Supporting Information

for

"SWITCH-China: A Systems Approach to Decarbonize China's Power System"

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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 by the authors based on an earlier version of SWITCH-WECC maintained and developed in Professor Daniel 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. By simulating representative hours, the computing time has been reduced by a factor of 10 than simulating consecutive hours, from 20-30 hours to about 2-3 hours. 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 are 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*	pumped hydroelectric projects

PHP⊂S)		
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	
$G_{p,i}$	Generation or storage capacity to install at project *p* in investment period *i*
$T_{a,a',i}$	Transmission capacity to install between load area *a* and load area *a'* in investment period *i*
E_i	Whether or not to run existing plant *ep* in investment period *i* (binary)

Construction times are 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 times 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 today. 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 [1]. 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 per MW·km, reflecting the difficulty of new transmission siting and planning [2]. 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*
$SP_{p\subset \mathrm{DP}U\mathrm{IP},t}$	Spinning reserve provided by dispatchable or intermediate project *p* in hour *t* ($p\subset \mathrm{DP}U\mathrm{IP}$)
$Q_{p\subset \mathrm{DP}U\mathrm{IP},t}$	Quickstart capacity provided by project *p* in hour *t* ($p\subset \mathrm{DP}U\mathrm{IP}$)
$OP_{p\subset \mathrm{HP}U\mathrm{SP},t}$	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 [3]. This document allocates authority and responsibility for dispatch, sets an organizational hierarchy, and specifies a basic process and rules governing dispatch [4]. In 2007, the National Development and Reform Commission (NDRC), 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 [5]. 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 [6]. Therefore, in this study, we 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 [3,7]. 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 [6,7]. 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 [8]. 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	$+\sum_{p,t} O_{p,t} \times (m_{p,t} + f_{p,t} + c_{p,t}) \times hs_t$ $+ \sum_{p \subset \mathrm{DP} \cup \mathrm{IP}, t} SP_{p,t} \times (spf_{p,t} + spc_{p,t}) \times hs_t$	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

		$+\sum_{p\subset \text{FBP}\cup\text{IP},t} DC_{p,t} \times (dcf_{p,t} + dcc_{p,t}) \times hs_t$	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, $t_{a,a',i}$.
Transmission	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 [9]. The capital cost 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 [10], so 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 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 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 1990 carbon emissions levels in 2050 [11–13].

1.6.1 Load-Meeting Constraints

1. 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 during that same hour. 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$_{a,t}$	$NP_{a,t} \times (1 + dl) \leq$	For every load area *a*, in each hour *t*, the amount of non-distributed energy $NP_{a,t}$ consumed in the load area in 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$_{a,t,f}$ $DP_{a,t} \leq \sum_{vdp \in GP_a} O_{vdp,t}$	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	$$+\sum_{sp\in SP_a} R_{sp,t} - \sum_{sp\in SP_a} S_{sp,t}$$	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 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$_i$ $$\sum_{p,t \in T_i} O_{p,t} \times hr_p \times CO2_{f_p} + \sum_{p \in DP \cup IP, t \in T_i} SP_{p,t} \times sp\_penalty_p \times CO2_{f_p} + \sum_{p \in FBP \cup IP, t \in T_i} DC_{p,t} \times dc\_penalty_p \times CO2_{f_p} + \sum_{p \in DP \cup IP, t \in T_i} ST_{p,t} \times startup\_fuel_p \times CO2_{f_p} \leq carbon\_cap_i$$	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 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).

1.6.5 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$_{vp,t}$ $$O_{vp,t} = cf_{vp,t} \times (1 - o_{vp}) \times \sum_i G_{vp,i}$$	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$_{bp,t}$ $$O_{bp,t} = (1 - o_{bp}) \times (1 - s_{bp}) \times \sum_i G_{bp,i}$$	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$_{fbp,d}$	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

$$O_{fbp,d} \leq (1 - o_{fbp}) \times \sum_i G_{fbp,i}$$	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$_{hp,t}$	For every hydroelectric project *h* in every hour *t*, the

$OP_{hp,t} \leq hydro\_op\_reserve\_frac \times hg_{hp}$	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 *sp* 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 *sp* 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$_{cp,t}$ $R_{cp,t} + OP_{cp,t} + O_{cp,t} + SP_{cp,t} + Q_{cp,t} \leq (1 - o_{cp}) \times r_{cp} \times \sum_{i} G_{cp,i}$	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$_{cp,t}$ $OR_{cp,t} = (SP_{cp,t} + Q_{cp,t}) \times caes\_ratio$	For every CAES project *cp* in every hour *t*, the amount of operating reserve dispatched from the 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_{sp}. 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 [14]. 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 [14].

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 cost 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.

We assume 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 [14]; 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 [15]. 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 [16]. 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 [16]. 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.

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

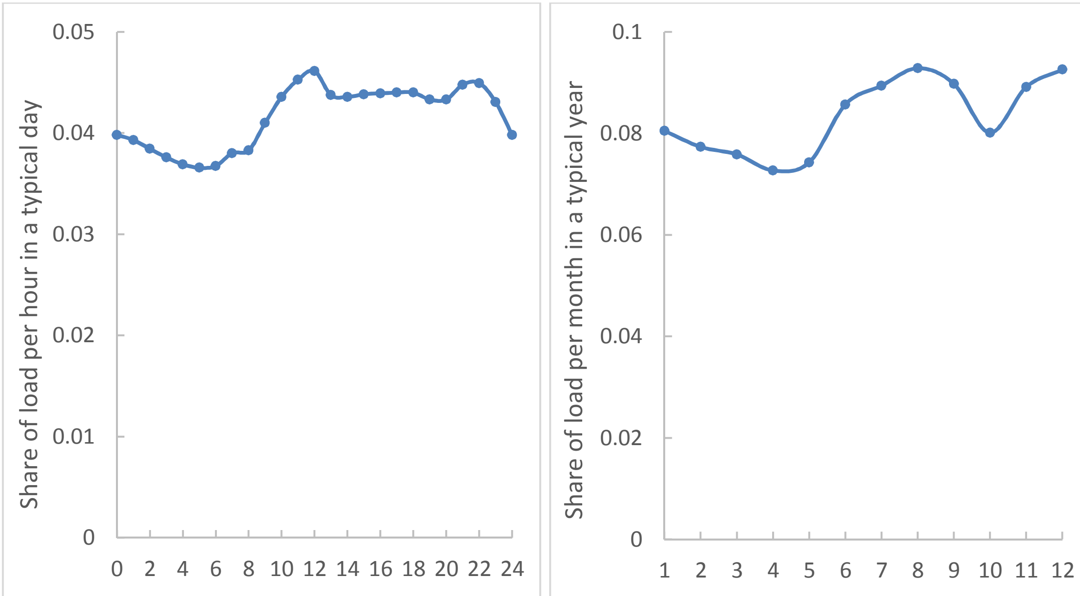

Figure SI-2 Typical daily load profile by hour and yearly load profile by month

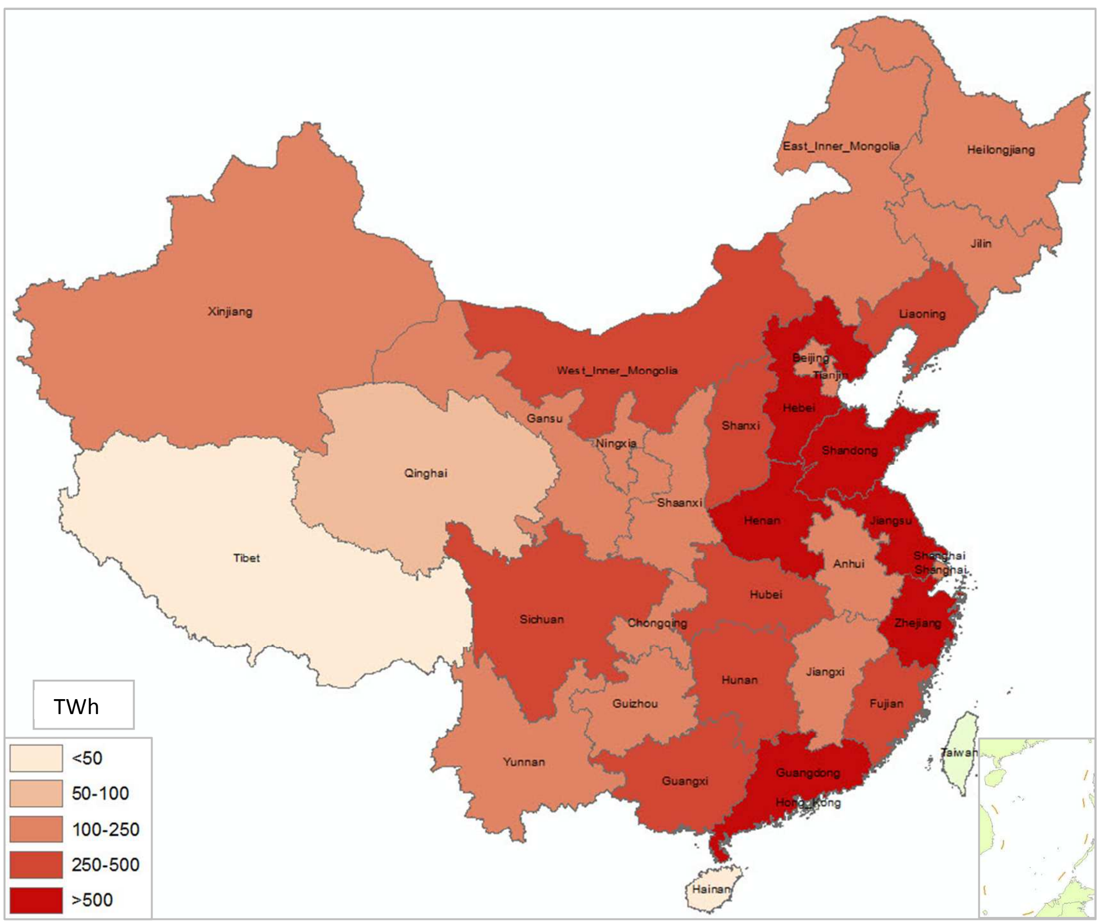

Figure SI-3 Total projected load in 2030 for each load area

2.5 Non-fossil targets/Technology-specific targets

Provincial or national non-fossil targets (NFT), or technology-specific targets require that a fraction of electricity consumed within a load area be produced by qualifying generators. 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.

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

Category	Targets	2015	2020		Source	
Wind	Onshore wind (GW)	99	170	(200)	Wind development 12^{th} Five-year plan	(China Energy Development Strategy Action Plan 2014-2020)
	Offshore wind (GW)	5	30			
Solar	Central PV (GW)	10	20	(100)	Solar development 12^{th} Five-year plan	
	CSP (GW)	1	3			
	Residential PV Commercial PV(GW)	10	27			
Nuclear	Nuclear (GW)	25	40 (58)		Nuclear Medium and Long-term development plan	

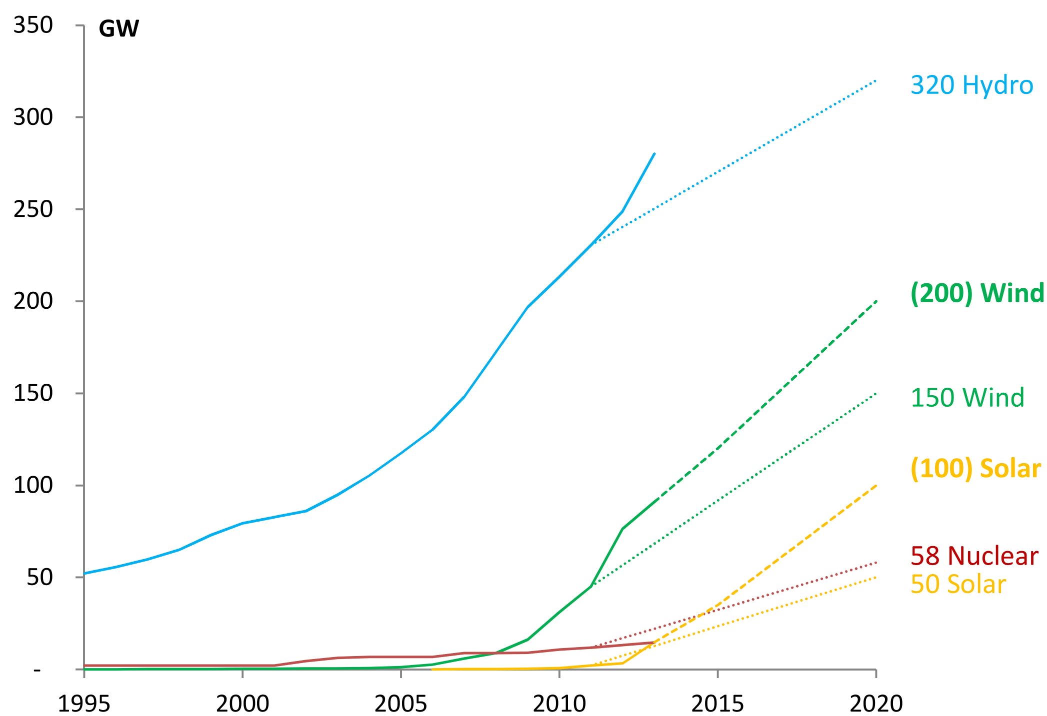

Figure SI-4 China's development of non-fossil fuel capacity and targets

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[1]. 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 [17]. 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.

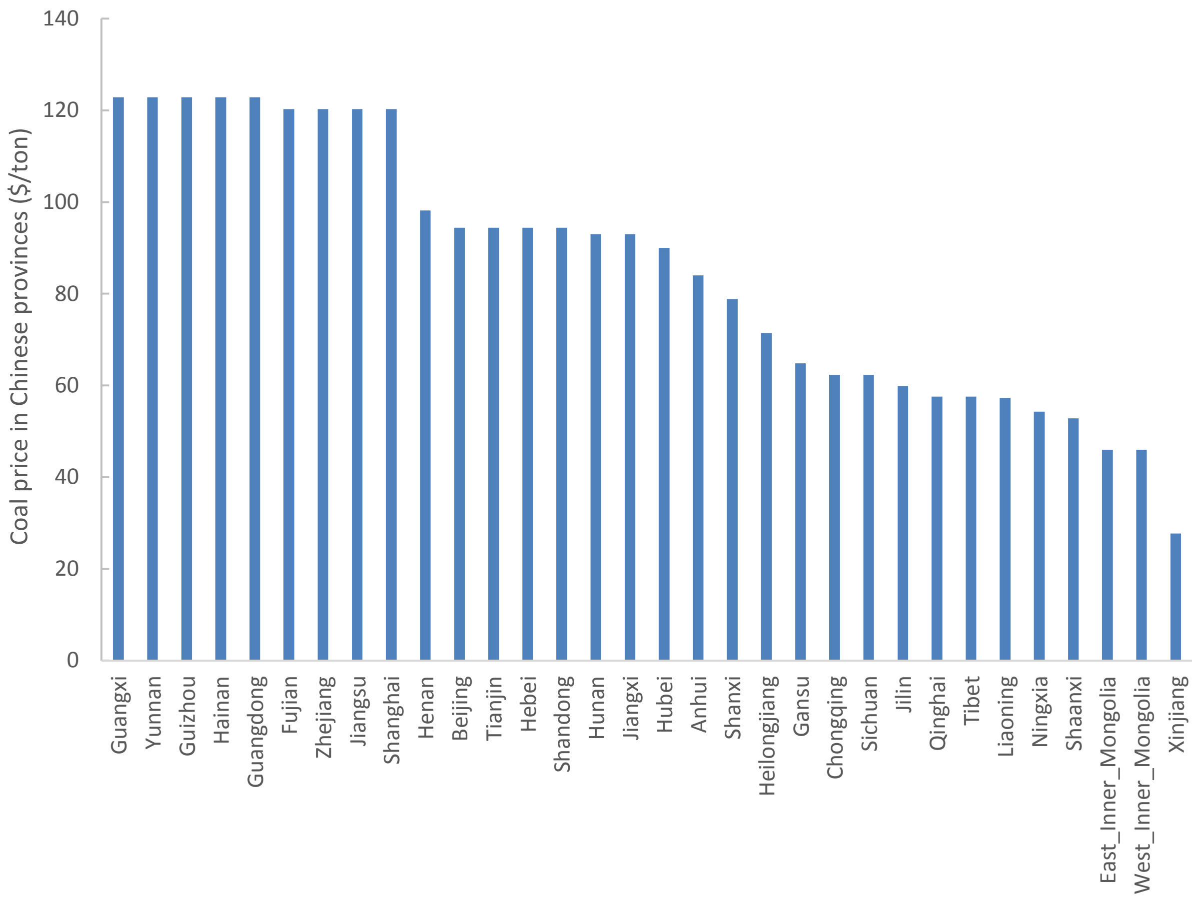

Figure SI-5 Average coal prices in China in 2010

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 [18]. For future price, annual growth rates are

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

derived from Annual Energy Outlook 2013, where yearly projections are made for each provinces through 2035, and are extrapolated for years after 2035 [19].

Oil and uranium prices are more or less globalized markets. Therefore, oil prices projections are derived from the World Energy Outlook 2013 [20] and uranium price projections are taken from the California Energy Commission's 2010 Cost of Generation Model [21]. 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 [22]. 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. 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 we 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 [23]. These wind speeds are put through an ideal turbine power output curve [24] to generate the hourly power output for each wind farm in each province [25].

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)[9], with reference of U.S. data as comparison [26]. 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.

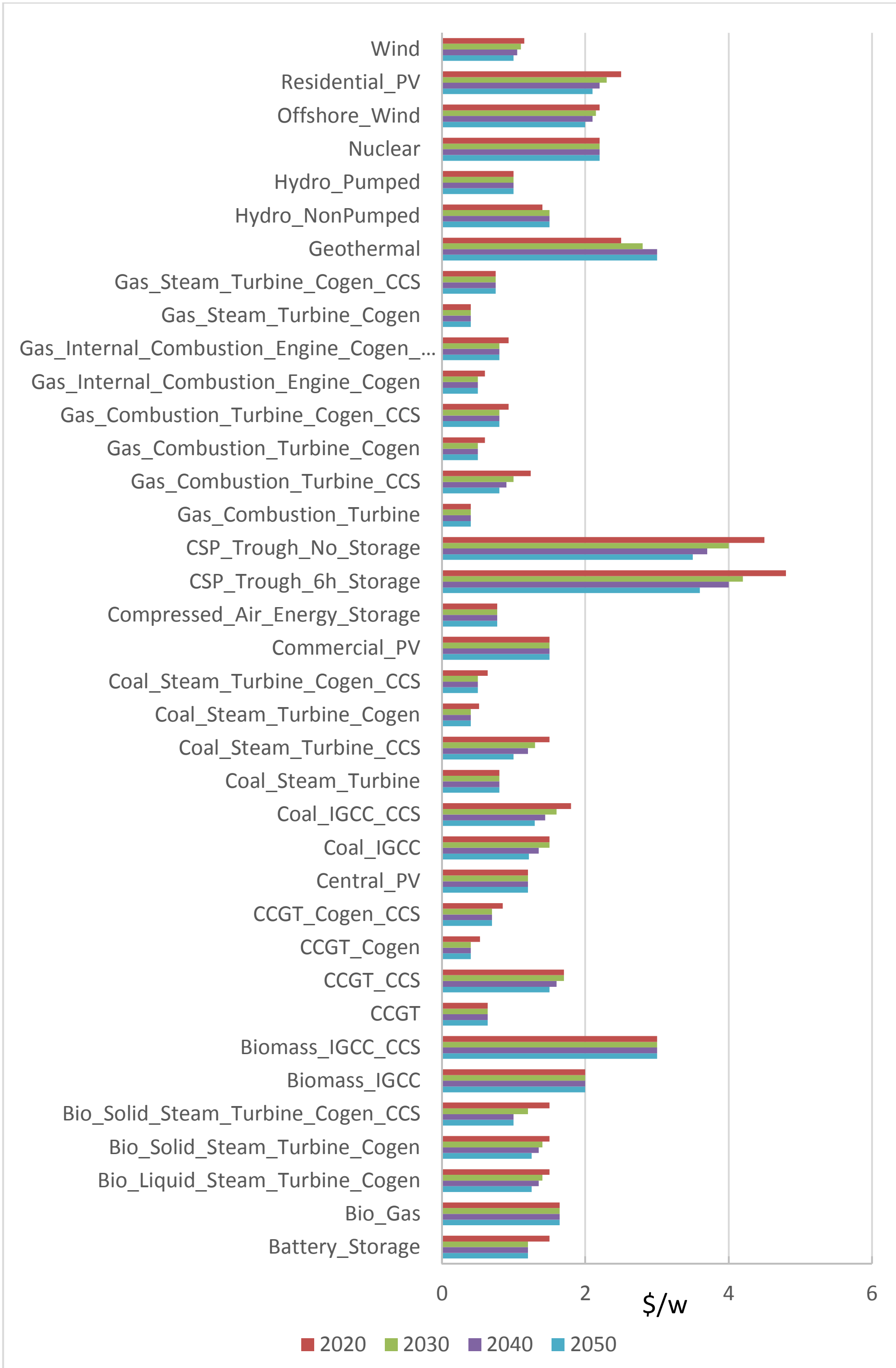

Figure SI-6 Generator and storage overnight capital costs in each investment period

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 [14]. 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

Non-Renewable Non-CCS Thermal Generators

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* [9]. 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 at \$10/tCO_2 consistent with those found in Dahowski et al., 2009 [27].

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 [28] 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 [29] is assumed.

Battery Storage

Sodium sulfur (NaS) batteries are modeled using performance data from Black and Veatch (2012) [26]. 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 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 SWITHC-China. In the next version, we 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 [25]. 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 interpolated and again averaged over each group of aggregated wind sites to create the hourly output of new wind farms.

Solar Resources

Hourly solar output of each load area was obtained from He and Kammen (2016) with 3TIER hourly solar irradiation data [30]. Solar sites were selected by the following criteria:

1) Average solar irradiation GHI larger than 160 W/m^2
2) Elevation less than 3000 meters
3) Slope less than 1 percent

4) Land uses that are not appropriate for solar development are excluded from the site selection
5) Sites with high degree of temporal correlation to load profiles near the grid point

All of the solar points within China are aggregated into 200 solar farms. The power output for each solar site is averaged over the hour before each timestamp, and then these hourly averages are again averaged over each group of aggregated solar sites to create the hourly output of new solar plants. Five types of technologies are included: stationary solar technologies include solar PV, CSP with 6 h of storage, CSP without storage; distributed solar technologies include commercial and residential PV.

3. CHINA'S CARBON TARGETS AND POWER SECTOR EMISSIONS

China released a 40-45 percent carbon intensity reduction by 2020 compared to 2005 level in 2009. However, this is an economy wide target. We utilized the projection of GDP to 2020 by the World Bank Group[2], assuming a 6 percent GDP growth rate from 2015 to 2020 [31], and calculated the economy wide carbon emission by 2020. Historical emissions from power sector are extracted from *IEA CO2 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 [32]. 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 SI-5 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

4. MODEL SCENARIOS DESCRIPTION

We model four major scenarios with different key technology and policy options: a BAU Scenario, a BAU with Carbon Cap Scenario, a Low Cost Renewables Scenario, and an IPCC Target Scenario. In the BAU scenario, we assume the technology evolving at current trend with no carbon constraint. In the Low Cost Renewables scenario, we assume aggressive learning curve of wind and solar technologies to model

[2] Using 2005 constant dollar.

the potential for achieving higher penetration of renewables in China's grid. We assume that the overnight cost of wind and solar capacities will significantly decrease to half of its cost of 2010 by 2020, then wind cost stays the 2020 level till 2050; solar cost continue decreasing to that given by the Solar Shot initiative by 2020 [33], then maintain the 2020 level until 2050. In the IPCC Target scenario, we assume the 2020 carbon intensity target, and 2030 carbon peak target, and we examine what needs to be put in place to achieve an 80 percent deep carbon reduction on 1990 level, as proposed in the 2° target agreed by the Intergovernmental Panel on Climate Change (IPCC) [11].

Table SI-6 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

Table SI-7 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

5. THE BENEFITS OF LOW CARBON POWER TRANSITION

To evaluate the impact of a green strategy to generate electricity in 2050, assuming an IPCC Target scenario as modeled in SWITCH-China, we use the findings from the emerging literature on the external cost of coal to quantify the benefits. China's power sector is currently heavily relying on coal, accounting for 79.3 percent of total power generation in 2013 [34]. Coal consumption is also a large source of wide spread of air pollution in Chinese cities. On average, 60 percent on average of the concentration in PM2.5 in Chinese cities' air pollutants come from coal combustion [35].

The research on "true cost of coal" or "external cost of coal" aims at including the costs along the life cycle of coal – extraction, transport, processing, and consumption – that has impact on the environment and human health but are not currently reflected in the coal prices. Epstein et al (2011) estimated the life cycle effects of coal and showed that the generated waste stream costs the U.S. public $175.2 billion to $523.3 billion dollars annually, ranging from 9.42 ¢/kWh to 26.89 ¢/kWh on per kWh base [36]. Mao et al (2008) analyzed the value chain cost of coal in China using 2005 data and found an external cost of 211.47 RMB/ton (~30USD/ton). The result was further confirmed by a recent estimation at 204.76 RMB/ton (~30USD/ton) by the Coal Cap Policy Research Group [35,37]. Teng et al (2014) uses 2012 data and estimates the external cost of coal is estimated at 260 RMB/ton (~40USD/ton) [38]. However, the carbon cost of coal is not included in those estimation.

In order to capture the benefits of reducing coal in the IPCC Target Scenario compared to the BAU Scenario, we consider a lower case and an upper case with different assumptions on external cost of coal, carbon cost based on the literature and in our model, see Table SI-8. The benefits of transiting to a low carbon power sector are a sum up of the avoided external cost of coal and the social cost of carbon. This ranges from 500 billion USD to 950 billion USD, which can provide about 22-42% of the 2269 billion USD investment needed annually in 2050 to make such transition possible. By 2050, China's GDP is projected to be six to ten times of that of 2010 [39–41], if the external cost is correlated to GDP, then incorporating the co-benefits would make such clean transition even more attractive.

Table SI-8 Benefits of China's low carbon power transition

		2020	2030	2040	2050
Coal reduction (Mt)		774	1227	915	2362
Carbon reduction (MtCO2)		1266	2160	5287	8534
Lower	External cost ($/t)	30	30	30	30
	Carbon cost ($/tCO2)	10	20	30	50
	Benefits (B$)	36	80	186	498
Upper	External cost ($/t)	40	40	40	40
	Carbon cost ($/tCO2)	20	30	50	100

	Benefits (B$)	56	114	301	948
Additional costs (B$)		102	340	819	2269
Total benefits as share of additional costs		35-55%	24-33%	23-37%	22-42%

6. KEY SENSITIVITY ANALYSIS

The transition to low carbon power generation will be influenced by many factors, including the fuel costs, the investment cost of different technologies and their competitive advantages, the transmission costs. The regulation over air pollutants, adoption of carbon price and other policy will also impact the investment in technologies. In addition, the uncertainties over disruptive technologies, the breakthrough in next generation of nuclear technology, the improvements of wind and solar technology, or carbon capture, utilization, and storage, and the high voltage/super conductive lines, etc.

We examined three key parameters: the carbon prices, the limit of realistic nuclear construction, and the cost of CCS. When no carbon constraints are implemented, a higher carbon price will drive more capacity in nuclear, wind, solar, and will make CCS available. A 50$/t$CO_2$ carbon price will drive the nuclear capacity to its up limit at 300GW in the model. A price of 100$/ton$CO_2$ will replace most of coal capacity with coal-CCS.

Table SI-9 The carbon price sensitivity assumptions

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

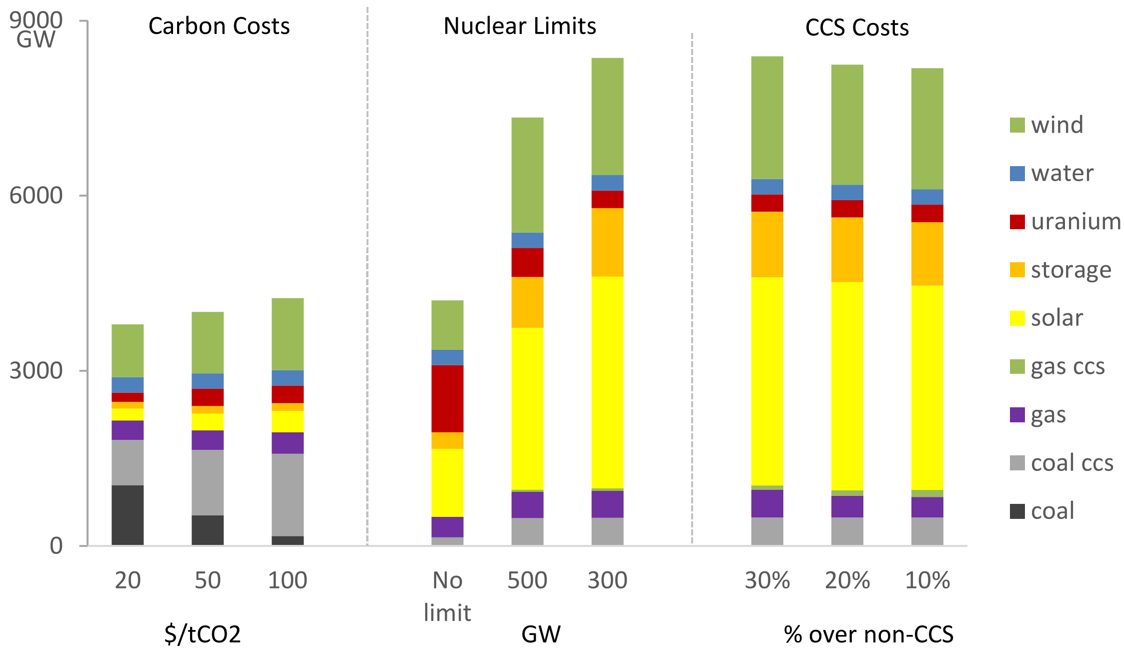

Figure SI-7 The impact of carbon price, nuclear limits, and CCS costs to the capacity mix in 2050

In the IPCC Target scenario, the share of nuclear energy in the mix is significant, if no nuclear limit is applied, 1155GW of nuclear capacity will be online by 2050 to meet the carbon cap given nuclear can provide stable baseload. If nuclear reactor construction is artificially limited to 500GW or 300GW, as reported of the available sites to build nuclear in China, then wind, solar and storage have to fill the gap to meet demand. In the IPCC Target scenario, decrease in CCS cost would not make much difference on the installation of CCS capacity by 2050, as renewables would have already competitive in achieving carbon mitigation by then.

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