Electronic Supplementary Material (ESI) for Energy & Environmental Science.

Supplementary Materials for

The role of dispatchability in China's power system decarbonization

S1. Method: long-term, high-resolution integrated resource planning model for the electric power sector

We develop a long-term, high-resolution integrated resource planning model for the electric power sector in China. The model integrates annual (electric power generation, electricity transmission, and energy storage) capacity expansion planning (CEP) and hourly power system operations (unit commitment and economic dispatch, UC-ED) into an analytical framework. The model minimizes the total power supply system costs while satisfying all economic, technical, operational, and regulatory constraints of power system operations at a high temporal resolution. With this model, we explore the capacity expansion and power system dispatch of China's electricity supply system.

The modelling framework involves two consecutive steps. First, we run the CEP model, which reflects system operations in typical days. The results of this model ensure that we can satisfy real-time power system operations while reducing model size. Second, with capacity expansion decisions as given inputs, we run the UC-ED model. This model optimizes power system dispatch in each of the 8,760 hours of the year, generating more accurate power system operations results than the CEP model.

We solve this large-scale programming model using the IBM CPLEX optimization engine on a server with a 32-thread processor with 3.5 GHz and 512 GB of RAM. It takes around 7 days to simulate each scenario.

Table S1 summarizes the parameters and decision variables of the CEP and UC-ED model.

Abbreviations in Table S1:

EGU: electric generating unit; VRE: variable renewable energy; CSP: concentrating solar power; ESS: energy storage system; PHS: pumped-hydro storage; BESS: battery energy storage system; HVAC: high-voltage alternating current; HVDC: High-voltage direct current.

Table S1 Semantics of the CEP and UC-ED model.

Subscripts	Description	Set	Range
p	Index describing a specific province/node	Ψ^P	1 to N_P
r	Index describing a specific power grid region	Ψ^R	1 to N_R
u	Index describing a specific EGU	Ψ^U	1 to N_U
n	Index describing a specific site for renewable deployment	Ψ^N	1 to N_N
l	Index describing a specific transmission line	Ψ^L	1 to N_L
o	Index describing the origin of a specific transmission line	Ψ^O	1 to N_O
d	Index describing the destination of a specific transmission line	Ψ^D	1 to N_D
y	Index describing a specific year	Ψ^Y	1 to N_Y
t	Index describing a specific time interval	Ψ^T	1 to N_T
m	Index describing a specific month	Ψ^M	1 to N_M
Superscripts	**Description**	**Set**	**Range**
EGU	Refers to parameters/variables for EGUs (including coal, natural gas, hydro, and nuclear)		
VRE	Refers to parameters/variables for VRE (onshore and offshore wind, ground-mounted and rooftop solar PV)		
CSP	Refers to parameters/variables for CSP		
$Trans$	Refers to parameters/variables for electricity transmission		
ESS	Refers to parameters/variables for ESS (including PHS and BESS)		
$Penalty$	Refers to parameters/variables for system-wide (over/under generation, reserve shortage) penalty		
Cost function	**Description**	**Unit**	**Range**
$TC(\cdot)$	Function of total costs of electric power supply system during the research period	RMB	
$TC^{EGUInvest}(\cdot)$	Function of total capital investment costs of new EGUs during the research period	RMB	
$TC^{EGUFixOM}(\cdot)$	Function of total fixed O&M costs of new EGUs during the research period	RMB	
$TC^{EGUVar}(\cdot)$	Function of total variable electricity generation costs of EGUs during the research period	RMB	
$TC^{EGURes}(\cdot)$	Function of total costs for providing reserves of EGUs during the research period	RMB	
$TC^{EGUStart}(\cdot)$	Function of total costs for units' start-ups of EGUs during the research period	RMB	
$TC^{EGUNL}(\cdot)$	Function of total no load costs for committed EGUs during the research period	RMB	
$TC^{TransInvest}(\cdot)$	Function of total capital investment costs of new transmission lines during the research period	RMB	
$TC^{TransFixOM}(\cdot)$	Function of total fixed O&M costs of new transmission lines during the research period	RMB	
$TC^{TransVar}(\cdot)$	Function of total operational costs of electricity transmission during the research period	RMB	
$TC^{VREInvest}(\cdot)$	Function of total capital investment costs of new VRE during the research period	RMB	

$TC^{VREFixOM}(\cdot)$	Function of total fixed O&M costs of new VRE during the research period	RMB	
$TC^{VREVar}(\cdot)$	Function of total operational costs of VRE during the research period	RMB	
$TC^{CSPInvest}(\cdot)$	Function of total capital investment costs of new VRE during the research period	RMB	
$TC^{CSPFixOM}(\cdot)$	Function of total fixed O&M costs of new VRE during the research period	RMB	
$TC^{CSPVar}(\cdot)$	Function of total operational costs of VRE during the research period	RMB	
$TC^{ESSInvest}(\cdot)$	Function of total capital investment costs of new ESS during the research period	RMB	
$TC^{ESSFixOM}(\cdot)$	Function of total fixed O&M costs of new ESS during the research period	RMB	
$TC^{ESSVar}(\cdot)$	Function of total operational costs of ESS during the research period	RMB	
$TC^{Penalty}(\cdot)$	Function of over/under generation and reserve shortage penalty	RMB	
Parameter	**Description**	**Unit**	**Range**
$MC_{m,u}^{EGU}$	Per MWh power generation variable costs of unit u in month m	RMB/MWh	
$RC_{m,u}^{EGU}$	Cost for providing per MWh reserve of unit u in month m	RMB/MWh	
SUC_{u}^{EGU}	Per time start-up cost of unit u	RMB/MW/time	
NLC_{u}^{EGU}	Per MW no-load cost when unit u is committed	RMB/MW	
$Capacity_{y,u}^{EGU}$	Installed capacity of unit u in year y	MW	
CF_{u}^{EGU}	Annual capacity factor of unit u	%	
Max_{u}^{EGU}	Maximum hourly power generation of unit u	% of capacity	
$Hydro_{m,u}^{EGU}$	Maximum monthly hydro energy resources of unit u in month m	% of capacity	
Min_{u}^{EGU}	Minimum hourly power generation of unit u	% of capacity	
$RRUp_{u}^{EGU}$	Ramp up capability of unit u	% of capacity	
$RRDn_{u}^{EGU}$	Ramp down capability of unit u	% of capacity	
$RRSU_{u}^{EGU}$	Startup ramping capability of unit u	% of capacity	
$RRSD_{u}^{EGU}$	Shutdown ramping capability of unit u	% of capacity	
$MinUT_{u}^{EGU}$	Minimum up time of unit u	Hours	
$MinDT_{u}^{EGU}$	Minimum down time of unit u	Hours	
MC^{Trans}	Operational cost per MWh electricity transmission	RMB/MWh	
$Capacity_{y,l}^{Trans}$	Transmission capacity of line l in year y	MW	
$LossRate_{l}^{Trans}$	Transmission loss of line l	%	

MC^{VRE}	Marginal cost of renewable energy generation	RMB/MWh
$Capacity_{y,n}^{VRE}$	Installed capacity of VRE at site n in year y	MW
$Resource_{t,n}^{VRE}$	Hourly capacity factor of wind/solar energy resources at site n time interval t	% of capacity
$PR_{y,n}^{CSP}$	Installed power rating of CSP power block at site n in year y	MW
$ER_{y,n}^{CSP}$	Installed energy capacity of CSP storage system at site n in year y	MWh
$MinGen_{n}^{CSP}$	Minimum hourly power generation of CSP power block at site n	% of capacity
SM^{CSP}	Solar multiple of CSP	
$Resource_{t,n}^{CSP}$	Hourly capacity factor of solar field at site n time interval t	% of capacity
$EFCh^{CSP}$	Efficiency of charging energy to CSP storage system	%
$EFDisch^{CSP}$	Efficiency of discharging energy from CSP storage system	%
$LossRate^{CSP}$	Hourly energy loss rate of CSP storage system	%
MC^{ESS}	Per MWh of charging/discharging energy cost for ESS	RMB/MWh
$PR_{y,p}^{ESS}$	Installed power rating of ESS in province p at year y	MW
$ER_{y,p}^{ESS}$	Installed energy capacity of ESS in province p at year y	MWh
$EFCh^{ESS}$	Efficiency of charging ESS	%
$EFDisch^{ESS}$	Efficiency of discharging ESS	%
$LossRate^{ESS}$	Hourly energy loss rate of ESS	%
Max^{ESS}	Maximum energy level of ESS	%
Min^{ESS}	Minimum energy level of ESS	%
$OverGen^{Penalty}$	Per MWh over generation penalty	RMB/MWh
$UnderGen^{Penalty}$	Per MWh under generation penalty	RMB/MWh
$ShortRes^{Penalty}$	Per MWh reserve scarcity penalty	RMB/MWh
$D_{t,p}$	Power demand in province p at time interval t	MWh
$MinCap_i$	Minimum installed capacity of technology i in each year	MW
$MaxCumCap_{n}^{VRE}$	Maximum cumulative installed capacity of VRE due to eligible areas at site n	MW
$MaxCumCap_{n}^{CSP}$	Maximum cumulative installed capacity of CSP due to eligible areas at site n	MW
$MaxCap_i$	Maximum installed capacity of technology i in each year	MW
δ	Annual discount rate	%
ϕ	The coefficient to scale up the operational costs from typical hours (192) to the annual level (8760), $\phi = \frac{8760}{192}$	

Decision variable	Description	Unit	Range
$NewCap_{y,p}^{EGU}$	Capacity of newly built EGU in year y in province p	MW	≥ 0
$BD_{y,p}^{EGU}$	Whether to install new EGU in year y in province p or not		0, 1
$E_{t,u}^{EGU}$	Power generation of unit u at time interval t	MWh/h	≥ 0
$Res_{t,u}^{EGU}$	Amount of reserves provided by unit u at time interval t	MWh/h	≥ 0
$Commit_{t,u}^{EGU}$	Commitment status of unit u at time interval t	-	0, 1
$v_{t,u}^{EGU}$	Startup action of unit u at time interval t	-	0, 1
$w_{t,u}^{EGU}$	Shutdown action of unit u at time interval t	-	0, 1
$NewCap_{y,l}^{Trans}$	Capacity of newly built transmission line l in year y	MW	≥ 0
$E_{t,l:o\rightarrow d}^{Trans}$, $E_{t,l:d\rightarrow o}^{Trans}$	Amount of electricity flow through line l at time interval t	MWh/h	≥ 0
$D_{t,l:o\rightarrow d}^{Trans}$, $D_{t,l:d\rightarrow o}^{Trans}$	Direction of electricity flow of line l at time interval t	-	0, 1
$NewCap_{y,n}^{VRE}$	Capacity of newly built wind and solar farms at site n in year y	MW	≥ 0
$EIn_{t,n}^{VRE}$	Amount of integrated renewable energy (wind/solar) at site n at time interval t	MWh/h	≥ 0
$ECu_{t,n}^{VRE}$	Amount of curtailed renewable energy (wind/solar) at site n at time interval t	MWh/h	≥ 0
$NewCap_{y,n}^{CSP}$	Capacity of newly built CSP at site n in year y	MW	≥ 0
$EIn_{t,n}^{CSP}$	Direct solar energy integration (with CSP system energy losses considered) at site n at time interval t	MWh/h	≥ 0
$ECh_{t,n}^{CSP}$	Charging power of CSP energy trough at site n at time interval t	MWh/h	≥ 0
$EDisch_{t,n}^{CSP}$	Discharging power of CSP energy trough at site n at time interval t	MWh/h	≥ 0
$Res_{t,n}^{CSP}$	Amount of reserves provided by CSP at site n at time interval t	MWh/h	≥ 0
$TE_{t,n}^{CSP}$	Current energy level of CSP energy trough at site n at time interval t	MWh	≥ 0
$Commit_{t,n}^{CSP}$	Commitment status of CSP power block at site n at time interval t	-	0, 1
$NewCap_{y,p}^{ESS}$	Capacity of newly built ESS in province p in year y	MW	≥ 0
$x_{t,p}^{ESS}$	Charging status of ESS in province p at time interval t	-	0, 1
$y_{t,p}^{ESS}$	Discharging status of ESS in province p at time interval t	-	0, 1
$ECh_{t,p}^{ESS}$	Power being charged in ESS in province p at time interval t	MWh/h	≥ 0
$EDisch_{t,p}^{ESS}$	Power being discharged from ESS in province p at time interval t	MWh/h	≥ 0
$Res_{t,p}^{ESS}$	Reserves provided by ESS in province p at time interval t	MWh/h	≥ 0

$TE_{t,p}^{ESS}$	Current energy level of ESS in province p at time interval t	MWh	≥ 0
$OverGen_{t,p}$	Amount of system wide over generation in province p at time interval t	MWh	≥ 0
$UnderGen_{t,p}$	Amount of system wide under generation in province p at time interval t	MWh	≥ 0
$ShortRes_{t,r}$	Amount of system wide reserve scarcity in region r at time interval t	MWh	≥ 0

Note: Light blue represents parameters and decision variables of electricity generation from EGUs (coal, natural gas, nuclear, and hydro); purple represents parameters and decision variables of electricity transmission (HVAC and HVDC); green represents parameters and decision variables of VRE (onshore and offshore wind, ground-mounted and rooftop solar PV) and CSP; Grey represents parameters and decision variables of ESS (PHS and BESS); orange represents parameters and decision variables related to system wide penalty, including penalties of over generation, under generation and shortage in reserve.

S1.1 Capacity expansion planning (CEP) model

The CEP model minimizes the total capital investment and operational costs of the power supply system and aims to find the optimal decisions for capacity, timing, and siting of investments in various power generation, transmission and energy storage technologies. To reduce model size, we use one typical workday and weekend day of a season to represent the whole season. Thus, there are 192 time intervals in a modeled year (24 hours per day and 8 typical days per year). In order to eliminate the asymmetry between annualized capital investment costs and operational costs due to the selection of typical days, we multiple operational costs by 8760/192 to obtain annual total operational costs.

The CEP model minimizes total costs (equation 1) subject to constraints (equation 2 to equation 46). All parameters and decision variables are as defined in table 1.

S1.1.1 Objective function

The objective of the CEP model is to minimize total discounted electricity supply system costs (including capacity expansion costs and system operational costs) during the research period. These costs consist of:

- Discounted total capital investment costs of new EGUs
- Discounted total fixed O&M costs of new EGUs
- Discounted total variable power generation costs of both existing and new EGUs
- Discounted total reserve costs of both existing and new EGUs
- Discounted total start-up costs of both existing and new EGUs
- Discounted total no-load costs of both existing and new EGUs
- Discounted total capital investment costs of new renewable energy infrastructures
- Discounted total fixed O&M costs of new renewable energy infrastructures
- Discounted total operational costs of renewable energy generation
- Discounted total capital investment costs of new transmission lines
- Discounted total fixed O&M costs of new transmission lines
- Discounted total operational costs for electricity transmission of both existing and new transmission lines
- Discounted total capital investment costs of new ESS
- Discounted total fixed O&M costs of new ESS

- Discounted total operational cost of both existing and new ESS
- Discounted penalty

The sunk costs, including capital costs for existing EGUs, transmission lines, and ESS, are not included in the objective function. Nuclear generating units consume water for cooling usage. Considering water constraints as well as the security and safety requirements, we assume that all nuclear generating units can only be installed in 9 coastal provinces, including Fujian, Guangdong, Guangxi, Hainan, Hebei, Jiangsu, Liaoning, Shandong, and Zhejiang (another 2 coastal provinces, -Shanghai and Tianjin-, cannot deploy nuclear generating units, because they do not have eligible sites for nuclear units' installation). Also, only the 11 coastal provinces can install and be directly connected to offshore wind farms.

Objective function: min

$$TC\begin{pmatrix} NewCap^{EGU}_{y,p}, E^{EGU}_{t,u}, Res^{EGU}_{t,u}, v^{EGU}_{t,u}, Commit^{EGU}_{t,u}, \\ NewCap^{VRE}_{y,n}, EIn^{VRE}_{t,n}, ECu^{VRE}_{t,n}, NewCap^{CSP}_{y,n}, EIn^{CSP}_{t,n}, EDisch^{CSP}_{t,n}, \\ NewCap^{Trans}_{y,l}, E^{Trans}_{t,l:o\to d}, E^{Trans}_{t,l:d\to o}, \\ NewCap^{ESS}_{y,p}, ECh^{ESS}_{t,p}, EDisch^{ESS}_{t,p}, \\ OverGen_{t,p}, UnderGen_{t,p}, ShortRes_{t,r} \end{pmatrix} =$$

$$\Big[TC^{EGUInvest}\left(NewCap^{EGU}_{y,p}\right) + TC^{EGUFixOM}\left(NewCap^{EGU}_{y,p}\right) + TC^{EGUVar}\left(E^{EGU}_{t,u}\right) + TC^{EGURes}\Big($$

$$+$$

$$\left[TC^{VREInvest}\left(NewCap^{VRE}_{y,n}\right) + TC^{VREFixOM}\left(NewCap^{VRE}_{y,n}\right) + TC^{VREVar}\left(EIn^{VRE}_{t,n}, ECu^{VRE}_{t,n}\right)\right] +$$

$$\left[TC^{CSPInvest}\left(NewCap^{CSP}_{y,n}\right) + TC^{CSPFixOM}\left(NewCap^{CSP}_{y,n}\right) + TC^{CSPVar}\left(EIn^{CSP}_{t,n}, EDisch^{CSP}_{t,n}\right)\right] +$$

$$\left[TC^{TransInvest}\left(NewCap^{Trans}_{y,l}\right) + TC^{TransFixOM}\left(NewCap^{Trans}_{y,l}\right) + TC^{TransVar}\left(E^{Trans}_{t,l:o\to d}, E^{Trans}_{t,l:d\to o}\right)\right]$$

$$+$$

$$\left[TC^{ESSInvest}\left(NewCap^{ESS}_{y,p}\right) + TC^{ESFixOM}\left(NewCap^{ESS}_{y,p}\right) + TC^{ESSVar}\left(ECh^{ESS}_{t,p}, EDisch^{ESS}_{t,p}\right)\right] +$$

$$TC^{Penalty}\left(OverGen_{t,p}, UnderGen_{t,p}, ShortRes_{t,r}\right) \quad \text{eq. 1}$$

The cost items are explained as below:

1. Costs of electric generating units (EGUs)
1.1 Total capital investment and annual fixed O& M costs of new installed generating units during the research period

(1) Capital cost	$TC^{EGUInvest}(NewCap^{EGU}_{y,p}) = \sum_y \sum_p \left[TC^{EGUInvest}_y(NewCap^{EGU}_{y,p}) \times \frac{1}{(1+\delta)^y}\right]$
	Capital cost of new EGU in year y ($TC^{EGUInvest}_y(NewCap^{EGU}_{y,p})$) is the result of (1) new capacity ($NewCap^{EGU}_{y,p}$), (2) per MW capital costs, (3) construction time (year), and (4) technical lifetime (year); it is similar for the capital costs of other new energy infrastructure.
	There are new hydropower units that are being built or have been planned to be built during the research period. We include these units and capacities in our research and consider the year they are connected to the grid. The capacity expansion of hydro power is given from official planning, rather than the results of our optimization. The reasons for this assumption are as follows: hydropower generating infrastructures have various functions, and power generation is only one function among others like irrigation and flood control. Therefore, among all power generators, hydropower development is much more holistically (and often centrally) planned rather than purely economic. China has development plans for future hydro power, specifically noting installed capacities. We collect these development plans for future hydro power from various sources.
(2) Fixed O&M cost	$TC^{EGUFixOM}(NewCap^{EGU}_{y,p}) = \sum_y \sum_p \left[TC^{EGUFixOM}_y(NewCap^{EGU}_{y,p}) \times \frac{1}{(1+\delta)^y}\right]$
1.2 Total operational costs of existing and new generating units during the research period	
(1) Variable production cost	$TC^{EGUVar}(E^{EGU}_{t,u}) = \sum_y \sum_{m \in y} \sum_{t \in m} \sum_u \left[E^{EGU}_{t,u} \times MC^{EGU}_{m,u} \times \frac{1}{(1+\delta)^y}\right] \times \phi$
	For a coal or natural gas EGU, its per MWh variable generation cost ($MC^{Gen}_{m,u}$) is the result of (1) fuel price in month m and (2) fuel consumption per MWh electricity generation.
(2) Reserves cost	$TC^{EGURes}(Res^{EGU}_{t,u}) = \sum_y \sum_{m \in y} \sum_{t \in m} \sum_u \left[Res^{EGU}_{t,u} \times RC^{EGU}_{m,u} \times \frac{1}{(1+\delta)^y}\right] \times \phi$
(3) Start-up cost	$TC^{EGUStart}(v^{EGU}_{t,u}) = \sum_y \sum_{t \in y} \sum_u \left[v^{EGU}_{t,u} \times SUC^{EGU}_u \times \frac{1}{(1+\delta)^y}\right] \times \phi$
(4) No load cost	$TC^{EGUNL}(Commit^{EGU}_{t,u}) = \sum_y \sum_{t \in y} \sum_u \left[Commit^{EGU}_{t,u} \times NLC^{EGU}_u \times Capacity^{EGU}_{y,u} \times \frac{1}{(1+\delta)^y}\right] \times \phi$
2. Costs of renewable energy	
2.1 Total capital investment costs and annual fixed O& M costs of new variable renewable energy infrastructure during the research period	
(1) Capital cost	$TC^{VREInvest}(NewCap^{VRE}_{y,n}) = \sum_y \sum_n \left[TC^{VREInvest}_{y,n}(NewCap^{VRE}_{y,n}) \times \frac{1}{(1+\delta)^y}\right]$

(2) Fixed O&M cost	$TC^{VREFixOM}\left(NewCap^{VRE}_{y,n}\right)=\sum_{y}\sum_{n}\left[TC^{VREFixOM}_{y,n}\left(NewCap^{VRE}_{y,n}\right)\times\frac{1}{(1+\delta)^{y}}\right]$
2.2 Total operational costs of existing and new renewable energy infrastructure during the research period	
Operational cost	$TC^{VREVar}\left(EIn^{VRE}_{t,n},ECu^{VRE}_{t,n}\right)=\sum_{y}\sum_{t\in y}\sum_{n}\left[MC^{VRE}\times\left(EIn^{VRE}_{t,n}+ECu^{VRE}_{t,n}\right)\times\frac{1}{(1+\delta)^{y}}\right]\times\phi$
2.3 Total capital investment costs and annual fixed O& M costs of new CSP during the research period	
(1) Capital investment cost	$TC^{CSPInvest}\left(NewCap^{CSP}_{y,n}\right)=\sum_{y}\sum_{n}\left[TC^{CSPInvest}_{y}\left(NewCap^{CSP}_{y,n}\right)\times\frac{1}{(1+\delta)^{y}}\right]$
(2) Fixed O&M cost	$TC^{CSPFixOM}\left(NewCap^{CSP}_{y,n}\right)=\sum_{y}\sum_{n}\left[TC^{CSPFixOM}_{y}\left(NewCap^{CSP}_{y,n}\right)\times\frac{1}{(1+\delta)^{y}}\right]$
2.4 Total operational costs of existing and new CSP during the research period	
Operational cost	$TC^{CSPVar}\left(EIn^{CSP}_{t,n},EDisch^{CSP}_{t,n}\right)=\sum_{y}\sum_{t\in y}\sum_{n}\left[MC^{CSP}\times\left(EIn^{CSP}_{t,n}+EDisch^{CSP}_{t,n}\times EFDisch^{CSP}\right)\times\frac{}{(1}\right.$
3. Costs of electric power transmission	
3.1 Total capital investment costs and annual fixed annual O& M costs of additional transmission lines during the research period	
(1) Capital cost	$TC^{TransInvest}\left(NewCap^{Trans}_{y,l}\right)=\sum_{y}\sum_{l}\left[TC^{TransInvest}_{y,l}\left(NewCap^{Trans}_{y,l}\right)\times\frac{1}{(1+\delta)^{y}}\right]$
	Both HVAC and HVDC lines consist of line and station costs. HVAC has a higher station cost but lower line cost than HVDC. Therefore, HVAC is cheaper for short-distance transmission, while HVDC is cost competitive for long-distance transmission. In this model, whether two nodes are connected by new HVAC or HVDC transmission line depends on their geographical distance.
(2) Fixed O&M cost	$TC^{TransFixOM}\left(NewCap^{Trans}_{y,l}\right)=\sum_{y}\sum_{l}\left[TC^{TransFixOM}_{y,l}\left(NewCap^{Trans}_{y,l}\right)\times\frac{1}{(1+\delta)^{y}}\right]$
3.2 Total operational costs of existing and new transmission lines during the research period	
Operational cost	$TC^{TransVar}\left(E^{Trans}_{t,l}\right)=\sum_{y}\sum_{t\in y}\sum_{l}\left[\left(E^{Trans}_{t,l:o\to d}+E^{Trans}_{t,l:d\to o}\right)\times MC^{Trans}\times\frac{1}{(1+\delta)^{y}}\right]\times\phi$
4. Costs of energy storage system (ESS)	
4.1 Total capital investment costs and annual fixed O & M costs of additional ESS during the research period	

(1) Capital cost	$TC^{ESSInvest}\left(NewCap_{y,p}^{ESS}\right) = \sum_{y}\sum_{p}\left[TC_{y,p}^{ESSInvest}\left(NewCap_{y,p}^{ESS}\right) \times \frac{1}{(1+\delta)^{y}}\right]$
(2) Fixed O&M cost	$TC^{ESSFixOM}\left(NewCap_{y,p}^{ESS}\right) = \sum_{y}\sum_{p}\left[TC_{y,p}^{ESSFixOM}\left(NewCap_{y,p}^{ESS}\right) \times \frac{1}{(1+\delta)^{y}}\right]$
4.2 Total operational costs of existing and new ESS during the research period	
Operational costs	$TC^{ESSVar}\left(ECh_{t,p}^{ESS}, EDisch_{t,p}^{ESS}\right) = \sum_{y}\sum_{t\in y}\sum_{p}\left[\left(ECh_{t,p}^{ESS} + EDisch_{t,p}^{ESS}\right) \times MC^{ESS} \times \frac{1}{(1+\delta)^{y}}\right] \times \phi$
5. System-wide penalty	
$TC^{Penalty}\left(OverGen_{t,p}, UnderGen_{t,p}, ShortRes_{t,r}\right) = \sum_{y}\sum_{t\in y}\sum_{p}\left[\left(OverGen_{t,p} \times OverGen^{Penalty} + UnderGen_{t,p} \times UnderGen^{Penalty}\right) \times \frac{1}{(1+\delta)^{y}}\right] \times \phi + \sum_{y}\sum_{t\in y}\sum_{r}\left[\left(ShortRes_{t,r} \times ShortRes^{Penalty}\right) \times \frac{1}{(1+\delta)^{y}}\right] \times \phi$	

S1.1.2 Constraints

<u>(1) Power balance equation</u>

For each time interval and within each province, power supply (minus any over-generation) must equal power demand (minus any under-generation). The power supply is equal to the power generation plus energy inflow minus energy outflow through transmission lines plus energy being discharged from ESS minus energy being stored in ESS.

$\sum_{u\in p} E_{t,u}^{EGU}$	Power generation from existing and new EGUs located in province p at time step t
$+\sum_{n\in p} EIn_{t,n}^{VRE}$	Integrated energy from existing and new VRE located in province p at time step t
$+\sum_{n\in p}\left(EIn_{t,n}^{CSP} + EDisch_{t,n}^{CSP} \times EFDisch^{CSP}\right)$	Power generation from existing and new CSP facilities located in province p at time step t
$+\sum_{d=p}\left[E_{t,l:o\to d}^{Trans} \times \left(1 - LossRate_{l}^{Trans}\right)\right] - \sum_{d=p} E_{t,l:d\to o}^{Trans}$	Energy inflow into province p (with transmission loss considered) minus energy outflow from province p via existing and new transmission lines
$+\left(EDisch_{t,p}^{ESS} \times EFDisch^{ESS}\right)$	Energy being discharged from existing and new ESS minus energy

$-\ ECh_{t,p}^{ESS}$	being charged in ESS in province p at time step t
$-\ OverGen_{t,p} + UnderGen_{t,p}$	Any over generation or under generation in province p at time step t
=	
$D_{t,p}$	Power demand in province p at time step t
$\forall t,p$ eq.2	

<u>(2) Reserve constraints</u>

Conversations with system operators indicate that it is fair to assume that all provinces in a regional power grid share the same reserve resources, instead of each province scheduling reserves in its territory. This assumption reduces the cost of procuring reserves for provinces with expensive reserve providers.

We assume that EGUs (coal, natural gas, nuclear, hydro), CSP, and ESS (both PHS and BESS) provide reserves for China's electric power system.

$\sum_{u \in r} Res_{t,u}^{EGU}$	Reserves provided by existing and new coal, natural gas, nuclear, and hydro EGUs within power grid region r at time step t
$+\sum_{n \in r} \left(Res_{t,n}^{CSP} \times EFDisch^{CSP}\right)$	Reserves provided by existing and new CSP within power grid region r at time step t
$+\sum_{p \in r} \left(Res_{t,p}^{ESS} \times EFDisch^{ESS}\right)$	Reserves provided by existing and new ESS within power grid region r at time step t
$+ShortRes_{t,r}$	Any reserve shortage of region r at time step t
$\geq$	
$ResReq_{t,r}$	Reserve requirements for each region r and time step t
$\forall t,r$ eq.3	

<u>(3) Technical constraints of each generating unit</u>

Generating units have technical flexibility constraints, such as range of generation, maximum ramping up/down capability, minimum up/down time. This research includes these technical constraints of generating units. We take the existing EGUs as an example and model their operations as follows. New EGUs have similar equations and we do not repeat.

Maximum hourly generation constraints for coal, natural gas, and nuclear EGUs:

$E_{t,u}^{EGU} + Res_{t,u}^{EGU} \leq Capacity_{y,u}^{EGU} \times Max_{u}^{EGU} \times Commit_{t,u}^{EGU} \quad \forall\ y,t \in y,u \in Coal, Natural\ gas, or\ Nuclear$ eq.4
Maximum hourly generation constraints for hydro EGUs: $E_{t,u}^{EGU} + Res_{t,u}^{EGU} \leq Capacity_{y,u}^{EGU} \times Max_{u}^{EGU} \quad \forall\ y,t \in y,u \in Hydro$ eq.5 $\sum_{t \in m} E_{t,u}^{EGU} \leq \sum_{t \in m} \left(Capacity_{y,u}^{EGU} \times Hydro_{m,u}^{EGU}\right) \quad \forall\ y,m \in y,t \in m,u \in Hydro$ eq.6
Minimum hourly generation constraints: $E_{t,u}^{EGU} \geq Capacity_{y,u}^{EGU} \times Min_{u}^{EGU} \times Commit_{t,u}^{EGU} \quad \forall\ y,t \in y,u$ eq.7
Ramp up capability constraints: $E_{t,u}^{EGU} + Res_{t,u}^{EGU} - E_{t-1,u}^{EGU} \leq Capacity_{y,u}^{EGU} \times RRUp_{u}^{EGU} \times Commit_{t-1,u}^{EGU} + Capacity_{y,u}^{EGU} \times RRSU_{u}^{EGU} \times v_{t,u}^{EGU} - Capacity_{y,u}^{EGU} \times RRSD_{u}^{EGU} \times w_{t,u}^{EGU}$ $\forall\ y,t \in y,u$ eq.8
Ramp down capability constraints: $E_{t-1,u}^{EGU} + Res_{t-1,u}^{EGU} - E_{t,u}^{EGU} \leq Capacity_{y,u}^{EGU} \times RRDn_{u}^{EGU} \times Commit_{t,u}^{EGU} + Capacity_{y,u}^{EGU} \times RRSD_{u}^{EGU} \times w_{t,u}^{EGU} - Capacity_{y,u}^{EGU} \times RRSU_{u}^{EGU} \times v_{t,u}^{EGU}$ $\forall\ y,t \in y,u$ eq.9
Relationship between start-up action, shut-down action and unit commitment status: $v_{t,u}^{EGU} = \begin{cases} 1, & if\ Commit_{t,u}^{EGU} - Commit_{t-1,u}^{EGU} = 1 \\ 0, & otherwise \end{cases} \quad \forall t,u$ eq.10 $w_{t,u}^{EGU} = \begin{cases} 1, & if\ Commit_{t-1,u}^{EGU} - Commit_{t,u}^{EGU} = 1 \\ 0, & otherwise \end{cases} \quad \forall t,u$ eq.11
Initial period minimum up time requirements: $\sum_{t=1}^{InitMinUp_u} \left(1 - Commit_{t,u}^{EGU}\right) = 0 \quad \forall\ u$ eq.12
Transition period minimum up time requirements: $\sum_{j=t}^{t+MinUT_u-1} \left(Commit_{j,u}^{EGU}\right) \geq MinUT_{u}^{EGU} \times \left(Commit_{t,u}^{EGU} - Commit_{t-1,u}^{EGU}\right)$ $\forall\ u, \forall\ t \in \{InitMinUp_u + 1, T - MinUT_{u}^{EGU} + 1\}$ eq.13
Final period minimum up time requirements: $\sum_{k=t}^{T} \left(Commit_{k,u}^{EGU} - \left(Commit_{t,u}^{EGU} - Commit_{t-1,u}^{EGU}\right)\right) \geq 0 \quad \forall\ u, \forall t \in \{T - MinUT_{u}^{EGU} + 2,T\}$ eq.14

Initial period minimum down time requirements: $$\sum_{t=1}^{InitMinDown_u} Commit_{t,u}^{EGU} = 0 \quad \forall u$$ eq.15
Transition period minimum down time requirements: $$\sum_{j=t}^{t+MinDT_u-1} \left(1 - Commit_{j,u}^{EGU}\right) \geq MinDT_u^{EGU} \times \left(Commit_{t-1,u}^{EGU} - Commit_{t,u}^{EGU}\right)$$ $\forall u, \forall t \in \{InitMinDown_u + 1, T - MinDT_u^{EGU} + 1\}$ eq.16
Final period minimum down time requirements: $$\sum_{j=t}^{T}\left(\left(1 - Commit_{j,u}^{EGU}\right) - \left(Commit_{t-1,u}^{EGU} - Commit_{t,u}^{EGU}\right)\right) \geq 0 \quad \forall u, \forall t \in \{T - MinDT_u^{EGU} + 2, T\}$$ eq.17
Maximum annual capacity factor constraints: $$\sum_{t \in y} E_{t,u}^{EGU} \leq \sum_{t \in y}\left(Capacity_{y,u}^{EGU} \times CF_u^{EGU}\right) \quad \forall y, t \in y, u$$ eq.18

(4) Renewable integration constraints

These constraints define the operations of renewable energy technologies. For each onshore wind, offshore wind, and solar PV farm, the sum of integrated and curtailed renewable energy should equal renewable energy generation. CSP facilities are equipped with thermal energy storage, and hence their output variations are significantly eliminated. CSPs have operational constraints and their operations can be simplified as follows: the heliostat field reflects solar energy to a receiver tower, heating a fluid. The energy can be used to convert water into steam in a heat exchanger. Then, the energy can be directly run through a steam turbine to generate electricity, or can be stored in thermal energy storage system for later use. We take the existing renewable facilities as an example and model their operations as follows. New renewable facilities have similar equations that are not shown.

1. Onshore wind, offshore wind, and solar PV
$EIn_{t,n}^{VRE} + ECu_{t,n}^{VRE} = Capacity_{y,n}^{VRE} \times Resource_{t.n}^{VRE} \quad \forall y, t \in y, n$ eq.19   Please refer to Li et.al (2022) for more details of methods to calculate hourly capacity factor ($Resource_{t,n}^{VRE}$).
2. CSP
$EIn_{t,n}^{CSP} + ECh_{t,n}^{CSP} = Gen_{t,n}^{CSP} \quad \forall t, n$ eq.20

$Gen_{t,n}^{CSP}$ is a result of CSP power capacity ($PR_{y.n}^{CSP}$), solar multiple SM^{CSP}, hourly solar energy resources ($Resource_{t.n}^{CSP}$), energy losses for the heliostat field and receiver tower, and some other system losses.
$EIn_{t,n}^{CSP} + \left(EDisch_{t,n}^{CSP} + Res_{t,n}^{CSP}\right) \times EFDisch^{CSP} \leq PR_{y,n}^{CSP} \times Commit_{t,n}^{CSP} \quad \forall y,t \in y,n$ eq.21
$EIn_{t,n}^{CSP} + EDisch_{t,n}^{CSP} \times EFDisch^{CSP} \geq PR_{y,n}^{ES} \times MinGen^{CSP} \times Commit_{t,n}^{CSP} \quad \forall y,t \in y,n$ eq.22
$EDisch_{t,n}^{CSP} + Res_{t,n}^{CSP} - ECh_{t,n}^{CSP} \times EFCh^{CSP} \leq TE_{t-1,n}^{CSP} \times \left(1 - LossRate^{CSP}\right) \quad \forall t,n$ eq.23
$TE_{t,n}^{CSP} \leq ER_{y,n}^{CSP} \quad \forall y,t \in y,n$ eq.24
$TE_{t,n}^{CSP} = TE_{t-1,n}^{CSP} \times \left(1 - LossRate^{CSP}\right) - EDisch_{t,n}^{CSP} + ECh_{t,n}^{CSP} \times EFCh^{CSP} \quad \forall t,n$ eq.25

(5) Transmission constraints

The following constraints simulate the operation of existing transmission lines. New transmission lines have similar constraints (not shown).

Maximum energy flow at each time step: $E_{t,l:o\to d}^{Trans} \leq Capacity_{y,l}^{Trans} \times D_{t,l:o\to d}^{Trans} \quad \forall y,t \in y,l$ eq.26 $E_{t,l:d\to o}^{Trans} \leq Capacity_{y,l}^{Trans} \times D_{t,l:d\to o}^{Trans} \quad \forall y,t \in y,l$ eq.27
Linkage between energy flow and flow direction: $D_{t,l:o\to d}^{Trans} = \begin{cases} 1, & if E_{t,l:o\to d}^{Trans} > 0 \\ 0, & otherwise \end{cases} \quad \forall t,l$ eq.28 $D_{t,l:d\to o}^{Trans} = \begin{cases} 1, & if\ E_{t,l:d\to o}^{Trans} > 0 \\ 0, & otherwise \end{cases} \quad \forall t,l$ eq.29
Only one direction at each time step: $D_{t,l:o\to d}^{Trans} + D_{t,l:d\to o}^{Trans} \leq 1 \quad \forall t,l$ eq.30

(6) Energy storage system constraints

Energy storage systems have operational constraints, such as maximum/minimum energy level of storage system, maximum charging/discharging power, and so on. This research includes these operational constraints. We model the operations for each of the existing and new BESS and PHS facilities. We take the existing BESS facilities as an example and model their operations as follows. New ESS facilities have similar equations that are not shown.

Maximum energy storage constraints in MWh (energy storage cannot exceed its allowed upper energy bound): $TE_{t,p}^{ESS} \leq Max^{ESS} \times ER_{y,p}^{ESS} \quad \forall y,t \in y,p$ eq.31
Minimum energy storage constraints in MWh (energy storage cannot be lower than its allowed lower energy bound): $TE_{t,p}^{ESS} \geq Min^{ESS} \times ER_{y,p}^{ESS} \quad \forall y,t \in y,p$ eq.32

Power charging limits in MW (charging power cannot exceed its power charging capacity):

$$ECh_{t,p}^{ESS} \leq PR_{y,p}^{ESS} \times x_{t,p}^{ESS} \quad \forall y,t \in y,p \quad \text{eq.33}$$

Power discharging limits in MW (discharging power cannot exceed its power discharging capacity):

$$\left(EDisch_{t,p}^{ESS} + Res_{t,p}^{ESS}\right) \times EFDisch^{ESS} \leq PR_{y,p}^{ESS} \times y_{t,p}^{ESS} \quad \forall y,t \in y,p \quad \text{eq.34}$$

Maximum discharged power from energy storage systems:

$$EDisch_{t,p}^{ESS} + Res_{t,p}^{ESS} - ECh_{t,p}^{ESS} \times EFCh^{ESS} \leq TE_{t-1,p}^{ESS} \times \left(1 - LossRate^{ESS}\right) - Min^{ESS} \times ER_{y,p}^{ESS} \quad \forall y,t \in y,p \quad \text{eq.35}$$

Energy level balance constraints:

$$TE_{t,p}^{ESS} = TE_{t-1,p}^{ESS} \times \left(1 - LossRate^{ESS}\right) - EDisch_{t,p}^{ESS} + ECh_{t,p}^{ESS} \times EFCh^{ESS} \quad \forall t,p \quad \text{eq.36}$$

Charge and discharge state exclusive:

$$x_{t,p}^{ESS} = \begin{cases} 1, & if\ ECh_{t,p}^{ESS} > 0 \\ 0, & otherwise \end{cases} \quad \forall t,p \quad \text{eq.37}$$

$$y_{t,p}^{ESS} = \begin{cases} 1, & if\ EDisch_{t,p}^{ESS} > 0 \\ 0, & otherwise \end{cases} \quad \forall t,p \quad \text{eq.38}$$

(7) Maximum and minimum installed capacities of various technologies

The accumulated installed capacity of renewable energy facilities (onshore wind, offshore wind, solar PV, and CSP) at each site in each year should not be higher than the allowed maximum capacity due to constraints regarding site eligibility. The annual installed capacity of each generating/transmission/energy storage technology cannot be higher than its installation capability, and cannot be lower than the minimum capacity.

Maximum accumulated capacity of renewable energy technologies:

$$TotalCap_{y,n}^{VRE} \leq MaxCumCap_{n}^{VRE} \quad \forall y,n \quad \text{eq.39}$$

$$TotalCap_{y,n}^{CSP} \leq MaxCumCap_{n}^{CSP} \quad \forall y,n \quad \text{eq.40}$$

The accumulated installed capacity of wind/solar PV/CSP ($TotalCap_{y,n}^{VRE}$, $TotalCap_{y,n}^{CSP}$) is the result of (1) new capacity ($NewCap_{y,n}^{VRE}$, $NewCap_{y,n}^{CSP}$), (2) construction time (year), and (3) technical lifetime (year).

Please refer to Li et.al (2022) for more details of methods to calculate the maximum installed capacity for each site ($MaxCumCap_{n}^{VRE}$, $MaxCumCap_{n}^{CSP}$).

Maximum new installed capacity of each generating/transmission/energy storage technology in each year:

New EGU: $NewCap_{y,p}^{EGU} \leq MaxCap_i \times BD_{y,p}^{EGU}\ \forall y,p,\ i \in EGU$ eq.41

New VRE: $NewCap_{y,n}^{VRE} \leq MaxCap_i\ \forall y,n,\ i \in VRE$ eq.42

New CSP: $NewCap_{y,n}^{CSP} \leq MaxCap_i\ \forall y,n,\ i \in CSP$ eq.43

New transmission: $NewCap_{y,l}^{Trans} \leq MaxCap_i\ \forall y,l,\ i \in Trans$ eq.44

New ESS: $NewCap_{y,n}^{ESS} \le MaxCap_i \; \forall y,n, \; i \in ESS$ eq.45
Minimum new installed capacity of each power generating technology in each year: $NewCap_{y,p}^{EGU} \ge MinCap_i \times BD_{y,p}^{EGU} \; \forall y,p, \; i \in EGU$ eq.46 We assume that the installed capacity of a new nuclear unit ($MinCap_i$) is no less than 600 MW, to represent China's energy policy of encouraging large nuclear power reactors.

S1.2 Unit commitment and economic dispatch (UC-ED) model

The UC-ED yields the optimal hourly dispatch of existing and newly installed energy infrastructure, with capacity expansions prescribed by the CEP model. Mathematically, this model looks similar to the CEP model, with the following key differences. First, they have different time horizons. The CEP model optimizes power system operations in typical days across the whole research period, while the UC-ED model optimizes power system operations for each of the 8760 hours in a year and iterates until the last year is completed. Second, they have different decision variables and objective functions. In the CEP model, capacity expansions are decision variables, but in the UC-ED model they are given inputs; as a result, the objective function of the UC-ED model only includes the operational cost of the power supply system and takes the capital investment cost as given. The results from the UC-ED model can further be used to analyze the future energy mix, transmission among regions, power system reliability, and CO_2 emissions from power system operations.

S2 Data

S2.1 Provinces and regional power grids in China

This research includes 32 nodes/load areas, which covers 31 provinces of mainland China. Inner Mongolia is segregated into 2 load areas (East Inner Mongolia and West Inner Mongolia), because they are connected to different regional power grids. Hongkong, Macau, and Taiwan are not included in this research.

The 32 load areas are segregated into seven power grid regions. China's regional power grids have changed many times; the current seven regional power grids and their corresponding load areas are shown in Figure S1.

Figure S1 China's 32 load areas and seven power grid regions in this research.

S2.2 Research period and existing infrastructure

The model takes 2020 as the base year and covers 41 years for the research period 2020-2060. We assume no new installations in the base year 2020. The existing power generating units at the beginning of 2020 are considered to be the existing generating units in the base year. Also, the power generating units whose construction has been approved (or has commenced) at the beginning of 2020 are treated as existing infrastructures, which means that our model does not get to decide whether they will be built; we do not include their capital investment costs and treat them as existing facilities.

S2.2.1 Existing electric generating units

In 2020, the installed capacity of existing power generation infrastructure covered by this research accounts for most of total installed capacity providing electricity in China. It includes:

- 4833 coal units which together represent a total of 1054.4 GW;
- 322 natural gas power generators which account for 92.8 GW of total installed capacity;
- 686 conventional hydro power plants accounting for 330 GW of total installed capacity[1];
- 48 nuclear units which represent 49.8 GW of total installed capacity; and
- All onshore, offshore wind, central, and distributed solar PV and CSP projects in each province.

In summary, our research covers 100% of coal-fired, natural gas, hydro, and nuclear power generating capacity (the same with the data reported by CEC). Also, 100% of onshore wind (204.8 GW), offshore wind (5.3 GW), solar PV (204.3 GW), and CSP (270 MW) capacity are included in this research. Other fuel sources, such as diesel and geothermal, account for a small proportion of China installed generation base and are left out of this research. The existing installed capacity by generating technology that is covered in each province is shown in Figure S2.

[1] The raw data includes 2175 conventional (i.e., non-pumped storage) hydro units. In the model, the large hydro units with installed capacities of 40MW or more are aggregated at the plant level. In contrast, the small hydro units with less than 40MW are aggregated at the provincial level.

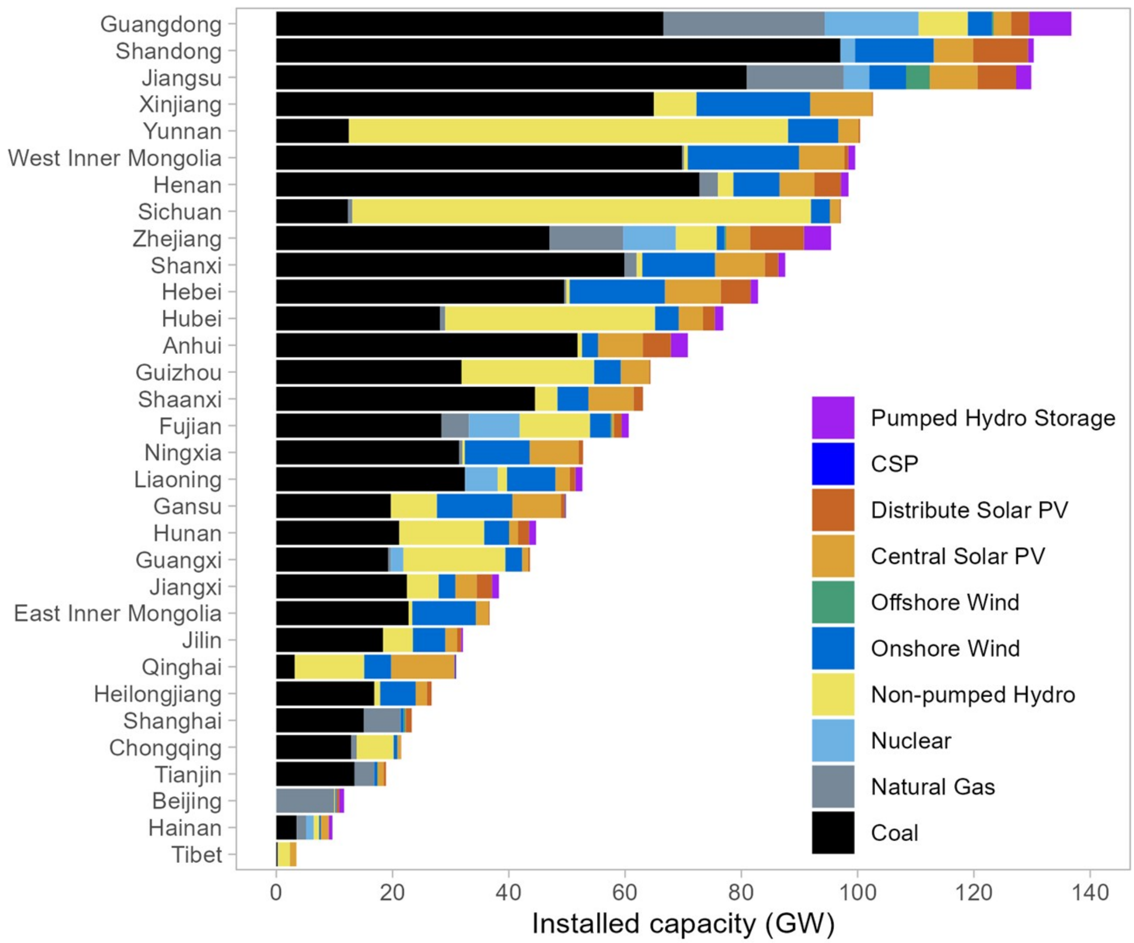


Figure S2 Installed capacity of different technologies in each province at the beginning of 2020.

Our model also includes power generating units that are under construction or whose construction has been approved by 2020. These include:

- 32 large coal units which together represent a total of 22.4 GW;
- 14 natural gas power generators which account for 6.5 GW of total installed capacity;
- 248 large hydro power plants accounting for 130.9 GW of total installed capacity; and
- 34 nuclear units which represent 37.9 GW of total installed capacity;

The installed capacity of each generating unit in each province is shown in Figure S3. The provinces of Jiangsu and Shandong installed the most fossil fuel generating units. Natural gas power generators are centered in more developed provinces, such as Beijing, Guangdong, Jiangsu, Shanghai, and Zhejiang.

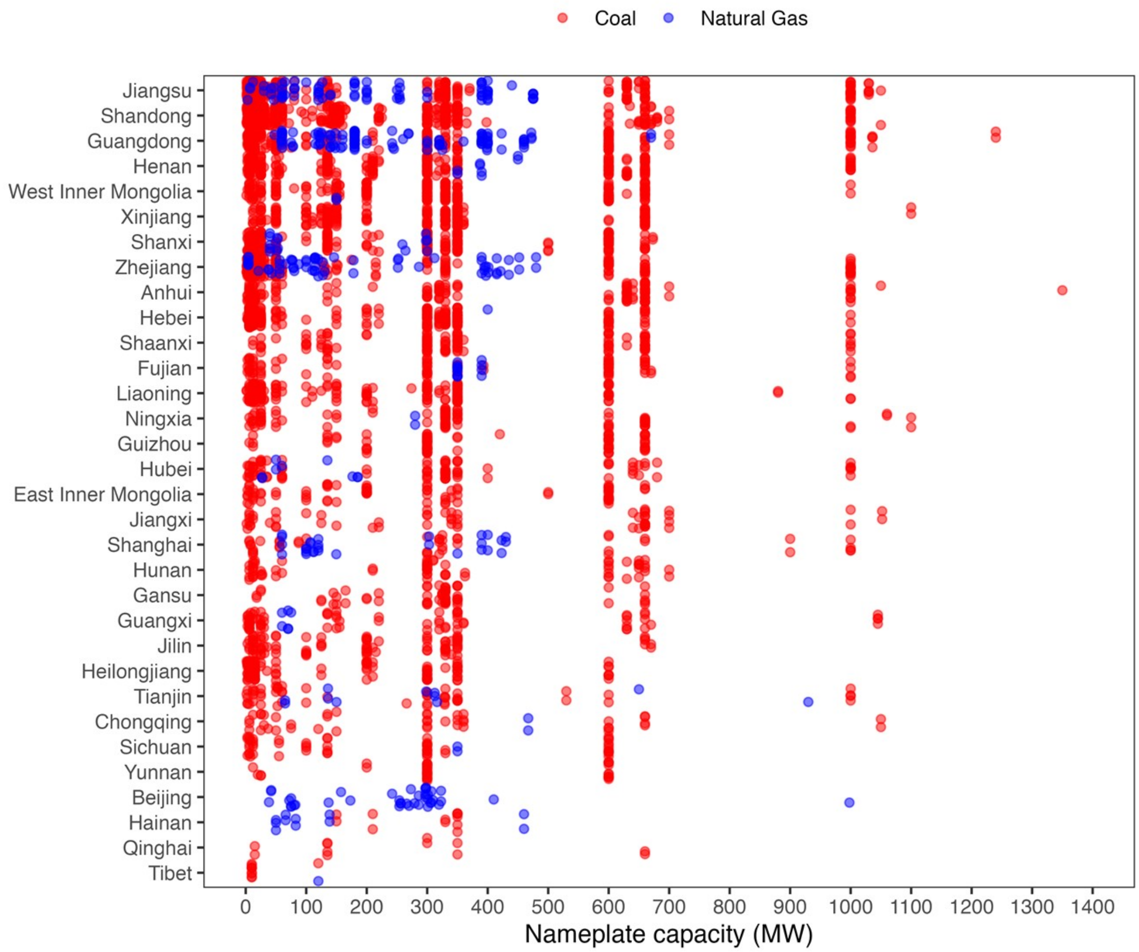


Figure S3 Capacity distribution of coal and natural gas electric generating units in each province at the beginning of 2020. The provinces are arranged by the total installed capacity of fossil fuel generating units. Most natural gas power units in China are combined cycle gas turbines (NGCC or called CCGT), which are combinations of gas combustion turbines and steam turbines. Compared with gas combustion turbines, NGCC are more efficient in energy and economic performance. This figure shows the nameplate capacity of NGCC.

Some generating units will retire within the research period, because of their technical life time or lack of economic competitiveness. No more power is generated from these units once they retire. The age distribution of electric generating units can be seen in Figure S4.

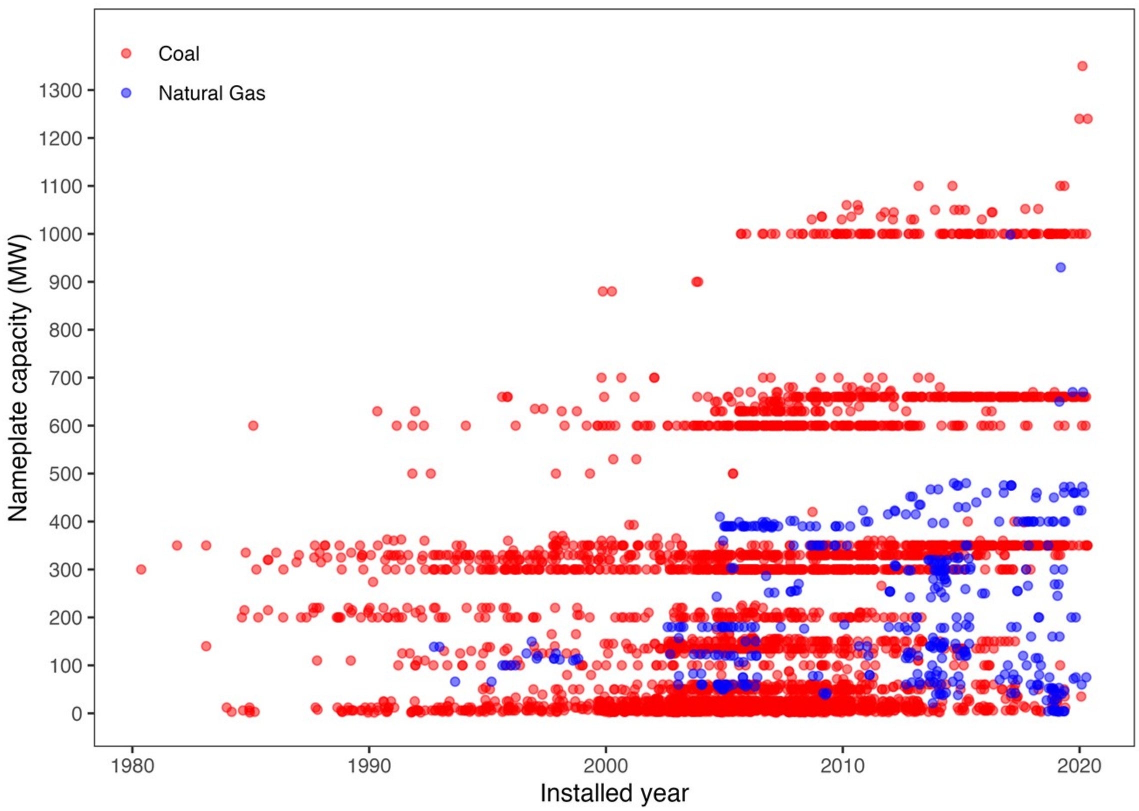


Figure S4 Installed year of coal and natural gas power generating units.

Most coal and natural gas generating units are new, and more than three quarters of electric generating units (in terms of installed capacity) were built after 2005. Most large generating units (for example, installed capacity higher than 1000MW) were built after 2010, which means that they are likely to remain operational in 2040.

S2.2.2 Existing transmission lines

Each of the provinces are represented as a power balancing node connected by inter-provincial AC and DC transmission lines. From various sources, we collect data on each of the transmission lines (origin, destination, distance, power capacity, energy loss). The capacity of inter-provincial transmission is over 400 GW in 2020, and this capacity increases to over 460 GW in 2023. We include these AC and DC transmission lines in this study. The model ignores intra-provincial power transmission and distribution lines. A summary of the total capacity and average loss of the inter-provincial AC and DC transmission lines is shown in Figure S5.

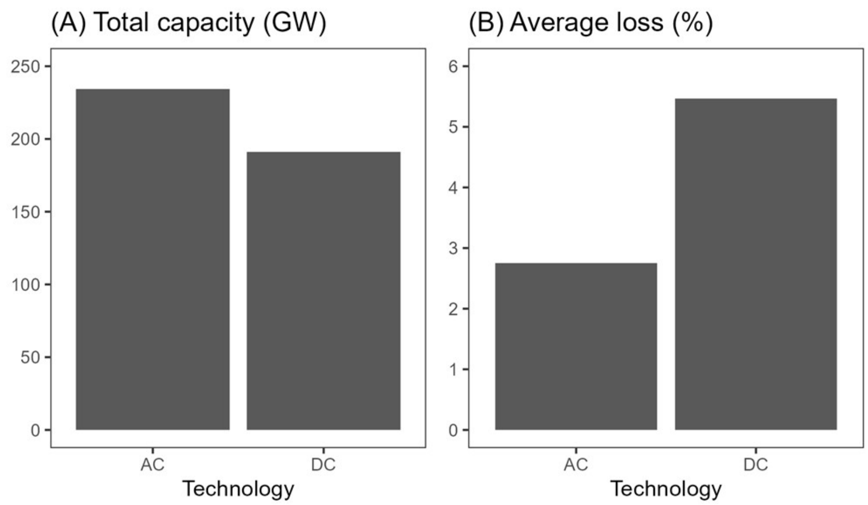


Figure S5 (A) Total capacity and (B) average loss of AC and DC transmission lines.

S2.2.3 PHS planning

From various sources, we collect the information of 129 existing PHS units installed by 2020. We can see that by 2020, the capacity of PHS projects was over 30 GW. The *Base*, *D-Gen* and *D-Tra* scenarios assumes that no new PHS will be installed and the PHS capacity remains the same as it has been built in 2020.

As the official government planning of PHS, the capacity will be over 60 GW, 150 GW, and 300 GW by 2025, 2030, and 2035, respectively. Many PHS projects are under construction or approved for construction. These projects have been identified suitable and feasible with the consideration of physical or socio-political constraints. From various sources, we collect information on these 550 pumped hydro storage projects/units which represent 284 GW of total capacity. The existing and new projects together will account for more than 314 GW of capacity. The *D-PHS* and *D-All* scenarios assume that the PHS capacity expansion will follow the official government plans for PHS until 2040 in China. We collect detailed information on these PHS projects and include them in the *D-PHS* and *D-All* scenarios.

A summary of the PHS capacity in each province is shown in Figure S6. Zhejiang, Hubei, Guangdong, and Guangxi will have the largest PHS capacity by 2040; each of these provinces will have more than 20 GW of PHS capacity.

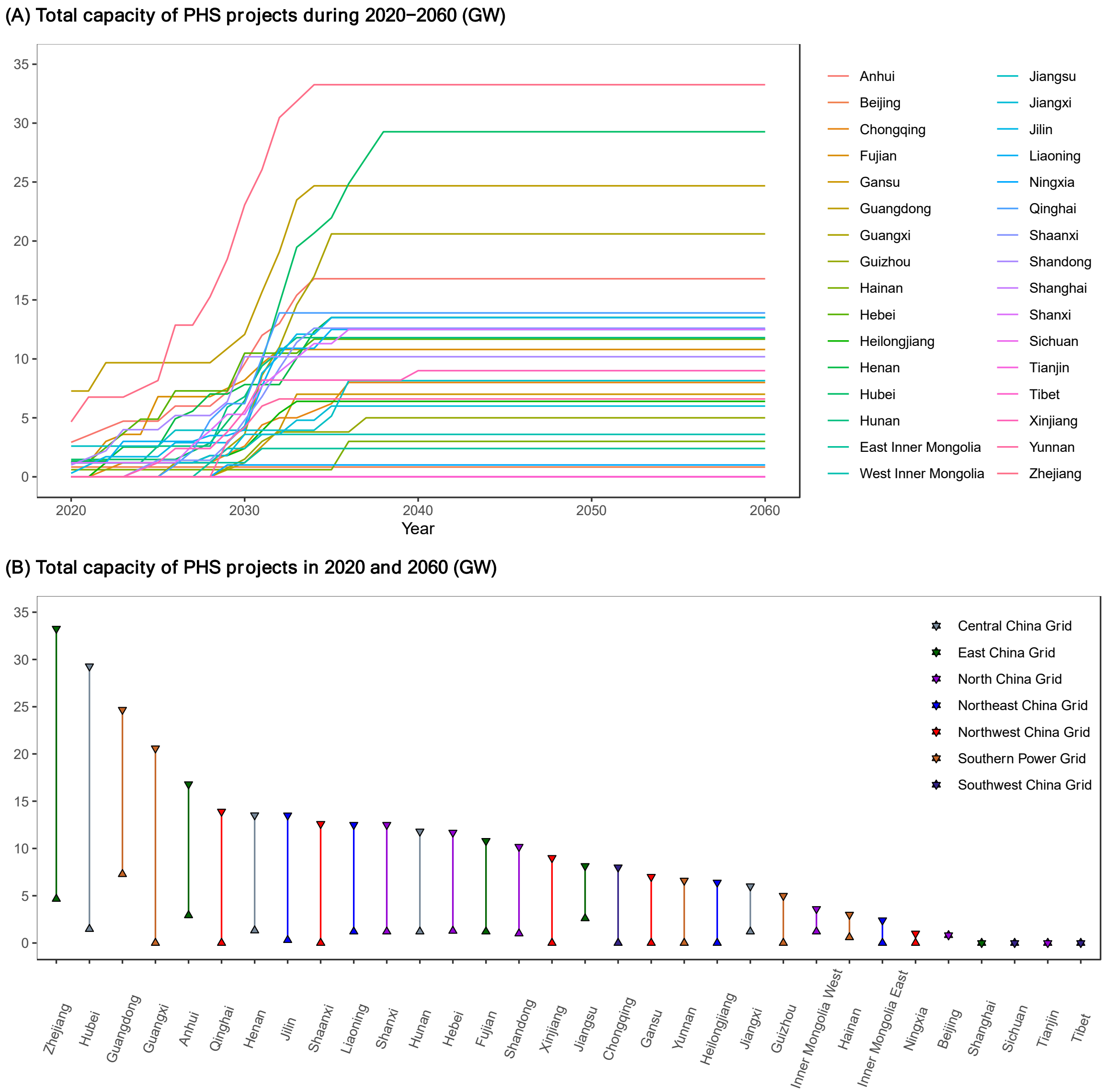


Figure S6 PHS capacity at a provincial level between 2020 and 2060.

S2.3 Hourly power demand in each province

S2.3.1 Electricity demand in each province in each year of 2020-2060

China's electricity demand has experienced rapid growth in recent years. Electricity demand has grown more than fivefold from 1.36×10^{12} kWh in 2000 to about 7.51×10^{12} kWh in 2020. It is projected that China's power demand in 2050 will be twice as high as today's. By collecting data on provincial electricity demand from 2000 to 2021, we obtain annual growth rate of electricity demand at the provincial level during this period (Figure S7). We can see a dramatic difference in growth rate among provinces, ranging from less than 5% to more than 15% (Figure S8).

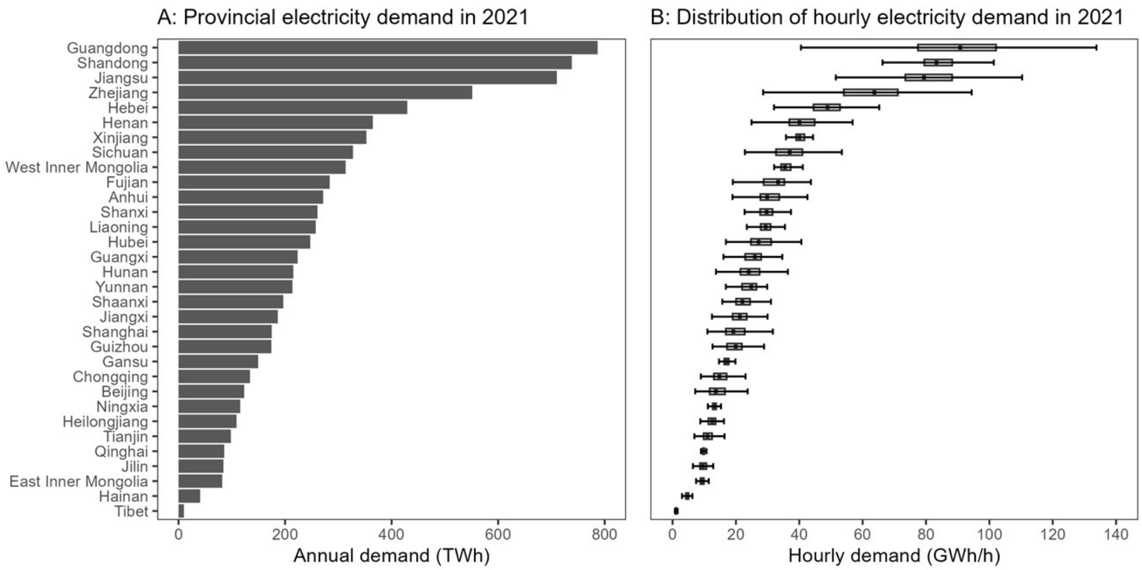


Figure S7 China's provincial electricity demand in 2021.

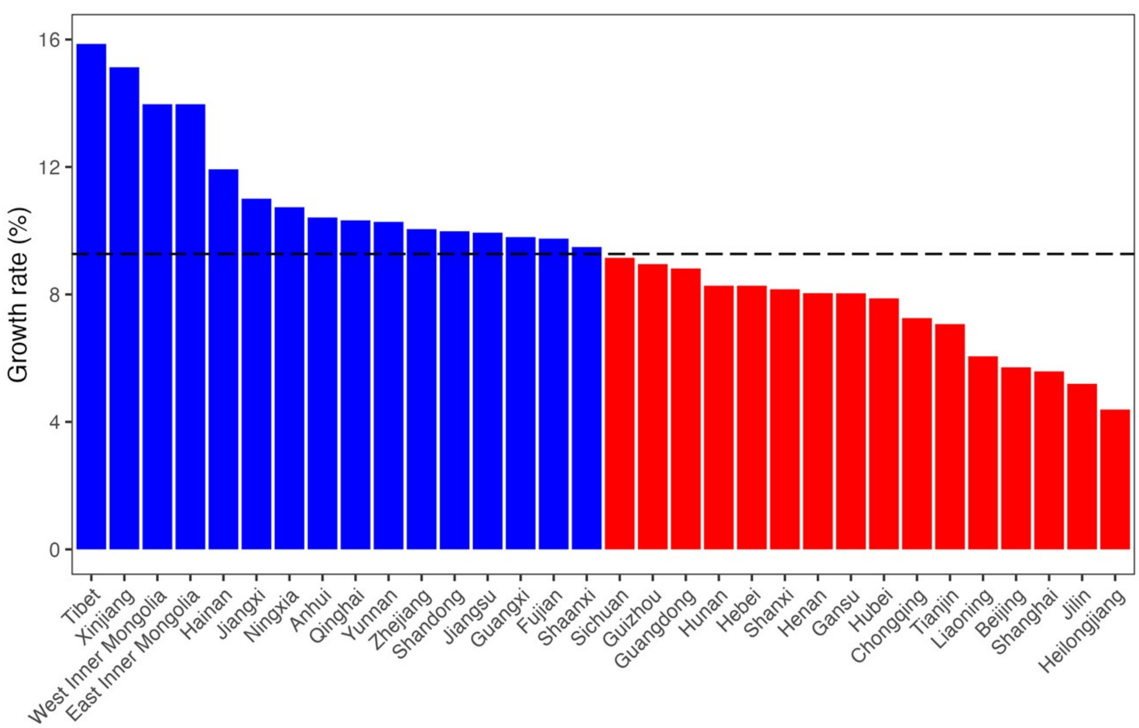


Figure S8 China's provincial difference in growth rate of electricity demand from 2000 to 2021. The dashed line represents the average electricity demand growth rate from 2000 to 2021.

For simplicity, we assume that provincial growth trends will continue, which is unlikely, relative to the average growth rate of China. In other words, the growth rate in province p for years $y = 2022, 2023, ..., 2059, 2060$ is

$$\frac{DGR_{p,y}}{DGR_y} = \frac{DGR_{p,2000-2021}}{DGR_{2000-2021}} \qquad \text{eq.47}$$

Where $DGR_{2000-2021}$ is China's average annual demand growth rate during 2000-2021, $DGR_{p,2000-2021}$ is the growth rate in province p during 2000-2021, and DGR_y is the assumptions of average demand growth rate of China in year y. China's provincial electricity demand growth rates are shown in Figure S9.

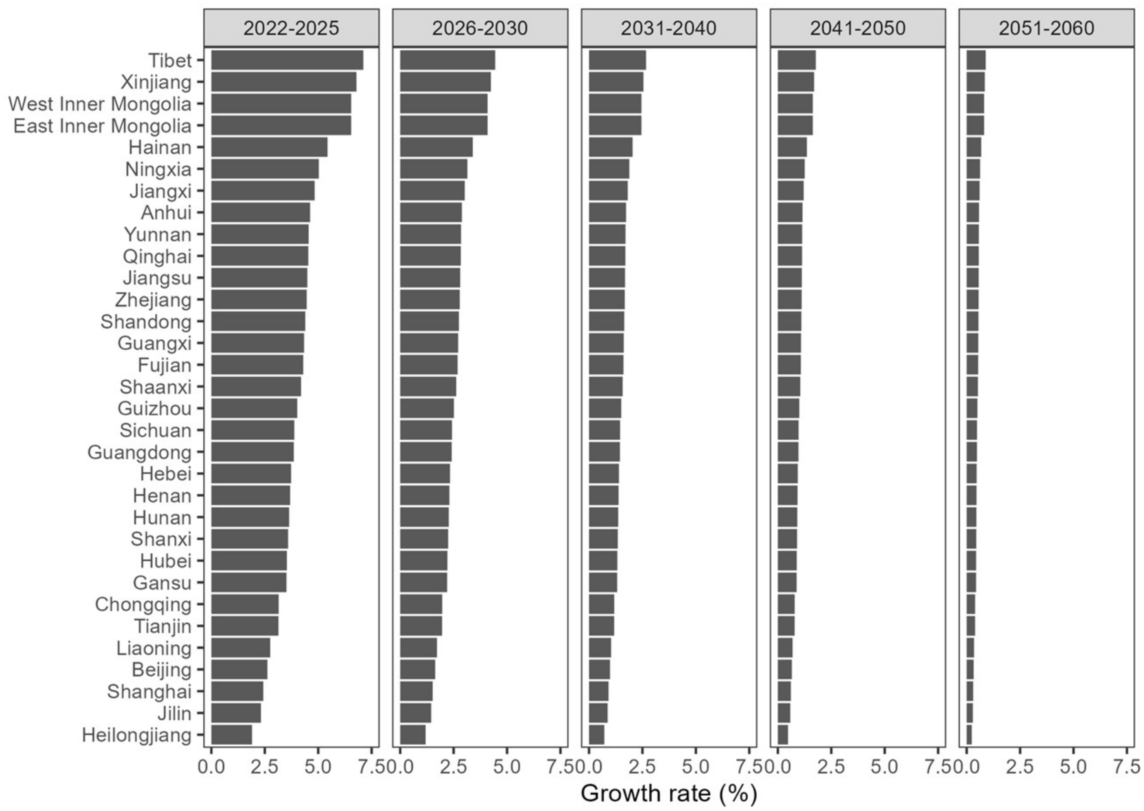


Figure S9 Assumptions of China's electricity demand growth at the provincial level between 2022 and 2060.

Using provincial electricity demand in 2021 and growth rates from 2022 to 2060, we obtain China's provincial electricity demand in each year of the research study's time horizon (Figure S10).

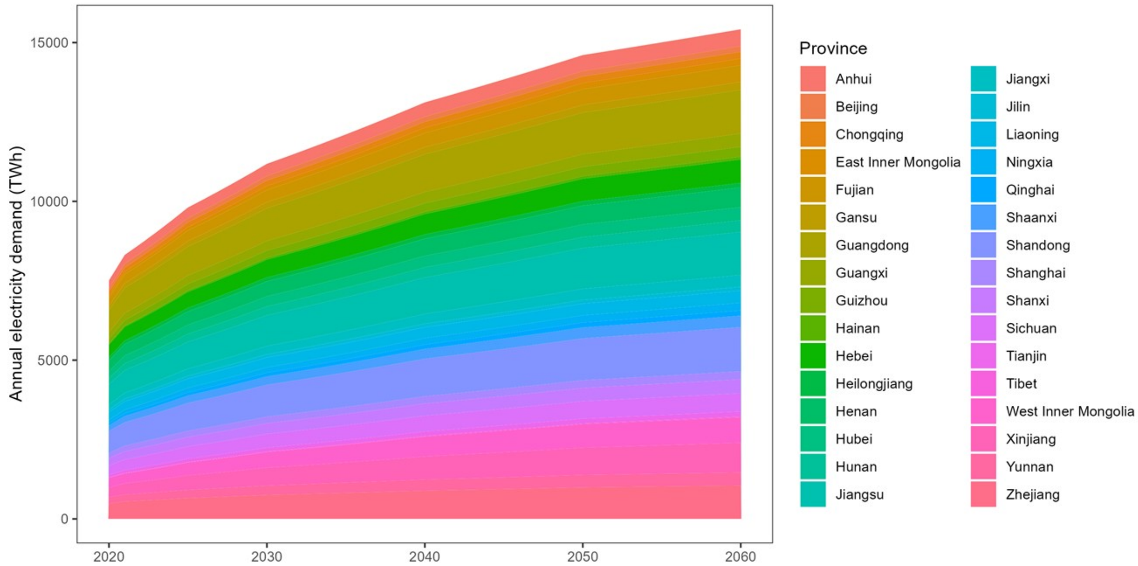


Figure S10 China's electricity demand projections at the provincial level during 2020-2060.

S2.3.2 From yearly to hourly electricity demand in each province

We obtain the hourly power demand in each province in 2019. We assume that the shape of provincial load profiles during the research period remains identical to 2019, and therefore, we scale up the hourly power demand so that the annual total is equal to the electricity consumption in target years according to annual electricity demand growth projections in each province. As a result, there will be huge spatial differences and temporal variations in power demand at the hourly and seasonal levels in 2060. Peak demand in China will grow from around 1000 GW in 2019 to more than 2100 GW in 2060. Guangdong, Shandong, Jiangsu, and Zhejiang, which are all more developed eastern provinces, contribute the most to the peak demand in China (Figure S11).

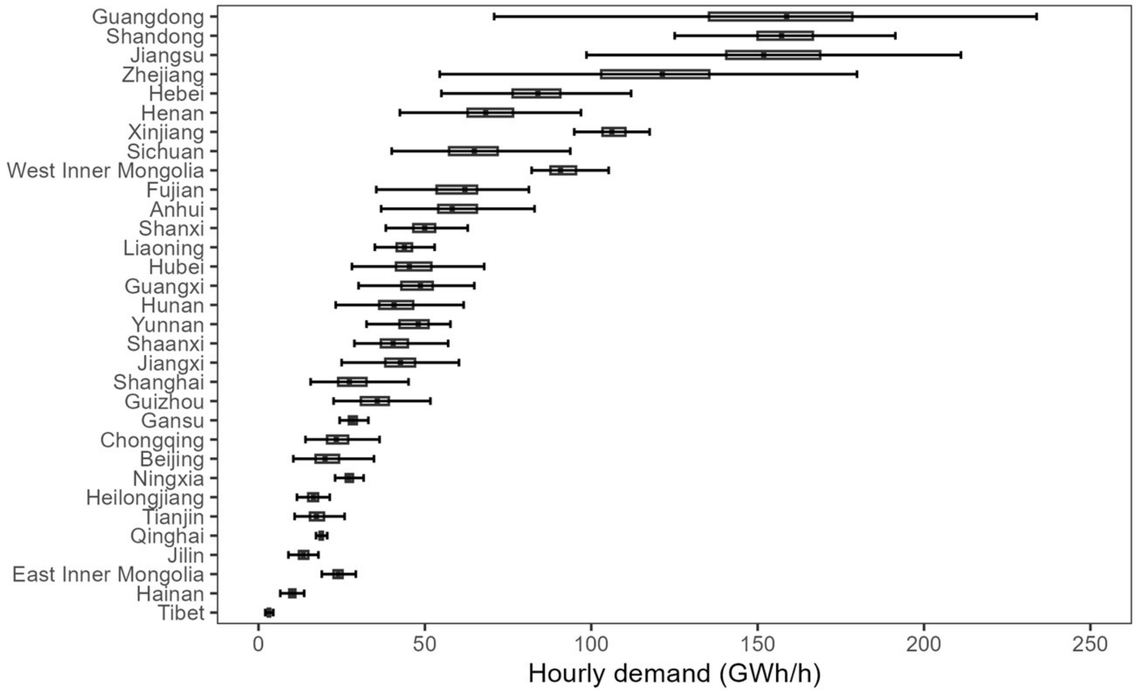


Figure S11 Distribution of hourly electricity demand at the provincial level in 2060.

S2.4 Assumptions and parameters of the model

S2.4.1 Economic, technical and environmental parameters

EGU parameter data come from different sources, as indicated in Tables S2 – S4.

Table S2 Technical parameters of coal, nuclear, natural gas and hydro EGUs under various scenarios.

Technology	Scenario	Minimum power output (% of nameplate capacity)	Maximum power output* (% of nameplate capacity)
Coal	Non-dispatchable	60	100
	Dispatchable	30	
Nuclear	Non-dispatchable	85	100
	Dispatchable	60	
Natural gas	-	30	100
Hydro	-	5	Varies among months and units

Technology	Scenario	Maximum ramping up/down rate (% of nameplate capacity/hour)	Maximum startup/shutdown ramping rate (% of nameplate capacity/hour)
Coal	Non-dispatchable	50	60/100
	Dispatchable	100	100
Nuclear*	Non-dispatchable	10	85/100
	Dispatchable	20	70/100
Natural gas	-	100	100
Hydro	-	100	100
Technology		Minimum up time (hours)	Minimum down time (hours)
Coal	-	10	8
Nuclear	-	22	22
Natural gas	-	3	1
Hydro	-	0	0

Table S3 Operational costs of electric generating units.

Technology	Startup cost (RMB/MW/time)	Marginal cost (RMB/MWh)	Reserve cost (RMB/MWh)	No load cost (RMB/MW)
Coal	1000	Marginal heat rate * Fuel price	20% marginal cost	15
Natural gas	360			40
Nuclear	2000	55		5

Table S4 Energy and environmental performance parameters of fossil fuel generating units.

No load fossil fuel consumption (kg standard coal equivalent per installed capacity in MW)	
Coal	25 (coal units with installed capacity equal or smaller than 300 MW) 20 (coal units with installed capacity larger than 300 MW)
Natural gas	15
Marginal fossil fuel consumption rate of power supply (kg standard coal equivalent per MWh)	
Coal	90% of average fossil fuel consumption rate *

Natural gas	
	Unit start up fossil fuel consumption (kg standard coal equivalent per MW)
Coal	500
Natural gas	100
	CO_2 emissions rate (kg CO_2 emissions per kg standard coal equivalent)
Coal	2.77
Natural gas	1.63

* We do not have the detailed dispatch of each electric generating unit, and hence we cannot know exactly the incremental fossil fuel consumption of each electric generating unit. We assume that the marginal fossil fuel consumption rate is 90% of average fossil fuel consumption rate reported by each electric generating unit, and the rest 10% of average fossil fuel consumption rate is attributed to the no load and start up fossil fuel consumption. In other words, the average fossil fuel consumption rate is a result of the marginal fossil fuel consumption rate, no load fossil fuel consumption, and start up fossil fuel consumption.

We collect the fossil fuel consumption rate of each EGU in 2021 from various sources. Fossil fuel rates of coal units with capacity less than 100 MW is not available and we assume it as 378 kg coal/MWh. Figure S12 shows the distribution of fossil fuel consumption rate. We can see that larger units generally have better energy performance (i.e., lower fossil fuel consumption rate).

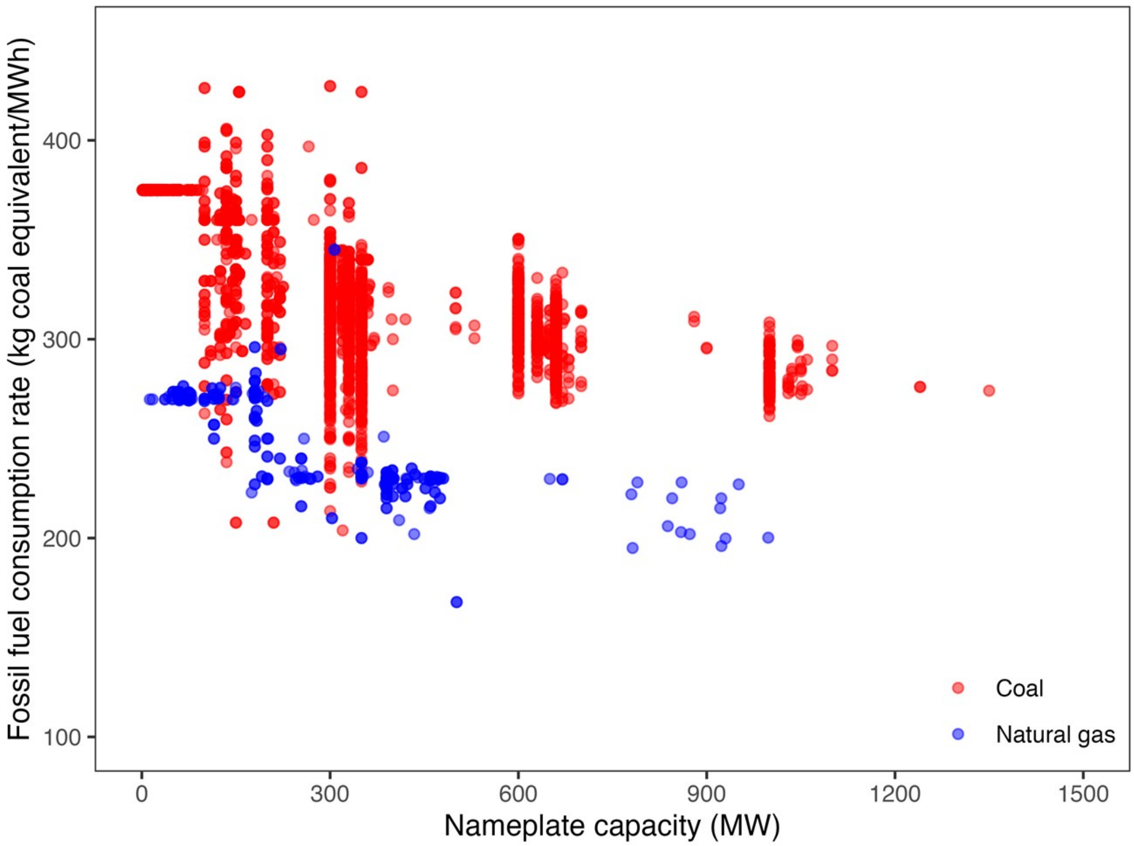


Figure S12 Fossil fuel consumption rate of each of the electric generating units in 2021.

The technical parameters of energy storage systems (including PHS and BESS) are shown in Table S5.

Table S5 Parameters of energy storage system. Unit: %.

	Maximum state of charge (SOC)	Maximum depth of discharge (DOD)	Round-trip efficiency	Hourly energy loss
PHS	100	93	76	0.05
BESS	100	99	90	0.05

Following Zappa et.al. [1], this research models new CSP as solar tower power plants. Each new CSP plant is equipped with eight hours of storage capacity at nominal load. The technical parameters of new CSP are summarized in Tables S6.

Table S6 Parameters of new CSP.

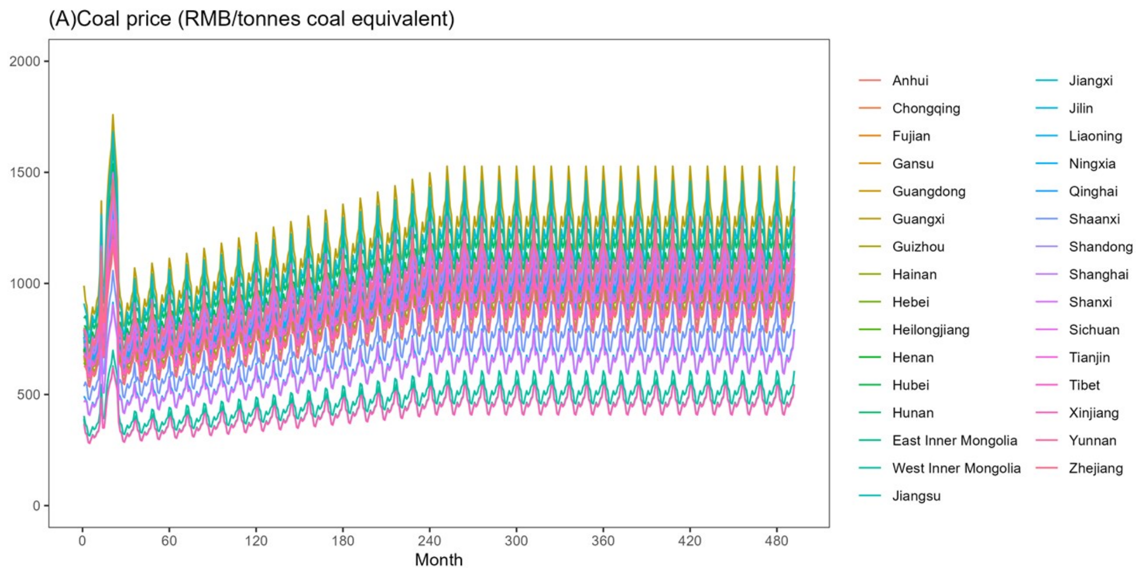
	Maximum state of charge (SOC)	Maximum depth of discharge (DOD)	Round-trip efficiency of storage (%)	Hourly energy loss (%)
Storage block	100	100	98	1
	Minimum power output (% of nameplate capacity)		Maximum power output* (% of nameplate capacity)	
Power block	20		100	
	Solar Multiple			
Solar field	2.5			

This research allows over generation, under generation and shortage in reserve in China's power grid. Their penalties are summarized in Table S7.

Table S7 System penalty parameters.

Type	Penalty (RMB/MWh)
Over generation	1500
Under generation	10000
Reserve scarcity	3500

We obtain the monthly fossil fuel (coal and natural gas) prices during 2020-2022 from various sources, and project the monthly prices during 2023-2060. Monthly fossil fuel (coal and natural gas) prices during 2020-2060 are shown in Figure S13.



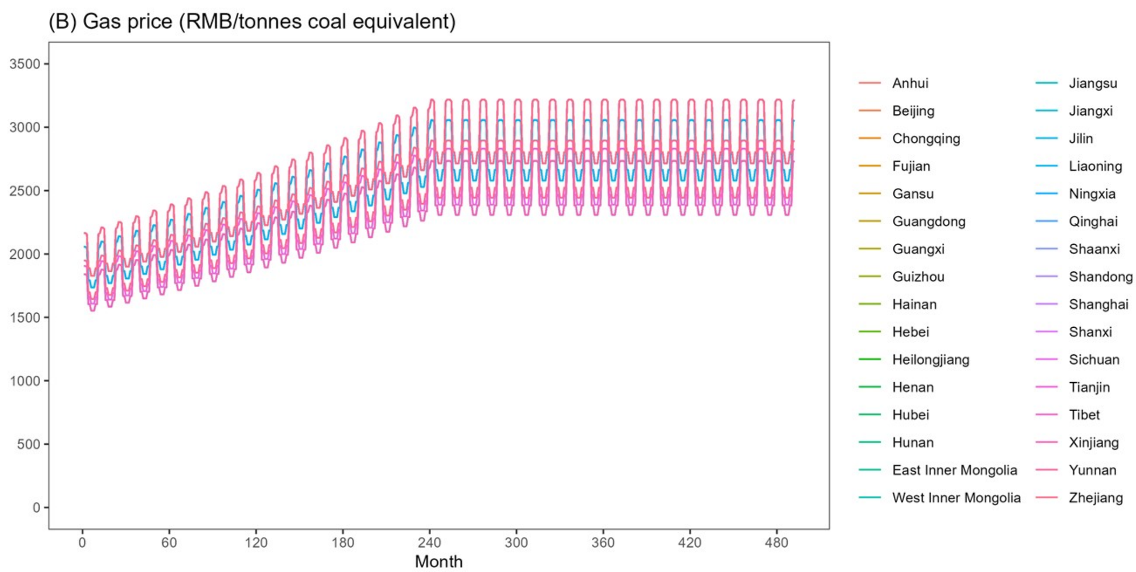


Figure S13 Assumptions of monthly fossil fuel (coal and natural gas) prices during 2020-2060 in each province.

The parameters of new technologies are collected from various sources and summarized in Tables S8.

Table S8 Parameters of new facilities.

Technology	Annual fixed O&M (% of capital cost)	Construction time (year)	Technical life time (year)
Coal	1	2	30

Natural gas	1	2	30
Nuclear	1.5	6	60
Onshore & offshore wind	2.5	1	20
Central & distribute solar PV	1	1	20
CSP	1	3	35
BESS	1	3	15
Transmission	3.5	2	60

We collect the most recent launched projects of various technologies (including coal, natural gas, nuclear, onshore wind, offshore wind, central solar PV, distribute solar PV, CSP, PHS and BESS) and use the average values to represent their current capital costs. Various sources project future capital costs of these technologies. These sources show that capital costs of emerging technologies (wind, solar PV, CSP, and BESS) are expected to decline as the technologies become mature. By collecting the information from various sources, combined with interviews and verification with experts and system operators, this study proposes evolutions in overnight investment costs from 2020 to 2060 (Figure S14).

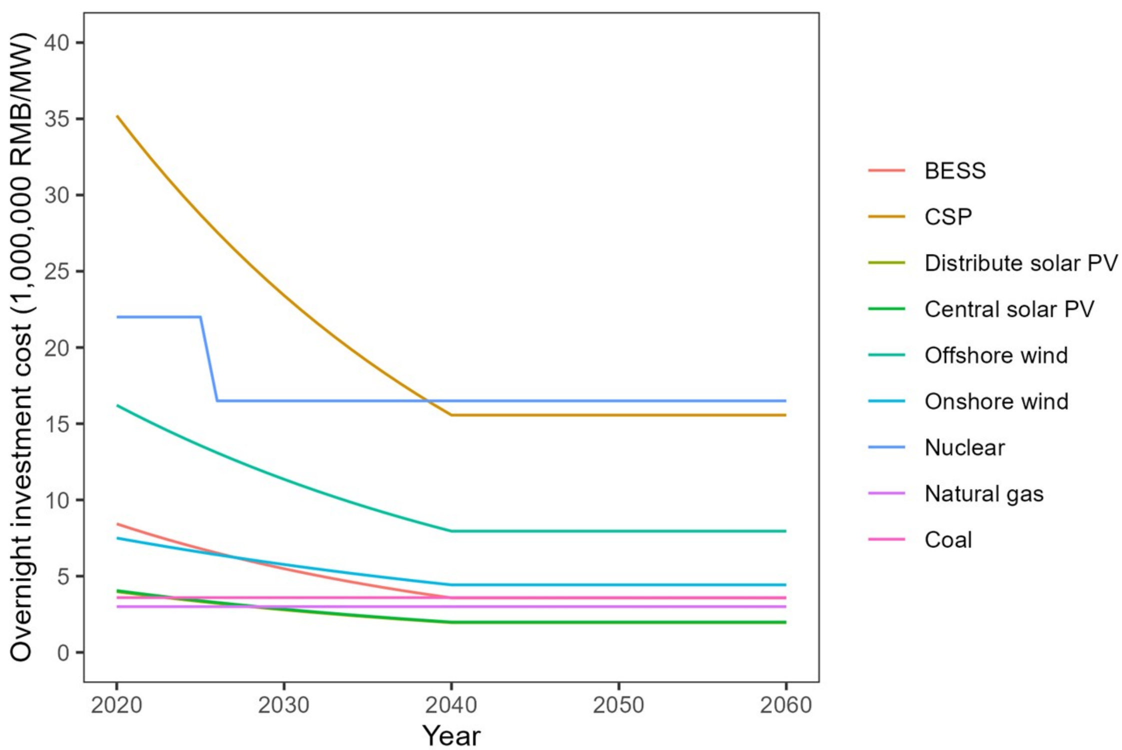


Figure S14 Evolutions in the capital cost of various technologies during 2020-2060.

The capital cost of transmission lines and substations/converters are shown in Table S9. We can derive from the station costs—which are independent of distance—and line costs—which are positively correlated with distance—that a new HVDC line is more cost-competitive for distances over 700km. Therefore, we assume that HVDC lines would be adopted for each two nodes whose distances are greater than 700km while HVAC would be adopted for the opposite. HVDC has advantages in undersea transmission, and therefore we assume that new transmission lines between Guangdong and Hainan will adopt HVDC lines.

Table S9 Capital cost of transmission systems.

Technology	Capital cost		
	Substation/Converters (CNY/kW)	Line (CNY/kW/km)	Source
UHVAC	377.5	1.12	The data are collected from the latest transmission projects.
UHVDC	722.6	0.60	

Losses in AC transmission lines comes mainly from line transmission, while losses from DC transmission lines include losses from converters and lines. We can see that HVDC has lower transmission losses than HVAC when transmission distances are higher than a certain value (around 259km in this research). Transmission losses are shown in Table S10.

Table S10 Transmission loss of AC and DC transmission lines.

Technology		Losses
HVAC		7%/1000km
HVDC	Substations/Converters pair	1.4%
	Line	1.6%/1000km

We assume that carbon prices will gradually increase to 100RMB/tonnes CO_2 by 2030 and then remain stable.

S2.4.2 Reserve requirements

Reserve requirements are calculated for each region r and time step t as a percentage ($ResPerDem$) of its provinces' load plus a percentage ($ResPerInter$) of the system's intermittent power integration from onshore wind, offshore wind and solar PV:

$$ResReq_{t,r} = ResPerDem \times \sum_{p \in r} D_{t,p} + ResPerInter \times \sum_{n \in r} EIn_{t,n}^{RE}$$

We assume that reserves in each hour equal 8 percent of load ($ResPerDem = 8\%$) and an additional 8 percent of power integration from wind and solar ($ResPerInter = 8\%$).

S2.4.3 Assumptions of discount rate

We assume a discount rate of 5% in this paper.

2.5 Wind, solar and hydro power generation

Following the methods explained in Li et.al [2,3], we obtain the suitable sites and generation capacity potential of wind and solar in each grid-cell of 0.5-latitude-degree and 0.625-longitude-degree in China; we also obtain the hourly resources of wind and solar and monthly resources of hydro power in China. The methods can be summarized as follows:

S2.5.1 Wind power generation

Wind generation is calculated based on the wind speed and the power curve. The hourly wind speed in 2000-2018 is retrieved from NASA MERRA-2 dataset (Gelaro et al. [4]) with wind speed measured at 50 meters. We assume the model of wind turbines as the General Electric GE 1.5sl with its power curve shown below (Figure S15). The cut-in speed is 3.5m/s, and the cut-out speed is 25m/s.

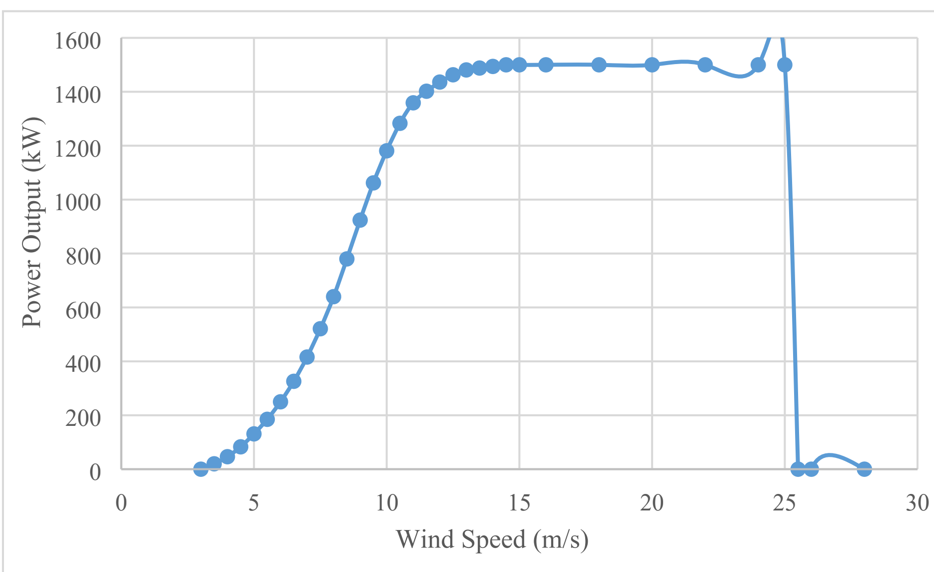


Figure S15 Wind turbine power curve.

We assume the height of wind turbines is 80-meter. We adopt the power law to extrapolate the wind speed at 50 meters to 80 meters. The equation is as follows:

$$u(h_1) = u(h_0) * \left(\frac{h_1}{h_0}\right)^{\alpha}$$

where

$u(h)$ is the wind speed at height h;

h_0 = 50 m;

h_1 = 80 m;

α (wind shear exponent) = 0.143.

Li et.al. [2] provide the methods to select suitable sites for wind turbine deployment for each grid-cell of 0.5-latitude-degree and 0.625-longitude-degree in China. With this method, we calculate hourly wind power generation for each grid-cell of the suitable sites in China. Please refer to Li et.al. [2] for more details.

S2.5.2 Solar power generation

The hourly solar radiation data in 2000-2018 is also retrieved from MERRA-2 dataset but adjusted based on previous research (Feng and Wang [5]) which pointed out MERRA-2's overestimation of solar radiation in China. The research use ground monitored solar radiation from 1980 to 2014 to calculate the average bias of each monitor site in W/m^2. We map the nearest monitor site to each grid cell. Then we calculate the annual average radiation of each cell and get an adjustment coefficient which is calculated as the bias over the average radiation. Finally, we multiply the adjustment coefficient to the hourly solar radiation data.

Li et.al [2] provide the methods to select suitable sites for solar panel deployment for each grid-cell of 0.5-latitude-degree and 0.625-longitude-degree in China. With this method, we calculate hourly solar power generation for each grid-cell of the suitable sites in China. Please refer to Li et.al [2] for more details.

S2.5.3 Hydropower

In order to model hydroelectric generating units as dispatchable units, it is necessary to include daily water management constraints. These constraints are based on information from previous research [6] on the daily hydropower generation of many large hydro plants in China. We use this information together with the data on annual hydropower generation in a four-step process.

1. Calculation of the maximum daily generation for each of the 12 months in a year:

   We first calculate the average daily generation in each month. Then we assume this average generation in historical observations of a given month as the maximum they can provide each day of that month. Looking at the maximum daily production for each month allows us to represent the seasonality of the annual water cycle.

2. Calculation of the maximum daily capacity factor for each month:

   If we just took the daily maximum for each month as the available capacity in a month, we would grossly overestimate the generation from hydropower. Due to its low marginal cost, hydropower is likely to be dispatched at its maximum capacity every day, and if the modelled capacity is higher than real, the results would be biased. To address this possible overestimation of hydropower generation we adopt additional steps. First, we calculated the daily maximum capacity factor for each month. By dividing the maximum daily generation by the installed capacity and by 24 hours, we obtained the maximum daily capacity factor (for each of the 12 months).

3. Adjustment of any daily capacity factor exceeding 1:

   During the wet season, some hydropower plants generate above their name-plate installed capacity and hence the capacity factor results in a number above 1. We adjust any capacity factor above 1 to 1.

4. Calculation of the annual capacity factor from the estimated maximum and adjustment to match historical annuals:

   We aggregated the maximum daily capacity factor to obtain a maximum annual capacity factor. We then compared this estimated annual maximum with historical data published in the China Energy Statistical Yearbook and made necessary adjustments. If the maximum annual capacity factor was lower than the historical data, we adjusted the maximum daily capacity factor of the wet season's months accordingly where we previously reduced the capacity factor larger than 1 to 1.

For smaller hydropower units without historical daily data, we used the average maximum daily capacity factor of large hydro units in the same province as the estimate.

Please refer to Li et.al [3] for more details of the methods to calculate the hydro, wind and solar energy data used in this research.

2.6 Employment parameters of wind and solar

The data on parameters of employment come from different sources as indicated in Table S11 [7,8].

Table S11 Parameters of employment.

Technology	Mfc. (job-yrs /MW)	C&I (job-yrs /MW)	O&M (jobs/MW)	Dcm. (job-yrs /MW)
Onshore wind	6.721	4.576	0.429	1.0296
Offshore wind	22.308	11.44	0.286	4.2757
Utility solar PV	9.581	18.59	1.001	1.144
Distribute solar PV	9.581	37.18	2.002	1.7303

S3 Major results: installed capacities from 2020 to 2060 under different scenarios

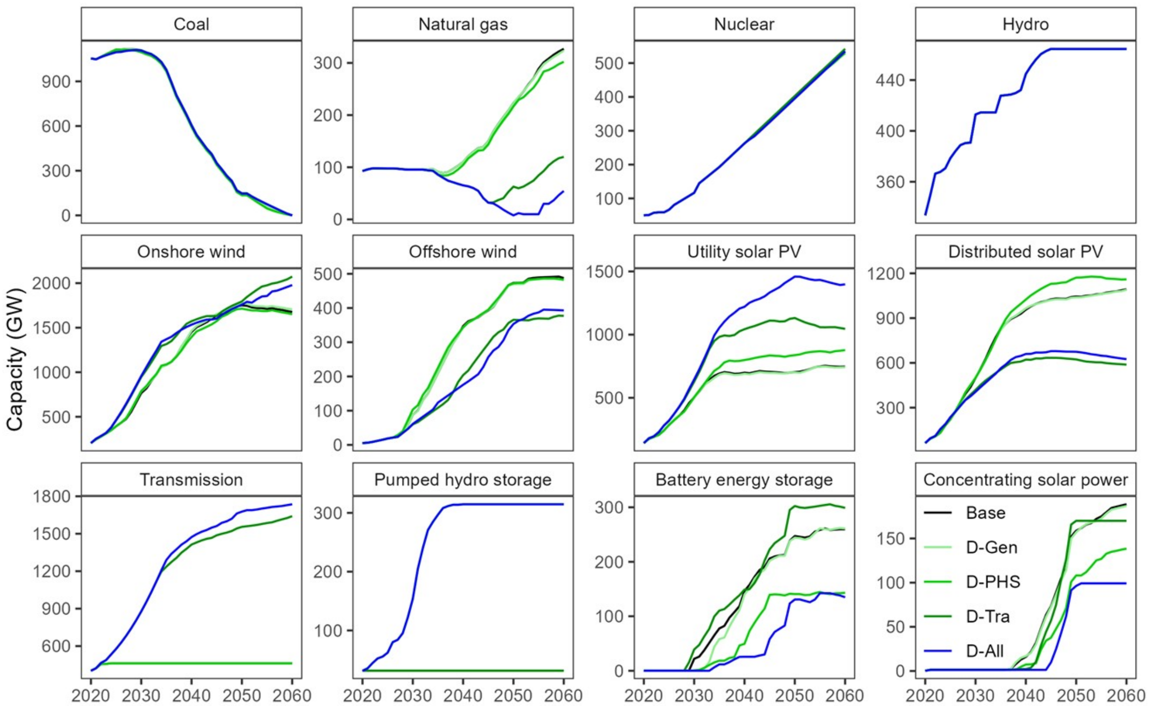


Figure S16 Capacity expansions of various technologies from 2020 to 2060 under various scenarios.

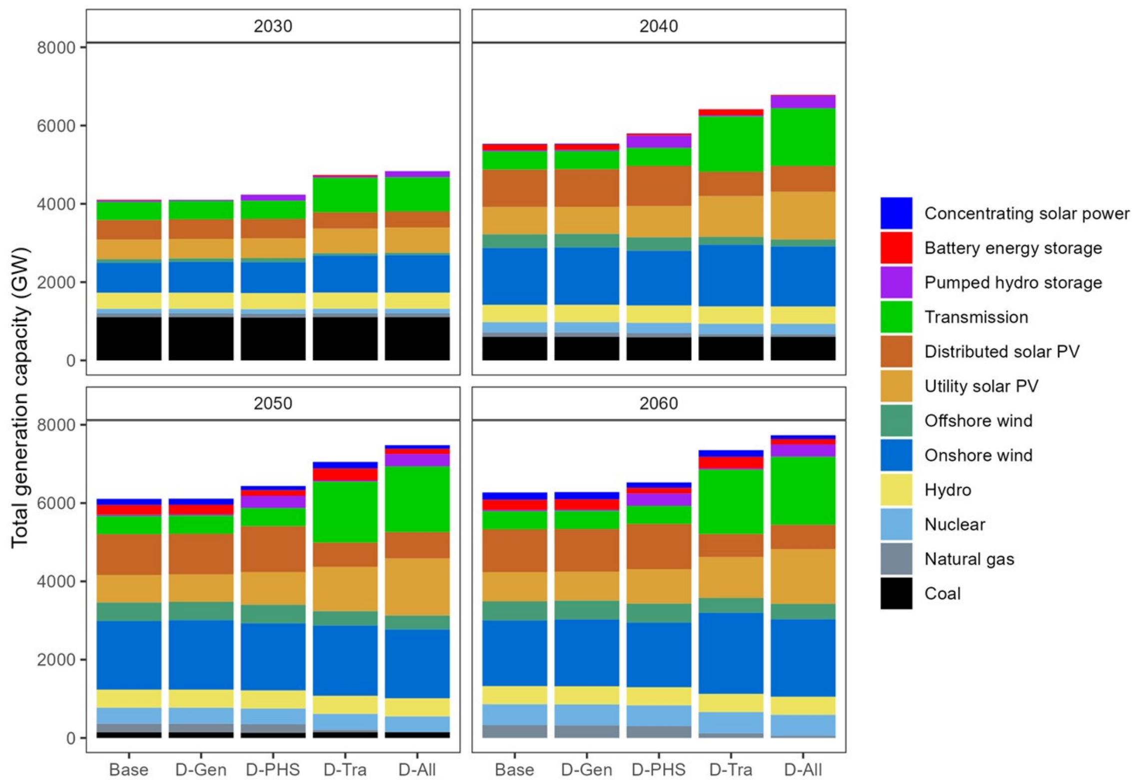


Figure S17 Capacity expansions of various technologies in 2030, 2040, 2050, and 2060 under various scenarios.

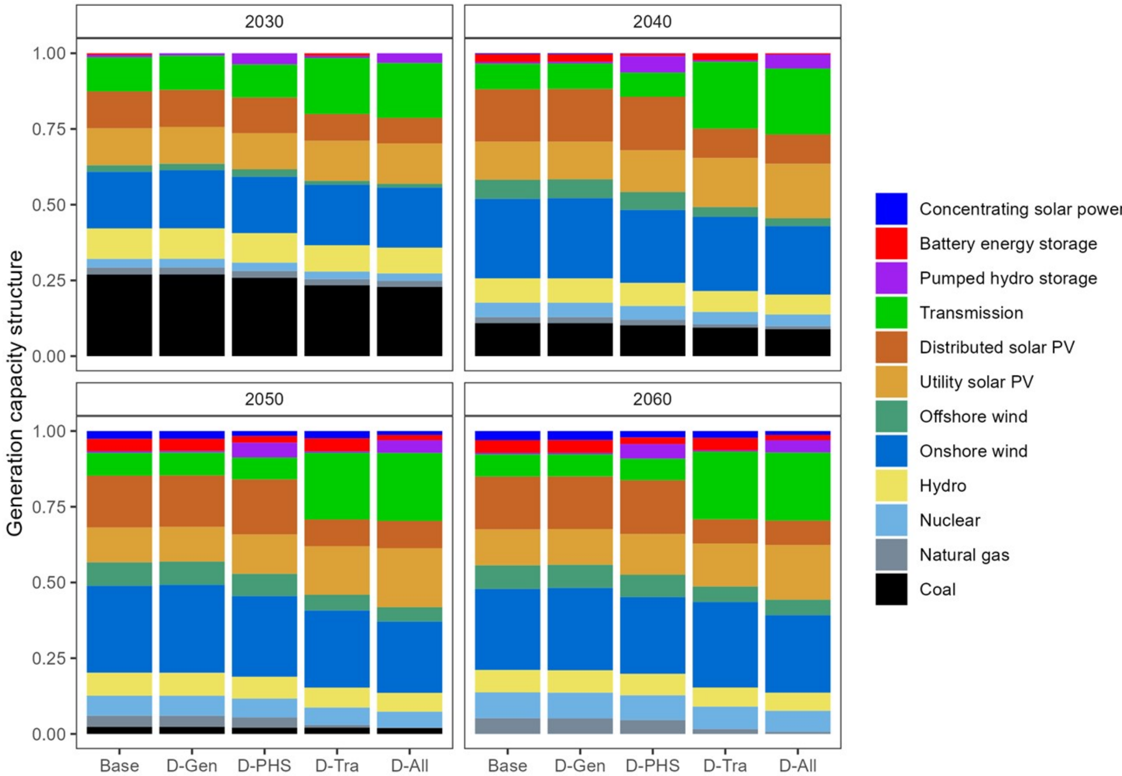


Figure S18 Capacity structure of China's electric power system in 2030, 2040, 2050, and 2060 under various scenarios.

S4 Major results: annual and hourly power supply under different scenarios

S4.1 Annual power supply under different scenarios

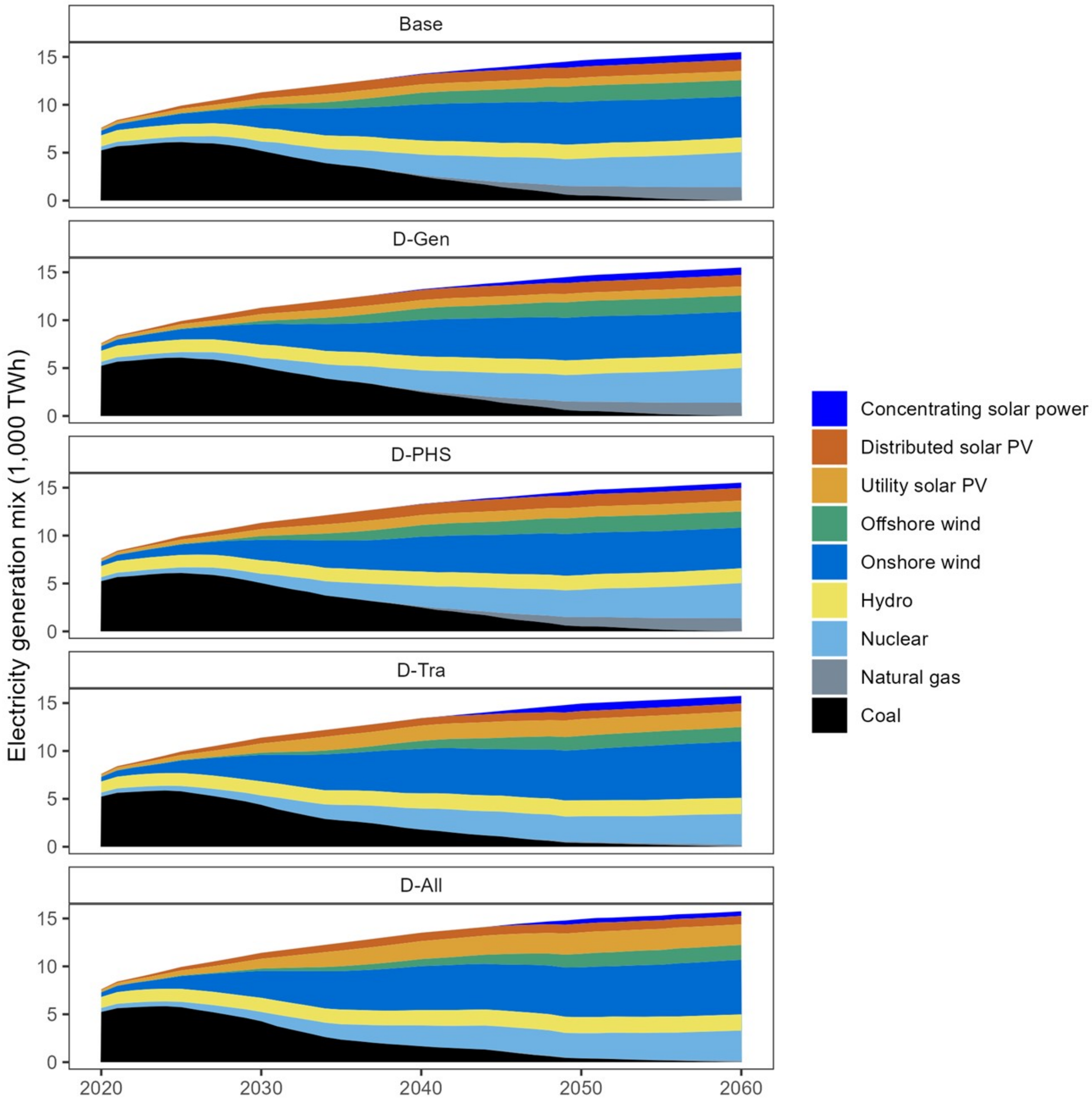


Figure S19 Annual electricity generation of various technologies from 2020 to 2060 under various scenarios.

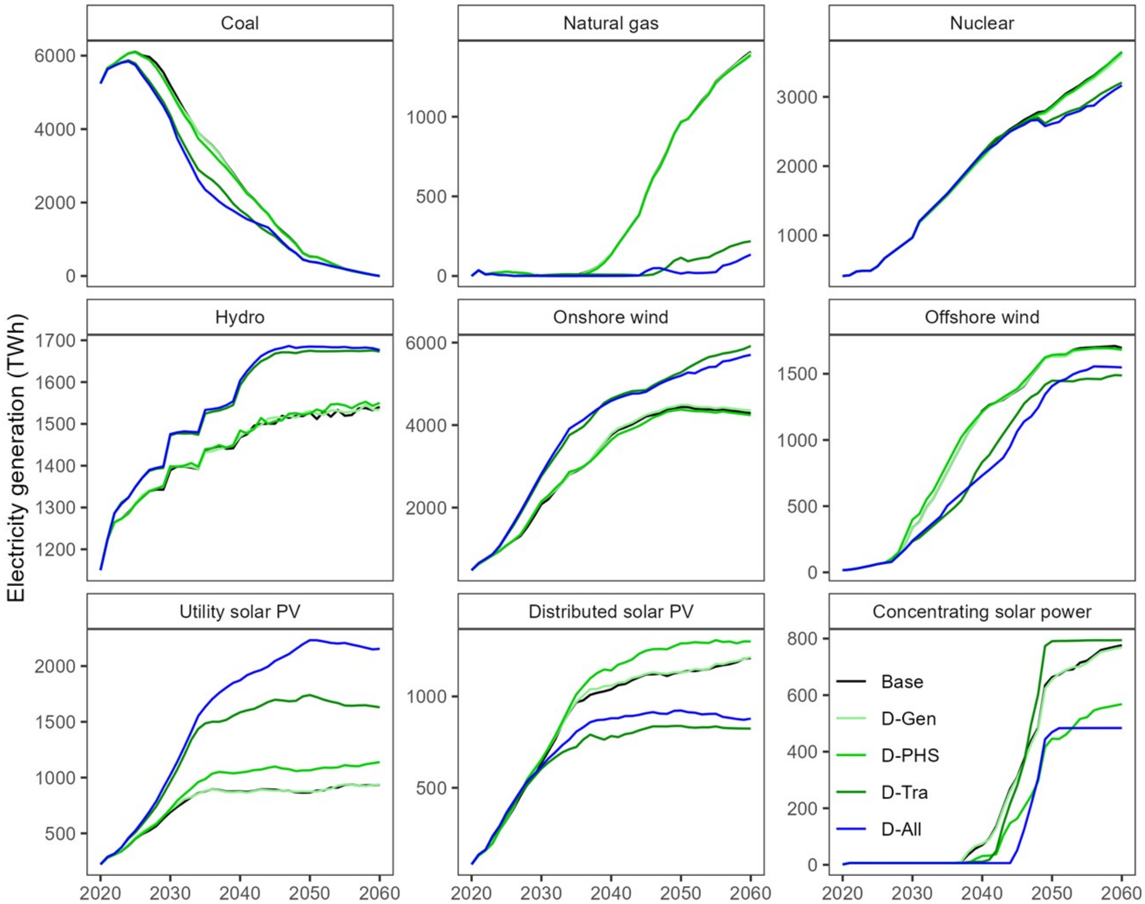


Figure S20. Electricity generation of various technologies from 2020 to 2060 under various scenarios.

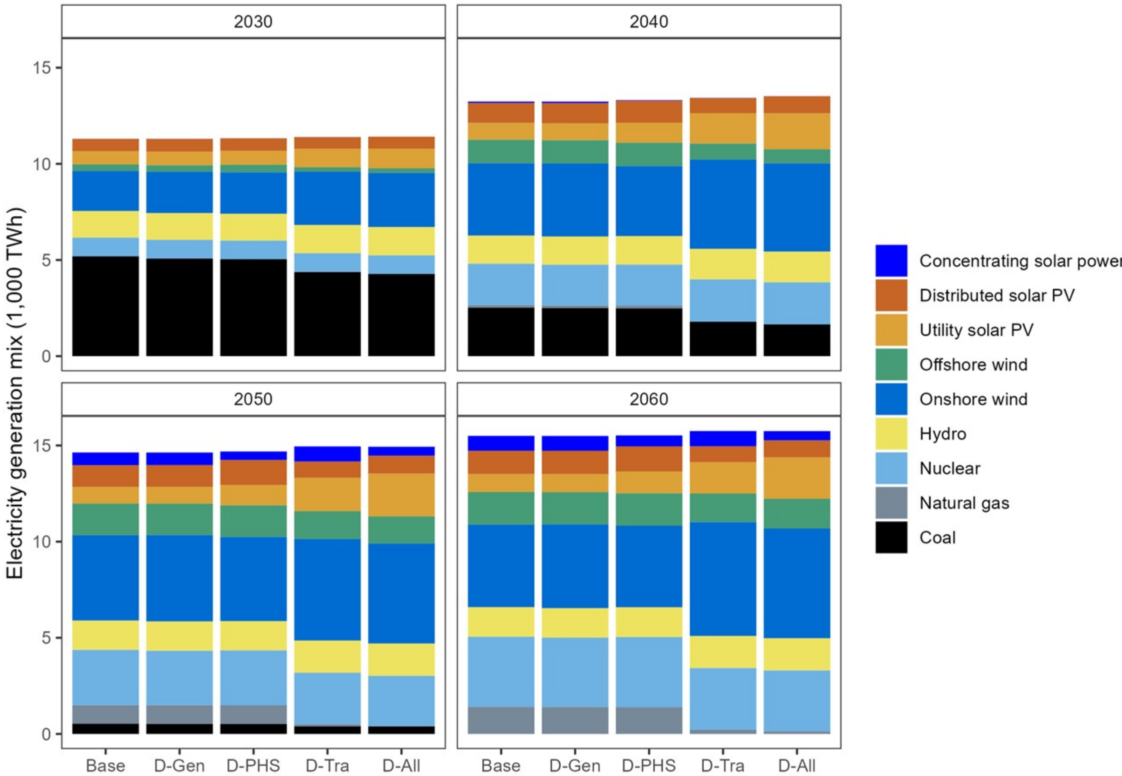


Figure S21. Electricity generation mix of various technologies in 2030, 2040, 2050, and 2060 under various scenarios.

S4.2 Hourly power supply under different scenarios

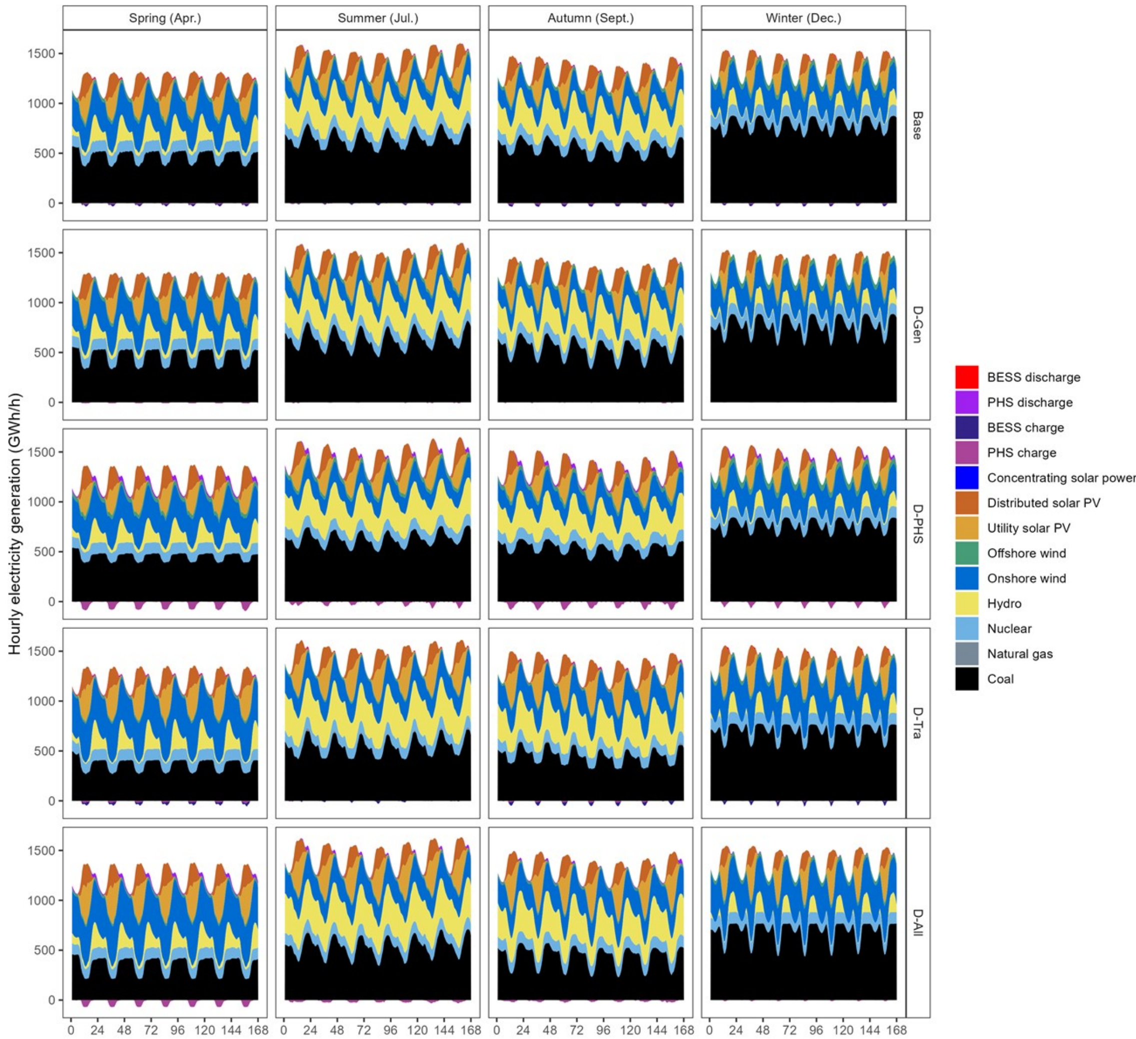


Figure S18 Hourly power system operations of China during a full week (168 hours) and four seasons in 2030 under different scenarios.

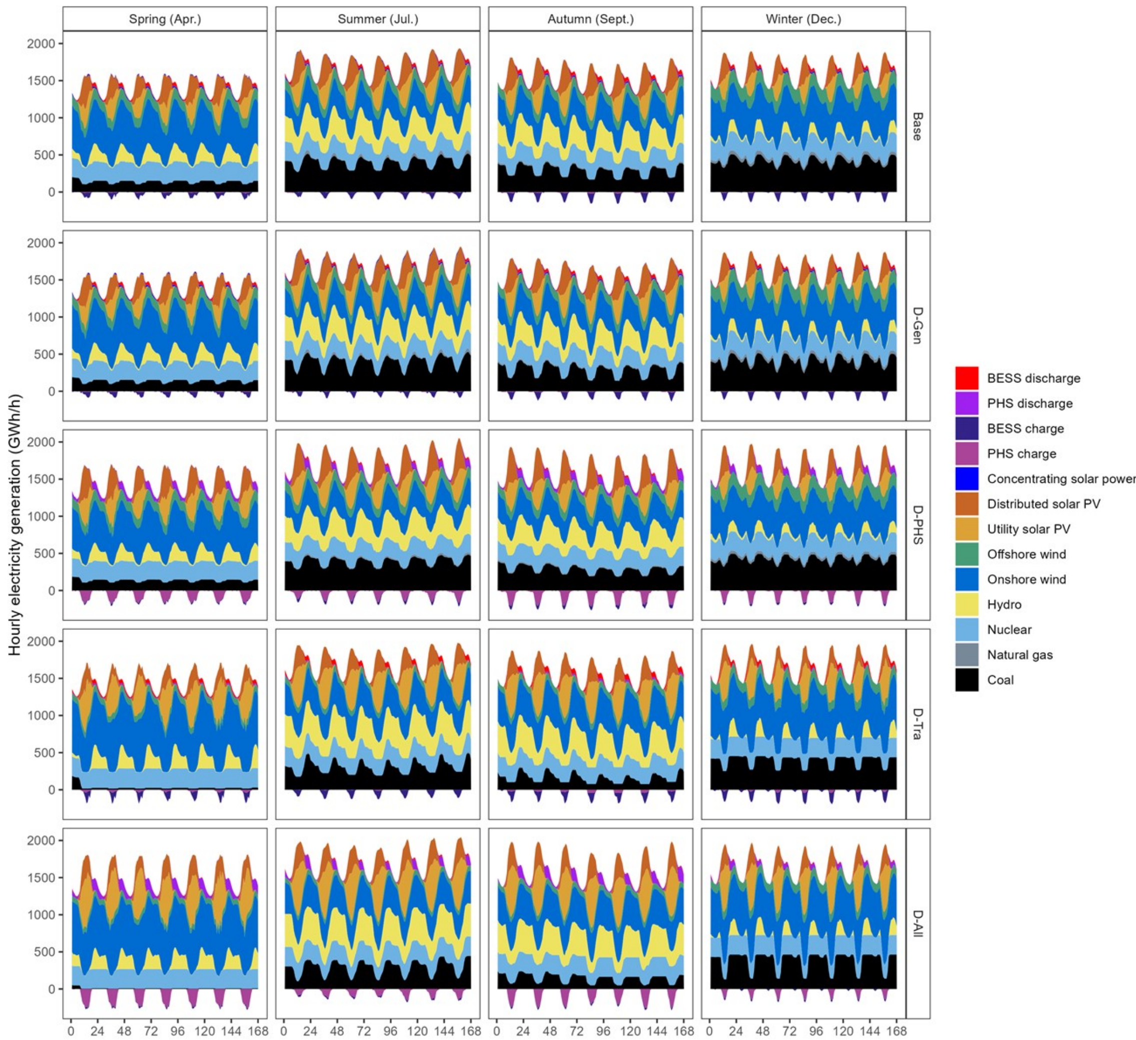


Figure S19 Hourly power system operations of China during a full week (168 hours) and four seasons in 2040 under different scenarios.

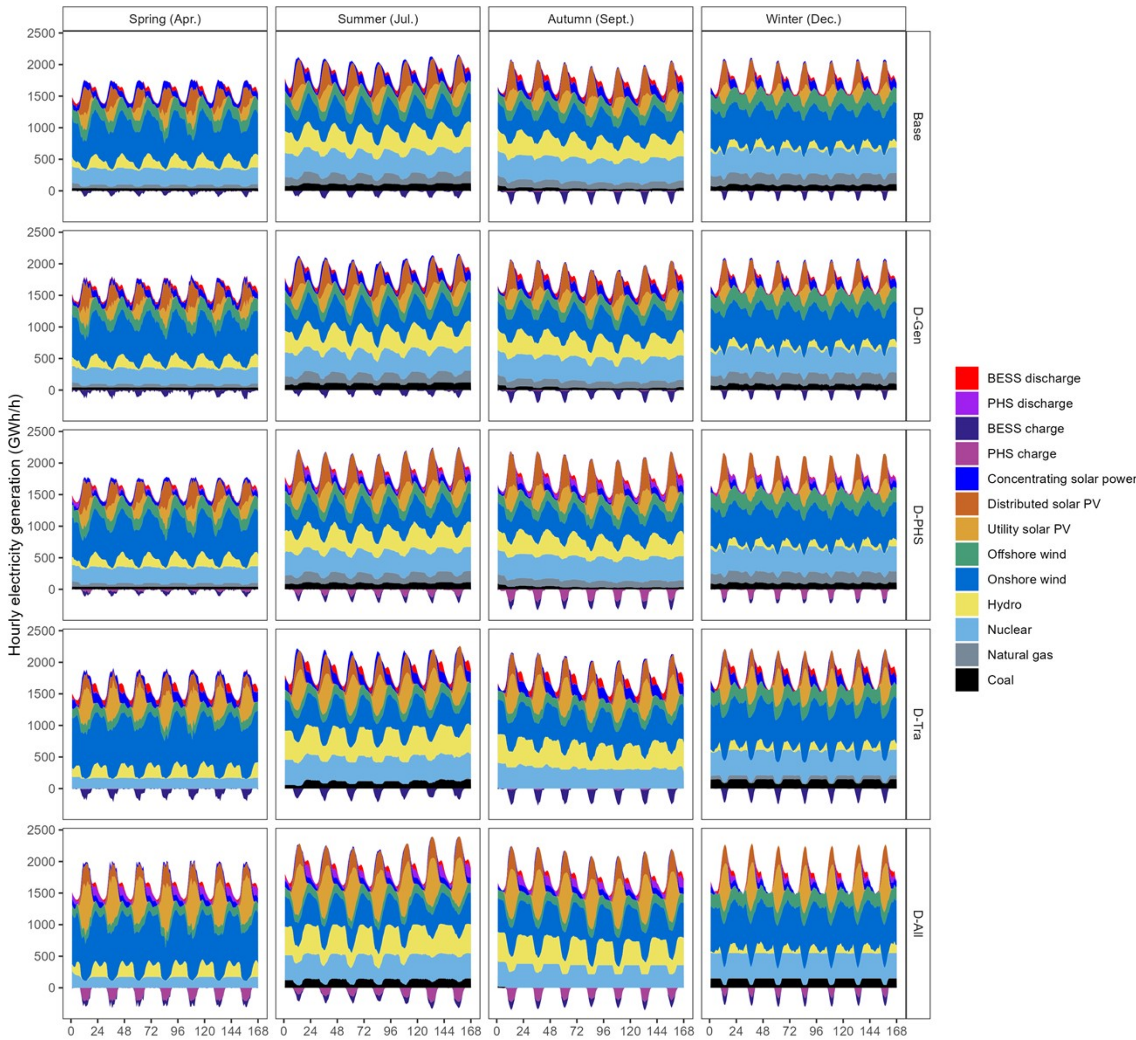


Figure S20 Hourly power system operations of China during a full week (168 hours) and four seasons in 2050 under different scenarios.

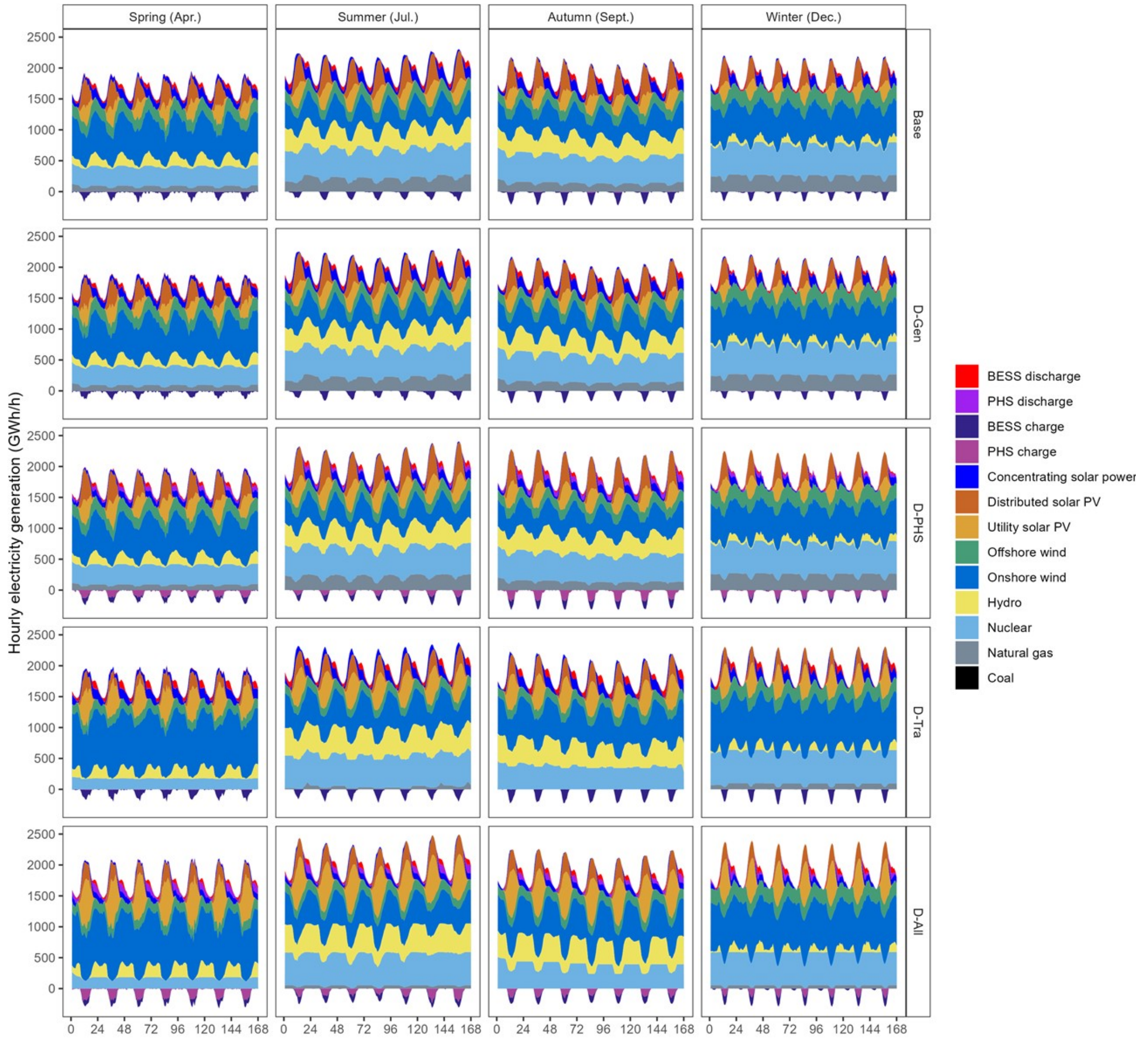


Figure S21 Hourly power system operations of China during a full week (168 hours) and four seasons in 2060 under different scenarios.

S5 Major results: renewable energy integration and curtailment

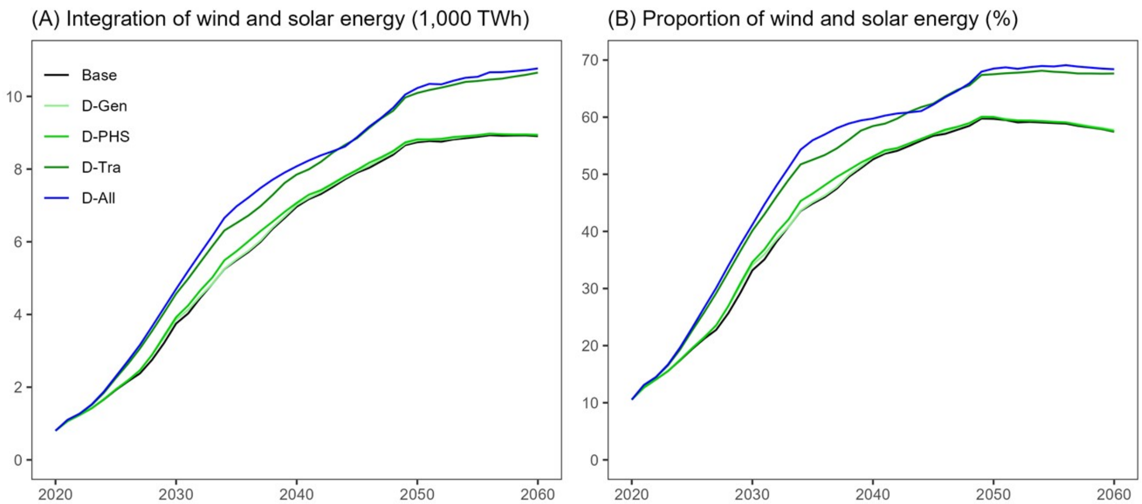


Figure S22 Energy integration from wind and solar under various scenarios.

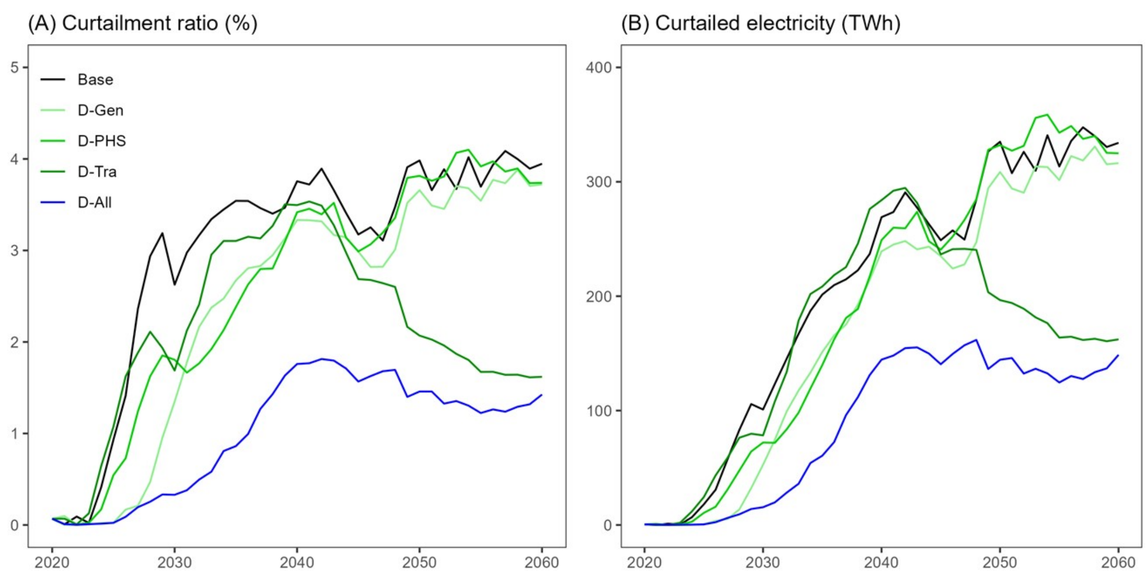


Figure S23 (A) Curtailment ratio of variable renewables and (B) curtailed electricity from 2020 to 2060 under various scenarios.

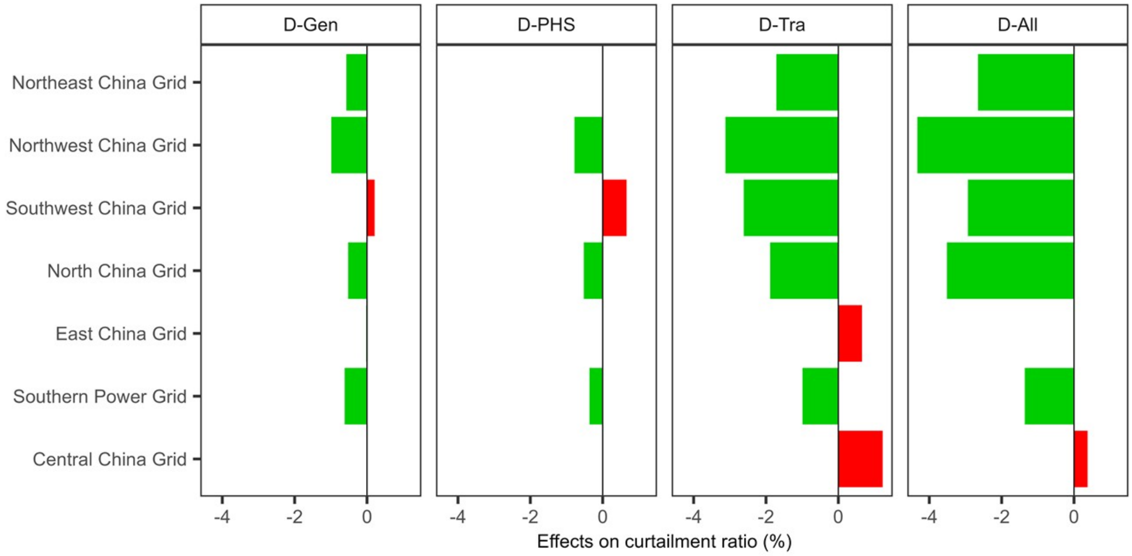


Figure S24 Changes in average curtailment ratio in each power grid from 2020 to 2060 under various dispatchability scenarios, relative to the *Base* scenario. Positive values (in red) indicate that average curtailment ratios increase due to the deployment of dispatchable resources.

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