Feasibility Study of CMM Utilization for Songzao Coal and Electricity Company Coal Mines

Located in Chongqing Municipality, People's Republic of China

U.S. Environmental Protection Agency
May 2009

Acknowledgements

This publication was developed at the request of the United States Environmental Protection Agency. Through the Coalbed Methane Outreach Program, Raven Ridge Resources, Incorporated team members: Raymond C. Pilcher, James S. Marshall, Candice L. M. Tellio, Charlee A. Boger, Martin Weil and Boni Jiang authored this report. Raven Ridge Resources, Incorporated wishes to thank Chongqing Energy Investment Group, Songzao Coal and Electricity Company, BCCK Engineering for their assistance in development of this report.

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Acronyms and Abbreviations

CAPEX	Capital Expenditures
CDM	Clean Development Mechanism
CER	Certified Emission Reduction
CMM	Coal Mine Methane
CO2e	Carbon Dioxide (CO2) Equivalent
CQEIG	Chongqing Energy Investment Group
IC	Internal Combustion
IRR	Internal Rate of Return
KWH	Kilowatt Hour
LNG	Liquefied Natural Gas
MMBTU	Million British Thermal Units
MW	Megawatt
NPV	Net Present Value
OPEX	Operating Expenditures
p10	Indicates there is a 10% chance that the forecast will be less than or equal to the p10 amount
p50	Indicates there is a 50% chance that the forecast will be less than or equal to the p50 amount
p90	Indicates there is a 90% chance that the forecast will be less than or equal to the p90 amount
RMB	Renminbi, Chinese currency
¥	Yuan, Unit of Chinese currency (RMB)
SCEC	Songzao Coal and Electricity Company
Tonnes	Metric tons
USD	United States Dollars
VAM	Ventilation Air Methane
VAT	Value Added Tax
VER	Voluntary Emission Reduction

Please note throughout this report it is assumed that $ USD = 6.85 RMB as of September 4, 2008 (Federal Reserve, 2008).

1.0 Executive Summary

Under contract number EP-W-05-063 TO 13, USEPA awarded a task order for a prefeasibility and feasibility study of the potential to develop a methane emissions reduction project utilizing medium quality coal mine methane (CMM) drained and recovered from mines located in the Songzao coal basin which is situated in Chongqing Municipality of China (**Figure I)**.

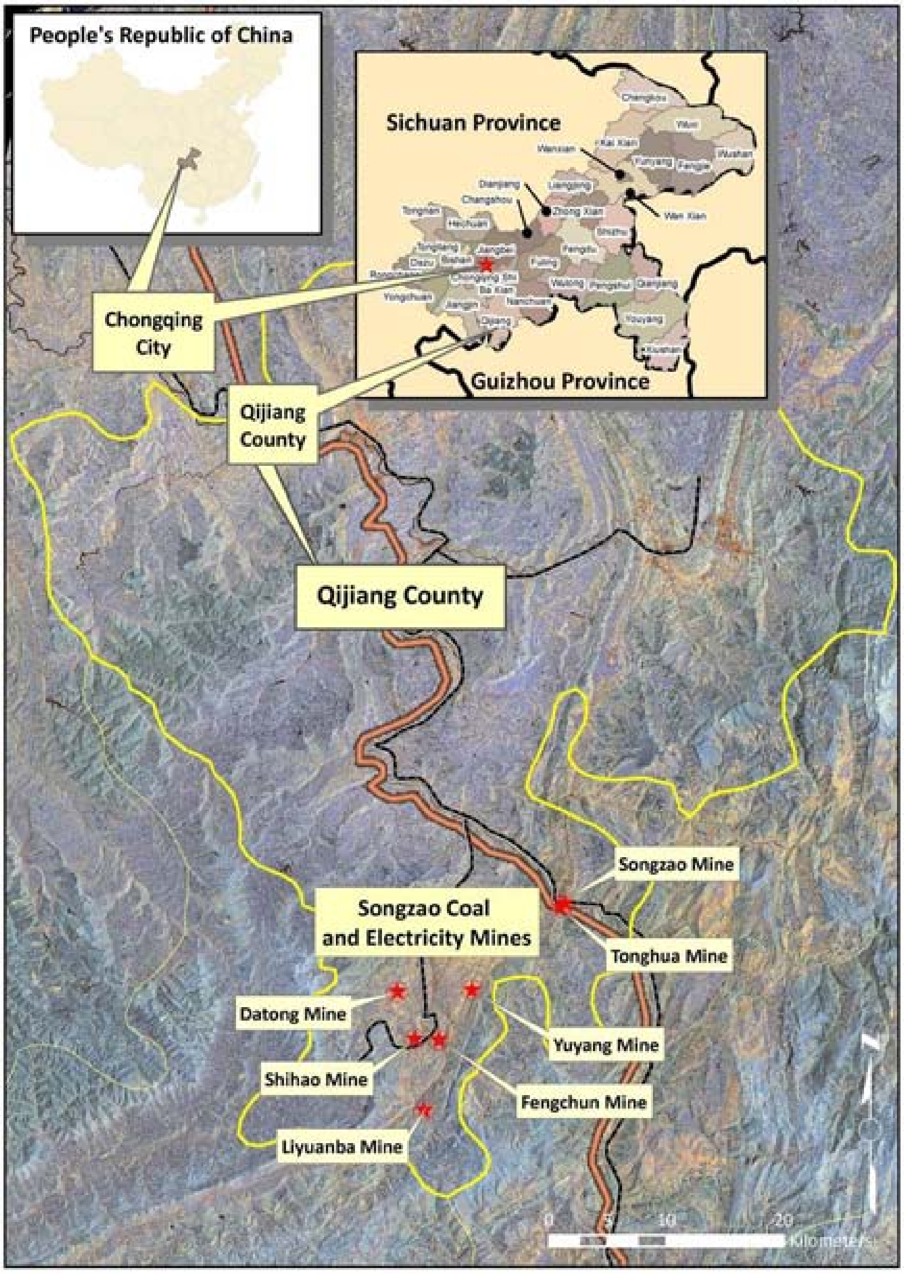


FIGURE I: SONGZAO COAL AND ELECTRICITY MINES' LOCATION AND OVERVIEW MAP

Coal mine methane is drained from each of the coal mines operated by Songzao Coal and Electricity Company (SCEC). Presently, six SCEC mines operate in the northern part of the coal basin: the Songzao, Tonghua, Fengchun, Yuyang, Shihao, and Datong. An outlying district of the Fengchun mine is accessed by the Zhangshiba mine shaft which is located in the southern part of the basin far from the northernmost shafts. The Liyuanba mine, which is located even further south, is presently under development on the far southern margin of the Songzao coal basin. Not withstanding their location, the Zhangshiba shaft and the Liyuanba mine will liberate significant volumes of methane as coal is extracted during the period time considered by this study.

CMM is presently being used in the Songzao basin. Some of the gas is metered as it is being used for civil, industrial and commercial purposes, and by SCEC related entities for cooking, heating and power generation. In addition, a sizable but unmetered amount of gas is also used by local farmers and villagers. After civil and industrial consumption has been deducted from production, large quantities of CMM remain unused as it is vented to atmosphere. Three technically feasible options for using the remaining unused gas are considered in this study:

1. LNG Only Option- comprises linking the six mines located in the northern part of the basin, and the Zhangshiba shaft and Liyuanba mine to a gathering and storage system, which will feed CMM to a gas purification and liquefaction system to be located near the Anwen power plant;

2. Power Generation Only Option- entails installing CMM fueled internal combustion power generation facilities at each of the active mines in the northern part of the basin, the Zhangshiba shaft, and the Liyuanba mine to follow when CMM flow is sufficient to provide adequate fuel;

3. Optimized Option- begins by linking the six active mines to a gathering and storage facility, but delays the decision for linking the Zhangshiba shaft and Liyuanba mine until 2013, when CMM production from the southern area can be more accurately determined. A decision to link the southern production into the centralized gas gathering system, thereby executing a LNG only option can be taken, or the gas production can be used to fuel distributed power generation facilities installed at one or both of the southern locations.

Project Sponsors

The two principal sponsors of the Songzao CMM utilization project are Chongqing Energy Investment Group Company (CQEIG), and its majority-owned subsidiary the Songzao Coal and

Electricity Company (SCEC). CQEIG leadership has taken a leading role in the CMM purification and liquefaction project planning, will make the major commercial, investment, and financing decisions, and will manage the relevant regulatory and political approval procedures. SCEC operates the coal mines and the existing CMM drainage, collection, and storage system, and will play an important operational role for new CMM gathering and processing facilities associated with the project. Precise project ownership structure (including possible foreign investment) has not been finalized as of year-end 2008.

Coal and Gas Resource Extraction in Songzao Coal Basin

The Songzao coal basin is the largest anthracite coal producing area in Chongqing Municipality. Large scale coal mining started here in 1965 and presently covers an area of 236 square kilometers. There are presently six coal mines operating in this area with plans to add two more mines. The six mines currently producing coal are the Songzao, Tonghua, Datong, Yuyang, Shihao and Fengchun mines. The Liyuanba Mine is presently under construction and scheduled to be producing commercial quantities of coal by 2013. Coal production in 2007 was 4.88 million tonnes; but, by the end of 2008, SCEC mine production had increased to over 5 million tonnes. Mineable coal reserves from these eight mines are estimated at 729 million tonnes. There are an estimated 607 million tonnes of mineable coal reserves associated with the six active mines.

Gas content data collected by SCEC for the mineable coal seams and associated strata was used to estimate the reserves of recoverable gas for the active mines. In order to quantify the uncertainty related to estimating the reserves, a probability distribution function was constructed to depict the recoverable gas reserves for each of the mining areas. This probability function was constructed by multiplying the mineable coal reserves by a drained gas recovery factor determined by SCEC for each mine. Gas reserve estimates were calculated and reported for each of three probability thresholds, P90, P50, and P10. **Figure II** shows the gas reserves estimated at each probability for each mine. As an example for Songzao Mine p90 threshold, there is a 90 percent probability that the recoverable gas reserves will be 0.49 billion cubic meters or greater; but there is only a 10 percent probability that the recoverable reserves will be greater than 0.75 billion cubic meters.

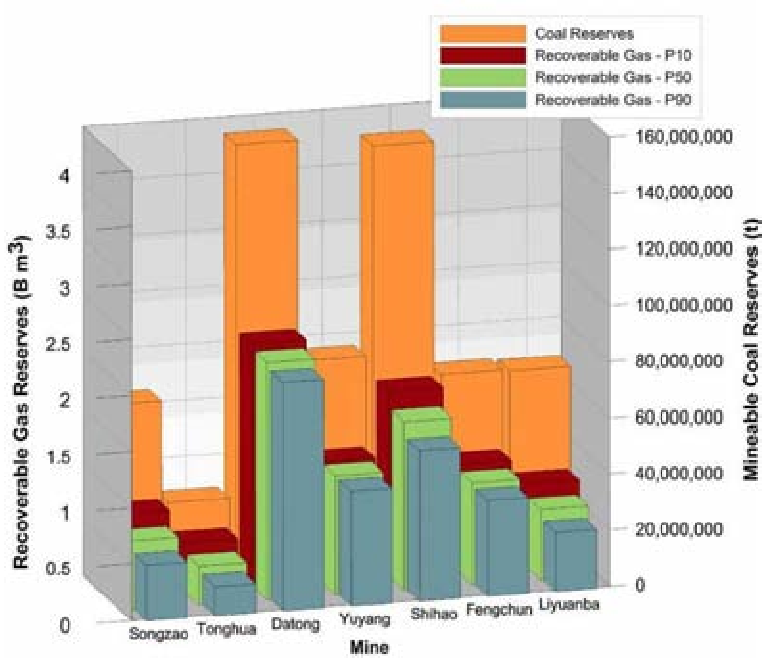


FIGURE II: MINEABLE COAL RESERVES AND RECOVERABLE GAS RESERVES CATEGORIZED BY PROBABILITY THRESHOLDS

Determining economic feasibility of an end-use option within acceptable limits requires reliable forecasts of future gas production. The feasibility study team developed models that forecast future gas production by incorporating data provided by SCEC. Data used in the modeling activities are listed below and graphically depicted in **Figures III and IV**:

- coal production,
- gas drainage volume,
- concentration of gas drained,
- ventilation air methane (VAM) volume, and
- VAM concentration.

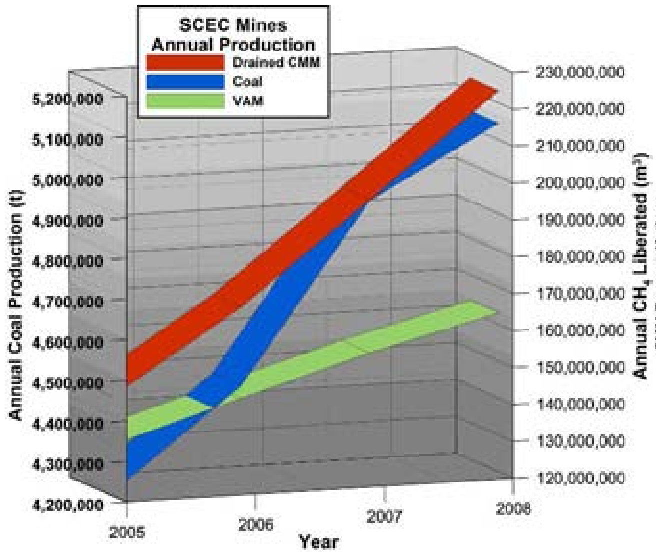


FIGURE III: SCEC COAL, CMM AND VAM PRODUCTION

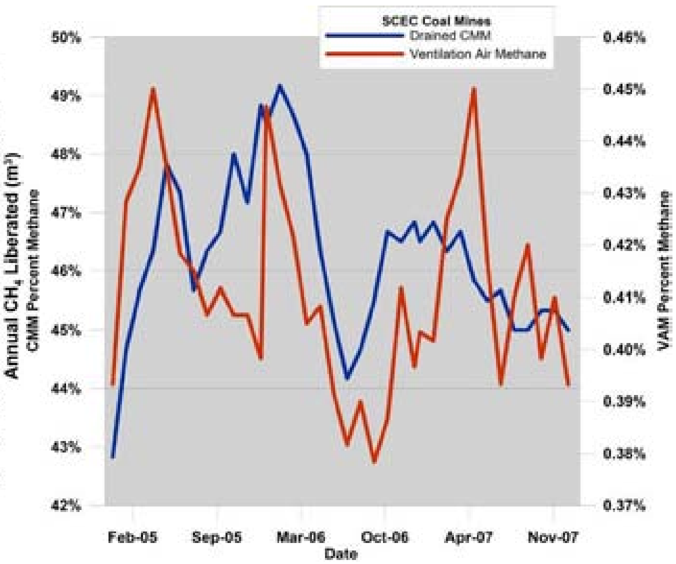


FIGURE IV: SUMMARY OF RANGE OF DRAINED GAS AND VAM METHANE CONCENTRATIONS

The study team prepared forecasts of CMM production for the years 2009 through 2025, by using the following stepwise process:

- The first step was to develop a way to predict the volume of CMM produced for any given quantity of coal mined at a specified time in the future. This was accomplished by developing probability functions that mathematically describe the relationship of the monthly volume of drained CMM to the amount of coal produced at each mine were developed as a first step;
- SCEC supplied the annual coal production planned for each of its coal mines through 2025. These values were input to forecast CMM production at each mine using the probability functions described in the previous step;
- Based on the annual coal production the study team then developed an aggregate annual forecast of gas production for the SCEC mines. From that quantity, annual forecasts of civil use (residential, commercial and agricultural) based on SCEC estimates, were subtracted, yielding an annual forecast of the gas available for an end-use project.

SCEC estimates that more than 700 million tonnes of coal reserves are distributed among its mining blocks. These coal reserves contain as much as 7 billion cubic meters of methane that will be liberated during mining. **Figure V** shows the volume of gas that will be drained from the SCEC mines but go unused if an end-use project is not implemented. Estimates shown are for p10, 50, and 90 probabilities for the years 2008 through 2025.

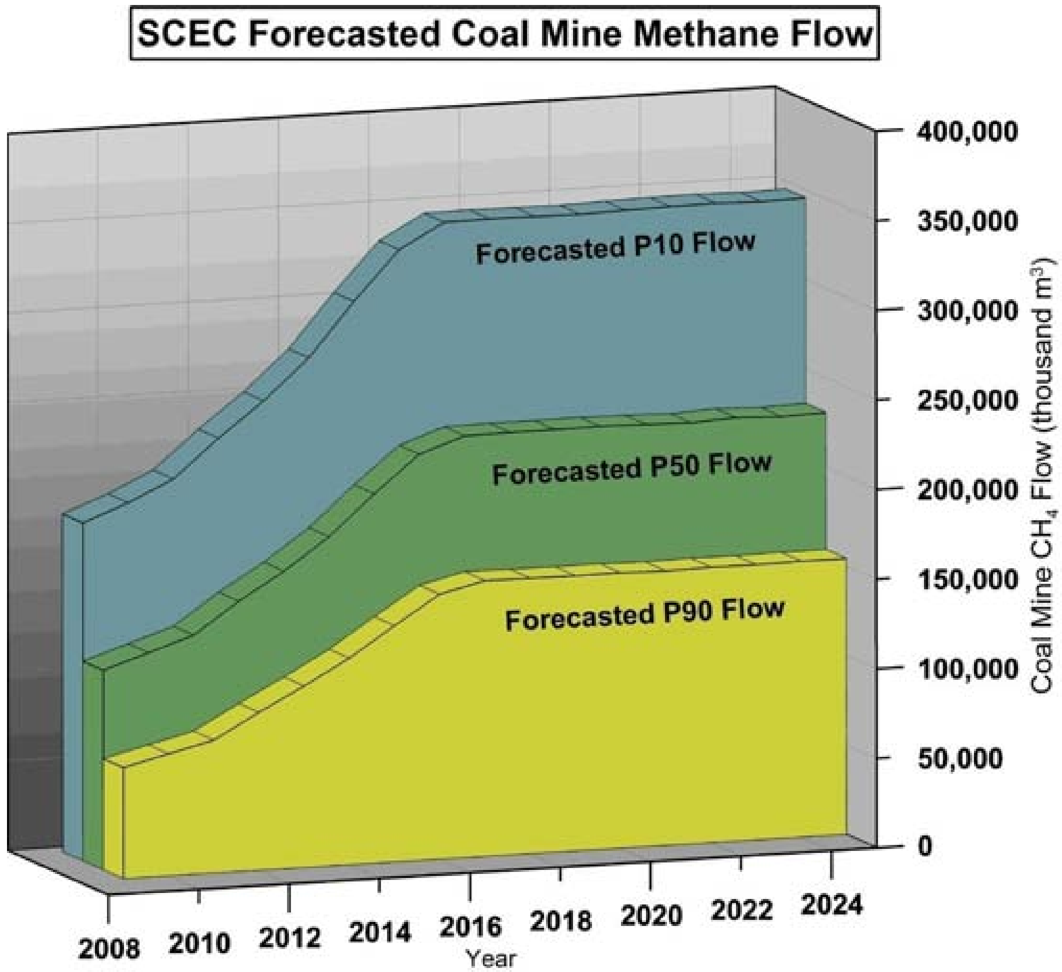


FIGURE V: SCEC ANNUAL UNUSED GAS SHOWN BY P10, P50 AND P90 PROBABILITY THRESHOLDS

Given the reasonable probability that a large quantity of unused gas will be available in the foreseeable future to be consumed by an end-use project, commercial risks will be defined by the likelihood that SCEC coal mines will continue producing coal that can be sold in China's coal markets; and that gas or electricity can be sold to consumers at a profit. The study team conducted a review of the market conditions that impact SCEC's commercial viability as a coal producer and market studies for each of the gas and electricity markets.

China Coal Market Overview

Coal has consistently accounted for 65-70 percent of China's primary energy in recent years, with consumption rising by an estimated 10 percent per year 2000-2007 to a level of 2.58 billion tonnes, (assumed thermal value 5000 kcal/kg). **Figure VI** shows the contributions of various sources to China's energy profile in 2007.

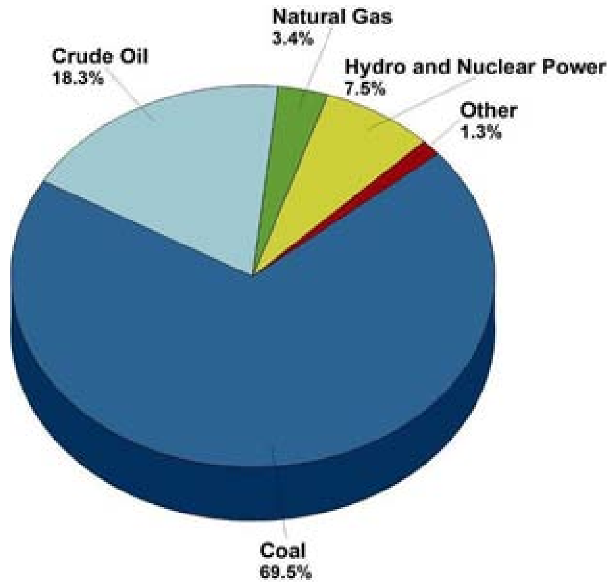


FIGURE VI: CHINA'S PRIMARY ENERGY SOURCES

Thermal power generation, which grew at a nearly 15 percent rate from 2004 to 2007, has been the principal driver for coal industry expansion. In 2007, power plants consumed approximately 1.4 billion tonnes of coal, or 55 percent of the total.

SCEC produced 5.1 million tonnes of high sulfur anthracite coal in 2008, 41 percent of the output of mines controlled by CQEIG, and more than any other company in Chongqing. It operates one washing plant with throughput of 900,000 tonnes, with the remaining 80 percent sold as-is. Approximately half of SCEC's 2008 output was sold by the CQEIG to the Huaneng Luohuang 2600 MW power plant, the premier plant in Chongqing which was designed specifically to burn SCEC's high sulfur anthracite coal, and was the first plant in China to incorporate modern flue gas desulfurization technology. An additional 20 percent, including almost all of SCEC's washed coal output, went to the 740 MW Chongqing Power Plant located on the Yangzi River just upstream from the main urban district. Another 20 percent, consisting of the highest ash, lowest thermal value portion of its output, is dedicated to the 300 MW Anwen power plant majority owned and operated by SCEC itself. The remaining 10 percent has been sold at free market prices to industrial end-users such as cement plants in Chongqing and Sichuan.

SCEC's status as the primary dedicated supplier to Luohuang offers strong protection against sales risk for its coal even in the slackest of markets. At its full 2600 MW capacity, assuming a modest 5000 hours per year of operation, Luohuang would require approximately 5.5 – 6 million tonnes per year of 5000 kcal/kg coal. In 2008, SCEC was only able to supply about 2.5 million tonnes. Most of SCEC's planned expansion projects over the next 3-5 years – including the new 900,000 tonne per year Liyuanba mine, the 600,000 tonne per year Zhangshiba expansion of the Fengchun mine, and the 600,000 tonne per year expansion of the Shihao mine - have been designated, according to media reports and government documents, to supply the 2 x 600 MW Phase III units at Luohuang which came on-stream in 2006-2007.

This study makes the conservative assumption, furthermore that the expansion projects mentioned above, as well as others designed to raise SCEC's output to 8.9 million tonnes will only reach their design capacity in 2015-2017. In short, we find little reason to doubt the ability of Chongqing and neighboring provincial markets to absorb an additional 3.8 million tonnes of coal from SCEC over an eight-year period under almost any conceivable economic scenario.

As in other parts of China, output of heavy industrial products such as power, steel, and cement began to decline during the fourth quarter of 2008. The consequent softening of overall coal demand is significantly narrowing the gap between controlled and spot prices, and is likely to make CQEIG sale of coal to power plants at planned prices more attractive to the coal producers than it has been in the recent past.

There is little chance, however that the softening of the market will cause the coal from the CQEIG mines to be displaced by newly available higher quality coal from outside of Chongqing. The delivered cost of northern coal in Chongqing was reported at approximately 480 RMB per tonne in December 2008, more than twice the controlled price of CQEIG coal; transport bottlenecks severely limit the quantity of northern coal that could enter Chongqing regardless of price.

High quality coal from Guizhou Province, a 100 million tonne producer due south of Chongqing is both more convenient with regard to transport and more price-competitive than northern coal. The CQEIG controlled price, however, will still be difficult for the Guizhou mines to match. The Chongqing power plants, furthermore, are designed to burn the Chongqing coal, largely negating the quality advantage of Guizhou coal. Finally, the municipal government will likely adopt administrative measures to protect the interests of its coal mines in times of stress, just as it has adopted coal price controls to protect the interests of its power plants during the sellers' market of 2007- 1st-half 2008.

Gas Market

After decades of stagnation, the natural gas market in China has experienced a surge of historic proportions in recent years. Production and consumption grew at average annual rates of 12 percent and 13 percent respectively 1995-2008, and by over 16.5 percent 2003-2008. **Figure VII** shows China's natural gas market development by sector.

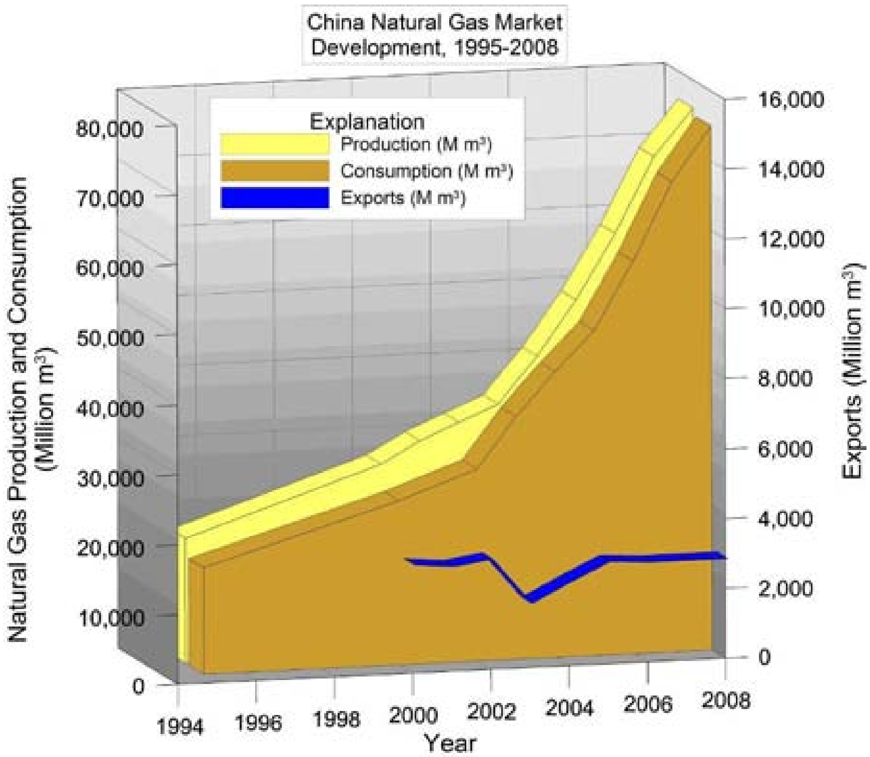


FIGURE VII: CHINA'S NATURAL GAS MARKET DEVELOPMENT

Official and semi-official projections call for China's natural gas consumption to increase to 100-110 billion cubic meters in 2010, and to 200 billion cubic meters by 2020, implying a steady growth of approximately 10 billion cubic meters per year. Shanghai and Beijing gas company authorities' project that demand in these two cities alone – which, are already well-served with natural gas in relative terms - will rise by an aggregate 19.3 billion cubic meters between 2007 and 2020.

The long term fundamentals of China's macro economic environment are therefore highly favorable for the absorption of purified, liquefied SCEC CMM in the Chinese market. The investments of the past 8 years in natural gas transmission and distribution have made access to natural gas a real possibility for the first time in China's urban centers, and have unleashed an enormous pent-up demand.

Domestic supply has been, remains at present and will likely continue to be far short of demand. Under these conditions, supply of LNG by truck from a modestly sized coal mine methane purification/liquefaction plant is far more competitive than it would be in a country with plentiful domestic gas sources and a fully developed long distance pipeline network. The success of other small scale domestic LNG plants based on trucking to end users sets a positive precedent for a new plant such as SCEC.

The macro implications of the global economic slowdown cannot be predicted. But at least as of the beginning of 2009 natural gas remains a seller's market in China. From a supply-demand point of view, the absorption of 100-150 million cubic meter equivalent of LNG from SCEC should be automatic in a market growing at 10 billion cubic meters per year that is going to be relying increasingly on gas imports.

Gas distribution companies with franchises across China indicate a willingness to pay up to 3.0 RMB per cubic meter for LNG from SCEC at the beginning of 2009 for delivery to cities without easy access to either pipeline gas or imported LNG. A reasonable guess is that the truck transport distances contemplated by these companies are as high as 1000-1500 km, and that the retail prices charged are between 4 and 5 RMB per cubic meter.

Given the virtual certainty that China will rely significantly on imported gas for future growth, the city gate prices of imported pipeline gas and LNG will drive the long-run price that SCEC's LNG will be able to command. The benchmarks for SCEC should therefore be delivered cost of gas from international pipelines and from imported LNG.

It has been reported that, with crude oil at $60 a barrel, the city gate price of imported pipeline gas from Central Asia will be in the vicinity of 3.0 – 3.5 RMB per cubic meter in East and South China. Further assuming: (1) an order of magnitude cost for truck transport of LNG of 0.07 RMB per cubic meter per 100 km provided in second half 2008 by a Chinese company in the business and; (2) a transport radius of 1000 – 1500 km, which would enable SCEC to reach a number of the markets along this pipeline, SCEC should reasonably be assumed to be able to command a price in the vicinity of 2.5 RMB per cubic meter ($10.76 per mmbtu at 36,000 KJ per cubic meter methane) using Central Asian gas as a benchmark, and allowing approximately 0.5 RMB per cubic meter for recovery of distribution costs, assuming the international oil price recovers to $60 per barrel by the time SCEC's plant comes on-stream.

LNG imports in the range of $10-11 per mmbtu (the approximate reported spot price around year-end 2008) would also be consistent with at least 2.5 RMB per cubic meter of liquefied CMM ex factory SCEC, assuming the transportation cost for SCEC is offset by the costs of imported LNG loading and transportation to city gate. There would likely be considerable upside potential for SCEC if international LNG prices were to rise further, and risk if they fell lower.

At present, the pipeline network of China National Petroleum and Natural Gas Company (PetroChina) extends to the county seat of Qijiang County, approximately 45 kilometers from the Songzao area. The extension of a pipeline to Songzao and purchase of the purified methane by PetroChina is theoretically possible (as would be the transportation of LNG from Songzao to the Qijiang pipeline terminus), but is unlikely to be economically attractive under the domestic natural gas price control regime in effect at year-end 2008, which fixes pipeline prices to Chongqing at 0.92 – 1.275 RMB per cubic meter in the Chongqing area, depending on the final end user.

Due to its proximity to the Sichuan gasfields, Chongqing has one of the oldest and best-developed natural gas distribution infrastructures in the entire country. Its total natural gas consumption reached a reported 4.5 billion cubic meters in 2007, putting it in the top three provincial consumers on a per capita basis, with 14 percent average growth 2004-2007.

The Chongqing Gas Group, a subsidiary of the same Chongqing Energy Investment Group which owns the Songzao Coal Mining and Electricity Company, has the franchise for gas distribution in the core Chongqing metropolitan area, as well as in a number of the outlying counties and cities, and accounted for approximately 1/3 of Chongqing's gas consumption in 2007. Most of the remainder was purchased directly from PetroChina by large industrial enterprises, with a small amount going to smaller distribution companies in some of the outlying areas (including some owned by PetroChina itself).

There seems little doubt that the Chongqing Gas Group by itself could absorb the liquefied gas produced by SCEC. Chongqing Gas projects that its sales will increase by at least 500 million cubic meters between 2007 and 2010, with demand being driven by gradual expansion of the residential coverage base from 1.63 million customers (approximately 5.25 million people altogether) to 2.1 million customers (6.8 million people), as well as by continued industrial growth.

Precisely because of its proximity to the gas source and because of its long history of gas use, however, Chongqing's regulated natural gas retail sales prices are among the lowest in China. The cost of purification and liquefaction of SCEC's gas will exceed the price at which Chongqing Gas is permitted to sell to end users, at least as of January 2009. While spot sales to Chongqing Gas for peaking purposes are a possibility, Chongqing Gas is unlikely to prove a reliable long-term customer absent administrative direction from the municipal government and/or a major increase in the cost of gas to Chongqing from the domestic producers.

The obvious target markets for Songzao are underserved areas where there is no history of low retail prices. Guizhou Province to the immediate south of Chongqing is especially attractive geographically. Substitution for the six billion cubic meters of coal gas produced in the province would create an instant market of approximately 2.5 billion meters of natural gas/methane. Guizhou will receive no pipeline gas until the Burma-China pipeline is completed 2012-2013, and is served at present only by small amounts of domestic LNG produced at

Dazhou just north of Chongqing and at Hainan Island. Its capital city Guiyang and number two city Zunyi are located 283 and 133 km distance respectively from Songzao.

Guangxi Province is another possible target. It will receive no pipeline gas until the Central Asia gas pipeline is completed. Retail residential sales prices in Guilin (a major tourist city) and Nanning (the capital), both located approximately 950 km from Songzao, are 4 and 4.5 RMB per cubic meter respectively.

In some cases, SCEC may be able to reach agreements with local distribution companies on a delivered price. Most of the local distribution companies in the underserved areas that are SCEC's prime targets, however, are controlled by major companies such as Xin'ao or China Gas or Hong Kong Gas that will wish to deal with SCEC directly, and will most likely take the gas ex-factory. Dealing with one or more of these majors, who each operate in multiple cities around China would also leave SCEC less exposed to the risk posed by over-reliance on single cities. These companies have all expressed strong interest in LNG from SCEC.

Electricity Market

Electricity production and generation capacity in China increased at robust rates of 14.4 and 15.3 percent respectively 2003-2007, considerably in excess of average economic growth of around 10 percent during the same period. Total generating capacity increased by a staggering two hundred thousand megawatts during 2006 and 2007.

This growth trend for power output continued through May 2008. Starting from June, however, monthly growth dropped into single digits as shown below in **Figure VIII.** In October, as the world economic downturn accelerated, China recorded negative electricity growth for the first time in memory; November 2008 output was 9.6 percent lower than November 2007.

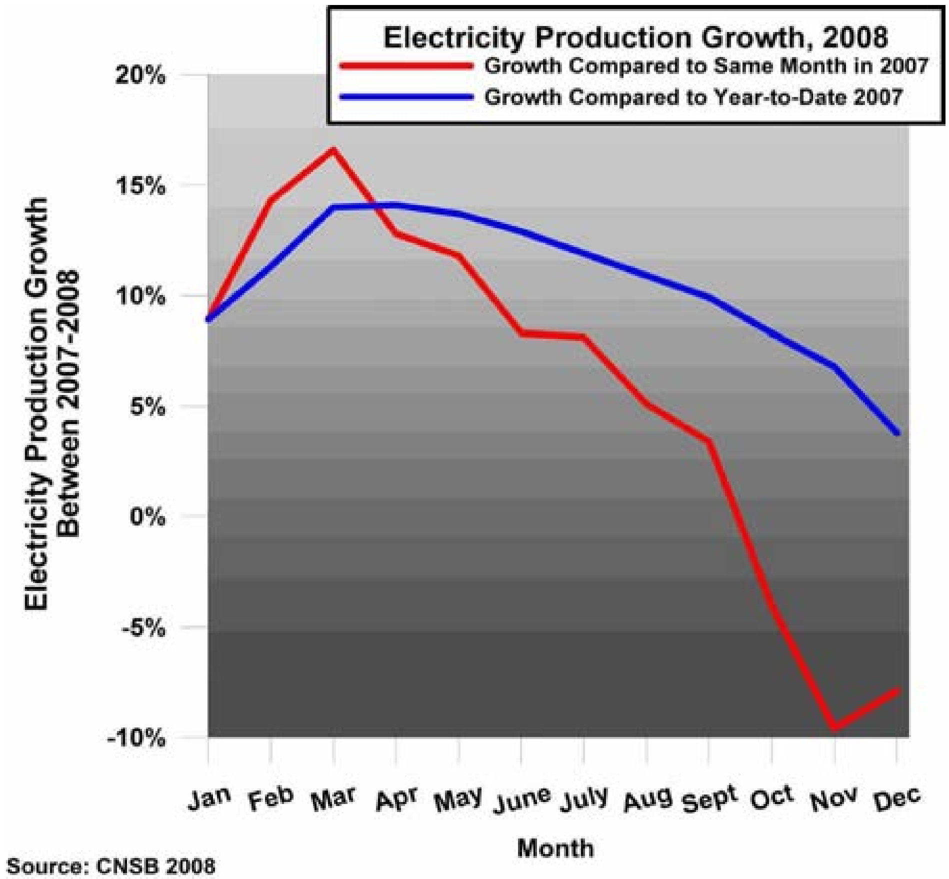


FIGURE VIII: ELECTRICITY PRODUCTION GROWTH

The World Bank has projected that China's economy as a whole will grow by approximately 7.5 percent in 2009, with as much as half of this growth coming from the implementation of the government's announced 4 trillion RMB economic stimulus package 2009-2010 (WB, 2008). As this package is to be centered on government investment in infrastructure directly related to people's livelihood – such as public housing, transport, urban environmental protection including sewage and pollution treatment, earthquake reconstruction, power grids – some recovery in output of electricity-intensive industrial products such as steel can be expected.

But it is questionable as of year-end 2008 whether national demand for electric power will grow as quickly in the next five years as it did in the 2001-2008 period. Civil and commercial consumption of power will certainly grow rapidly as urbanization accelerates – but as these sectors only account at present for 14 percent of total electricity consumption, (CESY, 2008, p. 107) it cannot be expected to completely substitute for more modest growth in electricity-intensive industry.

Given the rapid construction of electricity generation capacity since 2003, including many projects still outstanding, there is a distinct possibility that power generation capacity will outstrip demand in many parts of the country over the next 3-5 years. The appetite for new power construction will likely decrease correspondingly, and dispatch of existing plants – particularly coal-fired power plants – will decrease.

China is divided into six regional (transprovincial) grids that are largely independent, but engage in some electricity exchange through selected transmission links. Chongqing is one of six provincial level units that make up the Central China Electricity grid, which reports to the State Power Grid Corporation. Electricity consumption within the region covered by the Central China grid increased by 15 percent per year, 2005-2007. Nonetheless, the Central China grid is a net power exporter to the rest of China, with generation exceeding supply within the grid by about 60,000 GWH in 2007.

Power consumption in Chongqing grew by approximately 9.6 percent 2002-2007, and by 13 percent per year 2004 – 2007 to 44,921 GWH, driven primarily by rapid growth in industrial production which accounts for 70 percent of total electricity demand, and particularly by growth in steel, non-ferrous metals, building materials, and chemicals, which account for about half of the total demand. In Chongqing as in the country as a whole, the sudden decline in production of these sectors in second-half 2008 depressed electricity consumption, with year-on-year electricity growth dropping by a reported 2.13 percent in October 2008, and by projected 17.9 and 10 percent respectively in November and December (CPEC, 2008.2)

It appears that, barring the rapid resumption of the industrial growth patterns of the 2003 - 2007 period, the market for thermal power in Chongqing will be soft for some time to come. This leaves little incentive for the Chongqing grid to buy power from proposed new plants burning coal mine methane in locations such as Songzao.

At the least, the grid would have to pay the going rate for coal-fired power plants. If regulations published by the NDRC in 2007 with the purpose of incentivizing coal mines to generate power using CMM were to be implemented, the grid would have to pay a 0.25 RMB per kwh supplement to the 2006 coal-fired wholesale price which would raise the total to 0.577 RMB/kwh (NDRC, 2007.4). It is thus not surprising that the grid has no interest at the present time to pay for the considerable expenses of linking a prospective large-scale CMM power plant at Songzao to the major grid substations.

CMM End-use Options and Analysis

Through consultation with CQEIG the study team determined that there were three principal options for using methane gas drained from SCEC mines. These options are:

1. LNG Only Option- which would link the six mines located in the northern part of the basin, as well as the Zhangshiba shaft and the Liyuanba mine to the south into an integrated gathering and storage system. The system would supply feed gas to a CMM gas purification and liquefaction system to be built at a site near the power plant in Anwen Township. The LNG facilities would be built in two stages: (1) a plant with capability to process 150 million cubic meters of CMM per year (pure methane) beginning construction in 2009 and coming on-stream in 2011; and (2) a second plant with capacity of 60 million cubic meters per year coming on-stream in 2015 to process newly available methane associated with increasing coal production through the remainder of the project's life. Product would be sold ex-factory, and transported by tanker truck to end-users.

2. Power Generation Only Option- entails installing CMM fueled internal combustion power generation facilities with aggregate capacity of 166.2 MW at each of the active mines in the northern part of the basin, the Zhangshiba shaft, and eventually at the Liyuanba mine when CMM flow is sufficient to provide adequate fuel; approximately 20% of the capacity would be dedicated to the use of the Songzao Coal and Electricity Company itself, with the remainder sold to the public grid.

3. Optimized Option- is a hybrid solution that would link the six active mines to a gathering and storage facility for delivery of feed gas to the LNG planned Anwen; but this plan calls for delaying the decision to either link the Zhangshiba shaft and Liyuanba mine to the Anwen plant or install distributed power plants at each location until CMM production can be measured against forecasts and the operational efficiency of the first (built in 2009-2011) LNG facility can be determined. LNG would be sold ex-factory and transported by tanker truck to end-users; power would be entirely consumed by SCEC itself, offsetting electricity consumed by the gas purification and liquefaction system.

The following **Table I** allows the comparison of each end-use option examined by the study team for this feasibility study. The study team has concluded that the best economic performance would result from an LNG only end-use option. Yet, the risks associated with changes in the market price of LNG, lower than expected CMM production, issues relative to building a pipeline linking the southern mining facilities to the central gathering system or any combination of these factors could adversely impact the economic performance of an LNG only option. For that reason the third option that allows for a mid-project development decision point seems the most prudent and gives management an active role in determining the economic outcome.

The economic analysis for the Optimized Option assumes that LNG facilities with the capability to process 170 million cubic meters of CMM (100 percent basis) and power generation facilities with a nominal capacity of 28.9 MW will be constructed over the life of the project as follows:

(1) All gas flow from the six existing mines in excess of that already committed for local civil use and for previously planned and/or installed CMM power plants would feed an LNG plant in Anwen Township with capacity to process 130 million cubic meters of CMM per year (100 percent methane basis) to be completed by the middle of 2011.

(2) An additional LNG plant with capacity of 40 million cubic meters per year would be completed in 2015 to process the additional gas flow resulting from expanded coal production from the six existing mines.

(3) All gas from the Zhangshiba new mining area of the Fengchun mine in excess of that committed for local civil use would feed a power station with nominal installed capacity of 11 megawatts (MW), consisting of 22 x 500 KW internal combustion engines produced by the Shengli Oilfield Power Equipment Factory, to come on-stream during 2010.

(4) All gas from the new Liyuanba mine in excess of that committed for local civil use would fuel an additional power station with total capacity of 15.9 MW, consisting of 8 x 1.8 MW high efficiency internal combustion engines from Caterpillar (or a comparable supplier) plus 1 x 1.5 MW steam turbine to come on-stream gradually during the 2011-2016 period as coal production increases at the mine.

Table I allows the comparison of each end-use option examined by the study team for this feasibility study. The study team has concluded that the best economic performance would result from an LNG only end-use option. Yet, the risks associated with changes in the market price of LNG (see discussion in the following subsection), lower than expected CMM production, issues relative to building a pipeline linking the southern mining facilities to the central gathering system or any combination of these factors could adversely impact the economic performance of and LNG only option. For that reason the third option that allows for a mid-project development decision point seems the most prudent and gives management an active role in determining the economic outcome.

TABLE I: COMPARISON OF END-USE OPTIONS

Probability Threshold		Optimized Use		Only Power Generation		Only LNG	
		2011	2015	2011	2015	2011	2015
p90	LNG Plant Installed Mm^3	90	20			100	40
	PowerGen Installed MW	22.1		113.2			
	Net Emissions Reduced (Tons CO2e)	29,223,668		35,841,687		28,117,403	
	Total CAPEX	Business Confidential		Business Confidential		Business Confidential	
	Ratio: CapEx/Tons CO2e	Business Confidential		Business Confidential		Business Confidential	
	NPV @ 10% Discount Rate	$16.30		$19.89		$45.59	
	Ratio: NPV/tons CO2e	0.56		0.55		1.62	
	IRR	12.41%		12.97%		16.10%	
p50	LNG Plant Installed Mm^3	130	40			150	60
	PowerGen Installed MW	26.9		166.2			
	Net Emissions Reduced (Tons CO2e)	44,081,205		54,163,128		42,729,483	
	Total CAPEX	Business Confidential		Business Confidential		Business Confidential	
	Ratio: CapEx/Tons CO2e	Business Confidential		Business Confidential		Business Confidential	
	NPV @ 10% Discount Rate	$84.03		$58.82		$123.52	
	Ratio: NPV/tons CO2e	1.91		1.09		2.89	
	IRR	20.49%		16.25%		24.19%	
p10	LNG Plant Installed Mm^3	220	50			240	70
	PowerGen Installed MW	32.7		241.8			
	Net Emissions Reduced (Tons CO2e)	66,381,438		81,681,623		64,686,343	
	Total CAPEX	Business Confidential		Business Confidential		Business Confidential	
	Ratio: CapEx/Tons CO2e	Business Confidential		Business Confidential		Business Confidential	
	NPV @ 10% Discount Rate	$187.33		$107.64		$223.98	
	Ratio: NPV/tons CO2e	2.82		1.32		3.46	
	IRR	28.91%		18.13%		31.28%	

The project analyzed four different scenarios for the optimized option regarding carbon credit sales, with results as shown in **Table II**: (1) no carbon credit sales l; (2) sales of Certified Emissions Reductions (CERs) through the conclusion of the Kyoto Protocol in 2012, at a price of \$13.00 USD per tonne of CO_2 equivalent (CO_2e, under which the greenhouse effect of 1 cubic meter of methane is considered to be the same as 0.01428 tonnes of CO_2); (3) sales of Verified Emissions Reductions (VERs) for the years following 2012 at a price of \$6.12 USD per tonne of CO_2e; (4) sales of both CERs through 2012 and VERs after 2012 per the prices above.

TABLE II: IMPACT OF CARBON CREDITS ON ECONOMIC RESUTS FOR OPTIMIZED OPTION

	Internal Rate of Return (IRR)	Net Present Value at 10% Discount Rate (NPV) – Million USD
Scenario 1: No carbon credits	9.31	-5.31
Scenario 2: CERs, 2010-2012	13.72	25.16
Scenario 3: VERs, 2013-2025	15.96	53.56
Scenario 4: CERs, 2010-2012 and VERs, 2013-2015	20.49	84.03

The study team considers the potential for VER sales post 2013 to be high, and for CERs 2010-2012 to be moderate. Scenario 3 is therefore considered to be the baseline in **Table II** above. The low rate of return under Scenario 1 clearly shows the importance of carbon credits to the economic return for the project.

The study team also conducted sensitivity analysis on the optimized option regarding the impact of change in capital cost, change in cost of CMM purchase, and gas sales price using the p50 CMM production forecast. **Figures IX and X** depict the contribution to the statistical variance in the estimated NPV and IRR.

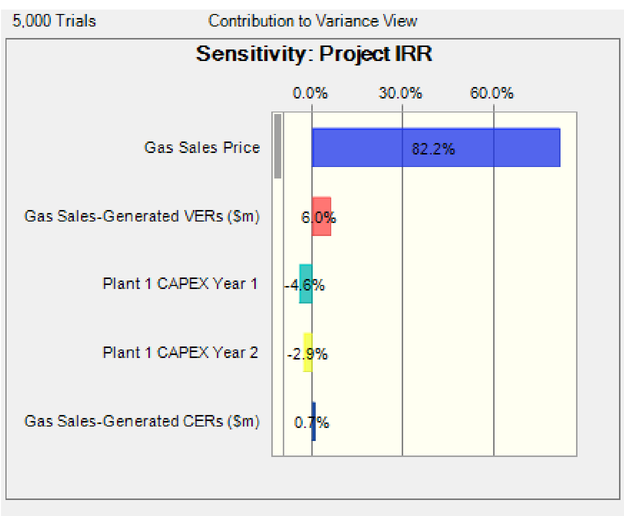


FIGURE IX: IRR CONTRIBUTION TO VARIANCE

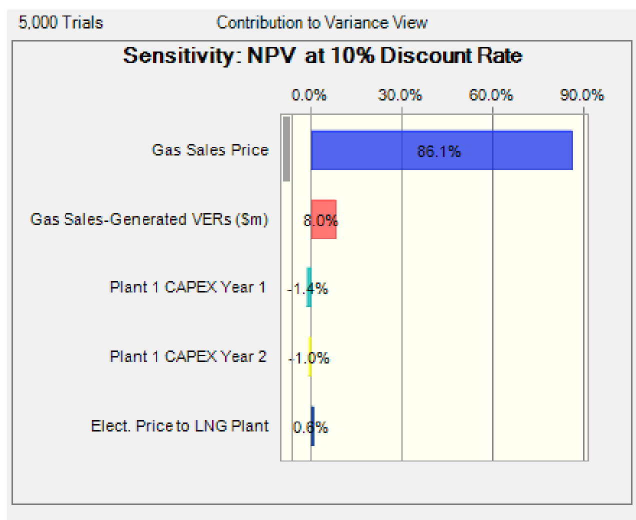
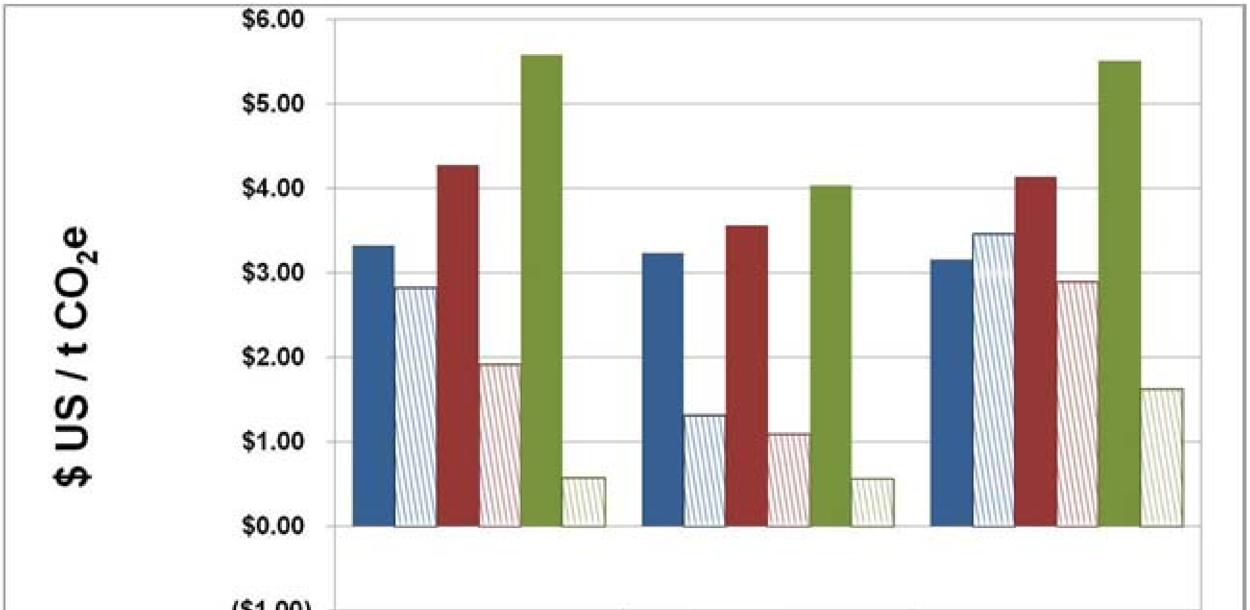


FIGURE X: NPV CONTRIBUTION TO VARIANCE

Gas sales price overshadows other factors, with the next largest contributions coming from the gas sales-derived VER sales-- then CAPEX from the first LNG processing plants. CER sales makes a less than one percent contribution to the Project IRR and avoided cost of electricity contributes a similarly negligible amount to the variance in NPV.

The economic performance of an investment in a CMM end-use project can be measured by commonly used indicators such as return on investment, net present value, and internal rate of return. Economic and sensitivity analysis performed by the study team indicates that the end-use options being contemplated all have strengths and weaknesses; but the bar chart included in **Figure XI** shows the advantage that the LNG project option has over the power generation option if the economic efficiency of reducing methane emissions is considered. This analysis was prepared using the p90, p50, and p10 methane production forecasts. Two performance indicators are depicted on the chart: *the ratio of CAPEX dollars invested to tonnes* of CO_2e shown as solid bars; and the *ratio of dollars of NPV realized per tonne of* CO_2e shown in hachured bars. Economic efficiency of the power generation option appears to be moderately attractive when considering only the amount of CAPEX invested per tonne of CO_2e emissions reduced, but the dollars of NPV realized per tonne of CO_2e emissions reduced is substantially lower than realized by the other end-use options. The poor economic efficiency of reducing carbon emissions relative to NPV dollars realized is principally due to the fact that electricity is being generated and consumed internally by SCEC and not sold to the grid. The amount of carbon emissions reduced is limited to the methane destroyed in the IC engines, and the amount of coal-fired generated electricity that is displaced on the SCEC-owned mine electrical grid; but displacement of coal fired electric power generation would be much greater if electricity generated by CMM fueled plants were sold to the regional grid.

Analysis of the economic efficiency associated with the LNG project option presents a very different picture. The CAPEX dollars per tonne of CO_2e emissions reduced is substantially higher as is the dollars of NPV realized by reducing emissions in this manner. The optimized use option also demonstrates strong economic performance, but is slightly less so than the LNG option due to the power generation component included in this scenario.



	Optimized Use	Only Power Generation	Only LNG
p10 CAPEX $s / t CO2e	$3.33	$3.24	$3.16
p10 $s NPV / t CO2e	$2.82	$1.32	$3.46
p50 CAPEX $s / t CO2e	$4.28	$3.57	$4.14
p50 $s NPV / t CO2e	$1.91	$1.09	$2.89
p90 CAPEX $s / t CO2e	$5.59	$4.04	$5.52
p90 $s NPV / t CO2e	$0.56	$0.55	$1.62

FIGURE XI: ECONOMIC EFFICIENCY OF END-USE OPTIONS RELATIVE TO CARBON EMISSION REDUCTIONS

In summary, we recommend a project centering on the purification and liquefaction of the majority of the CMM produced at Songzao in view of the strong gas market in China, and the higher returns relative to producing power to be sold to the public grid. The return on investment from an emissions reduction perspective is also favorable to the purification/liquefaction option. In view of logistical and other issues involved with the purification and liquefaction of CMM from newly developing mines in more distant areas, we recommend that management wait until 2013 to decide whether to try to purify/liquefy the CMM in these areas, or whether to use it as fuel for small power plants built at the mine site which will supply electricity to the mine grid system and offset power consumed by the purification and liquefaction. Additional revenues from the sale of carbon credits significantly improve the economic performance of the project.

2.0 Project Overview

2.1 Feasibility Study Background

This document serves as the final report for a feasibility study that was conducted by the study team assembled and managed by Raven Ridge Resources, Incorporated. The study effort extended from February of 2008 through February of 2009 and is a Methane to Markets activity supported by the USEPA under contract number EP-W-05-063 TO 13. Information and data used in this report was supplied to the study team by professionals employed by Chongqing Energy Investment Group Company (CQEIG), and its majority-owned subsidiary the Songzao Coal and Electricity Company (SCEC). The project was identified as a potential candidate worthy of additional investigation in August of 2007, and was subsequently featured in the first Methane to Markets Partnership Expo held in December 2007 in Beijing. In January 2008 a task order for a prefeasibility and feasibility study of the potential to develop a methane emissions reduction project utilizing medium quality coal mine methane (CMM) drained and recovered from mines located in the Songzao coal basin was awarded to Raven Ridge Resources.

2.2 Location and General Description of Proposed Project

Coal mine methane is drained from each of the coal mines operated by SCEC located in the Songzao coal basin which is situated in Chongqing Municipality along its border with Guizhou Province. Presently, six SCEC mines operate in the northern part of the coal basin: the Songzao, Tonghua, Fengchun, Yuyang, Shihao, and Datong. In addition, the SCEC mines operate an outlying shaft of the Fengchun mine, the Zhangshiba shaft, located in the southern part of the basin far removed from the central area of operations. The Liyuanba mine is presently under development and is also located on the far southern margin of the basin (**Figure 1**). Liyuanba is expected to be operational in 2010.

Civil uses of drained CMM are currently taking place at the SCEC mining area. SCEC has provided drained CMM free of charge to both miners' families and local townspeople and to commercial enterprises. Additionally, farmers in the area are obtaining unmetered gas. Estimating the current and future gas consumption of these civil uses is difficult because little of the gas is metered. Details of civil uses and methods of estimating gas consumption are provided in **Section 3.3.2**. Uses for the CMM remaining after dedicated civil and industrial consumption considered by this study include three potential options:

1. LNG Option- comprises linking the six mines located in the northern part of the basin, the Zhangshiba shaft and the Liyuanba mine to a gathering and storage system, which will feed CMM to a gas purification and liquefaction system to be located near the Anwen power plant;

2. Power Generation Option- entails installing CMM fueled internal combustion power generation facilities at each of active mines in the northern part of the basin, the Zhangshiba shaft, and the Liyuanba mine when CMM flow is sufficient to provide adequate fuel;

3. Optimized Option- linking the six active mines to a gathering and storage facility, and delaying the decision for linking the Zhangshiba shaft and Liyuanba mine until CMM production performance of the first LNG facility could be determined. **Map 1** shows the general layout and physiographic setting of existing and proposed SCEC mining and gas recovery, storage, and transportation facilities.

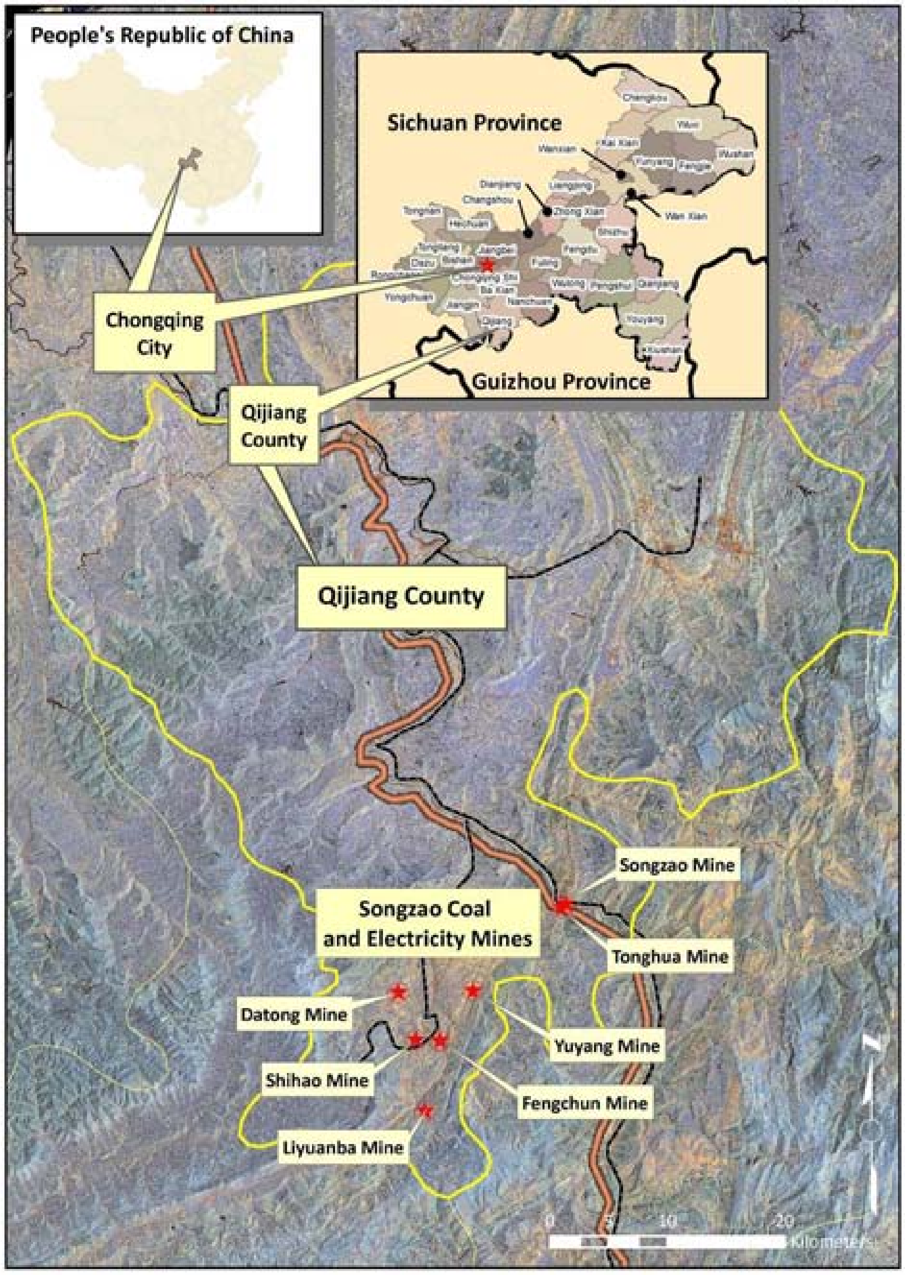


FIGURE 1: SONGZAO COAL AND ELECTRICITY MINES' LOCATION AND OVERVIEW MAP

2.3 Identification and Financial Profile of Project Sponsors

The two principal sponsors of the Songzao CMM utilization project are Chongqing Energy Investment Group Company (CQEIG), and its majority-owned subsidiary the Songzao Coal and Electricity Company (SCEC). CQEIG leadership has taken a leading role in the CMM purification and liquefaction project planning, will make the major commercial, investment, and financing decisions, and will manage the relevant regulatory and political approval procedures. SCEC operates the coal mines and the existing CMM drainage, collection, and storage system, and will play an important operational role for new CMM gathering and processing facilities associated with the project. Precise project ownership structure (including possible foreign investment) has not been finalized as of year-end 2008.

2.3.1 Chongqing Energy Investment Group

Chongqing Energy Investment Group (CQEIG) was established by the Chongqing Municipal government in 2006 to consolidate and manage the municipality's diverse energy investments. As of year-end 2008, the CQEIG's major assets include:

- The Chongqing Gas Group (wholly-owned subsidiary), the largest natural gas distribution utility in Chongqing with total sales volume of 1.7 million cubic meters in 2008. Chongqing Gas has the exclusive distribution franchise for the urban/suburban core of Chongqing, as well as 12 outlying municipalities, districts, and counties.

- Five coal companies (whole-or majority owned subsidiaries), including SCEC, with aggregate output of 12 million tonnes of coal in 2008.

- Partial ownership stakes in approximately 6,000 MW of operating hydro and thermal coal-fired power plants in Chongqing, and an additional 4,000 MW under construction. In most cases, one of the five Chinese national power generating companies is majority owner and operator.

Key 2007 financial indicators for the CQEIG are as follows:

TABLE 1: CHONGQING ENERGY INVESTMENT GROUP FINANCIAL INDICATORS, 2007

Total Assets (million RMB)	20,006
Total liabilities (million RMB)	10,052
Owner's Equity (million RMB)	9,954
Revenue from principal business (million RMB)	7,844
Gross profit (million RMB)	362.5
Net profit (million RMB)	344.8
Debt ratio	50.54%
Net return on assets	3.87%

Top managers of the CQEIG are appointed by the Chongqing Municipal government leadership. A possible public offering in 2009-2010 would dilute the municipal government's current 100 percent ownership of the CQEIG without altering the government's de-facto control.

While the SCEC CMM project ultimately stands or falls on its technical, economic, and environmental merits, the strong direct interest of CQEIG leadership in the project, combined with that leadership's strong ties to the highest level of the political structure of China's largest centrally-administered municipality should facilitate resolution of regulatory and political approval issues, and generally smooth the project implementation process. CQEIG's balance sheet is also an important source of financial strength for the project.

2.3.2 Songzao Coal and Electricity Company

Songzao Coal and Electricity Company (SCEC) was established in December 2002 as the successor organization to the Songzao Coal Mining Bureau, which was founded in 1958 and operated under various combinations of Chinese central and provincial government ownership throughout the second half of the 20th century. SCEC's current ownership is as follows:

Chongqing Energy Investment Group (CQEIG):	76.62 percent
Cinda Asset Management Company:	20.54 percent
Huarong Asset Management Company:	2.5 percent
China Energy Investment Company	0.34 percent

Cinda and Huarong are state-owned companies which were directed by the central government from 1999 to acquire non-performing loans of the major China state-owned banks, while China

Energy Investment Company is one of the five national power generation companies. Cinda's and Huarong's stakes in SCEC are legacies of the late 20th century when SCEC, like many other major Chinese coal producers, suffered financial losses caused by government coal price controls that did not allow for full cost recovery.

SCEC is the largest coal mining complex in Chongqing, accounting for over 40 percent of output of mines controlled by CQEIG. In addition to six producing coal mines with aggregate output of 5.2 million tonnes of raw coal in 2008 and one new mine under construction, SCEC operates one coal washing plant with throughput of approximately 900,000 tonnes in 2008, as well as a 24 MW coal tailings power plant generating power for SCEC's own use, and the 300 MW Anwen coal tailings plant (2 x 150 MW circulating fluidized bed) generating power for sale to the public grid. With the hope of earning carbon credit revenue under the Kyoto Protocol's Clean Development Mechanism, SCEC has also installed an aggregate 14 MW (nominal) of CMM-fired power generation (28 x 500 KW internal combustion units) since 2005 at three of its mines, with 6 additional units to be added to one of the sites and 6 others at a new site by the end of 2010, all generating power for SCEC's own use.

SCEC's 2007 financial indicators are as follows:

Total assets:	3,412 million RMB
Total liabilities:	1,925 million RMB
Sales Revenue:	1,336 million RMB
Profits:	12.6 million RMB
Taxes and fees to the government:	163 million RMB

The company's modest profit margin results mainly from the fact that the majority of its coal is sold to local power plants at modest prices controlled by the government (260 RMB per ton, 2008).

SCEC is widely acknowledged within the Chinese coal industry for its long experience and prowess with regard to CMM management and recovery. Its methane recovery (54 percent during the period extending from 2005 through 2007 at approximately 46 percent methane concentration) puts it among the leaders in the country.

3.0 Coal and Gas Resource Extraction in Songzao Coal Basin

3.1 Geologic Setting of the Songzao Coal Basin

The Songzao coal basin is the largest anthracite coal producing area in Chongqing Municipality. The coal mines lie within the northeast-southwest trending coal basin, which has been uplifted folded and faulted resulting in geologic structures that control the areal extent and depth at which the coal occurs. The average dip of the exploited seams is 12 degrees, but can vary locally from three to 13 degrees. There are more than 300 faults in the area with displacements that range from 10-55 meters with strike length usually less than 3,000 meters. These faults form the principal boundaries of the mining reserve blocks. **Map 2** uses a false color Landsat image of the area to show the ruggedness of the terrain and the control that the underlying geologic structure and stratigraphy exerts on the surface water flow and availability of arable land. A slope analysis map (**Map 4**) depicting the degree of slope was calculated using a twenty-five meter digital elevation model and illustrates the significant changes in topography. Stream courses follow bedding planes eroding the softer rock as they flow to lower elevations forming steep-sided valleys with only sparse, narrow benches and flat valley floors. The steep sides of the valleys and intervening benches are often terraced for agricultural use and human habitation. Valley floors offer the only useable areas for human activities and are the location of mine facilities and supporting industry; which often compete for space with agricultural cultivation and residential buildings (**Map 5**).

Coal is extracted from the seams which are interbedded with limestone, siltstone, and limey organic mudstone beds of the Upper Permian Longtan Group. Mudstone commonly forms the roof and floor of the mineable coal seams. **Map 3** uses the same Landsat image as **Map 2**, but is presented as a black and white rendition with a semi-transparent overlay that depicts the general geologic structures and bedrock geology of the coal bearing strata. Each mine is located along the structural margins of the coal basin where three to six mineable or partially mineable coal seams occur at mineable depth. The seams most commonly mined are the M_6, M_7 and $M_{8,}$ although other seams may be mined locally. The M_8 coal seam reaches a maximum thickness of 3.83 meters and is the most widely distributed of all of the coal seams, accounting for as much as 60 percent of the mineable coal reserves. The mining depth of these coal seams is presently 250-500 meters deep, but will go deeper as the mines continue to expand.

Large scale coal mining started here in 1965 and presently covers an area of 236 square kilometers. There are six coal mines operating in this area with plans to add two more mines. The six mines currently producing coal are the Songzao, Tonghua, Datong, Yuyang, Shihao and Fengchun mines. The Liyuanba Mine will be in production by 2013, and is presently under construction. Coal production in 2007 was 4.88 million tonnes; but, by the end of 2008, SCEC mine production had increased to over 5 million tonnes **(Figure 2)**. Growth in production will come from expansion of the existing mines and the addition of the Liyuanba Mine causing coal production to plateau at 8.9 million tonnes per year by 2017. Mineable coal reserves from these eight mines are estimated at 728.85 million tonnes.

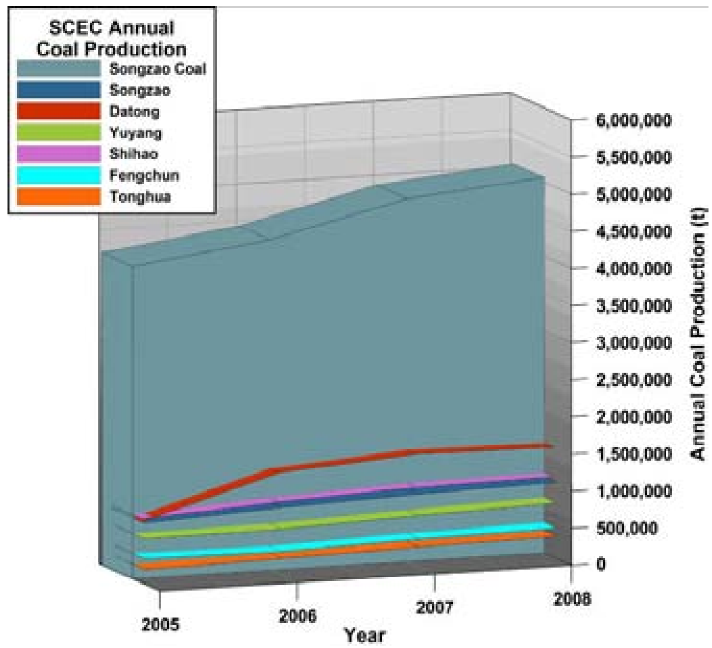


FIGURE 2: SCEC ANNUAL COAL PRODUCTION

3.2 Coal and Gas Resources and Reserves

There are an estimated 607 million tonnes of mineable coal reserves associated with the active mines. This estimate includes coal deeper than 200 meters and permanent coal pillars. The source of coal reserves data are found within the tables included in the Chongqing Design Institute's summary of coal and gas reserves for 2009-2025, which are merely a restatement of SCEC's data based on mining capacity and rate of mining for the subject years.

Gas content of the coal seams average 17.1 – 29 cubic meters per tonne. Coal seam permeability ranges from 0.057 to 0.319 millidarcies. The coal seams are prone to outbursts with 472 incidences reported in this mining area. Most outbursts are produced from the deeper and gassier M_8 seam, which is also the source of most coal reserves. Gas content data was used to estimate the reserves of recoverable gas for the active mines. A lognormal probability distribution function was constructed to depict the recoverable gas reserves for each of the mining areas listed in **Table 2** and is also depicted graphically in **Figure 3**. This probability function was constructed by multiplying the mineable coal reserves and a drained gas recovery factor determined by SCEC for each mine. The study team reviewed the process used for developing the factor and determined that it was based on sound data and derived through use of industry standard practices. Gas reserve estimates were calculated for each of three probability thresholds, P90, P50, and P10. The gas reserve estimated at each threshold has the probability of being the actual value that will be measured equal to or greater than the stated probability. As an example for Songzao Mine, there is a 90 percent probability that the recoverable gas reserves will be 0.49 billion cubic meters or greater; but there is only a 10 percent probability that the recoverable reserves will be greater than 0.75 billion cubic meters.

TABLE 2: RECOVERABLE DRAINED GAS RESOURCES ASSOCIATED WITH COAL RESERVES OF ACTIVE MINING AREA

Mining Area	Mineable Coal Reserves (million tonnes)	Recoverable Gas Reserves Categorized by Probability Thresholds (billion cubic meters)		
		P90	P50	P10
Songzao	64.9	0.49	0.61	0.75
Tonghua	28.6	0.26	0.34	0.45
Datong	154.4	2.03	2.11	2.18
Yuyang	75.5	1.02	1.06	1.09
Shihao	150.4	1.34	1.50	1.67
Fengchun	67.2	0.85	0.91	0.98
Liyuanba	66.7	0.52	0.63	0.76
TOTAL	728.9	6.90	7.18	7.45

Note estimates are as of November, 2008

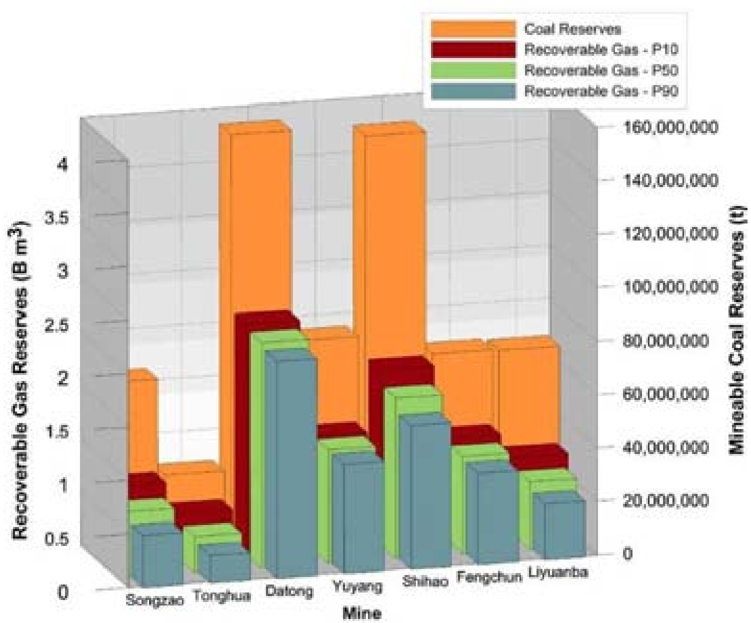


FIGURE 3: MINEABLE COAL RESERVES AND RECOVERABLE GAS RESERVES CATEGORIZED BY PROBABILITY THRESHOLDS

3.3 Coal and Gas Production Forecasting

At SCEC coal mines, gas is drained from coal seams and associated strata using underground drainage techniques that have proven to be productive and safe through many years of innovation and practice. SCEC gas drainage experts are recognized at a national level for their experience in safely draining gassy, outburst-prone coal seams and are often called upon to train gas drainage engineers from other mines.

Draining gas from the mineable coal seams occurring in the Songzao coal basin is challenging due the complex geologic and mining conditions and low permeability of the coal seams and neighboring strata. A strategy that is commonly used at SCEC mines is referred to as the "relief seam drainage system". This system works by drilling gas drainage boreholes into a target seam--the thickest mineable seam in the stratigraphic package, and then mining the overlying seam. This process reduces pressure on the mineable seam by extracting the overlying seam creating a void space and causing the underlying target seam to relax as the overlying strata fill the void. This successfully practiced gas drainage strategy relies on employing radiating fan patterns drilled upward from drilling galleries carved along entryways driven in hard limestone beneath the thickest mineable coal. Drainage boreholes are linked together using rubber tubing manifolds that are in turn, connected to an underground gas gathering system. The gas gathering system ties to surface gas pumping stations which evacuate the gas from the boreholes using water-ring vacuum pumps. Other technologies have been tried over the years including long directionally drilled boreholes, but many have failed and none have offered significant improvement or reduced cost. SCEC gas drainage experts are working to improve the as relief seam mining practice by reducing the amount of air that is sucked into the system from leaks in the drainage and gathering system and hope to develop strategies that further increase the permeability by encouraging greater relaxation and permeability increases in the mineable seams.

For the six active SCEC mines total methane emissions were 666 cubic meters per minute in 2007, including 294 cubic meters per minute as ventilation air methane (VAM). Ten surface pumping stations with twenty pumps are being used for draining gob gas at the SCEC mines. Composition of the gas taken at each mine's drainage station ranges from 43.4 to 59.29 percent methane, a trace to 0.41 percent CO_2, 6.15–10.34 percent O_2, and 34.22–48 percent N_2. A total of 195,830,900 cubic meters of gas was pumped from drainage stations in 2007; 105,340,000 cubic meters were used for residential and power generation. Total liberated methane for all SCEC mines was 386,360,750 cubic meters in 2008, as shown in **Figure 4**.

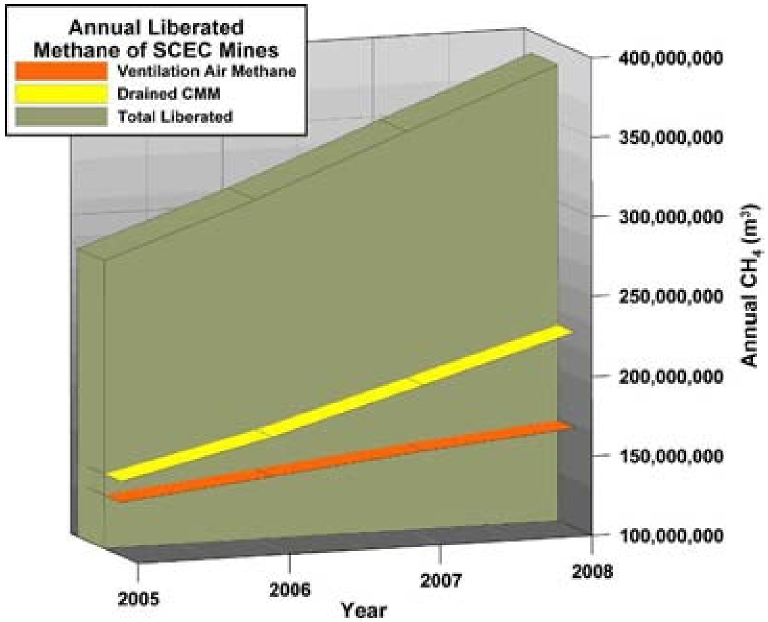


FIGURE 4: ANNUAL LIBERATED METHANE OF SCEC MINES

In order to determine the feasibility of an end-use option, reliable models which forecast future gas production and gas availability must be developed. The models constructed by the study team used recent historical data and information to understand the potential range in values that occur through time and the uncertainty involved in predicted future values. The following narrative explains the process used for developing gas production and gas availability forecasts.

3.3.1 Assumptions

The SCEC data was used for developing probability distributions to model each of the parameters used to forecast gas production and available gas for the end-use project. At the study team's request, SCEC provided three years, 2005 through 2007 (**Figure 5**), of monthly records containing data for each of the following parameters (2008 data was recently received and used to update certain graphs, but was not used for forecasting purposes):

- coal production,
- gas drainage volume,
- concentration of gas drained,
- VAM volume, and
- VAM concentration.

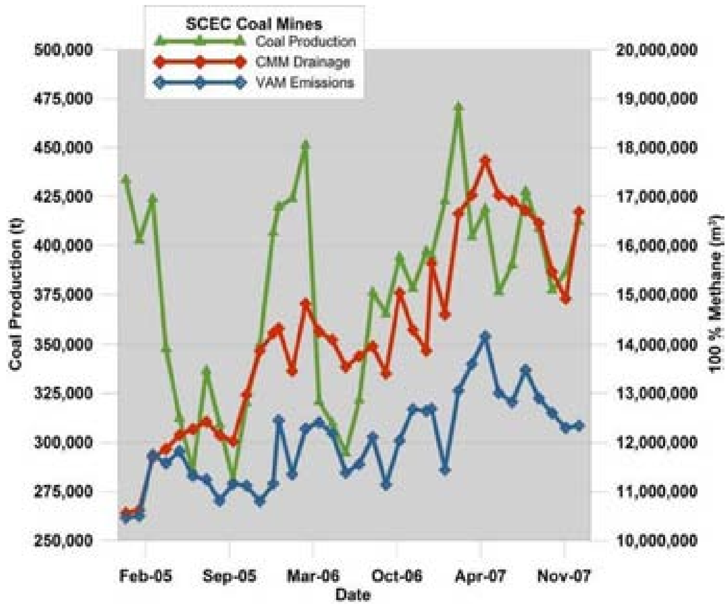


FIGURE 5: SUMMARY OF SCEC COAL MINES COAL PRODUCTION AND VOLUME OF METHANE LIBERATED THROUGH DRAINAGE AND VENTILATION AIR

Records for 36 consecutive months were examined for each of the active mines and associated drainage stations. Liberation of methane has steadily increased for most mines as coal production has increased. Whereas VAM has increased moderately in volume through time, the volume of drained gas has increased more rapidly (**Figure 6**).

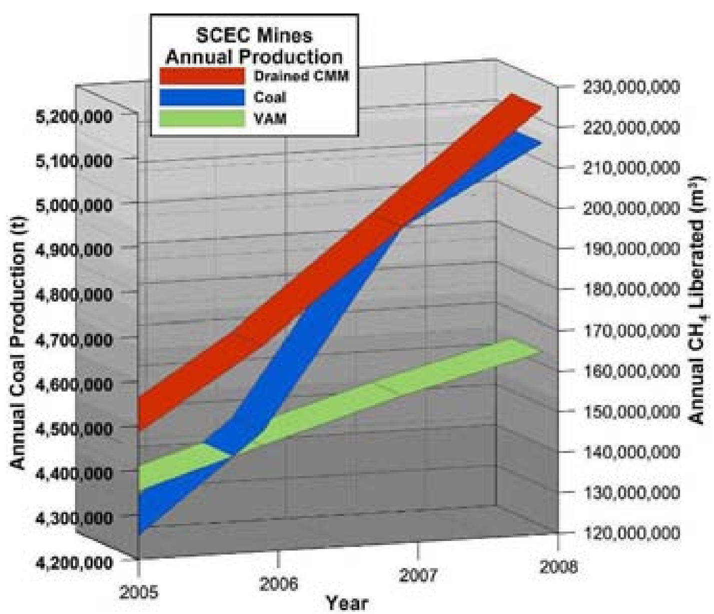


FIGURE 6: SCEC MINES ANNUAL COAL, CMM AND VAM PRODUCTION

Concentration of drained gas has ranged from 43 to 49 percent methane but concentration has remained relatively constant; concentration of VAM has ranged from 0.38 to 0.45 percent methane but may decrease as drained gas recovery efficiency increases (**Figure 7**).

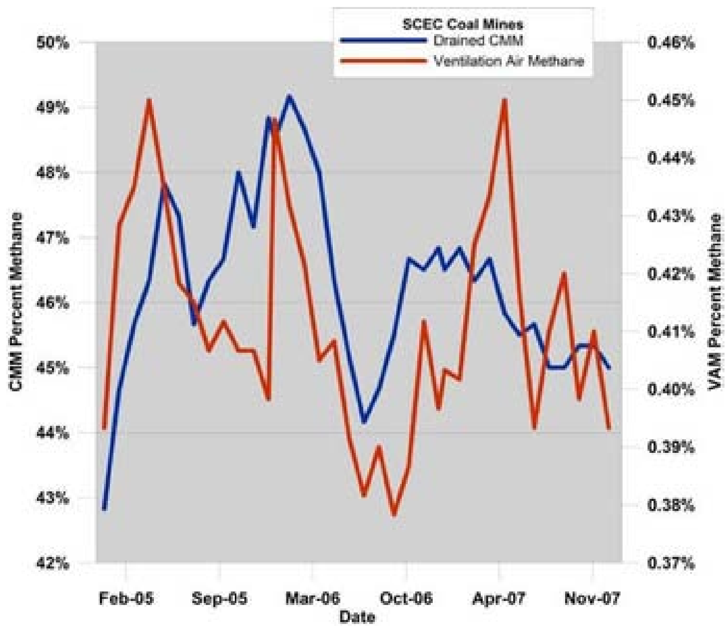


FIGURE 7: SUMMARY OF SCEC COAL MINES RANGE OF DRAINED GAS AND VAM METHANE CONCENTRATIONS

3.3.2 Probabilistic Approach to Forecasting

Forecasts of CMM produced were prepared for the years 2009 through 2025, through the following process:

- Drainage volume of CMM was related to the amount of coal produced at each mine by dividing the volume of gas drained by the monthly coal production for each of the 36 months, and a probability density function was fit to the data. The monthly coal and gas production values were annualized by simply multiplying the distributions by 12. The resultant function can then be used to calculate the probability of a volume of CMM being produced for any given value for coal production. This parameter is expressed in cubic meters per tonne of coal mined.

- Annual forecasts of CMM production were calculated by randomly sampling the probability frequency distributions developed in the previous step and multiplying those values by the planned coal production forecasted by SCEC for each year during the 2008 through 2025 period. Statistically valid results were ensured by sampling the distribution 5,000 times for each calculation. This yields the estimate of CMM that will be produced for a given year. The forecast volume is not a single point estimate, but rather it is also a probability distribution depicting the likelihood of producing a given amount of methane predicated on the predicted amount of coal produced in a given year. **Figure 8** shows the geographic distribution of forecasted coal and methane production at each of SCEC's mines.

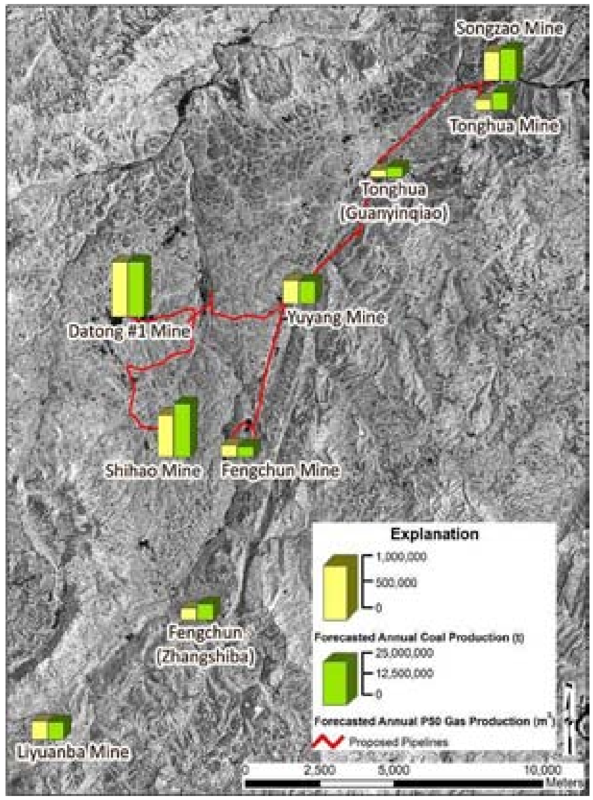


FIGURE 8: FORECASTED ANNUAL COAL AND GAS PRODUCTION

- Each of the annual coal mine forecasts for coal produced and for CMM production were then each aggregated as probability frequency distributions and a probability function was then fit to each resulting in the annual production of gas and coal for each of SCEC's coal mines. This data set is used for obtaining forecasts for individual mines and can be summed to calculate the total for SCEC mines in aggregate (**Figure 9)**.

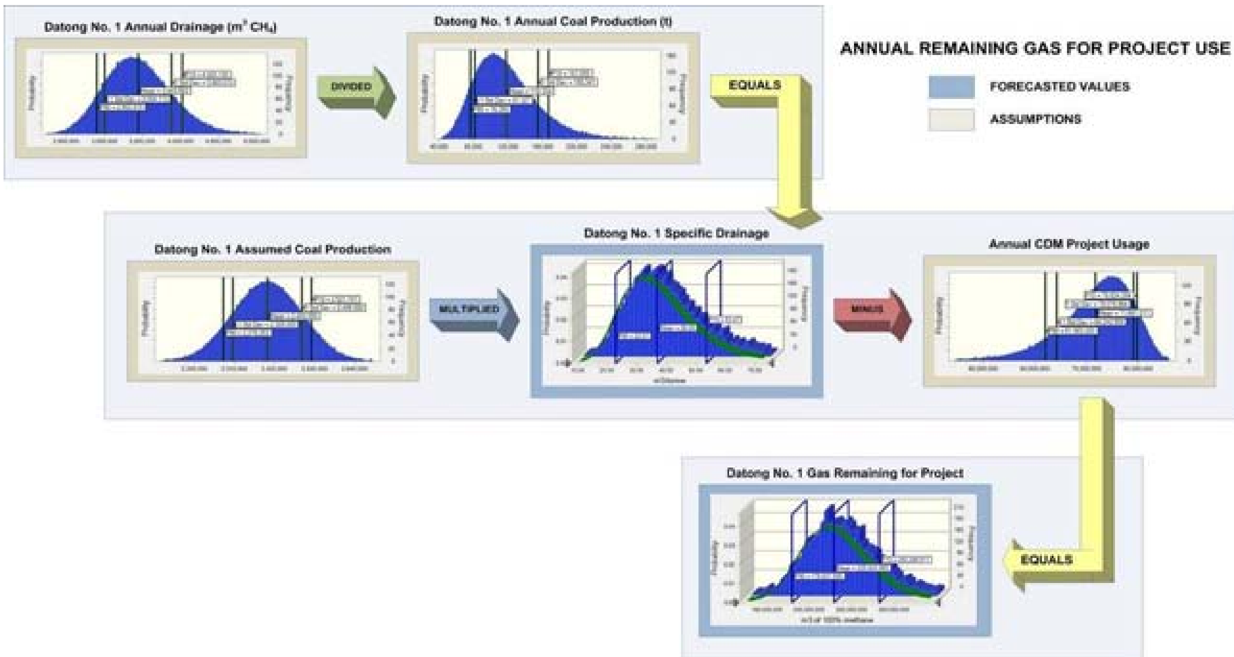


FIGURE 9: PROCESS FLOW DIAGRAM OF REMAING GAS CALCULATIONS FOR INDIVIDUAL MINES

To determine the amount of gas that will be available for an end-use project, annual forecasts of civil use (residential, commercial and agricultural) based on estimates supplied by SCEC were subtracted from the aggregated annual gas production distributions for each mine, resulting in a frequency distribution for the entire SCEC mining complex **(Figure 10)**. This distribution was once again fit to a probability density function, that forecasts of the annual volume of unused gas could be estimated for any given year.

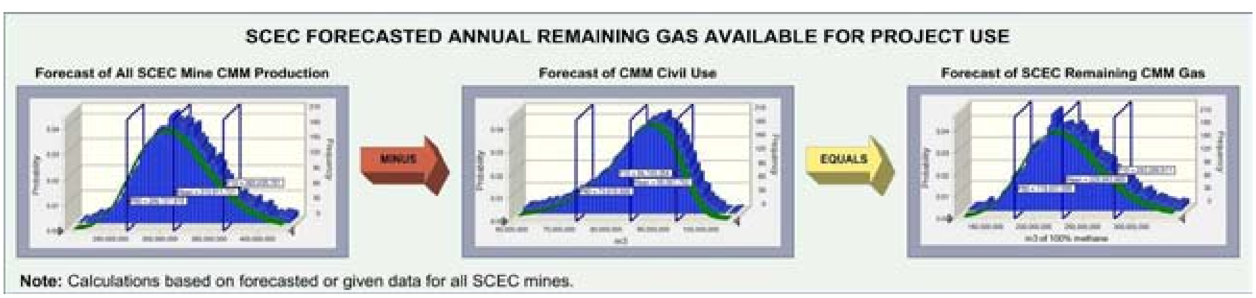


FIGURE 10: PROCESS FLOW DIAGRAM OF REMAINING GAS CALCULATIONS FOR ALL MINES

There are several factors that contribute in aggregate to the large degree of uncertainty present in estimates of civil use; they are:

- For many years, the Songzao Coal and Electricity Company has provided drained CMM free of charge both to miners' families and local townspeople/commercial enterprises for hot water heating and cooking, as well as to public facilities in the mining area such as cafeterias, small district heating boilers, etc. In response to pressure from the county government, an increasing amount of CMM is flowing to local farming households as well. Because supply of CMM has been viewed as a form of social welfare rather than as a business, little of this civil usage is metered, let alone paid for, and a culture of entitlement has arisen among consumers.

- SCEC reported that total civil consumption (including leakage) was 65.7 million cubic meters in 2005 and 64 million in 2006. The Chongqing Coal Design Institute undertook another investigation in 2007, and estimated the civil use for that year to be 66.6 million cubic meters, including 48.7 million from 47,331 households, with the remainder coming from commercial and public facilities. SCEC officially reported total civil consumption to be 85.5 million cubic meters in 2007 – 20 million cubic meters higher than the audit suggested, and a more than 20 million cubic meter increase over the officially reported 2006 total. SCEC supplied information that shows the distribution of civil use by mine.

- The study team assumes that the actual total for civil consumption lies somewhere between the estimate given by SCEC, 85 million cubic meters, and 65 million cubic meters offered by Chongqing Design Institute. The difference between the two estimates can largely be attributed to two principal sources of uncertainty: burgeoning use by farmers who obtain unmetered gas by running high density polyethylene pipe; and the inability to measure the leakage from the CMM distribution system.

The study team used the two estimates to construct a probability function that with a mean of approximately 71 million cubic meters with a growth of 2 percent per year until 2016, at which time, growth slows to 1.8 percent; then declines to 1.6 percent in 2018, and goes to zero growth in 2018. The probability distribution is asymmetrical and is skewed toward the higher values so that some higher values are sampled during the forecasting process. The maximum value that can be obtained during the 5,000 sample Monte Carlo simulation is 105.3 million, but this value occurs less than one percent of the time.

3.3.3 Results of Forecasting

Probability distributions resulting from simulations performed to forecast the amount of unused gas that will be available at each mine for the years 2008 through 2025 was then aggregated to give a distribution for the SCEC mining complex. This aggregated distribution was in turn fit to a probability density function which is used to mathematically describe the potential estimates that could be given for any year chosen between 2008 and 2025 **(Figure 11)**.

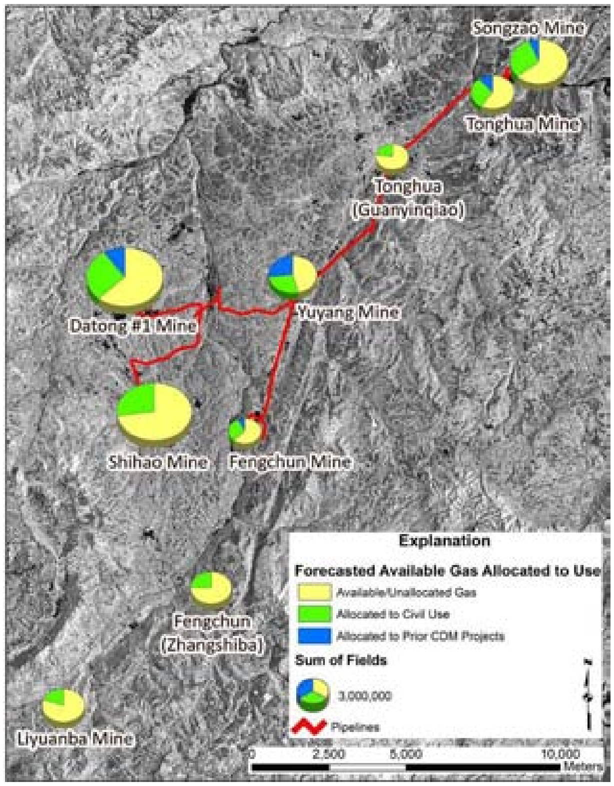
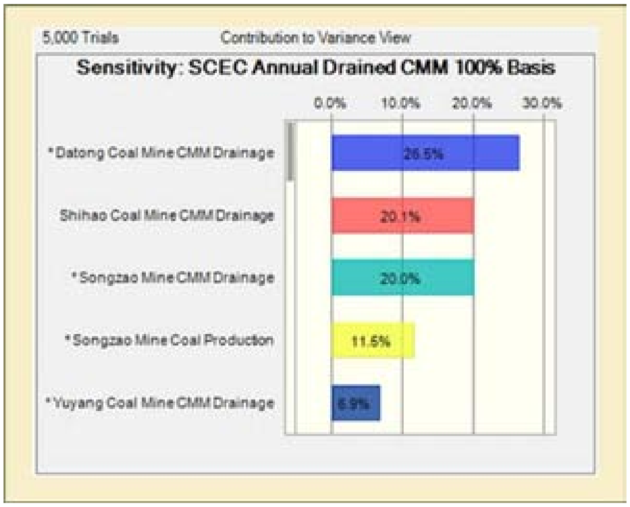


FIGURE 11: FORECASTED AVAILABLE GAS ALLOCATED TO USE

The resulting forecasts were compared with the CMM reserve estimates for the mines that are active, including Liyuanba, which will be fully developed in within the next few years. Sensitivity analysis was performed to determine the largest sources of variance in the estimates. Not surprisingly, the largest contributors to uncertainty come from the estimate of gas production from the most prolific gas producers among SCEC's coal mines, the Datong, Shihao, and Songzao mines. The remaining uncertainty stems from the forecast of Songzao coal production and the amount of gas that is forecasted to be drained from the Yuyang mine. The coefficient for each of the estimated parameters is positive, indicating that as each of the estimates increase, the estimated overall volume of produced gas will increase as well **(Figure 12)**.



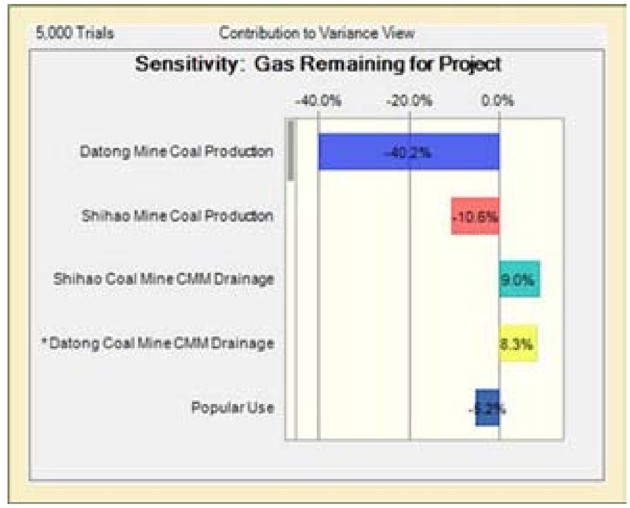


FIGURE 12: DRAINED CMM SENSITIVITY CHART

FIGURE 13: SENSITIVITY CHART OF GAS REMAINING FOR PROJECT USE

Sensitivity analysis was also performed on the estimate of gas that will remain for the end-use project. A contribution of -40.2 percent of the uncertainty incorporated in this estimate comes from the estimate of coal production at the Datong mine, followed by a contribution of -10.6 percent due to coal production estimated for the Shihao mine, and -6.2 percent arising from the civil use (designated popular use on **Figure 13**). This indicates that as these three factors having a negative coefficient decreases, the overall amount of unused gas will decrease. Conversely as the following factors increase, Shihao coal mine methane drainage (9.0 percent) and Datong CMM drainage (8.3 percent), the amount of unused gas will increase.

Figure 14 shows the annual gas available for the probability threshold values for P10, P50, and P90 for the years 2008 through 2025. Given the reasonable probability that a large quantity of gas will be available for use over the next 16 years, market analysis was performed to determine the opportunities for developing an economically robust end-use project. The gas and electricity markets were studied to determine suitable options.

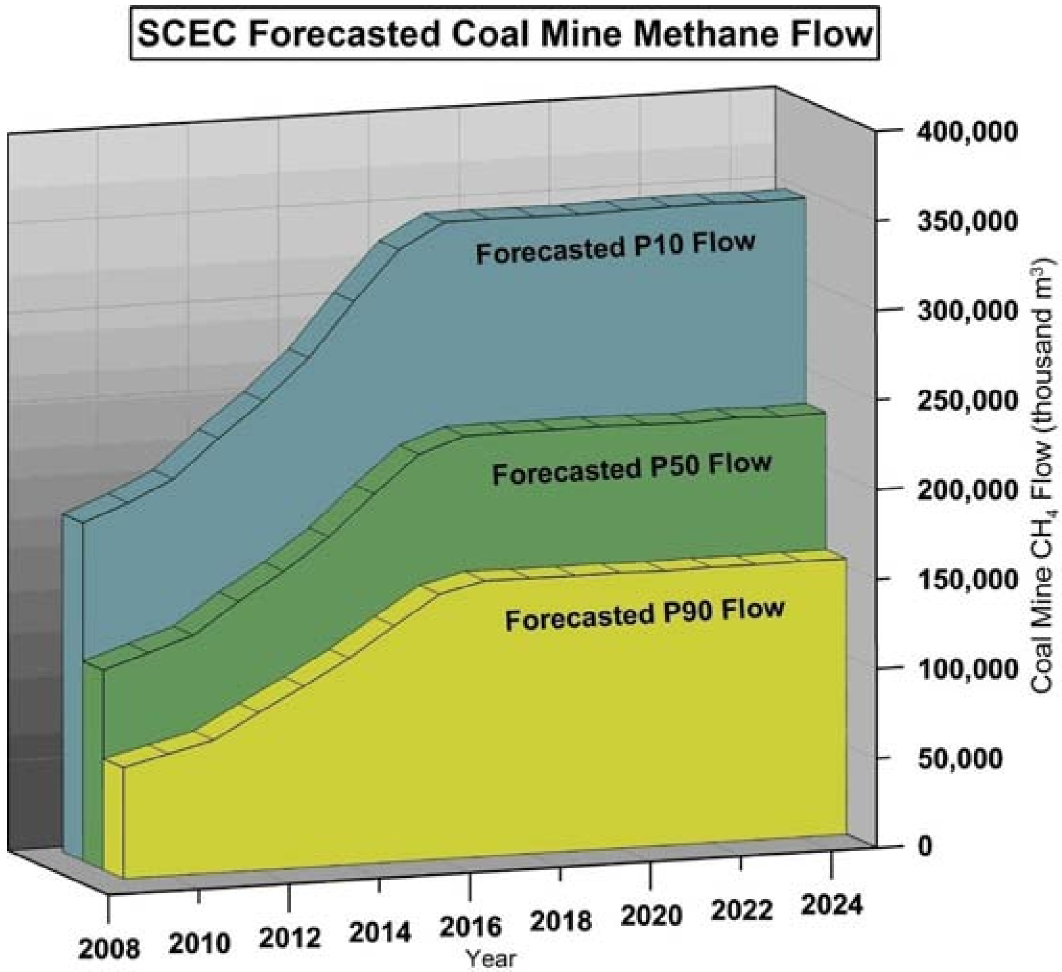


FIGURE 14: SCEC ANNUAL UNUSED GAS SHOWN BY P10, P50 AND P90 PROBABILITY THRESHOLDS

3.3.4 Risks Associated with Increasing Production of CMM

Forecasts of future CMM production and use act as the basis of this feasibility study. These forecasts rely on analysis of historical data describing past performance and SCEC's plans to increase coal and related drained gas production in the future. Increases in drained gas production will concomitantly increase as coal production increases because gas must be drained to make the mines safe, but SCEC also hopes to increase gas drainage efficiency, which further ensure the safety of the miners. Moreover, the increases in gas production will impact the timing and magnitude of investment that must be incorporated into analysis of potential end-use strategies. Gas drainage efficiency comprises the amount of gas drained as a proportion of the overall gas liberated during mining. That gas which is not evacuated by the gas drainage system is released to atmosphere through the mines' ventilation systems. Risks are associated with achieving the planned increases in future gas production. Any strategy undertaken to increase CMM production must weigh the risks that affect coal production and resultant production of CMM, including the selection and deployment of technology that may be used to increase drainage efficiency. The study team identified and assessed the impact of the risks listed in **Table 3**, below.

TABLE 3: RISKS ASSOCIATED WITH INCREASING PRODUCTION OF CMM

Risk	Assessment	Mitigant
Production and Supply of CMM to End-use Project:		
Capability of the SCEC mines to increase production of coal and concomitantly increase gas production in quantities sufficient to support a large scale end-use project	Low	SCEC has a long history of successfully mining the coal resources in the Songzao basin. They have recently demonstrated their ability to increase production at several mines. Carefully planning and adoption of innovative ways to manage and monitor increase in drilling and recovery efficiency are key to maintaining reliable production.
Measurement and control of quantity of gas consumed for civil use	Moderate	Addressing the issue and quickly implementing a program to regulate, monitor, and charge for gas that is consumed. Leakage of gas distribution system must be corrected.
Technology:		
Drilling and recovery systems to increase drainage efficiency are important. SCEC has so far been successful at increasing drilling and recovery efficiency, but efficiency increase beyond the present level are becoming more difficult.	Low	Management must continue to review its systems for recovery and look for ways of improvement. Much of the drilling is done by outside contractors and innovative ways to monitor quality and effectiveness of their labor is important.
Pumping, storage and transportation. The systems size and complexity will increase substantially.	Moderate	Use of equipment and methods that have been proven is key factor for successfully supplying gas of consistently high quality to the end-use projects, but management must also look for improvements to measurement and monitoring systems. Computerized digital control and record keeping is important for provision of timely management reports.

Risk	Assessment	Mitigant
Implementation:		
Integration and transformation of the gas recovery system that is now mostly oriented to mine safety and local supply into a system that primarily exists to fuel a large scale end-use project	Moderate	SCEC management must convince mine managers that the added responsibility associated with supplying high quality gas is equal to that of mining coal safely. Incentive programs will have to be implemented.
Development of infrastructure elements such as an improved roadway	High	CQEIG has expressed willingness to develop necessary infrastructure to facilitate access to LNG market.

4.0 China's Economy and Energy Markets

4.1 Coal Market Overview

4.1.1 Growth in China's Coal Production

Note: Because of the large number of suppliers, and in particular the significant role played by small, lightly regulated mines owned by local governments or private interests, official coal production statistics are not as reliable as those of other forms of energy such as electric power and natural gas. While the overall patterns described below based on recently reported official statistics or estimates derived from earlier official statistics are reasonably reliable, some of the specific numbers may diverge from the underlying reality, and some inconsistencies can be seen when comparing statistics from different sources. In particular, certain statistics (e.g., provincial reports on annual output based on "mines of scale") appear to leave out a substantial portion of small mine production. Even national total output statistics contained in official communiqués, which try to account for the entirety, are on occasion revised after release.

4.1.1.1 Supply/Demand

Coal has consistently accounted for 65-70 percent of China's primary energy in recent years, with consumption rising by an estimated 10 percent per year 2000-2007 to a level of 2.58 billion tonnes (**Table 4**), (assumed thermal value 5000 kcal/kg). Despite official calls to gradually reduce the weight of coal in the energy mix, the percentage actually increased slightly between 2005 and 2007 as heavy industry surged.

TABLE 4: ESTIMATED COAL CONSUMPTION IN CHINA, 2000 -2007
(MILLION TONNES, 5000 KCAL/KG THERMAL VALUE AVERAGE)

	2000	2005	2006	2007
Volume	1,320	2,167	2,390	2,580
Percentage of total primary energy	68.0%	68.9%	69.4%	69.5%

Sources: CESY (2008), p. 79; NDRC (2008.1)

Figure 15 below shows the prevalence of coal in the mix of China's primary energy sources.

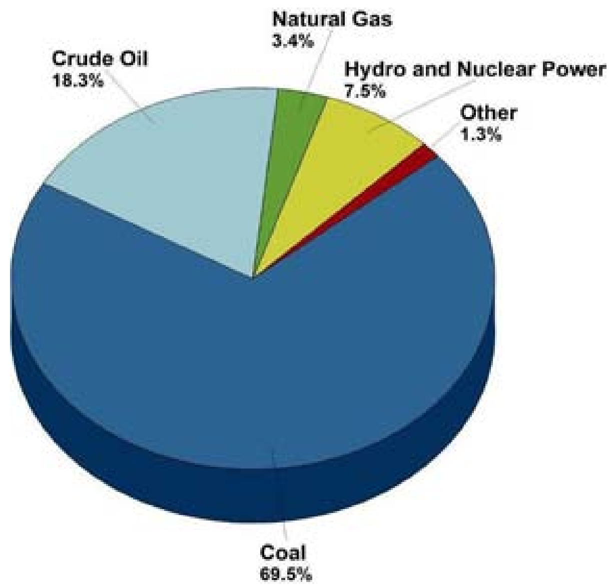


FIGURE 15: CHINA'S PRIMARY ENERGY SOURCES, 2007

Domestic coal production has strained to keep pace with rapidly growing demand in recent years. Although output overall grew by the same 10 percent per year as consumption between 2000-2007, the most rapid growth took place in 2003-2005, the years immediately following the government's decision to largely free coal prices. Since 2005, by contrast, the rate of growth has steadily decreased, with the mix of coal production, import and exports shown in **Figure 16** below.

TABLE 5: RAW COAL SUPPLY IN CHINA

			Exports		Imports	
	Million tonnes	Growth (%)	Million tonnes	Growth (%)	Million tonnes	Growth (%)
2000	1,299	-	55.1	-	2.2	-
2001	1,382	6.4	90.1	33.8	2.7	18.5
2002	1,455	5.3	83.9	(7.4)	11.3	76.1
2003	1,722	18.4	94.0	10.7	11.1	(1.8)
2004	1,992	15.7	86.7	(8.4)	18.6	40.3
2005	2,204	9.9	71.7	(20.9)	26.2	29.0
2006	2,373	7.7	63.3	(13.3)	38.1	31.2
2007	2,526	6.41	53.2	(19.0)	51.0	25.3
2008	2,622	3.8	45.3	(14.8)	40.4	(20.8)

Source: CESY(2008), p. 33, 60; NBSC (2008) ; China Customs (2009.1)

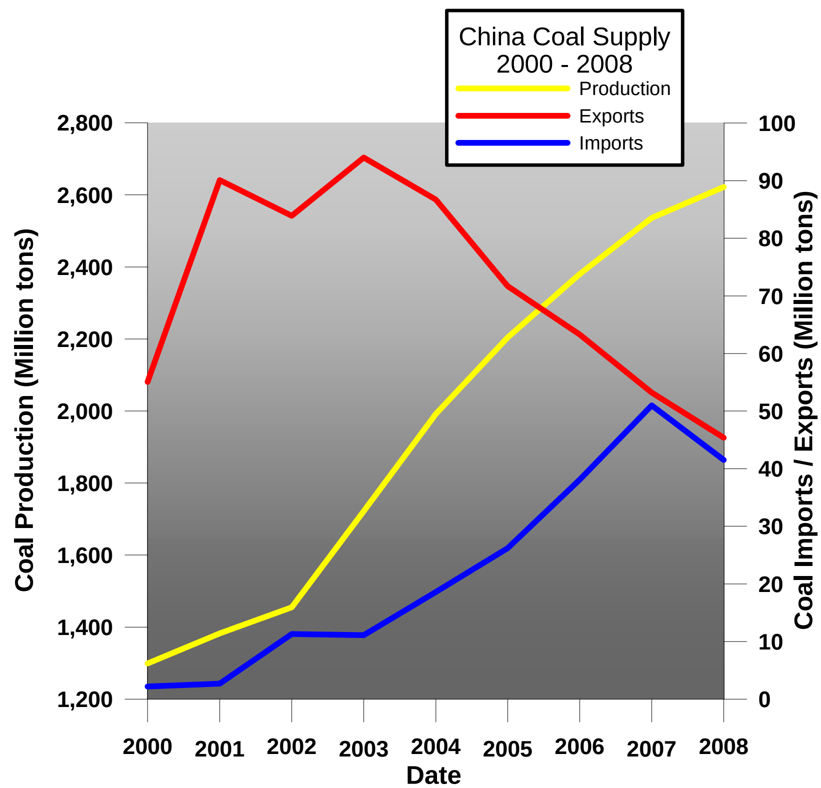


FIGURE 16: CHINA'S RAW COAL SUPPLY

As a result, coal exports, which had expanded steadily from the mid 1990s through 2003, declined by over 50 percent between 2004 and 2008. As domestic transport bottlenecks worsened and transport prices increased, imports of coal into eastern and southern coastal provinces increased to a level that virtually counterbalanced exports by 2007. These imports declined somewhat in 2008 to 41-42 million tonnes, approximately 1.5 percent of total national demand.

4.1.1.2 Coal Use

Thermal power generation, which grew at a nearly 15 percent rate through 2004-2007 (see **Electricity Market Section 4.3**) has been the principal driver for coal industry expansion. In 2007, power plants consumed approximately 1.4 billion tonnes of coal, or 55 percent of the total. The steel industry, which grew at a 23 percent rate over the same period, consumed an estimated 17 percent (about 450 million), split approximately equally between direct burning and indirect consumption in the form of coke. Cement and coal-based chemicals accounted for an additional 11 percent of total consumption, with the remainder scattered among other usages (CESY, 2008, pp. 109-110).

4.1.1.3 Coal Production

Coal type

In 2007, output of coal by type was reported by knowledgeable sources as follows:

TABLE 6: OUTPUT OF COAL BY CLASSIFICATION, 2007 (MILLION TONNES)

Classification	Coal Output (million tonnes)
Anthracite	439
Bituminous	1,937
of which	
Coking Coal	979
Non-coking	958
Lignite	146

The Chinese definition of coking coal, which follows former Soviet standards, is somewhat broader than is prevalent in the west; only about 25 percent of "coking coal" is actually used to make coke. A substantial portion of China's anthracite coal is used for power generation, with much of the rest used as raw material for chemicals production.

Coal Production Company Ownership

An estimated 49.1 percent of China's 2007 coal output originated from large scale, fully mechanized mines (mainly underground) operated independently according to commercial principles by approximately 100 companies owned by arms of provincial and central governments. This ownership structure represents the culmination of a commercialization process during the 1990s which transformed most of these companies from appendages of a central government Coal Ministry to independent (though still government owned) entities responsible for their own profits and losses. The two largest companies, including Shenhua, which produces close to 200 million tons of coal per year and also controls significant railroad, port, and power generation assets, are owned by the central government; the remainder are owned by provincial governments. According to official estimates, an additional 12.8 percent of 2007 coal output came from less mechanized companies owned by city and county governments. The remaining 40 percent was mined by an estimated 14,000 companies owned by townships, villages, and private interests. Both the scale and the technological level of these mines are variable, and they account for a disproportionate share of accidents and fatalities. In a number of cases, they impinge upon the properties of the larger mechanized mines.

The proliferation of these locally owned mines in response to the freeing of coal prices was an important factor behind the rapid growth in coal production 2003-2006. The government regulated them relatively lightly during this period in the interest of ensuring adequate coal supply, but has been trying for several years to hold them to higher safety and technical standards. It has forbidden the commissioning of any new mines with annual capacity of less than 300,000 tonnes per year, and is attempting to shut down the least technically advanced and most dangerous of the existing locally owned mines. This effort probably accounts in part for the slower growth in coal production in recent years.

Geographic Distribution

China's coal reserves and production are disproportionately concentrated in the north-central part of the country as shown below in **Figure 17**. Shanxi Province alone accounts for over 600 million tonnes, or approximately 25 percent of national output, and neighboring Inner Mongolia, Shaanxi and Henan for approximately 30 percent aggregate. The three northeastern (Manchurian) provinces provide 8-9 percent and the three provinces of Hebei, Anhui, and Shandong located south and east of Beijing and north of the Yangzi River approximately 13 percent.

By contrast, the major Yangzi Delta and Pearl River load center provinces of Jiangsu, Shanghai, Zhejiang, Jiangsu, and Fujian, and Guangdong only produce about 2 percent of the national total. These areas depend heavily on coal transported by rail from the north central provinces (particularly Shanxi, Shaanxi and Inner Mongolia) to northern coastal cities such as Qinhuangdao, Huanghua and Tianjin, and by ship from these cities to their ultimate destinations, supplemented in recent years by imports from abroad.

The seven inland provinces south of the Yangzi River (Jiangxi, Hubei, Hunan, Chongqing, Sichuan, Guizhou, Yunnan) account for approximately 23 percent of the country's population, and 17 percent of its coal production. Guizhou, at approximately 125 million tonnes per year, is the major producer of this group. Although the quantity, coal quality, and mining conditions of deposits in these provinces (excepting Guizhou) are generally inferior to those in the north, they are nonetheless being developed to the maximum extent, with northern coal relegated to a supplementary role due to limited north south rail transport capability and high transport expense (CESY 2008, p.109).

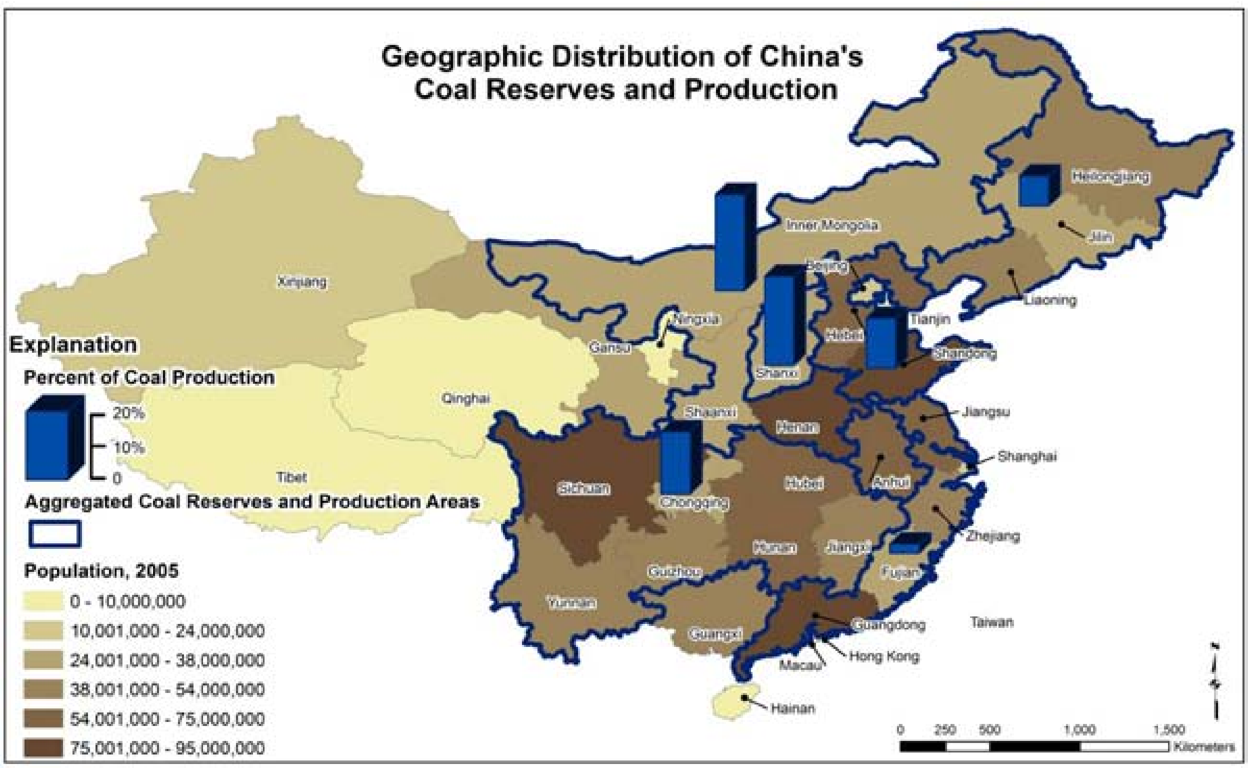


FIGURE 17: GEOGRAPHIC DISTRIBUTION OF CHINA'S COAL RESERVE AND PRODUCTION

4.1.1.4 Marketing and Pricing

As the central government released control of the large mines to provincial governments during the late 1990s and the turn of the 21st century, it also gradually relaxed control of marketing and pricing in order to ensure an adequate supply of the country's most important source of primary energy. This decision, together with a sustained upsurge in coal demand (which had actually dropped in the late 1990s) transformed the large mechanized companies from money losers to money earners by 2002, and succeeded in greatly increasing coal production.

One institution from the centrally planned economy was retained: the annual national coal marketing meetings at which supply agreements are reached between key coal producers and the most important consumers, who were formerly directly covered by central planning. These agreements fix volumes and prices for the coming year; the pricing is referred to as "contract pricing", or "long-term contract pricing", as distinct from spot pricing. Only rarely does a "long-term" contract have a duration longer than one year.

In 2007, approximately 850 million tonnes of coal – or about two thirds of the output of the major mechanized companies - were sold at the conference. About three quarters of this volume was purchased by electric power plants, represented in cartel-like fashion by the five national generation companies, with the remainder split between large steel, cement, chemical, and coal exporting companies. The contracts have traditionally satisfied only a portion – perhaps half to two-thirds – of the large power plant customers' needs, and a smaller percentage of the needs of industrial customers.

While the central government does not directly dictate prices for coal sold at these meetings, the National Development and Reform Commission (NDRC) is a participant, and retains a final veto power in extreme circumstances. NDRC's main goal in recent years, not always fully achieved, has been to ensure that prices to power plants do not rise more rapidly than their owners can bear, in view of the strict central price controls on power sales which severely limit the degree to which the power plants can pass price increases through to their customers. Other classes of coal consumers are for the most part left to fend for themselves in price negotiations with the sellers.

The central government also guarantees rail transport for all coal sold at the annual sales meetings (rail operations are still directly managed by the Ministry of Railroads). The transport guarantee is an important consideration for transactions involving long distance, trans-provincial shipping in a country in which rail capacity has been chronically insufficient to meet demand.

Provincial governments exercise more direct price controls on an ad hoc basis. In Chongqing, for example, the local government has put a strict upper limit on coal sold to local power plants by its largest producers.

The approximately one-third share of the output of the large mechanized mine not sold at the annual supply meetings, as well as virtually all of the output of the smaller locally or privately operated mines which account for 38 percent of national total output are sold under short term contracts at spot market prices. These spot market prices have been substantially higher than the national sales conference contract prices in recent years.

4.1.1.5 Recent Market Trends

Coal Price Increases 2007 – 1st-half 2008

As the economy, and in particular major coal consuming industries such as electric power and steel grew at 13-15 percent rates and a sellers' market psychology took hold, coal prices increased dramatically in 2007 and the first half of 2008. The ex-mine price for one-year contract coal power plant (see above) sold by major producers in Shanxi rose by 20 percent to a reported 490 yuan ($72) per tonne for 5500 kcal/kg steaming coal in 2008. Ex-mine spot prices for power plant coal spiked as high as 600-700 RMB ($88-103) per tonne in the first quarter of 2008.

Ex-mine spot prices for power plant coal spiked as high as 600-700 RMB ($88-103) per tonne in the first quarter of 2008.

The sudden upsurge in steam coal prices created particular problems for power plants, whose ability to absorb the increases were limited by central government controls on the prices the plants could charge to the grid for their output. Coal which they could purchase at one year contract prices could fulfill only a portion of their needs; large and small coal producers alike preferred to direct their sales to other industrial users such as cement plants, who were not limited by ceilings on the price increases they could pass to their customers. As a result, coal stocks ran dangerously low at power plants throughout the country in the early months of 2008. Only at mid-year did the government grant thermal power plants some relief through two price increases that raised the per kwh thermal power sales price to the grid by about 0.04

fen per kwh on average, allowing the plants to recoup coal cost increases of about 88 RMB per tonne (at 5000 kcal/kg coal and 38 percent coal conversion efficiency in the plants).

The market price run-up for coking coal sold to steel mills or independent coking plants rose even more dramatically to 800 – 1000 RMB ($117-$147) per tonne at year-end 2007 depending on quality to 1400 RMB ($206) per tonne in the first quarter of 2008 . By mid-year spot coking coal was sold for as much as 2000 RMB, or almost $300 per ton. On June 30, the government took the step of freezing prices across the board at June 19 levels for the remainder of the year.

Coal Price Decreases in 2nd- half 2008

The Chinese economic slowdown of fourth quarter 2008, and most particularly the average 11.4 percent and 13.3 percent declines (year-to-year basis) in production of thermal power and steel during the quarter has reduced coal demand by as much as 12 percent and thus dramatically changed the dynamics of the coal market in China. While there was some lag in reaction time, coal production started to follow the trend of consumption, with a 1.3 percent drop in December 2008 compared to December 2007. Spot prices for steaming coal ex-mine Shanxi were reported in late November to have dropped from a range of 600-700 RMB per tonne to 450-500 RMB per ton, and for high quality coking coal from 1800 to about 1300 RMB per ton, considerably lessening, though not wiping out the gap between spot and contract prices.

Although spot prices for all kinds of coal have decreased, the drop has been most pronounced for lower quality coal (low thermal value, high ash and/or high sulfur). Tens of millions of tonnes of such coal were reported to have accumulated at the major northern transshipment ports in the last two months of 2008.

While prices for the higher quality coal sold by the major mines to their key customers under the on-year contracts appear to be holding up better as of the beginning of 2009, it remains unclear in what direction they will move over the longer term. Participants at the annual sales conference for 2009 held in December 2008 report a deadlock in the negotiations between the coal seller and power plant buyer cartels, with the former demanding a 10 percent increase over 2008 contract prices, and the latter a 10 percent decrease. It is logical to expect that the spot price drop will facilitate the central government's efforts to close down the least productive and most dangerous of the locally controlled small mines, which together with moves by some mines to withhold production while prices are low could moderate coal price drop through reduction in supply. But it remains unclear how deep and how long-lasting the drop in coal demand will be, and what will be its long-term impact on coal pricing.

4.1.2 Market for Songzao Coal and Electricity Company's Coal

SCEC produced 5.1 million tonnes of high sulfur anthracite coal in 2008, 41 percent of the output of mines under the CQEIG, and more than any other company in Chongqing. It operates one washing plant with throughput of 900,000 tonnes, with the remaining 80 percent sold as-is. The analysis of SCEC coal is shown in **Table 7** below:

TABLE 7: ANALYSIS OF SCEC RAW AND WASHED COAL

	Ash content	Volatile content	Sulfur Content	Heating value
Raw coal	32-35%	9.5%	3.5-4.5%	4887 kcal/kg
Washed Coal	22-25%	9.3%	2 – 3.1%	5565 kcal/kg

Approximately half of SCEC's 2008 output was sold by the CQEIG to the Huaneng Luohuang 2600 MW power plant, the premier plant in Chongqing which was designed specifically to burn SCEC's high sulfur anthracite coal, and was the first plant in China to incorporate modern flue gas desulfurization technology. An additional 20 percent, including almost all of SCEC's washed coal output, went to the 440 MW Chongqing Power Plant located on the Yangzi River just upstream from the main urban district. Another 20 percent, consisting of the highest ash, lowest thermal value portion of its output, is dedicated to the 300 MW Anwen power plant majority owned and operated by SCEC itself. The remaining 10 percent has been sold at free market prices to industrial end-users such as cement plants in Chongqing and Sichuan.

SCEC's status as the primary dedicated supplier to Luohuang offers strong protection against sales risk for its coal even in the slackest of markets. At its full 2600 MW capacity, assuming a modest 5000 hours per year of operation, Luohuang would require approximately 5.5 – 6 million tonnes per year of 5000 kcal/kg coal. In 2008, SCEC was only able to supply about 2.5 million tonnes. Most of SCEC's planned expansion projects over the next 3-5 years – including the new 900,000 tonne per year Liyuanba mine, the 600,000 tonne per year Zhangshiba expansion of the Fengchun mine, and the 600,000 tonne per year expansion of the Shihao mine - have been designated, according to media reports and government documents, to supply the 2 x 600 MW Phase III units at Luohuang which came on-stream in 2006-2007.

Since all new power plants in Chongqing are equipped with domestically produced flue gas desulfurization units installed at modest costs, the high sulfur content of SCEC's coal will not be an obstacle to its use for power generation. Sulfur emission regulations for industrial users such as cement plants are likely to become stricter over time, but (a): these plants are not at present nor are they likely in future to be the main consumers of SCEC's coal, and (b): they too are more likely to add desulfurization capabilities than to reject local coal in favor of more expensive coal from other provinces.

This study makes the very conservative assumption, furthermore that the expansion projects mentioned above, as well as others designed to raise SCEC's output to 8.9 million tonnes will only reach their design capacity in 2015-2017. In short, we find little reason to doubt the ability of Chongqing and neighboring provincial markets to absorb an additional 3.8 million tonnes of coal of coal from SCEC over an eight-year period under almost any conceivable economic scenario.

4.1.2.1 Chongqing Market

Supply and Demand

Coal consumption in Chongqing climbed steadily with economic growth 2005-2007 to a reported 42.9 million tonnes. Power plants, reported by a number of different sources to have consumed about 15 million tonnes in 2007, are the most significant end-users, at approximately 35 percent of the total.

TABLE 8: ESTIMATED COAL CONSUMPTION AND PRODUCTION IN CHONGQING (MILLION TONNES)

	2005	2006	2007
Consumption (million tonnes)	33.3	37.4	40.8
- Power Plants	NA	12	15
- Steel	NA	NA	3.5
Production	36.2	39.9	42.9

Source: CESY 2008, p.92, 109; Chongqing Economic Commission 2007

Historically, the difficulties of transporting coal over the mountains from the north have forced Chongqing to rely primarily on its own coal production, despite the difficult mining conditions and the mediocre quality (high sulfur content in particular) of the Chongqing deposits. Coal production has climbed steadily with consumption in recent years to a reported 42.9 million tonnes in 2007, of which approximately 27 million came from "mines of scale" according to the Chongqing Statistics Bureau. Production from these mines of scale are estimated to have reached 32 million tonnes in 2008, of which 12.4 million originated from the five largest coal companies, including SCEC, owned by the Chongqing Energy Investment Group.

As many as 6 million tonnes per year produced in the remote Three Gorges reservoir counties to the northeast are shipped down the Yangzi by boat. The larger mines closer to metropolitan Chongqing also sell modest amounts outside the province, mainly to neighboring Sichuan. In 2008, Chongqing power plants purchased approximately two million tonnes from other provinces, approximately three quarters of which came from Shaanxi and Shanxi to the north, with the remainder entering from Guizhou to the south. Chongqing's steel mills purchased an additional 1-2 million tonnes of coking coal from outside the province.

Marketing of coal by the Chongqing Energy Investment Group

The Chongqing Municipal government, through the Chongqing Energy Investment Group, controls both the distribution and the pricing of 80-90 percent of the approximately 12 million tons of coal produced by the five mining companies under the Chongqing Energy Investment Group, including SCEC. This coal is allocated mainly to the municipality's large power plants and steel mills, but only fills a part (perhaps 50-75 percent) of their demand, the remainder of which is met by coal from smaller local mines or spot purchases from outside the province. Coal sold to other industrial users such as cement plants is sold primarily at market prices by mines other than those controlled by the CQEIG, in view of the consideration that, in contrast to the power plants, these facilities are free to adjust their sales price to cover coal purchase costs.

In 2008, the government controlled price for Chongqing Energy Investment Group power plant coal sold to power plants (most of them partially owned by the CQEIG itself) was 260 RMB per tonne (5000 kcal per kg), about half of the spot price in the first half of the year. This left little incentive for the CQEIG's mines to sell any coal in excess of target to the power plants, and was an important reason why the power plants faced coal shortages for the first half of 2008. For a period of time, the municipal government resorted to administrative measures to block the sale of coal produced in Chongqing (both CQEIG and local mines) to industrial users in neighboring provinces at spot market prices in order to ensure adequate supply for the power plants.

4.1.2.2 oal Market Risk

As in other parts of China, output of heavy industrial products such as power, steel, and cement began to decline during the fourth quarter of 2008. The consequent softening of overall coal demand is significantly narrowing the gap between controlled and spot prices, and is likely to make CQEIG sale of coal to power plants at planned prices more attractive to the coal suppliers than it has been in the recent past.

There is little chance, however that the softening of the market will cause the coal from the CQEIG mines to be displaced by newly available higher quality coal from outside of Chongqing. The delivered cost of northern coal in Chongqing was reported at approximately 480 RMB per tonne in December 2008, almost more than twice the controlled price of CQEIG coal; transport bottlenecks severely limit the quantity of northern coal that could enter Chongqing regardless of price.

High quality coal from Guizhou Province, a 120 million tonne producer due south of Chongqing is both more convenient with regard to transport and more price-competitive than northern coal. The CQEIG controlled price, however, will still be difficult for the Guizhou mines to match. The Chongqing power plants, furthermore, are designed to burn the Chongqing coal, largely negating the quality advantage of Guizhou coal. Finally, the municipal government will likely adopt administrative measures to protect the interests of its coal mines in times of stress, just as it has adopted coal price controls to protect the interests of its power plants during the sellers' market of 2007- 1st-half 2008.

4.2 Gas Market

Wholesale

1. Pipeline gas

Domestic natural gas wellhead and long-distance pipeline transport prices are determined by the central government's National Development and Reform Commission (NDRC) in Beijing. Typically, prices have been adjusted every 2-3 years. As of January 2009, the most recent across the board price adjustment took place in early 2006.

The NDRC indicated at the time that it intended to link domestic prices more closely to international prices, and to make annual adjustments based on international prices of a basket of fuels, including crude oil, coal, and LPG, but does not appear to have actually carried out these adjustments. It has suggested in late 2008 that it intends both to raise prices in 2009 and to try again, against a back-drop of temporarily lower international prices, to establish a price-fixing mechanism that ties the domestic price of natural gas more strongly both to costs and to the international price.

Wellhead prices from the major gasfields have traditionally been fixed according to both source and category of end user. The prices to non-industrial users and chemical fertilizer plants in **Table 9** below have been unchanged since 2006; prices to all other industrial users include an increase of 0.4 RMB per cubic meter in November 2007.

TABLE 9: CHINA WELLHEAD NATURAL GAS PRICES, JANUARY 2009

Field	**End-use**							
	Chemical Fertilizer		**Direct Sale to Industrial User**		**Sale to Municipal Distribution Companies**			
					Industrial end-uses		**Non-industrial end-uses**	
	RMB/m^3	**\$/mmbtu**	**RMB/m^3**	**\$/ mmbtu**	**RMB/ m^3**	**\$/ mmbtu**	**RMB/m^3**	**\$/ mmbtu**
Sichuan Chongqing	0.69	$2.81	1.275	$5.20	1.32	$5.38	0.92	$3.75
Changqing (Shaanxi-Inner Mongolia)	0.71	$2.90	1.125	$4.59	1.17	$4.77	0.77	$3.14
Qinghai	0.66	$2.69	1.06	$4.32	1.06	$4.32	0.66	$2.69
Xinjiang	0.56	$2.28	0.985	$4.02	0.96	$3.92	0.56	$2.28
Other	0.66	$2.69	1.32	$5.38	1.23	$5.02	0.83	$3.39

Source: NDRC (2005), NDRC (2007.3). Conversion to mmbtu assumes 6.8 RMB:dollar exchange rate, 38,000 KJ/m^3.

As they have historically, chemical fertilizer plants pay the lowest prices (0.56 – 0.71 RMB/m^3) in view of their importance to agriculture. Industry for now pays the highest wellhead prices after the November 2007 adjustment (0.96 – 1.32 RMB/m^3), but the central government is believed to be considering measures to raise wholesale prices to residential and commercial consumers by as much as 0.6 RMB per cubic meter in 2009 from 0.56 – 0.83 RMB per cubic meter, which would once again place them higher than industrial prices. The low relative prices for Xinjiang gas to all categories of end users seem set in part to counterbalance high pipeline transport costs to East China.

Pipeline costs have been fixed separately by the NDRC for each pipeline and are also differentiated by category of end user. For the West to East pipeline which extends 3,900 km from Xinjiang to Shanghai, the average prices range from 0.66 RMB per cubic meter in Henan Province (about three quarters of the way along the pipeline) to 0.84 RMB per cubic meter in Shanghai. Prices along the new Sichuan – Shanghai pipeline will reportedly be fixed so that the city gate price to Shanghai is the same as the West to East pipeline. The average pipeline cost from Chongqing to Wuhan (about 700 km) is 0.4 RMB per cubic meter; the cost to terminal cities on branches of this pipeline is 0.49 RMB per cubic meter.

City gate prices for pipeline gas range from as low as about 0.60 – 1.0 RMB per cubic meter (2.45 - $4.08 per mmbtu) near the Xinjiang gas field to as high as 1.54 – 1.76 RMB per cubic meter ($6.28 - $7.18 per mmbtu) in Shanghai, depending on end-use. In Chongqing, located adjacent to the Sichuan gas fields, the range is approximately 1 – 1.3 RMB ($4.08 - $5.30 per mmbtu). The prices for other cities along major pipelines lie between the Chongqing and Shanghai prices.

The move to imported pipeline gas through the 30 billion cubic meters per year second East to West pipeline will almost certainly have a strong upward impact on the Chinese natural gas price structure. Unofficial reports indicate that assuming an international oil price $60 per barrel oil, the delivered price of Turkmeni gas delivered to the Chinese border via the 1800 km pipeline through Uzbekistan will be 2.02 RMB per cubic meter (Xinhua, 2008). According to these same sources, the average delivery price to various city-gate offtake points along the route in eastern and southern China will be 3.1 RMB per cubic meter ($12.64 per mmbtu), which probably implies prices of at least 3.5 ($14.28 per mmbtu) at the more distant terminus points in East and South China.

Reports attributed to Burmese sources in October 2008 suggest that Burma would charge China a price in the vicinity of $9 per mmbtu (2.2 per cubic meter) for gas piped through the new pipeline to Yunnan and Guizhou provinces starting in 2012-2013 (Intellasia, 2008). The formula for linkage to the international price in the December 2008 sales contract is not clear.

2. Imported LNG

The China National Offshore Oil Company's initial long-term LNG import contracts in the early 2000s did not seriously upset the domestic price structure, as shown in **Table 10** below. The charge levied by the Dapeng Terminal in Guangdong based on these costs – 1.60 RMB per cubic meter, is comparable to the price of pipeline gas delivered from Xinjiang to Shanghai.

TABLE 10: IMPORTED LNG PRICES IN CHINA

Source	Price		Date Agreed	Comment
	$ per mmbtu	RMB/m^3 equivalent		
Australia to Dapeng Terminal, Guangdong	2.4	0.63	2003	25-year contract starting 2006 pegged to $20 per barrel oil with escalation capping $25 per barrel
Indonesia to Putian Terminal, Fujian	3.4	0.90	2006	25 year contract starting 2009, pegged to maximum $38 per barrel oil; renegotiated in 2006 from lower level, Indonesia trying to renegotiate further
Malaysia to Shanghai terminal	6	1.58	2006	Reportedly pegged to $60 per barrel oil with unknown price ceiling
Spot deliveries to Dapeng	18	4.76	2008	

Sources: International Herald Tribune, June 7, 2005; Energy Tribune November 10, 2008; Trading Markets October 8, 2008

Spot prices as high as $17-18 per mmbtu for an estimated 1 million tonnes of LNG in 2008 were a major shock to the system. The reported decline in spot market to $9.50 - $10.50 per mmbtu by end-year 2008 – which some speculate could drop further to $7-8 per mmbtu in 2009 – still represent a considerable premium over both the previous LNG contract import prices and domestic pipeline gas prices.

Likewise, the more recent long-term LNG contracts will probably represent significant increases over presently prevailing wholesale prices of China domestic pipeline gas. Already in October 2006, the CNOOC had agreed to pay Petronas (Malaysia) a reported $6 million per mmbtu (1.58 RMB per cubic meter – Trading Markets October 2008) pegged to the then prevailing international oil price of $60 per barrel. Chinese industry sources believe that the 25-year contracts signed with Qatargas and Shell in 2008 could be in the vicinity of $10-11 per mmbtu. The peg to international prices for these contracts, however, is not known, and a prolonged slump in oil prices (approximately $47 per barrel in March 2009) could reduce the impact of imported LNG on the Chinese wholesale price structure.

Retail Prices

Retail prices charged by distribution companies to their customers are controlled by local governments at either the provincial, or more usually the municipal level. In principle, prices are designed to recover both the wholesale costs paid to pipeline companies or LNG terminals and the local transmission/distribution costs. Many cities have put in mechanisms to automatically pass through increases in wholesale costs. Intense competition for distribution rights among municipal utilities, companies owned by the upstream suppliers CNPC and Sinopec, domestic private companies such as Xin'ao and Chinagas, and even foreign companies such as the Hong Kong giant Hong Kong gas suggests that natural gas distribution yields a positive return, especially in areas that are receiving access to gas for the first time.

In view of higher distribution costs to large numbers of small users, most local distribution companies strive to charge more to residential customers than to industrial customers. The 0.4 RMB per cubic meter increase in wholesale costs for industrial-use gas of November 2007, however, raised industrial prices in some areas higher than residential prices (by 20-50 percent in Shanghai, for example). Prices to commercial users such as stores, restaurants, etc. tend to be highest of all, given their lack of political influence.

TABLE 11: NATURAL GAS RETAIL SALES PRICES, CHINESE CITIES

Location	Natural Gas Price, Residential Use (RMB/m^3)	Principal Gas Source
Ji'an, Jiangxi	5.3	Imported or small scale domestic LNG
Small-medium cities in Guangdong	4.2 – 4.7	Imported or small scale domestic LNG
Nanning, Guangxi	4.6	Domestic LNG
Guilin, Guangxi	4.0	Imported or small-scale domestic LNG
Foshan, Guangdong	3.85	Imported LNG
Shenzhen, Guangdong	3.5 – 4.0	Imported LNG
Guangzhou, Guangdong	3.45	Imported LNG
Qinhuangdao, Hebei	3.38	Shaanxi-Beijing-Shenyang pipeline; domestic LNG
Kaili, Guizhou	3.18	Domestic LNG (Hainan)
Shanghai	2.5	West to East pipeline
Wuhan, Hubei	2.3	Chongqing – Wuhan pipeline
Changsha, Hunan	2.33	Chongqing – Wuhan pipeline
Nanjing, Jiangsu	2.2	West to East Pipeline
Beijing	2.05	Jingbian-Beijing pipeline
Zhengzhou, Henan	1.9 – 2.2	West to East Pipeline, local oilfield

Location	Natural Gas Price, Residential Use (RMB/m^3)	Principal Gas Source
Xian	1.75	Jingbian-Xian pipeline
Chongqing	1.4	Local gasfields

Sources: Xinhuanet November 11, 2008; Xinhuanet July 15, 2005: Sina News Center June 6, 2005; Xinhuanet August 31, 2006; Shenzhen Gas November 25, 2008; Guilin Evenings News January 4, 2009; Sina News January 4, 2009; Sou Fun March 15, 2006; Ji'an Net March 31, 2008; China Energy Net July 3, 2008; Beijing Zhenbao December 14, 2006; Guangzhou Daily News December 31, 2008; Yanzhao Du Daily, June 18, 2007; East Guizhou News Bulletin (2006)

As **Table 11** shows, prices to residential users vary considerably by region. Lowest prices are found in areas closest to domestic gas fields such as Chongqing, with residential use price at year-end 2008 of 1.4 RMB per cubic meter. Cities served by long-distance domestic pipelines occupy the next tier, with prices to residential consumers in the range of 2.0 – 2.5 RMB per cubic meter (Beijing, Shanghai, Nanjing, Wuhan, Changsha, etc). Residential users in cities in Guangdong and Fujian receiving LNG imported under long-term contracts signed in the in 2002 and 2004 pay still higher prices (3.45 – 3.8 RMB per cubic meter in Guangdong).

The highest prices of all are paid by cities that have access neither to pipeline nor to long-term contract LNG, and are dependent either on intermittent spot imports of LNG or domestic LNG transported over long distances (see below). Industry sources indicate that residential users in smaller cities in coastal Guangdong pay as much as 4.8 RMB per cubic meter. Certain cities in poorer land-locked provinces, such as Guangxi or Jiangxi also pay prices of this magnitude. The prices in some of these cities could fall as they obtain access to gas from the new Sichuan-Shanghai, second West to East (Central Asian), and Burma-China pipelines. But a number of them will continue to depend to some extent on long distance transport of imported or domestic LNG.

Role of Small Domestic LNG Plants

The rudimentary nature of the long distance pipeline network in China, together with certain peculiarities of the pricing system have stimulated the construction of at least 10 small–scale LNG plants of the order of magnitude under consideration by SCEC (50,000 – 400,000 tonnes per year, or 70-560 million cubic meter equivalent). Most appear to be privately owned, some by companies specializing in municipal gas distribution. Product is transported by tanker truck, in some cases over thousands of kilometers; domestic LNG from Xinjiang in the far northwest has moved as far as the east coast and Nanning city in Southwest China. For some cities in China at present, these small plants constitute the only available source of supply.

The output of the small domestic LNG plants is not subject to the wholesale price controls imposed by the government on pipeline gas, and is sold at market prices. Many of their owners, however, gained access to pipeline or wellfield gas allocated to local governments at controlled prices by the state-owned major producers under political arrangements. In an attempt to crack down on this price arbitrage, the NDRC banned the construction of additional LNG plants processing gas originating from the fields of the state-owned producers starting from late 2007, and allowed the gas producers to negotiate market-based supply contracts with plants that had already begun construction (NDRC, 2007.3).

LNG Plants processing either virgin coalbed methane (CBM) or coalmine methane (CMM), however, appear to be exempted from the ban on new construction. The gas distribution company Xin'ao owns one CBM LNG plant in Shanxi Province, and will be the offtaker for another plant in Shanxi that is applying for a loan from the World Bank. The Jincheng Anthracite Group and the Hong Kong Gas utility are building yet another CBM liquefaction plant in the same area. A pilot-scale plant employing domestic Chinese technology will purify and liquefy CMM in Yangquan, Shanxi. Small scale LNG plants in China are described in **Table 12** and shown in **Figure 18**.

TABLE 12: SMALL SCALE LNG PLANTS

Location	Owner	Scale (tpy)	Technology Supplier	Date On-stream	Customers
Gansu Lanzhou	Lanzhou Gas and Chemical Group	120,000	Chemtex/Black and Veatch	2010	Peak natural gas supply for local gas distribution utility
Guangdong Zhuhai	CNOOC/Zhuhai	120,000	Chemtex/Black and Veatch	2008	Either Guangdong local or Shanghai
Guangxi Beihai	Xin'ao Gas	50,000	Kryopak (New Braunfels, TX)	2006	Around SW China; Guilin, Zhaoqing, Dongguan, Shantou
Hainan Fushan	Hainan Hairan High Tech Energy Company	50,000	Propak (Canada)	2005	Guizhou Province and other

Location	Owner	Scale (tpy)	Technology Supplier	Date On-stream	Customers
Inner Mongolia Ordos City	Xingxing Energy	200,000	Chemtex/Black and Veatch	2008-2009	Qinhuangdao City, Hebei
Shanxi Jincheng (coalbed methane)	Jincheng Anthracite Mining Group/Hong Kong Gas	70,000	NA	2008	Hong Kong Gas Distribution Companies
Shanxi Jincheng (coalbed methane)	Shanxi Energy Investment Group	250,000	NA	2011	Xin'ao
Shanxi Jincheng (coalbed methane)	Xin'ao Gas	30,000	Chinese Technology	2008	Xin'ao owned distribution companies
Sichuan Dazhou City	Huifeng Energy/ Ordos Xingxing	200,000	Chemtex/Black and Veatch	2008-2009	Guizhou Province
Shaanxi Jingbian County	Xian Blue Sky Energy	100,000	Chemtex/Black and Veatch	2009	Xian City, probably Henan
Xinjiang Shanshan County	Guanghui New Energy Company	150,000	Linde	2004	Gas moved in rail containers
Xinjiang Kuche County	Guanghui New Energy Company	400,000	Chemtex/Black and Veatch	2009	All over

Sources: TianshanNet May 16, 2006; Hainan Government December 13, 2006; Xin'ao June 29, 2004; China Bidding February 25, 2009; private communication from Chemtex Company; private communication from Shanxi Energy Enterprise Company; Sichuan Daily December 9, 2008; Ordos Daily December 12, 2008; Yanzhao Du Daily, April 30, 2007; Yanzhao Du Daily June 18, 2007; Sina News April 6, 2007

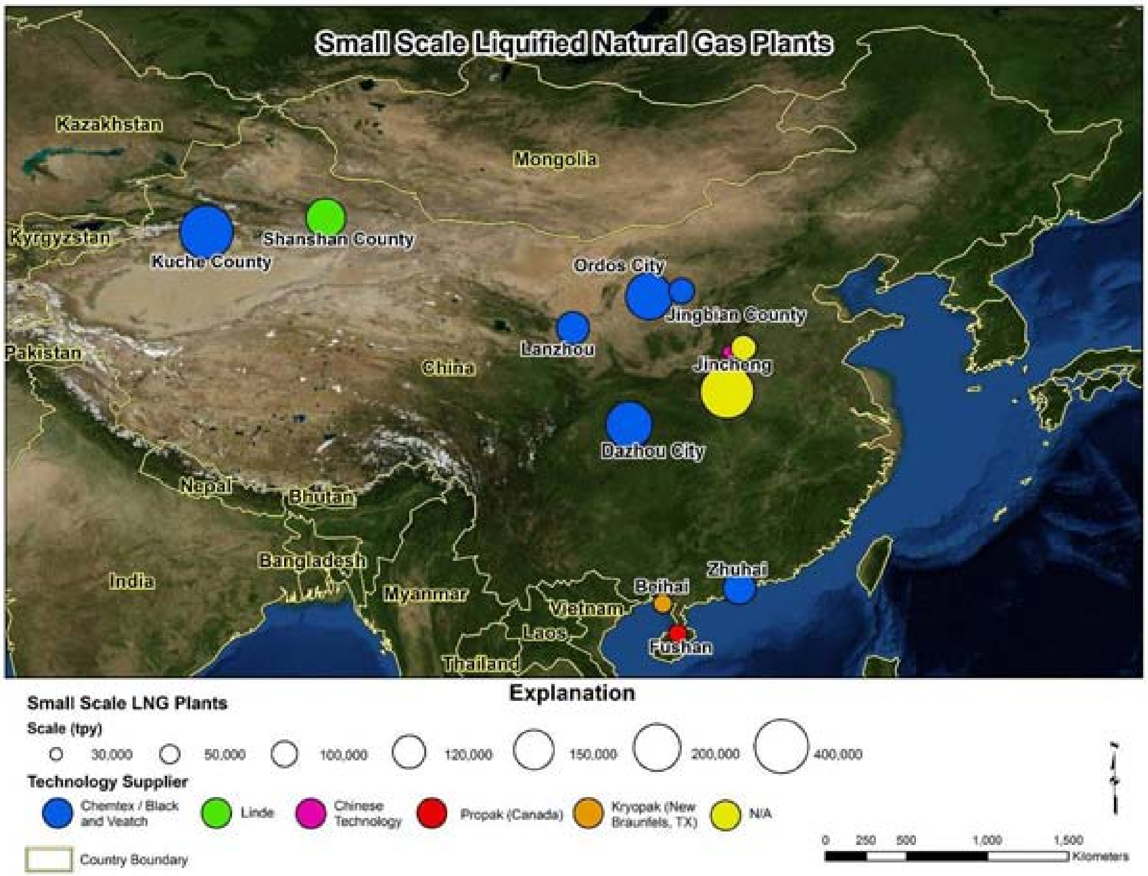


FIGURE 18: SMALL SCALE LNG PLANTS

4.2.1 Market for SCEC's CMM

4.2.1.1 Recent Trends in China's Natural Gas Market

After decades of stagnation, the natural gas market in China has experienced a surge of historic proportions in recent years. Production and consumption grew at average annual rates of 12 percent and 13 percent respectively 1995-2008, and by over 16.5 percent 2003-2008. **Table 13** and **Figure 19** show China's natural gas market development by sector.

TABLE 13: CHINA NATURAL GAS MARKET DEVELOPMENT, 1995-2008

	Production	LNG Imports	Exports	Consumption (million
1995	17,900	NA	NA	15,253
2000	27,200	NA	3,140	23,531
2001	30,300	NA	3,040	NA
2002	32,700	NA	3,200	27,544
2003	35,000	NA	1,873	34,829
2004	41,500	NA	2,440	40,798
2005	49,300	NA	2,970	46,474
2006	58,539	698	2,900	56,141
2007	69,310	2,931	2,600	69,523
2008	76,000	3,336	2,900 (est)	75,000 (est)

Sources: CESY (2008), p. 75, 105, NBSC (2007), China Customs (2009.2). (est) indicates estimated.

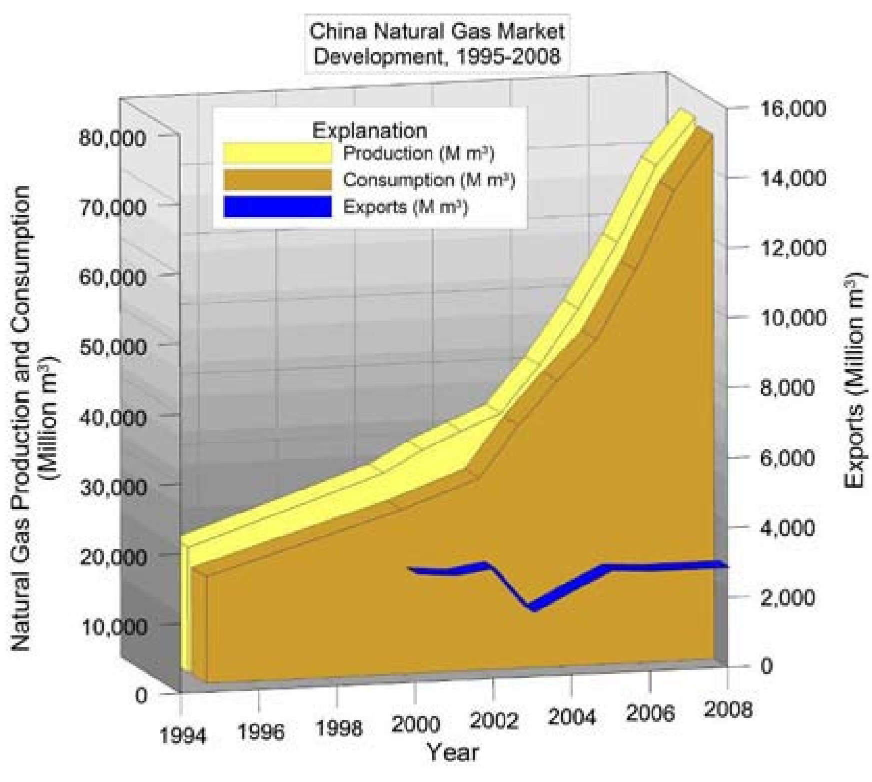


FIGURE 19: CHINA NATURAL GAS MARKET DEVELOPMENT, 1995-2008

Prior to the mid-1990s, natural gas consumption in China was restricted to Sichuan Province, the location of the only major on-land gasfields developed at that time, and to areas in the vicinity of major oilfields which burned small volumes of recovered associated gas. Almost 90 percent of the gas was used in industry, primarily as a raw material in ammonia/urea plants and as fuel for the oil and gasfields themselves.

The key to the expansion over the past decade has been the decision of the Chinese central government, acting through the two land-based state-owned oil and gas producers China National Petroleum and Natural Gas Corporation (PetroChina) and China National Petrochemical Corporation (Sinopec) and the state-owned banking system, to aggressively develop gasfields in remote areas of western part of China and, for the first time in the country's history, to build long-distance pipelines to connect these sources (as well as the existing Sichuan gasfields) to major population and industrial centers in the eastern part of the country. As a direct result, some of China's largest cities, including Beijing, Shanghai, Nanjing, Wuhan, Changsha, Xian, and Lanzhou as well as numerous smaller and medium sized cities in the surrounding provinces are burning natural gas for the first time. A third government-owned company China National Offshore Oil Corporation (CNOOC) has completed two large LNG import terminals which have inaugurated the use of natural gas in urban areas of the southern coastal provinces of Guangdong and Fujian.

TABLE 14: CHINA MAJOR LONG-DISTANCE GAS PIPELINES, 1995-2007

Pipeline	Length (km.)	Design Capacity (million m^3)	Gas Source	Date in Operation
Jingbian County (Shaanxi) – Beijing	853	3,500	Changqing (Shaanxi – Inner Mongolia)	1997
Jingbian County (Shaanxi) – Beijing Number 2	935	12,000	Changqing (Shaanxi – Inner Mongolia)	2006
Jingbian County (Shaanxi) – Xian	488	1,000	Changqing (Shaanxi – Inner Mongolia)	1997
Jingbian County (Shaanxi) – Xian	476	1,500	Changqing (Shaanxi – Inner Mongolia)	2005
Sebei – Golmud (Qinghai)	190	700	Sebei Field, Qinghai	1996
Sebei – Xining (Qinghai) - Lanzhou (Gansu)	953	2,000	Sebei Field, Qinghai	2001
"West to East"	3,900	12,000 (original)	Tarim Basin,	2005

pipeline: Xinjiang - Shanghai		17,000(expanded)	Xinjiang, and Changqing	2009
Yizheng (Jiangsu) – Anping (Hebei) connector pipeline	886 (1498 including branches)	9,000	West to East and Second Jingbian-Beijing pipelines	2006
Chongqing – Wuhan	695	3,000	Sichuan Gasfields	2005
Huaiyang (Henan) – Wuhan connector pipeline	475	1,500	Chongqing-Wuhan and West to East pipelines	2007

Sources: Xinhuanet December 12, 2001; China Central Government Website December 16, 2006; Yangzi Evening News December 31, 2005; China Oil and Gas Pipeline Website March 29, 2004; China Oil Network Website September 22, 2005; General Electric Company November 24, 2008; China Daily August 5, 2005

TABLE 15: CHINA OPERATING LARGE-SCALE LNG RECEIVING STATION PROJECTS

Location	Capacity	On-stream	Gas Source	Gas Use
Fujian	2.6 million tonnes (3.5 billion m^3 equivalent)	2008	Indonesia	Three large power plants (65%); municipal distribution in 5 cities (35%)
Shenzhen	3.7 million tonnes (5 billion m^3 equivalent)	2006	Australia	Five power plants (70%); municipal distribution in Guangzhou, Shenzhen, Dongguan, Foshan (30%)

Sources: ChinaPower July 4, 2006; People's Daily Online, June 29, 2006; Xinhuanet September 12, 2004; WhatsonXiamen May 9, 2008

While the traditional chemical/fertilizer raw material end-use maintained its 33 percent share of total gas consumption from 1995-2005, it is clear that increased supply is opening up new markets for natural gas in China, in particular:

- *Residential and commercial use:* these two categories combined accounted for over 21.7 percent of consumption in 2007, compared to only 11 percent in 1995, and the percentage continues to increase.
- *Power plant fuel:* gas-fired combined cycle power plants with at least 20,000 MW of capacity are coming on-stream in the 2005-2010 period, which if run at 3500 – 4000 hours per year as planned, will consume an average 15 billion cubic meters of gas per year. Gas-

fired combined cycle power plants will account for more than half of the consumption of the two operating LNG terminals in Guangdong and Fujian provinces.

- *Cement manufacture:* consumption as fuel in "non-metallic minerals" manufacture, which in China means mainly cement, rose more than 10-fold to about 2 billion cubic meters (4.5 percent of total national consumption) in the period from 1995 to 2007.

Table 16 below and **Figures 20, 21, 22, and 23** show China's natural gas consumption by sector for years 1995, 2000, 2005, and 2007.

TABLE 16: CHINA: NATURAL GAS CONSUMPTION BY SECTOR (MILLION CUBIC METERS)

	1995		**2000**		**2005**		**2007**	
	Volume	%	Volume	%	Volume	%	Volume	%
TOTAL	**17,741**	**100.0%**	**24,503**	**100.0%**	**46,763**	**100.0%**	**69,523**	**100%**
INDUSTRY	**15,439**	**87.0%**	**20,200**	**82.4%**	**35,379**	**75.7%**	**50,967**	**73.3%**
Mining	***5,187***	***29.2%***	***7,302***	***29.8%***	***8,799***	***18.8%***	***9,632***	***13.9%***
Petroleum Extraction	5,058	28.5%	7,288	29.7%	8,346	17.8%	9,108	13.1%
Manufacturing	***10,080***	***56.8%***	***12,081***	***49.3%***	***23,921***	***51.2%***	***33,321***	***47.9%***
Petroleum Processing and Coking	1,514	8.5%	1,342	5.5%	1,952	4.2%	2,652	3.8%
Chemical Manufacturing	6,336	35.7%	9,032	36.9%	15,443	33.0%	22,343	32.1%
Non-metallic mineral manufacturing	227	1.3%	250	1.0%	2,604	5.6%	3,125	4.5%
Iron and Steel Making	369	2.1%	171	0.7%	1,068	2.3%	1,422	2.0%
Nonferrous Metals	50	0.3%	50	0.2%	423	0.9%	579	0.8%
Transport Equipment	66	0.4%	171	0.7%	537	1.1%	715	1.0%
Electronic Equipment	101	0.6%	341	1.4%	522	1.1%	666	1.0%
Utilities	***172***	***1.0%***	***817***	***3.3%***	***2,660***	***5.7%***	***8,013***	***11.5%***
Electricity and Heat	114	0.6%	644	2.6%	1,881	4.0%	7,078	10.2%
Gas distribution	58	0.3%	171	0.7%	772	1.7%	927	1.3%

TRANSPORT, STORAGE, POST	**157**	**0.9%**	**581**	**2.4%**	**1,301**	**2.8%**	**1,689**	**2.4%**
COMMERCIAL	**55**	**0.3%**	**344**	**1.4%**	**1,079**	**2.3%**	**1,711**	**2.5%**
RESIDENTIAL	**1,941**	**10.9%**	**3,232**	**13.2%**	**7,943**	**17.0%**	**13,339**	**19.2%**
OTHER	**147**	**0.8%**	**146**	**0.6%**	**1,061**	**2.3%**	**1,609**	**2.3%**

Source: CESY (2008), pp. 104 - 105

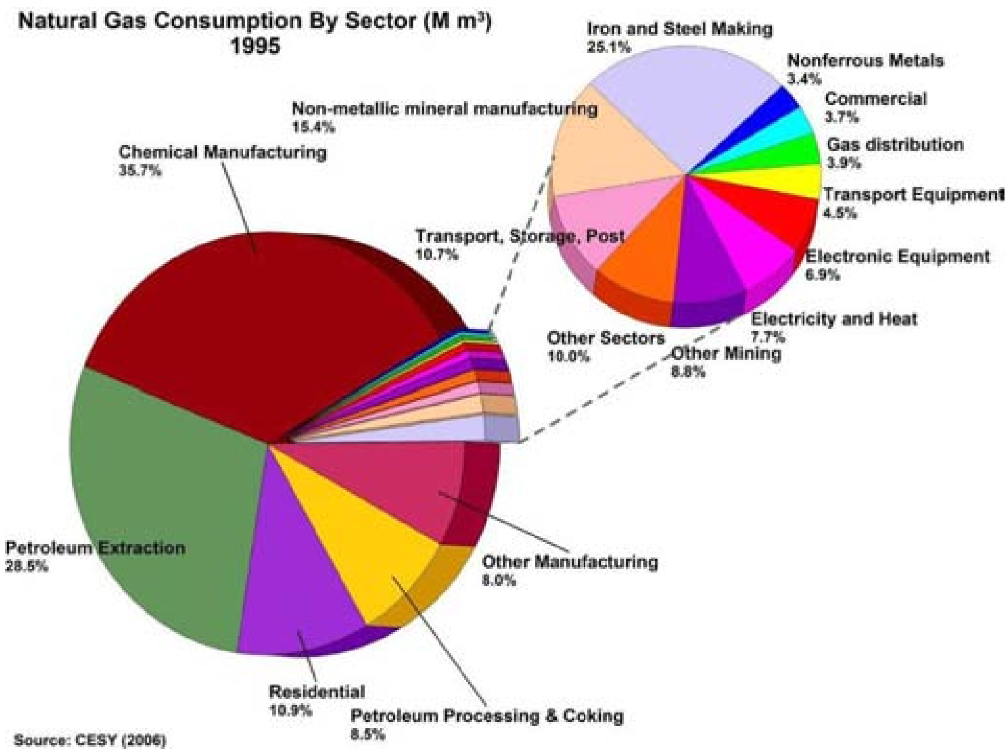


FIGURE 20: CHINA'S NATURAL GAS CONSUMPTION BY SECTOR, 1995

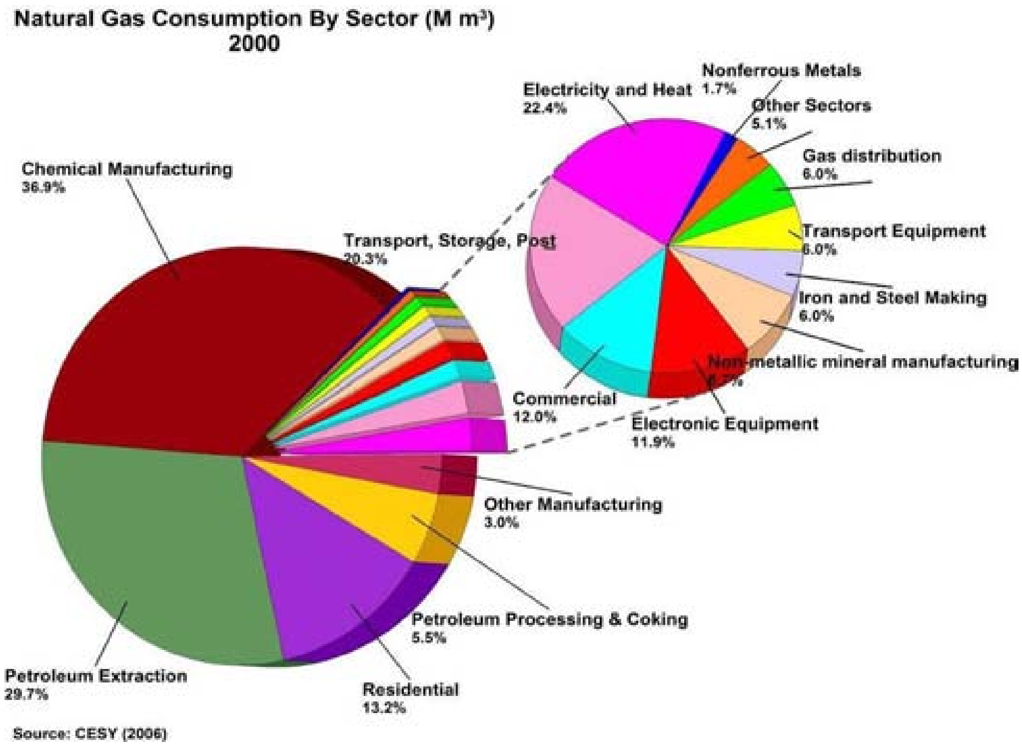


FIGURE 21: CHINA'S NATURAL GAS CONSUMPTION BY SECTOR, 2000

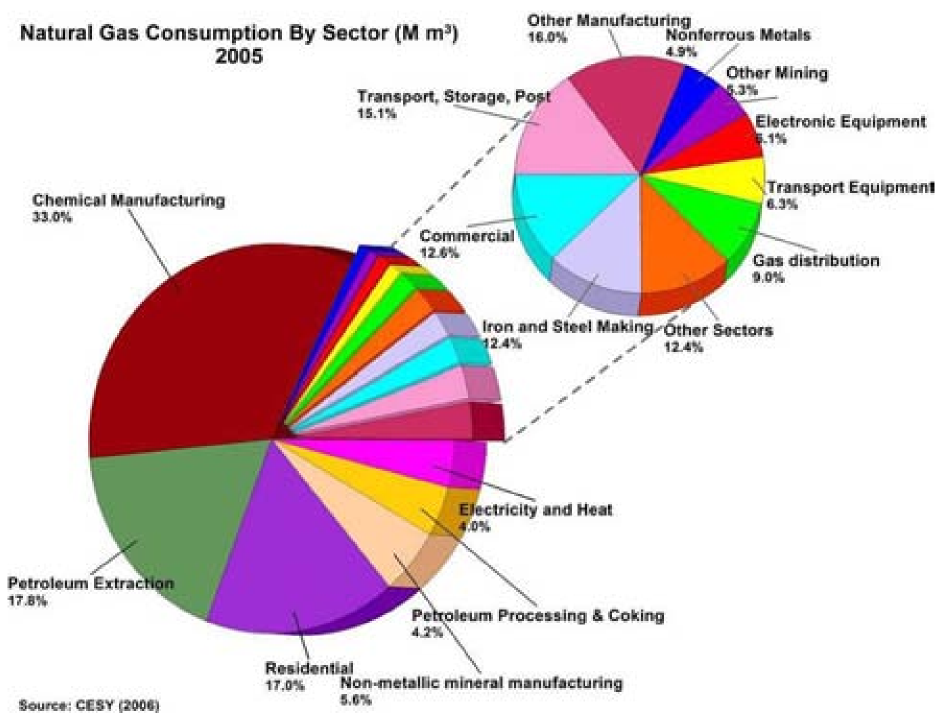


FIGURE 22: CHINA'S NATURAL GAS CONSUMPTION BY SECTOR, 2005

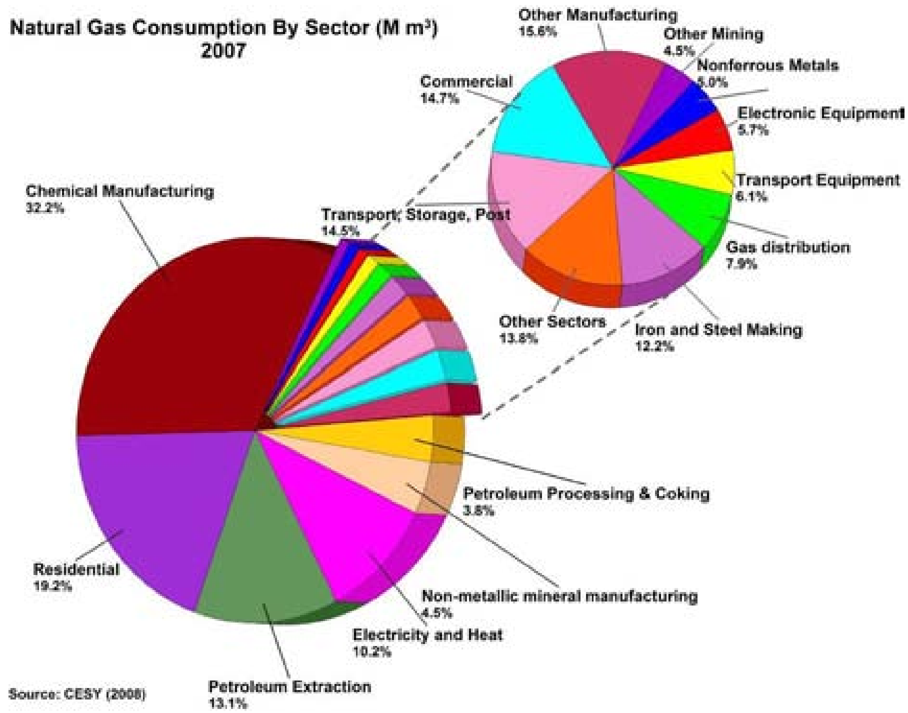


FIGURE 23: CHINA'S NATURAL GAS CONSUMPTION BY SECTOR, 2007

4.2.1.2 Future Demand

Official and semi-official projections call for China's natural gas consumption to increase to 100-110 billion cubic meters in 2010, and to 200 billion cubic meters by 2020, implying a steady growth of approximately 10 billion cubic meters per year. Shanghai and Beijing gas company authorities' project that demand in these two cities alone – which, are already well-served with natural gas in relative terms - will rise by an aggregate 19.3 billion cubic meters between 2007 and 2020.

Central Government Policy

The central government has been strongly motivated by the local and global environmental advantages of natural gas to increase its percentage of the energy mix relative to other fuels. The country's 11th Five-year plan (2006-2010) calls for natural gas to rise from 2.8 percent of total primary energy consumption in 2005 to 5.3 percent in 2010, and for coal to fall from 69.1 percent to 66.1 percent (NDRC, 2006.3).

As of 2007, gas had only risen to 3.4 percent of the national primary energy total. This represented a failure to contain growth in coal consumption during years of double digit economic growth led by energy intensive heavy industries, rather than any slowdown in gas development. Possibly, as coal consumption moderates in reaction to heavy industrial slowdown starting from second half of 2008, the gas ratio of primary energy will rise at a more rapid rate in coming years.

Government sources have expressed the hope of increasing the percentage of primary energy coming from natural gas to 8-10 percent by 2020. Even this growth would leave China well short of the 23-25 percent level prevailing at present in the United States and the European Union.

A white paper issued by the NDRC in August 2007 outlines in some detail the sectors in which natural gas substitution for other fuels is most encouraged:

- Cooking and hot water heating for urban residents
- Use in government offices, commercial enterprises, and public facilities
- Transport/automotive (compressed natural gas)
- Distributed district heating/air conditioning

Second tier priorities include:

- Centralized space heating and air conditioning in big cities, as well as individual residence space heating
- Substitution of natural gas for petroleum products or coal gas as an industrial fuel
- Peak regulation power stations in areas where natural gas is readily available

In a break with over 30 years of previous government policy, the White Paper recommends sharply curtailing construction of new chemical fertilizer plants using natural gas as a raw material, and for completely banning new natural gas-derived methanol plants (NDRC, 2007.5).

Demand Pull from the Residential Sector

Now that government policy actively encourages residential use of natural gas and significant numbers of urban residents are finally experiencing the environmental benefits and the convenience of natural gas relative to competing household fuels, such as liquefied petroleum gas, coal gas, and coal, demand for residential natural gas use is rising rapidly. Local governments in all areas of the country are scrambling to obtain access to natural gas, and private as well as publicly owned natural gas distribution networks are sprouting up in cities all over the country.

Of the estimated 577 million people living in Chinese cities, suburbs, and towns, only 102 million had access to natural gas at year-end 2005. Entire provinces, such as Guizhou, Yunnan, Guangxi, Jiangxi, and Fujian offered virtually no gas to their urban residents, and even highly developed provinces such as Guangdong and Jiangsu only offered gas to 18 and 6.6 percent of their respective city and town dwellers.

In the municipality of Chongqing, households connected to gas consumed an average of 70 cubic meters per connected resident per year in 2007. Projected across the approximately 475 million unconnected city and town dwellers, this implies unmet urban residential demand in the vicinity of at least 33 billion cubic meters per year.

This figure does not factor in either the use of natural gas for space heating in colder parts of China (little gas is used for space heating in Chongqing homes), or increasing urbanization over time; the current national urbanization ratio is reported to be 43.9 percent of the national population, with growth in the vicinity of 1 - 1.2 percent per year. Nor does it include commercial consumption, which in Chongqing was an additional 27 percent on top of residential consumption in 2007. When these additional factors are considered, it seems reasonable to assume that the level of unmet demand in the residential/commercial sector combined is at least 50 billion cubic meters nationally.

Table 17 shows China's urban population with access to natural gas by province. **Figure 24** shows China's population distribution and **Figure 25** graphically displays the information from **Table 17.**

TABLE 17: CHINA URBAN POPULATION WITH ACCESS TO NATURAL GAS, 2005 & 2007

Province	Population ('000)	Urban Population ('000)	Total Natural Gas Consumption (all uses, million m^3)		Population with access to natural gas ('000)	
			2005	2007	2005	2007
Anhui	61,180	23,677	85	403	2,078	3,285
Beijing	13,820	11,556	3,204	4,664	8,800	10,090
Chongqing	28,080	13,113	3,550	4,353	5,090	6,402
Fujian	35,810	17,440	51	48	0	200
Gansu	26,172	8,268	962	1,297	1,176	1,449
Guangdong	94,490	59,623	249	4,569	785	3,986
Guangxi	47,680	17,280	112	134	5	397
Guizhou	39,755	11,227	544	514	17	87
Hainan	7,870	3,526	2,097	2,340	211	328

Province	Population ('000)	Urban Population ('000)	Total Natural Gas Consumption (all uses, million m^3)		Population with access to natural gas ('000)	
			2005	2007	2005	2007
Hebei	67,440	22,690	914	1,205	1,420	3,188
Heilongjiang	38,240	20,611	2,443	3,070	1,037	1,363
Henan	92,560	29,940	2,371	3,314	3,987	4,691
Hubei	60,280	26,330	611	863	2,639	3,811
Hunan	68,057	27,529	100	584	616	2,068
Inner Mongolia	24,490	12,061	635	2,651	496	1,491
Jiangsu	74,380	38,603	1,362	4,458	3,804	6,999
Jiangxi	43,391	16,784	11	104	384	598
Jilin	27,298	14,512	618	647	1,669	1,817
Liaoning	42,380	24,770	1,481	1,424	5,666	6,573
Ningxia	5,620		663	899	341	547
Qinghai	5,516	2,210	2,211	2,025	326	697
Shaanxi	36,050	14,103	1,876	4,134	3,588	4,006
Shandong	90,790	41,854	1,789	2,333	3,813	7,604
Shanghai	16,740	14,848	1,872	2,778	5,219	6,965
Shanxi	33,926	14,938	324	691	502	1,654
Sichuan	81,270	28,932	8,952	11,215	9,665	9,601
Tianjin	9,489	5,710	904	1,427	4,115	5,956
Tibet	2,620				154	
Xinjiang	20,500	7,778	5,646	6,981	2,204	3,072
Yunnan	44,830	13,673	612	549	49	570
Zhejiang	46,770	26,425	225	1,809	1,189	3,000
Total	**1,287,494**	**570,011**	**46,474**	**71,483**	**71,045**	**101,898**

Sources: China Today (2005), NBSC (2007), CESY (2006)

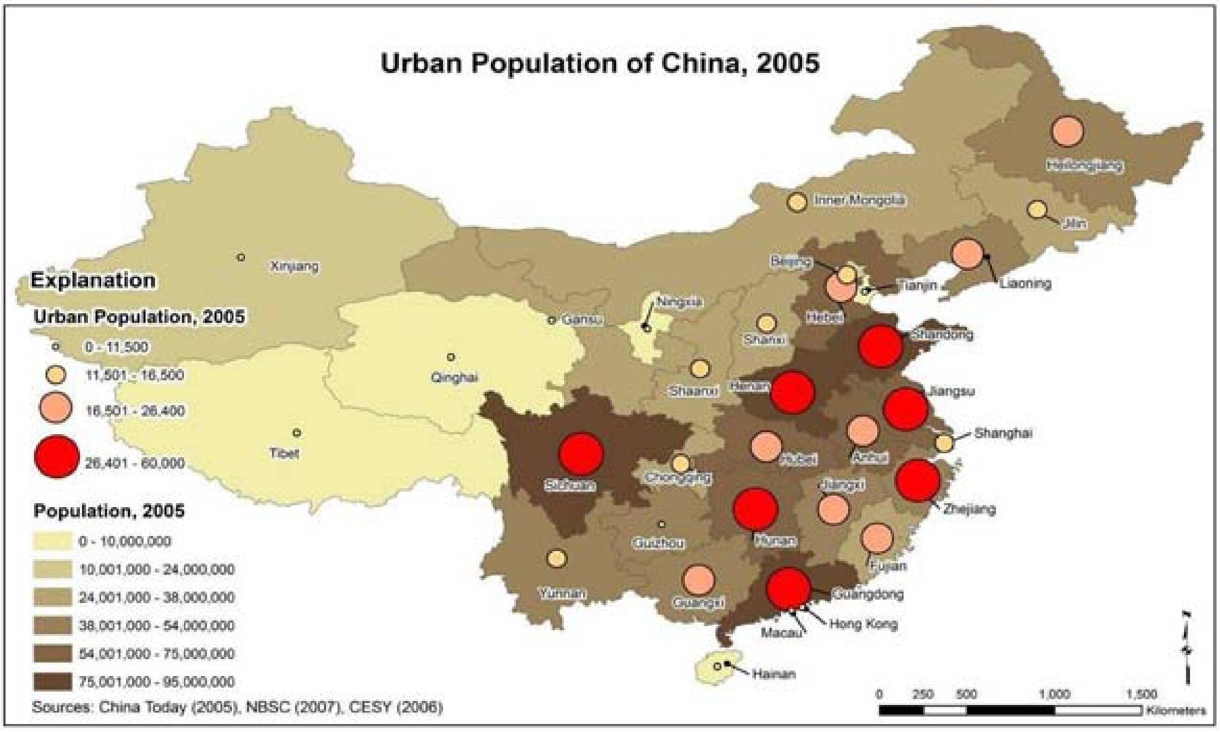


FIGURE 24: URBAN POPULATION OF CHINA

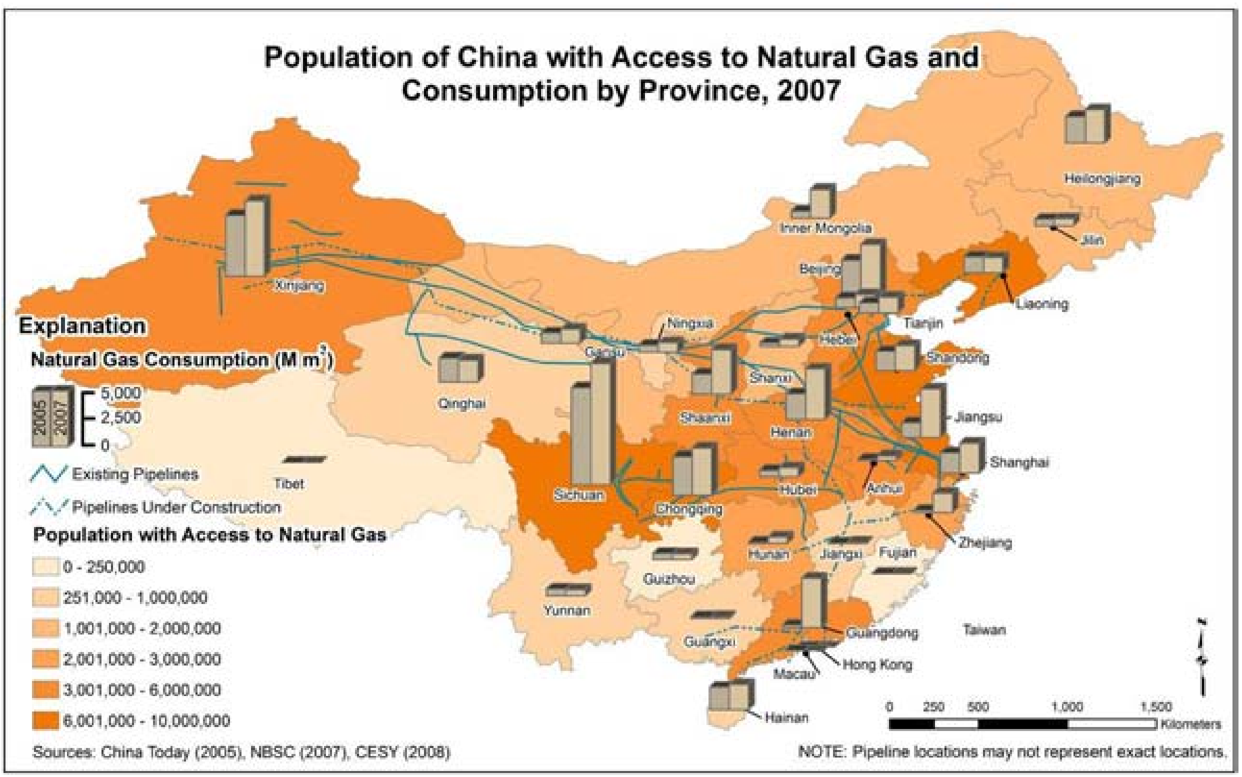


FIGURE 25: POPULATION OF CHINA WITH ACCESS TO NATURAL GAS AND CONSUMPTION BY PROVINCE, 2007

At least thus far, price has not been a deterrent to household natural gas consumption. This is in part a function of price controls at both the wholesale and retail level (see Section 4.2 above) that have kept the price to consumers in much of the country in the range of 2 – 2.5 RMB per cubic meter ($8.16 – 10.20 per mmbtu assuming 38,000 kilojoules per cubic meter and 6.8 RMB per dollar), competitive with the prices of competing fuels such as coal gas and liquefied petroleum gas. But residential consumers in some southern coastal cities and even certain small interior cities have paid up to 3.5 – 4.5 RMB per cubic meter ($14.27 - $18.36 per mmbtu), reflecting local scarcities and high costs of imported LNG in 2007-2008. Assuming a per household consumption of approximately 230 cubic meters per year as is the case at present in Chongqing, even these price levels only translate to 805 – 1035 RMB ($118 - $152) per household per year, which remains a relatively small percentage of urban disposable income.

Demand from Other Sectors

Industrial Fuel

As noted above, the central government's 2007 white paper on natural gas use called for substitution of natural gas for fuel oil and coal gas in industry where possible. In 2005, Chinese industry consumed a reported 19.8 million tonnes of fuel oil (CESY 2008, p. 103); if the thermal value of number 6 fuel oil is assumed to be 42,390 kj/kg, and that of natural gas 38,000 kj/m^3, this implies a potential market size of order of magnitude 20 billion cubic meters of gas from fuel oil substitution. Anecdotal evidence suggests that this shift is gradually taking place, particularly in oil refineries themselves.

Provincial and sub-provincial governments are also applying pressure on local industry to convert from coal or coal gas to natural gas fuel in order to improve air quality. Just one enterprise – the Yaohua Glass Company in Qinhuangdao, Hebei Province - will consume 400 million cubic meters of natural gas by 2011 after making the switch.

Planners of the 30 billion cubic meters per year Central Asia – China gas pipeline (see below) assume that close to 30 percent of its throughput will be consumed as an industrial fuel as similar conversions take place (Xinhua, 2008). As with residential use, supply is the only limit to increased use of natural gas as an industrial fuel.

Power Sector

Combined cycle electric power plants have been an important source of demand for natural gas over the last five years, accounting for at least half of the allocation of the first West to East pipeline, and for about two thirds of the allocation from the first two LNG terminals in operation in Guangdong and Fujian. They appear unlikely, however to play as important a role in new demand over the coming 3-5 years.

Over 20,000 MW of large combined cycle power plants were built in the 2005-2008 period, driven both by acute power shortages, and by central and local government concern that there be firm offtakers for the gas coming through the new pipelines and LNG import terminals. All indications are that the unexpectedly strong demand in the residential/commercial sector has increased the willingness of municipal distribution company offtakers to commit to pipeline companies for future projects, and lessened the pressure to construct new combined cycle power plants simply to ensure the success of the pipelines. The China National Petroleum Corporation projects that only about 15 percent of the throughput from the new Central Asia-China pipeline will be sold to power plants (Xinhua, 2008).

The high price of gas relative to coal (at 400 RMB per tonne for 5000 kcal/kg coal and 1.5 RMB per cubic meter of gas, coal is approximately 40 percent cheaper than gas per kwh) has led the grid to use them as peak regulation plants producing at 3500-4000 hours per year, rather than base-loaded plants, despite their high thermal efficiency. The rapid run-up in coal prices of first half 2008 may have closed this gap in some places, but the decline of second half 2008 has almost certainly restored it.

The overall softening of the Chinese power market (see **Section 4.3.1.1** of this report) in late 2008 may also act as a further inhibitor on the construction of new combined cycle power plants in the near term. A return to rapid growth for combined cycle power plants will likely require a change in economics of gas relative to coal and/or a stronger environmental commitment by the government to substitute for coal-fired power.

Automotive Sector

The NDRC listed automotive fuel as one of the encouraged uses of natural gas in its 2007 white paper. In Chongqing, where gas is relatively abundant, the automotive sector accounted for over five percent of total gas consumption in 2007; virtually all taxicabs in the city operate on compressed natural gas. Favorable pricing relative to gasoline appears to be the main driver behind CNG use, and growth in this sector will depend on the price relationship between the fuels in the future. The central government has indicated a desire that the price of CNG be at least 75 percent of that of gasoline on a heat value basis in order to avoid excessive diversion of natural gas to the automotive sector (NDRC 2007.3).

Impact of Economic Slowdown on Natural Gas Demand

Insufficient data is available as of early 2009 to assess the impact on natural gas demand of the slowdown in the rate of economic growth caused by the sudden contraction in exports associated with the world economic crisis, augmented by the drop in production of heavy industrial materials such as metals caused by a policy-induced slowdown in real estate investment. These events have had an obvious adverse effect on coal and electricity demand starting from the fourth quarter of 2008, but there are a number of reasons to believe that the impact will not be nearly as large on natural gas, including:

- The concentration of increased natural gas consumption in the residential sector. Although there are significant pockets of urban unemployment and return of potential natural gas consuming workers to the countryside associated with the shutdown of export processing factories, certain data suggest that urban consumption generally has not been impacted by the slowdown as of late 2008. According to the China National Statistics Bureau, urban consumption in November 2008 was 20.3 percent higher than in November 2007, broadly consistent with trends earlier in the year (NBSC, 2008).

- The concentration of industrial consumption in the chemical fertilizer industry, which serves domestic agriculture. There has been no suggestion that Chinese agriculture will be seriously affected by either the global crisis or a slowdown in Chinese real estate/factory investment. And even a temporary slowdown in the output of steel, etc. need not necessarily affect fuel switching from coal gas or heavy oil to natural gas in these industries.

- The 4 trillion RMB domestic Chinese stimulus package, with its emphasis on infrastructure construction will cushion the blow of the global economy and the domestic real-estate slowdown. The World Bank projects that the Chinese economy as a whole will grow 7.5 percent in 2008 – significantly lower than the double digit rates prevailing since the turn of the century, but still robust -- with the stimulus package accounting for as much as half of this growth (WB, 2008).

Most importantly, companies in the natural gas sales business indicate that there have not as of year-end 2008 been any signs of slowdown in their markets.

This study therefore assumes:

(1) The growth rate of natural gas consumption by an average of 10 billion cubic meters per year for the foreseeable will not be affected by the world economic downturn and the lower rates of growth in China caused both by that downturn and domestic factors in China.

(2) The duration of any such slowdown in gas consumption growth as may occur will be of short enough impact to eliminate any adverse impact on the proposed Songzao project.

These assumptions will have to be tested against reality as time progresses. In particular, potential investors should monitor whether the rate of urbanization slows down, urban unemployment increases, or disposable income decreases sufficiently in response to macro disruptions to adversely affect previous patterns of growth in urban consumption of basic utilities such as natural gas. They should also pay attention to whether the drop in heavy industrial growth is of a magnitude and duration as to significantly reduce the rate of growth of industrial natural gas consumption.

4.2.1.3 New Supply

Almost all of the spectacular growth in supply over the last 3-5 years has come from domestic sources, in particular the newly developed Tarim gasfield in Xinjiang (the major gas source for the West to East pipeline), and from the Changqing gasfield in western Inner Mongolia and Shaanxi provinces (the gas source for the pipelines to Beijing). There are already signs, however, that growth from these fields is slowing. National output in 2008 is reported to have grown by 6.5 – 7 billion cubic meters in 2008, compared to almost 11 billion in 2007 and over 9 billion in 2006. Output from Xinjiang grew by 3 billion cubic meters in 2008 compared to 4.5 billion in 2007, and almost 6 billion in 2006. See **Table 18 and Figure 26.**

TABLE 18: CHINA NATURAL GAS PRODUCTION BY PROVINCE (BILLION CUBIC METERS)

Provinces and Municipalities	2005	2006	2007	2008
North				
Beijing	NA	NA	NA	NA
Tianjin	879	1,050	1,334	NA
Hebei	692	655	714	NA
Shanxi	324	602	NA	NA
Inner Mongolia	1,719	5,307	7,050	NA
Northeast				
Liaoning	1,172	1,194	872	NA
Jilin	540	241	522	NA
Heilongjiang	2,443	2,452	2,550	NA
East				
Shanghai	604	564	507	NA
Shandong	925	855	784	NA
Central-South				
Henan	1,762	1,868	1,576	NA
Guangdong	4,475	4,894	5,247	NA
Hainan	166	205	203	NA
Southwest				
Chongqing	327	647	500	NA
Sichuan	14,230	15,995	18,746	NA
Northwest				
Shaanxi	7,546	8,047	11,010	NA
Qinghai	2,226	2,503	3,430	NA
Xinjiang	10,671	16,420	21,020	24,000
Total	49,300	58,539	69,310	76,000

Sources: CESY (2008), p. 41; NBSC (2008),; ChinaGate December 11, 2008

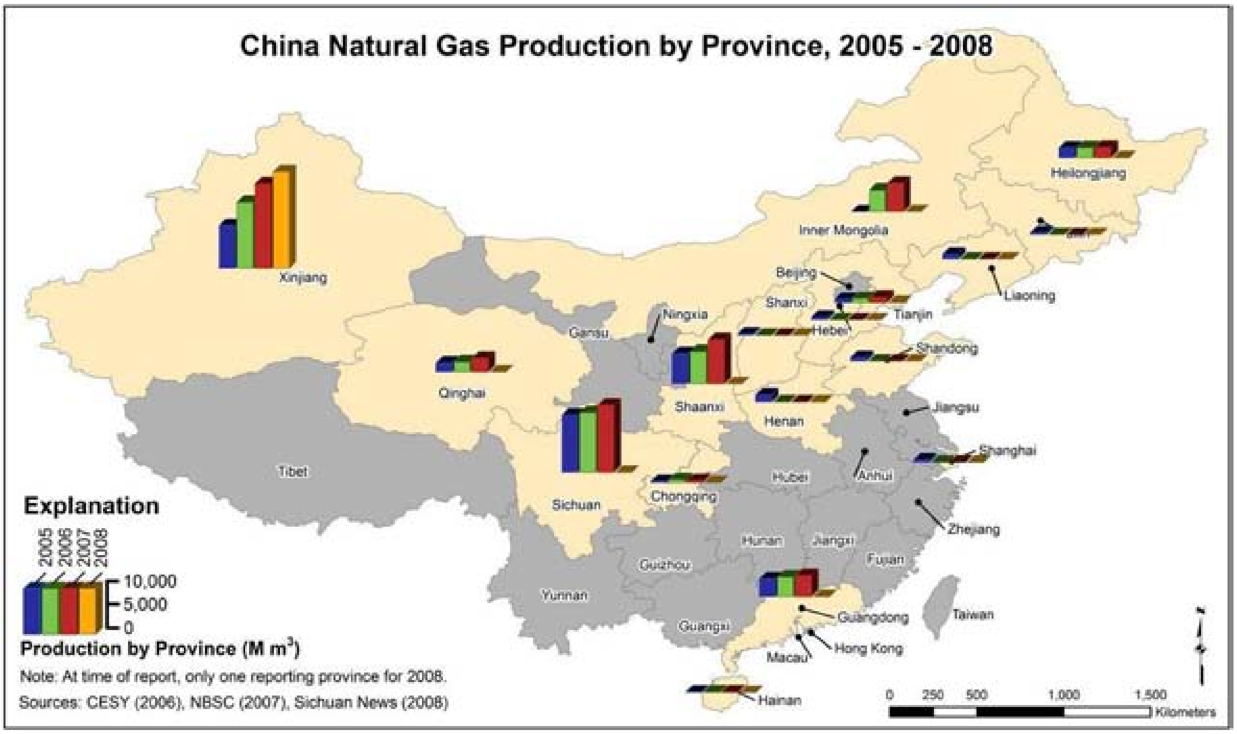


FIGURE 26: NATURAL GAS PRODUCTION BY PROVINCE, 2005-2008

The most important new domestic source of gas in the coming 3-4 years will be the Puguang field in Sichuan province, just north of Chongqing which is being developed by Sinopec, the smaller of the two state-owned onshore gas producers. Sinopec is building an 8 billion cubic meter per year pipeline from Chongqing to Shanghai, which is planned to allocate gas as follows when it comes on stream in 2010. See **Table 19** and **Figure 27**.

TABLE 19: SINOPEC GAS ALLOCATION BY PROVINCE

Province	Allocation (million m^3)
Jiangsu	2,350
Shanghai	1,900
Zhejiang	1,850
Anhui	800
Jiangxi	300

Source: China Development Gateway Network, 2007

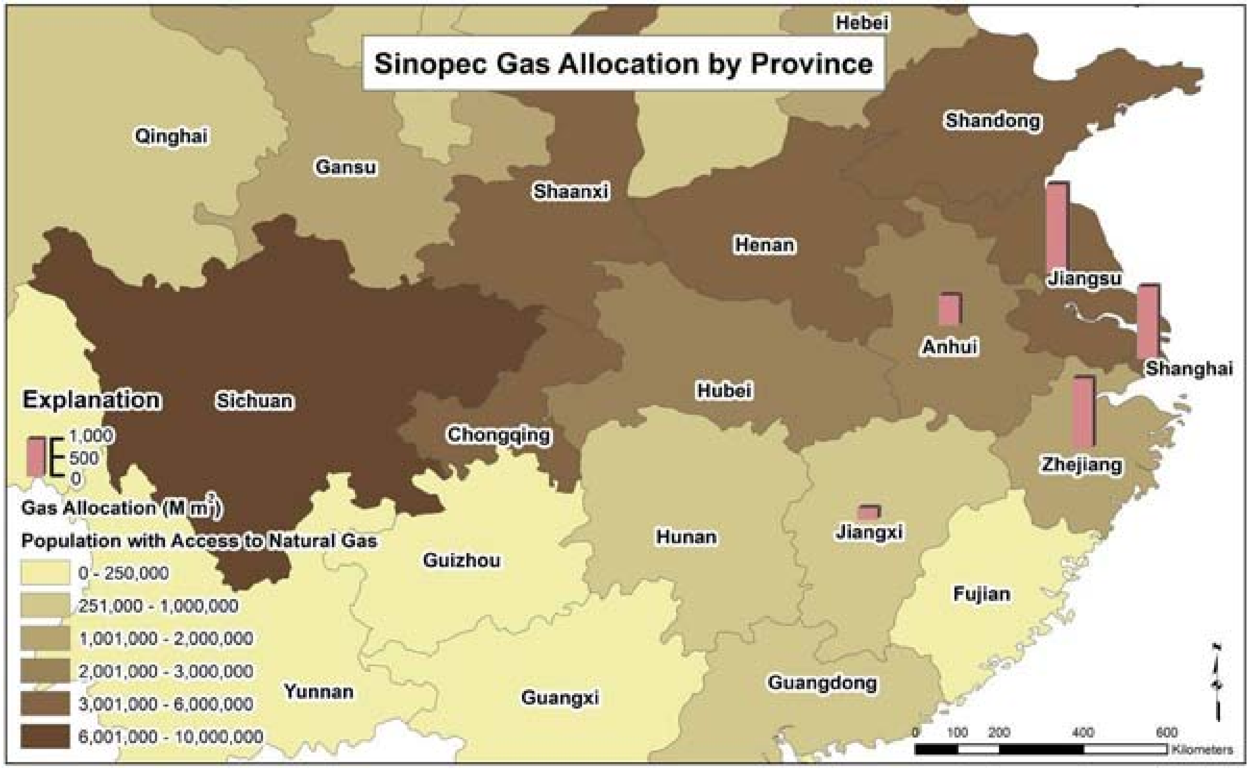


FIGURE 27: SINOPEC GAS ALLOCATION BY PROVINCE

An additional two million tonnes each will be allocated to Chongqing Municipality and Sichuan Province.

But Puguang is the only major new find publicly announced in recent years, and the government appears to be planning for the bulk of new supply in medium term to come from abroad via the following megaprojects:

Second West to East Gas Pipeline

With a designed throughput of 30 billion cubic meters per year and estimated cost of 140 billion RMB (about $20 billion USD), this project involves the following:

- Construction of 1,818 km of pipeline through Uzbekistan and Kazakhstan to the Chinese border at Xinjiang
- Construction of 4,945 km of trunk pipeline through China to Guangzhou
  Construction of 8 branch pipelines totaling 3,849 km to load centers throughout eastern, central, and southern China (Xinhua, 2008)

A reported 13 billion cubic meters will come from fields developed by China National Petroleum Corporation (PetroChina) in Turkmenistan, under production sharing agreements with the remainder purchased from Turkmeni oil companies.

Construction of the China portion of the pipeline has begun in 2008, with first gas flow projected for 2010, and achievement of full capacity in 2012. As far as can be determined, the project is being financed by a combination of equity from PetroChina and other Chinese investors, corporate bonds issued by PetroChina, and loans from Chinese government banks.

Figure 28 below shows consumption of Sinopec gas by sector.

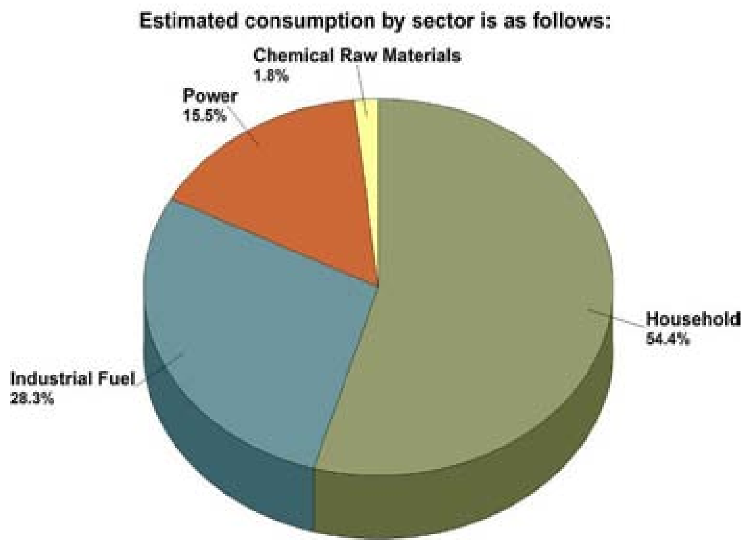


FIGURE 28: CONSUMPTION OF SINOPEC GAS BY SECTOR

Burma-China Gas Pipeline

In December 2008, CNPC signed a series of agreements with the Burmese government and a Daewoo gas production consortium to build an approximately 1000 km, 10 billion cubic meter capacity pipeline to transport gas from two offshore blocs in the Bay of Bengal across Burma to Yunnan and Guizhou Provinces in China's southwest. Unofficial reports suggest that the route of the pipeline has yet to be finalized as of early 2009, and that gas is projected to start flowing to China in 2012-2013. CNPC has already negotiated preliminary offtake agreements with local distribution companies in the provinces (shxb.net, 2008).

The new pipelines described above will extend the national network into virtually all provinces of China. But there will likely remain small-medium sized cities within these provinces that will not be tied into the local distribution grids, and many of the larger cities will not receive sufficient gas to fully cover their residential populations.

LNG Import Terminals

In addition to the two major LNG import terminals already operating in Shenzhen (Guangdong) and in Fujian Province, at least nine others are planned by the state-owned oil companies along the coast. Four of these – in Shanghai, Zhuhai (Guangdong), Dalian, and Jiangsu—with aggregate capacity of 12.5 million tonnes, or approximately 16.5 billion cubic meters per year regasified, are reported under construction.

Of equal importance, the following long term LNG supply contracts have been signed for these projects:

TABLE 20: LNG SUPPLY CONTRACTS

Supplier	Buyer	Date Signed	Volume (tpy)
Petronas (Malaysia)	CNOOC/Shanghai	2006	1.1million (2009-2011) 3 million (2012-2034)
Qatargas	CNPC	November 2008	3 million (2011-2036)
Shell	CNPC	November 2008	2 million (2011-2031)
Qatargas	CNOOC	June 2008	2 million (2009-2034)
Total (France)	CNOOC	June 2008	1 million (from 2010)

Sources: Xinhua January 23, 2007; Shell October 4, 2008; Xinhua November 25, 2008; China Daily June 25, 2008

TABLE 21: PROPOSED LNG IMPORT TERMINAL PROJECTS, 2008-2010

Location and Sponsor	Capacity	Status	Gas Source
Shanghai (CNOOC)	3 million tonnes (4 billion m^3 equivalent))	Under construction, due on-stream 2009	Malaysia
Dalian, Liaoning (CNPC PetroChina)	3 million tonnes (4 billion m^3 equivalent)	Under construction, due on-stream 2011, includes pipelines to Shenyang and Fushun	Qatar
Ningbo, Zhejiang (CNOOC)	3 million tonnes (4 billion m^3 equivalent)	Planning	Not settled
Zhuhai, Guangdong (CNOOC)	3.4 million tonnes (4.5 billion m^3	Under construction On-stream 2011?	Own resources/Qatar

Location and Sponsor	Capacity	Status	Gas Source
	equivalent)		
Rudong, Jiangsu (CNPC)	3.5 million tonnes (4.5 billion m^3 equivalent)	Civil Construction On-stream 2011	Qatar/Shell
Yangpu, Hainan (CNOOC)	2 million tonnes (2.67 billion m^3 equivalent)	Planning On-stream 2012-2015?	Not settled
Tangshan, Hebei (CNPC PetroChina)	3 million tonnes (4 billion m^3 equivalent)	Planning On-stream 2012-2015?	Not settled
Qingdao, Shandong (Sinopec)	3 million tonnes (4 billion m^3 equivalent)	Planning On-stream 2012-2015?	Not settled
Tianjin (Sinopec)	3 million tonnes (4 billion m^3 equivalent)	Planning On-stream 2012-2015?	Not settled

Sources: Xinhua January 23, 2007; PetroChina June 2, 2008; PetroChina April 23, 2008; Bloomberg November 28, 2008; China Daily June 25, 2008; ChinaMining.org January 23, 2008

4.2.1.4 Implications of China's Macro Gas Market for Songzao Project

As noted above, the long term fundamentals of China's macro economic environment are highly favorable for the absorption of purified, liquefied SCEC CMM in the Chinese market. The investments of the past 8 years in natural gas transmission and distribution have made access to natural gas a real possibility for the first time in China's urban centers, and have unleashed an enormous pent-up demand.

Domestic supply has been, remains at present and will likely continue to be far short of demand. The success of other small scale domestic LNG plants based on trucking to end users sets a positive precedent for a new plant such as Songzao.

The macro implications of the global economic slowdown cannot be predicted. But at least as of the beginning of 2009 natural gas remains a seller's market in China. From a supply-demand point of view, the absorption of 100-150 million cubic meter equivalent of LNG from Songzao should be automatic in a market growing at 10 billion cubic meters per year.

Gas distribution companies with franchises across China indicate a willingness to pay up to 3.0 RMB per cubic meter for LNG from Songzao at the beginning of 2009 for delivery to cities without easy access to either pipeline gas or imported LNG. A reasonable guess is that the truck transport distances contemplated by these companies are as high as 1000-1500 km, and that the retail prices charged are between 4 and 5 RMB per cubic meter.

Given the virtual certainty that China will rely significantly on imported gas for future growth, the city gate prices of imported pipeline gas and LNG will drive the long-run price that Songzao's LNG will be able to command. The benchmarks for Songzao should therefore be delivered cost of gas from international pipelines and from imported LNG.

It has been reported that, with crude oil at $60 USD a barrel, the city gate price of imported pipeline gas from Central Asia will be in the vicinity of 3.0 – 3.5 RMB per cubic meter in East and South China (Xinhua, 2008). Further assuming: (1) an order of magnitude cost for truck transport of LNG of 0.07 RMB per cubic meter per 100 km provided in second half 2008 by a Chinese company in the business and; (2) a transport radius of 1000 – 1500 km, which would enable SCEC to reach a number of the markets along this pipeline, SCEC should reasonably be assumed to be able to command a price in the vicinity of at least 2.5 RMB per cubic meter ($10.76 USD per mmbtu at 36,000 KJ per cubic meter methane) using Central Asian gas as a benchmark, and allowing approximately 0.5 RMB per cubic meter for recovery of distribution costs, assuming the international oil price recovers to $60 USD per barrel by the time SCEC's plant comes on-stream.

LNG imports in the range of $10-11 USD per mmbtu (the approximate reported spot price around year-end 2008) would also be consistent with at least 2.5 RMB per cubic meter of liquefied CMM ex factory SCEC, assuming the transportation cost for SCEC is offset by the costs of imported LNG loading and transportation to city gate. There would likely be considerable upside potential for SCEC if international LNG prices were to rise further, and risk if they fell lower.

4.2.2 Options for SCEC Purified Gas Marketing

4.2.2.1 Sale to Pipeline Company

At present, the pipeline network of China National Petroleum and Natural Gas Company (PetroChina) extends to the county seat of Qijiang County, approximately 45 kilometers from the Songzao area. The extension of a pipeline to Songzao and purchase of the purified methane by PetroChina is theoretically possible (as would be the transportation of LNG from Songzao to the Qijiang pipeline terminus), but is unlikely to be economically attractive under the domestic natural gas price control regime in effect at year-end 2008, which fixes pipeline prices to

Chongqing at 0.92 – 1.275 RMB per cubic meter in the Chongqing area, depending on the final end user (NDRC, 2005, NDRC ,2007.3).

4.2.2.2 Sale to Chongqing Gas Company or other Chongqing End-Users

Due to its proximity to the Sichuan gasfields, Chongqing has one of the oldest and best-developed natural gas distribution infrastructures in the entire country. Its total natural gas consumption reached a reported 4.5 billion cubic meters in 2007, putting it in the top three provincial consumers on a per capita basis, with 14 percent average growth 2004-2007.

The Chongqing Gas Group, a subsidiary of the same Chongqing Energy Investment Group which owns the Songzao Coal Mining and Electricity Company, has the franchise for gas distribution in the core Chongqing metropolitan area, as well as in a number of the outlying counties and cities, and accounted for approximately 1/3 of Chongqing's gas consumption in 2007. Most of the remainder was purchased directly from PetroChina by large industrial enterprises, with a small amount going to smaller distribution companies in some of the outlying areas (including some owned by PetroChina itself).

There seems little doubt that the Chongqing Gas Group by itself could absorb the liquefied gas produced by SCEC. Chongqing Gas projects that its sales will increase by at least 500 million cubic meters between 2007 and 2010, with demand being driven by gradual expansion of the residential coverage base from 1.63 million customers (approximately 5.25 million people altogether) to 2.1 million customers (6.8 million people), as well as by continued industrial growth.

TABLE 22: CHONGQING GAS CONSUMPTION (MILLION CUBIC METERS)

	2004	2005	2006	2007	2008	2009	2010
Chongqing Gas Group	860	965	1250	1482	1700	NA	2400
Industrial	168	207	296	346	406	446	467
Residential	236	262	341	371	421	466	510
Commercial	37	51	78	100	131	171	215
"Independent networks"	NA	NA	NA	268	NA	NA	NA
Automotive CNG	101	142	174	240	245	276	344

	2004	2005	2006	2007	2008	2009	2010
"Collective" (public)	NA	NA	NA	45	NA	NA	NA
"Non-industrial boilers" (heating/air conditioning)	NA	NA	NA	52	NA	NA	NA
Loss	NA	NA	NA	60	NA	NA	NA
Subtotal	NA	NA	NA	1482	NA	NA	1536
Direct Purchase by Industry/ Other Distribution Companies	**2174**	**2585**	**NA**	**3018**	**NA**	**NA**	**7242**
Total	**3034**	**3550**	**NA**	**4500**	**NA**	**NA**	**9642**

Source: Chongqing Gas Group, Chongqing Energy Investment Company

Precisely because of its proximity to the gas source and because of its long history of gas use, however, Chongqing's regulated natural gas retail sales prices are among the lowest in China.

TABLE 23: REGULATED NATURAL GAS RETAIL PRICES, CHONGQING MUNICIPALITY, DECEMBER 2008

End-use Category	Price: (RMB/cubic meter)
Industrial user:	1.67
Residential:	1.40
Commercial:	2.21
Automotive CNG (to gas station):	1.17

Source: Chongqing Gas Group, Chongqing Energy Investment Company

The cost of purification and liquefaction of SCEC's gas will exceed the price at which Chongqing Gas is permitted to sell to end users, at least as of January 2009. While spot sales to Chongqing Gas for peaking purposes are a possibility, Chongqing Gas is unlikely to prove a reliable long-term customer absent administrative direction from the municipal government and/or a major increase in the cost of gas to Chongqing from the domestic producers.

4.2.2.3 Sales Outside of Chongqing

The obvious target markets for SCEC are underserved areas where there is no history of low retail prices. Guizhou Province to the immediate south of Chongqing is especially attractive geographically. Substitution for the six billion cubic meters of coal gas produced in the province would create an instant market of approximately 2.5 billion meters of natural gas/methane. Guizhou will receive no pipeline gas until the Burma-China pipeline is completed 2012-2013, and is served at present only by small amounts of domestic LNG produced in Dazhou just north of Chongqing, and from Hainan Island (Guizhou Province Bureau of Commerce and Trade). Its capital city Guiyang and number two city Zunyi are located 283 and 133 km distance respectively from Songzao.

Guangxi Province is another possible target. It will receive no pipeline gas until the Central Asia gas pipeline is completed. Retail residential sales prices in Guilin (a major tourist city) and Nanning (the capital), both located approximately 950 km from Songzao, are 4 and 4.5 RMB per cubic meter respectively (Guilin Evening News, 2009).

In some cases, SCEC may be able to reach agreements with local distribution companies on a delivered price. Most of the local distribution companies in the underserved areas that are SCEC's prime targets, however, are controlled by major companies such as Xin'ao, China Gas or Hong Kong Gas that will wish to deal with SCEC directly, and will most likely take the gas ex-factory. Dealing with one or more of these majors, who each operate in multiple cities around China would also leave SCEC less exposed to the risk posed by over-reliance on single cities. These companies have all expressed strong interest in LNG from SCEC.

4.3 Electricity Market

4.3.1 Chongqing Power Market

4.3.1.1 National Electricity Supply and Demand Overview

Electricity production and generation capacity in China increased at robust rates of 14.4 and 15.3 percent respectively 2003-2007, considerably in excess of average economic growth of around 10 percent during the same period. Total generating capacity increased by a staggering two hundred thousand megawatts during 2006 and 2007.

The growth has come primarily from thermal power plants (overwhelmingly coal-fired) which have consistently accounted for about 82% electrical output (**Table 24**). Despite the construction of a number of large hydro projects, the hydro percentage of total output has remained at a level of about 15-16 percent. Nuclear has accounted for virtually all the remaining 2-3 percent of output, a percentage that is likely to increase over the coming 5-10 years. While China is beginning to construct large numbers of wind power plants, their output is not yet a significant component of the overall power mix. The torrid growth in generation capacity, which represented the completion of projects begun several years earlier, continued through 2008. Starting from June 2008, however, monthly output growth dropped into single digits, as is shown below in **Figure 29**. In October, as the world economic downturn accelerated, China recorded negative electricity growth for the first time in memory; November 2008 output was 9.6 percent lower than November 2007 (NBSC, 2008).

TABLE 24: CHINA ELECTRICITY GROWTH, 2000 - 2008

	2000	2003	2004	2005	2006	2007	2008
Electricity Output (TWH)	1,355.6	1,910.6	2,203.3	2,500.3	2,865.7	3,281.6	3,404.7
Growth			*15.3%*	*13.5%*	*14.6%*	*14.5%*	*3.8%*
Thermal	1,114.2	1,580.4	1,795.6	2,047.3	2,369.6	2,722.9	2,785.7
Growth			*13.6%*	*14.0%*	*15.7%*	*14.9%*	*2.3%*
Hydro	222.4	283.7	353.5	397.0	435.8	485.3	527.7
Growth			*24.6%*	*12.3%*	*9.7%*	*11.4%*	*8.7%*
Nuclear	16.7	43.3	50.5	53.1	54.8	62.1	NA
Growth			*16.5%*	*5.2%*	*3.2%*	*13.3%*	
Electricity Capacity (MW)		403,353	453,903	517,163	623,698	713,261	803,771
Growth			*12.5%*	*13.9%*	*20.6%*	*14.4%*	12.7%

Sources: CESY (2008), p. 75; NBSC (2008); NBSC (2007.1), Table 5, NBSC (2008.1), Table 5; CEPY (2007, p. 625)

TABLE 25: ELECTRICITY PRODUCTION GROWTH, 2008

	Growth compared to same month 2007	Growth compared to year-to-date 2007
January	8.9%	8.9%
February	14.3%	11.3%
March	16.6%	14.0%
April	12.8%	14.1%
May	11.8%	13.7%
June	8.3%	12.9%
July	8.1%	11.9%
August	5.1%	10.9%
September	3.4%	9.9%
October	-4.0%	8.3%
November	-9.6%	6.8%
December	-7.9%	3.8%

Source: CNSB (2008)

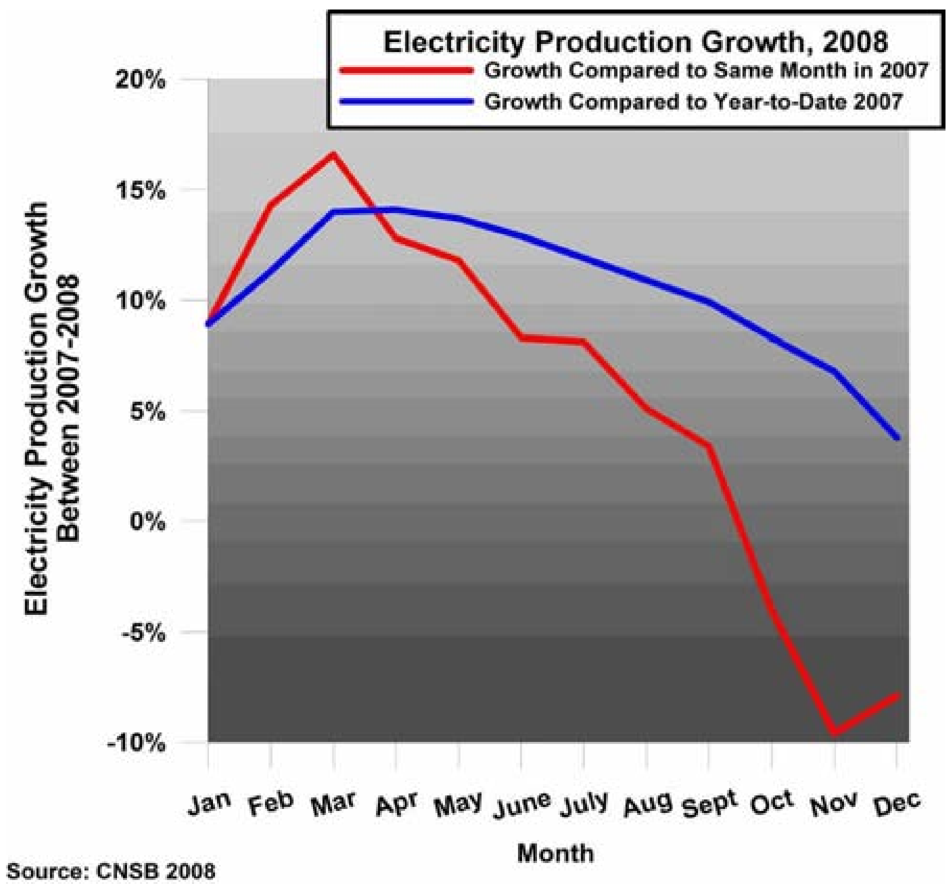


FIGURE 29: ELECTRICITY PRODUCTION GROWTH

Industry accounts for approximately 75 percent of electricity consumption (CESY 2007, p. 20). The electricity fall-off has been driven by steeply declining output of energy-intensive industrial products, such as steel, by far the largest industrial consumer of electricity (-12.4 percent), November 2008 compared to November 2007); non-ferrous metals (-4.3 percent); key industrial chemicals including soda ash (-21.8 percent), caustic soda (20.6 percent), and sulfuric acid (-26.2 percent).

The World Bank has projected that China's economy as a whole will grow by approximately 7.5 percent in 2009, with as much as half of this growth coming from the implementation of the government's announced 4 trillion RMB economic stimulus package 2009-2010 (WB, 2008). As this package is to be centered on government investment in infrastructure directly related to people's livelihood – such as public housing, transport, urban environmental protection including sewage and pollution treatment, earthquake reconstruction, power grids – some recovery in output of electricity-intensive industrial products such as steel can be expected.

But it is questionable as of year-end 2008 whether national demand for electric power will grow as quickly in the next five years as it did in the 2001-2008 period. At the least, it will take time for the investment environment to recapture the go-go atmosphere of the 2001-2007 period; the Chinese government itself hopes to use the downturn of 2008 to recalibrate growth along a more sustainable, less energy-intensive path, and it is conceivable that the least energy efficient steel, cement plants, etc. will be weeded out during the immediate period of slower growth. Civil and commercial consumption of power will certainly grow rapidly as urbanization accelerates – but as these sectors only account at present for approximately 14 percent of total electricity consumption, (CESY, 2008, p. 107) they cannot be expected to completely substitute for slower growth in electricity-intensive industry.

Given the rapid construction of electricity generation capacity since 2003, including many projects still outstanding, there is a distinct possibility that power generation capacity will outstrip demand in many parts of the country over the next 3-5 years. The appetite for new power construction will likely decrease correspondingly, and dispatch of existing plants – particularly coal-fired power plants – will decrease.

4.3.1.2 Central China Regional Grid

China is divided into six regional (transprovincial) grids that are largely independent, but engage in some electricity exchange through selected transmission links. Chongqing is one of six provincial level units that make up the Central China Electricity grid, which reports to the State Power Grid Corporation. Transmission links among the six provinces are owned by the Central China Electricity Grid Company, and the dispatch plans of the provincial level transmission-distribution companies are coordinated within the regional grid.

Electricity consumption within the region covered by the Central China grid increased by 15 percent per year, 2005-2007. Nonetheless, the Central China grid is a net power exporter to the rest of China, with generation exceeding supply within the grid by about 60,000 GWH in 2007. The surplus comes from the rich hydropower resources in the region (hydro accounted for about one third of the Central China grid's output in 2006, far and away the highest such percentage in the country), and particularly from the 18,200 megawatt Three Gorges megaproject in Hubei and the 3300 megawatt Ertan project in Sichuan which sold 40,100 and 1,670 GWH respectively to other regions in China in 2007 via dedicated transmission lines under long term contracts (SGCC, 2008). **Figure 30** below illustrates the geographic connection of the six regional grids along with the electricity generated with each grid, 2005 – 2007.

TABLE 26: CENTRAL CHINA POWER GRID SUPPLY AND CONSUMPTION

	2005	2006	2007
Electricity Generation (GWH)	499,328	561,985	650,628
Chongqing	25,390	29,130	37,455
Hunan	64,441	75,490	86,015
Henan	141,468	160,050	191,826
Jiangxi	37,349	43,990	50,201
Hubei	128,980	130,667	158,839
Sichuan	101,700	122,658	126,292
Total Electricity Consumption (GWH)	450,000	511,566	590,675
Generating Capacity (MW)	108,800	129,200	NA

Sources: CESY (2008), p.43, 117, NBSC (2007), CEPY (2007), p.625

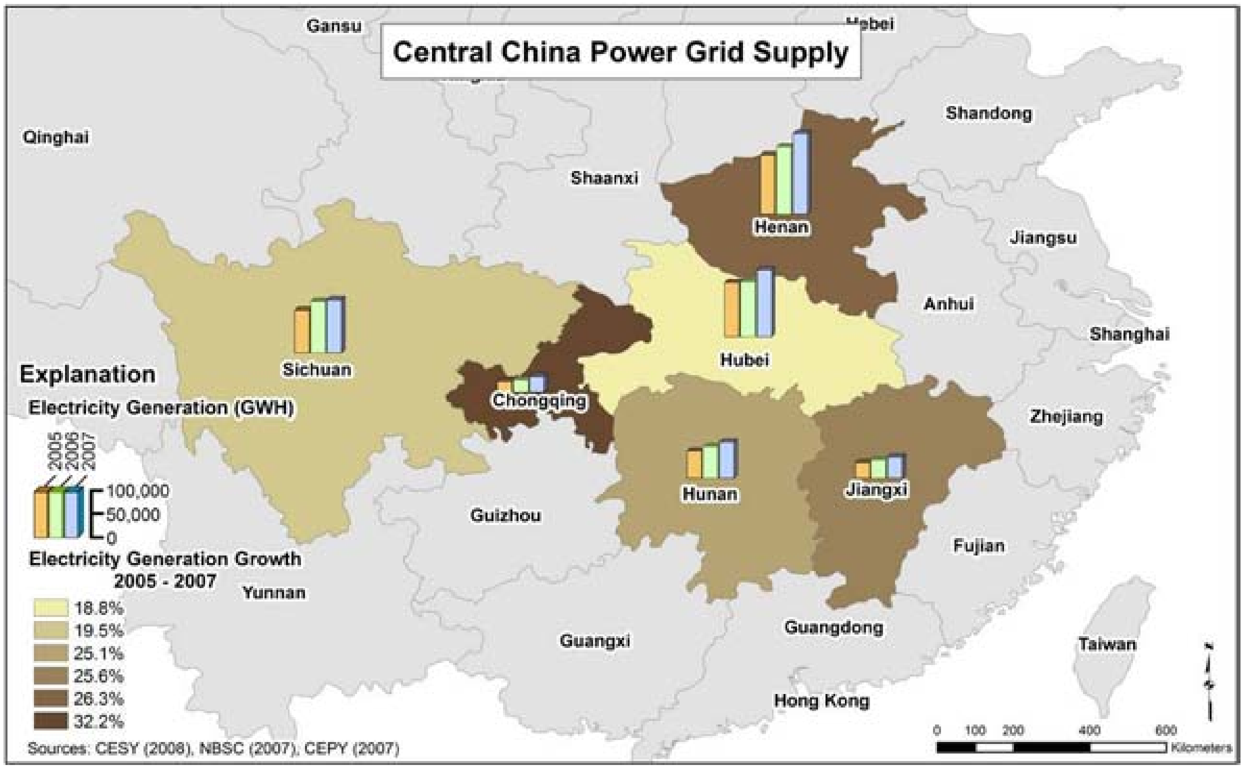


FIGURE 30: CENTRAL CHINA POWER GRID SUPPLY

4.3.1.3 Chongqing Electricity Supply Demand, Organizational Structure, Dispatch and Pricing

The Chongqing electrical distribution system is dominated by the Chongqing Power Company, a subsidiary of the Central China Grid Company which accounts for about 78 percent of total supply, with the remainder coming from small regional grids and self-owned power plants of industrial enterprises (**Table 27)**. Generation facilities are owned by a combination of the five major national generating companies, the Chongqing Energy Investment Group and other local investors. While the Chongqing Power Company itself has modest peaking power generation capacity, generation and transmission/distribution are fundamentally separated under the power system reforms of 2002.

Power consumption in Chongqing grew by approximately 9.6 percent 2002-2007, and by 13.3 percent per year 2004 – 2007 to 44,921 GWH, driven primarily by rapid growth in industrial production which accounts for 70 percent of total electricity demand, and particularly by growth in steel, non-ferrous metals, building materials, and chemicals, which account for about half of the total demand (CESY2006, p. CESY 2008, p.117). In Chongqing as in the country as a whole, the sudden decline in production of these sectors in second-half 2008 resulting from domestic real-estate investment slowdown and the international financial crisis has depressed electricity consumption, with year-on-year electricity growth dropping by a reported 2.13 percent in October 2008, and by projected 17.9 and 10 percent respectively in November and December (CPEC, 2008.2).

The Chinese government's economic stimulus plan of 2008, with its focus on infrastructure construction will probably bring about some rebound in demand for key industrial materials, and thus of electricity. Civil consumption of electricity will also grow as the urbanization ratio in Chongqing increases from approximately 46.4 percent in 2007 to a projected 53 percent in 2010, and possibly 70 percent by 2020. But there remains considerable uncertainty as of year-end 2008 how strong the rebound will be, and few observers predict immediate resumption of the heavy-industry and construction-driven hyper growth of previous years.

TABLE 27: CHONGQING POWER SUPPLY AND DEMAND

	2005	**2006**	**2007**	**2008 (estimated)**
Electricity Consumption (GWH) Centrally dispatched	35,158	40,131 (+14.1%) *31,254*	44,707 (+11.4%) *34,848* *(+11.5%)*	48,430 (+8.3%) *37,689* *(+8.2%)*
Electricity Generation (GWH) 1. Thermal 2. Hydro Centrally dispatched	25,390 NA NA NA	28,862 (+13.6%) 23,460 5,300 *21,486*	35,196 (+21.9%) 29,500 5,400 *28,551* *(+32.8%)*	NA NA NA *31,200* *(+9.3%)*
Maximum Load (MW) Centrally dispatched	7,390 *5,024*	8,350 *6,115*	9,066 (estimated) *6,640*	9,790 *7,170*
Generating Capacity (MW) Centrally dispatched	5,678 NA	7,597 NA	NA? *8,000*	NA *8,639*
Thermal	3,790	5,594	NA	6,040 (central dispatch)

Sources: Chongqing Energy Investment Corporation private communication, CQPC (2008.1, 2008.2), CESY (2008), pp. 43, 117, Chongqing's generation capacity grew from 5680 MW in 2005 to at least 8,639 MW in 2008 (the amount centrally dispatched – figures for capacity owned by users themselves are not available), the result of an aggressive investment program begun during the severe national power shortages in 2003. By year-end 2007 total capacity exceeded peak load for the centrally-operated grid by about 20 percent.

Nonetheless, the Chongqing grid purchased about 6,300 GWH, or approximately 18 percent of its electricity from outside of the municipality in 2007, in line with the Central China grid's policy to dispatch hydro whenever possible, due to hydro's lower wholesale power purchase cost. According to the Chongqing Energy Investment Group, Chongqing imports approximately 1,000 GWH annually from the Three Gorges project at a price of 0.291 RMB per KWH as of July 1, 2008, and 4,600 GWH from the Ertan hydro station in Sichuan at 0.278 RMB per KWH (prices in effect July 2008); some off the smaller local hydro probably supply at an even lower cost (NDRC, 2008.2).

This means that thermal power plants, which constitute 70 percent of Chongqing's centrally dispatched capacity as of year-end 2008, are operating significantly below capacity. During 2006, a year of water shortage and low reservoir levels, Chongqing's thermal power plants were utilized only 5341 hours on average (CEPY, 2007, p.628). The number was undoubtedly lower than 5000 in both 2007 and 2008, when water levels were higher. The 2 x 150 MW Anwen circulating fluidized bed coal-fired power plant operated by the Songzao Coal and Electricity Company produced for only about 4250 hours in 2007, and was running at about half capacity during daytime hours when visited in February 2008. Given wholesale power prices of about 0.36 - 0.43 RMB per kwh for coal power (with the exception of plants that signed long-term power purchase agreements in earlier years), and 0.48 - 0.50 RMB per kwh for natural gas power compared to hydro wholesale prices between 0.2 and 0.3 RMB per kwh, neither the Central China grid nor the Chongqing grid has incentive to dispatch thermal power plants more than necessary (NDRC, 2008.2).

In 2008, a year that power consumption in Chongqing increased by an estimated 8.4 percent, thermal power generation had only increased by 2.3 percent as of end-October, and may have registered a decline for the year as a whole (CQPC, 2008.2). Part of the reason for this was a coal price crisis that limited the ability of thermal power plants to operate in the first half of the year, but the availability of cheap hydro from in and outside of Chongqing was clearly a factor by the second half. Furthermore, in an era of uncertain growth prospects for power consumption, nearly 3000 MW of additional power capacity are already under construction in the Chongqing, including the Shuanghuai, Shizhu, and Fengjie coal fired plants with aggregate 2400 MW capacity.

4.3.1.4 Market Risks for Coal Mine Methane Fueled Power Generation

It appears that, barring the rapid resumption of the industrial growth patterns of the 2003-2007 period, the market for thermal power in Chongqing will be soft for some time to come. This leaves little incentive for the Chongqing grid to buy power from proposed new plants burning coalmine methane in locations such as Songzao.

At the least, the grid would have to pay the going rate for coal-fired power plants. If regulations published by the NDRC in 2007 with the purpose of incentivizing coal mines to generate power using CMM were to be implemented, the grid would have to pay a 0.25 RMB per kwh supplement to the 2006 coal-fired wholesale price which would raise the total to 0.577 RMB/kwh (NDRC, 2007.4). It is thus not surprising that the grid has no interest at the present time to pay for the considerable expenses of linking a prospective large-scale CMM power plant at Songzao to the major grid substations.

TABLE 28: ELECTRICITY WHOLESALE PRICES TO CHONGQING

Three Gorges Hydro:	0.291 RMB per KWH (delivered to Chongqing)
Ertan Hydro:	0.278 RMB per KWH (delivered to Chongqing
Local Coal-fired (includes flue gas desulfurization)	0.3543 RMB per KWH (existing plants) 0.3793 RMB per KWH (new plants)
Gas-fired (Henan Province)	0.48 RMB per KWH (to grid)

Sources: NDRC (2008.2); NDRC (2008.3) Hubei Wuchang Natural Gas Power Plant Clean Development Mechanism Project Definition Document, Section B.5

5.0 CMM End-use Options and Analysis

Through thorough evaluation of the regional energy markets, and through consultation with CQEIG the study team determined that there were three principal options for using methane gas drained from SCEC mines. These options are:

1. *LNG Option*- The configuration for this option would link the six mines located in the northern part of the basin, as well as the Zhangshiba shaft and the Liyuanba mine into an integrated gathering and storage system. The system will feed a CMM gas purification and liquefaction system which is planned for location at a site near the Anwen power plant. The LNG facilities will be built in two stages the first beginning in 2009, sized to fit the CMM production rates forecasted by plant completion in 2011; and the second construction phase will beginning in 2013 and completed in 2015, sized to fit the remainder of the forecasted flow for the project's life through 2025.

2. *Power Generation and Electricity Sales Option*- This option entails installing CMM fueled internal combustion power generation facilities at each of active mines in the northern part of the basin, the Zhangshiba shaft, and eventually at the Liyuanba mine when CMM flow is sufficient to provide adequate fuel;

3. *Optimized Option*- is a hybrid solution that would link the six active mines to a gathering and storage facility for delivery of feed gas to the LNG plant located at Anwen, and a power generation station at the Zhangshiba shaft to generate power for local use. This plan then calls for delaying the decision to either Liyuanba mine to the Anwen plant or install distributed power plants at this location until CMM production can be measured against forecasts and the operational efficiency of the existing LNG plant (built in 2009-2011) can be determined.

Each option is discussed in the following three subsections, where background information and conceptual design is provided, and the economic performance of each end-use project is discussed. The final subsection compares the economic performance of the three end-use options.

5.1 Inputs and Assumptions Used in Economic Model for All Options

There are certain inputs and assumptions used in the economic model that are applicable to all three scenarios; these are listed in **Table 29** below.

TABLE 29: INPUTS AND ASSUMPTIONS USED IN ECONOMIC MODEL

Project Duration	2009 – 2025	
Project ownership and financial structure	Power plants and LNG plant are profit centers, independent from the SCEC mining operations; debt and equity structure has not yet been decided by sponsor.	IRR is calculated against entire project investment, no debt service included in cash flow analysis.
Gas flows to project	According to p50 probability threshold (Section 3.2)	Separate models also constructed for p10 and p90 thresholds but base case economic analysis is based on P50 volumes.
Depreciation Method	15 year straight line	
Certified Emission Reduction (CER) Sales Price	12.72 USD per tonne of CO_2 equivalent	CER sales in years 2010-2012 only
Verified Emission Reduction (VER) Sales Price	6.12 USD per tonne of CO_2 equivalent	VER sales in years 2013-2025
Project Emissions	0.1784 tons/MWhr 13.1%	Factor used to determine project emissions resulting from power consumed by LNG plant and outlying facilities, and for all power generated by the CMM power generation plants. Percent that project emission reductions generated from sale of LNG gas is reduced due to combustion of gas off site.
Conversion of methane to CO_2 equivalent	0.01428 tons CO_2e per cubic meter of methane	
CMM Purchase Price	Business Confidential	Assumed arms length transaction between mines and power plants/LNG plant. This price does not include the 0.2 yuan per cubic meter incentive payment from central government to CMM producer (SCEC) for gas consumed by power plants or LNG plant under regulations

		designed to encourage the utilization of CMM (MOF, 2007).
Value added Tax (VAT) special incentives	None	Base case assumes that government regulations calling for refund of all VAT taxes paid by CMM producers do not apply to the project as a CMM processor; (MOF, 2007).
VAT Refund on Project Inputs	VAT component of purchase price for gas, electricity, and water inputs to the project are refunded	Per government VAT regulations
VAT Rates	CMM: 14.04% Electricity: 18.36%:	Inclusive of 8 percent surtaxes for urban construction, education, etc. CMM base rate: 13% Electricity base rate: 17%
Income Tax	5 year income tax holiday; 25 percent per year starting from year 6 of operations	Per government regulations encouraging comprehensive utilization of coal products (MOF, 1994, NDRC, 2004).

5.2 Power Generation and Electricity Sales Options

SCEC mines presently use CMM for generation of power at three separate locations in the Songzao region; which are listed below.

- Jinjiyan site: 16 x 500 kW for a total of 8 MW
- Fengchun Dicao (670) site: 8 x 500 kW for a total of 4 MW
- Songtong site: 6 x 500 kW for a total of 3 MW

All three of these sites are sponsored by Mitsui under the Clean Development Mechanism; utilizing Chinese manufactured Shengli 500 kW engines (Model 300GFI-3RW). SCEC will continue to use these Shengli engines, but will also incorporate Caterpillar G350C IC engines, with a design capacity of 1,800 kW, into their plan. Also, the waste heat from the Caterpillar engines is recycled; for every 7 Caterpillar engines installed, an additional 1,500 kW of steam-generated power is available.

Figure 31, below depicts a conceptual design for developing a distributed power systems at eight mining locations. The staged installations culminate in 107 MW of installed capacity using approximately 167 million cubic meters of methane per year at the p50 forecasted production level.

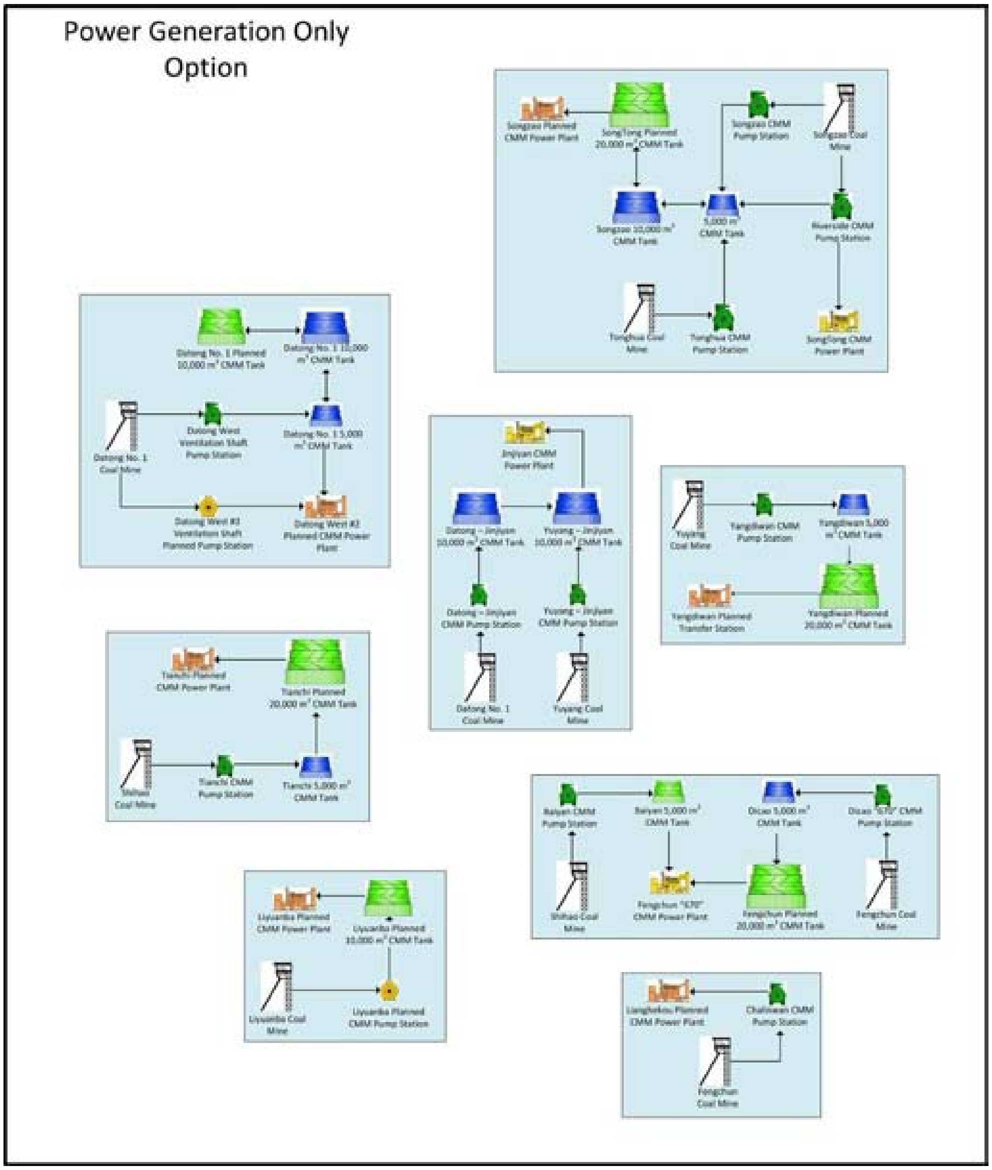


FIGURE 31: BLOCK FLOW DIAGRAM FOR CONCEPTUAL DESIGN OF POWER GENERATION ONLY OPTION

5.2.1 Technology and Deployment Options: Power Generation and Electricity Sales Options

A power generation and electricity sales project is the first end-use option evaluated by the study team. The system consists of a series of plants with total capacity of 166.2 megawatts located at the CMM pump stations of the various mines. The project is conceptually designed to utilize all available CMM drained from Songzao mines to generate power for use at the mines and for sale to the national grid. The installation will comprise of a combination of 43 Shengli 500 kW engines and 65 1,800 kW Caterpillar G350C engines whereas the waste heat from the Caterpillar engines would be recycled to generate an additional 8,250 kW of electricity. The design standard used in the analysis is 1 x 1.5 MW steam turbine associated with every eight internal combustion engines, and 1 x 0.75 MW steam turbine associated with every four internal combustion engines.

The Shengli units are specified at the Fengchun and Fengchun Zhangshiba shafts and the Yuyang Mine shaft either because these sites are already operating Shengli engines, or a commitment has already been made.

Caterpillar engines are specified at all other sites due to lower life-cycle power generation costs associated with these higher-efficiency engines. The sites include the Datong Mine, Shihao Mine, Songzao and Tonghua Mine shafts, and the Liyuanba Mine, based on a feasibility study performed for SCEC in 2007 by the Chongqing Coal Design Institute; the plants could also be designed to use high-efficiency internal combustion engines from other manufacturers.

Overall layout for the power generation facilities is as follows in **Table 30**.

TABLE 30: LAYOUT OF POWER GENERATION FACILITIES

Location	Final Capacity	Configuration
Datong West Ventilation Shaft	42.31 MW	20 x 1.8 MW Caterpillar engines 1 x 1.5 plus 1 x 0.75 MW steam turbines
Shihao Mine (Tianchi and Baiyan areas)	40.5 MW	19 x 1.8 MW Caterpillar engines 1 x 1.5 MW plus 1 x 0.75 MW steam turbines
Songzao (includes Songzao Mine, Tonghua Mine & Tonghua Guanyingqiao shaft)	40.5 MW	19 x 1.8 MW Caterpillar engines 1 x 1.5 MW plus 1 x 0.75 MW steam turbines
Fengchun Lianghekou (includes Fengchun Mine & Fengchun Zhangshiba shafts)	16 MW	32 x 500 kW Shengli engines
Liyuanba Mine	15.9 MW	7 x 1.8 MW Caterpillar engines

		1 x 1.5 MW steam turbine
Yangdiwan and Jinjiyan sites	11 MW	22 x 500 kW Shengli engines

The unit costs for this equipment were derived from a previous study carried out by the Chongqing Design Institute. These unit costs were used as the basis for developing a budget for each site, sizing the equipment based on available projected drained gas. Included in the capital cost (CAPEX) estimates are equipment purchase, installation, gas gathering, land purchase, and existing mine grid system upgrade. It was determined that an upgrade to the mine's internal electrical grid system is necessary prior to adding any additional load, as the existing system is already at or near maximum capacity. Cost estimates for upgrading the SCEC internal electrical grid system were supplied by SCEC's staff electrical engineer.

Installation of the internal combustion power generation facilities at each site was done in stages, ranging in time over the first four years (2009 through 2012) in the case of the Yangdiwan site, to the first nine years of the project (2009 through 2017) in the case of the Datong West Vent Shaft site. This was done to match increased installed capacity with the growth in methane drainage volumes over time. In each case, additional capacity was added only so as to utilize available gas, with the goal of maximizing gas use at each stage, while minimizing the amount of unused drained gas that would otherwise have to be vented the atmosphere.

5.2.2 Risk Factors and Mitigants: Power Generation and Electricity Sales Options

As with any project there are risks associated with developing a successful project. **Table 31** lists the risks that have been identified, an assessment of the level of risk, and possible mitigants to each identified risk. Overall the study team has determined that the risks associated with technology, and implementation is low to moderate, but the risk due to market issues is high. High market risk is strong reason to reject this as an option.

TABLE 31: RISK FACTORS AND MITIGANTS: POWER GENERATION AND ELECTRICITY SALES OPTIONS

Risk	Assessment	Mitigant
Market:		
Access to and the ability to dispatch all available generated power to the grid	High	Use power locally and avoid sale to national grid

Access to national electricity market	High	Use power locally and avoid sale to national grad
Ability to get rational prices for power sold to grid	High	Avoid selling power to the grid, but sell only locally (SCEC)
Technology:		
Reliability and dependability of equipment: 1. Shengli Engines	Moderate	SCEC has experience with Shengli engines; requires more maintenance than Caterpillars, thus requires locally trained technician on site.
2. Caterpillar Engines	Low	Very dependable equipment, train local technicians to monitor, maintain, and repair engines and associated systems.
Fluctuations in gas concentrations	Moderate	Storage tanks scheduled for installation allow for gas mixing; also, install fuel injection systems on engines that allow for fluctuations
Implementation:		
Fluctuation in pricing of equipment and services	Moderate	Current trend for prices is downward; Procure contracts that lock in favorable prices
Procurement of permits and right-of-ways	Low	Develop timeline that incorporates time necessary to secure all necessary permits and right-of-ways, allow for delays
Delays in deliverability of equipment	Low	Detailed planning; incorporate necessary lead time into orders
Delays in installation	Low	Detailed planning: SCC has experience in installing power gen equipment

5.2.3 Economic Analysis: Power Generation and Electricity Sales Options

The project was modeled to determine the economic performance of this option. The subsections below list the assumptions and inputs used for the modeling followed by a subsection reporting the resulting estimates of economic performance.

5.2.3.1 Inputs and Assumptions: Power Generation and Electricity Sales Options

When available, actual costs and pricing are used in the model, otherwise reasonable estimates based on industry standards were used. The following assumptions were used to model this option:

TABLE 32: INPUTS & ASSUMPTIONS: POWER GENERATION SCENARIO

Project Duration	2009 – 2025	
Plant construction	Construction for all sites begins in 2009;	Sites containing Shengli engines are completed in 2009 (Fengchun and Yangdiwan). Sites containing caterpillar engines are completed in 2010 (Datong, Shihao, Songzao, and Liyuanba).
Capital Investment for p50 scenario (million yuan)	Business Confidential	Power station investment based on unit costs as follows (yuan per kilowatt)- Caterpillar units: 7,148.39 Shengli units: 4,039.60
Annual Power Sales	Self-consumption 20.25 MW by SCEC Sale to public grid: 146 MW	
Hours of operation for self-consumption by Songzao	6500 per year	Per current practice at SCEC's existing CMM power plants.
Hours of operation for sale to public grid	5000 hrs. per year (2010) 6150 hrs. per year (2015-2025)	Figures for 2010 based on historic dispatch hours for thermal power plants in Chongqing (CEPY, 2007 p. 626), Increase to 6150 hours based on assumption that government policies calling for priority dispatch for CMM power plants are gradually implemented (NDRC, 2007.2),
Shengli engine specifications:	391 kW nominal output, 0.35 cubic meters per kWh generated Utilizes 6.5% of gas stream as fuel	Based on actual experience of Songzao with similar units in existing CMM power plants.
Caterpillar engine specifications:	1.8 MW output 0.232 cubic meters per kWh generated Utilizes 5.6% of gas stream as fuel	Based on contacts with manufacturer's representatives and end-users.
Power sales price, self-use by SCEC	0.417 yuan per kWh	Per present practice for self-use CMM power plants operated by SCEC.
Power sales price to public grid	0.3793 yuan per kWh	Present price paid by grid for purchase of power from new

		coal-fired units (NDRC, 2008.2, NDRC, 2008.3). Policy calling for 0.25 yuan per kWhr supplement for CMM power (NDRC, 2007.4) not applied due to perceived power grid company resistance.
Annual equipment repair & maintenance costs	2.5 percent of the purchase price for the equipment	
Annual labor cost	13.9 million yuan per year	305 workers at average 40,000 yuan per year salary, plus 14 percent social welfare benefits
Water consumption and cost	0.0038 cubic meters per kWh generated at 2.5 yuan per cubic meter	Consumption per Chongqing Coal Design Institute 2007 study; price provided by Chongqing Energy Investment Corporation.

5.2.3.2 Probabilistic Forecast Results: Power Generation and Electricity Sales Options

Economic analysis was performed on this end-use option using the forecast of gas production at the p90, p50, and p10 probability thresholds. At the p50 production rate, the project returns a positive value for the NPV at 58.82 million USD, and an IRR of 16.25 percent.

The economic performance of this project is lower, however, than the other two options considered, and at this time does not warrant further consideration without guaranteed access to the regional electricity grid and rational price for the electricity that is sold. **Table 33** below summarizes the results of economic analysis of the Power Generation end-use option.

TABLE 33: POWER GENERATION END-USE OPTIONS FORECAST RESULTS

	Probability Threshold					
	p90		p50		p10	
	2011	2015	2011	2015	2011	2015
PowerGen Installed MW	113.2		166.2		241.8	
Net Emissions Reduced (Tons CO2e)	35,841,687		54,163,128		81,681,623	
Total CAPEX	Business Confidential		Business Confidential		Business Confidential	
CapEx/Tons CO2e	Business Confidential		Business Confidential		Business Confidential	
NPV @ 10% Discount Rate	$19.89		$58.82		$107.64	
NPV/tons CO2e	0.55		1.09		1.32	
IRR	12.97%		16.25%		18.13%	

5.3 Sales of LNG Produced from CMM

Figure 32, below depicts a conceptual design for developing an LNG production facility which would require linking six mines located in the northern part of the basin, and the southern Zhangshiba shaft and Liyuanba mine into an integrated gathering and storage system. The system will feed into CMM gas purification and liquefaction system which would be located at the Anwen power plant. Two CMM purification and liquefaction processing plants would be built, one finished in 2011 and the other in 2015 culminating in production capacity of 170 million cubic meters of LNG per annum.

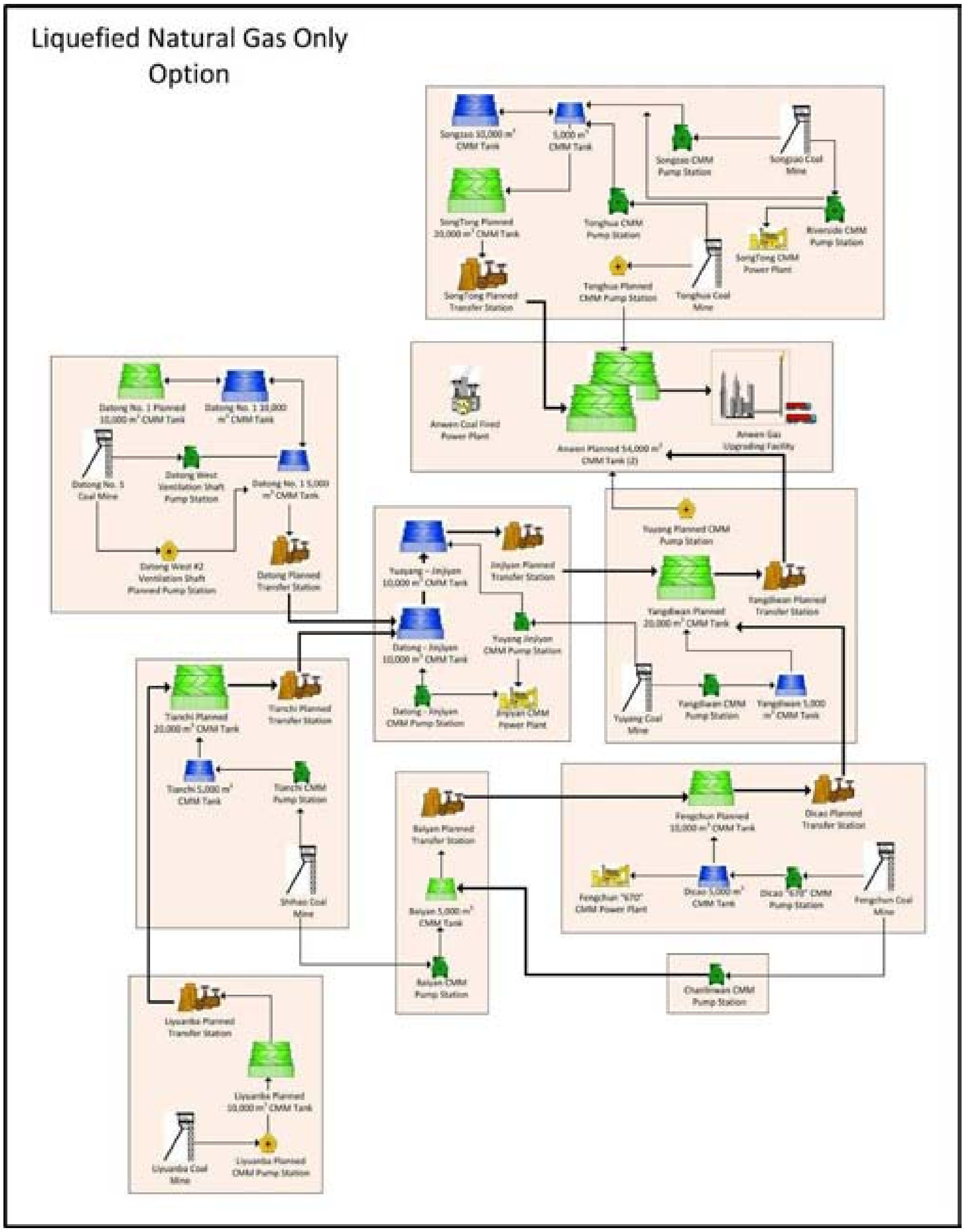


FIGURE 32: BLOCK FLOW DIAGRAM FOR CONCEPTUAL DESIGN OF LNG ONLY OPTION

5.3.1 Technology and Deployment Options: Sales of LNG Produced from CMM

The second methane use option evaluated by the study team is the generation of liquefied natural gas (LNG) utilizing a BCCK Engineering gas enrichment plant, and selling the gas to a buyer that will truck the product to market[1].

Purifying and liquefying CMM to produce LNG is a multi-step process requiring a sophisticated system that integrates contaminating gas removal with methane liquefaction. The CMM that is drained at the SCEC mines contains normal percentages of nitrogen, carbon dioxide, but considerable oxygen ranging up to 10.34 percent. Due to safety considerations, oxygen must be removed prior to compressing the gas to high pressures. Although several companies offer natural gas liquefaction plants, oxygen removal equipment is not normally an integral part of the process train. BCCK Engineering includes oxygen removal as an integral part of processing plant that it provides for CMM processing. Moreover, BCCK has reference plants at coal mines in the United States operating under similar conditions to that found at SCEC mines. For these reasons, CQEIG requested that the study team use a BCCK designed system for this study. This should not be construed as an endorsement of the BCCK process or construed that other companies could not offer similar solutions, but rather as an example of the type of system required and indicative of costs that would be incurred.

The gas would be transported to the BCCK plant, which would be sited in Anwen, via a series of transfer stations, storage tanks, and a sophisticated gathering system. The final product of BCCK's gas enrichment process is a LNG product, which is approximately 95 percent methane, with a minimal amount of impurities, such as nitrogen and carbon dioxide. A process flow diagram of the BCCK plant design is in **Appendix A**.

The unit costs for all gathering, storage, transportation equipment, and installation were derived from an earlier study completed by the Chongqing Design Institute. These unit costs were used as the basis to develop a cost estimate for each site sized to consume nearly all of forecasted gas available for use at the time each plant is finished. Included in the CAPEX estimates are the purchase of gas transfer stations and storage tanks, their installation, gas gathering, land purchase. CAPEX estimates for different size gas enrichment plants were provided by BCCK. The study team applied a mathematical fit for a range of costs supplied by BCCK for various plant sizes, **Figure 33** below. This allowed flexibility for the study team to generate reliable CAPEX and operating costs (OPEX) for any given plant size dictated by

[1] An explanation of the BCCK technology and example case studies describing the use of the technology can be found at BCCK's website: http://www.bcck.com/coal_mine_methane.html

forecasted volumes of produced CMM. The OPEX included in **Figure 33** exclude the cost for electricity, which is calculated separately based on load requirements for each plant size.

For each of the forecasted production levels, installation of the plant was carried out in two stages in the economic model. Construction of the first plant was completed after two years and ready for operation in 2011. A second, smaller, plant was constructed and ready for operations by 2015, which coincides with achieving the forecasted peak drained gas production. CAPEX and OPEX were allocated accordingly in the model to reflect the deployment of these plants.

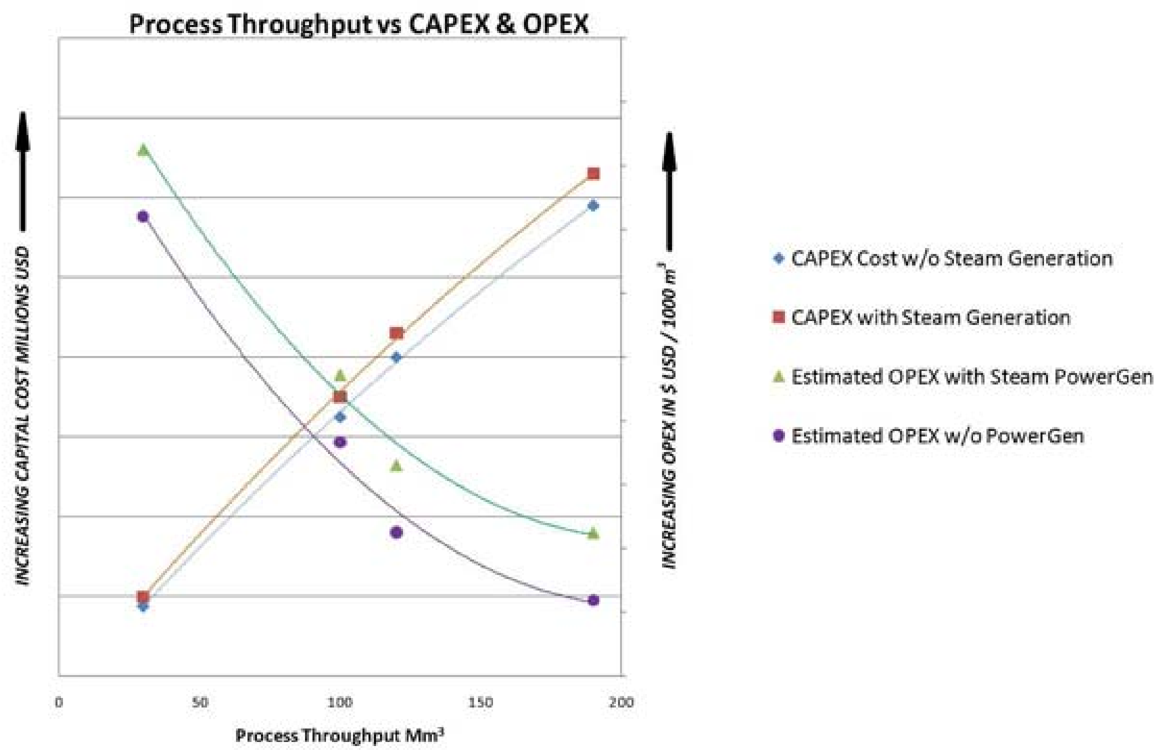


FIGURE 33: BCCK OPERATING AND CAPEX COSTS

5.3.2 Risk Factors and Mitigants: Sales of LNG Produced from CMM

Table 34 lists the associated risks that are identified for an LNG processing project located at the Anwen site. The table includes an assessment of the level of risk, and possible mitigants to each identified risk. Overall the study team has determined that the risks associated with technology, and implementation is low to moderate, but the risk due to market issues is moderate to high. After consultation with CQEIG the study team concluded that the project economics should be based on product offtake at the plant gate. The uncertainty associated with the potential for a temporary over supply of LNG to the market exists, but probably only poses a moderate threat to the economic performance. However, the ability for a LNG gas purchaser to transport commercial quantities of LNG in tanker trucks along the existing road linking Anwen to the interprovincial highway poses high market risk which could unfavorably impact the economic performance of the project. Fortunately, corrective measures such as widening the existing road and controlling local traffic, or developing an alternate restricted and secure route are relatively simple to implement; but these costs have not been included in the analysis. Rail transport is an additional possibility, and other LNG producers are petitioning the central government to make regulatory changes that will allow this mode of transport for LNG.

TABLE 34: RISK FACTORS AND MITIGANTS: SALES OF LNG PRODUCED FROM CMM

Risk	Assessment	Mitigant
Market:		
Ability to transport LNG via tanker to major highway along existing local roads	High	Present roads cannot accommodate heavy tanker traffic, they must either be improved or alternate route constructed.
Reliability of gas purchaser to move LNG product so as to avoid plant stoppages	Moderate	Establish long-term contracts with clauses that guarantee sale of gas.
Technology:		
Reliability and dependability of equipment	Low	Train local technicians to monitor, maintain and repair equipment.
Fluctuations in gas concentrations	Moderate	Incorporate equipment into drainage, collection, and storage system that regulates gas quality.
Implementation:		
Fluctuation in pricing of equipment and services	Moderate	Current trend for prices is downward; Procure contracts that lock in favorable prices.

Procurement of permits and right-of-ways	Low	Develop timeline that incorporates necessary time to secure all necessary permits and right-of-ways, allow for delays.
Delays in deliverability of equipment	Low	Plan for delays when placing orders.
Delays in installation	Moderate	Plan for delays when laying out timeline for construction and installation.

5.3.3 Economic Analysis: Sales of LNG Produced from CMM

The CMM end-use option was modeled to determine its economic performance. **Section 5.3.3.1** below lists the assumptions and inputs used for the modeling followed by **Section 5.3.3.2** reporting the resulting estimates of economic performance.

5.3.3.1 Inputs and Assumptions: Sales of LNG Produced from CMM

The following inputs and assumptions were used as a basis for the economic analysis of this end-use option:

TABLE 35: INPUTS & ASSUMPTIONS FOR LNG SCENARIO

Capacity	Phase 1: 150 million cubic meters Phase 2: 60 million cubic meters	Full operation by 2011 Full operation by 2015
Construction timing	LNG Plants Transfer stations and storage facilities	2 years per plant Construction begins in 2009; Songtong, Yangdiwan and Anwen transfer stations, and office building are completed in 2009, the remaining facilities are completed in 2010.
Capital investment: gas gathering and storage system	Business Confidential	Based on feasibility work conducted by Chongqing Coal Design Institute in 2006, with prices adjusted to year-end 2008 levels, and 8% contingency included
Capital investment,	Phase I: Business Confidential	Cost estimates supplied by

purification/LNG plant	Phase II: Business Confidential	technology/equipment suppliers
Hours of operation	8286 hours per year	
Methane gas losses in purification/LNG plant	10.34% of total gas flow	Amount is deducted from total gas processed to determine sales volume. Of the 10.34% lost during processing, 8.5% is combusted and credited appropriately to the project as emission reductions.
Electricity consumption, LNG plant	0.497 kWh per cubic meter of gas processed	Equivalent to 0.552 kilowatt hours per cubic meter of gas sold
Electricity consumption, gas gathering system	0.086 kWh per cubic meter of gas processed	Equivalent to 0.096 kilowatt hours per cubic meter sold
Electricity purchase price	0.554 yuan per kWh (including VAT)	Government-fixed purchase price from public grid
Labor costs, gathering system	13.68 million yuan per year (2 million USD per year)	300 workers at 40,000 yuan per year plus 14 percent welfare expenses
Operating costs, purification/LNG plant (excludes electricity, depreciation)	0.0224 USD per cubic meter processed	0.025 USD per cubic meter sold; includes labor, water, and equipment maintenance, excludes electricity and depreciation
Equipment maintenance cost, gas gathering and storage system	2 percent per year of capital investment in the system	
LNG sales price	Business Confidential	Sold ex-factory, with customer taking responsibility for transportation by tanker truck

5.3.3.2 Probabilistic Forecast Results: Sales of LNG Produced from CMM

Table 36 below summarizes the results of the modeling performed to determine the economic performance of a LNG end-use option. Using the p50 CMM production forecast, two LNG processing plants producing 210 million cubic meters per annum can be built to process the majority of the CMM that will be produced from all of the SCEC mines. A LNG plant that will produce 150 million cubic meters of LNG will be completed in 2011 and a second one that produces 60 million cubic meters of LNG will be completed in 2015. The economic model estimates and NPV of $123.52 million USD and an IRR of just over 24 percent. This indicates a strong economic performance and results in an estimated net reduction of 42.7 million tonnes of CO2e over the life of the project.

TABLE 36: LNG END-USE OPTION FORECAST RESULTS

	Probability Threshold					
	p90		p50		p10	
	2011	2015	2011	2015	2011	2015
LNG Plant Installed Mm3	100	40	150	60	240	70
Net Emissions Reduced (Tons CO2e)	28,117,403		42,729,483		64,686,343	
Total CAPEX	Business Confidential		Business Confidential		Business Confidential	
CapEx/Tons CO2e	Business Confidential		Business Confidential		Business Confidential	
NPV @ 10% Discount Rate	$45.59		$123.52		$223.98	
NPV/tons CO2e	1.62		2.89		3.46	
IRR	16.10%		24.19%		31.28%	

5.4 Optimized LNG and Power Production

In order to maximize the project NPV and the volume of emission reductions generated, consideration was given to employing both the LNG technology as well as power generation at Songzao mines. It was decided that the best combination of the two technologies, primarily for logistical reasons, was to employ the LNG technology at a site near Anwen town to process the methane recovered by existing operation at the Datong, Shihao, Songzao, Yuyang, Tonghua, and Fengchun mines, and to construct separate power plants fueled by methane from new mining developments at the Zhangshiba area of the Fengchun mine, and at the Liyuanba mine (see **Figure 34**). Logistical considerations include the long distance (over 13 kilometers) from the southern location of the Liyuanba mine and the Zhangshiba shafts to the area of concentrated mining in the northern reaches of the basin. Moreover, the pipeline from the southern mining facilities would pass through prime agricultural land. Costs and potential construction and security issues associated with building the pipeline through this area may outweigh the advantages.

This optimized option included a milestone in year 2013 in which a decision would have to be made whether to install power generating equipment at Liyuanba or to transport the gas via pipeline and tie into the existing gathering system which transports gas to the LNG plant. By design, the decision to either link the mines in the south to the LNG gathering system or install power plants can be delayed until the performance of the first LNG processing plant is assessed.

CMM production rates can be more accurately gauged at that point allowing SCEC and CQEIG to make choices of end-use options and the determinations of the appropriate size with more assurance. In short this option allows a great deal of flexibility. The economic analysis below for this optimized option assumes that management ultimately chooses to build power plants to burn the gas at Zhangshiba and Liyuanba.

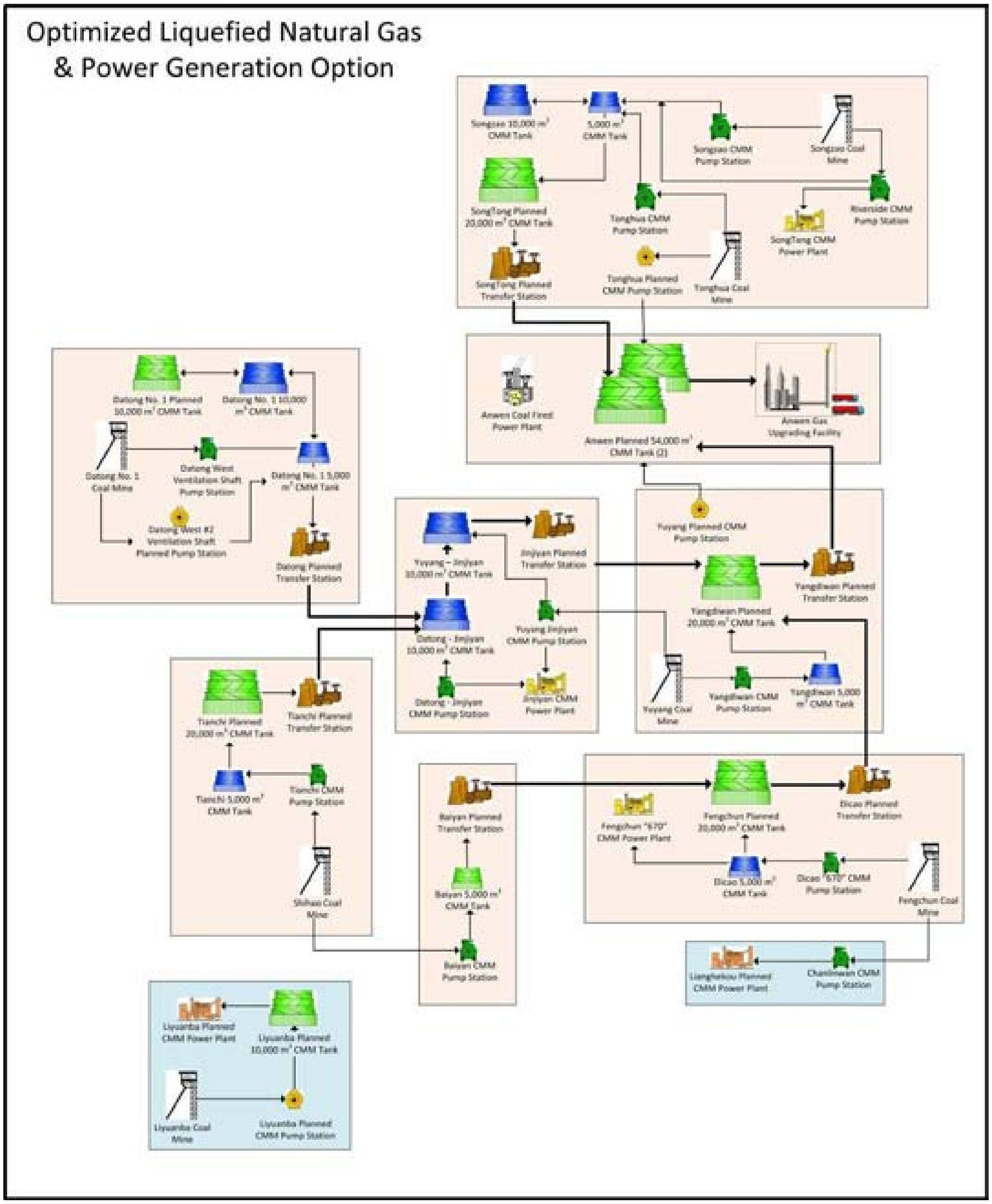


FIGURE 34: BLOCK FLOW DIAGRAM FOR CONCEPTUAL DESIGN OF OPTIMIZED OPTION

5.4.1 Configuration and Deployment Options: Optimized LNG and Power Production

The types of equipment employed as well as the unit costs are the same as in the two single end-use models. The same logic was used in this model as in the other options, to size equipment and deploy the LNG plants and internal combustion power generation facilities.

The gathering system to transport methane from the mines to the centralized LNG facility in Anwen town is designed for the total maximum flow to the plant over the life of the project. The purification/liquefaction facility itself, however, is designed to be built in two phases, with the first phase consuming the methane volumes available as of 2009-2010, and the second consuming the additional methane associated with expanded coal production in the existing mines that will become available by 2015-2016.

Capacity of the purification/LNG plants for the p50 scenario is as follows:

	Throughput Capacity	*Year Operational*
• Phase I	130 million cubic meters	2011
• Phase II:	40 million cubic meters	2015

The purification/liquefaction plant design is based on existing units in the United States which are processing CMM, and includes the following facilities:

- Electric motor driven inlet compression, and associated equipment
- Electric motor driven methane recycle compression, and associated equipment
- Electric motor driven propane refrigeration compression
- Electric motor driven ethylene refrigeration compression
- Propane refrigeration system
- Ethylene refrigeration system
- CO2 removal system (amine)
- Oxygen removal system
- Steam system, integrated with oxygen system (utilizing excess heat from O2 reactor)
- Mole sieve dehydration system
- Nitrogen Removal Unit with integrated LNG system
- Steam powered turbine for power generation (see 9 above)
- Control system and HMI consoles
- Control valves and instrumentation required for operation
- Motor starters and MCC gear

The steam system/steam turbine is designed to utilize the heat generated by the oxygen removal system to generate electricity used by the plant itself, and thereby reduce the need for electricity from external sources.

The gas gathering system is based on a design employed by the Chongqing Coal Design Institute in a 2006 feasibility study, including:

1. Transfer stations at the sites of evacuation of methane from the mines, including roots-type blowers (positive displacement pumps) of varying capacities to transport the methane to downstream gathering stations and to the central gathering station in Anwen town.

2. Low pressure wet gas storage tanks using existing proven Chinese technology of 5,000-20,000 cubic meters capacity at the methane evacuation sites and intermediate stations and a 54,000 cubic meter tank sited at the central gathering facility at Anwen town. These storage tanks service the purpose of regulating both methane concentration and gas flow.

3. Pipelines of 400-600 millimeter diameter with length totaling approximately 40.5 kilometers to connect the evacuation sites to each other, and to the Anwen gathering site. Inlet pressure is 178.4 kilopascals; outlet pressure is 116 – 142 kilopascals depending on location.

The costing for these facilities has also taken land acquisition costs into account.

The power generation component of the optimized option consists of two stations selling power to SCEC for its own use without going through the public grid, as follows:

Location	Lianghekou, at new Zhangshiba Shaft of Fengchun Mine	Liyuanba Mine
Capacity	11 MW (nominal)	15.9 MW
Construction timeline:	2010 – 2016	2011-2016
Configuration:	22 x 500 kW Chinese-produced internal combustion engines	24 x 1.8 MW Caterpillar engines plus a 1.5 MW steam turbine utilizing waste heat from engines

In addition to the generating units themselves, the design includes various auxiliary systems, such as water supply, as well as interconnection facilities to SCEC's internal power grid, and short gas gathering lines connecting the mines' methane pumping stations to the plant sites.

The Shengli units are specified for Lianghekou because SCEC has already committed to them for a portion of the plant that is designed to sell carbon credits to Mitsui under the Kyoto Protocol's Clean Development Mechanism. The Caterpillar units are specified for Liyuanba due to the lower life-cycle power generation unit costs associated with use of higher-efficiency engines. Caterpillar was named in a feasibility study performed for SCEC in 2007 by the Chongqing Coal Design Institute; however, the plant could be designed using any high-efficiency internal combustion engines available from other manufacturers.

5.4.2 Risk Factors and Mitigants: Optimized LNG and Power Production

The same market, technical, and implementation risks attributed to the single use options described in **Sections 5.2.2** and **5.3.2** apply to the optimized option. Under the optimized option a decision point is reached in 2013 where additional risks must be assessed. **Table 37** summarizes the risk and mitigants that will impact the decision to either:

1. Build a second LNG plant, next to the original plant, to process additional gas available from the northern mines, and install a power generating facility at the Liyuanba Mine and Zhangshiba shaft to generate electricity to be used only on the mine's grid; or
2. Build a pipeline from Liyuanba to join the northern gathering system, build a second plant capable of processing all additional gas produced from all Songzao mines to produce LNG.

In both cases, the risks identified in **Table 37** below are moderate and the mitigants can satisfactorily provide assurance that the risks will not adversely impact the economic performance of the project. However the actions required to appropriately mitigate the risks will take active forethought to be successful and available at the time of need.

TABLE 37: RISK FACTORS AND MITIGANTS: OPTIMIZED OPTION

Risk	Assessment	Mitigant
Market:		
LNG: Price is down due to economic conditions	Moderate	Establish long-term contracts, establish low-cost transportation, and develop new markets.
Electricity: Access to the grid does not improve	Moderate	Produce electricity that can be used only by the mine's grid.

5.4.3 Economic Analysis: Optimized LNG and Power Production

This end-use project option was modeled to determine its economic performance. **Section 5.4.3.1** lists the assumptions and inputs used for the modeling followed by **Section 5.4.3.2** reporting the resulting estimates of economic performance.

5.4.3.1 Inputs and Assumptions: Optimized LNG and Power Production

The following inputs and assumptions serve as the basis for this economic performance model:

TABLE 38: INPUTS & ASSUMPTIONS FOR THE OPTIMIZED OPTION

Project Duration	2009 – 2025	
Project ownership and financial structure	Power plants and LNG plant are profit centers, independent from the SCEC mining operations; debt and equity structure has not yet been decided by sponsor	IRR is calculated against entire project investment, no debt service included in cash flow analysis.
Gas flows to project	According to p50 probability threshold (Section 3.2)	Separate models also constructed for p10 and p90 thresholds but base case economic analysis is based on P50 volumes
Depreciation Method	15 year straight line	
Certified Emission Reduction (CER) Sales Price	13.00 USD per tonne of CO_2 equivalent	CER sales in years 2010-2012 only
Verified Emission Reduction (VER) Sales Price	6.50 USD per tonne of CO_2 equivalent	VER sales in years 2013-2025
Conversion of methane to CO_2 equivalent	0.01428 tons CO_2e per cubic meter of methane	
CMM Purchase Price	Business Confidential	Assumed arms length transaction between mines and power plants/LNG plant. This price does not include the 0.2 yuan per cubic meter incentive payment from central government to CMM producer (SCEC) for gas consumed by power plants or LNG plant under regulations designed to encourage the utilization of CMM (MOF, 2007).

Value added Tax (VAT) special incentives	None	Base case assumes that government regulations calling for refund of all VAT taxes paid by CMM producers do not apply to the project as a CMM processor; (MOF, 2007).
VAT Refund on Project Inputs	VAT component of purchase price for gas, electricity, and water inputs to the project are refunded	Per government VAT regulations
VAT Rates	CMM: 14.04% Electricity: 18.36%:	Inclusive of 8 percent surtaxes for urban construction, education, etc. CMM base rate: 13% Electricity base rate: 17%
Income Tax	5 year income tax holiday; 25 percent per year starting from year 6 of operations	Per government regulations encouraging comprehensive utilization of coal products (MOF, 1994, NDRC 2004).
Inputs and assumptions specific to the power generation operations		
Plant construction	Construction for Lianghekou begins in 2010, construction for Liyuanba begins in 2011	Liangkekou site containing Shengli engines is completed in 2016. Liyuanba site containing caterpillar engines is completed in 2016.
Capital Investment for p50 scenario (million yuan)	Business Confidential	Power station investment based on unit costs as follows (yuan per kilowatt)- Caterpillar units: 7,148.39 Shengli units: 4,039.60
Annual Power Sales	Self-consumption 26.9 MW by SCEC	
Hours of operation for self-consumption by Songzao	6500 per year	Per current practice at SCEC's existing CMM power plants.
Hours of operation for sale to public grid	5000 hrs. per year (2010) 6150 hrs. per year (2015-2025)	Figures for 2010 based on historic dispatch hours for thermal power plants in Chongqing (CEPY, 2007 p. 626) Increase to 6150 hours based on assumption that government policies calling for priority dispatch for CMM power plants are gradually implemented (NDRC, 2007.2)
Shengli engine specifications:	• 391 kW nominal output, • 0.35 cubic meters per kwh generated	Based on actual experience of Songzao with similar units in existing CMM power plants

	• Utilizes 6.5% of gas stream as fuel	
Caterpillar engine specifications:	• 1.8 MW output • 0.232 cubic meters per kwh generated • Utilizes 5.6% of gas stream as fuel	Based on contacts with manufacturer's representatives and end-users.
Power sales price, self-use by SCEC	0.417 yuan per kWh	Per present practice for self-use CMM power plants operated by SCEC
Power sales price to public grid	0.3793 yuan per kWh	Present price paid by grid for purchase of power from new coal-fired units (NDRC, 2008.2, NDRC, 2008.3). Policy calling for 0.25 yuan per kwh supplement for CMM power (NDRC, 2007.4) not applied due to perceived power grid company resistance.
Annual equipment repair & maintenance costs	2.5 percent of the purchase price for the equipment	
Annual labor cost	3.5 million yuan per year	305 workers at average 40,000 yuan per year salary, plus 14 percent social welfare benefits
Water consumption and cost	.0038 cubic meters per kWh generated at 2.5 yuan per cubic meter	Consumption per Chongqing Coal Design Institute 2007 study; price provided by Chongqing Energy Investment Corporation
Inputs and assumptions specific to the LNG operations		
Capacity	Phase 1: 130 million cubic meters Phase 2: 40 million cubic meters	Full operation by 2011 Full operation by 2015
Construction timing	LNG Plants Transfer stations and storage facilities	2 years per plant Construction begins in 2009; Songtong, Yangdiwan and Anwen transfer stations, and office building are completed in 2009, the remaining facilities are completed in 2010.
Capital investment, gas gathering and storage system	Business Confidential	Based on feasibility work conducted by Chongqing Coal Design Institute in 2006, with prices adjusted to year-end 2008 levels.
Capital investment, purification/LNG plant	Business Confidential	Cost estimates supplied by technology/equipment suppliers
Hours of operation	8286 hours per year	

Methane gas losses in purification/LNG plant	10.34% of total gas flow	Amount is deducted from total gas processed to determine sales volume
Project Emissions	0.1784 tons/MWh 13.1%	Factor used to determine project emissions resulting from power consumed by LNG plant and outlying facilities, and for all power generated by the CMM power generation plants. Percent that project emission reductions generated from sale of LNG gas is reduced due to combustion of gas off site.
Electricity consumption, LNG plant	0.497 kWh per cubic meter of gas processed	Equivalent to 0.552 kilowatt hours per cubic meter of gas sold
Electricity consumption, gas gathering system	0.086 kWh per cubic meter of gas processed	Equivalent to 0.096 kilowatt hours per cubic meter sold
Electricity purchase price	0.554 yuan per kWh (including VAT)	Government-fixed purchase price from public grid
Labor costs, gathering system	13.68 million yuan per year (2 million USD per year)	300 workers at 40,000 yuan per year plus 14 percent welfare expenses
Operating costs, purification/LNG plant (excludes electricity, depreciation)	0.0224 USD per cubic meter processed	0.025 USD per cubic meter sold; includes labor, water, and equipment maintenance, excludes electricity and depreciation
Equipment maintenance cost, gas gathering and storage system	2 percent per year of capital investment in the system	
LNG sales price	Business Confidential	Sold ex-factory, with customer taking responsibility for transportation by tanker truck

5.4.3.2 Probabilistic Forecast Results: Optimized LNG and Power Production

Table 39 below lists key indicators of the economic performance for an optimized LNG and Power Production end-use option. Using the p50 CMM production forecast, two LNG processing plants producing 160 million cubic meters per annum can be built to process the majority of the CMM that will be produced from all of the SCEC mines. A LNG plant that will produce 120 million cubic meters of LNG will be completed in 2011 and a second one that produces 40 million cubic meters of LNG will be completed in 2015. If the decision is made to install electric power production facilities at Liyuanba and the Zhangshiba shaft, the total installed electric power generation capacity fueled by CMM produced by SCEC mines would increase by 26.9 MW. The economic model estimates and NPV of $84.03 million USD and an IRR of 20.49 percent. This indicates a strong economic performance and results in an estimated net reduction of 44.1 million tonnes of CO2e over the life of the project. As discussed previously, the decision to implement power production can be delayed and the final choice could be made to build an additional LNG plant instead. This, of course would result in economic performance similar to the ones reported in the section covering the LNG only end-use option.

TABLE 39: OPTIMIZED END-USE FORECAST RESULTS

	Probability Threshold					
	p90		p50		p10	
	2011	2015	2011	2015	2011	2015
LNG Plant Installed Mm3	90	20	130	40	220	50
PowerGen Installed MW	22.1		26.9		32.7	
Net Emissions Reduced (Tons CO2e)	29,223,668		44,081,205		66,381,438	
Total CAPEX	Business Confidential		Business Confidential		Business Confidential	
Ratio: CapEx/Tons CO2e	Business Confidential		Business Confidential		Business Confidential	
NPV @ 10% Discount Rate	$16.30		$84.03		$187.33	
Ratio: NPV/tons CO2e	0.56		1.91		2.82	
IRR	12.41%		20.49%		28.91%	

5.5 Comparison and Economic Performance of End-use options

Table 40 allows the comparison of each end-use option examined by the study team for this feasibility study. The study team has concluded that the best economic performance would result from an LNG only end-use option. Yet, the risks associated with changes in the market price of LNG (see discussion in the following subsection), lower than expected CMM production, issues relative to building a pipeline linking the southern mining facilities to the central gathering system or any combination of these factors could adversely impact the economic performance of and LNG only option. For that reason the third option that allows for a mid-project development decision point seems the most prudent and gives management an active role in determining the economic outcome.

TABLE 40: COMPARISON OF END-USE OPTIONS

Probability Threshold		Optimized Use		Only Power Generation		Only LNG	
		2011	2015	2011	2015	2011	2015
p90	LNG Plant Installed Mm^3	90	20			100	40
	PowerGen Installed MW	22.1		113.2			
	Net Emissions Reduced (Tons CO2e)	29,223,668		35,841,687		28,117,403	
	Total CAPEX	Business Confidential		Business Confidential		Business Confidential	
	Ratio: CapEx/Tons CO2e	Business Confidential		Business Confidential		Business Confidential	
	NPV @ 10% Discount Rate	$16.30		$19.89		$45.59	
	Ratio: NPV/tons CO2e	0.56		0.55		1.62	
	IRR	12.41%		12.97%		16.10%	
p50	LNG Plant Installed Mm^3	130	40			150	60
	PowerGen Installed MW	26.9		166.2			
	Net Emissions Reduced (Tons CO2e)	44,081,205		54,163,128		42,729,483	
	Total CAPEX	Business Confidential		Business Confidential		Business Confidential	
	Ratio: CapEx/Tons CO2e	Business Confidential		Business Confidential		Business Confidential	
	NPV @ 10% Discount Rate	$84.03		$58.82		$123.52	
	Ratio: NPV/tons CO2e	1.91		1.09		2.89	
	IRR	20.49%		16.25%		24.19%	
p10	LNG Plant Installed Mm^3	220	50			240	70
	PowerGen Installed MW	32.7		241.8			
	Net Emissions Reduced (Tons CO2e)	66,381,438		81,681,623		64,686,343	
	Total CAPEX	Business Confidential		Business Confidential		Business Confidential	
	Ratio: CapEx/Tons CO2e	Business Confidential		Business Confidential		Business Confidential	
	NPV @ 10% Discount Rate	$187.33		$107.64		$223.98	
	Ratio: NPV/tons CO2e	2.82		1.32		3.46	
	IRR	28.91%		18.13%		31.28%	

5.5.1 Sensitivity Analysis of End-use options

The study team performed sensitivity analysis on the optimized option using the p50 CMM production forecast. As can be seen below in the tornado diagrams, **Figures 35 and 36**, which depict the contribution to the statistical variance in the estimated NPV and IRR, gas sales price is the largest factor.

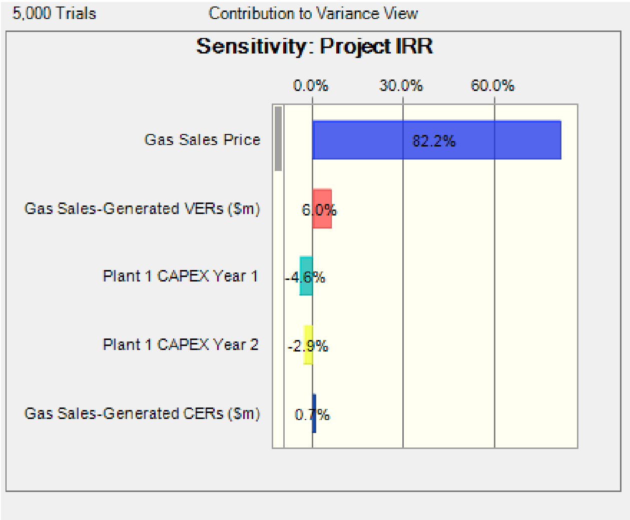


FIGURE 35: IRR CONTRIBUTION TO VARIANCE

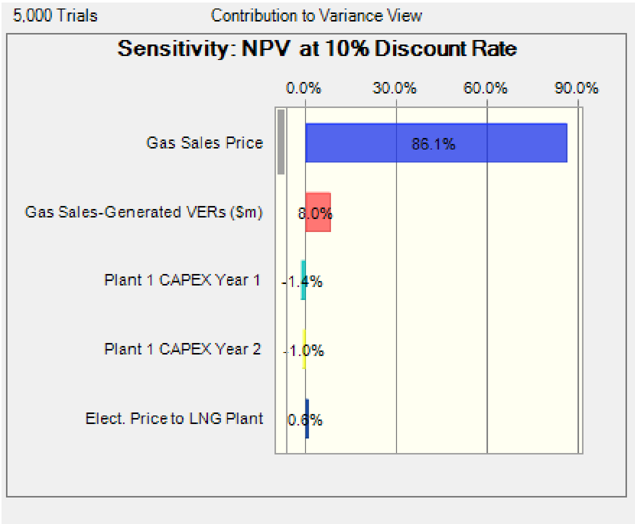


FIGURE 36: NPV CONTRIBUTION TO VARIANCE

Gas sales price overshadows other factors, with the next largest contributions coming from the gas sales-derived VER sales—followed by the CAPEX from installation of the first LNG processing plant .CER sales makes a less than one percent contribution to the Project IRR and avoided cost of electricity contributes a similarly negligible amount to the variance in NPV.

An additional sensitivity analysis was performed to determine the impact of having the option to sell either CERs and/or VERs would have on project economics. The study team analyzed four different scenarios for the optimized option regarding carbon credit sales, with results as shown in **Table 41**. The four scenarios are: (1) no carbon credit sales at all; (2) sales of Certified Emissions Reductions (CERs) through the conclusion of the Kyoto Protocol in 2012 at a price of \$12.72 USD per tonne of CO_2 equivalent (CO_2e) under which the greenhouse effect of 1 cubic meter of methane is considered to be the same as 0.01428 tonnes of CO_2); (3) sales of Verified Emissions Reductions (VERs) for the years following 2012 (2013 through 2025) at a price of \$6.12 USD per tonne of CO_2e; and (4) sales of both CERs through 2012 and VERs after 2012 per the prices above.

TABLE 41: IMPACT OF CARBON CREDITS ON ECONOMIC RESUTS FOR OPTIMIZED OPTION

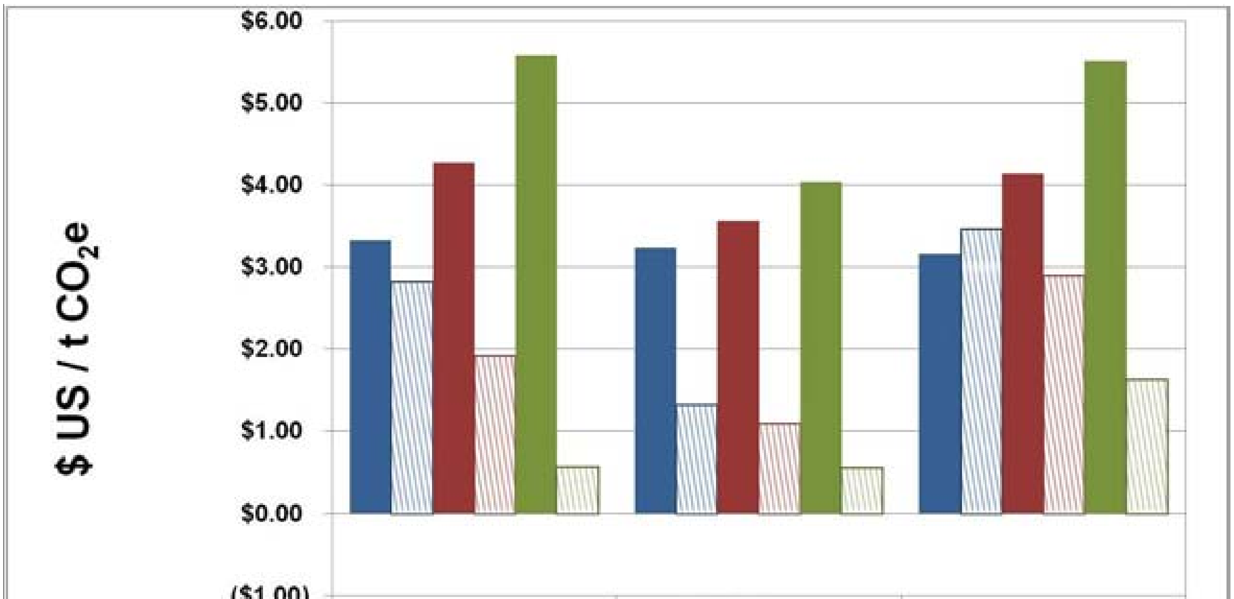
	Internal Rate of Return (IRR)	Net Present Value at 10% Discount Rate (NPV) – Million USD
Scenario 1: No carbon credits	9.31	-5.31
Scenario 2: CERs, 2010-2012	13.72	25.16
Scenario 3: VERs, 2013-2025	15.96	53.56
Scenario 4: CERs, 2010-2012 and VERs, 2013-2015	20.49	84.03

The study team considers the probability for VERs (post 2012) to be high, and for CERs (years 2010-2012) to be moderate. Scenario 3 is therefore considered to be the baseline in **Table 41** above. The low rate of return under Scenario 1 clearly shows the importance of sale of carbon credits to the economic return for the project.

5.5.2 Economic Performance Relative to Carbon Emissions

The economic performance of an investment in a CMM end-use project can be measured by commonly used indicators such as return on investment, net present value, and internal rate of return. Economic and sensitivity analysis performed by the study team indicates that the end-use options being contemplated all have strengths and weaknesses; but the bar chart included in **Figure 37** shows the advantage that the LNG project option has over the power generation option if the economic efficiency of reducing methane emissions is considered. This analysis was prepared using the p90, p50, and p10 methane production forecasts. Two performance indicators are depicted on the chart: *the ratio of CAPEX dollars invested to tonnes* of CO_2e shown as solid bars; and the *ratio of dollars of NPV realized per tonne of CO_2e* shown in hachured bars. Economic efficiency of the power generation option appears to be moderately attractive when considering only the amount of CAPEX invested per tonne of CO_2e emissions reduced, but the dollars of NPV realized per tonne of CO_2e emissions reduced is substantially lower than realized by the other end-use options. The poor economic efficiency of reducing carbon emissions relative to NPV dollars realized is principally due to the fact that electricity is being generated and consumed internally by SCEC not sold to the grid. The amount of carbon emissions reduced is limited to the methane destroyed in the IC engines, and the amount of coal-fired generated electricity that is displaced on the SCEC-owned mine electrical grid; but displacement of coal fired electric power generation would be much greater if electricity generated by CMM fueled plants were sold to the grid.

Analysis of the economic efficiency associated with the LNG project option presents a very different picture. The CAPEX dollars per tonne of CO_2e emissions reduced is substantially higher as is the dollars of NPV realized by reducing emissions in this manner. The optimized use option also demonstrates strong economic performance, but is slightly less so than the LNG option due to the power generation component included in this scenario.



	Optimized Use	Only Power Generation	Only LNG
p10 CAPEX $s / t CO2e	$3.33	$3.24	$3.16
p10 $s NPV / t CO2e	$2.82	$1.32	$3.46
p50 CAPEX $s / t CO2e	$4.28	$3.57	$4.14
p50 $s NPV / t CO2e	$1.91	$1.09	$2.89
p90 CAPEX $s / t CO2e	$5.59	$4.04	$5.52
p90 $s NPV / t CO2e	$0.56	$0.55	$1.62

FIGURE 37: ECONOMIC EFFICIENCY OF END-USE OPTIONS RELATIVE TO CARBON EMISSION REDUCTIONS

5.6 Recommendations

Based the findings of the feasibility study, the study team recommends that CQEIG undertake a project focusing on gathering, purifying and liquefying of the majority of the CMM produced at SCEC mines. The end product of this effort would be LNG product supplied to commercial and industrial gas markets. Our recommendation recognizes the existence of a strong and expanding gas market in China, and the higher returns that would be realized by selling LNG to the gas market versus producing power from CMM for sale to the public grid. The return on investment from an emissions reduction perspective is also favorable to the LNG processing and supply option. However, in view of logistical and other issues involved with the purification and liquefaction of CMM from the Liyuanba Mine and Zhangshiba shaft, which are located a significant distance from the central gathering and processing area, we recommend that management wait until 2013 to decide whether to link these sites to the central gas gathering and LNG processing system or to use the CMM as fuel for small power plants built at the mine site. If CQEIG elects to generate power at the outlying sites, the electricity would be supplied the mine grid system and offset power consumed by the purification and liquefaction plant. It is also apparent from the sensitivity analysis performed that additional revenues from the sale of carbon credits significantly improve the economic performance of the project. Qualifying the project under the appropriate carbon emission trading schemes must be a priority as the project moves forward, in order to maximize the economic performance of the project regardless of the final mix of LNG and power sales.

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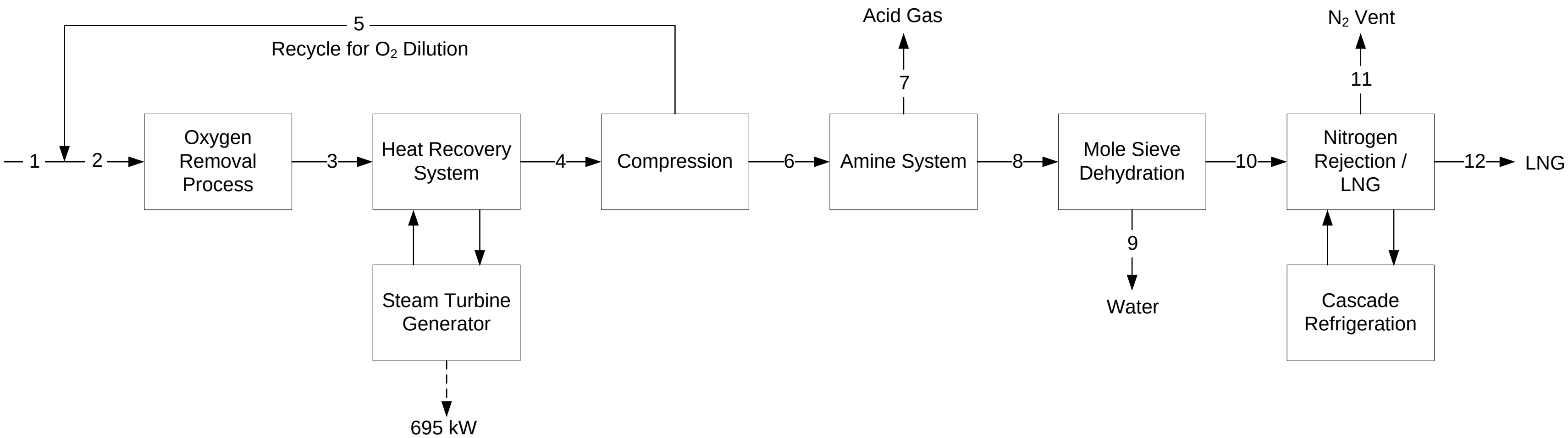
Appendix A: CMM NRU/LNG Project Block Flow Diagram

Chongqing Energy Investment Group – CMM NRU/LNG Project

Block Flow Diagram – 130 MMm^3/yr



Process Streams		1	2	3	4	5	6	7	8	9	10	11	12
Property	**Units**												
Temperature	°C	48.9	47.7	517.3	64.1	48.8	48.9	49.6	49.2	49.2	49.2	28.9	-155.1
Pressure	bar	11.4	11.4	11.0	10.6	16.1	44.4	1.8	44.3	44.2	44.2	7.9	2.1
Molar Flow	kmol/h	1395.06	5228.62	5228.62	5228.62	3833.56	1265.38	65.85	1203.08	3.02	1200.06	571.84	628.2
Std Vapor Volumetric Flow	m^3/h	33049.48	123868.32	123868.32	123868.32	90818.83	29977.34	1559.95	28501.44		28429.91	13547.08	14883.0
Std Liquid Volumetric Flow	lpm									0.9			558.1
Composition													
Mole Fraction		mol %	mol %	mol %	mol %	mol %	mol %	mol %	mol %	mol %	mol %	mol %	mol %
Carbon Dioxide		0.09	3.51	4.65	4.65	4.76	4.78	91.83	0.00	0.00	0.00	0.00	0.00
Nitrogen		40.79	43.69	43.69	43.69	44.75	44.96	0.27	47.27	0.00	47.39	98.00	1.32
Methane		49.55	49.68	48.55	48.55	49.73	49.96	1.22	52.48	0.00	52.61	2.00	98.67
Water		1.07	0.85	3.11	3.11	0.76	0.31	6.68	0.25	99.87	0.00	0.00	0.00
Oxygen		8.49	2.27	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

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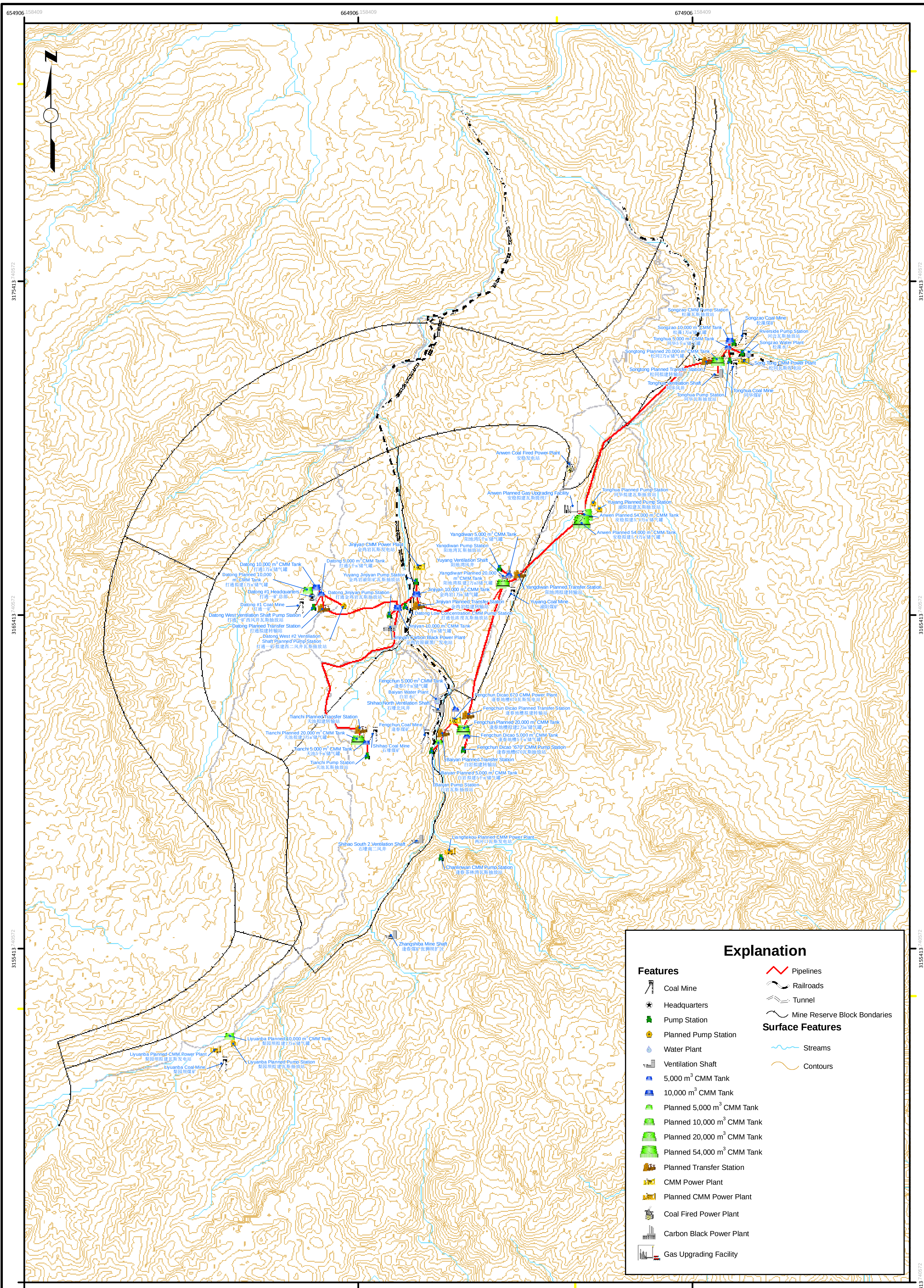
Appendix B: Capex Costs for Gas Transfer and Storage Facilities – LNG Option

Capital Costs - Construction (x1000)		*Capital Costs - Equipment (x1000)*	
Land acquistion	¥69,164	Distribution pipelines - cost of pipe	¥15,421
		Distribution pipelines - cost of installation	¥36,303
		Newly added pump station equip.	¥12,004
Datong Transfer Station (Datong Mine)	¥3,967	Datong	¥1,572
		Datong Storage Tank	¥4,494
Jinjiyan Transfer Station (Yuyang Mine)	¥3,368	Jinjiyan	¥1,480
		Jinjiyan Storage Tank	¥2,666
Songtong Transfer Station (Tonghua & Songzao mines)	¥4,106	Songtong	¥2,139
		Songtong Storage Tank	¥7,680
Shihao Transfer Station (Shihao Mine)	¥4,106	Shihao	¥3,379
		Shihao Storage Tank	¥7,680
Yangdiwan Transfer Station (Yuyang Mine)	¥4,429	Yangdiwan	¥5,927
		Yangdiwan Storage Tank	¥7,680
Dicao Transfer Station (Fengchun Mine)	¥3,547	Dicao	¥2,139
		Dicao Storage Tank	¥4,494
Liyuanba Transfer Station (Liyuanba Mine)	¥3,547	Liyuanba	¥2,139
		Liyuanba Storage Tank	¥4,494
Baiyan Transfer Station (Shihao Mine)	¥3,295	Baiyan	¥2,139
		Baiyan Storage Tank	¥3,129
Anwen Main Station	¥15,076	Anwen	¥69,462
		Anwen Storage Tank	¥21,873
Office Bldg	¥12,950	Office Bldg	¥990
Totals	**¥127,553**		**¥219,283**
Grand Total (x1000)			**¥346,836**



Project Name: China Feasibility Study EPA	
Map Document: D-size Facilities.mxd	
Drawn By: Candice L.M. Tellio	Date: Jun 18, 2008
Approved By: Raymond C. Pilcher	Date: Jul 2, 2008
Source: Songzao Coal And Electricity Co.	Date: Dec 17, 2008
Current Revision No.: Final	Date: Apr 9, 2009
Revised By: CLMT	

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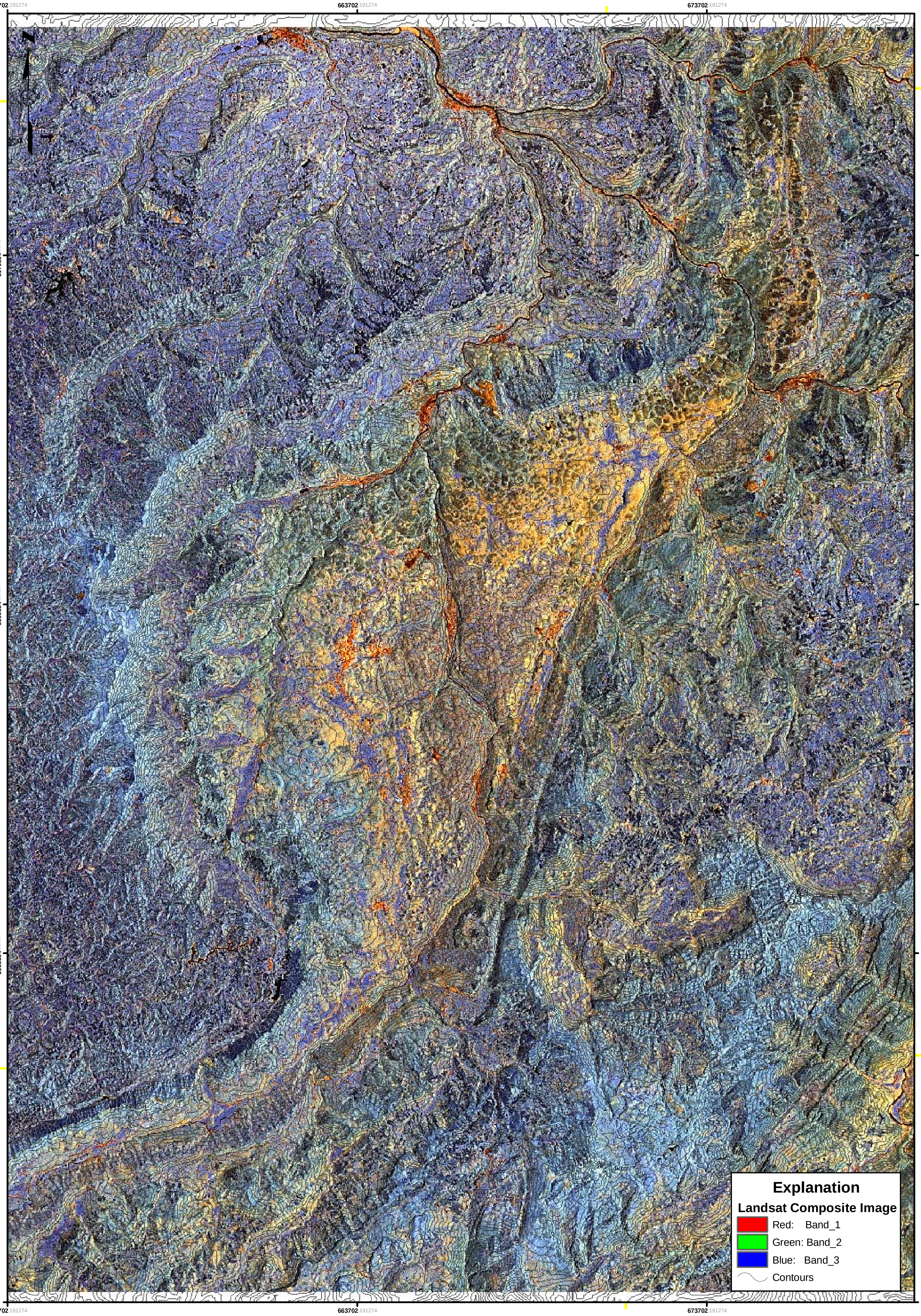
Map 1: Facilities Map

SCALE 1:100,000

0 500 1,000 2,000 3,000 4,000 Meters

CONTOUR INTERVAL 50 METERS WGS 1984, UTM ZONE 48N



Project Name: China Feasibility Study EPA	
Map Document: D-size False Color Image.mxd	
Drawn By: CLMT	Date: July 1, 2008
Approved By: Raymond C. Pilcher	Date: July 2, 2008
Source: Landsat.org	Date: Apr 10, 2009
Image Date: July 31, 2000	
Revised By: CLMT Nov. 14, 2008	

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Map 2: False Color Image

Landsat Enhanced Thematic Mapper Plus

SCALE1:100,000

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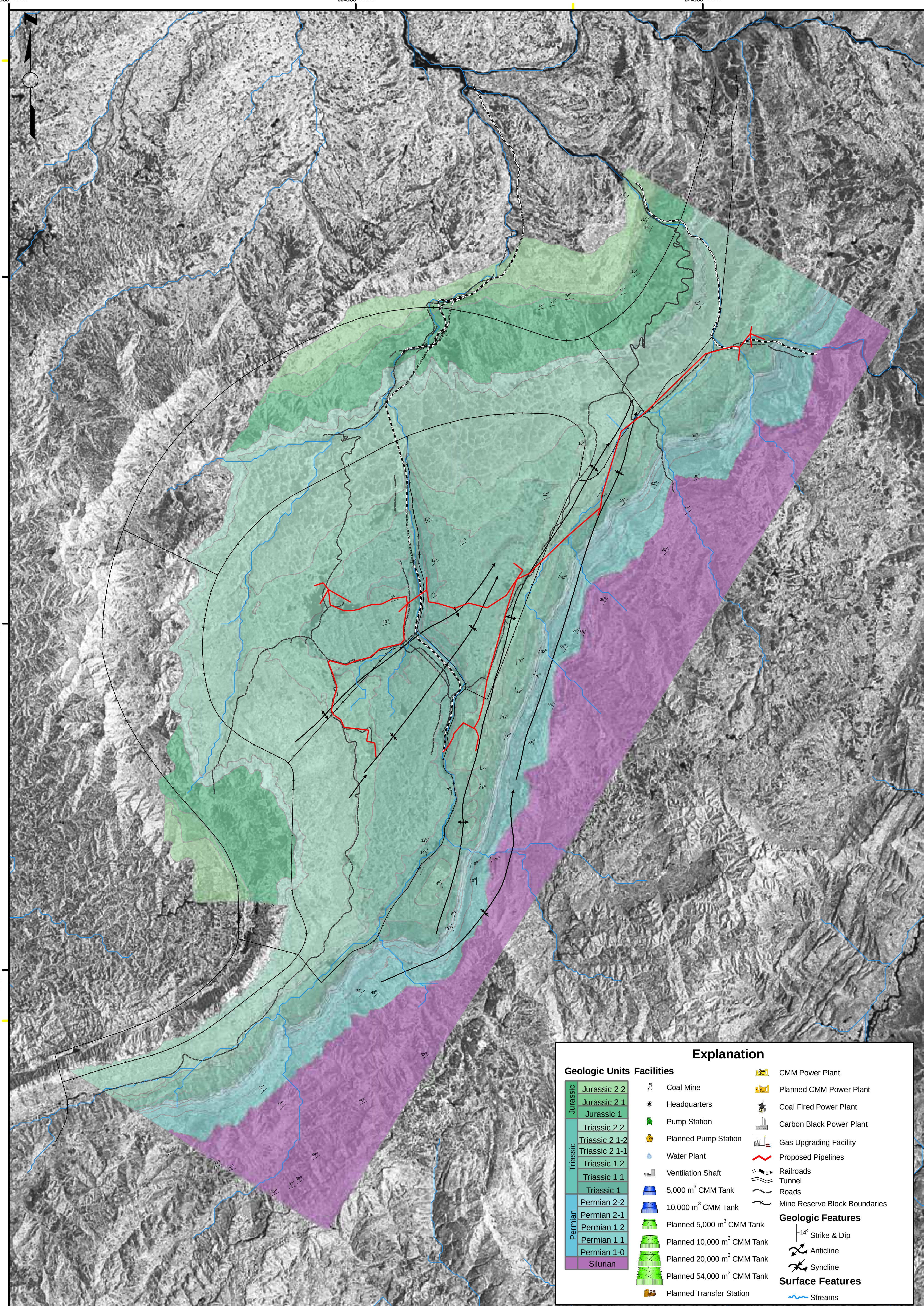
CONTOUR INTERVAL 50 METERS WGS 1984, UTM ZONE 48N



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Map Document: D-size Geology.mxd	
Drawn By: CLMT	Date: June 30, 2008
Approved By: Raymond C. Pilcher	Date: July 2, 2008
Source: Songzao Coal And Electricity Co.	Date:
Current Revision No.:	Date: Dec. 29, 2008
Revised By: CLMT	

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Map 3: Geologic Map

SCALE 1:100,000

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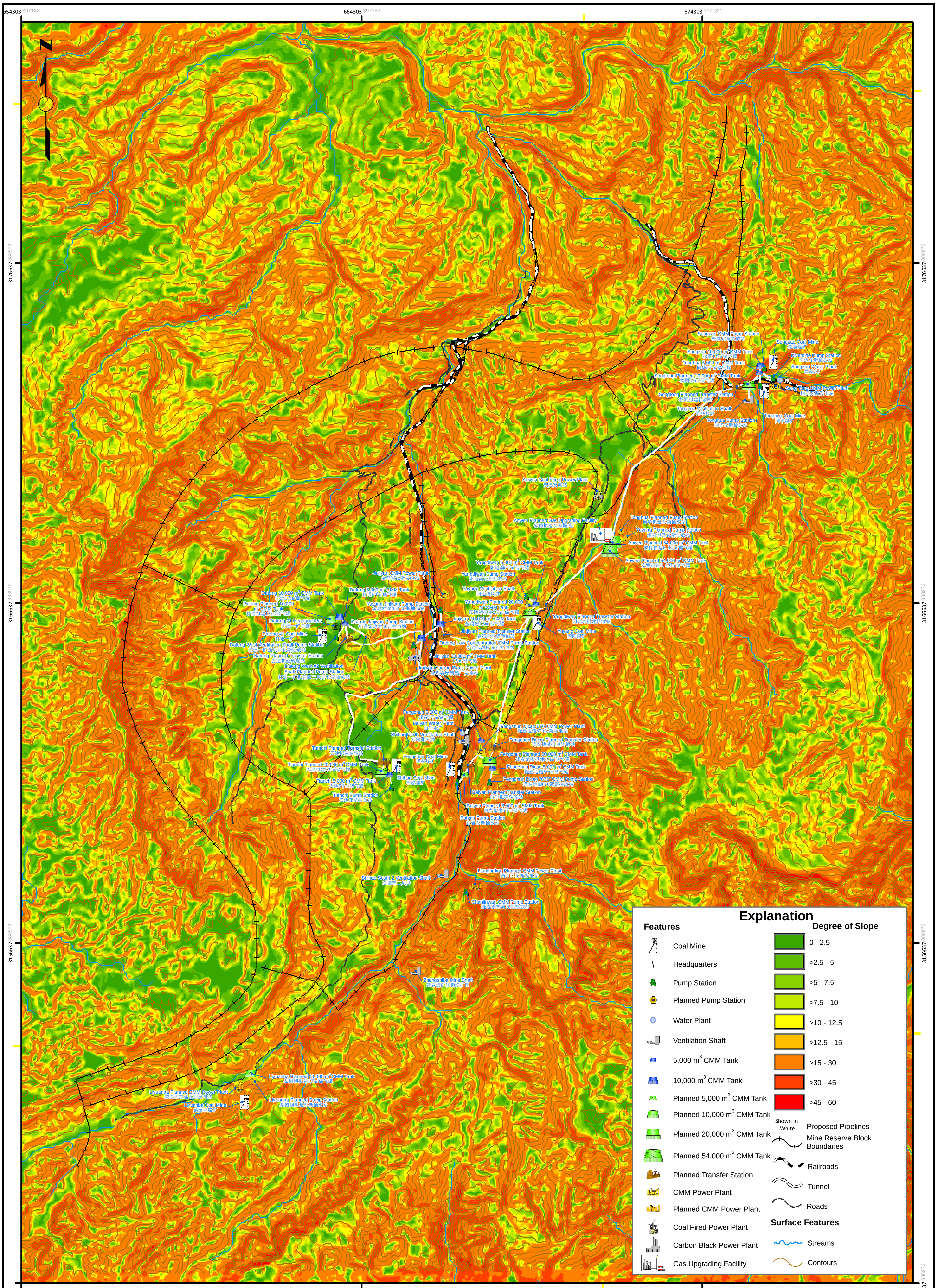
CONTOUR INTERVAL 50 METERS WGS 1984, UTM ZONE 48N



Project Name: China Feasibility Study EPA
Map Document: D-size Slope Analysis.mxd
Drawn By: CLMT Date: July 1, 2008
Approved By: Raymond C. Pilcher Date: July 2, 2008
Source: ESRI Data & Maps Media Kit Date:
Current Revision No.: Date: Dec 17, 2008
Revised By: CLMT

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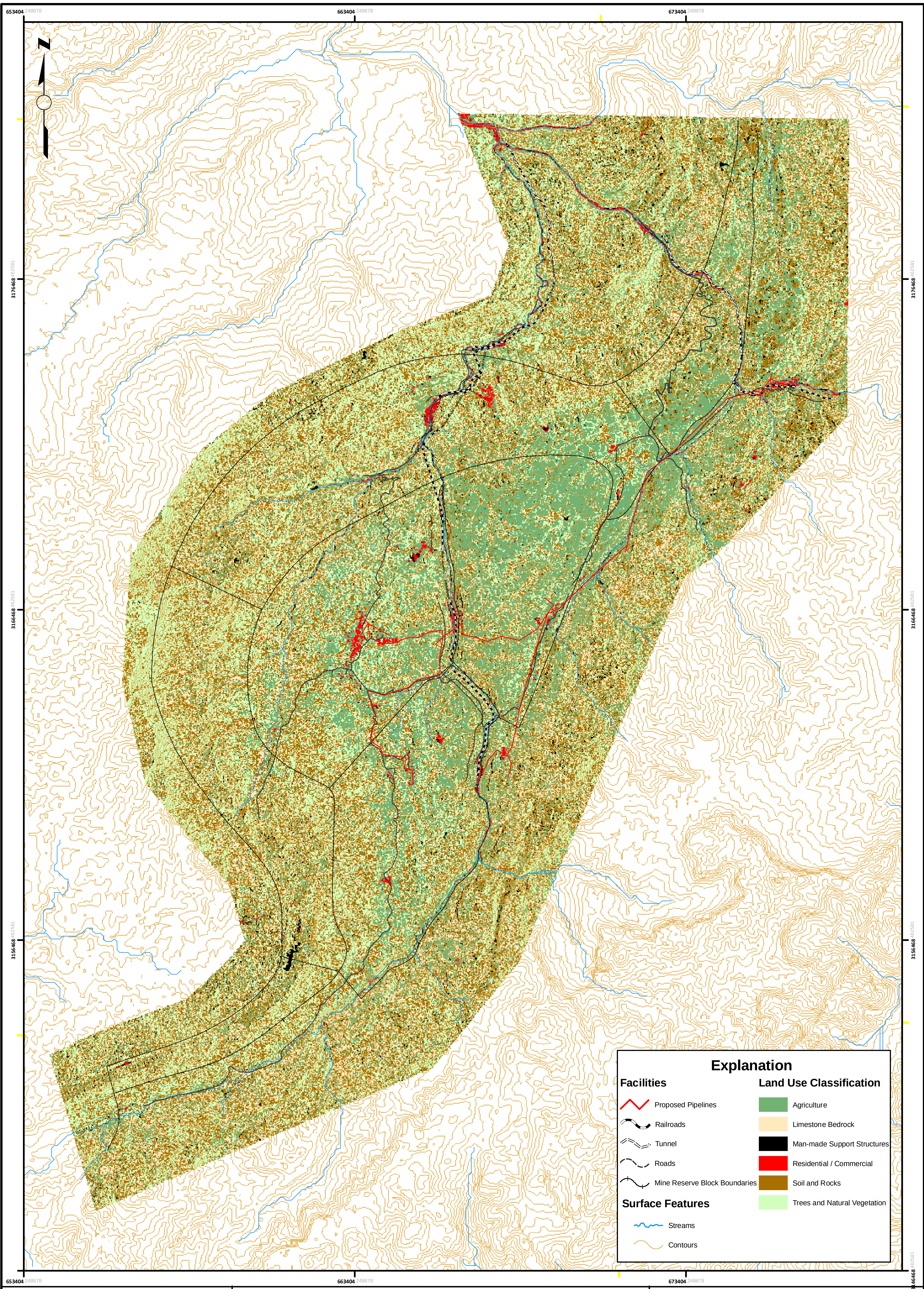
Map 4: Slope Analysis Map

SCALE 1:100,000

0 500 1,000 2,000 3,000 4,000 Meters

CONTOUR INTERVAL 50 METERS WGS 1984, UTM ZONE 48N



Project Name: China Feasibility Study EPA	
Map Document: D-size Land Use.mxd	
Drawn By: CLMT	Date: July 1, 2008
Approved By: Raymond C. Pilcher	Date: July 2, 2008
Source: Landsat.org & RRR	Date: July 2, 2008
Current Revision: 2	
Revised By: CLMT	Date: Dec. 17, 2008

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Map 5: Land Use Classification Map

SCALE 1:100,000

0 500 1,000 2,000 3,000 4,000 Meters

CONTOUR INTERVAL 50 METERS WGS 1984, UTM ZONE 48N