Scenario Analysis of Energy Transition in Eastern Coastal Metropolitan Regions of China

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Scenarios: a question of perspectives?!

Local solutions to local challenges require specific transition pathways

Abstract

Ratifying the Paris Treaty in 2016, China committed itself to the global climate target to keep the global temperature increase well below 2 °C. With an expected accelerated urbanization process until 2050 and high industrial activity, China faces big challenges in achieving an environmentally friendly energy supply and, in particular, mitigating CO_2 emissions. Especially the eastern coastal metropolitan regions are playing an important role in decision making and implementation processes on the way to a decarbonized economy and society. The national and provincial administrations in China have already started to address the issue of energy transition towards a low-carbon system, but long-term integrated transition plans are not yet available on the regional level. In this thesis I therefore focus on two metropolitan regions of eastern China (Beijing-Tianjin-Hebei region in the north and Yangtze River Delta region in the south) with high energy consumption and related CO_2 emissions. The analysis starts with the main challenges the regions are facing with regard to energy transition and the existing energy policy plans on different administrative levels. The review shows that the current policies are rather short-term driven and weak regarding sector coupling and regional integration.

As in China economic activities and population are concentrated in the eastern coastal regions, while renewable energy resources are concentrated in the western inland regions, specific regional challenges and conditions must be taken into account when modelling long-term integrated energy systems. In my thesis, three scenarios are therefore constructed, namely the Current Policy Scenario (CPS), the Natural Gas & Nuclear Scenario (NGNS) and the Renewable & Import Scenario (RIS), which are based on a normative storyline-and-modelling approach. The scenario analysis shows that regional CO_2 emissions could be significantly reduced in all sectors by adjusting the economic structure, implementing efficiency measures, replacing coal and oil, and multi-sector electrification supported by enhanced electricity import capacities. Due to the massive electrification, CO_2 emissions in both regions will remain mainly from gas combustion in the power sector. The scenario comparison provides insights into requirements of the energy transition regarding the implementation of new technologies and their effects. Thus, it can serve as a basis for deriving political strategies from long-term perspective to further shape the transition process in metropolitan regions from both the supply and the demand side.

In order to analyze import options from renewable electricity for the metropolitan regions, a case study focusses on the Beijing-Tianjin-Hebei region with Inner Mongolia as the supply region. Main research questions are how a predominantly renewable energy power supply can be implemented and which shares of locally available or imported renewable resources can be used. Based on the Renewable & Import Scenario (RIS), the future power systems are further analyzed applying the REMix energy system model developed at DLR, which uses a cost-minimizing algorithm. Temporally and spatially resolved load profiles and variable wind and solar power generation are the most important input data. A sensitivity analysis for key parameters provides important information on the robustness and interactions in modelling. The results provide insights into the infrastructural needs such as storage and grid expansion.

The above model-based scenario analysis depends on a number of key assumptions and leads to conclusions mainly from a system perspective. It demonstrates that the eastern metropolitan regions could largely be supplied with imported electricity from onshore wind and solar power plants in the west at reasonable costs. Therefore, regional coordination and governance, the establishment of energy and carbon markets are crucial factors for successful energy transition processes at different administrative levels. Regionally integrated modelling of the energy system can support decision making in the implementation of new technologies and infrastructure options for metropolitan regions to achieve the long-term climate targets.

Zusammenfassung

Mit der Ratifizierung des Übereinkommens von Paris im Jahr 2016 hat sich China dem globalen Klimaziel verpflichtet, den globalen Temperaturanstieg deutlich unter 2 °C zu halten. Mit einem erwarteten beschleunigten Urbanisierungsprozess bis 2050 und einer hohen industriellen Aktivität steht China vor großen Herausforderungen, um eine umweltfreundliche Energieversorgung zu erreichen und insbesondere die CO_2-Emissionen zu verringern. Insbesondere die Metropolregionen an der Ostküste spielen eine wichtige Rolle bei der Entscheidungsfindung und Umsetzung auf dem Weg zu einer dekarbonisierten Wirtschaft und Gesellschaft. Die nationalen und provinzialen Verwaltungen in China haben bereits begonnen, sich mit der Frage der Energiewende hin zu einem kohlenstoffarmen System zu befassen, aber auf regionaler Ebene liegen noch keine langfristigen integrierten Übergangspläne vor. In dieser Arbeit konzentriere ich mich daher auf zwei Metropolregionen Ostchinas (Peking-Tianjin-Hebei-Region im Norden und Yangtse-Delta-Region im Süden) mit hohem Energieverbrauch und damit verbundenen CO_2-Emissionen. Die Analyse beginnt mit den wichtigsten Herausforderungen, denen sich die Regionen im Hinblick auf die Energiewende und die bestehenden energiepolitischen Pläne auf verschiedenen Verwaltungsebenen gegenübersehen. Die Überprüfung zeigt, dass die derzeitige Politik in Bezug auf die Kopplung der Sektoren und die regionale Integration eher kurzfristig und schwach ist.

Da sich in China die wirtschaftlichen Aktivitäten und die Bevölkerung auf die östlichen Küstenregionen konzentrieren, während sich die erneuerbaren Energiequellen auf die westlichen Binnenregionen konzentrieren, müssen bei der Modellierung langfristiger integrierter Energiesysteme spezifische regionale Herausforderungen und Bedingungen berücksichtigt werden. In meiner Arbeit werden daher drei Szenarien konstruiert, nämlich das aktuelle politische Szenario (CPS), das Erdgas- und Nuklearszenario (NGNS) und das erneuerbare und importierte Szenario (RIS), die auf einem normativen Storyline- und Modellierungsansatz basieren. Die Szenarioanalyse zeigt, dass die regionalen CO_2-Emissionen in allen Sektoren erheblich reduziert werden könnten, indem die Wirtschaftsstruktur angepasst, Effizienzmaßnahmen umgesetzt, Kohle und Öl ersetzt und die sektorübergreifende Elektrifizierung durch verbesserte Stromimportkapazitäten unterstützt werden. Aufgrund der massiven Elektrifizierung bleiben die CO_2-Emissionen in beiden Regionen hauptsächlich bei der Gasverbrennung im Stromsektor. Der Szenariovergleich liefert Einblicke in die Anforderungen der Energiewende hinsichtlich der Implementierung neuer Technologien und deren Auswirkungen. Somit kann es als Grundlage für die Ableitung politischer Strategien aus einer langfristigen Perspektive dienen, um den Übergangsprozess in Metropolregionen sowohl von der Angebots- als auch von der Nachfrageseite weiter zu gestalten.

Um die Importoptionen aus erneuerbarem Strom für die Metropolregionen zu analysieren, ich konzentriere mich eine Fallstudie auf die Region Peking-Tianjin-Hebei mit der Inneren Mongolei als Versorgungsregion. Hauptforschungsfragen sind, wie eine überwiegend erneuerbare Energieversorgung implementiert werden kann und welche Anteile lokal verfügbarer oder importierter erneuerbarer Ressourcen genutzt werden können. Basierend auf dem erneuerbaren und importierten Szenario (RIS) werden die zukünftigen Stromversorgungssysteme anhand des am DLR entwickelten REMix-Energiesystemmodells weiter analysiert, das einen kostenminimierenden Algorithmus verwendet. Zeitlich und räumlich aufgelöste Lastprofile sowie variable Wind- und Sonnenenergieerzeugung sind die wichtigsten Eingangsdaten. Eine Sensitivitätsanalyse für Schlüsselparameter liefert wichtige Informationen zur Robustheit und den Wechselwirkungen bei der Modellierung. Die Ergebnisse liefern Einblicke in die Infrastrukturanforderungen wie Speicher und Netzausbau.

Die obige modellbasierte Szenarioanalyse hängt von einer Reihe wichtiger Annahmen ab und führt hauptsächlich aus Systemsicht zu Schlussfolgerungen. Es zeigt, dass die östlichen Metropolregionen größtenteils zu angemessenen Kosten mit importiertem Strom aus Onshore-Wind- und Solarkraftwerken im Westen versorgt werden könnten. Regionale Koordination und Governance, die Errichtung von Energie- und Kohlenstoffmärkten sind daher entscheidende Faktoren für erfolgreiche Energiewendeprozesse auf verschiedenen Verwaltungsebenen. Die regional integrierte Modellierung des Energiesystems kann die Entscheidungsfindung bei der Implementierung neuer Technologien und Infrastrukturoptionen für Metropolregionen unterstützen, um die langfristigen Klimaziele zu erreichen.

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List of Acronyms

AC	Alternating Current
ADV	Advanced Scenario
B2°C	Below 2°C Scenario
Bcf/D[1]	billion cubic feet per day
bcm[2]	billion cubic meters
BNI	Beam Normal Irradiance
Bt	Billion tons
BTH	Beijing-Tianjin-Hebei
CAES_AD	Compressed Air Energy Storage (Adiabatic)
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CHP	Combined Heat and Power
CNG	Compressed Natural Gas
CNREC	China National Renewable Energy Center
CPS	Current Policy Scenario
CR	Curtailment Rate
CREO	China Renewable Energy Outlook
CSP	Concentrating Solar Power
DC	Direct Current
DH	District Heating
DNI	Direct Normal Irradiance
DSM	Demand Side Management
E[R]	Energy Revolution Scenario
EEZ	Exclusive Economic Zones
EHV	Extra High Voltage
EIA	U.S. Energy Information Administration
EnDAT	Energy Data Analysis Tool
ESM	Electricity Spot Market
EU	European Union
EVs	Electric Vehicles
FFP	Fossil Fuel Prices
FITs	Feed-in Tariffs
FLH	Full Load Hours
FYP	Five-year Plan
GAMS	General Algebraic Modelling System
GDP	Gross Domestic Product
GHG	Greenhouse Gases
GHI	Global Horizontal Irradiance
GIS	Geographic Information System
GOJP	General Office of Jiangsu Province
GOSC	General Office of the State Council
GT	Gas Turbine

[1] A common unit of measurement for large production rates of natural gas.
[2] A unit of natural gas production and trade.

HDV	Heavy Duty Vehicles
HP	Heat Pump
HVAC	High Voltage Alternating Current
HVDC	High Voltage Direct Current
ICT	Information Communications Technology
IEA	International Energy Agency
IPCC	Intergovernmental Panel on Climate Change
LDV	Light Duty Vehicles
LNG	Liquefied Natural Gas
MEIC	Multi-resolution Emission Inventory for China
MHC	Ministry for Housing and Construction
MIIT	Ministry of Industry and Information Technology
MLR	Ministry of Land and Resources
MMbbl[3]	Million Barrels per Day
mtpa[4]	metric tonnes per annum
NBS	National Bureau of Statistics
NC	National Congress
NDCs	Nationally Determined Contributions
NDRC	National Development and Reform Commission
NDSAP	National Energy Development Strategy and Action Plan
NEA	National Energy Administration
NGNS	Natural Gas & Nuclear Scenario
NMLR	National Ministry of Land and Resources
NPS	New Policy Scenario
OECD	Organisation for Economic Co-operation and Development
PC	Passenger Cars
PV	Photovoltaic
RE	Renewable Energy
REMix	Renewable Energy Mix
RIS	Renewable & Import Scenario
RMB	Renminbi (Chinese yuan)
RPS	Renewable Portfolio Standard
SDGs	Sustainable Development Goals
SDS	Sustainable Development Scenario
SM	Solar Multiple
SPS	Stated Policy Scenario
TES	Thermal Energy Storage
UHV	Ultra-high Voltage
UN	United Nations
UNEP	United Nations Environment Programme
VRE	Variable Renewable Energy
WEO	World Energy Outlook
YRD	Yangtze River Delta

[3] It means a production rate of 1 000 000 barrels of petroleum per day.
[4] A typical measurement unit in liquefied natural gas (LNG) markets for production and facility capacity.

1 Introduction and Outline

1.1 Background

According to the Intergovernmental Panel on Climate Change (IPCC), greenhouse gas (GHG) emissions need to decrease by 70 - 95% until 2050 for a significant chance to keep the temperature increase well below 2 °C. With almost 80% of all CO_2 emissions, the energy sector must be the focus of mitigation [41]. Additionally, it becomes increasingly obvious that China will play a major role, in transforming the energy system: "When China changes, everything changes" [39] (p. 25). Ratifying the Paris Treaty in 2016, China committed itself to the global climate target. This commitment poses huge challenges for the energy system, with the Chinese president calling for no less than an "energy revolution" [39]. The main imminent challenges specific to the country have already been identified. By and large these are: (1) limiting the growth of energy demand, (2) phasing out fossil fuels, especially coal and oil, and 3) integrating large shares of renewable energy sources (RES) into the system [39, 178]. Besides, cities account for 70% of gross domestic product (GDP), over 60% of global energy consumption, and 70% of greenhouse gas (GHG) emissions [128]. Specifically, urban agglomerations contribute 64% to China's energy-related CO_2 emissions and thus play a vital role in determining the future of climate change [135]. Important global agendas addressing sustainable urbanization are the Sustainable Development Goals (SDGs) and the New Urban Agenda [92]. Both have a broad range of ambitious development goals and visions regarding, e.g., safety, sustainability, and resilience. Also, the Paris Agreement, which is much more focused on climate change, implies ambitious development goals for cities and urban agglomerations. Improving energy efficiency and reducing CO_2 emissions from the energy supply have become major tasks for sustainable urban development [63, 64, 67, 134]. However, especially in cities, a transition of the energy system is difficult to implement as the demand is high and the renewable energy (RE) potentials are relatively low. Thus, RE expansion requires integrated strategies for the joint development of cities and their hinterlands.

The cities in eastern coastal metropolitan regions of China are focal points of energy demand in terms of electricity, heat, cooling, and mobility due to high population densities and economic activities. In addition, with the different roles cities are playing in industry, service, commerce, education, culture and tourism, they can particularly promote changes in energy-consumption structures. The provincial-level cities of Beijing, Tianjin, and Shanghai are each home to a population of more than 10 million, thus they are megacities according to the definition of the UN [129]. They are characterized by high economic growth rates and large industrial economic structures, but also considerable service-oriented economic activities. However, they all have a limited hinterland and RE resources. Due to the fast urbanization and industrialization processes, serious air pollution has occurred and urbanized areas have become major contributors to global GHG emissions [124]. However, a transition towards low-carbon-emission pathways poses novel challenges beyond traditional planning and urban development polices [19, 141]. Current fossil fuel dominated energy supply systems and industries are the major sources of CO_2, $PM_{2.5}$, and SO_2 emissions, while transport sector also significantly contributes to NO_x emissions especially concentrated in urban environment. In particular, coal reduction and transport decarbonization are key strategies to improve air quality, which are therefore important drivers of the energy system transition, especially for the eastern coastal metropolitan regions of China.

The provincial administrations in China have already started to address the topic of energy transition. A variety of local policy plans have been released to tackle RE expansion from provincial authorities. But long-term integrated energy plans are neither yet available, nor is it clear, if the most pressing challenges of the energy transition are sufficiently and simultaneously addressed in the existing policy plans within the metropolitan regions. Regional focuses of this study are therefore two metropolitan regions of eastern China with high energy consumption and related CO_2 emissions. However, current policies are rather short-term driven and weak from sectoral coupling and regional integration (see detailed analysis in Section 2.4).

1.2 State of Knowledge

The stringency of China's energy and climate targets in 2030 and the policy needed to realize these targets are full of controversy, mainly as a result of multiple future uncertainties [12]. Various scientific studies already exist on necessary or achievable energy transition processes in China. Several long-term scenarios have explored target-oriented pathways towards a low-carbon-energy future on the national level [48, 154, 174]. China's energy transition toward the 2 °C goal until 2100 were examined in [95] by a bottom-up model with non-fossil energy accounting for 50 - 70% and 85% of primary energy consumption in 2050 and 2100, respectively. In a high renewable penetration scenario analysis, the percentage of RE in the primary energy supply would reach 62% by 2050 according to [178]. In addition, decarbonization scenarios for China can be found in global scenario studies such as World Energy Outlook 2017 [2] and Energy [R]evolution: A Sustainable World Energy Outlook 2015 [8]. However, current policies in China still seem to have no clear vision for the role of RES in the long-term future. The new five-year plans on different administrative levels released recently define short-term targets mainly for the energy system in 2020 [82]. These kinds of near-term policies have a strong impact on the development of future market and infrastructures and thus have important implications for further long-term transformation pathways (see, e.g., [1, 24]). Just recently, the China Renewable Energy Outlook 2017 (CREO) [178] identified a gap between the currently available policy on the national level and the necessary development and measures to comply with the Paris Agreement. Additionally, [178] picked the specific example of the Beijing-Tianjin-Hebei (BTH) region to identify the significance of regional integrated policy development for successful energy system transition. In general, the regional dimension plays an important role in sustainable energy system transformations, demanding integrated strategies of subnational governments (see, e.g., [7]). This obviously specifically holds true for a large country such as China, where energy transition policies need to be embedded in regional development plans [149] to coordinate cities and their hinterlands in terms of energy supply and demand and successful implementation of national policies [128].

Long-term strategies for energy system transformation have to cope with large uncertainties regarding the development of the society, the economy, relevant technologies and their successful implementation under certain policy and market mechanisms. Model-based scenario analysis is usually applied to guide the decision-making process regarding investments into the future energy systems and to analyze the corresponding consequences such as environmental benefits. Several representative examples of such studies exist following different approaches for scenario building, which show that alternative technical and structural options could be key elements for the realization of long-term transition pathways [39, 99, 100, 123, 174]. Some important options and aspects will be further discussed in Section 2.3 and related measures and developments targeted in current short-term national and regional policy plans (see Section 2.4), with the potential to further concretize and enhance them within a regionally integrated low-carbon transition pathway from long-term perspectives (see detail analysis in Chapter 4). One obvious issue is the further promotion of renewable energy, which covers most available technologies, including offshore wind, geothermal and biomass. However, it seems to be unclear whether expansion rates have already been in line with long-term national decarbonization targets.

Besides, the focus of renewable energy expansion policies should extend from the power sector and increasingly include the heat and transport sectors to fully decarbonize the entire energy system. Here it is essential that the development of future energy policies in the medium term also addresses sector coupling as a means to integrate larger shares of variable renewable energy (VRE) sources with consideration of the corresponding economic benefits (see, e.g., [91]), together with the development of information and communication technologies (ICT) [3]. Still, as RE heating targets are defined related to the supplied area while the development of future floor space in building sector is uncertain, it remains unclear how far near-term targets and measures are on track with long-term targets. In all energy systems, decarbonization of the heat sector generally poses great challenges and will require strict regulations and huge investments also on the aspect of efficiency improvement. In general, current energy transition related policies at different administrative levels are rather short-term and determined by the time horizon of 5 years (see detailed analysis in Section 2.4) without long-term transition perspectives. This increases the risk that the necessary policy measures will not be implemented in a timely manner and thus the ambitious long-term climate goals will not be achieved or that the required energy transition costs will be higher than necessary. Besides, there are still various barriers and implementation deficiencies of energy policies at the local level in China’s urban areas [142]. There is a lack of detailed studies on how long-term climate protection goals can be implemented in China's regions. The special boundary conditions in the eastern metropolitan regions also require analyses of the possible interactions between demand and supply regions and supporting infrastructural requirements for their use.

1.3 Scope and Structure of this Work

Therefore, the intention of my work is to contribute to the above topics by applying sophisticated methods and models for long-term scenario analysis with a focus on two metropolitan regions of eastern China. I combined a short term policy analysis on regional level with developing target-oriented normative storylines supported by quantitative energy system modelling. This was supplemented by a high spatial-temporal optimization of the power sector to investigate the penetration of renewable energies during the transition process from long-term perspectives to reach regional CO_2 emissions reduction targets and guarantee power supply security for metropolitan regions. This leads to conclusions regarding the suitability of different development pathways for overcoming the key challenges, the possible interaction of demand and supply regions, and relevant implications on technological and infrastructural needs as well as supporting energy policy strategies for the success of regional energy transition in China.

In this context I addressed in my thesis different key research questions with regard to the regional energy transition. In the first step I explored the current situation of the energy system in eastern coastal China, the major challenges of energy transition, and how far these have already been addressed by existing policy plans (Chapter 2). Based on this, I designed and applied a model-based scenario analysis to support policy advice for the strategic implementation of long-term integrated energy transition options both from supply and demand sides. This analysis comprises the assessment of renewable resources of China (Chapter 3), scenario building with three different variants for the overall regional energy system transformations (Chapter 4), and a detailed power system modelling for one exemplary demand and one supply region (Chapter 5). Finally, the results of the analyses are evaluated and discussed with regard to conclusions, limitations and outlook (Chapter 6). The summary of the structure of this work is shown in Figure 1.1.

More specifically, first, I analyzed in Chapter 2 if existing energy policy plans at different administrative levels in China are suitable for addressing the current challenges for energy system transition. I selected regions in China, which are specifically affected by these challenges. I considered two metropolitan regions in eastern China, the Beijing-Tianjin-Hebei (BTH) region and the Yangtze River Delta (YRD) region, which play a central role in the Chinese energy system in terms of economic growth and energy consumption while also, provide differences in the energy system layout mainly in terms of heat demand in the building sector. In this chapter I therefore characterized the energy systems of the two selected metropolitan regions, discussed specific challenges for the energy system transition, and carried out a systematic review of the relationship between the current available policies both on national, regional and provincial resp. municipal levels with corresponding measures and targets. Based on these overviews the analysis then focusses on how these policy plans comply with the main challenges and what are the gaps for long-term regional transition pathways. The evaluation of energy statistics in Section 2.1 reveals how far current energy supply systems in eastern coastal China are dominated by fossil fuels especially by coal for heat and power supply and oil products for transport, which results in serious air pollutions especially in urban areas and during the heating season in winter of northern China. In Section 2.2, key challenges of regional energy system transition are identified and characterized, whereas in Section 2.3 a literature review helped to identify key strategies, required actions and further aspects to overcome these challenges.

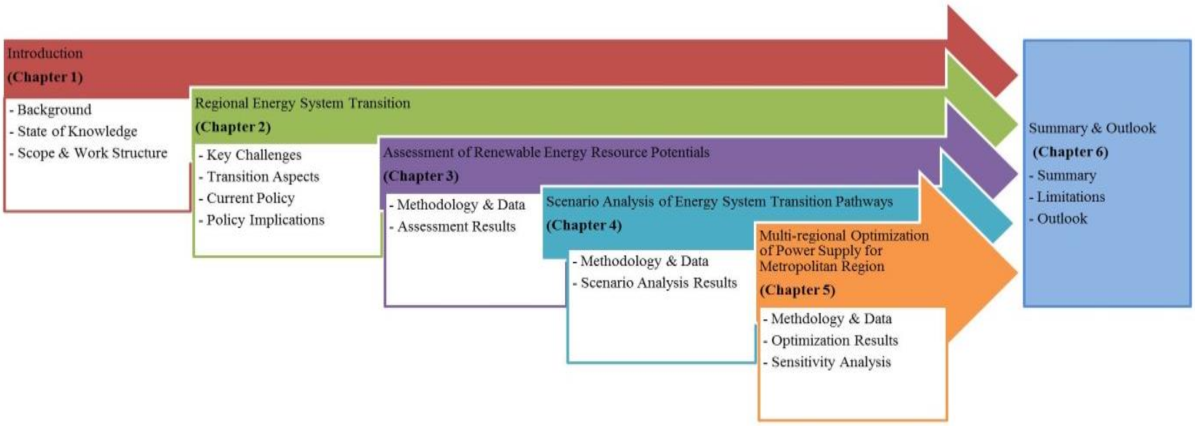


Figure 1.1 Structure of this work.

The result of these analyses provides insights into opportunities and difficulties for metropolitan regions to transform towards a decarbonized energy system. Therefore, storyli nes of future development pathways for such regions need to take into account several important context related factors. The concentration of population and economic activities in eastern China requires a high energy demand especially in regions with heavy industry (such as Hebei Province). The continuous urbanization process will further increase energy demand if no effective efficiency measures for building and transport sectors are taken [76]. On the other hand, land and renewable energy resources in eastern China are relatively limited (see analysis in Chapter 3), which will largely depend on importing fuels (such as natural gas and crude oil) from overseas market and electricity from domestic market especially from western China (e.g. hydro power to YRD region). Besides, the decarbonization of heat and transport sectors also largely rely on the strategy of deep electrification with the integration of variable renewable energies (VRE) especially for wind and solar both locally and imported. However, due to the lack of short-term electricity market, there are large curtailments from wind and solar power in still coal dominated inflexible power supply system and low utilization rate in existing transmission lines under current regulation and dispatching paradigms (see Section 5.1).

China has already started to deal with decarbonizing its energy system by releasing short-term policies in forms of five-year plans and action measures among different administrative levels. A detailed and systematic analysis in Section 2.4 investigates, if integrated, consistent and comparable targets among provinces already exist, both from short-term and long-term perspectives. Administrative barriers may exist for implementing decarbonization policies especially between renewable energy resource abundant regions and load centers such as megacities, and among different ministries and administrations. The analysis of Section 2.4 demonstrates the focus of current short-term policies. e.g., with regard to shutting down low-efficient coal boilers and power plants, enhancing natural gas import capacity to eastern China, planning of long distance high voltage transmission capacity to connect the west and the east, promoting the exploitation of wind resources, geothermal energy for heat supply, and solar radiation utilization in eastern regions. Policy decision making and transition processes also need the participation from other stakeholders such as State Grid, the five biggest power companies, distributed energy providers, city governors and citizens (see discussion in Chapter 6). I specifically identified, where regional policy currently fails to pave the way for an energy system transition at the beginning of Section 2.5 and discuss possible implications for a regional integration to solve energy system challenges of metropolitan regions from long-term perspectives.

Based on the regional policy aspects addressed in Chapter 2, the second step of my analysis focusses on three central consecutive aspects of energy transition: assessment of available renewable energy potentials (Chapter 3), transformation pathways covering the whole energy system (Chapter 4) and a detailed analysis for power system optimization, assessing the integration of variable renewable power and its spatial and temporal integration between regions (Chapter 5). In the last chapter I provide the policy implications based on the above scenario analysis for energy system transformation in eastern coastal metropolitan regions of China.

I assessed the renewable energy potentials for wind, solar photovoltaic (PV) and Concentrating Solar Power (CSP) of China using the GIS-based Energy Data Tool (EnDAT) developed at DLR. Other RE potentials of biomass, geothermal, small hydro power and pumped hydro were quantified based on a literature review in Chapter 3. The results represent annual generation potentials for each of the considered regions.

Based on that, the energy system for both regions was modelled with different transition perspectives by a normative approach. Chapter 4 documents methods and assumptions for scenario construction for the regional energy systems and provides the results and discussion for three different transition pathways for each of the two study regions. The energy scenarios were built as target-oriented pathways using an accounting framework to discuss different transition strategies. In order to address the option of a possible import of renewable energy in forms of electricity to metropolitan regions, a modelling case study focusses on the Beijing-Tianjin-Hebei metropolitan region with Inner Mongolia as a supply region (Chapter 5). The contextual energy scenario from Chapter 4 follows a pathway towards high renewable energy shares for power generation. Based on this framework, I analyzed the future power systems using the energy system model REMix, developed at DLR. The model applies a cost-minimizing algorithm. The parameterization was done assuming to limit CO_2 emissions to the level of 1995 and by achieving a minimum of 60% of renewable power generation by 2050. The model calculates the temporally and spatially resolved power load, the variable wind and solar power generation and infrastructural needs such as storage and grid expansion. Quantitative results illustrate the utilization of different technologies, investments in backup generation, storage, grid transfer and costs for electricity generation. The spatial resolution allows for conclusions about the power supply structure of the metropolitan region regarding generation, storage, transmitted energy and energy losses (such as curtailment during periods when production exceeds demand).

In the last chapter I provide the derived conclusions and modelling limitations with regard to the two eastern coastal metropolitan regions. Finally, an outlook regarding renewable energy-oriented market design is given (Chapter 6).

2 Regional Energy System Transition

The following chapter was previously published in [144]. The analysis is based on an overview of major challenges of energy system transition in China on the regional level and the identification of key transition aspects and required actions. In order to analyze the regional policies, I selected regions in China that are specifically affected by these challenges. I consider two metropolitan regions in eastern China, the Beijing–Tianjin–Hebei (BTH) region and the Yangtze River Delta (YRD) region, each of which plays a central role in China in terms of economic growth and energy consumption, while they have significant differences in the energy system layout. A detailed characterization of the energy systems of the two metropolitan regions is provided in the first section followed by a discussion of specific challenges, transition aspects, and fields for policy interventions for the energy system transition. A systematic review of current available policies related to energy transition targets at different administrative levels reveals how these policy plans comply with the main challenges. I try to identify where regional policies currently fail to pave the way for a target-oriented energy system and discuss possible implications for regional integration to solve the challenges from a long-term perspective. Figure 2.1 provides an overview of the approach for this analysis.

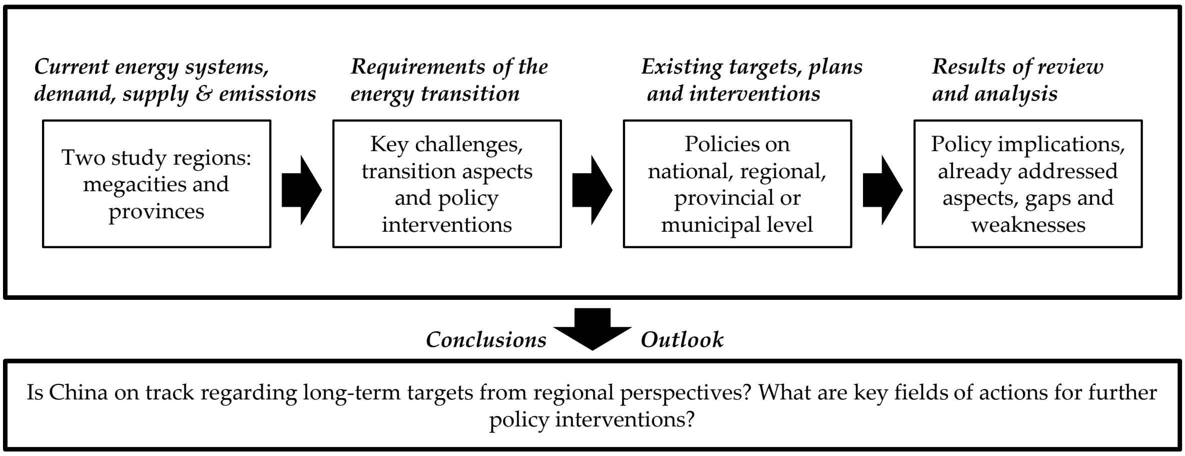


Figure 2.1 Overview of the methodology for the policy analysis [144].

2.1 Study regions

Due to the distribution of natural resources and various geographic conditions, population density and economic activity are unbalanced in China, especially between eastern and western parts of the country. This is also reflected in the spatial structure of energy demand and supply. The two study regions are located in eastern China in different climate zones, implying different heating and cooling demands. Regional and national energy balance tables from China Energy Statistical Yearbook 2016 can be used to compare current energy supply and consumption structures. The provided conversion factors are used for universal energy unit calculation from original physical quantities [140]. Data on population, urbanization rate, and added value by sector in 2015 are taken from the China Statistical Yearbook 2016 [180].

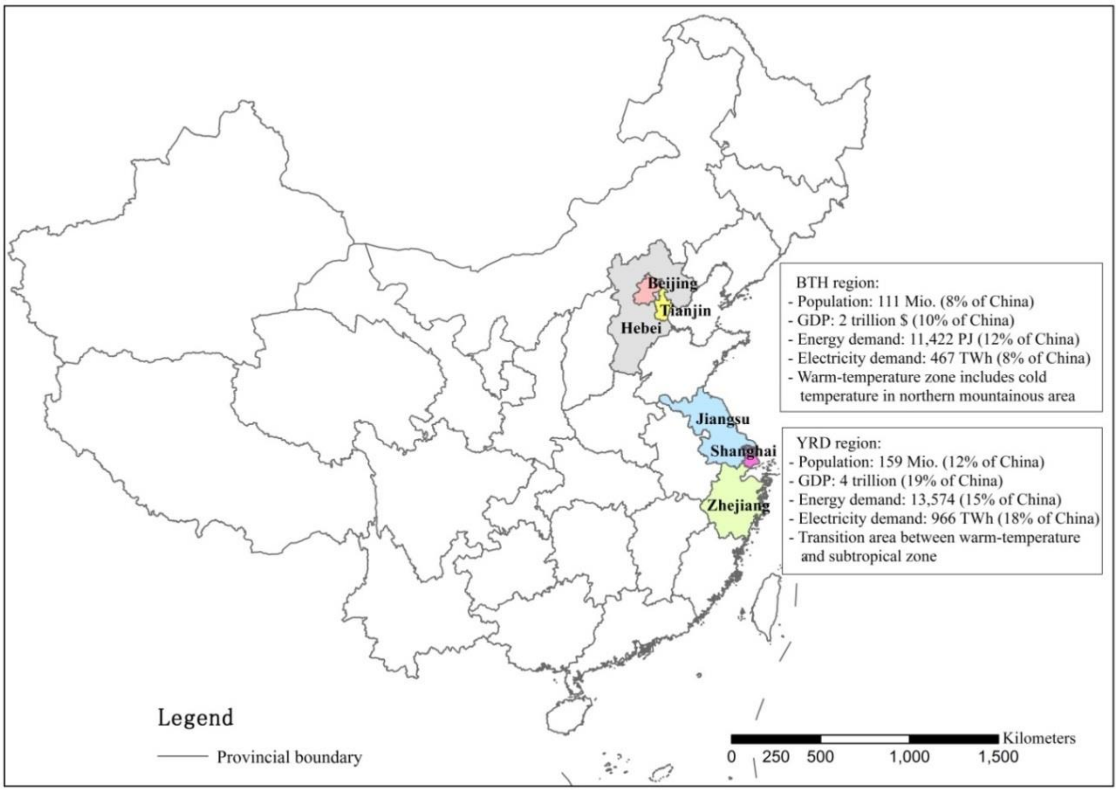


Figure 2.2 Geographical and administrative information of two study regions (statistical data of 2015 [180]).

The BTH region consists of two provincial-level cities, Beijing and Tianjin, and the province of Hebei (see Figure 2.2). It is located in warm-temperature zone with cold temperature in northern mountainous area, resulting in significant heating demand during the winter season, which is often covered by district heat in urban areas. The YRD region, with one provincial-level city, Shanghai, and two provinces, Jiangsu and Zhejiang, is located in a transition area between warm-temperature and subtropical climate zone characterized by hot summers and temperate winters with more cooling demand in the summer season and much less heat demand in winter. Currently, no widespread district heating system is implemented in this region. The energy demand is quite high in both study regions, accounting for 12% and 15% of national energy demand, respectively, in 2015 [175]. With an agglomeration of population and economy as well as continuous urbanization, the energy demand is expected to grow further if no effective efficiency control measures are taken [76].

In 2015, the population of the two study regions accounted for 8% and 12% of the national population, respectively [180]. The population densities in BTH and YRD are four to five times higher than the national average. The GDP per capita is also significantly higher in the two regions than the national average of 53,000 RMB per capita. In 2015, the GDP of the two study regions accounted for 29% of the national GDP [180]. In the same year, the energy demand accounted for 27% of the national energy demand, according to [180]. Also, the specific energy consumption per GDP in BTH is significantly higher than the national average of 1.3 MJ/RMB. The YRD region specifically accounts for a disproportionately high share of national GDP and electricity demand.

The current energy supply and consumption structures for the study regions and China are shown in the Appendix A: Figure A.1 to Figure A.**4**3. The following sections highlight specific characteristics of the two study regions regarding energy production and use.

2.1.1 Characteristics of Energy Supply

Except Beijing, all considered municipalities and provinces currently have coal-dominated heat and power supply systems, especially in Hebei Province, with shares higher than the national average. In the two municipalities of Tianjin and Shanghai, natural gas is used for around 10% of public power and heat supply, and in Beijing the share of natural gas is 54% for public heating plants and 82% for public power generation. Except in Beijing, with oil-dominated industrial energy consumption, coal is also the main final energy use in industry, but with regional differences: Beijing, Shanghai, and Zhejiang are well below the national average, while Hebei's consumption is much higher, with a coal share of 80%. The BTH region has a higher heat demand in residential and services and commerce sectors than the YRD region due to different temperature zones. District heating systems have a significant share in urban areas of BTH supplemented by a mixture of other technologies, mainly oil heaters. In rural areas, the use of coal in small boilers is still dominant in the residential sector. The shares of coal use are higher than the national average and reach 65% in Beijing, 64% in Hebei, and 48% in Tianjin. Compared to BTH, the final energy consumption of the residential sector in YRD is composed of different shares of electricity, oil, and gas. However, the penetration of RE into regional power generation is increasing recently. In 2018, there are 15 GW and 11GW grid connected installed wind capacity in BTH and YRD region with 29 TWh and 22 TWh generated electricity respectively (see Table 2.1). In 2018, 70% of grid connected PV are centralized PV stations in the BTH region while the installed PV power plants are more decentralized in the YRD region with 55% (see Table 2.2).

Table 2.1 Wind power development in study regions and China of 2018 (data source: [173])

	Wind			
Province	Installed capacity (grid connected)	Power generation	FLH	Curtailment rate[5]
	GW	TWh/yr	h/yr	%
Beijing	0.2	0.3	1866	/
Tianjin	0.5	0.8	1830	/
Hebei	13.9	28.3	2276	5.2
BTH	**14.6**	**29.4**	**2012**	**5.2**
Shanghai	0.7	1.8	2489	/
Jiangsu	8.7	17.3	2216	/
Zhejiang	1.5	3.1	2173	/
YRD	**10.9**	**22.2**	**2037**	**/**
Inner Mongolia	28.7	63.2	2204	10.3
China	**184.3**	**366**	**2095**	**7**

Table 2.2 PV power development in study regions and China of 2018 (data source: [89])

	PV	
Province	Installed capacity (grid connected)	
	GW	*of which centralized PV stations*
Beijing	0.4	*0.05*
Tianjin	1.3	*1.0*
Hebei	12.3	*8.6*
BTH	**14.0**	***9.7***
Shanghai	0.9	*0.06*
Jiangsu	13.3	*7.9*
Zhejiang	11.4	*3.6*
YRD	**25.6**	***11.6***
Inner Mongolia	9.5	*9.1*
China	**174.5**	***123.8***

[5] "/" means there is currently no curtailment from wind power.

In 2017, there are different types of resources were used for biomass power plants. The three municipal cities are dominated by municipal wastes while in three provinces there were also agriculture and forest residuals used for power generation (see Table 2.3).

Table 2.3 Biomass power development from different sources in study regions and China of 2017 (data source: [86])

Province	Biomass: Installed capacity (grid connected)[6] MW — Total	Agriculture & Forest Residuals	Municipal Waste	Biogas	Power generation TWh/yr — Total	Agriculture & Forest Residuals	Municipal Waste	Biogas
Beijing	213	0	195	18	1.3	0.0	1.2	0.1
Tianjin	103	0	103	0	0.5	0.0	0.5	0.0
Hebei	676	426	241	9	3.4	2.4	1.0	0.0
BTH	**992**	**426**	**539**	**27**	**5.2**	**2.4**	**2.7**	**0.1**
Shanghai	272	0	255	17	1.9	0.0	1.8	0.1
Jiangsu	1459	494	908	57	9.1	3.2	5.7	0.2
Zhejiang	1580	214	1331	35	8.2	1.2	6.9	0.2
YRD	**3311**	**708**	**2494**	**109**	**19.2**	**4.3**	**14.3**	**0.5**
Inner Mongolia	172	102	69	1	0.8	0.6	0.2	0.0
China	**14762**	**7009**	**7253**	**500**	**79.5**	**39.7**	**37.5**	**2.2**

Energy consumption for transportation is clearly dominated by oil products, similar to other countries, although electric vehicles have achieved a mass market in China. Except for Shanghai and Zhejiang, the share of oil products in urban areas is higher than their rural counterparts due to higher ownership of private cars. The shares of electricity and natural gas are still small and differ among regions. However, in Hebei and Tianjin, electricity reaches a share of 12% of final energy due to the high importance of public transportation.

The electrification rate is also an important characteristic of energy systems. Generally speaking, the YRD region has higher shares of electricity in end-use sectors than China on average due to the cooling demand in summer and power demand in industry. Still, coal consumption is dominant in industry and electricity is mainly used for electrical appliances and mechanical energy. Electricity

[6] does not include auto-producers due to data limitation.

reaches only small shares in BTH, but, as already mentioned, with higher shares in Tianjin and Hebei compared to the national average. However, the current statistics reveal still huge potential for further electrification as a core strategy towards a more efficient and renewable energy supply system.

In the three municipalities, also defined as national megacities, more than 95% of electricity needs to be imported from other provinces. With larger areas forming their hinterlands, the three provinces achieve much higher shares of domestic production, but the import shares still account for 77% in Hebei, 75% in Jiangsu, and 46% in Zhejiang. On the national scale, only 11% of electricity was imported in 2015. However, eastern coastal regions largely rely on energy imports from western and central China due to their limited energy resources. A detailed overview over the current power exchange situation in the study regions and China is given in Figure A.6.

2.1.2 Characteristics of Energy Demand

Technical and structural characteristics and the degree of efficiency are key drivers of energy demand. Among the cities and provinces considered, Beijing has the lowest share of energy consumption in industry, indicating a more service-based economy with rather low energy intensity. The economic centers of Beijing and Shanghai have the highest share of energy consumption in the transport sector (rail, road, and aviation) as national and international transportation hubs. Hebei and Jiangsu, which have the highest share of energy consumption in industry, especially face the challenges of efficiency improvement, industrial upgrading, and air pollution mitigation. Industrial energy consumption of Tianjin and Zhejiang accounts for 69% and 65%, respectively, similar to the national average. Figure A.5 shows the current energy consumption structure by sector with regional differences.

As an indicator of the status of the energy demand, I present energy intensity in Figure 2.3, where current energy intensity by sector is calculated as a ratio between energy consumption and added value. Hebei has by far the highest energy intensity in industry (4.97 MJ/RMB), more than two times of the national average (2.23 MJ/RMB). The reason behind this is high production capacity in energy, steel, and chemical industries, which were partly shifted from Beijing and Tianjin as an adjustment of economic structures strategy. Higher energy intensity in transportation of Beijing and Shanghai is mainly due to being domestic transport hubs. Tianjin has the highest energy intensity in the construction sector. Energy intensity in the services and commerce sector is similar in all regions, with a maximal value in Hebei of 0.48 MJ/RMB.

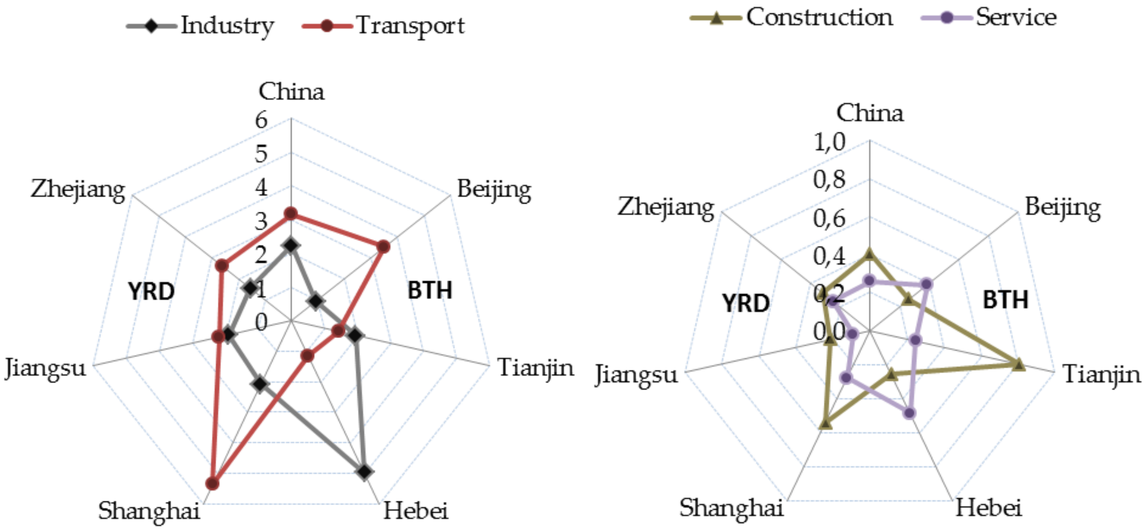


Figure 2.3. Energy intensity (MJ/RMB) of study regions and China in 2015 by sector (data source: China Energy Statistical Yearbook 2016 and China Statistical Yearbook 2016).

Energy intensity in the residential sector is calculated as energy consumption per capita differentiated by urban and rural areas [7](see Figure 2.4). Heating demand in winter causes higher residential intensity in BTH compared to YRD and the national average. Shanghai, Beijing, and Tianjin have the highest urban energy intensity, indicating higher living standards, and relatively high rural intensity, indicating the long commuting distances because of the large urban scale. Hebei Province has relatively high urban and rural energy intensity, although the urbanization rate is the lowest of all considered provinces. Comparing Figure A.1 and Figure A.2 with Figure A.3 reveals an obvious interrelation between higher shares of electricity use plus district heating and lower energy intensity. Rural areas with still considerable shares of traditional use of coal and biomass have mostly higher intensity. The differences in energy consumption structures of urban and rural areas and the ongoing urbanization process, especially in Hebei, Jiangsu, and Zhejiang, cause high uncertainty about future development; however, there is the potential for significant efficiency improvement. (Note: not all traditional energy use, like biomass, is included in the statistics.)

[7] Note: the residential transport energy demand is included in the residential sector from China energy balance table.

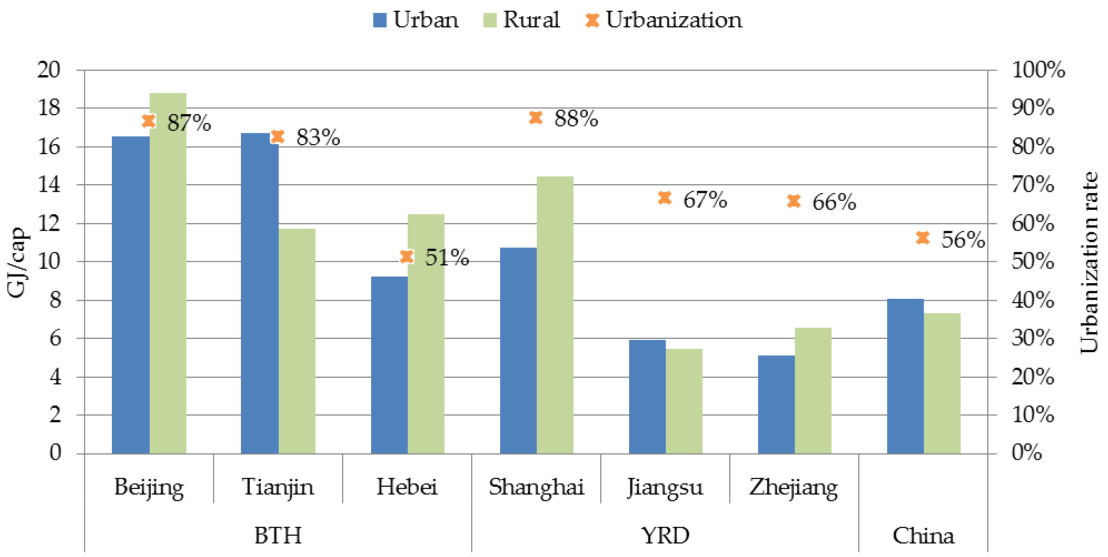


Figure 2.4. Energy intensity in residential sector and urbanization rate of study regions and China in 2015 (Data source: China Energy Statistical Yearbook 2016 and China Statistical Yearbook 2016).

2.2 Key Challenges

Based on the regional characteristics and current energy supply and demand structures described in the previous section, the challenges of regional energy system transition are identified in the following. The strong growth in energy demand and its concentration in some regions represent an extremely challenging context. Four main challenges were identified as a research focus and were presented in [144]. I summarize the analysis and conclusions from this paper in the subsections below.

2.2.1 Efficiency Improvement

Energy demand in China is expected to still increase due to urbanization, resulting in higher living standards, growing passenger traffic and car fleets, and further industrialization processes [76]. However, the strong industrial sector with high energy intensity stands out in energy demand compared with Organisation for Economic Co-operation and Development (OECD) countries. Thus using energy more efficiently must be a major target as mentioned already in [40, 123].

Efficiency improvement directly influences how energy consumption control targets are achieved in various end-use sectors. Specific policies can focus on, e.g., overall energy conservation and emissions reduction, technology standards, integrated transportation system development, building energy conservation, or green building development. Existing policies usually support near-term energy saving targets in industry, transportation, and building sectors [144]. A successful energy system transition requires achieving high energy intensity reduction targets in the eastern coastal regions, which is especially challenging in the light of a fast economic growth rate and industrial-sector dominated economic structure.

2.2.2 Reduction of Coal Use

In addition to the usual challenges of maintaining the security of supply and increasing public access to clean energy, the huge increase in coal consumption during the last decade led to high CO_2 emissions in China, which is a huge burden for the decarbonization process [74]. Coal reduction strategies, which are on short-term available in both considered regions, not only aim to increase non-fossil fuel shares in the primary energy supply, but also to considerably improve air quality. In northern China, e.g., in the BTH region, heating demand in the winter season contributes to serious local air pollution, especially small coal boilers in areas without efficient district heating systems. In rural areas, space heating still relies on individual stoves supplied with briquettes and straw, which means there is huge potential to expand modern heating systems to include the use of solar and geothermal energy in the future. Shifting from coal to electric heating would enable China to integrate more electricity from wind and solar into its energy mix, under the so-called “coal-to-electricity” program. Under current heat zone classification, district heating is only available for the northern parts of the Huai River, as the geographical boundary of northern and southern China. Therefore, only individual units like air-conditioners and electric ventilation fans are normally used for short-time heating in the YRD region, where the temperature frequently drops below 5 °C during winter season. Strategies to implement modern district energy systems but also highly efficient decentralized energy systems for heating and cooling services, using technologies such as combined heat and power (CHP), thermal storage, and heat pumps, need to be further explored [130] in both regions.

2.2.3 Transport Decarbonization

Continuous urbanization and development of road transport both from passengers and freight and air transport will further increase fuel demand and China’s dependence on imported oil. Also, in dense urban areas, local pollution from private cars imposes serious negative effects on citizens’ health and the urban environment. Urban expansion increases commuting distances and travel for leisure or business. Decarbonizing China’s transport sector highly depends on further electrification and the complementary implementation of other alternative fuels such as hydrogen and biofuels, but also from transport modal shift such as the development of public transport infrastructures to limit further growth of private car fleets [47, 51, 96, 126, 150].

2.2.4 Multi-sector Electrification with Regional Integration

The continuous urbanization process leads to growing mobility and heating/cooling demand of households [76]. Further electrification on the supply side is thus essential to decarbonize the current coal- and oil-dominated energy system. However, integrating high shares of variable renewable energy (VRE) into the future energy system needs additional infrastructures such as grid and charging technologies, transmission lines, storage, and other flexibility measures. The development of new business models could combine distributed generation systems with storage facilities and electric vehicles, which would improve system flexibility and efficiency. Deep decarbonization of energy systems therefore calls for sector coupling of electricity, mobility, and heating sectors. This strategy requires implementing suitable and efficient sector-coupling technologies, but also favorable supporting market and other policy framework conditions.

Globally, installed renewable energy capacity is booming, but problems regarding grid integration have appeared due to the variability of the electricity feed-in. Therefore, large amounts of electric power are curtailed to keep a real-time balance between load and generation in power systems [60]. Efficient load-balancing strategies require trans-regional and trans-provincial resource allocation [152]. The transmission system was originally planned to convey coal-fired electricity from coal-rich regions such as Inner Mongolia and Shanxi over moderate distances to load centers [20]. However, current transmission capacity planning aims to improve the integration of large amounts of remote wind and solar capacity, to reduce high curtailment rates in some areas (especially in north-western China) and to assist coal power reduction plans in eastern coastal China. A reliable power transmission infrastructure will play a crucial role in supporting continued economic expansion and China's commitment to decarbonizing the whole energy system [132]. In addition to transmission capacity expansion, planning for local storage and other flexibility measures is also a key factor in balancing VRE-dominated energy systems.

2.3 Transition Aspects and Required Actions

Based on the above identified key challenges, a literature review helped to identify essential long-term transition aspects and policy intervention suggestions. A large variety of technical solutions could be addressed by policy: wind power and photovoltaics (PV) promise high potential at low cost. However, their variable supply poses challenges to load balancing in electricity grids and security of supply (see, e.g., [53, 58]). Thus, dispatchable renewable power, e.g., based on hydro reservoirs, concentrating solar power (CSP) plants, or high-efficiency cogeneration plants based on biomass, will play an important role as well but is still associated with high generation costs. Flexible backup generation capacity based on gas turbines and short- to long-term power storage is expected to be the backbone of the future power system (see, e.g., [22, 105]). Gas power stations could also be fueled with hydrogen or synthetic gas produced on the basis of renewable power. Synthetic fuel applications, such as hydrogen for the transportation sector, could provide flexibility in addition to storage, as well as power transmission between regions, or demand-side management [77]. Due to high efficiency and no direct emissions, it seems to be a general view that electric vehicles will be the key technology in low-carbon transportation. They also offer the possibility to provide additional flexibility to the power system via controlled charging (see, e.g., [55, 120]). Heat supply also needs fundamental changes that lead to high efficiency of buildings and industrial applications and the large-scale use of solar and geothermal heat. A massive implementation of solar collectors, heat pumps, and efficient cogeneration would benefit from an expansion of district heating, which could include larger heat storage and power-to-heat applications. In addition to these briefly summarized technical and structural options for the energy transition, other concepts are more or less promoted depending on national policies, such as the implementation of carbon capture and storage (CCS) or the expansion of nuclear power plants.

Decarbonizing the energy system in metropolitan regions requires the strong support of regional policy, e.g., for adjusting the economic structure, implementing new technologies and infrastructure, and reducing fossil fuels. China has strengthened its economic integration of metropolitan areas and the governance of urban agglomerations [195]. However, in general there is a need for integrated strategies considering all essential aspects of the transition process in order to define required policy actions on different administrative scales. Some of the most relevant aspects are further discussed in the following sections.

2.3.1 Adjustment of Economic Structure and Efficiency Measures

There seems to be a consensus in the energy systems analysis community that a reliable, binding, and courageous energy-efficiency policy is the backbone of each decarbonization pathway. Rapid efficiency improvements in all sectors are essential, especially under the continued urbanization and industrialization process in China [17, 28]. Changes in the regional economic structure may support the implementation of new and more efficient techniques and processes [65]. The enormous investments in technical and structural substitutions can only be realized through regulatory measures, economic incentives, and intensive stakeholder decision-making processes. New efficiency standards for techniques based on best available options require international agreement and regulations. Vehicle fuel economy and emission standards are a suitable measure to stimulate innovation and the replacement of internal combustion engines (ICE) by more efficient electric drivetrains. In each field of action, it is important that uniform legal frameworks are established in all regions to support the development of low-carbon technologies.

2.3.2 Control of Consumption of Fossil Fuels and Expansion of Renewables

Reducing fossil fuels and expanding renewable energies are two sides of the same coin, but both need to be addressed by specific measures. Limiting and controlling the further consumption of coal and oil products may be an effective option; another option discussed is a general carbon tax or surcharge to increase the price of fossil fuels. Effective carbon pricing on a national and international level is seen globally as a key mechanism to support the energy system transition. On the other hand, a rapid and strong expansion of renewable energies is required for the large-scale production of power, heat, and fuels. In northern regions such as BTH, where space heat demand is high in the winter season, coal substitution needs to be done with regionally available renewable energies such as biomass, solar, geothermal, and wind power. Natural gas combustion as a substitute for coal burning can be a bridging technology that can be converted to the use of biogas and synthetic gas in a later transition phase. All strategies for the expansion of renewable energies require sufficiently high economic incentives, competitive RE industries, and investment security. Favorable regulatory frameworks and interventions such as renewable portfolio standard (RPS), promotion of electric vehicles and alternative fuels, stable energy market design, and finance mechanisms are preconditions for large investments in new technologies and infrastructures such as transmission lines, storage and charging facilities. Financial markets to support the development of renewable energy expansion need to be designed with regulation support [30, 178]. Cost reduction of low-carbon technologies is another key aspect to guarantee a cost-effective and dynamic energy system transition. Research and development funding and promotion of innovation on the production side are essential to achieve further significant cost reduction and possibly even disruptive technology implementation.

2.3.3 Sector Coupling and Supporting Infrastructure

The decarbonization of heating and the transport sector in particular poses huge challenges in the transition of all energy systems. These targets need support from a widely decarbonized power sector via electrification of supply technologies. Sector coupling adds further power demand and complexity to the transformation of fossil fuel-based power supply systems and the implementation of renewable energies [17]. However, it is a key strategy to integrate large shares of renewable energy into these sectors, to make use of flexibility options across the energy system, and to achieve a cost-effective power supply system. In addition to direct electrification by power-to-heat via electric heaters and heat pumps and the implementation of electric vehicles in transportation, the power-to-gas option enables the production of synthetic gas (hydrogen or methane) using renewable electricity and electrolyzers with gas storage [7, 36]. With further processing routes, even liquid synthetic fuels for transport could be produced. In order to deal with the fluctuating characteristics of renewable energies, additional expansion of storage systems, transmission grids, and other flexibility options, such as smart grids and demand-side measures, is required. Implementing these supporting infrastructures necessitates huge investments, and therefore requires new business concepts and suitable market conditions. A flexible power-driven operation of combined heat and power plants with supervisory control and increased use of heat storage as well as the flexible use of heat pumps with storage are also important in terms of sector coupling and improving system flexibility.

2.4 Current Policy

National policies and related targets have obvious impacts on the energy system transition globally [132]. Some of the challenges identified need a national (or even international) perspective, especially regarding carbon pricing and market mechanisms. Others, in contrast, need to be addressed at the regional and local levels where the implementation and investment take place, and regional coordination is highly needed. A set of specific and concrete policies that allow the integration of different stakeholders, decision-makers, and regulators will be required. The China Renewable Energy Outlook [178] advocates a strong role of regional policy in the energy transition, especially for tapping regional synergies between demand and supply and ensuring public acceptance of the transition. In the following, currently available short-term policies at different administrative levels of China are analyzed in detail with regard to the identified challenges in metropolitan regions and with a focus on the two study regions (see Figure 2.5).

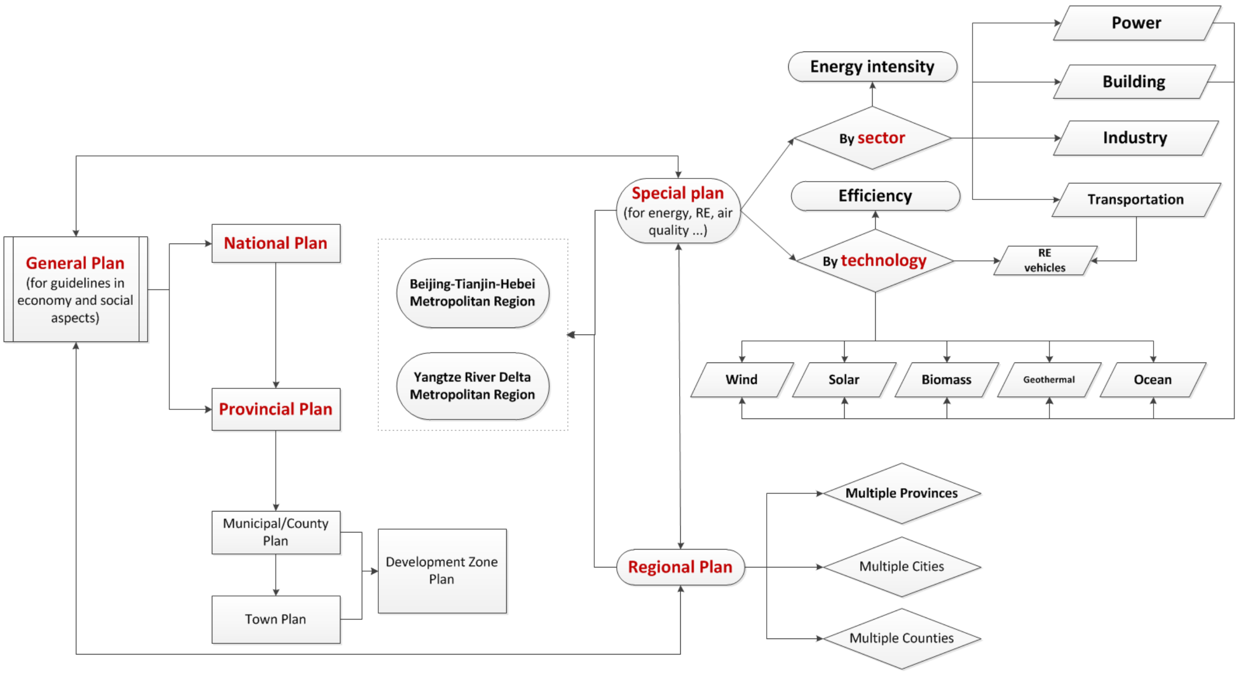


Figure 2.5 Energy related policy decision making hierarchy in China (own summary).

2.4.1 National Level

Since the 12th Five-Year Plan (2011–2015), China's economic policy has prioritized a transition from energy-intensive growth based on heavy industry, exports from manufacturing, and high investment to a more balanced economy. This is characterized by slower growth, an increasing role of services and domestic consumption, and a focus on innovation and low-carbon technologies [178]. The latest general energy development targets for 2020 were set in June 2014, when the National Energy Development Strategy and Action Plan (NDSAP) for 2014 to 2020 released by the General Office of the State Council (GOSC) came into force [27]. It provided a fundamental guidance for the 13th Five-Year energy-related plans [178] two years later, as shown in Table 2.4.

Table 2.4 Overview of national energy development-related policies toward 2020.

Release date	**7 June 2014**	**11 January 2016**	**March 2016**	**7 November 2016**	**10 December 2016**	**26 December 2016**	**30 December 2016**
		13th Five-Year National Plans and Guidelines for:					
Policy	Energy Development Strategy & Action Plan (2014–2020)	Renewable Vehicles: Promotion of Infrastructure & Vehicles (2016–2020)	Economic & Social Development (2016–2020)	Power Development Plan (2016–2020)	Renewable Energy Development Plan (2016–2020)	Energy Plan (2016–2020)	Ocean Energy Plan (2016–2020)
Policy maker	Office of the State Council	National Development and Reform Commission					State Oceanic Administration
		Ministries of - Finance - Science & Technology - Industry & Information - Energy		National Administration of Energy		National Administration of Energy	

The special 13th Five-Year Energy Plan, released in December 2016, further concretized general climate- and energy-related targets (see Table 2.5). It therefore serves as an improved guideline for policy-making, public investment, and project planning in the energy sector. The specific energy plan aims to optimize the energy mix and promote low-carbon energy development. The diversification of existing energy resources and the deployment of new sources are important for renewable energy policy implementation [8]. The national targets for non-fossil fuels in the primary energy mix are 15% by 2020 and 20% by 2030. Regarding the 12th Five-Year Plan (2011–2015), China has failed to comply with the target for offshore wind development. With more efforts to solve industrial, institutional, and technical barriers, there is more emphasis on offshore wind development in the 13th Five-Year Plan.

Table 2.5 Key national energy targets by 2020 [84, 85].

Aspect	Parameter	Unit	Statistics 2015 (2017)	Target 2020	Average annual change rate (%)
Electricity consumption	Total installed capacity	GW	1530 (1800)	2000	5.5
	Transmission of electricity from west to east	GW	1400	2700	14
	Total electricity consumption	TWh/yr	5690	6800–7200	3.6–3.8
	% of electricity in final energy consumption	%	25.8	27	1.2
	% of non-fossil fuels for power generation	%	12	15	3
	Average annual consumption per capita	kWh/cap	4,142	4860–5140	3.3–4.4
	Fuels replaced by electricity	TWh/yr	–	450	–
Power generation structure, installed capacity	Conventional hydro power	GW	297 (341)	340	2.8
	Pumped hydro storage	GW	23	40	11.7
	Nuclear	GW	27 (35.8)	58	16.5
	Wind	GW	131 (164)	210	9.9
	Solar	GW	42 (130)	110	21.2
	Coal	GW	900	<1100	4.1
	Natural gas	GW	66	110	10.8
	Non-fossil fuels	GW	520	770	9.6
	Share of fossil fuel power plants	%	65	61	–4
	Share of coal power plants	%	59	55	–4
	Share of non-fossil fuel power plants	%	35	39	4
	Share of gas power plants	%	–	>5	–
	Share of non-fossil fuel electricity generation	%	–	31	–
Efficiency	Newly installed coal power plants	gCE/kWh	–	300	–
		kJ/kWh	–	10.24	–
	Existing coal power plants	gCE/kWh	318	< 310	–1.6
Electric vehicles (EVs)	Public charging infrastructure	–	–	for 5 million EVs	–

The described energy planning is binding only on the national level. However, those targets need to be broken down to the regional level, where technology implementation and investment decisions happen.

Therefore, the regions are supposed to further concretize the plans, and steer the transition process with regard to the overall targets.

2.4.2 Provincial/Municipal Level

The 13th Five-Year Provincial and Municipal Renewable Energy Development Plans were released by the respective provincial and municipal Development and Reform Commissions. In general, no harmonized policy for the energy sector exists on the regional level; instead, the provinces and municipal cities set their own plans. The basic direction is set by the general plans, providing guidelines for provincial and municipal economic and social development, which were released from January to November 2016. The next subsections give a detailed overview of available plans for the two regions, disaggregated by the three provinces and three provincial-level municipal cities.

2.4.2.1 Beijing–Tianjin–Hebei Region

The provincial-level 13th Five-Year Renewable Energy Development Plan was released by the end of 2016 in the BTH region. The plan proposes that total renewable energy use and installed renewable energy capacity in the power sector should reach 1000 PJ and 45 GW, respectively, by 2020. In separate plans for renewable energy development (see Table 2.6), regional integration and cooperation have been further emphasized as important aspects for regionally balanced development. Electrification was addressed as a key measure to improve air quality, thus 12 interregional transmission lines have been approved to be built in order to get access to the western abundant RE resources [85].

Policies in the BTH region are disaggregated to the level of individual technologies or subcategories such as straw use. All three provinces address the issue of renewable heat supply by targets for specific technologies within special plans for renewable energy development (see Table 2.6). Hebei Province specifically mentions solar collectors and geothermal energy for heating. Other renewable options addressed by policy plans are biofuels and offshore wind. In Hebei Province there is also a target for electricity storage, considering the future challenges for a power system with high shares of VRE. Within this context, Hebei Province plans to improve its ability to control curtailment rates from wind power and PV below 10%. Both Tianjin and Beijing also plan to further increase their ability to import electricity from the surrounding renewable energy abundant regions. Beijing has a target to import 10 TWh per year in renewable electricity by 2020, accounting for 50% of its total imported electricity. Its power dispatch challenges due to VRE will be addressed as the first priority. Tianjin plans to cooperate more with Hebei Province and Inner Mongolia, which are characterized by high on-shore wind potential. This is supposed to increase electricity imports to Tianjin to around 6 TWh per year by 2020.

During the energy transition process, the plans for Beijing and Tianjin strive for regionally integrated development together with Hebei Province. The plans also include utilizing the import potential from other surrounding regions, such as Inner Mongolia, especially for renewable electricity from wind and solar energy. At the same time, new transmission lines are planned to solve curtailment problems that arose due to the fast expansion of wind power plants [145]. In Tianjin, imported electricity by 2020 would account for 60% of its total demand (see Table 2.6).

Table 2.6 Energy transition-related targets in Beijing, Tianjin, and Hebei Province [160, 164, 168–170].

Province			**Beijing**	**Tianjin**	**Hebei**
Related policy	13th Five-Year Plans for:		Renewable Energy Development	Renewable Energy Development	Economic & Social Development Energy Development Renewable Energy Development
Policy maker			Development & Reform Commission	Development & Reform Commission	Development & Reform Commission
Release date			26 September 2016	19 December 2016	14 October 2016
Aspects	Main indicators	Unit	2020	2020	2020
Primary energy	From renewable	PJ/yr	181	147	674
	Local renewable	PJ/yr		94	
	Renewable share	%	8	4	7
Electricity generation	Coal share	%	<10		
	Local RE electricity	TWh/yr		4	
	Renewable share	%		10	>13
Electricity generation	Imported RE electricity	TWh/yr	10	6	
	Wind	TWh/yr			40
Installed RE capacity	Total RE installed capacity	GW	2	2.12	
	Renewable share	%		10	>41
Installed RE capacity	Solar	GW	1.16	0.8	
	Wind	GW	0.65	1.16	20.8
	Offshore	MW		800	290
	Biomass (waste/straw)	MW	350	155 (120/35)	
	Hydro	MW		5	

Storage	Pumped storage	GW			>16
Heating supply (area)	Renewable heating	km^2			160
	Geothermal (deep/shallow)	km^2	70	51 (35/16)	
	Solar heating	km^2	9	20.4	16
Fuel	Biomass for fuel	PJ/yr		23	

The BTH region also sets targets for geothermal energy deployment as an option to replace coal for heating. Currently there are 48 geothermal fields in the BTH region, with 10 in Beijing, 8 in Tianjin, and 30 in Hebei Province. The annual exploitable geothermal energy accounts for 10^4 PJ. Based on the existing planning for geothermal development in the region, this technology is expected to play a key role in replacing coal consumption, especially for heat supply.

Based on the adapted national offshore targets, the 2020 offshore development targets for Hebei Province and Tianjin were set at 800 MW and 290 MW, respectively (see Table 2.6). In Hebei Province, the renewable energy plan mentions an exploitable potential of 79 GW onshore and 10 GW offshore. In addition, 90 GW of biomass-based power plants are mentioned, which can provide backup capacity and flexible generation. In Beijing, a specific integrated transportation development plan was released, similar to Shanghai and Zhejiang Province, which is discussed in the next subsection.

2.4.2.2 Yangtze River Delta Region

Energy-related policy in the YRD region is an integral part of the overall development plans. Table 2.7 gives an overview of energy-related targets and corresponding policy plans in the YRD region. While a specific energy plan is not yet available in Shanghai, at least renewable fuels and CO_2 reduction are already addressed via the regional policy. Similar to the BTH region, the regional integrated transportation system is enhanced in Shanghai by the 13th Five-Year Plan, promoting the expansion of highways, railways, and public bus lanes.

Table 2.7 Energy transition-related targets in Shanghai, Jiangsu, and Zhejiang Province [161, 162, 165, 167].

Province			**Shanghai**	**Jiangsu**	**Zhejiang**
Related policy	13th Five-Year Plans for:		Economic & Social Development	Economic & Social Development	Economic & Social Development
			Energy development	Power Development	
Policy maker			City government	Province government	Province government
Release date			January 2016	30 March 2016	February 2016
Aspects	Main indicators	Unit	2020	2020	2020
GDP	Annual growth rate	%	6.5	7.5	
Population	Total (urban %)	Mill.	<25	(67%)	
Energy supply	Primary energy	PJ/yr	3663	11723	6448
	Supply capacity of natural gas	km^3	10		
	Increase in natural gas supply	%	12		
	Share of non-fossil/clean energy	%		10	20/32.5
	Share of renewable energy	%			12.5
	Renewable energy total	PJ/yr			945
Installed capacity	Total	GW		130	94
	Nuclear	GW			
	Wind (onshore and offshore)	GW		8-10	9
	PV	GW		8-10	6
	Biomass (waste and straw)	GW		1.5	
Transportation	Modal share of rail in city	%	60		
	Share of renewable fuels	%	50		
CO_2 emissions		Bill. tons	<0.25		

In contrast to Shanghai, Jiangsu Province developed a special 13th Five-Year Plan for Power Development and Renewable Vehicle Development Actions, released at the end of 2016. The first plan included a limited set of renewable energy technologies: biomass, PV, and wind [167]. The second plan aimed for market development of electric and fuel cell vehicles and was released at the end of 2016 [23]. In 2009, the province announced it was building an offshore “three gorges” project (in the style of the Three Gorges hydro dam project in China) with a target of 10 GW installed capacity by 2020. The Power Development Plan also addresses the aspect of electrification in the transport sector, by targeting increased electric rail traffic. This provides an interrelation with the region’s Plan for Integrated Transportation Development, released in October 2017 [155]. The development of efficient combined heat and power (CHP) production is also included qualitatively as the promotion of residential CHP projects in northern Jiangsu Province. It prioritizes industrial CHP for economic development zones and gradual substitution of coal CHP by natural gas in urban areas in the southern part of the province. Expansion targets for renewable power plants are complemented by the solar plan for both utility and decentralized applications, especially for rooftop distributed PV. The promotion of wind power is focused on offshore, but also includes onshore for middle to low wind speed resources. In addition, biomass expansion plans mainly focus on residues, such as straw and municipal and rural waste.

Energy policy in Zhejiang Province also relies on its overarching plan for economic and social development. However, this plan is rather specific with regard to energy targets, but less focused on renewable energy. In comparison with the other energy plans, the Zhejiang Province plan also includes a nuclear target of 9 GW, with 5 GW under construction. It also focuses on energy consumption and providing additional services to the population by promoting electrification in rural areas to replace fossil fuels.

Comparing the BTH and YRD regions, it becomes clear that there is no common standard for addressing energy decarbonization in China on the regional level. From detailed insight into energy policy, a variety of short-term targets can be identified addressing the immediate specific needs of each province (or provincial-level city). While the principle of subsidiarity is a valuable asset for the adoption of regional policies, it needs to be complemented by a mechanism that ensures a consistent transition process between regions in the long term.

2.4.3 Regional Level

Regional policy makers are aware of the need to cooperate in the field of regional development and to harmonize policies in metropolitan regions. There are more and more collaborative interactions between urban and regional energy governance related to the energy transition, with diverse and dynamic organizational responses [16, 78]. Policy makers are advised to intensify regional integration in order to lower the barriers to improved energy and CO_2 emissions performance [118]. This addresses especially administrative and policy barriers, which are even more important than geographical distance [61]. Mainly air pollution issues currently drive regional integrated strategic development, and all stakeholders should be aware that an integrated energy system transition is required beyond the single municipal or provincial level [151]. Therefore, Beijing, Tianjin, and Hebei Province together are one of the first regions developing a joint collaborative development plan, as presented in Table 2.8. China’s first regional development plan integrating several provinces was released at the end of 2016. It aims to promote regionally balanced development and regional integration in terms of finding effective solutions to air pollution, transportation, energy, and CO_2 emissions and other issues.

Table 2.8 Energy transition targets related to regional integrated development in Beijing–Tianjin–Hebei region [156, 157, 159].

Related policy	13th Five-Year Plan for Beijing–Tianjin–Hebei Region Collaborative Development 13th Five-Year Plan for Beijing–Tianjin–Hebei Region Economic and Social Development 13th Five-Year Plan for Beijing–Tianjin–Hebei Region Renewable Energy Development			
Policy maker	National Development and Reform Commission (NDRC)			
Release date	25 November 2016			
Aspect	**Main indicators**	**Unit**	**2020**	**Remarks**
GDP	Average annual growth rate	%	7	
Population	Urbanization rate	%	60	
Industry	Industry shifting			11 municipal level cities in Hebei Province and special node cities of Dingzhou and Xinji have special roles in BTH collaborative development regarding industrial shifting from capital city of Beijing
Transportation	Remove non-capital city functions to improve efficiency and sustainability			
Air quality	Solve regional air pollution problems			
RE development	Total exploited RE energy	PJ/yr	181.7	
	Share of RE in total energy consumption	%	>8	
	RE installed capacity within city	GW	2	
	Share of RE in installed capacity within city	%	15	Newly installed capacity mainly focused on RE
Installed RE capacity	Total RE	GW	45	
	Wind	GW	10.7	
	Offshore wind	*GW*	*1.09*	
	PV	GW	3.09	
	Biomass	MW	667	
Total exploited and consumed RE		PJ/yr	1002	

As can be seen from the joint regional development plan of the BTH region, the demand for integrated energy system planning is already addressed here. This plan integrates all three provinces into collaboration and considers specific issues referring to energy demand and supply, such as transport and industry development, as well as renewable power plants (see Table 2.8). In addition, the regional plan for geothermal heating and cooling in BTH has a target of covering 440 km^2 heating area in 2020. With these actions implemented, the expected CO_2 reduction would be 7 million tons in the BTH region [157, 163]. The YRD region also features a variety of development trends connected to economic and energy transition: polycentric agglomerated urbanization, industrial upgrading [62], and infrastructure development for transportation [139] are also under process. These dynamic developments within the region require an integrated assessment instead of analyses of single metropolitan cities or provinces. However, for the YRD region, no integrated renewable energy-related plan exists so far. Therefore, the BTH regional development plan is a showcase for regional integration in terms of promoting low-carbon transition pathways.

Some efforts are already under way to integrate policy across regions, especially for the power and transport sectors. One example of integrated planning in the transportation sector is the discussion of regional railway and highway plans. In both the BTH and YRD regions, the transport system is a major challenge that needs more integrated approaches in the future to overcome previous administrative barriers.

2.5 Policy Implications

In the following I show, how well the four major challenges of efficiency improvement, coal reduction, transport decarbonization, and electrification/sector coupling as well as the related transition aspects and required measures are addressed by these policies. In addition, the near-term regional policy targets are compared with long-term transition scenarios for China to identify possible gaps and inconsistencies.

2.5.1 Strengths and Shortcomings of Existing Policies

Current national and regional policies have already addressed the reduction of coal consumption. The national and provincial air pollution action plans demand peak coal consumption before 2020 in the BTH and YRD regions [25]. Therefore, provinces in BTH have set absolute coal consumption reduction targets and provinces in YRD have defined negative growth targets by 2017. Recently, the CREO concretized a possible decarbonization strategy combining significant reduction of coal and deployment of renewable energies [178]. This can provide a sound basis for policy advice on all administrative levels, reflecting the long-term perspective of the energy system transformation.

Policies and regulations have tried to establish stable and attractive market conditions for at least some new technologies and to reduce investment risks and lower the cost of financing. To achieve this on a large scale, economic incentives such as electricity feed-in tariffs and subsidies for efficiency improvement from both national and local governments were implemented. Current policy also supports the deployment of wind and solar energy at sites with lower potential by higher feed-in tariffs and renewable portfolio standard (RPS) policy, which defines a minimum provincial-level penetration of non-hydro renewable energy for power generation [88]. Besides national distributed PV on a grid subsidy of 0.42 RMB/kWh, Shanghai and Zhejiang Provinces also provide an additional 0.25 RMB/kWh and 0.1 RMB/kWh, respectively, to promote local solar penetration, even under relative limited land availability and lower solar irradiation compared to western China.

Short-term targets for the heating sector exist mainly for the northern region of BTH, which has significant heat demand during winter season. The short-term targets already address the further development of solar and geothermal energy use and promote the decarbonization of cogeneration plants as the most important options on the supply side. In Shanghai, pilot programs to integrate RE into buildings are supported by national and local funding; subsidies of 60 RMB/m^2 are provided to promote the use of solar and geothermal energy for heat supply and 150 RMB/m^2 for window efficiency improvement [33]. In Tianjin, 45 RMB/m^2 subsidies from both national and local funding are provided for efficiency improvement in the building sector, such as insulation materials and smart meter installations [189].

The implementation of favorable market conditions is above all a task at the national level. In addition, a long-term carbon price appears to be necessary, which still leads to affordable energy prices but has a real impact on investment decisions. Pilot carbon cap-and-trade programs started in five municipalities (including Beijing, Tianjin, and Shanghai) and two provinces in 2013 to develop and test different trading modes, and a cross-provincial program in BTH and the Shanxi-Inner Mongolia-Shandong region was launched [191]. By the end of 2017, a national carbon trading system was launched for the power sector [136], and more sectors are expected to be included by 2020, according to "three-year road map" of the National Development and Reform Commission (NDRC).

The policy stakeholders are aware that it is important to deal with fluctuating characteristics of VRE technologies and implement storage technologies and other flexibility measures. However, there is not yet much activity on the regional level to further develop concepts and implement prototype plants for load balancing. Their implementation needs market conditions for promising favorable business cases as well. Development of the power transmission system is aimed at linking the rich RE resources of western and northern regions with the demands of eastern coastal regions of China.

The current renewable vehicle-related policies are focused not only on supporting the development of the industry itself, but also on shifting transportation modes. Important strategies include prioritizing the development of public transportation, prioritizing railway development instead of road transportation, and encouraging low carbon mobility such as bicycles together with new business models of bicycle sharing in main cities as a connection to public stations. All Chinese provinces already have ambitious projects for the promotion of electric vehicles, with a focus on public transportation and the build-up of public charging infrastructure. Due to serious air pollution in most main cities, China pursues its EV strategy on both the national and local level. The Chinese government offers outright subsidies for EV buyers, exempts electric and other “new energy” vehicles such as hydrogen fuel-cell vehicles from purchase tax, and demands a defined share of low-emission vehicles from all car manufacturers that want to be active in the Chinese market. Until 2014, electric vehicles were not common on Chinese roads; however, during 2015 and 2016 the market increased rapidly, so that China has now the world’s biggest market for plug-in vehicles. According to the China Association of Automobile Manufacturers, more than 500,000 plug-in vehicles were sold in China in 2016, of which more than 400,000 were battery electric vehicles [66]. The overall EV stock reached around 1 million vehicles, thus China is on the way to meeting its 2020 target. How far this will also lead to target-oriented long-term development cannot easily be assessed, because it strongly depends on the overall development of mobility behavior and demand in Chinese society.

Regarding the governance aspect, the policy review showed that, besides the National Energy Administration, there are at least three ministries directly involved. For example, the Ministry for Housing and Construction (MHC) is in charge of building sector efficiency improvement; geothermal energy development needs support from the Ministry of Land and Resources (MLR); and the Ministry of Industry and Information Technology (MIIT) is responsible for RE industry development. At the moment, the State Council is in charge of key national energy decarbonization policies, such as energy conservation and emission reduction; integrated transportation system development; guidance and incentive policies for promoting electric vehicles, alternative fuels, and charging infrastructure; and the air pollution prevention and control action plan. Thus, structures and processes for integrated strategies across different fields of action exist, at least on the national level. However, there still seems to be no integrated regional energy policy under the current national decision- and policy-making system. This endangers, above all, the regionally coordinated infrastructure development and effective sector coupling that are highly needed for deep decarbonization of the energy system. The eastern coastal metropolitan regions of China especially need integrated strategies to cope with limited RE resources, efficiency improvement, and energy demand control targets. New mechanisms are required to establish cooperation between the agglomerations, nearby hinterlands, and remote RE-abundant regions. Important national framework conditions of such regionally integrated strategies could be RE-oriented energy markets, a CO_2 trading or tax system, and promotion schemes for new technology implementation and integrated transportation systems.

Besides existing policies, specific energy-focused plans considering local characteristics and conditions are also needed, especially to concretize the long-term vision of energy transition. In addition, for both regions, the integration does not yet cover the whole energy system and all technologies required. While the BTH region initiatives can serve as a model for increased interprovincial cooperation, the temporal perspective is too short and needs to be extended to convincingly address energy decarbonization in the context of national and international targets. The in detail analysis to cover this research gap is presented in Chapter 4.

Energy policies need to provide regulatory options and instruments to tackle the challenges of the energy transition by improving transition planning and management. China's administration addressed these challenges in the latest Five-Year Plans. Compared with national development plans for 2020, the special plans on the level of provinces, municipal cities, and regions are less systematic. Also, the consistency of assumed interrelations among different sectors, technologies, social and economic developments are not clear from these plans. Within the two regions considered, a strong heterogeneity in energy policy exists regarding policy makers and specific targets. While in the BTH region policies are driven by the National Development and Reform Commission, the energy plans in the YRD region are released by provincial governments. Although all provinces focus their policies on renewable energies, there is not a joint set of indicators and measures that could help to coordinate the policies within or across regions. In Chapter 4 I therefore develop a regional approach for long term transformation pathways, providing consistent scenarios across the regions with a focus on sector coupling and a discussion of different decarbonization strategies and their environmental and economic consequences.

Regional integration is a prerequisite to achieving the essential technical and structural changes needed. However, this requires a deeper understanding of interdependencies and connections among the various current plans made by different administration levels and ministries.

2.5.2 Implications for Long-term Targets

A comparison of short-term policy targets with long-term scenarios targets provides indications of additional policy requirement and the need to implement more effective measures. As an example, average annual wind power installation between 2015 and 2020 derived from the regional plans ranges between 4.2 W (Beijing) and 28 W (Zhejiang province) per year and per capita. The national target of 210 GW of wind power in 2020 requires an average annual wind power installation of around 9.2 W per year and per capita during these five years. Comparing the national short-term expansion rate with a target-oriented pathway (around 80% CO_2 emission reduction in 2050 compared to 2010) according to [123], the average expansion rate between 2020 and 2050 has to increase by a factor of four (to around 36 W per year and per capita). Regarding PV power generation, the regional expansion rate accounts for around 9 W (Beijing and Tianjin) and up to 34 W (Hebei province) per year and per capita in terms of average annual installation. For PV, the national target of 105 GW of power in 2020 requires an average annual PV installation of 8.8 W per year and per capita. Compared to the target-oriented pathway from [123] aiming at 80% CO_2 emission reduction, the average national expansion rate between 2020 and 2050 has to again increase by a factor of four (to around 37 W per year and per capita). This simple comparison demonstrates that the investments in future infrastructure development for renewable energy use has to be significantly increased after 2020 in order to be in line with long-term national energy transition pathways. Regarding additional infrastructure needs related to power storage and transmissions as well as other load-balancing requirements, current policy plans have already partly considered the integration challenges for long-term development. For example, to increase pumped hydro storage in Hebei province and extending transmission capacity for the supply of Beijing and Tianjin will also be significant measures to support the long-term pathway toward higher renewable power supply shares for metropolitan regions. Regarding primary energy demands, I can also quantitatively compare existing short-term targets and target-oriented long-term scenarios. According to the 80% CO_2 emission reduction scenario of [123], the energy intensity in 2050 will be reduced from around 93 GJ per year and per capita (8.2 MJ/$GDP PPP) to below 65 GJ per year and per capita (1.4 MJ/$GDP PPP). This compares to a national efficiency target limit for primary energy consumption at around 105 PJ per year and per capita (7 MJ/$GDP PPP). This national short-term target corresponds to an annual growth rate of energy intensity of 2.4% related to population and –3.1% related to GDP. Compared to annual growth rates of –1.6% related to population and –5.2% related to GDP, which are required between 2020 and 2050 in the target-oriented scenario, there is still a significant gap. The regional targets appear to be more ambitious than the national one; however, overall energy demand is strongly influenced by local industry structure and population density. Primary energy demand per capita is supposed to increase up to 2020 only between 0.9% (Shanghai) and 1.8% (Hebei) per year in the two study regions. In relation to GDP, the negative annual growth rate is between –5.2% (Beijing) and –6.5% (Tianjin). However, the absolute energy intensity is significantly higher than the national average in most provinces and cities of eastern China. Comparing the intensity targets for 2020, the highest can be found in Tianjin, at 165 PJ per year and per capita. This comparison again demonstrates that the regional short-term targets are quite ambitious but still will not lead to an overall reduction of primary energy demand, which appears to be mandatory in order to achieve CO_2 reductions in China in line with a global 1.5-2.0 °C pathway.

2.6 Summary and Discussion

The analysis in this chapter provides a reflection of today's energy policy in China and two selected regions with regard to identified challenges and required actions of an energy system transition with the aim of far-reaching decarbonization. The policy review and analysis reveal that some important and ambitious short-term targets already exist. When further specifying, extending, and integrating target-oriented pathways, policy makers need to consider all relevant infrastructure demands and possibilities to implement new technologies. Several alternative options may exist to achieve required decarbonization targets, and their specific impacts have to be analyzed. This requires more comprehensive and transparent scenario analyses and assessments to significantly broaden the background knowledge for political decision making.

Specific challenges for the energy system transition in metropolitan regions, such as low RE potential from the hinterland and high pollution burden, call for inter-regional and inter-sectoral integration.

This aspect is addressed by national and regional authorities, especially with regard to power grid extension, demands but not yet enough to also cover future demands e.g. from sector coupling (see Chapter 4). Therefore, my further analysis addresses explicitly available options for sector-coupling and the regional integration. Other examples of ongoing regional integration actions are related to air pollution control and integrated regional transportation systems, but coordination needs to be improved regarding the overall targets of the transition process.

The analysis shows that long-term CO_2 reduction targets require more political action at all administrative levels. There is considerable effort in energy policy in China on the national level, which is committed to achieve peak CO_2 emissions by 2030 at the latest. However, energy policy in the analyzed regions is a conglomerate of more or less coordinated actions in line with an overarching national plan. They are focused on near-term targets and lack the long-term perspective necessary for transforming the whole energy system. Long-term vision is necessary to identify the most efficient and feasible transition pathways, to start the development of solutions needed in the long term, and to avoid technical and structural lock-in effects. This not only is important at the national level, but also needs to be identified at the regional policy level, where the implementation of new infrastructures takes place and specific challenges exist. Especially for the eastern coastal regions of China, with their high industrialization and energy density, a convincing and consistent transformation pathway needs to be further explored. The new urban plan of China, addressing continuous urbanization processes and an industrial shift from the eastern coast to central and western regions, could help to transfer successful concepts for regional energy transition to other metropolitan regions and to achieve the successful implementation of national targets.

3 Assessment of Renewable Energy Resource Potentials in China

3.1 Introduction

In the light of the imbalanced distribution of human activities and resources in China, the assessment of renewable energy resource potentials is a prerequisite for evaluating how their deployment could support the decarbonization of China’s energy sector. Therefor I conducted a nationwide RE potentials assessment for power generation of onshore and offshore wind, PV and CSP with provincial/municipal level resolution. The results for the two study regions as well as Inner Mongolia with abundant solar and wind energy are presented in this chapter. In addition, RE potentials of biomass, geothermal, small hydro and pumped hydro power were evaluated based on a literature review (see Section 3.3.3 and Section 3.3.4).

3.2 Methodology and Data

The renewable energy resource potentials of wind and solar for power generation in China were assessed by applying the Energy Data Analysis Tool (EnDAT) developed by [106] and expanded by [116]. It performs a land use assessment to identify areas on which the wind and solar resources can be exploited and is then overlapped with meteorological weather data and typical technology data such as power curves. The Global Land Cover database in a spatial resolution of 300 m x 300 m with 23 land use types is employed to identify suitable areas for power generation from renewables with three categories of closed to open (>15%) shrub land, closed to open (>15%) herbaceous and sparse (<15%) vegetation and bare areas in each pixel of 0.045° taken into consideration [116]. The minimum distance away from settlement is set to 1 km. According to the geographical conditions of China , the maximum elevation could reach 3000 m or even 3500 m [32] for renewable resource abundant regions (such as Qinghai Province) [125]. In the assessment for the Chinese provinces, default values in EnDAT were therefore changed, e.g., for the maximum elevation and for the minimum annual Direct Normal Irradiance (DNI) for economic deployment of CSP. Maximum elevation was set to 3000 m instead of the default value of 2500 m as large plains with good solar insolation are located at high elevation. The summary of main exclusion criteria to determine suitable areas for solar and wind power plants installation in China is shown in Table 3.1.

Table 3.1 Main exclusion criteria to determine suitable areas for solar and wind power plants installation in China.

Renewable energy	**Solar**		**Wind**	
Technology	**Open area PV**	**CSP**	**Onshore**	**Offshore**
Minimum resource	/	1600 kWh/yr	4 m/s	5 m/s
Maximum slope [°]	45	2.1	15	15
Maximum elevation above sea level [km]	3	3	3	/
Minimum distance to settlement [km]	1	1	1	/
Maximum distance from coast within exclusive economic zones (EEZ) [km]	/	/	/	200
Maximum sea depth [m]	/	/	/	40

The potentials analysis and the generation of hourly time series for PV, CSP, onshore and offshore wind were generated with EnDAT based on the NASA SSE 6.0 dataset for 1984 to 2004 which has an hourly temporal resolution and 0.045° spatial resolution. The hourly power generation is based on bottom-up power plant models in terms of installable capacity, technology parameters and resource availability for different scenario years with consideration of assumed technological improvement (see Table 3.2). From the time series, a pixel based typical meteorological year is generated to determine the most representative month out of long term data available with a better representation of variable solar irradiance and wind speed [116]. Following the above resource and land use assessment, EnDAT calculates the maximum installable capacities on the suitable areas and their potential power output. For PV, the area-specific installable capacity is derived at the standard testing conditions from module efficiency and q-factor representing the efficiency of the remaining plant components, such as DC-AC converters [106, 116]. The hourly electricity output of each grid is determined by the parameters of hourly average irradiance on the PV module both from satellite data of global horizontal irradiance (GHI) and beam normal irradiance (BNI) and the loss factor of PV modules accounting for shadowing and dirt. Other influencing factors are the hourly average difference of the module temperature and the temperature at standard testing conditions (25°C) multiplied by the temperature factor representing the temperature dependence of the modules performance. In addition, an availability factor is taken into account with consideration of module breaking down or maintenance periods [106, 116]. Both centralized and decentralized PV power plants are taken into consideration.

For CSP solar fields, a defined nameplate capacity is considered: at the standard irradiance of 800 W/m^2, a solar field with a nameplate capacity of 1 MW generates a thermal power output of 1 MW. At higher irradiances, the thermal power output can thus be higher than the nameplate capacity of the solar field. The default technology is a parabolic trough system with an area specific installable solar field capacity of 176.2 MW_{th}/km^2. To calculate the potential hourly output for each raster cell, the direct irradiance on the tilted surface of the parabolic troughs is calculated from the DNI, then related to the standard DNI of 800 W/m^2 and finally multiplied with the installable capacity. The lower threshold for the annual direct normal irradiance sum was set to 1600 kWh/m^2/yr. This is lower than the threshold of 1800 or 2000 kWh/m^2/yr in previous global ([2, 125]), country specific ([15, 73]) or regional ([127]) assessments with consideration of local resources and economic constraints. The reason for using a lower threshold is under the assumption that the distance to load centers might play a significant role in China and might compensate lower resource quality due to reduced transmission costs. Now, there is one CSP demonstration project located in Hebei Province (see Figure 3.3, No. 9) with a local DNI value of 1600 kWh/m^2/yr, which is close to a load center compared to provinces with higher DNI resources in northwestern China which are far from consumption centers in eastern China. With the consideration of technological requirement for CSP , the maximum slope is defined as 2.1 [116].

For the installation of wind turbines, the minimum distance is guaranteed to minimize the influence of interference. The area-specific installable capacity is calculated by the nominal capacity of a single wind turbine over its area demand determined by the parameters of the distance factor and the turbine diameter. The corresponding wind electricity is determined by the maximum installable capacity and the velocity of wind at the assumed turbine hub height [106, 116]. The threshold of wind speed for minimum power generation is 4 m/s for onshore wind and 5 m/s for offshore wind. Then the results of maximum installable capacities by technology in each grid are aggregated on provincial level based on the geographical boundary data from [185].

Table 3.2 Parameters for calculating installable capacities and power output according to [106].

Parameter	**2010**	**2020**	**2030**	**2040**	**2050**
PV module efficiency [%]	16.1	17.3	18	18	18
PV q-factor [%]	81.1	82	82.9	83.8	84.7
Loss factor of centralized PV [%]	10	10	10	10	10
Loss factor of decentralized PV [%]	15	15	15	15	15
Temperature coefficient PV [1/°C]	-0.005	-0.0045	-0.0045	-0.004	-0.004
CSP thermal capacity factor [MW_{th}/km]	176.2	176.2	176.2	176.2	176.2
Availability factor of CSP [%]	0.95	0.95	0.95	0.95	0.95
Efficiency of the CSP power block [%]	0.37	0.37	0.37	0.37	0.37
Efficiency of the CSP thermal storage [%]	0.95	0.95	0.95	0.95	0.95
Onshore wind nominal capacity turbine [kW]	1950	3400	4400	5000	5500

Offshore wind nominal capacity turbine [kW]	3000	6000	8000	10,000	12,000
Onshore wind rotor diameter [m]	77.5	102.3	116.4	124.1	130.1
Offshore wind rotor diameter [m]	96.1	135.9	156.9	175.4	192.2
Onshore and offshore wind distance factor [m]	6	6	6	6	6
Hub height for onshore wind turbines [m]	112	122	127	131	132
Hub height for offshore wind turbines [m]	80	102	116	128	140
Loss factor wind [%]	0.15	0.15	0.15	0.15	0.15
Availability factor wind [%]	0.95	0.95	0.95	0.95	0.95
Input data	**2010**	**2020**	**2030**	**2040**	**2050**
PV area-specific installable capacity [MW/km^2]	130.6	141.9	149.2	150.8	152.5
CSP solar field area-specific installable capacity [MW$_{th}$/km^2]	176.2	176.2	176.2	176.2	176.2
Onshore wind area-specific installable capacity [MW/km^2]	10.4	10.4	10.4	10.4	10.4
Offshore wind area-specific installable capacity [MW/km^2]	10.4	10.4	10.4	10.4	10.4

The annual biomass energy potential in chemical TWh is calculated from provincial biomass power potentials with assumed full load hours of 5844 and power plants efficiency of 0.3 [113]. The annual geothermal exploitable energy could reach 37.8 TWh nationally [186]. Medium to low geothermal potentials can be found in the Beijing-Tianjin-Hebei region (6.1 TWh). The pumped hydro storage potential in China is 200 GW [194]. The planned pumped hydro power stations will reach 60 GW during the period of 2016 to 2020 with a total installed target of 40 GW by 2020 [85]. Since the distribution of the 200 GW potential is unknown, the distribution of the planned stations given in [85] is used as a proxy to distribute the total potential. Apart from that, the explored coastal sea water pumped storage potentials in 8 provinces from near-shore and islands is 42 GW [188]. It could provide economic feasibility for storage in large offshore wind bases development such as in Zhejiang and Jiangsu Province.

3.3 Results

3.3.1 Wind Energy

The results for wind power generation potentials show that the onshore wind potentials are concentrated in north-western China because of better wind speed and useable land resources (see Figure 3.1). All coastal regions have potentials for offshore wind power capacity between 6-9 MW/km^2.

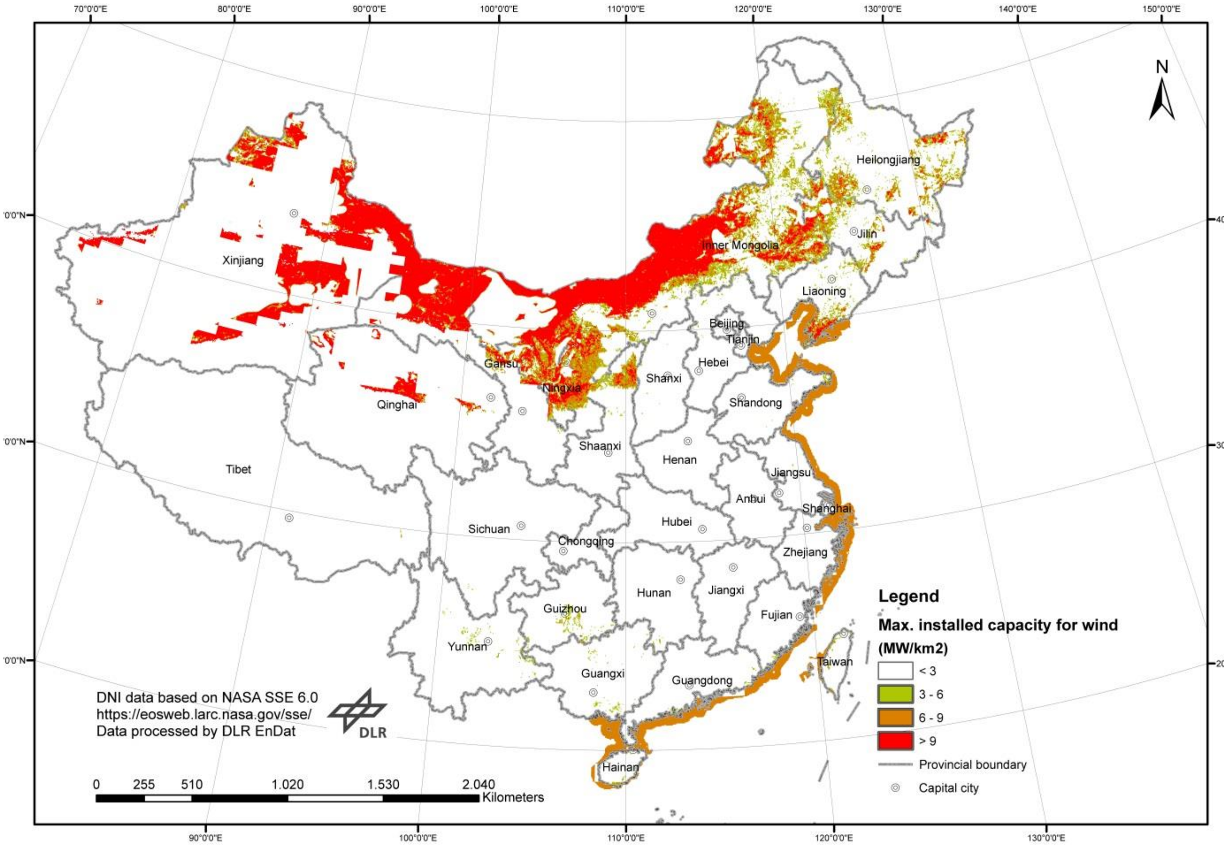


Figure 3.1 Maximum installable wind power capacity per km^2 over 4 m/s threshold in China.

The annual power generation potential in terms of maximum installable capacities and average full load hours (FLH) as well as hourly time series were calculated with EnDAT. Four different thresholds from 4 m/s to maximum 6.5 m/s for onshore wind and 7 m/s for offshore wind were applied to evaluate capacities and corresponding FLH in the study regions (see Table 3.3). Since onshore wind resources in Inner Mongolia have such high potentials, the highest threshold of 6.5 m/s is applied in order to explore the most economic output for its onshore wind power generation. Beijing, Tianjin, Shanghai and Jiangsu Province only have onshore wind potentials below 5 m/s, while Hebei, Zhejiang and Inner Mongolia also have onshore wind potentials above 6 m/s. According to the different assessment thresholds applied, the maximum installed onshore wind capacity for power generation ranges from 20 GW to 40 GW in BTH region, from 10 GW to 60 GW in YRD region, and from 1700 GW to 5400 GW in Inner Mongolia as a potential supply region. The FLH are increasing with higher wind speed. Compared with onshore wind, the potentials for maximum installed offshore wind capacities in the two study regions are higher, with ranges from 80 GW to 90 GW in BTH region and from 20 GW to 370 GW in YRD region.

Table 3.3 Onshore and offshore wind power generation potentials under different wind speed thresholds in study regions and Inner Mongolia.

Onshore wind

	4 m/s		5 m/s		6 m/s		6.5 m/s	
	Max. installed capacity	FLH	Max. installed capacity	FLH	Max. installed capacity	FLH	Max. installed capacity	FLH
	GW	h	GW	h	GW	h	GW	h
Beijing	0.5	1477	0.175	2021	-			
Tianjin	2.6	1492	1.499	1573	-			
Hebei	34	2538	28.97	2752	24	2941	21	3041
BTH region	**37**	**2449**	**31**	**2690**	**31**	**2690**	**21**	**3041**
Shanghai	0.2	1811	0.2	1811	-			
Jiangsu	7	1549	5	1600	-			
Zhejiang	50	1066	3	1662	0.1	2504	-	
YRD region	**57**	**1130**	**9**	**1626**	**9**	**1626**	**-**	
Inner Mongolia	**5382**	**2447**	**5253**	**2470**	**4598**	**2571**	**1738**	**2950**

Offshore wind

	4 m/s		5 m/s		6 m/s		7 m/s	
	Max. installed capacity	FLH	Max. installed capacity	FLH	Max. installed capacity	FLH	Max. installed capacity	FLH
	GW	h	GW	h	GW	h	GW	h
Beijing	-							
Tianjin	39	1966	39	1966	11	2083		
Hebei	49	1985	41	2071	16	2202	-	
BTH region	**88**	**1976**	**88**	**1976**	**27**	**2021**		
Shanghai	60	2020	60	2709	49	2836	2	3069
Jiangsu	127	2160	127	2160	46	2493	-	
Zhejiang	185	2247	181	2270	93	2693	16	3020
YRD region	**372**	**2181**	**368**	**2303**	**187**	**2682**	**18**	**3026**
Inner Mongolia	-							

3.3.2 Solar Energy

The potential of PV technology for power generation is distributed nationwide but still concentrated in north-western China (see Figure 3.2). The assessment results of PV for power generation show that the BTH region has higher FLH than the YRD region (see Table 3.4). Three thresholds for minimum annual direct normal irradiance sum of 1600, 1900 and 2000 kWh/m^2/yr were applied to evaluate the maximum installed CSP capacities and corresponding full load hours in the study regions. CSP generation potentials exist in Hebei Province of the BTH region, but only to a small extent. However, large potentials exist in the north-western provinces of Inner Mongolia, Xinjiang, Qinghai, Gansu, Ningxia, where also most of the current 20 CSP demonstration projects are located (see Figure 3.3). The highest threshold of 2000 kWh/m^2/yr is applied to Inner Mongolia in order to explore the most economic output for CSP power generation. Due to lower CSP resources, the threshold of 1800 kWh/m^2/yr was applied to Hebei Province.

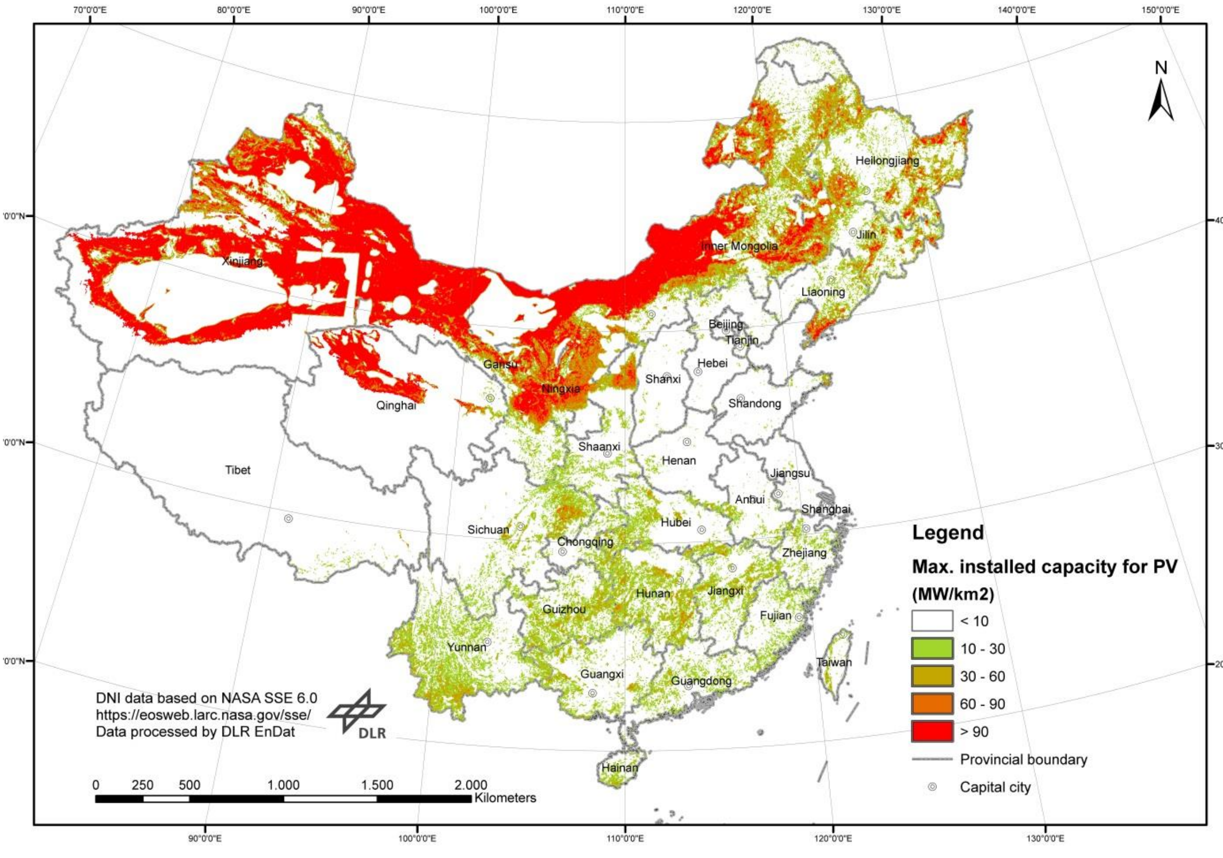


Figure 3.2 Maximum installable PV capacity per km^2 in China.

Table 3.4 PV and CSP potentials for power generation in the study regions and in Inner Mongolia.

	PV		CSP					
			1800 kWh/m²/yr		1900 kWh/m²/yr		2000 kWh/m²/yr	
	Max. installed capacity	FLH	Max. installed capacity	FLH	Max. installed capacity	FLH	Max. installed capacity	FLH
	GW	h	GW	h	GW	h	GW	h
Beijing	6	1218			-			
Tianjin	25	1176			-			
Hebei	345	1256	7	1600		-		
BTH region	**376**	**1250**	**7**	**1600**		-		
Shanghai	2	994						
Jiangsu	67	1045			-			
Zhejiang	548	958						
YRD region	**617**	**968**						
Inner Mongolia	**53154**	**1268**	**25661**	**1664**	**9100**	**1735**	**919**	**1665**

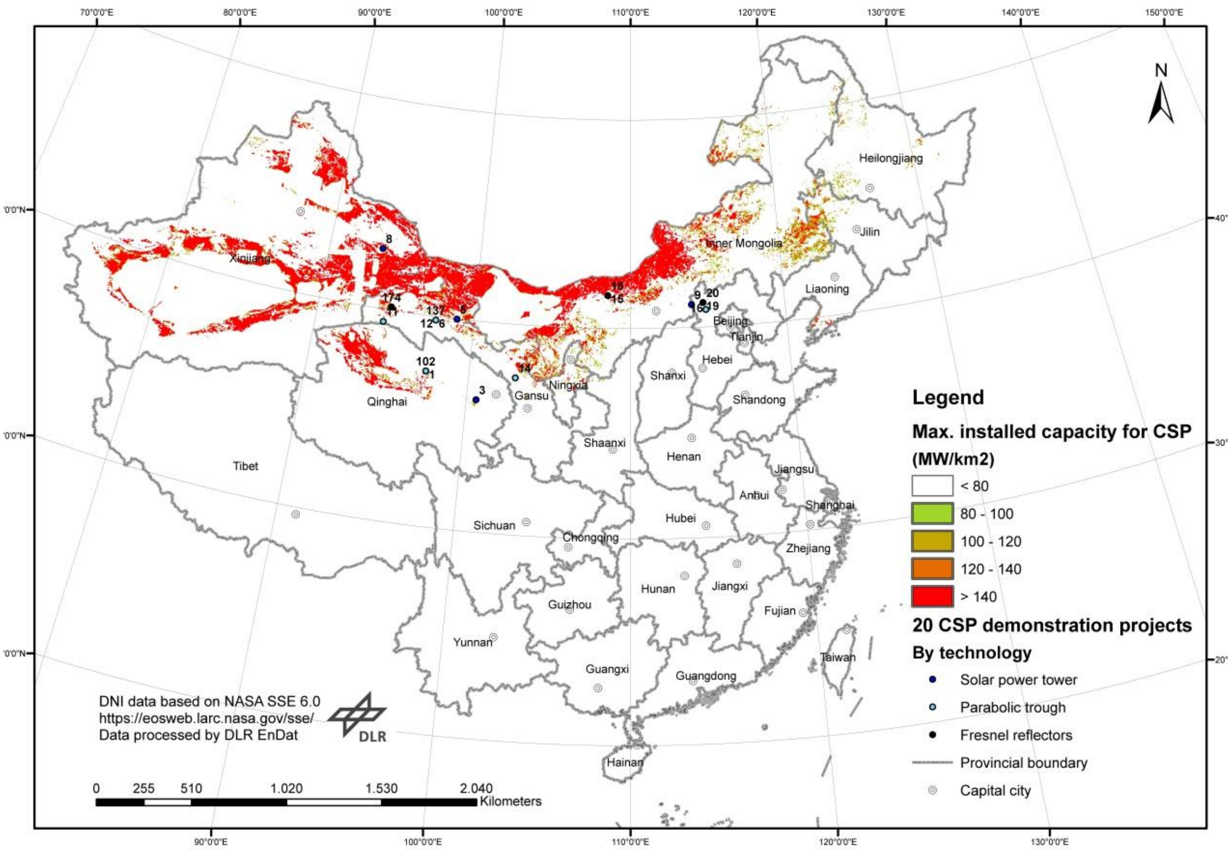


Figure 3.3 Maximum installable CSP capacity per km² and distribution of 20 demonstration CSP projects by technology in China.

3.3.3 Hydro Power

The hydro power resources in China are concentrated in the three south-western provinces of Sichuan, Yunnan and Tibet while eastern coastal China only accounts for very little potentials (see Figure 3.4). The hydro power generation of today corresponds very well with the exploitable potentials in eastern China, whereas in the middle of China and especially in the western part still relative high shares of the technical potentials[8] are not yet deployed due to environmental constraints [46].

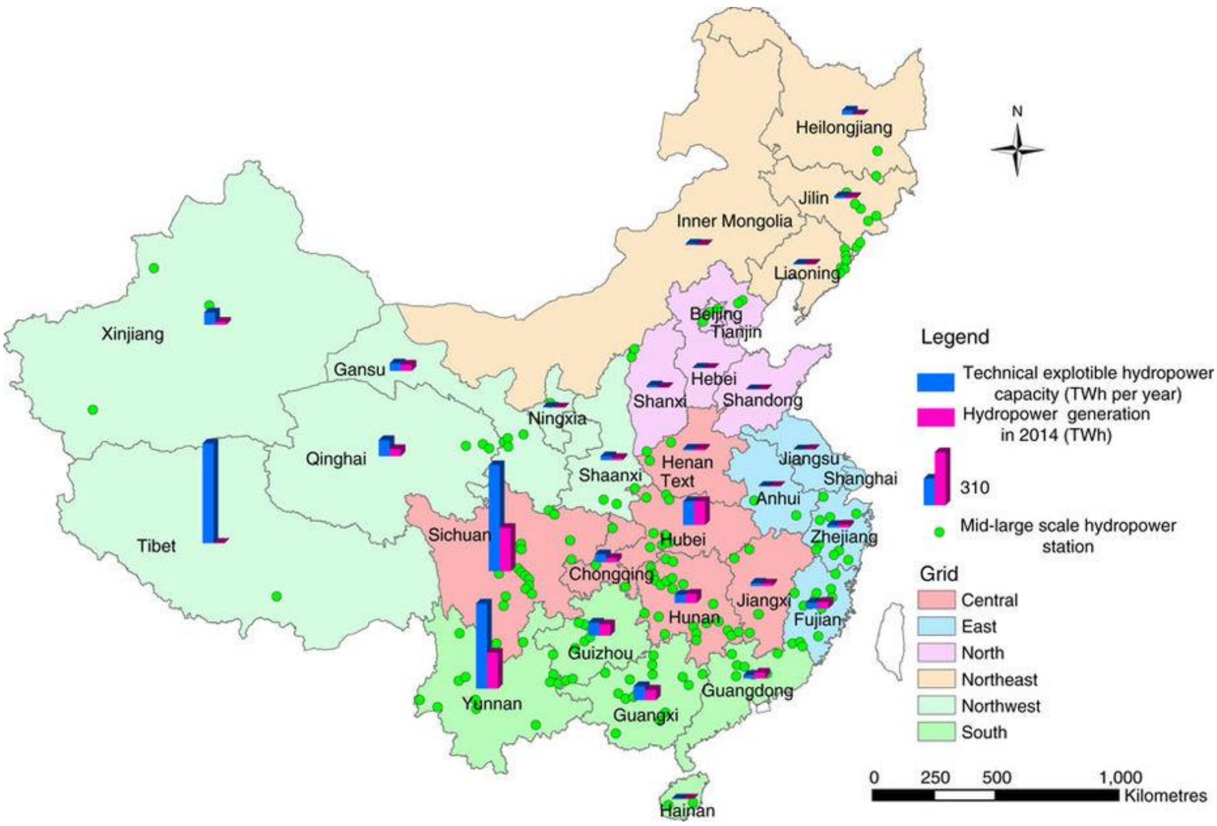


Figure 3.4 Spatial distribution of technical exploitable hydro power in China [35].

More specifically, according to the report of [177], the economic potentials of hydro power of China are concentrated in the south-western provinces of Sichuan, Yunnan, Guizhou and Guangxi, central provinces of Hubei and Hunan, north-western provinces of Xinjiang and Qinghai. The hydro power resources in the BTH region and YRD region are relatively very limited (see Table 3.5).

[8] Technical potentials: geographical and technical restrictions limit the theoretical potentials (the theoretical potential of a renewable resource is the amount of the physical energy flow) [177].

Table 3.5 Hydro power potentials by province of China [177].

Region/Province	Theoretical potentials		Technical potentials		Economic potentials	
	Installed capacity	Generated electricity	Installed capacity	Generated electricity	Installed capacity	Generated electricity
	GW	TWh	GW	TWh	GW	TWh
Sichuan	144	1257	120	612	103	523
Yunnan	104	914	102	492	98	471
Hubei	17	151	36	139	35	138
Guizhou	18	158	19	78	19	75
Guangxi	18	155	19	81	19	80
Xinjiang	38	334	17	71	16	68
Qinghai	22	192	23	91	15	56
Hunan	13	116	12	49	11	46
Fujian	11	94	10	35	10	35
Gansu	15	130	11	44	9	37
Tibet	201	1764	110	576	8	38
Chongqing	23	201	10	45	8	38
Heilongjiang	8	66	8	24	7	21
Zhejiang	**6**	**54**	**7**	**16**	**7**	**16**
Shaanxi	13	112	7	22	7	22
Jilin	3	30	5	12	5	12
Guangdong	6	53	5	20	5	18
Jiangxi	5	43	5	17	4	14
Shanxi	6	49	4	12	4	12
Henan	5	41	3	10	3	9
Inner Mongolia	6	51	3	7	3	7
Liaoning	2	18	2	6	2	6
Ningxia	2	18	1	6	1	6
BTH region	**2**	**20**	**2**	**4**	**1**	**3**
Anhui	3	27	1	3	1	3
Hainan	1	7	1	2	1	2
Shandong	1	10	0.1	0.2	0.1	0.1
Jiangsu and Shanghai	**2**	**15**	**0.1**	**0.2**	**0.02**	**0.1**
China	**694**	**6083**	**542**	**2474**	**402**	**1753**

3.3.4 Other Renewable Energy Resources

The other regional RE resources for power generation are summarized in the Table 3.6 based on literature review (refer to Section 3.2). Compared to wind and solar energy, the other renewable energy resources for power generation are relatively low both in the two study regions and Inner Mongolia. However, pumped hydro power could act as storage to balance fluctuating wind and PV generation in the study regions and in Inner Mongolia. Biomass can have other competitive uses such as fuels for heat and transport.

Table 3.6 Biomass, geothermal, small hydro (5-50 MW) and pumped hydro potentials for power generation and storage in the study regions and Inner Mongolia.

	Biomass [113]		**Geothermal** [186]		**Small hydro (5-50 MW)** [35]		**Pumped hydro** [85, 188]
	Max. installed capacity	FLH	Max. installed capacity	FLH	Max. installed capacity	FLH	Max. installed capacity
	GW	h	MW	h	MW	h	GW
Beijing	0.4	5844	94	6654	186	2263	2
Tianjin	0.6	5844	364	6654	5	4000	1
Hebei	8	5844	461	6654	1206	3191	12
BTH region	**9**	**5844**	**918**	**6654**	**1397**	**3071**	**15**
Shanghai	0.4	5844	-		-		-
Jiangsu	6	5844	0	6654	0	2983	9
Zhejiang	2	5844	1	6654	5	2602	18
YRD region	**9**	**5844**	**1**	**6654**	**5**	**2607**	**27**
Inner Mongolia	**8**	**5844**	**6**	**6654**	**658**	**3236**	**12**

3.4 Summary and Discussion

The potentials assessment shows that the eastern coastal regions of China have relatively low RE resources for power generation compared with northern and western China in terms of solar, onshore wind and hydro potentials. However, the abundant offshore wind in eastern coastal China could be fully exploited with the assumed cost reduction of the offshore wind technology. Eliminating administrative barriers and implementing supporting storage technologies such as pumped hydro, power to hydrogen, etc. are generally seen as important preconditions. Instead of fossil fuels that are dominated by coal for power and heat supply in China, solar and wind energy could contribute largely to the energy system transition in China. Especially Inner Mongolia with its abundant wind and solar energy could act as key supply region for the eastern coastal metropolitan regions, especially the neighboring BTH region. The RE potentials for power generation could also cover additional power demand from the electrification of heat and transport sectors as an important measure for decarbonization. National planning of power transmission capacity expansion largely relies on the distribution of RE resources and demand [31, 68, 84, 147, 148].

4 Scenario Analysis of Energy System Transition Pathways

4.1 Introduction

This Chapter shows the approach and results of the generation and evaluation of different energy scenarios for the two selected regions. Different basic strategies for the future energy supply are examined and compared considering all sectors of the energy system. The reduction of greenhouse gas emissions is one of the major global challenges of this century and the main background also of this scenario analysis. In 2015 China's first "Nationally Determined Contributions" (NDCs) set targets of peaking CO_2 emissions at around 2030, lower carbon intensity per GDP and increasing share of non-fossil fuels in primary energy for 2030 [138]. However, current studies providing energy scenarios for China are predominantly focused on the national level and lack a specific perspective on the regions with urban agglomerations, which have specific challenges [40, 178] (as discussed in Section 2.2). The metropolitan region of Beijing-Tianjin-Hebei (BTH) in the north and the southern region of Yangtze River Delta (YRD) accounted for 20% of national population, 30% of Gross Domestic Product (GDP) and 24% of energy consumption in 2015 [180]. These regions represent huge demand centers and suffer from severe air pollution and energy shortage problems [59].

However, as shown in Section 2.5, their current policies related to energy system transition are rather short-term driven with 5 years planning horizon and lack sectoral or regional integration, which would be necessary to address these challenges. This scenario analysis is intended to add a long-term and cross sectoral perspective to the overall picture of energy system development for the above mentioned focus regions in China, where the challenges are becoming most acute. In this chapter I provide long-term energy system scenarios to derive integrated energy system transition policies for metropolitan regions of China, which help to implement the decarbonization of the energy sector.

In order to account for the imbalanced distribution of economic growth and urbanization with available renewable resources in China, I construct a regional based long-term integrated energy system model with sector coupling among power, heat, transport and fuels. With this model I explore different energy transition pathways for the two study regions towards 2050. The scenario analysis aims to deal with regional specific challenges of efficiency improvement, coal reduction [94], transport decarbonization and multi-sector electrification as discussed in Section 2.2. Main research questions are how a low-carbon energy supply system could look like in each region and how much of the locally available renewable resources can be integrated into the energy system. Above that I also explore how much renewable energy, mainly in form of electricity, needs to be imported from western or surrounding renewable energy abundant regions to guarantee energy supply safety and to achieve the target of CO_2 emissions reduction in eastern China. I apply a normative scenario approach, backcasting from the target year of 2050. This long-term perspective could help policy makers to compare different options in terms of total system costs and environmental benefits in order to avoid "lock-in effects" especially in the investments of energy related infrastructures which are normally of long life time.

The analysis in this chapter is structured as following: Section 4.2 shows the methods, the energy system modeling and scenario construction process of regional energy system towards low carbon future. Section 4.3 presents the results and discussion from the transition pathways of two study regions. Section 4.4 is the conclusion and policy advice derived from scenario analysis for eastern coastal metropolitan regions of China in terms of energy system transition.

4.2 Methodology and Data

4.2.1 Energy System Model

I developed normative scenarios targeting a region-specific low-carbon energy system within an energy system modelling framework with sector coupling. The energy system models are implemented in the Mesap/PlaNet platform [103, 107]. The model represents a time frame until 2050 divided in five years steps (see Figure 4.1). It starts with energy demand development, driven by GDP and population. With a broad representation of different technologies in the sectors of industry, residential, transport, services and commerce, the model assesses the required energy supply, as well as capacities for electricity and heat supply, CO_2 emissions and costs for heat and power production. A detailed description of the basic layout of the model can be found in [111]. I have adapted the original model structure by disaggregating the residential and the services and commerce sectors, in order to better capture the urbanization aspects.

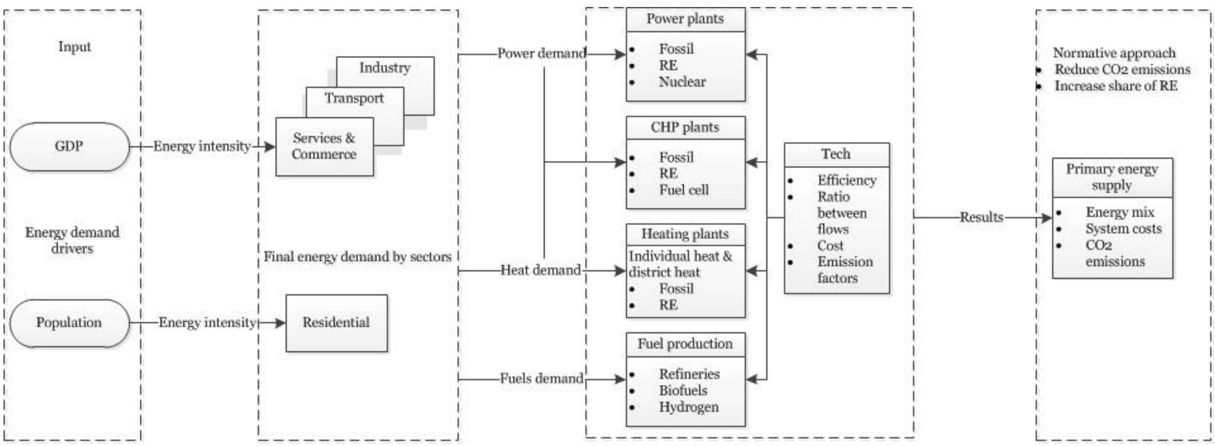


Figure 4.1 Applied regional energy scenario model for the two study regions in China.

The technologies for power, heat and fuels supply are represented by efficiency, ratios between flows (e.g. defined for Combined Heat and Power (CHP) plants, transport modes, hybrid vehicles both for passenger & light duty vehicles (LDV) and heavy duty vehicles (HDV)), costs and emission factors.

The basic input data for the modelling is provided via a comprehensive assessment of regional energy statistics. The energy balance tables by province or resp. municipality from the China Energy

Statistical Yearbook 2016 [175] were used for calibrating the energy model up to the base year (2015). Additionally, since renewable energies for heat, power and transport are not included or specified by source in the regional energy balance table yet, China Renewable Energy Data Booklet [177] was used for additional information. For the transport sector, the regional energy balance table also does not specify energy consumption by traffic modes. Therefore, the traffic volume both for passengers and goods from China Transportation Yearbook [181] was used for energy consumption calculation disaggregated by traffic modes of aviation, rail, road and pipelines. The adopted converter parameters from traffic volume to energy consumption are from high intervention scenario in 2050 Shanghai Low Carbon Development Roadmap Report [143]. The provided conversion factors from China Energy Statistical Yearbook were used for universal energy unit (PJ) calculation from original individual physical quantities [140].

Regional Gross Domestic Product (GDP) and population are two main drivers for energy demand in end-use sectors. Therefore, energy intensities by GDP or population are used to calculate final energy demand for power, heat and fuels by sectors. I used population and GDP in terms of Purchasing Power Parity (PPP) from national forecast [39] for the projection of regional development maintaining the same national shares as in 2015 (see Table 4.1).

Table 4.1 Assumption of population and economic growth in the two study regions.

	Population (Mio.)					**GDP per capita ($$_{2015PPP}$/cap)**				
	2015	2020	2030	2040	2050	2015	2020	2030	2040	2050
BTH	111	112	120	126	133	18,109	25,560	39,535	51,650	65,124
YRD	159	168	176	182	189	25,334	34,080	53,768	71,516	91,657

The calculated regional energy systems with energy supply structures for each sector, total primary energy supply, CO_2 emissions, and energy supply costs are presented and discussed in Section 4.3.

4.2.2 Current Situation and Policy in Study Regions

This thesis focuses on the BTH and the YRD region, which each consists of three provinces or municipalities. Figure 2.2 gives an overview of geographical and administrative information over the study regions. The population densities are much higher than national average and they account for 27% of national energy demand in 2015 [180]. As located in different temperature zones, YRD region has much higher electricity demand for cooling while BTH region has much higher heat demand for building sector especially in winter season.

For the long term scenarios I first analyzed the current status of the regional energy system as well as the current or newly implemented policies, which influence the short-term development of the energy system (refer to Chapter 2). In both regions the energy system today is still largely based on coal and oil products. Since 1993, China has been a net importer of crude oil with increasing import dependency over years. The share of imported crude oil in total consumption has increased from 53% in 2009 to 68% in 2017, turning China into the world's largest crude oil importer [14, 176]. In 2015, most of the municipalities in my focus regions still feature a coal dominated heat and power supply system, with less than 12% from natural gas. Beijing is an exception, with 82% and 54% of natural gas for power and heat supply respectively. In three provinces (namely Hebei, Jiangsu and Zhejiang) coal covers even over 97% of the heat supply. The shares of coal for power supply in Hebei, Jiangsu and Zhejiang Province are 97%, 91% (6% for natural gas) and 89% (6% for natural gas) respectively (data source: [175]). More data on the current energy supply and consumption structures as it was also used for model parameterization are documented in Figure A.1 to Figure A.5. Since 2016, natural gas is promoted as "clean fuel" and a flexible option for power and heat supply, to reduce air pollution from industry and buildings [102], especially in northern China where district heating systems and coal boilers are widely used in winter season [183].

During the 13th Five-year period (2016-2020), China plans to expand its natural gas and Liquefied Natural Gas (LNG) import infrastructure to replace coal in the near future [81]. The "Coal to Gas" program promoted in northern China covers almost 15 provinces as a pollution reduction corridor to the Beijing-Tianjin-Hebei region with "2+26" key cities aiming to erase small coal-fired boilers [26, 183]. Under this background, the share of natural gas should increase from 6% in 2015 to 10% and 15% of national primary energy by 2020 and 2030 respectively. However, this strategy faces challenges to fulfil peak demand, as in 2017, China's underground natural gas storage capacity could only cover 5% of its consumption compared with a coverage ratio of 17% in United States and 27% in Europe [102]. Additionally bottlenecks from transmission infrastructures lead to difficult situations especially along the eastern coastal region [102]. This is especially challenging for small cities and towns, where higher prices occurred during the process of gradual price liberalization of natural gas (implemented for non-residential customers since 2015 but still remains semi-regulated [102, 183]). Furthermore from long-term perspectives, it is questionable, if a transition to natural gas is economically feasible, ecologically sufficient to guarantee a decarbonized and secure energy supply (e.g. in the newest version of China Renewable Energy Outlook 2018 does not require the growth of natural gas after 2020 in its Below 2°C scenario [179]). The BTH region relies heavily on pipeline gas from Central Asia [102]; with limited conventional natural gas resources and challenging exploitation and utilization of unconventional shale gas in terms of domestic production, demand growth still far outpaces domestic supply in any plausible scenarios [102]. Therefore also nuclear energy is considered as a key option to reduce coal consumption as pointed in the 13th Five-year Plans for Power Development and regional specific power development plans [84, 157, 167].

A widely discussed scenario strategy is a renewable energy dominated system both worldwide or specifically for China [45, 123, 174, 178]. However the renewable energy resources in eastern coastal China are limited (as discussed in Chapter 3). Therefore the share of imported electricity (ideally also from renewable energies to be in line with national decarbonization targets) needs to increase as already addressed in the 13th Five-year Plans for Renewable Energy Development towards 2020 [85]. In 2016, the percentage of non-hydro renewable resources for electricity generation of the two study regions are no more than 2% (with the exception of the Hebei Province) and the targets set to increase the share to 5% in Shanghai, 7% for the provinces of Zhejiang and Jiangsu, 10% for BTH region by 2020 (according to Renewable Portfolio Standard Policy released on 29.02.2016 by the National Energy Administration) [88]. However, these short-term targets are still too low to meet regional climate targets in the long term. Currently eastern coastal China still features low renewable energy shares, since much of the recently installed renewable energy capacities are located in western and northern China with relatively abundant wind and solar resources. The decarbonization of the heat and transport sectors also largely rely on electrification based on renewable energies. Within this background, 12 transmission lines were finished by end of 2017, under the 2013 Action Plan on Prevention and Control of Air Pollution [26] to support the coal reduction plan in eastern coastal China and the “Electricity from West and North to East” program. By 2020, the electricity transmission capacity across provinces and regions will reach 270 GW, of which 130 GW are planned during the period 2016 to 2020 [84]. With the penetration of variable renewable energy (VRE) into regional power system, balancing supply and demand is crucial for a secure supply of electricity to metropolitan regions. During the 13th Five-year period, demonstration projects start to balance hydro, wind and PV power in YRD region and Sichuan Province etc. which are power supply regions with abundant hydro resources.

Especially in the medium- to long-term future, distributed energy systems with PV and wind, storage such as batteries, electric vehicles, power to heat systems with heat storages, flexible power to gas generation will also promote the penetration of VRE into energy supply system both in urban and rural areas. After fast growth of installed onshore wind and PV capacities of large utility scale in northern and western China, during the 13th Five-year period, eastern China has also set targets for distributed installed onshore wind and PV power plants [82]: the Hebei Province set a target for on-grid distributed onshore wind capacity of 4.3 GW from 2018 to 2020 [164]; high load centers like Shanghai develop smart grids to integrate wind, PV and storage systems on local scale [165]; the Jiangsu Province promotes distributed onshore wind in low wind speed areas [167]; and the Beijing area accelerates installation of onshore wind together with systematic balancing of PV [163]. The fast development of distributed PV has started in 2014. During the 13th Five-year period, the 110 GW target for solar power plants includes 60 GW of distributed PV by 2020 [82]. In the 13th Five-year Plan of Renewable Energy Development in BTH region [157], the Hebei Province plans to improve its ability to control and export its electricity surplus from wind and PV power plants at around 10% of its total power supply; both Tianjin and Beijing target to enhance import capacity from the surrounding renewable energy abundant provinces by 6 TWh and 10 TWh respectively. During the 13th Five-year period, Jiangsu Province has set priority for offshore wind development with 10 GW on-grid by 2020 [167] to access these abundant resources (details on the resource assessment in Chapter 3).

Restructuring the industry sector in eastern China from heavy industry based economy towards service and innovation based economy is seen as another option to limit energy demand. Hebei is the largest steel production base of China [117] and in the Jiangsu Province industry accounts for 80% of energy demand, which is higher than the national average of 66% [175]. Energy demand is also expected to increase with the continuous process of urbanization in the region. At the same time residential and commercial buildings have large potentials to save up to 74% of the energy by 2050 according to a scenario study of [9]. For example, energy efficiency of heating supply could be gained from “Green Building” Labelling Standards for new residential and commercial buildings and retrofitting program with smart metering and thermal insulation materials applied for existing building stocks [196].

In 2015, Passenger Cars (PC) and Light Duty Vehicles (LDC) consumed most of the energy in transport sector with 66% in BTH region and 58% in YRD region, and account for 67% and 58% of total CO_2 emissions in transport sector respectively [182]. According to the 13th Five-year Plan for Modern Integrated Transport System Development (2016-2020) [166], by 2020, high speed railway service will cover 113 big cities (including megacities), civil aviation will cover 260 cities and another 36 lines of highway will be completed. The electrification rate of railway is supposed to increase from 61% in 2015 to 70% by 2020, at the same time doubling the transport service. Especially the metropolitan regions strive for a limited commuting time under 2 hours. By June, 2018, 27 provinces and municipalities in China have set targets for electric vehicles used in private and public transport with supporting charging infrastructures during the 13th Five-year period [193]. By 2020, built charging infrastructures need to support 5 Mio. electric vehicles [84]. However, future uncertainties exist in terms of the competition among different transport modes thus affecting energy consumption structures. Especially for freight transport with a growing demand particularly in developing countries generally lack proper designed supporting policies for modal shifting from road transport to rail [51]. The future low-carbon fuel supply could involve successful deployment of Compressed Natural Gas (CNG) and biofuels; advanced vehicle concepts in LDV market segment include battery electric, plug-in hybrid and fuel cell vehicles [131] supported by fast charging or battery exchange infrastructures and refuelling stations. However, a regional plan with multiple provinces and core cities such as metropolitan regions under sectoral coupling context among power, heat, fuels and transport sector is not available yet.

4.2.3 Normative Scenario Approach

The normative scenario approach sets desired future targets for 2050, namely the transformation of regional energy system towards lower CO_2 emissions. From this starting point I apply a backcasting process for the transition pathways with different decarbonizing strategies and efficiency potentials explored. This approach has been previously used for assessing the decarbonization of the energy sector in various studies [41, 99, 111] and is one option to incorporate structural changes beyond current trends. For this study, the CO_2 emissions reduction targets would be achieved through efficiency improvement, the implementation of low carbon technologies, the expansion of import capacity, mode shifts and behavior changes. In order to develop a reference case for the future trajectory of the energy system I did a thorough analysis of recent Chinese energy scenarios as well as current and emerging energy policy on regional level.

First of all, the current available national energy scenario studies that target an energy system transition to meet various climate targets are reviewed in order to identify regional transitional targets and tasks. Seven scenarios from three studies are reviewed to compare main policies and strategies behind to deal with energy system transition of China (see Table 4.2.).

- The China Renewable Energy Outlook (CREO) examined energy system transition pathways under current domestic policies and below 2°C targets according to the Paris Agreement. It reflects the latest coal reduction policies in China and, compared to the other studies, has the lowest share of energy consumption in industry taking into account current economic structure adjustment policies in China [178].
- The World Energy Outlook (WEO) of the International Energy Agency (IEA) provides three scenarios for China following different storylines. Transition pathways without new policy targets are the basis of the Current Policy Scenario (CP), Nationally Determined Contributions (NDCs) for Paris Agreement are considered in the New Policy Scenario (NP), and interlinked energy related goals to UN Sustainable Development Goals (SDGs) are achieved in the Sustainable Development Scenario (SD) [39].
- Two scenarios from the Energy [R]evolution study funded by Greenpeace represent pathways with high shares of renewable energy, presupposing nuclear phase-out and assuming a maximum deployment of efficiency measures. These are the Energy [R]evolution Scenario (E[R]) and the 100% renewable energy system in the Advanced Scenario (ADV) [123].

Table 4.2. Reviewed national energy scenario studies.

Study	**Institute**	**Scenarios**		
China Renewable Energy Outlook	Energy Research Institute	Stated Policy Scenario	Below 2°C Scenario	
(Abbreviation)	(CREO)	(SP)	(B2°C)	
Time horizon	2050			
Main policy and strategy		Based on current domestic policies	Below 2°C targets	
Achieved CO_2 emissions by 2050 (Bt)		4.6	2.6	
World Energy Outlook	International Energy Agency	Current Policy Scenario	New Policy Scenario	Sustainable Development Scenario
(Abbreviation)	(WEO)	(CP)	(NP)	(SD)
Time horizon	2040			
Main policy and strategy		Exclude new policy targets	NDCs for Paris Agreements	Interlinked energy related goals to UN SDGs
Achieved CO_2 emissions by 2040 (Bt)		11.4	8.6	3.3
Energy [R]evolution	Greenpeace	Energy Revolution Scenario	Advanced Scenario	
(Abbreviation)	(E[R])	(E[R])	(ADV)	
Time horizon	2050			
Main policy and strategy		High share of renewable energy with nuclear phase-out and high efficiency	100% renewable energy system and high efficiency	
Achieved CO_2 emissions by 2050 (Bt)		1.3	0	

Table 4.3 compares two dimensions of energy efficiencies referring to the economic output and CO_2 intensities of these scenarios related to the primary energy use. The CREO study expects a higher energy efficiency in 2020 due to the consideration of domestic adjustment of economic structure during the 13th Five-year period. The Energy [R]evolution study has the lowest CO_2 intensity by 2050 with even zero emissions in its advanced scenario due to the implementation of high shares of renewable energies in all sectors of the energy system. The WEO study considers different energy efficiencies and CO_2 intensities in its three scenarios. More in-detail comparisons of reviewed national scenario studies are provided in the Appendix D with regard to the installed power capacity by

technology, the electrification rate by sector, final energy consumption by sector with the consideration of different efficiency measures and economic structures, and the resulting peak year for the consumption of fossil fuels.

Table 4.3 Comparison of energy efficiency and CO_2 intensity of reviewed scenarios.

Item	**Energy efficiency**				**CO_2 intensity**			
Unit	**MJ/$GDP**				**g/MJ**			
Year	**2020**	**2030**	**2040**	**2050**	**2020**	**2030**	**2040**	**2050**
CREO-SP	4.6	3.1	2.2	1.5	74	63	55	35
CREO-B2°C	4.5	2.9	2.1	1.4	68	57	39	22
WEO-CP	4.8	3.5	2.8	/	69	64	62	/
WEO-NP	4.6	3.2	2.4	/	68	61	54	/
WEO-SD	4.4	2.8	1.9	/	65	48	26	/
E[R]	4.9	2.9	1.7	1.1	65	55	35	14
ADV	4.8	2.8	1.7	1.1	66	53	23	0

The scenario comparison illustrates the range of future development pathways that are seen as possible and plausible on the national level. It also reveals the importance of exogenously, i.e., politically set strategies and constraints, e.g., regarding the use of nuclear power, CCS, biomass and other controversially discussed renewable options such as variable decentralized renewable power and large hydro. Also regarding efficiency the scenarios reveal large differences in terms of average energy intensities. The range of intensities, deployment pathways, and mitigation trajectories were used to define my own regional storylines for the scenario assessment.

Three different regional scenarios are the basis for the analysis of development pathways in this thesis. The Five-year plans until 2020 and their following trends until 2050 for each province or municipal city are the basis for the reference, the Current Policy Scenario (CPS). In order to reach regional CO_2 reduction targets I compare it with two alternative options, a Natural Gas & Nuclear Scenario (NGNS) and Renewable & Import Scenario (RIS), which are constructed to discuss regional energy system transition pathways of the two study regions (see Table 4.4). The three scenarios vary not only with regard to low-carbon heat and power generation options and technologies but also in assumed efficiency improvement potentials. The scenarios differ with regard to:

- Energy saving in industry due to economic structure adjustment from heavy industry based economy towards service and innovation based economy (from guidelines raised in the 13th Five-year Plans for Economic and Social Development [80]);
- Degree of electrification in heating and the transport sector as addressed in China Renewable Energy Outlook [178];
- Energy conservation in the building sector (addressed in the 13th Five-year Plans for Energy Saving in Buildings and Green Buildings [171]);

- Transport mode shift from road transport and aviation to rail transport (highlighted in the 13th Five-year Plans for Integrated Transportation Development [166]);
- CO_2 emission reduction targets (as emissions per capita) according to different national scenario studies with proportional to differences between regional and national average in 2015 (2.4 times more in the BTH region and 2.7 times more in the YRD region) [39, 123, 178].

Therefore, based on the strategy developed for the two scenarios, options to transform the fossil fuel dominated energy system in the study regions are also presented in the following. Table 4.4 gives a detailed insight in the assumptions for each of the scenarios.

Table 4.4 Main assumptions and strategies for scenario construction in two study regions.

Scenario	Current Policy Scenario	Natural Gas & Nuclear Scenario	Renewable & Import Scenario
Abbreviation	CPS	NGNS	RIS
Assumptions			
Efficiency	Same intensity changing rate as WEO-CP scenario for China indicating no additional new policy effects on energy consumption by sectors, extending the trend to 2050	Same intensity changing rate as WEO-SD scenario for China indicating moderate electrification rate effects on energy consumption by sectors, extending the trend to 2050	Same intensity changing rate as national CREO-2°C scenario indicating the highest electrification rate effects on energy consumption by sectors
Power supply	Current situation, driven by short-term policies	Use natural gas and nuclear as alternatives to replace coal and oil for local generation, moderate expansion of regional RE power generation and import capacity	Deep electrification and decarbonization of regional energy systems, phase-out of nuclear energy, full utilization of regional RE potentials, high share of power import from RE abundant regions
Heat supply	Current situation, driven by short-term policies	Use natural gas as alternative to replace coal, moderate expansion of RE heating supply and electricity for heat	Further expansion of RE heating supply, district heating and cooling system and electricity for heat
Transport sector	Current situation, driven by short-term policies	Moderate electrification rate	Transport modes shift from road to rail both in terms of passengers and goods, high electrification rates, utilize RE hydrogen and synthetic fuels
CO_2 emissions per capita (2050)	Based on WEO-CP scenario for China: 8 t CO_2 per capita, year	Based on WEO-NP scenario for China: 4 t CO_2 per capita, year	Based on CREO-2°C scenario for China: 2 t CO_2 per capita, year

NGNS is characterized by the utilization of natural gas and nuclear as a key strategy together with moderate electrification rate in end-use sectors to replace coal and oil products for heating, cooling and mobility. In NGNS natural gas and nuclear power plants are further expanded as a strategy to reduce coal power plants. The scenario assumes a moderate exploitation of regionally available renewable energies for power generation and a moderate share of imported electricity compared with RIS.

However, there is a risk that over-investing in gas infrastructure and nuclear expansion may delay a transition to a deep decarbonization by preventing the further development of renewable energy [112]. Besides, this strategy can lead to a permanent import dependency. China has already become the world's largest importer of natural gas via pipeline and as liquefied natural gas (LNG) since 2018 with a doubling since 2014. The main reasons are the domestic projects to replace coal by natural gas in its households and industry sectors to deal with local air pollutions [13]. Therefore, RIS follows the strategy of early and consistent promotion of renewable energies combined with a high electrification rate both in heat and transport sectors. This may even allow to achieve higher regional climate targets compared to the national average [54]. RIS also phases out nuclear in the YRD region, does not promote nuclear power plants in the BTH region and limits the expansion of natural gas power and heat plants. Additional power demand from electric heating and electrification of transport sector is taken into consideration. According to the 13th Five-year Plan for Power Development, by 2020 the electricity used to replace fuels will reach 450 TWh [84]. Power import will be available from other renewable energy abundant provinces such as Inner Mongolia or Sichuan Province. Hydrogen produced from electricity of renewable energies is introduced as an option for chemical storage and can be utilized in cogeneration for the production of heat and electricity or reconversion into electricity for short periods as well [99].

Compared to NGNS with moderate electrification rates implemented in transport sector, RIS will further deepen electrification rate and utilize RE hydrogen and synthetic fuels to replace fossil fuels [108, 109]. For the heating sector, district heating system is further developed in the northern region to improve system efficiency compared with CPS [93]. The effects of these main assumptions will be further discussed in Section 4.2.4.

4.2.4 Main Assumptions

The main assumptions for constructing the scenarios are discussed with regard to energy efficiency by sectors, imported share of electricity as well as costs and efficiency of adopted fuels and technologies. Lower energy intensities are assumed in RIS compared with NGNS due to a further decarbonization of the economy, deep electrification in heat and transport sectors, a shift to more efficient and sustainable transport modes, higher efficiency standards for buildings, and an adoption of more efficient electric appliances and changes of customer behaviors. Final energy demand by sectors is calculated on the basis of the reviewed national scenario studies in terms of energy intensity (see Table 4.4). Table 4.5

shows the average reduction of final energy demand by sectors in 2050 resulting from the assumed efficiency improvements. The higher reduction rate in the residential sector of BTH compared with YRD is due to the current low efficient heating system in northern China. The higher reduction rate in industry of BTH compared with YRD is because of cutting over capacities especially for steel production in Hebei Province.

Table 4.5 Assumption of final energy demand reduction potential in NGNS and RIS compared with CPS of the two study regions in 2050.

	NGNS				RIS			
	Industry	Residential	Transport	Services & Commerce	Industry	Residential	Transport	Services & Commerce
BTH	49%	22%	22%	24%	64%	30%	35%	35%
YRD	28%	4%	20%	26%	34%	8%	37%	27%

The assessment of power generation from wind and solar energies was conducted with the tool EnDAT (as discussed in Chapter 3). Biomass as a renewable fuel is a limited resource, which has many competing utilizations such as for electricity and heat generation or as transportation fuels influenced by market-oriented policies [131]. I therefore assume a very restricted implementation of biomass and biofuels across all sectors. The annual biomass power generation and technical exploitable hydropower generation potentials by province or municipality are taken from [113] and [35] respectively. A medium to low temperature geothermal potential of 6.1 TWh could be found only for the BTH region [186], where a significant potential could be used for individual and district heating of buildings [83, 186].

The regional renewable energy potentials for power generation and power demand in the scenarios are compared in Figure 4.2. The minimum and maximum electricity demands are derived from the three constructed scenarios (see Section 4.3). After 2020, the regional power generation from renewable energies cannot meet the growing regional power demand even for the minimum level. Thus electricity from other regions, ideally from renewable energies, is strongly needed, especially when the further electrification of the heat and transport sectors increases the power demand towards 2050. The renewable resources for power generation in the BTH region are dominated by solar (mostly PV) and onshore wind. The YRD region has a higher share of offshore wind and a lower share of solar (PV only) compared to the BTH region. The regional potentials of renewable energies for power generation in the two study regions are fully deployed in RIS (in detail see Section 4.3.2).

Figure 4.2 Regional renewable energy potentials for power generation compared with power demand ranges from three scenarios (see Section 4.3.2) in the two study regions.

Specific investment costs, fixed operation and maintenance costs for power and CHP plants are taken from the 1.5°C scenario study for China in 2015 values [121]. Regional historic full load hours (FLH) by technology [197] are used for future assumptions based on national scenario studies [123]. CO_2 costs since 2020 are assumed for CHP auto-producers in industry, the residential and the services and commerce sectors, public CHP and power plants based on [121] assuming carbon markets as evaluated in [191]. Also prices for fossil fuels and their future projections are taken from the national 1.5°C scenario study [121]. Due to the lack of comprehensive investment data for the heat sector I only accounted for new installations of renewable technologies. Investment costs for biomass, solar heat, geothermal and heat pumps are based on [191]. Emission factors for gas transport, refineries and coal transformation are calibrated from the Multi-resolution Emission Inventory for China v1.0 Database [190]. Technology and fuels transformation efficiency is assumed to increase from CPS to NGNS and RIS. For example, efficiency improvement for electrolysis improves by 4% in RIS compared with CPS in 2050. Discount rate was set to 6%. The detailed cost and efficiency assumptions used for scenario construction are available in the Appendix C.

4.3 Results of Scenario Analysis

The resulting transition pathways for the two study regions are shown and discussed in the following sub-sections. First I provide an overview over the energy efficiency gains by sectors and regions in Section 4.3.1. Then energy supply structures in power, heat and transport sectors and the resulting primary energy use are discussed in the following sections. Section 4.3.6 finally shows the corresponding CO_2 emissions reduction by sectors under NGNS and RIS compared with CPS and gives an analysis on power and heat supply costs.

4.3.1 Energy Demand

The energy intensity reductions assumed for heat, power and fuels are translated into final energy demand developments in end-use sectors shown in Figure 4.3 and Figure 4.4. A higher efficiency improvement is assumed for RIS compared with NGNS, which has especially a significant effect in the BTH region due to the high fossil fuel use for heating and transport. Especially the share of energy consumption for industry could be reduced here from 62% in 2015 to 42% under NGNS and to 37% under RIS. While in YRD it would be reduced from 70% in 2015 to 55% under NGNS and to 49% under RIS. The application of energy saving standards in building sectors contribute to the efficiency improvement in the residential and the services and commerce sectors. By 2050, the energy demand per capita in households of the BTH region could decrease by 6 GJ/cap from CPS to NGNS and with further 2 GJ/cap reductions under RIS. In southern regions like YRD energy demand per capita is much lower due to a lower heat demand in winter season. However, significant energy efficiency gains can be realized through more efficient cooling systems and other electric appliances. Thus the energy demand per capita of the residential sector in YRD region could also decline from CPS to NGNS and RIS. There are similar trends in the services and commerce sectors of the two study regions as well. However, even with the implementation of efficiency measures, energy consumption in both residential and services and commerce sectors of BTH region and residential sector in YRD region will increase in the future due to a continuous urbanization process with higher energy consumption per urban resident compared with rural residents due to improved living standards [49, 133, 137, 196]. Energy consumption per capita in the services and commerce sector of YRD region is assumed to be a little lower by 2050 under NGNS and RIS compared with 2015 level due to an improved district heating and cooling system [93], which transfers industry waste heat to commercial buildings (e.g. policy to prioritize industrial CHP plants for economic development zones in southern Jiangsu Province [167]). In both regions efficiency measures are essential to curb the massive increase in energy consumption until 2030. They are the major target if CO_2 emissions are to be limited in the short to mid-term. During the continuous urbanization process, the integrated building design with smart system, passive houses and more efficient equipped appliances contributed to energy saving compared to past decades. The changes of the regional economic structures from heavy industry based to service based also contribute largely to the reduction of heat demand in industry, especially in the three provinces of Hebei, Jiangsu and Zhejiang. Efficiency could also be gained from the utilization of waste industry heat for buildings through well connected district heat networks [93]. In the BTH region, the scenario result shows that efficiency measures have the potential to reduce heat demand by

50% under NGNS and 72% under RIS in 2050. Otherwise, heat demand could increase by 11% under CPS from 2015 to 2050. Similar shares could be achieved in the YRD region.

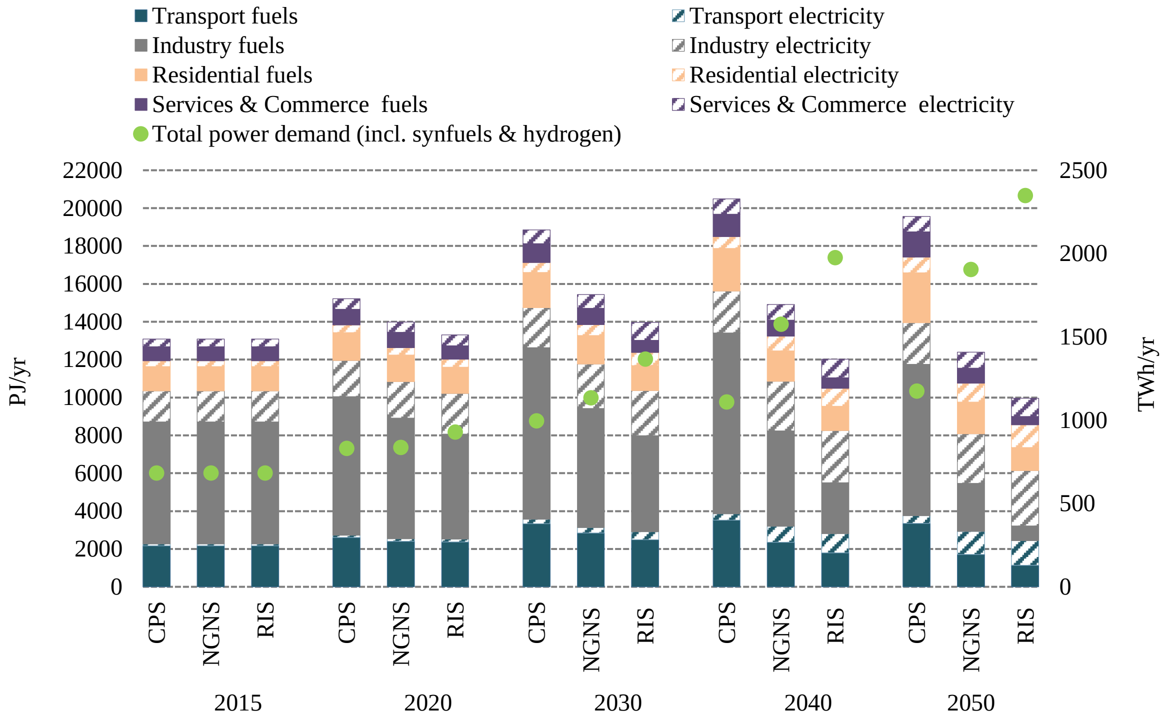


Figure 4.3 Final sectoral energy demand by fuels and electricity in the scenarios for the BTH region.

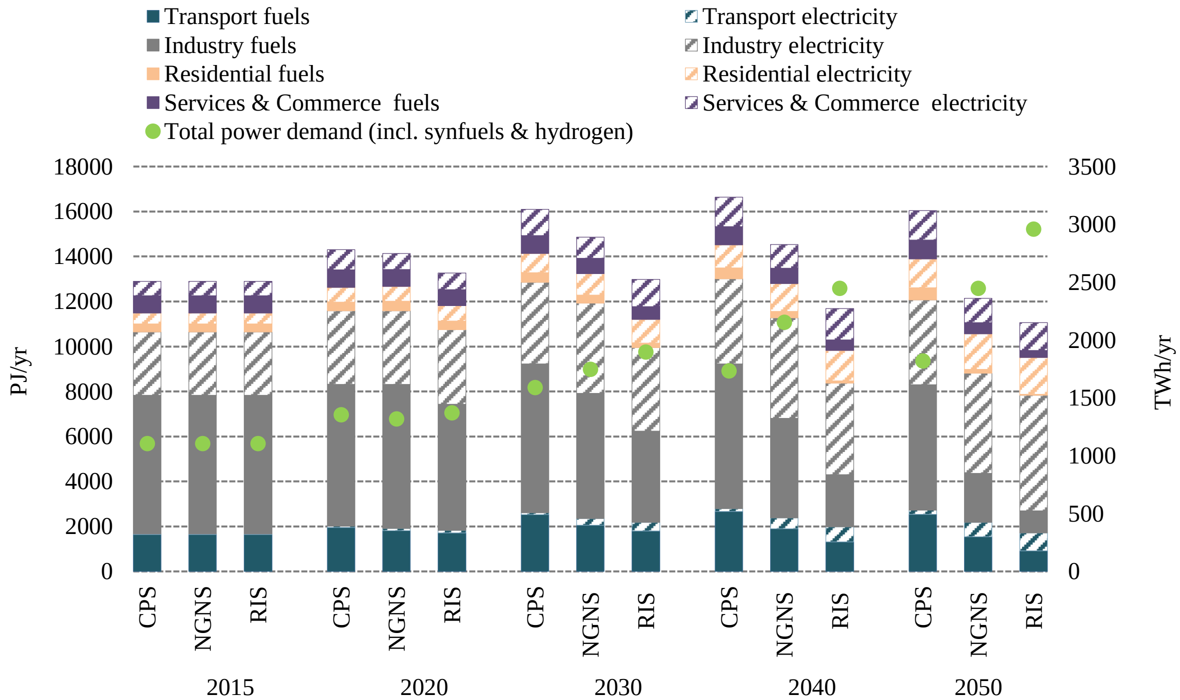


Figure 4.4 Final sectoral energy demand by fuels and electricity in the scenarios for the YRD region.

The modal shift from private cars to public transportation contributes to control energy demand in the transport sector. Besides, electrification of rail and road transport are key options to significantly reduce the fuel demand. The results therefore also demonstrate how electricity is supposed to replace fuels in transportation, especially for road traffic, but also for heating, especially coal use in the heat sector. By 2050, the share of power for heat supply could increase from 22% in 2015 to 47% under NGNS and to 68% under RIS compared with only 24% under CPS. The YRD region already covers a higher share of heat by electricity, as no widespread district heating systems are available. The share of power for heat supply could increase from 48% under CPS to 70% under NGNS and to 82% under RIS compared with only 35% in 2015. For the transport sector, power consumption could increase from 11% under CPS to 41% under NGNS and 54% under RIS, providing the main share of transport services compared with only 5% in 2015 in the BTH region. Starting from only 2% in 2015, YRD transport is slightly lagging behind, with 30% under NGNS, and 47% under RIS by 2050. However electrification of heating and transport leads to "new" power demand sectors, which add to the consumption of "conventional" electric applications. Overall this results in a huge increase in overall power demand in the NGNS and RIS scenarios in comparison to today and to the CPS scenario. By 2050, the share of electricity for heating and transport of total power demand could increase from 19% under CPS to 27% under NGNS and to 32% under RIS. In the YRD region, the share of electricity for heating and transport in total power demand could be rather stable in all scenarios, due to a lower heat demand. Nevertheless, power could become the main heat source in the RIS scenario in this region. In the next sections I present, how this can be exploited for a transformation of the supply system.

4.3.2 Power Sector

The scenarios show a fundamental change in the structure of the power sector, due to the challenges of coal reduction and a massive increase in consumption due to the electrification of heat and transport sectors. Especially the integration of renewable sources required new infrastructures, to allow for an integration of VRE both in the NGNS and RIS scenarios.

Figure 4.5 shows that by 2050, the share of regionally available renewable energy for power generation could increase to 47% under NGNS and 75% under RIS compared with only 17% under CPS in the BTH region. Additional storage and other flexibility options such as Demand Side Management (DSM), power to heat, hydrogen and other fuels will be needed in order to reduce curtailment of VRE power generation, and to improve load balancing and supply security of electricity [21, 70]. Under RIS 90% of the Concentrating Solar Power (CSP) plants potentials in Hebei Province could be utilized and can act as load balancing with its thermal storage system, similar to the 15 MW demonstration project in Hebei Province in operation. If nuclear power plants are also promoted in BTH region as other eastern coastal provinces, it could reach 9 GW installed capacity under NGNS by 2050. The reduced use of natural gas and nuclear energy and the assumed further electrification of heat and transport sectors under RIS require larger shares of electricity to be imported from renewable energy (RE) abundant regions. This is even the case with fully exploited regionally available RE resources in BTH and YRD. Under RIS the total installed capacity of wind and solar by 2050 needs to increase by 50% compared with NGNS and increase 5.7 times compared with CPS in the BTH region. Here PV could become the main power supplier in the domestic electricity mix: with 85% of exploited PV resources under RIS, PV could support 44% of regional self-produced electricity. The share of imported electricity (ideally also from renewable energies to avoid "carbon leakage" from consumption centers to supply regions) in BTH region needs to reach 76% in RIS compared with 56% under NGNS and 40% under CPS, starting from 30% in 2015. Regional coordination and integration within metropolitan regions and RE abundant regions in terms of renewable power generation and consumption is crucial to reach overall climate targets. From the energy policy context it is important to overcome potential administrative barriers in order to formulate consolidated targets, as described in section 4.2.2.

To back up expansion of renewable energies for power generation, conventional power plants need to run with reduced FLH, thus, more system flexibility will be required. For natural gas power plants I assumed a reduction to 900 hours per year in the RIS according to assumptions used in [122]. There is a more significant change in the mode of operation in BTH, with currently 4830 hours compared to YRD region, with currently 2340 hours. In contrast, I assumed that FLH for wind and solar energy could significantly increase by 2050 if technologies will further develop and flexibility options will be implemented for load balancing (e.g. increase from 1655 hours to 2449 hours for onshore wind electricity generation in the BTH region with increasing wind turbine sizes and higher hubs height).

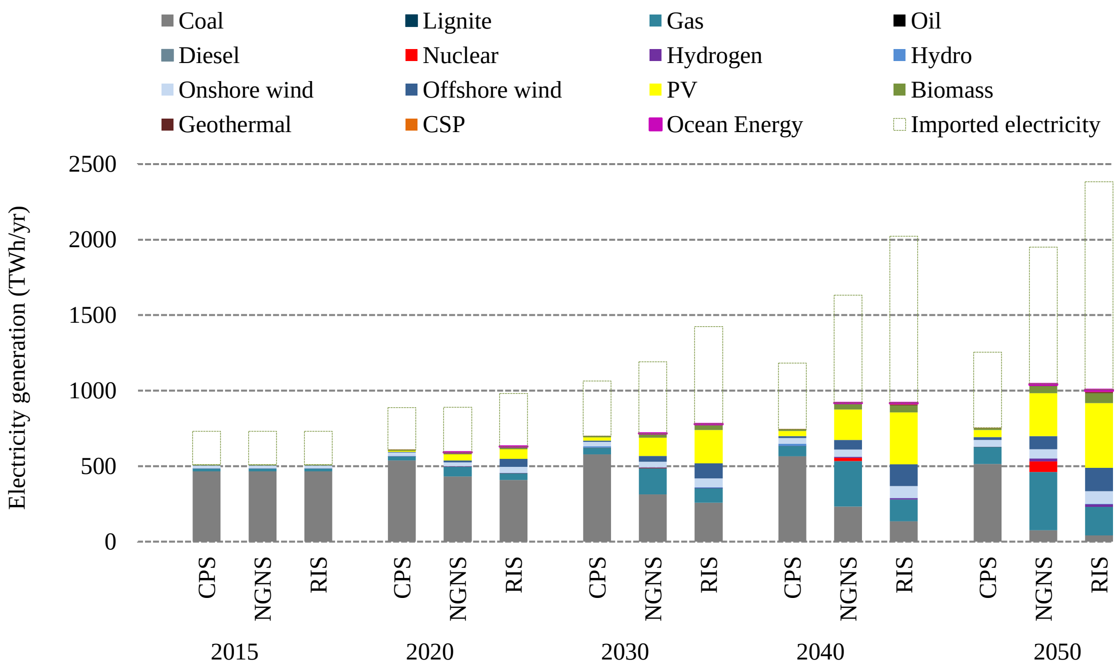


Figure 4.5 Power generation structure in the scenarios for the BTH region.

Figure 4.6 shows that in YRD region, by 2050, the renewable energy generation could increase from 41 TWh in 2015 to 897 TWh under NGNS and to 1486 TWh under RIS (more than 80% is VRE) compared with only 211 TWh under CPS. If nuclear power plants are further developed in YRD, the installed capacity could reach 27 GW under NGNS by 2050 compared with 12 GW under CPS. In the RIS scenario only the existing 3 GW remained. Electricity imports to both regions could be implemented from RE abundant regions such as Sichuan Province with hydro resources and Inner Mongolia as well as other western provinces with wind and solar energies, supported by planned and expanded cross-regional High Voltage Direct Current (HVDC) and High Voltage Alternating Current (HVAC) transmission lines [84]. Under RIS the total installed capacity of wind and solar by 2050 could increase 55% compared with NGNS and increase 7 times compared with CPS, exploiting 95% of onshore and offshore wind potentials. The installed capacity for offshore wind nationwide is currently far behind the set target of 5 GW by 2015 [172]. However, future cost reductions [42, 44], the development of a domestic offshore wind industry and eliminating administrative barriers for ocean resource management and utilization would ensure further installations [34, 153]. Offshore wind could then provide electricity to the eastern coastal regions with a relative short transmission distance, competitive system costs, and less landscape impact compared with onshore wind [192]. This is especially important in dense urban areas of eastern coastal China. In the YRD region by 2050, offshore wind could supply 47% of its own power generation under RIS while only 25% are achieved under NGNS and 6% under CPS. Opposite to the BTH region, wind would be the backbone of power production in YRD. With a higher share of offshore wind in its power system, renewable hydrogen could be produced during peak hours as a storage option. A demonstration project has already been discussed in the 13th Five-year Plan for Wind Power Development (e.g. in Jiangsu Province) [84]. Unlike the large wind farms developed in northern China with high wind speed, onshore wind resources in YRD are of low to medium wind speed. However, exploiting its own available onshore wind resources for power generation has the advantage of being close to load centers, thus, reducing transmission costs and losses.

Under RIS the share of imported electricity could be significantly higher: 57% in YRD by 2050 compared with 43% under NGNS and 40% under CPS. The share of imported electricity is lower in the YRD region compared with BTH region as YRD covers just one megacity but two provinces with larger hinterlands and coastal areas having a significant higher offshore wind potential. 3 GW and 9 GW of offshore wind energy under NGNS and RIS respectively are expected to provide electricity generation by 2050 with consideration of assumed cost reduction and regional resource potentials [192].

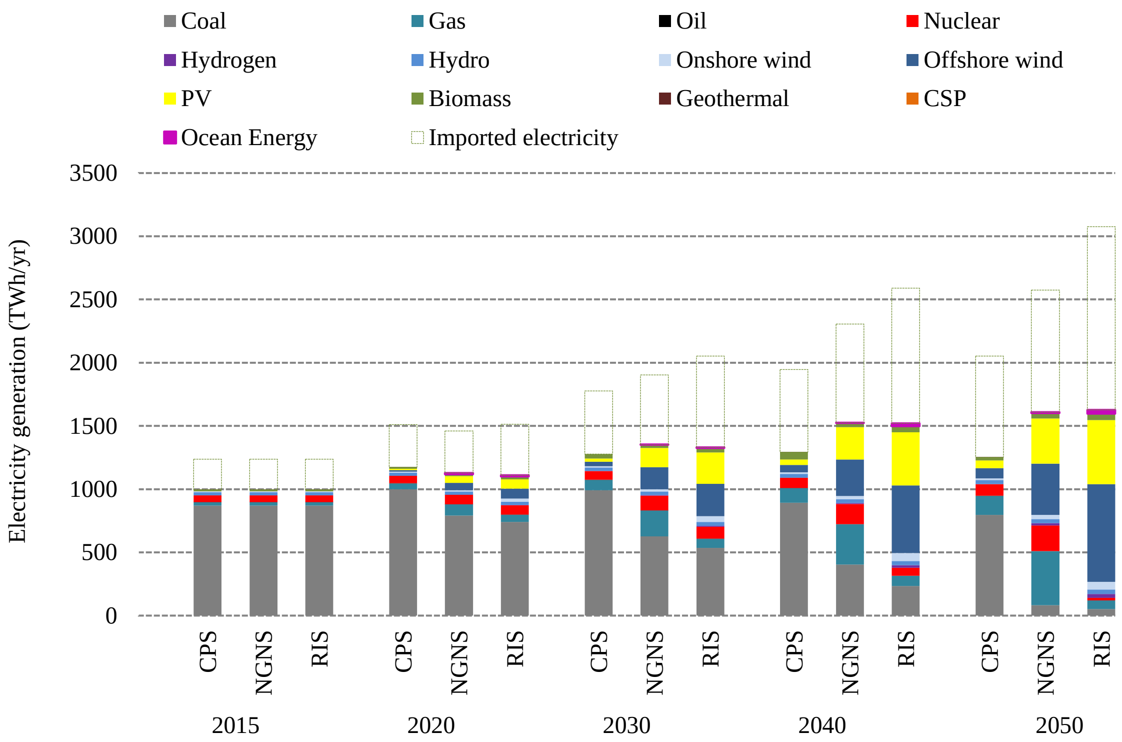


Figure 4.6 Power generation structure in the scenarios for the YRD region.

4.3.3 Heat Sector

Under the precondition of massive efficiency improvements, both NGNS and RIS scenarios manage to phase out oil and most of the coal in the heat sector in both regions. CPS assumes “clean coal” technology as a basic heat supply option according to the current policy and therefore retains coal as the main heat source also in the long term. The alternative scenarios implement a strong diversification of heat applications instead. The NGNS follows and enhances the short-term policy of promoting natural gas for heating to replace coal boilers and coal fired CHP plants and supplements this with geothermal and solar energy, heat pumps and electric heaters. The RIS scenario with even larger efficiency gains could further reduce gas and coal use, leading to a predominantly renewable heat supply system. Modern use of biomass and waste for heating and CHP plants with existing and planned district heating systems could contribute to eliminate low efficient and pollutant coal fired boilers and CHP plants, especially in urban areas. Moreover, the development includes a consequent exploitation of low temperature sources for space heating and hot water, such as solar thermal collectors and ambient heat via heat pumps. In the BTH region, the share of renewables for heat supply could reach 45% under NGNS and 69% under RIS by 2050, up from only 6% in 2015 and 12% under CPS in 2050. Solar heat and biomass could complement each other specifically in district heating systems. Also the regional potentials of geothermal heat [83, 186] are exploited in the RIS (see Figure 4.7). In the YRD region, renewables could supply 44% under NGNS and 65% under RIS by 2050. Here electric heating - directly or via heat pumps becomes the backbone of space heating and hot water (see Figure 4.8). However, the total power demand for heating in 2050 is even lower than in the CPS scenario due to efficiency improvements. For both regions this requires strong efforts and coordinated planning in refurbishment and new construction of buildings.

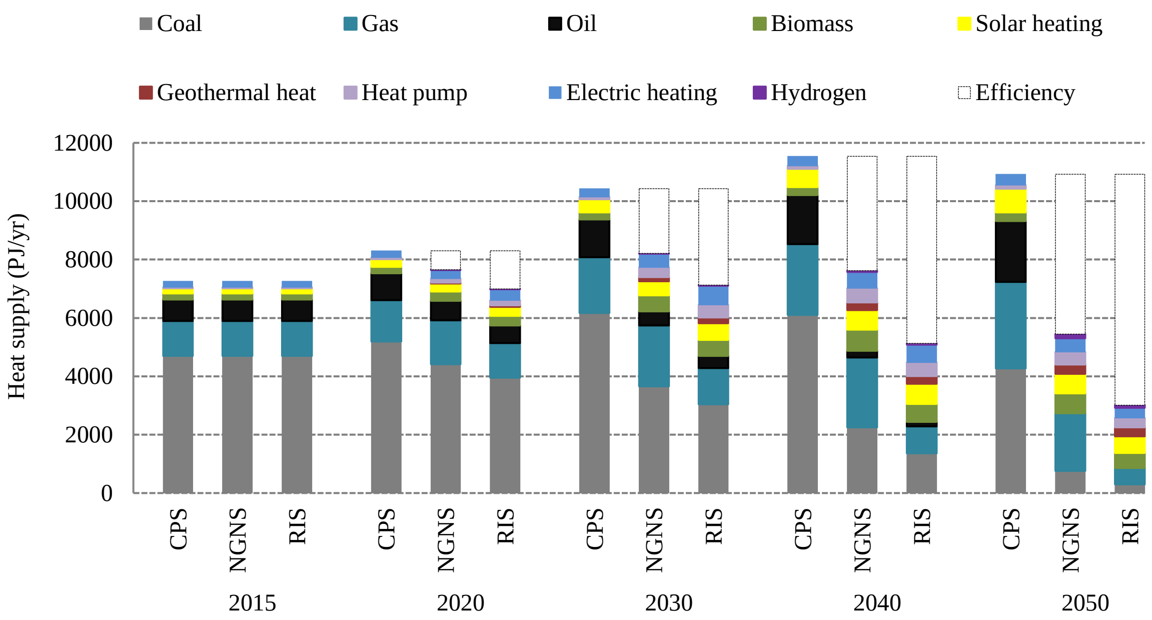


Figure 4.7 Final energy for heat supply by fuels in the scenarios for the BTH region.

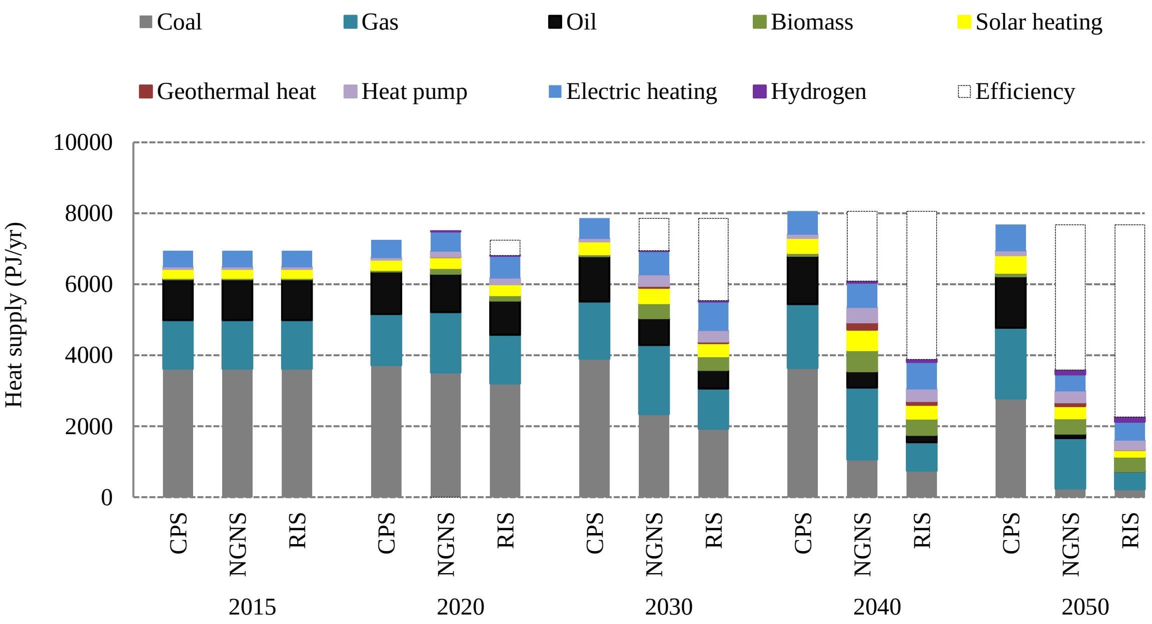


Figure 4.8 Final energy for heat supply by fuels in the scenarios for the YRD region.

Besides, district heating and utilization of natural gas, electricity, solar and geothermal energy for heating in small towns and rural areas need to be further promoted in order to achieve such a consequent replacement of coal stoves and low efficient traditional biomass utilization [183]. Especially in winter season when heat demand is higher, fluctuating wind power during peak generation periods could be used for heat production. This also helps on the one hand to compensate the lower solar radiation and on the other hand to balance VRE through heat storage. Specifically the balancing has already been mentioned as a valuable option of sector coupling [146] to improve system performance. Compared with YRD region, BTH region has potentials of geothermal for individual and district heating supply in buildings [83, 186].

4.3.4 Transport Sector

The energy supply for transport changes significantly in the NGNS and RIS, as a result from the two major strategies of mode shifting and a change in drive systems. RIS gains higher efficiency in the transport sector compared with NGNS by further shifting transport from road and aviation to rail (including urban transit and medium to long distance for regional transport). The shift to electric mobility induces additional efficiency gains. By 2050 electricity could be the major "fuel" for transport in both scenarios of NGNS and RIS and in both regions. The utilization of synthetic fuels could further contribute to replace gasoline for mobility in RIS, specifically for heavy duty transport, ships and planes (see Figure 4.9 and Figure 4.10). By 2050, the share of oil products consumption in transport sector could drop from 80% under CPS to 34% under NGNS and only 6% under RIS in BTH. In YRD by 2050, the share could decrease from 83% under CPS to 46% under NGNS and only 7% under RIS. Such a transformation could largely reduce urban air pollutions from road transport.

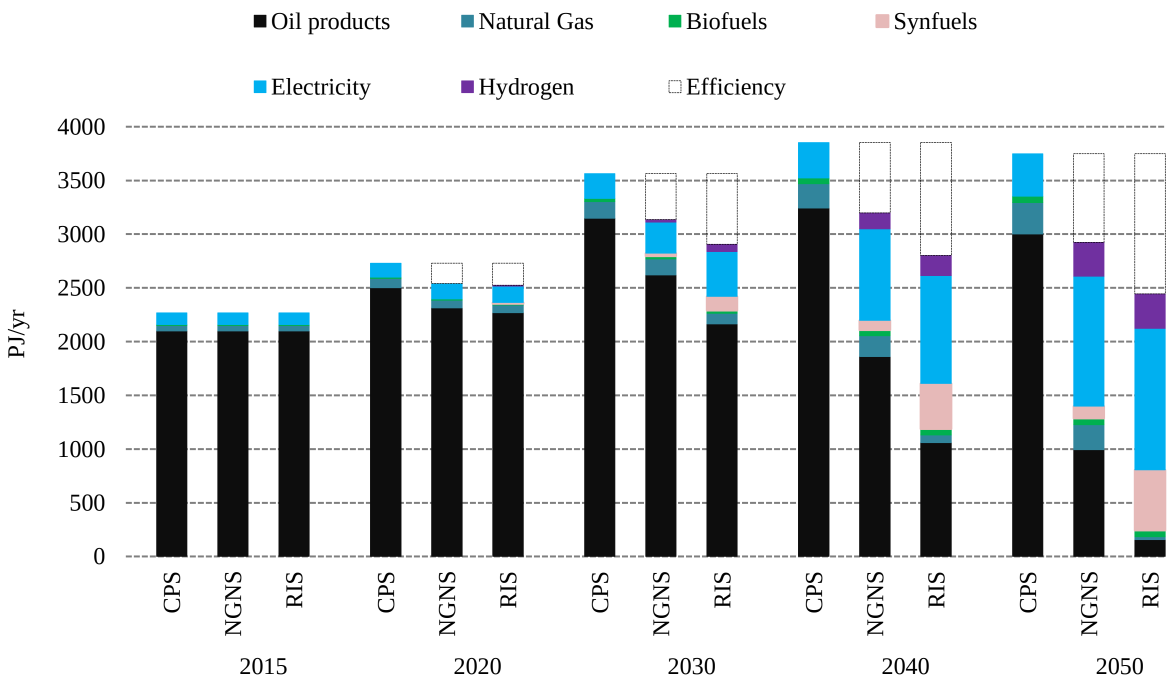


Figure 4.9 Final energy demand by fuels for transport in the scenarios for the BTH region.

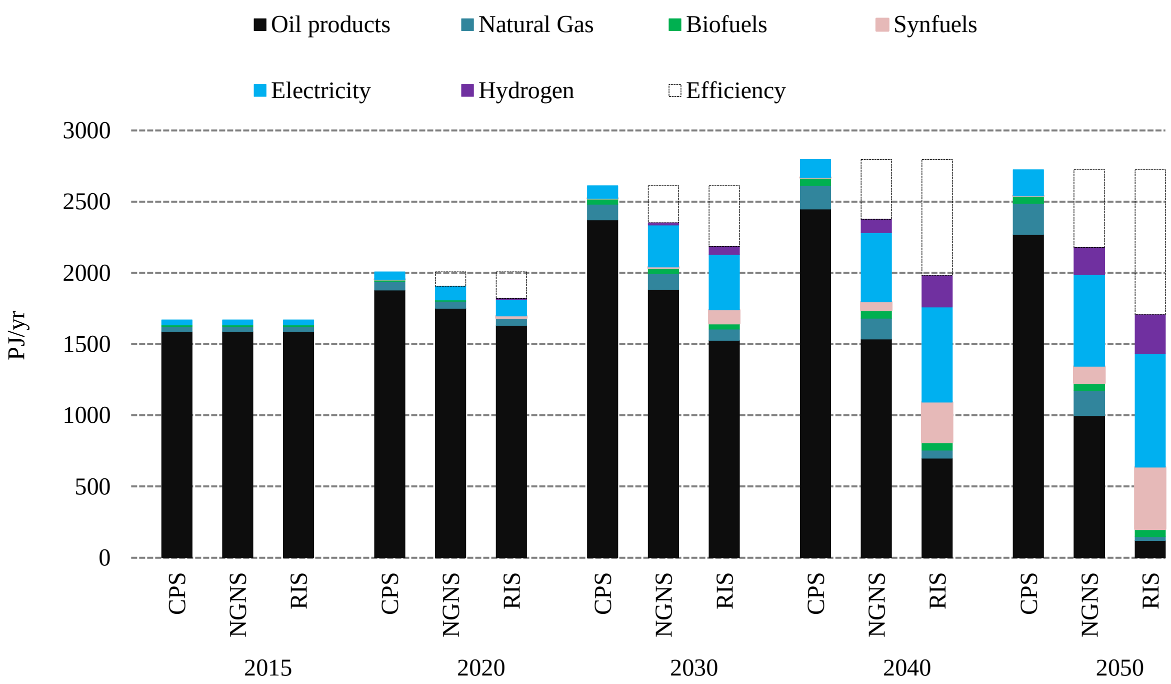


Figure 4.10 Final energy demand by fuels for transport in the scenarios for the YRD region.

The transport energy consumption of metropolitan regions in a developing country such as China cannot be separately discussed without its urbanization context. Sustainable and integrated urban and regional planning help to increase efficiency and energy saving. Moving freight transport from trucks to rail and ships have continuously been seen as an efficiency measure, as rail and water modes are more energy efficient on a per-ton-km basis [131]. The shift of passengers from aviation and cars to rail in RIS both for urban mobility and long distance travels leads to significant reductions of fuel demand. However, such mode switching needs to be supported by a corresponding development of infrastructures, in line with the widespread adoption of alternative fuel vehicles and customer behavior changes [131]. These strategies then lead to a much slower increase in energy demand in road transport in the NGNS and RIS and the latter could even stabilize its demand towards 2050.

On one hand, electric vehicles help to reduce road pollution from gasoline and diesel cars; on the other hand, they could act as storage to utilize electricity from wind and PV during peak generation periods. This helps to integrate VRE into the power system in a cost-effective way. This is especially important in a high renewable penetration power system such as RIS [119]. Although battery electric vehicles dominate renewable vehicles in the Chinese market at the moment and hydrogen refueling stations in China only exist in 7 main cities, after 2030, hydrogen and other synthetic fuels produced from renewable energy electricity could supply fuels for road transport as well, where electric drive systems are at their limit (e.g. in heavy duty vehicles).

4.3.5 Primary Energy

As a result of the shifts in final energy demand there is a major transformation of the primary energy supply in the NGNS and RIS. In both regions the transformation leads to a significant reduction of coal and oil products, which takes place more rapidly in the BTH region, mainly due to the more comprehensive electrification of the heat and transport sectors. However, the perspective of primary energy supply must be amended by the additional primary energy demand caused in other regions by power imports, which are therefore also presented in the figures. In both the BTH and YRD region, power imports increase in line with the renewable share in the system. In order to further replace natural gas and nuclear power, 58% and 54% of power need to be imported in RIS in BTH and YRD respectively, which result in “exported” primary energy demand from Inner Mongolia, Sichuan Province etc. This is a much higher share than in the other scenarios.

Nevertheless, compared with CPS, primary energy demand including renewable electricity import could be reduced in both regions. In the RIS, the remaining primary energy is mainly based on renewables. In BTH the reduction of total primary energy could be 43% under NGNS and 61% under RIS. Without additional decarbonization measures under CPS, coal consumption could peak in 2035 at 13487 PJ; crude oil and natural gas could continue to grow until 2050 to 7000 PJ and 4100 PJ respectively. Effective measures especially for fuel alternatives in the transport sector could largely reduce the demand for crude oil products thus reducing national energy import dependency (see Figure 4.11).

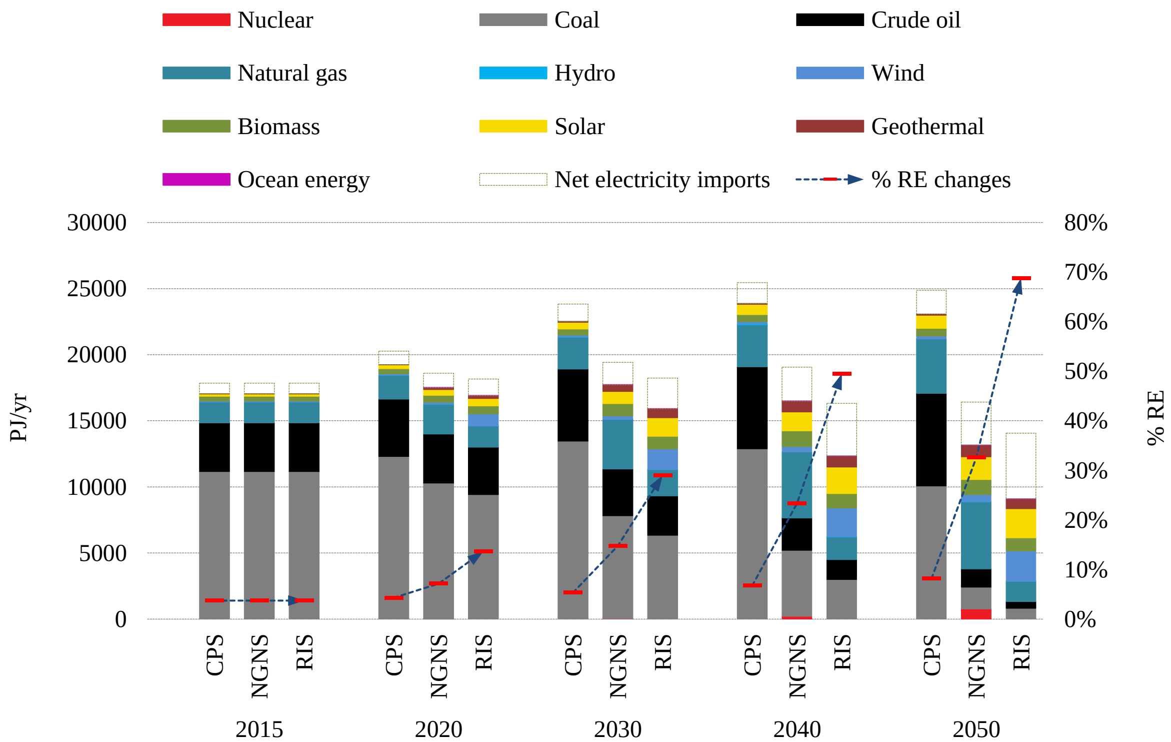


Figure 4.11 Primary energy supply and share of renewables in the BTH region.

In the YRD region, compared with CPS, primary energy demand is reduced in the alternative scenarios slightly less than in BTH, by 34% under NGNS and 59% under RIS. But coal consumption under CPS peaks in YRD much earlier (in 2020) than in BTH at 15,000 PJ (see Figure 4.12).

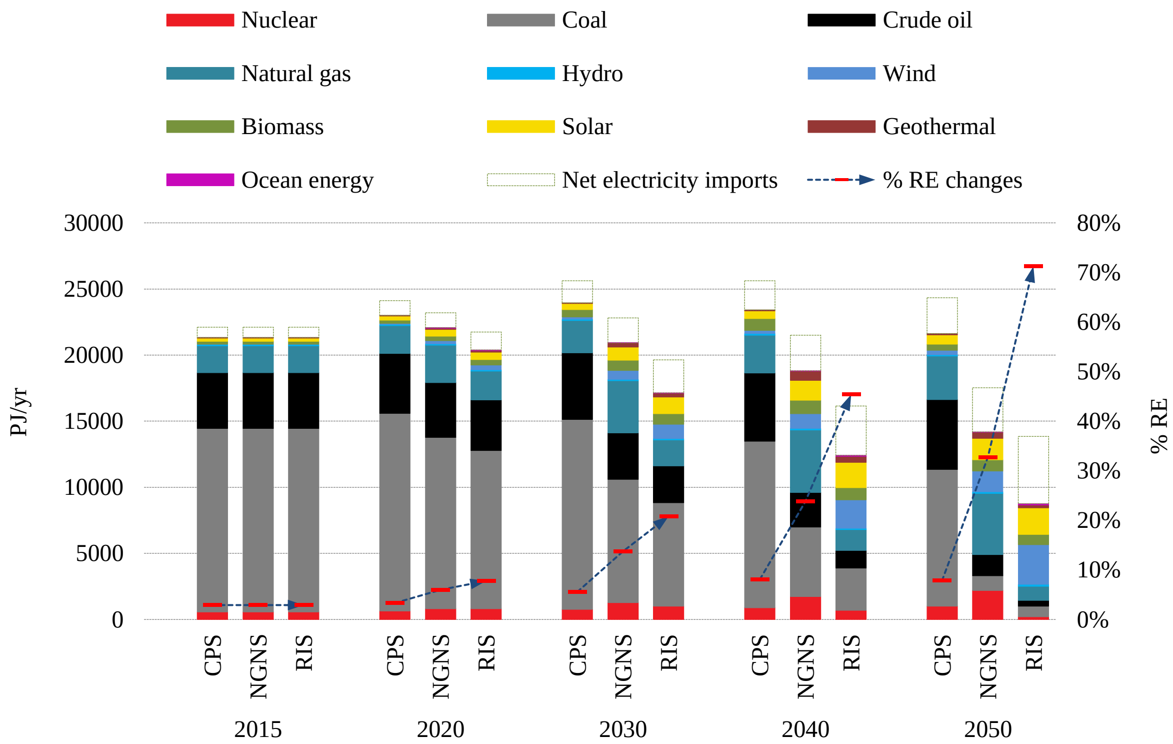


Figure 4.12 Primary energy supply and share of renewables in the YRD region.

4.3.6 Effects on CO_2 Emissions and Costs

With the penetration of renewable energies to replace fossil fuels, efficiency measures, and, electrification in heating and transport sectors, the regional CO_2 emissions could be significantly reduced in NGNS and RIS compared with CPS. In BTH, the regional CO_2 emissions per capita reduce from 15.5 t/cap in 2015 to 4.4 t/cap under NGNS and 1.1 t/cap under RIS compared with still 15.2 t/cap in the CPS. CO_2 emissions remain predominantly from gas combustion in the power sector in the NGNS and RIS in both regions. In YRD region, the regional CO_2 emissions per capita could be reduced even more from 17.6 t/cap in 2015 to 3.5 t/cap of NGNS and 0.6 t/cap of RIS by 2050 compared with 12.5 t/cap of CPS. This leads to even higher overall emission reductions in YRD than in BTH. However, compared with national below 2°C climate targets, regional NGNS scenarios could not match the national average target of 2.15 t/cap by 2050 according to [179]. RIS scenarios could help the regions to achieve higher climate targets than in national average. Besides, the energy system transformation in large demand centers could also support the transition process in supply regions under the condition of high penetration of renewable energies in power sector. The cumulative CO_2 budget from 2015 to 2050 could be cut by half in the RIS (see Figure 4.13), with higher reduction in the BTH region. The figure also shows that the reduction will only come into effect in the long run following the assumed trajectories which all take into account the national NDCs until 2030. Therefore it becomes clear, that only an immediate start in the energy transition towards a low carbon future can help to curb CO_2 emissions as fast as possible so that the cumulative emissions are low enough to reach the 2 °C target with a high probability.

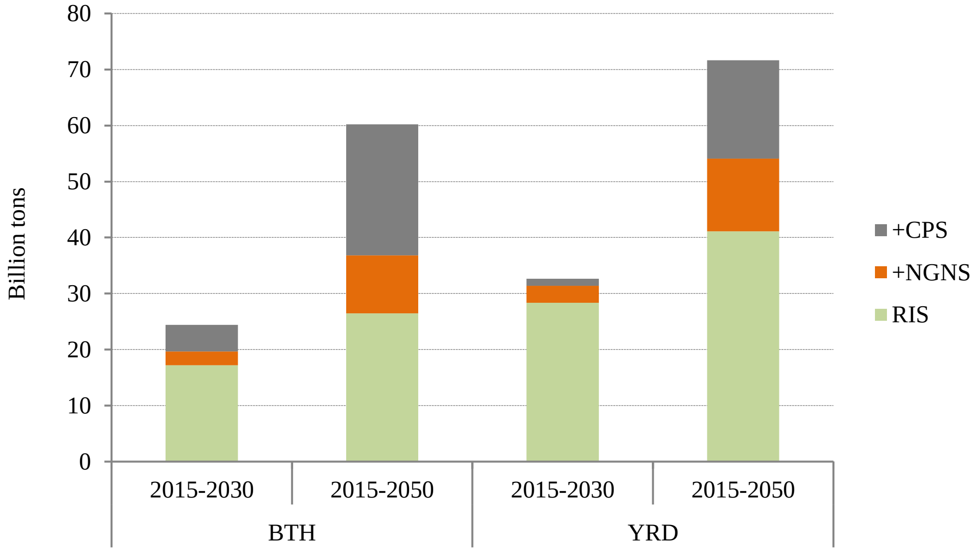


Figure 4.13 Cumulative CO_2 budgets during 2015-2030 and 2015-2050 periods in two study regions.

However, the transition process needs continuous and consistent investments into renewable energies for power and heat supply. The power sector investments for an energy transition could be huge, both in terms of installed capacity as well as grid and storage infrastructures, as has been previously pointed out [97, 112, 123, 178]. On the other hand, these studies also calculate, the energy transition pays off via reduced fuel costs and massive cost reduction for installations such as PV and wind in the long run. My study shows that the total investment costs for power and CHP plants would increase from CPS to NGNS to RIS, mainly due to additional power demand from heat and transport sectors (see Figure 4.14). However this will be compensated for mainly by reduced fuel costs for power and CHP. Compared with CPS, the fuel costs in NGNS and RIS would be largely reduced: compared with CPS only 67% will occur in NGNS and 43% in RIS in the BTH region; for the YRD region the reduction is slightly lower, reaching 78% of CPS in NGNS and 51% in RIS. However, in order to reach regional climate targets, additional costs are needed for imported electricity. From the following multi-regional optimization analysis I calculated a mean imported electricity price of 5.4 \$ ct /kWh, which is 1.8 \$ ct/kWh lower than the costs of locally generated electricity in average (refer to Chapter 5).

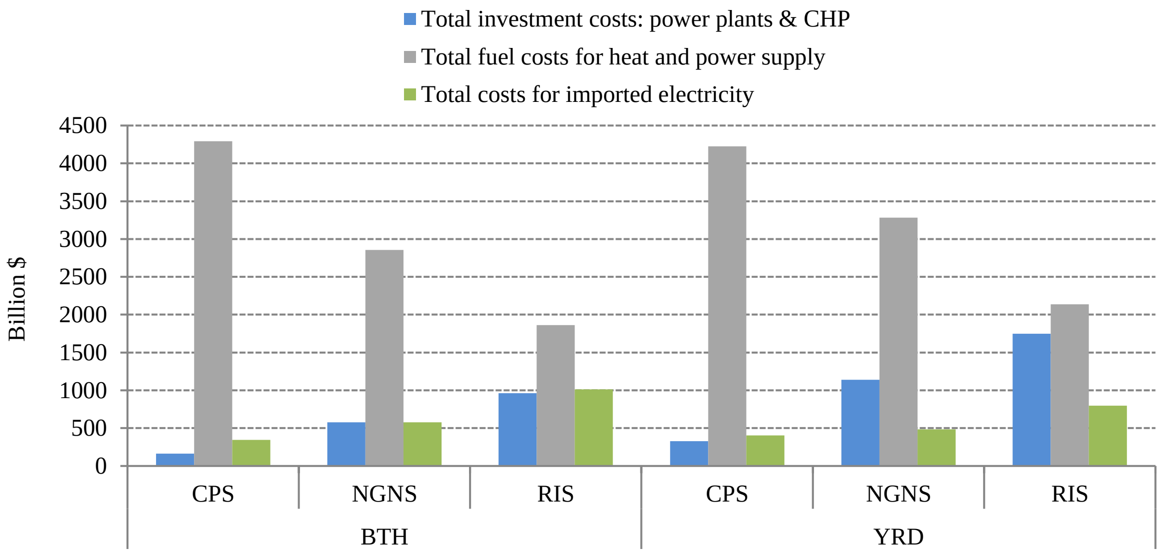


Figure 4.14 Selected cumulative costs during transition period (2015-2050) in the scenarios for the two study regions.

Moreover, in the alternative scenarios the accelerated electrification could also curb investment costs in the heat sector. However, without a comprehensive investment accounting of the heat sector as for the power sector, I calculated only cumulative investment costs for the renewable heat applications in each scenario as an indicator for additional heat cost. For the BTH region, investments in renewable heat range between 500 and 600 billion $ in NGNS and RIS. Here they are much higher than in YRD, where no district heating systems in urban areas need to be retrofitted. In the YRD region, which is dominated by individual heating devices the additional investment costs for heat supply range between 200 and 300 billion $ between NGNS and RIS. In both regions these investments are relatively small compared to investment and fuel costs in the power and CHP sector.

4.4 Summary and Discussion

The development of a normative scenario model integrates national and regional targets, characteristics and development perspectives for decarbonizing the energy systems with a focus on two metropolitan regions of China: the northern Beijing-Tianjin-Hebei (BTH) metropolitan region and the southern region of Yangtze River Delta (YRD). The scenario analysis characterizes two possible and significantly different transition pathways for decarbonizing the regional energy systems, which highly depend on efficiency measures, policies for nuclear, natural gas and coal development, regional exploitation of renewable resources (especially for solar and wind) with storage and import capacity expansion connected to large wind and solar resources of China by HVDC/HVAC transmission lines. This study extends national targets (NDCs) by 2030 to possible regional targets until 2050 applying a regional multi-sectoral analysis. The scenario analysis reveals that policies to increase the penetration of renewable energies and natural gas as alternative fuels for coal and oil products into both supply and end-use sectors are necessary not only on the national but also on the regional level. However, my analysis of current policy in Chapter 2 identified, that such measures are not yet in place. To formulate these kinds of firm commitments beyond 2030 is required to avoid stop-start investment cycles and to provide confidence to supply chain investors for long-term business opportunities especially for technologies that are still in the early stages of deployment such as CSP, offshore wind and ocean energy [192]. Both alternative scenarios, NGNS and RIS, require substantial additional policies triggering the transformation and necessary sectoral and regional integration. Especially in the RIS, regional CO_2 emissions could be largely reduced in order to address national climate targets. Main strategies this scenario follows are the penetration of renewable energies into various sectors, transport mode shifts, the development of district heating and cooling systems, electrification in heating and the transport sector, and the use of synthetic renewable fuels. Energy efficiency improvement is the backbone for decarbonization options, thus, different potentials are considered in NGNS and RIS. The analysis also shows, that the focus of policy with regard to industrial restructuring [29] especially to cut excess capacity in heavy industry and district heating in the BTH region can complement other coal reduction measures. In the YRD region, the exploitation of offshore wind, the efficiency in both individual and central cooling systems and utilization of industry waste heat can provide important contributions. The decarbonization of the transport sector in both regions would largely depend on electrification, with alternative fuels such as biofuels, hydrogen and synthetic fuels as a backup. Electrification not only allows renewable energies to be integrated more efficiently into the transport sector, but also significantly reduces the specific energy consumption for mobility and results in large environmental benefits especially in urban areas. The scenario RIS is characterized by a high electricity demand due to electrification and hydrogen generation and therefore needs to be supported by developing a suitable market-based power trading mechanism, which also enables to implement new strategies for sector coupling, improved system flexibility and security of supply. The import issues both from electricity and natural gas are particular important for the eastern coastal metropolitan regions of China on the way to reach their CO_2 emissions reduction targets.

However, the discussion of key premises and strategies in this study is limited to two possible decarbonization pathways and energy systems of two selected regions. Further sensitivity analysis of key assumptions is needed to discuss the robustness and uncertainty of constructed scenarios. A big uncertainty comes from the future economic structure of China, i.e., how much of the economy could be service and innovative based. Further important open questions are related to the electrification rates that could be achieved in heat and transport sectors. Uncertainties also come from the competitiveness among various low carbon technologies and the possible implementation of transmission capacities or storages. The technology of Carbon Capture and Storage (CCS) of fossil fuel power and heating plants for the reduction of CO_2 emissions is not taken into consideration because of possible constraints from storage capacity and uncertainties related to the costs by 2050 and the long-term effectiveness. Additionally, global natural gas markets with import pipelines and capacity to China and future global and domestic natural gas prices add further uncertainties especially for the NGNS case.

These scenarios are a necessary step to quantitatively identify the key challenges not only from a national but a regional perspective, highlighting the importance of regional integration especially for the power system. Electricity generations from VRE sources are highly dependent on weather conditions thus more information is necessary to guarantee supply security on extreme weather conditions. Challenges of system integration rise with the penetration of renewable energies both from regional generated and imported electricity. In order to analyze storage needs for short term up to seasonal electricity storage as well as for utilizing surplus electricity from VRE, a higher temporal resolution is needed. Still, the scenario analysis in this chapter provides insights into the possible development of the overall energy system, related cross-sectoral challenges and requirements for achieving the long-term targets, which need to come into focus when developing regional policies for medium to long-term.

5 Multi-regional Optimization of Power Supply for Metropolitan Region

5.1 Introduction

Metropolitan regions are defined as cities and their surrounding areas with close socio-economic connections and with a concentration of population, transport and economic activities that largely rely on importing energy from their hinterland [92]. Accelerated urbanization and industrialization in China result in big challenges of increasing energy demand and emissions, especially in eastern coastal metropolitan regions. The current serious urban air pollution and greenhouse gas emissions are caused by local coal dominated power and heating plants as well as road transport mainly from oil products. The electrification of heating and transport combined with a decarbonization of the power system is therefore a main transition strategy for urban areas [178].

The current penetration of renewable energies into the power sector in metropolitan regions is quite low with less than 5% of the total electricity generation (see Figure 5.1). The national average target by 2020 is 9% and four levels of 5%, 7%, 10% and 13% are allocated to different provinces. Except three provinces of Qinghai, Gansu and Ningxia which have exceeded the set targets by 2020 in 2016, most of the provinces still have big gaps towards the 2020 minimum targets, especially in eastern provinces. The Chinese Renewable Portfolio Standard Policy (RPS) was released on February, 2016 by the National Energy Administration (NEA) and aims to increase renewable energy penetration especially in consumption centers and to reduce wind and PV curtailment in western RES abundant provinces such as Inner Mongolia, Gansu and Ningxia [145]. However, due to relatively limited RES potentials in consumption centers especially the eastern coastal regions will need to import large amounts of electricity from surrounding RES abundant regions [84, 157]. In order to solve the current curtailment from PV in western provinces, the newly installed PV stations are now predominantly located in eastern provinces. Beijing and Tianjin want to further increase the share of imported electricity from the provinces of Hebei and Inner Mongolia, given the high demand for electricity and limited local renewable resources, and in order to achieve local climate targets and guarantee security of supply. By 2020, Beijing and Tianjin will import 10 TWh and 6 TWh annually respectively, in which half is from renewable energy generated electricity [157]. By 2020, the installed renewable energy capacity in Beijing-Tianjin-Hebei (BTH) region will reach 45 GW [157].

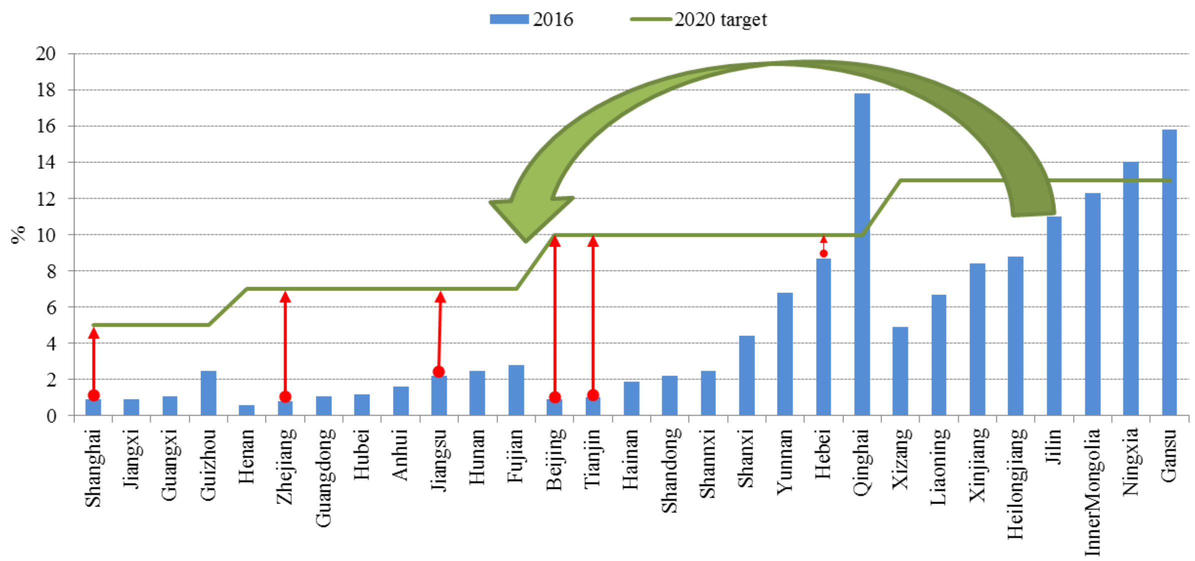


Figure 5.1 Percentage of non-hydro renewable resources in electricity generation of 2016 compared to 2020 targets [88] with an indication of possible regional power exchanges.

In addition to the scenario analysis for the regional energy systems in Chapter 4, a modelling case study with focus on the power sector is conducted in this chapter. The aim is to analyze the future power supply system hourly and regionally and to focus on interactions between the regional systems regarding the integration of high shares of VRE. Under this context, the case study provides insights into options for decarbonizing the power supply in the Beijing-Tianjin-Hebei metropolitan region as described in Section 2.1. It includes 4 megacities with a population of over 10 million [129] and other 9 main cities. The case study considers Inner Mongolia as a resource-abundant supply region. It is characterized by regional heterogeneity in terms of infrastructures, resources and consumptions. Provinces with higher installed wind and solar capacities such as Inner Mongolia are facing serious curtailment. In 2017, the curtailed wind power in Inner Mongolia reached 9.5 TWh [199]. The aim of the study in this chapter is to develop cost efficient strategies to implement a regional low-carbon power system. Main research questions are how a predominantly renewable energy supply could be implemented, how much locally available renewable resources can be integrated into the power system and how much need to be imported from neighboring supply regions. In order to deal with intermittent characteristics of PV and wind, the case study analyses the role of inter-provincial transmission capacity and its expansion. Furthermore, the modelling reveals the role of local storage expansion as well as of the integration of electric vehicles (EVs) and power to gas into the future energy system. Provincial level municipal cities with high power demand like Beijing and Tianjin have announced to increase import ability from Province of Hebei and Inner Mongolia by 2020. As there is a lack of long term targets till 2050 in terms of regional CO_2 caps or certain shares of renewable energies, the following case study assumes predefined regional CO_2 emission limits, to analyze selected goal-oriented pathways for power generation as well as required storage and transmission expansion. Due to the high expansion of renewable energies in scenarios such as RIS and the associated curtailment and system integration costs, it is important to analyze investment decisions in this way.

5.2 Methodology and Data

5.2.1 Methodology

The Renewable Energy Mix (REMix) model [22] was parameterized according to the regional conditions and used for this case study. It applies a cost minimization approach for capacity expansion planning and operation optimization with hourly resolution under certain constraints of CO_2 emissions and shares of renewable energy. A myopic modelling approach was applied to calculate the transition pathway from 2020 to 2050 in 10 year steps (see Figure 5.2). In this approach, the result of one model run is used as input for the next. Essential input data are resource time series, technology characterizations and the scenarios of the electricity demand and supply system. The historical weather data of the year 2001 are used to model the future power feed-in time series from RE.

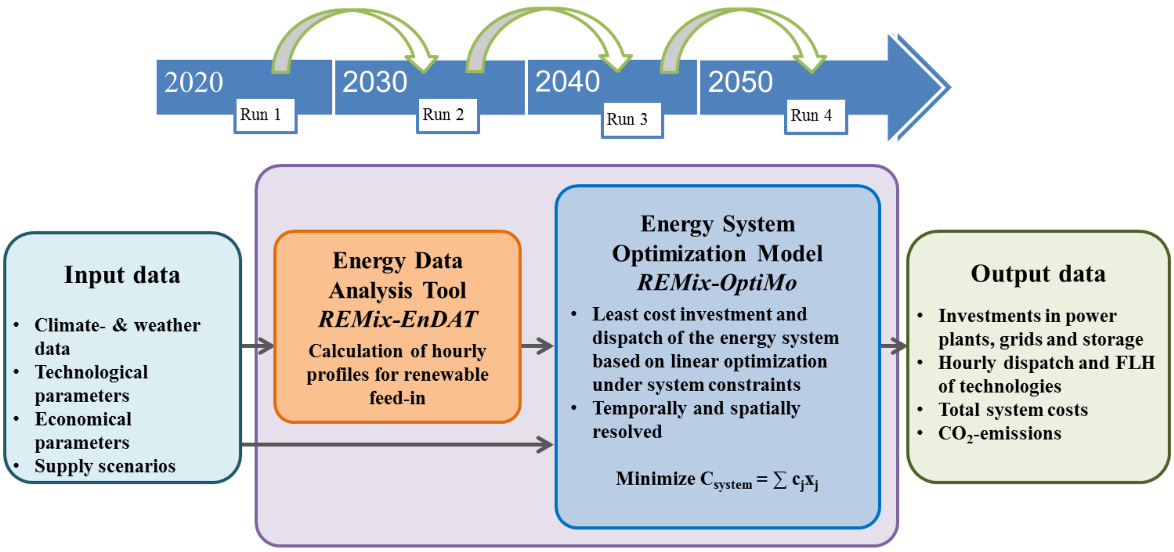


Figure 5.2 Renewable Energy Mix (REMix) energy system model based on [22].

REMix-OptiMo represents the energy system optimization model which is a deterministic linear optimization program developed under general algebraic modelling system (GAMS). It aims to analyze future energy supply scenarios in high spatial and temporal resolution. The model is set up based on a modular structure represented by technical and economic parameters of each available technology, maximum installable capacities, specific investment and operation costs and efficiency. The applied modules are power demand, variable and dispatchable renewable power generation, conventional power generation, power-to-power storage, power-to-hydrogen, direct current (DC) power transmission and simplified representation of electric cars with assumptions of load shifting potentials. Investments in new capacities consider technology cost, amortization time and interest rate, allowing for the calculation of proportional capital costs for the chosen optimization periods [22]. The annual operational costs are calculated according to the capacity of newly installed units and the annual power output. The latter may include variable production costs, fuel and CO_2 certificate costs [22]. The model regions (in this case, two municipality cities and two provinces) are represented by technology specific power generation and storage and are connected with transmission lines. The capacity expansion of power plants, grid and storage are optimized according to available potentials and system constraints. The objective function is to minimize the total system costs for all analyzed regions, composing of proportional investment and fixed operational costs of all endogenously installed system components for one year of their amortization time and variable operational costs of all technologies.

The model contains a detailed representation of CSP plants. They use the energy of direct solar irradiation to heat the working fuels, which are then used for the production of steam for turbine operation. Equipped with thermal energy storage (TES) and backup firing systems, CSP plants can provide dispatchable or even continuous power generation. The overall solar field thermal capacity is composed of the exogenously defined existing capacity and the endogenously calculated added capacity with limited to overall potentials as assessed by EnDAT (refer to Chapter 3). Hourly changes in TES energy level are described by the storage balance represented by charging, discharging and self-discharging [22]. The thermal power plants could use biomass, geothermal and fossil fuels for power generation. In the following analysis, natural gas is used as back-up fuel in CSP plants. In the biomass and geothermal module the technical generation is restricted by available resources. For fossil fuel power plants, fuel consumption is calculated by net efficiency according to the power generation. Then fuel costs, CO_2 emissions and costs are calculated. For the analysis of electric vehicles (EVs), only the passenger cars were analyzed with the additional power demand from RIS scenario assumptions (refer to Section 4.3.4). The regional power system is optimized within pre-defined system constraints such as maximum CO_2 emissions and minimum share of renewable energy and the least system cost (in detail refer to Section 5.2.3.3).

5.2.2 Input Data

5.2.2.1 Power and Hydrogen Demand

The hourly power demand curve is based on the data from China Southern Power Grid Company and was modified according to the yearly demand of each modelling node based on the RIS scenario analysis for the BTH region. Future power demand is determined by the high electrification rate in heat and transport sectors in line with the national below 2°C scenario study [178] (also see Section 4.2.3). The additional power and hydrogen demand for the analysis of electric and hydrogen vehicles is calculated based on the assumed market shares only for passenger cars (PC) and light duty vehicles (LDV) under RIS scenario (see Table E.1 in the Appendix E). It is further assumed that half of the energy consumptions of hybrid vehicles come from electricity. The share of electricity used for PC and LDV would increase from 4% in 2015 to 55% in 2050. The absolute consumption values considered in the modelling are 229 TWh electricity for electric vehicles and 74 TWh hydrogen used in fuel cell vehicles in 2050.

5.2.2.2 Renewable Energy Potentials for Power Generation

The assessment of renewable energy resource potentials in China contributes to evaluate how regionally available RE resources could support the decarbonization of its power sector (see Chapter 3 and Section 4.2.4). In contrast to the limited available RE resources for power generation in the metropolitan region, the neighboring region of Inner Mongolia is abundant in terms of both solar and onshore wind energy that provides the opportunity for power export especially from renewable energies (see Figure 5.3).

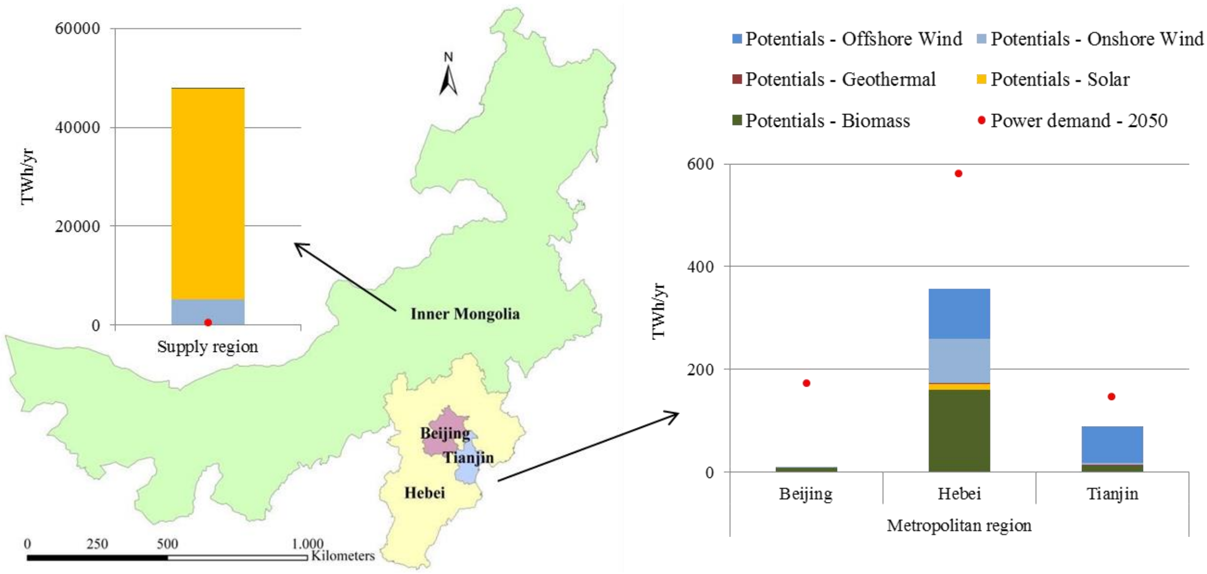


Figure 5.3 Renewable energy resources assessment compared to projected power demand in 2050 in supply region of Inner Mongolia and metropolitan region of BTH (includes the demand from electric vehicles under RIS scenario).

5.2.2.3 Existing Installed Capacities and Short-term Targets

Currently installed power generation capacities of photovoltaic (PV), wind (onshore and offshore), biomass, geothermal, concentrating solar power (CSP) with grid connection targets by 2020 or 2030 if available at provincial (for Hebei and Inner Mongolia) and municipal level (for Beijing and Tianjin) are taken into consideration for both base year and scenario parameterization [83, 158, 187] (see Table 5.1). Hebei and Inner Mongolia have the targets to increase installed onshore wind capacity to 18 GW and 45 GW by 2020 respectively. Hebei province will install 1 GW CSP by 2020 [164] while in Inner Mongolia the targets are 3 GW by 2020, 6 GW from 2020 to 2025, and 7 GW from 2025 to 2030 [198]. Existing installed capacities and short-term targets are used as exogenously defined capacities which will be reduced according to the assumed life time of each technology. They are complemented by endogenously calculated power generation capacities as result of the REMix modelling of a cost optimized load balancing.

Table 5.1 Exogenously assumed capacities of renewable power plants in the study regions for scenario years.

	Technology	**Onshore wind**	**Offshore wind**	**PV**	**CSP**	**Biomass**	**Geothermal**
Year	**Life time**	**25 yrs**	**25 yrs**	**25 yrs**	**40 yrs**	**25 yrs**	**20 yrs**
	Unit	GW	GW	GW	GW	MW	MW
2020	Beijing	0.5	-	1	-	109	0
	Tianjin	1	0.1	0.8	-	83	10
	Hebei	18	0.5	12	1	1640	10
	Inner Mongolia	45	-	12	3	340	0
2030	Beijing	0.5	0	1	-	109	0
	Tianjin	1	0.1	0.8	-	83	10
	Hebei	18	0.5	12	1	1640	10
	Inner Mongolia	45	-	12	16	340	0
2040	Beijing	0.3	0	1	-	0	0
	Tianjin	0.9	0.1	0.8	-	0	0
	Hebei	13	0.5	12	1	1202	0
	Inner Mongolia	31	-	12	16	174	0
2050	Beijing	0	0	0	-	0	0
	Tianjin	0	0	0	-	0	0
	Hebei	0	0	0	1	0	0
	Inner Mongolia	0	-	0	7	0	0

World Electric Power Plants Database (2015) [98] is used to generate base year of 2015 and exogenously assumed scenario capacities for conventional power plants of combined cycle gas turbine (CCGT), gas turbine (GT), coal and lignite with different assumed life times (see Table 5.2). Currently there is no nuclear power plant in the study region and it is assumed that there is no further planning for nuclear power development in inland China (under RIS scenario). By 2050, without “phasing out” of coal power plants, still 10 GW and 8 GW remain by 2050 in Hebei and Inner Mongolia respectively.

Table 5.2 Base year of 2015 and exogenously assumed capacities of fossil fuel power plants in the study regions for scenario years.

	Technology	**CCGT**	**GT**	**Coal**	**Lignite**
Year	**Life time**	**30 yrs**	**30 yrs**	**40 yrs**	**40 yrs**
	Unit	GW	GW	GW	GW
2015	Beijing	1.5	0.01	1.6	0
	Tianjin	0.06	0	10.7	0.6
	Hebei	0.2	0	32.5	1.6
	Inner Mongolia	0.7	0	35.6	20.1
2020	Beijing	8.3	0.01	1.6	0
	Tianjin	2.7	0.12	10.8	1.3
	Hebei	0.3	0.17	41.5	2.8
	Inner Mongolia	1.2	0	41.8	25.8
2030	Beijing	8.3	0.01	1.0	0
	Tianjin	2.7	0.12	10.4	1.3
	Hebei	0.3	0.17	38.8	2.4
	Inner Mongolia	1.2	0	43.0	24.3
2040	Beijing	6.8	0	0	0
	Tianjin	2.7	0.12	7.4	1.3
	Hebei	0.02	0.17	31.1	2.0
	Inner Mongolia	0.5	0	40.1	22.3
2050	Beijing	0	0	0	0
	Tianjin	0	0	0.2	0.7
	Hebei	0	0	10.2	1.2
	Inner Mongolia	0	0	7.6	6.0

5.2.3 Assumptions

5.2.3.1 Other Renewable Energy Potentials for Power Generation

The potential of biomass and geothermal energy for power generation is assumed based on [113] and [186] with FLH of around 5800 h and 6650 h respectively. Most of the hydro power potentials are located in central and southern China with very few in north eastern and northern China [35]. The potentials of small hydro power (5-50 MW) generation in the study regions are based on the analysis from [6]. The explored pumped hydro storage potential in China is 200 GW [194]. Pumped hydro power stations of 60 GW are planned and under construction with a total installed target of 40 GW by 2020 [85].

Table 5.3 Assumed power generation potentials for biomass, geothermal, small hydro and pumped hydro in the study regions.

Technology	**Biomass**		**Geothermal**		**Small hydro (5-50 MW)**		**Pumped hydro**
	Installed capacity	FLH	Installed capacity	FLH	Installed capacity	FLH	Installed capacity
Province	MW	h/yr	MW	h/yr	MW	h/yr	MW
Beijing	422	5844	94	6654	186	2263	1902
Tianjin	570	5844	364	6654	5	4000	1000
Hebei	8202	5844	461	6654	1206	3191	12,255
Inner Mongolia	8713	5844	6	6654	658	3236	12,255

5.2.3.2 Technical-economic Parameters

The future cost reductions and efficiency improvements are assumed for renewable energy power generation, transmission and storage technologies (see Table 5.4 and Table 5.5). The solar multiple (SM) is defined as the ratio of the thermal output from the solar field against the thermal input of the steam turbine. In the system modelling, SM is freely optimized and heat storage is added to the system according to this design parameter. The thermal balance is determined by the thermal output from the solar field and the backup unit, as well as the charging and discharging of the heat storage in interaction with the power generation and curtailment [22]. For the provision of firm capacity, all CSP plants use natural gas fired backup systems allowing for a full-load power block operation [22].

Table 5.4 Assumed economic and technological parameters for power generation based on [4, 22, 179].

Technology	**Investment costs** (€/kW)				**Fixed O&M costs**	**Variable O&M costs**	**Efficiency**	**Availability**	**Amortization time**
					% of investment costs/yr	€/MWh	%	%	yrs
	2020	2030	2040	2050			2020 ~ 2050		
Onshore wind	861	832	818	789	4	0		92	25
Offshore wind	2400	2200	2000	1800	5.5	0	n/a	92	25
PV	689	603	502	430	1	0		95	25
CSP_power block	980	980	980	980	2.5	2.2	37	95	40
CSP_solar field	399	320	256	192					25

CSP_thermal storage	38	29	24	19					25
Biomass	2400	2200	2100	2000	4	2	30	90	25
Geothermal	10000	9000	8000	7600	4.5	0	9 ~ 11	95	20
Gas turbine (GT)	437	437	437	437	4	0	43.6 ~ 46.5	95	25
CCGT	850	850	850	850	4	0	60 ~ 63	96	25
Coal	1500	1500	1500	1500	4	0	46.8 ~ 49.1	90	25
Lignite	1640	1640	1640	1640	4	0	50 ~ 51	91	25

Four different electricity storage technologies are considered in the modelling. The energy storage unit and converter unit are modelled separately in REMix-OptiMo with the consideration of installation costs as well as fixed and variable operational costs. The operating costs depend directly on the stored electricity.

Table 5.5 Assumed economic and technological parameters for electric energy storage [4].

	Investment costs (2020 ~ 2050)		**Amortization time (2020 ~ 2050: yrs)**	
Technology	**Storage (€/kWh)**	**Converter (€/kW)**	**Storage**	**Converter**
Pumped hydro	10	530 ~ 450	60	20
Lithium-ion battery	300 ~ 150	100 ~ 50	21 ~ 25	21 ~ 25
Hydrogen storage	1	1500 ~ 1200	30	15
CAES_AD	41 ~ 47	1020 ~ 570	40	20

	Fixed O&M costs	**Availability**	**Efficiency (%)**		
	% of investment costs/yr	**%**	**Charge**	**Discharge**	**Self-discharge rate of storage per hour**
Technology	**2020 ~ 2050**				
Pumped hydro	1	98	89 ~ 91	89 ~ 91	0.0005
Lithium-ion battery	0.9 ~ 0.5	98	93 ~ 97	93 ~ 97	0.0011
Hydrogen storage	2	95	71 ~ 75	60 ~ 62	0
CAES_AD	1 ~ 2	95	81 ~ 84	86 ~ 89	0.08

The assumed economic and technological parameters for electric cars and local electrolyzers used for onsite hydrogen generation at gas stations are shown in Table 5.6 and Table 5.7. The installed electrolyzer capacities and full load hours for hydrogen production are freely optimized.

Table 5.6 Assumed economic and technological parameters for electric cars [4].

Year	Availability of delayed loading	Ratio of charging capacity and maximum charging load	Variable O&M costs (load shifting)
	%	/	€ ct/kWh
2020	15	2	1
2030	30	2	1
2040	45	2	1
2050	60	2	1

Table 5.7 Assumed economic and technological parameters for local electrolyzers used for hydrogen cars [4].

Year	Efficiency	Investment costs	Amortization time	Fixed O&M costs	Variable O&M costs
	%	$€/kW_{el}$	yrs	% of investment costs/yr	$€\ ct/kWh_{el}$
2020	70	527	30	1.5	0.1
2030	70	439	30	1.5	0.1
2040	70	366	30	1.5	0.1
2050	70	305	30	1.5	0.1

The assumed development pathways for fossil fuel prices are shown in Figure 5.4 based on [4]. The high development pathways are assumed for the scenario analysis, the low development pathways are used for the sensitivity analysis in Section 5.4.

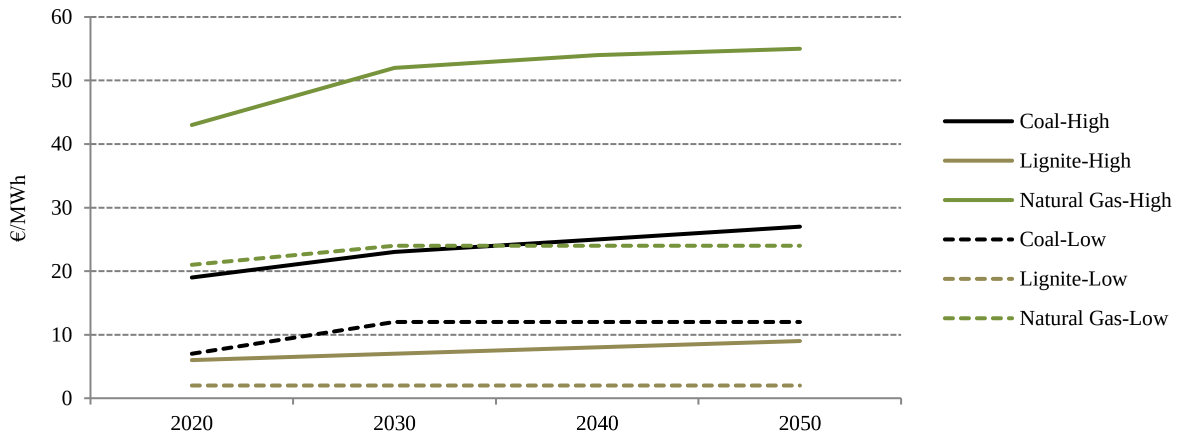


Figure 5.4 Assumed development pathways for fossil fuel prices.

Grid capacity expansion is limited to point to point HVDC grid technology between neighboring modelling nodes. The maximum transfer capacity between model regions is assumed to be 50 GW for reasons of acceptance and feasibility. Currently, ten extra high voltage (EHV) direct current (DC), three ultra-high voltage (UHV) alternating current (AC) and six UHV-DC transmission lines are existing and three UHV-AC transmission lines are planned to be in operation by 2020 in China. They are taken into consideration as options to connect RE supply regions with consumption centers in the eastern coastal region (see Figure 5.5).

Figure 5.5 China's national power grid plan for 2020 (map source: State Grid Corporation of China).

For simplification, all the historic and scenario transmission capacities are aggregated by model nodes and represented by HVDC technology. In Beijing-Tianjin-Hebei and Inner Mongolia region, 6 HVDC transmission lines are modelled with a rated power of 1000 MW. Investment cost for overhead lines is assumed to be 544 k€/km [4] and additional costs for the installation of each converter station are assumed with a reduction trend (see Table 5.8). The amortization time of transmission lines and converters are assumed to be 40 and 20 years respectively. The annual fixed operational costs are set to be 1% of the investments. The power flow over each connection is limited by the pre-defined capacity of the available lines.

Table 5.8 Assumed costs of converter stations for HVDC transmission lines (Unit: Mio. €) [4].

2020	2030	2040	2050
108	102	96	90

The distances between modelled regions, which are defined as the distance between the capital city of each province and municipality cities, are listed in Table 5.9. A length factor of 1.2 between geographical distance and length of overhead transmission lines is assumed for this analysis.

Table 5.9 Assumed distances between model regions (Unit: km).

Connection	Assumed transmission line length
Beijing – Tianjin	115
Beijing – Hebei	265
Beijing – Inner Mongolia	406
Tianjin – Hebei	262
Tianjin – Inner Mongolia	506
Hebei – Inner Mongolia	396

Besides, all investments in new power generation, storage and grid technology are set to a fixed capital interest rate of 6%.

5.2.3.3 System Constraints

Based on the scenario analysis of carbon emission trajectory for the Chinese power sector by [31] the national CO_2 cap in this study is assumed to be 4.5 Bt in 2020, with reductions to 3 Bt by 2030, 2 Bt by 2040 and 1 Bt by 2050 respectively. This mitigation path is in line with the IPCC targets to fulfil a carbon intensity reduction by 2020, to peak emissions by 2030 and to achieve a minimum 80% CO_2 emissions reduction on 1990 level by 2050 for China. The regional CO_2 cap is allocated by the current CO_2 emissions in power sector according to the Multi-resolution Emission Inventory for China (MEIC) database [190]. It is assumed that a minimum of 60% of electricity would be generated from renewable energies by 2050. The shares are allocated to each province/municipality city based on the available 2020 targets (see Table 5.10). Furthermore, grid expansion is limited to a maximum of 50 transmission lines for each transmission corridor from supply region to consumption centers.

Table 5.10 Assumed regional CO_2 limits and RE shares in power sector by province/city.

Regional CO_2 emission limit in power sector (Mt)	Minimum share of RE in power sector (%)	Beijing	Tianjin	Hebei	Inner Mongolia
700	2020 (targets)	10	10	10	13
470	2030	18	18	18	24
300	2040	38	38	38	43
150	2050	58	58	58	64

5.3 Optimization Results

The analysis in this section provides quantitative results of the scenario analysis in terms of installed capacity, investment and fuel costs, annual electricity production and resulting CO_2 emissions, as well as hourly dispatch for modelled regions. In addition, the required grid expansion between the regions is calculated under the objective function of minimized system costs.

5.3.1 Summary of Key Results

The optimization results show that under set system constraints, the share of renewable energy in installed power generation capacity and annual electricity production would significantly increase under the RIS scenario in both the BTH metropolitan region and the supply region of Inner Mongolia (Table 5.11). However, compared with the share of non-hydro renewable energy for annual electricity generation in 2017, the short-term gaps are still high in the modelled regions.

Table 5.11 Share of renewable energy (without hydro power) in terms of installed capacity and annual generation in the study regions.

Installed capacity	**2017**[9]	**2020**	**2030**	**2040**	**2050**
Beijing	/	16%	25%	28%	38%
Tianjin	/	21%	43%	52%	56%
Hebei	/	55%	78%	86%	86%
Inner Mongolia	/	64%	76%	84%	98%
Annual electricity generation	**2017** [184]	**2020**	**2030**	**2040**	**2050**
Beijing	5%	30%	33%	36%	52%
Tianjin	3%	16%	32%	40%	49%
Hebei	14%	45%	65%	78%	77%
Inner Mongolia	15%	70%	80%	86%	98%

CO_2 emissions from power generation would only reduce after 2030 in the two municipality cities under the current short-term policy till 2020 and the set system constraints (Table 5.10). In contrast, in Hebei and Inner Mongolia, the emissions could reduce immediately under the same scenario. These results reveal that the current short-term policy till 2020 is not yet sufficient to stop CO_2 emissions growth in the medium term in municipality cities. However, with the further penetration of renewable energy for power generation and the implementation of regional CO_2 emissions constraints, the emissions in the metropolitan region could be reduced by 2050 to 76% of its peak emissions in 2030 (see Figure 5.6).

[9] Data not available.

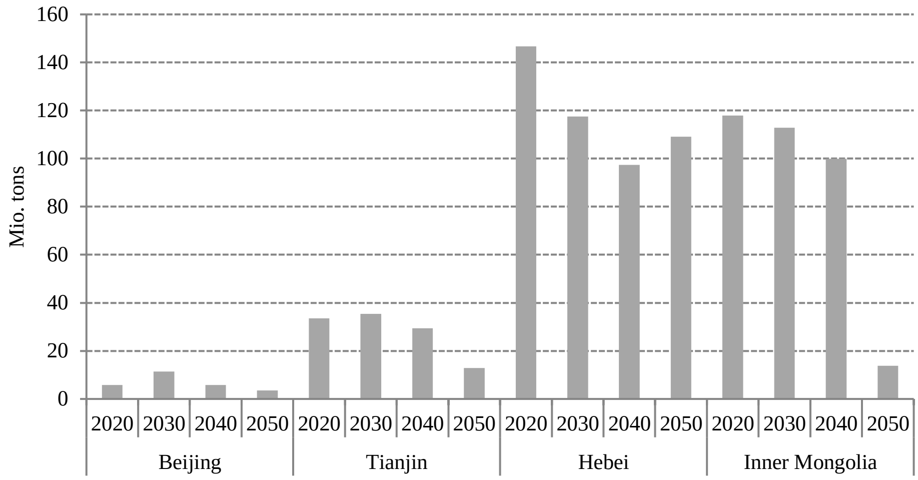


Figure 5.6 CO_2 emissions from power generation for 2020 to 2050 by study regions.

With the penetration of renewable energy into the regional power system the full load hours (FLH) of variable renewable energy (VRE) is decreasing with increasing curtailed energy both in demand and supply regions; while the FLH of dispatchable CSP technology is increasing in Hebei till 2040 and Inner Mongolia till 2050 with its thermal energy storage (TES) system. However, by 2050, the curtailment rate (CR) in its power block would increase to 14% in Hebei Province and to 33% in Inner Mongolia (see Table 5.12). The results demonstrate that in VRE dominated power systems such as that of 2050 a much higher flexibility of demand and residual generation is required. Except storages, grid extension and flexible backup generators as additional load balancing options not considered in this case study could be power to heat, power to fuels and measures of demand side management (DSM) to further reduce power curtailment from VRE generation. However, such further flexibilities and resulting infrastructural needs which I could not consider in this case study due to data constraints would further increase the costs for system integration.

Table 5.12 Annual curtailment rate (CR)[10] and full load hours (FLH) by RE technology from 2020 to 2050 in the study regions.

PV						Onshore Wind					
		2020	**2030**	**2040**	**2050**			**2020**	**2030**	**2040**	**2050**
Beijing	CR	0%	0%	36%	44%	Beijing	CR	0%	0%	40%	45%
	FLH	1218	1218	783	687		FLH	1477	1477	884	816
Tianjin	CR	7%	0%	17%	34%	Tianjin	CR	8%	0%	17%	-
	FLH	1099	1176	971	777		FLH	1366	1492	1236	-
Hebei	CR	0.2%	3%	4%	5%	Hebei	CR	0%	0.1%	11%	13%
	FLH	1254	1224	1202	1194		FLH	2537	2536	2255	2216
Inner Mongolia	CR	10%	24%	29%	21%	Inner Mongolia	CR	2%	9%	9%	13%
	FLH	1138	969	904	1005		FLH	2888	2698	2696	2574
Offshore Wind						**CSP_power block**					
Tianjin	CR	8%	0%	16%	-	Hebei	CR	0.4%	2%	6%	13%
	FLH	2331	2547	2146	-		FLH	1537	2373	3615	3305
Hebei	CR	0.3%	5%	10%	-	Inner Mongolia	CR	3%	7%	18%	33%
	FLH	2757	2629	2480	-		FLH	1553	1444	2730	3305

The optimization results show that the mean value of marginal electricity generation costs over the optimization periods would increase till 2040 in all modelled cities and provinces (see Figure 5.7). With better solar and wind resources, Inner Mongolia has lower marginal costs compared with the metropolitan region that are below 57 €/MWh. The mean marginal electricity costs in Inner Mongolia is used to calculate the imported electricity costs for metropolitan region that will add to the transition costs for energy system transition in metropolitan regions (see Table C.1 in the Appendix C energy carrier costs for imported electricity).

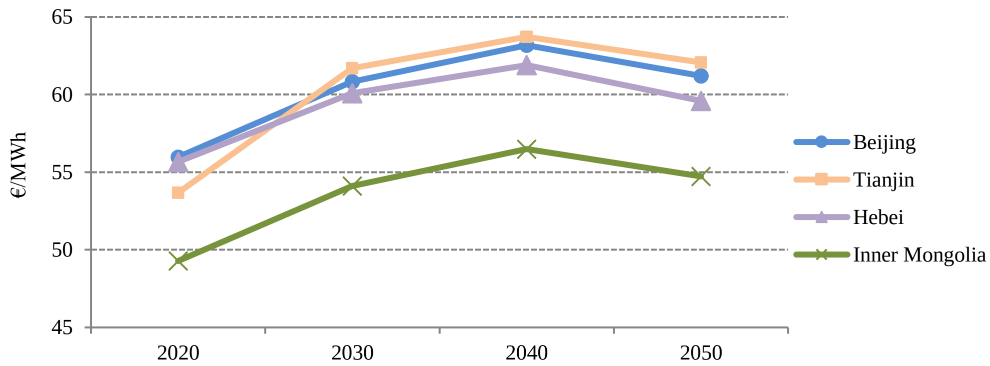
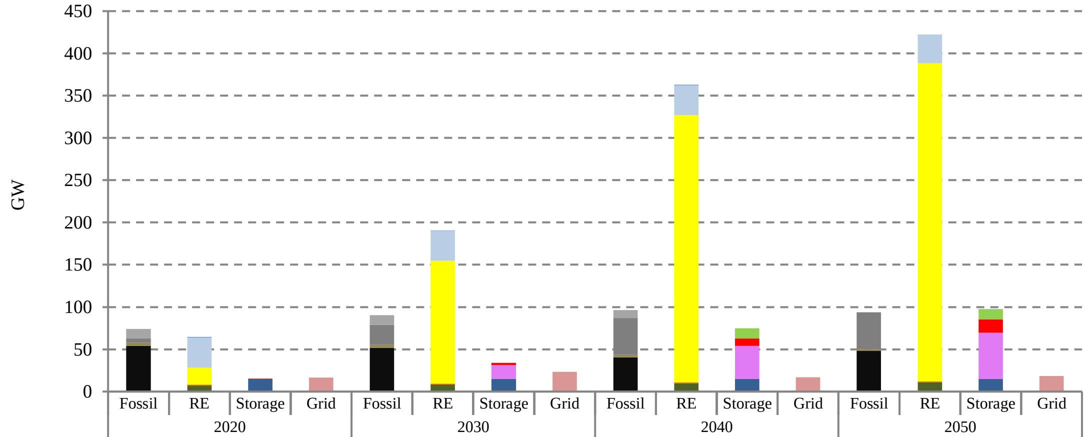


Figure 5.7 Mean marginal electricity costs over optimization period by city and province.

[10] Calculated from curtailed energy divided by the potential annual VRE power generation.

5.3.2 Total Installed Capacity

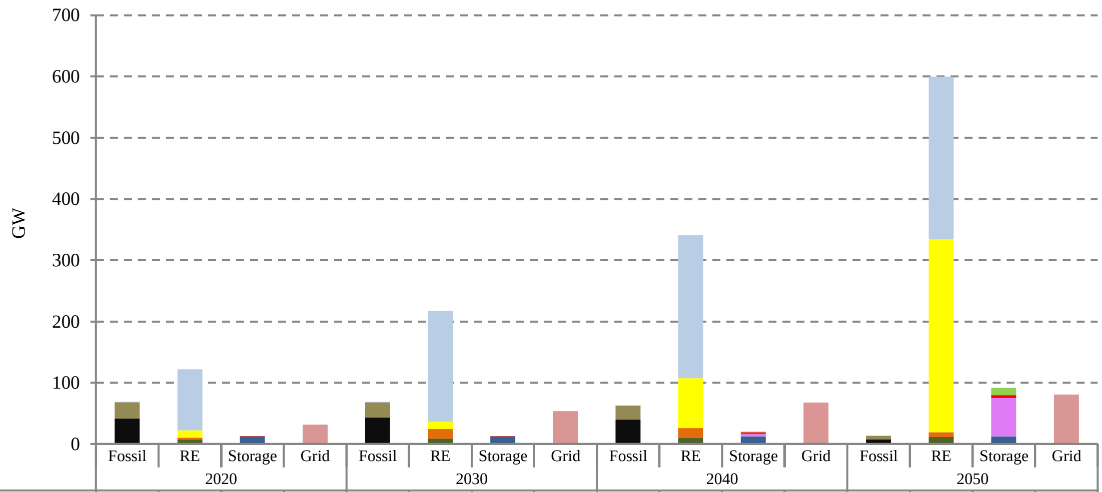
Figure 5.8 shows the total installed capacities for power generation, electricity storage and grid transfer as a result of exogenously assumed existing installations and additionally required capacities which are an endogenous result of the system optimization. The total installed capacity from fossil fuels in BTH region would decrease after 2040 but only slightly. In contrast, the share of PV in terms of total installed capacity would increase from 15% in 2020 to 73% by 2050 in BTH region. Limited by regionally available onshore wind potentials (36 GW and 31 GW under 4 m/s and 5 m/s assessment thresholds respectively) and not competitive costs for offshore wind energy, the share of wind in terms of installed capacity would decrease from 26% in 2020 to only 7% by 2050 in the BTH region. The maximum regional potentials of biomass would be exploited by 2050 while only the planned capacities for geothermal and CSP would be installed due to higher costs compared with other technologies. The maximum potentials for pumped hydro would be fully exploited already by 2020. This results in a continuous increase of installed capacity for lithium-ion battery, hydrogen storage and adiabatic compressed air energy storage (CAES_AD) from 16 GW, 3 GW and 0 GW in 2030 to 55 GW, 16 GW and 12 GW by 2050 respectively in the BTH region to balance the increasing variable generation of PV.



	2020				2030				2040				2050			
	Fossil	RE	Storage	Grid	Fossil	RE	Storage	Grid	Fossil	RE	Storage	Grid	Fossil	RE	Storage	Grid
Grid				17				23				17				18
CAES_AD											12				12	
Hydrogen Storage			0				3				9				16	
Lithium-ion Battery							16				39				55	
Pumped Hydro			15				15				15				15	
Offshore Wind		1				1				1						
Onshore Wind		36				36				36				34		
Photovoltaic		20				145				316				376		
CSP		1				1				1				1		
Geothermal		0				0										
Biomass		7				8				10				11		
CCGT	11				11				10							
GT	5				24				43				44			
Lignite	4				4				3				2			
Coal	54				52				40				48			

Figure 5.8 Total installed capacity by technologies in the BTH region.

Quite different from the metropolitan region, both PV and onshore wind would dominate the power supply system in Inner Mongolia (with a growth from 59% in 2020 to 95% by 2050) in terms of installed capacity (see Figure 5.9). Because PV has lower power generation costs compared with onshore wind, large amounts of PV would be installed during the 2040-2050 period in the supply region (315 GW). Similarly to BTH, only the planned installed capacity for geothermal and CSP would be installed due to higher costs compared with other technologies. The maximum regional potentials of biomass would be exploited by 2050. The growth of installed capacity for modelled storage technologies has the similar trend as that in the metropolitan region, especially for the expansion of lithium-ion battery during the last decade as a result of the large installation of PV. The installed capacity for fossil fuels would decrease from 69 GW in 2020 to 14 GW by 2050, which is only 20% of the amount in 2020. The installed capacities for RE and backup power generation, storage and grid transfer could guarantee that the increasing power demand both from metropolitan and supply regions is covered in every hour of the modeled years.



	2020 Fossil	2020 RE	2020 Storage	2020 Grid	2030 Fossil	2030 RE	2030 Storage	2030 Grid	2040 Fossil	2040 RE	2040 Storage	2040 Grid	2050 Fossil	2050 RE	2050 Storage	2050 Grid
Grid				32				54				68				81
CAES_AD											1				12	
Hydrogen Storage			0				1				2				5	
Lithium-ion Battery											4				63	
Pumped Hydro			12				12				12				12	
Onshore Wind		100				181				233				265		
Photovoltaic		12				12				82				315		
CSP		3				16				16				8		
Biomass		7				9				10				11		
CCGT	1				1				0							
Lignite	26				24				22				6			
Coal	42				43				40				8			

Figure 5.9 Total installed capacity by technologies in the supply region of Inner Mongolia.

Figure 5.10 shows the grid expansion between supply and metropolitan regions. The RIS scenario would increase total transfer capacities between Inner Mongolia and the metropolitan regions from 32 GW in 2020 to 81 GW by 2050 due to the increasing power exchange demand. Compared with the supply region of Inner Mongolia, grid expansion within the metropolitan region won’t see much growth. The results are below the set maximum of 50 GW for all transmission corridors.

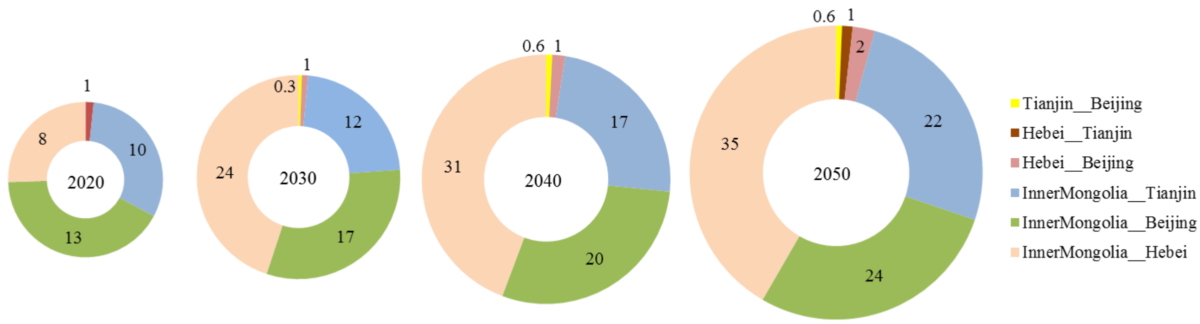
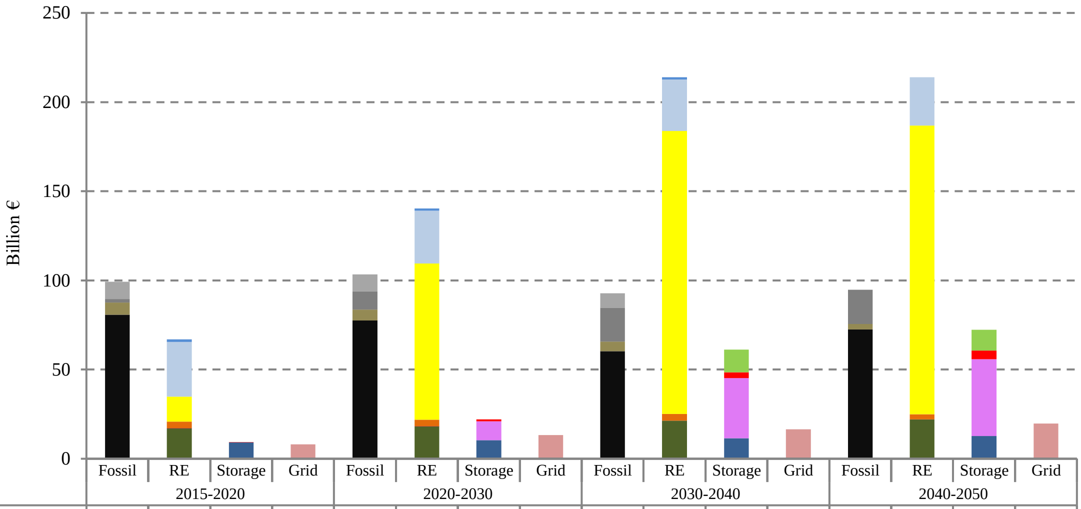


Figure 5.10 Grid expansion between supply and metropolitan regions from 2020 to 2050 (Unit: GW).

5.3.3 Investment and Fuel Costs

5.3.3.1 Investment into Installed Capacity

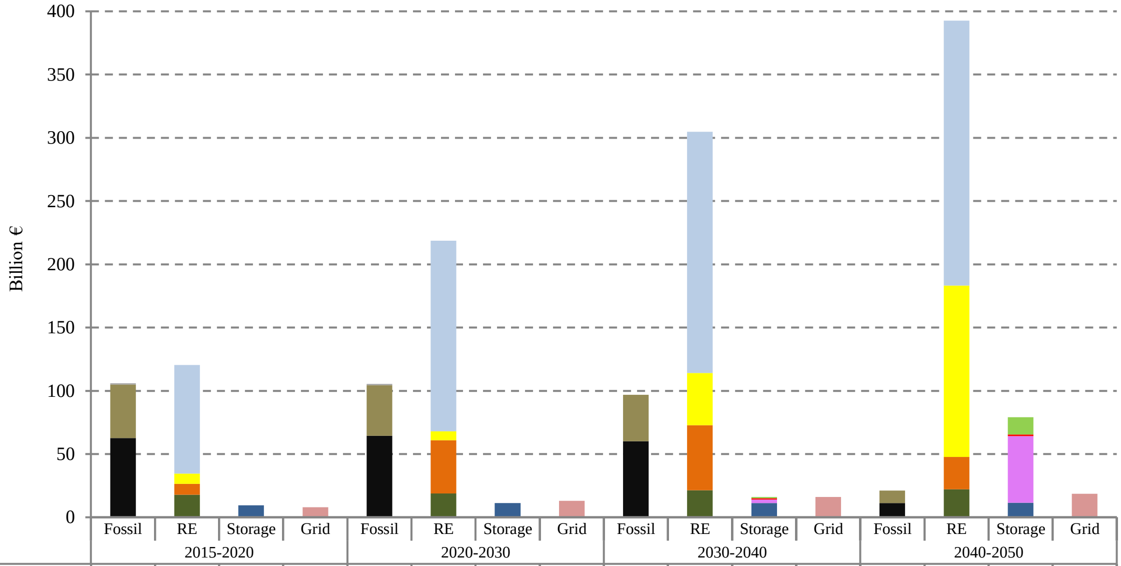
In the metropolitan region, investments in renewable power plants would sharply increase in this scenario from 64 billion € during 2015-2020 period to 214 billion € during 2040-2050 period (see Figure 5.11). In contrast, the investment into fossil fuel power plants would peak during 2020-2030 period and reduce to 95 billion € during the last decade. The total investment into renewable power capacities would exceed that of fossil fuels after 2030. Compared with relative large investments into power generation capacities, storage expansion requires only between 9 and 72 billion € for each decade from 2020 to 2050. Investments in storage facilities are dominated by lithium-ion batteries for short-term load balancing due to a PV dominated power supply system, which, unlike pumped storage facilities, have no limited potential. To a limited extent, investments are also made in seasonal hydrogen storage facilities and the investment into CAES_AD would be required after 2030. Investment in biomass, onshore wind and CSP installed capacities would remain rather stable at around 20 billion €, 30 billion € and 3 billion € respectively for each decade. Due to the fast expansion of PV in BTH region, the investments would also increase accordingly from 88 billion € during 2020-2030 period to 162 billion € during the last decade. Compared to that, investments in wind power remain at a lower level, even slightly declining in the long term, with only minor investments in offshore wind for the planned capacities of 2020. The reason for the latter result is on the one hand the limited regional onshore wind potential and assumed relatively higher offshore wind costs at relative low FLH in the region. On the other hand PV generation in the region combined with imported electricity from onshore wind will be beneficial from a system point of view.



	Fossil	RE	Storage	Grid	Fossil	RE	Storage	Grid	Fossil	RE	Storage	Grid	Fossil	RE	Storage	Grid
	2015-2020				2020-2030				2030-2040				2040-2050			
Grid				8				13				17				20
CAES_AD											13				12	
Hydrogen Storage			0				1				3				5	
Lithium-ion Battery							10				34				43	
Pumped Hydro			9				10				12				13	
Offshore Wind		1				1				1						
Onshore Wind		31				30				29				27		
Photovoltaic		14				88				159				162		
CSP		3				3				4				3		
Geothermal		0				0										
Biomass		17				18				21				22		
CCGT	10				10				8							
GT	2				10				19				19			
Lignite	7				6				5				3			
Coal	81				77				60				73			

Figure 5.11 Investment costs of total installed capacity by technology in the BTH region.

In the supply region of Inner Mongolia with an onshore wind and solar dominated power supply system, large investments in wind power plants would be required during each decade (from 151 billion € during 2020-2030 period to 209 billion € during the last decade respectively) (see Figure 5.12). The investment into PV capacity would sharply increase only during the last decade (for 136 billion €). The investments into fossil fuel power plants would decrease from 105 billion € during 2020-2030 period to only 21 billion € during the last decade. With a decreasing installed capacity of CSP by 2050, more investments are required for lithium-ion batteries and CAES_AD to balance variable PV and onshore wind power generation. Storage demand arises primarily with regard to short-term load balancing using lithium-ion batteries with less demand for hydrogen storage than in the BTH region. The per decade investments into biomass power plants remain rather stable at around 20 billion €.



	2015-2020 Fossil	2015-2020 RE	2015-2020 Storage	2015-2020 Grid	2020-2030 Fossil	2020-2030 RE	2020-2030 Storage	2020-2030 Grid	2030-2040 Fossil	2030-2040 RE	2030-2040 Storage	2030-2040 Grid	2040-2050 Fossil	2040-2050 RE	2040-2050 Storage	2040-2050 Grid
Grid				8				13				16				19
CAES_AD											1				14	
Hydrogen Storage											1				1	
Lithium-ion Battery											3				53	
Pumped Hydro			10				11				11				12	
Onshore Wind		86				151				191				209		
Photovoltaic		8				7				41				136		
CSP		9				42				51				26		
Biomass		18				19				21				22		
CCGT	1				1											
Lignite	42				40				37				10			
Coal	63				65				60				11			

Figure 5.12 Investment costs of total installed capacity by technology in the supply region.

During the energy system transition process also additional investments would be required for grid expansion with an increase from 26 billion € during the 2020-2030 period to 38 billion € during the last decade (see Figure 5.13).

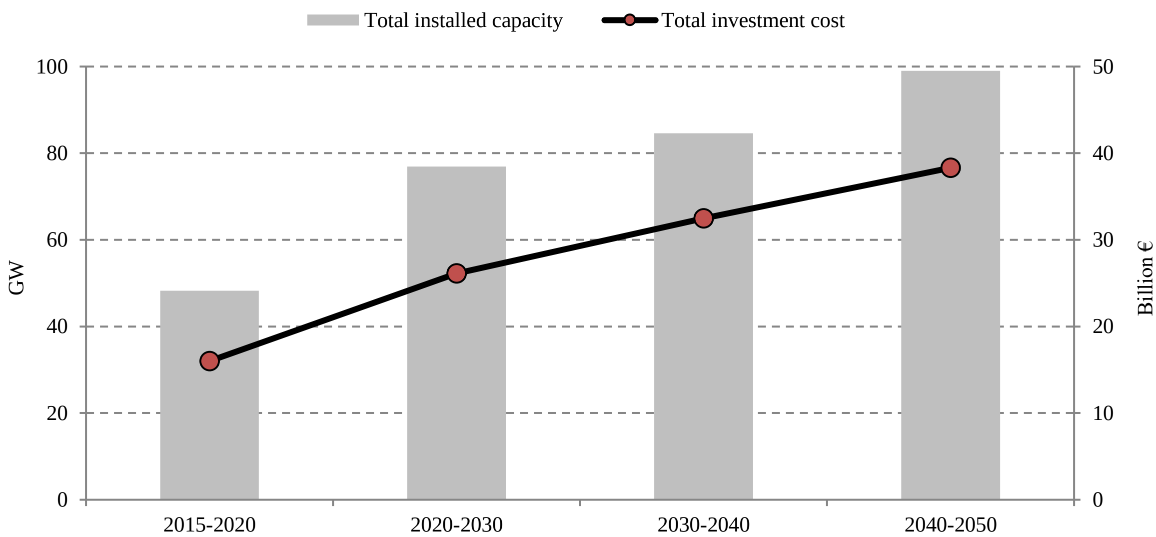


Figure 5.13 Total installed transfer capacity (incl. grid expansion) between the supply and the metropolitan regions with corresponding investments by decades from 2015 to 2050.

5.3.3.2 *Fuel Costs*

Continuously increasing investments would be required for installed capacities of power plants, storages and grid expansion according to the RIS scenario. However, the total fuel costs from fossil fuel power plants would be reduced in the long-term (see Figure 5.14) especially considering the increase in fuel demand in the REF scenario compared with RIS scenario (see Chapter 4). In BTH region, fuel costs for coal power plants and natural gas for CCGT would peak during the 2020-2030 period. In contrast, fuel costs for natural gas used for gas turbines (GT) would increase by decade till 2050. In the last decade, fuel costs for coal power plants in the supply region of Inner Mongolia would decrease sharply to only 1.1 billion € with some remaining fuel costs for natural gas used for CCGT, GT and CSP as back-up fuels, which would provide additional flexibility in wind and PV dominated power supply systems.

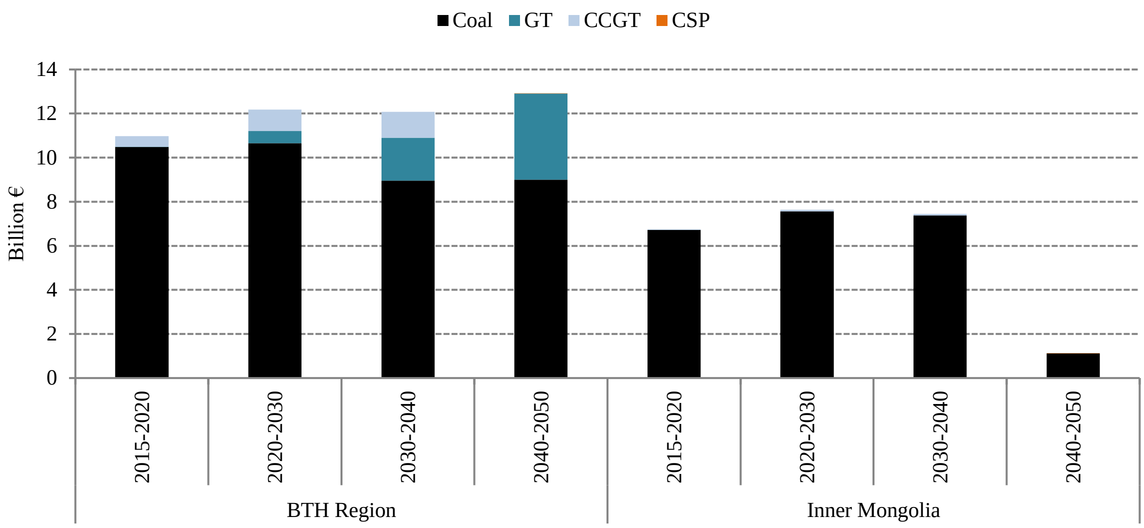


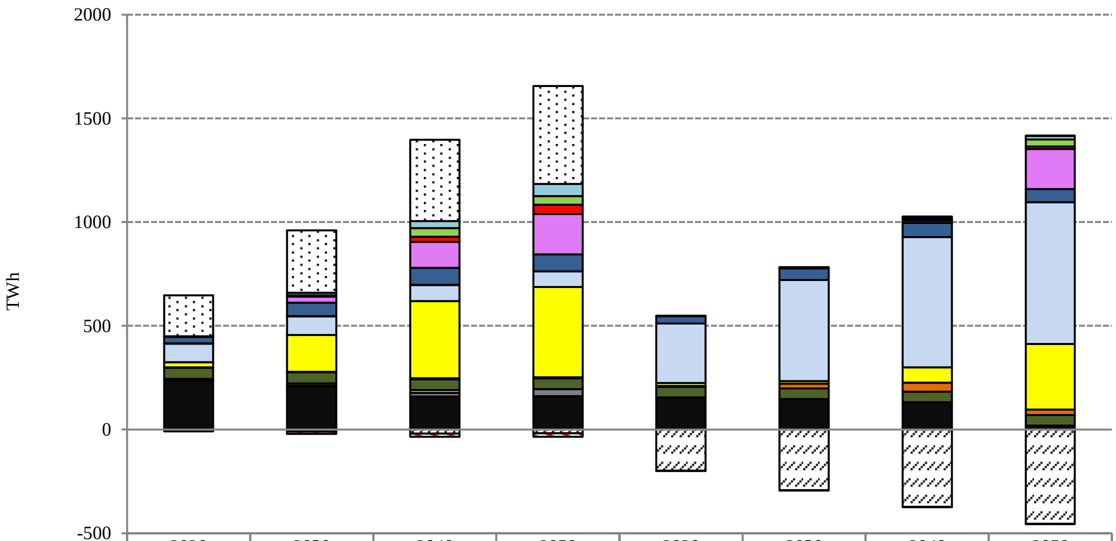
Figure 5.14 Fuel costs by power generation technology by decades from 2015 to 2050 in the supply and metropolitan regions under the high fuel price path.

5.3.4 Annual Power Supply and Hourly Balance

5.3.4.1 *Annual Power Supply*

Figure 5.15 shows that from 2020 to 2050, the imported electricity for the metropolitan region is increasing due to the additional power demand from heat and transport sectors and the massive installation of RE generation capacity in the supply region. The share of imported electricity to total power demand would be at around 30% over the optimized period. According to the modelling results a cost-minimized electricity system would already achieve considerable electricity imports in the first scenario year 2020. By 2050, PV would dominate the power supply system in BTH region (28%) while onshore wind would dominate that in the supply region (69%). Therefore, the electricity generation from coal power plants would decrease after 2020 in both regions. Given the limited potentials for pumped hydro storage, other storage technologies of lithium-ion batteries, hydrogen and

CAES_AD would play a more and more important role in VRE dominated power supply systems both in metropolitan and supply regions with increasing full load hours over time. Local electrolysers would contribute to generate hydrogen as an alternative fuel and to integrate VRE into the system, especially in the BTH region. With increasing shares of renewable power generation, a change in the backup power supply from CCGT to GT takes place in the long term.



	BTH Region				Inner Mongolia			
	2020	2030	2040	2050	2020	2030	2040	2050
Losses	-7	-11	-15	-18	0	0	-1	0
Export	-1	-9	-20	-18	-198	-292	-373	-455
Import	198	301	392	473		1	0	0
Local Electrolyzer	2	13	35	59	0	4	10	17
CAES_AD			41	42			3	35
Hydrogen Storage	0	5	25	45	0	1	6	12
Lithium-ion Battery		29	125	193			10	192
Pumped Hydro	31	65	81	82	35	56	68	64
Offshore Wind	2	2	1					
Onshore Wind	89	89	78	76	288	488	629	683
Photovoltaic	25	177	372	436	14	12	74	317
CSP	2	2	4	3	5	23	44	26
Geothermal	0	0						
Biomass	54	54	54	54	51	51	51	51
CCGT	7	11	13		0	1	1	
GT	0	5	17	33				
Coal	238	207	160	162	155	147	131	19

Figure 5.15 Annual power supply for the metropolitan and the supply region from 2020 to 2050.

5.3.4.2 *Dispatch Characteristics*

The hourly balancing among power generation, storage, transmission and demand shows typical seasonal variations in the study regions. In this sub-chapter, the hourly dispatch in the years 2030 and 2050, which have clearly different characteristics, is discussed as an example.

In Beijing in 2030, its power supply system would be dominated by imported electricity with pumped hydro dominated storage system. Lithium-ion battery, hydrogen and EVs still play a minor role for balancing PV and onshore wind and there is no curtailment from fluctuating energy yet (see Figure F.1

in the Appendix F). From February to May, coal and biomass need to be operated flexibly depending on imported electricity and power generation from PV and onshore wind to fulfill the hourly power demand. From June to October, coal and biomass would be operated as base loads with GT and CCGT as flexible generators. From November to January, GT and CCGT would not be operated with only coal and biomass as base load power generators.

Tianjin in 2030 would have a lower share of imported electricity than Beijing but still play a major role (see Figure F.2). The storage system would be similar to that of Beijing with pumped hydro dominating and lithium-ion battery, hydrogen and EVs playing a minor role. From January to May, coal and biomass would be operated flexibly with pumped hydro storages to balance PV and onshore wind. From June to October, coal and biomass would act as base load power plants with GT and CCGT as flexible generators. Later in November and December, only coal and biomass would act as base load power plants but are also operated more flexibly if power generation from onshore wind increases. Overall the dispatch has quite similar characteristics to the one in Beijing, however, with considerably higher generation from coal and lower electricity import shares.

Unlike the two cities with imported electricity and PV dominated power supply systems, due to limited land resources, in Hebei in 2030 onshore wind would also play a major role resulting in less import (see Figure F.3). CSP would operate intermittently especially when PV is not available. Due to limited pumped hydro storage potentials, more lithium-ion batteries would be needed to balance PV in this system. From January to May, coal and biomass would be operated flexibly with increasing curtailment from PV over time. From June to August, coal and biomass would act again as base load power plants, GT and CCGT would be operated flexibly without curtailment from PV and wind. The higher percentage of power generation from PV results in the charging of lithium-ion battery and export during peak periods. After September, the share of power generation from onshore wind would be increasing with less export from PV and flexibly operated coal and biomass power plants.

As a supply region, Inner Mongolia in 2030 will have a power system dominated by onshore wind with high share of exported electricity (see Figure F.4). CSP would operate intermittently when PV is not available to fulfill peak demand and to balance base loads. The local pumped hydro potentials could mostly satisfy the need for balancing fluctuating wind and solar energies. Due to relatively lower power consumption from EVs compared with large power generation demand, EVs would only play a minor role for balancing fluctuating wind and solar energies. From January to May, coal and biomass would be operated flexibly with high curtailment from wind and solar during peak periods. From June to October, coal and biomass would act as baseload with less curtailment. In November and December, coal and biomass would be operated in a more flexible way, again with increasing curtailment.

In Beijing in 2050, the share of imported electricity would be further increased with higher share of hydrogen as storage and EVs would play a major role but still with curtailment from PV and onshore wind during several periods when demand is lower (see Figure F.5). From February to May, local PV tends not to be utilized due to relatively cheaper imported electricity resulting in higher curtailment and biomass power plants would be operated flexibly. From June to January, coal, biomass and GT would be used as flexible generators and local PV tends to be utilized resulting in less curtailment.

Compared with 2030, the share of imported electricity in Tianjin would also be largely increased with higher curtailment from PV (see Figure F.6). Different from Beijing, CAES_AD would also act as short-term storage together with EVs, pumped hydro, lithium-ion battery and hydrogen. From January to July, coal, biomass and GT would be again used for flexible generation. During several time periods power supply would be fully renewable energy based but with higher curtailment from PV. From August to December, coal and biomass would act as base load power plants and GT would be operated flexibly with decreasing curtailment from PV.

In Hebei in 2050, a large share of lithium-ion battery would be installed to balance power generation from PV (see Figure F.7). From February to May, the power supply system is PV and onshore wind dominated with an increasing curtailment rate. In June and July, coal, biomass and GT would be operated flexibly with a still PV dominated power supply system but less curtailment and increasing export. From August to January, coal and biomass would act as base load generators with flexibly operated GT and an increasing share of onshore wind but less curtailments.

Inner Mongolia in 2050 would still have an onshore wind dominated power system but with a higher share of PV compared with that of 2030 (see Figure F.8). CSP would operate intermittently when PV is not available to fulfill peak demand and to balance base loads. Except fully exploited storage potentials of pumped hydro, lithium-ion battery would dominate the storage system together with the operation of CAES_AD and hydrogen. Unlike the metropolitan region, EVs would still only play a minor role by 2050 due to less EVs available and relatively higher power generation for export. From January to May, the power system would be fully renewable energy based with flexibly operated biomass power plants and increasing curtailments from onshore wind and PV over time. In June and July, remaining coal power plants would need to be operated flexibly and PV would dominate its power supply system instead of onshore wind. From August to December, coal and biomass power plants would act as base load power plants but only play a minor role with less curtailment and an increasing share of onshore wind for power generation.

5.4 Sensitivity Analysis

The above derived modelling results (hereinafter referred to as reference scenario) are based on an optimization approach and therefore largely rely on uncertain costs assumptions for the future. Other parameters may influence the results as well such as historic time series of renewable energies for power generation and exogenously defined system constraints. In this section, the influence of costs assumptions on main output parameters is discussed for variable renewable energy of PV and wind, all storage technologies and grid expansion. The sensitivity analysis was also conducted for the restriction of grid expansion, the restriction of curtailment for VRE and CSP, the low development pathway for fossil fuel prices and time series for offshore wind from surrounding coastal Liaoning and Shandong provinces with higher FLH. The detailed sub-scenario assumptions are shown in Table 5.13. The sensitivity analysis focuses on the output parameters of installed capacity portfolios, curtailed energy, full load hours and system costs.

Table 5.13 Scenario assumptions for sensitivity analysis on investment costs, restriction of grid expansion and curtailment, low development pathways for fossil fuel prices and higher FLH for offshore wind.

Scenarios	**Assumptions**
VRE_Inv_low	Decreased investment costs for VRE technologies by 50%
VRE_Inv_high	Increased investment costs for VRE technologies by 50%
Stor_Inv_low	Decreased investment costs for converter and storage units by 50%
Stor_Inv_high	Increased investment costs for converter and storage units by 50%
Grid_Inv_low	Decreased investment costs for transmission grid expansion by 50%
Grid_Inv_high	Increased investment costs for transmission grid expansion by 50%
Cur_restriction_20%	Restricted curtailment ratio for VRE and CSP by region and year (below 20% in 2050)
Cur_restriction_10%	Restricted curtailment ratio for VRE and CSP by region and year (below 10% in 2050)
Cur_restriction_5%	Restricted curtailment ratio for VRE and CSP by region and year (below 5% in 2050)
Grid_restriction	No further transmission grid expansion from Inner Mongolia to BTH region is allowed (except current or planned transfer capacities)
FFP_low	Assumed low development pathway for fossil fuel prices (FFP)
Offshore_FLH_high	Applied higher FLH for offshore wind times series from surrounding coastal Liaoning and Shandong provinces

5.4.1 Influence on Installed Capacities

Figure 5.16 shows the influence of the sensitivity cases on the calculated installed capacity by technology in 2050 with a comparison to the reference scenario in the BTH region. The case of grid restriction between Inner Mongolia and BTH results in the highest variations achieving a maximum of

64 GW offshore wind and 10 GW transmission lines within the BTH region. Compared with the reference case, 26 GW lithium-ion batteries, 37 GW CCGT and 1 GW onshore wind would be additionally installed to compensate for the reduced electricity import. In contrast, increasing the FLH of offshore wind energy would not contribute to the use of regional offshore wind resources. Assuming lower investment costs for VRE and storage technologies and a low development pathway for fossil fuel prices would further reduce the installed capacity of coal power plants by 33 to 38 GW by 2050. Assuming lower investment costs of storage, grid restriction and higher investment costs of VRE would further reduce the installation of GT by 29 to 44 GW by 2050. 50% lower investment costs for storages would further increase the installation of hydrogen electrolyzers, lithium-ion batteries and grid transfer capacities by 20 GW, 6 GW and 16 GW respectively. 50% lower investment costs for VRE technologies would contribute the most to the additional installation of CAES_AD and biomass power plants by 9 GW and 4 GW respectively and also lead to 6 GW additional grid expansion within the BTH region. Lower investment costs for grid expansion and higher VRE costs would further reduce the installation of onshore wind by 30 GW and 13 GW respectively. Assuming higher investment costs for all storage systems would contribute to the installation of local electrolyzers compared to the other storage technologies while the low storage cost case would reduce the installation of electrolyzers. Higher investment costs for VRE and storage technologies, the restriction of grid expansion and assuming a low development pathway for fossil fuel prices would contribute the most to reduce the installation of CAES_AD by up to 12 GW while lower investment for VRE technologies would result in an additional installation of CAES_AD of 9 GW. The influence of higher grid costs on the installed capacities would be rather small with a slightly growth of coal power plants and a reduction of GT capacities. The more restricted the curtailment ratio, the more the need for gas turbines will be reduced and additional lithium-ion batteries will be installed, with up to minus 21 GW and plus 9 GW respectively if limited to 5% curtailment.

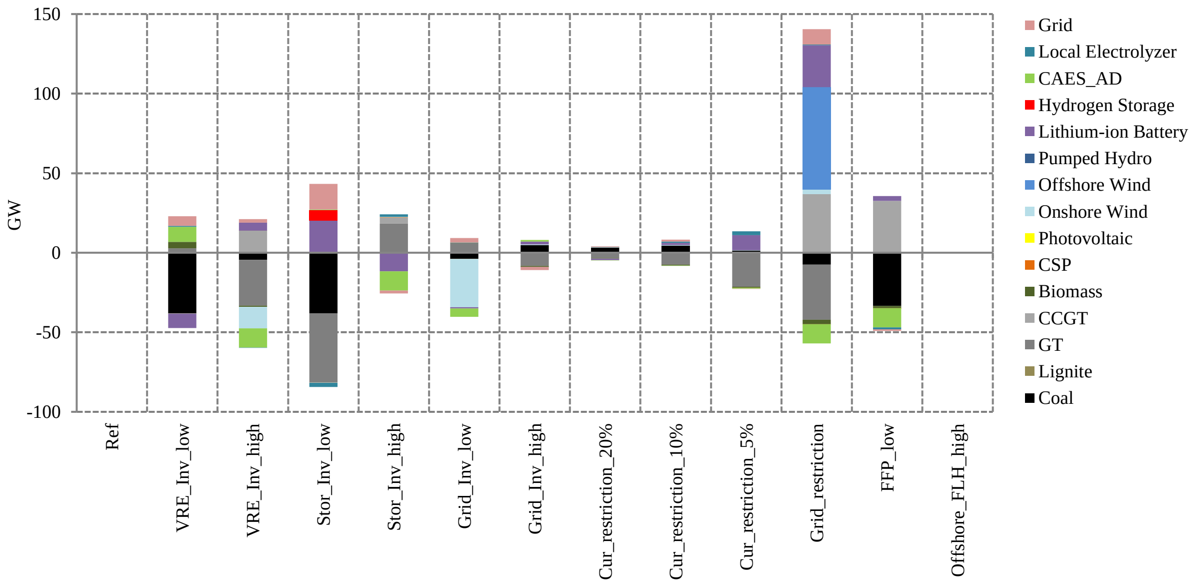


Figure 5.16 Sensitivity analysis on total installed capacities of 2050 shown as deviations from the reference scenario in BTH.

Quite different from metropolitan regions, the influence of the selected parameter variations would mostly be on the installation of wind, solar and storage technologies due to the highly renewable energy based power supply system in Inner Mongolia by 2050 (see Figure 5.17). Assuming lower investment costs of VRE and storage technologies would increase the installation of PV by 113 GW and 99 GW respectively. Accordingly, higher costs of VRE and storages and also lower fossil fuel prices would reduce the installation of PV by 202 GW, 143 GW and 120 GW respectively. Reducing investment costs of VRE has the largest influence on the installation of onshore wind and leads to an increase of 163 GW. Lower grid costs, and both higher and lower investment costs of storage technologies would also increase the installation of onshore wind by 47 GW, 28 GW and 16 GW respectively. In the case of low storage costs, this depends on the generally better integration of renewable energies; in the case of high storage costs, it depends on a sharp decline in PV capacities caused by this. In contrast, assuming grid restriction, higher VRE technology costs and lower fossil fuel prices would reduce the installation of onshore wind by 109 GW, 84 GW and 34 GW respectively.

Lower investment costs of storage technologies contribute the most to the additional installation of lithium-ion batteries and hydrogen storage of 40 GW and 50 GW respectively. In contrast, higher costs for VRE and storage technologies and the low development pathway for fossil fuel prices would lead to a reduction of lithium-ion batteries by 62 GW, 51 GW and 39 GW respectively, corresponding to a sharp decline in the installation of PV systems in all three cases. Furthermore, low VRE costs and induced additional VRE capacities result in the installation of 16 GW more compressed air energy storage systems while high VRE costs, low and high storage costs would reduce capacities of CAES_AD by 11 GW, 9 GW and 7 GW respectively. The grid restriction would result in the highest reduction of grid expansion by 65 GW while low grid and VRE costs as well as high and low storage costs would increase capacities of grid by 28 GW to 8 GW. Higher investment costs of VRE would also lead to the highest increase of CSP installation of 80 GW followed by high storage costs resulting in additional 19 GW. The low development pathway for fossil fuel prices has the highest influence on the installation of GT and CCGT resulting in additional 1 GW and 16 GW respectively. The highest curtailment restriction scenario results in the reduction of PV by 79 GW, onshore wind by 44 GW, and pumped hydro by 17 GW and the additional installation of 21 GW CSP capacity and 13 GW hydrogen storage.

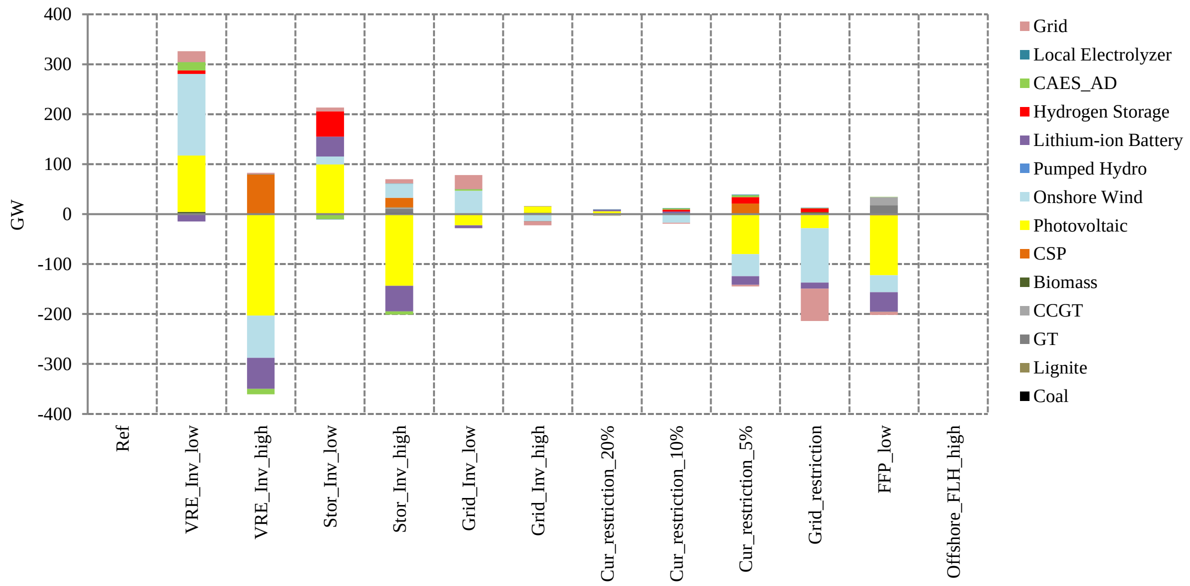


Figure 5.17 Sensitivity analysis on total installed capacities in 2050 shown as deviations from the reference scenario in Inner Mongolia.

5.4.2 Influence on Curtailed Energy

Assuming higher investment costs of storages change the curtailed energy from PV and onshore wind the most, by 51 TWh and 12 TWh respectively in 2050 (see Figure 5.18). The restriction of curtailment to 20% could reduce the curtailment from onshore wind and PV by 30 TWh but increases curtailed offshore wind by 11 TWh. A further limitation of the curtailment ratio to 10% in 2050 would result in the highest curtailed PV of 48 TWh among the curtailment ratio restriction scenarios in the BTH region, which is due to the curtailment of PV in Hebei Province. This is because the curtailment ratios in the two cities and Inner Mongolia are much higher than Hebei under the 20% restriction scenario. When restricting the curtailment ratios to 10% and 5% by 2050, the curtailment ratio in Hebei is increased due to the effects from other regions. This illustrates that if regional policy would introduce curtailment limits to increase renewable shares it might be counterproductive and instead a “free” regional cooperation will better serve the purpose. The high VRE cost assumptions would reduce the curtailed PV generation by 16 TWh compared to the reference case, followed by the low grid cost case with a reduction of 7 TWh. Assuming lower grid costs would also reduce the curtailed onshore wind energy by maximal 10 TWh. Lower VRE and grid costs would increase curtailed energy from CSP by 1 TWh. The restricted grid expansion, low fossil fuel prices and higher FLH for offshore wind would not have much influence on the curtailed energy from PV and wind compared with the reference case.

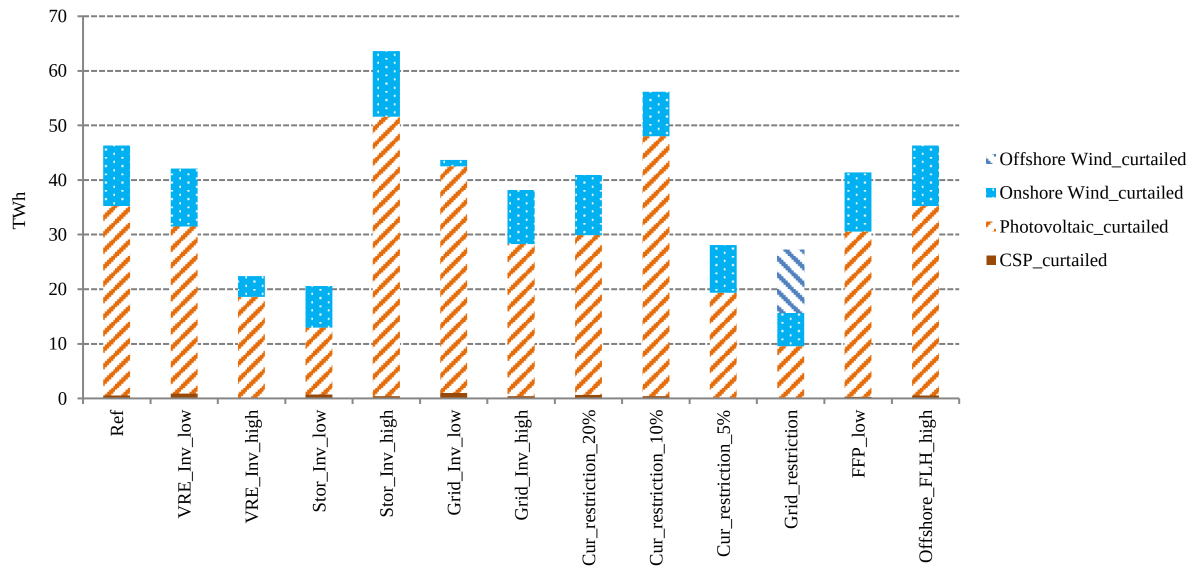


Figure 5.18 Sensitivity analysis on curtailed energy in 2050 in BTH.

In Inner Mongolia, lower VRE costs have the reverse effect than in BTH. The resulting higher installations would increase the curtailed energy from PV and onshore wind by a maximum of 96 TWh and 172 TWh respectively compared to the reference case (see Figure 5.19). Assuming higher VRE costs would reduce the curtailed energy from PV and onshore wind largely but increases the curtailed energy from CSP considerably by 135 TWh, followed by the case of high storage costs with an increase of 40 TWh. Assuming low fossil fuel prices would reduce the curtailed energy the most by 93 TWh followed by the cases of low storage costs and restricted curtailment with reductions of 67 TWh and 61 TWh respectively. The assumptions of higher and lower grid costs, the restriction of grid expansion and higher FLH of offshore wind have only small influences on the curtailed energy compared with the reference case. Quite different from the BTH region, the stronger restriction of RE curtailment results in lower curtailed energy especially for PV in Inner Mongolia.

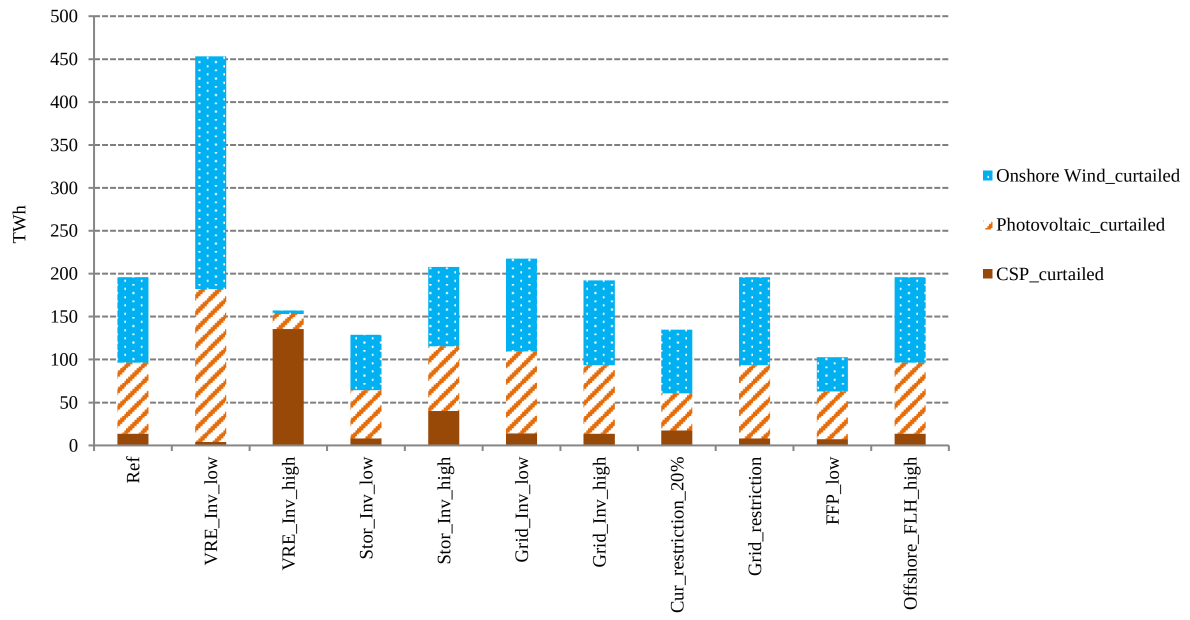


Figure 5.19 Sensitivity analysis on curtailed energy in 2050 in Inner Mongolia.

Comparing the curtailment ratios in the study regions in 2050 (Figure 5.20) provides further insights. Assuming low investment costs of VRE technologies would result in the highest curtailment ratio of CSP of 27% followed by the assumption of low grid investment costs with 24% in BTH region, while in Inner Mongolia, the restriction of grid expansion would result in the highest curtailment ratio of CSP at 38%. Most of the cases would contribute to reduce the curtailment ratio of CSP in Inner Mongolia compared to the reference case with the restriction of curtailment cases achieving the lowest. The influence of restricting curtailment ratio for VRE is higher on PV than onshore wind in both regions. Assuming high VRE costs would reduce the curtailment ratio of CSP below 5% in the BTH region. The restriction of grid expansion and the assumption of low storage and high VRE costs would reduce the curtailment ratio of PV below 5% in the BTH region. In contrast, both higher storage and lower VRE cost cases would increase PV curtailment ratio up to 35% in Inner Mongolia in 2050, followed by the low grid cost case at 26%. Assuming lower storage and higher VRE costs and the restriction of grid expansion would reduce PV curtailment ratio from 21% to below 15% in Inner Mongolia and reduces the curtailment ratio of onshore wind in the BTH region below 10% in 2050. In contrast, lower VRE costs and restricted grid expansion increase the wind curtailment ratio in Inner Mongolia to 23% and 16% respectively from 13% in the reference case. High VRE costs reduce the curtailment ratio of onshore wind the most to 1% followed by the case of low fossil prices and low storage costs at 6% and 8% respectively. The grid restriction case results in a curtailment ratio of offshore wind in the BTH region of 7%.

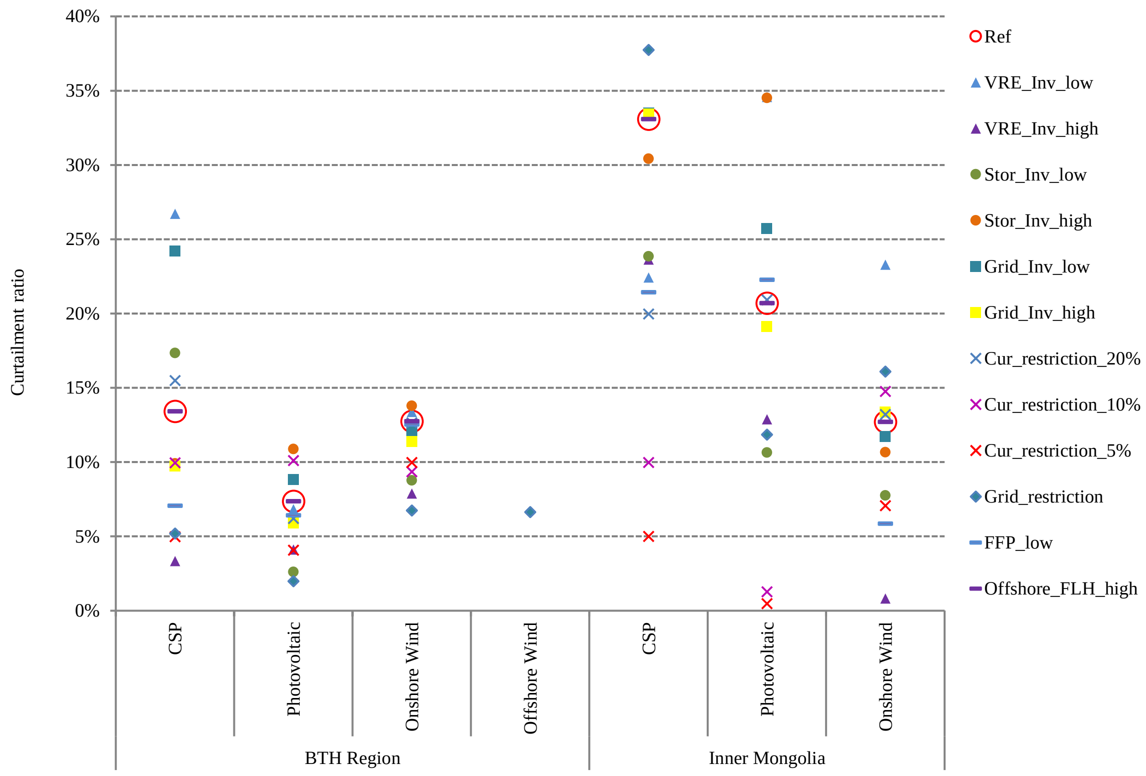


Figure 5.20 Sensitivity analysis on the curtailment ratio in 2050 in both study regions.

5.4.3 Influence on Full Load Hours

The sensitivity analysis of influences on the full load hours is discussed only for Hebei Province and Inner Mongolia in 2050 due to higher installation of power plants compared to the two cities (see Appendix G). Assuming lower VRE costs results in the lowest FLH for coal power plants in Hebei at 2243 h while high VRE cost assumptions result in the highest FLH for coal power plants at 4135 h (see Figure 5.21). In most cases the FLH for GT would be at around 1000 h with a minimum below 500 h in the two cases of low investment costs of VRE and the restriction of grid expansion. Only three cases would result in the operation of CCGT, assuming low fossil fuel prices and a restricted grid expansion at around 5000 h and assuming high VRE costs at around 2500 h. The FLH for biomass combustion is relatively higher compared to other technologies in the cases of the restriction of grid expansion (maximum of 6700 h) and low VRE costs (minimum of around 3600 h). Assuming low VRE costs would further reduce the FLH of CSP from 3300 h in the reference case to 2100 h. There are almost no variations for the FLH of PV, onshore wind, lithium-ion battery and CAES_AD in Hebei Province. In the case of a restricted grid expansion, the FLH for offshore wind would reach at around 2600 h and result in the lowest FLH for pumped hydro power at around 1400 h compared with 2500 h in the reference case. Low storage costs would result in a FLH of hydrogen storage at around 1800 h and increase the FLH for local electrolyzer above 4000 h compared with 3600 h in the reference case. The restriction of the curtailment ratio results in higher FLH for storage technologies and renewable energies. However, to restrict the curtailment ratio to 5% results in lower FLH for storage than the 10% case due to increasing operation hours for coal, GT, biomass and CSP which is required to reduce the curtailment from VRE.

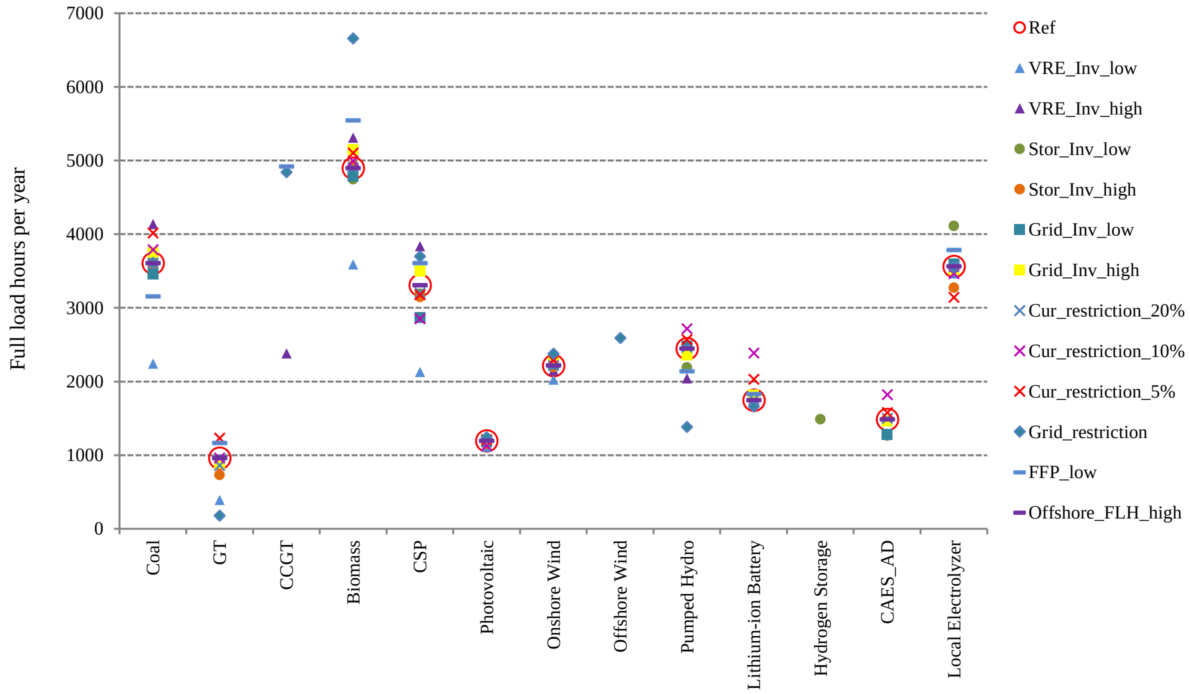


Figure 5.21 Sensitivity analysis on full load hours by technology in 2050 in Hebei province.

In Inner Mongolia, the case of restricted grid expansion reduces the FLH of coal power plants to the minimum of below 1000 h, followed by the low VRE cost case with less than 2000 h, compared to most of the cases with around 3000 h (see Figure 5.22). Only three cases would result in the operation of GT at below 2000 h, the assumption of high storage and grid costs and low fossil fuel prices. Two cases result in the operation of CCGT at FLH of around 2000 h and above 4000 h respectively, the assumption of high storage costs and of low fossil fuel prices. Low VRE costs and a restricted grid expansion would result in a reduction of the FLH of biomass power plants from around 4500 h in the reference case to below 3500 h. Low VRE costs reduce the FLH of CSP to the lowest value at around 1600 h (due to the exogenous assumption of the planned capacities as a minimum installation) while high VRE costs would increase the FLH of CSP from around 3300 h in the reference case to the maximum of almost 5000 h. Similarly to Hebei Province, the selected parameters have very few influences on the FLH of PV, lithium-ion batteries and CAES_AD. In addition, low VRE costs reduce the FLH of onshore wind by 500 h compared to above 2500 h in the reference case, and the same influence is calculated for high VRE costs on the FLH of pumped hydro power. Only the two cases of low storage costs and the restriction of grid expansion result in FLH of hydrogen storage at around 1500 h and 2000 h respectively. Finally, low storage costs result in the highest FLH for local electrolyzer at around 4700 h while high storage costs result in the lowest FLH for local electrolyzer at around 3000 h, compared to 3700 h in the reference case. Similarly to Hebei Province, the restriction of the curtailment ratio results in higher FLH for storage technologies but also for PV in the 5%

restriction case. The restriction of the curtailment ratio to 5% results in lower FLH for storage than the 10% case, again due to an increase in operation hours for coal, biomass and CSP to reduce the curtailment from VRE.

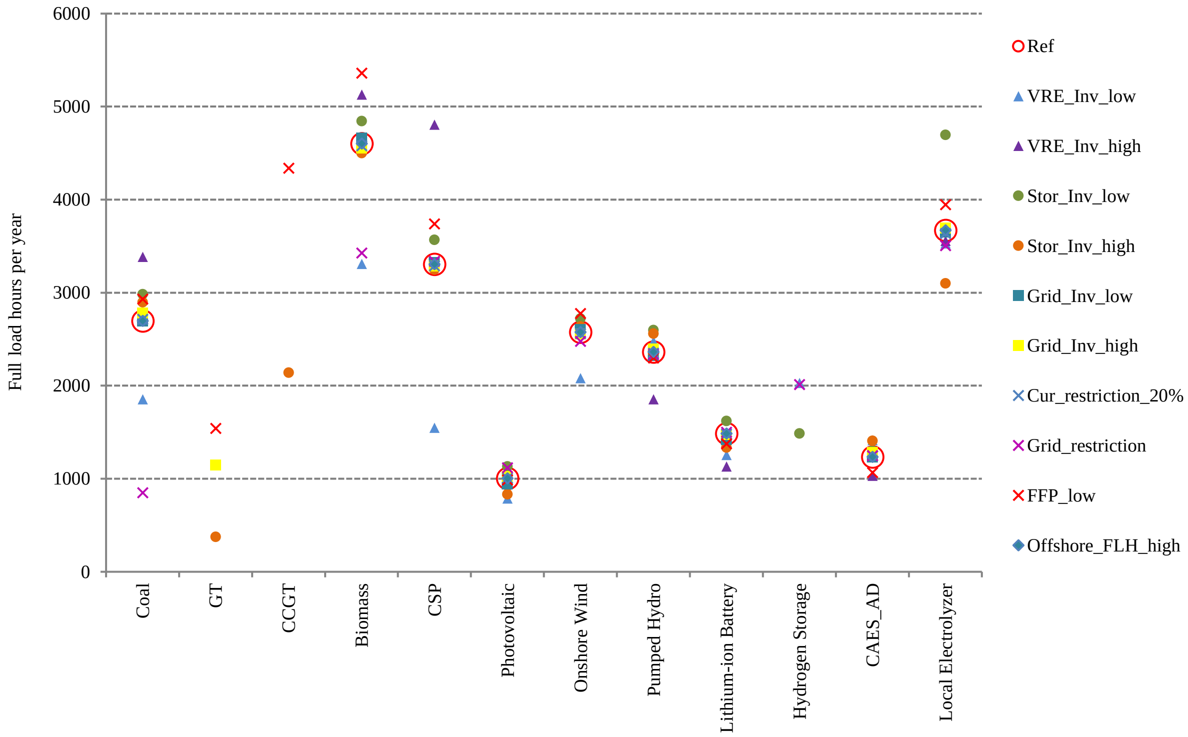


Figure 5.22 Sensitivity analysis on full load hours by technology in 2050 in Inner Mongolia.

5.4.4 Influence on Total System Costs

The influences of selected parameters for the total system costs from 2020 to 2050 in the BTH region and Inner Mongolia are shown in Figure 5.23 and Figure 5.24. The total system costs are calculated by the annuities of investments of all installed capacities, the fuel costs, fixed and variable operational and maintenance costs and the operational costs for the load shifting of electric vehicles. The influence of storage costs clearly dominates the variation of total system costs between 2030 and 2050 with around 150 billion € and 100 billion € variations in the BTH region and Inner Mongolia respectively. The reason behind is that the investment costs of storage would also influence the installation of fossil fuel power plants in the BTH region and of renewable energy capacities in Inner Mongolia. Compared to that, influences resulting from VRE cost variations are relatively small. The restriction of grid expansion increases the system costs in the BTH region between 5 billion € in 2020 and 20 billion € in 2050 compared to the reference case. To restrict the curtailment ratio by 10% or 5% could reduce the system costs by 10 billion € to 12 billion € in the BTH region and by 7 billion € to 9 billion € in Inner Mongolia before 2040. However, the 5% case would increase the system costs by 5 billion € in Inner Mongolia in the year 2050.

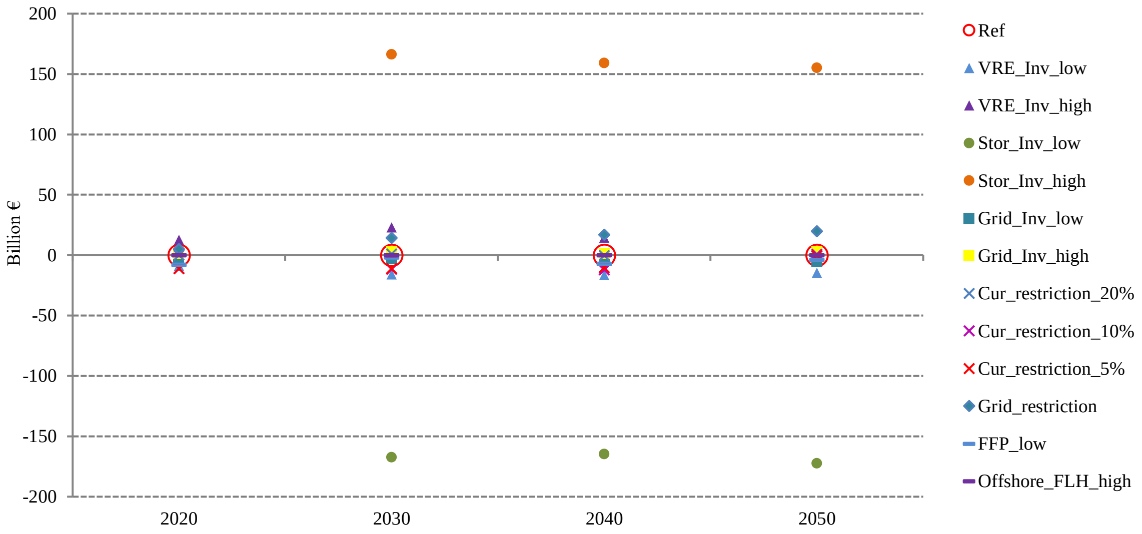


Figure 5.23 Sensitivity analysis on system costs from 2020 to 2050 in the BTH region.

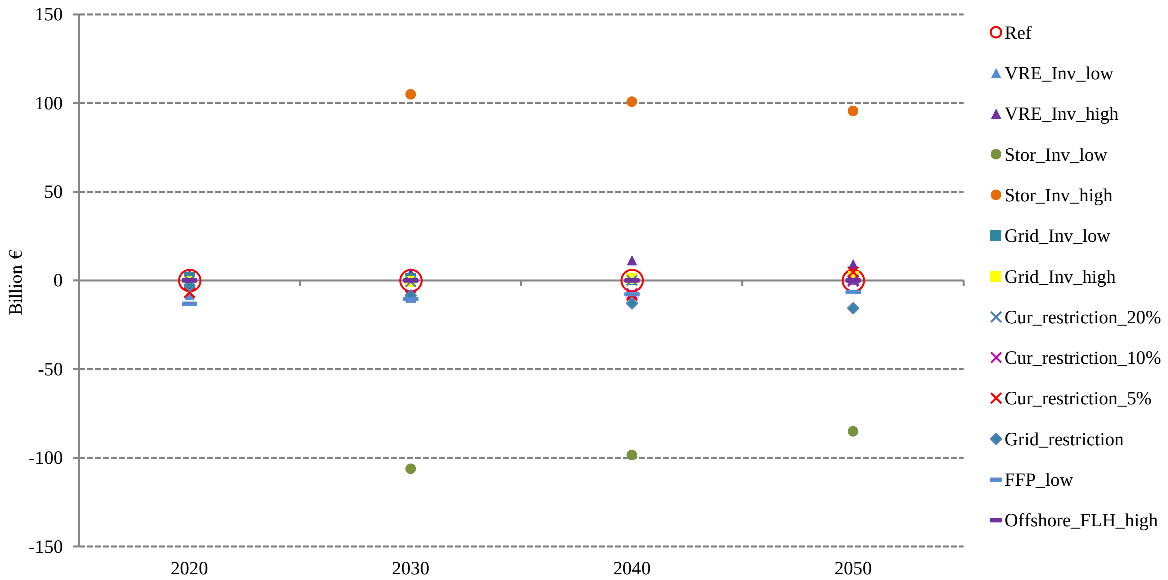


Figure 5.24 Sensitivity analysis on system costs from 2020 to 2050 in Inner Mongolia.

5.5 Summary and Discussion

Based on the resources, policies and RIS scenario framework from Chapter 2 to 4, the future power supply systems are further analyzed in this chapter using the energy system model REMix and applying a cost-minimizing algorithm under the main constraints of limiting CO_2 emissions to the level of 1995 and achieving more than 60% of renewable power generation by 2050.

The optimization results show that under the set system constraints, the share of renewable energy both in terms of installed capacity and annual energy would significantly increase both in the metropolitan region and the supply region, which result in a reduction of CO_2 emissions from power generation immediately after 2020 in both regions. With the further expansion of renewable energy into the regional power system the curtailed energy would be also increasing. Therefore, significantly more flexible technologies and operating strategies need to be implemented in the electricity system in the medium to long term. The modeling of the selected regions in China could consider different storage technologies, grid expansion, as well as flexible EV charging and local hydrogen generation. However, still partly high curtailment rates are calculated depending on key assumptions for sensitive parameters. The results reveal that in RE dominated power supply systems such as that of the year 2050, additional flexibility measures such as power to heat and measures of demand side management (DMS) are required to further reduce power curtailment from VRE generation. However, this would further increase the costs for the system integration, especially under even more ambitious decarbonization targets.

The optimization results also show that the mean value of marginal electricity generation costs would increase till 2040 in all modelled cities and provinces. With better solar and wind resources, Inner Mongolia has lower marginal costs compared to the BTH region that could achieve a value below 57 €/MW. The total installed capacity from fossil fuels in the BTH region would decrease after 2040, but only slightly. The installed capacity for coal power plants would peak in 2020 in the BTH region. In contrast, the installed capacity for fossil fuels in Inner Mongolia could be largely reduced by 2050. The modelling results with regard to temporally and spatially resolved load, fluctuating wind and solar power generation and the infrastructural needs illustrate the utilization of different technologies, investments into backup generation, storage, grid transfer and the system costs for electricity generation. The spatial resolution allows for the in-detail analysis of the regional power supply structures regarding generation, storage, power imports and exports and energy losses. The combination of spatial and temporal balancing measures is able to deal with fluctuating renewable energy such as PV and wind for power generation to meet the hourly demand. It illustrates the necessity of integrated regional planning to deal with the situation of the unbalanced distribution of electricity demand and variable renewable resources in a cost-minimized way. The modeling also provides evidence, that such a regional cooperation will reduce overall curtailment, leading to a more efficient energy system.

However, it must be taken into account that the model results have uncertainties due to the optimization approach which largely relies on uncertain costs assumptions, certain defined system constraints and the use of historic time series for VRE power generation. Therefore a sensitivity analysis was conducted to discuss the influence especially of costs assumptions for PV and wind, storage and grid technologies on the installed capacity portfolios, curtailed energy, full load hours and system costs.

Since the regional pumped hydro power potentials have already been exploited in 2020, there is a high correlation between the installation of PV and lithium-ion batteries, which is observed from 2030 to

2050 in BTH and in 2050 in Inner Mongolia. The offshore wind within the BTH region or beyond is not cost competitive compared with imported electricity from Inner Mongolia except when further import is restricted, which leads to increased system costs and higher FLH of most regional power plants. The hydrogen and CAES_AD storage technologies are usually charged when peak generation from PV occurs during daytime and are discharged when onshore wind, having limited regional potentials in BTH, generates less electricity during night. Besides, natural gas turbines are operated flexibly together with storage technologies to compensate the deficits from import during night. In Inner Mongolia, storage and grid technologies work together to balance peak generation from PV during daytime and to compensate low power generation from onshore wind during night. As expected, lower fossil fuel prices would also contribute to the higher FLH of all the power generation technologies except PV in Inner Mongolia. Higher investment costs of VRE and storage technologies would promote the further installation of CSP due to increased cost competitiveness with its power generation and storage systems. Due to an unbalanced distribution of renewable resources and load demands, the future low-carbon power system would highly depend on the expansion of transmission corridors. The system costs would be largely determined by the future development of storage costs. More rigid curtailment requirements most likely will lead to an increase in storage expansion [5] but to restrict the curtailment ratio down to 5% would result in a shift to higher operation hours for coal, GT, biomass and CSP, thus leading to reduced FLH for storage technologies. For example in February in 2050 of Inner Mongolia, the operation of CSP would eliminate the requirements for the charging and discharging of lithium-ion batteries during the periods of peak generation from onshore wind when changing the restriction of curtailment ratio from 10% to 5% (see Figure 5.25).

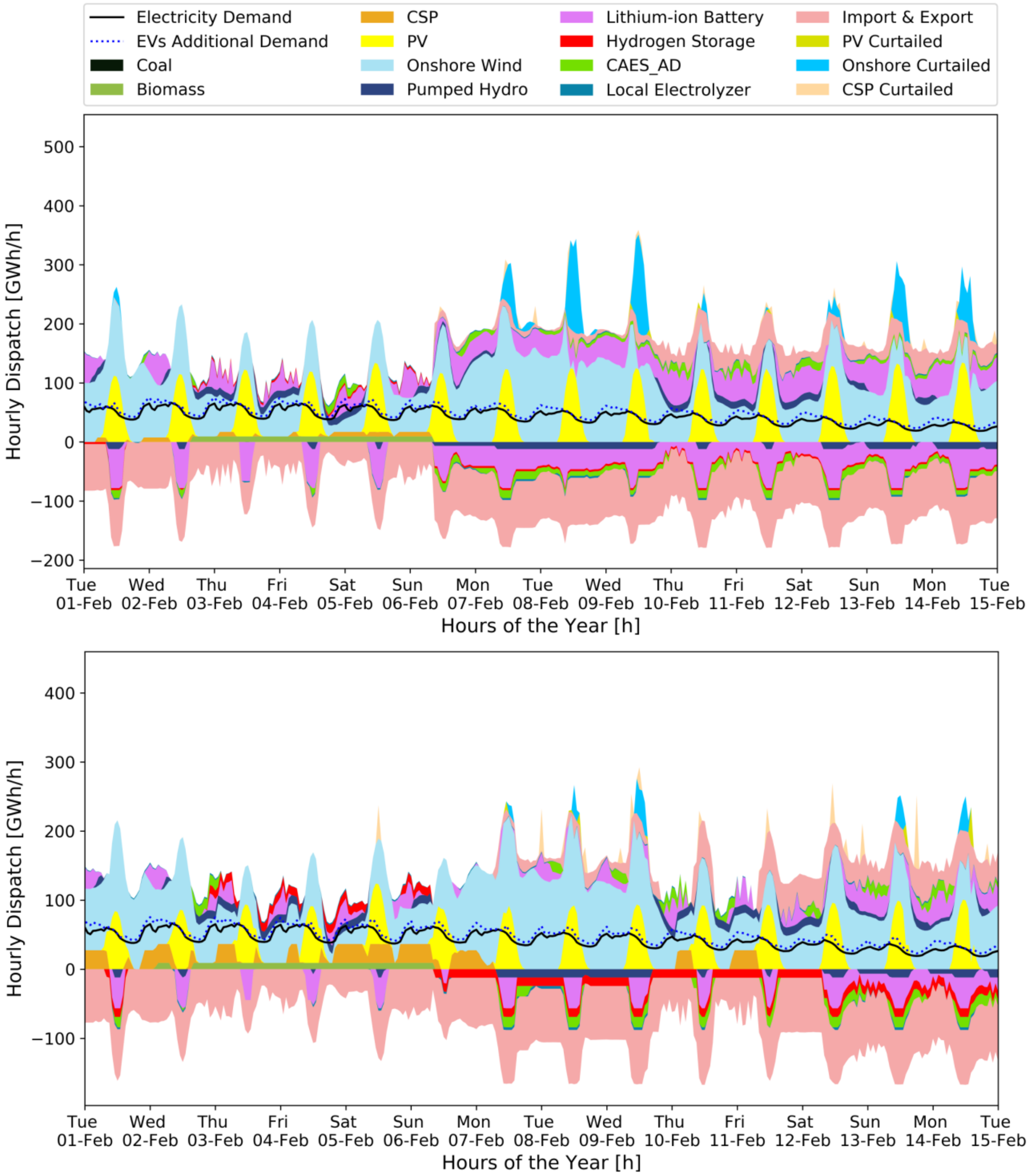


Figure 5.25 Typical hourly generation by technologies, export and charge (-), import & discharge (+) to meet power demand in the restriction of curtailment ratio by 10% (above) and 5% (below) scenario in Inner Mongolia of February in 2050.

6 Discussion and Outlook

6.1 Summary and Conclusions

In this study I discussed two possible trajectories of the energy transition regarding policy making and technological transformation compared to a scenario which follows current policies. Due to the relevance of urban agglomerations with regard to energy consumption and specific challenges of decarbonization, the analysis focuses on selected regional energy systems, namely that of the Beijing-Tianjin-Hebei Region and the Yangtze River Delta region (including Shanghai, Jiangsu and Zhejiang). First, the current status of the energy systems and key challenges to a low-carbon future were identified with a review of transition aspects and required actions. This was complemented by an analysis of current policy targets and actions from most recent policy plans at different administrative levels of China as discussed in Chapter 2. An assessment of renewable energy potentials on the provincial level provided information on an essential prerequisite for energy system transformation (in detail see Chapter 3). The bottom-up scenario building represented the regional energy system from 2015 status towards 2050 in a consistent and transparent quantitative way. All relevant processes are considered from primary energy supply with various conversion processes for power, heat and fuels to the end-use sectors of industry, residential, services and commerce, and transport. The three developed pathways, namely current policy (CPS), natural gas & nuclear (NGNS) and renewable & import (RIS) scenarios were constructed with a normative approach in order to discuss options for reducing regional CO_2 emissions and as a framework to model the integration of RE into the regional energy systems. The comparison of three scenarios contributes to discuss the impact of near to medium-term policies on long-term transition pathways due to the path dependency in terms of investments in energy infrastructures (as discussed in Chapter 4). The main conclusions are that only a turnaround in energy policy to promote the integration of renewable energies will achieve desired climate targets in both the national and international context. However, a slow and gradual adaptation of low carbon technologies for the power generation portfolios and investments as in the NGNS scenario is not sufficient and would result in the risks of path dependency on gas infrastructures. Except for the power sector, measures to the integration of heat and transport sectors such as power to heat, EVs and power to X would also play a key role for the decarbonization of the whole energy system with improved system flexibility.

One key strategy applied for decarbonizing the heat and transport sectors is electrification. Since the distribution of renewable energies in China is unbalanced between resource abundant regions and consumption centers (see Chapter 3), next a multi-regional power supply system is modelled focusing on the BTH metropolitan region with Inner Mongolia as a supply region (as discussed in Chapter 5). The RIS scenario was used as a scenario framework as it assumes the highest electrification rate and implies an ambitious expansion of technologies to generate electricity from renewable energies, providing the largest challenges for regional integration. The multi-regional optimization results contribute to reach overall regional energy system transition targets with higher spatial and temporal resolution.

The main conclusions drawn from the bottom-up scenario analysis are: first the implementation of efficiency measures is the backbone for cost-effective energy system transition as discussed in Chapter 4 with a comparison among CPS, NGNS and RIS due to different efficiency assumptions in end-use sectors . Second, it needs different regional strategies and strong interrelations of metropolitan regions and renewable energy abundant regions that wind and solar power in northern resp. western regions can play an important role for the future power supply of eastern metropolitan regions as shown from the renewable energy potential assessment results in Chapter 3. Third, transmission capacity expansion and local storage installations are necessary to balance power generation from variable renewable energy (VRE) and power demand, especially under RIS as discussed in Chapter 5 with multi-regional power system optimization in higher temporal resolution. Fourth, the scenario comparison among CPS, NGNS and RIS and the regional integrated modelling between Inner Mongolia and the BTH region support decision making regarding the implementation of new technologies and infrastructures for metropolitan regions towards long-term climate targets. The development paths in NGNS and RIS differ, e.g., with regard to the future development of natural gas pipelines and electricity transmission capacities required in eastern coastal metropolitan regions to support its low-carbon energy system transition. The investment in such infrastructures in an early stage would have an influence in a long run with profound impacts on energy independency. But more research needs to be done to identify how to support and develop a market based flexible system for the supply and consumption of power, heat and fuels combining utility-scale and decentralized renewable sources, backup capacities and various flexibility options with cross-province or cross-regional transmission.

The analysis considers a variety of options to supply a metropolitan region of China with renewable power. Biomass, PV and wind appear to be more cost competitive than dispatchable power generation from CSP and geothermal energy, of which only the currently planned capacities are operated at the modelled system cost minimum. Since the regional potential of pumped hydro power is already exploited before 2030, there is a high correlation between the installation of PV and lithium-ion batteries, which is observed from 2030 to 2050 in BTH and in 2050 in Inner Mongolia. Offshore wind energy within the BTH region is only cost competitive if further imports are restricted. Thus, the two municipalities of Beijing and Tianjin will largely depend on imported electricity. In Hebei province, the power system in 2050 is dominated by PV supplemented with onshore wind and some residual coal in the winter season. Inner Mongolia’s power system is dominated by onshore wind energy, especially in the winter season. Compared to the metropolitan region, the role of electric vehicles in its renewable energy-dominated power system is rather small. The hydrogen systems, compressed air storages and natural gas turbines are operated flexibly to compensate for deficits from import during the night. In Inner Mongolia, storage and grid technologies are of complementary importance to balance peak PV generation during the day and low onshore wind generation at night.

The key assumptions for the low-carbon scenarios in this thesis largely rely on the exploitation of efficiency potentials and measures (e.g., adjustment of economic structure, sustainable urbanization strategies, application of new energy efficiency standards), medium to long-term decarbonization targets (e.g., share of renewable energy for primary supply, reduction of regional CO_2 emissions, improvement of electrification rates), and adopted low-carbon technologies and their future costs reduction potentials that would largely affect the energy supply mix and transition costs. Therefore, further sensitivity analysis of key assumptions would be needed to discuss the robustness and uncertainty of constructed scenarios. Some key assumptions for the future investment costs of VRE, storage and grid, the restriction of curtailment from renewable energies, the restriction of grid expansion from renewable energy abundant region to load centers, the future development of fossil fuel prices and higher FLH for offshore wind potentials have been discussed in Section 5.4. However, great uncertainties also arise from China’s future economic structure (e.g., how large will the future economic growth be? How much of the economy would be service and innovation based?). Uncertainties also result from the unclear future competitiveness of various low carbon technologies and the expansion of transmission capacity or storage (e.g. to what extent electrification can take place in the heat and transport sectors? What will be the policy for nuclear development and the costs of power and heat generation from renewables in the future?). The uncertainties would also be related to the development of the global natural gas market as well as import pipelines and capacities for China and future global and national natural gas price. The main limitations in modelling the regional energy system are further discussed in the next section.

6.2 Limitations for Regional Energy System Modelling

In this work I constructed an integrated energy system model with combined statistics and assumptions from various sources to support the scenario analysis of future energy system transition in two eastern coastal metropolitan regions of China, which integrates the power, heat and transport sectors to reach the targets of energy system decarbonization on an annual basis. In addition, I applied a higher spatial and temporal resolution energy system model to address the imported electricity in the power sector under the scenario characterized with high electrification and penetration of renewable energies. The hourly dispatch shows the interactions among power generation, storage and grid technologies in an hourly resolution in different provinces and cities with seasonal variations. Furthermore I conducted a sensitivity analysis on key parameters under the costs optimization approach, which shows the robustness of the constructed transition pathways. However, such a pure costs optimization approach neglects the market aspects as shown curtailment from PV in cities with imported electricity during several months by 2050 and other social aspects of the energy system transition process. The limitations for regional energy system modelling are further discussed below.

6.2.1 Transparency and Availability of Energy Statistics

Compared to the published IEA World energy balances, the currently available provincial energy balances in Chinese statistics could not fully support the annually based bottom-up scenario analysis as applied in Chapter 4. The main limitations are:

- Data on the use of renewable energies are missing, e.g., in the heating sector only “other energies” are given without differentiation between solar, biogas and geothermal energy [177].
- Fuels for heat and power supply are not distinguished by technologies, including the distinction of CHP and auto-producers.
- Energy consumption in transport sector is not distinguished by transport modes. It is confusing that energy consumption in transport is partly included in the residential sector in contrast to other international statics.

Therefore for this thesis, I combined other provincial level energy related statistics as described in Section 4.2.

All these statistical data need to be converted from original physical units into a single energy unit (e.g. PJ). Assumptions were made for fuels based on the total primary energy from the province’s energy balance table. Electricity demand data with higher temporal resolution are urgently needed to deal with the fluctuating characteristics of RE for power generation. In this study original hourly electricity demand data from five provinces belonging to the Southern Power Grid Company of China (not publicly available) were used for the analysis of the future power system in Chapter 5. Compared to data availability in the power sector, time-resolved data for the heating sector are even more difficult to obtain because of the lack of installation of smart meters. Thus, the temporal variability of heat demand could not be included in the analysis in Chapter 5. Compared to the above mentioned published statistics, the latest information regarding the current development of RE in terms of grid-connected installed capacity, generated electricity, FLH and curtailment rate is available online. They are published quarterly by NEA to monitor the performance of the penetration of RE into power generation in each province in terms of gaps with development targets regarding installed capacity and curtailment rate. The overview on additional data sources for regional energy system modelling of China for this study as discussed in Chapter 4 and 5 is provided in the Appendix H. All the above mentioned statistical and data limitations further complicate data availability, accuracy and consistency to support regional energy systems analysis with a focus on the integration of renewable energies and with the objective to further support public debate and stakeholder involvement in policy making.

Statistical data are a key input for the parametrization of the models for scenario analysis as also revealed by the review of three scenario studies focusing on different geographical scopes with specific normative targets and analytical approaches [50]. Against this background, there is an urgent need to improve China’s energy statistics status at both the national and provincial levels, in particular with regard to technology- and fuel-specific data on electricity, heat and fuel supply, including renewable energy forms. For accompanying analyses of the expansion of fluctuating RE into the regional energy system, the public availability of data with higher temporal and spatial resolution for power and heat needs to be improved on both the supply and demand sides. On the demand side, data on customer consumption patterns for the demand of electricity, heat and mobility needs to be collected and harnessed in compliance with data protection guidelines to ensure adequate demand side management with the support of ICT technology and open data platforms. The further improvement of transparency and integration of energy statistics in China will be the basis for developing open source energy system models for the analysis of the power market on different scales [87].

6.2.2 Sensitivity of Scenario Analysis

The work in this thesis is focused on the construction of energy transition scenarios based on different decarbonization strategies. However, this analysis largely relies on social and economic framework conditions such as

- future national and regional economic and population structures,
- domestic energy policies and efficiency improvement potentials,
- set system constraints such as national and regional CO_2 caps and the share of RE for power, heat and fuels supply,
- the future development pathways of fossil fuel and CO_2 prices,
- the assumed key technical and economic parameters for RE technologies for power generation, heat supply, storage, energy transmission and distribution (especially for applied multi-regional power system optimization models in Chapter 5),
- additional power demand depending on the assumed electrification rates in the heat and transport sectors (as analyzed in Chapter 4).

All these factors would influence the transition paths for study regions in terms of future electricity, heat and fuel demand, peak energy demand, national and regional CO_2 budgets and peak CO_2 emissions. In addition, the national and regional energy supply and investment structures depend on the generation, storage and transmission of energy in the form of electricity, heat and fuels and therefore directly influence the system transition costs and national and regional energy independence (see Table 6.1).

Table 6.1 Summary of key influencing parameters for constructed regional energy transition scenarios.

Parameters	**Items**	**Influenced Results**
Economic structure	Transfer from energy intensive industry to low carbon economy especially for three provinces	Power, heat and fuel demand
Population structure	Urbanization rate with different energy consumption	

	structures for rural and urban residents	
Energy policy	Domestic policy for the development of nuclear, natural gas, coal, RE and CCS	Power, heat and fuel supply and investment structures
Efficiency	Efficiency improvement potentials in buildings, industry and transport sectors	Peak energy demand
System constraints	CO_2 cap Share of RE for power, heat and fuels supply	Peak CO_2 emissions, CO_2 budgets
Price development pathways	Fossil fuels both from domestic and international markets CO_2 price	
Technology costs with assumed learning curves	RE technology for heat and power supply Storage technology Transmission and distribution technology	System transition costs
Electrification rate	Assumed electrification rates in heat and transport sectors	Power demand structure and energy independency

In my thesis I made the first steps towards a comprehensive sensitivity analysis by varying a broad range of cost variations and other main influencing system constraints for the optimization of multi-regional power system (see Section 5.4). However, in order to further discuss the robustness of constructed regional energy transition scenarios, the sensitivity analysis for key socio-economic framework conditions need to be conducted in the future. This also includes that the scenario modelers need to consider the latest RE cost data from the development of the real market such as the current auction prices and future trends of the RE industry development during innovation processes. Only then can it be avoided in the future that an overestimation of energy transition costs and an underestimation of the deployment potential of RE technologies in various sectors is carried out in such analyses (see e.g. [56]).

6.2.3 Social Aspects of Energy Transition

Beyond technical aspects, research is increasingly focusing on governance as a success factor of energy system transition [57, 114]. New analytical frameworks are developed to cover the necessary institutional changes and address stakeholder integration [104]. Experience to date in various countries shows that comprehensive regional planning and energy-, sector-, and technology-specific planning are important strategies for energy policy [101, 110]. Continuously monitoring the achievements in light of the targets and using milestones under consistent legal and policy conditions can guarantee an effective energy transition [71, 101]. Thus, well-founded energy transition management needs to navigate, i.e., continuously identify the most favorable solutions and effective measures in the course of the transition process. Long-term scenario analyses help to identify robust and/or optimal transition pathways with the capability of integrating qualitative aspects such as governance and acceptability in the future to reach certain economic, societal, environmental, and climate goals [69] as discussed in Chapter 4 and 5 of this study. All of the above mentioned transition aspects and related measures require the support of specific or integrated policies across various administrative levels.

Besides, public acceptance is an important pre-condition for long-term energy system transition. It involves different market, socio-political, and community issues [10, 11, 52], especially for the investment in and construction of energy-related infrastructures (e.g. nuclear, fossil fuels and renewable energies) [18]. Public involvement in the decision-making process may be an important aspect, but may not necessarily lead to higher local acceptance. However, opportunities for (economic) participation, transparent information, and fair sharing of the burden help to avoid local rejection of projects. For example, the expanding of nuclear, onshore wind farms and transmission lines usually poses the highest risk regarding local acceptance. The market development of low-carbon technologies and efficiency improvement also relies on public awareness. Improving public awareness, e.g., by active discourse and communicating the societal long-term targets of energy transition, contributes to public acceptance [52]. Public consensus, constructive and fact-based discourse in the media, and political stability regarding the targets are preconditions for a successful transition process. Transforming the energy system toward low carbon pathways also requires major sociotechnical changes and a paradigm shift, which affect not only technology itself, but also business models and institutions [72, 79, 115], which has not been discussed in this study.

6.3 Outlook: Renewable Energy-oriented Market Design

The above discussed process for scenario construction does not consider the implementation of market mechanism to integrate renewable energy sources into various sectors. According to the latest market report of renewables from IEA towards 2023 [38], the share of competitively set remuneration will become higher (see Figure 6.1). For China’s case, it is driven by the policy transition from administratively set feed-in tariffs (FITs) to auction schemes for onshore wind and solar PV installations will continue to stimulate hydropower, offshore wind, bioenergy and CSP growth in China [38]. Compared with other regions, the market competitive mechanism for the installation of renewable energies in China needs to be further developed such as through proper designed auction schemes.

Figure 6.1 Utility-scale renewable capacity growth by remuneration type, 2018-23 [37].

Besides, in the future a new energy market needs to be designed and developed with enhanced flexibility and involving more market players in order to further support the integration of renewable energies into the system in a cost-effective way. Such a mechanism with a combination of power and carbon market would support the realization of the energy system transition targets both regionally and nationally. RE electricity could participate in market trading in financial, day-ahead, intraday, and real-time balancing market as well as provide other ancillary services [179] such as flexibility, frequency adjustment and reserve capacity with the involvement of energy storage facilities [87]. However, there are no such short-term trading markets existing in the current power dispatch paradigm of China [178]. The power market reform in China started in March 2015, aiming to establish competitive wholesale and retail electricity markets especially for industry customers, which is supported by several market pilot projects in multiple provinces. Just recently, NEA has released a new draft guidance on the development of a domestic electricity spot market (ESM) to support the energy transition towards low-carbon future with the coordination between planning and market operation under flexible market price signals [87]. Specifically, the local and regional conditions in terms of RE potentials and electricity consumption need to be taken into consideration when developing the models for electricity market analysis. This guidance has pointed out that regions with less frequent grid congestion and high market concentration on the generation side are best suited for a decentralized model with real-time markets (or real-time balancing mechanism) as a start; in those regions with rather frequent grid congestion or large share of RE, a centralized model with day-ahead markets (or a day-ahead pre-clearing mechanism) will be a good choice to start with [87]. Nevertheless, the ESM development in China should facilitate the development of regional markets as well such as the coordinated development of Beijing-Tianjin-Hebei region and Yangtze River

Economic Zone with creating favorable conditions for intra-market transactions and market integration so as to further promote the consumption of clean energy in a broader scope [87].

The current demonstration projects to test a carbon market in China only cover the power sector. By 2020, it is planned to extend them to a national wide scheme and to include industry, building and transport sectors as well. From the above scenario analysis I conclude, that a more integrated approach of CO_2 pricing across all sectors should be considered. However more sectoral specific modelling would be needed specifically to address the impacts of carbon pricing on the future transport demand and its mode shifting. The establishment of a power market in China would also help to implement effective CO_2 pricing under a market mechanism and trans-provincial or trans-regional trading of electricity. Besides, other flexibility options such as demand side management would also require effective price signals. In order to further improve security of supply, measures such as monitoring supply security parameters, developing capacity and grid reserve [43] also need to be implemented under market mechanism, which is the guarantee for the implementation of a political agenda required for energy system transition.

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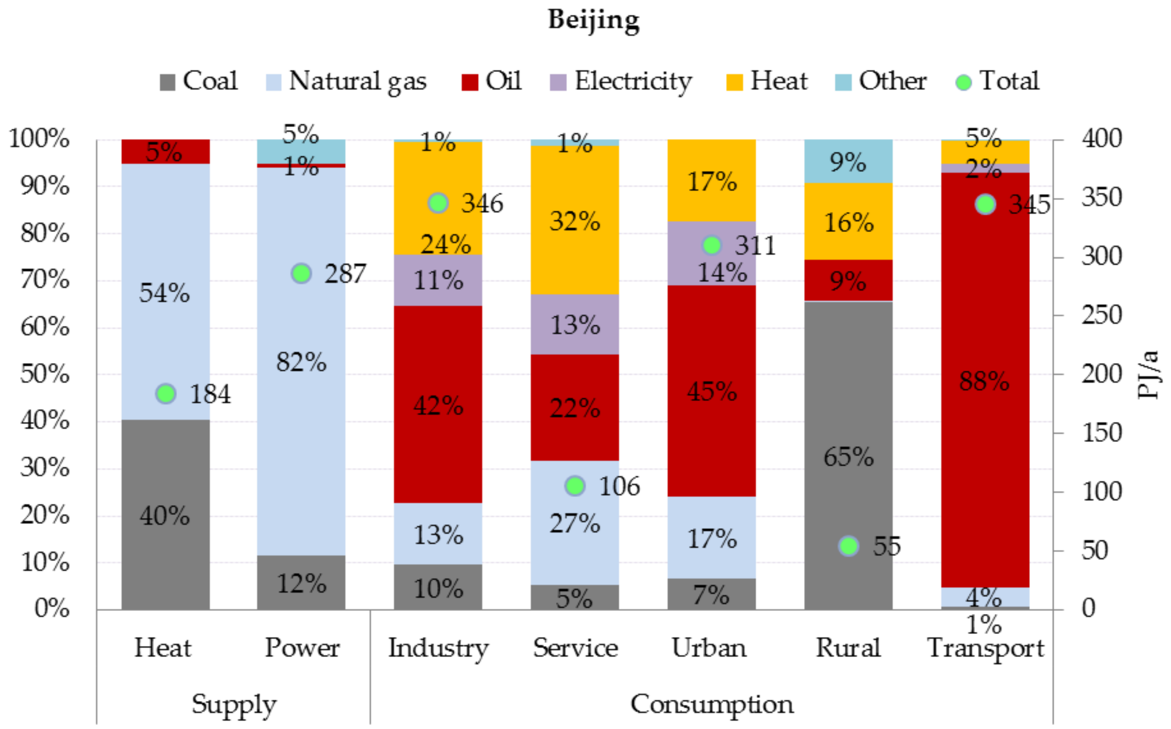
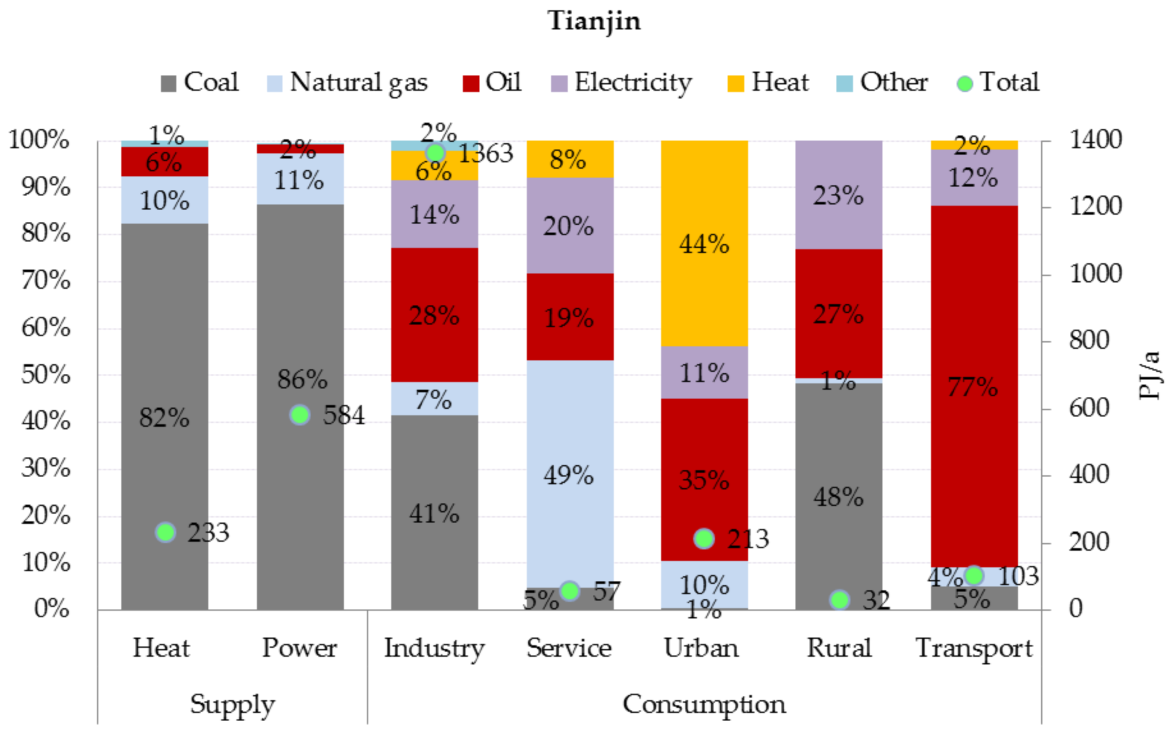
Appendix A Current Energy System Situation and Energy Related Emissions in Study Regions and China





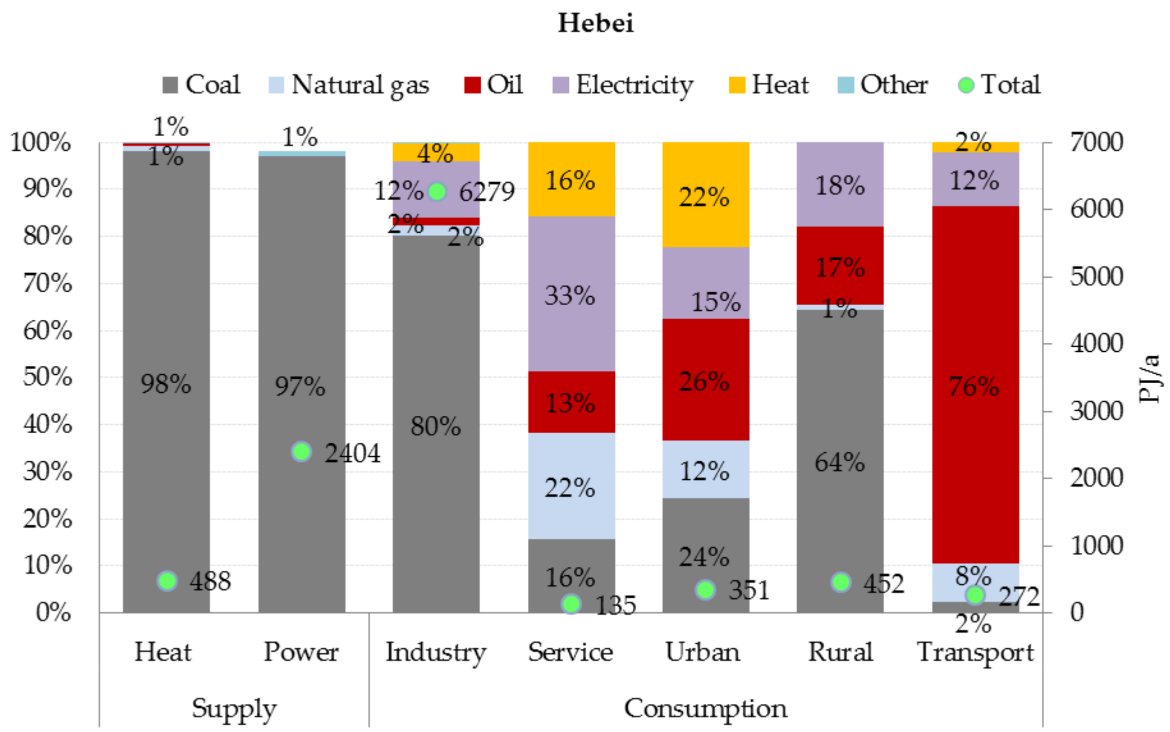
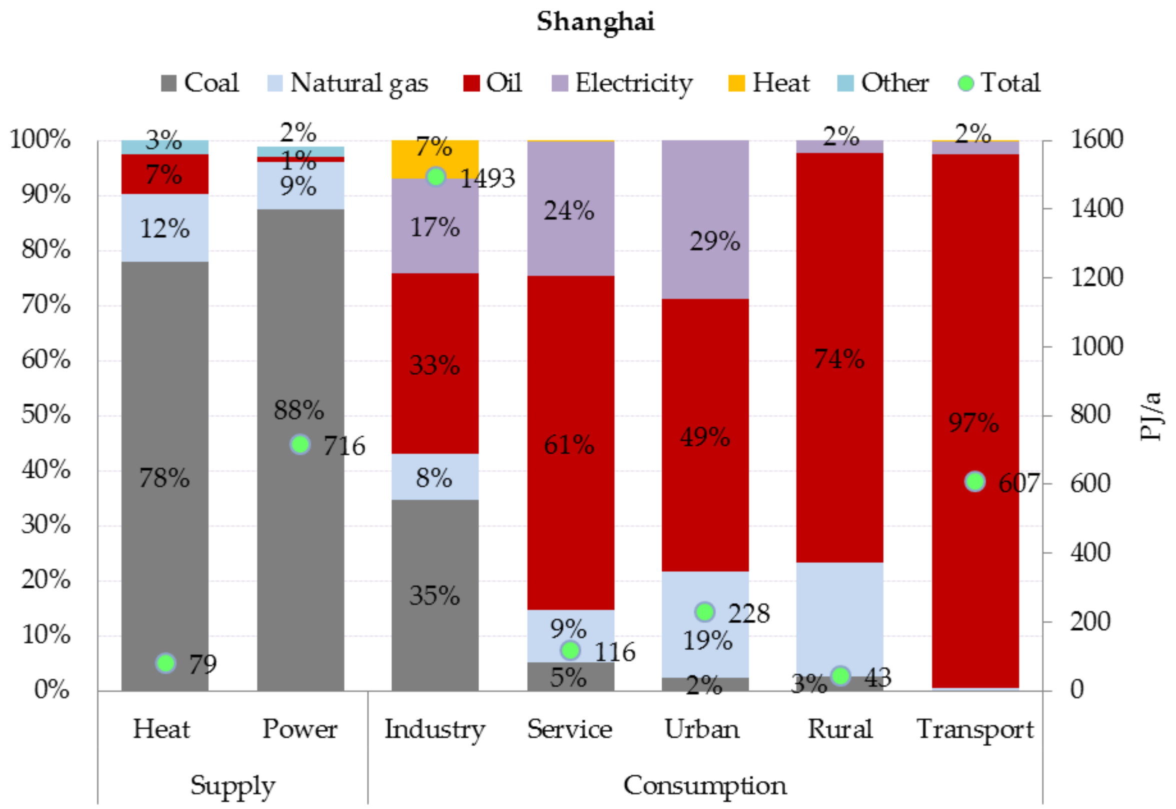


Figure A.1 Heat and power energy supply and final energy consumption in BTH region in 2015 by sector [175].



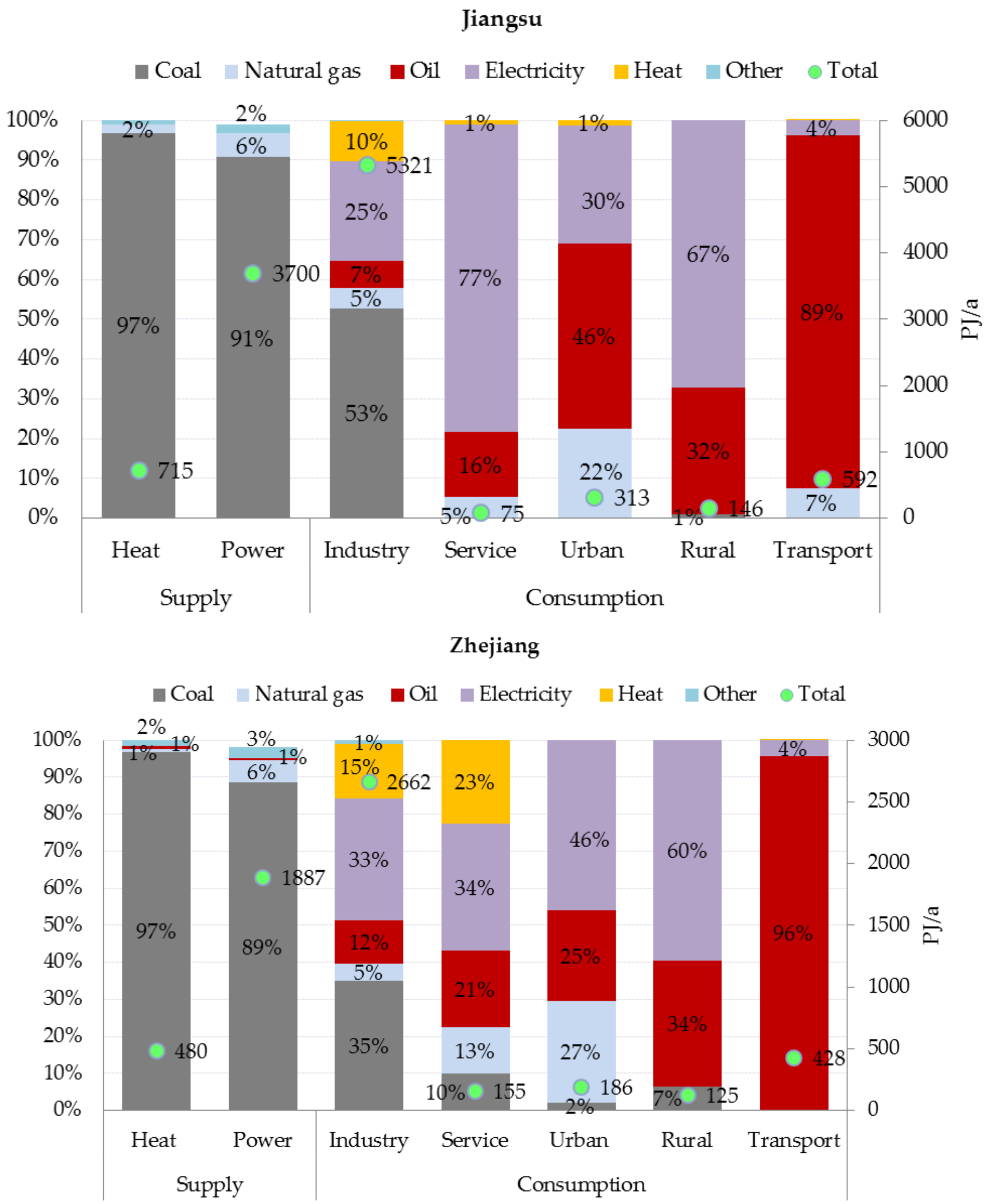


Figure A.2 Heat and power energy supply and final energy consumption in YRD region in 2015 by sector [175].

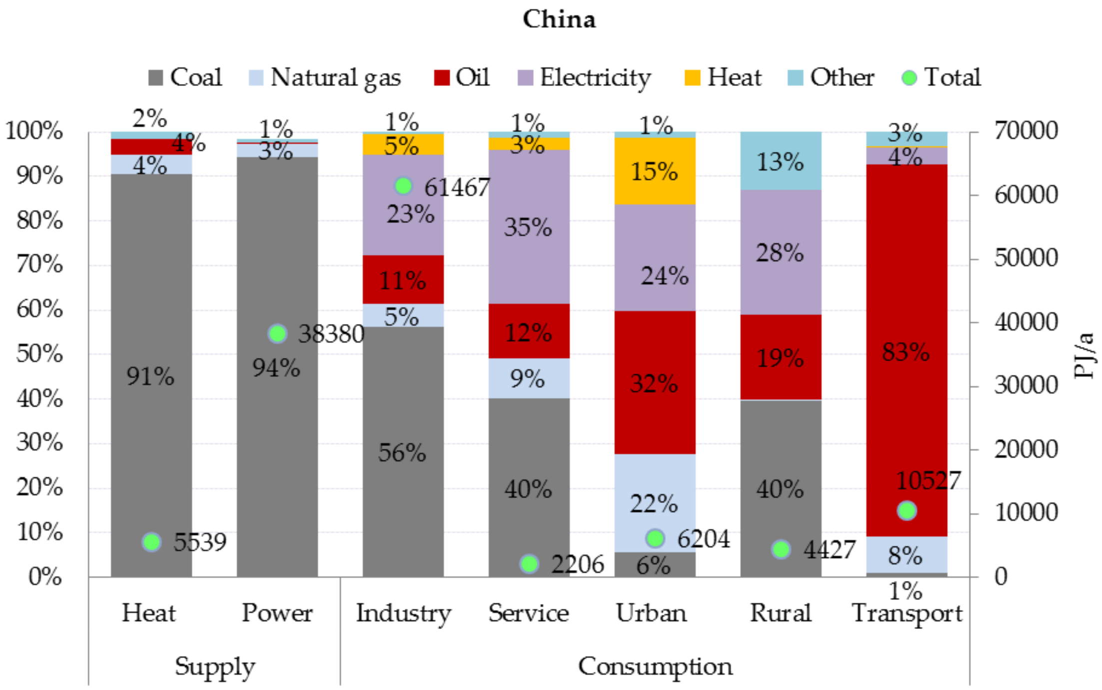


Figure A.3 Heat and power energy supply and final energy consumption in China in 2015 by sector [175].

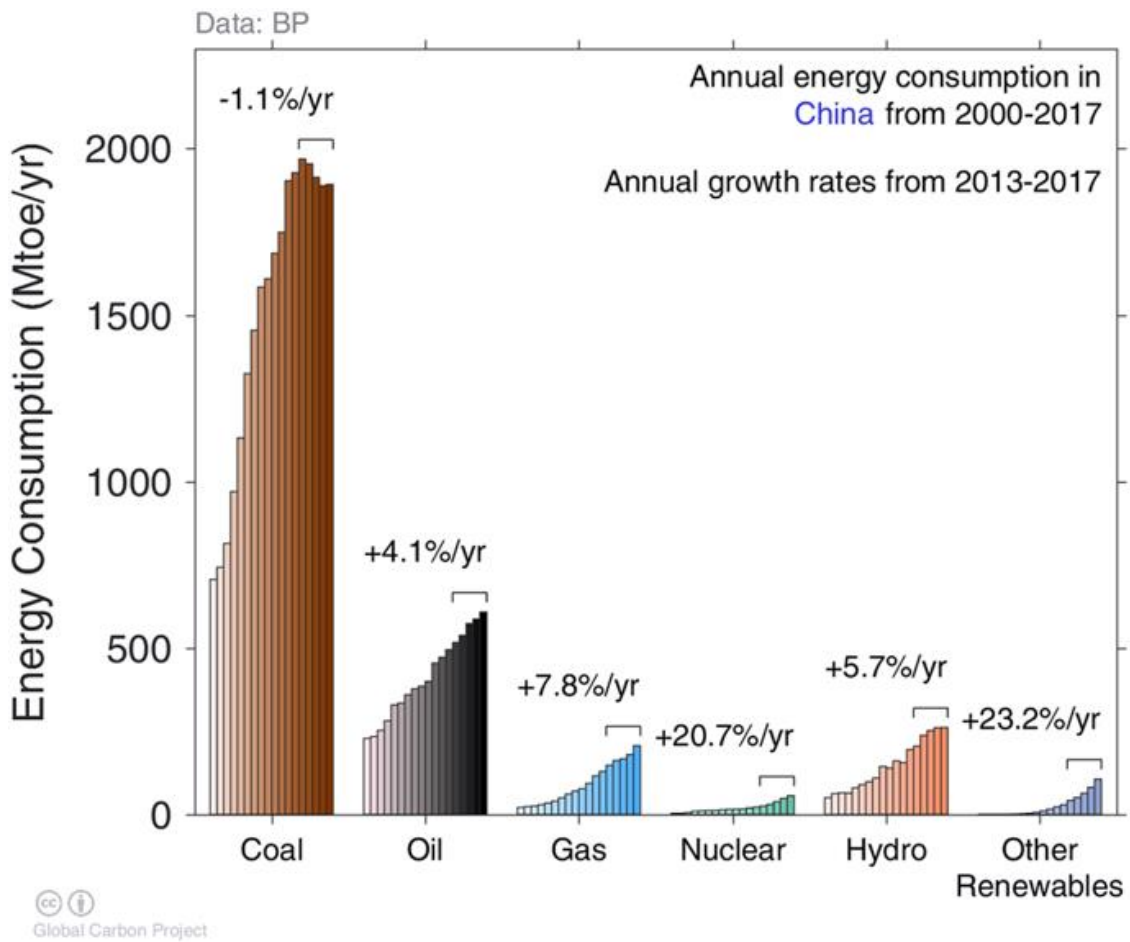


Figure A.4 China’s annual energy consumption by energy source from 2000 to 2017 according to [13].

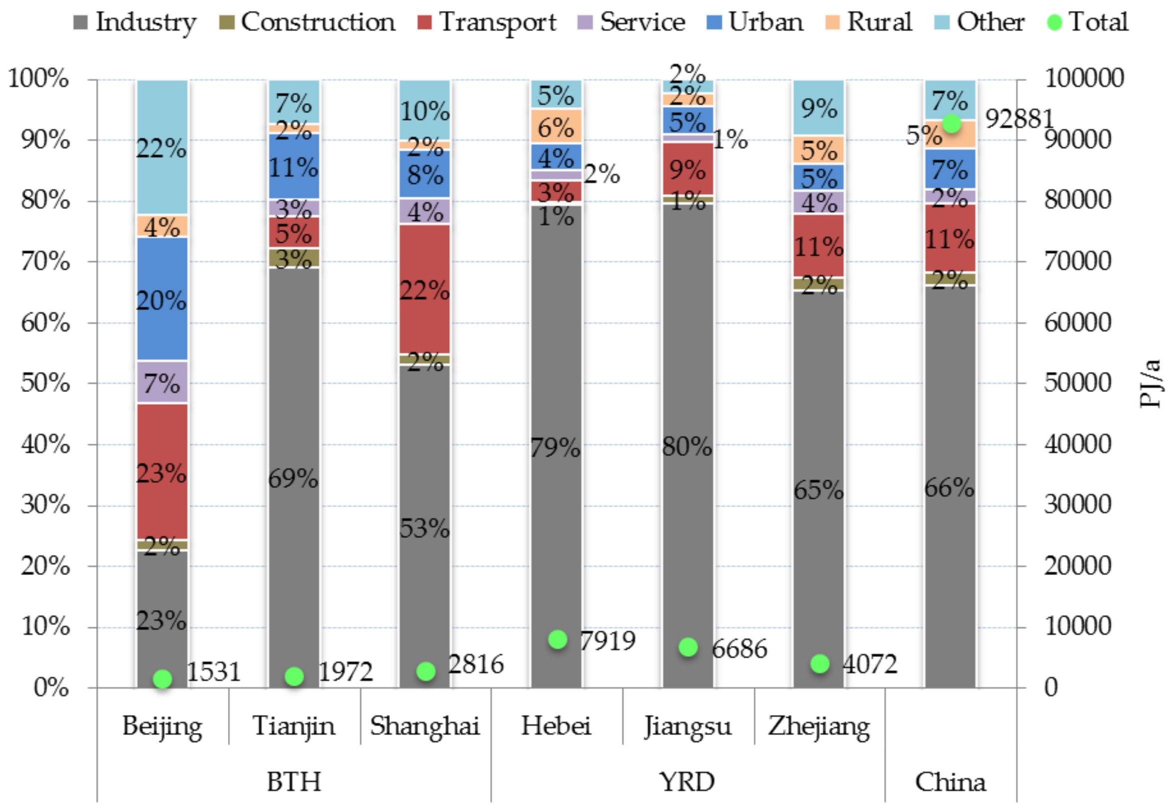


Figure A.5 Energy consumption structure of study regions and China in 2015 by sector (data source: China Energy Statistical Yearbook 2016 [175]).

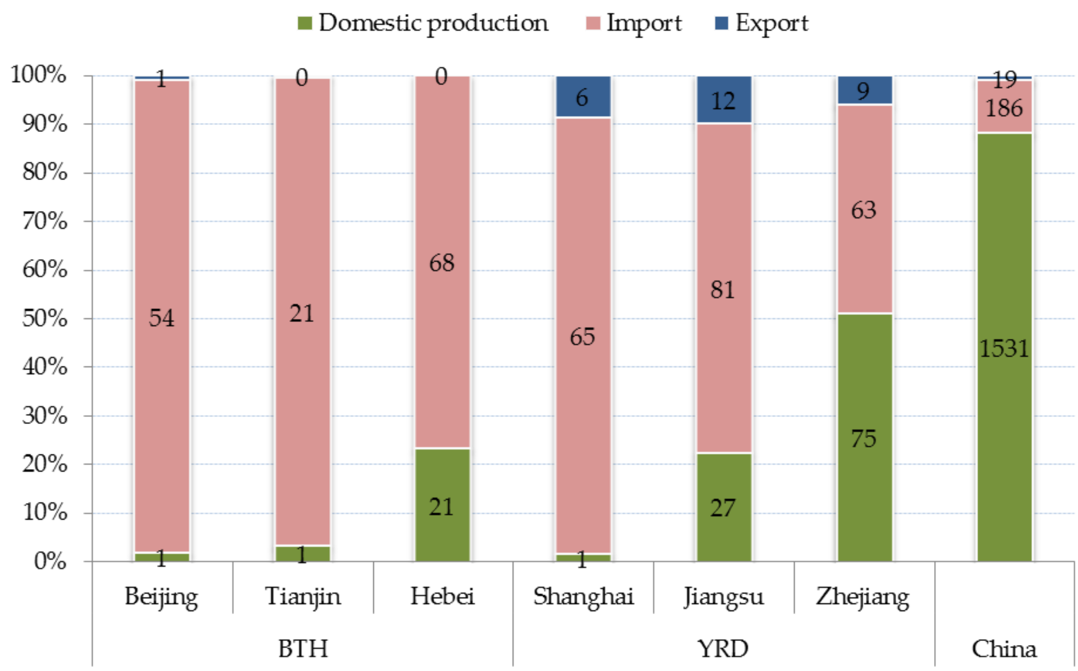
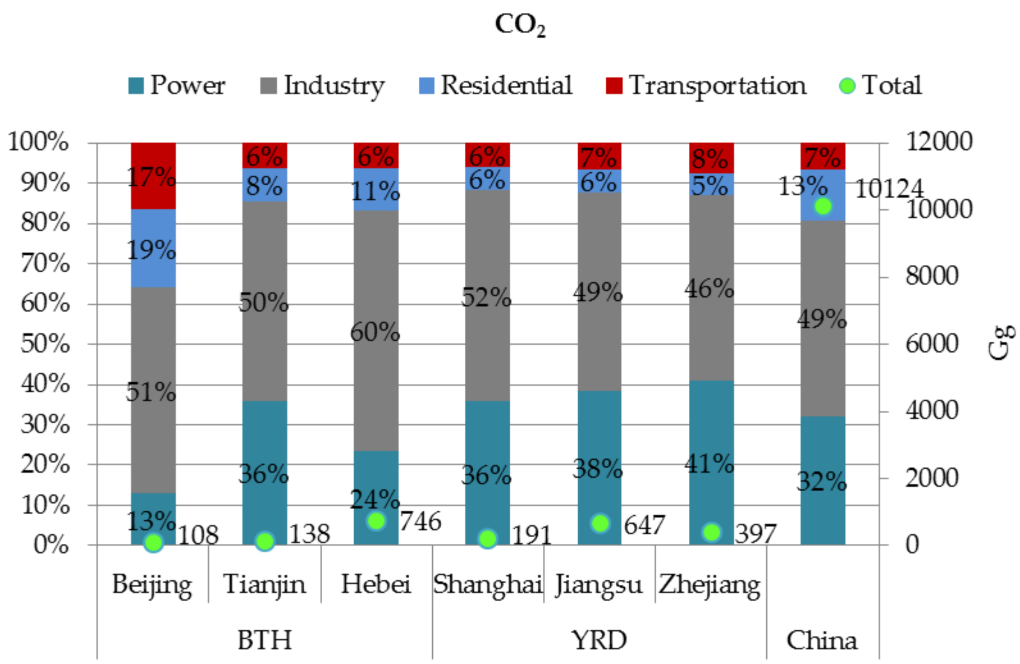
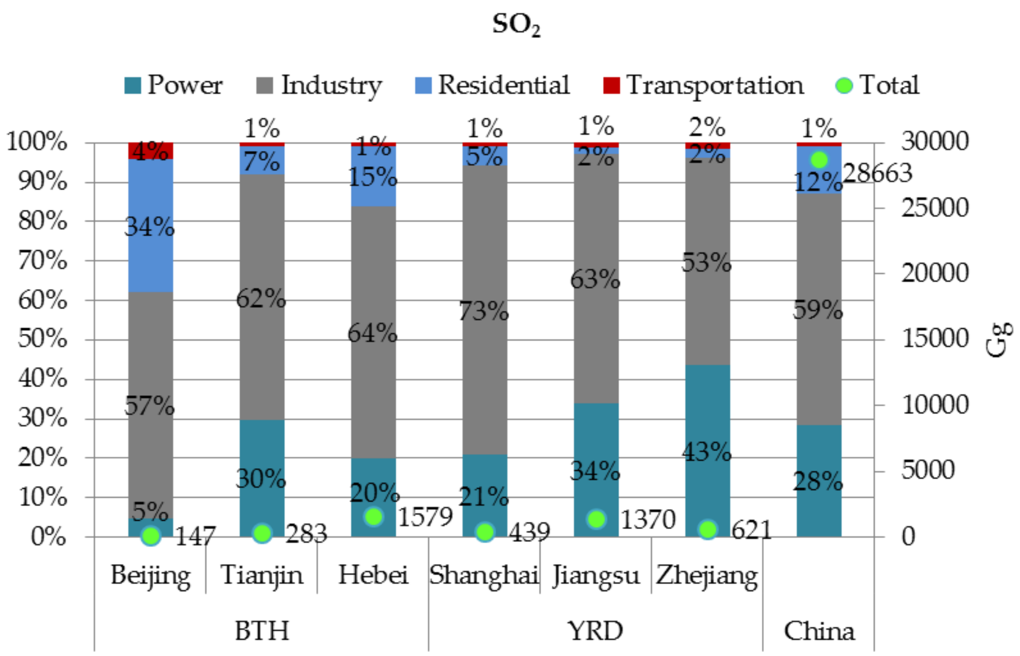


Figure A.6 Power exchange (TWh/yr) of study regions and China in 2015 (data source: China Energy Statistical Yearbook 2016 [175]).


CO2
Power
Industry
Residential
Transportation
Total
Gg
Beijing
Tianjin
Hebei
Shanghai
Jiangsu
Zhejiang
BTH
YRD
China
10124


SO2
Power
Industry
Residential
Transportation
Total
Gg
Beijing
Tianjin
Hebei
Shanghai
Jiangsu
Zhejiang
BTH
YRD
China
28663

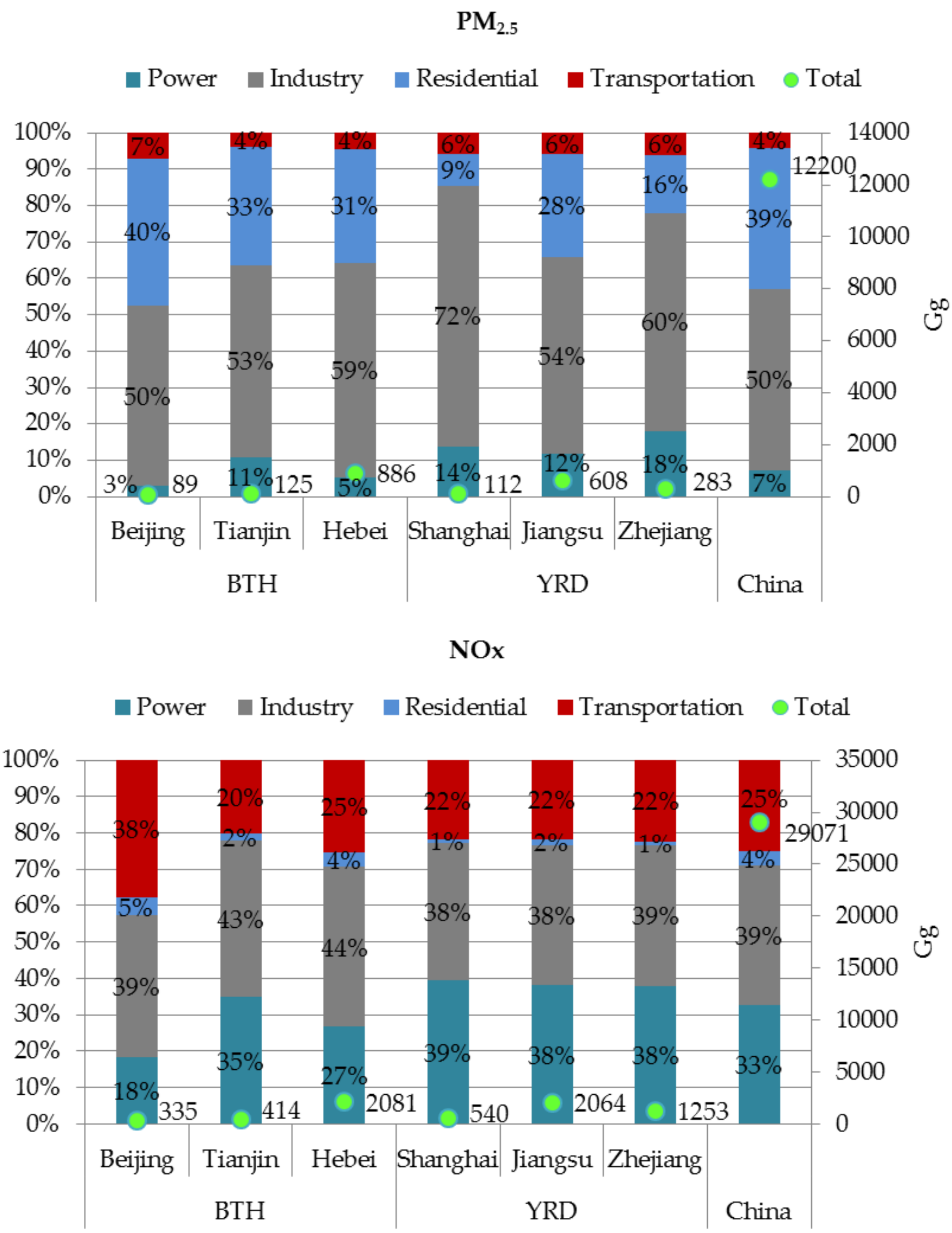


Figure A.7 Main emissions of study regions and China in 2010 by sector (data source: MEIC (Multi-resolution Emission Inventory for China) database [190]).

Appendix B China's Energy Dependency and Its Projections

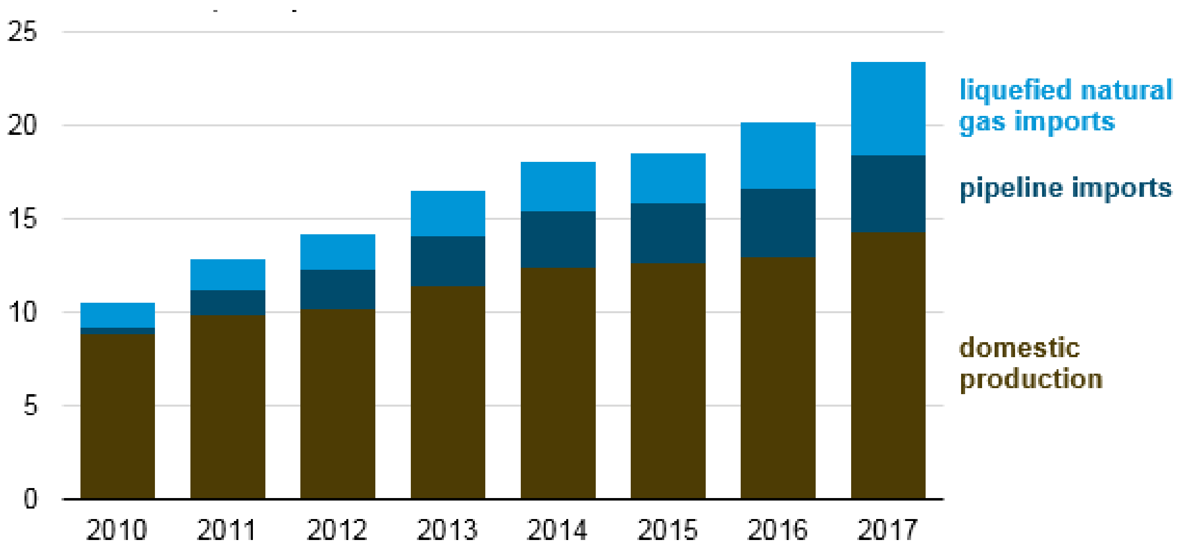


Figure B.1 China's natural gas supply from 2010 to 2017 (unit: Bcf/D) according to [13]

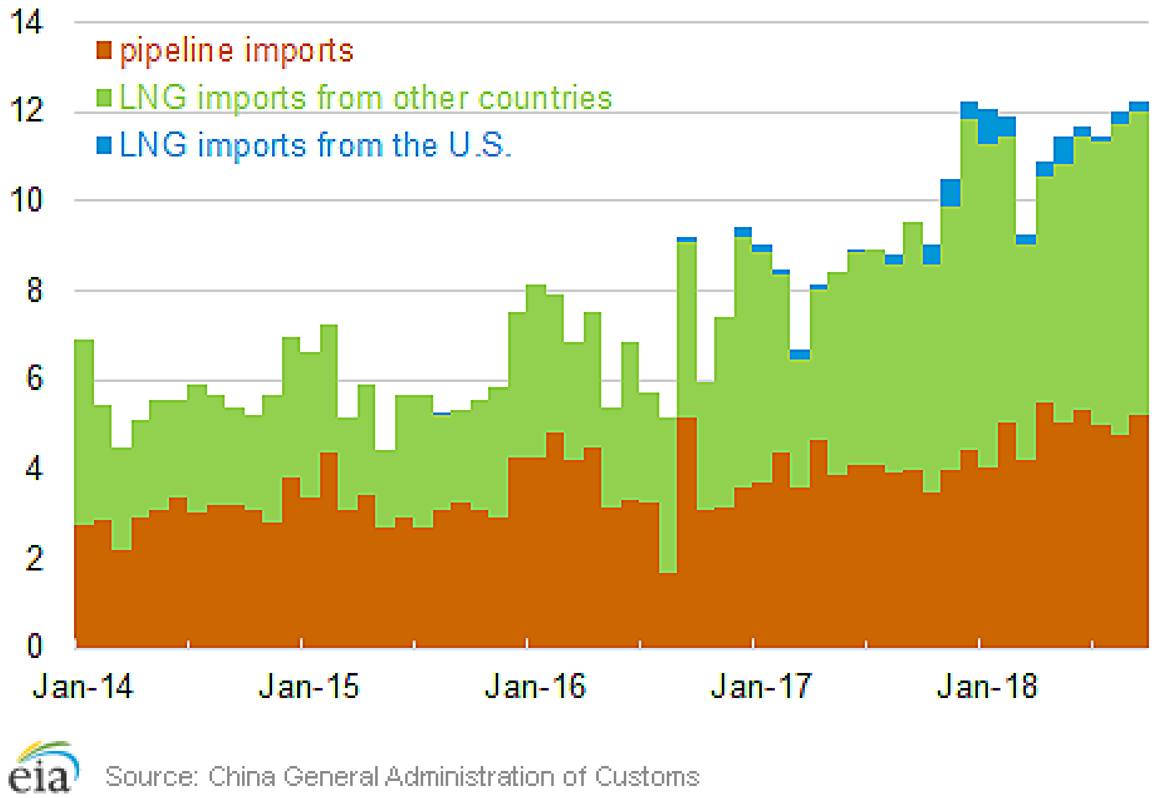


Figure B.2 China's natural gas imports by pipeline and as LNG from 2014 to 2018 (unit: Bcf/D) [13].

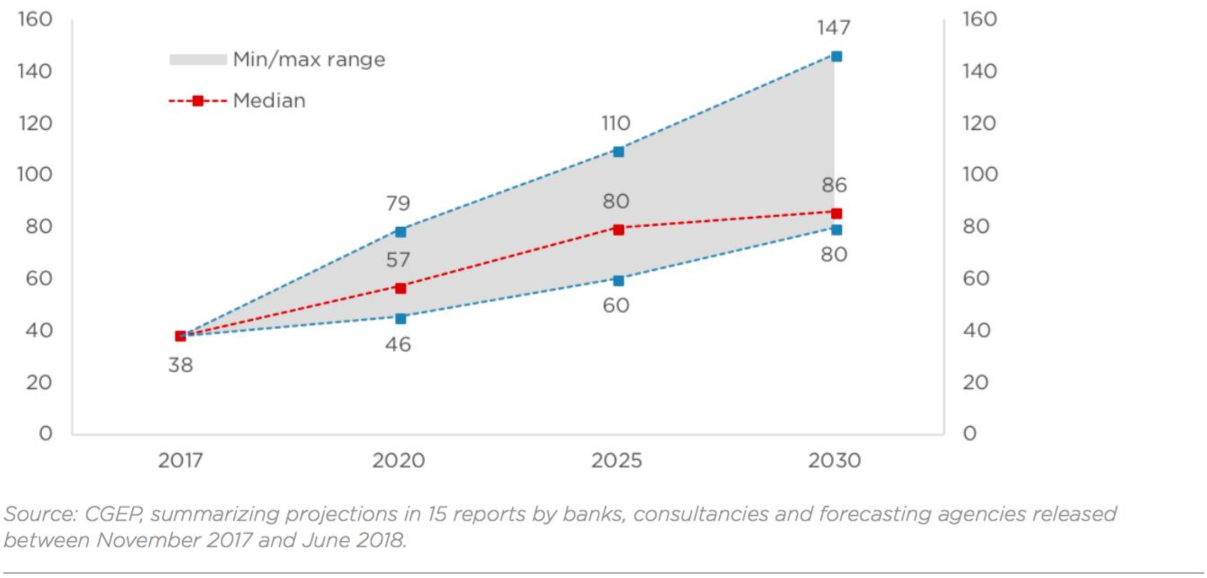


Figure B.3 LNG demand projections for China (unit: mtpa) [102].

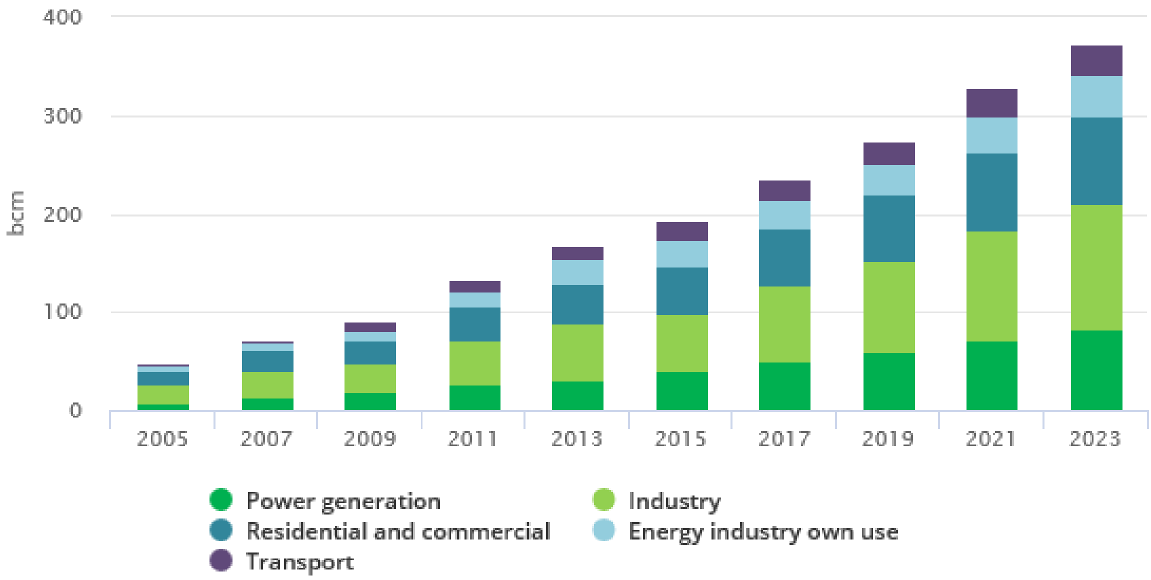


Figure B.4 Natural gas consumption by sector in China from 2005 to 2023 according to [38].

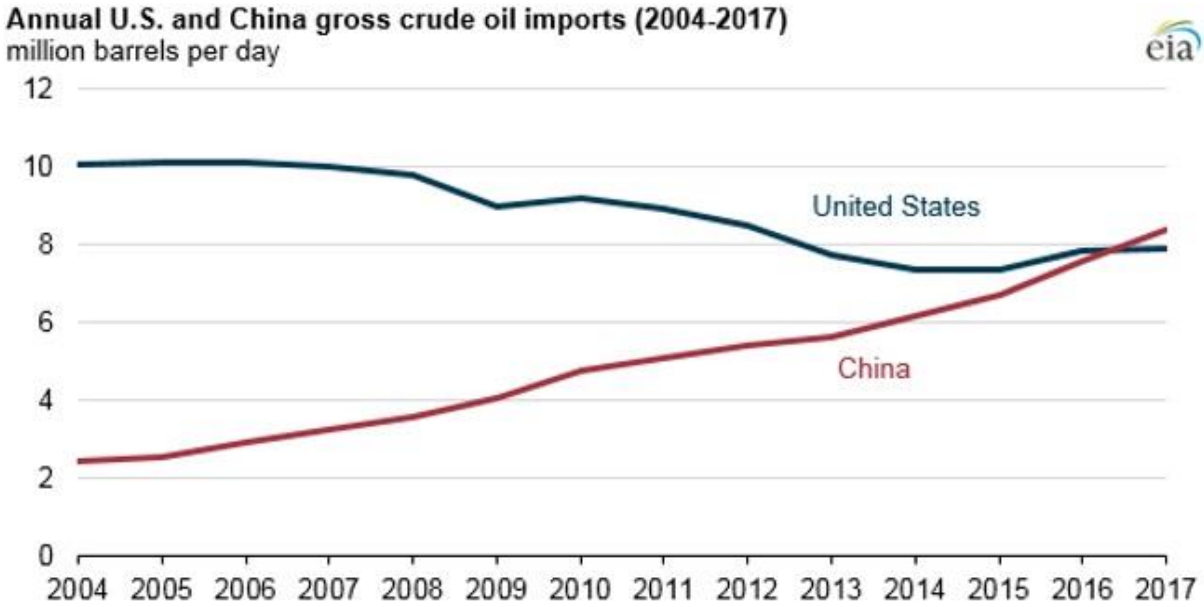


Figure B.5 Annual gross crude oil imports of China and U.S. from 2004 to 2017 (unit: MMbbl) [14].

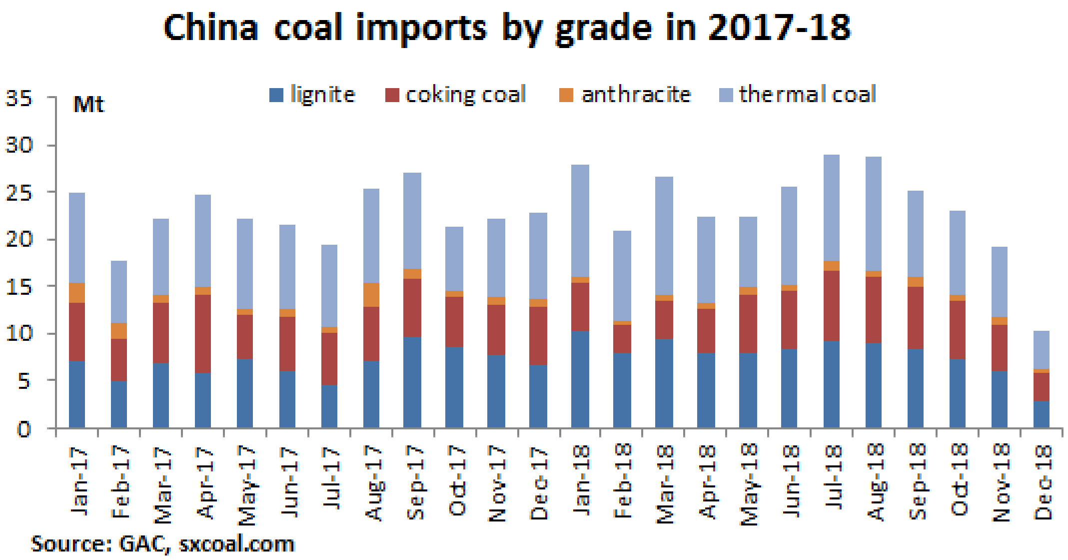


Figure B.6 China’s coal imports by grade from 2017 to 2018 [200].

Appendix C Input Data of Costs and Efficiency Assumptions, Final Energy Demand of CPS in Regional Energy System Model of Two Study Regions

Table C.1 Input data of costs for regional energy system model of two study regions (Unit: € 2015)[11].

Attribute	Sector	Technology	Substance	Unit	2015	2020	2025	2030	2035	2040	2045	2050
Specific CO_2 cost	CHP Plants	CHP Coal	CO_2	€/t	0	19	42	66	89	113	136	160
Specific CO_2 cost	CHP Plants	CHP Gas	CO_2	€/t	0	19	42	66	89	113	136	160
Specific CO_2 cost	CHP Plants	CHP Lignite	CO_2	€/t	0	19	42	66	89	113	136	160
Specific CO_2 cost	CHP Plants	CHP Oil	CO_2	€/t	0	19	42	66	89	113	136	160
Specific CO_2 cost	Industry CHP	CHP Coal	CO_2	€/t	0	19	42	66	89	113	136	160
Specific CO_2 cost	Industry CHP	CHP Gas	CO_2	€/t	0	19	42	66	89	113	136	160
Specific CO_2 cost	Industry CHP	CHP Lignite	CO_2	€/t	0	19	42	66	89	113	136	160
Specific CO_2 cost	Industry CHP	CHP Oil	CO_2	€/t	0	19	42	66	89	113	136	160
Specific CO_2 cost	Residential CHP	CHP Coal	CO_2	€/t	0	11	21	31	41	50	60	70
Specific CO_2 cost	Residential CHP	CHP Gas	CO_2	€/t	0	11	21	31	41	50	60	70
Specific CO_2 cost	Residential CHP	CHP Lignite	CO_2	€/t	0	11	21	31	41	50	60	70
Specific CO_2 cost	Residential CHP	CHP Oil	CO_2	€/t	0	11	21	31	41	50	60	70
Specific CO_2 cost	Oth.Sect. CHP	CHP Coal	CO_2	€/t	0	11	21	31	41	50	60	70
Specific CO_2 cost	Oth.Sect. CHP	CHP Gas	CO_2	€/t	0	11	21	31	41	50	60	70
Specific CO_2 cost	Oth.Sect. CHP	CHP Lignite	CO_2	€/t	0	11	21	31	41	50	60	70
Specific CO_2 cost	Oth.Sect. CHP	CHP Oil	CO_2	€/t	0	11	21	31	41	50	60	70
Specific CO_2 cost	Power plants	Coal power plant	CO_2	€/t	0	19	42	66	89	113	136	160
Specific CO_2 cost	Power plants	Diesel generator	CO_2	€/t	0	19	42	66	89	113	136	160
Specific CO_2 cost	Power plants	Gas power plant	CO_2	€/t	0	19	42	66	89	113	136	160
Specific CO_2 cost	Power plants	Lignite power plant	CO_2	€/t	0	19	42	66	89	113	136	160

[11] Note: Oth.Sect. refers to the services and commerce sector, the same below.

Specific CO_2 cost	Power plants	Oil power plant	CO_2	€/t	0	19	42	66	89	113	136	160
Specific fixed O&M cost	CHP Plants	CHP Biomass and waste	Electricity	€/kW/a	63	63	62	61	61	61	61	61
Specific fixed O&M cost	CHP Plants	CHP Coal	Electricity	€/kW/a	34	34	34	34	34	34	34	34
Specific fixed O&M cost	CHP Plants	CHP Gas	Electricity	€/kW/a	23	23	23	23	23	23	23	23
Specific fixed O&M cost	CHP Plants	CHP Geothermal	Electricity	€/kW/a	232	197	177	157	144	131	123	114
Specific fixed O&M cost	CHP Plants	CHP Lignite	Electricity	€/kW/a	34	34	34	34	34	34	34	34
Specific fixed O&M cost	CHP Plants	CHP Oil	Electricity	€/kW/a	35	35	34	33	33	32	31	31
Specific fixed O&M cost	Hydrogen production	Electrolysis	Hydrogen	€/kW/a	25	22	19	17	14	13	11	10
Specific fixed O&M cost	Industry CHP	CHP Biomass and waste	Industry electricity consumption	€/kW/a	63	63	62	61	61	61	61	61
Specific fixed O&M cost	Industry CHP	CHP Coal	Industry electricity consumption	€/kW/a	34	34	34	34	34	34	34	34
Specific fixed O&M cost	Industry CHP	CHP Fuel cell	Industry electricity consumption	€/kW/a	135	135	101	68	68	68	43	30
Specific fixed O&M cost	Industry CHP	CHP Gas	Industry electricity consumption	€/kW/a	23	23	23	23	23	23	23	23
Specific fixed O&M cost	Industry CHP	CHP Geothermal	Industry electricity consumption	€/kW/a	232	197	177	157	144	131	123	114
Specific fixed O&M cost	Industry CHP	CHP Lignite	Industry electricity consumption	€/kW/a	34	34	34	34	34	34	34	34
Specific fixed O&M cost	Industry CHP	CHP Oil	Industry electricity consumption	€/kW/a	68	66	65	64	62	61	59	58
Specific fixed O&M cost	Residential CHP	CHP Biomass and waste	Residential electricity consumption	€/kW/a	126	126	125	124	123	121	119	117
Specific fixed O&M cost	Residential CHP	CHP Coal	Residential electricity consumption	€/kW/a	34	34	34	34	34	34	34	34
Specific fixed O&M cost	Residential CHP	CHP Fuel cell	Residential electricity consumption	€/kW/a	135	135	101	68	68	68	43	30
Specific fixed O&M cost	Residential CHP	CHP Gas	Residential electricity consumption	€/kW/a	23	23	23	23	23	23	23	23
Specific fixed O&M cost	Residential CHP	CHP Geothermal	Residential electricity consumption	€/kW/a	232	197	177	157	144	131	123	114
Specific fixed O&M cost	Residential CHP	CHP Lignite	Residential electricity consumption	€/kW/a	34	34	34	34	34	34	34	34
Specific fixed O&M cost	Residential CHP	CHP Oil	Residential electricity consumption	€/kW/a	68	66	65	64	62	61	59	58
Specific fixed O&M cost	Oth.Sect. CHP	CHP Biomass and waste	Other sectors electricity consumption	€/kW/a	126	126	125	124	123	121	119	117
Specific fixed O&M cost	Oth.Sect. CHP	CHP Coal	Other sectors electricity consumption	€/kW/a	34	34	34	34	34	34	34	34
Specific fixed O&M cost	Oth.Sect. CHP	CHP Fuel cell	Other sectors electricity	€/kW/a	135	135	101	68	68	68	43	30

			consumption									
Specific fixed O&M cost	Oth.Sect. CHP	CHP Gas	Other sectors electricity consumption	€/kW/a	23	23	23	23	23	23	23	23
Specific fixed O&M cost	Oth.Sect. CHP	CHP Geothermal	Other sectors electricity consumption	€/kW/a	232	197	177	157	144	131	123	114
Specific fixed O&M cost	Oth.Sect. CHP	CHP Lignite	Other sectors electricity consumption	€/kW/a	34	34	34	34	34	34	34	34
Specific fixed O&M cost	Oth.Sect. CHP	CHP Oil	Other sectors electricity consumption	€/kW/a	68	66	65	64	62	61	59	58
Specific fixed O&M cost	Power plants	Biomass and waste power plant	Electricity	€/kW/a	50	50	50	50	49	48	47	47
Specific fixed O&M cost	Power plants	Coal power plant	Electricity	€/kW/a	27	27	27	27	27	27	27	27
Specific fixed O&M cost	Power plants	Diesel generator	Electricity	€/kW/a	99	99	99	99	99	99	99	99
Specific fixed O&M cost	Power plants	Gas power plant	Electricity	€/kW/a	21	18	18	18	18	18	23	34
Specific fixed O&M cost	Power plants	Geothermal power plant	Electricity	€/kW/a	217	41	39	38	37	37	37	36
Specific fixed O&M cost	Power plants	Hydro large	Electricity	€/kW/a	35	36	37	37	38	38	39	39
Specific fixed O&M cost	Power plants	Hydro small	Electricity	€/kW/a	36	36	37	38	38	39	39	39
Specific fixed O&M cost	Power plants	Lignite power plant	Electricity	€/kW/a	30	30	30	30	30	30	30	30
Specific fixed O&M cost	Power plants	Nuclear power plant	Electricity	€/kW/a	77	108	107	106	101	96	96	96
Specific fixed O&M cost	Power plants	Ocean energy power plant	Electricity	€/kW/a	178	171	141	112	96	79	67	57
Specific fixed O&M cost	Power plants	Oil power plant	Electricity	€/kW/a	49	48	47	46	45	44	43	42
Specific fixed O&M cost	Power plants	PV power plant	Electricity	€/kW/a	15	11	10	8	7	6	6	5
Specific fixed O&M cost	Power plants	Solar thermal power plant	Electricity	€/kW/a	176	153	132	112	103	94	88	85
Specific fixed O&M cost	Power plants	Wind turbine offshore	Electricity	€/kW/a	135	122	107	93	87	82	76	72
Specific fixed O&M cost	Power plants	Wind turbine onshore	Electricity	€/kW/a	28	27	27	27	26	26	26	26
Specific investment cost	CHP Plants	CHP Biomass and waste	Electricity	€/kW	1665	1665	1643	1620	1620	1620	1620	1620
Specific investment cost	CHP Plants	CHP Coal	Electricity	€/kW	788	788	788	788	788	788	788	788
Specific investment cost	CHP Plants	CHP Gas	Electricity	€/kW	495	495	495	495	495	495	495	495
Specific investment cost	CHP Plants	CHP Geothermal	Electricity	€/kW	11879	10071	9038	8005	7360	6714	6262	5810
Specific investment cost	CHP Plants	CHP Lignite	Electricity	€/kW	788	788	788	788	788	788	788	788
Specific investment cost	CHP Plants	CHP Oil	Electricity	€/kW	1183	1158	1135	1112	1088	1064	1041	1017

Specific investment cost	Hydrogen production	Electrolysis	Hydrogen	€/kW	1238	1102	966	829	693	632	571	510
Specific investment cost	Industry CHP	CHP Biomass and waste	Industry electricity consumption	€/kW	1665	1665	1643	1620	1620	1620	1620	1620
Specific investment cost	Industry CHP	CHP Coal	Industry electricity consumption	€/kW	788	788	788	788	788	788	788	788
Specific investment cost	Industry CHP	CHP Fuel cell	Industry electricity consumption	€/kW	4500	4500	3375	2250	2250	2250	1421	1007
Specific investment cost	Industry CHP	CHP Gas	Industry electricity consumption	€/kW	495	495	495	495	495	495	495	495
Specific investment cost	Industry CHP	CHP Geothermal	Industry electricity consumption	€/kW	11879	10071	9038	8005	7360	6714	6262	5810
Specific investment cost	Industry CHP	CHP Lignite	Industry electricity consumption	€/kW	788	788	788	788	788	788	788	788
Specific investment cost	Industry CHP	CHP Oil	Industry electricity consumption	€/kW	1183	1158	1135	1112	1088	1064	1041	1017
Specific investment cost	Residential CHP	CHP Biomass and waste	Residential electricity consumption	€/kW	3330	3330	3308	3285	3240	3195	3150	3105
Specific investment cost	Residential CHP	CHP Coal	Residential electricity consumption	€/kW	788	788	788	788	788	788	788	788
Specific investment cost	Residential CHP	CHP Fuel cell	Residential electricity consumption	€/kW	4500	4500	3375	2250	2250	2250	1421	1007
Specific investment cost	Residential CHP	CHP Gas	Residential electricity consumption	€/kW	495	495	495	495	495	495	495	495
Specific investment cost	Residential CHP	CHP Geothermal	Residential electricity consumption	€/kW	11879	10071	9038	8005	7360	6714	6262	5810
Specific investment cost	Residential CHP	CHP Lignite	Residential electricity consumption	€/kW	788	788	788	788	788	788	788	788
Specific investment cost	Residential CHP	CHP Oil	Residential electricity consumption	€/kW	1182	1158	1135	1112	1088	1064	1041	1017
Specific investment cost	Oth.Sect. CHP	CHP Biomass and waste	Other sectors electricity consumption	€/kW	3330	3330	3308	3285	3240	3195	3150	3105
Specific investment cost	Oth.Sect. CHP	CHP Coal	Other sectors electricity consumption	€/kW	788	788	788	788	788	788	788	788
Specific investment cost	Oth.Sect. CHP	CHP Fuel cell	Other sectors electricity consumption	€/kW	4500	4500	3375	2250	2250	2250	1421	1007
Specific investment cost	Oth.Sect. CHP	CHP Gas	Other sectors electricity consumption	€/kW	495	495	495	495	495	495	495	495
Specific investment cost	Oth.Sect. CHP	CHP Geothermal	Other sectors electricity consumption	€/kW	11879	10071	9038	8005	7360	6714	6262	5810
Specific investment cost	Oth.Sect. CHP	CHP Lignite	Other sectors electricity consumption	€/kW	788	788	788	788	788	788	788	788
Specific investment cost	Oth.Sect. CHP	CHP Oil	Other sectors	€/kW	1182	1158	1135	1112	1088	1064	1041	1017

			electricity consumption									
Specific investment cost	Power plants	Biomass and waste power plant	Electricity	€/kW	1440	1440	1440	1440	1418	1395	1375	1357
Specific investment cost	Power plants	Coal power plant	Electricity	€/kW	630	630	630	630	630	630	630	630
Specific investment cost	Power plants	Diesel generator	Electricity	€/kW	810	810	810	810	810	810	810	810
Specific investment cost	Power plants	Gas power plant	Electricity	€/kW	375	315	315	315	315	315	410	600
Specific investment cost	Power plants	Geothermal power plant	Electricity	€/kW	11104	2070	2003	1935	1913	1890	1872	1859
Specific investment cost	Power plants	Hydro large	Electricity	€/kW	1440	1485	1508	1530	1553	1575	1595	1613
Specific investment cost	Power plants	Hydro small	Electricity	€/kW	1800	1800	1845	1890	1913	1935	1955	1973
Specific investment cost	Power plants	Lignite power plant	Electricity	€/kW	693	693	693	693	693	693	693	693
Specific investment cost	Power plants	Nuclear power plant	Electricity	€/kW	1800	2520	2498	2475	2363	2250	2250	2250
Specific investment cost	Power plants	Ocean energy power plant	Electricity	€/kW	5940	5715	4725	3735	3195	2655	2223	1921
Specific investment cost	Power plants	Oil power plant	Electricity	€/kW	853	837	820	803	786	770	753	736
Specific investment cost	Power plants	PV power plant	Electricity	€/kW	1170	880	770	660	580	500	460	420
Specific investment cost	Power plants	Solar thermal power plant	Electricity	€/kW	4410	3825	3308	2790	2565	2340	2205	2124
Specific investment cost	Power plants	Wind turbine offshore	Electricity	€/kW	3641	3285	2903	2520	2363	2205	2063	1936
Specific investment cost	Power plants	Wind turbine onshore	Electricity	€/kW	1125	1080	1071	1062	1053	1044	1036	1029
Specific investment cost	Industry heat plants	Electric heat pump	Industry heat consumption	€/kW	1500	1455	1411	1369	1328	1288	1249	1212
Specific investment cost	Industry heat plants	Solar heat plant	Industry heat consumption	€/kW	714	684	628	612	583	540	499	460
Specific investment cost	Industry heat plants	Geothermal heat plant	Industry heat consumption	€/kW	2000	1900	1800	1700	1603	1508	1417	1328
Specific investment cost	Industry heat plants	Biomass and waste heat plant	Industry heat consumption	€/kW	500	485	470	456	443	429	416	404
Specific investment cost	Residential heat plants	Electric heat pump	Residential heat consumption	€/kW	1500	1455	1411	1369	1328	1288	1249	1212
Specific investment cost	Residential heat plants	Solar heat plant	Residential heat consumption	€/kW	107	107	107	107	107	107	107	107
Specific investment cost	Residential heat plants	Geothermal heat plant	Residential heat consumption	€/kW	2000	1900	1800	1700	1603	1508	1417	1328
Specific investment cost	Residential heat plants	Biomass and waste heat plant	Residential heat consumption	€/kW	100	100	100	100	100	100	100	100
Specific investment cost	Oth.Sect. heat plants	Electric heat pump	Other sectors heat consumption	€/kW	1500	1455	1411	1369	1328	1288	1249	1212
Specific investment cost	Oth.Sect. heat plants	Solar heat plant	Other sectors heat consumption	€/kW	107	107	107	107	107	107	107	107
Specific investment cost	Oth.Sect. heat plants	Geothermal heat plant	Other sectors heat consumption	€/kW	2000	1900	1800	1700	1603	1508	1417	1328

Specific investment cost	Oth.Sect. heat plants	Biomass and waste heat plant	Other sectors heat consumption	€/kW	100	100	100	100	100	100	100	100
Specific investment cost	Heat plants	Solar heat plant	District heat	€/kW	814	780	715	698	664	616	569	524
Specific investment cost	Heat plants	Geothermal heat plant	District heat	€/kW	2000	1900	1800	1700	1603	1508	1417	1328
Specific investment cost	Heat plants	Biomass and waste heat plant	District heat	€/kW	500	485	470	456	443	429	416	404
Energy carrier cost			Biomass and waste	€/GJ	5	6	8	10	10	10	10	10
Energy carrier cost			Crude oil	€/GJ	8	11	14	19	17	22	27	32
Energy carrier cost			Electricity import	€/kWh	0.05	0.05	0.052	0.054	0.055	0.056	0.055	0.055
Energy carrier cost			Geothermal energy	€/GJ	0	0	0	0	0	0	0	0
Energy carrier cost			Hard coal	€/GJ	3	3	3	4	4	4	4	5
Energy carrier cost			Hydro power	€/GJ	0	0	0	0	0	0	0	0
Energy carrier cost			Lignite	€/GJ	3	3	3	4	4	4	4	5
Energy carrier cost			Natural gas	€/GJ	8	9	9	9	9	9	10	10
Energy carrier cost			Nuclear energy	€/GJ	1	1	1	1	1	2	2	2
Energy carrier cost			Ocean energy	€/GJ	0	0	0	0	0	0	0	0
Energy carrier cost			Solar radiation	€/GJ	0	0	0	0	0	0	0	0
Energy carrier cost			Wind energy	€/GJ	0	0	0	0	0	0	0	0
Energy carrier cost			Synfuel_import	€/GJ	0	0	0	0	0	0	0	0
Energy carrier cost	Residential		Gas	€/GJ	8	9	9	9	9	9	10	10
Energy carrier cost	Residential		District heat	€/GJ	0	0	0	0	0	0	0	0
Energy carrier cost	Residential		Lignite	€/GJ	3	3	3	4	4	4	4	5

Table C.2 Input data of efficiency for regional energy system model of BTH region [12].

Sector	Technology	Substance	Attribute	Unit	Scenario	2005	2007	2009	2010	2012	2013	2015	2020	2025	2030	2035	2040	2045	2050
CHP Plants	CHP Biomass and waste	Biomass and waste*District heat	Fuel Efficiency	PJ/PJ	CPS	0.11	0.11	0.11	0.11	0.11	0.11	0.12	0.12	0.13	0.13	0.14	0.14	0.15	0.15
CHP Plants	CHP Coal	Hard coal*District heat	Fuel Efficiency	PJ/PJ	CPS	0.39	0.37	0.26	0.24	0.20	0.20	0.21	0.21	0.22	0.23	0.23	0.24	0.24	0.24
CHP Plants	CHP Gas	Gas*District heat	Fuel Efficiency	PJ/PJ	CPS	0.44	0.41	0.28	0.27	0.22	0.22	0.25	0.27	0.29	0.30	0.30	0.30	0.30	0.30
CHP Plants	CHP Geothermal	Geothermal energy*District heat	Fuel Efficiency	PJ/PJ	CPS	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40
CHP Plants	CHP Lignite	Lignite*District heat	Fuel Efficiency	PJ/PJ	CPS	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.19	0.19	0.19	0.19
CHP Plants	CHP Oil	Fuel Oil*District heat	Fuel Efficiency	PJ/PJ	CPS	0.08	0.08	0.08	0.08	0.08	0.08	0.09	0.10	0.12	0.13	0.15	0.17	0.18	0.20
Industry CHP	CHP Biomass and waste	Biomass and waste*Heat	Fuel Efficiency	PJ/PJ	CPS	0.11	0.11	0.11	0.11	0.11	0.11	0.12	0.14	0.16	0.19	0.23	0.28	0.38	0.56
Industry CHP	CHP Coal	Hard coal*Heat	Fuel Efficiency	PJ/PJ	CPS	0.45	0.43	0.31	0.29	0.25	0.26	0.21	0.23	0.24	0.26	0.27	0.29	0.30	0.31
Industry CHP	CHP Fuel cell	Hydrogen*Heat	Fuel Efficiency	PJ/PJ	CPS	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.66
Industry CHP	CHP Gas	Gas*Heat	Fuel Efficiency	PJ/PJ	CPS	0.41	0.37	0.27	0.25	0.22	0.21	0.26	0.29	0.31	0.33	0.35	0.37	0.38	0.40
Industry CHP	CHP Geothermal	Geothermal energy*Heat	Fuel Efficiency	PJ/PJ	CPS	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50
Industry CHP	CHP Oil	Fuel Oil*Heat	Fuel Efficiency	PJ/PJ	CPS	0.08	0.08	0.08	0.08	0.08	0.08	0.10	0.13	0.17	0.21	0.26	0.33	0.42	0.54
Industry CHP	CHP Lignite	Lignite*Heat	Fuel Efficiency	PJ/PJ	CPS	0.20	0.20	0.20	0.20	0.20	0.20	0.21	0.23	0.25	0.28	0.31	0.36	0.43	0.53
Industry heat production	Biomass burner	Biomass and waste*Heat	Fuel Efficiency	PJ/PJ	CPS	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.76	0.77	0.78	0.80	0.81	0.83	0.84
Industry heat production	Coal burner	Hard coal*Heat	Fuel Efficiency	PJ/PJ	CPS	0.81	0.81	0.81	0.81	0.81	0.81	0.81	0.82	0.82	0.83	0.83	0.84	0.84	0.85
Industry heat production	District heat	District heat*Heat	Fuel Efficiency	PJ/PJ	CPS	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Industry heat production	Electric heater	Industry electricity consumption*Heat	Fuel Efficiency	PJ/PJ	CPS	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Industry heat production	Gas burner	Gas*Heat	Fuel Efficiency	PJ/PJ	CPS	0.82	0.82	0.82	0.82	0.82	0.82	0.84	0.85	0.87	0.89	0.91	0.92	0.94	0.95
Industry heat production	Gasoline/Diesel /Kerosene burner	Gasoline/Diesel/ Kerosene*Heat	Fuel Efficiency	PJ/PJ	CPS	0.80	0.80	0.80	0.80	0.80	0.80	0.81	0.82	0.83	0.84	0.85	0.86	0.87	0.88

[12] Note: It does not account for efficiency of the engine in transport sector and the efficiency for all other renewable energy power generation (except for geothermal) is set to 1 for both regions.

Industry heat production	Geothermal	Geothermal energy*Heat	Fuel Efficiency	PJ/PJ	CPS	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Industry heat production	Oil burner	Fuel Oil*Heat	Fuel Efficiency	PJ/PJ	CPS	0.80	0.80	0.80	0.80	0.80	0.80	0.81	0.81	0.82	0.83	0.83	0.84	0.84	0.85
Industry heat production	Solar collector	Solar radiation*Heat	Fuel Efficiency	PJ/PJ	CPS	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Industry heat production	Lignite burner	Lignite*Heat	Fuel Efficiency	PJ/PJ	CPS	0.81	0.81	0.81	0.81	0.81	0.81	0.81	0.82	0.82	0.83	0.83	0.84	0.84	0.85
Residential CHP	CHP Biomass and waste	Biomass and waste*Heat	Fuel Efficiency	PJ/PJ	CPS	0.15	0.15	0.15	0.15	0.15	0.15	0.16	0.18	0.20	0.22	0.26	0.31	0.40	0.56
Residential CHP	CHP Coal	Hard coal*Heat	Fuel Efficiency	PJ/PJ	CPS	0.16	0.16	0.16	0.16	0.16	0.16	0.18	0.20	0.22	0.25	0.29	0.35	0.42	0.55
Residential CHP	CHP Fuel cell	Hydrogen*Heat	Fuel Efficiency	PJ/PJ	CPS	0.21	0.21	0.21	0.21	0.21	0.21	0.23	0.25	0.28	0.32	0.36	0.43	0.52	0.66
Residential CHP	CHP Gas	Gas*Heat	Fuel Efficiency	PJ/PJ	CPS	0.33	0.33	0.33	0.33	0.33	0.33	0.34	0.35	0.36	0.37	0.38	0.39	0.40	0.42
Residential CHP	CHP Geothermal	Geothermal energy*Heat	Fuel Efficiency	PJ/PJ	CPS	0.20	0.20	0.20	0.20	0.20	0.20	0.22	0.24	0.26	0.29	0.32	0.36	0.42	0.50
Residential CHP	CHP Oil	Fuel Oil*Heat	Fuel Efficiency	PJ/PJ	CPS	0.20	0.20	0.20	0.20	0.20	0.20	0.22	0.24	0.27	0.30	0.34	0.39	0.45	0.54
Residential CHP	CHP Lignite	Lignite*Heat	Fuel Efficiency	PJ/PJ	CPS	0.25	0.25	0.25	0.25	0.25	0.25	0.27	0.28	0.30	0.32	0.35	0.39	0.45	0.53
Residential heat production	Biomass burner	Biomass and waste*Heat	Fuel Efficiency	PJ/PJ	CPS	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.76	0.78	0.79	0.80	0.81	0.83	0.84
Residential heat production	Charcoal burner	Charcoal*Heat	Fuel Efficiency	PJ/PJ	CPS	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.76	0.78	0.79	0.81	0.82	0.84	0.85
Residential heat production	Coal burner	Hard coal*Heat	Fuel Efficiency	PJ/PJ	CPS	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
Residential heat production	District heat	District heat*Heat	Fuel Efficiency	PJ/PJ	CPS	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Residential heat production	Electric heater	Residential electricity consumption*Heat	Fuel Efficiency	PJ/PJ	CPS	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Residential heat production	Gas burner	Gas*Heat	Fuel Efficiency	PJ/PJ	CPS	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.88	0.89	0.90	0.91	0.93	0.94	0.95
Residential heat production	Gasoline/Diesel /Kerosene burner	Gasoline/Diesel/ Kerosene*Heat	Fuel Efficiency	PJ/PJ	CPS	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.86	0.86	0.86	0.87	0.87	0.88	0.88
Residential heat production	Geothermal	Geothermal energy*Heat	Fuel Efficiency	PJ/PJ	CPS	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Residential heat production	Oil burner	Fuel Oil*Heat	Fuel Efficiency	PJ/PJ	CPS	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
Residential heat production	Solar collector	Solar radiation*Heat	Fuel Efficiency	PJ/PJ	CPS	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Residential heat production	Lignite burner	Lignite*Heat	Fuel Efficiency	PJ/PJ	CPS	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
Oth.Sect. CHP	CHP Biomass and waste	Biomass and waste*Heat	Fuel Efficiency	PJ/PJ	CPS	0.15	0.15	0.15	0.15	0.15	0.15	0.16	0.18	0.20	0.22	0.26	0.31	0.40	0.56
Oth.Sect. CHP	CHP Coal	Hard coal*Heat	Fuel	PJ/PJ	CPS	0.16	0.16	0.16	0.16	0.16	0.16	0.18	0.20	0.22	0.25	0.29	0.35	0.42	0.55

			Efficiency																
Oth.Sect. CHP	CHP Fuel cell	Hydrogen*Heat	Fuel Efficiency	PJ/PJ	CPS	0.21	0.21	0.21	0.21	0.21	0.21	0.23	0.25	0.28	0.32	0.36	0.43	0.52	0.66
Oth.Sect. CHP	CHP Gas	Gas*Heat	Fuel Efficiency	PJ/PJ	CPS	0.33	0.33	0.33	0.33	0.33	0.33	0.34	0.35	0.36	0.37	0.38	0.39	0.40	0.42
Oth.Sect. CHP	CHP Geothermal	Geothermal energy*Heat	Fuel Efficiency	PJ/PJ	CPS	0.13	0.13	0.13	0.13	0.13	0.13	0.14	0.16	0.18	0.20	0.24	0.29	0.37	0.50
Oth.Sect. CHP	CHP Oil	Fuel Oil*Heat	Fuel Efficiency	PJ/PJ	CPS	0.20	0.20	0.20	0.20	0.20	0.20	0.22	0.24	0.27	0.30	0.34	0.39	0.45	0.54
Oth.Sect. CHP	CHP Lignite	Lignite*Heat	Fuel Efficiency	PJ/PJ	CPS	0.25	0.25	0.25	0.25	0.25	0.25	0.27	0.28	0.30	0.32	0.35	0.39	0.45	0.53
Oth.Sect. heat production	Biomass burner	Biomass and waste*Heat	Fuel Efficiency	PJ/PJ	CPS	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.76	0.78	0.79	0.80	0.81	0.83	0.84
Oth.Sect. heat production	Charcoal burner	Charcoal*Heat	Fuel Efficiency	PJ/PJ	CPS	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.76	0.78	0.79	0.81	0.82	0.84	0.85
Oth.Sect. heat production	Coal burner	Hard coal*Heat	Fuel Efficiency	PJ/PJ	CPS	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
Oth.Sect. heat production	District heat	District heat*Heat	Fuel Efficiency	PJ/PJ	CPS	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Oth.Sect. heat production	Electric heater	Other Sectors electricity consumption*Heat	Fuel Efficiency	PJ/PJ	CPS	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Oth.Sect. heat production	Gas burner	Gas*Heat	Fuel Efficiency	PJ/PJ	CPS	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.88	0.89	0.90	0.91	0.93	0.94	0.95
Oth.Sect. heat production	Gasoline/Diesel /Kerosene burner	Gasoline/Diesel/ Kerosene*Heat	Fuel Efficiency	PJ/PJ	CPS	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.86	0.86	0.86	0.87	0.87	0.88	0.88
Oth.Sect. heat production	Geothermal	Geothermal energy*Heat	Fuel Efficiency	PJ/PJ	CPS	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Oth.Sect. heat production	Oil burner	Fuel Oil*Heat	Fuel Efficiency	PJ/PJ	CPS	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
Oth.Sect. heat production	Solar collector	Solar radiation*Heat	Fuel Efficiency	PJ/PJ	CPS	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Oth.Sect. heat production	Lignite burner	Lignite*Heat	Fuel Efficiency	PJ/PJ	CPS	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
Power plants	Coal power plant	Hard coal*Electricity	Fuel Efficiency	PJ/PJ	CPS	0.36	0.37	0.38	0.37	0.40	0.42	0.33	0.34	0.35	0.36	0.37	0.37	0.38	0.39
Power plants	Biomass and waste power plant	Biomass and waste*Electricity	Fuel Efficiency	PJ/PJ	CPS	0.25	0.25	0.25	0.25	0.25	0.25	0.27	0.28	0.29	0.30	0.30	0.30	0.32	0.34
Power plants	Oil power plant	Fuel Oil*Electricity	Fuel Efficiency	PJ/PJ	CPS	0.35	0.87	1.19	0.46	0.17	0.20	0.16	0.18	0.27	0.42	0.42	0.42	0.42	0.42
Power plants	Lignite power plant	Lignite*Electricity	Fuel Efficiency	PJ/PJ	CPS	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.34	0.35	0.36	0.37	0.37	0.38	0.39
Power plants	Nuclear power plant	Nuclear energy*Electricity	Fuel Efficiency	PJ/PJ	CPS	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33
Power plants	Gas power plant	Gas*Electricity	Fuel Efficiency	PJ/PJ	CPS	0.32	0.32	0.34	0.32	0.35	0.34	0.35	0.40	0.43	0.46	0.47	0.48	0.51	0.52

Power plants	Diesel generator	Gasoline/Diesel/Kerosene*Electricity	Fuel Efficiency	PJ/PJ	CPS	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
Heating plants	Solar thermal district heating	Solar radiation*District heat	Fuel Efficiency	PJ/PJ	CPS	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Heating plants	Coal heating plant	Hard coal*District heat	Fuel Efficiency	PJ/PJ	CPS	0.59	0.58	0.81	0.68	0.63	0.65	0.63	0.63	0.63	0.63	0.63	0.63	0.63	0.63
Heating plants	Biomass and waste heating plant	Biomass and waste*District heat	Fuel Efficiency	PJ/PJ	CPS	0.60	0.49	0.54	0.48	0.46	0.50	0.60	0.63	0.66	0.69	0.72	0.75	0.78	0.84
Heating plants	Geothermal heating plant	Geothermal energy*District heat	Fuel Efficiency	PJ/PJ	CPS	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50
Heating plants	Gas heating plant	Gas*District heat	Fuel Efficiency	PJ/PJ	CPS	0.50	0.78	0.74	0.79	0.80	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90
Heating plants	Oil heating plant	Gasoline/Diesel/ Kerosene*District heat	Fuel Efficiency	PJ/PJ	CPS	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37
Heating plants	Lignite heating plant	Lignite*District heat	Fuel Efficiency	PJ/PJ	CPS	0.80	0.80	0.80	0.80	0.80	0.80	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.88
Refineries	Refinery fuel oil	Crude oil*Fuel Oil	Fuel Efficiency	PJ/PJ	CPS	0.87	0.94	0.95	0.91	0.93	0.93	0.95	0.97	0.99	1.00	1.00	1.00	1.00	1.00
Refineries	Refinery gasoline diesel	Crude oil*Gasoline/Diesel/ Kerosene	Fuel Efficiency	PJ/PJ	CPS	0.87	0.94	0.95	0.91	0.93	0.93	0.95	0.97	0.99	1.00	1.00	1.00	1.00	1.00
Refineries	Coal transformation	Hard coal*Gas	Fuel Efficiency	PJ/PJ	CPS	0.83	0.54	0.32	0.04	0.56	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55
Gas transport		Natural gas*Gas	Fuel Efficiency	PJ/PJ	CPS	0.64	0.53	0.33	0.56	0.87	0.87	0.87	0.93	0.95	0.96	0.96	0.96	0.96	0.96
Industry electricity transmission		Industry electricity consumption* Electricity	Fuel Efficiency	TWh/ TWh	CPS	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Industry electric appliances	Electric appliance	Industry electricity consumption* Electric appliances	Fuel Efficiency	TWh/ TWh	CPS	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Industry other appliances	Gas appliance	Gas*Other appliances	Fuel Efficiency	PJ/PJ	CPS	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Industry other appliances	Gasol/Diesel/ Keros appliance	Gasoline/Diesel/ Kerosene*Other appliances	Fuel Efficiency	PJ/PJ	CPS	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Oth.Sect. other appliances	Gas appliance	Gas*Other appliances	Fuel Efficiency	PJ/PJ	CPS	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Oth.Sect. other appliances	Gasol/Diesel/ Keros appliance	Gasoline/Diesel/ Kerosene*Other appliances	Fuel Efficiency	PJ/PJ	CPS	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
OthSec electric appliances	Electric appliance	Other Sectors electricity	Fuel Efficiency	TWh/ TWh	CPS	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

		consumption* Electric appliances																	
Residential electric appliances	Electric appliance	Residential electricity consumption* Electric appliances	Fuel Efficiency	TWh/ TWh	CPS	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Power plants	Geothermal power plant	Geothermal energy*Electricity	Efficiency	PJ/PJ	CPS	0.10	0.10	0.10	0.10	0.10	0.10	0.11	0.13	0.15	0.16	0.17	0.18	0.19	0.20
Power plants	Solar thermal power plant	Solar radiation*Electricity	Efficiency	PJ/PJ	CPS	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40
Refineries	Biofuel production	Biofuel/Synfuel* Biomass and waste	Efficiency	PJ/PJ	CPS	1.00	1.00	1.00	1.00	1.00	1.00	0.64	0.64	0.65	0.65	0.65	0.65	0.68	0.72
Refineries	Charcoal production	Biomass and waste*Charcoal	Efficiency	PJ/PJ	CPS	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Residential electricity transmission		Residential electricity consumption* Electricity	Efficiency	TWh/ TWh	CPS	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Oth.Sect. electricity transmission		Electricity*Other Sectors electricity consumption	Efficiency	TWh/ TWh	CPS	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Hydrogen production	Electrolysis	Electricity* Hydrogen	Efficiency	TWh/ TWh	CPS	0.65	0.65	0.65	0.65	0.65	0.65	0.67	0.68	0.68	0.71	0.71	0.73	0.73	0.75
Residential CHP	CHP Fuel cell	Heat*Residential electricity consumption	Efficiency	PJ/PJ	CPS	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Residential electricity transmission		Electricity* Residential electricity consumption	Efficiency	TWh/ TWh	CPS	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Residential heat production	District heat	Heat*District heat	Efficiency	PJ/PJ	CPS	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Residential heat production	Biomass burner	Heat*Biomass and waste	Efficiency	PJ/PJ	CPS	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.76	0.78	0.79	0.80	0.81	0.83	0.84
Residential heat production	Solar collector	Solar radiation*Heat	Efficiency	PJ/PJ	CPS	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Residential heat production	Coal burner	Hard coal*Heat	Efficiency	PJ/PJ	CPS	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
Residential heat production	Electric heat pump	Heat* Geothermal energy	Efficiency	PJ/PJ	CPS	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

Table C.3 Input data of efficiency for regional energy system model of YRD region.

Sector	Technology	Substance	Attribute	Unit	Scenario	2005	2007	2009	2010	2012	2013	2015	2020	2025	2030	2035	2040	2045	2050
CHP Plants	CHP Biomass and waste	Biomass and waste*District heat	Fuel Efficiency	PJ/PJ	CPS	0.11	0.11	0.11	0.11	0.11	0.11	0.12	0.12	0.13	0.13	0.14	0.14	0.15	0.15
CHP Plants	CHP Coal	Hard coal*District heat	Fuel Efficiency	PJ/PJ	CPS	0.39	0.37	0.26	0.24	0.20	0.20	0.21	0.21	0.22	0.23	0.23	0.24	0.24	0.24
CHP Plants	CHP Gas	Gas*District heat	Fuel Efficiency	PJ/PJ	CPS	0.44	0.41	0.28	0.27	0.22	0.22	0.25	0.27	0.29	0.30	0.30	0.30	0.30	0.30
CHP Plants	CHP Geothermal	Geothermal energy*District heat	Fuel Efficiency	PJ/PJ	CPS	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40
CHP Plants	CHP Lignite	Lignite*District heat	Fuel Efficiency	PJ/PJ	CPS	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.19	0.19	0.19	0.19
CHP Plants	CHP Oil	Fuel Oil*District heat	Fuel Efficiency	PJ/PJ	CPS	0.08	0.08	0.08	0.08	0.08	0.08	0.09	0.10	0.12	0.13	0.15	0.17	0.18	0.20
Industry CHP	CHP Biomass and waste	Biomass and waste*Heat	Fuel Efficiency	PJ/PJ	CPS	0.11	0.11	0.11	0.11	0.11	0.11	0.12	0.14	0.16	0.19	0.23	0.28	0.38	0.56
Industry CHP	CHP Coal	Hard coal*Heat	Fuel Efficiency	PJ/PJ	CPS	0.46	0.44	0.36	0.32	0.26	0.28	0.21	0.23	0.24	0.26	0.27	0.29	0.30	0.31
Industry CHP	CHP Fuel cell	Hydrogen*Heat	Fuel Efficiency	PJ/PJ	CPS	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.66
Industry CHP	CHP Gas	Gas*Heat	Fuel Efficiency	PJ/PJ	CPS	0.15	0.10	0.09	0.12	0.12	0.10	0.26	0.29	0.31	0.33	0.35	0.37	0.38	0.40
Industry CHP	CHP Geothermal	Geothermal energy*Heat	Fuel Efficiency	PJ/PJ	CPS	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50
Industry CHP	CHP Oil	Fuel Oil*Heat	Fuel Efficiency	PJ/PJ	CPS	0.08	0.08	0.08	0.08	0.08	0.08	0.10	0.13	0.17	0.21	0.26	0.33	0.42	0.54
Industry CHP	CHP Lignite	Lignite*Heat	Fuel Efficiency	PJ/PJ	CPS	0.20	0.20	0.20	0.20	0.20	0.20	0.21	0.23	0.25	0.28	0.31	0.36	0.43	0.53
Industry heat production	Biomass burner	Biomass and waste*Heat	Fuel Efficiency	PJ/PJ	CPS	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.76	0.77	0.78	0.80	0.81	0.83	0.84
Industry heat production	Coal burner	Hard coal*Heat	Fuel Efficiency	PJ/PJ	CPS	0.81	0.81	0.81	0.81	0.81	0.81	0.81	0.82	0.82	0.83	0.83	0.84	0.84	0.85
Industry heat production	District heat	District heat*Heat	Fuel Efficiency	PJ/PJ	CPS	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Industry heat production	Electric heater	Industry electricity consumption*Heat	Fuel Efficiency	PJ/PJ	CPS	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Industry heat production	Gas burner	Gas*Heat	Fuel Efficiency	PJ/PJ	CPS	0.82	0.82	0.82	0.82	0.82	0.82	0.84	0.85	0.87	0.89	0.91	0.92	0.94	0.95
Industry heat production	Gasoline/Diesel/ Kerosene burner	Gasoline/Diesel/ Kerosene*Heat	Fuel Efficiency	PJ/PJ	CPS	0.80	0.80	0.80	0.80	0.80	0.80	0.81	0.82	0.83	0.84	0.85	0.86	0.87	0.88
Industry heat production	Geothermal	Geothermal energy*Heat	Fuel Efficiency	PJ/PJ	CPS	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Industry heat production	Oil burner	Fuel Oil*Heat	Fuel Efficiency	PJ/PJ	CPS	0.80	0.80	0.80	0.80	0.80	0.80	0.81	0.81	0.82	0.83	0.83	0.84	0.84	0.85
Industry heat production	Solar collector	Solar radiation*Heat	Fuel Efficiency	PJ/PJ	CPS	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

Industry heat production	Lignite burner	Lignite*Heat	Fuel Efficiency	PJ/PJ	CPS	0.81	0.81	0.81	0.81	0.81	0.81	0.81	0.82	0.82	0.83	0.83	0.84	0.84	0.85
Residential CHP	CHP Biomass and waste	Biomass and waste*Heat	Fuel Efficiency	PJ/PJ	CPS	0.15	0.15	0.15	0.15	0.15	0.15	0.16	0.18	0.20	0.23	0.27	0.32	0.41	0.58
Residential CHP	CHP Coal	Hard coal*Heat	Fuel Efficiency	PJ/PJ	CPS	0.16	0.16	0.16	0.16	0.16	0.16	0.18	0.20	0.22	0.25	0.29	0.35	0.42	0.55
Residential CHP	CHP Fuel cell	Hydrogen*Heat	Fuel Efficiency	PJ/PJ	CPS	0.21	0.21	0.21	0.21	0.21	0.21	0.23	0.25	0.28	0.32	0.36	0.43	0.52	0.66
Residential CHP	CHP Gas	Gas*Heat	Fuel Efficiency	PJ/PJ	CPS	0.33	0.33	0.33	0.33	0.33	0.33	0.34	0.35	0.36	0.37	0.38	0.39	0.40	0.42
Residential CHP	CHP Geothermal	Geothermal energy*Heat	Fuel Efficiency	PJ/PJ	CPS	0.20	0.20	0.20	0.20	0.20	0.20	0.22	0.24	0.26	0.29	0.32	0.36	0.42	0.50
Residential CHP	CHP Oil	Fuel Oil*Heat	Fuel Efficiency	PJ/PJ	CPS	0.20	0.20	0.20	0.20	0.20	0.20	0.22	0.24	0.27	0.30	0.34	0.39	0.45	0.54
Residential CHP	CHP Lignite	Lignite*Heat	Fuel Efficiency	PJ/PJ	CPS	0.25	0.25	0.25	0.25	0.25	0.25	0.27	0.28	0.30	0.32	0.35	0.39	0.45	0.53
Residential heat production	Biomass burner	Biomass and waste*Heat	Fuel Efficiency	PJ/PJ	CPS	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.76	0.78	0.79	0.80	0.81	0.83	0.84
Residential heat production	Charcoal burner	Charcoal*Heat	Fuel Efficiency	PJ/PJ	CPS	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.76	0.78	0.79	0.81	0.82	0.84	0.85
Residential heat production	Coal burner	Hard coal*Heat	Fuel Efficiency	PJ/PJ	CPS	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
Residential heat production	District heat	District heat*Heat	Fuel Efficiency	PJ/PJ	CPS	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Residential heat production	Electric heater	Residential electricity consumption*Heat	Fuel Efficiency	PJ/PJ	CPS	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Residential heat production	Gas burner	Gas*Heat	Fuel Efficiency	PJ/PJ	CPS	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.88	0.89	0.90	0.91	0.93	0.94	0.95
Residential heat production	Gasoline/Diesel/ Kerosene burner	Gasoline/Diesel/ Kerosene*Heat	Fuel Efficiency	PJ/PJ	CPS	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.86	0.86	0.86	0.87	0.87	0.88	0.88
Residential heat production	Geothermal	Geothermal energy*Heat	Fuel Efficiency	PJ/PJ	CPS	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Residential heat production	Oil burner	Fuel Oil*Heat	Fuel Efficiency	PJ/PJ	CPS	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
Residential heat production	Solar collector	Solar radiation*Heat	Fuel Efficiency	PJ/PJ	CPS	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Residential heat production	Lignite burner	Lignite*Heat	Fuel Efficiency	PJ/PJ	CPS	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
Oth.Sect. CHP	CHP Biomass and waste	Biomass and waste*Heat	Fuel Efficiency	PJ/PJ	CPS	0.15	0.15	0.15	0.15	0.15	0.15	0.16	0.18	0.20	0.22	0.26	0.31	0.40	0.56
Oth.Sect. CHP	CHP Coal	Hard coal*Heat	Fuel Efficiency	PJ/PJ	CPS	0.16	0.16	0.16	0.16	0.16	0.16	0.18	0.20	0.22	0.25	0.29	0.35	0.42	0.55
Oth.Sect. CHP	CHP Fuel cell	Hydrogen*Heat	Fuel Efficiency	PJ/PJ	CPS	0.21	0.21	0.21	0.21	0.21	0.21	0.23	0.25	0.28	0.32	0.36	0.43	0.52	0.66
Oth.Sect. CHP	CHP Gas	Gas*Heat	Fuel Efficiency	PJ/PJ	CPS	0.33	0.33	0.33	0.33	0.33	0.33	0.34	0.35	0.36	0.37	0.38	0.39	0.40	0.42
Oth.Sect. CHP	CHP Geothermal	Geothermal energy*Heat	Fuel Efficiency	PJ/PJ	CPS	0.13	0.13	0.13	0.13	0.13	0.13	0.14	0.16	0.18	0.20	0.24	0.29	0.37	0.50

Oth.Sect. CHP	CHP Oil	Fuel Oil*Heat	Fuel Efficiency	PJ/PJ	CPS	0.20	0.20	0.20	0.20	0.20	0.20	0.22	0.24	0.27	0.30	0.34	0.39	0.45	0.54
Oth.Sect. CHP	CHP Lignite	Lignite*Heat	Fuel Efficiency	PJ/PJ	CPS	0.25	0.25	0.25	0.25	0.25	0.25	0.27	0.28	0.30	0.32	0.35	0.39	0.45	0.53
Oth.Sect. heat production	Biomass burner	Biomass and waste*Heat	Fuel Efficiency	PJ/PJ	CPS	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.76	0.78	0.79	0.80	0.81	0.83	0.84
Oth.Sect. heat production	Charcoal burner	Charcoal*Heat	Fuel Efficiency	PJ/PJ	CPS	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.76	0.78	0.79	0.81	0.82	0.84	0.85
Oth.Sect. heat production	Coal burner	Hard coal*Heat	Fuel Efficiency	PJ/PJ	CPS	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
Oth.Sect. heat production	District heat	District heat*Heat	Fuel Efficiency	PJ/PJ	CPS	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Oth.Sect. heat production	Electric heater	Other Sectors electricity consumption*Heat	Fuel Efficiency	PJ/PJ	CPS	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Oth.Sect. heat production	Gas burner	Gas*Heat	Fuel Efficiency	PJ/PJ	CPS	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.88	0.89	0.90	0.91	0.93	0.94	0.95
Oth.Sect. heat production	Gasoline/Diesel/ Kerosene burner	Gasoline/Diesel/ Kerosene*Heat	Fuel Efficiency	PJ/PJ	CPS	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.86	0.86	0.86	0.87	0.87	0.88	0.88
Oth.Sect. heat production	Geothermal	Geothermal energy*Heat	Fuel Efficiency	PJ/PJ	CPS	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Oth.Sect. heat production	Oil burner	Fuel Oil*Heat	Fuel Efficiency	PJ/PJ	CPS	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
Oth.Sect. heat production	Solar collector	Solar radiation*Heat	Fuel Efficiency	PJ/PJ	CPS	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Oth.Sect. heat production	Lignite burner	Lignite*Heat	Fuel Efficiency	PJ/PJ	CPS	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
Power plants	Coal power plant	Hard coal*Electricity	Fuel Efficiency	PJ/PJ	CPS	0.37	0.38	0.45	0.41	0.41	0.44	0.43	0.44	0.45	0.46	0.47	0.47	0.48	0.49
Power plants	Biomass and waste power plant	Biomass and waste*Electricity	Fuel Efficiency	PJ/PJ	CPS	0.25	0.25	0.25	0.25	0.25	0.25	0.27	0.28	0.29	0.30	0.30	0.30	0.32	0.34
Power plants	Oil power plant	Fuel Oil*Electricity	Fuel Efficiency	PJ/PJ	CPS	0.31	0.47	0.15	0.27	0.22	0.21	0.16	0.18	0.27	0.42	0.42	0.42	0.42	0.42
Power plants	Lignite power plant	Lignite*Electricity	Fuel Efficiency	PJ/PJ	CPS	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.34	0.35	0.36	0.37	0.37	0.38	0.39
Power plants	Nuclear power plant	Nuclear energy*Electricity	Fuel Efficiency	PJ/PJ	CPS	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33
Power plants	Gas power plant	Gas*Electricity	Fuel Efficiency	PJ/PJ	CPS	0.32	0.32	0.33	0.33	0.34	0.34	0.35	0.40	0.43	0.46	0.47	0.48	0.51	0.52
Power plants	Diesel generator	Gasoline/Diesel/Kerosene*Electricity	Fuel Efficiency	PJ/PJ	CPS	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
Heating plants	Solar thermal district heating	Solar radiation*District heat	Fuel Efficiency	PJ/PJ	CPS	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Heating plants	Coal heating plant	Hard coal*District heat	Fuel Efficiency	PJ/PJ	CPS	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.88
Heating plants	Biomass and waste heating	Biomass and waste*District heat	Fuel Efficiency	PJ/PJ	CPS	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98

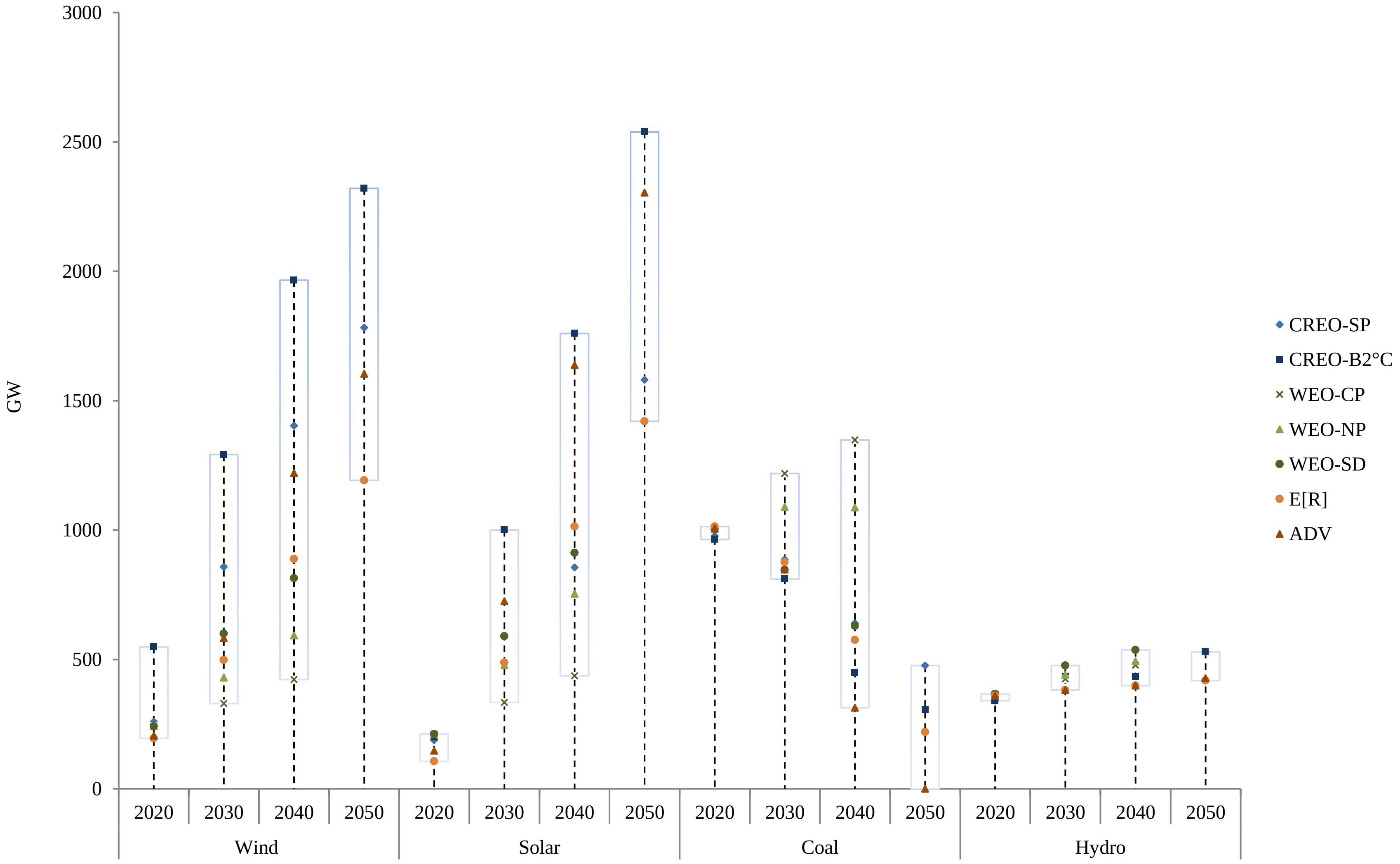
	plant																		
Heating plants	Geothermal heating plant	Geothermal energy*District heat	Fuel Efficiency	PJ/PJ	CPS	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50
Heating plants	Gas heating plant	Gas*District heat	Fuel Efficiency	PJ/PJ	CPS	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90
Heating plants	Oil heating plant	Gasoline/Diesel/ Kerosene*District heat	Fuel Efficiency	PJ/PJ	CPS	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24
Heating plants	Lignite heating plant	Lignite*District heat	Fuel Efficiency	PJ/PJ	CPS	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80
Refineries	Refinery fuel oil	Crude oil*Fuel Oil	Fuel Efficiency	PJ/PJ	CPS	0.80	0.89	0.73	0.81	0.81	0.81	0.83	0.85	0.87	0.88	0.89	0.90	0.90	0.90
Refineries	Refinery gasoline diesel	Crude oil*Gasoline/Diesel/ Kerosene	Fuel Efficiency	PJ/PJ	CPS	0.80	0.89	0.73	0.81	0.81	0.81	0.83	0.85	0.87	0.88	0.89	0.90	0.90	0.90
Refineries	Coal transformation	Hard coal*Gas	Fuel Efficiency	PJ/PJ	CPS	0.76	0.93	0.93	0.66	0.54	0.54	0.54	0.54	0.54	0.54	0.54	0.54	0.54	0.54
Gas transport		Natural gas*Gas	Fuel Efficiency	PJ/PJ	CPS	0.15	0.05	0.12	0.22	0.34	0.87	0.87	0.93	0.95	0.96	0.96	0.96	0.96	0.96
Industry electricity transmission		Industry electricity consumption* Electricity	Fuel Efficiency	TWh/ TWh	CPS	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Industry electric appliances	Electric appliance	Industry electricity consumption* Electric appliances	Fuel Efficiency	TWh/ TWh	CPS	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Industry other appliances	Gas appliance	Gas*Other appliances	Fuel Efficiency	PJ/PJ	CPS	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Industry other appliances	Gasol/Diesel/ Keros appliance	Gasoline/Diesel/ Kerosene*Other appliances	Fuel Efficiency	PJ/PJ	CPS	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Oth.Sect. other appliances	Gas appliance	Gas*Other appliances	Fuel Efficiency	PJ/PJ	CPS	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Oth.Sect. other appliances	Gasol/Diesel/ Keros appliance	Gasoline/Diesel/ Kerosene*Other appliances	Fuel Efficiency	PJ/PJ	CPS	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
OthSec electric appliances	Electric appliance	Other Sectors electricity consumption* Electric appliances	Fuel Efficiency	TWh/ TWh	CPS	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Residential electric appliances	Electric appliance	Residential electricity consumption* Electric appliances	Fuel Efficiency	TWh/ TWh	CPS	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Power plants	Geothermal power plant	Geothermal energy*Electricity	Efficiency	PJ/PJ	CPS	0.10	0.10	0.10	0.10	0.10	0.10	0.11	0.13	0.15	0.16	0.17	0.18	0.19	0.20
Power plants	Solar thermal power plant	Solar radiation*Electricity	Efficiency	PJ/PJ	CPS	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40

Refineries	Biofuel production	Biofuel/Synfuel* Biomass and waste	Efficiency	PJ/PJ	CPS	0.64	0.64	0.64	0.64	0.64	0.64	0.64	0.64	0.65	0.65	0.65	0.65	0.68	0.72
Refineries	Charcoal production	Biomass and waste*Charcoal	Efficiency	PJ/PJ	CPS	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Residential electricity transmission		Residential electricity consumption* Electricity	Efficiency	TWh/ TWh	CPS	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Oth.Sect. electricity transmission		Electricity*Other Sectors electricity consumption	Efficiency	TWh/ TWh	CPS	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Hydrogen production	Electrolysis	Electricity* Hydrogen	Efficiency	TWh/ TWh	CPS	0.65	0.65	0.65	0.65	0.65	0.65	0.67	0.68	0.68	0.71	0.71	0.73	0.73	0.75
Residential CHP	CHP Fuel cell	Heat*Residential electricity consumption	Efficiency	PJ/PJ	CPS	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Residential heat production	District heat	Heat*District heat	Efficiency	PJ/PJ	CPS	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Residential heat production	Biomass burner	Heat*Biomass and waste	Efficiency	PJ/PJ	CPS	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.76	0.78	0.79	0.80	0.81	0.83	0.84
Residential heat production	Solar collector	Solar radiation*Heat	Efficiency	PJ/PJ	CPS	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Residential heat production	Coal burner	Hard coal*Heat	Efficiency	PJ/PJ	CPS	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
Residential heat production	Electric heat pump	Heat*Geothermal energy	Efficiency	PJ/PJ	CPS	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

Table C.4 Final energy demand by sector from 2015 to 2050 of CPS in two study regions (unit: PJ).

Region	Sector	2015	2020	2030	2040	2050
BTH	**Industry**	8085	9227	11182	11763	10206
	Residential	1586	1868	2381	2886	3451
	Transport	2268	2729	3563	3853	3750
	Services & Commerce	1140	1386	1720	1981	2146
YRD	**Industry**	8976	9583	10237	10210	9349
	Residential	846	1042	1285	1509	1822
	Transport	1671	2007	2613	2796	2724
	Services & Commerce	1405	1675	1963	2131	2145

Appendix D Comparison of Reviewed National Energy Scenario Studies



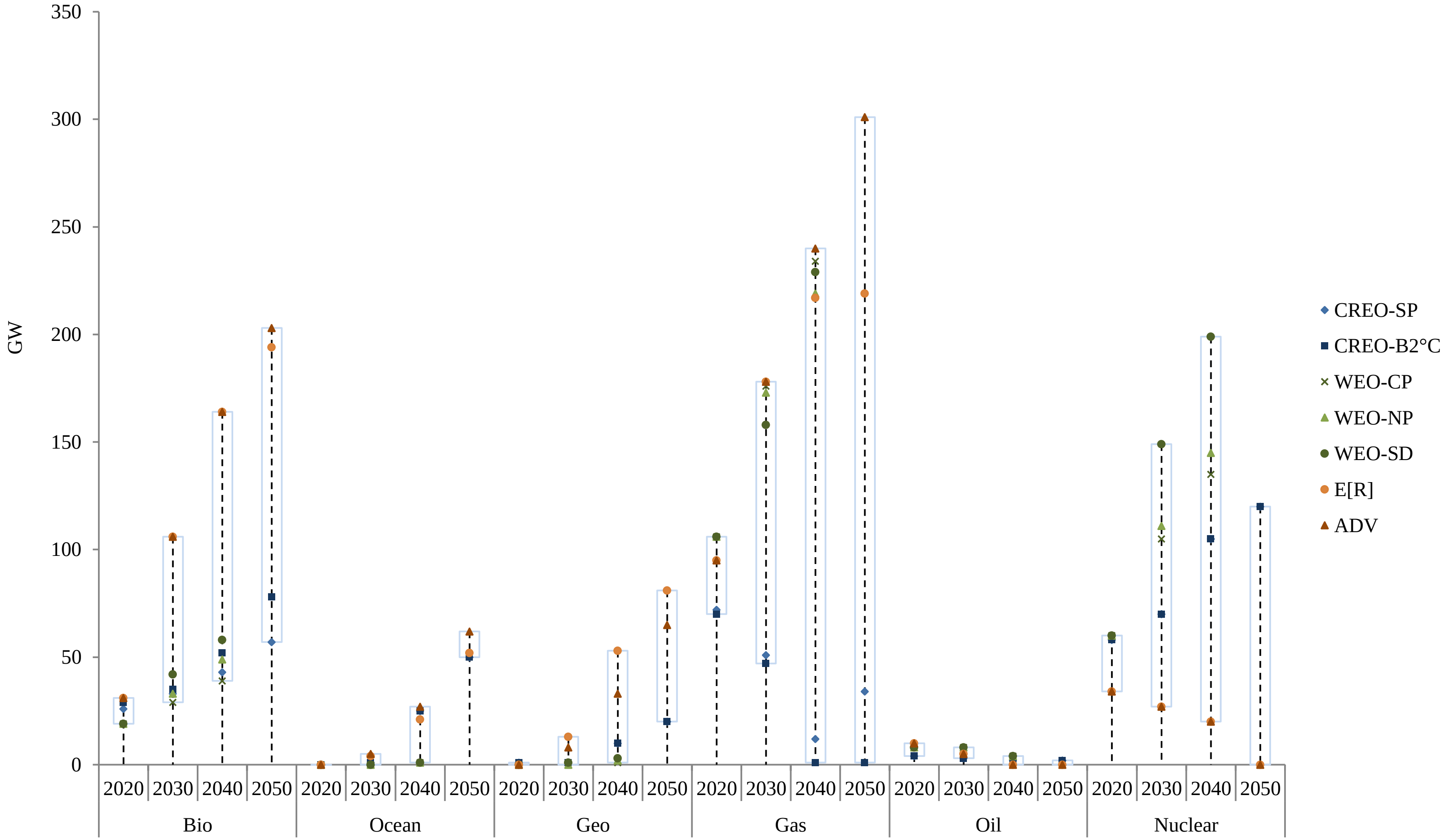


Figure D.1 Installed capacity for power generation by technology from 2020 to 2050 of reviewed national energy scenario studies.

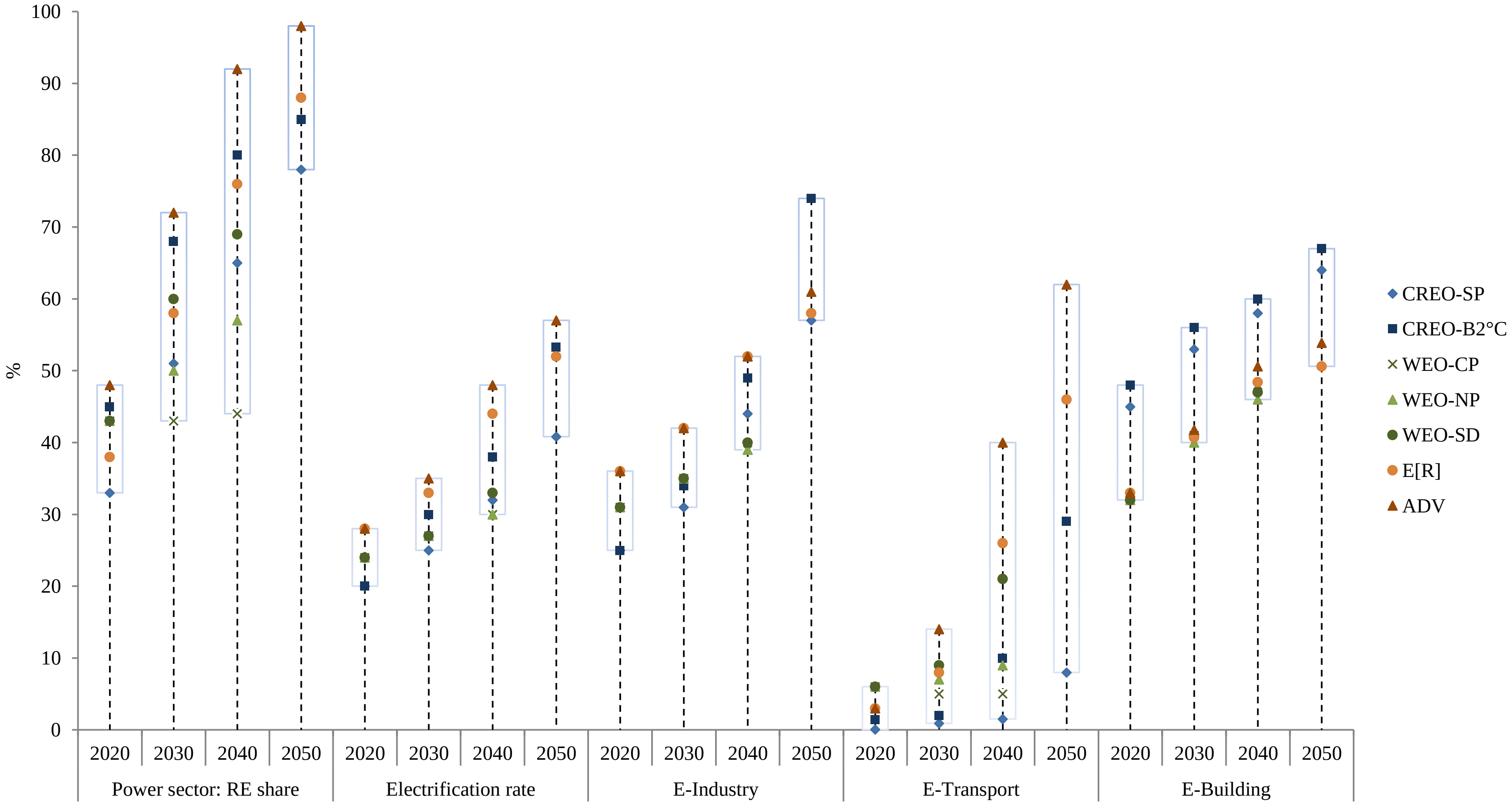


Figure D.2 Share of RE for power generation and electrification rate by sector from 2020 to 2050 of reviewed national energy scenario studies.

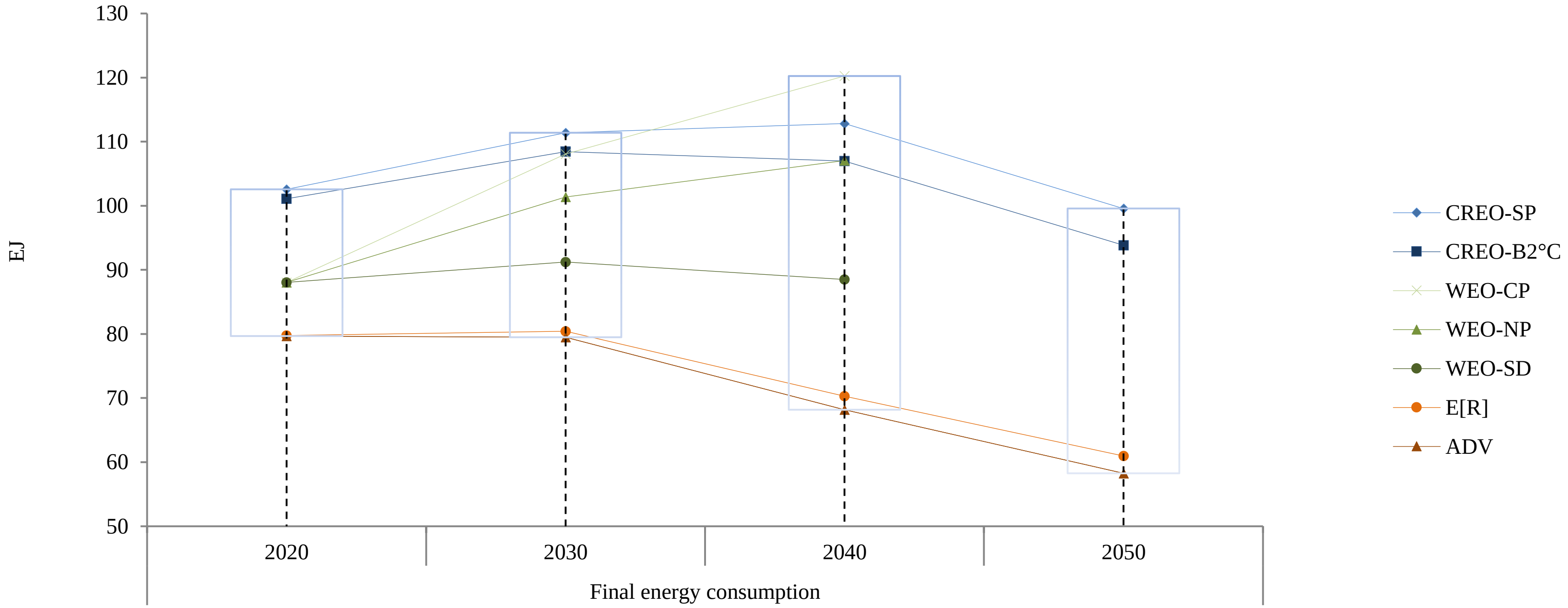


Figure D.3 Final energy consumption from 2020 to 2050 of reviewed national energy scenario studies.

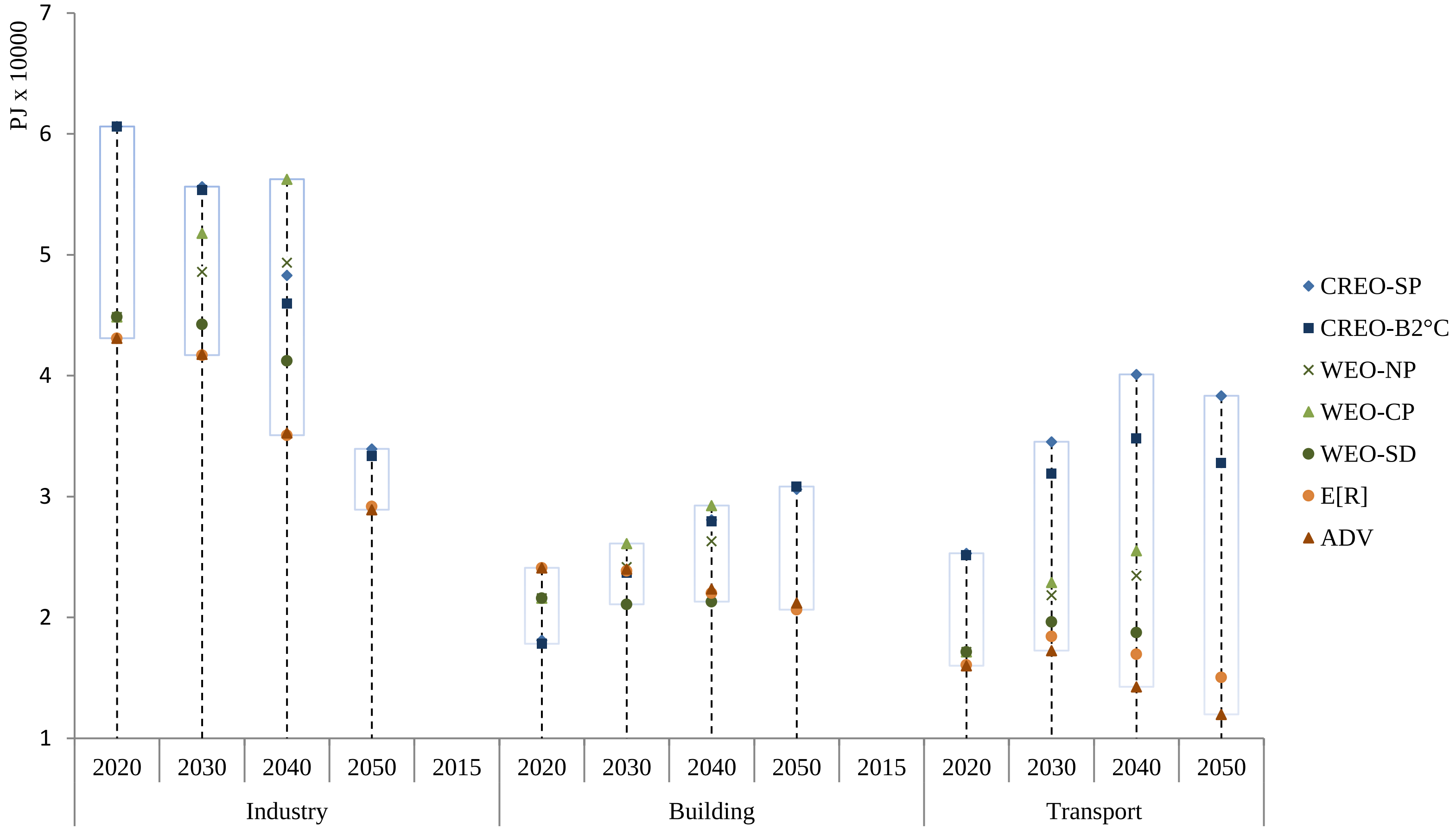


Figure D.4 Final energy consumption by sector from 2020 to 2050 of reviewed national energy scenario studies.

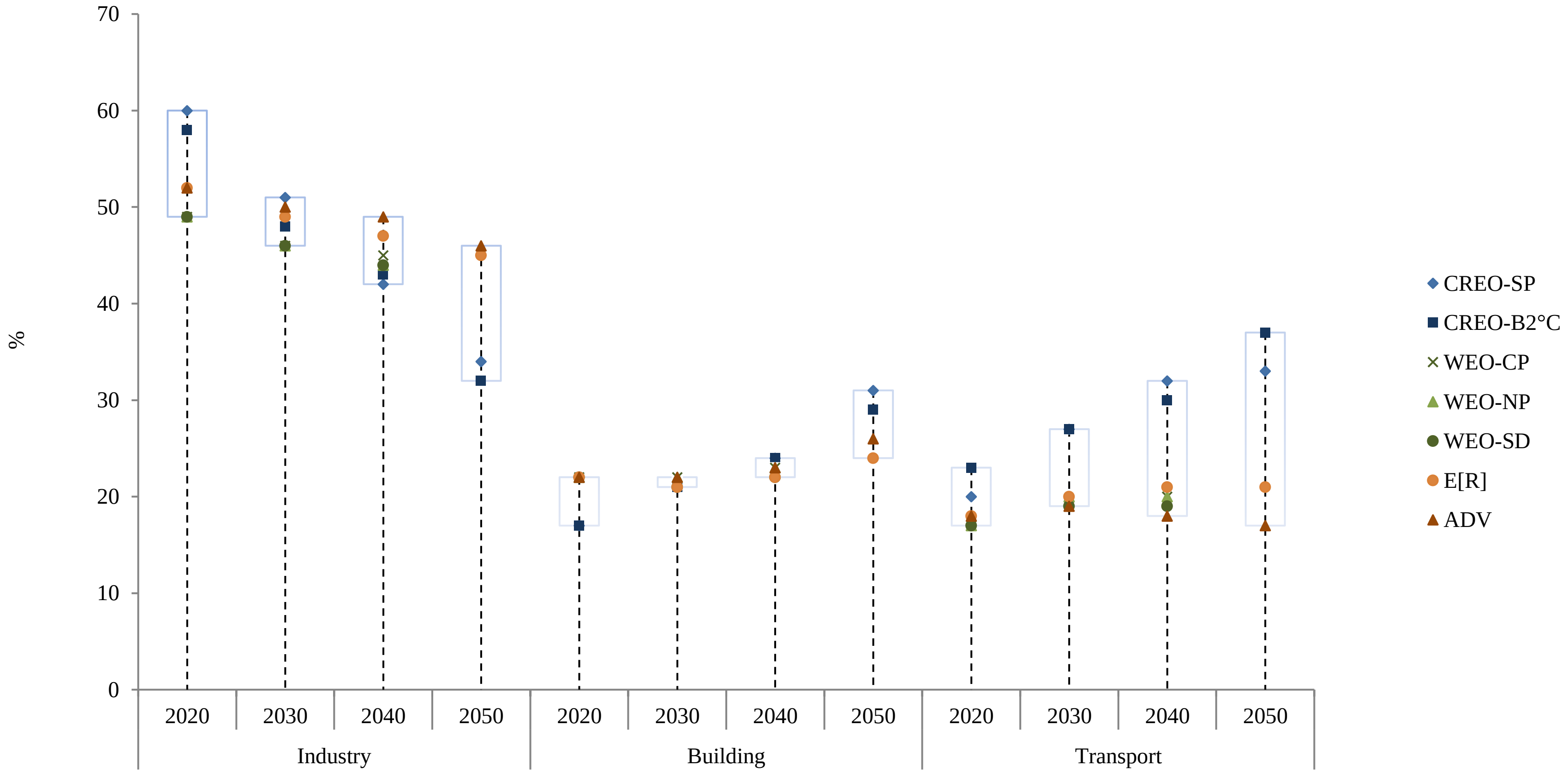


Figure D.5 Share of final energy consumption by sector from 2020 to 2050 of reviewed national energy scenario studies.

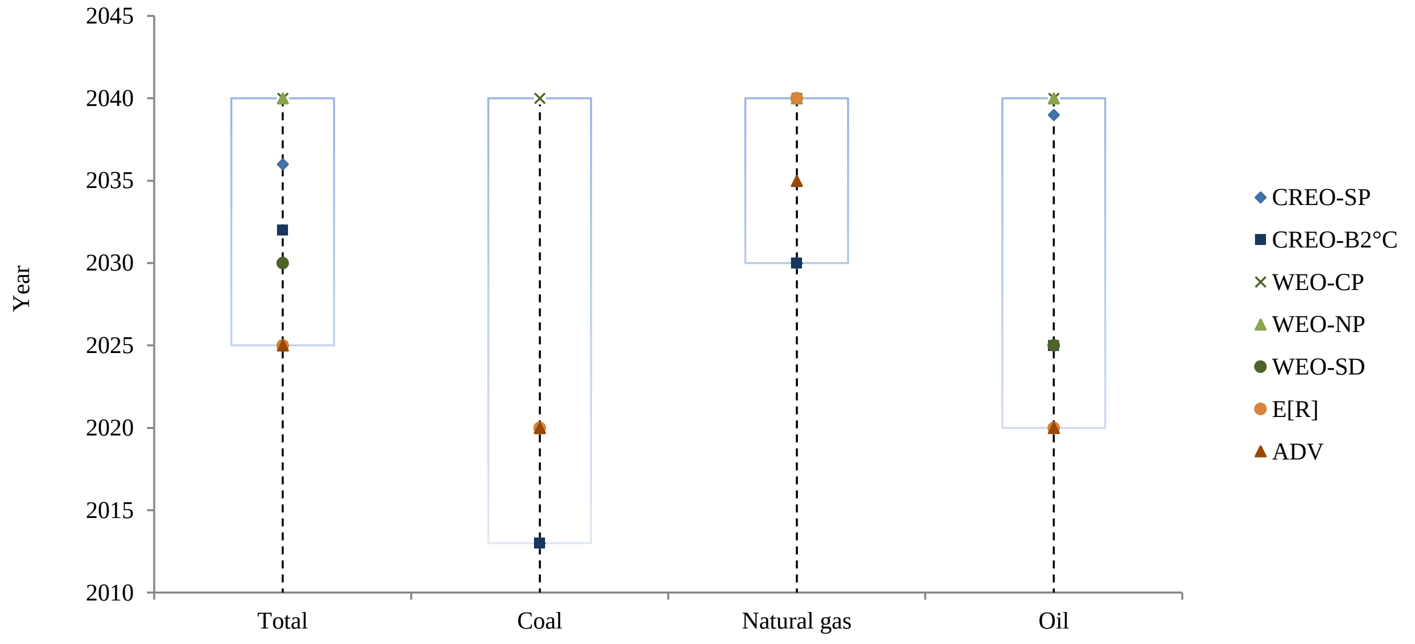


Figure D.6 Peak year for the consumption of fossil fuels in reviewed national energy scenario studies.

Appendix E Assumed Market Shares for Modes and Vehicle Types under the RIS Scenario

Table E.1 Assumed market shares for modes and vehicle types under the RIS scenario.

Market shares transport (RIS)	**2015**	**2020**	**2030**	**2040**	**2050**
Aviation domestic	11%	11%	8%	7%	7%
Navigation	4%	4%	4%	4%	4%
Pipeline Transport	0%	0%	0%	0%	0%
Rail	4%	5%	7%	10%	15%
Electric train etc.	*55%*	*70%*	*89%*	*96%*	*99%*
Diesel train	*45%*	*30%*	*11%*	*4%*	*1%*
Road: total (PC + LDV + HDV)	80%	80%	82%	79%	75%
PC + LDV (in total road)	*82%*	*82%*	*81%*	*80%*	*80%*
HDV (in total road)	*18%*	*18%*	*19%*	*20%*	*20%*
Road: PC + LDV					
Biofuel/Synfuel vehicle	0%	1%	4%	10%	7%
Electric vehicle	4%	4%	8%	27%	40%
Gas vehicle	3%	4%	4%	3%	1%
Gasoline/diesel car + others	93%	90%	68%	23%	2%
Hybrid vehicle	0%	1%	12%	28%	31%
Hydrogen car	0%	0%	3%	9%	18%
Road: HDV					
Biofuel/Synfuel vehicle	0%	1%	5%	18%	31%
Electric vehicle	0%	0%	7%	21%	30%
Gas vehicle	2%	2%	3%	3%	1%
Gasoline/diesel car + others	98%	97%	81%	43%	8%
Hybrid vehicle	0%	0%	1%	7%	16%
Hydrogen car	0%	0%	3%	8%	15%

Appendix F Typical Dispatch Characteristics in Study Regions

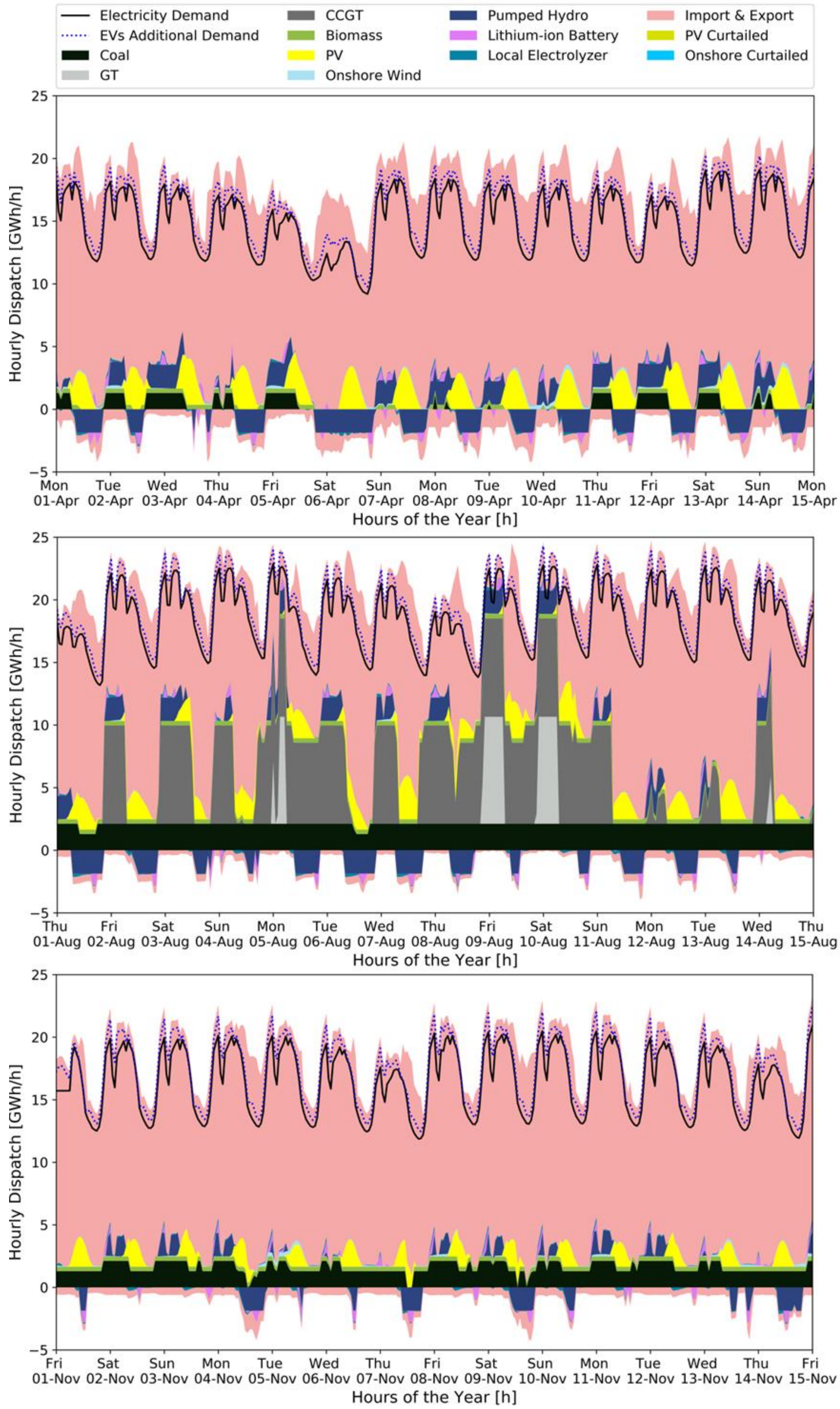


Figure F.1 Typical hourly generation by technologies, export and charge (-), import & discharge (+) to meet power demand in Beijing of April, August and November in 2030.

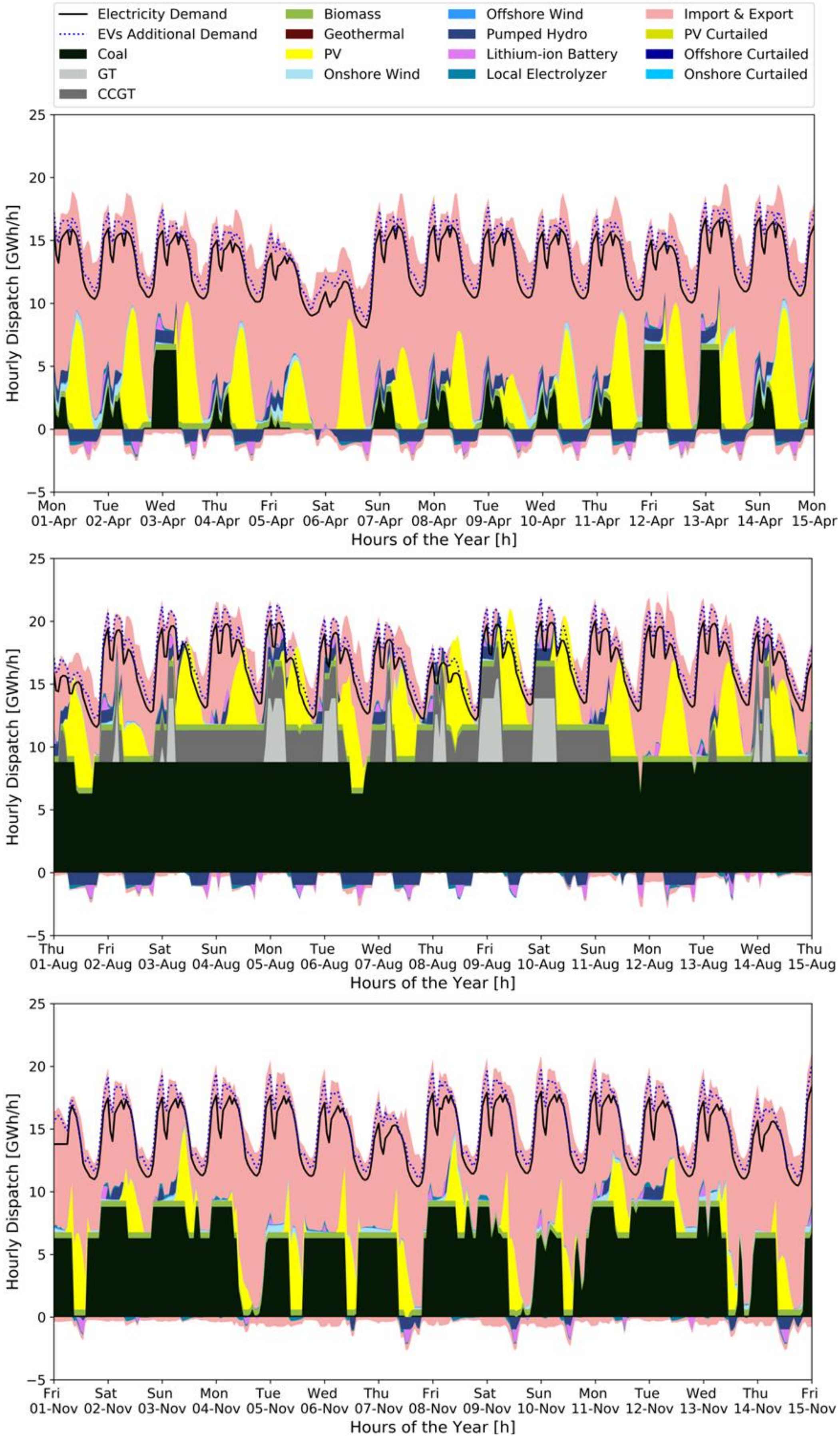


Figure F.2 Typical hourly generation by technologies, export and charge (-), import & discharge (+) to meet power demand in Tianjin of April, August and November in 2030.

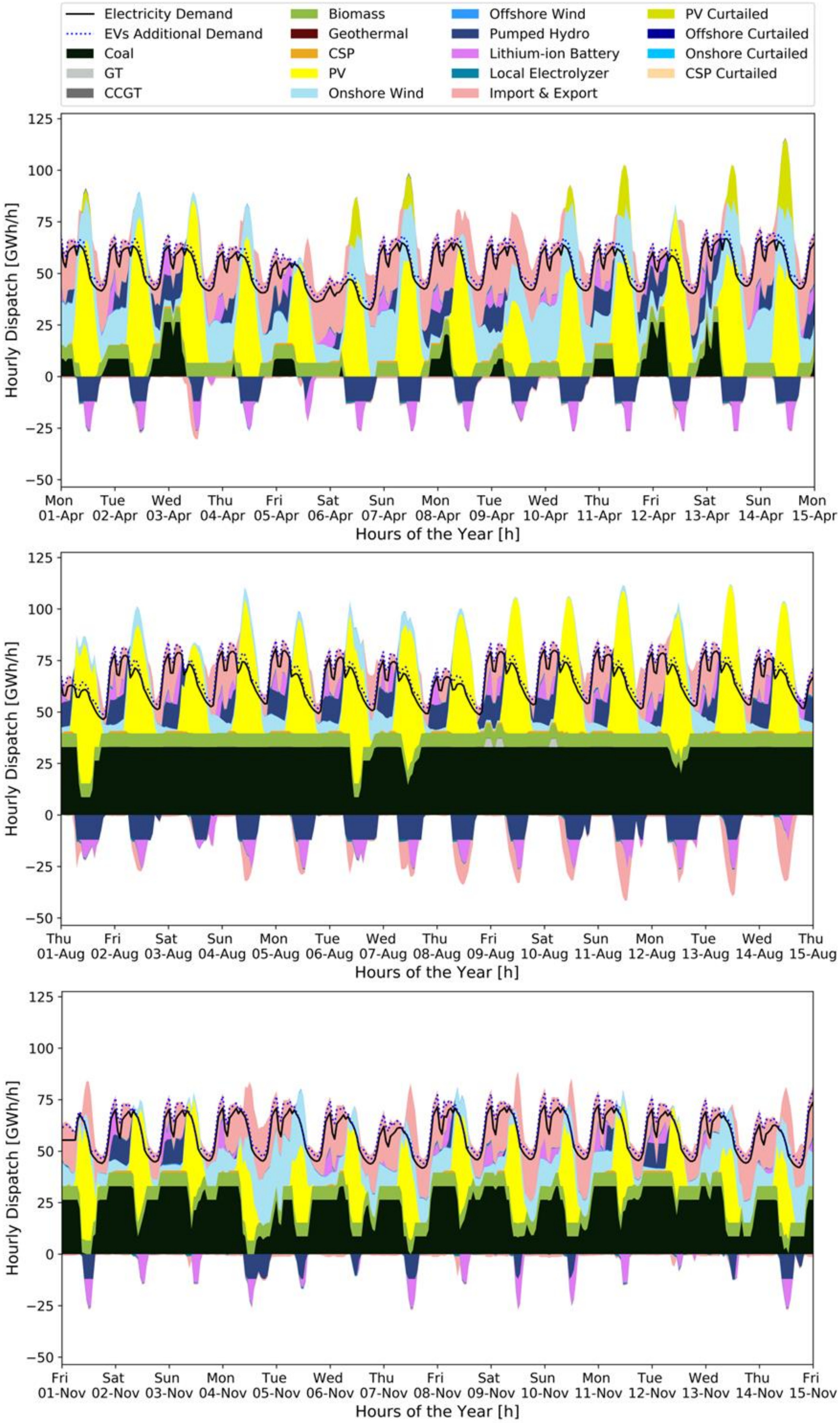


Figure F.3 Typical hourly generation by technologies, export and charge (-), import & discharge (+) to meet power demand in Hebei of April, August and November in 2030.

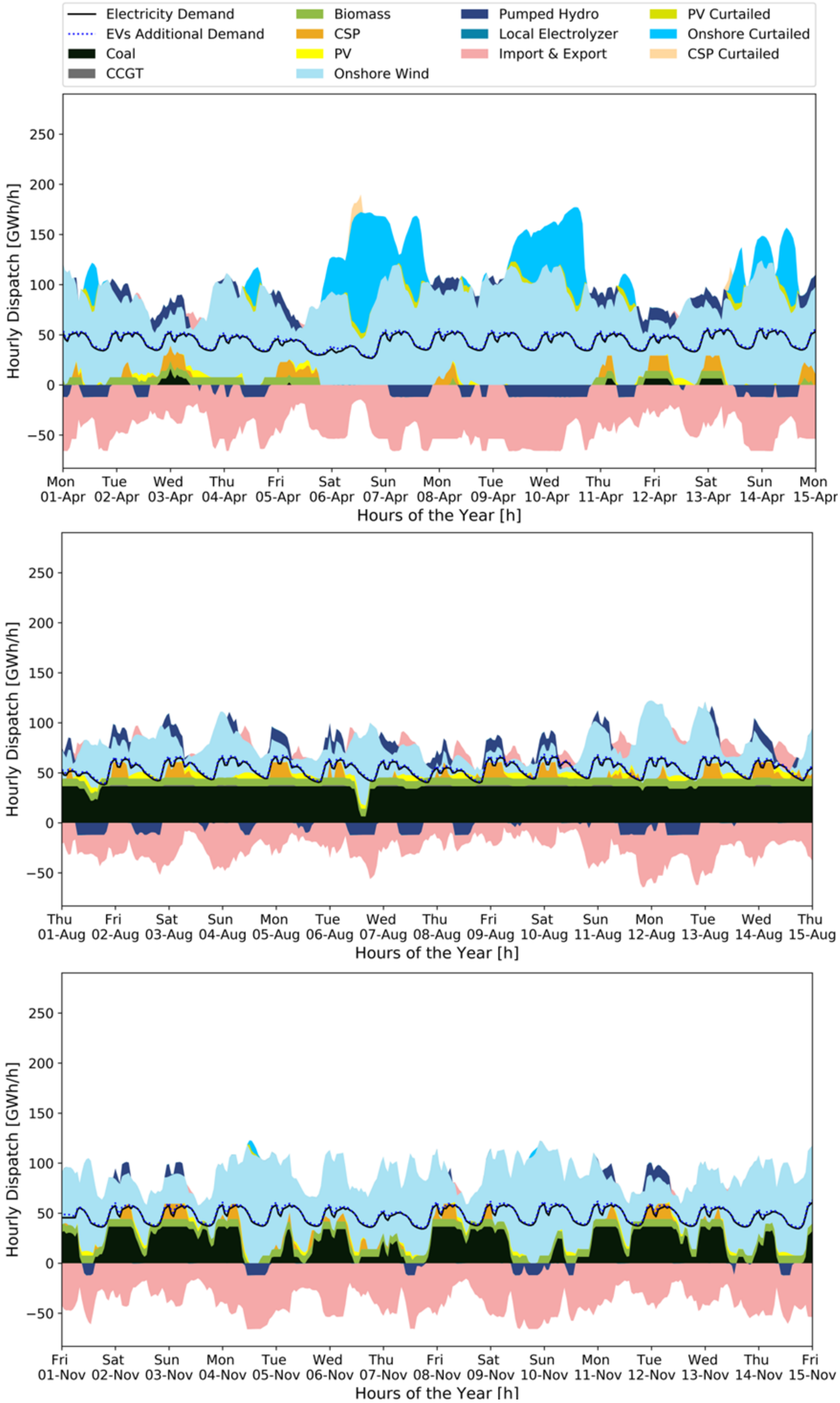


Figure F.4 Typical hourly generation by technologies, export and charge (-), import & discharge (+) to meet power demand in Inner Mongolia of April, August and November in 2030.

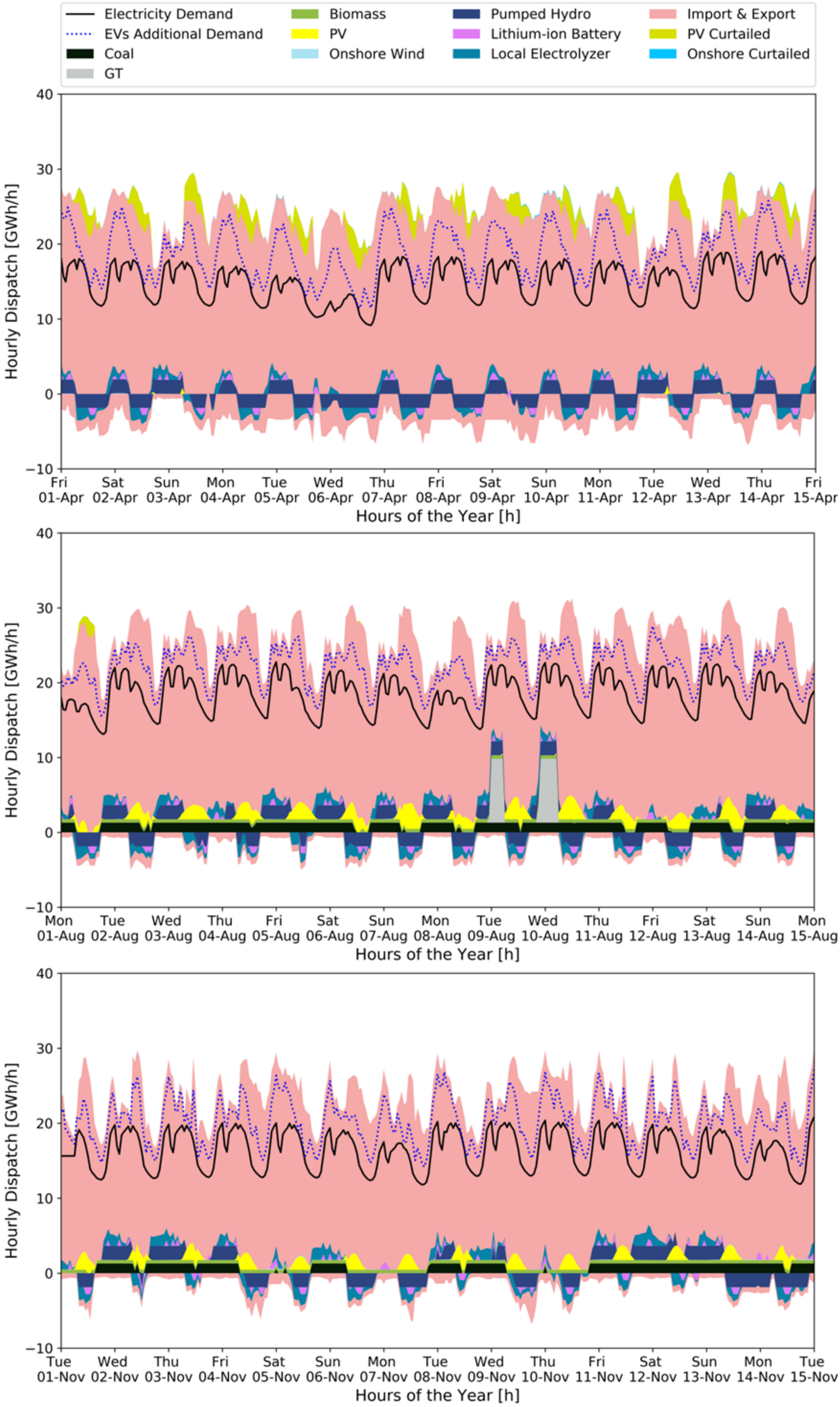


Figure F.5 Typical hourly generation by technologies, export and charge (-), import & discharge (+) to meet power demand in Beijing of April, August and November in 2050.

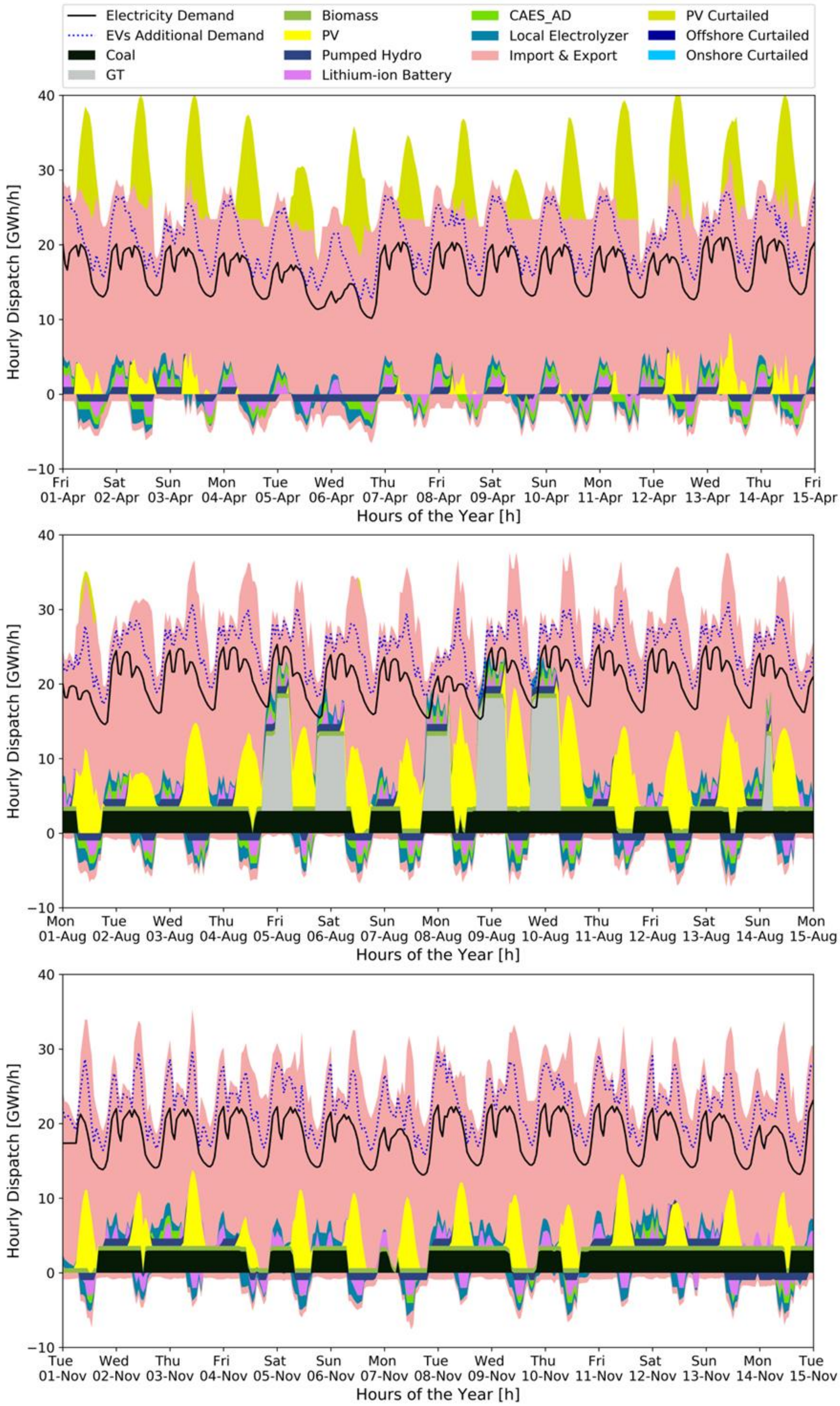


Figure F.6 Typical hourly generation by technologies, export and charge (-), import & discharge (+) to meet power demand in Tianjin of April, August and November in 2050.

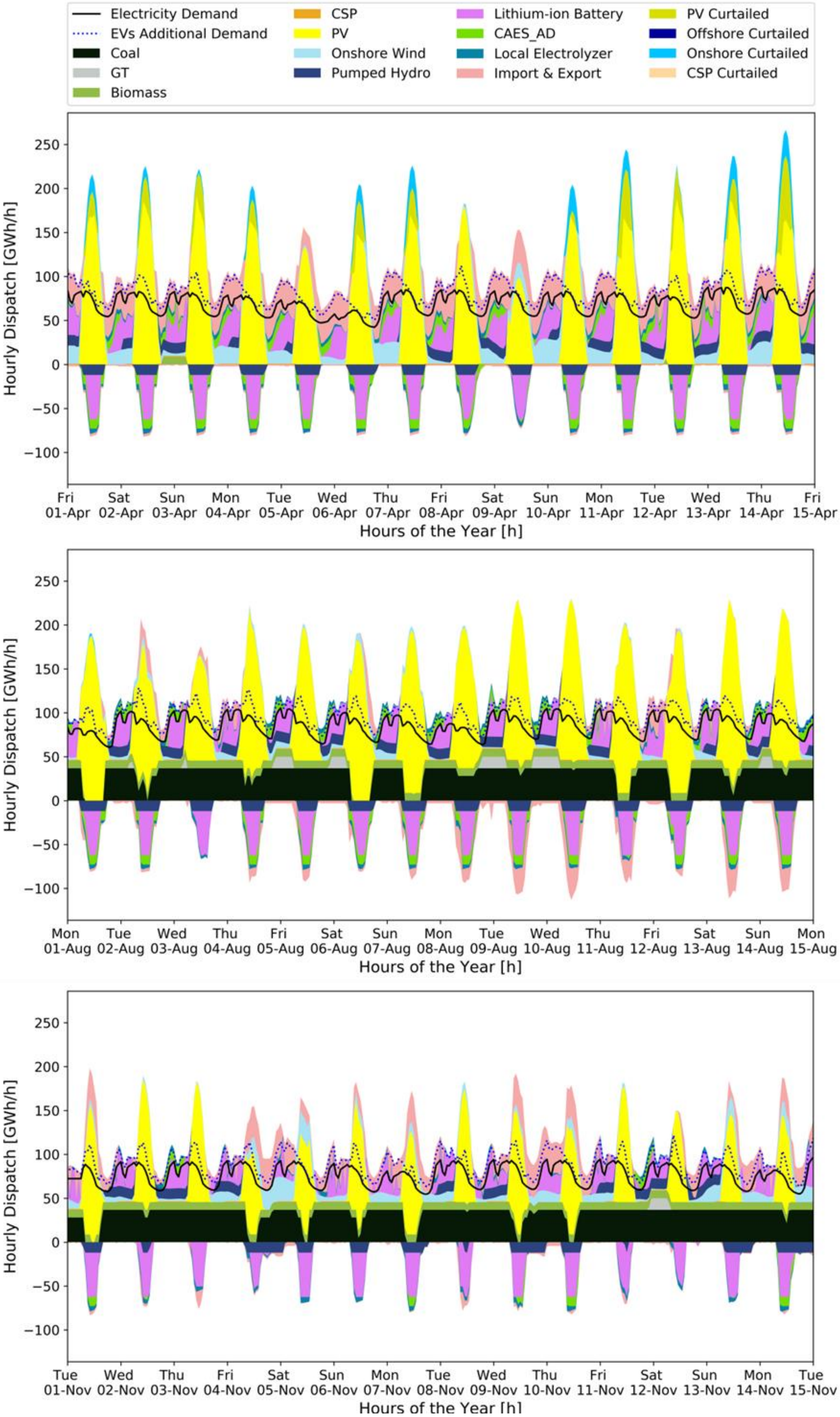


Figure F.7 Typical hourly generation by technologies, export and charge (-), import & discharge (+) to meet power demand in Hebei of April, August and November in 2050.

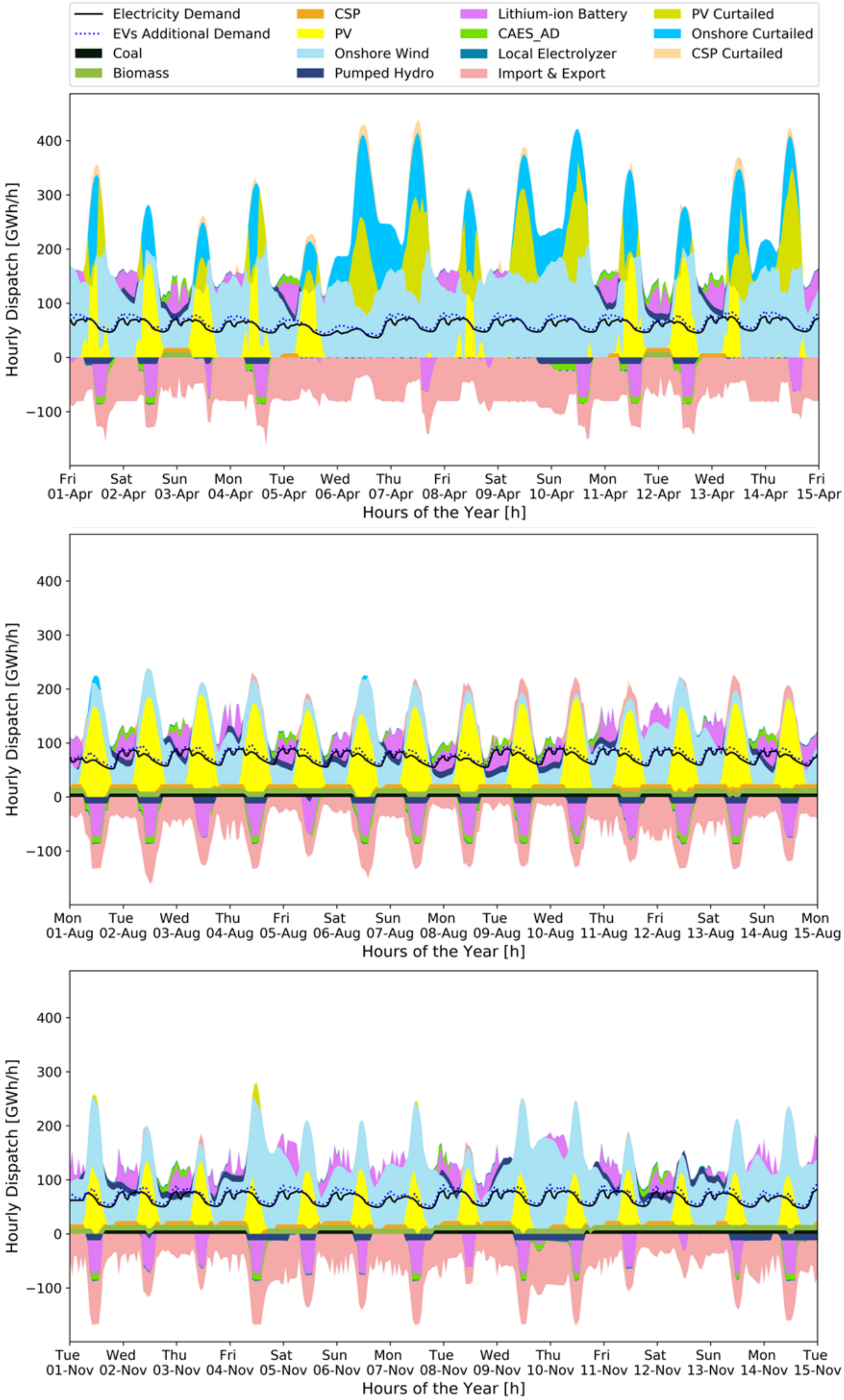


Figure F.8 Typical hourly generation by technologies, export and charge (-), import & discharge (+) to meet power demand in Inner Mongolia of April, August and November in 2050.

Appendix G Influence of Sensitivity Analysis on Full Load Hours

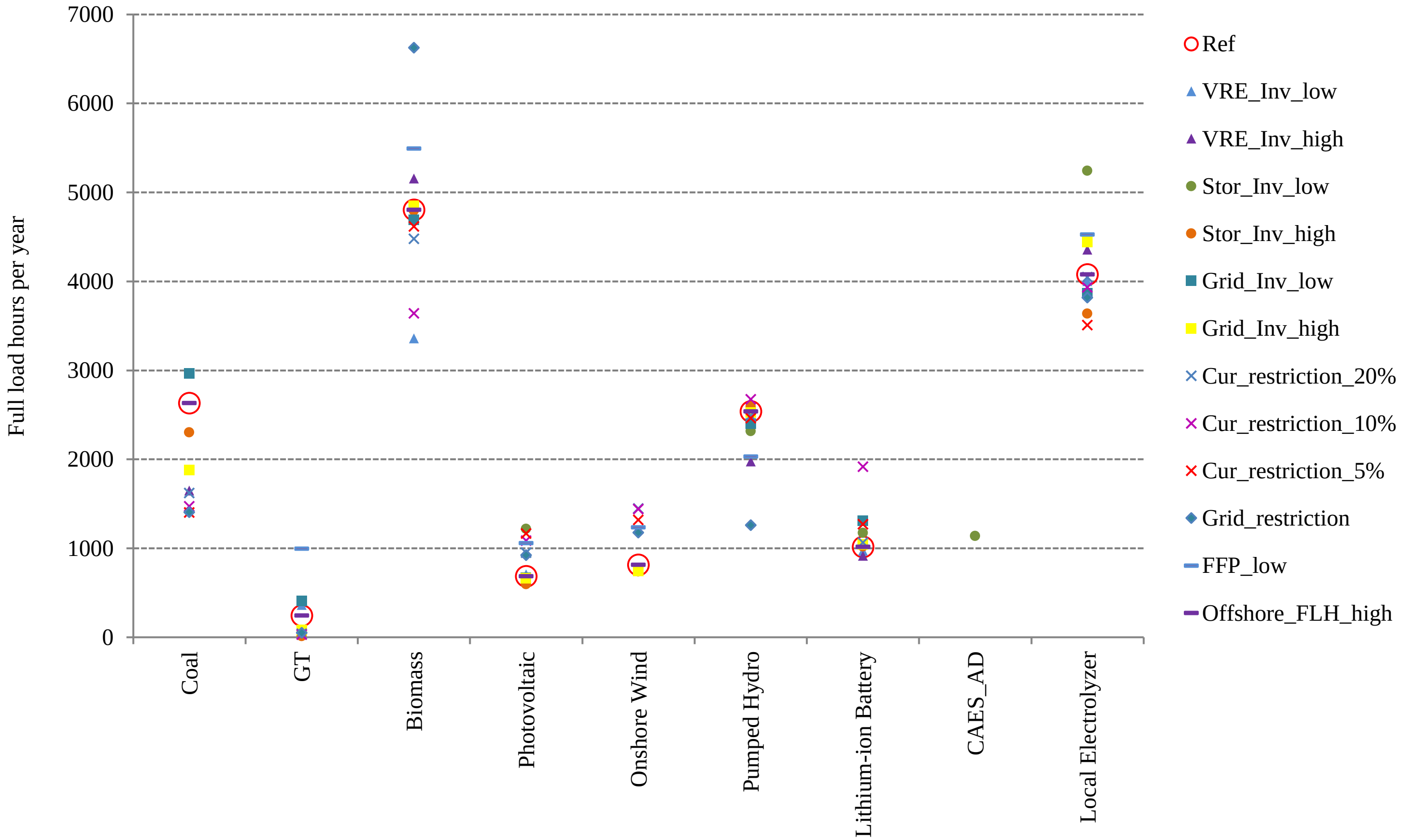


Figure G.1 Influence of Sensitivity Analysis on Full Load Hours in Beijing in 2050.

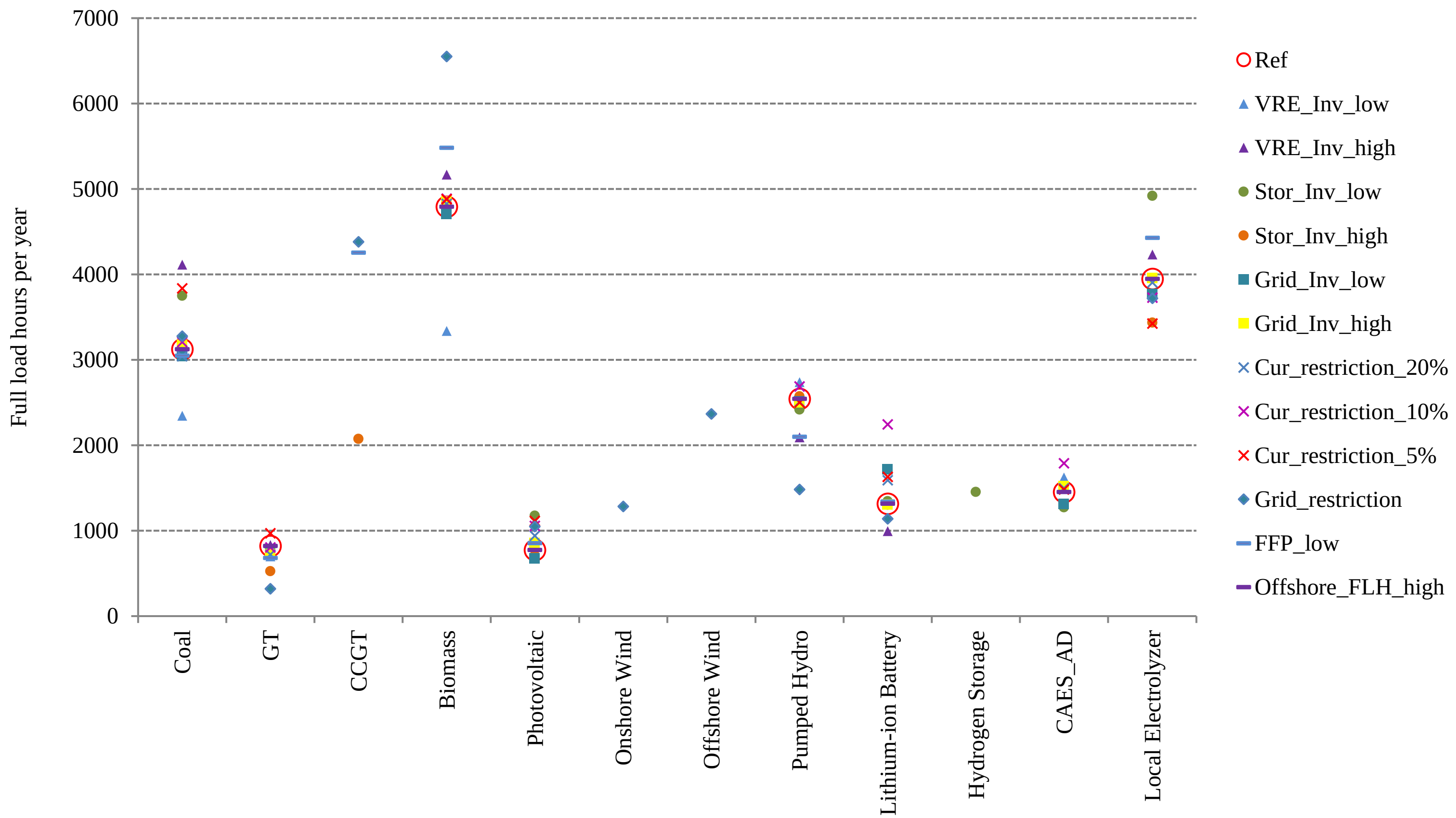


Figure G.2 Influence of Sensitivity Analysis on Full Load Hours in Tianjin in 2050.

Appendix H Overview on Data Sources for Regional Energy System Modelling of China Applied in this Study

Table H.1 Overview on data sources for regional energy system modelling of China applied in this study.

Additional Data Sources	**Publication Authority**	**Spatial Resolution**	**Temporal Resolution**	**Main Data**
China Renewable Energy Data Booklet [177]	China National Renewable Energy Center	Provincial level	Annually	The utilization of RE (solar, wind and biomass) for power and heat supply
Statistics of Power Industry Development of China [197]	China Electric Power Press	Provincial level	Annually	Installed capacity, power generation and heat supply, technical-economic parameters for power plants (> 6 MW)
World Electric Power Plants Database [98]	S&P Global Platts	Provincial, municipal and prefectural level	Annually with historical data	A global inventory of electric power generating units including CHP with design data for plants of all sizes and technologies operated by regulated utilities, private power companies, and industrial auto-producers
China Urban-Rural Construction Statistical Yearbook [75]	Ministry of Housing and Urban-Rural Development	Provincial, municipal and prefectural level	Annually	District heating by CHP and boilers in terms of installed capacity and heat supply for buildings
China Transportation Yearbook [182]	China Transportation Publication	Provincial level	Annually	Traffic volume of passenger and freight by transport modes of aviation, rail, road and pipelines
The current development of RE for power generation [90, 173]	National Energy Administration	Provincial level	Quarterly	The development of RE in terms of grid-connected installed capacity, generated electricity, FLH and curtailment rate
Power Demand (not public available)	Southern Power Grid Company of China	Provincial level (available only for five provinces under Southern Power Grid Company of China)	Hourly	Hourly power demand