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Investment and Technologies for Net-Zero Carbon Infrastructure

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EU-China Energy Cooperation Platform was launched on 15 May 2019, to support the implementation of activities announced in the 'Joint Statement on the Implementation of EU-China Energy Cooperation'. The overall objective of ECECP is to enhance EU-China cooperation on energy. In line with the EU's Green Deal, Energy Union, the Clean Energy for All Europeans Package, the Paris Agreement on Climate Change and the EU's Global Strategy, this enhanced cooperation will help increase mutual trust and understanding between EU and China and contribute to a global transition towards clean energy on the basis of a common vision of a sustainable, reliable and secure energy system. Phase II of ECECP is implemented by a consortium led by ICF, and with National Development and Reform Commission - Energy Research Institute.

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Executive Summary

China and the EU have set ambitious net-zero carbon emission targets for 2060 and 2050 respectively. Many studies point to a high share of variable renewable energy (VRE) and electrification of energy consuming sectors as the crux of decarbonisation with power-to-X (P2X) and carbon capture, utilisation and storage (CCUS) key technologies for hard to abate sectors (steel, cement, heavy traffic, etc.).

A key challenge for the power system is how to integrate high VRE and ensure system adequacy with very low fossil-based generation. In addition, power sector models need stronger links with the consumption side, including CCUS and P2X. So, there is a need to optimise power, natural gas, green gas and liquid fuel infrastructure. Modelling analyses are essential to ensure successful sector coupling and optimal coordination among energy carriers.

This is the final report from Project B2.6 *Investment and Technologies for Net-zero Carbon Infrastructure* under the EU China Energy Cooperation Platform (ECECP). The project aims to facilitate cooperation between the EU and China in achieving net-zero targets. It acknowledges that only through cooperation can the energy system be transformed into a climate neutral system.

The project presents models of the Chinese integrated power and gas sectors under liberalised market conditions. The impacts/benefits of systems integration (enhanced energy storage through sector coupling, P2X, and the hydrogen sector) on carbon neutrality targets is assessed based on the modelling results.

- As **background knowledge** for setting up the integrated model for China, the project assesses and compares:
- Energy system scenarios in Europe and China for carbon neutrality.
- Power generation planning in China and Europe.
- Carbon capture utilisation and storage, P2X and hydrogen in China and Europe.

The **key takeaways from the background studies** are:

- Scenarios in both China and Europe are focussing on net-zero CO_2 emissions (China in 2060, Europe in 2050).
- A key challenge in the future is to balance generation from variable renewables (wind and solar) with flexible demand; adequacy in VRE-dominated systems is of paramount importance.
- P2X and CCUS are necessary technologies for hard-to-abate economic sectors (where direct electrification is harder to achieve); the technologies must be deployed at large scale and swiftly both in China and the EU. In this process cooperation is vital.

Modelling of Chinese integrated power and gas sector - methodological approach

Recognising the potential benefits of renewable energy integration, this study explores synergies and opportunities by integrating multiple energy sectors. By adopting an integrated approach, the potential for enhanced sector coupling is unlocked, thereby facilitating the seamless integration of renewable energy sources, and maximising overall system efficiency.

To see the impact of the integrated modelling, three scenarios are considered:

- **Scenario 0: This is a reference scenario without the pipeline infrastructure representation** and where natural gas consumption (in the heat and power sector) is optimised according to exogenous prices at provincial level. This implies that transport of CO_2 and X-fuels (e-methanol, ammonia, and hydrogen) between provinces is based on a variable cost of transport, i.e., a cost per unit of fuel per distance, but not constrained by pipeline capacity.
- **Scenario 1: Gas infrastructure is considered alongside pipelines to third countries**, LNG terminals and pipeline constraints between provinces, but CO_2 and X-fuels pipeline infrastructure is not considered, i.e., transport of CO_2 and X-fuels is as in the reference Scenario 0 based on CNS2 from CETO 2023. No additional investments in the gas infrastructure are allowed, only investments into CO_2, e-methanol, ammonia, and hydrogen infrastructure. This is because the scenario assumptions from the outset describe a situation where consumption of fossil fuel-based gas is reducing due to the carbon neutrality requirements.
- **Scenario 2: Transportation between provinces of CO2, e-methanol, ammonia, and hydrogen is restricted by pipeline capacity.** Pipeline capacity is determined as an endogenous investment option, however the economic cost of using the pipeline, versus not using it, is considered negligible for the optimisation. Hence if pipeline capacity is established, it is likely to have high utilisation. Natural gas pipeline infrastructure is represented as in Scenario 0.
- **Scenario 3: Transmission infrastructure relating to gas, CO2 and P2X is considered.** As in Scenario 1, no additional investments in the gas infrastructure are allowed, only investments into CO_2, e-methanol, ammonia, and hydrogen infrastructure.

This setup has the aim of answering specific questions as to the impact of the alternative modelling approach. Firstly, looking at the implication of adding the natural gas pipeline infrastructure to the modelling approach in isolation (i.e., by comparing Scenario 1 with Scenario 0). Secondly, comparing Scenario 2 with Scenario 0 will demonstrate the impact of including pipeline capacity and investments on the utilisation and transportation of the four commodities CO_2, e-methanol, ammonia, and hydrogen. Thirdly, comparing e.g., Scenario 3 with full infrastructure with Scenario 0 will demonstrate the impact of including pipeline capacity and investments on the utilisation and transportation of natural gas and the four commodities CO_2, e-methanol, ammonia, and hydrogen.

Key results from modelling

The first ECECP collaboration entitled: 'ENTSO-E Grid Planning Modelling Showcase for China Report', focused on using the ENTSO-E methodology for a Cost Benefit Analysis in grid planning processes in China. Building on the experience from that previous study this project expanded upon the concept of an integrated energy system approach to highlight the impacts of an integrated system modelling approach. Through this comprehensive analysis, the report seeks to provide valuable insights into how to optimise system planning processes and achieve a more sustainable and resilient energy future.

As the findings show, an integrated energy system approach can enhance efficiency, promote renewable energy integration, improve flexibility and resilience, enable sector coupling and electrification, optimise costs, and support coordinated policy and planning efforts, all of which contribute to achieving decarbonisation targets more effectively.

The comparison of scenarios that consider the physical transmission infrastructure representation (SC1, SC2, SC3) with a scenario that does not consider the physical gas and X-pipelines (SC0) highlights the benefits of the integrated modelling approach.

In the results, the pipeline representation reflects the competition between alternative forms of energy commodity transportation. While the power transmission capacity is lower in the full infrastructure scenario (SC3) than in a scenario where only the electricity grid is considered as infrastructure for optimisation (SC0), we see more hydrogen pipeline capacity is built in the northwest, while fewer hydrogen pipelines are built in the north, which shows that provinces with high VRE potential such as Xinjiang, Qinghai and Gansu are prime candidates for installation of hydrogen infrastructure, to satisfy both local demand and to ship to high-consumption provinces such as Beijing, Hebei and Tianjin.

The results show that the utilisation rate of the X-pipelines is significantly higher in the scenarios that take account of physical transmission infrastructure. The reason is that once a pipeline has been built its subsequent use is virtually cost-free. This can be illustrated by the results for the Qinghai province, where the modelling results of the different scenarios show a significant difference between the scenarios. For all years between 2030 and 2060, the capacities of the H_2 pipelines and the utilisation rates are significantly higher in the infrastructure scenarios (SC2, SC3) than in the scenario that omits hydrogen infrastructure (SC0).

At the same time, the use of natural gas for power generation differs significantly in the modelling depending on whether the gas-pipeline infrastructure is taken into account. In the scenarios where natural gas pipelines are factored in (SC1 and SC3), the use of natural gas for power generation is higher, since existing as infrastructure is used as long as it is economically the better option and within the emissions constraint.

In the scenarios, CO_2 capture installations are built primarily in regions which have heavy industries that continue to emit CO_2 in 2060. Also, carbon capture is mounted on power plants where biomass can be sourced, so that the CO_2 can be captured and used (e.g., to produce X-fuels) or stored to generate negative CO_2 emissions. Pipeline investments connect this CO_2 with areas that have carbon sequestration potential.

In general, high volumes of carbon imports and carbon capture occur in provinces with high sequestration potential. We can see that high load provinces in the centre, north and south are importing CO_2, while provinces in the north-east and north-west are more export-oriented.

The examples show that an integrated system approach better represents the existing resources and ensures that they are used. This contributes to a cost-efficient transition of the energy system to achieve the net-zero target.

Energy modelling is often focused on the power sector to achieve net-zero targets, as the knowledge of how to decarbonise the power system already exists and the costs and challenges are understood. However, solutions for ‘hard-to-abate’ emissions require an integrated focus on the energy supply chain, resources, technologies, system efficiency and sector coupling.

As this analysis indicates, P2X and CCUS are only cost-effective if inputs are low-cost and value streams are integrated. Carbon capture and sequestration are seen as the main solutions to negative emissions in the power sector but are expensive and energy intensive. However, these approaches also offer flexibility opportunities to support the energy transition that are often overlooked. To achieve a carbon-free energy system at reasonable economic cost, optimised use and development of key energy infrastructures is crucial. For this, jointly optimised gas and electricity infrastructure is necessary, as it leads to a more efficient use of existing infrastructure and influences the use of gas as a transition fuel. It will require significant new infrastructure and investment to achieve a net-zero carbon energy system.

By showcasing an integrated modelling approach of China's electricity, gas and P2X sector, the project has strengthened the understanding of the future needs for more coordinated approaches towards energy infrastructure investment and operational planning and regulation.

This final report of the project B2.6 Investments and Technologies for Net-Zero Carbon Infrastructure under the EU-China Energy Cooperation Platform (ECECP) showcases not only the implementation of integrated energy system modelling, but also a successful exercise of modelling cooperation between European and Chinese teams. The project acknowledges that only through cooperation can the energy system be transformed towards a climate neutral system.

The time to achieve a net-zero energy system is very limited. If each country develops technology on their own, it will be difficult to reach the target. The EU will not be able to reach its climate targets without China, and China will not be able to reach its climate targets in isolation from the rest of the world.

Table of Contents

1. Introduction

This is the final report from Project B2.6 *Investment and Technologies for Net-Zero Carbon Infrastructure* under the EU China Energy Cooperation Platform (ECECP).

The background of the project can be summarised as follows:

- Both China and the EU have ambitious targets for carbon and climate neutrality.
- Achieving this requires a transformation of energy infrastructure, planning and regulation.
- It is evident that future energy infrastructure development and operations need to be more coordinated between energy carriers and sectors.
- Modelling analyses are essential to ensure successful sector coupling and optimal coordination among energy carriers.

Against this background, the objective of the project is for a strengthened understanding of future needs for more coordinated approaches to energy infrastructure investment and operational planning and regulation, as seen through the lens of coordinated energy systems modelling and scenarios. In addition, the project aims to facilitate cooperation between the EU and China in achieving net-zero targets. It acknowledges that the energy system can only be transformed into a climate neutral system by means of cooperation.

The project was launched in March 2022 and ended in September 2023. The project partners are SGERI, CEC, CNREC/ERI[1], Ea Energy Analyses, with ECECP (ICF) as facilitator. All joint work undertaken by Chinese and international experts was conducted via online workshops and other online cooperation due to the travel restrictions imposed as a result of the Covid-19 pandemic. It was not until the study tour in July 2023 that the teams were able to meet in person.

The project includes six work packages, as follows:

WP1: Inception, consisting of a discussion about alignment of partners' contributions. An inception report was submitted in April 2022.

WP2: Energy system scenarios for carbon neutrality. The WP2 report was submitted in September 2022.

WP3: Power generation planning in the context of carbon neutrality and power market reform. The WP3 report was submitted in November 2022.

WP4: Carbon capture, utilisation, and storage (CCUS), P2X and hydrogen. The WP4 report was submitted in January 2023.

WP5: Modelling and planning of net-zero carbon infrastructure. The WP5 report from the kickoff was submitted in April. The main report of WP5 was issued in September 2023.

WP6: Finalisation and final report. This is the final report, which is publicly available.

The key results of the work packages are described in the present report (chapters 2-7), see Table of Contents. Modelling of Chinese net-zero carbon infrastructure is described in Chapter 6. Chapter 7 provides a discussion of the modelling results, the authors' conclusion and an assessment of the future outlook.

[1] Represented by Kaare Sandholt and the results from the China Energy Transition Project (CET)

2. Key Concepts on the Pathway to Carbon Neutrality in China

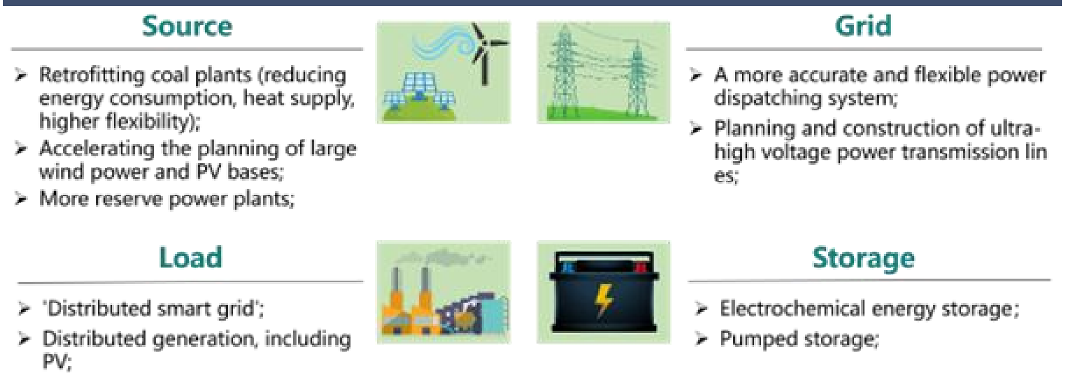
This chapter describes several key concepts and technologies that will enable the carbon neutral energy system of the future, including energy security in a system that includes an increasing share of renewable energy, the concept of an integrated energy system and a virtual power plant, as well as key technologies such as nuclear power technology, storage technology and CCUS.

Energy security

Concerning energy security, the priority for the grid is to ensure a safe and stable operation of the power system. At the source side, coal plants should be retrofitted gradually, the primary aim being to reduce energy consumption, increase flexibility, and lower carbon emissions with CCUS. In addition, large wind and solar power bases should be planned and constructed.

Since most of the VRE are located in the north-west of China, while the load centre is located at the coastal area in the east, more ultra-high voltage power transmission lines are needed to realise an optimal large-scale energy transport for the grid (see Figure 2.1). For the load side, the distributed smart grid needs to achieve a self-balanced state, such as is found in a micro-grid. For the storage side, more pumped storage and electro-chemical energy storage units are needed. Furthermore, a developed electrical energy market, capacity market and ancillary services market are necessary to reflect the relationship between supply and demand, which could bring about a more efficient large-scale energy distribution.

Figure 2.1: Requirements for energy security on the pathway to carbon neutrality



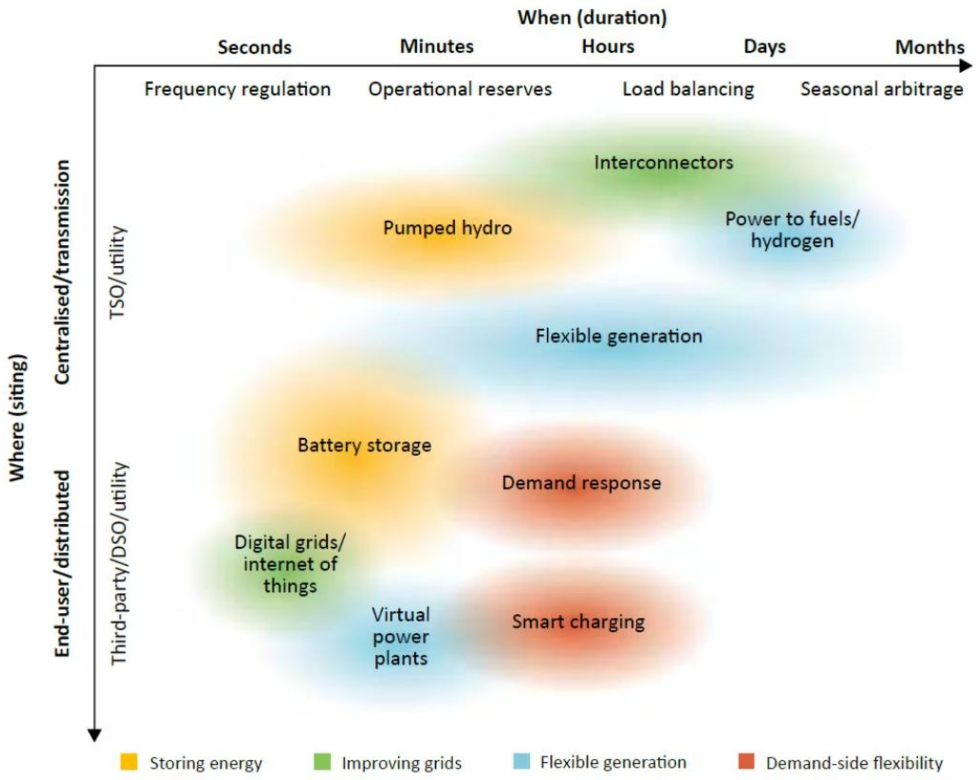
The China Electricity Council (CEC) defines energy security using three key points:

- **Firstly, a diversified power supply system that follows some basic principles**, such as the energetic development of new energies in both concentrated and decentralised forms, the development of hydropower in accordance with local conditions, and the safe and orderly development of nuclear power. The ultimate goal is to create a low-carbon electricity supply structure.
- **Secondly**, **the market position of coal power should be clearly defined**. Fossil fuels such as coal are still crucial, given that coal-fired power plants are set to provide flexibility and peak load capacity. For coal power, the key principle is that energy supply, pollution reduction and overall carbon emission reduction should be considered. Coal-fired power capacity should be increased to meet

energy balance requirements, while coal-fired power energy generation should be reduced, giving way to a growing proportion of renewable energy renewables.

- **Thirdly, the flexibility of the system should be significantly improved** (see Figure 2.2). Taking into account the technical characteristics of the different resources and the requirements of the scenarios, the potential of all resources such as power plants, power grid, power demand and energy storage should be maximised to ensure significant system flexibility and to promote the wide scale development and consumption of new fossil free energy.

Figure 2.2: Overview of different power system flexibility resources



Source: IEA

Sector coupling and electrification

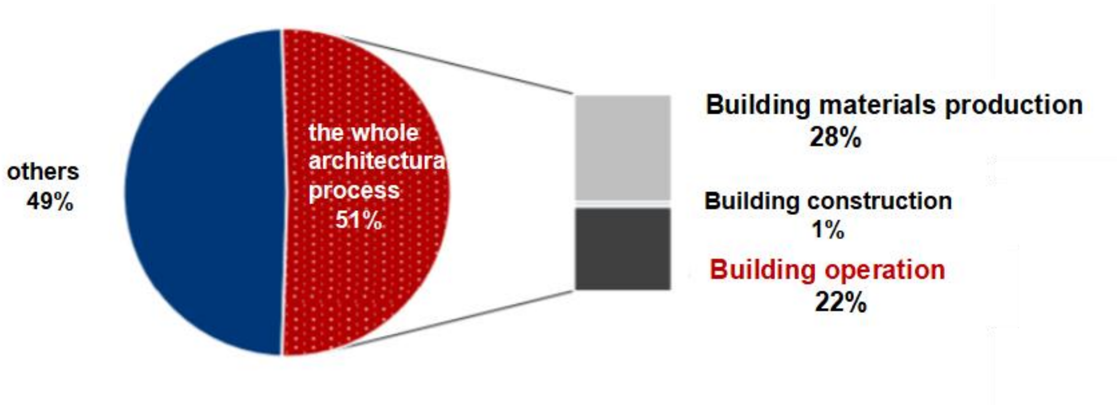
Sector coupling' is the new buzz word in the energy transition. In this report, we will focus on the latest developments in China. In order to achieve carbon peaking and carbon neutrality, it is important to formulate a strategy that considers the energy industry alongside other hard-to-abate industries such as steel, non-ferrous metals, building materials, petrochemicals and transport (see Figure 2.3). An effective way to reduce carbon emissions in such industries is to increase electricity consumption and reduce the use of fossil fuels such as coal or oil. This means that overall carbon reduction is closely linked to electrification and sector coupling.

Figure 2.3: The strong relations between the power industry and other industries

Buildings Sector: Carbon emissions

In 2019, total carbon emissions throughout the construction industry was about 5 billion tonnes of CO_2, accounting for 51% of the total carbon emissions in China. The demand for reductions in carbon emissions from buildings is urgent. In the same period, carbon emissions produced during building construction and operation 2.13 billion ton CO_2, or 23% of total emissions, mainly from fossil energy, electricity and heat (see Figure 2.4).

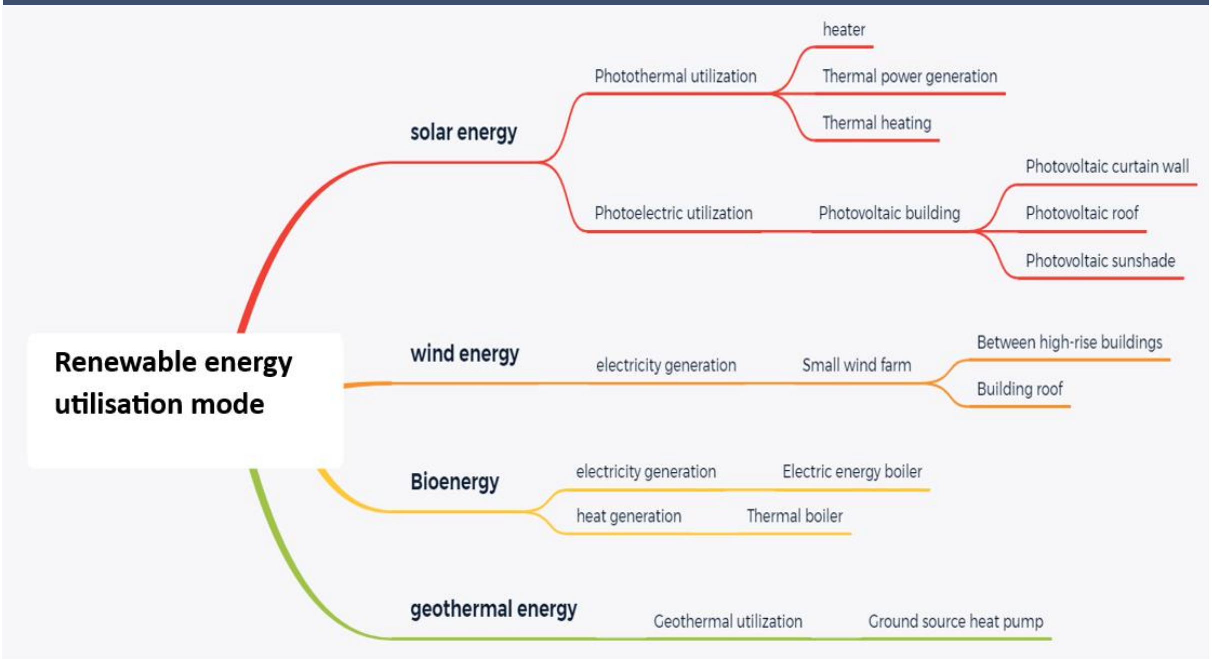
Figure 2.4: Total carbon emissions in China's construction industry in 2019



Buildings Sector: The coupling between renewable energy and buildings in China is accelerating

Among renewable energy sources, solar energy, wind energy, ground temperature heat source and biomass energy relate mainly to buildings. The current penetration rate of household PV is still low, accounting for about 1.4% of total PV. Driven by policies, household PV is set to see rapid growth in China. The Ministry of Housing and Urban-Rural Development (MOHURD) has issued the '14th Five-Year Plan' for building energy efficiency and green building development which promotes the use of renewable energy in buildings (see Figure 2.5).

Figure 2.5: Application of renewable energy in buildings.

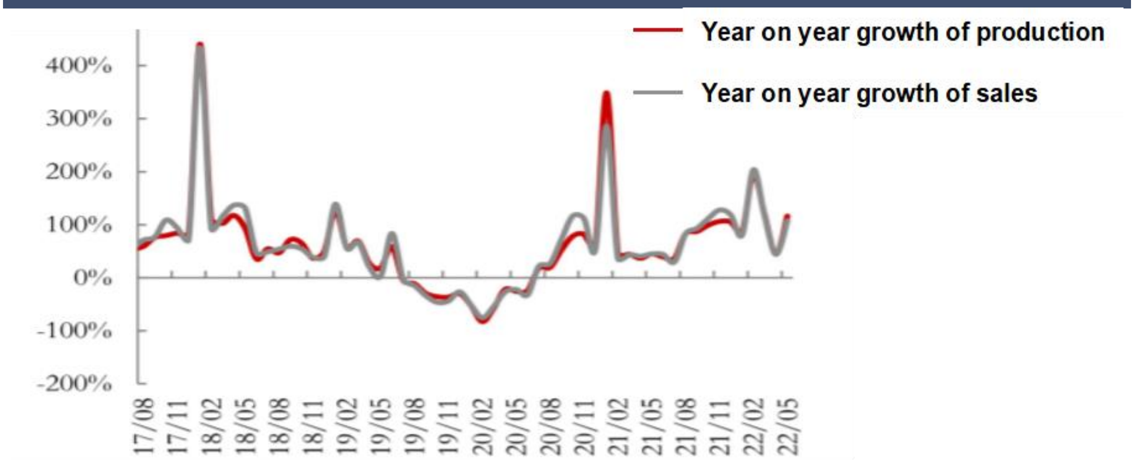


Source: Report on the operation of China's solar thermal utilisation industry in 2020, 'The 14th Five-Year Plan for building energy conservation and green building development'

Mobility Sector: The penetration rate of new energy vehicles in China has reached new highs

Carbon emissions from automobiles account for more than 80% of carbon emissions in China's transportation sector and about 7.5% of carbon emissions in society as a whole. The electrification of the automobile sector is an effective route to decarbonisation. In 2021, the production and sales of 'new energy' vehicles[2] exceeded 3.5 million, achieving a substantial increase of 1.6 times year-on-year (see Figure 2.6).

Figure 2.6: Year on year growth of production and sales of 'new energy' vehicles in China.

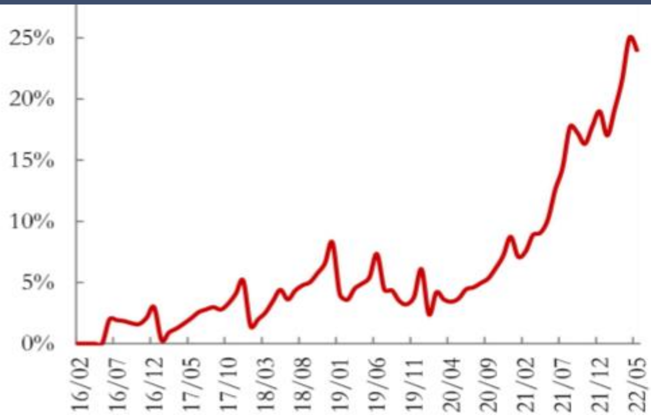


Source: Chinese Association of Automobile Manufacturers

[2] 'New energy vehicles' is a term used in Chinese policies to describe vehicles mainly powered by electric energy, including plug-in vehicles, battery vehicles, hybrid cars and fuel-cell vehicles.

In the first half of 2022, the penetration rate of new energy vehicles was set to reach 9.27% (of the whole fleet of vehicles) and that of passenger vehicles was predicted to reach 11.28%, both of which figures represent a new record.

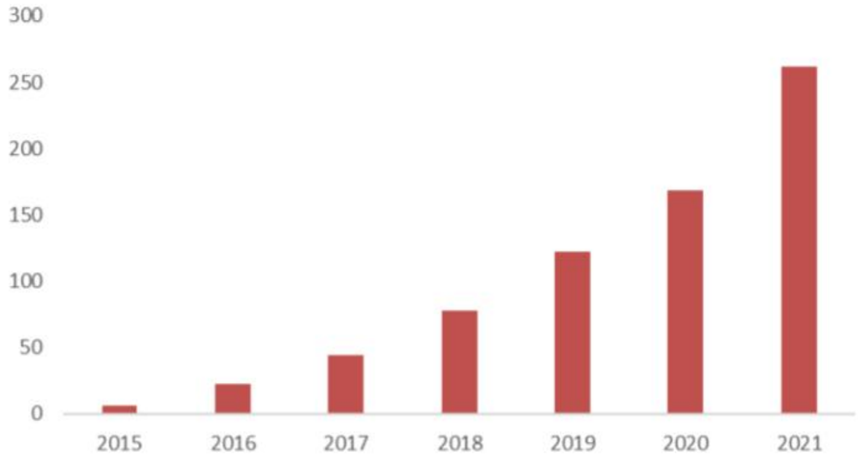
Figure 2.7: Penetration rate of production/sales of new energy vehicles in China



Source: Chinese Association of Automobile Manufacturers

By the end of 2021, the number of charging points in China had reached 2.6 million (see Figure 2.8). From 2017 to 2021, the Compound Annual Growth Rate (CAGR) was 56%. The State Grid has continued to improve its operation mode in the field of charging points. Its main strategies are to liberalise provincial joint ventures, decentralise bidding rights, cooperate with real estate operators to provide community charging points and introduce private EV charging station sharing.

Figure 2.8: Number of charging points in China. Unit: 10 000 sets



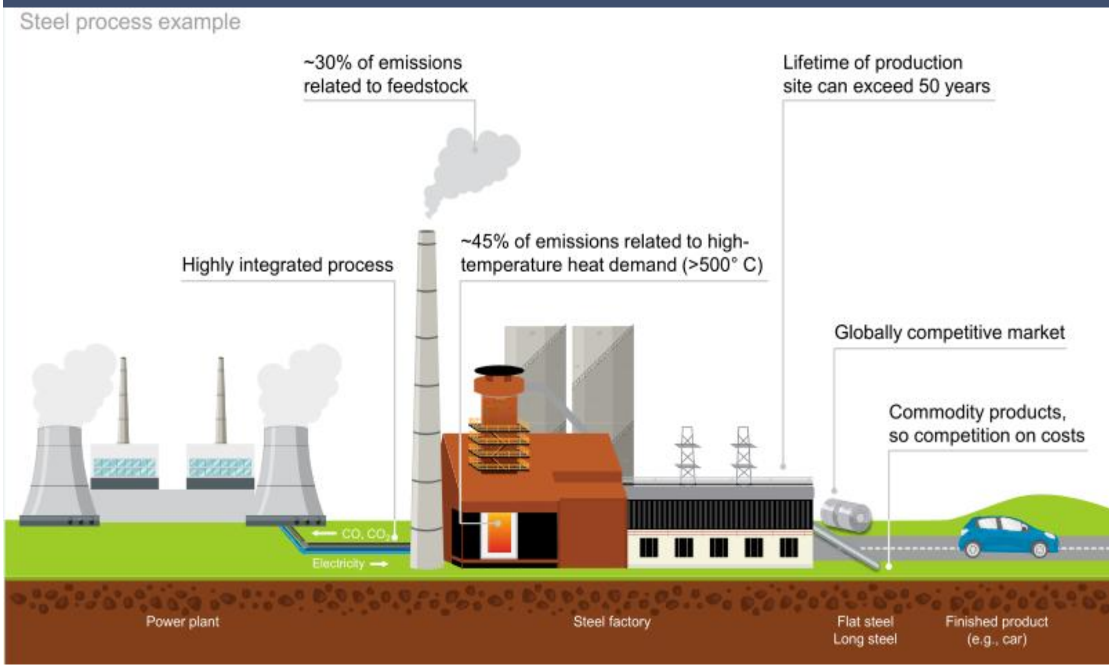
Source: iFinD, EVCIPA

By October 2021, China had built 1 086 EV battery swapping stations, with a year-on-year increase of more than 100%. Compared with the charging model, the scale of battery swapping facilities remains relatively small. It is estimated that during the 14th Five-Year Plan period (2021-25), the State Grid will build more than 1 000 public and commercial battery swapping stations.

Industry Sector: Constrained by the industrial structure of high energy consuming industries, the task of low-carbon industrial development in China remains arduous

It is not easy to cut emissions from cement, steel, ammonia, and ethylene production (see Figure 2.9, Figure 2.10). The processing of feedstocks generates about 45% of emissions in these four focus sectors. These sectors require high-temperature heat (in the focus sectors demand for high-temperature heat ranges from 700 to over 1 600 degrees Celsius, generating about 45% of emissions). Given the deep integration of the industrial processes involved, any change to one part of the process will have to be accompanied by changes elsewhere. Industrial production sites, especially in the four focus sectors, typically have lifetimes exceeding 50 years, with regular maintenance.

Figure 2.9: It is difficult to abate emissions from cement, steel, ammonia, and ethylene production

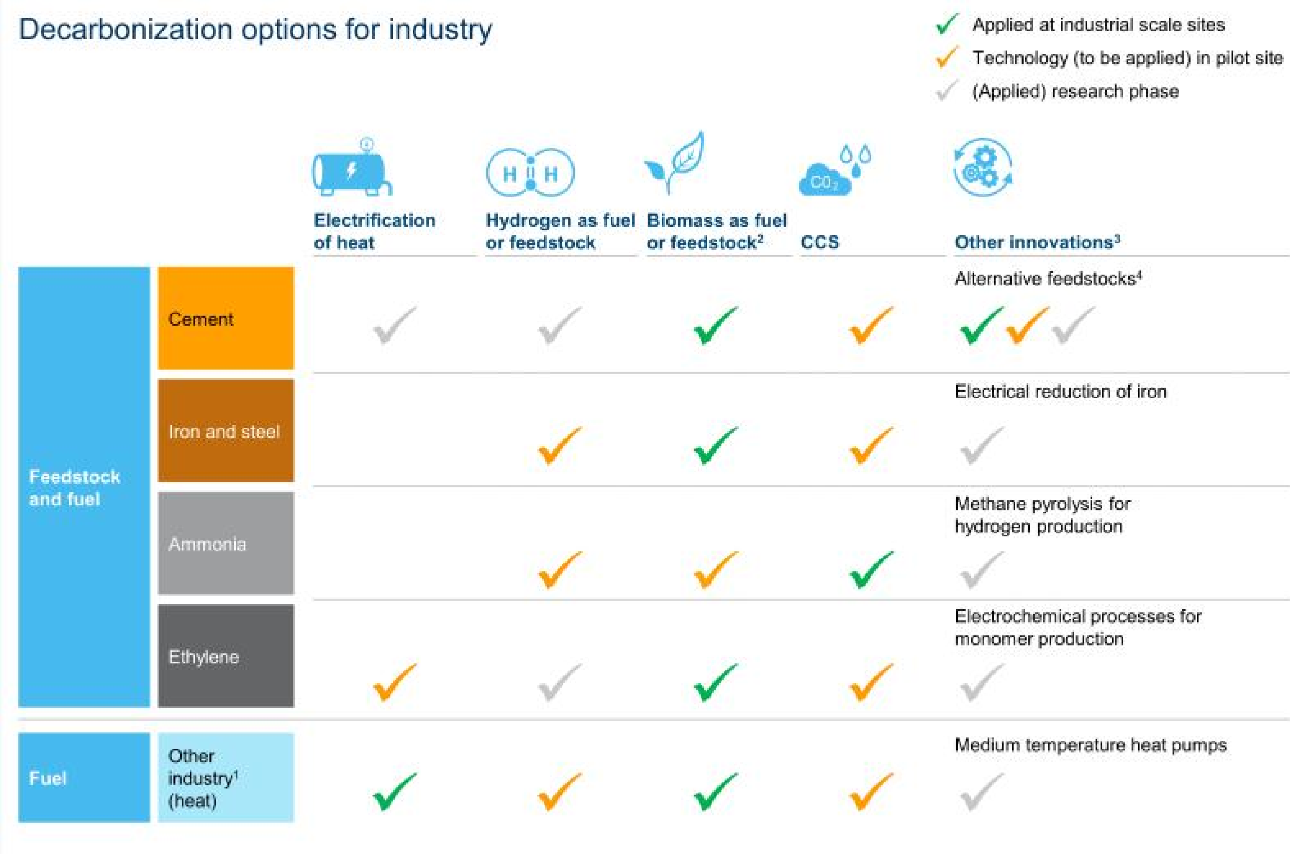


Source: 'Green and low carbon technology for industrial process'

Industry Sector: Driven by policies, China's green manufacturing system has taken shape. New (green) energy and technologies are increasingly integrated into industries

So far, 2 121 green factories, 171 green industrial parks and 189 green supply chain enterprises have been established and nearly 20 000 green products have been developed. The Chinese government has promoted the coordinated development of new energy production services and equipment manufacturing; supported intelligent power generation and intelligent energy use equipment systems; pushed for energy efficient management and trading; developed distributed energy storage services; and promoted innovation and centralised development for the hydrogen energy industry. All these actions are intended to accelerate China's industrial low-carbon transformation.

Figure 2.10: Decarbonisation options for industry

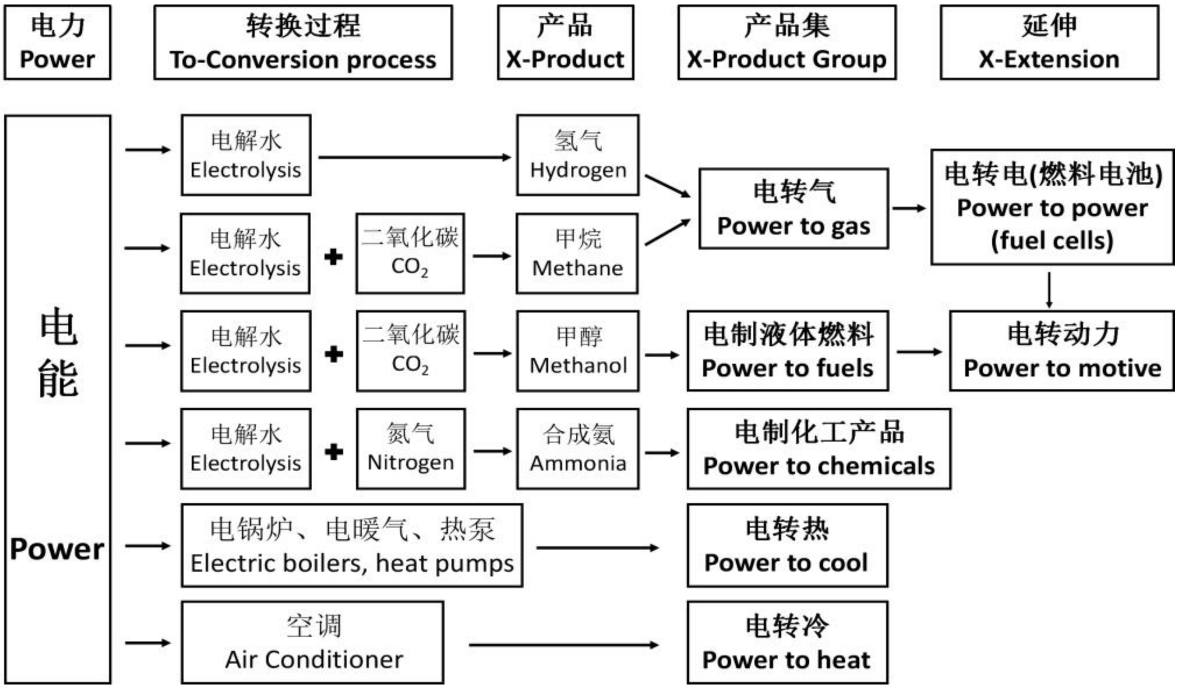


Source: 'Green and low carbon technology for industrial process'

P2X[3] can serve as controllable loads, which can be used for load shifting, peak shaving, and other demand-side management services. P2X can also be used as energy storage, which could help address seasonal variability in supply and demand. Furthermore, P2X can function as an interface between different systems and build synergy among separate energy sectors and networks. Hydrogen is an important intermediate in P2X technologies (see Figure 2.11).

[3] Power-to-X (also P2X and P2Y) refers to a variety of electricity conversion, energy storage, and reconversion pathways that use surplus electric power, typically during periods where fluctuating renewable energy generation exceeds load.

Figure 2.11: Technical routes of Power-to-X



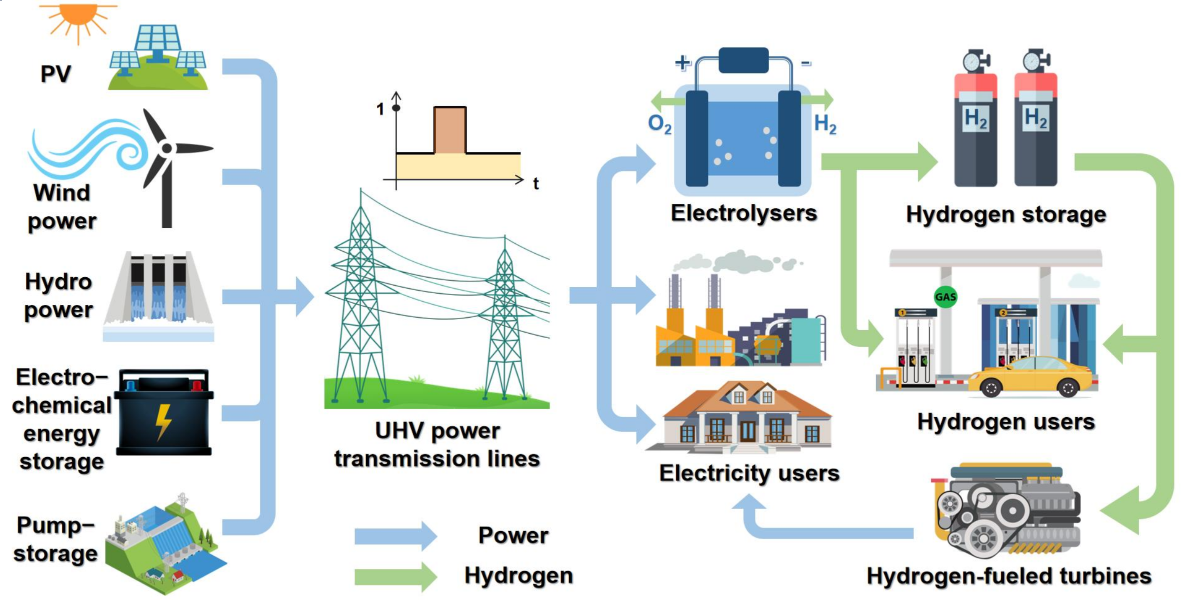
Integrated system

In an integrated system, supply, conversion, storage and consumption of different energy sources such as electricity, heating, cooling, gas and water are optimised at the same time in order to increase efficiency and reduce costs.

There are three types of integrated systems. The first type includes regional projects such as new urban areas, urban renewal areas, new towns, etc. The second type includes park and zone projects such as industrial parks, science and technology parks, logistics parks, cultural industrial parks, airports, etc. The third type includes construction projects such as office buildings, business complexes, schools, hospitals, data centres, etc.

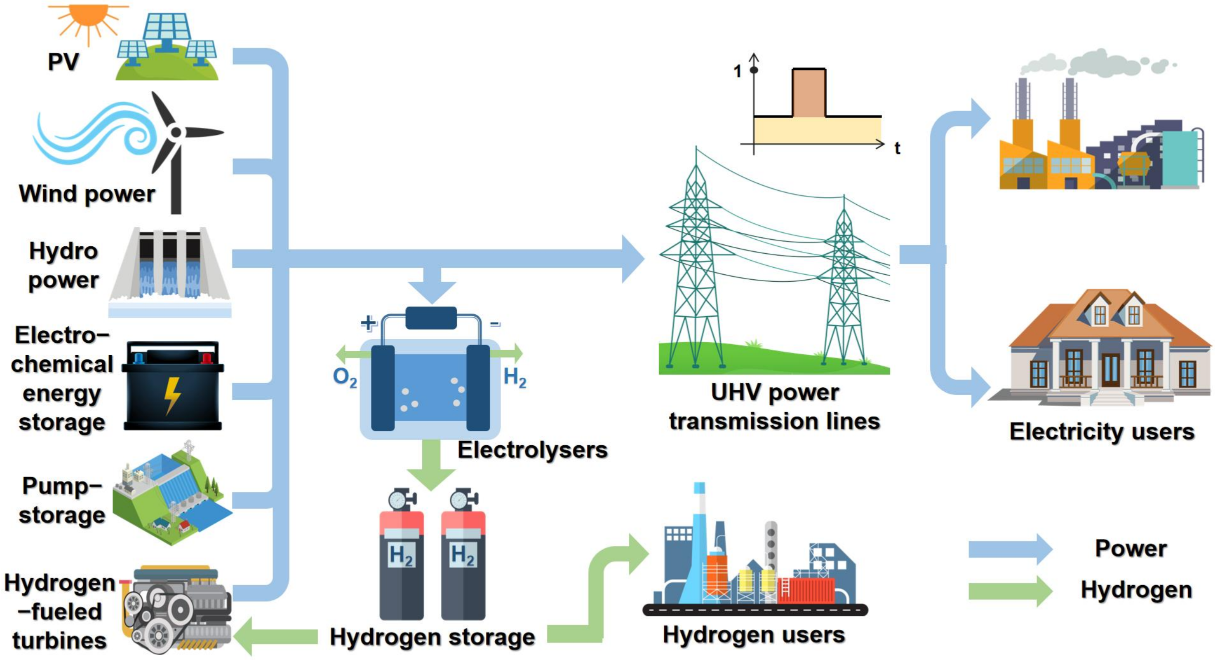
The integrated energy system is becoming more common at the demand/load side, and can include coupling between electric, thermal, cooling and gas systems. The most frequently used equipment is gas-fired supply, heat pump, compression refrigeration and electric energy storage cells. Coupling between power and hydrogen systems is a topic of heated discussion right now. It can be delivered in different modes, including coupling at the load side and coupling at the source side.

Figure 2.12: Coupling between power and hydrogen system on the load side



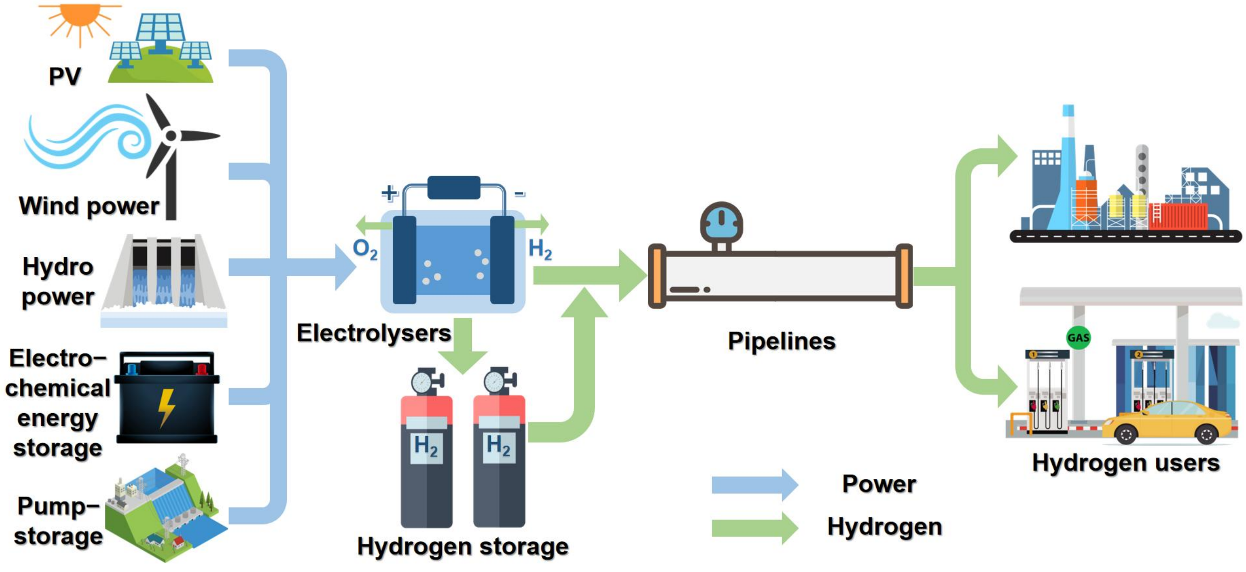
For coupling between power and hydrogen systems on the load side (see Figure 2.12), the main advantages are: 1) flexibility in the choice of site, since the electricity is supplied by the grid; 2) profitability, given the potentially large electricity price difference between peak period and valley period. However, such coupling does not take full advantage of the dynamic regulation capabilities offered by electrolysers.

Figure 2.13: Coupling between power and hydrogen systems on the source side, energy transmitted by power



Coupling between power and hydrogen systems on the source side (see Figure 2.13) and energy transmitted over large distances by power allows full advantage to be taken of the dynamic regulation capabilities of electrolysers. The volatility of renewable energy can be absorbed by electrolysers without exerting huge pressure on the power grid. However, significant energy losses and low efficiency in the electricity-hydrogen-electricity conversions are inevitable.

Figure 2.14: Coupling between power and hydrogen systems on the source side, energy transmitted by hydrogen

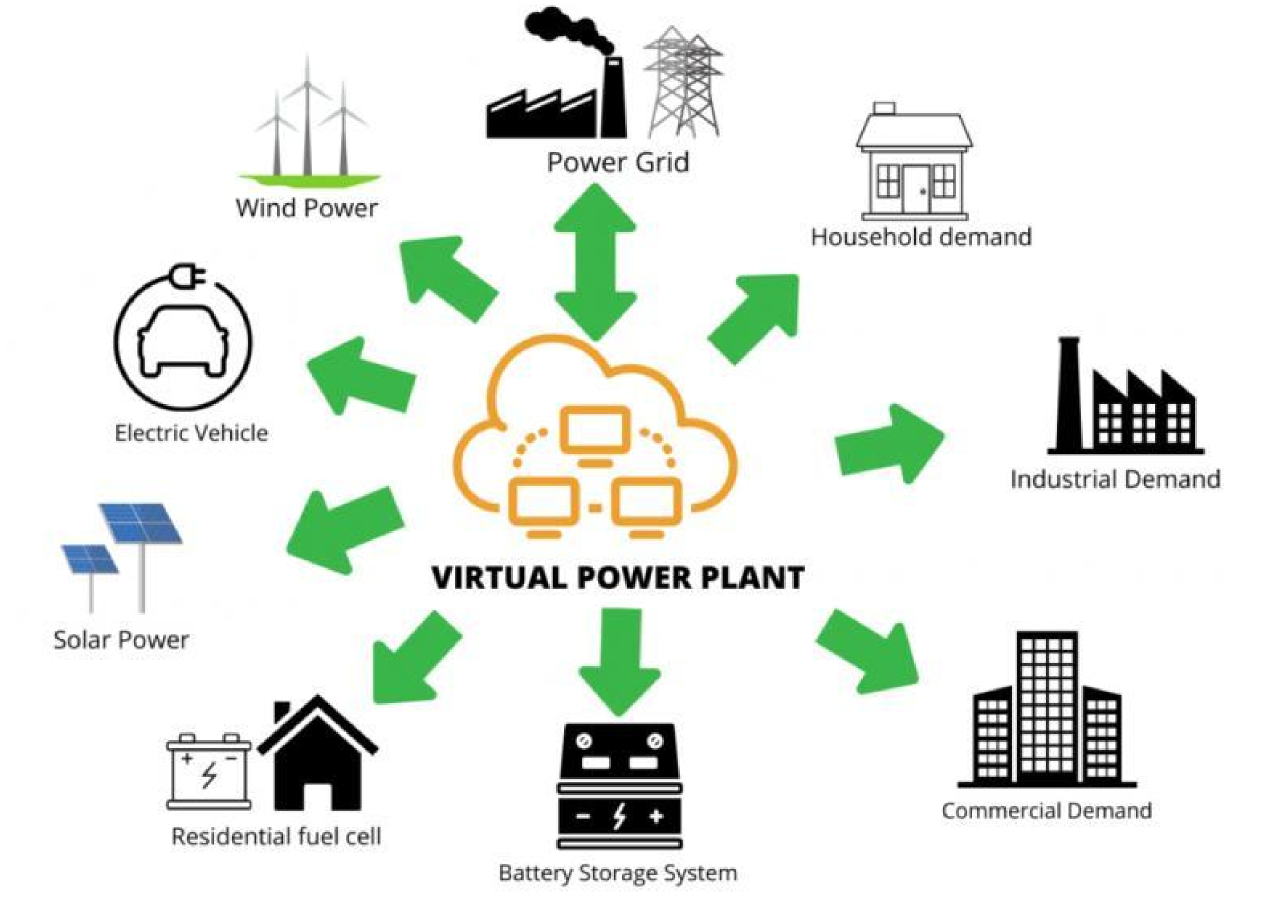


A more promising scenario is offered by coupling between power and hydrogen systems on the source side and the energy transmitted over large distances by hydrogen (see Figure 2.14). Apart from the fact that it takes full advantage of the dynamic regulation capabilities of electrolysers, it has higher energy utilisation efficiency and may offer cost savings.

Virtual power plant

A Virtual Power Plant (VPP) uses intelligent control technology and interactive business models. It bundles different types of resources to achieve energy balance and flexible interaction based on modern information communication and advanced smart technology, as shown in Figure 2.15.

Figure 2.15: Sketch of a virtual power plant

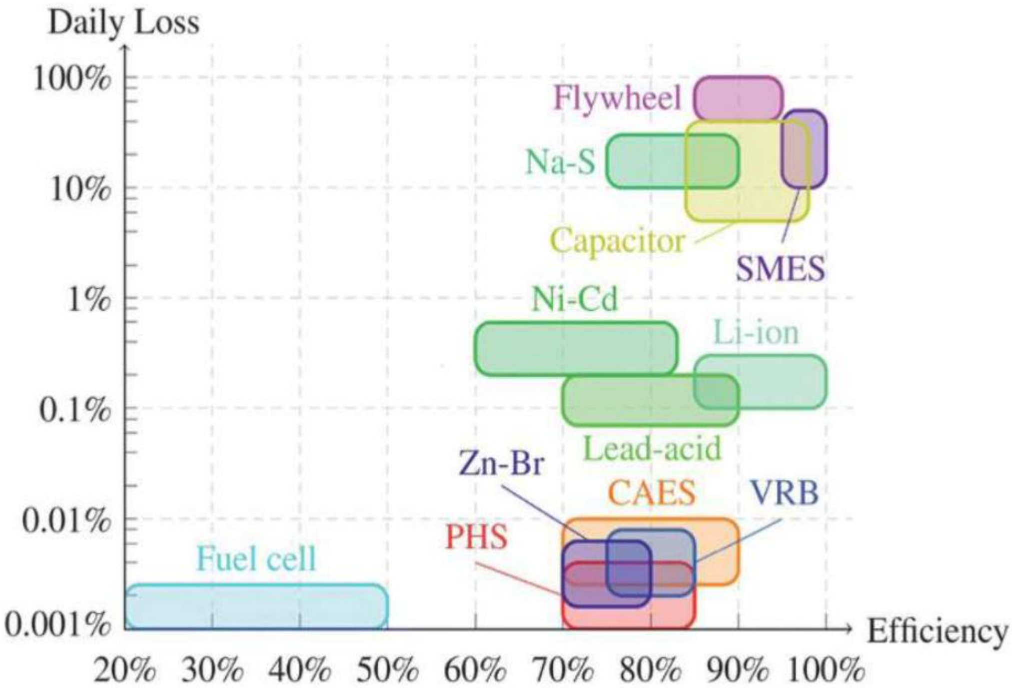


Key technologies

In its analysis, the CEC has highlighted four key technologies that will help bring about a future carbon neutral energy system, including nuclear power, storage technology, carbon capture, utilisation and storage (CCUS), and hydrogen.

- **The first key technology of the future is nuclear power technology.** This includes several new developments, such as the third-generation pressurised water reactor, the high-temperature gas-cooled reactor, the small, modularised reactor and nuclear fusion. Nuclear power can also be used for steam and heat supply, industrial hydrogen production and sea water desalination.
- **The second key technology is storage technology.** The different types of storage technologies have different characteristics and are therefore suitable for a range of applications. Using traditional technology, pumped storage power plants can be built between e.g., cascade power plants or run-of-river power plants. There are also some new technologies, such as electrochemical energy storage, flywheel energy storage, compressed air storage, heat and cold storage, etc. (see Figure 2.16.

Figure 2.16:Sketch of efficiency and loss of energy for different storage technologies.



- **The third key technology is CCUS** (Carbon Capture Utilisation and Storage). Given that the share of fossil fuels is set to remain significant in the coming years, CCUS is a necessary technology for carbon reduction in combination with fossil fuels. However, more research is needed to overcome technical bottlenecks and reduce energy consumption costs. More attention should be paid to utilisation, e.g., large-scale CCUS for enhanced oil recovery (CCUS-EOR), chemical synthesis of starch, methanol and ammonia, and some other industrial applications such as physical conversion into building materials, carbon nanotubes, etc. According to a report from Global CCS Institute (CCSI), there were 135 commercial CCUS facilities globally at the end of 2021 (see Figure 2.17). Of these, 27 are in operation, two have had their operations suspended, while others are under construction or in the early stages of development. Most projects are located in the US and European countries.

Figure 2.17: Global CCUS facilities at the end of 2021

Source: GCCSI (2021)

- **The fourth key technology is hydrogen technology.** Hydrogen can be part of an integrated energy system and can be used in a variety of applications. In particular, it can be used to reduce carbon emissions from hard-to-abate sectors such as industry and transport. If renewable energy is abundantly available, it can be used to produce green hydrogen. In addition, hydrogen gas turbines can produce inertia like synchronous generators but are low carbon and can reduce coal consumption.

3. Energy System Scenarios for Carbon Neutrality in China and the EU

This chapter discusses various scenarios for achieving carbon neutrality. The chapter is based on work package 2 of the project (Energy System Scenarios for Carbon Neutrality), in which the participating experts discussed different energy system scenarios for the EU and China. For China, energy system scenarios created by CEC, SGERI, ERI (CET project), and the China National Petroleum Corporation Economics & Technology Research Institute (CNPC ETRI) are presented. The European scenarios are based on the ENTSOs' Ten Year Network Development Plans (TYNDPs) and the European Commission scenarios.

Overview of different energy system scenarios

Modelling and techno-economic analysis of energy system scenarios offer important tools for climate goal setting, infrastructure planning and assessment of possible policy measures. This work supports government and private sector stakeholders in their decision-making. Scenarios should not be confused with forecasts. In contrast to forecasts, scenarios provide the opportunity to present a range of possible futures based on different assumptions about the key drivers of change in the energy system.

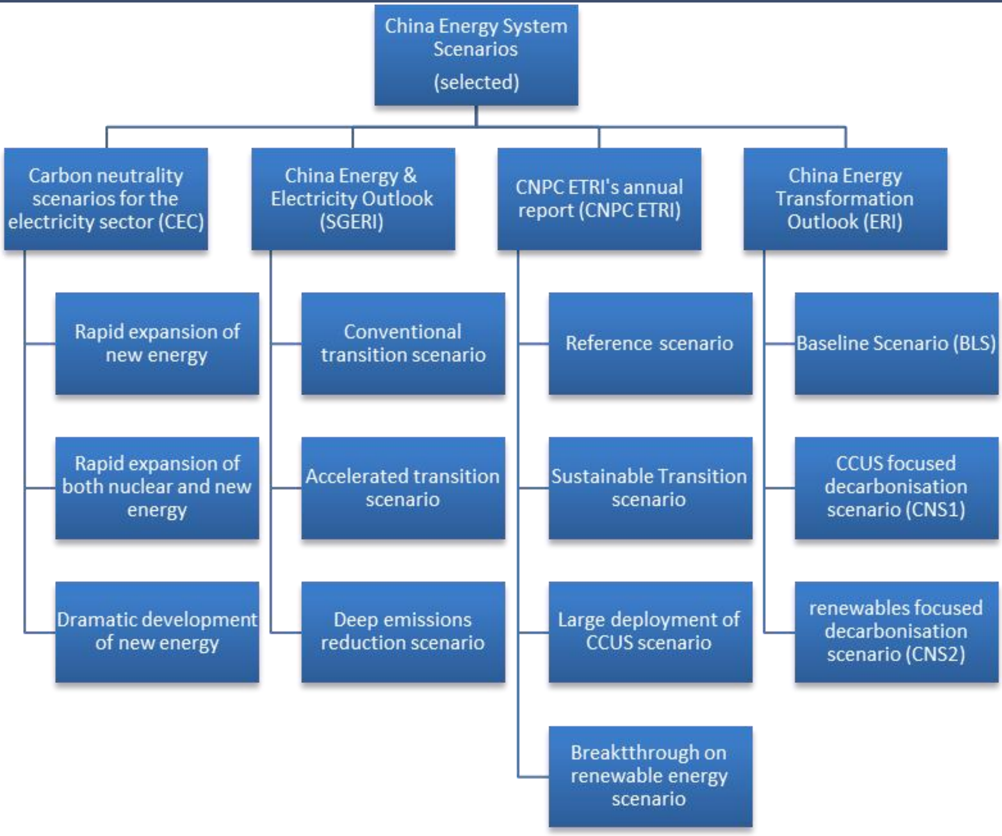
Common features in the Chinese and European energy system scenarios:

- Both the Chinese and European scenarios have the main objective of showing ways to achieve CO_2 neutrality. In most Chinese scenarios, the CO_2 emissions peak occurs in 2030 and CO_2 neutrality is achieved by 2060. European scenarios, in general, aim for CO_2 neutrality to occur by 2050.
- The main measures to reach the targets are the same in China and Europe. Fossil fuels will be phased down and replaced by renewable energy technologies, mainly wind and solar power. Electrification and sector coupling are pursued, together with energy efficiency measures.
- For hard-to-abate sectors, hydrogen and P2X based on renewables come into play. This is particularly relevant for heavy road transport and ship transport and for the steel and cement industry.
- Power system flexibility, grid development, power system adequacy and security, and large-scale power exchange between regions are key to a successful transition of the Chinese and European energy systems.

3.1. China energy system scenarios

Different institutions in China work with a range of energy system scenarios. In the WP2, a selection of these scenarios used by CEC, SGERI, ERI (CET project), and CNPC ETRI (China National Petroleum Corporation, Economics & Technology Research Institute) were described and discussed. An overview of the scenarios is depicted in Figure 3.

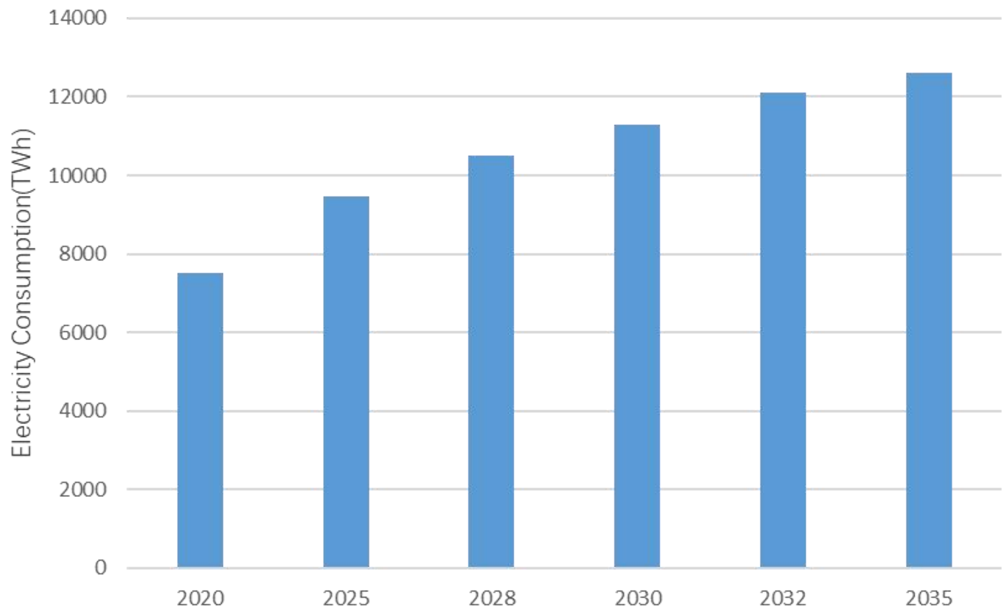
Figure 3.1: Overview of Chinese scenarios



3.1.1. CEC Power system scenarios

The China Electricity Council (CEC) industry association in China represents the country's power generation and electricity industry. CEC's carbon neutrality scenarios focus on the power industry and are presented from a power generation perspective.

Figure 3.2: China's electricity demand forecast



China's electricity demand is projected to continue growing for the foreseeable future, as depicted in Figure 3.2. CEC's estimates indicate that total electricity consumption will reach 9 500 TWh, 11 300 TWh, and 12 600 TWh by 2025, 2030, and 2035, respectively. This represents a compound annual growth rate (CAGR) of 4.8%, 3.6%, and 2.2% for every five-year period.

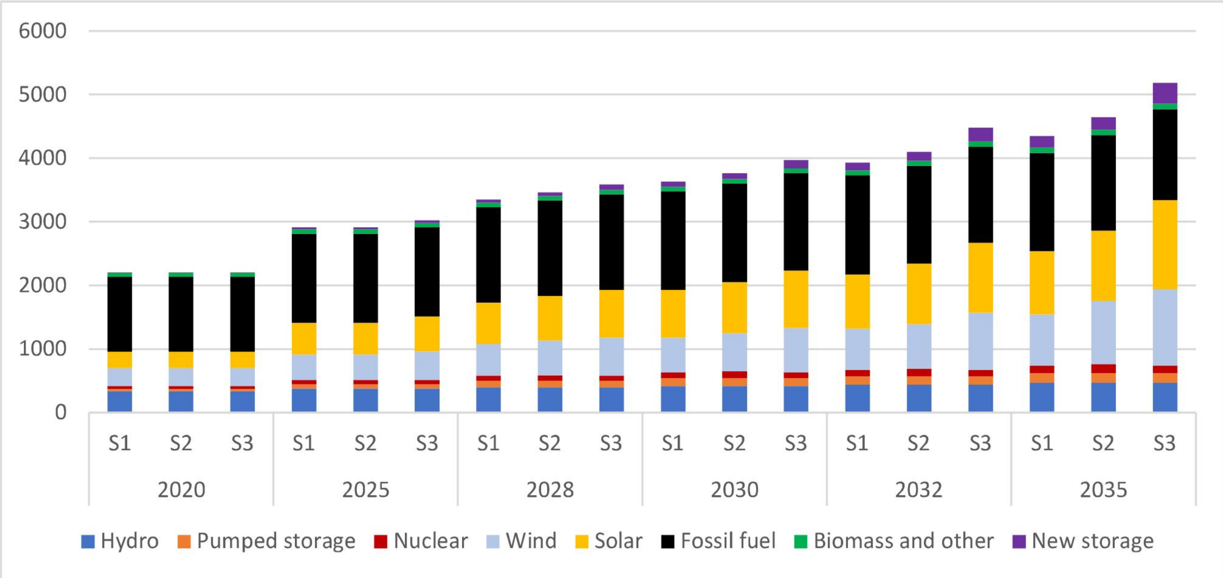
Scenarios with different storylines

In order to meet the huge increase in demand described above, power capacity will increase significantly. The basic principles of energy development to satisfy the energy balance are to expand hydropower while respecting environmental protection requirements, vigorously develop renewable energy, expand nuclear power in a safe and orderly manner, moderately develop gas power, strictly limit the increase in coal consumption, and gradually raise the use of energy storage in line with the technological maturity of storage facilities.

In the carbon neutrality scenario building, CEC distinguishes between three different carbon neutrality scenarios:

- *Rapid expansion of new energy*[4]*(S1)*, where 70-80 GW of wind and solar energy and four nuclear power plants are constructed annually during the 2020s.
- *Rapid expansion of both nuclear and new energy (S2)*, where the nuclear power develops faster than in the first scenario.
- *Dramatic development of new energy (S3)*, where it is assumed that storage technology matures enough for commercial application and can therefore provide more flexibility for a higher share of renewable energy.

Figure 3.3 depicts an overview of the fuel mix by scenario (S1-S3)



[4] The terms 'renewable energy' and 'new energy' are often used interchangeably. Here, 'new energy' refers more broadly to emerging technologies and innovations in the energy sector, including renewable energy sources as well as new or improved methods for energy storage, distribution, and consumption.

Rapid expansion of new energy (S1)

The first scenario is called *Rapid expansion of new energy*. In this scenario, it is assumed that 70-80 GW of wind and solar energy and four nuclear power plants are added annually during the 2020s. Wind and solar energy provide clean electricity, and nuclear energy provides sufficient load supply. After 2030, 100 GW of new energy (wind and solar) is added each year. New energy capacity is 1 300 GW by 2030. Ultimately, the gap in electricity supply is filled by fossil fuels such as coal and natural gas. Under these circumstances, CO_2 emissions from the power industry are set to peak around 2032.

Rapid expansion of both nuclear and new energy (S2)

The second scenario is called *Rapid expansion of both nuclear and new energy*. In this scenario, nuclear energy is assumed to develop faster than in the first scenario, at six units per year. This allows 80 to 100 GW of wind and solar power plants to be built each year. Normally, the construction period of nuclear power plants is more than five years, so the first five years (2020-25) are the same as in the first scenario. After 2025, the carbon reduction is faster than in the first scenario. New energy capacity is 1 400 GW in 2030. CO_2 emissions from the power industry are set to peak around 2030.

Dramatic development of new energy (S3)

The third scenario is called *Dramatic development of new energy*. In this scenario, it is assumed that storage technology is developing well and is sufficiently mature for commercial application. Therefore, the new storage capacity is larger than in the first and second scenario. This provides more stability and flexibility in the power system, similar to nuclear power, and wind and solar capacity will therefore be larger. From 2020 to 2030, over 100 GW of new energy will be added annually. New energy capacity is 1 600 GW by 2030. CO_2 emissions from the energy industry are set to peak around 2028.

Comprehensive analysis

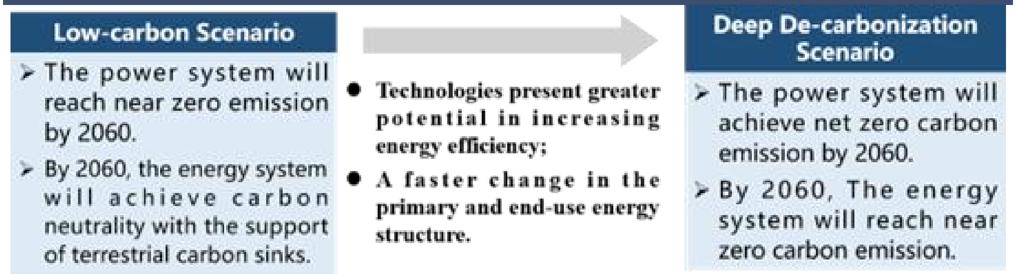
The results of the analysis show that inertia in the power grid in 2030 is high enough to ensure the stability of the system. The power industry should be able to provide green electricity for industry, transport, construction, and other sectors of the economy, and serve the energy transition and carbon peaking of society as a whole.

Uncertainties include whether there will be a heated supply chain to build nuclear power plants and manage uranium resources. Additionally, it is uncertain whether the new energy storage technology will be fully mature, especially when it comes to providing safe long-term operation during periods without wind and sun.

3.1.2. SGERI’s annual energy & electricity outlook

The State Grid Energy Research Institute (SGERI) publishes an annual report named *China Energy & Electricity Outlook* (see Figure 3.4). In this section, scenarios from this series of reports are described.

Figure 3.4: Low-Carbon and Deep Decarbonisation scenarios



Source: SGERI/China Energy & Electricity Outlook 2021

China's President Xi has announced that China will reach peak carbon emissions by 2030 and achieve carbon neutrality by 2060. Therefore, the two scenarios for these years have made achieving the 'dual carbon' goal mandatory (see Figure 3.4). On the energy supply side, due to coal serving as the main energy source in China at the present time, the authors of this report recognise the importance of coal and the fact that coal power serves as a key energy source in the country. This report therefore advocates the clean and orderly reduction of coal usage, and the safe and stable supply of electricity.

In terms of critical energy and electricity technologies, the predicted cost and development potential of hydrogen energy, CCUS, pumped-hydro energy storage and other aspects are viewed positively when considering the low-carbon development and technological progress required.

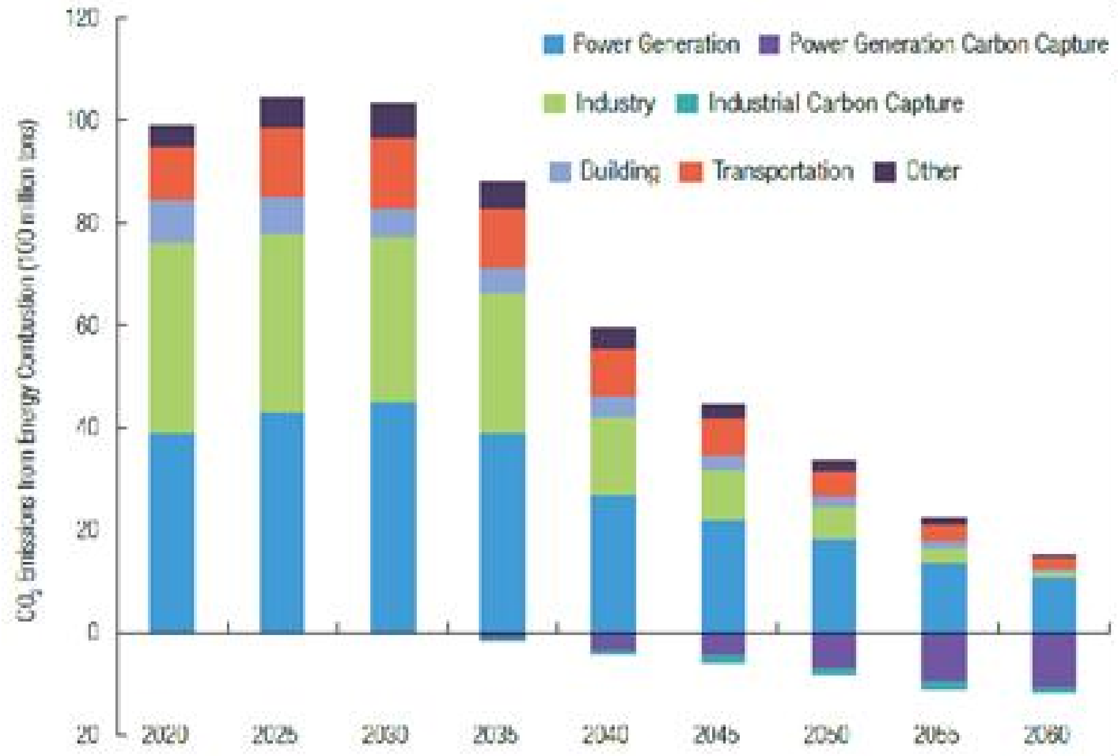
In the Low-carbon Scenario, the power system will reach near zero emissions by 2060. The energy system will achieve carbon neutrality with the support of terrestrial carbon sinks by 2060. In the Deep Decarbonisation Scenario, end-use energy utilisation technologies offer more potential for raising energy efficiency, the structural reform of end-use energy and primary energy will be further accelerated and various emission reduction technologies such as CCUS, hydrogen energy and biofuels will be rapidly developed. The energy system will achieve near-zero CO_2 emissions by 2060.

Table 3.1: Main Parameters in the Scenarios (2021)

Key indicators	Low Carbon Scenario	Deep Decarbonization Scenario
Economic Environment	The average annual GDP growth rates for between 2021-2060 will be 5.5%, 4.8%, 4.3%, 3.8%, 3.3%, 3.0%, 2.8% and 2.7%, respectively (every 5 years). The total population will reach 1.28 billion in 2050 and nearly 1.20 billion in 2060.	
Electricifcation Level	The proportion of electric furnace steel will reach 20% in 2030 and 55%-60% in 2060. The number of small and micro electric vehicles will reach 74 million in 2030 and 310 million in 2060. The electrification rate in cooking will reach 60% in 2060.	The proportion of electric furnace steel will reach 60% earlier. The population of small and micro electric vehicles will reach 320 million in 2060. The electrification rate in cooking will reach 65% in 2060.
CAPEX for Renewble Power / (RMB/kW)	Onshore wind power: 5800 (2030), 5000 (2060) Offshore wind power: 12000 (2030), 7500 (2060) PV: 2600 (2030), 2000 (2060).	Onshore wind power: 5500 (2030), 4500 (2060) Offshore wind power: 10500 (2030), 6700 (2060) PV: 2300 (2030), 1500 (2060).
Cost of CO_2 Emission	About 80 RMB/t in 2030 and 300 RMB/t in 2060	About 120 RMB/t in 2030 and 400 RMB/t in 2060
Demand Response	5%-6% and 10%-12% of the maximum load in 2030 and 2060 respectively	6%-7% and 12%-15% of the maximum load in 2030 and 2060 respectively.
Energy Storage Cost	CAPEX in 2030 and 2060 will fall to about 1800 and 600 RMB/kWh, respectively	CAPEX in 2030 and 2060 will fall to about 1400 and 400 RMB/kWh, respectively

The main parameters used in the scenarios are shown in Table 3.1. The main differences between the two scenarios are electrification level, CAPEX for renewable power generation units, cost of CO_2 emissions, potential for demand response and cost of energy storage.

Figure 3.5: China's CO_2 emissions by sector in the Deep Decarbonisation scenario



The main sectors responsible for carbon emissions from energy combustion include power generation, industry, building, and transportation (see Figure 3.5). In the near to medium term, the power generation and industry sectors will be the main sources of CO_2 emissions from energy combustion, while in the long term, transportation and the building sector will become relatively larger sources of carbon emissions as a result of the promotion of CCUS technology and the increase in carbon capture capacity.

Figure 3.6: China Energy & Electricity Outlook 2020 Scenarios

Conventional Transition Scenario	➢ A steady increase in the electricification rate.
Accelarated Electricification Scenario	➢ A faster growth in end-use electricity consumption; ➢ A more rapid development of clean energy.
Deep Emissions Reduction Scenario	➢ A substantially greater energy efficiency; ➢ A further increase in electrification rates; ➢ A higher proportion of clean energy in the primary energy structure, including hydrogen, biomass...

In SGERI's China Energy & Electricity Outlook 2020 three scenarios are evaluated: a conventional transition scenario, an accelerated electrification scenario and a deep emission reduction scenario (see Figure 3.6). In the Conventional Transition Scenario, a steady increase in the electrification rate is assumed. In the Accelerated Electrification Scenario, there is a faster growth in end-use electricity consumption and a more rapid development of clean energy. In the Deep Emission Reduction Scenario, the increase in energy efficiency and electrification rate is more significant and there is a higher proportion of clean energy in the primary energy structure.

Table 3.2: Main Parameters in the Scenarios (2020-21)

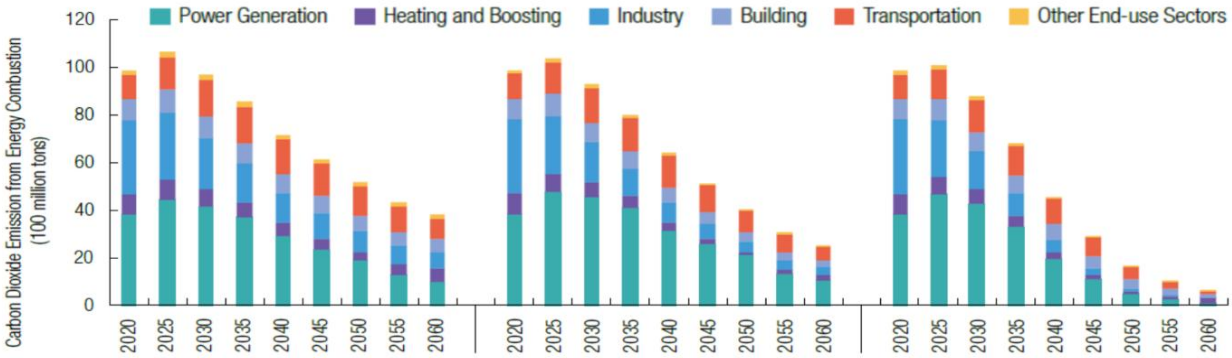
Key indicators	Conventional Transition Scenario	Accelarated Electricification Scenario	Deep Emissions Reduction Scenario
Economic Environment	The average annual GDP growth rates for between 2021-2060 will be 5.5%, 5.0%, 4.2%, 4.2%, 3.2%, 3.2%, 2.5% and 2.5%, respectively (every 5 years). The total population will reach 1.40 billion in 2050.		
Electricifcation Level	The proportion of electric furnace steel will reach 15% in 2030 and 30% in 2050. The number of electric vehicles will reach 92 million in 2030 and 240 million in 2050.	The proportion of electric furnace steel will reach 24% in 2030 and 54% in 2050. The number of electric vehicles will reach 140 million in 2030 and 350 million in 2050.	The proportion of electric furnace steel will reach 25% in 2030 and 55% in 2050. The number of electric vehicles will reach 150 million in 2030 and 360 million in 2050.
CAPEX for Renewble Power / (RMB/kW)	Onshore wind power: 4800 (2035), 4400 (2060) Offshore wind power: 9500 (2035), 7500 (2060) PV: 2400 (2035), 2100 (2060).	Onshore wind power: 4500 (2035), 3800 (2060) Offshore wind power: 9000 (2035), 6700 (2060) PV: 2200 (2035), 1800 (2060).	Onshore wind power: 4500 (2035), 3800 (2060) Offshore wind power: 9000 (2035), 6700 (2060) PV: 2200 (2035), 1800 (2060).
Cost of CO_2 Emission	About 20 RMB/t in 2020 and 300 RMB/t in 2060	About 20 RMB/t in 2020 and 300 RMB/t in 2060	About 20 RMB/t in 2020 and 400 RMB/t in 2060

Table 3.3: Main Parameters in the Scenarios (2020-22)

Key indicators	Conventional Transition Scenario	Accelarated Electricification Scenario	Deep Emissions Reduction Scenario
Change in the Flexibility of Coal Power	The peak-shaving depth of co-generation units will reach 30% in 2035 and 40% in 2060. The peak-shaving depth of non-cogeneration units will respectively reach 60% in 2035 and 70% in 2060.	The peak-shaving depth of co-generation units will reach 40% in 2035 and 50% in 2060. The peak-shaving depth of non-cogeneration units will respectively reach 70% in 2035 and 80% in 2060.	The peak-shaving depth of co-generation units will reach 40% in 2035 and 50% in 2060. The peak-shaving depth of non-cogeneration units will respectively reach 70% in 2035 and 80% in 2060.
Demand Response	6%-8% and 12%-15% of the maximum load in 2035 and 2060 respectively	7%-9% and 18%-20% of the maximum load in 2035 and 2060 respectively.	7%-9% and 18%-20% of the maximum load in 2035 and 2060 respectively.
Energy Storage Cost	CAPEX in 2035 and 2060 will fall to about 3000 and 1500 RMB/kW, respectively	CAPEX in 2035 and 2060 will fall to about 2000 and 700 RMB/kW, respectively	CAPEX in 2035 and 2060 will fall to about 2000 and 700 RMB/kW, respectively

The main parameters used in the 2020 scenarios are shown in Table 3.2 and Table 3.3. The main differences for the three scenarios are electrification level, CAPEX for renewable power generation units, cost of CO_2 emissions, change in the flexibility of coal power, potential for demand response and cost of energy storage units.

Figure 3.7: Carbon dioxide emissions from energy consumption for each sector in three scenarios (2020)



	Conventional Transition Scenario									Accelerated Electrification Scenario									Deep Emissions Reduction Scenario								
	2020	2025	2030	2035	2040	2045	2050	2055	2060	2020	2025	2030	2035	2040	2045	2050	2055	2060	2020	2025	2030	2035	2040	2045	2050	2055	2060
Power Generation	38.3	44.3	41.3	36.8	28.9	23.3	18.8	13.0	9.9	38.3	47.6	45.5	41.1	31.6	25.5	21.0	13.3	10.2	38.2	46.4	42.8	33.3	19.5	10.9	5.1	2.5	0.9
Heating and Boosting	8.2	8.3	7.4	6.6	5.6	4.7	3.8	4.4	5.6	8.6	7.7	6.2	4.8	3.4	2.4	1.6	2.0	2.5	8.6	7.5	5.9	4.3	2.8	1.8	1.0	1.4	2.0
Industry	31.1	28.4	21.9	16.3	12.5	10.6	9.0	7.8	7.0	31.1	24.3	16.9	11.5	8.1	6.2	4.4	3.8	3.4	31.1	23.6	16.2	9.6	5.3	2.8	1.1	0.6	0.2
Building	8.8	9.7	8.9	8.6	8.2	7.2	6.2	5.8	5.4	8.8	9.2	7.9	7.2	6.5	5.1	4.0	3.3	2.7	8.8	9.2	7.8	7.1	6.4	4.9	3.9	2.7	1.5
Transportation	10.3	13.5	15.1	15.1	14.5	13.7	12.3	10.6	8.7	10.3	13.4	14.9	14.4	13.3	11.1	8.6	7.5	6.0	10.3	12.7	13.7	12.4	10.6	8.0	5.1	3.0	1.5
Other End-use Sectors	1.8	2.1	2.2	2.1	2.0	1.8	1.7	1.6	1.4	1.4	1.5	1.3	1.1	1.0	0.8	0.7	0.6	0.5	1.4	1.4	1.2	1.0	0.8	0.7	0.5	0.4	0.3

The industry and power generation sectors will be the main sources of CO_2 emissions in the near and medium future, while the emissions from the transportation and building sectors will see a relative increase in the long term (see Figure 3.7. The power generation sector will play a significant role in reducing carbon emissions. In the near future, it will help end-use energy sectors to reduce emissions using electrification.

3.1.3. CNPC ETRI's Annual Report

In the annual report published by CNPC Economics & Technology Research Institute in 2021, there are four scenarios in total, which are: Reference Scenario, Sustainable Transition Scenario, Large Deployment of CCUS Scenario and Breakthrough on Renewable Energy Scenario (see Figure 3.8).

Figure 3.8: Scenarios for the annual report published by CNPC ETRI (2021)

Reference Scenario	➢ **Extrapolation according to existing policies and technology** development trends, without additional policy constraints.
Sustainable Transition Scenario	➢ China will peak the carbon emissions before 2030. Then, the carbon emissions will decrease rapidly and reach nearly zero in 2060. ➢ Fossil energy will serve as flexible resources, for instance, the power supply for peak shaving and emergency reserve units. ➢ Low-carbon and zero-carbon technologies, such as wind, solar, CCUS and hydrogen, will make improvement continuously, and the costs will continue to decline.
Large Deployment of CCUS Scenario	➢ Compared to the sustainable transition scenario, CCUS technology and industry will make larger improvements. ➢ **A large-scale commercial application will be realized earlier than expected.**
Breakthrough on Renewable Energy Scenario	➢ Compared to the sustainable transition scenario, **breakthroughs will be made in renewable energy and related supporting technologies.** ➢ The power system can operate safely and stabely with high proportion of renewable energy. The scale of fossil energy will decrease faster.

In the Reference Scenario, all parameters are set by extrapolation according to existing policies and technology development trends. In the Sustainable Transition Scenario, fossil fuels will serve as flexible resources, for instance, meeting power needs for peak shaving and emergency reserve units. Low-carbon and zero-carbon technologies, such as wind, solar, CCUS and hydrogen, will make steady progress, and costs will continue to decline. In the Large Deployment of CCUS Scenario, compared to the Sustainable Transition Scenario, a large-scale commercial application of CCUS technology will be realised earlier than expected. In the Breakthrough on Renewable Energy' Scenario, breakthroughs will be made in renewable energy and related supporting technologies.

Table 3.4: Main Parameters in the Scenarios

Scenario's name	Reference Scenario	Scenarios with the goal of carbon neutrality		
		Sustainable Transition Scenario	Large Deployment of CCUS Scenario	Breakthrough on Renewable Energy Scenario
Society and Economy	(1) The population will peak before 2030. (2) The urbanization rage will increase gradually and reach 75% in 2060. (3) The annual economic growth rate will be 4.8% before 2035 and 3.1% between 2036-2060.			
Energy Efficiency	(1)The fuel economy for vehicles increases 1.5% annually before 2035, and then remains stable. (2) The efficiency for energy-intensive products increases 1.2% annually.	(1) The fuel economy for vehicles increases 2% annually before 2035, and then remains stable. (2) The efficiency for coal-fired power generation increases 0.3% annually. (3) The efficiency for energy-intensive products increases 1.3% annually.		
Technology Development	(1) For the reference scenario, costs for certain technologies are the upper boundary. (2) For the large deplolyment of CCUS scenario, costs for CCUS technologies are the lower boundary, while others are the mid-value. (3) For the breakthrough on renewable energy scenario, costs for PV and wind power technologies are the lower boundary, while others are the mid-value.			
Carbon Emissions	-	(1) The carbon emissions will peak before 2030. (2) China will reach carbon neutrality before 2060.		

The main parameters used in the scenarios are shown in the above Table 3.4. The main differences between the four scenarios are energy efficiency level, costs for key technologies and carbon emissions.

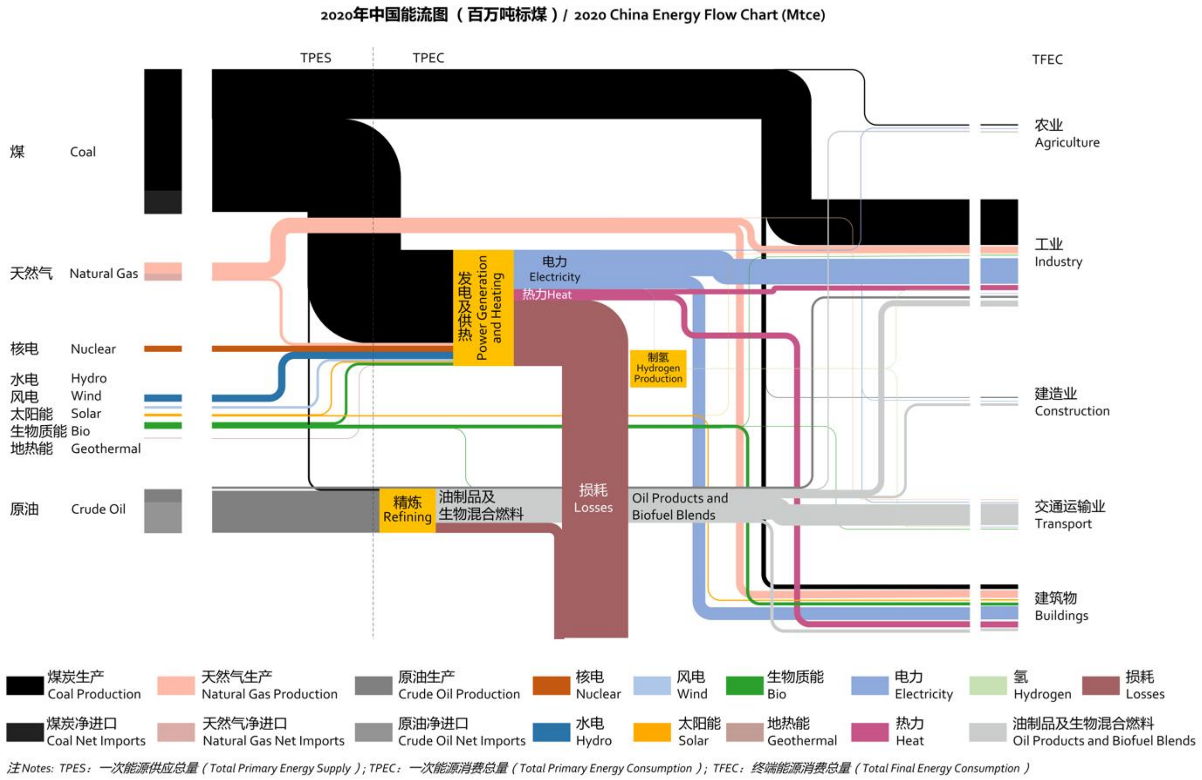
3.1.4. China Energy Transformation Outlook (CETO)

The Energy Research Institute of the Chinese Academy of Macroeconomic Research prepares an annual China Energy Transformation Outlook (CETO), which focuses on different energy system scenarios for the Chinese energy transformation. The CETO 2021 includes two types of scenarios. The first type is the baseline scenario, where China contributes to the global 2-degree goal and achieves carbon neutrality around 2070. The other scenario type shows a path to meet the climate targets to peak CO_2 emissions before 2030 and reach carbon neutrality before 2060, the so-called climate neutral scenarios 1 and 2, (CN1 and CN2). Also, the report includes several thematic analyses, including end-use transformation, power sector transformation, power market reform, power-to-X, carbon pricing, and the status and prospects of CCUS in China. This chapter describes the key features of the carbon-neutral scenario.

The current energy system

The current energy system in China is dominated by fossil fuels, although non-fossil fuels have been deployed at an increasingly rapid pace in the last ten years. As shown in Figure 3.9, coal is used mainly in the power and industry sectors. The transport sector is heavily dependent on oil products, and total losses in the energy system are high due to losses in the transformation from coal to electricity.

Figure 3.9: The 2020 energy flow chart for the Chinese energy system



Source: CETO 2021

The energy transformation strategy

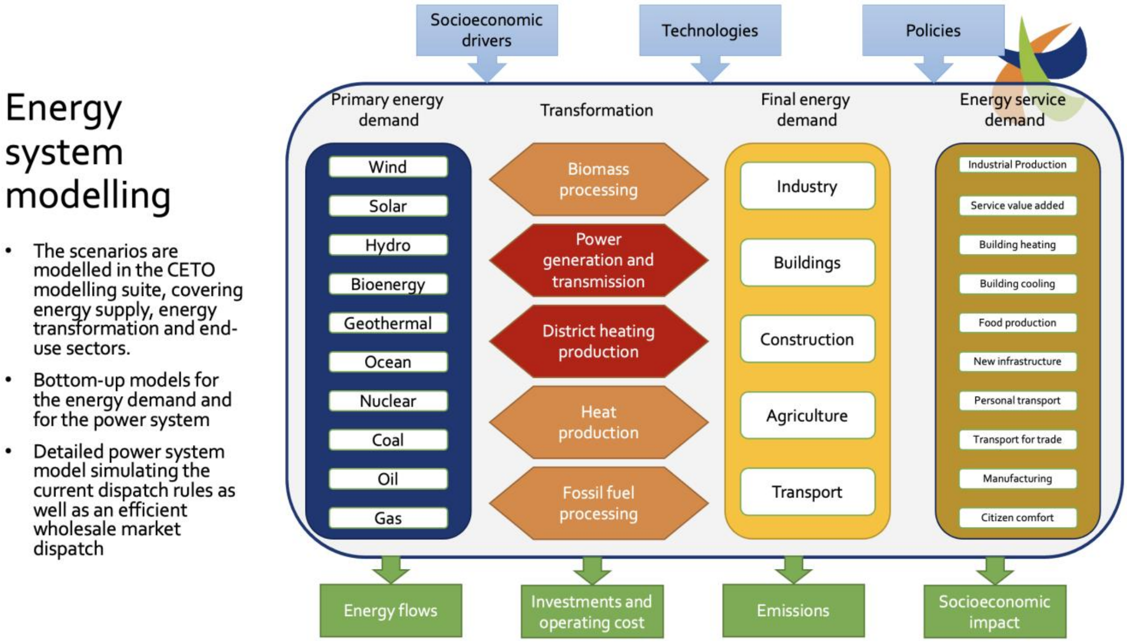
To reach China's carbon peak and carbon neutrality goals, its energy transformation strategy relies on three main pillars:

- Strong energy efficiency measures in tandem with the economic restructuring process.
- Substitution of fossil fuels in the end-use sectors by electricity.
- Massive deployment of solar and wind power to replace coal in the power sector.

These pillars must be implemented together with a focus on avoiding stranded investments and using carbon pricing and efficient power markets as essential drivers for the transformation.

To analyse the impact of this transformation strategy, the CETO scenarios are based on comprehensive modelling tools, as illustrated in Figure 3.10. The end-use sectors are represented in a sector-specific bottom-up model, and the power sector is described in a detailed economic dispatch and investment optimisation model.

Figure 3.10: The CETO energy system modelling suite



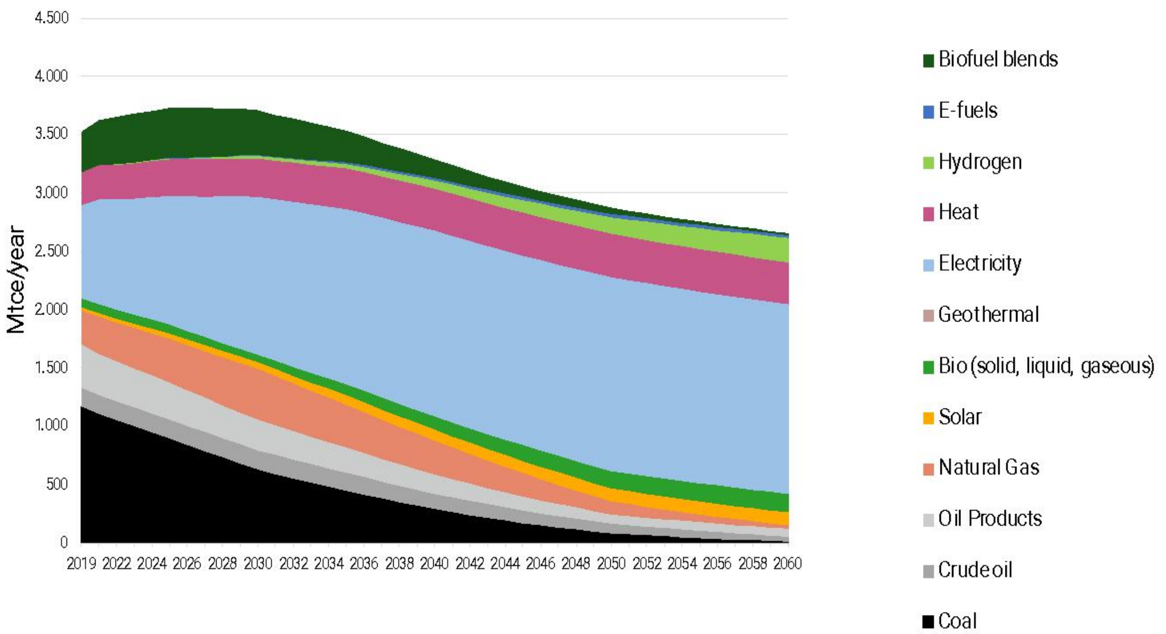
Source: CNREC

Main scenario results

Energy efficiency in the end-use sectors

As a framework boundary for the CETO scenarios, we assume that the economy will be 4.2 times larger in 2060 than in 2020. Despite the economic growth, total final energy consumption will be controlled and will decline from the 2030s, as illustrated in Figure 3.11.

Figure 3.11: Total final energy consumption towards 2060 in the Carbon Neutrality Scenario

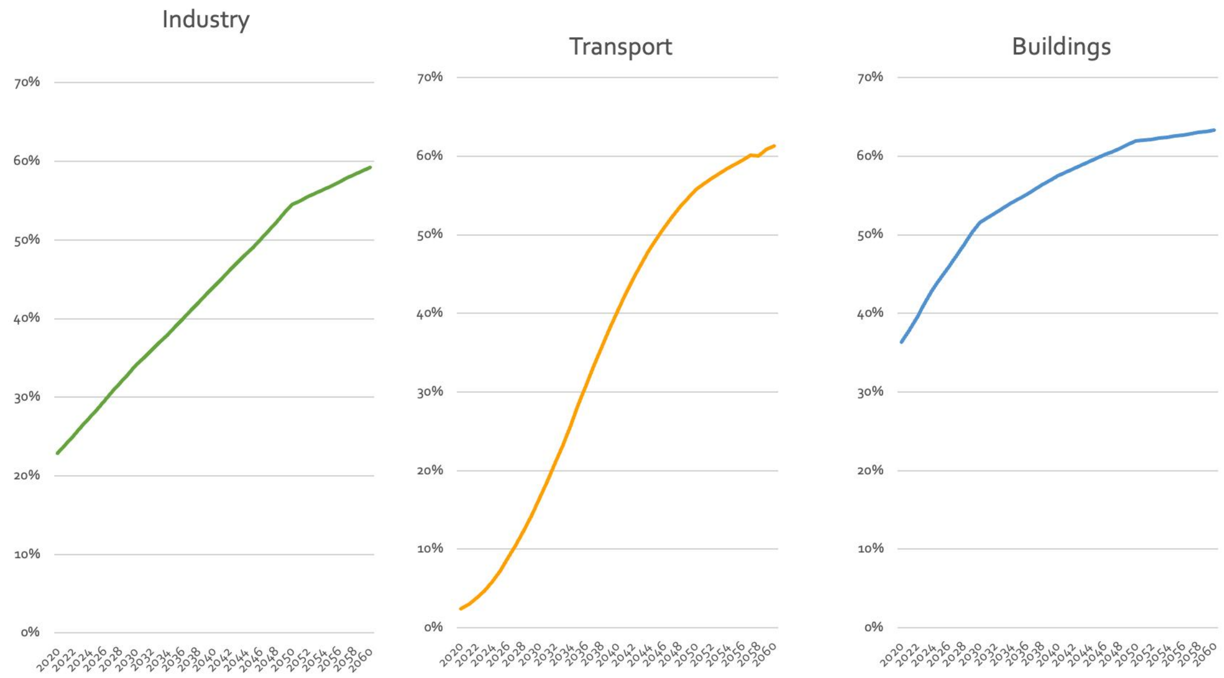


Source: CETO 2021

Fossil fuels are replaced by electricity, and by the end of the period, hydrogen plays a more significant role in the final energy consumption. The electrification of end-use sectors delivers massive energy efficiency improvements, and economic restructuring from heavy energy-intensive industries to light industries and services will reduce energy intensity per unit of GDP.

In the industry sector, the electrification rate (the share of final energy demand supplied by electricity) grows from 23% in 2020 to almost 60% in 2060. In the transport and building sectors, the electrification rate reaches more than 60% in 2060 (see Figure 3.12).

Figure 3.12: The development of the electrification rate for the main end-use sectors



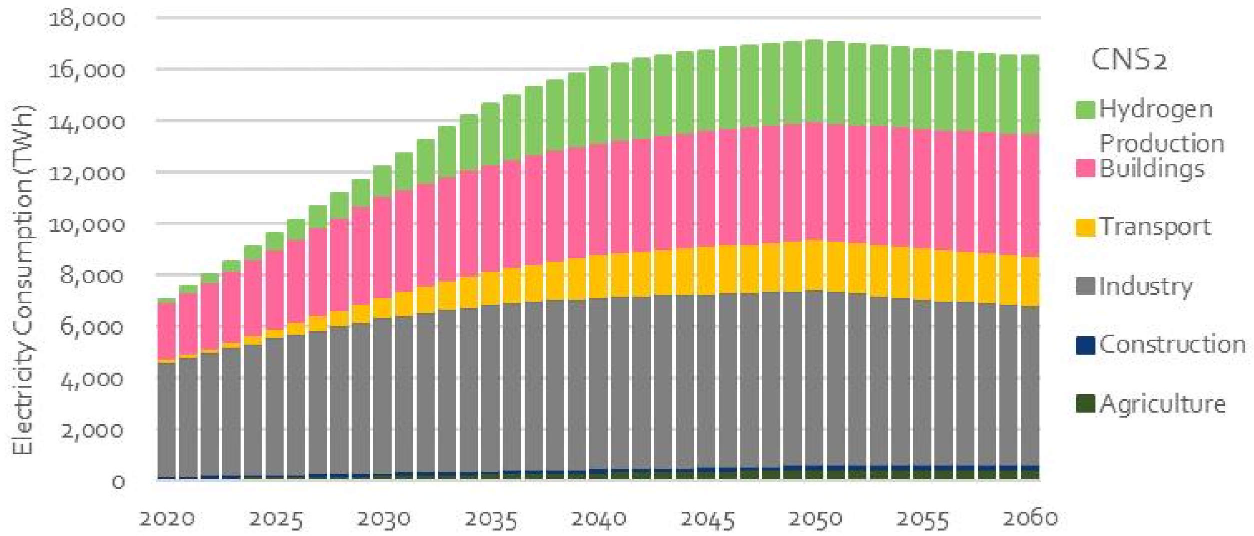
Source: CETO 2021

The power sector transformation

Electricity consumption grows rapidly in the Carbon Neutral Scenario[5] because of the electrification strategy, as illustrated in Figure 3.13.

[5] CETO includes two climate neutral scenarios 1 and 2, CNS1 and CNS2. The CNS1 is a conservative scenario in which the dual-carbon goal is achieved through a smooth, 'passive' transition. The CNS2 is an accelerated transition scenario.

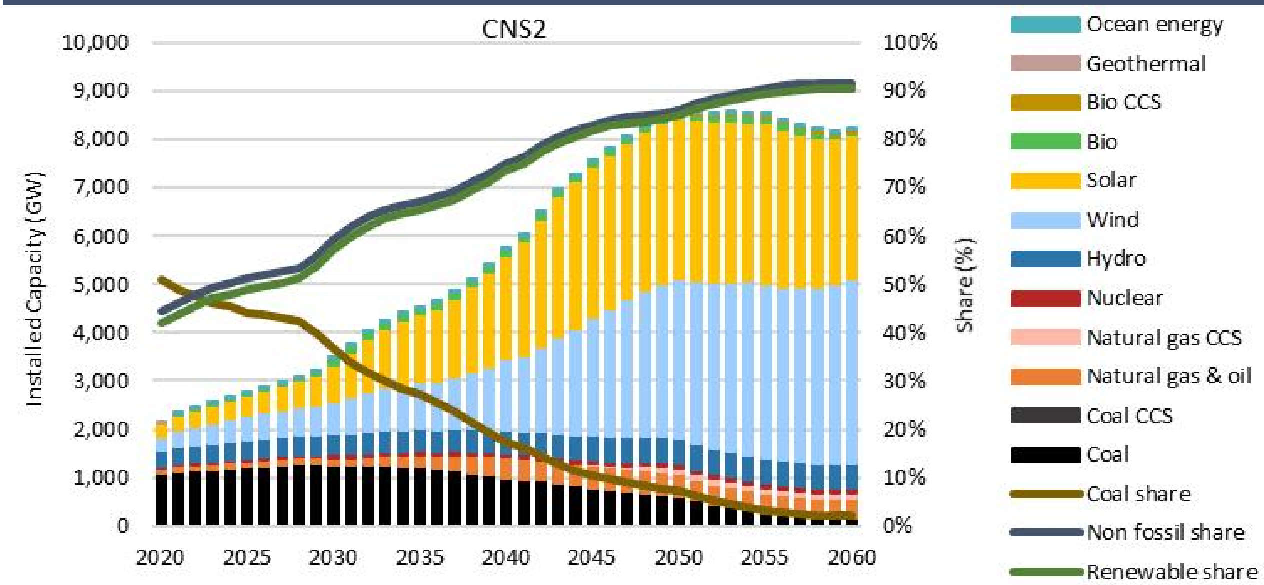
Figure 3.13: Climate neutral CNS2 scenario. Total electricity consumption (TWh) in main end-use sectors and hydrogen production 2020-60



Source: CETO 2021

Total electricity consumption more than doubles from 2020 to 2050, at which point consumption peaks. At the beginning of the period, growth is achieved by the electrification of the industry, transport and building sectors. Later on, the growth rate is underpinned by electricity consumption for the production of green hydrogen.

Figure 3.14: Installed capacity in the power sector (GW) in the period 2020-60

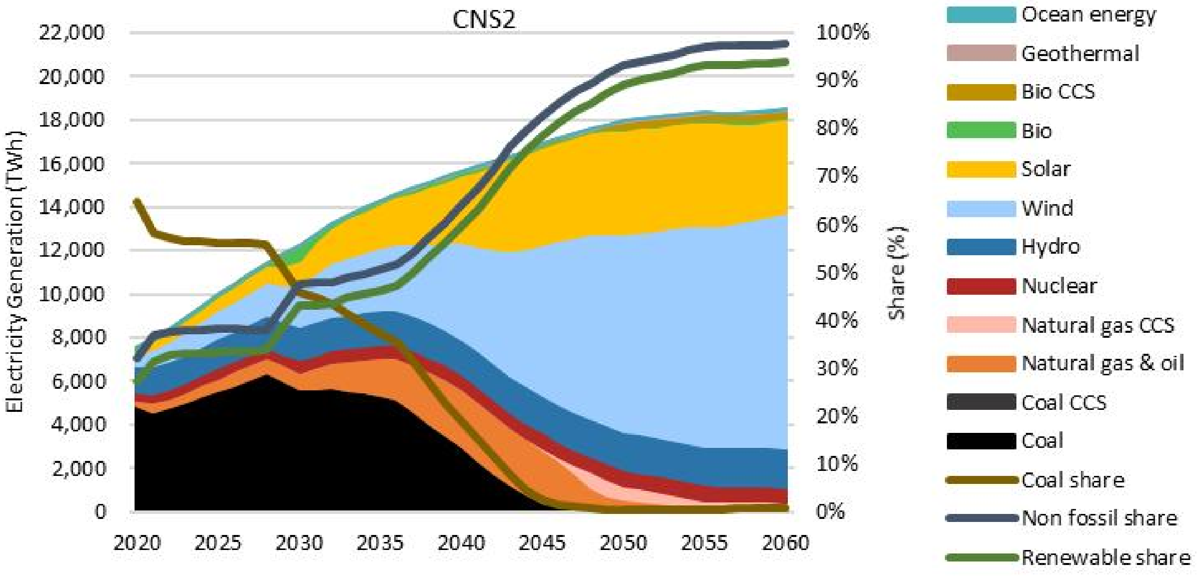


Source: CETO 2021

Figure 3.14 shows the amount of installed capacity relating to different power sources in the period 2020-60. The new installed capacity is mainly solar and wind power capacity, while coal capacity shows a modest growth until 2030, after which it drops back.

A similar pattern is seen for power production. Figure 3.15 shows a large increase in wind and solar power generation, alongside a more modest growth in power production from fossil fuels until 2030, which sees a rapid decline after 2035.

Figure 3.15: Power generation from different sources (TWh) in the period 2020-60



Source: CETO 2021

In the CNS2 scenario, the rapid substitution of coal and oil in the end-use sectors in the period 2020-35 comes at a price. The green power sector transformation cannot match the increase in power consumption, which results in an increase in the use of fossil fuels for power generation over this period. After 2035, the deployment of wind and solar power not only covers the increase in power consumption but also rapidly replaces coal in power generation.

Power system flexibility

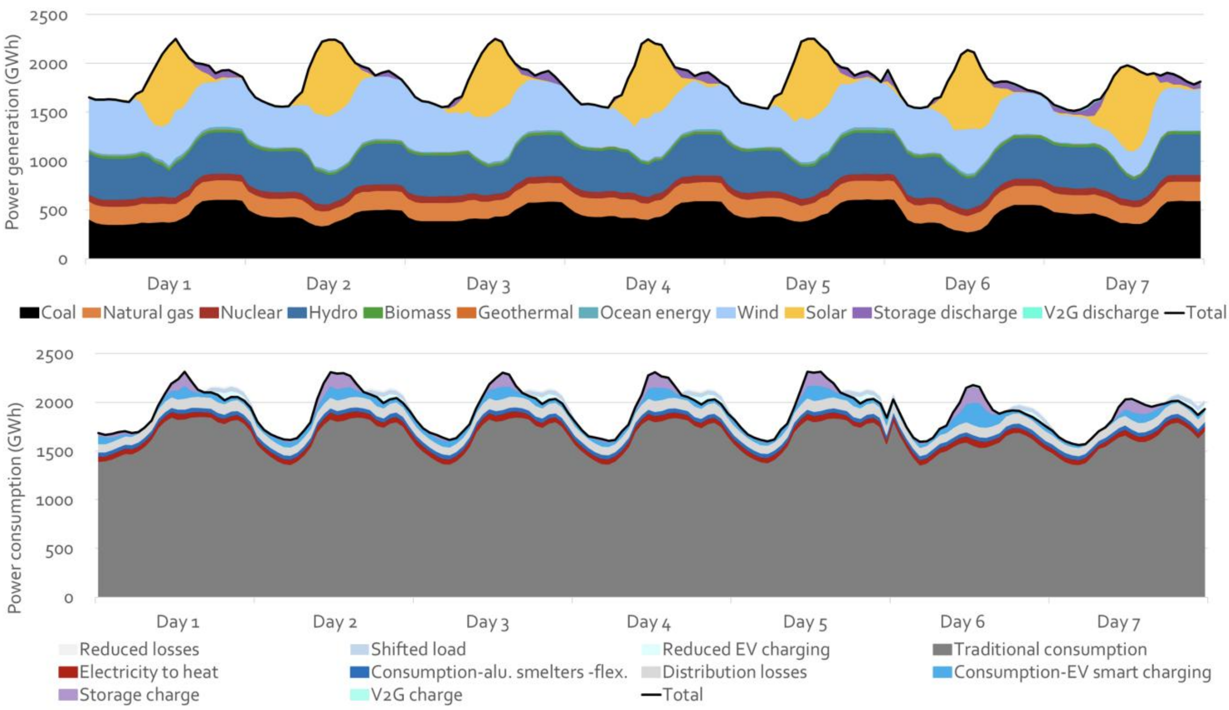
The large amount of variable power generation from wind and solar power plants requires a very flexible power system. In the CNS2 scenario, coal power and pumped storage remain the most important flexibility resources in China for a considerable period of time, while electric vehicles and electrochemical energy storages play an increasingly important role, as shown in Table 3.5: New Flexibility Providers in CNS2 (capacity in GW). (Source: CETO 2021).

Table 3.5: New Flexibility Providers in CNS2 (capacity in GW). (Source: CETO 2021)

Flexibility provider (GW)		Status	Scenario year		
Year		2020	2025	2035	2060
Demand response (DR)	EV smart charging	14	145	870	1187
	Industrial DR	21	36	59	77
Pumped storage		30	43	91	91
New-type storage	Chemical storage	3	2	4	520
	EV V2G	0	0	109	593
Total		68	227	1133	2468

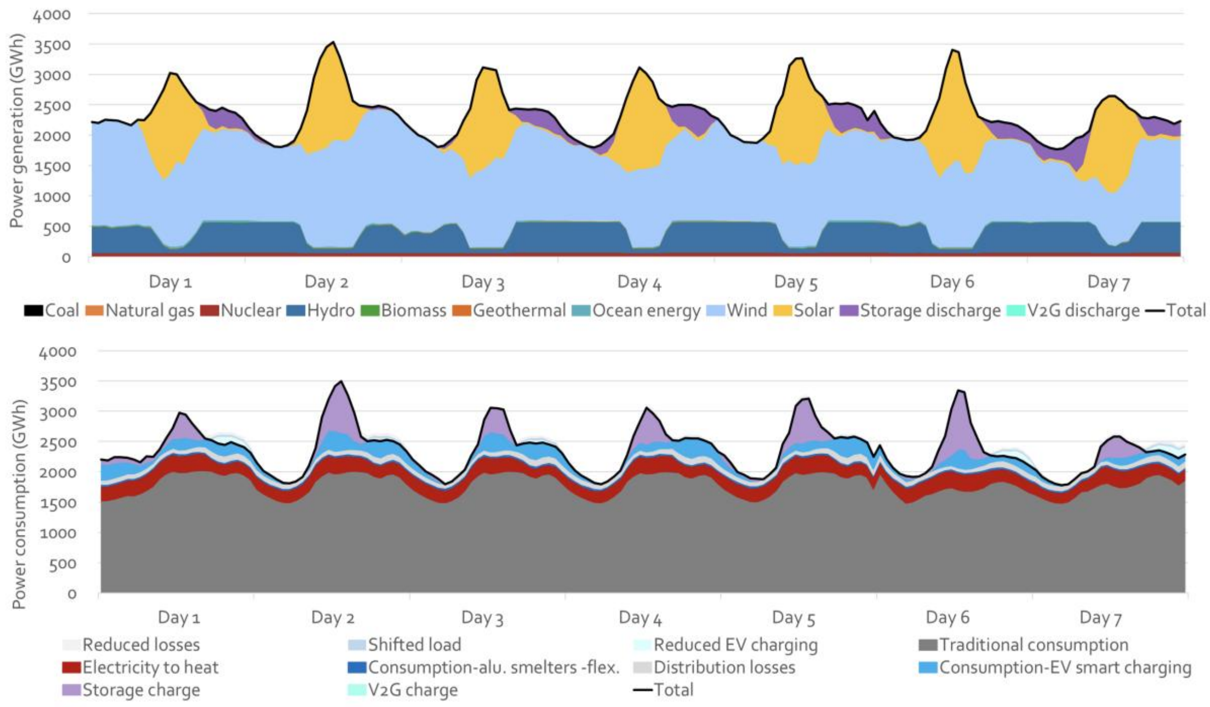
The hourly power balance in the power system in the winter of 2035 and in the winter of 2060 is shown in Figure 3.16 and Figure 3.17.

Figure 3.16: Hourly power balance in the power system for the winter of 2035 (CNS2)



Source: CETO 2021

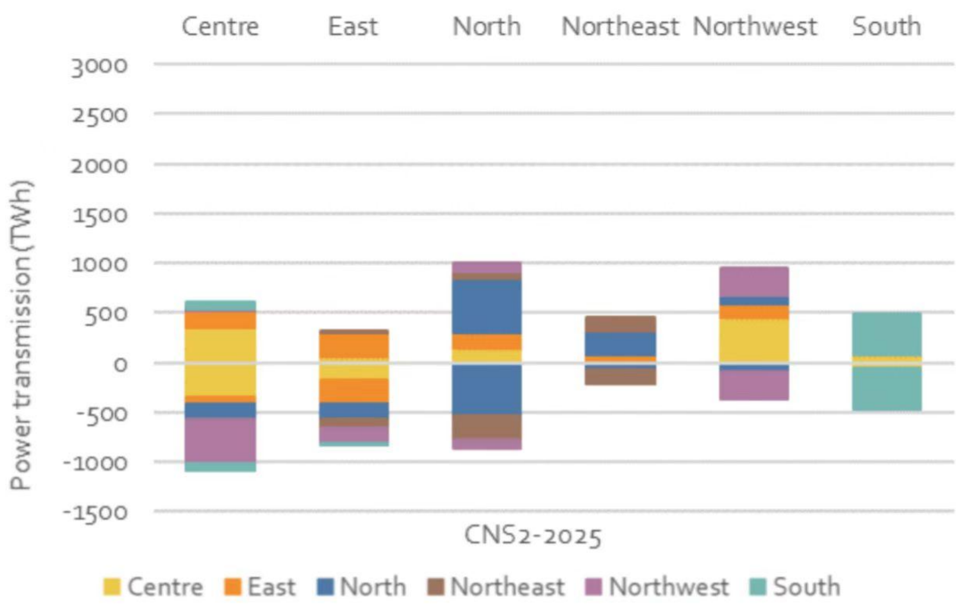
Figure 3.17: Hourly power balance in the power system for the winter of 2060 (CNS2)



Source: CETO 2021

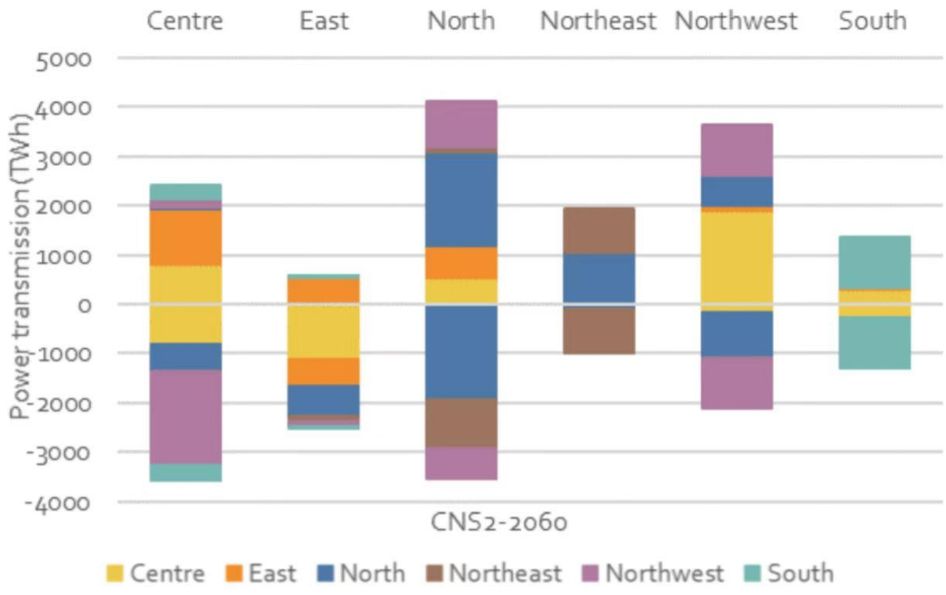
Apart from flexibility, the balancing of the power system also requires large-scale cross-province power exchange. The transmission grid flows between the Chinese regions are illustrated in Figure 3.18 and Figure 3.19 for 2025 and for 2060, respectively.

Figure 3.18: Transmission grid flows (TWh) within and between the Chinese regions in 2025 (CNS2)



Source: CETO 2021

Figure 3.19: Transmission grid flows (TWh) within and between the Chinese regions in 2060 (CNS2)



Source: CETO 2021

The Carbon Neutral Scenario shows several key trends for the energy transformation of the Chinese energy system:

- **Energy efficiency** improvement on the demand side is needed to ensure that the pace of supply-side deployments can keep up with and sustain the required economic growth.
- **Green energy supply** – technological progress and cost reduction will enable the large-scale production of renewable energy, particularly through renewable electricity.
- **Electrification** will support the switch away from fossil fuels in end-use consumption, in conjunction with the decarbonisation of the electricity supply.
- **Hydrogen** becomes an important energy carrier, which creates a link between the abundant supply of cheap green electricity and the hardest to abate sectors. Green hydrogen, combined with captured carbon, allows for the creation of fuels for hard-to-abate sectors such as heavy transport, shipping, and aviation.
- **Sequestration of CO_2** creates a backstop or last resort option, particularly with negative emissions and carbon sinks. Negative emissions can compensate for a modest level of emissions that remain in the system in 2060.

3.2. European energy scenarios: ENTSO-TYNDP and European Commission scenarios

For the EU, perhaps the most comprehensive energy system scenarios can be found in the ENTSO Ten Year Network Development Plans (TYNDPs) for power and gas. These are developed jointly by the European Network of Transmission System Operators for Electricity (ENTSO-E) and the European Network of Transmission System Operators for Gas (ENTSOG)[6]. The scenarios are then merged and further developed in stakeholder workshops and several rounds of feedback.

Key points of the European energy scenarios:

- Net-zero CO_2 emissions can be achieved by 2050 while ensuring the security of energy supply.
- Energy efficiency is key to achieve the EU's long-term climate and energy objectives.
- Ambitious development of renewable energy across Europe will transform the power sector.
- Sector Integration provides efficient decarbonisation solutions.
- Hydrogen will create the link between the supply of cheap green electricity and the hardest to abate sectors. Green hydrogen, combined with captured carbon, allows for the creation of fuels for hard-to-abate sectors such as heavy transport, shipping, and aviation.
- Innovations in the supply chain, in the system integration of technologies, in P2X technology and flexible demand and energy security issues are all key to ensuring a sustainable energy future.

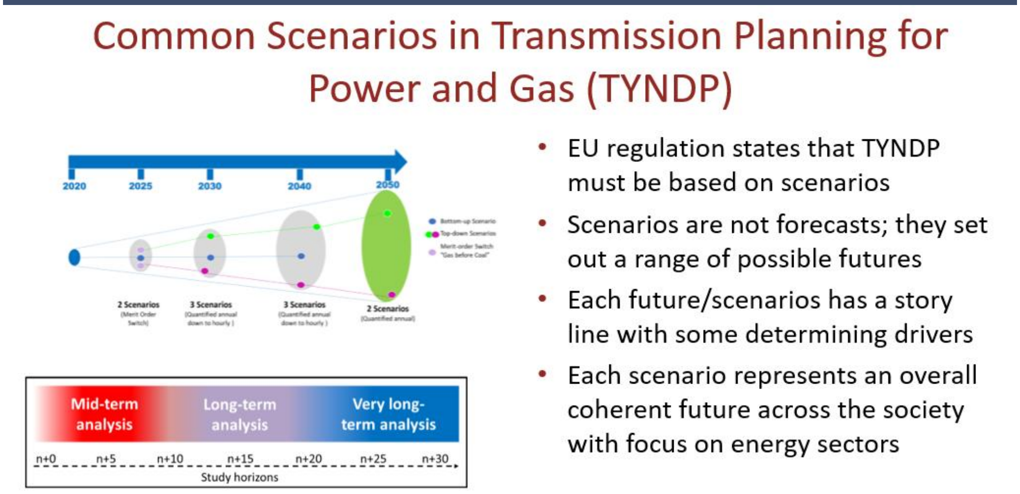
An overview of the recent ENTSO scenario reports relevant for this chapter is presented in Figure 3.20. The common scenarios for power and gas are updated every other year.

[6] TYNDP 2022 Scenario Report – Introduction and Executive Summary

Figure 3.20: Overview of the recent ENTSO scenario reports

The EU regulation states that TYNDP must be based on scenarios. It is again important to note that scenarios are not forecasts, but rather set out a range of possible futures, each with distinct determining drivers. Each scenario represents an overall coherent future across the energy sectors (see Figure 3.21).

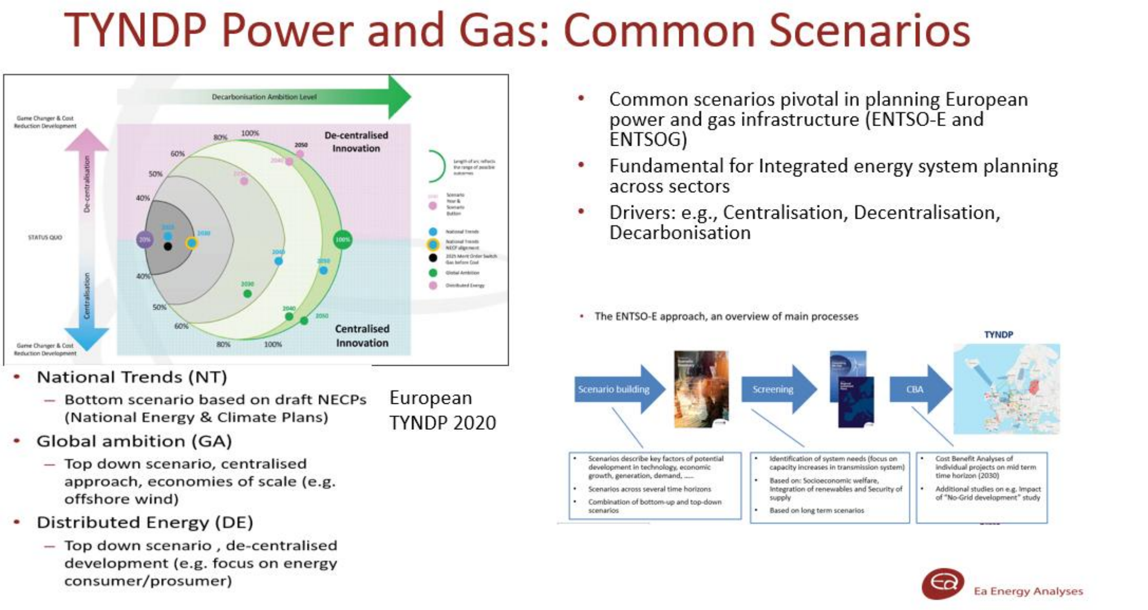
Figure 3.21: Common TYNDP scenarios, general outline



Based on ENTSO TYNDP

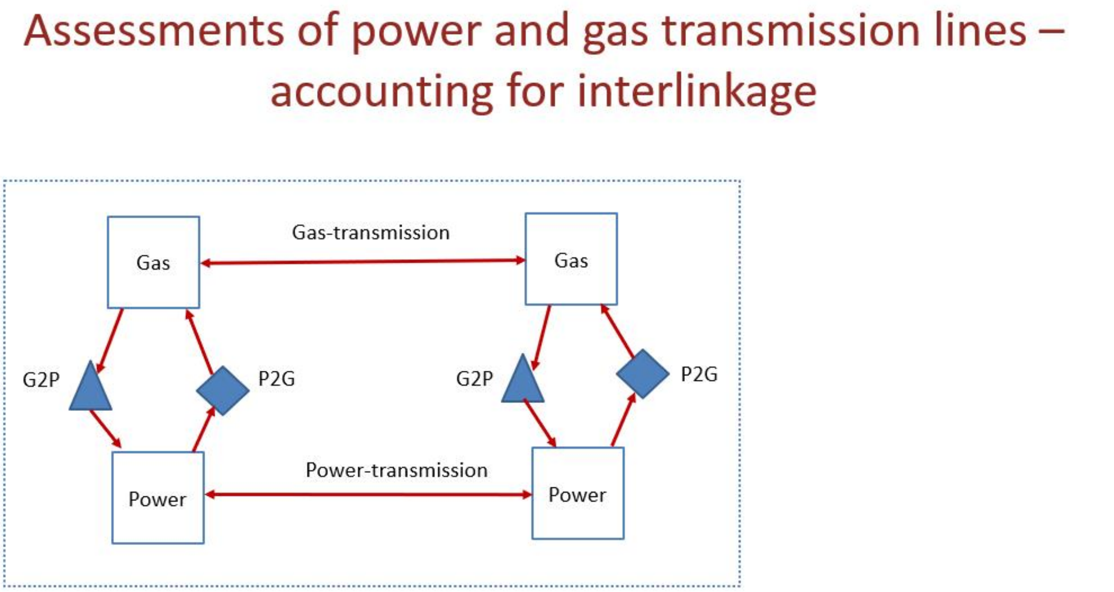
Common scenarios are pivotal in the European TYNDPs for power and gas. They are fundamental for integrated energy system planning across sectors. Figure 3.22 illustrates three scenarios in the ENTSO TYNDP 2020. The important drivers are decentralisation (Distributed Energy Scenario) and centralised innovation (Global Ambition Scenario), respectively. In both of these scenarios the target is net-zero carbon emissions by 2050. The third scenario is a bottom-up scenario based on national energy and climate plans (NECP).

Figure 3.22: Scenarios (TYNDP 2020) are pivotal for planning of transmission



Based on ENTSO TYNDP

Figure 3.23: Scenarios accounting for interlinkages between power and gas



The example in Figure 3.23 shows the importance of taking interlinkage between power and gas into account. The assessment of e.g., a new power transmission line should include the alternative of building the corresponding gas transmission line. In this case the interlinkage between the systems is G2P (gas to power) and P2G (power to gas).

Table 3.6 illustrates the scenario framework of TYNDP 2022. The storylines for 'Distributed Energy' scenario and 'Global Ambition' scenario differ in 'driving force for energy transition', 'energy intensity' and 'technology'. However, both scenarios achieve a 55% CO_2 reduction by 2030 and carbon neutrality by 2050.

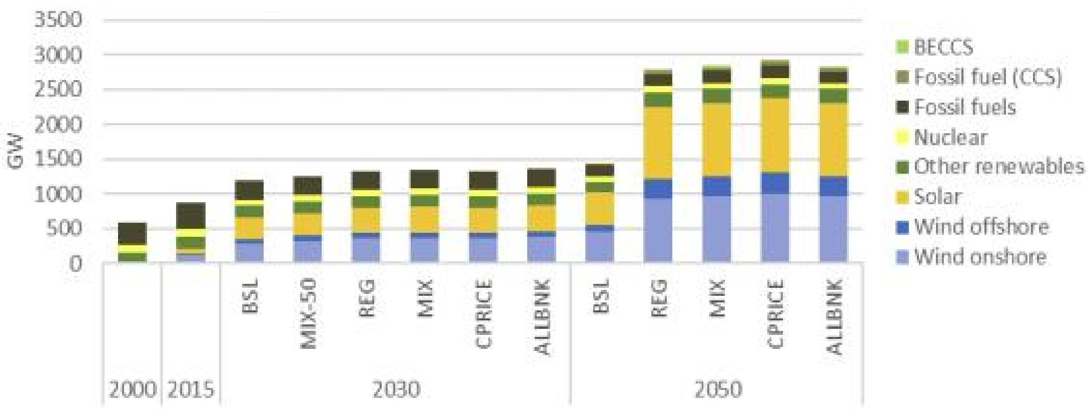
Table 3.6: Scenario framework of TYNDP 2022

	Distributed Energy Higher European autonomy with renewable and decentralised focus	**Global Ambition** Global economy with centralised low carbon and RES options
Green Transition	At least a −55 % reduction in 2030, climate neutral in 2050	
Driving force of the energy transition	Transition initiated at a local/national level (prosumers)	Transition initiated at a European/international level
	Aims for EU energy autonomy through maximisation of RES and smart sector integration (P2G/L)	High EU RES development supplemented with low carbon energy and imports
Energy intensity	Reduced energy demand through circularity and better energy consumption behaviour	Energy demand also declines, but priority is given to decarbonisation of energy supply
	Digitalisation driven by prosumer and variable RES management	Digitalisation and automation reinforce competitiveness of EU business
Technologies	Focus of decentralised technologies (PV, batteries, etc.) and smart charging	Focus on large scale technologies (offshore wind, large storage)
	Focus on electric heat pumps and district heating	Focus on hybrid heating technology
	Higher share of EV, with e-liquids and biofuels supplementing for heavy transport	Wide range of technologies across mobility sectors (electricity, hydrogen and biofuels)
	Minimal CCS and nuclear	Integration of nuclear and CCS

Source: ENTSO-E TYNDP

The European Commission has also developed scenarios for future planning. Figure 3.24 shows scenarios for installed generation capacity of different technologies in 2030 and 2050. For example, the 'REG' scenario policies and measures are the main drivers for attaining CO_2 reduction targets. In the 'CPRICE' scenario, carbon pricing is the main driver.

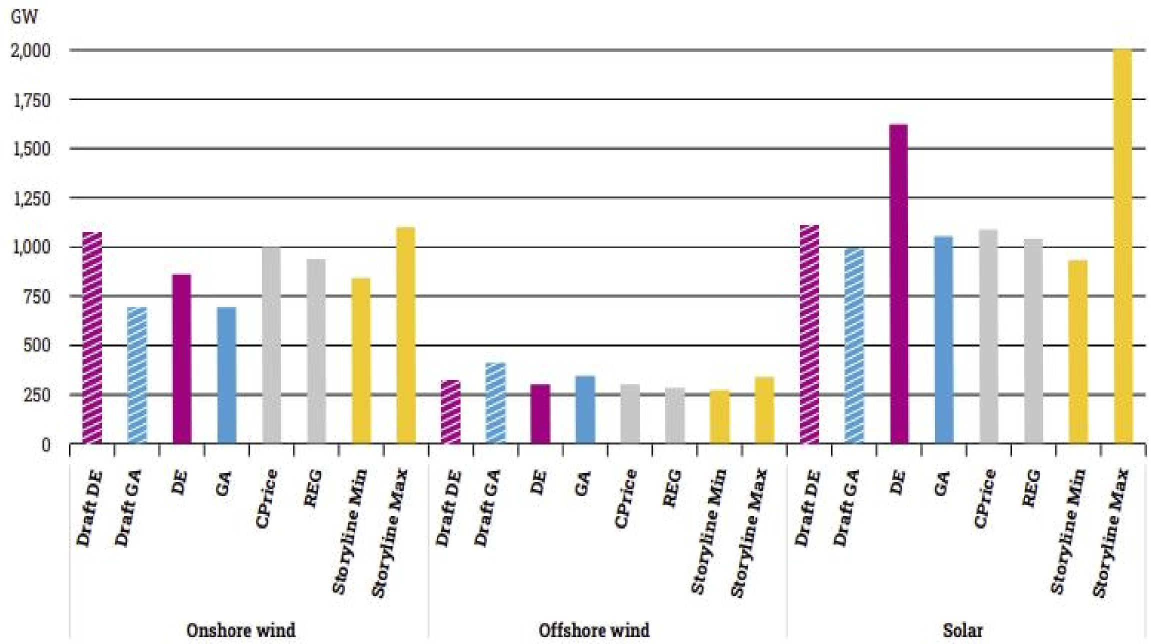
Figure 3.24: European Commission scenarios



Source: 2000, 2015: Eurostat, 2030-2050: PRIMES model

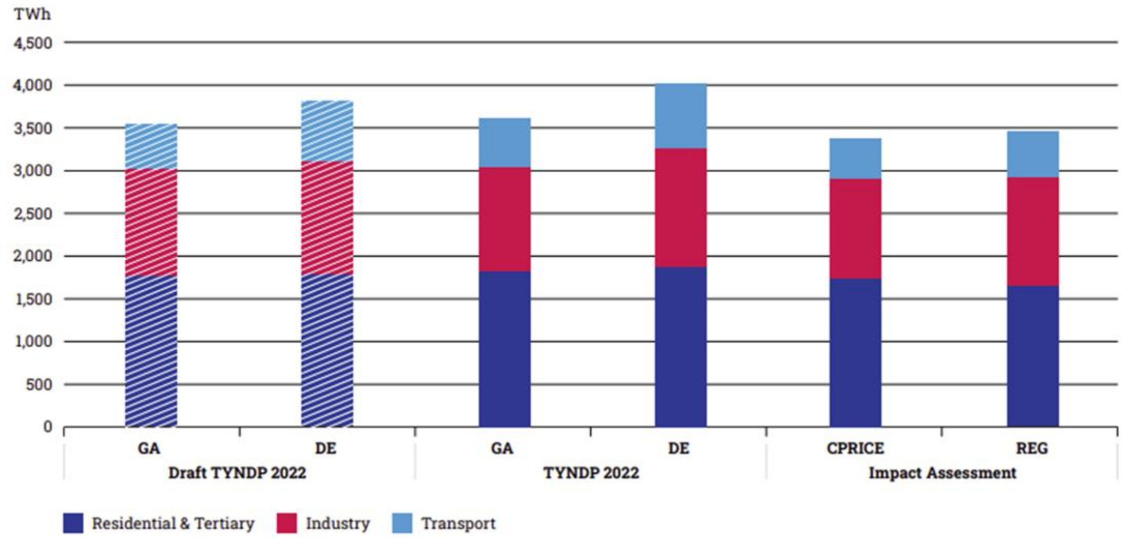
Figure 3.25 and Figure 3.26 are examples of benchmarking the ENTSO scenarios with the Commission scenarios. In Figure 3.25 the benchmarking is done for onshore wind, offshore wind and solar. In Figure 3.26 demand is benchmarked. It follows from these Figures that overall there is a good corollary between ENTSO and Commission scenarios.

Figure 3.25: Benchmarking of ENTSO and Commission scenarios



Source: ENTSO TYNDP

Figure 3.26: Benchmarking electricity demand in TYNDP and Commission Scenarios



Source: ENTSO TYNDP

4. Power Generation Planning in the Context of Carbon Neutrality and Power Market Reform

This chapter is based on Work Package 3 (WP3) of the project: Power Generation Planning in the Context of Carbon Neutrality and Power Market Reform. WP3 started with an online workshop that was held on 7 and 8 September 2022. A second workshop was arranged to focus on WP3 topics. The format of this second workshop, which took place on 18 October, left more room for in-depth discussions on key subjects. Apart from the project partners, external experts from CEC, IEA and the Oxford Institute for Energy Studies were invited to give their thoughts on the WP3 themes. In addition, a selection of topics was discussed in plenum.

Common key factors in power generation planning

As the world transitions towards sustainable energy systems with an increasing share of variable renewable energy resources, it is crucial to address various challenges while ensuring energy security. The following key factors when ensuring the long-term viability of the energy system have been identified:

- *Power system adequacy* refers to the ability of an electrical power system to meet the demand for electricity reliably and at all times, taking into account factors such as generation capacity, transmission infrastructure, and operational flexibility.
- *An effective electricity price mechanism* refers to a pricing system that efficiently reflects the supply and demand dynamics of the electricity market, encourages optimal investment in generation capacity, promotes cost-effective utilisation of resources, and incentivizes demand response and efficient consumption patterns.
- *Power system flexibility* refers to the capability of an electrical grid to adapt to changes quickly and efficiently in electricity demand and supply, allowing for the integration of variable renewable energy sources and the maintenance of a stable and reliable power supply.
- *Energy security*, in the context of a modern energy system with a high share of renewable energy, refers to the assurance of a reliable, resilient, and sustainable energy supply that mitigates risks associated with the variability of renewable sources and ensures the stability and adequacy of the power system.

4.1. Electricity security in the context of the energy transition

Given the paramount importance of energy security, this section describes the security concept in the context of power system planning. Drawing insights from the 2020 IEA report 'Power Systems in Transition'[7], as well as leveraging the Danish infrastructure

[7] https://www.iea.org/reports/power-systems-in-transition

planning methodology, this section sheds light on the key considerations and strategies that are relevant when planning a secure and reliable electricity supply.

The electricity security concept

The concept of electricity security comprises several features, as illustrated in Table 4.1. Adequacy, operational security, and resilience are all essential elements of the overall electricity security, with different time constants.

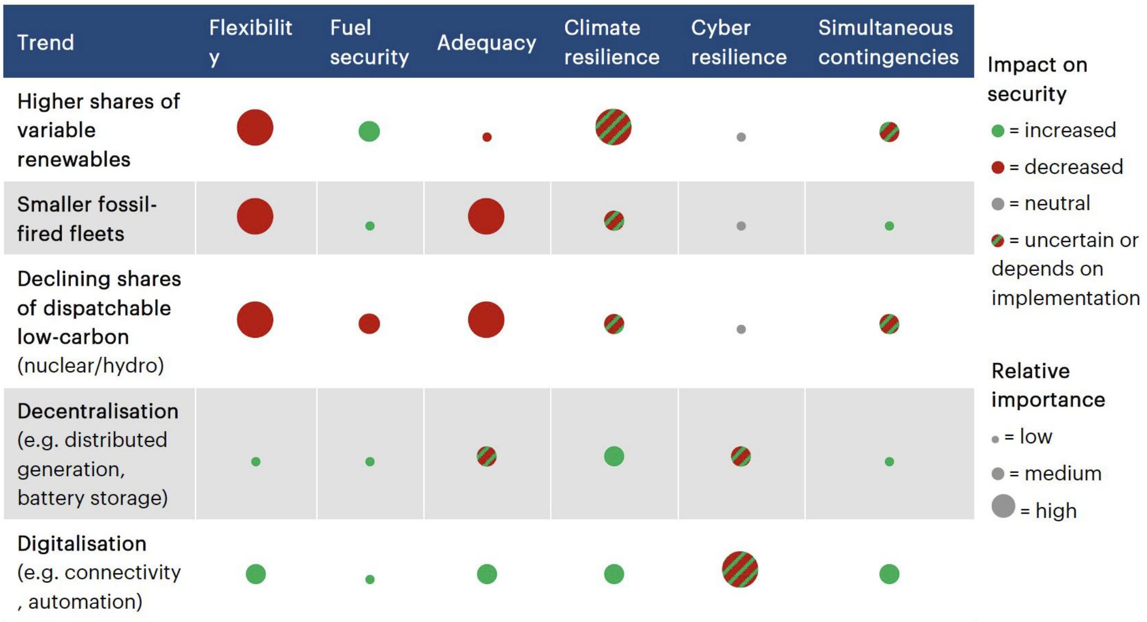
Table 4.1: Key Electricity Security Terms and Definitions. (Source: IEA, 2020)

Term	Definition
Adequacy	The ability of the electricity system to supply the aggregate electrical demand within an area at all times under normal operating conditions. The precise definition of what qualifies as normal conditions and understanding how the system copes with other situations is key in policy decisions.
Operational security	The ability of the electricity system to retain a normal state or to return to a normal state after any type of event as soon as possible.
Resilience	The ability of the system and its component parts to absorb, accommodate and recover from both short-term shocks and long-term changes. These shocks can go beyond conditions covered in standard adequacy assessments.

Sources: Based on European Commission JRC and IEA Electricity Security.

At a more detailed level, electricity security includes flexibility, fuel security, adequacy, cyber resilience, and the ability to recover from simultaneous contingencies. Table 4.2 shows how different electricity system trends impact these electricity security features. The table shows a potential conflict between the low-carbon development required and the need for electricity security.

Table 4.2: Electricity System Trends and Their Potential Impacts on Various Aspects of Electricity Security. (Source: IEA, 2020)



Notes: Circle colour indicates the potential impacts on various security aspects, e.g. flexibility. Circle size indicates the relative level of importance for a specific security aspect. The intent of the table is to illustrate the potential impacts in a generalised way. Actual impacts in specific countries and states/provinces will depend on their context and circumstances, e.g. generation mix, existing infrastructure, geography, climate. Simultaneous contingencies are outages of generation and transmission assets which are unexpectedly affected at the same time by the same event, such as earthquakes.

Electricity security in the context of the energy transition

The IEA report recommends several measures to ensure electricity security:

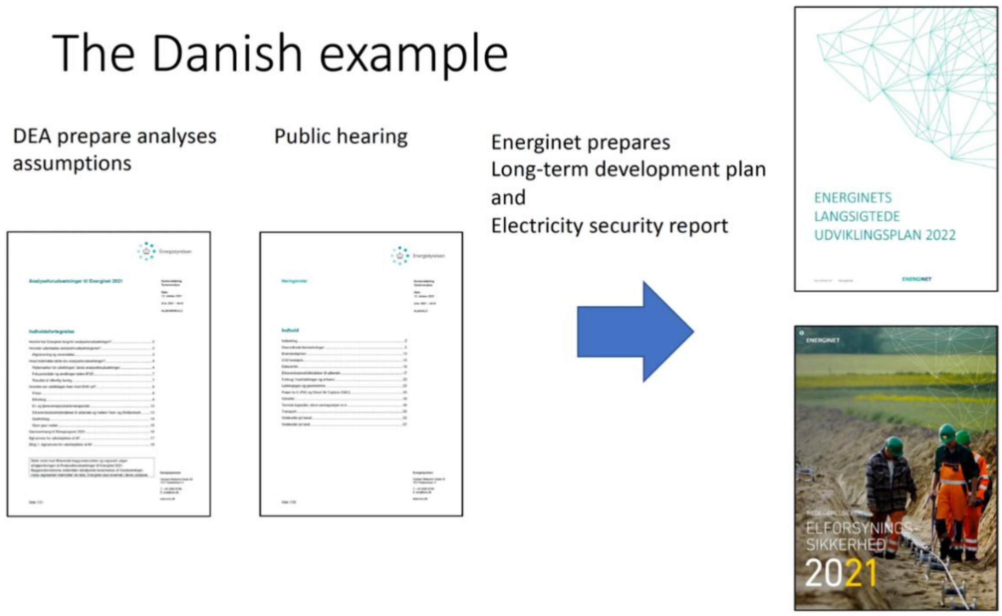
1) Institutionalise: establish clear responsibilities, incentives, and rules.
2) Identify risks: undertake regular system-wide risk analyses.
3) Manage and mitigate risk: improve preparedness across the electricity supply chain.
4) Monitor progress: keep track, record, and share experiences.
5) Respond and recover: cope with outages or attacks and capture the lessons learned.

Furthermore, the report recommends introducing new tools for monitoring electricity security, including long-term planning and probability analysis, to ensure that electricity market design translates stress periods in the power system into higher wholesale prices, and to provide the appropriate incentives for energy efficiency measures on the consumer side and for investments on the supply side.

This can be illustrated by the Danish system for assessing energy security (see Figure 4.1).

The Danish Energy Agency, as the energy authority, is responsible for the assumptions for the assessment. The assumptions are aired at a public hearing to get the stakeholders' viewpoints before they are submitted to the Danish System Operator for Electricity and Gas, Energinet. Energinet is responsible for monitoring electricity security by preparing long-term development plans and dedicated annual electricity security reports.

Figure 4.1: The Danish case for electricity security assessment as an interplay between the authorities and the system operator



4.2. Power generation planning in China

The energy transition in China's power sector faces significant challenges and has been extensively studied by various research institutes, associations, and energy suppliers. These studies provide insights into roadmaps, implementation paths, and action plans covering aspects such as the construction of new power systems, power markets, electricity pricing mechanisms, technological innovation, policies, and financing. Each institute sets different priorities for power generation planning. The focal points of the participating Chinese partners are presented below:

- The first section focuses on power system adequacy and flexibility during China's energy transition. In the study presented here, power adequacy, energy adequacy and power system flexibility are assessed in different scenarios for the years 2030 and 2050.
- The second section discusses the challenges associated with fluctuating renewable electricity generation and raises higher requirements for market mechanisms while taking advantage of the opportunities presented by cleaner electricity generation, digitised grid systems and growing renewable energy capacity. This is followed by a discussion of flexibility and energy security in the Chinese energy system.

4.2.1. Power and energy adequacy assessment

This section is centred on an assessment of power system adequacy and flexibility, assuming some appropriate energy generation mix scenarios for the power sector in China's energy transition. This is not a complete power generation plan. One of the key challenges is the integration of variable renewable energy (VRE) into the power system. This poses a series of problems that impact power adequacy, which in turn affects the security of power supply. Additionally, the level of flexibility within the power system plays a crucial role in minimising curtailment and effectively accommodating VRE. These topics highlight the importance of assessing power adequacy and flexibility during the energy transition in China's power sector.

The assessment includes different scenarios, such as the baseline scenario that aligns with national targets for carbon peaking and carbon neutrality. Other scenarios address specific issues such as extreme weather conditions, high VRE penetration, and various degrees of coal capacity phase-down.

Several major assumptions underpin the assessment. Firstly, the forecasts for demand growth vary across regions. Secondly, the deployment of VRE in regional systems is based on the distribution of VRE resources, with a slight increase in the VRE share in central and eastern regions. Lastly, the transmission capacity between regional systems is expected to almost double from 2030 to 2050.

Scenarios setting

Demand forecast assumptions in six regional energy systems

The demand forecast assumptions in six regional energy systems can be summarised as follows (Table 4.3):

Table 4.3: Demand Forecast Assumptions (2020-50). (Source: CEC)

	2021-2025	2026-2030	2031-2050
Load forecasts	4-6.5%	3-5%	1.8%
Electricity consumption forecasts	3-5%	2-4%	1.2%

Annual peak demand occurs in winter in northern regions and in summer in southern regions, and demand response is assumed to be 2% of peak load.

Generation mix and layout in different regions

The assumptions for the generation mix and layout in the different regions are given in Table 4.4.

Table 4.4: Generation Mix Assumed by 2030 and 2050. (Source: CEC)

Source	2030	2050	Note
Coal	1180 GW	550 GW	Different annual growth of 6 regional systems until 2030.
Wind	621.5 GW	1500 GW	Slightly increasing shares in central and eastern regions.
Solar	693.4 GW	2500 GW	
Hydro	419 GW	500 GW	
Nuclear	100 GW	200 GW	
Gas	200 GW	320 GW	

It is further assumed that cross-regional power transmission capacity among the six regional systems will reach 180 GW in 2030 and 324 GW in 2050, with transmitted VRE and conventional generation bundled, and that the maintenance of generation infrastructure will be carried out according to standard criteria established in China.

Assumptions for VRE contribution factors to annual peak load

The assumptions for variable renewable energy (VRE) contribution factors to the annual peak load can be summarised as follows:

(a) The local wind capacity contribution factor is assumed to be 5% of installed capacity and that of cross regional wind power is assumed to be 15%.

(b) The solar power capacity contribution factor is assumed to be 0% because peak load generally occurs in the evening; cross regional solar power is assumed to be 10% because of the time difference between regions.

Trading capacities

The cross-regional power trading capacity among the six regional systems is based on the PDP (Power Development Plan) which will deliver 180 GW power trading capacity in 2030 (including conventional generation and VRE bundled). The corresponding capacity in 2050 is assumed to be 324 GW.

Methodology

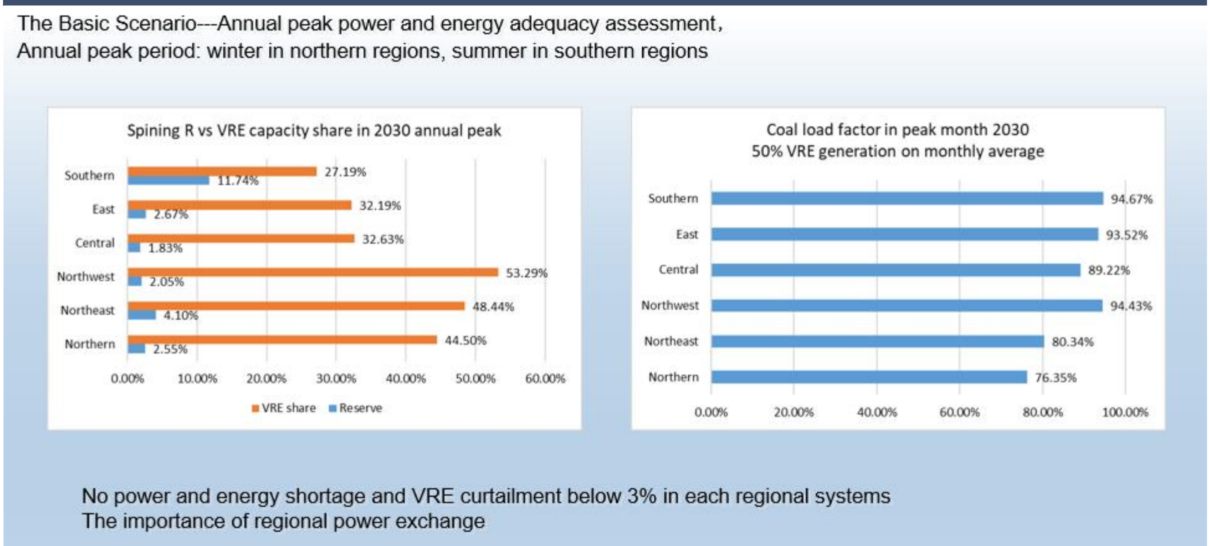
Based on 'The Planning Guidelines of Power Development Plan' developed by the Chinese government, power and energy adequacy assessments are to be calculated on a monthly basis during the planning year. The methodology is deterministic and assumes some simplifications, such as focusing on the annual peak day for power adequacy assessment and the annual peak day and month for energy adequacy assessment.

The capacity factors of different generation technologies, apart from coal generation, are based on assumptions that take into account the particularities of different regional power systems. Maintenance plans of the infrastructure are assumed to be properly arranged. Cross regional power trading is taken into consideration. P&B (pumped hydro storage and battery) is the last to provide peaking power for power adequacy and coal generation is also the last to provide energy for energy adequacy on the day and month that are the focus of the assessments.

2030 and 2050 power and energy adequacy assessment

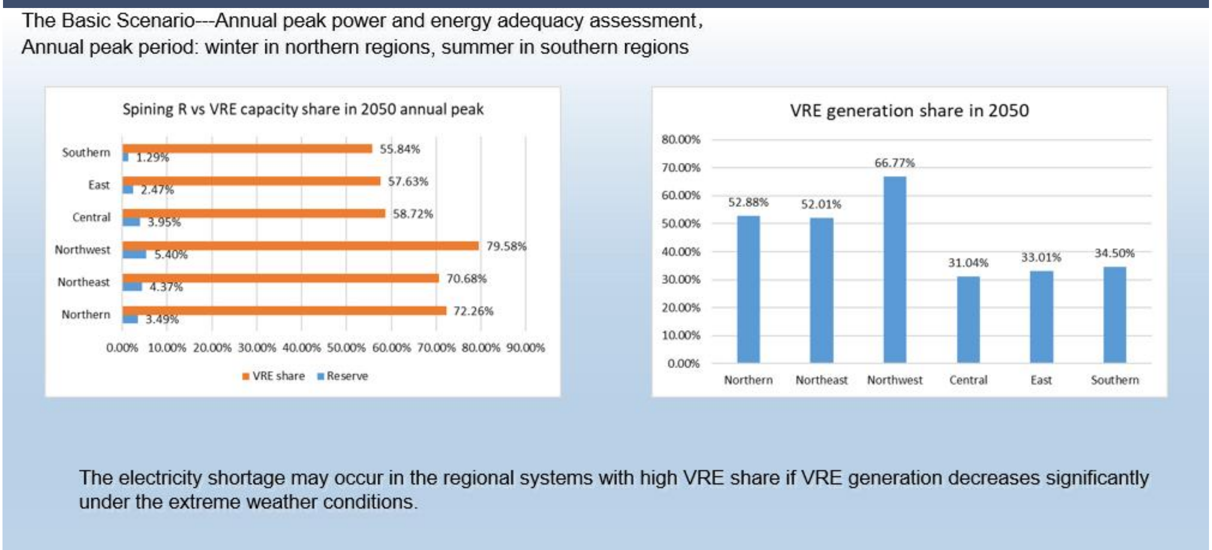
As an example of results, Figure 4.2 shows the spinning reserve as a percentage of the annual peak load and VRE capacity share as a percentage of total generating capacity installed in 2030 for the six regions of China, based on the assumptions for VRE contribution to annual peak load. Also, the load factors for coal generation in the peak month are indicated if VRE generation is assumed to be 50% of the monthly average. There is no power and energy shortage and VRE curtailment is below 3% in each region in 2030.

Figure 4.2: Basic scenario, spinning reserve versus VRE capacity, 2030



The corresponding results for 2050 are given in Figure 4.3. The conclusion for 2050 is that electricity shortages may occur in regional systems with a high VRE share if VRE generation decreases significantly in extreme weather situations.

Figure 4.3: Basic scenario, spinning reserve versus VRE capacity, 2050

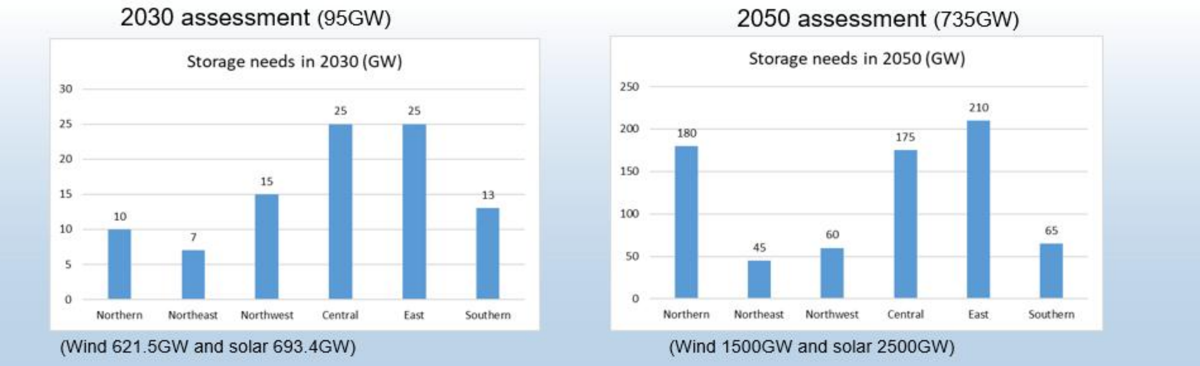


2030 and 2050 storage/flexibility needs

The assessment concerning flexibility with focus on storage requirements is summarised in Figure 4.4. Storage requirements in 2030 are 95 GW, with an assumed capacity of wind and solar of about 620 GW and 695 GW, respectively.

In 2050 the corresponding storage requirement is 735 GW, with assumed capacities of wind and solar of 1 500 GW and 2 500 GW, respectively.

Figure 4.4: Basic scenario, assessment of storage needs in 2030 and 2050



4.2.2. Power system flexibility assessment

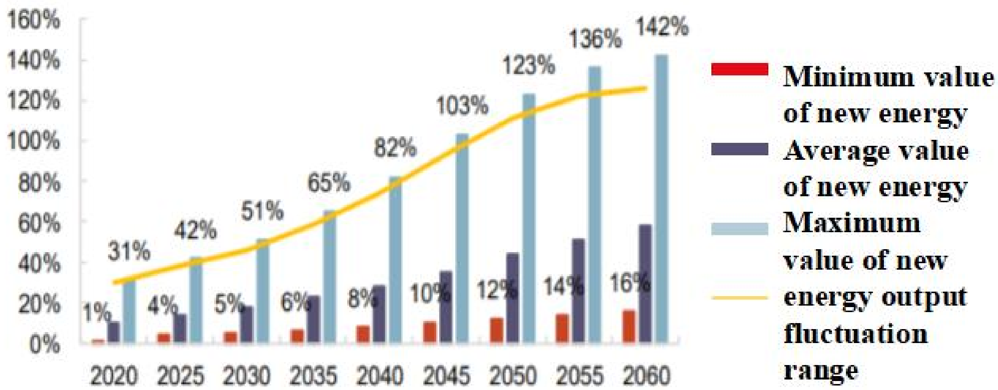
This section addresses the challenges related to fluctuations intrinsic to renewable electricity generation and higher requirements for market mechanisms, while also highlighting the opportunities presented by cleaner electricity generation, digitised grid systems, and the growth in renewable energy capacity. This is followed by a discussion of flexibility and energy security in the Chinese energy system.

Challenges and opportunities

This section identifies two key challenges for China's energy system planning for the carbon neutrality pathway: the fluctuating VRE resources are hard to integrate and will bring risks to safe operation of the power system, and secondly, a high proportion of renewable energy raises higher requirements to the market mechanisms

The fluctuation range of new energy (renewables) output is constantly increasing. In 2030, the amount of new energy output in relation to the total power system load will be between 5% and 51%, while in 2060, the amount of new energy output in relation to the total power system load will be between 16% and 142% (see Figure 4.5).

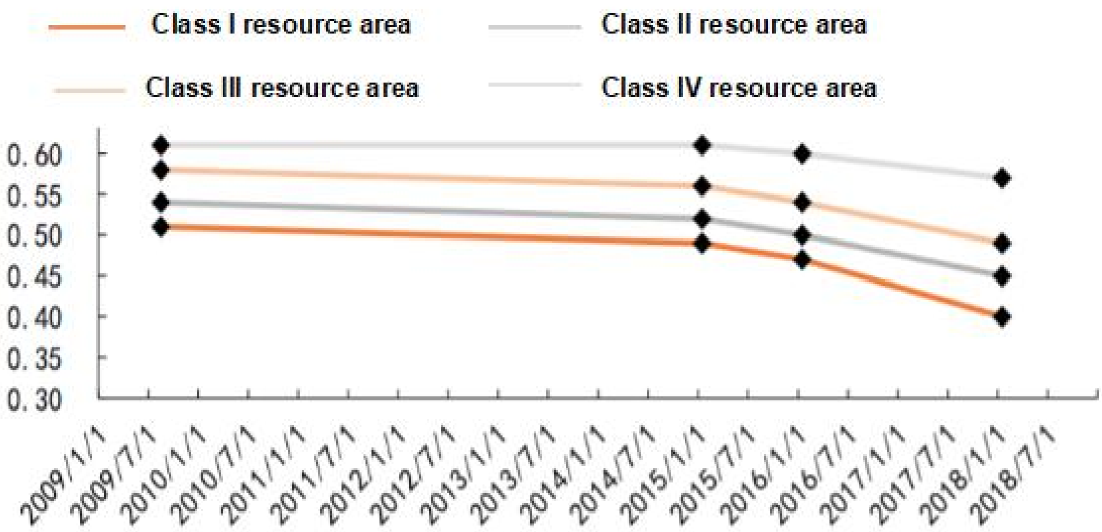
Figure 4.5: Prediction of proportion of new energy output (renewables) compared to total system load



Source: WIND

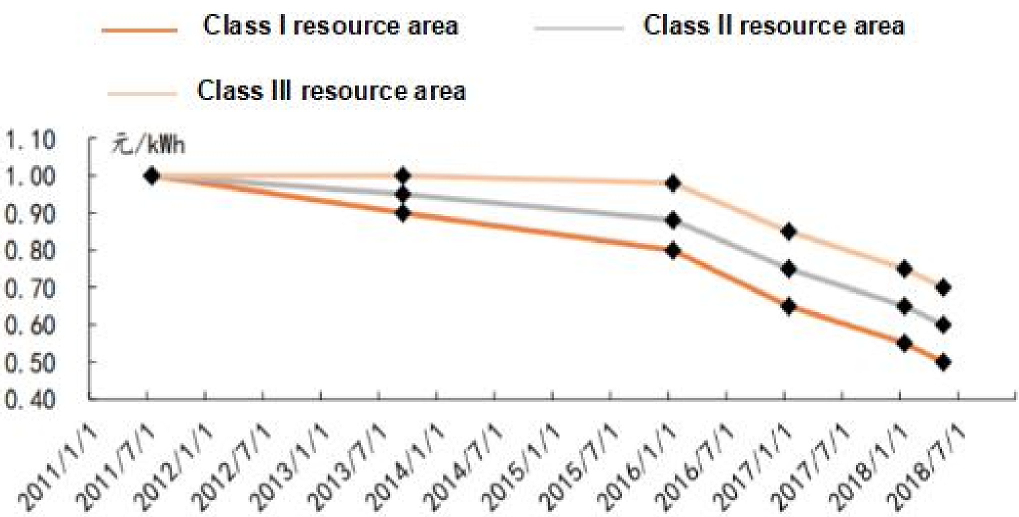
The second challenge is the lack of an electricity price mechanism suitable for the development of the new power system. At present, the market pricing concept has not been fully integrated into the electricity price reform (see Figure 4.6 and Figure 4.7). There is a lack of supporting electricity price measures suitable for a high proportion of renewable development. The structure of the power market currently lacks an auxiliary service market, a capacity market, a transmission rights market and other supporting mechanisms.

Figure 4.6: Wind power benchmark price (unit: RMB/kWh)



Source: WIND

Figure 4.7: Changes in benchmark price of photovoltaic power generation (unit: RMB/kWh)



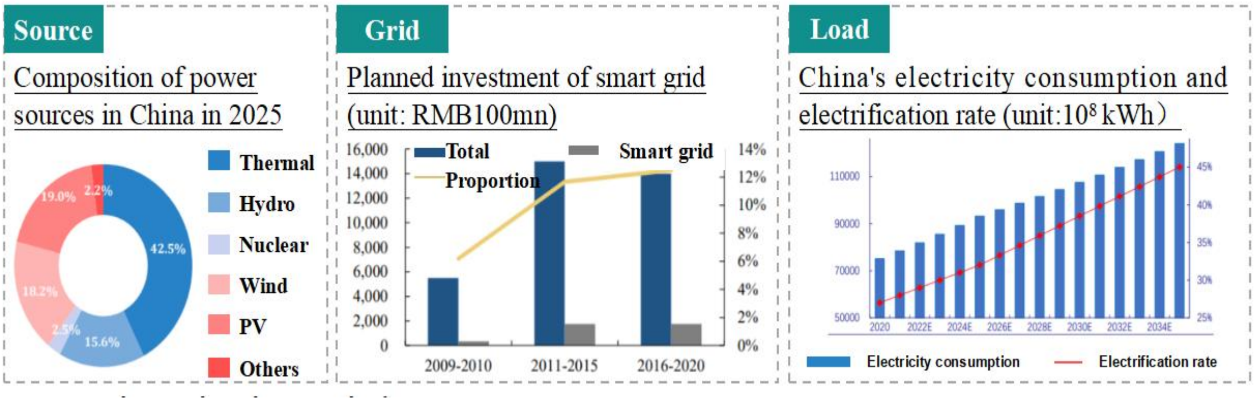
Source: WIND

Apart from the aforementioned challenges, there are also several opportunities on the horizon. These include the prospect of cleaner electricity generation, the ongoing digitisation of electricity grids, and the increasing electrification of electricity consumption.

The share of renewable energy in the electricity mix continues to grow. It is estimated that the annual average new installed capacity of PV is about 65-77 GW, and that of wind power is about 44-55 GW.

The scale of smart grid investment in total power grid investment has been growing. There is plenty of space for improvements in electrification when seeking to reduce energy demand. By 2025, China's electrification rate is expected to increase to 32%, and to 45% by 2035 (see Figure 4.8).

Figure 4.8: Opportunities of supply sources, grid and load



Source: WIND

Power system flexibility

The inherent unreliability and intermittency of renewable energy sources have introduced unprecedented challenges in achieving a balanced supply and demand within the power system. Consequently, there is a need to conduct a thorough analysis of the flexibility demand arising from substantial integration of VRE. The residual load is calculated by subtracting the combined load from wind and solar power output. The daily peak-to-valley difference in the residual load is growing, leading to an increased requirement for system flexibility (see Figure 4.9).

Figure 4.9: Sequence diagram of peak-valley load and net-load differences in China, 2050

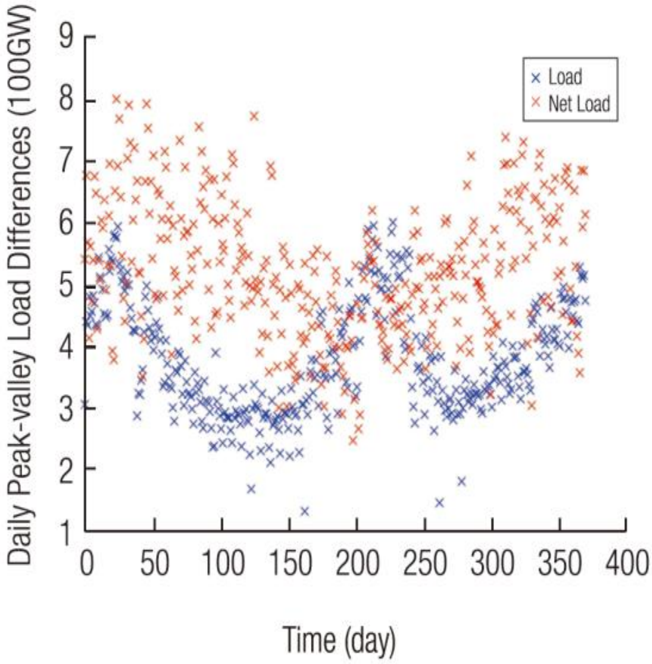
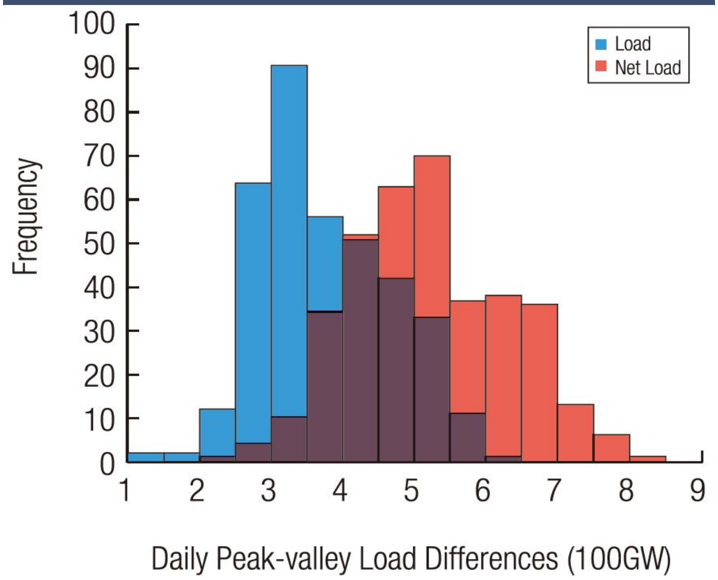


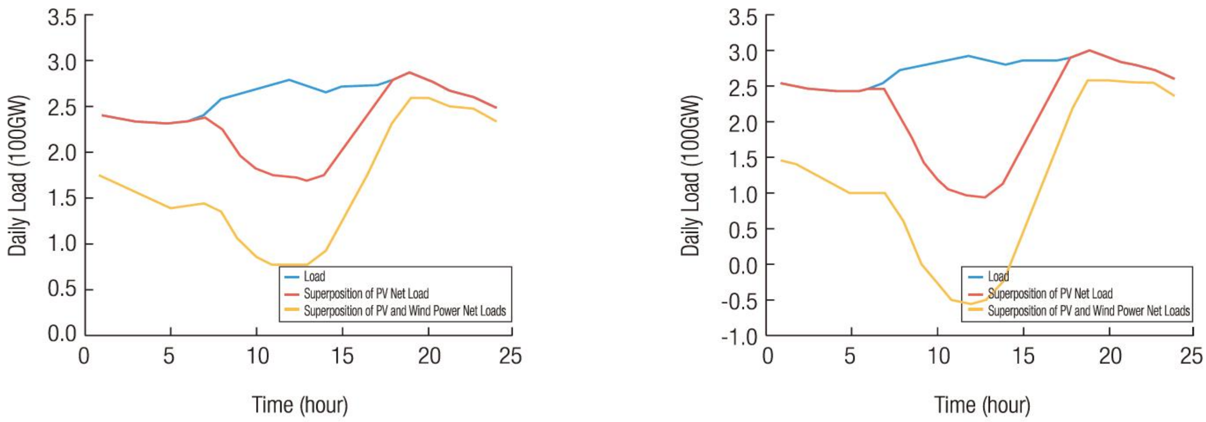
Figure 4.10: Histogram of peak-valley load and residual-load differences in China, 2050



In 2050, the maximum daily load in China will be approximately 2 340 GW, while the maximum daily peak-valley difference will be approximately 600 GW, accounting for 25.7% of the peak load. The maximum peak-valley difference for **residual load** will be approximately 800 GW, accounting for 34.2% of the peak load, see Figure 4.10. Regarding intra-day characteristics, the hourly variation of the residual load increases significantly, along with uncertainties.

Taking North China as an example, the maximum one-hour variation of the load in North China will be approximately 30 GW in 2035, accounting for 6.7% of the peak load. In 2035, the maximum hourly variation in residual load will be approximately 50 GW, accounting for 13.8% of the residual load. In 2050, the maximum hourly variation of the residual load will be approximately 100 GW, accounting for 23.4% of the peak load over the entire year.

Figure 4.11: Typical daily load curve in North China in 2035 (left) and 2050 (right)



As the installation capacity of renewable power plants (especially PV power plants) increases, the daily residual load curve becomes a 'duck curve' (see Figure 4.11). Noon, which used to be a time of peak load, becomes the valley time for residual loads. The residual load varies widely between 12:00 and 20:00. When PV output increases sharply at midday, the original load peak will become the residual load valley and may even be negative. From 15:00 to 20:00, the power loads climb as PV output slumps, and residual demand increases rapidly.

Figure 4.12: Daily peak-valley difference for load

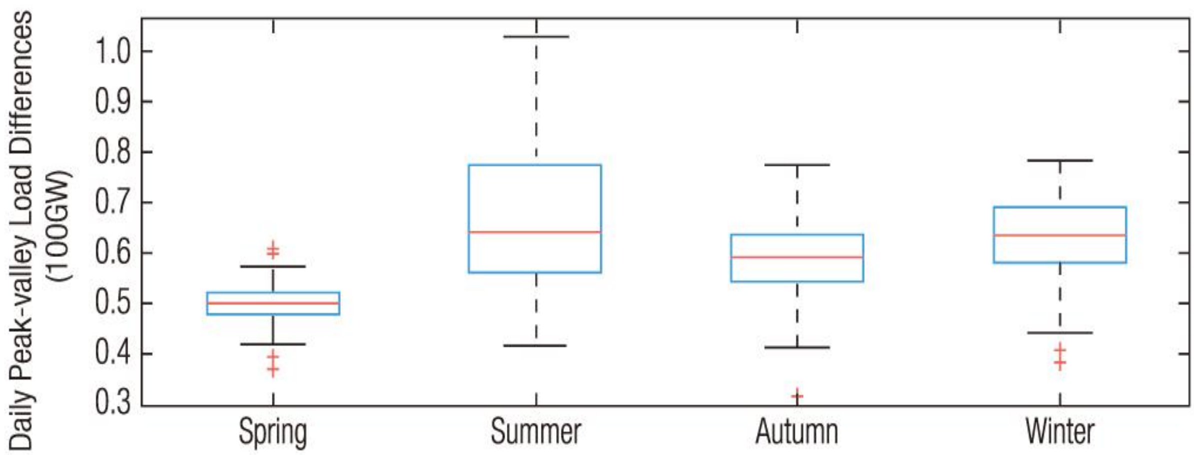
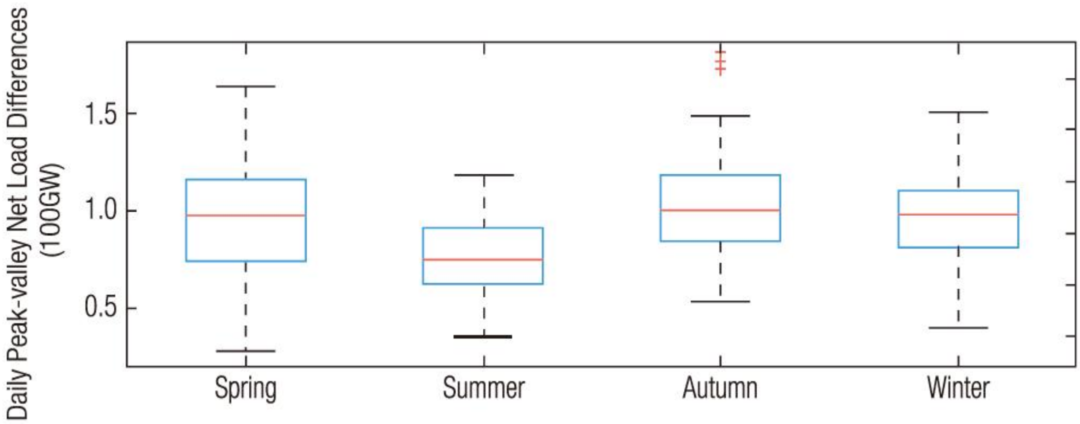


Figure 4.13: Daily peak-value differences of residual (net) load

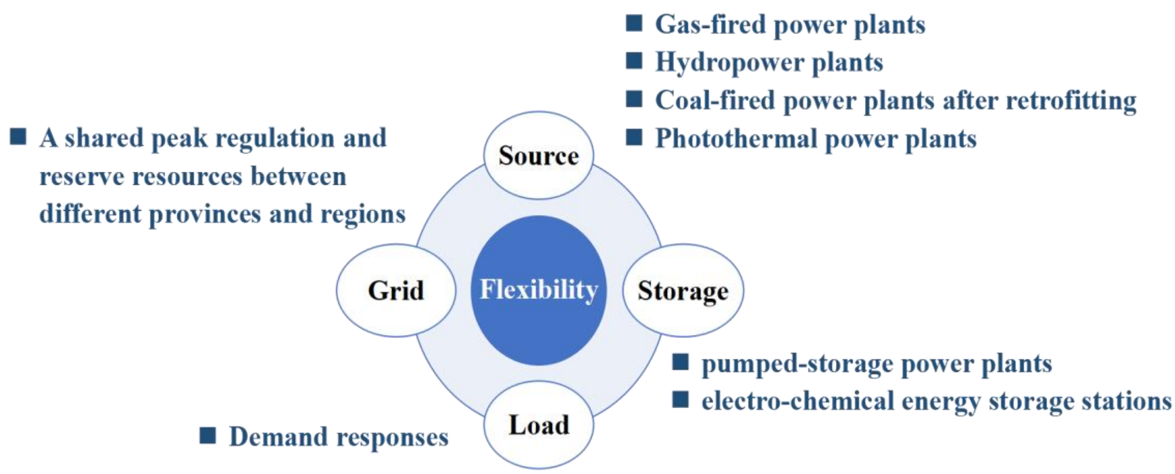


The daily peak-valley difference for load is relatively large in summer and winter (see Figure 4.12), while that for residual load is relatively large in spring and autumn (see Figure 4.13). The reasons are as follows: air conditioning accounts for a relatively large proportion of the load peak at noon in summer, when temperatures are highest. The output of PV power generation and loads for air conditioning are positively correlated, which stabilises residual load fluctuations in summer. Electric heating accounts for a relatively large proportion of the load peak in winter at nighttime, when temperatures are relatively low. The output of wind power and loads for electric heating in North China are positively correlated, which stabilises residual load fluctuations in winter. The correlation between the load and renewable energy output is relatively low in spring and autumn, causing peak-valley differences for residual load to be relatively large.

Flexibility resources

Flexible resources are becoming increasingly diversified (see Figure 4.14). At the source side, the natural gas-fired power plants and hydro power plants provide flexibility. Coal-fired power plants offer great potential as they benefit from flexibility retrofits and the ancillary service market. Furthermore, concentrated solar power stations (CSP) will also make a contribution to the flexible regulation of the system.

Figure 4.14: Flexibility resources in the power system



As for the grid, the planning and arrangement of power flow should take the flexibility needs of different regions into consideration. A positive step would be to share peak regulation and reserve resources between different provinces and regions.

At the load side, the demand response can also function as flexible resources, which can be leveraged using electricity prices in the spot market or other economic incentives.

As for energy storage, pumped-storage stations and electro-chemical energy storage stations are ideal tools to increase the flexibility of the power system.

Table 4.5: Advantages and Disadvantages of Flexibility Resources.

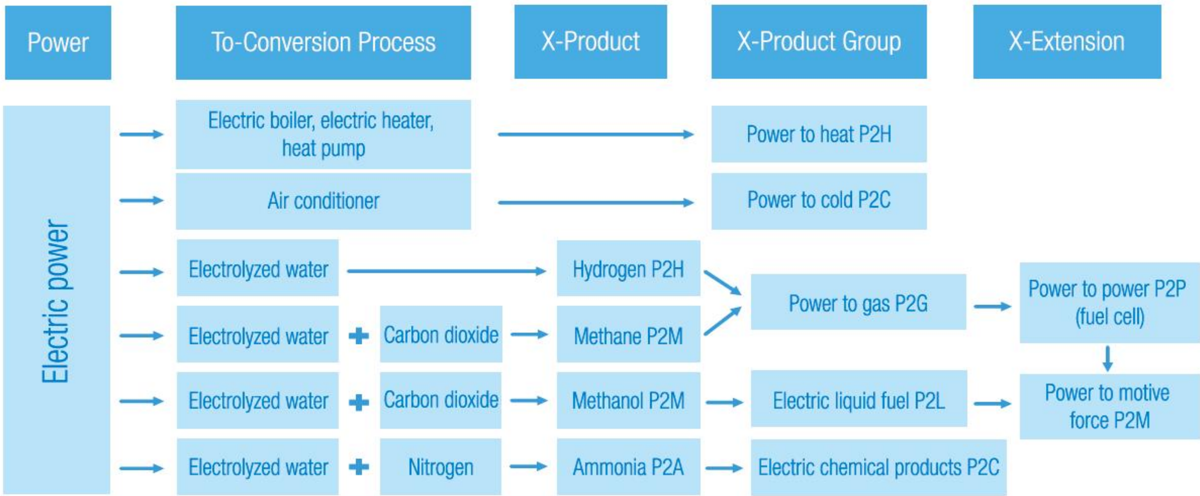
		Advantages	Disadvantages
Source	Coal-fired power plants	Large installed capacity and large potential for flexibility	Absent compensation mechanisms for peak regulation services of coal-fired power plants
	Gas-fired power plants	Favorable adjustment performances and relatively flexible in site choosing	Relatively high fuel costs and highly dependent on a stable supply of gas
	Hydropower plants	Favorable adjustment performances and zero carbon emissions	Highly dependent on water inflows
	Photothermal power plants	Zero-carbon emissions	Limitation on site choosing and function time periods.
Grid	Coordination of peak-regulation and reserve resources between different regions	Economic and efficient, with little additional cost	Highly dependent on the differences of peak hours between different provinces and regions
Load	Demand responses	Economic and efficient	Market mechanisms are inadequate and unclear sources of incentive funds
	A real-time electricity price in the spot market	Economic and efficient	Market mechanisms require improvement and uncertain effects on the cost of electricity
Storage	Pumped storage	High reliability and favorable adjustment performances	Limitation on site availability and inadequate market mechanisms
	Electro-chemical energy storage	Favorable adjustment performances and flexible layout	Relatively high investment costs and potential safety risks

The above-mentioned resources can introduce flexibility into the power system. However, their limitations are also evident (see Table 4.5).

For coal-fired power plants, compensation mechanisms for peak regulation services are absent. For gas-fired power plants, fuel costs are relatively high and are highly dependent on a stable supply of gas. For hydro power plants, the output is heavily dependent on water inflows. For the coordination of peak-regulation and reserve resources between different regions, the effect depends largely on the displacement of peak hours between different provinces and regions.

As for demand responses, market mechanisms are inadequate, and it is not clear how easy it would be to access incentive funds.

Figure 4.15: Technology routes for P2X



Hydrogen, heat, cooling, gas and other types of energy carriers can function as flexibility resources by means of key energy conversion equipment and by coupling between different energy systems (see Figure 4.15).

The barriers between different energy systems should be broken. P2X can allow different forms of energy to complement one another: hydrogen, heating and cooling resources are easy to store, and could introduce more flexibility into the power system.

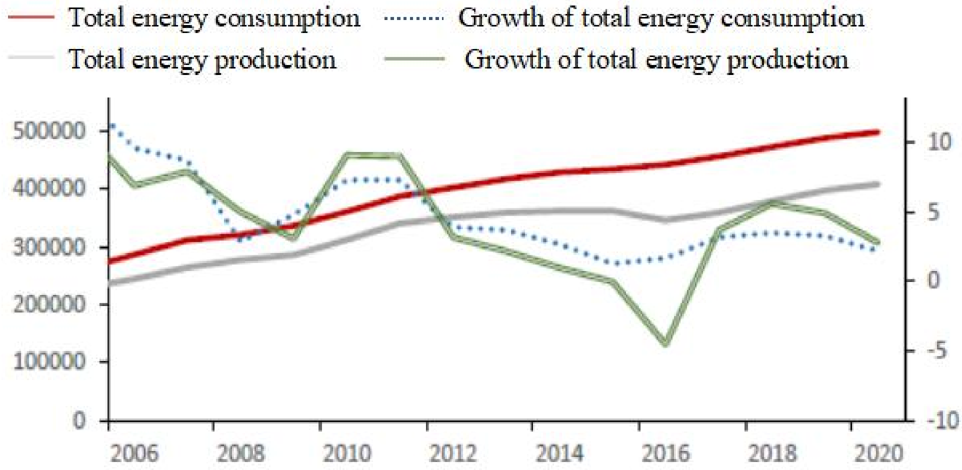
Power-to-heat and power-to-cool technologies are used on a large scale. Technologies such as heat pumps, electric boilers and air conditioners have become relatively mature. In the future, more heating and cooling units and more smart control modules are likely to be introduced into buildings. These technologies can use cheap off-peak electricity to lower costs and help regulate the power system.

Power-to-hydrogen technologies are in the R&D and early demonstration phases. Alkaline electrolysis (ALK) is in large-scale use, while Polymer Electrolyte Membrane (PEM) fuel cell technology has so far only been applied in demonstration projects. It is possible that PEM will be the main source of electrolysers in the future. The cost of green hydrogen will likely be economically competitive against grey and blue hydrogen around 2030. Any surplus clean electricity can be used for hydrogen production.

Energy security

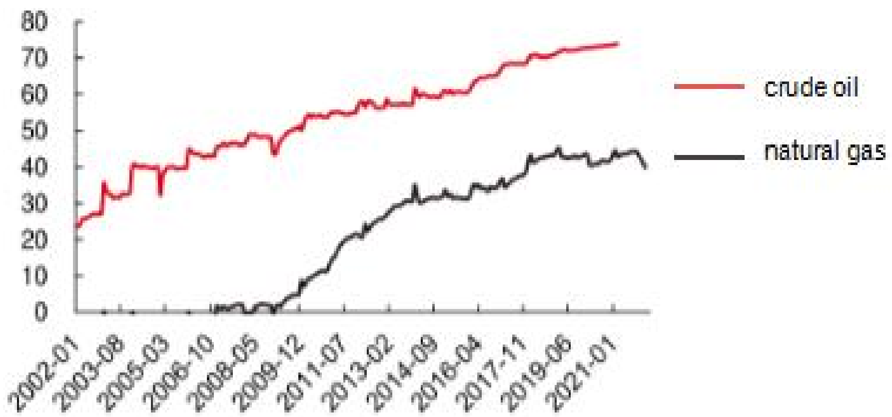
The increasing challenge of energy security arises from the growing gap between energy production and consumption. The growth in energy demand is outpacing energy production, thereby imposing constraints on the supply side. This is illustrated in Figure 4.16.

Figure 4.16: Total energy production and consumption in China, left axis. Growth, right axis. (Unit left axis: Ten thousand tons of standard coal, unit right axis: percentage annual change).



China is heavily dependent on other countries for supplies of oil, natural gas, and other key energy sources, and this is the weak link in China's energy supply chain (see Figure 4.17).

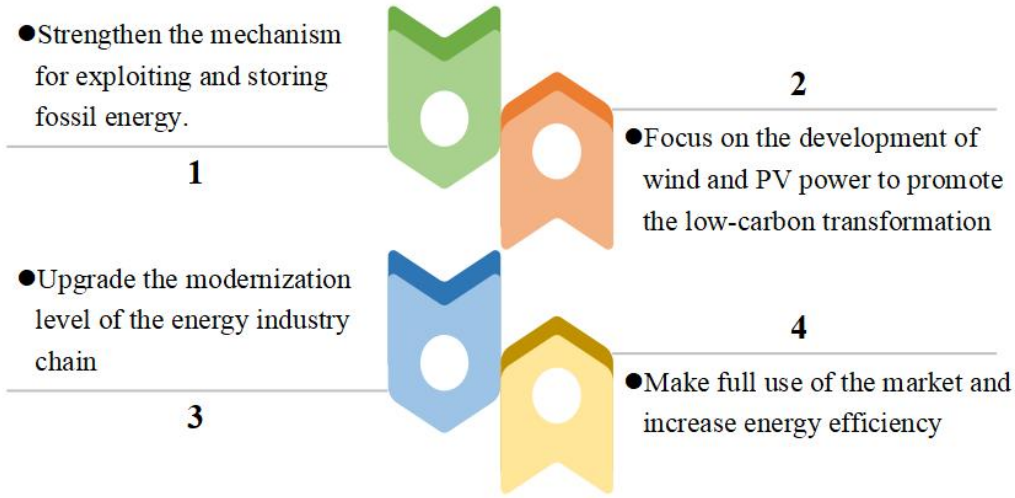
Figure 4.17: China's dependence on foreign fossil energy supplies. (unit: percentage)



China's vision of the modern energy system

In order to ensure energy security, China is building a 'modern energy system'. The mechanisms to support this modernisation are illustrated in Figure 4.18. They include four key aspects: strengthening the exploitation and storing of fossil energy resources; prioritising the development of wind and solar power to facilitate low-carbon transformation; enhancing the modernisation of the energy industry chain; and maximising the use of markets while striving for improved energy efficiency.

Figure 4.18: Mechanisms to build a 'modern energy system'



China's vision for the modern energy system is defined in the 14th Five-Year Plan. A summary is given in Table 4.6.

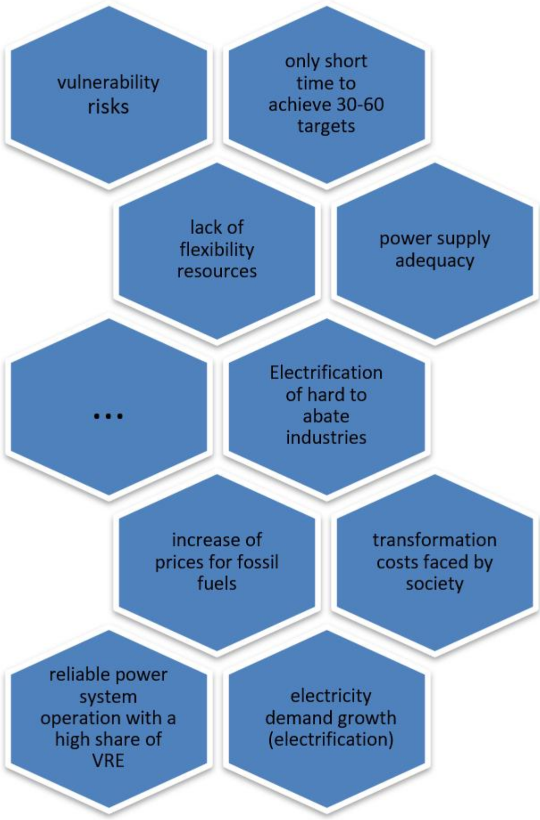
Table 4.6: Development Goals of the Modern Energy System During the 14th Five-Year Plan

field	project	goal	Current level
Energy security	Annual comprehensive production capacity of energy	More than 4.6 billion tons of standard coal	4.08 billion tons of standard coal
	Annual output of crude oil	200 million tons	199 million tons
	Annual output of natural gas	More than 230 billion cubic meters	207.580 billion cubic meters
	Total installed capacity of power generation	3 billion kw	2.377 billion kw
Low carbon transformation of energy	CO_2 emissions per unit GDP	A cumulative decrease of 18% in five years	-
	Proportion of non fossil energy consumption	20%	15.9%
	Proportion of non fossil energy power generation	39%	32.59%
	Energy consumption proportion of electric energy terminal	30%	-
Energy system efficiency	energy consumption per unit of GDP	A cumulative decrease of 13.5% in five years	-
	Flexibly adjust the proportion of power supply	24%	-
	Power demand side response capability	3%-5%	-

4.3. Key challenges for China's energy system in transition

During the workshops, discussion centred around the key challenges facing the transformation of China's energy system on the way to achieve the country's 30-60 targets. An overview of those key challenges is given in Figure 4.19.

Figure 4.19: Key challenges for China's energy system transformation



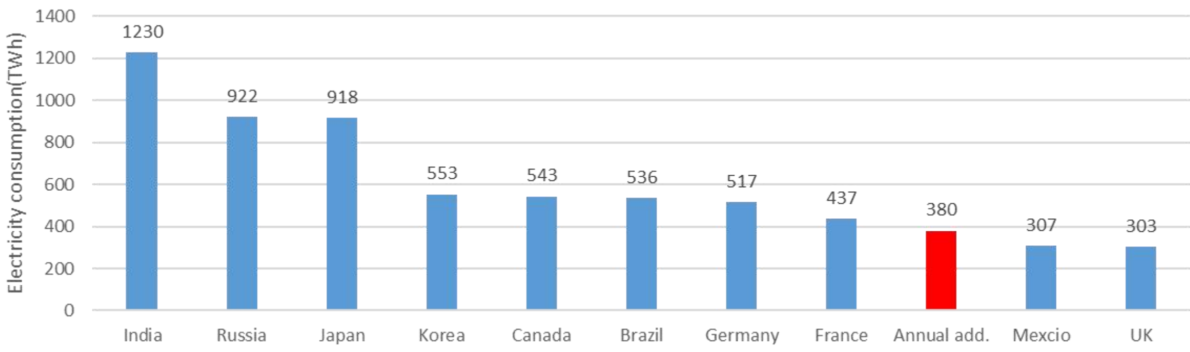
Short timeline to achieve the 30-60 target

The first challenge is that the timeline to reach the 30-60 target is very short. China has less than 10 years to reach the carbon dioxide peak and only 30 years from reaching the peak to carbon neutrality. If successful, China will have achieved the largest and most rapid reduction in carbon dioxide emission intensity in world history.

Adequacy of electricity supply

One of the biggest challenges is that total electricity consumption in China is set to grow for years to come, as the country's economy continues its steady and rapid growth. Research by CEC shows that over the coming decade China's annual additional electricity consumption will increase to over 380 TWh, which almost equals the total electricity consumption of the whole of France (currently ranked the world's 10th largest electricity consumer).

Figure 4.20: Global electricity consumption by country, excluding China and the US. The red column represents annual additional electricity consumption in China



The balance between power supply and demand is tight, and power rationing problems occur frequently, with negative effects on people's livelihoods. China's economic structure continues to upgrade and power consumption is growing. The industrialisation process and electrification level have improved. However, China has seen a spate of abnormal temperatures and extreme weather events in recent years. The balance of power supply and demand in China is becoming tighter, especially during the summer peak period.

Security and reliability of an electricity system with a higher share of renewables

There is a widely accepted consensus that a reduction in carbon emissions needs to happen alongside economic and social development. Consequently, guaranteeing a secure and orderly transition poses a significant challenge. Extreme weather conditions can trigger severe incidents, such as the power outages caused by wind turbines freezing during the cold winter months. Additionally, the growing adoption of renewable energy sources requires adjustments to the power grid's control mechanisms, further complicating the task of ensuring a reliable power supply.

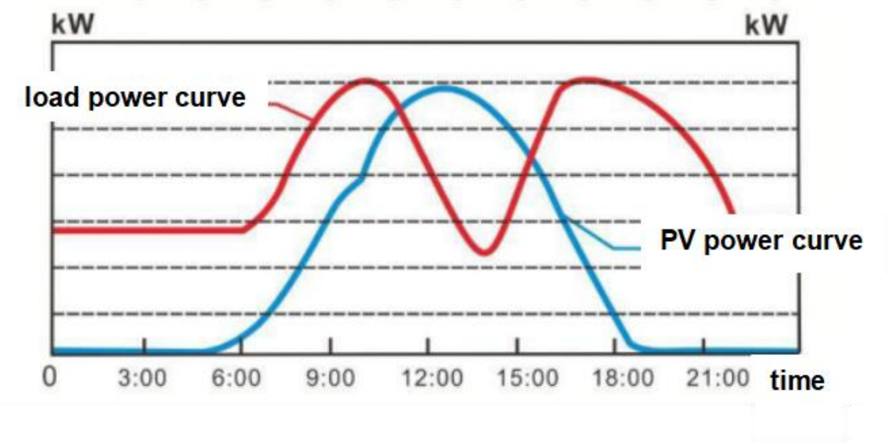
Several safeguards have been proposed, such as strengthening the planning and implementation mechanism, reinforcing the law-based governance system, working intensively on the management of the energy sector, establishing a planning and coordination mechanism, and improving tax, levy and investment policies. A brief introduction can be found on the CEC website[8].

Vulnerability risks

In recent years, the proportion of new energy installed capacity has increased rapidly. Wind power, PV and other power sources are vulnerable to the weather (see Figure 4.21). The fluctuation of power supply capacity at the power generation side is clearly intensifying and the high volatility of new energy output cannot be effectively addressed in the short term.

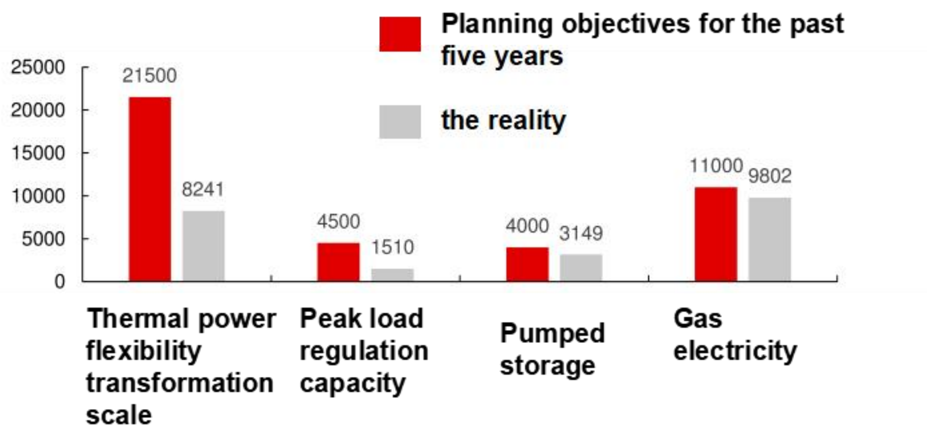
[8] https://english.cec.org.cn/#/datareliability?name=Reliability

Figure 4.21: Mismatch between PV power curve and load power curve



The installed capacity of flexible power supply has for a long time been less than planned (see Figure 4.22). This limits the actual output capacity of new energy (renewables) in peak periods of power consumption and restricts the power balance.

Figure 4.22: The installed capacity of regulating/flexible power supply is less than the planned target. (Unit: 10 MW)



Source: WIND

Reliability of the electricity grid

The power system in China will continue to operate under the synchronisation mechanism for a long time to come. Variable renewables pose a major challenge to the secure and reliable operation of the power system, as the fluctuations and high penetration of wind and solar reduce system inertia.

Lack of flexibility in the Chinese power system

A further obstacle is the lack of flexibility in the electricity grid, which makes the integration of renewable energies a major challenge. The ever-increasing penetration of renewables in the grid requires sufficient system flexibility.

Compared to countries like Spain, Germany or the US, where the share of variable renewables is relatively high, in China the share of flexible generation such as pumped storage or gas turbines is much lower. A comparison of the shares of variable renewable energy and curtailments is presented in Figure 4.23 and in Figure 4.24. Although China should be hailed for its actions to reduce curtailments of wind and solar power in recent years, curtailments remain high in provinces such as Qinghai and Gansu, where wind and solar power have become the main power generation technology. In other words, power system flexibility will be the key factor for renewable energy development in the future. The lack of power system flexibility will limit the development and consumption of renewable energy.

Figure 4.23: A comparison of shares of VRE generation capacity and flexible generation capacity (only pumped storage hydro and gas turbines are included) in various countries

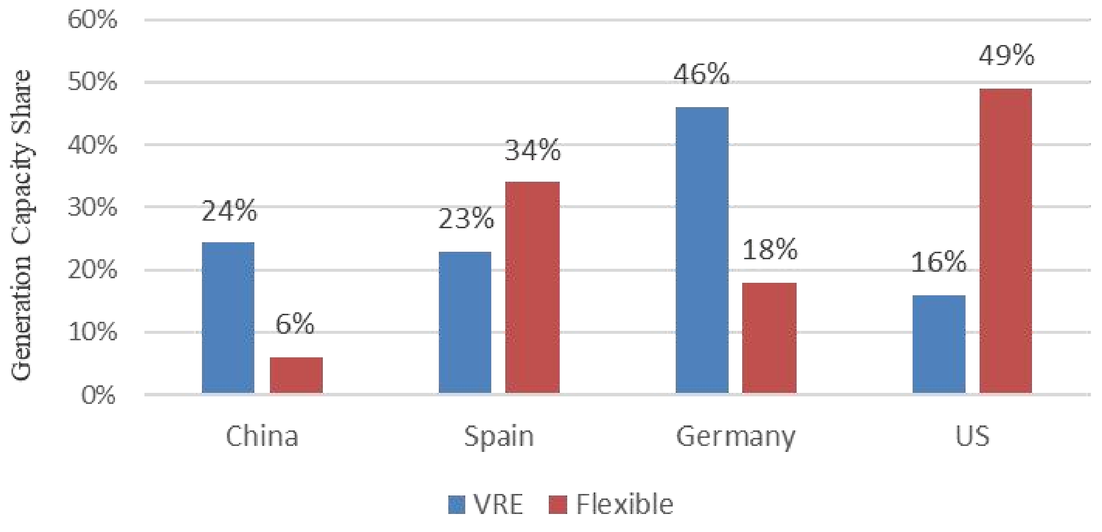
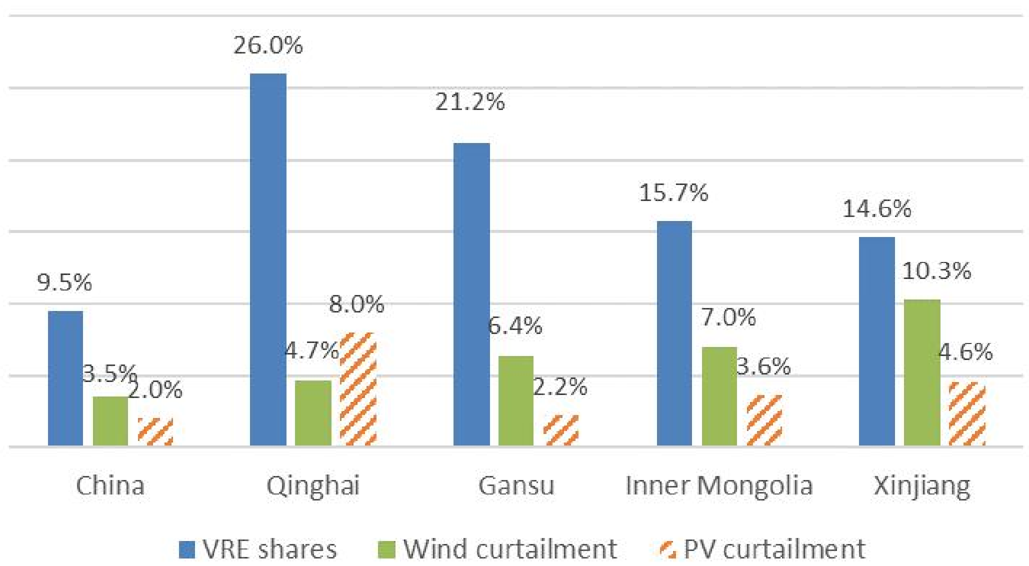


Figure 4.24: A comparison of shares of VRE capacity alongside wind and PV curtailment in China as a whole and in several of its provinces



Electrification of hard-to-abate industries

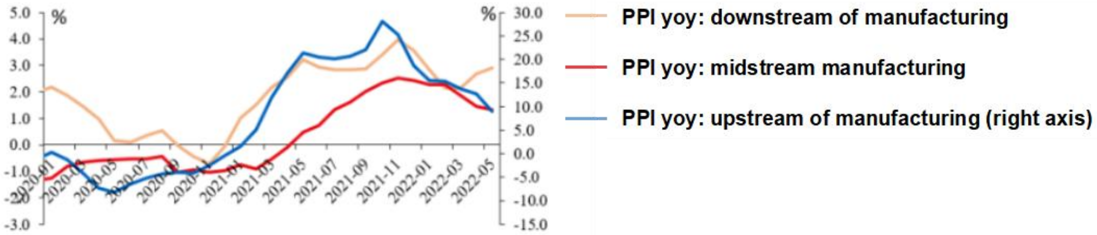
An additional significant challenge in power planning is the need to consider the power industry's relationship with other industries. For instance, industries like steel, non-ferrous metal, petrochemical, building, and transportation may shift from fossil fuels to electricity to decrease carbon emissions, leading to increased electricity consumption.

The national carbon market was launched in China on 16 July 2021, covering over 2 000 power companies. However, much work remains to be done, such as improving the carbon pricing mechanism, enhancing coordination between the carbon market and the power market, and fully leveraging the market mechanism's role.

Transformation costs for the society

The high 'transformation cost' will affect all of society, which will have a negative impact on China's economic growth. As Figure 4.25 shows, driven by rising coal and steel prices, the year on year producer price index (PPI) of the upstream manufacturing industry reached a high of 25.2% in October last year. The equivalent figures for downstream manufacturing and midstream manufacturing also show an upward trend.

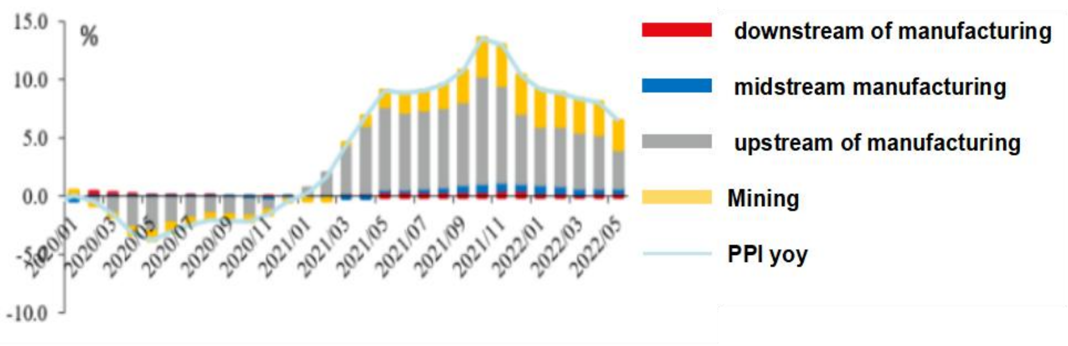
Figure 4.25: PPI (Producer Price Index) yoy (year on year) of upstream(right axis), middle, and downstream (left axis) of the manufacturing industry



Source: WIND

Meanwhile, in terms of the pull on PPI year-on-year, the upstream manufacturing industry and mining industry exert the most pull (Figure 4.26). The sharp rise in energy prices has led to a price spike affecting related industrial products.

Figure 4.26: Contribution of upstream, middle, and downstream sectors of the manufacturing industry to year-on-year changes in PPI



Source: WIND

4.4. Power generation planning in Europe

Overview of power and energy system planning

Figure 4.27 illustrates the overall concept of a stepped approach to expanding the capacity of a power system when short term marginal costs exceed long term marginal costs. Each step of expansion is illustrated with a new cost curve (in red). The capacity of a given power system is defined as the capacity to supply demand. The system includes both generation and transmission in a balanced way.

Figure 4.27: Basic concept of power system expansion

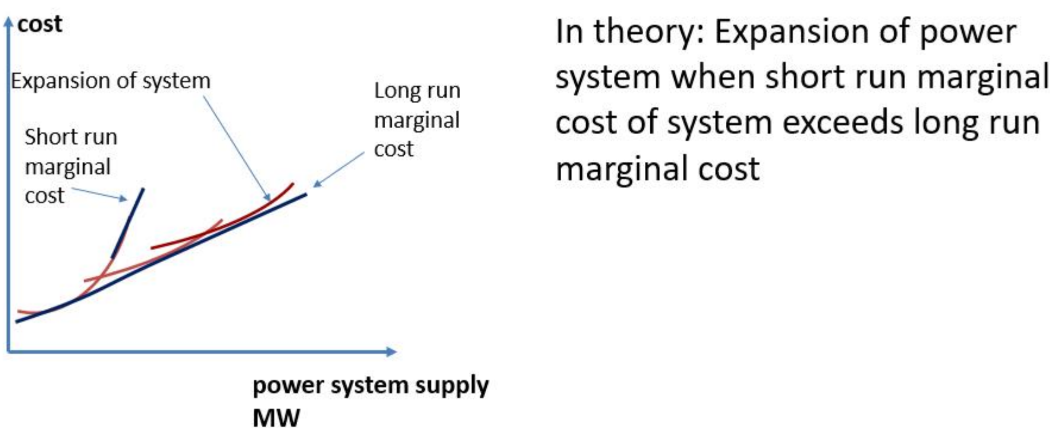
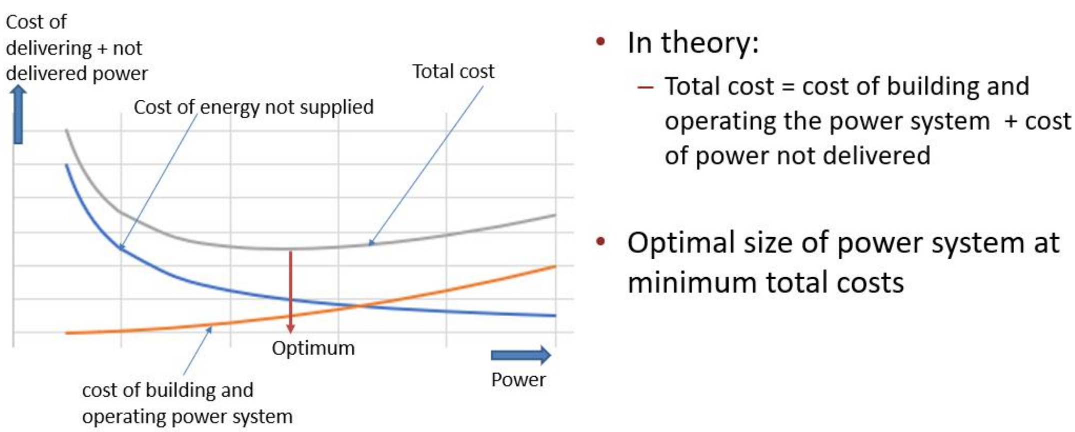


Figure 4.28 the cost curve of building and operating a power system is shown together with the cost curve of energy not supplied (cost = energy not supplied multiplied by value of lost load). Adding the two cost curves together creates the total cost. In theory, the optimal size of a power system is obtained when total costs are at a minimum.

Figure 4.28: Theoretical optimal size of power system



Previously, generation and transmission were planned together within the framework of the (former) vertically integrated utilities. That made sense because transmission expansion depends on generation expansion, and vice versa. With the unbundling and liberalisation of the power sector and creation of open markets for generation, the planning paradigm has changed. Nowadays, transmission and generation planning are handled separately (see Figure 4.29).

Figure 4.29: Power system planning before and after liberalisation of the sector

- Transmission expansion investment decision depends on generation portfolio
- Generation expansion decision depends on transmission infrastructure

=>ideally expansion of generation and transmission should be jointly optimized

- This was done in the "old vertical integrated utilities" before liberalisation of power sector
- Liberalisation and unbundling of the power sector and creation of open markets for generation => transmission and generation planning and investment decisions are handled separately.

Figure 4.30 shows the division of planning tasks for the power system currently employed in Europe. Generation planning is mainly done by the generator companies based on market signals/indicators, transmission is carried out by TSOs (regulated monopolies) and the Security of Supply (SoS) is taken care of by TSOs/energy authorities.

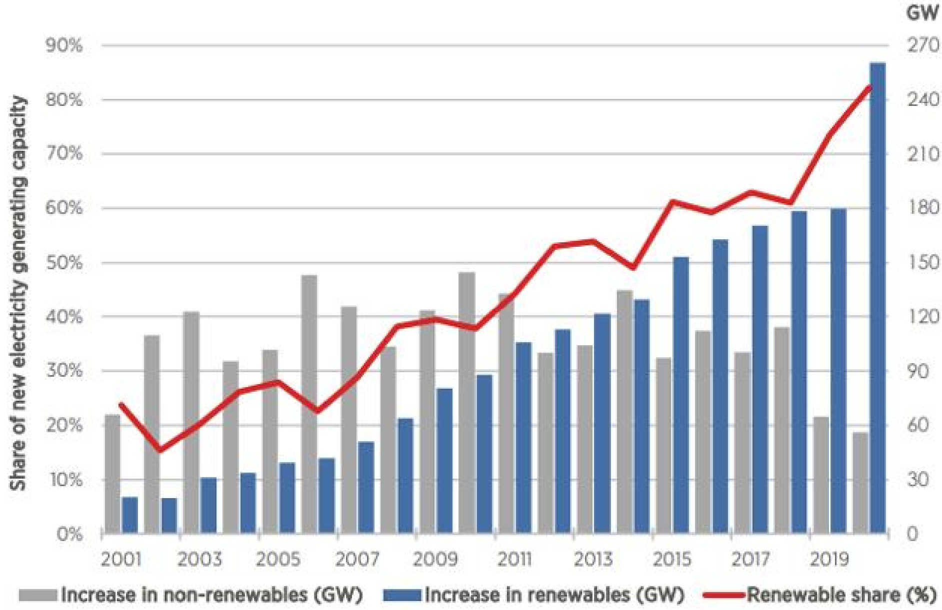
Figure 4.30: Planning: Generation, transmission and SoS in Europe

- Generation
  - Commercial new investment decisions and decisions on decommissioning are taken by generator companies (commercial decision criteria)
  - Based on market signals, future demand and assumptions on transmission buildout
  - Build out of renewables according to CO_2 targets (European/national). Tenders and support schemes.
- Transmission
  - Planning by TSO based on socio economic criteria
  - Regulated monopoly. TSO must convince regulator that investments are in public interest
  - Planning based on future demand and scenarios for future generation portfolios (connection and integration of renewables)
- SoS
  - TSO /energy authority is responsible for SoS (adequacy/system security)

VRE and change of generator portfolio

The global annual share of investments in renewables and non-renewables is shown in Figure 4.31. It shows that the investment share in renewables has increased over the years and is now significantly larger than investments in non-renewables. In 2021, the investment share of renewables reached about 80%.

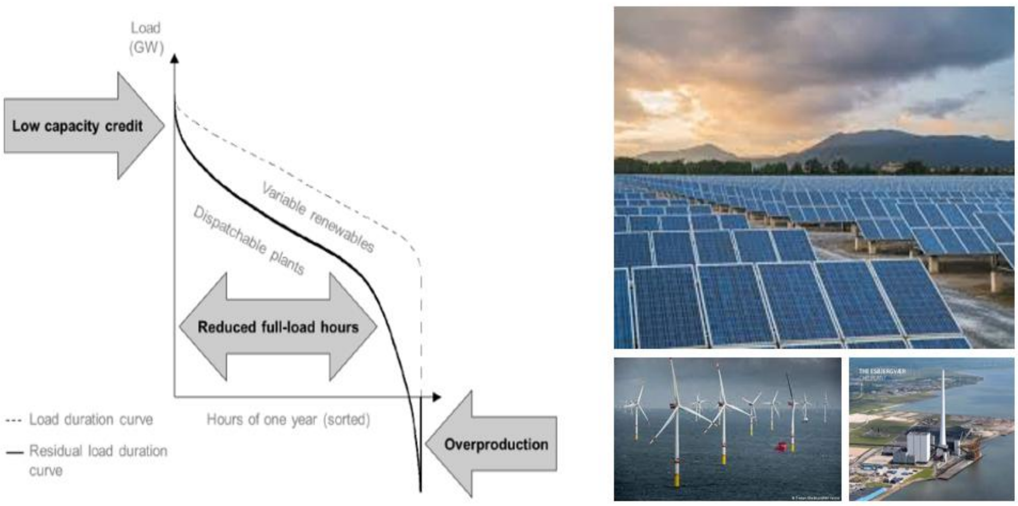
Figure 4.31: Global renewable share of annual capacity expansion



Source: IRENA, Renewable capacity statistics, 2021

With increasing installation of wind and PV, the change in net-load duration curve for the power system is illustrated in Figure 4.31. It shows a reduction in generation volumes from dispatchable generation, such as fossil fuels and nuclear.

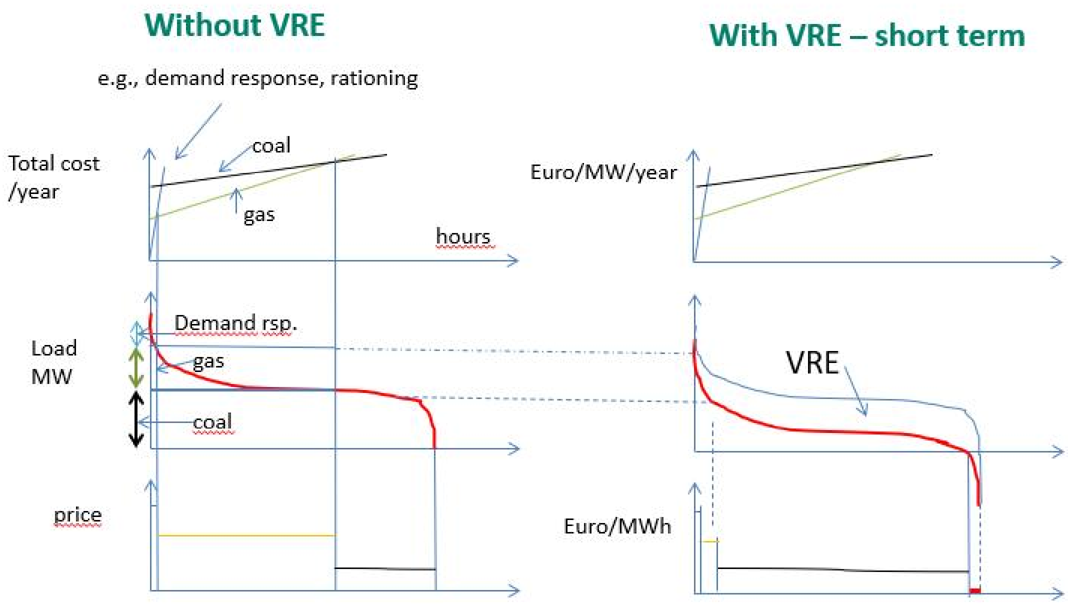
Figure 4.32: Integration of renewables - impact on net-load curve to be covered by dispatchable generators



The left hand side of Figure 4.33shows a simple illustration of how the capacity of a system without VRE can be optimised. The approach is based on investment costs, application of different technologies and the duration curve for demand. Income from hours during which system prices are above the marginal costs of coal generation (e.g., in this case gas) can be used to cover the investment costs for coal optimisation, etc.

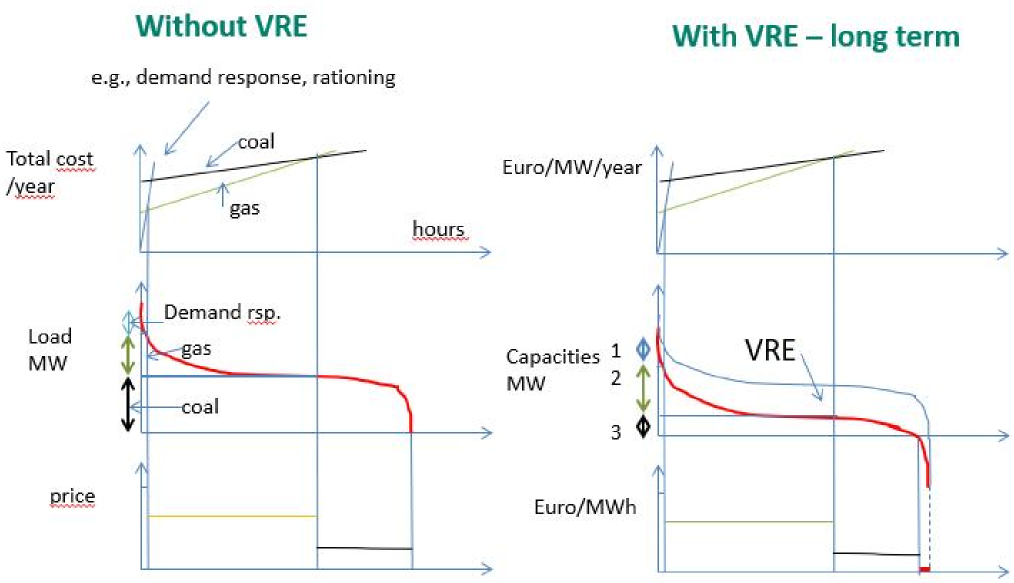
If the amount of VRE is expanded swiftly compared to the lifetime of dispatchable units, the operation of the system will be as shown in the right hand side of Figure 4.33. Here, there are more hours where coal covers the full load and thereby sets the marginal costs or price of the system. This leads to a lack of funds to meet coal optimisation and therefore an economic imbalance.

Figure 4.33: Short term change of system expanded with VRE (conceptual screening curves)



The long term balanced solution for the generator portfolio is shown in Figure 4.34. There will be less coal capacity and relatively more capacity for less capital-intensive generation (in this case gas).

Figure 4.34: Long-term change of system expanded with VRE (conceptual screening curves.)

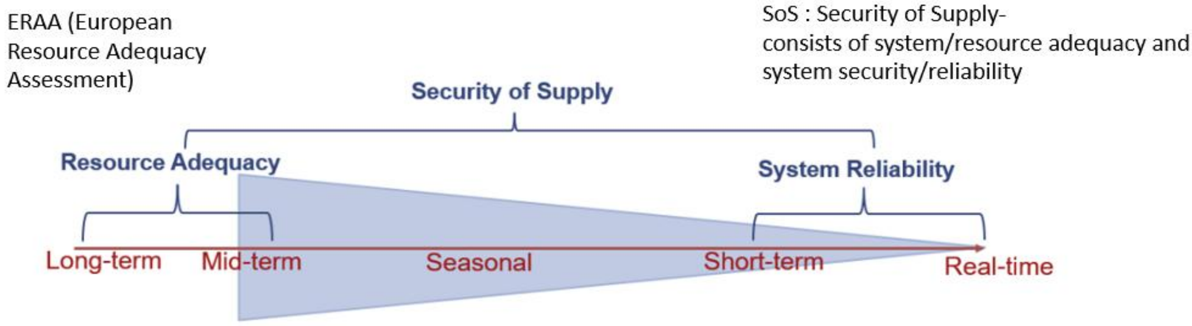


Security of Supply (SoS) – Focus on adequacy

When discussing security of supply (SoS), it is important to distinguish between resource adequacy and system reliability, jointly often referred to as security of supply (see Figure 4.35).

- ***Resource adequacy*** is about ensuring that enough resources are available in the power system to meet demand at any hour. A resource adequacy assessment is typically done several years ahead of power delivery.
- ***System reliability*** is about making sure that supply equals demand in real time, without violating any security limits. The system operator typically relies on ancillary service markets to assure system reliability.

Figure 4.35: SoS divided into resource adequacy and system reliability



Source: Capacity Remuneration Mechanisms in the EU: today, tomorrow, and a look further ahead, Robert Schuman Centre for Advanced Studies, RSC 2021/71

The adequacy standards for a number of European countries are listed in Figure 4.36. Most standards are in the unit LOLE (Loss of Load Expectancy) and are typically between three and eight hours per year. Denmark operates a different set of standards: under its system, the number of outage minutes (due to generation shortage) for an average consumer should be less than 5 minutes.

Figure 4.36: EU adequacy standards

National Reliability Standards

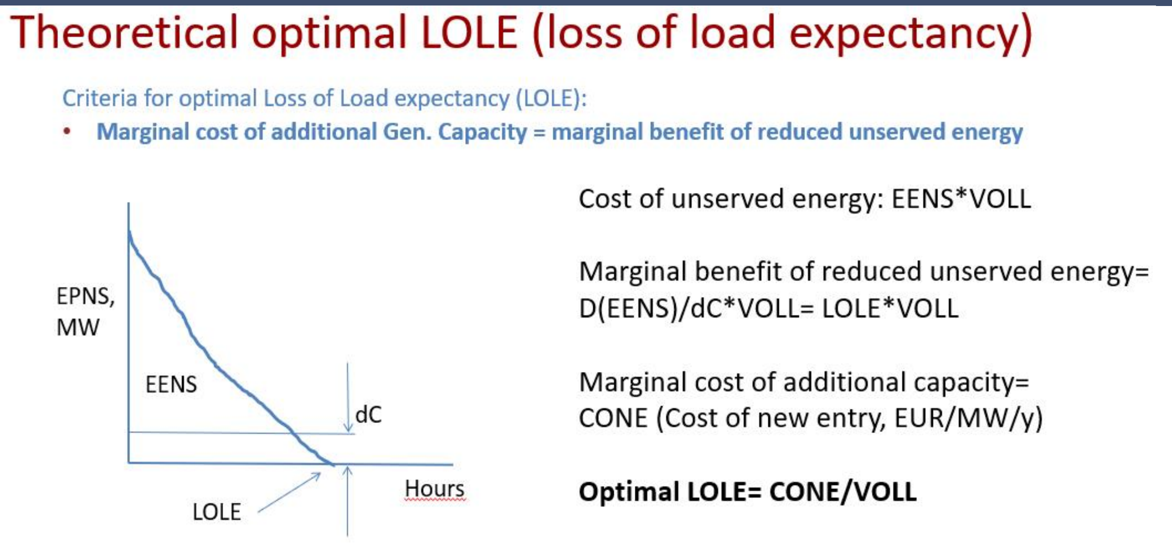
Member state	Type of reliability standard	Value	Binding (B) / non-binding (NB)
BE	LOLE	3 h / year	B
BG*	LOLE	16 h / year	
CY	Reserve margin	189 MW	B
DE	LOLE	5 h / year	NB
DK	Outage minutes	5 minutes	B
EE*	LOLE	9 h / year	
ES*	LOLE	3 h / year	NB
	Reserve Margin	10 %	NB
FI*	LOLE	3 h / year	B
FR*	LOLE	3 h / year	B
	LOLE	2 h / year (after post-market measures)	B
GR	LOLE	3 h / year	NB
ISEM	LOLE	8 h / year	B
IT	LOLE	3 h / year	B
LT	LOLE	8 h / year	B
NL	LOLE	4 h / year	NB
PT*	LOLE	5 h / year	B
	Load supply index	≥ 1	B
PL	LOLE	3 h / year	NB
UK (GB only)	LOLE	3 h / year	B

Table 1: National reliability standards applied by EU Member States as of the end of 2019 (ACER Market Monitoring Report 2019) and updated where relevant by more recent ENTSO-E information (updated information is marked with an *). Non-listed member states do not have a reliability standard in place.

Source: ACER Market Monitoring report 2019

Figure 4.37 presents the derivation of a simple formula for the optimal level of LOLE. As can be observed, Expected Energy Not Served (EENS) decreases as installed capacity increases. Increasing capacity (dC in Figure 4.37) is only optimal when the marginal benefit of adding capacity equals the marginal cost of adding capacity. Note here, that the Value of Lost Load (VOLL) expresses the unit cost of an interruption to electricity supply, and Cost of New Entry (CONE) is the cost of new capacity.

Figure 4.37: Optimal LOLE (Loss of Load Expectancy)



4.5. Power generation adequacy assessment in the EU

In the EU, the implementation of the Clean Energy Package (2019) brought about a revised resource adequacy assessment framework, which – unlike its predecessor – now explicitly takes account of the variability of weather conditions and its impact on both Variable Renewable Energy (VRE) generation and demand. The revised framework, which has a 10-year horizon, builds on a deterministic forecast of generation (based on set scenarios), planned outages and demand, and explicitly adds an uncertainty component into the assessment. To achieve this, a probabilistic assessment of wind, solar and hydro generation patterns (including forced outages) and climate-dependent consumption patterns are incorporated into several alternative scenarios. Rather than producing point estimates of resource adequacy, the framework produces adequacy measures that explicitly account for the inherent uncertainties.

A fundamental feature of the framework is that it is performed in a coordinated and consistent manner. Each Member State establishes a reliability standard and performs a national assessment. At the EU level, it is the responsibility of the European Association of TSOs (ENTSO-E) to prepare the adequacy assessment report, while it is the duty of the EU's Agency for the Cooperation of Energy Regulators (ACER) to approve the report or request amendments. The assessment informs policy decisions aimed at solving capacity adequacy issues.

Figure 4.38 presents an outline of the European Resource Adequacy Assessment (ERAA) methodology.

Figure 4.38: ERAA (European Resource Adequacy Assessment)

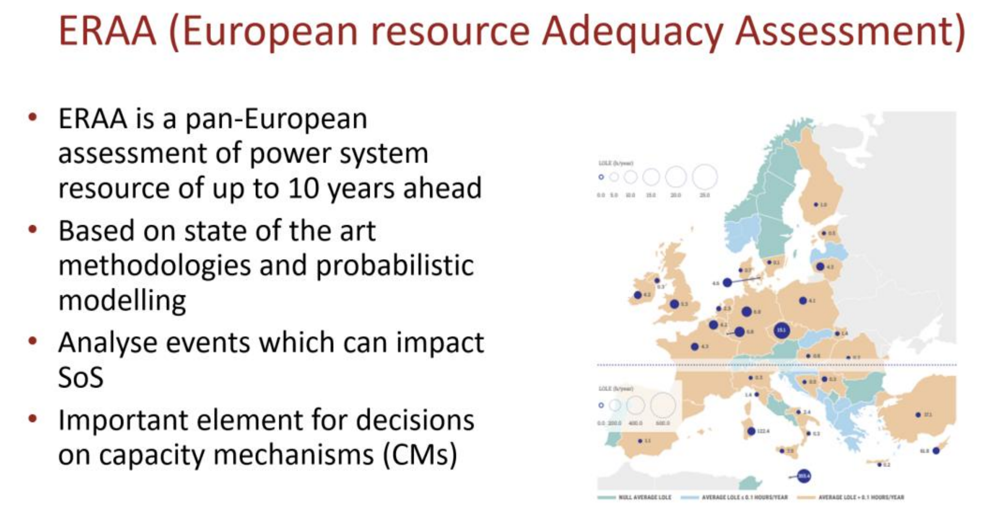


Figure 4.39 lists a few important new features of the ERAA.[9] Among the new requirements is the use of the Economic Viability Assessment (EVA) methodology, which is used to assess the economic viability of generation resources in an energy-only market, excluding capacity mechanisms. Under this assumption, generators not profitable in the market must be removed from the calculations as they cannot be assumed to continue operation in a market environment.

Given that some EU Member States employ capacity mechanisms, a scenario with and without these is part of the ERAA. A comparison of scenarios with and without capacity mechanisms may indicate that a capacity payment needs to be introduced to sustain a certain target level of reliability, often expressed as maximum expected number of hours with loss of load (LOLE).

[9] Relevant references in relation to the ERAA are as follows:

- The ENTSO-E website for the ERAA in 2021: https://www.entsoe.eu/outlooks/eraa/
- The European Regulation on the Internal Market for Electricity: https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:32019R0943&from=DA

Figure 4.39: ERAA features

Some important ERAA features

- ERAA specified in REGULATION (EU) 2019/943 OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL of 5 June 2019 on the internal market for electricity (Article 23 and 24)
- 10 years ahead scenarios (2020-30)
- Multiple climate years (PV and wind time series)
- Resource adequacy assessed by calculating EENS (expected energy not served) and LOLE (Loss of load Expectation) using probabilistic approach (e.g., SysyfosR model)
- NEW: EVA (economic viability assessment) of capacity resources; remove capacity which is not viable in the market, consider adding new viable capacity (assessment by market model, e.g., Balmorel)
- NEW: Scenarios with and without Capacity Measures (payment for capacity)

Figure 4.40 compares some of the new features in the ERAA with the previously used Medium-term Adequacy Forecast (MAF) methodology used by the ENTSO-E for adequacy assessments of the European electricity system.

Figure 4.40: Additional new features in the ERAA

NEW in ERAA compared to previous MAF (Medium Term Adequacy Forecast)

- An EVA of resource capacities;
- FB modelling of the power network (when applicable);
- Impact of climate change on adequacy;
- Analysis of additional scenarios, including the presence or absence of CMs;
- Consideration of energy sectoral integration;
- Time horizons of 10 years with annual resolution.

- ERAA not yet fully implemented within ENTSO-E; in progress:
  - Flow based modelling
  - Improved DSR
  - Improve sector integration (PtX..)
  - Full ten year horizon

It should be mentioned that ERAA is still not fully implemented within ENTSO-E. Remaining aspects to be integrated include the flow-based inter-zonal transmission capacity allocation mechanism, as well as further considerations relating to the integration of sectors, also known as 'sector coupling'.

A graphical presentation of the methodological approach underlying the ERAA is provided in Figure 4.41. Forced generation and transmission outages are assessed probabilistically. Variable generation of wind, solar and hydro are described via time series for several years. Specifically, ENTSO-E uses 34 different climate years, that is to say 34 different climate scenarios. On the demand side, demand side response (DSR) and temperature-driven demand are also taken into account. ENTSO-E scenarios provide the basis for setting the generation portfolio and deterministic forecasts of demand.

Figure 4.41: ERAA methodological approach

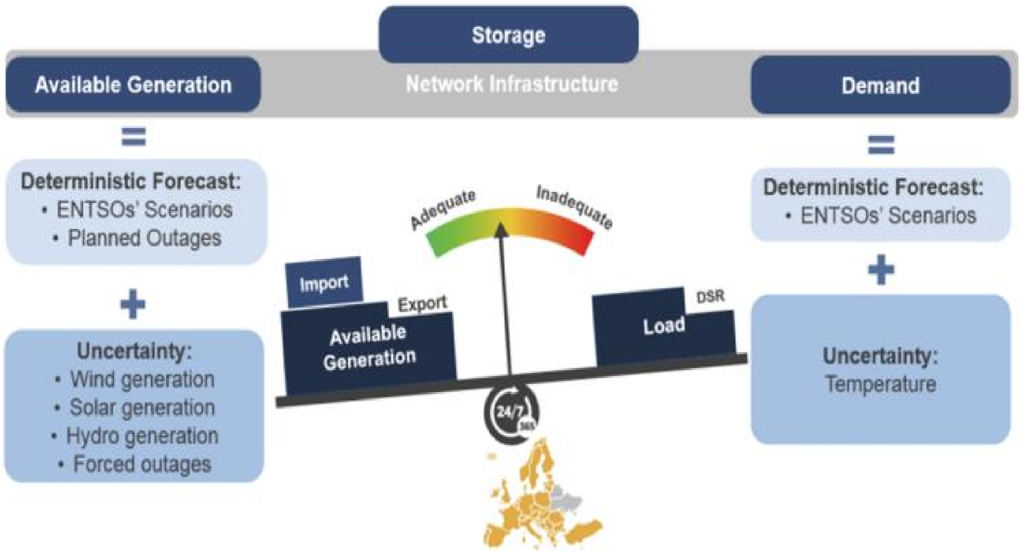
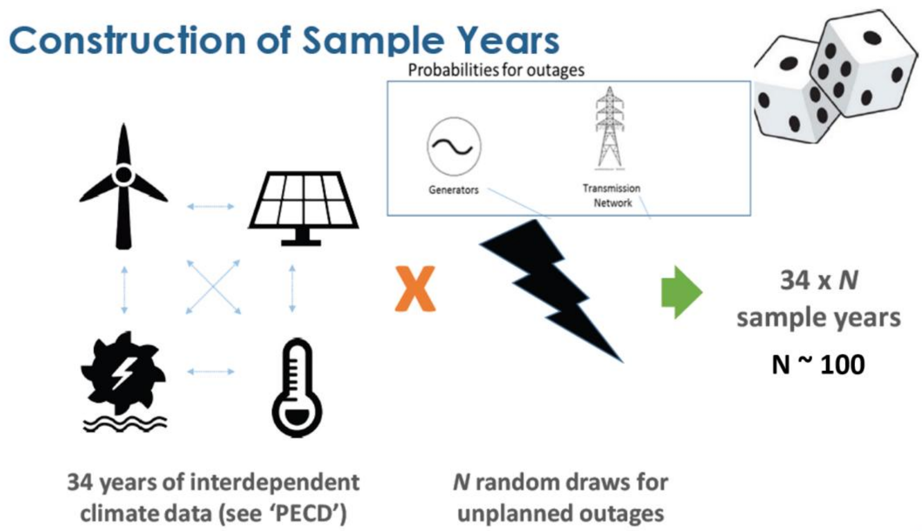


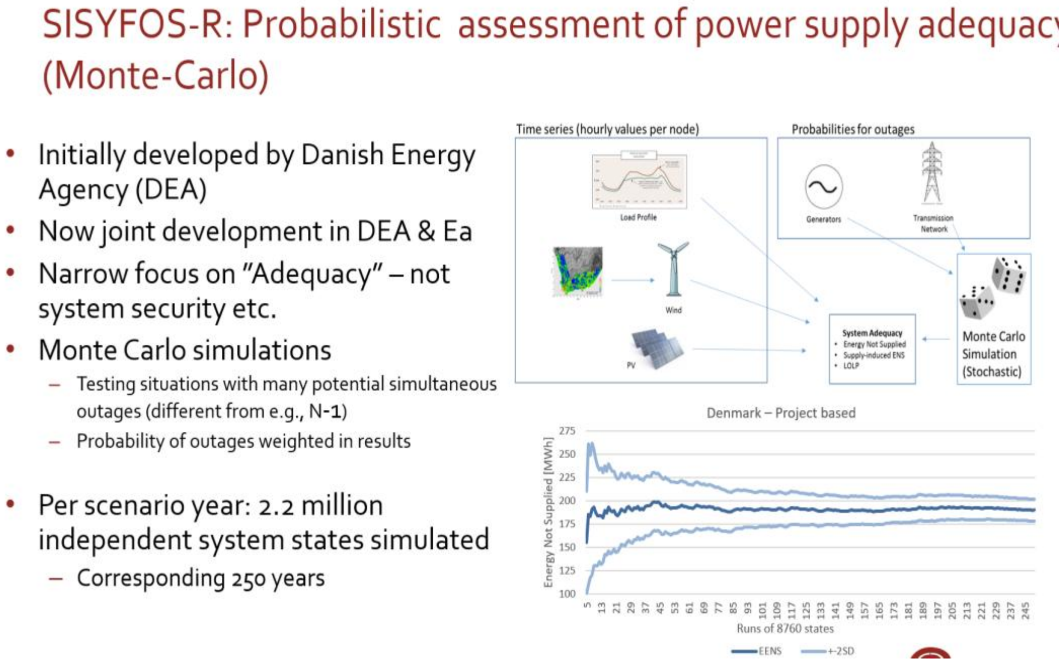
Figure 4.42 illustrates the construction of sample years. For each of the 34 meteorological years, a number N of sample years (each consisting of 8 760 hours) is constructed using the Monte Carlo method. For example, if N=100, then 3 400 possible realisations are calculated. As the number of realisations increases, the uncertain statistical parameters LOLE and EENS stabilise.

Figure 4.42: Construction of sample years



An example of probabilistic results is shown in Figure 4.43. In this case, the Monte Carlo-based Sisyfos-R model has been applied to 250 randomly generated samples of outage years for generation and transmission, in total 2.2 million system states (8 760 x 250). It follows that the average Energy Not Served (ENS) converges towards a stable value, with uncertainty of +/- 2 standard deviations.

Figure 4.43: Example of Monte Carlo calculations with 250 sample years of outages



An overview of capacity remuneration mechanisms (CRMs) and capacity measures (CMs) in Europe is given in Figure 4.44. The CRMs have been divided according to:

- approval/non-approval by the European Commission under state aid rules.
- CRM in place with or without adequacy concerns identified.

The reason for the involvement of the EU Commission is that additional payment to generators outside the day-ahead market is likely to distort the competition between countries in the European power market.

Figure 4.44: CRM (Capacity Remuneration Mechanisms) in Europe

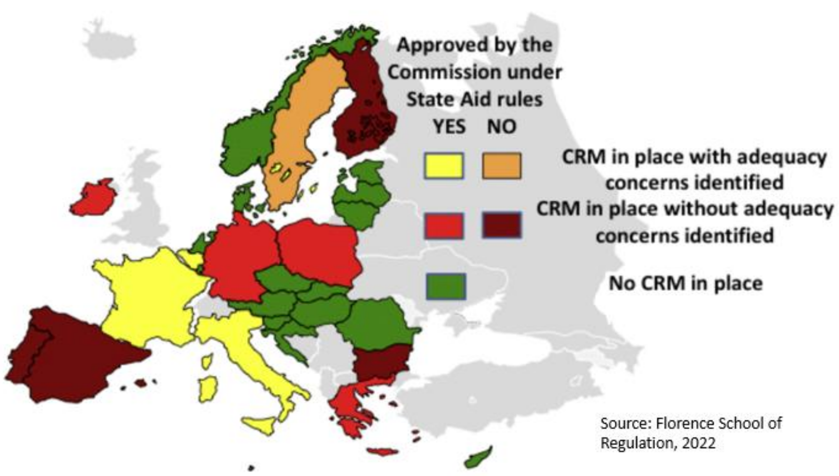
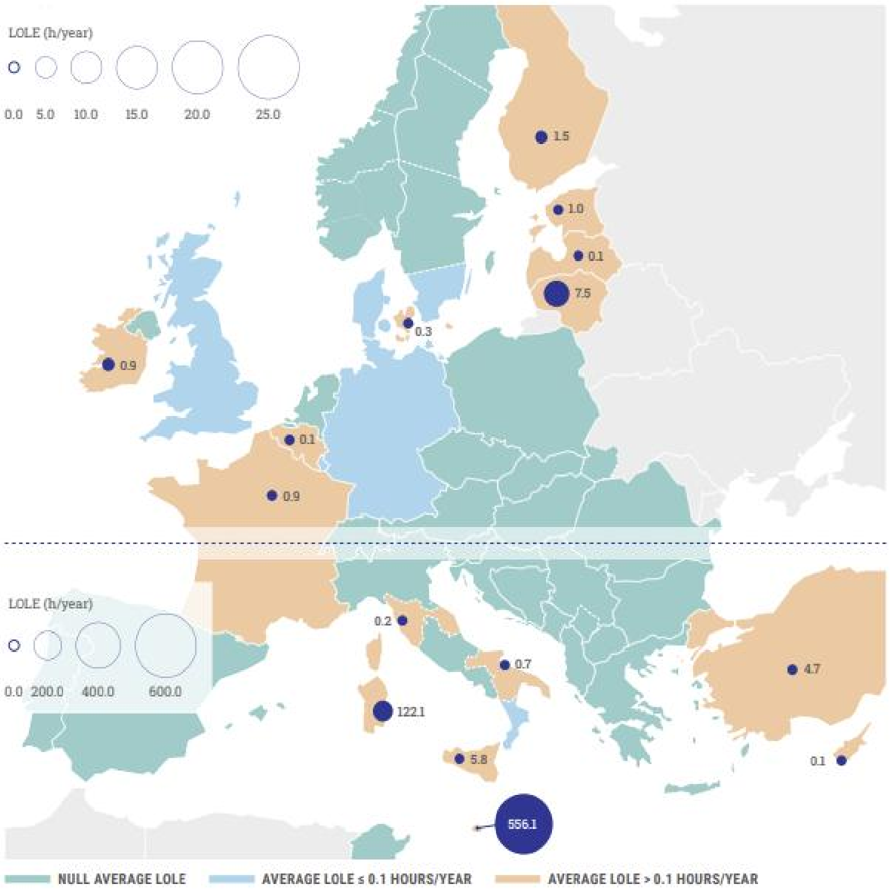


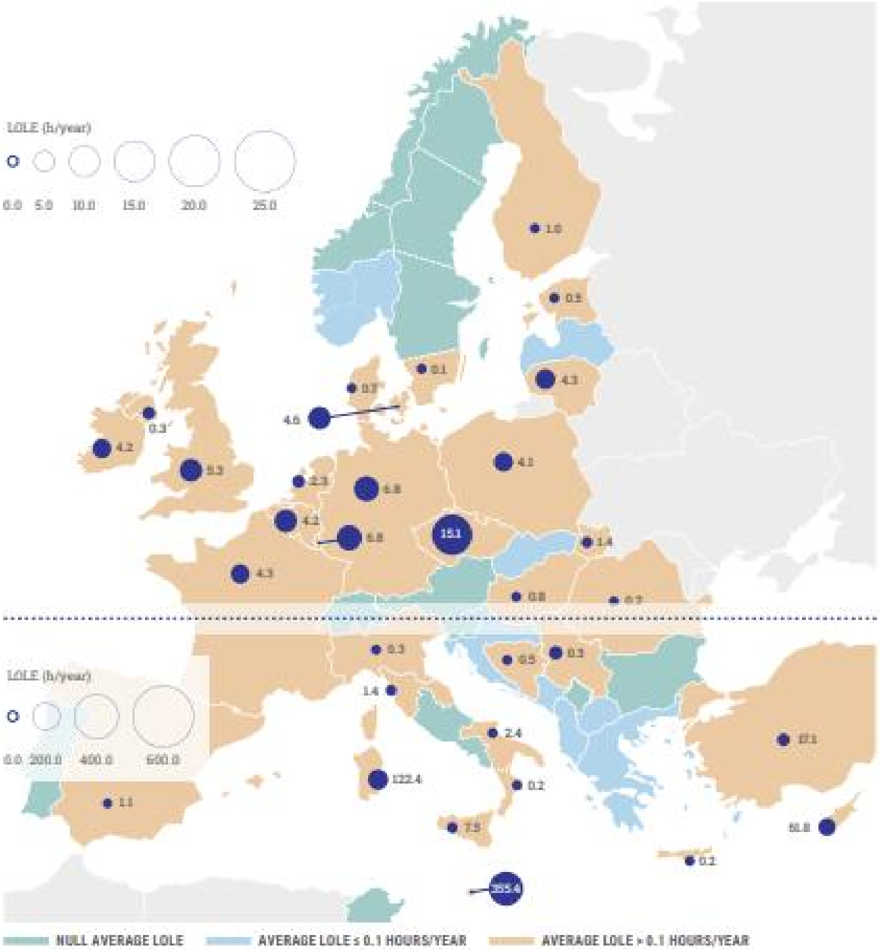
Figure 4.45 and Figure 4.46 illustrate adequacy results (LOLE) from the ENTSO-E ERAA study 2021 for the year 2025. Two cases are shown: national estimates without an economic viability assessment (EVA) or CM (see Figure 4.45) and national estimates with EVA but without CM (see Figure 4.46).

Figure 4.45: LOLE, 2025, scenario national estimates, without EVA, without CM



As expected, taking EVA into account leads to higher LOLE values.

Figure 4.46: LOLE, 2025, scenario national estimates with EVA, without CM



4.6. Comparability / Discussion

A WP3 follow-up workshop, held on 18 October 2022, provided an opportunity for extensive discussions and deeper exploration of the WP3 themes. In addition to project partners, esteemed external experts from CEC, IEA, and the Oxford Institute for Energy Studies were invited to share their insights and reflections on the key topics. Key points from the discussion are given below:

- Both in China and the EU, ensuring energy security in a rapidly evolving landscape presents complex challenges that require comprehensive strategies.
- Institutional mechanisms play a crucial role, including the establishment of efficient and consistent energy markets, as well as clearly defined roles and effective collaboration among key stakeholders.
- In order to fully grasp the dynamics of energy security, future planning will necessitate the use of energy system scenario tools and probabilistic analyses, enabling a holistic understanding of potential risks and opportunities. It is going to be both valuable and necessary to conduct wildcard analyses and assess combinations of extreme cases.
- Additionally, climate resilience must be a priority, with appropriate consideration of the impacts of climate change and extreme weather events. The time-sensitive

nature of energy system development makes it a challenge to respond swiftly to price signals, and this highlights the importance of resilience and flexibility in ensuring a secure and reliable energy supply.

Key aspects and considerations with respect to power system planning in China

Adequacy:

- Deterministic methods are employed to assess power adequacy, taking into account demand forecasts for the future, including peak and off-peak periods.
- The expansion of variable renewable energy (VRE) sources necessitates increased flexibility in the power system, which can be achieved through coal-based units, battery storage and pumped storage.
- Mechanisms such as Capacity Remuneration Mechanisms could be implemented to incentivise investment in generation capacity.
- Coal-fired power plants are transitioning to operate as peak or standby units.

Energy Security:

China's energy supply chain is vulnerable due to the country's high dependence on foreign countries for oil, natural gas, and other key energy sources.

Flexibility Needs:

- The development of power transmission lines, including DC point-to-point and AC network buildout, is essential.
- Fluctuations in wind power and PV output are expected to increase, leading to potential power supply shortages and high curtailment rates.
- The power market and pricing mechanisms require further development to support a higher proportion of renewables, including the establishment of auxiliary services, capacity, and transmission-rights markets.
- The electricity pricing system should take account of the cost of flexibility and regulation.
- The power generation sector is transitioning towards cleaner sources, the power grid is becoming digitised, and power consumption is increasingly electrified.
- Growing daily peak-valley differences in residual load necessitate greater system flexibility.
- The demand for system flexibility is highest in northwest China and northern China.
- There are significant hourly fluctuations and uncertainties in residual load, with the period from 12:00 to 20:00 showing the greatest demand for additional power.
- Flexible resources in the power system are becoming more diverse, encompassing generators, storage, the grid, and demand-side resources.
- Different energy systems, including hydrogen, heat, cooling, and gas, can serve as flexibility resources by means of coupling mechanisms.

Key aspects and considerations with respect to power system planning in the EU

- Liberalisation and unbundling of the power sector and creation of open markets for generation has led to transmission and generation planning being handled separately.
- Short-term and long-term operational change of system when adding VRE (change in capacity portfolio of dispatchable power).
- The link between security of supply, resource adequacy, and system reliability.
- ERAA (European Resource Adequacy Assessment) is based on state of the art methodologies and probabilistic modelling. Now used in ENTSO-E.
- Importance of interconnections/expansions of transmission capacity.
- Ensuring availability of sufficient dispatchable resources. i.e., CRMs (Capacity Remuneration Mechanisms) in Europe based on assessments by ERAA.
- Method for probabilistic assessment of capacity credit for VRE (general method: Effective Load Carrying Capability (ELCC)).
- Much focus has been on adequacy and operational system security. Experience from Europe shows that in the future more focus must be on energy security in relation to:
  - availability of fuels at affordable prices (gas, nuclear, oil, coal (CCS), biomass, …).
  - risk of international political disputes/conflicts/war.
  - link between natural gas, supply security, electricity security.
- Recently the surging energy prices (electricity, gas) in Europe have resulted in a significant demand response thereby reducing demand and consumer costs.
- Until recently, reliance on gas for generation adequacy in Europe created an important link between electricity supply security and gas deliverability. This must now be updated to ensure that coal and nuclear units continue to be available.

5. CCUS, P2X, Hydrogen in China and the EU

This chapter is based on Work Package 4 (WP4)- Carbon Capture, Utilisation and Storage (CCUS), P2X, and Hydrogen of the ECECP project. WP4 had its online kickoff workshop on 15 and 16 November 2022. The participants were the project partners SGERI, Matteo d'Andrea (Danish Energy Agency), who substituted Kaare Sandholt (CET program, ERI), CEC, ECECP and Ea Energy Analyses, with ECECP (ICF) as the facilitator.

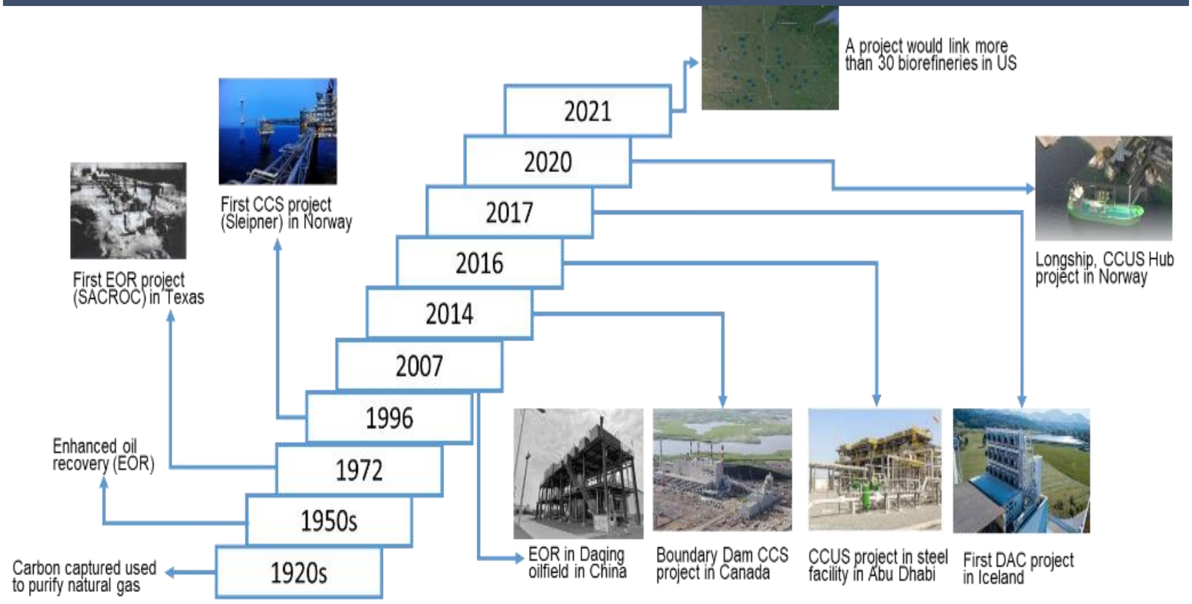
5.1. CCUS

Carbon Capture, Utilisation and Storage (CCUS) refers to a set of technologies and processes that involve capturing CO_2 emissions from industrial sources, utilising, or converting the captured CO_2 for beneficial purposes, or storing it underground to prevent its release into the atmosphere. The aim of CCUS is to mitigate greenhouse gas emissions and combat climate change by reducing the amount of CO_2 released into the atmosphere. CCUS is currently the only technological option to realise low-carbon utilisation of fossil energy. To strike a balance between carbon neutrality and energy stability in China, a diversified supply system composed of renewables, fossil and nuclear energy is needed. It is estimated that by 2060, fossil energy will account for less than 20% of China's energy consumption.

The history of CCUS

The CCUS process was developed in the 1920s, when carbon capture equipment was used for the first time to purify natural gas, hydrogen, and other gas streams (see Figure 5.1). In the 1950s, it was found that CO_2 injected into oilfields can force more oil out of the wells - a process known as enhanced oil recovery (EOR). In 1972, the first large-scale commercial CCUS project was implemented in Texas, which used the captured CO_2 for commercial purposes. In 1996, the first pure geological carbon storage project (without EOR) was constructed, when Norway started pumping CO_2 captured from natural gas production into a saline aquifer under the North Sea. In the 21st century, CCUS projects have been widely constructed in several North American and European countries, not only in oil fields but also in coal-fired power generation units, as well as iron and steel and bio-energy production units.

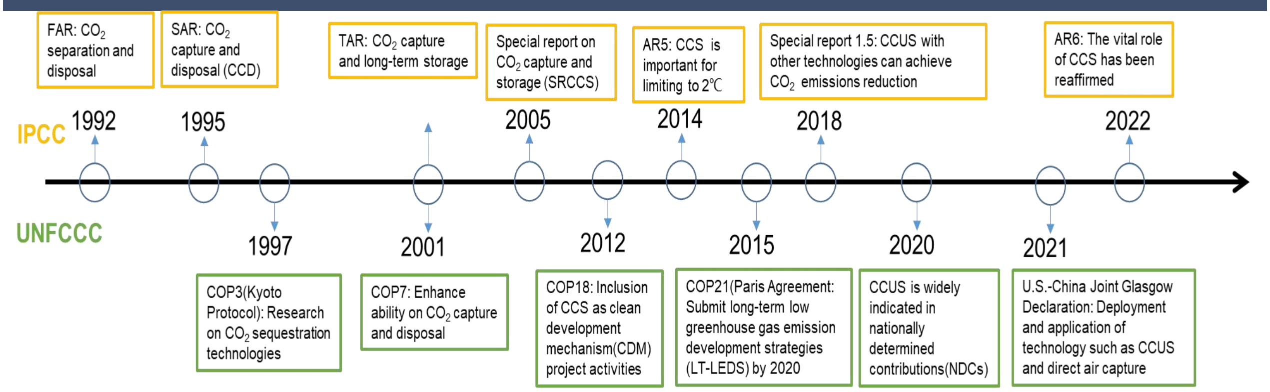
Figure 5.1: Overview of CCUS technology development



The role of CCUS as a key technology for mitigating climate change strengthened in earlier reports from the Intergovernmental Panel on Climate Change (IPCC) and United Nations Framework Convention on Climate Change (UNFCCC). In the first IPCC assessment report (FAR) in 1992, and its supplement in 1992, CO_2 separation and geological and marine disposal was given as an example of technology that could be used to control greenhouse gases (see Figure 5.2). Three years later, in the second IPCC assessment report (SAR), a formal definition of CCS was introduced.

In 2001, IPCC's third assessment report (TAR) found that, 'most model results indicate that known technological options could achieve a broad range of atmospheric CO_2 stabilisation levels', but that 'no single technology option will provide all of the emissions reductions needed'. Rather, a combination of mitigation measures would be needed to achieve stabilisation, stated the authors. In 2005, IPCC released a special report on CCS that described sources, capture, transport and storage of CO_2, which can be seen as a systematic definition of CCS. The most recent report, IPCC AR6, has once again confirmed that CCS is key to reaching net-zero emissions by mid-century and mitigating climate change. Past UNFCCC conferences have referred to CCS as a key decarbonisation technology.

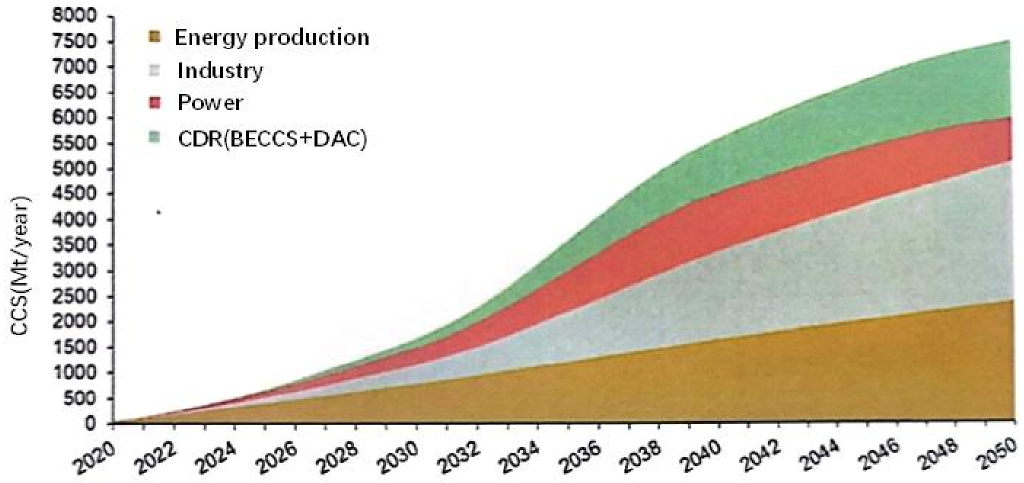
Figure 5.2: CCUS timeline



A consensus then formed around the importance of CCUS. According to IPCC's sixth assessment report (AR6), the remaining carbon budget for limiting warming to 1.5°C has been assessed as 500 Gt CO_2 and as 1 150 Gt CO_2 for limiting warming to 2°C. Based on these results, CCUS is an important technology to achieve net-zero emissions and maintain energy security.

The energy transition also faces the risk of stranded assets. IPCC AR6 shows that the combined global discounted value of the unused fossil fuels and stranded fossil fuel infrastructure is projected to be between USD 1 trillion and USD 4 trillion from 2015 to 2050 to limit global warming to 2ºC, and it will be higher if global warming is limited to 1.5ºC. CCS could allow fossil fuels to be used for longer, reducing stranded assets. IPCC AR6 also gives a detailed summary of carbon dioxide removal (CDR) methods, especially for bio-energy CCS (BECCS) and direct air CCS (DACCS). The mitigation potential for BECCS could reach between 0.5 Gt and 11 Gt CO_2 yr^{-1} and for DACCS the figure is between 5 Gt and 40 Gt CO_2 yr^{-1}.

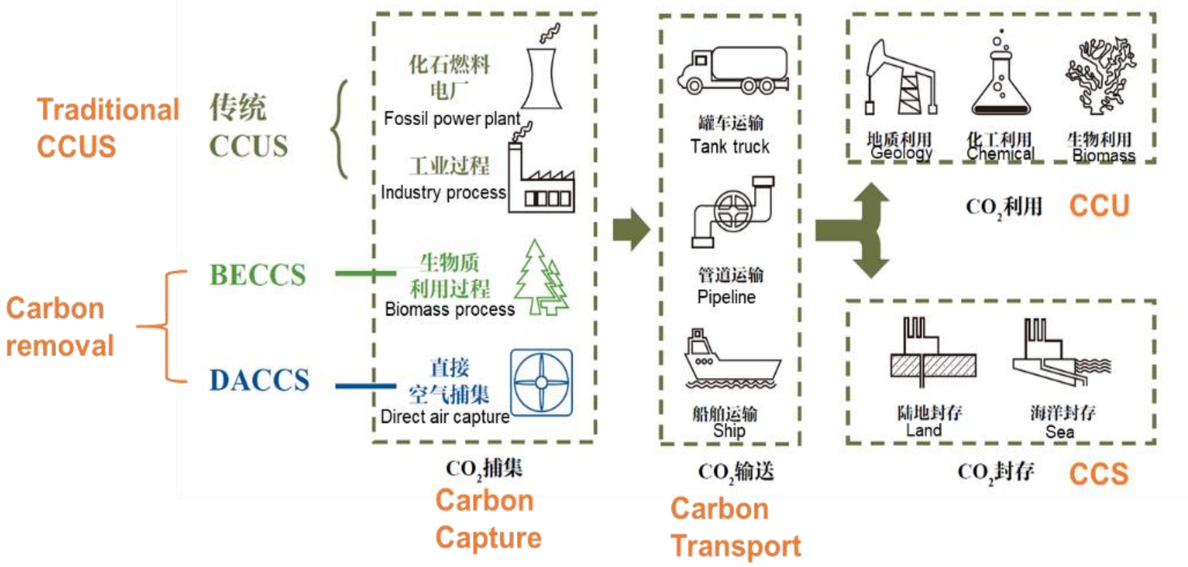
Figure 5.3: Application of CCUS from 2020 to 2050 to limit global warming to 1.5ºC, by sector



Source: IPCC, 2022; IEA, 2021

Originally, CCUS technology was developed for carbon capture, then expanded to encompass utilisation in oil fields and geological storage. Focusing on mitigation potential and cost, comprehensive benefits and application prospects, IPCC's AR6 report has systematically defined four categories: carbon capture and storage (CCS), carbon capture and utilisation (CCU), bioenergy with carbon capture and storage (BECCS), direct air carbon capture and storage (DACCS) (see Figure 5.3). The IPCC AR6 report introduces the term 'negative emissions', i.e., carbon dioxide removal (CDR), which refers to anthropogenic activities removing CO_2 from the atmosphere and durably storing it in geological, terrestrial, or ocean reservoirs, or in products. Under this definition, BECCS and DACCS are included in CDR (Figure 5.4), but CCU and CCS applied to fossil fuel-based CO_2 do not count as CDR.

Figure 5.4: Illustration of CCUS process chains



CCUS for carbon neutrality

CCUS can maintain the flexibility of a power system to realise carbon neutrality. By avoiding an early phasing out of coal-fired power stations in China, the necessary support for system inertia and frequency control is then guaranteed when facing the volatility of renewable energy and potential seasonal power shortages.

CCUS is a feasible technology option for hard-to-abate sectors, like steel and cement. After implementing measures like efficiency improvement, raw material substitution, etc., it is estimated that 34% of carbon emissions in the steel industry and 48% of carbon emissions in the cement industry are hard to abate , making the prospects for CCUS very positive.

CCUS coupling with bioenergy, usually referred to as BECCS, could realise negative emissions. Negative emission technologies can neutralise greenhouse gas emissions and provide important support for achieving carbon neutrality.

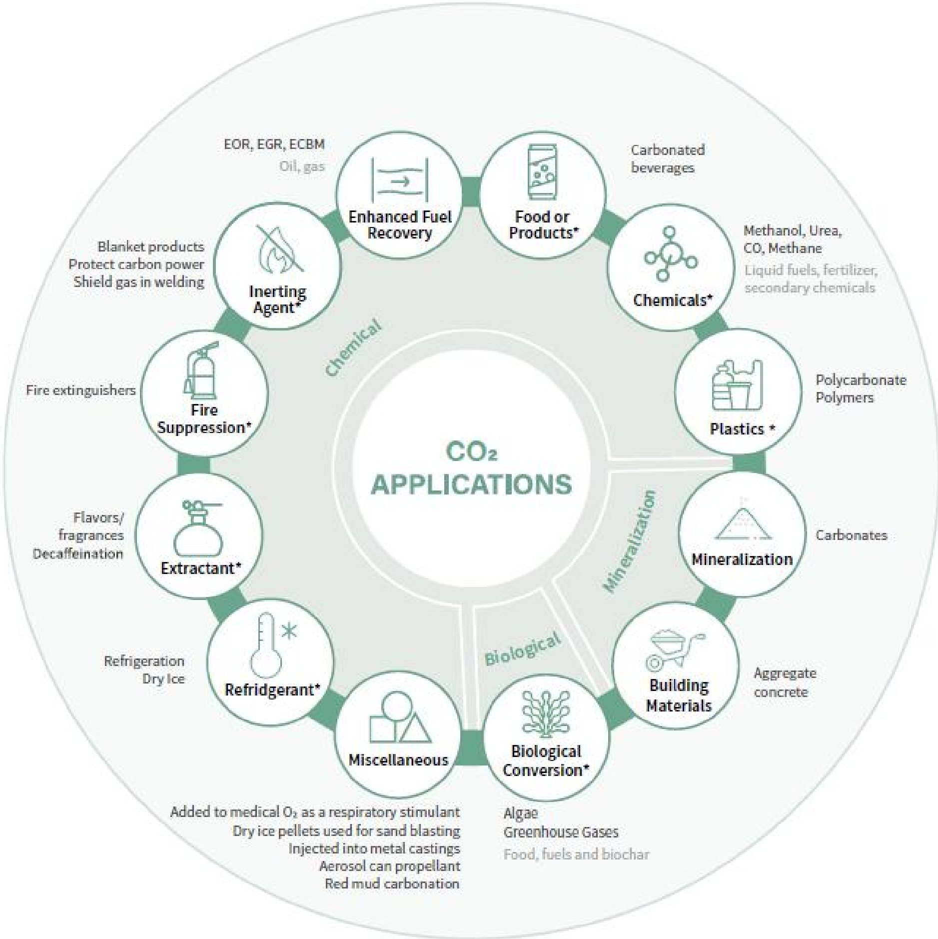
Table 5.1 gives key parameters for carbon capture technologies. The first-generation capture technology is mature, yet the energy consumption and costs are high. China lacks large-scale CCUS demonstration projects. The second-generation capture technology can significantly reduce energy consumption and cost, yet it is still in the stage of R&D or small-scale testing. It is expected to be more widely applicable around 2035.

Table 5.1: Key Parameters for Carbon Capture Technologies (China)

		Cost （CNY/ton）	Efficiency loss (%)	Energy consumption (GJ/ton)
First-generation capture	Post-combustion	300~450	10~13	3.0
	Pre-combustion	250~430	7~10	2.2
	Oxy-fuel combustion	300~400	8~12	-
Second-generation capture	Post-combustion	-	5~8	2~2.5
	Pre-combustion	-	3~7	1.6~2.0
	Oxy-fuel combustion	-	5~8	-

Table 5.1 demonstrates the prospects for the cost and energy consumption of CO_2 capture technology. China's thermal power industry will reach a peak for unit renewal between 2035 and 2045. In terms of development of carbon capture technology, first-generation capture technology should be mainstream until 2035. After 2035, second-generation technology should be mainstream.

Figure 5.5: Overview of CO_2 applications



Source: UNECE, Technology Brief: Carbon capture, use and storage (CCUS)

Figure 5.5 presents CO_2 applications. Carbon utilisation can be subdivided into three main areas: mineralisation, biological and chemical. CO_2 is used to make fertiliser, synthetic fuels, syngas, methanol, and polymers. CO_2 can be captured in soils by using biochar to increase soil quality and promote plant growth. Carbon dioxide reacts with calcium and magnesium and as a result the durability of concrete can be improved.

Current Status of CCUS

According to a report from the Global CCS Institute[10], there were 135 commercial CCUS facilities at the end of 2021. Of these, 27 are in operation, two are suspended, while others are under construction or in early development (see Figure 5.6). Most projects are located in the US and in European countries.

[10] Global CCS Institute (2021) Global Status of CCS 2021. https://www.globalccsinstitute.com/wp-content/uploads/2021/10/2021-Global-Status-of-CCS-Report_Global_CCS_Institute.pdf

Figure 5.6: Global CCUS facilities till the end of 2021

Source: GCCSI, 2021

The range in the scale of facilities is becoming broader and the projects are becoming more diverse. Of those that are still at an early stage of development, most projects were in the fields of natural gas processing and chemical production. For now, the projects have been implemented in power generation, iron and steel production, cement production and DACCS.[11]

Example CCUS projects

The Boundary Dam CCUS project in Canada is the world's first megaton post-combustion CCS project for a coal power plant. This CCS retrofit was constructed on Unit 3 of the power plant. The unit started operations in 1968 and was scheduled for closure in 2013 after 45 years of service. The CCS was intended to extend the life of the unit by a further 30 years, avoiding the cost of decommissioning it and constructing a new unit. Cansolv's flue gas desulphurisation (FGD) system, operated by Shell Energy, was integrated in the project which is capable of limiting both sulphur dioxide (SO_2) and CO_2 emissions.

The Petra Nova project in the USA is the world's biggest CCS for flue gas from coal power plants. This project is designed to capture approximately 90% of CO_2 from flue gas and use and sequester approximately 1.4 Mt annually. The captured CO_2 will be compressed and transported through an 80 miles pipeline to an operating oil field where it will be used for enhanced oil recovery (EOR) and ultimately sequestered. The project costs are estimated at USD 55-60 per ton of $CO_{2\ captured}$. Unfortunately, this project was suspended in May 2020 due to the impact of the Covid-19 pandemic and low oil prices (USD 50 per barrel at the end of 2020). Experts said the project only makes economic sense with an oil price of between USD 75 and USD 100 per barrel.

Construction on the Port Arthur project in the USA began in 2011. At that time, most CCS facilities in the world utilised amine absorption technology. Vacuum-swing adsorption (VSA) gas separation technology had not previously been used on a large scale for CO_2 separation and purification. This project is the world's first commercial-scale, steam methane reformer (SMR) hydrogen production facility incorporating vacuum-swing adsorption (VSA). It is a remarkable achievement and a leading example of an alternative technology.

The Illinois project in the USA is the world's first megaton demonstration BECCS project. It is designed to collect CO_2 from an ethanol production plant, making it a by-product from

[11] Ibid.

processing corn into fuel-grade ethanol through biological fermentation. The CO_2 is stored in a deep underground sandstone reservoir.

The Climeworks project in Iceland is the world's largest direct air capture (DAC) and CO_2 storage plant. It has the capacity to remove 4 000 tons of CO_2 from the air each year. The CO_2 is mixed with water and pumped deep underground. It is subsequently trapped in stone by means of a natural mineralisation process that takes under two years.

5.1.1. CCUS in China

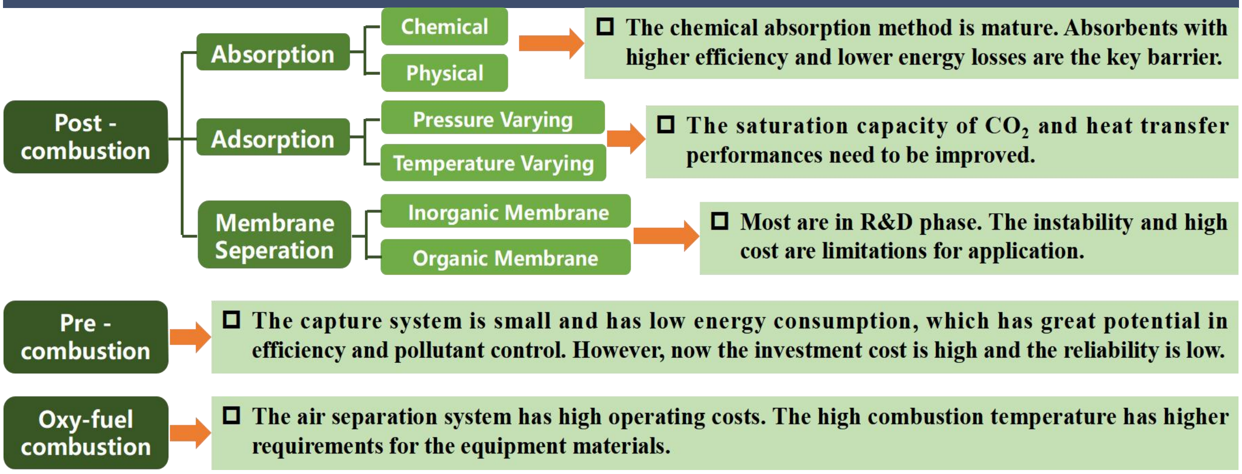
CCUS technologies in China

China has developed a variety of carbon capture technologies (see Figure 5.7). Its pre-combustion technology is already in the commercial application stage. Its post-combustion (chemical adsorption) method is in the pilot stage. Most other technologies are in the industrial demonstration stage.

The post-combustion method

In general, post-combustion carbon capture technology is at the pilot stage in China. It can be further categorised into three sub-types: absorption, adsorption, and membrane separation. Of the three, the chemical absorption method is a mature technology. Absorbents with higher efficiency and lower energy losses are the key barrier. For adsorption, the saturation capacity of CO_2 and heat transfer performance need to be improved. Most projects involving membrane separation are in the R & D phase. Price instability and high costs are the key limitations on application of this technology.

Figure 5.7: Carbon capture technology in China



The pre-combustion method

For pre-combustion, the capture system is small and has low energy consumption, offering great potential for efficiency and pollutant control. However, the investment costs are currently high, and the technology does not offer reliable outcomes.

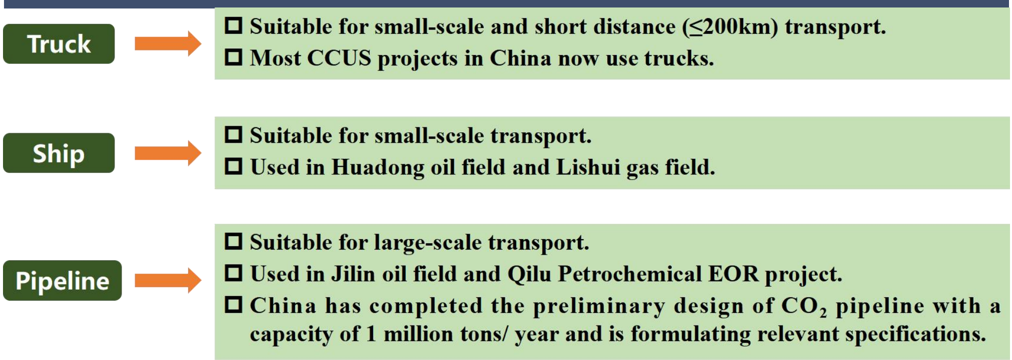
Oxy-fuel combustion

When it comes to oxy-fuel combustion, there are high costs associated with air separation systems. The high combustion temperature poses higher requirements on the materials that need to be deployed.

CO_2 transport

For CO_2 transport, truck and offshore pipeline transportation have achieved industrial or commercial maturity (see Figure 5.8).

Figure 5.8: CO_2 transport technology in China

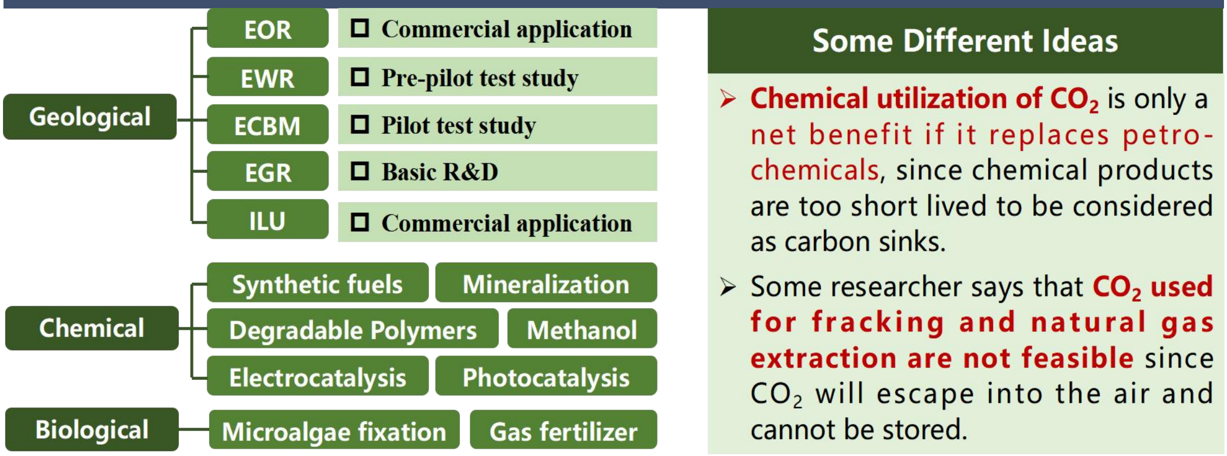


Trucks are suitable for small-scale and short distance (≤200km) transport. Most CCUS projects in China now use trucks. Ships are also suitable for small-scale transport, and these are used in Huadong oil field and Lishui gas field. Pipelines are suitable for large-scale transport, and have been built in Jilin oil field and Qilu Petrochemical EOR project.

Carbon Utilisation

Carbon utilisation includes geological, chemical and biological utilisation (see Figure 5.9). For geological utilisation, enhanced oil recovery and in-situ leaching of uranium have reached the phase of commercial application. The enhanced gas, coal-bed methane and water recovery are mainly in the R&D phase or pilot project.

Figure 5.9: CO_2 utilisation technology in China

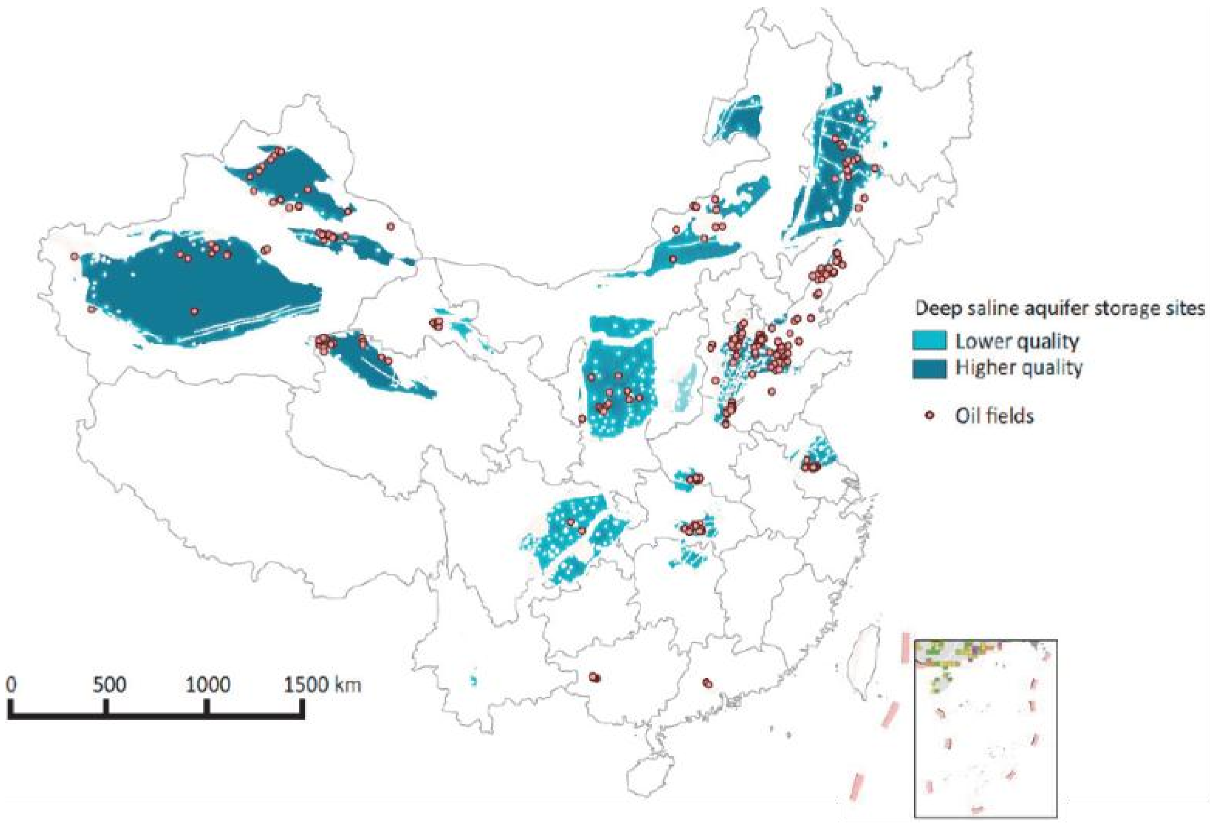


For chemical utilisation, CO_2 can be synthesised into fuels or polymers, or used in the production of concrete to increase its strength and durability. However, there are some different ideas concerning CO_2 utilisation. Since chemical products are too short-lived to be considered as carbon sinks, chemical utilisation of CO_2 is only a net benefit if it replaces petrochemicals. Biological utilisation of carbon can be applied in microalgae fixation. We should note that it is not sustainable to use CO_2 for fracking and natural gas extraction because the CO_2 will escape into the air and cannot be stored.

CO_2 storage potential

The total estimated potential for CO_2 storage in China is between 1.21 and 4.13 trillion tons (see Figure 5.10. China's oil fields are mainly distributed in Songliao Basin, Bohai Bay Basin, Ordos Basin and Junggar Basin. Its gas fields are mainly situated in Ordos Basin, Sichuan Basin, Bohai Bay Basin and Tarim Basin.

Figure 5.10: Map of CO_2 storage potential in China



Source: OECD, IEA, Ready for CCS retrofit: the potential for equipping China's existing coal fleet with carbon capture and storage.

Table 5.2 shows the estimated costs of CCUS in China.

Table 5.2: Cost of CCUS Technologies in 2025-2060 (Unit: RMB/t, including fixed costs and operational costs)

Year		2025	2030	2035	2040	2050	2060
Capture	Pre-combustion	100-180	90-130	70-80	50-70	30-50	20-40
	Post-combustion	230-310	190-280	160-220	100-180	80-150	70-120
	Oxy-fuel combustion	300-480	160-390	130-320	110-230	90-150	80-130
Transport (RMB/t·km)	Truck	0.9-1.4	0.8-1.3	0.7-1.2	0.6-1.1	0.5-1.1	0.5-1
	Pipeline	0.8	0.7	0.6	0.5	0.45	0.4
Storage		50-60	40-50	35-40	30-35	25-30	20-25

China’s CCUS demonstration projects

China's CCUS demonstration projects are small-scale and expensive. The cost of CCUS consists mainly of economic and environmental costs. Economic costs include fixed and operating costs. Environmental costs include environmental risks and energy consumption.

There are about 40 CCUS projects that are in operation or under construction in China. Their combined capture capacity is around 3 million tons/year, and they offer a cumulative storage capacity of 2 million tons. China’s existing CCUS pilot demonstration projects focus on demonstrating carbon capture technology and EOR technology. Large-scale, full-chain projects are rare. China has the design capability for a large-scale, full-process system and is actively preparing for full-chain CCUS industrial clusters.

The history of CCUS in China’s power industry began in 2008 (see Table 5.3). By the end of 2020, 11 projects with a total capacity of 600 000 t CO_2 yr^{-1} had been constructed. Most of these are post-combustion projects and they are applied in sectors that vary from industry to food.

Table 5.3: CCUS Projects in China’s Power Industry

No.	Project	Type	Transport	S&U	Year	Capacity (10kt/year)
1	Gaobeidian power plant	PC	/	/	2008	0.3
2	Shidongkou power plant	PC	/	Industry & food	2009	12
3	Shuanghui power plant	PC	/	Welding shielding & gas change	2010	1
4	Shengli oil field power plant	PC	Tank truck	EOR	2010	4
5	Lianyungang power plant	Pre-combustion	Pipeline	Basalt rock	2011	3
6	Beitang power plant	PC	Tank truck	Food	2012	2
7	Changchun power plant	PC	/	/	2014	0.1
8	Hubei power plant	Oxy-fuel combustion	Tank truck	Industry	2014	10
9	Tianjin IGCC power plant	Pre-combustion	Tank truck	Designed for EOR	2015	10
10	Haifeng power plant	PC	/	Industry & food	2019	2
11	Jinjie power plant	PC	/	Basalt rock	2020	15

The first CCS project in a Chinese power plant was constructed in 2007 and began operations before the 2008 Beijing Olympic Games (see Figure 5.11). The project is designed to capture 3 000 ton CO_2 per year, a relatively low capacity compared with projects in the USA and Canada, making the overall investment relatively lower (only CNY

24 million). The captured CO_2 is refined for food processing, such as manufacture of carbonated drinks, or of antiseptics and disinfectants. The cost of producing solidified CO_2 is about CNY 600 per ton, while the market price can be as high as CNY 1000 per ton. The project ought to have delivered a healthy profit, but the power plant did not have the necessary food licensing, which resulted in lower product sale prices of CO_2 (about half the anticipated price).

Figure 5.11: First CCUS project at a power plant in China with CO_2 utilisation

The Jinjie CCUS project is a post-combustion carbon capture facility that started commissioning in early 2021 and completed its test run in June 2021. The facility has the capacity to capture 150 000 tons of CO_2 per year. After construction of this facility, the cost of power generation is estimated to increase by 61%.

The Sinopec Qilu-Shengli CCUS project in Shandong province is China’s first megaton CO_2-EOR project. The project will capture CO_2 from the Qilu fertiliser plant and inject CO_2 into Shengli oilfield for EOR and storage. It came into operation in January 2022.

Challenges for CCUS in China

China faces several challenges when it comes to implementation of CCUS. These are summarised in Figure 5.12.

Figure 5.12: Major Obstacles of CCUS in China

1. Mismatching of Source and Sink

- The largest issue is where does the captured CO_2 go. The local need for CO_2 is much smaller than the amount produced.
- Costs are high. Investers have low motivation.

2. Concerns on Environmental Risks

- Fast leakage is easy to detect while slow leakage could only be discorvered through researches on local crops, animals and water.
- The safety period for CO_2 storage is no less than 20 years.

3. Lack of Financial Support

- China encourages the development of CCUS, but mainly through guidance documents, and does not have dedicated fiscal or taxation support for the development of CCUS.

4. Lack of Regulatory Framework

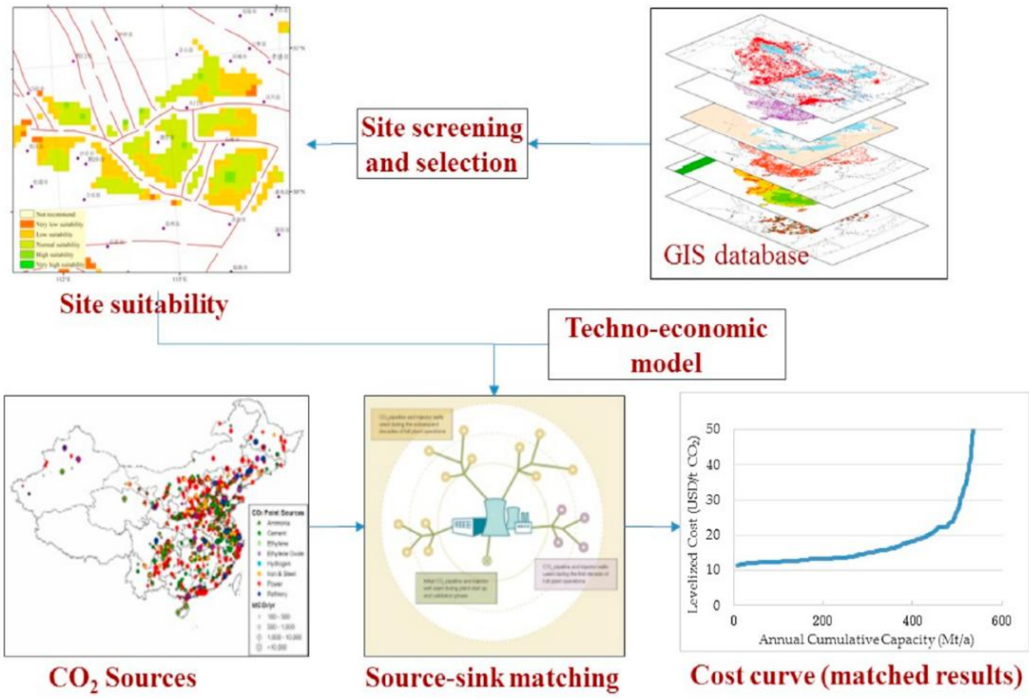
- Laws and regulations on site selection, construction, operation, and geological utilization of demonstration projects, as well as environmental risk assessment and monitoring after the closure of storage sites.

The most pressing issue is what to do with the captured CO_2. The local need for CO_2 is much lower than the amount produced. Secondly, there are environmental concerns. There is a risk of leakage associated with underground CO_2 storage. Rapid leakage is easy to detect while slow leakage can only be detected through detailed monitoring of local crops, animals, and water. In the US, the safety period for CO_2 storage is no less than 20 years. However, in China, not enough research has been carried out concerning CO_2 storage monitoring, reporting and verification. Thirdly, China encourages the development of CCUS, but mainly through guidance documents, and does not have dedicated fiscal or taxation support for the development of CCUS. Fourthly, there is a lack of regulatory framework. That means there are not enough laws and regulations governing site selection, construction, operation, and geological utilisation of demonstration projects, as well as environmental risk assessment and monitoring after the closure of storage sites.

The economy of CCUS projects

Research results concerning CCUS in China are available. Firstly, the evaluation framework for the whole CCUS project is shown in Figure 5.13. The framework includes CO_2 emission evaluation, site suitability evaluation, source sink matching evaluation including techno-economic modelling, and the cost curve of potential integrated CCUS projects.

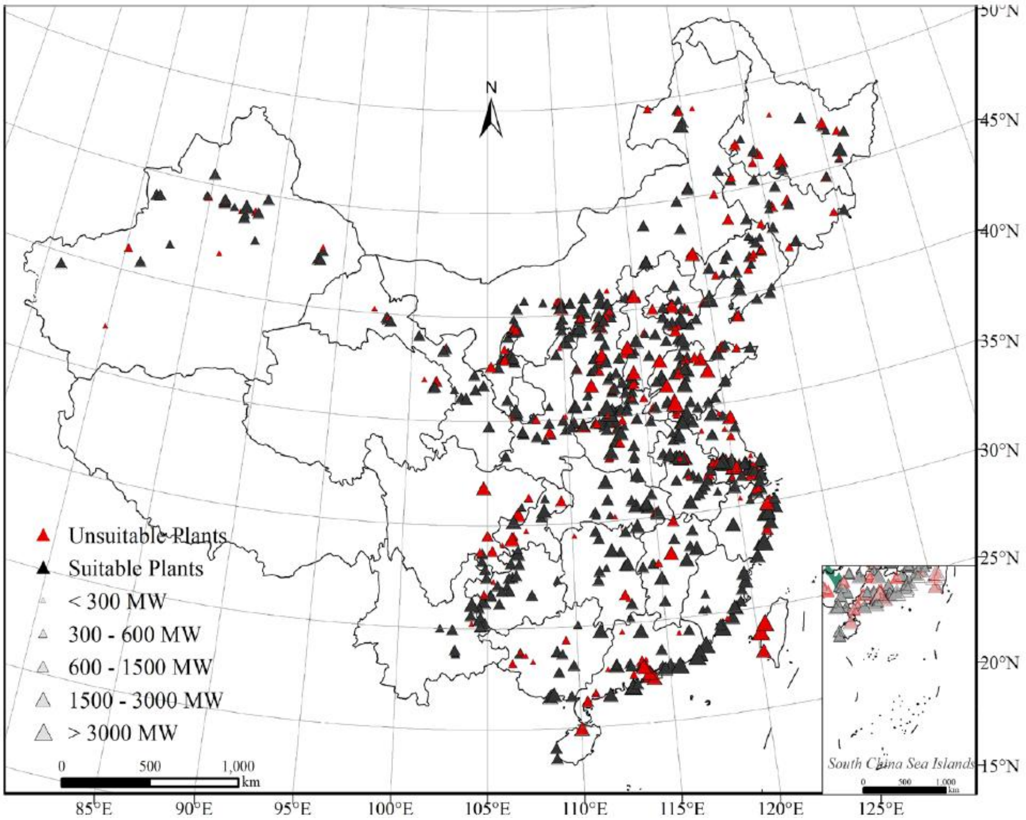
Figure 5.13: Evaluation framework for cost curve analysis



Source: CAS

The analysis of site suitability is mainly based on the geographic information system (GIS) database. It includes parameters that represent whether a site can store CO_2 and its potential capacity. Suitable sites are identified by means of screening and selection. On the source side, a techno-economic analysis is conducted on power plants or chemical plants to arrive at a carbon capture cost. Subsequent source-sink matching then yields the cost curve.

Figure 5.14: Distribution of coal power plants with suitability results

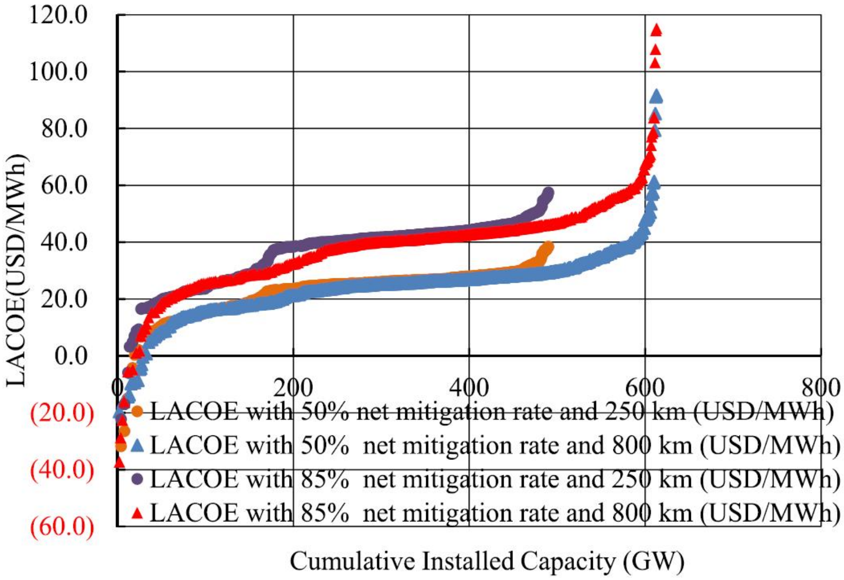


Source: CAS

The suitability criteria for coal power plants include proximity to CO_2 storage site (≤ 800km), unit age (≤ 40 years) and unit size (≥ 600 MW, or the total amount of capturable CO_2 ≥ 10 Mt/year and annual operating hours ≥ 4000) (see Figure 5.14).

After screening, at least 613 GW or 508 plants (73% of total installed capacity or 63% of total number of coal plants) appear suitable for CCUS retrofits. Total CO_2 emissions are about 2.2 Gt/year. Almost all selected coal power plants with one or more generating units of more than 600 MW capacity were built between 2005 and 2015. These plants still have several decades of expected operational life. Most coal plants in China are relatively new, having been built within the last two or three decades, and already have strict standards for control of SOx, NOx, and other emissions. These plants require fewer upgrades and hence less capital investment compared with plants lacking modern environmental controls, and this puts coal plants in China at an advantage compared with many other countries.

Figure 5.15: The cost curve for retrofitting coal power plants with CCUS. (LACOE is the Levelised Additional Cost of Electricity caused by CCUS (USD/MWh)



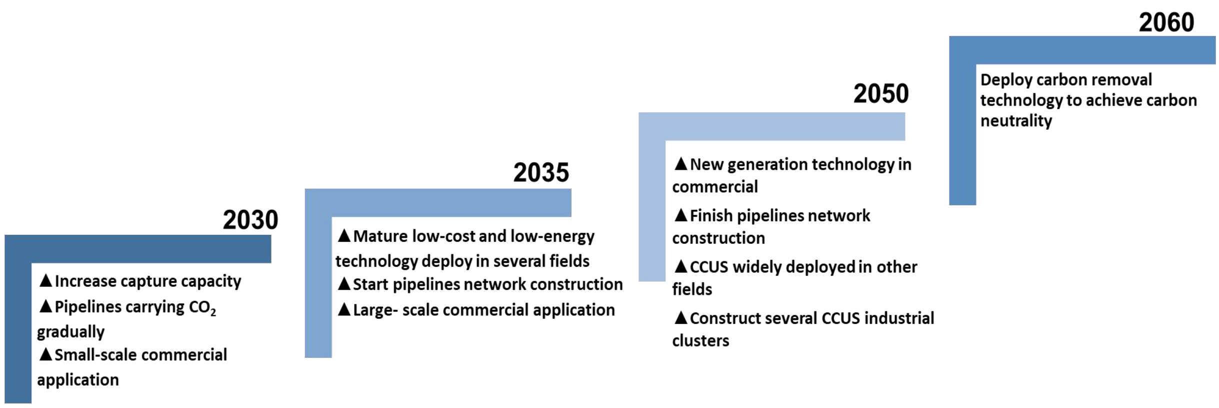
Source: CAS

As for the cost, retrofitting CCUS to the existing coal fleet would increase the Levelised Cost of Electricity (LCOE) by an average of USD 24 to USD 37/MWh for the entire fleet with between 50% and 85% net mitigation rates (see Figure 5.15).

Outlook and recommendations for CCUS in China

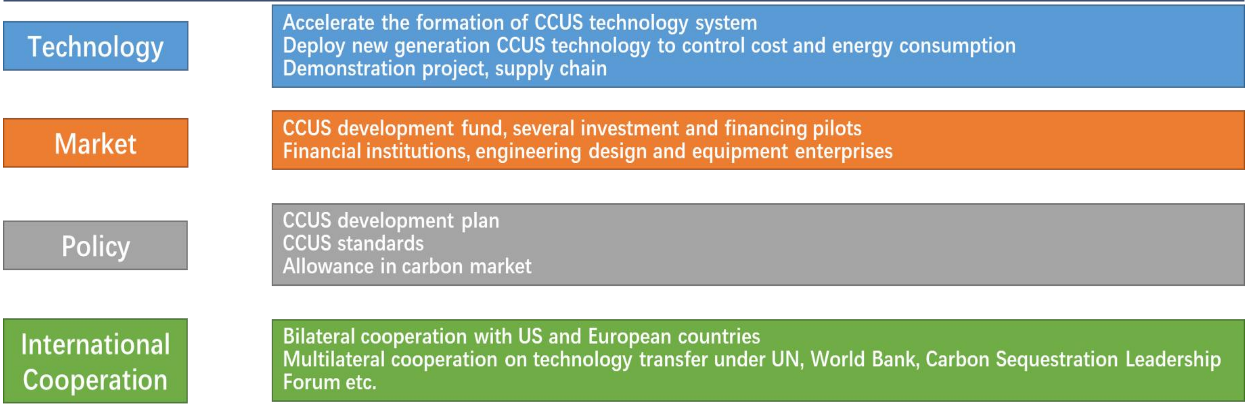
CCUS has attracted more attention following the announcement of China's carbon dioxide peaking and carbon neutrality targets. In future, more effort needs to be put into building a low-cost, efficient, safe and reliable CCUS technology system as well as industrial clusters to provide technology for the low-carbon utilisation of fossil energy and the implementation of carbon neutrality, energy security and sustainable economic and social development (see Figure 5.16). It is estimated that CCUS will reach large-scale commercial application in China around 2040 and will support carbon neutrality before 2060.

Figure 5.16: Vision and goal for CCUS development



In the short-term, several steps need to be taken to promote the development of CCUS, such as to coordinate design, to accelerate the construction of technology systems, to explore market incentive mechanisms, and to strengthen international cooperation (see Figure 5.17).

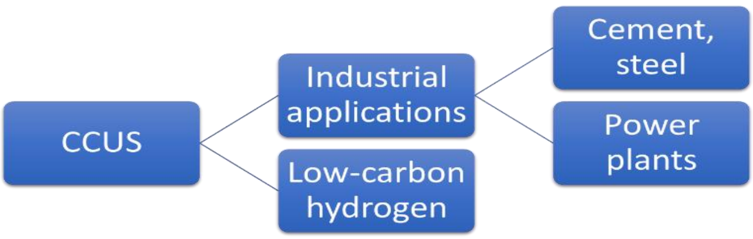
Figure 5.17: Short-term CCUS development tasks



5.1.2. CCUS in the EU

The European Commission frames the potential of CCS/CCUS in industries such as cement, steel and in power for the production of low-carbon hydrogen, as well as in combination with biogenic CO_2 sources for the generation of negative emissions[12] (see Figure 5.18).

Figure 5.18: Potential of CCS/CCUS applications



EU regulatory framework for CCUS

At the CCUS Forum in Norway on 27 October 2022, the EU Commissioner for Energy, Kadri Simson, summarised the EU Commission's view on CCUS in her opening remarks, and stressed that '(…) CCUS has incredible potential in our race to reach climate neutrality. And without CCS and CCU, it will be practically impossible to limit the global warming to the 1.5 degrees Celsius objective.'[13] Whilst the EU CCUS strategy is not due to be published until 2023, there is already a regulatory framework in place, as shown in Table 5.4.

[12] European Commission: Carbon capture, storage and utilisation. https://energy.ec.europa.eu/topics/oil-gas-and-coal/carbon-capture-storage-and-utilisation_en

[13] European Commission (27/10/2022): Speech by Commissioner Simson at the Carbon Capture, Use and Storage Forum. https://ec.europa.eu/commission/presscorner/detail/en/SPEECH_22_6424

The EU Green Deal and Climate Law set out the EU's decarbonisation targets and thus form the foundation for CCUS as a decarbonisation technology. Directive 2009/31/EC is specifically significant for CCS/CCUS, providing the legal framework for the safe transport and geological storage of CO_2. Directive (EU) 2018/2001 regulates promotion of the use of energy from renewable sources. Among other initiatives, renewable fuels of non-biological origin are promoted, such as fuels produced from captured CO_2.

Table 5.4: EU CCUS framework

EU Green Deal, the **Climate Law**	EU energy and climate targets → decarbonisation efforts
Directive 2009/31/EC	regulatory framework for safe transport and (geological) storage of CO_2
Directive (EU) 2018/2001	promotion of renewable sources, which promotes renewable fuels of non-biological origin, and among others, **fuels produced from captured CO_2**
Communication on Sustainable Carbon Cycles (2021/EC)	lists key actions to support industrial CCUS, including the assessment of cross-border CO_2 infrastructure deployment needs at EU, regional and national level until 2030 and beyond; proposal for certification of carbon removals.
5th list of Projects of Common Interest (2021/EC) *[key priority projects]*	list includes six CO_2 trans-European infrastructure projects focusing on the development of CO_2 hubs.
EU-wide voluntary framework to certify carbon removals (30 November 2022)	Support of industrial carbon removal technologies, such as bioenergy with carbon capture and storage (BECCS) or direct air carbon capture and storage (DACCS)

The Communication on Sustainable Carbon Cycles, published by the EU Commission in December 2021, aims to create sustainable and climate-resilient carbon cycles, e.g., by supporting the industrial capture, use and storage of CO_2. On 30 November 2022, the EU Commission adopted a proposal for an EU-wide voluntary framework for carbon capture certification. This will promote industrial carbon capture technologies such as Bioenergy with Carbon Capture and Storage (BECCS) or Direct Airborne Carbon Capture and Storage (DACCS).

EU funding for CCUS

The scarcity of funds for high upfront R&D costs is a barrier to CCUS implementation. However, there are several funding options in the EU, in particular the Innovation Fund, Horizon Europe and state aid from Member States (see Table).

Table 5.5: EU CCS funding schemes

Name	Funding/size	What is funded?
Innovation Fund https://climate.ec.europa.eu/eu-action/funding-climate-action/innovation-fund/what-innovation-fund_en	Funded through EU ETS: around **EUR 38 billion of support from 2020 to 2030** (at EUR 75 / tCO_2), depending on the carbon price	**cross-cutting projects** on innovative low-carbon solutions; First round (11/2021): 4 of 7 awarded projects, part of CCUS value chain; Second round (07/2022): 7 of 17 projects CCUS;
Horizon Europe https://research-and-innovation.ec.europa.eu/funding/funding-opportunities/funding-programmes-and-open-calls/horizon-europe_en	The EU's key funding programme for research and innovation with a budget of **EUR 95.5 billion (2021-2027)**	research and innovation in developing, supporting and implementing EU policies while tackling global challenges, i.e., **developing new and/or improve existing CO_2 capture technologies**;
State aid https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=uriserv%3AOJ.C_.2022.080.01.0001.01.ENG&toc=OJ%3AC%3A2022%3A080%3ATOC	/ (Denmark: EUR 5 billion; The Netherlands continues to incentivise CCUS. Belgium, Sweden, Croatia and Greece have all included CCS and CCU related investments in their national recovery plans.)	EU Member States can support CCUS through state aid under certain conditions specified in its *Guidelines on State aid for climate, environmental protection and energy 2022.*

Carbon capture transport and storage

Technology data for energy technologies such as CCUS can be found in technology data catalogues, such as those regularly published by the Danish Energy Agency (DEA)[14]. Table 5.6 shows examples of carbon capture technologies from DEA's technology catalogue, including post-combustion, oxy-fuel combustion, and direct air capture.

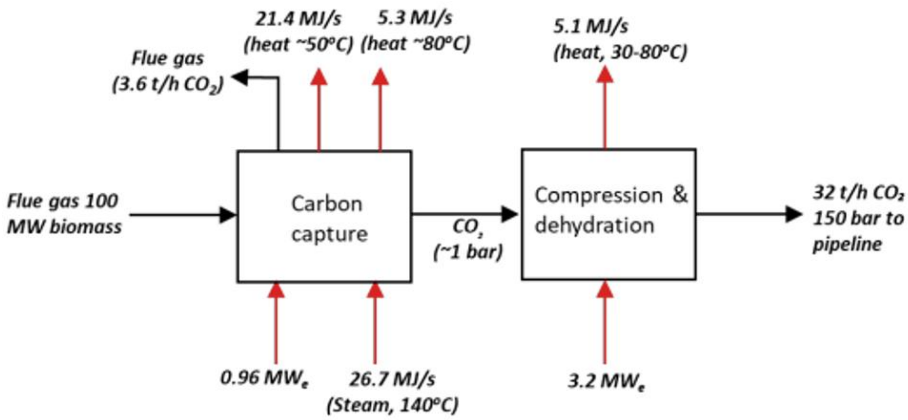
Table 5.6: Danish technology catalogue for carbon capture

CC technology	Plant description	Advantages	Limitations
Post-Combustion (Tsiropoulos I, 2017)	CO_2 is removed from the flue gas through absorption by selective solvents, the most promising as of today is mono ethanolamine (Used at the Boundary dam project)	Can be applied on existing technologies with a flue gas	Energy intensive and costly post separation methodology, requires direct connection to stationary plant
Oxy-fuel combustion (Tsiropoulos I, 2017)	The fuel is burned with oxygen instead of air, producing a flue stream of CO_2 and water vapour without nitrogen. From this stream water is condensed and a stream of CO_2 is obtained. The oxygen required for the combustion is extracted in situ from air.	The flue gas would primarily consist of CO_2 and H_2O, which are easier and cheaper to separate.	Energy intensive and costly oxygen production, requires direct connection to stationary plant
Direct Air Capture (Keith, Holmes, Angelo, & Heidel, 2018)	CO_2 is captured directly from the air through absorption by selective solvents and large air conductors. Pure CO_2 is afterwards released for future processing The most used solvent today is $CaCO_3$.	Does not require a CO_2 heavy flue gas and can therefore be located close to storage or electro fuel production.	Very energy intensive

14 https://ens.dk/en/our-services/projections-and-models/technology-data

In addition, Figure 5.19 illustrates an example of energy and mass balances for a 100 MWth biomass boiler equipped with 90% carbon capture and compression resulting in 32 t/h CO_2, 150 bar to pipeline.

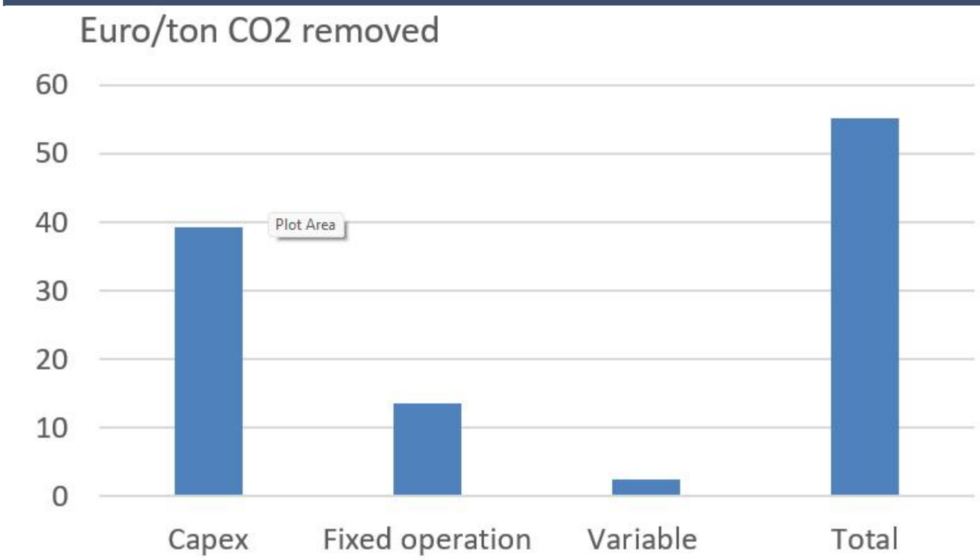
Figure 5.19: Carbon Capture — Energy balance; Post-combustion retrofit; 100 MW (th) biomass boiler



Black arrows: Mass streams. Red arrows: Energy streams.

An example of cost estimates for carbon capture appears in Figure 5.20. The total costs amount to about EUR 50/ton CO_2 (2020 prices). For comparison, the EU ETS quota price for CO_2 is about EUR 75/ton (Nov 2022).

Figure 5.20: Carbon capture cost estimate post combustion retrofit 500 MW(th) biomass boiler



Source: Danish technology catalogue

Carbon transport and storage

Carbon is often most efficiently and economically transported in liquid form. Figure 6.30 shows the type of information provided in the Danish Technology Catalogue regarding carbon transport by pipeline, ship or overland.

The right hand side of Figure 5.21 shows a pressure-temperature phase diagram. The critical point for CO_2 is at 31°C and 74 bar, which represents the highest temperature and pressure where a liquid phase can be present. On the lower temperature end of the phase diagram is the triple point of CO_2, - 56.6°C and 5.2 bar, which represents the lower temperature and pressure where a liquid phase can be present. For transport of CO_2 in liquid state e.g., by tanker truck or ship, it thus follows that the temperature must be in the range of -56 to +31°C and the pressure 5.2 to 74 bar.

In practice some operating margin to the phase change curve will be required, which will reduce the operating window. For CO_2 pipeline transport it is normally not desirable to operate at conditions where phase change may occur (gas-liquid). Therefore, pipelines are often operated above the critical pressure of CO_2 (74 bar) to avoid two phase formation. Another important factor is to achieve high density.

For transport of large volumes (>1 million tonne per annum (MTPA)), only pipeline and ship transport are viable transport options. Road transport is typically only considered for smaller volumes and for short distances when establishing a pipeline is not feasible.

It appears from the left hand side of Figure 5.21 that pipeline transport is economically advantageous for distances of up to 700 km, whereafter ship transport is the favoured option[15]. It also appears that over very short distances the ship option much more costly. CO_2 emissions as a percentage of transported volume are normally negligible (upper part of Figure 5.21).

Figure 5.21: Illustration of carbon transport in the Danish Technology Catalogue

- Carbon transport
  - In pipelines
  - By ship
  - Road/ (rail) transport

	Pipeline	*Ship*	*Truck*
CO_2 emission in % of transported volume	0.05 %*	0.4 %	1.6%

200 km by different transport forms. Only CO_2 related to the energy (fuel and electricity) requirement for operation is considered. *estimated as emission related to electricity consumption for pumping using 135 g CO_2/kWhe.

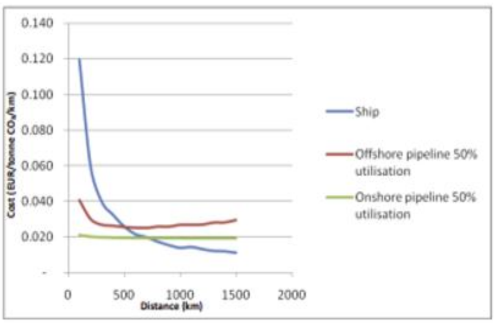
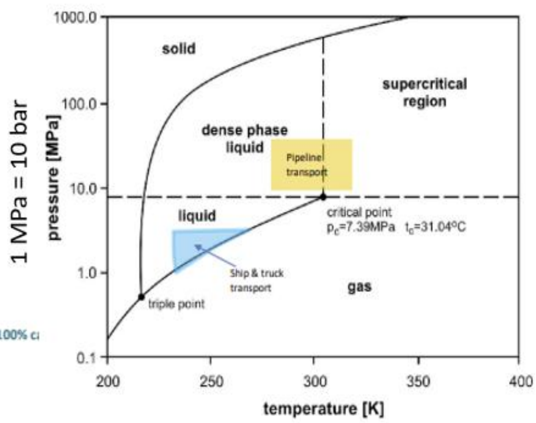


Figure 3. Cost of CO_2 transport (EUR/tonne/km, 2010 cost level) by pipeline at 50% capacity and by ship at 100% capacity (including terminal) for 10 MTPA. Source: ZEP [2]

MTPA= million ton per year

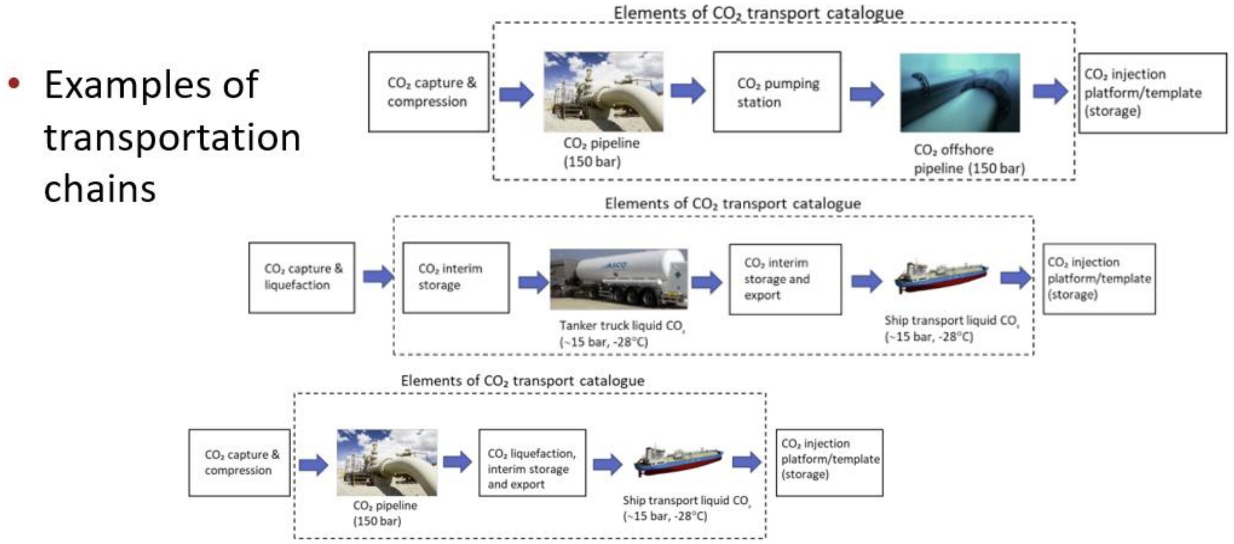


Source: Danish technology catalogue

Figure 5.22 and Figure 5.23 present examples of carbon transport chains from the catalogue. The transport phase is defined as being from capture/ compression until the CO_2 is injected into storage.

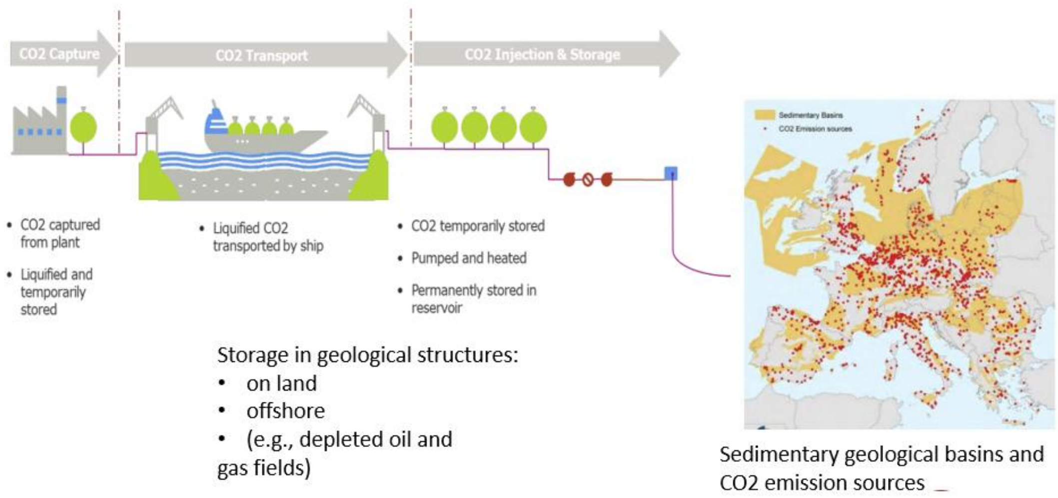
[15] Cost of CO_2 transport (EUR/tonne/km, 2010 prices) by pipeline at 50% capacity and by ship at 100% capacity (including terminal) for 10 MTPA.

Figure 5.22: Examples of carbon transportation chains from the Danish Technology Catalogue



Source: Danish technology catalogue

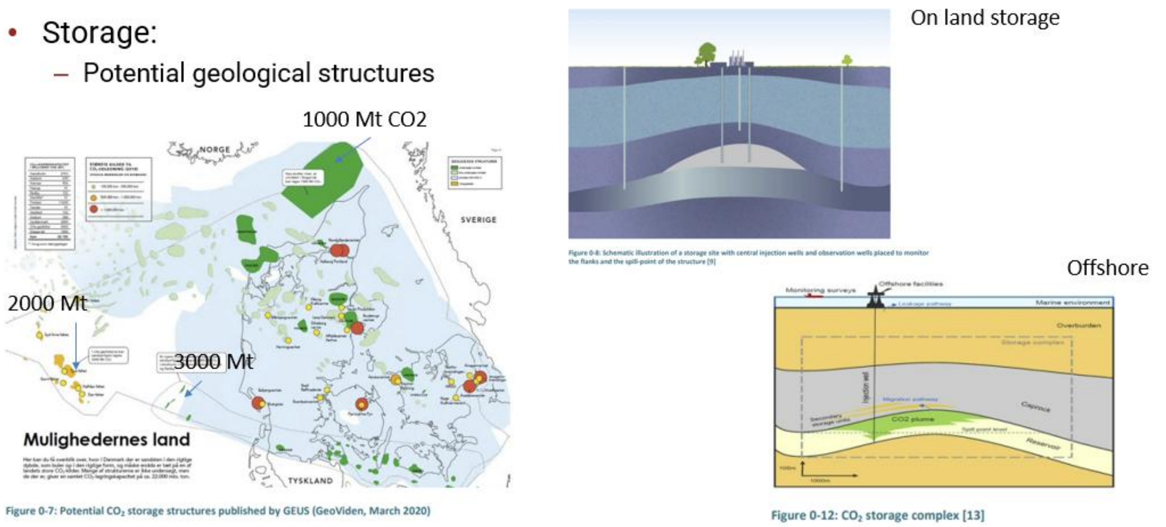
Figure 5.23: Interface of elements of CCS, transport and injection/storage



Source: Danish technology catalogue

The catalogue also includes data on storage. Different storage options are illustrated in Figure 5.24. The Geological Survey of Denmark and Greenland (GEUS) has mapped a number of potential storage structures, and some offshore oil and gas operators have assessed the possibility of using depleted oil and gas fields or offshore aquifers for CO_2 storage. The geology of Denmark is found to be well suited for CO_2 storage with capacities as follows: ~1 000 million tons in the sea north of Denmark, ~2 000 million tons in depleted Danish oil and gas fields in the North Sea and ~3 000 million tons in structures in the southern part of Denmark.

Figure 5.24: Examples of storage options from the Danish Technology Catalogue



Source: Danish technology catalogue

5.2. P2X

Power to X (P2X) refers to a set of technologies that enable the conversion of electrical power into various energy carriers or chemical products. It can be used to convert surplus renewable electricity into various energy carriers such as hydrogen, synthetic fuels, and heat. P2X can provide long-term energy storage, decarbonisation solutions, and integration of renewable energy into existing systems. P2X enables large-scale production of green hydrogen, synthesis of synthetic fuels, and district heating. It enhances sector coupling and contributes to a sustainable energy future. An overview of the main technologies of P2X (China) is given in Figure 5.7. Apart from power-to-cool and power-to-heat, most P2X technologies are based on power-to-hydrogen.

Table 5.7: Main Technologies of P2X

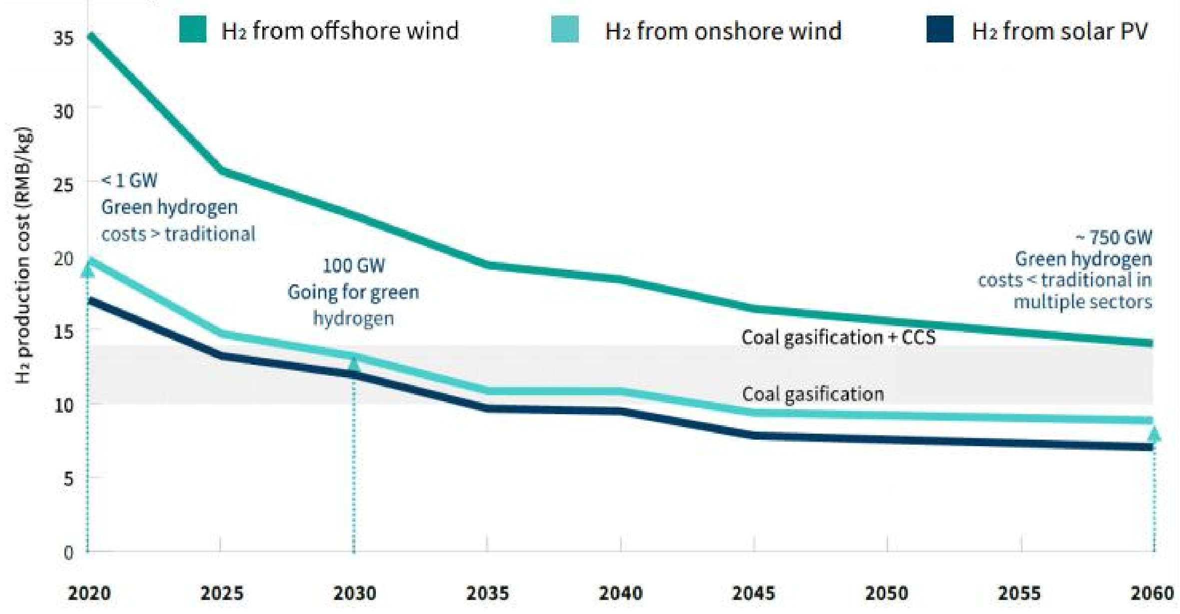
Name	Advantages	Limitation	Technologies	Stage
Power to Cool (P2C)	clean, convinient	-	air conditioners	**commecial application**
Power to Heat (P2H)	clean, safe, convinient	low energy efficiency in a complete cycle, high cost	heat pumps, electric boiler, electric heater	**initial stage of commecial application**
Power to Gas (P2G)	clean, flexible	low energy efficiency in a complete cycle, high cost	electrolysers	**demonstration & initial stage of commercial application**
Power to Liquid (P2L) or Power to Fuels (P2F)	clean	high cost	electrolysers, synthesis	**demonstration**
Power to Chemicals (P2C) or Power to Products (P2P)	clean	high cost	electrolysers, synthesis	**demonstration**
Power to Power (P2P)	long storage time	high cost, low efficiency	fuel cells	**demonstration**

5.2.1. P2X in China

Hydrogen production in China in 2019 was around 33.42 million tons, which is about one-third of the global total (115 million tons). Less than 1% is produced by electrolysis. There are currently 12 green hydrogen projects in operation, 22 projects under construction, and 161 green hydrogen projects in the planning stage, which together could produce 23 100 tons of hydrogen per year.

According to RMI's projections, 7.7 million tons of hydrogen will be produced annually by 2030. The installation capacity of electrolysers will reach 100 GW. By 2060, between 75 and 100 million tons of hydrogen will be produced every year.

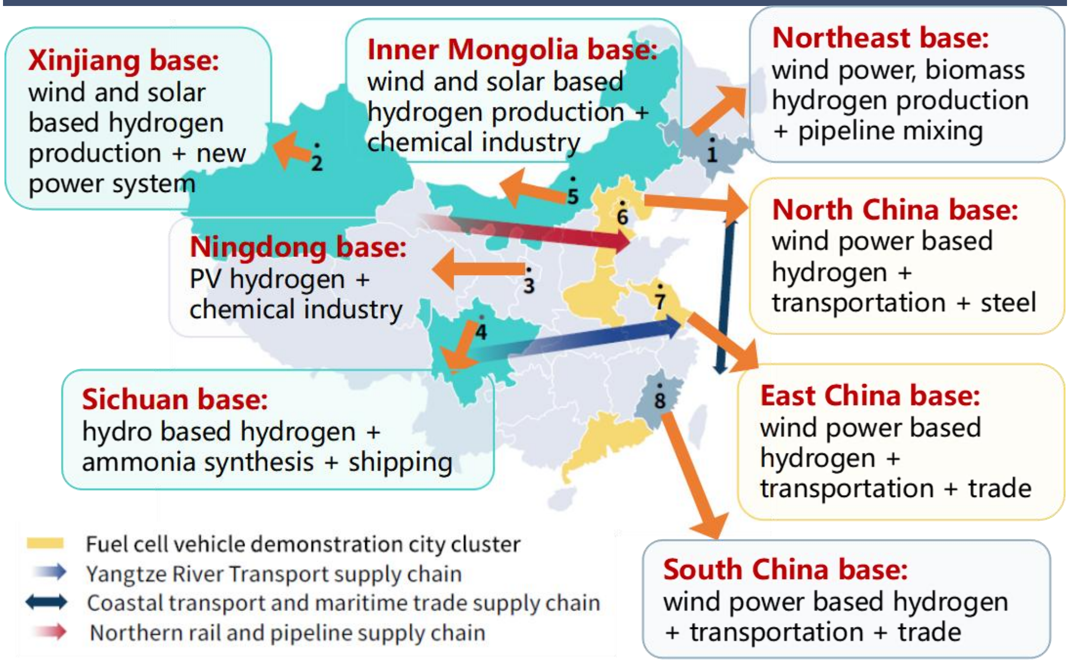
Figure 5.25: Production cost of green hydrogen



Source: RMI

Currently, the cost of hydrogen production from coal and industrial by-products in China is around CNY 10-12/kg, while renewable hydrogen costs between CNY 20-25/kg (see Figure 5.25). To transition from grey and blue hydrogen to renewable hydrogen, it is crucial to enhance the cost competitiveness of renewable hydrogen. To achieve this, the most effective approach is to expand industrial-scale production, particularly by rapidly increasing installed capacity. As the scale of electrolysers reaches 100 GW, the investment cost of alkaline electrolysers in China is projected to drop from CNY 2 000 RMB/kW in 2020 to CNY 1 500/kW in 2030. Additionally, with the ongoing reduction in the cost of renewable power, the average total cost of hydrogen production from renewable sources is expected to decline to about CNT 13/kg, making it competitive with the cost of hydrogen derived from fossil fuels.

Figure 5.26: Blueprin for green hydrogen bases



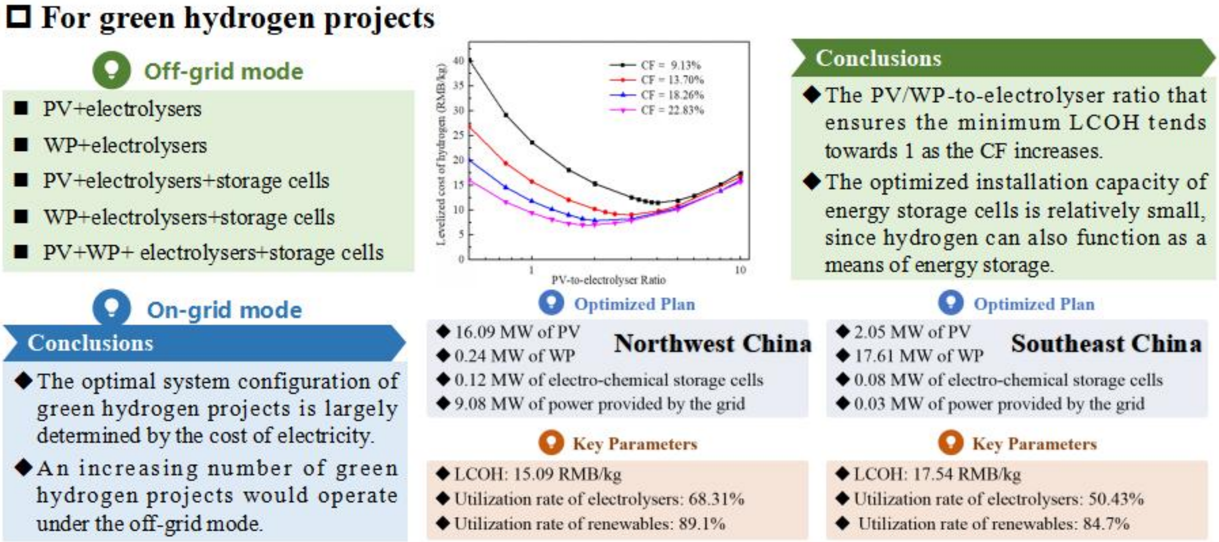
Source: RMI

In northeastern China, hydrogen production from wind and biomass power sources is feasible. The produced hydrogen can be transported via pipeline. In northern China, hydrogen generated from wind power can be utilised in the steel industry or transported to other regions (see Figure 5.26).

The eastern and southern parts of China can produce hydrogen from wind power, which can be transported domestically or traded internationally. In Inner Mongolia Province, hydrogen derived from wind and solar power can be utilised by nearby chemical industries. Xinjiang Province has the potential to produce hydrogen from wind and solar power sources.

The power sector has the potential to integrate with green hydrogen projects to establish a new power system. In Sichuan Province, hydrogen produced from hydroelectric power can be used in ammonia synthesis or transported over long distances to the eastern and southern regions of China. In Ningxia Province's eastern area, hydrogen produced from photovoltaic power can be utilised in the local chemical industry.

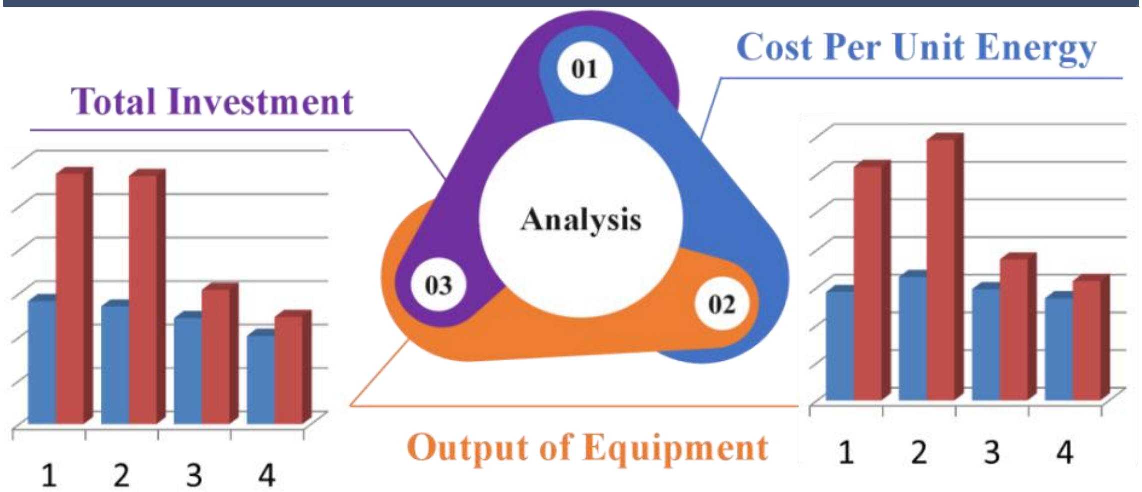
Figure 5.27: Selected research results concerning green hydrogen projects



Green hydrogen projects can be operated either off-grid or on-grid. In the off-grid mode (as shown in Figure 5.27, upper middle section), the levelised cost of hydrogen (LCOH) initially decreases and then increases as the photovoltaic (PV)-to-electrolyser ratio increases. The PV-to-electrolyser ratio that ensures the minimum LCOH decreases with higher capacity factors. Additionally, as the capacity factor increases, the PV/wind power-to-electrolyser ratio tends to converge towards 1. The need for large-scale energy storage systems is relatively reduced since hydrogen can itself serve as a form of energy storage.

In the on-grid mode, the optimal configuration of green hydrogen projects depends significantly on the cost of electricity. If capital expenditure (CAPEX) decreases to a point where the levelised cost of electricity becomes lower than grid electricity prices during off-peak periods, electrolysers would operate in the off-grid mode. Assuming future electricity prices remain similar to current levels, an increasing number of green hydrogen projects would likely choose the off-grid mode (see Figure 5.27).

Figure 5.28: Selected research results concerning power-hydrogen coupling at regional scale



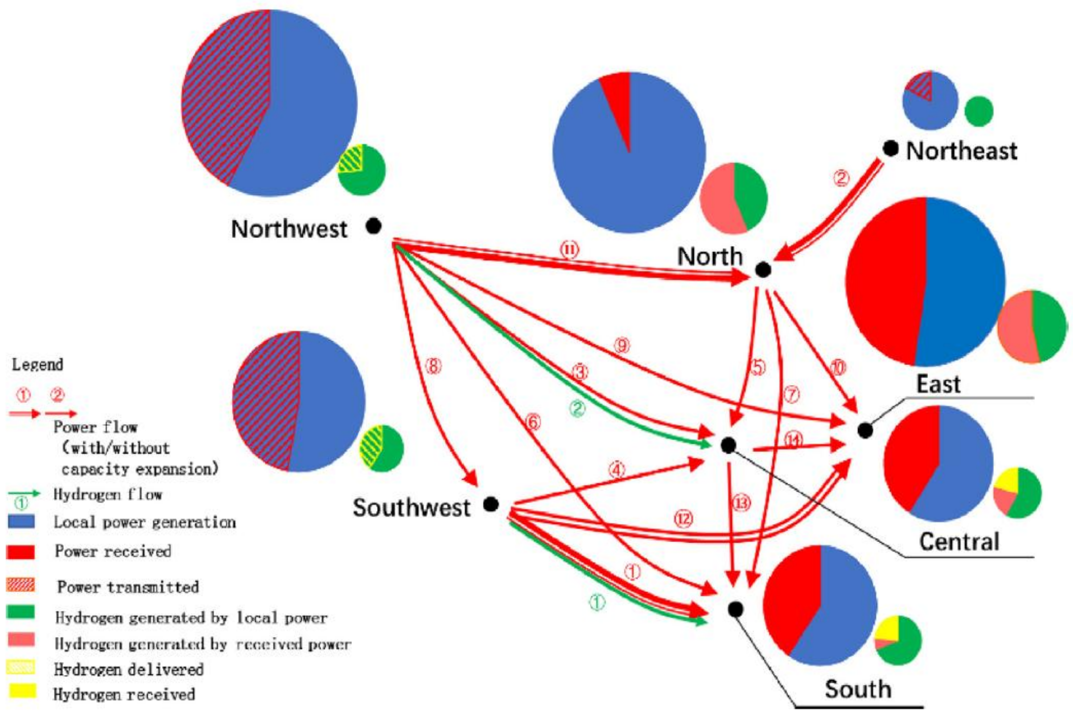
SGERI performed a case study in northwest China, in which four different plans were assessed (see Figure 5.28).

- Plan 1: No power-hydrogen coupling, relying on electro-chemical storage cells for peak modulation.
- Plan 2: Power-hydrogen coupling implemented at the load side.
- Plan 3: Power-hydrogen coupling at the source side, with power transmission through ultra-high-voltage (UHV) lines to the load side.
- Plan 4: Power-hydrogen coupling at the source side, followed by local use of hydrogen or transmission to the load side.

The case study examined two scenarios: one characterised by relatively stable outputs of VRE sources, depicted by the blue columns in Figure 5.28, and another scenario with more volatile outputs, represented by the red columns in Figure 5.28.

An analysis of the four plans revealed that power-hydrogen coupling is advantageous compared to no coupling. Coupling at the source side was identified as a superior approach compared to coupling at the load side. The optimal solution was found to be local utilisation of hydrogen. In scenarios with greater VRE volatility, power-hydrogen coupling demonstrated higher competitiveness, as evidenced by the larger difference between the red columns in plans 1-4.

Figure 5.29: Power transmission and hydrogen transportation scheme



Source: GEIDCO

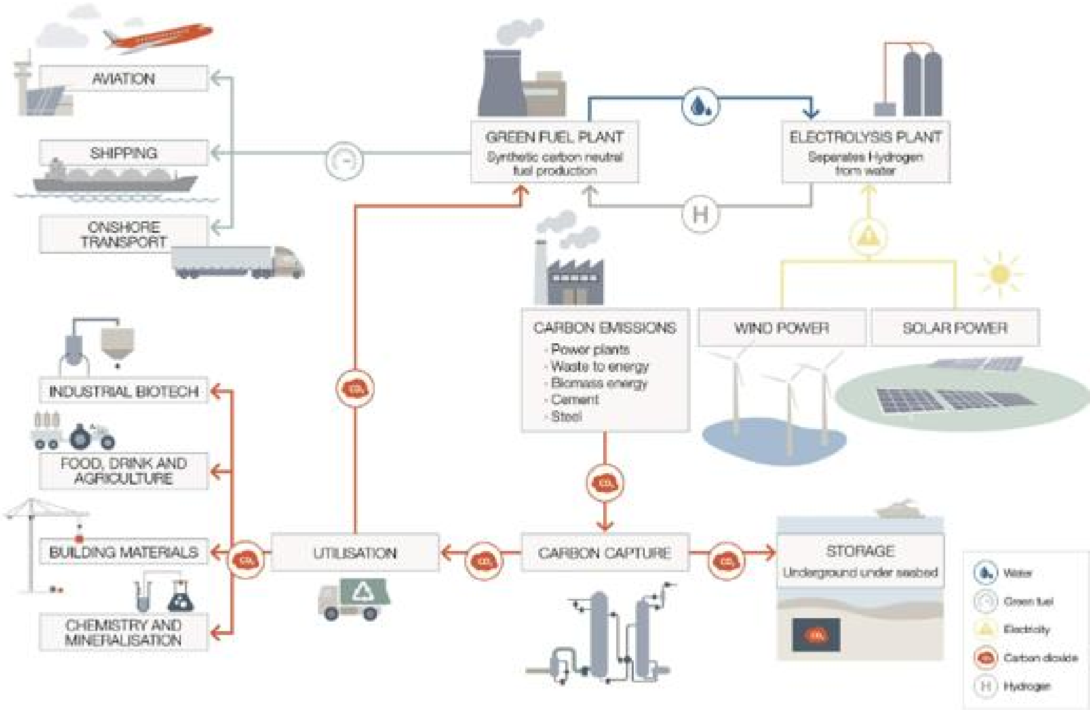
Research findings on the optimisation of power-hydrogen coupling at a national scale indicate a need for two new hydrogen transportation channels. These channels are required to facilitate the transfer of hydrogen from southwest China to southern China and from northwest China to central China, as depicted in Figure 5.29.

5.2.2. P2X in the EU

P2X technologies have emerged as a crucial component of the EU's energy transition strategy, facilitating the integration of renewable energy sources, and enabling the conversion of surplus electricity into storable and transportable forms such as hydrogen or synthetic fuels.

Figure 5.30 presents an overview of production of green hydrogen and green fuels and of carbon capture, utilisation, and storage. Green fuels are used in aviation, shipping, and heavy onshore transport. Carbon is utilised in e.g., industrial biotech, building materials, chemistry and food, drinks and agriculture. Any remaining carbon is stored underground.

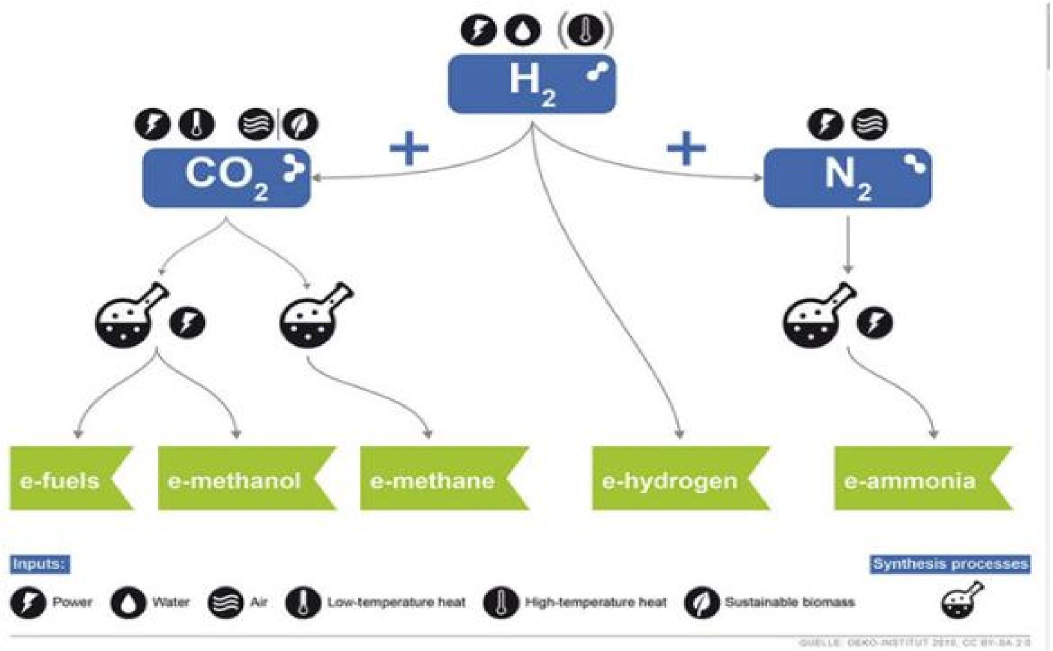
Figure 5.30: CCUS and green fuels – overview



Source: COWI-website

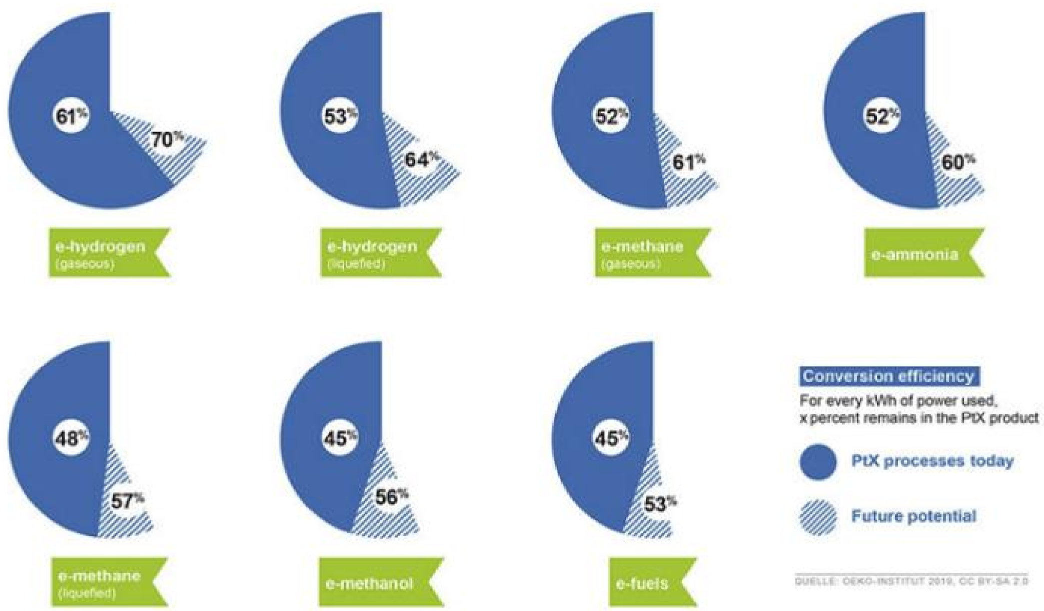
Figure 5.31 and Figure 5.32 illustrate the composition of e-fuels and the conversion losses involved in their production. Conversion losses today amount to between 40% and 55 % with the prospect of improvement to these figures. Still, the conversion losses are likely to remain high, to the order of about 40%.

Figure 5.31: Overview of inputs, processes and P2X products



Source: OEKO Institut (2019)

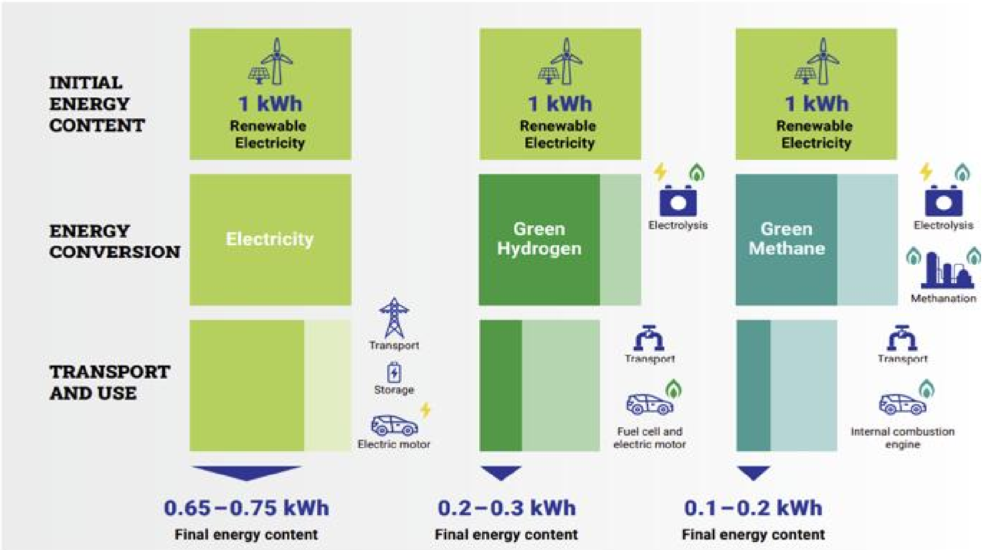
Figure 5.32: P2X - how much power is left from 100 % power input



Source: OEKO Institut (2019)

Figure 5.32 shows the importance of direct electrification whenever it is possible, in this case within the transportation sector. In the case of an electric vehicle, about 70% of the energy can be utilised. This figure reduces to between 10% and 30% for cars fuelled by green hydrogen (fuel cell) and for cars with combustion engines that rely on green methane.

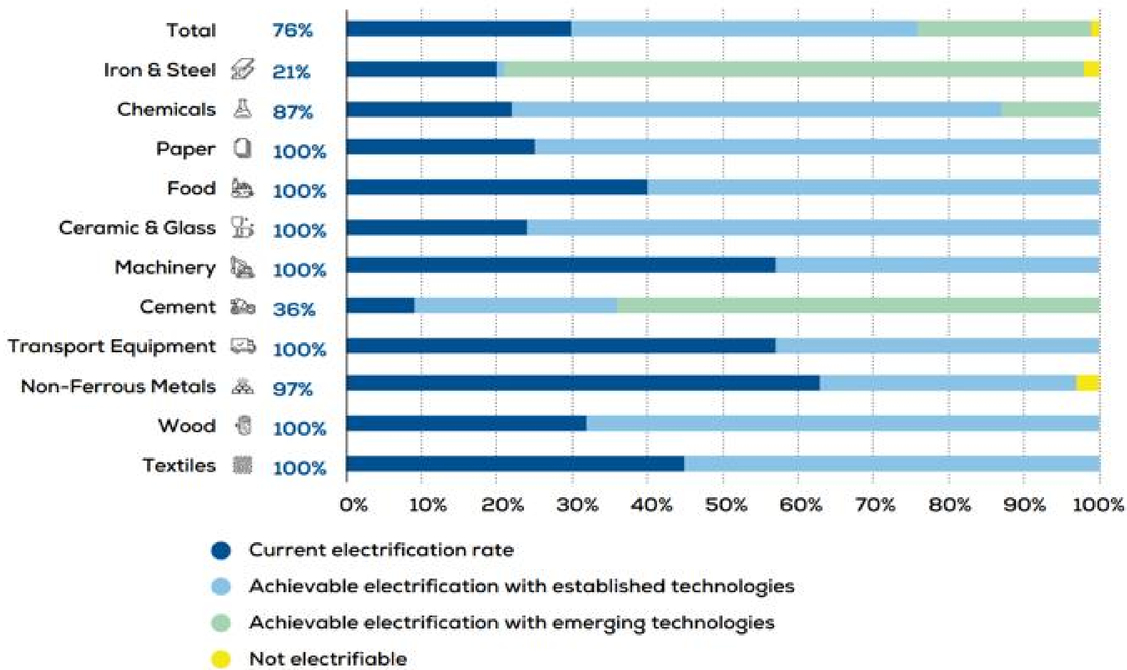
Figure 5.33: Comparison of the efficiency of different types of green fuel in transportation



Source: ENTSO-E Vision, October 2022

Figure 5.34 illustrates the present level of electrification within European industry together with the levels achievable using established and emerging technologies, respectively. The current overall level is about 30%, which could rise to 75% using established technologies. It follows from this illustration that the primary challenges are associated with the iron, steel, and cement industries.

Figure 5.34: Europe: Comparison of different industries' electrification potential (excluding transport)

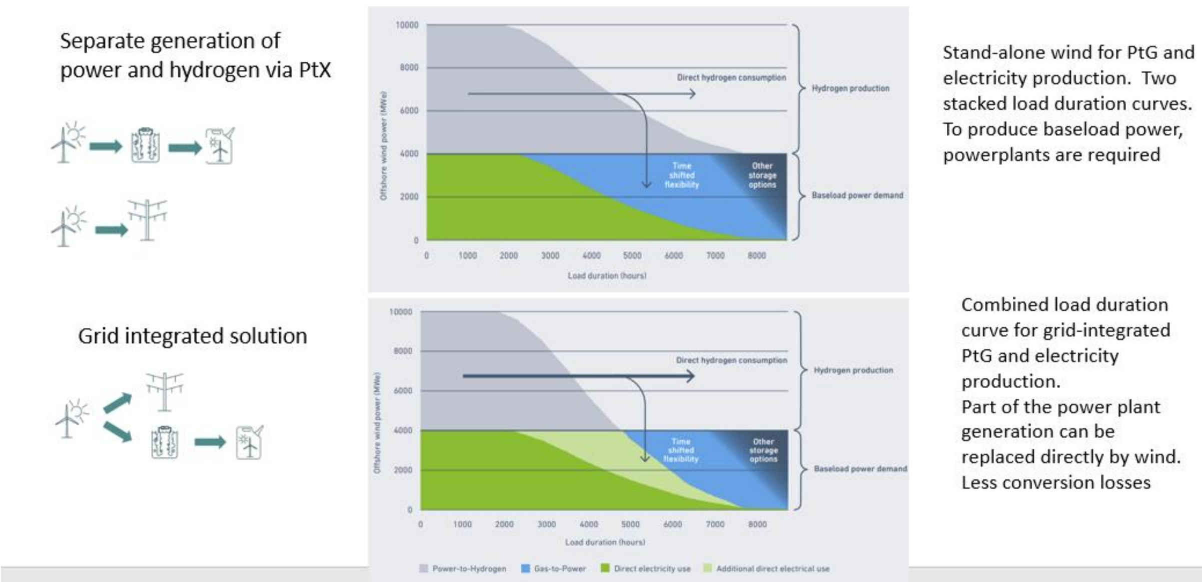


Source: ETIPWind and WindEurope

System integration

Figure 5.35[16] illustrates the importance of system integration of P2X. In the Figure, separate generation of power and hydrogen (stacked load duration curves) is compared with a combined solution (combined load duration curve). To cover the power baseload, a relatively large proportion of the hydrogen must be used as fuel in a power plant in the stand-alone setup. In the combined setup, additional power can be directed to cover the base load without first being converted to hydrogen.

Figure 5.35: Importance of system integration of P2X



The Figure demonstrates that the combined solution will be more efficient because relaxing the constraint of separate generation of power and hydrogen opens the door to more optimal solutions.

P2X processes - CO_2 emissions

Figure 5.36 and Figure 5.37 show examples of P2X: Power to liquid fuels, power to methanol and power to green ammonia NH_3[17]. Green ammonia does not emit CO_2 in its use phase. However, liquid fuels and methanol do emit CO_2. It is therefore important that the CO_2 used to produce green fuels is of a biogenic nature (e.g., CO_2 captured from biomass power plant) or that it can be captured directly from the air (DAC process).

[16] ETIPWind and WindEurope: Getting fit for 55 and set for 2050 – Electrifying Europe with wind energy, 2021. ETIPWind based on Madeddu et al. (2020)

[17] Danish Energy Agency, Technology data: https://ens.dk/en/our-services/projections-and-models/technology-data

Figure 5.36: Power to liquid fuels and power to methanol

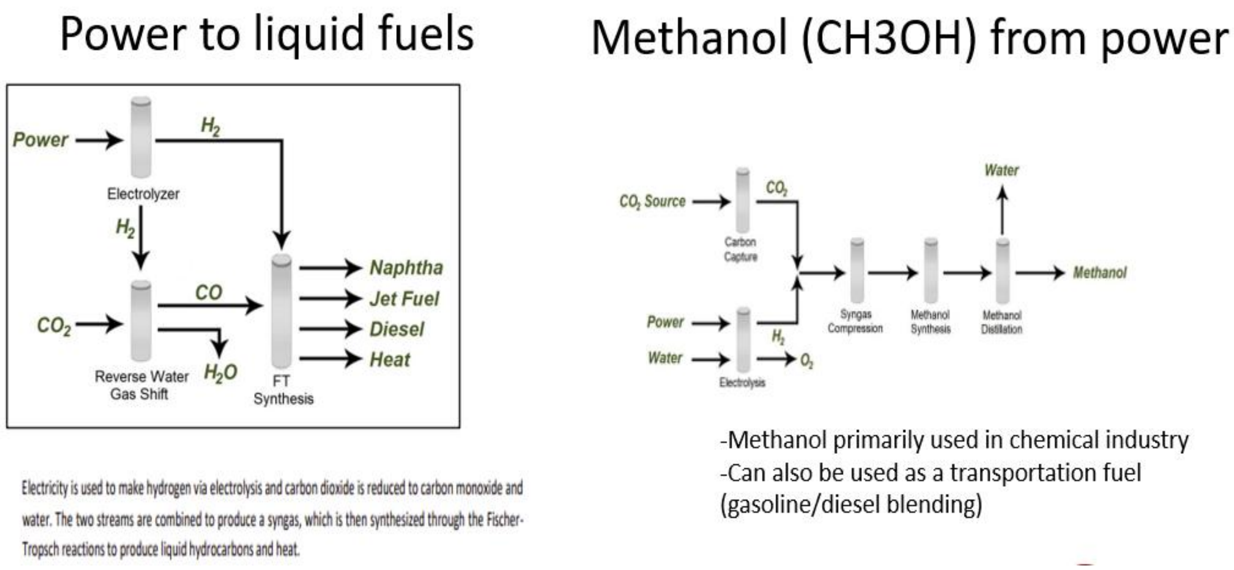
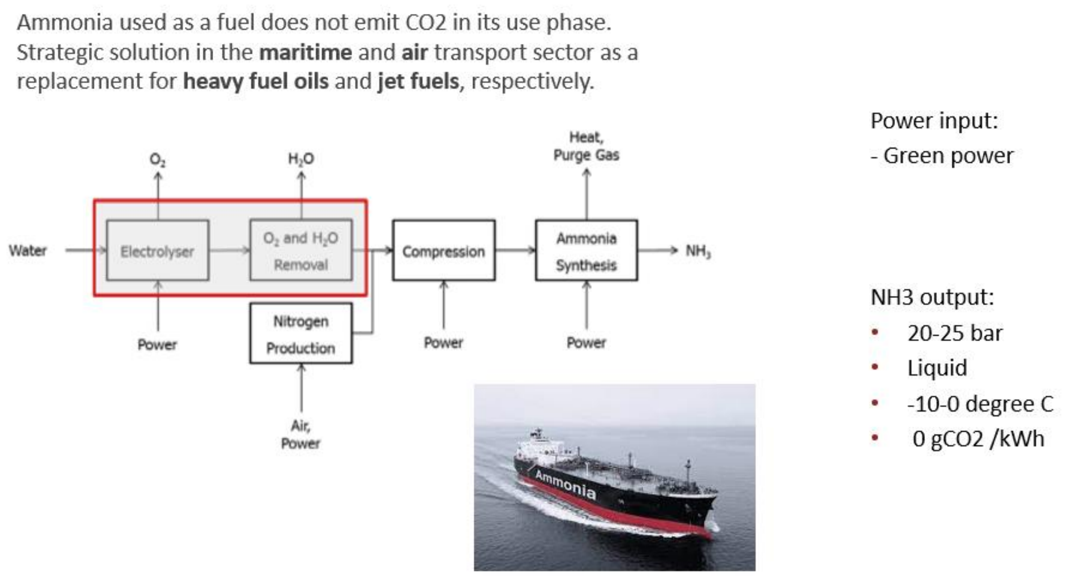
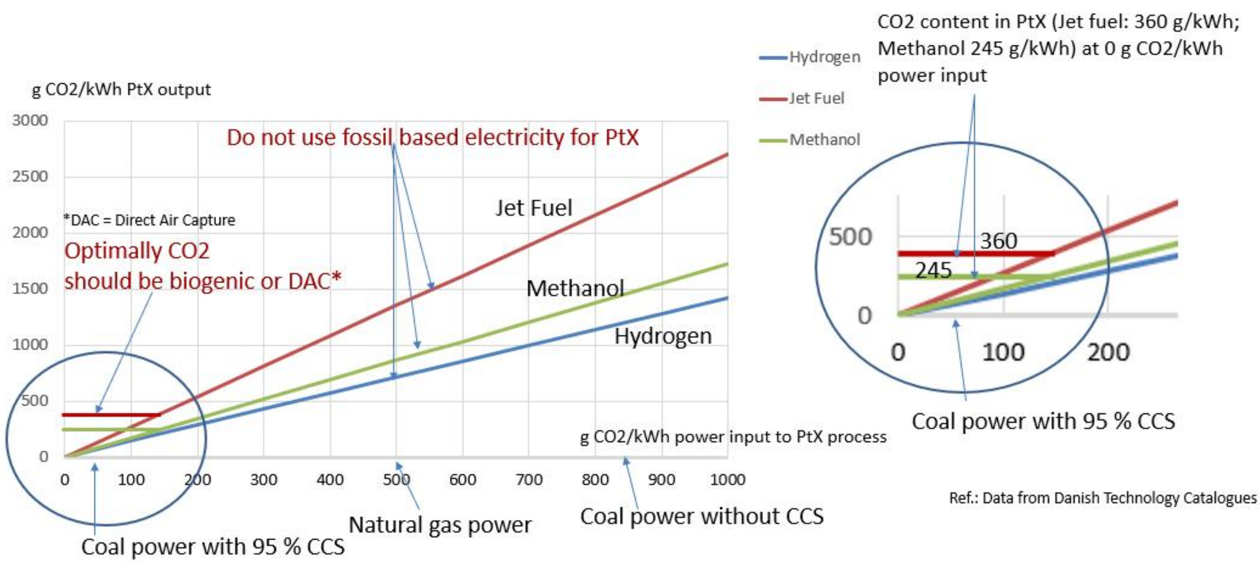


Figure 5.37: Green NH_3 (ammonia) plant: zero CO_2



The CO_2 emissions from P2X products depend heavily on the CO_2 produced from power input to the processes. This is illustrated by Figure 5.38, showing g CO_2/kWh P2X output.

Figure 5.38: CO_2/kWh P2X output as a function of CO_2 of power input

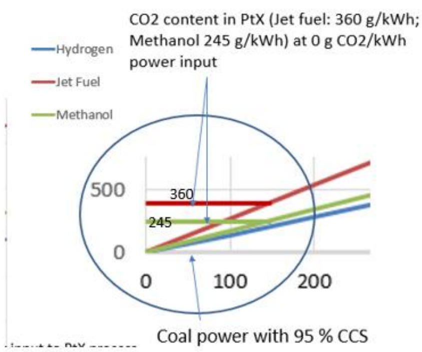


It follows that fossil fuel based power input to P2X will lead to higher CO_2 emissions from the process (g CO_2/kWh) than in the input power (g CO_2/kWh), because the process efficiencies are less than 1. In addition, the P2X products themselves contain CO_2 which will be released when used. The approximate CO_2 content in jet fuel and methanol is 360g CO_2/kWh and 245g CO_2/kWh, respectively.

It follows from this reasoning that when producing P2X, from a climate perspective, it is optimal to use a green power source and to use CO_2 captured from a biogenic source or from DAC (direct air capture).

Figure 5.39: P2X production needs additional renewable generation

Electricity-based substances only contribute to climate protection if **additional** renewable generation is installed to cover the consumption. (unless average emission in power system is very low)



CO2 content "traditional" fuels

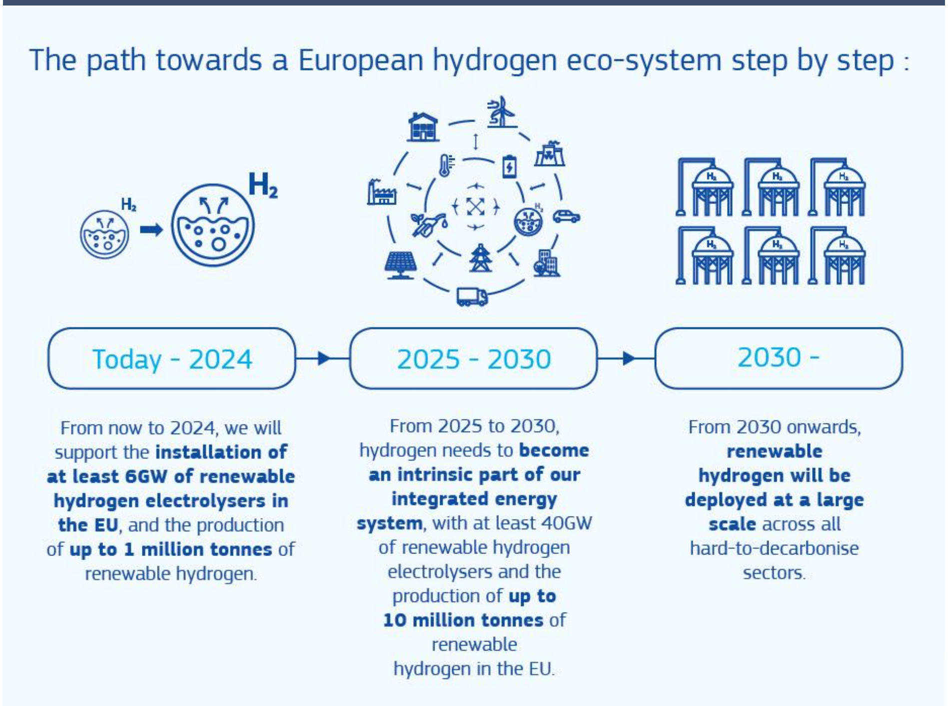
	gCO2/kWh
Natural gas	200
Petrol	260
Coal	340
H2 (steam reforming of natural gas, SMR)	295
Diesel	300

In other words, electricity based substances only contribute to climate protection if **additional** renewable generation is installed to cover the consumption or if the CO_2 emissions from the power system supplying the P2X process is extremely low (see Figure 5.39).

Hydrogen strategy of the EU

On 8 July 2020, the European Commission published the 'Hydrogen Strategy for a Climate Neutral Europe'[18], which describes the step-by-step development of hydrogen to fulfil the Green Deal and as part of the 'Next Generation EU' recovery plan (see Figure 5.40).

Figure 5.40: Hydrogen Strategy for a Climate Neutral Europe



Source: European Commission, 2020

The outline of the strategy and its stepped development is shown in Figure 5.40. Until

2024 the target is 6 GW electrolysis in Europe, rising to 40 GW in 2030: from 2030 onwards green hydrogen should be deployed at large scale across all hard-to-decarbonise sectors.

In Figure 5.41, a list of promotion activities is suggested by the European Clean Hydrogen Alliance (ECHA). The ECHA brings together industry, public authorities, civil society, and other stakeholders. In its proposed approach, the structure of a hydrogen eco system is based on six pillars, as shown in Figure 6.50.

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18 https://energy.ec.europa.eu/topics/energy-system-integration/hydrogen_en#eu-hydrogen-strategy

Figure 5.41: Promotion of hydrogen in Europe

Source: European Commission, 2020

While other forms of low-carbon hydrogen will be needed in the short- and medium-term, the priority is to develop clean, renewable hydrogen produced using mainly wind and solar energy. In the Fit for 55 package, which sets out the EU’s plans to achieve the Green Deal, the target for the share of renewable energy sources in the overall energy mix has been increased to at least 40% by 2030. For hydrogen, a target of 5.6 Mt by 2030 has been set (see Table 5.8). In the face of the recent escalation in hostilities between Russia and Ukraine, the EU sees the need to become independent of Russian energy imports and has therefore increased the target for hydrogen development to 20 Mt of renewable hydrogen by 2030 in its REPower EU plan. Of this, 10 Mt of renewable hydrogen are to be produced in the EU and the same amount imported.

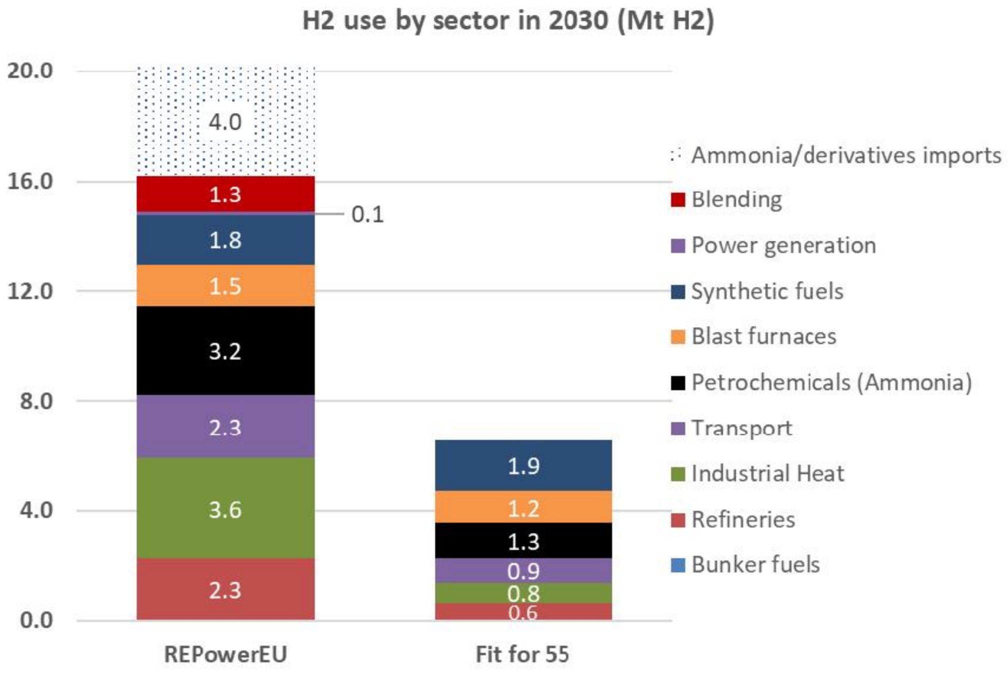
Table 5.8: EU Hydrogen Targets by 2030. (Source: European Commission, 2022)

Renewable Energy Directive / Fit for 55	REPower EU
5.6 Mt by 2030 (44 GW)	20 Mt by 2030 (65 GW)

The enormous change becomes particularly apparent when one compares the planned use of hydrogen by 2030. The use of hydrogen in industrial heat supplies is projected to increase by 4.5 times compared to the already ambitious Fit for 55 targets, and in the transport sector an increase of more than 2.5 times is planned[19](see Figure 5.42).

[19] European Commission (2022). Implementing the REPower EU Action Plan: Investment Needs, Hydrogen Accelerator and Achieving the Bio-Methane Targets.

Figure 5.42: H_2 use by sector in 2030



Source: European Commission, 2022

5.3. P2X and CCUS in CETO

CETO overview

The China Energy Transformation Outlook (CETO, 2022) report encompasses various aspects such as Chinese and international energy policies, energy scenarios for China up to 2060, analyses of the power sector and end-use sectors, assessments of socio-economic impacts, and thematic analyses. An overview of the contents is given in Figure 5.43. It is important to note that the CETO report is published annually, providing up-to-date insights and information on China's energy landscape.

Figure 5.43: Overview of contents in CETO

P2X technology has the technical capability to be deployed in various applications. However, due to process inefficiencies and limited availability of suitable biogenic CO_2 sources, it is advisable to prioritise the utilisation of P2X in hard-to-abate sectors. These sectors include industries such as steel, cement, shipping, air transport, and heavy road transport, which face significant challenges in achieving decarbonisation. By focusing P2X applications on these sectors, the potential for reducing emissions and addressing the most challenging areas of the economy can be maximised.

Comparative study of P2X

The CETO 2022 included a comparative study of P2X deployment in two provinces in China. The provinces Guangdong and Qinghai were selected because they possess different characteristics (see Figure 5.44). Guangdong is a load with limited RE potential and a net electricity importer, while Qinghai is a net exporter and has high RE potential.

Figure 5.44: Selection of two provinces for P2X analysis

Figure 5.45 shows the model setup in the analysis. The setup uses OptiFlow (conversion module), Balmorel (power module) and LEAP (demand). The X is fixed input and P (power) and conversion processes are cost optimised to meet the demand (X).

Figure 5.45: Model setup in OptiFlow for P2X analysis

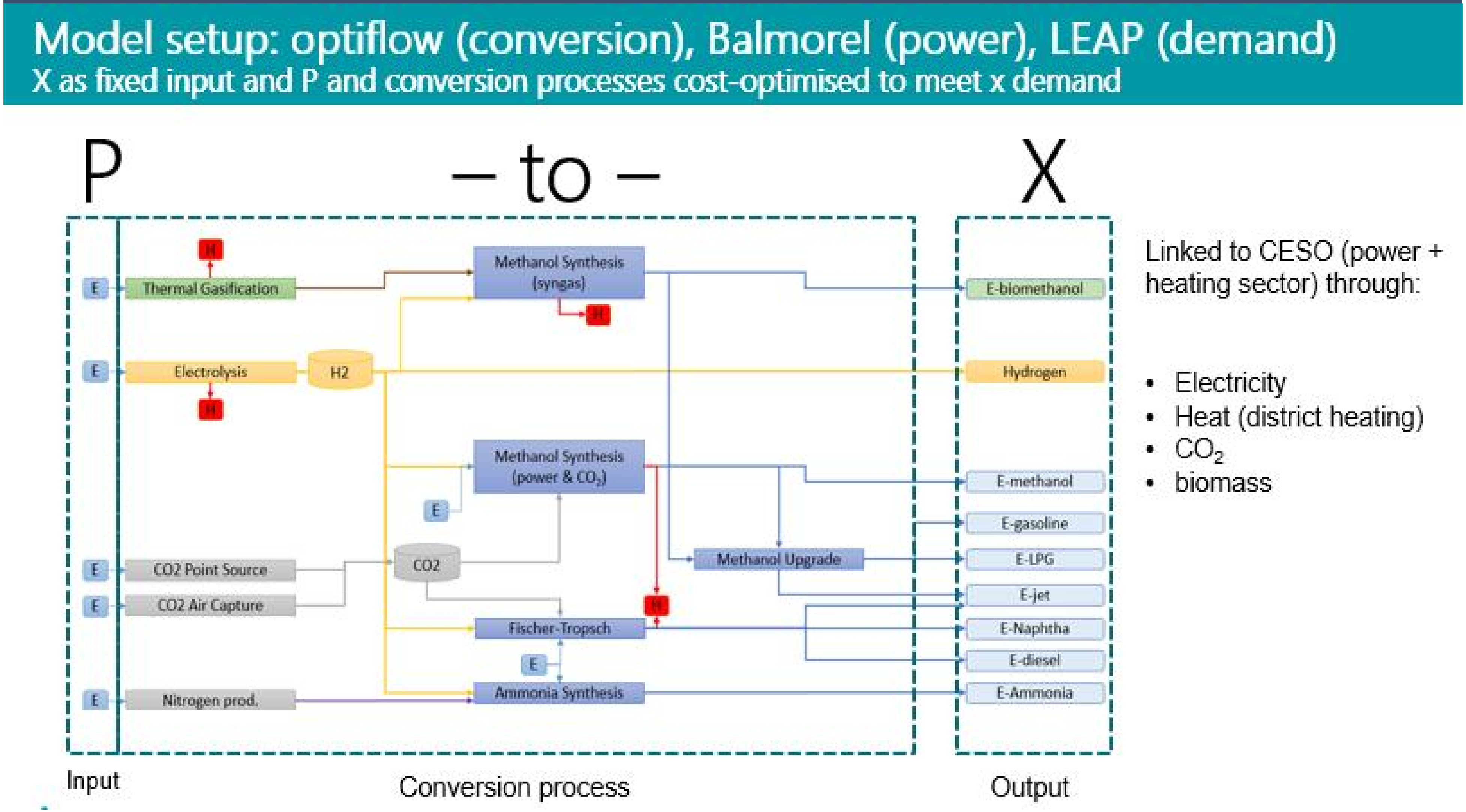
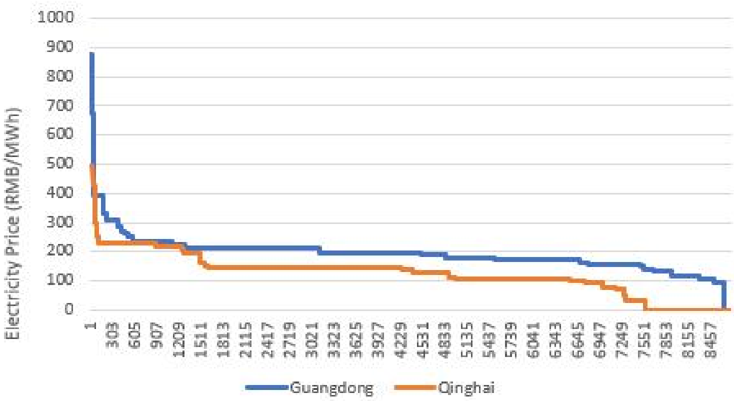


Figure 5.46 shows the influence of the electricity price on a selection of electrolyser investment options. The graphs show the duration curve of electricity prices in the two provinces. In Guangdong, the electricity prices are higher than in Qinghai. Therefore, in Guangdong the model invests in SOEC (Solid Oxide Electrolysis Cell) which is substantially more expensive than AEC (Alkaline Electrolysis Cell) but is more efficient. In Qinghai there is no investment in SOEC.

Figure 5.46: Electricity prices and investment in electrolysers

Electricity price duration curve (2050): higher electricity prices leads to investment in SOEC (CAPEX vs efficiency)

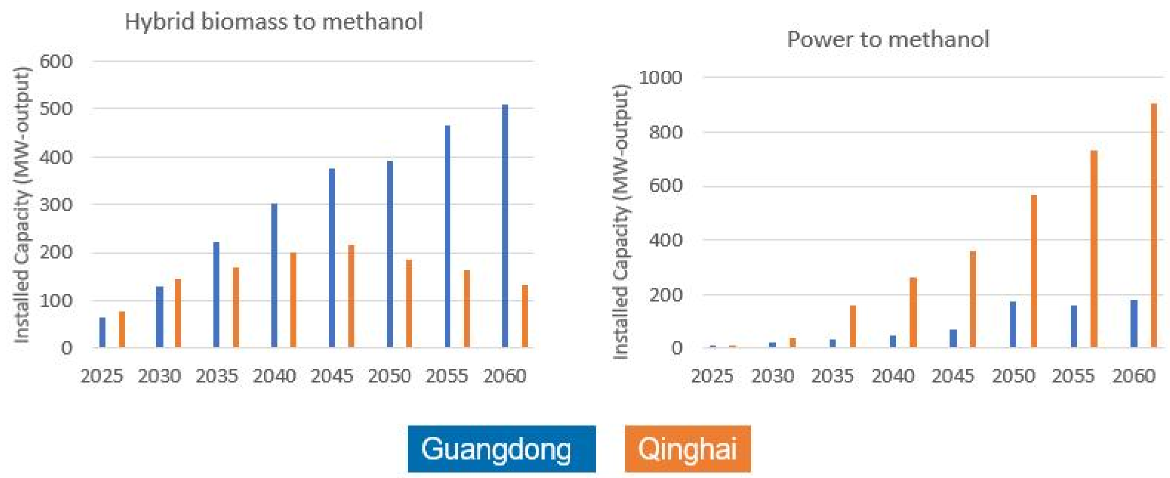
Modelled installed capacities (MW)	Guangdong				Qinghai			
	2030	2040	2050	2060	2030	2040	2050	2060
AEC	698	2730	2288	2032	831	3669	4272	4185
SOEC	0	199	771	572	0	0	0	0



In Figure 5.47 the focus is on CO_2 sources and how they influence the investment options for methanol production. In the two provinces, the prevalent methanol technologies are different. In Guangdong, CO_2 can be extracted from biomass, which is abundant in the province. Therefore, the biomass to methanol process is selected. In Qinghai, where there is no biomass, power to methanol is preferred. Here, CO_2 is captured from air or from CCS installed at power plants.

Figure 5.47: Selected methanol processes

Carbon as a limited resource: biomass vs carbon capture determines methanol process

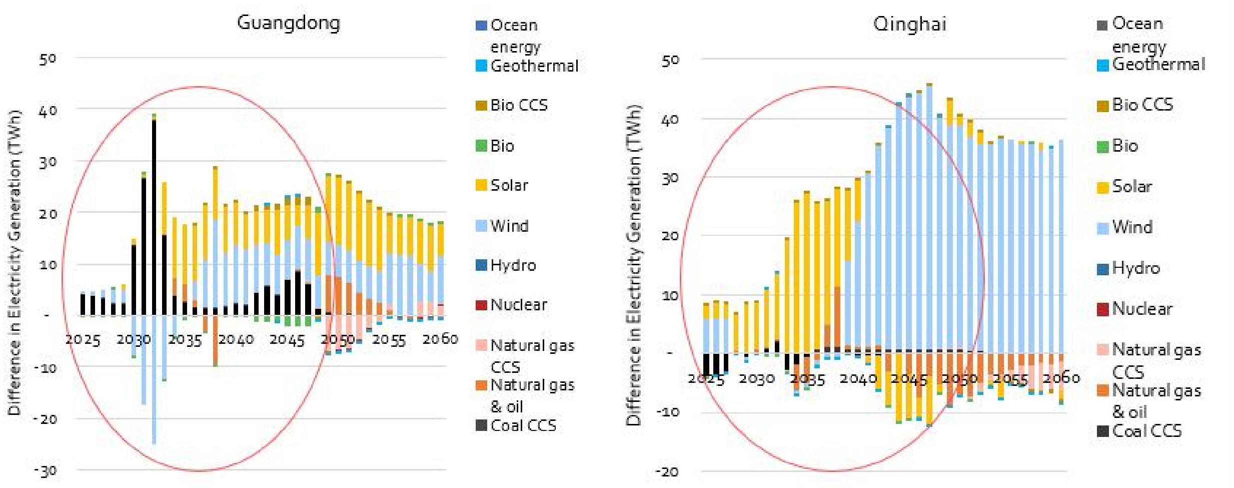


The graphs in Figure 5.48 show the differences in the electricity generation between the baseline scenario without P2X and a scenario with P2X. Positive values mean an increase in power generation compared to a baseline scenario.

Figure 5.48: Introducing P2X too early can lead to increased coal consumption and CO2 emissions

Introducing PtX too early can lead to increased FLHs of coal

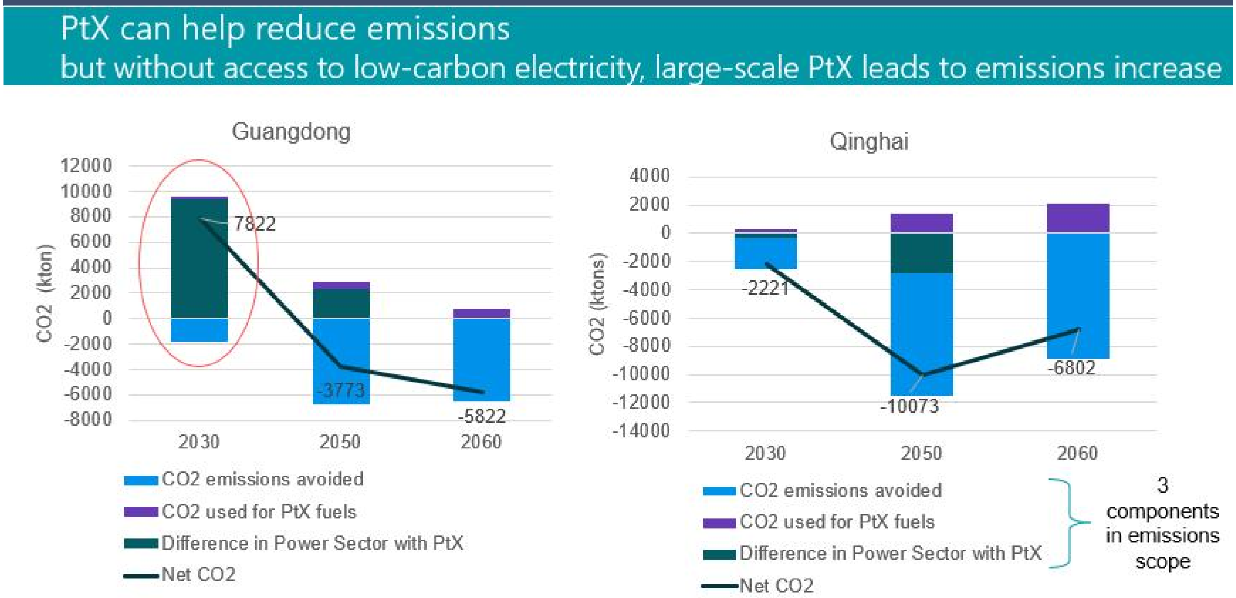
Difference in electricity mix compared to baseline w/o PtX



Guangdong is highly dependent on coal, so with an increase in electricity demand due to the P2X we see an increase in coal usage in the short term. In Qinghai, where there is more RE power generation, this effect is less prominent.

Figure 5.49 illustrates the changes in CO_2 emissions compared to baseline in the two provinces due to installation of P2X. In Guangdong, in 2030, the P2X demand is initially satisfied by coal, which leads to additional emissions from the power sector (dark green part in 2030). This addition exceeds the emissions avoided by P2X. In 2050, we still see an increase in emissions from the power sector as it is not yet fully decarbonised, although the increase is less than in 2030. In Qinghai, the situation is different as RE energy supplies the additional demand from P2X. So, in this province CO_2 emissions reduce compared to baseline.

Figure 5.49: Without access to low carbon electricity P2X may lead to a rise in CO_2 emissions



In conclusion, large scale P2X production assets should not be built unless it is certain that the additional electricity demand required can be met by CO_2-free power generation.

6. Modelling and Planning of Chinese Net-Zero Carbon Infrastructure

This chapter is based on Work Package 5 (WP5) - Modelling and planning of net-zero carbon infrastructure. It describes an integrated study of the power and gas sector of China under liberalised conditions.

6.1. Objectives

Both China and the EU have ambitious targets moving towards carbon and climate neutrality. Achieving this requires a transformation of energy infrastructure, planning and regulation. It is evident that future energy infrastructure development and operations need to be more coordinated between energy carriers and sectors. The net-zero targets raise the bar for energy system models. With the consensus that a high share of VRE and electrification will be the bedrock of decarbonisation, as well as the need for P2X and CCS as key technologies for hard-to-abate consumption, new challenges for the power system arise: how to integrate the high share of VRE while ensuring system adequacy with very low fossil-based generation? The power sector model needs a stronger link with the consumption side and should include CCS and P2X. Modelling analyses are essential to ensure successful sector-coupling and optimal coordination among energy carriers.

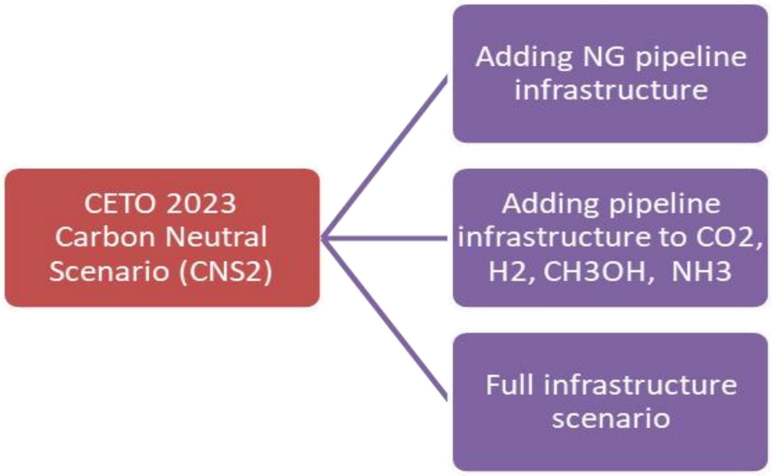
Therefore, the aim of this project is to model - at a conceptual level - the Chinese integrated power and gas sectors under liberalised market conditions, and to assess the impacts and benefits of systems integration (enhanced energy storage using sector coupling, P2X, and the hydrogen sector) on reaching carbon neutrality targets.

6.2. Modelling in CETO 2023 and ECECP infrastructure project

6.2.1. Overview

Building on the CETO 2023 model, in this project the natural gas infrastructure, as well as P2X infrastructure and a full infrastructure scenario are added, as depicted in Figure 6.1. The CETO 2023 model includes demand-side modelling (in LEAP), power, district heating and e-fuel transformation and supply (EDO model), a projection of provincial natural gas prices, but no pipeline infrastructure representation.

Figure 6.1: Overview of scenario variants, and model enhancements, built onto the CETO 2023 CNS2 Scenario

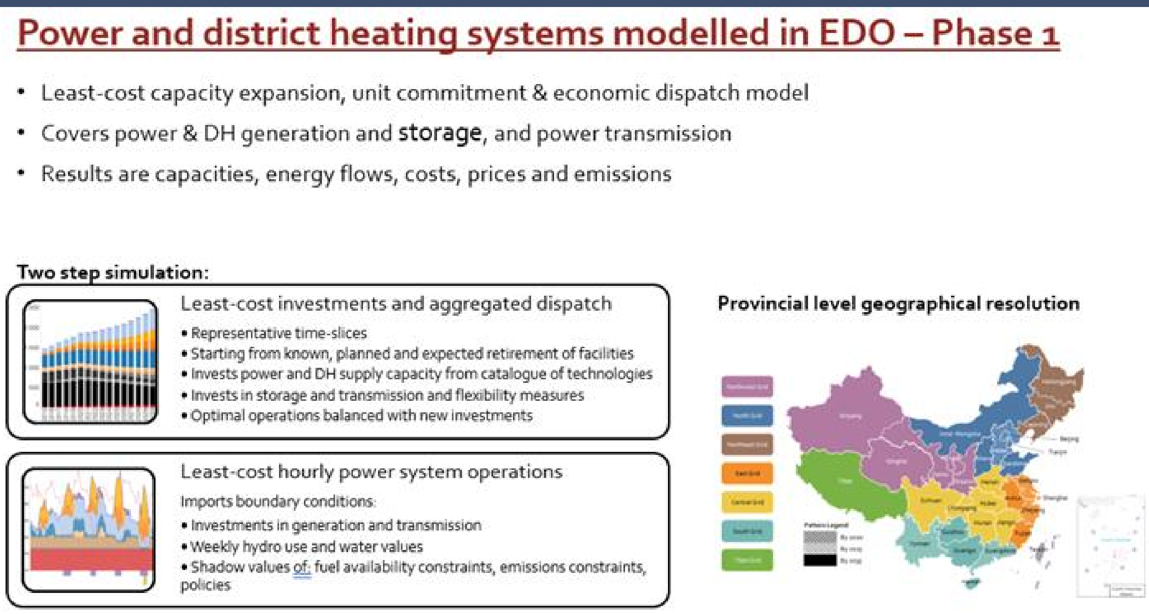


In the CETO 2023 model, three scenarios were assumed as development pathways for the Chinese energy system:

- The Baseline Scenario (BLS), where China contributes to the global two- degree target and achieves carbon neutrality around 2070.
- The Carbon Neutral Scenario 1 (CNS1), which illustrates the pathways for achieving the dual goals of peaking CO_2 emissions before 2030 and achieving carbon neutrality in the energy system before 2055.
- The Carbon Neutral Scenario 2 (CNS2), which illustrates the pathways for achieving the dual goals of peaking CO_2 emission before 2030 and achieving carbon neutrality in the energy system before 2050.

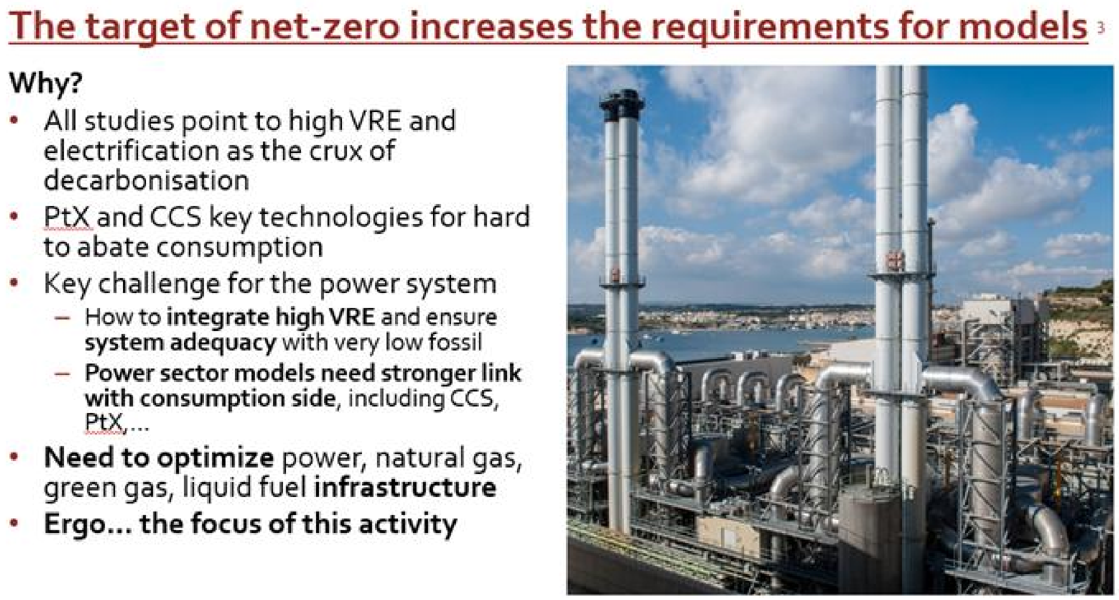
The modelling of power and district heating in EDO is outlined in Figure 6.2. The EDO model was used in the ECECP phase 1 project (ENTSO-E transmission planning showcase for China). The model has two steps: the least cost investment model and hourly dispatch model.

Figure 6.2: Modelling of power and district heating in EDO



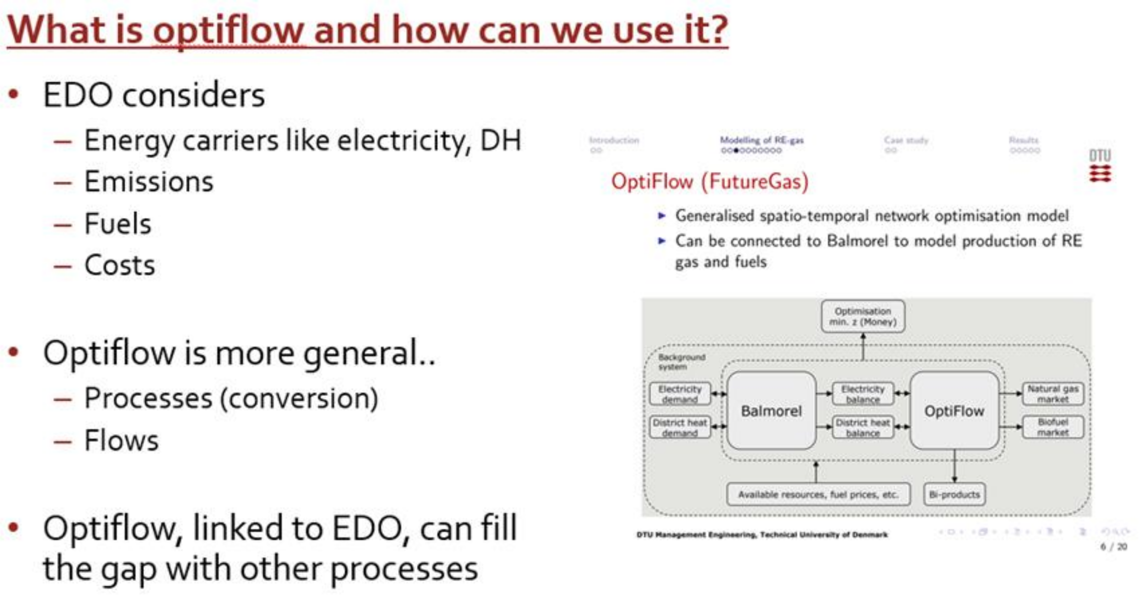
The net-zero target across energy sectors increases the requirements for energy modelling frameworks (see Figure 6.3). The target makes it impossible to avoid combined optimisation of infrastructure for power, natural gas, green gas, and green fuel (including storage).

Figure 6.3 Requirement for models to optimise zero-carbon infrastructure



The OptiFlow model can be used in this regard (see Figure 6.4). OptiFlow is a general process-flow model which can be coupled with EDO and fill the gap of coupling energy sectors: power, natural gas, hydrogen, green gas, green fuels etc.

Figure 6.4: OptiFlow characteristics



OptiFlow’s key components are nodes (= processes) and arcs (= flows) (see Figure 6.5). Flows represent ‘something’ going in and out of processes. Processes represent ‘something’ being transformed to 'something else' and allow for multiple inputs and outputs, while consistently representing relationships between the different inputs and outputs. Thus, OptiFlow adopts a very generic approach to modelling, which is useful for representing new or emerging technologies, representing different possible configurations. The hard-link integration with the EDO model of power and district heating ensures representation of sector coupling considerations and the implication of processes’ connections to the power sector can reflect the impact on power system balancing and system adequacy.

Figure 6.5: Key components in OptiFlow

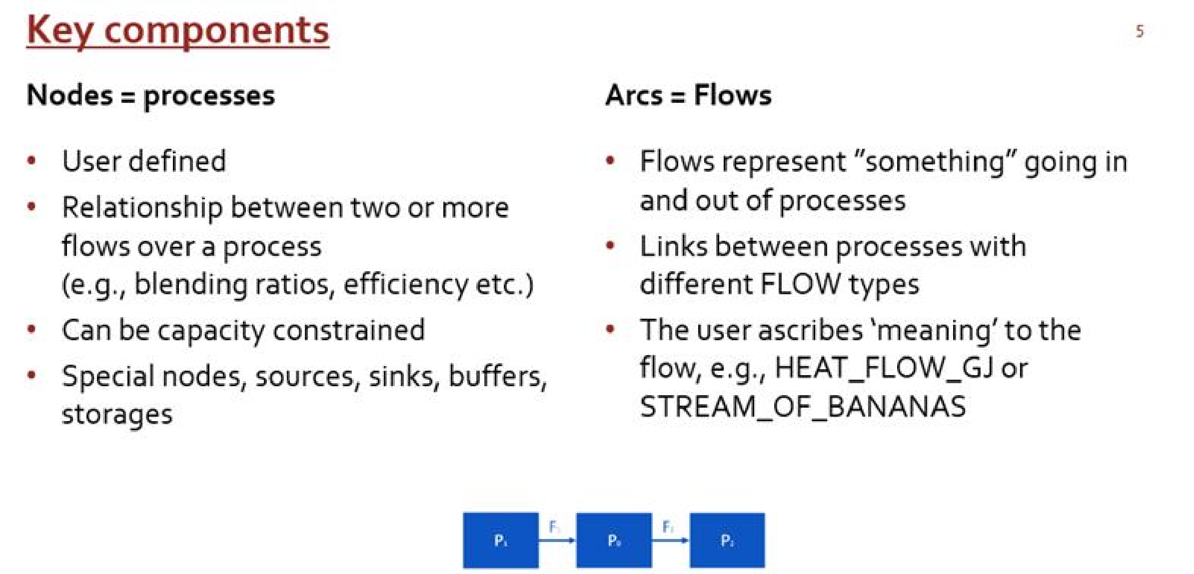
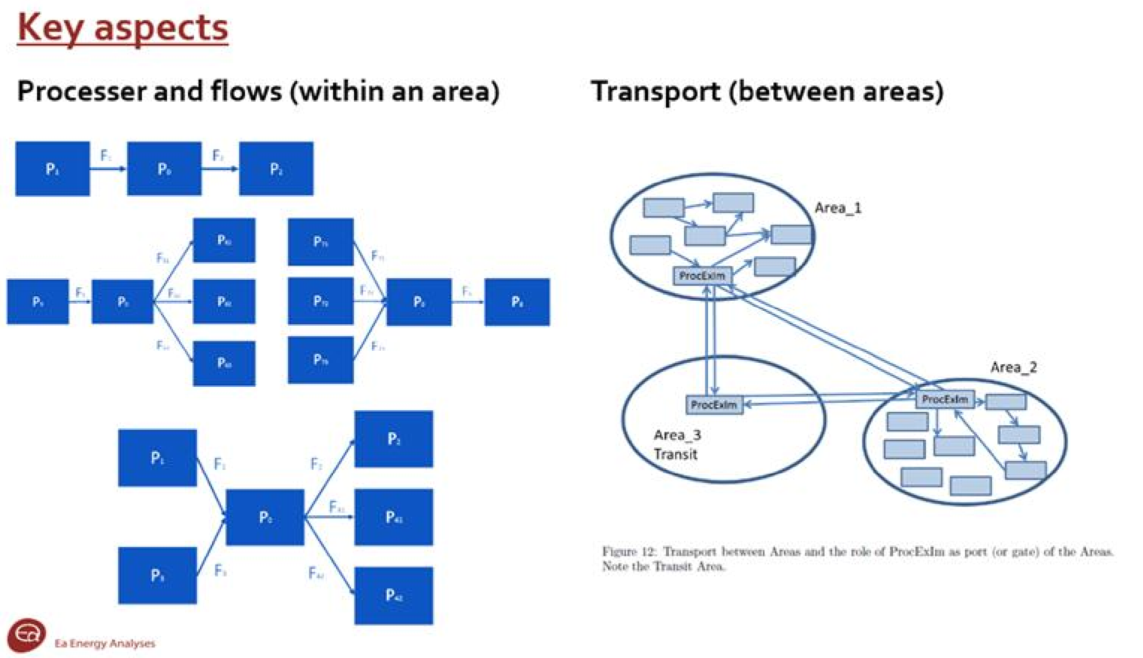


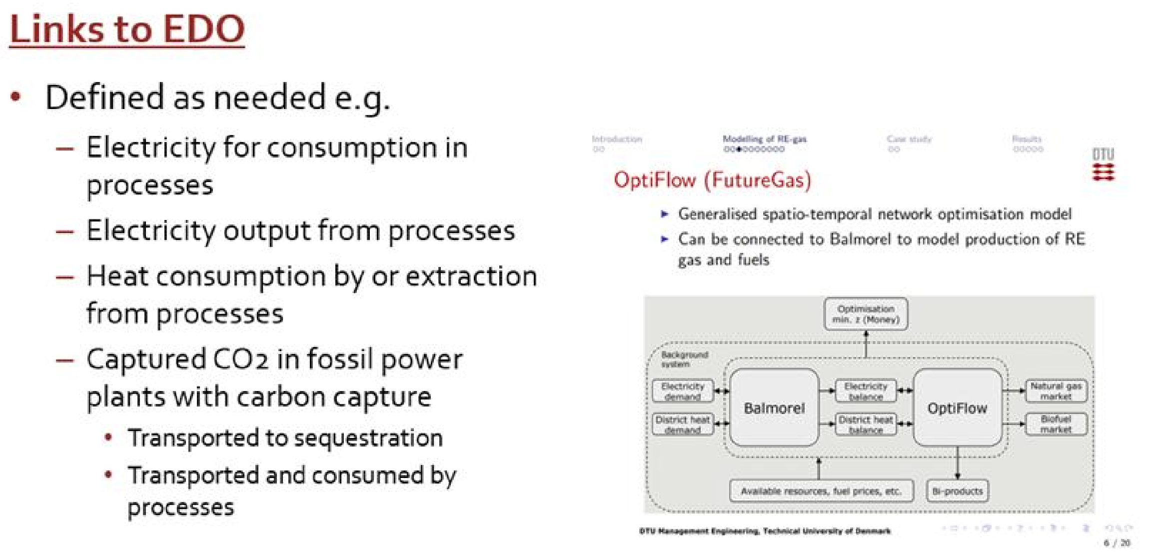
Figure 6.6 shows the flexibility of setting up and combining processes and flows in OptiFlow. It is also possible to simulate transport between areas.

Figure 6.6: OptiFlow - key aspects



Links between OptiFlow and EDO/Balmorel can be flexibly defined as needed (see Figure). This applies to e.g., electricity consumption in processes, electricity output from processes, heat consumption by processes or extraction from processes, captured CO_2 in power plants with subsequent transport and consumption by processes or CO_2 transport to final storage.

Figure 6.7: Links between EDO (Balmorel) and OptiFlow



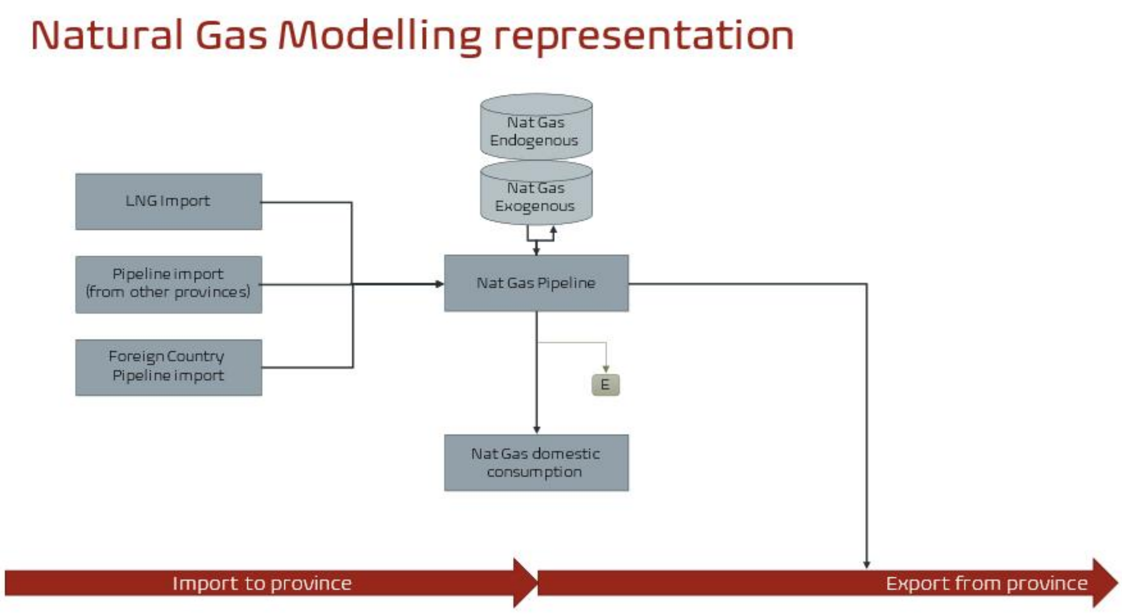
6.2.2. Natural gas modelling in the OptiFlow model

The CETO 2023 EDO model uses an assumption of natural gas prices at provincial level; however, the pipeline infrastructure is not directly represented. As an add-on, in this project, natural gas infrastructure is added on the basis of ENTSO-E and ENTSOG scenarios. The model takes into account the domestic supply and storage capacity of natural gas, residual consumption, as well as pipeline and LNG imports. Furthermore, the infrastructure representation for key commodities, such as CO_2, hydrogen, methanol, and ammonia is enhanced, and the pipeline capacities are determined in economic co-optimisation with power and heating. The goal of the modelling is to assess the impact of integrated system modelling, such as the effect of infrastructure considerations on the role of P2X and CCUS, and whether natural gas infrastructure can be used to enhance hydrogen's role in the net-zero energy system.

The following processes and connections are implemented:

- **LNG import capacity:** denotes the available capacity of every LNG terminal in each province.
- **Pipeline import capacity:** expresses the import capacity of the province connected to foreign countries via pipeline.
- **Natural gas source:** indicate the specific availability of gas extraction of the specific province.
- **Gas pipeline:** considers gas pipeline connections to other provinces and the total input and output for each province.
- Natural gas storage (exo)**:** denotes existing natural gas storage capacity; this process relates to natural gas pipelines flowing in both directions, whereby the natural gas can be either stored or withdrawn from storage.
- **Natural gas storage (endo):** denotes future natural gas storage capacity, the functioning of the process is analogous to natural gas storage (exo).
- **Natural gas local consumption:** indicates provincial natural gas consumption, including industrial, transport, and domestic use. This figure accounts for all the consumption in the province excluding power and heat generation (connected to district heating).
- **Gas to EDO:** expresses the link between the OptiFlow and EDO models with the first accounting for the commodity flow and the second for natural gas used for power and heat for district heating.

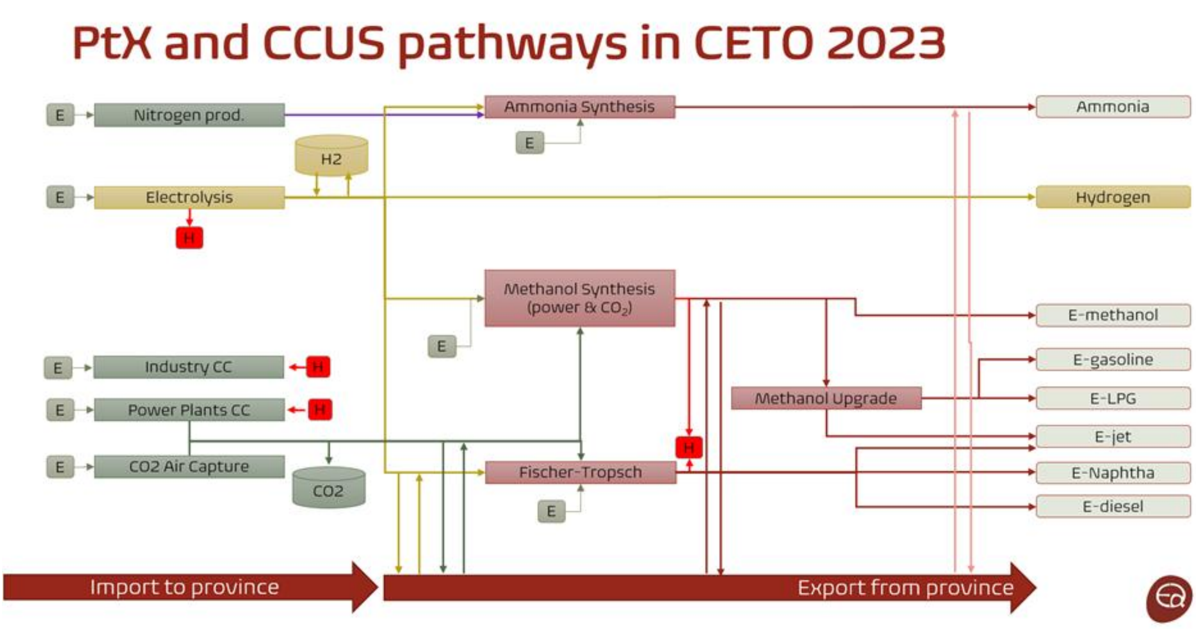
Figure 6.8: Gas infrastructure modelling representation



6.2.3. P2X, CCUS modelling in the OptiFlow model

The setup of the analysis for PtX and CCUS is described in Chapter 6, building on the CETO 2023 report. The process uses OptiFlow (conversion module), EDO (power and district heating module) and LEAP (demand). The power-based fuel production pathways (P2X) are shown in Figure 6.9. The processes and flows can be modelled in OptiFlow alongside EDO / Balmorel.

Figure 6.9: Fuel production pathways



6.2.4. Data: P2X, CCUS and natural gas in the Chinese energy system

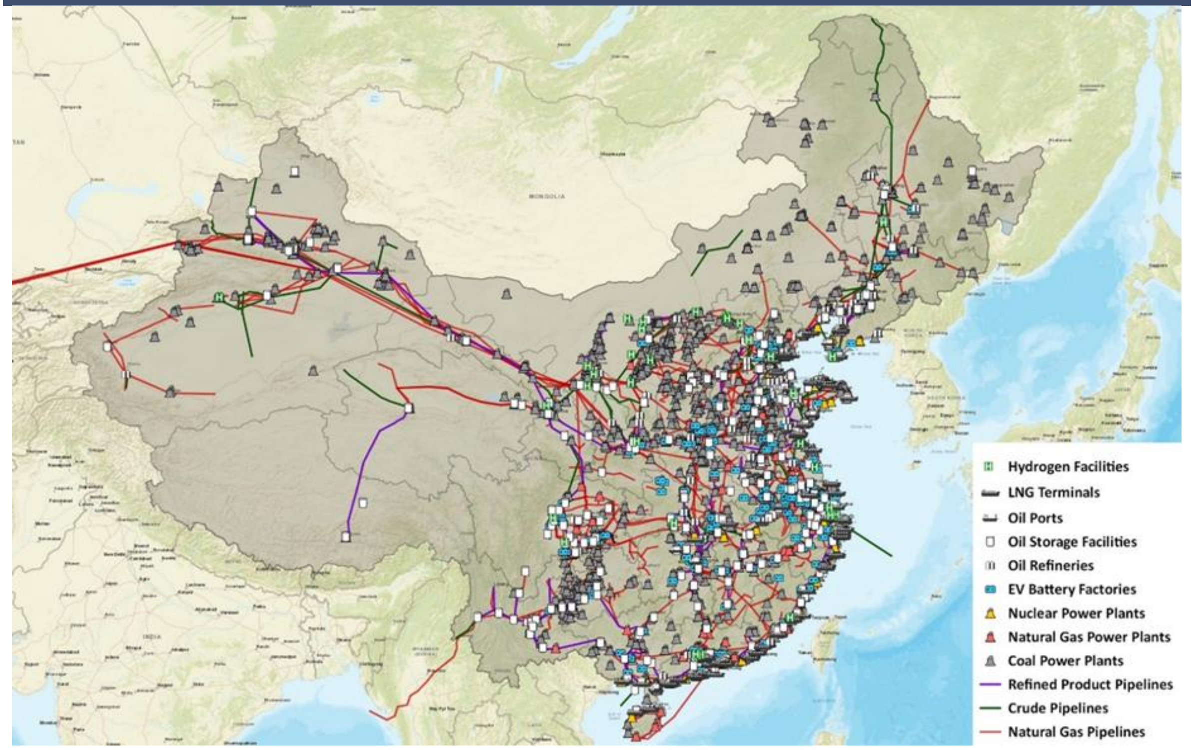
Historical data for natural gas production and demand by province, as well as data on existing natural gas storage by province are based on the figures from National Bureau of Statistics of China. The demand forecast is based on CETO. Domestic gas production is predicted on the assumption that in the context of the 'net zero by 2060' policy, China is unlikely to have a significant level of domestic gas production in the long run, but it may be used as a bridging technology. Therefore, the maximum domestic gas generation is given as a constant value starting from 2023, and decreases in the last two decades before the net-zero target in 2060. As China has committed itself to achieving net-zero carbon by 2060, residual gas demand decreases in the CETO CNS2 scenario and natural gas consumption is also displaced from the power sector once the carbon reduction pathway becomes a binding constraint. From an economic point of view, new investments in natural gas infrastructure will be feasible at this time. Therefore, we assume a decrease in domestic gas production indexed according to the decline in demand for natural gas, starting from 2043. It is at this time that residual gas consumption and domestic gas production reach parity. This reduction is also necessary since a price drop (caused by lower demand with stable supply) would not sustain further investments in the development of natural gas supply.

The natural gas modelling takes into account interprovincial gas transmission pipeline capacities, natural gas storage capacities (including injection, withdrawal and volume), natural gas border capacities for pipeline and LNG imports, projected gas supply options (pipeline volumes available), projected domestic gas production options, as well as the distribution of 'residual' natural gas demand by provinces. Some of the energy infrastructure data for China, such as data for LNG terminals, is based on the Baker Institute China Energy Map[20], shown in Figure 6.10. The natural gas pipeline network by province is based on a study by Zhang et al.[21]

[20] Baker Institute (2023). Open Source Mapping of China's Energy Infrastructure. https://www.bakerinstitute.org/open-source-mapping-chinas-energy-infrastructure

[21] Zhang et al. (2022). Potential role of natural gas infrastructure in China to supply low-carbon gases during 2020–2050. Applied Energy. https://doi.org/10.1016/j.apenergy.2021.117989

Figure 6.10: China Energy Map



Source: Baker Institute, 2023

In this context, China is heavily reliant on natural gas imports to satisfy its energy needs. These imports are delivered via pipeline (existing, under-construction or planned) or in liquid form via the LNG terminals in the coastal provinces. Natural gas is imported via provinces with LNG terminals or pipeline infrastructure that connects with third countries. Existing pipelines connect China with Russia, Myanmar, and Central Asia. In the model, the status of these cross-border pipelines is based on data from Rystad Energy, as depicted in Table 6.1.

Table 6.1: China's Cross-Border Pipelines. (Source: Rystad Energy Gas Market Cube)

From	Cross-border pipelines	Status	Start year	Capacity (Bcm/year)
Russia	Power of Siberia 1	Operational	2019	38
	Far East Pipeline	Under construction*	2026	10
	Power of Siberia 2 (via Mongolia)	Planned	2030	50
	Power of Siberia 1 expansion	Speculative	2028	6
	China-Russia Pipeline West Stream	Shelved	-	-
Central Asia	Central Asia-China Pipeline A	Operational	2009	15
	Central Asia-China Pipeline B	Operational	2010	15
	Central Asia-China Pipeline C	Operational	2017	25
	Central Asia-China Pipeline D	Under construction**	2026	30
Myanmar	China-Myanmar pipeline	Operational	2013	12

*The Russian section of the Far East Pipeline is near-complete with the section in China yet to be scheduled. **Construction of the section in Kyrgyzstan began in 2014.
Source: Rystad Energy GasMarketCube

Similarly, the capacity and utilisation of China's cross-border pipelines and LNG terminals is based on the projection by Rystad Energy.

6.2.5. Scenarios

To see the impact of the integrated modelling, a reference scenario and three infrastructure scenarios are considered (see Table 6.2):

- **Scenario 0 (SC0):** This is a reference scenario (based on CNS from CETO 2023) without the pipeline infrastructure representation described above, and where natural gas consumption (in the heat and power sector) is optimised according to exogenous prices at provincial level. This implies that transport of X-fuels between provinces is based on a variable cost of transport, i.e., a cost per unit of fuel per distance, but not constrained by a pipeline capacity.
- **Scenario 1 (SC1):** Natural gas infrastructure includes pipelines to third countries, LNG terminals and pipeline constraints between provinces but X-fuels pipeline infrastructure is not considered, i.e., transport of X-fuels is as in the reference scenario based on CNS2 from CETO 2023. (No additional investments in the gas infrastructure are allowed. This is because at the outset, the scenario assumptions describe a situation where due to carbon neutrality requirements, consumption of fossil gas is falling). The natural gas pipeline infrastructure is considered to be as it is in the first year modelled with no investment option for expansion of the infrastructure.
- **Scenario 2 (SC2):** Transportation of CO_2, methanol, hydrogen, and ammonia between provinces is restricted by pipeline capacity. The pipeline capacity is determined as an endogenous investment option, however, the economic cost of using the pipeline, versus not using it, is considered negligible for the optimisation. Hence, if pipeline capacity is established, it is likely to have high utilisation. Natural gas pipeline infrastructure is represented as in scenario 0, i.e., with exogenous natural gas prices in each province, but does not include modelling of natural gas transportation throughout the gas network.
- Scenario 3 (SC3): Both natural gas and P2X infrastructure are considered. No additional investments in the gas infrastructure are allowed, only into ammonia, CO_2, methanol, and hydrogen infrastructure. This is because at the outset the scenario assumptions describe a situation where use of fossil-fuel gas is falling due to carbon neutrality requirements.

This setup has the aim of answering specific questions as to the impact of the alternative modelling approach. Firstly, by looking in isolation at the implications of adding natural gas pipeline infrastructure to the scenario (e.g., by comparing Scenario 1 with Scenario 0). In the CNS2 scenario of the CETO 2023 report (scenario 0), we see that the role of natural gas is declining rapidly. Since localised natural gas prices in CNS2 are a function of observed prices in a fairly congested system, the pricing mechanism for transporting natural gas is likely to change if the system becomes less, or more, congested.

By only imposing exogenous prices for gas on the import nodes, i.e., third country pipeline imports or at receiving LNG terminals, and assuming that a specific domestic gas production scenario is followed, the gas will attain an opportunity value in the model, based on the import volumes available to the market, and the value of using residual gas in the system (e.g., for power and district heating generation in EDO). Congestion in the natural gas grid will be factored in as constraints in the modelling, and thus plays a role in the allocation of gas consumption to different provinces based on this transport limitation.

Secondly, comparing Scenario 2 with Scenario 0 will demonstrate the impact of including pipeline capacity and investments on the utilisation and transportation of the four commodities CO_2, e-methanol, ammonia, and hydrogen.

Thirdly, comparing e.g., Scenario 3 with full infrastructure with Scenario 0 will demonstrate the impact of including pipeline capacity and investments (note, however, that this refers only to investments in CO_2 and X-fuels[22] infrastructure) and the further impact on the utilisation and transportation of natural gas and the four commodities CO_2, e-methanol, ammonia, and hydrogen.

Table 6.2: Overview of the Integrated Modelling Scenarios

	Variable cost transport of X's	**With X-pipelines**
Exogenous natural gas prices without natural gas pipeline infrastructure	Scenario 0	Scenario 2 (P2X-infrastructure scenario)
With natural gas pipeline infrastructure	Scenario 1 (Gas infrastructure scenario)	Scenario 3 (Full infrastructure scenario)

6.3. Results

The Chinese integrated power and gas sectors were modelled under liberalised market conditions to assess the impacts/benefits of different systems on achieving carbon neutrality targets. Below, the results are presented in three sections, demonstrating the following outcomes:

- Firstly, the implication of adding natural gas pipeline infrastructure to the modelling approach (by comparing Scenario 1 and Scenario 3 with Scenario 0).
- Secondly, the impact of including pipeline capacity and investments on the utilisation and transportation of the four commodities CO_2, e-methanol, ammonia, and hydrogen (by comparing Scenario 2 with Scenario 0).
- Thirdly, the impact of including pipeline capacity and investments (note, however, that this includes only new additional investments in CO_2 and X-fuels infrastructure) and the further impact on the utilisation and transportation of natural gas and the four commodities CO_2, e-methanol, ammonia, and hydrogen (by comparing e.g., Scenario 3 with full infrastructure with Scenario 0).

6.3.1. Implication of adding natural gas pipeline infrastructure to the modelling

Co-optimisation of gas and electricity infrastructure offers a comprehensive view of the transition in natural gas usage in the energy system. Once a gas infrastructure is in place, the true costs of using it are low, often much lower than the tariffs needed to recoup initial investments. Yet policy developments, such as China's net-zero carbon target, may diminish natural gas usage. In an uncongested system, transmission costs may decrease

[22] 'X' includes CO_2, e-methanol, ammonia, and hydrogen

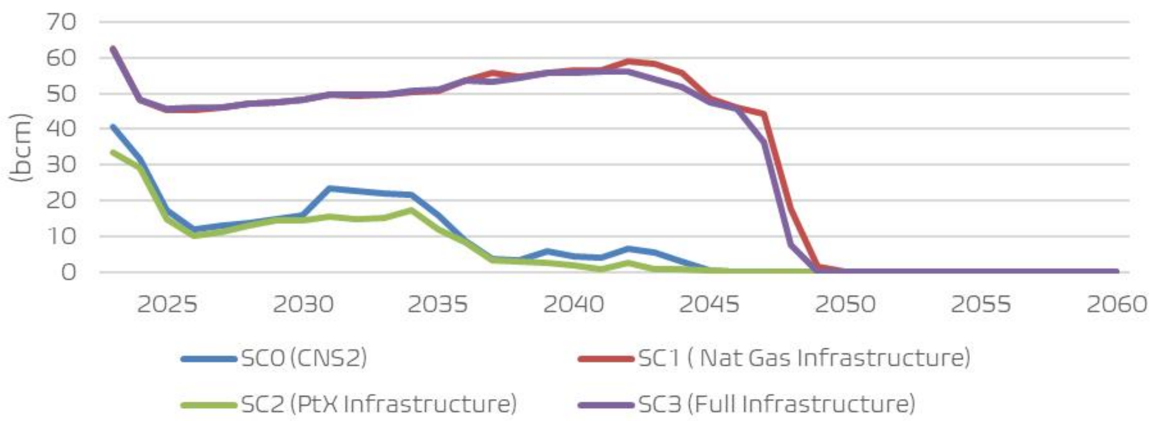
only if the infrastructure remains idle. Conversely, with rising demand leading to increased congestion, there need to be stable, long-term prospects for consumption to justify further infrastructure investments. The models in this report capture gas consumption patterns during energy transitions.

Alternative models that overlook this can inadvertently make projections for gas market prices based on existing infrastructure and congestion levels into futures with different congestion levels. Some scenarios may show a temporary rise in natural gas usage before it declines to net-zero. Such models may implicitly suggest the need for further grid investments which would become redundant in a net-zero carbon context. This model details the natural gas demand side, incorporating the needs of power and district heating sectors in the EDO model and other gas demands from LEAP, providing a representation of natural gas demand during China’s shift towards net zero. The supply side relies on basic domestic supply estimates, which are crucial in determining China's natural gas imports, warranting further detailed analysis.

Comparing the modelling results of Scenario 0, Scenario 1 and Scenario 3 gives us an indication of the implications of adding natural gas and X-fuels pipeline infrastructure to optimise the system.

Under the net-zero emissions target, it is assumed that overall natural gas demand will decrease over time. As can be seen in Figure 6.11, gas demand in the power sector is already in decline in the ten to 15 years before 2060.

Figure 6.11: Scenario results for natural gas consumption in the power and district heating sectors



A similar trend for natural gas demand in the power sector can be observed in SC0 and SC2 (the two scenarios that do not take account of the natural gas infrastructure) and SC1 and SC3 (the two scenarios that take account of the natural gas infrastructure). Interestingly, natural gas demand in the power sector is much higher in the scenarios where the natural gas infrastructure is taken into consideration.

While in SC0 and SC2 the model makes an optimal demand decision on the basis of historical gas prices (which have been high in the past), under SC1 and SC3 the model pinpoints the optimal demand in the context of the natural gas infrastructure. Since the natural gas infrastructure has already been built, it is used for longer in these scenarios but phases out natural gas demand for electricity production in 2050 because of the CO_2 emissions constraint. Figure 6.12 and Figure 6.13 present the natural gas balance.

Figure 6.12: Natural gas balance in Scenario 1

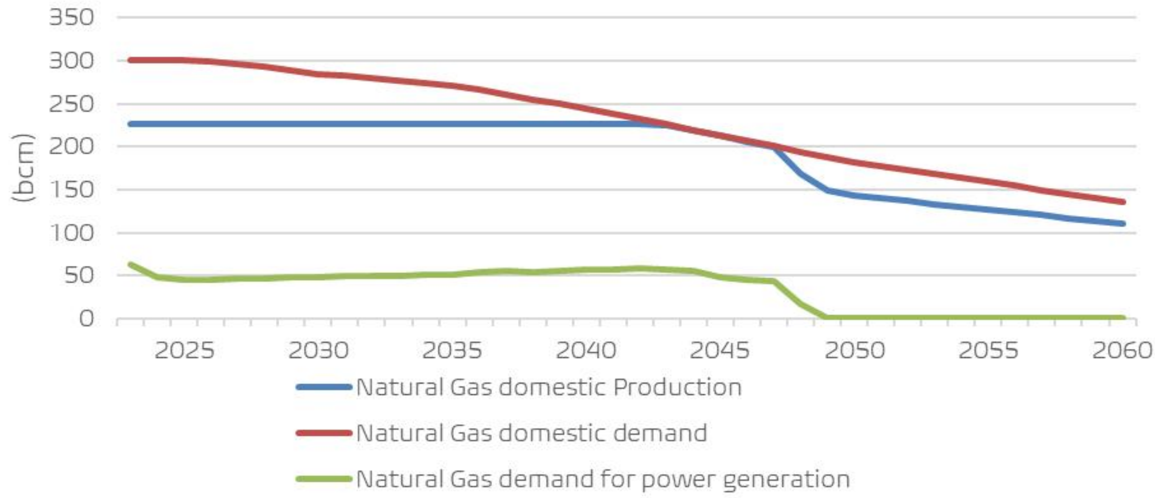
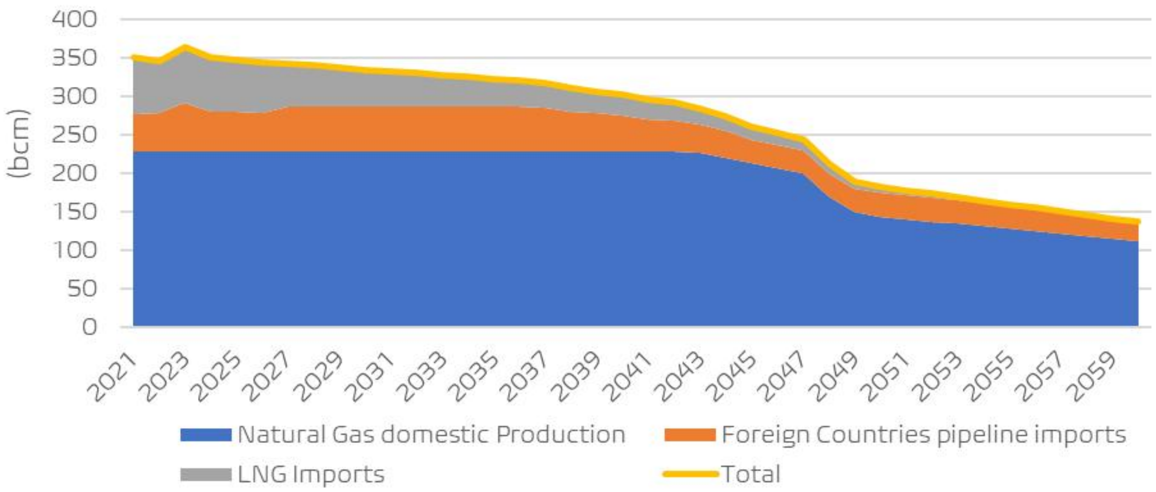
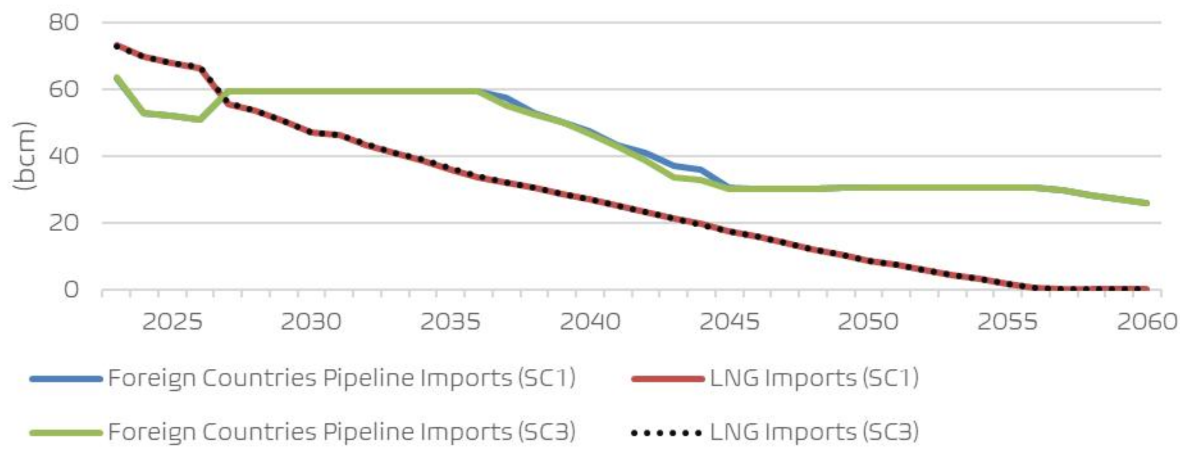


Figure 6.13: Natural gas available in the Chinese system under Scenario 1



As can be seen in Figure 6.12 and Figure 6.13, the majority of natural gas demand is covered by domestic production, supplemented by pipeline imports and LNG imports. Following the drop in demand after 2043, domestic production and LNG imports decline while third party pipeline imports remain constant.

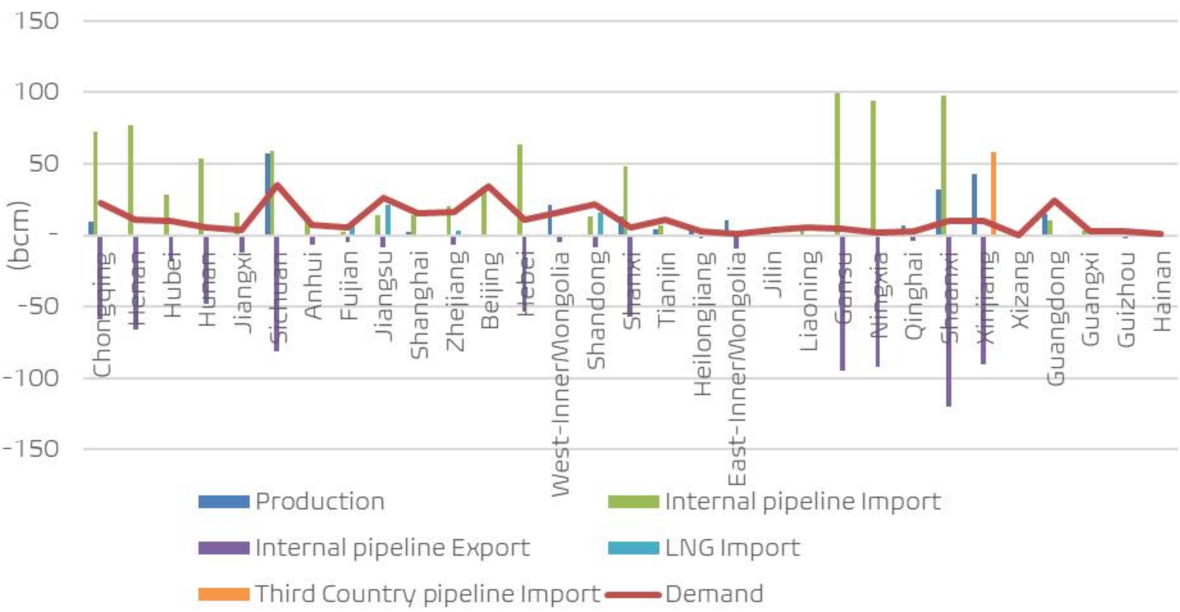
Figure 6.14: Pipeline gas and LNG imports



The pattern of natural gas and LNG imports is similar in Scenario 1 and Scenario 3 (see Figure 6.14). There is no difference in LNG import volumes and only a small difference in the volume of pipeline imports from foreign countries. That means that including infrastructure for X-pipelines (Scenario 3) does not impact natural gas imports (Scenario 1).

Figure 6.15 gives an overview of natural gas balances at a provincial level in 2060 in Scenario 3 (full infrastructure scenario). It is evident that in general large volumes of natural gas move between provinces, the aim being to optimise natural gas transport in order to meet demand. The outcome supports the approach of including gas-infrastructure in the modelling and thereby obtaining valid results based on technical capacity and potential congestion in the distribution network.

Figure 6.15: Natural gas balance at a provincial level. 2060, SC3

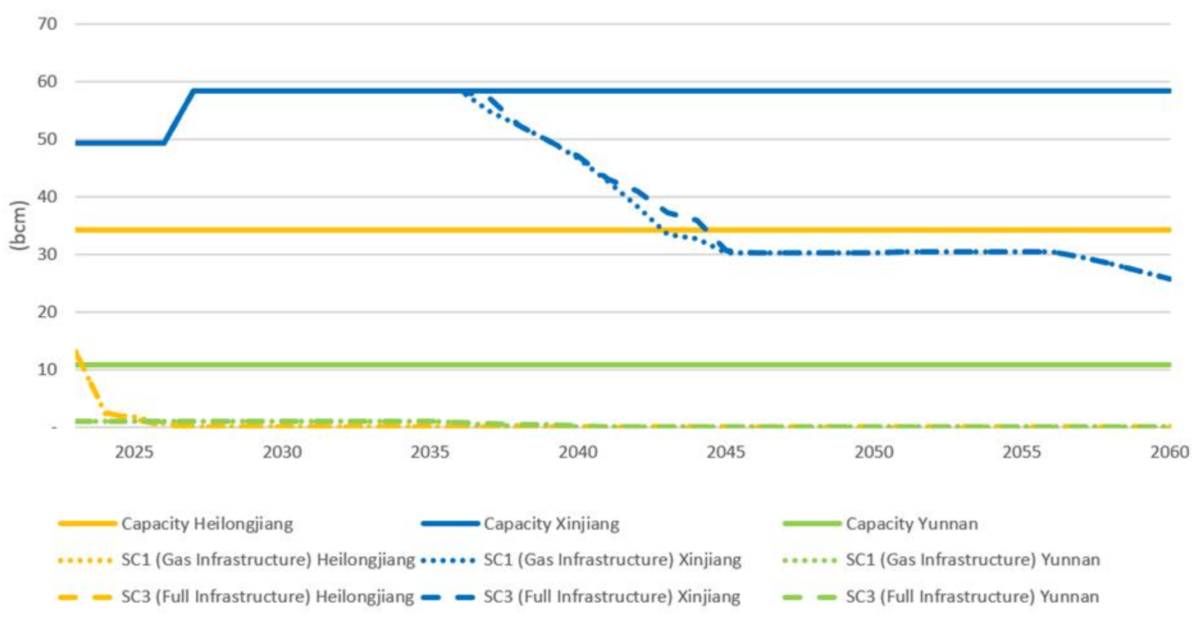


Taking a closer look at natural gas pipeline imports from third countries, Figure 6.16 depicts the three provinces Heilongjiang, Xinjiang, and Yunnan showing their pipeline connections with gas-exporting countries (SC1 and SC3).

Since the natural gas infrastructure is not represented in SC0, it is not possible to include the scenario results here. This shows a limitation of the 'electricity grid only' modelling of the energy sector, which takes natural gas and P2X into account, but without including a representation of the infrastructure.

The solid line represents the pipeline capacity for each of the three provinces, while the dashed and dotted lines present the utilisation (used capacity) in the different scenarios. In Heilongjiang and Yunnan, pipeline imports are lower than pipeline capacity from the beginning and remain at a very low level. Pipeline imports through Xinjiang are close to available capacity until after 2035 and then decrease in line with falling demand. The imports coming into Xinjiang are the most long-standing, as the import prices are assumed to be the lowest: as consumption declines there is generally sufficient interprovincial pipeline capacity to move gas from the West to East of the country. Between 2045 and 2057, pipeline imports from Central Asia via Xinjiang are almost constant. Since domestic production of gas is declining, pipeline imports continue to meet a proportion of gas demand.

Figure 6.16: Natural gas pipeline imports from abroad



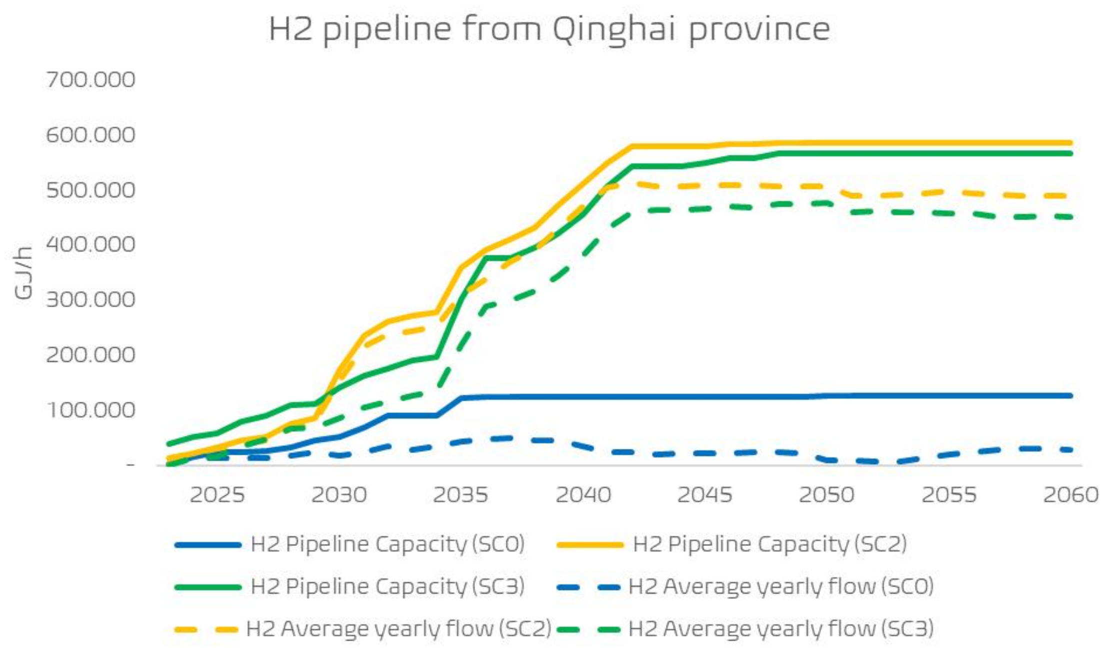
6.3.2. The impact of including P2X and CO_2 infrastructure to the modelling

Pipelines, cables etc., operate in a different way compared to other means of transportation. On a levelised cost basis, they are often cheaper than alternative forms of shipping, e.g., trucks, ships etc. When a pipeline or transmission line is built, a transportation corridor is created, and the relevant commodity can be shipped between point A and point B at low variable cost. When representing such transportation options in energy system optimisation models, representation of a limited (but potentially expandable) pipeline capacity yields a different transportation pattern, in contrast to simply applying a levelised cost of transport per unit of a relevant commodity that is shipped. On the one hand, when the pipeline has been built, it will generally feature a high utilisation rate. That is, of course, unless the economic imperative driving the pipeline investment changes substantially after the pipeline investment has been made. On the other hand, flow patterns tend to be locked in by prior pipeline investments. To see the impact of including pipeline capacity and investments (note, the model considers only new additional investments in CO_2 and X-fuels infrastructure), we take a closer look at the utilisation and transportation of natural gas and the four commodities CO_2, e-methanol, ammonia, and hydrogen.

To see the impact of including pipeline capacity and investments on the utilisation and transportation of the four commodities CO_2, e-methanol, ammonia, and hydrogen, the results of Scenario 0 are compared with Scenario 2 and Scenario 3.

Hydrogen

Figure 6.17: Hydrogen pipeline capacity and annual flow from Qinghai



Regarding the utilisation of the hydrogen (H2) pipelines, there are a number of provinces where the utilisation rate differs significantly between the base scenario (SC0) and the infrastructure scenarios (SC2 and SC3) Examples are Qinghai, Sichuan and Yunnan.

In Qinghai province, the modelling results of the different scenarios show a significant difference. The hydrogen pipeline capacity depicted in Figure 6.17 represents the aggregated capacity of all hydrogen pipelines from Qinghai to other neighbouring provinces.

Similarly, the average flow is the aggregated hydrogen flow. Figure 6.17 shows that the hydrogen capacity remains constant in the SC0[23] scenario from 2035 to 2060, while there is a sharp increase in the construction of new hydrogen pipeline capacity in the two infrastructure scenarios (SC2 and SC3). The average annual flow of hydrogen follows the pattern of available capacity. Table 6.3shows the hydrogen pipeline utilisation, calculated by dividing the annual flow by available capacity. As can be seen in the table, for all years between 2030 and 2060, the utilisation rate is significantly higher in the infrastructure

[23] Capacities in SC0 scenario, which does not consider physical transmission, are defined as the maximum transport that has taken place until the year shown.

scenarios (SC2, SC3) than in the scenario that does not take account of hydrogen infrastructure (SC0).

Table 6.3: Hydrogen Pipeline Utilisation (Qinghai)

H2 Pipeline utilization (Qinghai)			
Year	SC0	SC2	SC3
2030	34%	89%	61%
2040	29%	92%	84%
2050	7%	87%	84%
2060	23%	84%	80%

Table 6.4: Full Load Hours of Electrolysers and E-fuel Production Processes

		2030	2040	2050	2060
SC0 (CNS2)	Electrolysers (total)	61%	64%	60%	65%
	AEC	59%	48%	48%	57%
	PEM	26%	44%	33%	36%
	SOEC	98%	100%	100%	100%
	Ammonia Synthesis	99%	97%	100%	100%
	Fischer-Tropsch	0%	88%	21%	49%
	Methanol Synthesis	100%	94%	78%	68%
	Methanol Upgrade	100%	95%	77%	71%
SC2 (P2X Infrastructure)	Electrolysers (total)	65%	60%	55%	57%
	AEC	64%	58%	37%	50%
	PEM	46%	23%	29%	21%
	SOEC	85%	100%	98%	100%
	Ammonia Synthesis	100%	100%	100%	100%
	Fischer-Tropsch	6%	89%	66%	31%
	Methanol Synthesis	100%	99%	67%	71%
	Methanol Upgrade	100%	95%	68%	71%
SC3 (Full Infrastructure)	Electrolysers (total)	64%	59%	55%	57%
	AEC	63%	57%	37%	50%
	PEM	45%	20%	29%	21%
	SOEC	85%	99%	100%	100%
	Ammonia Synthesis	100%	100%	100%	100%
	Fischer-Tropsch	5%	89%	68%	58%
	Methanol Synthesis	100%	99%	64%	71%
	Methanol Upgrade	100%	95%	68%	71%

Table 6.4 shows the difference in full load hours for electrolysers and e-fuel production processes in the different scenarios for the whole of China. Except for 2030, the utilisation rate for electrolysers is slightly lower on average in the infrastructure scenarios (SC2 and

SC3) compared to SC0. This is linked to a relatively reduced flexibility in the infrastructure, from the pipeline representation, leading to slightly more 'overplanting' in different provinces. In general, the SOEC electrolysers have more full-load hours as they are more expensive but also more efficient than PEM and AEC.

For ammonia and methanol, the full load hours are over 64% in all scenarios and years – these commodities however only play a minor role in the calculations. Average full load hours for these processes drop over time, due either to cost reductions or their increasing role in supporting balancing of the power system on the consumption side.

CO_2

In the scenarios, CCS facilities are installed primarily in regions which have heavy industries that are still emitting CO_2 by 2060. Also, carbon capture facilities are built at power plants where biomass can be sourced, so that the CO_2 can be captured and either used or stored to generate negative CO_2 emissions. Pipeline investments connect these areas with areas which hold carbon sequestration potential.

Figure 6.18 shows model results for CO_2 capture per region in 2060. While the patterns in Scenario 0 are very similar to those in the infrastructure scenarios (SC2, SC3), there is a significant difference visible in the East of the country, i.e., the provinces Zhejiang, Shanghai, Jiangsu, Fujian and Anhui. The CO_2 capture potential of the industrial centres in these provinces is only partly utilised in SC0.

Figure 6.18: CO_2 capture per region in 2060

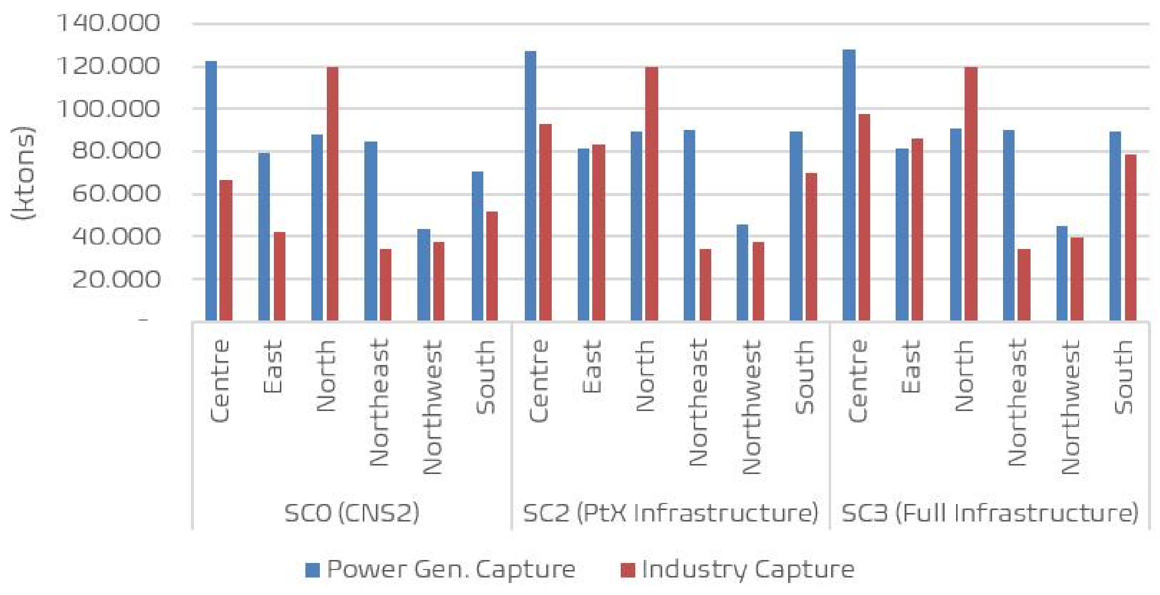
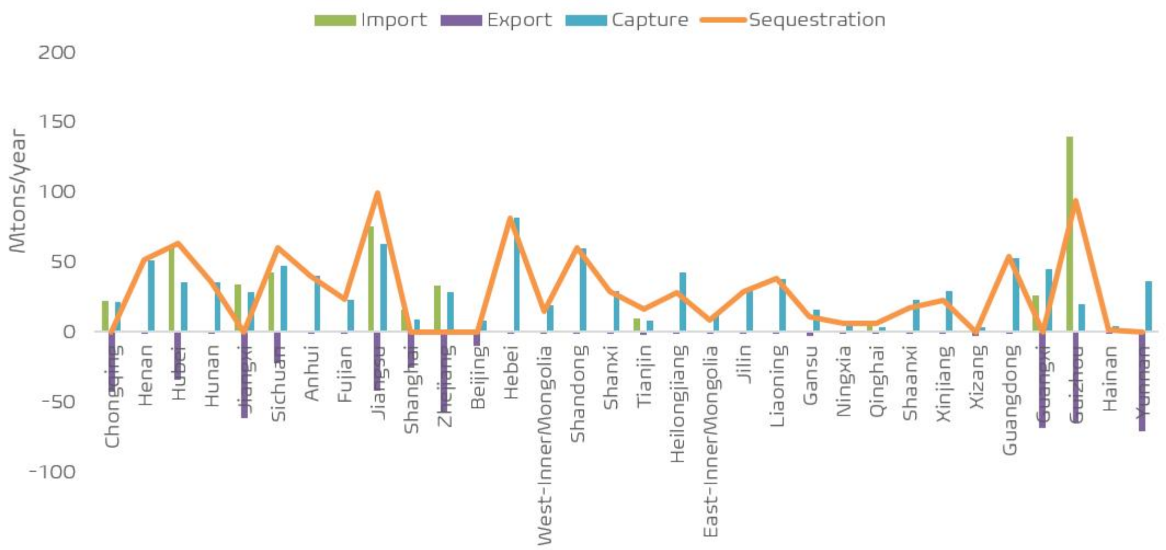


Figure 6.19 CO_2 balance by province SC3, 2060



The results show that CO_2 capture from power generation is estimated by the model to be particularly high in 2060 in the provinces of Heilongjiang, Henan, Shandong, and Guangdong, while industrial CO_2 capture is particularly high in Hebei. The pattern is similar with and without consideration of the gas and P2X pipeline infrastructure (SC3 and SC0). These provinces are all high load centres. No import or export of CO_2 is assumed in Heilongjiang, Henan, Shandong, and Guangdong in SC0.

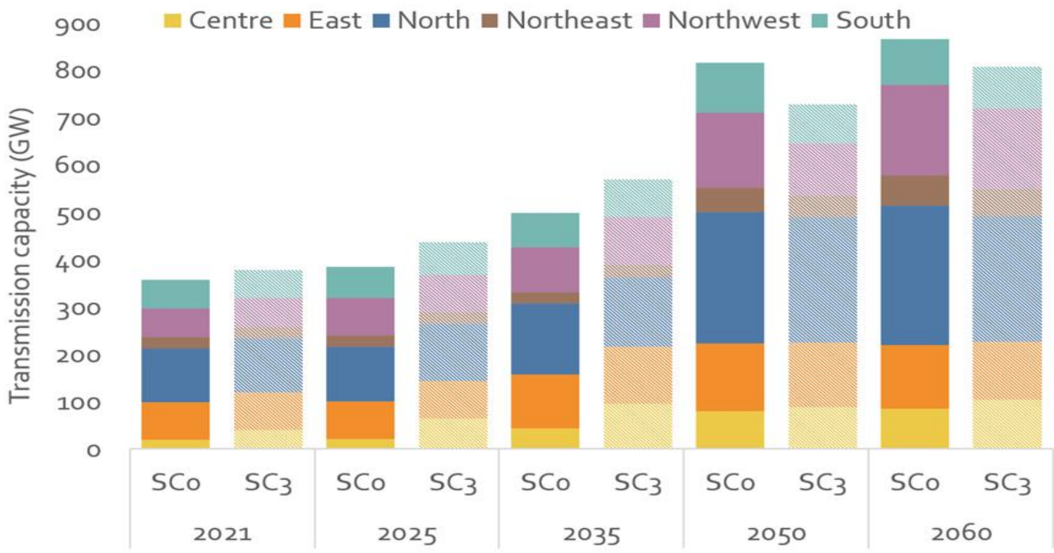
Figure 6.19 supports this interpretation. It depicts an overview of the CO_2 balances in 2060 in SC3 showing import, capture, export and sequestration. A small proportion of the CO_2 is utilised in further processing of X-fuels. It follows that high volumes of carbon capture and imports take place in provinces with a high value of sequestration. It is clear that high load provinces in the centre, north and south of the country are importing CO_2, while provinces in the north-east and north-west are export-oriented.

6.3.3. The impact of including natural gas and P2X infrastructure modelling

It is evident from the modelling that the pipeline representation reflects competition between alternative forms of energy commodity transportation. The transmission of hydrogen is an alternative to the transmission of electricity and infrastructure investment in one form of energy affects the others. Figure 6.20 shows the results for the power transmission capacity in Scenario 0 (CNS2) and Scenario 3 (full infrastructure scenario). Until 2035, the total power intra-transmission provincial capacity is higher in Scenario 3 than in Scenario 0, while in 2050 and 2060 the power transmission capacity is lower in Scenario 3 than in Scenario 0.

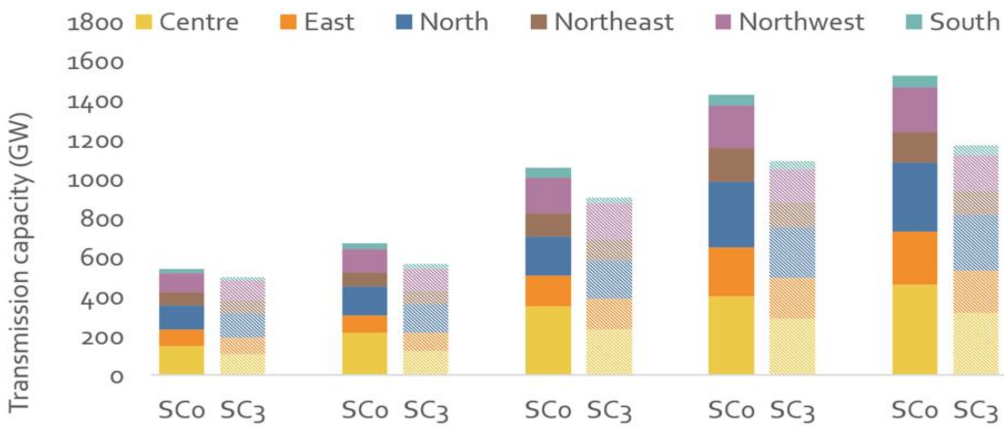
The electricity grid is considered in both scenarios, but the gas and P2X infrastructure is only considered in Scenario 3. In the centre of China more transmission capacity is being built over the whole time frame in Scenario 3. This could reflect the fact that grid investments are made at an earlier stage, when the full infrastructure is considered, and moreover, in later years less power transmission capacity is required because hydrogen is being transported rather than power.

Figure 6.20: Intra-provincial power transmission capacity in SC0 and SC3



Like intra-provincial transmission capacity, inter-provincial transmission capacity (Figure 6.21) is lower when gas and P2X infrastructure are taken into account, on all time horizons.

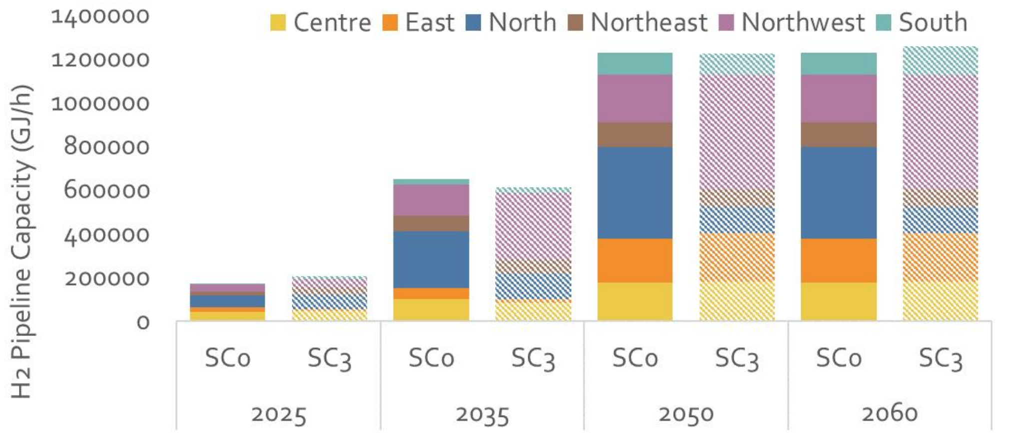
Figure 6.21: Inter-provincial power transmission capacity in SC0 and SC3



The results show lower amounts of inter-provincial power transmission capacity when natural gas and P2X infrastructure are taken into account (Scenario 3).

Looking at the results for hydrogen pipeline capacity in Figure 6.22, there is a slightly higher capacity for hydrogen infrastructure visible in 2060. Interestingly, in Scenario 3, between 2035 and 2060, more hydrogen pipeline capacity is built in the northwest, and fewer hydrogen pipelines are built in the north. It is evident that provinces with high VRE potential, like Xinjiang, Qinghai and Gansu, feature installation of hydrogen infrastructure, both to satisfy local demand and to meet demand in high-consumption provinces such as Beijing, Hebei and Tianjin.

Figure 6.22: Hydrogen pipeline capacity in SC0 and SC3



7. Discussion and conclusion

The first ECECP collaboration entitled: 'ENTSO-E Grid Planning Modelling Showcase for China Report'[24], focused on using the ENTSO-E methodology for a Cost Benefit Analysis in grid planning processes in China. Building on the experience from that previous study, the current project has expanded upon the concept of an integrated energy system approach to highlight the impact of an integrated system modelling approach.

Recognising the potential benefits of renewable energy integration, the study explores synergies and opportunities by integrating multiple energy sectors. By adopting an integrated approach, the potential for enhanced sector coupling is unlocked, thereby facilitating the seamless integration of renewable energy sources, and maximising overall system efficiency.

Through this comprehensive analysis, the report seeks to provide valuable insights into how best to optimise system planning processes and achieve a more sustainable and resilient energy future.

As the findings show, an integrated energy system approach can enhance efficiency, promote renewable energy integration, improve flexibility and resilience, enable sector coupling and electrification, optimise costs, and support coordinated policy and planning efforts, all of which contribute to achieving decarbonisation targets more effectively.

A comparison of scenarios that take account of the physical transmission infrastructure representation (SC1, SC2, SC3) with a scenario that does not take account of the physical gas and X-pipelines (SC0) highlights the benefits of the integrated modelling approach.

The pipeline representation in our model reflects the competition between alternative forms of energy commodity transportation. The results of the analysis in Chapter 7 have shown that on the level of the electricity grid, power transmission capacity is lower in the full infrastructure scenario (SC3) than in a scenario where only the electricity grid is considered as infrastructure for the optimisation (SC0). At the same time, we see changes in the hydrogen infrastructure capacity, where more hydrogen pipeline capacity is built in provinces with high VRE potential to ship to provinces with high energy consumption.

Furthermore, the usage of natural gas for power generation differs significantly in the modelling, depending on whether the gas pipeline infrastructure is factored in or not. In the scenarios where natural gas pipelines are considered (SC1 and SC3), the usage of natural gas for power generation is higher, since the gas infrastructure has been already built and is used as long as it is economically the better option and within the emissions constraint.

With regard to P2X infrastructure additions, the results show that the utilisation rate of the X-pipelines was significantly higher in the scenarios that took account of physical transmission infrastructure. This is because once a pipeline has been built it can be used virtually cost-free. This is illustrated by the results for Qinghai province, where the modelling results yielded by the different scenarios show a significant difference. For all years between 2030 and 2060, the capacities of the hydrogen pipelines and the utilisation rates are significantly higher in the infrastructure scenarios (SC2, SC3) than in the scenario that omits hydrogen infrastructure (SC0).

In all the scenarios, CO_2 capture and storage facilities are installed primarily in regions which have heavy industries that still emit CO_2 by 2060. Also, carbon capture is mounted on power plants where biomass can be sourced, so that the CO_2 can be captured and used or stored to generate negative CO_2 emissions. Pipeline investments connect the captured CO2 with areas which hold carbon sequestration potential.

[24] http://www.ececp.eu/en/entso-e/

In general, provinces showing high volumes of carbon import and capture have high potential for carbon sequestration. It is clear that high load provinces in the centre, north and south are importing CO_2, while provinces in the north-east and north-west are more export-oriented.

In terms of the link between VRE and hydrogen, the modelling shows more hydrogen pipeline capacity being built in the northwest, and fewer hydrogen pipelines in the north, demonstrating that provinces with high VRE potential like Xinjiang, Qinghai and Gansu are prime candidates for installation of hydrogen infrastructure, to satisfy both local demands and to ship to consuming provinces such as Beijing, Hebei and Tianjin.

The examples show that an integrated system approach better represents the existing resources and ensures that they are used. This contributes to a cost-efficient transition of the energy system to achieve the net-zero target.

Energy modelling is often focused on the power sector when seeking to achieve net-zero targets: knowledge of how to decarbonise the power system already exists and the costs and challenges are understood. However, solutions for 'hard-to-abate' emissions require an integrated focus on the energy supply chain, resources, technologies, system efficiency and sector coupling.

As this analysis indicates, P2X and CCUS are only cost-effective if inputs are low-cost and value streams are integrated. Carbon capture and sequestration are seen as the main solution to address negative emissions in the power sector but they are expensive and energy intensive. However, it is often overlooked that these approaches also offer flexibility opportunities to support the energy transition.

It is crucial to reach a carbon-free energy system at reasonable economic cost, with optimised use and development of key energy infrastructure. For this, optimisation of both gas and electricity infrastructure is vital: this is how to ensure the most efficient use of existing infrastructure and influence the use of gas as a transition fuel. Significant new infrastructure and investment will be necessary to achieve a net-zero carbon energy system.

By showcasing an integrated modelling approach of China's electricity, gas and P2X sector, the project has strengthened our understanding of the country's future needs for more coordinated approaches towards energy infrastructure investment and operational planning and regulation.

This final report of the project B2.6 *Investments and Technologies for Net-Zero Carbon Infrastructure* under the EU-China Energy Cooperation Platform (ECECP) showcases not only the implementation of integrated energy system modelling, but also a successful exercise of modelling cooperation between European and Chinese teams. The project acknowledges that only through cooperation can the energy system be transformed towards a climate neutral system.

The time to achieve a net-zero energy system is very limited. If each country develops technology on its own, it will be difficult to reach the target. The EU will not be able to reach its climate targets without China, and China will not be able to reach its climate targets in isolation from the rest of the world.

Annex

Glossary

CAGR - Compound Annual Growth Rate

CEC – China Electricity Council

CETO - China Energy Transformation Outlook

CNREC/ERI - China National Renewable Energy Centre/Energy Research Institute

CONE – cost of new entry

CCUS - Carbon Capture, Utilisation, and Storage

DEA – Danish Energy Agency

Ea – Ea Energy Analyses

ECECP – EU-China Energy Cooperation Platform

EENS – expected energy not served

EV – Electric vehicle

G2P - gas to power

LNG - Liquified Natural Gas

LCOE – levelised cost of electricity

LOLE - loss of load expectancy

MOHURD - Ministry of Housing and Urban-Rural Development

NECP - national energy and climate plans

P2C – power to cool / power to chemicals

P2F – power to fuels

P2G - power to gas

P2H – power to heat

P2L – power to liquid

P2P – power to power / power to products

P2X / PtX – Power to X

RE – renewable energy

SGERI – State Grid Energy Research Institute

SoS – Security of Supply

TSO – Transmission System Operator

TYNDP – Ten Year Network Development Plan (developed by ENTSO-E and ENTSO-G)

VOLL - value of lost load

VRE – Variable renewable energy

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