Decarbonizing Electrical Power Generation through Carbon Pricing: Generation Expansion Planning and Investment Assessment

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Declaration of Author's Right

This thesis is the result of the author's original research. It has been composed by the author and has not been previously submitted for examination which has led to the award of a degree.

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Date: 26/06/2025

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Abstract

Generation Expansion Planning (GEP) consists of finding the optimal long-term plan for the construction of new generation capacity subject to various economic and technical constraints to meet future load demand. This thesis develops a GEP model that incorporates a carbon pricing mechanism to stimulate long-term power system decarbonization without relying on annual emission caps. The model simulates at an hourly time resolution (8,760 hours per year) enabling detailed simulation of renewable variability and hourly demand fluctuations. It also includes key low-carbon technologies such as pumped storage and carbon capture, utilization, and storage (CCUS). This study employs scenario analysis to evaluate the impacts of carbon pricing, fuel price trajectories, electricity demand growth, and technology availability on the expansion of the power generation system.

The results reveal how different assumptions shape technology mix for electricity supply, system costs, carbon emissions, and technology deployment trajectories. In particular, rising carbon prices and ambitious renewable energy targets drive a clear transition away from coal-based generation toward cleaner alternatives such as gas, nuclear, and renewables, while encouraging investment in supporting technologies like pumped storage and CCUS. These insights provide evidence-based guidance for policymakers and energy planners in designing effective carbon pricing policies to achieve long-term climate goals.

In addition, LCOE, or levelized cost of electricity, is defined as the average total cost of building and operating an energy system over its lifetime, divided by the total energy output produced during that period. It represents the minimum price at which electricity must be sold to break even over the life of the plant. The proposed LCOE approach is employed, which integrates annual carbon prices and annual capacity factors derived from the GEP model. This provides more reliable investment

assessments by reflecting the actual operating conditions of thermal power plants under different scenarios, rather than relying on static assumptions that may not hold in future low-carbon systems. The GEP and LCOE models are implemented using the General Algebraic Modelling System (GAMS) and Microsoft Excel, and are tested under 18 distinct scenarios representing a range of policy and market conditions. Results offer insights into optimal system development pathways and the investment viability of thermal power technologies in carbon-constrained environments. These findings highlight how different combinations of carbon pricing, fuel cost trajectories, technology availability, and renewable energy targets influence the long-term competitiveness of thermal power plant. These insights can support policymakers and investors in designing more adaptive and economically viable strategies for decarbonizing the East Asian regional power system.

Contents

List of Abbreviations and Definitions

AC	Alternating Current
BWR	Boiling Water Reactor
CAPEX	Capital Costs
CCGT	Combined-Cycle Gas Turbines
CCS	Carbon Capture and Storage
CCUS	Carbon Capture Utilization and Storage
CF	Capacity Factor
CHP	Combined Heat and Power
CP	Carbon Price
CSP	Concentrated Solar Power
DC	Direct Current
ETS	Emissions Trading System
GAMS	General Algebraic Modelling System
GEP	Generation Expansion Planning
IEA	International Energy Agency
IRR	Internal Rate of Return
LCOE	Levelized Cost of Electricity
LIMES	Long-term Investment Model for the Electricity Sector
LP	Linear Programming
NEA	Nuclear Energy Agency
NPC	Net Present Cost
NPV	Net Present Value
NREL	National Renewable Energy Laboratory
OCGT	Open-Cycle Gas Turbine
OPEX	Operating Costs
PHWR	Pressurized Heavy Water Reactors

PT	Parabolic Trough
PV	Photovoltaic
PWR	Pressurized Water Reactor
ReEDs	Regional Energy Deployment System
ST	Solar Tower
USC	Ultra-supercritical power plant
VRE	Variable Renewable Energy
WACC	Weighted Average Cost of Capital

CO2e	*It stands for "Carbon Dioxide Equivalent." It is a unit of measurement used to compare the warming effects of different greenhouse gases, expressing them in terms of their global warming potential relative to carbon dioxide. (kg or tonne)*
Carbon intensity	*It is a measure of how much CO2 emissions are produced per megawatt hour of electricity consumed. (kgCO2/MWh)*
Capacity factor	*It represents the efficiency and utilization of a power generation facility. It is defined as the ratio of the actual energy generated over a given period to the maximum energy that could have been generated during the same period.*
Discount rate	*It is an interest rate used to calculate the present value of future cash flows. (%)*

List of Symbols

Investment appraisal method

i	$Discount\ rate$
n	$Number\ of\ years$
t	*The number of years*
r	$Discount\ rate$
P_n	$Nominal\ value\ of\ a\ single\ payment\ in\ the\ year\ n$
PV	$Present\ value$
NPV	*Net present value*
NPC	$Net\ present\ cost$
I	$Capital\ expenditures\ present\ value$
E_t	$Time\ value\ of\ expenses\ at\ the\ year\ t$
$LCOE$	$Levelized\ cost\ of\ electricity$
W_t	$Energy\ produced\ in\ year\ t$
R_t	$Time\ value\ of\ sale\ revenues\ at\ the\ year\ t$
$CAPEX_t$	$Capital\ costs\ in\ year\ t$
$O\&M_t$	$Operation\ and\ maintenance\ costs\ in\ year\ t$
$Fuel_t$	$Fuel\ costs\ in\ year\ t$
$Carbon_t$	$Carbon\ costs\ in\ year\ t$
IRR	$Internal\ rate\ of\ return\ in\ \%$
A_n	$Annuity\ or\ equivalent\ annual\ amount\ (\ £/year)$
a_n	$Annuity\ factor\ \ (1/year)$
t_{pb}	$Payback\ time$ in years
ΔI_0	$Initial\ investment$
ΔR	$Net\ profit\ per\ year$

ROI	*Return on investment*

Quantification of carbon costs in fuel

CP	*Carbon price (US$/tonneCO2e)*
EF	*Emission factor*
AD	*Activity data (tonne)*

Generation expansion planning model

i	*Generation technologies comprise VRE, dispatchable generation, and power storage.*
j	*VRE generation technologies (variable renewable energy, such as solar PV and wind)*
k	*Dispatchable generation technologies (such as Nuclear, USC, CCGT and USC-CCUS)*
s	*Power storage technology (such as pumped storage system)*
t	*Time period*
C	*Total system costs (US$)*
c_i^{inv}	*Investment cost of generation technology* i *(US$)*
C_i^{fix}	*Fixed generation costs (capital costs) (US$)*
$C_{t,i}^{var}$	*Variable generation costs (operation costs) (US$)*
c_i^{om}	*Variable O&M costs of generation technology* i *(US$)*
c_i^{fuel}	*Fuel costs of generation technology* i *(US$)*
$c_i^{emissions}$	*Carbon costs of generation technology* i *(US$)*
$p_{t,i}$	*Electricity generated in year* t *for generation technology* i *(MWh)*

δ_t	*Power demand at time* t *(MWh)*
s_t^{out}	*Power storage output at time* t *(MWh)*
s_t^{in}	*Power storage input at time* t *(MWh)*
$p_{t,j}$	*Hourly generation from VRE at time* t *(MWh)*
$p_{t,k}$	*Hourly generation from dispatchable technology at time* t *(MWh)*
$\varphi_{t,j}$	*Generation profiles of VRE at time* t *(1)*
$\alpha_{t,k}$	*Availability of dispatchable technology at time* t *(GW)*
g_j	*Installed capacity of VRE (GW)*
g_i^{inv}	*New capacity of all generation technology (GW)*
g_i^0	*Existing capacity of all generation technology (GW)*
g_j^0	*Existing capacity of VRE (GW)*
g_k	*Installed capacity of dispatchable technology (GW)*
g_k^0	*Existing capacity of dispatchable technology (GW)*
g_k^{inv}	*New capacity of dispatchable technology (GW)*
g_k^{dec}	*Decommissioned capacity of dispatchable technology (GW)*
g_s^0	*Existing capacity of pumped storage generators (GW)*
g_s^{inv}	*New capacity of pumped storage generators (GW)*
v_t	*Energy stored in storage system at time* t *(MWh)*
v_{t-1}	*Energy stored in the energy storage system in the past hour (MWh)*
y	*The number of years*
CP	*Carbon price (US$/tonneCO2e)*
FCP	*Fixed carbon price (US$/tonneCO2e)*
CPR	*Carbon price rate*
d	*Capacity growth rate for solar PV*
w	*Capacity growth rate for solar wind*
n	*Capacity growth rate for nuclear*
u	*Capacity growth rate for pumped storage system*

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Chapter 1 Introduction

1.1 Motivation background

It is generally agreed that carbon dioxide (CO2) emissions are changing global climate with severe effect on our planet and human life. Climate change brings more wildfires, higher sea level and poorer air quality. The climate change makes the country of UK with hotter and drier summers and warmer and wetter winters [1]. All the top 10 warmest years in the UK's temperature recorded have occurred since 2002 [2]. About 2500 heat-related deaths happened during 2020 summer in England, which is the highest number since 2003 [3]. Annual average rainfall over Scotland in recent decade (2008-2017) are on average 4% wetter than 1981-2010 and 11% wetter than 1961-1990 [4]. If global temperature rises above 3°C from pre-industrial level, heatwave could cause as many as 7000 death due to high temperature each year in the UK by 2050, river flood damage in the EU and UK in 2100 would be six times larger than current losses, reaching 48 billion euros per year, and nearly 0.5 million people would be exposed to flooding annually [5-7].

In 2016, 196 countries signed the Paris Agreement and the aim is to limit the global temperature increment to below 2 degrees Celsius by reducing carbon emissions as much and as soon as possible [8]. The primary source of carbon emissions is the combustion of fossil fuels such as coal, natural gas, and oil, which accounted for 93% of human-produced carbon dioxide emissions in 2023, shown in Figure 1-1 [9, 10]. One key strategy to reduce CO2 emissions is to replace fossil-fuels technologies (such as internal combustion engines and gas boilers) with electrically-powered equivalents technologies (such as electric vehicles or heat pumps) is an important strategy for reducing CO2 emissions. As a result, electricity would become one of the main energy sources in the transition to a low-carbon future. The power industry will play an important role in reducing carbon emissions by shifting to cleaner energy sources.

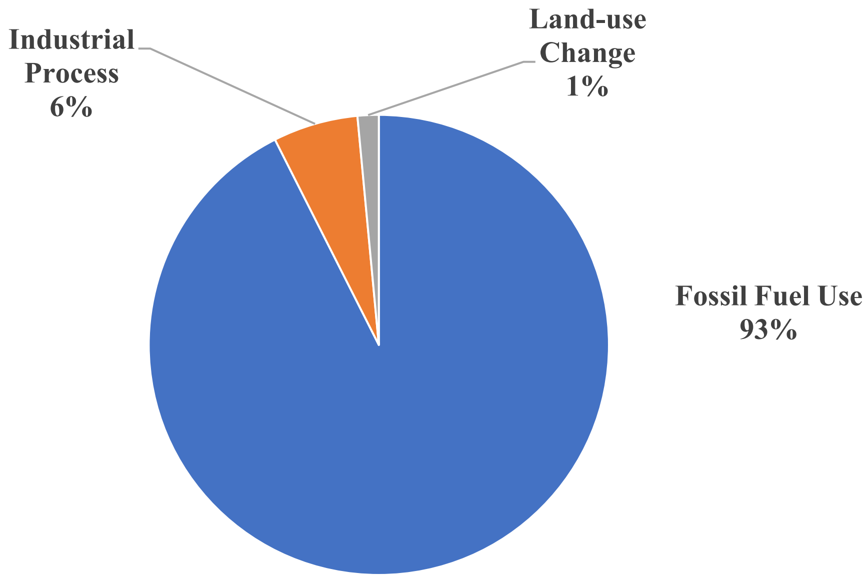


Figure 1-1 Carbon emission sources from human activities (2023) [9, 10].

Power generation systems generate electricity from various energy sources and supply it to consumers. These sources can be fossil-fuels, such as coal, natural gas, and oil, or renewable energy sources like solar, wind, hydropower, geothermal, and biomass. Additionally, nuclear energy is another significant source of power generation, where nuclear fission reactions release heat to produce steam, which drives turbines connected to electrical generators. In fossil-fuel power plants, energy is produced by burning these fuels to generate heat, which is then used to produce steam that drives turbines. On the other hand, renewable energy sources directly use natural forces, such as sunlight, wind, or water flow.

However, one of the main challenges with renewable energy is its intermittency. Renewable sources like solar and wind depend on natural conditions that can vary throughout the day or season. For example, solar power generation is only available during daylight hours, and wind energy is contingent on wind speeds, which can fluctuate. This variability means that the supply of renewable energy may not always match demand, leading to potential gaps in power availability. To address these gaps, power generation systems often rely on fossil-fuel power plants (such as coal and natural gas plants) to provide backup power or peaking capacity when renewable generation is insufficient. These plants can be quickly ramped up or down to compensate for the variability of renewable energy sources. Therefore, it is unrealistic to rapidly expand renewable energy while immediately shutting down all fossil-fuel power plants, as this disregards the crucial role that fossil-fuel plants continue to play in ensuring grid stability and meeting energy demand during the transition to cleaner energy sources. In addition, fossil fuel power plants typically have a lifespan of 30 to 40 years, meaning that both ongoing investment in these plants and the replacement of aging facilities must be carefully considered to ensure a stable energy supply.

Different countries have set ambitious targets to address climate change. For example. the UK in 2020 has set a Net Zero Target to be achieved by 2050 [11]. Similarly, the European Union (EU) aims to have an economy with net zero greenhouse gas emissions by 2050 [12]. Meanwhile, China, as one of the world's largest carbon emissions emitter, announced in 2020 that it will achieve carbon neutrality (net zero carbon emissions) by 2060 [13, 14]. One of the critical steps to achieving carbon emission targets is reducing emissions from the power generation sector, which is a major contributor to global carbon emissions. According to the carbon emissions report of the European Commission, the power sector accounts for about 29% of global carbon dioxide emissions, shown in Figure 1-2 [10].

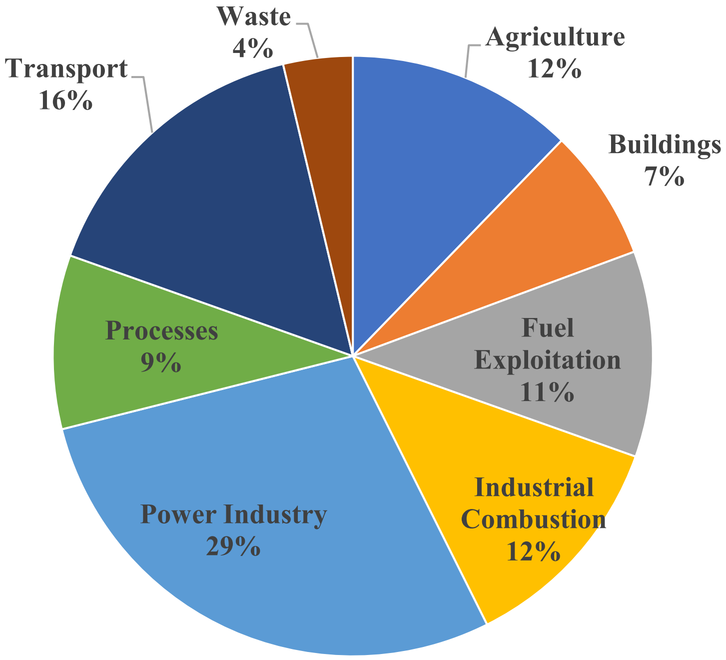


Figure 1-2 Global carbon emissions by sector in 2023 [10].

To address this, several instruments are being employed to reduce emissions from the sector, including increasing the share of renewable energy, implementing carbon pricing mechanisms and introducing Carbon Capture, Utilization, and Storage (CCUS) technology. Transitioning from fossil fuels to renewable energy sources, such as solar, wind and hydropower, is one of the most effective ways to reduce carbon emissions in the power sector. Carbon pricing, such as carbon taxes or Emissions Trading Systems (ETS) is being introduced to incentive companies to reduce their emissions [15]. By putting a price on carbon, these mechanisms create financial incentives for cleaner energy production and the adoption of low-carbon technologies. CCUS technologies capture carbon emissions from power plants, preventing them from being released into the atmosphere, illustrated in Figure 1-3 [16]. This captured CO2 can either be stored underground or utilized in various industrial applications. CCUS is particularly important for achieving deep reductions in emissions, especially in power plants that continue to rely on fossil fuels for energy generation in the short term. A combination of these instruments, including shifting to renewable energy, implementing carbon pricing, and adopting CCUS technologies, are essential for significantly reducing emissions from the power sector and meeting carbon reduction targets.

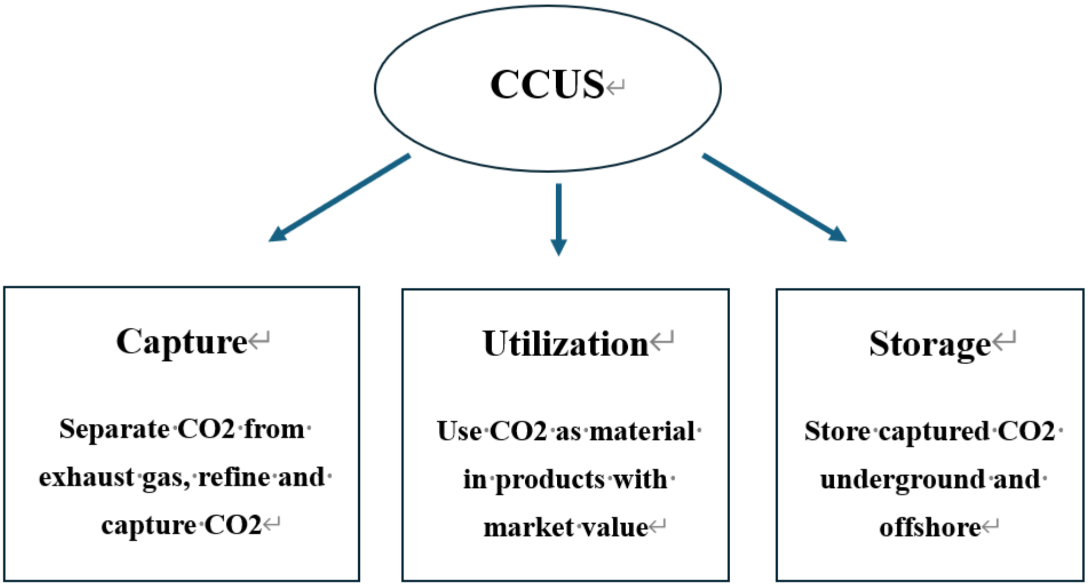


Figure 1-3 Function of CCUS technology [16].

This thesis investigates the long-term expansion planning of the power generation system under the background of the increasing renewable energy and carbon pricing mechanisms. Moreover, a further analysis on the levelized cost of electricity (LCOE) is achieved in Microsoft Excel to provide an investment assessment of thermal power plants. Fossil-fuel power plants equipped with CCUS technology are also considered. The proposed Generation Expansion Planning (GEP) model is developed and implemented in the General Algebraic Modelling System (GAMS), using the Linear Programming (LP) solver to simulate the operation and investment of power generation system [17]. The test system used in the simulation is taken from a section of a very large system of an East Asia country. The data employed in the simulation are collected from online publications and open-access databases.

1.2 Literature review

The GEP problem is a critical aspect of power system planning. Optimization methods are widely used in GEP because they provide a clear and structured mathematical framework to identify the least-cost or optimal technology mix for electricity supply while satisfying technical, economic, and environmental constraints. GEP models can be broadly categorized based on their focus into two types: dynamic GEP models and traditional GEP models [18]. Dynamic GEP models primarily emphasize the operation of power generation systems, with current research focusing on the reliability and stability of these systems, especially after integrating renewable energy sources [19, 20]. Typical dynamic GEP model is ReEDs (Regional Energy Deployment System) developed by the National Renewable Energy Laboratory (NREL) which is broadly used in the US power system to analyze the stability and reliability of renewable energy in low-carbon power system. For example, P. Deholm et al. use the ReEDs to examine supply-side options to achieve 100% clean electricity in the US [21]. In contrast, traditional GEP models typically concentrate on long-term issues such as environmental impacts and policy implications for power generation systems [22]. For example, C. E. Paes et al. analyze how reducing emissions changes the generation expansion plan in Brazil [23]. He and Wang assess the impact of carbon tax impacts on new investment in renewable energy generation capacity [24]. Traditional GEP models used to simply ignore short-term system operational details or account for them by using highly simplified assumptions. For example, cycling and load following features of individual power plants are often overlooked.

When addressing environmental considerations in GEP models, two primary approaches are commonly employed to reduce carbon emissions from power generation systems: carbon emission caps and carbon pricing mechanisms [25]. Setting an annual carbon emissions cap is a direct method to limit emissions, ensuring that carbon reduction targets are met. Sirikum and Techanitisawad added air pollutant emission limits to their dynamic GEP model [26]. Karaki et al. estimates the carbon emissions of each unit and sets a maximum carbon emissions for the power system to estimate the environmental impact on the proposed generation scenario [27]. The disadvantage of this approach is that it ignores the impact of market factors on the generation system, such as merit order of dispatch and carbon pricing mechanisms. By focusing on emission limit, these researches often overlook the influence of market forces on the operation and investment of power generation systems. On the other hand, carbon price mechanism imposes additional fees on carbon emissions and it provides an economic incentive for power plants to lower emissions. For example, Bakirtzis et al. incorporated the cost of purchasing emission allowances into the GEP model [28]. The carbon price is determined by a carbon price quota curve that reflects the impact of increased demand for emission allowances on the carbon price. Similarly, Mena et al. incorporated the carbon tax into GEP model to analyze the Chilean electric power system [29]. Carbon tax was set at around 30 €/tonne CO2 to model the transition of the Kosovo energy system [30]. Zhang et al. use a combination of carbon price and carbon tax, with the long-term trends and volatility of carbon prices being simulated by a geometric Brownian motion process model [31]. Park and Baldick use a multi-year stochastic generation capacity expansion planning model to investigate changes in generation building decisions and carbon emissions under an increasing carbon tax [32]. The disadvantage of this approach is that carbon pricing mechanism cannot guarantee the specific carbon reduction targets will be achieved. Therefore, while carbon pricing mechanisms have been considered in previous studies, they are typically introduced alongside annual emission caps, and the carbon price levels employed are often too low to provide a strong incentive for substantial emission reductions. In such frameworks, the emission cap, rather than the carbon price, usually becomes the dominant driver of decarbonization. This creates a research gap. There is still relatively limited work that systematically examines carbon pricing mechanisms as the primary long-term strategy for reducing carbon emissions in power generation systems. In particular, little attention has been paid to whether a sufficiently high and predictable carbon price, implemented without binding caps, could independently guide investment decisions and achieve emission targets. However, if the power system depends solely on high carbon prices, its expansion path may become highly sensitive to varying scenarios and policy conditions. In such cases, the effectiveness of carbon pricing in guiding generation investment and emission reductions could be undermined by price volatility, policy uncertainty, and design limitations.Therefore, current research (including researches above) often combines annual emissions cap and carbon pricing mechanisms. But their carbon price levels employed are too low to provide sufficient motivation for reducing carbon emissions. Instead, the primary driver for reducing carbon emissions remains the annual emissions cap. Therefore, there is a gap in research focusing solely on the use of carbon pricing mechanisms as a long-term strategy for reducing carbon emissions in power generation systems.

To fill this gap, this thesis proposes a GEP model that builds on the traditional GEP model and incorporates a carbon pricing mechanism. It focuses on using carbon prices to reduce emissions and achieve carbon reduction targets. This study examines how a carbon price mechanism influences the expansion and decarbonization of the power generation system without relying on annual emissions caps.

In addition, while the GEP model can identify the optimal technology mix for electricity supply for a given power system, it lacks economic indicators that investors require to evaluate thermal power generation projects. The LCOE method is an appropriate approach for assessing power plant investments, as it provides a comprehensive cost measure over the plant's lifetime. However, the accuracy of LCOE assessments depends heavily on estimated data related to power plant operation and costs. Therefore, most research focused on improving the accuracy of the input data used in the LCOE calculations to enhance the reliability of LCOE assessment. Shea and Ramgolam use local data to estimate LCOE of various technologies in Mauritius [33].

Although, local data as input data is more accurate than international data or generalized assumptions, the local capacity factor cannot reliably indicate how the plant will perform in the future. Choi et al. estimated the future capital costs and LCOE of generation technologies through learning rates [34]. This approach increases the reliability of the LCOE, but most fossil-fuel generation technologies are well-established and the impact of capital costs on their LCOE is relatively small. Veselov et al. utilize two different future scenarios to estimate the LCOE of energy technologies in the future, taking into account the potential impact of carbon pricing and fuel pricing on LCOE [35]. Hansen utilizes long-term planning models to estimate the LCOE of power plants under different technology mix for electricity supply scenarios, including the dismantling of nuclear power capacity [36]. Both Veselov's and Hansen's research estimated the LCOE of thermal power plants under different scenarios, however they did not consider the potential impact of increased renewable energy in the system. In addition, the capacity factor that they have used is derived from a specific technology mix for electricity supply, which is fixed because they do not consider the fluctuation in capacity factor from the existing technology mix for electricity supply to the specific mix. Using a fixed capacity factor to estimate the LCOE of a power plant during the transition to a specific technology mix for electricity supply reduces the reliability of the LCOE assessment. Therefore, these studies share a common limitation: they rely on static or simplified assumptions for key parameters such as capacity factors and carbon prices. Local data may improve short-term accuracy, but it cannot predict how capacity factors will evolve as the technology mix for electricity supply changes. Similarly, capital cost learning improves projections for emerging technologies but has little impact on mature fossil-fuel plants. Scenario-based LCOE assessments, while valuable, often use a fixed technology mix for electricity supply and therefore cannot capture the year-to-year fluctuation of capacity factors or the dynamic influence of carbon pricing as the system transitions toward higher renewable penetration. This highlights a clear research gap. Although existing approaches have improved LCOE inputs in specific aspects, they fall short of fully capturing the influence of system evolution on the economic performance of power plants. In particular, the fluctuation of annual capacity factors under different technology mix for electricity supply and the impact of rising carbon prices are rarely incorporated into LCOE assessment frameworks.

To address this gap, the proposed LCOE approach integrates the LCOE method with the GEP model to account for annual carbon prices and annual capacity factors of power plants. This approach enables a more comprehensive economic assessment of power plant investments by considering the evolving power system conditions, including shifts in the technology mix for electricity supply, increasing renewable energy penetration, and fluctuating carbon prices. By linking the LCOE method with the GEP model, the proposed approach enhances the reliability of investment evaluations.

1.3 Objectives of research

The objectives of this thesis include:

- To investigate long-term plans for reducing carbon emissions in electricity generation. To select a suitable model for long-term, large-scale generation expansion planning.
- To investigate the use of carbon tax on electricity generation to encourage carbon emission reductions. To select a suitable carbon pricing mechanism for electricity generation system.
- To investigate the use of LCOE in assessing carbon emissions. To evaluate the impact of carbon tax on power plants.

- To formulate a Generation Expansion Planning (GEP) model that simulates the annual expansion of the power generation system over the long-term planning horizon. To analyze and discuss the generation expansion plan based on the simulation results.
- To conduct computational simulations of the proposed Generation Expansion Planning (GEP) method on a test system, which considers the integration of renewable energy, carbon pricing mechanisms, and carbon reduction targets. To compare and analyze the generation expansion plans under various scenarios.
- To calculate the LCOE of thermal power plants based on the results of the generation expansion plans. To analyze the difference of LCOE in different years and different scenarios.

1.4 Original contributions

The main original contributions of the thesis are listed below:

Contribution 1: A novel GEP model is developed to simulate the long-term expansion of large-scale power generation systems. The model features hourly resolution for dispatch decisions, enabling a detailed representation of renewable energy variability and storage operation, while capacity expansion decisions are made annually over the 30-year planning horizon. In addition, the model considers the operation and investment in pumped storage systems and power plants equipped with CCUS.

Contribution 2: A novel carbon pricing mechanism is incorporated into the proposed GEP model to address the carbon emissions issue in power generation system. This mechanism uses an increasing carbon tax to provide a strong economic signal to incentivize the power generation system to reduce carbon emissions. The GEP model with carbon pricing mechanism examines the transition from conventional to low-carbon power generation systems. Furthermore, scenario analysis is utilized to evaluate the impacts of carbon pricing on the operational and investment in the power generation system.

Contribution 3: A proposed LCOE approach is developed and used to assess investment in thermal power plants. This approach considers annual carbon price and annual capacity factor of power plant derived from the result of GEP model to improve the reliability of LCOE method. By integrating these dynamic factors, the approach is used to analyze the differences in LCOE of power plants across different years and under various scenarios.

1.5 Thesis structure

The thesis consists of seven chapters and the contents are organized as follows:

Chapter 2 reviews the background of the GEP model and the method of investment appraisal. Firstly, this chapter reviews power generation technologies including ultra-supercritical (USC) coal-fired generation, combined-cycle gas turbines, carbon capture utilization and storage (CCUS) technology, nuclear generation, onshore and offshore wind power, solar energy, and pumped-storage hydropower technologies. Then, the carbon pricing mechanisms such as carbon tax and Emissions Trading System (ETS) are described. Secondly, this chapter reviews the principles, modelling method and environmental consideration of the GEP model. After that, the GEP model with a carbon pricing mechanism is proposed. Finally, this chapter reviews investment appraisal methods and existing LCOE research on power generation technologies. Based on this review, a novel approach is proposed to enhance the reliability of LCOE method.

Chapter 3 provides a detailed analysis of the existing LCOE methodology for power generation projects, including its equation, key assumptions and limitations. Then, it presents the LCOE calculation and sensitivity analysis for the power plant, as well as the impact of different carbon prices and capacity factors on the LCOE of the power plant, to explore how changes in key parameters affect the LCOE.

Chapter 4 provides a detailed explanation of the proposed GEP model and its application to a case study. First, it introduces the model, including its objectives, constraints, and limitations. Then, the case study demonstrates the practical application of the model to analyze the expansion of the power generation system under carbon pricing mechanisms.

Chapter 5 is an extension to Chapter 4 and presents scenario analysis on generation expansion plan to examine the uncertainties associated with the generation expansion planning. First, it provides a detailed description of the scenarios to explain the assumptions and variations considered in the scenarios. Next, the generation expansion plans for 18 scenarios are described, allowing for a comparative assessment of the differences among them. Finally, this chapter analyzes and discusses the generation expansion results to evaluate the impact of different scenarios on the expansion of power generation system.

Chapter 6 presents the results of the LCOE for thermal power plants to further analysis the impact of generation expansion planning on the investment assessment of different power plants. First, it compares the existing LCOE method with the proposed LCOE approach, emphasizing how the latter enhances the reliability of LCOE by incorporating annual capacity factors and annual carbon prices. Then, it compares the

LCOE of power plants commissioned in different years under Scenario 1, analyzing the impact of the commissioned year on the LCOE and the investment attractiveness of different generation technologies. Finally, this chapter compares the LCOE of power plants commissioned in different years across all scenarios, evaluating the impact of various scenarios on the LCOE and the investment attractiveness of power plants.

Chapter 7 is the concluding chapter to the whole thesis and future work.

1.6 Publication

Tianxiang Luan and Kwok Lo, “Effect of carbon price floor on levelized cost of gas-fired generation technology in the UK” World Journal of Engineering and Technology Vol 4 No.6, October 20, 2016, PP 66-71, DOI: 10.4236/wjet.2016.43D009

This paper examined how the introduction of a carbon price floor affects the LCOE of gas-fired generation in the UK. It provided an early analysis of the interaction between carbon pricing policy and the economics of fossil-fuel power plants. The study highlighted the importance of integrating carbon pricing into investment assessments, which directly informed the thesis work on incorporating carbon pricing mechanisms into the GEP model.

Tianxiang Luan, Kwok Lo and Jianfeng Lu, “Forecasting the impact of CCGT-CCS on the UK's electricity market by LCOE” Energy and Power Engineering Vol 9 No.4B, April 6, 2017, PP 198-203 DOI: 10.4236/epe.2017.94B024

This paper evaluated the role of carbon capture and storage (CCS) by comparing the LCOE of CCGT with CCS against renewable technologies, in order to forecast its potential impact on the UK electricity market. The study demonstrated the relevance of CCS-equipped fossil plants in supporting system reliability while achieving carbon reduction, complementing renewable energy deployment. This work informed the thesis by motivating the integration of CCS technologies and renewable penetration within long-term expansion planning, as well as linking LCOE analysis with scenario-based system modelling.

Together, these publications laid the initial conceptual and methodological foundation for this thesis. They highlighted the influence of carbon pricing on LCOE, the importance of CCUS technologies in future decarbonization, and the role of LCOE in evaluating investment decisions in power generation. These perspectives directly evolved into the contributions of this thesis: the development of a GEP model incorporating carbon pricing and CCUS, and the enhancement of the LCOE approach to improve the reliability of investment assessments under evolving system conditions.

Chapter 2 Background and Literature Review

2.1 Introduction

As a result of climate issues, major emitters of carbon dioxide (CO2) such as electrical power generation will need to be converted to low-carbon power generation sources. This will lead to revised procedure for power generation expansion and investment appraisal of power plants. Section 2.2 will introduce the characteristics of different power generation technologies, such as ultra-supercritical coal-fired generation, combined-cycle gas turbines, carbon capture utilization and storage, nuclear generation, onshore and offshore wind power, solar energy, and pumped-storage hydropower technologies. The world still depends heavily on coal for electricity generation. To reduce CO2 emissions from power generation, many countries have adopted carbon pricing mechanisms for power generation systems, and that provide economic incentives to reduce carbon emissions and add new alternative energy sources. In order to understand the carbon pricing mechanisms, the principle of different carbon pricing mechanisms (carbon tax and carbon trading systems) and their uncertainties will be presented and discussed in Section 2.3. Under the influence of carbon pricing mechanisms, the expansion of the power generation system not only need to meet future demand of the grid, but also considers the price of carbon emissions and aims to minimize the overall cost. For understanding the expansion of the power generation system, Section 2.4 presents and discusses the principles of power generation expansion planning and the consideration of CO2 emissions in its modelling. Although power generation expansion planning can identify the optimal technology mix for electricity supply for a given situation, there is a lack of economic indicators that could help investors to assess various expansion projects. Therefore, Section 2.5 presents and discusses different investment appraisal methods to find the right one for a power generation project. Appropriate investment appraisal methodologies can ensure a more reliable assessment of power generation projects. When combined with an appropriate generation expansion planning model, which is able to simulate operational and investment scenarios under a carbon pricing mechanism, this combination contributes to a smooth transition to a low-carbon generation system.

2.2 Review of generation technologies

This section introduces the generation technologies included in the proposed GEP model. The focus is on their key techno-economic parameters that are directly relevant to long-term expansion planning. Detailed engineering principles and operational processes are not repeated here but can be found in the cited references. Numerical data used in the modelling are summarized in the Appendix.

The portfolio covers ultra-supercritical (USC) coal, combined-cycle gas turbine (CCGT), nuclear, wind, solar PV, pumped storage, and fossil-fuel plants equipped with carbon capture, utilization and storage (CCUS).

2.2.1 Ultra-supercritical (USC) coal

USC coal remains a widely used baseload technology due to its relatively low fuel cost and high availability. The reference unit has a net capacity of 347 MW, efficiency of 45%, and lifetime of 40 years. With a capacity factor of 85%, USC offers stable power generation, but its carbon intensity is high at around 0.34 kg CO_2/kWh, making it less competitive under strict carbon policies. The capital cost is USD 175/kW-year (over four years of construction), with fixed O&M at USD 34.5/kW and variable O&M at USD 10.35/MWh.
For technical descriptions of USC combustion and turbine operation, see [37, 38].

2.2.2 Combined-cycle gas turbines (CCGT)

CCGT plants are more efficient and emit less CO_2 compared to coal. The reference plant has 475 MW net capacity, 58% efficiency, and 30 years lifetime. Its carbon intensity is 0.18 kg CO_2/kWh, with capital cost of USD 186/kW-year over three years, and O&M costs of USD 31.0/kW fixed and USD 9.3/MWh variable. Their relatively short construction time and low costs make them a flexible option for balancing renewable variability.
For operational details of open-cycle and combined-cycle systems, see [39, 40].

2.2.3 Carbon capture, utilisation and storage (CCUS)

CCUS technologies reduce emissions by ~90% but reduce efficiency and raise costs.

- USC+CCUS: 633 MW, 30% efficiency, emissions 0.034 kg CO_2/kWh, construction cost USD 201/kW-year (9 years).
- CCGT+CCUS: 437 MW, 41% efficiency, emissions 0.018 kg CO_2/kWh, construction cost USD 121/kW-year (10 years).

Both options require higher capital expenditure and longer construction time, but they provide low-carbon, dispatchable generation when carbon prices are high.
For further detail on capture technologies (post-combustion, pre-combustion, oxyfuel), see [41-43].

2.2.4 Nuclear

Nuclear provides reliable low-carbon baseload generation with a long plant life. The reference unit has 950 MW capacity, 33% efficiency, and 60 years lifetime. Construction is lengthy (7 years) and costly (USD 357/kW-year), but once operational,

nuclear provides stable output with zero direct CO_2 emissions. O&M costs are USD 112/kW fixed and USD 11.5/MWh variable.
For detailed reactor types and operation principles (PWR, BWR, PHWR), see [44, 45].

2.2.5 Wind (onshore)

Onshore wind is one of the most cost-competitive renewable technologies. The reference farm is 50 MW, with a 26% capacity factor, 25 years lifetime, and 1 year construction. Capital costs are high (USD 1200/kW), but O&M is relatively low (USD 7/kW fixed, USD 7/MWh variable). Its zero emissions and low LCOE make it a key part of future generation portfolios.
For resource assessment and turbine technology details, see [46, 47].

2.2.6 Solar PV

Solar PV has achieved rapid cost reductions over the last decade. The reference plant is 20 MW, with 18% capacity factor, 25 years lifetime, and 1 year construction. Capital cost is USD 780/kW, O&M USD 7.9/kW fixed and USD 3/MWh variable. Despite intermittency, solar is increasingly attractive due to its short construction time and declining costs.
For more information on PV and CSP technologies, see [48, 49].

2.2.7 Pumped-storage hydropower

Pumped storage is the dominant large-scale storage option, essential for balancing variable renewables. The reference plant has 175 MW capacity, 52% round-trip efficiency, and 40 years lifetime. Capital costs are USD 526/kW-year, with low O&M (USD 7.2/kW fixed and USD 5.0/MWh variable). With a high capacity factor (85%), pumped storage provides flexibility and system stability.
For design details and global deployment examples, see [50, 51].

2.2.8 Discussion

In summary, USC and CCGT provide stable dispatchable power but at high emission costs, while CCUS reduces emissions but increases capital and efficiency penalties. Nuclear delivers reliable low-carbon baseload, whereas wind and solar provide emission-free energy but are intermittent. Pumped storage complements renewables by providing large-scale flexibility. These techno-economic parameters — efficiency, lifetime, cost, O&M, and emission factors — are the essential inputs for the proposed GEP model.

2.3 Review of carbon pricing mechanism

Carbon pricing is a widely adopted policy tool that assigns a monetary cost to carbon emissions, encouraging the adoption of low-carbon technologies by making emitters internalize the environmental costs. The two principal forms are carbon taxes, which set a fixed price per tonne of CO_2, and emissions trading systems (ETS), which cap total emissions and allow trading of emission permits.

Global uptake of carbon pricing has grown significantly in recent years. The World Bank's State and Trends of Carbon Pricing 2025 report notes that approximately 28% of global greenhouse gas emissions are now covered by direct carbon pricing, up from just 7% when the tracking began and 24% in 2023 carbon pricing dashboard [52]. Revenue from carbon pricing schemes surpassed US$100 billion in 2024, highlighting its dual role in climate mitigation and fiscal policy.

Sectoral coverage also varies—over half of power sector emissions are priced, whereas sectors like agriculture and waste remain largely unpriced carbon.

The effectiveness of carbon pricing rests on localized design and implementation that reflect national economic and energy contexts. Examples illustrate this clearly:

European Union (EU): The EU ETS, operational since 2005, covers nearly 45% of the EU's emissions, primarily in sectors like power and industry. Despite early issues like oversupply of allowances, reform (including tighter caps and the Market Stability Reserve) has enhanced effectiveness. The EU also plans to extend coverage to buildings and transport via ETS2 and is pioneering the Carbon Border Adjustment Mechanism (CBAM) to address carbon leakage.

China: China’s national ETS currently targets the power sector and, since 2027, will move towards absolute emissions caps across multiple industries (~60% of national emissions). This reflects a shift from intensity-based targets toward more stringent, economy-wide control.

South Korea: The KETS, initiated in 2015, covers ~68% of national GHG emissions. It includes phased implementation, tightened caps, and operates within the industrial context of heavy energy dependence, addressing both emission reduction and energy security concerns.

Switzerland: Since 2008, a CO_2 tax on fossil fuels has covered approximately 40% of the nation's emissions. Revenue is largely redistributed to households and firms to maintain public support. The scheme is linked with the EU ETS to improve efficiency and market integration.

Chile: Implemented a relatively low carbon tax (~US$5/t CO_2), which proved insufficient to meet emission reduction pledges. Modeling suggests that a significantly higher carbon price—up to ten times the current level—would be needed to drive meaningful shifts toward renewables

These cases underscore that while carbon pricing is gaining global traction, its design must reflect national circumstances: the structure of energy systems, sectoral contributions to emissions, economic development stage, and political feasibility all play critical roles.

2.3.1 Carbon tax

Carbon tax is a direct levy on carbon emissions, and the rate is defined by governments based on their national circumstances. The concept of a carbon tax was first described by Arthur C. Pigou in 1920 and was implemented in Finland in 1990 at a rate of €1.12 per tonne of CO2e [53, 54]. Since then, other countries have followed suit, with Sweden having the highest carbon tax rate in the world at €108.81 per tonne of CO2e in 2020 [55]. The coverage of the carbon tax will also be determined by national circumstances. For example, , France's carbon tax affects sectors that account for 35% of the country's total carbon emissions, while Japan's carbon tax applies to sectors that account for 75% of the country's total carbon emissions in 2021 [56, 57].

The use of a carbon tax can have both economic and environmental benefits. One of the advantages of a carbon tax is that it can generate revenue for governments. The funds generated from carbon tax can be used to support investments in clean energy and other climate mitigation efforts [58]. This can create economic benefits such as job creation and increased competitiveness in the clean energy sector.

The downside is carbon tax will increase per unit cost of electrical energy or fuel supplied. This can indirectly increase the cost of good products and food products especially those that rely heavily on electrical/fuel energy to produce. Carbon tax can have a socio-economic cost on the society. This is likely to disproportionally affect the cost of living at different strata of society with the lower income households affected the most. This can explain why some countries are more aggressive in pricing carbon tax than others.

2.3.2 Emission trading system (ETS)

The ETS is a cap-and-trade system where emitters such as power stations can trade emission allowances with each other, with the total amount of allowances capped by the regulator. Each allowance grants the right to emit one tonne of CO_2-equivalent (CO_2e) over a specified period [59].

The EU ETS, launched in 2005, was the world's first large-scale carbon market [60]. Participants include power stations, industrial plants, and aviation operators. Allowances are distributed through a combination of free allocation and auctions. While free allocation is intended to mitigate risks of carbon leakage and maintain industrial competitiveness, auctions and the secondary market provide flexibility for firms to trade, hedge, and manage compliance costs [61].

Figure 2-1 illustrates the fluctuations in EU carbon prices between 2005 and 2020 [62]. These movements reflect the interaction between market fundamentals, external economic shocks, and regulatory adjustments:

- 2006–2007: Price collapse due to surplus allowances. In Phase I (2005–2007), allowance allocation was based on incomplete data, and emissions were lower than anticipated. This resulted in a significant oversupply of allowances, causing prices to fall from around €30/tonneCO_2e to near zero by 2007 [63]. This highlighted the importance of accurate baseline data and effective cap-setting.
- 2008–2012: Financial crisis and oversupply. During Phase II, the global financial and European debt crises led to reduced industrial activity and power demand, which lowered emissions. As a result, demand for allowances dropped, leading to another sustained period of low carbon prices

(~€10/tonneCO_2e). Structural weaknesses in the market design, such as the rigid supply of allowances, amplified the effect of the economic downturn [63].

- 2013–2017: Persistent surplus despite reforms. In Phase III, the EU introduced auctioning as the default allocation method and expanded coverage to more sectors. However, a large surplus of allowances from earlier phases carried over, continuing to depress prices, which hovered between €5–10/tonneCO_2e for most of this period [61].

- 2018 onwards: ETS reform and Market Stability Reserve (MSR). Recognizing the persistent oversupply, the EU introduced the MSR in 2018 to automatically adjust the supply of allowances by transferring surplus units into a reserve. At the same time, the linear reduction factor for the emissions cap was tightened (1.74% per year in Phase III to 2.2% from 2021 onwards). These reforms significantly boosted market confidence, leading to a sharp rise in allowance prices to above €25/tonneCO_2e by 2019 and stabilizing thereafter [64].

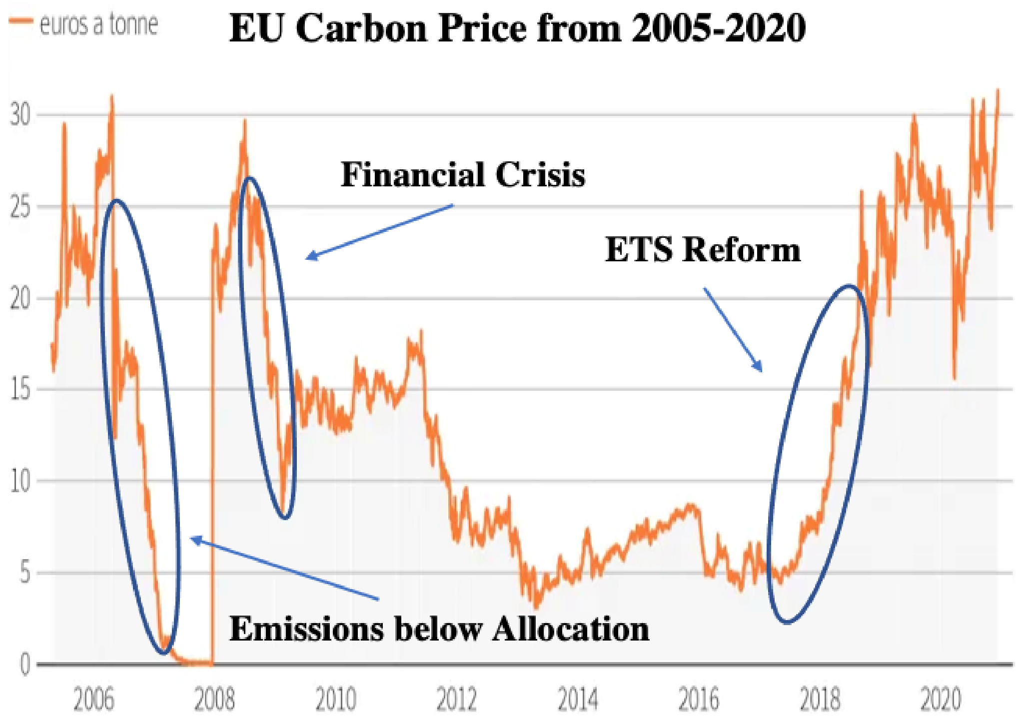


Figure 2-1 EU carbon price from 2005 to 2020 and events [62].

Overall, the EU ETS experience demonstrates that carbon prices are highly sensitive to both macroeconomic conditions and policy design. Early phases showed how over-allocation and weak demand can undermine price signals, while recent reforms highlight the role of dynamic supply management and more ambitious caps in ensuring that carbon pricing provides a strong and predictable incentive for decarbonization.

2.3.3 Basic comparison under uncertainty

In their pure forms, carbon taxes provide certainty in the emissions price while emissions are determined by market factors. Conversely, ETS provides certainty about the total emissions allowed, with the price determined by market factors. Without uncertainty, the carbon tax rate could be matched to the emission reduction cap in the

ETS. This matching would have the same revenue potential if allowances under the ETS were auctioned.

However, future emissions reduction costs are uncertain, influenced by variables such as fuel price fluctuations and the availability and cost of cleaner technologies. This uncertainty prevents governments from guaranteeing both price and emissions certainty.

For example, in Ireland the carbon tax is scheduled to rise €7.50 a year to reach €100 per tonne by 2030), while emissions are determined by the market. The ETS of the EU, South Korean and California, have fixed emissions cap, and prices vary with market conditions, as shown in Figure 2-2 [65, 66].

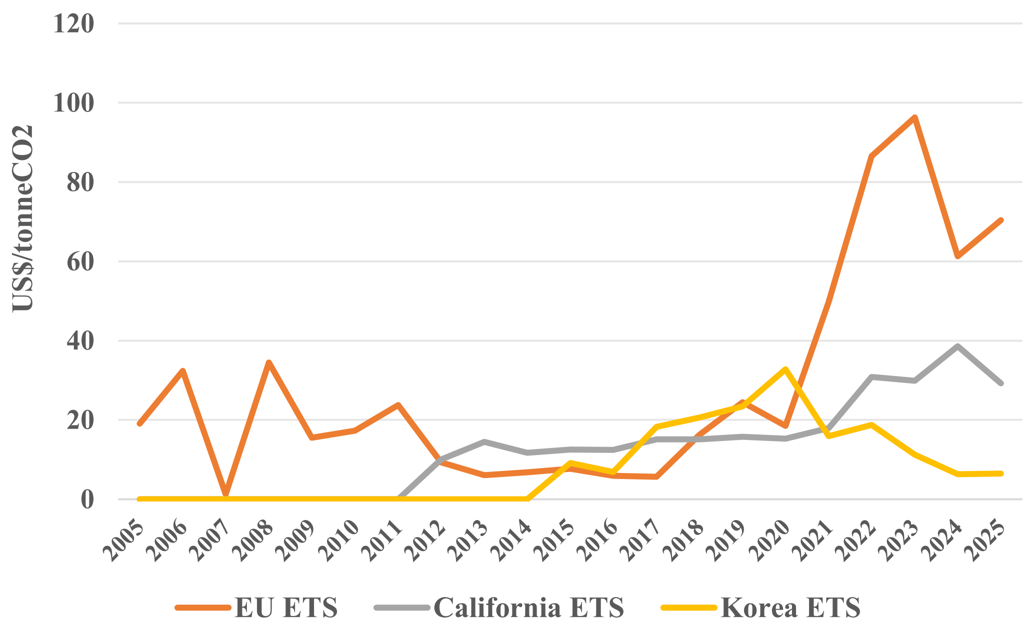


Figure 2-2 Carbon price in ETS of EU, Korea and California [65, 66].

2.3.4 Balancing uncertainty in the carbon pricing mechanism

In practice, both carbon taxes and ETS can reduce either emissions or price uncertainty to some extent, so the differences between the two approaches may be less apparent. In many carbon tax schemes, tax rates are fixed but can be periodically adjusted to align with progress toward emissions reduction goals.

By contrast, ETS faces the challenge of carbon price volatility, which can weaken the predictability of investment signals. To address this, many ETS designs include price stability mechanisms, most notably the carbon price floor. A carbon price floor establishes a minimum price level for allowances, either through auction reserve prices or complementary policies, ensuring that carbon prices cannot fall below a certain threshold. This mechanism provides investors with greater certainty about the future value of low-carbon investments, even when market conditions lead to an oversupply of allowances.

For example, Figure 2-3 compares the Canadian Carbon Tax Scheme with the price floor in California's ETS [67-69]. Canada's carbon tax follows a predetermined escalating trajectory, rising from US$ 20/tonneCO_2e in 2019 to US$ 65/tonneCO_2e in 2023, thereby providing transparent long-term investment signals. Similarly, California's ETS incorporates an auction price floor that increases annually, preventing allowance prices from collapsing during periods of weak demand.

Overall, the balancing uncertainty approach in carbon pricing mechanisms shows that both carbon taxes and ETS require a rising carbon price to provide sufficient economic incentives for emission reductions. According to the World Economic Forum, setting a gradually increasing carbon price in advance creates stronger incentives for firms to cut emissions, as it provides both certainty and predictability for long-term investment planning [70, 71].

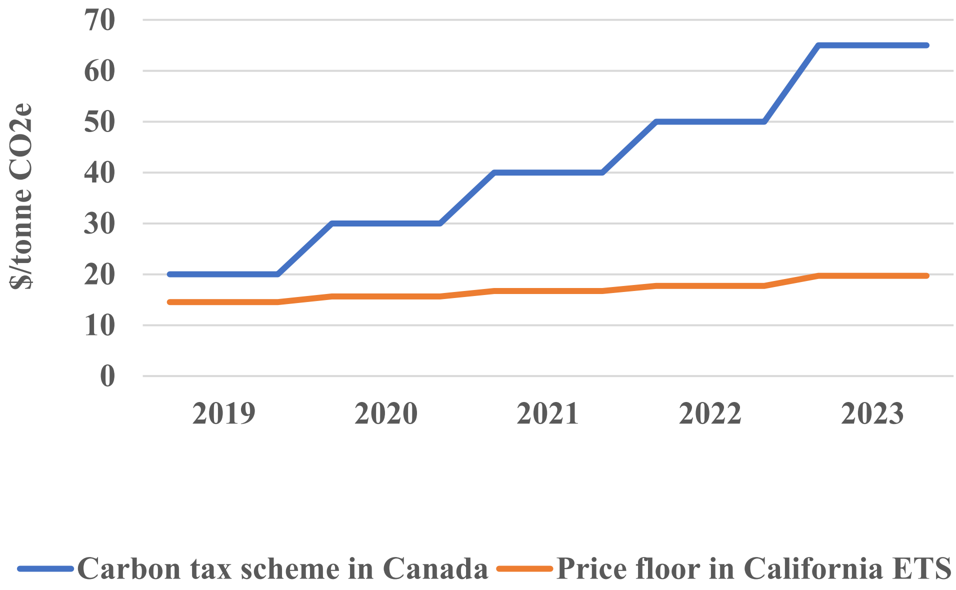


Figure 2-3 Price stability mechanism: Carbon Price Floor and Carbon Tax Scheme [67-69].

2.4 Review of generation expansion planning

Population growth, economic development, and electrification are major drivers of the growth in electricity demand, requiring expansion of the power system to meet future energy consumption. However, the power generation industry is capital-intensive with long lead times for investment, making the decision on generation expansion planning usually spanning over decades [72]. The aim of generation expansion planning is to determine the least-cost technology mix for electricity supply to meet future demand.

The purpose of this section is to examine the theory behind power plant expansion planning, the models used in power plant expansion planning and the environmental considerations considered in these planning models. This will explain how the power generation system can be expanded with reduced carbon emissions while minimizing the total cost of the system.

2.4.1 Theory of generation expansion planning

The least-cost technology mix for electricity supply required to meet future demand is determined by evaluating the costs of generation and the operating loads within the system. To reveal the cost of generation, this section introduces the concept of power plant cost, capacity factor and the screening curves. To characterize system load, this section presents the load duration curve, merit order and the residual load duration curve. The merit order effect is also discussed to explain the impact of renewable energy on fossil-fuel power plants. Finally, the section on the optimal technology mix for electricity supply will present how to determine the least-cost technology mix for electricity supply based on the cost of generation and system load.

2.4.1.1 The cost of a power plant

Electricity generation is a complex process that involves various inputs such as land cost, labour cost, raw materials cost, and capital availability and repayment. These inputs contribute to the overall cost of generation, which can be broadly classified into fixed or capital costs (CAPEX) and variable or operating costs (OPEX) [73].

Every power plant has CAPEX, which can be broken down as follow [74]:

- Infrastructure cost: the cost of manufacture, assembly and delivery to site of all equipment needed to build a functioning plant.
- Engineering, procurement and construction cost: it includes the cost of civil works, foundations, buildings, fencing, labour, engineering and material (such as concrete, piping and cabling).
- Development cost: the cost of land, environmental permission, interest during construction and interconnection costs to the transmission or distribution system.

OPEX is often determined at the plant level and calculated as the total cost per megawatthour ($/MWh). Major OPEX are as follow [75]:

- Fuel cost: often the most expensive operating cost for thermal plants.
- Staffing: it is the cost for permanent staffing.
- Network, phone and sewer charges: needed for plant operations and often set as a fixed annual or monthly fee.
- Emission cost: pay for CO_2 emissions released by the power plant.
- Annual maintenance costs: this cost occurs annually to keep the operation of power plant. For example, regular panel cleaning for solar farm or annual maintenance activities on a thermal plant.
- Variable operations and maintenance costs: day to day operations costs and minor maintenance activities.
- Decommission cost: the costs incurred when a power plant is shut down and its equipment and infrastructure are dismantled and disposed of safely.
- Waste management cost: the costs associated with the proper disposal of waste generated during the operation of the power plant.

The cost of electricity generation plays a critical role in planning the expansion of power generation systems, as it directly influences the selection of generation technologies. Lower-cost power generation technologies are usually prioritized to minimize overall system costs.

2.4.1.2 Capacity factor

The capacity factor represents the efficiency and utilization of a power generation facility. It is defined as the ratio of the actual energy generated over a given period to the maximum energy that could have been generated during the same period [76]. A higher capacity factor indicates a more consistent and efficient use of the facility, while a lower capacity factor may reflect intermittent operation due to factors such as maintenance, fuel supply limitations, or variability in energy resources, as is common with renewable energy sources like wind and solar. This definition ensures that variations in capacity factors can be consistently evaluated across different technologies and time periods.

$$CF_{t,i} = \frac{p_{t,i}}{g_i \times t} \tag{2.1}$$

Where:

CF: Capacity factor of technology i in the year t;

$p_{t,i}$: Actual electricity generated by technology i in year t;

g_i: Installed capacity of technology i;

t: Total number of hours in the given year t;

2.4.1.3 The screening curves

The annual cost of power generation refers to the total cost incurred to operate and maintain a power plant over the course of a year. It typically includes fixed costs (which do not depend on the amount of electricity generated) and variable costs (which are directly proportional to the amount of electricity produced). The screening curve is a visual representation of the relationship between the capacity factor and the annual cost of power generation [77]. It is commonly used to identify the most cost-effective technology for a specific capacity requirement by comparing the fixed and variable costs of different generation options.

Equation 2.2 shows the annual cost equation for a power plant, which is the sum of annual fixed and variable costs based on the plant capacity factor [16]. The unit of annual cost is expressed as cost per megawatt in a year.

$$\begin{aligned} Annual\ cost(\$/MW - year) \\ &= Annual\ fixed\ costs(\$/MW) \\ &+ Variable\ costs(\$/MW - year) \\ &\times Capacity\ factor(unitless) \end{aligned} \tag{2.2}$$

Figure 2-4 illustrates the screening curve of a power plant, where the blue line represents the annual cost. The green part represents the annual fixed cost of the plant, and the orange part represents the variable cost of the plant. As the capacity factor increases, the variable costs increase, leading to an increase in the annual cost. If the power plant does not produce power, the annual fixed cost is the annual cost. Thus, screening curves can assess the annual cost of different power plants for a given capacity factor.

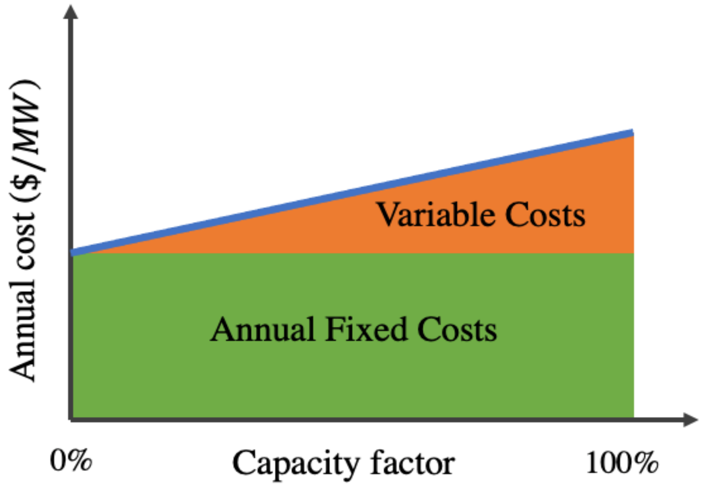


Figure 2-4 Screening curve: the annual cost of a power plant.

2.4.1.4 The load duration curve

The load duration curve is a method for analyzing the relationship between load level and time duration over a specified period (usually one year). The curve is plotted by arranging the hourly load values in descending order and then graphing them against their corresponding time duration [78]. As shown in Figure 2-5, the orange line in the curve is the load duration curve, indicating the duration of the load, and the blue line indicates the load per hour [79].

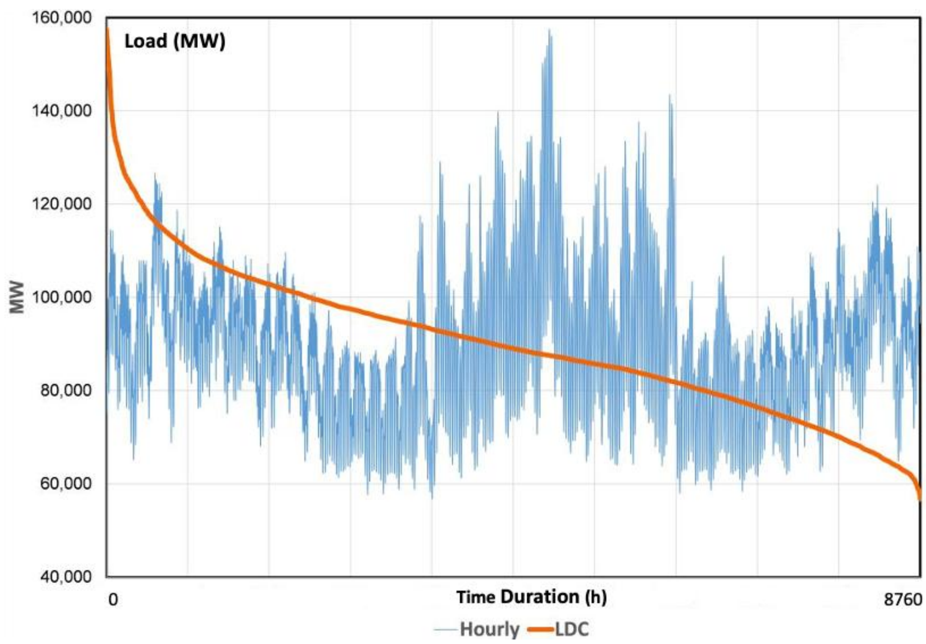


Figure 2-5 Load duration curve and hourly power load [79].

By analyzing the curve, it becomes possible to determine the load duration at any given point on the curve and to calculate the total energy consumed during that period [80]. Load duration curves provide a visual representation of load level and duration, thus assisting in the planning of the power system.

However, with the increasing complexity of modern power systems—driven by high shares of variable renewable energy, integration of storage technologies, and more stringent environmental constraints—the LDC approach alone is insufficient. It does not capture chronological variations in demand and supply, nor does it adequately account for operational and policy constraints. As a result, more advanced methods are required to determine the truly optimal technology mix for electricity supply under evolving system conditions.

In the proposed GEP model, these limitations are addressed by explicitly considering hourly load demand rather than relying solely on aggregated duration curves. This allows the model to capture system dynamics more accurately and to determine suitable generation capacity in response to real-time variations in demand, resource availability, and carbon pricing mechanisms. In this way, the proposed GEP framework improves upon the traditional LDC approach by providing a more realistic and reliable basis for long-term system planning.

2.4.1.5 The merit order principle

The merit-order is the principle of dispatching generators in the wholesale electricity market, which means that the cheapest source of electricity is used first to meet electricity demand [81]. In the wholesale electricity market, power plants submit their offers for dispatch. Their offers are based on the variable costs of the power plant, such as fuel, carbon and maintenance costs. These offers are then ranked in the merit-order starting with the lowest offer to the highest offer. These generators will be dispatched from the lowest offer until demand is met. Merit-order ensures that the generators are dispatched at the lowest cost.

Furthermore, the merit-order leads to the concept of the marginal generator, which is the last power plant dispatched to meet the electricity demand [82]. The marginal generator sets the price of electricity for all other generators in the market. The price that the marginal generator is paid to generate electricity is known as the marginal price. Figure 2-6 illustrates the merit-order, marginal generator and marginal price.

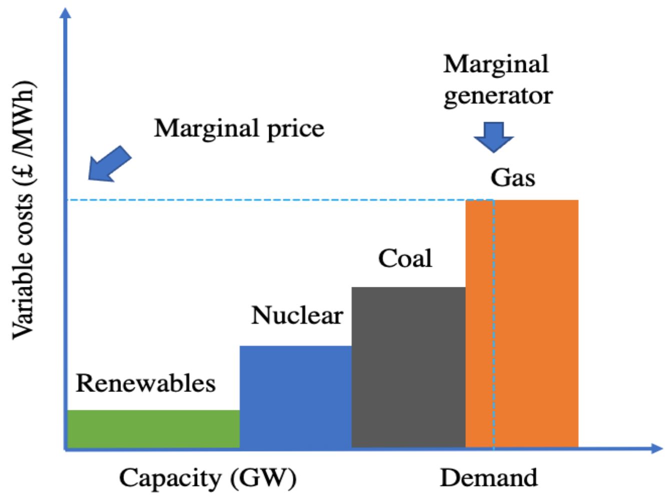


Figure 2-6 The merit-order in the wholesale market [82].

It is important to note that fossil-fuel power plants have high fuel and carbon costs, resulting in high variable costs. In contrast, renewable sources of energy like wind and solar PV have zero fuel and carbon costs, which translates to low variable costs. As a result, power companies tend to purchase electricity from renewable sources first, before moving to other sources of energy.

As the share of renewable energy, such as wind power, increases in the energy mix, electricity prices decrease for the same level of power demand. This phenomenon, known as the merit order effect, occurs because low-cost renewable energy sources displace higher-cost fossil-fuel generation in the electricity market. This dynamic is a key reason why coal- and gas-fired power plants, with their high variable costs, are increasingly at risk of being phased out in favor of low-carbon energy systems.

Figure 2-7 demonstrates the impact of the merit order effect on electricity prices [82]. The x-axis represents the capacity of power plant and y-axis represents the variable costs. Power plants are ranked in ascending order of variable costs, forming the merit order curve. As renewable energy sources are introduced, the power generation of fossil-fuel power plants will decrease.

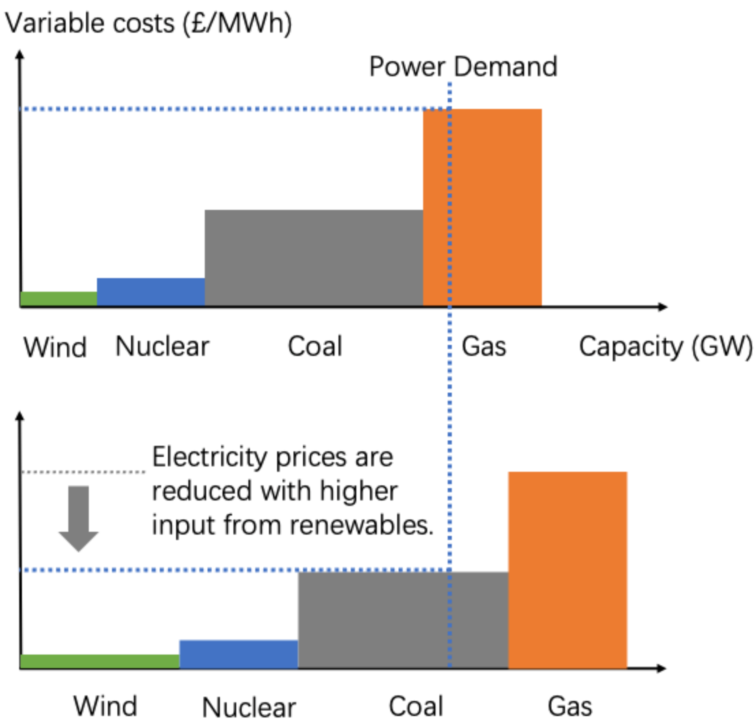


Figure 2-7 Electricity price fell due to the merit order effect [82].

The merit-order effect has been demonstrated and analyzed by many researchers and institutes. A 2007 study by the Fraunhofer Institute found that merit order effect had allowed solar power to reduce the price of electricity on the German energy exchange by 10% on average, and as much as 40% in the early afternoon [83]. In 2019, a study found that an extra GW of dispatched wind capacity in Australia decreases the wholesale electricity price by 11 AUD/MWh [84]. In the Iberian electricity market model, the increased wind power lead to the load for conventional power plants is decrease [85]. In Spanish electricity market, increasing share of wind generation has resulted in a continuous reduction in the operating hours of CCGT plants, which were only half as many hours in 2010 compared to 2004 [86]. These findings highlight the impact of renewable energy on fossil-fuel power plants in the electricity market.

2.4.1.6 The residual load duration curve

The residual load duration curve is a valuable tool for analyzing the impact of renewable energy sources, such as wind and solar PV, on the overall electricity load. It is obtained by subtracting the load of wind and solar PV from the load duration curve. The residual load duration curve directly illustrates how much of the total load must be met by conventional power plants after accounting for renewable generation.

In Figure 2-8, the black line is load duration curves, representing the total electricity load, and the blue line is residual load duration curve, representing the residual electricity load. In between these two lines represent the generation from wind and solar PV. The residual electricity load is limited by the total electricity load and the generation from wind and solar PV. This is because wind and solar PV, with their near-zero variable costs, are dispatched first according to the merit order principle [87-90].

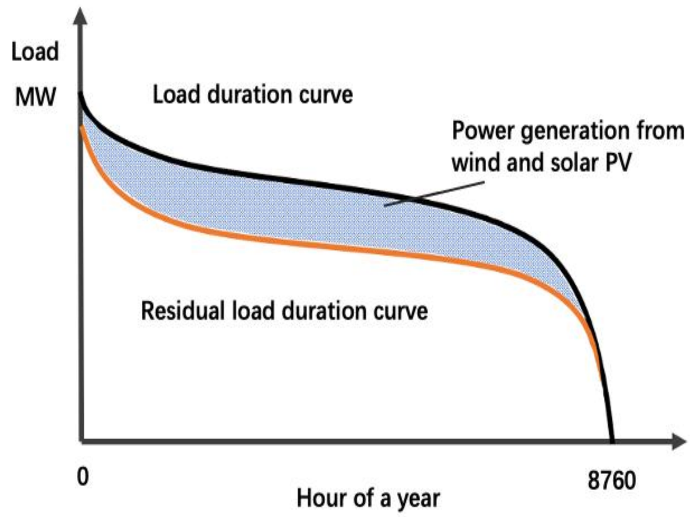


Figure 2-8 The load duration curve and residual load duration curve in a year [91].

2.4.1.7 The optimal technology mix for electricity supply

Optimal technology mix for electricity supply means that the generators in the system meet the demand at the lowest cost. The optimal technology mix for electricity supply can be determined by a graphical method, that is, the integration of the screening curve and the residual load duration curve [92]. Screening curves provide the annual costs of different power generation technologies at different capacity factors. Residual load duration curve shows the frequency and duration of specific load levels. By integrating these two curves, decision-makers can determine the optimal mix of power generation technologies that can meet the load requirements while minimizing the overall annual cost of power generation [93].

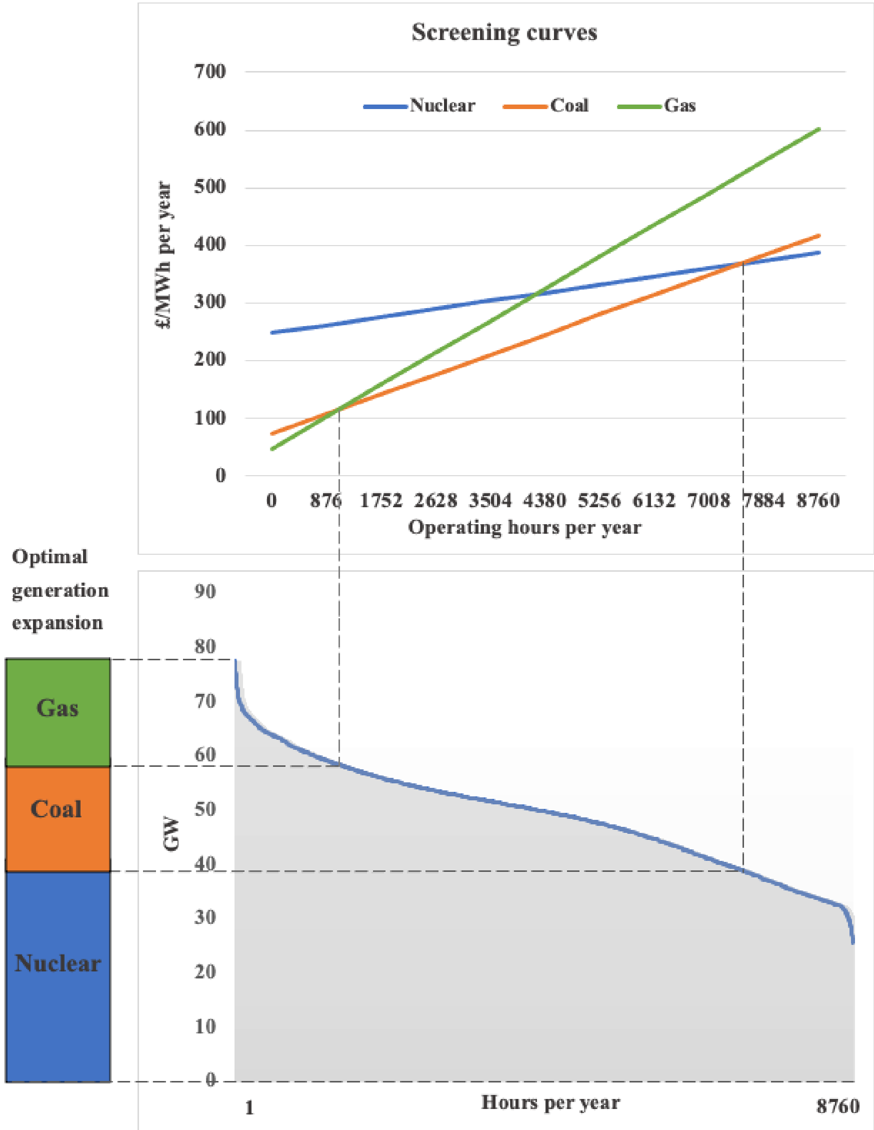


Figure 2-9 Optimal technology mix for electricity supply from the projection of screening curves on a residual load duration curve.

Figure 2-9 demonstrates the approach of the integration of screening curves and residual load duration curve to determine the lowest cost technology mix for electricity supply. The screening curves include the annual cost of nuclear power plant with high annual fixed costs and low variable costs, gas-fired power plant with low annual fixed costs and high variable costs, and coal-fired power plant with medium annual fixed costs and variable costs. The lowest cost or optimal situation is that each technology serves the segments which it has the lower cost. When these segments are projected onto the residual load duration curve, the optimal generation expansion can be found. This approach was first proposed in 1969, and these basic principles are still used in modern models [94].

2.4.2 Generation expansion planning (GEP) model

The approach using residual load duration and screening curves to determine the optimal technology mix for electricity supply is applicable to small power systems with fewer power plants. As the number of generators increases, these approaches become messy and it is impossible to find the lowest cost generation plan, especially when the operation of one power plant affects the other power plants in the expansion planning. For example, a wind power plant is expected to be built; the power generated by the wind power plant causes a reduction in the power generation from other power plants. Therefore, a GEP model is needed to simulate the operation of large-scale generation systems to solve complicated cost calculations and find the lowest cost expansion plan.

For the GEP model, the objective is to minimize the total cost of the power system, subject to technical constraints. The output of the model is the hourly power generation and the optimal technology mix for electricity supply that meets the electricity demand while minimizing the investment and operation cost of generators in the system.

Equation 2.3 and Equation 2.4 list the objective function and power balance constraint of GEP model. Equation 2.3 shows the objective function of GEP model, minimizing the total cost of system [95]. The total cost of system is the sum of capital cost depending on the number of units d_i of technology i installed, and operating cost depending on the power generation $P_{i,t}$ of technology i at time period t. Equation 2.4 shows the power balance constraint that at any time t, the sum of output power $P_{i,t}$ equal to power demand SD_t. The optimal value of variable d_i and $P_{i,t}$

determine the amount of installation and power output of each technology at time period to achieve the minimum system cost.

$$Minimize \sum_{i,t} CAPEX_i d_i + OPEX_i P_{i,t} \tag{2.3}$$

$$\sum_{i} P_{i,t} = SD_t \quad \forall t \tag{2.4}$$

The objective function of the GEP model consists of two main components: investment and operation. The investment component involves deciding when and what type of generation capacity to build. The operation component involves deciding how to operate the available generation capacity, based on the investment decisions that have already been made. These two components are interdependent and present a significant challenge in GEP modeling since the investment decisions impact the operational decisions and vice versa. Thus, GEP modeling requires careful consideration of both components to ensure reliable, efficient, and cost-effective planning.

According to the component of GEP objective function, GEP models can be divided into two categories, dynamic GEP models and traditional GEP models [18]. Dynamic GEP models focus on the operation of the system and traditional GEP models focus on the investment decisions for power plants.

2.4.2.1 Dynamic GEP model

Dynamic GEP model determines the optimal technology mix for electricity supply while considering the dynamic features of power system [19]. The dynamic features of a power system refers to its constantly changing operational and environmental conditions [20]. This is because power systems are subject to a wide range of uncertainties and variations, including changes in demand, fluctuations in renewable energy sources, variations in fuel prices, and equipment failures [96]. Additionally, power systems are subject to various operational constraints, such as grid stability and transmission capacity limitations [97]. These dynamic factors can have an impact on the operation and performance of the power system. Dynamic GEP model consider these dynamic features in planning and decision-making processes to ensure system stability and reliability [98].

To capture the detailed dynamics of power systems, dynamic GEP models with sub-hourly temporal resolution (e.g., 5-minute, 15-minute, or 30-minute intervals) are often employed. Such fine granularity allows the model to reflect operational variability with high precision, but it also significantly increases computational complexity, as the number of decision variables and constraints grows dramatically compared to hourly-resolution models. Consequently, these models are generally feasible only for small-scale systems or very short-term horizons (e.g., one day to one week).

However, with the increasing penetration of variable renewable energy (VRE), there is a growing need to evaluate long-term expansion pathways while still accounting for key operational dynamics. To address this challenge, researchers have developed approximate dynamic GEP methods, which reduce computational burdens by adopting representative time slices or sampled sub-periods (e.g., clusters of hours, days, or weeks) instead of modeling every chronological hour of the year [99, 100]. Techniques such as temporal clustering and typical period selection enable long-term planning models to strike a practical balance between fidelity and tractability.

Two widely used long-term generation expansion planning (GEP) tools are ReEDS for the United States and LIMES-EU for Europe. Both are reduced-form dynamic capacity-expansion models that minimize total system cost while co-optimizing investment and dispatch of generation, storage, and transmission over multiple decades. To maintain computational tractability at continental scales, they rely on representative time slices rather than full chronological simulation. ReEDS features high spatial detail (~132 zones and ~300 interfaces across the U.S.) and typically selects ~33 representative days with 3-hour blocks to capture diurnal and seasonal variability [21]. In contrast, LIMES-EU operates at the country level within the EU ETS perimeter, usually adopting 6–10 representative days (≈48–80 time slices per year) and explicitly linking to EU ETS/MSR policy mechanisms [100]. Despite these differences in spatial resolution, temporal aggregation, and policy emphasis, both frameworks are well suited to assessing system reliability and renewable energy integration under long-term decarbonization pathways.

These models are widely applied in research on low-carbon power systems. For example, Deholm et al. used ReEDS to examine supply-side options for achieving 100% clean electricity in the U.S. [21]; Cole and Frazier analyzed the impacts of increased VRE on system operation using ReEDS [101]; Novacheck and Schwarz evaluated the grid impact of Oregon offshore wind with ReEDS [102]. Similarly, Haller et al. applied LIMES-EU to analyze the spatial distribution and short-term dynamics of renewable generation in Europe[103], while Gerbaulet and Lorenz used LIMES-EU to assess the operation of a low-carbon electricity system under EU policy frameworks [104].

Comparable frameworks also exist in China. For instance, SWITCH-China provides provincial-level, hourly capacity-expansion-plus-dispatch modeling to study high-VRE pathways; REPO (Balmorel-based) offers provincial capacity expansion and operation with China-specific technology and policy features using representative periods; and China TIMES/MESSAGEix-China deliver economy-wide optimization that embeds the power sector for cross-sector consistency in long-term scenarios [7, 105, 106]. These models are functionally analogous to ReEDS and LIMES in scope and purpose, while reflecting China's unique institutional, resource, and policy context.

Overall, dynamic GEP model provides powerful support for decision-makers to optimize the operation of power systems and ensure their reliability, stability, and cost-effective. However, due to the large number of variables, dynamic GEP model cannot handle long-term horizons and large-scale power system. Even if the dynamic GEP model is simplified, it still requires a significant amount of computing time and results in a loss of accuracy. Thus, in long-term GEP models, short-term operational aspects are typically avoided.

2.4.2.2 Traditional GEP model

Traditional GEP models focus on investment in the power system. Its main objective is to identify the technology, size, location, and time horizon for installing candidate plants to meet predicted demand at minimum cost. Traditional GEP models usually simplify operation constraints, so they are tractable for large-scale power system and for the long-term horizons [22]. The traditional GEP model is used to determine the optimal technology mix for electricity supply over a longer time horizon, considering various factors such as capital costs, operating costs, and fuel costs.

Traditional GEP model are mainly used to analyze economic aspects of power system expansion. For example, F. Careri et al. identify the optimal strategy to plan the construction of new power plants under economical constraints in the Italian system [21]. S. Kannan et al. presents how power producing companies invest power plant in a competitive environment [22]. He and Wang assess carbon tax impacts on new investment in renewable energy generation capacity [24]. S. Majumdar and D. Chattopadhyay discuss the various interactions between investment and finance in investment planning [107]. Lu et al. analyze the investment decisions of power generation companies under different risk scenarios and considered the uncertainty risk constraint [108].

With the increase in renewable energy sources, incorporating a high percentage of renewable energy into the traditional GEP model has become an important topic. The researchers considered a number of factors in their expansion planning, such as the operation of wind energy, the uncertainty of renewable power, the flexibility of the power system, frequency and security assessments [109-114].

Currently, the reduction of CO2 emissions is the main issue of power system, traditional GEP model is used to study the integrating environmental considerations as constraints. For example, V. Oree et al. consider carbon emissions and the flexibility of the power system in GEP model [115]. A. Z. Khan, S. Yingyun, and A. Ashfaq examine the effect of damage costs of pollutions on the generation expansion plan in China [23]. C. E. Paes et al. analysis how reducing emissions change the generation expansion plan in Brazil [24].

Although traditional GEP models simplify short-term operational aspects, it directly and transparently expresses the interrelationships of variables and results, while saving a lot of computational time.

2.4.2.3 Discussion

The choice between dynamic and traditional GEP models depends on the research objectives, system size, and planning horizon. Both approaches aim to identify the least-cost generation expansion pathway, but they differ in temporal detail, computational burden, and policy applicability, as shown in Table 2-1.

Table 2-1 summarizes their main similarities and differences

Feature	Traditional GEP Model	Dynamic GEP Model
Objective	Long-term investment planning (technology type, capacity, timing)	Joint optimization of investment and short-term operation
Time resolution	Multi-year or seasonal averages; representative periods	High temporal granularity (hourly or sub-hourly)
Constraints	Simplified: annual demand balance, fuel limits, emissions caps	Detailed: ramping, reserves, unit commitment, VRE variability
Strengths	Computationally tractable for decades and large-scale systems	Realistic representation of operational dynamics
	Ignores short-term operational feasibility	Computationally demanding, feasible only for small systems or short horizons
Typical tools	TIMES, MESSAGE, China-TIMES	ReEDS (US), LIMES-EU, SWITCH-China
	Long-term decarbonization pathways, policy assessment, cost comparison	Reliability, renewable integration, flexibility assessment

In practice, the two approaches are complementary rather than competing. Traditional models are better suited for long-term horizons (20–40 years) and large-scale systems because they simplify operational detail, making them computationally efficient. Dynamic models, on the other hand, are valuable for studying short-term reliability and operational feasibility, especially with high penetration of variable renewable energy (VRE).

To overcome the computational limits of dynamic models, many recent frameworks adopt a reduced dynamic approach, which uses representative time slices or typical periods to capture essential variability without modeling every chronological hour. Examples include ReEDS in the United States and LIMES-EU in Europe, which approximate operational dynamics while remaining feasible for multi-decade studies. Comparable frameworks exist in China, such as SWITCH-China (high temporal resolution at provincial level) and China-TIMES (economy-wide optimization with power sector detail).

Overall, the trade-off between fidelity (capturing operational detail) and tractability (ensuring solvable long-term optimization) defines the choice of model. Researchers often select or combine approaches depending on whether the focus is on long-term investment pathways or short-term system operation under high VRE penetration.

2.4.3 Environmental considerations in the GEP model

There are two ways to incorporate environmental considerations into GEP models: (1) treating environmental impacts as constraints by setting tolerance thresholds for maximum acceptable emission level, and (2) integrating the external costs associated with the environmental impact of energy production from different power plants in the system [25]. Figure 2-10 gives diagrammatic paths of including environmental consideration in GEP model. One path is to set a threshold for carbon emission level, and another is to use external costs with power production. These two paths are separately explained below.

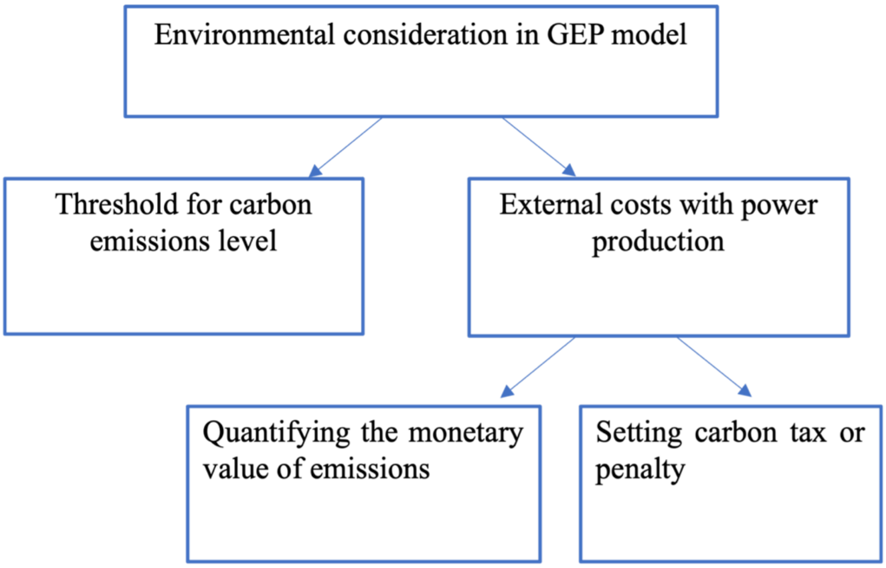


Figure 2-10 Environmental consideration in GEP model.

2.4.3.1 Threshold for carbon emissions level

Many researchers have considered integrating the setting of maximum acceptable emission level into GEP models to find the best mix of electricity generation while meeting emission reductions. Sirikum and Techanitisawad added air pollutant emission limits to their dynamic GEP model [26]. They find the optimal level of generation for a viable generation mix, considering demand and emission constraints. Karaki et al. estimates the carbon emissions of each unit and sets a maximum carbon emissions for the power system to estimate the environmental impact on the proposed generation scenario [27]. The disadvantage of this approach is that it ignores the impact of market factors on the generation system, such as merit order of dispatch and carbon pricing mechanisms. By focusing on emission limit, these researches often overlook the influence of market forces on the operation and investment of power generation systems.

2.4.3.2 External costs with power production

Another way to consider environmental considerations into GEP model is the integration of external costs associated with the environmental impact of energy production from power plants. There are two ways to address the external costs associated with power generation. The first approach is to quantify the external costs by assessing the monetary value of power plant emissions to the environment and human health. The second approach is to set a carbon tax or penalty on electricity generation directly.

Incorporating the monetary value of calculated emissions into the GEP model requires two steps. The first step is to quantify the monetary value of emissions through an energy model that simulates and analyzes the behavior of the energy system. The second step is to combine the monetary value of emissions with electricity generation in the GEP model. For example, Nguyen used an energy model to estimate the damage costs of CO2, NOx, SO2, and particulate matter emissions produced by different power generation technologies, and then integrated the damage costs into the GEP model as a tax on fossil fuels [116, 117]. Although energy models can provide a comprehensive view of the energy system and consider external costs in GEP model, they are complex and require significant resources and expertise to develop and use effectively, including a large amount of data on historical energy use, economic data, and technical information on energy systems [116].

Incorporating a carbon tax or penalty into the GEP model has simplicity and reflects more directly the impact of external environmental costs on power generation technologies. For example, Bakirtzis et al. incorporated the cost of purchasing emission allowances into the GEP model [28]. The carbon price is determined by a carbon price quota curve that reflects the impact of increased demand for emission allowances on the carbon price. Similarly, Mena et al. incorporated the carbon tax into GEP model to analyze the Chilean electric power system [29]. Carbon tax is set at around 30 €/tonne CO2 to model the transition of the Kosovo energy system. Zhang et al. use a combination of carbon price and carbon tax, with the long-term trends and volatility of carbon prices being simulated by a geometric Brownian motion process model [30, 31].

However, as discussed in the carbon pricing mechanisms section, traditional market-based carbon prices and fixed-rate carbon taxes have shortcomings in providing certainty of financial incentives for investment in power generation. In this thesis, an increasing carbon price trajectory is implemented in the GEP model to stabilize and strengthen the investment signal.

Some researchers have incorporated carbon pricing floor into GEP model. For example, Park and Baldick use a multi-year stochastic generation capacity expansion planning model to investigate changes in generation building decisions and carbon emissions under an increasing carbon tax [32]. In their setting, the carbon tax begins at US$0 in the initial model year and then increases by US$10 per tonne of CO_2 every five years, until it reaches a ceiling of US$30 per tonne. Emodi et al. used an energy model to analyze the effectiveness of carbon reduction policies, with a carbon tax of US$15/tonneCO2 in 2012, then increasing linearly to US$30/tonneCO2 by 2030 and then slowing to US$45/tonneCO2 by 2050 [118].

2.4.3.3 Discussion on incorporating an increasing carbon price into the GEP model

The use of an increasing carbon price can enhance the incentive for investing in low-carbon generation. However, many studies adopt relatively low carbon price levels, which are insufficient to drive the transition of the generation system toward a low-carbon future. This limitation arises because in models that combine an annual carbon emissions cap with carbon prices, the cap itself determines the maximum emission level. In such designs, the carbon price functions mainly as a variable to balance allowance supply and demand, rather than as the primary driver of long-term investment. As a result, the effective carbon price signal is often lower, reducing its ability to guide generation expansion decisions.

To address this gap, this thesis develops a carbon pricing mechanism that implements an increasing carbon tax while eliminating the annual emission cap. This approach aims to facilitate the transition of the power system to a low-carbon system solely through economic incentives. By simulating the market power to drive decision making, this approach ensures that the carbon pricing mechanism provides sufficient economic incentives to reduce carbon emissions in power generation system.

It should be noted that an increasing carbon tax is not the only possible solution. Other policy designs—such as hybrid instruments combining cap-and-trade with price floors/ceilings, price corridors, or indexation of carbon prices to macroeconomic variables—could also provide more predictable investment signals. However, this thesis focuses on the increasing carbon tax approach because it offers transparency, simplicity, and direct integration into the GEP framework, thereby allowing clearer evaluation of its long-term effectiveness in driving decarbonization.

2.5 Review of investment appraisal method

As the transition to low-carbon power generation systems progresses, the operations and costs of power plants will change, especially those powered by fossil fuels. However, the GEP model is unable to provide financial indicators for individual power plants because its formulation focuses on minimizing the total system cost from a system planner's perspective, rather than evaluating project-level cash flows. The outputs of a GEP model typically include system-wide results such as installed capacities, generation levels, total costs, and emissions, but they do not directly capture investment-specific measures such as net present value (NPV), internal rate of return (IRR), or profitability. These indicators require explicit consideration of plant-level revenues, discounting of future cash flows, and investment risk, which are outside the scope of standard GEP formulations.

Therefore, there is a need for an investment appraisal methodology that can provide economic indicators for power generation investments to reflect the financial aspects of power generation technologies. This section describes the investment appraisal methods, including discounting methods such as net present value, net present cost, levelized cost of electricity, internal rate of return, annuity and non-discounting methods such as payback time and return on investment. Compared to non-discounted methods, discounted methods primarily consider the time value of money. Finally, this section reviews research on the LCOE method for power generation technologies.

2.5.1 Financial mathematics and the component of the appraisal process

Before introducing financial appraisal methods, it is necessary to have some knowledge of financial mathematics and valuation for better understanding. Thus, this section presents the time value of money, present value, present value of a series payments, discount rate and the components of investment appraisal.

2.5.1.1 The time value of money

In financial mathematics, the value of money depends on its nominal value and the due date of the payment. The nominal value of money represents its current price and is not affected by inflation or interest. However, the real value of money is subject to inflation and may generate interest through investment. [119, 120]. An amount of money invested today would be worth more in "n" years when the initial payment and the accumulated interest are due. In other words, money today can be invested and potentially grow into a larger amount in the future. Thus, the principle of the time value of money states that the value of money today is worth more than the value of money in the future.

Due to the time value of money, investment payments from different times, added to or subtracted from each other cannot be compared directly. Thus, making investment payment comparison is an important issue in financial mathematics. In order to compare the payments with different times, compounding and discounting are two operations used to determine the time value of money [121]. Compounding converts the present value into future value and discounting converts the future value into present value. In investment appraisal, future payments are usually discounted to their present value.

2.5.1.2 Present value

Present value (PV) is a financial concept that represents the current value of a future payment or cash flow [122]. The calculation of PV is done through a process called discounting, which considers the nominal value of the payment, the discount rate and the number of years until the payment is due.

Equation 2.5 provides the equation for calculating PV for a single payment at the end of the year, It using a discount rate “i” [123].

$$PV = \frac{P_n}{(1+i)^n} \tag{2.5}$$

Where:

$PV: Present\ value$

$P_n: Nominal\ value\ of\ a\ single\ payment\ in\ the\ year\ n$

$i: Discount\ rate$

$n: Number\ of\ years$

In investment analysis, early returns are significant because they have a higher PV and therefore have a greater impact on the overall profitability of the investment. Conversely, later returns have a relatively smaller impact. Figure 2-11 illustrates the relationship between PV, the year the payment is due and the discount rate. The PV of a payment of £1,000 made today is £1,000. If a discount rate of 10 percent is applied, the PV of the same payment received 30 years later will be less than £100. Also, as the discount rate increases, the PV of the payment decreases.

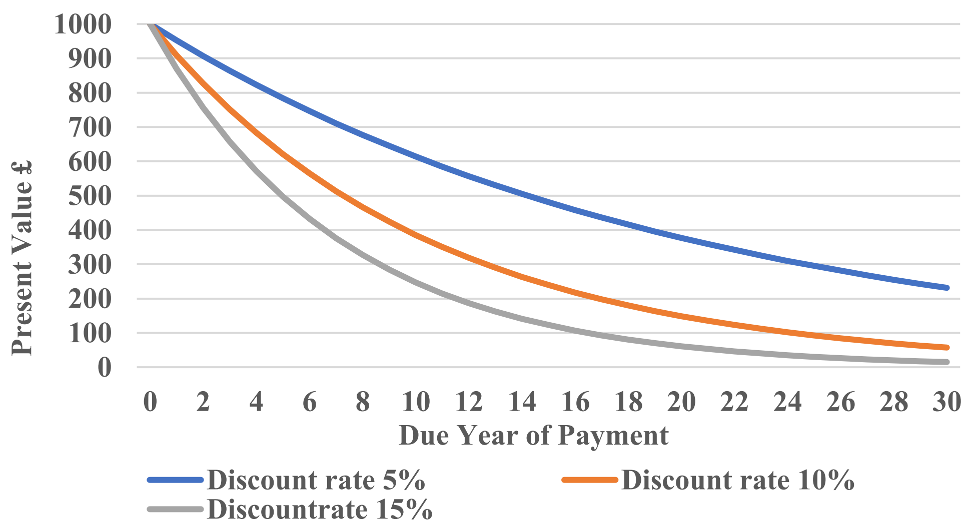


Figure 2-11 Present value of a single payment of nominal value £1000.

2.5.1.3 Present value of a series payments

When it comes to investment appraisal, investors often encounter a series of payments throughout the lifetime of their investments.

Assuming that payments are due at the end of the year, the calculation of PV of such a series involves determining the sum of the PVs of each individual payment, as shown in Equation 2.6 [124].

$$PV = \sum_{t=1}^{t=n} \frac{P_t}{(1+i)^t} \tag{2.6}$$

Where:

$PV: Present\ value$

$P_t: Nominal\ value\ of\ a\ single\ payment\ in\ the\ year\ t$

$i: Discount\ rate$

$n: Number\ of\ years$

This equation allows investors to calculate the present value of a series payments by summing the individual present values of each payment.

2.5.1.4 Discount rate

The discount rate is crucial in financial analysis because it determines the present value of future cash flows, and it greatly influences the assessment of the profitability of an investment. A higher discount rate will place greater emphasis on the present value of cash flows in the near term, while a lower discount rate will assign more value to cash flows in the far future.

Financial professionals must carefully consider the appropriate discount rate for their analysis [125]. One commonly used measure is the Weighted Average Cost of Capital (WACC). WACC represents the average rate of return required by both debt and equity investors to finance a project. It considers the cost of debt and the cost of equity, considering the respective weights of each component in the capital structure of a company. The calculation of WACC is represented by Equation 2.7 [126]. It involves multiplying the cost of equity and the cost of debt by their respective weights and summing the results [127]. In the Equation, E/V represents the proportion of equity-based financing and D/V represents the proportion of debt-based financing, presenting the capital structure of the investment. The cost of equity R_e is the rate of return that investors expected, the cost of debt R_d is the interest rate to pay for the debt. The tax rate T is incorporated to calculate the after-tax cost of debt, as interest payments are tax-deductible in some countries.

$$WACC = \left(\frac{E}{V} \cdot R_e\right) + \left[\frac{D}{V} \cdot R_d \cdot (1 - T)\right] \tag{2.7}$$

Where:

$E: Market\ value\ of\ the\ firm's\ equity$

$D: Market\ value\ of\ the\ firm's\ debt$

$V: Total\ value\ of\ capital\ (equity\ plus\ debt)$

$R_e: Cost\ of\ equity$

$R_d: Cost\ of\ debt$

$T: Tax\ rate$

WACC is particularly important for projects with high capital expenditures, such as power stations, which often involve significant investments ranging in the millions or even billions of pounds. Funding for these projects typically comes from a combination of equity from investors and loans from banks, each with different return expectations. By using the WACC as the minimum acceptable discount rate, financial professionals can ensure that the projected cash flows are appropriately discounted to their present value [128]

2.5.1.5 The components of investment appraisal

The investment appraisal process revolves around the cash inflows and outflows that occur throughout the lifespan of a project [128]. Figure 2-12 shows the components of an investment appraisal process, including the direction of the cash flow [125]. Cash inflows, such as sales revenues and other revenues, while cash outflows, including operating expenses, imputed costs, and capital expenditures. Usually in investment calculations, cash inflows are expressed in positive terms and cash outflows in negative term.

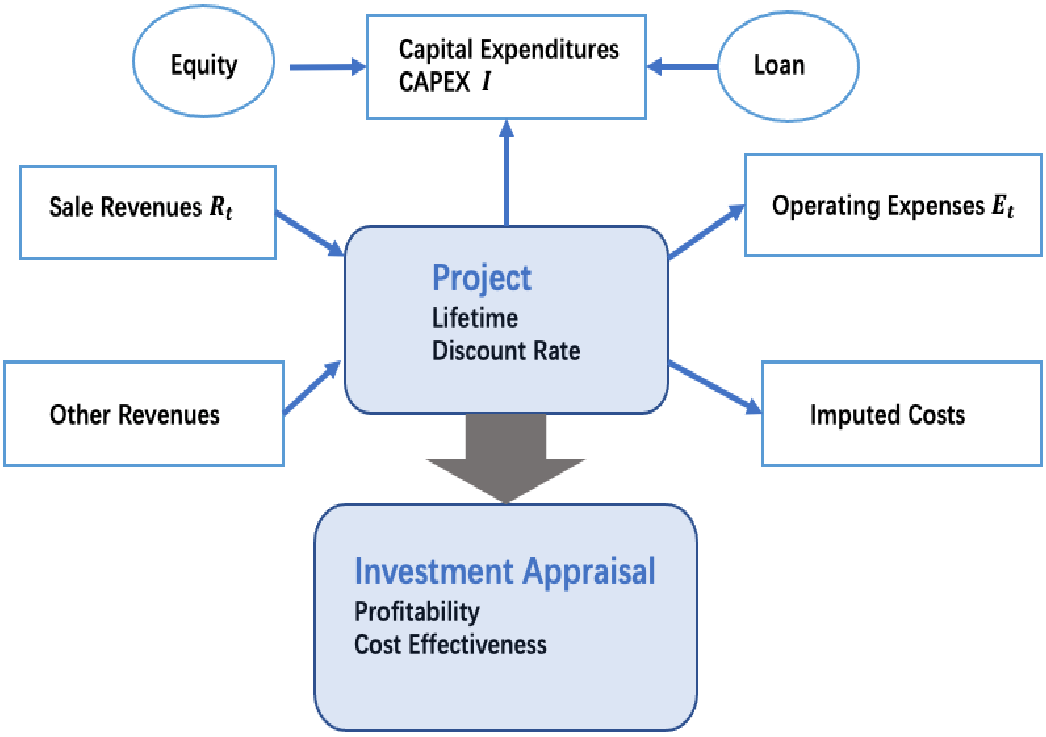


Figure 2-12 Components of an investment appraisal process [125].

- Capital expenditures: refer to the initial payments made for an investment project to generate future returns. Typically, it consists of a combination of bank loans and equity financing. Equity represents the portion of capital contributed by the investors themselves towards the total capital expenditures.
- Operating expenses: are regular payments incurred during the operation of the project, such as fuel costs and personnel expenses.

- Sales revenues are derived from the sale of goods or services. They are calculated by multiplying the price of the product by the quantity produced and sold.
- Imputed costs: also known as opportunity costs, are incurred when capital that could have been invested or used for another purpose is utilized for the project [129]. For instance, if an individual decides to pursue graduate school instead of working, the imputed cost would be the salary they forego during their time in school. Such costs are often indirect and not explicitly stated on financial statements.
- Other revenue: is income from sources of revenue other than core business activities. These revenues are derived from sources external to the business operations. It is important to note that imputed costs and other revenue are considered hidden costs and do not appear on financial statements, whereas capital expenditures, operating expenses, and sales revenues are reflected in the financial statements [130].
- lifetime: is the defined period within which the invested capital and interest must be recovered. It is worth mentioning that the project's lifetime is often shorter than the technical lifespan of the plant or asset.
- Discount rate: determines the present value of future cash flows.

It is important to note that imputed costs and other revenue are considered hidden costs and do not appear on financial statements [130]. Therefore, the key components of the investment appraisal process are capital expenditures, operating expenses, sales revenues, the project's lifetime, and the discount rate. By analyzing and considering these components, investors can assess the financial feasibility and profitability of their investment projects.

2.5.2 Net present value (NPV)

The NPV is a fundamental investment appraisal method that discounts all cash flows occurring throughout the investment period to their present value. It is a widely used financial metric for evaluating the viability of a project. The equation of NPV is shown below [131]:

$$NPV = -I + \sum_{t=1}^{t=n} \frac{(R_t - E_t)}{(1+i)^t} \tag{2.8}$$

Where:

I: $Capital\ expenditures\ present\ value$

R_t: $Time\ value\ of\ sale\ revenues\ at\ the\ year\ t$

E_t: $Time\ value\ of\ expenses\ at\ the\ year\ t$

i: $Discount\ rate\ in$ %

n: $Lifetime\ of\ project\ in\ years$

The NPV equation illustrates that the capital investment I must be recovered through appropriate returns $(R_t - E_t)$ during the project's lifetime [132]. A NPV of zero indicates that the returns $(R_t - E_t)$ precisely cover the invested capital I at the discount rate of return. A positive NPV suggests that the rate of return exceeds the discount rate, indicating a profitable investment. Conversely, a negative NPV implies that the investment is expected to result in a net loss. The option with the highest positive NPV is the most profitable and preferred option under the same investment risk.

The NPV method has one limitation. It is not suitable for comparing projects with different lifetimes. For instance, suppose Project A has an NPV of £1,000 and a lifespan of 20 years, while Project B has an NPV of £900 and a lifespan of 5 years. According to the NPV profitability criteria, Project A appears more favorable due to its higher NPV. However, considering the shorter duration of Project B, which yields a profit of £900 in just 5 years, it becomes evident that Project B is the superior option. Therefore, NPV alone may not accurately reflect the attractiveness of projects with differing lifetimes.

2.5.3 Net present cost (NPC)

The NPC method is typically used for projects where the focus is on cost analysis. Unlike the NPV method, which considers both cash inflows and outflows, NPC concentrates solely on the cost side of the investment. It calculates the present value of all costs incurred throughout the project's lifetime. In other words, NPC represents the cost aspect of NPV for an investment. The NPC equation is as follows [133]:

$$NPC = I + \sum_{t=1}^{t=n} \frac{E_t}{(1+i)^t} \tag{2.9}$$

Where:

NPC: $Net\ present\ cost$

I: $Capital\ expenditures\ present\ value$

E_t: $Time\ value\ of\ expenses\ at\ the\ year\ t$

i: $Discount\ rate\ in\ \%$

$n: Lifetime\ of\ project\ in\ years$

NPC solely focuses on costs and does not consider the benefits or cash inflows associated with the investment. The option with the lowest NPC is the most preferred option. It provides a comprehensive view of the overall cost of the project but does not allow comparisons between projects with different lifespans.

2.5.4 Levelized cost of electricity (LCOE)

LCOE is an investment appraisal methodology derived from the NPC concept and is widely used in the power generation sector [134]. It represents the average cost of electricity generation per unit of output over the lifetime of a project, expressed in £/MWh. LCOE can also be seen as the electricity price at which the total present value of costs equals the total present value of revenues, resulting in a zero NPC. At this point, the project neither generates a profit nor incurs a loss. Therefore, the LCOE serves as a breakeven electricity price required to recover all costs associated with the project.

In Equation 2.10, the NPC is expressed as the multiplication of the LCOE and the energy produced W_t during the project's lifetime [125]. This Equation captures the total cost associated with energy production. By combining Equation 2.9 and 2.10, the NPC is expressed as LCOE multiplied by the total amount of energy generated over the lifetime of the project. After rearranging the terms, Equation 2.12 shows the LCOE equation.

$$NPC = \sum_{t=1}^{t=n} LCOE \cdot \frac{W_t}{(1+i)^t} \tag{2.10}$$

Combining Equation 2.9 and 2.10:

$$I + \sum_{t=1}^{t=n} \frac{E_t}{(1+i)^t} = \sum_{t=1}^{t=n} LCOE \cdot \frac{W_t}{(1+i)^t} \tag{2.11}$$

Converting Equation 2.11 to LCOE Equation 2.12:

$$LCOE = \frac{I + \sum_{t=1}^{t=n} \frac{E_t}{(1+i)^t}}{\sum_{t=1}^{t=n} \frac{W_t}{(1+i)^t}} \tag{2.12}$$

$NPC: Net\ present\ cost$

$LCOE: Levelized\ cost\ of\ electricity$

W_t : $Energy\ produced\ in\ year\ t$

$I: Capital\ expenditures\ present\ value$

$E_t: Time\ value\ of\ expenses\ at\ the\ year\ t$

$i: Discount\ rate\ in\ \%$

$n: Lifetime\ of\ project\ in\ years$

Consolidating the expressions, the LCOE term is placed in front of the summation symbol, as LCOE is a constant. This adjustment allows it to express the total NPC as the LCOE multiplied by the sum of energy produced over the project's lifetime. Finally, Equation 2.12 provides the relationship between LCOE, the project's financial costs, and energy generation [125]. Equation 2.12 shows that LCOE is calculated by dividing the total expenditure discounted to present value by the total energy production and it is also discounted to present value [125]. It is important to note that the present value of electricity generation represents the revenue generated over the project's lifetime, rather than a discount on the amount of electricity produced.

2.5.5 Internal rate of return （IRR）

IRR is an investment appraisal method used to present the project's profitability. It is closely related to the NPV method, as both methods utilize the same equation. The IRR represents the discount rate at which the NPV of a project becomes zero, as expressed in Equation 2.12 [135].

$$NPV = -I + \sum_{t=1}^{t=n} \frac{(R_t - E_t)}{(1+i)^t} = -I + \sum_{t=1}^{t=n} \frac{(R_t - E_t)}{(1+IRR)^t} = 0 \tag{2.13}$$

Where:

I: $Capital\ expenditures\ present\ value$

R_t: $Time\ value\ of\ sale\ revenues\ at\ the\ year\ t$

E_t: $Time\ value\ of\ expenses\ at\ the\ year\ t$

IRR: $Internal\ rate\ of\ return\ in$ %

n: $Lifetime\ of\ project\ in\ years$

In Equation 2.13, the NPV is calculated by discounting the capital expenditures I and the net cash flows $(R_t - E_t)$ over the project's lifetime. The IRR is the rate at which this equation is satisfied, resulting in an NPV of zero. It essentially represents the annualized rate of return that the project is expected to generate based on its initial investment.

By comparing the calculated IRR with the minimum acceptable rate of return, investors can assess the profitability of the investment. As mentioned before, the WACC is the minimum acceptable rate of return for large projects. Investment is profitable when the IRR is higher than or at least equal to the minimum acceptable rate of return. The option with the highest positive IRR is the preferred option under the same investment risk.

2.5.6 Annuity method

The Annuity method, also known as the Annual Equivalent Amount method, is a useful approach for evaluating investments. It represents a fixed annual amount of money that will be returned to the investor over the lifetime of the project.

In Equation 2.14, the annuity A_n is calculated by multiplying the annuity factor a_n by the NPV of the investment [128]. The annuity factor a_n is the inverse of the sum of the present value of 1 in each year of the project's lifetime. It represents the discount used to convert the net present value into equivalent annualized future cash flows. Therefore, the annuity A_n is the equivalent annual amount that the investor can expect to receive from the investment.

$$A_n = a_n \cdot \left[-I + \sum_{t=1}^{t=n} \frac{(R_t - E_t)}{(1+i)^t} \right] = a_n \cdot NPV \tag{2.14}$$

$$a_n = \frac{1}{\sum_{t=1}^{t=n} \frac{1}{(1+i)^t}} \tag{2.15}$$

Where:

A_n: $Annuity\ or\ equivalent\ annual\ amount\ (£/year)$

a_n: $Annuity\ factor\ \ (1/year)$

I: $Capital\ expenditures\ present\ value$

R_t: $Time\ value\ of\ sale\ revenues\ at\ the\ year\ t$

E_t: $Time\ value\ of\ expenses\ at\ the\ year\ t$

i: $Discount\ rate\ in\ \%$

n: $Lifetime\ of\ project\ in\ years$

In the annuity method, the discount rate represents the minimum acceptable rate of return required by investors to undertake a project, commonly approximated by the weighted average cost of capital (WACC). It serves as the benchmark against which the project's returns are evaluated. An investment is profitable when the annuity of an investment is positive or at least zero ($Annuity \geq 0$). The option with the highest positive annuity is the most profitable and preferred option. By applying the Annuity method, investors can assess the regular and consistent returns they can expect to receive from an investment over their lifetime.

2.5.7 Payback time method

The Payback Time method is used to assess the time required to recover the initial investment in a project. This method is commonly employed in energy audits and evaluations of cost-saving measures, particularly when considering investments in technologies aimed at improving energy efficiency. By analyzing the payback time, investors can make decisions regarding the economic viability of such projects.

The payback time, denoted as t_{pb}, is calculated by dividing the initial investment I_0 by the net profit per year ΔR, as shown in Equation 2.16 [125]. For instance, when considering the installation of a new high-efficiency motor, the potential fuel cost savings is ΔR and the initial investment in the motor is I_0. A shorter payback time indicates a faster recovery of the investment, which is generally considered favorable. On the other hand, a longer payback time suggests a slower return on investment, which may be less desirable.

$$t_{pb} = \frac{I_0}{\Delta R} \tag{2.16}$$

Where:
t_{pb}: $Payback\ time$ in years

I_0: $Initial\ investment$

ΔR: $Net\ profit\ per\ year$

In practice, the payback time is only meaningful when it is a positive, finite value. If ΔR≤0, the investment will never recover its initial cost, and t_{pb} becomes undefined or tends toward infinity, which indicates that the investment is not profitable. Therefore, an investment is considered profitable only if it has a finite positive payback time, and among such cases, the option with the lowest payback time is the most preferred. It is worth noting that the Payback Time method has limitations: it does not consider the time value of money or account for cash flows beyond the payback period, and it does not provide a view into the long-term profitability or overall financial performance of the investment.

2.5.8 Return on investment

The Return on Investment (ROI) method is used to assess the profitability of an investment by measuring the ratio of the return or gain from the investment to the initial capital investment. It expresses the ratio of return from an investment to the invested capital, as shown in Equation 2.17.

To calculate ROI, the net profit or gain generated by the investment is divided by the initial investment cost and then multiplied by 100 to express it as a percentage [136]. Its equation is the inverse of the payback time equation. The net profit is determined by deducting the initial investment cost from the total revenue or gains realized from the investment. For example, if an investment generates a net profit of $10,000 and the initial investment cost was $50,000, the return on Investment would be 20%.

$$ROI = \frac{\Delta R}{I_0} \times 100 \tag{2.17}$$

Where:

ROI: $Return\ on\ investment$

I_0: $Initial\ investment$

ΔR: $Net\ profit$

A higher ROI indicates a better profit margin and a more favourable return on the invested capital. However, it is important to note that ROI is a non-discounted measure: it does not consider the time value of money or the distribution of cash flows across the project lifetime. Therefore, while it provides a simple and intuitive criterion for comparing investment options, it is less suitable for evaluating long-term projects where the timing of returns is critical.

2.5.9 Discussion on investment appraisal methods

The Payback Time and Return on Investment methods provide straightforward information in terms of years and percentages, making it easier for investors to understand the time required to recover their initial capital investment. However, their main limitation is that they do not consider the time value of money. This makes them less suitable for assessing the long-term profitability of a project. The Payback Time and Return on Investment methods are particularly useful for small-scale cost-saving

projects with shorter lifetimes.

To highlight these strengths and limitations more clearly, Table 2-2 summarizes the applicability of different investment appraisal methods under various conditions, including whether they are suitable for small-scale or large-scale investments, whether they can compare projects with different lifetimes, and whether they incorporate discounting of cash flows.

Table 2-2 Limitation of Investment appraisal methods.

Method	**Small-scale investment**	**Large-scale investment**	**Appraise investment with different lifetime**	**Discounting cash flow**
NPV		√		√
NPC		√		√
LCOE		√	√	√
IRR		√		√
Annuity		√	√	√
Payback time	√		√	
Return on Investment	√		√	

On the other hand, the NPV, NPC, LCOE, IRR, and Annuity methods take into consideration the time value of money, providing a more comprehensive analysis of investment profitability. However, one major limitation of the NPV, NPC, and IRR methods is their inability to compare projects with different lifetimes. These methods can only be used to compare projects that have the same lifespan. The Annuity method allows for the comparison of projects with different lifetimes. However, its presentation is based on an annual basis, which is more suitable for evaluating projects that may demand the generation a fixed annual return such as property rents [137].

Among these methods, the LCOE stands out as a powerful tool for evaluating investments in the power generation sector [138]. It considers the time value of money. It could compare the cost-effectiveness of projects over different lifetimes. It is expressed based on the cost of generation per unit of electricity (expressed in £/MWh), which gives a clearer assessment of power generation projects.

In addition, the LCOE focuses on the cost aspect of the project, which is important for power generation projects. This is because one of the distinguishing aspects of engineering economics, in contrast to classical economics, is the emphasis on the least-cost approach [128]. In the power sector, where electricity is a fundamental commodity for national economies, these investments are driven by the need to minimize costs rather than maximize profits. Power plants are considered essential investments to meet growing power demands. Therefore, investment appraisal in engineering economics focuses on evaluating the cost effectiveness of projects [139].

To summarize, the choice of method depends on the scale and nature of the investment. The LCOE method is effective in evaluating power projects because it considers the time value of money, enables comparisons across the life of the project, and emphasizes cost assessment.

2.5.10 Review of LCOE research on power generation technologies

Researchers have widely investigated the LCOE of power generation technologies, particularly low-carbon technologies such as wind energy, solar photovoltaics, biomass, nuclear, and wave energy [140-146]. These studies typically focus on estimating costs under different technical and policy assumptions, with an emphasis on the rapid cost declines and competitiveness of renewable technologies. For example, a large body of research has highlighted the role of technological learning, economies of scale, and regional resource availability in reducing the LCOE of wind and solar power, thereby supporting their accelerated deployment in decarbonization pathways. Nuclear and biomass have also been assessed in terms of long-term cost competitiveness, safety, and policy implications, though they exhibit greater variation across regions. In contrast, fossil-fuel generation technologies have received relatively less attention in LCOE research. This is partly because fossil-fuel plants are technologically mature, and their future costs are less affected by capital cost learning, while their LCOE is highly sensitive to uncertain factors such as volatile fuel prices and carbon pricing policies. Nevertheless, fossil-fuel technologies remain an important part of the generation mix, especially as providers of flexibility in systems with high penetration of variable renewable energy (VRE).

For fossil-fuel generation technologies, most research focused on improving the accuracy of the input data used in the LCOE calculations to enhance the reliability of LCOE assessment. Shea and Ramgolam use local data to estimate LCOE of various technologies in Mauritius [33]. Although, local data as input data is more accurate than international data or generalized assumptions, the local capacity factor cannot reliably indicate how the plant will perform in the future. Choi et al. estimated the future capital costs and LCOE of generation technologies through learning rates [34]. This approach increases the reliability of the LCOE, but most fossil-fuel generation technologies are well-established and the impact of capital costs on their LCOE is relatively small. Veselov et al. utilize two different future scenarios to estimate the LCOE of energy technologies in the future, taking into account the potential impact of carbon pricing and fuel pricing on LCOE [35]. Hansen utilizes long-term planning models to estimate the LCOE of power plants under different generation mix scenarios, including the dismantling of nuclear power capacity [36]. Both Veselov's and Hansen's research estimated the LCOE of thermal power plants under different scenarios, however they did not consider the potential impact of increased VRE in the system. In addition, the capacity factor they use is derived from a specific generation mix, which is fixed because they do not consider the fluctuation in capacity factor from the existing generation mix to the specific mix. This fluctuation will be magnified by the time value of money when it is used to estimate the LCOE. Therefore, using a fixed capacity factor to estimate the LCOE of a power plant during the transition to a specific generation mix reduces the reliability of the LCOE assessment.

To address this gap, this thesis proposes an LCOE approach that integrates the LCOE method with the GEP model. This approach incorporates annual capacity factors and annual carbon prices into the LCOE calculation, enhancing the reliability and accuracy of the cost assessment. The capacity factors and carbon prices used in the LCOE will be simulated on a year-by-year basis through the GEP model. Additionally, the GEP model considers carbon pricing mechanisms and with increasing in renewable energy. Therefore, the LCOE, incorporating annual capacity factors and carbon prices, can more effectively capture the economic performance of power generation technologies under carbon pricing mechanisms and with increasing renewable energy sources.

2.6 Summary

This chapter provides background and a review of power generation technologies, carbon pricing mechanisms, power generation expansion planning and investment financing methodologies.

However, the investment appraisal section reviewed focuses on the LCOE principles without clearly outlining their practical application to power generation projects. For example, while it is emphasized that LCOE considers the total costs of a power plant over its lifetime, it does not make it clear what specific components are included in the cost and what factors are required besides cost. This lack of clarity prevents a full understanding of how LCOE works when evaluating power generation projects and how various factors may affect it.

To better understand the LCOE assessment of power generation projects, the next chapter provides more details such as the calculation methodology, limitations, and the impact of renewable energy and carbon pricing on the LCOE of fossil-fuel fired generation technologies.

Chapter 3 Levelized Cost of Electricity Method in Generation Project

3.1 Introduction

This chapter provides an in-depth description of the LCOE methodology used for power generation projects. Section 3.2 describes the components of the LCOE equation specific to power generation projects. The inputs of LCOE have uncertainty, hence Section 3.3 discusses the uncertainty inherent in the LCOE method.

Calculating the LCOE for a power generation project requires a complex calculation that takes into account the project's cost which can include equipment and staff cost, power generation level, life cycle, and financial cost such as investment and discount rate. To illustrate the LCOE calculation in more detail, Section 3.4 shows the LCOE calculation process and clarifies the practical application of the LCOE methodology. Since the inherent uncertainty in the LCOE inputs affects the LCOE output values, a detailed analysis of the sensitivity of the LCOE to the various input factors is presented in Section 3.5, emphasizing the impact of these factors on the overall LCOE values.

Due to the different sensitivities of the various generation technologies to input data, any change in these data elements can favourably or adversely affect the competitiveness of investments in generation projects. In Sections 3.6 and 3.7, the LCOE methodology is be used to assess how carbon pricing and capacity factors respectively affect the competitive landscape for generation projects.

Finally, Section 3.8 describes and discusses two methods designed to address LCOE input uncertainty in order to improve the reliability of LCOE assessments. This chapter aims to provide an explanation of how LCOE is calculated and how input uncertainty affects investment in power generation projects.

3.2 LCOE equation

LCOE is used to evaluate the cost of power project by calculating the present value of life cycle energy costs and the present value of life cycle energy production. It considers all relevant costs, including capital costs, operating and maintenance costs, fuel costs, and any other costs associated with power generation, as mentioned in Chapter 2.4.1.1 [147]. In addition, it considers the energy produced by power generation project over its lifetime. In calculating the LCOE, besides the cost and the energy generated, some parameters are also important, such as the duration of the construction, the lifetime of the plant, and the discount rate. Figure 3-1 displays the components of LCOE in generation project and their relationship. The LCOE calculation mainly consists of a generation project's total cost, power generation, discount rate, and lifetime.

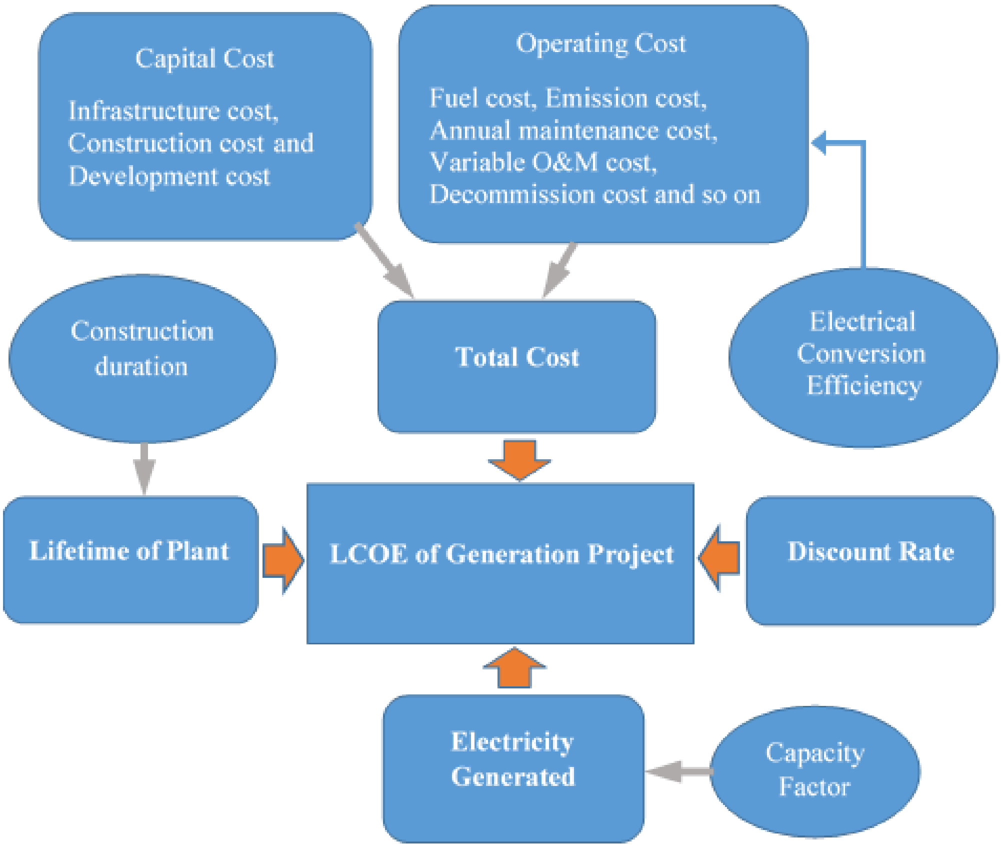


Figure 3-1 Components of LCOE.

Equation 3.1 shows the LCOE equation used in generation project, the numerator represents the sum of all costs, including capital costs, operating and maintenance costs, fuel costs, and carbon costs (emission cost), discounted over the plant's lifetime, while the denominator represents the sum of energy generated over the plant's lifetime, also discounted over time [147]. Discounting costs to net present value allows for a more accurate assessment of the economic viability of a project, as mentioned in Chapter 2.5.1. Equation 3.1 may indicate that the LCOE discounts the energy generated, this is not actually the case. Rather, it discounts the revenue generated from that energy over the lifetime of the power plant, this has been explained in Chapter 2.5.4.

$$LCOE = \frac{\sum_{t=1}^{n}[(CAPEX_t + O\&M_t + Fuel_t + Carbon_t) \cdot (1+r)^{-t}]}{\sum_{t=1}^{n} W_t \cdot (1+r)^{-t}} \quad (3.1)$$

Where

$CAPEX_t$: $Capital\ costs\ in\ year\ t$

$O\&M_t$: $Operation\ and\ maintenance\ costs\ in\ year\ t$

$Fuel_t$: $Fuel\ costs\ in\ year\ t$

$Carbon_t$: $Carbon\ costs\ in\ year\ t$

W_t: $Electeicity\ generated\ in\ year\ t$

r: $Discount\ rate$

From an investment perspective, if the LCOE of a project is higher than that of other projects, then it is less competitive and less attractive to investors. On the contrary, if the LCOE is lower than other projects, it is more competitive and will attract investors [36].

The advantage of LCOE is that it enables a uniform comparison across different generation technologies by consolidating all direct costs into a single metric. The most obvious application of this advantage is the design of renewable energy subsidies. Many countries subsidize wind technologies to increase their competitiveness and the difference between the LCOE of wind energy and that of fossil-fueled power plant is often considered to design the right amount of subsidy [148-152]. The disadvantage of LCOE is that the input data contains uncertainty, which is discussed in the next section.

3.3 Assumptions and limitations

The LCOE assessment is a detailed process that considers the expected costs and generation of a power plant over its whole operating life. The calculation of LCOE is highly dependent on various assumptions made about the input data, including expected expenditures for equipment, maintenance, and fuel, as well as estimates of operating efficiency and potential technological advances. This introduces uncertainty into the LCOE.

For example, capital costs may be affected by fluctuations in construction and labour costs. The lifetime of power plants may be extended or temporarily halted by political decision which is particularly relevant in nuclear power plant [153]. The fuel price can be influenced by global market trends, including geopolitical tensions and change in trade agreements [154]. Carbon prices can be affected by changes in government policies, global agreements and treaties [155]. The project's discount rate can vary with economic conditions, global financial markets, and policy and regulatory changes [156]. Power generation can be affected by changes in weather, transmission constraints, and regulator.

The limitation of the LCOE assessment is the uncertainty of the input data. The uncertainty of input data directly affects the calculated LCOE values and then influences the decision-making process for investment. For instance, the uncertainty of carbon policies and carbon price is the biggest barrier to the construction of new coal-fired power plants in the world; similarly, the uncertainty of capital costs is the major barrier to the development of nuclear plants in countries such as the UK and the US [157-160]. Therefore, the uncertainty of input data limits the reliability of LCOE values and investor motivation.

The next sections will show the LCOE calculation process and a sensitivity analysis in power generation projects to present how the input data affects the LCOE results.

3.4 Case study: LCOE calculation for USC

The calculation of LCOE requires a sequence of interrelated steps rather than a single direct computation. Specifically, it involves: (1) estimating the main cost components, including capital, fixed and variable O&M, fuel, and carbon costs; (2) calculating the total electricity generation over the project lifetime; (3) applying discounting to both costs and generation to reflect the time value of money; and (4) deriving the LCOE as the ratio of total discounted costs to total discounted electricity generation.

To facilitate understanding, this section describes the LCOE calculation process in detail. All technical data and assumed data used in this study are provided and detailed in Appendix A. As an example of ultra-supercritical (USC) power generation technology, Table 3-1 lists the technical parameters and costs used to calculate the LCOE.

Table 3-1 Technical parameters and costs for LCOE of ultra-supercritical generation technology [161, 162].

Net Capacity	347 MW
Electrical conversion efficiency	45%
Construction duration	4 years
Capacity factor	85%
Lifetime	40 years
Discount rate	7%
Fuel price	88 USD/tonne
Carbon price	30 USD/tonne
Construction price per year	0.17493 USD/MW
Fixed O&M price	0.0345 USD/MW
Variable O&M price	10.35 USD/MWh
CO2 conversion factor	0.3398 MWh/tonne CO2
Fuel property	6.9445 MWh/tonne

The calculation of each cost in the LCOE is shown in Equations 3.2-3.7 [163, 164]. Bringing all values into these equations shows the cost without discounting. These costs without discounting are fixed in each year because all the assumptions such as fuel prices, carbon prices and generation capacity factors are fixed. In the equations below, 1,000 is the conversion factor for plant capacity from MW to kW.

$$\begin{aligned} &Construction\ costs \\ &= Net\ capacity \times Construction\ price = 347 \times 0.17493 \\ &\qquad\qquad = 60{,}700{,}710\ USD \end{aligned} \tag{3.2}$$

$$Fixed\ O\&M\ costs$$

$$= Net\ capacity \times Fixed\ O\&M\ price = 347 \times 0.0345 \tag{3.3}$$

$$= 11{,}971{,}500\ USD$$

$$Variable\ O\&M\ costs$$

$$= Net\ capacity \times Capacity\ factor \times 8760 \times Variable\ O\&M\ price \tag{3.4}$$

$$= 347 \times 0.85 \times 8{,}760 \times 10.35 = 26{,}741{,}937\ USD$$

$$Fuel\ costs$$

$$\begin{aligned} &= [(Net\ capacity \times 8{,}760) \div Electrical\ conversion\ efficiency] \\ &\quad \div Fuel\ property \times Fuel\ price \times capacity\ factor \\ &\quad = [(347 \times 8{,}760) \div 0.45] \div 6.95 \times 88 \times 0.85 \\ &\quad = 72{,}758{,}155.9\ USD \end{aligned} \tag{3.5}$$

$$Carbon\ costs$$

$$\begin{aligned} &= [(Net\ capacity \times Capacity\ factor \times 8{,}760 \times 1{,}000) \\ &\quad \div Electrical\ conversion\ efficiency \\ &\quad \times CO2\ conversion\ factor] \div 1{,}000 \times Carbon\ price \\ &\quad = [(347 \times 0.85 \times 1{,}000 \times 8{,}760) \div 0.45 \times 0.3398] \\ &\quad \div 1{,}000 \times 30 = 58{,}530{,}822\ USD \end{aligned} \tag{3.6}$$

$$Energy\ generated = Net\ capacity \times Capacity\ factor \times 8{,}760 = 347 \times 0.85 \times 8{,}760 = 2{,}583{,}762\ MWh \tag{3.7}$$

Then, these costs and the energy generated are multiplied by a discount factor to obtain the discounted costs and generated energy, that is, the present value of each cost and energy. It is important to note that the present value of electricity generation represents the revenue generated over the project's lifetime, rather than a discount on the amount of electricity produced.

Equation 3.8 shows the relationship between the discount factor and the number of years of investment t and discount rate r [165].

$$Discount\ factor = \frac{1}{(1+r)^t} \tag{3.8}$$

Table 3-2 shows the process of calculating the LCOE, including assumptions on fuel prices, carbon prices and capacity factors, discounted costs for construction, O&M, fuel, carbon and total costs and power generation. As the number of years increases and the discount factor becomes smaller, each discounted cost becomes smaller, which means that the cost at the beginning of the project is important for the LCOE value. Finally, the LCOE is total discounted costs divided by total discounted generation and is 74.74 USD/MWh.

Table 3-2 The process of LCOE calculation.

USC 347MW, Capacity factor: 85%, Efficiency : 45%, Lifetime :40 years, Discount rate: 7% (cost in US dollars)											
Year No.	Fuel price	Carbon price	Discount factor	Capacity factor	Discounted construction cost	Discounted fixed O&M	Discounted variable O&M	Discounted fuel cost	Discounted carbon cost	Discounted costs in this year	Discounted generation in this year
0	88	30	1		60,700,000					60,700,000	
1	88	30	1		56,728,972					56,728,972	
2	88	30	1		53,017,731					53,017,731	
3	88	30	1		49,549,281					49,549,281	
6	88	30	1	1		7,977,116	17,819,282	48,482,219	39,001,558	113,000,000	1,721,670
7	88	30	1	1		7,455,249	16,653,534	45,310,485	36,450,054	106,000,000	1,609,037
8	88	30	1	1		6,967,522	15,564,051	42,346,248	34,065,471	98,943,292	1,503,773
9	88	30	1	1		6,511,703	14,545,842	39,575,933	31,836,889	92,470,366	1,405,395
10	88	30	1	1		6,085,704	13,594,245	36,986,853	29,754,102	86,420,903	1,313,454
11	88	30	0	1		5,687,573	12,704,901	34,567,152	27,807,572	80,767,199	1,227,527
12	88	30	0	1		5,315,489	11,873,740	32,305,750	25,988,385	75,483,364	1,147,221
13	88	30	0	1		4,967,747	11,096,953	30,192,290	24,288,210	70,545,200	1,072,169
14	88	30	0	1		4,642,754	10,370,984	28,217,093	22,699,262	65,930,093	1,002,027
15	88	30	0	1		4,339,023	9,692,509	26,371,115	21,214,263	61,616,909	936,474
16	88	30	0	1		4,055,161	9,058,419	24,645,902	19,826,414	57,585,897	875,210
17	88	30	0	1		3,789,870	8,465,812	23,033,553	18,529,359	53,818,595	817,953
18	88	30	0	1		3,541,935	7,911,974	21,526,685	17,317,158	50,297,752	764,442

19	88	30	0	1		3,310,220	7,394,368	20,118,397	16,184,260	47,007,245	714,432
20	88	30	0	1		3,093,663	6,910,625	18,802,240	15,125,477	43,932,005	667,693
21	88	30	0	1		2,891,274	6,458,528	17,572,187	14,135,959	41,057,948	624,012
22	88	30	0	1		2,702,125	6,036,007	16,422,605	13,211,177	38,371,914	583,189
23	88	30	0	1		2,525,351	5,641,128	15,348,229	12,346,894	35,861,602	545,037
24	88	30	0	1		2,360,141	5,272,082	14,344,139	11,539,154	33,515,516	509,380
25	88	30	0	1		2,205,739	4,927,180	13,405,738	10,784,256	31,322,912	476,056
26	88	30	0	1		2,061,438	4,604,841	12,528,727	10,078,744	29,273,750	444,912
27	88	30	0	1		1,926,578	4,303,590	11,709,090	9,419,387	27,358,645	415,806
28	88	30	0	1		1,800,540	4,022,046	10,943,075	8,803,165	25,568,827	388,604
29	88	30	0	1		1,682,748	3,758,922	10,227,173	8,227,257	23,896,100	363,181
30	88	30	0	1		1,572,661	3,513,011	9,558,106	7,689,025	22,332,804	339,421
31	88	30	0	1		1,469,777	3,283,188	8,932,809	7,186,005	20,871,779	317,216
32	88	30	0	1		1,373,623	3,068,400	8,348,420	6,715,893	19,506,336	296,464
33	88	30	0	1		1,283,760	2,867,664	7,802,261	6,276,535	18,230,220	277,069
34	88	30	0	1		1,199,776	2,680,059	7,291,833	5,865,921	17,037,589	258,943
35	88	30	0	1		1,121,286	2,504,728	6,814,797	5,482,169	15,922,980	242,003
36	88	30	0	1		1,047,931	2,340,868	6,368,969	5,123,522	14,881,290	226,171
37	88	30	0	1		979,375	2,187,727	5,952,308	4,788,339	13,907,748	211,375
38	88	30	0	1		915,303	2,044,604	5,562,905	4,475,083	12,997,895	197,546
39	88	30	0	1		855,424	1,910,845	5,198,976	4,182,320	12,147,565	184,623

40	88	30	0	1		799,461	1,785,837	4,858,856	3,908,711	11,352,865	172,545
41	88	30	0	1		747,160	1,669,006	4,540,987	3,653,001	10,610,154	161,257
42	88	30	0	1		698,281	1,559,819	4,243,913	3,414,019	9,916,032	150,707
43	88	30	0	1		652,599	1,457,775	3,966,274	3,190,672	9,267,319	140,848
44	88	30	0	1		609,905	1,362,406	3,706,798	2,981,937	8,661,046	131,634
45	88	30	0	1		570,005	1,273,277	3,464,297	2,786,857	8,094,436	123,022
									Total discounted costs (USD)	**Total discounted generation (MWh)**	
									1,840,000,000	24,559,495	
									LCOE	**74.75 USD/MWh**	

Figure 3-2 shows the individual cost components of USC in USD/MWh, calculated as the sum of discounted costs divided by the total discounted generation. The largest component of the LCOE is the fuel cost, at 28.16 USD/MWh, which represents 38% of the total cost. This dominance of fuel costs reflects the high dependence of USC plants on continuous coal supply over their lifetime. The second largest component is the carbon cost at 22.65 USD/MWh (30%), whose contribution exceeds that of capital costs. This is due to the large amount of carbon emissions produced by coal combustion, combined with the assumed carbon price of 30 USD/tonne, which significantly increases overall costs. O&M costs contribute 14.98 USD/MWh (20%), reflecting the labor- and maintenance-intensive nature of coal-fired power plants. Finally, capital costs represent only 8.96 USD/MWh (12%), the smallest share of the LCOE. Overall, the results highlight that for USC plants, variable costs (fuel and carbon) dominate the LCOE, whereas fixed costs (capital) play a secondary role. This cost structure highlights the sensitivity of coal-fired power generation to fuel price fluctuations and carbon pricing policies.

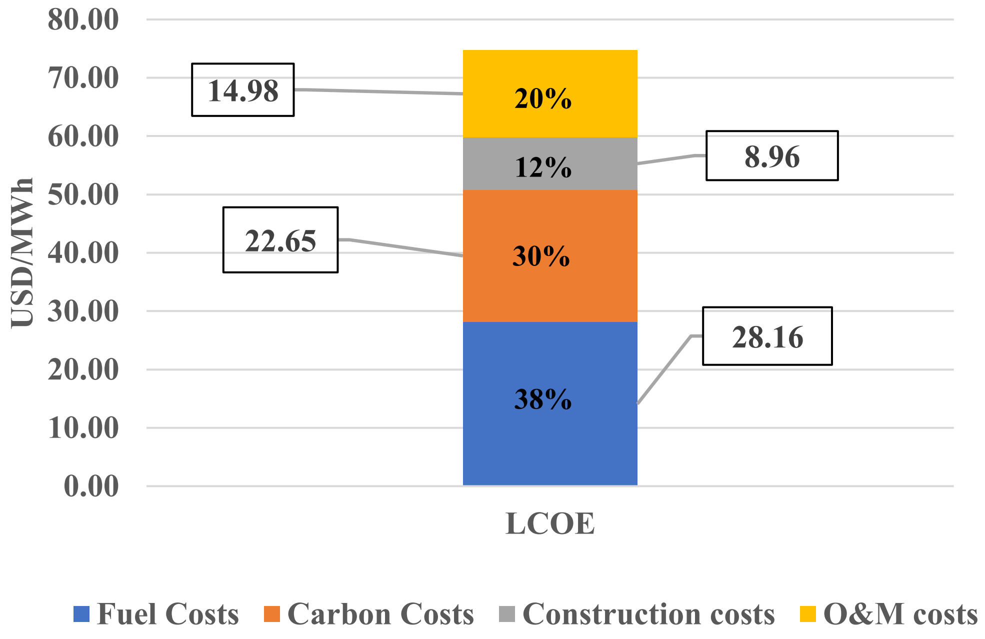


Figure 3-2 Levelized cost of ultra-supercritical generation technology.

3.5 Case study: LCOE sensitivity analysis

This section demonstrates the sensitivity of LCOE to assumptions on fuel price, carbon price, construction price, discount rate and capacity factor. It can reveal the effect of uncertainty in the input data on the LCOE value.

Figure 3-3 presents the sensitivity analysis of LCOE, which shows the change in the LCOE when one of the input data changes by ±50%. The green bar indicates that the value of the input data has increased by 50% from the baseline, while the orange bar indicates that it has decreased by 50%. For example, when the fuel price varies from 44 USD/tonne to 132 USD/tonne (±50%), the LCOE changes by about ±19%. Similarly, changing the carbon price from 15 USD/tonneCO_2 to 45 USD/tonneCO_2 leads to a ±15% change in LCOE. Construction costs varying by ±50% (around 87–262 USD/kW) affect LCOE by about ±6%. Discount rate changes from 3.5% to 10.5% lead to a 7% increase or a 5% decrease in LCOE. This difference reflects the cost structure of USC plants: fuel and carbon costs together account for nearly 70% of the total LCOE, whereas capital costs represent only around 12%. Moreover, construction costs are incurred upfront and then amortized over the plant's long lifetime and large generation output, which further reduces their relative impact on the unit cost of electricity. Overall, LCOE is most sensitive to fuel price and carbon price fluctuation.

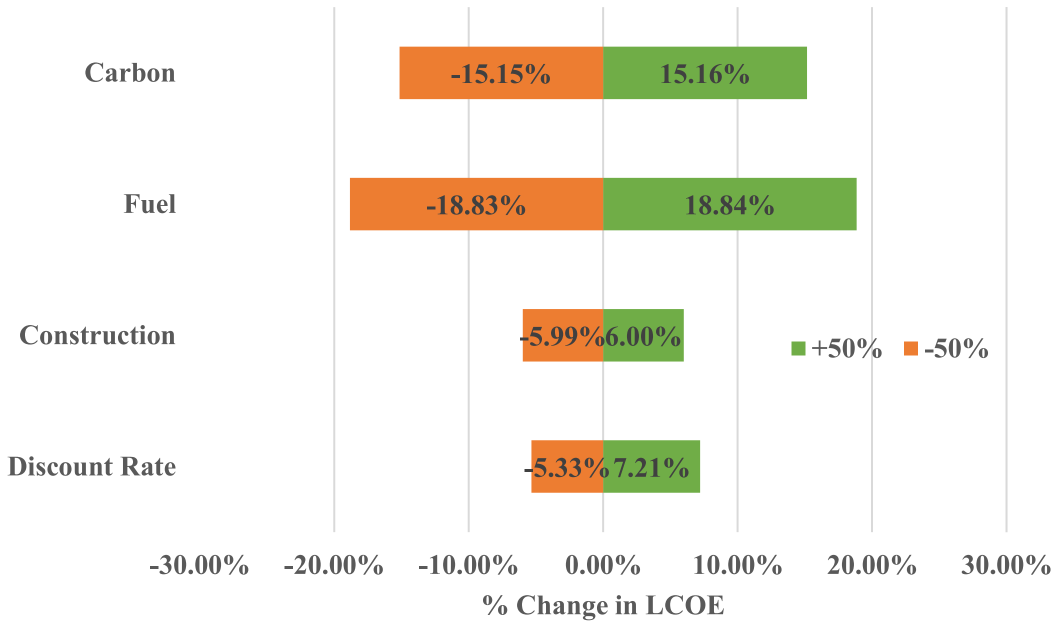


Figure 3-3 The sensitivity analysis of levelized cost of coal-fired generation technology.

Figure 3-4 presents the sensitivity of LCOE to capacity factor. The x-axis represents the capacity factor (in percent) and the y-axis represents USC's LCOE (USD/MWh). As the capacity factor decreases from 85% to 55%, the LCOE increases from \$74.75/MWh to \$82.17/MWh, a 10% increase in LCOE. It is worth noting that the LCOE rises faster as the capacity factor decreases. This suggests that for high capacity factor generation technologies such as USC, CCGT, and nuclear power plants, a reduction in capacity factor will result in a faster rise in their LCOE.

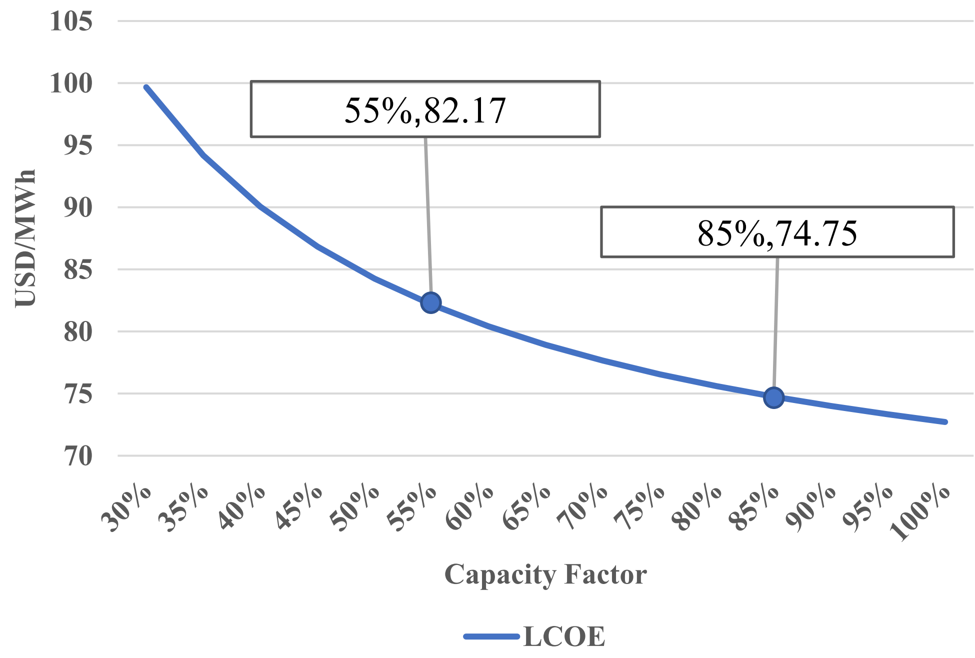


Figure 3-4 The change of LCOE over a range of capacity factor.

This section explains the sensitivity of the USC to different inputs by showing changes in its LCOE. Changes in LCOE directly influence the investment attractiveness of a technology, since LCOE reflects its relative cost-competitiveness in the generation mix. The next sections demonstrate how carbon price and capacity factors affect USC's investment competitiveness.

3.6 Case study: the impact of carbon prices on the competitiveness of generation project by LCOE

Carbon cost is an important component of LCOE for fossil-fuel based generation technologies. The value of carbon cost depends on the carbon price and the amount of carbon emission produced by the power plant, which varies depending on the type of fuel used.

This section first quantifies the carbon costs in fuel to show the difference between the carbon costs of coal and natural gas. Then, the LCOE of coal-fired generation technology, gas-fired generation technology, and wind farms are compared at carbon prices of \$0/tonneCO2e, \$30/tonneCO2e, and \$60/tonneCO2e to illustrate the impact of carbon prices on the competitiveness of power generation projects.

3.6.1 Quantification of carbon costs in fuel

The relationship between carbon costs, carbon prices, emission factors and activity data is shown in Equation 3.9 [166]. The activity data refers to resource consumption. The emission factor is a coefficient that describes the rate at which a given activity releases carbon emissions into the atmosphere. The carbon cost is the multiplication of the carbon price, the activity data, and the emission factor.

$$Carbon\ cost = CP \cdot AD \cdot EF \tag{3.9}$$

AD: $activity\ data\ (tonne)$

EF: $emission\ factor$ (tonneCO2/tonne)

CP: carbon price (£/tonneCO2)

Table 3-3 shows the UK 2022 emission factors in terms of gross calorific value (the amount of heat released per unit of fuel burned) and in terms of kWh [166]. Coal (domestic) is associated with home heating, coal (power generation) is used to generate electricity, coal (industrial) is used in a variety of industrial processes, and coking coal is used exclusively for the production of coke for steelmaking. Each type of coal has different uses based on its characteristics and suitability for specific applications. The combustion of coking coal emits the most CO2 equivalents, followed by coal (domestic), then coal (industrial) and finally coal (electricity generation). According to this table, the coal (electricity generation) emits 0.32133 kg CO2e per kWh, which includes 0.31945 kgCO2, 0.00009 kgCH4 and 0.00179 kgN2O. Moreover, Natural gas emits 0.18254 kgCO2 per kWh.

Table 3-3 Emission factors for fossil fuels [166].

Fuel	Unit	kgCO2e	kgCO2	kgCH4	kgN2O
Coal (industrial)	tonnes	2403.84	2377.98	6.82	19.04
	kWh (gross CV)	0.32463	0.32115	0.00092	0.00256
Coal (electricity generation)	tonnes	2252.34	2239.12	0.6	12.62
	kWh (gross CV)	0.32133	0.31945	0.00009	0.00179
Coal (domestic)	tonnes	2883.26	2632	214.6	36.66
	kWh (gross CV)	0.34462	0.31459	0.02565	0.00438
Coking coal	tonnes	3165.24	3144.16	7.56	13.52
	kWh (gross CV)	0.35797	0.35559	0.00085	0.00153
Natural gas	tonnes	2538.48	2533.69	3.44	1.34
	kWh (gross CV)	0.18254	0.18219	0.00025	0.0001

When emissions factors are available, the carbon cost in fuel can be calculated by using Equation 3.9 [166]. For example, if the price of carbon is \$2/tonneCO2e and 10 tonnes of natural gas are burned, this would generate 25,384.8 kg of CO2e based on the emission factor, resulting in a carbon cost of \$50.7696.

In addition, natural gas and coal are the two main fuels used to generate electricity. According to the emission factor, natural gas produces lower carbon emissions than coal when generating the same amount of electricity. Thus, the carbon cost of burning natural gas is lower than that of coal. Moreover, as the carbon price increases, the gap in carbon cost between gas and coal will widen. Figure 3-5 shows the relationship between the carbon price and the carbon cost for 1 kWh of electricity generated from coal and natural gas. When the carbon price is \$100/tonneCO2e, the carbon cost of coal is \$32.1, while that of natural gas is only \$18.3, which is 42% lower than coal.

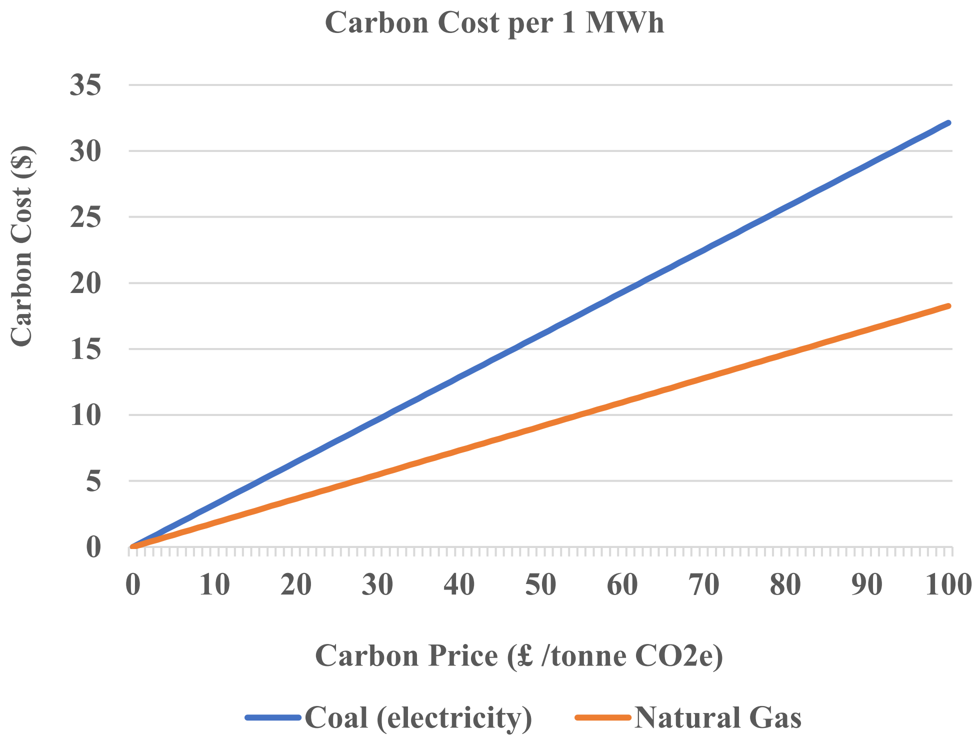


Figure 3-5 The relationship between carbon price and carbon cost.

3.6.2 Analyzing competitiveness of generation project at different carbon prices

In terms of power generation, fossil-fuel based power plants produce large amounts of carbon emissions and have to pay for them according to the carbon price. Different carbon prices will affect the competitiveness or attractiveness of power generation projects.

The following analysis will illustrate the impact of carbon pricing on the competitiveness of various power generation technologies by comparing the LCOE at carbon prices of $30, $0, and $60 per tonne of CO2 equivalent. In the first paragraph, the LCOE values of gas-fired generation technology, coal-fired generation technology and wind farm at a carbon price of $30 per tonne of CO2 equivalent are compared, highlighting the LCOE costs associated with a moderate carbon price. The next paragraph compares the LCOE values for the same technologies at a carbon price of $0 per tonne of CO2 equivalent to provide insight into the LCOE costs under a low carbon price scenario. The final paragraph provides a similar comparison for a carbon price of \$60 per tonne of CO2 equivalent, clarifying the LCOE costs associated with a high carbon price. See Appendix A for parameters related to the cost of the generation project. Coal-fired generation technology refers to USC technology and gas-fired generation technology refers to CCGT technology.

Figure 3-6 shows that when the carbon price is \$30/tonneCO2e over the power plant lifetime, the LCOE of coal-fired, gas-fired, and wind power plants are \$74.75/MWh, \$83.88/MWh, and \$58.28/MWh, respectively. In this case, wind power is the most competitive technology as it has the lowest LCOE. Even though gas-fired plants pay less carbon costs than coal-fired plants, they are still less competitive than coal-fired plants. Therefore, in the absence of other considerations, investors will prioritize investments in wind power technologies, followed by coal-fired technologies and finally gas-fired technologies.

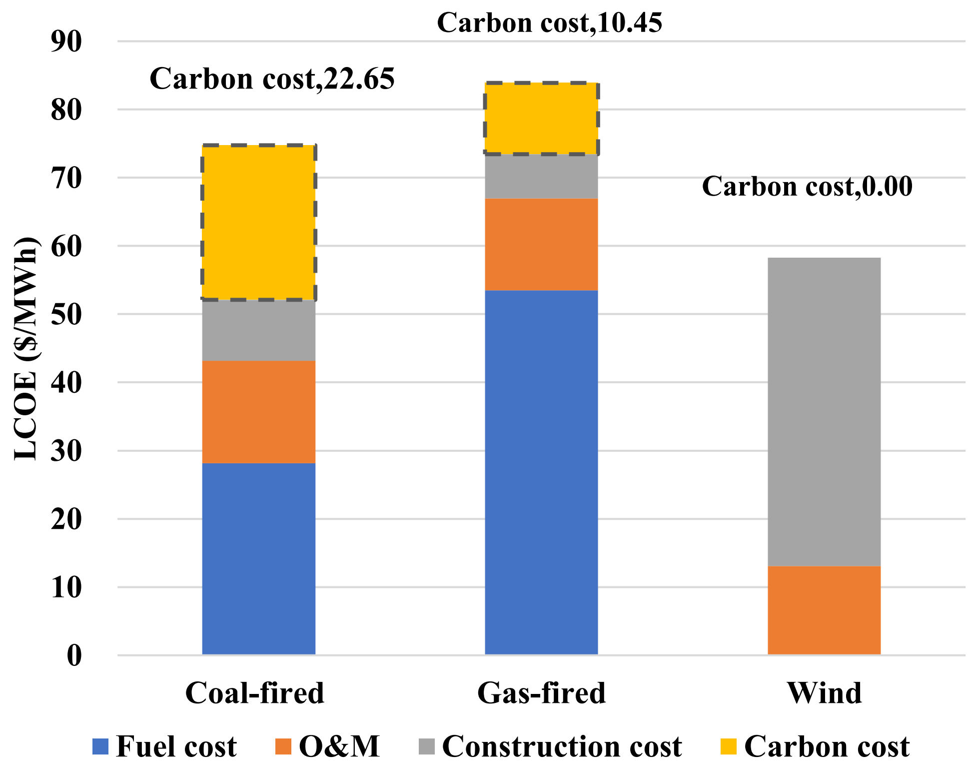


Figure 3-6 when carbon price is \$30/tonne CO2e, the LCOE of coal-fired, gas-fired and wind power plant.

Then, the carbon price is reduced to $0/tonneCO2e over the power plant lifetime to compare the LCOE of generation technology. Figure 3-7 shows the LCOE of coal-fired, gas-fired, and wind power plants are $52.10/MWh, $73.44/MWh, and $58.28/MWh, respectively. In this scenario, all power generation technologies achieve zero carbon cost; coal-fired technologies are the most competitive, followed by wind, while gas-fired technologies are the least competitive. The significantly lower LCOE is a key factor driving the dominance of coal-fired technologies in power generation.

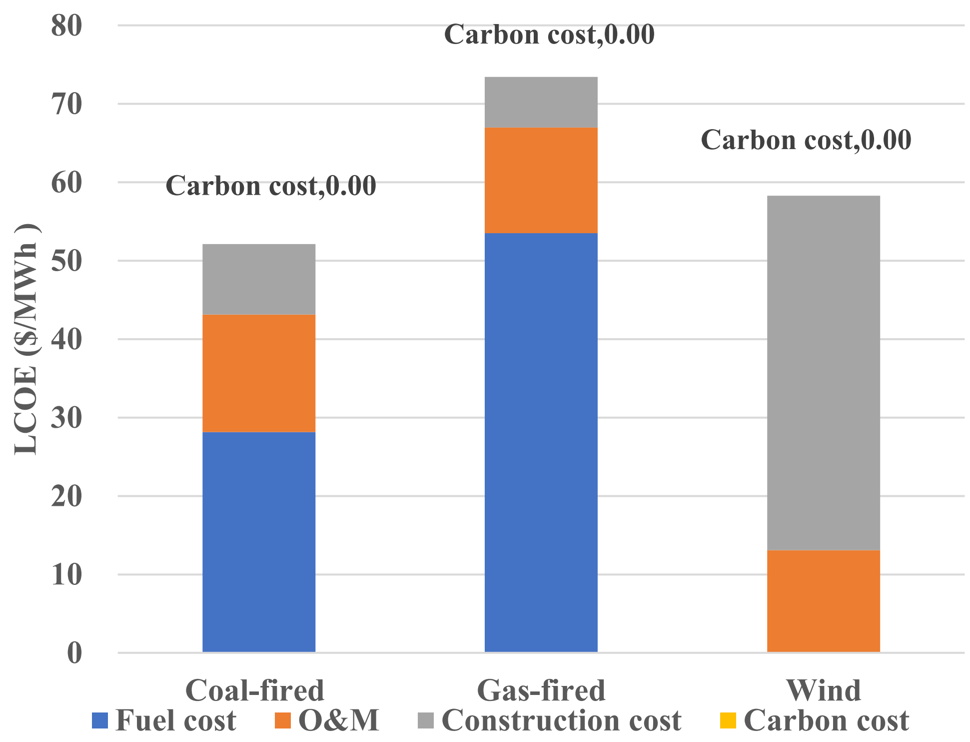


Figure 3-7 when carbon price is $0/tonne CO2e, the LCOE of coal-fired, gas-fired and wind power plant.

Finally, the carbon price is increased to $60/tonneCO2e over the power plant lifetime to compare the LCOE of generation technology. Figure 3-8 shows the LCOE of coal-fired, gas-fired, and wind power plants are $97.40/MWh, $94.33/MWh, and $58.28/MWh, respectively. Coal-fired power is the least competitive technology due to its high carbon cost of $45.30/MWh, while wind power remains the most competitive technology with an LCOE of only 60% of that of coal-fired power. Increased carbon pricing will reduce the competitiveness of coal-fired generation. High carbon emissions and LCOE may eventually lead to the phasing out of coal-fired generation from the investment market.

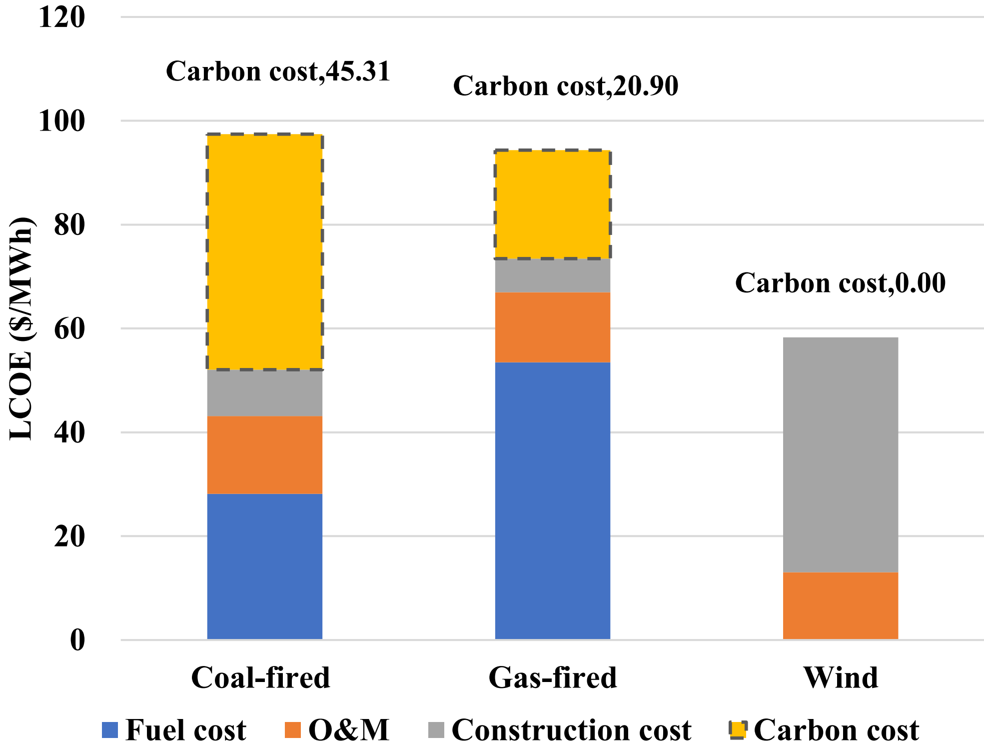


Figure 3-8 when carbon price is \$60/tonne CO2e, the LCOE of coal-fired, gas-fired and wind power plant.

In summary, the price of carbon plays a crucial role in determining the economic competitiveness of power generation technologies and has a direct impact on the investment landscape. When the carbon price is high, it creates financial incentives for the development of low-carbon or renewable generation technologies. When the carbon price is low, investment in coal-fired generation is still competitive compared to gas-fired generation. This analysis highlights the mechanism through which carbon pricing functions as a climate policy: by raising the cost of high-emission technologies and improving the relative competitiveness of low-carbon options, it guides investment decisions toward cleaner technologies and thereby supports carbon reduction targets.

3.7 Case study: the impact of capacity factor on competitiveness of generation project by LCOE

The increase in renewable energy generation reduces the capacity factor of gas-fired and coal-fired power plants, as mentioned in Chapter 2.4, the merit order effect. In particular, gas-fired plants are typically the marginal generating plant in the merit order, and their capacity factors will be reduced more than coal-fired plants. This section will compare the LCOE for gas-fired and coal-fired generation projects at capacity factors of 65%, 75%, and 85% respectively to illustrate the impact of capacity factor on the competitiveness of generation projects.

Table 3-4 and Table 3-5 shows the LCOE for gas-fired and coal-fired generation projects under different capacity factors. The results show that a decrease in the capacity factor leads to an increase in the LCOE. It is not the absolute construction and O&M costs that rise; these remain fixed in total terms. Rather, their contribution per MWh increases because the same fixed costs are spread over a smaller amount of generated electricity. Moreover, as the capacity factor decreases, the cost of fuel and carbon emissions per MWh does not change, but the cost of construction and O&M per MWh increases, which contributes to the increase in the LCOE. This suggests that generation projects with higher construction and O&M costs have a more significant increase in LCOE when the capacity factor is reduced.

When the capacity factor is reduced from 85% to 65% the LCOE for coal-fired technology rises from 74.75 $/MWh to 78.94 $/MWh, an increase of 5.3%, while the LCOE for gas-fired technology rises from 83.89 $/MWh to 87.17 $/MWh, an increase of 3.7%. While it may not seem like a big change in LCOE, it can have a big impact on investment decisions. Because CCGT is normally the marginal generator, an increase in renewable energy output is likely to reduce the CCGT's capacity factor. When the capacity factors of coal-fired generation and CCGT stand at 85%, the LCOE difference between the two is 9.14 $/MWh. If the CCGT's capacity factor drops to 75%, the LCOE difference rises to 10.56 $/MWh, and further increases to 12.42 $/MWh when the CCGT's capacity factor declines further to 65%. These results indicate that higher renewable penetration amplifies the LCOE gap between coal- and gas-fired technologies, diminishing the relative investment attractiveness of gas-fired generation.

Table 3-4 LCOE of coal-fired power plants operating at 65%, 75% and 85% capacity factor.

	Fuel cost ($/MWh)	Carbon cost ($/MWh)	Construction cost ($/MWh)	O&M ($/MWh)	LCOE ($/MWh)
Coal-fired (65%)	28.16	22.65	11.71	16.41	78.94
Coal-fired (75%)	28.16	22.65	10.15	15.60	76.57
Coal-fired (85%)	28.16	22.65	8.96	14.98	74.75

Table 3-5 LCOE of gas-fired power plants operating at 65%, 75% and 85% capacity factor.

	Fuel cost ($/MWh)	Carbon cost ($/MWh)	Construction cost ($/MWh)	O&M ($/MWh)	LCOE ($/MWh)
Gas-fired (65%)	53.50	10.45	8.48	14.74	87.17
Gas-fired (75%)	53.50	10.45	7.35	14.02	85.31
Gas-fired (85%)	53.50	10.45	6.48	13.46	83.89

Overall, the growth of renewable energy reduces capacity factor of power plants, thereby weakening the competitiveness of coal-fired and gas-fired power generation, especially for projects with high construction and O&M costs.

These results are consistent with the ranges reported in the literature. The International Energy Agency (IEA) in the Projected Costs of Generating Electricity report provide LCOE estimates for coal- and gas-based power generation. The parameters and cost assumptions in this thesis are drawn from that report. Under the conditions of an 85% capacity factor and a carbon price of 30 USD/tonne CO2, the LCOE values calculated in this thesis closely align with those reported by IEA, which confirms the validity and reliability of the results.

3.8 Discussion on the uncertainty of LCOE assessment

The LCOE methodology provides a basis to help investors make comparisons and investment decisions. However, it contains uncertain input values that can reduce the reliability of using LCOE assessment. The uncertainty of input data for LCOE is unavoidable so it is crucial to account for this uncertainty during the whole assessment process. By incorporating uncertainty, decision makers can fully consider the different scenarios they will face in the future, thus obtaining more reliable results to make informed investment decisions. This section discusses methods for addressing uncertainty in LCOE assessments, probabilistic models, and scenario analysis methods.

Probabilistic models and scenario analysis are two distinct methods used to address uncertainty in different ways. Probabilistic models utilize statistical methods to quantify uncertainty by assigning probabilities to various outcomes, drawing from historical data or expert opinions [167, 168]. On the other hand, scenario analysis involves constructing multiple hypothetical scenarios that capture different potential future conditions [169, 170]. These scenarios are typically based on specific assumptions about key factors that influence the analysis.

Probabilistic models are well-suited for analyzing uncertainties when historical data or expert knowledge is available, allowing for a quantitative assessment of the likelihood of various outcomes. They provide a probabilistic distribution of results, enabling decision-makers to understand the range of potential outcomes and associated probabilities. In contrast, scenario analysis is useful when there is a need to explore and understand the potential impacts of different future scenarios, even if historical data is limited or unavailable. It allows decision-makers to evaluate how different assumptions about key factors might affect the outcomes of the analysis. By examining multiple scenarios, decision-makers can gain insights into the sensitivity of the results to changes in underlying assumptions and identify the range of potential outcomes.

The application scope of probabilistic models and scenario analysis is different according to their distinct methodologies. For example, Geissmann and Ponta used a probabilistic model based on generalized assumptions and historical data to calculate the LCOE for nuclear and natural gas-fired power projects [171]. The use of probabilistic models based on historical data to estimate the LCOE for nuclear power projects is appropriate because nuclear fuel prices are stable and carbon taxes are not required. However, it is not appropriate to use this approach to estimate the LCOE for gas-fired power projects because natural gas prices and carbon prices are highly uncertain in the future. In another example, Hansen used the scenario analysis to estimate the LCOE of CCGT generation projects after nuclear decommissioning [36]. In such cases, historical data may not adequately reflect future uncertainty. Therefore, scenario analysis is more appropriate for assessing LCOE under conditions of structural change or policy-driven uncertainty, such as the phase-out of nuclear power.

In summary, when LCOE uncertainty is driven by dynamic factors such as evolving carbon pricing mechanisms, increasing renewable energy integration, and significant structural shifts in the power generation system, scenario analysis offers a more suitable framework for capturing these future uncertainties. Unlike probabilistic models that rely heavily on historical data, scenario analysis allows for the exploration of a wide range of future developments, making it particularly useful in long-term generation expansion planning.

3.9 Summary

This chapter illustrates the LCOE methods for power generation projects, including LCOE calculations, sensitivity analyses, the impacts of carbon prices and capacity factors on the competitiveness of projects, and a discussion of uncertainty in

LCOE assessments. It highlights the critical role of input data and its importance in ensuring the reliability of LCOE assessments for generation projects.

Minimizing uncertainty in input data is critical to improving the reliability of LCOE assessments. The next chapter describes the proposed Generation Expansion Planning (GEP) model in the thesis, which allows for the simulation of input data associated with generation projects in the generation system to further improve the reliability of LCOE assessments.

Chapter 4 Proposed Generation Expansion Planning (GEP) Model

4.1 Introduction

This chapter presents the proposed GEP model, designed to simulate the operation and investment in the power generation system, incorporating carbon pricing mechanisms and renewable energy integration. Section 4.2 provides an overview of the structure of the GEP model and clarifies the mechanisms of its operation in order to establish a fundamental understanding of the model. Then, Sections 4.3 and 4.4 present the objectives and constraints function of the GEP model, clarifying the principles for the expansion of the generation system in the model. The constraints include power balance, maximum power generation, energy storage function, CO2 price setting and installed capacity limits, all of which contribute to a more realistic model for system expansion.

Section 4.5 provides the possible limitations of the proposed GEP model, such as ignoring transmission constraints. It also highlights the distinguishing features of the GEP model, emphasizing its ability to provide long-term, high-resolution planning for the generation system.

Section 4.6 presents a case study using the proposed GEP model to illustrate the expansion of the power generation system, ensuring that it meets a carbon reduction target. This case study demonstrates the effectiveness and output of the proposed model and analyzes the impact of carbon pricing mechanisms and renewable energy integration on the study results.

4.2 Overview of the GEP model

The proposed GEP model in this thesis is a long-term linear traditional GEP model that considers the carbon pricing mechanism and the growth of renewable energy generation. The difference between dynamic and traditional GEP model have been explained in Chapter 2. The proposed model is a long-term model which does not include constraints imposed by short-term generation operations and transmission losses. In the long-term optimization process, the model determines the optimal capacity expansion of the power generation system on a yearly basis while deliberately excluding information about future carbon price variations. This intentional exclusion is designed to reflect the uncertainty of carbon pricing in real-world decision-making. If future carbon price changes were known in advance, power plant investments would be made with full foresight, leading to overly optimistic and unrealistic outcomes. To better reflect real-world decision-making, the model deliberately excludes perfect foresight of future carbon price trajectories. In practice, investors cannot predict the exact path of carbon prices, which depend on uncertain policy, market, and technological developments. By limiting investment decisions to information available in each year, the model captures the uncertainty faced by investors and provides a more realistic representation of long-term expansion planning under carbon pricing.

The proposed GEP model simulates the operation and investment of a power generation system in an energy-only market, with the objective of minimizing total system cost while meeting demand. The energy-only market is a form of electricity market structure in which generators receive revenues only from the sale of electricity and do not receive any compensation for capacity.

In addition, the deterministic nature of the model ensures that it consistently produces the same output when provided with the same set of inputs. This predictability improves the reliability of the model because it allows users to predict and replicate results under the same conditions. A deterministic framework provides a stable basis for scenario evaluation based on reliable results, thus contributing to the purpose of the analysis.

As discussed in Section 2.4.3.3, the key difference between the proposed GEP model and other GEP models is that it relies solely on the carbon pricing mechanism to provide economic incentives for reducing carbon emissions in the power system, without considering an annual carbon emissions cap. This approach allows the model to focus entirely on market-driven carbon reduction, offering an economically driven pathway for transitioning to a low-carbon power system.

Figure 4-1 illustrates the structure of the proposed GEP model, which aims to minimize the power system's capital and operating costs while considering various constraints. The inputs of the model include fuel price, carbon price rate, capital costs and operation costs of generation technologies, energy storage system parameters, generation efficiency, emission factor, hourly demand, variable renewable load profile, and existing installed generation capacity. The main outputs are the annual technology mix for electricity supply and hourly electricity generated from various technologies. The model's constraints include power balance, CO2 price, maximum power generation constraints, energy storage limits and installed capacity limits in the generation system.

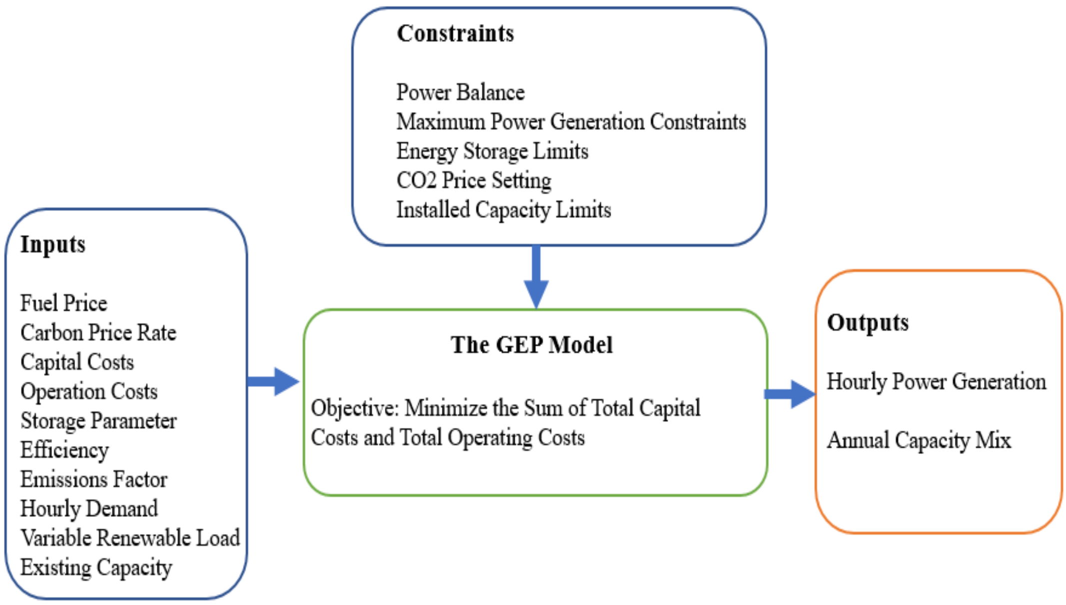


Figure 4-1 Structure of the proposed GEP model.

To make the proposed GEP model transparent and reproducible, this subsection details how the model runs from inputs to outputs and how decisions are made year by year. Figure 4-2 shows the flowchart of the proposed GEP modelling process.

Time structure: The model operates with two time resolutions: (i) hourly resolution (8,760 hours) for operational dispatch; and (ii) annual resolution for capacity expansion and parameter updates (demand growth, carbon price, renewable additions). The planning horizon covers 30 years.

Optimization paradigm: The model uses a myopic (rolling-horizon) annual optimization without perfect foresight of future carbon prices. In each year y, capacity expansion and hourly dispatch are optimized using only the information available in that year (fuel prices, carbon price, demand, VRE profiles, constraints). The process then moves to year y+1 with updated capacities and parameters.

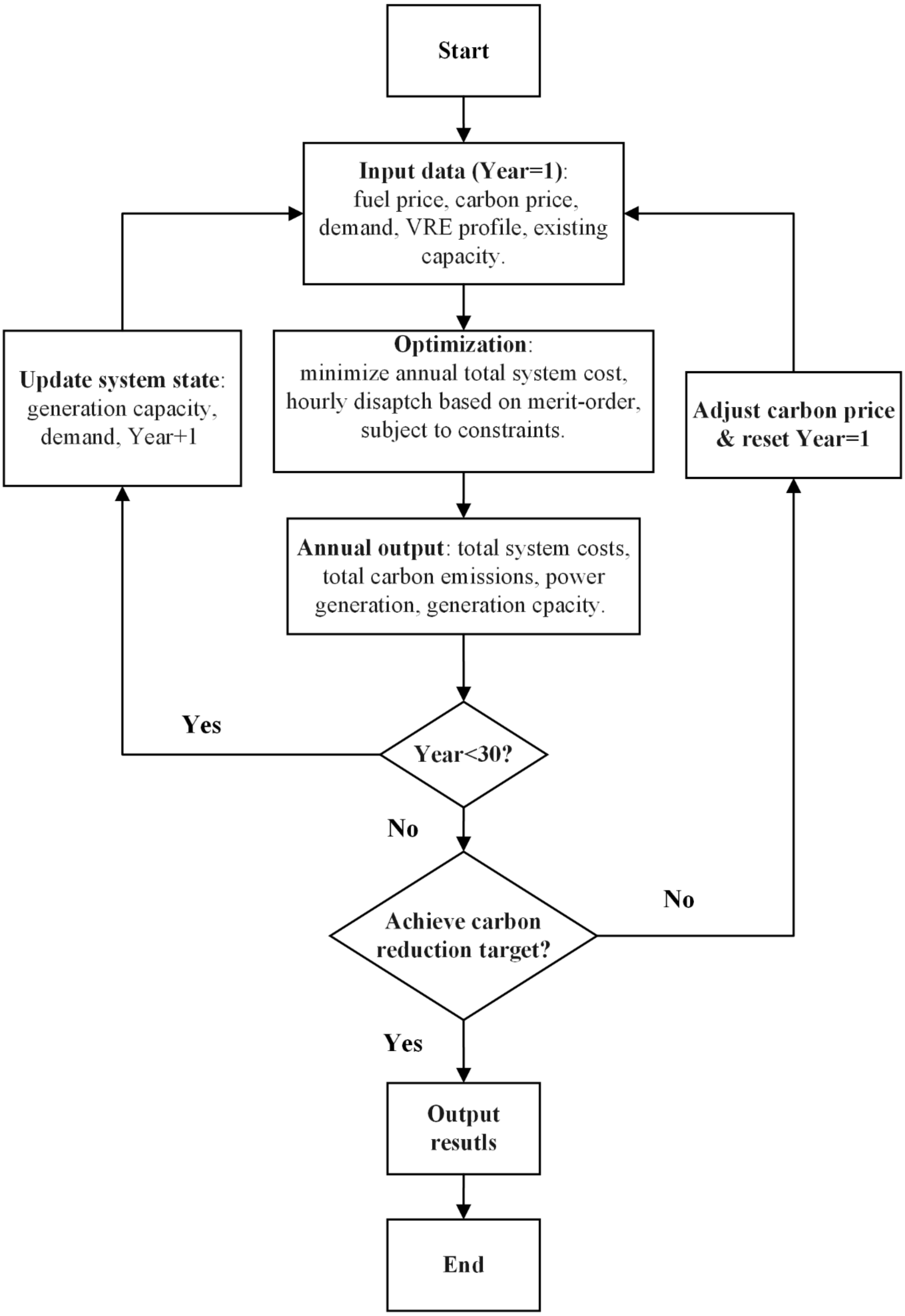


Figure 4-2 Flowchart of the proposed GEP modelling process.

The GEP model and the LCOE model are developed as two separates but connected analytical tools. The GEP model first performs the system-level optimization, producing outputs such as hourly dispatch, annual generation by technology, and carbon price trajectories. These outputs are then used as inputs to the LCOE model. Specifically, the annual capacity factors for each technology are calculated based on the GEP results, and the annual carbon prices determined by the GEP model are also incorporated into the LCOE calculation.

It is important to note that while the LCOE model relies on the outputs from the GEP model, the results of the LCOE analysis are not fed back into the GEP model and therefore do not influence its optimization process. This one-way linkage ensures a clear separation between system-wide planning and plant-level economic evaluation. The GEP model provides an optimized view of long-term system development, while the LCOE model uses that information to assess the economic viability of individual generation technologies under different scenarios. Together, these two independent models offer a comprehensive framework for analyzing both the evolution of the power system and the investment performance of specific power plants.

4.3 Objective

The objective function of the GEP model is Equation 4.1, which minimizes total system costs C with respect to a number of decision variables and technical constraints. The generation technologies i consist of VRE technologies j (variable renewable energy, such as solar PV and wind), dispatchable generation technologies k (such as nuclear, USC, CCGT and USC-CCUS) and power storage technologies s (such as pumped storage system). The total system costs C consist of the sum of fixed generation costs (capital costs) C_i^{fix} and variable generation costs (operation costs) $C_{t,i}^{var}$, where i is generation technologies, t is the time step.

In addition, the sum of fixed and variable generation costs could be expressed in Equation 4.2 and Equation 4.3, respectively. The sum of fixed generation cost C_i^{fix} equals the sum of new capacity g_i^{inv} multiplied by investment cost c_i^{inv} and all generation capacity multiplied by fixed O&M cost c_i^{fix} for each generation technologies i. g_i^0 is the existing capacity of all generation technology. The variable generation costs $C_{t,i}^{var}$ are the sum of variable O&M costs c_i^{om}, fuel costs c_i^{fuel} and carbon costs $c_i^{emissions}$ multiplied by the amount of electricity generated in one year for each generation technology $p_{t,i}$, respectively.

$$Minimizing\ C = \sum_i C_i^{fix} + \sum_{t,i} C_{t,i}^{var} \tag{4.1}$$

$$\sum_i C_i^{fix} = \sum_i \left(g_i^{inv} \cdot c_i^{inv} + \left(g_i^0 + g_i^{inv}\right) \cdot c_i^{fix}\right) \tag{4.2}$$

$$\sum_{t,i} C_{t,i}^{var} = \sum_{t,i} p_{t,i} \cdot c_i^{om} + p_{t,i} \cdot c_i^{fuel} + p_{t,i} \cdot c_i^{emissions} \tag{4.3}$$

4.4 Constraints

This section describes the constraints of the proposed GEP model to clarify the constraints and conditions that the model optimization process needs to satisfy, including power balance, maximum power generation constraints, energy storage limits, CO2 price setting and installed capacity limits.

4.4.1 Power balance

Energy balance is the main constraint of power generation system, whereby the hourly electricity supply must be equal to the demand. This GEP model includes a power storage system so the output and input of the storage system are included in the balancing equation. In Equation 4.4, the demand δ_t in time t equal to the power generation $p_{t,i}$ from all generation technology i plus storage output s_t^{out} minus storage input s_t^{in} in time t. It is worth noting that storage is not treated as a generation source because it does not create new electricity but only shifts energy across time. By accounting for storage output and input separately in the balance equation, the model avoids double-counting electricity, ensures consistency in the energy balance, and provides a clearer distinction between generation and storage technologies.

$$\delta_t = \sum_i p_{t,i} + s_t^{out} - s_t^{in} \tag{4.4}$$

4.4.2 Maximum power generation constraints

Equation 4.5 shows the hourly generation for VRE technologies j, such as onshore wind and solar PV. The hourly generation from VRE $p_{t,j}$ is the product of installed capacity g_j and generation profiles $\varphi_{t,j}$. In this thesis, the term generation profile $\varphi_{t,j}$ refers to the normalized availability factor (0–1) of renewable technologies at each hour, while the generation curve represents the actual generation obtained by multiplying the profile with installed capacity. In other words, the profile is an input, and the curve is the resulting output. Generation curves provide the amount of electricity generated by a renewable energy system during a specific time, which varies depending on factors such as the time of day, season, and weather conditions. VRE installed capacity g_j consists of the existing capacity g_j^0 and the new capacity g_j^{inv}.

$$p_{t,j} = g_j \cdot \varphi_{t,j} = \left(g_j^0 + g_j^{inv}\right) \cdot \varphi_{t,j} \qquad j \in i \tag{4.5}$$

Equation 4.6 states the maximum hourly generation for dispatchable technologies k, such as nuclear, coal and gas power plant. The hourly generation $p_{t,k}$ from dispatchable generation technologies is less than or equal to the product of installed capacity g_k and availability $\alpha_{t,k}$. The availability refers to the proportion of time during which dispatchable generation technology k is actually available for operation at a specific time t. Factors affecting availability include maintenance schedules, equipment reliability, and response to unplanned outages. The installed capacity g_k is the existing capacity g_k^0 plus new capacity g_k^{inv} minus decommissioned capacity g_k^{dec}.

$$p_{t,k} \le g_k \cdot \alpha_{t,k} = \left(g_k^0 + g_k^{inv} - g_k^{dec}\right) \cdot \alpha_{t,k} \qquad k \in i \tag{4.6}$$

4.4.3 Energy storage limits

Pumped storage technology is a widely used energy storage technology in generation system. The equations to follow show the operation of pumped storage technology in generation system. Equation 4.7 shows that the amount of energy stored in storage system at certain hour v_t is last hour's amount v_{t-1} minus output power s_t^{out} plus input power s_t^{in}. It should be noted that, for computational tractability, the model assumes an ideal storage system without efficiency losses. In practice, pumped storage systems have a round-trip efficiency of 70–85%, which could be incorporated in future extensions of the model. Equation 4.8 and Equation 4.9 show the maximum input and output power of power generation system. They are constrained by the capacity of generators in pumped storage technology, which is the existing pumped storage generators g_s^0 plus new pumped storage generators g_s^{inv}. These do not imply that charging and discharging are equal in practice; rather, the optimization process decides the charging and discharging schedule depending on system conditions and cost minimization. Equation 4.10 shows that the amount of energy stored is limited by the installed capacity of the generators in the pumped storage system and assumes that the turbine-generator sets can refill the storage system within 8 hours.

$$v_t = v_{t-1} - s_t^{out} + s_t^{in} \tag{4.7}$$

$$s_t^{in} \leq g_s^0 + g_s^{inv} \qquad s \in i \tag{4.8}$$

$$s_t^{out} \leq g_s^0 + g_s^{inv} \qquad s \in i \tag{4.9}$$

$$v_t \leq (g_s^0 + g_s^{inv}) \times 8 \qquad s \in i \tag{4.10}$$

4.4.4 CO2 price setting

Equation 4.11 shows that the carbon pricing mechanism in the power generation system can introduce an increasing carbon tax. The equation establishes a linear correlation between carbon price CP and the number of years y. Specifically, the carbon price CP is equal to the fixed carbon price FCP plus the product of the carbon price rate CPR and the year y.

$$CP = FCP + CPR \cdot y \tag{4.11}$$

4.4.5 Installed capacity limits

Equations 4.12 to 4.15 define the new capacity constraints for solar PV, wind, nuclear, and pumped storage technologies. In each year, the amount of new capacity that can be added is limited by both the existing installed capacity and the assumed capacity growth rates. When the growth rate is fixed, a higher existing capacity implies greater technological maturity and market acceptance, which in turn allows for larger annual additions. The capacity growth rates themselves are influenced by external factors such as geographic limitations, political considerations, and regulatory environments, all of which affect the feasibility and pace of technology deployment.

$$g_{solar}^{inv} = \mathrm{d} \cdot g_{solar}^{0} \tag{4.12}$$

$$g_{wind}^{inv} = w \cdot g_{wind}^{0} \tag{4.13}$$

$$g_{nuclear}^{inv} = n \cdot g_{nuclear}^{0} \tag{4.14}$$

$$g_{pumped}^{inv} = u \cdot g_{pumped}^{0} \tag{4.15}$$

d: $capacity\ growth\ rate\ for\ solar\ PV$

w: $capacity\ growth\ rate\ for\ wind$

n: $capacity\ growth\ rate\ for\ nuclear$

u: $capacity\ growth\ rate\ for\ pumped\ storage$

4.5 Limitations

The GEP model has certain limitations in representing detailed technical constraints. It lacks constraints related to the short-term operation of power plants and transmission systems, such as minimum and maximum production levels, ramp rates, ramping and start-up costs, spinning reserve requirements, and transmission line capacity limits. These constraints are used extensively in the day-to-day operational planning. However, in a long-term model, simplifying these constraints is essential for decision-making over longer time scales and improving computational efficiency.

Another limitation of the GEP model is its incomplete foresight. The model's decision-making process for expanding generating capacity, that occurs annually, may result in the selection of less capital-intensive generation technologies that may not be optimal in the long-term. For example, the model may select wind or solar PV generation technologies to meet current demand, whereas a more cost-effective choice in the long-term may be CCGT technology.

Other limitations include uncertainties arising from factors such as government policy changes and the monitoring of technological advances in power generation. This includes innovations in emerging technologies and improvements in existing technologies. In addition, the model ignores the potential for efficiency gains through economies of scale, such as several plants sharing a single CCUS facility to reduce costs. Table 4-1 summarizes the features and limitations of the GEP model.

Table 4-1 Features and limitations in the GEP model.

Feature modelled	Feature not modelled
• High resolution (hourly) • Long-term • Carbon prices • Pumped storage system • Load-shedding (demand response technology) • Realistic (historical) wind power, solar power and load profiles • Restrictions on new installed generating capacity	• Operational constraints of power plant • Transmission constraints • Imperfect foresight • Innovation in generation technology • Year-to-year variability of wind and solar capacity factors • Policy uncertainty • Economies of scale

4.6 Simulation study

The main objective of this research is to explore the expansion of the power generation system, ensuring that it meets the carbon reduction target in the long term. This study uses the proposed GEP model to simulate the annual operation and investment in generation system. The carbon pricing mechanism provides an increasing carbon tax to incentivize the reduction of carbon emissions within the system. A key target is to ensure that the carbon intensity in power generation system is reduced to below 157 kg CO2/MWh by 2050. This is the target of a region of a country in East Asia.

The study includes a series of scenarios based on a basic case. The basic case is called Scenario 1 that will be explained in the following sub-section.

4.6.1 Scenario description (Scenario 1)

This study uses real-world carbon emission targets as the background of generation system to make the generation expansion plans closer to reality. According to information in the public domain, the region has set a target of achieving carbon intensity below 157 kgCO2e/MWh by 2050 [13, 14]. Therefore, this study will simulate the expansion of power generation from 2021 to 2050, and requires that the carbon intensity in the last year, which is 2050, is lower than 157kgCO2e/MWh. This target represents a 70% reduction from the 2021 level of 554 kgCO2e/MWh.

The IEA (International Energy Agency) and NEA (Nuclear Energy Agency) reports on electricity generation costs state that, to ensure the applicability of carbon pricing across all countries, a harmonized carbon price of 30 USD/tonne CO2e has been adopted. Based on this report, this scenario assumes a carbon pricing mechanism that starts at 30 USD/tonne CO2e and increases by a fixed amount each year [161, 172]. Moreover, the annual increase in the carbon price is adjusted based on whether the power generation system is on track to meet the 2050 carbon emission target. Specifically, if the carbon price results in the carbon intensity of the power generation system exceeding 157 kg CO2/MWh by 2050, the carbon price will be gradually increased until the intensity falls below the target. Conversely, if the carbon price has already reduced the carbon intensity to below 157 kg CO2/MWh, the carbon price will be adjusted downward to maintain the intensity just below the target. The minimum carbon price is set at 30 USD/tonne CO2e, ensuring that the carbon price remains within a reasonable range.

In practice, this mechanism is implemented through repeated runs of the model, where the carbon price is incrementally adjusted until the target is satisfied. The increments are uniform in each iteration, and the process continues until the carbon intensity is aligned with the required level for 2050. This iterative adjustment approach reflects how policymakers might gradually modify carbon pricing instruments in response to observed system outcomes.

To simulate the increase in renewable energy sources within the power generation system, the installed capacities of wind and solar energy will increase each year, and the penetration rate of renewable energy will reach 60% by 2050. The increase in renewable penetration is assumed to follow a steady year-on-year growth based on the installed capacity of wind and solar technologies. In other words, the additional installed capacity each year is determined as a fixed proportion of the installed capacity in that year, leading to a gradual build-up rather than a sudden surge. The 60% penetration is defined relative to total electricity demand, ensuring that by 2050 renewable generation will account for 60% of the system's electricity supply.

This Scenario 1 serves as a baseline for analyzing the expansion of the power generation system in the next chapter.

4.6.2 Description of model input data

This section describes and graphically illustrates the inputs used in the proposed GEP model including screening curves, load duration curve, hourly capacity factor for wind and solar PV and existing capacity in generation system.

To secure practical data for investigation in this thesis is not an easy matter. Power companies, either privately owned or state companies or publicly listed companies, are highly unlikely to release their data. This is because of commercial competition which may involve daily bidding into power market to gain market share as well as signing bilateral contract for longer term power purchase. Also, some of the data needed are related to existing or future government policies, the former maybe released publicly and can be accessed from published public documents. But the latter would depend on political decisions of the day and are likely to have deviations from existing ones because of different ruling government body. Also, some of the data would depend on the geographical location and topography of the land mass which the power company covers. This can present restrictions on the amount of available wind energy and pumped storage scheme. Additionally, most countries would like to utilize the energy resources that are available locally without the need to import alternative primary fuels. This is particularly the case in relation to nuclear power. The aim is to improve energy supply security and also to keep a control on the financial import/export balance of the country. This sort of decision is beyond the control of power companies.

The data used in this thesis is extracted from different sources. One such source is the extraction of data directly available from a power company's open website. Other sources would include IEA reports and published journals.

4.6.2.1 Screening curves

Table 4-2 lists the technical and cost parameters for power generation technologies. The generation technologies include nine types: nuclear, USC, CCGT, onshore wind, solar PV, pumped storage, USC with CCUS, CCGT with CCUS and load shedding technology. Load shedding technology is a demand response method that reduces demand to balance the supply of electricity, such as shedding load, and it has no investment, fuel costs and fixed O&M costs, but variable O&M costs are very high because it can only be used in emergencies to support the balance of the power system [173-175]. Table 4-2 shows the technical input data for various type of generation technology and Figure 4-3 shows the screening curve for these generation technologies respectively [161]. The figure presents the annual cost of power generation, including USC, CCGT, nuclear, USC with CCUS and CCGT with CCUS. Carbon price is 30 US$/tonneCO2e based on scenario assumption. In addition, fuel price and heat value are 88 US$/tonne and 25GJ/tonne for coal, 9.1 US$/MBtu and 0.001GJ/MBtu for natural gas, and 10 US$/MWh for nuclear fuel [161, 172]. The screening curves shows that CCGT is the lowest cost generation technology when capacity factor is below 11.5%. For capacity factors between 11.5% and 44.5%, USC has the lowest cost generation, while nuclear becomes the lowest cost option for capacity factor above 44.5%.

Table 4-2 Input data: technical and cost parameters [161].

Technology	Investment cost (US$/kW)	Electrical Conversion Efficiency (%)	Fixed O&M (US$/kW)	Variable O&M (US$/MWh)	Emission Factor (kWh/kgCO2e)
Nuclear	2497.9	100 (1)	112.0	11.5	0
USC	699.7	45	34.5	10.3	0.321
CCGT	558.9	58	31.0	9.3	0.183
USC with CCUS	1812.8	30	74.2	9.0	0.032
CCGT with CCUS	1087.0	41	65.0	10.0	0.018
Pumped Storage	525.7	100 (2)	7.21	5.0	0
Load Shedding	0	100 (2)	0	1510.6	0
Onshore Wind	1200.0	n/a (3)	7.0	10.0	0
Solar PV	780.0	n/a (3)	8.0	3.0	0

(1) The fuel price for nuclear power already considers the power conversion efficiency, which is set at 100%.

(2) They are simplified and assumed to have 100% power conversion efficiency.

(3) Power conversion efficiency does not apply to them because their output power depends on generation profiles.

USC with CCUS and CCGT with CCUS are economically expensive technologies for power generation, mainly due to their high annual fixed and variable costs. When the capacity factor exceeds 35%, the annual cost of CCGT with CCUS surpasses that of USC-CCUS, indicating that USC-CCUS becomes a more cost-effective option.

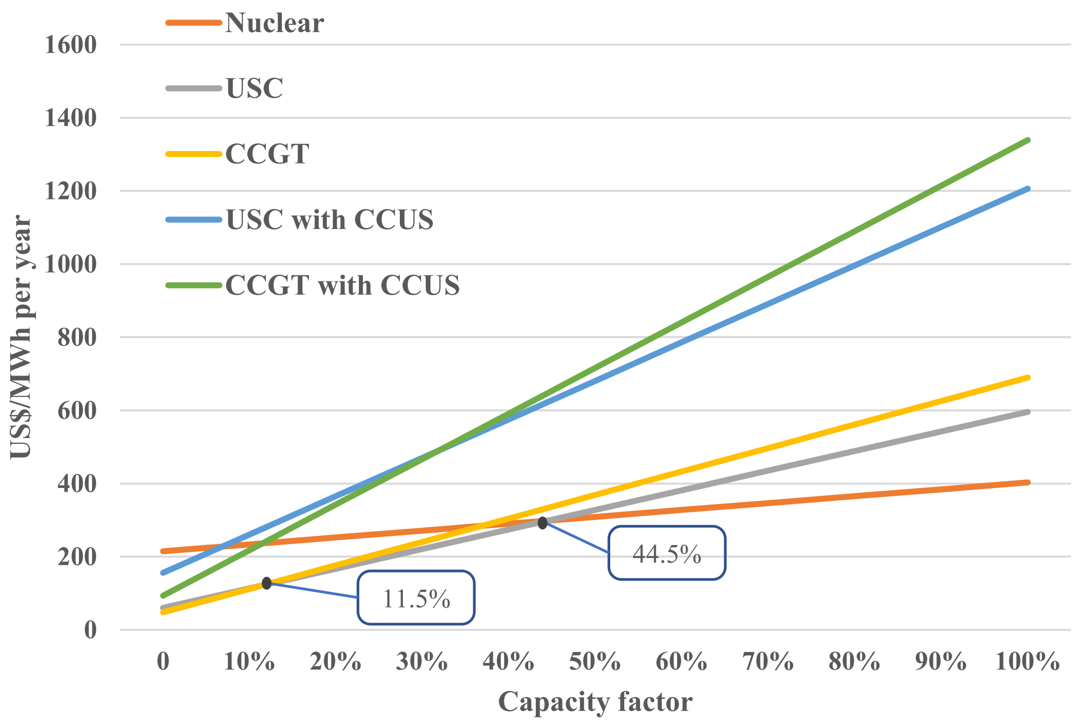


Figure 4-3 The screening curves in the GEP model [161].

4.6.2.2 Load duration curve

Load duration curves for loads are obtained by sorting the load data for a year from a power company (see Appendix A) [176]. Figure 4-4 provides the combined load duration curve that is used in the model, offering insights into the distribution of electricity demand over time. The curve ranges from a peak load of 77 GW to a minimum load of 26 GW, demonstrating the variation in electricity demand throughout the year. In addition, the model includes an assumption of a 5% annual growth rate in demand to reflect the expected growth in electricity demand.

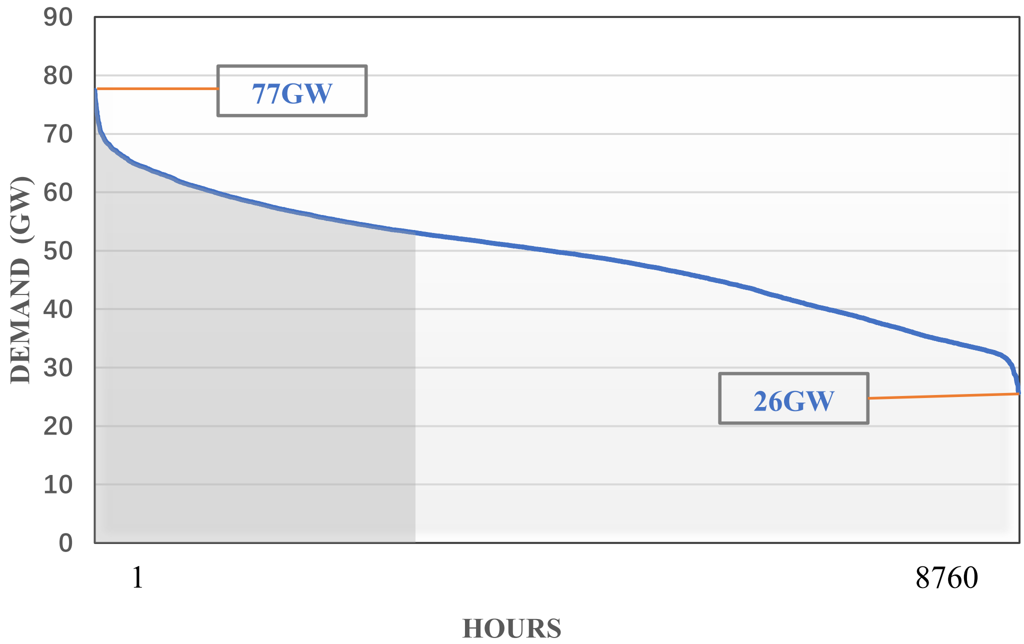


Figure 4-4 The load duration curve in the GEP model [176].

4.6.2.3 Capacity factor for wind and solar PV

Figure 4-5 presents the daily average capacity factors for wind and solar PV in a year. The blue line indicates the capacity factor for wind power and the orange line indicates the capacity factor for solar PV. The data comes from an online simulation called the Renewable Ninja Simulation, which estimates the power output of renewables based on VRE modelling and weather conditions [177]. The annual capacity factor is used as a representative value, with the assumption that the capacity factor remains the same each year.

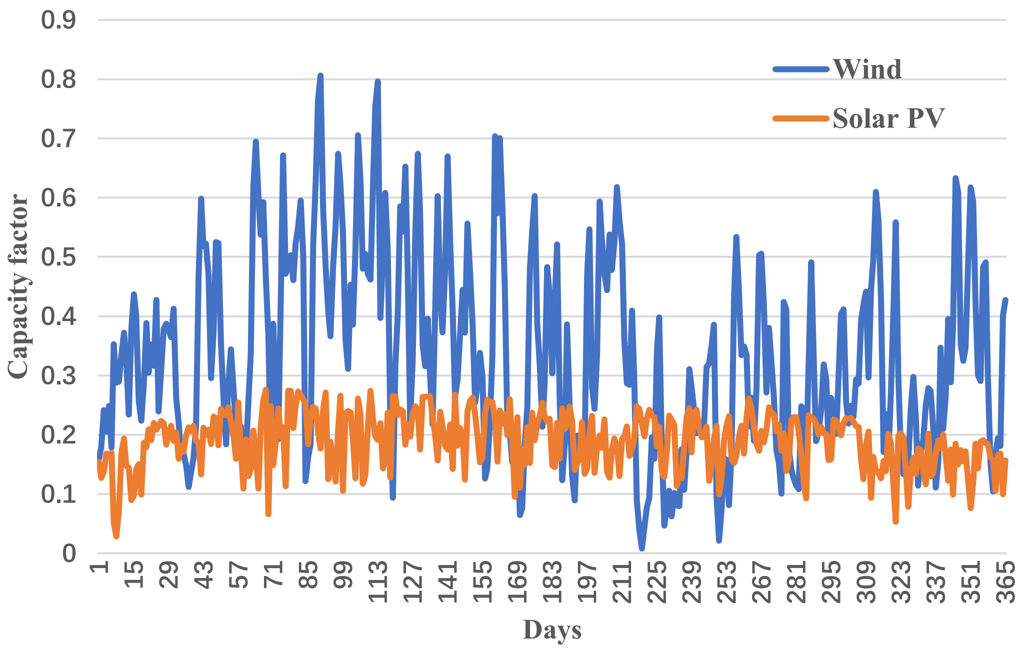


Figure 4-5 The daily capacity factors for wind and solar PV [177].

4.6.2.4 Existing Generation Capacity

Table 4-3 lists the existing capacity of various plants in the model. Additionally, the availability of power plants is assumed to be 80% to cater for down time for regular maintenance and operational planning. This value reflects a reasonable average across a range of conventional and low-carbon technologies and is commonly used in long-term capacity expansion studies when detailed technology-specific outage data are unavailable. In practice, the availability factor can vary significantly depending on the technology type, for example, nuclear power plants typically have high availability rates (above 85%), while variable renewable energy sources such as wind and solar may exhibit lower effective availability. However, when the objective is to assess long-term trends and investment demand, using a uniform availability factor of 80% to construct the model provides a practical and transparent approximation method.

In terms of the geography of the region under study, wind resources are much better than solar resources, so the development of onshore wind will be better than solar PV [178]. Furthermore, according to publicly available data from the regional power system company, newly added electricity generation from wind power is reported to be 82.7 TWh, while that from solar PV is 39.4 TWh, resulting in an approximate wind-to-solar generation ratio of 2:1 [179]. Based on this trend, it is reasonable to assume that wind energy will generate approximately twice as much electricity as solar PV in future capacity expansion scenarios.

The development potential of large-scale pumped hydro power generation is limited due to the local topography, which restricts the expansion of its total capacity [180]. Similarly, as observed in many other countries, the total installed capacity of nuclear power is expected to remain relatively moderate due to economic factors, regulatory restrictions, and long project preparation times [181]. Given these constraints, Scenario 1 assumes that pumped-storage and nuclear power generation will gradually increase over time, reaching a maximum generation capacity of 25 GW and 40 GW, respectively, by the 30th year. This assumption is in line with geographical constraints while ensuring a diverse technology mix for electricity supply. Otherwise, neglecting these constraints could lead to an overestimation of capacity potential, resulting in unrealistic result.

In the model, new nuclear and pumped-storage capacity is represented as a continuous variable, expressed in gigawatts (GW) rather than discrete unit sizes. For example, the assumption of 40 GW of nuclear capacity by 2050 reflects an overall expansion level rather than a specific number of individual plants.

Regarding time granularity, the model operates at two levels: hourly resolution for system demand balance and annual resolution for capacity expansion. This means that capacity additions are accounted for on a yearly basis, with the simplifying assumption that newly added plants become operational within the same year. The multi-year construction lead times of technologies such as nuclear (8–10 years) or pumped storage (5–7 years) are not explicitly modeled. Instead, long construction cycles are approximated by gradual year-to-year increases in installed capacity. This approach is consistent with common practice in long-term generation expansion planning, where the objective is to capture investment trends and long-term pathways rather than the commissioning schedules of individual projects.

Table 4-3 Existing generation capacity in 2020 [179].

Technology	Existing Capacity (GW)
Nuclear	4.48
USC	74
CCGT	0.5
Onshore Wind	18.73
Solar PV	7.82
Pumped Storage	7.73
Load Shedding	0
USC with CCUS	0

4.6.3 Results of Scenario 1

This section shows the results of Scenario 1 to achieve the carbon emission reduction target. The results include total system costs, total emissions, carbon prices, carbon intensity, technology mix for electricity supply in 2050, annual power generation, annual generator capacity and capacity factor for different generation technologies. To better understand the results the main points are summarized below.

a) Total system costs cover all costs from 2021 to 2050, including investment cost, fuel cost, carbon cost and O&M cost for all generation technologies.
b) Total emissions include all carbon emissions from power generation technologies from 2021 to 2050.
c) Carbon price is designed to achieve the carbon intensity of generation system below 157 kgCO2e/MWh in 2050. The carbon price increases linearly, on an annual basis.
d) Carbon intensity is annual carbon emissions divided by annual electricity generation in the generation system and is expressed in kgCO2e/MWh.

e) Generation in 2050 is the power generation in 2050 from different generation technologies combined.

f) Annual power generation is the amount of electricity generated from the generation system each year.

g) Annual generator capacity is the value of generator capacity each year.

h) Capacity factor of a generation technology is calculated based on its annual power generation output and annual generator capacity, based on the equation mentioned in Chapter 2. It indicates the average capacity factor of this generation technology in that year.

This study covers a total of 30 years from 2021 to 2050, and for the convenience of displaying the results, the results are plotted using year 1 to year 30 to describe the years 2021 to 2050.

4.6.3.1 Total system cost and total carbon emissions

In Scenario 1, the total system cost from 2021 to 2050 is 1342.9 US$ billion. The total carbon emissions from 2021 to 2050 is 7975.6 Mt CO2e.

4.6.3.2 Carbon price and carbon intensity

Figure 4-6 shows the carbon price and carbon intensity from 2021 to 2050 of Scenario 1. The x-axis represents the number of year, the left y-axis represents the carbon intensity in kgCO2e/MWh and the right y-axis represents the carbon price in US$/tonneCO2e. Carbon price increases gradually from 30 US$/tonne CO2e in 2020 to 59.7 US$/tonneCO2e in 2050. Carbon intensity decreases from 554.1 kgCO2e/MWh in 2021 to 101.4 kgCO2e/MWh in 2050. It is worth noting that between 2049 and 2050, the carbon emission intensity dropped significantly, reaching a carbon emission target of less than 157 kgCO2e/MWh. The significant reduction in emission intensity was mainly due to the replacement of high-emission USC power plants with low-emission

CCGT power plants, which make up a considerable share of the technology mix for electricity supply.

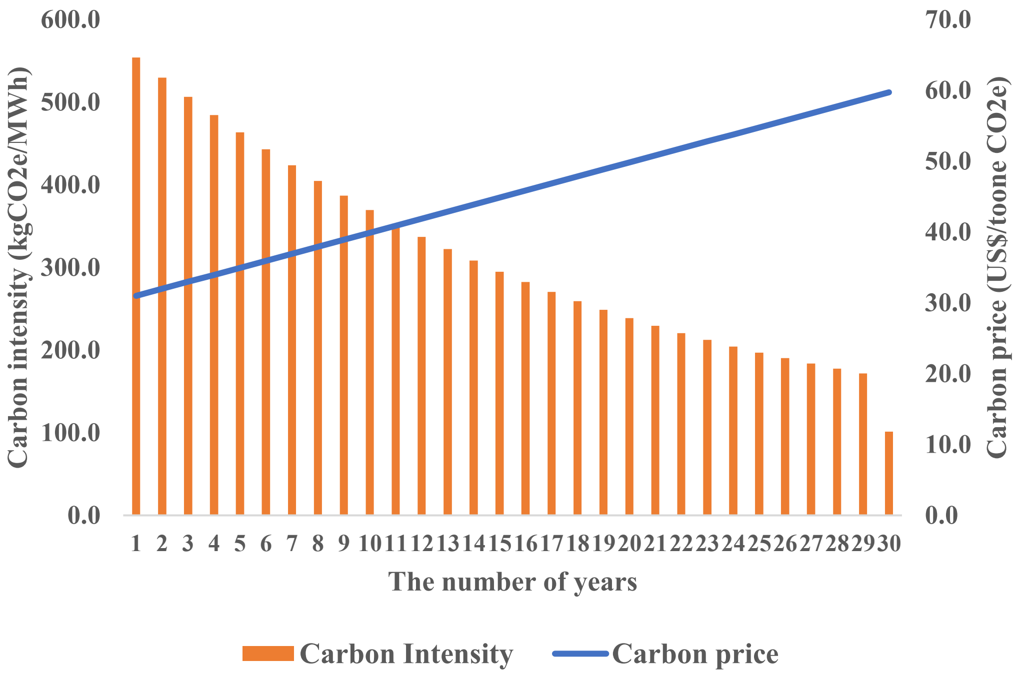


Figure 4-6 Carbon price and carbon intensity in Scenario 1.

4.6.3.3 Technology mix for electricity supply in 2050

Figure 4-7 shows the technology mix for electricity supply for 2050 in Scenario 1 in a pie chart. Wind is the largest power producer, at 40%. CCGT is the second largest producer, at 26%. The power generation of solar PV is 20% of the total, followed by nuclear at 13%, and then USC at 1%. The smallest producer in power generation in 2050 is load shedding technology, less than 1%. Pumped storage stores electrical energy and does not produce it, so its output is 0. In this scenario, the power generation system does not use CCUS technology.

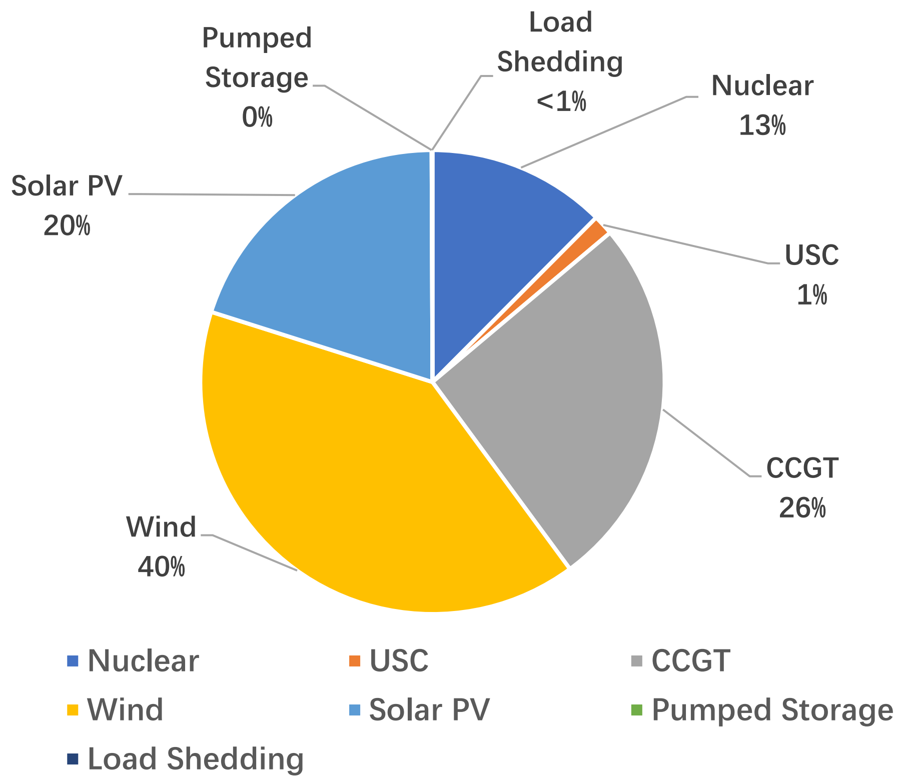


Figure 4-7 Technology mix for electricity supply in 2050 for Scenario 1.

4.6.3.4 Annual power generation by type of generation

Figure 4-8 illustrates the annual power generation from 2021 to 2050 in Scenario 1. The x-axis represents the number of years, and the y-axis represents the power generation in the generation system measured in TWh. From 2021 to 2050, wind, solar PV, nuclear and load shedding technology generation continue to rise. In particular, wind power generation increases from 66.6 TWh to 785.8 TWh; solar PV generation rises from 18.3 TWh to 372.6 TWh; nuclear power generation climbs from 35.1 TWh to 231.5 TWh and load shedding increases from 0.1 TWh to 1.1 TWh. USC and CCGT, as emitters of carbon dioxide, have experienced dramatic changes in their electricity generation which decreases from 331.2 TWh to 26.2 TWh for USC but CCGT increases from 0.01 TWh to 484 TWh. This is because gas has a lower content of carbon than solid fuel for USC.

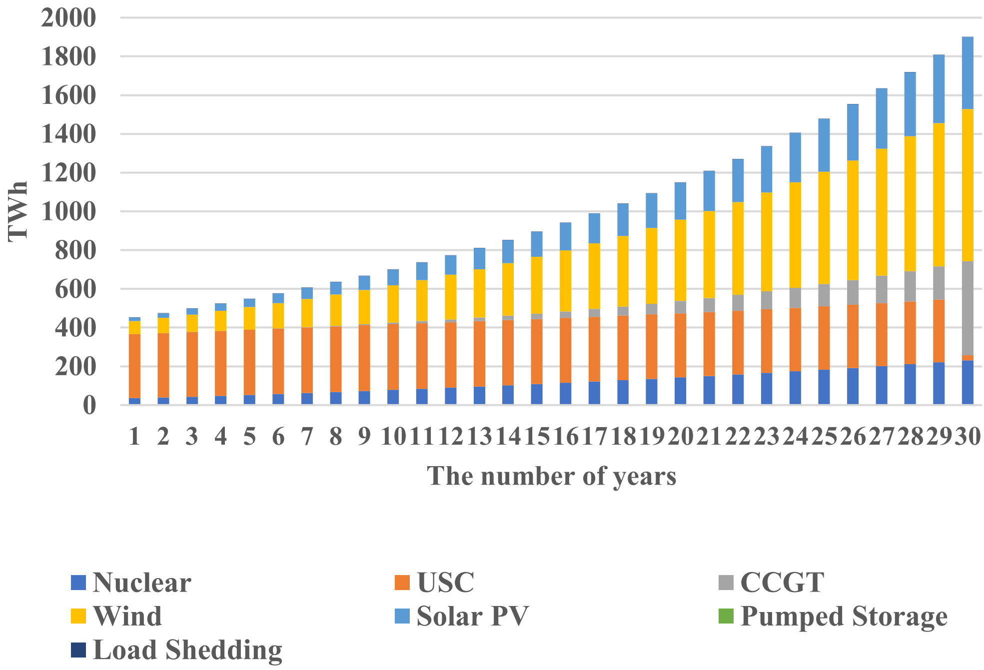


Figure 4-8 Annual power generation from generation system in Scenario 1.

4.6.3.5 Annual generator capacity by type of generation

Figure 4-9 illustrates the annual generator capacity in Scenario 1. The x-axis represents the years, while the y-axis indicates the generator capacity measured in GW. The total generator capacity continues to grow annually, starting at 141.7 GW in 2021 and reaching 847.2 GW in 2050. The capacity of CCGT, wind, and solar PV experiences relatively rapid growth. CCGT capacity rises from 0.5 GW in 2021 to 155.7 GW in 2050. Meanwhile, the capacity of USC remains constant at 74 GW throughout the entire period. The growth in capacity for other technologies is comparatively slower when compared to CCGT, wind, and solar PV.

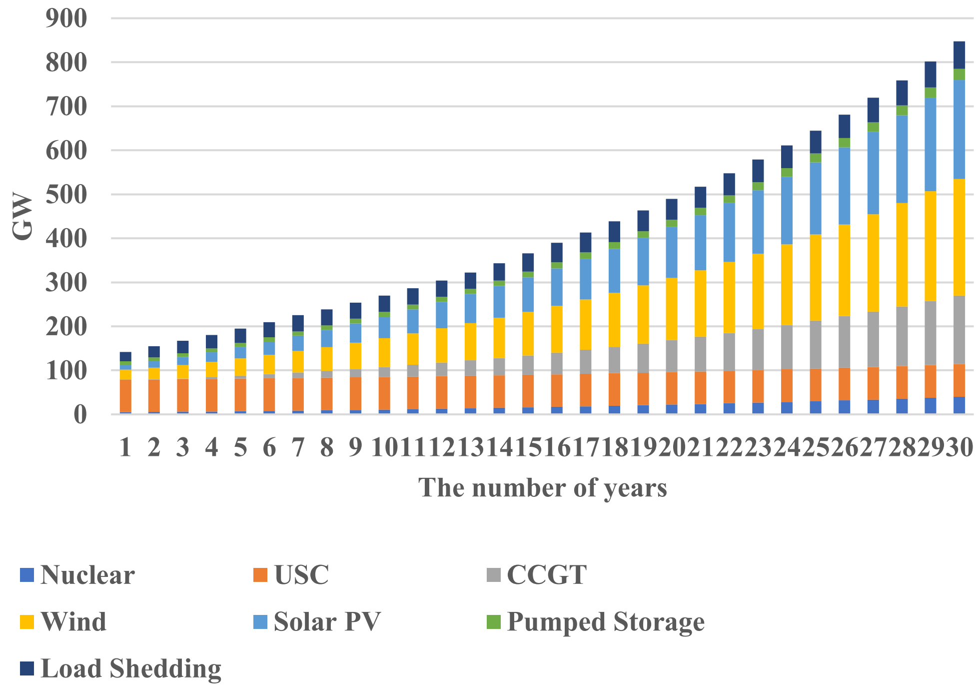


Figure 4-9 Annual generator capacity of generation system in Scenario 1.

4.6.3.6 Capacity factor for thermal generation technologies

Figure 4-10 illustrates the annual capacity factor for thermal generation technologies in Scenario 1, including nuclear, USC and CCGT. The x-axis represents the number of years and the y-axis represents the capacity factor. The capacity factor for nuclear power is 0.8 in 2021 and then declines to 0.66 in 2050. USC's capacity factor stays around 0.5 until 2049, then it suddenly drops to 0.04 in 2050. The capacity factor for CCGT increases steadily from 0.004 in 2021 to 0.134 in 2049 and then suddenly increases to 0.35 in 2050. This sudden drop in USC and sudden increase of CCGT in 2050 are due to changes in their power generation, which will be explained in detail in the next section.

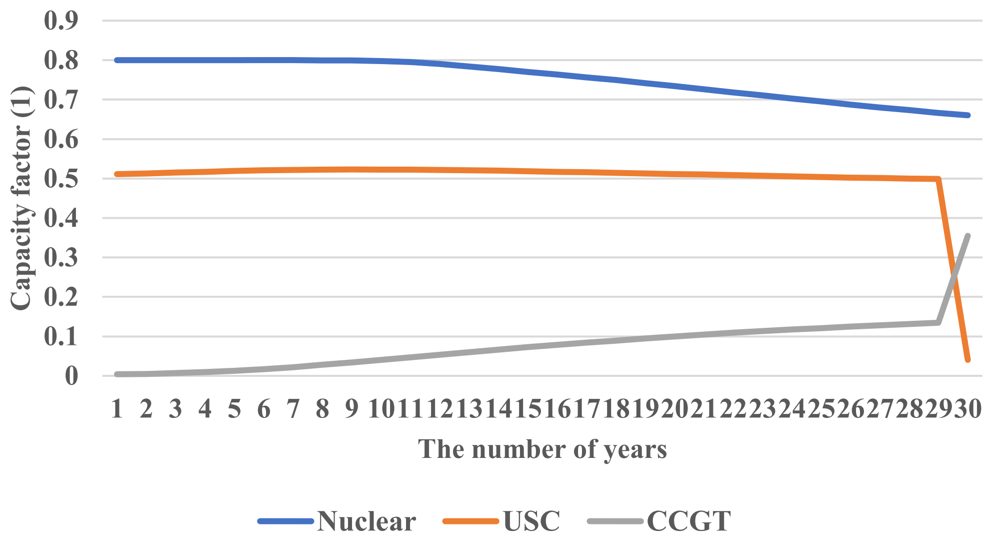


Figure 4-10 Capacity factors for thermal technologies.

4.6.4 Discussion

In this Scenario 1 study, the generation expansion plan demonstrates how the power system can meet the carbon reduction target using a carbon pricing mechanism. The results on carbon prices and carbon intensity (Figure 4-6) indicate that the carbon tax increases from 30 US$/tonneCO2e to 59.7 US$/tonneCO2e, leading to a gradual decrease in carbon intensity from 554.1 kgCO2e/MWh to 101.4 kgCO2e/MWh, without relying on an annual emissions cap to limit emissions.

The primary driver for achieving the carbon reduction target is the shift in the technology mix for electricity supply driven by the increasing carbon tax. As the carbon tax rises, USC power plants significantly reduce their power generation from 331.2 TWh to 26.2 TWh, making way for low-carbon and renewable energy sources to dominate the energy mix. This transition demonstrates the effectiveness of carbon pricing in promoting cleaner energy production and supporting decarbonization goals.

Notably, the carbon intensity in 2050 decreased significantly, from 171 kgCO2e/MWh in 2049 to 101 kgCO2e/MWh. This large decrease indicates that a major change has taken place in the power generation system. According to the results of the technology mix for electricity supply and annual power generation, the large decrease in carbon intensity in 2050 is mainly due to the sharp reduction in USC power generation. Because USC power generation technology is a CO2 intensive technology, its electricity generation decreases from 323.5 TWh in 2049 to 26.2 TWh in 2050, resulting in a significant reduction in CO2 emissions. The gap in power generation is filled by CCGT power generation technology. CCGT power generation increases from 171.5 TWh in 2049 to 484.0 TWh in 2050.

The reason for the change is that the carbon price in 2050 makes the operating cost of CCGT (mainly fuel cost plus carbon cost) lower than that of USC, resulting in CCGT becoming a more cost-effective option. Therefore, CCGT replaces USC as one of the main sources of electricity in the power generation system.

Although the generation of CCGT and USC changes dramatically in 2050, their generator capacity does not change much. This is because the power generation system prefers to use existing USC power plants to meet demand to minimize costs, rather than spending more money building new CCGT power plants to meet demand. This explains why the USC generation still has 26.2 TWh in 2050, even though the cost of USC generation is higher than that of CCGT generation. Additionally, the existing capacity of CCGT power plants in 2049 is sufficient to meet the increased demand in 2050 without significant additions to their capacity.

The capacity factors of CCGT and USC power plants highlight the impact of these changes. The capacity factor of USC drops sharply from 0.5 in 2049 to 0.04 in 2050, while the capacity factor of CCGT increases significantly from 0.134 in 2049 to 0.35 in 2050. This shows that the power output of USC and CCGT power plants in 2049 and 2050 is very different. This difference reflects the transition in the power generation system driven by economic incentives, emphasizing the reduced role of coal-based generation and the growing reliance on gas-fired power to meet demand.

4.7 Summary

This chapter introduces the methodology of the proposed GEP model and applies it to a case study, Scenario 1. The methodology covers the model's structure, objectives, constraints, and limitations. Scenario 1 study demonstrates the practical application of the model to analyze the expansion of the power generation system under carbon pricing mechanisms. The resulting generation expansion plan highlights how the power system changes to achieve the 2050 carbon reduction target through the economic incentives provided by carbon pricing.

In the next chapter further investigation is centered on analyzing uncertainties associated with the power generation expansion plan. It evaluates how variations in key parameters, such as fuel prices, renewable energy penetration rates, and demand growth rates, influence the expansion of generation system. By exploring multiple scenarios, the analysis provides deeper insights into future development of the power generation under different parameter uncertainties.

Chapter 5 Effects of Parameter Variations on Generation Expansion Plan

5.1 Introduction

This chapter presents an analysis of the uncertainties of parameters associated with the study in Chapter 4. The findings from this chapter offer insights into how different conditions, such as fuel price fluctuations, demand growth and renewable energy penetration affect the expansion of the power generation system.

Section 5.2 provides a detailed description of different scenarios to establish a clear understanding of the assumptions and variations considered.

Next, this chapter presents the results of the power generation expansion modelling across various scenarios. The analysis includes key indicators such as total system costs, total carbon emissions, carbon prices, carbon intensity, the technology mix for electricity supply in 2050, and the annual trends in power generation, installed capacity, and capacity factors for different technologies. Detailed numerical results are provided in Appendix B. Due to the wide range of results, the analysis is organized into three main sections to facilitate clarity and interpretation.

Section 5.3 System-wide Indicators: Total System Cost, Total System Emissions, Carbon Price and Carbon Intensity.

Section 5.4 Long-term Planning Results: Technology mix for electricity supply and Installed capacity mix in 2050.

Section 5.5 Temporal Evolution: Annual power generation, Annual installed capacity, and capacity factor from 2025 to 2050.

Together, these results illustrate the power generation expansion pathways and the deployment of generation technologies under different policy, economic, and technological scenarios.

5.2 Scenario description

This section outlines 18 scenarios designed to analyze the uncertainties in power generation expansion planning, with Scenario 1 serving as the benchmark scenario. Each scenario is based on the same power generation system as described in Scenario 1 but with specific parameters adjusted. The input data for the power generation system is detailed in Chapter 4. The details of these scenarios are described below:

Scenario 0, the carbon tax is set to zero, implying that no carbon pricing mechanism is in place. As a result, there is no financial incentive to reduce carbon emissions, and the expansion decisions are made solely based on cost considerations.

Scenario 1 serves as the benchmark scenario, with all modelling assumptions and input data described in detail in Chapter 4.

Scenario 2 to 5 examine the sensitivity of the generation expansion plan to changes in fuel prices, specifically for coal and natural gas. In these scenarios, fuel prices are either increased or decreased by 50% relative to the baseline values used in Scenario 1. This analysis aims to assess how fluctuations in fossil fuel costs influence investment decisions and technology mix for electricity supply.

Scenarios 6 and 7 explore the effect of varying electricity demand growth rates. Scenario 6 assumes a high growth rate of 7%, while Scenario 7 considers a lower growth rate of 3%. These are compared to the 5% annual demand growth rate assumed in Scenario 1. The objective is to understand how different demand trajectories affect capacity expansion and the role of various generation technologies.

Scenarios 8 and 9 assess the impact of varying levels of renewable energy penetration by the year 2050. Scenario 8 represents a high renewable penetration case, targeting 70% of total electricity generation from renewable sources, while Scenario 9 assumes a lower penetration level of 50%. These are compared to the 60% renewable share assumed in Scenario 1. The purpose of these scenarios is to evaluate how different levels of renewable integration influence system expansion decisions, technology mix, and carbon emissions.

Scenario 10 describes the generation system without CCGT technology. This is because some regions/countries lack resources of natural gas, and rely heavily on imported natural gas. Natural gas is also the primary source of fuel for heating both in industry and in domestic environment. Under severe winter condition when the demand for gas is high the price of natural gas can fluctuate violently. This creates uncertainty for electricity price. The results of this scenarios help to understand the possibility of eliminating this uncertainty.

Scenarios 11 and 12 investigate the impact of restricting coal-fired power generation using USC technology. Scenario 11 simulates a system in which all USC power plants—both existing and future—are excluded from the technology mix for electricity supply. In contrast, Scenario 12 allows the operation of existing USC plants but prohibits the construction of new ones. These scenarios reflect growing political and environmental pressure to phase out coal-fired power generation due to its high carbon emissions.

Scenarios 13 and 14 focus on nuclear power. Scenario 13 simulates a generation system without any nuclear power plants, effectively assuming a full phase-out. Scenario 14 allows existing nuclear capacity to remain but prevents the commissioned of new nuclear facilities. These scenarios are motivated by ongoing debates over the future of nuclear energy, which, while considered a low-carbon source, raises safety concerns and faces public opposition in several regions.

Scenarios 15, 16, and 17 evaluate the impact of removing capacity constraints on key low-carbon technologies, including nuclear, wind, solar, and pumped storage. In these scenarios, “unlimited potential” means that the model input removes any imposed upper limits on capacity expansion for these technologies, rather than implying that they are physically or geographically unlimited in reality. These scenarios assume unlimited potential for the deployment of these technologies. Scenario 15 applies a fixed carbon tax of 30 USD/tonneCO2e. Scenario 16 assumes no carbon pricing is in place. Scenario 17 implements a carbon pricing mechanism designed to achieve a specific carbon reduction target. This series of scenario analysis aims to assess changes in energy structure under different carbon pricing policies when technological constraints are relaxed.

In addition, while the model allows for investment in USC-CCUS technology, its high capital and operational costs significantly limit its attractiveness under most scenarios. The observed deployment of CCUS in Scenarios 3, 4, 8, 10, 13, and 14 is not the result of an imposed constraint, but rather emerges endogenously from the optimization process. It only occurs where coal remains economically viable or where CCGT and nuclear options are constrained, and where the carbon price is sufficiently high to justify the adoption of carbon capture technologies. As a result, CCUS deployment occurs only in Scenarios 3, 4, 8, 10, 13, and 14, where coal remains economically viable, or where CCGT and nuclear options are constrained. In these cases, the carbon price is sufficiently high to justify the adoption of carbon capture technologies. These conditions create a favourable environment in which USC-CCUS emerges as a strategic option for balancing emission reduction targets with electricity supply needs.

These 18 scenarios provide a comprehensive analysis of the key uncertainties affecting power generation expansion planning. By varying critical factors such as fuel prices, demand growth, renewable energy penetration, technology availability, and carbon pricing mechanisms, the scenarios explore different pathways to reach the carbon intensity target.

5.3 System-wide Indicators: Total System Cost, Total System Emissions, Carbon Price and Carbon Intensity

This section presents and discusses the results for total system cost, total system emissions, carbon price and carbon intensity to evaluate the economic and environmental performance of the power generation system under different scenario conditions.

5.3.1 Total system cost and total carbon emissions

Figure 5-1 presents a comparison of total system costs and total carbon emissions across different scenarios. The x-axis represents the scenarios, while the right y-axis represents the total carbon emissions in million tonnes CO2e, the left y-axis represents the total system cost in US$ billion.

Fuel price effects:
The scenarios with varying coal and natural gas prices highlight how relative fuel costs influence the generation mix and, consequently, both costs and emissions.

- In Scenario 2 (High coal price), cumulative emissions fall significantly to 5,752.7 $MtCO_2e$, compared to 7,975.6 $MtCO_2e$ in the benchmark (Scenario 1). This is because higher coal prices make coal generation less competitive, accelerating the shift to cleaner technologies such as gas, nuclear, and renewables. Interestingly, total system cost remains almost unchanged, at 1,342.7 billion USD, compared to 1,342.9 billion USD in the benchmark. This suggests that reducing coal reliance can be achieved without increasing overall system cost when alternatives are available.

- In contrast, Scenario 3 (Low coal price) leads to increased coal consumption. Emissions rise to 7,703.6 $MtCO_2e$, while total system cost decreases to 1,131.7 billion USD. This reflects a clear cost-emission trade-off: cheap coal lowers costs but locks the system into a high-emission pathway.
- The effects of natural gas prices show a different pattern. Scenario 5 (Low gas price) demonstrates a win-win outcome: emissions drop sharply to 4,157.9 $MtCO_2e$, and system cost also declines to 1,025.3 billion USD. This indicates that competitively priced natural gas can replace coal during the transition, reducing both environmental and economic burdens. Conversely, Scenario 4 (High gas price) results in higher emissions (8,216.4 $MtCO_2e$) and higher costs (1,363.1 billion USD) due to reduced gas deployment and continued reliance on coal.

Impact of demand growth:

Demand assumptions strongly shape the overall size and performance of the power system.

- In Scenario 7 (High demand growth of 7%), cumulative emissions rise to 10,863.9 $MtCO_2e$, while total system cost reaches 1,989.8 billion USD, the highest among all scenarios.
- Conversely, Scenario 6 (Low demand growth of 3%) achieves much lower emissions (5,704.9 $MtCO_2e$) and lower costs (834.0 billion USD).

These results demonstrate that higher electricity demand not only increases the amount of capacity required but also intensifies pressure on decarbonization policies, leading to higher system-wide costs and emissions.

Role of renewable penetration:

The share of renewable energy is a decisive factor in both emissions and cost outcomes.

- Scenario 8 (50% renewable penetration by 2050) shows higher emissions (9,118.7 $MtCO_2e$) and costs (1,481.1 billion USD) than the benchmark, indicating that lower renewable deployment slows the decarbonization process and raises costs by relying on fossil generation.
- By contrast, Scenario 9 (70% renewable penetration) achieves lower emissions (6,832.7 $MtCO_2e$) and lower system costs (1,098.1 billion USD), showing that higher renewable integration not only reduces carbon output but also provides long-term economic benefits.

This demonstrates that renewable energy plays a dual role: reducing emissions directly and indirectly lowering costs by decreasing reliance on fossil fuels and imported fuel sources.

Capacity and technology constraints:

Relaxing capacity restrictions on key low-carbon technologies has a profound effect on system performance.

- Scenario 17 (No capacity constraints with carbon pricing mechanism) delivers one of the best results, with emissions reduced to 5,133.4 $MtCO_2e$ and costs to 902.0 billion USD.
- Scenario 16 (Zero carbon tax with no capacity limit), however, results in the worst environmental performance, with emissions soaring to e, the highest of all scenarios, despite a moderate total cost of 1,111.8 billion USD.

These results show that while flexibility in technology deployment is essential, it must be coupled with effective policy mechanisms such as carbon pricing to prevent excessive reliance on cheap, high-emission generation.

Impact of specific generation technologies:

The phase-out or restriction of specific technologies also plays a significant role:

- In Scenario 11 (No USC), emissions drop by almost 50% to 4,035.6 $MtCO_2e$, while total cost remains similar to the benchmark at 1,330.9 billion

USD, showing that removing coal generation is both environmentally beneficial and economically feasible.

- In contrast, Scenario 12 (No new USC) shows little change from the benchmark, with emissions at 7,975.6 $MtCO_2e$ and cost at 1,345.5 billion USD, suggesting that simply halting new coal projects is insufficient without addressing existing capacity.
- Similarly, Scenario 13 (No nuclear) causes costs to rise to 1,687.1 billion USD and emissions to 8,820.3 $MtCO_2e$, while Scenario 14 (No new nuclear) also leads to increased costs (1,585.4 billion USD) and emissions (8,623.9 $MtCO_2e$). These findings highlight the importance of nuclear as a stable, low-carbon baseload technology.

Policy implications:

These results underscore several key insights for policymakers. First, carbon pricing is critical: Scenario 0 (No carbon tax) shows emissions 30% higher than the benchmark, whereas Scenario 15 (Fixed $30/tonne tax) cuts emissions by 33%. Second, fuel price and policy signals must align—low gas prices naturally support decarbonization, but low coal prices without a carbon tax can reverse progress. Third, flexible deployment of low-carbon technologies is essential to achieve both economic and environmental goals. Lastly, targeted retirement of high-emission assets, especially USC coal plants, is far more effective than restricting only future developments.

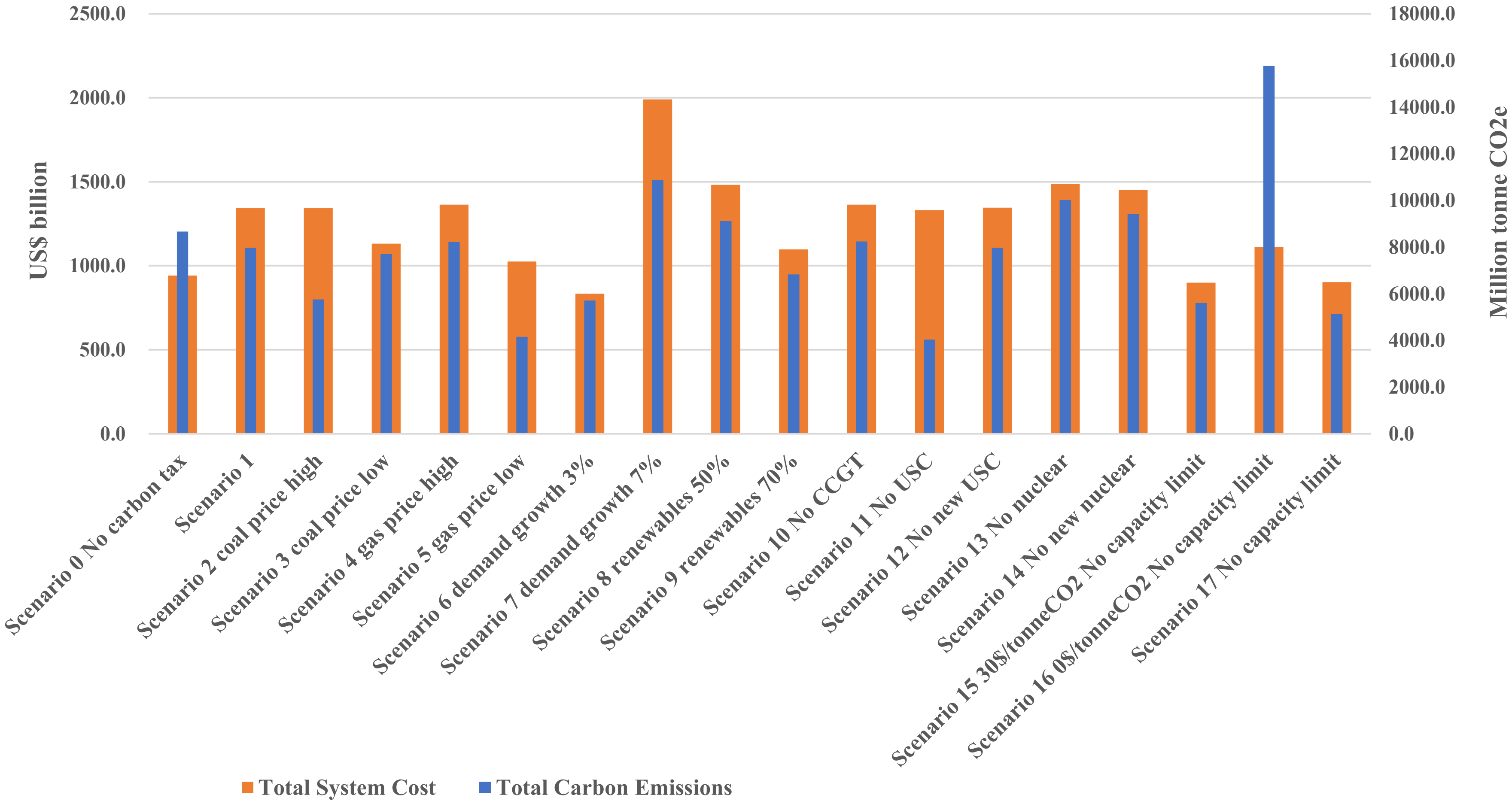


Figure 5-1 Total system cost and total carbon emissions in all scenarios.

5.3.2 Carbon intensity

illustrates the annual carbon intensity (kgCO_2e/MWh) across all scenarios over the 30-year planning horizon, with a particular focus on comparisons to Scenario 1 (Benchmark Scenario). Carbon intensity reflects how efficiently the system generates electricity relative to its emissions, providing a key measure of progress toward decarbonization. By comparing different trajectories, it becomes clear how policies, fuel prices, demand growth, and technology availability interact to shape the system's long-term pathway.

In the benchmark scenario (Scenario 1), carbon intensity steadily declines from 529.8 kgCO_2e/MWh in 2021 to 101.4 kgCO_2e/MWh in 2050. This consistent downward trend demonstrates the combined effect of rising carbon prices and the gradual expansion of renewable energy, both of which encourage a cleaner generation mix. In contrast, Scenario 0 (No carbon tax) begins at a slightly higher initial value of 554.1 kgCO_2e/MWh and only falls to 203.8 kgCO_2e/MWh by 2050. Although carbon intensity still decreases over time due to natural growth in renewables and nuclear, the pace is much slower without the economic pressure provided by carbon pricing. This comparison clearly illustrates that while structural changes alone can reduce emissions intensity, achieving deeper decarbonization requires a strong and sustained policy signal.

Fuel prices have a notable impact on emissions intensity. In Scenario 2 (High coal prices), carbon intensity falls sharply to 101.3 kgCO_2e/MWh, nearly identical to the benchmark. Higher coal prices make coal-fired generation less competitive, accelerating the transition to natural gas, nuclear, and renewables. By contrast, Scenario 3 (Low coal prices) ends at 156.6 kgCO_2e/MWh, as cheaper coal encourages greater consumption and delays the shift toward cleaner technologies. This demonstrates how, without counteracting policy measures, low coal prices can significantly undermine emissions reduction efforts.

Natural gas also plays a pivotal role as a transition fuel. When gas prices are low, as in Scenario 5, carbon intensity starts at 278.3 $kgCO_2e/MWh$ and declines to 96.3 $kgCO_2e/MWh$, the lowest value among all scenarios. Affordable gas facilitates coal-to-gas switching, which reduces emissions while maintaining reliability. However, in Scenario 4, where gas prices are high, carbon intensity remains elevated, only reaching 156.5 $kgCO_2e/MWh$ by 2050, as gas becomes less competitive and coal use persists. These contrasting outcomes highlight the importance of maintaining reasonable gas prices or using carbon pricing to offset market disadvantages for cleaner fuels.

Demand growth assumptions also influence the carbon intensity trajectory. In Scenario 6 (Low demand growth of 3%), carbon intensity falls to 136.9 $kgCO_2e/MWh$, as lower overall demand reduces the need for high-carbon generation. Surprisingly, in Scenario 7 (High demand growth of 7%), carbon intensity declines slightly further to 116.0 $kgCO_2e/MWh$ by 2050. Although total emissions are higher, rapid demand growth drives significant investment in new low-carbon capacity, which improves the emissions efficiency of the system. This suggests that while high demand increases the scale of the challenge, it also creates opportunities for faster modernization of the generation fleet.

The share of renewable energy is another decisive factor. Scenario 8, with a target of 50% renewable penetration by 2050, reduces carbon intensity from 559.6 to 115.5 $kgCO_2e/MWh$. Scenario 9, with a more ambitious 70% renewable target, initially follows a similar trajectory but ends at 137.8 $kgCO_2e/MWh$, slightly higher than Scenario 8. This counterintuitive outcome reflects the system's need for backup fossil generation to manage higher variability from renewable sources. It shows that simply increasing renewable targets is not enough—supporting measures such as storage and flexible dispatchable capacity are equally important to ensure efficient decarbonization.

The availability of specific technologies also shapes outcomes. In Scenario 10 (No CCGT), the final carbon intensity mirrors the high-gas-price scenario, at 156.4 $kgCO_2e/MWh$, demonstrating the value of gas-fired generation in balancing the system during the transition. Scenario 11 (No USC) delivers the most favorable result, with carbon intensity dropping to just 95.6 $kgCO_2e/MWh$ by 2050. Completely eliminating conventional coal significantly accelerates decarbonization, underscoring the importance of phasing out the most carbon-intensive technologies. In Scenario 12 (No new USC), the results are almost identical to the benchmark, indicating that halting future coal plant development alone is insufficient unless the existing fleet is also addressed.

Scenarios 13 and 14, which restrict nuclear development, both reach around 132 $kgCO_2e/MWh$ by 2050. These scenarios show that while nuclear can be replaced by other low-carbon options, doing so often leads to higher reliance on renewables and fossil backup, which may raise costs and complexity.

The combined influence of policy design and system flexibility is evident when comparing Scenarios 15, 16, and 17. In Scenario 15, a fixed carbon tax of $30/tonne reduces carbon intensity from 228.1 to 186.6 $kgCO_2e/MWh$, showing some benefit but falling short of deep decarbonization. Scenario 16, with no carbon tax and no capacity limits, performs worst, with carbon intensity barely declining from 561.9 to 533.0 $kgCO_2e/MWh$, as the system freely expands with cheap, high-emission generation. In contrast, Scenario 17, which combines dynamic carbon pricing with unrestricted deployment of low-carbon technologies, achieves a substantial reduction, falling from 226.7 to 155.4 $kgCO_2e/MWh$. This demonstrates that policy signals and technological flexibility must work together to guide the system toward sustainable outcomes.

Overall, these results highlight that carbon intensity alone cannot capture the full picture of system performance, but it provides a clear indicator of progress. Strong carbon pricing, the phase-out of coal, and strategic integration of renewables and flexible generation are essential for maintaining a steady downward trajectory..

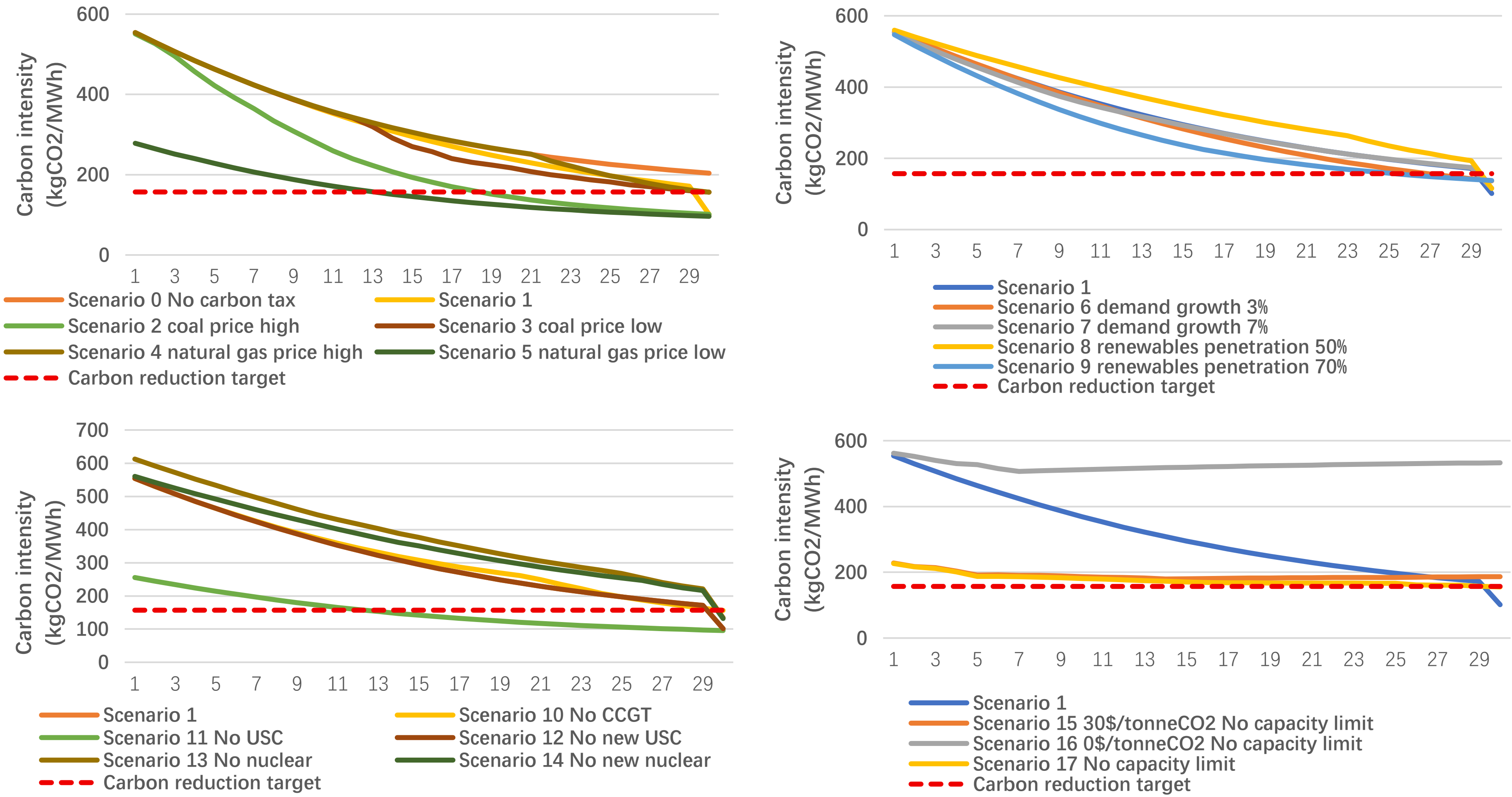


Figure 5-2 Carbon intensity for all scenarios.

5.3.3 Carbon price

Figure 5-3 presents the carbon price trajectories from 2021 to 2050 across all 18 scenarios. Carbon price acts as the key policy lever influencing investment decisions and operational behavior in the generation system. The figure highlights how different policy settings, fuel prices, demand levels, and capacity constraints shape the evolution of carbon pricing over time. In some scenarios, overlapping trends indicate similar policy or market dynamics, while in others, distinct divergences reveal how sensitive the system is to external drivers.

In the benchmark scenario (Scenario 1), the carbon price rises gradually from 31 US$/tonne CO_2e in 2021 to 59.7 US$/tonne CO_2e in 2050, providing a moderate yet consistent signal to drive decarbonization. This pathway reflects a balanced approach, offering enough incentive to encourage investment in low-carbon technologies while avoiding sudden shocks to the system.

In the absence of any carbon pricing mechanism, as in Scenario 0, the carbon price remains at 0 US$/tonne CO_2e throughout the period. Without an explicit cost on emissions, fossil-fuel generation, especially coal, remains highly competitive, leading to continued reliance on high-emission technologies. This scenario serves as a baseline, illustrating the consequences of policy inaction.

Fuel prices strongly influence the need for carbon pricing adjustments. When coal prices are high (Scenario 2), the carbon price stays fixed at 30 US$/tonne CO_2e, indicating that market forces alone are sufficient to discourage coal use and support decarbonization. Conversely, when coal prices are low (Scenario 3), the carbon price must increase steadily, rising from 30.8 to 53.6 US$/tonne CO_2e by 2050. This reflects the additional policy pressure required to counteract the economic attractiveness of cheap coal and maintain progress toward emissions targets.

Natural gas prices show a similar dynamic but in the opposite direction. In Scenario 5, with low gas prices, the carbon price remains constant at 30 US$/tonne CO_2e, as inexpensive natural gas naturally displaces coal, reducing emissions without heavy policy intervention. In contrast, when gas prices are high (Scenario 4), the carbon price climbs steeply from 31.2 to 65.0 US$/tonne CO_2e. This indicates that, under unfavorable gas market conditions, stronger economic incentives are required to promote the deployment of low-carbon alternatives such as nuclear, renewables, and CCUS-equipped plants.

Demand growth also affects carbon price trajectories. In Scenario 6, with a lower annual demand growth rate of 3%, the carbon price remains flat at 30 US$/tonne CO_2e throughout the period, as the combination of modest demand and a relatively high share of nuclear generation allows the system to meet environmental targets without additional policy tightening. In contrast, Scenario 7, with a higher demand growth rate of 7%, requires gradually increasing carbon prices, peaking at 59.9 US$/tonne CO_2e by 2050. This shows that rapid demand growth puts pressure on the system, necessitating stronger carbon signals to keep emissions in check.

The level of renewable penetration plays a critical role in determining the strength of carbon pricing needed. In Scenario 8, with 50% renewable penetration by 2050, the carbon price follows a similar increasing trend to the benchmark, ending at 59.7 US$/tonne CO_2e. However, in Scenario 9, with a more aggressive 70% renewable target, the carbon price remains fixed at 30 US$/tonne CO_2e. The higher renewable share reduces dependence on carbon pricing by directly lowering emissions through clean generation, illustrating how renewable policies can complement or even partially substitute for carbon pricing.

Technology availability also has a significant impact. Scenario 10, which removes CCGT from the system, shows a sharp rise in carbon price, from 31.2 to 65.3 US$/tonne CO_2e, as the absence of gas-fired generation forces greater reliance on more expensive or higher-emission options. By contrast, Scenario 11 (No USC) maintains a constant carbon price of 30 US$/tonne CO_2e, since removing high-emission coal plants makes it easier to meet environmental targets without increasing policy pressure. Scenario 12 (No new USC) behaves similarly to the benchmark, with a slight increase to 60.4 US$/tonne CO_2e, reflecting the limited effect of restricting only new coal development while keeping existing capacity operational.

Nuclear constraints in Scenarios 13 and 14 lead to slightly higher carbon prices, reaching 59.8 and 59.7 US$/tonne CO_2e respectively by 2050. These results suggest that reducing reliance on nuclear requires stronger price signals to maintain the same decarbonization trajectory, as other technologies must compensate for the lost low-carbon baseload capacity.

The interplay between policy and flexibility is most evident in Scenarios 15, 16, and 17. Scenario 15, with a fixed carbon tax of 30 US$/tonne CO_2e, provides a stable but limited signal, useful for analyzing the system under constant policy conditions. Scenario 16, with no carbon tax and no capacity constraints, keeps the carbon price at 0 US$/tonne CO_2e, representing complete policy absence and leading to the most environmentally damaging outcome. In contrast, Scenario 17, which combines dynamic carbon pricing with unrestricted technology deployment, achieves effective decarbonization with only a moderate increase in carbon price, rising from 30 to 38.2 US$/tonne CO_2e. This demonstrates that when the power system has full flexibility, even relatively low carbon prices can be sufficient to guide investments and achieve long-term emissions reduction targets.

Overall, these results emphasize that carbon pricing must be carefully calibrated to reflect external conditions. While higher prices are sometimes necessary to counteract low fuel costs or rising demand, a well-designed policy can work in tandem with market forces and technology availability to achieve decarbonization at minimal economic cost.

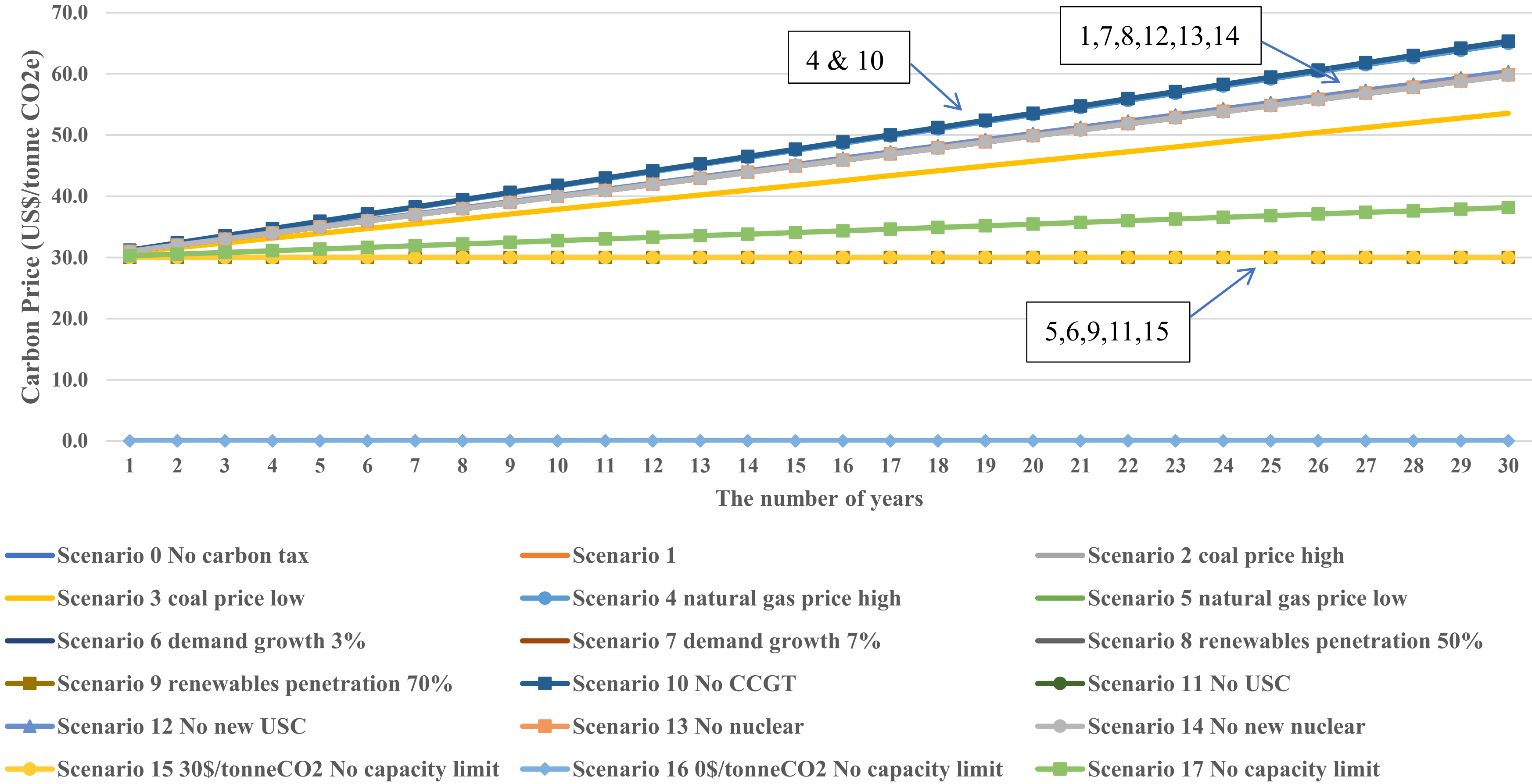


Figure 5-3 Carbon price for all scenarios.

5.3.4 Discussion

The total system cost and total carbon emissions reflect the economic and environmental performance of the power system under different scenario conditions. Meanwhile, annual fluctuations in carbon intensity reflect the response of the system to carbon pricing mechanisms. This section focuses on analyzing the differences in total costs and emissions compared to Scenario 1 (the Benchmark Scenario).

Table 5-1 summarizes the differences in total system cost and carbon emissions for each scenario compared to Scenario 1. Based on this comparison, four key findings emerge concerning: (1) sensitivity to input assumptions, (2) the role of carbon pricing, (3) the effect of capacity constraints, and (4) the impact of specific generation technology.

The sensitivity analysis reveals that total system costs are notably influenced by changes in coal prices, natural gas prices, renewable energy penetration, and demand growth. Similarly, total carbon emissions are particularly sensitive to low coal prices, low natural gas prices, renewable energy penetration, and demand variations.

The effects of demand and renewable energy penetration are relatively intuitive: higher demand leads to increased system costs and emissions, while lower demand reduces both. However, the impacts of fuel price changes are more complex. For example, high coal prices have a minimal impact on total emissions, whereas low coal prices can lead to a large reduction in emissions, as the system shifts toward greater reliance on USC-CCUS technology due to its ability to utilize cheaper coal while still meeting emissions constraints. In contrast, low natural gas prices result in notable decreases in both costs and emissions, while high gas prices have a minimal impact. These observations highlight that fuel price changes can significantly affect the expansion of generation system and should therefore be carefully considered in long-term planning.

The findings confirm that carbon pricing plays a critical role in emission reductions. In Scenario 0 (No carbon tax), emissions increase by 29.9% compared to Scenario 1. The comparison between Scenario 15 (fixed carbon tax of \$30/tonne CO_2, no capacity constraints) and Scenario 16 (no carbon tax, no capacity constraints) further emphasizes this point: emissions in Scenario 15 are 29.7% lower than in Scenario 1, while emissions in Scenario 16 rise by 97.1%. These results strongly indicate that implementing a carbon tax is effective in reducing emissions, whereas removing it leads to a large escalation in emissions.

The role of capacity constraints is obvious. Scenario 17 (no capacity limits, with carbon pricing mechanism) achieves a 35.6% reduction in system cost and a 32.8% reduction in emissions compared to Scenario 1. This demonstrates that relaxing capacity restrictions enable the power system to expand more efficiently and cost-effectively.

Finally, generation technologies—especially Nuclear and USC—have a major influence on system cost and emissions. In Scenarios 13 and 14, where nuclear power is either entirely removed or new development is restricted, both system costs and emissions increase. Specifically, Scenario 13 (No nuclear) leads to a 25.6% increase in cost and a 10.7% increase in emissions, while Scenario 14 (No new nuclear) results in an 18.1% increase in cost and an 8.1% increase in emissions. These outcomes highlight the value of nuclear energy in controlling costs and supporting emission reductions. With respect to USC technology, the effects differ depending on whether all USC capacity is removed or only new developments are constrained. In Scenario 11 (No USC), total system cost decreases significantly by 49.4%, which shows that eliminating all coal-fired power generation can result in cost saving. In contrast, Scenario 12 (No new USC) shows no significant impact on costs or emissions, indicating that the continued operation of existing USC plants does not heavily influence system-wide outcomes. These findings highlight that completely phasing out coal-fired generation yields notable benefits, while limiting new coal investments alone has limited effectiveness.

Table 5-1 Difference in total system cost and total carbon emission compared to Scenario 1.

	Total system cost	Total carbon emission
Scenario 0 No carbon tax	8.6%	29.9%
Scenario 1 bench scenario	0.0%	0.0%
Scenario 2 coal price high	-27.9%	0.0%
Scenario 3 coal price low	-3.4%	-15.7%
Scenario 4 natural gas price high	3.0%	1.5%
Scenario 5 natural gas price low	-47.9%	-23.6%
Scenario 6 demand growth 3%	-28.5%	-37.9%
Scenario 7 demand growth 7%	36.2%	48.2%
Scenario 8 renewable energy penetration 50%	14.3%	10.3%
Scenario 9 renewable energy penetration 70%	-14.3%	-18.2%
Scenario 10 No CCGT	3.3%	1.6%
Scenario 11 No USC	-49.4%	-0.9%
Scenario 12 No new USC	0.0%	0.2%
Scenario 13 No nuclear	25.6%	10.7%
Scenario 14 No new nuclear	18.1%	8.1%
Scenario 15 30$/tonneCO2 No capacity limit	-29.7%	-33.1%
Scenario 16 0$/tonneCO2 No capacity limit	97.7%	-17.2%
Scenario 17 No capacity limit	-35.6%	-32.8%

5.4 Long-term Planning Outcomes: Technology Mix for Electricity Supply and Installed Capacity in 2050

This section presents and discusses the results for technology mix for electricity supply and installed capacity in 2050. The aim is to evaluate the long-term impacts of different scenarios on the composition of the power system and the deployment of various generation technologies.

5.4.1 Technology mix for electricity supply in 2050

Figure 5-4 presents the technology mix for electricity supply in the year 2050 for all scenarios. The chart illustrates electricity generation by technology type, including Nuclear, USC, CCGT, Wind, Solar PV, Pumped-storage, Load shedding, and USC-CCUS for each scenario. However, since the Pumped-Storage system is not considered as a 'primary' energy source and it is considered as a form of 'storage', its power generation remains zero.

A summary of key observations is provided below:

Nuclear Generation: In most scenarios, nuclear capacity is fixed, resulting in a relatively stable generation output of approximately 231–232 TWh. This consistency suggests that nuclear power is economically competitive in most scenarios. In scenarios with higher overall electricity demand—such as Scenario 7 (7% demand growth)—nuclear generation increases slightly to 232.9 TWh, but its share of total generation decreases, indicating that additional demand is primarily met by other technologies. In contrast, in scenarios without capacity constraints—such as Scenarios 15, 16, and 17—nuclear generation drops significantly to 25.0 TWh, 31.4 TWh, and 53.3 TWh, respectively. This downward trend indicates that, in the absence of mandatory nuclear energy development or capacity targets, the system tends to favor other potentially more cost-effective technologies. Thus, without policy intervention to ensure technology diversity, the likelihood of new nuclear investments appears relatively low.

USC Generation: Generation from USC plants varies widely across scenarios. In Scenario 1, USC contributed a relatively small amount of 26.2 TWh, but reached a peak of 1308.4 TWh in Scenario 16 (0$/tonne CO_2, No Capacity Limit). These scenarios highlights that, in the absence of carbon pricing mechanisms, coal becomes a dominant and economically attractive option. On the other hand, Scenario 5 (Low Gas Price) USC generation is reduced to just 3.1 TWh, demonstrating the competitive displacement of coal by affordable gas.

CCGT Generation: CCGT plays a significant and flexible role in most scenarios. In Scenario 1, it generates 484.0 TWh, while in Scenario 7, under high demand, its output peaks at 1053.5 TWh. In contrast, under low demand conditions (Scenario 6), its generation drops sharply to just 6.9 TWh. It highlights how power demand influences the CCGT power generation.

Wind Energy Generation: Wind energy serves as a key source of low-carbon electricity across nearly all scenarios. In many cases, wind generation levels are similar due to the assumed 40% penetration target by 2050, which acts as a binding constraint in the modelling framework. In the baseline scenario (Scenario 1), wind power generation reaches 785.8 TWh, while in Scenario 7 (high demand growth), it increases significantly to 1410.4 TWh. In contrast, Scenario 16 (carbon price of $0/tonne CO_2, with no capacity restrictions) records the lowest wind generation, at just 239.4 TWh. This indicates that in the absence of regulatory support or pricing incentives, wind power struggles to compete purely on economic terms within the market.

Solar PV Generation: In most scenarios, solar PV generation remains relatively consistent due to the assumed 20% penetration cap by 2050, which acts as a binding constraint within the modelling framework. As a result, solar output remains stable across scenarios, reaching 372.6 TWh in the baseline scenario (Scenario 1) remaining at similar levels in other scenarios. However, in Scenarios 15 and 17, where capacity expansion is unrestricted, solar PV generation increases significantly to 600.4 TWh and 633.6 TWh, respectively. In these scenarios, carbon prices enhance the competitiveness of solar PV technology, so its power generation is so large. The results suggest that solar PV is a cost-effective low-carbon option, particularly in policy environments that remove deployment limits and apply carbon pricing.

USC-CCUS Generation: Due to its high capital costs, USC-CCUS is deployed only in specific scenarios, typically where conventional coal is restricted or where additional emission reductions are required. This technology is not utilized in the baseline scenario (Scenario 1), reflecting its limited cost competitiveness under standard policy and capacity assumptions. In Scenario 10 (No CCGT), USC-CCUS achieves its highest generation level, producing 147.4 TWh—likely serving as a substitute for the absent gas-fired generation, particularly to meet dispatchable capacity needs while maintaining low emissions. The lowest USC-CCUS generation occurs in Scenario 14 (No New Nuclear), at 63.5 TWh, suggesting that the technology is deployed to partially compensate for the reduction in nuclear capacity. These achievements highlight the key role of USC-CCUS as a strategic low-carbon technology, which is primarily applied under conditions where other low-carbon power generation technologies are constrained, to support system reliability and emission targets.

Load Shedding: Load shedding remains minimal in all scenarios, indicating that system reliability is generally maintained. In Scenario 1, load shedding accounts for 1.1 TWh, a slightly higher values are seen in Scenario 7 (1.96 TWh) and Scenario 9 (1.22 TWh) respectively. The increase in load shedding is likely caused by an increase in renewable energy and higher demand.

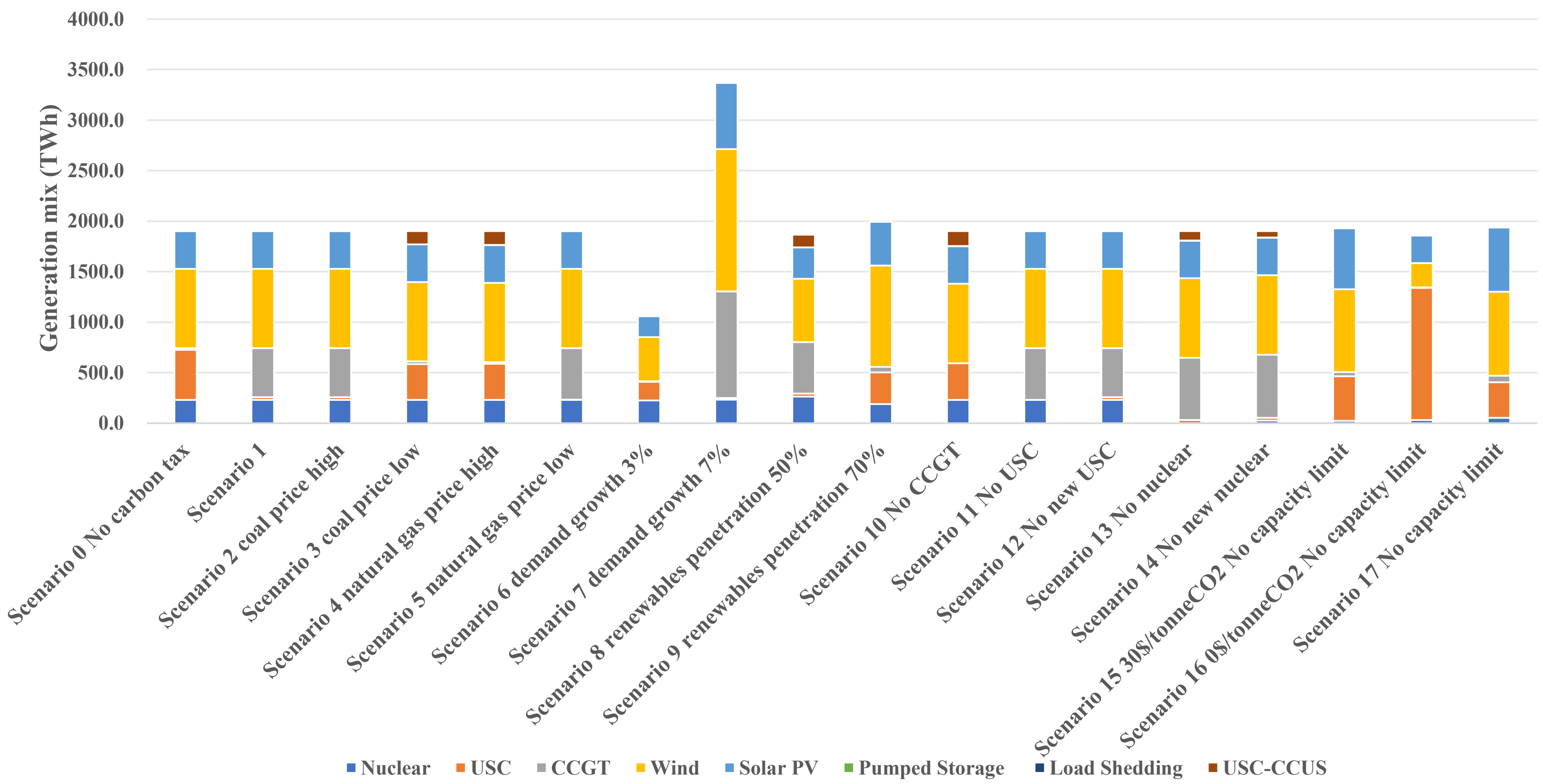


Figure 5-4 Technology mix for electricity supply in 2050 for all scenarios.

5.4.2 Installed capacity mix in 2050

Figure 5-5 illustrates the installed capacity mix (in GW) for different power generation technologies in the year 2050 across all scenarios. The following summary categorizes the findings by technology type:

Nuclear Power: In most scenarios, nuclear capacity remains constant at 40 GW, including in the baseline scenario (Scenario 1), reflecting the modelling framework's assumption of a fixed nuclear contribution. However, in scenarios without capacity constraints—such as Scenarios 15, 16, and 17—nuclear power capacity declines significantly. This suggests that, in the absence of policy support or regulatory mandates, nuclear power may struggle to remain economically competitive.

USC (Ultra-Supercritical Coal): USC capacity in Scenario 1 is 74 GW, but varies widely across other scenarios. It peaks at 245.6 GW in Scenario 16 (0$/tonne CO_2, No Capacity Limit), highlighting the cost-driven preference for coal in the absence of carbon pricing. The lowest capacity appears in Scenario 5 (Low Gas Price), at just 28 GW, suggesting that affordable gas can effectively displace coal in the technology mix for electricity supply.

CCGT (Combined Cycle Gas Turbine): CCGT capacity plays a key role in supplying dispatchable power to the electricity system. In the base scenario (Scenario 1), the installed capacity is 155.7 GW. In Scenario 7 (high demand growth), CCGT capacity increases significantly to 368.2 GW, reflecting the system's growing reliance on CCGT to meet growing electricity demand and environmental requirements. Conversely, under low demand conditions (Scenario 6), CCGT capacity drops sharply to 25.2 GW, clearly demonstrating the sensitivity of this technology to low demand growth.

Wind Power: In most cases, wind power generation remains strong due to the wind penetration requirements specified in the modeling framework, with an installed capacity of 264.7 GW in the baseline scenario (scenario 1). In Scenario 7, under conditions of high electricity demand, wind power capacity increases significantly to 475 GW. In contrast, Scenario 16 (0$/tonne CO_2, No Capacity Limit) shows the lowest wind power capacity, at only 80.6 GW. The results of Scenario 16 highlight the critical role of policy support in promoting large-scale deployment of wind energy. Without the support of carbon pricing mechanisms and mandatory wind energy deployment, wind energy would struggle to compete economically with other power generation technologies in an unrestricted market environment.

Solar PV: Due to the solar penetration requirement embedded in the modelling framework, solar PV capacity remains stable at 225.3 GW in the baseline scenario (Scenario 1) and across most other scenarios. However, in Scenario 7 (high demand growth) and Scenario 15 (Carbon tax of $30/tonne and no capacity constraints), solar capacity increases significantly to 394.6 GW and 363 GW, respectively. These results indicate that solar PV deployment is highly responsive to both increased electricity demand and no capacity constraints, particularly when supported by carbon pricing.

Pumped Storage: In most scenarios, including the baseline scenario (Scenario 1), pumped-storage capacity is fixed at 25 GW due to limitations set by the modelling framework. However, in no capacity constraint scenarios—such as Scenario 15 (fixed carbon tax, with no capacity limits) and Scenario 17 (carbon pricing, with no capacity limits)—pumped-storage capacity increases significantly to 114.2 GW and 128.2 GW respectively. This expansion reflects the growing demand for energy storage in the system, which is mainly driven by the large-scale integration of solar PV technology in these scenarios.

Load Shedding: Although load shedding technology contributes relatively little to reducing annual electricity generation, it requires a large amount of installed capacity. In systems with a high share of renewable energy, there are significant short-term energy gaps that need to be filled through load shedding technology, leading to a large-scale demand for installed capacity of load shedding technologies. In the baseline scenario (Scenario 1), load shedding capacity is 62.5 GW. In Scenario 17 (no capacity constraints, with carbon pricing mechanism), the capacity is more than doubled to 158.8 GW, primarily driven by the large-scale deployment of solar energy, which introduces greater variability into the system. This highlights the value of load shedding as a supplementary balancing mechanism in high-renewable environments. In contrast, Scenario 6 (low demand growth) exhibits the lowest shedding capacity, at 44.1 GW, reflecting a reduced need for demand-side interventions in systems with more modest electricity requirements.

USC-CCUS: The deployment of USC-CCUS occurs only in specific scenarios where carbon capture is required to offset high fossil fuel usage. In the baseline scenario (Scenario 1) and most others, this technology is not utilized, reflecting its high cost and limited competitiveness under standard conditions. The highest installed capacity appears in Scenario 10 (without CCGT), where 29.5 GW of USC-CCUS is deployed, to compensate for the absence of flexible gas-fired generation while still achieving emissions reduction targets. In contrast, Scenario 14 (without new nuclear power) sees the lowest USC-CCUS capacity, at 10.6 GW, suggesting that CCUS is used to partially supplement the system's low-carbon technology mix for electricity supply in the absence of nuclear expansion.

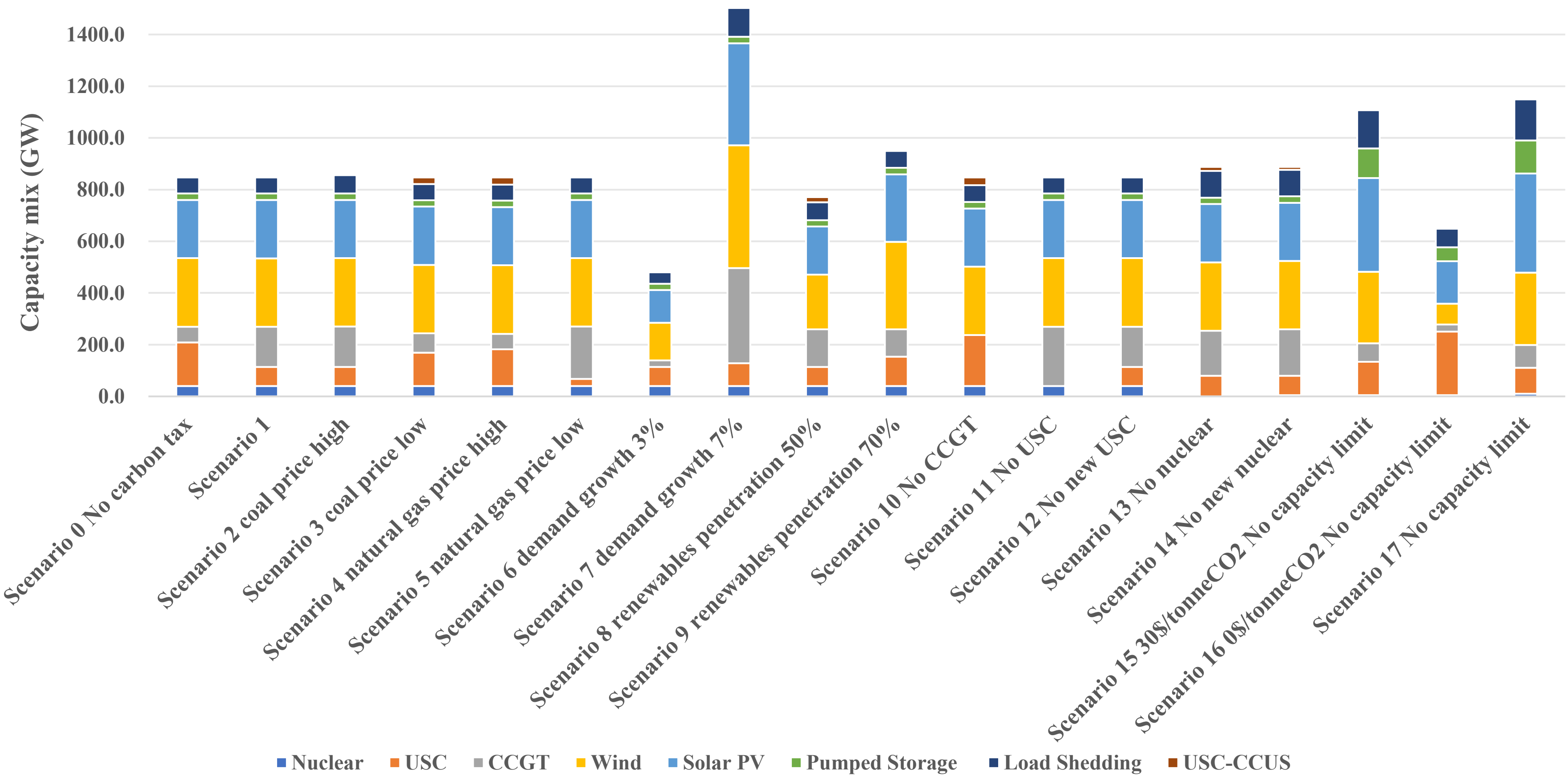


Figure 5-5 Installed capacity mix in 2050 for all scenarios.

5.4.3 Discussion

The previous section analyzed the development of various power generation technologies under different scenarios, based on the installed capacity and technology mix for electricity supply in 2050. The section focuses on discussing and identifying the conditions under which USC remains the dominant power generation source and the scenarios that enable the deployment of USC-CCUS technology.

Table 5-2 summarizes the scenarios in which USC emerges as the dominant electricity generation source, the presence of USC-CCUS, and the corresponding carbon price levels. In several cases, USC continues to dominate the technology mix for electricity supply even after 30 years. The comparison results indicate that USC remains dominant when carbon emission reduction targets are relatively weak or fuel prices favour coal-fired power generation. Specifically, continued reliance on USC is observed in Scenario 0 (No carbon tax), Scenario 3 (Low coal price), Scenario 4 (High gas price), Scenario 6 (Low demand growth), Scenario 9 (70% renewable energy penetration), and Scenario 10 (No CCGT). These results suggest that, in the absence of strong carbon pricing mechanisms or under favourable economic conditions, the power system tends to maintain its dependence on traditional coal-based generation to meet baseload demand.

Table 5-2 Summary of power generation technologies and carbon prices.

	USC is the main energy source in the 30th year	Use USC-CCUS	Carbon price in the 30th year (US$/tonneCO2)
Scenario 0 No carbon tax	√		0
Scenario 1 bench scenario			59.7
Scenario 2 coal price high			30
Scenario 3 coal price low	√	√	53.6
Scenario 4 gas price high	√	√	65
Scenario 5 gas price low			30
Scenario 6 demand growth 3%	√		30
Scenario 7 demand growth 7%			59.9
Scenario 8 renewable energy penetration 50%		√	59.7
Scenario 9 renewable energy penetration70%	√		30
Scenario 10 No CCGT	√	√	65.3
Scenario 11 No USC			30
Scenario 12 No new USC			60.4
Scenario 13 No nuclear		√	59.8
Scenario 14 No new nuclear		√	59.7
Scenario 15 30$/tonneCO2 No capacity limit			30
Scenario 16 0$/tonneCO2 No capacity limit			0
Scenario 17 No capacity limit			38.2

USC-CCUS generally appears in scenarios with higher carbon prices, indicating that its deployment is highly sensitive to economic incentives for emissions reduction. Additionally, the lack of viable lower-carbon alternatives—such as natural gas or nuclear—further contributes to the adoption of USC-CCUS. For example, the technology is implemented in Scenario 3 (Low coal price), Scenario 4 (High gas price), Scenario 8 (50% renewable penetration), Scenario 10 (No CCGT), Scenario 13 (No nuclear), and Scenario 14 (No new nuclear). These scenarios demonstrate that USC-

CCUS becomes a viable option when USC is no longer economically feasible and alternatives such as nuclear or CCGT are constrained, making carbon capture a necessary solution to meet both energy and emission reduction goals.

5.5 Temporal Evolution: Annual Power Generation, Installed Capacity and Capacity Factor (2025–2050)

This section presents and discusses the results for annual power generation, installed capacity, and capacity factors from 2025 to 2050 to analyze the temporal evolution of the power system, highlighting how different technologies are utilized and expanded over time under varying scenario conditions.

5.5.1 Annual power generation

Figure 5-11 illustrate the annual generation of different power generation technologies under various scenarios. These scenarios explore different pathways for power generation by considering factors such as demand growth, carbon pricing, fuel prices, and the availability of technology including nuclear power, USC, CCGT, Wind energy, Solar energy, and USC-CCUS.

In all cases, the annual power generation trends of nuclear power, USC-CCUS, wind power, and solar power are relatively clear and stable. In contrast, the annual electricity generation of USC and CCGT shows greater variation and is more responsive to specific scenario.

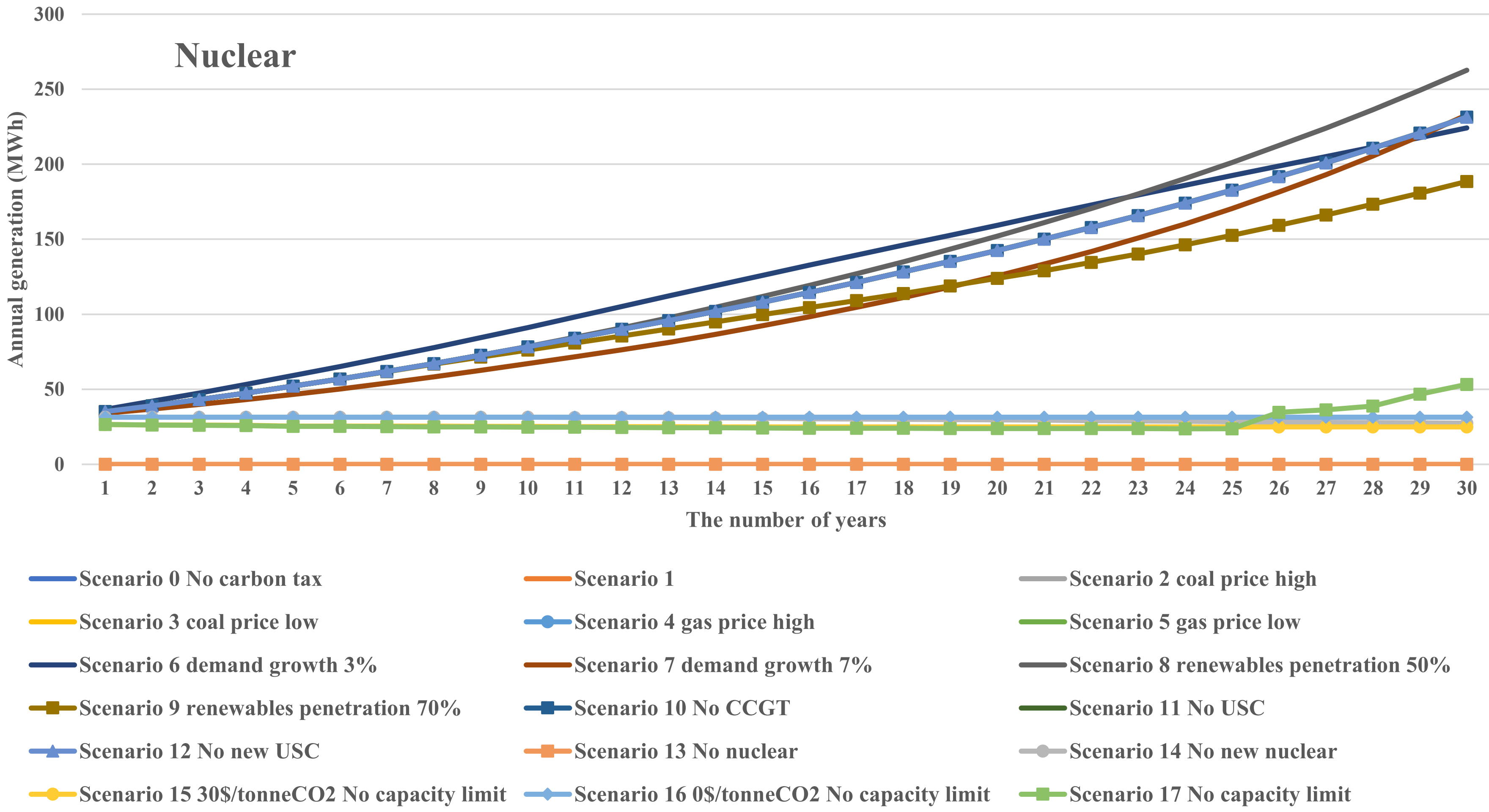


Figure 5-6 Annual power generation form nuclear power.

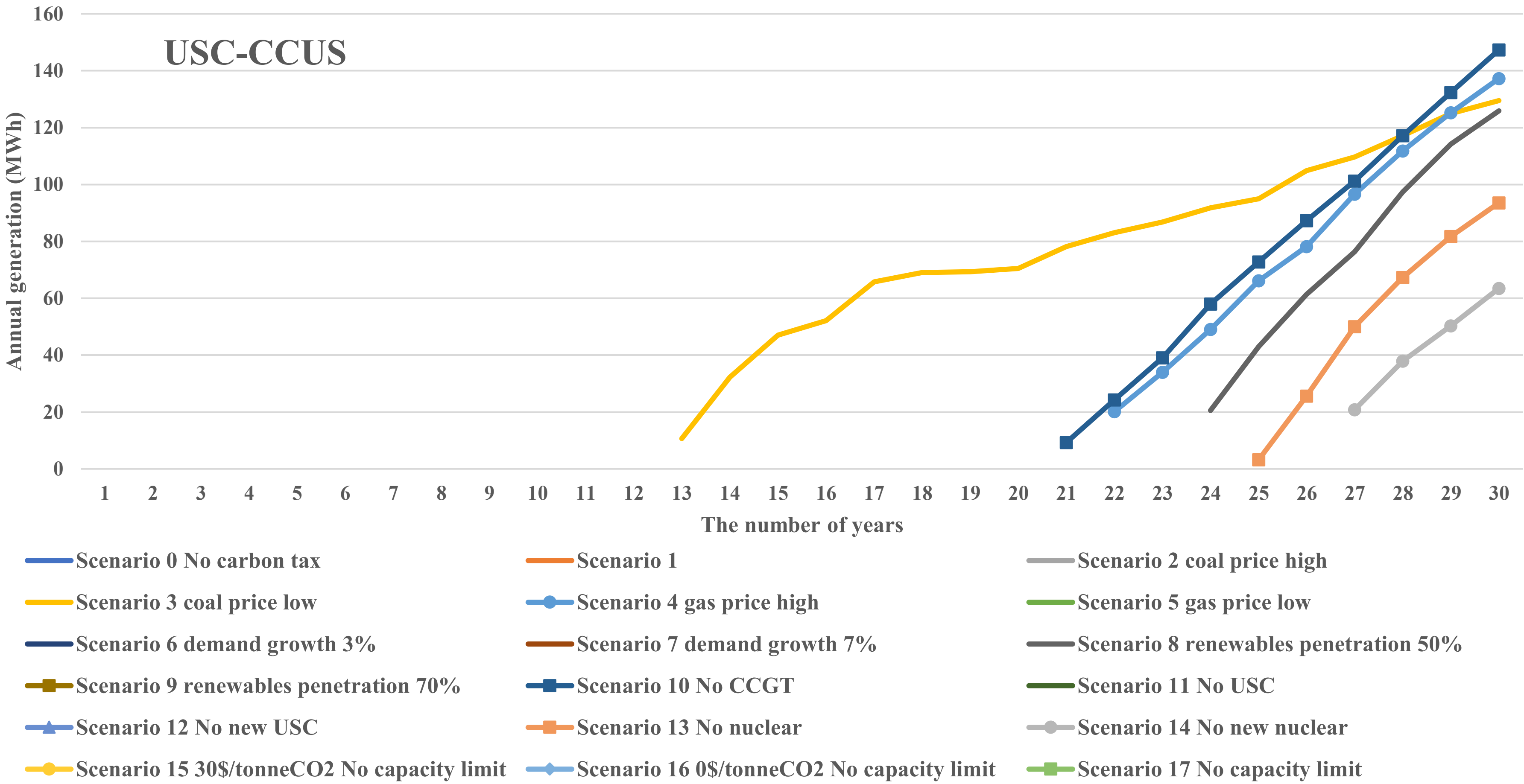


Figure 5-7 Annual power generation form USC-CCUS.

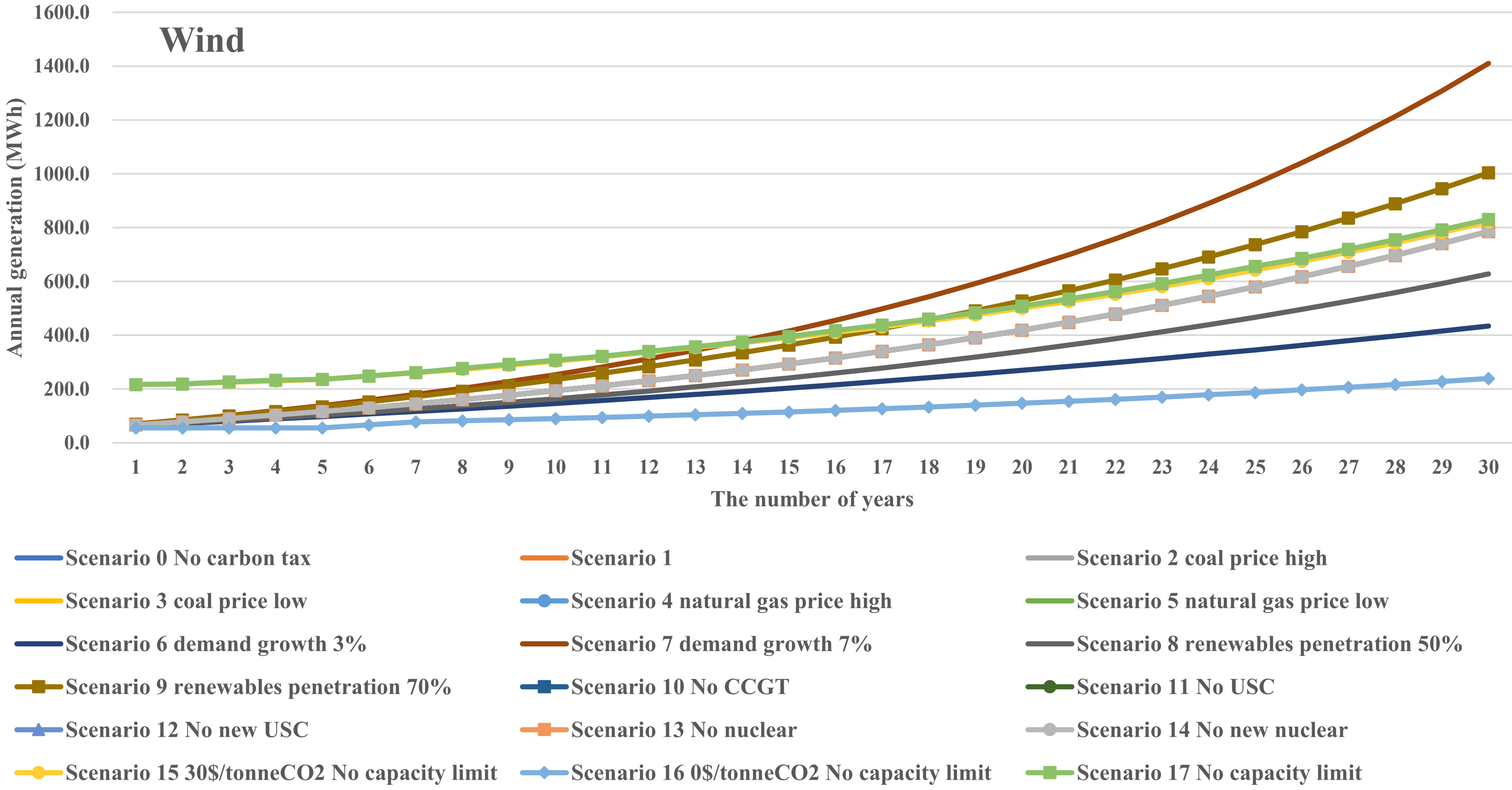


Figure 5-8 Annual power generation from wind energy.

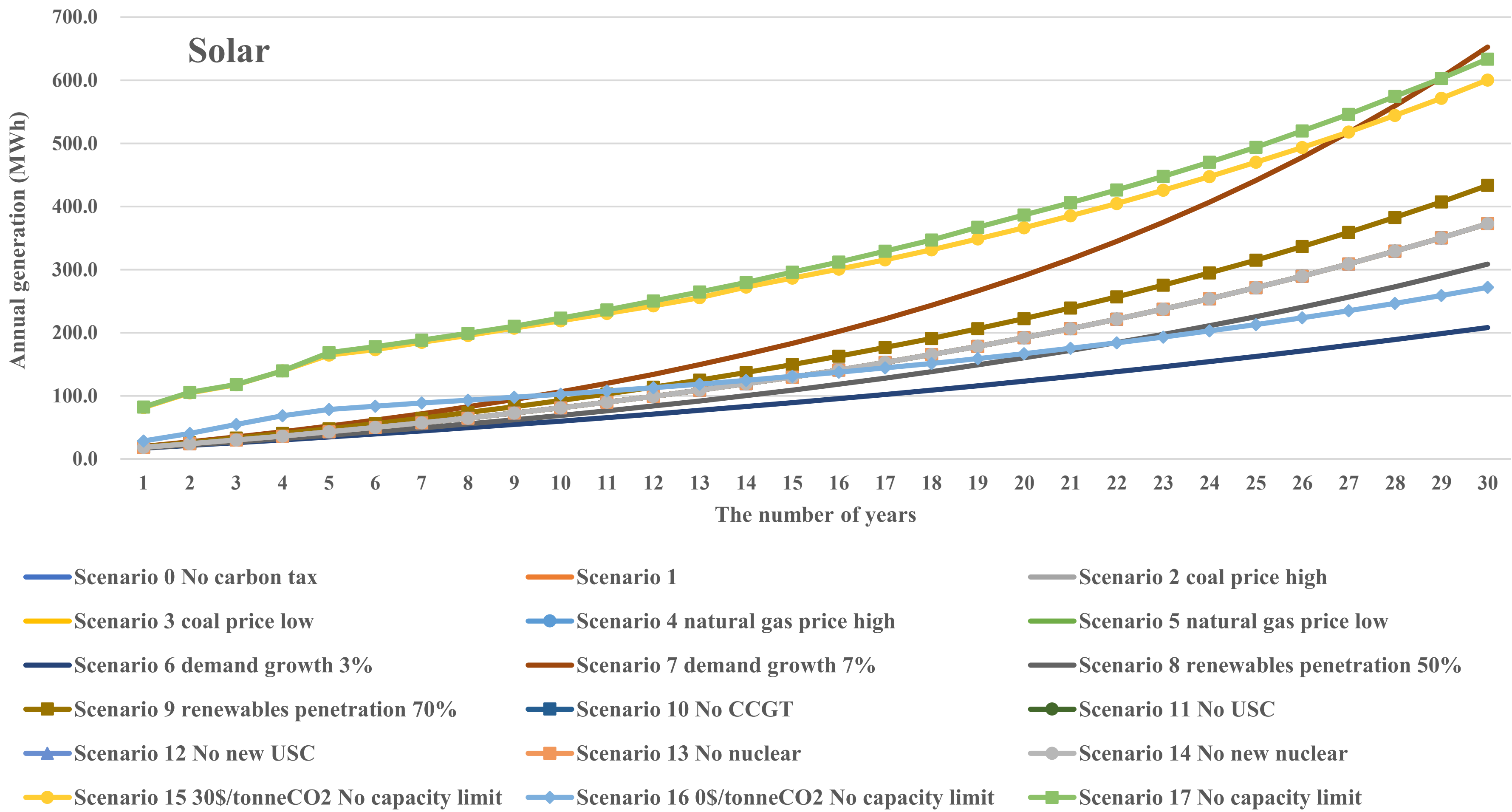


Figure 5-9 Annual power generation from solar energy.

For USC, most scenarios exhibit relatively stable or gradually increasing electricity generation, typically ranging between 200 and 500 TWh by 2050. However, Scenario 0 (no carbon tax) stands out with a sharply rising trajectory, with USC generation exceeding 1300 TWh by the 30th year. This reflects the dominance of coal in the absence of carbon pricing. In contrast, Scenarios 2 (high coal price) and 6 (low demand growth) show a declining trend in USC generation over time. These trends indicate that either increased coal price or reduced electricity demand can significantly diminish the role of coal-fired generation in the power mix. Additionally, several scenarios—1, 7, 8, 12, 13, and 14—display a sharp decline in USC generation toward the end of the planning horizon. This reflects a system shift toward cleaner technology in the final years of the planning horizon, driven by tightening carbon policies and increasing pressure to reduce emissions. Overall, these trends highlight the sensitivity of coal-fired power generation to economic signals.

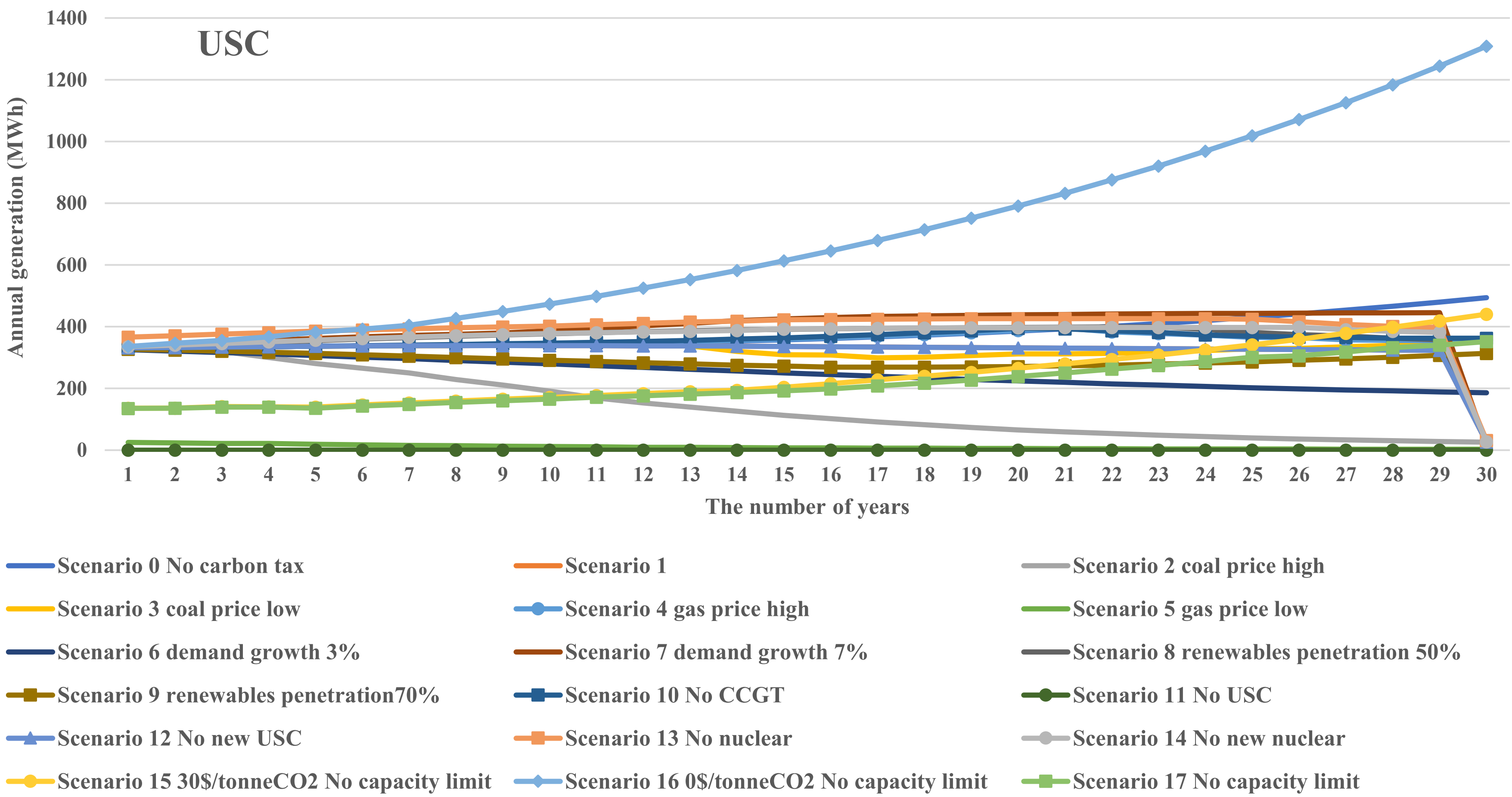


Figure 5-10 Annual power generation from USC.

For CCGT, most scenarios show a steady increase in electricity generation, typically ranging between 200 and 400 TWh by 2050. In scenarios with limited demand growth or poor natural gas price competitiveness—such as Scenarios 3, 5, and 6—CCGT generation remains relatively low, falling below 100 TWh in the final year. In contrast, Scenario 7 (high demand growth) exhibits a rapid expansion of gas-fired generation, exceeding 1000 TWh by 2050. This demonstrates the key role of CCGT in meeting growing electricity demand, particularly as a dispatchable power source that can respond quickly to system needs. Furthermore, several scenarios—including Scenarios 1, 7, 8, 12, 13, and 14—show significant increases in CCGT generation toward the end of the planning horizon. These sharp increases reflect reductions or phase-outs of other sources of power generation in the system. Overall, these trends highlight CCGT's strategic role as a transitional technology, providing both reliability and flexibility in the power system.

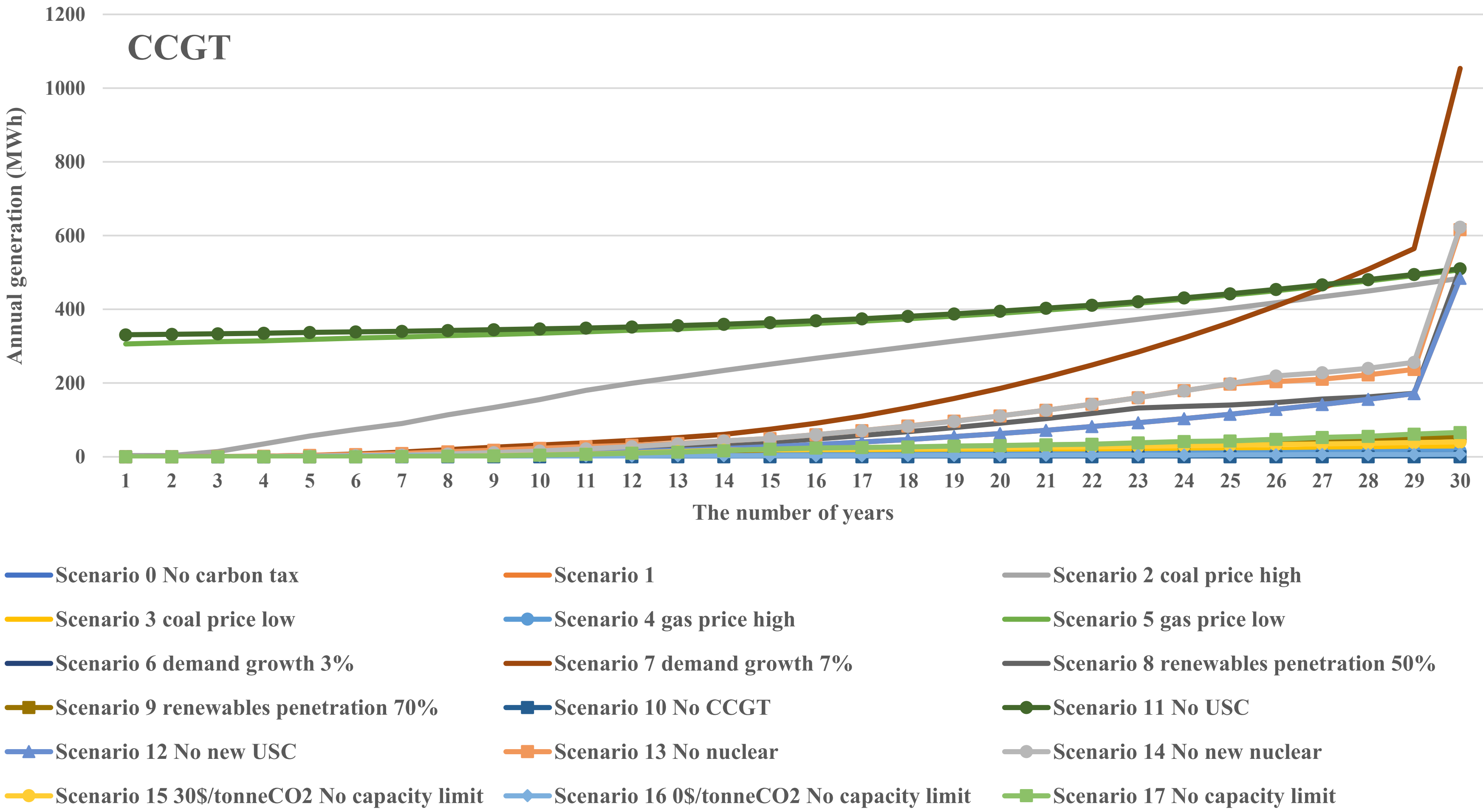


Figure 5-11 Annual power generation from CCGT.

Overall, the fluctuations in USC and CCGT electricity generation under different scenarios highlight the high sensitivity of fossil fuel technologies to changes in the power generation system. Their deployment is strongly influenced by carbon pricing signals and fuel cost changes.

5.5.2 Annual installed capacity

Figure 5-12to Figure 5-17 illustrate the trend of installed capacity by technology over time across all scenarios. Although the scenarios differ, the overall trend in the installed capacity of power generation technologies is upward to meet growing demand. However, the pace and timing of this growth vary considerably depending on assumptions regarding electricity demand, fuel prices, carbon pricing, and technology availability.

Nuclear Power: In most scenarios, nuclear power capacity gradually increases to 40 GW by the end of the planning horizon, in line with the model framework's requirement for maintaining a baseline level of nuclear capacity. This ensures nuclear energy holds a stable position within the technology mix for electricity supply, providing reliable, low-carbon electricity throughout the planning period. However, in Scenarios 15 and 16, where no capacity restrictions are imposed, nuclear capacity remains below 5 GW, reflecting the limited competitiveness of nuclear power when it is not mandated or supported by targeted policy interventions. Scenario 17 (no capacity constraints, with carbon pricing mechanism) presents a unique outcome. In this case, nuclear capacity remains at 4.5 GW for most of the planning period but then increases slightly to 10.5 GW near the end. This delay suggests that, with carbon pricing and planning flexibility in place, nuclear energy may re-enter the technology mix for electricity supply in the long term, as the system needs to find additional low-carbon baseload power sources to address rising carbon costs.

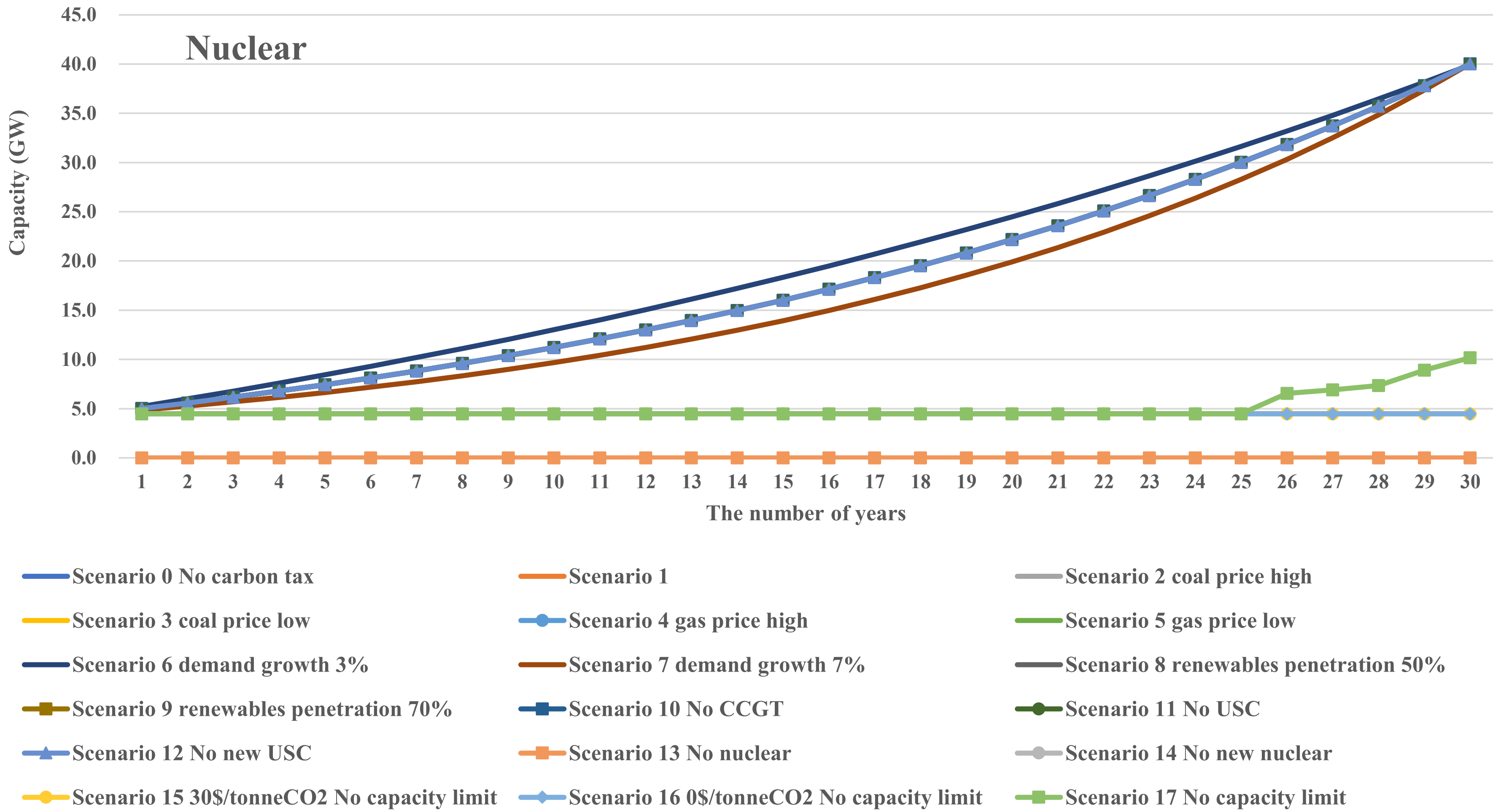


Figure 5-12 Annual installed capacity of nuclear power.

USC: In Scenarios 1, 2, 8, and 16, the installed capacity of USC remains constant at 74 GW, indicating that the available coal-fired capacity in these scenarios is sufficient to meet electricity demand without further expansion. In most other scenarios, however, USC capacity increases gradually year by year, reflecting the system's reliance on coal generation to meet growing energy needs. For instance, in Scenarios 13 and 14, where nuclear energy deployment is restricted, USC capacity increases moderately to 79.7 GW and 75.4 GW, respectively. These outcomes suggest that in the absence of nuclear energy, the system turns to USC as a supplementary low-cost dispatchable option to maintain generation adequacy. In scenarios with low carbon prices and high natural gas prices, such as Scenario 3 and Scenario 4, USC capacity rises significantly from 74 GW to 128.6 GW and 142.6 GW, respectively. This reflects the sensitivity of USC deployment to relative fuel prices, with coal becoming a more attractive option when gas is less economically viable. In Scenarios 15, 16, and 17, where no capacity constraints are imposed, USC capacity expands quickly to 128.8 GW, 245.6 GW, and 100.7 GW, respectively. These results indicate that USC is highly competitive when there are no constraints on power generation capacity expansion.

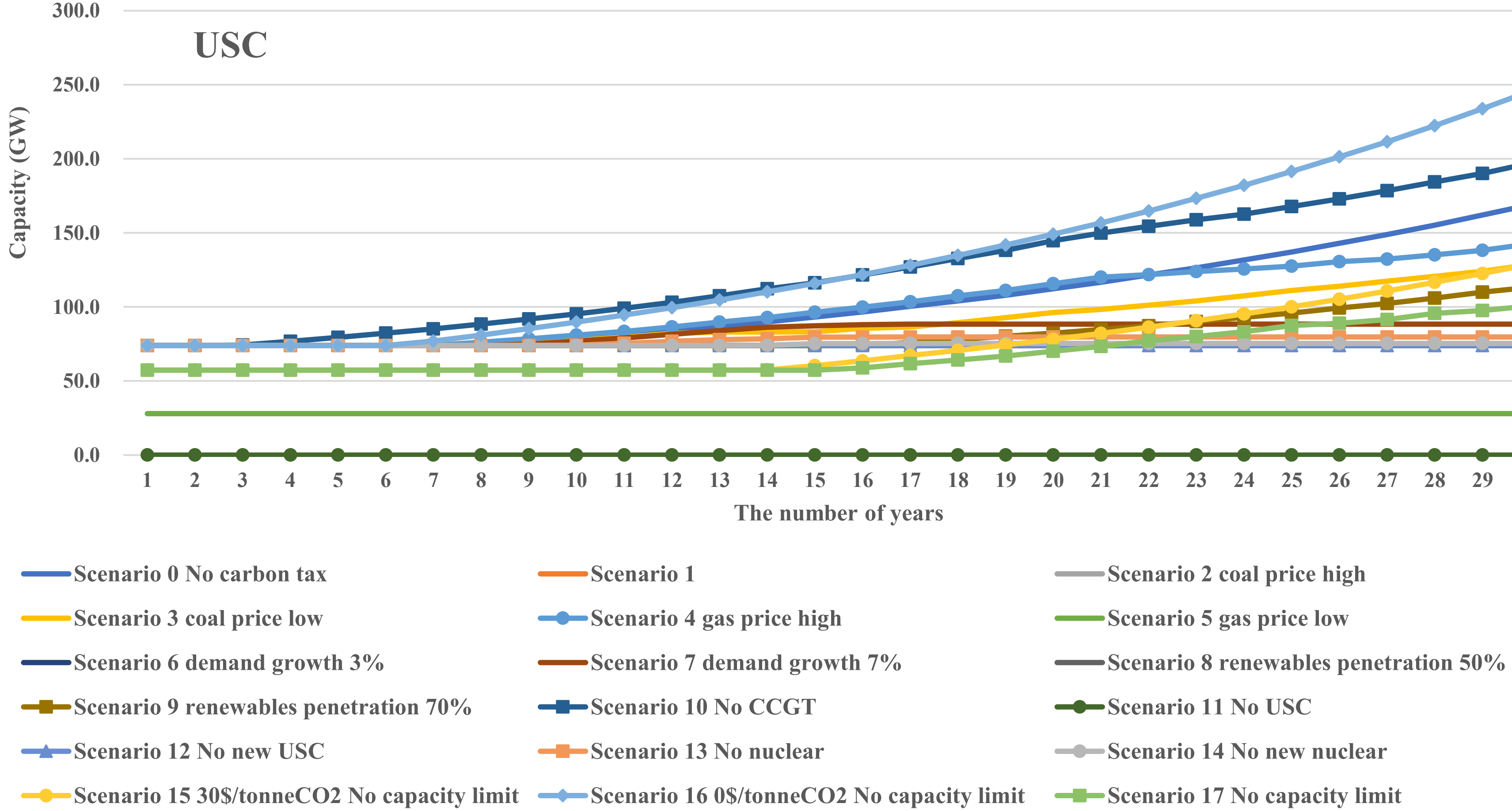


Figure 5-13 Annual installed capacity of USC.

CCGT: The capacity trend for CCGT is highly variable across scenarios, reflecting its flexible role in balancing the system under different demand and policy conditions. In many scenarios, CCGT capacity increases significantly over time, particularly in response to rising electricity demand. Scenario 7 (high demand growth at 7%) shows the most significant growth, with CCGT capacity exceeding 350 GW by year 30. This highlights the critical role of gas-fired technology in supporting rapid demand growth and providing dispatchable backup power to complement variable renewable energy sources such as wind and solar. In other scenarios—such as Scenario 0 (no carbon tax), Scenario 3 (low coal price), Scenario 4 (high gas price), Scenario 15 (fixed carbon tax at $30/tonne), and Scenario 16 (no carbon tax, no capacity restrictions)—CCGT capacity is also increasing, although the increase was relatively small. This more moderate growth is primarily due to the lack of strong economic incentives and fuel price disadvantages.

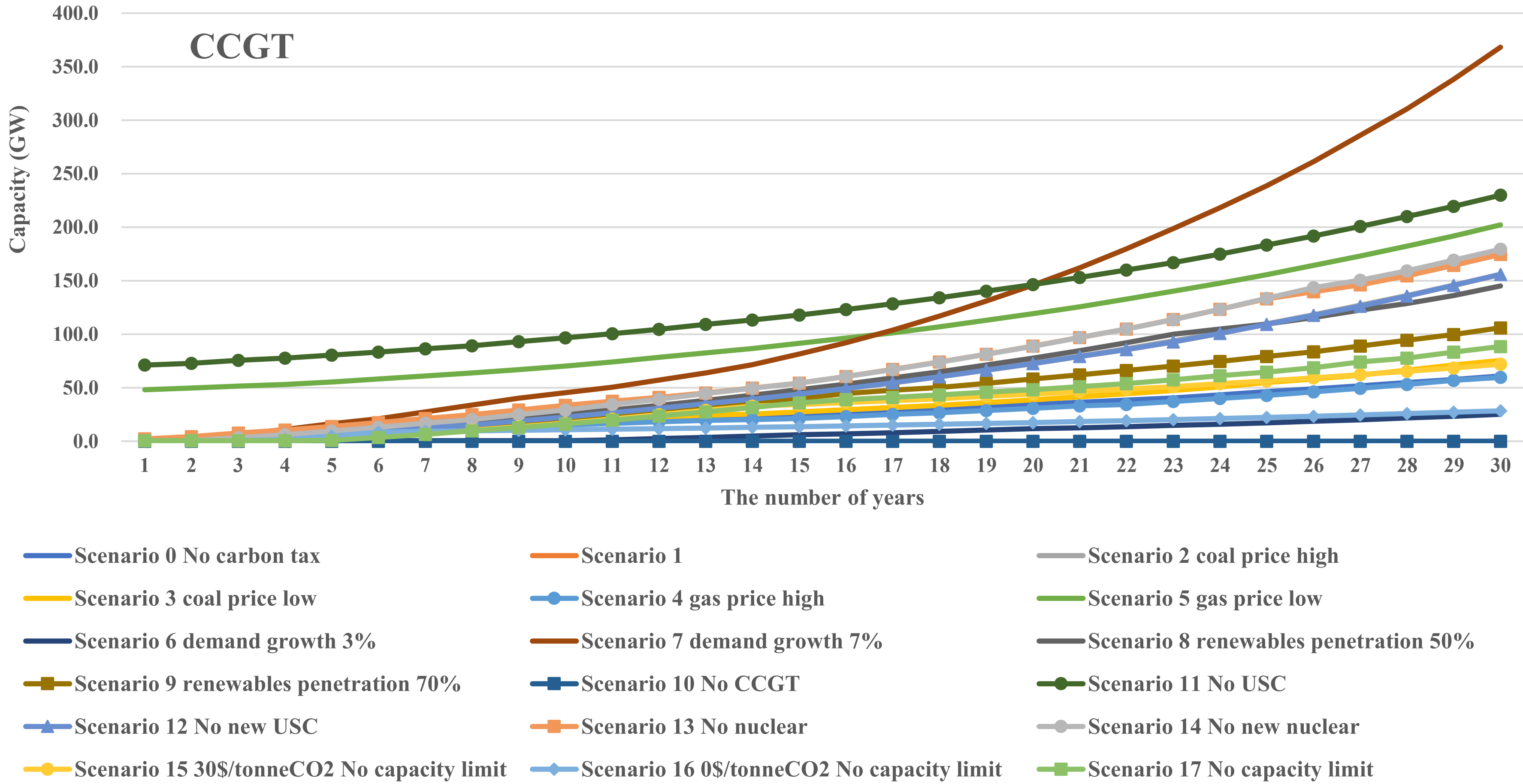


Figure 5-14 Annual installed capacity of CCGT.

USC-CCUS: The deployment of USC-CCUS varies across scenarios, with most reaching between 20 and 30 GW of installed capacity by the end of the planning horizon. Scenario 3 (low coal price) demonstrates an early adoption trend, with USC-CCUS capacity beginning to rise around year 12 and reaching approximately 30 GW by year 30. This reflects that when coal prices are low, coal-fired power generation becomes more economically attractive, prompting USC-CCUS technology to be integrated into the power generation system at an earlier stage to slow down emissions. In other scenarios, USC-CCUS deployment tends to start later, typically in the second half of the planning period, but then grows steadily to reach similar capacity levels at the end. These trends indicate that USC-CCUS technologies are typically introduced in response to increasingly stringent emissions restrictions, rising carbon prices, or the gradual phase-out of traditional coal technologies.

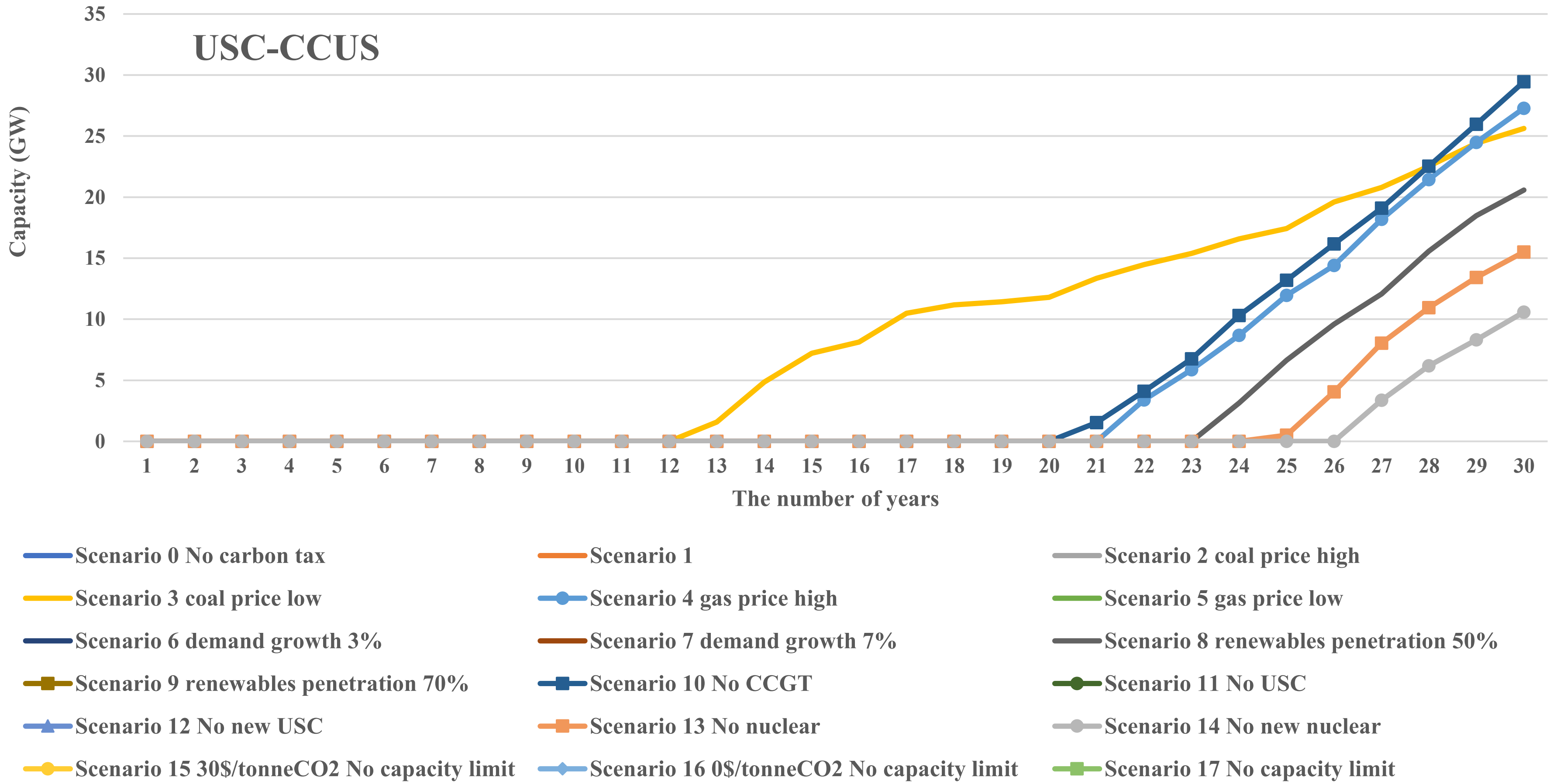


Figure 5-15 Annual installed capacity of USC-CCUS.

Wind Energy: In most scenarios, the installed capacity of wind energy steadily increases over time, driven by the modelling framework's requirement for wind energy penetration, reaching 264.7 GW by 2050. As a result, the capacity trajectories are nearly identical across scenarios, leading to overlapping trend lines in the visual data. However, deviations from this trend occur in scenarios that include varying electricity demand, different renewable energy penetration targets, or no capacity constraints. In those cases, wind capacity adjusts accordingly to meet system needs, reflecting its role as a low-carbon generation option in long-term decarbonization strategies.

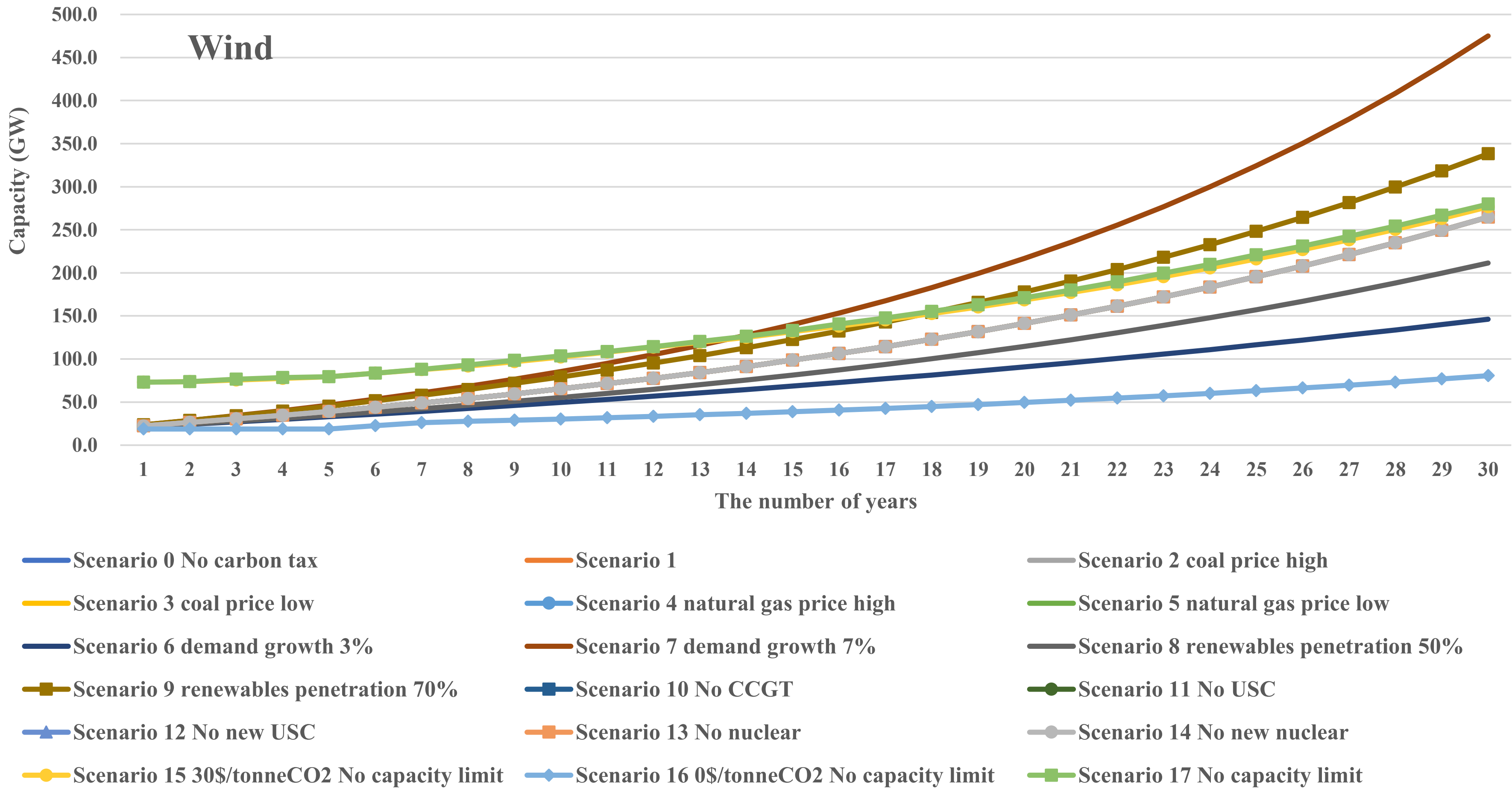


Figure 5-16 Annual installed capacity of wind energy.

Solar PV: A similar situation is observed for solar PV, with capacity consistently set at 225.3 GW in most scenarios. Similar to wind conditions, these results are caused by constraints imposed by the model and produce minimal variability during the planning period, resulting in a uniform trend line that may not fully reflect potential changes within the system. Solar PV remains a core component of the power technology mix for electricity supply, especially in scenarios where capacity restrictions are relaxed and carbon pricing mechanisms are introduced to support low-emission technologies.

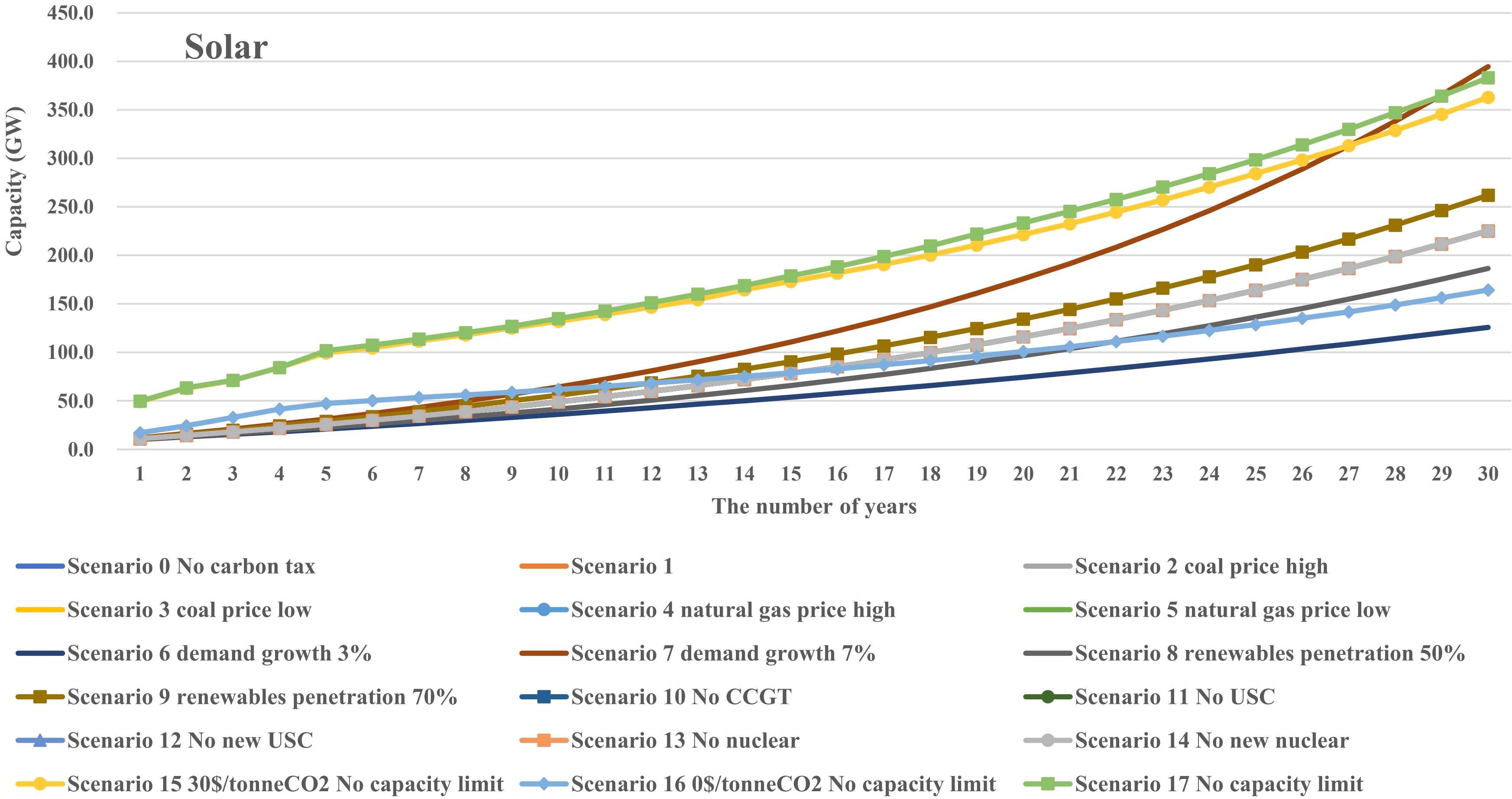


Figure 5-17 Annual installed capacity of solar energy.

5.5.3 Capacity factor for thermal generation technologies

to 5-21 display the capacity factor trends for nuclear, USC, CCGT, and USC-CCUS technologies across different scenarios from 2021 to 2050. (Wind and solar are excluded from this discussion, as their capacity factors are inherently weather-dependent). These trends provide insights into the utilization of each technology under varying policy, demand, and fuel price conditions.

Nuclear Power: In most scenarios, nuclear power maintains a high capacity factor of approximately 0.8, reflecting its role as a reliable baseload power source. Over time, the capacity factor declines slightly, generally stabilizing between 0.6 and 0.8 by 2050. This modest reduction is likely due to the increased share of renewable energy, such as wind and solar PV. The capacity factor remains relatively high, indicating that nuclear power continues to play a stable and consistent role in the technology mix for electricity supply across a wide range of scenario conditions.

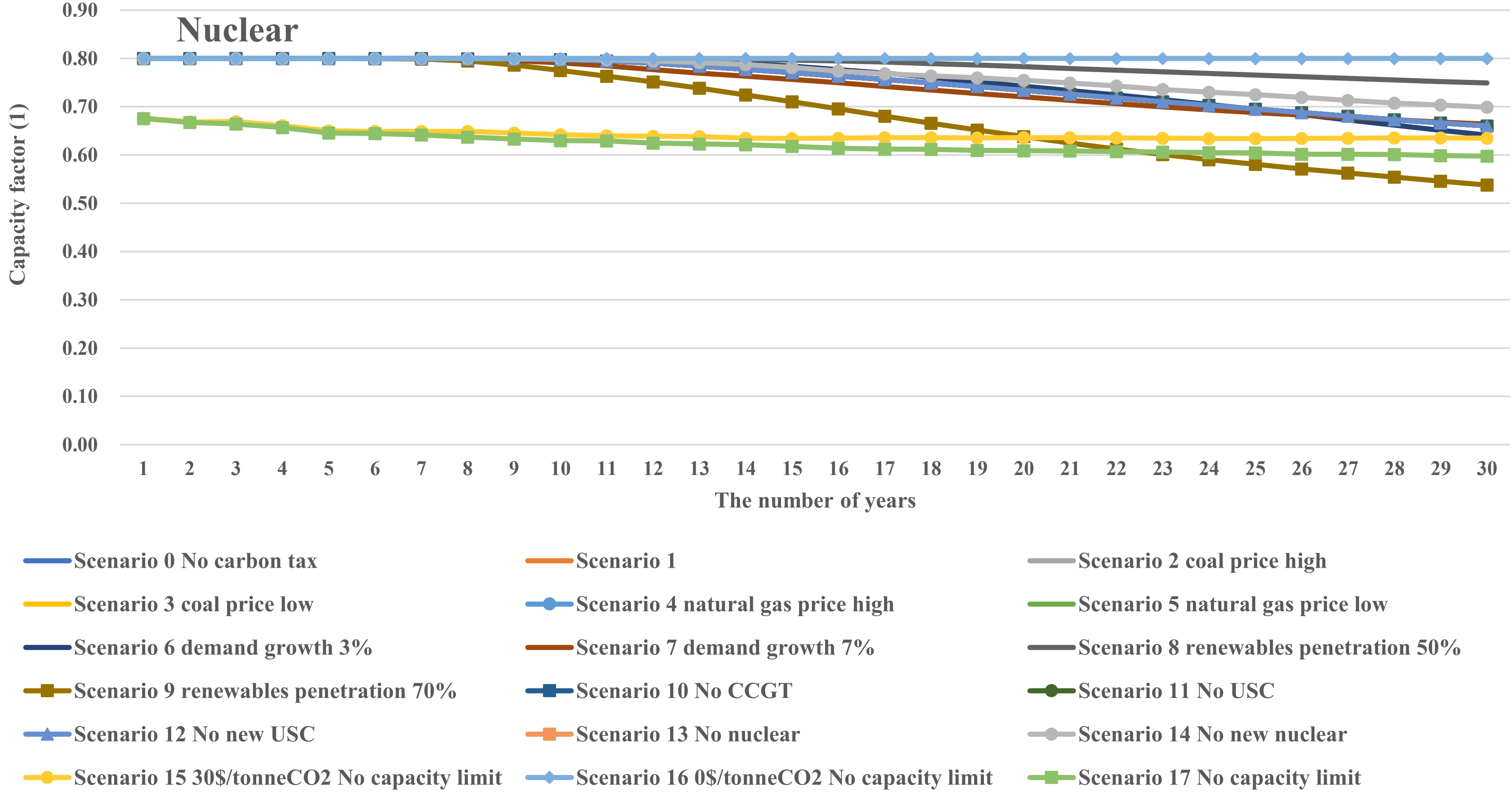


Figure 5-18 Nuclear capacity factor for all scenarios.

USC: The capacity factor for USC plants varies significantly depending on the scenario. Most cases begin within a range of 0.4 to 0.6, followed by a gradual decline. For instance, Scenario 2 (High coal price) starts at 0.51, but due to high fuel cost, capacity factor fall sharply, dropping below 0.2 by the 30th year.

Scenario 5 (Low gas price) shows a very low initial value of 0.1, dropping further to 0.01, suggesting that USC is almost entirely displaced by more affordable and lower-emission gas-fired generation. In contrast, Scenarios 15, 16, and 17 show a modest increase in USC capacity factors over time, potentially due to the relaxation of capacity limits and economic favorability of coal. Notably, several scenarios—1, 7, 8, 12, 13, and 14—show a sharp drop in USC capacity factor near the end of the planning horizon. This trend reflects the tightening of emissions policies, which drive a rapid transition away from coal, with natural gas or other low-carbon technology increasingly replacing coal-fired generation in the final years.

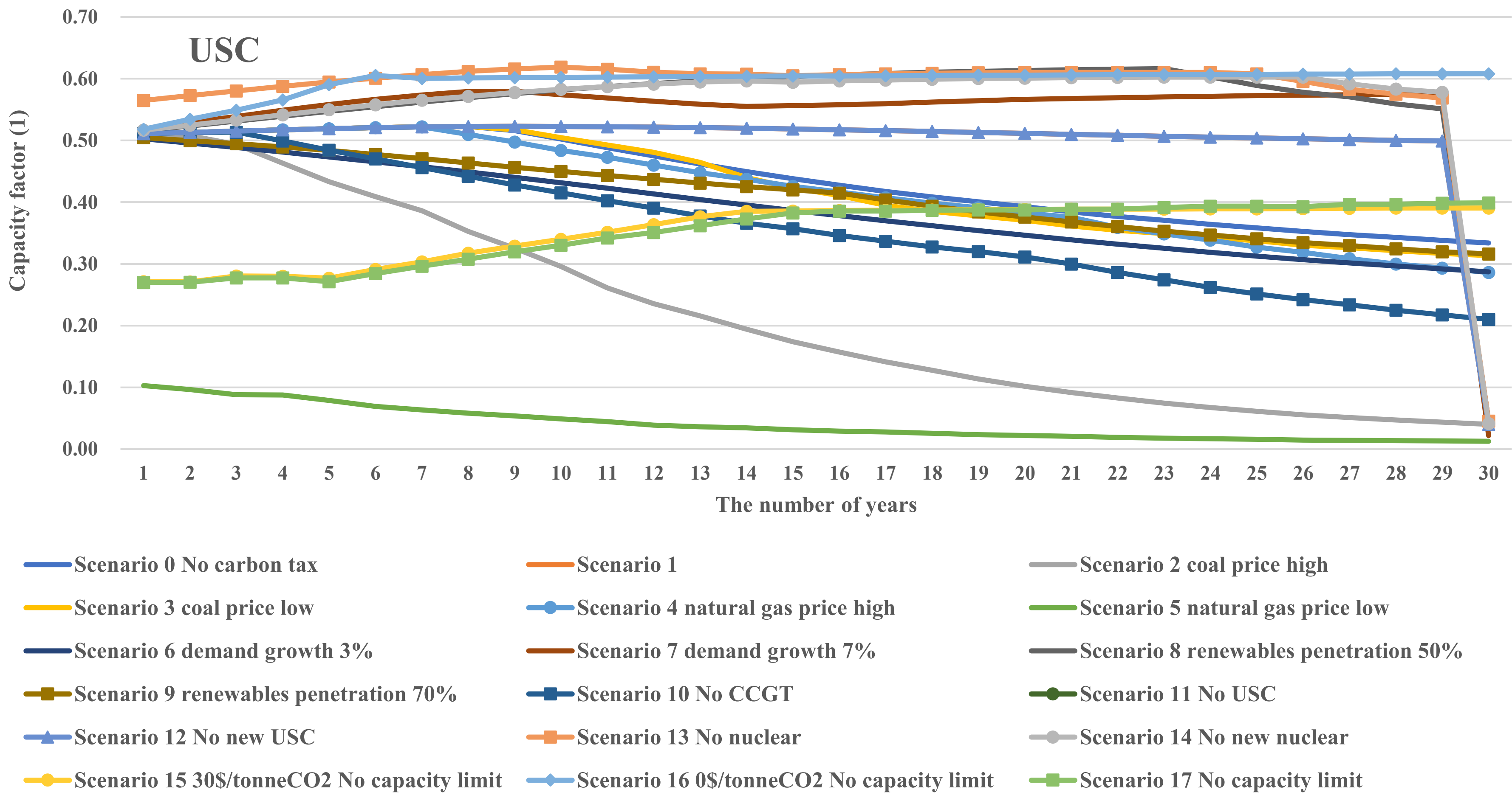


Figure 5-19 USC capacity factor for all scenarios.

CCGT: CCGT capacity factor trends vary widely across scenarios. In many scenarios, the capacity factor starts below 0.2 and increases steadily over time. This increasing trend is mainly driven by carbon pricing mechanisms, which are making natural gas-fired power generation a cheaper and lower-emission alternative to coal-fired power generation. In Scenarios 2 (high coal price), 5 (low gas price), and 11 (No USC), the CCGT capacity factor begins at a higher level—above 0.5, peaks at around 0.8, and then gradually declines to below 0.4 by year 30. This trend indicates that, during the early and mid-planning stages, a favorable natural gas fuel economy environment promoted the deployment of CCGT. The downward trend that followed may reflect an increase in renewable energy penetration, which led to a decline in demand for gas-fired power generation. Additionally, in Scenarios 1, 7, 8, 12, 13, and 14, a sharp increase in CCGT capacity factor is observed near the end of the planning horizon. This late-stage growth indicates that CCGT are beginning to dominate system dispatch. Overall, these trends highlight the strategic role of CCGTs as a transitional technology, offering system flexibility and emissions reduction potential in diverse policy contexts.

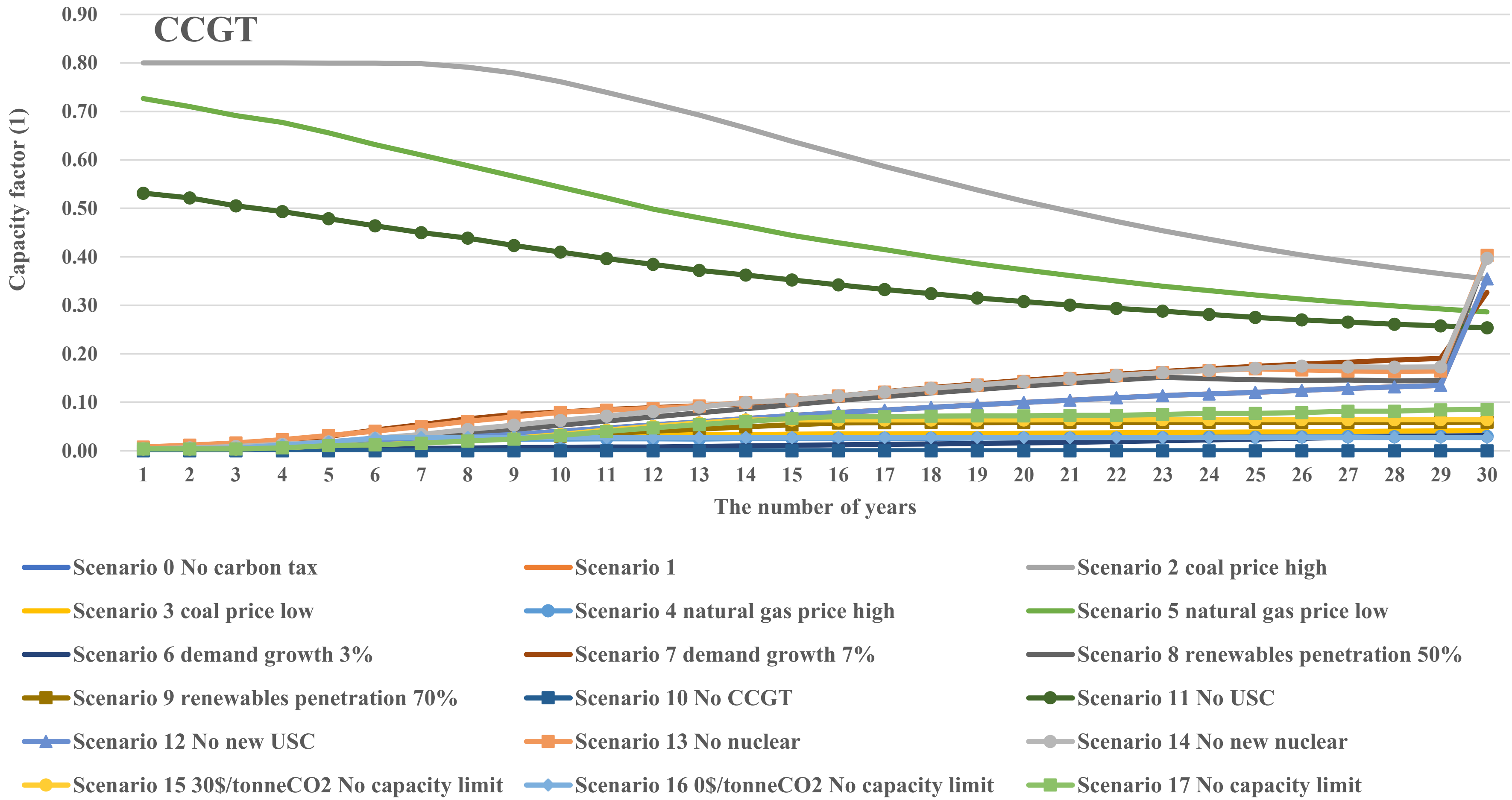


Figure 5-20 CCGT capacity factor for all scenarios.

USC-CCUS: The capacity factor for USC-CCUS technology generally starts at a relatively high level of around 0.8 and gradually declines to approximately 0.6 by the end of the planning horizon in most scenarios. This steady decrease reflects the growing share of renewable energy in the technology mix for electricity supply, which reduces the system's dependence on fossil fuel-based generation, including coal with carbon capture. The continued presence of this technology in power generation structures reflects its strategic role in providing dispatchable baseload generation capacity while contributing to decarbonization goals. This characteristic is particularly important in systems where other low-carbon alternatives are limited, constrained, or economically uncompetitive.

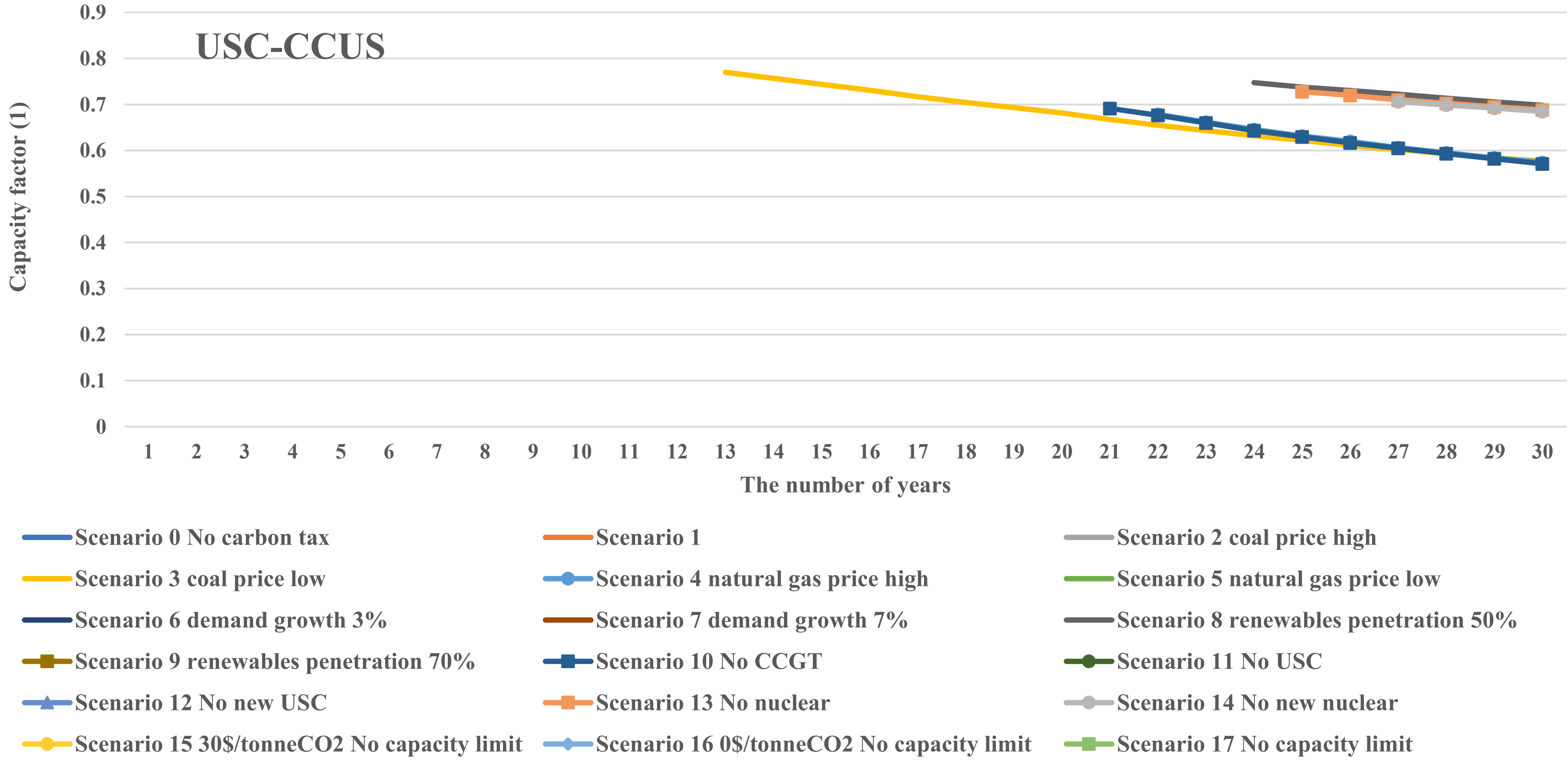


Figure 5-21 USC-CCUS capacity factor for all scenarios.

5.5.4 Discussion

An analysis of annual electricity generation, installed capacity, and capacity factor reveals significant differences across the scenarios. In particular, USC and CCGT are highly sensitive to variations in fuel prices, demand growth, and renewable energy penetration levels, leading to large fluctuations in electricity generation over time.

The research results also show that, in several scenarios, both annual power generation and capacity factors experienced significant fluctuations, including Scenario 1 (baseline), Scenario 7 (7% demand growth), Scenario 8 (50% renewable energy penetration), Scenario 12 (no new USC), and Scenario 13 (no nuclear power). As outlined in Chapter 4, these significant fluctuations are primarily caused by sudden increases or decreases in electricity generation, while installed capacity remains relatively stable. This phenomenon is largely attributed to a shift in the technology mix for electricity supply, where CCGT replaces USC as the primary electricity source. This shift has been driven by rising carbon prices, which have made USC less cost-competitive compared to CCGT. As a result, USC's capacity factor declined, while CCGT's capacity factor gradually increased to meet demand requirements.

5.6 Summary

This chapter presents a scenario analysis for 18 scenarios to evaluate the uncertainties associated with Scenario 1. First, it provides a detailed description of the 18 scenarios. The results across different scenarios about generation expansion plans are also presented. Finally, it analyzes and discusses the generation expansion results to identify key trends and influencing factors. The findings indicate that total system cost and emissions are highly sensitive to fuel prices, demand growth, and renewable energy penetration. Fuel prices play a crucial role in determining both total system costs and emissions due to their complex impact on the expansion of generation system.

Additionally, carbon pricing, nuclear power, and not using USC technology are significant factors affecting both total system cost and emissions. Moreover, the results highlight that economic conditions and carbon reduction pressures are key determinants in the deployment of USC and USC-CCUS power generation.

The annual capacity factor analysis reveals significant differences in the electricity generation of thermal power plants across different scenarios. These differences highlight the high dependence of power plant generation on power system conditions, including fuel prices, demand growth, and renewable energy penetration rates. However, traditional investment assessment methods often overlook these dynamic external factors, leading to unreliable assessment results. To address this issue, the next chapter will apply the proposed Levelized Cost of Electricity (LCOE) approach to estimate the LCOE of power plants under all scenarios, thereby assessing the impact of different scenarios on power plant investments.

Chapter 6 Further Analysis: the LCOE of Power Plants

6.1 Introduction

The results in Chapter 5 highlight that capacity factors fluctuates over time due to the expansion of the power generation system. Consequently, these varying capacity factors need to be considered when assessing the investment of power plants. However, the traditional Levelized Cost of Electricity (LCOE) method uses a fixed capacity factor, typically derived from historical data, to evaluate investments. This traditional method is increasingly inaccurate when applied to investments in expanding power systems incorporating renewable sources and carbon prices.

To address this issue, this chapter introduces a proposed LCOE approach, which uses data from power generation expansion plans to more reliably and accurately evaluate power plant investments. This proposed LCOE approach incorporates annual carbon prices and annual capacity factors derived from the generation expansion plan, which allows it to reflect changing conditions of the power system. Compared to the traditional LCOE approach commonly used in reports from institutions such as the IEA, which relies on fixed capacity factors and fixed carbon prices, the approach adopted in this study accounts for temporal variations in these parameters, thereby significantly enhancing the accuracy of investment assessments.

This chapter focuses on thermal power generation technologies, specifically Nuclear, USC (ultra-supercritical coal), CCGT (combined cycle gas turbine), and USC-CCUS (ultra-supercritical coal with carbon capture, utilization, and storage). This is because thermal power plants continue to play a crucial role in the transition to low-carbon power systems. However, there remains a significant gap in the literature regarding the investment evaluation of these technologies under system expansion. Moreover, investment decisions in thermal technologies are particularly sensitive to changes in capacity factors and carbon prices, both of which are influenced by the expansion of the generation system. In contrast, renewable energy sources are not directly affected by carbon pricing or capacity factor fluctuations, as they do not produce carbon emissions, and their capacity factors are primarily driven by weather conditions rather than system expansion.

Section 6.2 provides an overview of the input data used in the LCOE method, including technical and economic parameters.

Section 6.3 compares the traditional LCOE method with the proposed LCOE approach, highlighting methodological differences and demonstrating how capacity factors and carbon prices influence the LCOE of power generation technologies in Scenario 1.

Section 6.4 compares the LCOE of thermal power plants commissioned in different years under Scenario 1, analyzing how the timing of commissioned influences both the LCOE and the investment attractiveness of various power generation technologies.

Section 6.5 compares the LCOE of thermal power plants commissioned in different years under all 17 scenarios introduced in Chapter 4, including variations in fuel prices, demand growth rates, renewable penetration levels, technology availability, and carbon pricing mechanisms. This allows the analysis to evaluate the impact of different scenario conditions on LCOE outcomes, and analyzes the resulting changes in the investment attractiveness of various power generation technologies.

6.2 Input data for the LCOE method

The detailed technical and economic parameters used in the calculations are provided in Appendix A, covering the following technologies: Ultra-Supercritical (USC) coal power plant, Nuclear power plant, Combined Cycle Gas Turbine (CCGT), USC-CCUS (USC with Carbon Capture, Utilization and Storage), Onshore wind farm, and Solar Photovoltaic (PV).

The parameters include: net capacity, electrical conversion efficiency, construction duration, plant lifetime, discount rate, fuel price, annual construction cost, fixed and variable O&M costs, CO_2 emission factors, and fuel properties.

In addition, the annual carbon price and capacity factor—both of which have a significant impact on LCOE results—are derived from the proposed generation expansion modelling presented in Chapter 5. This integration ensures that the LCOE calculations accurately reflect the changing system conditions over time, thereby enhancing the realism of the investment assessment.

The planning horizon for power generation systems is 30 years, and these thermal power plants have a lifespan of more than 30 years. Therefore, any new thermal power plants added between 2020 and 2050 are likely to continue generating electricity after 2050. Therefore, it is assumed that the data for carbon price and capacity factor after 2050 are the same as those in 2050.

The LCOE of power plants commissioned in different years is calculated based on the carbon price and capacity factor of the corresponding year. Figure 6-1 shows the carbon prices used for power plants commissioned in different years and have a lifetime of 30 years.

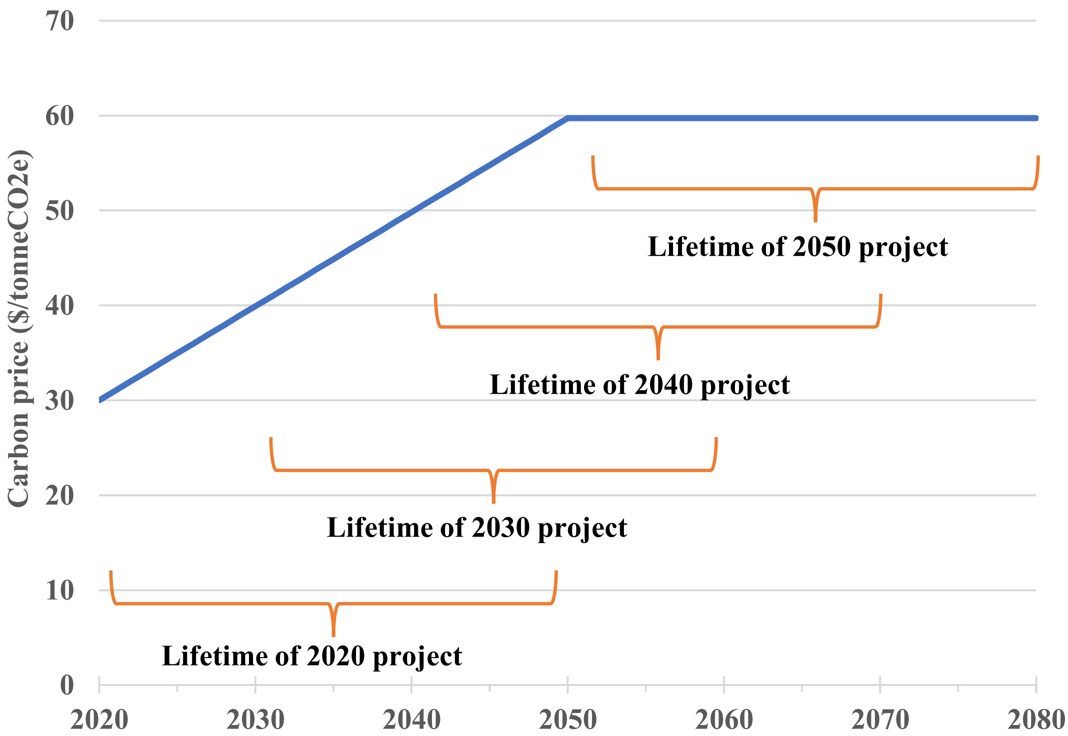


Figure 6-1 Carbon prices for power plants commissioned in different years.

6.3 Comparison of the traditional LCOE method with the proposed LCOE approach

This section compares the traditional LCOE method, as commonly used in IEA reports, with the proposed LCOE approach, highlighting how differences in capacity factors and carbon prices influence the resulting LCOE values of thermal power plants.

Table 6-1 shows the differences between the traditional LCOE assumptions and the proposed LCOE approach in terms of carbon price and capacity factor. Under the traditional assumptions—as adopted in the LCOE methodology used by the IEA—both the carbon price and the capacity factor of thermal power plants are assumed to be fixed.

Specifically, the carbon price is set at 30 \$/tonneCO2e, and the capacity factor for thermal technology is fixed at 85% [1]. The IEA applies these fixed values uniformly across all years when calculating the LCOE. In contrast, the proposed LCOE approach uses the annual carbon prices and annual capacity factors derived from the generation expansion plans, which can fluctuate yearly, reflecting the changing conditions of the power system in each year.

Figure 6-2 illustrates the changes in the capacity factors of thermal power plants and carbon prices under Scenario 1 and traditional assumption. The x-axis indicates the number of years, the left y-axis indicates the capacity factor, and the right y-axis indicates the carbon price. It is evident that capacity factors from generation expansion plan vary every year, with particularly notable fluctuations observed for USC and CCGT technologies. This variation reflects the impact of system developments—such as demand shifts, fuel prices, and carbon pricing on the capacity factor of thermal power plants over time.

Table 6-1 Differences in traditional assumptions and proposed LCOE approach assumptions.

Traditional assumptions	Proposed LCOE approach assumptions
■ Carbon price (CP): 30 \$/tonneCO2e over lifetime (Fixed) ■ Capacity factor (CF): 85% for thermal power plants (Fixed)	■ Carbon price (CP): Carbon price from generation expansion plan (Varying) ■ Capacity factor (CF): Capacity factor from generation expansion plan (Varying)

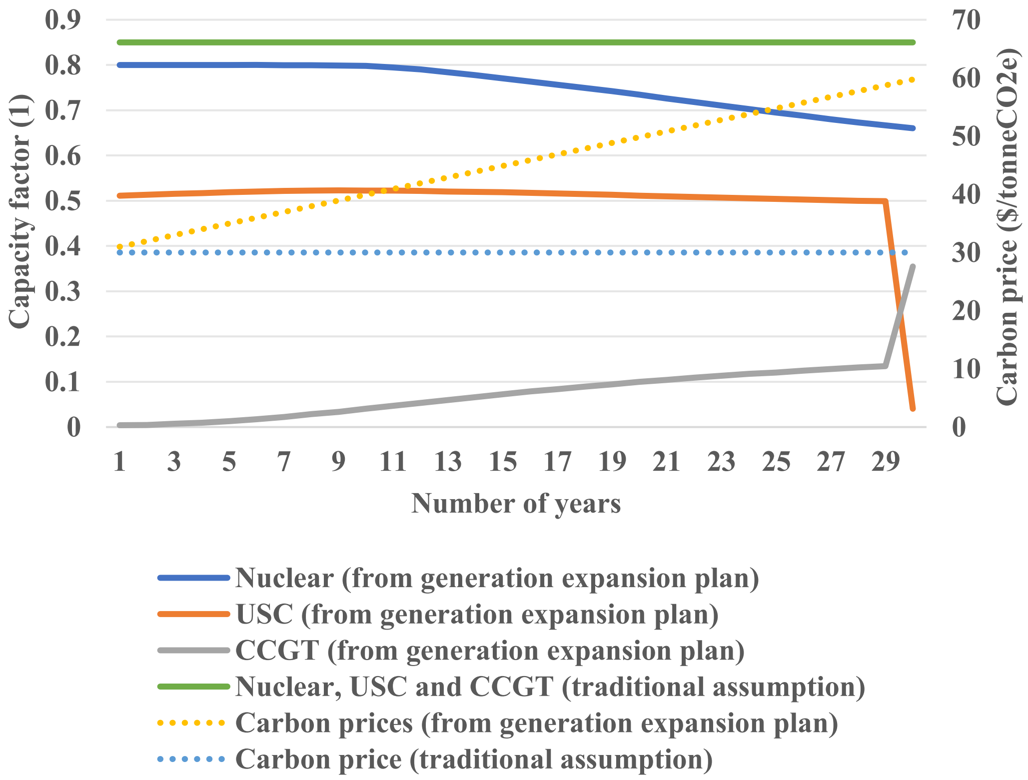


Figure 6-2 Capacity factors for thermal technologies and carbon prices in Scenario 1.

This section uses the thermal power plant commissioned in 2020 as an example. The carbon prices and capacity factors come from the generation expansion plan in Scenario 1. To illustrate the differences between the traditional LCOE method and the proposed LCOE approach, the results are presented in four items:

- **Traditional**: The LCOE result calculated using fixed capacity factors and carbon prices.
- **Add varying CF (Capacity factor)**: The incremental change in LCOE when varying capacity factors are applied, while keeping carbon prices fixed.

- **Add varying CF (Capacity factor) and varying CP (Carbon price)**: The incremental change in LCOE when both varying capacity factors and varying carbon prices are applied.
- **Proposed LCOE**: The LCOE result using varying capacity factors and carbon prices, derived from the generation expansion plan.

6.3.1 Nuclear

Figure 6-3 shows the differences in the LCOE of a nuclear power plant between the traditional LCOE method and the proposed LCOE approach. The x-axis represents assumptions used to calculate the LCOE. The y-axis represents the value of LCOE in $/MWh.

Under traditional method, the LCOE for a nuclear power plant is 75.4 $/MWh. When varying capacity factors from the generation expansion plan are applied, the LCOE increases by 5.1 $/MWh, reflecting the effect of fluctuating plant utilization over time. Since nuclear power plants do not produce carbon emissions, the LCOE remains unaffected by changes in carbon prices.

Finally, the proposed LCOE reaches 80.5 $/MWh, demonstrating the importance of incorporating varying capacity factors and carbon prices into investment assessments. This approach provides a more accurate estimation of generation costs, especially when compared to traditional methods based on fixed assumptions.

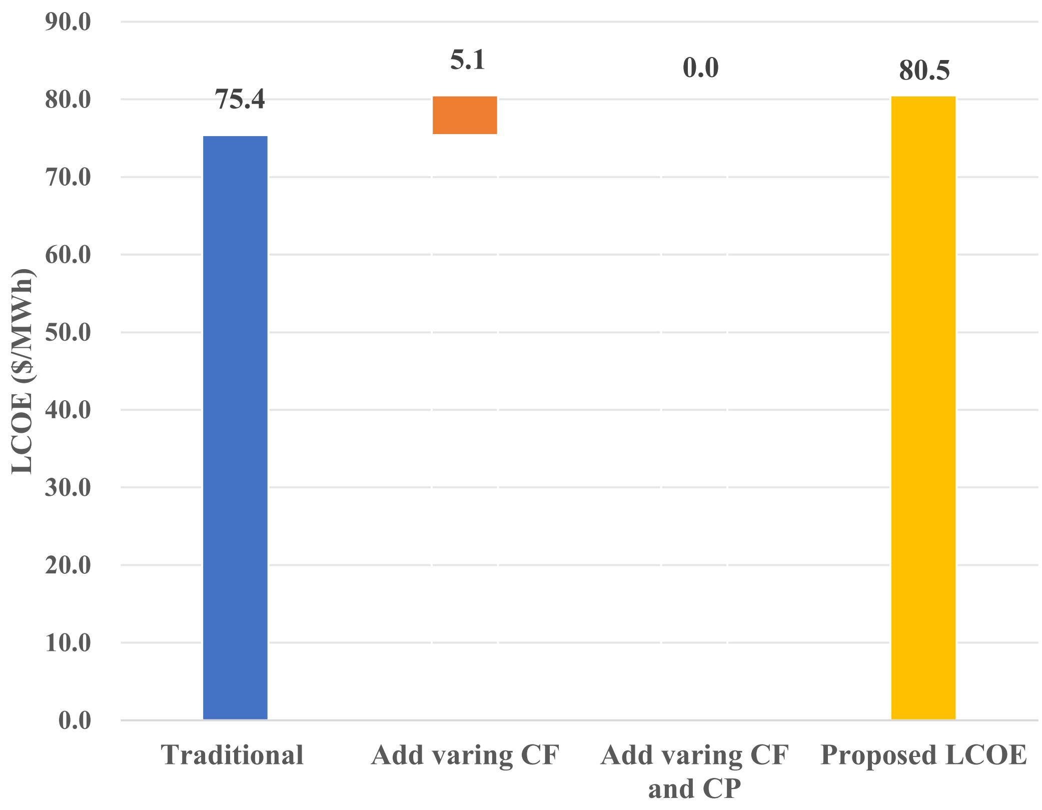


Figure 6-3 Difference between the LCOE values for nuclear power plants using the traditional LCOE and the proposed LCOE.

6.3.2 USC

Figure 6 4 shows the differences in the LCOE of a USC power plant between the traditional LCOE method and the proposed LCOE approach. The x-axis represents the assumptions used to calculate the LCOE, and the y-axis represents the value of LCOE in $/MWh.

Under traditional assumptions, the LCOE for USC is calculated at 74.8 $/MWh. When the fixed capacity factor is replaced with varying capacity factors derived from the generation expansion plan, the LCOE increases by 10.6 $/MWh, reflecting the impact of reduced and fluctuating capacity factor over time. Furthermore, when the fixed carbon price is replaced with annual carbon prices, the LCOE rises by an additional 8.0 \$/MWh. As a result, the proposed LCOE for USC reaches 93.3 \$/MWh, highlighting the impact of carbon pricing and capacity factors on LCOE.

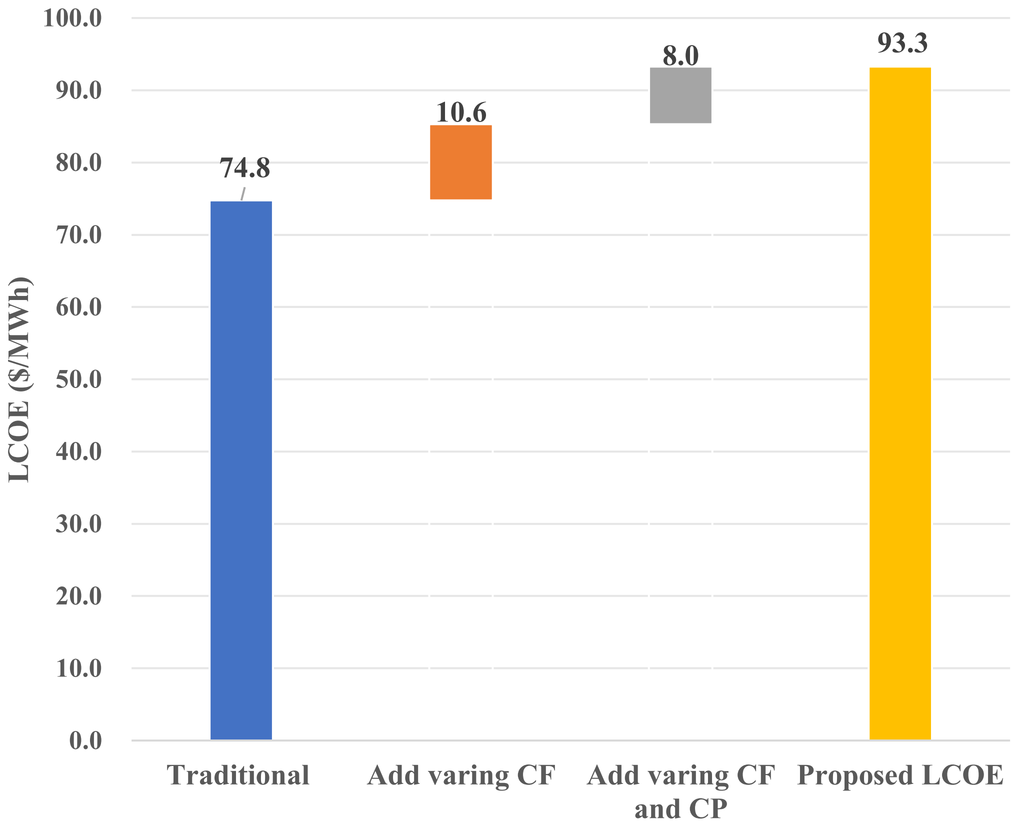


Figure 6-4 Difference between the LCOE values for USC power plants using the traditional LCOE and the proposed LCOE.

6.3.3 CCGT

Figure 6 5 shows the differences in the LCOE of a CCGT power plant between the traditional LCOE method and the proposed LCOE approach. The x-axis represents the assumptions used to calculate the LCOE, and the y-axis represents the value of LCOE in \$/MWh.

Under the traditional assumptions, the LCOE of CCGT is calculated at 91.3 \$/MWh. However, when the capacity factor derived from the power generation expansion plan is applied, the LCOE increases significantly by 165.6 USD/MWh. This is primarily because the IEA assumes that CCGT operates as a baseload technology, with a consistently high capacity factor. In Scenario 1, CCGT is primarily used as a load peaking technology, resulting in a much lower capacity factor. This significant difference in operational role leads to a sharp decline in capacity factor, which in turn causes a significant rise in the levelized cost.

When varying carbon prices are considered, the LCOE increases by another 6.3 $/MWh. As a result, the proposed LCOE for CCGT reaches 263.2 $/MWh. This demonstrates that different assumptions about capacity factors can significantly underestimate the LCOE of gas-fired power generation, particularly when the technology is no longer utilized as a baseload resource.

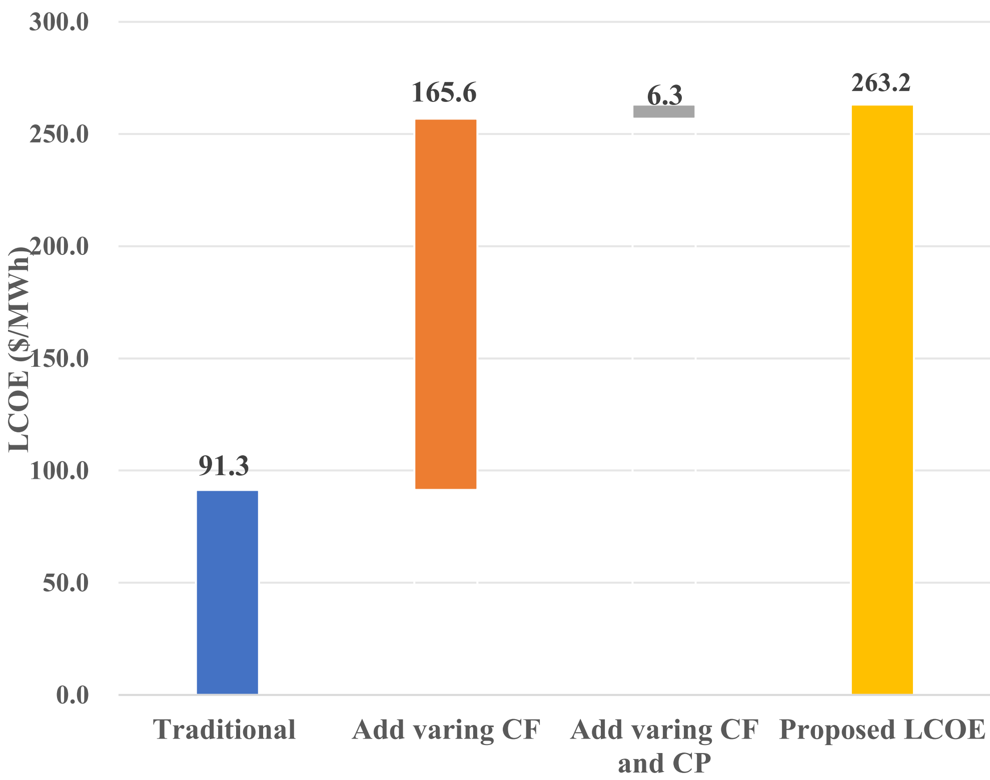


Figure 6-5 Difference between the LCOE values for CCGT power plants using the traditional LCOE and the proposed LCOE.

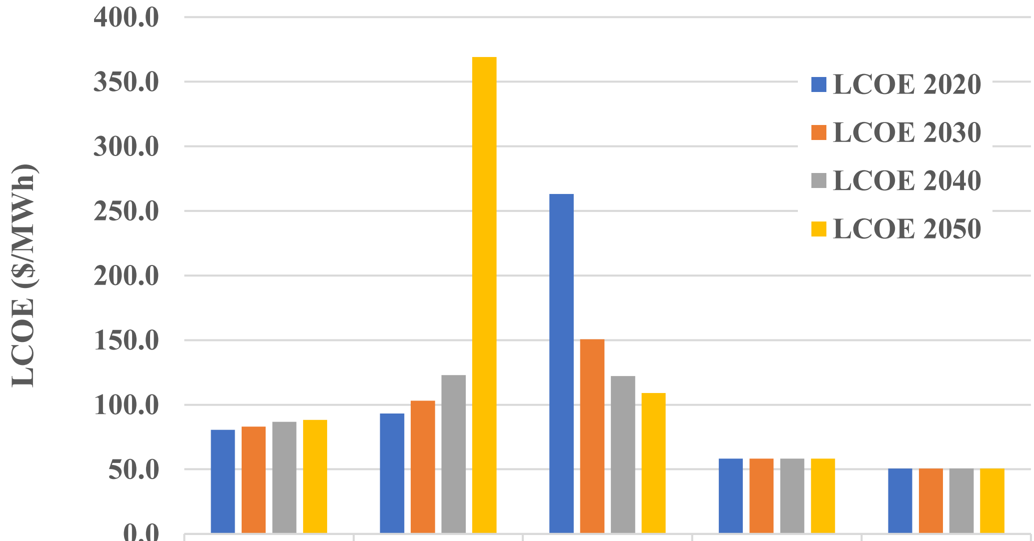
6.3.4 Discussion

The comparison between the LCOE calculated using the traditional LCOE method and the proposed LCOE approach reveals significant differences, with the LCOE based on the expansion plan data generally being higher than the LCOE calculated using traditional assumptions. Specifically, for a nuclear power plant, the LCOE calculated using the expansion plan data is approximately 5% higher compared to the traditional method. For a USC power plant, the LCOE increases by around 25%, and for a CCGT power plant, the LCOE is 188% higher when using the expansion plan data. These findings highlight the impact of varying capacity factors and carbon prices on the LCOE of power plants. The fundamental difference is that traditional LCOE methods overlook the impact of power generation system conditions on capacity factors and carbon prices. In contrast, the proposed LCOE method incorporates annual capacity factors and carbon prices obtained from system expansion modeling, providing a more accurate reflection of changes in the power generation system.

6.4 LCOE of power plants in different years in Scenario 1

This section compares the LCOE of power plants in different years in Scenario 1. It shows the impact of plant commissioned years on their investment assessment and attractiveness. The capacity factor and carbon price are derived from the expansion plan data in Scenario 1. Power generation technologies include nuclear, USC, CCGT, onshore wind and solar PV. This comparison highlights how the timing of plant commissioned can significantly affect the investment assessment of various power generation technologies.

shows the LCOE of power plants commissioned in 2020, 2030, 2040 and 2050. The X-axis indicates the generation technology, and the Y-axis indicates the LCOE in \$/MWh. Each bar corresponds to a specific commissioned year for a given technology.



	Nuclear	USC	CCGT	Onshore Wind	Solar PV
LCOE 2020	80.5	93.3	263.2	58.3	50.5
LCOE 2030	83.1	103.1	150.6	58.3	50.5
LCOE 2040	86.7	123.0	122.3	58.3	50.5
LCOE 2050	88.2	369.2	109.1	58.3	50.5

Figure 6-6 The LCOE (in \$/MWh) of power plants in different years in the generation expansion Scenario 1.

For nuclear power, the LCOE gradually increases over time, with the bar for 2020 standing at 80.5 \$/MWh, and reaching 88.2 \$/MWh by 2050. This shows a steady rise in cost for later commissioned nuclear plants. The primary reason for this is that the capacity factor of nuclear power declines over time, influenced by structural changes in the power generation system, such as the growing share of electricity generated from renewable energy sources, which reduces the operational hours and power generation of nuclear plants.

For USC power plants, the LCOE starts at 93.3 \$/MWh in 2020 and increases significantly as the years progress, with the 2050 LCOE reaching a value of 369.2 \$/MWh. This increase indicates that when the commissioned of the USC power plant is delayed, the LCOE rises significantly. The increase is primarily driven by two factors: a steady rise in the carbon price and a decline in the capacity factor due to structural changes in the power generation system. By 2050 in Scenario 1, the capacity factor of USC plants declines significantly, reflecting their diminishing role in the technology mix for electricity supply due to rising operational costs. This reduction in capacity factor is largely attributed to CCGT technologies replacing USC as the primary thermal generation option.

For CCGT power plants, the LCOE is relatively high at 263.2 \$/MWh in 2020, but it decreases sharply over time, with 2050 showing a much lower LCOE of 109.1 \$/MWh. This shows a downward trend in cost for CCGT plants commissioned in later years. The primary driver of this decline is the increasing competitiveness of CCGT under higher carbon price conditions, which leads to higher capacity factors. Although rising carbon prices tend to increase the LCOE, this effect is more than offset by the improvements in capacity factor. By 2050, CCGT will replace USC as the primary thermal power generation technology. This technological shift will lead to a significant increase in the capacity factor of CCGT units, thereby driving down the LCOE.

For onshore wind and solar PV, the capacity factors in Scenario 1 are 0.26 and 0.18, respectively. These values remain constant over time, as they are primarily determined by weather conditions rather than system change. As a result, the LCOE for wind and solar also remains constant across all commissioned years at 58.3 USD/MWh for wind and 50.5 USD/MWh for solar PV. This stability reflects the fact that renewable energy sources such as wind and solar are not affected by carbon pricing or shifts in the structure of the electricity system, making their long-term costs predictable and less sensitive to policy or operational variability compared to thermal power technologies.

6.4.1 Discussion

The results indicate that the year of plant commissioned has a significant impact on the LCOE of both USC and CCGT power plants. Specifically, the LCOE of a USC plant in 2050 is approximately four times higher than that of a USC plant commissioned in 2020. And the LCOE of a CCGT plant in 2050 is about two-fifths of its 2020 value.

This variation highlights that the timing of plant commissioned not only affects the LCOE itself but also changes the relative investment attractiveness of different power generation technologies. In 2020, the LCOE of USC is 93.3 $/MWh, significantly lower than CCGT's 263.2 $/MWh, making USC more attractive for investment at that point in time. However, this advantage diminishes rapidly over time. By 2040, the LCOE of USC rises to 123.0 $/MWh, just 0.7 $/MWh lower than CCGT. By 2050, the trend reverses entirely: USC’s LCOE reaches 369.2 $/MWh, which is more than three times the CCGT’s LCOE of 109.1 $/MWh. This reversal in cost competitiveness highlights the growing economic advantage of CCGT over time, particularly as increasing carbon prices and declining capacity factors make USC increasingly expensive.

Thus, analyzing LCOE across different commissioned years provides critical insight into the investment landscape for power generation technologies, highlighting how carbon prices and system changes reshape their cost competitiveness and long-term economic viability over time.

6.5 LCOE of power plants in different years in all scenarios

This section presents the LCOE of power plants across different commissioned years under all 18 scenarios, aiming to evaluate the impact of varying scenario conditions on the cost of electricity generation. The scenarios, each described in Chapter 5, reflect a wide range of assumptions related to fuel prices, demand growth, carbon pricing, and technology availability.

The analysis focuses on four major thermal power generation technologies: Nuclear, USC, CCGT, and USC-CCUS. The LCOE results are presented separately for each technology, allowing for a comparative analysis of how different scenario parameters influence the investment attractiveness of each power generation type over time.

6.5.1 Nuclear

Table 6 2 and Figure 6 7 display the LCOE of nuclear power plants commissioned in 2020, 2030, 2040, and 2050 across all scenarios. The x-axis in Figure 6 7 represents the different scenarios in the power generation system, and the y-axis indicates the LCOE value in $/MWh.

The LCOE for nuclear power plants generally increases with later commissioned years across most scenarios. The highest LCOE is observed in Scenario 9 (70% renewable energy penetration), where it reaches 101.3 USD/MWh for nuclear plants commissioned in 2050. This reflects the decline in nuclear capacity factor in power systems with high renewable energy shares. In contrast, the lowest LOCE is observed in Scenario 16 (0 USD/tCO2, no capacity constraints), where the penetration of renewable energy is lower and nuclear power plays a more prominent role as a cost-effective energy source. Because of the stable and high capacity factor of nuclear power in this scenario, the LCOE remains constant at 78.2 USD/MWh across all commissioned years.

Scenario 6 (demand growth 3%) and Scenario 7 (demand growth 7%) show slightly differences in LCOE values compared to Scenario 1. In Scenario 6, the LCOE values are slightly higher than those in Scenario 1, reaching 89.9 $/MWh in 2050 compared to 88.2 $/MWh in Scenario 1. In Scenario 7, the LCOE values remain relatively close to Scenario 1, reaching 87.9 $/MWh in 2050, which is slightly lower than in Scenario 6. These differences are mainly driven by the impact of demand fluctuations on the nuclear capacity factor. In Scenario 7, increased demand leads to higher capacity factor at nuclear power plants, resulting in a slight decrease in LCOE. In Scenario 6, reduced demand leads to lower capacity factor, causing a slight increase in LCOE.

In Scenario 14 (no new nuclear power plants), the LCOE is slightly lower than in Scenario 1, with values of 79.8 USD/MWh in 2020 and 85.1 USD/MWh in 2050. This is mainly attributable to the increased capacity factor of existing nuclear power plants, which has offset the shortfall in low-carbon power generation.

Scenario 17 (no capacity constraints, with carbon pricing mechanism) shows a higher LCOE, reaching 94.2 USD/MWh in 2050, while Scenario 15 (30 USD/tCO2 with no capacity constraints) maintains a consistently elevated LCOE, reaching approximately 90.5 USD/MWh in 2050. In both scenarios, renewable energy penetration is higher than in Scenario 1, leading to reduced capacity factor of nuclear power.

Table 6-2 The LCOE of nuclear power plant in all scenarios.

	LCOE 2020 ($/MWh)	LCOE 2030 ($/MWh)	LCOE 2040 ($/MWh)	LCOE 2050 ($/MWh)
Scenario 0 No carbon tax	80.5	83.1	86.7	88.2
Scenario 1 benchmark scenario	80.5	83.1	86.7	88.2
Scenario 2 coal price high	80.5	83.1	86.7	88.2
Scenario 3 coal price low	80.5	83.1	86.7	88.2
Scenario 4 natural gas price high	80.5	83.1	86.7	88.2
Scenario 5 natural gas price low	80.5	83.1	86.7	88.2
Scenario 6 demand growth 3%	80.5	83.2	87.6	89.9
Scenario 7 demand growth 7%	80.8	83.7	86.8	87.9
Scenario 8 renewable energy penetration 50%	78.9	79.6	80.9	81.4
Scenario 9 renewable energy penetration 70%	83.7	90.5	98.4	101.3
Scenario 10 No CCGT	80.5	83.1	86.7	88.2
Scenario 11 No USC	80.5	83.1	86.7	88.2
Scenario 12 No new USC	80.5	83.1	86.7	88.2
Scenario 13 No nuclear	0.0	0.0	0.0	0.0
Scenario 14 No new nuclear	79.8	81.6	84.0	85.1
Scenario 15 30$/tonneCO2 No capacity limit	89.4	90.4	90.5	90.5
Scenario 16 0$/tonneCO2 No capacity limit	78.2	78.2	78.2	78.2
Scenario 17 No capacity limit	90.9	93.0	93.9	94.2

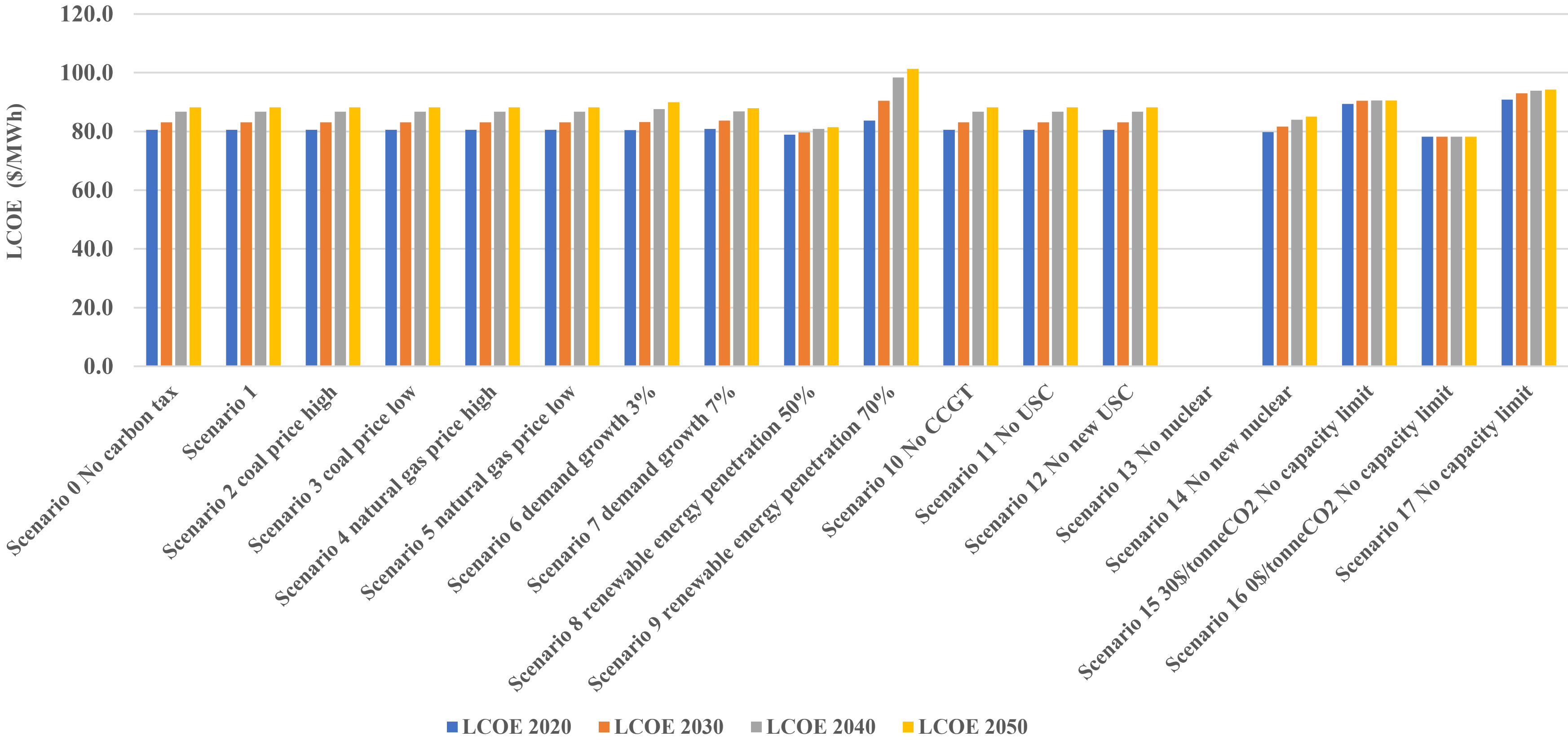


Figure 6-7 The LCOE of nuclear power plant in all scenarios.

6.5.2 USC

Table 6-3and Figure 6-8 show the LCOE of USC power plants commissioned in 2020, 2030, 2040, and 2050 across all scenarios. The x-axis in Figure 6-8 represents the different scenarios in the power generation system, and the y-axis indicates the LCOE value in $/MWh.

In most scenarios, the later a USC power plant is commissioned, the higher its LCOE becomes. In Scenarios 0 (No carbon tax), 3 (Low coal price), 4 (High natural gas price), 6 (3% demand growth), 8 (50% renewable energy penetration), 9 (70% renewable energy penetration), and 10 (No CCGT), the LCOE of USC power plants rises steadily over time, indicating relatively stable cost growth associated with delayed commissioned.

In contrast, Scenarios 2 (High coal price) and 5 (Low natural gas price) show a sharper increase in LCOE of USC, with Scenario 5 reaching a peak of 973.9 USD/MWh for plants commissioned in 2050. These cases reflect the combined impact of rising carbon prices and declining capacity factors at USC power plants.

In Scenarios 1 (baseline), 7 (7% demand growth), 8 (50% renewable energy penetration), 12 (no new USC), 13 (no nuclear power), and 14 (no new nuclear power), the LCOE of USC power plants commissioned in 2050 is significantly higher than in 2040. This increase is primarily driven by a notable decline in capacity factor, prompted by the implementation of carbon pricing mechanisms. As carbon costs rise, CCGT technologies replace USC as the primary thermal generation option.

Scenarios 15 (30 $/tonne CO_2, no capacity limit), 16 (0 $/tonne CO_2, no capacity limit), and 17 (no capacity limit) exhibit a relatively stable LCOE trajectory across different commissioned years, indicating that the absence of capacity constraints helps maintain stable capacity factors, resulting in a more stable LCOE over time.

Table 6-3 The LCOE of USC power plant in all scenarios.

	LCOE 2020 ($/MWh)	LCOE 2030 ($/MWh)	LCOE 2040 ($/MWh)	LCOE 2050 ($/MWh)
Scenario 0 No carbon tax	63.5	67.6	71.7	73.1
Scenario 1 benchmark scenario	93.3	103.1	123.0	369.2
Scenario 2 coal price high	115.4	170.4	293.0	363.2
Scenario 3 coal price low	78.8	88.9	98.6	101.7
Scenario 4 natural gas price high	96.1	109.3	122.3	128.0
Scenario 5 natural gas price low	279.1	539.8	852.8	973.9
Scenario 6 demand growth 3%	89.0	94.4	99.5	101.3
Scenario 7 demand growth 7%	91.7	101.0	119.6	614.1
Scenario 8 renewable energy penetration 50%	91.3	99.2	116.7	336.0
Scenario 9 renewable energy penetration 70%	87.8	91.9	96.2	97.7
Scenario 10 No CCGT	98.9	116.6	134.4	142.8
Scenario 11 No USC	0.0	0.0	0.0	0.0
Scenario 12 No new USC	93.4	103.4	123.5	371.0
Scenario 13 No nuclear	90.1	97.8	116.4	338.2
Scenario 14 No new nuclear	91.3	99.3	116.7	361.2
Scenario 15 30$/tonneCO2 No capacity limit	95.7	91.3	90.8	90.7
Scenario 16 0$/tonneCO2 No capacity limit	58.7	59.1	61.4	68.1
Scenario 17 No capacity limit	98.7	95.6	96.0	96.3

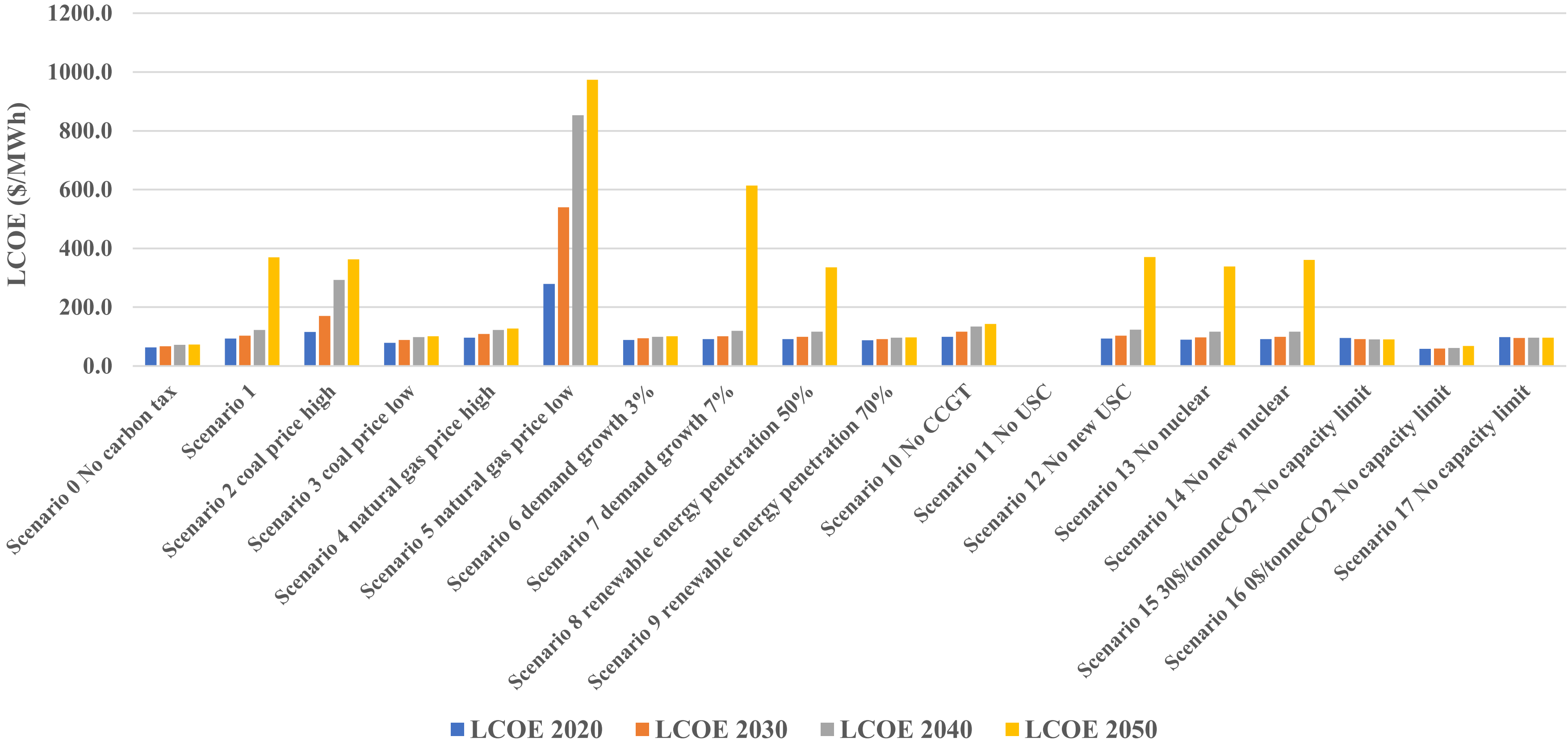


Figure 6-8 The LCOE of USC power plant in all scenarios.

6.5.2 CCGT

Table 6-4 and Figure 6-9In most cases, the LCOE of CCGT power plants declines over time, reflecting that the improvement in capacity factor is sufficient to offset the cost impact of rising carbon prices. As capacity factor improves, the fixed costs are distributed over a greater volume of electricity generated, leading to a lower LCOE despite carbon-related cost pressures.

This trend is evident in Scenarios 1 (baseline), 3 (low coal price), 4 (high gas price), 7 (7% demand growth), 8 (50% renewable energy penetration), 9 (70% renewable energy penetration), 12 (no new USC), 13 (no nuclear), and 14 (no new nuclear), where the LCOE of CCGT plants shows a consistent downward trajectory. These results highlight the increasing cost competitiveness of gas-fired power generation over the planning period.

Scenario 6 (3% demand growth), however, starts with an exceptionally high LCOE of 1069.4 USD/MWh in 2020, followed by a gradual decline. This reflects the initially low utilization of CCGT units due to limited demand, which improves over time as the system evolves and reliance on gas-fired generation increases.

Scenario 2 (high coal price), Scenario 5 (low natural gas price), and Scenario 11 (no USC) show a relatively low and stable LCOE for CCGT across different commissioned years. This stability is primarily due to favorable fuel prices or the absence of competing coal-based technology, which maintains high capacity factors for CCGT.

Similarly, Scenarios 15 (30 \$/tonne CO_2, no capacity limit), 16 (0 \$/tonne CO_2, no capacity limit), and 17 (no capacity limit) exhibit relatively stable LCOE values for CCGT across the 2030, 2040, and 2050 commissioned years. The absence of capacity constraints in these scenarios allows for optimal deployment of CCGT, leading to consistent capacity factors over time.

Table 6-4 The LCOE of CCGT power plant in all scenarios.

	LCOE 2020 ($/MWh)	LCOE 2030 ($/MWh)	LCOE 2040 ($/MWh)	LCOE 2050 ($/MWh)
Scenario 0 No carbon tax	485.4	364.3	363.3	363.0
Scenario 1 benchmark scenario	263.2	150.6	122.3	109.1
Scenario 2 coal price high	86.2	90.1	96.2	98.8
Scenario 3 coal price low	455.9	327.0	306.7	298.4
Scenario 4 natural gas price high	583.4	448.5	426.0	416.5
Scenario 5 natural gas price low	63.1	69.7	75.9	78.1
Scenario 6 demand growth 3%	1069.4	584.2	407.3	362.2
Scenario 7 demand growth 7%	196.6	137.4	120.0	111.4
Scenario 8 renewable energy penetration 50%	225.2	138.3	116.9	106.1
Scenario 9 renewable energy penetration 70%	374.4	242.0	227.6	227.1
Scenario 10 No CCGT	0.0	0.0	0.0	0.0
Scenario 11 No USC	95.1	101.7	107.1	109.0
Scenario 12 No new USC	263.3	150.8	122.5	109.3
Scenario 13 No nuclear	197.2	137.0	115.8	106.1
Scenario 14 No new nuclear	209.1	134.8	115.9	106.4
Scenario 15 30$/tonneCO2 No capacity limit	348.1	222.0	214.8	214.8
Scenario 16 0$/tonneCO2 No capacity limit	494.0	394.6	394.6	394.6
Scenario 17 No capacity limit	331.8	206.3	187.3	182.0

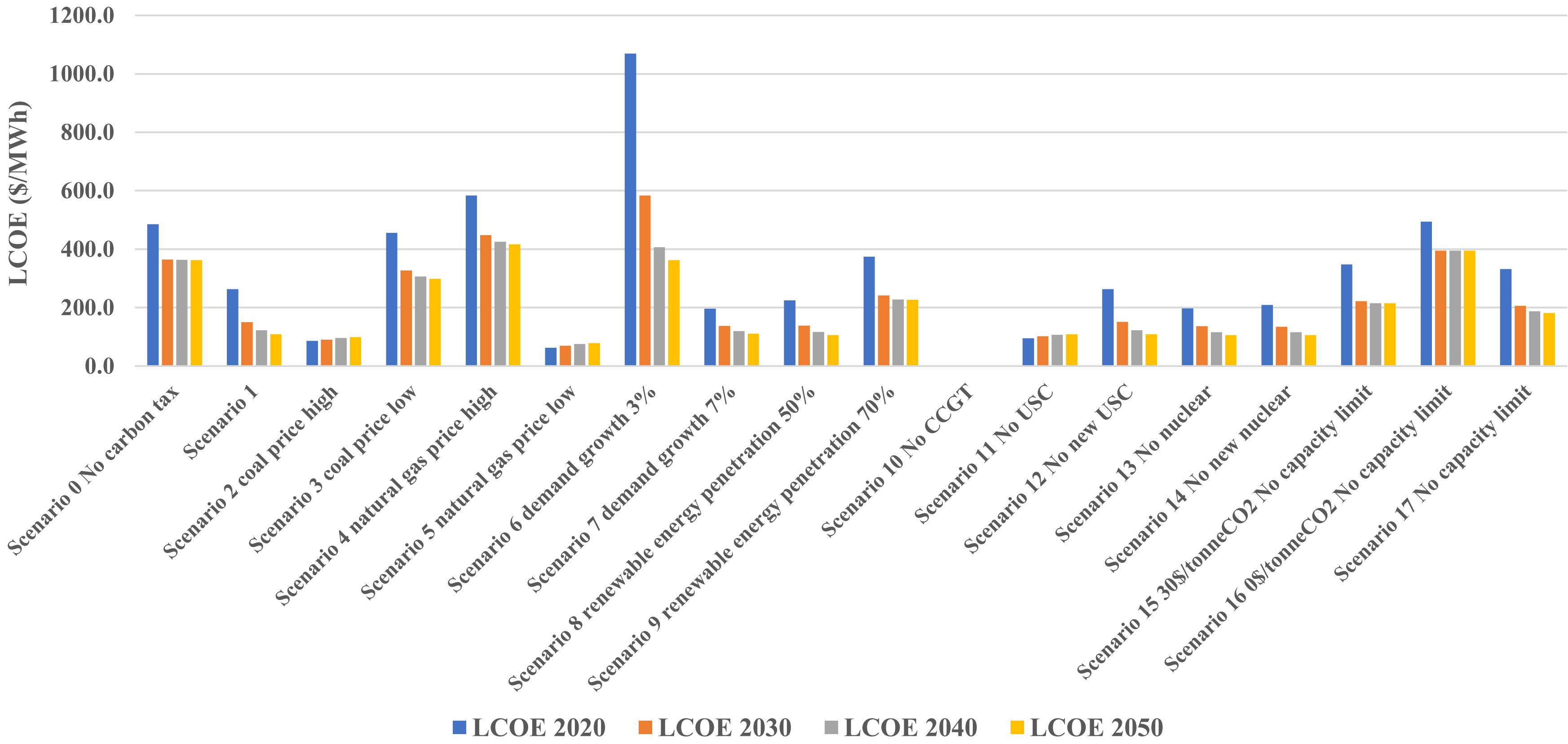


Figure 6-9 The LCOE of CCGT power plant in all scenarios.

6.5.3 USC-CCUS

Table 6 5 and Figure 6 10 show the LCOE of USC-CCUS power plants commissioned in 2020, 2030, 2040, and 2050 across all scenarios. The x-axis in Figure 6 10 represents the different scenarios in the power generation system, and the y-axis indicates the LCOE value in $/MWh.

In most scenarios, USC-CCUS is not selected for generation expansion, reflecting its high capital and operational costs. In the scenario where USC-CCUS is deployed, LCOE only appears in later commissioned years and its LCOE gradually increases over time. USC-CCUS, as an expensive low-carbon technology, show an upward trend in its LCOE, which is mainly attributed to the continuous increase in the proportion of cheap renewable energy in the power system. The increase in the proportion of renewable energy has led to a decrease in the power generation of USC-CCUS power plants, which in turn has caused the capacity factor to gradually decline over time, ultimately resulting in an increase in the LCOE. The scenarios in which USC-CCUS technology is applied include: Scenario 3 (low coal price), Scenario 4 (high natural gas price), Scenario 8 (50% renewable energy penetration), Scenario 10 (no CCGT), Scenario 13 (no nuclear), and Scenario 14 (no new nuclear).

In Scenario 3 (low coal price), the LCOE starts at 80.8 USD/MWh in 2030 and increases progressively to 88.1 USD/MWh by 2050. Scenario 4 (high natural gas price) with LCOE values beginning to appear in 2040 and rising to 89.6 USD/MWh by 2050. And Scenario 10 (no CCGT) with LCOE values beginning to appear in 2040 and rising to 111 USD/MWh by 2050. Scenario 8 (50% renewable energy penetration), Scenario 13 (no nuclear), and Scenario 14 (no new nuclear) report LCOE values exceeding 100 USD/MWh, highlighting the high cost of adopting CCUS technology for emissions reduction in systems lacking alternative low-carbon baseload power sources.

Table 6-5 The LCOE of USC-CCUS power plant in all scenarios.

	LCOE 2020	LCOE 2030	LCOE 2040	LCOE 2050
Scenario 0 No carbon tax	0.00	0.00	0.00	0.00
Scenario 1	0.00	0.00	0.00	0.00
Scenario 2 coal price high	0.00	0.0	0.0	0.0
Scenario 3 coal price low	0.00	80.8	85.7	88.1
Scenario 4 natural gas price high	0.00	0.0	87.0	89.6
Scenario 5 natural gas price low	0.00	0.0	0.0	0.0
Scenario 6 demand growth 3%	0.00	0.0	0.0	0.0
Scenario 7 demand growth 7%	0.00	0.0	0.0	0.0
Scenario 8 renewable energy penetration 50%	0.00	0.0	99.9	100.9
Scenario 9 renewable energy penetration 70%	0.00	0.0	0.0	0.0
Scenario 10 No CCGT	0.00	0.0	107.7	111.0
Scenario 11 No USC	0.00	0.0	0.0	0.0
Scenario 12 No new USC	0.00	0.0	0.0	0.0
Scenario 13 No nuclear	0.00	0.0	100.7	101.5
Scenario 14 No new nuclear	0.00	0.0	101.5	101.7
Scenario 15 30$/tonneCO2 No capacity limit	0	0	0	0
Scenario 16 0$/tonneCO2 No capacity limit	0	0	0	0
Scenario 17 No capacity limit	0	0	0	0

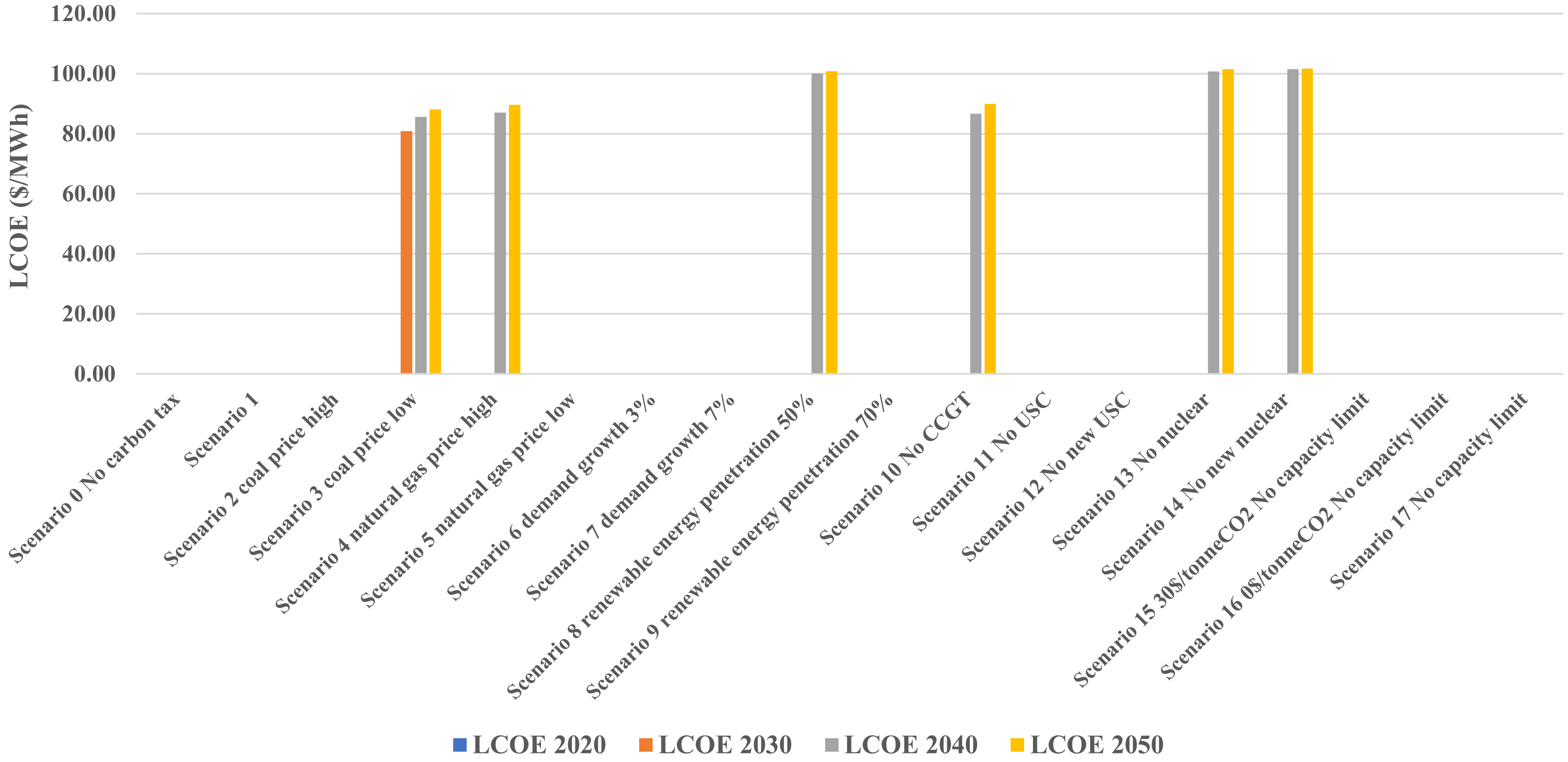


Figure 6-10 The LCOE of USC-CCUS power plant in all scenarios.

6.5.4 Discussion

The analysis of LCOE results for nuclear, USC, CCGT, and USC-CCUS across different scenarios reveals that LCOE is affected by the commissioned year, fuel prices, carbon prices, and technology constraints. The research results reveal the economic attractiveness of each technology under varying conditions.

- **Nuclear power: Gradual Cost Increase with Time**

Nuclear power exhibits a steady slight increase in LCOE over time across most scenarios. The LCOE of nuclear remains within a stable range of 80–90 \$/MWh, demonstrating relatively low sensitivity to external market fluctuations. However, nuclear power is highly sensitive to renewable energy penetration.

In Scenario 9 (renewable energy penetration 70%), nuclear LCOE reaches its highest level at 101.3 \$/MWh, suggesting that higher renewable energy shares reduce nuclear power generation, lowering its capacity factor and increasing its LCOE.

Conversely, Scenario 16 (0\$/tonne CO_2 No Capacity Limit) exhibits the lowest nuclear LCOE at 78.2 \$/MWh, indicating that in the absence of carbon pricing and with flexible capacity expansion, nuclear remains cost-effective.

- **USC Power: Significant LCOE Increase in Later Years**

Unlike nuclear power, USC power demonstrates a significant increase in LCOE for later commissioned years, particularly in scenarios where capacity factors decline sharply in the final years.

The LCOE for USC is highly sensitive to high coal prices (Scenario 2) and low natural gas prices (Scenario 5). In Scenario 5 (low natural gas price), the LCOE of USC in 2050 reaches 973.9 $/MWh, making investment in a USC plant almost economically infeasible.

In contrast, Scenarios 0, 3, 4, 6, 9, 15, 16 and 17 show a more gradual increase in the LCOE of USC, remaining under 130 $/MWh for most commissioned years.

These findings suggest that USC technology are highly sensitive to market change and fuel cost fluctuations. In addition, the sharp increase in LCOE in later years indicates that as cleaner alternatives become more dominant, the attractiveness of USC becomes less overtime.

- **CCGT Power: Declining LCOE Over Time**

CCGT power plants exhibit an opposite trend compared to USC, with the LCOE declining over time in most scenarios. This trend is largely driven by changes in carbon pricing, fuel prices, and generator capacity constraints over time.

The LCOE of CCGT is highly sensitive to carbon prices, coal prices, natural gas prices, low demand growth, high renewable energy penetration, and capacity constraints. Scenario 5 (low natural gas price) results in the lowest LCOE of CCGT, staying below 80 $/MWh across all years, indicating that favourable natural gas prices make CCGT an attractive investment option.

This suggests that CCGT remains a cost-competitive technology, particularly in systems with high carbon tax or declining natural gas prices.

- **USC-CCUS: Limited Deployment and Gradual Cost Increase**

In scenarios where USC-CCUS is used, the LCOE of USC-CCUS is between 80 and 100 $/MWh. Compared to other technologies, the LCOE of USC-CCUS remains relatively stable across different commissioned years and scenario assumptions.

Scenarios with no capacity limits (Scenario 15, 16 and 17), USC-CCUS is not deployed, which indicates that USC-CCUS is still not economically viable when other low-carbon options are available. This suggests that alternative generation technologies (e.g., Nuclear, Renewables, or CCGT) are often more cost competitive.

These findings suggest that CCUS technologies remain a costly option compared to other low-carbon alternatives. Their economic viability is highly dependent on strong economic conditions or scenarios where nuclear and renewable energy deployment is restricted.

6.6 Summary

This chapter presents a comprehensive analysis of the LCOE for various power generation technologies under different commissioned years and scenarios. First, this chapter compares the traditional LCOE method and the proposed LCOE approach. This indicates that the proposed LCOE method accounts for the changing conditions of the power generation system, thereby enhancing the accuracy and reliability of investment assessment. Secondly, this chapter compares the LCOE of power plant commissioned in different years in Scenario 1. It indicates that the commissioned year is important in the investment assessment of power plants, because it changes the LCOE and investment attractive of power plants. Finally, this chapter compares the LCOE of power plant commissioned in different years under all scenarios to evaluate the impact of different scenarios on the LCOE value. It demonstrates the sensitivity and development trends of LCOE for different power generation technologies under various conditions, including fuel prices, demand growth, renewable energy penetration rates, and capacity constraints.

Overall, this chapter highlights the importance of considering changing system conditions in evaluating the investment of power generation technologies. The proposed LCOE approach, by incorporating these varying factors, offers a more reliable investment assessment, which is critical for decision-making in the expansion of future power generation systems.

Chapter 7 Conclusion and Future Work

7.1 Conclusion

This thesis developed a Generation Expansion Planning (GEP) model that incorporates a carbon pricing mechanism into the traditional GEP model. The model is designed to simulate the long-term expansion of the power generation system under decarbonization targets, using carbon pricing as an economic incentive to reduce emissions.

Importantly in this study decarbonization does not necessarily imply that the carbon intensity of power generation must be reduced to zero. Achieving zero or near-zero emissions would require either the complete elimination of fossil fuel-based generation or the widespread deployment of carbon capture, utilization, and storage (CCUS) technologies. While this may be desirable and technically feasible, direct pursuing absolute zero emissions can pose several significant challenges for the power system. These challenges include significant increases in system costs due to a speedy excessive investment in low-carbon infrastructure (particularly renewable energy and energy storage technologies). One of the consequences is the likely increase of per unit cost of electricity supplied to consumers which may have socio-economic consequence. In addition, too rapid a reliance on variable renewable energy sources (lacking sufficient flexible backup capacity) may reduce system reliability. During periods of insufficient solar or wind supply, the lack of dispatchable generation capacity may make it difficult to maintain supply-demand balance, thereby posing a risk to overall grid stability. One possible example is the recent blackout in the Spanish peninsula on 28 April 2025 which lasted for about 10 hours [182]. The cause is due to a sudden loss of power but the source of the cause is still under investigation. Spain has a large proportion of renewable generation about 50% and a sudden loss of power from this source cannot be totally ruled out

This study aims to decarbonize the power system to achieve a carbon intensity of less than 157 kg CO_2/MWh by 2050, in line with national climate targets. Compared to full decarbonization, this target is more realistic and cost-effective. According to publicly available sources, this value reflects the official 2050 carbon intensity target set by a region in an East Asian country, representing a 70% reduction from the 2021 level of 556 kg CO_2e/MWh [13, 14]. This value provides a quantifiable reference point for the research.

Rather than imposing annual emission caps, this study adopts a more market-based approach to decarbonization by implementing a gradually increasing carbon price. This mechanism enables the power system to gradually reduce emissions while maintaining operational flexibility and economic viability.

By integrating the carbon pricing mechanism into the GEP model, the model explores how the power system responds to carbon price signals under different scenarios. The results highlight the importance of balancing emission reduction, investment viability, and system reliability. This approach provides valuable insights for policymakers and planners, helping them design practical and economically long-term decarbonization pathways.

In addition, this thesis also investigates a Levelized Cost of Electricity (LCOE) approach, which integrates the LCOE method with the GEP model to account for annual carbon prices and annual capacity factors of power plants. Unlike traditional LCOE calculations that use fixed values, the proposed approach reflects the actual conditions of a changing power system—such as increasing renewable energy, shifting technology mix for electricity supply, and rising carbon prices. By using annual data from the GEP model, the LCOE results can vary by year and scenario, helping to better understand when different power plants are most cost-effective. This proposed LCOE method offers more accurate insights into the long-term economic performance of thermal power plants under different power system conditions. It supports smarter investment decisions by showing how changing system conditions affect project viability.

The GEP model is designed to simulate long-term power system expansion under various scenarios, while the LCOE approach provides an economic evaluation of power plant investments by incorporating scenario-based carbon prices and capacity factors derived from the GEP model. All models developed in this study were implemented using well-established software tools, specifically the General Algebraic Modelling System (GAMS) for optimization modelling and Microsoft Excel for data handling, result processing and LCOE calculations. These tools ensured transparency, consistency and reliability of the modelling framework. The main contributions of this thesis are listed below reflecting those outlined in Chapter 1.

Contribution 1: A novel GEP model is developed to simulate the long-term expansion of large-scale power generation systems. The model features hourly resolution for dispatch decisions, enabling a detailed representation of renewable energy variability and storage operation, while capacity expansion decisions are made annually over the 30-year planning horizon. In addition, the model considers the operation and investment in pumped storage systems and power plants equipped CCUS.

Many existing GEP models, which typically use representative time slices—such as seasonal averages or typical days—to approximate annual system behaviour, the proposed GEP model simulates an hourly resolution (8,760 hours per year). This high time granularity can more accurately reflect the operational dynamics of intermittent renewable energy sources, demand variations, and low-carbon power systems.

To ensure computational tractability over long planning horizons, the model simplifies operational constraints, focusing on long-term generation system expansion.

In addition, the model incorporates pumped storage systems and power plants equipped with CCUS. These technologies are recognized as critical enablers of the low-carbon transition, providing system flexibility and emission reduction potential. By integrating these technologies, the model is better suited to simulate a broader range of generation options in future decarbonized power systems.

The proposed GEP model can generate a wide range of output results. For instance, the case study presented in Chapter 4 demonstrates how the model can produce valuable insights, including total system costs, total emissions, carbon prices, carbon intensity, technology mix for electricity supply in 2050, annual power generation, annual generator capacity and capacity factors for different generation technologies. For example, in Scenario 1, a gradual increase in carbon taxes (from \$30/tonneCO2 to \$59.7/tonneCO2) leads to a significant decline in carbon intensity, from 554.1 kgCO2e/MWh in 2020 to 101.4 kgCO2e/MWh in 2050. This shift is primarily driven by a transformation in the technology mix for electricity supply: the share of high-emission USC power generation decreases, while the share of cleaner technologies such as CCGT increases. Although the installed capacity of USC and CCGT remains relatively stable, their operational roles have changed significantly, as reflected in their capacity factors. These results provide a comprehensive overview of the power generation system expansion, offering valuable insights for long-term planning and investment decisions.

Contribution 2: A novel carbon pricing mechanism is incorporated into the proposed GEP model to address the carbon emissions issue in power generation system. This mechanism uses an increasing carbon tax to provide a strong economic signal to incentivize the power generation system to reduce carbon emissions. The GEP model with carbon pricing mechanism examines the transition from conventional to low-carbon power generation systems. Furthermore, scenario analysis is utilized to evaluate the impacts of carbon pricing on the operational and investment in the power generation system.

Power sector is one of the largest sources of CO_2 emissions. In practice, both fixed carbon tax and highly volatile carbon pricing schemes can undermine investor confidence and limit the effectiveness of carbon pricing in promoting emissions reduction. The proposed carbon pricing mechanism addresses this issue by adopting an annually increasing carbon price trajectory, which reduces uncertainty, improves investment predictability, and gradually strengthens the incentive to decarbonize the technology mix for electricity supply.

By integrating this mechanism within the GEP model, the research can simulate how carbon pricing policy alone, without the need for binding annual emissions caps, can guide the system towards a low-carbon transition. This model also allows for a comprehensive examination of how carbon pricing interacts with other economic and policy variables, such as fuel price fluctuations, renewable energy targets, and technology availability.

Chapter 5 presents and analyses the expansion pathways of the power generation system under 18 different scenarios, each reflecting a unique combination of assumptions such as coal and gas prices, electricity demand growth, renewable energy penetration and technology constraints. The results demonstrate how carbon pricing affects technology choices, capacity investments, total system costs, and carbon emissions. For example, in a scenario without a carbon tax, total emissions increase significantly—by up to 97% compared to the baseline Scenario 1—due to continued reliance on coal-fired power generation. In contrast, scenarios with gradually increasing carbon prices achieve significant emission reductions by encouraging a shift toward cleaner/clean technologies such as natural gas, nuclear power, and renewable energy. The study also indicates that in scenarios with high carbon prices and limited availability or constraints on other low-carbon technologies (such as nuclear or natural gas), ultra-supercritical coal with carbon capture and storage (USC-CCUS) becomes a more attractive option. This demonstrates how carbon pricing can drive strategic decisions about which technologies to invest in, depending on market and policy conditions. Overall, these findings provide valuable insights for policymakers and planners aiming to design effective carbon pricing policies that align investment incentives with long-term decarbonization goals.

Contribution 3: A proposed LCOE approach is developed and used to assess the investment in combustion power plants. This approach consider annual carbon price and annual capacity factor of power plant derived from the result of GEP model to improve the reliability of LCOE method. By integrating these dynamic factors, the approach is used to analyze the differences in LCOE of power plants across different years and under various scenarios.

Carbon prices and capacity factors have a significant impact on the calculation of the LCOE for combustion power plants. Traditional LCOE methods often rely on fixed carbon prices and static or historically derived capacity factors, which fail to reflect how the transition towards a low-carbon power system affects investment performance. For example, in systems with increasing carbon prices and a rising share of renewable energy, these assumptions can lead to underestimation of investment risks and overestimation of plant performance, thereby reducing the reliability of the assessment.

The proposed LCOE approach addresses this limitation by integrating annual carbon prices and annual capacity factors derived from the GEP model, capturing how the conditions of a changing power system affect the LCOE of thermal power plants. As shown in Chapter 6, the LCOE values calculated using this approach are generally higher than those obtained from traditional methods, particularly for high-carbon emission technologies such as USC. This is because the calculation of LCOE introduces the annual capacity factor and annual carbon price from the GEP model.

Chapter 6 also highlights the influence of scenarios and commissioned year on LCOE outcomes. For instance, the LCOE of a USC plant in 2050 is nearly four times that of a similar plant commissioned in 2020, due to reduced capacity factors and increasing carbon prices. In contrast, CCGT plants become more economically attractive over time, with their LCOE in 2050 falling to less than half of the 2020 level. In most scenarios, the LCOE of CCGT generally shows a gradual downward trend, especially when natural gas prices are low and carbon pricing mechanisms are strong. However, USC becomes significantly less competitive as carbon prices rise.

Overall, the proposed LCOE approach provides more reliable and realistic insights into the economic viability of thermal power investments. By considering system changes and policy factors, it makes investment evaluations more accurate and helps support better decisions for long-term power system decarbonization.

7.2 Future work

Improvement to the GEP Model

In future work, the proposed GEP model could be further adapted to capture a wider range of system dynamics and provide more realistic insights. One possible direction is to extend the model to include detailed operational constraints of power plants, such as ramp rates, start-up and shut-down costs, minimum stable generation levels, and spinning reserve requirements. Incorporating these operational features would enhance the model's ability to approximate short-term dispatch conditions while still operating within a long-term planning framework.

Another key extension would be to integrate transmission network planning. At present, the model focuses primarily on generation expansion, while assuming an unconstrained transmission system. Future developments could incorporate network topology, inter-regional transmission capacities, congestion effects, and power losses. This would enable a more holistic optimization that simultaneously considers generation and transmission investments, providing a more reliable assessment of system costs and security of supply.

The model could also be enhanced by including technology learning curves and innovation pathways. Accounting for endogenous technological learning—where costs decline with cumulative deployment—would reflect the likely evolution of renewable energy technologies, CCUS, and energy storage. Similarly, policy uncertainty and stochastic modelling of fuel and carbon prices could be introduced to better capture investment risks under uncertain future conditions.

Finally, the model could be extended to incorporate sector coupling and multi-energy systems, such as electrification of transport, hydrogen production, or integration with district heating. This would broaden the scope of the analysis beyond electricity and provide insights into the role of the power sector in economy-wide decarbonization.

Developing the LCOE Approach

The LCOE method developed in this study improves investment assessments by incorporating annual carbon prices and capacity factors derived from the GEP model.

Future research could build on this approach by incorporating time-varying capital costs, O&M costs, and technology-specific learning rates. Such extensions would better reflect how emerging technologies—such as advanced nuclear, CCUS-equipped plants, or long-duration energy storage—evolve over time and affect competitiveness.

Another important direction would be to extend the proposed LCOE framework into a probabilistic or stochastic LCOE model. Instead of relying on deterministic inputs, probabilistic methods could capture the uncertainty in fuel prices, carbon pricing trajectories, demand growth, and renewable resource availability. This would provide investors and policymakers with not only a single LCOE value but also a distribution of possible outcomes, allowing for risk-informed decision-making.

Furthermore, the approach could be expanded to compare system-level LCOE or avoided cost metrics. By linking the plant-level LCOE with system-wide benefits such as reduced emissions, avoided fuel imports, or increased reliability, the analysis could move beyond purely financial evaluation toward a more holistic understanding of value creation.

Finally, integrating the LCOE method with real option analysis could provide a powerful tool for evaluating the flexibility of investments under uncertainty. For example, the option to delay, expand, or repurpose power plants could be explicitly valued, giving investors and policymakers more robust insights into long-term strategies in the context of uncertain carbon pricing and renewable integration.

Appendix A

Parameters for power plants

The data used for generation technologies in this study are primarily sourced from the **International Energy Agency (IEA) report: *Projected Costs of Generating Electricity 2020*** [161, 172]. This report provides detailed, comprehensive, and authoritative information on a wide range of power generation technologies. The selection of technologies analyzed in this study is also based on those covered in the IEA report, ensuring consistency and international comparability.

Among various available data sources, the IEA 2020 report was chosen because it was the year that simulated was started and offers a standardized and transparent methodology for comparing the levelized costs of electricity (LCOE) across different technologies and countries. The Covid19 pandemic period offers much interruption to the work. Although some of the data—such as the assumed carbon price of 30 US$/tonne CO_2—may not perfectly align with current market values (2025), it is important to note that the IEA 2020 report still represents an official reference. Its assumptions are widely used in academic research and policy modelling, thus offering a robust basis for scenario development and comparative analysis.

All data used in this study are drawn from the IEA report, with **one exception**: the **CO_2 conversion factor**, which is not provided in the IEA publication. As this factor is essential for calculating carbon emissions and related costs, it was supplemented from a reputable alternative source: the **UK Government's "Greenhouse Gas Reporting: Conversion Factors 2020"**, published by the **Department for Energy Security and Net Zero** and the **Department for Business, Energy & Industrial Strategy (BEIS)**

[161, 162]. This dataset is widely used for corporate carbon accounting and provides standardized conversion factors for CO_2 emissions associated with various fuels.

By combining the IEA report with official UK government data where necessary, this study ensures that all input assumptions are based on publicly available, credible, and widely accepted sources, supporting both the transparency and reliability of the modelling outcomes.

Ultra-supercritical (USC) coal power plant

Net Capacity	347 MW
Electrical conversion efficiency	45%
Construction duration	4 years
Capacity factor	85%
Lifetime	40 years
Discount rate	7%
Fuel price	88 USD/tonne
Carbon price	30 USD/tonne
Construction price per year	174.93 USD/kW
Fixed O&M price	34.5 USD/kW
Variable O&M price	10.35 USD/MWh
CO2 conversion factor	0.3398 kWh/kg CO2
Fuel property	6.9445 kWh/kg

Nuclear power plant

Net Capacity	950 MW
Electrical conversion efficiency	33%
Construction duration	7 years
Capacity factor	85%
Lifetime	60 years
Discount rate	7%
Fuel price	3.3 USD/MWh
Carbon price	30 USD/tonne
Construction price per year	356.84 USD/kW
Fixed O&M price	112 USD/kW
Variable O&M price	11.5 USD/MWh
CO2 conversion factor	0.0 kWh/kg CO2

Combined-cycle gas turbines (CCGT) power plant

Net Capacity	475 MW
Electrical conversion efficiency	58%
Construction duration	3 years
Capacity factor	85%
Lifetime	30 years
Discount rate	7%
Fuel price	9.1 USD/MBtu
Carbon price	30 USD/tonne
Construction price per year	186.31 USD/kW
Fixed O&M price	31.0 USD/kW
Variable O&M price	9.3 USD/MWh
CO2 conversion factor	0.18254 kWh/kg CO2
Fuel property	0.293 kWh/MBtu

USC-CCUS (Carbon Capture Utilization and Storage) power plant

Net Capacity	633 MW
Electrical conversion efficiency	30 %
Construction duration	9 years
Capacity factor	85%
Lifetime	40 years
Discount rate	7%
Fuel price	88 USD/tonne
Carbon price	30 USD/tonne
Construction price per year	201.42 USD/kW
Fixed O&M price	78.24 USD/kW
Variable O&M price	9 USD/MWh
CO2 conversion factor	0.03398 kWh/kg CO2
Fuel property	6.9445 kWh/kg

CCGT-CCUS power plant

Net Capacity	437 MW
Electrical conversion efficiency	41%
Construction duration	10 years
Capacity factor	85%
Lifetime	30 years
Discount rate	7%
Fuel price	9.1 USD/MBtu
Carbon price	30 USD/tonne
Construction price per year	120.77 USD/kW
Fixed O&M price	74.32 USD/kW
Variable O&M price	9.1 USD/MWh
CO2 conversion factor	0.018254 kWh/kg CO2
Fuel property	0.293 kWh/MBtu

Onshore wind farm

Net Capacity	50 MW
Electrical conversion efficiency	-
Construction duration	1 years
Capacity factor	26%
Lifetime	25 years
Discount rate	7%
Fuel price	-
Carbon price	-
Construction price per year	1200 USD/kW
Fixed O&M price	7.0 USD/kW
Variable O&M price	7.0 USD/MWh
CO2 conversion factor	-
Fuel property	-

Solar PV (photovoltaic) power plant

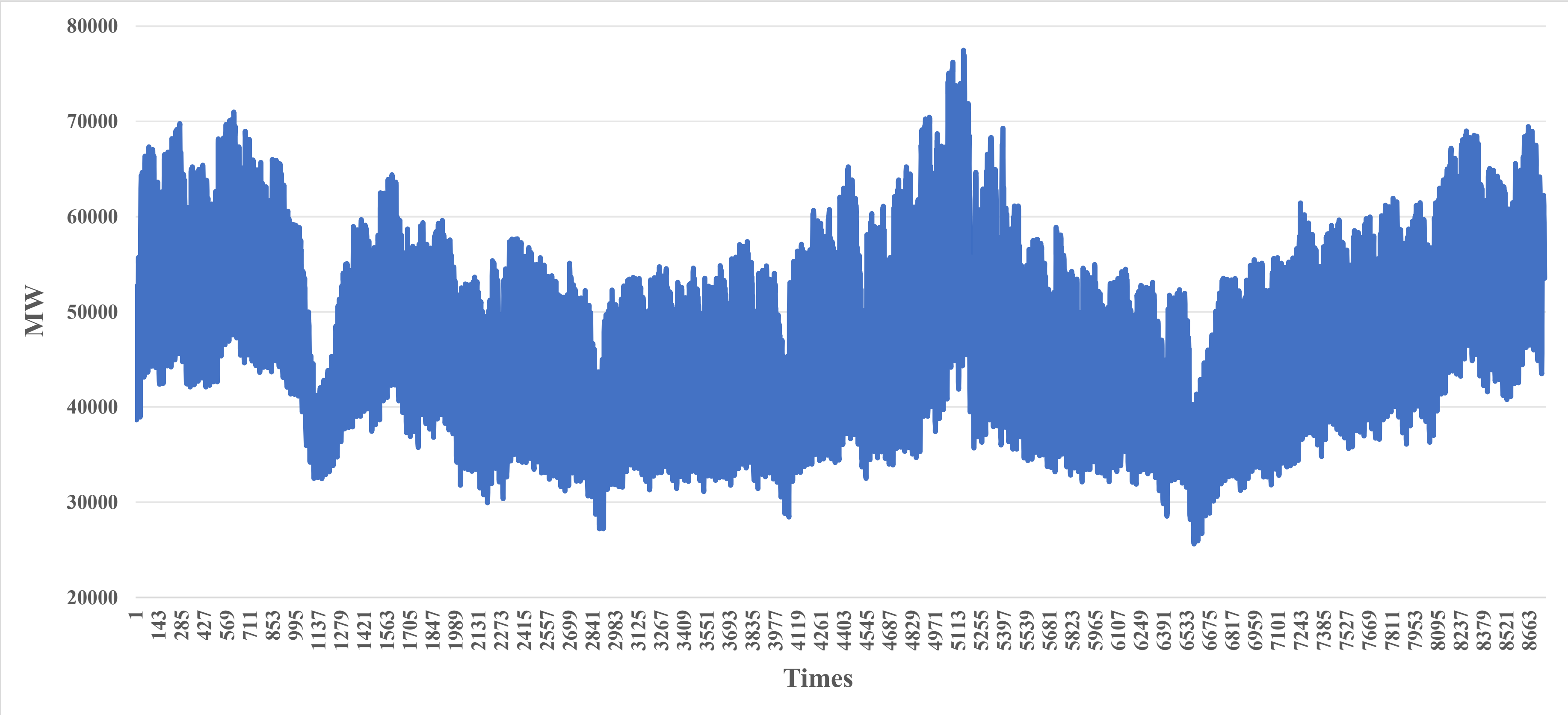
Net Capacity	20 MW
Electrical conversion efficiency	-
Construction duration	1 years
Capacity factor	18%
Lifetime	25years
Discount rate	7%
Fuel price	-
Carbon price	-
Construction price per year	779.95 USD/kW
Fixed O&M price	7.9 USD/kW
Variable O&M price	3.0 USD/MWh
CO2 conversion factor	-
Fuel property	-

Pumped storage hydro power plant

Net Capacity	175 MW
Electrical conversion efficiency	52%
Construction duration	1 years
Capacity factor	85%
Lifetime	40 years
Discount rate	7%
Fuel price	-
Carbon price	-
Construction price per year	525.71 USD/kW
Fixed O&M price	7.2 USD/kW
Variable O&M price	5.0 USD/MWh
CO2 conversion factor	-
Fuel property	-

Hourly power demand

The load duration curve used in this study is constructed by reordering the hourly electricity demand data in descending order. The hourly power demand data are derived from the "China Statistical Yearbook 2021", published by the National Bureau of Statistics of China [3]. This yearbook is an authoritative national statistical publication that compiles various statistical data from different industries and time periods, including energy consumption and electricity demand. The China Statistical Yearbook can be easily accessed online, ensuring transparency and repeatability in the modeling process.


80000
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6533
6675
6817
6959
7101
7243
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7527
7669
7811
7953
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8379
8521
8663
Times

Appendix B

Generation expansion plans

Total system cost and total carbon emissions

	Total Carbon Emissions (million tonnes)	Total System Cost (US$ billion)
Scenario 0 No carbon tax	8663.0	942.0
Scenario 1	7975.6	1342.9
Scenario 2 coal price high	5752.7	1342.7
Scenario 3 coal price low	7703.6	1131.7
Scenario 4 gas price high	8216.4	1363.1
Scenario 5 gas price low	4157.9	1025.3
Scenario 6 demand growth 3%	5704.9	834.0
Scenario 7 demand growth 7%	10863.9	1989.8
Scenario 8 renewables 50%	9118.7	1481.1
Scenario 9 renewables 70%	6832.7	1098.1
Scenario 10 No CCGT	8241.5	1363.9
Scenario 11 No USC	4035.6	1330.9
Scenario 12 No new USC	7975.6	1345.5
Scenario 13 No nuclear	10018.3	1486.0
Scenario 14 No new nuclear	9419.2	1451.4
Scenario 15 30$/tonneCO2 No capacity limit	5603.0	898.9
Scenario 16 0$/tonneCO2 No capacity limit	15770.9	1111.8
Scenario 17 No capacity limit	5133.4	902.0

Carbon intensity (kgCO2/MWh)

Scenario 0 No carbon tax	Scenario 1	Scenario 2 coal price high	Scenario 3 coal price low	Scenario 4 natural gas price high	Scenario 5 natural gas price low	Scenario 6 demand growth 3%	Scenario 7 demand growth 7%	Scenario 8 renewables penetration 50%	Scenario 9 renewables penetration 70%	Scenario 10 No CCGT	Scenario 11 No USC	Scenario 12 No new USC	Scenario 13 No nuclear	Scenario 14 No new nuclear	Scenario 15 30$/tonneCO2 No capacity limit	Scenario 16 0$/tonneCO2 No capacity limit	Scenario 17 No capacity limit
554.1	554.1	550.9	554.1	554.1	278.3	555.2	551.8	559.6	547.1	554.1	255.4	554.1	612.5	560.3	228.1	561.9	226.7
529.8	529.8	526.8	529.8	529.8	264.7	531.5	525.9	540.7	516.1	529.8	244.3	529.8	591.6	542.0	217.1	551.9	216.3
506.7	506.7	495.2	506.7	506.6	251.5	508.5	501.4	522.6	486.6	506.6	233.7	506.7	571.4	524.5	214.2	539.9	211.5
484.6	484.6	457.4	484.6	484.6	240.4	486.2	478.1	505.3	458.5	484.7	223.6	484.6	551.9	507.6	203.5	530.1	201.2
463.4	463.4	422.2	463.4	463.4	228.4	464.6	455.7	488.6	431.7	463.9	214.0	463.4	532.9	491.4	191.7	527.1	187.5
443.1	443.1	392.1	443.1	443.1	216.9	443.5	434.0	472.5	406.1	444.0	204.8	443.1	514.3	475.5	192.0	515.4	187.4
423.6	423.6	364.5	423.6	423.6	206.6	423.1	413.1	456.9	381.7	425.2	196.1	423.6	496.2	460.0	191.0	506.5	186.3
404.8	404.8	334.3	404.8	405.5	197.0	403.3	393.0	441.7	358.5	407.2	187.8	404.8	478.6	444.7	190.7	508.4	184.7
387.2	386.7	308.5	387.1	388.3	188.1	384.0	374.4	426.8	337.1	390.1	179.9	386.7	461.4	429.9	188.9	510.2	183.1
371.0	369.3	283.9	370.9	372.1	179.5	365.4	358.3	412.3	317.1	373.9	172.5	369.3	444.8	415.3	186.8	511.9	181.0
355.8	352.8	259.2	355.5	356.8	171.5	347.3	343.4	398.3	298.6	358.7	165.5	352.8	430.0	401.2	185.2	513.5	179.7
341.6	337.1	239.4	341.2	342.6	164.0	329.9	329.8	384.7	281.4	344.5	158.9	337.1	416.1	387.4	183.8	515.0	176.8
328.5	322.2	223.0	319.4	329.4	157.3	313.3	317.1	371.4	265.5	331.3	152.9	322.2	402.5	374.1	182.6	516.5	174.8
316.2	308.2	207.4	291.3	317.0	151.2	297.6	305.0	358.5	250.8	319.0	147.2	308.2	388.8	361.5	179.5	517.9	172.9
304.7	294.9	193.2	270.1	305.5	145.4	282.6	292.5	346.1	237.3	307.5	141.9	294.9	376.3	350.4	179.9	519.2	170.3

294.0	282.3	181.2	257.5	294.7	140.1	268.4	280.8	334.1	224.9	296.9	137.0	282.3	363.1	338.8	180.8	520.5	168.6
284.0	270.5	170.2	240.2	284.7	135.2	255.0	269.3	322.6	214.6	287.0	132.4	270.5	350.5	327.6	181.9	521.7	168.4
274.7	259.3	160.6	230.9	275.4	130.6	242.3	258.2	311.6	205.2	277.7	128.1	259.3	338.5	316.7	182.5	522.8	167.9
266.0	248.7	151.8	224.1	266.7	126.4	230.3	247.7	301.0	196.6	269.1	124.2	248.7	327.0	306.4	182.7	523.9	167.0
258.1	238.8	144.0	217.3	258.8	122.4	218.9	238.0	290.9	188.6	261.2	120.5	238.8	316.0	296.5	183.3	524.9	167.0
250.7	229.4	137.3	207.6	251.4	118.8	208.2	228.8	281.3	181.5	248.9	117.1	229.4	305.5	287.1	183.7	525.9	167.1
243.8	220.6	131.3	200.0	234.2	115.5	198.0	220.2	272.1	174.9	234.6	114.0	220.6	295.5	278.1	183.9	526.9	167.2
237.4	212.2	125.9	193.6	221.5	112.4	188.5	212.3	263.4	168.9	221.7	111.0	212.2	286.0	269.7	184.0	527.8	166.9
231.5	204.4	121.1	187.3	209.2	109.5	179.6	204.8	248.8	163.3	207.9	108.3	204.4	277.0	261.6	184.2	528.6	166.6
226.0	197.1	116.9	182.3	197.2	106.9	171.3	197.8	234.9	158.1	197.2	105.8	197.1	267.7	253.9	184.4	529.4	166.7
220.9	190.2	113.1	175.0	188.4	104.4	163.5	191.3	223.2	153.5	187.6	103.5	190.2	253.9	246.6	185.0	530.2	161.9
216.2	183.7	109.7	170.3	177.8	102.2	156.2	185.2	213.2	149.0	179.1	101.3	183.7	240.8	234.8	185.6	531.0	161.1
211.8	177.5	106.7	164.9	169.4	100.1	149.4	179.6	202.6	145.0	170.6	99.3	177.5	230.3	224.8	186.2	531.7	160.5
207.7	171.8	103.9	160.0	162.4	98.1	142.9	174.3	193.7	141.3	163.1	97.4	171.8	221.3	216.5	186.4	532.3	157.4
203.8	101.4	101.3	156.6	156.5	96.3	136.9	116.0	115.5	137.8	156.4	95.6	101.3	134.1	131.9	186.6	533.0	155.4

Carbon price (US$/tonne CO2e)

Scenario 0 No carbon tax	Scenario 1	Scenario 2 coal price high	Scenario 3 coal price low	Scenario 4 natural gas price high	Scenario 5 natural gas price low	Scenario 6 demand growth 3%	Scenario 7 demand growth 7%	Scenario 8 renewables penetration 50%	Scenario 9 renewables penetration 70%	Scenario 10 No CCGT	Scenario 11 No USC	Scenario 12 No new USC	Scenario 13 No nuclear	Scenario 14 No new nuclear	Scenario 15 30$/tonneCO2 No capacity limit	Scenario 16 0$/tonneCO2 No capacity limit	Scenario 17 No capacity limit
0.0	31.0	30.0	30.8	31.2	30.0	30.0	31.0	31.0	30.0	31.2	30.0	31.0	31.0	31.0	30.0	0.0	30.3
0.0	32.0	30.0	31.6	32.3	30.0	30.0	32.0	32.0	30.0	32.4	30.0	32.0	32.0	32.0	30.0	0.0	30.5
0.0	33.0	30.0	32.4	33.5	30.0	30.0	33.0	33.0	30.0	33.5	30.0	33.0	33.0	33.0	30.0	0.0	30.8
0.0	34.0	30.0	33.1	34.7	30.0	30.0	34.0	34.0	30.0	34.7	30.0	34.0	34.0	34.0	30.0	0.0	31.1
0.0	35.0	30.0	33.9	35.8	30.0	30.0	35.0	35.0	30.0	35.9	30.0	35.1	35.0	35.0	30.0	0.0	31.4
0.0	35.9	30.0	34.7	37.0	30.0	30.0	36.0	35.9	30.0	37.1	30.0	36.1	36.0	35.9	30.0	0.0	31.6
0.0	36.9	30.0	35.5	38.2	30.0	30.0	37.0	36.9	30.0	38.2	30.0	37.1	37.0	36.9	30.0	0.0	31.9
0.0	37.9	30.0	36.3	39.3	30.0	30.0	38.0	37.9	30.0	39.4	30.0	38.1	38.0	37.9	30.0	0.0	32.2
0.0	38.9	30.0	37.1	40.5	30.0	30.0	39.0	38.9	30.0	40.6	30.0	39.1	38.9	38.9	30.0	0.0	32.4
0.0	39.9	30.0	37.9	41.7	30.0	30.0	40.0	39.9	30.0	41.8	30.0	40.1	39.9	39.9	30.0	0.0	32.7
0.0	40.9	30.0	38.6	42.8	30.0	30.0	41.0	40.9	30.0	43.0	30.0	41.1	40.9	40.9	30.0	0.0	33.0
0.0	41.9	30.0	39.4	44.0	30.0	30.0	42.0	41.9	30.0	44.1	30.0	42.1	41.9	41.9	30.0	0.0	33.3
0.0	42.9	30.0	40.2	45.2	30.0	30.0	43.0	42.9	30.0	45.3	30.0	43.2	42.9	42.9	30.0	0.0	33.5
0.0	43.9	30.0	41.0	46.3	30.0	30.0	44.0	43.9	30.0	46.5	30.0	44.2	43.9	43.9	30.0	0.0	33.8
0.0	44.9	30.0	41.8	47.5	30.0	30.0	45.0	44.9	30.0	47.7	30.0	45.2	44.9	44.9	30.0	0.0	34.1
0.0	45.9	30.0	42.6	48.7	30.0	30.0	46.0	45.9	30.0	48.9	30.0	46.2	45.9	45.9	30.0	0.0	34.4
0.0	46.8	30.0	43.4	49.8	30.0	30.0	46.9	46.8	30.0	50.0	30.0	47.2	46.9	46.8	30.0	0.0	34.6

0.0	47.8	30.0	44.1	51.0	30.0	30.0	47.9	47.8	30.0	51.2	30.0	48.2	47.9	47.8	30.0	0.0	34.9
0.0	48.8	30.0	44.9	52.2	30.0	30.0	48.9	48.8	30.0	52.4	30.0	49.2	48.9	48.8	30.0	0.0	35.2
0.0	49.8	30.0	45.7	53.3	30.0	30.0	49.9	49.8	30.0	53.6	30.0	50.2	49.9	49.8	30.0	0.0	35.4
0.0	50.8	30.0	46.5	54.5	30.0	30.0	50.9	50.8	30.0	54.7	30.0	51.3	50.9	50.8	30.0	0.0	35.7
0.0	51.8	30.0	47.3	55.7	30.0	30.0	51.9	51.8	30.0	55.9	30.0	52.3	51.9	51.8	30.0	0.0	36.0
0.0	52.8	30.0	48.1	56.8	30.0	30.0	52.9	52.8	30.0	57.1	30.0	53.3	52.9	52.8	30.0	0.0	36.3
0.0	53.8	30.0	48.9	58.0	30.0	30.0	53.9	53.8	30.0	58.3	30.0	54.3	53.9	53.8	30.0	0.0	36.5
0.0	54.8	30.0	49.6	59.2	30.0	30.0	54.9	54.8	30.0	59.5	30.0	55.3	54.8	54.8	30.0	0.0	36.8
0.0	55.8	30.0	50.4	60.3	30.0	30.0	55.9	55.8	30.0	60.6	30.0	56.3	55.8	55.8	30.0	0.0	37.1
0.0	56.8	30.0	51.2	61.5	30.0	30.0	56.9	56.8	30.0	61.8	30.0	57.3	56.8	56.8	30.0	0.0	37.3
0.0	57.7	30.0	52.0	62.7	30.0	30.0	57.9	57.7	30.0	63.0	30.0	58.3	57.8	57.7	30.0	0.0	37.6
0.0	58.7	30.0	52.8	63.8	30.0	30.0	58.9	58.7	30.0	64.2	30.0	59.4	58.8	58.7	30.0	0.0	37.9
0.0	59.7	30.0	53.6	65.0	30.0	30.0	59.9	59.7	30.0	65.3	30.0	60.4	59.8	59.7	30.0	0.0	38.2

Technology mix for electricity supply in 2050 (TWh)

	Scenario 0 No carbon tax	Scenario 1	Scenario 2 coal price high	Scenario 3 coal price low	Scenario 4 natural gas price high	Scenario 5 natural gas price low	Scenario 6 demand growth 3%	Scenario 7 demand growth 7%	Scenario 8 renewables penetration 50%	Scenario 9 renewables penetration 70%	Scenario 10 No CCGT	Scenario 11 No USC	Scenario 12 No new USC	Scenario 13 No nuclear	Scenario 14 No new nuclear	Scenario 15 30$/tonneCO2 No capacity limit	Scenario 16 0$/tonneCO2 No capacity limit	Scenario 17 No capacity limit
Nuclear	231.5	231.5	231.5	231.5	231.5	231.5	224.2	232.9	262.7	188.5	231.5	231.5	231.5	0.0	27.4	24.9	31.4	53.3
USC	494.1	26.2	26.0	353.2	357.4	3.1	186.0	16.9	29.7	313.8	362.7	0.0	26.1	31.7	27.5	440.6	1308.4	351.8
CCGT	16.2	484.0	484.3	27.6	15.5	507.2	6.9	1053.5	510.9	54.6	0.0	510.3	484.1	616.4	623.3	40.3	6.8	66.2
Wind	785.8	785.8	785.8	785.8	785.8	785.8	434.1	1410.4	627.8	1004.0	785.8	785.8	785.8	785.8	785.8	821.2	239.4	830.7
Solar PV	372.6	372.6	372.6	372.6	372.6	372.6	208.1	652.6	308.6	433.4	372.6	372.6	372.6	372.6	372.6	600.4	271.8	633.6
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Load Shedding	1.1	1.1	1.1	1.1	1.1	1.1	0.6	2.0	1.0	1.2	1.3	1.1	1.1	1.1	1.1	0.4	0.5	0.4
USC-CCUS	0.0	0.0	0.0	129.5	137.3	0.0	0.0	0.0	125.9	0.0	147.4	0.0	0.0	93.6	63.5	0.0	0.0	0.0

Installed capacity mix in2050 (GW)

	Scenario 0 No carbon tax	Scenario 1	Scenario 2 coal price high	Scenario 3 coal price low	Scenario 4 natural gas price high	Scenario 5 natural gas price low	Scenario 6 demand growth 3%	Scenario 7 demand growth 7%	Scenario 8 renewables penetration 50%	Scenario 9 renewables penetration 70%	Scenario 10 No CCGT	Scenario 11 No USC	Scenario 12 No new USC	Scenario 13 No nuclear	Scenario 14 No new nuclear	Scenario 15 30$/tonneCO2 No capacity limit	Scenario 16 0$/tonneCO2 No capacity limit	Scenario 17 No capacity limit
Nuclear	40.0	40.0	40.0	40.0	40.0	40.0	39.9	40.0	40.0	40.0	40.0	40.0	40.0	0.0	4.5	4.5	4.5	10.2
USC	168.9	74.0	74.0	128.6	142.6	28.0	73.9	88.4	74.0	113.3	197.1	0.0	74.0	79.7	75.4	128.8	245.6	100.7
CCGT	60.9	155.7	156.0	75.5	59.6	202.1	25.2	368.2	145.1	106.0	0.0	229.9	155.9	174.5	179.3	72.0	28.4	88.5
Wind	264.7	264.7	264.7	264.7	264.7	264.7	146.2	475.0	211.4	338.2	264.7	264.7	264.7	264.7	264.7	276.6	80.6	279.8
Solar PV	225.3	225.3	225.3	225.3	225.3	225.3	125.8	394.6	186.6	262.0	225.3	225.3	225.3	225.3	225.3	363.0	164.3	383.1
Pumped Storage	25.0	25.0	25.0	25.0	25.0	25.0	25.1	25.1	25.0	25.0	25.0	25.0	25.0	25.0	25.0	114.2	53.4	128.2
Load Shedding	62.0	62.5	71.3	62.5	62.3	61.7	44.1	111.1	68.7	65.5	65.3	62.0	62.0	103.5	103.1	148.4	71.3	158.8
USC-CCUS	0.0	0.0	0.0	25.6	27.3	0.0	0.0	0.0	20.6	0.0	29.5	0.0	0.0	15.5	10.6	0.0	0.0	0.0

Annual power generation (MWh)---Nuclear

Scenario 0 No carbon tax	Scenario 1	Scenario 2 coal price high	Scenario 3 coal price low	Scenario 4 gas price high	Scenario 5 gas price low	Scenario 6 demand growth 3%	Scenario 7 demand growth 7%	Scenario 8 renewables penetration 50%	Scenario 9 renewables penetration 70%	Scenario 10 No CCGT	Scenario 11 No USC	Scenario 12 No new USC	Scenario 13 No nuclear	Scenario 14 No new nuclear	Scenario 15 30$/tonneCO2 No capacity limit	Scenario 16 0$/tonneCO2 No capacity limit	Scenario 17 No capacity limit
35.1	35.1	35.1	35.1	35.1	35.1	36.6	34.0	35.1	35.1	35.1	35.1	35.1	0.0	31.4	26.6	31.4	26.5
39.1	39.1	39.1	39.1	39.1	39.1	42.0	36.9	39.1	39.1	39.1	39.1	39.1	0.0	31.4	26.2	31.4	26.2
43.2	43.2	43.2	43.2	43.2	43.2	47.5	39.9	43.2	43.2	43.2	43.2	43.2	0.0	31.4	26.3	31.4	26.1
47.6	47.6	47.6	47.6	47.6	47.6	53.2	43.1	47.6	47.6	47.6	47.6	47.6	0.0	31.4	25.9	31.4	25.8
52.1	52.1	52.1	52.1	52.1	52.1	59.1	46.6	52.1	52.1	52.1	52.1	52.1	0.0	31.4	25.5	31.4	25.3
56.9	56.9	56.9	56.9	56.9	56.9	65.2	50.2	56.9	56.9	56.9	56.9	56.9	0.0	31.4	25.5	31.4	25.3
61.9	61.9	61.9	61.9	61.9	61.9	71.4	54.2	61.9	61.8	61.9	61.9	61.9	0.0	31.4	25.5	31.4	25.2
67.2	67.2	67.2	67.2	67.2	67.2	77.8	58.3	67.2	66.8	67.2	67.2	67.2	0.0	31.4	25.5	31.4	25.0
72.6	72.6	72.6	72.6	72.6	72.6	84.4	62.6	72.7	71.5	72.6	72.6	72.6	0.0	31.4	25.3	31.4	24.9
78.3	78.3	78.3	78.3	78.3	78.3	91.2	67.1	78.5	76.1	78.3	78.3	78.3	0.0	31.3	25.2	31.4	24.7
84.1	84.1	84.1	84.1	84.1	84.1	98.1	71.6	84.6	80.8	84.1	84.1	84.1	0.0	31.3	25.1	31.4	24.7
89.9	89.9	89.9	89.9	89.9	89.9	105.2	76.3	91.0	85.6	89.9	89.9	89.9	0.0	31.2	25.1	31.4	24.5
95.9	95.9	95.9	95.9	95.9	95.9	112.2	81.3	97.7	90.3	95.9	95.9	95.9	0.0	31.1	25.0	31.4	24.5
101.9	101.9	101.9	101.9	101.9	101.9	119.0	86.7	104.6	95.0	101.9	101.9	101.9	0.0	30.9	24.9	31.4	24.4
108.1	108.1	108.1	108.1	108.1	108.1	125.9	92.4	111.8	99.7	108.1	108.1	108.1	0.0	30.7	24.9	31.4	24.2
114.6	114.6	114.6	114.6	114.6	114.6	132.7	98.4	119.3	104.4	114.6	114.6	114.6	0.0	30.4	24.9	31.4	24.1

121.3	121.3	121.3	121.3	121.3	121.3	139.4	104.6	127.0	109.1	121.3	121.3	121.3	0.0	30.2	25.0	31.4	24.0
128.2	128.2	128.2	128.2	128.2	128.2	146.1	111.2	135.0	113.9	128.2	128.2	128.2	0.0	30.0	25.0	31.4	24.0
135.3	135.3	135.3	135.3	135.3	135.3	152.7	118.2	143.4	118.8	135.3	135.3	135.3	0.0	29.8	24.9	31.4	23.9
142.6	142.6	142.6	142.6	142.6	142.6	159.3	125.6	152.0	123.9	142.6	142.6	142.6	0.0	29.6	25.0	31.4	23.9
150.0	150.0	150.0	150.0	150.0	150.0	166.1	133.5	161.0	129.1	150.0	150.0	150.0	0.0	29.4	25.0	31.4	23.9
157.8	157.8	157.8	157.8	157.8	157.8	172.8	141.8	170.4	134.5	157.8	157.8	157.8	0.0	29.2	24.9	31.4	23.8
165.8	165.8	165.8	165.8	165.8	165.8	179.4	150.7	180.2	140.3	165.8	165.8	165.8	0.0	28.9	24.9	31.4	23.8
174.1	174.1	174.1	174.1	174.1	174.1	186.0	160.3	190.5	146.3	174.1	174.1	174.1	0.0	28.7	24.9	31.4	23.7
182.8	182.8	182.8	182.8	182.8	182.8	192.4	170.5	201.2	152.7	182.8	182.8	182.8	0.0	28.4	24.9	31.4	23.7
191.7	191.7	191.7	191.7	191.7	191.7	198.8	181.4	212.4	159.3	191.7	191.7	191.7	0.0	28.2	24.9	31.4	34.6
200.9	200.9	200.9	200.9	200.9	200.9	205.0	193.1	224.1	166.2	200.9	200.9	200.9	0.0	28.0	24.9	31.4	36.4
210.6	210.6	210.6	210.6	210.6	210.6	211.3	205.4	236.3	173.4	210.6	210.6	210.6	0.0	27.8	24.9	31.4	38.7
220.8	220.8	220.8	220.8	220.8	220.8	217.8	218.7	249.2	180.8	220.8	220.8	220.8	0.0	27.6	24.9	31.4	46.7
231.5	231.5	231.5	231.5	231.5	231.5	224.2	232.9	262.7	188.5	231.5	231.5	231.5	0.0	27.4	24.9	31.4	53.3

Annual power generation (MWh)---USC

Scenario 0 No carbon tax	Scenario 1	Scenario 2 coal price high	Scenario 3 coal price low	Scenario 4 gas price high	Scenario 5 gas price low	Scenario 6 demand growth 3%	Scenario 7 demand growth 7%	Scenario 8 renewables penetration 50%	Scenario 9 renewables penetration70%	Scenario 10 No CCGT	Scenario 11 No USC	Scenario 12 No new USC	Scenario 13 No nuclear	Scenario 14 No new nuclear	Scenario 15 30$/tonneCO2 No capacity limit	Scenario 16 0$/tonneCO2 No capacity limit	Scenario 17 No capacity limit
331.2	331.2	327.8	331.2	331.2	25.2	325.6	336.2	334.6	327.1	331.2	0.0	331.2	366.1	335.0	136.4	335.9	135.5
332.6	332.6	329.1	332.6	332.6	23.6	321.1	342.7	339.4	324.0	332.6	0.0	332.6	371.1	340.2	136.3	346.4	135.8
333.9	333.9	319.9	333.9	333.9	21.6	316.4	349.4	344.4	320.7	333.9	0.0	333.9	376.2	345.6	141.2	355.9	139.4
335.2	335.2	300.3	335.2	335.2	21.5	311.6	355.9	349.5	317.3	335.5	0.0	335.2	381.0	351.0	140.8	366.8	139.2
336.4	336.4	280.8	336.4	336.4	19.3	306.6	361.9	354.6	313.5	337.1	0.0	336.4	385.5	356.4	139.3	382.7	136.2
337.5	337.5	265.2	337.5	337.5	16.9	301.5	367.2	359.6	309.5	338.8	0.0	337.5	389.6	361.5	146.3	392.3	142.8
338.3	338.3	250.4	338.3	338.3	15.5	296.3	371.7	364.5	305.1	340.6	0.0	338.3	393.2	366.3	152.6	404.8	148.8
338.8	338.8	228.7	338.8	339.9	14.3	290.9	375.5	369.0	300.5	342.5	0.0	338.8	396.5	370.5	159.6	426.6	154.6
339.8	339.0	210.8	339.7	341.6	13.2	285.3	379.9	373.2	296.0	344.6	0.0	339.0	399.3	374.4	165.4	449.5	160.5
341.7	338.9	191.7	341.5	343.6	12.0	279.6	386.7	377.1	291.7	346.8	0.0	338.9	401.7	377.8	170.9	473.6	165.8
344.0	338.5	169.3	343.5	345.8	10.9	273.7	394.2	380.7	287.5	349.3	0.0	338.5	406.2	380.8	176.8	498.8	171.8
346.8	338.0	152.7	345.9	348.5	9.5	267.7	402.4	383.9	283.3	352.3	0.0	338.0	411.1	383.3	182.9	525.3	176.3
350.0	337.5	139.7	338.0	351.7	8.9	261.9	411.2	386.7	279.5	355.7	0.0	337.5	415.4	385.4	189.3	553.2	181.8
353.6	337.0	126.0	320.1	355.3	8.4	256.1	419.6	389.1	275.7	359.7	0.0	337.0	418.3	387.6	194.0	582.4	187.3
357.7	336.2	112.7	308.9	359.5	7.6	250.4	424.9	391.2	272.2	364.1	0.0	336.2	422.5	391.8	204.1	613.1	192.0
362.2	335.3	102.0	308.1	363.9	7.2	244.9	429.9	393.0	269.2	369.0	0.0	335.3	423.6	393.5	215.4	645.3	198.6

367.3	334.5	91.6	299.1	369.0	6.8	239.5	433.4	394.4	269.0	374.5	0.0	334.5	424.6	394.8	227.7	679.2	208.2
372.8	333.6	82.7	301.2	374.7	6.3	234.3	435.4	395.7	269.4	380.6	0.0	333.6	425.3	395.7	239.9	714.7	217.6
378.8	332.6	73.7	306.8	380.8	5.8	229.3	437.1	396.7	270.1	387.2	0.0	332.6	425.8	396.4	252.1	752.0	226.9
385.7	331.5	65.9	312.2	387.7	5.4	224.4	438.6	397.6	271.2	394.6	0.0	331.5	426.1	396.8	265.6	791.2	238.3
393.2	330.6	59.4	311.5	395.2	5.0	219.6	439.8	398.5	273.3	393.4	0.0	330.6	426.2	397.2	279.5	832.3	250.1
401.4	329.6	53.6	314.1	383.4	4.7	215.0	440.9	399.1	275.7	387.2	0.0	329.6	426.2	397.5	293.7	875.5	262.7
410.1	328.6	48.4	318.3	378.2	4.4	210.6	441.8	399.5	278.9	381.8	0.0	328.6	426.2	397.7	308.7	920.8	274.5
419.8	327.6	43.7	322.4	372.3	4.1	206.4	442.6	390.8	282.3	373.1	0.0	327.6	426.1	397.9	324.4	968.4	286.8
430.1	326.7	39.6	328.7	365.5	3.9	202.5	443.4	381.7	286.1	369.3	0.0	326.7	424.7	397.9	340.9	1018.4	301.4
441.4	325.8	36.1	329.4	364.4	3.6	198.8	444.0	374.8	290.9	366.7	0.0	325.8	416.1	398.0	359.3	1070.9	306.0
453.3	325.0	33.1	335.5	357.7	3.4	195.4	444.6	369.7	295.7	365.5	0.0	325.0	407.2	390.7	378.5	1126.0	318.1
466.0	324.2	30.6	339.7	355.2	3.3	192.1	445.1	362.5	301.4	363.2	0.0	324.2	401.5	385.2	398.7	1183.9	332.6
479.7	323.5	28.2	344.3	354.9	3.2	189.0	445.5	357.4	307.8	362.3	0.0	323.5	397.1	381.6	419.2	1244.6	340.6
494.1	26.2	26.0	353.2	357.4	3.1	186.0	16.9	29.7	313.8	362.7	0.0	26.1	31.7	27.5	440.6	1308.4	351.8

Annual power generation (MWh)---CCGT

Scenario 0 No carbon tax	Scenario 1	Scenario 2 coal price high	Scenario 3 coal price low	Scenario 4 gas price high	Scenario 5 gas price low	Scenario 6 demand growth 3%	Scenario 7 demand growth 7%	Scenario 8 renewables penetration 50%	Scenario 9 renewables penetration 70%	Scenario 10 No CCGT	Scenario 11 No USC	Scenario 12 No new USC	Scenario 13 No nuclear	Scenario 14 No new nuclear	Scenario 15 30$/tonneCO2 No capacity limit	Scenario 16 0$/tonneCO2 No capacity limit	Scenario 17 No capacity limit
0.0	0.0	3.5	0.0	0.0	306.1	0.0	0.0	0.0	0.0	0.0	331.1	0.0	0.1	0.0	0.0	0.0	0.0
0.0	0.0	3.5	0.0	0.0	309.1	0.0	0.2	0.0	0.0	0.0	332.5	0.0	0.4	0.0	0.0	0.0	0.0
0.1	0.1	14.1	0.1	0.1	312.6	0.0	0.7	0.2	0.0	0.0	334.0	0.1	1.1	0.2	0.0	0.0	0.0
0.3	0.3	35.3	0.3	0.3	314.2	0.0	2.0	0.5	0.2	0.0	335.5	0.3	2.1	0.7	0.0	0.1	0.0
0.7	0.7	56.5	0.7	0.7	318.0	0.0	4.3	1.0	0.4	0.0	337.2	0.7	3.8	1.5	0.1	0.8	0.1
1.4	1.4	73.8	1.4	1.4	322.1	0.0	7.9	2.0	0.9	0.0	338.9	1.4	6.2	2.9	0.5	1.9	0.4
2.4	2.4	90.3	2.4	2.4	325.3	0.0	12.9	3.4	1.5	0.0	340.7	2.4	9.4	4.9	1.0	2.2	0.9
3.8	3.8	114.0	3.8	2.7	328.4	0.0	19.5	5.4	2.5	0.0	342.6	3.8	13.2	7.8	1.9	2.3	1.7
4.8	5.6	133.9	4.9	3.0	331.5	0.0	26.3	8.2	3.7	0.0	344.6	5.6	18.0	11.5	3.1	2.4	2.7
5.1	8.0	155.2	5.4	3.2	334.9	0.0	31.7	11.5	5.3	0.0	346.8	8.0	23.4	16.0	5.0	2.6	4.5
5.4	10.9	180.1	5.9	3.6	338.6	0.1	37.7	15.6	7.2	0.0	349.4	10.9	27.3	21.4	7.7	2.7	6.9
5.6	14.3	199.8	6.5	3.9	343.0	0.2	44.3	20.4	9.5	0.0	352.4	14.3	31.3	27.9	10.9	2.8	9.7
5.9	18.3	216.1	7.1	4.1	347.0	0.3	51.9	26.1	12.2	0.0	355.8	18.3	36.4	35.3	14.6	3.0	12.9
6.1	22.8	233.8	7.4	4.4	351.4	0.4	61.1	32.7	15.3	0.0	359.7	22.8	43.4	43.2	18.2	3.1	16.7
6.5	27.9	251.5	8.3	4.7	356.6	0.6	75.1	40.1	18.7	0.0	364.2	27.9	49.8	49.8	19.2	3.3	20.9
6.9	33.8	267.1	8.9	5.1	362.0	0.7	91.1	48.4	22.4	0.0	369.1	33.8	60.0	59.8	20.1	3.4	23.9

7.2	40.1	283.0	9.7	5.6	367.8	0.9	110.4	57.6	24.0	0.0	374.6	40.1	71.3	70.9	21.1	3.6	25.1
7.8	47.1	298.0	10.4	6.0	374.4	1.1	133.2	67.8	25.7	0.0	380.7	47.1	83.6	83.2	22.2	3.8	27.1
8.5	54.8	313.7	11.2	6.6	381.6	1.4	158.3	78.9	27.6	0.0	387.4	54.8	96.9	96.5	23.4	4.0	28.9
9.1	63.2	328.9	12.1	7.0	389.4	1.6	185.8	90.9	29.8	0.0	394.8	63.2	111.3	110.8	24.6	4.2	30.5
9.6	72.2	343.4	13.2	7.6	397.8	1.9	215.9	103.7	31.7	0.0	402.8	72.2	126.7	126.3	25.9	4.4	32.7
10.1	81.9	358.0	14.4	8.0	406.9	2.3	248.7	117.6	33.8	0.0	411.5	81.9	143.1	142.6	27.2	4.6	34.4
10.8	92.4	372.6	15.8	8.8	416.7	2.7	284.3	132.4	35.8	0.0	420.9	92.4	160.6	160.1	28.6	4.8	37.7
11.4	103.6	387.5	16.9	9.8	427.1	3.1	322.7	136.7	38.2	0.0	431.2	103.6	179.3	178.8	30.1	5.1	41.3
12.2	115.6	402.7	18.6	10.6	438.4	3.6	364.1	140.5	40.7	0.0	442.3	115.6	197.1	198.6	31.6	5.3	43.4
12.8	128.3	418.1	19.8	11.6	450.6	4.2	408.8	147.2	42.8	0.0	454.2	128.3	204.1	219.6	33.2	5.6	47.3
13.6	141.9	433.8	21.7	12.5	463.5	4.8	457.0	156.4	45.7	0.0	466.9	141.9	210.6	228.2	34.8	5.9	52.8
14.4	156.2	449.9	23.6	13.5	477.2	5.4	508.8	162.9	48.3	0.0	480.5	156.2	222.4	240.2	36.5	6.1	55.6
15.2	171.5	466.7	25.7	14.8	491.7	6.2	564.6	172.4	50.9	0.0	494.9	171.5	236.9	256.2	38.4	6.5	61.5
16.2	484.0	484.3	27.6	15.5	507.2	6.9	1053.5	510.9	54.6	0.0	510.3	484.1	616.4	623.3	40.3	6.8	66.2

Annual power generation (MWh)--USC-CCUS

Scenario 0 No carbon tax	Scenario 1	Scenario 2 coal price high	Scenario 3 coal price low	Scenario 4 gas price high	Scenario 5 gas price low	Scenario 6 demand growth 3%	Scenario 7 demand growth 7%	Scenario 8 renewables penetration 50%	Scenario 9 renewables penetration 70%	Scenario 10 No CCGT	Scenario 11 No USC	Scenario 12 No new USC	Scenario 13 No nuclear	Scenario 14 No new nuclear	Scenario 15 30$/tonneCO2 No capacity limit	Scenario 16 0$/tonneCO2 No capacity limit	Scenario 17 No capacity limit
			10.7														
			32.2														
			47.0														
			52.1														

			65.8														
			69.1														
			69.4														
			70.5														
			78.1							9.3							
			83.1	20.1						24.3							
			86.8	34.0						39.0							
			91.8	49.1				20.6		58.0							
			95.0	66.2				43.0		72.8			3.2				
			104.9	78.2				61.3		87.3			25.6				
			109.7	96.6				76.4		101.2			50.0	20.9			
			117.1	111.7				97.3		117.1			67.3	37.9			
			124.9	125.2				114.2		132.4			81.7	50.3			
			129.5	137.3				125.9		147.4			93.6	63.5			

Annual power generation (MWh)---Wind

Scenario 0 No carbon tax	Scenario 1	Scenario 2 coal price high	Scenario 3 coal price low	Scenario 4 natural gas price high	Scenario 5 natural gas price low	Scenario 6 demand growth 3%	Scenario 7 demand growth 7%	Scenario 8 renewables penetration 50%	Scenario 9 renewables penetration 70%	Scenario 10 No CCGT	Scenario 11 No USC	Scenario 12 No new USC	Scenario 13 No nuclear	Scenario 14 No new nuclear	Scenario 15 30$/tonneCO2 No capacity limit	Scenario 16 0$/tonneCO2 No capacity limit	Scenario 17 No capacity limit
66.6	66.6	66.6	66.6	66.6	66.6	63.6	70.0	64.2	69.9	66.6	66.6	66.6	66.6	66.6	217.0	55.6	217.0
78.1	78.1	78.1	78.1	78.1	78.1	71.8	85.3	73.3	84.9	78.1	78.1	78.1	78.1	78.1	218.8	55.6	218.6
90.3	90.3	90.3	90.3	90.3	90.3	80.2	101.7	82.8	100.6	90.3	90.3	90.3	90.3	90.3	224.9	55.6	227.3
103.0	103.0	103.0	103.0	103.0	103.0	88.9	119.3	92.7	117.1	103.0	103.0	103.0	103.0	103.0	230.2	55.6	232.6
116.3	116.3	116.3	116.3	116.3	116.3	97.8	138.1	103.2	134.5	116.3	116.3	116.3	116.3	116.3	235.9	55.6	236.0
130.4	130.4	130.4	130.4	130.4	130.4	107.1	158.2	114.2	152.7	130.4	130.4	130.4	130.4	130.4	248.4	67.1	248.3
145.1	145.1	145.1	145.1	145.1	145.1	116.6	179.7	125.7	171.8	145.1	145.1	145.1	145.1	145.1	260.0	77.9	261.5
160.6	160.6	160.6	160.6	160.6	160.6	126.3	202.8	137.8	191.9	160.6	160.6	160.6	160.6	160.6	272.7	81.8	276.4
176.8	176.8	176.8	176.8	176.8	176.8	136.4	227.4	150.6	213.0	176.8	176.8	176.8	176.8	176.8	287.6	85.9	292.0
193.9	193.9	193.9	193.9	193.9	193.9	146.8	253.8	163.9	235.2	193.9	193.9	193.9	193.9	193.9	303.8	90.2	307.3
211.8	211.8	211.8	211.8	211.8	211.8	157.5	282.0	178.0	258.4	211.8	211.8	211.8	211.8	211.8	320.2	94.7	322.2
230.6	230.6	230.6	230.6	230.6	230.6	168.5	312.2	192.7	282.8	230.6	230.6	230.6	230.6	230.6	337.0	99.5	339.6
250.3	250.3	250.3	250.3	250.3	250.3	179.8	344.5	208.2	308.5	250.3	250.3	250.3	250.3	250.3	354.3	104.4	357.1
271.0	271.0	271.0	271.0	271.0	271.0	191.5	379.0	224.4	335.4	271.0	271.0	271.0	271.0	271.0	371.3	109.7	375.3
292.8	292.8	292.8	292.8	292.8	292.8	203.6	416.0	241.4	363.6	292.8	292.8	292.8	292.8	292.8	390.7	115.1	394.8
315.6	315.6	315.6	315.6	315.6	315.6	216.0	455.6	259.3	393.3	315.6	315.6	315.6	315.6	315.6	410.3	120.9	417.2

339.6	339.6	339.6	339.6	339.6	339.6	228.7	497.9	278.1	424.5	339.6	339.6	339.6	339.6	339.6	431.2	126.9	438.4
364.8	364.8	364.8	364.8	364.8	364.8	241.9	543.2	297.9	457.2	364.8	364.8	364.8	364.8	364.8	453.1	133.3	460.6
391.3	391.3	391.3	391.3	391.3	391.3	255.4	591.7	318.6	491.5	391.3	391.3	391.3	391.3	391.3	476.1	140.0	483.7
419.0	419.0	419.0	419.0	419.0	419.0	269.4	643.6	340.4	527.6	419.0	419.0	419.0	419.0	419.0	500.1	146.9	508.3
448.2	448.2	448.2	448.2	448.2	448.2	283.7	699.1	363.2	565.5	448.2	448.2	448.2	448.2	448.2	525.4	154.3	534.6
478.8	478.8	478.8	478.8	478.8	478.8	298.5	758.4	387.2	605.3	478.8	478.8	478.8	478.8	478.8	552.5	162.0	562.8
511.0	511.0	511.0	511.0	511.0	511.0	313.8	822.0	412.4	647.0	511.0	511.0	511.0	511.0	511.0	580.9	170.1	592.3
544.7	544.7	544.7	544.7	544.7	544.7	329.5	890.0	438.9	690.9	544.7	544.7	544.7	544.7	544.7	610.7	178.6	623.3
580.2	580.2	580.2	580.2	580.2	580.2	345.6	962.7	466.6	736.9	580.2	580.2	580.2	580.2	580.2	641.8	187.5	655.8
617.4	617.4	617.4	617.4	617.4	617.4	362.3	1040.6	495.8	785.2	617.4	617.4	617.4	617.4	617.4	674.2	196.9	685.8
656.5	656.5	656.5	656.5	656.5	656.5	379.4	1123.8	526.4	836.0	656.5	656.5	656.5	656.5	656.5	708.0	206.8	719.7
697.5	697.5	697.5	697.5	697.5	697.5	397.1	1213.0	558.6	889.3	697.5	697.5	697.5	697.5	697.5	743.4	217.1	754.9
740.6	740.6	740.6	740.6	740.6	740.6	415.3	1308.3	592.3	945.3	740.6	740.6	740.6	740.6	740.6	781.3	228.0	792.3
785.8	785.8	785.8	785.8	785.8	785.8	434.1	1410.4	627.8	1004.0	785.8	785.8	785.8	785.8	785.8	821.2	239.4	830.7

Annual power generation (MWh)---Solar PV

Scenario 0 No carbon tax	Scenario 1	Scenario 2 coal price high	Scenario 3 coal price low	Scenario 4 natural gas price high	Scenario 5 natural gas price low	Scenario 6 demand growth 3%	Scenario 7 demand growth 7%	Scenario 8 renewables penetration 50%	Scenario 9 renewables penetration 70%	Scenario 10 No CCGT	Scenario 11 No USC	Scenario 12 No new USC	Scenario 13 No nuclear	Scenario 14 No new nuclear	Scenario 15 30$/tonneCO2 No capacity limit	Scenario 16 0$/tonneCO2 No capacity limit	Scenario 17 No capacity limit
18.3	18.3	18.3	18.3	18.3	18.3	17.0	19.7	17.4	19.3	18.3	18.3	18.3	18.3	18.3	81.3	28.4	82.3
24.0	24.0	24.0	24.0	24.0	24.0	21.3	27.0	22.1	25.9	24.0	24.0	24.0	24.0	24.0	104.4	40.4	105.3
30.0	30.0	30.0	30.0	30.0	30.0	25.6	34.7	27.0	32.9	30.0	30.0	30.0	30.0	30.0	117.5	54.7	117.8
36.3	36.3	36.3	36.3	36.3	36.3	30.1	43.0	32.1	40.2	36.3	36.3	36.3	36.3	36.3	139.7	68.5	139.7
42.8	42.8	42.8	42.8	42.8	42.8	34.7	51.9	37.5	47.9	42.8	42.8	42.8	42.8	42.8	164.6	78.2	168.4
49.8	49.8	49.8	49.8	49.8	49.8	39.5	61.4	43.2	56.0	49.8	49.8	49.8	49.8	49.8	173.3	83.3	177.8
57.0	57.0	57.0	57.0	57.0	57.0	44.4	71.5	49.2	64.5	57.0	57.0	57.0	57.0	57.0	184.8	88.5	188.3
64.6	64.6	64.6	64.6	64.6	64.6	49.4	82.4	55.4	73.4	64.6	64.6	64.6	64.6	64.6	195.5	92.9	199.0
72.6	72.6	72.6	72.6	72.6	72.6	54.6	94.0	62.0	82.7	72.6	72.6	72.6	72.6	72.6	207.1	97.5	210.2
81.0	81.0	81.0	81.0	81.0	81.0	60.0	106.5	68.9	92.5	81.0	81.0	81.0	81.0	81.0	218.6	102.4	223.0
89.8	89.8	89.8	89.8	89.8	89.8	65.5	119.8	76.2	102.8	89.8	89.8	89.8	89.8	89.8	230.5	107.5	235.9
99.1	99.1	99.1	99.1	99.1	99.1	71.1	134.1	83.8	113.7	99.1	99.1	99.1	99.1	99.1	242.7	112.9	250.3
108.8	108.8	108.8	108.8	108.8	108.8	77.0	149.3	91.8	125.0	108.8	108.8	108.8	108.8	108.8	255.5	118.6	264.6
119.0	119.0	119.0	119.0	119.0	119.0	83.0	165.6	100.2	137.0	119.0	119.0	119.0	119.0	119.0	272.4	124.5	279.6
129.7	129.7	129.7	129.7	129.7	129.7	89.2	183.1	109.0	149.5	129.7	129.7	129.7	129.7	129.7	286.4	130.7	296.0
141.0	141.0	141.0	141.0	141.0	141.0	95.6	201.8	118.2	162.6	141.0	141.0	141.0	141.0	141.0	300.8	137.3	311.7

152.8	152.8	152.8	152.8	152.8	152.8	102.2	221.8	127.9	176.5	152.8	152.8	152.8	152.8	152.8	315.2	144.1	328.9
165.2	165.2	165.2	165.2	165.2	165.2	109.0	243.2	138.1	191.0	165.2	165.2	165.2	165.2	165.2	331.3	151.3	346.9
178.3	178.3	178.3	178.3	178.3	178.3	116.0	266.1	148.8	206.2	178.3	178.3	178.3	178.3	178.3	348.6	158.9	367.1
191.9	191.9	191.9	191.9	191.9	191.9	123.1	290.6	160.1	222.2	191.9	191.9	191.9	191.9	191.9	366.2	166.8	386.3
206.3	206.3	206.3	206.3	206.3	206.3	130.6	316.8	171.9	239.0	206.3	206.3	206.3	206.3	206.3	385.0	175.2	405.8
221.4	221.4	221.4	221.4	221.4	221.4	138.2	344.8	184.3	256.6	221.4	221.4	221.4	221.4	221.4	404.8	183.9	426.3
237.2	237.2	237.2	237.2	237.2	237.2	146.0	374.8	197.3	275.1	237.2	237.2	237.2	237.2	237.2	425.5	193.1	447.7
253.8	253.8	253.8	253.8	253.8	253.8	154.1	406.9	211.0	294.5	253.8	253.8	253.8	253.8	253.8	447.3	202.8	470.3
271.3	271.3	271.3	271.3	271.3	271.3	162.5	441.3	225.3	315.0	271.3	271.3	271.3	271.3	271.3	470.2	212.9	493.9
289.6	289.6	289.6	289.6	289.6	289.6	171.1	478.0	240.4	336.4	289.6	289.6	289.6	289.6	289.6	493.5	223.6	519.5
308.9	308.9	308.9	308.9	308.9	308.9	179.9	517.3	256.2	358.9	308.9	308.9	308.9	308.9	308.9	518.1	234.8	545.8
329.1	329.1	329.1	329.1	329.1	329.1	189.0	559.4	272.8	382.5	329.1	329.1	329.1	329.1	329.1	544.0	246.5	574.3
350.3	350.3	350.3	350.3	350.3	350.3	198.4	604.4	290.3	407.3	350.3	350.3	350.3	350.3	350.3	571.4	258.8	602.7
372.6	372.6	372.6	372.6	372.6	372.6	208.1	652.6	308.6	433.4	372.6	372.6	372.6	372.6	372.6	600.4	271.8	633.6

Annual installed capacity (GW)---Nuclear

Scenario 0 No carbon tax	Scenario 1	Scenario 2 coal price high	Scenario 3 coal price low	Scenario 4 gas price high	Scenario 5 gas price low	Scenario 6 demand growth 3%	Scenario 7 demand growth 7%	Scenario 8 renewables penetration 50%	Scenario 9 renewables penetration 70%	Scenario 10 No CCGT	Scenario 11 No USC	Scenario 12 No new USC	Scenario 13 No nuclear	Scenario 14 No new nuclear	Scenario 15 30$/tonneCO2 No capacity limit	Scenario 16 0$/tonneCO2 No capacity limit	Scenario 17 No capacity limit
5.0	5.0	5.0	5.0	5.0	5.0	5.2	4.9	5.0	5.0	5.0	5.0	5.0	0.0	4.5	4.5	4.5	4.5
5.6	5.6	5.6	5.6	5.6	5.6	6.0	5.3	5.6	5.6	5.6	5.6	5.6	0.0	4.5	4.5	4.5	4.5
6.2	6.2	6.2	6.2	6.2	6.2	6.8	5.7	6.2	6.2	6.2	6.2	6.2	0.0	4.5	4.5	4.5	4.5
6.8	6.8	6.8	6.8	6.8	6.8	7.6	6.2	6.8	6.8	6.8	6.8	6.8	0.0	4.5	4.5	4.5	4.5
7.4	7.4	7.4	7.4	7.4	7.4	8.4	6.6	7.4	7.4	7.4	7.4	7.4	0.0	4.5	4.5	4.5	4.5
8.1	8.1	8.1	8.1	8.1	8.1	9.3	7.2	8.1	8.1	8.1	8.1	8.1	0.0	4.5	4.5	4.5	4.5
8.8	8.8	8.8	8.8	8.8	8.8	10.2	7.7	8.8	8.8	8.8	8.8	8.8	0.0	4.5	4.5	4.5	4.5
9.6	9.6	9.6	9.6	9.6	9.6	11.1	8.3	9.6	9.6	9.6	9.6	9.6	0.0	4.5	4.5	4.5	4.5
10.4	10.4	10.4	10.4	10.4	10.4	12.0	9.0	10.4	10.4	10.4	10.4	10.4	0.0	4.5	4.5	4.5	4.5
11.2	11.2	11.2	11.2	11.2	11.2	13.0	9.7	11.2	11.2	11.2	11.2	11.2	0.0	4.5	4.5	4.5	4.5
12.1	12.1	12.1	12.1	12.1	12.1	14.0	10.4	12.1	12.1	12.1	12.1	12.1	0.0	4.5	4.5	4.5	4.5
13.0	13.0	13.0	13.0	13.0	13.0	15.1	11.2	13.0	13.0	13.0	13.0	13.0	0.0	4.5	4.5	4.5	4.5
14.0	14.0	14.0	14.0	14.0	14.0	16.1	12.1	14.0	14.0	14.0	14.0	14.0	0.0	4.5	4.5	4.5	4.5
15.0	15.0	15.0	15.0	15.0	15.0	17.2	13.0	15.0	15.0	15.0	15.0	15.0	0.0	4.5	4.5	4.5	4.5
16.0	16.0	16.0	16.0	16.0	16.0	18.3	13.9	16.0	16.0	16.0	16.0	16.0	0.0	4.5	4.5	4.5	4.5
17.1	17.1	17.1	17.1	17.1	17.1	19.5	15.0	17.1	17.1	17.1	17.1	17.1	0.0	4.5	4.5	4.5	4.5

18.3	18.3	18.3	18.3	18.3	18.3	20.7	16.1	18.3	18.3	18.3	18.3	18.3	0.0	4.5	4.5	4.5	4.5
19.5	19.5	19.5	19.5	19.5	19.5	21.9	17.3	19.5	19.5	19.5	19.5	19.5	0.0	4.5	4.5	4.5	4.5
20.8	20.8	20.8	20.8	20.8	20.8	23.2	18.5	20.8	20.8	20.8	20.8	20.8	0.0	4.5	4.5	4.5	4.5
22.2	22.2	22.2	22.2	22.2	22.2	24.5	19.9	22.2	22.2	22.2	22.2	22.2	0.0	4.5	4.5	4.5	4.5
23.6	23.6	23.6	23.6	23.6	23.6	25.8	21.4	23.6	23.6	23.6	23.6	23.6	0.0	4.5	4.5	4.5	4.5
25.1	25.1	25.1	25.1	25.1	25.1	27.2	22.9	25.1	25.1	25.1	25.1	25.1	0.0	4.5	4.5	4.5	4.5
26.6	26.6	26.6	26.6	26.6	26.6	28.7	24.6	26.6	26.6	26.6	26.6	26.6	0.0	4.5	4.5	4.5	4.5
28.3	28.3	28.3	28.3	28.3	28.3	30.1	26.4	28.3	28.3	28.3	28.3	28.3	0.0	4.5	4.5	4.5	4.5
30.0	30.0	30.0	30.0	30.0	30.0	31.6	28.3	30.0	30.0	30.0	30.0	30.0	0.0	4.5	4.5	4.5	4.5
31.8	31.8	31.8	31.8	31.8	31.8	33.2	30.3	31.8	31.8	31.8	31.8	31.8	0.0	4.5	4.5	4.5	6.6
33.7	33.7	33.7	33.7	33.7	33.7	34.8	32.5	33.7	33.7	33.7	33.7	33.7	0.0	4.5	4.5	4.5	6.9
35.7	35.7	35.7	35.7	35.7	35.7	36.5	34.9	35.7	35.7	35.7	35.7	35.7	0.0	4.5	4.5	4.5	7.4
37.8	37.8	37.8	37.8	37.8	37.8	38.2	37.4	37.8	37.8	37.8	37.8	37.8	0.0	4.5	4.5	4.5	8.9
40.0	40.0	40.0	40.0	40.0	40.0	39.9	40.0	40.0	40.0	40.0	40.0	40.0	0.0	4.5	4.5	4.5	10.2

Annual installed capacity (GW)---USC

Scenario 0 No carbon tax	Scenario 1	Scenario 2 coal price high	Scenario 3 coal price low	Scenario 4 gas price high	Scenario 5 gas price low	Scenario 6 demand growth 3%	Scenario 7 demand growth 7%	Scenario 8 renewables penetration 50%	Scenario 9 renewables penetration 70%	Scenario 10 No CCGT	Scenario 11 No USC	Scenario 12 No new USC	Scenario 13 No nuclear	Scenario 14 No new nuclear	Scenario 15 30$/tonneCO2 No capacity limit	Scenario 16 0$/tonneCO2 No capacity limit	Scenario 17 No capacity limit
74.0	74.0	74.0	74.0	74.0	28.0	73.9	74.0	74.0	74.0	74.0	0.0	74.0	74.0	74.0	57.4	74.0	57.3
74.0	74.0	74.0	74.0	74.0	28.0	73.9	74.0	74.0	74.0	74.0	0.0	74.0	74.0	74.0	57.4	74.0	57.3
74.0	74.0	74.0	74.0	74.0	28.0	73.9	74.0	74.0	74.0	74.2	0.0	74.0	74.0	74.0	57.4	74.0	57.3
74.0	74.0	74.0	74.0	74.0	28.0	73.9	74.0	74.0	74.0	76.7	0.0	74.0	74.0	74.0	57.4	74.0	57.3
74.0	74.0	74.0	74.0	74.0	28.0	73.9	74.0	74.0	74.0	79.5	0.0	74.0	74.0	74.0	57.4	74.0	57.3
74.0	74.0	74.0	74.0	74.0	28.0	73.9	74.0	74.0	74.0	82.2	0.0	74.0	74.0	74.0	57.4	74.0	57.3
74.0	74.0	74.0	74.0	74.0	28.0	73.9	74.0	74.0	74.0	85.3	0.0	74.0	74.0	74.0	57.4	76.9	57.3
74.0	74.0	74.0	74.0	76.1	28.0	73.9	74.0	74.0	74.0	88.5	0.0	74.0	74.0	74.0	57.4	81.0	57.3
75.2	74.0	74.0	75.0	78.4	28.0	73.9	74.8	74.0	74.0	91.9	0.0	74.0	74.0	74.0	57.4	85.3	57.3
77.7	74.0	74.0	77.3	81.1	28.0	73.9	76.9	74.0	74.0	95.4	0.0	74.0	74.1	74.0	57.4	89.8	57.3
80.4	74.0	74.0	79.6	83.5	28.0	73.9	79.1	74.0	74.0	99.1	0.0	74.0	75.4	74.0	57.4	94.5	57.3
83.4	74.0	74.0	82.1	86.5	28.0	73.9	81.5	74.0	74.0	103.0	0.0	74.0	76.8	74.0	57.4	99.4	57.3
86.5	74.0	74.0	83.1	89.7	28.0	73.9	84.0	74.0	74.0	107.6	0.0	74.0	78.0	74.0	57.4	104.6	57.3
89.8	74.0	74.0	83.1	92.8	28.0	73.9	86.3	74.0	74.0	112.2	0.0	74.0	78.6	74.2	57.5	110.1	57.3
93.2	74.0	74.0	83.4	96.4	28.0	73.9	87.2	74.0	74.0	116.4	0.0	74.0	79.7	75.2	60.4	115.8	57.3
96.7	74.0	74.0	85.6	99.8	28.0	73.9	88.0	74.0	74.1	121.7	0.0	74.0	79.7	75.3	63.6	121.8	58.8
100.5	74.0	74.0	86.5	103.4	28.0	73.9	88.4	74.0	76.0	127.0	0.0	74.0	79.7	75.4	67.2	128.2	61.6
104.1	74.0	74.0	89.3	107.4	28.0	73.9	88.4	74.0	78.2	132.6	0.0	74.0	79.7	75.4	70.7	134.8	64.2

107.9	74.0	74.0	92.7	111.2	28.0	73.9	88.4	74.0	80.3	138.2	0.0	74.0	79.7	75.4	74.2	141.8	66.9
112.2	74.0	74.0	96.1	115.7	28.0	73.9	88.4	74.0	82.3	144.7	0.0	74.0	79.7	75.4	78.1	149.1	70.2
116.7	74.0	74.0	98.4	120.2	28.0	73.9	88.4	74.0	84.8	149.9	0.0	74.0	79.7	75.4	82.1	156.7	73.4
121.6	74.0	74.0	101.2	121.8	28.0	73.9	88.4	74.0	87.3	154.4	0.0	74.0	79.7	75.4	86.2	164.8	77.1
126.3	74.0	74.0	104.1	123.9	28.0	73.9	88.4	74.0	90.2	158.8	0.0	74.0	79.7	75.4	90.6	173.3	80.1
131.7	74.0	74.0	107.6	125.6	28.0	73.9	88.4	74.0	92.9	162.7	0.0	74.0	79.7	75.4	95.2	182.2	83.2
137.1	74.0	74.0	111.1	127.6	28.0	73.9	88.4	74.0	95.8	167.8	0.0	74.0	79.7	75.4	100.0	191.5	87.4
143.0	74.0	74.0	113.9	130.5	28.0	73.9	88.4	74.0	99.2	172.9	0.0	74.0	79.7	75.4	105.3	201.3	88.9
149.0	74.0	74.0	117.4	132.4	28.0	73.9	88.4	74.0	102.4	178.5	0.0	74.0	79.7	75.4	110.8	211.6	91.5
155.2	74.0	74.0	120.7	135.2	28.0	73.9	88.4	74.0	106.0	184.3	0.0	74.0	79.7	75.4	116.6	222.4	95.7
162.0	74.0	74.0	124.0	138.3	28.0	73.9	88.4	74.0	109.9	190.2	0.0	74.0	79.7	75.4	122.6	233.7	97.6
168.9	74.0	74.0	128.6	142.6	28.0	73.9	88.4	74.0	113.3	197.1	0.0	74.0	79.7	75.4	128.8	245.6	100.7

Annual installed capacity (GW)---CCGT

Scenario 0 No carbon tax	Scenario 1	Scenario 2 coal price high	Scenario 3 coal price low	Scenario 4 gas price high	Scenario 5 gas price low	Scenario 6 demand growth 3%	Scenario 7 demand growth 7%	Scenario 8 renewables penetration 50%	Scenario 9 renewables penetration 70%	Scenario 10 No CCGT	Scenario 11 No USC	Scenario 12 No new USC	Scenario 13 No nuclear	Scenario 14 No new nuclear	Scenario 15 30$/tonneCO2 No capacity limit	Scenario 16 0$/tonneCO2 No capacity limit	Scenario 17 No capacity limit
0.5	0.5	0.5	0.5	0.5	48.1	0.5	0.5	0.5	0.5	0.0	71.1	0.5	2.1	0.5	0.5	0.5	0.5
0.5	0.5	0.5	0.5	0.5	49.7	0.5	2.3	0.5	0.5	0.0	72.8	0.5	4.3	0.5	0.5	0.5	0.5
1.5	1.5	2.0	1.5	1.0	51.6	0.5	6.3	2.2	0.5	0.0	75.5	1.5	7.7	3.2	0.5	0.5	0.5
3.7	3.7	5.0	3.7	3.7	53.0	0.5	11.0	5.2	2.4	0.0	77.7	3.7	10.5	6.0	0.5	1.4	0.5
6.5	6.5	8.1	6.5	6.2	55.4	0.5	16.4	7.8	5.0	0.0	80.5	6.5	13.9	9.4	1.1	4.9	0.6
9.3	9.3	10.5	9.3	9.1	58.2	0.5	21.1	10.7	6.9	0.0	83.3	9.3	17.5	13.0	4.2	8.4	3.5
12.5	12.5	12.9	12.5	12.5	60.9	0.5	27.4	14.0	10.1	0.0	86.5	12.5	21.3	16.8	7.0	9.2	6.5
15.2	15.2	16.4	15.2	12.9	63.8	0.5	33.9	17.7	12.8	0.0	89.2	15.2	24.8	20.3	10.3	9.7	9.6
17.7	18.9	19.6	17.9	14.4	66.8	0.5	40.1	21.4	16.3	0.0	92.9	18.9	29.3	24.8	13.5	10.2	12.9
18.9	22.6	23.3	19.3	15.2	70.3	0.5	45.4	25.0	19.9	0.0	96.6	22.6	33.7	29.3	17.0	10.7	16.2
20.2	26.6	27.8	21.0	16.7	74.1	1.2	50.6	29.2	23.3	0.0	100.6	26.6	37.3	34.2	20.7	11.2	19.8
21.3	30.7	31.9	22.6	18.1	78.5	2.4	57.0	33.5	26.9	0.0	104.7	30.7	40.9	39.2	24.7	11.8	23.4
22.6	35.1	35.6	24.4	19.3	82.5	3.6	63.8	38.2	31.2	0.0	109.1	35.1	45.1	44.6	28.9	12.4	27.4
23.4	39.2	40.1	25.3	20.1	86.7	4.7	71.6	43.1	35.3	0.0	113.2	39.2	49.6	49.5	32.7	13.0	31.5
24.8	44.0	45.0	27.4	21.3	91.6	6.0	81.4	48.1	39.9	0.0	118.0	44.0	54.3	54.3	34.4	13.6	35.7
26.4	49.1	49.8	29.3	23.0	96.4	6.8	91.9	53.4	44.6	0.0	123.1	49.1	60.5	60.4	36.1	14.3	38.9

28.0	54.5	55.1	31.5	25.0	101.2	7.8	103.7	59.1	47.5	0.0	128.5	54.5	67.1	67.0	37.9	15.0	40.8
30.0	60.1	60.5	33.6	26.6	106.9	9.1	116.9	64.9	50.3	0.0	134.1	60.1	73.9	73.8	39.8	15.8	43.4
32.3	66.3	66.5	36.1	28.6	112.9	10.4	131.0	71.3	54.1	0.0	140.3	66.3	81.3	81.2	41.9	16.6	45.8
34.3	72.4	72.9	38.5	30.7	119.2	11.6	146.0	77.6	58.2	0.0	146.5	72.4	88.8	88.7	44.0	17.4	48.2
36.4	79.1	79.4	41.4	33.0	125.7	12.6	162.1	84.7	62.0	0.0	153.1	79.1	97.0	96.9	46.3	18.3	51.1
38.3	85.6	86.4	44.3	34.4	132.7	13.6	179.8	92.1	66.0	0.0	159.9	85.6	104.9	104.8	48.6	19.2	53.7
40.5	92.8	93.7	47.3	37.0	140.1	14.7	198.6	99.8	70.1	0.0	166.8	92.8	113.7	113.6	51.1	20.2	57.4
43.2	100.8	101.4	50.7	40.1	147.6	15.9	218.3	104.7	74.6	0.0	174.9	100.8	123.4	123.3	53.7	21.2	61.3
46.3	109.3	109.6	54.8	42.9	155.7	17.1	238.7	109.5	79.2	0.0	183.4	109.3	133.1	133.5	56.4	22.2	64.5
48.9	117.7	118.2	58.1	46.1	164.3	18.6	261.3	115.5	83.7	0.0	191.9	117.7	139.7	143.6	59.2	23.3	68.7
51.8	126.1	127.0	61.9	49.4	173.1	20.0	285.8	122.4	89.0	0.0	200.7	126.1	146.0	150.6	62.2	24.5	73.9
54.8	135.6	136.1	66.4	52.9	182.2	21.7	310.6	128.7	94.3	0.0	210.1	135.6	154.6	159.2	65.3	25.7	77.7
57.5	145.6	145.8	71.1	56.8	191.9	23.4	338.2	136.2	99.6	0.0	219.6	145.6	164.2	169.2	68.5	27.0	83.4
60.9	155.7	156.0	75.5	59.6	202.1	25.2	368.2	145.1	106.0	0.0	229.9	155.9	174.5	179.3	72.0	28.4	88.5

Annual installed capacity (GW)---USC-CCUS

Scenario 0 No carbon tax	Scenario 1	Scenario 2 coal price high	Scenario 3 coal price low	Scenario 4 gas price high	Scenario 5 gas price low	Scenario 6 demand growth 3%	Scenario 7 demand growth 7%	Scenario 8 renewables penetration 50%	Scenario 9 renewables penetration 70%	Scenario 10 No CCGT	Scenario 11 No USC	Scenario 12 No new USC	Scenario 13 No nuclear	Scenario 14 No new nuclear	Scenario 15 30$/tonneCO2 No capacity limit	Scenario 16 0$/tonneCO2 No capacity limit	Scenario 17 No capacity limit
			0.0	0.0				0.0		0.0			0.0	0.0			
			0.0	0.0				0.0		0.0			0.0	0.0			
			0.0	0.0				0.0		0.0			0.0	0.0			
			0.0	0.0				0.0		0.0			0.0	0.0			
			0.0	0.0				0.0		0.0			0.0	0.0			
			0.0	0.0				0.0		0.0			0.0	0.0			
			0.0	0.0				0.0		0.0			0.0	0.0			
			0.0	0.0				0.0		0.0			0.0	0.0			
			0.0	0.0				0.0		0.0			0.0	0.0			
			0.0	0.0				0.0		0.0			0.0	0.0			
			0.0	0.0				0.0		0.0			0.0	0.0			
			0.0	0.0				0.0		0.0			0.0	0.0			
			1.6	0.0				0.0		0.0			0.0	0.0			
			4.9	0.0				0.0		0.0			0.0	0.0			
			7.2	0.0				0.0		0.0			0.0	0.0			
			8.1	0.0				0.0		0.0			0.0	0.0			

			10.5	0.0				0.0		0.0			0.0	0.0			
			11.2	0.0				0.0		0.0			0.0	0.0			
			11.4	0.0				0.0		0.0			0.0	0.0			
			11.8	0.0				0.0		0.0			0.0	0.0			
			13.4	0.0				0.0		1.5			0.0	0.0			
			14.5	3.4				0.0		4.1			0.0	0.0			
			15.4	5.9				0.0		6.8			0.0	0.0			
			16.6	8.7				3.1		10.3			0.0	0.0			
			17.4	12.0				6.7		13.2			0.5	0.0			
			19.6	14.4				9.6		16.2			4.1	0.0			
			20.8	18.2				12.1		19.1			8.0	3.4			
			22.5	21.4				15.6		22.5			10.9	6.2			
			24.4	24.5				18.5		26.0			13.4	8.3			
			25.6	27.3				20.6		29.5			15.5	10.6			

Annual installed capacity (GW)---Wind

Scenario 0 No carbon tax	Scenario 1	Scenario 2 coal price high	Scenario 3 coal price low	Scenario 4 natural gas price high	Scenario 5 natural gas price low	Scenario 6 demand growth 3%	Scenario 7 demand growth 7%	Scenario 8 renewables penetration 50%	Scenario 9 renewables penetration 70%	Scenario 10 No CCGT	Scenario 11 No USC	Scenario 12 No new USC	Scenario 13 No nuclear	Scenario 14 No new nuclear	Scenario 15 30$/tonneCO2 No capacity limit	Scenario 16 0$/tonneCO2 No capacity limit	Scenario 17 No capacity limit
22.4	22.4	22.4	22.4	22.4	22.4	21.4	23.6	21.6	23.5	22.4	22.4	22.4	22.4	22.4	73.1	18.7	73.1
26.3	26.3	26.3	26.3	26.3	26.3	24.2	28.7	24.7	28.6	26.3	26.3	26.3	26.3	26.3	73.7	18.7	73.6
30.4	30.4	30.4	30.4	30.4	30.4	27.0	34.3	27.9	33.9	30.4	30.4	30.4	30.4	30.4	75.8	18.7	76.6
34.7	34.7	34.7	34.7	34.7	34.7	29.9	40.2	31.2	39.5	34.7	34.7	34.7	34.7	34.7	77.5	18.7	78.3
39.2	39.2	39.2	39.2	39.2	39.2	33.0	46.5	34.8	45.3	39.2	39.2	39.2	39.2	39.2	79.5	18.7	79.5
43.9	43.9	43.9	43.9	43.9	43.9	36.1	53.3	38.5	51.4	43.9	43.9	43.9	43.9	43.9	83.7	22.6	83.6
48.9	48.9	48.9	48.9	48.9	48.9	39.3	60.5	42.3	57.9	48.9	48.9	48.9	48.9	48.9	87.6	26.2	88.1
54.1	54.1	54.1	54.1	54.1	54.1	42.6	68.3	46.4	64.6	54.1	54.1	54.1	54.1	54.1	91.9	27.6	93.1
59.5	59.5	59.5	59.5	59.5	59.5	45.9	76.6	50.7	71.7	59.5	59.5	59.5	59.5	59.5	96.9	28.9	98.3
65.3	65.3	65.3	65.3	65.3	65.3	49.4	85.5	55.2	79.2	65.3	65.3	65.3	65.3	65.3	102.3	30.4	103.5
71.3	71.3	71.3	71.3	71.3	71.3	53.0	95.0	59.9	87.0	71.3	71.3	71.3	71.3	71.3	107.8	31.9	108.5
77.7	77.7	77.7	77.7	77.7	77.7	56.8	105.1	64.9	95.3	77.7	77.7	77.7	77.7	77.7	113.5	33.5	114.4
84.3	84.3	84.3	84.3	84.3	84.3	60.6	116.0	70.1	103.9	84.3	84.3	84.3	84.3	84.3	119.3	35.2	120.3
91.3	91.3	91.3	91.3	91.3	91.3	64.5	127.7	75.6	113.0	91.3	91.3	91.3	91.3	91.3	125.1	36.9	126.4
98.6	98.6	98.6	98.6	98.6	98.6	68.6	140.1	81.3	122.5	98.6	98.6	98.6	98.6	98.6	131.6	38.8	133.0
106.3	106.3	106.3	106.3	106.3	106.3	72.7	153.4	87.4	132.5	106.3	106.3	106.3	106.3	106.3	138.2	40.7	140.5

114.4	114.4	114.4	114.4	114.4	114.4	77.0	167.7	93.7	143.0	114.4	114.4	114.4	114.4	114.4	145.2	42.8	147.7
122.9	122.9	122.9	122.9	122.9	122.9	81.5	183.0	100.3	154.0	122.9	122.9	122.9	122.9	122.9	152.6	44.9	155.1
131.8	131.8	131.8	131.8	131.8	131.8	86.0	199.3	107.3	165.6	131.8	131.8	131.8	131.8	131.8	160.4	47.1	162.9
141.1	141.1	141.1	141.1	141.1	141.1	90.7	216.8	114.6	177.7	141.1	141.1	141.1	141.1	141.1	168.4	49.5	171.2
151.0	151.0	151.0	151.0	151.0	151.0	95.6	235.5	122.3	190.5	151.0	151.0	151.0	151.0	151.0	177.0	52.0	180.1
161.3	161.3	161.3	161.3	161.3	161.3	100.5	255.5	130.4	203.9	161.3	161.3	161.3	161.3	161.3	186.1	54.6	189.6
172.1	172.1	172.1	172.1	172.1	172.1	105.7	276.9	138.9	217.9	172.1	172.1	172.1	172.1	172.1	195.7	57.3	199.5
183.5	183.5	183.5	183.5	183.5	183.5	111.0	299.8	147.8	232.7	183.5	183.5	183.5	183.5	183.5	205.7	60.2	209.9
195.4	195.4	195.4	195.4	195.4	195.4	116.4	324.3	157.2	248.2	195.4	195.4	195.4	195.4	195.4	216.2	63.2	220.9
207.9	207.9	207.9	207.9	207.9	207.9	122.0	350.5	167.0	264.5	207.9	207.9	207.9	207.9	207.9	227.1	66.3	231.0
221.1	221.1	221.1	221.1	221.1	221.1	127.8	378.5	177.3	281.6	221.1	221.1	221.1	221.1	221.1	238.5	69.6	242.4
234.9	234.9	234.9	234.9	234.9	234.9	133.8	408.5	188.1	299.5	234.9	234.9	234.9	234.9	234.9	250.4	73.1	254.3
249.4	249.4	249.4	249.4	249.4	249.4	139.9	440.7	199.5	318.4	249.4	249.4	249.4	249.4	249.4	263.2	76.8	266.9
264.7	264.7	264.7	264.7	264.7	264.7	146.2	475.0	211.4	338.2	264.7	264.7	264.7	264.7	264.7	276.6	80.6	279.8

Annual installed capacity (GW)---Solar PV

Scenario 0 No carbon tax	Scenario 1	Scenario 2 coal price high	Scenario 3 coal price low	Scenario 4 natural gas price high	Scenario 5 natural gas price low	Scenario 6 demand growth 3%	Scenario 7 demand growth 7%	Scenario 8 renewables penetration 50%	Scenario 9 renewables penetration 70%	Scenario 10 No CCGT	Scenario 11 No USC	Scenario 12 No new USC	Scenario 13 No nuclear	Scenario 14 No new nuclear	Scenario 15 30$/tonneCO2 No capacity limit	Scenario 16 0$/tonneCO2 No capacity limit	Scenario 17 No capacity limit
11.1	11.1	11.1	11.1	11.1	11.1	10.3	11.9	10.5	11.6	11.1	11.1	11.1	11.1	11.1	49.1	17.2	49.7
14.5	14.5	14.5	14.5	14.5	14.5	12.9	16.3	13.3	15.7	14.5	14.5	14.5	14.5	14.5	63.1	24.4	63.6
18.1	18.1	18.1	18.1	18.1	18.1	15.5	21.0	16.3	19.9	18.1	18.1	18.1	18.1	18.1	71.0	33.1	71.2
21.9	21.9	21.9	21.9	21.9	21.9	18.2	26.0	19.4	24.3	21.9	21.9	21.9	21.9	21.9	84.5	41.4	84.5
25.9	25.9	25.9	25.9	25.9	25.9	21.0	31.4	22.7	29.0	25.9	25.9	25.9	25.9	25.9	99.5	47.3	101.8
30.1	30.1	30.1	30.1	30.1	30.1	23.9	37.1	26.1	33.8	30.1	30.1	30.1	30.1	30.1	104.8	50.3	107.5
34.5	34.5	34.5	34.5	34.5	34.5	26.8	43.3	29.7	39.0	34.5	34.5	34.5	34.5	34.5	111.7	53.5	113.8
39.1	39.1	39.1	39.1	39.1	39.1	29.9	49.8	33.5	44.4	39.1	39.1	39.1	39.1	39.1	118.2	56.2	120.3
43.9	43.9	43.9	43.9	43.9	43.9	33.0	56.9	37.5	50.0	43.9	43.9	43.9	43.9	43.9	125.2	59.0	127.1
49.0	49.0	49.0	49.0	49.0	49.0	36.3	64.4	41.7	55.9	49.0	49.0	49.0	49.0	49.0	132.2	61.9	134.8
54.3	54.3	54.3	54.3	54.3	54.3	39.6	72.4	46.0	62.2	54.3	54.3	54.3	54.3	54.3	139.4	65.0	142.6
59.9	59.9	59.9	59.9	59.9	59.9	43.0	81.1	50.6	68.7	59.9	59.9	59.9	59.9	59.9	146.7	68.3	151.3
65.8	65.8	65.8	65.8	65.8	65.8	46.6	90.3	55.5	75.6	65.8	65.8	65.8	65.8	65.8	154.5	71.7	160.0
72.0	72.0	72.0	72.0	72.0	72.0	50.2	100.2	60.6	82.8	72.0	72.0	72.0	72.0	72.0	164.7	75.3	169.1
78.4	78.4	78.4	78.4	78.4	78.4	53.9	110.7	65.9	90.4	78.4	78.4	78.4	78.4	78.4	173.1	79.0	179.0
85.3	85.3	85.3	85.3	85.3	85.3	57.8	122.0	71.5	98.3	85.3	85.3	85.3	85.3	85.3	181.9	83.0	188.5

92.4	92.4	92.4	92.4	92.4	92.4	61.8	134.1	77.3	106.7	92.4	92.4	92.4	92.4	92.4	190.6	87.1	198.9
99.9	99.9	99.9	99.9	99.9	99.9	65.9	147.0	83.5	115.5	99.9	99.9	99.9	99.9	99.9	200.3	91.5	209.7
107.8	107.8	107.8	107.8	107.8	107.8	70.1	160.9	90.0	124.7	107.8	107.8	107.8	107.8	107.8	210.8	96.1	221.9
116.0	116.0	116.0	116.0	116.0	116.0	74.5	175.7	96.8	134.3	116.0	116.0	116.0	116.0	116.0	221.4	100.9	233.6
124.7	124.7	124.7	124.7	124.7	124.7	78.9	191.5	103.9	144.5	124.7	124.7	124.7	124.7	124.7	232.8	105.9	245.4
133.8	133.8	133.8	133.8	133.8	133.8	83.6	208.5	111.4	155.1	133.8	133.8	133.8	133.8	133.8	244.7	111.2	257.7
143.4	143.4	143.4	143.4	143.4	143.4	88.3	226.6	119.3	166.3	143.4	143.4	143.4	143.4	143.4	257.3	116.8	270.7
153.5	153.5	153.5	153.5	153.5	153.5	93.2	246.0	127.6	178.1	153.5	153.5	153.5	153.5	153.5	270.5	122.6	284.3
164.0	164.0	164.0	164.0	164.0	164.0	98.2	266.8	136.2	190.4	164.0	164.0	164.0	164.0	164.0	284.3	128.7	298.6
175.1	175.1	175.1	175.1	175.1	175.1	103.4	289.0	145.3	203.4	175.1	175.1	175.1	175.1	175.1	298.4	135.2	314.1
186.8	186.8	186.8	186.8	186.8	186.8	108.8	312.8	154.9	217.0	186.8	186.8	186.8	186.8	186.8	313.3	141.9	330.0
199.0	199.0	199.0	199.0	199.0	199.0	114.3	338.2	165.0	231.3	199.0	199.0	199.0	199.0	199.0	328.9	149.0	347.3
211.8	211.8	211.8	211.8	211.8	211.8	120.0	365.5	175.5	246.3	211.8	211.8	211.8	211.8	211.8	345.5	156.5	364.4
225.3	225.3	225.3	225.3	225.3	225.3	125.8	394.6	186.6	262.0	225.3	225.3	225.3	225.3	225.3	363.0	164.3	383.1

Capacity factor---Nuclear

Scenario 0 No carbon tax	Scenario 1	Scenario 2 coal price high	Scenario 3 coal price low	Scenario 4 natural gas price high	Scenario 5 natural gas price low	Scenario 6 demand growth 3%	Scenario 7 demand growth 7%	Scenario 8 renewables penetration 50%	Scenario 9 renewables penetration 70%	Scenario 10 No CCGT	Scenario 11 No USC	Scenario 12 No new USC	Scenario 13 No nuclear	Scenario 14 No new nuclear	Scenario 15 30$/tonneCO2 No capacity limit	Scenario 16 0$/tonneCO2 No capacity limit	Scenario 17 No capacity limit
0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80		0.80	0.68	0.80	0.68
0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80		0.80	0.67	0.80	0.67
0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80		0.80	0.67	0.80	0.66
0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80		0.80	0.66	0.80	0.66
0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80		0.80	0.65	0.80	0.65
0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80		0.80	0.65	0.80	0.64
0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80		0.80	0.65	0.80	0.64
0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.79	0.80	0.80	0.80		0.80	0.65	0.80	0.64
0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.79	0.80	0.80	0.80		0.80	0.65	0.80	0.63
0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.79	0.80	0.78	0.80	0.80	0.80		0.80	0.64	0.80	0.63
0.79	0.79	0.79	0.79	0.79	0.79	0.80	0.78	0.80	0.76	0.79	0.79	0.79		0.80	0.64	0.80	0.63
0.79	0.79	0.79	0.79	0.79	0.79	0.80	0.78	0.80	0.75	0.79	0.79	0.79		0.79	0.64	0.80	0.62
0.78	0.78	0.78	0.78	0.78	0.78	0.79	0.77	0.80	0.74	0.78	0.78	0.78		0.79	0.64	0.80	0.62
0.78	0.78	0.78	0.78	0.78	0.78	0.79	0.76	0.80	0.72	0.78	0.78	0.78		0.79	0.64	0.80	0.62
0.77	0.77	0.77	0.77	0.77	0.77	0.78	0.76	0.80	0.71	0.77	0.77	0.77		0.78	0.63	0.80	0.62
0.76	0.76	0.76	0.76	0.76	0.76	0.78	0.75	0.79	0.70	0.76	0.76	0.76		0.77	0.63	0.80	0.61

0.76	0.76	0.76	0.76	0.76	0.76	0.77	0.74	0.79	0.68	0.76	0.76	0.76		0.77	0.64	0.80	0.61
0.75	0.75	0.75	0.75	0.75	0.75	0.76	0.73	0.79	0.67	0.75	0.75	0.75		0.76	0.64	0.80	0.61
0.74	0.74	0.74	0.74	0.74	0.74	0.75	0.73	0.79	0.65	0.74	0.74	0.74		0.76	0.64	0.80	0.61
0.73	0.73	0.73	0.73	0.73	0.73	0.74	0.72	0.78	0.64	0.73	0.73	0.73		0.75	0.64	0.80	0.61
0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.71	0.78	0.62	0.73	0.73	0.73		0.75	0.64	0.80	0.61
0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.71	0.78	0.61	0.72	0.72	0.72		0.74	0.64	0.80	0.61
0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.70	0.77	0.60	0.71	0.71	0.71		0.74	0.63	0.80	0.61
0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.69	0.77	0.59	0.70	0.70	0.70		0.73	0.63	0.80	0.61
0.70	0.70	0.70	0.70	0.70	0.70	0.69	0.69	0.77	0.58	0.70	0.70	0.70		0.72	0.63	0.80	0.60
0.69	0.69	0.69	0.69	0.69	0.69	0.68	0.68	0.76	0.57	0.69	0.69	0.69		0.72	0.63	0.80	0.60
0.68	0.68	0.68	0.68	0.68	0.68	0.67	0.68	0.76	0.56	0.68	0.68	0.68		0.71	0.63	0.80	0.60
0.67	0.67	0.67	0.67	0.67	0.67	0.66	0.67	0.76	0.55	0.67	0.67	0.67		0.71	0.64	0.80	0.60
0.67	0.67	0.67	0.67	0.67	0.67	0.65	0.67	0.75	0.55	0.67	0.67	0.67		0.70	0.64	0.80	0.60
0.66	0.66	0.66	0.66	0.66	0.66	0.64	0.66	0.75	0.54	0.66	0.66	0.66		0.70	0.63	0.80	0.60

Capacity factor---USC

Scenario 0 No carbon tax	Scenario 1	Scenario 2 coal price high	Scenario 3 coal price low	Scenario 4 natural gas price high	Scenario 5 natural gas price low	Scenario 6 demand growth 3%	Scenario 7 demand growth 7%	Scenario 8 renewables penetration 50%	Scenario 9 renewables penetration 70%	Scenario 10 No CCGT	Scenario 11 No USC	Scenario 12 No new USC	Scenario 13 No nuclear	Scenario 14 No new nuclear	Scenario 15 30$/tonneCO2 No capacity limit	Scenario 16 0$/tonneCO2 No capacity limit	Scenario 17 No capacity limit
0.51	0.51	0.51	0.51	0.51	0.10	0.50	0.52	0.52	0.50	0.51		0.51	0.56	0.52	0.27	0.52	0.27
0.51	0.51	0.51	0.51	0.51	0.10	0.50	0.53	0.52	0.50	0.51		0.51	0.57	0.52	0.27	0.53	0.27
0.52	0.52	0.49	0.52	0.52	0.09	0.49	0.54	0.53	0.49	0.51		0.52	0.58	0.53	0.28	0.55	0.28
0.52	0.52	0.46	0.52	0.52	0.09	0.48	0.55	0.54	0.49	0.50		0.52	0.59	0.54	0.28	0.57	0.28
0.52	0.52	0.43	0.52	0.52	0.08	0.47	0.56	0.55	0.48	0.48		0.52	0.59	0.55	0.28	0.59	0.27
0.52	0.52	0.41	0.52	0.52	0.07	0.47	0.57	0.55	0.48	0.47		0.52	0.60	0.56	0.29	0.61	0.28
0.52	0.52	0.39	0.52	0.52	0.06	0.46	0.57	0.56	0.47	0.46		0.52	0.61	0.57	0.30	0.60	0.30
0.52	0.52	0.35	0.52	0.51	0.06	0.45	0.58	0.57	0.46	0.44		0.52	0.61	0.57	0.32	0.60	0.31
0.52	0.52	0.33	0.52	0.50	0.05	0.44	0.58	0.58	0.46	0.43		0.52	0.62	0.58	0.33	0.60	0.32
0.50	0.52	0.30	0.50	0.48	0.05	0.43	0.57	0.58	0.45	0.42		0.52	0.62	0.58	0.34	0.60	0.33
0.49	0.52	0.26	0.49	0.47	0.04	0.42	0.57	0.59	0.44	0.40		0.52	0.62	0.59	0.35	0.60	0.34
0.47	0.52	0.24	0.48	0.46	0.04	0.41	0.56	0.59	0.44	0.39		0.52	0.61	0.59	0.36	0.60	0.35
0.46	0.52	0.22	0.46	0.45	0.04	0.40	0.56	0.60	0.43	0.38		0.52	0.61	0.59	0.38	0.60	0.36
0.45	0.52	0.19	0.44	0.44	0.03	0.40	0.56	0.60	0.43	0.37		0.52	0.61	0.60	0.39	0.60	0.37
0.44	0.52	0.17	0.42	0.43	0.03	0.39	0.56	0.60	0.42	0.36		0.52	0.60	0.59	0.39	0.60	0.38
0.43	0.52	0.16	0.41	0.42	0.03	0.38	0.56	0.61	0.41	0.35		0.52	0.61	0.60	0.39	0.60	0.39

0.42	0.52	0.14	0.39	0.41	0.03	0.37	0.56	0.61	0.40	0.34		0.52	0.61	0.60	0.39	0.60	0.39
0.41	0.51	0.13	0.38	0.40	0.03	0.36	0.56	0.61	0.39	0.33		0.51	0.61	0.60	0.39	0.61	0.39
0.40	0.51	0.11	0.38	0.39	0.02	0.35	0.56	0.61	0.38	0.32		0.51	0.61	0.60	0.39	0.61	0.39
0.39	0.51	0.10	0.37	0.38	0.02	0.35	0.57	0.61	0.38	0.31		0.51	0.61	0.60	0.39	0.61	0.39
0.38	0.51	0.09	0.36	0.38	0.02	0.34	0.57	0.61	0.37	0.30		0.51	0.61	0.60	0.39	0.61	0.39
0.38	0.51	0.08	0.35	0.36	0.02	0.33	0.57	0.62	0.36	0.29		0.51	0.61	0.60	0.39	0.61	0.39
0.37	0.51	0.07	0.35	0.35	0.02	0.33	0.57	0.62	0.35	0.27		0.51	0.61	0.60	0.39	0.61	0.39
0.36	0.51	0.07	0.34	0.34	0.02	0.32	0.57	0.60	0.35	0.26		0.51	0.61	0.60	0.39	0.61	0.39
0.36	0.50	0.06	0.34	0.33	0.02	0.31	0.57	0.59	0.34	0.25		0.50	0.61	0.60	0.39	0.61	0.39
0.35	0.50	0.06	0.33	0.32	0.01	0.31	0.57	0.58	0.33	0.24		0.50	0.60	0.60	0.39	0.61	0.39
0.35	0.50	0.05	0.33	0.31	0.01	0.30	0.57	0.57	0.33	0.23		0.50	0.58	0.59	0.39	0.61	0.40
0.34	0.50	0.05	0.32	0.30	0.01	0.30	0.57	0.56	0.32	0.22		0.50	0.57	0.58	0.39	0.61	0.40
0.34	0.50	0.04	0.32	0.29	0.01	0.29	0.58	0.55	0.32	0.22		0.50	0.57	0.58	0.39	0.61	0.40
0.33	0.04	0.04	0.31	0.29	0.01	0.29	0.02	0.05	0.32	0.21		0.04	0.05	0.04	0.39	0.61	0.40

Capacity factor---CCGT

Scenario 0 No carbon tax	Scenario 1	Scenario 2 coal price high	Scenario 3 coal price low	Scenario 4 natural gas price high	Scenario 5 natural gas price low	Scenario 6 demand growth 3%	Scenario 7 demand growth 7%	Scenario 8 renewables penetration 50%	Scenario 9 renewables penetration 70%	Scenario 10 No CCGT	Scenario 11 No USC	Scenario 12 No new USC	Scenario 13 No nuclear	Scenario 14 No new nuclear	Scenario 15 30$/tonneCO2 No capacity limit	Scenario 16 0$/tonneCO2 No capacity limit	Scenario 17 No capacity limit
0.00	0.00	0.80	0.00	0.00	0.73	0.00	0.00	0.00	0.00		0.53	0.00	0.01	0.00	0.00	0.00	0.00
0.00	0.00	0.80	0.00	0.00	0.71	0.00	0.01	0.01	0.00		0.52	0.00	0.01	0.01	0.00	0.00	0.00
0.01	0.01	0.80	0.01	0.01	0.69	0.00	0.01	0.01	0.01		0.51	0.01	0.02	0.01	0.00	0.01	0.00
0.01	0.01	0.80	0.01	0.01	0.68	0.00	0.02	0.01	0.01		0.49	0.01	0.02	0.01	0.01	0.01	0.01
0.01	0.01	0.80	0.01	0.01	0.66	0.00	0.03	0.02	0.01		0.48	0.01	0.03	0.02	0.01	0.02	0.01
0.02	0.02	0.80	0.02	0.02	0.63	0.00	0.04	0.02	0.01		0.46	0.02	0.04	0.03	0.01	0.03	0.01
0.02	0.02	0.80	0.02	0.02	0.61	0.00	0.05	0.03	0.02		0.45	0.02	0.05	0.03	0.02	0.03	0.02
0.03	0.03	0.79	0.03	0.02	0.59	0.01	0.07	0.04	0.02		0.44	0.03	0.06	0.04	0.02	0.03	0.02
0.03	0.03	0.78	0.03	0.02	0.57	0.01	0.07	0.04	0.03		0.42	0.03	0.07	0.05	0.03	0.03	0.02
0.03	0.04	0.76	0.03	0.02	0.54	0.01	0.08	0.05	0.03		0.41	0.04	0.08	0.06	0.03	0.03	0.03
0.03	0.05	0.74	0.03	0.02	0.52	0.01	0.09	0.06	0.04		0.40	0.05	0.08	0.07	0.04	0.03	0.04
0.03	0.05	0.72	0.03	0.02	0.50	0.01	0.09	0.07	0.04		0.38	0.05	0.09	0.08	0.05	0.03	0.05
0.03	0.06	0.69	0.03	0.02	0.48	0.01	0.09	0.08	0.04		0.37	0.06	0.09	0.09	0.06	0.03	0.05
0.03	0.07	0.67	0.03	0.03	0.46	0.01	0.10	0.09	0.05		0.36	0.07	0.10	0.10	0.06	0.03	0.06
0.03	0.07	0.64	0.03	0.03	0.44	0.01	0.11	0.10	0.05		0.35	0.07	0.10	0.10	0.06	0.03	0.07
0.03	0.08	0.61	0.03	0.03	0.43	0.01	0.11	0.10	0.06		0.34	0.08	0.11	0.11	0.06	0.03	0.07

0.03	0.08	0.59	0.04	0.03	0.41	0.01	0.12	0.11	0.06		0.33	0.08	0.12	0.12	0.06	0.03	0.07
0.03	0.09	0.56	0.04	0.03	0.40	0.01	0.13	0.12	0.06		0.32	0.09	0.13	0.13	0.06	0.03	0.07
0.03	0.09	0.54	0.04	0.03	0.39	0.01	0.14	0.13	0.06		0.32	0.09	0.14	0.14	0.06	0.03	0.07
0.03	0.10	0.51	0.04	0.03	0.37	0.02	0.15	0.13	0.06		0.31	0.10	0.14	0.14	0.06	0.03	0.07
0.03	0.10	0.49	0.04	0.03	0.36	0.02	0.15	0.14	0.06		0.30	0.10	0.15	0.15	0.06	0.03	0.07
0.03	0.11	0.47	0.04	0.03	0.35	0.02	0.16	0.15	0.06		0.29	0.11	0.16	0.16	0.06	0.03	0.07
0.03	0.11	0.45	0.04	0.03	0.34	0.02	0.16	0.15	0.06		0.29	0.11	0.16	0.16	0.06	0.03	0.08
0.03	0.12	0.44	0.04	0.03	0.33	0.02	0.17	0.15	0.06		0.28	0.12	0.17	0.17	0.06	0.03	0.08
0.03	0.12	0.42	0.04	0.03	0.32	0.02	0.17	0.15	0.06		0.28	0.12	0.17	0.17	0.06	0.03	0.08
0.03	0.12	0.40	0.04	0.03	0.31	0.03	0.18	0.15	0.06		0.27	0.12	0.17	0.17	0.06	0.03	0.08
0.03	0.13	0.39	0.04	0.03	0.31	0.03	0.18	0.15	0.06		0.27	0.13	0.16	0.17	0.06	0.03	0.08
0.03	0.13	0.38	0.04	0.03	0.30	0.03	0.19	0.14	0.06		0.26	0.13	0.16	0.17	0.06	0.03	0.08
0.03	0.13	0.37	0.04	0.03	0.29	0.03	0.19	0.14	0.06		0.26	0.13	0.16	0.17	0.06	0.03	0.08
0.03	0.35	0.35	0.04	0.03	0.29	0.03	0.33	0.40	0.06		0.25	0.35	0.40	0.40	0.06	0.03	0.09

Capacity factor---USC-CCUS

Scenario 0 No carbon tax	Scenario 1	Scenario 2 coal price high	Scenario 3 coal price low	Scenario 4 natural gas price high	Scenario 5 natural gas price low	Scenario 6 demand growth 3%	Scenario 7 demand growth 7%	Scenario 8 renewables penetration 50%	Scenario 9 renewables penetration 70%	Scenario 10 No CCGT	Scenario 11 No USC	Scenario 12 No new USC	Scenario 13 No nuclear	Scenario 14 No new nuclear	Scenario 15 30$/tonneCO2 No capacity limit	Scenario 16 0$/tonneCO2 No capacity limit	Scenario 17 No capacity limit
			0.77														
			0.76														
			0.74														
			0.73														

			0.72														
			0.70														
			0.69														
			0.68														
			0.67							0.69							
			0.65	0.68						0.68							
			0.64	0.66						0.66							
			0.63	0.65				0.75		0.64							
			0.62	0.63				0.74		0.63			0.73				
			0.61	0.62				0.73		0.62			0.72				
			0.60	0.61				0.72		0.60			0.71	0.71			
			0.59	0.59				0.71		0.59			0.70	0.70			
			0.58	0.58				0.71		0.58			0.70	0.69			
			0.58	0.57				0.70		0.57			0.69	0.68			

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