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Coal and gas competition in power generation in Asia

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Preface

This report has been produced by IEA Clean Coal Centre and is based on a survey and analysis of published literature, and on information gathered in discussions with interested organisations and individuals. Their assistance is gratefully acknowledged. It should be understood that the views expressed in this report are our own, and are not necessarily shared by those who supplied the information, nor by our member countries.

IEA Clean Coal Centre is an organisation set up under the auspices of the International Energy Agency (IEA) which was itself founded in 1974 by member countries of the Organisation for Economic Co-operation and Development (OECD). The purpose of the IEA is to explore means by which countries interested in minimising their dependence on imported oil can co-operate. In the field of Research, Development and Demonstration over fifty individual projects have been established in partnership between member countries of the IEA.

IEA Clean Coal Centre began in 1975 and has contracting parties and sponsors from: Australia, Austria, Canada, China, the European Commission, Germany, India, Italy, Japan, New Zealand, Poland Russia, South Africa, Thailand, the UK and the USA. The Centre provides information and assessments on all aspects of coal from supply and transport, through markets and end-use technologies, to environmental issues and waste utilisation.

Abstract

Coal and natural gas are the two most important fuels in electricity generation globally, with a share of approximately 40% and 22% in 2012, respectively. Coal and natural gas can compete with each other for power generation under certain market conditions. Coal is generally more widely available and cheaper than natural gas. However, natural gas-fired power plants are generally cheaper and quicker to build than coal-fired power plants, and also tend to have higher efficiencies and greater flexibility in plant operation. As electricity demand is expected to continue growing strongly in Asia, the question is raised to investors and policy-makers as to whether coal or natural gas should be used to meet this growing demand. This report explains the factors that affect the competition between coal and natural gas in power generation in nine selected Asian countries. For each country, it illustrates the respective roles of coal and natural gas in the power sector by analysing both the current electricity generation mix and the new generation capacity addition plans. Second, the supply options for coal and natural gas are analysed, which together with pricing reforms in some of these countries indicate the likely future pricing trends of coal and natural gas. The average generation costs are then modelled for the fleet of natural gas combined cycle gas turbine (CCGT) power plants and the fleets of subcritical and supercritical (in some countries) coal-fired power plants. The generation cost is the fundamental factor determining the relative competitiveness of coal- and natural gas-based generation. Finally, the factors other than the generation cost are also discussed to give a holistic view on the coal versus gas competition issue. The impacts of shale gas in the USA on Asian coal and natural gas markets are also considered in this report.

Acronyms and abbreviations

ACP	applicable coal price (Malaysia)
APM	Administered Pricing Mechanism (India)
BGR	German Federal Institute for Geosciences and Natural Resources
CAPEX	capital expenditure
CBM	coal bed methane
CCGT	combined cycle gas turbine
CEC	China Electricity Council
CHP	combined heat and power
CIL	Coal India Limited
CNPC	China National Petroleum Corporation
DGMC	Director General of Mineral and Coal (Indonesia)
DMO	Domestic Market Obligation (Indonesia)
EIA	US Energy Information Administration
EGAT	Electricity Generating Authority of Thailand
ETS	Emission Trading System
FOB	free on board
FY	fiscal year
FYP	Five-Year plan
GCV	gross calorific value
IEA	International Energy Agency
IPP	independent power producer
KEPCO	Korean Electric Power Company
LNG	liquefied natural gas
LPG	liquefied petroleum gas
MATS	Mercury and Air Toxics Standards (USA)
NELP	New Exploration Licensing Policy (India)
NDRC	National Development and Reform Commission (China)
NPC	National Power Corporation (the Philippines)
OECD	Organisation for Economic Co-operation and Development
Opex	operational expenditure
PLN	Perusahaan Listrik Negra (Indonesian state-owned electricity utility company)
PV	PetroVietnam
RMB	Renminbi (Chinese currency)
SCCL	Singareni Collieries Company Limited
SPP	small power producer
TAPI	Turkmenistan-Afghanistan-Pakistan-India gas pipeline project
UMPP	Ultra-Mega Power Projects (India)
WEC	World Energy Council

Contents

List of Figures

List of Tables

1 Introduction

The world relies on fossil fuels for its primary energy demand. In 2013, oil accounted for 33% of global primary energy consumption, while coal and natural gas had a share of 30% and 24%, respectively (BP, 2014). Although oil remained the most important energy resource, coal and natural gas were the biggest contributors to the global growth in primary energy consumption between 2000 and 2013. Coal and gas contributed 45% and 24%, respectively, as opposed to10% for oil (BP, 2014). According to IEA projections, the future demand trends differ markedly for the three fossil fuels, and are heavily influenced by the policy paths that governments take to address the climate and energy challenges. Natural gas is the only fossil fuel to experience considerable growth in demand regardless of the policy paths taken. The demand for coal and oil, however, could swing from large increases to considerable decreases, reflecting the considerable range of uncertainty resulting from different policy paths.

No matter how the future demand trends unfold, the world is unlikely to be restricted by coal and gas resources for many decades. According to the World Energy Council and BGR (the German Federal Institute for Geosciences and Natural Resources), the two leading sources of coal resources information in the world, proved coal reserves were in the range of 891.5–1052.1 Gt (WEC, 2013; BGR, 2013). The corresponding reserves-to-production ratios are 113–133 years. Total remaining recoverable resources of coal are more than twenty times proved reserves and could support current production levels for much longer (IEA, 2013a). Proven reserves of natural gas globally have been reported to be in the range of 185.7–209.7 trillion cubic metres (tcm), equal to 55.1–59.6 years of production at current production rates (BGR, 2013, 2014; EIA, 2013; OPEC, 2013; WEC, 2013). Remaining recoverable resources are assessed to be 810 tcm and are equivalent to 233 years of production at current rates (IEA, 2013a). BGR (2013) estimated that unconventional gas resources account for 51 % of the global total gas resources with shale gas 33%, coal bed methane (CBM) 8% and tight gas 10%. As such, unconventional gas has the largest potential for future gas supply.

Non-OECD countries have been the driving force behind the growth in both coal and natural gas consumption. In 2013, non-OECD countries accounted for 72% of the global coal consumption, and slightly more than half of the global gas consumption.

Coal consumption in non-OECD countries increased by 128% during this period, while it declined by 6% in OECD countries as a result of an increased share of gas and renewables in electricity generation (BP, 2014). The biggest growth in coal consumption was in Asia. China alone contributed 84% of the global growth in coal demand during 2000–13 and has become the world's largest coal consumer. India was the second largest contributor with a share of 12.1%, while the countries of the Association of Southeast Asian Nations (ASEAN) accounted for 5.5% of the global growth in coal consumption during this period (BP, 2014).

Global natural gas consumption increased by nearly 39% during 2000–13, with non-OECD countries accounting for almost three quarters of this growth. Although the largest growth was in the Middle East (accounting for a quarter of the global growth), Asian countries also experienced significant growth. China registered a 14.5% share of the global growth, while India and the ASEAN countries contributed 2.7% and 7.6%, respectively (BP, 2014).

The power (and heat) sector has been the main driver for increased coal and natural gas consumption. In 2012, this sector accounted for 62% of coal consumption and 41% of natural gas consumption worldwide (IEA, 2014a). The power sector will be the largest source of demand for coal in IEA projection (IEA, 2013a).

Coal and natural gas can face competitive pressure from each other as a generation fuel due to their relative advantages. Coal is generally less expensive than gas, especially in the absence of a price for CO_2, outside major gas-producing countries. Its low cost and wider availability have made it a preferred fuel for power generation in these countries. However, natural gas has a number of advantages that can make it attractive to investors and policymakers as a fuel for power generation. These include high technical efficiency and flexibility of gas-fired power plants, their relative ease and speed of construction and low CO_2 and other emissions characteristics, compared with power plants firing coal and oil. Moreover, the up-front capital expenditures tend to be lower for gas-fired power plants due to their lower plant system complexity.

The competition between coal and natural gas in power generation has been observed in the USA and Europe. In the USA, exceptionally low gas prices in 2012 led to a strong surge in gas-fired electricity generation, displacing coal-fired generation. The opposite was true in the European Union: a noticeable drop in gas-fired power generation was observed in 2012 as gas became increasingly expensive, combined with other factors such as low CO_2 prices, weaker economic activity, lower electricity demand and continued expansion of renewable-based capacity (IEA, 2013a).

In Asia, where electricity demand continues to grow strongly, the issue of coal and gas competition is more related to what type of new power plant should be built to meet the increasing demand. Such a decision is based mainly on the relative generation cost advantages of coal- and gas-fired power plants, which are affected by a variety of factors such as fuel prices, capital costs, financing costs, and operational costs. However, the decision will also be affected by government policies on energy and environment.

This report seeks to understand the key factors determining the relative competitiveness between coal and natural gas in power generation in Asia. Countries in Asia are diverse in the scale and patterns of their energy use and energy resource endowments. To reflect this diversity, the report selects nine countries as case studies in Chapters 3–11, including China, India, Indonesia, Thailand, Malaysia, Vietnam, Philippines, Japan and South Korea. For each country, the respective roles of coal and natural gas in the power generation mix are firstly studied. The supply options of coal and natural gas as well as the latest changes to fuel pricing systems are then analysed to indicate the potential trends in coal and gas prices to power plants. The key part of each case study is the modelling of the average generation costs of the gas CCGT fleet and the fleets of subcritical and supercritical coal-fired power plants, which provide a comparison of the relative generation costs between coal- and gas-based power generation. The modelling approach is described in detail in Chapter 2. Each case study concludes with discussion on major issues that can affect the relative competitiveness between coal and natural gas as a generation fuel. The potential impacts of the shale gas boom in the USA on the coal and natural gas markets in Asia are discussed in Chapter 12.

2 The approach for generation cost comparison

This chapter explains the approach used to model the average generation cost of the coal and gas CCGT fleet in 2013. The average generation cost consists of three components, the fixed cost of capital plus the interest during construction, the fixed operation & maintenance (O&M) cost, and the variable cost of fuel. They are discussed below in detail.

(1) Repayment of the fixed cost of capital and interest during plant construction

The fixed cost of capital is the amortised capital expenditure per kWh incurred by the power plant construction. It is assumed to remain constant in nominal terms through the amortisation period (assumed to be half of the operational life of the power plant). It is calculated based on the representative specific capital cost ($/kW) as per the formula below:

$$Fixed\ cost\ of\ capital\ = \frac{Specific\ captial\ cost\ in\ \$/kWe}{Fleet\ average\ utilisation\ in\ hours * AF}$$

$$Fleet\ average\ utilisation\ in\ hours = \frac{Electricity\ generation\ in\ GWh}{Capacity\ in\ GWe}$$

$$AF = \frac{1}{interest\ rate} - \frac{1}{interest\ rate \times (1 + interest\ rate)^{amortisation\ period\ in\ years}}$$

The specific capital cost is based on published capital expenditure (CAPEX) data on actual power plant projects in each country built since 2000, gathered by the authors (IEA CCC, 2014). Where the CAPEX is in local currency, it is converted to US dollar based on the average exchange rates of the last five years.

The fleet average utilisation is the average number of hours in a year the coal or gas fleet actually ran for between 2006 and 2012. For each year, the annual fleet utilisation is calculated by dividing the actual electricity generation (GWh) by the GWe capacity in operation in that year. The actual electricity generation is reported by IEA energy statistics, while the capacity in operation is based on the Platt's World Electric Power Plants Database.

Annualisation Factor (AF) is used to amortise the specific capital cost, which is based on the discounted cash flow method. The interest rate on loan is the 10-year average of the loan rates for each country published by World Bank.

Interest on loan is accumulated over the plant construction period, which is then amortised over the capital depreciation period (typically half that of the operational life of the power plant). The calculation formula is as follows.

$$Interest\ during\ construction = \frac{Specific\ captial\ cost \times interest\ rate \times consturction\ period}{AF}$$

(2) Operation and Maintenance (O&M) costs

The O&M cost is assumed to be a proportion of the specific capital cost as recommended by IEA Energy Technology Systems Analysis Programme. The proportion is typically 3% for non-OECD countries, and 6% for OECD countries unless the actual data are available. The calculation formula is as follows.

$$O\&M\ cost = \frac{3\%\ (or\ 6\%) \times specific\ capital\ cost \times installed\ generation\ capacity\ in\ 2013}{Electricity\ generation\ in\ 2013}$$

(3) Variable cost of fuel

To calculate the fuel cost of electricity ($/GWh), a representative cost of fuel delivered to the power station is required. Consistent fuel cost data are not always publicly available and assumptions have to be made based on literature reviews and fuel market journals.

The representative coal price is a three-year (2012-14) average of estimates for domestic coal and/or imported Indonesian coals (5000 kcal/kg) delivered to power plants obtained from a commercial trader. All are adjusted to $/toe ($ per tonne of oil equivalent) for analysis. Gas prices for most countries are derived from import prices, while domestic prices are used for India, Indonesia, Malaysia and Thailand.

The calculation formula of the variable cost of fuel ($/GWh) is as follows:

$$Variable\ operating\ cost\ of\ fuel = \frac{Representative\ fuel\ cost}{Average\ fleet\ efficiency}$$

The average fleet efficiency is based on the fuel input and the electricity generation data published by the IEA; the latest available data at the time of analysis was 2011. However, the IEA data do not differentiate between power generation technology types, so adjustment has to be made based on the following criteria:

- single cycle gas turbine fleet, typically no more than 35%;
- gas CCGT fleet, in the range of 41–59%;
- subcritical coal fleet, no more than 39%;
- supercritical and ultra-supercritical fleets, in the range of 39–44%.

The base assumptions for each country are summarised as follows:

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China

Table 1 The basic assumptions underlying the generation cost assessment of existing fleets in China

	Average fuel price, $/toe	Fuel price in $/t coal and $/million Btu gas	Total fleet, GWe	Estimated fleet output, GWh	Specific capital cost, $/kW	Construct-ion period, y	Life of plant, y	Loan interest rate, %	Average fleet efficiency, %	Average annual utilisation, %
Natural gas CCGT	575	14.7	34	101	516	3	35	5.9	43	34
Coal subcritical pf	161	80.3	505	2507	583	4.5	40	5.9	32	57
Coal supercritical/USC pf	161	80.3	325	1641	583	4.5	40	5.9	41	58

Gas price: Assumes the 2013 city gate prices ranging 10.3–15.0 $/million Btu for incremental gas supply under the new price mechanism based on Lantau (2014) (although domestic gas supplies to Shanghai can be as low as 7–10 $/million Btu).

Coal price: based on 2013 domestic coal price FOB Qinhuangdao on a 5000 kcal/kg net as received (NAR).

Total fleet: refers to the total operating plants and plants due for commissioning as of 2013, based on Platt's World Electric Power Plants Database as of December 2013.

Estimated total fleet output in 2013: where the 2013 data are not available, the output GWh is calculated based on 2013 GWe capacity and the average utilisation in hours (average taken over 2006-12).

Specific capital cost ($/kWe): sample $/kWe for supercritical units based on E3 (2012).

Construction period: gas CCGT at 3 years and coal at 4.5 years but can be shorter.

Operational life of plant: 35 year for gas CCGT; 40 years for coal.

Rate of interest: World Bank average loan rates for 2003-13.

Calculated fleet efficiency for 2013: average of the years 2006-11 (IEA last year's data for TJ fuel input is 2011).

Average fleet utilisation for 2013: the average over 2006-12 (IEA last year for GWh is 2012, and averages over 7 years to even out irregular renewable output).

India

Table 2 The basic assumptions underlying the generation cost assessment of existing fleets in India

	Average fuel price, $/toe	Fuel price in $/t coal and $/million Btu gas	Total fleet, GWe	Estimated fleet output, GWh	Specific cost of capital $/kW	Construct-ion period, y	Life of plant, y	Loan interest rate, %	Average fleet efficiency, %	Average annual utilisation, %
Natural gas CCGT	333	8.5	17	132	667	3	35	11.1	51	86
Coal subcritical pf	102	71.7	159	1005	824	4.5	40	11.1	26	72
Coal supercritical/USC pf	102	71.7	25	112	824	4.5	40	11.1	39	52

Gas price: based on the new inflated price of 8.49 $/million Btu authorised in 2013 (Chaturved and Jagota, 2013); this estimate takes into account the three different pricing regimes in India, as described in Chapter 4.

Coal price: based on the average domestic price of 66 $/t (5000 kcal/kg) and a basket of imported Indonesian coals (72–76 $/t, 5000 kcal/kg) delivered to ports in north west India in Mundra.

Total fleet: refers to the total operating plants and plants due for commissioning as of 2013, based on Platt's World Electric Power Plants Database as of December 2013.

Estimated total fleet output in 2013: where the 2013 data are not available, the output GWh is calculated based on 2013 GWe capacity and the average utilisation in hours (average taken over 2006-12).

Specific capital cost ($/kWe): the average CAPEX of four coal-fired power plants built in 2010-13, Mundra UMPP, Mundra Adani, Salaya, and Ratnigiri, in the range of 476–1035 $/kWe; CCGT based on three power projects built between 1992 and 2014 ranging 476–833 $/kWe.

Construction period: gas CCGT at 3 years and coal at 4.5 years but can be shorter.

Operational life of plant: 35 year for gas CCGT; 40 years for coal.

Rate of interest: World Bank average loan rates for 2003-13.

Calculated fleet efficiency for 2013: average over 2006-11 (IEA last year's data for TJ fuel input is 2011).

Average fleet utilisation for 2013: the average over 2006-12 (IEA last year for GWh is 2012, and averages over 7 years to even out irregular renewable output).

Indonesia

Table 3 The basic assumptions underlying the generation cost assessment of existing fleets in Indonesia

	Average fuel price, $/toe	Fuel price in $/t coal and $/million Btu gas	Total fleet, GWe	Estimated fleet output, GWh	Specific cost of capital $/kW	Construct-ion period, y	Life of plant, y	Loan interest rate, %	Average fleet efficiency, %	Average annual utilisation, %
Natural gas CCGT	105	2.7	10	33	728	3	35	13.8	41	37
Coal subcritical pf	119	59.6	22	122	1304	4.5	40	13.8	30	63

Gas price: based on 13-year long-term contract for PLTG Muara Karang signed in 2003 at 2.65 $/million Btu (Energypedia, 2003); contract prices have subsequently risen to 5–11 $/million Btu landed in Java (Parkinson, 2014).

Coal price: based on domestic coal price (5000 kcal/kg).

Total fleet: refers to total operational plants and plants due for commissioning as of 2013, based on Platt's World Electric Power Plants Database as of December 2013.

Estimated total fleet output in 2013: where the 2013 data are not available, the output GWh is calculated based on 2013 GWe capacity and the average utilisation in hours (average taken over 2006-12).

Specific capital cost ($/kWe): for the coal-fired fleet, based on five power projects built between 2006-12, and the forthcoming Batang plant due online in 2016. For the CCGT fleet, based on Malaysian CCGT due to lack of data.

Construction period: gas CCGT at 3 years and coal at 4.5 years but can be shorter.

Operational life of plant: 35 year for gas CCGT; 40 years for coal.

Rate of interest: World Bank average loan rates for 2003-13.

Calculated fleet efficiency for 2013: average over 2006-11 (IEA last year's data for TJ fuel input is 2011).

Average fleet utilisation for 2013: average over 2006-12 (IEA last year for GWh is 2012, and averages over 7 years to even out irregular renewable output).

Thailand

Table 4 The basic assumptions underlying the generation cost assessment of existing fleets in Thailand

	Average fuel price, $/toe	Fuel price in $/t coal and $/million Btu gas	Total fleet, GWe	Estimated fleet output, GWh	Specific cost of capital $/kW	Construct-ion period, y	Life of plant, y	Loan interest rate, %	Average fleet efficiency, %	Average annual utilisation, %
Natural gas CCGT	314	8.0	24	141	861	3	350	6.5	50	66
Coal subcritical pf	133	66.4	5	23	1304	4.5	40	6.5	37	54
Coal supercritical/USC pf	133	66.4	1	5	824	4.5	40	6.5	40	50

Gas price: based on the Tier-2 pooled gas price, which is the weighted average of the price of domestically produced gas and imported gas (LNG and pipeline imports).

Coal price: based on imported Indonesian coal (5000 kcal/kg GAR).

Total fleet: refers to total operational plants and plants due for commissioning as of 2013, based on Platt's World Electric Power Plants Database as of December 2013.

Estimated total fleet output in 2013: where the 2013 data are not available, the output GWh is calculated based on 2013 GWe capacity and the average utilisation in hours (average taken over 2006-12).

Specific capital cost ($/kWe): for the coal-fired fleet, based on three diverse projects with CAPEX in the range of 495–2273 $/kWe: the lowest 2.6 GWe Mae Moh plant (1995), the highest 0.8 GW Krabi plant, and 1.3 GWe plants Banpu/CLP at 900 $/kWe; for the CCGT fleet, based on several plants with the cost in the range of 535–1186 $/kWe.

Construction period: gas CCGT at 3 years and coal at 4.5 years but can be shorter.

Operational life of plant: 35 year for gas CCGT; 40 years for coal.

Rate of interest: World Bank average loan rates for 2003-13.

Calculated fleet efficiency for 2013: average over 2006-11 (IEA last year's data for TJ fuel input is 2011).

Average fleet utilisation for 2013: average over 2006-12 (IEA last year for GWh is 2012, and averages over 7 years to even out irregular renewable output).

Malaysia

Table 5 The basic assumptions underlying the generation cost assessment of existing fleets in Malaysia

	Average fuel price, $/toe	Fuel price in $/t coal and $/million Btu gas	Total fleet, GWe	Estimated fleet output, GWh	Specific cost of capital $/kW	Construct-ion period, y	Life of plant, y	Loan interest rate, %	Average fleet efficiency, %	Average annual utilisation, %
Natural gas CCGT	169	4.3	10	63	728	3	35	5.7	51	68
Coal subcritical pf	127	63.7	8	41	1408	4.5	40	5.7	33	59

Gas price: based on the 2012 price of 13.7 RM/million Btu (4.3 $/million Btu) at the time of analysis; more recent prices delivered to TNB estimate at 3.17 $/million Btu (Parkinson, 2014); unsubsidised prices are more than double the TNB price; LNG prices are significantly higher at 16 $/million Btu.

Coal price: based on imported Indonesian coal of 5000 kcal/kg gross as received (GAR).

Total fleet: refers to total operational plants and plants due for commissioning as of 2013 based on Platt's World Electric Power Plants Database as of December 2013.

Estimated total fleet output in 2013: where the 2013 data are not available, the output GWh is calculated based on 2013 GWe capacity and the average utilisation in hours (average taken over 2006-12).

Specific capital cost ($/kWe): for the coal-fired fleet, based on four projects with CAPEX in the range of 1086–1740 $/kWe; for the CCGT fleet, based on two CCGT projects with CAPEX ranging 708–747 $/kWe.

Construction period: gas CCGT at 3 years and coal at 4.5 years but can be shorter.

Operational life of plant: 35 year for gas CCGT; 40 years for coal.

Rate of interest: World Bank average loan rates for 2003-13.

Calculated fleet efficiency for 2013: average during 2006-11 (IEA last year's data for TJ fuel input is 2011).

Average fleet utilisation: average over 2006-12 (IEA last year for GWh is 2012, and averages over 7 years to even out irregular renewable output).

Vietnam

Table 6 The basic assumptions underlying the generation cost assessment of existing fleets in Vietnam

	Average fuel price, $/toe	Fuel price in $/t coal and $/million Btu gas	Total fleet, GWe	Estimated fleet output, GWh	Specific cost of capital $/kW	Construct-ion period, y	Life of plant, y	Loan interest rate, %	Average fleet efficiency, %	Average annual utilisation, %
Natural gas CCGT	163	4.2	7	36	933	2	35	12	54	64
Coal subcritical pf	121	60.5	6	39	1274	4	40	12	37	72

Gas price: based on average of domestic pipeline gas ranging 1–8 $/million Btu (Parkinson, 2014).

Coal price: average of domestic and imported coal ranging 53–68 $/t (5000–5200 kcal/kg).

Total fleet: refers to total operational plants and plants due for commissioning as of 2013, based on Platt's World Electric Power Plants Database as of December 2013.

Estimated total fleet output in 2013: where the 2013 data are not available, the output GWh is calculated based on 2013 GWe capacity and the average utilisation in hours (average taken over 2006-12).

Specific capital cost ($/kWe): for the coal-fired fleet, based on eleven projects with the cost in the range of 1067–1667 $/kWe; for CCGT, based on Nhon Trac 2.

Construction period: gas CCGT at 3 years and coal at 4.5 years but can be shorter.

Operational life of plant: 35 year for gas CCGT; 40 years for coal.

Rate of interest: World Bank average loan rates for 2003-13.

Calculated fleet efficiency for 2013: average over 2006-11 (IEA last year's data for TJ fuel input is 2011).

Average fleet utilisation: average for 2013: taken as the average over 2006-12 (IEA last year for GWh is 2012, and averages over 7 years to even out irregular renewable output).

Philippines

Table 7 The basic assumptions underlying the generation cost assessment of existing fleets in the Phillippines

	Average fuel price, $/toe	Fuel price in $/t coal and $/million Btu gas	Total fleet, GWe	Estimated fleet output, GWh	Specific cost of capital $/kW	Construct-ion period, y	Life of plant, y	Loan interest rate, %	Average fleet efficiency, %	Average annual utilisation, %
Natural gas CCGT	422	10.8	3	19	973	3	35	8.3	61	70
Coal subcritical pf	132	66.2	6	25	1315	4.5	40	8.3	34	50

Gas price: based on estimated the domestic gas price for Ilijian gas in 2014 (Lantau, 2013); LNG prices are higher averaging 15.97 $/million Btu.

Coal price: based on imported Indonesian coal (5000 kcal/kg, NAR).

Total fleet: refers to total operational plants and plants due for commissioning as of 2013, based on Platt's World Electric Power Plants Database as of December 2013.

Estimated total fleet output in 2013: where the 2013 data are not available, the output GWh is calculated based on the 2013 GWe capacity and the average utilisation in hours (average taken over 2006-12).

Specific capital cost ($/kWe): for coal based on 232 MWe Mindanao built 2006; for CCGT based on 666 MWe Limay Bataan 1 built in 1995.

Construction period: gas CCGT at 3 years and coal at 4.5 years but can be shorter.

Operational life of plant: 35 year for gas CCGT; 40 years for coal-fired power plants.

Rate of interest: World Bank average loan rates for 2003-13.

Calculated fleet efficiency for 2013: the average over 2006-11 (IEA last year's data for TJ fuel input is 2011).

Average fleet utilisation for 2013: the average over 2006-12 (IEA last year for GWh is 2012, and averages over 7 years to even out irregular renewable output).

Japan

Table 8 The basic assumptions underlying the generation cost assessment of existing fleets in Japan

	Average fuel price, $/toe	Fuel price in $/t coal and $/million Btu gas	Total fleet, GWe	Estimated fleet output, GWh	Specific cost of capital $/kW	Construct-ion period, y	Life of plant, y	Loan interest rate, %	Average fleet efficiency, %	Average annual utilisation, %
Natural gas CCGT	556	14.2	42	315	934	3	35	1.7	55	85
Coal subcritical pf	164	81.8	12	56	2274	4.5	40	1.7	32	54
Coal supercritical/USC pf	164	81.8	31	220	2274	4.5	40	1.7	42	82

Gas price: based on LNG import price 2013.

Coal price: based on the Japanese average annual marker price for 2013 CIF (6080 kcal/kg) provided by McCloskey Coal Information Services.

Total fleet: refers to total operational plants and plants due for commissioning as of 2013, based on Platt's World Electric Power Plants Database as of December 2013.

Estimated total fleet output in 2013: where the 2013 data are not available, the output GWh is calculated based on the 2013 GWe capacity and the average utilisation in hours (average taken over 2006-12).

Specific capital cost ($/kWe): for the coal-fired fleets, the average of two plants with the cost in the range of 1587–2960 $/kWe, the higher is for a new proposed plant; for CCGT, based on four plants ranging 442–2222 $/kWe.

Construction period: gas CCGT at 3 years and coal plants at 4.5 years but can be shorter.

Operational life of plant: 35 year for gas CCGT; 40 years for coal.

Rate of interest: World Bank average loan rates for 2003-13.

Calculated fleet efficiency for 2013: the average over 2006-11 (IEA last year's data for TJ fuel input is 2011).

Average fleet utilisation: average for 2013: the average over 2006-12 (IEA last year for GWh is 2012, and averages over 7 years to even out irregular renewable output).

South Korea

Table 9 The basic assumptions underlying the generation cost assessment of existing fleets in South Korea

	Average fuel price, $/toe	Fuel price in $/t coal and $/million Btu gas	Total fleet, GWe	Estimated fleet output, GWh	Specific cost of capital $/kW	Construct-ion period, y	Life of plant, y	Loan interest rate, %	Average fleet efficiency, %	Average annual utilisation, %
Natural gas CCGT	621	15.9	26	128	652	3	35	5.9	51	61
163	163	81.4	7	51	1500	4.5	40	5.9	40	80
Coal supercritical/USC pf	163	81.4	29	146	1500	4.5	40	5.9	41	86

Gas price: based on LNG import price 2013.

Coal price: annual the average of Asian marker price for 2013 from McCloskey Coal Information Services.

Total fleet: refers to total operational plants and plants due for commissioning as of 2013, based on Platt's World Electric Power Plants Database as of December 2013.

Estimated total fleet output in 2013: where the 2013 data are not available, the output GWh is calculated based on the 2013 GWe capacity and the average utilisation in hours (average taken over 2006-12).

Specific capital cost ($/kWe): for coal-fired power plants, the average of two plants with CAPEX in the range of 1500–1563 $/kWe; the CAPEX of the gas CCGT fleet is based on Kwangyang CCGT plant.

Construction period: gas CCGT at 3 years and coal plants at 4.5 years but can be shorter.

Operational life of plant: 35 year for gas CCGT; 40 years for coal plants.

Rate of interest: World Bank average loan rates for 2003-13.

Calculated fleet efficiency for 2013: the average over 2006-11 (IEA last year's data for TJ fuel input is 2011).

Average fleet utilisation: average for 2013: the average over 2006-12 (IEA last year for GWh is 2012, and averages over 7 years to even out irregular renewable output).

Appendix 1 includes a High Efficiency Low Emission (HELE) scenario for each of the nine countries. The scenario is based on operating the coal or gas power plant at 80% utilisation and at the highest possible efficiency: 60% for gas CCGT plants, 40% for subcritical coal pulverised fuel (pf) power plants and 45% for supercritical/ultra-supercritical pf power plants. The purpose of modelling the HELE scenario is to demonstrate how utilisation and plant efficiency can affect the generation costs of coal and gas power plants. It also presents a comparison between the generation cost of the best available coal and gas-based power generation technologies.

3 China

3.1 Key energy indicators in 2012

Population	1350.7	million
GDP	8229.5	billion US$
Electricity consumption	4693.7	TWh
Electricity consumption per capita	3.48	MWh/capita
Electricity generation	4994	TWh
Electricity imports/exports	6.9/17.7	TWh
Generation capacity	1147	GWe
Coal-fired capacity	754	GWe
Gas-fired capacity	37	GWe

(IEA, 2014a; CEC, 2013; World Bank, 2014)

3.2 Power generation mix

China is the world's largest producer of electricity. As shown in Figure 1, China relies on coal and hydropower for its electricity generation. In 2012, the total electricity generation was 4994 TWh; coal's share was 75%, followed by hydropower (17%), natural gas (2.2%), wind power (2%) and nuclear power (2%) (IEA, 2014a). During 2000–2012, the biggest growth in absolute terms was coal-based generation, driven largely by the vast addition of large-sized coal-fired units with high steam parameters during the 11th Five-Year plan (FYP) period (2006-10). The second largest growth in absolute terms was hydropower generation, which quadrupled between 2000 and 2012, due mainly to the addition of two mega hydropower projects, Three Gorges of 18.2 GW and Yellow River of 15.8 GWe (WNA, 2014). Nuclear power generation increased nearly five-fold as China's nuclear industry moved into a rapid construction phase in 2005. Gas-based power generation, starting from a low base, experienced a 14-times increase during 2000-12. In contrast, the use of oil in power generation decreased sharply to a low level. There was significant increase in renewable-based generation, particularly wind power, driven by its promotion in the Chinese central government's energy policy.

Figure 2 illustrates the overall dispatch of the various types of power station in China's generation fleet. The x-axis shows the fleet utilisation, based on the average annual operating hours calculated over 2006-12. The y-axis shows the current generation capacity in the country, including existing units and those expected to be commissioned in 2013, based on Platts World Electric Power Plant Database as of December 2013 (Platts, 2013).

The total power generation capacity was 1232 GWe at the end of 2013. There were 505 GWe subcritical coal, 325 GWe supercritical/ultra-supercritical (SC/USC) coal, and 64 GWe lignite, compared with 34 GWe gas CCGT and 13 GWe gas turbine/boiler/CHP. As illustrated by Figure 2, the baseload generation is provided by nuclear power plants and coal-fired power plants. However, coal plants operate at only 60% utilisation, which is low by world standards. Gas-fired power plants appear to provide peaking operation.

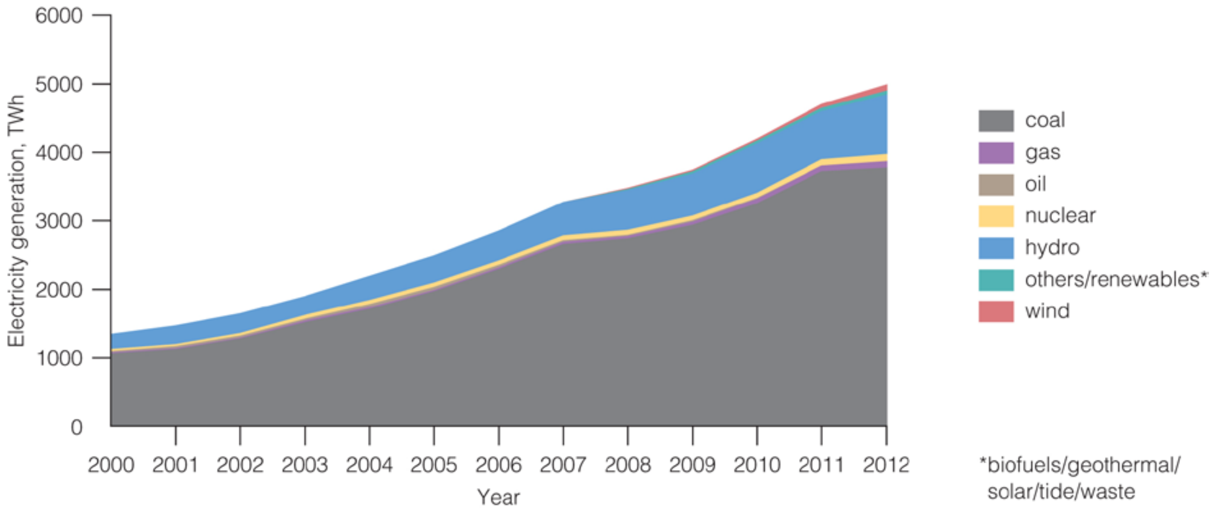

Figure 1 The historic trend of the electricity generation mix in China between 2000 and 2012 (IEA, 2014a)

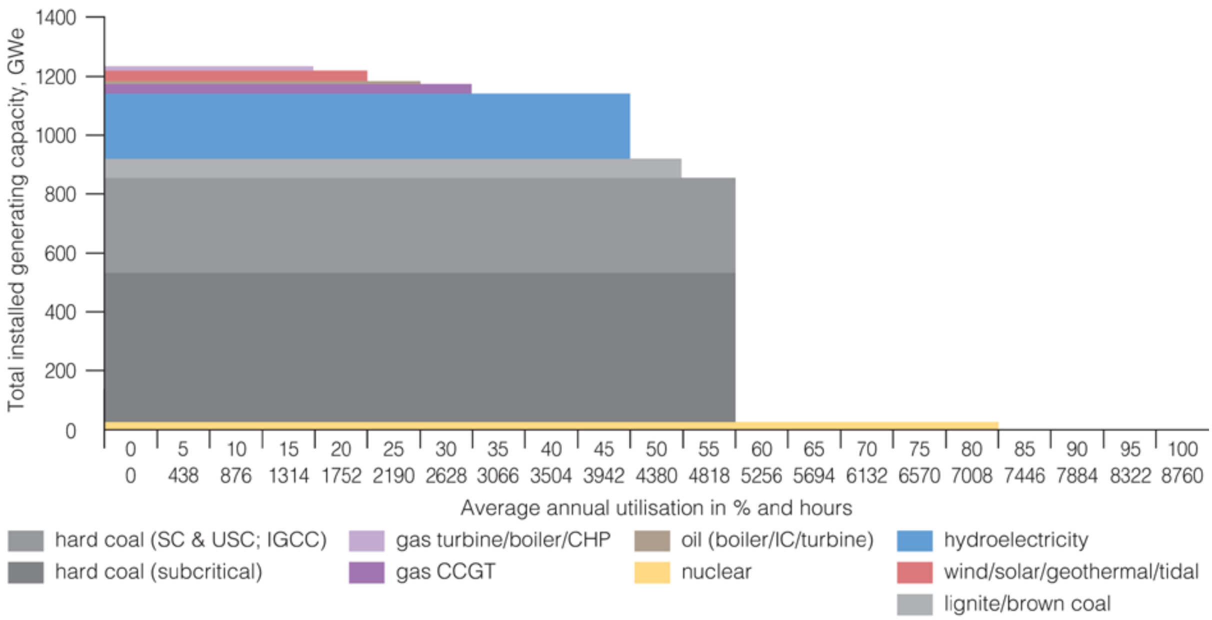

Figure 2 The representative dispatch graph of various types of power generation plant fleet in 2013 (based on Platts World Electric Power Plant Database, December 2013)

3.3 Fuel supply

3.3.1 Gas

According to China National Petroleum Corporation (CNPC), total conventional natural gas resources stood at 90.9 trillion cubic metres (tcm) at the end of 2011, of which about 22 tcm was considered as recoverable resources (Liu, 2012). The proved recoverable conventional gas reserves were 3.8 tcm and distributed mainly in nine basins in western and central-northern parts of China. Gas exploration and production in the early years were closely associated with oil production, with the exception of the Sichuan Basin in central China. Discovery of new gas fields accelerated over the past decade as a result of active exploration. More than two-thirds of the proven reserves are currently classified as non-associated gas.

China's unconventional gas resources are also large. CNPC reported 10.9 tcm of recoverable coal bed methane (CBM) reserves and 12 tcm tight gas reserves (Liu, 2012). The US Energy Information Administration (EIA) estimated 31.6 tcm of technically recoverable shale gas reserves in China, the largest in the world (EIA, 2013). China's own assessment put recoverable shale gas reserves at 25.1 tcm in 2012 and total shale gas resources at 134.4 tcm (Gao, 2013).

Natural gas production increased by more than four-fold from 27.2 bcm in 2000 to 121 bcm in 2013 (BP, 2014; CNPC, 2014). Nearly all the production comprised conventional gas and tight gas; tight gas is categorised as a conventional gas resource in China, and it accounts for more than one third of the gas production (CEFC, 2013). More than half of the gas production was concentrated in four major basins: the Ordos Basin, the Sichuan Basin, the Tarim Basin, and the South China Sea.

Unconventional gas is in the early stage of production. In 2013, CBM production reached 3 bcm, while shale gas production was only 200 million cubic metres (million m^3) (CNPC, 2014). China is promoting coal-based synthetic natural gas (SNG), which could potentially become an important source of gas. Two commercial SNG projects have started operation in Xingjiang (developed by China Qinghua Group with a design capacity of 5.5 bcm/y) and Inner Mongolia (developed by Datang Group with a designed capacity of 4 bcm/y) in 2013.

The 12th Five-Year plan (FYP) *for Natural Gas Development* is the overarching policy for the gas sector development in China. The Plan set ambitious production targets (by 2015) for various types of gas: conventional gas 138.5 bcm (including tight gas), CBM 30 bcm (16 bcm for surface extraction), shale gas 6.5 bcm and coal-based SNG 15–18 bcm (NDRC, 2012b).

These targets are, however, challenging to meet. For conventional gas, production growth will largely come from deeper basins with higher pressure and greater geological complexity (Higashi, 2009). A study based on interviews with industry experts argued that a more realistic target could be 134 bcm in 2015 and near 200 bcm in 2020 (CEFC, 2013).

The growth in CBM production is constrained by a number of factors. The biggest barrier is the high production costs associated with surface extraction. Despite a central government subsidy of 0.2 RMB /m^3 (in some regions, the local government provides an additional 0.1 RMB/m^3), the average selling price (1.6–1.7 RMB/m^3) of CBM cannot recover the production costs (typically around RMB2/m^3) (Xinhua, 2014). There was a plan by the central government to raise the CBM subsidy to 0.6 RMB/m^3, but the exact date on which this will take effect is not set (State Council, 2013b). Another key constraining factor is the overlapping of exploration and mining rights for coal and CBM. As stipulated by the *Mineral Resources Law*, the exploration and mining rights for CBM is administrated by the Ministry of Land and Resources, while these rights for coal are regulated by the Ministry only if the exploration area is larger than 30 km^2 and the reserve is larger than 100 Mt. Otherwise, the rights for exploration and mining will just need to be approved by the provincial agencies of the Ministry. A problematic consequence of this regulation approach was that the exploration and mining rights were granted to different companies at some coal mines. This has caused disputes and conflicts over whether the extraction priority should be given to coal or CBM, thus delaying the development of CBM resources. To resolve this issue, the Ministry of Land and Resources stipulated rules to establish a 'CBM first then coal' principle, but this incongruity can remain for some CBM projects. Other barriers relate to marketing CBM, such as inadequate pipelines to bring CBM to distant markets where the profit margins are higher and the lack of power grid access and inadequate tariff that hinder the use of CBM for pit-head power generation.

Shale gas, despite its vast estimated reserves, faces the greatest uncertainty and the largest potential among all unconventional gas resources in China. With a total production of only 200 million m^3 in 2013, shale gas development falls way short of the 12th FYP target of 6.5 bcm/y by 2015 (Zhao and others, 2014). Most projects are still in the exploration phase. Extraction technologies are not considered a major obstacle as China has the capacity of horizontal drilling and fracking at 3500 m depth and the fracking pumps/trucks with domestic intellectual properties are commercially available. However, the geological conditions of the shales are generally more difficult compared to the USA shales, implying higher production costs. The current gas prices are not sufficient to cover such production costs even with the government subsidies for shale gas production. Similar to CBM, inadequate pipelines also constrain shale gas development. Although the producers can instead sell their output as compressed natural gas (CNG) to nearby users, they first need to apply for licences from the government. However, the licence application is often rejected due to incomplete land rights registration as for most exploration projects the land acquisition is based on a rent-then-acquire approach. These above-ground factors stand in the way of fast shale gas development in China.

Coal-based SNG emerges as a more promising unconventional gas supply. As of August 2013, the central government had approved four SNG projects (two of which were commissioned in 2013) with a total planned capacity of 15.1 bcm/y, in line with the 12th FYP target. Fourteen additional projects have been given permission to proceed with early stage studies, which together add up to 54 bcm/y (based on the announced capacity for each project). Since coal-to-gas conversion consumes large amounts of water and has a large environmental footprint, these factors may constrain large scale SNG project development. The outlook for coal-based SNG must be viewed with caution.

China was self-sufficient in natural gas supply until 2006. It began to import LNG in 2006 and pipeline natural gas from Central Asia (including Turkmenistan, Kazakhstan, and Uzbekistan) in 2009 and Myanmar in 2013. In 2013 China's LNG imports were 24.5 bcm, while pipeline imports were 30.2 bcm (BP, 2014). Taken together, China's reliance on imported gas has climbed to 33.8%. According to NDRC (2012b), China's natural gas imports will reach 93.5 bcm by 2015 based on existing contracts.

At the end of 2013, there were nine LNG regasification terminals in operation and seven more under construction due online in 2014 and 2015. The capacity of LNG regasification terminals will be 69.0 bcm/y by 2015 and could increase to 136.2 bcm/y when phased expansions at some of the

16 terminals are made eventually. The Central Asia gas import pipelines now consists of three lines (A, B and C) with a total capacity of 85 bcm/y and Line D is planned with a capacity of 30 bcm. The Sino–Myanmar natural gas pipeline began operation in July 2013 with a capacity of 12 bcm/y. China has signed an agreement with Russia to develop a gas import pipeline of 38 bcm/y with the start of operation scheduled in 2018. If the existing and planned LNG regasification terminals and import pipelines are taken together, China's total gas import capacity will be approximately 301.2 bcm, 5.5 times larger than the year-2013 import volume of 54.7 bcm (BP, 2014). As such, China should have sufficient gas import capacity to meet its future growth in gas import.

3.3.2 Coal

China has an estimated 5900 Gt of coal resources at less than 2000 m depth, based on the latest assessment by the Ministry of Land and Resources (MLR, 2014). According to World Energy Council, China's proved recoverable coal reserves stood at 114.5 Gt in 2013, ranking the third largest in the world behind the USA and Russia, and comprised 62.2 Gt of anthracite and bituminous coal, 33.7 Gt of subbituminous coal and 18.6 Gt of lignite (WEC, 2013).

Coal production reached 3.68 Gt in 2013, more than double the output in 2000 (BP, 2014). China's coal reserves, albeit large in absolute terms, can provide for only 31 years at the 2013 production level. New reserves discovery are more likely to be in deeper deposits in western parts of China, which are more remote from the demand centres in the coastal areas (CNCA, 2013). This implies higher production and transportation costs, and thus potential competition from imported coals.

The 12th Five-Year Plan for the Coal Industry targets a total coal production capacity of 4.1 Gt for the period 2011–15, while capping the coal production at around 3.9 Gt (NDRC, 2012a). The production capacity reached 3.9 Gt in 2012, and now becomes excessive due to weak coal demand resulting from both decelerating economic growth and on-going transition to a less energy-intensive economy. The National Energy Administration has called for elimination of small and obsolete production mines in 2013 to resolve the excessive capacity issue. However, the actual capacity closed was less than 0.7% of the total production capacity in 2012; meanwhile, the added new production capacity was estimated to be 200 Mt in 2013. As such, the overcapacity issue is not alleviated and could remain for many years. The weak coal demand combined with excessive coal production capacity, have depressed coal prices resulting in most coal producers operating at a loss over the past few years. Shenhua, the largest coal producer in China, has moved to cut production to control the losses.

China became a net coal importer in 2009, and is now the largest steam coal importer in the world. In 2012, China imported 288 Mt of coal and exported only 9 Mt (NSB, 2014). The imported coal in 2012 comprised 70% steam coal, 19% coking coal and 12% anthracite (Zhuang, 2014). The sources of steam coal import in 2012 were as follows: Australia (38%), Indonesia (34%), South Africa (13%), Russia (7%) USA (4%), Colombia (3%) and Canada (1%) (Du, 2013). Whilst significant in terms of global coal trade, coal imports account for a small portion of China's total coal supply, 7.3% in 2012 (NSB, 2014). China's growth in coal imports has been driven mainly by the competitive prices of imported coal (particularly low CV Indonesian coals) and the domestic railway transportation bottlenecks. With plans to build new rail lines, excessive domestic coal production capacity, and the resurrected import tax, a sizeable proportion of imported coal will be displaced by domestic coal supplies.

3.4 Generation cost comparison

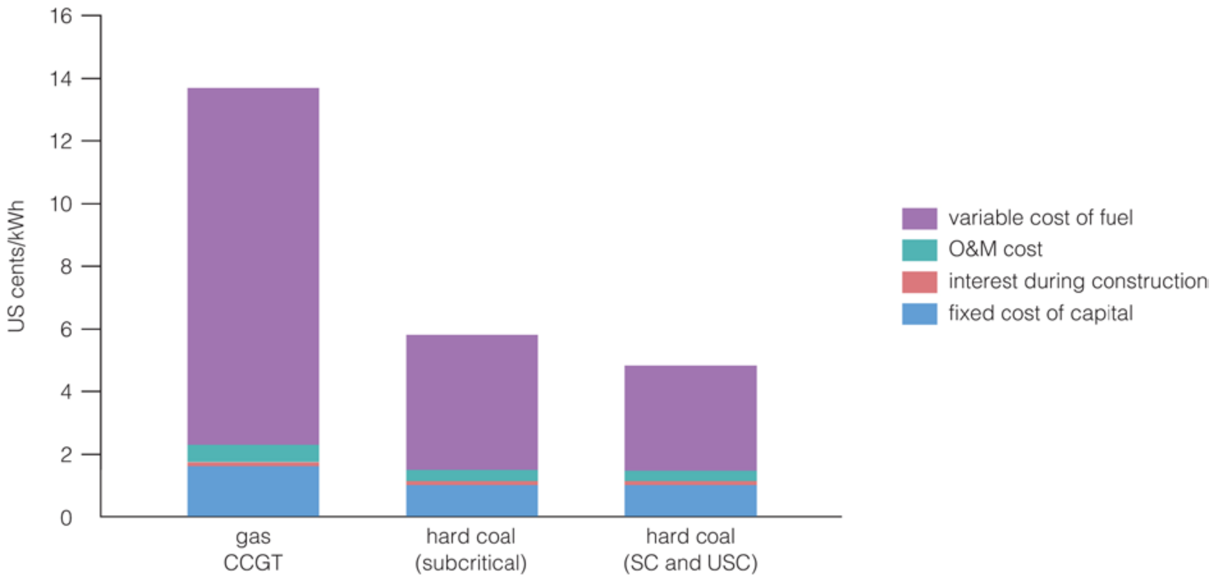

Figure 3 The average generation cost of the natural gas CCGT units and coal-fired units in China

The average generating costs are modelled for the natural gas CCGT and coal pf fleets, based on the assumptions in Table 1. As shown in Figure 3, gas-based generation is more than twice as expensive as coal-based generation. Supercritical coal is also more economic than subcritical coal. The primary reason is the large price differential between natural gas and coal in our assumption, with gas being 3.5 times more expensive than coal. Our analysis indicates that the natural gas price needs to drop to $5.24 per million British thermal units (million Btu) to equalise the generation cost of CCGT to that of subcritical coal pf power plants. The gas price has to drop further to 3.11 $/million Btu to equalise supercritical coal pf power plants.

Gas CCGT plants also appear to be more costly to build than coal-fired power plants on a per kWh basis, which contradicts the general perception of lower CAPEX of gas plants compared to that of coal plants. Although this is partly due to low utilisation of gas CCGT plants in China, the major reason is the very low CAPEX of coal-fired pf plants in China resulting from economy of sale. China's vast expansion of coal-fired generation plants has driven down the costs for plant construction and equipment fabrication and manufacturing, in addition to low labour costs.

3.5 Discussion on issues affecting competition

Pricing reforms for coal and natural gas

Since the price differential between coal and natural gas is the primary reason for gas CCGT to have a more competitive generation cost, the latest pricing reforms of coal and natural gas have important implications for coal versus gas competition.

Before 2006, coal was sold under a two-track pricing system. The first track referred to the long-term contract, under which coal was sold at prices tightly regulated by the central government. The second track was the retail market where prices were determined by the demand/supply balance. The retail prices were generally much higher than the contract prices, but the majority of the coal was sold under long-term contracts. As a result, there was little incentive for coal producers to increase coal sales at contracted prices to meet rising coal demand. The National Development and Reform Commission (NDRC) therefore began reforming the coal pricing system in 2006 to make the coal prices subject to the market. In 2013, the two-track pricing system was fully abolished as per the *State Council's Guidance on Deepening Thermal Coal Market Reform*. Coal producers and buyers can now freely negotiate coal prices. This Guidance also seeks to better protect the interests of electricity generators from coal price movement in the currently regulated electricity market of China. It allows the electricity tariff to be adjusted once the coal price changes by 5%. It also reduces the portion of coal price rise that has to be absorbed by electricity generators from 30% to 10%, thus passing more of the fuel cost rise to end users of electricity.

This latest reform has two main implications for thermal coal prices in China. Firstly, domestic coal prices will better reflect the demand/supply balance in the coal market. Under current market conditions where coal demand is weak and production capacity is excessive, it is likely that coal prices will remain depressed in the coming years. Secondly, there will be a closer correlation between domestic coal prices and imported coal prices. This is because without government intervention Chinese utilities will base their coal procurement primarily on price. Domestic coal prices have to be marked to import coal prices to win the buyers, and vice versa. Evidence for this is given by the latest seaborne coal market price fall in response to price cuts by China's largest coal producer, Shenhua (Platts, 2014). However, taxes on coal imports, imposed by the central government in October 2014, may break the link between domestic and imported prices.

Natural gas pricing has already changed from regulating prices on a cost-plus basis at production wells to setting prices at transmission city gates in each province. Suppliers and buyers can now negotiate actual gas procurement prices up to the regulated city-gate prices. However, the city gate prices fail to reflect the supply costs as more gas imports come into the supply market. Gas importers are making a loss at the regulated city gate gas prices. The Chinese central government undertook another reform in 2013 to address this issue by establishing a two-tier pricing system for gas supplied to non-residential users (known as non-residential supply). This system divides non-residential natural gas supply into two parts: the reserved volume and excessive volume. The reserved volume equals the gas consumption volume in 2012, 112 bcm. The city gate prices for the reserved volume will be progressively increased over the next three years with the overall price rise not exceeding 0.4 RMB/m^3 (the capped increase is 0.25 RMB/m^3 for fertiliser producers to maintain their competitiveness). Any gas supply in excess of the reserved volume will be charged at the Tier 2 price, which equals 85% of the weighted (by heating values) average prices of fuel oil and liquefied petroleum gas (LPG). Tier 1 and Tier 2 prices will be made to converge at the end of 2015. This reform is expected to raise the average city gate gas price (Tier 1) from

1.69 RMB/m^3 (7.84 US$/million Btu) to 1.95 RMB/m^3 (9.05 US$/million Btu) (NDRC, 2013a). [Note: the authors assume one cubic metre of natural gas has a heating value of 35314.667 Btu, and an average exchange rate of 1 US$ = 6.1 RMB, where RMB1/m^3= 4.64 US$/million Btu.]

The latest gas price reform establishes a link between domestic gas prices to fuel oil and LPG prices, which is due to push up domestic gas prices. It is argued that the price rise may not be enough to fully offset the losses incurred to gas importers (CEFC, 2013). Nonetheless, the perceived gas price rise will hit the gas-fired power plants strongly. These plants were already operating at losses as the low electricity tariffs were insufficient to recover generation costs. In response to this adverse impact, the NDRC has moved to increase the electricity tariffs for natural gas power plants in several provinces in September 2013 (NDRC, 2013b). The actual tariff rise varies between natural gas-fired power plants. The effect however remains to be seen in the coming years.

National energy policy

The 12th Five-Year Plan for Energy is the overarching national energy policy for the period of 2011–15 (State Council, 2013a). A key objective of this 12th FYP is to diversify the primary energy mix away from coal, with a target of reducing coal's share from 70% in 2010 to 65% in 2015. This is to be achieved by increasing the use of natural gas and non-fossil energy. The 12th FYP envisages the share of gas to increase from 4.4% to 7.5% during the 12th FYP period, and the priority of gas use is placed on the residential sector.

According to the targets set in this Plan, there are 300 GW of new coal power plants and 30 GW of new gas power plants to be built during 2011–15. At the end of 2015, coal-fired generation capacity will be 960 GW, while gas-fired generation capacity will be 56 GW (State, Council, 2013a). Coal therefore remains the backbone of China's power industry. The 12th FYP calls for orderly development of natural gas-based power generation in China. This includes building peaking gas CCGT plants in more developed regions in eastern parts of the country with reliable natural gas supply, prioritising the development of large gas CCGT CHP projects, and promoting gas-based distributed generation and CBM-based power generation.

Environmental regulations

China's latest *National Air Pollution Standard for Thermal Power Plants* came into effect on 1 January 2012 (MEP, 2011). This standard is much more stringent than previous ones and is in line with standards in the EU and the USA; it includes provisions for even stricter emission limits in highly polluted areas. This standard is being phased in quickly. New power plants needed to comply with the new standard from 1 January 2012, while compliance of existing power plants began on 1 July 2014. Compliance with mercury emission limits will took effect from 1 January 2015.

To comply with the new Air Pollution Standard, the electric utilities need to commit significant investment to install or upgrade pollution control equipment and cover additional O&M costs. According to China's Ministry of Environmental Protection, the estimated capital costs required for desulphurisation during the 12th FYP period are RMB 50–60 billion and the additional annual operational costs are

RMB 8–10 billion; for NOx control, these two cost components are RMB 52 billion and RMB 6 billion/y, respectively (Wang and others, 2010). Since such costs are generally higher for coal-fired power plants, the new Standard could make coal less favourable if financing for investment is expensive or difficult to obtain.

Another key environmental regulation is *State Council's Action Plan for Air Pollution Prevention* released on 10 September 2013 (State Council, 2013c). This Action Plan is the central government's response to the ever worsening air pollution of inhalable particulates (PM_{10} and $PM_{2.5}$). Widely shared concerns about air quality and local pollutants among China's rapidly expanding urban population make a forceful case for gas, rather than coal, as the preferred fuel for powering the country's cities. It prohibits new coal-fired power plants to be built in the Beijing-Tianjin-Hebei region, the Yangtze River Delta, and the Pearl River Delta. It requires replacing coal with natural gas in coal-fired boilers, industrial kilns and captive power plants in these three regions by 2017, thus resulting in falling coal consumption. The reduced coal use will be made up by increased electricity imports from other regions, increased consumption of natural gas, and increased non-fossil fuel consumption. This Action Plan also targets reduction of coal's share in China's total primary energy mix to be less than 65% by 2017.

The Action Plan restates the central government's intention for an orderly development of the natural gas industry. Priority is given to the residential sector and substitution for coal. In principle no new natural gas power plants will be built. This suggests that the central government has realised the constraint on gas supply and is cautious with the potentially large increase in natural gas demand from the power sector.

Finally, there is an emerging carbon cost in China. China's climate change-related goals for 2020 under the Copenhagen Accord include the following: (1) Reduce CO_2 per unit of GDP by 40–45% relative to 2005; (2) Increase the share of non-fossil energy in primary energy consumption to 15%. As part of the efforts to achieve these goals, the State Council stated its intention to gradually establish a CO_2 emission trading market in the 2011 white paper *China's Policies and Actions for Addressing Climate Change*. NDRC selected five cities (Beijing, Tianjin, Chongqing, Shanghai, and Shenzhen) and two provinces (Hubei and Guangdong) to establish pilot Emission Trading Schemes (ETS) through the issuance of *The Notice on Carrying Out the Work of Carbon Emission Trading Pilot Programme* in November 2011. The pilot ETS was subsequently opened in Shenzhen, Shanghai, Guangdong, Tianjin and Beijing in 2013; Hubei Province and Chongqing opened their pilot Schemes in 2014. The seven pilot schemes are collectively expected to cover 700 $MtCO_2$-e, a quantity second only to the EU ETS scheme, by 2014 (Scotney and others, 2012). Based on these pilot schemes, a nationwide unified ETS will be established during the 13th FYP period. In addition to the ETS, China is still considering a form of carbon tax and proposals have been submitted to the government (Scotney and others, 2012). The emerging carbon costs could put coal power at a disadvantage against natural gas as more CO_2 is emitted from coal-fired power stations on a per MWh basis. However, this will depend on whether or not the carbon costs will be passed on to end users of electricity, which is uncertain at the moment.

Implications

Coal will remain the backbone of China's power sector given the sheer size of the coal plant fleet and its lower generation costs. Natural gas consumption will grow fast but its role in China's primary energy mix will remain small.

Increased use of natural gas for power generation seems to concentrate in three major industrialised areas of China: the Beijing-Tianjin-Hebei region, the Yangtze River Delta, and the Pearl River Delta. This is not based on generation economics, but rather driven by the government's policy to address ever-worsening air pollution issues.

Outside these regions, natural gas is unlikely to compete with coal as a generation fuel. China's energy policy places the priority of gas supply on the residential sector rather than the power sector. Moreover, the latest gas pricing reform implies that natural gas will be more expensive. In contrast, the coal price could remain low as a result of both weak demand and excessive production capacity. Coal will therefore remain much cheaper than gas in China. Nevertheless, the new air emission standard and the emerging carbon cost could potentially put coal at a disadvantage against gas for power generation.

4 India

4.1 Energy indicators in 2012

Population	1236	million
GDP	1858.7	billion US$
Electricity consumption	940	TWh
Electricity consumption per capita	0.76	MWh/capita
Electricity generation	1128	TWh
Electricity imports/exports	4.8/0	TWh
Generation capacity (end of 2013)	234	GWe
Coal-fired capacity (end of 2013)	138	GWe
Gas-fired capacity (end of 2013)	20.4	GWe

(IEA, 2014a; World Bank, 2014)

4.2 Power generation mix

The total electricity generation in India nearly doubled between 2000 and 2012, as shown in Figure 4. Coal dominated the electricity generation mix with a share of 71% in 2012, and was also the largest contributor to the growth in electricity generation during 2000–12. Hydropower was the second largest source of electricity generation with a share of 11% in 2012, while natural gas came in third with a share of 8%. Generation from natural gas has decreased during 2010-12 as a result of a shortage of gas supply, which will be discussed in Section 4.5. Oil-based generation decreased steadily but at a low pace during this period and still accounted for 2% of total electricity generation in 2012. Nuclear, wind and other renewables increased their shares in recent years, but remain small contributors.

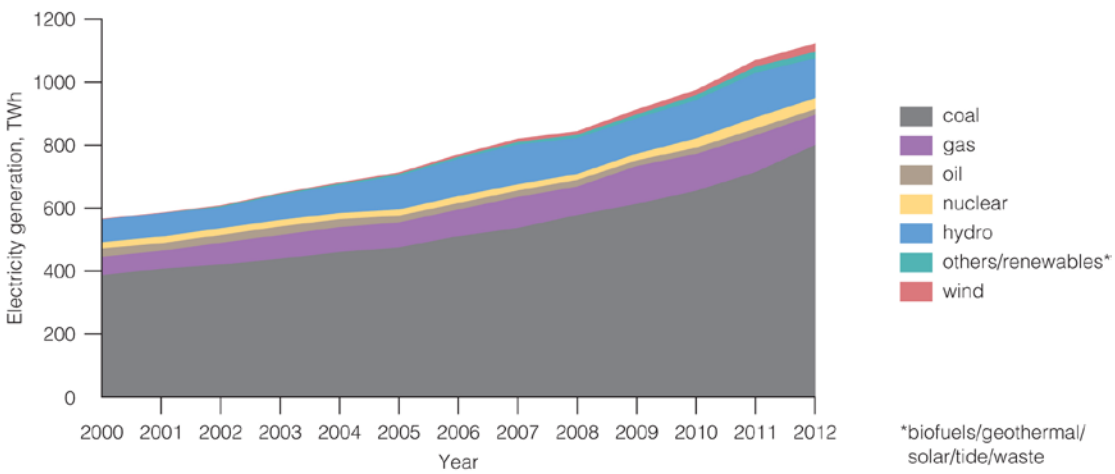

Figure 4 The historic trend of the electricity generation mix in India between 2000 and 2012 (IEA, 2014a)

Figure 5 illustrates the overall dispatch of the various types of power station in India's generation fleet. The x-axis shows the fleet utilisation, based on the average annual operating hours calculated over 2006–12. The y-axis shows the current generating capacity in the country, including existing units and those expected to be commissioned in 2013, based on Platts World Electric Power Plant Database (Platts, 2013). India had a total installed generation capacity of 234 GW at the end of 2013, including coal (59%), hydropower (17%), renewables (13%), gas (8%), nuclear 2% and diesel (0.5%) (CEA, 2014).

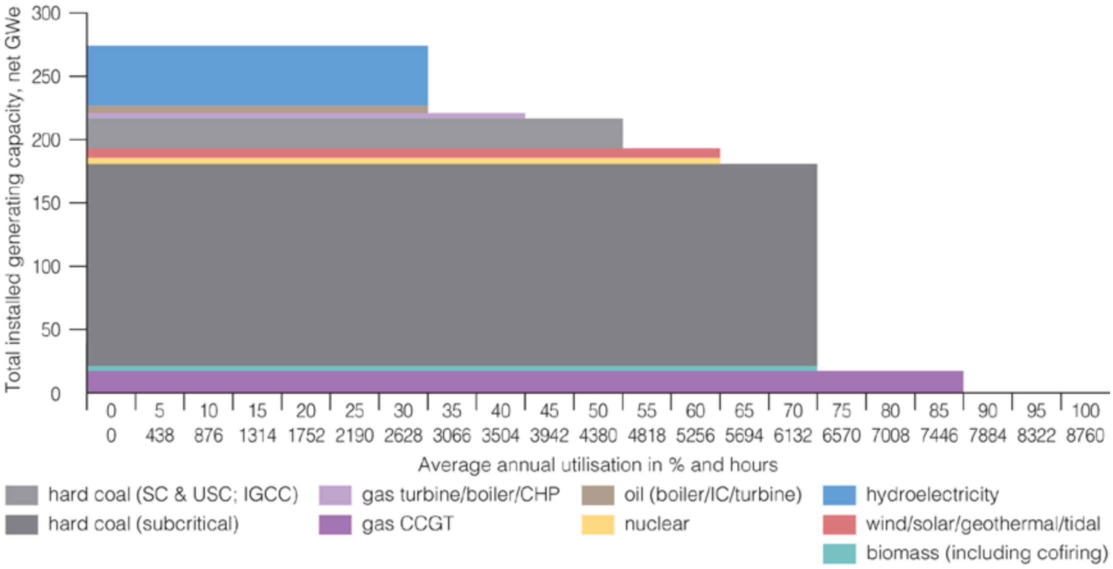

Figure 5 The representative dispatch graph of various types of power generation plant fleet in 2013 (based on Platts World Electric Power Plant Database, December 2013)

Natural gas CCGT plants operated at 80% utilisation, the second highest after Japan, which reflects the reality in India that fast growing electricity demand necessitates the use of all available generation capacity. About 73% of the total installed natural gas-fired generation capacity (20.4 GW) is located in five states: Delhi (2.1 GW), Gujarat (4.9 GW), Maharashtra (3.5 GW), Andhra Pradesh (3.4 GW) and Tamil Nadu (1.0 GW) %) (CEA, 2014). Gujarat has a relatively large gas-based installed capacity, accounting for nearly a quarter of India's total. This is attributed to Gujarat's proximity to significant gas fields and the LNG import terminals in Hazira and Dahej.

Coal-fired generation was dominated by subcritical coal-fired power plants, which comprised the majority of India's installed coal-fired generation capacity. These subcritical coal units have an average efficiency of about 34% (LHV), compared to 37% (LHV) for subcritical plants in China and 39% (LHV) for subcritical plants in the USA (IEA, 2012). Supercritical coal-fired power plants were built only in recent years, which may partly explain their low utilisation as it takes time for new units to achieve stable and optimised operation (Another reason might be the shortage of coal supply, as discussed in Section 4.5). The first 660 MW supercritical coal-fired unit was commissioned at the Mundra Adani power plant in December 2010. There were approximately 16 GW of supercritical coal-fired power plants in operation at the end of 2013 (Platts, 2014).

The Indian central government is promoting supercritical coal-fired power generation in order to improve the energy efficiency of the coal fleet in the country. Its major effort has been the Ultra-Mega Power Projects (UMPP) initiative, launched in 2005, which brings in private investment to accelerate coal-based generation capacity expansion with supercritical technology. As of the time writing this report, there are fifteen UMPP projects envisioned with four projects of 4000 MW each being successfully awarded to private power companies on the basis of competitive tariff-based tender. Among these four UMPP projects, the coastal Mundra UMPP is fully commissioned, while the four units of the minemouth Sasan UMPP (4 x 660 MW) were commissioned in 2013 (IEA, 2012; Platts, 2014; MOP, 2014). However, the tender-based power tariff does not contain a provision for passing on any increase in coal costs, which is considered to have adversely affected UMPP initiative (Planning Commission, 2013).

According to the Ministry of Power's 12th Five-Year Plan (2012–17), the planned new generation capacity is 76 GW, of which 62.7 GW or 83% will be coal-based (IEA, 2012). The Planning Commission of Indian government (2013) expected that around half of coal-based capacity addition in the 12th FYP would be based on supercritical technology. For the 13th FYP, it has been decided that all coal-fired capacity addition shall be supercritical units. The Platts' World Electric Power Plant Database shows 33.7 GW of coal capacity under construction in 2013. The experience from the 11th FYP suggests that these targets are challenging to achieve; during 2006–11, only 55 GW of the targeted 78.7 GW were actually built (Planning Commission, 2013).

The 12th FYP targeted only 1 GW of new gas-fired capacity to be built as a result of declining domestic gas production. The Platts' Database shows 3.4 GW of gas-fired plants being built in 2013. Interestingly, no private investment is planned in new gas-fired generation, indicating the concerns of private investors over the project risks related to insufficient gas supply.

IEA projected that India's total generation capacity would reach 887 GW in 2035 under its New Policies Scenario. This projection implies new capacity addition of 28 GW per year between 2011 and 2035. Considering that the largest annual capacity addition was about 18 GW in the FY 2011–12, it will be challenging for India to fulfil this projection.

Furthermore, the fuel mix for power generation will remain almost unchanged, despite an absolute growth in capacity of every fuel under the IEA New Policies Scenario. Coal will remain the dominant fuel, although its share in the generation mix will reduce from 71% in 2012 to 56% in 2035. Coal's share would be taken largely by nuclear, wind and solar PV (IEA, 2013a). The share of natural gas is projected to increase from 8% to 12% during this period.

4.3 Fuel supplies and prices

4.3.1 Gas

According to India's Ministry of Petroleum and Natural Gas, India had 1.35 trillion cubic feet (38.23 tcm) of proved and indicated recoverable natural gas reserves in 2013 (MOPNG, 2013).

This figure includes the CBM reserves in Jharkhand and West Bengal, and is consistent with the data from the World Energy Council. The majority (74%) of these reserves are located offshore. These reserves could provide for around 40 years at the current production level (BP, 2014).

India's total natural gas production (including CBM) peaked at 53.3 bcm in 2010 and has since declined to 40.7 bcm in FY 2012–13 (MOPNG, 2013). Around 78% of gas production was from offshore gas fields (mainly off the western coast), while on shore production was concentrated in four states: Assam in the northeast, Gujarat in the west, Tamil Nadu and Andhra Pradesh in the southeast (together accounting for 83% of total onshore production in FY 2012–13). Production from India's maturing gas fields is largely stagnating and even declining in some more mature fields. Notably, the Krishna–Godavari (KG) basin off India's eastern coast, which was the largest discovery in recent years and expected to compensate for declining production from other maturing fields, failed to deliver the expected production boost due to unexpected geological complexity (EIA, 2014).

The latest assessment by the Ministry of Petroleum and Natural Gas showed a broad range of 254–2605 bcm both onshore and offshore (EIA, 2014). India began offering CBM blocks for exploration in 2001, but it took almost a decade to begin production. Total CBM production reached 164 million m^3 in 2013, mainly in West Bengal where the Raniganj block has an estimated 28 bcm potential (MOPNG, 2013; EIA, 2014).

There is interest in exploring the Cambay basin in Gujarat, the Assam-Arakan basin in northeast India, and the Gondwana basin in central India for shale gas resources, although there has been no commercial production or publicly released reserve figures. In its 2013 assessment of global shale gas reserves, the US EIA estimates India has 96 trillion cubic feet (or 2.7 tcm) of technically recoverable shale gas reserves.

The stagnant production of conventional gas and limited development of unconventional gas led to increasing gas imports to fill the supply gap. Currently, gas import is not through pipeline, although the Indian government has attempted several international projects (many of which have proved unfeasible). The potential lies with the Turkmenistan-Afghanistan-Pakistan-India (TAPI) project (also known as the Trans-Afghanistan Pipeline) to import natural gas from Turkmenistan to India. Although all countries involved have made some progress in moving TAPI forward, major geopolitical risks and technical challenges have prevented the project from materialising following a decade-long discussion.

India started importing LNG from Qatar in 2004, and has now become the world's fourth largest LNG importer, accounting for 17.8 bcm, or 5.5% of global total LNG trade in 2013. Qatar's RasGas is India's sole long-term supplier of LNG with a volume of 15.3 bcm in 2013. India has been actively importing spot cargoes following interruptions in the KG-D6 field production after 2010. It began receiving cargos from a variety of exporting countries; Nigeria (0.9 bcm), Yemen (0.7 bcm) and Egypt (0.4 bcm) became India's largest short-term LNG suppliers in 2013

(BP, 2014). Indian LNG importers actively sought supply from various new sources and signed several short- and long-term purchase agreements with Australian and USA terminals and a number of international gas companies. Oil India Limited has invested in LNG projects in Canada and Mozambique to secure LNG imports for India.

Petronet is the major importer of LNG supplies to India and owns two existing LNG terminals, Dahej (13.6 bcm/y) and Kochi (3.4 bcm/y) (EIA, 2014). In addition, Shell and Total jointly own the Hazira terminal (6.8 bcm/y), which operates as a merchant facility, importing only short-term and spot cargoes at present. India's total regasification capacity now stands at 26.5 bcm, and terminal owners have proposed capacity expansion at all three existing terminals.

There are three gas pricing regimes in India. The first regime applies to gas produced by state-owned producers under the Administered Pricing Mechanism (APM) and by Joint Ventures under the 'discovered fields' exploration policy. Prices of APM gas are regulated by the government on a cost-plus basis, while prices paid to private companies in the Joint Venture are loosely pegged to international gas prices based on a fixed formula in their Production Sharing Contracts. The second regime covers regasified LNG, where prices are completely market-driven and determined on the basis of contracts and spot purchases. The third regime applies to gas extracted from fields allocated under the New Exploration Licensing Policy (NELP), which awards exploration blocks through international competitive bidding and allows 100% foreign and private participation. This is a new pricing regime approved by the Indian government in June 2013 in order to attract investment critical to increase domestic gas production and mitigate upstream project delays. Under the third regime, prices for NELP gas are being 'discovered' during the bidding process and subject to government approval. Multiple gas pricing regimes have resulted in gas in India being sold at different prices. LNG prices are the highest, and APM gas prices are the lowest. The third pricing regime is still evolving; there was a plan to double the NELP gas prices, but the actual price increase for Reliance's KG-D6 project was more modest – from 4.2 $/million Btu (3.98 $/GJ) to 5.61 $/million Btu (5.32 $/GJ) – partly due to political pressure.

4.3.2 Coal

According to India's Central Statistics Office, India's coal resources to a depth of 1200 metres were estimated to be 293.5 Gt in 2012. Approximately 117 Gt of these resources were classified as proven coal reserves (MOSPI, 2013). These figures are thought to be optimistic, considering that the Indian coal classification system is based primarily on geological evaluation without assessing the quality and mineability of deposits (Chikkatur, 2008). BGR estimated 256 Gt of remaining potential (175 Gt of resources) and 80.4 GT of reserves in 2012 (BGR, 2013). The World Energy Council estimates in 2013 put India's proved recoverable coal reserves at 60.6 Gt, the fourth largest in the world behind the USA, Russia and China. Although India's coal reserves cover all ranks from lignite to bituminous, they tend to have high ash contents (typically 30–50%) and low-to-medium calorific values (on average 4500 kcal/kg) .

The principal deposits of bituminous coal are in the eastern half of the country, with four eastern states, Chhattisgarh, Jharkhand, Orissa and West Bengal, together accounting for 77% of hard coal reserves (WEC, 2013). Lignite deposits mostly exist in the southern State of Tamil Nadu, where the Neyveli area with 2.4 Gt proved reserves is regarded mineable. India's 11th Five-Year plan (2007–12) reported 4.5 Gt of total proved lignite reserves and 38.3 Gt of total lignite resources in India.

Coal production in India reached 605 Mt in 2013, more than double that in 2000, which included 42 Mt lignite output. Two state-owned companies have a near-monopoly on coal production and distribution. Coal India Limited (CIL) is the country's largest coal producer, and produced about 81% of India's coal in 2012. Singareni Collieries Company Limited (SCCL) was responsible for 10% of the country's coal production in 2012, mainly in the southern regions of India.

India's proved recoverable coal reserves imply about 100 years of production at the current production level. However, only a fraction of the coal reserves will be mineable as indicated by the Indian government in its *Integrated Energy Policy 2008*. This, coupled with growing production, implies that the extractable coal reserves may last for a much shorter period of time (45 years at a 5% annual growth in coal production – the compound average annual growth rate of coal production between 2000 and 2013) (IEA, 2012).

Growing coal production, however, has been short of coal consumption during 2000–13. This is largely because CIL and SCCL have failed to reach the government's production targets. The 'supply gap' (the consumption minus production) has widened, in percentage terms, from 8.3% total coal consumption in 2000 to 29.5% in 2013 (BP, 2014). The abovementioned cautions over reserves' mineability lead to questions of whether the current coal shortage is temporary due to insufficient production capacity or more fundamental due to limited extractable coal reserves.

The increasing supply shortage has led India to turn to the international seaborne coal market to bridge the supply gap. Net coal imports have steadily increased from 19.6 Mt in FY 2000–01 to 100.8 Mt in FY 2011–12; India's reliance on imported coal for consumption has thus risen from 6% in FY 2000-01 to 19% in 2011-12 (MOSPI, 2013). In 2012, Indonesia was the largest source of coal imports to India, accounting for 55% of total coal imports, followed by Australia (23%) and South Africa (14%) (EIA, 2014).

Rising consumption of imported coal is partly due to the need to use imported coal to blend with poor quality indigenous coal to arrive at the desirable properties for coal feed into coal-fired power plants. Firing poor quality indigenous coal alone adversely affects the operation of coal-fired power plants and has been reported to have caused the loss of 35% of coal-based generation in FY 2010–11 (CEA, 2011). Coal washing could reduce the loss, but India has inadequate coal washing plants. According to India's Ministry of Coal, about 243 Mt of coal needed to be washed in 2012, but there was only 135 Mt of washing capacity. The capacity will be increased to 175 Mt at the end of the 12th FYP period (2012–17), but this is still short of what is needed (MOC, 2011).

The inadequate coal washing has two important implications. Firstly, a considerable portion of the coal fleet is operated at low efficiencies and availabilities, as around 100 Mt of unwashed coal is burned. Secondly, the demand for imported coal is somewhat inelastic as imported coal is needed for blending with indigenous coal to get to the desired coal feed properties for coal-fired power plants.

Coal prices in India were deregulated in 2000 as part of the government's efforts to encourage foreign and private investment into the coal sector. Coal mining companies are allowed to increase coal prices if their production costs increase. With the dominant position in the coal sector, Coal India Coal Ltd (CIL) has the pricing power for coal in India. The current coal pricing system divides coal into 17 grade bands based on its gross calorific value (GCV). Good quality (Grade 1–5) non-coking coals are sold at 15% discount to the prices of imported coal at the nearest port. Non-coking coals in all other bands are sold at lower prices; for priority customers such as power generators, the price they pay is 35% lower than non-priority customers. In 2007, the government passed the New Coal Distribution Policy that attempted to allocate limited coal supplies to priority sectors, in particular power and fertiliser plants. India's 12th FYP calls for CIL to prioritise indigenous coal production with the fuel requirement of new power plants coming online by 2017. In addition, CIL sells around 10% of its coal through e-Auction, a procurement system acting to some extent as a spot and future market of coal in India. It is noted that coal has been sold through e-Auction at a premium of 80% on average to the contract price paid by the power sector (IEA, 2012).

4.4 Generation cost comparison

Figure 6 illustrates the average generation costs of existing coal and natural gas CCGT plant fleets based on assumptions in Table 2. The fixed cost of capital, interest and O&M costs are lower for the gas CCGT fleet, but the annualised fuel cost of natural gas is more than double that of coal. Taken together, the average generation cost of gas CCGT is higher than that of both types of coal fleets. Our analysis shows that the gas price needs to drop from the base price of 8.5 $/million Btu (8.06 $/GJ) to below 6.2 $/million Btu to make the gas CCGT fleet competitive with the subcritical coal fleet burning India's cheapest coals. The gas price needs to further decline to 6.0 $/million Btu to equalise the generation cost of gas CCGT fleet to that of the supercritical coal fleet.

Since the gas CCGT fleet already operates at high utilisation rates (80%), there is little room for generation cost reduction by further increasing the utilisation rate. However, cost reduction can be achieved by improving the gas fleet's efficiency, which is on average around 42% (LHV, net), among the lowest in Asia. The low efficiency of the gas CCGT fleet is possibly due to the fact that the fleet includes many old, small (less than 150 MW) units and larger units were commissioned only after 2007 (Platts, 2014).

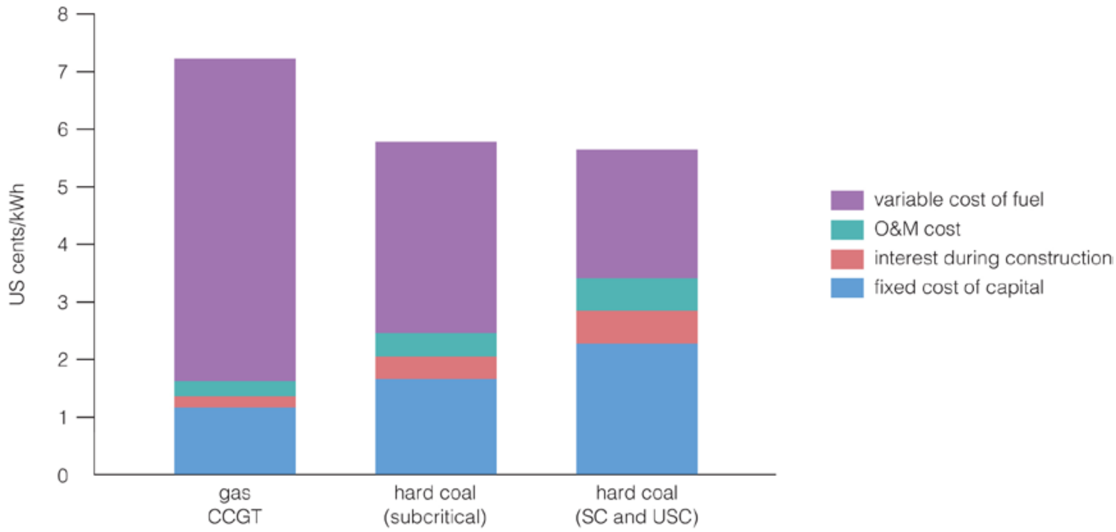

Figure 6 The modelled average generation costs of natural gas CCGT fleet and coal-fired subcritical and supercritical fleets

4.5 Discussion on issues affecting competition

India is facing severe challenges for its power sector. On one hand, the country, with a quarter of its population still having no access to electricity, has to increase the electrification rate of its population as a major priority of the government's energy policies (IEA, 2012; IEA, 2013a). On the other hand, the country is facing a severe shortage of electricity supply that has caused large scale blackouts. The power supply shortage is due to a variety of factors, including distribution losses, theft of electricity and coal, fuel supply shortages and unreliable power plant operation.

In particular, the fuel (coal and gas) supply shortage has increasingly restricted the electricity supply. Fuel supply shortage is caused by flattening or declining domestic production and constrained fuel imports as a result of inadequate import terminal capacity and higher import prices. Fuel shortage has resulted in power plants sitting idle or operating at lower than optimal levels (IEA, 2012). Such shortages undermine investors' confidence in India's power sector, as the profitability of investments is questioned. To address this fuel shortage issue, the Indian government has applied a mandatory allocation of domestic coal and gas to the power sector through the *New Coal Distribution Policy* and *Gas Utilisation Policy*. However, this serves only as a temporary solution without substantial expansion of domestic and import supply or addressing the waste and losses occurring throughout the supply chain.

Both coal and gas are needed to resolve the power supply shortage. Gas CCGT units are concentrated in five states with readily accessible gas supply; these units operate at very high utilisation rates to provide baseload generation. India is building more coal-fired power plants, a considerable proportion of which are supercritical, while only several GW of new gas-fired power plants are under construction due to concerns over security of gas supply.

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5 Indonesia

5.1 Energy indicators in 2012

Population	241	million
GDP	876.7	billion US$
Electricity consumption	154	TWh
Electricity consumption per capita	0.64	MWh/capita
Electricity generation	197.3	TWh
Electricity imports/exports	2.99/0	TWh
Generation capacity	45.3	GWe
Coal-fired capacity	19.8	GWe
Gas-fired capacity	13.8	GWe

(IEA, 2014a; KESDM, 2014; World Bank, 2014)

5.2 Power generation mix

As the largest economy in Southeast Asia, Indonesia is the largest energy consumer in this region. It is a net importer of oil, but the world's top exporter of steam coal and also a major supplier of LNG. As the largest and most populous archipelago in the world, providing access to modern energy is a challenge. More than a quarter of the Indonesian population does not have access to electricity, and this issue is worse in the eastern parts of the country. For example, only a third of the population in Papua is electrified, according to state-owned electric utility Perusahaan Listrik Negara (PLN) (PLN, 2013).

As illustrated by Figure 7, the Indonesian electricity generation mix is dominated by fossil fuels. In 2012, coal accounted for almost 50% of the total electricity generation, while natural gas and oil/diesel contributed 27.5% and 11.2%, respectively (KESDM, 2014). The largest growth in absolute terms was from coal-based generation. The generation based on gas and diesel also increased, while generation from oil-fired steam power plants diminished considerably in this period. There was also sizable generation from hydropower and geothermal with a share of 6.5% and 4.8%, respectively (KESDM, 2014). Notably, Indonesia is now the third largest producer of geothermal energy behind the USA and Philippines.

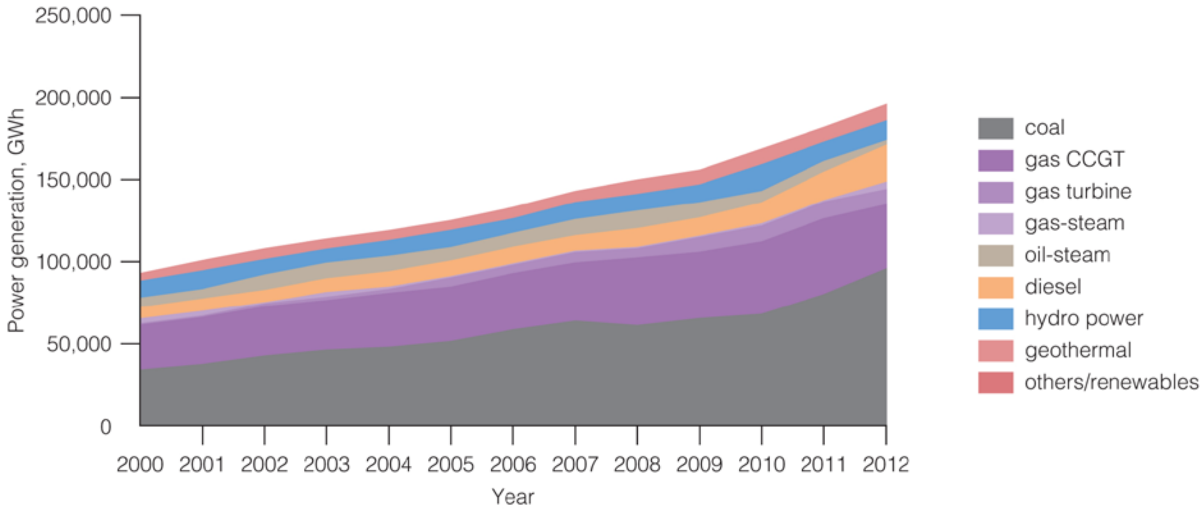

Figure 7 The historic trend of the electricity generation mix between 2000 and 2012 (KESDM, 2014)

Figure 8 illustrates the representative dispatch of the various types of power generation plants in Indonesia. The x-axis shows the fleet utilisation, based on the average annual operating hours calculated over the period of 2006–12. The y-axis shows the current generating capacity in the country, including existing units and those expected to be commissioned in 2013, based on Platts World Electric Power Plant Database (Platts, 2013).

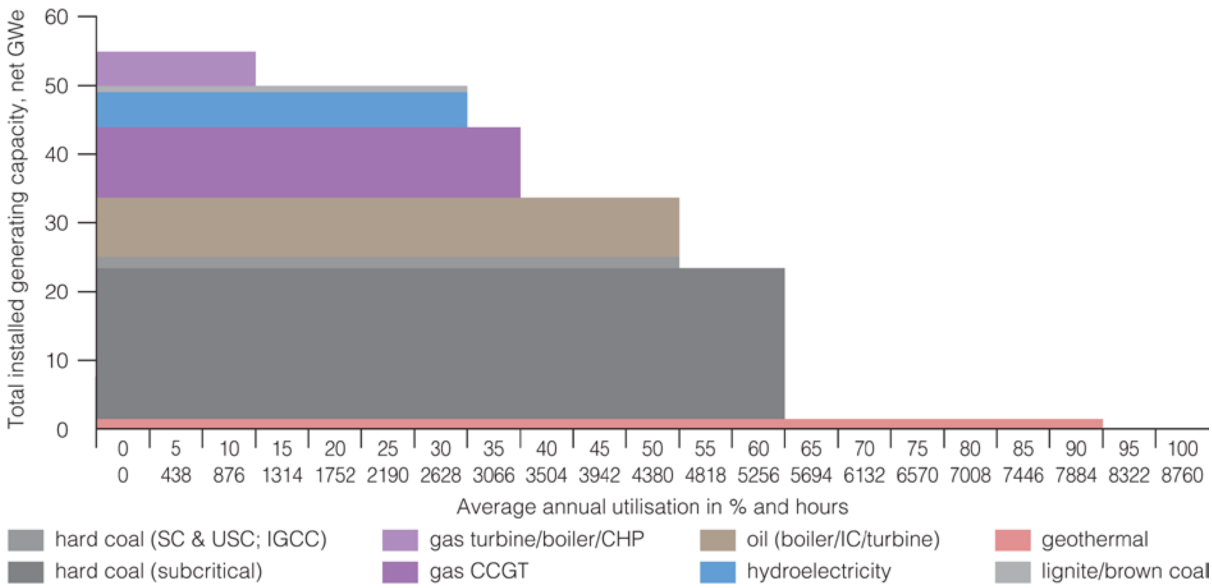

Figure 8 The representative dispatch graph of various types of power generation plant fleet in 2013 (based on Platts World Electric Power Plant Database, December 2013)

As shown in Figure 8, the baseload power generation is provided primarily by subcritical hard coal power plants. Oil-based power generation (mainly diesel) appears to be over the mid merit part of the dispatch, while natural gas CCGT and gas turbine power plants have low utilisation rates. The large share of diesel in the power generation mix was due mainly to the operation of many diesel engines outside the Java and Bali regions to meet the electricity demand. In addition, several gas CCGT and gas turbine power plants in the Java–Bali system are using diesel as the fuel due to a lack of gas supply (KESDM, 2013a). As shown in

Figure 7, the consumption of fuel oil for power generation has been reduced considerably because the Indonesian government removed the fuel subsidies for fuel oil in 2005 to relieve the fiscal budget burden of oil products. In contrast, diesel is still subsidised, and the tight electricity supply implies that it may be difficult to reduce the share of diesel unless alternative generation capacity is available.

Indonesia's renewable potential lies in geothermal and mini-hydropower. According to the Ministry of Energy and Mineral Resources, only 5% of potentially 29 GW of geothermal resources are currently being used (Jarman, 2012). Generation from hydropower has been roughly stable over the past decade. Future growth opportunities depend on development of mini-hydropower plants, as the areas with the biggest potential, Papua and Kalimantan, are isolated from the demand centres. Other renewables, including biomass cogeneration, solar PV and waste-to-energy, are small in capacity, but can play an important role, particularly by accelerating electrification in remote areas.

Growth in coal use for power generation is linked to completion of two Fast Track programmes. Fast Track Programme 1 was launched in 2006 to build 10 GW of coal power plants to meet growing electricity demand and to switch from oil-based to coal-based power. Initially, Fast Track Programme 1 was to be completed by 2009, but was changed to 2014. Fast Track Programme 2 was launched in 2009 to develop a further 10 GW of capacity by 2014, comprising 40% coal, 34% geothermal, 11% hydro and 15% natural gas (IEA, 2013c). Fast Track Programme 2 has been amended several times, including:

- the completion date is now beyond 2014;
- gas power plants have been cancelled in view of shortage of gas supply to the domestic market;
- many geothermal plants have been delayed;
- several units of very large coal plants have been added making the total capacity of Fast Track Programme 2 almost 18 GW.

Notably, Indonesia is planning to add supercritical coal-fired generation capacity. The 660 MW Cirebon steam power plant, commissioned in 2012, is the first supercritical coal-fired power plant in Indonesia. It is one of the independent power producer (IPP) projects, jointly developed by Japan-based Marubeni Corporation, Korea Midland Power Co, South Korean Samtan Co Ltd and the Indonesian listed firm PT Indika Energy. In 2011, a 2000 MW supercritical power plant was proposed to be built in Pemalang in Central Java, jointly by two Japanese companies (J-Power and Itochu) and Indonesia-based Adaro Power. Central Java power plant is the first project to be awarded a government guarantee by the Indonesia Infrastructure Guarantee Fund created and backed by the World Bank. Originally, the plan was for the first 1000 MW unit to begin operating in late 2016, followed by a second unit in 2017. But the plant was delayed due to difficulties in land acquisition, environmental assessment and local opposition. Consequently, the construction has been postponed by two years to October 2014.

5.3 Fuel supplies and prices

5.3.1 Gas

According to Indonesia's Ministry of Energy and Mineral Resources, Indonesia has natural gas reserves of 4.27 tcm in 2012, comprising 2.93 tcm proven reserves and 1.34 tcm potential reserves (KESDM, 2014). This ranks the country as the 13th largest holder of proven natural gas reserves in the world, and the second largest in the Asia Pacific region after China. Indonesia's upstream gas sector is dominated by foreign oil companies, while the state-owned Pertamina accounted for 13% of natural gas production in 2012. Natural gas production was 89.9 bcm in 2012, down from a peak of 96.6 bcm in 2010 (KESDM, 2014). More than 87% of the production was from offshore fields not associated with oil production. Indonesia's largest fields are located in the Aceh region of South Sumatra and East Kalimantan. In recent years, production companies have shifted attention to newer, underexplored offshore areas, particularly in the eastern regions of the country such as West Papua.

The Ministry of Energy and Mineral Resources estimates that the country has CBM reserves of 12.8 tcm based on preliminary studies (EIA, 2014). The Indonesian government started awarding CBM blocks on Sumatra Island and East Kalimantan in 2007. Singapore-based Dart Energy and Indonesian PT Energi Pasir Hitam began CBM exploration activities in East Kalimantan in 2013, with the goal of supplying both power plants and the Bontang LNG facility. The government anticipates that CBM production will reach about 5 bcm/y by 2020 (EIA, 2014).

EIA estimates that Indonesia possesses 1.3 tcm of technically recoverable shale gas resources out of 8.58 tcm in place. There is currently no shale gas production, but there have been more than 70 proposals for shale gas projects with the bulk focusing on Sumatra, East Kalimantan, Central Kalimantan and West Papua. A major challenge to shale gas development in this country is the high costs because the deposits are far from demand centres and the infrastructure needs to be developed to transport the gas. The more promising projects are those located in Sumatra, which lie close to markets in Java, the most populous island, and those in Kalimantan near to the 22.5 Mt/y Bontang LNG export terminal, which is operating well below its nameplate capacity. The two shale gas blocks awarded by the Indonesian government so far are both located in North Sumatra; they are the Sumbagut block awarded to Pertamina, the state-owned oil company, and the Kisaran block awarded to a consortium of foreign oil companies, including New Zealand Oil & Gas Ltd, Canada's Bukit Energy and Pacific Oil & Gas Ltd based in Hong Kong.

Indonesia is a leading gas exporter in Asia. In 2013, it exported 7.6 bcm to Singapore and 1.2 bcm to Malaysia via pipelines, and exported 22.4 bcm of LNG mainly to China, Japan, South Korea and Taiwan (BP, 2014). In contrast, its natural gas consumption was 38.4 bcm in 2013. However, the Indonesian government has been promoting gas for domestic consumption as a measure to reduce dependence on expensive oil imports. The Domestic Market Obligation requires that 25% of natural gas produced from Production Sharing Contracts must be supplied to the domestic markets. In light of the continued fast growth in domestic consumption of gas, the government has imposed larger obligations in recent specific contracts. Nonetheless, there has been a shortage of natural gas supply to domestic markets, which has led to some gas power plants burning oil to generate electricity. This is largely due to inadequate gas transmission and distribution infrastructure. There are no integrated pipeline networks in Indonesia because pipelines are developed on a project by project basis and concentrated close to the production areas and large industries that use natural gas as fuel and feedstocks. The developed pipelines are mostly located on the Sumatra Island and extend from south Sumatra to west Java. There was a plan to build a transmission pipeline to connect east Kalimantan to central Java and western Java. The oil & gas upstream regulator, SKK Migas, reported that Singapore plans to end gas purchase from Indonesia's pipeline once the existing long-term contracts expire in 2020. The reduction in exports should allow Indonesia to secure more domestic supply in the next few years.

The Indonesian government has also sought to meet the growing gas demand by increasing the country's LNG regasification capacity. The first domestic regasification terminal, Nusantara, in West Java (14 million m^3/d) was commissioned in 2012 to process LNG from Indonesia's Bontang and Tangguh LNG plants. The government has authorised Pertamina to convert the Arun LNG plant in north Sumatra to a regasification terminal (4 bcm/y) which was due to come online in late 2014. Pertamina plans to construct a pipeline from the Arun regasification facility to Belawan to serve the power and fertiliser plants there. The second floating regasification terminal, Lampung, in southern Sumatra with a capacity of 6.8 million m^3/d was brought online in July 2014. In the eastern regions of the country, Pertamina and PLN announced plans to develop eight mini-LNG receiving terminals with a total capacity of 1.9 bcm/y by 2015. The government expects these facilities to supply natural gas to domestic electricity plants. In addition, Indonesia plans to import LNG from other countries. Pertamina has signed two long-term contracts to purchase LNG (1.52 Mt/y) from US-based Cheniere Energy for 20 years from its planned Corpus Christi liquefaction terminal, located in the Gulf Coast, which will start in 2018 and 2019, respectively (Reuters, 2014).

The natural gas price assumed in this study is the average of domestic prices obtained from literature reviews and market journals. It is the lowest among all the Asian countries studied in this report. The sustained shortage of gas supply and LNG imports could increase the gas price for domestic markets.

5.3.2 Coal

Indonesia has substantial coal resources. Indonesia's Ministry of Energy and Mineral Resources estimated a total resource base of nearly 120 Gt, of which 28 Gt were proved recoverable reserves, at the end of 2011 (WEC, 2013). These reserves are mostly located in Sumatra, East and South Kalimantan, and can provide 79 years of production at the production level of 353 Mt in 2011. Indonesia has overtaken Australia as the world's largest coal exporter, with more than 75% of coal output exported in 2011 (WEC, 2013).

Coal consumption in Indonesia has grown by almost four-fold since 2000 to 76 Mt in 2012. The electricity sector is the largest coal consumer, and is expanding as a result of the addition of coal-fired generation capacity. The Indonesian government encourages increased use of coal in the power sector because of relatively abundant domestic supply and the need to reduce the use of expensive diesel and fuel oil for power generation. In order to guarantee sufficient domestic supply, the Indonesian government introduced a Domestic Market Obligation (DMO) in 2010, which required nominated coal producers to sell a minimum percentage of their coal output to the domestic market. The DMO requires that coal be sold at or above the coal reference price, which is a price set by the Ministry of Energy and Mineral Resources on a monthly basis. If the DMO is not fulfilled by a producer, there will be a sanction of 50% cut of coal production in the following year. The minimum DMO percentage is decided by the Ministry of Energy and Mineral Resources based on projections of domestic coal demand. The minimum DMO percentage set for 2014 was 25.9%, equivalent to 95.55 million short ton (86.7 Mt) of coal for the domestic market; around 82% of this was allocated to the power sector (ESDM, 2013b).

The Indonesian government has also taken other regulatory actions to curb coal exports. It requires exporters to produce an IUP-OPK mining business licence pertinent to *Law No. 4 of 2009 on Mineral and Coal Mining*, which allows them to trade and transport coal. Exporters are also required to produce a 'clean and clear' certification of the producing coal mines before they are allowed to ship out their cargoes. There was also a proposed ban on export of low calorific value coal, though this never materialised. The calorific value threshold discussed oscillates between 5100–5700 kcal/kg, which is actually not 'low'. (When China proposed to ban low calorific value coal imports in 2013, the threshold was reportedly at a more realistic 4540 kcal/kg. The Chinese government eventually abandoned its proposed ban and instead imposed a tax, set at 3%). Moreover, the government is expected to raise coal royalty payments for small and mid-sized producers from 4–7% to 13.5%, a rate paid by major Indonesian coal companies holding the Coal Contracts of Work granted by the central government.

Coal prices are strictly regulated in Indonesia. The Regulation No. 17/2010 of the Guidelines of Stipulating Coal and Mineral Sale Benchmark stipulates that all coal produced by IUP/IUPK (Mining Business Permit /Special Mining Business Permit) holders must be sold at the regulated benchmark price (HPB, or Harga Patokan Batubara), for both domestic or export sale. The HPBs are determined by the Director General of Minerals and Coal (DGMC) for metallurgical coal, thermal coal, and low rank coal monthly. The HPBs for the metallurgical coal and thermal coal are calculated using a formula that refers to a Coal Price Reference (HBA or Harga Batubara Acuan), which is the calorific value weighted average of four coal price indices: Newcastle Coal Index, Global Coal Index, Platts and Indonesia Coal Index. There will be eight benchmark price categories covering the calorific value in the range of 4200–7000 kcal/kg (Kumbhat, 2011). Certain types of coal are exempted from this regulation; for example, coal for self-use in production processes or in the poorly developed regions, can be sold at a price lower than the HPB. For coal consumed in minemouth power plants, the Regulation No. 1348.K/30/DJB/2011 stipulates that coal with no less than 3000 kcal/kg GAR (gross as-received) can be sold at a price lower than HPB if approved by the DGMC. Coal with a lower heating value must be sold on production cost plus margin basis. The margin is determined at the level of 25% of the production cost; the production cost must be approved by the DGMC (Baker & McKenzie, 2014).

5.4 Generation cost comparison

Figure 9 illustrates the average generation costs of gas CCGT and subcritical coal fleets, based on assumptions listed in Table 3. The Gas CCGT appears to be a more economic form of generation than the subcritical coal. Since the specific CAPEX of a gas CCGT plant is around half that of a subcritical coal plant, the per kWh capital cost and interest repayment are lower for gas CCGT. Moreover, the gas price to power plants in Indonesia is very low, comparable to the price of coal, which results in lower per kWh fuel cost of natural gas than coal. Our analysis shows that gas CCGT can remain competitive until the gas price increases to 4.7 $/million Btu. Subcritical coal-fired power plants can improve their economics by increasing their utilisation and thermal efficiencies, which are currently at low levels (*see* Table 3).

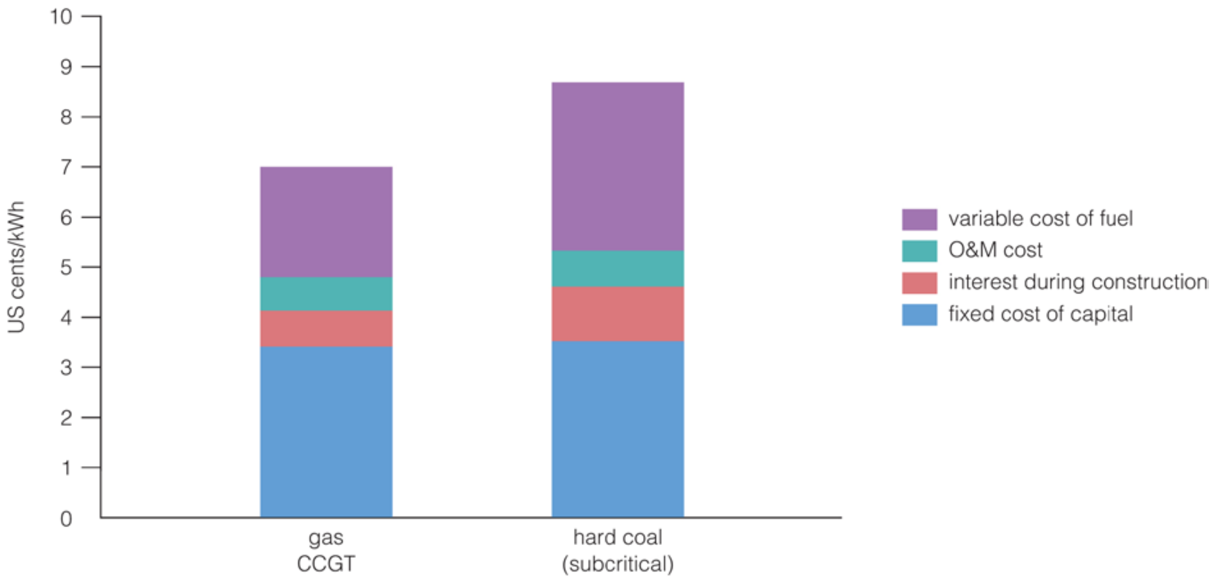

Figure 9 The modelled average generation costs of natural gas CCGT fleet and coal-fired subcritical fleet

5.5 Discussion on issues affecting competition

Indonesia needs both coal and gas to meet increasing demand for electricity while reducing the use of expensive fuel oil and diesel. Coal has emerged as the choice of the government in the two Fast Track programmes for adding generation capacity due to its relative low cost and abundance. IPPs are also building large supercritical coal-fired power plants to seek better plant economics. The major issue with coal-based power generation is to ensure adequate coal supply for domestic markets as more than 75% of coal output in Indonesia is sold onto the seaborne export markets at higher prices. Another issue is the difficulties encountered in land acquisition, environmental assessment and local opposition, which have caused delays in construction of new coal-fired power plants.

Natural gas was included initially in Fast Track programme 2, but subsequently excluded due to concerns over shortage of gas supply. The supply shortage also makes the existing gas power plants run at low utilisation or even burn oil instead. Low utilisation results in higher fixed capital costs and O&M costs of gas CCGT plants compared to coal-fired power plants. Development of gas transmission and distribution infrastructure is the key to achieving reliable gas supply, which is required for increasing the utilisation of gas-fired units. If the natural gas price is low enough, as assumed in our analysis, the overall generation cost of the gas CCGT fleet can be lower than that of the coal fleet. However, the natural gas price is expected to rise considering the rising domestic gas demand and the beginning of LNG imports at the end of this decade. If the gas price rises considerably, coal-fired generation could become more economic.

6 Thailand

6.1 Key Energy Indicators in 2012

Population	66.8	million
GDP	366.0	billion US$
Electricity consumption*	165.54	TWh
Electricity consumption per capita	2.48	MWh/capita
Electricity generation	166.6	TWh
Electricity import/export	10.3/1.9	TWh
Generation capacity	32.6	GWe
Coal-fired capacity	2	GWe
Lignite-fired capacity	2.2	GWe
Gas CCGT capacity	16.1	GWe

(IEA, 2014a; EPPO, 2012; World Bank, 2014)

6.2 Power generation mix

The power sector ownership has diversified in Thailand. The Thai government awards generation licences to private investors to promote competition and attract more investment in renewable energy generation and advanced technology for fossil fuel plants. In 2012, around 46% of the country's total installed electricity generation capacity (32.6 GW) belonged to Electricity Generating Authority of Thailand (EGAT) (EPPO, 2013). Independent Power Producers (IPPs) owned 39% of the generation capacity, with GDF Suez as one of the major investors. The remaining generation capacity comprises small power plants (SPPs) of less than 300 MW, which are owned by small state-owned power generators or manufacturers. All electricity generated is sold to EGAT, which is the sole electricity transmission provider in Thailand. EGAT transmits the electricity to Thailand's two distribution authorities, the Metropolitan Electricity Authority (which supplies the Bangkok region) and the Provincial Electricity Authority (which supplies the rest of Thailand).

As shown in Figure 10, electricity generation in Thailand has been on a rising trend except for 1998 due to the Asian economic crisis and 2011 due to heavy flooding. In 2012, total electricity supply reached about 177 TWh, with the use of fuel as follows: natural gas 67%, coal/lignite 20%, electricity import and others 7%, hydropower 5%, and oil 1% (EPPO, 2013). Natural gas dominates power generation in Thailand, and has been used to replace oil-based generation since the late 1990s. Lignite-based generation remains stable, while generation using imported coal has been increasing since 2006. Coal and gas power have driven down oil-based generation to a negligible level in recent years. The contribution of hydropower has been stable over the past two decades, while electricity imports have increased considerably in recent years.

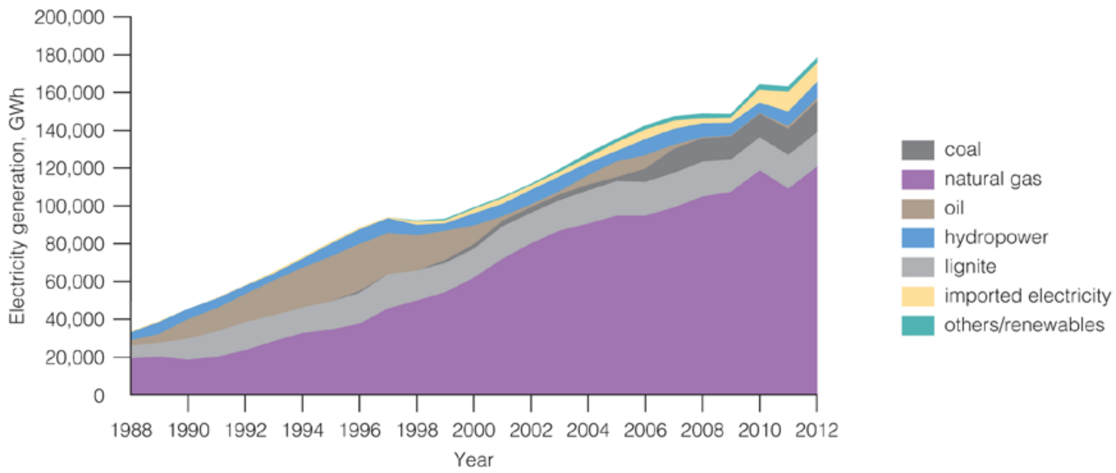

Figure 10 The historic trend of the electricity generation mix between 1988 and 2012 (EPPO, 2013)

Figure 11 illustrates the representative dispatch curves of the various forms of power generation in Thailand. The x-axis shows the fleet utilisation, based on the average operating hours annually calculated over 2006–12. The y-axis shows the current generating capacity in the country, including existing units and those expected to be commissioned in 2013, based on Platts World Electric Power Plant Database (Platts, 2013).

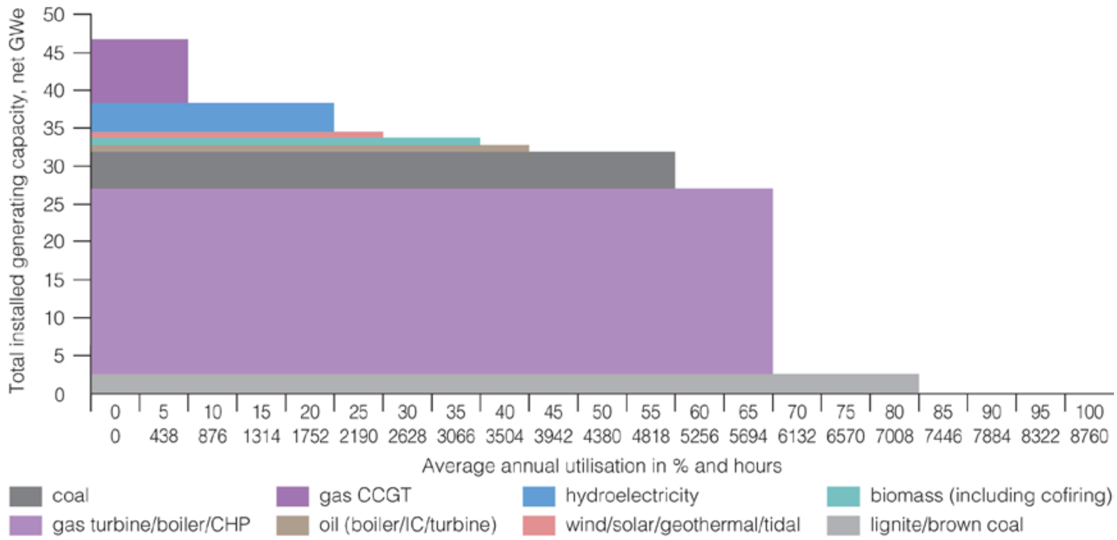

Figure 11 The representative dispatch graph of various types of power generation plant fleet in 2013 (based on Platts World Electric Power Plant Database, December 2013)

With 24.5 GW of available generation capacity, natural gas CCGT plants dominate and provide baseload power generation with an average utilisation rate of about 70%. Subcritical power plants (2.4 GW lignite-fired units and 2.0 GW hard coal-fired units) also appear to provide baseload generation with a slightly lower average utilisation rate of 65%. The utilisation of the 660 MW supercritical GHECO One is the highest among all generating plants in the country, favouring the recovery of capital costs for the IPP investors. There is a large capacity of non-CCGT natural gas-based generation (8.48 GW), consisting of open cycle gas turbine units and gas-fired steam generator units. These units operate as peaking plants, but due to their large capacity still contribute a significant share to total electricity generation. There is also a sizable generation from hydropower, while the contributions from biomass, wind and solar, and oil are small due to their small capacity and low utilisation.

6.3 Fuel supply

6.3.1 Gas

According to the Energy Policy and Planning Office, the country's estimated natural gas reserves stood at 572 Mtoe in 2012, which comprised proved reserves of 222 Mtoe, probable reserves of 235 Mtoe, and possible reserves of 115 Mtoe (EPPO, 2013). The majority of Thailand's natural gas fields are located offshore in the Pattani Trough in the Gulf of Thailand, including the largest producing field Bongkot. The Malaysia-Thailand Joint Development Area (JDA), located in the lower part of the Gulf of Thailand and northern part of the Malay Basin, is becoming a large contributor of natural gas supply to Thailand.

Natural gas production started in 1981 and has increased by more than seven times over the past three decades. In 2012, domestic natural gas production was around 3994 million standard cubic feet per day or 41.4 bcm (OPPO, 2013). The historical production data compiled by EPPO show that gas fields except for Bongkot and JDA are depleting or struggling to maintain output. The total gas output growth has therefore slowed down. There are some undeveloped fields in the Pattani Trough, which could provide new opportunities for exploration.

Thailand imports pipeline natural gas from the offshore Yadana and Yetakun gas fields of Myanmar. Imports started in 1998 and 2000, respectively, and total pipeline imports reached 820 million standard cubic feet per day or 9.8 bcm in 2012. In addition, Thailand started importing LNG in 2011 through its first LNG receiving terminal, Map Ta Phut in the Rayong province. This terminal currently has a capacity of 5 million short ton per year (4.5 Mt/y, 700 million standard cubic feet per day or 7.2 bcm/y), while the total capacity will double once the second phase is completed in 2017 (PTTLNG, 2014). The LNG import volume was low at 130 million standard cubic feet per day or 1.3 bcm in 2012, only 19% of the terminal's design capacity (EPPO, 2013).

Natural gas consumption in Thailand has more than doubled between 2000 and 2012, reaching 46.9 bcm (EPPO, 2013). The power sector was the largest consumer of natural gas with a share of 59% in 2012, while the second largest consumer was the gas separation plants (GSPs) with a share of 21%, which process gas for petrochemical consumers. The demand from the GSPs has grown faster than demand in the power sector because the liquids produced from GSPs bring higher profits due to their favourable costs compared to oil-derived liquid fuels. The industrial sector and the transport sector (as fuel for road vehicles) accounted for 14% and 6% of total natural gas consumption in 2012, respectively. The transport sector could see strong growth in natural gas consumption, as the Thai government is promoting natural gas vehicles (NGVs) to replace more expensive petroleum-derived fuels to alleviate the petroleum subsidy burden on the government.

Natural gas demand has already exceeded domestic production, and the supply gap is widening with faster growth expected in gas demand than in production. Increasing natural gas import, especially LNG import, is thus required to fill the supply gap.

6.3.2 Coal

Thailand has only lignite reserves, which were estimated to be 577 Mtoe, comprising proved reserves (340 Mtoe) and probable reserves (237 Mtoe) (EPPO, 2013). The majority of the lignite reserves are located in the northern parts of the country, with smaller reserves in Krabi and Saba Yoi regions in the south. The Mae Moh mine is currently the only operating large lignite coal mine in Thailand after Banpu and Lanna Lignite Public Company Ltd closed their lignite mines in the late 2000s. The Mae Moh lignite mine is located in the northern Lampang province and owned by the Electricity Generation Authority of Thailand (EGAT), the state-owned electricity generator. This mine produces 14.5 Mt annually and has an estimated 427.3 Mt of remaining lignite reserves (EGAT, 2013). All lignite produced from the Mae Moh mine is consumed in the 2400 MW minemouth Mae Moh power station. EGAT has plans to develop the Wiang Haeng lignite deposit close to the northwest border with Myanmar and the Saba Yoi Coal resource in southern Thailand. According to EPPO, the total proved lignite reserves in Thailand could last 65 years at the current production level.

Coal imports into Thailand started in 1988 and have been growing fast since the late 1990s. Most of the imported coal is of subbituminous and bituminous rank, while a small amount of anthracite and coal briquettes are also imported. The calorific values of imported coal are in the range of 5000–6000 kcal/kg. Coal imports are projected to rise further considering the expiry of lignite mining concessions in recent years and the low costs of coal relative to alternative imported fuels.

The combined consumption of coal and lignite in Thailand has more than doubled between 2000 and 2012. Demand for imported coal has grown much faster than demand for domestic lignite. The country consumed 4.5 Mt of lignite and 10.4 Mt of imported coal in 2012 (EPPO, 2013). The majority (84%) of lignite was consumed to generate electricity, with the remaining lignite used for cement manufacturing. In contrast, 58% of imported coal was used in various industrial applications, while power plants operated by independent power producers (IPPs) and small power producers (SPPs) consumed the remaining coal. Demand for imported coal rose as the 660 MW GHECO One power plant came online in August 2012. GHECO One is the first and currently the only supercritical coal-fired power plant in Thailand; it is operated by a subsidiary of GDF Suez as an IPP power plant.

6.4 Generation cost comparison

Since coal and gas dominate electricity generation in Thailand, it is interesting to compare the average generation cost of coal and gas plant fleets. The authors modelled the average generation cost of the gas CCGT fleet, the subcritical coal plant fleet and the supercritical coal plant fleet, based on assumptions shown in Table 4.

Table 4 The basic assumptions underlying the generation cost assessment of existing fleets in Thailand

	Average fuel price, $/toe	Fuel price in $/t coal and $/million Btu gas	Total fleet, GWe	Estimated fleet output, GWh	Specific cost of capital $/kW	Construct-ion period, y	Life of plant, y	Loan interest rate, %	Average fleet efficiency, %	Average annual utilisation, %
Natural gas CCGT	314	8.0	24	141	861	3	350	6.5	50	66
Coal subcritical pf	133	66.4	5	23	1304	4.5	40	6.5	37	54
Coal supercritical/USC pf	133	66.4	1	5	824	4.5	40	6.5	40	50

As illustrated in Figure 12, the gas CCGT fleet has a higher average generation cost than both types of coal fleet, while the supercritical coal fleet is more economic than the subcritical fleet. This result is as expected and resonates with the findings from most of the other countries.

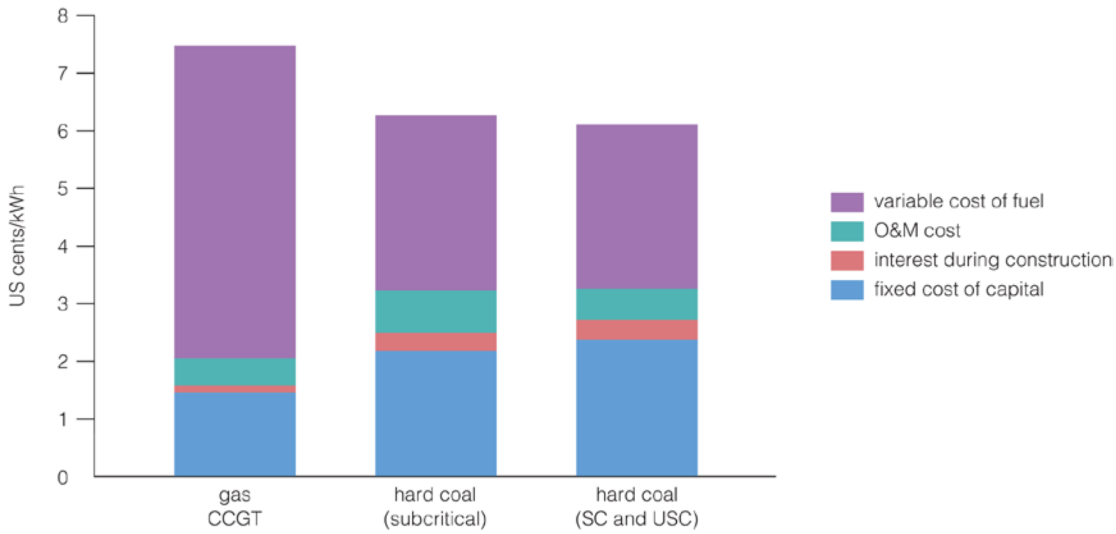

Figure 12 The modelled average levelised generation costs of natural gas CCGT fleet and coal-fired subcritical fleet

As elsewhere in the world, natural gas CCGT plants are generally cheaper to build than coal-fired power plants. The lower CAPEX of gas CCGT plants, combined with their high utilisation (70%), makes their fixed cost of capital and O&M cost lower than those of coal-fired power plants. The authors assumed the same specific capital cost for subcritical and supercritical coal fleets, which is arguable. However, the GHECO One supercritical plant uses the Korean power plant technology (supplied by Doosan Power). Through the 1980s and 1990s, Korea adopted a modular construction approach for their coal-fired fleet, manufacturing power units of identical size and specification. This approach to building power plants reduced the CAPEX of coal-fired power plants. Our assumption of the specific capital cost for supercritical coal-fired plants is therefore considered acceptable for our analysis.

As illustrated by Figure 12, the higher cost of natural gas is the reason for higher generation cost of the gas CCGT fleet. Our research on fuel prices to power plants suggests that natural gas is more than twice as expensive as coal in Thailand (*see* Table 4).

The natural gas price needs to drop to 245 $/toe or 6.2 $/million Btu to equalise the generation cost of gas CCGT fleet to that of subcritical coal plant fleet; to equalise to that of supercritical coal plant fleet, the gas price has to fall further to 235 $/toe or 5.9 $/million Btu.

6.5 Discussion on issues affecting competition

In Thailand, the National Energy Policy regulates the domestic natural gas retail prices, which are below the prices of imported natural gas (the LNG imports are more expensive than pipeline imported gas). As such, the government is subsidising the domestic users of natural gas. To alleviate the subsidy burden, the government established a two-tier pricing system for natural gas. The Tier 1 price is for petrochemical plants and NGVs, which are given priority access to domestically produced natural gas in order to maintain their competitiveness in the region. The Tier 1 price is based on the weighted average of the price of domestically produced natural gas. Any domestic natural gas in excess of supply to the petrochemical plants and NGVs is pooled with imported gas. The weighted average price of this pool forms the Tier 2 natural gas price with adjustment based on economic indicators. Power plants owned by EGAT, IPPs and SPPS pay the Tier 2 price for their natural gas supply.

As discussed in Section 6.3.1, the gap between natural gas consumption and domestic production will widen unless there is successful new exploration in the Pattani Trough. Natural gas imports are expected to increase, particularly LNG. The weight of the imported natural gas will thus increase in the gas pool for the Tier 2 price. As a result, the fuel price to gas-fired power plants is expected to increase, which will make gas-based power generation more expensive.

The Thai government is trying to diversify away from natural gas for power generation. In its third revision of the Power Development Plan 2010–2030, the government requires fuel diversification and a generation capacity reserve margin of no less than 15% (EPPO, 2012). The Plan considers coal-fired power plant development in an appropriate proportion as a necessity for Thailand’s power system. Moreover, clean coal technologies are recommended in the Plan in order to increase generation efficiencies and reduce air pollutant emissions from the country’s power sector.

According to the projection in the Plan, the share of natural gas in total electricity generation reduces from 64.6% in 2012 to 58.0% in 2030, while the share of imported coal increases from 9.5% to 12.6%. The share of indigenous lignite decreases from 9.6% to 6.9%, despite lignite-based generation increasing in absolute terms. No new lignite-fired units will be built during this period, while 3.74 GW of new coal-fired capacity will be added. The gas CCGT capacity will almost double during this period, reaching 31.12 GW in 2030; gas use in other types of generation, except cogeneration plants, will be gradually phased out. Notably, the Plan projects electricity imports from its neighbour, Laos, which is building new lignite-fired power stations.

Coal-fired power plants face strong public resistance in Thailand, which is largely due to the poor images resulting from the operation of the Mae Moh lignite-fired power station in the 1990s. Sulphur dioxide and particulates emissions from this power plant have had a severe impact on the surrounding environment and the health of nearby villagers. Flue gas treatment equipment, including eight units of wet scrubbing desulphurisation systems, low-NOx burners, and electrostatic precipitators (ESPs) were subsequently retrofitted to the Mae Moh power station; EGAT claimed that the Mae Moh Power plant can ‘now control the emissions of air pollutants better than the law requires’ (Supasri, 2013). Nonetheless, the legacy of bad images of dirty coal has yet to be overcome, as evidenced in the protest against construction of a new coal power plant in the southern Krabi province. Educating the public about coal and clean coal technologies is thus important for wider deployment of coal-based generation in the country.

Thailand is facing a severe problem with its security of energy supply as both its indigenous lignite and natural gas reserves are depleting. The country will increasingly rely on imported coal and natural gas for power generation. The existing gas-dominated generation fleet, combined with more gas capacity addition, means that large volumes of natural gas will continue to be consumed for power generation. However, coal-based generation will have an increasingly important role to play in the future. The primary reason is the cheaper generation cost of the coal fleet compared to gas CCGT units due mainly to the large price differential between coal and natural gas. The current natural gas pricing mechanism indicates that the natural gas price could rise further as LNG imports increase. This will further undermine the competitiveness of gas-based generation. Coal-fired power plants are also promoted by the Thai government as a necessary alternative to diversify away from natural gas in power generation. Nevertheless, the poor image of coal power leads to strong public resistance to new coal-fired power plants. This could restrict the wider deployment of coal-fired power plants; public engagement and education of clean coal technologies are therefore essential.

7 Malaysia

7.1 Energy indicators in 2012

Population	29	million
GDP	305.0	billion US$
Electricity consumption	126	TWh
Electricity consumption per capita	4.31	MWh/capita
Electricity generation	134	TWh
Electricity imports/exports	105/12	GWh
Generation capacity	29.1	GWe
Coal-fired capacity	7.7	GWe
Gas-fired capacity	15.5	GWe

(IEA, 2014a; MEIH, 2014; World Bank, 2014)

7.2 Power generation mix

Malaysia is the third largest energy consumer in Southeast Asia, and has the highest per capita energy consumption in this region. Malaysia's economic development and population growth resulted in electricity generation almost doubling between 2000 and 2012, reaching 134 GWh in 2012 (MEIH, 2014). The Malaysian government anticipates that electricity demand will grow by more than 3% at least through to 2020. A greater generation capacity is thus needed in high demand centres, particularly in Peninsular Malaysia.

As shown in Figure 13, fossil fuels, primarily coal and natural gas, have dominated the power generation mix in Malaysia. Natural gas has been the most important fuel for power generation, but coal has taken an increasing share since 2000. Coal has become more competitive with natural gas-fired power in terms of fuel prices and has gained a larger share of power generation in Peninsular Malaysia during the past decade. In 2012, coal accounted for 41% of total electricity generation, slightly lower than natural gas's share of 43% (MEIH, 2014). Many of the gas power plants are located in Peninsular Malaysia, and some have dual fuel capabilities allowing for greater flexibility in fuel input. Declining gas production has caused tight natural gas supply in Peninsular Malaysia in recent years. This has resulted in power outages and increased power generation using coal and even more expensive fuel oil and diesel. This reversed the trend of decreased use of oil and diesel in power generation seen since 2000 as they were replaced by coal and natural gas. Also diesel is the main fuel in the Sabah state. The electricity production from hydropower plants has been roughly stable with only a slight increase during the past decade, accounting for approximately 7% of total electricity generation in 2012.

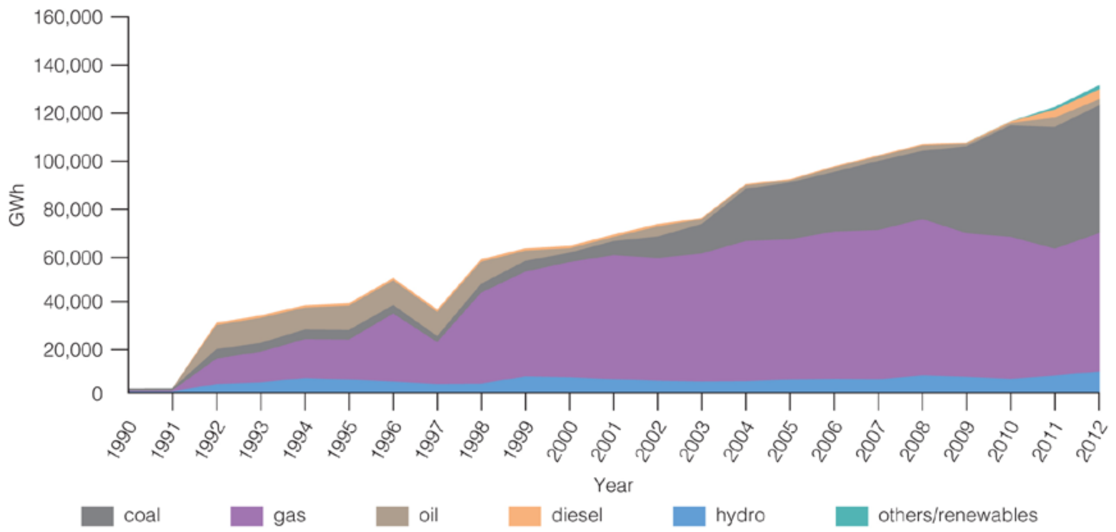

Figure 13 The power generation mix evolvement between 1990 and 2012 (MEIH, 2014)

Figure 14 illustrates the representative dispatch curves of the various forms of power generation in Malaysia. The x-axis shows the fleet utilisation, based on the average operating hours annually calculated over 2006–12. The y-axis shows the current generating capacity in the country, including existing units and those expected to be commissioned in 2013, based on Platts World Electric Power Plant Database (Platts, 2013).

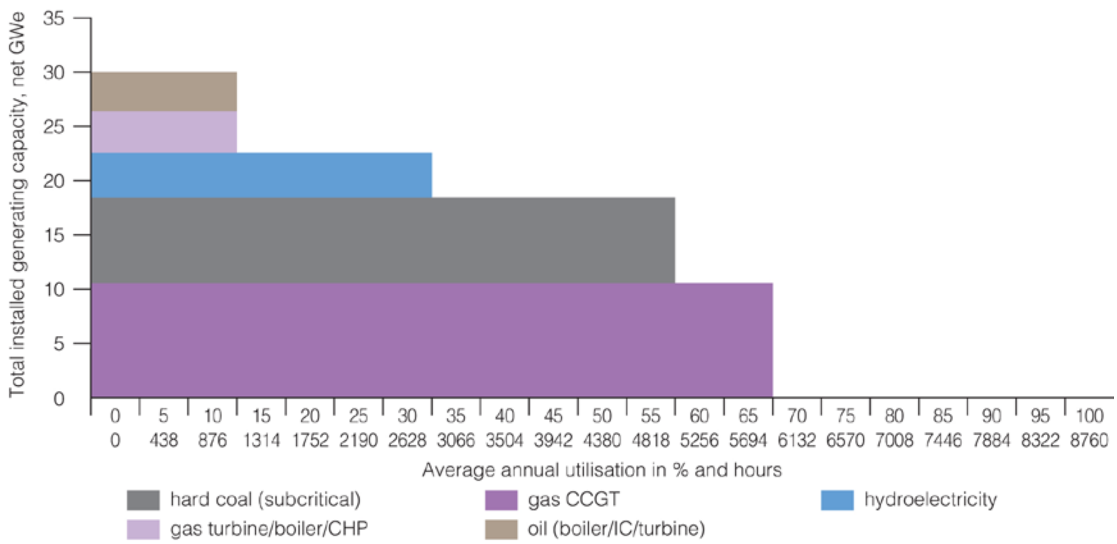

Figure 14 The representative dispatch graph of various types of power generation plant fleet in 2013 (based on Platts World Electric Power Plant Database, December 2013)

There was 29.1 GW total installed generation capacity in 2013, comprising 15.5 GW of natural gas (of which 10.5 GW gas CCGT plants), 7.7 GW of coal, 3.3 GW of hydro and 1.8 GW of fuel oil/diesel (Platts, 2014; MEIH, 2014). Gas CCGT plants and subcritical coal plants provide baseload power generation, while oil plants and open cycle gas turbine plants operate to meet peaking loads. Utilisation of hydropower plants is low at around 35%, reflecting the large seasonal variation of generation.

According to Malaysia's Energy Commission, the generation mix for Peninsular Malaysia will be increasingly dominated by coal with its share increased from 41% in 2012 to 58% in 2014, while the share of natural gas will be reduced from 43% in 2012 to 25% in 2014 (ST, 2014). Notably, Malaysia is starting to build ultra-supercritical coal-fired power plants. Malaysia signed construction contracts for the country's first two ultra-supercritical power plants located at Manjung 4 and Tanjung Bin on Peninsular Malaysia, which will add 2 GW of coal-fired capacity by 2016. Another 2 GW ultra-supercritical coal-fired power plant, Jimah East Power, will also be constructed on Peninsular Malaysia, jointly by the Ministry of Finance and Mitsui of Japan, and is expected to come online in 2019. These ultra-supercritical power plants are owned by IPPs.

In the state of Sarawak, the generation mix is dominated by thermal power plants firing gas and diesel. There are only three coal-fired power plants with a total capacity of 480 MW. There is a plan to build a new 2 x 300 MW coal-fired power plant near the Balingian River. There is no coal-fired generation capacity in the state of Sabah, and no plans to build any.

7.3 Fuel supplies and prices

7.3.1 Gas

According to data from the Malaysia Energy Information Hub, Malaysia possessed an estimated 2.78 trillion cubic metres of natural gas reserves in 2013, with 51% located offshore Sarawak, 36% on Peninsular Malaysia and 13% in Sabah (MEIH, 2014). The majority (83%) of these gas reserves are in non-associated basins, particularly in Peninsular Malaysia and Sarawak.

Natural gas is the largest indigenous energy resource, and accounted for 65% of all primary energy production in 2012 (MEIH, 2014). Natural gas production reached 69.1 bcm in 2013; at this level, the proved natural gas reserves can provide for 40 years of production (BP, 2014). Natural gas production has experienced a steady growth over the past two decades, but the growth rate has slowed somewhat since 2007. Malaysia is importing natural gas via pipeline from Indonesia, which amounted to 1.2 bcm in 2013 (BP, 2014).

Meanwhile, domestic consumption of natural gas has increased at a fast pace, reaching 34.0 bcm and accounting for half of Malaysia' production in 2013 (BP, 2014). The power sector accounted for about 56% of total natural gas consumption in 2012, while the industry and the non-energy sectors consumed 20% and 23%, respectively (MEIH, 2013). Gas demand from the power sector is expected to increase, especially in Peninsular Malaysia, and consumption in the industrial sector will also remain strong.

Malaysia is a major natural gas exporter in Asia, exporting about 35 bcm of natural gas in 2013, of which 97% was in the form of LNG with the remaining exported via pipeline to Singapore (BP, 2014). The pipeline exports to Singapore, which accounted for just 24% of the country's gas imports, are likely to decline in the near future as the country becomes more reliant on imported LNG in an attempt to move away from pipeline imports.

As the world's second largest LNG exporter behind Qatar, Malaysia supplies key LNG importers in East Asia, including Japan (60% of Malaysian LNG exports in 2013), South Korea (17%), Taiwan (12%), and China (11%) (BP, 2014), which hold medium- or long-term supply contracts with Malaysia. Malaysia is also an active player in the global LNG spot market, and has the second largest LNG fleet in the world, consisting of 27 LNG tankers. Petronas, Malaysia's state-owned oil and gas company, is keen to maintain its long-term export contracts as they currently capture higher prices than gas sold onto domestic markets where the gas prices are regulated and subsidised.

Rising domestic demand and the LNG export contract obligations are placing pressure on the natural gas supply. Petronas currently operates three LNG processing plants at its massive LNG complex in Bintulu Sarawak. It proposed two floating liquefaction terminals offshore Sarawak and Sabah in addition to the 9th train at the existing Bintulu LNG Complex. The proposed new projects and expansion would add about 9.5 bcm/y to Malaysia's LNG capacity over the next few years (EIA, 2014).

Despite being a leading LNG exporter, Malaysia experiences a geographic disparity of natural gas supply and demand. The Western Peninsular of Malaysia demands more natural gas to fuel the power and industrial sectors, while the eastern states of Sarawak and Sabah produce natural gas but currently lack the local demand for it. As such, Malaysia plans to use LNG imports to meet the pressing gas needs in Peninsular Malaysia. The country's first regasification terminal at Sungai Udang near Malacca with a capacity of 5.2 bcm/y began operating in May 2013. Petronas proposed a LNG regasification terminal as part of the company's Refinery and Petrochemical Integrated Development (RAPID) project in Johor near Singapore. This project, slated to start operation in 2016, will also include LNG storage and serve as a strategic gas trading hub for the Asian region. There were two more proposals but the details are not known. In addition, Petronas Gas has plans to construct two regasification terminals in Lahad Datu in the eastern state of Saba. These terminals are designed primarily to serve the proposed 300 MW power plant at Lahad Datu in order to replace some of the diesel that is heavily used for power generation in the state of Sabah. According to the agreements signed by Petronas, the potential LNG supply could come from Australia, Brunei, Canada, and Norway. Petronas's new liquefaction projects in Sarawak could also supply these regasification terminals.

Domestic natural gas prices are regulated by the Malaysian government, and kept lower than the international market prices. The Malaysian government is thus subsidising domestic consumers of natural gas. In 1992, the gas price for the power sector was decided by the government to be indexed to 104% medium fuel oil. Subsequent revision was made to this pricing mechanism following the economic downturn and sharp depreciation of Ringgit Malaysia (RM) against the US dollar in 1997. Natural gas prices had been fixed at RM6.40 per million Btu between May 1997 and June 2008. Rapidly increasing oil prices in early 2008 forced the Malaysian government to re-examine domestic natural gas prices in order to reduce gas subsidies that the government pays to Petronas and power producers and to create more incentives for upstream natural gas investment. This led to a considerable rise in domestic natural gas prices; in 2012 the natural gas price to the power sector was increased to RM13.70/million Btu (or about 3.4 US$/million Btu based on the average exchange rates between 2012 and 2013) (MEIH, 2014). Also, in line with the subsidy rationalisation effort, the Malaysian government launched a price reform in 2011 that sought to raise the natural gas price for electric power users by RM3.00/million Btu every six months and eventually allow domestic natural gas prices to rise to international market levels (for example, the gas price to Singapore was RM55.08/million Btu in 2012). However, domestic prices remained at the 2012 level until an 11% upward adjustment in the gas price to the power sector (RM15.2/million Btu) in January 2014. In May 2014, the government also raised the price for large non-power gas users (industrial and commercial sectors) by an average of 20% to about 586 US$/million Btu (EIA, 2014).

7.3.2 Coal

According to data from the Malaysia Energy Information Hub, at the end of 2012 Malaysia possessed coal reserves of 1938 Mt, including 280 Mt of measured reserves, 378 Mt of indicated reserves and 299 Mt of inferred reserves (MEIH, 2013). Almost all of the measured reserves are located in the state of Sarawak; coal production is currently taking place only in this state. Total coal production was around 2.9 Mt in 2012, consisting of 2.3 Mt of lignite from the Mukah-Balingian region, 0.6 Mt of subbituminous coal from the Kapit region, and 34 kt of coking coal from the Sri Aman region (MEIH, 2013).

Malaysia consumed 25.2 Mt of coal in 2012, with 89% of this in power stations and the rest in industrial applications. Coal consumption in the industrial sector increased by 76% between 2000 and 2012, while the amount of coal used for power generation increased by more than nine-fold during the same period. The growth in coal consumption has been largely met by coal imports, which increased by more than seven-fold between 2000 and 2012. Malaysia procured about 60% of its coal imports from Indonesia, 17% from Australia and 12% from South Africa in 2013; it started to import coal from Russia in 2013 for diversification and continues to look for new potential suppliers (Coaltrans, 2014).

For coal pricing, a mechanism known as Applicable Coal Price (ACP) was introduced at the beginning of 2011 to set common coal prices for coal-fired power plants. The ACP, set every three months, is based on the forward-looking weighted average delivery prices (CIF prices) of all bituminous and subbituminous coals for delivery in each quarter in the future. ACP will be used as a reference for coal prices in the electricity tariff review process. ACP prices have been relatively low and stable.

7.4 Generation cost comparison

As shown in Figure 15, the average annualised generation cost of natural gas CCGT power plants is less than half that of subcritical coal-fired power plants, exacerbated by the lower utilisation of coal-fired power plants, as indicated in Figure 14. As in many other countries, natural gas CCGT fleet has a lower fixed capital cost, O&M cost and interest repayment. Moreover, the gas price to power plants in Malaysia is very low (the same as in Indonesia), making the annualised fuel cost for gas CCGT power plants just one third that for coal-fired power plants (*see* Table 5). The average coal price in Malaysia is only slightly higher than that in Indonesia, implying that the cost of shipping coal from Indonesia is low given the geographic proximity. Our analysis shows that the natural gas price needs to rise to 360.5 $/toe or 7.7 $/million Btu to equalise the average annualised generation costs of a CCGT power plant to that of a subcritical coal-fired power plant.

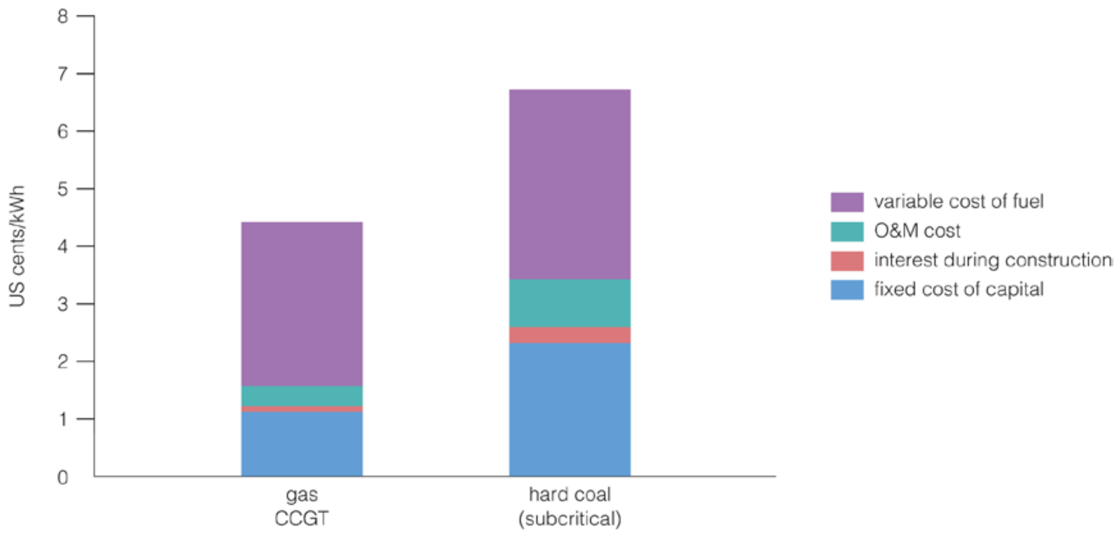

Figure 15 The modelled average generation costs of natural gas CCGT fleet and coal-fired subcritical fleet

7.5 Discussion on issues affecting competition

The major issue affecting natural gas-based power generation is the future trend of natural gas prices to the power sector. As discussed, domestic gas prices have increased since 2008, but it is uncertain whether the Malaysian Government will fully implement its gas price reform to reduce subsidies and bring the domestic gas price up to the level of the international market price (the projected market price is RM44.36/million Btu or approximately 13.6 US$/million Btu). If the gas price to the power sector were raised to the market price level, this would make coal-fired generation more competitive. This may change the merit-order of power dispatching, increasing the utilisation of coal-fired generation while reducing that of gas-fired generation. This may affect the decision on whether to extend the life of aging gas-fired units or to build new gas-fired units. Thomas (2012) found that it would be more economical to run the old gas-fired units if their capacity factor is reduced to below 40%.

For coal-fired generation, the major issue is to diversify coal supplies. Malaysia is currently reliant on Indonesia for its coal imports; the geographical proximity keeps the coal price for the power plants in Malaysia low. However, potentially there is a risk of price rises and shortages of supply as Indonesia is set to use more coal to meet its own increasing electricity demand. Diversification of coal imports will lead to more volatile and likely higher coal prices to power plants as Malaysia needs to compete with other major traditional coal importers on the international seaborne coal markets.

8 Vietnam

8.1 Energy indicators 2012

Population	87	million
GDP	155.8	billion US$
Electricity consumption	90	TWh
Electricity consumption per capita	1.27	MWh/capita
Electricity generation	123	TWh
Electricity imports/exports	6/1	GWh
Generation capacity	27	GWe
Coal-fired capacity	6	GWe
Gas-fired capacity	7	GWe

(IEA, 2014a; World Bank, 2014)

8.2 Power generation mix

Fossil fuels are becoming increasingly important in Vietnam. As illustrated by Figure 16, the generation mix is dominated by hydropower and gas power. Capacity development favoured hydropower in the past. However, the large capital investment required for hydro projects resulted in gas-fired plants being built since the 1990s due to the relatively low investment required per kW compared with hydro. Oil consumption for power generation decreased gradually in the last decade, but has rebounded over the past few years to meet fast growing electricity demand. Vietnam is seeking a greater diversity in its power sector with the growing role of coal; It began investing in biofuel-based generation and wind power in late 2000s, but the generation is very small in absolute terms so far. Moreover, the country's first nuclear reactor is planned to start construction sometime before 2020 pending safety approvals for the design.

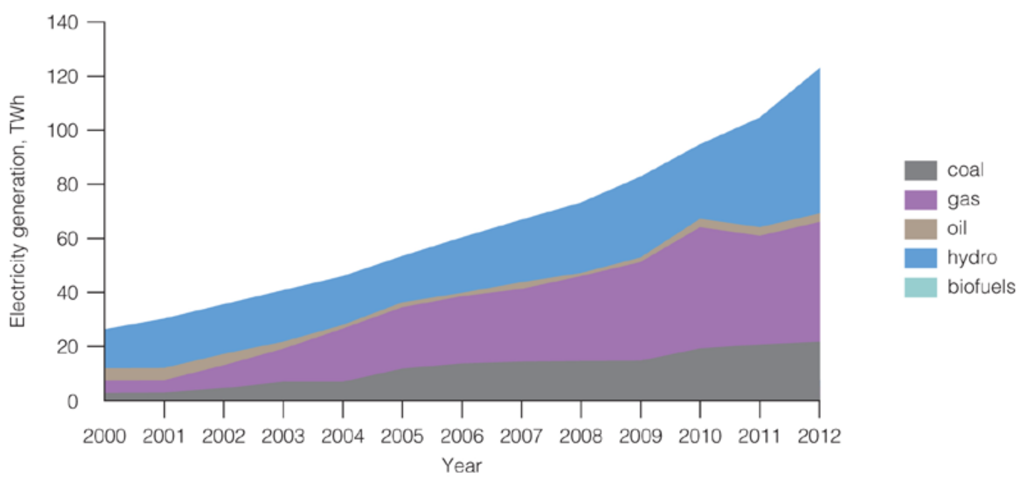

Figure 16 The historic trend of the electricity generation mix in Vietnam between 2000 and 2012 (IEA, 2014a)

Hydropower made the largest contribution (43%) to Vietnam's electricity generation in 2012, while natural gas and coal accounted for 36% and 18%, respectively (IEA, 2014a). Much of the gas power has been developed in the south of the country, close to the country's offshore gas reserves. Coal has been developed in the north where the domestic coal reserves are found. The central region of the country is dominated by hydropower and gas.

Various power development plans have indicated a rapid growth in electricity demand in coming decades. Electricity demand is growing with an increasing industrial and manufacturing sector as well as rising incomes per capita. Losses in transmission and distribution are equivalent to 10% of consumption, and interconnections with neighbouring countries are few. Projected electricity demand ranges from 440 TWh to 670 TWh by 2030, with coal possibly contributing 25–50% of this future demand (Parkinson, 2012). The higher projections represent the official expectations of the Vietnam Government.

Figure 17 illustrates the overall dispatch of the various forms of power stations in the Vietnam fleet. The x-axis shows the fleet utilisation, based on the average operating hours annually calculated over 2006–12. The y-axis shows the current generating capacity in the country, including existing units and those expected to be commissioned in 2013, based on Platts World Electric Power Plant Database (Platts, 2013).

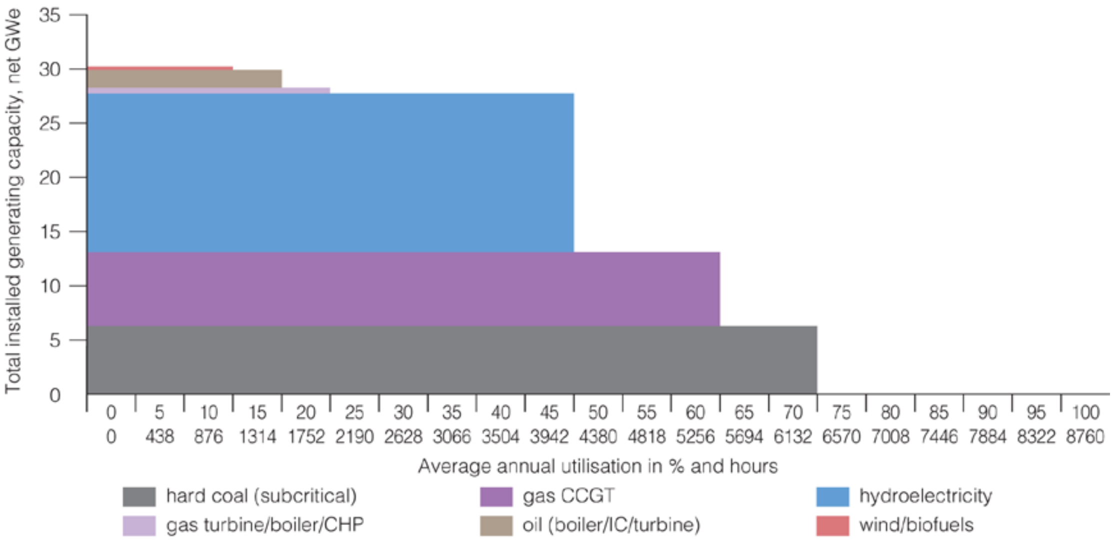

Figure 17 The representative dispatch graph of various types of power generation plant fleet in 2013 (based on Platts World Electric Power Plant Database, December 2013)

Vietnam's total generation capacity was approximately 30 GWe in 2013, comprising 15 GWe hydropower, 7 GWe gas CCGT plants and 455 MW gas turbine units, 6 GWe coal and 2 GWe oil. Baseload power is provided by the high utilisation of coal-fired power plant fleet. This was entirely a subcritical fleet until 2013. Bituminous coal is used in most coal-fired power plants, although some also burn anthracite. Gas CCGT appears to be over the mid-merit and baseload part of the dispatch curve, while single cycle gas turbine units operate alongside oil plants as peaking plants.

What is obvious is that hydropower occupies much of the dispatch graph. It has the largest installed capacity, but a modest utilisation rate of around 50% due to dependence on seasonal rainfall. The past decade has seen the share of hydropower in total electricity generation vary from 29% to 59% (IEA, 2014a). The power sector has relied on the gas fleet to accommodate this large variability of hydropower generation.

Vietnam's power sector suffers from ongoing electricity shortages, and continued investment and development are occurring in an increasingly liberalised market. Private sector investors and finance from foreign banks have boosted capacity development in the country. Most of the new capacity being built in Vietnam is coal and hydropower. Vietnam is building 13 GWe of new coal plants (due online 2014 to 2018), half of which use subcritical or ultra-supercritical technologies. The most advanced in environmental terms is the 1.2 GWe Vinh Tan-2, which employs Doosan USC boilers equipped with semi wet FGD, ESP, and SCR. Some 2.5 GWe of new capacity will use domestic anthracite. A further 14 GW of supercritical coal-fired stations are planned, with heavy involvement from Indian and Japanese developers such as Tata Vietnam, and Sumitomo. In contrast, Vietnam is building just one gas-fired power station due online in 2015; in addition, 6 GW of gas-fired generation capacity is planned.

8.3 Fuel supply

8.3.1 Gas

Vietnam has significant offshore natural gas resources, with proved reserves estimated to be 0.6 tcm at the end of 2013 (BP, 2014). Most of the gas reserves are in the south of the country. Although gas is found in the north, technical issues, such as CO_2 contamination, make the gas more expensive to extract.

Production has increased at a fast pace from 1.6 bcm in 2000 to 9.8 bcm in 2013(BP, 2014). The proved gas reserves can provide for 63 years at the production level of 2013. Vietnam is currently self-sufficient in natural gas. Nearly all of Vietnam's natural gas production originates from three offshore basins: Cuu Long, Nam Con Son, and the Malay Basin.

The Vietnamese government has considered importing liquefied natural gas (LNG) in the future to meet growing natural gas demand. PetroVietnam (PV) Gas has signed a memorandum of understanding and a front-end engineering and development (FEED) contract with the Tokyo Gas Company to develop the Thi Vai LNG terminal in the Vung Tau province.

Domestic gas prices in Vietnam are much lower than world LNG prices delivered to other Asian economies like Japan and Korea. Gas prices to the power sector are below the market price, which is set at 46% of the average fuel oil prices set on the Singapore market (Huong, 2014). The price for gas sold under long-term contracts is generally lower, while non-contracted prices tend to reflect Singapore fuel oil prices. In 2014, the buyers of non-contract gas were paying

8 $/million Btu, while contract-based gas was reported to be almost 4 $/million Btu. The impact on the economics of gas power can therefore be very different for non-contracted gas supplies.

8.3.2 Coal

The reported coal reserve data are in a wide range. BGR (2013) reported hard coal (>16500 kJ/kg LHV, including subbituminous, bituminous and anthracite) reserves of 3.1 Gt and resources of 3.5 Gt in 2012; lignite (<16500 kJ/kg LHV) reserves were just 244 Mt, but lignite resources were almost 200 Gt. WEC (2013) reported proved recoverable reserves only for anthracite, which was 150 Mt at the end of 2011. According to Vinacomin, the state-owned coal company responsible for 95% of Vietnam's coal production, coal resources are located in the northeast of the country, comprising 8.7 Gt in the Quang Ninh coal basin (anthracite) and 39.3 Gt in the Red River Basin (subbituminous coal) in 2011 (Le, 2012). In addition, there are some anthracite and fat coal (coking coal) in the northern provinces and peat in the Mekong River Delta in southern Vietnam. The measured and indicated coal reserves were much smaller at 2.75 Gt, comparable to the data from BGR (L2, 2012). Coal production reached 42.4 Mt in 2012; at this production level the coal reserves can provide for about 65-74 years of production (BGR, 2013).

Coal production comprised entirely anthracite from the Quang Ninh basin, a low-volatile coal that can cause problems with combustion. The subbituminous coal in the Red River Basin, despite its large potential, is still in the exploration phase. Coal mining development faces complicated geological and mining conditions due partly to the large population and rice farms in this region.

Vietnam has long been a net exporter of anthracite, but the increasing domestic coal demand has reduced anthracite exports from the peak of 32 Mt down to 15 Mt in 2012 (IEA, 2014a). Imports, mainly of bituminous coals, have been increasing to nearly 1 Mt/y in 2012 (IEA, 2014a). Most of the imported bituminous coal is supplied to power stations in the south, which are far from the northern coalfields. Using imported coal can increase the security of electricity supply in the southern region where gas-based generation and hydropower currently dominate.

The price of coal delivered to a Vietnamese power station averages approximately 60 $/t (5000 kcal/kg). Domestic anthracite is sold at a discount of 15–25 $/t compared to imported coal, which is assumed to be approximately 70 $/t including a 3% import tax (IEA CCC, 2014). In 2013, the Vietnamese government increased the anthracite export tax from 10% to 13% to reduce exports so that more anthracite can be supplied to domestic power plants (Vinacomin, 2013).

8.4 Generation cost comparison

Figure 18 illustrates generation economics of gas CCGT and subcritical coal pf fleets based on the assumptions in Table 6. The gas CCGT fleet, even at a low utilisation rate of 64%, is more competitive than the subcritical coal fleet. The CAPEX of a gas CCGT plant is lower than that of a coal plant based on projects seen in the last few years. Compared with other Asian countries, the amortised fixed cost of capital and interest payment are higher due to the high interest rate (12%) assumed in our analysis. Some coal projects are expected to have the finances amortised over a shorter period than the 20 years used in our analysis, hence the fixed capital costs for Vietnamese power projects could be higher than shown in Figure 18. The cost of gas (163 $/toe or 4.2 $/million Btu) is modestly higher than that of coal (121 $/toe) in our assumption. However, the higher efficiency of CCGT (54% as opposed to 37% for subcritical coal) makes the annualised variable cost of gas lower than that of coal.

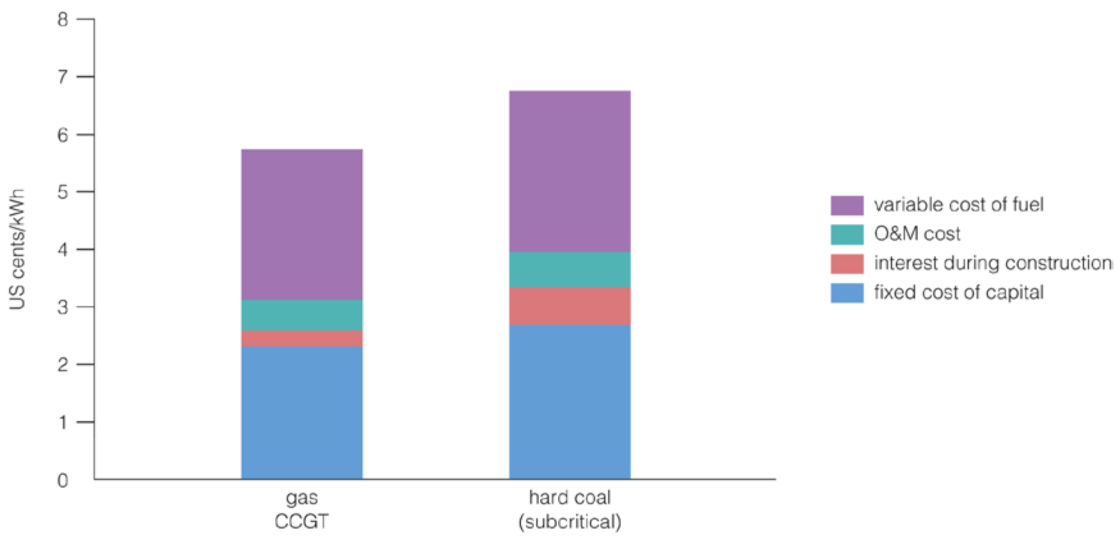

Figure 18 The modelled average generation costs of natural gas CCGT fleet and coal-fired subcritical fleet

8.5 Discussion on issues affecting competition

Our analysis shows that the low cost of natural gas makes gas more competitive than coal for power generation in Vietnam. However, Vietnam is building 13 GW of new coal generation capacity, while currently building only one natural gas CCGT power plant (750 MW) at the O Mon thermal power complex in the city of Can Tho. The major reason is the concern over security of gas supply in the future. The official *Power Development Plan of Vietnam* expects declining domestic gas production and a massive shift towards more expensive imported LNG, which could account for half of Vietnam's gas supplies by 2030. This implies higher fuel cost for natural gas-based generation, and the generation cost competitiveness of gas-based generation could be undermined unless the higher gas costs can be passed on to end users of electricity.

The issue with coal power, however, is that future coal supply will increasingly rely on coal imports as domestic coal production grows slowly. Consequently, the cost of coal will be increasingly subject to the international seaborne coal markets. A variety of key international trade factors would thus be crucial to the economics of coal power. It remains to be seen whether coal power plants burning imported coal could compete with gas power plants, particularly in the central and southern parts of Vietnam. In the northern parts, the power sector continues to be dominated by power plants that burn cheap indigenous anthracites.

9 Philippines

9.1 Energy indicators in 2012

Population	97	million
GDP	250.2	billion US$ (year 2005)
Electricity consumption	65	TWh
Electricity consumption per capita	0.67	MWh/capita
Electricity generation	73	TWh
Electricity imports/exports	0/0	TWh
Generation capacity	17.0	GWe
Coal-fired capacity	5.6	GWe
Gas-fired capacity	2.9	GWe

(IEA, 2014a; Philippines DOE, 2012; World Bank, 2014)

9.2 Power generation mix

The Philippines is the second most populous country in Southeast Asia, but the smallest energy consumer in this region. Despite almost tripling growth in electricity consumption over the past two decades, the country has a very low level of electrification with its per capita electricity consumption as low as that of Indonesia. There are 28 million people or 30% of the population without access to electricity (IEA, 2013c).

As shown in Figure 19, oil once dominated the power generation mix, but has been gradually replaced by coal and natural gas. Total power generation reached 73 TWh in 2012, comprising coal (38.8%), natural gas (26.9%), geothermal (14.1%), hydro (14.1%), oil (5.8%) and other renewables (0.4%) (Philippines DOE, 2012).

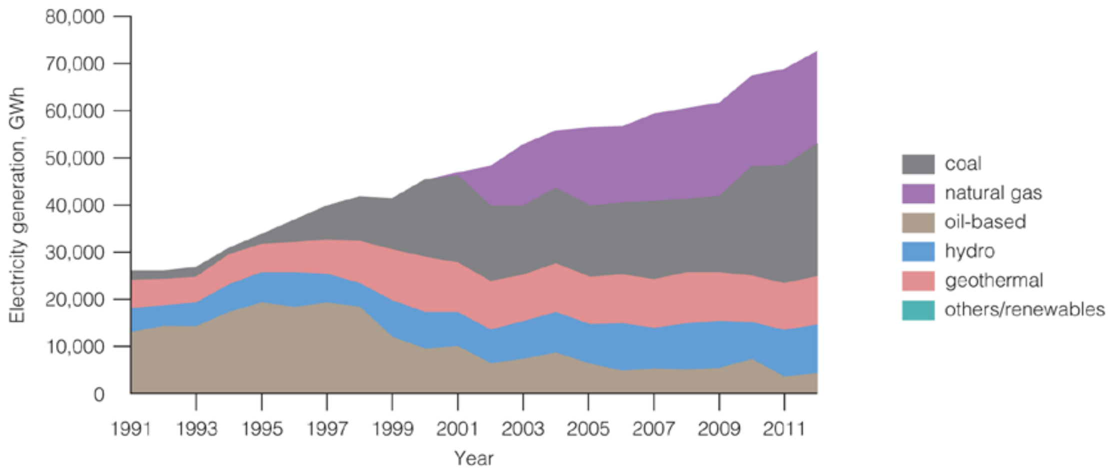

Figure 19 The evolvement of the fuel mix for power generation between 1992 and 2012 (Philippines DOE, 2012)

The power system in the Philippines comprises three regional grids: Luzon, Visayas, and Mindanao. The Luzon grid is the largest, accounting for 72% of total electricity demand in 2012, while the Visayas and Mindanao grids had a share of 16% and 13%, respectively (Philippines DOE, 2012). The fuel mix for the three grids varies considerably. The Luzon grid is primarily supplied by coal-fired capacity (42%) and natural gas-fired capacity (38%). Geothermal and coal dominate the supply to the Visayas grid with a share of 52% and 41%, respectively. For the Mindanao grid, the major supply is provided by hydropower (53%), followed by oil (19%) and coal (18%). There is currently no natural gas fired generation in the Visayas and Mindanao grids. All the existing gas CCGT power plants are located in the province of Batangas in the southwestern part of Luzon. These include Ilijan power plant (1200 MW), Santa Rita power station (1000 MW), and San Lorenzo power station (500 MW). A new gas CCGT power plant, San Gabriel, is currently under construction in this province with the first 414 MW unit due to be commissioned in 2016 (Power Technology, 2014).

Figure 20 shows the representative dispatch of the various types of power generation plants in the Philippines. The x-axis shows the fleet utilisation, based on the average operating hours annually calculated over 2006–12. The y-axis shows the current generating capacity in the country, including existing units and those expected to be commissioned in 2013, based on Platts World Electric Power Plant Database (Platts, 2013).

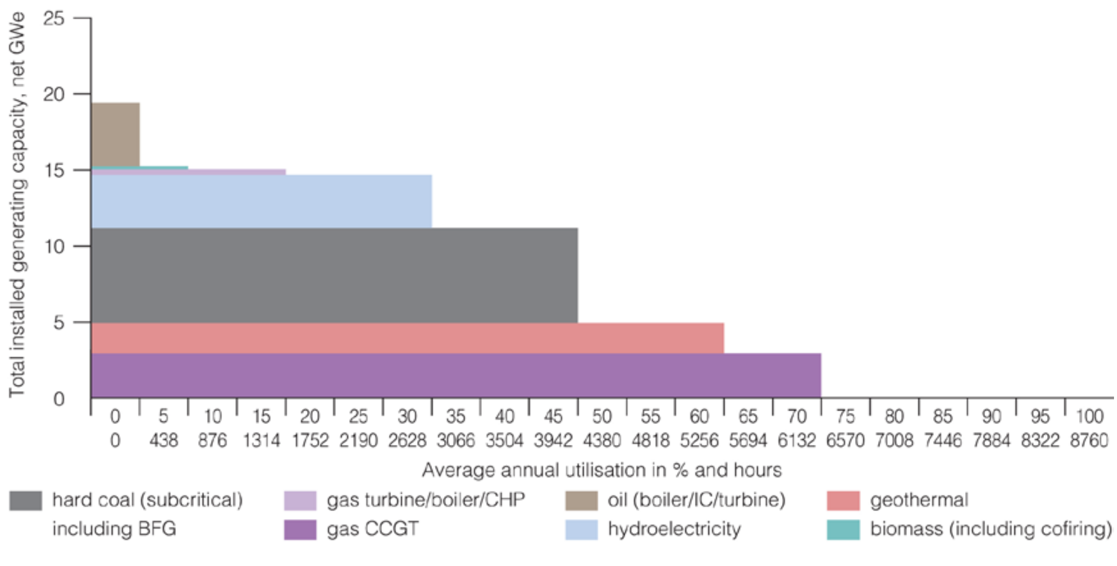

Figure 20 The representative dispatch graph of various types of power generation plant fleet in 2013 (based on Platts World Electric Power Plant Database, December 2013)

There was 18.7 GW total installed generation capacity in 2013, comprising 5.6 GW of subcritical coal, 3.0 GW of natural gas, 3.5 GW of hydro, 1.9 GW of geothermal and 4.2 GW of oil (Platts, 2013). Gas CCGT plants and geothermal power plants provide baseload power generation, while the average utilisation rate of subcritical coal-fired power plants is low at about 50%. Hydropower's utilisation rate is around 35%, reflecting the large seasonal variation of generation. Oil plants and open cycle gas turbine plants appear to be peaking power plants.

According to the Philippines' Energy Plan 2012–2030, the country will need about 13.2 GW of new generation capacities to meet domestic power demand and reserve margin requirements (PEP, 2012). Out of this substantial capacity addition requirement, only 1767 MW has been committed, while the remaining 11. 4 GW will be open for private sector investment. In addition, various interconnection links between the island grids need to be developed to support the addition of new capacity. It will be critical for the Philippine government to devise the right incentives and polices to enable capacity addition and grid connectivity.

9.3 Fuel supplies and prices

9.3.1 Gas

According to the Philippine Department of Energy, the total natural gas resources stand at 0.7–1.1 tcm, of which 96–153 bcm are discovered, recoverable gas reserves (Philippines DOE, 2014a). Oil and gas reserves are concentrated in the province of Palawan, where Malampaya, the country's only commercial gas field is located. Other gas deposits include San Antonio in Cagayan valley and Libertad in Northern Cebu, where test drills have been made. The Spratly Islands could be potentially rich in oil and gas resources. However, the sovereignty dispute over these islands represents a major barrier to resource exploration and development.

Natural gas production was 124 billion cubic feet (3.5 bcm) in 2013, and all the output was for domestic consumption. Natural gas consumption has been concentrated in the province of Batangas, where the three existing gas CCGT power plants are located. These power plants together consumed 117 bcm or 94% of Philippine's natural gas production in 2013 (Philippines DOE, 2014b). The remaining natural gas produced was mostly used in an oil refinery in Batangas city to fuel the captive gas turbine generators as well as to supplement its low-pressure fuel gas system. In addition, a small amount of natural gas was used in the transport sector.

LNG imports are expected to provide additional gas supply if no new gas field is discovered. The Philippine Department of Energy promotes the balanced development of LNG imports in parallel with the exploration of indigenous gas reserves. The Department of Energy has granted the Hong Kong-based Energy World Corporation Ltd a contract to construct the country's first LNG import terminal in Pagbilao in the Quezon province in Luzon. This LNG terminal project also includes a 650 MW gas CCGT power plant adjacent to the LNG import terminal. The project is scheduled to be commissioned in early 2015. The Department of Energy, with technical assistance from the World Bank, also conducted a feasibility study for a possible LNG project on Mindanao Island.

Since fossil fuels are not subsidised in the Philippines, the gas power plants are supplied with indigenous natural gas at prices that are pegged to international market prices. In our analysis, the gas price is assumed at 10.8 $/million Btu.

9.3.2 Coal

Coal reserves in Philippines comprise mostly lignite and subbituminous coals. Estimates of coal reserves in the Philippines range widely from 316 Mt to as much as 19 Gt, reflecting the lack of consistent and complete geological assessment in this country (Kessels and Baruya, 2013). Lignite is found in the Cagayan Valley in the northeastern part of the Luzon Island and in the southern part of the Mindanao Island. The majority of subbituminous coals are distributed in islands across the Visayas region as well as in the offshore basins in the Philippine Sea. Some small hard coal reserves are found in the western part of Mindanao.

Coal production in Philippines fluctuated between 1 and 2 Mt annually before 2003, but has since grown steadily to 8.15 Mt in 2012 (Philippines DOE, 2013). Around 94% or 7.7 Mt of coal was produced by the Semirara Mining Corporation from its mine complex on the Semirara Island. According to the company's 2012 annual report, 3.17 Mt was exported and 2.53 Mt was sold to power plants, with the remaining output sold to cement and other industrial plants (SMC, 2013). All coal supply contracts with the company are already priced to the market, which fluctuates with global coal prices. The base coal price assumed in our analysis is 66 $/t, which is consistent with the disclosed average FOB prices in the Semirara Mining Corporation's 2012 annual report.

The Philippines began importing coal in 1988 to meet the increasing demand; since the mid-1990s, coal imports have been growing at a fast pace, and reached 11.90 Mt in 2012 (Philippines DOE, 2013). Indonesia has been the dominant supplier of imported coal. The Philippines also imported small amounts of coal from Australia, China, Russia, South Africa, the USA and Vietnam, but imports from these suppliers varied considerably year on year, suggesting these were cargoes purchased from spot markets rather than on a contract basis.

9.4 Generation cost comparison

Figure 21 illustrates the average generation costs of the subcritical coal pf and natural gas CCGT plant fleets based on assumptions in Table 7. The average generation cost of gas CCGT is marginally higher than that of the subcritical coal fleet. Although the fixed capital cost, the O&M cost and the interest payment are much lower for gas CCGT than for subcritical coal plants, the cost of gas is much higher than the cost of coal as neither fuel is subsidised. Our analysis shows that a marginal decrease of gas price from 10.8 $/million Btu to 10.0 $/million Btu can equalise the average generation cost of CCGT to that of subcritical coal. As such, the relative cost competitiveness of coal- and gas-based generation is sensitive to the fuel price volatility in the Philippines.

Since gas CCGT plants already operate as baseload as shown in Figure 20, it is unlikely that the average generation cost of gas CCGT power plants can be reduced by further increasing their utilisation rates. There is also little room for reducing the generation cost of gas plants by further efficiency improvement. This is because the gas CCGT plants are new (commissioned in early 2000s) and already run at 56% efficiency, among the highest in Asia.

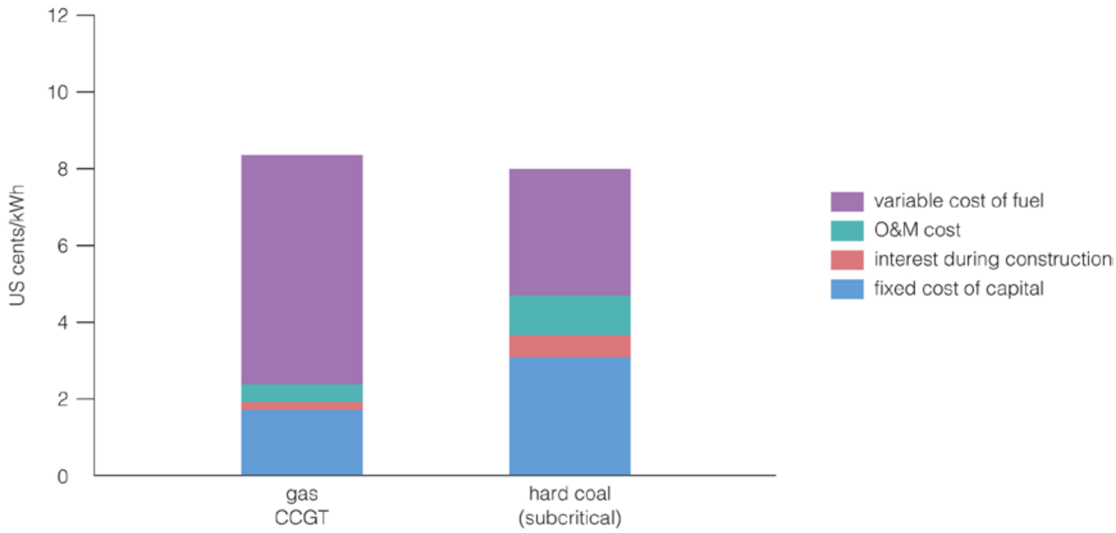

Figure 21 The modelled average generation costs of natural gas CCGT fleet and coal-fired subcritical fleet

9.5 Discussion on issues affecting competition

The power sector in the Philippines has been extensively deregulated since the *Electric Power Industry Reform Act* was launched in 2001. Privatisation and sale of the generation assets of the monopolistic National Power Corporation (NPC) and its contracts with IPPS not only generated the cash flows that the government needed to pay off NPC's debts but also created a more competitive generation market. In addition, an integrated wholesale electricity spot market has been established in the Luzon and Visayas grid in early 2011, which accounted for around 9% of the total electricity consumed in the Luzon and Visayas region. Furthermore, the government is currently working to implement *Open Access and Retail Competition*, which will create a competitive and transparent regime to determine electricity prices.

As the electricity market becomes more competitive, the generation cost will be the major factor affecting the decisions related to power dispatch and new generation capacity construction. Our analysis shows that coal is more competitive than gas for power generation due mainly to the low cost of coal. Since the Philippines will import LNG soon and the government does not provide subsidies, gas prices to power plants are expected to rise, keeping coal-based generation even more competitive than gas-based generation. Unlike many of its neighbours, the Philippine Government does not subsidise the electricity and the average electricity tariff is the second highest in Asia after Japan. The generation cost is the largest component of the electricity tariff with a share of 65% on average (KPMG, 2013). As such, using coal for power generation is key to providing affordable electricity in the Philippines, where 30% of the population still have no access to electricity (IEA, 2013a).

10 Japan

10.1 Energy indicators in 2012

Population	128	million
GDP	5937.8	billion US$ (year 2005)
Electricity consumption	989	TWh
Electricity consumption per capita	7.75	MWh/capita
Electricity generation	1034	TWh
Electricity imports/exports	0/0	GWh
Generation capacity	226	GWe
Coal-fired capacity	42	GWe
Gas-fired capacity	85	GWe

(IEA, 2014a; World Bank, 2014)

10.2 Power generation mix

As shown in Figure 22, Japan's power generation mix has significantly changed in the wake of the Fukushima incident in 2011. Only two nuclear power units out of a total 50 are currently operating in Japan. Gas- and oil-fired power plants are the main replacement for the closed nuclear power plants. Although a number of coal-fired stations suffered in the 2011 Fukushima incident which resulted in a 10 Mt/y drop in steam coal imports, the overall national coal-fired generation remained strong. The extremely high share (18% in 2012 compared to the average level of 5% in Asia) of oil-based generation is not sustainable, and may be partly replaced by coal-based generation in the future.

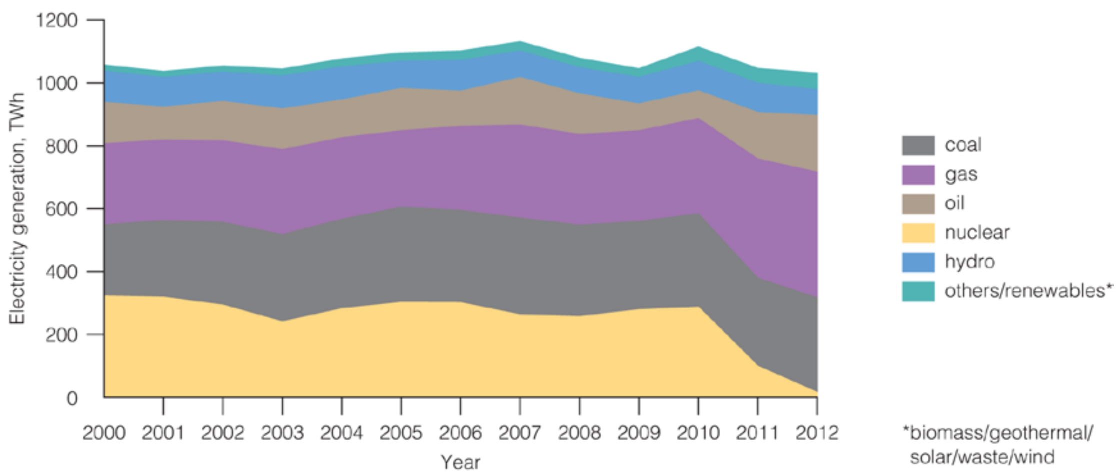

Figure 22 The Japanese power generation mix before and after the Fukushima incident (IEA, 2014c)

According to Platts World Electric Power Plant Database, Japan had 226 GWe of installed generation capacity in 2013, including 30 GW SC/USC coal, 12 GW subcritical coal, 42 GW natural gas CCGT, 41 GW gas turbine/CHP, 47 GW oil, and 47 GW hydro. An additional 3.3 GW of new gas-fired capacity is expected to come online during 2014–2017, while only 1 GWe of coal is under construction. The planned LNG plants are 9 GWe, while only 4.5 GWe of coal power plants are planned. The 1.3 GWe Oma nuclear power station is still planned, but doubts hang over the completion of this plant.

Figure 23 illustrates the overall dispatch of the various forms of power stations in the Japanese fleet. The x-axis shows the fleet utilisation, based on the average operating hours calculated over 2006–12, although it does show how nuclear power has all but disappeared compared to pre-2011 levels. The y-axis shows the current generating capacity in the country, including existing units and those expected to be commissioned in 2013, based on Platts World Electric Power Plant Database (Platts, 2013). The utilisation rates shown here may be misleading as they are based on years before and after 2011 when the thermal plants have been operated at different loads as a result of the close down of nuclear power stations. As such, this figure should be treated with some caution.

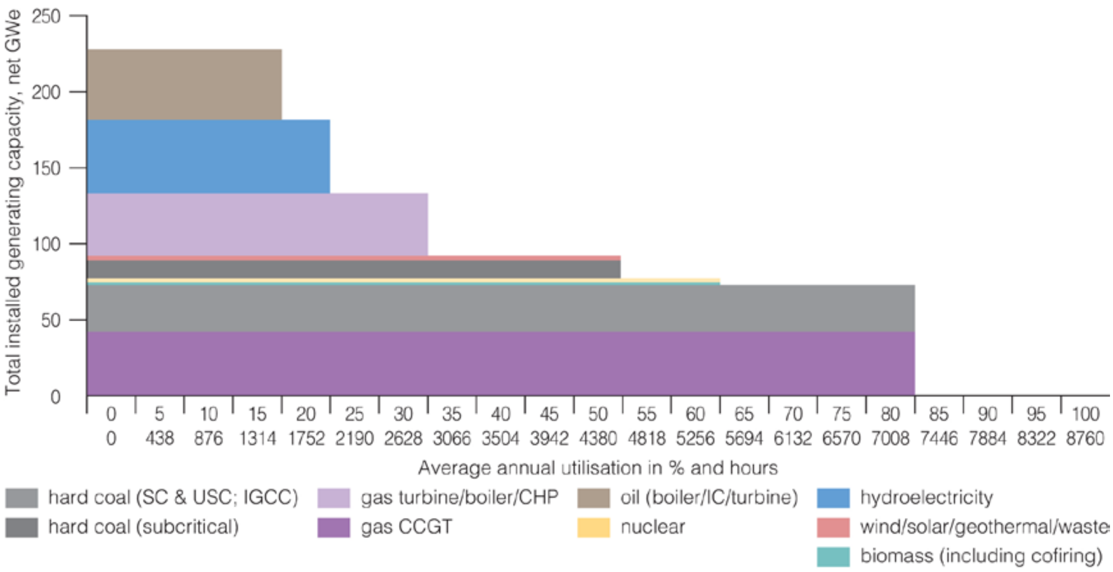

Figure 23 The representative dispatch graph of various types of power generation plant fleet in 2013 (based on Platts World Electric Power Plant Database, December 2013)

Nevertheless, Figure 23 shows that baseload power is dominated by CCGT and supercritical coal power plants. All types of gas-fired power plants (CCGT and Gas turbine/boiler/CHP) together accounted for 38% of the total generation in 2012 (IEA, 2014a). Japan has almost as much non-CCGT gas-fired capacity as CCGT capacity. Non-CCGT gas power plants operate at lower utilisation rates of 35%. Coal-fired power is dominated by supercritical power plants. A large fleet of oil-fired plants are still operating albeit at low loads, and account for almost a fifth of total generation capacity. Unless there is a major U-turn in the use of nuclear power stations, it is likely that coal and gas CCGT power stations will continue to be run at high loads.

10.3 Fuel supply

Japan does not have adequate indigenous fossil fuel resources. Its fuel reserve is effectively dependent on its ability to own fuel operations overseas and negotiate contracts with foreign suppliers. Fuel prices assumed for our analysis are derived from the market indices or trade information.

10.3.1 Gas

Japan relies on LNG for all of its natural gas supply and is the world's largest importer of LNG. LNG imports rose after the Fukushima incident as more gas-based generation is used to fill the gap left by closed nuclear power plants. Japan imported 119 bcm LNG from 18 countries in 2013. Despite the diversity in LNG suppliers, around 66% of the LNG imports were procured from the top four suppliers: Australia, Qatar, Malaysia and Russia (BP, 2014). Interestingly, Japan sourced 30% of LNG from Southeast Asia. Japan has been actively acquiring natural gas assets to secure its gas supply. Tokyo Gas owns small amounts of shares in various Australian gas projects such as Darwin, Pluto and Gorgon. Long term LNG contracts are associated with all of these projects. Unconventional gas provides another opportunity; the Queensland Curtis LNG project which could in future be the world's first integrated CBM based LNG project.

The gas supply sector is dominated by just a few players; some of the largest include Inpex, Mitsubishi, and Mitsui in gas production and exploration, and Osaka Gas, Tokyo Gas, and Toho Gas in gas retail. Despite being a large gas consumer, Japan has a relatively limited gas pipeline network due to the geographic constraints posed by the mountainous terrain. The power sector is the largest consumer of gas, accounting for 67% of gas demand (IEA, 2014a).

LNG prices are indexed to oil, which forms the basis for LNG contracts in Asia. Higher gas demand and tighter world LNG supplies have resulted in large increases in LNG prices – from 9-11 $/million Btu before Fukushima nuclear incident to 16–17 $/million Btu in 2013 (BP, 2014). The increased cost of LNG is passed on to the end users of electricity. Japan's Ministry of Economy, Trade and Industry is urging utilities to secure cheaper gas before passing on costs of gas to consumers. Negotiations are underway to adopt contracts that delink from oil and link to the US Henry Hub price. In November2012, Kansai Electric reached agreement with BP on a long-term deal linked to the US Henry Hub prices.

10.3.2 Coal

Coal imports provide all of Japan's coal supply. In 2012, Japan imported 129 Mt of steam coal, mainly from Australia (69%), Indonesia (16%) and Russia (9%) (IEA, 2014b). Traditionally, Japan has met most of its coal supply requirements through the use of long-term contracts based on annual collective negotiation between Japanese electric utilities and Australian coal producers. Annual negotiations not only adjust the price but also negotiate quantity and quality components of long-term coal contracts with foreign suppliers. The negotiated reference price is used later in the year as the basis for setting contract prices for steam coal used at Japanese utilities. It also serves as the basis for setting contract prices in other Asian countries such as South Korea and Taiwan. The importance of the term contracts and the reference price has been reduced in recent years. The primary reason is the ongoing liberalisation of the Japanese electricity market. Increasing competition is placing cost-cutting pressure on Japanese utilities, making them less inclined to accept a collective negotiation in favour of individual bargaining with suppliers and increasing reliance on spot market purchases. The outcome of negotiations between individual suppliers and Japanese utilities has largely become confidential. The second reason is an increasing ability or willingness by utilities to purchase a wider range of coals, reducing their dependence on any one specific region or mine. This trend is not only the result of newer power plants being technically capable of burning a wider range of coals but is also attributable to a greater flexibility in fuel procurement. With the reduced importance of the reference price, spot price indices, such as the BJI and globalCOAL index, have become more important in price setting, as both buyers and sellers look for suitable market indicators. In some contracts, price indices are written into contract price adjustment formulas and weighted to reflect the contract's nature, either spot-oriented or long-term security oriented.

10.4 Generation cost comparison

As illustrated by Figure 24 the cost of coal-based generation are typically lower than that of gas CCGT generation. But the differential between gas CCGT and subcritical coal plants is small based on our assumptions shown in Table 8.

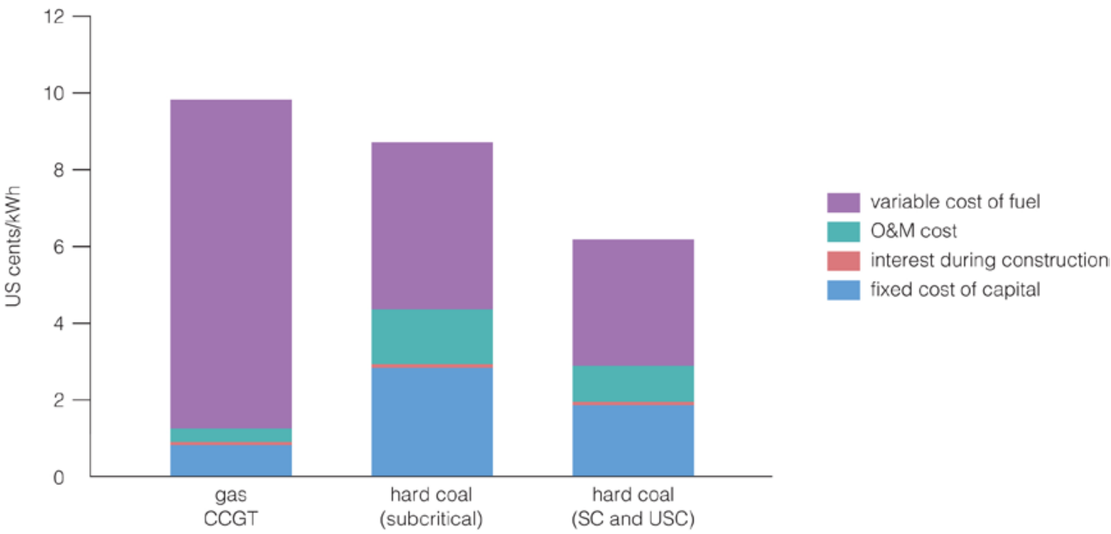

Figure 24 The modelled average generation costs of natural gas CCGT fleet and coal-fired subcritical and supercritical plant fleets

In terms of fixed capital, the costs of building power stations in Japan are high due to land constraints, materials and the high cost of labour. Rong and Victor (2012) compared the overnight CAPEX of supercritical coal-fired power plants for 10 countries, and found that Japan's overnight CAPEX was the highest at 2500–3000 $/kWe (based on 2008 data). Since our analysis assumes the fixed O&M cost as 3% of fixed capital cost (typical for OECD countries), the fixed O&M cost also appears high by world standards. Financing costs are quite low, partially compensating for high capital and fixed O&M costs, as a result of a low interest rate (just 2%) and more than 70% utilisation rates across the fleets.

In addition to the high costs of building capital intensive plants, Japan's LNG supplies are expensive. At a price of more than 14 $/million Btu for imported gas, any high efficiency CCGT plant incurs high operating costs, pushing its generation cost above that of coal-fired power plants. Our analysis shows that the LNG price needs only to drop from 14 $/million Btu to 12.2 $/million Btu for the generation cost of a CCGT plant to match that of a subcritical coal power plant, but must drop to 8.1 $ to match that of a SC/USC coal power plant (assuming no other costs apply, such as CO_2).

Japan has imposed a carbon tax on all fossil fuels since 1 October 2012. This *Tax for Climate Change Mitigation* is non-discriminatory and imposed on a tonne of CO_2 basis. It is being introduced progressively through three phases to reach the full rate of 289 JPY/tCO_2 (2.6 $/t) by 1 April 2016; the full carbon tax imposed on coal and gas is 670 JPY/t and 780 JPY/t, respectively (Japan MOE, 2012). This adds to the generation costs of both coal and natural gas power plants. Since coal power plants emit more CO_2 per MWh of electricity than gas power plants, the carbon tax is expected to negatively impact coal generation more than gas generation. The implication is that CCGT units will likely be run at high utilisation rates to keep CO_2 emissions across all the thermal fleets at minimum.

10.5 Discussion on issues affecting competition

Japan already has more installed gas-fired generation capacity (42 GW CCGT and 41 GW gas turbine/CHP) than coal-fired generation capacity (30 SC/USC and 12 GW subcritical), and is building more gas-fired power plants (3.3 GW) than coal-fired power plants (1 GW). This reflects the uncertainty over Japan's energy policy, which has led power utilities to opt for the low capital cost option (gas CCGT power plants) for new generation capacity addition. The recently imposed carbon tax also favours gas-based power generation.

Currently, gas CCGT plants run at high utilisation rates comparable to those of coal-fired power plants to replace lost nuclear power. Our analysis shows that coal-fired generation is still more economic (not considering CO_2 tax) than gas CCGT generation at such high utilisation rates because the cost of natural gas is much higher than the cost of coal. The increased use of gas CCGT power plants and the loss of nuclear power as baseload have resulted in the power market clearing prices being determined by gas-fired power generation even in off-peak periods and spring and autumn, in which coal-fired generation used to determine the clearing prices before the Fukushima crisis.

11 South Korea

11.1 Energy indicators in 2012

Population	50	million
GDP	1222.8	billion US$
Electricity consumption	517	TWh
Electricity consumption per capita	10.35	MWh/capita
Electricity generation	535	TWh
Electricity imports/exports	0/0	GWh
Generation capacity	230	GWe
Coal-fired capacity	27	GWe
Gas-fired capacity	33	GWe

(IEA, 2014a; World Bank, 2014)

11.2 Power generation mix

The power sector in South Korea is dominated by the Korean Electric Power Company (KEPCO), in which the Korean government has a majority share. KEPCO's generation assets were divided into six generating companies in 2001, but it remains in control of transmission and distribution assets. Entry of IPPs are permitted, and they compete with the six power companies to sell power into an hourly auction pool operated by the new Korea Power Exchanger, with KEPCO acting as the single buyer.

As shown in Figure 25 coal power is the most important form of generation in South Korea with a share of 45% in 2012 (IEA, 2014a). It also accounted for the largest growth in absolute terms between 2000 and 2012. The second largest form of generation is nuclear power with a share of 28% in 2012, but its growth during 2000–2012 was modest. Natural gas-based generation nearly tripled during this period and accounted for 21% of the total electricity generation in 2012. The use of oil for power generation decreased steadily over this period. The contributions from hydropower and renewables are small, with each less than 1% in 2012.

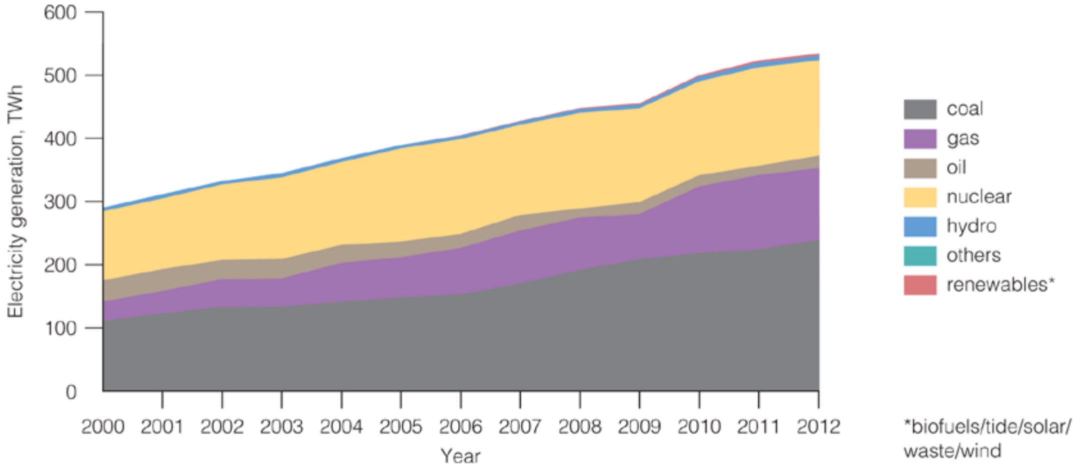

Figure 25 Electricity generation mix of South Korea in 2012 (IEA, 2014a)

Figure 26 illustrates the representative dispatch of the various forms of power stations in the Korean fleet. The x-axis shows the fleet utilisation, based on the average operating hours annually calculated over 2006–12. The y-axis shows the current generating capacity in the country, including existing units and those expected to be commissioned in 2013, based on Platts World Electric Power Plant Database (Platts, 2013).

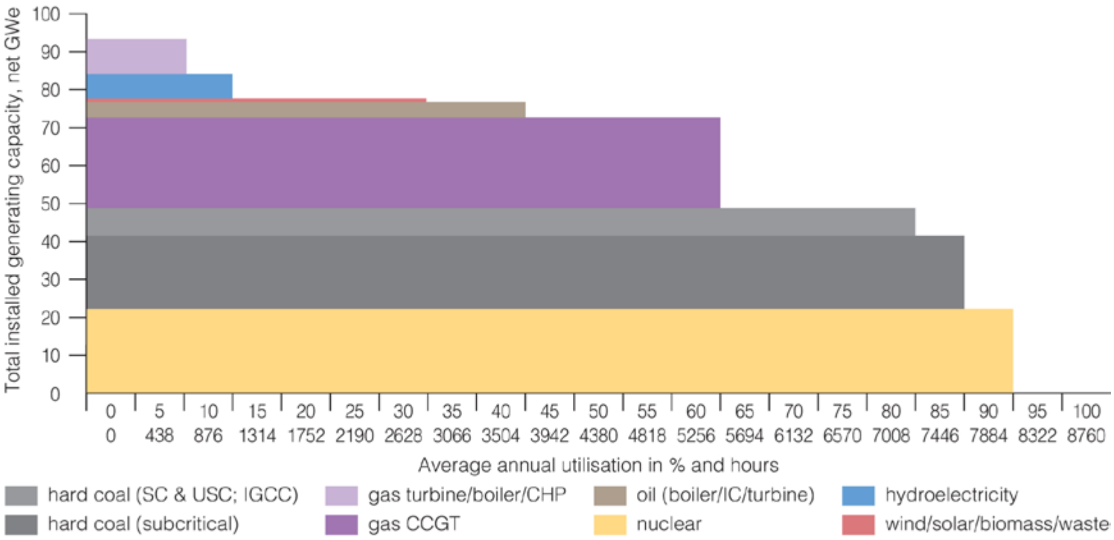

Figure 26 The representative dispatch graph of various types of power generation plant fleet in 2013 (based on Platts World Electric Power Plant Database, December 2013)

Based on the generation mix and the dispatch curve, there does not appear to be any direct competition between coal and gas. Almost all the thermal power stations operate at above 60% utilisation, indicating that Korea has a substantial baseload power generation, probably a feature of an economy that is heavily based on manufacturing and heavy industry.

Baseload power is provided by nuclear, which consistently operates at 90% utilisation, closely followed by the coal-fired fleet. The bulk of the thermal fleet comprises 33 GWe of gas–fired power plants and 27 GWe coal-fired power plants. Gas CCGT plants appear to operate over the mid merit order, while other forms of gas-fired power plants provide peak generation.

Korea's only indigenous coal resource is anthracite. There is about 1.2 GWe of anthracite-fired power plants all of which are subcritical. KEPCO's operational data show that the utilisation of these power plants averaged 84–86%, which is very high by world standards and normally reserved for nuclear power stations. The power plants that burn imported bituminous coals operate at even higher utilisation, often exceeding 90%. At such high utilisation, the coal-fired power plants operate at optimum efficiency.

South Korea's utilities are constructing 27 GWe of new generating capacity to be commissioned during 2014–2018. This includes 9 GWe of gas-fired capacity, 10.5 GWe of coal-fired capacity, 6.7 GWe of nuclear power, and 1–2 GWe of renewables. The majority of the new coal-fired capacity uses ultra-supercritical pulverised coal combustion technology. South Korea is also building its first ultra-supercritical CFB power station with 4 x 550 MW capacity in Samcheok, Gangwon-do Province. This power station employs Foster Wheeler's CFB technology and is scheduled to start operation in June 2015. It is capable of burning imported wood pellets and low rank coal, and has an estimated net efficiency of 42% (Foster Wheeler, 2013).

11.3 Fuel supply

South Korea has a great deal in common with Japan; some 97% of the country's energy demands are imported due to insufficient domestic resources. Crude oil, LNG and coal are all imported in large quantities, although the country does have some anthracite reserves. Korea is the second largest importer of LNG in the world, after Japan.

11.3.1 Gas

South Korea produced about 37 billion cubic feet (1 bcm) of natural gas (about 2% of its consumption) in 2012 from the domestic gas field Donghae-1 (EIA, 2014). This field will continue to produce until 2018, when it will be converted to an offshore gas storage facility. There is ongoing exploration at deepwater blocks and studies of methane hydrates deposits.

South Korea has no pipeline infrastructure linking it to foreign gas reserves. There have been protracted talks towards a gas pipeline being laid from Russia to South Korea via North Korea, or directly from Russia to South Korea using a subsea route. This however seems a long way off due to political and technical risks as well as capital requirements.

All the gas imports to South Korea are through LNG. Korea Gas Corporation (KOGAS) has a near monopoly control over the country's LNG import and wholesale marketing of gas. KOGAS currently operate 3 LNG receiving terminals in Incheon, Pyeongtaek, and Tongyeong, and are constructing a fourth terminal at Samcheok, which was scheduled to start operation at the end of 2014. A fifth import terminal is planned at Jeju Island off the southern coast with start-up in 2017.

In addition, the steel company, POSCO, operate a small LNG receiving terminal (1.7 Mt/y) at Gwangyang on the southern coast, which supplies the POSCO's steel works and K-Power's power station. The Gwangyang LNG terminal is the only facility in the Pacific basin to have been used for re-exports to take advantage of seasonal LNG arbitrage opportunities. Another non-KOGAS new LNG terminal at Boryeong is planned by GS Energy and SK E&S with a capacity of 1.5 Mt/y to supply the company's two power stations. However, this terminal is now suspended due to the government's lack of progress with gas price liberalisation.

LNG imports began in 1980 and increased rapidly to 54.2 bcm in 2013, ranking the second largest LNG importer in the world behind Japan. The major suppliers include Qatar (18.3 bcm in 2013), Indonesia (7.7 bcm), Malaysia (5.9 bcm), Yemen (4.9 bcm) and Nigeria (3.8 bcm) (KEEI, 2013b; BP, 2014).

Similar to Japan, South Korea purchases most of its LNG through long-term supply contracts and uses spot cargos primarily to correct small market imbalances. It pays the highest prices in the world for LNG; the average LNG import price was 14.6 $/million Btu in 2012 (assuming 1 tonne of LNG equals 51.7 million Btu) (KEEI, 2013b). Almost half of the natural gas is supplied to the power stations and the remainder is sold to the city gas network. Domestic gas prices have long been regulated by the government to curb inflation. This regulation has caused KOGAS losses at high LNG import prices, and the government has subsequently raised the regulated gas prices to alleviate the losses. In this sense, the rise in the cost of LNG imports can be partly passed onto to the power plants.

11.3.2 Coal

South Korea only produces anthracite and all its steam coal and coking coal are imported. The smaller anthracite market in South Korea is close to 10 Mt/y with more than half being imported, and the rest produced in local mines. Most of the anthracite is used in a handful of small anthracite-fired power plants, while the remainder is used for metallurgical processes. Anthracite has its own supply and demand market internationally and is seen as separate to the hard steam coal or low rank steam coal trade that is more common in the seaborne market. Local anthracite production is subsidised, but this has fluctuated in past years. Between 1998 and 2004 the subsidy burden fell considerably from 65 US$/tce to around 34 US$/tce, but then rose to 41 $/tce (28 $/t) (Baruya, 2012).

In 2012, South Korea imported 94.3 Mt of steam coal and 31.3 Mt of coking coal (KEEI, 2013b). The majority of imported steam coal came from Australia, Indonesia and South Africa, while Canada, China and Russia together supplied 15% of imported volume in 2012. Steam coal imports are largely through long-term contracts, complemented by spot market purchases. The pricing mechanism is similar to that in Japan. The steam coal price assumption is derived from the average MCIS Japanese marker (6080 kcal/kg) price index since 2009.

Coal prices are partly affected by the cost of seaborne freight rates, and have been in the doldrums for some years now. In some ways the low freight rates have been perpetuated by the surplus capacity in the dry bulk market which was brought about by the building programme of shipbuilders in many Asian economies, not least Korea. More vessels are expected to come online in coming years, and will help to keep CIF coal costs low.

11.4 Generation cost comparison

Figure 27 illustrates the average generation cost of the gas CCGT fleet and coal-fired plant fleets, based on assumptions in Table 9. As in most other countries, gas CCGT units are cheaper to build than coal-fired units. South Korea has taken a modular approach to the building of coal-fired power plants through the 1980s and 1990s, which has resulted in faster construction and lower capital costs compared to most OECD countries such as Japan. However, the gas price is nearly 4 times higher than the coal price. At such a high price level, even the highest-efficiency CCGT power plant running at baseload would struggle to beat a coal-fired power plant operating at similar load. Our analysis shows that the gas price needs to drop to 6–7 $/million Btu to be able to compete with coal-fired power plants. Moreover, the generation cost of CCGT could be reduced if the utilisation of the CCGT fleet were to be increased.

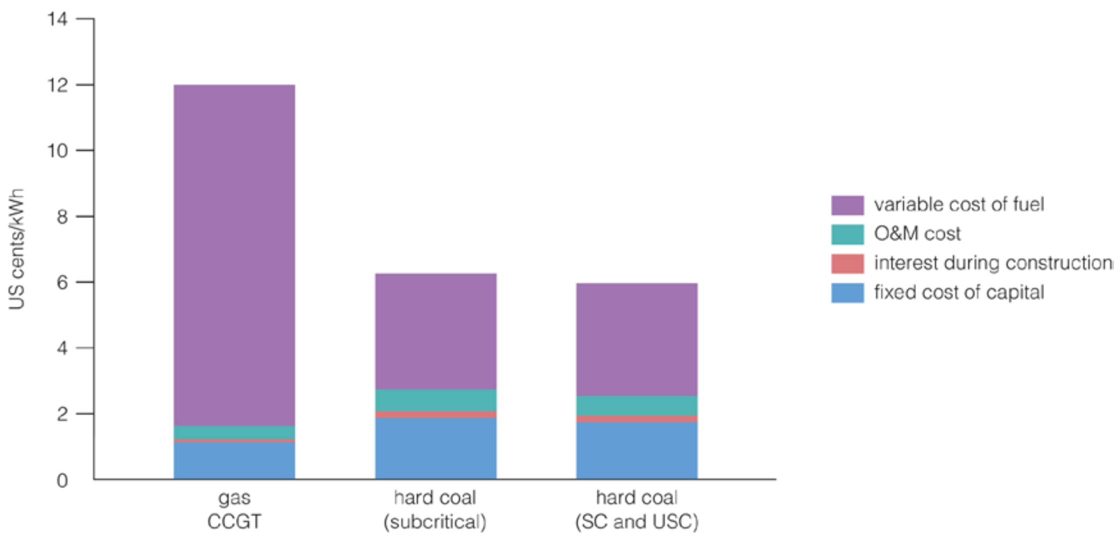

Figure 27 The modelled average generation costs of natural gas CCGT fleet and coal-fired subcritical and supercritical plant fleets

11.5 Discussion on issues affecting competition

In South Korea, the electricity supply is tight as the generation capacity reserve margin has been squeezed to be as low as 5% on average between 2011 and 2013 (Pittman, 2014). The government has set a target to raise the reserve margin to 22% by adding 50 GW of new generation capacity by 2027 under the *6th Basic Plan of Long-term Electricity Supply and Demand* for the period of 2013-2027 (Han and Kim, 2013).

This target can only be achieved by using more thermal (coal and gas) power generation as the government scaled back on its nuclear power ambition following the Fukushima disaster in Japan and recent misconduct in Korea's own nuclear industry (the corruption at Korea Hydro and Nuclear Power has led to shut-down of several nuclear plants due to safety concerns). According to the government's Second *Long-term National Energy Basic Plan* for the period 2014 to 2035, nuclear is now projected to grow from 26% to 29% of the power generation mix by 2035, down from the previous target of 41% by 2030. Moreover, the target for renewable energy has remained at 11%, but is projected to be achieved by 2035 instead of 2030. Although specific targets for gas and coal in the energy mix were not stated in the energy plan and should be announced later in 2014, it is clear that the slack created by a scaled-down nuclear ambition will need to be filled by a combination of coal and gas.

A comparison between the 6th Basic Power Plan and the previous 5th Basic Power Plan (2010-2024) reveals that the weight of thermal power generation has increased. In particular, the targeted share of coal-fired generation is 34.6% in 2027 under the 6th Basic Power Plan as opposed to 27.9% in 2024 under the 5th Basic Power Plan. Moreover, the 6th Basic Power Plan indicates that more coal-fired generation capacity will be built (20.4 GW) than LNG-based generation capacity (9.8 GW). The increased targets are due to a greater number of IPPs intending to build coal-fired power plants as they perceive coal as a cheaper generation option than gas.

As LNG prices are expected to remain high, coal will remain more competitive than gas in power generation. Since there will be less nuclear power development, South Korea will increasingly rely on coal to provide baseload power generation.

12 Impact of shale gas in the USA on Asian coal and gas markets

In recent years, the shale gas revolution in the USA has not only transformed the US domestic energy market, but also has serious repercussions for the rest of the world. This chapter discusses the development of shale gas in the USA and its impact on coal and LNG supply in Asia.

12.1 Shale gas development in the USA

The discovery of shale gas has boosted US gas reserves by 750 tcf (21.2 tcm) to 2300 tcf (65.1 tcm), making unconventional reserves more than 30% larger than the conventional reserves and also greatly boosting oil reserves. Shale gas is found across the country, but the most favourable and abundant reserves are found in six major regions, Bakken, Niobrara, Permian, Eagle Ford, Haynesville, and one of the most productive regions in the USA, Marcellus.

Since the regulatory relaxation on hydraulic fracturing in 2005, shale gas production has increased considerably and, together with CBM production, has more than compensated for the decline in gas production from conventional oil and gas wells (*see* Figure 28). Consequently, the overall gas production in the USA has increased by 34.5% and net gas imports have plummeted by 50% between 2005 and 2013 (BP, 2014).

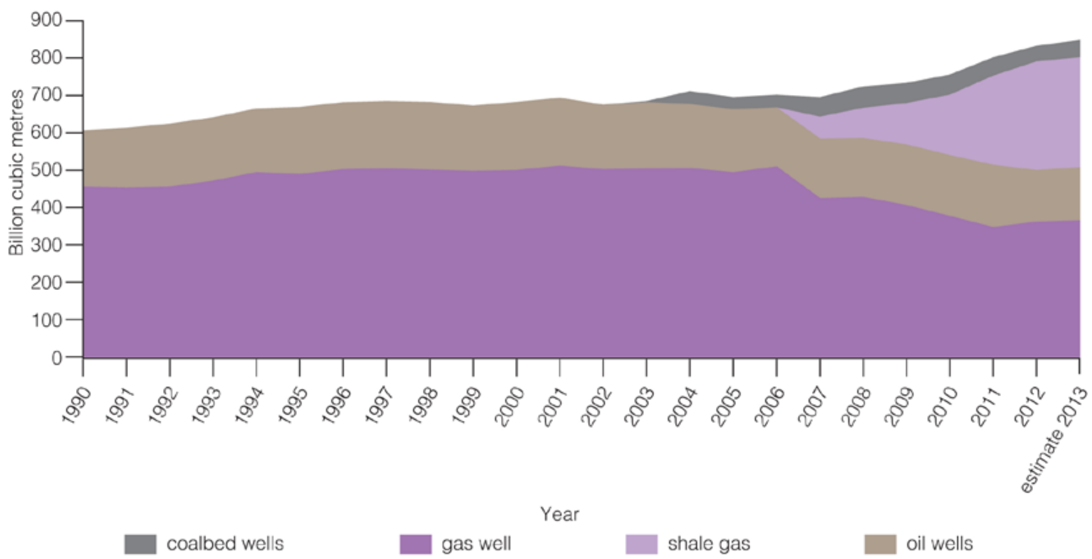

Figure 28 Historic trends in US gas production

12.2 Impact on the US power market

The availability of shale gas has kept US gas prices low, which intensified competition between coal and gas in power generation. Switching from coal to gas for power generation has been observed, as shown in Figure 29. According to an IEA study, there was a maximum switching potential of 613 TWh of CCGT generation, and the actual switching generation from coal to gas was observed to be 122.5 TWh (or around 20% of coal-fired generation capacity) between October 2010 and September 2011 (Macmillan and others, 2013).

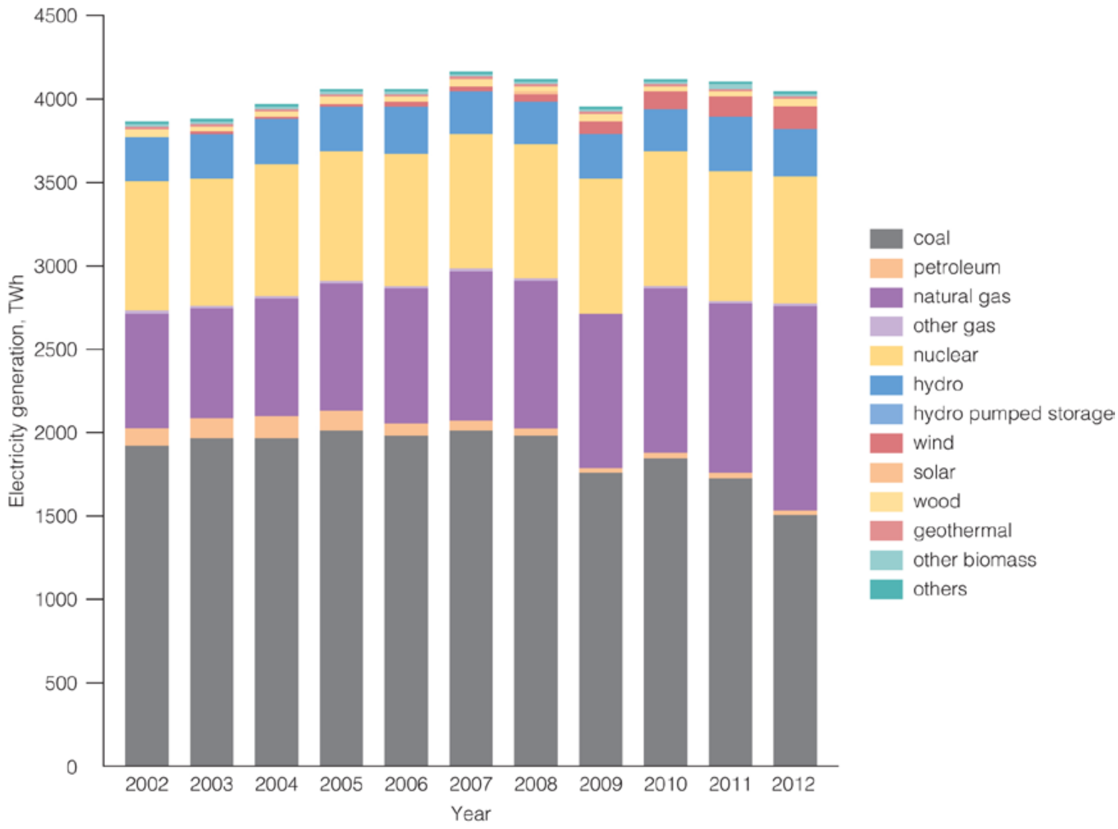

Figure 29 Historic trend in electricity generation mix in the USA (EIA, 2014)

Switching from coal to gas is sensitive to natural gas prices; 4 $/million Btu is the level below which switching has been observed to occur. The bulk of the switched generation would switch back to coal if the Henry Hub gas price reached 4.7 $/million Btu (Macmillan and others, 2013). With new LNG export terminals being built in the US, gas exports could lead to a price rise of 1-2 million Btu on the current price of 4 $/million Btu, potentially making coal generation competitive again. However, the new air emission legislation, Mercury and Air Toxics Standards (MATS), and the new regulations on CO_2 emissions from both existing and new power plants make coal-fired generation less favourable compared to gas-based generation.

12.3 Potential for coal export to Asia

As a result of a combination of the shale gas boom and regulations on power station emissions, the shift in the US domestic market provides opportunities for the USA to export coals to Asia. US steam coal exports are however an uncertain prospect. US exports have traditionally been supplied from the east coast of the USA and the US Gulf to the Atlantic market, and have been mostly coking coals for metallurgical applications. Five coal export terminals are being considered on the west coast of Canada and USA, including Gateway Pacific, Millennium, Morrow Pacific, County Coal and Fraser Surrey, which in total provide 113.5 Mt/y export potential.

However, the planned export terminals are facing regulatory hurdles and opposition from local lobby groups. The Fraser Surrey terminal is the most likely to proceed to construction. With a planned capacity of 8 Mt/y, this terminal would provide an export route for subbituminous coals from the Powder River Basin (PRB)

12.4 Potential for LNG export to Asia

The shale gas boom has driven down the USA gas prices, while the LNG prices in Asia, mostly linked to oil prices, are several times higher. In 2013, the differential between the average price for LNG landed in Japan and the average Henry Hub price was 12.46 $/million Btu (BP, 2014). Such a high price differential generates huge interests in exporting LNG from the USA to Asia. The US EIA projected in the Reference Case of its 2014 Annual Energy Outlook that the USA may become a net LNG exporter in 2016 with gross exports reaching their peak of 3.5 tcf (99 bcm) in 2030 (EIA/AEO, 2014).

However, the Federal government is concerned about the possibility that a large volume of exports could push up domestic gas prices. As such, it has been cautious to approve the LNG export projects. According to Federal Energy Regulatory Commission (FERC), there are 14 proposed LNG export terminals in the USA, with a combined capacity of 6.38 tcf/y (or 180 bcm/y) (FERC, 2014). FERC has approved 4 export terminals, including Sabine and Hackberry in Louisiana, Freeport in Texas, and Cove Point in Maryland, which in total represent 7.08 bcf/d (2.58 tcf/y or 73 bcm/y) of export capacity. Sabine is currently the only terminal under construction, and is expected to start operation over the next two years.

The destinations of LNG exports from these terminals were initially limited to countries that have a free trade agreement (FTA) with the USA. Under the *Natural Gas Act*, LNG exports to the FTA countries are automatically considered to be in the public interest. Applications to export gas to these countries must be approved without modification or delay. However, except for South Korea and Singapore, many LNG importers do not have FTA with the USA. Exports to non-FTA countries have to be authorised by the Department of Energy (DOE), which must determine whether or not the proposed exports are consistent with the public interest in the USA. In addition, DOE must review the potential environmental effects of the proposed exports under the *National Environmental Policy Ac*t.

As of the time of writing, DOE has issued final non-FTA authorisations with a cumulative volume of exports totalling 2.095 tcf/y (59.3 bcm/y) (DOE, 2014). This total export volume is within the range of scenarios (6–12 bcf/d or 62–124 bcm/y) that are considered to bring net economic benefits to the USA (DOE, 2014). DOE will continue taking a measured approach in reviewing the other pending applications to export domestically produced LNG. Specifically, DOE will continue to assess the cumulative impacts of each succeeding request for export authorisation in the public interest with due regard to the effect on domestic natural gas supply and demand fundamentals. This implies that the total export volumes can be limited to a point where exports result in a considerable rise in domestic gas prices.

In addition, future US LNG exports depend on a number of external factors that are difficult to anticipate. These include the speed and extent of price convergence in global natural gas markets and the pace of natural gas supply growth outside the USA (notably Australia).

13 Summary

This report seeks to understand the competition between coal and natural gas in power generation in nine Asian countries. For each country, the power generation mix is first analysed to understand the respective role of coal and gas in power generation. Next, coal and gas supply options are analysed to help understand the coal and gas pricing development where information is available. The average generation costs of gas CCGT fleets and coal-fired plant fleets are modelled to provide a comparison of their generation economics. Finally, specific issues affecting coal and gas-fired generation are discussed.

In China, coal remains the dominant fuel for power generation due to the sheer size of the existing coal fleet and its lower generation costs. Natural gas is used to replace coal for power generation only in the three industrialised zones with a large urban population. This is not based on generation economics, but is driven by the Chinese central government's policies to address the worsening air pollutions in these areas. Elsewhere in China, use of natural gas for power generation is limited because coal power is generally cheaper and natural gas supply is prioritised to the residential sector. The latest pricing reforms imply coal prices remaining weak but rising natural gas prices, reaffirming the lower generation cost of coal power. However, the new air emission standards and the emerging carbon price could put coal out of favour for power generation, but their impact remains to be seen.

India is facing severe power supply shortages due largely to insufficient coal and gas supplies to power plants and substantial losses during transmission and distribution. The country thus needs both coal and natural gas to address the severe electricity shortage issue in the country. Gas CCGT units are concentrated in the five states with proximity to gas fields or LNG terminals, where they operate at 80% utilisation to provide baseload generation. Coal-fired generation dominates elsewhere in India. India is adding considerably more coal-fired generation capacity than gas-fired generation capacity.

In Indonesia, coal- and gas-fired power generation have been used to replace the more expensive generation using fuel oil and diesel. Coal has emerged as the choice of the government in its two Fast Track Programmes for new generation capacity construction due to its low cost and abundant supply. Supercritical coal-fired power plants are being built by IPPs. Natural gas-fired power plants have suffered from gas supply shortages, which have resulted in gas plants running at low utilisation rates and even burning oil. The low gas prices make gas CCGT more competitive than coal-based generation. However, as the country is set to import LNG, gas prices will increase and thus coal-based generation may become more economic.

Natural gas is the dominant fuel used for power generation in Thailand. Gas-based generation has increased at a fast pace during the past two decades, while generation using indigenous lignite has been stable. Thailand started importing coal for power generation in 2006. Coal-fired generation is more economic than gas CCGT generation due mainly to the lower cost of coal. The likely increase in gas price due to LNG imports would further undermine the competitiveness of gas-fired generation. Coal-fired power plants are being promoted by the government as a necessary alternative to diversify away from natural gas. However, new coal-fired power plant projects are facing strong public resistance as a result of the poor image of polluting lignite-fired power plants.

In Malaysia, natural gas has been the most important fuel for power generation, while coal has taken an increasing share since 2000. Coal-fired power plants are concentrated on Peninsular Malaysia; large supercritical coal-fired power plants are being built by IPPs in this state. There are only three coal-fired power plants in the state of Sarawak and no coal plants in the State of Sabah. In Peninsular Malaysia, coal is expected to replace gas as the dominant fuel for power generation. Gas-fired power plants are fuelled by domestic gas with very low prices, while the majority of coal supplied to coal-fired power plants is imported. Low gas prices make the gas CCGT fleet more competitive than the subcritical coal fleet. However, the gas price reform by the government could eventually increase the price to international market rates, making gas-based generation less competitive than coal-based generation. Malaysia needs to diversify its coal supply from Indonesia to increase its coal supply security.

In Vietnam, the low cost of natural gas makes gas more competitive than coal in power generation. However, the country is building 13 GW of new coal-fired power plants, while building only one natural gas CCGT plant. This is probably due to concerns over rising natural gas prices as domestic gas production grows only slowly and more LNG imports are needed. But Vietnam may need to import more coal as the growth in domestic coal production is also slow. It remains to be seen whether power plants burning imported coal could compete with gas CCGT plants, particularly in the central and southern parts of Vietnam. In northern Vietnam, power generation continues to be dominated by power plants burning cheap indigenous anthracites.

In the Philippines, coal is used to generate electricity in all three regional grids, while natural gas plays a significant role only in the Luzon grid. The country's three natural gas CCGT plants are located in the province of Batangas, which together consume 94% of Philippine gas production and operate as baseload plants. The generation cost of the gas CCGT fleet is slightly higher than that of the subcritical coal fleet. The country is currently self-sufficient in gas supply, but is expected to import LNG as domestic production has been stagnant. Imported coal already accounts for the majority of coal supply. Fossil fuels are not subsidised in the Philippines, so coal and natural gas prices are in line with international market rates. This means the coal price is likely to remain lower than gas prices to power plants in the country. Since the electricity price is not subsidised either, it fully reflects the electricity generation costs. As such, coal-based generation appears to be more competitive than gas-based generation, and is key to making electricity affordable in the country.

After the Fukushima incident in Japan, both coal- and gas-fired power plants have been running at very high utilisation rates to fill the gap left by closure of nuclear power plants in Japan. Coal-fired generation is still more competitive (not taking the CO_2 tax into account) than gas CCGT generation even at such high utilisation rates. Japan already has more installed gas-fired generation capacity than coal-fired capacity; it is building more gas-fired power plants than coal-fired power plants. Gas-fired plants are preferred by the investors in the face of uncertainty in Japan's energy policy due to their low capital costs. The recently imposed carbon tax also put coal-fired power plants out of favour.

In South Korea, coal is the most important fuel for power generation, followed by nuclear and then gas. The average generation cost of the gas CCGT fleet is almost double those of coal-fired supercritical and subcritical fleets because LNG prices are nearly four times higher than imported coal prices. As such, the 6th Basic Power Development Plan aims to build more coal-fired power plants than gas-based power plants. Moreover, as the nuclear power plan has been scaled back, coal will play an increasing role in providing baseload generation.

It can be seen that coal remains attractive in all nine countries studied. In China, India, Indonesia, Philippines, and South Korea, where coal-based generation is dominant, coal remains the most favoured fuel for generation due to its low costs and greater availability. For other Southeast Asian countries where natural gas is dominant in generation, coal is attractive primarily due to perceived domestic gas supply shortages and increases in gas prices resulting from expensive LNG imports. In Japan, gas may become more important than coal because of the uncertainty over the government's energy policy and the new carbon tax which puts coal at a disadvantage to gas.

Generation cost is not the only factor determining the competition between coal and gas in power generation. In Malaysia and Vietnam, the low cost of gas makes the average generation cost of the gas CCGT fleet lower than that of the coal fleet. However, these two countries are attempting to use more coal than gas for the new generation capacity addition. On the other hand, coal-based generation is cheaper than gas CCGT generation in Japan, but Japan is building more new gas CCGT plants than coal-fired power plants.

The shale gas boom in the USA has not only dramatically shifted the energy sector within the country, but also has strong implications for coal and LNG markets in Asia. Low gas prices have caused fuel switching from coal to gas for power generation. This makes more steam coal available for export. But the major issue is the lack of port terminals dedicated to exporting coal to Asia on the west coast. Five terminals have been proposed, but are facing regulatory hurdles and local resistance. Only one terminal is likely to proceed to construction. The large price disparity between the Henry Hub price and LNG prices in Asia generates huge interest in exporting LNG to Asia. There are 14 proposed LNG export terminal projects, most of which are based on existing regasification terminals to make use of existing facilities, but only four projects have been approved by FERC. The government is cautious about exporting LNG because of concerns over the possibility of pushing up domestic gas prices. The government has authorised LNG exports to non-FTA nations with a cumulative volume totalling 59.3 bcm/y. Additional export volume authorisation will depend on whether the cumulative export volume will have any adverse impact on the public interest (for example, significantly increase domestic gas prices). External factors, such as the speed of price convergence in global natural gas markets and the pace of gas supply growth outside the USA, also contribute to the uncertainty of LNG exports from the USA.

The analyses in this report are based on a generic generation cost comparison between the gas CCGT fleet and coal fleets in the nine Asian countries. However, a more in-depth analysis for each country is recommended to take into account the different power generation mix structure and fuel supply options as well as the geographical concentration of coal and gas power plants. A more detailed analysis will identify the specific regions in a country where the coal versus gas competition is most likely to take place. Moreover, the possibility of CO_2 pricing and its impact on the average electricity generation costs also need to be discussed. In addition, the factors affecting the fuel prices and electricity tariffs, such as subsidy reforms, should be analysed in more detail.

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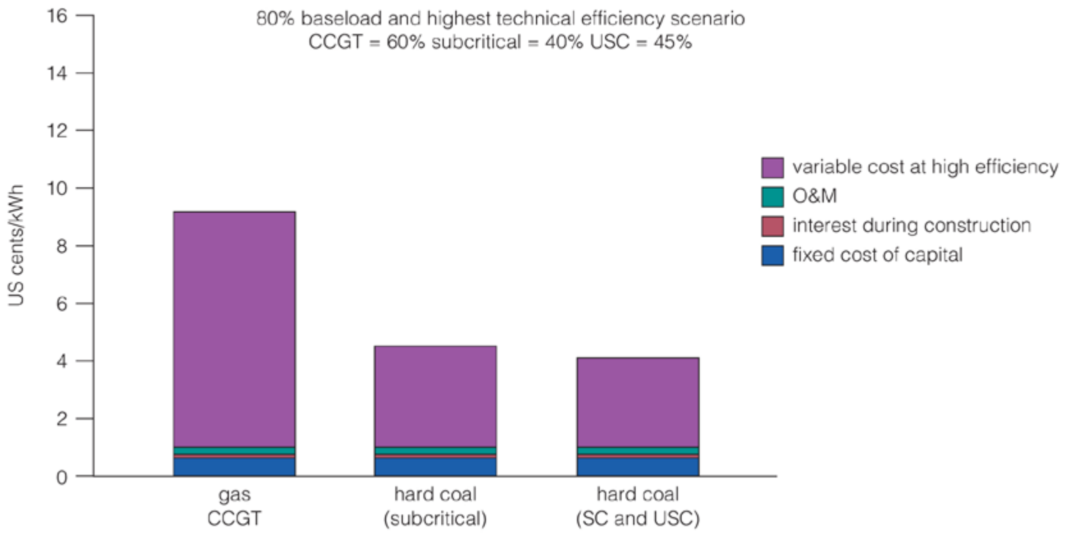
15 APPENDIX – High efficiency high load scenario

The following series of charts show the comparison between coal and gas power plants for each country under a scenario of high load factors (80%) and best available technology for CCGT and coal plants.

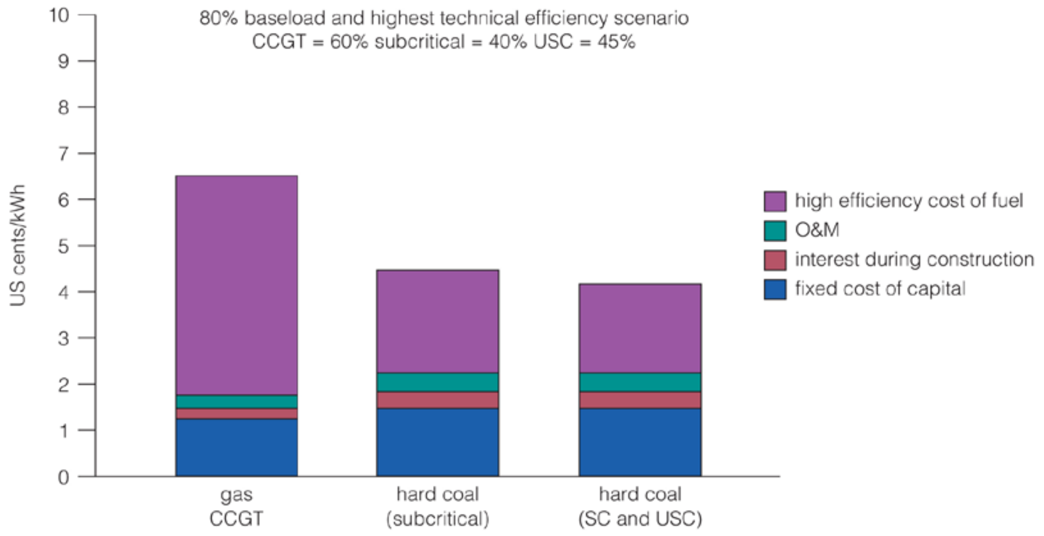
For simplicity, all other costs and factors remain the same; these other costs include: overnight plant cost (CAPEX), interest rates, delivered fuel prices, build periods, economic life and O&M. Also, efficiencies are not adjusted for fuel or climatic variations that can often impair power station optimal performance.

The purpose of the exercise is to see the effect of maximising ideal operating conditions for a thermal power plant while keeping all other factor the same; this is done purely for comparative purposes.

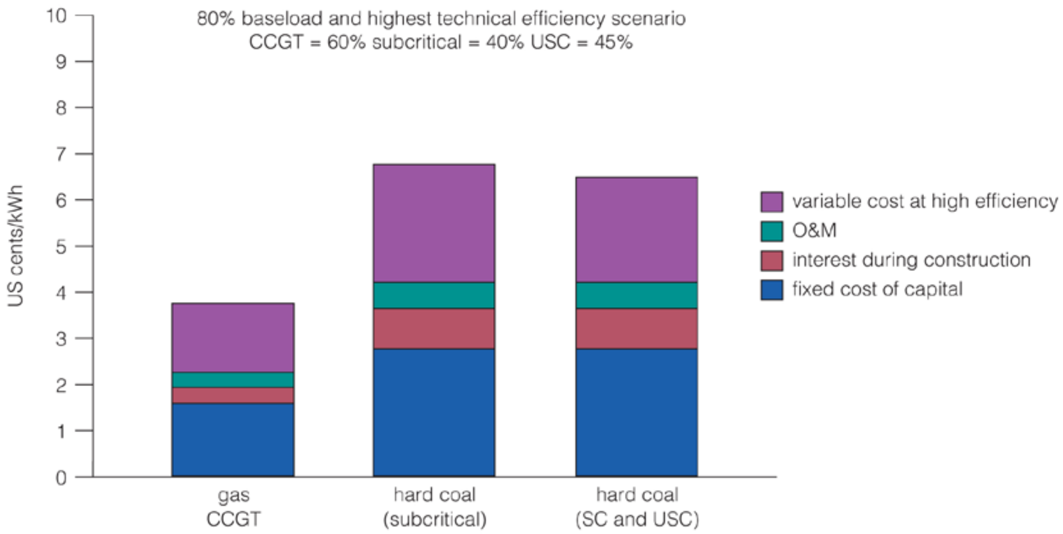
China high load/high efficiency scenario



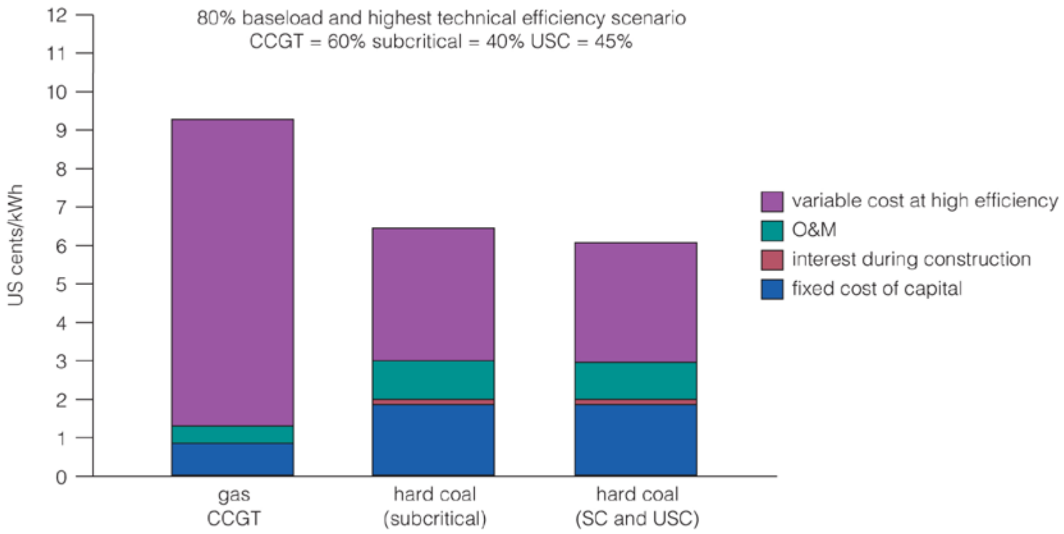
India high load/high efficiency scenario



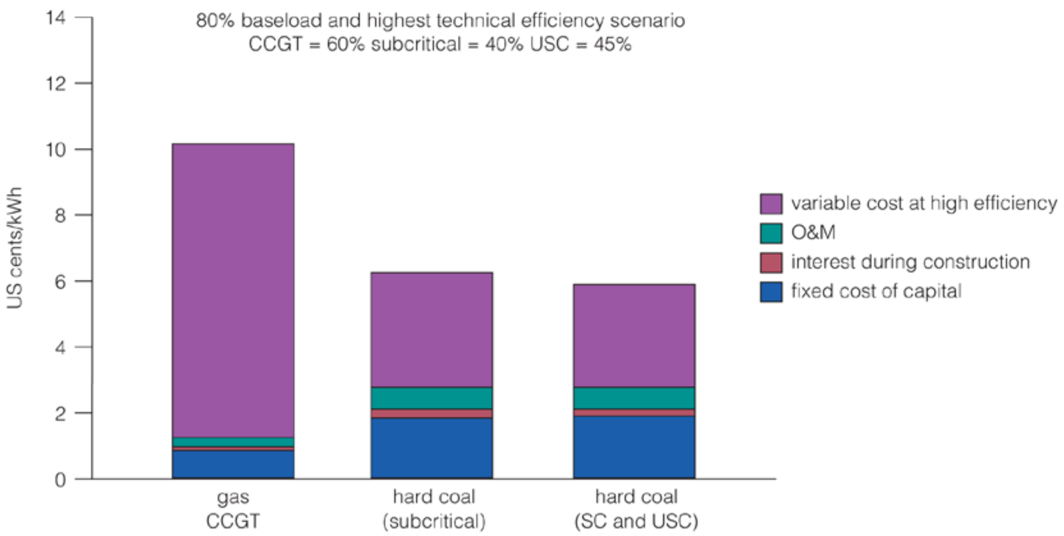
Indonesia high load/high efficiency scenario



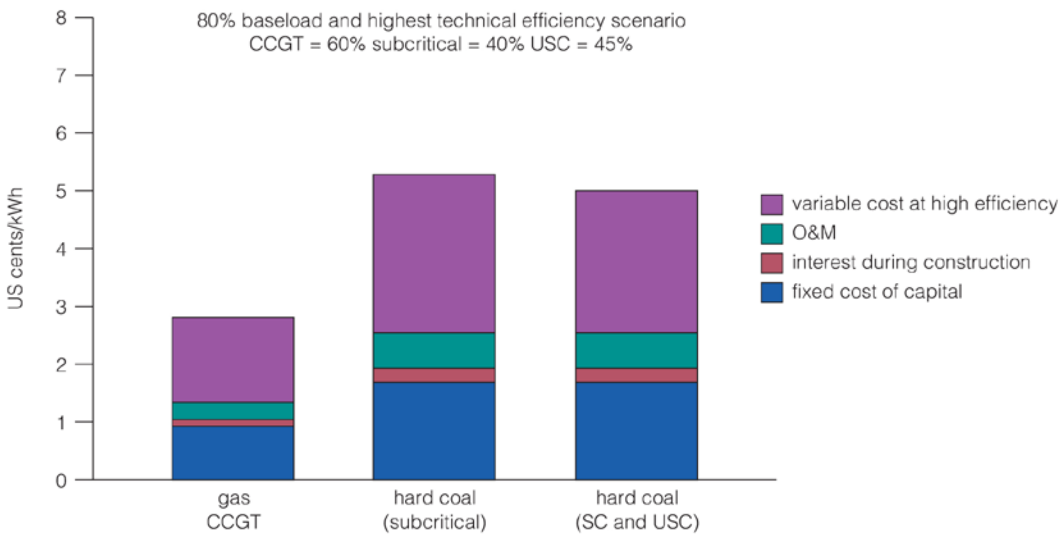
Japan high load/high efficiency scenario



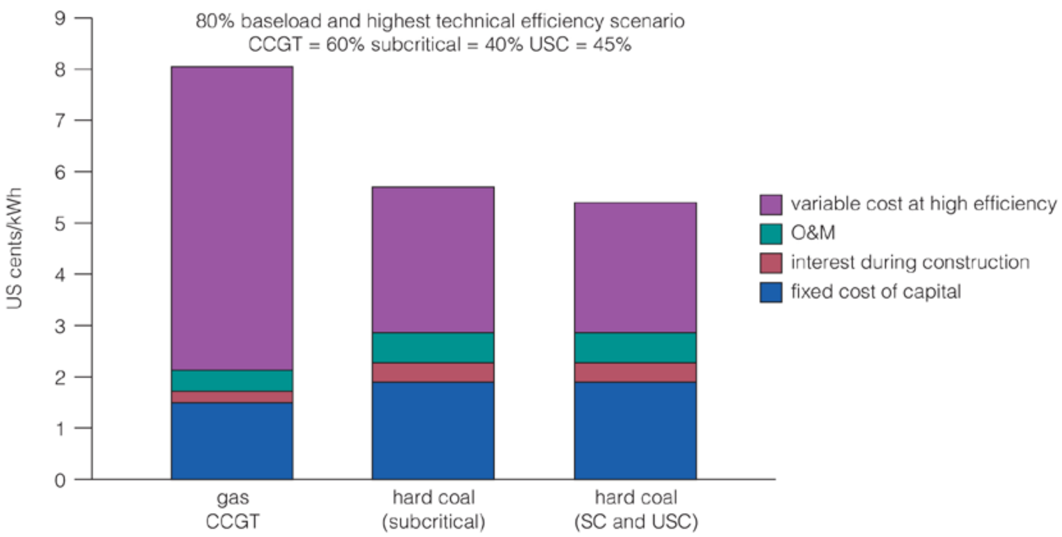
Korea high load/high efficiency scenario



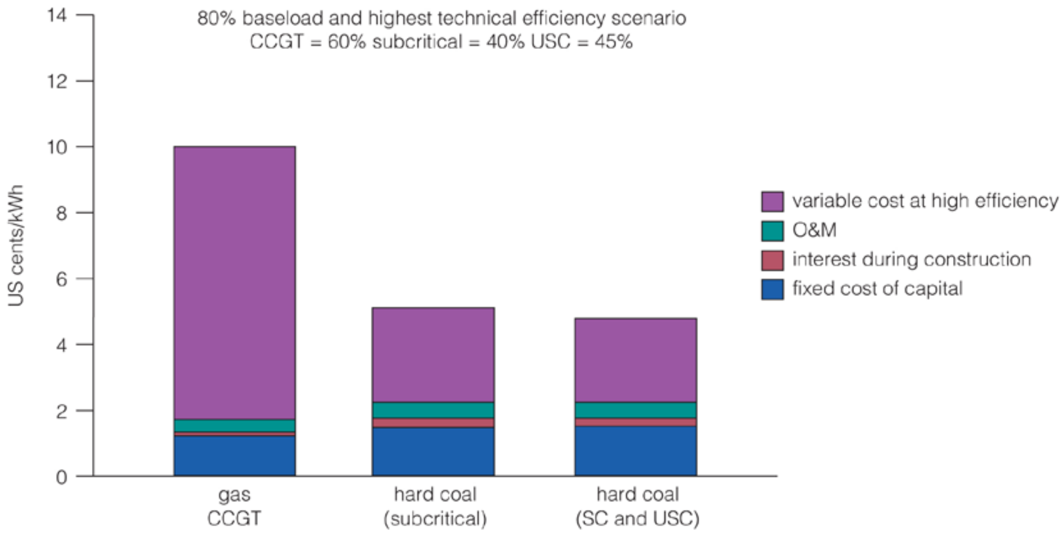
Malaysia high load/high efficiency scenario



Philippines high load/high efficiency scenario



Thailand high load/high efficiency scenario



Vietnam high load/high efficiency scenario