.0	20.0	20.0	7.0	5.2	0.0	0.0	0.0	**139.2**
2032	26.6	33.4	27.9	21.5	20.9	7.0	5.3	0.0	0.0	0.0	**142.6**
2033	26.6	33.4	27.9	23.0	22.4	7.0	5.4	0.0	0.0	0.0	**145.7**
2034	26.6	33.4	28.2	24.5	23.9	8.2	5.5	0.0	0.0	0.0	**150.2**
2035	26.6	33.4	28.2	26.0	25.4	9.3	5.6	0.0	0.0	0.0	**154.4**
2036	26.6	33.4	28.3	27.5	26.9	9.3	5.7	0.0	0.0	0.0	**157.6**
2037	26.6	33.4	28.3	29.0	28.4	9.3	5.8	0.0	0.0	0.0	**160.7**
2038	26.6	33.4	28.3	30.5	29.9	9.3	5.9	0.0	0.0	0.0	**163.8**
2039	26.6	33.4	28.3	32.0	31.4	9.3	6.0	0.0	0.0	0.0	**166.9**
2040	26.6	33.4	28.3	33.5	32.9	10.4	6.1	0.0	0.0	0.0	**171.1**
2041	26.6	33.4	29.3	35.0	34.4	11.5	6.2	0.0	0.0	0.0	**176.3**
2042	26.6	33.4	30.2	36.5	35.9	11.5	6.3	0.0	0.0	0.0	**180.4**
2043	26.6	33.4	30.2	38.0	37.4	11.5	6.4	0.0	0.0	0.0	**183.5**
2044	26.6	33.4	31.2	39.5	38.9	12.6	6.5	0.0	0.0	0.0	**188.7**
2045	26.6	33.4	31.3	41.0	40.4	13.7	6.6	0.0	0.0	0.0	**192.9**
2046	26.6	33.4	31.3	42.5	41.9	13.7	6.7	0.0	0.0	0.0	**196.0**
2047	26.6	33.4	31.3	44.0	43.4	13.7	6.8	0.0	0.0	0.0	**199.1**
2048	26.6	33.8	31.3	45.5	44.9	13.7	6.9	0.0	0.0	0.0	**202.6**
2049	26.6	34.3	31.3	47.0	46.4	13.7	7.0	0.0	0.0	0.0	**206.2**
2050	26.6	34.8	31.3	48.5	47.9	13.7	7.1	0.0	0.0	0.0	**209.8**
2051	26.6	35.3	32.2	50.0	49.4	13.7	7.2	0.0	0.0	0.0	**214.3**
2052	26.6	35.8	33.1	51.5	50.9	13.7	7.3	0.0	0.0	0.0	**218.8**
2053	26.6	36.0	34.1	53.0	52.4	13.7	7.4	0.0	0.0	0.0	**223.2**

Table A.11. Installed capacity by fuel and technology sources – the NET-1 Scenario (2020-2053, GW)

	Natural Gas	**Hydro**	**Coal**	**Solar**	**Wind**	**Nuclear**	**Others**	**Coal with CCS**	**Natural Gas with CCS**	**Battery Storage**	**Total**
2020	26.5	31.0	19.6	6.7	8.8	0.0	3.3	0.0	0.0	0.0	**95.9**
2021	26.6	31.7	21.0	7.8	9.6	0.0	4.2	0.0	0.0	0.0	**100.8**
2022	26.6	31.7	21.0	8.5	10.6	0.0	4.4	0.0	0.0	0.0	**102.8**
2023	26.6	32.0	21.1	10.0	11.9	1.2	4.6	0.0	0.0	0.0	**107.3**
2024	26.6	32.7	21.6	11.0	12.0	2.4	4.6	0.0	0.0	0.0	**110.8**
2025	26.6	33.4	22.3	12.0	13.0	3.6	4.6	0.0	0.0	0.0	**115.4**
2026	26.6	33.9	22.3	13.0	14.0	4.8	4.8	0.0	0.0	0.0	**119.4**
2027	26.6	34.4	22.3	14.0	15.0	4.8	5.1	0.0	0.0	0.0	**122.1**
2028	26.6	34.4	22.3	17.0	16.5	4.8	5.3	0.0	0.0	0.0	**126.9**
2029	26.6	34.4	22.3	20.0	18.3	4.8	5.4	0.0	0.0	0.0	**131.7**
2030	26.6	34.4	22.3	23.0	20.0	5.9	5.7	0.0	0.0	0.0	**137.8**
2031	26.6	34.4	22.3	26.0	23.0	7.0	5.9	0.0	0.5	0.0	**145.7**
2032	26.6	34.4	22.3	29.0	26.0	7.0	6.2	0.0	1.0	0.0	**152.4**
2033	26.6	34.4	22.3	32.0	29.0	7.0	6.4	0.0	1.5	0.0	**159.2**
2034	26.6	34.4	22.3	35.0	32.0	8.2	6.7	0.0	2.0	0.0	**167.1**
2035	26.6	34.4	22.3	38.0	35.0	9.3	6.9	0.1	2.5	0.0	**175.0**
2036	26.6	34.4	22.3	41.0	38.0	9.3	7.2	0.6	3.0	0.0	**182.3**
2037	26.6	34.4	22.3	44.0	41.0	9.3	7.4	1.1	3.5	0.0	**189.5**
2038	26.6	34.4	22.3	47.0	44.0	9.3	7.7	2.1	4.0	0.0	**197.3**
2039	26.6	34.4	22.3	50.0	47.0	9.3	7.9	3.1	4.5	0.0	**205.0**
2040	26.6	34.4	22.3	53.0	50.0	10.4	8.2	4.1	5.0	0.0	**213.9**
2041	26.6	34.4	22.3	56.0	53.0	11.5	8.4	5.1	5.5	0.0	**222.7**
2042	26.6	34.4	22.3	59.0	56.0	11.5	8.7	6.1	6.0	0.0	**230.5**
2043	26.6	34.4	22.3	62.0	59.0	11.5	8.9	7.1	6.5	0.0	**238.2**
2044	26.6	34.4	22.3	65.0	62.0	12.6	9.2	8.1	7.0	0.0	**247.1**
2045	26.6	34.4	22.3	68.0	65.0	13.7	9.4	9.1	7.5	0.0	**255.9**
2046	26.6	34.4	22.3	71.0	68.0	16.1	9.7	10.1	8.0	0.0	**266.1**
2047	26.6	34.4	22.3	74.0	71.0	18.5	9.9	11.1	8.5	0.0	**276.2**
2048	26.6	34.4	22.3	77.0	74.0	20.9	10.2	12.1	9.0	0.0	**286.4**
2049	26.6	34.4	22.3	80.0	77.0	23.3	10.4	13.1	9.5	0.0	**296.5**
2050	26.6	34.5	22.3	83.0	80.0	25.7	10.7	14.1	10.0	0.0	**306.8**
2051	27.6	35.0	22.3	86.0	83.0	28.1	10.9	15.1	10.5	0.0	**318.4**
2052	28.6	35.5	22.3	89.0	86.0	30.5	11.2	16.1	11.0	0.0	**330.1**
2053	29.6	36.0	22.3	92.0	89.0	32.9	11.4	17.1	11.5	0.0	**341.7**

Table A.12. Installed capacity by fuel and technology sources – the NET-2 Scenario (2020-2053, GW)

	Natural Gas	Hydro	Coal	Solar	Wind	Nuclear	Others	Coal with CCS	Natural Gas with CCS	Battery Storage	Total
2020	26.5	31.0	19.6	6.7	8.8	0.0	3.3	0.0	0.0	0.0	**95.9**
2021	26.6	31.7	21.0	7.8	9.6	0.0	4.2	0.0	0.0	0.0	**100.8**
2022	26.6	31.7	21.0	8.5	10.6	0.0	4.4	0.0	0.0	0.0	**102.8**
2023	26.6	32.0	21.1	10.0	11.9	1.2	4.6	0.0	0.0	0.0	**107.3**
2024	26.6	32.7	21.6	11.0	12.0	2.4	4.6	0.0	0.0	0.0	**110.8**
2025	26.6	33.4	22.3	12.0	13.0	3.6	4.6	0.0	0.0	0.0	**115.4**
2026	27.2	33.9	22.3	13.0	14.0	4.8	4.8	0.0	0.0	0.0	**120.0**
2027	28.4	34.4	22.3	14.0	15.0	4.8	5.1	0.0	0.0	0.0	**123.9**
2028	29.6	34.9	22.3	17.0	16.5	4.8	5.3	0.0	0.0	0.0	**130.4**
2029	30.8	34.9	22.3	20.0	18.3	4.8	5.6	0.0	0.0	0.0	**136.6**
2030	32.0	34.9	22.3	23.0	20.0	5.9	5.8	0.0	0.0	0.0	**143.9**
2031	33.2	34.9	22.3	26.0	23.0	7.0	6.1	0.0	0.0	0.0	**152.5**
2032	34.4	34.9	22.3	29.0	26.0	7.0	6.3	0.0	0.0	0.0	**159.9**
2033	35.6	34.9	22.3	32.0	29.0	7.0	6.6	0.0	0.0	0.0	**167.4**
2034	36.8	34.9	22.3	35.0	32.0	8.2	6.8	0.0	0.0	0.0	**175.9**
2035	38.0	34.9	22.3	38.0	35.0	9.3	7.1	0.0	0.0	0.0	**184.5**
2036	39.2	34.9	22.3	41.0	38.0	9.3	7.3	0.0	0.0	0.0	**192.0**
2037	40.4	34.9	22.3	44.0	41.0	9.3	7.6	0.0	0.0	0.0	**199.4**
2038	41.6	35.1	22.3	47.0	44.0	9.3	7.8	0.0	0.0	0.0	**207.0**
2039	42.8	35.6	22.3	50.0	47.0	9.3	8.1	0.0	0.0	0.0	**215.0**
2040	44.0	36.0	22.3	53.0	50.0	10.4	8.3	0.0	0.0	0.0	**224.0**
2041	45.2	36.0	22.3	56.0	53.0	11.5	8.6	0.0	0.0	0.0	**232.5**
2042	46.4	36.0	22.3	59.0	56.0	11.5	8.8	0.0	0.0	0.0	**240.0**
2043	47.6	36.0	22.3	62.0	59.0	11.5	9.1	0.0	0.0	0.0	**247.4**
2044	48.8	36.0	22.3	65.0	62.0	12.6	9.3	0.0	0.0	0.0	**256.0**
2045	50.0	36.0	22.3	68.0	65.0	13.7	9.6	0.0	0.0	0.0	**264.5**
2046	50.0	36.0	22.3	71.0	68.0	18.5	9.8	0.0	0.0	0.0	**275.6**
2047	50.0	36.0	22.3	74.0	71.0	23.3	10.1	0.0	0.0	0.0	**286.6**
2048	50.0	36.0	22.3	77.0	74.0	28.1	10.3	0.0	0.0	0.0	**297.7**
2049	50.0	36.0	22.3	80.0	77.0	32.9	10.6	0.0	0.0	0.0	**308.7**
2050	50.0	36.0	22.3	83.0	80.0	37.7	10.8	0.0	0.0	0.0	**319.8**
2051	50.0	36.0	22.3	86.0	83.0	42.5	11.1	0.0	0.0	0.0	**330.8**
2052	50.0	36.0	22.3	89.0	86.0	47.3	11.3	0.0	0.0	0.0	**341.9**
2053	50.0	36.0	22.3	92.0	89.0	52.1	11.6	0.0	0.0	0.0	**352.9**

Table A.13. Installed capacity by fuel and technology sources – the NET-3 Scenario (2020-2053, GW)

	Natural Gas	Hydro	Coal	Solar	Wind	Nuclear	Others	Coal with CCS	Natural Gas with CCS	Battery Storage	Total
2020	26.5	31.0	19.6	6.7	8.8	0.0	3.3	0.0	0.0	0.0	**95.9**
2021	26.6	31.7	21.0	7.8	9.6	0.0	4.2	0.0	0.0	0.0	**100.8**
2022	26.6	31.7	21.0	8.5	10.6	0.0	4.4	0.0	0.0	0.0	**102.8**
2023	26.6	32.0	21.1	10.0	11.9	1.2	4.6	0.0	0.0	0.0	**107.3**
2024	26.6	32.7	21.6	11.0	12.0	2.4	4.6	0.0	0.0	0.0	**110.8**
2025	26.6	33.4	22.3	12.0	13.0	3.6	4.6	0.0	0.0	0.0	**115.4**
2026	27.8	33.9	22.3	13.0	14.0	4.8	4.8	0.0	0.0	5.0	**125.6**
2027	29.0	34.4	22.3	14.0	15.0	4.8	5.1	0.0	0.0	10.0	**134.5**
2028	30.2	34.4	22.3	17.5	16.5	4.8	5.3	0.0	0.0	15.0	**146.0**
2029	31.4	34.4	22.3	21.0	18.3	4.8	5.6	0.0	0.0	20.0	**157.7**
2030	32.6	34.4	22.3	24.5	20.0	4.8	5.8	0.0	0.0	25.0	**169.4**
2031	33.8	34.4	22.3	28.0	24.0	4.8	6.1	0.0	0.0	30.0	**183.3**
2032	35.0	34.4	22.3	31.5	28.0	4.8	6.3	0.0	0.0	35.0	**197.3**
2033	36.2	34.4	22.3	35.0	32.0	4.8	6.6	0.0	0.0	40.0	**211.2**
2034	37.4	34.4	22.3	38.5	36.0	4.8	6.8	0.0	0.0	45.0	**225.2**
2035	38.6	34.4	22.3	42.0	40.0	4.8	7.1	0.0	0.0	50.0	**239.1**
2036	39.8	34.4	22.3	45.5	44.0	4.8	7.3	0.0	0.0	50.0	**248.1**
2037	41.0	34.4	22.3	49.0	48.0	4.8	7.6	0.0	0.0	50.0	**257.0**
2038	42.2	34.4	22.3	52.5	52.0	4.8	7.8	0.0	0.0	50.0	**266.0**
2039	43.4	34.4	22.3	56.0	56.0	4.8	8.1	0.0	0.0	50.0	**274.9**
2040	44.6	34.4	22.3	59.5	60.0	4.8	8.3	0.0	0.0	50.0	**283.9**
2041	45.8	34.4	22.3	63.0	64.0	4.8	8.6	0.0	0.0	50.0	**292.8**
2042	47.0	34.4	22.3	66.5	68.0	4.8	8.8	0.0	0.0	50.0	**301.8**
2043	48.2	34.4	22.3	70.0	72.0	4.8	9.1	0.0	0.0	50.0	**310.7**
2044	49.4	34.4	22.3	73.5	76.0	4.8	9.3	0.0	0.0	45.0	**314.7**
2045	50.6	34.7	22.3	77.0	80.0	4.8	9.6	0.0	0.0	40.0	**318.9**
2046	51.8	34.7	22.3	85.0	88.0	4.8	9.8	0.0	0.0	35.0	**331.4**
2047	53.0	34.7	22.3	93.0	96.0	4.8	10.1	0.0	0.0	30.0	**343.8**
2048	54.2	34.7	22.3	101.0	104.0	4.8	10.3	0.0	0.0	34.7	**366.0**
2049	55.4	34.7	22.3	109.0	112.0	4.8	10.6	0.0	0.0	39.5	**388.2**
2050	56.6	34.9	22.3	117.0	120.0	4.8	10.8	0.0	0.0	44.2	**410.6**
2051	57.8	35.4	22.3	125.0	128.0	4.8	11.1	0.0	0.0	51.1	**435.4**
2052	59.0	35.9	22.3	133.0	136.0	4.8	11.3	0.0	0.0	61.1	**463.4**
2053	60.2	36.0	22.3	141.0	144.0	4.8	11.6	0.0	0.0	71.1	**490.9**

Table A.14. Electricity generation by fuel sources and technologies – the BAU Scenario (2020-2053, TWh)

	Natural Gas	**Hydro**	**Coal**	**Solar**	**Wind**	**Nuclear**	**Others**	**Coal with CCS**	**Natural Gas with CCS**	**Total**
2020	70.9	78.1	105.8	11.0	24.8	0.0	16.1	0.0	0.0	**306.7**
2021	37.4	86.1	128.5	12.9	27.8	0.0	24.3	0.0	0.0	**317.0**
2022	42.5	86.1	129.5	14.1	30.7	0.0	26.1	0.0	0.0	**329.0**
2023	39.0	87.0	128.0	16.6	34.4	9.9	27.1	0.0	0.0	**342.0**
2024	37.2	88.8	129.1	18.3	34.7	19.8	27.1	0.0	0.0	**355.0**
2025	34.4	90.7	130.6	20.0	37.6	29.6	27.2	0.0	0.0	**370.0**
2026	28.1	90.7	134.7	21.6	40.5	39.5	27.9	0.0	0.0	**383.0**
2027	29.5	90.7	142.1	23.3	43.4	39.5	28.6	0.0	0.0	**397.0**
2028	29.8	90.7	149.0	25.0	47.7	39.5	29.3	0.0	0.0	**411.0**
2029	30.4	90.7	156.0	26.6	52.8	39.5	30.0	0.0	0.0	**426.0**
2030	30.3	90.7	162.7	28.3	57.8	39.5	30.7	0.0	0.0	**440.0**
2031	32.9	90.7	170.7	30.0	57.8	39.5	31.4	0.0	0.0	**453.0**
2032	35.5	90.7	178.7	31.6	57.8	39.5	32.2	0.0	0.0	**466.0**
2033	38.2	90.7	186.7	33.3	57.8	39.5	32.9	0.0	0.0	**479.0**
2034	41.6	90.7	194.9	35.0	57.8	39.5	33.6	0.0	0.0	**493.0**
2035	45.0	90.7	203.1	36.6	57.8	39.5	34.3	0.0	0.0	**507.0**
2036	49.9	90.7	211.9	38.3	57.8	39.5	35.0	0.0	0.0	**523.0**
2037	52.7	90.7	219.7	39.9	60.7	39.5	35.7	0.0	0.0	**539.0**
2038	56.4	90.7	227.8	41.6	63.6	39.5	36.4	0.0	0.0	**556.0**
2039	60.1	90.7	235.8	43.3	66.5	39.5	37.1	0.0	0.0	**573.0**
2040	64.6	90.7	244.0	44.9	69.4	39.5	37.8	0.0	0.0	**591.0**
2041	59.0	90.7	249.4	46.6	72.3	39.5	38.5	0.0	0.0	**596.0**
2042	60.3	90.7	256.8	48.3	75.2	39.5	39.3	0.0	0.0	**610.0**
2043	61.7	90.7	264.2	49.9	78.1	39.5	40.0	0.0	0.0	**624.0**
2044	63.1	90.7	271.5	51.6	80.9	39.5	40.7	0.0	0.0	**638.0**
2045	64.4	90.7	278.9	53.3	83.8	39.5	41.4	0.0	0.0	**652.0**
2046	65.8	90.7	286.3	54.9	86.7	39.5	42.1	0.0	0.0	**666.0**
2047	67.9	90.7	293.9	56.6	89.6	39.5	42.8	0.0	0.0	**681.0**
2048	69.3	90.7	301.2	58.3	92.5	39.5	43.5	0.0	0.0	**695.0**
2049	70.7	90.7	308.6	59.9	95.4	39.5	44.2	0.0	0.0	**709.0**
2050	72.0	90.7	316.0	61.6	98.3	39.5	44.9	0.0	0.0	**723.0**
2051	73.4	90.7	323.3	63.2	101.2	39.5	45.6	0.0	0.0	**737.0**
2052	74.8	90.7	330.7	64.9	104.1	39.5	46.3	0.0	0.0	**751.0**
2053	76.2	90.7	338.1	66.6	107.0	39.5	47.1	0.0	0.0	**765.0**

Table A.15. Electricity generation by fuel sources and technologies – the MIT Scenario (2020-2053, TWh)

	Natural Gas	Hydro	Coal	Solar	Wind	Nuclear	Others	Coal with CCS	Natural Gas with CCS	Total
2020	70.9	78.1	105.8	11.0	24.8	0.0	16.1	0.0	0.0	**306.7**
2021	43.2	86.1	122.7	12.9	27.8	0.0	24.3	0.0	0.0	**317.0**
2022	48.5	86.1	123.5	14.1	30.7	0.0	26.1	0.0	0.0	**329.0**
2023	39.0	87.0	128.0	16.6	34.4	9.9	27.1	0.0	0.0	**342.0**
2024	37.2	88.8	129.1	18.3	34.7	19.8	27.1	0.0	0.0	**355.0**
2025	34.4	90.7	130.6	20.0	37.6	29.6	27.2	0.0	0.0	**370.0**
2026	28.1	90.7	134.7	21.6	40.5	39.5	27.9	0.0	0.0	**383.0**
2027	29.5	90.7	142.1	23.3	43.4	39.5	28.6	0.0	0.0	**397.0**
2028	29.3	90.7	148.7	25.8	47.7	39.5	29.3	0.0	0.0	**411.0**
2029	33.3	90.7	151.4	28.3	52.8	39.5	30.0	0.0	0.0	**426.0**
2030	24.9	90.7	156.3	30.8	57.8	48.7	30.7	0.0	0.0	**440.0**
2031	24.7	90.7	157.2	33.3	57.8	58.0	31.4	0.0	0.0	**453.0**
2032	25.4	90.7	163.6	35.8	60.5	58.0	32.2	0.0	0.0	**466.0**
2033	29.6	90.7	164.8	38.3	64.8	58.0	32.9	0.0	0.0	**479.0**
2034	26.8	90.7	164.8	40.8	69.2	67.2	33.6	0.0	0.0	**493.0**
2035	25.7	90.7	163.1	43.3	73.5	76.4	34.3	0.0	0.0	**507.0**
2036	31.6	90.7	165.7	45.8	77.8	76.4	35.0	0.0	0.0	**523.0**
2037	38.1	90.7	167.7	48.3	82.2	76.4	35.7	0.0	0.0	**539.0**
2038	45.4	90.7	169.9	50.8	86.5	76.4	36.4	0.0	0.0	**556.0**
2039	56.3	90.7	168.4	53.3	90.8	76.4	37.1	0.0	0.0	**573.0**
2040	56.0	90.7	170.1	55.8	95.2	85.5	37.8	0.0	0.0	**591.0**
2041	41.3	90.7	173.2	58.3	99.5	94.5	38.5	0.0	0.0	**596.0**
2042	41.3	90.7	179.7	60.8	103.9	94.5	39.3	0.0	0.0	**610.0**
2043	46.3	90.7	181.1	63.2	108.2	94.5	40.0	0.0	0.0	**624.0**
2044	39.9	90.7	184.9	65.7	112.5	103.6	40.7	0.0	0.0	**638.0**
2045	38.4	90.7	183.8	68.2	116.9	112.6	41.4	0.0	0.0	**652.0**
2046	43.4	90.7	185.3	70.7	121.2	112.6	42.1	0.0	0.0	**666.0**
2047	49.1	90.7	187.0	73.2	125.5	112.6	42.8	0.0	0.0	**681.0**
2048	54.1	91.7	187.4	75.7	129.9	112.6	43.5	0.0	0.0	**695.0**
2049	59.6	93.0	187.1	78.2	134.2	112.6	44.2	0.0	0.0	**709.0**
2050	65.0	94.4	186.8	80.7	138.5	112.6	44.9	0.0	0.0	**723.0**
2051	68.0	95.7	188.9	83.2	142.9	112.6	45.6	0.0	0.0	**737.0**
2052	70.9	97.1	191.1	85.7	147.2	112.6	46.3	0.0	0.0	**751.0**
2053	77.0	97.8	190.8	88.2	151.6	112.6	47.1	0.0	0.0	**765.0**

Table A.16. Electricity generation by fuel sources and technologies – the NET-1 Scenario (2020-2053, TWh)

	Natural Gas	Hydro	Coal	Solar	Wind	Nuclear	Others	Coal with CCS	Natural Gas with CCS	Total
2020	70.9	78.1	105.8	11.0	24.8	0.0	16.1	0.0	0.0	**306.7**
2021	56.5	86.1	109.4	12.9	27.8	0.0	24.3	0.0	0.0	**317.0**
2022	64.3	86.1	107.7	14.1	30.7	0.0	26.1	0.0	0.0	**329.0**
2023	56.8	87.0	110.3	16.6	34.4	9.9	27.1	0.0	0.0	**342.0**
2024	55.4	88.8	110.9	18.3	34.7	19.8	27.1	0.0	0.0	**355.0**
2025	53.4	90.7	111.5	20.0	37.6	29.6	27.2	0.0	0.0	**370.0**
2026	47.5	92.0	113.2	21.6	40.5	39.5	28.6	0.0	0.0	**383.0**
2027	57.2	93.4	110.1	23.3	43.4	39.5	30.1	0.0	0.0	**397.0**
2028	62.3	93.4	108.2	28.3	47.7	39.5	31.6	0.0	0.0	**411.0**
2029	69.1	93.4	105.7	33.3	52.8	39.5	32.3	0.0	0.0	**426.0**
2030	60.6	93.4	107.5	38.3	57.8	48.7	33.7	0.0	0.0	**440.0**
2031	37.3	93.4	113.0	43.3	66.5	58.0	35.2	0.0	3.4	**450.0**
2032	39.6	93.4	111.2	48.3	75.2	58.0	36.6	0.0	6.8	**469.0**
2033	42.1	93.4	109.2	53.3	83.8	58.0	38.1	0.0	10.1	**488.0**
2034	34.5	93.4	109.7	58.3	92.5	67.2	39.6	0.0	12.9	**508.0**
2035	28.3	93.4	109.5	63.2	101.2	76.4	41.0	0.8	15.2	**529.0**
2036	30.0	93.4	106.9	68.2	109.9	76.4	42.5	4.7	18.1	**550.0**
2037	34.3	93.4	103.4	73.2	118.5	76.4	43.9	8.7	21.1	**573.0**
2038	35.0	93.4	100.2	78.2	127.2	76.4	45.4	16.5	23.6	**596.0**
2039	38.3	93.4	96.2	83.2	135.9	76.4	46.9	24.4	26.3	**621.0**
2040	30.9	93.4	94.5	88.2	144.5	85.5	48.3	32.3	28.4	**646.0**
2041	24.8	93.4	92.2	93.2	153.2	94.5	49.8	40.2	30.6	**672.0**
2042	32.6	93.4	86.6	98.2	161.9	94.5	51.2	48.1	33.5	**700.0**
2043	41.8	93.4	80.5	103.2	170.6	94.5	52.7	56.0	36.4	**729.0**
2044	40.2	93.4	76.6	108.2	179.2	103.6	54.2	63.8	38.8	**758.0**
2045	41.9	93.4	71.5	113.2	187.9	112.6	55.6	71.7	41.2	**789.0**
2046	33.7	93.4	69.1	118.2	196.6	132.4	57.1	79.3	42.3	**822.0**
2047	28.2	93.4	64.9	123.2	205.2	152.2	58.5	85.9	43.6	**855.0**
2048	23.3	93.4	62.4	128.2	213.9	171.9	59.9	91.9	45.1	**890.0**
2049	19.8	93.4	57.5	133.2	222.6	191.7	61.3	98.0	49.6	**927.0**
2050	17.3	93.7	52.1	138.1	231.3	211.5	62.7	103.8	54.6	**965.0**
2051	16.7	95.0	45.6	143.1	239.9	231.2	64.2	109.1	59.1	**1004.0**
2052	23.3	96.4	35.9	148.1	248.6	251.0	65.6	114.7	61.3	**1045.0**
2053	58.3	97.8	0.1	153.1	257.3	270.7	66.4	98.6	85.8	**1088.0**

Table A.17. Electricity generation by fuel sources and technologies – the NET-2 Scenario (2020-2053, TWh)

	Natural Gas	Hydro	Coal	Solar	Wind	Nuclear	Others	Coal with CCS	Natural Gas with CCS	Total
2020	70.9	78.1	105.8	11.0	24.8	0.0	16.1	0.0	0.0	306.7
2021	56.5	86.1	109.4	12.9	27.8	0.0	24.3	0.0	0.0	317.0
2022	64.3	86.1	107.7	14.1	30.7	0.0	26.1	0.0	0.0	329.0
2023	56.8	87.0	110.3	16.6	34.4	9.9	27.1	0.0	0.0	342.0
2024	55.4	88.8	110.9	18.3	34.7	19.8	27.1	0.0	0.0	355.0
2025	53.4	90.7	111.5	20.0	37.6	29.6	27.2	0.0	0.0	370.0
2026	47.5	92.0	113.2	21.6	40.5	39.5	28.6	0.0	0.0	383.0
2027	57.2	93.4	110.1	23.3	43.4	39.5	30.1	0.0	0.0	397.0
2028	60.4	94.7	108.8	28.3	47.7	39.5	31.6	0.0	0.0	411.0
2029	66.1	94.7	106.5	33.3	52.8	39.5	33.0	0.0	0.0	426.0
2030	57.6	94.7	108.3	38.3	57.8	48.7	34.5	0.0	0.0	440.0
2031	39.1	94.7	112.5	43.3	66.5	58.0	35.9	0.0	0.0	450.0
2032	46.0	94.7	109.5	48.3	75.2	58.0	37.4	0.0	0.0	469.0
2033	53.1	94.7	106.2	53.3	83.8	58.0	38.9	0.0	0.0	488.0
2034	49.3	94.7	105.7	58.3	92.5	67.2	40.3	0.0	0.0	508.0
2035	47.2	94.7	104.5	63.2	101.2	76.4	41.8	0.0	0.0	529.0
2036	57.7	94.7	99.9	68.2	109.9	76.4	43.2	0.0	0.0	550.0
2037	71.1	94.7	94.3	73.2	118.5	76.4	44.7	0.0	0.0	573.0
2038	84.1	95.2	88.7	78.2	127.2	76.4	46.1	0.0	0.0	596.0
2039	98.9	96.6	82.4	83.2	135.9	76.4	47.6	0.0	0.0	621.0
2040	104.0	97.8	76.9	88.2	144.5	85.5	49.1	0.0	0.0	646.0
2041	113.4	97.8	69.4	93.2	153.2	94.5	50.5	0.0	0.0	672.0
2042	142.4	97.8	53.3	98.2	161.9	94.5	52.0	0.0	0.0	700.0
2043	173.5	97.8	36.0	103.2	170.6	94.5	53.4	0.0	0.0	729.0
2044	189.3	97.8	25.0	108.2	179.2	103.6	54.9	0.0	0.0	758.0
2045	209.2	97.8	12.5	113.2	187.9	112.6	55.8	0.0	0.0	789.0
2046	179.3	97.8	20.2	118.2	196.6	152.2	57.8	0.0	0.0	822.0
2047	150.1	97.8	27.7	123.2	205.2	191.7	59.3	0.0	0.0	855.0
2048	125.2	97.8	33.3	128.2	213.9	231.0	60.7	0.0	0.0	890.0
2049	107.6	97.8	35.5	133.2	222.6	268.3	62.1	0.0	0.0	927.0
2050	94.4	97.8	35.5	138.1	231.3	304.3	63.5	0.0	0.0	965.0
2051	85.5	97.8	33.6	143.1	239.9	339.2	64.9	0.0	0.0	1004.0
2052	81.0	97.8	29.5	148.1	248.6	373.6	66.3	0.0	0.0	1045.0
2053	99.1	97.8	0.0	153.1	257.3	408.4	67.2	0.0	0.0	1082.8

Table A.18. Electricity generation by fuel sources and technologies – the NET-3 Scenario (2020-2053, TWh)

	Natural Gas	Hydro	Coal	Solar	Wind	Nuclear	Others	Coal with CCS	Natural Gas with CCS	Total
2020	70.9	78.1	105.8	11.0	24.8	0.0	16.1	0.0	0.0	**306.7**
2021	44.3	86.1	113.0	21.5	27.8	0.0	24.3	0.0	0.0	**317.0**
2022	51.0	86.1	111.6	23.6	30.7	0.0	26.1	0.0	0.0	**329.0**
2023	41.1	87.0	114.9	27.7	34.4	9.9	27.1	0.0	0.0	**342.0**
2024	38.1	88.8	116.0	30.5	34.7	19.8	27.1	0.0	0.0	**355.0**
2025	34.6	90.7	117.1	33.3	37.6	29.6	27.2	0.0	0.0	**370.0**
2026	27.2	92.0	119.2	36.1	40.5	39.5	28.6	0.0	0.0	**383.1**
2027	35.3	93.4	116.5	38.8	43.4	39.5	30.1	0.0	0.0	**397.1**
2028	34.2	93.4	116.5	48.5	47.7	39.5	31.6	0.0	0.0	**411.4**
2029	34.0	93.4	116.0	58.3	52.8	39.5	33.0	0.0	0.0	**426.9**
2030	32.8	93.4	115.6	68.0	57.8	39.5	34.5	0.0	0.0	**441.6**
2031	18.1	93.4	119.1	77.7	69.4	39.5	35.9	0.0	0.0	**453.0**
2032	15.6	93.4	118.8	87.4	80.9	39.5	37.4	0.0	0.0	**473.0**
2033	13.2	93.4	118.3	97.1	92.5	39.5	38.9	0.0	0.0	**492.9**
2034	12.4	93.4	117.2	106.8	104.1	39.5	40.3	0.0	0.0	**513.7**
2035	13.6	93.4	115.0	116.5	115.6	39.5	41.8	0.0	0.0	**535.4**
2036	14.2	93.4	113.5	126.2	127.2	39.5	43.2	0.0	0.0	**557.3**
2037	18.2	93.4	110.6	135.9	138.8	39.5	44.7	0.0	0.0	**581.0**
2038	22.4	93.4	107.4	145.6	150.3	39.5	46.1	0.0	0.0	**604.7**
2039	29.5	93.4	103.2	155.3	161.9	39.5	47.6	0.0	0.0	**630.4**
2040	36.8	93.4	98.7	165.1	173.4	39.5	49.1	0.0	0.0	**656.0**
2041	45.7	93.4	93.7	174.8	185.0	39.5	50.5	0.0	0.0	**682.6**
2042	57.5	93.4	87.7	184.5	196.6	39.5	52.0	0.0	0.0	**711.1**
2043	71.8	93.4	79.4	194.2	208.1	39.5	53.4	0.0	0.0	**739.8**
2044	87.9	93.4	68.3	203.9	219.7	39.5	54.9	0.0	0.0	**767.6**
2045	105.8	94.3	56.2	213.6	231.3	39.5	56.4	0.0	0.0	**797.1**
2046	94.4	94.3	56.4	235.8	254.4	39.5	57.8	0.0	0.0	**832.7**
2047	97.2	92.4	50.4	258.0	277.5	34.4	56.5	0.0	0.0	**866.4**
2048	91.4	91.6	47.8	280.2	300.6	34.4	57.5	0.0	0.0	**903.6**
2049	89.0	91.0	43.5	302.4	323.8	34.4	58.7	0.0	0.0	**942.7**
2050	87.6	91.0	38.5	324.6	346.9	34.4	60.0	0.0	0.0	**982.9**
2051	82.6	93.7	34.8	346.8	370.0	34.6	62.0	0.0	0.0	**1024.5**
2052	75.4	97.5	31.8	368.9	393.1	36.6	65.1	0.0	0.0	**1068.5**
2053	99.1	97.8	0.0	391.1	416.3	38.8	67.2	0.0	0.0	**1110.2**

Table A.19. Cost of generation by cost categories – the BAU Scenario (2020-2053, 2021 Billion USD)

	Capital Costs	Feedstock Fuel Costs	Fixed O&M Costs	Variable O&M Costs	Total
2020	6.7	3.7	3.1	0.8	14.4
2021	7.2	10.0	3.4	0.9	21.4
2022	7.4	20.7	3.5	0.9	32.4
2023	8.0	14.0	3.7	0.9	26.6
2024	8.6	12.5	3.9	0.9	26.0
2025	9.3	11.0	4.1	1.0	25.4
2026	10.0	9.2	4.4	1.0	24.6
2027	10.2	8.5	4.5	1.0	24.2
2028	10.4	7.6	4.6	1.1	23.6
2029	10.5	6.6	4.7	1.1	22.9
2030	10.8	5.5	4.8	1.1	22.2
2031	10.9	5.8	4.9	1.2	22.7
2032	10.9	6.1	5.0	1.2	23.1
2033	10.9	6.4	5.0	1.2	23.5
2034	10.9	6.7	5.1	1.3	24.0
2035	11.0	7.1	5.1	1.3	24.6
2036	11.1	7.5	5.2	1.4	25.2
2037	11.3	8.0	5.3	1.4	26.0
2038	11.4	8.3	5.4	1.5	26.6
2039	11.5	8.7	5.5	1.5	27.2
2040	11.6	9.1	5.6	1.6	27.8
2041	11.6	8.9	5.7	1.6	27.7
2042	11.5	9.1	5.8	1.6	28.0
2043	11.3	9.2	5.9	1.7	28.0
2044	11.3	9.4	6.0	1.7	28.4
2045	11.4	9.6	6.1	1.7	28.8
2046	11.4	10.0	6.2	1.8	29.3
2047	11.3	10.3	6.3	1.8	29.6
2048	11.3	10.4	6.4	1.9	29.9
2049	11.3	10.6	6.5	1.9	30.3
2050	11.2	10.9	6.6	1.9	30.6
2051	11.0	11.1	6.7	2.0	30.8
2052	11.1	11.3	6.8	2.0	31.2
2053	11.1	11.4	6.9	2.0	31.5

Table A.20. Cost of generation by cost categories – the MIT Scenario (2020-2053, 2021 Billion USD)

	Capital Costs	Feedstock Fuel Costs	Fixed O&M Costs	Variable O&M Costs	Total
2020	6.7	3.7	3.1	0.8	14.4
2021	7.2	10.4	3.4	0.9	21.8
2022	7.4	21.6	3.5	0.9	33.3
2023	8.0	14.0	3.7	0.9	26.6
2024	8.6	12.5	3.9	0.9	25.9
2025	9.3	11.0	4.1	1.0	25.4
2026	9.9	9.2	4.4	1.0	24.5
2027	10.1	8.5	4.5	1.0	24.1
2028	10.3	7.5	4.6	1.0	23.5
2029	10.5	6.7	4.7	1.1	23.0
2030	11.2	5.1	5.0	1.1	22.4
2031	11.6	5.2	5.1	1.1	23.1
2032	11.7	5.4	5.2	1.2	23.5
2033	11.8	5.6	5.3	1.2	23.9
2034	12.3	5.6	5.5	1.2	24.6
2035	12.9	5.5	5.7	1.2	25.3
2036	13.0	5.9	5.8	1.2	26.0
2037	13.2	6.4	5.9	1.3	26.8
2038	13.3	6.8	6.0	1.3	27.4
2039	13.4	7.4	6.0	1.3	28.2
2040	13.9	7.5	6.3	1.3	29.0
2041	14.3	6.8	6.5	1.3	29.0
2042	14.3	7.0	6.6	1.4	29.3
2043	14.1	7.2	6.7	1.4	29.4
2044	14.6	7.0	7.0	1.4	29.9
2045	15.0	7.0	7.2	1.4	30.5
2046	15.0	7.4	7.2	1.4	31.0
2047	14.8	7.7	7.3	1.5	31.3
2048	14.8	8.0	7.4	1.5	31.7
2049	14.8	8.3	7.5	1.5	32.1
2050	14.7	8.6	7.6	1.5	32.4
2051	14.6	8.8	7.7	1.5	32.7
2052	14.8	9.0	7.9	1.6	33.2
2053	14.8	9.3	8.0	1.6	33.7

Table A.21. Cost of generation by cost categories – the NET-1 Scenario (2020-2053, 2021 Billion USD)

	Capital Costs	Feedstock Fuel Costs	Fixed O&M Costs	Variable O&M Costs	Total
2020	6.7	3.7	3.1	0.8	14.4
2021	7.2	11.3	3.4	0.8	22.7
2022	7.4	24.1	3.5	0.8	35.8
2023	8.0	16.1	3.7	0.9	28.7
2024	8.6	14.4	3.9	0.9	27.8
2025	9.3	12.8	4.1	2.2	28.4
2026	9.9	10.8	4.4	2.4	27.5
2027	10.1	10.4	4.5	2.6	27.6
2028	10.4	9.3	4.6	2.8	27.0
2029	10.5	8.1	4.7	3.0	26.3
2030	11.2	6.1	4.9	3.1	25.4
2031	12.1	5.2	5.2	3.3	25.9
2032	12.5	5.5	5.4	3.5	26.9
2033	12.9	5.8	5.6	3.7	27.9
2034	13.7	5.7	5.9	3.8	29.1
2035	14.6	5.6	6.2	4.0	30.4
2036	15.2	5.9	6.4	4.1	31.7
2037	15.9	6.4	6.6	4.3	33.2
2038	16.6	6.7	6.9	4.4	34.6
2039	17.3	7.2	7.1	4.6	36.2
2040	18.4	7.1	7.5	4.7	37.7
2041	19.4	7.2	7.8	4.8	39.2
2042	20.0	7.9	8.1	4.9	40.7
2043	20.4	8.6	8.3	4.9	42.1
2044	21.4	8.8	8.7	5.0	43.8
2045	22.4	9.2	9.0	5.0	45.7
2046	23.9	9.3	9.6	5.0	47.7
2047	25.2	9.3	10.1	5.0	49.6
2048	26.6	9.3	10.6	5.0	51.6
2049	28.0	9.7	11.1	5.0	53.8
2050	29.4	10.1	11.7	4.9	56.0
2051	30.7	10.5	12.2	4.8	58.3
2052	32.3	11.2	12.8	4.7	61.0
2053	33.8	14.0	13.4	3.8	65.0

Table A.22. Cost of generation by cost categories – the NET-2 Scenario (2020-2053, 2021 Billion USD)

	Capital Costs	**Feedstock Fuel Costs**	**Fixed O&M Costs**	**Variable O&M Costs**	**Total**
2020	6.7	3.7	3.1	0.8	14.4
2021	7.2	11.3	3.4	0.8	22.7
2022	7.4	24.1	3.5	0.8	35.8
2023	8.0	16.1	3.7	0.9	28.7
2024	8.6	14.4	3.9	0.9	27.8
2025	9.3	12.8	4.1	2.2	28.4
2026	10.0	10.8	4.4	2.4	27.5
2027	10.2	10.4	4.5	2.6	27.7
2028	10.6	9.1	4.6	2.8	27.1
2029	10.8	7.9	4.8	3.0	26.5
2030	11.6	5.9	5.1	3.1	25.7
2031	12.5	5.1	5.4	3.3	26.2
2032	12.8	5.4	5.5	3.5	27.2
2033	13.2	5.7	5.7	3.6	28.2
2034	14.0	5.6	6.0	3.8	29.4
2035	14.8	5.5	6.3	3.9	30.6
2036	15.3	6.0	6.5	4.0	31.8
2037	15.7	6.7	6.7	4.2	33.3
2038	16.2	7.3	6.9	4.3	34.6
2039	16.6	8.0	7.1	4.3	36.0
2040	17.3	8.3	7.4	4.4	37.5
2041	18.0	8.8	7.7	4.5	39.0
2042	18.2	10.1	7.9	4.5	40.8
2043	18.3	11.6	8.1	4.5	42.4
2044	18.9	12.3	8.4	4.5	44.2
2045	19.6	13.3	8.7	4.5	46.2
2046	21.5	12.5	9.4	4.6	48.0
2047	23.3	11.3	10.2	4.6	49.3
2048	25.2	10.2	10.9	4.5	50.9
2049	27.1	9.6	11.7	4.5	52.8
2050	28.8	9.2	12.4	4.4	54.8
2051	30.5	8.9	13.2	4.3	57.0
2052	32.5	8.9	13.9	4.2	59.5
2053	34.3	9.7	14.7	3.4	62.1

Table A.23. Cost of generation by cost categories – the NET-3 Scenario (2020-2053, 2021 Billion USD)

	Capital Costs	Feedstock Fuel Costs	Fixed O&M Costs	Variable O&M Costs	Total
2020	6.7	3.7	3.1	0.8	14.4
2021	7.2	10.0	3.4	0.8	21.4
2022	7.4	21.2	3.5	0.8	32.8
2023	8.0	13.6	3.7	0.8	26.2
2024	8.6	11.9	3.9	0.9	25.3
2025	9.3	10.4	4.1	2.2	26.0
2026	10.9	8.5	4.6	2.4	26.3
2027	12.0	8.3	4.8	2.6	27.6
2028	13.1	7.0	5.1	2.7	28.0
2029	14.2	5.8	5.4	2.9	28.4
2030	15.4	4.6	5.7	3.1	28.8
2031	16.7	3.9	6.0	3.2	29.9
2032	17.9	3.8	6.4	3.4	31.4
2033	19.1	3.6	6.7	3.5	32.9
2034	20.4	3.5	7.0	3.7	34.6
2035	21.6	3.5	7.3	3.8	36.3
2036	22.0	3.5	7.5	3.9	37.0
2037	22.4	3.7	7.7	4.0	37.8
2038	22.7	3.9	7.9	4.1	38.6
2039	23.0	4.2	8.1	4.2	39.4
2040	23.3	4.5	8.2	4.2	40.2
2041	23.5	4.9	8.4	4.3	41.1
2042	23.6	5.4	8.6	4.3	42.0
2043	23.6	6.1	8.8	4.3	42.8
2044	23.3	6.8	8.9	4.3	43.2
2045	23.0	7.6	9.0	4.3	43.8
2046	23.1	7.1	9.2	4.2	43.7
2047	23.2	7.1	9.5	4.1	43.9
2048	24.2	6.7	10.0	4.0	44.9
2049	25.3	6.4	10.4	3.9	46.1
2050	26.2	6.3	10.9	3.8	47.1
2051	27.3	5.9	11.4	3.6	48.2
2052	28.9	5.4	11.9	3.4	49.6
2053	30.3	6.2	12.4	2.5	51.4

Table A.24. Unit cost of generation by scenarios between 2020 and 2053 (USD/MWh)

	BAU Scenario	MIT Scenario	NET-1 Scenario	NET-2 Scenario	NET-3 Scenario
2020	46.9	46.9	46.9	46.9	46.9
2021	67.6	68.8	71.6	71.6	67.7
2022	98.4	101.2	108.7	108.7	99.8
2023	77.9	77.8	83.9	83.9	76.5
2024	73.1	73.1	78.4	78.4	71.3
2025	68.8	68.6	76.7	76.7	70.2
2026	64.2	64.0	71.7	71.8	68.6
2027	61.0	60.8	69.4	69.7	69.5
2028	57.4	57.2	65.7	66.0	68.0
2029	53.9	53.9	61.7	62.2	66.4
2030	50.5	50.8	57.7	58.5	65.1
2031	50.2	51.0	57.6	58.3	65.9
2032	49.6	50.3	57.4	58.1	66.4
2033	49.1	49.8	57.3	57.9	66.8
2034	48.8	49.9	57.3	57.9	67.3
2035	48.5	50.0	57.4	57.9	67.7
2036	48.2	49.7	57.6	57.9	66.3
2037	48.2	49.6	57.9	58.2	65.1
2038	47.8	49.3	58.1	58.1	63.8
2039	47.4	49.2	58.2	58.0	62.5
2040	47.0	49.0	58.3	58.0	61.3
2041	46.5	48.7	58.3	58.1	60.2
2042	45.9	48.0	58.2	58.2	59.1
2043	44.9	47.0	57.8	58.2	57.8
2044	44.5	46.9	57.8	58.3	56.3
2045	44.2	46.8	57.9	58.6	55.0
2046	44.0	46.5	58.1	58.4	52.5
2047	43.5	46.0	58.0	57.7	50.6
2048	43.1	45.6	58.0	57.2	49.7
2049	42.7	45.3	58.0	57.0	48.8
2050	42.3	44.9	58.0	56.8	48.0
2051	41.8	44.4	58.1	56.8	47.0
2052	41.5	44.2	58.4	57.0	46.4
2053	41.1	44.0	59.8	57.4	46.3

Table A.25. Carbon expenses by fuels – the NET-1 Scenario (2020-2053, 2021 Million USD)

	Liquid Fuels	Natural Gas	Lignite	Hard Coal	Total
2025	5.3	193.9	345.4	711.8	**1256.4**
2026	6.1	198.4	420.8	818.6	**1443.8**
2027	6.9	270.1	425.8	925.4	**1628.3**
2028	7.7	328.2	441.0	1032.2	**1809.1**
2029	8.5	401.6	436.3	1139.0	**1985.4**
2030	9.3	385.1	516.0	1245.8	**2156.2**
2031	10.2	257.4	713.8	1336.7	**2318.1**
2032	11.0	294.9	722.8	1443.5	**2472.2**
2033	11.8	336.6	719.1	1550.4	**2617.8**
2034	12.6	294.9	812.6	1634.9	**2754.9**
2035	13.4	256.9	896.1	1713.9	**2880.3**
2036	14.1	287.2	869.0	1803.4	**2973.7**
2037	14.8	346.5	794.1	1898.5	**3054.0**
2038	15.6	370.6	742.4	1977.8	**3106.4**
2039	16.3	425.3	639.3	2061.6	**3142.6**
2040	17.1	357.9	700.9	2087.9	**3163.7**
2041	17.8	300.6	742.7	2106.2	**3167.4**
2042	18.6	410.8	523.0	2200.0	**3152.3**
2043	19.3	547.9	250.3	2301.0	**3118.5**
2044	20.0	546.9	170.1	2328.8	**3065.8**
2045	20.8	591.5	0.0	2366.5	**2978.7**
2046	21.5	493.3	60.7	2327.3	**2902.9**
2047	22.3	426.9	0.0	2300.6	**2749.8**
2048	19.4	364.6	0.0	2286.4	**2670.4**
2049	20.0	320.0	0.0	2176.2	**2516.3**
2050	19.2	287.1	0.0	2031.4	**2337.7**
2051	19.2	286.6	0.0	1832.8	**2138.6**
2052	19.3	411.3	0.0	1486.2	**1916.9**
2053	0.5	1057.8	0.0	2.5	**1060.8**
Total	**418.7**	**11050.7**	**11942.3**	**49127.2**	**72538.9**

Table A.26. Carbon expenses by fuels – the NET-2 Scenario (2020-2053, 2021 Million USD)

	Liquid Fuels	Natural Gas	Lignite	Hard Coal	Total
2025	5.34	193.89	345.43	711.76	**1256.4**
2026	6.15	198.35	420.76	818.57	**1443.8**
2027	6.95	270.14	425.82	925.37	**1628.3**
2028	7.75	318.10	451.08	1,032.18	**1809.1**
2029	8.55	384.23	453.65	1,138.98	**1985.4**
2030	9.35	366.11	534.96	1,245.79	**2156.2**
2031	10.15	269.73	708.87	1,332.00	**2320.8**
2032	10.95	342.40	685.94	1,438.67	**2478.0**
2033	11.75	424.32	645.55	1,545.57	**2627.2**
2034	12.55	421.13	705.56	1,628.33	**2767.6**
2035	13.35	428.53	746.71	1,709.43	**2898.0**
2036	14.10	552.71	626.06	1,812.55	**3005.4**
2037	14.84	717.27	446.56	1,922.67	**3101.3**
2038	15.58	890.75	247.81	2,031.61	**3185.8**
2039	16.32	1,097.43	-	2,143.25	**3257.0**
2040	17.07	1,206.68	-	2,091.47	**3315.2**
2041	17.81	1,372.17	-	1,968.98	**3359.0**
2042	18.55	1,795.18	-	1,573.88	**3387.6**
2043	19.30	2,275.44	-	1,105.78	**3400.5**
2044	20.04	2,577.52	-	798.98	**3396.5**
2045	8.24	2,953.82	-	413.10	**3375.2**
2046	21.52	2,622.54	-	691.49	**3335.6**
2047	22.27	2,270.87	-	983.85	**3277.0**
2048	21.52	1,956.83	-	1,220.31	**3198.7**
2049	20.46	1,736.42	-	1,342.40	**3099.3**
2050	20.67	1,571.06	-	1,386.80	**2978.5**
2051	19.03	1,465.16	-	1,351.40	**2835.6**
2052	19.31	1,430.16	-	1,219.71	**2669.2**
2053	-	1,798.85	-	-	**1798.8**
Total	**409.5**	**33907.8**	**7444.8**	**37584.9**	**79346.9**

Table A.27. Carbon expenses by fuels – the NET-3 Scenario (2020-2053, 2021 Million USD)

	Liquid Fuels	Natural Gas	Lignite	Hard Coal	Total
2025	5.34	125.49	413.88	711.76	**1256.5**
2026	6.15	113.48	505.67	818.57	**1443.9**
2027	6.95	166.79	529.22	925.37	**1628.3**
2028	7.75	179.96	589.27	1,032.18	**1809.2**
2029	8.55	197.67	640.26	1,138.98	**1985.5**
2030	9.35	208.49	692.62	1,245.79	**2156.2**
2031	10.15	124.78	833.26	1,352.60	**2320.8**
2032	10.95	115.81	891.85	1,459.40	**2478.0**
2033	11.75	105.64	943.64	1,566.21	**2627.2**
2034	12.55	105.57	976.48	1,673.01	**2767.6**
2035	13.35	123.08	971.73	1,779.82	**2888.0**
2036	14.10	135.83	976.87	1,878.68	**3005.5**
2037	14.84	183.29	925.77	1,977.54	**3101.4**
2038	15.58	236.95	856.97	2,076.40	**3185.9**
2039	16.32	327.15	738.49	2,175.26	**3257.2**
2040	17.07	426.92	597.38	2,274.12	**3315.5**
2041	17.81	552.99	415.47	2,372.98	**3359.2**
2042	18.55	724.43	173.20	2,471.84	**3388.0**
2043	19.30	940.84	-	2,440.89	**3401.0**
2044	20.04	1,196.28	-	2,180.78	**3397.1**
2045	20.78	1,494.45	-	1,860.56	**3375.8**
2046	21.52	1,380.80	-	1,933.78	**3336.1**
2047	18.94	1,469.86	-	1,788.54	**3277.3**
2048	19.02	1,428.96	-	1,750.92	**3198.9**
2049	19.63	1,435.81	-	1,643.99	**3099.4**
2050	20.84	1,457.76	-	1,499.99	**2978.6**
2051	22.08	1,415.63	-	1,397.91	**2835.6**
2052	23.64	1,330.71	-	1,314.88	**2669.2**
2053	-	1,798.85	-	-	**1798.8**
Total	**422.9**	**19504.3**	**12672.0**	**46742.7**	**79341.9**

Table A.28. Cumulative and yearly investment costs – the BAU Scenario (2021-2053) (2021 billion USD)

	Natural Gas	Hydro	Coal	Solar	Wind	Nuclear	Others	Coal with CCS	Natural Gas with CCS	Battery Storage	Total
2021	0.1	1.3	2.0	0.6	1.1	0.0	3.3	0.0	0.0	0.0	**8.5**
2022	0.0	0.0	0.0	0.4	1.4	0.0	0.7	0.0	0.0	0.0	**2.5**
2023	0.0	0.7	0.1	0.9	1.8	7.6	0.4	0.0	0.0	0.0	**11.3**
2024	0.0	1.3	1.1	0.6	0.2	7.6	0.0	0.0	0.0	0.0	**10.7**
2025	0.0	1.3	1.5	0.6	1.4	7.6	0.0	0.0	0.0	0.0	**12.4**
2026	0.0	0.0	1.4	0.6	1.4	7.6	0.2	0.0	0.0	0.0	**11.2**
2027	0.0	0.0	1.4	0.6	1.4	0.0	0.2	0.0	0.0	0.0	**3.6**
2028	0.0	0.0	1.4	0.5	2.1	0.0	0.2	0.0	0.0	0.0	**4.3**
2029	0.0	0.0	1.4	0.5	2.5	0.0	0.2	0.0	0.0	0.0	**4.7**
2030	0.0	0.0	1.4	0.5	2.5	0.0	0.2	0.0	0.0	0.0	**4.6**
2031	0.0	0.0	1.4	0.5	0.0	0.0	0.2	0.0	0.0	0.0	**2.2**
2032	0.0	0.0	1.4	0.5	0.0	0.0	0.2	0.0	0.0	0.0	**2.1**
2033	0.0	0.0	1.4	0.5	0.0	0.0	0.2	0.0	0.0	0.0	**2.1**
2034	0.0	0.0	1.4	0.5	0.0	0.0	0.2	0.0	0.0	0.0	**2.1**
2035	0.0	0.0	1.4	0.5	0.0	0.0	0.2	0.0	0.0	0.0	**2.1**
2036	0.0	0.0	1.4	0.5	0.0	0.0	0.2	0.0	0.0	0.0	**2.1**
2037	0.0	0.0	1.4	0.5	1.4	0.0	0.2	0.0	0.0	0.0	**3.5**
2038	0.0	0.0	1.4	0.5	1.4	0.0	0.2	0.0	0.0	0.0	**3.4**
2039	0.0	0.0	1.4	0.5	1.4	0.0	0.2	0.0	0.0	0.0	**3.4**
2040	0.0	0.0	1.4	0.5	1.4	0.0	0.2	0.0	0.0	0.0	**3.4**
2041	0.0	0.0	1.4	0.4	1.4	0.0	0.2	0.0	0.0	0.0	**3.4**
2042	0.0	0.0	1.4	0.4	1.4	0.0	0.2	0.0	0.0	0.0	**3.4**
2043	0.0	0.0	1.4	0.4	1.4	0.0	0.2	0.0	0.0	0.0	**3.4**
2044	0.0	0.0	1.4	0.4	1.4	0.0	0.2	0.0	0.0	0.0	**3.3**
2045	0.0	0.0	1.4	0.4	1.4	0.0	0.2	0.0	0.0	0.0	**3.3**
2046	0.2	0.0	1.4	0.4	1.4	0.0	0.1	0.0	0.0	0.0	**3.5**
2047	0.6	0.0	1.4	0.4	1.4	0.0	0.1	0.0	0.0	0.0	**3.9**
2048	0.4	0.0	1.4	0.4	1.3	0.0	0.1	0.0	0.0	0.0	**3.7**
2049	0.4	0.0	1.4	0.4	1.3	0.0	0.1	0.0	0.0	0.0	**3.7**
2050	0.4	0.0	1.4	0.4	1.3	0.0	0.1	0.0	0.0	0.0	**3.7**
2051	0.4	0.0	1.4	0.4	1.3	0.0	0.1	0.0	0.0	0.0	**3.7**
2052	0.4	0.0	1.4	0.4	1.3	0.0	0.1	0.0	0.0	0.0	**3.7**
2053	0.4	0.0	1.4	0.4	1.3	0.0	0.1	0.0	0.0	0.0	**3.7**
Total	**3.5**	**4.5**	**43.9**	**16.0**	**38.9**	**30.4**	**9.7**	**0.0**	**0.0**	**0.0**	**146.9**

Table A.29. Cumulative and yearly investment costs – the MIT Scenario (2021-2053) (2021 billion USD)

	Natural Gas	Hydro	Coal	Solar	Wind	Nuclear	Others	Coal with CCS	Natural Gas with CCS	Battery Storage	Total
2021	0.1	1.3	2.0	0.6	1.1	0.0	3.3	0.0	0.0	0.0	**8.5**
2022	0.0	0.0	0.0	0.4	1.4	0.0	0.7	0.0	0.0	0.0	**2.5**
2023	0.0	0.7	0.1	0.9	1.8	7.6	0.4	0.0	0.0	0.0	**11.3**
2024	0.0	1.3	0.7	0.6	0.2	7.6	0.0	0.0	0.0	0.0	**10.3**
2025	0.0	1.3	1.0	0.6	1.4	7.6	0.0	0.0	0.0	0.0	**11.9**
2026	0.0	0.0	1.4	0.6	1.4	7.6	0.2	0.0	0.0	0.0	**11.2**
2027	0.0	0.0	1.4	0.6	1.4	0.0	0.2	0.0	0.0	0.0	**3.6**
2028	0.0	0.0	1.4	0.8	2.1	0.0	0.2	0.0	0.0	0.0	**4.6**
2029	0.0	0.0	0.7	0.8	2.5	0.0	0.2	0.0	0.0	0.0	**4.2**
2030	0.0	0.0	1.4	0.8	2.5	7.1	0.2	0.0	0.0	0.0	**12.0**
2031	0.0	0.0	0.3	0.8	0.0	7.1	0.2	0.0	0.0	0.0	**8.4**
2032	0.0	0.0	1.3	0.8	1.3	0.0	0.2	0.0	0.0	0.0	**3.6**
2033	0.0	0.0	0.0	0.8	2.1	0.0	0.2	0.0	0.0	0.0	**3.1**
2034	0.0	0.0	0.4	0.8	2.1	7.1	0.2	0.0	0.0	0.0	**10.6**
2035	0.0	0.0	0.0	0.7	2.1	7.1	0.2	0.0	0.0	0.0	**10.1**
2036	0.0	0.0	0.1	0.7	2.1	0.0	0.2	0.0	0.0	0.0	**3.1**
2037	0.0	0.0	0.0	0.7	2.1	0.0	0.2	0.0	0.0	0.0	**3.0**
2038	0.0	0.0	0.0	0.7	2.1	0.0	0.2	0.0	0.0	0.0	**3.0**
2039	0.0	0.0	0.0	0.7	2.1	0.0	0.2	0.0	0.0	0.0	**3.0**
2040	0.0	0.0	0.0	0.7	2.1	7.0	0.2	0.0	0.0	0.0	**9.9**
2041	0.0	0.0	1.4	0.7	2.1	7.0	0.2	0.0	0.0	0.0	**11.3**
2042	0.0	0.0	1.3	0.7	2.1	0.0	0.2	0.0	0.0	0.0	**4.2**
2043	0.0	0.0	0.0	0.6	2.0	0.0	0.2	0.0	0.0	0.0	**2.9**
2044	0.0	0.0	1.4	0.6	2.0	7.0	0.2	0.0	0.0	0.0	**11.2**
2045	0.0	0.0	0.1	0.6	2.0	7.0	0.2	0.0	0.0	0.0	**9.9**
2046	0.0	0.0	0.0	0.6	2.0	0.0	0.1	0.0	0.0	0.0	**2.8**
2047	0.0	0.0	0.0	0.6	2.0	0.0	0.1	0.0	0.0	0.0	**2.8**
2048	0.0	0.7	0.0	0.6	2.0	0.0	0.1	0.0	0.0	0.0	**3.4**
2049	0.0	0.9	0.0	0.6	2.0	0.0	0.1	0.0	0.0	0.0	**3.7**
2050	0.0	0.9	0.0	0.6	2.0	0.0	0.1	0.0	0.0	0.0	**3.6**
2051	0.0	0.9	1.3	0.6	2.0	0.0	0.1	0.0	0.0	0.0	**4.9**
2052	0.0	0.9	1.3	0.6	2.0	0.0	0.1	0.0	0.0	0.0	**4.9**
2053	0.0	0.5	1.4	0.6	2.0	0.0	0.1	0.0	0.0	0.0	**4.6**
Total	**0.1**	**9.4**	**20.3**	**21.9**	**60.1**	**86.7**	**9.7**	**0.0**	**0.0**	**0.0**	**208.0**

Table A.30. Cumulative and yearly investment costs – the NET-1 Scenario (2021-2053) (2021 billion USD)

	Natural Gas	Hydro	Coal	Solar	Wind	Nuclear	Others	Coal with CCS	Natural Gas with CCS	Battery Storage	Total
2021	0.1	1.3	2.0	0.6	1.1	0.0	3.3	0.0	0.0	0.0	**8.5**
2022	0.0	0.0	0.0	0.4	1.4	0.0	0.7	0.0	0.0	0.0	**2.5**
2023	0.0	0.7	0.1	0.9	1.8	7.6	0.4	0.0	0.0	0.0	**11.3**
2024	0.0	1.3	0.7	0.6	0.2	7.6	0.0	0.0	0.0	0.0	**10.3**
2025	0.0	1.3	1.0	0.6	1.4	7.6	0.0	0.0	0.0	0.0	**11.9**
2026	0.0	0.9	0.0	0.6	1.4	7.6	0.9	0.0	0.0	0.0	**11.4**
2027	0.0	0.9	0.0	0.6	1.4	0.0	0.9	0.0	0.0	0.0	**3.8**
2028	0.0	0.0	0.0	1.6	2.1	0.0	0.9	0.0	0.0	0.0	**4.6**
2029	0.0	0.0	0.0	1.6	2.5	0.0	0.2	0.0	0.0	0.0	**4.3**
2030	0.0	0.0	0.0	1.6	2.5	7.1	0.9	0.0	0.0	0.0	**12.0**
2031	0.0	0.0	0.0	1.6	4.2	7.1	0.8	0.0	1.3	0.0	**15.0**
2032	0.0	0.0	0.0	1.5	4.2	0.0	0.8	0.0	1.3	0.0	**7.9**
2033	0.0	0.0	0.0	1.5	4.2	0.0	0.8	0.0	1.3	0.0	**7.8**
2034	0.0	0.0	0.0	1.5	4.2	7.1	0.8	0.0	1.3	0.0	**14.9**
2035	0.0	0.0	0.0	1.5	4.2	7.1	0.8	0.6	1.3	0.0	**15.4**
2036	0.0	0.0	0.0	1.5	4.2	0.0	0.8	3.0	1.3	0.0	**10.7**
2037	0.0	0.0	0.0	1.4	4.2	0.0	0.8	3.0	1.3	0.0	**10.7**
2038	0.0	0.0	0.0	1.4	4.1	0.0	0.8	6.0	1.3	0.0	**13.6**
2039	0.0	0.0	0.0	1.4	4.1	0.0	0.8	6.0	1.3	0.0	**13.6**
2040	0.0	0.0	0.0	1.4	4.1	7.0	0.8	6.0	1.3	0.0	**20.5**
2041	0.0	0.0	0.0	1.3	4.1	7.0	0.8	6.0	1.3	0.0	**20.5**
2042	0.0	0.0	0.0	1.3	4.1	0.0	0.8	6.0	1.3	0.0	**13.5**
2043	0.0	0.0	0.0	1.3	4.1	0.0	0.8	6.0	1.3	0.0	**13.4**
2044	0.0	0.0	0.0	1.3	4.1	7.0	0.8	6.0	1.3	0.0	**20.4**
2045	0.0	0.0	0.0	1.3	4.1	7.0	0.8	6.0	1.3	0.0	**20.3**
2046	0.0	0.0	0.0	1.2	4.1	15.2	0.8	6.0	1.3	0.0	**28.5**
2047	0.0	0.0	0.0	1.2	4.1	15.2	0.8	6.0	1.3	0.0	**28.5**
2048	0.0	0.0	0.0	1.2	4.0	15.2	0.7	6.0	1.3	0.0	**28.4**
2049	0.0	0.0	0.0	1.2	4.0	15.2	0.7	6.0	1.3	0.0	**28.4**
2050	0.0	0.2	0.0	1.1	4.0	15.2	0.7	6.0	1.3	0.0	**28.6**
2051	0.8	0.9	0.0	1.1	4.0	15.2	0.7	6.0	1.3	0.0	**30.1**
2052	0.8	0.9	0.0	1.1	4.0	15.2	0.7	6.0	1.3	0.0	**30.1**
2053	0.8	0.9	0.0	1.1	4.0	15.2	0.7	6.0	1.3	0.0	**30.1**
Total	**2.4**	**9.4**	**3.7**	**39.5**	**110.2**	**208.3**	**26.2**	**102.2**	**29.6**	**0.0**	**531.5**

Table A.31. Cumulative and yearly investment costs – the NET-2 Scenario (2021-2053) (2021 billion USD)

	Natural Gas	Hydro	Coal	Solar	Wind	Nuclear	Others	Coal with CCS	Natural Gas with CCS	Battery Storage	Total
2021	0.1	1.3	2.0	0.6	1.1	0.0	3.3	0.0	0.0	0.0	**8.5**
2022	0.0	0.0	0.0	0.4	1.4	0.0	0.7	0.0	0.0	0.0	**2.5**
2023	0.0	0.7	0.1	0.9	1.8	7.6	0.4	0.0	0.0	0.0	**11.3**
2024	0.0	1.3	0.7	0.6	0.2	7.6	0.0	0.0	0.0	0.0	**10.3**
2025	0.0	1.3	1.0	0.6	1.4	7.6	0.0	0.0	0.0	0.0	**11.9**
2026	0.5	0.9	0.0	0.6	1.4	7.6	0.9	0.0	0.0	0.0	**11.9**
2027	0.9	0.9	0.0	0.6	1.4	0.0	0.9	0.0	0.0	0.0	**4.7**
2028	0.9	0.9	0.0	1.6	2.1	0.0	0.9	0.0	0.0	0.0	**6.5**
2029	0.9	0.0	0.0	1.6	2.5	0.0	0.9	0.0	0.0	0.0	**5.9**
2030	0.9	0.0	0.0	1.6	2.5	7.1	0.9	0.0	0.0	0.0	**12.9**
2031	0.9	0.0	0.0	1.6	4.2	7.1	0.8	0.0	0.0	0.0	**14.7**
2032	0.9	0.0	0.0	1.5	4.2	0.0	0.8	0.0	0.0	0.0	**7.5**
2033	0.9	0.0	0.0	1.5	4.2	0.0	0.8	0.0	0.0	0.0	**7.5**
2034	0.9	0.0	0.0	1.5	4.2	7.1	0.8	0.0	0.0	0.0	**14.6**
2035	0.9	0.0	0.0	1.5	4.2	7.1	0.8	0.0	0.0	0.0	**14.5**
2036	0.9	0.0	0.0	1.5	4.2	0.0	0.8	0.0	0.0	0.0	**7.4**
2037	0.9	0.0	0.0	1.4	4.2	0.0	0.8	0.0	0.0	0.0	**7.3**
2038	0.9	0.3	0.0	1.4	4.1	0.0	0.8	0.0	0.0	0.0	**7.6**
2039	0.9	0.9	0.0	1.4	4.1	0.0	0.8	0.0	0.0	0.0	**8.2**
2040	0.9	0.8	0.0	1.4	4.1	7.0	0.8	0.0	0.0	0.0	**15.0**
2041	0.9	0.0	0.0	1.3	4.1	7.0	0.8	0.0	0.0	0.0	**14.2**
2042	0.9	0.0	0.0	1.3	4.1	0.0	0.8	0.0	0.0	0.0	**7.1**
2043	0.9	0.0	0.0	1.3	4.1	0.0	0.8	0.0	0.0	0.0	**7.1**
2044	0.9	0.0	0.0	1.3	4.1	7.0	0.8	0.0	0.0	0.0	**14.0**
2045	0.9	0.0	0.0	1.3	4.1	7.0	0.8	0.0	0.0	0.0	**14.0**
2046	0.0	0.0	0.0	1.2	4.1	30.4	0.8	0.0	0.0	0.0	**36.5**
2047	0.0	0.0	0.0	1.2	4.1	30.4	0.8	0.0	0.0	0.0	**36.4**
2048	0.0	0.0	0.0	1.2	4.0	30.4	0.7	0.0	0.0	0.0	**36.4**
2049	0.0	0.0	0.0	1.2	4.0	30.4	0.7	0.0	0.0	0.0	**36.3**
2050	0.0	0.0	0.0	1.1	4.0	30.4	0.7	0.0	0.0	0.0	**36.3**
2051	0.0	0.0	0.0	1.1	4.0	30.4	0.7	0.0	0.0	0.0	**36.3**
2052	0.0	0.0	0.0	1.1	4.0	30.4	0.7	0.0	0.0	0.0	**36.3**
2053	0.0	0.0	0.0	1.1	4.0	30.4	0.7	0.0	0.0	0.0	**36.3**
Total	**18.3**	**9.4**	**3.7**	**39.5**	**110.2**	**330.0**	**26.8**	**0.0**	**0.0**	**0.0**	**538.0**

Table A.32. Cumulative and yearly investment costs – the NET-3 Scenario (2021-2053) (2021 billion USD)

	Natural Gas	Hydro	Coal	Solar	Wind	Nuclear	Others	Coal with CCS	Natural Gas with CCS	Battery Storage	Total
2021	0.1	1.3	2.0	0.6	1.1	0.0	3.3	0.0	0.0	0.0	**8.5**
2022	0.0	0.0	0.0	0.4	1.4	0.0	0.7	0.0	0.0	0.0	**2.5**
2023	0.0	0.7	0.1	0.9	1.8	7.6	0.4	0.0	0.0	0.0	**11.3**
2024	0.0	1.3	0.7	0.6	0.2	7.6	0.0	0.0	0.0	0.0	**10.3**
2025	0.0	1.3	1.0	0.6	1.4	7.6	0.0	0.0	0.0	0.0	**11.9**
2026	0.9	0.9	0.0	0.6	1.4	7.6	0.9	0.0	0.0	6.6	**18.9**
2027	0.9	0.9	0.0	0.6	1.4	0.0	0.9	0.0	0.0	6.5	**11.2**
2028	0.9	0.0	0.0	1.9	2.1	0.0	0.9	0.0	0.0	6.4	**12.2**
2029	0.9	0.0	0.0	1.9	2.5	0.0	0.9	0.0	0.0	6.2	**12.4**
2030	0.9	0.0	0.0	1.9	2.5	0.0	0.9	0.0	0.0	6.1	**12.2**
2031	0.9	0.0	0.0	1.8	5.6	0.0	0.8	0.0	0.0	6.0	**15.2**
2032	0.9	0.0	0.0	1.8	5.6	0.0	0.8	0.0	0.0	5.8	**15.0**
2033	0.9	0.0	0.0	1.8	5.6	0.0	0.8	0.0	0.0	5.7	**14.8**
2034	0.9	0.0	0.0	1.8	5.6	0.0	0.8	0.0	0.0	5.6	**14.7**
2035	0.9	0.0	0.0	1.7	5.6	0.0	0.8	0.0	0.0	5.4	**14.5**
2036	0.9	0.0	0.0	1.7	5.6	0.0	0.8	0.0	0.0	5.3	**14.3**
2037	0.9	0.0	0.0	1.7	5.5	0.0	0.8	0.0	0.0	5.2	**14.1**
2038	0.9	0.0	0.0	1.6	5.5	0.0	0.8	0.0	0.0	5.0	**13.9**
2039	0.9	0.0	0.0	1.6	5.5	0.0	0.8	0.0	0.0	4.9	**13.8**
2040	0.9	0.0	0.0	1.6	5.5	0.0	0.8	0.0	0.0	4.8	**13.6**
2041	0.9	0.0	0.0	1.6	5.5	0.0	0.8	0.0	0.0	4.6	**13.4**
2042	0.9	0.0	0.0	1.5	5.5	0.0	0.8	0.0	0.0	4.5	**13.2**
2043	0.9	0.0	0.0	1.5	5.5	0.0	0.8	0.0	0.0	4.4	**13.1**
2044	0.9	0.0	0.0	1.5	5.4	0.0	0.8	0.0	0.0	0.0	**8.6**
2045	0.9	0.6	0.0	1.5	5.4	0.0	0.8	0.0	0.0	0.0	**9.2**
2046	0.9	0.0	0.0	3.3	10.8	0.0	0.8	0.0	0.0	0.0	**15.8**
2047	0.9	0.0	0.0	3.2	10.8	0.0	0.8	0.0	0.0	0.0	**15.7**
2048	0.9	0.0	0.0	3.2	10.8	0.0	0.7	0.0	0.0	7.2	**22.8**
2049	0.9	0.0	0.0	3.1	10.7	0.0	0.7	0.0	0.0	7.0	**22.5**
2050	0.9	0.3	0.0	3.0	10.7	0.0	0.7	0.0	0.0	6.7	**22.5**
2051	0.9	0.9	0.0	3.0	10.7	0.0	0.7	0.0	0.0	7.8	**24.2**
2052	0.9	0.9	0.0	3.0	10.7	0.0	0.7	0.0	0.0	9.5	**25.9**
2053	0.9	0.2	0.0	3.0	10.7	0.0	0.7	0.0	0.0	9.1	**24.7**
Total	**26.3**	**9.4**	**3.7**	**59.5**	**184.7**	**30.4**	**26.8**	**0.0**	**0.0**	**146.3**	**487.0**

Table A.33. GHG emissions by fuel and technology types – the BAU Scenario (2020-2053, Mt CO_2-eq)

	Natural Gas	Coal	Liquid Fuels	Coal with CCS	Natural Gas with CCS	Total
2020	25.8	105.2	0.2	0.0	0.0	**131.2**
2021	13.6	127.3	0.5	0.0	0.0	**141.5**
2022	15.4	128.6	0.5	0.0	0.0	**144.5**
2023	14.2	126.7	0.5	0.0	0.0	**141.4**
2024	13.5	128.0	0.5	0.0	0.0	**142.1**
2025	12.5	129.9	0.5	0.0	0.0	**142.9**
2026	10.2	132.1	0.5	0.0	0.0	**142.8**
2027	10.7	138.3	0.5	0.0	0.0	**149.5**
2028	10.8	144.0	0.5	0.0	0.0	**155.4**
2029	11.1	149.8	0.5	0.0	0.0	**161.4**
2030	11.0	155.2	0.5	0.0	0.0	**166.8**
2031	12.0	162.2	0.5	0.0	0.0	**174.7**
2032	12.9	169.2	0.5	0.0	0.0	**182.7**
2033	13.9	176.2	0.5	0.0	0.0	**190.6**
2034	15.1	183.4	0.5	0.0	0.0	**199.0**
2035	16.4	190.6	0.5	0.0	0.0	**207.5**
2036	18.1	198.5	0.5	0.0	0.0	**217.1**
2037	19.2	205.3	0.5	0.0	0.0	**225.0**
2038	20.5	212.3	0.5	0.0	0.0	**233.4**
2039	21.9	219.3	0.5	0.0	0.0	**241.7**
2040	23.5	226.6	0.5	0.0	0.0	**250.6**
2041	21.4	230.5	0.5	0.0	0.0	**252.5**
2042	21.9	236.7	0.5	0.0	0.0	**259.2**
2043	22.4	243.0	0.5	0.0	0.0	**265.9**
2044	22.9	249.2	0.5	0.0	0.0	**272.7**
2045	23.4	255.5	0.5	0.0	0.0	**279.4**
2046	23.9	261.7	0.5	0.0	0.0	**286.2**
2047	24.7	268.2	0.5	0.0	0.0	**293.5**
2048	25.2	274.5	0.5	0.0	0.0	**300.2**
2049	25.7	280.7	0.5	0.0	0.0	**307.0**
2050	26.2	287.0	0.5	0.0	0.0	**313.7**
2051	26.7	293.3	0.5	0.0	0.0	**320.5**
2052	27.2	299.5	0.5	0.0	0.0	**327.3**
2053	27.7	305.8	0.5	0.0	0.0	**334.0**

Table A.34. GHG emissions by fuel and technology types – the MIT Scenario (2020-2053, Mt CO_2-eq)

	Natural Gas	Coal	Liquid Fuels	Coal with CCS	Natural Gas with CCS	Total
2020	25.8	105.2	0.2	0.0	0.0	**131.2**
2021	15.7	120.1	0.5	0.0	0.0	**136.4**
2022	17.6	121.1	0.5	0.0	0.0	**139.3**
2023	14.2	126.7	0.5	0.0	0.0	**141.4**
2024	13.5	128.0	0.5	0.0	0.0	**142.1**
2025	12.5	129.9	0.5	0.0	0.0	**142.9**
2026	10.2	132.1	0.5	0.0	0.0	**142.8**
2027	10.7	138.3	0.5	0.0	0.0	**149.5**
2028	10.6	143.7	0.5	0.0	0.0	**154.9**
2029	12.1	145.5	0.5	0.0	0.0	**158.2**
2030	9.1	149.3	0.5	0.0	0.0	**158.9**
2031	9.0	149.8	0.5	0.0	0.0	**159.3**
2032	9.2	155.2	0.5	0.0	0.0	**165.0**
2033	10.8	156.5	0.5	0.0	0.0	**167.8**
2034	9.8	156.1	0.5	0.0	0.0	**166.4**
2035	9.4	154.4	0.5	0.0	0.0	**164.3**
2036	11.5	157.0	0.5	0.0	0.0	**169.1**
2037	13.9	159.2	0.5	0.0	0.0	**173.5**
2038	16.5	161.5	0.5	0.0	0.0	**178.5**
2039	20.5	159.4	0.5	0.0	0.0	**180.4**
2040	20.4	161.5	0.5	0.0	0.0	**182.4**
2041	15.0	163.6	0.5	0.0	0.0	**179.1**
2042	15.0	169.0	0.5	0.0	0.0	**184.5**
2043	16.8	170.5	0.5	0.0	0.0	**187.9**
2044	14.5	173.2	0.5	0.0	0.0	**188.3**
2045	14.0	172.2	0.5	0.0	0.0	**186.7**
2046	15.8	173.6	0.5	0.0	0.0	**189.9**
2047	17.9	175.3	0.5	0.0	0.0	**193.7**
2048	19.7	175.6	0.5	0.0	0.0	**195.8**
2049	21.7	175.0	0.5	0.0	0.0	**197.2**
2050	23.6	174.4	0.5	0.0	0.0	**198.6**
2051	24.7	174.7	0.5	0.0	0.0	**199.9**
2052	25.8	174.9	0.5	0.0	0.0	**201.2**
2053	28.0	171.9	0.5	0.0	0.0	**200.4**

Table A.35. GHG emissions by fuel and technology types – the NET-1 Scenario (2020-2053, Mt CO_2-eq)

	Natural Gas	Coal	Liquid Fuels	Coal with CCS	Natural Gas with CCS	Total
2020	25.8	105.2	0.2	0.0	0.0	**131.2**
2021	20.6	103.6	0.5	0.0	0.0	**124.6**
2022	23.4	101.4	0.5	0.0	0.0	**125.3**
2023	20.6	104.6	0.5	0.0	0.0	**125.8**
2024	20.1	105.4	0.5	0.0	0.0	**126.1**
2025	19.4	106.2	0.5	0.0	0.0	**126.2**
2026	17.3	108.3	0.5	0.0	0.0	**126.1**
2027	20.8	104.4	0.5	0.0	0.0	**125.8**
2028	22.7	102.1	0.5	0.0	0.0	**125.3**
2029	25.1	98.9	0.5	0.0	0.0	**124.6**
2030	22.0	101.1	0.5	0.0	0.0	**123.7**
2031	13.6	108.4	0.5	0.0	0.1	**122.7**
2032	14.4	106.2	0.5	0.0	0.3	**121.4**
2033	15.3	103.6	0.5	0.0	0.4	**119.9**
2034	12.6	104.6	0.5	0.0	0.5	**118.3**
2035	10.3	104.9	0.5	0.1	0.6	**116.4**
2036	10.9	101.7	0.5	0.5	0.8	**114.4**
2037	12.5	97.4	0.5	0.9	0.9	**112.2**
2038	12.7	93.7	0.5	1.8	1.0	**109.8**
2039	13.9	88.8	0.5	2.8	1.1	**107.2**
2040	11.2	87.7	0.5	3.7	1.2	**104.4**
2041	9.0	85.9	0.5	4.7	1.3	**101.4**
2042	11.8	78.8	0.5	5.6	1.4	**98.2**
2043	15.2	71.0	0.5	6.6	1.5	**94.8**
2044	14.6	67.0	0.5	7.5	1.6	**91.3**
2045	15.2	61.1	0.5	8.5	1.7	**87.1**
2046	12.3	59.6	0.5	9.4	1.8	**83.6**
2047	10.3	55.5	0.5	10.2	1.8	**78.3**
2048	8.5	53.4	0.5	10.9	1.9	**75.1**
2049	7.2	49.2	0.5	11.5	2.1	**70.5**
2050	6.3	44.5	0.4	12.2	2.3	**65.8**
2051	6.1	39.0	0.4	12.8	2.5	**60.8**
2052	8.5	30.7	0.4	13.5	2.6	**55.7**
2053	21.2	0.0	0.0	11.7	3.6	**36.5**

Table A.36. GHG emissions by fuel and technology types – the NET-2 Scenario (2020-2053, Mt CO_2-eq)

	Natural Gas	Coal	Liquid Fuels	Coal with CCS	Natural Gas with CCS	Total
2020	25.8	105.2	0.2	0.0	0.0	**131.2**
2021	20.6	103.6	0.5	0.0	0.0	**124.6**
2022	23.4	101.4	0.5	0.0	0.0	**125.3**
2023	20.6	104.6	0.5	0.0	0.0	**125.8**
2024	20.1	105.4	0.5	0.0	0.0	**126.1**
2025	19.4	106.2	0.5	0.0	0.0	**126.2**
2026	17.3	108.3	0.5	0.0	0.0	**126.1**
2027	20.8	104.4	0.5	0.0	0.0	**125.8**
2028	22.0	102.8	0.5	0.0	0.0	**125.3**
2029	24.0	100.0	0.5	0.0	0.0	**124.6**
2030	20.9	102.2	0.5	0.0	0.0	**123.7**
2031	14.2	107.9	0.5	0.0	0.0	**122.7**
2032	16.7	104.1	0.5	0.0	0.0	**121.4**
2033	19.3	100.1	0.5	0.0	0.0	**119.9**
2034	17.9	99.8	0.5	0.0	0.0	**118.2**
2035	17.2	98.7	0.5	0.0	0.0	**116.4**
2036	21.0	92.8	0.5	0.0	0.0	**114.3**
2037	25.9	85.7	0.5	0.0	0.0	**112.1**
2038	30.6	78.5	0.5	0.0	0.0	**109.6**
2039	36.0	70.5	0.5	0.0	0.0	**107.0**
2040	37.8	65.8	0.5	0.0	0.0	**104.1**
2041	41.2	59.3	0.5	0.0	0.0	**101.1**
2042	51.8	45.5	0.5	0.0	0.0	**97.9**
2043	63.1	30.8	0.5	0.0	0.0	**94.4**
2044	68.8	21.4	0.5	0.0	0.0	**90.8**
2045	76.1	10.7	0.2	0.0	0.0	**87.0**
2046	65.2	17.2	0.5	0.0	0.0	**83.0**
2047	54.6	23.7	0.5	0.0	0.0	**78.8**
2048	45.5	28.5	0.5	0.0	0.0	**74.5**
2049	39.1	30.3	0.5	0.0	0.0	**69.9**
2050	34.3	30.4	0.5	0.0	0.0	**65.2**
2051	31.1	28.8	0.4	0.0	0.0	**60.2**
2052	29.5	25.2	0.4	0.0	0.0	**55.1**
2053	36.0	0.0	0.0	0.0	0.0	**36.0**

Table A.37. GHG emissions by fuel and technology types – the NET-3 Scenario (2020-2053, Mt CO_2-eq)

	Natural Gas	Coal	Liquid Fuels	Coal with CCS	Natural Gas with CCS	Total
2020	25.8	105.2	0.2	0.0	0.0	**131.2**
2021	16.1	108.0	0.5	0.0	0.0	**124.7**
2022	18.5	106.3	0.5	0.0	0.0	**125.3**
2023	14.9	110.3	0.5	0.0	0.0	**125.8**
2024	13.9	111.7	0.5	0.0	0.0	**126.1**
2025	12.6	113.1	0.5	0.0	0.0	**126.2**
2026	9.9	115.7	0.5	0.0	0.0	**126.1**
2027	12.8	112.4	0.5	0.0	0.0	**125.8**
2028	12.4	112.3	0.5	0.0	0.0	**125.3**
2029	12.4	111.7	0.5	0.0	0.0	**124.6**
2030	11.9	111.3	0.5	0.0	0.0	**123.7**
2031	6.6	115.6	0.5	0.0	0.0	**122.7**
2032	5.7	115.2	0.5	0.0	0.0	**121.4**
2033	4.8	114.6	0.5	0.0	0.0	**119.9**
2034	4.5	113.3	0.5	0.0	0.0	**118.3**
2035	4.9	110.6	0.5	0.0	0.0	**116.0**
2036	5.2	108.7	0.5	0.0	0.0	**114.4**
2037	6.6	105.0	0.5	0.0	0.0	**112.1**
2038	8.1	101.0	0.5	0.0	0.0	**109.7**
2039	10.7	95.8	0.5	0.0	0.0	**107.1**
2040	13.4	90.3	0.5	0.0	0.0	**104.2**
2041	16.6	84.0	0.5	0.0	0.0	**101.2**
2042	20.9	76.5	0.5	0.0	0.0	**98.0**
2043	26.1	67.9	0.5	0.0	0.0	**94.5**
2044	31.9	58.4	0.5	0.0	0.0	**90.9**
2045	38.5	48.1	0.5	0.0	0.0	**87.1**
2046	34.3	48.2	0.5	0.0	0.0	**83.1**
2047	35.3	43.1	0.5	0.0	0.0	**78.9**
2048	33.2	40.9	0.4	0.0	0.0	**74.5**
2049	32.4	37.2	0.4	0.0	0.0	**70.0**
2050	31.9	32.9	0.5	0.0	0.0	**65.2**
2051	30.0	29.7	0.5	0.0	0.0	**60.2**
2052	27.4	27.2	0.5	0.0	0.0	**55.1**
2053	36.0	0.0	0.0	0.0	0.0	**36.0**

Table A.38. Power generation GHG intensities by scenarios between 2020 and 2053 (tons of CO_2-eq/MWh)

	BAU Scenario	**MIT Scenario**	**NET-1 Scenario**	**NET-2 Scenario**	**NET-3 Scenario**
2020	0.43	0.43	0.43	0.43	0.43
2021	0.45	0.43	0.39	0.39	0.39
2022	0.44	0.42	0.38	0.38	0.38
2023	0.41	0.41	0.37	0.37	0.37
2024	0.40	0.40	0.36	0.36	0.36
2025	0.39	0.39	0.34	0.34	0.34
2026	0.37	0.37	0.33	0.33	0.33
2027	0.38	0.38	0.32	0.32	0.32
2028	0.38	0.38	0.30	0.30	0.30
2029	0.38	0.37	0.29	0.29	0.29
2030	0.38	0.36	0.28	0.28	0.28
2031	0.39	0.35	0.27	0.27	0.27
2032	0.39	0.35	0.26	0.26	0.26
2033	0.40	0.35	0.25	0.25	0.24
2034	0.40	0.34	0.23	0.23	0.23
2035	0.41	0.32	0.22	0.22	0.22
2036	0.42	0.32	0.21	0.21	0.21
2037	0.42	0.32	0.20	0.20	0.19
2038	0.42	0.32	0.18	0.18	0.18
2039	0.42	0.31	0.17	0.17	0.17
2040	0.42	0.31	0.16	0.16	0.16
2041	0.42	0.30	0.15	0.15	0.15
2042	0.42	0.30	0.14	0.14	0.14
2043	0.43	0.30	0.13	0.13	0.13
2044	0.43	0.30	0.12	0.12	0.12
2045	0.43	0.29	0.11	0.11	0.11
2046	0.43	0.29	0.10	0.10	0.10
2047	0.43	0.28	0.09	0.09	0.09
2048	0.43	0.28	0.08	0.08	0.08
2049	0.43	0.28	0.08	0.08	0.07
2050	0.43	0.27	0.07	0.07	0.07
2051	0.43	0.27	0.06	0.06	0.06
2052	0.44	0.27	0.05	0.05	0.05
2053	0.44	0.26	0.03	0.03	0.03

Table A.39. Cumulative and yearly captured CO_2 – the NET-1 Scenario (2031-2053) (million ton CO_2)

	Natural Gas with CCS	Lignite with CCS	Hard Coal with CCS	Total
2031	1	0	0	**1**
2032	3	0	0	**3**
2033	4	0	0	**4**
2034	5	0	0	**5**
2035	6	0	1	**6**
2036	7	0	4	**11**
2037	8	0	7	**15**
2038	9	5	11	**25**
2039	10	10	14	**34**
2040	11	15	17	**43**
2041	12	19	21	**52**
2042	13	24	24	**61**
2043	14	29	28	**70**
2044	15	34	31	**80**
2045	16	39	34	**89**
2046	16	43	38	**97**
2047	16	47	41	**104**
2048	17	49	44	**111**
2049	19	52	48	**118**
2050	21	55	51	**126**
2051	22	57	53	**133**
2052	23	60	56	**139**
2053	32	54	47	**133**
Total	**298**	**592**	**569**	**1459**

APPENDIX 4 – Publications Derived from the Thesis

- U. Calikoglu, M. Aydinalp Koksal, A pathway to achieve the net zero emissions target for the public electricity and heat production sector: A case study for Türkiye, Energy Policy, 179 (2023) 113653. https://doi.org/10.1016/j.enpol.2023.113653.