Decarbonizing China's Power Sector: Potential, Prospects and Policy

By

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A dissertation submitted in partial satisfaction of the

requirements for the degree of

Doctor of Philosophy

in

Energy and Resources

in the

Graduate Division

of the

University of California, Berkeley

Committee in charge:

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Professor Duncan S. Callaway
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Spring 2015

To my wife Keqin Wei

Abstract

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China's power sector accounts for 25% of the world coal consumption–fully about 13% of total global carbon emissions from fossil fuel. Decarbonizing China's power sector will shape how the country and to a large extent the world uses energy and addresses pollution and climate change. Combining methods of GIS modeling and wind and solar capacity factor simulation, this study utilized 200 representative locations each independently for wind and solar, with 10 years of hourly wind speed and solar irradiation data to investigate provincial capacity and output potentials from 2001 to 2010, and to build wind and solar availability profiles. This study then examined the implications of the solar and wind variability and availability in the context of an overall energy strategy for China by using a system optimization model: SWITCH-China to analyze the feasibility, costs and benefits of China's clean power transition under three key policy scenarios: Reference Scenario, Low Cost Renewable Scenario, and Carbon Cap Scenario. By optimizing capacity expansion and hourly generation dispatch simultaneously, SWITCH-China is uniquely suited to explore both the value of and synergies among various power system technology options, providing policymakers and industry leaders with important information about the optimal development of the electricity grid. China's power sector is in the midst of fast development, and today's investment decisions will have a large impact on the country's ability to achieve its environmental and carbon mitigation goals. Concerted actions are needed to enable such a transition, including introducing a meaningful carbon price, coordinating the investment decisions, and building the necessary infrastructure for moving energy around.

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Acknowledgments

First, thank my wife Keqin Wei, I would not start a Ph.D. without her support, and this dissertation is dedicated to her. I want to thank the support from my family.

I also want to take the opportunity to thank my mentors, collaborators, and friends, without whom I could not make my adventure to energy and climate research, and this study would not be possible.

My qualifying exam and dissertation committee: Daniel M. Kammen, Richard Norgaard, Duncan Callaway, John Zysman; and the Renewable and Appropriate Energy Laboratory (RAEL) and SWITCH team: Chris Jones, James Nelson, Josiah Johnston, Ana Mileva, Daniel Sanchez, Anne-Perrine Avrin, Diego Barido, Juan Pablo Carvallo, and Patricia Hidalgo-Gonzalez.

China Energy Group at Lawrence Berkeley National Laboratory (LBNL): Mark Levine, Lynn Price, Nan Zhou, David Fridley, LIN Jiang, Stephanie Ohshita, HONG Lixuan, SHEN Bo, Chris Marnay, FENG Wei, LU Hongyou, Nina Khanna, Christopher Williams, and John Romankiewicz.

The Berkeley and ERG community: Thomas Gold, You-tien Hsing, Solomen Hsiang, Orville Schell, James Williams; Fritz Kharl, Joe Kantenbacher, Zoe Chafe, Amber Kerr, Stacy Jackson, Ranjit Deshemoth, Grace Wu, Kay Burns, and many other ERGies; ZHI Huayong, LIU Yongdong, ZENG Di, XIE Yang, LU Xi, SUN Zhen, CAO Siwei, GU Yizhen, TANG Qu, and Andy ZHENG Cheng.

Colleagues in the Program on Energy and Sustainable Development (PESD) of Stanford University: David Victor, Mark Thurber, Thomas Heller, Frank Wolak, Richard Morse, Vaun Rai, Jeremy Carl, Danny Cullenward, and Kathy Lung.

My mentors and teachers at Peking University: C.S. Kiang(江家驷), CAI Yunlong(蔡运龙), ZHANG Shiqiu(张世秋), JIA Feng(贾峰), MENG Jijun(蒙吉军), XU Xuegong(许学工), LI Shuangcheng(李双成), and LIU Hongyan(刘鸿雁).

Collaborators and friends: HU Min(胡敏), HU Zhaoguang(胡兆光), JIANG Kejun(姜克隽), Jessica Kao, LI Jie(李杰), LI Hongjun(李宏军), LIU Zhu(刘竹), LU Xi(鲁玺), LUO Rui(罗锐), RUI Huaichuan(芮怀川), Susan Shirk, TAO Wendi(陶文娣), TIAN Jianwei(田建伟), Pamela Tomski, TU Jianjun(涂建军), Jennifer Tuner, XIE Xuxuan(谢旭轩), XIE Zhikai(谢志凯), SHI Han(施涵), XU Yuan(徐袁), YANG Ailun(杨爱伦), YANG Pingjian(阳平坚), Yiaway Yeh, ZHANG Xiliang(张希良), ZHANG Xin(张鑫), ZHAO Jun(赵俊), ZHONG Liheng(仲立恒), and many others who have helped my research in their capacity.

1 China’s clean power transition

1.1 Why China?

As the world’s largest energy consumer, biggest carbon emitter, and soon to be the world greatest economy, China presents the frontier of global energy and climate research and debate. China’s energy and climate news hits international headlines. China became the world largest carbon emitter in 2006 (MNP 2007), and the world largest energy consumer in 2010 (IEA 2010), as a result of its fast economic development, energy intensive manufacture-based industry, and enormous urbanization process. The Chinese economy overtook the United States economy to become the largest in the world in 2014, if using the purchasing power parity (PPP) adjustments (IMF 2014).

China’s fast industrialization as the global manufacture base is a prominent driver of its energy demand. From 1996 to 2010, China’s industrial energy consumption increased by 134%, even the industrial economic energy intensity decreased by 46%. Decomposition analysis shows that the rapid growth in industrial energy consumption was dominantly driven by the production expansion, the growth of industrial energy consumption would be even larger without the improvement of energy (Ke et al. 2012). Analysis shows the strong association of industrial energy consumption with the growth of China’s economy and changing energy policies.

China is still in the midst of fast urbanization, while this process has largely completed in the West. In 1978 when China started the Reform and Open Policy, less than 20 percent of China’s population lived in cities. Now the share has exceeded half. China’s urbanization rate is projected to reach 70 percent—about 1 billion people—by 2030. Over the past three decades, China’s urbanization has supported high growth and rapid transformation of the economy, allowing people—among them some 260 million migrants—to move from rural China to urban China (The World Bank and Development Research Center 2014). This has big implications on China’s energy demand, as urban residents consume three times energy than those live in rural.

The life style change and the motorization of transport has been an emerging driver for energy demand and pollution in China’s crowed cities. By the end of 2013, the motor vehicle exceeded 250 million in China, among which 137 million were private cars. From 2003 to 2013, the ownership had increased by 100 million, 10 million per year on average. By the end of 2013, there were 31 cities which have more than 1 million cars, and 8 of them had over 2 million (Ministry of Public Security 2014).

The inconvenient reality is that China relies heavily on coal to fuel its economy and to power its crowded cities. China accounts for about half of global total coal consumption annually. About 70 percent of its primary energy is from coal and nearly 80% of its electricity is generated from coal. China’s energy systems is highly coal dominant due to its resource endowment (IEA 2007). China has abundant coal but comparatively less oil and gas. China has a coal reserve up to 114.5 Billion tons (Bt) and this number keeps refreshing with new findings in western coal centers, for example, Xinjiang. Coal is the default energy choice as it is vastly available and cost competitive for China.

However, the pollution as a result of fossil fuel consumption has caused severe environmental and human health impacts. Chinese cities have been suffering from waves of “beyond index” air pollution. In extreme cases, the concentration of PM2.5 reached 800-1000μg/m^3 on Jan 12, 2014 in downtown Beijing, compared to the safe threshold of 25μg/m3 recommended by World Health Organization. Coal burning induced air pollution caused estimated 670,000 deaths in China in 2012. The damage to the environment and human health added up to 260 RMB (40 USD) for each ton produced, transported and used in 2012 (Teng 2014).

China’s coal dominated energy system also presents great challenge on tackling global climate change. China is already world’s largest carbon emitter, whose emission has exceeded world average even on per capita base. China’s role in global climate negotiation has been involving to more proactive position (H. Zhang 2006; He 2014). In the U.S.-China Joint Announcement on Climate Change, China is determined to peak its carbon emission by 2030 and have 20% of its primary energy from non-fossil sources by the same year (White House 2014). The challenge is to peak at what level. This will depend on when China would peak its coal consumption.

China also presents the emerging hope for decarbonization. China has been the center of renewable energy development. Installed wind capacity has sustained a remarkable 80% annual growth rate since 2005, putting China far in the global lead with over 91 gigawatts (91 GW; and 4% of national electricity, or C_N, capacity) of installed capacity in 2013 compared to the to the next two largest deployments, namely 61 GW in the United States (5% of C_N), and 34 GW in Germany (15% of C_N) (He and Kammen 2014). China’s solar power installed capacity has also been growing at an unprecedented pace. Its grid connected installed solar photovoltaic (PV) capacity has reached 19.42 gigawatt (GW) by the end of 2013 (1.6% of C_N), 20 fold increase of its capacity in four years from 0.9 GW in 2010 (Li et al. 2011; National Energy Administration 2014). In addition, half of all the new nuclear power plants planned by 2030 worldwide are forecast to be built in China.

The development of China’s energy sector has large implications for global energy and climate, is therefore at the center of international policy debate. China imported 290 million metric tons of coal in 2014, a cost minimizer links the international price of coal to China’s domestic price, and passes the impacts of China’s domestic policy to the international energy market through the global coal value chain (He and Morse 2014). China’s oil dependence was 58.5% in 2014 and is projected to reach 65% to 70% by 2020. As China advances toward a middle-income country to fulfill its Chinese Dream of renaissance, China’s energy and carbon footprint captures the attention of global policy domain.

1.2 Why China's power sector?

China's power sector consumes half of China's annual coal, and emits 45 percent to 50 percent of annual carbon emission. That means China's power sector accounts for 25% of the world coal consumption–fully about 13% of total global carbon emissions from fossil fuel (IEA 2011). China's power sector is therefore the one single largest energy consumer and carbon emitter in the world. The transition from the current fossil-fuel dominated electricity supply and delivery system to a sustainable, resource-wise system will shape how the country, and to a large extent, the world, addresses local pollution and global climate change.

In 1980, China's total electricity consumption was only about 300 terawatt-hour (TWh), it reached 1,350 TWh by 2000, and has grown to 5,523 TWh in 2014[1] (see Figure 1-1 to Figure 1-4). By the end of 2014, non-fossil sources, including hydro, nuclear, wind, solar, biomass, and geothermal, have provided 25.6 percent of China's electricity. Non-fossil source, which counts for 450 GW out of a 1360 GW total capacity, and 1420 TWh out of a 5550 TWh total generation, has grown rapidly in China's power mix and investment. Wind investment has grown to 99.3 billion RMB, exceeding that of hydro, thermal, and nuclear, to be the largest investment technology (CEC 2015).

It is projected that the average electricity consumption per capita in China will reach 6,272 kWh/cap, 7,737 kWh/cap, 9,207 kWh/cap, by 2030, 2040, and 2050 respectively. The total electricity consumption is project to 9,800 TWh by 2030, and to 14,300 TWh by 2050 (Z. Hu, Tan, and Xu 2011). Even though there are uncertainties on China's population growth and economic sustainability, the electrification of China's economic and societal energy demand, for example, electric high speed railway and electric vehicle, and the penetration of electric devices and appliances, will drive new growth of the electricity consumption.

China's power sector is under a major transition. While coal is still the dominant energy source today, ongoing rapid technological change coupled with strategic national investments in transmission capacity and new nuclear, solar and wind generation demonstrate that China has the capacity to completely alter the trajectory (NEA 2012b; State Council 2013). China has announced ambitious goals for renewable and non-fossil energy development targets (Figure SI-4). In the China Energy Development Strategy Action Plan 2014-2020, China plans to have 200GW wind capacity and 100GW solar capacity by 2020, and 58GW nuclear capacity plus a 30GW capacity under construction (State Council 2014). The continuous efforts of China's clean power development will have large impact on China's energy trajectory, and its environmental and climate footprint. Understanding the potential, prospect and policy of decarbonizing China's power sector is therefore essential to facilitate such a transition.

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[1] NEA released societal electricity consumption data in 2014. http://www.nea.gov.cn/2015-01/16/c_133923477.htm (accessed February 25, 2015)

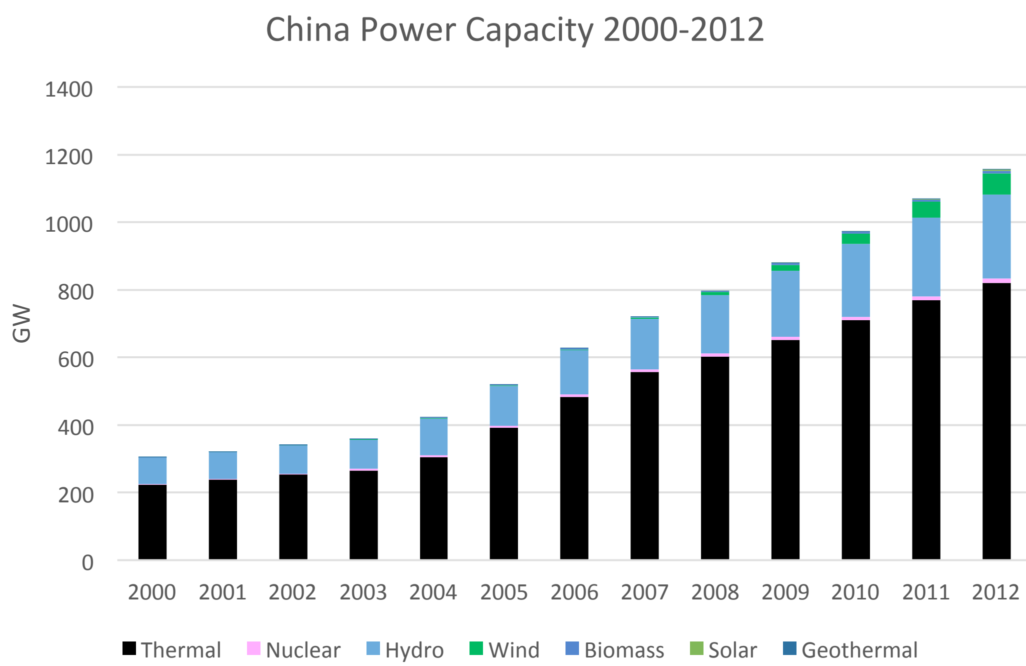


Figure 1-1 China's power capacity 2010-2012

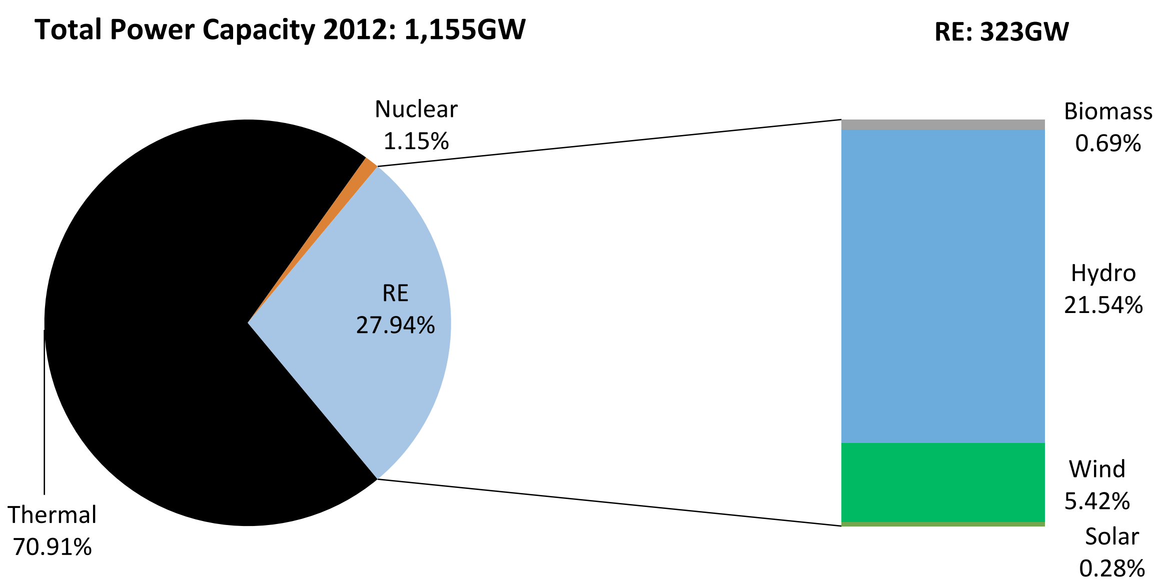


Figure 1-2 China's power capacity composition in 2012

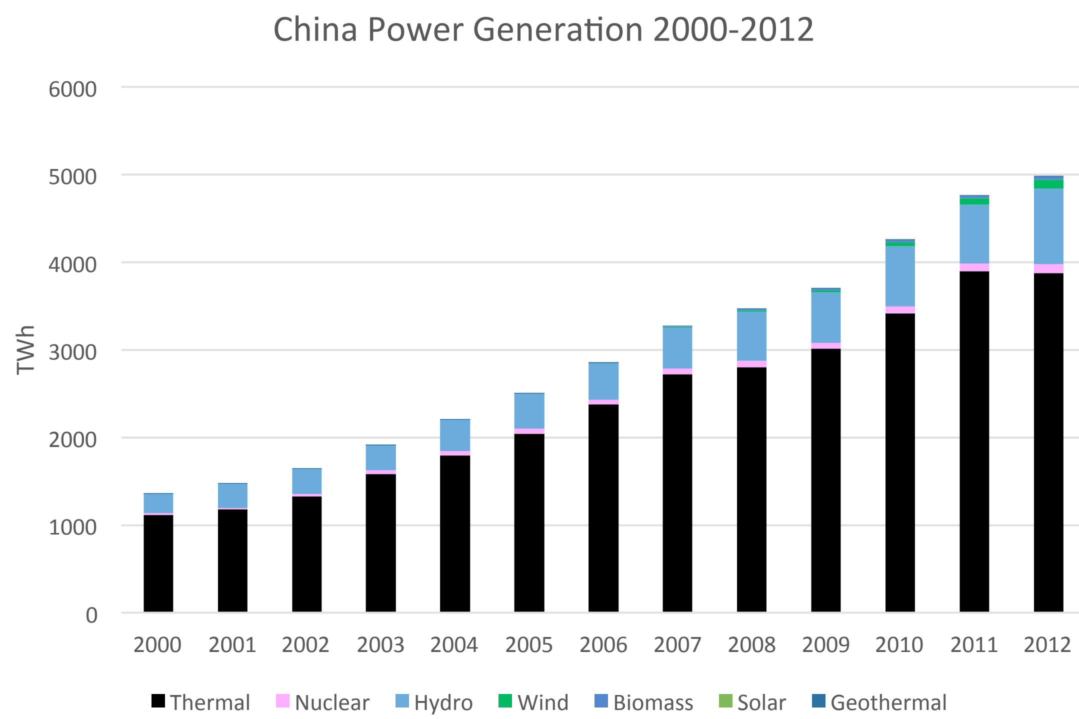


Figure 1-3 China's power generation 2010-2012

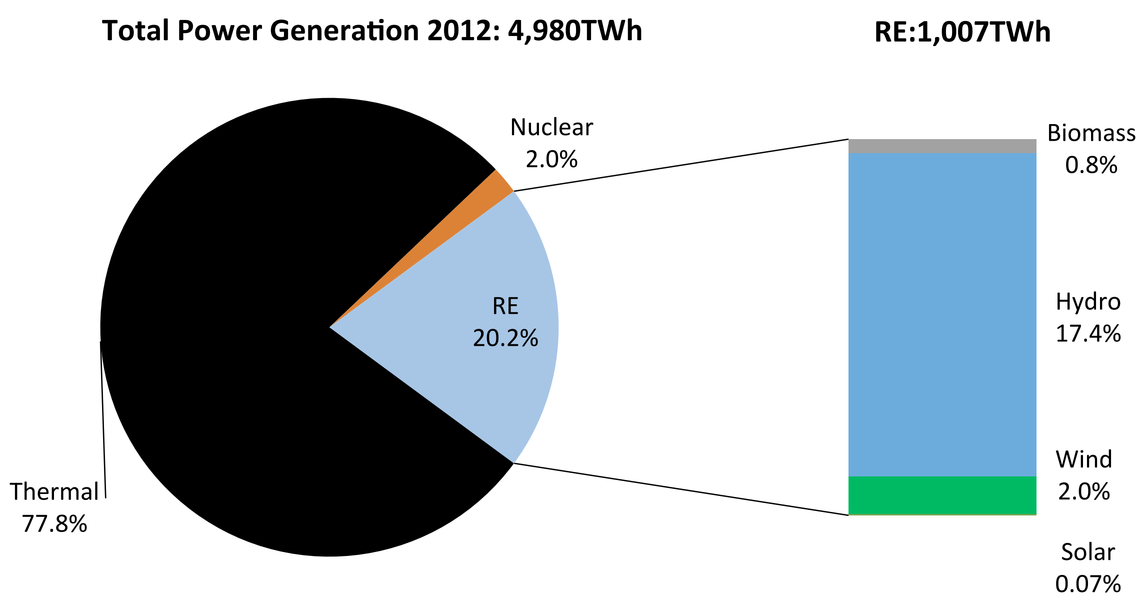


Figure 1-4 China's power generation composition in 2012

China's power sector is also the key to achieve China's carbon targets. In 2009, China released a target of 40-45 percent carbon intensity reduction by 2020 compared to 2005 level. However, this is an economy wide target. This study utilized the projection of GDP to 2020 by the World Bank Group[2], assuming a 6 percent GDP growth rate from 2015 to 2020 (The World Bank 2013), and calculated the economy wide carbon emission by 2020. Historical emissions from power sector are extracted from IEA CO_2 Emissions from Fuel Combustion 2013, future projection is based on the share of power sector emission in the total emission, from 0.4985 in 2010 to 0.5185 in 2020 (IEA 2013c, 2). In order to achieve the 40-45 percent carbon intensity targets, it would need to control the carbon emission from power sector at 4.5-4.9 $BtCO_2$, compared to 2005 frozen carbon intensity at 8.1 $BtCO_2$. Assuming China continues the existing efforts to improve its carbon intensity for the 2020 target to peak its carbon emission by 2030, the carbon emission in power sector will reach about 5.4 $BtCO_2$ in 2030.

Table 1-1 China's national carbon targets in power sector.

Category	Targets	2015	2020	2030	2050	Source
Carbon	Carbon intensity reduction (on 2005 level)	17%	40-45%	Peak	-	State Council
	Carbon intensity reduction (on 1990 level)	-	-	-	80%	IPCC
	Power sector carbon emission (Bt) to achieve 40-45% carbon intensity targets	-	4.47-4.87	5.4	-	Authors research

1.3 Modeling China's power sector

China's energy and power sector has been central topics in global energy and climate modeling community (N. Zheng, Zhou, and Fridley 2010; Mischke and Karlsson 2014). A range of models exist that provide important perspectives on China's long-term energy supply and demand challenges (CAE 2011; Jiang, Hu, et al. 2010; Wang and Watson 2010; N. Zhou et al. 2011). Macro-scale models provide insights into the resource constraints that national and regional energy systems face (Cai et al. 2007; Q. Chen et al. 2011). For China these models provide particular insight into the management of coal as the main future source because of its current predominance in the country (Cai et al. 2007; W. Zhou et al. 2010; Zhu and Fan 2010). The studies that undertake an optimization approach to identify best pathways for the long-term energy mix (Chandler et al. 2014; De Laquil, Chen, and Larson 2003; X. Hu, Jiang, and Yang 2003; Jiang, Liu, et al. 2010; D. Zhang et al. 2012) have low geographical and temporal resolutions, often limited to national scale and annual demand, which does not take into account the intrinsic

[2] Using 2005 constant U.S. dollar.

intermittency or variability of renewable energies.

To explore the realistic management of energy generation and transmission assets, a new generation of big-data models is needed. To address this need I have worked with the Renewable and Appropriate Energy Laboratory (RAEL) to develop a high-resolution integrated model that accurately reflects the performance of each element of the energy system. Explorations of the possibility of China transitioning to a low-carbon energy system require the capacity accurately reflect the performance of intermittent solar and wind resources so that overall system reliability and costs can be explored. Within this framework, the impacts of physical bottlenecks, supply constraints, and realistic policy choices can be studied.

A set of models now exist demonstrate that deep decarbonization (generally taken as 80% or more reductions in total CO_2 emissions) in the power sector by 2050 is physically possible for regions of the United States (Short et al. 2011; Williams et al. 2012). There are increasing interests on what emerging economies can do, especially China, since China consumes half of global total coal, and emits about 13 percent of global total carbon emission.

China's power sector is evolving fast. The efficient use of new generating capacity and the integration of even larger quantities of clean energy requires a platform on which investment and operational decisions can be optimized to meet reliability and cost management objectives on a previously unstudied scale, particularly for rapidly growing cities. Carbon capture, utilization and sequestration (CCUS), shale gas development, and new hydropower infrastructure all add additional complexity to this system. Missing from the discussion of these resources is an open-access platform to explore the implications of different investment options for energy generation and transmission in China, as well as means to examine the implications of different operating decisions and network topologies. Such a platform greatly enhances the opportunity for shared learning and dialog around the opportunities to engage in cost-effective decarbonization of the energy system.

1.4 Structure of the dissertation

I will address China's low carbon power transition from resource potential, scenario and policy perspectives. Understanding the resource potential and the characteristics of resources is the foundation for renewable integration. I will first introduce my work on provincial level resources assessment of wind (Chapter 2) and solar (Chapter 3), using GIS model and capacity factor simulation to explore where, when and how much wind and solar resources are available.

With these assessments as key inputs, I have worked with the Renewable and Appropriate Energy Laboratory (RAEL) to develop an integrated planning model of the Chinese power sector, the SWITCH China model, to analyze the feasibility, costs and benefits of China's clean power transition under three key policy scenarios: Reference Scenario, Low Cost Renewable Scenario, and Carbon Cap Scenario.

I will present the key findings in Chapter 4 from the modeling efforts and discuss the policy implications in Chapter 5 of China's clean power transition. Incorporating the true cost of coal and a meaningful cost price would facilitate the clean power transition by the co-benefits of such transition.

China's power sector is in the midst of fast development, and today's investment decisions will have a large impact on the country's ability to achieve its environmental and carbon mitigation goals. I conclude in Chapter 6 by calling for concerted actions are needed to enable such a transition, including introducing a meaningful carbon price, coordinating the investment decisions, and building the necessary infrastructure for moving energy around.

The model description, methods and data, and assumptions are all included in the Supplemental Information.

2 Wind resources availability

2.1 Introduction

China's installed wind capacity has been growing at an unprecedented pace, by the end of 2013, the total installed capacity has reached 91.5 GW, a 16.1 GW growth from 2012, and over 80 percent annual growth rate on average since 2005 (CWEA 2013; GWEC 2014). Total wind electricity generation was 100.8 TWh in 2012, accounting for 2% of China total electricity consumption, placing wind behind only coal and hydropower, with a calculated average capacity factor of 18.36% (CWEA 2013; NEA 2013). Despite this rapid progress continues, wind development in China faces challenges of grid connection (He and Morse 2013; Lewis 2012; Li et al. 2012; Zhao et al. 2013). According to the wind integration regulatory report in key regions released by the State Electricity Regulatory Commission, about 12.3 TWh wind electricity was lost in the curtailment in 2011, with an average curtailment rate of about 16%, resulting to a loss of 6.6 billion RMB (SERC 2012d).

The essential difficulties of integrating wind power lies in its high cross-spatial imbalance, inter-temporal variation and limited predictability (Xia and Song 2009; Xie et al. 2011). The variability of the wind resource, impacts the availability, dispatchability, and reliability of the electricity unless larger, regional planning and synergies between intermittent and dispatachable resources are integrated into the planning grid (Masters 2004; Loutan et al. 2009; Lu, McElroy, and Kiviluoma 2009; Nelson et al. 2012). However, wind resources can be managed through better wind resources assessment, proper plant interconnection, integration, transmission planning, and system and market operations, among which better resources assessment is the foundation of other measures and has big impact on adapting the appropriate measure (DeCesaro, Porter, and Milligan 2009; Smith et al. 2007).

The existing literature on wind resources assessment in China has focused on national level, with specific efforts examining the onshore and offshore capacity and potential. The China Meteorological Administration (CMA) has conducted three rounds of national wind resource surveys using the national weather station data, the most recent one projected a theoretical reserve of 4,350 GW and a technologically feasible resource of 297 GW at 10-meter height (CWEAR 2010). Researchers in the Energy Research Institute (ERI) showed the total technological available onshore wind capacity range from 600-1000 GW and around 150 GW offshore (Elliott et al. 2002; ERI 2010; Xue et al. 2001). McElroy and Lu *et al*. reported that wind could satisfy all of the demand for electricity projected for 2030, and that the wind electricity resources could displace 23% of electricity generated from coal at a price of 0.4 RMB (US$0.07) per kilowatt-hour (McElroy et al. 2009). For offshore wind resources, Hong and Moller reported offshore wind energy could contribute 46% of total electricity demand by 2020 and 42% of demand by 2030 in the coastal region within China's exclusive economic zone (Hong and Möller 2011). Those studies shed lights on overall resources but do not provide the necessary spatial resolution or give sufficient attention on the temporal variability of wind resources.

China has proposed a target to have 200 GW wind capacity (170 GW onshore and 30 GW offshore) by 2020 in the Wind Development 12^{th} Five Year Plan, aiming to build major onshore and offshore wind bases each at 10 GW scale, including those in Xinjiang, West Inner Mongolia, East Inner Mongolia, Hebei, Jiangsu, Jilin, and Liaoning (NEA 2012a). Expanding wind development in China therefore requires deeper understanding of the resources availability, both spatially and temporally. The existing research does not provide necessary details that policy maker and wind planner need to make plan for wind energy development to address the integration of the variable resources. This chapter provides a comprehensive assessment of China's onshore and offshore wind resources at provincial level with high spatial and temporal resolution.

2.2 Methods and data

This chapter combines the geographic information system (GIS) modeling methods and wind simulation with a large hourly dataset to study the availability of China's wind resources. The hourly wind speed data from 2001 to 2010 for 200 chosen locations (Figure 2-1) are obtained from 3TIER with a total of 200 × 8760 × 10 = 17.52 million data entry. Each data entry shows the wind speed, wind direction, temperature, and pressure of given hour, which are important inputs to simulate wind capacity factor. The wind speeds are at 100 meters height above ground, which is the average height of a 3MW-size wind turbine. This chapter pick those locations based on the following criteria: wind resources with average wind speed larger than 6 meters per second; site conditions are appropriate for building wind projects; and spatial distribution representativeness within each province, which allows 4 to 5 locations in each of China's 31 provinces (excluding Hong Kong and Macau, Inner Mongolia is considered as East Inner Mongolia and West Inner Mongolia as they belong to two different grid systems), along with 11 provinces that have offshore resources. This chapter created Thissen/Voronoi Polygon of those 200 sites to interpolate the area each site represents.

This chapter accessed China's national and province-level GIS information from the National Fundamental Geographic Information System. The land use and land cover dataset and the digital elevation model (DEM) dataset are provided by the Environmental and Ecological Science Data Center for West China, both are at 1km×1km resolution (Ran, Li, and Lu 2010). The land use and land cover data of 2010 was compiled by Chinese Academy of Science based on county level land use survey. The General Bathymetric Chart of the Oceans (GEBCO) data is downloaded from British Oceanographic Data Center (BODC 2010). This chapter trimmed it with China's Exclusive Economic Zone (EEZ) to get China's offshore area. This study used ArcGIS 10.0 and PostGIS to perform the spatial analysis.

This chapter calculated the available land for wind development for each province by applying the following filters in the GIS modeling: DEM with elevation less than 3,000 meters and slope less than 20 percent (NREL 2012), land use in the categories of woody savannas, shrublands, savannas, grasslands, barren, as defined in the land use data that are available for wind development, and average annual wind speed larger than 6 meters per second (AQSIQ 2002; ERI 2010). This chapter excluded forestry, cropland, wetland, urban built-up land, water, snow and glacial, and protected land in the onshore land. For offshore space, this study used bathymetry less than negative 20 meters as threshold, and excluded the buffer zone of tropical cyclone paths, ship lines, and cable lines in the offshore space (ERI 2010; Hong and Möller 2011). The installation capacity conversion factor ranges from 2 to 8 MW per square kilometers depending on the slope, the land availability conversion factor ranges from 30 percent to 90 percent depending on the surface condition and wind turbine layout (ERI 2010). The land use and slope conversion factors usually have uncertainties depending on the technology and local condition, and this study included a lower case and upper case for the conversion factors as listed in Table 2-1.

Table 2-1 GIS model thresholds and capacity conversion factors

Cases		Threshold/Capacity conversion index		
		Onshore		Offshore
		Lower case	Upper case	
Elevation/Bathymetry		3000m	3500m	-20m
Wind speed threshold		6 m/s	6 m/s	6 m/s
Slope α (%) factor	α≤2	5 MW/km^2	8 MW/km^2	4MW/km^2
	2≤α≤3	3 MW/km^2	6 MW/km^2	
	3≤α≤4	2 MW/km^2	4 MW/km^2	
	4≤α≤20	0 MW/km^2	2 MW/km^2	
Land use factor	Mixed forest	30%	50%	64%
	Shrublands	65%	75%	
	Savannas	65%	75%	
	Grassland	80%	90%	
	Barren	80%	90%	

Source: The assumptions in the lower case of onshore are from ERI, 2010. 2030 China wind development outlook: the feasibility study of meeting 10% of electricity demand. Energy Research Institute, Beijing. pp: 28-49. Assumptions of the upper case are based on expert interview in the field and for comparison use. Offshore land use factor is from Hong and Moller, 2011.

The potential wind capacity is calculated from below,

$$PC = \sum l_i \times sf_i \times lf_i$$

Where PC: potential capacity; l_i: land area of land use type of grid i. The selection criteria are listed as the following: Wind speed: $v_{avg} \geq 6\text{m/s}$, Elevation: $\text{E} \leq 3{,}000\text{m}$ in lower case or $\text{E} \leq 3{,}500\text{m}$ in higher case, Bathymetry: $\text{B} \geq -20\text{m}$, Slope: $\text{s} \leq 20\%$; sf_i and lf_i are the slope factor and land use factor of grid i specified in Table 1. All calculations are applied at 1km×1km grid and then summarized by using zonal statistics at provincial level. By applying the land selection criteria in the GIS model, the land that is appropriate for wind development for each province is shown in Figure 1. Areas with the richest wind resources lay in northern China and along the coastal offshore area.

The CF of each location is simulated with the hourly wind speed values based on the power curves of representative newly installed turbine sizes in 2012, correcting with air density. The shares of turbines whose sizes are larger than 2.5MW, 2MW, 1.5MW, less than 1MW, and others are 6.6%, 26.1%, 63.69%, 1.06% and 2.55% respectively, as reported in 2012 (Li et al. 2013). 2MW size turbine is considered as mainstream size for new installation. For offshore wind, the newly installed turbines are shared by 2.5MW and 3MW size turbines, popular sizes for newly built offshore wind projects in China (Li et al. 2012; Zhao et al. 2013). This study applied the power curves of a representative Goldwind 2MW size wind turbine for onshore CF simulation, and a representative Vestas 3MW size wind turbine for offshore CF simulation.

$$\text{Capacity factor} = \frac{reference\ capacity}{rated\ capacity}$$

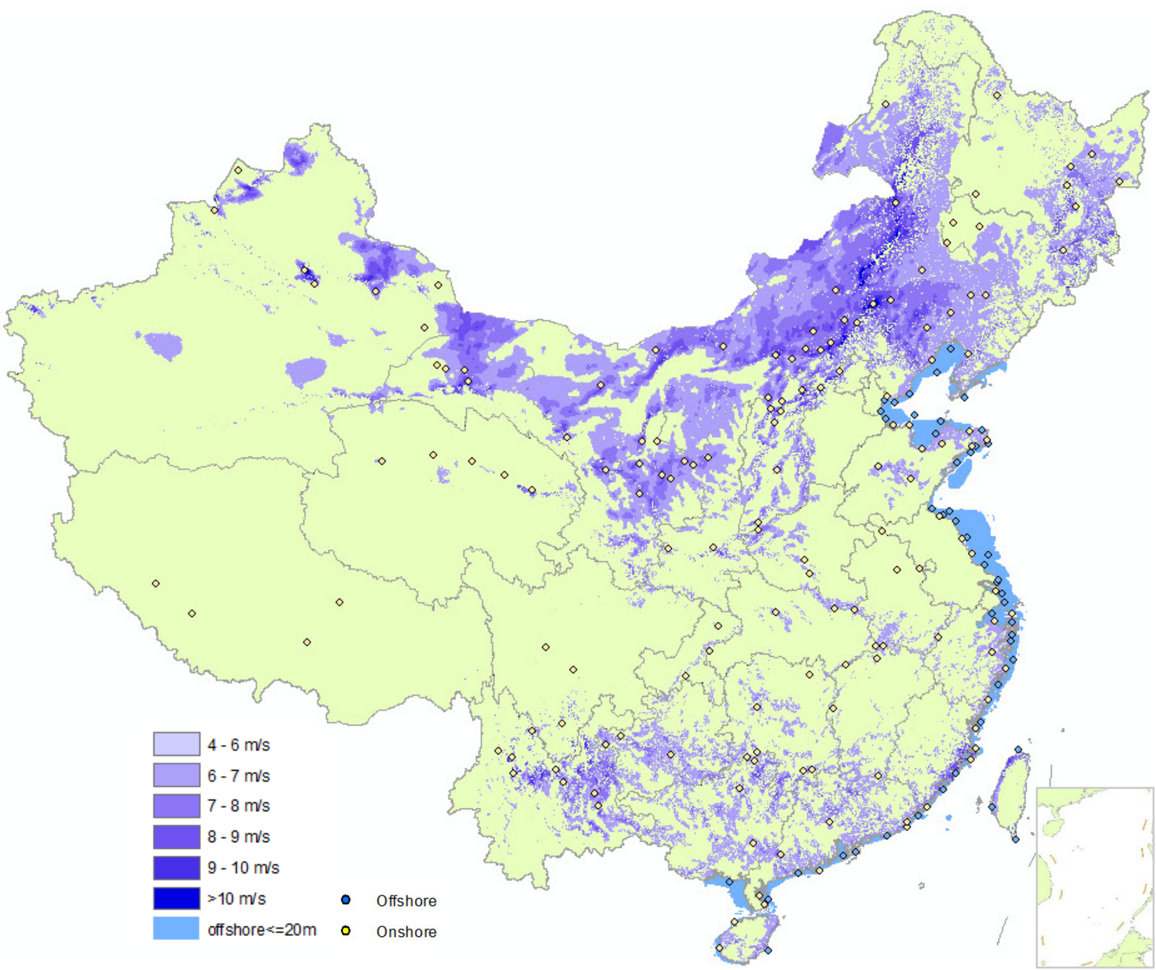


Figure 2-1 China wind appropriate area map and the hourly data points

2.3 Results

2.3.1 Average capacity factor, potential capacity and output

The results of the study are presented in terms of CF, potential capacity and output by resource type: onshore and offshore and by province. The annual average CFs of each province are comparatively stable across years during the study period, see Figure 2-2. Therefore, ten-year average CF is representative for the long-term CF for each province.

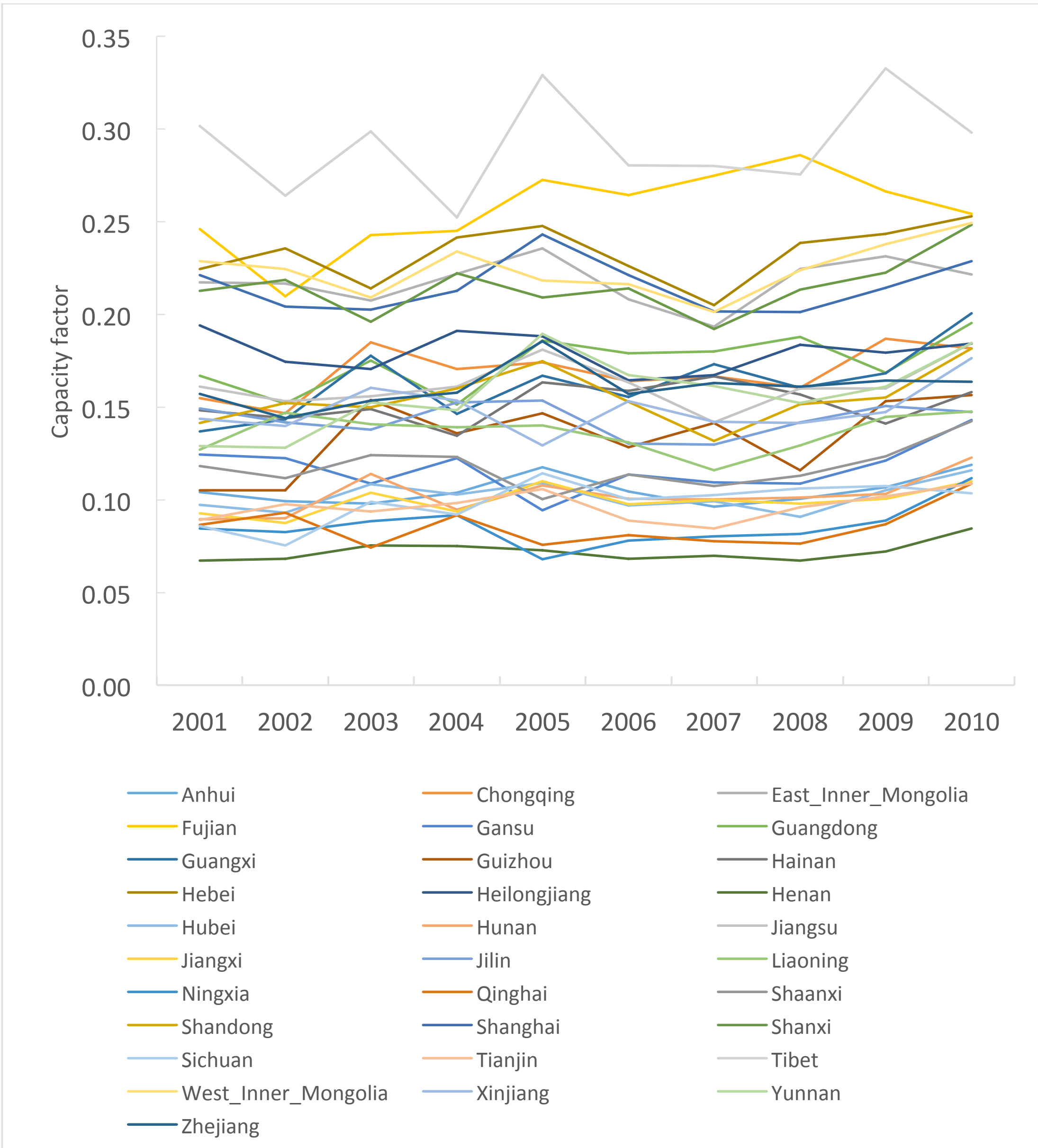


Figure 2-2 Annual average capacity factor by province 2001-2010

The ten-year average CFs of onshore and offshore wind for all provinces are shown in Table 2-2. Xizang (Tibet), Fujian, Hebei, East Inner Mongolia, West Inner Mongolia, Shanghai, and Shanxi have better onshore wind availability compared to other onshore provinces, and Zhejiang, Shanghai, Fujian, Hainan, Liaoning, and Jiangsu have better offshore wind availability, each with an average CF bigger than 0.2.

China has a national total potential wind capacity from 1,300 GW to 2,300 GW and national potential annual wind output between 2,000 TWh and 3,500 TWh in the lower case and upper case respectively, assuming all the land appropriate for wind projects is developed.

The overall calculated average capacity factor based on hourly data including onshore and offshore is at 0.18, which is lower compared to what has been reported at 0.23 based on annual output (Cyranoski 2009). Capacity factors that calculated from yearly output do not reflect the real availability of a country's wind resources because they do not capture the spatial imbalance and temporal variation. A low observed overall capacity factor might be due to unusually low winds that are below their long term potential. This phenomena is also observed in European wind CF studies (Boccard 2009). This difference shows the spatial and a temporal characteristic of wind resources is key to understand the availability and integration of variable wind resources.

Table 2-2 Average capacity factor and potential capacity and output of onshore and offshore wind by province 2001-2010

	Onshore Potential					**Offshore Potential**		
Province	**Avg. CF**	**Capacity (GW) (lower)**	**Output (TWh) (lower)**	**Capacity (GW) (upper)**	**Output (TWh) (upper)**	**Avg. CF**	**Capacity (GW)**	**Output (TWh)**
Anhui	0.1050	3.31	3.04	9.03	8.30			
Beijing	0.1044	0.37	0.34	1.59	1.45			
Chongqing	0.1690	1.46	2.16	5.70	8.44			
East Inner Mongolia	0.2178	102.55	195.67	210.10	400.88			
Fujian	0.2562	2.84	6.37	12.20	27.38	0.2240	28.05	55.03
Gansu	0.1168	54.99	56.27	120.85	123.66			
Guangdong	0.1742	6.88	10.50	19.05	29.07	0.1890	51.71	85.62
Guangxi	0.1629	13.85	19.76	36.40	51.93	0.1196	26.59	27.86
Guizhou	0.1342	8.87	10.42	26.28	30.89			
Hainan	0.1520	2.28	3.04	5.04	6.71	0.2237	10.36	20.30
Hebei	0.2329	5.78	11.79	17.86	36.44	0.1329	24.12	28.08
Heilongjiang	0.1797	37.54	59.10	85.81	135.10			
Henan	0.0720	2.22	1.40	7.00	4.42			
Hubei	0.1018	4.98	4.44	15.71	14.02			
Hunan	0.1024	10.12	9.08	27.93	25.05			
Jiangsu	0.1622	0.44	0.63	0.90	1.28	0.2010	107.62	189.54
Jiangxi	0.0993	8.67	7.54	22.48	19.55			

Jilin	0.1435	13.29	16.70	30.09	37.82			
Liaoning	0.1362	5.58	6.66	14.07	16.79	0.2049	60.58	108.75
Ningxia	0.0855	6.42	4.81	13.76	10.31			
Qinghai	0.0852	28.47	21.24	80.41	59.98			
Shaanxi	0.1177	13.55	13.97	35.06	36.16			
Shandong	0.1551	4.23	5.75	8.81	11.97	0.1965	76.54	131.73
Shanghai	0.2150	0.01	0.02	0.07	0.13	0.2241	24.30	47.72
Shanxi	0.2149	7.21	13.57	22.35	42.07			
Sichuan	0.0985	2.06	1.78	12.98	11.20			
Tianjin	0.0964	0.09	0.08	0.17	0.14	0.1083	5.56	5.27
Tibet (Xizang)	0.2912	0.10	0.26	0.83	2.12			
West Inner Mongolia	0.2243	189.00	371.32	351.90	691.37			
Xinjiang	0.1486	285.14	371.30	567.60	739.11			
Yunnan	0.1574	8.13	11.21	33.59	46.30			
Zhejiang	0.1607	2.22	3.12	9.44	13.29	0.2332	53.84	110.00
Average/Total	0.1771	832.65	1,243.35	1,805.06	2,643.34	0.1970	469	810

Note: Those provinces without offshore resources are left blank.

2.3.2 Spatial variation of provincial wind availability

The wind resources potential varies across provinces in China. Provinces with large wind capacity potentials are most located in the northern China for onshore and along the coast for offshore. For offshore wind, Jiangsu has the largest potential capacity, more than 100 GW, following by Shandong, Liaoning, Zhejiang, Guangdong, Fujian, Guangxi, Shanghai, Hebei, Hainan, and Tianjin.

For onshore wind, Table 2-2 shows wind capacity potential at provincial level varies at great scale, from less than 1 GW to near 600 GW. This is mainly due to the imbalance of wind power distribution, overlaid with land use, elevation, slope and bathymetry, and other surface conditions.

In the upper case, Xinjiang, West Inner Mongolia, East Inner Mongolia, and Gansu each has a potential capacity more than 100 GW. West Inner Mongolia has a capacity potential of 350 GW, combined with 210 GW in East Inner Mongolia, together make Inner Mongolia the province with the largest capacity potential, equivalent with Xinjiang and following by Gansu. In the lower case, only Xinjiang, East Inner Mongolia, and West Inner Mongolia are with a capacity more than 100 GW. The Three-North regions, including Northwest (Xinjiang, Shaanxi, Ningxia, Qinghai, and Gansu), Northeast (Heilongjiang, Jilin and Liaoning) and North China (Inner Mongolia, Hebei, Shanxi, Beijing and Tianjin) in total account for 90% and 85% of national onshore capacity, in the lower and upper cases respectively. The spatial variation across China and the concentration in northern part of China are the fundamental geographical features of the wind resources.

Potential wind output has similar geographic pattern, but slightly different order, as the capacity potential and CF are not always coupled with each other. Inner Mongolia and Xinjiang are the top provinces, which have the potential annual output larger than 100 TWh in the lower case. In the upper case, this list expands to Heilongjiang and Gansu. Inner Mongolia, Xinjiang, Heilongjiang and Gansu are the top potential producers, together accounting for 91% and 88% of national total potential onshore output in the lower and upper case, respectively.

2.3.3 Temporal variation of provincial wind availability

This chapter examined the inter-hourly wind variability within a day, the inter-daily wind variability within a month, and the inter-monthly wind variability within a year for all the 200 chosen locations. The inter-hourly and inter-daily variability is extremely disperse and does not show any regular trend, however, both the onshore and offshore wind resources show regular inter-monthly (seasonal) variation pattern, due to the monsoon wind pattern in East Asia (see Figure 2-3 and Figure 2-4).

For onshore wind, all provinces have better availability during spring and winter than in summer and autumn, but some provinces, for example, Guangxi, Shanghai, and Zhejiang have a small increase in July. The CF varies a lot between provinces and along seasons within a province. The highest monthly CF reaches as high as 0.5446 in Xizang in January, and the lowest reaches 0.0318 in Tianjin in August. The difference between the highest of lowest of the same province can as high as 0.48 in Xizang, and the maximum monthly average CF is more than 8 times of the minimum. Jiangxi has the minimum difference between extreme values, but has comparatively low average CF of 0.0994.

For offshore wind, Fujian, Zhejiang, and Hainan have superior availability in spring and winter, while Shanghai has the best availability during summer. Similar to onshore wind, all provinces have better availability during spring and winter than in summer and autumn, but some provinces, for example, Zhejiang, Shanghai, and Jiangsu have a small increase in July. The highest monthly average CF researches 0.4254 in Hainan in November, and the lowest 0.0354 in Tianjin in August. The biggest difference between the highest and the lowest in the same province is 0.3208 in Hainan, and the maximum monthly average CF in more than 5 times of the minimum. Shanghai has the minimum difference between extreme values.

The regional differences and spatial variability of wind resources show national coordination is needed to develop transmission corridors to transmit wind power out of the wind rich areas. However, as provinces follow similar seasonal variability pattern, inter-provinces coordination might provide less value than expected at seasonal time scale, back up capacity or storage assets has to be in place in order to tackle such variation and keep the power system reliable. The integration and optimization of different energy resources, such as wind and natural gas fired power, wind and solar, wind and storage, wind and hydro, other flexible sources, and demand response/demand side management will be essential to deal with such temporal variation pattern.

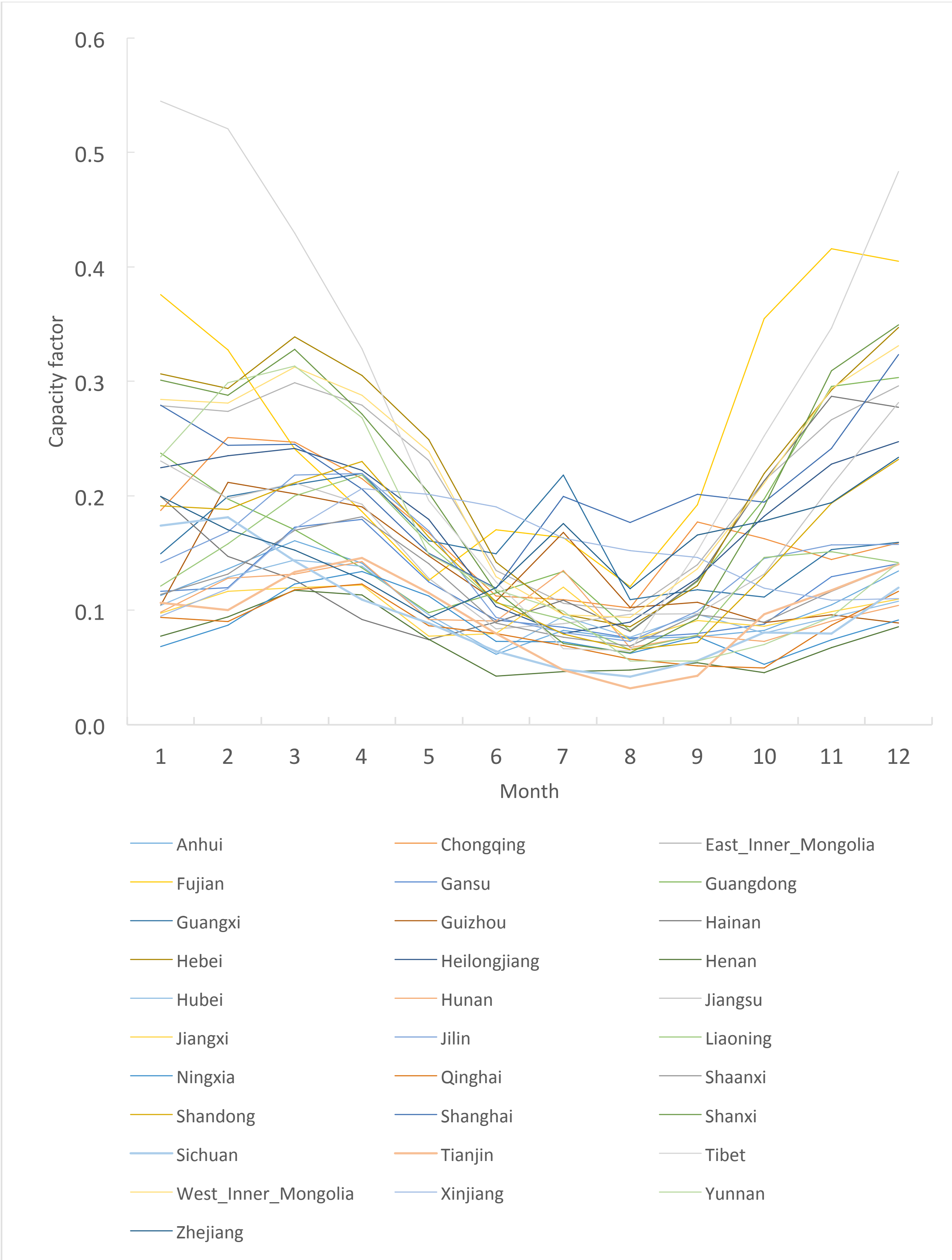


Figure 2-3 Monthly average onshore wind capacity factor 2001-2010

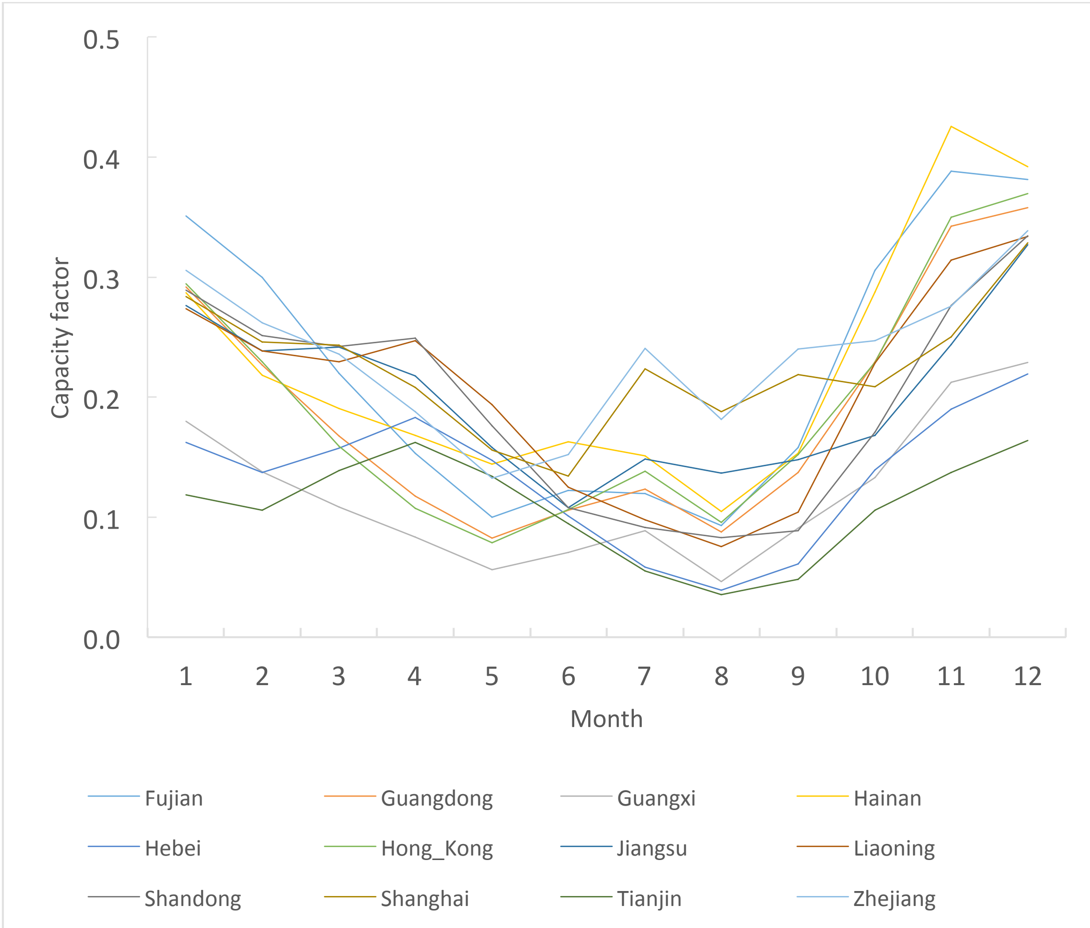


Figure 2-4 Monthly average offshore wind capacity factor 2001-2010

2.3.4 Potential contribution of wind generation

This chapter compared the provincial potential power output with projected provincial demand of 2030 and showed the potential share of wind power in total electricity demand in each province. This study uses electricity demand of 2030 as it is the best available year with projected provincial electricity demand reported by the Electricity Supply and Demand Lab in the State Grid Energy Research Institute (Z. Hu, Tan, and Xu 2011). Wind energy development and the total energy demand in each province have many uncertain factors, for example, economic development, competition and integration from other sources, investments and costs, etc. This study uses the ratio of potential output in total projected electricity demand (the potential/demand ratio) as an indicative number to show the potential contribution of wind can possibly achieve, and a schematic balance sheet of wind energy supply and demand.

Seen from Table 2-3, the potential/demand ratio at provincial level varies at great scale, from 1% to 420%, which reiterates the geographic variability of wind resources. In the upper case, West Inner Mongolia, Xinjiang, and East Inner Mongolia each generates more than what it needs therefore transmission is needed to transfer the extra energy to the coastal demand centers. Inner Mongolia at the upper case generates more than 4 times of the projected demand which tops all provinces. Xizang and Qinghai have relatively high average CFs but with the land at high elevation, greater than 3,000 meters, are excluded in the assessment. Nationwide, potential wind annual output could reach 2,000 TWh and 3,500 TWh in the lower case and upper case, respectively.

Table 2-3 Potential share of wind generation by province in 2030

Province	**Demand 2030 (TWh)**	**Lower case**		**Upper case**	
		Total output (TWh)	**Potential/Demand Ratio**	**Total output (TWh)**	**Potential/Demand Ratio**
Anhui	240.00	3.04	1%	8.30	3%
Beijing	133.20	0.34	0%	1.45	1%
Chongqing	171.10	2.16	1%	8.44	5%
East Inner Mongolia	272.44	195.67	72%	400.88	147%
Fujian	308.50	61.40	20%	82.40	27%
Gansu	205.10	56.27	27%	123.66	60%
Guangdong	815.10	96.12	12%	114.69	14%
Guangxi	254.30	47.61	19%	79.78	31%
Guizhou	218.00	10.42	5%	30.89	14%
Hainan	47.40	23.34	49%	27.01	57%
Hebei	676.90	39.87	6%	64.52	10%
Heilongjiang	153.50	59.10	39%	135.10	88%
Henan	614.20	1.40	0%	4.42	1%
Hubei	341.70	4.44	1%	14.02	4%
Hunan	298.70	9.08	3%	25.05	8%
Jiangsu	791.50	190.16	24%	190.82	24%
Jiangxi	165.30	7.54	5%	19.55	12%
Jilin	139.70	16.70	12%	37.82	27%
Liaoning	409.30	115.40	28%	125.53	31%
Ningxia	141.30	4.81	3%	10.31	7%
Qinghai	96.90	21.24	22%	59.98	62%
Shaanxi	233.50	13.97	6%	36.16	15%
Shandong	760.30	137.48	18%	143.70	19%
Shanghai	232.80	47.74	21%	47.85	21%
Shanxi	370.30	13.57	4%	42.07	11%
Sichuan	366.50	1.78	0%	11.20	3%
Tianjin	136.70	5.35	4%	5.42	4%
Tibet (Xizang)	7.30	0.26	3%	2.12	29%
West Inner Mongolia	163.46	371.32	227%	691.37	423%

Xinjiang	244.10	371.30	152%	739.11	303%
Yunnan	238.90	11.21	5%	46.30	19%
Zhejiang	596.80	113.13	19%	123.29	21%
Total/Average	9845	2053	21%	3453	35%

2.3.5 Sensitivity analysis and uncertainties

This chapter conducted sensitivity analysis on four key assumptions of the GIS model: the 6 meters per second wind speed threshold, the 20 percent slope threshold, the 3000 meters elevation threshold, and the 20 meters of bathymetry threshold. This chapter studied the relations of those factors with the potential capacity, and plotted them in Figure 2-5. The results in the upper case and lower case are quite similar as those four factors follow the same change pattern.

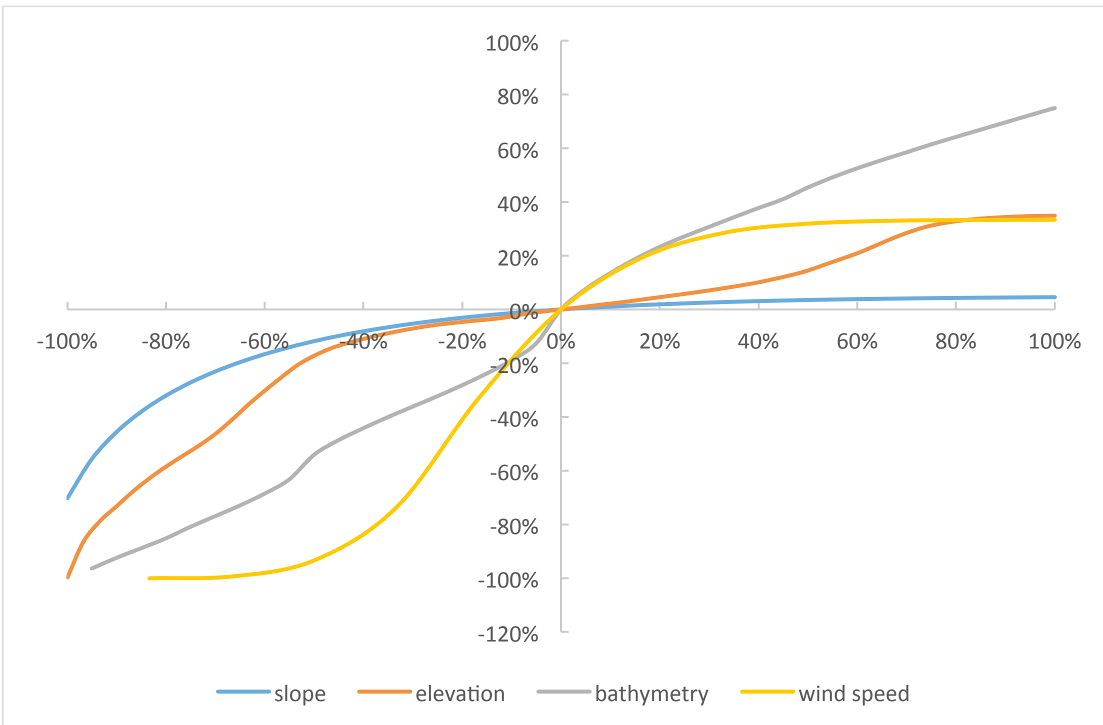


Figure 2-5 The sensitivity analysis of key assumptions to the capacity potential

All four factors are following non-linear relations with the capacity potential. The capacity potential are more sensitive to the 6 meter per second average annual wind speed threshold and the 20 meter bathymetry threshold, but less sensitive to the 20% slope and 3000 elevation threshold.

In addition, there are many uncertainties related to this study. The inter-annual variations in some sites are not trivial, and should be incorporated into long-term projection. Technology advancement might make it possible to harvest lower speed wind, at places with steeper slope, in land with less favorable surface conditions, and deeper bathymetry offshore wind resources, therefore the results of this analysis will need update in the future as technologies develop.

2.4 Conclusion

China's wind installed capacity has grown at a remarkable rate, reaching 91.5GW of capacity by the end of 2013. Existing research has been focusing on national scale and does not provide the necessary spatial resolution or give sufficient attention on the spatial and temporal variation of wind availability. Given wind as an inherently variable resource, China's ambitious wind development plan will be greatly aided with a detailed wind resource assessment that identifies total resources, spatial availability, and seasonal and daily variability across China. Knowing where, when and how much wind is available at provincial level can help the researchers and policy makers on wind development planning and integration.

Table 2-4 Comparison to other similar research

Study	**Results**			**Methods**	**Data**
	Capacity potential	**Average CF**	**Total generation potential**		
This study, 2014	Onshore: 800–1,800GW Offshore: 470GW	0.18	Total: 2,000 – 3,500TWh	GIS model/CF simulation	3TIER hourly data WESTDC
China Meteorological Administration, 2005	Onshore: 297GW	N/A	N/A	Wind Energy Simulation Toolkit	Meteorologic al data
Energy Research Institute, 2010	Onshore: 600-1000GW Offshore: 150GW	N/A	N/A	Numerical Simulation	SWEAR
McElroy and Lu, 2009	N/A	0.23	Technical: 24,700TWh Economic:6,960 TWh	GIS/ Financial model	GEOS-5
Hong and Moller, 2011	Offshore: 570 GW, 848 GW, and 1007 GW by 2010, 2020 and 2030	0.375	Offshore: 637TWh	GIS model	SWERA

Note: WESTDC refers to the Cold and Arid Regions Science Data Center at Lanzhou of China. SWERA refers to the Solar and Wind Energy Resource Assessment project for the United Nations Environment Program. GEOS-5 refers to the Goddard Earth Observing System Model, Version 5.

Combining methods of GIS modeling and wind CF simulation, this chapter utilized 200 representative locations for which 10 years of hourly wind speed data exist to study provincial capacity factor from 2001 to 2010, and to build wind availability profiles. From these data, this analysis found that China could have a potential wind capacity from 1,300GW to 2,300GW, and annual wind output could reach 2,000 TWh to 3,500 TWh. The calculated average capacity factor is 0.18, which is lower compared to what has been reported.

This study extends the existing research by investigating wind availability in China at higher spatial resolution and temporal resolution so to understand the spatial and temporal availability of wind resources across China. The results of this study can be used to facilitate local and national wind development plans and can be also utilized by developers and regulators to develop strategies on wind integration. Table 2-4 listed the comparison of this study with other major similar research in their methods, data and key findings.

While spatial variation demands highly interconnected and coordinated power system, similar temporal variation pattern restricted the effectiveness of such a system. This study looked into the diurnal and seasonal features of the wind availability at provincial level and found similar seasonal variation pattern between provinces, which indicates the difficulties to integrate wind resources through regional coordination, and back up capacity or storage assets has to be in place in order to incorporate such variation. The diurnal and seasonal variability demand a larger, systems-level analysis of China's energy options with more careful investigation of technical and economic availabilities and the role of inter-province transmissions.

3 Solar resources availability

3.1 Introduction

China's solar power installed capacity has been growing at an unprecedented pace. China's grid-connected installed solar photovoltaic (PV) capacity has reached 19.42 GW by the end of 2013, including 16.32 GW of stationary PV and 3.1 GW of distributed PV, resulting in a 20-fold increase of capacity from 0.9 GW in 2010 (Li et al. 2011; National Energy Administration 2014). The total solar electricity generation was 9 TWh in 2013, accounting for about 0.17% of China's total electricity consumption in the same year (CEC 2014). The share of solar energy in total generation is still small, however, the rapid growth and expanding installation of solar power has increasingly posed a real challenge for the grid (S. Zhang and He 2013; C. Zheng and Kammen 2014).

Solar, similar to wind, is referred to as a variable energy resource because its electricity production varies based on the availability of sun. Some aspects of solar variability are predictable, for example, sunrise and sunset. Other aspects, such as intermittent cloud cover or other types of weather change, are much less so. The spatial imbalance and inter-temporal variation makes solar generation difficult to integrate (D. Low et al. 2013). The variability of the solar resource, impacts the availability, dispatchability, and reliability of the electricity (Masters 2004). Better solar resources assessment is fundamental for proper plant placement, transmission interconnection planning, system integration, and market operations.

The existing literature on solar resources assessment in China has focused on the theoretical potential at national level or a specific region, without giving the spatial and temporal variation and availability. Zhou et al (2010) used the daily irradiation and sunshine duration data of 163 meteorological stations in Shaanxi, Qinghai, Gansu, and Xinjiang and provided a spatial distribution of solar radiation in those provinces (Y. Zhou, Wu, Hu, and Liu 2010). A few other provinces have conducted resource assessments for distributed solar, for example, Jiangsu and Shandong (Y. Zhou, Wu, Hu, Fang, et al. 2010). Those studies shed lights on overall resources assessment, but do not provide the necessary spatial resolution or give sufficient attention on the temporal variability of solar resources.

China has proposed a target to have 21 GW solar power capacity (11 GW station and 10 GW distributed) by 2015 and 50 GW capacity (23 GW station and 27 GW distributed) by 2020 in the Solar Power Development 12th Five Year Plan (NDRC 2012). It was then upgraded to 70 GW by 2017 and 100 GW by 2020 to boom domestic installation and cut air pollution, with a focus in Jing-Jin-Ji region (Beijing, Tianjin, and Hebei), Yangtze River Delta and Pearl River Delta area where air pollution are severe, and Qinghai, Xinjiang and Gansu where solar and land are abundant (NDRC 2014). To achieve those ambitious targets and high penetration of solar power requires deeper understanding of the resources availability, both spatially and temporally. He and Kammen (2014) conducted a research on the availability of wind resources at provincial level (He and Kammen 2014). This chapter provides a comprehensive assessment of China's solar resources at provincial level with hourly solar irradiation data.

3.2 Methods and data

This chapter combines the geographic information system (GIS) modeling and solar simulation with a large hourly data set to study the availability of China's solar resources. The hourly solar irradiance data from 2001 to 2010 for 200 chosen locations (Figure 3-1) are obtained from 3TIER, with a total of 200 × 8760 × 10 = 17.52 million data entry. Each data entry shows the basic location information, hourly Global Horizontal Irradiance (GHI), Direct Normal Irradiance (DNI), and Diffuse Horizontal Irradiance (DHI). The locations were matched with the hourly weather data from Chinese Standard Weather Data (CSWD) (China Meteorological Bureau et al. 2005).

This chapter pick those locations based on the following criteria: solar resources have an average GHI larger than 160 W/m^2, which is the threshold of GHI that are fit for solar project development recommended by China Meteorological Administration (CMA 2008) (Table 3-1); site conditions are appropriate for building solar projects (independent to the wind sites); and spatial distribution representativeness within each province, which allows 4 to 6 locations in each of the 31 provinces in mainland China (excluding Hong Kong and Macau; Inner Mongolia is considered as East Inner Mongolia and West Inner Mongolia as they belong to two different regional grid systems). This chapter created Thissen/Voronoi Polygon within province boundary of those 200 sites and applied Kriging method to interpolate the area that each site represents.

Table 3-1 Solar resources classification in China

Class	Total solar irradiation	Average GHI	Diurnal peak daylight hours	Resource
1	>6660 MJ/m^2·a >1850 kWh/ m^2·a	>211W/m^2	>5.1 h	Very good
2	6300~6660 MJ/m^2·a 1750~1850 kWh/ m^2·a	200~211 W/m^2	4.8~5.1 h	Good
3	5040~6300 MJ/m^2·a 1400~1750 kWh/ m^2·a	160~200 W/m^2	3.8~4.8 h	Fair
4	<5040 MJ/m^2·a <1400 kWh/ m^2·a	<160 W/m^2	<3.8 h	Poor

Note: Resource in the "Poor" category is not recommended for solar development. Source: CMA. Assessment Method for Solar Energy. Beijing: China Meteorological Administration; 2008.

This chapter accessed China's national and province-level GIS dada from the National Fundamental Geographic Information System. The land use and land cover dataset and the digital elevation model (DEM) dataset are provided by the Cold and Arid Regions Science Data Center at Lanzhou, both are at 1 km×1 km resolution (Ran, Li, and Lu 2010). The land use and land cover data of 2010 was compiled by of Chinese

Academy of Science based on county level land use survey. The desert land use map is provided by "Environmental & Ecological Science Data Center for West China, National Natural Science Foundation of China" (http://westdc.westgis.ac.cn). The urban area GIS layer, where the commercial and residential solar PV locate, is obtained from Beijing City Lab (Long and Shen 2014). The protected land GIS layer is downloaded from World Database on Protected Areas (WDPA) (http://protectedplanet.net/). This study used PostgreSQL for data management and ArcGIS 10.0 and PostGIS to perform the spatial analysis.

Table 3-2 Setting of the upper case and lower case

Cases	Lower case	Upper case
Elevation	3500m	3000m
Slope threshold	1%	3%
Land use filter	Exclude all desert land	Exclude shifting sandy land and semi-shifting sandy land; Include fixed sandy land, semi-fixed sandy land and Gobi desert

Source: The slope threshold is from NREL.

Table 3-3 Total land use requirements by solar technology

Technology		Land requirement (U.S.)		Land requirement (China)
		Average area requirement (acres/MW)	Land conversion factor (MW/km^2)	Land conversion factor (MW/km^2)
Central PV	Fixed	7.5	33	30
	1-axis	8.3	30	
	2-axis CPV	8.1	31	
CSP25	All	10	25	25
	Trough	9.5	26	
	Tower	10	25	
	Dish Stirling	10	25	
	Linear Fresnel	4.7	53	

(a)

Technology	Average space requirement (m^2/kW)	Space conversion factor (kW/m^2)
Residential PV	12	0.083
Commercial PV	12	0.083

(b)

Source: The capacity weighted average area requirement with project larger than 20MW are extracted from Ong et al., 2013, and are for comparison purpose.

This chapter calculated the available land for solar development for each province by applying the following filters in the GIS modeling: DEM with elevation less than 3000 meters and slope less than 1 percent in the lower case, and 3500 meters and 3 present in the upper case (NREL 2012), land use in the categories of barren land, as defined in the land use data that are available for solar development. The study excluded forestry, cropland, wetland, water, woody savannas, shrublands, savannas, grasslands, snow and glacial, and protected land for stationary PV. Desert land is assumed into a lower case and an upper case by type of sandy land (Table 3-2). The study interpreted urban construction land to the roof space that potentially available for commercial and residential solar PV installation. The installation capacity conversion factor ranges from 7.5 to 10 acres per MW (25 to 33 MW/km^2), depending on the technology, array configuration, and tracking technologies (Ong et al. 2013). The land use conversion factors usually have uncertainties depending on the technology and local condition, and Chinese sites are usually denser as land resource is scare in China. In this study, this chapter uses an average 30MW/km^2 for Central PV, and 25 MW/km^2 for CSP based on interview with solar project developers (Table 3-3).

The potential solar capacity is calculated from below,

$$PC = \sum l_i \times lf_{ss} + \sum l_i \times lf_{ds}$$

Where PC: potential capacity; l_i: land area of land use type of grid i. The selection criteria for stationary solar land are listed as the following: Solar radiation: $\mathrm{GHI}_{avg} \geq 160\ \mathrm{W/m^2}$, Elevation: $\mathrm{E} \leq 3000\mathrm{m}$ in the upper case and $\mathrm{E} \leq 3500\mathrm{m}$ in the lower case, Slope: $\mathrm{s} \leq 1\%$ in the lower case and $\mathrm{s} \leq 3\%$ in the upper case; lf_{ss} and lf_{ds} are the land use factors of stationary solar and distributed solar as specified in Table 3-3. stationary solar technologies compete for land which means only one technology can be built in grid i. For distributed solar, lf_{ds} is the land use factor of distributed solar specified in Table 1, distributed solar does not compete for space as residential and commercial PV use different rooftop space where appropriate. This study included 6 types of key solar power technologies: stationary solar technology including solar PV, concentrate solar power (CSP) with 6 hours of storage, CSP without storage, and distributed solar including commercial and residential PV. This chapter does not include solar thermal technologies. All calculation are applied at 1km×1km grid and then summarized by using zonal statistics at provincial level. By applying the land filter criteria in the GIS model, the lands that are appropriate for solar development in the lower case and upper case for each province are shown in Figure 3-1.

The CF of each location by technology is simulated with the hourly solar irradiation values using the System Advisor Model (SAM) developed by National Renewable Energy Laboratory (NREL) (http://sam.nrel.gov). Using the power curve of most commonly installed solar panel modules (Li, Wang, and Wang 2013), combining standardized setting of inverter and array setting, SAM is able to use the irradiation data, dry bulb temperature, and wind speed in the weather file to simulate the output of specific solar capacity at designated locations. The CF is then calculated by the simulated output and the solar capacity at each location. We used SamUL Script to run the bulk simulation.

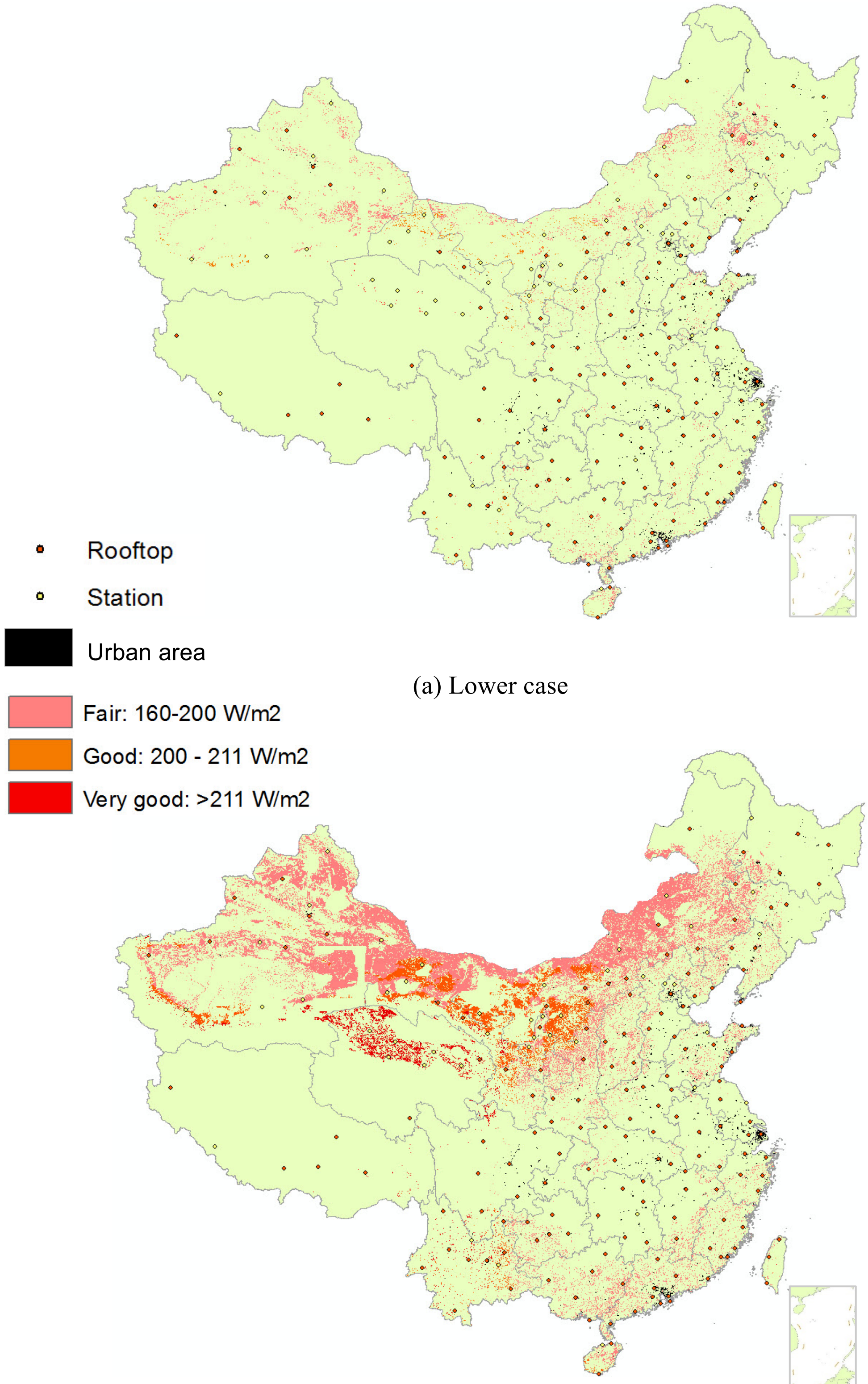


Figure 3-1 China solar appropriate area map in the lower and upper case

3.3 Results

3.3.1 Average capacity factor, potential capacity and output

This chapter calculated the CF, potential capacity and output by technology type in each province. This chapter chooses the central PV as a representative technology to show the results in chart. The annual average CFs of each province are comparatively stable across years during the study period (Figure 3-2). Therefore, ten years average CF is representative for the long-term CF in each province and is used in the calculation of potential output.

The ten-year average CFs of central PV, CSP, residential PV and commercial PV for each province are shown in Table 3-5. Xizang (Tibet), Yunnan, Hainan, West Inner Mongolia, Gansu, and Ningxia have comparatively larger CFs compared to provinces, they are either locate in the west at high elevation or in the south with better insolation, each has an average CF bigger than 0.2 in the stationary solar. Central PV and CSP have larger CFs than residential and commercial PV.

China has a national total potential central PV capacity from 4,700 GW to 39,300 GW and national potential annual solar output between 8,000 TWh and 69,900 TWh in the lower case and upper case respectively, assuming all the lands appropriate for solar projects are developed for central PV. This large difference is caused by the inclusion or exclusion of those lands with a slope between 1% and 3%, and the fixed sandy land, semi-fixed sandy land and Gobi desert land (Table 3-3). The difference shows the spatial and temporal characteristics of solar resources are key to understand the availability and integration of variable solar resources.

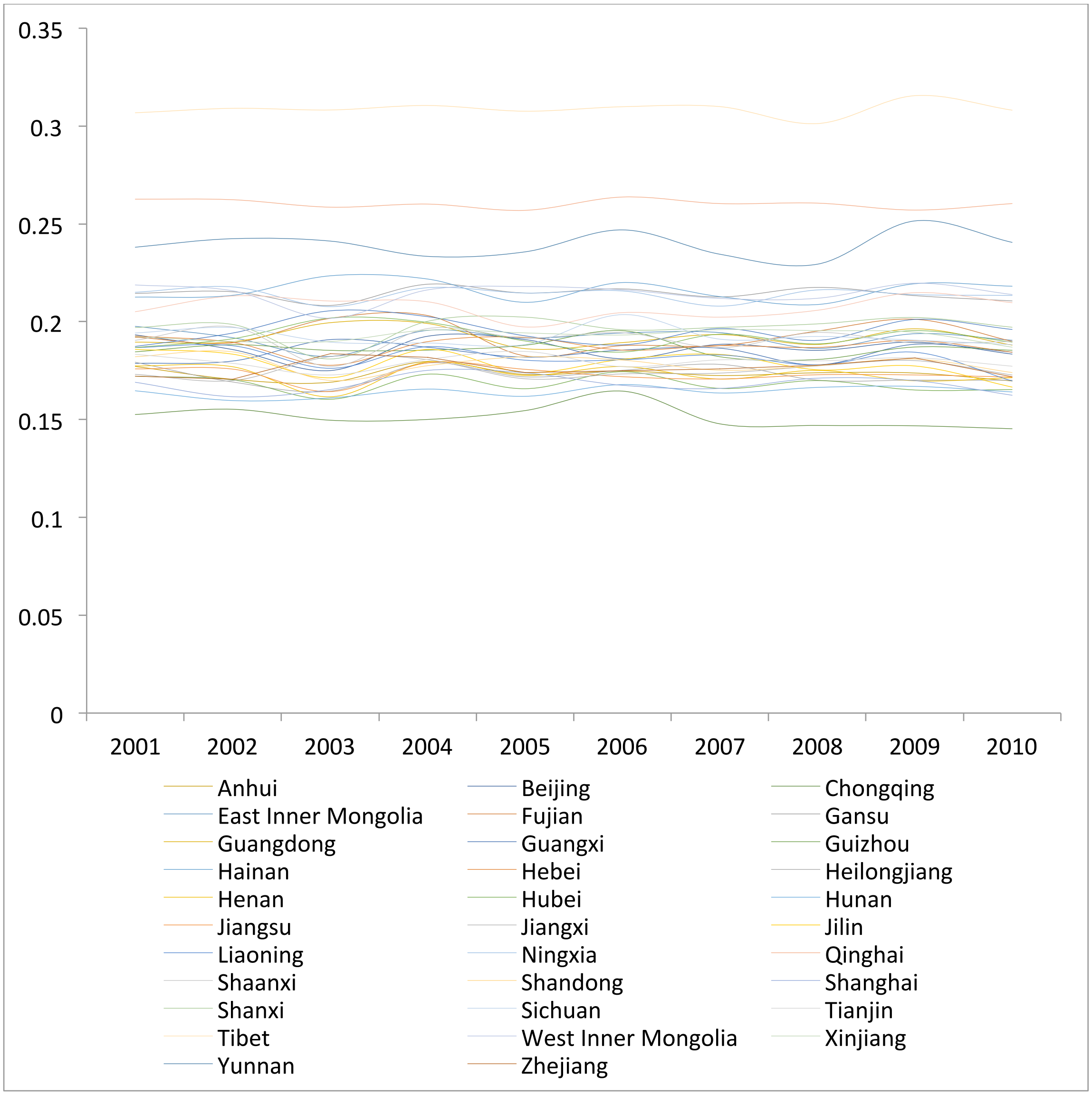


Figure 3-2 Annual average central PV capacity factor by province 2001-2010

3.3.2 Spatial variation of provincial solar availability

The solar resources potential varies across provinces in China. Provinces with large solar capacity potentials are most located in northwestern China for stationary solar and spread in the city clusters for distributed solar.

For central PV, Xinjiang has the largest potential capacity, close to 1,400 GW, followed by Inner Mongolia, Gansu, and Jilin in the lower case. Qinghai and Shaanxi would move up in the list in the upper case if the desert land and higher elevation land can be used for solar development.

In the lower case, Xinjiang, West Inner Mongolia, East Inner Mongolia, Gansu, Jilin, Guangxi, Heilongjiang, Guangdong, and Shandong each has a potential capacity more than 100 GW. West Inner Mongolia has a capacity potential of 860GW, combined with 540 GW in East Inner Mongolia, together make Inner Mongolia the province with the largest solar capacity potential. In the upper case, only Hubei, Anhui, Beijing, Xizang, Hunan, Jiangsu, Tianjin, and Shanghai are with a capacity less than 100 GW, Xinjiang, Inner Mongolia, Gansu, Qinghai, and Shaanxi each has a capacity potential larger than 1000 GW. This shows solar resource are vastly available in China, however, the spatial variation across China and the concentration in northern west China are important geographical features of the solar resources.

Potential solar output has similar geographic pattern, the provinces which have large CFs also have large available lands. Xinjiang, Inner Mongolia and Gansu are the top provinces, which have the potential annual output larger than 500 TWh in the lower case. In the upper case, Xinjiang, Inner Mongolia, Gansu, Qinghai, Shaanxi, Yunnan, Shanxi, Guangxi, and Guangdong have the potential annual output larger than 1000 TWh. Inner Mongolia, Xinjiang, and Gansu are the top potential producers, together accounting for 67% and 75% of national total central PV solar potential output in the lower and upper case, respectively.

For distributed solar, Table 3-5 shows potential capacity at provincial level varies at great scale, from about 0.3 GW in Xizang to near 14 GW in Guangdong for residential PV, and from 0.2 GW to 10 GW for commercial PV. This mainly due to the availability of rooftop space within the built-up area of cites in those provinces.

3.3.3 Temporal variation of provincial solar availability

CF is a good indicator to show the solar variation and its availability. This chapter examined the hourly solar variability within a day, the daily solar variability within a month, and the monthly solar variability within a year for all the 200 chosen locations by province. Both solar and wind are temporal variable resources, however, compared to wind, the variation of solar follows the natural cycle of solar irradiation therefore is more predictable. The daily variability are extremely disperse and does not show any regular trend, however, all technologies show regular monthly (seasonal) and hourly (within a day) variation pattern, due to the hourly and seasonal variation pattern of solar irradiation (Figure 3-3 and Figure 3-4).

Using central PV as an example, all provinces have better availability during summer than in spring, autumn and winter. CFs usually peak in June or July. The highest monthly CF reaches as high as 0.3978 in Xizang in June, and the lowest is 0.0621 in Jilin in December. The difference between the highest and the lowest month of the same province can be as high as 0.225 in Xinjiang. The highest monthly average CF is in Xizang, which is about twice the lowest average in Chongqing. Yunnan has the minimum differences between extreme values. Other technologies follow similar pattern.

For the average hourly variation within a day, the CFs peak between 12PM and

15PM, as Chinese provinces all use China Standard Time but are actually cross wide longitude. The regional differences and temporal variability of solar resources show national coordination is needed to develop transmission corridors to transmit solar power out of the solar generation areas and coordinating the time of generation and demand. The integration and optimization of solar and other complimentary energy resources, such as solar and wind, solar and storage, solar and hydro, other flexible sources, and demand response/demand side management will be essential to deal with such temporal variation pattern.

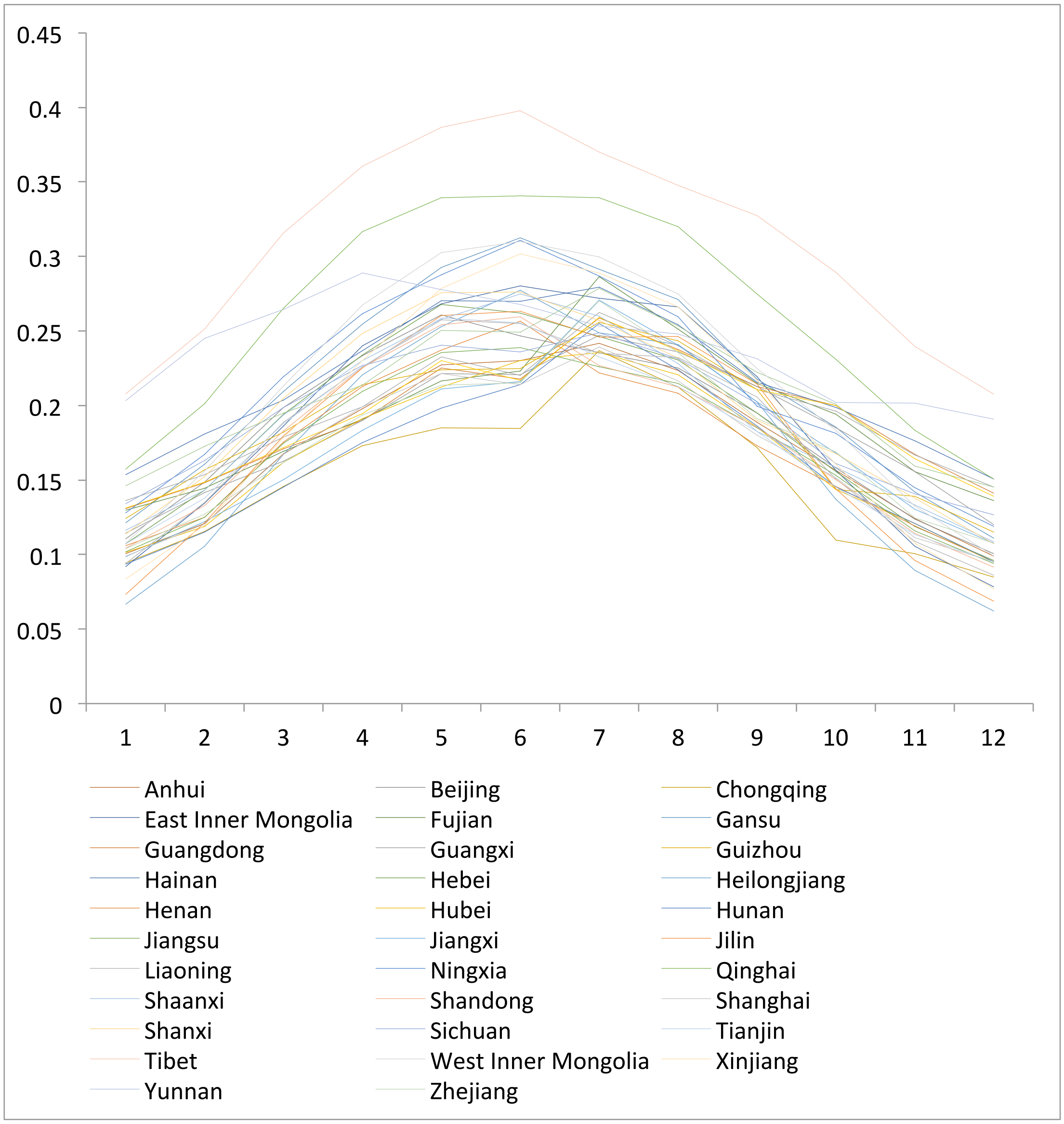


Figure 3-3 Monthly average central PV capacity factor 2001-2010

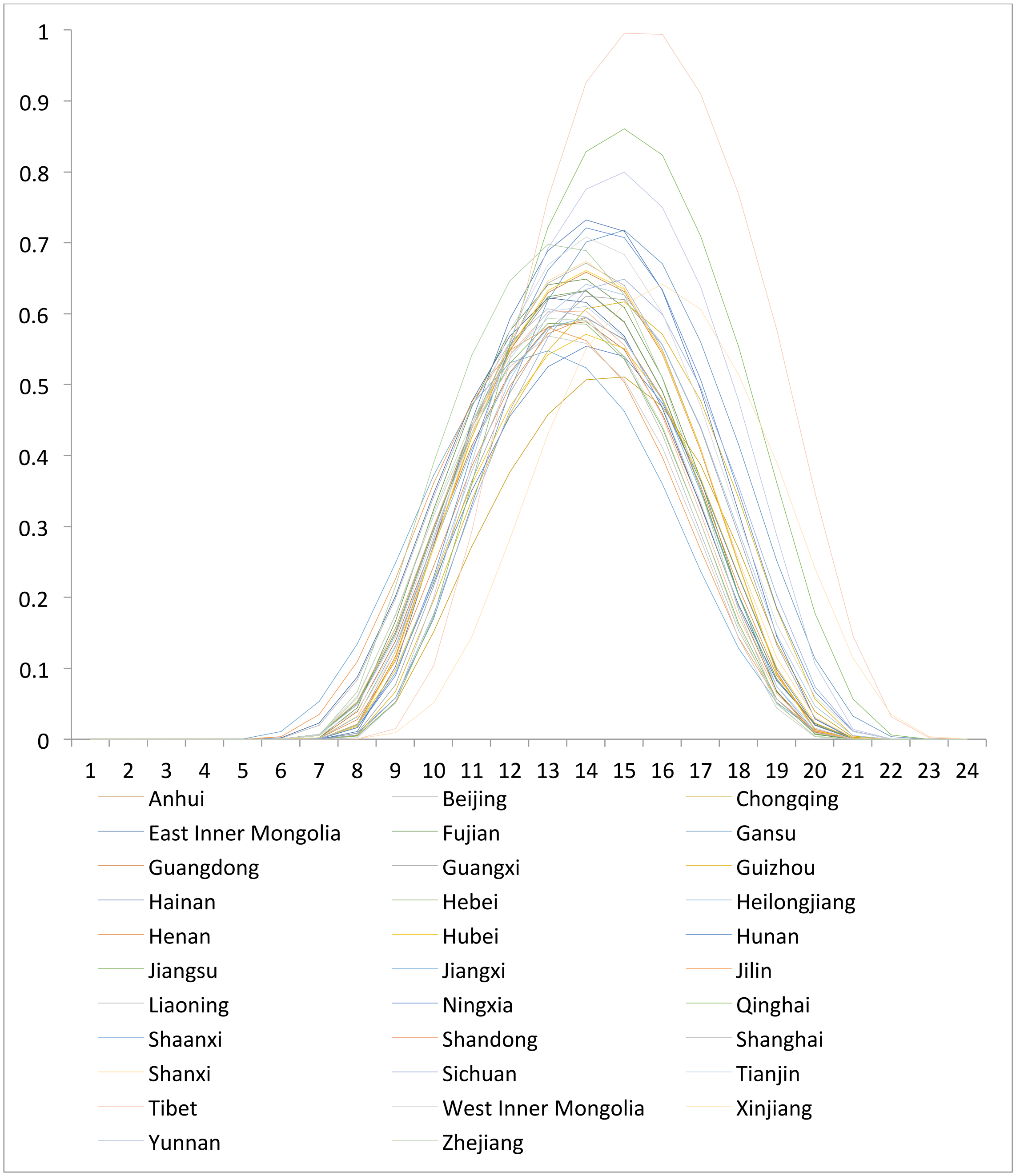


Figure 3-4 Hourly average central PV capacity factor 2001-2010

3.3.4 Potential contribution of solar generation

Similar to the wind assessment, this study also compared the provincial potential solar power output with projected provincial electricity demand of 2030 and showed the potential share of solar power in total electricity demand in each province. The study uses electricity demand of 2030 as it is the best available year with projected provincial electricity demand reported by the Electricity Supply and Demand Laboratory in the State Grid Energy Research Institute (Z. Hu, Tan, and Xu 2011). Many uncertain factors may impact the solar energy development and the total energy demand in each province, for example, economic development and industrial structure, urbanization, competition and integration from other sources, investments and costs, etc. The potential/demand ratio is therefore an indicative number to show the potential contribution of solar can possibly achieve.

Seen from Table 3-4, the potential/demand ratio at provincial level varies at great scale, from 0.03 of demand to more than 100 times of demand. In the lower case, West Inner Mongolia, Xinjiang, East Inner Mongolia, Gansu, Hainan, Jilin and Heilongjiang could each produce more than its demand. Inner Mongolia in the upper case could generate more than 100 times of the projected demand which makes it the heart for solar energy. Xizang and Qinghai have relatively high average CFs but unmatched output as most of the land at high elevation, greater than 3000 meters, are excluded in the assessment. Nationwide, annual potential solar output could reach 6900 TWh and 70100 TWh in the lower case and upper case, respectively. The potential output at national scale shows China has more than enough solar resource, and the real challenges are cost reduction, investment need, and system integration.

Table 3-4 Potential share of solar generation by province in 2030

Province	**Demand 2030 (TWh)**	**Lower case**		**Upper case**	
		Total output (TWh)	**Potential/ demand ratio**	**Total output (TWh)**	**Potential/ demand ratio**
Anhui	240	16	0.07	61	0.25
Beijing	133	15	0.11	50	0.37
Chongqing	171	7	0.04	25	0.15
East Inner Mongolia	272	790	2.90	6912	25.37
Fujian	309	35	0.11	480	1.56
Gansu	205	478	2.33	6936	33.82
Guangdong	815	158	0.19	1109	1.36
Guangxi	254	156	0.61	1147	4.51
Guizhou	218	41	0.19	554	2.54
Hainan	47	102	2.14	389	8.22
Hebei	677	97	0.14	806	1.19
Heilongjiang	154	220	1.44	435	2.83
Henan	614	22	0.04	188	0.31
Hubei	342	17	0.05	113	0.33
Hunan	299	8	0.03	30	0.10
Jiangsu	792	27	0.03	32	0.04
Jiangxi	165	52	0.31	412	2.49
Jilin	140	287	2.06	736	5.27
Liaoning	409	86	0.21	684	1.67
Ningxia	141	95	0.67	971	6.87

Qinghai	97	65	0.67	4083	42.14
Shaanxi	234	115	0.49	1854	7.94
Shandong	760	151	0.20	514	0.68
Shanghai	233	7	0.03	8	0.03
Shanxi	370	81	0.22	1196	3.23
Sichuan	367	14	0.04	206	0.56
Tianjin	137	9	0.06	16	0.12
Tibet (Xizang)	7	4	0.58	58	7.96
West Inner Mongolia	163	1547	9.46	17829	109.07
Xinjiang	244	2080	8.52	20856	85.44
Yunnan	239	108	0.45	1259	5.27
Zhejiang	597	25	0.04	198	0.33
Total/Average	9845	6900	0.70	70100	7.13

3.3.5 Sensitivity analysis and uncertainties

This chapter conducted sensitivity analysis on several key assumptions of the GIS model and land filter: the 160 W/m^2 GHI threshold, the 1 percent slope threshold, the 3000-meter elevation threshold. This chapter studied the relations between those factors and the potential capacity, and plotted them in Figure 3-5. The results in the upper case and lower case are quite similar as the change patterns of those factors are the same.

Those factors follow non-linear relations with the capacity potential. The capacity potential is most sensitive to the 160 W/m^2 GHI threshold. However, as 80% of the grids have a GHI larger than 160 W/m^2, the results have already included those available resources. The results are less sensitive to the 3000-meter elevation threshold. The 1% slope threshold has big impact on the final results. About 40% of China's total land cover is under 1% slope threshold. 3% slope threshold would increase to 60% of the total land cover.

In addition, there are many uncertainties that will impact the results of this chapter. The inter-annual variations in some sites are not trivial, and should be incorporated into long-term assessment. The land conversion factor of different technologies, the rooftop availability in the residential and commercial land use deserves deep investigation so to make more accurate estimates. China is still in the midst of fast urbanization, more rooftop space will be available as the cities expand. Technology advancement is an active area to observe, if it enables building solar plants in more severe conditions that are not appropriate for solar development traditionally, or if the efficiency improvement would change the CF simulation, the results of this analysis will need update in the future as technologies develop.

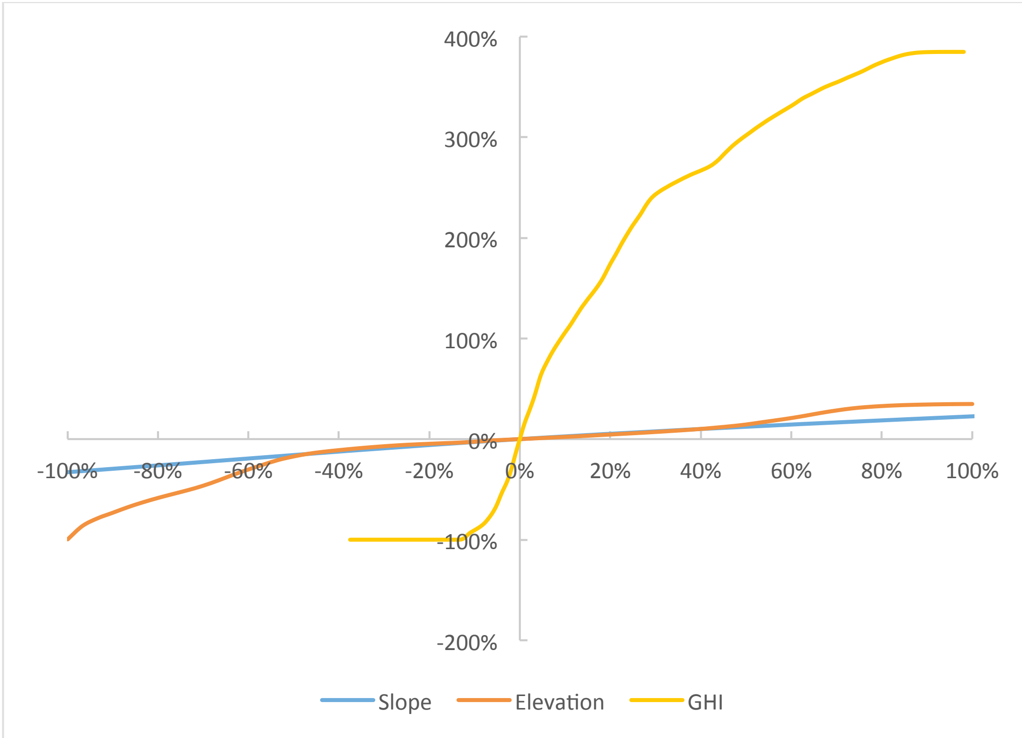


Figure 3-5 The sensitivity analysis of key assumptions to the potential capacity

3.4 Conclusion and discussion

China has released ambitious solar energy development goals. Knowing where, when and how much solar is available at provincial level can help the researchers and policy makers on solar development planning and integration. However, the existing literature does not provide the necessary spatial resolution or give sufficient attention on the spatial and temporal variation of solar availability.

In this chapter, combining GIS modeling and solar CF simulation with SAM model, this chapter utilized 10-year hourly solar irradiation data from 2001 to 2011 of 200 representative locations to study provincial solar resources potential, and to build provincial solar availability profiles. This chapter found that China could have a potential stationary solar capacity from 4700 GW to 39300 GW, distributed solar about 200 GW, and the annual solar output could reach 6900 TWh to 70100 TWh.

This chapter studied the diurnal and seasonal features of the solar availability at provincial level and found similar diurnal and seasonal variation patterns cross provinces. The peaking time lag with-in a day and the difference cross provinces offer opportunities for coordination. The diurnal and seasonal variability of solar and wind resources demand a larger, system-level analysis of China's energy options with more careful investigation of technical and economic availabilities and the role of inter-province transmissions.

Table 3-5 Average capacity factor, potential solar capacity and output by province

Province	Stationary Solar										Distributed Solar					
	Central PV					CSP					Residential PV			Commercial PV		
	Avg. CF	Lower Case		Upper Case		Avg. CF	Lower Case		Upper Case		Avg. CF	GW	TWh	Avg. CF	GW	TWh
		GW	TWh	GW	TWh		GW	TWh	GW	TWh						
Anhui	0.1734	8	12	34	52	0.1202	7	7	28	30	0.1290	4.5	5	0.1340	3.4	4
Beijing	0.1865	4	7	25	40	0.1855	4	6	21	34	0.1642	3.7	5	0.1711	2.7	4
Chongqing	0.1514	5	6	15	20	0.0805	4	3	13	9	0.1094	2.6	3	0.1138	2.0	2
East Inner Mongolia	0.1918	540	907	4111	6909	0.1996	450	786	3426	5990	0.1744	1.3	2	0.1816	1.0	2
Fujian	0.1931	32	55	280	473	0.1223	27	29	233	250	0.1306	3.2	4	0.1358	2.4	3
Gansu	0.2143	287	540	3692	6931	0.2253	240	473	3077	6073	0.1787	1.9	3	0.1864	1.4	2
Guangdong	0.1920	163	274	643	1081	0.1088	136	129	535	510	0.1308	13.9	16	0.1363	10.4	12
Guangxi	0.1841	199	320	707	1141	0.1037	166	150	590	536	0.1256	2.8	3	0.1310	2.1	2
Guizhou	0.1862	45	73	338	551	0.1169	37	38	282	288	0.1363	1.4	2	0.1419	1.0	1
Hainan	0.2160	91	172	205	388	0.1510	76	100	171	226	0.1452	0.7	1	0.1511	0.5	1
Hebei	0.1877	63	104	483	794	0.1850	53	85	402	652	0.1610	4.9	7	0.1677	3.6	5
Heilongjiang	0.1727	183	276	279	423	0.1562	152	208	233	319	0.1580	4.9	7	0.1639	3.7	5
Henan	0.1732	11	16	116	175	0.1241	9	10	96	105	0.1329	6.0	7	0.1380	4.5	5
Hubei	0.1682	10	15	70	104	0.1022	9	8	59	52	0.1195	5.1	5	0.1245	3.8	4
Hunan	0.1642	1	2	16	23	0.0942	1	1	13	11	0.1152	4.0	4	0.1197	3.0	3

Jiangsu	0.1730	7	11	8	12	0.1322	6	7	7	8	0.1341	9.8	12	0.1392	7.4	9
Jiangxi	0.1754	56	86	265	406	0.1128	47	46	220	218	0.1217	2.8	3	0.1266	2.1	2
Jilin	0.1784	252	393	465	727	0.1515	210	278	387	514	0.1564	3.7	5	0.1621	2.8	4
Liaoning	0.1814	59	94	420	667	0.1621	49	70	350	497	0.1559	6.7	9	0.1618	5.0	7
Ningxia	0.2140	58	108	516	968	0.2197	48	92	430	828	0.1786	1.0	2	0.1859	0.8	1
Qinghai	0.2603	30	67	1791	4082	0.2933	25	63	1492	3834	0.2157	0.3	1	0.2261	0.3	1
Shaanxi	0.1908	91	153	1106	1849	0.1636	76	109	922	1321	0.1497	2.3	3	0.1564	1.7	2
Shandong	0.1784	113	177	313	490	0.1540	94	127	261	352	0.1456	10.7	14	0.1511	8.0	11
Shanghai	0.1682	0.6	0.9	1.1	1.6	0.1251	0.5	0.6	0.9	1.0	0.1308	3.0	3	0.1356	2.2	3
Shanxi	0.1970	51	88	689	1190	0.1998	43	74	574	1006	0.1663	2.6	4	0.1733	1.9	3
Sichuan	0.1924	3	6	116	195	0.1358	3	3	97	115	0.1383	4.9	6	0.1447	3.7	5
Tianjin	0.1797	3	5	7	11	0.1672	3	4	6	8	0.1513	2.1	3	0.1577	1.5	2
Tibet (Xizang)	0.3087	1	3	21	57	0.3689	1	3	18	57	0.2379	0.3	1	0.2495	0.2	0
West Inner Mongolia	0.2144	858	1611	9488	17824	0.2463	715	1542	7907	17058	0.1901	1.8	3	0.1980	1.4	2
Xinjiang	0.1928	1363	2302	12343	20850	0.2085	1136	2074	10286	18788	0.1605	2.5	4	0.1674	1.9	3
Yunnan	0.2394	67	140	598	1253	0.2094	56	102	498	913	0.1733	2.3	3	0.1813	1.7	3
Zhejiang	0.1764	13	21	120	185	0.1238	11	12	100	108	0.1264	6.4	7	0.1314	4.8	6
Average/Total	0.1940	4700	8000	39300	69900	0.1932	3900	6600	32700	60700	0.1427	120	150	0.1522	90	120

Note: Stationary solar, central PV and CSP, compete land use, therefore only one type of technology is built at one time. Residential PV and commercial PV are supplemental in roof space.

4 Prospects for decarbonization

4.1 Introduction

In this chapter, I use the SWITCH model to model the prospects of decarbonizing China's power sector. The SWITCH model is a mixed-integer linear program whose objective function is to minimize the cost of producing and delivering electricity through the construction or retirement of various power generation, storage, and transmission options between present day and future target dates – to 2050 – according to projected demand. The model uses a combination of existing and new grid assets. Optimization is subject to reliability, operational and resource availability constraints, as well as both existing and possible future climate policies (Fripp 2012; Nelson et al. 2012). The SWITCH model parameterizes the entire power system as an optimization problem, permitting studies of the most cost-effective long-term investment and operational decisions across Western North America (Fripp 2012; Mileva et al. 2013; Nelson et al. 2012).

The overwhelming dominance of coal in China today means that models based simply on aggregate resources of fossil fuels, hydropower, or renewable resources are not sufficient to examine how operationally and financially a transition to low-carbon future would be managed. This paper uses the SWITCH model to combine high-spatial and temporal fidelity with detailed information on both renewable energy resources as well as on the price and performance of specific energy technologies necessary. This combination is needed to explore the cost, reliability and impacts of specific policy choices that are necessary for China to meet future energy and environmental targets.

4.2 Scenario description

This chapter includes four major scenarios: a Business-as-Usual (BAU) Scenario for which no carbon constraints are applied, a Business-as-Usual with Carbon Cap Scenario which differs from the BAU Scenario only by the inclusion of carbon constraints, a Low Cost Renewables Scenario, and an IPCC Target Scenario (see Table 4-1).

The Business-as-Usual Scenario and Business-as-Usual with Carbon Cap Scenario ('BAU' and 'BAU with Carbon Cap' hereafter) assume the current evolution of technology costs and takes as exogenous the availability and costs of fossil fuel, hydropower, and renewable energy assets. 'BAU' assumes no carbon constraints. 'BAU with Carbon Cap' reflects continuous existing policy that China will achieve its 2020 carbon intensity targets and 2030 peak carbon commitment.

In the Low Cost Renewables Scenario ('Low Cost Renewables'), this chapter models aggressive levels of innovation and cost declines in wind and solar technologies. This scenario provides particular insight into in the impacts of recent significant investments in ‘cleantech’ but with few examples of successful integrated national climate strategies. This is an aggressive scale-up of a number of technology specific efforts, such as the U.S. SunShot Initiative (Mileva et al. 2013) and the U.S. national roadmap for wind power. This scenario is consistent with the state-supported growth of both the solar and wind manufacturing and deployment in China (NDRC 2013). Specifically, this study assumes that the overnight cost of wind and solar technologies will decrease to half of their cost in 2010 by 2020, then wind cost stays at the 2020 level till 2050 (Table 4-2 and Table 4-3); solar cost continues decreasing to the level given by the SunShot Initiative by 2020 (DOE 2012), then maintains the 2020 level until 2050. Further, this study assumes the cost for storage is consistent with the projection by U.S. ARPA-E program (Gur, Sawyer, and Prasher 2012). No carbon constraints are applied in this scenario.

In the IPCC Target Scenario (‘IPCC Target’), the study restricts overall greenhouse gas emissions from a 2030 peak to a level 80 percent below the 1990 level baseline, as proposed in the 2° scenario recommended by the Intergovernmental Panel on Climate Change (IPCC) (IPCC 2007).

Table 4-1 Model scenario description

	Carbon constraints
Business-as-usual Scenario (‘BAU’)	2010 base, no carbon constraints
Business-as-usual with Carbon Cap Scenario (‘BAU with Carbon Cap’)	2020 carbon intensity target and 2030 peak emission commitment
Low Cost Renewables Scenario (‘Low Cost Renewables’)	2010 base, aggressive wind and solar learning curve, no carbon constraints
IPCC Target Scenario (‘IPCC Target’)	2020 carbon intensity target, 2030 peak emission, and 2050 80% carbon reduction on 1990 level

China has existing policy targets in place to reach 15% of primary energy from non-fossil sources by 2020 and newly updated to 20% by 2030 (100 GW for solar and 200 GW for wind energy as proposed in the Energy Development Strategy Action Plan 2014-2020) (NEA 2012a; NEA 2012b; White House 2014; State Council 2014). Further, China has targets of 40 and 45% reductions in carbon intensity by 2020 on 2005 level and the carbon emission is announced to peak by 2030. Today China is well on track to achieve its short-term energy targets with more wind and solar capacity installed each year than what would be needed to achieve those targets (Table SI-S2). However, long-term carbon mitigation and technology pathways are more uncertain.

Table 4-2 Wind cost assumptions in the three scenarios

Technology	Period	Overnight Cost ($/W)	
		BAU/BAU with Carbon Cap/IPCC Target	Low Cost Renewables
Onshore Wind	2010	1.2	
	2020	1.15	0.6
	2030	1.1	0.6
	2050	1	0.6
Offshore Wind	2010	3	
	2020	2.25	1.5
	2030	2.15	1.5
	2050	2	1.5

Source: Li, Junfeng, Fengbo Cai, Wenqian Tang, et al. China Wind Power Outlook 2011. Beijing: China Environment Press, 2011.

Table 4-3 Solar cost assumptions in the three scenarios

Technology	Period	Overnight Cost ($/W)	
		BAU/BAU with Carbon Cap/IPCC Target	Low Cost Renewables
Central PV	2010	2.2	
	2020	1.2	1
	2030	1.2	1
	2050	1.2	1
Commercial PV	2010	2.5	
	2020	1.5	1.25
	2030	1.5	1.25
	2050	1.5	1.25
Residential PV	2010	2.9	
	2020	2.5	1.5
	2030	2.3	1.5
	2050	2.1	1.5
CSP without Storage	2010	5	
	2020	4.5	2.5
	2030	4	2.5
	2050	3.5	2.5
CSP with Storage	2010	6.5	
	2020	4.8	3.07
	2030	4	3.07
	2050	3.6	3.07

Source: DOE. *SunShot Vision Study*. Washington D.C.: Department of Energy, 2012.

4.3 Model results

Starting from the current energy supply mix, the existing transmission network, and current energy prices, with SWITCH this study finds that a 30 USD/tCO_2 carbon price is needed to achieve the 45% carbon intensity reduction target in 2020 and a 40 USD/tCO_2 carbon price for the 2030 peak commitment. In addition to an aggressive clean energy mandate, the study finds that a carbon price will boost the installation of wind and solar, and a transition from planned coal facilities to nuclear and natural gas to meet the carbon intensity goal by 2020. This carbon price is not as much of a departure from current policy as some may suspect. China has already launched multiple cap and trade pilot programs in Beijing, Shanghai, Tianjin, Guangdong, Shenzhen, Wuhan and Chongqing (Lo 2012; NDRC 2011b), where the price range varies from RMB 20-130 (USD 3-20). Extending this program to a nationwide system is, in fact, the stated national cap and trade program is set up as early as 2017, 30 USD/tCO_2 by 2020 and 40 USD/tCO_2 are realistic prices that are in shaping.

This chapter finds that China's 2020 energy intensity targets and continuous commitment to peak its carbon emission by 2030 as reflected in the power sector has big impact on the carbon emission and technology choice. A 40-45% carbon intensity reduction compared to 2005 level translates into maintaining the total carbon emission between 4.5 and 4.9 (Bt), whereas under 'BAU' path emissions in 2020 are forecast to reach 8.1 Bt 2020. This case is essentially a forecast to grow the Chinese economy at 6% year with the carbon intensity frozen at the 2005 level of 2.57 kgCO_2/2005, see (SI-S5) (Liao, Ji, and Ma 2013). The 2030 commitment in 'BAU with Carbon Cap' is a real diversion from the 'BAU' scenario, which means China needs to curb its emission in power sector at 1.5 BtCO_2 compared to 'BAU' scenario, and 0.5 BtCO_2 even with low cost renewables, by 2030 (see Fig. 1).

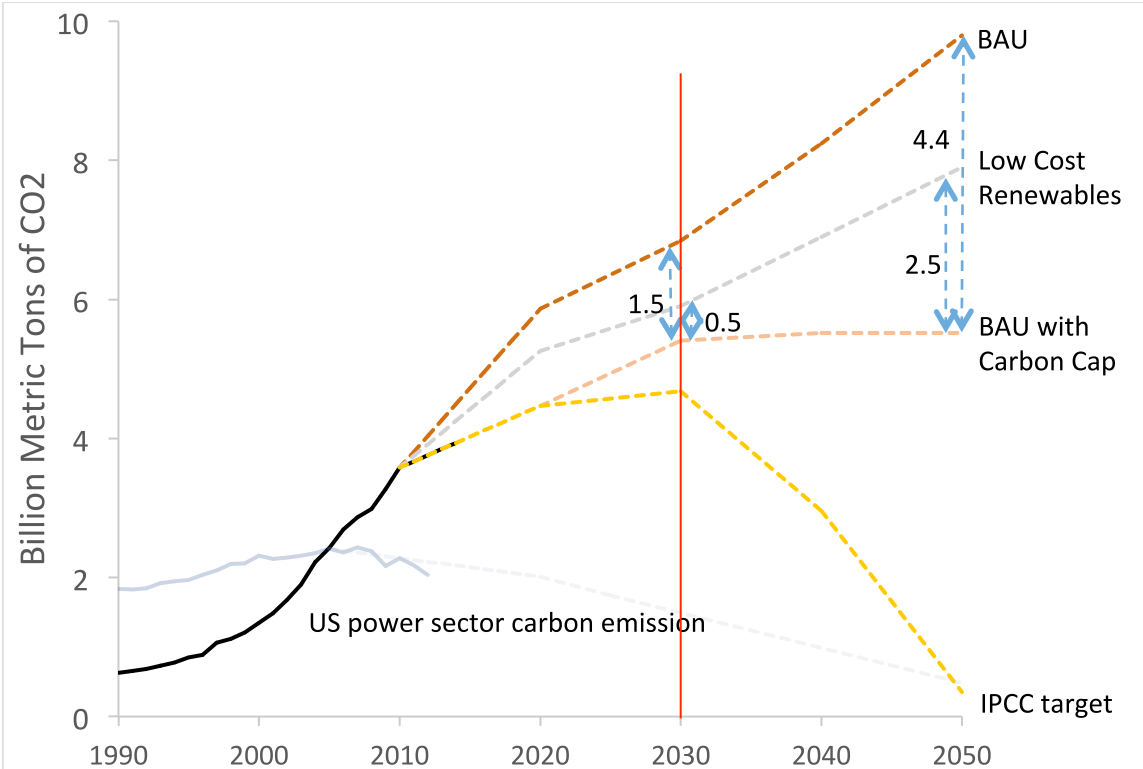


Figure 4-1 Carbon emission trajectory for the Chinese power sector under the four major scenarios

What this chapter observes from comparing the 'BAU' and 'Low Cost Renewables' scenarios, in particular, is that an aggressive renewables technology policy to then driven by a larger manufacturing base and lower prices, as we have seen in recent years, is important but is not sufficient to make more than a small reduction in the rate of deploying new coal-fired power plants, and thus the growth in GHG emissions. The 'Low Cost Renewables' scenario shows that an aggressive learning curve for renewables would replace about 300 GW of coal - compared to the 'BAU' scenario. In addition this case deploys 40 GW more gas capacity between today and 2050 than in 'BAU' scenario because of its flexibility to ramping up and down to integrate the variable resources until 2050. Despite this, coal and CCS coal would still dominate the energy mix by 2050, comprising 70% of total generation under the 'BAU' scenario and still providing 62% of total electricity in the 'Low Cost Renewables' scenario in 2050.

An 80% carbon emission reduction by 2050 is, however, achievable by a combination of solar, wind, storage, nuclear and CCS at high cost if no major technological innovation happens till then. In the medium and long terms, nuclear becomes competitive as its high capacity factor provides stable baseload with no or little carbon emission, therefore will be installed to the maximum capacity of about 300GW that China can locate. 80% of the 1000 GW coal capacity need to install CCS facility. The rest will be filled by wind and solar capacities, which together will supply 60% of total demand in 2050. Electricity costs will be boosted from 64.3 USD/MWh in the 'BAU' scenario to 87.8 USD/MWh in the 'IPCC Target' scenario, a 37 percent increase of power cost, driven by large scale installation of wind, solar, CCS and storage.

Excessive wind and solar generation will present challenges to the operation of the grid in 2050. With such a large expansion in variable energy resources, mainly wind and solar, and a large-scale deployment of storage assets to smooth the output, and increasing nuclear energy as baseload, the challenge of operating the country's power system is significant. The system dispatch shows seasonal pattern of renewables electricity generation. Wind has better availability in winter and spring while hydro is more productive during summer and fall. The ramp up and down of solar energy during daytime creates huge needs for storage, even though solar energy matches peak demand fairly well. The role of natural gas is limited given its comparative high price in simulated scenarios. In the model simulation, flexible load is met by a combination of wind, solar, natural gas, hydro and storage.

As of 2013, the global installed capacity of grid energy storage is 130 GW, and China accounts for 17% of this amount with about 22 GW capacity (Akhil et al. 2013). The results show that, by 2050, China will need about 600 GW of energy storage maximum to integrate variable wind and solar resources in the 'IPCC Target' scenario, which is double of the 310 GW of estimated additional grid-connected electricity storage capacity needed in the United States, Europe, China and India, based on the results of IEA Energy Technology Perspectives 2014 (ETP 2014) 2°C Scenario (2DS) vision for energy storage (IEA 2014). Considering that China plans to have a 70 GW of pumped hydro storage online by 2020, on the path to explore its 200 GW pumped hydro potential, additional storage systems will have to come from other sources. This requires the development of breakthrough storage technologies that have not been implemented on a large scale yet.

Decarbonizing China's power sector would also require new transmissions to connect energy supply regions and demand centers. The optimal electricity that makes China meet its national target by 2020 and the 'IPCC Target' by 2050 shows that coal will largely, but not completely, be phased out in most provinces by 2050. CCS coal plants are built in provinces where coal prices are comparatively cheap, notably in Xinjiang, Inner Mongolia, Shaanxi, and Jilin. Nuclear capacity expands significantly on the country's eastern coast. Many provinces present significant potential for both solar and wind. Large transmission capacity is built to send power from Xinjiang, Qinghai, Inner Mongolia, Shaanxi, Shanxi to Beijing, Tianjin, Shanghai, Zhejiang, Guangdong, and other coastal demand centers. Transmission capacity makes coal in Xinjiang competitively available, even though the province presents large potential for wind and solar. Xizang (Tibet) has assets for wind and solar operation, transmission infrastructure is not built in this model because of its remote location, unless related costs decrease significantly over the study period.

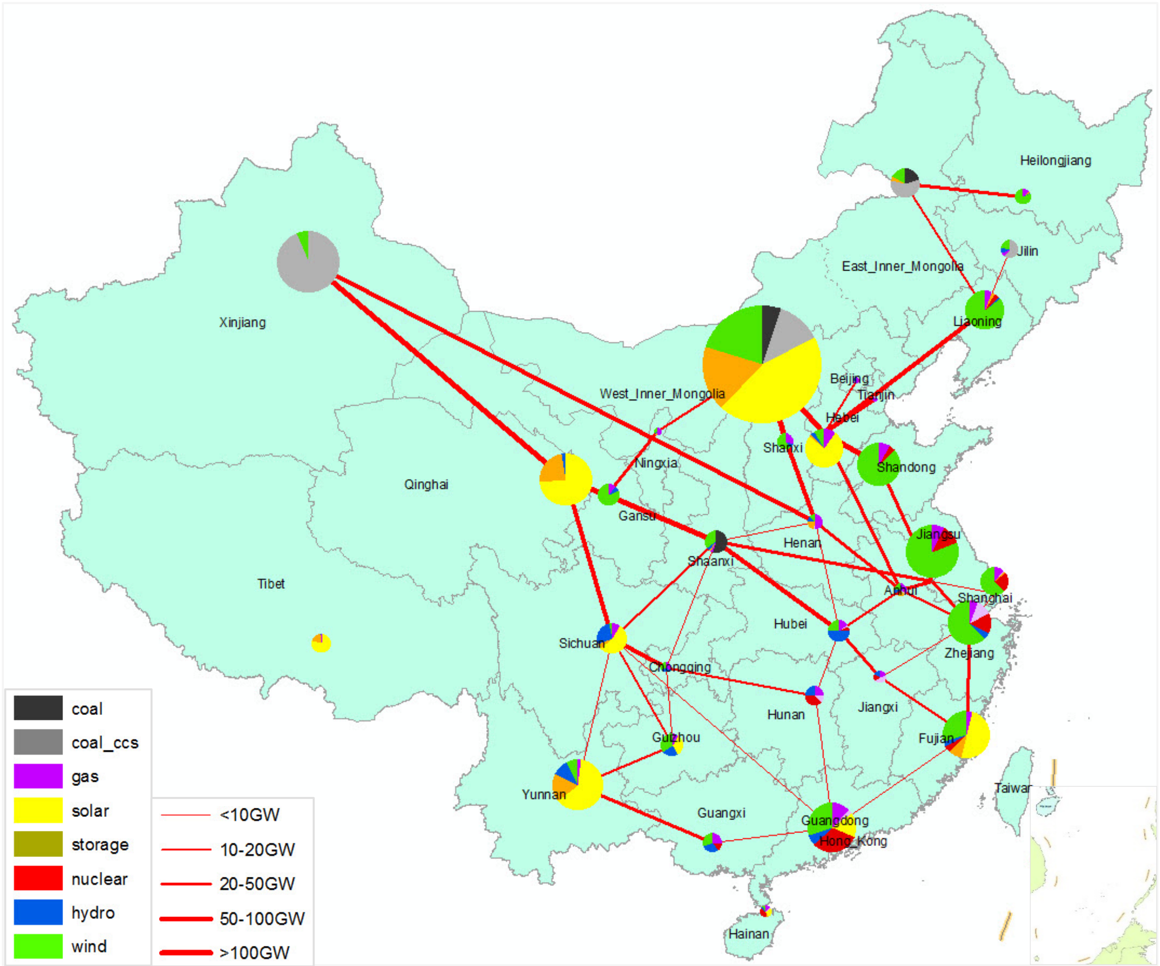


Figure 4-2 The infrastructure, generation capacity and transmission, needed to achieve 80% carbon reduction by 2050

Note: All lines are new transmission expansion by 2050. Inner Mongolia emerges as a major center of clean energy generation due to a mixture of energy resources and location.

National policy actions consistent with the 'IPCC Target' scenario would have a large positive impact on fuel cost saving, air pollution reduction and other co-benefits. Increased energy costs resulting from this strategy would be offset by the decrease in costs related to environmental pollution, public health and climate benefits. To capture the benefits quantitatively in concept, the study uses the results from emerging literature on the "external cost of coal", which include the life cycle environmental cost of coal value chain (Epstein et al. 2011; Mao, Sheng, and Yang 2008; CAEP 2014). The external cost of coal in China is reported range from 204.76 RMB/t (~30 USD/t) to 260 RMB/t (~40 USD/t) (CAEP 2014; Mao, Sheng, and Yang 2008; Teng 2014), the total benefits from avoided external cost adds to 540 to 1,000 billion USD. The extra cost of the 'IPCC Target' scenario is 3,310 billion USD annually in 2050 compared to the 'BAU' scenario. The benefits of a decarbonized power sector would offset 16% to 30% of the increased power cost in 2050.

4.4 Key sensitivities analysis

China's power sector is evolving and the pathway of transiting to low carbon power generation will be influenced by many factors, for example, the cost of fuel, the investment cost of different technologies and their competitive advantages, and the transmission cost. The regulation over air pollutants, adoption of carbon price and other policy will also impact the technological investment and cause the uncertainties over disruptive technologies, such as the breakthrough in next generation of nuclear technology, the improvement of wind and solar technology, or carbon capture, utilization, and storage, and the high voltage/super conductive lines, etc.

This study examined three key parameters: the cost of carbon, the limit of nuclear that China can build, and the cost of carbon capture and storage. In the carbon costs without any carbon cap constraints, a higher carbon price will drive more capacity in nuclear, wind, solar, and will make CCS available. A 50 USD/tonCO_2 will drive the nuclear capacity to its up limit at 300 GW in the model. A 100 USD/tonCO_2 will replace most of coal capacity with CCS.

Table 4-4 The carbon price sensitivity assumptions

Carbon Price	2020	2030	2050
Low	5	10	20
Medium	10	20	50
High	20	50	100

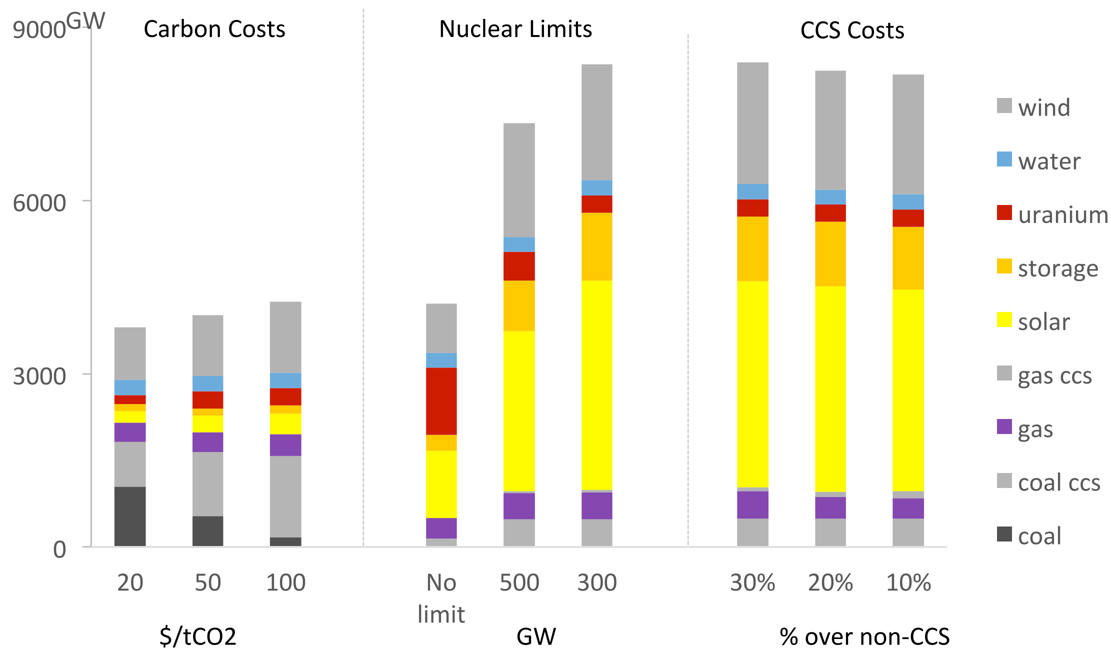


Figure 4-3 The impact of carbon costs, nuclear limits, and CCS costs to the capacity mix in 2050

In the IPCC Target scenario, the impact of nuclear is significant, if no nuclear limit is applied, 1,155 GW of nuclear capacity will be online by 2050 to meet the carbon cap given nuclear can provide stable base load. If nuclear is limited to 500 GW or 300 GW as reported by the available sites to build nuclear in China, then wind, solar and storage have to meet the gap to meet demand. In the IPCC Target scenario, decrease of CCS would not make much difference on the installation of CCS capacity by 2050, mainly because renewables will have already been competitive in achieving carbon mitigation by then.

4.5 Conclusion and discussion

By optimizing capacity expansion and hourly generation dispatch simultaneously, SWITCH-China is uniquely suited to explore both the value of and synergies among various power system technology options, providing policymakers and industry leaders with important information about the optimal development of the electricity grid. SWITCH helps identify the least-expensive response to achieving national energy and climate targets: it demonstrates that a carbon price at ~30 USD/tCO_2 by 2020 is needed to meet the 2020 carbon intensity target and ~40 USD/tCO_2 by 2030 for the 2030 carbon peak announcement. To reach an 80% reduction in CO_2 emissions by 2050, as proposed by the IPCC, the resulting energy mix in 2050 would include nuclear (14%), wind (23%), solar (27%), hydro (6%), gas (1%), coal (3%), CCS coal (26%). This will result in a 37% increase in total power cost over 'BAU' scenario.

There are a few uncertainties about the setting of the model, and a better understanding of these uncertainties will help further improve the model. The current cited demand projection is driven by GDP growth and energy efficient technologies, which both have potential uncertainties that can impact the electricity demand. Fuel price fluctuation may change the technology choice and impact the competitive advantage of different technologies over time. The gas price cut caused by the shale gas boom potentially has large impact beyond in the U.S. The current investment cost assumptions will face uncertainties in the learning curve of new technologies and do not include external costs of conventional technologies. Other policy developments, which are not directly related to economics, such as nuclear safety and security, public perception and acceptance of nuclear and hydro projects, may add more uncertainty to the applications of available technologies.

China's power sector is in the midst of fast development, and today's investment decisions will have a large impact on the country's ability to achieve its environmental and carbon mitigation goals. Especially, today's investment decisions will have lasting impacts due to the lock-in effects of technology deployment. SWITCH is the "facilitator" which helps understand how technologies, policies, and investment decisions can be coupled, and enables a strategic thinking on the future of China's transition to a low carbon power system. Concerted action is needed to develop such a system, including introducing a meaningful carbon price, coordinating the investment decisions, and building the necessary infrastructure for moving energy around.

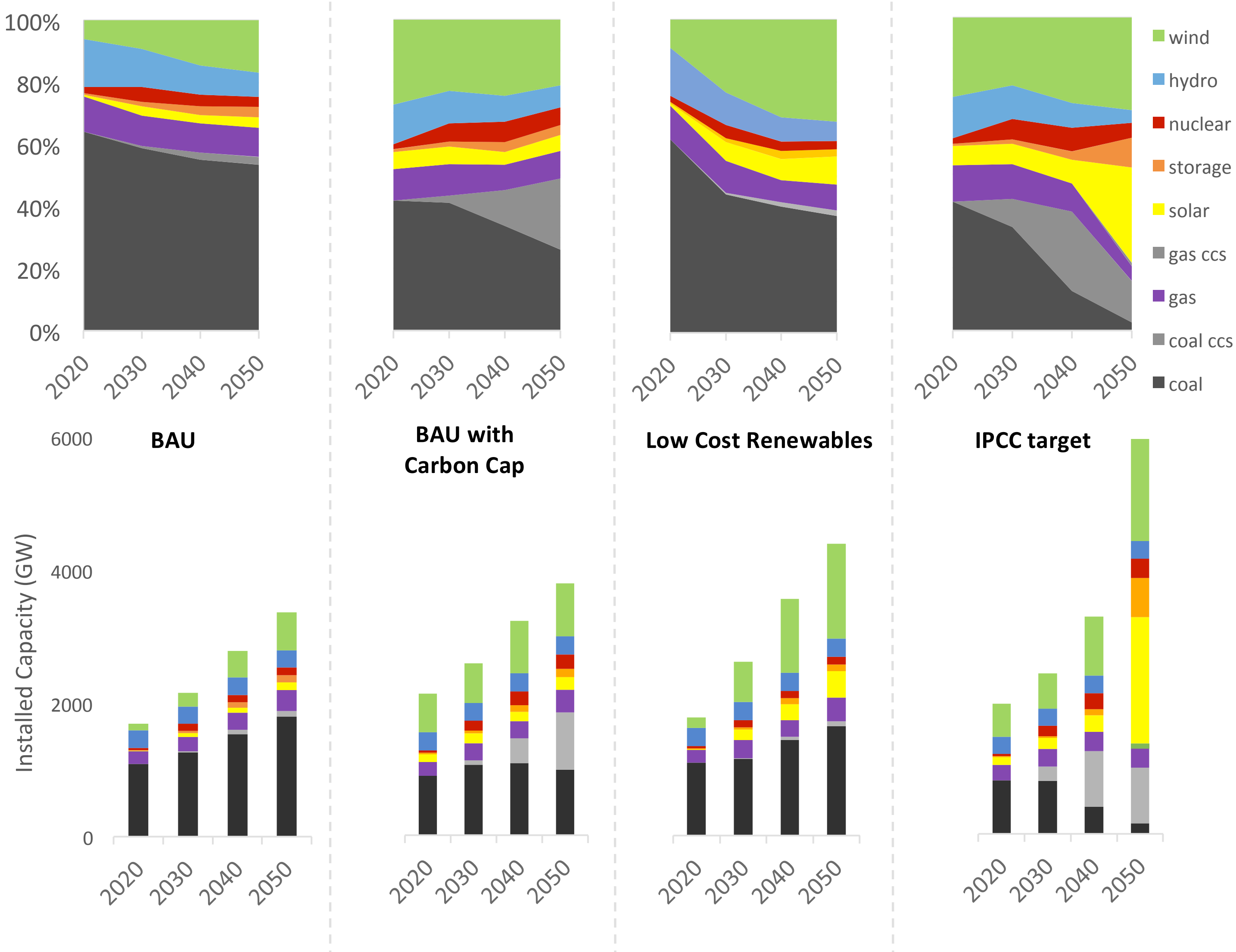


Figure 4-4 Installed power generation capacity mix for the four scenarios

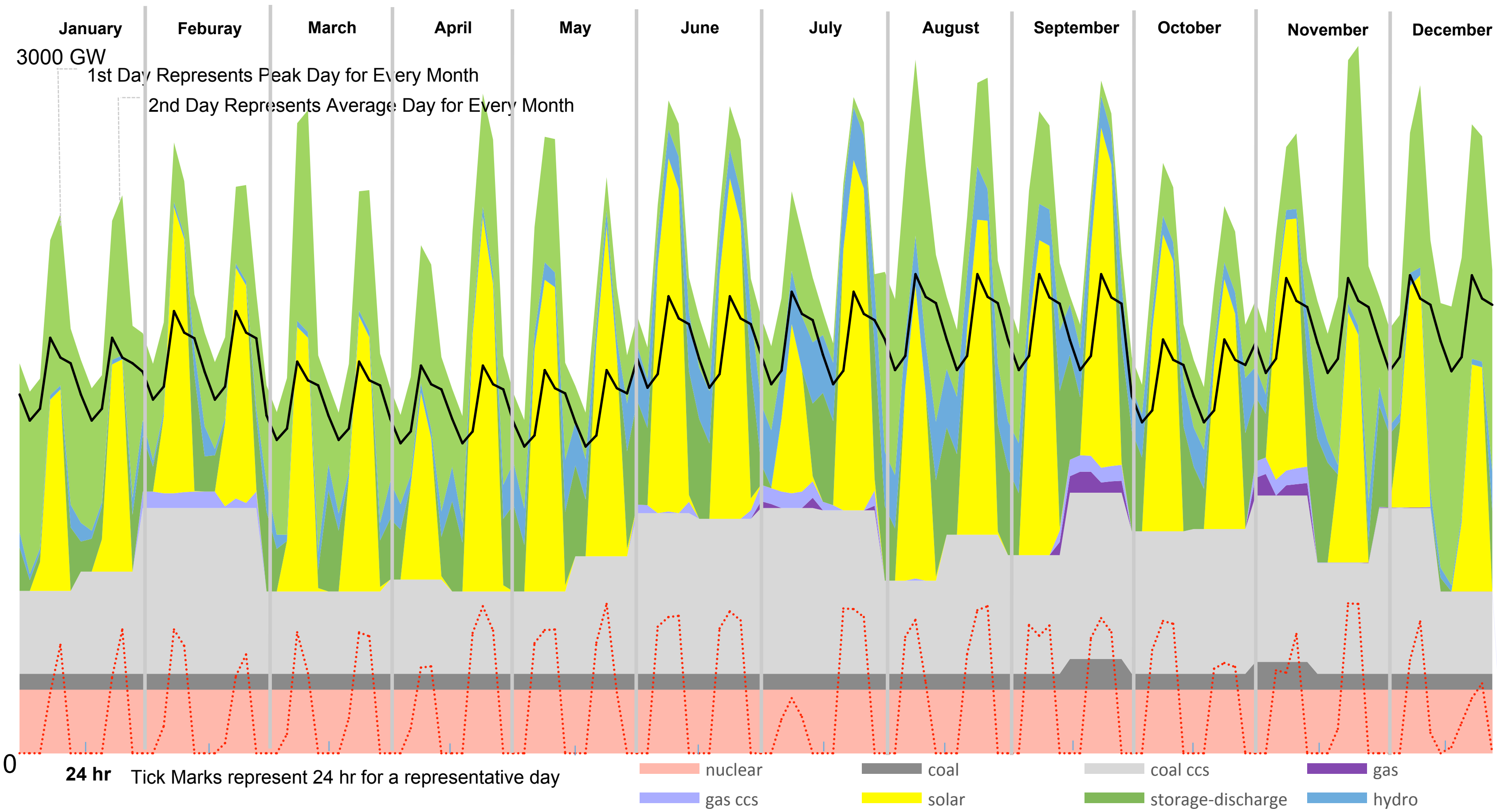


Figure 4-5 2050 dispatch schedule for 80% Carbon Cap (C) Scenario.

Note: An 80% carbon reduction is achievable in China's power system by a combination of wind, solar, storage, CCS and nuclear. This system will require vast capacity of storage to provide flexibility of the power operation. Storage charges on average 8% of the generation power and 26% maximum on a storage incentive day when solar generation is peaked, and storage discharges provide on average 9% of system load, and 30% maximum on a storage incentive day during night time when thousand GW scale solar is offline.

5 Policy implications

5.1 Renewable integration

Non-fossil power, including hydro, wind, solar, bio, and geothermal, contributed 25.6 percent of China's total power generation in 2014. This is the first time that non-fossil power actually exceeded one quarter of China's power supply, and wind generation for the first time surpassed that from nuclear (CEC 2015). Wind and solar contributed 156.3 TWh and 23.1 TWh, 2.82% and 0.42% of total generation, respectively. Wind and solar together only contributed 3.24% of total generation, however, even this small share has presented challenges for the grid integration. It is reported that about 12.3 TWh wind electricity was lost in the curtailment in 2011, with an average curtailment rate of about 16%, resulting to a loss of 6.6 billion RMB (~1 billion USD)(SERC 2012d).

Given China's ambitious renewable targets to have 200 GW wind and 100 GW solar by 2020, the challenges along renewable integration is emerging. Renewable integration is a complicated task, however, it can be facilitated by better prediction of variability and well planned strategies to reduce it, changes in the operation of power plants, reserves, transmission systems, and storage; improved planning of renewable capacity expansion planning, implementation of new regulatory paradigms, rate structures, and standards (Apt and Jaramillo 2014).

As wind and solar resources vary both temporally and spatially, resources assessment at high temporal and spatial resolution is fundamental to the integration strategy. This research studies China's wind and solar resources at provincial level with hourly data by applying the GIS modeling and CF simulation, the spatial feature of China's wind and solar resources show that China has rich wind and solar resources, however, both onshore wind and solar concentrate in western and northern China which is far away from the demand centers along the coast (Figure 5-1). This means transmission is needed to bring the renewable energy from the resource center to the load centers, the optimized capacity for such expansion is discussed in Chapter 4, depending on the targets and scenarios.

While the spatial assessment shows wind and solar have similar spatial pattern, the temporal assessment show wind and solar complement each other quite well in both at the provincial level and nationally (Figure 5-2). Wind has better availability in spring and winter while solar has better availability at summer, this seasonal complementarity show it make sense to develop the infrastructure and policy to facilitate the complementary integration of solar and wind. The technical details require more research, but from resources availability, the wind-solar complementary integration is one direction to promote the integration of variable renewable resources.

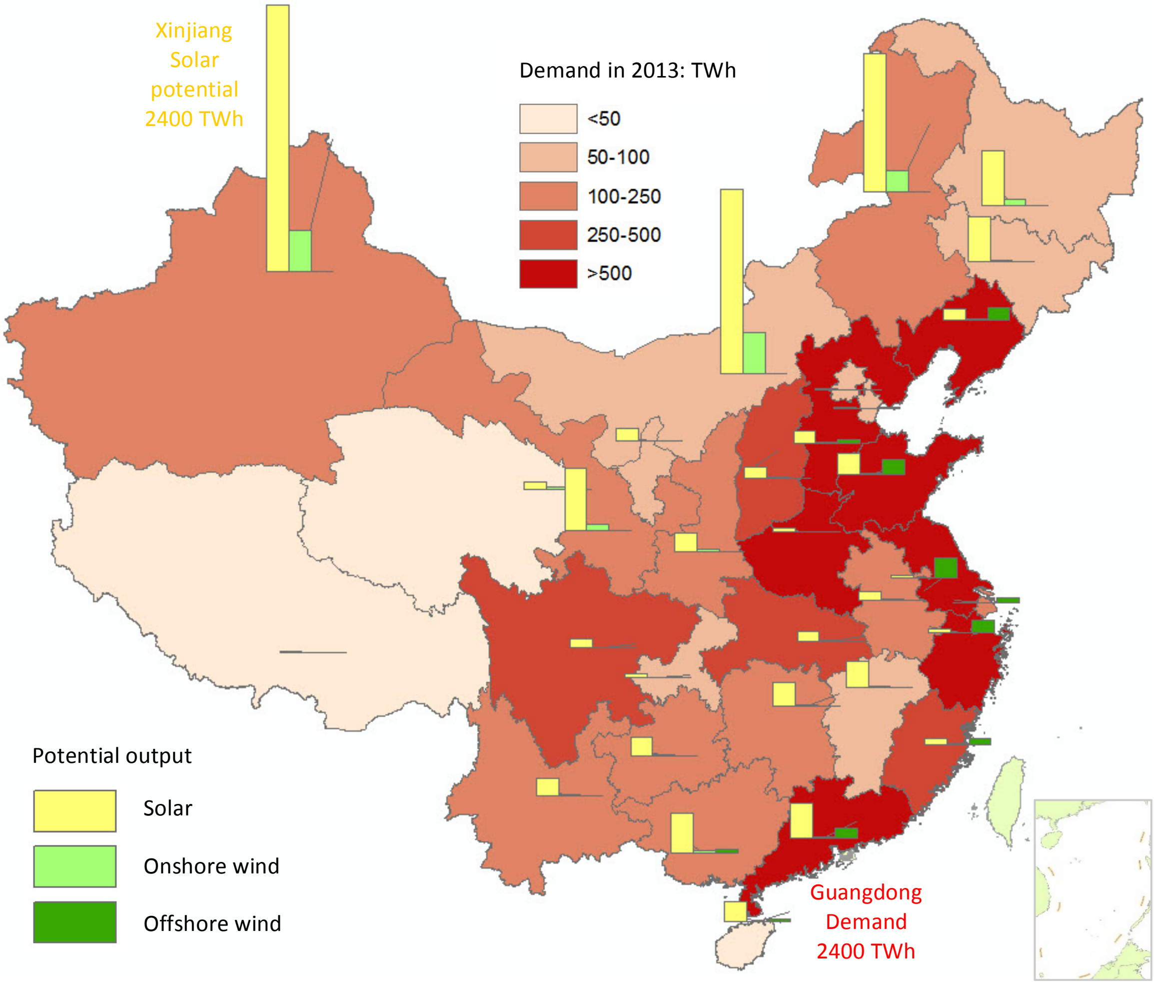


Figure 5-1 Wind and solar resources assessment results

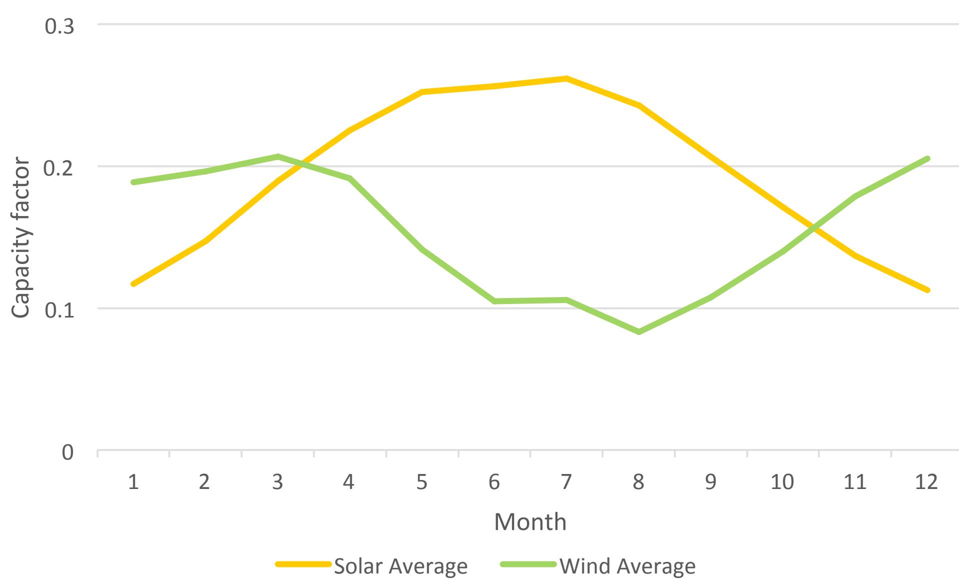


Figure 5-2 Average wind and solar availability complimentary on seasonal base

In addition, the SWITCH-China model results show that better planning and coordination of investment strategy, including the capacity expansion, transmission connection, storage placement, would facilitate most cost effective approaches to bring variable renewable resources online. SWITCH-China model, along with other similar models, is a useful tool to discuss the planning strategy and variable renewable resources integration under different technology, cost and policy scenarios.

5.2 Co-benefits of China's clean power transition

5.2.1 True cost of coal

The external costs, mainly the costs associated with the environmental and health impacts of burning coal are currently not integrated in the market price of coal. To evaluate the impact of a green strategy resulting from the operation of coal plants to generate electricity in 2050, assuming an IPCC Target scenario as modeled in SWITCH, this study uses the findings from the emerging literature on the external cost of coal to quantify the benefits. China's power sector currently heavily relies on coal, accounting for 79.3 percent of total power generation in 2013 (NBS 2014). Coal consumption is also a big source of wide spread air pollution in Chinese cities, 60 percent on average of the air pollutant PM2.5 in Chinese cities is contributed to coal combustion (Coal Cap Research Team 2014).

The research on "true cost of coal" or "external cost of coal" is intended to include the costs along the life cycle of coal – extraction, transport, processing, and consumption – that has impact on the environment and human health but is not reflected in the coal prices. Epstein et al (2011) estimated the life cycle effects of coal and showed the waste stream generated costing the U.S. public 175.2 billion USD to 523.3 billion USD annually, ranging from 9.42 ¢/kWh to 26.89 ¢/kWh on per kWh base (Epstein et al. 2011). Mao et al (2008) analyzed the value chain cost of coal in China using 2005 data and concluded a 211.47 RMB/ton (~30 USD/ton) external cost, the result was reaffirmed by a recent estimation at 204.76 RMB/ton (~30 USD/ton) by the Coal Cap Policy Research Group (Coal Cap Research Team 2014; Mao, Sheng, and Yang 2008). Teng et al (2014) uses 2012 data and shows the external cost of coal is estimated at 260 RMB/ton (~40 USD/ton) (Teng 2014). However, the carbon cost of coal is not included in those estimations.

5.2.2 Carbon prices

China's carbon market started with the clean development mechanism (CDM) which brings carbon finance to China while filling up the carbon mitigation targets in the developed countries as agreed in the Kyoto Protocol (He and Morse 2013). CDM provides carbon prices varies between highest 40 USD/tCO_2 and lower level at just about

1 USD /tCO_2. The carbon finance from CDM has facilitated the development of renewable energy in China. Up to 83.7GW (out of 114.2GW) of wind capacity and 3.32 GW (out of 28GW) solar capacity has been registered in the CDM pipeline to receive CDM credit, by the end of 2014[3]. CDM, in additional to the feed-in-tariff, has been an effective driving force to China's renewable energy development.

The successful experience has incentivized China to establish its own domestic carbon market so to harvest the benefits of market oriented mechanism to improve its unsatisfactory environmental regulation (He 2014). Since 2011, China has started the cap and trade pilots in Beijing, Tianjin, Shanghai, Chongqing, Hubei, Guandong provinces and Shenzhen City to accumulate experiences of market-oriented approaches to achieve China's energy saving and emission mitigation goals (NDRC 2011b). China is planning to have a national carbon market as early as 2016.

Table 5-1 China's cap and trade pilots

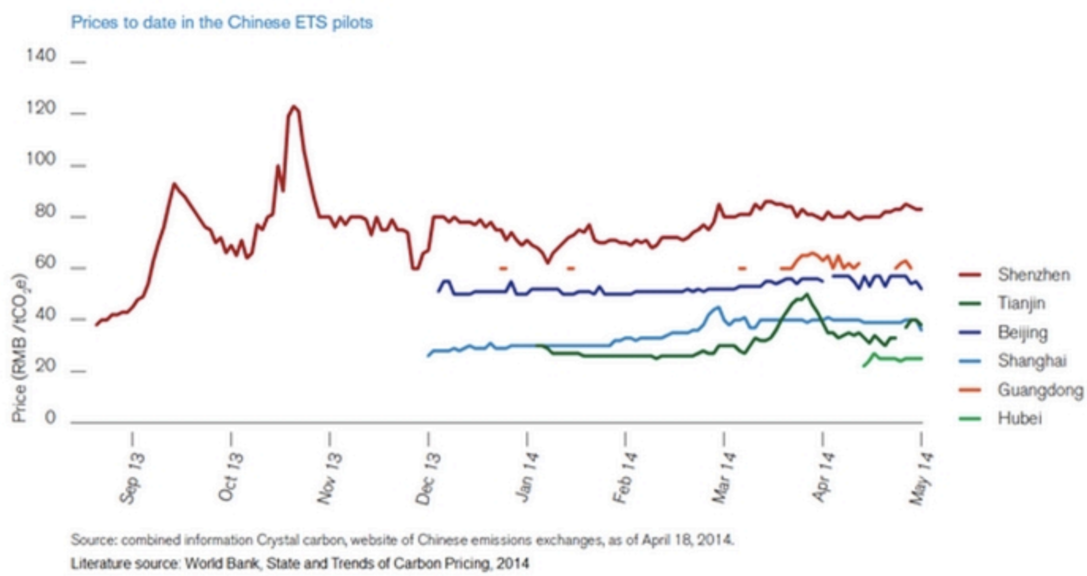
Pilots	2015 carbon intensity targets (on 2010 level)	Emission covered (MtCO2e)	Sectors covered (criteria: annual tCO_2)	Cap type	Start year
Beijing	18%	57	All companies meeting inclusion criteria (10000)	Absolute	2013
Shanghai	19%	160	Iron and steel, petrochemical, non-ferrous metals, power, materials, textile, paper, rubber, aviation, railways, commerce, finance (20000 for industry, 10000 for non-industry)	Absolute	2013
Tianjin	19%	160	Iron and steel, chemicals, power, petrochemical (20000)	Absolute	2013
Chongqing	17%	125	Companies meeting inclusion criteria (20000)	Absolute	2014
Guangdong	19.5%	388	Power, cement, iron and steel, ceramic, petrochemical, textile, non-ferrous metals, plastics, paper (10000 for industry, 5000 for non-industry)	Absolute	2013
Shenzhen	21% (Societal) 25% (Manufacture)	33	Industry, public building (3000)	Intensity	2013

[3] CDM project data is summarized from UNEP CDM Pipeline, http://www.cdmpipeline.org/publications/CDMPipeline.xlsm; the wind installed capacity data is from China Wind Energy Association, http://www.cwea.org.cn/upload/2014%E5%B9%B4%E4%B8%AD%E5%9B%BD%E9%A3%8E%E7%94%B5%E8%A3%85%E6%9C%BA%E5%AE%B9%E9%87%8F%E7%BB%9F%E8%AE%A1.pdf; the solar installed capacity is from China Energy Administration (accessed April 4, 2015).

Hubei	17%	324	Industry (165000)	Absolute	2014

Source: adapted from Carbon Brief (http://www.carbonbrief.org/blog/2014/09/analysing-china-carbon-market/), CCICED, and China Climate Change Info-Net (ccchina.gov.cn).

By October 10, 2014, the total traded carbon in those pilots reached 28.7 million tons, with a total value of 1.27 billion RMB (205.4 million USD)[4]. The carbon prices from those pilots are highly volatile at the early stage of Shenzhen demonstration project and comparatively stable in other pilots. The price ranges from 20 RMB to 120 RMB, with an average carbon at about 44 RMB/t, see Figure 5-3. The Guangdong pilot covers power sector and the carbon prices initiated by the pilot has started to provide a price message to the fossil and renewables, though some of the credits are awarded as free allowance.



Source: http://en.ccchina.gov.cn/Detail.aspx?newsId=46802&TId=96 (assessed March 20, 2015)

Figure 5-3 Carbon prices in China's cap and trade pilots

The carbon price is embedded in the idea of social cost of carbon as proposed to estimate the economic damages associated with the marginal increase of CO_2 emissions (Pizer et al. 2014; van den Bergh and Botzen 2015). As China moves to a national carbon market, a meaningful carbon price underway will be an incentive for the development of power from low carbon sources. The carbon prices and the external cost of fossil fuels as discussed above provide the foundation of discussing the co-benefits of China's clean energy transition.

5.2.3 Co-benefits implications

[4] CCICED, Cap and trade and mechanism innovation: experiences from China's carbon trading pilots. 2014. http://www.cciced.net/ztbd/nh/2014/wybg/201412/P020141201318189474825.pdf

In order to capture the benefits of reducing coal in the IPCC Target Scenario compared to the BAU Scenario, this study assumes a lower case and an upper case with different assumptions of external cost of coal, carbon cost based on the literature and assumptions in the model, see Table 5-2. The benefits of transition to a low carbon power sector are a sum up of the avoided external cost of coal and the social cost of carbon. This in the fixed external cost scenario ranges from 540 billion USD to 1004 billion USD, which can provide about 16-30% of the 2,269 billion USD investments needed annually in 2050 to make such transition possible.

Table 5-2 Benefits of China's low carbon power transition

		2020	2030	2040	2050
Coal reduction (Mt)		617	1,078	2,627	3,775
Carbon reduction ($MtCO_2$)		1,266	2,160	5,287	8,534
Lower	External cost ($/t)	30	30	30	30
	Carbon cost ($/$tCO_2$)	10	20	30	50
	Benefits (B$)	31	76	237	540
Upper	External cost ($/t)	40	40	40	40
	Carbon cost ($/$tCO_2$)	20	30	50	100
	Benefits (B$)	50	108	369	1,004
Additional costs (B$)		102	340	819	2,269
Total benefits as share of additional costs		9-15%	13-19%	17-26%	16-30%

(a) Fixed external cost

		2020	2030	2040	2050
GDP (Trillion RMB)		21.67	35.30	47.44	57.83
Coal reduction (Mt)		617	1,078	2,627	3,775
Carbon reduction ($MtCO_2$)		1,266	2,160	5,287	8,534
Lower	External cost ($/t)	110	179	240	293
	Carbon cost ($/$tCO_2$)	10	20	30	50
	Benefits (B$)	80	236	789	1,531
Upper	External cost ($/t)	146	238	320	390
	Carbon cost ($/$tCO_2$)	20	30	50	100
	Benefits (B$)	116	321	1,105	2,326
Additional costs (B$)		102	340	819	2,269
Total benefits as share of additional costs		79-113%	69-95%	96-135%	67-103%

(b) GDP adjusted external cost

Think about China's GDP growth, if we scale up the external cost of coal with GDP, which assumes 7% growth rate through 2020, and then 5% from 2020 to 2030, and 3% from 2030 to 2040, and 2% from 2040 to 2050, the benefits will covers 67-103% of the extra cost of such a transition by 2050, which means that the clean energy transition can almost be fully funded by the co-benefits of the renewable penetration and clean power transition.

5.3 Implications for power sector reform

5.3.1 High penetration of renewable demands an inter-connected smart grid

Based on the assessments in chapter 2 and 3 of wind and solar resources, the spatial and temporal features of the variable renewable energy resources demands an inter-connected grid to link the supply bases and demand centers, and to coordinate the supplementary resources (He and Kammen 2014).

In the U.S., FERC Order No. 1000[5] is intended to address the transmission challenges presented by large scale of variable resources. Order No. 1000 is a final rule that reforms FERC's electric transmission planning and cost allocation requirements for public utility transmission providers. With the introduction and affirmation of Order 1000, every grid region, especially those isolated renewable resource rich areas, have more regulatory tools to use regional planning to bring more renewables online.

In China, a national ultra high voltage (UHV) transmission network gains momentum given the need of bulk power transmission and merit of UHV transmission can provide (D. Huang et al. 2009). The State Grid Corporation of China (SGCC) and China Southern Power Grid (CSG) both have ambitious plans to develop UHV lines to connect energy base with load centers. SGCC has started constructing multiple UHV lines at 1000 kV AC and ±800 kV DC covering north and central China, connecting east China, which brings energy from the energy base to the demand centers. By 2020, the AC and DC hybrid system of UHV grid will be over 200 GW.

Renewable integration has been a focal point in the transmission expansion. The State Grid plans to develop 27 GW annual transmission capacity (17 GW for wind, and 10 GW for solar) on average toward to 2020 for renewable integration (State Grid 2015). It will build seven cross-region transmission channels for renewables, among which the Zhangbei-Ganzhou UHV transmission line demonstration project is already under construction. This plan also includes six pumped hydro projects in the Three North (north, northeast, and northwest) region.

Those plans are mainly driven by the SGCC and CSG and the national science and technological innovation initiatives. It involves billions of investments[6] and will have

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[5] The FERC Order No. 1000. http://www.ferc.gov/whats-new/comm-meet/2011/072111/E-6.pdf (Accessed April 16, 2015)

[6] Reuters, China to invest $391 bln in power grids from 2011-2015-report. http://www.reuters.com/article/2011/04/26/china-power-idUSL3E7FQ03D20110426 (Accessed April, 2015)

huge impact on the cost-effectiveness and performance of the grid. Tool like SWITCH is especially usefully when planning the resources and infrastructure needed at great spatial and temporal scale to meet the demand of achieving high penetrations of renewables while model the optimization of investment decision under different scenarios.

In addition, the penetration of variable resources, and the expanding use of smart appliances, smart control, and automated sensors, etc, in all, the big data enabled smart grid has provided opportunities for renewable integration, however, price signals will be key to allocate resources more efficiently. On the demand side, flexible loads, demand response, and other market-oriented tools cannot function without a major power sector reform that can make the market work. Renewables will benefits from a larger market where price signal reflects cost and value of the electricity supply and demand.

5.3.2 Make the market work

China's power sector is still heavily under state control after several rounds of reforms and is currently under the pressure of one of the last frontiers of China's deep market reform (C. Zhang 2007; CCCPC 2013). In March 2015, the State Council released the Opinions on Deepening Power Sector Reform (it is also referred as No. 9 Document)[7] restated power sector reform in China and proposed further steps to reform China's power sector.

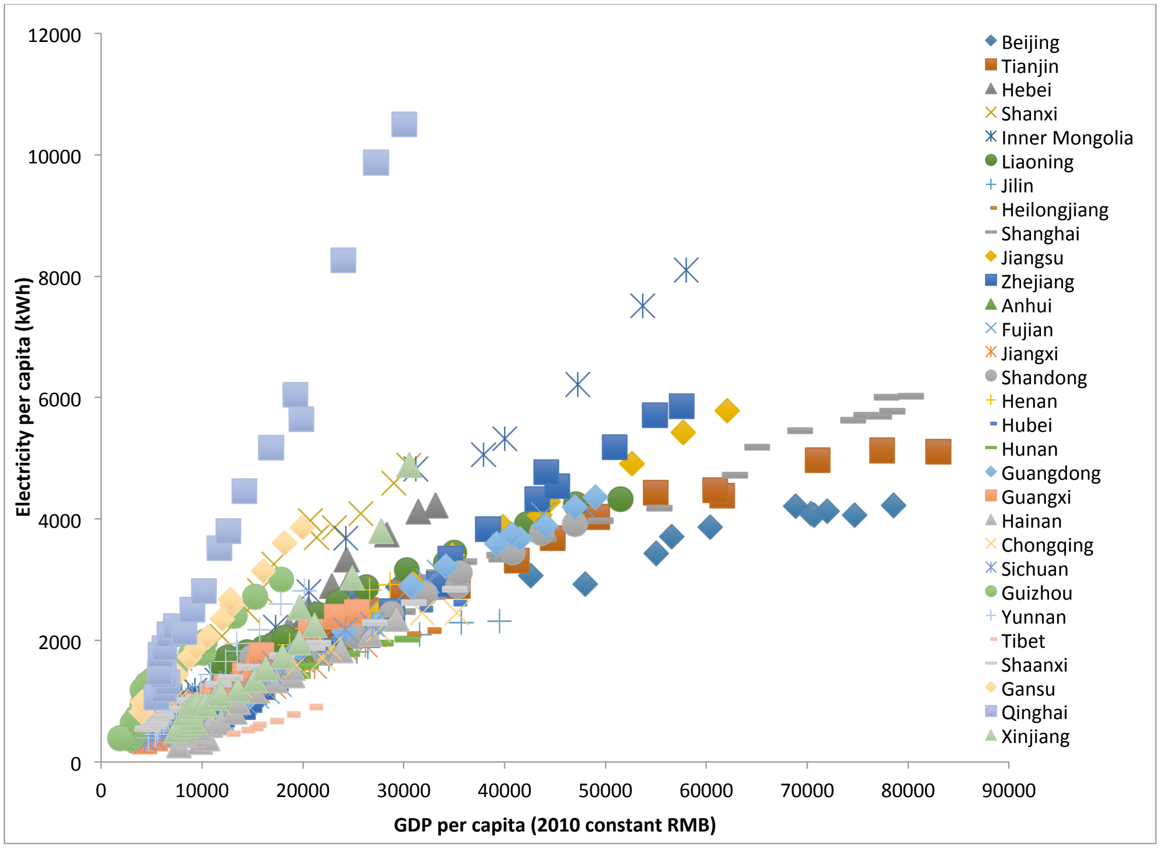
The No. 9 Document highlighted several key tasks of this round of reform: streamline the price formation mechanism; improve the power exchange market; establish independent power exchange agency; reform the power planning process; reform the retail market step by step and open it to social capital; open grid for fair access and promote new mechanism for distributed energy development; and improve power safety and reliability (State Council 2015).

The power sector reform or restructuring in the U.S. has been mainly driven by the technology stasis, energy crisis, and environmental movement (Hirsh 1999; Newberry 2002; Zysman and Huberty 2013). China faces similar situations but new challenges. The increasing penetration of renewable energy, the complexity of demand landscape, and the other emerging priorities of the power supply, require the power market to function in order to connect the involving supply and demand more efficiently.

However, the regional socio-economic disparities cross provinces show that the reform will take a progressive strategy and be adaptive by provincial situation (see Figure 5-4). After near 10 years fast growth since 2005, in some provinces, for example, Beijing, Tianjin, Shanghai, Jiangsu, and Zhejiang, the average electricity consumption per capita starts to plateau while average GDP per capita keeps growing. The threshold is at around 60,000 RMB per capita. In some resource rich provinces, for example, Qinghai, Xinjiang,

[7] The full text of this Document can be found at: http://www.ne21.com/news/show-64828.html (in Chinese; accessed April 17, 2015)

Gansu, Shanxi, and Inner Mongolia, average electricity consumption per capita still keeps going at a high level even the GDP per capita is at a lower level. Power sector reform will be more likely to succeed in those provinces where the electricity supply is less tight. Relations between electricity use and GDP has many uncertainties and impact by multiple factors (Asafu-Adjaye 2000; Lee and Chang 2008), this shows electricity consumption has a plateau effect that needs to be considered while planning for the future demand, and the plateau offer an opportunity window for market reform.



Source: Gang He, Jiang Lin, David Fridley, and Alex Yuan.

Figure 5-4 Relations of Electricity per capita and GDP per capita by province

5.3.3 Get the prices right

The power price reform has embedded in the larger socio-economic reform agenda. It has experienced stages of price inventory, payback price, fuel and transpiration surcharge, electric construction fund, flag price, and competing prices, and is currently a hybrid system as power plants keep the legacy of the pricing mechanisms in time when they were built (S. Huang 2009). Those pricing mechanisms have played roles at specific timeframe however is not kept up with the demand of changing landscape of China's power sector with increasing variable renewable resources, distributed generation, flexible loads, and complex supply and demand profiles. It is essential to get the pricing mechanism to function in order to make the market work. The current power prices do not reflect the value of electricity supply and demand, and it fails to capture the external cost of existing coal-dominant fuel structure of power generation.

Market power prices reflect the value of electricity supply and demand, and will create incentives for energy efficiency, renewable generation, and distributed energy to meet the energy need at given location or time (Borenstein, Jaske, and Rosenfeld 2002; Borenstein 2012). As discussed in Chapter 2-3, the variable wind and solar resources have spatial and temporal dynamics, therefore, there would be no base for renewables to compete without a price mechanism. Market prices will also motivate the development of storage, transmission, the complement of wind and solar, wind and hydro, and wind and gas, as the benefits of doing so will have to harvest in the market that driven by the value of electricity supply and demand.

On the other hand, renewables will be more competitive if the external cost of electricity generation from fossil fuel is included. As discussed in section 5.2, various researches have shown that the external cost of coal is calculated at 30-40 USD per ton in 2010, and the carbon price from the cap and trade pilot programs varies from 3-20USD in China (Mao, Sheng, and Yang 2008; Teng 2014). Adding those costs in can substitute 16-30% of the extra cost needed to decarbonize China’s power sector emission by 80% compared to 2005 level. If scale up with the GDP growth by 2050, almost all extra cost can be covered by substituting the external costs. The power sector transition can be financed by the co-benefits of such a transition.

6 Conclusion

China needs to decarbonize its currently coal dominated power sector to achieve the long-term stabilization of carbon emission to tackle climate change. China has sufficient wind and solar resources to satisfy China's demand, however, the resources are geographically and temporally varied.

China has released ambitious wind and solar energy development goals. Knowing where, when and how much wind and solar are available at provincial level can help researchers and policy makers with wind and solar development planning and integration. However, the existing literature does not provide the necessary spatial resolution or give sufficient attention to the spatial and temporal variation of wind and solar availability.

Combining methods of GIS modeling and wind and solar CF simulation, this study utilized 200 representative locations each independently for wind and solar, with 10 years of hourly wind speed and solar irradiation data to study provincial capacity factor from 2001 to 2010, and to build wind and solar availability profiles.

From these data, this analysis found that China could have a potential wind capacity from 1,300GW to 2,300GW, and the annual wind output could reach 2,000 TWh to 3,500 TWh. The calculated average capacity factor is 0.18, which is lower compared to what has been reported. This study found that China could have a potential stationary solar capacity from 5,700 GW to 44,800 GW, distributed solar about 200 GW, and the annual solar output could reach 9,700 TWh to 78,900 TWh.

While spatial variation demands highly interconnected and coordinated power system, similar temporal variation pattern restricted the effectiveness of such a system. The study looked into the diurnal and seasonal features of the wind and solar availability at provincial level and found similar seasonal variation pattern between provinces for single resource, which indicates the difficulties to integrate wind resources through regional coordination, and explains why back up capacity or storage assets has to be in place in order to incorporate such variation. However, for solar, the peaking time lag with-in a day and the difference cross provinces offer opportunities for coordination. Wind and solar complement each quite well on the seasonal variation, which shows wind-solar hybrid complementing system can add value and can be a new research area.

The diurnal and seasonal variability of solar and wind resources demand a larger, systems-level analysis of China's energy options with more careful investigation of technical and economic availabilities and the role of inter-province transmissions. This study extends the exiting research by investigating wind and solar availability in China at higher spatial resolution and temporal resolution so to understand the spatial and temporal availability of wind and solar resources across China. The results of this study can be used to facilitate local and national wind and solar development plans and can be also utilized by developers and regulators to develop strategies on wind and solar integration.

This study then examined the implications of the solar and wind variability and availability in the context of an overall energy strategy for China by using a system optimization model: SWITCH-China. By optimizing capacity expansion and hourly generation dispatch simultaneously, SWITCH-China is uniquely suited to explore both the value of and synergies among various power system technology options, providing policymakers and industry leaders with important information about the optimal development of the electricity grid. SWITCH helps identify the least-expensive response to achieving national energy and climate targets: it demonstrates that a carbon price at ~30 USD/tCO_2 by 2020 is needed to meet the 2020 carbon intensity target and ~40 USD/tCO_2 by 2030 for the 2030 carbon peak announcement. To reach an 80% reduction in CO_2 emissions by 2050, as proposed by the IPCC, the resulting energy mix in 2050 would include nuclear (14%), wind (23%), solar (27%), hydro (6%), gas (1%), coal (3%), CCS coal (26%). This will result in a 37% increase in total power cost over 'BAU' scenario.

There are a few uncertainties about the setting of the model, and a better understanding of these uncertainties will help further improve the model. The current cited demand projection is driven by GDP growth and energy efficient technologies, which both have potential uncertainties that can impact the electricity demand. Fuel price fluctuation may change the technology choice and impact the competitive advantages of different technologies over time. The current cost assumptions will also face uncertainties in the learning curve of new technologies and do not include external costs of conventional technologies. Other policy developments, which are not directly related to economics, such as nuclear safety and security, public perception and acceptance of nuclear and hydro projects, may add more uncertainty to the applications of available technologies.

China's power sector is in the midst of fast development, and today's investment decisions will have a large impact on the country's ability to achieve its environmental and carbon mitigation goals. SWITCH is the "facilitator" which helps understand how technologies, policies, and investment decisions can be coupled, and enables a strategic thinking on the future of China's transition to a low carbon power system. Concerted action is needed to develop such a system, including introducing a meaningful carbon price, coordinating the investment decisions, and building the necessary infrastructure for moving energy around.

Supplemental Information

The SWITCH model was created at the University of California, Berkeley by Dr. Matthias Fripp (Fripp 2008, Fripp 2012). SWITCH-China used in this study is developed based on an earlier version SWITCH-WECC maintained and developed by Dr. James Nelson, Dr. Ana Mileva, and Josiah Johnston in Professor Daniel M. Kammen's Renewable and Appropriate Energy Laboratory at the University of California, Berkeley.

1 SWITCH Model Description

1.1 Study Years, Months, Dates and Hours

To simulate power system dynamics over the course from 2010 to 2050, four levels of temporal resolution are employed by the SWITCH model: investment periods, months, days and hours. A single investment period contains historical data from 12 months, two days per month (the peak and median load days) and six hours per day. There are four ten-year long investment periods: 2015-2025, 2025-2035, 2035-2045, and 2045-2055 in each optimization, resulting in (4 investment periods) x (12 months/investment period) x (2 days/month) x (6 hours/day) = 576 study hours over which the system is dispatched. Additional hours can be added if the power system designed by the initial 576-timepoint optimization fails to meet load in any hour during the post-optimization dispatch check. The middle of each period is representative of conditions within that period, e.g. the year 2030 represents the period 2025-2035. The results of 2020, 2030 and 2050 are representative years for 2015-2025, 2025-2035, and 2045-2055, and their representation within the study is consistent with the targeted years of China's planning cycles.

The peak and median days from each historical month are sampled in order to characterize a large range of possible load and weather conditions over the course of each investment period. Each sampled day is assigned a weight: peak load days are given a weight of one day per month, while median days are given a weight of the number of days in a given month minus one. The purpose of this weighting scheme is threefold: 1) to ensure that the total number of days simulated in each investment period is equal to the number of days between the start and end of this investment period; 2) to emphasize the economics of dispatching the system under 'average' load conditions; and 3) to guarantee that sufficient capacity is available during times of peak load.

The output of renewable generators can be correlated not only across renewable sites but also with electricity demand as both are affected by weather conditions. A classic example of this type of correlation is the large magnitude of air conditioning load that is present on sunny, hot days. To account for these correlations in SWITCH-China, time-synchronized historical hourly load and generation profiles for locations across China are employed. Each date in future investment periods corresponds to a distinct historical date from 2010, for which historical data on hourly loads, simulated hourly wind and solar capacity factors, and monthly hydroelectric availability. Hourly load data is scaled up to projected future demand, while solar, wind and hydroelectric resource availability is used directly from historical data.

To make the optimization computationally feasible, six distinct hours of load and resource data are sampled from each study date, spaced four hours apart. For median days, hourly sampling begins at midnight China Standard Time (CST) and includes hours 0, 4, 8, 12, 16, and 20. For peak days, hourly sampling is offset to ensure the peak hour is included, which may be at 14 on some days and 15 on other days.

1.2 Important Sets and Indices

Important Sets and Indices		
Set	***Index***	***Description***
I	*i*	investment periods
M	*m*	months
D	*d*	dates
T	*t*	timepoints (hours)
$T_d \subset T$	-	set of timepoints on day *d*
A	*a*	load areas (province)
LSE	*lse*	load-serving entities
BA	*ba*	balancing areas
F	*f*	fuels
$R \subset F$	*r*	RPS-eligible fuels
P	*p*	all generation and storage projects
$GP \subset P$	*gp*	all generation projects
$GP_a \subset GP$	-	all generation projects in load area *a*
$DP \subset P$	*dp*	dispatchable generation projects
$IP \subset P$	*ip*	intermediate generation projects
$FBP \subset P$	*fbp*	flexible baseload generation projects
$BP \subset P$	*bp*	baseload generation projects
$VP \subset P$	*vp*	variable generation projects
$VDP \subset VP$	*vdp*	variable distributed generation projects
$VCP \subset VP$	*vcp*	variable centralized generation projects
$SP \subset P$	*sp*	storage projects (including pumped hydro, compressed air energy storage and battery storage)
$SP_a \subset SP$	-	storage projects in load area *a*
$HP \subset P$	*hp*	hydroelectric projects
$PHP \subset HP$ (also, $PHP \subset S$)	*php*	pumped hydroelectric projects

BP⊂S	*bp*	battery storage projects
CP⊂S	*cp*	compressed air energy storage projects
EP	*ep*	existing plants
RP	*rp*	RPS-eligible projects

1.3 Decision Variables: Capacity Investment

SWITCH-CHINA's first set of decision variables consists of the following infrastructure investment choices for the power system, which are made for each investment period.

Capacity Investment Decision Variables:

1. Amount of new generation capacity to install for each generation and storage technology type in each load area in each investment period
2. Amount of transmission capacity to add between load areas in each investment period
3. Whether to operate or retire each existing power plant in each investment period

Investment Decision Variables	
$G_{p,i}$	Capacity to install in period *i* at project *p*
$T_{a,a',i}$	Capacity to install in period *i* between load area *a* and load area *a'*
E_i	Whether or not to run existing plant *e* in investment period *i* (binary)

Construction time is taken into account, so generation and storage projects can only be built if there is sufficient time to build the project between present day and the start of each investment period. This is important for projects with long construction time such as nuclear plants and compressed air energy storage projects, which could not be finished by 2015, the start year of the first investment period, even if construction began earlier than that. Carbon capture and sequestration (CCS) generation cannot be built in the first investment period of 2015-2025, as this technology is not likely to be mature enough for large–scale deployment before 2020 (IEA 2008). In the mixed-integer formulation, new nuclear plants have a minimum capacity of 1 GW to represent large nuclear plants. Small and medium size nuclear plants have a minimum capacity of 100MW. The installed capacity of resource-constrained generation and storage projects cannot exceed the maximum available resource for each project.

During each investment period, the model decides whether to operate or retire each of the ~4000 existing power plants in China. Once retired, existing plants cannot be re-started. All existing plants except for hydro plants and nuclear plants are forced to retire at the end of their operational lifetime. Nuclear plants can extend operation past their operational lifetime, but are required to pay operations and maintenance as well as fuel costs for any period in which they remain operational. Hydroelectric facilities are required to operate throughout the whole study as, in addition to their value as electric generators, they also have other important functions such as controlling stream flow, irrigation, and shipping.

New high-voltage transmission capacity is built along existing transmission corridors between the provincial capitals of each load area. If no transmission corridor exists between two load areas, new transmission lines can be built at 1.5 times the straight-line transmission cost of 300 USD per MW·km, reflecting the difficulty of new transmission siting and planning (SERC 2012b). Transmission can be built between adjacent load areas, non-adjacent load areas with capital cities less than 300 km from one another, and non-adjacent load areas that are already connected by existing transmission. Existing transmission links that are approximated well by two or more shorter links between load areas are removed from the new expansion decisions. Investment in transmission lines greater than 300 km in length is approximated by investment in a handful of shorter links.

Investment in new local transmission and distribution within a load area is included as a sunk cost and hence does not have associated decision variables.

1.4 Decision Variables: Dispatch

1.4.1 Generation Dispatch

The second set of decision variables in SWITCH-CHINA includes choices made in every study hour about how to dispatch generation, storage, and transmission in order to meet load.

Dispatch Decision Variables:

1. Amount of energy to generate from each dispatchable and intermediate generation project (hydroelectric and non-cogen natural gas plants) in each hour and from each flexible baseload generation project (coal plants) each day
2. Amount of energy to transfer along each transmission corridor in each hour
3. Amount of energy to store and release at each storage facility (pumped hydroelectric, compressed air energy storage, and sodium-sulfur battery plants) in each hour

Dispatch decisions are not made for baseload generation projects (nuclear) because these generators, if active in an investment period, are assumed to produce the same amount of power in each hour of that period. Dispatch decisions are also not made for intermittent renewable generators such as wind and solar. If the model chooses to install them, renewable facilities produce an amount of power that is exogenously calculated: a capacity factor is specified for each timepoint based on the weather conditions in the corresponding historical hour at the location of each renewable plant. Excess generation is allowed to occur in any hour; the excess is simply curtailed.

Dispatch Decision Variables	
$O_{p,t}$	Energy output of project *p* in hour *t*
$C_{ip,t}$	Capacity committed from intermediate generation project *ip* in hour *t*

$C_{fbp,d}$	Capacity committed from flexible baseload project *fbp* on day *d*
$Tr_{a,a',t}$	Energy transferred in hour *t* along the transmission line between load areas *a* and *a'*
$S_{sp,t}$	Energy stored in hour *t* at storage project *sp*
$R_{sp,t}$	Energy released in hour *t* from storage project *sp*
$SP_{p \subset DP \cup IP,t}$	Spinning reserve provided by dispatchable or intermediate project *p* in hour *t* ($p \subset DP \cup IP$)
$Q_{p \subset DP \cup IP,t}$	Quickstart capacity provided by project *p* in hour *t* ($p \subset DP \cup IP$)
$OP_{p \subset HP \cup SP,t}$	Operating reserve (spinning and quickstart) provided by hydroelectric (*h*) and storage (*s*) plants in hour *t*
$DR_{a,t}$	Shift load away from hour *t* in load area *a*
$MDR_{a,t}$	Meet shifted load in hour *t* in load area *a*

The rules and regulations currently governing electricity dispatch in China are stipulated in a 1993 State Council regulatory directive, *Grid Dispatch Regulations*, which was revised in 2011 (State Council 1993). This document allocates authority and responsibility for dispatch, sets an organizational hierarchy, and specifies a basic process and rules governing dispatch (Kahrl, Williams, and Hu 2013). In 2007, the National Development and Reform Commission (NDRC), State Electricity Regulatory Commission (SERC), and the Ministry of Environmental Protection (MEP) announced the "energy efficient" dispatch pilots, in Guangdong, Guizhou, Henan, Jiangsu, and Sichuan Provinces. This pilot system specifies a dispatch order, with renewable, large hydropower, nuclear, and cogeneration units given priority over conventional thermal units, and conventional thermal units within each category (e.g., coal-fired units) dispatched according to efficiency (heat rates) and emissions rate (NDRC 2007). China's power sector is restarting the reform process and should transit from generator output planning to a system-wide unit commitment and dispatch that is optimized around cost and emissions (Kahrl and Williams 2014). Therefore, this study assumed an economic dispatch system given the dispatch decision rules that China's power sector reform move toward.

1.4.2 Dispatch of Operating Reserves

Operating reserves in SWITCH-China are currently determined by the 'Grid Dispatch Regulations,' and its Implementation Measures (Ministry of Electric Power 1994; State Council 1993). This measure specified three categories of reserve and, for each category, reasonable reserve levels: load reserves, or regulation reserve to address short-term fluctuations in load, whose load forecast error should represent 2-5 percent of peak generator load; contingency reserves, which respond to equipment failure, should constitute around 10 percent of peak generator load, but not lower than the largest unit in the regional grid; and maintenance reserves, which are held to cover units undergoing routine maintenance, must represent 8-15 percent of peak generator load. The sum of these three reserves, should not be less than 20 percent of peak generator load (Kahrl and Williams 2014; Ministry of Electric Power 1994). To address what it assessed to be overly high spinning reserve levels in the Northwest of China, SERC developed a set of regulatory rules for operating reserves in the region, *Measures for Regulating Operating Reserves in the Northwest Grid*, which it released in 2012 (SERC Northwest Department

2012). SERC noted that spinning reserves for each province in the region should, in principle, not be higher than 10 percent of peak generator load.

SWITCH-CHINA holds a base operating reserve requirement of 10 percent of load in each study hour, half of which is spinning. In addition, ‘variability’ reserves: spinning and quickstart reserves each equal to 5 percent of the wind and solar output in each hour are held to cover the additional uncertainty imposed by generation intermittency. SWITCH-CHINA’s operating reserve requirement is based on the “3+5 rule” developed in the U.S. experiences of Western Wind and Solar Integration Study as one possible heuristic for determining reserve requirements that are “usable” for system operators (GE Energy 2010). The 3+5 rule requires that spinning reserves equal to 3 percent of load and 5 percent of wind generation are held. According to GE Energy’s report, when keeping this amount of reserves there were no conditions under which insufficient reserves were carried to meet the implied $3\Delta\sigma$ requirement for net load variability. For most conditions, a considerably higher amount of reserves were carried than necessary to meet the $3\Delta\sigma$ requirement. SWITCH-CHINA’s contingency reserve requirement is even more conservative, as quickstart reserves of 3 percent of load and 5 percent of intermittent generation are also held.

The size of the entity responsible for providing balancing services is important both in terms of ability to meet the reserve requirement and the cost of doing so. The sharing of generation resources, load, and reserves through interconnection and market mechanisms is one of the least-cost methods for dealing with load variability. Multiple renewable integration studies have now also demonstrated the benefits of increased balancing area size (through consolidation or cooperation) in managing the variability of intermittent renewable output. At present, China has 31 balancing areas, but only six regional grids in China for operating reserves – North China, Northwest, Central China, East China, Northeast and Southern. SWITCH-CHINA assumes the primary regional grids as the balancing area in its optimization. Six balancing areas are modeled: North China, Northwest, Central China, East China, Northeast and Southern.

Currently, the model allows natural gas generators (including gas combustion turbines, combined-cycle natural gas plants, and stream turbine natural gas plants), hydro projects, and storage projects (including CAES, NaS batteries, and pumped hydro) to provide spinning and non-spinning reserves. It is assumed that natural gas generators back off from full load and operate with their valves partially closed when providing spinning reserves, so they incur a heat rate penalty, which is calculated from the generator’s part-load efficiency curve. Natural gas generators cannot provide more than their 10-min ramp rates in spinning reserves and must also be delivering useful energy when providing spinning reserves as backing off too far from full load quickly becomes uneconomical. Hydro projects are limited to providing no more than 20 percent of their turbine capacity as spinning reserves, in recognition of water availability limitations and possible environmental constraints on their ramp rates.

1.5 Objective Function and Economic Evaluation

The objective function includes the following system costs:

1. capital costs of existing and new power plants and storage projects
2. fixed operations and maintenance (O&M) costs incurred by all active power plants and storage projects
3. variable costs incurred by each plant, including variable O&M costs, fuel costs to produce electricity and provide spinning reserves, and any carbon costs of greenhouse gas emissions
4. capital costs of new and existing transmission lines and distribution infrastructure
5. annual O&M costs of new and existing transmission lines and distribution infrastructure

Objective function: minimize the total cost of meeting load			
Generation and Storage	Capital	$\sum_{p,i} G_{p,i} \times c_{p,i}$	The capital cost incurred for installing capacity at generation project *p* in investment period *i* is calculated as the generator size in MW $G_{p,i}$ multiplied by the capital cost (including installation and connect costs) of that type of generator in \$2010/MW, $c_{p,i}$
	Fixed O&M	$+(ep_p + \sum_{p,i} G_{p,i}) \times x_{p,i}$	The fixed operation and maintenance costs paid for generation project *p* in investment period *i* are calculated as the total generation capacity of the plant in MW (the pre-existing capacity ep_p at plant *p* plus the capacity installed through investment period *i*) multiplied by the recurring fixed costs associated with that type of generator in \$2010/MW, $x_{p,i}$
	Variable	$+\sum_{p,t} O_{p,t} \times (m_{p,t} + f_{p,t} + c_{p,t}) \times hs_t$ $+ \sum_{p \subset \text{DPUIP},t} SP_{p,t} \times (spf_{p,t} + spc_{p,t}) \times hs_t$ $+ \sum_{p \subset \text{FBPUIP},t} DC_{p,t} \times (dcf_{p,t} + dcc_{p,t}) \times hs_t$	The variable costs paid for operating plant *p* in timepoint *t* are calculated as the power output in MWh, $O_{p,t}$, multiplied by the sum of the variable costs associated with that type of generator in \$2010/MWh. The variable costs include maintenance $m_{p,t}$, fuel $f_{p,t}$, and a carbon cost $c_{p,t}$ (if applicable), and are weighted by the number of hours each timepoint represents, hs_t. Variable costs also include the fuel ($spf_{p,t}$) and carbon ($spc_{p,t}$) costs incurred by projects providing spinning reserves, $SP_{g,t}$ (only dispatchable and intermediate generation projects are allowed to provide spinning reserves) as well as fuel ($dcf_{p,t}$) and carbon ($dcc_{p,t}$) costs incurred when deep-cycling below full load ($DC_{p,t}$ is the amount below full load and equals the committed capacity minus the actual power output of the flexible baseload or intermediate plant).

Transmission	Capital	$$+\sum_{a,a',i} T_{a,a',i} \times l_{a,a'} \times t_{a,a',i}$$	The cost of building or upgrading transmission lines between two load areas a and a' in investment period i is calculated as the product of the rated transfer capacity of the new lines in MW, $T_{a,a',i}$, the length of the new line, $l_{a,a'}$, and the area-adjusted per-km cost of building new transmission in \$2010/MW·km, $t_{a,a',i}$.
	O&M	$$+\sum_{a,a',i} T_{a,a',i} \times l_{a,a'} \times x_{a,a',i}$$	The cost of maintaining new transmission lines between two load areas a and a' in investment period i is calculated as the product of the rated transfer capacity of the new lines in MW, $T_{a,a',i}$, the length of the new line, $l_{a,a'}$, and the area-adjusted per-km cost of maintaining new transmission in \$2010/MW·km, $x_{a,a',i}$.
Distribution		$$+\sum_{a,i} d_{a,i}$$	The cost of upgrading local transmission and distribution within a load area a in investment period i is calculated as the cost of building and maintaining the upgrade in \$2010/MW, $d_{a,i}$. No decision variables are associated with these costs.
Sunk		$$+s$$	Sunk costs include capital payments for existing plants, existing transmission networks, and existing distribution networks.

Capital costs are amortized over the expected lifetime of each generator or transmission line, and only those payments that occur during the length of the study are included in the objective function. Capital costs are based on *Electric Engineering Project Construction Cost Report during the 11th Five-Year* (“十一五”期间投产电源工程造价分析) and are projected to future periods based on interview with industrial experts (SERC 2012a). The capital costs are specified for each technology and each year. For each project in the SWITCH-CHINA optimization, capital costs are assumed to be as in the first year of construction. Construction costs are tallied yearly, discounted to present value at the online year of the project, and then amortized over the operational lifetime of the project. The cost to connect new power plants to the grid is included in the year before operation begins.

For optimization purposes, all costs over the entire study are discounted to a present-day value using a common real discount rate of 8 percent (State Power Corporation 2002), accordingly a so that costs incurred later in the study have less impact than those incurred earlier. All costs are specified in real terms as of USD, indexed to the reference year 2010.

1.6 Constraints

The model includes five main sets of constraints: those that ensure the load is satisfied, those that maintain the capacity reserve margin, those that require operating reserves to be maintained, those that enforce technology specific targets, for example, wind and solar development plan, nuclear development plan, non-fossil energy targets and other technology targets, and those that impose a carbon cap.

The load-meeting constraints require that the power system infrastructure, including generation, transmission, and storage, be dispatched in such as a manner as to meet load in every hour in every load area. The nameplate capacity of grid assets is de-rated by their forced outage rates to represent the amount of power generation capacity that is available on average in each hour of the study. Baseload generator outputs are also de-rated by the respective scheduled outage rates.

The capacity reserve margin constraints require that the power system maintains reserve capacity at all times, i.e. that it would have sufficient capacity available to provide at least 15 percent extra power above load in every load area in every hour if all generators, storage projects and transmission lines were working properly. In calculating reserve margin, the outputs of these grid assets are therefore not de-rated by forced outage rates. SWITCH-CHINA determines the reserve margin schedule concurrently with the load-satisfying dispatch schedule.

The operating reserve constraints ensure that an operating reserve equal to a percentage of load plus a percentage of intermittent generation is maintained in each balancing area in each hour. At least half of the operating reserves must be spinning.

The RPS constraints/non-fossil or technology specific constraints require that a certain percentage of load be met by renewable energy sources/non-fossil sources or specific technology in each load-serving entity, consistent with state-based Renewable Portfolio Standards.

The carbon cap constraint limits the total amount of carbon emissions in the China electricity sector in each study period to a government proposed targets or pre-defined level, such as the 40-45 percent carbon intensity reduction in 2020 compared to 2005 level, the carbon emission peak in 2030, and the 80 percent reduction below 2005 carbon emissions levels in 2050 (IPCC 2007; White House 2014; NDRC 2011a).

1.6.1 Load-Meeting Constraints

The total expected supply of energy from generation, storage, and transmission in each load area during each hour must equal or exceed the amount of energy consumed in that load area and at that time. The total supply of power can exceed the demand for power to reflect the potential of spilling power or curtailment during certain hours.

$CONSERVATION\_OF\_ENERGY\_NON\_DISTRIBUTED_{a,t}$	For every load area a, in each hour t, the amount of non-distributed energy $NP_{a,t}$ consumed in the load area in

	$NP_{a,t} \times (1 + dl) \leq$	that hour plus any distribution losses *dl* cannot exceed
Generation	$$\sum_{gp(\neq vdp) \in GP_a} O_{gp,t}$$	the total power generated in load area *a* in hour *t* by all non-distributed projects including baseload, flexible baseload, intermediate, dispatchable, and hydroelectric generation projects
Transmission	$$\sum_{a,a'} Tr_{a,a',t} \times e_{a,a'} - \sum_{a'',a} Tr_{a'',a,t}$$	plus the total power supplied to load area *a* from other load areas *a'* via transmission, de-rated for the line's transmission efficiency, $e_{a,a'}$, minus the total power exported from load area *a* to other load areas *a''* via transmission
Storage	$$\sum_{sp \in SP_a} R_{sp,t} - \sum_{sp \in SP_a} S_{sp,t}$$	plus the total energy, $R_{sp,t}$, supplied to load area *a* in hour *t* by storage projects *sp* minus the total energy, $S_{sp,t}$, that is stored by storage projects *sp* (including pumped hydro)

$CONSERVATION\_OF\_ENERGY\_DISTRIBUTED_{a,t,f}$ $$DP_{a,t} \geq \sum_{vdp \in GP_a} O_{vdp,t}$$	In every load area *a*, in each hour *t*, the amount of distributed energy $DP_{a,t}$ consumed in the load area cannot exceed the total distributed generation available in load area *a* in hour *t*.

$SATISFY\_LOAD_{a,t}$ $$NP_{a,t} + DP_{a,t} \geq l_{a,t} - DR_{a,t} + MDR_{a,t}$$	For every load area *a* in each hour *t*, the total energy consumed from distributed and non-distributed sources must be greater than or equal the pre-defined system load $l_{a,t}$ minus any load response $DR_{a,t}$ provided in that hour plus any load $MDR_{a,t}$ shifted to hour t from other hours.

1.6.2 Reserve Margin Constraints

Power plants and transmission lines can experience outages due to various mechanical and electrical failures. To address system risk, the model requires that enough power plant and transmission capacity be built to provide a capacity reserve margin, usually set at 15 percent, above load in each load area in all hours.

CONSERVATION_OF_ENERGY_NON_DISTRIBUTED_RESERVE$_{a,t}$	$NPR_{a,t} \times (1 + dl) \leq$	In every load area a, in each hour t, the amount of non-distributed capacity $NPR_{a,t}$ available to meet the capacity reserve margin in the load area in that hour plus any distribution losses dl cannot exceed
Generation Capacity	$\sum_{vcp} (\sum_{i} G_{vcp,i} \times cf_{vcp,t}) + \sum_{p \in DP \cup IP \cup HP} \sum_{i} G_{p,i} + \sum_{p \in FBP \cup BP} (\sum_{i} G_{p,i} \times (1 - s_p))$	the total capacity of all intermittent non-distributed projects ($G_{vcp,i}$) multiplied by their capacity factor $cf_{vcp,t}$ in hour t, plus the total capacity of all dispatchable (*dp*), intermediate (*ip*), and hydro (*hp*) projects plus the total capacity, adjusted for scheduled outage rate s_p, of all flexible baseload (*fbp*)and baseload projects (*bp*) in load area *a* in hour *t*,
Transmission Capacity	$\sum_{a,a'} Tr_{a,a',t} \times e_{a,a'} - \sum_{a'',a} Tr_{a'',a,t}$	plus the total power transmitted to load area *a* from other load areas *a'* ($Tr_{a,a',t}$), de-rated for the line's transmission efficiency, $e_{a,a'}$, minus the total power transmitted from load area *a* to other load areas *a''* ($Tr_{a'',a,t}$)
Storage Capacity	$\sum_{a,a'} Tr_{a,a',t} \times e_{a,a'} - \sum_{a'',a} Tr_{a'',a,t}$	plus the total output $R_{s,t}$, of storage projects *s* in load area *a* in hour *t* minus the energy stored, $S_{s,t}$, by storage projects *s* in load area *a* in hour *t*.

CONSERVATION_OF_ENERGY_DISTRIBUTED_RESERVE$_{a,t}$ $DPR_{a,t} \geq \sum_{vdp} (\sum_{i} G_{vdp,i} \times cf_{vdp,t})$	In every load area *a*, in each hour *t*, the amount of distributed generation capacity $DPR_{a,t}$ available to meet the capacity reserve margin in the load area cannot exceed the total distributed generation capacity available in load area *a* in hour *t*.

SATISFY_RESERVE_MARGIN$_{a,t}$ $DPR_{a,t} + NPR_{a,t} \geq (1+r) \times (l_{a,t} - DR_{a,t} + MDR_{a,t})$	For each load area *a*, in each hour *t*, the total distributed and non-distributed capacity available for consumption must be a pre-specified reserve margin *r* above the pre-defined system load $l_{a,t}$ minus any load response $DR_{a,t}$ provided in that hour plus any load $MDR_{a,t}$ shifted to hour t from other hours.

1.6.3 Operating Reserve Constraints

SATISFY_SPINNING_RESERVE$_{ba,t}$ $\sum_{p \in DP_{ba} \cup IP_{ba}} SP_{p,t} + \sum_{p \in SP_{ba} \cup HP_{ba}} OP_{p,t} \geq spinning\_reserve\_reqt_{ba,t}$	In each balancing area *ba* in each hour *t*, the spinning reserve $SP_{p,t}$ provided by dispatchable and intermediate plants ($p \in DP_{ba} \cup IP_{ba}$), plus the operating reserve $OP_{p,t}$ provided by storage plants ($p \in S_{ba}$) and hydroelectric plants ($p \in H_{ba}$) must equal or exceed the spinning reserve requirement in that balancing area in that hour. The spinning reserve requirement is calculated as a percentage of load plus a percentage of intermittent generation in each balancing area in each hour.

SATISFY_OPERATING_RESERVE$_{ba,t}$ $\sum_{p \in DP_{ba} \cup IP_{ba}} (SP_{p,t} + Q_{p,t}) + \sum_{p \in SP_{ba} \cup HP_{ba}} OP_{p,t} \geq operating\_reserve\_reqt_{ba,t}$	In each balancing area *ba* in each hour *t*, the spinning reserve, $SP_{p,t}$, plus the quickstart reserve, $Q_{p,t}$, provided by dispatchable and intermediate plants ($p \in DP_{ba} \cup IP_{ba}$) plus the operating reserve $OP_{p,t}$ provided by storage plants and hydroelectric plants ($p \in S_{ba} \cup H_{ba}$) must equal or exceed the total operating reserve requirement (spinning plus quickstart) in that balancing area in that hour. The operating reserve requirement is calculated as a

	percentage of load plus a percentage of intermittent generation in each balancing area in each hour.

1.6.4 RPS/Non-fossil Constraint

This constraint requires that, for each load-serving entity and for every period, the percentage of total consumed power delivered by qualifying renewable sources is greater than or equal to the fraction specified by existing non-fossil targets (NFT), or other technology specific targets.

MEET_NFT$_{lse,i}$ $\frac{\sum_{t\in T_i, a\in A_{lse}} NFC_{lse,t}\times hs_t}{\sum_{t\in T_i, a\in A_{lse}} l_{a,t}\times hs_t} \geq nft_{lse,i}$	For every load-serving entity *lse* in every period *i*, the proportion of the total power $NFC_{lse,t}$ consumed from non-fossil or renewable sources in all hours of that period (the set T_i) from all NFT/RPS-eligible fuels ($f \in R$) as a fraction of total load in that period in that load area must be greater than or equal to the pre-defined NFT/RPS fraction, $nft_{lse,i}$, for that load area for that period. Each timepoint in the set T_i is weighted by the number of sample hours it represents, hs_t.

CONSERVATION_OF_RECS$_{lse,t}$ $REC_{lse,t} \leq \sum_{rp\in RP_{lse}} O_{rp,t} + \sum_{a\in A_{lse}, f\in R} Tr_{a,a',f,t} - \sum_{a\in A_{lse}, f\in R} Tr_{a'',a,f,t}$	For every load-serving entity *lse* in every hour *t*, the amount of renewable energy consumed cannot exceed the total output of renewable generators *rp* in the load-serving entity in that hour plus the energy from NFT/RPS-eligible fuels ($f \in R$) transmitted into the load-serving entity ($Tr_{a,a',f,t}$) minus the energy from NFT/RPS-eligible fuels transmitted out of the load-serving entity ($Tr_{a'',a,f,t}$). RECs do not undergo transmission and storage losses by definition.

1.6.5 Carbon Target/Cap Constraint

This constraint requires that, for every period, the total carbon dioxide emissions from generation and spinning reserve provision cannot exceed a pre-specified emission cap. Emissions are incurred for power generation, provision of spinning reserves, cycling of plants below full load, and generator start-up.

CARBON_CAP$_i$ $\sum_{p,t\in T_i} O_{p,t}\times ht_p \times co2\_fuel_p +$ $\sum_{p\in DP\cup IP, t\in T_i} SP_{p,t}\times sp\_penalty_p \times$	In every period *i*, the total carbon emissions cannot exceed a pre-specified carbon cap *carbon_cap*$_i$ for that period. Emissions are incurred from generation (calculated as the plant output $O_{p,t}$ times the plant heat rate hr_p times the carbon dioxide fuel content for that

$co2\_fuel_p +$ $\sum_{p \in FBP \cup IP, t \in T_i} DC_{p,t} \times dc\_penalty_p \times$ $co2\_fuel_p$ $+$ $\sum_{p \in DP \cup IP, t \in T_i} ST_{p,t} \times startup\_fuel_p \times$ $co2\_fuel_p \leq carbon\_cap_i$	plant); plus the carbon emissions from spinning reserve from dispatchable and intermediate plants (calculated as the amount of spinning reserves provided $SP_{p,t}$ times the plant per unit heat rate penalty for providing spinning reserve $sp\_penalty_p$ times the CO_2 fuel content for that plant); plus the carbon emissions from deep-cycling flexible baseload and intermediate plants below full load (calculated as the amount below full load $DC_{p,t}$ times the heat rate penalty for cycling below full load $dc\_penalty_p$ times the CO_2 fuel content); plus the emissions from starting up intermediate and dispatchable plants (calculated as the capacity started up since the previous hour $ST_{p,t}$ times the startup fuel required $startup\_fuel_p$ times the CO_2 fuel content).

1.6.6 Operational Constraints

1. ***Intermittent generators*** (solar and wind) produce the amount of power corresponding to their simulated historical power output in each hour, de-rated by their forced outage rate.

$VAR\_GEN_{vp,t}$ $$O_{vp} = cf_{vp,t} \times (1 - o_{vp}) \times \sum_i G_{vp,i}$$	For each variable generation project *vp* in every hour *t*, the expected amount of power, $O_{vp,t}$, produced by the variable generator in that hour must equal the sum, de-rated by the generator's forced outage rate o_{vp}, of generator capacities $G_{vp,i}$ installed at generator *vp* in the current and preceding periods *i*, multiplied by the generator's capacity factor in hour *t*, $cf_{vp,t}$. The operational generator lifetime limits the extent of the sum over *i* to only periods in which the generator would still be operational, but is not included here for simplicity.

2. ***Baseload generators*** (nuclear, geothermal, biomass solid, biogas and cogeneration) must produce an amount of power equal to their nameplate capacity, de-rated by their forced and scheduled outage rates.

BASELOAD_GEN$_{bp,t}$ $O_{bp,i} = (1 - o_{bp}) \times (1 - s_{bp}) \times \sum_i G_{bp,i}$	For every baseload project *bp* and every hour t, the expected amount of power, $O_{bp,t}$, produced by each baseload generator *bp* in each hour *t* cannot exceed the sum, de-rated by the generator's forced outage rate o_{bp} and scheduled outage rate s_{bp}, of generator capacities $G_{bp,i}$ installed at generator *bp* in the current and preceding periods i. The operational generator lifetime limits the extent of the sum over *i* to only periods in which the generator would still be operational, but is not included here for simplicity.

3. ***Flexible baseload generators*** (non-cogen coal) cannot commit more capacity in each day than their nameplate capacity, de-rated by their forced and scheduled outage rates.

MAX_DISPATCH_HOURLY$_{fbp,t}$ $O_{fbp,t \in T_d} = O_{fbp,d}$	For each flexible baseload generation project *fbp* in each hour *t* on day d (T_d is the set of hours on day *d*), the power output $O_{fbp,t}$ is equal to the output $O_{fbp,d}$ committed for that day.

MAX_DISPATCH$_{fbp,d}$ $O_{fbp,d} \leq (1 - o_{fbp}) \times \sum_i G_{fbp,i}$	For each flexible baseload generation project *fbp* on every day d, the output $O_{fbp,d}$ on that day cannot exceed the sum, de-rated by the generator's forced outage rate o_{fbp}, of generator capacities $G_{fbp,i}$ installed at generator *fbp* in the current and preceding periods i. The operational generator lifetime limits the extent of the sum over *i* to only periods in which the generator would still be operational, but is not included here for simplicity.

MIN_DISPATCH$_{fbp,t}$ $O_{fbp,d} \geq min\_loading\_frac_{fbp} \times \sum_i G_{fbp,i}$	For each flexible baseload generation project *fbp* on every day d, the output $O_{fbp,t}$ on that day must be more than the minimum loading fraction $min\_loading\_frac_{ip}$ times total installed capacity at project *fbp*.

4. ***Intermediate generators*** (natural gas combined cycle plants or natural gas steam turbines) cannot commit more capacity in each hour than their nameplate capacity, de-rated by their forced outage rate. Intermediate generation cannot provide more power, spinning reserve, and quickstart capacity in each hour than the amount of project capacity that was committed in that hour. Spinning reserve can only be provided in hours when the plant is committed and online and cannot exceed a pre-

specified fraction of capacity. Combined heat and power natural gas generators (cogenerators) are operated in baseload mode and are therefore not included here.

MAX_COMMIT$_{ip,t}$ $C_{ip,t} \leq (1 - o_{ip}) \times \sum_{i} G_{ip,i}$	For each intermediate generation project *ip* in every hour *t*, the capacity $C_{ip,t}$ commited in that hour cannot exceed the sum, de-rated by the generator's forced outage rate o_{ip}, of generator capacities $G_{ip,i}$ installed at generator *ip* in the current and preceding periods *i*. The operational generator lifetime limits the extent of the sum over *i* to only periods in which the generator would still be operational, but is not included here for simplicity.

MIN_DISPATCH$_{ip,t}$ $O_{ip,t} \geq min\_loading\_frac_{ip} \times C_{ip,t}$	For each intermediate generation project *ip* in every hour *t*, the power output $O_{ip,t}$ in that hour must be more than the minimum loading fraction $min\_loading\_frac_{ip}$ times total committed capacity $C_{ip,t}$ in that hour.

MAX_DISPATCH$_{ip,t}$ $O_{ip,t} + SP_{ip,t} + Q_{ip,t} \leq C_{ip,t}$	For each intermediate generation project *ip* in every hour *t*, the expected amount of power $O_{ip,t}$, spinning reserve $SP_{ip,t}$, and quickstart capacity $Q_{ip,t}$ supplied by the intermediate generator in that hour cannot exceed the generator capacity $C_{ip,t}$ committed in that hour.

MAX_SPIN$_{ip,t}$ $SP_{ip,t} \leq spin\_frac_{ip} \times C_{ip,t}$	For each intermediate generation project *ip* in every hour *t*, the spinning reserve $SP_{ip,t}$ supplied by the dispatchable generator in that hour cannot exceed a pre-specified fraction of committed capacity. This constraint is tied to the amount actually committed $C_{ip,t}$ to ensure that spinning reserve is only provided in hours when the plant is also producing useful generation. The parameter $spin\_frac_{ip}$ is based on the generator's 10-minute ramp rate.

STARTUP$_{ip,t}$ $ST_{ip,t} \geq C_{ip,t} - C_{ip,t-1}$	For each intermediate project *ip* in every hour *t*, the amount of capacity started up equals the committed capacity $C_{ip,t}$ in hour t minus the committed capacity $C_{ip,t-1}$ in the previous

	hour *t-1*.

5. ***Dispatchable generators*** (natural gas combustion turbines) cannot provide more power, spinning reserve, and quickstart capacity in each hour than their nameplate capacity, de-rated by their forced outage rate. Spinning reserve can only be provided in hours when the plant is also producing useful generation and cannot exceed a pre-specified fraction of capacity.

MAX_DISPATCH$_{dp,t}$ $O_{dp,t} + SP_{dp,t} + Q_{dp,t} \leq (1 - o_{dp}) \times \sum_{i} G_{dp,i}$	For each dispatchable generation project *dp* in every hour *t*, the expected amount of power $O_{dp,t}$, spinning reserve $SP_{dp,t,}$ and quickstart capacity $Q_{dp,t}$ supplied by the dispatchable generator in that hour cannot exceed the sum, de-rated by the generator's forced outage rate o_{dp}, of generator capacities $G_{dp,i}$ installed at generator *dp* in the current and preceding periods *i*. The generator's operational lifetime limits the extent of the sum over *i* to only periods in which the generator would still be operational, but is not included here for simplicity.

MAX_SPIN$_{dp,t}$ $SP_{dp,t} \leq \frac{spin\_frac_{dp}}{1 - spin\_frac_{dp}} \times O_{dp,t}$	For each dispatchable project *dp* in every hour *t*, the spinning reserve $SP_{dp,t}$ supplied by the dispatchable generator in that hour cannot exceed a pre-specified fraction of capacity. This constraint is tied to the amount actually dispatched $O_{dp,t}$ to ensure that spinning reserve is only provided in hours when the plant is also producing useful generation.

STARTUP$_{dp,t}$ $ST_{dp,t} \geq O_{dp,t} - O_{dp,t-1}$	For each dispatchable project *dp* in every hour *t*, the amount of capacity started up equals the output $O_{dp,t}$ in hour t minus the ouput $O_{dp,t-1}$ in the previous hour *t-1*.

6. ***Hydroelectric generators*** must provide output equal to or exceeding a pre-specified fraction of the average hydroelectric energy production for that day in each load area

in each hour, in order to maintain downstream water flow. The total energy (which, for pumped hydro, includes energy released from storage) and operating reserves provided by hydro projects in each load area in each hour cannot exceed the load area's total turbine capacity, de-rated by the hydroelectric projects' forced outage rate. Operating reserves from hydro cannot exceed a pre-specified fraction of capacity. The amount of energy produced from all hydroelectric facilities in a load area over the course of each study day must equal the historical daily average energy production for that day's month.

$HYDRO\_MIN\_DISP_{hp,t}$ $O_{hp,t \in T_d} \geq ah_{h,d} \times mf$	For every hydroelectric project *hp* in every hour *t* on day *d*, the amount of energy $O_{hp,t}$ dispatched by the project must be greater than or equal to a pre-specified average hourly flow rate for that project for that day, $ah_{hp,d}$, times a pre-specified minimum dispatch fraction, *mf*, necessary to maintain stream flow.

$HYDRO\_MAX\_DISP_{hp,t}$ $O_{hp,t} + R_{php,t} + OP_{hp,t} + OP_{php,t} \leq (1 - o_{hp}) \times hg_{hp}$	For every hydroelectric project *hp* in every hour *t*, the sum of watershed energy output $O_{hp,t}$ and operating reserve $OP_{hp,t}$ as well as, for pumped hydroelectric projects *php*, energy dispatched from storage, $R_{php,t}$, and operating reserve from storage, OP_{php}, cannot exceed the project's capacity, hg_{hp}, de-rated by the forced outage rate o_{hp}.

$HYDRO\_MAX\_OP\_RESERVE_{hp,t}$ $OP_{hp,t} \leq hydro\_op\_reserve\_frac \times hg_{hp}$	For every hydroelectric project *h* in every hour *t*, the amount of operating reserve $OP_{hp,t}$ dispatched cannot exceed a fraction *hydro_op_reserve_frac* of the project's capacity, hg_{hp}.

$HYDRO\_AVG\_OUTPUT_{hp,t}$ $\sum_{t \in T_d} O_{hp,t} = average\_daily\_output_d$	For every hydroelectric project *hp* and every day *d*, the historical average flow must be met, i.e. the sum over all hours on day *d* of energy, $O_{hp,t}$, dispatched by the hydroelectric project *p* must equal a pre-specified average daily level $average\_daily\_output_d$ for that day. T_d is the set of hours on day *d*.

7. ***Storage facilities*** cannot store more power in each hour than their maximum hourly store rate, de-rated by forced outage rate, and dispatch no more power in each hour than total capacity, de-rated by forced outage rate. Compressed Air Energy Storage (CAES) projects must maintain the proper ratio between dispatch of energy stored in the form of compressed air and energy dispatched from natural gas. In SWITCH-CHINA, days are modeled as independent dispatch units. The energy dispatched by each storage project each day must equal the energy stored by the project on that day,

adjusted for the storage project's round-trip efficiency losses.

MAX_STORE_RATE$_{sp,t}$ $S_{sp,t} \leq (1 - o_s)\times r_s\times \sum_i G_{sp,i}$	For every storage project *sp* in every hour *t*, the amount of energy, $S_{sp,t}$, stored at the storage project *s* in hour *t* cannot exceed the product of a pre-specified store rate for that project, $r_{sp,}$ and the total capacity $G_{sp,t}$ installed at project *sp* in the current and preceding periods *i*, de-rated by the storage project's forced outage rate o_{sp} (for pumped hydro, that's the preexisting capacity as no new capacity can be installed in SWITCH-CHINA). The operational storage project lifetime limits the extent of the sum over *i* to only periods in which the storage project would still be operational, but is not included here for simplicity.

MAX_BATTERY_STORAGE_DISPATCH$_{bp,t}$ $R_{bp,t} + OP_{bp,t} \leq (1 - o_{bp})\times r_{bp}\times \sum_i G_{bp,i}$	For every battery storage project *s* in every hour *t*, the amount of energy dispatched from the storage project in that hour, $R_{bp,t}$, plus the operating reserve provided $OP_{bp,t}$ in that hour cannot exceed the sum, de-rated by the storage project's forced outage rate o_s, of the storage project power capacity $G_{bp,i}$ installed in the current and preceding periods *i* (for pumped hydro, that's the preexisting capacity as no new capacity is installed).

MAX_CAES_DISPATCH$_{cp,t}$ $R_{cp,t} + OP_{bp,t} + O_{cp,t} + SP_{cp,t} + Q_{cp,t} \leq (1 - o_{cp})\times r_{cp}\times \sum_i G_{cp,i}$	For every CAES storage project *s* in every hour *t*, the sum of the energy dispatch, $R_{cp,t}$, and the operating reserve $OP_{cp,t}$ provided by the storage plant plus the energy $O_{cp,t}$, spinning reserve $SP_{cp,t}$ and quickstart reserve $Q_{cp,t}$ provided from natural gas cannot exceed the plant's total power capacity $SG_{cp,i}$ installed in the current and preceding periods *i*, de-rated by the plant's forced outage rate o_{cp}.

CAES_COMBINED_DISPATCH$_{cp,t}$ $R_{cp,t} = O_{cp,t}\times caes\_ratio$	For every CAES project *cp* in every hour *t*, the amount of energy dispatched from storage, $R_{cp,t}$, must equal the amount of energy dispatched from natural gas $O_{cp,t}$ multiplied by the dispatch ratio between storage and natural gas *caes_ratio*. The *caes_ratio* is derived from the storage efficiency and overall round-trip efficiency of CAES and is calculated to be ~1.4.

CAES_COMBINED_OR$_{cp,t}$	For every CAES project *cp* in every hour *t*, the amount of operating reserve dispatched from the

$OR_{cp,t} = (SP_{cp,t} + Q_{cp,t}) \times caes\_ratio$	CAES project in that hour must equal the operating reserve (spinning plus quickstart) dispatched from natural gas ($SP_{cp,t}$+ $Q_{cp,t}$) multiplied by the dispatch ratio between storage and natural gas *caes_ratio*.

$STORAGE\_ENERGY\_BALANCE_{sp,t}$ $$\sum_{t \in T_d} R_{sp,t} + op\_disp\_freq \times \sum_{t \in T_d} OR_{sp,t} = \sum_{t \in T_d} S_{sp,t} \times e_{sp}$$	For each storage project *sp* on each day *d*, the energy dispatched by the storage project in all hours *t* on day *d* must equal the energy stored by the storage project in all hours *t* on day *d*, de-rated by the storage project's round-trip efficiency e_s. It is assumed that operating reserve is called upon a fraction of the time, *op_fraction*, and this is included in the energy balance. T_d is the set of hours on day *d*.

8. ***Transmission lines*** cannot transfer more energy in each hour in each direction between each pair of connected load areas than the lines' capacity, de-rated by its forced outage rate. Once a transmission line is installed, it is assumed to remain in operation for the rest of the study.

$MAX\_TRANS_{a,a1,t}$ $$Tr_{a,a',t} \leq (1 - o_{a,a'}) \times (et_{a,a'} + \sum_{i} T_{a,a',i})$$	For each transmission line *(a, a')* in every hour *t*, the total amount of energy, $Tr_{a,a',t}$ dispatched along the transmission line between load areas *a* and *a'* in each hour *t* cannot exceed the sum, de-rated by the transmission line's forced outage rate $o_{a,a'}$, of the pre-existing transfer capacity $et_{a,a'}$ and the sum of additional capacities $T_{a,a',i}$ installed between the two load areas in the current and all preceding periods *i*.

2 Data Description

2.1 Load Areas: Geospatial Definition

SWITCH-China divides the geographic region of mainland China into 31 load areas, each province represents one independent load area. Hong Kong Special Administration Region (SAR) and Macau SAR, and Taiwan are excluded in this study. Inner Mongolia is divided into East Inner Mongolia and West Inner Mongolia as they belong to two separate grids. These areas represent sections of the grid within which there is significant existing local transmission and distribution, but between which there is limited existing long-range, high-voltage transmission. Consequently, load areas are areas between which transmission investment may be beneficial.

Load areas are divided predominantly according to pre-existing administrative and geographic boundaries, including, in descending order of importance: provincial boundaries and regional grid boundary. In addition, load area boundaries are defined to capture as many currently congested transmission corridors as possible. These pathways are some of the first places where transmission is likely to be built, and exclusion of these pathways in definition of load areas would allow power to flow without penalty along overloaded transmission lines.

Figure SI-1 Load areas and regional grids in SWITCH-China

2.2 Transmission Lines

The existing transmission capacity between load areas is found by matching transmission line data with State Energy Regulatory Commission (SERC) data (SERC 2012c). A small fraction of lines could not be matched to lines found in the SERC database; these lines are ascribed a generic transfer capacity equal to the average transfer capacity of their voltage class. In total, 186 existing inter-load-area transmission corridors are represented in SWITCH-CHINA.

The substation in each load area is chosen by the capital city that usually has the largest substation and total transfer capacities of all lines into and out of each load area. It is assumed that all power transfer between load areas occurs between these capital cities, using the corresponding distances along existing transmission lines between these capital cities. If no existing path is present, new transmission can be built between adjacent load areas assuming the same distances. The amount of power that can be transferred along each transmission line is set at the rated thermal limits of individual transmission lines. Additionally, transmission power losses are taken into account at 1 percent of power lost for every 200 kilometers over which it is transmitted (SERC 2012c).

Table SI-1 Transmission project cost in regional grids

Regional Grid	Voltage	Capacity (MW)	Line cost (10^4RMB/km)	Substation cost (RMB/kVA)
Cross region and the Three Gorges	330kV	1000	74.38	187.99
	500kV	1400	167.49	338.43
	1000kV	6400	462.62	340.70
North China	110kV	200	63.59	386.05
	220kV	700	98.37	328.85
	500kV	1400	182.22	193.59
Northeast China	110kV	200	58.11	468.84
	220kV	700	92.60	244.25
	500kV	1400	183.59	221.61
Northwest China	110kV	200	44.94	410.64
	220kV	700	75.49	345.76
	330kV	1000	101.76	318.27
	750kV	1400	257.62	285.54
East China	110kV	200	71.71	367.11
	220kV	700	135.49	320.76
	500kV	1400	332.15	196.60
Central China	110kV	200	54.69	356.89
	220kV	700	95.36	271.39
	500kV	1400	196.99	194.60
Southern China	110kV	200	64.90	381.86
	220kV	700	98.91	308.85
	500kV	1400	202.89	212.68

Source: *Grid Project Construction Cost Analysis in the 11th Five-year Period.*

The costs of building new transmission lines are derived from the Grid Project Construction Cost Analysis in the 11th Five-year Period (“十一五”期间投产电网工程项目造价分析) released by the State Electricity Regulatory Commission, Electric Power

Planning & Engineering Institute (电力规划设计总院), and Water Resources and Hydropower Planning and Design General Institute (水电水利规划设计总院). The transmission cost varies by line due to different surface conditions, however, it was assumed to be the same within each regional grid. For Ultra-High Voltage DC lines, the average capital cost of building transmission and substation is about \$300/MW·km, using ±800kV Xiangjiaba (向家坝)-Shanghai (上海) demonstration line as a case.

2.3 Local T&D and Transmission Costs

The costs for existing transmission and distribution systems are derived from the regional electricity tables of the SERC 2010 Annual Electricity Regulatory Report. The \$/MWh cost incurred in 2010 for each SERC regional grids is apportioned by present-day average load to each load area and is then assumed to be a sunk cost over the whole period of study. All existing transmission and distribution capacity is therefore implicitly assumed to be kept operational indefinitely, incurring the associated operational costs.

This study assumes that the distribution network is built to serve the peak load of 2010, and that in future investment periods this is assumed as a liner function with the growth of demand. Investment in new local transmission and distribution is therefore a sunk cost as projected loads are exogenously calculated. Distribution losses are assumed to be 6.5 percent of electricity transmitted (SERC 2012c); commercial and residential distributed PV technologies are assumed to experience zero distribution losses as they are sited inside the distribution network.

2.4 Load Profiles

The historical annual load was reported by the SERC Annual Electricity Regulatory Report. The daily load profile by hour, and the yearly load profile by month are obtained from the and State Grid Power Economic Research Institute (W. Chen et al. 2008). Future annual electricity demand by province in 2030 are derived from the results of ILE4 lab led by Dr. HU Zhaoguang in the State Grid Energy Research Institute (Z. Hu, Tan, and Xu 2011). According to the report, the electricity demand will reach 12,100 TWh and 14,300 TWh by 2040 and 2050, respectively. From 2030-2040, annual growth rate of electricity demand is 2.12 percent, and 2040-2050 is 1.7 percent for all provinces, same as the national growth rate (Z. Hu, Tan, and Xu 2011). The hourly load is calculated based on the electricity demand and typical yearly load profile by month and typical daily profile by hour, assuming there is no major difference between weekdays and weekends.

$$\text{Hourly load} = \frac{\text{Annual electricity demand} \times \text{Monthly share of load in a year}}{\text{Number of days in a month}} \times \text{Hourly share of load in a day}$$

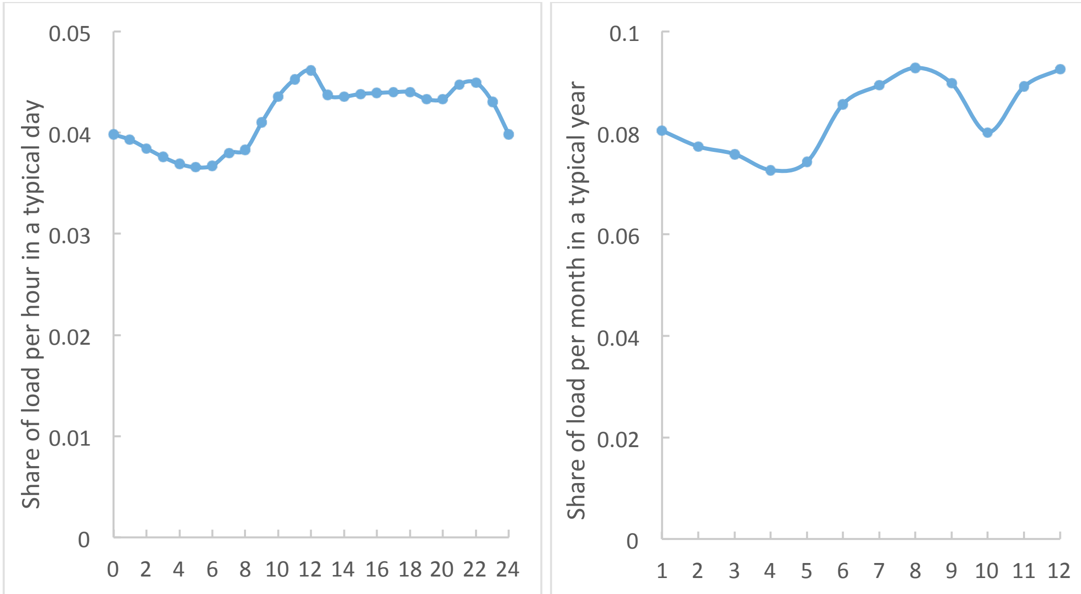


Figure SI-2 Typical daily load profile by hour and yearly load profile by month

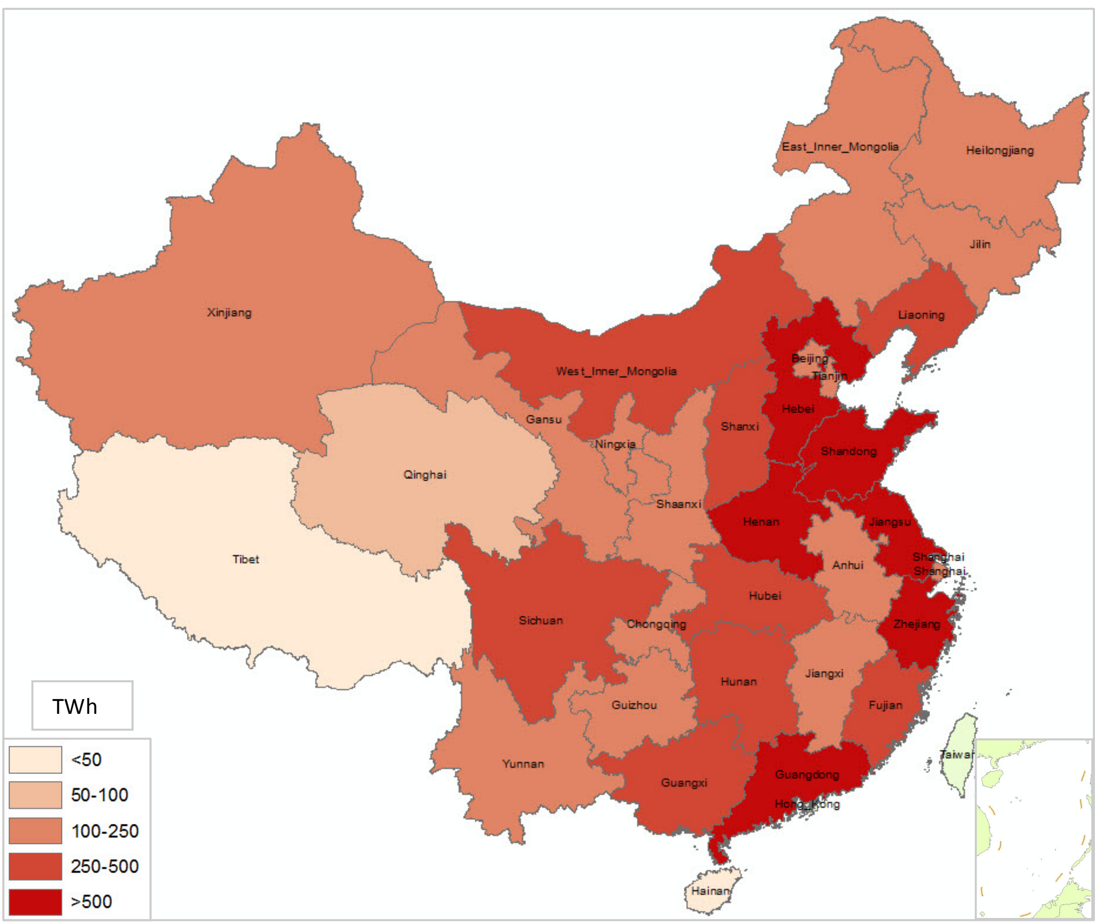


Figure SI-3 Total projected load in 2030 for each load area

2.5 Renewable Portfolio Standards/Non-fossil targets/Technology-specific targets

Provincial or national Renewable Portfolio Standards (RPS), non-fossil targets (NFT), or technology-specific targets require a fraction of electricity consumed within a load area to be produced by qualifying generators. RPS/NFT targets are subject to the political structure of each region and are therefore heterogeneous in not only what resources qualify as renewable or non-fossil, but also when, where and how the qualifying renewable or non-fossil power is made and delivered. To maintain computational feasibility, RPS is modeled as a yearly target for each load area for the percentage of load that must be met by delivered qualified power. Delivered power is power that is either generated within a load area and consumed immediately, or added to the power mix of the load area via transmission. To ensure proper accounting, the stocks and flows of qualifying power is kept separate from non-qualifying power.

Table SI-2 Technology specific targets in China's power sector

<table>
<tr><th>Category</th><th>Targets</th><th>2015</th><th colspan="2">2020</th><th colspan="2">Source</th></tr>
<tr><td rowspan="2">Wind</td><td>Onshore wind (GW)</td><td>99</td><td>170</td><td rowspan="2">(200)</td><td rowspan="2">Wind development 12th Five-year plan</td><td rowspan="6">(China Energy Developm ent Strategy Action Plan 2014-2020)</td></tr>
<tr><td>Offshore wind (GW)</td><td>5</td><td>30</td></tr>
<tr><td rowspan="3">Solar</td><td>Central PV (GW)</td><td>10</td><td>20</td><td rowspan="3">(100)</td><td rowspan="3">Solar development 12th Five-year plan</td></tr>
<tr><td>CSP (GW)</td><td>1</td><td>3</td></tr>
<tr><td>Residential PV
Commercial PV(GW)</td><td>10</td><td>27</td></tr>
<tr><td>Nuclear</td><td>Nuclear (GW)</td><td>25</td><td colspan="2">40 (58)</td><td>Nuclear Medium and Long-term development plan</td></tr>
</table>

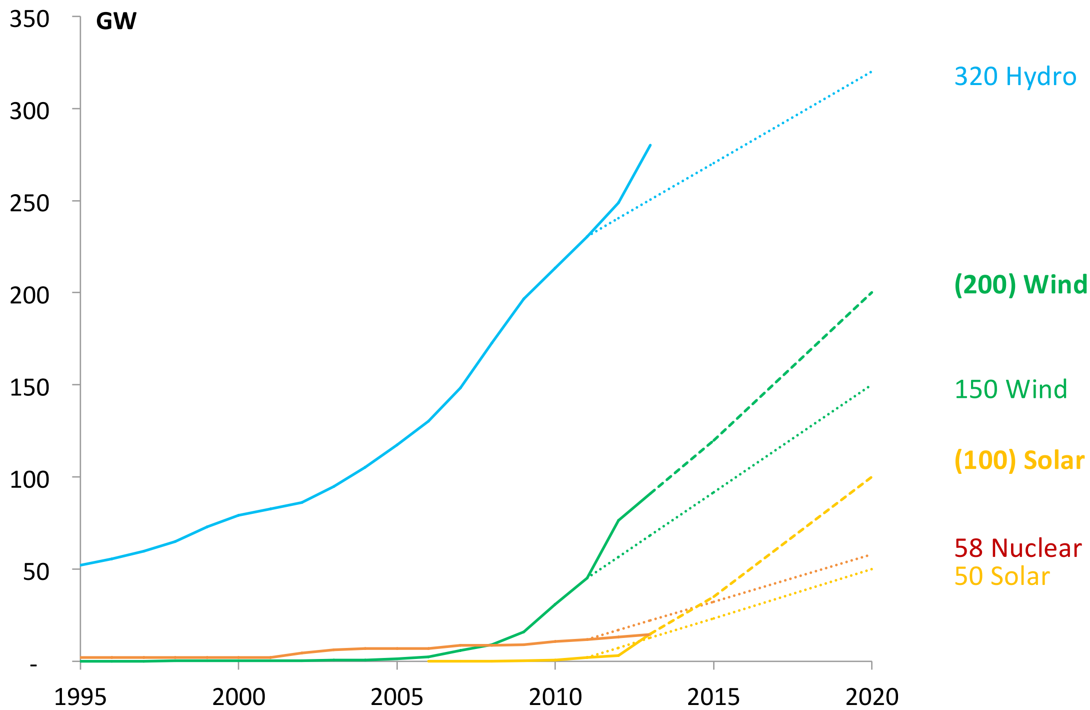


Figure SI-4 China's development of non-fossil fuel capacity and targets

In the version of SWITCH-CHINA used in this study, renewable power is defined as power from geothermal, biomass solid, biomass liquid, biogas, solar or wind power plants, and hydro power. Non-fossil targets include nuclear in China's context. China also has wind, solar and nuclear specific targets in the national plans.

2.6 Fuel Prices

Fuel prices of coal, natural gas, uranium and biomass are summarized from multiple sources. Historical coal prices in Qinhuangdao, a benchmark price for Chinese coal market, are obtained from China Coal Transportation and Distribution Association (CCTD). Exchange rates are derived from IRS yearly average currency exchange rates[8]. The price differences between average coal prices of each province and Qinhuangdao coal price are comparatively stable, which is a reflection of the transportation cost and other costs (Morse and He 2010). An annual 1 percent growth rate from 2010 to 2050 of Qinhuangdao's coal price is applied based on historical long-term trends. Then the transportation cost from Qinhuangdao is used to get coal prices for each province in each year between 2011 and 2050. All fuel prices are then converted into $/MBtu.

[8] IRS, Yearly average currency exchange rates. http://www.irs.gov/Individuals/International-Taxpayers/Yearly-Average-Currency-Exchange-Rates (accessed May 12, 2014)

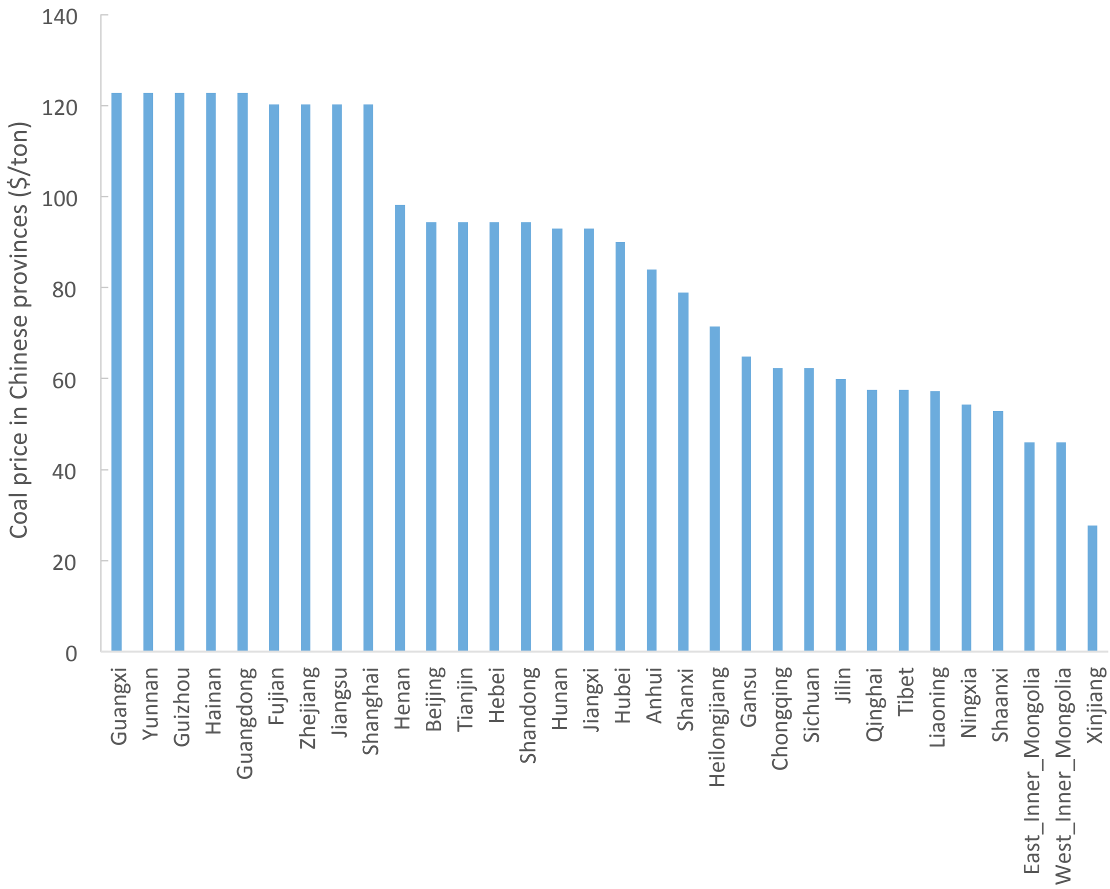


Figure SI-5 Average coal prices in China in 2010

Natural gas fuel price projections for electric power generation originate from the Asian LNG price developments in the IEA's Medium-Term Gas Market Report 2013, China paid around 11$/Mbtu in 2012 for LNG import from Australia, Indonesia and Malaysia (IEA 2013a). For future price, annual growth rates are derived from Annual Energy Outlook 2013, where yearly projections are made for each provinces through 2035, and are extrapolated for years after 2035 (EIA 2013).

Oil and uranium prices are more or less globalized markets. Therefore, oil prices projections are derived from the World Energy Outlook 2013 (IEA 2013b) and uranium price projections are taken from the California Energy Commission's 2010 Cost of Generation Model (Klein et al. 2009). Both prices use Chinese benchmark price in 2010 and apply the projection to future prices.

The prices of natural gas, oil and uranium do not assume regional disparity in this model.

2.7 Existing Generators

Existing Generator Data

Existing generators in SWITCH-CHINA are geolocated using the Manual of National Generation Units (全国机组手册) published by the Electricity Reliability Center under SERC (SERC 2013). Generators whose primary fuel is coal, natural gas, fuel oil, nuclear, water (hydroelectric, including pumped storage), geothermal, biomass solid, biomass liquid, biogas, wind or solar are included. The plant level data are summarized and matched with provincial capacity reported in the Electricity Statistical Yearbook.

Generator-specific heat rates of thermal power are derived from the Benchmarking and Competition in Energy Efficiency of National Thermal Plants 300MW Units in 2012 (2012 年度全国火电300MW级机组能效对标及竞赛资料) and Benchmarking and Competition in Energy Efficiency of National Thermal Plants 600MW Units in 2012e (2012 年度全国火电600MWe 级机组能效对标及竞赛资料) organized by China Electricity Council.

Costs of existing non-hydroelectric generators originate from compiling assumption from other models and interview with experts from the 'Big 5' Chinese power groups (China Huaneng Group, China Datang Corporation, China Huadian Group, China Guodian Corporation, and Power Investment Corporation). To reflect shared infrastructure costs, capital costs of cogeneration plants are assumed at 75 percent of the capital cost of those without cogeneration. Capital costs of existing plants are included as sunk costs and therefore do not influence decision variables.

Existing plants are not allowed to operate past their expected lifetime with the exception of nuclear plants, which are given the choice to continue plant operation by paying all operational costs in investment periods past the expected lifetime of the plant. In order to reduce the number of decision variables, non-hydroelectric generators are aggregated by prime mover for each plant and hydroelectric generators are aggregated by load area.

Existing Hydroelectric and Pumped Hydroelectric Plants

Hydroelectric and pumped hydroelectric generators include constraints derived from historical monthly generation data from 2010. For non-pumped hydroelectric generators in China, monthly net generation data from the China Electricity Council is employed. Hydroelectric and non-pumped hydroelectric plants that are less than 1GW are aggregated to the load area level in order to reduce the number of decision variables.

For pumped hydroelectric generators, the use of net generation data is not sufficient, as it takes into account both electricity generated from in-stream flows and efficiency losses from the pumping process. The total electricity input to each pumped hydroelectric generator is used to correct this factor. By assuming a 74 percent round-trip efficiency

(Electricity Storage Association 2010) and monthly in-stream flows for pumped hydroelectric projects similar to those from non-pumped projects, the monthly in-stream flow for pumped projects is derived.

New hydroelectric facilities are not built in the current version of the model.

Existing Wind Plants

Hourly existing wind farm power output is derived from the 3TIER wind speed dataset using idealized turbine power output curves on interpolated wind speed values. The total capacity, number of turbines, and installation year of each wind farm in China that currently exists or is under construction is obtained from the Energy Research Institute and the UNEP Risoe CDM/JI Pipeline Analysis and Database. The total existing wind farm capacity in China by 2010 is 45 GW, those from UNEP data sum up to 40GW, and this study assumed a big wind farm in each province to fill the capacity gaps in the province. Wind farms are geo-located by extracting the location information from the project design documents (PDD) files of wind farms in the UNEP dataset.

Historical production from existing wind farms could not be used as many of these wind projects began operation after the historical study year of 2006. In addition, historical output would include forced outages, a phenomenon that is factored out of hourly power output in SWITCH-CHINA.

In order to calculate hourly capacity factors for existing wind farms, the rated capacity of each wind turbine is used to find the turbine hub height and rotor diameter using averages by rated capacity from 'The Wind Power' wind turbines and wind farms database. Wind speeds are interpolated from wind points found in the 3TIER wind dataset to the wind farm location using an inverse distance-weighted interpolation. The resultant speeds are scaled to turbine hub height using a friction coefficient of 1/7 (Masters 2004). These wind speeds are put through an ideal turbine power output curve (Westergaard 2009) to generate the hourly power output for each wind farm in each province.

2.8 New Generators

Capital and O&M Costs

The present day capital costs and operation and maintenance (O&M) costs for each power plant type originate primarily from Electric Project Construction Cost Analysis in the 11th Five-year Period ("十一五"期间投产电源工程项目造价分析)(SERC 2012a), with reference of U.S. data as comparison (Black & Veatch 2012). Costs for most technologies are assumed to stay flat through 2050 as these technologies are mature. Technologies that are assumed to decline in costs over time include solar, wind, offshore wind, CCS, and battery storage.

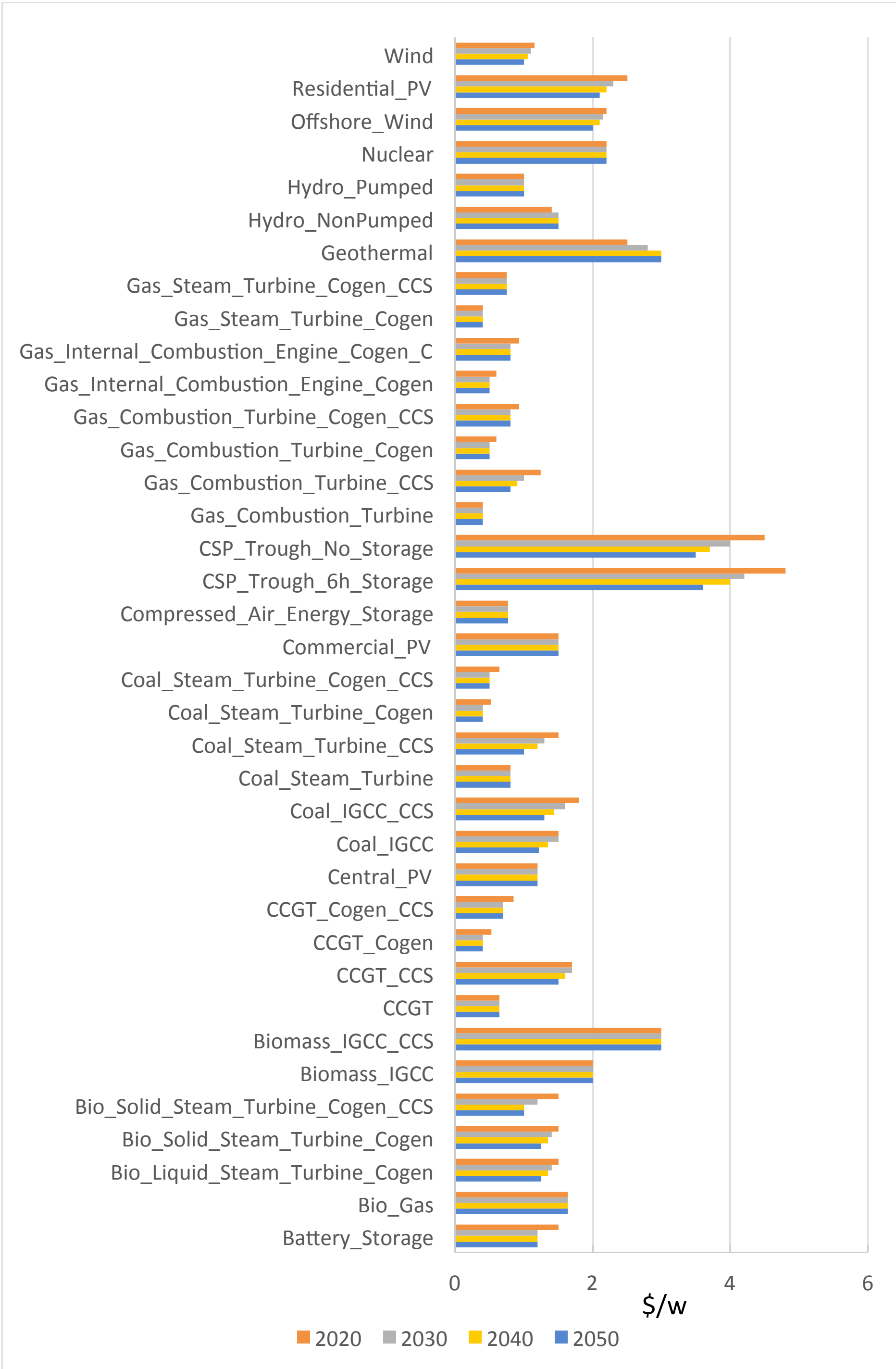


Figure SI-6 Generator and storage overnight capital costs in each investment period

Note: The shown costs do not include expenses related to project development such as interest during construction, connection costs to the grid and upgrades to the local grid, though these costs are included in the SWITCH optimization.

Table SI-3 New generator parameters, including heat rate, construction time, lifetime, forced and scheduled outage rates, and fixed and variable O&M costs

Technology	Heat Rate (MMBtu/ MWh)	Construction Time (yrs)	Max Age (yrs)	Forced Outage Rate	Scheduled Outage Rate	Fixed O&M Rate	Var O&M ($/ MWh)
Battery_Storage	0.0	3	15	2.0%	0.6%	1.0%	0.4
Bio_Gas	13.7	2	30	4.1%	3.2%	1.0%	0.1
CCGT	6.5	2	20	2.2%	6.0%	2.0%	1.7
CCGT_CCS	7.5	2	20	2.2%	6.0%	2.0%	4.0
Central_PV	0.0	1	20	2.0%	0.0%	2.0%	0.0
Coal_IGCC	8.7	3	40	5.0%	15.0%	1.0%	3.0
Coal_IGCC_CCS	10.7	3	40	5.0%	15.0%	1.0%	3.0
Coal_Steam_Turbine	8.8	3	40	5.0%	15.0%	1.0%	0.8
Coal_Steam_Turbine_CCS	12.0	3	40	5.0%	15.0%	1.0%	1.6
Commercial_PV	0.0	1	20	2.0%	0.0%	0.5%	0.0
Compressed_Air_Energy_Storage	4.4	6	30	3.0%	4.0%	2.0%	2.0
CSP_Trough_6h_Storage	0.0	1	20	1.6%	2.2%	0.5%	0.0
CSP_Trough_No_Storage	0.0	1	20	1.6%	2.2%	0.5%	0.0
Gas_Combustion_Turbine	8.6	2	20	4.1%	3.2%	2.0%	3.0
Gas_Combustion_Turbine_CCS	9.9	2	20	4.1%	3.2%	2.0%	3.0
Geothermal	0.0	3	30	2.5%	4.0%	1.0%	2.0
Hydro_NonPumped	0.0	6	30	5.1%	9.4%	0.3%	0.0
Hydro_Pumped	0.0	6	30	5.1%	9.4%	0.3%	0.0
Nuclear	10.4	6	60	2.7%	11.1%	3.0%	3.0
Nuclear_SMR	10.4	3	40	2.7%	11.1%	3.0%	2.5
Offshore_Wind	0.0	2	30	2.0%	2.6%	2.0%	4.7
Residential_PV	0.0	1	20	2.0%	0.0%	0.5%	0.0
Wind	0.0	2	30	2.0%	1.4%	1.0%	2.8

Connection Costs

The cost to connect new generators to the existing electricity grid is derived from the SERC Annual Electricity Regulatory Report (SERC 2012c). Connection costs for different technologies are shown in Table SI-4 below. The generic connection cost category applies to projects that are not sited at specific geographic locations in SWITCH-CHINA. For these projects, it is assumed that it is possible to find a project site near existing transmission in each load area, thereby not incurring significant costs to build new transmission lines to the grid.

The site-specific connection cost category applies to projects that are sited in specific geographic locations but are not considered distributed generation in SWITCH-CHINA. For these projects, the calculated cost to build a transmission line from the resource site to the nearest substation at or above 110 kV replaces the cost to build a small transmission line above. The cost to build this new line is $300 per MW per km, the same as to the assumed cost of building transmission between load areas. Underwater transmission for offshore wind projects is assumed to be five times this cost, namely $1500 per MW per km. The load area of each site-specific project is determined through connection to the nearest substation, as the grid connection point represents the part of the grid into which these projects will inject power.

Table SI-4 Connection Cost Types in SWITCH-CHINA

Generic	**Site Specific**	**Distributed**
$3,000/MW ($2010)	$2,500/MW ($2010)	$0/MW ($2010)
No Additional Transmission	Additional Distance-Specific Transmission Costs Incurred	Interconnection Included In Capital Cost
Nuclear	Wind	Residential Photovoltaic
Gas Combined Cycle	Offshore Wind	Commercial Photovoltaic
Gas Combustion Turbine	Central Station Photovoltaic	
Coal Steam Turbine	Solar Thermal Trough, No Thermal Storage	
Coal Integrated Gasification Combined Cycle	Solar Thermal Trough, 6h Thermal Storage	
Biomass Integrated Gasification Combined Cycle		
Biogas		
Battery Storage		
Compressed Air Energy Storage		

Notes: As these costs represent costs to connect a generator to the electricity grid, they are the same per unit of capacity for generation with or without cogeneration and/or carbon capture and sequestration.

The distributed connection cost category currently applies to residential and commercial photovoltaic projects only. For these projects, the interconnection costs are included in project capital costs and are therefore not explicitly specified in other parts of the model.

The connection cost of existing generators is assumed to be included in the capital costs of each existing plant.

Non-Renewable Thermal Generators

<u>*Non-Renewable Non-CCS Thermal Generators*</u>

Nuclear steam turbines are modeled as baseload technologies. Their output remains constant in every study hour, de-rated by their forced and scheduled outage rates. Coal steam turbines and coal integrated gasification combined cycle plants (Coal IGCC) can vary output daily subject to minimum loading constraints, incurring heat rate penalties when operating below full load. These technologies are assumed to be buildable in any load area.

Natural gas combined cycle plants (CCGTs) and combustion turbines are modeled as dispatchable technologies and can vary output hourly. CCGTs incur costs and emission penalties when new capacity is started up and heat rate penalties when operating below full load. Combustion turbines incur startup costs and emissions when new capacity is started up. The optimization chooses how much to dispatch from these generators in each study hour, limited by their installed capacity and de-rated by their forced outage rate. All thermal technologies in SWITCH-CHINA have a fixed heat rate, except for coal, throughout all investment periods.

All existing cogeneration plants are given the option to continue operation indefinitely at the existing plant's capacity, efficiency and cost.

Non-Renewable Thermal Generators Equipped with Carbon Capture and Sequestration (CCS)

Generators equipped with carbon capture and sequestration (CCS) equipment are modeled similarly to their non-CCS counterparts, but with different capital, fixed O&M and variable O&M costs, as well as different power conversion efficiencies. Newly installable non-renewable CCS technologies are: Gas Combined Cycle, Gas Combustion Turbine, Coal Steam Turbine, Coal Integrated Gasification Combined Cycle. In addition, all carbon-emitting existing cogeneration plants are given the option to replace the existing plant's turbine at the end of the turbine's operational lifetime with a new turbine of the same type equipped with CCS.

Costs for Gas Combined Cycle and Coal Steam generators with CCS are obtained from Electric Project Construction Cost Analysis in the 11th Five-year Period (SERC 2012a). In order to account for the additional cost of installing a CCS system into types of power plants for which consistent and up-to-date CCS cost data is not readily available, the capital cost difference between non-CCS and CCS generators with the same prime mover is added to the capital cost of the non-CCS generator. For example, the capital cost of Gas Combustion Turbine CCS is assumed to be equal to the capital cost of non-CCS Gas Combustion Turbine plus the difference in capital costs between Gas Combined Cycle and Gas Combined Cycle CCS (all values in units of $/W). The same method is used for fixed O&M costs. As is the case with non-CCS cogeneration technologies, CCS cogeneration plants incur 75 percent of the capital cost of non-cogeneration plants to reflect shared infrastructure costs. Variable O&M costs for CCS generators increase relative to their non-CCS counterparts from costs incurred during O&M of the CCS equipment itself, as well as costs incurred from the decrease in efficiency of CCS power plants relative to non-CCS plants.

Large-scale deployment of CCS pipelines would require large interconnected pipeline networks from CO_2 sources to CO_2 sinks. CCS generators that are not near a CO_2 sink would be forced to build longer pipelines, thereby incurring extra capital cost. If a load area does not contain an adequate CO_2 sink within its boundaries, a pipeline between the largest substation in that load area and the nearest CO_2 sink is built, incurring costs consistent with those found in Middleton et al., 2009.

CCS technology is in its infancy, with a handful of demonstration projects completed to date. This technology is therefore not allowed to be installed in the 2015-2025 investment period, as gigawatt scale deployment would not be feasible in this timeframe. Starting in 2025, CCS generation can be installed in unlimited quantities.

Compressed Air Energy Storage

Conventional gas turbines expend much of their gross energy compressing the air/fuel mixture for the turbine intake. Compressed air energy storage (CAES) works in conjunction with a gas turbine, using underground reservoirs to store compressed air for the intake. During off-peak hours, CAES uses electricity from the grid to compress air. During peak hours, CAES adds natural gas to the compressed air and releases the mixture into the intake of a gas turbine. CAES projects in the SWITCH-CHINA are sited in aquifer geology, with unlimited CAES potential in almost all load areas.

A storage efficiency of 81.7 percent is used, in concert with a round trip efficiency of 1.4 (Succar and Williams 2008) to apportion generation between renewable and non-renewable fuel categories when RPS is enabled, as natural gas is burned in addition to the input electricity from the grid. In addition, a compressor to expander ratio of 1.2 (Greenblatt et al. 2007) is assumed.

Battery Storage

Sodium sulfur (NaS) batteries are modeled using performance data from Black and Veatch (2012) (Black & Veatch 2012). An AC-DC-AC storage efficiency of 76.7 percent is used. NaS battery storage is available for construction in all load areas and investment periods.

Geothermal and Biogas and Biomass Solid

By the end of 2010, China's installed capacity of geothermal was 27 MW, and that for biogas and biomass were 5.5 GW, according to China Electricity Council. The capacity is less than 1 percent of China's total capacity, therefore is not included in this version of SWITCH-China. In the next version, I will incorporate the generation from development of biomass, biogas and geothermal.

Wind and Offshore Wind Resources

Hourly wind output of each load area was obtained from He and Kammen (2014) with 3TIER wind hourly wind speed (He and Kammen 2014). Wind sites were selected by the following criteria:

1) Average annual wind speed larger than 6 m/s
2) Elevation less than 3000 meters
3) Slope less than 20 percent
4) Wind projects that already exist or are under development
5) Sites with the high wind energy density at 100 m within 100 km of existing or planned transmission networks
6) Sites with high degree of temporal correlation to load profiles near the grid

point

All of the wind points within China are aggregated into 200 wind farms. The power output for each wind site is averaged over the hour before each timestamp, and then these hourly averages are again averaged over each group of aggregated wind sites to create the hourly output of new wind farms.

Solar Resources

Weather file creation

Hourly weather and insolation files in the standard typical meteorological year 2 (TMY2) format for 200 sites for the historical year 2005 were obtained from Chinese Standard Weather Data (CSWD) in the EnergyPlus dataset (China Meteorological Bureau et al. 2005). The weather files are used as inputs to the National Renewable Energy Laboratory's Solar Advisor Model to calculate the simulated historical output of various types of solar projects.

Distributed Photovoltaic – Residential and Commercial

Residential and Commercial photovoltaic sites were chosen by overlaying the solar radiation layer and the land use raster layer of urban land (Long and Shen 2014), both at 1km×1km resolution. These cells were aggregated to 200 sites by joining adjacent grid cells.

In SAM, residential, commercial and central station photovoltaic systems are simulated using representative 300 W multi-crystalline silicon Suntech STP270-24-Vb-1 modules. For residential photovolatics, these modules are connected in a 10-module string to make a 3 kW array and are coupled with a 3 kW inverter. The array is southward facing, not shaded, and is tilted at an angle equal to the latitude of the SUNY grid cell. The module-to-grid derating factor is assumed to be 89 percent.

Commercial photovoltaic systems are simulated as a 100 kW array with a single point efficiency inverter at 95 percent efficiency and a DC capacity of 105 kW. The array is southward facing, not shaded, and is tilted at an angle equal to the latitude of the chosen sites. The module-to-grid de-rating factor is assumed to be 91 percent.

The roof area available for distributed photovoltaic development is estimated based on existing researches on urban area rooftop PV potential (Choi et al. 2011; Hofierka and Kaňuk 2009; Wiginton, Nguyen, and Pearce 2010) and NREL (Denholm and Margolis 2008) reports. Twenty percent of all residential and thirty percent of all commercial roof area is assumed to be available for development.

Central Station Solar – Photovoltaics and CSP

Land suitable for large-scale solar development is derived using land exclusion criteria from NREL study (Mehos and Perez 2005) but without a minimum insolation cutoff. Types of land excluded are: national parks, monuments, wildlife refuges, military land, urban areas, land with greater than 1 percent slope (at 1 km resolution), and parcels of land smaller than 1 km^2. In addition, only areas with land cover of wooded and non-wooded grassland, closed and open shrubland, and bare ground are assumed to be available for solar development. The available solar land is aggregated on the basis of average global insolation and DNI. .

In SAM, central-station photovoltaics are modeled as 100 MW (AC) arrays using the same mulitcrystalline panels discussed above and mounted on a single axis tracker. The array is connected to a single point efficiency inverter with 95 percent efficiency. The tracker is modeled using SunPower specifications (SunPower Corporation 2009), and as such is southward facing at a 20° tilt on a one-axis tracker, with ground coverage ratios of 0.20 at low latitudes, increasing to 0.24 at high latitudes. A de-rating factor of 90 percent is used to convert from power produced at the module to power available to the grid.

CSP systems without thermal storage and with 6 hours of storage are modeled in SAM using the ‘Physical Trough’ model for CSP parabolic trough systems. In total, 100 MW nameplate systems using Solargenix SGX-1 collectors in an ‘H’ configuration with an evaporative cooling system are modeled with a total field aperture area calculated by minimizing the total levelized cost of energy with respect to aperture area. Costs for CSP systems are scaled to this aperture area from the base cost values. Dispatch of CSP storage is embedded in the hourly capacity factors – it is an input parameter rather than a variable.

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