Power sector decarbonization in China

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Ying Li – June 2016, Delft, the Netherlands

1
Introduction

1.1 Research background

The People's Republic of China has achieved a remarkable economic expansion during the past three decades, although this has come at a substantial environmental cost due to the coal-dominated energy system. The nation today accounts for more than a quarter of global CO_2 emissions (EIA, 2013b). Furthermore, the growth of CO_2 emissions is expected to continue in China in order to support its sustained economic growth and the energy demand needed to power the economy. Given this, the trajectory of China's CO_2 emissions is critical for any global efforts to address the climate change.

Since it is a developing country, China is not bound to international CO_2 emission reductions according to the 1997 Kyoto Protocol (United Nations, 1998). However, the Chinese government has been proactive in participating in international commitments for CO_2 emission reductions, even though it has been also confronted with huge challenges related to the developing economy, eliminating poverty and improving people's wellbeing in this time of fast industrialization and urbanization. Prior to the United Nations Climate Change Conference (COP15) in Copenhagen in 2009, the Chinese government made voluntary commitments to reduce its CO_2 emissions per unit of gross domestic product (GDP) by 40%-45% by 2020 relative to the 2005 level (State Council, 2012). For the Paris Climate Conference (COP21) in 2015, China further proposed to: 1) achieve the peak of CO_2 emissions around 2030 or earlier; 2) reduce 60%-65% of its CO_2 emission per unit of GDP by 2030 in comparison with the 2005 level; and 3) increase the use of non-fossil energy sources to at least 20% of the total primary energy consumption by 2030 (NDRC, 2015).

In addition to the pressure from the international commitments, the Chinese government is confronted with growing concerns over hazardous domestic air pollution (William et al., 2014). Air pollution has recently led to overcast skies in a large part of the country, and has become particularly bad in the winter time when more coal has to be burned to supply heat. Taking Beijing as an example, a "red alert", which indicates the highest level of air pollution, was declared twice by the city's government in December 2015. Following these alerts, a set of emergency measures has been taken, such as temporary closures of factories, limits on the number of vehicles on the road and halts of outdoor activities for schools, etc. This clearly has a large impact on people's daily lives (Xinhua, 2015).

It is therefore urgent for China to transform its coal-dominated energy system into a low-carbon one. Accordingly, the Chinese government has issued a number of national policies and strategies, such as compulsorily shutting down small coal power plants and promoting the building of high-efficiency large power plants (Wu et al., 2013), as well as improving the energy efficiency of industries. Most of the policies focus on aspects of energy security, where regulation that leads to energy savings also has a co-benefit of reducing CO_2 emissions. For instance, in 2006, the central government introduced the first compulsory target of reducing the energy intensity of its GDP by 20% during the 11th five year plan (FYP) period[1]. A reduction of 19.1% was achieved by the end of 2010, which is very close to the target. This reduction in energy intensity brings huge benefits for the nation, including a saving of 608 million tons standard coal equivalent (sce) and a reduction of 1510 million tons of CO_2 emissions (Yuan et al., 2011). Moreover, the 12th FYP issued in March 2011 also devoted substantial attention to energy security-oriented policies, including the creation of targets for reducing carbon intensity and energy intensity of GDP by 17% and 16% respectively by 2015, relative to 2010; and increasing non-fossil energy (including nuclear, hydro and other renewable energy sources) to 11.4% of total national energy use by 2015, from 8.3% in 2010 (State Council, 2011a; Xinhua, 2011).

As a milestone towards more targeted policies for CO_2 emissions mitigation, an emission trading system (ETS) was introduced to China following the European Union model. So far, seven local ETS pilots in five cities and two provinces have been established by the central government as macro-laboratories to experiment with this new policy (NDRC, 2011). As shown in Fig. 1.1, the pilots were rolled out starting in 2013, and most of these were located in the regions where the economy is relatively prosperous (Zhang et al., 2014). In total, the seven pilots were in areas that together comprised 19.23% of the nation's population and 30.15% of the national GDP in 2011 (NBS, 2012). A large part of China's economy can benefit from the ETS if these pilots succeed. Most coal-intensive industries, such as the power, iron, steel, petrochemical, plastic and paper manufacturing sectors, are included in the ETS.

In particular, the success of China's low-carbon transition hinges on the decarbonization of the power sector, as this sector accounts for almost half of domestic coal consumption and generates about 40% of national energy-related CO_2 emissions (Baron et al., 2012). Still, being confronted with the sustained high growth in electricity demand, a continuous growth of CO_2 emissions of the power sector is expected, if the increased demand can not be met by clean or low-carbon generation. Hence, the decarbonization of the power sector is critical for China to accomplish a transition to a low-carbon economy (Hu et al., 2011).

1.2 Problem statement

1.2.1 Power sector decarbonization: a daunting task

Although China has achieved rapid advancements in developing low-carbon generation technologies, especially renewable energy resource (RES) power technologies since 2006 (Li, 2014), decarbonization of the power sector is a daunting task. This is mainly due

[1] The 11th FYP refers to the years from 2006-2010.

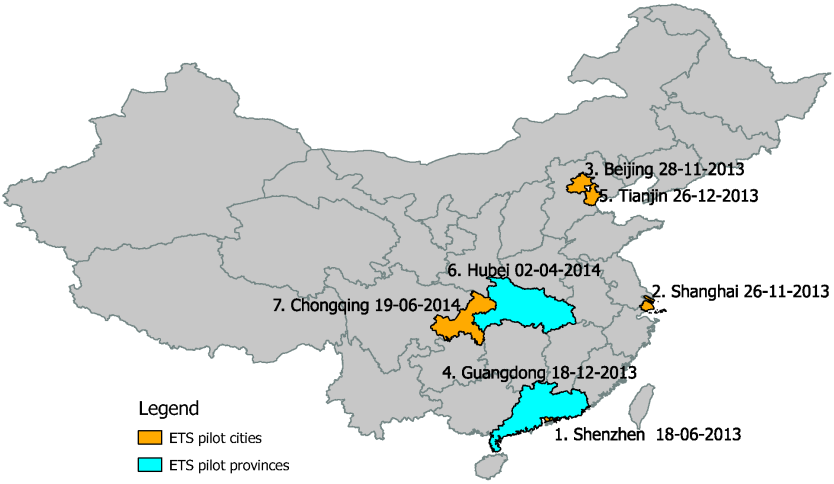


Figure 1.1 – The geographic distribution and the starting dates of the seven emission trading system pilots. Data sources: (World Bank, 2014; China Tanpaifang Web, 2014).

to the fact that the decarbonization of such a complex socio-technical system not only calls for substantial technical advancements, but also requires institutional adaptations to steer investments away from carbon-intensive power infrastructures towards low-carbon alternatives. This is even more difficult for China in view of its specific socio-technical context, as explained in the following paragraphs.

Technically, the entire value chain of China's power supply is confronted with huge challenges for decarbonization. On the generation side, China has been historically locked into coal power which accounts for about 70% of the national power supply. Moreover, the rapid growth of electricity demand has spurred significant investments in new thermal power plants, particularly in coal-based power plants with an average annual growth in installed capacity of 58 GW during the years 2006-2013 (see Fig. 1.2). This prevents a transition to a low-carbon energy system from taking place quickly, given the fact that coal-based power plants are capital-intensive and long-lived with operating lifetimes of more than 30-50 years. With regard to the development of RES power, although wind power capacity has undergone dramatic growth since 2006 (see Fig. 1.2), wind generation merely accounted for 2.6% of the national power supply in 2013 (SGC, 2014b).

Compared with the generation side, investments in transmission and distribution networks have lagged behind. Specifically, investments in the grid accounted for about 45% of total investments in the power sector during 2001-2009, which is much lower than the international standard of 50-60% (Yuan, Shen, Pan, Zhao and Kang, 2014). As a consequence, major issues for China's power grid are evident: 1) the inter-regional transmission grid needs to be expanded in view of the mismatches between energy resources and electricity demand across regions; 2) the regional grid capacity for integrating RES power is far from sufficient, which has led to about 30% of wind power capacity disconnected to the grid during 2007-2011 (Yang, Patiño-Echeverri and Yang, 2012); and 3) the level of automation in distribution networks is low, which might be a barrier for implementing demand response programs and for the utilization of distributed generation (Yuan, Shen, Pan, Zhao and Kang, 2014).

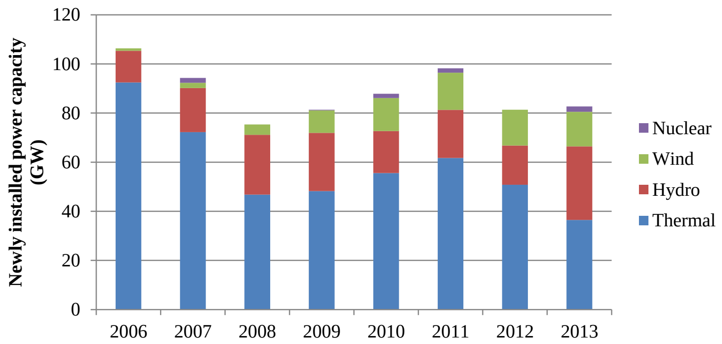


Figure 1.2 – The new installed power capacity by fuel in China during 2006-2013. Data source: (SGC, 2014b).

At the demand side, annual growth in electricity consumption has dropped from over 10% during 2001-2010 to 3.8% in 2014. However, the current growth rate in China is still much higher than it is in most developed economies. While the electricity demand from the tertiary sector, urban and residential users has slightly increased, energy-intensive industrial sectors (including the manufacturing sector) were still the largest electricity consumers and accounted for about 73% of national power demand in 2013 (SGC, 2014d). In addition, China's electricity consumption per capita is much lower in comparison with most developed countries, which indicates that the nation still has a large space for electricity demand growth.

Aside from the technical issues, the current institutional arrangements of the Chinese power sector also make decarbonization challenging. In contrast to most developed countries where electricity market liberalization was implemented, China's market-oriented reforms of the power sector have been very slow. The power sector has remained a single-buyer market since 2002, within which grid companies integrate the roles of grid operation and power supply. In addition, the government retains significant control over electricity planning, investment and pricing, and keeps a large ownership of the power sector. For instance, approval for large power projects, and the electricity pricing for generation, transmission and distribution (T&D) and retail, are all regulated by the government. The need for improving the current institutional arrangements has been made particularly evident by: 1) frequent blackouts triggered by the imbalance between market-based coal prices and regulated on-grid prices (Ma, 2011); and 2) serious wind generation curtailment which is partially attributed to unaligned interests between profit-seeking grid companies and wind power producers (Yang, Patiño-Echeverri and Yang, 2012), etc.

1.2.2 Policy evaluation to facilitate decarbonization

Given the technical and institutional challenges above, the decarbonization process of the Chinese power sector will be very slow unless effective policy interventions are implemented. Without effective policy interventions, there might be more investments in coal-based generation, which can lead to a future situation in which the costs of decarbonization are much higher than they are now.

However, policy-making for power sector decarbonization is highly complex, given the diversity of policy options available. Specifically, decarbonization can be achieved through various institutional and technical options that directly or indirectly allow for massive CO_2 emission reductions over the entire power supply chain (Jägemann et al., 2013). A set of technical and market-based innovations are emerging recently, such as emission trading systems, carbon capture and storage technologies and smart-grid technologies, which all bring opportunities for decarbonization of the power sector. Considering the specific technical and institutional features of the Chinese power system, decarbonization options for China are bound to be different from other countries. Accordingly, an understanding of the Chinese power system, especially the characteristics of the development pathways, is needed to explore what policy options may be most feasible in the context of China.

In addition to providing policy makers with a number of seemingly promising policy options, it is necessary to deliver knowledge regarding the effectiveness and efficiency of these policies for decarbonization. First, it is worth mentioning that the performance of policies in contributing to decarbonization should not be evaluated by looking solely at CO_2 emission reductions. The goals of energy policies should always be aimed at aligning concerns related to energy security, economic efficiency and environmental conservation. This reminds researchers to investigate the implications of policy options from a perspective that combines energy portfolio effects, economics and the environment (also known as the "3E" perspectives hereinafter). Policies that are not designed with concerns from the 3E perspectives will fail to facilitate long-term decarbonization. For instance, while promoting gas power has been acknowledged as a means to reduce CO_2 emissions for China's power supply, gas-fired generation accounted for as little as 2% of the national power supply by 2013 due to the high gas price in China (Kahrl, Hu, Kwok and Williams, 2013).

However, in most cases, policy options cannot fully facilitate all goals at the same time. It is therefore important to understand the trade-offs that need to be made when designing policies that are aimed at achieving the goals from the 3E perspectives. For example, the policy option of mandatory renewable energy targets is good in terms of national energy security and environmental conservation, but it interferes with the principle of least-cost decarbonization (Boeters and Koornneef, 2011). This occurs because investments in renewables must be taken first over other options for CO_2 emission abatement which are cheaper, such as nuclear. Based on the understanding of such trade-offs, challenges left for policy makers and researchers are to explore policy packages that are mutually reinforcing or at least not counter-productive in aligning the 3E goals.

Additionally, the extent to which given policy options can contribute to decarbonization is uncertain, as their performance is often context-specific and highly influenced by various uncertainties in the future (e.g. fuel price volatilities). Hence, policy makers need to be well aware of to what degree certain policy options can contribute to decarbonization, while also considering the influences arising from contextual factors and uncertainties in the future.

The abovementioned 3E perspectives, the trade-offs between the 3E goals, as well as the future uncertainties necessitate a comprehensive evaluation of policy options to better contribute to policy-making that facilitates effective and efficient decarbonization.

1.3 Research objectives and questions

Given the problem description, this work aims to assist policy makers in exploring the pathways for effective and efficient decarbonization of the Chinese power sector. Based on this, the main research question driving this research is:

What policy options can help China accomplish effective and efficient long-term decarbonization of the power sector by aligning concerns related to energy security, economic efficiency and environmental sustainability?

To answer the main question, several sub-questions are formulated as follows:

1. How did the Chinese power system historically evolve, and what can be learned from the past to gain insight into future development pathways?

2. What are the policy options for decarbonization of the power sector given the Chinese context, and what methods can be used to support the analysis of the implications of these options?

3. What are the implications of policy options for decarbonization of the Chinese power sector regarding concerns related to energy portfolio effects, economic efficiency and environmental sustainability?

1.4 Thesis structure

The remainder of this thesis consists of three parts, as shown in Fig. 1.3. Part 1 introduces the theoretical perspective of this study. Part 2 investigates the implications of the key policy options in achieving the goals of long-term decarbonization from the 3E perspectives. Part 3 synthesizes the findings of this thesis and points out future research directions. More explanations about how each chapter is structured are as follows:

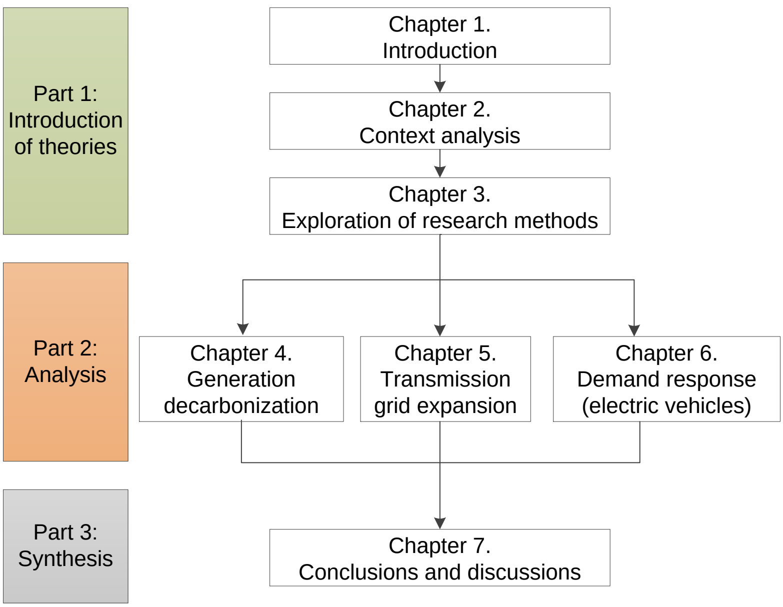


Figure 1.3 – The thesis structure.

Chapter 2 reviews the historical evolution of the Chinese power sector during 1949-2015. It summarizes both the key changes during this evolution and the current status of the Chinese power sector in terms of institutional and technical aspects. This historical analysis provides us with the foundation for exploring the future pathways for power sector decarbonization in China.

Chapter 3 provides methodological support for the policy evaluation in the following chapters. It first discusses the goals of power sector decarbonization from the 3E perspectives, and identifies the corresponding performance indicators of these goals. Further, it identifies a set of institutional and technical policy options that can contribute to the decarbonization of the Chinese power sector. From these, a number of key options are selected in order to clarify the research scope of this thesis. Also, this chapter selects the research method that is used to support the policy evaluation in this thesis.

Chapter 4, 5, 6 investigate the implications of the selected policy options for contributing to the goals of decarbonization from the 3E perspectives. Specifically, Chapter 4 investigates the key policy options on the generation side including the deployment of carbon capture and storage (CCS) technology and RES power technologies, as well as CO_2 pricing. Chapter 5 studies the policy options on the grid side that are concerned with the expansion of the inter-regional transmission grid. Chapter 6 focuses on the policy options on the demand side with demand response of electric vehicles as a case study. The main findings regarding the implications of these policy options are chapter-specific, and are summarized within the respective chapters.

Chapter 7 concludes the main findings, reflects on the limitations of this thesis, and formulates a future research agenda.

2
Historical evolution of the Chinese power sector: 1949-2015

2.1 Introduction

The development pathways of the power sector are very different between countries, since they are largely influenced by the broad political-economic context, the availability of natural resources, the demographic and geographical conditions, etc. Given this, this chapter aims to understand how the Chinese power system has historically evolved and how it is currently structured. This historical analysis provides us with the foundation for exploring the future pathways for power sector decarbonization in China.

Specifically, this chapter first introduces the key theoretical concepts that underpin the understanding of the structure and the evolution of the power system in Section 2.2. Then, Section 2.3 and Section 2.4 review the historical evolution of the Chinese power system in the institutional and technical aspects. The findings of this chapter regarding the features of the current Chinese power system and the implications of the historical evolution for future development pathways are provided in Section 2.5.

2.2 Theoretical foundations

The considerable expansion of sciences in socio-technical systems (Asbjørnsen, 1992; Holland, 1992; Trist, 1981; Trist et al., 1978), new institutional economics (Williamson, 2000), and the electrification evolution of western countries (Hughes, 1993) all provided momentum for developing the following ideas in this section:

- what the power system consists of;
- how the power system evolves.

2.2.1 Electric power systems as socio-technical systems

Electric power systems, regardless of their scale, have been increasingly seen as complex socio-technical systems by scholars and policy makers. The implications of being a socio-technical system, then, are: 1) the power system consists of a set of social and technical components; and 2) these components continuously interact, adapt and collectively determine what the system looks like and how the system changes over time and space.

The social subsystem Specifically, the social subsystem is comprised of a set of actors and interactions between these actors. Before the 1980s, most key tasks of electricity generation, transmission and distribution were vertically integrated by one organization which is normally state-owned. Then, electricity liberalization and privatization were widely adopted in many developed economies, which has gradually broken up the vertical integration of the power system and led to a shift from centralized to fragmented control and ownership over the system (Bollinger, 2015). Following the developed countries, many developing countries also started participating in the movement of electricity liberalization and privatization, despite considerable challenges for implementing such complex market-oriented reforms in their economies (Besant-Jones, 2006).

Influenced by the broad political-economic context, countries have shown large differences in the degree and speed of electricity liberalization and privatization. While the types of actors in the power sector are context-specific, they are generally grouped as follows according to the roles that they play in the power system: the government and regulators, power producers, grid operators (transmission system operators (TSO), distribution system operators (DSO) and system operators (SO)), power suppliers (e.g. retailers) and consumers (also prosumers[1]), etc.

Broadly, the interactions between these actors can be seen as institutions: "*human-devised constraints, both informal and formal, which shape human relations and interactions to simplify complexities and reduce uncertainties*" (North, 1990; Aoki, 2001; Williamson, 2000). According to the new institutional economics, three levels of institutions play major roles in determining the long-term economic and political development of a society. Specifically, the highest layer is labeled as "*embeddedness*" which refers to informal institutions or common social values that are deeply prevailing in society, such as traditions, norms, customs and beliefs. Below comes the second layer, the so-called "*institutional environment*" which refers to the political system, bureaucratic structures, judiciary and legal system. The third layer is known as "*governance*" which represents the institutions that govern transactions, such as markets, firms, networks and policies. These three levels of institutions jointly determine and constrain the behaviors in transactions, such as prices and quantities (Williamson, 2000; Andrews-Speed, 2010). All the features of the socio-subsystem can be finally traced back to these institutions.

The technical subsystem In the traditional sense, the technical subsystem is comprised of the hardware that physically produces electricity and transmits it to the load that consumes electricity (De Vries, 2004). The power flows used to have a single direction from generators, via transmission & distribution (T&D) networks, to the load. In recent years, however, the development in distributed generation (DG), energy storage systems and various demand response (DR) programs etc. has diversified the sources of power supply.

[1] A prosumer refers to a consumer who can sell electricity back to the power system.

Therefore, the direction of power flows through the value chain of power supply becomes bi-directional.

Different technologies and apparatuses have been developed and deployed in the technical system, which results in the diversity of physical features of the components. For instance, generators can be characterized by their capacity, controllability (the speed with which they can react to changes in electricity demand), availability (continuous or intermittent), energy sources (e.g. coal, uranium and wind) and environmental consequences (e.g. emissions, noise). T&D networks are normally comprised of a set of transformer-linked networks at different levels of voltage.

2.2.2 The evolution of the power system

The social and technical subsystems closely interact. Specifically, the technical subsystem sets up the physical fundamentals for a power supply; while the socio subsystem makes sure that the technical subsystem is invested, developed and operated efficiently. The complexity of such a socio-technical system not only arises from the interactions between various social and technical components, but also because the socio components are continuously changing due to their responsive behaviors, which together result in emergent behaviors of the system (van Dam et al., 2012).

In particular, Hughes (1993) investigated how social influences and technical advancement shape the evolution of the power system, by comparing the electrifications in the cases of Chicago, Berlin and London during 1880-1930. The regional variations in the electrifications of these three cases illustrated that social influences are dominant in shaping the evolution of the power system, while technical advancement is responsive and developed accordingly to suit the social context.

With regard to the social influences, given the fact that natural influences (e.g. geographical conditions) hardly change over a short time, therefore most studies focus more on human influences, also known as the institutions as explained in Section 2.2.1. While it is undeniable that both informal (e.g. an individual's and a group's decisions and learning) and formal institutions (e.g. laws and policies) influence the evolution of the power system, this thesis highlights that policy interventions (part of formal institutions) have a large impact on determining the direction and the speed of the power system evolution. This is clearly evidenced in reality with on-going policies for the power system. Also, the behaviors of actors in the power system can be seen as reactions to policy interventions.

Still, we acknowledge that policy interventions are able to partly but not fully steer the evolution of the power system, as the system does not always behave rationally due to the individual's and group's decisions. This argument establishes the principle regarding the role of policy interventions in steering the decarbonization of the power system in this thesis.

2.3 The Chinese power system evolution: the institutional aspect

The institutional development of the Chinese power sector is in the middle of a long and drawn-out evolution (IEA, 2006). This evolution is closely linked to the broad context of: 1) the socialist market economy reforms started in the late 1980s; and 2) the worldwide movement of electricity liberalization. Fig. 2.1 shows the milestones of the Chinese power system evolution in the institutional aspect since 1949 when it was first nationalized. These milestones have marked a slow process of institutional reform of the system. This section elaborates on the institutional reform of the Chinese power sector along with these milestones, focusing on changes in aspects of electricity governance, market structure, ownership and electricity pricing.

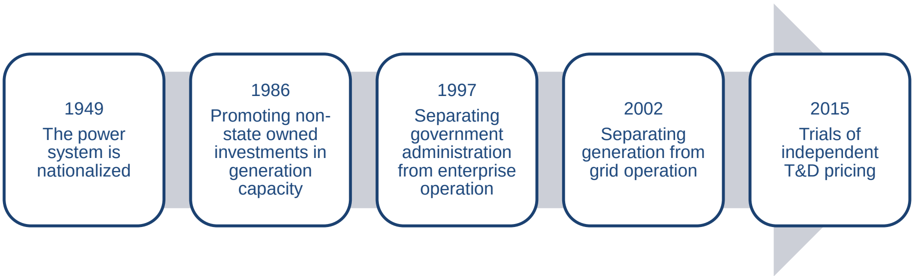


Figure 2.1 – The milestones of institutional reforms of the Chinese power sector during 1949-2015.

2.3.1 Electricity governance

This thesis understands electricity governance in the broad context of energy governance. The evolution of the Chinese energy governance at the state (central government) level is shown in Fig. 2.2.

Prior to 1993, China's energy policies were basically summations of individual industrial plans, when it comes to the coal and power sector in particular (Andrews-Speed, 2010). Specifically, before the 1980s, a set of ministries which owned the energy sector's assets were endowed to make individual industry policies and plans. The State Planning Commission (SPC), the chief macro-economic planning agency, took the responsibility for strategic issues (e.g. approvals of investments) across the energy sectors. In the late 1980s, China's "reform and opening-up" policies largely promoted the economic growth and first brought the ideas of market power to the central planning economy. Under such circumstances, separating governmental administration from enterprise operations was used as a means of introducing market power. Accordingly, the State Ministry of Petroleum was replaced by the China National Petroleum Corporation (CNPC), which indicates the first corporation of the energy sectors. To supervise and coordinate the operations of energy enterprises and the unincorporated energy ministries (e.g. for the coal and power sector), the Ministry of Energy was established in 1988. However, the Ministry of Coal and the Ministry of Power retained their strong power in the individual industry's policy making, which meant that the Ministry of Energy had very poor influence in energy-related governance. Given this, the Ministry of Energy was abolished in 1993.

Since 1998, the Ministry of Coal and the Ministry of Power were both replaced by provincial-level coal companies and the State Power Corporation. Accordingly, the State Economic and Trade Commission (SETC) was built to oversee operations of the state-owned corporations. The State Development and Planning Commission, which is the predecessor of the previous State Planning Commission, was endowed to develop medium and long-term energy plans, energy pricing and energy efficiency regulations.

Since 2003, China has tried to centralize the energy governance at the state level with a set of measures. With the dismantling of the SETC, strong power of the state's plan-

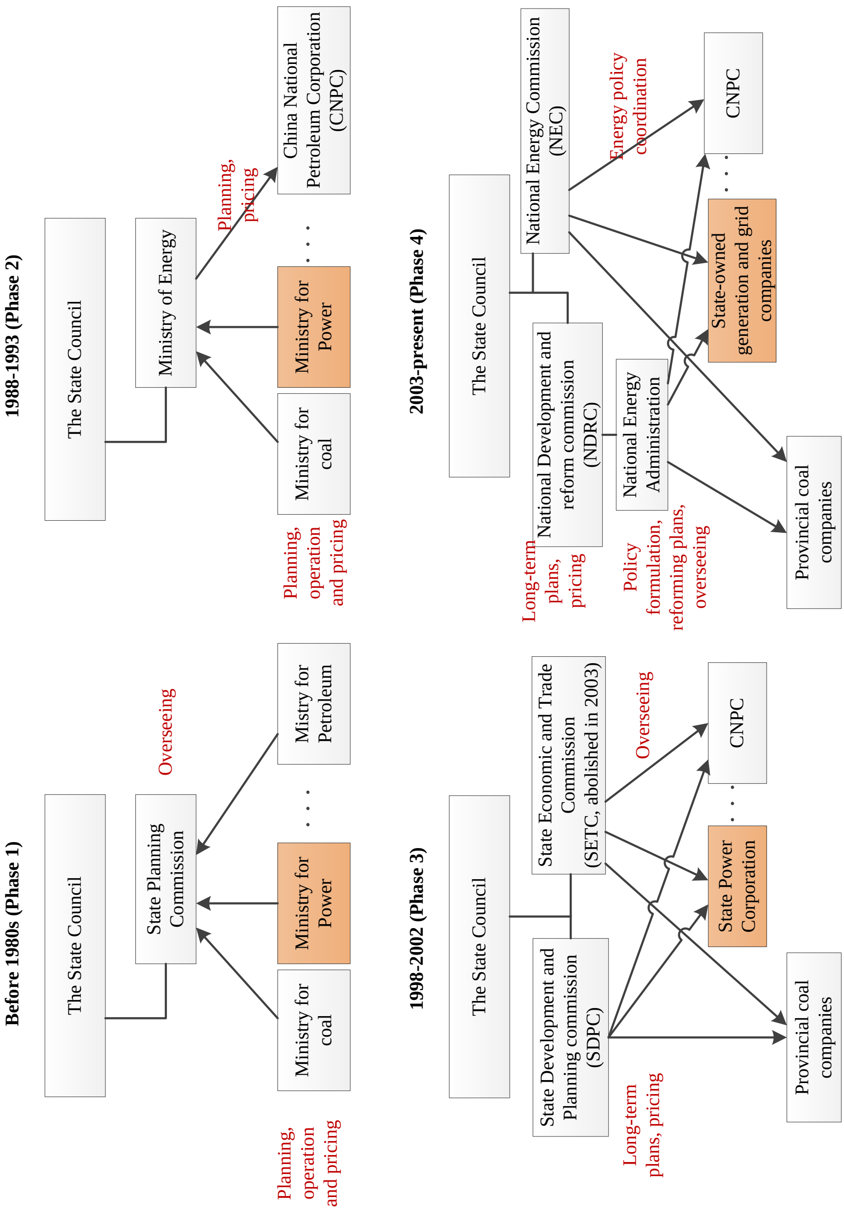


Figure 2.2 – The evolution of energy governance in China at the state level. This evolution is mainly drawn based on the information in (Andrews-Speed, 2010).

ning agency was retained by the National Development and Reform Commission (NDRC) (which replaced the previous SDPC) in 2003. The NDRC was endowed to have nation-wide and sector-wide responsibility for planning and reforming the macro-economic development. An Energy Bureau (within the NDRC) which later became the National Energy Administration (NEA) in 2008, was set up to formulate energy policies, draft the energy sectors' reform plans and oversee the routines of the energy sectors. However, the key responsibilities of energy pricing remained with the NDRC. The National Energy Commission (within the State Council) was set up to improve the coordination of energy policies and to establish national energy strategies.

In short, China has historically lacked a well-resourced national energy agency to coordinate the planning and operations between different energy sectors. Even today, the National Energy Agency is housed in the NDRC, which to some extent prevents itself from independent energy policy-making. The strong power of the NDRC (and its predecessors: the SPC, SETC) also to some extent reflects China's deep adherence to the ideology of the central planning economy. Accordingly, the Chinese energy governance has historically been of tight control by the government to serve the state's macro-economic planning and development. Although the State Electricity Regulation Commission (SERC) was set up to oversee the performance and promote market-oriented reforms of the power system in 2003, it was dismantled in 2013 given its poor influence in the electricity governance.

2.3.2 Market structure

China has been very cautious about the liberalization of the power sector, so that changes in the structure of the system have been very slow. Specifically, prior to 1985, the power system was organized as a vertically integrated utility. The key tasks of electricity generation, transmission and distribution were carried out by the State Power Ministry (SPM). While the SPM was replaced by the State Power Corporation (SPC) in 1997, the vertically integrated structure of the power system was not changed until 2002.

With the dismantling of the SPC in 2002, China's electricity generation was vertically unbundled by separating generation from the grid operation (see Fig. 2.3). This move has created a single buyer market of China's power system, in which power producers sell the power to grid companies and grid companies sell the power to end users, as shown in Fig. 2.4. However, the single buyer model of China's power system is slightly different from the classical one described in (Hunt and Shuttleworth, 1996), for the absence of a free market for generation competition. Hence, the Chinese power system is also labeled as "a relatively monopolized single buyer market".

In particular, two giant grid corporations, namely the State Grid Corporation (SGC) and the China Southern Grid Corporation (CSG), are responsible for almost all the grid operation and power supply in China. The division of the administrative territories of these two corporations has created a six-region power system in China, as illustrated in Fig. 2.5. In details, the SGC serves 88% of the nation's territory with five affiliated regional power systems, namely the North, East, Northwest, Northeast and the Central system; the CSG is responsible for the South regional power system which consists of five provinces in South China, namely Yunnan, Guizhou, Hainan, Guangxi and Guangdong. More explanations about the spatial coverage of each regional power system at the provincial basis are given in Table 2.1.

Despite a set of institutional changes that have been going on since 2002, such as the trials of regional electricity markets during 2003-2006 and the trials of the bilateral market

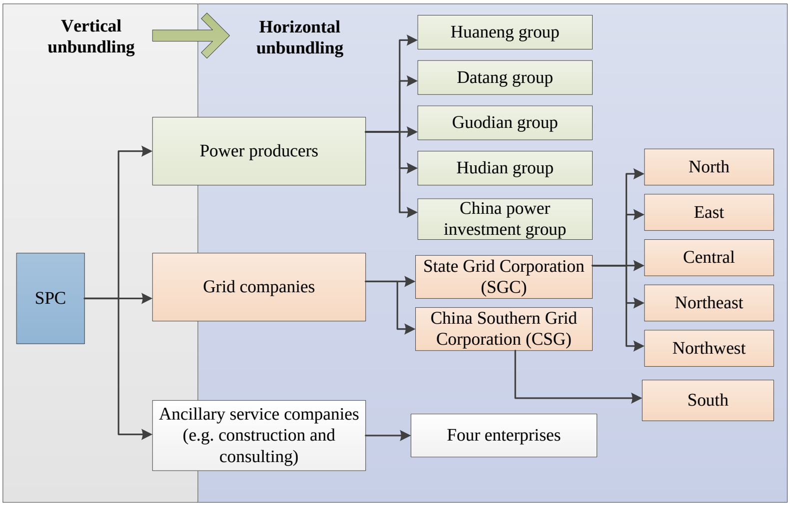


Figure 2.3 – The dismantling of the State Power Corporation (SPC), and the vertical and horizontal unbundling of the Chinese power sector in 2002.

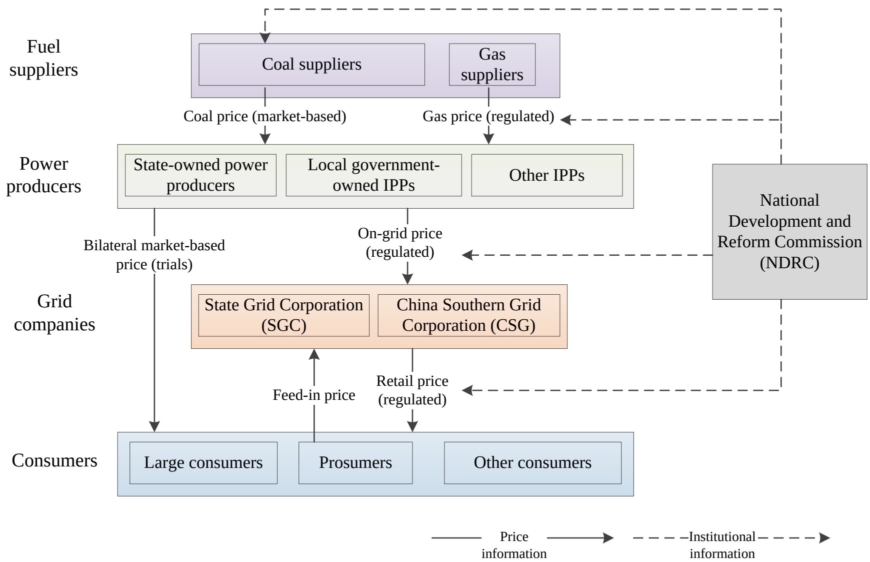


Figure 2.4 – The structure of the single buyer market of the Chinese power system and the electricity pricing between actors since 2002. The price labeled with "regulated" means it is under the government (the NDRC here) control. Considering the coal market has been liberalized since 2002, the institutional link between the NDRC to coal suppliers represents governmental interventions here.

for big industrial users and power producers, the structure of the single buyer market has remained in China so far. Since 2015, a new round of electricity reform which aims to change the role of grid companies within the single buyer market has gained much policy attention, while it seems that no fundamental changes of the structure are going to take place soon.

Figure 2.5 – The geographical division of the six regional power systems in China.

Table 2.1 – The spatial coverage of the six regional power systems (Wang et al., 2014).

Regional power system	Spatial coverage (including provinces, municipalities and autonomous regions)
North	Beijing, Tianjin, Hebei, Shanxi, Shandong and West Inner Mongolia[1]
East	Shanghai, Jiangsu, zhejiang, Anhui and Fujian
Central	Henan, Hubei, Hunan, Jiangxi, Sichuan and Chongqing
Northeast	Liaoning, Jilin, Heilongjiang and East Inner-Mongolia
Northwest	Shaanxi, Gansu, Qinghai, Ningxia, Xinjiang and Tibet[2]
South	Guangdong, Guangxi, Yunnan, Guizhou and Hainan

[1] West Inner-Mongolia covers the areas of Chifeng, Tongliao, Hulunbuir and Hinggan League of the Inner Mongolioa autonomous region; and East Inner Mongolia is the rest part of Inner Mongolia;

[2] Tibet used to be independent from the main power system, this work takes Tibet as a part of the Northwest power system considering growing grid connections between Tibet and the regions of the Northwest power system (e.g. Qinghai).

2.3.3 Ownership

Within the background of long-held socialist beliefs and values, the Chinese government has shown strong control over the key energy sectors (Andrews-Speed, 2010). As such, the governments, at both central and sub-central levels, have retained significant ownership of the power sector's assets. However, the ways in which the government owns and controls these assets have largely changed over time.

Prior to 1986, all generation and grid assets were fully owned by the State Power Ministry. The opening up of generation investments to parties other than the central government in 1986 to a large extent diversified the ownership of generation assets (Wang and Chen, 2012). However, the new investors back then were mainly comprised of provincial and local governments. In contrast, the number of private and foreign investors was quite limited, mainly due to long-standing institutional obstacles for new non-governmental entries (e.g. policy and legal ambiguity, and institutional unfairness) (Andrews-Speed, 2010). It is estimated that the generation assets owned by the sub-central governments[2] that emerged from this period account for about half of the national total today (Ngan, 2010; IEA, 2006). Still, the central government maintained the sole ownership of the grid assets during this period.

In 1997, with the corporation of the power sector, the power system assets owned by the State Power Ministry were transferred to the State Power Corporation (SPC) with the government treasury as the single stakeholder. Then, the SPC owned nearly 40% of the national generation assets and almost all the nation's grid assets (Wang and Chen, 2012; IEA, 2006).

Afterwards, the reform in 2002 vertically and horizontally unbundled the power system, yet it has not changed the significant government ownership. With regard to generation ownership, the new five state-owned generation corporations (see Fig. 2.3) inherited all the generation assets of the SPC, as shown in Fig. 2.3. Coupled with the generation assets owned by the sub-central governments, the government in total owns about 90% of the national generation capacity.

In addition, the significant government ownership continues in the new-developed renewable energy power market. Taking wind power for instance, the wind power capacity owned or partly owned by the government accounted for about 97% of the national total at the end of 2013, as shown in Fig. 2.6.

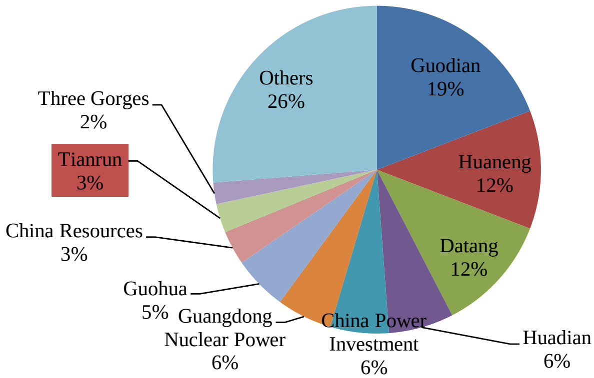


Figure 2.6 – The share of wind power capacity by enterprise at the end of 2013, and the total capacity is 91.412 GW (Li, 2014). Except for the Tianrun (marked in red), all enterprises are owned or partly owned by the government.

[2]These investors are also known as independent power producers (IPPs) within the context of China, given the fact that they are independent of the central government.

2.3.4 Electricity pricing

The electricity pricing which consists of the on-grid price, T&D price and the retail price (see Fig. 2.4) has been historically regulated as a means to achieve the target of the state's development and to ensure social welfare (Garcia, 2011).

On-grid price Within the vertically integrated power system during 1949-1985, electricity prices were internal transfer prices just for accounting purposes, rather than for allocating resources (Ma, 2011). Given the dominance of thermal power especially for coal power, the on-grid price of thermal power has been used as an economic lever to achieve the target for the development of the power system, as shown in Table 2.2.

Although the latest technology-based benchmark price to some extent provides competition for power producers, it fails to pass through the fluctuations in coal prices to end users. Considering the dominance of coal in China's power supply, the fixed on-grid price has lead to substantial economic loss and triggered frequent black-outs, especially when market-based coal prices soared during 2004-2008. To address this, a "coal and electricity price co-movement" mechanism was adopted in 2004, to periodically adjust the on-grid price of coal power according to coal price changes. However, the preconditions of this mechanism are: 1) the frequency of the adjustment cannot be shorter than six months, and it is only possible if the average coal price in the new period is 5% higher than the previous cycle; and 2) not all the power producers' cost are passed on; about 70% of the coal price growth can be passed on to end users, and the remaining cost has to be internalized by power producers (Zhang, 2012).

T&D price Since no separate T&D pricing was stipulated, grid companies obtain their revenues for providing services through residuals between retail sales and power supply costs. Although the State Electricity Regulation Commission (SERC) tried to develop accounting standards and reporting requirements for grid companies on T&D costs in 2005, the level of details and transparency required is insufficient for a public assessment (Kahrl et al., 2011). The lack of separate T&D pricing has to some extent resulted in the profit-seeking nature of grid companies, which has become a barrier for the use of clean yet expensive wind generation (Yang, Patiño-Echeverri and Yang, 2012). Given this, establishing separate T&D pricing has become the direction of the next round of reform (CEC, 2015). By the end of July 2015, trial operations of separate T&D pricing were carried out in six pilots, including Shenzhen city, the west of Inner Mongolia, Anhui, Hubei, Ningxia and Yunnan provinces. In addition, in the recently established bilateral power market trials, exclusive T&D pricing for large users is used depending on regions and voltage levels.

Retail price The electricity price for end-users, also known as the retail price, is regulated by the government rather than reflecting the costs associated with power supply services. The "catalogue pricing" has been used for retail price since the 1960s, in which eight groups of electricity consumers at three voltage levels can be identified. The eight groups are illustrated in Fig. 2.7. In general, commercial users, non-household lighting users and industrial users are assigned with a retail price higher than the national average. On the other hand, households and irrigation users, agricultural users and the poor get a subsidized price which is much lower than the national average. In particular, the price of big industrial users has been kept lower than other common-industrial users to protect the cost-competitiveness of heavy industry.

Table 2.2 – The evolution of on-grid price for thermal-based power generation since 1985.

	1985-2000	2001-2003	2003-2006	2004-present
On-grid price	Cost-recovery price	Cost-recovery price + Operating lifetime price	Two-tier price	Benchmark price
Unit	Energy-based price	Energy-based price	Energy-based and capacity-based price	Energy-based price
Key features	With this price, new investors are allowed to recoup capital investment, interests, operation costs and a reasonable rate of return (about 12% to 15%); also, the price is project-specific.	For new-built power plants, the investment costs are amortized over the technical life of plants rather than the financial lifespan; for the old power plants, cost-recovery price is still used; also, the price remains project-specific	Capacity price is determined based on the average investment cost of different technologies and energy price is decided based on market bidding	Setting benchmark price based on technologies
Objectives	To promote investments in generation capacity, and meet the fast-growing electricity demand arising from economic growth	To provide incentives for power producers in cost control and efficiency improvements	To establish regional electricity markets and experiment with market competition	To provide incentives for power producers in cost control and efficiency improvements; also, to simplify the complex pricing mechanisms towards a more uniformed one

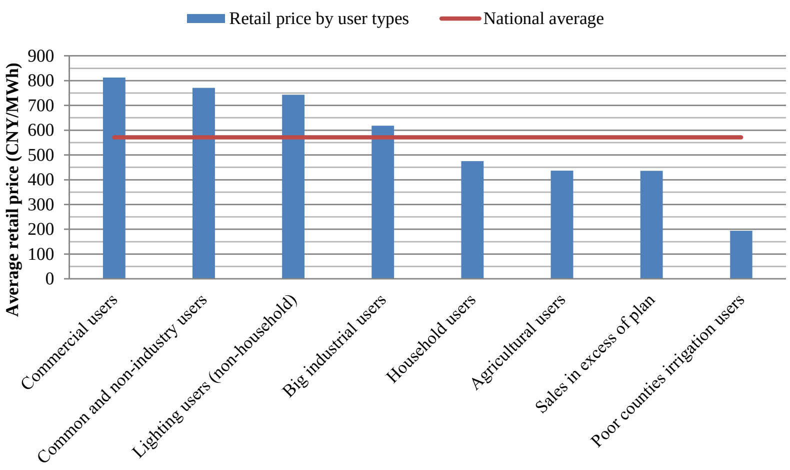


Figure 2.7 – The average retail price for different groups of electricity users in 2010 (SERC, 2011) .

In addition, several adjustments have been made in the retail price to reflect the state's development priorities. For instance, public funding surcharges have been added to the retail price for the development of hydro power projects, renewable energy power, rural network reinforcement and the urban utilities development (SERC, 2011). Moreover, a differential electricity price (DRP) was adopted for big industrial users in 2004, which attempted to restrict the blind development of energy-intensive industries (Chen, 2011). Time of use (TOU) prices are also applied but mainly limited to commercial and industrial users. For residential users, a tiered electricity price (TEP) was adopted in 2010, in which three price hierarchies were provided, and additional payment is required for users whose consumption exceeds the upper boundary of a given hierarchy.

2.3.5 Power dispatch mechanism

A "planned quota" contract that predefines the minimum quota of power dispatch for power producers in the next future years has been adopted since 1978, with the purpose of ensuring fairness for power producers in power dispatch. Specifically, each generator of the same type is roughly operated for the same hours per year, regardless of the operating cost or fuel efficiency.

To improve energy efficiency, a new "generation right trading (GRT)" was gradually implemented in 1999 to complement the previous planned quota dispatch. Specifically, with the planned quota as the basis, the GRT allows transactions of generation quota among power producers, as illustrated in Fig. 2.8. The GRT attempts to increase the generation from high-efficiency plants. It is only between power producers and at a voluntary basis, while it does not change the summation of the planned quota for all power plants (Gao and Li, 2010).

In 2007, the "Energy Saving Power Dispatch (ESPD)" mechanism was issued by the State Council to minimize the fossil fuel use and conserve the environment. Five pilot provinces were selected for the implementation of the new mechanism, including Jiangsu, Henan, Sichuan, Guangdong, Guizhou province (NDRC, 2007b). The new dispatch method in essence is a mandatory rule that favor the units with high energy efficiency and low CO_2

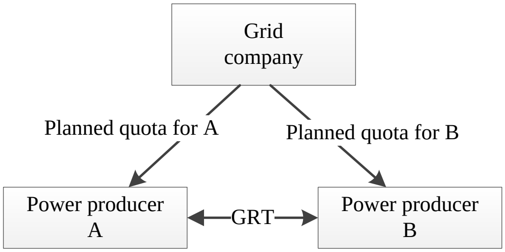


Figure 2.8 – The illustrative structure of the generation right trading mechanism.

emissions. Specifically, the ranking of the priorities between units for generation is: 1) non-dispatchable RES, such as wind, solar, hydro (run of river); 2) dispatchable RES, hydro-pumped, biomass, geothermal, garbage; 3) nuclear; 4) co-generation units where electricity is a by-product, such as CHP (combined heat and power); 5) coal gangue, washed coal, and other integrated resource use units; 6) natural gas, gasified coal; 7) coal-fired generators, and integrated resource use units that, use conventional coal, dispatch with the lowest coal consumption; and 8) oil-fired generation (Gao and Li, 2010).

2.4 The Chinese power system evolution: the technical aspect

2.4.1 Generation portfolios

The national generation capacity has undergone a dramatic growth, as shown in Fig. 2.9. In the following paragraphs, this thesis mainly highlights four key points of the Chinese electricity generation: 1) the coal lock-in; 2) the fast development of RES power; 3) large regional variations in generation portfolios; and 4) large improvements in generation efficiency.

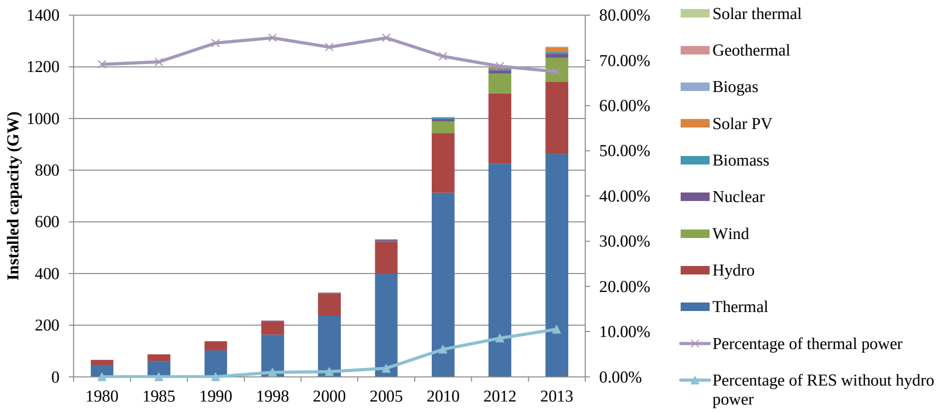


Figure 2.9 – The evolution of installed generation capacity during 1980-2013. Data source: (EIA, 2015b; GlobalData, 2015)

Coal lock-in With regard to generation capacity by fuel, coal power has historically taken the dominant position (around 70%) in China's power supply, followed by hydro power (around 20%). The dominance of coal power can be traced back to the country's natural resource landscape which features an abundance in coal yet a severe shortage of gas and oil. Still, considering the long technical lifetime of coal power plants and sustained electricity demand growth, China's power supply is more likely to rely on coal power in the near future.

Fast development of RES power and inefficient use of wind energy Although non-hydro RES power accounts for less than 10% of the nation's total capacity, its fast development especially in wind power has resulted in a slight decrease in the percentage of coal power (see the lines in Fig. 2.9). In particular, the annual growth in China's wind power capacity was doubled during 2006-2010 (Li, 2014). By the end of 2013, the accumulated wind power capacity exceeded 92 GW, which makes it the largest country in terms of capacity. However, it is worth mentioning that the use of wind energy in China has been particularly inefficient, which is mainly because: 1) around one third of wind power was not connected with the grid (see Fig. 2.10); 2) and a large amount of wind generation was curtailed especially for the three North regions (Yang, Patiño-Echeverri and Yang, 2012; Li, 2014). Additionally, solar power capacity has undergone a fast growth since 2011 when the feed-in tariff for solar power was issued.

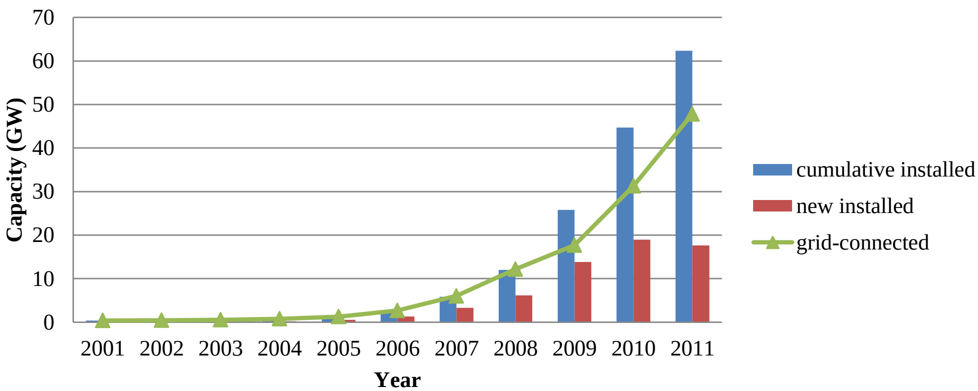


Figure 2.10 – The cumulative, new installed and grid-connected wind power capacity during 2001-2011. Data source: (Li, 2014; Yang, Patiño-Echeverri and Yang, 2012)

Regional variations in the generation portfolio China's generation portfolio shows large variations across the six regional power systems (see Fig. 2.11), mainly constrained by the imbalanced distributions of regional natural resources. Generally, China's coal, wind and solar resources are mostly reserved in the North, Northwest and Northeast (also known as the three North) regions, while hydro power is mainly allocated in the Central and South regions. However, the East region, a large load center, has scarce resources. The spatial imbalance between power resources and electricity demand makes the inter-regional transmission grid a necessity for China (as explained in Section 2.4.2). Besides, the dominance of coal power also results in a high thermodynamic inflexibility of integrating

RES generation for the three North regions, given the slow responsiveness of coal power and the fact that most coal-fired power plants must be turned on to supply heat.

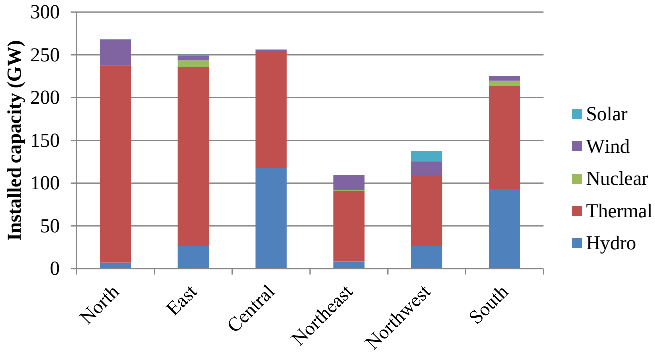


Figure 2.11 – The installed capacity mix of the six regional power systems in 2012 (SGC, 2013).

Improvements in generation efficiency China has achieved large improvements in developing high-efficiency coal generation technologies during the past few years. With the technology innovation in large-scale coal power units, coupled with the state's efforts in shutting down small coal power plants[3], the percentage of units larger than 300 MW increased from 39% in 2005 to 70% at the end of 2011 (Yuan, Xu, Hu, Yu, Liu, Hu and Xu, 2012). The focus of coal generation technology is on supercritical and ultra-supercritical (USC) pulverized coal technologies. The first USC unit with a capacity of 1000 MW was put into operation in 2006. Several integrated gasification combined cycle (IGCC) power plants which have a net efficiency higher than 45% are being demonstrated in China (Zhao et al., 2008). The improvements in generation efficiency largely mitigate the coal consumption and CO_2 emissions of power supply (Baron et al., 2012).

2.4.2 Transmission and distribution grid

As mentioned above, the spatial mismatches between energy resources and electricity demand across the regions have necessitated the development of an inter-regional transmission grid in China. The basic framework of inter-regional connections was achieved in 2005, while the transmission capacity is still quite limited. As shown in Fig. 2.12, the total transmission capacity by 2012 was in total 47.4 GW, which is less than 4% of China's total installed capacity. Accordingly, about 80% of energy exchange across the regions still relies on primary coal transportation through railways and shipping (Chen et al., 2014). In addition, expanding the inter-regional transmission grid is also seen as an important strategy to help China to increase the use of renewable energy across the regions.

In addition, China is making fast progress in ultra-high voltage (UHV) transmission technologies. The SGC and CSG have successfully applied core technologies for UHV transmission system and developed the cutting-edge AC (1000 kV) and DC (± 800 kV) UHV equipment, which effectively improves the safety, transmission capacity and energy

[3] Small units here refer to small (<=50MW), low efficient and high-polluting coal units (>=20 years and <=100MW, or <=200 MW that are reaching the ends of their economic life spans). In total, about 70 GW of these units were closed during 2006-2010.

Figure 2.12 – The capacity of the inter-regional transmission network by 2012 in GW. This capacity data is mainly achieved from (Chen et al., 2014) with adaptations for integrating Tibet into the Northwest regional power system.

efficiency of the power grid. Moreover, automation technologies at the distribution side have been preliminarily applied in the power system in China, and research in distributed renewable generation on the distribution network has achieved remarkable results (Yuan, Shen, Pan, Zhao and Kang, 2014). The development of other aspects of the grid, such as the micro-grid, is relatively slow. The SGC has proposed the concept of developing a "strong and smart" grid which uses the UHV grid as its backbone and subordinate grids coordinated at all levels to build a modern power grid that is IT-based, automatic and interactive.

2.4.3 Electricity demand

Propelled by the fast economic expansion, China's electricity demand has continued a striking growth since the 1990s, from 612.6 TWh in 1990 to 5322.3 TWh in 2013. The average annual growth rate of electricity consumption exceeded 10% during the last decade (see Fig. 2.13). The growth rate in electricity consumption since 2012 has slightly slowed down to about 5% and 7.5% in 2012 and in 2013 respectively.

The decline in electricity consumption growth is attributed to the following factors. First, the economy has slightly slowed down compared with the rapid expansion during the past decades. China's GDP growth since 2011 has largely dropped from double digits to single digits (see Fig. 2.13).

In particular, the steeper slowdown in electricity consumption than the total economy itself also indicates that China's economic structure is changing. As shown in Fig. 2.14, the demand from the tertiary sector, urban and residential users slightly increased to 12% and 13% of the total respectively, up by around four percentage points compared with 2005. On the contrary, the secondary sector which used to account for about 76% in 2005, reduced to 73% in 2013 (SGC, 2014d). Still, the manufacturing sector (which is one part of the secondary sector) accounts for about half of the nation's electricity demand, which is the largest electricity consumer today (CSB, 2012). Last but not least, it should be mentioned

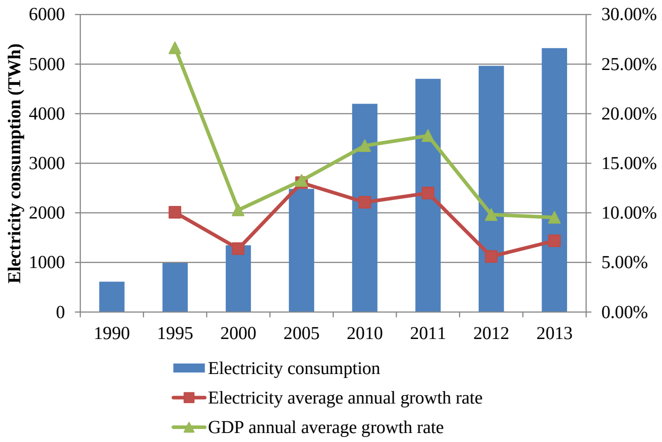


Figure 2.13 – The growth in national electricity demand and GDP during 1990-2013 (SGC, 2014d).

that large improvements in efficiency are also largely contributing to the reduction in the electricity demand growth (Yuan et al., 2011).

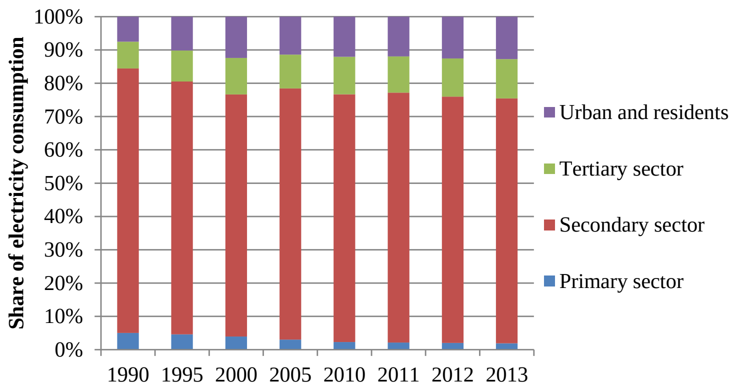


Figure 2.14 – The percentage of electricity consumption by sector during 1990-2013 (SGC, 2014d).

Nevertheless, such a demand portfolio by different types of user is far from mature compared with many developed economies in which the tertiary sector, urban and residential users together account for about half of the national electricity consumption. Moreover, China's per capita power consumption was around 4000 kWh/year at the end of 2013, which is less than one-third of the United States. This indicates considerable room for China to have a continued growth in electricity demand.

2.5 Conclusions

This chapter has reviewed the historical evolution of the Chinese power system during 1949-2015, focusing on key changes in the power system in both the institutional and technical aspects. Two theoretical concepts underlie our understanding of the power system in this thesis. First, we adopt the viewpoint of seeing the power system as a socio-technical system. Second, we highlight that the evolution of such a system is mainly determined by social influences, and the technical system is developed accordingly to suit the social context. The significance of social influences justifies why grand policy interventions are important to steer decarbonization of the power sector. Meanwhile, we also acknowledge that policy interventions are only able to partly but not fully steer the evolution, as the power system does not always behave rationally due to individuals' and groups' decisions.

With regard to the historical evolution of the Chinese power system, this chapter finds that China has experimented with courageous institutional reform by changing the roles of the government and electricity utilities, along with changing electricity pricing and dispatch mechanisms. This has promoted substantial infrastructure investments and technological advancement over the past decades. All these changes have revolved around building up a large-scale coal-based system to power the fast economic development. Market-oriented electricity reforms have been very slow and cautious in China, being constrained by the deep-rooted tradition of central planning in the socialist market economy. Consequently, the government has historically retained tight control over the planning, investments and pricing of the power system so far, as well as keeping significant ownership over the power sector assets. Moreover, the structure of the power system has remained a single-buyer market since 2002, within which: 1) power producers sell power to grid companies with benchmarked on-grid prices by technology; 2) two state-owned grid corporations monopolize the power supply service for the nation and make revenues based on the residuals between retail sales and generation costs; and 3) electricity users pay catalog prices by group. Given these factors, institutional reform of the power sector will be a slow process, and it seems that fundamental institutional changes are unlikely to take place in the near future.

In contrast to the slow pace of institutional change, progress in technical innovations in the power sector has been fast, such as the annual doubling of wind power capacity during 2006-2010 and the large improvements in generation efficiency. Nevertheless, when it comes to decarbonization, a large amount of technical challenges exist. First, the nation's power supply has been significantly locked in coal power. Even worse, new investments in coal power plants are still continuing at a spectacular speed to meet the sustained growth in electricity demand. Besides, bottlenecks arising from the imbalanced distribution between energy resources and electricity demand across regions, and the poorly automated distribution network coupled with insufficient grid capacity, are all technically challenging for China to achieve decarbonization of the power sector. More importantly, mismatches between institutional arrangements and technical developments of the power system have become evident recently, exemplified by the inefficient use of wind energy.

3

A generic framework of policy evaluations for power sector decarbonization

3.1 Introduction

To assist in policy-making for the decarbonization of the Chinese power sector, this thesis aims to inform the performances of key policy options in contributing to decarbonization. However, what policy options are critical to decarbonization, and from what perspectives and with which methods these policy options can be evaluated are not clear yet. To answer this, this chapter develops a framework to systematically guide the specific policy evaluations in this thesis.

The framework amounts to a series of steps as below. First, it interprets the policy goals for power sector decarbonization, and identifies the corresponding performance indicators for these goals in Section 3.2. Second, Section 3.3 identifies a set of policy options that can contribute to the decarbonization of the Chinese power sector, based on our understanding of the Chinese power sector in Chapter 2. The scope of policy options that are investigated in this thesis is also clarified. Third, Section 3.4 selects the research method that is used to support the policy evaluation in this thesis. The conclusions of this chapter are provided in Section 3.5.

3.2 Policy goals and performance indicators

3.2.1 Policy goals

When it comes to the policies for energy supply, the goals are usually ensuring the security of energy supply, economic efficiency and the environmental sustainability. Aligning the goals from the energy, economic and the environmental perspectives (also known as the "3E" perspectives) forms the concept of sustainability in the field of energy supply, as shown in Fig. 3.1. The policy goals for decarbonization of power supply are no exception, as people's pursuit of reliable, cheap and clean power supply never changes.

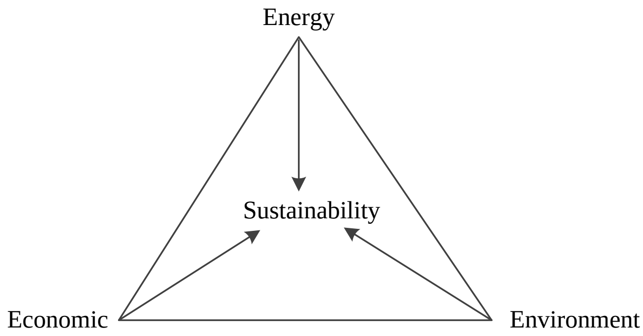


Figure 3.1 – The energy-economic-environment perspectives for energy policies.

Taking into account the dynamics of energy landscapes (e.g. the broad economic context), the priorities of policies between the 3E goals can change over time. As evidenced by the historical evolution of the Chinese power system, securing power supply was the primary goal before the 2000s with the purpose of satisfying the rapid growth in electricity demand and powering the fast economic expansion. Under such circumstances, the goal of keeping economic efficiency of power supply has come second, and concerns over environmental friendly have even been more or less overlooked (Li, Lukszo and Weijnen, 2015a). Since the 2000s, in response to the new energy landscape, such as domestic air pollution, pressures on climate change commitment and slowing down in the economic development, China's policy goals of power supply have gradually shifted to align the security of energy supply with economic efficiency and environmental conservation.

However, in most cases, policy options cannot always meet the three goals at once. Taking the development of gas power in China for instance, while the use of gas power can help China mitigate the CO_2 emissions of power supply, it entails high risks for the security of domestic energy supply given the fact that China has a high dependence on imported gas. Besides, the use of gas power results in higher costs for the power supply than the current widely-used coal power. As such, it is important for policy makers to understand the trade-offs of policies in achieving the 3E goals of power sector decarbonization, and deliver a comprehensive policy package to reconcile the achievements in the 3E goals (d'Oultremont, 2014).

3.2.2 Performance indicators

A wide set of key performance indicators (KPIs) can be used to measure to what degree certain policy goals can be achieved. For instance, with regard to achieving the goal of securing the energy supply, it can be measured from the short-term operational perspective with indicators such as the ramping capability of power plants and the amount of reserve capacity. Also, from the long-term perspective, it can be measured with indicators such as the dependency on fossil fuel import etc. Accordingly, from what perspectives and with what indicators policies are evaluated in this thesis should be clarified.

This work first identifies a set of KPIs for the 3E goals in the context of power sector decarbonization. These KPIs are further categorized into four groups according to the time scales of the power system operation that a given KPI reflects on, as shown in Table 3.1. These four time scales of the power system operation are: 1) seconds to hours; 2) days to months; 3) seasons to years; and 4) decades (Boston, 2013). The first three time scales mainly reflect the performance of power systems in the short term, whereas the fourth one reflects the performance of the power sector in the mid-term and long-term. Since decarbonization of the power sector is a long transitional process which requires substantial institutional and technical changes over decades, this thesis investigates the decarbonization mainly from the mid-term and long-term perspective. Accordingly, the KPIs within the time scales of decades are selected for policy evaluations in this thesis. The selected KPIs are marked with Light Cyan, as shown in Table 3.1.

Among the selected KPIs, first, the fossil fuel (mainly coal and gas) consumption and the generation portfolio especially the use of RES generation are used to indicate the impact of certain policy options on energy portfolio effects from the long-term perspective. The more RES generation, the more sustainable power supply is from the energy perspective in this thesis. Second, the system costs which are the summations of the capital investment costs and the operation costs for power supply, as well as the decarbonization costs[1] are used as the KPIs to measure the economic efficiency of power supply in the long term. Third, with concerns over the long-term climate change in particular, the amount of CO_2 emissions is used to indicate the environmental impact of policies.

3.3 Policy options

Although numerous institutional and technical policy options can be deployed for decarbonization of the power sector, the applicability of these options largely differ between countries. Taking nuclear power for example, China has viewed nuclear power as a strategic policy option to secure power supply at a low cost (Yuan, Xu, Hu, Yu, Liu, Hu and Xu, 2012). On the contrary, nuclear power is definitely not a choice for some western countries, such as Germany which has gradually phased out nuclear power after the Fukushima nuclear-leaking accident concerning nuclear security and waste disposal issues (Visschers and Siegrist, 2013). This thesis focuses on the policy options that are of high potential in the context of China. Additionally, policy options for decarbonization can either directly or indirectly contribute to CO_2 emission reductions of the power supply. For instance, developing RES power directly mitigates CO_2 emissions of the power supply, whereas, the development of RES power requires increased flexibility of the power system. As such, the measures that can increase the flexibility in the power system can also be seen as key policy options for power sector decarbonization.

Based on the understanding of the Chinese power system in Chapter 2, this section identifies a set of key policy options in the institutional and technical aspect, as shown in Fig. 3.2 and Fig. 3.3. The institutional options span the governance, system operation and the market aspect; and the technical options go through the entire value chain of power supply from generation, via transmission and distribution networks, energy storage system, to the load. The performances of these policy options in achieving the 3E goals can be very different. For instance, the costs associated with the options that improve the utilization of existing power infrastructures are normally lower than those of the options which need new investments. More importantly, it is worth mentioning that the performance of

[1] The costs exclusively associated with CO_2 emission mitigation, which can be expressed by the cost of per CO_2 emission reduction relative to the business-as-usual case.

Table 3.1 – Key peformance indicators for the 3E goals of power sector decarbonization at different times scales. Note that the KPIs marked with LightCyan are the KPIs used in this thesis.

Indicators / Aspects / Time scales	Energy	Economics	Environment
Seconds to hours	• Fuel consumption intensity of power supply, voltage and frequency, ramping capability, the amount of primary and second reserve, energy loss etc.	• Variable operation costs: fuel costs, start-up costs, shut-down costs, variable operation and maintenance costs and power transmission costs	• The amount of greenhouse gas (e.g. CO_2, sulfur-dioxide, nitrogen-dioxide), electro magnetic interference (EMI), noises
Days to months	• The amount of second reserve and tertiary reserve capacity, the amount of grid capacity, black-out time and frequency etc.	• Variable operation costs and fixed operation costs (e.g. fixed maintenance costs)	• The amount of greenhouse gas emissions, EMI, noises
Seasons to years	• Installed power capacity, grid capacity, reserve capacity, the availability of energy sources (e.g. hydro in reservoirs) etc.	• Variable, fixed operation costs and capital investment costs	• The amount of greenhouse gas emissions, EMI, noises, physical and chemical waste, eco-system deterioration (e.g. bird-safety)
Decades	• Fossil fuel consumption • Generation portfolio especially the use of RES generation	• System costs (summation of capital investment costs and operation costs) • The decarbonization costs	• The amount of CO_2 emissions

a given policy option is usually system-specific and evolves over time.

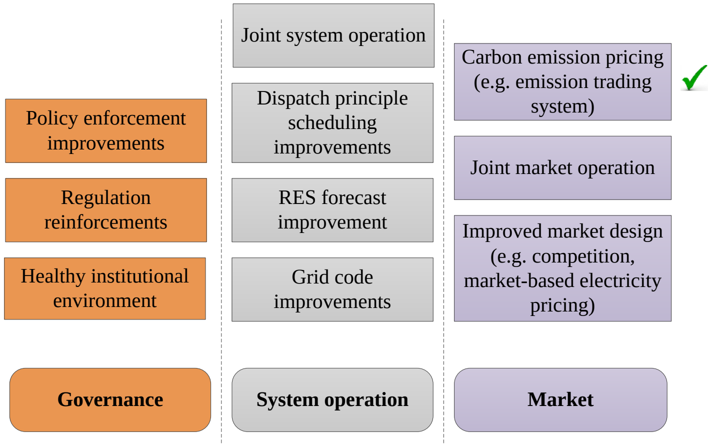


Figure 3.2 – Groups of key institutional policy options for decarbonization of the Chinese power sector. Note that the block with check marks represents the option that is studied in this work, as explained in the text. The structure of this figure is mainly inspired by (Cochran et al., 2014) which lists various socio-options for increasing the flexibility of the power system.

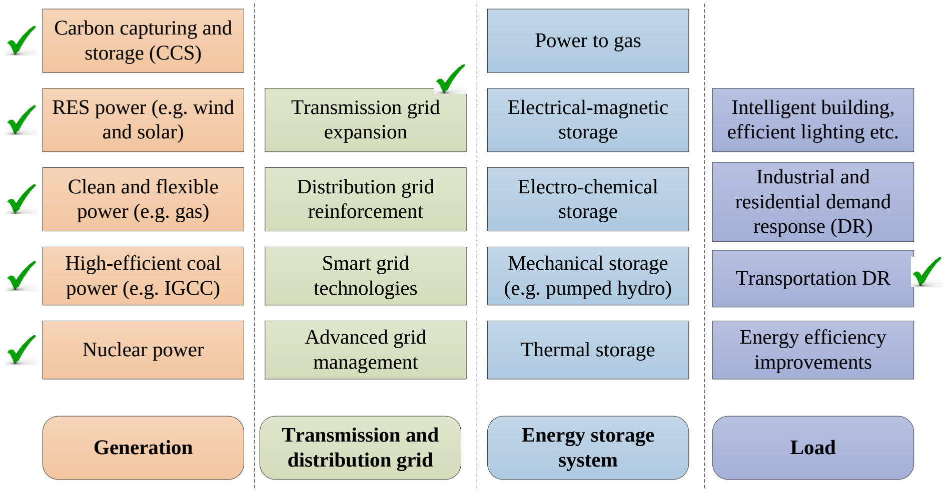


Figure 3.3 – Groups of key technical policy options for decarbonization of the Chinese power sector. Note that the blocks with check marks nearby represent the options that are selected and studied in this work, as explained in the text. The structure of this figure is mainly inspired by (Cochran et al., 2014) which lists various technical options for increasing the flexibility of the power system.

Additionally, these policy options often closely interact with each other. The interactions among these options might be mutually reinforcing, counter-productive and causal etc. For instance, increasing RES power can contribute to decarbonization by cleaning up generation, while this only happens with a healthy electricity market and regulatory environments which make sure RES generation can be appropriately dispatched. Different combinations of these policy options form various alternative pathways for decarbonization of the power sector.

While institutional and technical options are both significant to achieve decarbonization of the power sector, this thesis focuses on interpreting the technical pathways considering the slow pace of institutional reforms in China. Given the limited time for this research project, a set of key technical options on the generation side, grid side and the demand side are selected to be investigated in this thesis, as marked in Fig. 3.3. In particular, CO_2 pricing which is normally seen as a market-based policy option is also investigated in this thesis considering its large influence in determining the cost competitiveness of generation between different technologies.

Specifically, on the generation side, the roles of various low-carbon power technologies especially RES power and carbon capture and storage (CCS) technology in decarbonization, and the interactions between these technologies and CO_2 pricing deserve much research attention for the coal-powered nation. On the grid side, the planning of transmission grid expansion arising from concerns over promoting RES use and reallocating energy resources across regions is selected to look into the nation's ambition for a strong and smart grid development. On the demand side, demand response programs which aim to reduce electricity demand or to change the behaviors of electricity use are also desirable for power sector decarbonization in China, given the sustained and high growth of electricity demand. The case of demand response for the transportation sector is selected in this thesis considering the on-going transportation electrification in China.

3.4 Research methods

The research methods that can be used to evaluate policy implications generally include: 1) qualitative methods, which usually deploy empirical evidences and conceptual models; and 2) quantitative methods, which call for sophisticated mathematical modeling, intensive data collection and computational simulation. Since the 1970s, quantitative methods have become relatively dominating in the field of energy policy analysis, driven by the increased needs for developing energy models within the context of the oil crisis back then (Hoffman and Jorgenson, 1977). Accordingly, a large diversity of modeling approaches has been developed depending on their target groups, intended use (e.g. data analysis, forecasting and optimization) etc. (Herbst et al., 2012).

In general, two broad categories of qualitative energy models are identified, namely top-down models and bottom-up models. Both types of model have their own advantages and disadvantages in delivering quantitative support for policy analysis. Following the ideas of Herbst et al. (2012) and Götz et al. (2012), top-down models tend to interpret the system from a macro-economic perspective yet neglect the sectoral and technological explicitness. Hence, top-down models are often used to assess the long-term and aggregated effects of energy policies in economic development, while failing to take technical details into consideration which is important for the policy evaluation in this thesis. In contrast, bottom-up models feature a high degree of explicitness in socio-technical parameterizations, which allows researchers to analyze the technical evolution for certain economic sectors induced by policy interventions (Jägemann et al., 2013). At the same time, bottom-up models usually rule out inter-sectoral relations in macro-economy and consequently neglect the impact of certain polices on the whole economy, which makes them not fit for long-term projections of energy demand and supply (Herbst et al., 2012). As this work aims to investigate the impact of policy options on the power system rather than on the broad context of the economy, bottom-up models are more suitable for this thesis.

A decomposition of the top-down and bottom-up models is shown in Fig. 3.4. In general, the bottom-up model consists of three types of models, namely the simulation model, optimization model and the partial equilibrium model. Specifically, the simulation model, such as agent-based modeling (ABM), tends to describe the development of the energy system as combined results of individuals' decisions and interactions accounting for social complexities (Chappin, 2011). In contrast, the optimization model tends to explore the optimal scenarios of the energy system that best reflect the objectives, yet neglecting social complexities. Besides, the partial equilibrium model focuses on the equilibrium analysis of energy demand and supply, which is quite similar to the computable general equilibrium (CGE) model except for neglecting certain interrelations between the economic sectors and including more technical details for a certain subset of sectors.

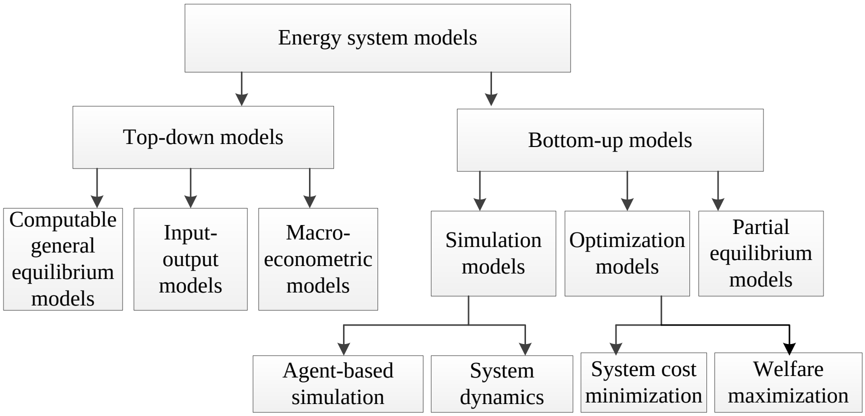


Figure 3.4 – Classifications of energy models (Jägemann et al., 2013; Götz et al., 2012; Herbst et al., 2012).

This work selects the optimization model as the research method for policy evaluations in this thesis, since it makes it possible to account for a set of technical explicitness of the power sector, and thus is able to interpret the technical evolution of the power sector induced by certain policy options. However, we also acknowledge that due to the absence of considering social complexities in the optimization model, the results in this thesis can only inform policy makers regarding the optimal performance of certain policy options in achieving the goals of decarbonization rather than the impact of policies in practice. Further, this thesis uses the cost minimization model rather than the welfare maximization model for policy evaluations with the assumption that electricity price is inelastic.

3.5 Conclusions

This chapter has presented a generic framework to guide the specific policy evaluations in this thesis. Within the framework, we clarify the policy goals for decarbonization of the power sector and the corresponding performance indicators, identify the key policy options for decarbonization, and select the research method to support policy analysis in this thesis.

Specifically, first, the framework translates the long-term policy goals for decarbonization concerning energy and environmental sustainability, and economic efficiency to specific performance indicators respectively. These indicators mainly include the fossil fuel consumption and the generation portfolio (mainly the use of RES generation), the system costs (including the capital investment costs and the operation costs), the average decarbonization costs (the costs per unit of CO_2 emission reduction) and the amount of CO_2 emissions of power supply.

Second, the framework identifies a set of institutional and technical policy options which can largely contribute to decarbonization of the Chinese power sector, based on the understanding of the Chinese context in Chapter 2. The institutional options span the governance, the system operation and the market aspect; and the technical options cover the generation, transmission and distribution networks, energy storage system and the demand side. As this work focuses on investigating the technical evolution of the power sector, a set of key technical options on: 1) the generation side that are concerned with various low-carbon power technologies; 2) the grid side focusing on the transmission grid expansion; and 3) the demand side focusing on demand response programs, are selected to be studied in this thesis. Among various institutional options, CO_2 pricing is studied in this thesis, given the fact that it largely influences the cost competitiveness of generation between different technologies.

Third, the optimization method is selected amongst various energy models to quantify the performance of policy options in achieving the above goals. Being one of the typical bottom-up models, the optimization model can capture a high degree of explicitness in technical parameterization, which allows us to analyze the technical evolution of the power system induced by the selected policy options. This chapter provides methodological support for the policy evaluation work in the following chapters.

4

Generation decarbonization with renewable power, CCS technology and CO_2 pricing

This chapter is mainly based on the following peer-reviewed articles:

- Li, Y., Lukszo, Z., and Weijnen, M. (2015). The implications of CO_2 price for China's power sector decarbonization. Applied Energy, 146 (2015): 53-64.
- Li, Y., Lukszo, Z., and Weijnen, M. (2015). Trade-offs between energy-environmental-economic objectives for China's power decarbonization policies. In 2015 IEEE conference on PowerTech.

4.1 Introduction

Given the fact that China's power supply is largely locked in coal power, the generation side is the key battle ground to fight for the decarbonization of the power sector. However, seeking an effective and efficient decarbonization pathway for electricity generation is challenging, considering the diversity of technological and regulatory options available on the generation side. For instance, the decarbonization of electricity generation can be achieved through various low-carbon power technologies, such as gas power and RES power, each allowing for a large amount of CO_2 emission mitigation (Jägemann et al., 2013). Moreover, the possible regulatory options for generation decarbonization (e.g. mandatory targets for RES generation and CO_2 pricing) always closely interact with the technical options and allow for CO_2 emission mitigation.

China's electricity generation is undergoing rapid changes now, as CO_2 emission regulations are put into place, and various new technologies are being developed. First, China has come to realize that market-based instruments, such as CO_2 pricing, are indispensable for achieving CO_2 mitigation in a cost-effective way. Before the 12th Five-year Planning (FYP) period[1], China did not establish policy instruments which were intended for CO_2 mitigation. Hence, most of the CO_2 emission reductions before 2011 were achieved as co-benefits from the state's energy conservation strategies (Han et al., 2012). For instance, during the 11th FYP[2], 52% of the CO_2 emission reductions in the power sector was achieved by energy efficiency improvement (CEC, 2011). China has biased in strengthening the energy sustainability through promoting highly efficient coal-fired power generation and RES power, although the economic effectiveness behind these measures is quite low (Li, Lukszo and Weijnen, 2015b). Next, China's policies have heavily relied on command-and-control regulations, such as the enforced shut-down of small coal-fired power plants (NDRC, 2007a). The cost inefficiency caused by these administrative orders as well as the expectations to develop a competitive low-carbon economy have inspired China to adopt more market-based instruments, in which the CO_2 emission trading system (ETS) is currently being developed (Yuan et al., 2011; Lo, 2012).

In theory, introducing a CO_2 price contributes to CO_2 emission reductions of the power sector in three major ways: 1) it shifts power supply towards using less carbon-intensive generation technologies; 2) it promotes the use of non-fossil fuel-based generation technologies; and 3) it provides incentives for innovations in low-carbon technologies, such as carbon capture and storage (CCS) technology (IEA, 2010). However, the degree to which CO_2 pricing can assist in reducing CO_2 emissions, the technologies needed to support CO_2 pricing regulation, and the costs involved are highly uncertain. For instance, the development of CCS technology and its integration with various fossil fuel-fired generation technologies are uncertain, which complicate the technological choices for the power supply in the future (Kannan, 2009). Furthermore, the impact of a CO_2 price on the development of different power technologies is also influenced by fuel prices which are fraught with high uncertainties.

Accordingly, this chapter focuses on the study of alternative pathways for electricity generation with three decarbonization policy options, including: 1) CO_2 pricing; 2) carbon capture and storage (CCS); and 3) RES power. Given the fact that the effect of CO_2 price regulation is highly influenced by the relative advantages of marginal fuel costs between technologies, this work also consider fuel prices as a key uncertainty in the future. This work complements a number of recently published articles in peer-reviewed journals, such as (Cai et al., 2007; Chen et al., 2011; Zhou et al., 2010; Wu et al., 2013; Zhang et al., 2013; Wang et al., 2014), which focus on the impact of carbon mitigation policies and low-carbon power technologies on China's power sector. In particular, Zhang et al. (2013) suggest that a clear and long-term climate mitigation policy should be executed as early as possible to avoid carbon lock-in investment. Wang et al. (2014) stress that a continuous and sTable carbon mitigation policy is effective in reducing CO_2 emissions and the system costs of the power supply during 2010-2050. This paper distinguishes itself from others by providing insights into the implications of CO_2 pricing, RES power and CCS technology for the decarbonization of the power sector from the energy and environmental sustainability, and economic efficiency point of view. In addition, most studies have not paid much attention to the interactions between these policy options and the influences from fuel price uncertainties in the future. Specifically, this chapter will answer the following questions.

[1]China issues its National Economic and Social Development Planning on a five-year basis. The 12th FYP refers to the years from 2011-2015.

[2]The 11th FYP refers to the years from 2006-2010.

Firstly, what are the implications of the alternative pathways of electricity generation for the decarbonization, in terms of the energy portfolio effects, economic efficiency and CO_2 emissions? Secondly, what policy recommendations can be proposed regarding the development of low-carbon power technologies and the regulation of CO_2 pricing for the decarbonization of the Chinese power sector?

The remainder of the chapter is organized as follows. Section 4.2 introduces the context of China's generation decarbonization. Section 4.3 presents the research methods used for the analysis in this chapter. Section 4.4 presents the scenario definitions and data collection. Section 4.5 analyzes the scenario results regarding the implications of the alternative pathways of electricity generation for the decarbonization. Section 4.6 discusses the interactions between CO_2 pricing, RES power and the development of CCS technology, as well as the policy implications. Final conclusions are drawn in Section 4.7.

4.2 Context of the policy options and uncertainties in the future

This section briefly reviews the current status of the CO_2 pricing regulation and CCS technology in China. In addition, this part also briefly introduces the current status of fuel prices which largely affect the performance of CO_2 price regulation.

4.2.1 CO_2 pricing: emission trading system

China has been a dominant carbon credit supplier for the developed countries in the clean development mechanism (CDM), while it has not established a domestic CO_2 pricing mechanism (Lo, 2012; Yu and Elsworth, 2012). In view of the expected environmental and economic benefits, the ETS (following the European ETS model) was first officially identified as one of the key policy initiatives for CO_2 mitigation in the 12th FYP for National Economic and Social Development (State Council, 2011b). Following the philosophy of "crossing the river by feeling for the stones", major policy changes in China are introduced incrementally and experimentally. The establishment of a CO_2 ETS is no exception. In 2011, seven local ETS pilots[3] were selected by the central government as macro-laboratories to test the ETS and improve its design before being rolled out nationwide. So far, all the seven pilots are operational. These pilots differ from each other in the details of market design, local regulations and implementation (Zhang et al., 2014). All of these pilots classify the power sector as a top candidate for CO_2 emission trading.

Although the lack of a free market has triggered much debate on the viability of the ETS in China (Lo, 2012, 2013), the trading of CO_2 emissions so far from the pilots is encouraging. For instance, the total CO_2 emission allocations of the first six pilots (except for the Chongqing ETS) by 2014 amounted to 1,115 million tons, which makes China the second largest ETS market just after the European Union (World Bank, 2014). Moreover, all the pilots have actively experimented with various measures to boost the market liquidity (Environmist Ltd., 2014). Based on the experience of the pilots, China's leading climate officials have suggested a nationwide carbon trading market could be established by 2016, despite many challenges ahead (CEG, 2014).

[3] The pilots are located in five cities, namely Shenzhen, Beijing, Shanghai, Tianjin and Chongqing, as well as in two provinces, Guangdong and Hubei.

4.2.2 The development of CCS technology

China has put efforts into promoting the development of CCS technology (Best and Beck, 2011). By April 2013, eleven large-scale CCS integrated projects had been built, including the Shenhua project in Inner Mongolia which was the first one to be put into trial operation in 2011 (Gu, 2013). Still, a number of key barriers need to be overcome before CCS can be commercially available, such as the immaturity of technology, the concerns about the so-called energy penalty[4] and the high cost (Liang and Wu, 2009).

Aside from the uncertainties of CCS technology itself, other technical uncertainties are related to the integration of CCS with various generation technologies, such as super-critical (SC), ultra-super-critical (USC), integrated gasification combined cycle (IGCC) and combined cycle gas turbine (CCGT). These uncertainties will be reflected in our assessment regarding the generation technology portfolio.

4.2.3 Fuel prices

China's efforts to liberalize its fuel markets have so far focused on coal and natural gas. As a result of deregulation of the coal and gas market, opening them up for competition, these fuels are now prone to price uncertainties which will affect the power sector. This chapter focuses on the impact of coal and gas price, since other fuels that are relevant for the power sector, such as uranium, remain under tight government control.

Coal price Since the electricity-coal market was liberalized in 2002, China's coal price has increased steadily, featuring unusual volatilities. The average coal price in 2011 was 126.67 $/ton, almost four times higher than that in 2003. In particular, the international coal prices and China's coal price peaked at the same time in mid 2008 (see Fig. 4.1). Yang et al. argued that China's coal market prompted the increasing volatilities of the international coal prices (Yang, Xuan and Jackson, 2012), as China accounts for almost half of the global coal consumption and has become the world's largest coal importer since 2009 (EIA, 2013a, 2014b). After the 2008 peak, China's coal price continued to increase, on average exceeding the coal price in other countries during 2008-2011.

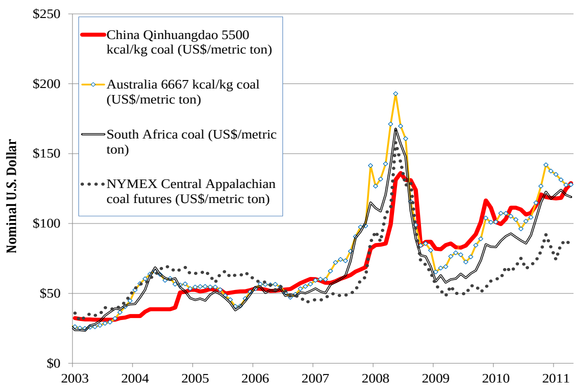


Figure 4.1 – The coal price of China and other three countries between 2003-2011. The figure is obtained from (Yang, Xuan and Jackson, 2012).

[4]The additional fuel consumption due to CCS operation.

Gas price China's natural gas price used to be tightly regulated by the central and local governments. As a consequence, the gas price was kept artificially lower than the gas import price, which fails to reflect the relations between gas supply and demand (Kahrl, Hu, Kwok and Williams, 2013). This has largely discouraged gas imports and undermined the expansion of gas use in the power sector. Next, China's gas demand dramatically increased to 143.8 billion cubic meters in 2012, with an annual growth rate of 15.9% during 2000-2012. Due to the scarcity of domestic natural gas resources, China's gas import dependency increased to 26.2% in 2012 (CEFC, 2013). Moreover, China's gas imports are expected to continue to grow in light of the huge and increasing gas demand. To cope with the issues mentioned above, the state started a market-oriented reform of the gas market in 2013[5] to gradually make the gas price reflect the balance between supply and demand, and to promote investments in gas infrastructure (CEFC, 2013). After the reform, natural gas price has slightly increased in 2013, as shown in Fig. 4.2. The market-oriented reform of the natural gas market is expected to be further expanded nationwide at the end of 2015. (State Council, 2013; Yuan, Xu and Hu, 2012). With the deregulation of gas price and the fast-growing gas imports, China's gas price will be more likely to be exposed to the international gas market which features high volatilities.

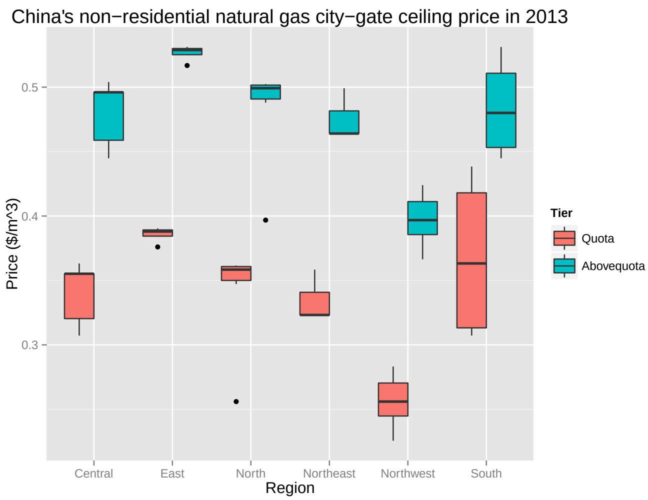


Figure 4.2 – China's non-residential natural gas city-gate ceiling prices by region, data source: (LBNL, 2013). Note that the regional price data here are the mean of the provincial (and sub-provincial administrative) gas prices.

4.3 Research methods

A low-carbon generation expansion planning model (GEP) is used here to quantify the implications of the alternative pathways of electricity generation by 2050. Normally, the GEP

[5]With this reform, the gas price is set as a two-tier price. Based on the volume of natural gas consumption in 2012, the natural gas in 2013 is divided into two tiers. The consumption that is lower than the 2012 quota remains the city-gate price with an increase not exceeding 0.4 CNY/m^3. While the consumption that exceeds the 2012 quota is dynamically calculated based on the price of fuel oil and liquefied petroleum gas (LPG) (CEFC, 2013).

model is used to optimize what type of power capacity should be expanded and be operated at what size, when and where, to meet the projected power demand while satisfying the system operating constraints (Seifi, 2011). Many GEP models have been developed for the Chinese studies, such as (Wang et al., 2014; Hu et al., 2010; Zhang et al., 2012; Yuan, Xu, Kang, Zhang and Hu, 2014; Chen, Kang, Xia and Zhong, 2010; Li et al., 2010; Cheng et al., 2015). For this study, CCS technology should be integrated with the conventional generation technologies. Therefore, we selected the low-carbon GEP model developed by Chen et al. (Chen, Kang, Xia and Zhong, 2010) which accommodates both the new building of CCS-embedded power plants and the CCS-retrofitting for conventional fossil fuel-based power plants. Moreover, this model works with a group of technology-based rather than unit-based power plants and uses linear optimization techniques, which fits the computational requirements for the study.

However, instead of using the overnight capital investment cost proposed by Chen et al. (Chen, Kang, Xia and Zhong, 2010), this study uses equal annuity which converts the overnight capital investment cost into discounted equalities over the entire operating lifetime (see the calculation of equal annuity in Appendix A.1). This enables a fair consideration of the capital investment cost even for the power plants installed in the years close to the boundary of the planning horizon (Rentizelas et al., 2012). Hence, the adapted GEP model can be used for reliable decision-making support regarding the least-cost generation expansion planning. More specifications of the adapted GEP model are given in Appendix A.2.

4.4 Scenario definitions and data collection

4.4.1 Scenario definitions

To systematically study the interactions between CO_2 prices, RES power, the development of CCS technology and fuel prices, this study defines 32 scenarios (see Fig. 4.3). Each scenario is comprised of different settings of the policy options[6] and the uncertainty factor. More specifications of the scenario settings are explained as below.

CO_2 price This study uses four scenarios to reflect the possible extremes of China's CO_2 price in the future. For reference purposes, "CZ" represents that no CO_2 price is used. For other scenarios, we assume that CO_2 price is introduced in 2016 with a starting point of 15 $/ton and increases annually by different rates (see Table 4.1).

Table 4.1 – The annual growth rates of different CO_2 prices.

	Low (CL)	Medium (CM)	High (CH)
Annual growth rate	2%	4%	6%

Fuel price As no official data for the long-term fuel price projection of China is available, this study estimates China's fuel price growth by referring to growth of fuel prices in the U.S. This reference is supported by two points. First, the U.S. coal market is similar

[6]RES power is not a scenario variable here, but the development of RES power is influenced by the settings of other factors.

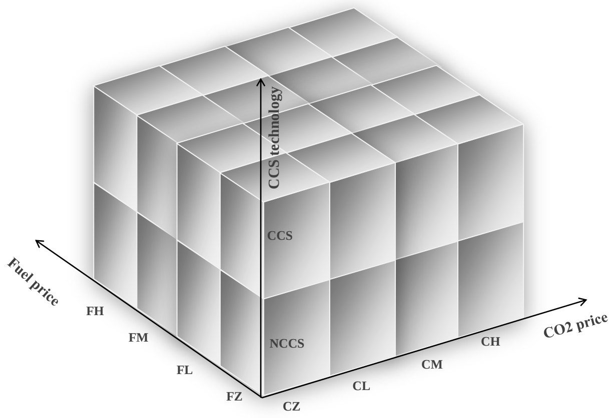


Figure 4.3 – The cube of scenario definitions.

to that of China where domestic coal consumption accounts for about half of the nation's coal production (Zhu and Fan, 2010). Moreover, China's coal price has historically shown a similar trend with that of the U.S. since the electricity-coal market was deregulated in 2002 (Yang, Xuan and Jackson, 2012). Second, China's gas price will become more exposed to the international gas market due to the deregulation of gas price and the increasing gas imports. In particular, the U.S. is playing an increasingly important role in the international gas market, as it is the largest gas producer among the OECD[7] countries and is expected to account for three-quarters of the total OECD gas production growth during 2010-2040 (EIA, 2013c). The U.S. Energy Information Administration forecasts that by 2040, the U.S. coal and gas price for electricity generation is growing annually by 2.9% and 5.0% respectively (EIA, 2014a). Based on this, this chapter defines four scenarios for China's coal and gas price growth, namely "FZ", "FL", "FM", "FH" (see Table 4.2), in which "FZ" is for the reference purpose. The data of coal and gas price in the year 2010 are obtained from (Yang, Xuan and Jackson, 2012).

Table 4.2 – Different settings of fuel prices.

	Year 2010	Annual growth rate			
		No (FZ)	Low (FL)	Medium (FM)	High (FH)
Coal price	126.27 \$/ton	0%	1%	1.45%	2.9%
Gas price	0.4425 \$/m^3	0%	1%	2.5%	5 %

The development of CCS technology Two cases, namely "CCS" and "NCCS", are defined to reflect whether CCS technology will be commercially available after 2020. The generation technology portfolios for these two cases are listed in Table 4.3. In addition, we assume that the newly installed capacity of either CCS-embedded power or the CCS-retrofitting power can not exceed 30 GW for one year given that it might take a few decades for emergent technologies to become technically mature and commercially available. Spe-

[7] The Organization for Economic Cooperation and Development.

cifically, the CCS-integrated power technologies include SC+CCS, USC+CCS, IGCC+CCS and CCGT+CCS.

Table 4.3 – The generation technology portfolios of different scenarios.

Scenario identity	Fossil fuel-based power technologies	Non-fossil power technologies	
		RES power	Others
"CCS"	conventional coal, SC, SC+CCS, USC, USC+CCS, IGCC, IGCC+CCS, CCGT, CCGT+CCS	hydro, wind, solar, biomass	nuclear
"NCCS"	conventional coal, SC, USC, IGCC, CCGT	hydro, wind, solar, biomass	nuclear

4.4.2 Data collection

The data used in this study mainly include: 1) the demand side data; 2) the existing system data, e.g. the current capacity portfolio and the technical and economic performance of power technologies; and 3) the future system data, such as the technology learning rates. It should be stressed that collecting technology-specific data is challenging and this is even more difficult in China where power generation has high regional variations and the data published in official reports are heavily aggregated. Therefore, a comprehensive literature study is done to ensure that the data in this chapter are representative for the average economic and technical performance of the power technologies in China. The data sources cover technical reports, academic publications and website information.

In addition, as most of the latest data regarding the economic performance of power technologies are for the year 2010, the planning horizon in our study starts from 2011 to reduce the impact of data uncertainties. More importantly, using the equal annuity in the adapted GEP model reduces the impact of the planning horizon on optimization results. The key data used in this chapter are uploaded on the Enipedia[8] which is a semantic wiki for energy and industry data.

4.4.2.1 Demand side data

The overall electricity demand in China was 4192.3 TWh in 2010 with an increase of 14.8% relative to 2009, and the yearly peak load was 588.23 GW with an increase of 15.75% (NBS, 2011). As China's economic development is coming to a stage of middle-and-later industrialization, the power demand is expected to keep growing fast (Hu et al., 2011). this chapter uses the power demand forecasting of the years 2020, 2030 and 2050 in (Zhang et al., 2012), assuming the power demand and yearly peak load increase linearly over the planning horizon (see Table 4.4).

Table 4.4 – The estimated annual growth rates for the power demand and yearly peak load in China (Zhang et al., 2012).

	2011-2020	2021-2030	2031-2050
Annual growth rate	4.70%	2.24%	1.55%

[8] $http://enipedia.tudelft.nl/wiki/DatacollectionChina.$

4.4.2.2 Existing and future system data

The data regarding the technical and economic performance of technologies are shown in Table A.7, which are derived based on an intensive literature study. The coal-fired power capacity data are mainly based on (IEA, 2012), and the capacity data of other technologies are obtained from the GlobalData database (Global Data, 2014). The existing capacity portfolio is simplified by assuming that the oil-fired power capacity (7.16 GW) is zero, as China has no clear intention to use oil for its power supply in the future. In addition, oil-based power capacity has kept decreasing since 2000. The capacity portfolio by technology in 2010 is shown in Table 4.5.

Table 4.5 – The power capacity portfolio by technology in 2010.

Technology	Capacity (MW)	Percentage (%)
Conventional coal (<= 300 MW)	475,000	48.26
Super critical (SC)	146,000	14.83
Ultra super critical (USC)	36,000	3.66
Combined cycle gas turbine (CCGT)	26,069	3.38
Biomass	5,271	0.54
Nuclear	10,065	1.02
Hydro	162,990	23.67
Wind	44,887	4.56
Solar	800	0.08
Total	984,242	100

According to the technology learning effect, the capital investment cost for a given technology decreases with its accumulated installed power capacity. To sustain the optimization in linearity, this study assumes that the overnight capital investment cost annually decreases with the exogenous learning rate, R_i^L, as shown in Eq. (4.1). The data regarding the learning rates are presented in Table 4.6.

$$C_{i,y}^{In} = C_{i,y-1}^{In}(1 - R_i^L) \tag{4.1}$$

Table 4.6 – The technology learning rates of different technologies in percentage (Chen et al., 2011; Zhang et al., 2012).

	SC, USC, CCGT	IGCC	CCS	Biomass, nuclear	Hydro	Wind	Solar
2011-2030	0.5	2	1	0.5	0.25	1	4
2031-2050	0.25	1	0.5	0.25	0.25	0.5	2

Other data The fuel consumption rates of fuel-fired generation technologies are assumed to annually decrease by 0.5%. In addition, the upper bounds of annual coal and gas supply are 1.5 billion tce[9] and 500 billion cubic meters respectively (Zhang et al., 2012). Other data used in this study are listed in Appendix A.3.

[9] tce: ton of coal equivalent, 1 tce =27.78 million Btu (MMBtu).

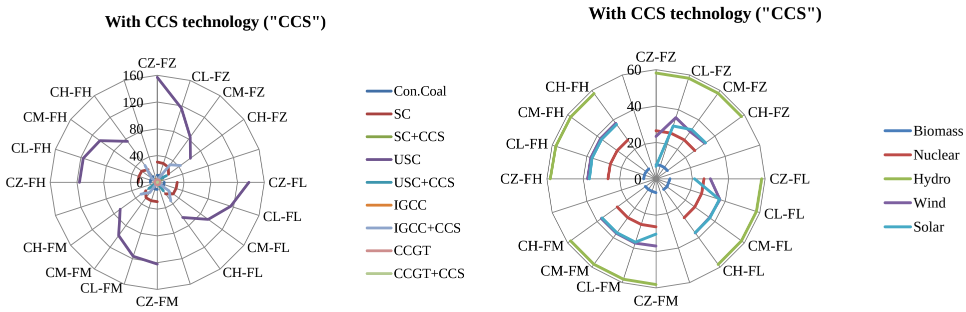
4.5 Result analysis

4.5.1 Energy portfolio

The implications of the alternative pathways from the energy portfolio perspective are analyzed in terms of generation mix by technology, the use of RES generation and coal consumption for the total power supply during 2011-2050. Note that although CO_2 pricing has potential to promote gas-fired power generation, while gas consumption is relatively negligible compared with coal consumption in this study. Hence, this chapter mainly uses coal consumption as the performance indicator of fossil fuel consumption.

4.5.1.1 Generation mix

with CCS technology As shown in Fig. 4.4, in the reference scenario of "CZ-FZ-CCS", fossil fuel-based electricity generation dominates the total power supply, while the RES power generation merely accounts for about 29% of the total power supply and the remaining generation is from nuclear power. Specifically, hydro power is the most deployed RES power technology, followed by wind power, while the roles of solar and biomass power are limited. Additionally, USC technology accounts for about 77% of the total fossil fuel-based electricity generation, followed by SC technology at 15%. Moreover, the conventional coal-fired power[10] plays a limited role, as it is assumed to be completely phased out by 2035 in accordance with the policy of shutting down small coal-fired power plants. In addition, gas-fired power merely accounts for about 2% of the total fossil fuel-based generation.



(a) The fossil fuel-based generation mix. (b) The non-fossil fuel-based generation mix.

Figure 4.4 – The generation mix by technology with CCS for different scenarios of CO_2 prices and fuel prices (unit: 1000*TWh).

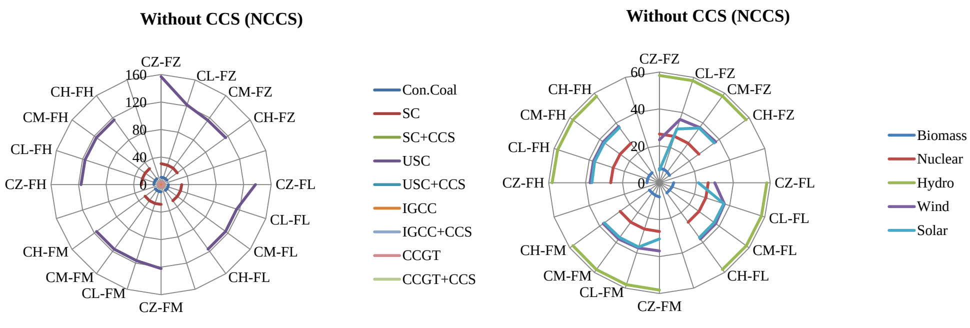
Without considering the fuel price growth, introducing the CO_2 price leads to a reduction in the generation from USC and SC technology. Meanwhile, it results in a large increase in the CCS-integrated power generation (i.e. SC+CCS, USC+CCS, IGCC+CCS and CCGT+CCS) and in the RES power generation especially for wind and solar power. However, the large increase in RES power generation only takes place when the CO_2 price is low, while the large increase in CCS-integrated power generation occurs when the CO_2 price becomes medium or high. This implies that the cost competitiveness of

[10]The conventional coal power is abbreviated as Con.Coal in the figures, which mainly refers to the small-coal power plants with low generation efficiency.

CCS-integrated power generation exceeds that of the RES power generation with the increase of CO_2 price. In addition, it should be noted that the increase in the generation from IGCC+CCS technology is the largest among all the CCS-integrated power technologies.

Taking the fuel price growth into account, the increase in CCS-integrated power generation for a given CO_2 price relative to the "CZ" slightly reduces with the fuel price growth. This is mainly because the fuel price growth reduces the cost competitiveness of the CCS-integrated power generation. Additionally, the increase in RES power generation for a given CO_2 price relative to the "CZ" slightly reduces with the fuel price growth as well. This is mainly due to the fuel price growth to some extent makes CO_2 pricing redundant in promoting the RES power generation. For instance, with the high fuel price growth ("FH"), wind and solar power generation are almost the same across different CO_2 price scenarios.

without CCS technology By comparing Fig. 4.4 with Fig. 4.5, this chapter finds that the generation mix for two scenarios, namely "CZ-FZ-CCS" and "CZ-FZ-NCCS", is totally the same. Therefore, the development of CCS technology in this study does not make any difference without a CO_2 price. Additionally, through comparing Fig. 4.4b and Fig. 4.5b, we find that without CCS technology, the RES power generation (mainly for wind and solar) is slightly higher than that in the corresponding scenarios with CCS technology. However, this only works when the fuel price growth is zero and low. Once the fuel price growth becomes medium and high, the RES power generation is the same across the scenarios with "CCS" and "NCCS". This implies that the RES power generation gets to the production limits which are about 42% of the total power supply during the 2011-2050. Furthermore, as the RES power generation substitutes part of the USC power generation with the increase of CO_2 price, the trend of USC generation is opposite to that of the RES power generation.



(a) The fossil fuel-based generation mix. (b) The non-fossil fuel-based generation mix.

Figure 4.5 – The generation mix by technology without CCS for different scenarios of CO_2 prices and fuel prices (unit: 1000*TWh).

4.5.1.2 RES generation

As shown in Fig. 4.6, without considering the CO_2 price and the fuel price growth, the share of RES power in the total generation during 2011-2050 is about 29%. The share of RES power increases with both CO_2 prices and fuel price growth yet not proportionally.

In maximum, the share of RES power is about 42% of the total power supply during 2011-2050, which is the production limit of RES power in this study. The production limit here is technically constrained by the capacity factor and the construction speed for RES power capacity. Specifically, the upper bounds of the construction speed for RES power capacity are mainly influenced by the manufacturing capability and the installation time for power capacity.

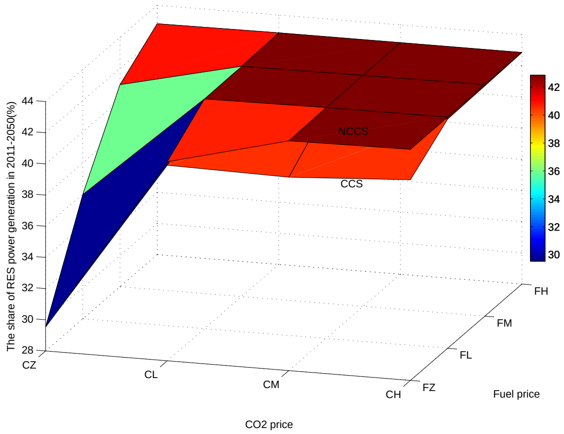


Figure 4.6 – The share of RES power generation in the total power supply for all the scenarios without CCS (upper layer) and with CCS (lower layer) technology.

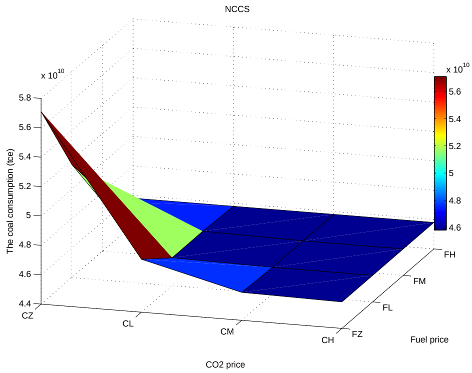
Regarding the interplay between CO_2 prices and fuel prices, low fuel prices complement a low CO_2 price in promoting the RES power generation, while a high fuel price growth makes CO_2 pricing redundant in RES power promotion. For instance, the share of RES power generation is almost the same in the scenarios with high fuel prices, no matter what the CO_2 price is. However, once the amount of RES power generation saturates, either CO_2 pricing and fuel price growth will be redundant for promoting RES power generation.

In addition to fuel prices and CO_2 prices, the optimal share of RES power generation is also largely influenced by the availability of CCS technology. For instance, the share of RES power generation in "CM-FZ-NCCS" and "CH-FZ-NCCS" are all higher than those of the corresponding scenarios with CCS technology. This implies that the cost competitiveness of CCS-integrated power generation (i.e. SC+CCS, USC+CCS, IGCC+CCS) exceeds that of the RES power generation with the increase of CO_2 prices.

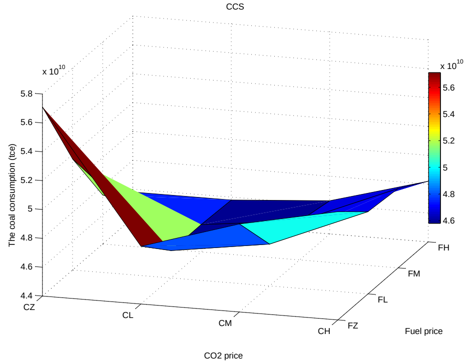
4.5.1.3 Coal consumption

As shown in Fig. 4.7a, without the CO_2 price and the fuel price growth, the coal consumption of power supply during 2011-2050 is about $5.71*10^{10}$ tce. Without CCS technology, both CO_2 pricing and fuel price growth lead to coal reductions through promoting RES power generation. Once the amount of RES power generation saturates, the coal consumption remains stable at about $4.6*10^{10}$ tce. In maximum, the coal consumption is reduced by 20% relative to the reference one.

In contrast, with CCS technology, only a low CO_2 price reduces the coal consumption



(a) The coal consumption without CCS technology.



(b) The coal consumption with CCS technology.

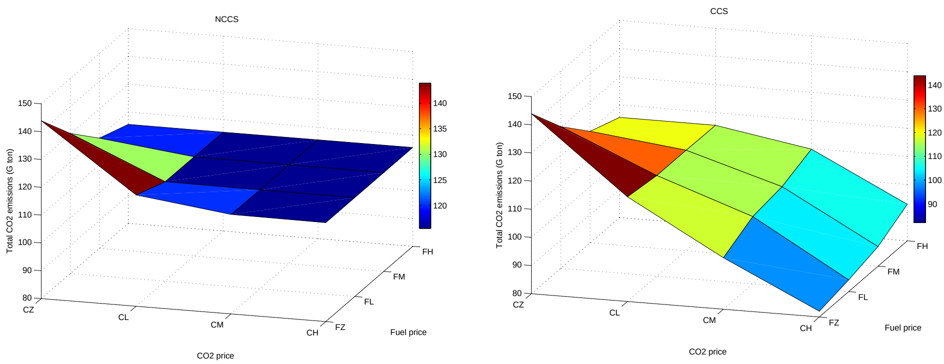
Figure 4.7 – The coal consumption with and without CCS technology.

(see Fig. 4.7b). However, a high CO_2 price results in an additional coal consumption as it promotes the CCS-integrated power generation and CCS technology consumes more coal because of the energy penalty effect. In addition, the increase in coal consumption for a given CO_2 price reduces with the fuel price growth. This is mainly due to higher fuel prices undermine the cost competitiveness of CCS-integrated power generation. Therefore, the coal consumption of the "CH-FZ-CCS" scenario is the highest among the scenarios accounting for the CO_2 price and fuel price growth, which is about 12% higher than that in the scenario of "CH-FZ-NCCS". However, it should be noted that this 12% is not the absolute difference of coal consumption between "CCS" and "NCCS", as we consider that the energy efficiency improvement of coal-fired power generation annually increases by 0.5% in the simulation. Therefore, the value of 12% might become higher if the increase in energy efficiency of fossil fuel generation is lower than we assumed in the simulation.

4.5.2 Environmental implications

The environmental implication is analyzed in terms of the total CO_2 emissions from the power supply during 2011-2050. As shown in Fig. 4.8, without the CO_2 price and the fuel price growth, the CO_2 emissions of the reference scenario are as high as 144 Gt. Without CCS technology, only the low CO_2 price and the low fuel price growth lead to CO_2 emission reductions. Furthermore, neither a higher CO_2 price nor a higher fuel price entails more CO_2 reductions once the amount of RES power generation saturates. Therefore, without CCS technology, the maximum CO_2 emission reductions are about 20% relative to the reference scenario.

In contrast, with CCS technology, the CO_2 emission reductions keep decreasing with the CO_2 price. Despite the CO_2 emission reductions for a given CO_2 price slightly decrease with fuel price growth, the CO_2 reductions with CCS technology are still much higher than those of the corresponding scenarios without CCS technology. Specifically, the CO_2 emissions of the "CH-FZ-CCS" scenario are the lowest among all the scenarios, which equal about a reduction of 44% relative to the reference scenario.



(a) The CO_2 emissions without CCS technology. (b) The CO_2 emissions with CCS technology.

Figure 4.8 – The CO_2 emissions for different scenarios of CO_2 prices and fuel prices.

4.5.3 Economic efficiency

4.5.3.1 The system costs

As shown in Fig. 4.9, the system costs which refer to the summation of the investment costs and the generation costs during 2011-2050 (see Eq. (A.4)) range from 4050 to 6930 billion $\$_{2010}$ across the scenarios. The system costs increase with the CO_2 price and the fuel price. In particular, if the CO_2 price is high, the system costs for the scenarios with CCS technology are slightly higher than those of the corresponding scenarios without CCS technology. This is mainly because the energy penalty of CCS technology results in a slight increase in electricity generation costs.

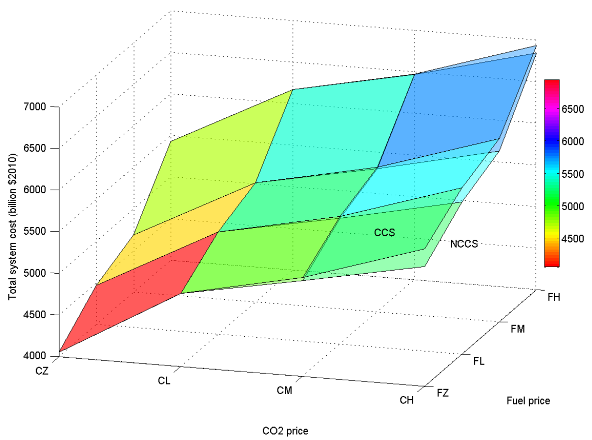
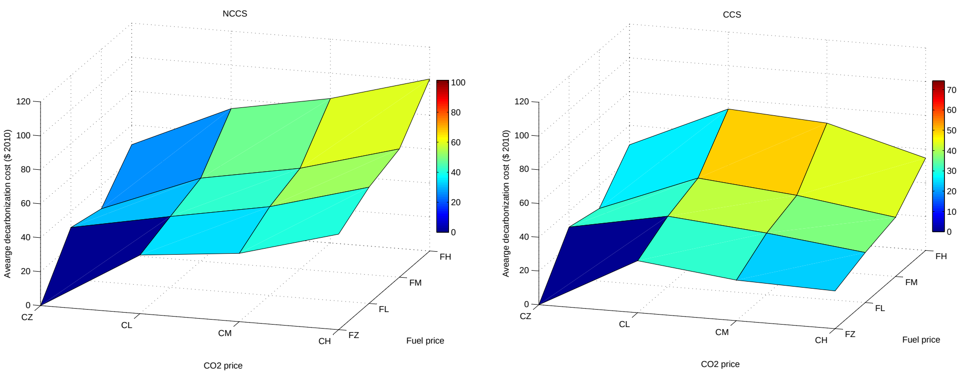


Figure 4.9 – The system costs without CCS (lower layer) and with CCS technology (upper layer) for different scenarios of CO_2 prices and fuel prices.

4.5.3.2 The average decarbonization costs

In addition, this chapter defines the average decarbonization costs to evaluate the economic effectiveness for a given scenario. The average decarbonziation costs refer to the difference in system costs divided by the difference in CO_2 emissions for a given scenario relative to the reference scenario. It should be stressed that, "CZ-FZ-CCS" and "CZ-FZ-NCCS" are two references for the scenarios with and without CCS technology respectively. However, CCS technology is not deployed without a CO_2 price in this study, and thus these two references have the same generation mix, CO_2 emissions and system costs. Therefore, either of them can be used as the reference scenario to calculate the average decarbonization costs.



(a) The average decarbonization costs without CCS technology.

(b) The average decarbonization costs with CCS technology.

Figure 4.10 – The average decarbonization costs for different scenarios of CO_2 prices and fuel prices.

As shown in Fig. 4.10a, without CCS technology, the average decarbonization costs range from 26.13 to 101.3157 $\$_{2010}$/ton, and increase with the CO_2 price as well as the fuel price. However, the average decarbonization costs in the scenarios with CCS technology are much lower than those of the corresponding scenarios without CCS technology, ranging from 22 to 55 $\$_{2010}$/ton (see Fig. 4.10b). In particular, with CCS technology, the average decarbonization costs decrease with the CO_2 price if the CO_2 price becomes medium or high. Based on the analysis in Section 4.5.1, we get that the CCS-integrated electricity generation results in a lower average decarbonization cost compared with RES power generation, even though with a higher CO_2 price.

4.6 Discussions and policy implications

This section first discusses the interactions between the policy options and reflects on the current policy implications for the Chinese power sector.

CO_2 price and CCS technology CO_2 pricing and CCS technology are mutually reinforcing in reducing CO_2 emissions yet keeping the economic effectiveness. Because the cost competitiveness of CCS-integrated power generation increases with CO_2 price, and thus a high CO_2 price is conducive to achieve a high degree of power decarbonization if

CCS technology is available. Without the incentives from CO_2 pricing, CCS technology is not deployed in this study. Moreover, without CCS technology, CO_2 pricing only promotes the RES power generation which leads to a limited degree of CO_2 reductions. Specifically, the maximum CO_2 emission reductions without CCS technology are 20% relative to the reference case, which are less than half of the reductions with CCS technology. This is mainly because the production limits of RES power are about 42% of the total power supply during 2011-2050, which are technically constrained by the capacity factor and the construction speed for RES power in this study. Specifically, the upper bounds of the construction speed for RES power capacity by technology are shown in Table A.6, which are mainly influenced by the manufacturing capacity and installation time of power capacity for a region. Compared with the data used in other peer-reviewed publications, such as (Zhang et al., 2012), the upper bounds of the construction speed in this chapter are slightly higher, given China's high and increasing ambitions for the development of RES power. In addition, coal-based power has to be largely expanded at the beginning of the planning horizon to meet the fast growing power demand, which prolongs the carbon lock-in investment.

Furthermore, although nuclear power has been considered as a critical non-fossil fuel-based power technology for securing a low-cost and low-carbon power supply in China, its development is under strict government regulation and is fraught with high social and political uncertainties. According to the mid & long-term planning for nuclear power, the Chinese government aims for about 80 GW of nuclear power by 2020. Assuming the nuclear power capacity permitted by the government will increase with the same amount as it does during 2010-2020, the share of nuclear power generation in the power supply during 2011-2050 is about 8%, which is relatively limited compared with RES power and coal-fired generation. As a consequence, nuclear power is not likely to largely contribute to China's power decarbonization. However, this is mainly based on the expectation that the current development of nuclear power will continue, and the contribution of nuclear power to the decarbonization may change in the future depending on the government's ambitions.

Additionally, the use of CCS technology largely reduces the average decarbonization costs especially when CO_2 price is high. Therefore, CCS technology is crucial for China to achieve a high degree of power decarbonization in a cost-effective way. However, considering the impact of a high CO_2 price on the economy, more policy efforts are needed to promote CCS-related R&D activities and make CCS technology affordable. More importantly, IGCC is the most cost-competitive fossil fuel-based technology for CCS integration in this study. This is in line with the discussions in (Wu et al., 2013; MIT, 2013) which stated that IGCC might become more cost-effective than USC and SC when a CO_2 price is introduced. Moreover, IGCC has advantages with respect to water efficiency, which makes it more attractive especially for the water-scarce regions in North China (Christopher et al., 2010).

CO_2 pricing and fuel prices The fast growing energy demand coupled with the deregulation of the coal and gas market will drive China's fuel prices to high growth in the future. Taking this into account, we argue that higher fuel prices undermine or nullify the effect of a CO_2 price on CO_2 emission reductions. Because high fuel prices to a certain degree make CO_2 pricing redundant in promoting RES power generation especially when CCS technology is not available. This is a situation that policy makers should avoid, otherwise, CO_2 pricing only increases the system costs rather than entailing more CO_2

reductions. Additionally, higher fuel prices undermine the cost competitiveness of CCS-integrated power generation, due to the energy penalty of CCS technology. Therefore, if the fuel price growth is high in the future, standalone CO_2 pricing might be insufficient to promote the development of CCS technology. In this sense, more incentives complementing CO_2 pricing are needed to overcome the cost disadvantages of CCS-integrated power technologies.

CO_2 pricing and RES power generation Although the numeric results regarding the optimal share of RES power generation are associated with assumptions, there is always an optimal share of RES power from the least-cost perspective. Hence, policy makers should be prudent regarding the mandatory targets for RES power generation, as these targets might entail extra costs or become redundant. In this study, the optimal share of RES power generation mainly depends on its comparative cost-advantage over the CCS-integrated power generation, and the cost-advantage is largely influenced by CO_2 price. Specifically, with a high CO_2 price, RES power generation might become less cost-effective compared with the CCS-integrated power generation. As a result, if the mandatory targets for RES power generation are higher than the optimal level, the targets will entail extra costs. Additionally, the targets lower than the optimum would become redundant, as both CO_2 pricing and fuel price growth can promote RES power generation to the optimal level. This is also in line with the discussions in (Jägemann et al., 2013) which analyzes the interactions between CO_2 pricing and the targets for RES power generation in the power sector of European. China has currently set up a series of short-term and long-term targets for the development of RES power. Considering the economic effectiveness of the power decarbonization, these mandatory targets should be coordinated with CO_2 pricing.

4.7 Conclusions

This chapter has investigated the implications of alternative pathways of electricity generation for the decarbonization of the Chinese power sector. The alternative pathways of electricity generation are formed by different settings of the key policy options including CO_2 price, the development of CCS technology and RES power, as well as different settings of the fuel price growth which is seen as an important uncertainty factor in the future. We quantify the implications using a least-cost generation expansion planning model which integrates CCS technology with the conventional fossil fuel-based power technologies. The implications of different pathways are analyzed from the energy portfolio (generation mix by technology, coal consumption and the use of renewable energy), economic efficiency (the system costs and the average decarbonization costs) and environmental sustainability (CO_2 emissions) perspectives.

Based on the analysis of the scenario results, the following policy implications for Chinese generation decarbonization can be given. First, developing RES power is not the silver bullet for generation decarbonization especially in terms of the degree of CO_2 emissions that it can achieve and the cost-efficiency thereof. The production limits of RES power are about 42% of the total power supply during 2011-2050, being subjected to the constraints arising from the speed of construction and the low capacity factor of RES power. Accordingly, the maximum CO_2 emission reductions only relying on RES power during 2011-2050 are 20% relative to the reference case. Next, the cost efficiency of RES power for exclusive CO_2 emission reductions is low in terms of the average decarbonization costs. In this study, the optimal share of RES power generation mainly depends on its comparative cost-advantage over the CCS-integrated power generation, and the cost-advantage is largely influenced by CO_2 prices. Hence, policy makers should coordinate the mandatory targets for RES power generation with CO_2 pricing, otherwise, these targets might entail extra costs or become redundant. Still, policy makers also need to weight factors relating to energy security and take into account which renewable energy sources they may wish to prioritize, even though this may lead to higher costs.

In addition, deploying CCS technology is critical to help China achieve a higher degree of CO_2 emission reductions of power supply, especially due to the coal-dominated power system can not be changed quickly. The maximum CO_2 emission reductions with CCS technology are 44% relative to the reference case, which are about two times higher than those without CCS technology. Additionally, the average decarbonization costs with CCS technology are much lower than those without CCS technology. However, the trade-off of using CCS technology is that it results in additional coal consumption by 12% (relative to no CCS) because of the energy penalties for powering CCS-related technologies, and it leads to extra system costs of power supply due to its high capital costs and the additional fuel consumption. Hence, there is still a large space to improve the technical and economic performance of CCS technology to make it affordable.

Next, a high CO_2 price is conducive to achieve a high degree of decarbonization in a cost-efficient way, but only when CCS technology is commercially available. If not, a high CO_2 price does not necessarily mean more CO_2 emission reductions but results in high system costs especially when RES power generation is close to production limits. Moreover, higher fuel prices will undermine or nullify the effect of CO_2 pricing on power sector decarbonization. This is mainly because, first of all, higher fuel prices to a certain extent make CO_2 pricing redundant in promoting RES power generation. Secondly, high fuel prices reduce the cost competitiveness of CCS-integrated power generation.

These recommendations can be used by China's policy makers regarding the implications of alternative pathways for electricity generation, and the supplementary packages for efficient CO_2 price regulation in the power sector. They are helpful for deliberations about the preference of CCS in the development of low-carbon technologies, the coordination between CO_2 price regulation and the targets for RES power generation, as well as the interactions between CO_2 prices and fuel prices. However, it should also be noted that the results in this chapter are based on a set of parameters associated with assumptions, such as the projected power demand, the exogenous learning rates of technologies and the construction speed of RES power capacity. Despite this, to cope with the complexities in the future, policy makers can be supported by the adapted model in this study through adapting the settings. Last but not least, the physical constraints stemming from grid network should also be integrated into the generation expansion planning model. Future work will address these issues.

5

Decarbonization with the inter-regional transmission grid expansion

This chapter is mainly based on the following peer-reviewed article:

- Li, Y., Lukszo, Z., and Weijnen, M. (2016). The impact of inter-regional transmission grid expansion on China's power sector decarbonization. Submitted to Applied Energy (under review).

5.1 Introduction

In addition to promoting various low-carbon power technologies as we studied in Chapter 4, reinforcing the inter-regional transmission grid is also proposed as one of the potential strategies to facilitate the decarbonization of the Chinese power sector (Chen et al., 2014). First, the inter-regional transmission grid is critical in view of the geographical imbalance between energy resources and electricity demand across regions. As described in Chapter 2, most energy resources are situated in the three-North regions of China, while the load centers are clustered in the East and South (Chen, Li and Wu, 2010). While the basic inter-regional interconnections established in 2005 mainly deliver power from the West to East China, and from the North to South China (see Fig. 2.12), the total capacity of the inter-regional transmission grid has been quite limited so far. Specifically, the total inter-regional transmission capacity was 47.40 GW by 2012, which is less than 5% of the national installed generation capacity (SGC, 2014c). Accordingly, about 80% of energy delivery across regions still relies on primary coal transportation (e.g. through railways and ships) (Chen et al., 2014).

More importantly, the fast development of generation capacity based on renewable energy sources (RES) in the three-North regions puts additional stress on the inter-regional transmission grid. As shown in Fig. 5.1, more than 70% of wind power capacity was centralized in the three-North regions by 2013. If the growth of RES power continues like this, as planned, an increasing amount of RES generation must be exported across regions. Moreover, the power system flexibility of the three-North regions might be challenged by the increasing amount of RES generation, considering the coal-dominated generation portfolio in these regions. This concern has already been evidenced by substantial wind generation curtailment in the three-North regions during 2010-2011, especially during the winter time when most coal-fired units must keep running to supply heat (Pei et al., 2015). Under such circumstances, expanding the inter-regional transmission grid is critical to increase the flexibility of the power system by distributing intermittent wind power in space and time, and thus improve the use of wind energy (Freris and Infield, 2008). Further, the development of solar power will call for more inter-regional transmission capacity, as solar resources are concentrated in the Northwest and North, which partially overlaps with the distribution of wind resources.

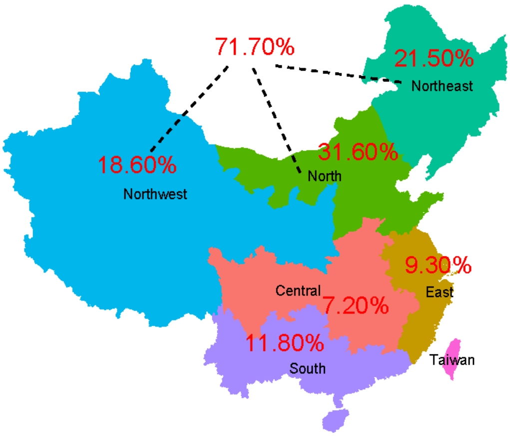


Figure 5.1 – The distribution of wind power capacity in China's six regional power systems by 2013. The total capacity was 91.42 GW (GWEC, 2014).

This chapter aims to investigate the implications of expanding the inter-regional transmission grid for the decarbonization of the Chinese power sector from energy portfolio effects, economic efficiency and environmental sustainability perspectives, considering uncertainties arising from RES penetration levels, environmental policies (CO_2 price) and the growth of electricity demand in the future. Many studies on the decarbonization of electricity in China have concentrated on the impact of policy interventions at the generation side (e.g. Li et al. (2010); Chen et al. (2011); Zhang et al. (2012); Li, Lukszo and Weijnen (2015a)) and the demand side (e.g. Hu et al. (2010); Yuan, Xu, Kang, Zhang and Hu (2014)), while very few have studied the role of inter-regional transmission capacity expansion. In particular, Chen et al. concluded that the government planned inter-regional transmission grid expansion can reduce 10% of CO_2 emissions (about 0.49 Gt) of the national power supply in 2030, based on a power dispatch model which aims to minimize the CO_2 emissions of power supply (Chen et al., 2014). Chen's work shows the possible best contribution of the inter-regional transmission grid to mitigate CO_2 emissions, as the objective of power dispatch in practice is to minimize the system cost rather than CO_2 emissions. Moreover, Chen et al. used average capacity factors for different types of generation technologies, which fail to model the variability of RES generation, and fail to capture some key technical constraints in power system operation (e.g. ramping constraints).

In light of this, a more practical and systematic evaluation regarding the impact of expanding inter-regional transmission capacity on the Chinese power sector is needed. Beyond China, many similar studies have been carried out for Europe. For instance, Brancucci et al. investigated the mid-term need for investing in cross-border transmission capacity in Europe considering different RES generation targets and CO_2 emission prices (Brancucci, 2013). Schaber et al. investigated the impact of transmission grid expansion on the electricity market, and concluded that the grid expansion helps alleviate the possible revenue losses for conventional fossil power suppliers confronted with competition from RES generation (Schaber et al., 2012). All these studies have provided useful insights for us to develop the ideas in this chapter.

Specifically, this chapter will answer two questions: 1) what are the implications of the inter-regional transmission grid expansion for the decarbonization of the Chinese power sector, from the energy portfolio, economic efficiency and the environment perspectives? and 2) how are these implications affected by CO_2 price, electricity demand growth and RES penetration levels in the future? With the answers to these questions, recommendations regarding the impact of and the need for investments in inter-regional transmission capacity will be formulated for achieving an effective and efficient decarbonization of the power sector.

The remainder of the chapter is organized as follows. Section 5.2 explains the research methods used in this chapter. Section 5.3 introduces the scenario definitions and the key data used for the scenarios. Section 5.4 analyzes the implications of the grid expansion for the energy portfolio, economic efficiency and the environment aspects, and provides insight into the utilization of transmission lines. Section 5.5 analyzes the sensitivity of the above implications to CO_2 price, electricity demand growth and RES penetration levels. Section 5.6 discusses the policy implications for China regarding the expansion of the inter-regional transmission grid. The conclusions of this chapter are given in Section 5.7.

5.2 Research methods

This chapter quantifies the impact of inter-regional transmission capacity with a multi-region power dispatch model. This model is able to compute the least-cost dispatch of power plants, energy storage systems and flexible demand (which refers to the case of electric vehicle demand response in this thesis, as described in Chapter 6) on an hourly basis, considering various system constraints. The model features a high computational performance by adopting the clustered integer approach in (Palmintier and Webster, 2011) to the conventional unit commitment model. Accordingly, the model can capture more technical details of power system operation with less computational efforts, which enables its application in the modeling and simulation of large-scale power systems.

5.2.1 Model structure and assumptions

The Chinese power system is modeled as six regional power systems reflecting the current division in network operation and power supply service provision across regions. The six regional power systems are the North, East, Central, Northeast, Northwest and the South, whose geographical distribution is shown in Fig. 2.12. More explanations about the spatial coverage of the six systems are shown in Table 2.1.

In our model, each of the six regions is represented by a single node which differs in generation portfolio and electricity demand. Specifically, the generation portfolio is represented by the combination of eleven power technologies including seven fossil fuel-based technologies and four non-fossil power technologies. The fossil power technologies include small-coal[1], sub-critical, supercritical (SC), ultra-supercritical (USC) and integrated gasification combined cycle (IGCC) coal turbines, combined cycle gas turbine (CCGT) and open cycle gas turbine (OCGT); and the non-fossil technologies are nuclear, hydro, wind and solar power. For a given fossil fuel-based technology, its generation capacity is composed of a group of generation units which have the same economic and technical performance (see Table B.6).

With regard to the modeling of non-fossil generation, we assume that: 1) the availability of RES power is exogenously determined based on the installed capacity and meteorological data; 2) curtailment of wind and solar power is allowed; and 3) hydro power (except for pumped hydro storage) is used for base load, and pumped hydro storage (PHS) is used either for generation or pumped depending on the demand situation. Modeling hydro power for base load basically implies that we neglect the role of reservoir plants[2] for peak load. We do so for the following practical reasons. In practice, run of river plants and reservoir plants can be combined in cascading river systems, and PHS can utilize the water stored in reservoirs plants, but we do not have access to data regarding the generation potential of reservoirs in China. Even if such data would be available, to what percentage reservoir plants are used for base load and for peak demand is hard to tell, given the fact that reservoir plants are local-specific (IEA, Ministeriro de Minas e-Energia, Brasil, 2012).

The modeling of transmission capacity constraints is challenging mainly given the fact that market-based power transactions between two nodes can not be directly translated to physical power flows on the specific lines connecting these nodes in meshed networks (Hagspiel et al., 2014). In addition, intensive calculations of the power transfer distribution factor (PTDF) are required at each time step of the modeling to determine the physical power flows on a specific line. Considering the limited computational capacity available, this chapter therefore simplifies the modeling of flows in the inter-regional transmission grid with market-based power flows. This means that the power flows are subjected to the net transfer capacity constraints between regions rather than the physical constraints of specific transmission lines. In addition, for the purpose of stressing the roles of the inter-regional interconnections, intra-regional grid congestion is not considered here, which means that the regional grid is assumed as a copper-plate which features perfect transmission capability.

5.2.2 Mathematical formulation

Basically, the proposed power dispatch model is a unit commitment (UC) model, which minimizes the system costs through optimizing the power output and commitment states of generation units while meeting certain system constraints. The model distinguishes itself by: 1) incorporating the transmission grid, pumped hydro storage and flexible demand

[1] In the Chinese context, small-coal represents low-efficient and high-polluting coal units, which specifically refers to the units with a capacity below 50 MW, or with operating lifetime longer than 20 years and a capacity is lower than 100 MW, or with a capacity lower than 200 MW yet reaching its economic lifetime.

[2] Hydro power plants are usually grouped into three categories: run of river, reservoir (storage) and pumped storage. First, run of river plants is mostly driven by natural river flows or releases from upstream reservoir plants. In the absence of such reservoirs plants, run of river generation has a large dependence on the variability of inflows, which makes it used for base load. Second, reservoir plants can store water in upstream reservoirs, which are normally operated following the demand. Depending on the ratio of capacity and generation intentional, reservoir plants can be used for base load or for peak demand. Third, in the pumping storage plants, water is pumped from a lower reservoir to an upper one or in the opposite direction, depending on the demand situation.

(e.g. electric vehicles' charging), which enables us to compare the value of different power system flexibility providers; 2) adopting the clustered integer approach developed by Palmintier et al. in (Palmintier and Webster, 2011; Palmintier, 2013), which largely reduces the amount of decision variables in the UC model and thus makes the model applicable for a large-scale power system. The key idea of the clustered integer approach here is to group generation units by technology, so that the commitment state for a given technology group with N_g units can be expressed as an integer varying from 0 to N_g, representing how many units of this group are turned on. Hence, with the clustered integer approach, the amount of combinatorial commitment states for the group with N_g units is $N_g + 1$, which is much less than that with the conventional UC model using binary integers. For instance, assuming that a power system consists of 3 groups of units with an amount of 10, 20, 70, respectively. The dimension of commitment state variables for these units using the two methods are calculated in Table 5.1.

Table 5.1 – The number of commitment state variables using the conventional UC and cluster integer-based UC.

Methods	Groups	Calculations	Number of variables
Conventional UC	1	2^{100}	1.2676506E+30
Cluster integer-based UC	3	$11 * 21 * 71$	16401

The mathematical formulation of the model is explained in Appendix B.1, which is mainly based on the work in (Brancucci, 2013; Palmintier and Webster, 2011; Palmintier, 2013; van Staveren, 2014; Poncelet et al., 2014; Verzijlbergh, 2013; Li and Lukszo, 2014). Specifically, a UC model incorporating transmission capacity constraints is developed in (Brancucci, 2013), which provides the basic framework of the mathematical formulation here. How to reduce the amount of decision variables by using the clustered integer approach is introduced in (Palmintier and Webster, 2011; Palmintier, 2013). The integration of the clustered integer approach with conventional UC models is applied in (van Staveren, 2014) to study the value of energy storage systems (ESS) in the EU context. The modeling regarding the flexible demand part is inspired by the work in (Verzijlbergh, 2013; Li and Lukszo, 2014), as explained in Chapter 6 regarding the case of electric vehicles.

5.3 Scenario definitions and data collection

5.3.1 Scenario definitions

The scenario year of 2030 is chosen to study the impact of inter-regional transmission capacity expansion for China. The year of 2030 includes most accessible projections of generation portfolio, and the government's plan regarding the expansion of the inter-regional transmission grid. To experiment with different levels of inter-regional transmission capacity expansion within the expected 2030 power system, four scenarios were used, as defined in Table 5.2. Specifically, the "RefGE" represents the government's planned grid expansion, and other scenarios differ from the planned one in terms of transmission capacity. More explanations regarding the planned 2030 expansion and projections of the 2030 system (e.g. generation portfolio and demand) are explained in Table 5.2.

Table 5.2 – The scenario definitions with different levels of inter-regional transmission capacity expansion.

Scenario indicator	Settings
NoGE[1]	No new capacity expansion during 2012-2030
LowGE	The expansion for each transmission line by 2030 will be 50% less than the planned value
RefGE	The government planned 2030 inter-regional transmission capacity expansion
HighGE	The expansion for each transmission line by 2030 will be 1.5 times higher than the planned value

[1] GE here represents grid expansion.

5.3.2 2030 plan: inter-regional transmission grid

5.3.2.1 Grid topology and capacity

Fig. 5.2 shows the planned inter-regional transmission grid by 2030, which mainly reflects the overall design of the State Grid Corporation (SGC) and the China Southern Grid Corporation (CSG) (Chen et al., 2014). The data in this figure are adapted from (Chen et al., 2014) with the following changes. First, this chapter integrates Tibet with the Northwest power system given increasing grid connections between them. Second, cross-border interconnection is beyond the scope of this research. Given that the planned cross-border transmission capacity will be around 20% of the inter-regional transmission capacity by 2030 (see Table 5.3), this chapter assumes cross-border transmission as a negative demand for the importing regions in China. Taking the cross-border transmission grid between Myanmar and the South for instance, a negative demand which equals the amount of cross-border transmission capacity, 20 GW, is imposed on the South power system.

Table 5.3 – The planned cross-border transmission grid by 2030 (Chen et al., 2014).

No.	Connected regions		Capacity (GW)
	From	To	
1	Myanmar	South	20.00
2	Kazakhstan	Central	9.00
3	Mongolia	North	18.40
4	Russia	Northeast	11.95

Based on these assumptions, the total inter-regional transmission capacity is planned to be expanded from 47.40 GW in 2012 to 308.40 GW in 2030. Comparing Fig. 2.12 with Fig. 5.2, we can observe that apart from the reinforcement of existing inter-regional connectors, new transmission lines connecting the Northwest-East, Northwest-South, and the North-East will also be built by 2030.

5.3.2.2 Transmission loss and cost

China has made great progress in improving energy efficiency for long-distance power transmission, and the average energy loss of inter-regional transmission is expected to decrease from 6.5% in 2010 to 4.34% in 2030 (Chen et al., 2014). This average energy loss of

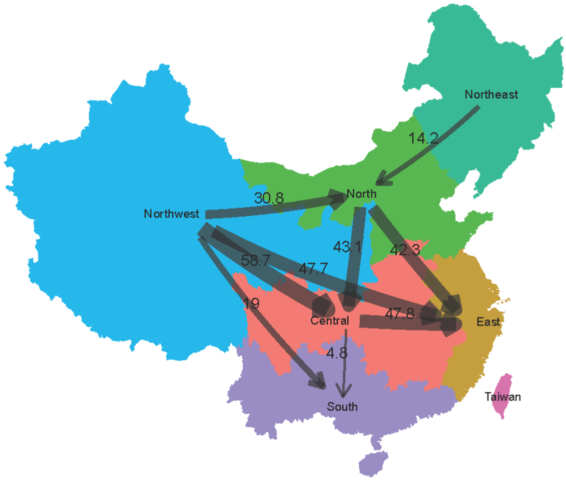


Figure 5.2 – The planning of inter-regional transmission grid in 2030. Note that the numbers close to the lines indicate transmission capacity (in GW), and the arrows reflect the main directions of power flows.

transmission lines is shown in Table B.5, mainly reflecting the length of transmission lines. Additionally, this chapter sets the transmission costs of the North-East line as the baseline, and the costs of other lines are inversely proportional to energy loss (see Table B.5).

5.3.3 2030 projections: generation portfolio

5.3.3.1 National generation portfolio

China's energy policies have been based on central planning which is regularly issued on a five-year basis. Consequently, an official planning for the mid-term generation portfolio by 2030 is not available. Hence, this work reviews the projections in the literature to gain an overall picture of the possible generation portfolio and capacity expansion in China. The review scope covers projections published by key organizations in China (e.g. China Electricity Council (CEC, 2014), National Energy Administration (NEA, 2014)), industries, the scientific literature (Chen et al., 2014; Cheng et al., 2015) and international associations (IRENA, 2014) etc. Based on these resources, Table 5.4 summarizes the evolution of generation portfolio during 2012-2030. It mainly shows that: 1) in terms of the absolute amount of generation capacity, coal power will still be the largest one till 2030, followed by hydro, wind and nuclear; and 2) in terms of the growth during 2012-2030, solar power will be the largest one, followed by nuclear power, wind power and pumped hydro storage.

5.3.3.2 Regional generation portfolio

The national generation capacity in Table 5.4 is further allocated to the six regional power systems according to the following principles: 1) the national capacity for nuclear, wind, solar and hydro power is divided into six regions using the same distribution ratio of installed capacity between regions as in December 2013; and 2) the division of national ca-

Table 5.4 – The evolution of generation capacity by fuel during 2012-2030.

Fuel	Generation capacity			Percentage	
	2012(GW)	2030(GW)	Ratio (2030/2012)	2012	2030
Coal	780.91	1388.25	1.78	67.03%	51.48%
Gas	38.27	142.44	3.72	3.29%	5.28%
Nuclear	12.58	200.00	15.90	1.08%	7.42%
Hydro	248.90	400.00	1.61	21.37%	14.83%
Wind	60.82	315.00	5.18	5.22%	11.60%
Solar	3.29	151.00	45.90	0.28%	5.60%
Hydro-pump storage	20.20	100.00	4.95	1.73%	3.71%
Total	1164.97	2696.69	2.31	100%	100%

pacity for coal and natural gas power between regions is mainly based on the regional data in (Chen et al., 2014). The derived regional generation portfolios are illustrated in Fig. 5.3, which shows a large diversity of power resources across the regions. For instance, hydro power is mainly available in the Central and the South, solar power will be largely situated in the Northwest, while nuclear power will mainly be built in the East, South and Northeast.

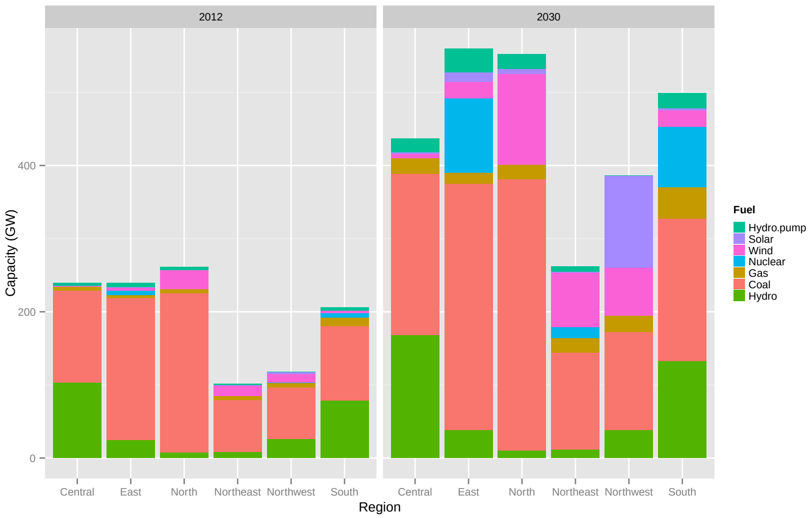


Figure 5.3 – The regional generation portfolio of 2012 and 2030. The data of 2012 are from (SGC, 2014a), and the data of 2030 are compiled by the authors based on projections in the literature.

5.3.3.3 Fossil generation technologies and fuel prices

The parameters regarding the economic and technological performance of fossil fuel-based generation technologies are listed in Table B.6.

Coal price The electricity coal market has been de-regulated since 2002 in China. Currently, North is the largest coal exporter with coal mined in Shanxi, Inner Mongolia and

Ningxia, followed by Northwest with large coal bases in Xinjiang, Shaanxi, Gansu and Qinghai. The other regions are main coal importers (Chen et al., 2014). The export from the North and Northwest is expected to increase with the continuous electricity demand growth in the load centers of China. In this work, the regional coal prices are simplified by setting the coal price of the North as a benchmark, and then varying the prices in other regions depending on their geographical distance from the North and local economic prosperity. The variation between regions is calibrated with historical data both in 2010 and 2012. In addition, to reflect the scarcity of natural resources over time, this work assumes an increasing coal price during 2012-2030 with an average annual rate of 1%. More data regarding the coal price are shown in Table 5.5.

Table 5.5 – The fuel price data used in this work. The data are compiled by the authors with sources of (Cheng et al., 2015; SGC, 2014a; CEFC, 2013; Wang et al., 2014). The percentage value within the bracket shows the variation of coal price and natural gas price relative to the benchmark region, in which the North and Northwest are the benchmark region for coal and gas price respectively.

Regions	Coal price ($/ton)		Gas price($/$m^3$)	
	2012	2030	2012	2030
North	64.00 (Ref.)	76.55	0.3584 (+40%)	0.4278
East	112.00 (+75%)	133.97	0.3880 (+52%)	0.4641
Central	112.00 (+75%)	133.97	0.3552 (+39%)	0.4249
Northeast	96.00 (+50%)	114.83	0.3232 (+26%)	0.3866
Northwest	51.20 (-25%)	61.24	0.2560 (Ref.)	0.3062
South	128.00 (+100%)	153.11	0.3632 (+42%)	0.4344

Natural gas price China has a very limited amount of natural gas production, which has historically constrained gas-based power supply (currently at about 2%) (Kahrl, Hu, Kwok and Williams, 2013). Natural gas is mainly produced in Sichuan (Central), Shanxi (Northwest) and Xinjiang (Northwest). Different from the coal market, the gas market in China is still under government's regulation (Kahrl, Hu, Kwok and Williams, 2013). Since 2013, the state has started market-oriented reforms of the gas market in Guangdong, Guangdxi and Shanghai pilots, to gradually make the gas price reflect the balance between supply and demand, and to promote investments in gas infrastructures (CEFC, 2013). After the reform (explained in Section 4.2.3), the natural gas price has slightly increased in 2013, as shown in Fig. 4.2. The market-oriented reform of the natural gas market is expected to be further expanded nationwide at the end of 2015. Similar to the coal price, this work assumes an annual growth rate of 1% for the natural gas price during 2012-2030. The specific data regarding regional gas prices are shown in Table 5.5.

Although we are fully aware that coal and gas prices in reality are highly uncertain and fluctuating, the difference between the real market price and the estimates used in this work hardly affects our results as long as the merit order of coal-fired and gas-fired power plants remains the same.

5.3.3.4 RES meteorological data

The wind speed data is provided in the form of surface flux data which is composed of two vector components at a 10 meter height with a six-hour interval (Kalnay et al., 1996). Further processing of wind speed data is done, including spline interpolations to adjust to hourly wind speed data, and converting wind speed to wind power based on wind turbine model E-33 (Thapar et al., 2011). More explanations regarding the wind power data are listed in Table B.4.

The calculation of solar PV production is mainly based on the PVWatts calculator from NREL[3], which can automatically identify the solar resource data at or near a given location. For each regional power system, a location is chosen to represent the average solar resources for the region. More explanations regarding solar power data are illustrated in Fig. B.1.

As we mentioned in the model structure part, the hydro power in this work mainly represents run of river plants whose generation highly depends on the amount of natural rainfall inflows, which varies substantially between seasons. The average annual utilization of hydro power generation in China is about 0.4 (SGC, 2014a). Depending on the abundance of hydro resources, this work categorizes the six regions into two groups, namely abundant and scarce. Specifically, North and Northwest have relatively lower rainfalls so that they are assumed to be in the group of scarce, while other regions are abundant in hydro. The hourly hydro power availability is assumed to be the same for a given month. The average hydro power availability for each month is illustrated in Fig. B.2, which is mainly based on the data of Guangxi province in the South (Kahrl, Hu, Kwok and Williams, 2013).

5.3.4 2030 projections: electricity demand

5.3.4.1 Total demand

During the past decade, China has experienced a fast growth of electricity demand with an average annual growth rate (AAGR) above 10%. Recently, the AAGR has slowed down from 7.5% in 2013 to 3.8% in 2014 (CEC, 2014). Depending on the settings of population, GDP, economic structure etc, the projections of demand growth in the literature are widely different, such as (Dai et al., 2009; Chen et al., 2014; Wang et al., 2014). Instead of providing an accurate forecast, this work focuses on the impact of a certain level of electricity demand on the role of inter-regional transmission capacity in China. Hence, this work directly uses the electricity demand data in (Chen et al., 2014) considering it shows a relatively moderate projection. As shown in Fig. 5.4, the projected average demand growth decreases over time given the slow-down of economic development, from 5.80% during 2012-2020, to 3.08% during 2020-2030. The growth rate between regions slightly differs. In general, the developed regions (e.g. North, East, Central and South) are in line with the national trend in terms of the growth rate. However, in the Northwest, a high drop of demand growth is expected during 2012-2020, while after that, the growth becomes more stable.

5.3.4.2 Demand profiles

We do not have access to regional demand profiles data of the Chinese power system. Therefore, this chapter refers to the data of four EU member states including Germany, France, Denmark, Italy to represent the regional demand profiles in China[4]. These four countries are chosen mainly because they show a large diversity in seasonal electricity demand, which is similar to the regional power systems in China. The illustration of the demand profiles of these countries is shown in Fig. B.3. This work matches the reference

[3]NREL: National Renewable Energy Laboratory, http://pvwatts.nrel.gov/pvwatts.php.

[4]The demand profiles data of EU member states are available on the website of the European Network of Transmission System Operators for Electricity (ENTSOE), with the link of https://www.entsoe.eu/data/data-portal/country-packages/Pages/default.aspx.

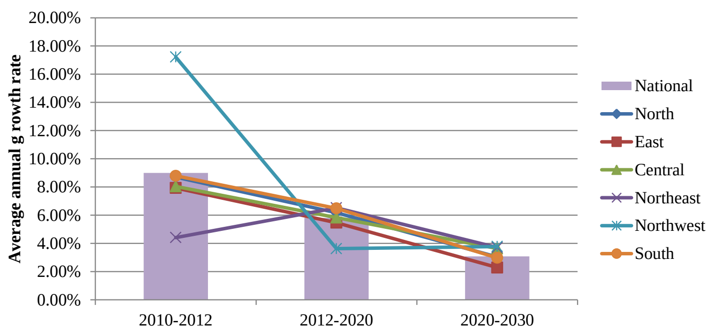


Figure 5.4 – The projected growth rates of electricity demand during 2012-2030 for the national and six regional power systems. The projections are from (Chen et al., 2014), and the historical data are from (SGC, 2014b). Note that the bars show the growth rates at the national level, and the lines with markers represent the growth rates for the regions.

of demand profile data between EU countries and the regional power systems in China as shown in Table 5.6. It should be emphasized that the assumptions regarding demand profile data here do not affect the meaning and validity of the results reported in this work, based on the sensitivity analysis we did.

Table 5.6 – The match between EU countries and the regions in China for the reference of demand profile data.

No.	Regions	Data source + adaptations	Reasons for matching
1	North	Germany	High peaks both in winter and Summer
2	East	Italy	Averagely high for the whole year, and demand is generally higher in summer than winter
3	Central	Italy	Averagely high for the whole year, and demand is generally higher in summer than winter
4	Northeast	Denmark	High demand in winter
5	Northwest	France + 2 hours delay	Low demand profiles and time lag caused by long distance from the East
6	South	Italy	Averagely high for the whole year, and demand is generally higher in summer than winter

5.4 Result analysis

This chapter first analyzes the impact of inter-regional transmission capacity expansion from the economic efficiency, energy portfolio and environmental perspectives, with the expected 2030 power system scenario defined in Section 5.3. To highlight the impact of the grid in the given 2030 scenario, CO_2 pricing is not yet considered in this section. Furthermore, this section investigates the utilization of inter-regional transmission lines.

5.4.1 Economic efficiency

5.4.1.1 Total generation costs

Fig. 5.5 shows that expanding the inter-regional transmission grid obviously reduces the total generation costs[5] for power supply. Specifically, the planned 2030 transmission expansion ("RefGE") reduces the total generation costs by 11% compared with that without any expansion since 2012 ("NoGE"). The marginal reduction in total costs decreases with additional transmission capacity, so that the differences in total costs between the "LowGE", "RefGE" and "HighGE" scenarios are negligible.

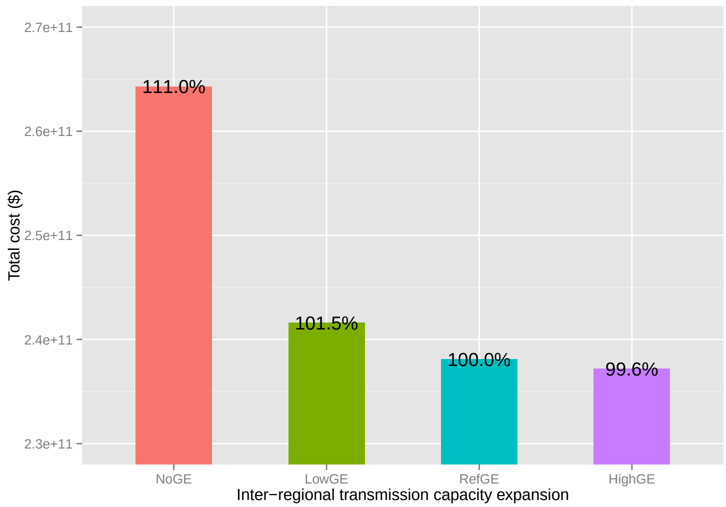


Figure 5.5 – The total generation costs for the scenarios with different inter-regional transmission capacity expansions. Note that the number close to the bar shows the relative difference of the costs between scenarios in percentage, in which the "RefGE" scenario is used as the reference and thus is marked with 100%.

5.4.1.2 Cost decomposition

Fig. 5.6 shows that the reduction in total generation costs caused by expanding the transmission capacity is mainly due to the reduction in fuel costs and in non-served load costs. The changes in other types of costs (e.g. transmission costs and start up costs) are much smaller.

First, the reduction in fuel costs is due to the improved ability of the transmission grid to deliver the power with low marginal generation costs. The degree to which the inter-regional transmission grid can reduce fuel costs largely depends on the difference in marginal generation costs between regions, and this difference is mainly influenced by the variation of fuel price across regions. Second, the reduction in non-served load arising from expanding inter-regional transmission capacity results in cost reductions, as the cost

[5]It should be stressed that the generation costs here only include the dispatch costs, while the investments costs are excluded.

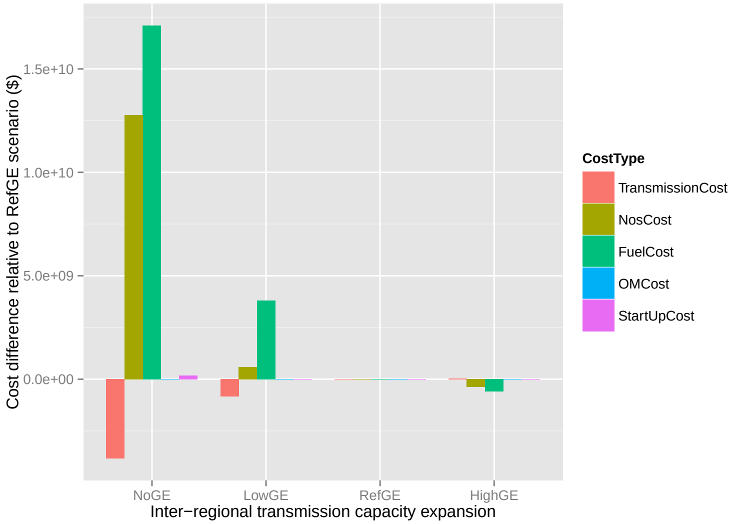


Figure 5.6 – The difference of costs by type between the "RefGE" and other scenarios. The "RefGE" scenario is used as the reference case so that its cost difference is zero. The total generation costs are comprised of: startup cost (StartUpCost), operation and maintenance cost (OMCost), fuel cost (FuelCost), non-served power cost (NosCost) and transmission cost (TransmissionCost).

per unit of non-served load is fixed and assumed to be 1 million $/GWh here. Non-served load is mainly caused by insufficient generation capacity at certain peak demand hours for some regions when the inter-regional transmission capacity is low. The generation capacity is constrained by the maximum output of power plants, as shown in Eq. B.10. Expanding inter-regional transmission capacity largely mitigates the insufficiency of generation capability for some regions through inter-regional power exchange, and thus contributes to mitigating high economic penalties caused by non-served load.

5.4.2 Energy portfolio

5.4.2.1 Non-RES generation

Fig. 5.7 shows that, first, expanding transmission capacity increases coal-based generation in the North, Northwest and the Northeast (the three-North regions), while reducing coal-based generation in other regions. This is mainly due to the fact that the marginal generation costs of coal-based power in the three-North regions are lower than those in other regions mainly due to lower coal prices. In these circumstances, expansion of the inter-regional transmission grid facilitates more exchange of coal-based generation across regions. Second, expanding transmission capacity largely reduces gas-based generation in the Central, Northwest and North, while the gas-based generation in other regions is not much affected. The implications, then, are expanding inter-regional transmission capacity reduces the needs for system flexibility provided by gas power plants, especially for the regions where RES penetration levels are high. Third, expanding the inter-regional transmission grid does not obviously affect the use of nuclear generation, except for the slight increase of nuclear generation in the South.

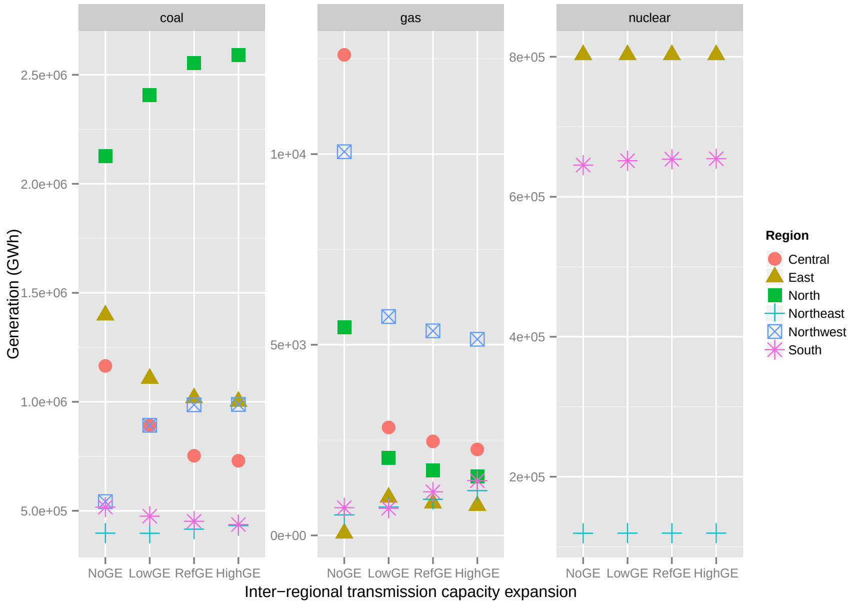


Figure 5.7 – The non-RES generation by fuel for each regional power system under different scenarios of transmission capacity expansion.

Fig. 5.8 shows what types of fossil fuel-based power technology are most influenced by transmission capacity expansion. First, we observe that the generation from sub-critical coal technology in the North, Northwest and Northeast largely increases with additional transmission capacity, while the generation from ultra-supercritical technology in the Central, East and South is clearly reduced. This implies that expanding the inter-regional transmission capacity promotes more low-efficient coal-based generation in the regions where coal prices are low, as long as their marginal costs are lower than those of high-efficient technologies in other regions. Considering the slight difference in generation efficiency between technologies, the regional coal prices are decisive in determining the differences in marginal generation costs of various technologies between regions.

With regard to the total generation of the whole system, it is clear that expanding the inter-regional transmission grid benefits generation based on sub-critical coal technology, which in turn substitutes part of the generation from ultra-supercritical coal technology. The influence of transmission capacity expansion on gas-based generation is negligible given the fact that the share of gas-based generation is very small.

5.4.2.2 RES generation

Table 5.7 shows to which extent expanding the inter-regional transmission capacity can mitigate the curtailment of wind and solar generation. In general, expanding inter-regional transmission capacity has very limited impact on promoting the use of RES generation which mainly refers to wind and solar-based generation here[6]. For instance, the planned

[6]This work assumes that hydro generation is fully utilized so that we do not consider the impact of grid on hydro power generation here.

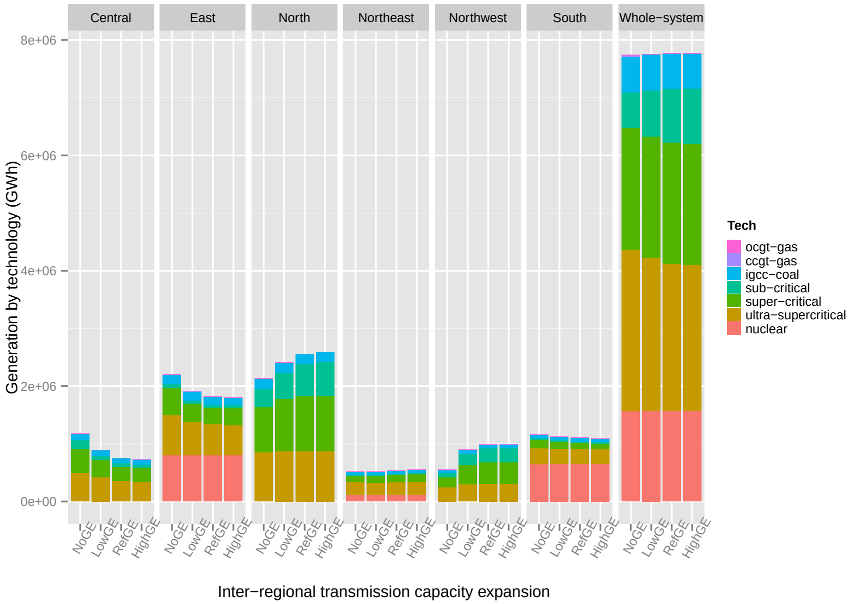


Figure 5.8 – The non-RES generation by technology for each regional power system under the scenarios with different transmission capacity expansion. Note that the whole-system in this figure represents the national power system which is an aggregation of the regional power systems.

2030 transmission grid merely reduces the curtailment of wind and solar generation by 3.34% relative to the "NoGE" scenario.

Table 5.7 – The curtailment rate (%) of wind and solar generation under different transmission capacity scenarios.

No.	Grid expansion scenario	Curtailment rate (%)		
		Solar	Wind	Wind and Solar
1	NoGE	5.44	2.88	3.37
2	LowGE	0.35	0.11	0.16
3	RefGE	0.00	0.05	0.04
4	HighGE	0.00	0.04	0.03

Furthermore, we observe that the curtailment rates of wind and solar generation in the "LowGE", "RefGE" and "HighGE" scenarios are all lower than 0.5%, and the differences between these scenarios are negligible. Hence, we deduce that the government planned inter-regional transmission grid expansion is basically sufficient for promoting RES generation, if the RES penetration level develops as expected.

5.4.2.3 Non-RES vs. RES generation

Although inter-regional transmission capacity expansion slightly changes the national generation mix by technology (the substitution of high-efficient coal power technologies by low-efficient ones), it does not change the fact that China's power supply still heavily relies on fossil fuels by 2030. Specially, coal-based generation in total accounts for about 58% of the national power supply. RES generation accounts for merely 22% of the national total, in which hydro power has the largest share (12.9%), followed by wind power (7.4%) and solar power (1.7%). Nuclear generation accounts for about 15% of the national power supply. In general, the ratio between RES and Non-RES generation does not change much with different levels of transmission expansion, as the increased RES generation caused by the expansion of the inter-regional grid is negligible.

5.4.2.4 Fuel consumption

Fig. 5.9 shows to what degree expanding the inter-regional transmission grid can affect the fuel consumption for national power supply. We find that, in terms of the relative proportion, expanding the transmission capacity slightly increases the use of coal consumption, and largely reduces the use of gas consumption. Hence, expanding inter-regional grid capacity is more likely to promote more use of coal in power supply and largely discourage the use of gas, especially in the absence of CO_2 emission-related regulations.

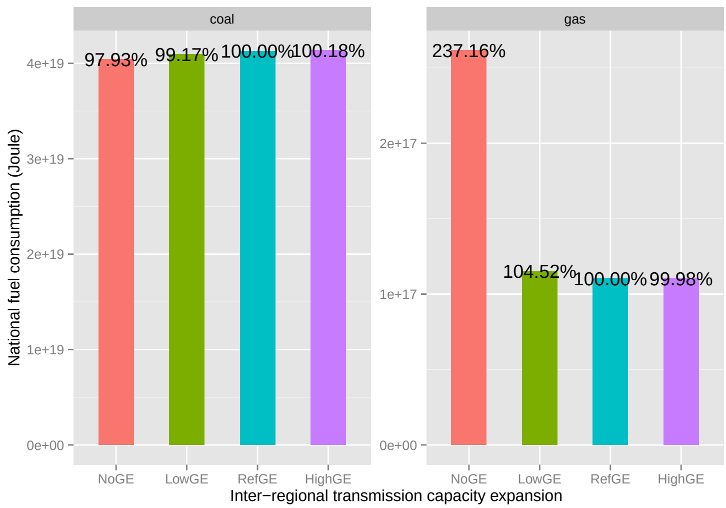


Figure 5.9 – The national fuel consumption for the scenarios with different transmission capacity expansion. Note that the number close to the bar shows the relative difference of the fuel consumption between scenarios in percentage. The "RefGE" scenario is used as the reference case so that it is marked with 100%.

5.4.3 Environmental impact

Fig. 5.10 shows that expanding the inter-regional transmission capacity increases the total CO_2 emissions of power supply. In comparison with the "NoGE" scenario, the planned transmission expansion ("RefGE") increases the CO_2 emissions by around 2% in 2030. Based on the analysis in Section 5.4.2, the causes of the increase of CO_2 emissions here are evident. First, expanding transmission capacity facilitates the use of more coal-based generation, yet less gas-based power generation, as shown in Fig. 5.7. Second, expanding transmission capacity encourages more use of low-efficient coal-based generation technologies with lower marginal generation costs, which partially substitute high-efficient coal-based generation, as illustrated in Fig. 5.8. In the absence of environmental or CO_2 emission-oriented regulations, inter-regional transmission capacity expansion is therefore likely to result in more CO_2 emissions of the Chinese power system.

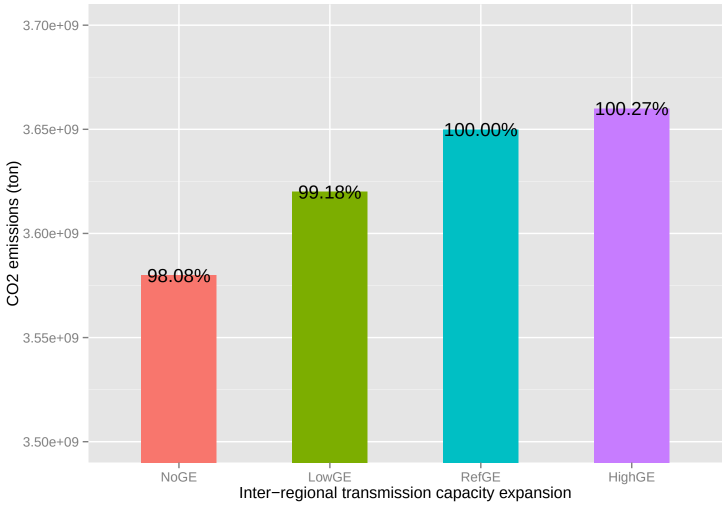


Figure 5.10 – The total CO_2 emissions for different scenarios of inter-regional transmission capacity expansion. Note that the number close to the bar shows the relative difference of the CO_2 emissions between scenarios in percentage. The "RefGE" scenario is used as the reference case so that it is marked with 100%.

5.4.4 Utilization of inter-regional transmission lines

5.4.4.1 Inter-regional power exchange

Fig. 5.11 shows the amount and directions of exported power for each transmission line[7] in 2030. This figure shows that, first, three transmission lines are most effectively used in terms of the total amount of power exchange, especially the lines connecting the North-East, North-Central and the Northwest-Central. Second, with the increase of transmission capacity, the power exchange between the Northwest-East is partly substituted by that between the North-East.

Table 5.8 shows the percentage of inter-regional power exchange relative to the national electricity demand for different scenarios. With the "RefGE" scenario, inter-regional power exchange accounts for about 11% of the national electricity demand. The marginal increase of inter-regional power exchange between the "RefGE" and the "HighGE" scenario becomes negligible, which implies that the amount of transmission capacity in the "RefGE" scenario is sufficient for enabling inter-regional power exchange.

[7]Note that the line hereinafter represents an aggregated connection of all lines between two regions, rather than one physical line.

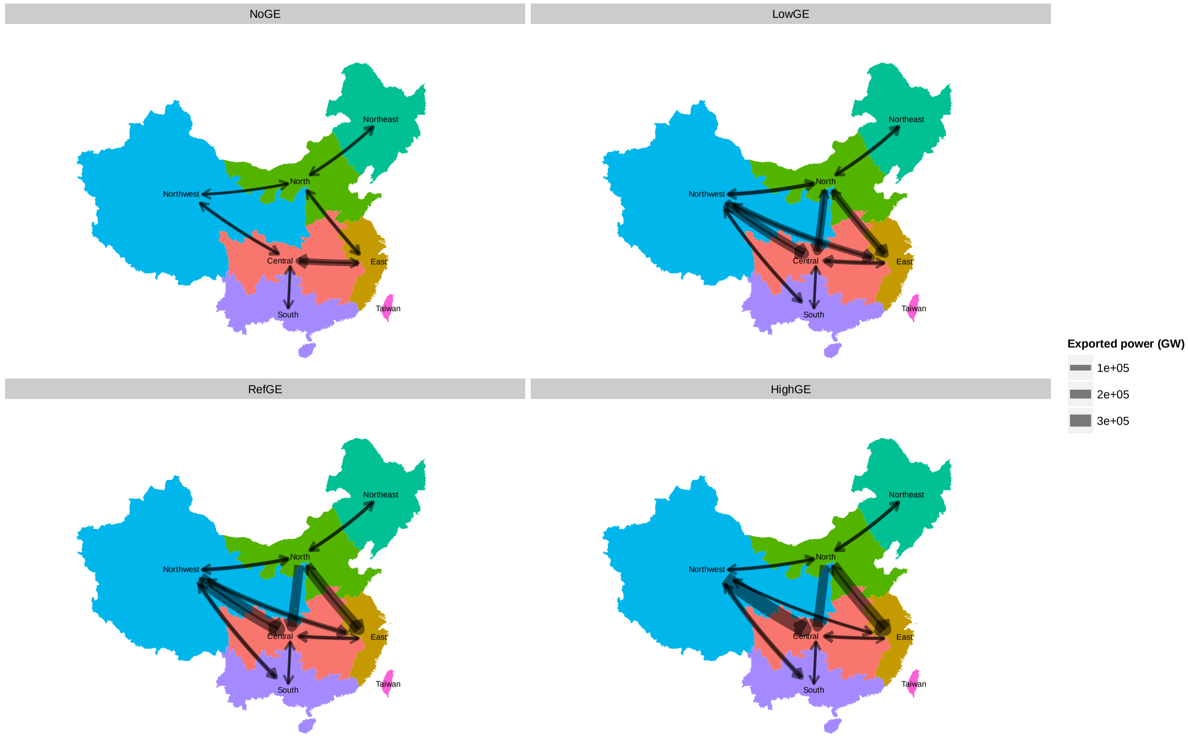


Figure 5.11 – The amount and directions of exported power for each transmission line in 2030 (in GW). Note that the width of the line indicates the amount of exported power, and the arrow shows the direction in which the power is exported to.

Table 5.8 – The amount of inter-regional electricity exchange relative to national electricity demand.

No.	Grid expansion scenario	Amount of electricity exchange (GWh)	Power exchange vs. national demand (%)
1	NoGE	264983.40	2.51
2	LowGE	963703.90	9.12
3	RefGE	1186646.40	11.23
4	HighGE	1216265.70	11.51

5.4.4.2 Utilization rates of transmission lines

Fig. 5.12 shows the utilization rate for each transmission line, which is calculated by the percentage of hours that a line is used to deliver power in a whole year. Clearly, the utilization rates of all transmission lines decrease with increasing transmission capacity. However, the lines between the Northwest-Central, Northwest-North, North-East, Northwest-South and the Northeast-North, all have utilization rates higher than 70% even in the "HighGE", which proves the significance of investing in these lines. In addition, it shows that the utilization rates of some lines largely decrease with transmission capacity. For instance, the utilization rate of the Central-South line reduces to about 20% with the "HighGE" scenario. Considering the relative cost competitiveness between transmission lines, the power flow through one line might be replaced by that through other lines, when sufficient transmission capacity is in place.

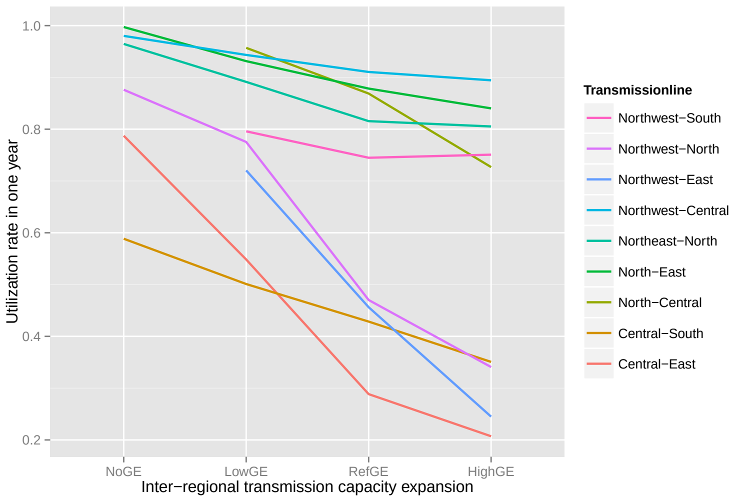


Figure 5.12 – The utilization rate of each line in 2030, which is calculated by the percentage of hours that the line is used to transport power in the whole year.

This chapter also analyzes the congestion of transmission lines which is indicated by the amount of hours that the exported power through a given line exceeds its maximum transmitting capacity. The results show that only the line of the Central-East line is more likely to be congested yet only for a few hours per year. For instance, the congestion rate of this line in the planned 2030 scenario is about 0.2% (17.52 hours).

5.5 Sensitivity analysis

The results provided in Section 5.4 compare different scenarios of transmission expansion with the expected generation portfolio and electricity demand, yet neglecting uncertainties in the future. Therefore, this Section focuses on the sensitivity of the results for the following key uncertainties: 1) CO_2 price; 2) electricity demand; and 3) RES penetration levels. The settings of these three sensitivity factors are listed in Table 5.9. The results of the sensitivity analysis are discussed below.

Table 5.9 – The settings of the sensitivity factors.

Sensitivity factor	Scenario indicator	Setting
1. CO_2 price	NoCP	The reference value, no CO_2 price
	HighCP	The CO_2 price is 50 $ per ton CO_2 emissions
2. Electricity demand	RefDem	The reference value
	HighDem	Regional electricity demand is 1.2 times higher than that in the "RefDem" scenario
	LowDem	Regional demand will be 20% less than that in the "RefDem" scenario
3. RES penetration levels	RefRES	The reference value
	HighWind	The wind power capacity for each region in 2030 is 1.5 times higher than that in the "RefRES" scenario
	HighSolar	The solar power capacity for each region in 2030 is 1.5 times higher than that in the "RefRES" scenario

5.5.1 CO_2 price

Fig. 5.13 shows that imposing an assumed CO_2 price of 50 $/ton largely increases the total generation costs, as expected. The CO_2 price substantially lower the generation costs for a given level of transmission expansion. For instance, in the "HighCP" scenario, the "RefGE" capacity expansion reduces the total costs by 5.6% (relative to "NoGE"), while this reduction is only about half of that in the "NoCP" scenario. This is mainly due to: 1) the CO_2 price makes gas power having lower marginal generation costs in some regions (e.g. Northwest) than coal power in other regions (e.g. South), which slightly promotes gas generation which has higher costs than coal generation; and 2) it reduces the differences in marginal generation costs between various coal power technologies across regions, which reduces the incentive for inter-regional exchange of coal power (see Table 5.10).

Fig. 5.14 shows that the CO_2 price reduces the additional CO_2 emissions caused by a given amount of inter-regional transmission capacity expansion, yet to a negligible degree. This is mainly due to the fact that the assumed CO_2 price of 50 $/ton only increases the use of gas in some regions (e.g. Northwest) slightly, and not fundamentally changes the merit order between coal and gas-based generation, so that the share of gas-based generation remains insignificant. Hence, CO_2 pricing hardly increase the cost competitiveness of gas power relative to coal power, given the large gap between coal and gas prices in China.

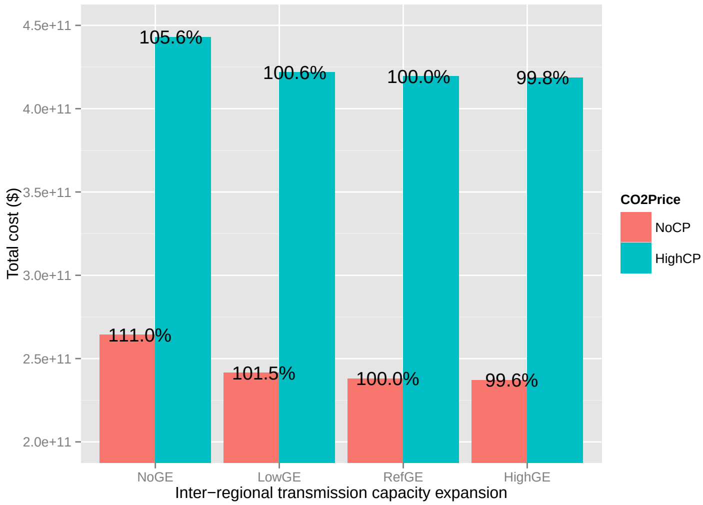


Figure 5.13 – The total generation costs for the scenarios with different inter-regional transmission capacity expansion and CO_2 prices. Note that the number close to the bar shows the relative difference of the costs between scenarios in percentage. The "RefGE" scenario is used as the reference case so that it is marked with 100%.

Table 5.10 – The amount of inter-regional power exchange with different inter-regional transmission expansion and CO_2 prices.

No.	Grid expansion scenario	Power exchange vs. national demand (%)	
		NoCP	HighCP
1	NoGE	2.51	2.46
2	LowGE	9.12	8.01
3	RefGE	11.23	9.26
4	HighGE	11.51	9.43

5.5.2 Electricity demand

Fig. 5.15 shows that the economic benefit for a given amount of transmission capacity largely increases with the electricity demand. For instance, within the "HighDem" scenario, the "RefGE" reduces the total generation costs by 24.5% (relative to the "NoGE"), which is 13.5% higher than that in the "LowDem" scenario.

The increased economic benefit from transmission expansion in the high demand situation stems from the reduction in the costs of non-served load. The amount of non-served load badly increases with electricity demand, especially in the regions where RES penetration levels are high. Hence, expanding transmission grid capacity is especially more important in high demand growth scenarios to mitigate the amount of non-served load and increase the security of national power supply.

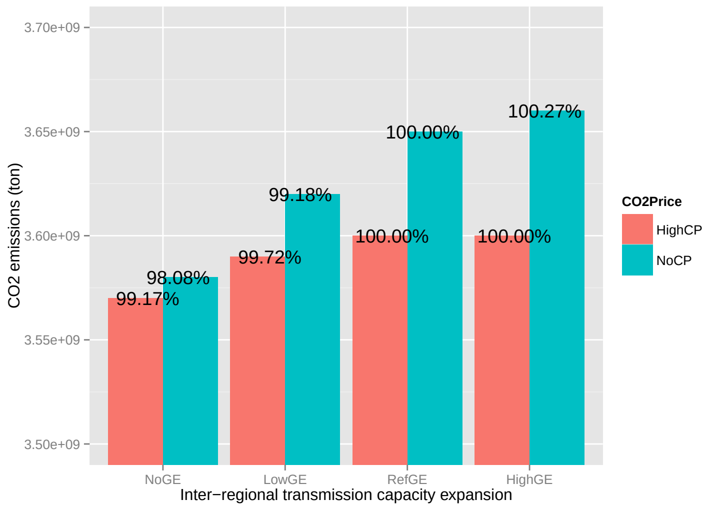


Figure 5.14 – The total CO_2 emissions with different inter-regional transmission expansion and CO_2 prices. Note that the number close to the bar shows the relative difference of the CO_2 emissions between scenarios in percentage. The "RefGE" scenario is used as the reference case so that it is marked with 100%.

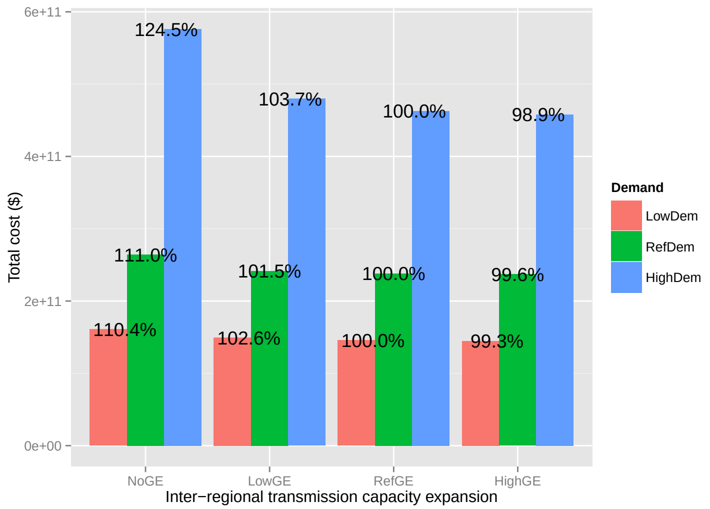


Figure 5.15 – The total generation costs for the scenarios with different inter-regional transmission capacity expansion and electricity demand. Note that the number close to the bar shows the relative difference of the costs between scenarios in percentage. The "RefGE" scenario is used as the reference case so that it is marked with 100%.

5.5.3 RES penetration levels

Fig. 5.16 shows that the degree to which expanding inter-regional transmission capacity can reduce RES generation curtailment increases with the RES penetration level. For instance, with the "HighSolar" scenario, the "RefGE" can reduce wind and solar generation curtailment by 7.59% (relative to "NoGE"), which is around 2.5% higher than that in the "RefRES" scenario. Inter-regional transmission expansion will become more significant for mitigating RES generation curtailment as the penetration level of RES power increases. However, unless the RES penetration level is much higher than the expected value, the impact of expanding inter-regional transmission capacity on promoting wind and solar generation in general is very limited by 2030. For instance, the maximum reduction in wind and solar curtailment facilitated by transmission expansion in the scenarios of this chapter is less than 8%. Moreover, although exploring the optimal inter-regional transmission expansion plan is beyond our scope, we find that the value of inter-regional transmission expansion largely varies between regions, considering large regional differences in spatial distribution and power output time series. Future research on inter-regional transmission grid planning is recommended to take this into account.

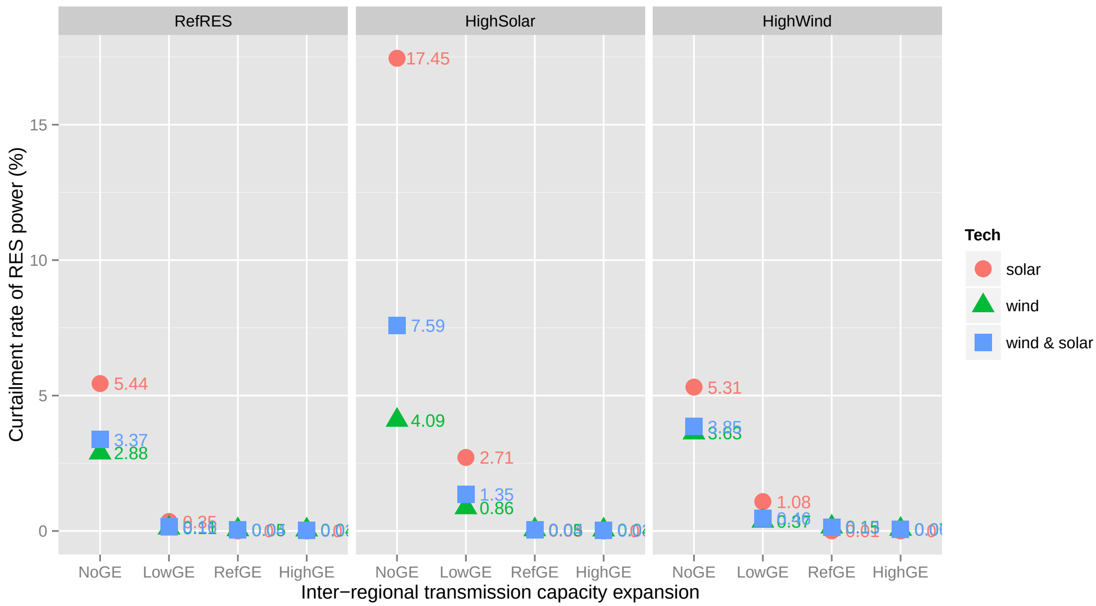


Figure 5.16 – The curtailment rate of renewable energy generation with different inter-regional transmission expansion and RES penetration levels. Note that the number close to the dots specifies the curtailment rate of renewable energy generation in percentage.

Fig. 5.17 shows that, the higher the RES penetration level, the lower the CO_2 emissions of national power supply, which is just as expected. However, within the given scenarios of different RES penetration levels, expanding inter-regional transmission capacity increases the CO_2 emissions of national power supply in all scenarios although at different degrees. This implies that unless the penetration level of RES becomes extremely high (which should of course be much more ambitious than our assumptions), the increased CO_2 emissions facilitated by grid expansion (mainly from increased use of coal-based generation) can not be counteracted by the increased use of RES generation.

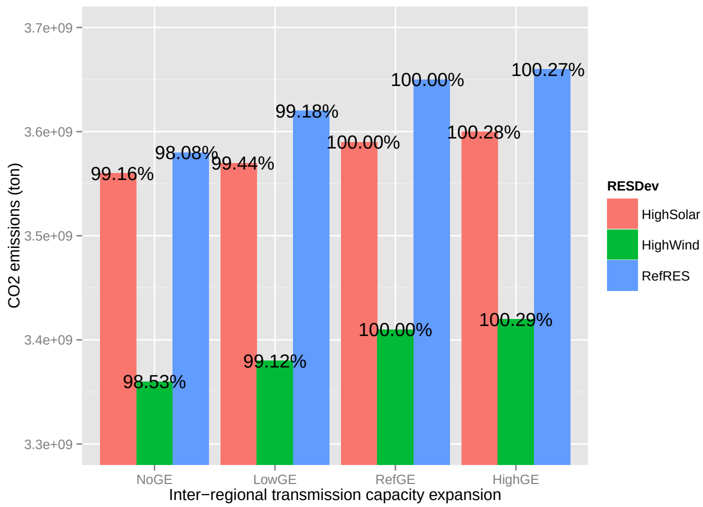


Figure 5.17 – The amount CO_2 emissions for different inter-regional transmission expansion and RES penetration levels. The number close to the bar shows the relative difference of CO_2 emissions between scenarios in percentage. The "RefGE" scenario is used as the reference case so that it is marked with 100%.

5.6 Discussions and policy implications

Based on the scenario results and sensitivity analysis presented above, this section first discusses to what extent inter-regional transmission expansion may benefit or threaten the Chinese power sector from the energy portfolio, economic efficiency and environmental perspectives. Next, this section provides insight into the needs for investments in inter-regional transmission in China.

5.6.1 The impact of inter-regional transmission capacity expansion

Economic benefit Expanding inter-regional transmission capacity obviously reduces the total variable generation costs for China's power supply (by around 11% with the planned 2030 expansion). This economic benefit is mainly caused by the reduction in fuel costs of power supply, as expanding inter-regional transmission capacity increases transport of coal power with low marginal costs, from the regions with low coal prices (mainly North and Northwest) to others (East, Central and South). Additional economic benefit comes from mitigating the penalties from non-served load becomes more significant with higher electricity demand. Accordingly, inter-regional transmission capacity expansion is indispensable for China to secure the power supply across regions especially when electricity demand is high.

Imposing CO_2 prices largely reduces the economic benefit for a given amount of inter-regional transmission expansion (by around 50% in this work), as it promotes the delivery of gas-fired generation across regions and gas-fired generation has much higher fuel costs than coal-based generation. However, even if the assumed CO_2 price (50 $/ton) in this work is five times higher than the real CO_2 price in the current ETS markets in China (ranging from 4-11 $/ton across the seven ETS pilots in 2013 (World Bank, 2014)), it does not fundamentally change the merit order between coal and gas-fired generation within regions, due to the large gap between coal price and gas price in China. Instead, the assumed CO_2 price slightly changes the merit order between coal and gas-fired generation across regions. For instance, with the assumed CO_2 price, the marginal cost of ccgt-based generation in the Northwest becomes lower than that of the small-coal generation in the South. Hence, the assumed CO_2 price only slightly promotes the use of gas-fired generation in China, and this has to be facilitated by inter-regional power exchange. Based on this, we reflect that it is ineffective for China to reduce CO_2 emissions relying on CO_2 pricing, as long as the big gap between coal price and fuel price remains. Instead, gas market reforms seems crucial to increase the cost competitiveness of gas power relative to coal power.

Positive impact on energy portfolio Expanding the inter-regional transmission grid has a limited impact on improving the use of RES generation, as it only reduces the curtailment of wind and solar generation by around 3.3% within the expected 2030 power system. Hence, if the development of RES power is just as expected, inter-regional transmission capacity will not be a major constraint for the use of renewable energy power in China by 2030. Instead, considering the level of wind energy curtailment in China during 2010-2011 (Pei et al., 2015), we suggest that the congestion within regional transmission and distribution grids is likely to be more critical for integrating RES power than congestion within the inter-regional transmission level. However, if the RES penetration level increases beyond the current projection for 2030, more inter-regional transmission capacity is needed to mitigate the RES curtailment. Therefore, the value of inter-regional transmission grid in promoting the use of RES energy will largely increase with the RES penetration level.

Negative impact on energy portfolio Without CO_2 pricing, expanding inter-regional transmission capacity increases the share of coal-based generation which in turn reduces gas-based generation, as grid capacity expansion stabilizes the power output of high-efficient coal power plants across regions and thus reduces the needs for more flexible gas power plants. Correspondingly, the planned inter-regional grid expansion slightly increases coal consumption by 2% in comparison with the scenario without expansion. However, it implies a large reduction of gas consumption (by about 57% with the planned expansion), as gas consumption itself is small. Furthermore, without a CO_2 price, expanding inter-regional transmission capacity will promote the use of low-efficient coal-based generation in the regions with low coal prices, as long as their marginal costs are lower than those of high-efficient coal-based power plants in other regions.

Environmental threat Expanding the inter-regional transmission grid slightly increases the CO_2 emissions of power supply (by around 2% with the planned 2030 expansion). Imposing CO_2 prices slightly reduces CO_2 emissions, yet to a very limited degree. Given the fact that the inter-regional grid expansion can mitigate the RES generation, it is expected that expanding the grid can reduce the CO_2 emissions of power supply if the RES penetration level becomes very high. Unless the RES penetration level is much more advanced than the level based on current government ambitions, the increased CO_2 emissions facilitated by the expansion (mainly from increased use of coal-based generation) will not be counteracted by the increased use of RES generation.

5.6.2 Investment recommendations

With the planned 2030 transmission grid expansion, inter-regional power exchange accounts for about 11% of the national electricity demand in 2030. The scenario with higher expansion only increases the amount of inter-regional power exchange by 0.03% which is negligible. Therefore, the planned 2030 expansion is basically sufficient for enabling bulk power delivery across regions in China.

With regard to the utilization rates of the transmission grid, first, the transmission lines connecting the North-Central, North-East and the Northwest-Central are most effectively used in terms of the total amount of inter-regional power exchange in 2030. Accordingly, these grid connections will be the key corridors for China to deliver bulk power across regions. Second, the transmission lines between the Northwest-Central, Northwest-North, North-East, Northwest-South and the Northeast-North all have utilization rates higher than 70% in one year. This confirms the need for investments in all transmission lines.

5.7 Conclusions

This chapter investigated the impact of expanding the inter-regional transmission grid on the decarbonization of China's power sector from the energy portfolio, economic efficiency and environmental sustainability perspectives, considering uncertainties arising from RES penetration levels, environmental policies (CO_2 price) and the growth of electricity demand in the future. The study was performed with a least-cost multi-region power dispatch model which features high computational performance compared with conventional unit commitment models.

Our analysis of scenarios for the China's power system in 2030 leads us to identify some policy implications of China's inter-regional transmission grid expansion. First, expanding the inter-regional transmission grid obviously reduces the variable generation costs for China (by around 11% with the government's plan of grid expansion), mainly due to: 1) the increased ability of transmitting coal power with low marginal generation costs across regions; and 2) the mitigation of economic penalties from non-served load across regions, which becomes more significant if electricity demand is high. Second, expanding the inter-regional transmission grid has a very limited impact on promoting the use of RES generation (by mitigating around 3% of RES generation curtailment with the government's plan of grid expansion), with which we argue that the grid congestion within regional transmission and distribution grids is likely more critical for promoting RES integration than inter-regional congestion. However, the degree to which inter-regional transmission expansion can mitigate the curtailment of RES generation largely increases with the penetration level of RES power, which implies that inter-regional transmission becomes more significant if the RES penetration level is higher than currently expected for 2030. Moreover, expanding inter-regional transmission promotes coal-based generation especially for regions where coal prices are low, which in turn largely discourages the use of gas in power supply. This can hardly be changed by CO_2 pricing in light of the big gap between coal and gas prices in China. Third, expanding inter-regional transmission grid increases the CO_2 emissions of power supply by around 2%, and it can only reduce the CO_2 emissions of national power supply when the RES power penetration level becomes very high.

Additionally, the government's plan of inter-regional grid expansion is basically sufficient in terms of enabling bulk power delivery and promoting RES integration across regions. In particular, the transmission lines connecting the North-Central, North-East and the Northwest-Central are three key corridors in terms of the total amount of power exchange, and the lines between the Northwest-Central, Northwest-North, North-East, Northwest-South and the Northeast-North have high utilization rates, which justifies substantial investments in all lines.

The results of this chapter can inform China's policy makers about the benefits and drawbacks of expanding the inter-regional transmission grid in view of China's policy focus for the future. However, it should also be noted that the results in this chapter are based on a set of parameters associated with assumptions, such as the projected generation portfolio and the exogenous meteorological data of RES generation. Despite this, to cope with the complexities in the future, policy makers can be supported by using the proposed model through adapting the settings. In addition, the use of this model can be extended to studies regarding the value of different power system flexibility provisions (e.g. transmission grid, energy storage system and flexible demand such as EV charging). Last but not least, this chapter does not consider the capital investment costs of expanding the inter-regional transmission grid, neglects the interplay between investments in the grid and in energy storage systems and other pollutions of power supply in the environmental aspect (e.g. SO_2 and NO_2). Future work will address these issues.

6 Decarbonization with demand response: the case of electric vehicles

This chapter is mainly based on the following peer-reviewed article:

- Li, Y., Davis, C., Lukszo, Z., and Weijnen, M. Electric vehicle charging in China's power system: energy, economic and environmental trade-offs and policy implications, accepted by Applied Energy, DOI: 10.1016/j.apenergy.2016.04.040.

6.1 Introduction

Being challenged with the sustained growing electricity demand, demand response programs which are designed to lower electricity consumption or change electricity consumption patterns, definitely become key policy options for the decarbonization of the Chinese power sector. Amongst various demand response programs with respect to different types of electricity users, the case of electric vehicles (EVs) is selected and studied in this thesis, considering the on-going transportation electrification in China, and the temporal and spatial flexibility that EVs have to coordinate with the power system operation (Li, Zhan, de Jong and Lukszo, 2015; Kempton and Tomić, 2005). Given substantial differences in the regional generation portfolios and the expanding inter-regional transmission grid, a detailed assessment is needed to estimate the value of deploying EVs in such a large-scale and complicated power system in China (Huo et al., 2013).

Furthermore, the implications of EVs for the decarbonization of the power sector are largely influenced by charging strategies. Most studies indicate that uncontrolled EV charging entails a series of challenges for the investments in and the operation of the power system (Richardson, 2013). For instance, it may require additional generation capacity (Kempton and Tomić, 2005) and upgrading of the existing power grid (Verzijlbergh et al., 2012). Accordingly, demand response of EVs has been proposed to cope with this. The key idea behind the EV demand response is that with certain mechanisms, EVs' charging (discharging) can be controlled as a dispatchable load or as an energy storage system to coordinate with the power system operation (Kempton and Tomić, 2005). Based on various controlled charging strategies, many benefits can be expected from EV demand response. For instance, studies show that EVs can provide ancillary services in the electricity market (Short and Denholm, 2006; Juul and Meibom, 2011), manage the intermittency issues of RES generation (Wang et al., 2011; Lund and Kempton, 2008), and mitigate grid expansion (Green et al., 2011; Verzijlbergh et al., 2014). The questions left here are how the implications of EVs are affected by different charging strategies, and which charging strategy would be more suitable to contribute to electricity decarbonization in light of China's power system characteristics.

In short, this chapter aims to assess the implications of deploying EVs for the decarbonization of the Chinese power system considering regional differences in generation portfolios and the expansion of transmission grid, and investigate the influences of the contextual power system and charging strategies on the value of EVs. The results of this chapter are expected to inform policy makers regarding the possible benefits and threats associated with EV deployment, and how to better exploit the promises of EVs by improving designs in the power system and charging strategies in demand response programs. Specifically, this chapter will answer three questions: 1) what are the implications of EV deployment for the decarbonization of the Chinese power sector from the energy portfolio, economic efficiency and environmental sustainability perspectives? 2) to what degree can the implications of EVs be affected by charging strategies? and 3) what can be improved in the power system and charging strategies to better deliver the value of EVs?

Although many studies assessing the value of EVs have been conducted in the literature, this chapter distinguishes itself in two main areas. First of all, this chapter distinguishes itself by providing a comprehensive evaluation of the value of EVs in China from the combined perspectives of energy portfolio, economic efficiency and environmental sustainability. We argue that these three perspectives are all desirable for policy designs to achieve an effective and efficient low-carbon transition in the long-term. Hence, this work can provide well-rounded policy evaluations of the value of EVs with regard to the different aspects and trade-offs involving goals related to these perspectives. However, the existing literature has omitted certain perspectives of the three, which might lead to biased policy decisions. For instance, some studies (e.g. Ou et al. (2010); Huo et al. (2013, 2010); Nansai et al. (2002)), only focused on the environmental aspect of deploying EVs; some studies (e.g. Kempton and Tomić (2005); Lund and Kempton (2008); Li and Lukszo (2014); Schill and Gerbaulet (2015); van der Kam and van Sark (2015); Liu et al. (2013)), focused more on energy portfolio effects especially for the integration for renewable energy; other studies, such as Zhao et al. (2015) and Yuan et al. (2015), focused more on a mix of two perspectives. Also, there are studies of EVs focusing on their impact on the distribution and transmission grids, such as Green et al. (2011) and Verzijlbergh et al. (2014); and other studies (e.g. Short and Denholm (2006); Foley et al. (2013)) focusing more on aspects of the electricity market.

Additionally, this chapter distinguishes itself by developing a new integrated transportation-power system model, which enables a better quantification of the value of EVs. First, the model can statistically estimate the temporal availability of EVs connecting to the grid. This addresses the lack of accurate driving data which has been identified as a key issue in creating EV-grid models (Richardson, 2013). Additionally, the model enables the simulation of power system operation with a high temporal and spatial resolution. Temporally, the model simulates power system operation on an hourly basis, which can estimate what types of power plants are reacting to the changes in EV load. Because of this, the model is better in terms of evaluation accuracy when compared with life-cycle assessment methods (e.g. Ou et al. (2010) and Zhao et al. (2015)), or with methods assuming a fixed generation portfolio or a given merit order (without considering start-up constraints) for EV charging (e.g. Huo et al. (2013, 2010) and Van Vliet et al. (2011)). Spatially, the Chinese power system is modeled as a six-region power system, which incorporates the constraints of inter-regional transmission capacity and the differences in regional generation portfolio by technology. In particular, this work highlights the influence of inter-regional power exchange on the value of EVs given the fact that it might shift EV-associated regional power supply to interconnected regions (Tamayao et al., 2015). This shift is likely to be more significant in China in light of its spatial imbalance between generation and demand as well as the fast expanding inter-regional transmission grid (Chen et al., 2014). However, existing model-based studies for the Chinese case, such as Li and Lukszo (2014) and Liu et al. (2013), fail to take this into consideration. Hence, this model enables a more accurate estimation of the value of EVs, and can provide a theoretical reference for the methods that can be used in studies that model the integration of EVs into the power system.

The remainder of the chapter is organized as follows. Section 6.2 introduces the transportation-power system model used to support the analysis of this chapter. Section 6.3 presents the scenario definitions and the key data used in this chapter. Section 6.4 analyzes the scenario results regarding the implications of EVs for the decarbonization of the Chinese power sector from the energy portfolio, economic efficiency and environmental sustainability perspectives. Section 6.5 discusses how to better deliver the value of EVs by improving designs in the power system and charging strategies. The final conclusions are provided in Section 6.6.

6.2 Research methods

6.2.1 An integrated transportation-power system model

This chapter develops an integrated transportation-power system model to quantify the interactions between EVs and the power system. The framework of the model is shown in Fig. 6.1. Specifically, the transportation model calculates the electricity demand of EVs, statistically estimates the availability of EVs connecting with the grid, and defines the strategies of using EVs. As the lack of accurate driving data has been identified as a key issue in creating useful EV-grid models (Richardson, 2013), the statistic estimation method used in our transportation model can be useful for similar studies. Specifically, the possible strategies of using EVs in this work are: 1) using EVs as loads (only charging) or as an energy storage system (both charging and discharging); and 2) having EVs' charging and discharging controlled by the power system operator or under control of the vehicle owner (Madzharov et al., 2014).

With the data from the transportation model as inputs, the power dispatch model computes how power plants across regions should theoretically behave in response to hourly load changes arising from EV charging considering technical constraints of the power system (e.g. ramping and transmission constraints). The power dispatch model here is expressed as a multi-region unit commitment (UC) optimization problem. Note that the inter-regional power exchange here is constrained by market-based net transfer capacity of the transmission grid rather than physical power flows. Instead of using the conventional mixed-integer UC optimization, this work adopts the clustered integer approach

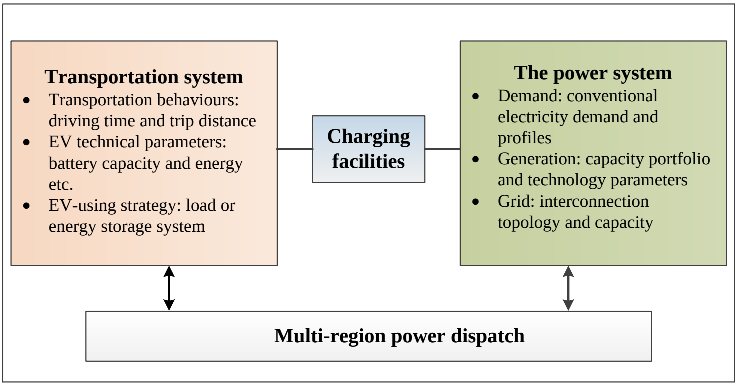


Figure 6.1 – The schematic diagram of the integrated transportation-power system model. The arrows represent the directions of power flows.

in (Palmintier and Webster, 2011) to group power plants by generation technology, which largely reduces the amount of commitment state variables in the UC optimization. Accordingly, the cluster integer based optimization method enables us to model detailed power system operation with less computational efforts, which makes our model applicable for the simulation of a large power system .

6.2.2 Transportation system model

This part mainly introduces how the model estimates EVs' temporal availability which determines how many EVs are connected to the grid at a given time. It is desirable to simulate EVs' availability using realistic patterns that mimic people's actual travel behaviors. However, comprehensive travel behavior data for EVs is unavailable yet. This work therefore builds a statistical transportation model based on actual travel survey data in the Netherlands to estimate EVs' temporal availability in China. Hereby we assume that: 1) EV driving patterns are similar to those of conventional cars; and 2) the driving time does not differ much between regions.

First, as a proxy to generate travel patterns, the Mobiliteitsonderzoek Nederland (MON) survey data for the year 2008[1] was used (see more details about the processing of the transportation data in Appendix C.1). To perturb the model and simulate expected variability in the number of EVs available for each hour of the day, kernel density estimates (Rosenblatt, 1956; Parzen, 1962) were constructed to represent the probability density function of the percentage of EVs available at each hour. The motivation for using kernel density estimates is that they allow for the creation of probability density functions which closely mirror variations in the actual data. The approach is similar to that of creating a probability density function using histogram data, except that every observation in the data is represented as a normal distribution, and all of these normal distributions are then summed to arrive at the final probability density function. With these probability density functions, we can then create synthetic data that has characteristics similar to that of the real data.

This chapter creates kernel density estimates per hour and type of day (weekday or

[1] http://www.scp.nl/Onderzoek/Bronnen/Beknopte_onderzoeksbeschrijvingen/Mobiliteitsonderzoek_Nederland_MON

weekend), as shown in Fig. 6.2. What we can see with this is that our data are able to capture patterns in the survey data that can not be represented with a normal distribution. In several of the figures, the distributions are seen to be skewed to one side or bimodal (e.g. 9pm on weekends, 3pm on weekdays).

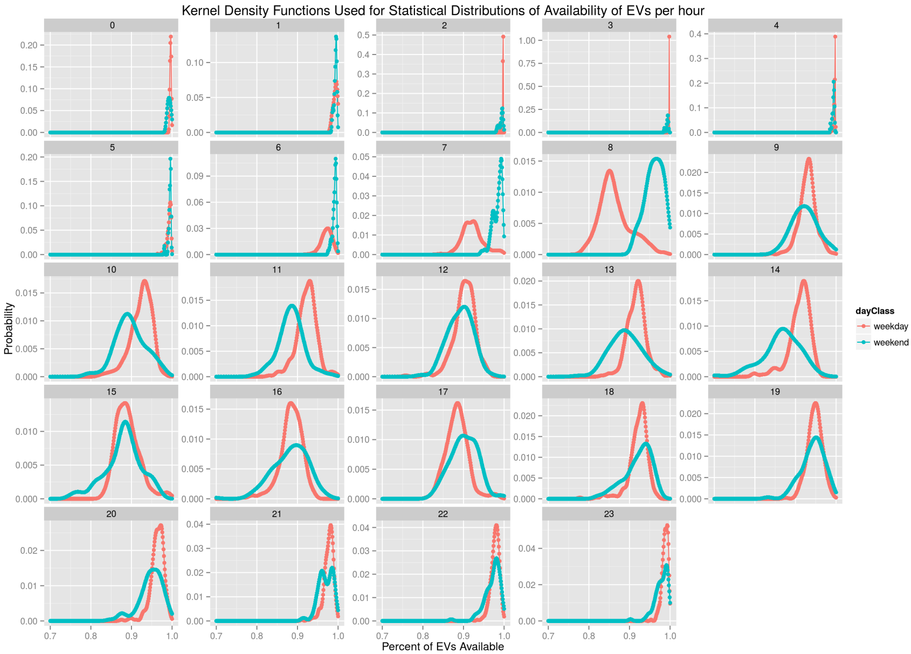


Figure 6.2 – Kernel Density Estimates of EVs' temporal availability per hour on weekdays and weekends.

For illustrative purposes, Fig. 6.3 shows the estimated temporal availability of EVs in connecting to the grid on an hourly basis for two days. Generally, we can observe that about 80%-90% of the entire fleet are available to connect with the grid, which is validated by the observations from the National Household Travel Survey of the U.S. in 2009[2]. In addition, on weekdays, the variability of EV availability tends to be much lower, especially during rush hours in morning and evening. In weekends, people are less constrained to a particular schedule and the range of temporal availabilities is much greater.

6.2.3 Power system model: multi-region power dispatch

Many unit commitment (UC)-based power dispatch models incorporating EVs have been developed in the literature, such as (Wang et al., 2011; Verzijlbergh et al., 2014; Madzharov et al., 2014). Most studies express the model as a mixed-integer linear programing (MILP) problem, in which binary variables, [0, 1], are used to indicate the commitment state and the start-up actions of generation units. However, applying the MILP approach for the

[2] http://nhts.ornl.gov/download.shtml

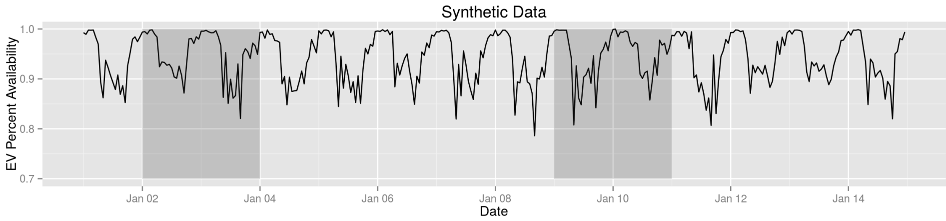


Figure 6.3 – Illustrative time series data showing EVs' temporal availability in connecting to the grid, calculated by sampling kernel density estimates. Note that the periods during the weekend are highlighted in gray boxes and other periods are weekdays.

large Chinese power system is computationally constrained as the combinatorial commitment states explode quickly with the number of generation units. To find a balance between computational ease and accuracy in practice, the work adopts the clustered integer approach developed in (Palmintier and Webster, 2011; Palmintier, 2013) to reduce the amount of variables in the UC model. More explanations regarding the advantages of adopting the clustering integer methods in the unit commitment models are provided in Section 5.2.2, and the detailed mathematical formulation of the cluster integer-based UC model is presented in Appendix B.1. For the mathematical formulation of the model, the research in (Palmintier and Webster, 2011; Palmintier, 2013; van Staveren, 2014) provides insight into the applications of the clustered integer approach to UC models, and the work in (Wang et al., 2011; Li and Lukszo, 2014; Verzijlbergh, 2013; Metz and Doetsch, 2012) presents more details about integrating EVs into UC models.

6.3 Scenario definitions and data collection

6.3.1 Scenario definitions

This work chooses the year of 2030 as the baseline scenario to depict the expected future power system in China. The 2030 scenario is chosen mainly because it has the most accessible data about the planning for the regional generation portfolios and the inter-regional transmission grid development in China. More detailed explanations about the data of this baseline scenario are shown in Section 6.3.2. This work focuses on studying the influences of the power system and charging strategies on the value of EVs. The diversity of these six regional power systems in generation portfolio and grid interconnections enables us to compare the influences of different regional power system contexts on the value of EVs. In this way, only one scenario variable is used in this work, namely charging strategies. Depending on the role and the controllability of EVs from the power operators' perspective, four types of charging strategies are defined in the scenarios, as shown in Table 6.1.

Specifically, the home charging and random charging are defined to indicate the cases when no artificial control is imposed to EV charging, so that EV users are free to charge whenever they have access to charging facilities. For the home charging, the access to charging facilities is constrained at home. However, the random charging represents a situation where charging facilities are widely spread so that EVs can be charged whenever parked without any delay. For the home charging, the energy stored in EVs steadily de-

Table 6.1 – The settings of charging strategies for different scenarios.

Scenario	Charging strategy	EVs		Explanations
		Role	Controllability	
No demand response	Home charging	Load	Uncontrolled	EVs are charged after returning home without delay, the time of staying home is from 6 pm to 8 am the next day.
No demand response	Random charging	Load	Uncontrolled	EVs are free to be charged whenever parked, until their batteries are full.
Demand response	Controlled charging	Load	Controlled	EVs' charging is optimally dispatched by the system operator.
Demand response	Vehicle to grid (V2G)	ESS	Controlled	Both EVs' charging and discharging are optimally dispatched by the system operator.

creases during the day as EVs are only able to charge after returning home at 6 pm. Home charging generates a large peak early in the evening, and the peak reaches a plateau based on the maximum charging power rate imposed by the charging infrastructure. For random charging, the flexibility of vehicles to charge when parked is enough to ensure that the entire EV fleet remains at a high state of charge (SOC). The charging profiles for the home charging and random charging are exogenous parameters for the model, while the profiles of controlled charging and V2G are optimized with the model.

6.3.2 Key data of the baseline scenario

6.3.2.1 Power system data

The Chinese power system is comprised of six inter-connected regional power systems, and the geographical distribution of these six regions is shown in Fig. 2.5. The settings of the Chinese power system in 2030 regarding regional generation portfolios, grid topology and capacity, regional electricity demand and the economic-technical parameters of technologies, etc. are explained in Chapter 5, and this chapter only focuses on introducing the EV-related data as below.

6.3.2.2 Transportation system

EV penetration level The number of EVs[3] deployed in China by 2014 is about 1.19 million, which is less than 1% of the conventional vehicles (EIA, 2015a). However, given the strong incentives from governments to promote EV deployment (Li, Zhan, de Jong and Lukszo, 2015), the number of EVs is expected to increase fast in the coming years. According to the National Development and Reform Commission, the number of EVs by 2030 is expected to account for about 28% of the vehicles in China (Zhuang and Jiang, 2011). With this penetration level, the expected amount of regional EV deployment in 2030 is shown in Table 6.2, which is estimated based on the provincial vehicle ownership of vehicles in China at the end of 2012.

Transportation data and EV-related parameters The temporal transportation data regarding to what percentage EVs are driving on the road or parked are calculated with the

[3] The electric vehicles here include normal passenger cars and buses.

Table 6.2 – The expected amount of EVs for different regions in 2030.

Regions	North	East	Central	Northeast	Northwest	South	National
Amount (million)	8.21	6.65	5.71	2.85	2.12	5.08	30.61

kernel density estimation method, as we explained in Section 6.2.2. The time series data regarding EVs' availability in connecting to the grid based on the kernel density estimates are shown in Fig. C.2, which are validated by the actual survey data in Fig. C.1. More EV-related parameters are shown in Table 6.3.

Table 6.3 – EV-related parameters for in this work.

Parameters	SOC_{min}, SOC_{max}	Battery energy	Driving power	Energy efficiency	Power conversion efficiency	Charging power rate
		kWh	kW	kWh/km		kW
Data	0, 1	25	10	0.25	90%	3

6.4 Result analysis

6.4.1 Energy portfolio

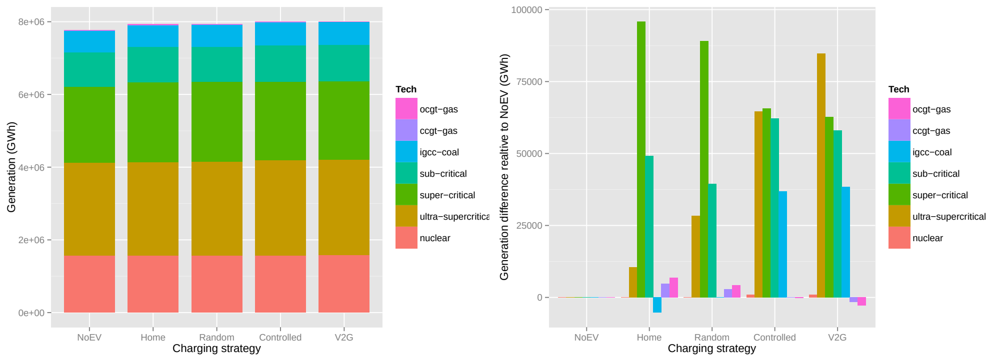
The energy portfolio is analyzed with respect to three aspects: fossil fuel consumption, the use of RES generation and the amount of non-served load which to some extent reflects the security of power supply. The results of the national generation mix generally show that deploying EVs mainly affects the non-RES generation yet has very limited impact on RES generation, as will be discussed in more detail below.

6.4.1.1 Non-RES generation mix and fossil fuel consumption

Fig. 6.4 shows to what degree the non-RES generation (including fossil fuel-based generation and nuclear generation) changes with the EV charging strategy. Compared with the "NoEV" cases, deploying the planned amount of EVs increases the national non-RES generation by 2.08%-3.10%. This additional coal consumption is still quite low relative to the huge amount of electricity demand in China. Moreover, controlled charging results in more non-RES generation than uncontrolled charging, in which the V2G charging leads to the highest increase and the home charging results in the least increase (see Fig. 6.4a).

Without controlled EV charging, deploying the planned amount of EVs increases the coal consumption of the power supply by around 3%, and controlled charging strategies increase coal consumption further by around 1% (see Fig. 6.5). Fig. 6.4b shows where the additional non-RES generation under the controlled charging strategies comes from. There are two economic mechanisms which lead to this increased amounts of electricity generation from coal plants. Although seemingly paradoxically, they favor both high and low-efficiency coal-fired power plants yet in different regions.

First, in comparison with uncontrolled charging, in many parts of the country, controlled charging leads to more generation from high-efficiency coal-fired power plants (e.g. ultra-supercritical and IGCC-coal power), which in turn reduces the use of low-efficiency



(a) The absolute amount of non-RES generation by technology.

(b) The differences in non-RES generation by technology, relative to the "NoEV" case.

Figure 6.4 – The national non-fossil generation with different charging strategies.

coal power technologies and the use of quick-reacting yet expensive gas power which has higher fuel costs.

However, we find that controlled charging also facilitates the sub-critical (low-efficiency) coal generation, which seems contradictory. Fig. 6.6 shows that the additional sub-critical coal generation with controlled charging strategies is from the North and Northwest. What is happening here is that the low coal prices make the marginal costs of sub-critical power even lower than that of high-efficiency coal-fired power plants in other regions. The same reasoning explains the increase in the super-critical coal generation in the North and Northwest.

These changes in inter-regional power exchange with charging strategies are further validated in Fig. 6.7, which shows that: 1) with uncontrolled charging, the amount of power exported from the North and from the Northwest is much lower than that in the "NoEV" case; while 2) the power exported from the North and from the Northwest largely increases if uncontrolled charging is used.

6.4.1.2 RES generation

Table 6.4 shows to what degree the use of RES generation (both wind and solar) changes with the EV charging strategies. In general, EV charging has a negligible impact on the use of RES generation. Still, comparing amongst the charging strategies, we find that controlled charging facilitates more RES generation than uncontrolled charging. Specifically, V2G performs a bit better than the controlled charging in terms of mitigating the curtailment of RES generation. Furthermore, home charging also performs better than random charging, given the fact that wind power generation (especially for the three North regions) is higher in the night than in the daytime.

6.4.1.3 Non-served load

Fig. 6.8 shows to what degree the amount of non-served load changes with different charging strategies. Clearly, uncontrolled charging strategies largely increase the amount of non-served load, which is mainly due to the EV charging load overlapping with the

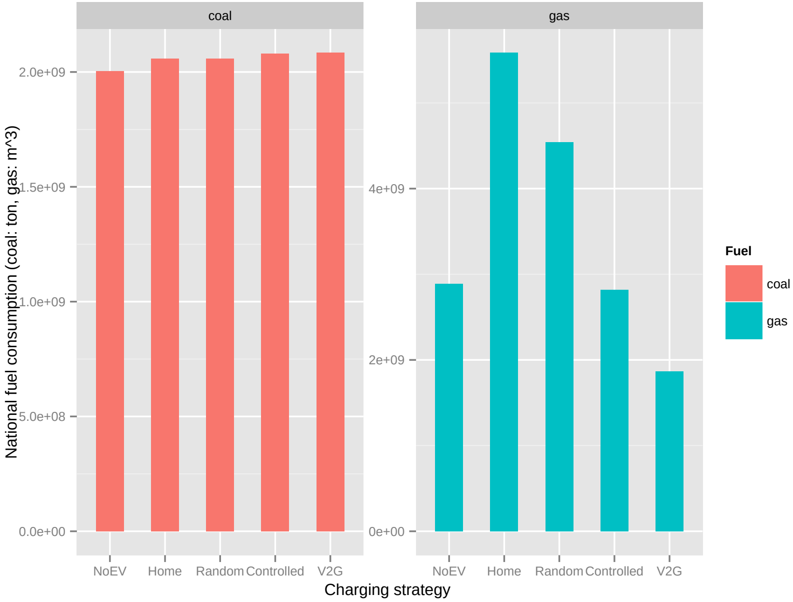


Figure 6.5 – The coal and gas consumption for power supply with different charging strategies.

Table 6.4 – The curtailment rate of RES generation of the national power system. Note that wind and solar means the summation of wind and solar generation.

	Curtailment rate (%)		
	Solar	Wind	Wind and solar
NoEV	0.0007	0.0493	0.0400
Home charging	0.0008	0.0459	0.0373
Random charging	0.0007	0.0504	0.0409
Controlled charging	0.0000	0.0020	0.0016
V2G	0.0000	0.0090	0.0007

peak load of the reference power system. Amongst two uncontrolled strategies, the random charging is slightly better than the home charging. In contrast, controlled charging strategies can largely mitigate the non-served load arising from EV charging. In particular, the V2G strategy can even reduce the non-served load of the reference power system ("NoEV").

6.4.2 Economic implications

Table 6.5 shows to what degree the generation costs of the national power supply change with the charging strategies. First, deploying the planned amount of EVs increases the variable generation costs of the national power system by 3.36%- 5.46%. Specifically, the home charging leads to the highest increase in the costs, and the V2G results in the lowest increase. Additionally, compared with home charging, the random charging reduces the additional costs of the power system arising from EV charging by 23.08%. This implies that

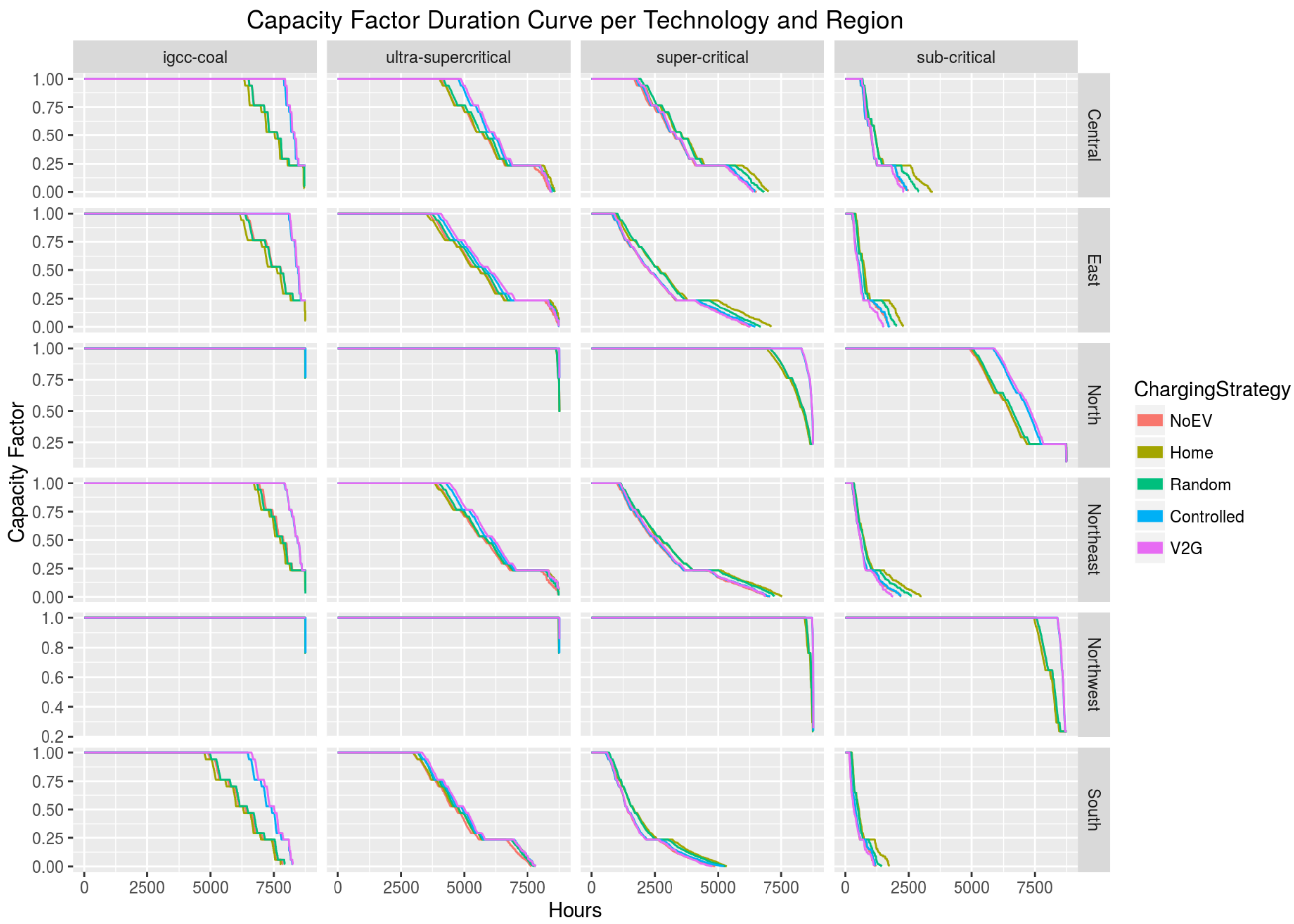


Figure 6.6 – The capacity factor duration curve for each fossil fuel-based technology and each region with different charging strategies. Note that the generation efficiency of the four technologies in this figure descends from left to right.

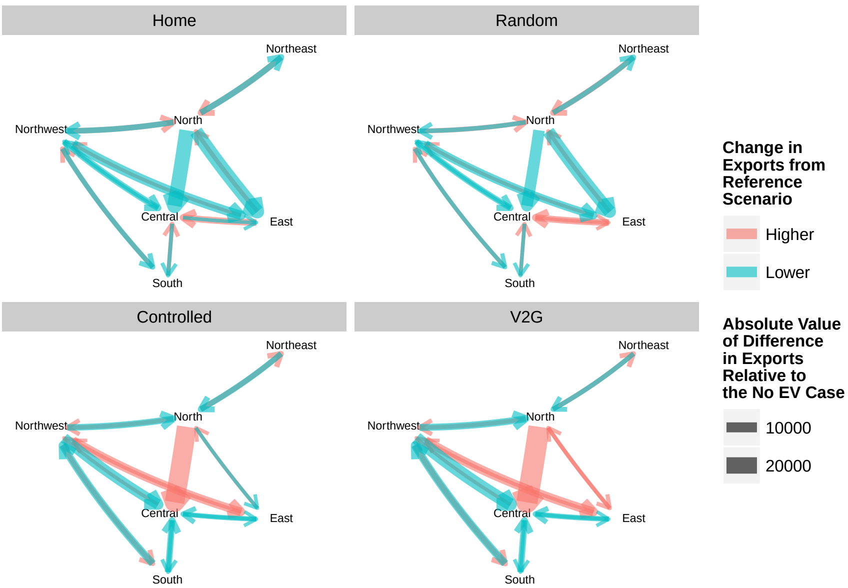


Figure 6.7 – The differences in the exported power between regions with different charging scenarios, relative to the "NoEV" case. The arrow shows the direction of net power exchange between regions. The pink color shows the amount of exported power is higher than the "NoEV" case, the blue shows the opposite. The width of the line represents the absolute amount of the power exchange between regions.

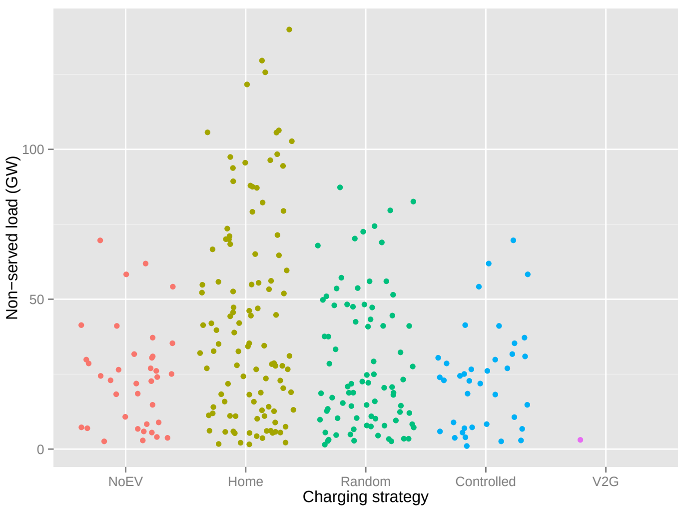


Figure 6.8 – The national non-served load with different charging strategies.

without controlling EV charging, developing more accessible and widely distributed charging facilities can help mitigate the additional costs for EV charging more than charging facilities clustered at home. Furthermore, relative to the home charging, both the controlled charging and V2G can reduce the additional costs for EV charging by more than 30%.

Table 6.5 – The total variable generation costs of the national power system with different charging strategies.

	Charging strategy	Total operating cost (billion $)	Cost difference relative to NoEV	Cost difference relative to home charging
NoEV	No	238	Reference	—
No control	Home	251	+ 5.46 %	Reference
	Random	248	+ 4.20 %	-23.08%
Imposing control	Controlled	247	+ 3.78 %	-30.77%
	V2G	246	+ 3.36 %	-38.46%

Fig. 6.9 explains what contributes to the changes in generation costs, by decomposing the total costs into different types including fuel costs, non-served (Nos) load costs[4], operation and maintenance (OM) costs, start up costs and transmission costs. It shows that the controlled charging strategies can largely reduce the fuel costs, non-served load costs and the start up costs of the power system for EV charging, while they increase the OM costs and transmission costs. This is in line with what we analyzed in the Section 6.4.1: relative to the uncontrolled charging strategies, the controlled charging strategies facilitate the utilization of high-efficiency coal generation, increase inter-regional load exchange and mitigate the non-served load around the peak load periods.

More importantly, home charging leads to the highest increase in fuel costs of the power system, as it clusters EV charging during peak load hours when costly yet quick-reacting gas power plants have to be dispatched. In addition, home charging results in the highest increase in the non-served load costs of the power system given the fact that the maximum generation capability of the system is insufficient to accommodate the clustered peak demand from EV charging. Compared with home charging, random charging can slightly reduce the additional fuel costs, and largely reduces the non-served load cost associated with EV charging. This is mainly due to random charging spreading the clustered load from EV charging over a longer time period. More specifically, the controlled charging can constrain the additional non-served load costs for EV charging to zero. The V2G charging can even reduce the non-served load costs for the reference power system (without EVs), which implies it increases the flexibility of the power system by allowing EVs to feed power back to the grid, and thus can mitigate the non-served load of the reference power system.

Given the inter-regional power exchange, it is hard for us to figure out the real generation costs associated with EVs for each region. Instead, we use the average generation costs at the national level in comparison with the costs of gasoline-driven vehicles, as shown in Fig. 6.10. In general, the average generation cost of EVs ranges from 0.013 to 0.022 $/km, which is much lower than that of gasoline-driven vehicles. Taking the home charging as the reference, the controlled charging strategies can reduce the average generation costs

[4]Nos load cost represents the economic penalty for non-served load, which is assumed to be 1 million $/GW in this work.

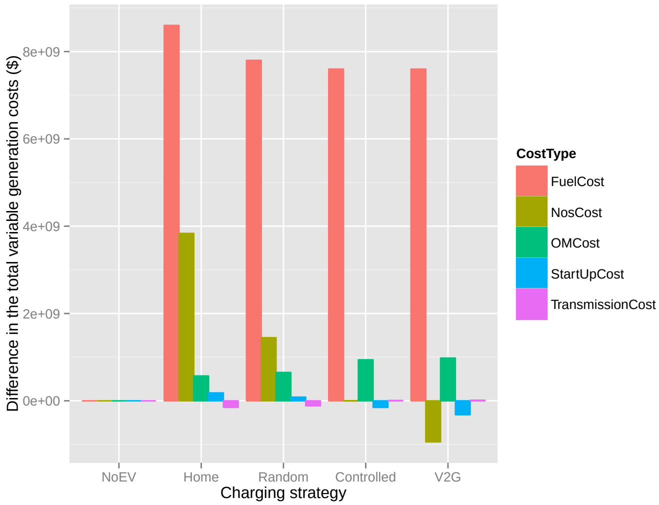


Figure 6.9 – The differences in costs of the national power system between EV cases and "NoEV" cases. Note that the "NoEV" case here is seen as the reference, so that the difference to itself is zero.

of EVs per km by around 41% maximum.

6.4.3 Environmental implications

Table 6.6 shows that deploying the planned amount of EVs results in increased CO_2 emissions of the national power system from 2.74% to 3.74%, which equals about 0.103-0.142 Gt. In particular, imposing controls on EV charging brings more CO_2 emissions than uncontrolled charging. For instance, taking home charging as the reference case, controlled charging and V2G charging increase the additional CO_2 emissions of the power system arising from EV charging by around 31% and 35%, respectively. With regard to uncontrolled charging strategies, random charging slightly lowers the CO_2 emissions associated with EV charging compared to home charging.

Table 6.6 – The total CO_2 emissions of the national power system with different charging scenarios.

	Charging strategy	Total CO_2 emissions (Gt)	Additional emissions caused by EV charging	Difference of the additional emissions
NoEV	No	3.651	Reference	—
No control	Home	3.755	+ 2.77 %	Reference
	Random	3.754	+ 2.74 %	-1.09 %
Imposing control	Controlled	3.789	+ 3.63 %	+ 31.05%
	V2G	3.793	+ 3.74 %	+ 35.02%

Fig. 6.11 shows to what degree the average CO_2 emissions of the power system in different regions change with the various EV charging strategies. First, at the national level, the average CO_2 emissions associated with one EV without controlled charging is

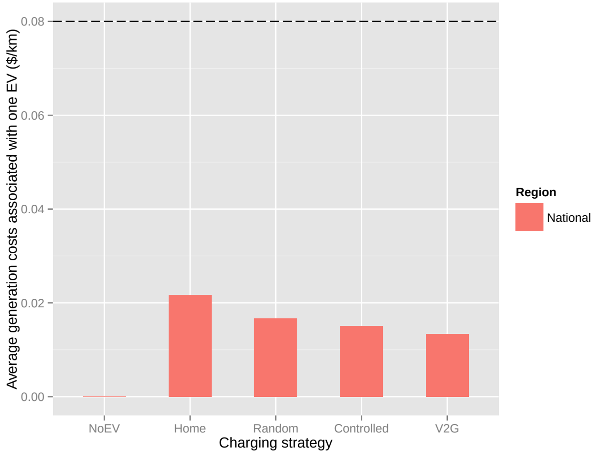


Figure 6.10 – The average generation costs associated with EVs with different charging strategies. The horizontal line represents the average costs of gasoline-driven vehicles with assumptions that the fuel consumption of gasoline-driven vehicles are 8L/100km, and the gasoline price is $1/L.

about 172-174 gram/km[5], which is around 20% less than gasoline-driven vehicles; and the random charging results in less CO_2 emissions than home charging although to a negligible degree. Compared with the uncontrolled charging strategies, imposing control on EV charging increases the average CO_2 emissions associated with EVs beyond the level of gasoline-driven vehicles. For instance, with the controlled charging, the CO_2 emissions associated with one EV is about 230 gram/km, around 4.5% higher than gasoline-driven vehicles. Further, the V2G strategy results in more CO_2 emissions than the controlled charging.

However, the environmental implications of EVs largely vary between regional power systems. First, Fig. 6.12 shows the CO_2 intensity of regional power supply when EV is charging and discharging. Generally, it shows that regardless of the charging strategy, the North and Northwest have the highest CO_2 emission intensity for EV charging, while the South has the lowest. This reflects that the CO_2 emissions associated with EV highly depend on the regional generation portfolio.

Interestingly, in the context of inter-regional grid connections, there is a shift of CO_2 emissions between regions, especially for the controlled charging cases, as shown in Fig. 6.11. For instance, for the East, Northeast, Central and the South regions, imposing controlled charging strategies can largely reduce the CO_2 emissions associated with EVs below the level of gasoline-driven vehicles. However, the impact of controlled charging has the opposite effect for the North and Northwest regions. Particularly, in the South, EVs always have lower CO_2 emissions than gasoline-driven vehicles and imposing controlled charging strategies reduces the average CO_2 emissions associated with EVs to around 124-133 gCO_2/km, which is 40%-44% lower than gasoline-driven vehicles. Clearly, the CO_2 emissions associated with EV charging are shifted from the regions where coal prices are high to those where coal prices are low, facilitated by the inter-regional trans-

[5]The yearly driving distance in this car is about 19520 km, and the yearly CO_2 emissions associated with one car is about 3.35-4.64 ton.

mission networks. This is in line with the shift of the power supply for EV charging as shown in Fig. 6.7. As analyzed above, the additional CO_2 emissions in the regions with cheap coal are mainly from low-efficiency technologies. This reflects a defect in the power system design regarding pursuing economic benefits yet neglecting concerns about the CO_2 emissions of various coal technologies across regions.

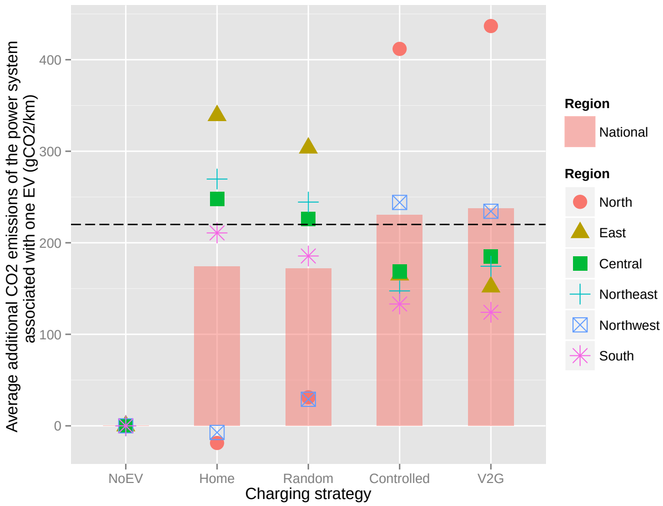


Figure 6.11 – The average CO_2 emissions of the power system associated with EVs in different regions. The horizontal line represents the average CO_2 emissions of gasoline-driven vehicles, which is assumed to be 220 g/km based on (Huo et al., 2010). Note that the value of y axis does not represent the absolute amount of CO_2 emissions for regional EV charging, given the fact that the changes of CO_2 emissions for a given region can be caused by the EV charging in this region or the EV charging in interconnected regions.

6.5 Discussions and policy implications

As we analyzed in the section above, the implications of EVs are uncertain and highly depend on the contextual power system and charging strategies. This section first summarizes the energy, economic and environmental implications of EVs for the Chinese power system, and elucidates the general comparisons between EVs and gasoline-powered vehicles. Furthermore, this chapter rates the performance of various charging strategies and discusses what policy efforts are needed to better deliver the promises of EVs with controlled charging strategies. Lastly, what optimal charging profiles from the power system perspective look like are illustrated with the purpose of guiding policy designs for the implementations of controlled charging strategies.

6.5.1 Implications of EVs

From an energy perspective, deploying EVs basically shifts gasoline consumption to coal-based electricity generation. Specifically, deploying the planned amount of EVs increases

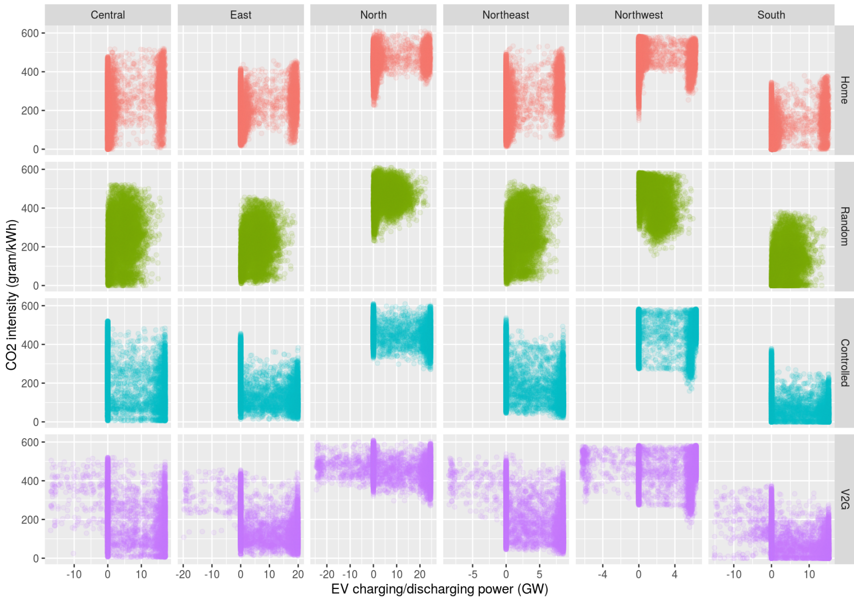


Figure 6.12 – The average CO_2 emission intensity of regional generation when EV is charging or discharging.

coal consumption of the national power system by around 3%-4% which is about 0.06-0.08 Gt. This additional coal consumption can save China about 48 GL gasoline consumption in the transportation sector. Furthermore, deploying the planned amount of EVs has a very limited impact on promoting the integration of RES energy with the given power system. Additionally, deploying EVs can benefit or threaten power supply security in terms of the amount of non-served load, depending on the charging strategy. Specifically, uncontrolled charging increases the amount of non-served load as it tends to cluster the EV charging load with the peak load in the reference power system. However, to what degree that uncontrolled EV charging increases the non-served load depends on a combination of EV penetration levels, charging power rates and inter-regional grid connections. On the other hand, controlled charging strategies can constrain the additional peak load arising from EVs, and the V2G strategy can even reduce the peak load of the reference power system.

From an economic perspective, deploying the planned amount of EVs increases the variable generation costs of the power system by around 3.36%-5.46%. Controlled charging strategies outperform uncontrolled charging strategies in terms of the generation costs, as they can shift EV charging from peak load hours to off-peak load hours. With the shift, EV charging can be fueled by cheap coal generation, and the clustering of the EV charging load with the peak load of the power system is avoided. On average, the generation/fueling cost of EVs is 0.013-0.022 $/km, which is around 75% lower than with gasoline-driven vehicles. Although the average fueling costs of EVs might slightly vary depending on the differences between the coal price and gasoline price, it indeed sends a clear incentive for consumers as they can save substantially on fuel costs when using EVs instead of gasoline-powered vehicles.

From an environmental perspective, deploying EVs increases the CO_2 emissions of the power system by around 2.74%-3.74%. Specifically, with uncontrolled charging strategies, the CO_2 emission associated with EVs is around 172-174 g/km, which is 20% less than gasoline-driven vehicles. Imposing controlled charging strategies increases the CO_2 emissions associated with EVs by around 31%-35% more than uncontrolled charging, which makes gasoline-powered vehicles outperform EVs in such cases.

Aside from the national power system, this chapter finds that the implications of EVs largely vary between regional power systems. This chapter highlights that given the inter-regional power exchanges, how good deploying EVs is in an environmental sense not only depends on where EVs charge, but also depends on the inter-connected regions. In the context of inter-regional transmission connections, there is a clear shift of coal generation and CO_2 emissions associated with EVs to the regions where fuel prices are cheap (e.g. the North and Northwest). In the North and Northwest, we see a situation where the high-efficiency coal-fired power plants are already operating at full capacity, and due to the low fuel prices, the low-efficiency coal-fired power plants are actually favored in the merit order over higher-efficiency coal plants in other regions. Meanwhile, this shift reduces the energy consumption and CO_2 emissions for the regions (e.g. the Central and East) which mainly import power for EV charging. This also reminds us that it would be one-sided to rate regions for EV deployment based on their regional generation portfolios. Still, when inter-regional power exchange for EV charging is negligible compared with regional power supply, the implications of EVs mainly depend on the regional generation portfolio. This has been exemplified by the South power system which shows the largest potential of using EVs in mitigating CO_2 emissions for all charging strategies, due to it has the cleanest generation mix amongst all regions.

6.5.2 Uncontrolled charging vs. controlled charging

To provide a general rule of thumb for policy makers to evaluate the performance of the four charging strategies, we rate the charging strategies based on the energy, economic and environmental implications of EVs under a given charging strategy in comparison with gasoline-fueled vehicles, as described in Table 6.7.

In general, controlled charging strategies outperform uncontrolled charging ones in terms of: 1) improving power supply security (indicated by mitigating non-served load); 2) facilitating RES generation; and 3) reducing generation costs and EV fueling costs. Amongst the two controlled charging strategies, V2G slightly performs better in both mitigating non-served load and facilitating RES generation yet to a limited degree. Although seeking the best charging strategy with a full cost-benefit analysis is out of the scope of this chapter, we argue that controlled charging itself might be sufficient for most regional power systems in bulk energy management unless RES generation is excessive. Uncontrolled charging strategies especially the home charging poses a threat to power supply security, which should be avoided in reality. The random charging is slightly better than the home charging in mitigating the clustering of EV load with the peak load of the reference power system, while it is not an attractive option considering the fact that huge capital costs are needed for developing charging infrastructure in this case.

In short, Table 6.7 shows a trade-off of using controlled charging strategies in the Chinese power system, between the benefits above and the cost of more coal consumption and more CO_2 emissions. We summarize the following two main aspects regarding the power system designs that lead to this trade-off. Accordingly, policy attentions are needed for these aspects to improve the performance of controlled charging strategies in delivering the potential of EVs especially with regard to environmental benefits.

Table 6.7 – The ratings for charging strategies based on the implications of EVs in comparison with gasoline-fueled vehicles under a given charging strategy. The "+" represents that EVs outperform gasoline-powered vehicles, while the "-" represents the opposite, and the amount of"+"/"-" are relative between charging strategies.

Aspect	Indicator	Uncontrolled charging		Controlled charging	
		Home	Random	Controlled	V2G
Energy	1) Coal consumption	−	−−	− − −	− − −−
	2) RES generation	++	−	+++	++++
	3) Non-served load	−−	−	+	++
Economic	1) Generation costs, EV charging costs	+	++	+ + +	+ + ++
Environment	1) CO_2 emissions	+	++	−	−−

First, the dominance of coal power and its absolute economic competitiveness relative to gas power prohibits controlled charging strategies from delivering the potential of EVs. Specifically, with the given 2030 power system, once least-cost oriented controlled charging is imposed, coal-fired electricity generators would be the cheapest marginal units to react to EV load. Possible solutions for changing this are making improvements to designs of the power system by increasing the use of RES energy or other less CO_2 intensive generation especially including gas power. With regard to RES power, China has so far made substantial progress in promoting wind and solar power capacity. However, the use of gas in the power system is still quite limited. Given the huge gap between the coal price and gas price in China, reforms on the gas market will be critical to lower the gap and thus improve the cost competitiveness of gas-fired generation (Kahrl, Hu, Kwok and Williams, 2013). Otherwise, controlled charging strategies entail more coal consumption and more CO_2 emissions, especially for the regions where coal prices are low.

Second, in the context of the inter-regional transmission network, the large variations of regional fuel prices facilitate controlled charging strategies to use more cheap yet low-efficiency coal generation in the regions where fuel prices are low (e.g. the North and Northwest), especially when energy efficiency and CO_2 emission-related regulations are absent. This further undermines the attractiveness of controlled charging strategies in saving the environment. Hence, regulations that discriminate against low-efficiency and dirty coal generation technologies across regions are required to complement economic-based electricity dispatch principles. Possible solutions for this include CO_2 pricing, energy efficiency-incorporated electricity dispatch (e.g. the on-going pilot energy-saving dispatch mechanism (Kahrl, Williams and Hu, 2013)) etc.

6.5.3 Moves towards controlled charging

In short, better fulfilling the benefits of EVs requires a cleaner power supply, and a healthy electricity dispatch which concerns economic, energy and emission issues. In addition to improving designs of the power system, the question of how to guide the charging behaviors of EV consumers as optimized/controlled is also of high interest for policy makers. Fig. 6.13 shows the differences in EVs' daily charging profiles between uncontrolled charging and controlled charging strategies. For instance, the home charging peaks between 6pm-11pm, while the random charging often peaks right after morning and noon traffic-rush hours. However, with controlled strategies, charging at 11:00 pm-7:00 am and at

2:00 pm-4:00 pm is expected from the power system perspective; moreover, the V2G distinguishes itself by discharging to the grid at the noon and evening peak load times. To shift the EV charging profile from uncontrolled ones to the optimized ones, incentives for EV consumers are needed. The incentives can be delivered by various demand response programs, such as designing EV-specific electricity rates (e.g. time of use (TOU) electricity tariff), and developing new business models between utilities, EV aggregators and EV consumers to facilitate centralized EV charging management. Accordingly, given the fixed categorized electricity price between utilities and consumers in China today, institutional changes regarding electricity tariffs/contracts between the involved actors are required.

Another interesting point in Fig. 6.13 is that with a given controlled charging strategy, the patterns of daily charging profiles are quite similar between regions although the amount of charging/discharging power are region-specific depending on the EV penetration levels. This implies that the EV demand response programs among the regions can be functionally similar to each other.

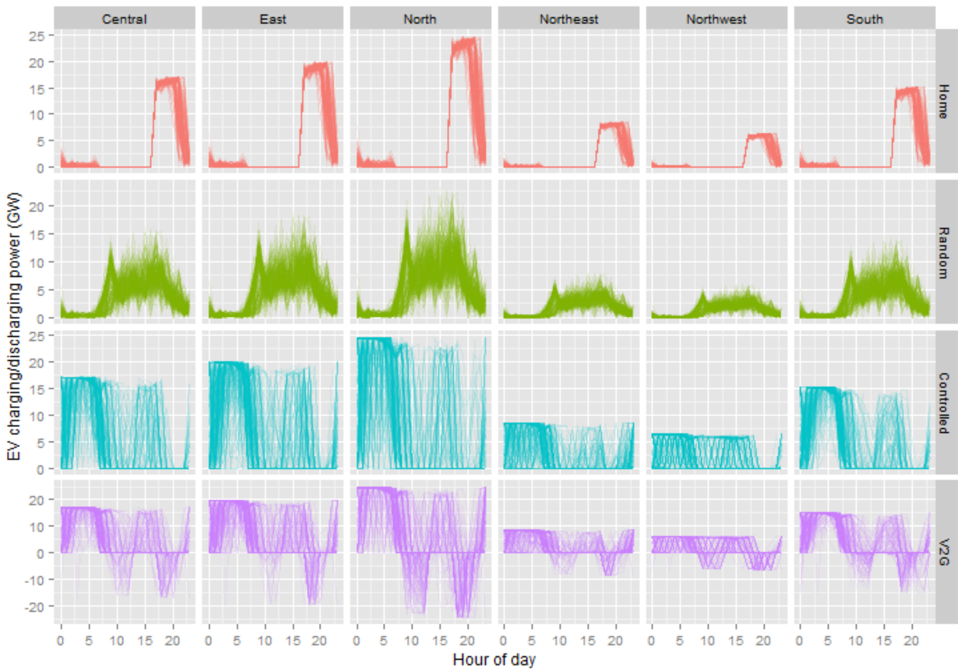


Figure 6.13 – The optimal daily EV charging profiles for each regional power system with different charging strategies in the whole year.

6.6 Conclusions

This chapter has investigated the implications of EV demand response for the decarbonization of China's power sector with regard to energy, economics and the environment, and explored how to better deliver the value of EVs by improving the designs in the power system and charging strategies, given the expected power system and EV penetration levels in 2030. The results are quantified mainly based on an integrated transportation-power system model which distinguishes itself with two key features. First, the model adopts the kernel density estimates approach to statistically determine the temporal availability of EVs connecting to the grid. Second, it applies the cluster-integer approach to reduce the amount of variables in the unit commitment model. This allows us to capture more technical details regarding the six regional power systems and their inter-regional transmission connections, which are used for modeling EV-incorporated power dispatch in China. Furthermore this approach allows us to work with increased model details in a computationally efficient manner.

The scenario results show that at the national level, deploying EVs basically shifts gasoline consumption to coal-based electricity generation. Although this can save the transportation sector in terms of dependency on oil, it comes with the cost of more coal consumption and more CO_2 emissions of the power system. Accordingly, EVs outperform gasoline-powered vehicles in terms of average fueling costs. However, how good EVs are in terms of CO_2 emissions at the national level largely depends on the charging strategy. Specifically, controlled charging results in more CO_2 emissions associated with EVs than uncontrolled charging, as it tends to feed EVs with cheap yet low-efficiency coal generation in the regions with low coal prices. This might be counter-intuitive, but what is happening is that the high-efficiency coal generation in the North and Northwest is already operating at full capacity. Due to the inter-regional transmission connections in China and the differences in coal prices among regions, the low-efficiency coal generation in the North and Northwest actually is more economically attractive and thus favoured in the merit order over high-efficiency coal generation in other regions with higher fuel prices. Still, compared with uncontrolled charging, controlled charging shows absolute advantages in: 1) mitigating the peak load arising from EV charging; 2) facilitating RES generation; and 3) reducing generation costs and EV charging costs.

Hence, in light of the trade-offs of controlled charging between energy security, economic efficiency and environmental destruction, policy efforts that improve designs of the power system are required to better use controlled charging strategies in delivering the promises of EVs for China. Accordingly, this chapter proposes that increasing generation with lower or zero CO_2 emission rates, such as RES power and gas power, are fundamental to make EVs more clean. In addition, establishing energy efficiency and CO_2 emission-concerned regulations for power dispatch is also helpful to discriminate against cheap yet dirty coal generation across regions. More importantly, this work illustrates what the optimized charging profiles from the power system perspective look like, which provides insight into the directions for designs of demand response programs for EV charging.

The methods we developed for the Chinese case can be used as a template for similar studies in other countries. Other countries, especially the ones with coal-intensive generation or with large cross-border transmission capacity, can learn lessons from the Chinese case. They should be aware that deploying EVs does not necessarily bring benefits for the environment or for energy security, even though it might come with economic savings for the power system. Accordingly, coordinating the development of clean electricity generation with EV deployment is needed to make EV more sustainable. In addition, given the high temporal flexibility of EVs connecting to the grid, it is crucial that the EV battery recharging system is designed to deliver the promises of EVs both for power system operations and the environment in the most affordable way. As power systems worldwide vary in their technical implementations, the model used in this work can be easily adapted to cope with the specifics of power systems in other countries than China.

Still, it should be noted that the results of this chapter are based on the statistical estimation method, the optimization-based power dispatch model and four predefined charging strategy scenarios, and thus the designs and assumptions related may affect the results of this chapter. First, the statistically estimated results regarding the availability of EVs connecting to the grid can only represent the behaviors of EV users with certain probabilities rather than the real behaviors. Second, the parameters used in the model, such as the projected generation portfolio and the exogenous economic and technical performance data of power technologies in 2030, are associated with high uncertainties. Also, the hourly-based power dispatch model only considers the value of EVs for the power system in bulk power management, while neglecting the roles of EVs in other fields, such as for ancillary services (e.g. frequency regulation). Third, the scenarios of charging strategies defined in our work typically represent four possibilities based on two scenario variables: 1) whether the development of EV charging facilities is constrained at home or widely distributed in public places; and 2) whether EV users can coordinate EV charging with power system operation. However, there might be more mixed scenarios relevant for real practice. The above research limitations should be addressed in future work.

7 Conclusions and discussions

This concluding chapter synthesizes the findings of this thesis and answers the research questions in Section 7.1. Further, this chapter summarizes the scientific contributions of this thesis in Section 7.2. Reflections on the limitations of the chosen research methods, research scope and the derived conclusions are provided in Section 7.3. The recommendations for policy makers and for future research are given in Section 7.4. Closing remarks are provided in Section 7.5.

7.1 Conclusions

China's ability to succeed in mitigating CO_2 emissions and help address global climate change will to a large extent depend on the decarbonization of the power sector, as the power sector accounts for about half of the nation's CO_2 emissions. Nevertheless, decarbonization of the power sector is a daunting task, considering that it requires substantial technical advancements and institutional adaptations to transform the current power system. This task even becomes more challenging for China, given the fact that its power sector has been historically dependent on coal power and is still rapidly expanding to meet the fast growth of electricity demand due to increasing industrialization and urbanization. Hence, effective policy interventions which can reduce the CO_2 emissions of the power system are needed to achieve long-term decarbonization. At the same time, these policy options should be able to address concerns over energy portfolio effects and economic efficiency.

Given this, this thesis sets out to assist policy makers in exploring effective and efficient pathways for the decarbonization of the Chinese power sector, by identifying key policy options and evaluating to what extent and how these policy options can facilitate decarbonization. Accordingly, the main research question posed in Chapter 1 of this thesis is:

What policy options can help China accomplish effective and efficient long-term decarbonization of the power sector by aligning concerns related to energy security, economic efficiency and environmental sustainability?

This main research question has been decomposed into a set of sub-questions. In the following paragraphs, this thesis summarizes the main findings with respect to these sub-questions.

(1). How did the Chinese power system historically evolve, and what can be learned from the past to gain insight into future development pathways?

The development pathways of the power sector differ widely between countries, since they are largely influenced by the broad political-economic context, the availability of natural resources, the demographic and geographical conditions, etc. Given this, sub-question 1 is posed with the purpose of understanding the historical evolution of the Chinese power sector, identifying the features of the current system and investigating the implications of the past for future development pathways. This subquestion is answered in Chapter 2 by reviewing the evolution of the Chinese power system during 1949-2015 focusing on changes in institutional and technical aspects.

In particular, Chapter 2 finds that China has experimented with courageous institutional reform by changing the roles of the government and electricity utilities, along with changing electricity pricing and dispatch mechanisms. This has promoted substantial infrastructure investments and technological advancement over the past decades. All these changes have revolved around building up a large-scale coal-based system to power the fast economic development. Market-oriented electricity reforms have been very slow and cautious in China, being constrained by the deep-rooted tradition of central planning in the socialist market economy. Consequently, the government has historically retained tight control over the planning, investments and pricing of the power system so far, as well as significant ownership over the power sector assets. Moreover, the structure of the power system has remained a single-buyer market since 2002, within which: 1) power producers sell power to grid companies with benchmarked on-grid prices by technology; 2) two state-owned grid corporations monopolize the power supply service for the nation and make revenues based on the residuals between retail sales and power supply costs; and 3) electricity users pay catalog prices by group. Given these factors, institutional reform of the power sector will be a slow process, and it seems that fundamental institutional changes are unlikely to take place in the near future.

In contrast to the slow pace of institutional change, progress in terms of technological innovation of the power sector has been fast and substantial, as evidenced by the annual doubling of wind power capacity during 2006-2010 and the large improvements in generation efficiency. Nevertheless, when it comes to decarbonization, many technical challenges exist for the nation. First, the nation's power supply has been significantly locked into coal power infrastructure. Second, there are bottlenecks arising from the mismatches of distribution between energy resources and electricity demand across regions. Third, poorly automated distribution networks are coupled with insufficient grid capacity. All of these present technical challenges for China to achieve efficient and clean power supply. More importantly, mismatches between institutional arrangements and technical developments of the power system have become evident recently, exemplified by the inefficient use of wind energy.

(2). What are the policy options for decarbonization of the power sector given the Chinese context, and what methods can be used to support the analysis of the implications of these options?

Based on the findings in Chapter 2, Chapter 3 identifies a suite of institutional and technical policy options which can contribute to decarbonization of the Chinese power sector. The institutional options span the governance, system operation and the market aspects. The technical options cover the generation, grid (transmission & distribution), energy storage system and the demand side. This work mainly focuses on investigating the technical evolution of power system decarbonization triggered by certain policy options. The key technical options explored in this thesis include generation capacity expansion with low-carbon power technologies, the inter-regional transmission grid expansion and demand response programs. Among various institutional options, CO_2 pricing is selected as a key option in this thesis, given the fact that it largely influences the cost competitiveness of generation from different technologies.

Besides, to analyze the performance of policy options in achieving decarbonization, Chapter 3 translates the long-term decarbonization goals concerning energy portfolio effects, economic efficiency and environmental sustainability (also known as the "3E" goals) to specific performance indicators. These indicators primarily include the generation portfolio (mainly the use of RES power generation) and the fossil fuel consumption, the system costs (including investment costs and operation costs), the average decarbonization costs (the system costs per unit of CO_2 emission reduction) and the CO_2 emissions of the power supply. Additionally, optimization models are selected amongst various other types of energy models in this thesis to quantify the performance of policy options in achieving the above goals. Being a typical type of bottom-up models, optimization models can capture a high degree of explicitness in technical parameterization, which makes it possible to quantify the technical evolution of power systems induced by certain policy interventions.

(3). What are the implications of policy options for decarbonization of the Chinese power sector regarding concerns related to energy portfolio effects, economic efficiency and environmental sustainability?

Based on the specifications of the research scope and research methods in Chapter 3, three case studies were performed in Chapter 4, 5 and 6 to investigate the implications of the selected policy options for contributing to the 3E goals of decarbonization. The selected policies address the entire value chain of power supply. Specifically, Chapter 4 investigates the key policy options on the generation side including the deployment of carbon capture and storage (CCS) and RES power technologies, and CO_2 pricing. Chapter 5 studies the policy options on the grid side that are concerned with the expansion of the inter-regional transmission grid. Chapter 6 focuses on the policy options on the demand side with demand response of electric vehicles as a case study. The main findings regarding the implications of these policy options are chapter-specific, and are summarized within the respective chapters. This section mainly synthesizes these implications and the interactions between the investigated policy options to answer the main research question.

First, according to the model-based results in Chapter 4, 5 and 6, the key findings regarding each policy option are summarized in Table 7.1. This table shows that, first, all the investigated policy options show trade-offs in contributing to the 3E goals of decarbonization. For some policy options, such as expanding the inter-regional transmission grid and implementing demand response of electric vehicles, addressing CO_2 emission mitigation usually comes with higher costs. For other policy options, such as deploying CCS technology, addressing CO_2 emission mitigation entails more coal consumption, which brings a negative impact on the energy portfolio. The trade-offs of other policy options in Table 7.1 between the 3E goals are mixed depending on different indicators.

Second, the interactions between the investigated policy options can be mutually counter-productive or reinforcing in contributing to the 3E goals. For instance, Chapter 4 shows that whether RES generation or fossil fuel-based generation (coupled with CCS technology) is more economically efficient for decarbonization depends on the CO_2 price. A high CO_2 price will make the fossil-based power generation (coupled with CCS technology) become more attractive than RES power, so that RES power and CCS technology are mutually competing for decarbonization with a given CO_2 price.

Based on the trade-offs in the 3E goals and the interactions between the policy options, we draw the following conclusions regarding: 1) the roles of the investigated policy options in the long-term decarbonization of the Chinese power sector; and 2) how these policy options can better contribute to decarbonization, while accounting for their mutual influences.

RES power is indispensable, but its role for China is limited by 2050.

Developing RES power helps to improve the security of the national energy power supply, but it is not the silver bullet for decarbonization of the Chinese power sector especially in terms of the reduction of CO_2 emissions that it can achieve and the economic efficiency thereof. Chapter 4 shows that the production limits of RES power are about 42% of the total power supply during 2011-2050, being subject to constraints arising from the speed of construction and the low capacity factor of RES power. Moreover, coal-based power has to be largely expanded at the beginning of the planning horizon to meet the fast-growing electricity demand, which prolongs the carbon lock-in investment. Accordingly, the maximum CO_2 emission reductions only relying on RES power during 2011-2050 are 20% relative to the reference case. Next, the economic efficiency of RES power for exclusive CO_2 emission reductions is low in terms of the average decarbonization costs indicated by the costs per unit of CO_2 emission reduction.

In addition, unless the current coal power generation can be cleaned up by developing RES power, the downstream policy options which are often taken for granted for decarbonization (e.g. EV demand response) are risky for China, as they are likely to result in effects that slow down the process of decarbonization. Specifically, Chapter 5 shows that, with the projected RES power development in 2030, expanding the inter-regional grid according to the government plan results in increased CO_2 emissions of the national power supply by around 2%. Unless the penetration level of RES power becomes much more ambitious than the assumptions in this thesis, the increased CO_2 emissions facilitated by the inter-regional grid expansion (mainly from increased use of coal-based generation) cannot be counteracted by the increased use of RES generation across regions. Similarly, Chapter 6 shows that despite the fact that EV demand response has potential in facilitating the use of RES generation, it increases additional CO_2 emissions of the power system arising from EV charging by around 30% (relative to uncontrolled charging) with the projected development of RES power in 2030.

CCS technology is critical for a high degree of decarbonization, but it leads to more coal consumption and needs to be further developed to be affordable.

Deploying CCS technology is critical to help China reduce the CO_2 emissions of the power supply, especially as the coal-dominated power system cannot be changed quickly. Chapter 4 shows that the maximum CO_2 emission reductions with CCS technology are 44% relative to the reference case, which are about two times higher than the reductions without CCS technology. Additionally, the average decarbonization costs with CCS technology, ranging from 22-55 $\$_{2010}$/ton in this thesis, are significantly lower than the costs without CCS technology, ranging from 26-101 $\$_{2010}$/ton. However, using CCS technology results in additional coal consumption by 12% (relative to no CCS) because of the

Table 7.1 – The implications of the investigated policy options for contributing to the 3E goals. The three colors used in this table are mainly to illustrate qualitative comparisons of the implications, in which gray represents negative, green stands for positive and yellows represents mixed results.

	-positive	-negative	-mixed results
Policy options	3E goals		
	Energy portfolio effects	Economic efficiency	Environment conservation
	(the use of RES energy and fossil fuel, non-served load)	(the system costs and the average decarbonization costs)	(CO_2 emissions)
RES power development	-increase the security of power supply in the long-term	-lead to low system costs, but is less cost-efficient than CCS in terms of the average decarbonization costs	-achieve around 20% of CO_2 emissions of the power supply during 2011-2050
The deployment of CCS technology	-result in additional coal consumption by about 12% (relative to no CCS) during 2011-2050	-result in higher system costs, but the average decarbonization costs with CCS are low	-achieve about 44% of CO_2 emissions of power supply during 2011-2050 together with RES power
CO_2 pricing	-can promote both the use of RES power and CCS technology, so its impact on energy portfolio depends	-is not a cost-efficient way to mitigate CO_2 emissions, as a moderate CO_2 price hardly undermines the cost competitiveness of coal power generation	-can achieve a high degree of CO_2 emissions if CCS technology is commercially available, otherwise, the impact is very limited
Expanding the inter-regional transmission grid (relative to no grid expansion)	-slightly increase coal consumption; largely reduce the need for gas power; show potential in facilitating the use of RES generation; largely reduce non-served load	-largely reduce the variable generation costs and the penalties of non-served load across regions	-slightly increase the CO_2 emissions of national power supply
Demand response of electric vehicles (relative to no demand response)	-slightly increase coal consumption; largely reduce the need for gas power; show potential in facilitating the use of RES generation; largely reduce non-served load	-largely reduce the variable generation costs and the penalties of non-served load across regions	-slightly increase the CO_2 emissions of national power system; shift the CO_2 emissions arising from EV charging between regions

energy penalties for powering CCS-related technologies. Hence, CCS technology should be used along with high-efficiency fossil fuel-based technologies, such as IGCC which has been proved to be the most economical coal power technology for CCS deployment (see Chapter 4). In addition, deploying CCS technology leads to extra system costs of the power supply due to its high capital costs and the additional fuel consumption. Therefore, CCS is unlikely to be deployed unless the CO_2 price is very high. This implies that there is still a long way to improve the technical and economic performance of CCS technology to make it affordable.

Stand-alone CO_2 pricing hardly works to achieve a cost-efficient decarbonization of power supply.

With the establishment of the seven ETS pilots first beginning in 2013, CO_2 pricing has been officially introduced to China. It seems that the nation has taken a right step moving towards regulations for exclusive CO_2 emission reductions. However, the analysis in this thesis finds that stand-alone CO_2 pricing has a very limited effect on the decarbonization of the power sector. First, among different types of fossil fuel-based power generation, although CO_2 pricing can undermine the cost competitiveness of low-efficiency coal-fired generation, it fails to fundamentally change the merit order between coal power and gas power in light of the big gap between coal and gas prices in China. The high gas price is largely caused by the lack of gas resources, but also by government regulation over the gas sector. So far, the gas market has not been liberalized like the coal sector. The government-regulated gas price to a large extent undermines free competition between gas suppliers in the Chinese market. If the current high gas price continues, an extremely high CO_2 price (around 250 $/ton in this thesis) is needed to increase the cost competitiveness of gas power against coal power. However, considering the impact of a high CO_2 price on the economy, market-oriented reforms of the gas sector might be more efficient to promote the use of gas power than stand-alone CO_2 pricing.

Of course, CO_2 pricing can promote the development of RES power and CCS technology, as shown in Chapter 4. However, CO_2 pricing will become redundant for the development of RES power considering various incentives provided by the government, such as the feed-in tariffs (FITs) and the binding capacity requirements for power producers in building up new RES and coal power capacity. With regard to the incentives for developing CCS technology, a moderate CO_2 price hardly can make CCS technology affordable unless the costs of CCS are largely reduced.

Another reason that makes stand-alone CO_2 pricing fail to achieve a high degree of CO_2 emission mitigation is the large difference between regional coal prices. The analysis in Chapter 5 shows that, if inter-regional power exchange is in place, a least-cost power dispatch tends to use the generation from low-efficiency technologies (e.g. small-coal and sub-critical power technologies) in regions where coal is cheap (e.g. North), which substitutes part of high-efficiency generation in other regions. Imposing a moderate CO_2 price hardly changes this, in light of the large difference between regional coal prices.

The inter-regional transmission grid expansion is not the main barrier for the use of RES generation by the mid-term, but it is strategically important to ensure the security of power supply and reduce the variable generation costs.

A common conception prevailing is that the inter-regional transmission grid expansion will address the curtailment of RES generation in China, in light of the mismatches between energy resources and electricity demand across the regions. However, the analysis in Chapter 5 shows that this highly depends on the share of RES power in the generation portfolio. With the projected development of RES power capacity in this thesis, the extent to which the inter-regional grid expansion can increase the use of RES generation is rather limited, at around 3% in 2030. In other words, most RES power generation can be absorbed by the intra-regional electricity demand by the mid-term, unless the penetration level of RES energy is much higher than the assumptions in this thesis.

In particular, expanding the inter-regional transmission grid according to the government plan will largely reduce the variable generation costs by around 11% relative to no grid expansion (mainly because of the large difference in coal prices between regions). Also, it can largely reduce non-served load especially when electricity demand is high. Hence, expanding the inter-regional transmission grid will be strategically important to improve the economic efficiency and the security of power supply. However, from the energy portfolio perspective, the inter-regional transmission grid expansion increases the coal consumption of power supply by around 2% and largely reduces the gas consumption by around 50% (relative to no grid expansion), with the given system in 2030. As a consequence, the expansion increases the CO_2 emissions of power supply by around 2%.

With regard to the need for additional investments in the inter-regional transmission grid, the government's expansion plan is basically sufficient in terms of enabling bulk power delivery and promoting renewable generation across the regions. In particular, the transmission lines connecting the North-Central, North-East and Northwest-Central are three key power corridors, and the lines between the Northwest-Central, Northwest-North, North-East, Northwest-South and Northeast-North have high utilization rates, which justify substantial investments according to the government plan.

EV Demand response results in low costs for power supply and mitigates non-served load, yet is at risk to generate more CO_2 emissions and shift CO_2 emissions among different regions.

Given the fast growth of electricity demand in China, demand response programs which aim to reduce electricity consumption or shift electricity consumption to off-peak times are desired for efficient decarbonization of the power sector. Amongst various demand response programs with respect to different types of electricity users, the case of electric vehicle (EV) demand response with controlled charging strategies is studied in this thesis, considering the on-going electrification of transportation in China and the temporal and spatial flexibility that EVs have in coordinating with the power system operation.

The results in Chapter 6 show that deploying EVs basically shifts gasoline consumption to coal-based electricity generation for China. Although this can save the transportation sector in terms of dependency on oil, it comes with the cost of more coal consumption and more CO_2 emissions of the power system. In particular, this thesis shows that EV demand response (with controlled charging strategies) can increase the economic efficiency of power supply. Specifically, with the expected power system and EV penetration level in 2030, EV charging without demand response increases the variable generation costs of the power system by around 4%-5% (relative to no EV), while demand response can reduce such additional costs for EV charging by more than 30%. Moreover, EV demand response can largely mitigate non-served load of the power system which is mainly caused by the clustering of uncontrolled EV charging at peak load time periods.

Nevertheless, with the expected power system and EV penetration level in 2030, EV charging without demand response increases the CO_2 emissions of the power system by around 3% (relative to no EV). Moreover, deploying demand response increases such additional CO_2 emissions by 31%-35%, as EVs are charged with low-efficiency coal power generation in regions with low coal prices. This means that EVs on average generate more CO_2 emissions than gasoline-powered vehicles at the national level, and are not as clean as might be expected. However, EV demand response shows potential in mitigating the CO_2 emissions of power supply (relative to no demand response), and this potential increases with the share of RES power in the generation portfolio. Moreover, it is worth mentioning that EV demand response tends to shift CO_2 emissions among regions if inter-regional power dispatch is in place. This calls for policy attention regarding the fairness of CO_2 emission regulations between regions.

7.2 Scientific contributions

By answering the research questions above, the scientific contribution of this thesis is two-fold.

This thesis first contributes to policy analysis for the decarbonization of the Chinese power sector by providing model-based quantification of the extent to which the key policy options can contribute to the 3E goals. Based on the analysis of the trade-offs between the 3E goals and the interactions between the investigated policy options, we propose recommendations on how policy packages can be improved such that the 3E goals can be better aligned. Second, this thesis contributes to the existing literature by developing a set of mathematical models which can support quantitative analysis of policy interventions for power sector decarbonization. Specifically, the models developed in this work consist of the following:

1. A low-carbon generation expansion planning model which incorporates the retrofitting of CCS technology with conventional fossil fuel-based power plants;

2. A cluster integer-based unit commitment model that can optimize the output of power plants and energy storage systems for a large-scale multi-region power system;

3. An integrated transportation-power system model that can statistically estimate the temporal availability of electric vehicles connecting to the grid, and can optimize the output of power plants and electric vehicles.

These models provide references for methods that can be used in policy analyses within the context of decarbonization of the power sector.

7.3 Reflections

7.3.1 On limitations of the research method

The analysis of this work is mainly based on a set of optimization models, and thus the designs and assumptions made in these models may affect the results of this thesis. First of all, a very common limitation of optimization models is that they assume perfect information, where all actors in the power system have complete foresight and rational behavior. This neglects the complexities of social actors in practice. Although optimization models were justified in this thesis as they are mainly used to quantify the technical evolution of the power system, we are fully aware that the optimization results in this thesis represent the optimal trajectory for decarbonization induced by certain policy options, rather than the real practice.

Second, as a compromise between the reality and computational feasibility of the optimization models, several simplifications have been made. With regard to the temporal resolution, this thesis focuses on the impact of policy options on bulk power management on an hourly basis. Ancillary services for power system operation at time scales from milliseconds to minutes have been neglected. This simplification affects the results of this thesis in the following ways. It results in an underestimation of the need for investments in quick-reacting power plants (e.g. gas power plants) in Chapter 4, and an underestimation of the value of grid expansion and demand response of electric vehicles in Chapter 5 and Chapter 6, respectively. In terms of spatial resolution, this thesis focuses on the national power system comprising of six regional sub-systems, yet neglects the explicitness of intra-regional power systems. This leads to an overestimation of the overall performance of the grid expansion and the EV demand response for decarbonization. For instance, in Chapter 6, the value of EV demand response is evaluated assuming that the intra-regional grid has perfect transmission capability. The neglect of physical congestion of the intra-regional grid results in an overestimation of the value of EV demand response.

The data used in the simulation are subject to large uncertainties, which could also have an impact on the results of this thesis. Although comprehensive overviews were conducted to collect the energy data that are representative for the Chinese case, it is difficult for us to compile a complete region-specific dataset. In addition, the data collection for the Chinese cases is hampered by the absence of machine-readable and free-accessible data for public use. Hence, simplifications and estimations of the average values for typical types of generation technologies had to be made in this thesis, which have an impact on the results. Also, instead of forecasting the future state of the Chinese power system, this work mainly uses data from the literature to construct future scenarios and test out policy options. The future, however, is highly uncertain, and better scenarios which incorporate more of the dynamics of future developments of the Chinese power system should be created.

7.3.2 On limitations of the research scope

First, the influences of various dynamics and uncertainties in real economies which can lead to large fuel price volatilities, technological innovations and demand fluctuations are not captured in this thesis. For instance, this work does not consider the impact of shale gas development in China. The unproved technically recoverable wet shale gas in China is about 1115.2 trillion cubic feet, almost two times higher than in the US (EIA, 2015c). If the development of shale gas booms in China, there will be a mixed impact on the results of this thesis. This will largely improve the cost competitiveness of gas power and thus promote investments in it. Then, the development of gas power will reduce the need for CO_2 emission reductions provided by other technical options, as well as reduce the need for power system flexibility offered by the grid and demand response programs.

Second, this thesis has focused more on technical policy options for decarbonization than on institutional ones. However, various institutional interventions can also help China contribute to decarbonization, and perhaps they are more cost-efficient than some technical options. For instance, a joint power dispatch across regions can easily increase the efficiency of the power system operation more than improving the generation efficiency of power technologies which are essentially mature today.

Third, this thesis is limited in evaluating the complete impact of certain policy options on the decarbonization of the power system. Taking environmental impact for example, this thesis only examines it with the indicator of CO_2 emissions. However, SO_x, NO_x and particulate emissions are also important especially given the fact that they are largely to be blamed for the severe air pollution in China. Next, the time horizon used to evaluate the impact of certain policy options is limited to 2050 or 2030 in different chapters, mainly due to practical difficulties in data collection. The time horizon should be prolonged beyond 2050, which makes it possible to investigate a more ambitious decarbonization target with more advanced technical advancements. For instance, with a high penetration level of RES power in a post-2050 horizon, both the value of the inter-regional transmission grid expansion in promoting RES generation and the expected environmental benefits of electric vehicles facilitated by demand response will be largely increased.

7.4 Recommendations

7.4.1 For policy makers

The modeling results have explained the roles of specific technologies and regulations (CO_2 pricing) in contributing to decarbonization from the 3E perspectives. Based on this, this section proposes the following policy recommendations to help China achieve effective and efficient decarbonization of the power sector.

(1). Coherent planning of RES power and grid development

In light of the significance of RES energy, policy efforts which can ensure the integration of RES power are needed to complement ongoing policies that focus on the building of RES power capacity. As observed from the past, around one third of installed wind turbines has been disconnected from the grid. To address this curtailment issue, new planning mechanisms which can coordinate the development of RES power and the grid are needed.

Specifically, the planning of RES power capacity and grid development should be coordinated both in time and space. The findings of this thesis suggest that the intra-regional grid expansion plays an important role in facilitating the use of RES energy in the short and mid-term. However, the inter-regional transmission grid expansion will become more significant in the long-term for higher penetration levels of RES power. Moreover, given the fact that it takes more time to construct grid infrastructure than building new power capacity, the planning of RES power generation capacity and grid development should be coherent from the beginning, and be updated frequently according to the changes over the course of development. This necessitates coordination between the government, grid companies and power producers in sharing information about where, what size and what types of RES power capacity will be built.

It is also worth mentioning that changes in the distribution of RES power capacity from large-scale and centralized wind farms to small-scale and decentralized solar power in China, will increase the complexity and uncertainties for grid companies in the planning of grid development. This is primarily due to the fact that large-scale wind farms are mainly built by large power producers (either state-owned or local-government owned); while the development of small-scale solar power might engage an increasing amount of diverse private investors and prosumers, which requires grid companies to spend more effort in coordinating with these decentralized power producers. Accordingly, new policies are needed to address these challenges of the planning of RES power capacity and the grid development.

(2). Planning efforts need to be extended from the supply side to the demand side

China has historically focused on the planning of investments on the supply side, while the planning for resources on the demand side has been more or less neglected. Demand side resources, such as energy efficiency (EE) investments and demand side management (DSM), should be more actively engaged in light of their huge potential in contributing to efficient decarbonization. First, demand side resources which aim to reduce electricity consumption or change the timing of electricity consumption are often more cost-efficient than building new power plants and grid infrastructure. In addition, demand side resources, such as the controlled charging of electric vehicles in this thesis, show potential in mitigating the peak load of the power system, along with facilitating the integration of RES power and the use of RES generation. Accordingly, the planning of investments in demand side resources can mitigate the need for investments in new power plants and grid capacity at the supply side, and largely contributes to efficient decarbonization. In particular, for some demand side resources, such as EVs in this thesis, the planning of the supply side and the demand side needs to be coordinated to deliver the expected value of demand side resources.

(3). Improving operational strategies, especially the power dispatch mechanism

In addition to the planning issues discussed above, improving operational strategies of the power system, especially the power dispatch mechanism, is also critical to ensure that RES power and coal power can be efficiently used. First, the current planned-quota dispatch fails to distinguish electricity generation from different technologies in terms of CO_2 emissions and generation efficiency, and thus is not able to promote the use of RES generation and high-efficiency coal generation. Second, this thesis shows that with a least-cost power dispatch, part of high-efficiency coal generation is replaced by low-efficiency coal generation in regions where fuel prices are low. Given this, regulatory power dispatch mechanisms which take CO_2 emissions and generation efficiency of the power supply into account are recommended to help facilitate decarbonization.

The government has already taken encouraging steps in this reform direction with the on-going pilots of "Energy Saving Power Dispatch (ESPD)" since 2007. Within the ESPD mechanism, the dispatch priorities of generation between different technologies are predefined based on their CO_2 emissions and fuel consumption. However, this reform has been slow and limited to few places so far. It is therefore recommended that reforms aiming to improve power dispatch mechanisms should be accelerated and spread to other regions given the tight timescales for decarbonization and the power exchange between regions.

(4). Institutional reforms focusing on changing electricity pricing and the roles of grid companies

Institutionally, changing the roles of grid companies from profit seeking to service provision will also help China to achieve efficient decarbonization, especially in promoting RES development and demand response programs. Without separate T&D pricing, grid companies today gain revenues through residuals between retail sales and power supply costs. With such circumstances, integrating RES power might result in less revenues for companies, not only because of the required grid expansion or reinforcement, but also due to the costs for ancillary services to deal with the intermittency of RES generation. Similarly, demand response programs might also lead to less revenue for grid companies because of the reduction in electricity consumption or the shift of electricity consumption between different time periods. Considering these conflicts of interest between grid companies, power producers and electricity users, changing the roles of grid companies will be critical to facilitate efficient decarbonization. China has started the pilots of separate T&D pricing since 2014, such as the Shenzhen pilot. Then, the question left here for policy makers is: how to change the roles of grid companies while retaining incentives for grid investments, considering the pressing need for grid expansions in China.

In addition to the T&D price, reforms over on-grid prices and retail prices are also critical to unlock the potential of demand side resources. For instance, if price-based measures (e.g. time of use pricing) are deployed for demand response programs, the regulated on-grid price and retail price today might fail to reflect the balance between power supply and demand, and thus cannot guide consumers to shift electricity consumption to the time periods desired by the power system operator. Moreover, the fixed on-grid price also prevents power producers from investing in new low-carbon technologies, such as CCS technology.

(5). Coherent reforms between the power sector and other energy sectors

It is recommended that the institutional reforms between the power sector and other energy sectors, especially for coal and gas, should be coherent. For instance, the coal price has been liberalized since 2002, while the on-grid price of coal generated power is under government regulation. The contradictions between the fluctuating coal price and the relatively fixed on-grid price have resulted in economic losses for power producers at times of high coal prices, and have triggered many artificial blackouts for China since 2004. In addition, promoting gas power can also largely facilitate the decarbonization of the Chinese power sector. However, as mentioned above, gas market reform is also critical to increase the cost competitiveness of gas power against coal power in China.

(6). Clear and long-term policy targets for CO_2 emission reductions

Additionally, clear and long-term policy targets for CO_2 emission reductions should be formulated to incentivize R&D activities and the market deployment of new low-carbon technologies. For instance, in comparison with the urgent need to control SO_2, NO_x and particulate emissions to improve air quality, the enthusiasm of the government in developing CCS technology has been low. Specifically, China's willingness to develop CCS has only been reflected in keynote speeches rather than in formal laws and regulations, which inevitably results in institutional uncertainties and ambiguities for investments in CCS technology (Liang and Wu, 2009). Although the ETS has been introduced in pilots, the low CO_2 price and the low market liquidity hardly provide incentives to develop CCS technology. In these circumstances, the most likely group of investors for CCS technology, namely the state-owned power producers, get little political pressure and economic incentives to reduce the CO_2 emissions of the power supply. Hence, clear and long-term targets for CO_2 emission reductions should be highlighted by the government to reduce the risks and provide incentives for enterprises in making investments in low-carbon technologies. Also, as we discussed in Section 7.1, the long-term targets for CO_2 emission reductions should be coordinated with CO_2 pricing regulation and the target for RES power generation to accomplish efficient power sector decarbonization.

In short, to achieve an effective and efficient decarbonization of the Chinese power sector, policy efforts should focus on: 1) coherent planning of the development between RES power and the grid; 2) moving more planning efforts beyond the supply side to the demand side; 3) improving operational strategies especially the power dispatch mechanism; 4) creating institutional reforms focusing on changing electricity pricing and the roles of grid companies; 5) making coherent reforms between the power sector and other energy sectors; and 6) setting clear and long-term policy targets for CO_2 emission reductions.

Considering the strong hold of the Chinese government in power system planning, investments and pricing, it seems promising that these policies will be enacted.

Basically, the governance structure and the ownership arrangement of the Chinese power sector fit the technical development needed for decarbonization in the short and mid-term, considering that huge investments are still needed for the nation not only for low-carbon development, but also for meeting the high growth in electricity demand. In comparison with the liberalized power systems where huge efforts are needed to coordinate various stakeholders in low-carbon investments, the centralized government planning and the significant government ownership seem to be more practical and efficient for decarbonization in China. Although one might argue that reforms towards liberalization and privatization are effective for efficiency improvements, we think that development currently deserves a higher priority than efficiency improvements in China. However, we should be cautious as the development of distributed generation (e.g. solar power), energy storage systems, electric mobility and smart grids are more likely to challenge the current centralized institutional arrangements of the Chinese power system in the future.

In addition to the policy recommendations above, the practical difficulties in collecting electricity data for the Chinese case studies need to be addressed by policy makers, even though this is beyond the discussions of the thesis. The types of sources that researchers can access to retrieve public electricity data have indeed largely increased in China, and mainly take the form of scientific literature, technical reports of the grid corporations, reports from research organizations and the official statistic bureaus. However, most electricity data provided by the Chinese authorities are still far from being well-structured and freely accessible. Specifically, a large amount of Chinese electricity data does not use standard open formats (CSV, JSON, XML etc.), which makes them hardly machine-readable. Moreover, the data published are often highly aggregated, and normally only available in hard copies of books or the media webs which cannot be accessed without registration and payment. This to a large extent undermines the efficiency of academic research and the transparency of the scientific process for studies of the Chinese power sector. Hence, it is recommended that opening up energy data should be of a high priority for policy makers, with the purpose of generating new insights from data-driven research. Although how to open data is beyond the scope of this research, the process of opening data should take into account many of the best practices already being employed for other open data initiatives (Davis, 2012; Zuiderwijk, 2015).

7.4.2 For future research

The complexity of exploring the pathways for achieving decarbonization of the power sector is substantial. There remains much to be investigated in future research. Based on the research done in this thesis, the following recommendations to the research community are proposed. These recommendations are essential for assisting researchers in delivering efficient and effective pathways for decarbonization of the Chinese power sector.

- **Research into integrated resource planning** is particularly recommended to identify cost-efficient and robust pathways towards decarbonization. Such studies not only enable researchers to compare the performance of candidate investments between the supply side and the demand side on an equal basis, but also make it possible to investigate the potential of combining different policy options on the supply and demand side for decarbonization. Additionally, such studies can help reduce the risks of plans arising from various uncertainties and assumptions made in the planning analysis. To support such studies, integrated power system models incorporating the resources on both the supply side and the demand side need to be developed.

- **Research into the roles of energy storage systems and other elements of smart grid technologies** is desirable to explore how RES power can be more efficiently integrated into the power system. Specifically, there need to be more investigations on the interactions between energy storage systems, grid expansions, electric vehicles and other types of flexibility providers. Future work should also examine what optimal investment portfolios are possible given these elements.
- **Research into the role of institutional interventions for decarbonization** is also important. First, institutional interventions are in particular significant in shaping the direction and the speed of technical evolution in the power system. Second, some institutional interventions are likely to be more cost-efficient than technical options. Hence, studies on institutional interventions in China's power sector are recommended to complement the results in this thesis to further explore effective and efficient decarbonization pathways. When it comes to research methods for institutional analysis, qualitative methods or simulation methods (e.g. agent-based modeling) are recommended to capture the dynamics of social complexities.
- **Research into demand response for other sectors** is also recommended to explore the potential of demand side resources for decarbonization. In particular, demand response for large industrial users (especially manufactures) and for residential users, is critical for a cost-efficient decarbonization in China. More importantly, with the increase of distributed generation and smart grid technologies, such demand response programs will play an increasing role in order to better utilize the power system infrastructure and to mitigate the need for new investments in generation and grid capacity.

7.5 Final remarks

This thesis has provided insights in to what extent the key policy options (spanning the generation side, grid side and the demand side) can contribute to the goals of decarbonization of the Chinese power sector in aligning the policy goals concerning energy portfolio effects, economic efficiency and environmental sustainability (CO_2 emissions). A set of mathematical models for the power system investment and operation were developed in this thesis to quantify the implications of the policy options. These models provide references for methods that can be used in future studies within the context of decarbonization of the power sector.

More importantly, this thesis finds that within the special institutional and technical context of the Chinese power sector, some taken for granted policy options, such as CO_2 pricing and controlled charging of electric vehicles, have a very limited or even negative contribution to decarbonization, in spite of what is often reported about their theoretical benefits. This calls for a set of coherent and deep transformations of the power sector in both institutional and technical aspects to deliver the decarbonization promises of these policy options. Accordingly, several policy recommendations are proposed. These need to take the form of improving the planning and operational strategies of the power sector, enabling institutional reforms focusing on changing electricity pricing and the roles of grid companies, facilitating coherent reforms between the power sector and other energy sectors especially coal and gas, as well as delivering clear and long-term climate policy targets for CO_2 emission mitigation.

Appendices

A
Chapter 4 appendix: the generation expansion planning model and related data

A.1 Calculation of equal annuities

According to Seifi (2011), the present value (P) that is paid back at the end of each year over the entire operating years (N) with the equal annuity (A) is:

$$P = \frac{1}{(1+R^I)}A + \frac{1}{(1+R^I)^2}A + \cdots + \frac{1}{(1+R^I)^N}A \tag{A.1}$$

Instead, we consider that the present value is paid at the beginning of each year rather than at the end. Therefore, Eq. (A.1) is adapted into:

$$P = A + \frac{1}{(1+R^I)^1}A + \cdots + \frac{1}{(1+R^I)^{N-1}}A \tag{A.2}$$

as $x + x^2 + x^3 + \cdots + x^n = \frac{x(1-x^N)}{1-x}$, the equal annuity in our case is:

$$A = P\frac{R^I(1+R^I)^{-1}}{1-(1+R^I)^{-N}} \tag{A.3}$$

A.2 Model description

A.2.1 Objective function

The objective of the GEP model is to minimize the system costs which are comprised of investment costs ($f^{In}(X)$) and generation costs ($f^G(X)$) (see Eq. (A.4)). All costs are expressed as the present value through introducing the interest rate, R^I. The investment costs are the summation of the equal annuity for newly expanded capacity ($C_{i,y}^{AIn}$) and the equal annuity for CCS-retrofitting capacity ($C_{i,y}^{AR_{ccs}}$) accumulated in the planning horizon (see Eq. (A.5)). The generation costs consist of the fixed operation and maintenance costs, fuel consumption costs and CO_2 emission costs (see Eq. (A.6)). The model nomenclatures are illustrated in Section A.2.3.

Eq. (A.7) and Eq. (A.8) show the calculation of the equal annuity for newly expanded capacity and the equal annuity for CCS-retrofitting capacity (Zhang et al., 2012). More derivations about the calculation of equal annuity are mainly based on Eq. (A.1). In particular, the overnight capital investment cost for CCS-retrofitting capacity is supposed to be equally discounted over the operating period (after retrofitting) which is determined by the building time and retrofitting time of a given power plant (see Eq. (A.8)). To reduce the number of variables, we approximate an average operating period, T_i^{opccs}, for all CCS-retrofitted power plants (see Eq. (A.9)). This assumption is made after validating that it has negligible impact on the optimization results.

$$\min_{X_{i,y}^E, X_{i,y}^{R_{ccs}}, X_{i,y}^G} f^{In}(X) + f^G(X) \tag{A.4}$$

$$f^{In}(X) = \sum_{i=1}^{I}\sum_{y=1}^{Y} \frac{C_{i,y}^{AIn} + C_{i,y}^{AR_{ccs}}}{(1+R^I)^y} \tag{A.5}$$

$$f^G(X) = \sum_{i=1}^{I}\sum_{y=1}^{Y} \frac{C^{OM} X_{i,y}^{IS} + P_{i,y}^F e_{i,y}^F X_{i,y}^G + P_y^{CO_2} e_{i,y}^{CO_2} X_{i,y}^G}{(1+R^I)^y} \tag{A.6}$$

$$C_{i,y}^{AIn} = \sum_{y'=y-T_i^{op}+1}^{y} X_{i,y'}^E C_{i,y'}^{In} \left(\frac{R^I(1+R^I)^{-1}}{1-(1+R^I)^{-T_i^{op}}} \right) \tag{A.7}$$

$$C_{i,y}^{AR_{ccs}} = \sum_{y'=y-T_i^{op}+1}^{y-1} \sum_{y''=y'+1}^{y} X_{i,y''}^{R_{ccs}^{y'}} C_{i,y'}^{R_{ccs}} \left(\frac{R^I(1+R^I)^{-1}}{1-(1+R^I)^{-(y'+T_i^{op}-y'')}} \right) \tag{A.8}$$

$$\approx \sum_{y'=y-T_i^{op}+1}^{y} X_{i,y'}^{R_{ccs}} C_{i,y'}^{R_{ccs}} \left(\frac{R^I(1+R^I)^{-1}}{1-(1+R^I)^{-(T_i^{opccs})}} \right) \tag{A.9}$$

The accumulative installed capacity ($X_{i,y}^{IS}$) varies with the newly expanded capacity ($X_{i,y}^E$), CCS-retrofitting capacity ($X_{i,y}^{R_{ccs}}$) and retired capacity ($X_{i,y}^{Ret}$), as shown in Eq. (A.10). Technology i shifts to technology i' after CCS-retrofitting. Except for the conventional coal power plants which are compulsorily phased out, the retired capacity of other plants is mainly determined by the operating lifetime, as shown in Eq. (A.11).

$$X_{i,y}^{IS} = \begin{cases} X_{i,0}^{IS} + \sum_{k=1}^{y} X_{i,k}^{E} - X_{i,k}^{R_{ccs}} - X_{i,k}^{Ret} & \forall i \in I^{R_{nccs}}, \forall y \\ X_{i,0}^{IS} + \sum_{k=1}^{y} X_{i,k}^{E} + X_{i',k}^{R_{ccs}} - X_{i,k}^{Ret} & \forall i \in I^{R_{accs}}, \forall y \\ X_{i,0}^{IS} + \sum_{k=1}^{y} X_{i,k}^{E} - X_{i,k}^{Ret} & others \end{cases} \tag{A.10}$$

$$X_{i,y}^{Ret} = X_{i,y-T_i^{op}}^{E} \tag{A.11}$$

A.2.2 Constraints

The model is subject to the following constraints:

$$\sum_{i \in I} X_{i,y}^{G} = D_y \qquad \forall y \tag{A.12}$$

$$\sum_{i \in I} X_{i,y}^{IS} \alpha_i^{max} \geq (1 + R^R) D_y^{peak} \qquad \forall y \tag{A.13}$$

$$a_i^{hmin} X_{i,y}^{IS} \leq X_{i,y}^{G} \leq a_i^{hmax} X_{i,y}^{IS} \qquad \forall i, \forall y \tag{A.14}$$

$$X_{i,y}^{IS} \geq 0 \qquad \forall i, \forall y \tag{A.15}$$

$$X_{i,y}^{IS} \leq C_{i,y}^{Cap} \qquad \forall i \in I^{nf}, \forall y \tag{A.16}$$

$$X_{i,y}^{E} \leq C_{i,y}^{S} \qquad \forall i \in I, \forall y \tag{A.17}$$

$$\sum_{i \in I'} e_{i,y}^{F} X_{i,y}^{G} \leq F_{I'}^{y} \qquad \forall i \in I^{nf}, \forall y \tag{A.18}$$

$$\sum_{i \in I} X_{i,y-1}^{E} (1 - R_i^{Flu}) \leq \sum_{i \in I} X_{i,y}^{E} \leq \sum_{i \in I} X_{i,y-1}^{E} (1 + R_i^{Flu}) \qquad \forall i \in I^{nccs}, \forall y \tag{A.19}$$

$$X_{i,y}^{E}, X_{i,y}^{R_{ccs}} \leq C^{ccs} \qquad \forall i \in I^{R_{nccs}}, \forall y \geq y^{ccsIn} \tag{A.20}$$

Eq. (A.12) shows that the yearly electricity generation equals the projected demand over the planning horizon. Eq. (A.13) ensures the maximum available power capacity can meet the yearly peak load plus a reserve which mitigates the risk of unplanned variations in power supply and demand. Eq. (A.14) states that the electricity generation for a given technology for one year is limited by its maximum and minimum yearly operating hours. Eq. (A.15) denotes that the accumulative installed capacity is non-negative, which ensures that the CCS-retrofitted capacity is lower than the available. The upper bounds of technically exploitable capacity are imposed to non-fossil fuel power (see Eq. (A.16)), given resource limits and the government's regulations. Eq. (A.17) shows that the newly expanded capacity each year can not exceed the upper bound of the construction speed. Eq. (A.18) shows the fuel supply limits for fuel-fired power generation. Eq. (A.19) presents that for all the technologies, the newly expanded capacity should not fluctuate violently between years, which ensures a steady investment for the power sector. Eq. (A.20) shows that CCS-related technologies can only be used when CCS technology becomes commercially available in year y^{ccsIn}. In addition, the newly expanded CCS-integrated power capacity and CCS retrofitting capacity for one year are constrained, which reflects the process for emergent technologies to develop.

A.2.3 Nomenclatures

Table A.1 – The parameters of the model.

Parameters	Specifications
$C_{i,y}^{In}$, $C_{i,y}^{AIn}$	The overnight and equal annuity of capital investment costs of technology i at year y [\$/MW]
$C_{i,y}^{R_{ccs}}$, $C_{i,y}^{AR_{ccs}}$	The overnight and equal annuity of CCS-retrofitting costs of technology i at year y [\$/MW]
R^I	The interest rate
C^{OM}	The operational and maintenance costs of technology i per capacity unit [\$/MW]
$X_{i,y}^{IS}$	The accumulated installed capacity of technology i at year y [MW]
$P_{i,y}^{F}$	The fuel price for technology i at year y [\$/ton], [\$/m^3]
$e_{i,y}^{F}$	The fuel consumption per generation unit of technology i at year y [ton/MWh], [m^3/MWh]
$P_{y}^{CO_2}$	The CO_2 price at year y [\$/ton]
$e_{i,y}^{CO_2}$	The CO_2 emissions per generation unit of technology i at year y [\$/MWh]
T_{i}^{op}	The operating lifetime of technology i-based power plants [years]
T_{i}^{opccs}	The operating lifetime of technology i-based power plants after being CCS-retrofitted [years]
$X_{i,0}^{IS}$	The existing capacity of technology i-based power plants [MW]
$X_{i,y}^{Ret}$	The retired capacity of technology i at year y [MW]
D_y	The projected power demand at year y [MWh]
D_y^{peak}	The peak load at year y [MW]
R^R	The ratio of reserve capacity [%]
a_i^{max}	The maximum capacity factor of technology i
a_i^{hmin}, a_i^{hmax}	The minimum and maximum yearly operating hours of technology i [hours]
$C_{i,y}^{Cap}$	The cap of the total capacity of technology i at year y [MW]
$C_{i,y}^{S}$	The cap of the newly expanded capacity of technology i at year y [MW]
R_i^{Flu}	The fluctuation rate for the newly expanded capacity of technology i between years [%]
C^{ccs}	The cap for CCS-related power capacity for one year [MW]
y^{ccsIn}	The year when CCS technology is commercially introduced

Table A.2 – The decision variables of the model.

Decision variables	Specifications
$X_{i,y}^{E}$	The newly expanded capacity of technology i at year y [MW]
$X_{i,y}^{R_{ccs}}$	The CCS-retrofitting capacity of technology i at year y [MW]
$X_{i,y}^{G}$	The electricity generation of technology i at year y [MWh]

Table A.3 – The indexes and sets of the model.

Sets and indexes	Specifications
i	The index of power technology
y	The index of year
I	The set of power technologies, $i \in I$
Y	The planning horizon of years, $y \in Y$
$I^{R_{nccs}}$	The set of technologies that can be CCS-retrofitted, but has not been retrofitted yet
$I^{R_{accs}}$	The set of technologies that are already CCS-retrofitted
I^{nf}	The set of non-fossil fuel-based power technologies
I^{ccs}	The set of CCS-related (i.e. CCS-embedded and CCS-retrofitted) power technologies
I^{nccs}	The set of power technologies that are not CCS-related
I'	The subsets of I based on fuel sources including coal-fired and gas-fired

A.3 Key data

The key data used in Chapter 4 are listed as below.

Table A.4 – The upper and lower bounds of the capacity factors of different technologies.

	SC/USC/IGCC/CCGT	Biomass	Nuclear	Hydro	Wind	Solar
Upper	0.8	0.5	0.8	0.45	0.25	0.25
Lower	0.2	0.2	0.6	0.25	0.25	0.25

Table A.5 – The technically exploitable capacity for non-fossil fuel power in China by 2050 (Cherni and Kentish, 2007; Liu et al., 2011).

	Hydro	Wind	Solar	Biomass	Nuclear[a]
Capacity	542 GW	2548 GW	180 TW	650 Mn tce	330 GW

[a] The technically exploitable capacity of nuclear power is calculated based on China's 2020 target, assuming that the amount of nuclear power capacity will maintain the same annual growth until 2050.

Table A.6 – The upper bounds of the construction speed of power capacity for one year.

	SC/USC	IGCC	CCGT	Biomass	Nuclear	Hydro	Wind	Solar
Capacity (GW)	50	30	30	30	30	30	50	50

Table A.7 – The key data regarding the technical and economic performance for various technologies in 2010. Main source: (Wu et al., 2013; Chen et al., 2011; Kahrl, Hu, Kwok and Williams, 2013; Christopher et al., 2010; Zhao et al., 2008; Zhou et al., 2012; Ren, 2013).

Technology	Energy efficiency	Capital investment cost	Fixed O&M cost	Operating lifetime[a]	CO_2 intensity[b]	Fuel consumption rate
	%	$/kW	$/kW/year	years	g/kWh	gce/kWh
Con.Coal	35	–	35	50	882	400.8
SC	42	640.3[c]	35	50	735	334
SC+CCS	30.24	956.61	58	50	1020.8*r[d]	463.9
USC	45	674	36	50	685.74	311.7
USC+CCS	32.4	1007	59	50	952*r	432.92
IGCC	45	1490 [e]	41	35	752.73	311.7
IGCC+CCS	37.35	1797	46	35	906.91*r	364.7
CCGT	52	566.64 [f]	27	35	506	0.22 (m^3/kWh)
CCGT+CCS	43.16	684	32	35	609.4*r	0.2574 (m^3/kWh)
Biomass[g]	32	1280.6[h]	20	20	–	–
Nuclear	32	1450[i]	48.52	50	–	–
Hydro	–	1032.5[j]	23.45	50	–	–
Wind	–	1251[k]	37	25	–	–
Solar PV	–	4075[l]	–	20	–	–

[a] The operating lifetime data are from (Kannan, 2009), assuming that the lifetime of generation technologies does not have much difference between countries.
[b] The CO_2 emissions of coal and gas power are based on (United Nations Environment Programme, OECD, 1995).
[c] The average capital investment costs of PC were 674 $/kW (4596 CNY/kW, exchange rate 6.78) in 2010 (Wu et al., 2013). In addition, to reflect that SC is currently more widely used than USC in China, we assume that the capital investment costs of SC are 95% of the costs of USC. The CCS incremental costs for SC and USC are assumed to be 66%, and the CCS energy penalty for SC and USC is 27% based on (Wu et al., 2013).
[d] The 'r' represents the capability of CCS technology in capturing CO_2 emissions, which is assumed to increase linearly from 70% to 90% during the planning period.
[e] The average investment costs of IGCC in 2010 were 1490 $/kW. The CCS incremental costs for IGCC are assumed to be 34% and the energy penalty of CCS is 17% based on (Wu et al., 2013).
[f] The ratio of capital investment costs between SC and CCGT in China is about 1.1 (?). The CCS incremental costs and energy penalty for CCGT are assumed to be the same with IGCC.
[g] The data regarding biomass power are mainly based on (Zhou et al., 2012).
[h] The construction costs of a biomass power plant are high in China. The current capital investment costs of biomass power are approximately twice as many as the costs of a coal-fired power plant (Zhao et al., 2012).
[i] The capital investment costs of nuclear are about 1400-1500 $/kW in China (Chen et al., 2011).
[j] The capital investment costs of hydro power are 6000-8000 CNY/kW, and we assume the average costs are 1032.5 $/kW (exchange rate, 6.78). The data are from the National Research Center for Hydro Sustainable Development, with the link of http://www.hydro.iwhr.com/gjsdkcxfzyjzx/rdgz/webinfo/2011/06/1307418575166983.htm.
[k] The capital investment costs of wind power in China are from (Chen et al., 2011).
[l] The capital investment costs for solar are about 3750-4400 $/kW (Chen et al., 2011).

B

Chapter 5 appendix: the multi-region power dispatch model and related data

B.1 Model description

For the purpose of consistency, variables and sets in the model are expressed in uppercase, indexes and parameters are in lowercase.

B.1.1 Objective function

The objective function is to minimize the annual total variable generation costs (C^{Var}), which are the sum of the fuel costs (C^{Fuel}), operation and maintenance costs ($C^{O\&M}$), start-up costs ($C^{Startup}$), non-served energy costs (C^{Nos}), CO_2 emission costs (C^{co_2}) and the transmission costs (C^{Tran}) for all regions over the dispatch horizon, as shown in Eq. (B.1). More explanations regarding each type of costs are shown from Eq. (B.2) to Eq. (B.7). As shown in Table B.3, the decision variables mainly include: the power output of all the units of a specific technology ($P_{r,g,t}$), of the ESS and flexible demand; the commitment states, start-up and the shut-down actions of all fossil fuel-based units; and the power exchange between regions. The optimization is done for a whole year on hourly basis.

$$\min C^{Var} = C^{Fuel} + C^{O\&M} + C^{Startup} + C^{Nos} + C^{co_2} + C^{Tran} \tag{B.1}$$

$$C^{Fuel} = \sum_{r \in R} \sum_{g \in G} \sum_{t \in T} \sum_{f \in F} P_{r,g,t} * \Delta t * \delta_{g,f} * c^{Fuel}_{r,f} \tag{B.2}$$

$$C^{O\&M} = \sum_{r\in R}\sum_{g\in G}\sum_{t\in T} P_{r,g,t} * \Delta t * c_g^{O\&M} \tag{B.3}$$

$$C^{Startup} = \sum_{r\in R}\sum_{g\in G}\sum_{t\in T} SU_{r,g,t} * c_g^{Startup} \tag{B.4}$$

$$C^{Nos} = \sum_{r\in R}\sum_{t\in T} P_{r,t}^{Nos} * \Delta t * c_r^{Nos} \tag{B.5}$$

$$C^{co_2} = \sum_{r\in R}\sum_{g\in G}\sum_{t\in T}\sum_{f\in F} P_{r,g,t} * \Delta t * \delta_{g,f} * e_f^{co_2} * c_r^{co_2} \tag{B.6}$$

$$C^{Tran} = \sum_{r\in R}\sum_{r_c\in R}\sum_{t\in T} P_{r,r_c,t}^{Ex} * \Delta t * c^{Tran} \tag{B.7}$$

B.1.2 Constraints

$$\sum_{g\in G} P_{r,g,t} - \sum_{g\in G^{Res}} P_{r,g,t}^{Cur} + \sum_{r_c\in R}\left(P_{r,r_c,t}^{Im} - P_{r_c,r,t}^{Ex}\right) + \sum_{s\in S}\left(P_{r,s,t}^{Gen} - P_{r,s,t}^{Sto}\right) = d_{r,t}^{Dem} - P_{r,t}^{Nos} + \left(P_{r,t}^{Cha} - P_{r,t}^{Dis}\right) \tag{B.8}$$

$$U_{r,g,t} = U_{r,g,t-1} + SU_{r,g,t} - SD_{r,g,t}, \forall g \in G^{Fossil} \tag{B.9}$$

$$U_{r,g,t}, SU_{r,g,t}, SD_{r,g,t} \in [0,1,2,,,n_{r,g}]$$

$$U_{r,g,t} * p_g^{min} \le P_{r,g,t} \le U_{r,g,t} * p_g^{max}, \forall g \in G^{Fossil} \tag{B.10}$$

$$P_{r,g,t} = p_{r,g,t}^{Ava} * \alpha_{r,g,t}^{Cp}, \forall g \in G^{Res} \tag{B.11}$$

$$0 \le P_{r,g,t}^{Cur} \le p_{r,g,t}^{Ava}, \forall g \in G^{Res} \tag{B.12}$$

$$0 \le P_{r,g,t} \le p_{r,g,t}^{Ava}, \forall g \in G^{Non(fossil\&Res)} \tag{B.13}$$

$$P_{r,g,t+1} - P_{r,g,t} \le \left(U_{r,g,t+1} - SU_{r,g,t+1}\right) * \Delta p_g^{Up} * \Delta t + SU_{r,g,t+1} * max\left(\Delta p_g^{Up} * \Delta t, p_g^{min}\right) - SD_{r,g,t+1} * p_g^{min}, \forall g \in G^{Fossil}, t \in T \tag{B.14}$$

$$P_{r,g,t} - P_{r,g,t+1} \le \left(U_{r,g,t+1} - SU_{r,g,t+1}\right) * \Delta p_g^{Down} * \Delta t + SD_{r,g,t+1} * max\left(\Delta p_g^{Down} * \Delta t, p_g^{min}\right) - SU_{r,g,t+1} * p_g^{min}, \forall g \in G^{Fossil}, t \in T-1 \tag{B.15}$$

$$P_{r,g,t+1} - P_{r,g,t} \leq n_{r,g} * \Delta p_g^{Up} * \Delta t, \forall g \in G^{Non(fossil\&Res)}, t \in T \tag{B.16}$$

$$P_{r,g,t} - P_{r,g,t+1} \leq n_{r,g} * \Delta p_g^{Down} * \Delta t, \forall g \in G^{Non(fossil\&Res)}, t \in T-1 \tag{B.17}$$

$$P_{r,r_c,t}^{Ex} \leq p_{r,r_c,t}^{Ntc}, \forall r, r_c \in R \tag{B.18}$$

$$P_{r,r_c,t}^{Im} = P_{r,r_c,t}^{Ex}\left(1 - e^{loss} * l_{r,r_c}\right) \tag{B.19}$$

$$E_{r,s,t} = E_{r,s,t-1} - P_{r,s,t}^{Gen} * \Delta t/\eta_s^{Gen} + P_{r,s,t}^{Sto} * \Delta t * \eta_s^{Sto} + E_{r,s,t}^{Hadd} \tag{B.20}$$

$$\left(e_{r,s}^{Ini}\right) * r^{ESSmin} \leq E_{r,s,t} \leq \left(e_{r,s}^{Ini}\right) * r^{ESSmax} \tag{B.21}$$

$$0 \leq P_{r,s,t}^{Gen}, P_{r,s,t}^{Sto} \leq p_{r,s}^{Ini} \tag{B.22}$$

$$SOC_{r,t} = SOC_{r,t-1} - p_{r,t}^{Dri} * \Delta t/\eta^{Dri} + P_{r,t}^{Cha} * \Delta t * \eta^{Cha} - P_{r,t}^{Dis} * \Delta t * /\eta^{Dis} \tag{B.23}$$

$$soc_r^{Rated} * r^{EVmin} \leq SOC_{r,t} \leq soc_r^{Rated} * r^{EVmax} \tag{B.24}$$

$$0 \leq P_{r,t}^{Cha}, P_{r,t}^{Dis} \leq p_r^{EVrated} \tag{B.25}$$

Eq. (B.8) shows that power supply should continuously equal power demand for each region at each time step, in which the left side represents the power supply from regional power plants, inter-regional power exchange and the ESS, and the right side represents the net power demand. Specially, as the RES generation for a given region is exogenously determined (as shown in Eq. (B.11)) so that $P_{r,t}^{Cur}$ is introduced to allow the curtailment of wind and solar generation (as constrained in Eq. (B.12)). Considering EV as a flexible demand case which works similarly to ESS, the charging and discharging power of EV in region r at time step t are represented by $P_{r,t}^{Cha}$ and $P_{r,t}^{Dis}$ respectively. Eq. (B.9) represents the dynamics of commitment states for the units which are of a given technology, g. Eq. (B.10) shows the maximum and minimum power output constraints for the group of units which are of fossil fuel-based technology g at time step t. Eq. (B.13) shows the power output constraints for non-fossil and non-RES power (which basically refers to nuclear power in this work). Eq. (B.14) and Eq. (B.15) show the ramping up and ramping down constraints for the group of units of a given fossil fuel-based technology g respectively. Eq. (B.16) and Eq. (B.17) represent the ramping up and ramping down constraints for non-fossil and non-RES power. Eq. (B.18) shows that the exported power between regions must be lower than the net transfer capacity, and the relations between exported power and imported power between two given regions are shown in Eq. (B.19). Eq. (B.21) shows the dynamics of energy stored in the energy storage system which is of technology s in region r. Eq. (B.21) and Eq. (B.22) show the minimum/maximum energy and power for a given type of energy storage system respectively. The constraints for EVs' charging are shown from Eq. (B.23) to Eq. (B.25), which are similar to those for the ESS above.

B.1.3 Nomenclatures

B.2 Key data

The average capacity factor of wind power in the six regions is further calibrated with the historical capacity factors in (Yang, Patiño-Echeverri and Yang, 2012), and is shown in Table B.4. The solar power output for the six regions are sampled from major cities inside the region, as shown in Fig. B.1. For most regions, solar power output gets to peaks

Table B.1 – The parameters.

Parameters	Specifications [units]
$\triangle t$	The time interval which is one hour in this case
p_g^{min}, p_g^{max}	The minimum and maximum power output of power technology g respectively [%]
$\triangle p_g^{Up}, \triangle p_g^{Down}$	The maximum ramping up and ramping down capability of technology g in one time [GW/h]
$\delta_{g,f}$	The consumption intensity of technology g for fuel f [Joule/GWh]
$e_f^{co_2}$	The CO_2 emission factor for fuel f [ton CO_2 per Joule]
$c_g^{O\&M}$	The variable operation and maintenance costs per generation unit for technology g [$/GWh]
$c_g^{Startup}$	The start up costs for technology g [$ per time]
$n_{r,g}$	The number of generation units of technology g in region r
$p_{r,g,t}^{Ava}$	The available generation capacity of technology g in region r at time t [GW]
$\alpha_{r,g,t}^{Cp}$	The capacity factor for RES technology g in region r at time t
$c_{r,f}^{Fuel}$	The price for fuel f in region r [$/Joule]
c_r^{co2}	The CO_2 emission price in region r r [$/ton CO_2 emission]
c_r^{Nos}	The penalty for per unit of non-served power in region r [$/GWh]
$d_{r,t}^{Dem}$	The power demand in region r at time t [GW]
c^{Tran}	The transmission cost per unit of power [$/GWh]
e^{loss}	The power loss per unit of transmission distance [GW/km]
l_{r,r_c}	The distance between region r and r_c [km]
p_{r,r_c}^{Ntc}	The net transfer capacity between region r and r_c [GW]
$p_{r,s}^{Ini}$	The initial capacity of ESS technology s [GW]
$e_{r,s}^{Ini}$	The initial energy stored in ESS technology s [GWh]
r_s^{P2E}	The power to energy ratio of ESS technology s
$e_{r,s,t}^{Hadd}$	The rainfall energy added to the reservoirs of pumped-hydro plants [GWh]
$c_{r,s}^{AInv}$	The annualized capital cost to invest ESS technology s in region r [$/GW]
$\eta_s^{Gen}, \eta_s^{Sto}$	The generation and storage efficiency of storage technology s
r^{ESSmin}, r^{ESSmax}	The minimum and maximum utilization factor for the energy of ESS
$\eta^{Dri}, \eta^{Cha}, \eta^{Discha}$	The power efficiency for EV driving, charging and discharging [%]
soc_r^{Rated}	The rated energy of EV batteries in region r [GWh]
r^{EVmin}, r^{EVmax}	The minimum and maximum utilization factors of EV energy [%]
$p_r^{EVrated}$	The rated capacity of EV batteries in region r [GW]
$p_{r,t}^{Dri}$	The power of EV used for driving in region r at time t [GW]

Table B.2 – The sets and indexes.

Sets and indexes	Specifications
T, t	The set and index of time
R, r	The set and index of regions
G, g	The set and index of generation technologies
S, s	The set and index of ESS technologies
F, f	The set and index of fossil fuels, including coal, gas and uranium
G^{Res}	The subset of G, which includes all the RES power technologies
G^{Fossil}	The subset of G, which includes all the fossil fuel-based power technologies
$G^{Non(fossil\&Res)}$	The subset of G, which includes all the non-fossil fuel and non-RES based power technologies (e.g. nuclear)

Table B.3 – The decision variables.

Decision variables	Specifications
$P_{r,g,t}$	The power output of the units of technology g in region r at time t [GW]
$SU_{r,g,t}$	The amount of the units of technology g which start up at time t in region r, $[0, 1, \ldots, n_g]$
$SD_{r,g,t}$	The amount of the units of technology g which shut down at time t in region r, $[0, 1, \ldots, n_g]$
$U_{r,g,t}$	The amount of the units of technology g which are committed at time t in region r, $[0, 1, \ldots, n_g]$
$P^{Nos}_{r,t}$	The non-served demand in region r at time t [GW]
$P^{Cur}_{r,g,t}$	The curtailed power for RES technology g in region r at time t [GW]
$P^{Ex}_{r,r_c,t}$	The power exported from region r_c to region r at time t [GW]
$P^{Im}_{r,r_c,t}$	The power imported from region r_c to region r at time t [GW]
$P^{Gen}_{r,s,t}$	The power generated from ESS technology s in region r at time t [GW]
$P^{Sto}_{r,s,t}$	The power flows to ESS technology s in region r at time t [GW]
$E_{r,s,t}$	The energy stored in ESS technology s at time t [GWh]
$P^{Cha}_{r,t}$	The charging power of EVs in region r at time t [GW]
$P^{Dis}_{r,t}$	The discharging power of EVs in region r at time t [GW]
$SOC_{r,t}$	The energy left in EV batteries in region r at time t [GWh]

in the noon, which is quite predictable. The duration of solar power output depends on seasons, in which summer normally has longer and higher solar power output than winter. Specially, the solar power in the Northwest is about 2-3 hours behind other regions.

Table B.4 – The annual average wind capacity factor calculated by the authors.

Regions	Average capacity factor
North	0.29
East	0.29
Central	0.27
Northeast	0.31
Northwest	0.25
South	0.29

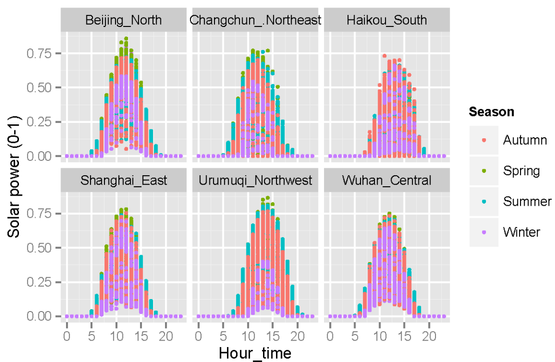


Figure B.1 – Illustration of normalized solar power output grouped by day and season in the six regions.

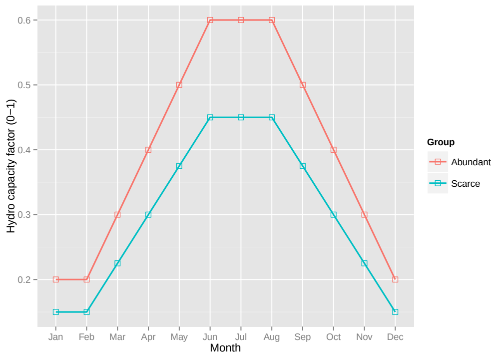


Figure B.2 – The average hydro power availability depending on month and the group of the regional power systems.

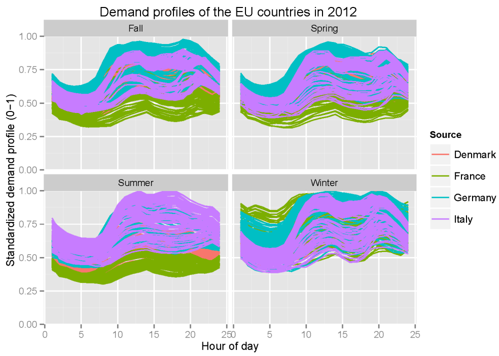


Figure B.3 – The demand profiles of the four EU member states (Germany, France, Denmark and Italy).

Table B.5 – The energy loss and transmission costs of inter-regional transmission lines (Chen et al., 2014; Cheng et al., 2015).

Transmission line		Energy loss	Transmission cost
From	To	[%/GW]	[$/GWh]
North	East	2.53	2400.00
North	Central	3.50	3320.16
Northeast	North	2.48	2352.57
Northwest	North	2.94	2788.93
Central	East	2.61	2475.89
Northwest	East	6.28	5957.31
Northwest	Central	5.01	4752.57
Central	South	3.33	3158.89
Northwest	South	7.67	7275.89

Table B.6 – The key economic and technical parameters of fossil fuel-based generation units. Data source: (Li, Lukszo and Weijnen, 2015a; van Staveren, 2014)

Technology	Capacity of a single unit	Unit availability	Maximum power output	Minimum power output	Ramp up[1]	Ramp down	Efficiency of power output	Emission factor	Start up cost	OM cost	Fuel consumption
Unit	GW	%	%	%	%	%	%	ton/GWh	$/time	$/GW/hour	GJ/GWh[2]
small-coal	0.25	0.99	0.85	0.20	0.10	0.10	0.90	882.00	16800	3995.43	9270.00
sub-critical	0.30	0.99	0.85	0.20	0.09	0.09	0.90	770.28	20000	4000.00	8095.80
super-critical	0.60	0.99	0.85	0.20	0.12	0.12	0.90	686.00	25200	4109.59	7210.00
ultra-supercritical	1.00	0.99	0.85	0.20	0.20	0.20	0.90	574.28	33600	4680.37	6035.80
igcc-coal	1.00	0.99	0.85	0.20	0.20	0.20	0.90	548.80	11760	3082.20	5356.00
ocgt-gas	0.50	0.99	0.85	0.20	0.40	0.40	0.90	240.00	11760	2283.11	9552.50
ccgt-gas	0.50	0.99	0.85	0.20	0.50	0.50	0.90	240.00	9408	2283.11	8406.20
nuclear	0.80	0.99	0.90	0.50	0.04	0.04	0.90	0	50400	5538.81	0
wind	0	1	0	0	0	0	0	0	0	0	0
solar	0	1	0	0	0	0	0	0	0	0	0
hydro	0	1	0	0	0	0	0	0	0	0	0
coal-biomass	0	1	0	0	0	0	0	0	0	0	0
gas-biomass	0	1	0	0	0	0	0	0	0	0	0

[1] The ramp up and ramp down capability is relative to the capacity of a single unit.
[2] The conversion factor used here is 1 ton coal =20.6*$E+10$ Joule, and 1 m^3 gas = 3.82*$E+07$ Joule.

C
Chapter 6 appendix: supportive explanations

C.1 Processing of the transportation data

The Mobiliteitsonderzoek Nederland (MON) survey covers over 30,000 people, each of whom had their travel patterns recorded for a day. The following techniques were applied to pre-process the MON data. As the survey data only records the trips rather than the total population of vehicles, an estimation about the total population of vehicle was made based on the number of distinct cars observed in the data traveling during a particular day of the week. In addition, the power dispatch is simulated on an hourly basis, the departure and arrival times from the survey data are also rounded to the nearest hour. Fig. C.1 shows after the data has been normalized, the estimated availability of EVs per hour and type of day. Each line represents a single day.

C.2 Validation of the transporation data from kernel density estimates

Fig. C.2 shows the EV availability for each day, which is constructed by sampling from the kernel density estimates (KDE) created. The data from the KDE are validated as it shows the similar pattern with the real survey data.

C.3 Illustrations of the home charging and the random charging strategy

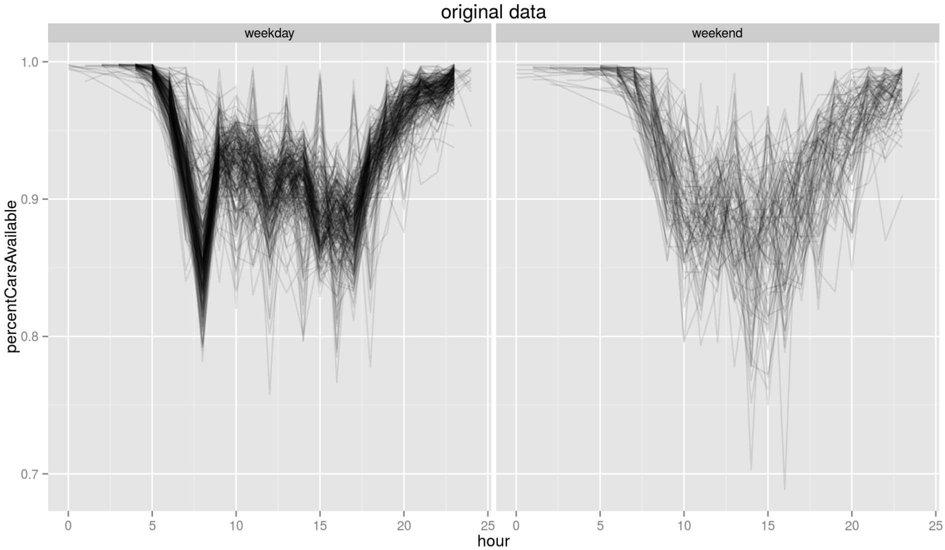


Figure C.1 – Calculations of EV availability per hour on weekdays and weekends based on the real survey data.

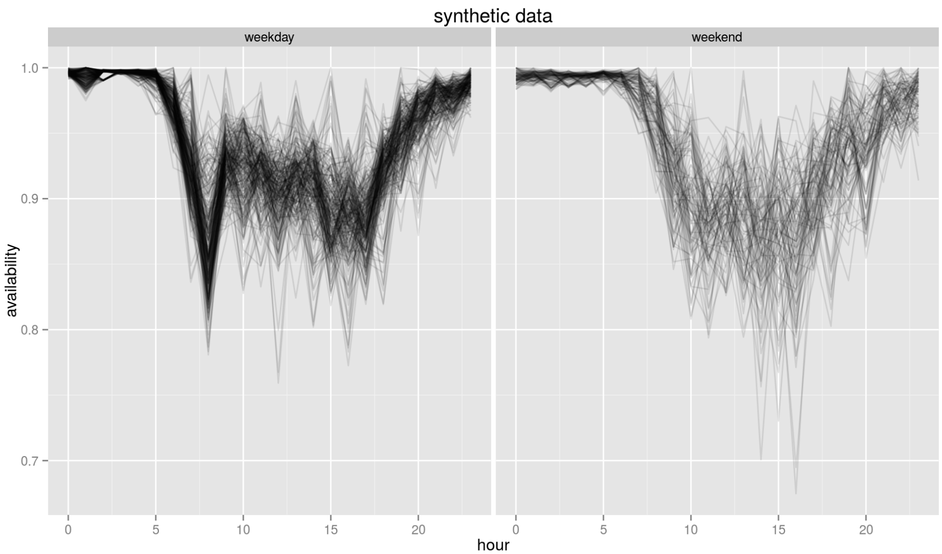


Figure C.2 – Kernel density estimates of EV availability per hour on weekdays and weekends.

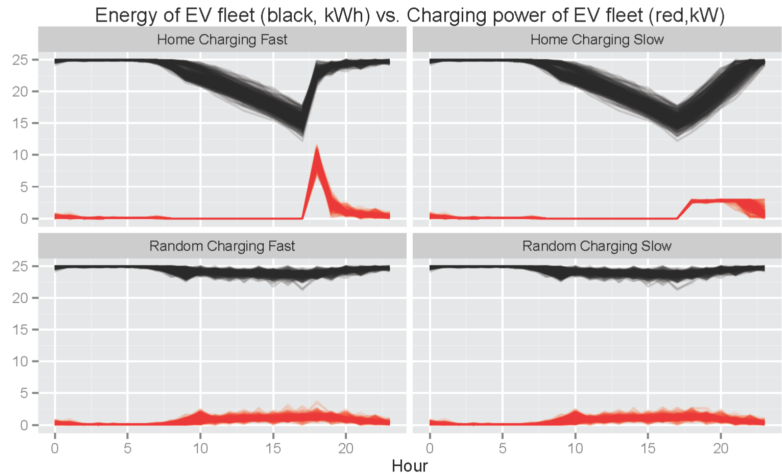


Figure C.3 – The charging power and energy of an individual EV for the random and the home charging strategy with different charging power rates. Each line represents a single day. For illustrative purpose, the fast charging rate in the figure is assumed to be 12 kW and the slow charging rate is 3 kW.

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Glossary

CO_2	Carbon dioxide
CCGT	Combined cycle gas turbine
CCS	Carbon capture and storage
CSG	China Southern Grid Corporation
DR	Demand response
ETS	Emission trading system
ESS	Energy storage system
EVs	Electric vehicles
GDP	Gross domestic product
GEP	Generation expansion planning
GRT	Generation right trading
IGCC	Integrated gasification combined cycle
KDE	Kernel density estimates
NDRC	National Development and Reform Commission
OCGT	Open cycle gas turbine
RES	Renewable energy sources
SC	Super-critical
SGC	State Grid Corporation
SPC	State Power Corporation
T&D	Transmission and distribution
UC	Unit commitment
USC	Ultra super-critical
V2G	Vehicle to grid

Summary

Introduction

China's dramatic economic expansion during the past decades has come with a severe environmental cost as a result of the nation's coal-intensive energy system and the lack of attention to environmental conservation in policy agendas. The nation today is the largest CO_2 emitter in the world, and the growth of CO_2 emissions is expected to continue in the near future. China has been pressured by international communities to mitigate its CO_2 emissions and reduce its contribution to global climate change. At the 2015 Paris Climate Conference (COP21) it proposed ambitious targets to get a peak in CO_2 emissions by 2030 and to reduce by 60%-65% its CO_2 emission per unit of GDP by the year 2030 (relative to 2005). Domestically, the country also suffers from severe air pollution. Although CO_2 emissions are not a direct health hazard, CO_2 emissions are usually accompanied by NO_x, SO_x and other harmful emissions from coal combustion. It is therefore urgent that the nation embarks on low-carbon economic development.

The success of a low-carbon transition in China depends to a large extent on the decarbonization of the power sector, since it accounts for around half of the nation's total CO_2 emissions. The decarbonization of the power sector is a daunting task, considering that it requires substantial technical and institutional changes to transform the current power system. This task is more challenging for China, given that it has been historically locked into using coal power and is still under pressure to quickly expand to meet the fast growth of electricity demand due to further industrialization and urbanization. Hence, effective policy interventions are needed which can mitigate long-term CO_2 emissions of the power sector while also addressing concerns about effects on the energy portfolio and economic efficiency.

This thesis sets out to assist policy makers in exploring effective and efficient pathways for the decarbonization of the Chinese power sector, by identifying key policy options and evaluating to what extent these policy options can facilitate decarbonization and how. Accordingly, the main research question posed in Chapter 1 of this thesis is:

What policy options can help China accomplish effective and efficient long-term decarbonization of the power sector by aligning concerns related to energy security, economic efficiency and environmental sustainability?

Research methods, results and insights

A historical understanding of the Chinese power sector

Given the fact that the development pathways of the power sector are highly context-specific, Chapter 2 of this thesis starts with a short review of the historical development of the Chinese power sector during 1949-2015. This chapter identifies key features of the current system and investigates the implications of the past for future development pathways.

Key institutional characteristics of the Chinese power system are identified, such as the single-buyer electricity market, regulated electricity pricing and significant government ownership of power system assets. Furthermore, this chapter finds that market-oriented electricity reforms have been very slow and cautious in China, as they have been constrained by the tradition of central planning in the socialist market economy. Given these factors, institutional reform of the Chinese power sector will be a slow process, and no fundamental institutional changes are likely to take place in the near future.

In contrast with the slow pace of institutional change, progress in technical innovation of the power sector has been fast and substantial, as can be seen with the annual doubling of wind power capacity during 2006-2010 and large improvements in generation efficiency. Still, when it comes to decarbonization, many technical challenges remain for the nation. Specific issues are the lock-in of coal power, bottlenecks arising from the mismatches of distribution between energy resources and electricity demand across regions, poorly automated distribution networks coupled with insufficient grid capacity, and fast-growing electricity demand.

A generic framework for evaluation of power sector decarbonization

To provide insight into the performance of key policy options for decarbonization, a generic framework is developed in Chapter 3 to systematically guide the evaluation of policies. A key aspect of the framework is that combined perspectives from the point of view of the energy portfolio, economic efficiency and environmental sustainability (also known as "3E" perspectives hereinafter) are used to evaluate policy options in achieving the goals of decarbonization. The use of "3E" perspectives can facilitate well-rounded policy evaluations and inform policy makers regarding the trade-offs related to the goals of these perspectives. To aid this, specific performance indicators for the "3E" perspectives are identified. These indicators capture aspects of the generation portfolio (mainly the use of renewable energy and the fossil consumption), the system costs (including investment costs and operational costs), the average decarbonization costs (the system costs per unit of CO_2 emission reduction) and the total CO_2 emissions of the power supply.

In addition, within the framework, a suite of key policy options that can contribute to decarbonization is identified. In particular, several key technical options covering aspects of generation, the grid and demand, as well as CO_2 pricing are chosen as the focus of policy evaluations in this thesis, as elaborated below.

Furthermore, optimization models are used to quantify and measure the performance of policy options in achieving the "3E" goals. Being one of the bottom-up models, the optimization model can capture a high degree of detail in technical parameterization and allow us to quantify the technical evolution of the power system induced by certain policy interventions. As shown below, a set of optimization models which feature efficient computation and enable a better quantification of power sector decarbonization has been developed. This framework can be used as a template to guide policy evaluations for similar studies.

Policy evaluation on alternative pathways of electricity generation

Chapter 4 investigates the implications of alternative pathways for decarbonization of electricity generation. These pathways incorporate different aspects of three policy options, namely renewable energy sources (RES), carbon capture and storage (CCS) technology and CO_2 pricing. The implications are quantified using a least-cost generation expansion planning model which distinguishes itself by integrating CCS technology with conventional power technologies.

The results show that, first, developing RES power is not a silver bullet for decarbonization, especially in terms of the degree of CO_2 emissions it can achieve and its cost-efficiency. The production limits of RES power are about 42% of the total power supply during 2011-2050, being subject to constraints arising from the speed of construction and the low capacity factor of RES power. Accordingly, the maximum CO_2 emission reductions only relying on RES power during 2011-2050 are 20% relative to the reference case. Next, the cost efficiency of RES power for CO_2 emission reductions is low in terms of the average decarbonization costs indicated by the costs per unit of CO_2 emission reduction.

In addition, deploying CCS technology is crucial to help China achieve a higher reduction of CO_2 emissions from the power supply, especially since the coal-dominated power system cannot be changed quickly. The maximum CO_2 emission reductions with CCS technology are 44% relative to the reference case, which are about two times higher than those without CCS technology. Furthermore, CCS can achieve these reductions with much lower average decarbonization costs. However, using CCS technology results in 12% additional coal consumption for electricity generation (relative to no CCS) because of the energy penalties for powering CCS-related technologies. This also leads to extra system costs due to its high capital costs and the additional fuel consumption. This implies that there is still a large space to improve the technical and economic performance of CCS technology to make it affordable.

Next, stand-alone CO_2 pricing has little impact on achieving a cost-efficient CO_2 emission reduction of power supply. First, it hardly changes the cost competitiveness between coal and gas power, given the large gap between the price of coal and gas in China. Also, a high CO_2 price is conducive to achieving a high degree of power decarbonization, but only if CCS technology is commercially available. If not, a high CO_2 price does not necessarily bring more CO_2 emission reductions, but results in high system costs especially when RES power generation is close to its production limits.

Policy evaluation of the inter-regional transmission grid expansion

Chapter 5 investigates the implications of expanding the inter-regional transmission grid capacity for decarbonization, considering uncertainties arising from RES penetration levels, environmental policies (CO_2 price) and the growth of electricity demand in the future. This study is done with a least-cost multi-region power dispatch model which features high computational performance by adopting the cluster integer approach to reduce the amount of variables in the unit commitment model.

The results show that, first, if renewable energy is developed as projected, the extent to which the inter-regional transmission grid expansion (according to the government plan) can increase the use of RES generation is rather limited at around 3% in 2030 (relative to no expansion). In other words, in the mid-term, most RES generation can be absorbed by the intra-regional electricity demand, unless the penetration level of RES energy is much higher than what we assumed.

Additionally, the expansion can reduce the variable generation costs by around 11% (relative to no expansion) mainly because of the large difference in coal prices between regions. Also, the expansion can largely reduce non-served load especially when electricity demand is high. Hence, expanding the inter-regional transmission grid will be strategically important to improve the economic efficiency and the security of the power supply. However, policy attention should be paid to the impact of the grid expansion on fossil fuel consumption as well, as our results show that the expansion increases the coal consumption of power supply by around 2% and largely reduces the gas consumption by around 50%

(relative to no expansion). Accordingly, the expansion results in increased CO_2 emissions of the power supply by around 2% with the projected power system in 2030.

With regard to the need for additional investments in the inter-regional transmission grid, the government's expansion plan is basically sufficient in terms of enabling bulk power delivery and promoting renewable generation across regions. In particular, the transmission lines connecting the North-Central, North-East and Northwest-Central are three key power corridors, and the lines between the Northwest-Central, Northwest-North, North-East, Northwest-South and Northeast-North have high utilization rates, which justify substantial investments according to the government plan.

Policy evaluation of demand response with electric vehicles

Chapter 6 investigates the implications of EV demand response (with controlled charging strategies) for decarbonization. The results are quantified mainly based on an integrated transportation-power system dispatch model which distinguishes itself by: 1) using kernel density estimates to statistically determine the temporal availability of EVs connecting to the grid; and 2) applying the cluster integer approach to reduce the amount of variables in the unit commitment model.

The results show that in China, the deployment of EVs generally results in a shift from gasoline consumption to coal-based electricity generation. Although this can reduce the dependency of the transportation sector on oil, it comes with the cost of more coal consumption and more CO_2 emissions of the power system. In particular, first, EV demand response can increase the economic efficiency of the power supply. Specifically, with the expected EV penetration level in 2030, EV charging without demand response increases the variable generation costs of the power system by around 4%-5% (relative to no EV); while demand response can reduce such additional costs for EV charging by more than 30%. More importantly, EV demand response can also mitigate non-served load of the power system which is mainly caused by the clustering of EV charging at certain peak load periods. In addition, with the expected power system and EV penetration level in 2030, EV charging without demand response increases the CO_2 emissions of the power supply by around 3% (relative to no EV), and deploying demand response increases such additional CO_2 emissions by 31%-35% as EVs are charged with low-efficiency coal power generation in regions with low coal prices. This calls for policy attention to take CO_2 emissions and generation efficiency into account for power dispatch. Also, EV demand response shows potential in mitigating the CO_2 emissions of the power supply (relative to no demand response), and this potential increases with the share of RES power in the generation portfolio. Hence, cleaning up generation is crucial to deliver the potential environmental benefits of electric vehicles.

Conclusions

This thesis focuses on to what extent the key policy options (spanning aspects of generation, the grid and demand) can contribute to the decarbonization of the Chinese power sector. This is done by investigating how to align the policy goals concerning energy portfolio effects, economic efficiency and environmental sustainability (CO_2 emissions), as well as how these policy options can better contribute to decarbonization given the characteristics of the Chinese power system. The results of this thesis can inform China's policy makers regarding the implications of alternative pathways for power sector decarbonization, and assist them in exploring effective and efficient pathways to accomplish the long-term decarbonization.

A set of mathematical models for quantifying the development pathways of the power system in the future are developed to explore the implications of selected policy options aiming at achieving decarbonization of the power system. The model-based results in this thesis basically show that within the special institutional and technical context of the Chinese power sector, policy options which are commonly taken for granted as being effective, actually have a very limited or even a negative contribution to the decarbonization, in spite of what is often reported about their theoretical benefits. In most cases, the investigated policy options show clear trade-offs between the energy portfolio effects, economic efficiency and CO_2 emission reductions. For instance, with regard to the policy options of expanding the inter-regional transmission grid and EV demand response, addressing mitigation of CO_2 emissions usually comes with higher costs. However, the interactions between these policy options bring opportunities to address these trade-offs. This calls for a set of coherent and deep transformations in both institutional and technical aspects over the entire power supply chain to better deliver the promises of these policy options for decarbonization.

Accordingly, the following policy recommendations are proposed to help China accomplish an effective and efficient decarbonization of the power sector: 1) coherent planning of RES power and grid development; 2) extending planning efforts from the supply side to the demand side; 3) improving operational strategies especially the power dispatch mechanism; 4) institutional reforms focusing on changing the roles of grid companies and on electricity pricing; 5) coherent reforms between the power sector and other energy sectors; and 6) clear and long-term policy targets for CO_2 emission reductions. Beyond this, opening energy data is also highly recommended for policy makers to facilitate research on the decarbonization of the Chinese power sector. Also, based on the reflections on this thesis, future research into integrated resource planning and other possible decarbonization options (e.g. smart grid technologies) are recommended.

Samenvatting

Introductie

China's dramatische economische uitbreiding van de afgelopen decennia is gepaard gegaan met grote milieuschade, zowel als gevolg van het kolenintensieve energiesysteem van dit land, alsook het gebrek aan aandacht voor milieubescherming in beleidsagenda's. Vandaag de dag is het land de grootste CO_2-uitstoter in de wereld, en de verwachting is dat de groei van CO_2-emissies zal doorzetten in de nabije toekomst. China is door de internationale gemeenschap aangespoord om zijn CO_2-emissies te beperken en zijn bijdrage aan mondiale klimaatverandering te reduceren. Bij de klimaatconferentie in Parijs in 2015 (COP21) heeft China de ambitieuze doelstelling voor gesteld om een CO_2-emissiepiek bereiken voor 2030, en om in 2030 zijn CO_2-emissie per BNP-eenheid te hebben gereduceerd met 60-65% ten opzichte van 2005. Het binnenland lijdt ook onder zware luchtvervuiling. Hoewel CO_2-emissies niet een direct gezondheidsgevaar vormen, gaan deze doorgaans samen met NOx, SOx en andere schadelijke emissies van kolenverbranding. Het is daarom urgent dat het land een koolstofarme economische ontwikkeling in gang zet.

Het succes van een koolstofarme transitie in China hangt in grote mate af van de decarbonisatie van de elektriciteitssector, omdat deze verantwoordelijk is voor circa de helft van de totale CO_2-emissies van het land. De decarbonisatie van de elektriciteitssector is een ontzagwekkende opgave, gezien het feit dat er substantiële technische en institutionele veranderingen nodig zijn om het huidige elektriciteitssysteem te transformeren. De taak vormt een grotere uitdaging voor China, omdat het zich historisch heeft vastgelegd op het gebruik van kolencentrales en nog steeds onder druk staat om te voldoen aan de snelle groei van de elektriciteitsvraag veroorzaakt door verdere industrialisering en urbanisatie, blijft die keuze gelden. Er zijn daarom effectieve beleidsinterventies nodig die de CO_2-emissies van de elektriciteitssector op de lange termijn kunnen beperken, en tegelijkertijd tegemoetkomen aan de eisen van energievoorzieningszekerheid en economische efficiëntie.

Dit proefschrift heeft tot doel om beleidsmakers te ondersteunen bij het verkennen van effectieve en efficiënte paden voor de decarbonisatie van de Chinese elektriciteitssector, door belangrijke beleidsopties te identificeren en te onderzoeken in welke mate en op welke wijze deze beleidsopties decarbonisatie kunnen faciliteren. Zodoende is de hoofdonderzoeksvraag die in Hoofdstuk 1 van dit proefschrift wordt gesteld:

Welke beleidsopties kunnen China helpen een effectieve en efficiënte decarbonisatie van de elektriciteitssector tot stand te brengen op de lange termijn, met inachtneming van eisen van energievoorzieningszekerheid, economische efficiëntie en milieukwaliteit?

Onderzoeksmethoden, resultaten en inzichten

Een historisch begrip van de Chinese elektriciteitssector

Gegeven het feit dat de ontwikkelingspaden van de elektriciteitssector zeer contextspecifek zijn, start Hoofdstuk 2 van dit proefschrift met een kort overzicht van de historische ontwikkeling van de Chinese elektriciteitssector gedurende 1949-2015. Dit hoofdstuk identificeert hoofdkenmerken van het huidige systeem en onderzoekt de implicaties van het verleden voor toekomstige ontwikkelingspaden.

Belangrijke institutionele kenmerken van het Chinese elektriciteitssysteem worden geïdentificeerd, zoals de 'single-buyer' elektriciteitsmarkt, gereguleerde elektriciteitsprijzen en een overheid die veel elektriciteitssysteemonderdelen in eigendom heeft. Marktgeoriënteerde elektriciteitshervormingen worden ingeperkt door de traditie van centrale planning in de socialistische markteconomie. Het is niet aannemelijk dat er fundamentele institutionele veranderingen zullen plaatsvinden in de nabije toekomst.

In tegenstelling tot het langzame tempo van institutionele verandering is er snelle voortgang in technologische innovatie van de elektriciteitssector, zoals onder meer blijkt uit de jaarlijkse verdubbeling van windvermogen gedurende 2006-2010, en grote verbeteringen in productie-efficiëntie. Echter, met betrekking tot decarbonisatie resteren er veel technische uitdagingen voor China. Specifieke kwesties zijn de lock-in van kolencentrales, de geografische mismatch van energiehulpbronnen in relatie tot de elektriciteitsvraag in urbane regio's, slecht geautomatiseerde distributienetwerken in combinatie met onvoldoende netwerkcapaciteit, en de snelgroeiende elektriciteitsvraag.

Een generiek raamwerk voor de waardering van decarbonisatie van de elektriciteitssector

Om inzicht ter verkrijgen in de prestaties van belangrijke beleidsopties voor decarbonisatie wordt een generiek raamwerk ontwikkeld in Hoofdstuk 3. Een hoofdaspect van het raamwerk is dat de gecombineerde perspectieven van de energieportfolio, economische efficiëntie en ecologische duurzaamheid (hierna ook wel "3E"-perspectieven genoemd) worden gebruikt om beleidsopties voor decarbonisatie te waarderen. Het gebruik van de "3E"-perspectieven faciliteert een evenwichtige evaluatie van beledsopties, en informeert beleidsmakers over de trade-offs tussen de drie energiedoelen. Om dit te ondersteunen worden specifieke prestatie-indicatoren voor de "3E"-perspectieven geïdentificeerd. Deze indicatoren omvatten aspecten van de productieportfolio (voornamelijk het gebruik van hernieuwbare energie en de consumptie van fossiele brandstoffen), de systeemkosten (inclusief investeringskosten en operationele kosten), de ge-middelde decarbonisatiekosten (de systeemkosten per eenheid van CO_2-emissiereductie) en de totale CO_2-emissies van de elektriciteitsvoorziening.

In dit proefschrift worden optimalisatiemodellen gebruikt om de prestaties van beleidsopties voor decarbonisatie te kwantificeren met betrekking tot de mate waarin de "3E" doelen worden gehaald. De onderzochte beleidsopties betreffen alle segmenten van de waardeketen: de productie van elektriciteit, het transmissienetwerk en het gebruik. Ook wordt de invloed van CO2-beprijzing onderzocht. Optimalisatiemodellen maken een hoog detailniveau van technische parametrering mogelijk, en geven ons daarmee inzicht in de technische evolutie van het elektriciteitssysteem veroorzaakt door bepaalde beleidsinterventies. De groep optimalisatiemodellen die in dit proefschrift is ontwikkeld wordt gekenmerkt door efficiënte berekening.

Beleidsevaluatie van alternatieve richtingen voor elektriciteitsopwekking

Hoofdstuk 4 onderzoekt de implicaties van alternatieve richtingen voor decarbonisatie van de elektriciteitsproductie. Het gaat hier om drie specifieke beleidsopties, namelijk duurzame energie bronnen (RES), opslag van CO_2 (CCS) en CO_2-beprijzing. De implicaties zijn gekwantificeerd door middel van een laagste-kosten generatie expansie planningsmodel dat zich onderscheidt door de integratie van CCS technologie met conventionele technologieën.

De resultaten laten zien dat de ontwikkeling van duurzame elektriciteitsproductie niet de 'silver bullet' is voor decarbonisatie, gemeten in termen van de mate van CO_2-uitstoot en de kostenefficiëntie. De productie grenzen van hernieuwbare energie zijn ongeveer 42% van de totale stroomvoorziening tussen 2011 en 2050; deze beperkingen voortvloeien uit de snelheid van nieuwe productie-eenheden en de lage capaciteitsfactor van RES productie. Als gevolg hiervan is de maximale reductie van CO_2-uitstoot door hernieuwbare energie in 2011-2050 slechts 20% ten opzichte van het referentiescenario. Bovendien is de kostenefficiëntie van CO_2-emissiereductie door hernieuwbare energie laag in termen van de gemiddelde decarbonisatie kosten, uitgedrukt in kosten per eenheid van CO_2-emissiereductie.

Dat betekent dat de inzet van CCS-technologie van cruciaal belang is voor China om een hogere reductie van de CO_2-uitstoot te behalen, vooral omdat het op kolen gebaseerde elektriciteitssysteem niet snel kan worden veranderd. De maximale CO_2-emissiereductie met CCS-technologie is 44% ten opzichte van het referentie scenario, wat ongeveer twee keer hoger is dan zonder CCS-technologie. Bovendien kan CCS deze reducties met veel lagere gemiddelde decarbonisatiekosten bereiken. Echter, het gebruik van CCS-technologie resulteert in 12% extra kolenconsumptie voor de opwekking van elektriciteit met kolencentrales (ten opzichte van geen CCS) als gevolg van de extra elektriciteitsconsumptie voor CCS-technologieën. Dit leidt tot extra systeemkosten vanwege de hoge kapitaalskosten en het extra brandstofverbruik. Dit impliceert dat er nog grote ruimte is voor verbetering van de technische en economische prestaties van CCS-technologie.

Beprijzing van CO_2 emissies heeft weinig invloed op het bereiken van een kostenefficiënte CO_2-emissiereductie van de stroomvoorziening. Dat resultaat is te wijten aan het grote prijsverschil tussen kolen en gas in China. Een hoge CO_2 prijs is weliswaar bevorderlijk voor het bereiken van een hoge mate van decarbonisatie, maar alleen als CCS-technologie commercieel beschikbaar is. Zo niet, dan zal een hoge CO_2-prijs niet per se zorgen voor meer CO_2-emissiereducties, maar resulteren in hoge systeem kosten, vooral wanneer de stroomopwekking uit hernieuwbare bronnen dicht bij de productie limiet is.

Beleidsevaluatie van de interregionale uitbreiding van het transmissienetwerk

Hoofdstuk 5 onderzoekt de gevolgen van uitbreiding van de interregionale transmissienetwerkcapaciteit voor decarbonisatie, gegeven de onzekerheden die voortvloeien uit RES penetratieniveaus, milieubeleid (CO_2-prijs) en de groei van de vraag naar elektriciteit in de toekomst. Dit onderzoek is gedaan met een interregionaal elektriciteitsdispatchmodel met hoge rekenprestaties door het gebruik van de cluster-integer-benadering om de hoeveelheid variabelen in het unit-commitmentmodel drastisch is verminderd.

De resultaten laten zien dat, als duurzame energie wordt ontwikkeld zoals verwacht, de bijdrage van de interregionale transmissie netwerkexpansie (volgens het plan van de overheid) aan het gebruik van duurzame energie beperkt zal zijn tot ongeveer 3% in 2030 (ten opzichte van scenario zonder expansie). Met andere woorden, op de middellange termijn, zal de meeste elektriciteits generatie uit RES worden geabsorbeerd door de intraregionale vraag naar elektriciteit, tenzij de penetratiegraad van hernieuwbare energie veel hoger is dan aangenomen op basis van de meerjarenplannen van de overheid.

Verder kan de uitbreiding van het transmissienetwerk de variabele generatiekosten met ongeveer 11% verminderen (ten opzichte van geen uitbreiding), voornamelijk als gevolg van het grote verschil in de prijzen van steenkool tussen regio's. Ook kan de uitbreiding in vergaande mate de voorzieningszekerheid verbeteren in tijden van piekvraag. De uitbreiding van het interregionale transmissie netwerk is van groot een strategisch belang voor de economische efficiëntie en de betrouwbaarheid van de elektriciteitsvoorziening. Toch zou aandacht besteed moeten worden aan de impact van netwerkuitbreiding op de consumptie van fossiele brandstoffen. Onze resultaten laten zien dat de uitbreiding het kolenverbruik voor elektriciteitsproductie zal verhogen met ongeveer 2% laat toenemen. De netwerkuitbreiding zal daardoor resulteren in een verhoogde CO_2-uitstoot van elektriciteitsproductie met ongeveer 2% in 2030.

Met betrekking tot de behoefte aan extra investeringen in het interregionale transmissie net, is het uitbreidingsplan van de Chinese overheid in principe voldoende voor bevordering van bulk-elektriciteitsvoorziening en de transmissie van duurzaam opgewekte elektriciteit tussen de regio's. Met name de transmissielijnen Noord-Centraal, Noord-Oost en Noordwest-Centraal zijn cruciale "verkeersaders". Ook de lijnen Noordwest-Centraal, Noordwest-Noord, Noord-Oost, Noordwest-Zuid en Noordoost-Noord hebben een hoge benuttingsgraad. We concluderen dat de investerings plannen van de overheid daarmee alleszins gerechtvaardigd zijn.

Beleidsevaluatie van vraagrespons met elektrische voertuigen

Hoofdstuk 6 onderzoekt de implicaties van vraagrespons van elektrische voertuigen (EV) (met gecontroleerde laadstrategieën) voor decarbonisatie. De resultaten zijn voornamelijk gekwantificeerd door gebruik van een geïntegreerd transport-elektriciteitssysteem dispatch model dat zich onderscheidt door: 1) het gebruik van kernel dichtheidsschattingen om statistisch de tijdelijke beschikbaarheid van EVs te bepalen die aangesloten zijn aan het net; en 2) het toepassen van de cluster integer-benadering om de hoeveelheid variabelen te verminderen in het unit commitment model.

De resultaten tonen aan dat, de inzet van EV in China algemeen resulteert in een verschuiving van benzine naar steenkool, in verband met de dominantie van steenkool in de elektriciteitsproductie. Hoewel dit de afhankelijkheid van olie voor de transportsector vermindert, zorgt dit wel voor meer kolenverbruik en CO_2-uitstoot in het elektriciteitssysteem. Toepassing van EV vraagrespons zal de economische efficiëntie van de elektriciteitsproductie verhogen. Met de verwachte EV penetratiegraad in 2030, zal EV opladen zonder vraagrespons de variabele productiekosten van het energiesysteem verhogen met ongeveer 4%- 5% ten opzichte van geen EV. Door toepassing van vraagrespons (gestuurd laden) kunnen de extra kosten voor EV opladen verminderen met meer dan 30%. Nog belangrijker, EV vraagrespons kan ook de 'non served load' van het elektriciteitssysteem verminderen die vooral wordt veroorzaakt door de clustering van EV laden op bepaalde piekuren.

Met het verwachte elektriciteitssysteem en EV penetratiegraad in 2030, zal EV opladen zonder vraagrespons de CO_2-uitstoot met ongeveer 3% verhogen (ten opzichte van geen EV); het inzetten van vraagrespons verhoogt die additionele CO_2-uitstoot met 31%-35% doordat EVs bij voorkeur opgeladen worden met elektriciteit van laag rendement-kolencentrales in regio's met lage prijzen voor steenkool. Dit vraagt aandacht van beleidsmakers voor het meewegen van CO_2-uitstoot en productie efficiëntie in de regels voor elektriciteitsdispatch. EV vraagrespons blijkt wel degelijk mogelijkheden te bieden voor het verminderen van de CO_2-uitstoot van de elektriciteitsvoorziening (met betrekking tot geen vraagrespons), en dit potentieel neemt toe met het aandeel hernieuwbare energie in de elektriciteitsproductiemix. Het verduurzamen van de elektriciteitsproductie is dus van cruciaal belang om de potentiële milieuvoordelen van elektrische voertuigen te realiseren.

Conclusies

Dit proefschrift laat zien in hoeverre de belangrijkste beleidsopties voor decarbonisatie van de elektriciteitssector (verspreid over alle segmenten van de waardeketen) daadwerkelijk aan decarbonisatie kunnen bijdragen in de Chinese context, en hoe zij zich verhouden tot de beleidsdoelstellingen van voorzieningszekerheid en economische efficiënte. De resultaten van dit proefschrift kunnen China's beleidsmakers informeren over de gevolgen van alternatieve routes om de elektriciteitssector te decarboniseren en hen ondersteunen bij het verkennen van effectieve en efficiënte routes naar lange termijn decarbonisatie van de sector.

Met behulp van een set van wiskundige modellen worden toekomstige ontwikkelingstrajecten van het elektriciteitssysteem gekwantificeerd om de gevolgen van de geselecteerde beleidsopties te verkennen. De modelberekeningen in dit proefschrift laten zien dat door de bijzondere institutionele en technische context van de Chinese elektriciteitssector beleidsopties die vaak gezien worden als vanzelfsprekend voor decarbonisate, slechts een zeer beperkte of zelfs een negatieve bijdrage leveren. In de meeste gevallen vertonen de onderzochte beleidsopties duidelijke trade-offs tussen energievoorzieningszekerheid, economische efficiëntie en CO_2-emissiereducties. Oplossingen daarvoor moeten gevonden worden in de interacties tussen de beleidsopties: zo kan het gestuurd laden van elektrische voertuigen alleen bijdragen aan decarbonisatie, voorzieningszekerheid en economische efficiency als de elektriciteitsproductie wordt gedecarboniseerd en de dispatchregels worden aangepast. Dit vraagt om een set van samenhangende transformaties in zowel de institutionele als de technische inrichting van de gehele stroomvoorzieningsketen. De in dit proefschrift onderzochte beleidsopties voor decarbonisatie van de elektriciteitssector in China kunnen hun beloften alleen waarmaken als ze in samenhang worden ontworpen en toegepast, in een socio-technisch systeemperspectief.

Curriculum vitae

Ying Li was born on the 13th of November 1987 in Zhangqiu, Shandong Province, China. In 2008, she received the bachelor degree in Transportation Engineering at the Ludong University, China. In the same year, she started her master program in the South China University of Technology. In 2011, she obtained the master degree in Vehicle Engineering with the specialization in power system design for electric vehicles.

In October 2011, She got a scholarship from the China Scholarship Council and became a Ph.D. candidate at the Energy and Industry Section in the Faculty of Technology, Policy and Management, Delft University of Technology, the Netherlands. Under the supervision of Prof. dr. ir. Margot Weijnen and Dr. ir. Zofia Lukszo, her research focused on the mathematical modeling and optimization of power system planning and operation, as well as policy analysis for power sector decarbonization from the energy, economic and environmental perspectives. During the Ph.D. period, she also conducted a research project in Shell studying the optimal investments in energy storage technologies in future energy system with a high penetration of renewable energy generation, considering uncertainties from the development of power grid.

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