Supplementary

S1. Status, Planning and Policies of GPG in Major Regions of China

S1.1. Status and planning of GPG **in Guangdong Province**

S1.1.1. Current development status of GPG

Guangdong Province is the largest province in China in terms of installed GPG capacity. By the end of December 2022, the installed GPG capacity reached 34,233,000 kilowatts, accounting for about 30% of the installed GPG capacity in China. GPG accounts for about 10.9% of the province's power generation, and gas consumption for power generation accounts for about 50% of the province's natural gas consumption. In terms of unit types, the GPG units commissioned in Guangdong Province are mainly large gas-steam combined cycle units of 9E, 9F and 9H classes, of which 9F units account for about 70% of the installed capacity.

Table S1. GPG projects in Guangdong Province, 2019-2022.

Years	2019	2020	2021	2022
Installed capacity (million kW)	2217	2838	3054.6	3423.3
Percentage of installed power generation in the province	17.3%	20.0%	19.2%	18.96%
Electricity generation (billion kWh)	594	751	891	829
Share of electricity generation in the province	12.2%	14.9%	15.2%	10.9%
Annual hours of utilization (h)	2863	2976	2917	2587
Gas consumption for power generation (billion Nm^3)	107.75	139.35	165	178
Share of natural gas consumption	52.3%	50.8%	45%	52.9%

S1.1.2. Electricity tariffs for GPG

At present, the feed-in tariff for GPG in Guangdong Province is implemented in the form of a unitary tariff plus subsidies. GPG units mainly obtain their quantity and price through participation in the electricity spot market and competition in the FM auxiliary service market, while subsidies are provided on the basis of the difference between the government-approved feed-in tariffs for GPG units and the base price of the approved coal-fired generating units (RMB 0.463/kWh) on the basis of the market price of electricity. The current approved feed-in tariff policy is Guangdong Development and Reform Price [2021] No. 400 issued in October 2021, as outlined in Table S2.

Table S2. Feed-in tariff level for GPG projects in Guangdong Province.

Unit Classification	Feed-in tariff (USD/kWh)
9F and above	0.094
9E	0.097
6F and below	0.099

In order to ease the production and operation difficulties of GPG caused by the surge in the international spot price of natural gas, Guangdong Province has established a corresponding "gas-electricity price linkage" mechanism to set up a trigger gas price for upward and downward adjustments to the compensation standard for the variable cost of GPG units. When the consolidated natural gas procurement price P (arrival price) is higher than the trigger gas price for upward adjustment (or lower than the trigger gas price for downward adjustment), the compensation standard for the variable cost of the market-based gas unit will be increased (or decreased) in accordance with a certain criterion, and the relevant costs will be included in the variable cost compensation, which will be shared or apportioned among all industrial and commercial users. The specific subsidies are categorized as shown in Table S3.

Tables S3. Guangdong provincial gas and electricity linkage mechanism.

Natural gas price bracket (USD/Nm^3)	Cost subsidy amount (USD/Nm^3)
>0.5	0.049
0.46~0.5	0.032+（P-0.46）×0.9×0.5×0.883
0.41~0.46	（P-0.41）×0.9×0.95×0.883
0.36~0.41	0
0.3~0.36	（P-0.36）×0.9×0.95×0.917
0.26~0.3	（P-0.3）×0.9×0.5×0.917+0.3136
<0.26	-0.062

S1.1.3 "14th Five-Year Plan" for GPG

Guangdong Province is actively developing GPG projects, and larger-scale new projects are now planned. It is expected that GPG will realize multiplying development in the "14th Five-Year Plan" period, with new installed capacity of about 36 million kilowatts, and the total installed capacity of GPG will reach more than 64 million kilowatts in 2025, which is about 2.3 times of that in 2020. New GPG projects have three main directions of development. One is to take into account the peak demand and construction conditions in GBA and other load centers to rationally plan the layout of the peak of GPG project construction. Secondly, natural gas co-generation will be laid out in the province's industrial parks in accordance with the "heat for electricity". Thirdly, natural gas distributed power generation will be vigorously developed.

Table S4. "14th Five-Year Plan": Key GPG projects in Guangdong Province.

New GPG projects commissioned	GPG co-generation projects in Dongguan Zhongtang, Dongguan Ningzhou, Guangzhou Development Zone East "Gas to Coal", GD Power Huadu, Datang International Foshan, Datang International Baochang, Shantou Gas, Zhaoqing Dinghu, etc.
	Guangzhou Zhujiang LNG Phase II, Shenzhen Guangming, Huizhou Fengda Phase II and other natural gas peaking power generation projects
	A number of natural-gas distributed energy station projects in Nansha Hengli and Shunde Longjiang (installed capacity of about 1 million kilowatts)
GPG projects to start construction in the 14th Five-Year Plan	Guangdong Yuehua Huangpu, Dongguan Huarun Dalang, Dongguan Huaneng Xiegang II, Guangzhou Hengyun Baiyun, Shenzhen East II, Dongguan Peaking Gas and Electricity Project (Shajiao C Plant Replacement) and other natural gas peaking projects
	A number of co-generation projects such as Huizhou Daya Bay West Comprehensive Energy Station, Guangzhou Heng Yun Knowledge City, Jiangmen Asia-Pacific Paper, Foshan Sanshui, etc.

S1.1.4 Discussion

In Guangdong province, the gradual replacement of coal by natural gas will progress continuously. The size of gas power stations has been confirmed to be further increasing from its current level. As an important way of increasing energy utilization efficiency, co-generation facilities will operate under a heat-following strategy, especially in industrial parks. With the increasing renewable energy generation capacity, the peak regulation power of gas-powered stations will play more supporting roles in the entire energy system.

S1.2. Status and planning of GPG projects **in Jiangsu Province**

S1.2.1. Current development status of GPG

Jiangsu Province has the advantages of more complete natural gas infrastructure, higher affordability, etc., as well as the constraints of energy resource endowment, environmental protection and others. The GPG industry is developing fast in Jiangsu Province, and the current installed gas power scale ranks second in China. In the past three years, the installed capacity of GPG has steadily increased in Jiangsu Province, as shown in Table 1, from 16.1 million kilowatts in 2019 to 19.7 million kilowatts in 2022; however, the share of GPG decreased from 10.5% in 2019 to 9% in 2022, and the number of annual hours of utilization decreased from 3,391 hours in 2019 to 2,668 hours in 2022. By the end of 2022, the installed capacity of GPG had reached 19.7 million kilowatts (kW), the cumulative power generation capacity had reached 52.6 billion kWh and the equivalent annual utilization hours had reached 2,668 hours. In terms of the type of installed capacity, the GPG units in Jiangsu Province are combined cycle units, of which peaking gas turbines accounted for about 30.87% and heating gas turbines accounted for about 69.13%.

Table S4. GPG projects in Jiangsu Province, 2019-2022.

Years	2019	2020	2021	2022
Installed capacity (million kW)	1610	1700	1898	1970
Percentage of installed power generation in the province	12.1%	12.0%	12.3%	12.9%
Electricity generation (billion kWh)	532	477	474	526
Share of electricity generation in the province	10.5%	9.4%	8.1%	9.0%
Annual hours of utilization (h)	3391	2934	2558	2668
Gas consumption for power generation (billion Nm^3)	111.55	81.65	86.2	101.8
Share of natural gas consumption	38.7%	29.1%	27.5%	33.1%

S1.2.2. Electricity tariffs for GPG

The GPG feed-in tariffs in Jiangsu Province implement a two-part tariff policy. At the same time, there is a linkage mechanism for GPG feed-in tariffs in Jiangsu Province, in accordance with the principle of total control of the tariff space. When a large change in the price of natural gas occurs, moderate adjustments are made in the established space GPG feed-in tariffs.

Peak natural gas generation units and co-generation units in Jiangsu Province are subject to a two-part tariff system, with tariffs approved at the current natural gas gate station level of RMB 2.04 per cubic meter, as shown in Table S6.

Table S6. Benchmark feed-in tariff table for GPG units in Jiangsu Province.

Crew Classification	Capacity tariff (USD/kW month)	Electricity tariff (USD/kWh)
Peaking unit	4	0.063
Co-generation units		
400MW	4	0.064
200MW	4.57	0.069
100MW	4.57	0.071

Jiangsu Province intends to implement a gas and electricity price linkage mechanism. In accordance with the principle of total control of tariff space, the feed-in tariff for GPG will be adjusted moderately within the established space when there is a large change in natural gas prices. The specific formula is as follows:

$$\Delta P = \Delta C \times 0.9 \times T \times C_i \qquad (S1)$$

where ΔP is the amount the tariff is adjusted for GPG units of electricity for this period, in units of "USD/kWh"; ΔC is the natural gas price change value, reflecting the level of change in the price of natural gas traded during the period compared with the benchmark gate price (RMB 2.04/m3), in units of "USD/m³"; T is the tax adjustment factor, which takes the value of 1.055 (10% tax rate for natural gas and 16% tax rate for electricity); and C_i is the gas consumption for power generation: 0.1882 m3/kWh for 400MW units; 0.2026 m3/kWh for 200MW units; and 0.1975 m3/kWh for 100MW units.

S1.2.3. "14th Five-Year Plan" for GPG

During the "14th Five-Year Plan" period, Jiangsu Province will develop GPG in an orderly manner, taking into consideration the balance of power, gas supply, tariff space, etc., in Jiangsu Province. A number of natural gas peaking power supply projects will be constructed in an orderly manner. Jiangsu Province will prioritize the construction of the first batch of gas turbine innovation and development demonstration projects listed in the country and launch a peaking unit stand-alone expansion project in due course according to the regional load development and system peaking needs. Development plans are shown in Table S7.

Table S7. Key GPG projects during the "14th Five-Year Plan" in Jiangsu Province.

Projects	Installed capacity (million kilowatts)	Type of unit	Location
Huaneng Nantong Power Plant Combustion Engine Innovation and Development Demonstration Project	2×74.5	H	Nantong
Datang Nandian Phase II Combustion Turbine Innovation and Development Demonstration Project	2×65.5	H	Nantong
Wangting Power Plant Phase II Combustion Engine Innovation and Development Demonstration Project	2×48.5	F	Suzhou
Jiangyin Combustion Engine Innovation and Development Demonstration Project	1×48.9	F	Jiangyin

S1.2.4 Discussion

Like in Guangdong Province, Jiangsu has established the target of controlling coal usage, especially in the electricity field. Natural gas consumption, as a partial replacement for coal consumption, will grow steadily in the current state. The heat supply cannot fulfil the demand, which will be fulfilled by additional co-generation units. These systems would further participate in the peak regulation of both the electricity market and gas market to balance supply and demand.

S1.3. Status and planning of GPG projects **in Zhejiang Province**

S1.3.1. Current development status of GPG

GPG started very early in Zhejiang Province, and its overall development history can be divided into two stages. In the first stage, construction of GPG plants first began in 1997-1998 and continued through 2004-2005. In the second stage, construction of GPG plants began to boom from 2011 and continued in 2016-2017, forming the current basic pattern of GPG development in Zhejiang Province. Since the 13th Five-Year Plan, no new GPG projects have been put into operation in Zhejiang Province. By the end of 2022, the installed capacity of GPG in the province was

13.28 million kilowatts (kW), accounting for 11.3% of the total installed capacity of electricity, of which 12.15 million kW are unified units and the remaining are small units, as shown in Table 7. In terms of unit type, GPG in the province basically comprises combined cycle units. In terms of power generation enterprises, there are more power plants held by China Huadian Corporation and Zhejiang Energy Group.

At present, GPG plants in Zhejiang Province assist during the peak of the main power system. A small number of units are employed to take into account the heat supply, and their mode of operation is basically "day start and night stop", so the annual hours of utilization is low. In 2020, GPG plants were utilized for less than 1,300 hours per year, while coal-fired generation was utilized for nearly 4,500 hours per year. In 2021, due to the impact of lower natural gas prices in the first half of the year and high demand for electricity across society, GPG utilization increased, but the annual utilization hours were only about 2,100 hours. In the past two years, as GPG has taken on more and more peaking tasks in the power system, the annual utilization hours of GPG have further improved.

Table S8. GPG in Zhejiang Province, 2019-2022.

Years	2019	2020	2021	2022
Installed capacity (million kW)	1261	1256	1256	1328
Percentage of installed power generation in the province	12.9%	8.9%	8.1%	11.3%
Electricity generation (billion kWh)	150	163	264	223
Share of electricity generation in the province	4.2%	3.2%	6.2%	6%
Annual hours of utilization (h)	1223	1287	2100	1832
Gas consumption for power generation (billion Nm³)	29.20	31.74	51.37	47.91
Share of natural gas consumption	19.8%	22%	27.9%	26.6%

S1.3.2. Electricity tariffs for GPG

GPG tariffs are implemented in Zhejiang Province under a two-part tariff system. The capacity tariff for units 9F and 9E is 43.2 USD/kW-yr (including tax, same below). Unit 6F's capacity tariff is 81.6 USD/kW-yr. Unit 6B's capacity tariff is 56.4 USD/kW-yr. Electricity tariffs are set on a "gas-electricity price linkage" basis. The formula for "gas-electric linkage" for units 9F and 6F is as follows:

$$P = \frac{C}{4.9} \times \frac{T_e}{T_g} \tag{S2}$$

The formula for "gas-electric linkage" for units 9E and 6B is as follows：

$$P = \frac{C}{4.5} \times \frac{T_e}{T_g} \tag{S3}$$

where P is the unit electricity tariff, "USD/kWh"; C is the CIF price of natural gas (including pipeline tariffs), "USD/Nm³"; and T_e/T_g is the VAT on power / VAT on gas.

S1.3.3. "14th Five-Year Plan" for GPG

Zhejiang Province is one of the earliest provinces in China to develop GPG, with good social acceptance and technical foundations. During the "14th Five-Year Plan" period, in order to promote the development of electricity and natural gas, and to ensure the security of energy supply, the Zhejiang Provincial Government has introduced a series of policies to support the development of GPG. By 2025, the proportion of GPG in the province will be increased to more than 19%. Relying on LNG receiving terminals and natural gas trunk lines, high-efficiency GPG projects will be built in load centers, natural gas-distributed energy will be promoted in accordance with local conditions and emergency peaking units will be stocked up, with an additional installed capacity of more than 7 million kilowatts. The Zhejiang Provincial Government proposes to synergize the reform of electric power and

natural gas in the future, steadily increase the power generation capacity of GPG and the number of hours of GPG utilization and, at the same time, improve the coordinated operation mechanism of GPG and study and explore new modes of GPG operation. At present, GPG construction is steadily advancing in Zhejiang Province, the vast majority of which is for a large 9H combined cycle unit of about 6 million kilowatts, with a distributed GPG installed capacity of about 800,000 kilowatts.

S1.3.4 Discussion

Based on existing statistical data, Zhejiang Province still lacks a sufficient energy supply ability to meet its high-quality energy demand. The continuous development of renewable energy generation will demand additional peak regulation power, which consists of gas power stations, storage, smart grids, etc. Energy generated by coal-powered stations will decrease steadily, and clean energy will be used to fulfil the growing demand. In addition, the natural gas infrastructure will expand to support the increasing gas power capacity.

S2 Financial evaluation model for GPG in the industrial chain

S2.1 Principles of calculation

(1) If the investment entity enters into each segment of upstream development, midstream pipeline or receiving station in the form of wholly owned, holding or equity participation, and the corresponding equity entity is an independent taxpaying legal person, the benefits of the industry chain will be calculated one by one for each segment, and the cash inflow and outflow of the investment entity as a shareholder will be calculated in conjunction with the dividend policy of the joint venture company.

(2) The financial evaluation of the industrial chain should follow the principle of correspondence and unification of the benefits and costs, and the financial analysis of each link should be calculated by the caliber of the financial boundary of the main body on which it is based.

(3) Prices of inputs and outputs. Financial evaluation is an estimate of economic activity in a future period, in which both inputs and outputs occur, and the financial analysis in this methodology uses forecast prices based on the market price system.

(4) The natural gas purchase price used in the financial analysis of the industry chain is determined by the agreed price or the analysis of the market price trend in the project location; the feed-in tariff of the gas power plant is determined by the price of the financial evaluation of the power plant's feasibility study report.

(5) Evaluation metrics selection. Dynamic analysis should be based on the sum of net cash flow before the financing of each link. The cash inflow and cash outflow of the industry chain in the whole calculation period should be examined, an investment cash flow statement of the industry chain should be prepared, the principle of the time value of money should be used for discounting, and the financial internal rate of return index of the project or shareholder's investment should be calculated.

(6) Calculation period. The calculation period is calculated according to the construction period and operation period of the natural gas power generation project. If the operation period of other links in the industrial chain is not consistent, the residual value of fixed assets will be recovered at the end of the operation period.

S2.2 Model for economic evaluation modeling

(1) Gas-fired power plant industry chain benefits

According to the marginal contribution analysis method, a GPG project is regarded as an incremental product in the industry chain, the incremental revenue brought by this incremental product to each link of the industry chain is calculated and the total incremental revenue is regarded as the revenue of the industry chain for financial evaluation. The cash flow statement of the GPG was used as the basis for analysis, and the incremental cash flow of each link was used to measure the cash flow statement of the industry chain in order to analyze the industry chain's financial

internal rate of return (FIRR) (shareholder's investment amount). The GPG industry chain benefit formula is as follows:

$$\sum_{t=1}^{n}(CI - CO)_t \times (1 + FIRR)^{-t} = 0 \qquad (S4)$$

where FIRR is the financial internal rate of return of the gas power plant industry chain; CI is the incremental total cash inflow of the industry chain in the t year; CO is the incremental total cash outflow of the industry chain in the t year; and n is the project calculation period.

The incremental total cash inflow is the sum of the incremental cash inflow from each link during the year, and the incremental total cash outflow is the sum of the incremental cash outflow from each link during the year, as shown in Figure S1.
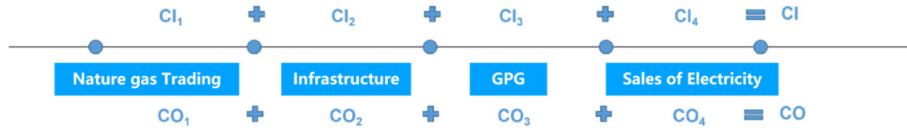

Figure S1. Incremental cash inflows and outflows in the LNG receiving chain.

The formula is

$$CI = CI_1 + CI_2 + CI_3 + CI_4 \qquad (S5)$$
$$CO = CO_1 + CO_2 + CO_3 + CO_4 \qquad (S6)$$

where CI_1, CI_2, CI_3 and CI_4 are the annual incremental cash inflows from the link of trade, infrastructure, GPG and sales of electricity, respectively, and CO_1, CO_2, CO_3 and CO_4 are the annual incremental cash outflows from the link of trade, infrastructure, GPG and sales of electricity. If the investment entity is not 100% owned in each segment, it should be converted according to the share ratio.

(2) Link of Natural gas trading

The incremental cash inflow (CI_1) in the natural gas trading segment consists of incremental sales revenue and value-added tax (VAT) refunds (st) with the following formula::

$$CI_1 = TS_1 + st \qquad (S7)$$
$$TS_1 = N \times P \qquad (S7.1)$$
$$st = N \times u_{st} \qquad (S7.2)$$
$$N = N_{LNG} + N_{PNG} \qquad (S7.3)$$

where TS_1 is the incremental sales revenue, obtained by multiplying the incremental total gas sales with the after-tax gas price, and st is the VAT refund, obtained by multiplying the incremental total gas sales (N) with the unit rebate (u_{st}). The incremental total gas sales (N) consists of the incremental LNG volume sold (N_{LNG}) and the incremental pipeline gas volume sold (N_{PNG}).

The incremental cash outflow (CO_1) in the natural gas trading segment consists of trade costs (CIF), procurement costs (PC), VAT surcharge (VAT) and enterprise income tax (EIT) with the following formula:

$$CO_1 = CIF + PC + VAT + EIT \qquad (S8)$$
$$CIF = N \times u_{CIF} \qquad (S8.1)$$

where u_{CIF} is the unit trade cost, which refers to the selling expenses, administrative expenses, financial expenses and other trade costs of the trade chain, less all the costs of the trade chain other than the procurement of resources and the use of infrastructure facilities, discounted to the cost of square meters of gas.

$$PC = CIF_{LNG} + CMT_{LNG} + CPT_{LNG} + CIF_{PNG} + CPT_{PNG} \qquad (S8.2)$$

where CIF_{LNG} is the cost insurance and freight of LNG, CMT_{LNG} is the cost of LNG receiving terminal processing, CPT_{LNG} is the cost of LNG pipeline tariffs, CIF_{PNG} is the cost insurance and freight of domestic natural gas and CPT_{PNG} is the cost of domestic natural gas pipeline tariffs.

The formula for calculating the cost insurance and freight of LNG (CIF_{LNG}) is as follows:

$$CIF_{LNG} = N_{LNG} \times p_{LNG} \tag{S8.3}$$

$$p_{LNG} = JCC \times k + a \tag{S8.4}$$

where p_{LNG} is the unit LNG purchase price varying with oil price, k is the slope and a is a constant.

The formula for the cost of LNG receiving terminal processing (CMT_{LNG}) is as follows:

$$CMT_{LNG} = N_{LNG} \times \frac{P_{CMT}}{1 + \gamma} \tag{S8.5}$$

where P_{CMT} is the unit price for receiving station processing and γ is the processing fee tax rate ($\gamma = 0.13$).

The formula for the cost of LNG pipeline tariffs (CPT_{LNG}) is as follows:

$$CPT_{LNG} = N_{LNG} \times \frac{\sum_{i=1}^{j} p_{CPT_{LNG}}}{1 + \sigma} \tag{S8.6}$$

where σ is the pipeline tariff rate ($\sigma = 0.09$) and $p_{CPT_{LNG}}$ is the unit price for each section of piping for LNG.

The formula for the cost insurance and freight of domestic natural gas (CIF_{PNG}) is as follows:

$$CIF_{PNG} = N_{PNG} \times \frac{P_{PNG}}{1 + \sigma} \tag{S8.7}$$

where P_{PNG} is the unit price of domestic gas.

The formula for the cost of domestic natural gas pipeline tariffs (CPT_{PNG}) is as follows:

$$CPT_{PNG} = N_{PNG} \times \frac{\sum_{i=1}^{j} p_{CPT_{PNG}}}{1 + \sigma} \tag{S8.8}$$

where $p_{CPT_{PNG}}$ is the unit price for each section of piping for domestic natural gas.

The formula for calculating the VAT surcharge and enterprise income tax (EIT) is as follows:

$$VAT = (CI_1 - PC) \times \sigma \times r_{VAT} \tag{S8.9}$$

$$EIT = (CI_1 - PC - CIF - VAT) \times r_{EIT} \tag{S8.10}$$

where r_{VAT} and r_{EIT} are the VAT surcharge and corporate income tax rate, respectively.

(3) Link in Infrastructure

Since the additional power plant projects do not have a significant impact on infrastructure costs, the cash inflow from the facilities segment is treated here as incremental profit. Infrastructure generally refers to receiving stations and pipelines. Therefore, the incremental cash inflow (CI_2) in this link consists of receiving terminal cash inflow (CI_{RT}) and pipeline cash inflow (CI_{RT}) with the following formula:

$$CI_2 = CI_{RT} + CI_{pipe} \tag{S9}$$

The receiving terminal cash inflow (CI_{RT}) is calculated as follows:

$$CI_{RT} = P_{RT} \times (1 - r_{EIT}) \times (1 - \theta_{RT}) \times \vartheta_{RT} \tag{S9.1}$$

where P_{RT} is the incremental profit for the receiving terminal, r_{EIT} is the EIT rate for the receiving terminal, θ_{RT} is the surplus reserve rate for the receiving terminal and ϑ_{RT} is the arbitrary surplus reserves rate for receiving terminal.

$$P_{RT} = N_{LNG} \times \frac{P_{CMT}}{1 + \gamma} - N_{LNG} \times \Delta u_{cRT} \tag{S9.2}$$

where Δu_{cRT} is the unit variable cost of the receiving terminal.

$$CI_{pipe} = P_{pipe} \times (1 - r_{EIT}) \times (1 - \theta_{pipe}) \times \vartheta_{pipe} \tag{S9.3}$$

where P_{pipe} is the incremental profits for the pipeline companies, θ_{pipe} is the surplus reserve rate for pipeline companies and ϑ_{pipe} is the arbitrary surplus reserves rate for pipeline companies.

$$P_{pipe} = N_{PNG} \times \frac{\sum_{i=1}^{j} p_{CPT_{PNG}}}{1 + \sigma} + N_{LNG} \times \frac{\sum_{i=1}^{j} p_{CPT_{LNG}}}{1 + \sigma} - N \times \Delta u_{pipe} \tag{S9.4}$$

where Δu_{pipe} is the pipeline company's variable cost per unit of gas supplied.

(4) Link of GPG

Cash flows during the construction period of a GPG project are calculated in accordance with the project-specific financing as well as the utilization plan. The construction period is mainly a cash outflow, consisting of construction costs (C_c), operating costs (u), interest (i) as well as VAT (Tax) for the construction period, according to the following formula:

$$CI_3(\text{Construction Period}) = 0 \tag{S10}$$

$$CO_3(\text{Construction Period}) = C_c + i + u + Tax \tag{S11}$$

The formula for calculating the cash inflow during the operating period of the power plant is as follows:

$$CI_3(\text{peak load balancing}) = N_e \frac{P_e}{1 + \gamma} + I_C \tag{S12}$$

$$CI_3(\text{combined heat and power}) = N_e \frac{P_e}{1 + \gamma} + N_h \frac{P_h}{1 + \partial} \tag{S13}$$

where P_e is the feed-in tariffs, I_C is the ancillary services revenues (tax included), N_h is the annual calorie sales, P_h is the heat tariff and ∂ is the tax rate of heat.

The formula for calculating the cash outflow during the operating period of the GPG project is as follows:

$$CO_3 = N \times P \times (1 + \gamma) + VAT_{pp} + EIT_{pp} + u + i \tag{S14}$$

(5) Link of electricity sale

The incremental cash inflow in this link is obtained by multiplying the amount of electricity sold by the price of electricity sold with the following formula:

$$CI_4 = N_e \times \frac{P_e + P_{sub}}{1 + \gamma} \tag{S15}$$

where P_{sub} is the subsidized price of electricity.

The incremental cash outflow of this link consists of the cost of purchasing power and the cost of operating it, obtained with the following formula:

$$CO_4 = N_e \times \left(\frac{P_e}{1 + \gamma} + \Delta u_{oc} \right) \tag{S16}$$

where Δu_{oc} is the operating cost per unit of electricity.

S3. Basic parameters of the industrial chain

Table S9. Basic parameters of the industrial chain.

Links	Parameters	Units	Value	Notes
Basic	LNG conversion factor1	Tons/million Btus	52.08	
	LNG conversion factor2	GJ/ton	54.86	
	Gasification rate	Nm³/ton	1415	
	Currency exchange rates	CNY/USD	7	
Trade	Natural gas sales price	USD/Nm³ (tax included)	P	
	Volume of total gas sold	Million Nm³/year	N	
	LNG volume	Million Nm³/year	N_{LNG}	

	Pipeline gas volume	Million Nm³/year	N_{gas}	
	Oil prices	USD/barrel	JCC	
	LNG price slope	%	12.50%	k
	LNG price constant	USD/million Btu	0	a
	Tax rebate coefficient	USD/Nm³	0.156	u_{st}
	Unit trade costs	USD/Nm³ (tax excluded)	0.001	u_{CIF}
	VAT surcharge rate	%	12%	r_{VAT}
	Income tax rate	%	25%	r_{EIT}
	Procurement costs of domestic gas	USD/Nm³ (tax included)	0.314	P_{gas}
	Natural gas VAT rate	%	9%	σ
	Unit tax refunds	USD/Nm³ (tax excluded)	0.014	u_{st}
Infrastructure	LNG processing costs	USD/Nm³ (tax included)	0.023	P_{CMT}
	LNG pipeline costs	USD/Nm³ (tax included)	0.013	$p_{CPT_{LNG}}$
	Domestic gas pipeline unit price	USD/Nm³ (tax included)	0.013	$p_{CPT_{gas}}$
	Surplus reserves rate of receiving terminal	%	10%	θ_{RT}
	Arbitrary surplus reserves rate of receiving terminal	%	0%	ϑ_{RT}
	Unit variable cost of receiving terminal processing	USD/Nm³ (tax excluded)	0.0041	Δu_{cRT}
	Pipeline surplus reserve rate	%	10%	θ_{pipe}
	Pipeline arbitrary surplus rate	%	0%	ϑ_{pipe}
	Pipeline unit variable cost	USD/Nm³ (tax excluded)	0.001	Δu_{pipe}
GPG	Electricity (to the grid)	MWh	N_e	
	Electricity price	USD/MWh	P_e	
	Revenue from ancillary services	Million USD/year	4.29	I_C
	Annual operating costs	Million USD	u	
	Average annual tax surcharge	Million USD	$VAT_{pp} + EIT_{pp}$	
Electricity sale	Electricity sale price	USD/MWh (tax included)	$P_e + P_{sub}$	

	USD/MWh (tax excluded)	0.19	Δu_{oc}
Unit operating costs	USD/MWh (tax excluded)	0.19	Δu_{oc}
Electricity purchase price	USD/MWh (tax included)	P_e	

S4. Basic parameters of the GPG project B

Table S10. Basic parameters of the Project B.

Parameters	Units	Value
Installed capacity	MW	2×460MW
Annual utilization hours	h	3000
Average annual standard gas consumption	Nm³/kWh	0.1861
Annual electricity output	×10⁸kWh/a	N_e/0.98
Plant electricity consumption rate	%	2.00%
Annual electricity supply	×10⁸kWh/a	N_e
Feed-in tariff (including tax)	USD/ MWh	P_e
Natural gas consumption	Million Nm³/year	N
Gas price (including tax)	USD/ Nm³	P
Urea (including tax)	USD/year	102571.43
Sewage charges (including taxes)	USD/year	147185.71
Crew		110
Insurance rate	%	0.15%
Construction investment loan ratio	%	30.00%
Repayment period	year	15
Construction period	year	2
Investment plan	%	50% :50%

S4. Validation of the financial evaluation model for GPG in the industrial chain

The oil and gas Enterprise A is the main body of the investment project, and the enterprise has a complete natural gas industry chain. The shares of the enterprise in the industry chain links are shown in Table 1 (in manuscript). The validity of the model was tested using Enterprise A's investment in Project C as an example.

The investment and operational periods of Power Plant C are 2 and 20 years, and the total evaluation period is 22 years. Ancillary service revenues are measured over a 10-year operating period. The construction investment of the project is USD 390,000,000, including USD 40,000,000 of value-added tax during the construction period. The investment plan for construction investment is 50% in the first year and 50% in the second year. Depreciable life is 18 years, and the salvage rate is 5%. The amortization period is 10 years, and the salvage rate is 0%. Basic parameters are detailed in Table S11.

Table S11. Basic parameters of the industrial chain.

Links	Parameters	Units	Value	Notes
Basic	LNG conversion factor1	Tons/million Btus	52.08	
	LNG conversion factor2	GJ/ton	54.86	
	Gasification rate	Nm³/ton	1415	
	Currency exchange rates	CNY/USD	7	

Trade	Natural gas sales price	USD/Nm³ (tax included)	0.37	
	LNG volume	Million Nm³/year	40982	
	Pipeline gas volume	Million Nm³/year	17564	
	Oil prices	USD/barrel	70	
	LNG price slope	%	12.50%	k
	LNG price constant	USD/million Btu	0	a
	Tax rebate coefficient	USD/Nm³	0.156	u_{st}
	Unit trade costs	USD/Nm³ (tax excluded)	0.0060	u_{CIF}
	VAT surcharge rate	%	12%	r_{VAT}
	Income tax rate	%	25%	r_{EIT}
	Procurement costs of domestic gas	USD/Nm³ (tax included)	0.314	P_{gas}
	Natural gas VAT rate	%	9%	σ
	Unit tax refunds	USD/Nm³ (tax excluded)	0.014	u_{st}
Infrastructure	LNG processing costs	USD/Nm³ (tax included)	0.023	P_{CMT}
	LNG pipeline costs	USD/Nm³ (tax included)	0.013	$p_{CPT_{LNG}}$
	Domestic gas pipeline unit price	USD/Nm³ (tax included)	0.013	$p_{CPT_{gas}}$
	Surplus reserves rate of receiving terminal	%	10%	θ_{RT}
	Arbitrary surplus reserves rate of receiving terminal	%	0%	ϑ_{RT}
	Unit variable cost of receiving terminal processing	USD/Nm³ (tax excluded)	0.03	Δu_{cRT}
	Pipeline surplus reserve rate	%	10%	θ_{pipe}
	Pipeline arbitrary surplus rate	%	0%	ϑ_{pipe}
	Pipeline unit variable cost	USD/Nm³ (tax excluded)	0.00014	Δu_{pipe}
GPG	Electricity (to the grid)	MWh	320.71	
	Electricity price	USD/MWh	95.7	
	Revenue from ancillary services	USD/year	4,285,714	I_C
Electricity sale	Electricity sale price	USD/MWh (tax included)	96.57	

	electricity purchase price	USD/MWh (tax included)	93.57	

The results of the financial evaluation of the project and the calculation of the financial evaluation of the whole investment in the industrial chain (after tax) are shown in Figure S2. The IRR of the project is 9.16%, and the financial net present value (NPV) is USD 24.66 million. The IRR of the industrial chain is 8.97%, and the NPV is USD 24.23 million. The IRR of project shareholder is 12.17%, and the NPV is USD 33.19 million. The IRR of the industry chain shareholder is 3.12%, and the NPV is USD -31.5 million. It can be seen that the IRR of Project C is higher than the benchmark rate of return (8%), but its industry chain internal rate of return and net present value are lower than that of the project, indicating that the investment of the project contributes negatively to the industry chain, and the operation of the project needs to be supported by the industry chain.

Due to the business model of the whole industrial chain, the shareholdings of investment entities in each link of the industrial chain are different. In the infrastructure sector of stable returns, Enterprise A's share is relatively small, resulting in a much lower IRR for shareholders in the shareholder chain than in stand-alone projects. According to the traditional project cash flow evaluation method, the project and the IRR of project shareholders exceeds the set benchmark rate of return, and the investment in the project should be agreed to. However, utilizing this project evaluation method as an auxiliary decision-making method, from the perspective of the natural gas industry chain dimension of Enterprise A, the investment in the project has a certain negative impact on the entire industry chain, and the investment was not recommended.
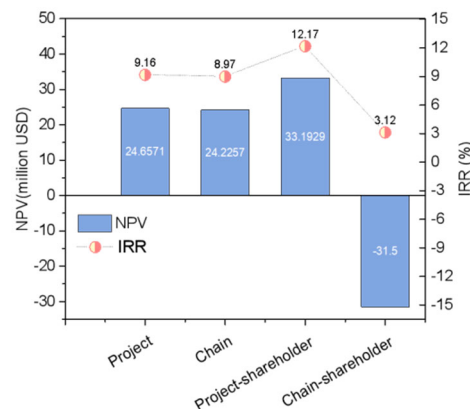

Figure S2. Financial evaluation of Project C and industry chain.

We calculate the annual incremental profit of each sector in the industry chain (the industry chain, except for the power plant part, does not take depreciation and amortization into account), and the results are shown in Figure S3. The incremental net profit of the trading sector was USD -10.08 million, the incremental net profit of the infrastructure sector was USD 8.41 million, the average annual net profit of the power plant sector was USD 23.95 million, the net profit of the electricity sales sector was USD 1.06 million and the total incremental profit of the natural gas chain was USD 23.34 million.

From the perspective of Enterprise A, the incremental net profit of the trading sector was USD -10.08 million, the incremental net profit of the infrastructure sector was USD 2.89 million, the average annual net profit of the power plant sector was USD 16.76 million, the net profit of the electricity sales sector was USD 1.06 million and the total incremental profit of the natural gas chain was USD 10.62 million. An analysis of the parameters of the trade chain reveals higher processing costs at the receiving terminal. Although this part of the profit is attributed to the receiving station, due to the inconsistency of the shareholding of the investing entity in the trading and infrastructure sectors, the investment in the power plant ultimately results in the profit of the whole industry chain being lower than the profit of the power plant project itself. The project's total incremental profit for the rest of the

industry chain was USD -6.14 million, and the investment was not recommended. By analyzing the industry chain through this model, the impact of the project on each link of the industry chain can be comprehensively examined, which helps the decision makers to make an objective decision on the investment in the power plant project.
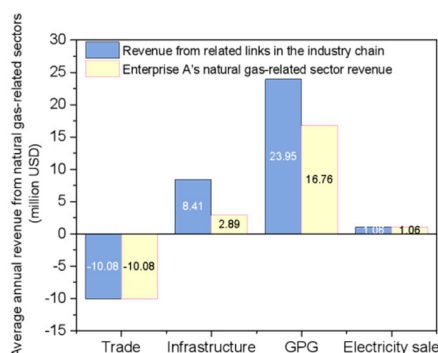

Figure S3. Average annual revenue from natural gas-related sectors.

S5 Discussion of carbon capture and storage (CCS)

In the face of severe pressure to reduce emissions, the National Development and Reform Commission (NDRC) announced in 2013 China's guidance on accelerating carbon capture, utilization and storage in six aspects:

1. Carrying out relevant pilot demonstration projects in conjunction with the actual situation of the process chain; carrying out demonstration projects and building bases;

2. Exploring the establishment of relevant policy incentive mechanisms;

3. Strengthening strategic research and planning;

4. Promoting the formulation of relevant standards and norms;

5. Strengthening capacity building and international cooperation;

This guideline points out the direction for the development of carbon capture and storage technology in China, which is conducive to the further development of carbon capture and storage technology in China.

However, there are still three major challenges to the widespread deployment of commercial-scale CCS in China:

1. Insufficient experience in building and operating large-scale integrated CCS projects;

2. Long-term CO_2 sequestration risks;

3. Lack of policy or financial support to ensure a reasonable return for investors.

Therefore, until these challenges are addressed, CCS is not developing as rapidly as expected, especially given the risks of long-term CO_2 sequestration. CO_2 leakage may lead to global and local risks: global risks are mainly climate change that may result from CO_2 leakage into the atmosphere; local risks are localized hazards to humans, ecosystems and nearby groundwater caused by CO_2 leakage. Therefore, geological structures for CO_2 sequestration should be carefully selected and managed.

For industries that do not promote carbon capture and storage (CCS), the cost of large-scale CO_2 emission reductions will more than double. However, CCS technology is expensive at this stage, so China, like the rest of the world, continues to focus on how to reduce the costs associated with this technology. The implementation of carbon capture and storage (CCS) technology in China depends mainly on two driving forces: the market and the government, both of which can promote the development of CCS in China. The key to CCS is the technology to utilize CO_2 after it is captured, and once it becomes a resource, the market mechanism will promote the development of CO_2 capture. One of the reasons for the current small scale of CCS is that there is no effective market for CO_2 utilization.

Facing the pressure of CO2 emission reduction, it is difficult to apply on a large scale, but it is necessary to accumulate experience through small-scale demonstrations. In 2014, China's CO2 emission reached 8.6 billion tons, of which 50% came from coal-fired power plants. Currently, China's coal-fired power plants have a capacity of about 900 gigawatts (GW), which is nearly half of the global coal-fired power generation capacity, and the capacity of coal-fired power plants under construction will reach nearly 200 GW. Of these, one-third of the coal-fired power plants are considered to meet the basic criteria for CCS and are suitable for retrofitting for CCS.