Study on the Strategic Usage of Coal in the EAS Region: A Technical Potential Map and Update of the First-Year Study

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List of Abbreviations and Acronyms

A-USC	advanced ultra super critical
BAU	business as usual
Btu	British thermal unit
CCS	carbon dioxide capture and storage
CCT	clean coal technology
CO_2	carbon dioxide
EAS	East Asia Summit
EPC	Engineering, procurement, and construction
ERIA	Economic Research Institute for ASEAN and East Asia
GW	gigawatt
GWh	gigawatt-hour
IEA	International Energy Agency
IGCC	integrated coal gasification combined cycle
IGFC	integrated gasification fuel cell
IRR	internal rate of return
Kcal	kilocalorie
Kg	kilogram
kWh	kilowatt-hour
LCOE	levelised cost of electricity
LNG	liquefied natural gas
MT	metric tonne
NOx	nitrogen oxide
OECD	Organisation for Economic Co-operation and Development
O&M	operation and maintenance
SC	super critical
SOx	sulphur oxide
TWh	terawatt-hour
USC	ultra super critical

Chapter 1
Introduction

1.1. Background and Objectives

Alongside economic development, electricity demand in the East Asia Summit (EAS) region is rapidly increasing. It is thought that thermal power generation, through a combination of coal and gas, will continue to play a central role to satisfy such demand,. As coal is cost competitive in terms of calorific value compared with gas, and large quantities of coal are produced in the EAS region, it is anticipated that coal-fired power generation as the main source of power will increase on a broad scale. In the region, Australia, Indonesia, China, India, and Viet Nam produce large quantities of coal; other energy sources such as gas are partially imported from outside the region. The magnification of the usage of coal in the EAS region has the merit of enhancing energy security.

However, with the increase in coal demand, notably that of China and India, the supply and demand relationship of coal has become tight in recent years. For the sustainable usage of coal, the dissemination of clean coal technology (CCT) for clean and efficient usage of coal in the region is thus of pressing importance. In addition, in order to facilitate the economic development within the region, a cost-effective and sustainable electricity supply system with CCT at its heart should be promoted. While the necessity for CCT has been recognised, the use of inefficient technology is still widespread. If this situation continues, valuable coal resources will be wasted, environmental impact will not be sufficiently reduced, and sustainability will be harmed.

The first-year project of this study has been completed and has focused on the economic return from the investments in different types of coal technologies. Its major findings were that investments in CCTs with high efficiency will bring high returns, including savings on coal utilisation. However, the upfront cost investment on CCTs remains barriers for developing countries to afford these technologies.

The second-year project will focus on updating the information from the first-year study and on laying out a technological potential map as part of the process to facilitate the deployment and dissemination of CCT. This study will essentially suggest a feasible efficiency level, an environmental performance, and a maintenance criterion for each technology so that countries in the region will be able to select and introduce the best technologies based on their individual situation. At the same time, this study will propose appropriate measures so that these technologies can be realised. Upon the completion of this proposed research, a practical technological potential map including the above-mentioned items will be developed so that policymakers from each country are able to introduce the technologies swiftly.

1.2. Methodologies of the Project

This research is a continuation of the first-year study. During the second-year study, the road map for the strategic usage of coal in the EAS region will be updated and five guidelines on the technological potential map will be formulated.

(1) Reconfirmation of the importance of coal in the EAS region

Based on the results of the analysis on the trend of energy demand, the political positioning of coal in the EAS region, and features of coal resources and their importance, the contribution of the enhanced use of coal towards improving energy security in the EAS region, and the importance of disseminating CCT for the continuous utilisation of coal were outlined in a previous study. In this current study, these analyses will be reconsidered by updating numbers and data based on latest trends. In addition, the impact of shale gas development, which has had a decreasing effect on natural gas prices, will be considered in comparison with coal prices.

(2) Economic benefits of the introduction of CCT in the EAS region

Four anticipated benefits of the introduction of CCT—the minimisation of capital outflow from the EAS region, environmental impact reduction benefits of CCT, development and investment benefits of CCT, and job creation benefits of CCT—were taken up in the previous study. Cost analysis and cost–benefit analysis for CCT introduction will be studied this year. Sensitivity analysis for ultra-super critical (USC), super critical (SC), and subcritical coal-fired power plants will be conducted by assuming capital cost and coal price.

(3) The development of a technological potential map for CCT dissemination in the EAS region

The outline and concept of a technical potential map for the introduction of CCT were discussed in the previous study. This year, the necessary guidelines included in the technological potential map will be studied and formulated.

At the Working Group meeting in Jakarta, the present conditions and policies regarding the promotion of CCT were heard and the nature of the technological potential map was considered.

Chapter 2

Review of the First Study

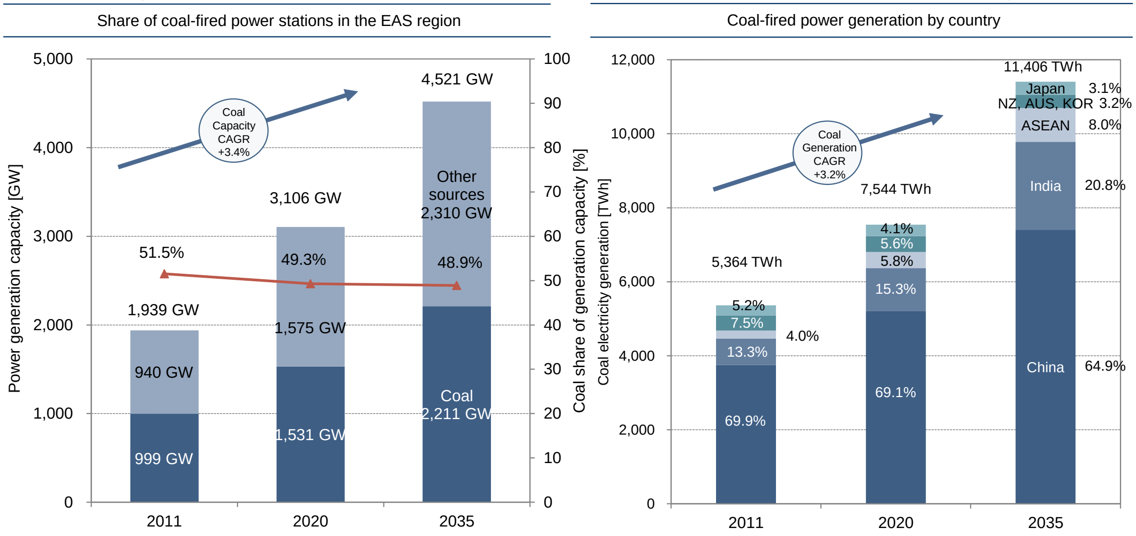
This chapter is a review of the first-year study. However, data is updated based on latest trends.

2-1. The Importance of Coal in the East Asia Summit Region

2-1-1. The trends of energy demand and the political positioning of coal

In the EAS region where economic development and growth have been remarkable, demand for electricity is forecasted to increase substantially, half of which will be met by coal-fired power generation as shown in Figure 2-1. In particular, coal-fired power generation has vastly increased in China and India, and future increases are also forecasted in the Association of Southeast Nations (ASEAN) region. As coal is priced lower compared to petroleum and natural gas, demand for coal is therefore expected to continue increasing from an economic point of view.

Figure 2-1. Estimate of Coal-Fired Power Plant in the East Asia Summit Region



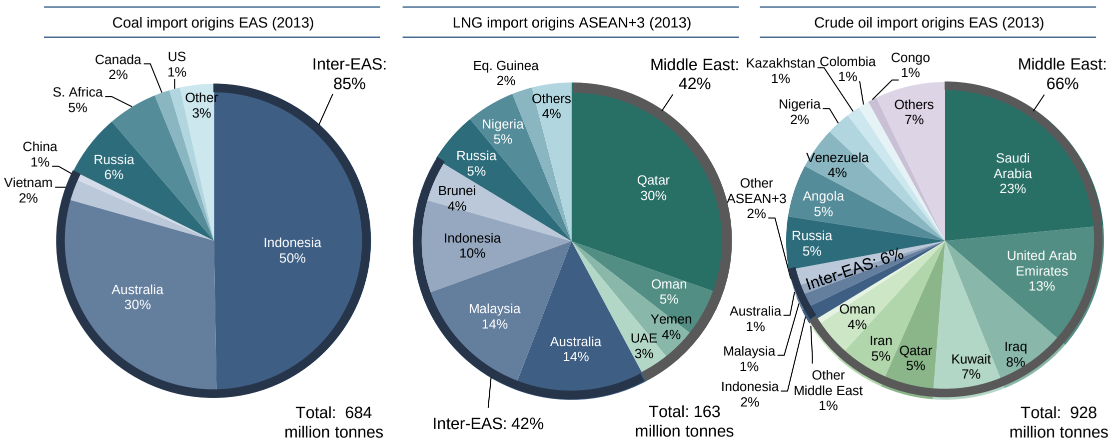
Share of coal-fired power stations in the EAS region

Coal-fired power generation by country

Note: ASEAN values refer to new policies scenario. All other values are taken from the reference scenario.
Sources: International Energy Agency (IEA) (2013), *World Energy Outlook Special Report: Southeast Asia Energy Outlook*.

As such, coal has become an important energy source in the EAS region. Petroleum and natural gas are also produced in the region and will remain important energy sources in the future. Figure 2-2 shows the origin of primary energy import in the EAS region where 42 percent of liquefied natural gas (LNG) consumed is produced within the region whereas 42 percent is imported from the Middle East. A mere 6 percent of the petroleum consumed is regionally produced with 66 percent being imported from the Middle East. In contrast, coal produced in the EAS region constitutes 85 percent of the total coal consumption in the region. All these data indicate that coal, mainly produced and consumed within the region, is not dependent on the Middle East as petroleum and natural gas are. In view of political uncertainties in the Middle East, which may raise concern over transportation security at strategic pathways such as the Strait of Hormuz, coal will be of further significance in the energy security context as well.

Figure 2-2. Origin of Primary Energy Imports in the East Asia Summit Region



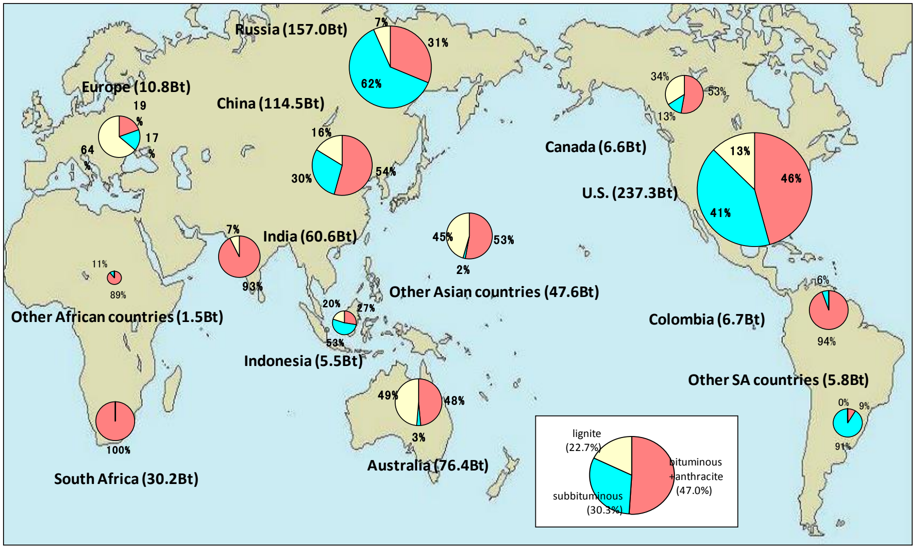
Sources: International Energy Agency (IEA), Coal Information; International Group of Liquefied Natural Gas (GIIGNL) Importers; and International Trade Centre (ITC) Trade Map.

2-1-2. Features of coal resources and their importance

(1) Coal resources

In global coal reserves, high-rank coals such as bituminous coal and anthracite that are used as cooking coal and steam coal make up around 47 percent of the reserves whereas low-rank coals constitute about half of the overall coal reserves with 30 percent sub-bituminous coal and 23 percent lignite. Figure 2-3 shows the world’s mineable coal reserves by region and by coal rank. Unlike other energy sources, coal is distributed widely but unevenly throughout the world. Coal reserves are large in Oceania and in Asia, and the proportion of their lignite reserves is high. Even in the world’s largest steam coal exporter Indonesia, which exports mainly to Asian countries, the amount of its bituminous coal reserves is only 27 percent of total reserves and thus its exports of sub-bituminous coal are increasing.

Figure 2-3. Recoverable Coal Reserves in the World (by region and coal rank)



Source: WEC “Survey of Energy Resources 2010,” BP Statistics 2010

Source: WEC, ‘Survey of Energy Resources’, BP Statistics 2010.

(2) Coal consumption in Asia

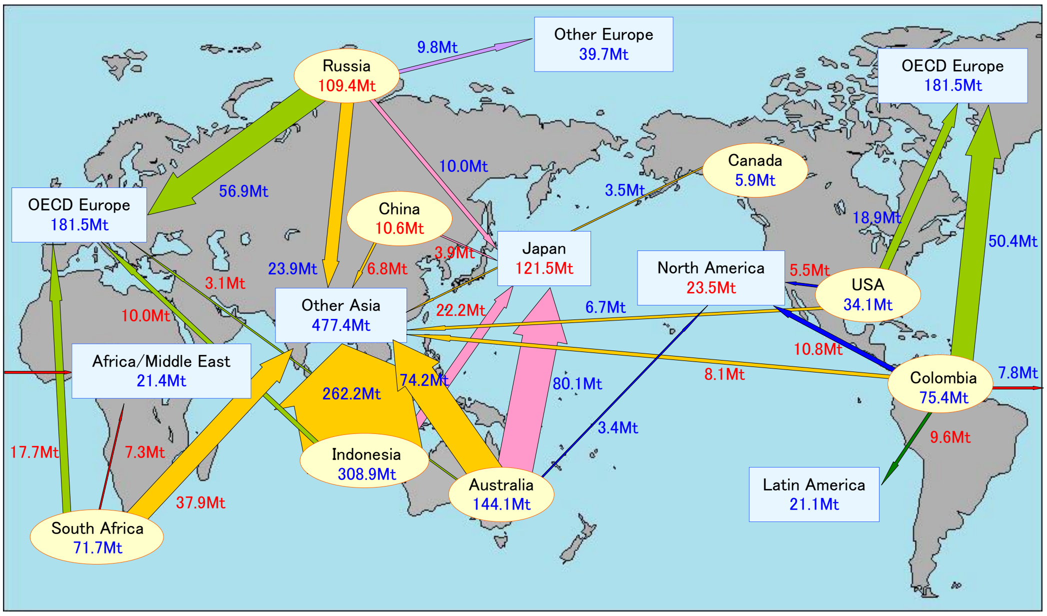
Figure 2-4 shows the flow of steam coal in 2012. Steam coal is mainly exported to Asia by Indonesia and Australia; it is also exported by South Africa and Russia as well as China, Colombia, the United States (US), and Canada, although in smaller volume.

Indonesia is the biggest steam coal exporter to China; its exports accounted for 48 percent of total Chinese imports in 2011. Republic of Korea (henceforth, Korea), Taiwan, and India also import coal from Indonesia. Of the nearly 300 million tonnes (MT) of steam coal exports from Indonesia, 96 percent are for Asia. It is estimated that other countries without adequate data also import big quantities from Indonesia.

Australia is the second largest steam coal exporter to Asia after Indonesia, with 97 percent of its steam coal exported to Asia, which totalled 144 MT in 2011. Indonesian and Australian coal exports account for three quarters of the steam coal imported by Asia. Australia exports the biggest quantity of steam coal to Japan. Its exports to China, Korea, and Taiwan exceed 15 MT but its exports to India are smaller. India imports more coal from South Africa, which is nearer than Australia.

Other Asian countries import mostly from Indonesia. According to forecasts of future coal demand, demand for energy and, in particular, electricity is expected to increase substantially as a result of the economic growth in Asia; thus, many new coal-fired power plants are being planned. Coal consumption for power generation is forecasted to increase in Asia. In Viet Nam, where anthracite used to be widespread, a plan for a new plant to be fired on blended coal, or anthracite with imported Indonesian coal, is in progress.

Figure 2-4. Flow of Steam Coal (2011 estimate)



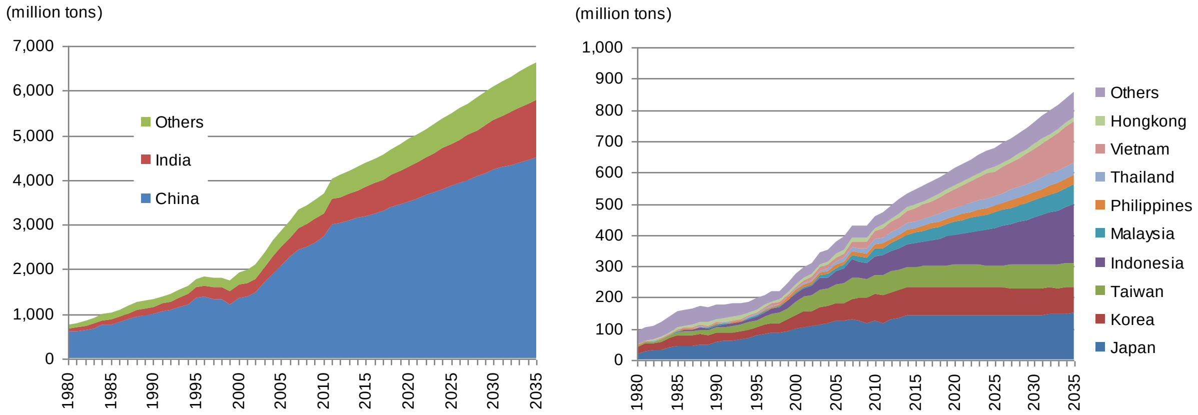
Note: The above figure does not show flows of less than 3 MT. The blue-coloured numbers show an increase relative to the previous year and the red-coloured numbers show a decrease relative to the previous year. North America as an importer includes Mexico.
Source: International Energy Agency (IEA,) Coal Information 2012.

(3) Consideration on future coal demand and supply

Demand for steam coal in Asia will increase at an annual growth rate of 2.4 percent from 2010 to 2035, and will increase by 1.8 times from 3,730 MT to 6,652 MT during the same period. Figure 2-5 shows a steam coal demand forecast in Asia. Steam coal demand in China will not show such a rapid growth as it did during the 2000s. But as the demand for electricity is expected to increase with economic growth in the future, the demand for power generation should likewise increase. The demand in India for steam coal will increase at an annual growth rate of 3.7 percent to 2035 due to a rapid increase in demand for power generation. India is expected to consume up to 1,297 MT in 2035, which is a 2.5-fold increase relative to 2010. ASEAN countries are expected to use cheap coal power in order to meet the increasing demand for power generation; hence, coal demand will increase.

Specifically, Indonesia is building a coal power generation station using low-rank coal produced domestically. Its steam coal demand will be close to 100 MT in 2020 and further increase to 190 MT in 2035. Steam coal demand in Viet Nam will increase to 132 MT in 2035 with the addition of coal power. The consumption of steam coal in other countries will increase by two to three times in 2035. On the contrary, Japan, Korea, and Taiwan, which have widely used steam coal for power generation, will still experience increases in their demand but their growth is expected to slow down.

Figure 2-5. Steam Coal Demand Forecast in Asia



Source: Actual data is from International Energy Agency (IEA) and forecast is by Japan International Cooperation Agency (JICA).

Most of these increases in coal demand in the region are expected to be addressed by Indonesia. Having abundant low-rank coal with low ash and low sulphur content that offer advantages in both price and environmental compliance, Indonesia expects its low-rank coal export to further increase in the future. Such trend has shed light on low-rank coals that used to be regarded as non-marketable; China and India have been importing low-rank coals with fuel efficiency mass lower than 4,000 kilocalorie/kilogram (kcal/kg), which have now entered the market.

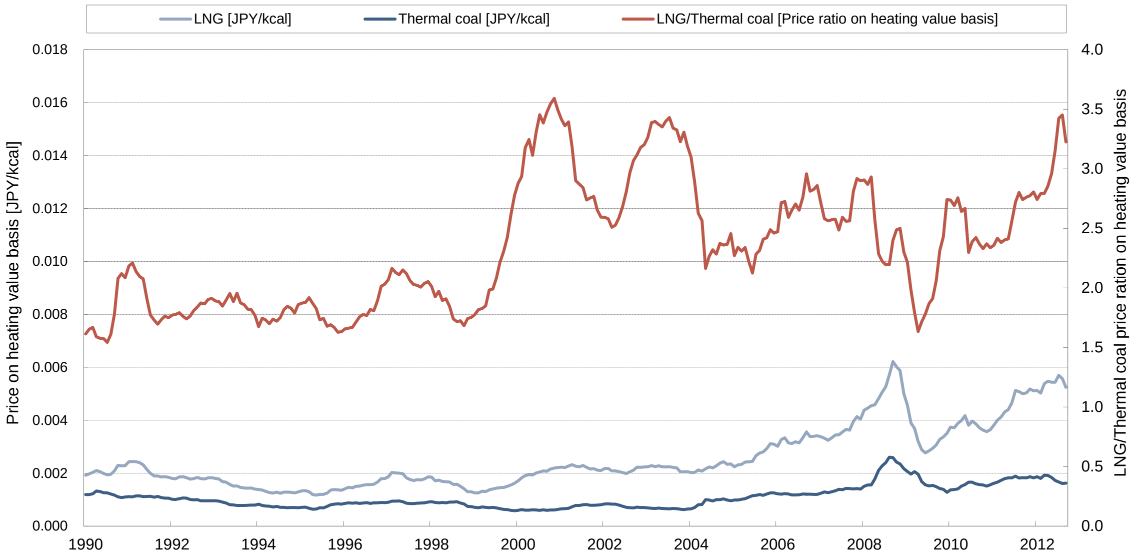
Korea has been expediting low-rank coal utilisation and expansion. Likewise, it has expedited measures such as combustion improvement through blending with high-rank coal and high efficiency clean coal technology (CCT) such as ultra super critical (USC) in consideration of high moisture and low calorific value that low-rank coals carry.

Indonesia, the major coal supplier in the region, in recent years saw a steady economic growth after having gone through the impact of the global financial crisis, which has boosted its own energy demand. Indonesia was once a member of the Organization of the Petroleum Exporting Countries (OPEC) as a major oil and gas producer; however, it has shifted its energy policy towards the effective use of domestically abundant and available energy source (i.e. coal) in view of gradually depleting oil and gas resources. To meet the increasing demand for electricity, it is planning to build many new large-scale, coal-fired power plants, which require a continuous supply of coal. More than 80 percent of Indonesia’s produced coal is exported and the rest is for domestic consumption. With a surging domestic demand by the power sector, coal export in the coming years may see a sluggish growth as the policy to prioritise domestic supply to meet domestic demand has come into force. It may come up as a common agenda that Asia needs a concerted coordination towards a balanced regional demand and supply.

2-1-3. Comparison of coal and natural gas prices

Figure 2-7 shows thermal coal and LNG import prices (in cost, insurance, and freight [CIF] prices) on heating value basis as well as the price ratio of LNG/thermal coal for Japan. The price of coal on heating value basis has always been more competitive than natural gas and provides a high economic rationale. Historically, the LNG/thermal coal price ratio has been between 1.5 and 3.5. Since 2000, the price ratio has increased and consistently been around 2.3–3.5, except in 2009.

Figure 2-7. Comparison of Coal and Natural Gas Prices



Source: Japan import statistics.

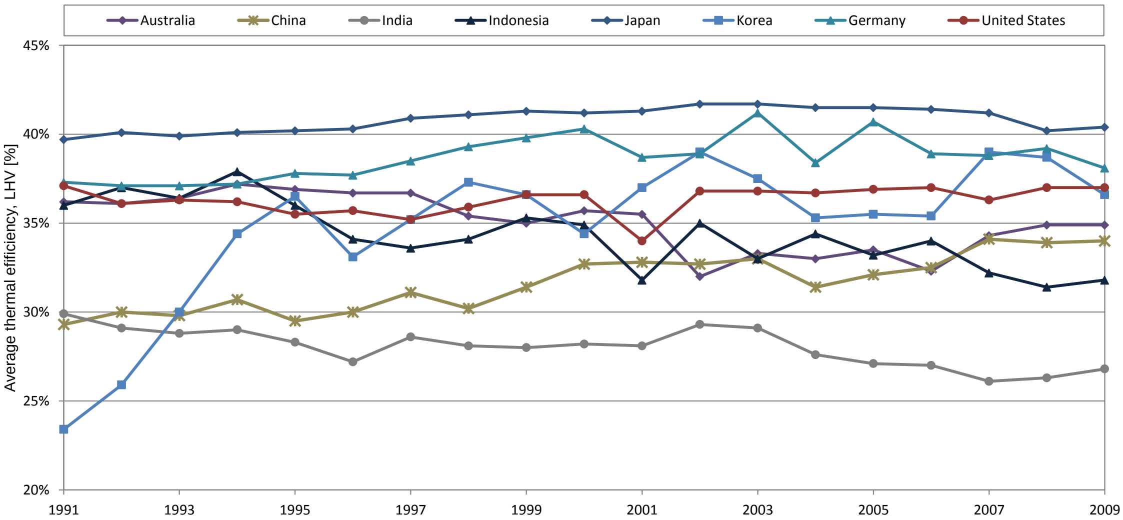
2-1-4. The importance of CCT for improving energy security

The main features of coal for the EAS region can be summarised as follows:

1. Coal is the primary energy source in the EAS region.
2. Coal is the most secure energy resource in the EAS region.
3. Coal supply potential can be further expanded by developing lower grade coal.
4. Coal is more cost-competitive than natural gas.

However, coal is not used efficiently. It is relatively abundant in the region and an important source of energy, and thus should be used as efficiently as possible. Figure 2-8 shows the thermal efficiency in Australia, China, India, Indonesia, Japan, and Korea as well as Germany and the US. In some Asian countries, thermal efficiency is still lower than 35 percent, leaving more room for improvement. In order to maximise the potential of coal, CCT should be introduced in the EAS region.

Figure 2-8. Thermal Efficiency of Coal-Fired Power Stations
in Asia, Germany, **and the United States**



Source: International Energy Agency (IEA), 2011, Energy Balances of Organisation for Economic Co-operation and Development (OECD) Countries, Energy Balances of Non-OECD Countries.

2-2. Economic Benefits of CCT Introduction in the East Asia Summit Region

2-2-1. Application benefits of the introduction of CCT in East Asia

(1) Minimisation of capital outflow

According to forecasts in the ERIA research project titled ‘Analysis on Energy Saving Potential in East Asia’ (hereinafter referred to as ERIA energy savings research project’), coal is expected to remain as the main source of electricity generation; yet electricity generation by natural gas is also expected to increase. If we assume that natural gas–fired power stations can be replaced by coal-fired power stations, then capital outflow can be avoided because coal is a self-sufficient natural resource in the EAS region.

Figure 2-9 displays the avoided capital outflow when new natural gas–fired power stations are replaced with coal-fired power stations. According to the ERIA energy savings research project, natural gas–fired power generation will increase by 2,300 terawatt-hours (TWh) from 981 TWh/year in 2010 to 3,281 TWh/year in 2035. Based on assumptions from the ERIA energy savings research project, the thermal efficiency of natural gas–fired power stations is expected to increase from 44.1 percent in 2010 to 46.6 percent in 2035. In British thermal unit (Btu), this means that natural gas consumption per year in 2035 will be 16.4 quadrillion Btu higher than in 2010.[1] As analysed in the previous section, 26.1 percent of

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[1] The output in terawatt-hours (TWh) divided by thermal efficiency is equal to input in TWh. The conversion of TWh to British thermal unit (Btu) is based on the IEA conversion rate of 1 TWh = 3412141.1565 million Btu (MMBtu).

natural gas consumed in the EAS region cannot be supplied within the region (estimated value in 2013) and therefore needs to be imported from outside the region, resulting in capital outflow. At the assumed price of US$15.85/MMBtu (the LNG import price to Japan, January 2013), capital outflow in 2010 would have been US$31.4 billion. Under the given assumptions, capital outflow would be US$99.2 billion in 2035. Therefore, the increase in imports from outside the EAS region is expected to increase capital outflow up to around US$67.9 billion until 2035.

Capital outflow can be reduced by replacing natural gas–fired power stations with coal-fired power stations. If we assume that all new natural gas–fired power stations can be replaced by coal-fired power stations, the additional amount of coal required to generate 2,300 TWh is around 758 MT per year[2]. From the utilities' point of view, at the assumed price of US$117.57/tonne (Thermal coal import price to Japan, January 2013), the expected total cost for 758 MT of thermal coal would be US$89.1 billion. The total cost for 16.4 quadrillion Btu required to generate 2,300 TWh would be US$260.4 billion (at US$15.85/MMBtu). In short, disregarding the origin of natural resources, the total savings for utilities would be US$171.3 billion.

If we assume that all additional coal can be produced in the EAS region, savings due to minimisation of capital outflow would be US$67.9 billion.

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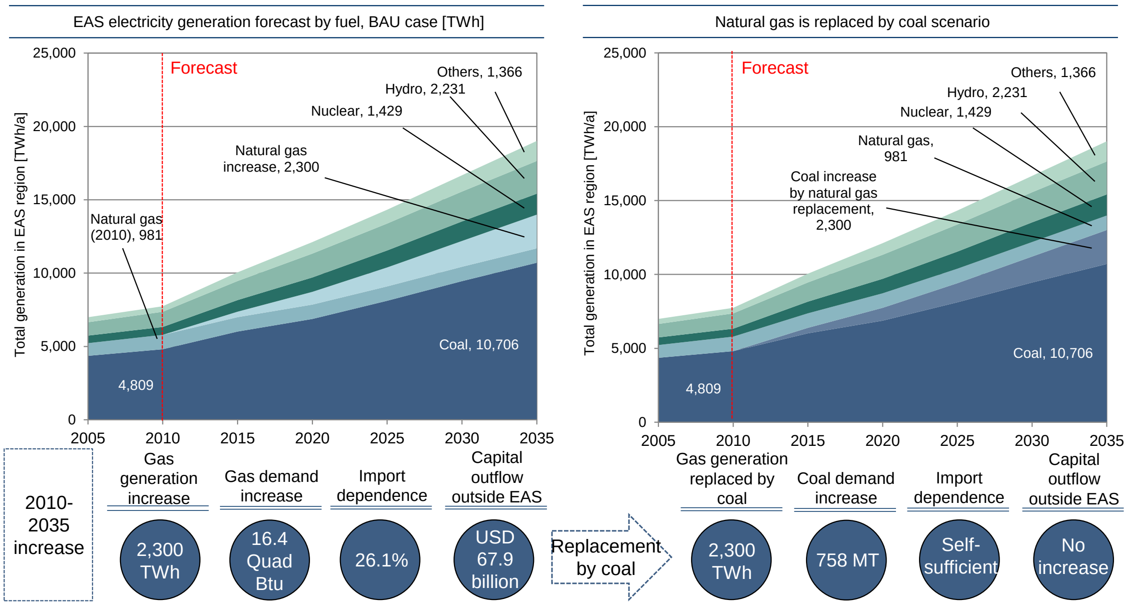
[2] The amount of coal necessary was calculated by dividing 2,300 TWh by the thermal efficiency, which was assumed at 43.5 percent (USC-type boiler thermal efficiency ranges from 41.5 percent–45 percent). With 1 TWh = 859845227.86 megacalorie (Mcal), and using the heating value of American Petroleum Institute (API) 6 Newcastle thermal coal at 6,000 kcal/kg, around 758 MT are necessary to generate 2,300 TWh.

Figure 2-9. Minimisation of Capital Outflow



Note: The definition of capital outflow is: 1 – Production (EAS region)/Consumption (EAS region). The price of natural gas assumed in this graph is US$15.85/MMBtu (LNG import price in Japan, January 2013)
Sources: Compiled from the Economic Research Institute for ASEAN and East Asia (ERIA) Energy Savings Research Project; International Energy Agency (IEA) Coal Information; IEA Natural Gas Information; Japan import statistics.

(2) Environment impact reduction

Compared to other primary energy sources such as petroleum and natural gas, coal contains more sulphur, nitrogen, and ash. These components are emitted as sulphur oxide (SOx), nitrogen oxide (NOx), or particulate matter due to coal combustion, thereby exerting a negative impact on the environment. As the carbon content in coal is higher than that in petroleum or natural gas, emissions of carbon dioxide (CO_2)—one of the gases that cause global warming—are also higher than other primary energy sources. As a result, reducing and removing such components that have an impact on the environment need to be considered in coal utilisation.

Sulphur Oxide, Nitrogen Oxide, Particulate Matter

In the past when there were small-scale coal-fired power plants and other combustion facilities only, emissions from coal combustion did not affect the environment much. But the situation is now quite different due to the high and extensive growth of the economy, and energy demand and consumption. These resulted in significant negative impact on the natural environment and on public health caused by acid rain and particulate matters emitted along with large amounts of SOx and NOx.

Asian countries saw rapid economic development in recent years, which has brought about industrial and environmental pollution including air and water, all of which have become huge social issues. In addressing these issues, streamlining relevant regulations and dissemination of key technologies are the major common agenda in the region.

In Japan, denitrification equipment has become standard, aside from desulphurisation equipment, to reduce NOx emissions. The desulphurisation equipment used to be uncommon in coal-fired power plants in the Asia region because coal with low sulphur content was then used and the number of coal-fired power plants used to be relatively small. Recently built coal-fired power plants have desulphurisation equipment while denitrification equipment is yet to be a standard. NOx has two types: fuel NOx is generated by the nitrogen in the coal whereas thermal NOx is formed by the nitrogen in the air during combustion. Thermal NOx can be reduced by using a low NOx burner, hence, it has become widespread. However, to further reduce NOx in the future, the installation of denitrification equipment is indispensable.

In summary, to mitigate the environmental impact caused by an increase in coal consumption in the future, the installation of high-efficiency desulphurisation, denitrification, and dust-collecting equipment in coal-fired power plants should be required.

Carbon Dioxide

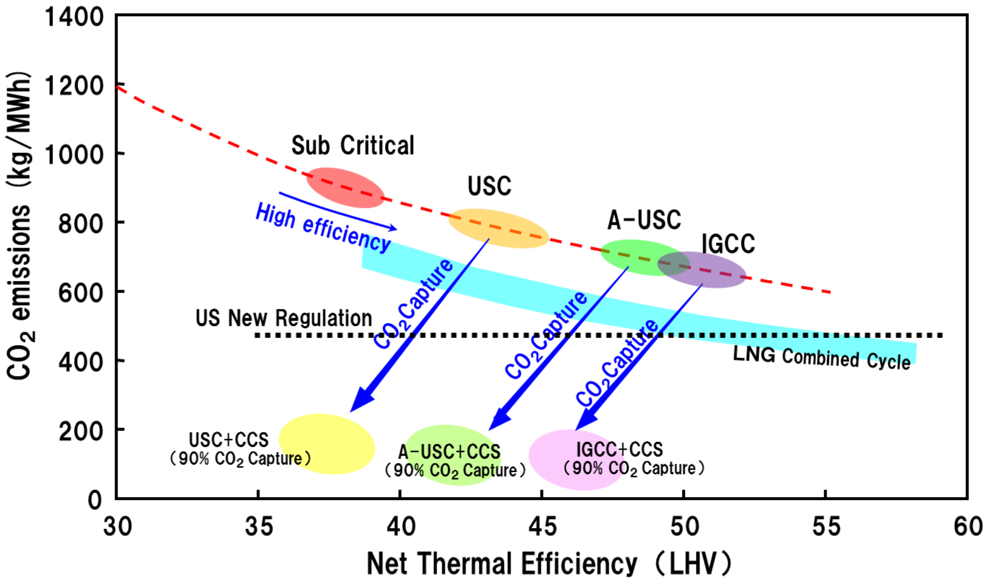
With higher carbon content than petroleum and natural gas, coal upon combustion generates the biggest amount of CO_2 per unit among all primary energy sources. The ratio of CO_2 emitted by coal, petroleum, and natural gas is 5:4:3; the amount of CO_2 emissions per kilowatt-hour (kWh) in a coal-fired power plant is twice than in a natural gas–fired power plant. It is necessary, therefore, to reduce the amount of coal used and improve the efficiency of coal-fired power plants to reduce CO_2 emissions. However, by using high efficiency CCT such as USC, integrated gasification combined cycle (IGCC) and integrated gasification fuel cell (IGFC), it is possible to reduce CO_2 emissions to the level similar to that of a petroleum-fired power plants or even less.

Figure 2-10 shows the connection between power generation efficiency and CO_2

emissions, where CO_2 emissions are evidently reduced as efficiency increases. Should a new CO_2 regulation for power plants proposed in the US on June 2014 be introduced, it is necessary to add carbon dioxide capture and storage (CCS) to CCT.

Looking into the future, CCS is supposed to have the most potential in bringing down CO_2 emissions, which may be close to zero. However, as coal storage sites are limited to sea bed and underground aquifers, coal seams, and oil fields, there are issues to be addressed such as the economic issue regarding the cost of recovery and transportation of CO_2, environmental and safety considerations required of the stored CO_2, the issue of public acceptance, among others. Accordingly, the commercialisation of CCS may be expected only around 2030.

Figure 2-10. Relationship between Power Plant Efficiency and CO_2 Emissions

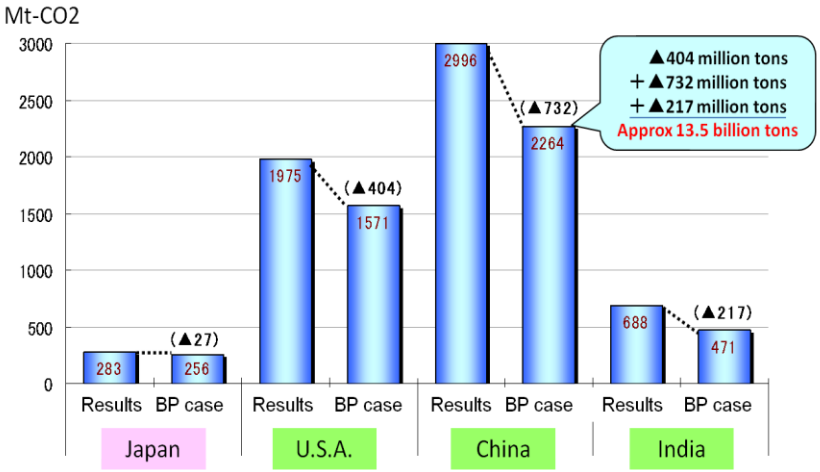


Sources: Author’s compilation.

In the meantime, high efficiency CCT like USC is already commercialised and CO_2 reduction is possible either for newly constructed plants or existing power plants. Figure 2-11 indicates the expected CO_2 reduction by deploying Japanese high-efficiency CCTs at numerous existing coal-fired power plants in Japan, US, China, and India. As power plants in Japan are already working at the highest global level, it is not necessary to expect more CO_2 reduction. However, a reduction of 13.5 billion tonnes of CO_2 can be expected if high efficiency CCTs are deployed at plants in the US, China, and India. The last two in Asia are expected to contribute a total reduction of 9.5 billion tonnes of CO_2.

As discussed, high efficiency CCT utilisation at coal-fired power plants will cause considerable effects on CO_2 reduction. It is highly recommended that CCT be applied to incoming coal-fired power plants at new sites as well as in newly replaced coal-fired power plants under a replacement plan of existing power plants in the region.

Figure 2-11. CO_2 Emission and Reduction Estimates in Coal-Fired Power Plants



Sources: International Energy Agency (IEA) (2009), *World Energy Outlook*; Ecofys (2010), *International Comparison of Fossil Power Efficiency and CO_2 Intensity.*

2-2-2. Development and investment benefits

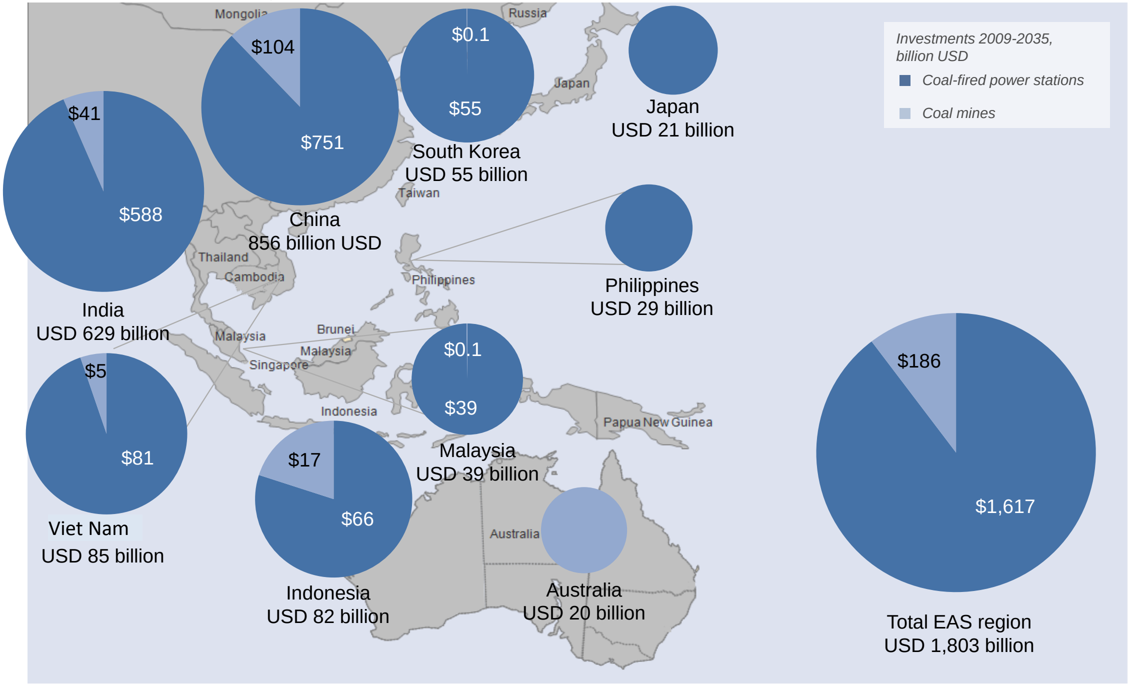
The increase in coal-fired power generation will provide ample investment opportunities within the EAS region. The investment benefits for the EAS region are assumed to be concentrated in new coal-fired power stations and new coal mines. In this section, the investment benefits for coal-fired power stations and coal mines are quantified. In reality, other investment opportunities associated with coal-fired power station development such as investment in infrastructure will also arise.

Figure 2-12 displays the investment opportunities in coal-fired power stations and coal mine development based on forecasts in the business as usual (BAU) case of the ERIA energy savings research project on energy saving potential in the EAS region. In the BAU case, electricity generated from coal per year is forecasted to increase by 5,897 TWh from 2010 to 2035. By 2035, this would require an estimated 898 gigawatt (GW) of new coal-fired capacity across the EAS region, assuming operation at 75 percent. The costs associated with utilising USC-type boilers are estimated at US$1.692 billion/GW to US$1.911

billion/GW. The total investment opportunities in coal-fired power stations across the EAS region amount to about US$1.617 trillion, with investment opportunity in China accounting for around US$751 billion.

Assuming that USC-type boilers with a thermal efficiency of 43.5 percent are installed at new coal-fired power stations, around 1,943 MT of thermal coal is required annually to generate the additional 5,897 TWh of electricity in 2035. Development costs per metric tonne can range from around US$78 million to US$113 million, depending on the type of coal mine (open-cut or underground). For the entire EAS region, the average investment cost for coal mines is therefore estimated to be US$186 billion. The coal mine investment opportunity per country was estimated based on projections of coal production in 2030, with respective country share applied to the 1,943 MT of coal necessary to generate the additional 5,897 TWh. In this approach, China, India, Australia, Indonesia, and Viet Nam account for 1,088 MT, 428 MT, 204 MT, 172 MT, and 47 MT, respectively (or in monetary terms, US$104 billion, US$41 billion, US$20 billion, US$16 billion, and US$5 billion of investment opportunity, respectively.

Figure 2-12. Investment and Development Benefits



Note: The coal amount necessary to generate 5,897 TWh was calculated using the American Petroleum Institute (API) 6 index for Newcastle free on board (FOB) coal at 6,000 kcal/kg and thermal efficiency of coal power stations at 43.5%. Values may not add up due to rounding.

Sources: Economic Research Institute for ASEAN and East Asia (ERIA) Energy Savings Research Project, Japan International Cooperation Agency (JICA), and author's own calculations.

2-2-3. Job creation benefits

New coal-fired power stations and newly developed coal mines will create jobs in the EAS region. Figure 2-13 shows an estimation of long-term job creation (excluding construction jobs) related to power stations and coal mines.

In the ERIA energy savings research project BAU case, coal-fired power generation is forecasted to increase by 5,897 TWh from 4,809 TWh/year in 2010, to 10,706 TWh/year in 2035. Assuming productivity in power stations to be about 42 persons/TWh (or 23.9 GWh/person/year) based on generation and employment data from Australia, 200,966 employees are necessary to generate 4,809 TWh/year in the EAS region. In order to generate 10,706 TWh/year, 447,423 employees are necessary. Under these assumptions, employment in coal-fired power stations is estimated to increase by 246,457 persons.

The amount of coal required to generate the additional 5,897 TWh/year by 2035 is around 1,943 MT/year. Under the assumption that employment in coal mines is 39 persons/MT,[3] new coal mine development in the EAS region is estimated to create 75,767 new jobs.

In addition to individuals required to operate power stations and coal mines, workers will be required during the construction phase of these projects.

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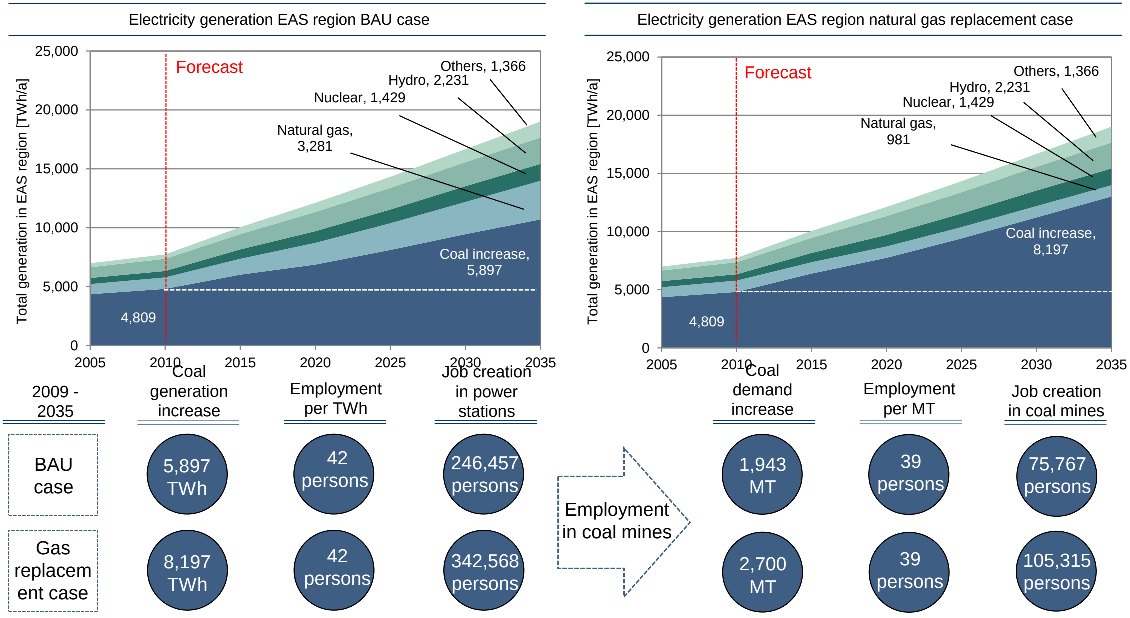
[3] From Robert D. Humphris (1999), 'The Future of Coal: Mining Costs and Productivity,' in *The Future Role of Coal*, International Energy Agency.

Figure 2-13. Job Creation Benefits



Note: Generation productivity is calculated as total generation excluding off-grid generation in Australia/number of employees in the power generation sector in Australia for FY 2006–2007. It was applied to the 2009 coal demand necessary for coal-fired power generation and to the 2035 coal-fired power generation to estimate the total number of employees in the EAS region. The coal mining productivity value was taken from Robert D. Humphris, ‘The Future of Coal: Mining Costs and Productivity’ from International Energy Agency (IEA) (1999), ‘The Future Role of Coal,” and applied to increased annual amount of coal required in 2035.

Sources: Compiled from the ERIA Energy Savings Research Project; Bureau of Statistics, Australia; Department of Resources, Energy, and Tourism, Australia; and author’s calculations.

Chapter 3

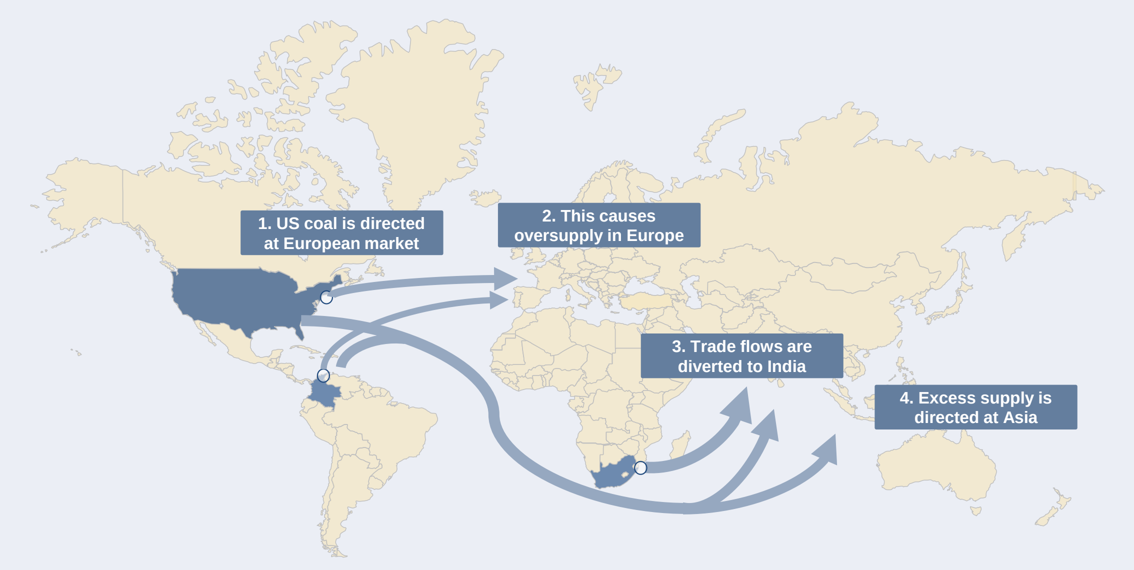
Impact of Shale Gas on the Coal Market

This chapter analyses how shale gas development in the United States (US) can affect international coal markets.

3-1. Shale Gas Impact Mechanism

The impact of shale gas development in the US is illustrated in Figure 3-1: (1) US coal is directed at the European market; (2) an oversupply is expected in the European market; (3) trade flows, particularly from South Africa, are diverted to India; and (4) excess coal supply is directed at Asia.

Figure 3-1. Impact of Shale Gas Development



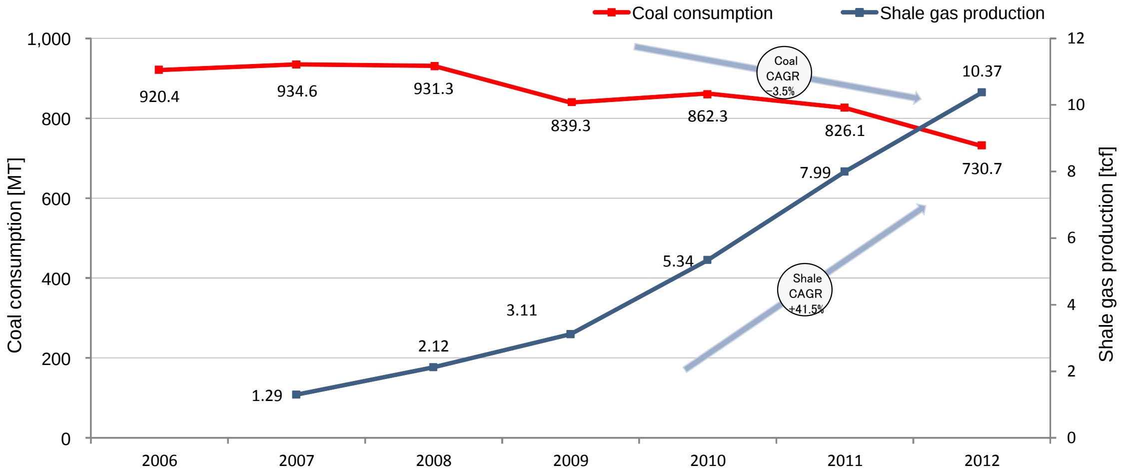
Source: Economic Research Institute for ASEAN and East Asia (ERIA) Energy Savings Research Project.

(1) US coal enters the European market

Figure 3-2 shows how shale gas development in the US concurred with a decrease in domestic thermal coal demand. Between 2007 and 2012, shale gas production increased from 1.29 trillion cubic feet (Tcf) to 10.37 Tcf. This corresponds to a compound annual growth rate (CAGR) of 41.5 percent. At the same time, coal consumption decreased from 934.6 MT to 730.7 MT, which corresponds to a CAGR of -3.5 percent.

The rise in cost-effective natural gas supply in the US particularly affects coal from the high-cost Appalachian basins. To maintain production levels, coal from these regions is increasingly aimed at export markets, particularly in Europe where it is mainly competitive.

Figure 3-2. Coal Consumption and Shale Gas Production Trends in the United States



Source: International Energy Agency (IEA) Coal Information and Energy Information Administration (EIA) statistics.

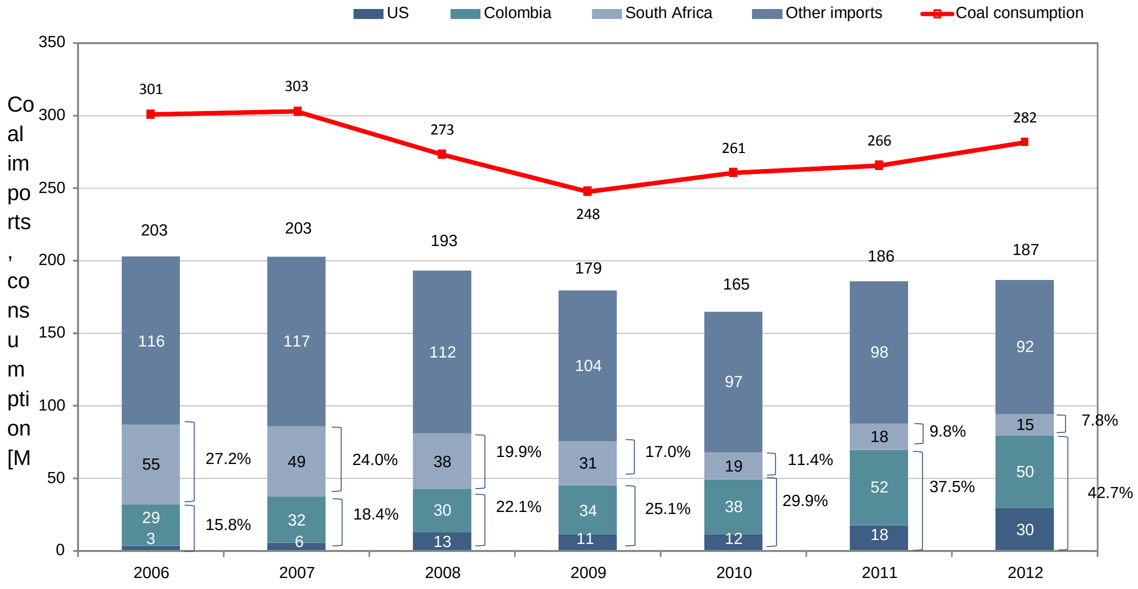
(2) Oversupply in Europe

US coal has to compete with Colombian and South African coal on a relatively saturated European market. As a result, oversupply in the European market is expected in the future.

Figure 3-3 shows thermal coal consumption and imports by origin for the Organisation for Economic Co-operation and Development (OECD) Europe between 2006 and 2012. During this period, coal consumption peaked in 2007 and reached 308 MT. After a significant decrease in coal consumption in 2009 to 248 MT, consumption started to recover in 2010. However, consumption did not attain pre-financial crisis levels by 2012 and reached only 282 MT.

Total imports generally followed consumption trends but import origins are changing. In 2006, South Africa was one of the major coal suppliers to Europe, accounting for 27.2 percent of total imports. By 2012, South Africa’s share has shrunk to 7.8 percent. On the contrary, imports from Colombia and the US have steadily risen. While Colombia’s share in 2006 was only 14.1 percent, it increased to 26.9 percent in 2012. On the other hand, US share increased from 1.7 percent in 2006 to 15.9 percent in 2012.

Figure 3-3. Coal Consumption and Imports in OECD Europe



OECD = Organisation for Economic Co-operation and Development.
Source: International Energy Agency (IEA) Coal Information.

(3) Trade flows are directed at India

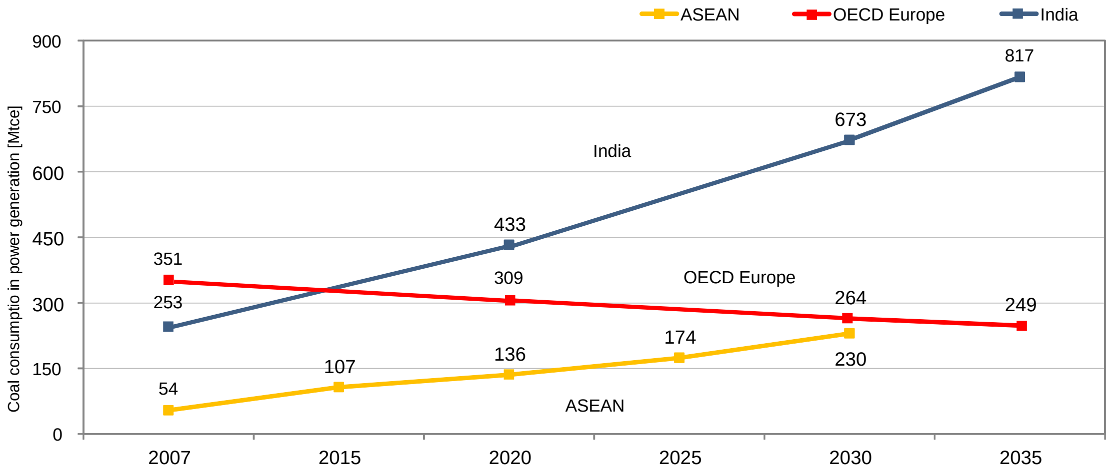
As illustrated in Figure 3-3, South African coal was traditionally directed at European markets. However, now that competition in Europe is intensifying, South African coal is increasingly redirected at India. In 2012, South Africa exported 20.9 MT to India, overtaking Europe as the largest export destination. If competition in Europe remains fierce even after South Africa withdraws part of its supply from Europe, Colombian coal and US coal may also be supplied to India.

(4) Excess supply is directed at Asia

Figure 3-4 displays coal demand forecasts for power generation in ASEAN, India, and OECD Europe. Demand in OECD Europe is forecasted to steadily decline to 249 million tonnes of coal equivalent (Mtce) in 2035. On the contrary, demand in India is expected to increase up to 817 Mtce by 2035. Similarly, demand in ASEAN is also expected to increase, reaching 230 Mtce in 2030.

In case competition in Europe remains fierce after Colombian and US coal is supplied to the Indian market, Colombian and US excess supply may be directed at other Asian markets, including ASEAN, to satisfy the growing demand. However, this will depend on the cost competitiveness of Colombian and US coal in the Asian market.

Figure 3-4. Coal Demand Forecasts for ASEAN, India, and OECD Europe



OECD = Organisation for Economic Co-operation and Development.
Source: International Energy Agency (IEA), 2009 and 2013, *World Energy Outlook*.

3-2. Implications for Asia

From the Asian point of view, suppliers to Asia such as Australia and Indonesia are expected to remain the main suppliers, with sufficient capacity to supply the Asian market. However, shale gas development is favourable for Asian markets because excess coal from South Africa can be directed at India. Depending on cost structure and transportation costs, US coal and Colombian coal can also potentially contribute to coal supply in India and other Asian markets, which further enhances supply security of existing coal sources from Australia and Indonesia.

Chapter 4

Economic Benefits of the Introduction of Clean Coal Technology in the East Asia Summit Region

4-1. Cost–benefit Analysis of USC

This chapter covers a cost–benefit analysis of ultra-supercritical (USC), supercritical (SC), and subcritical coal-fired power plants. In this analysis, levelised cost of electricity (LCOE) is calculated for three different coal prices.

This section outlines the general assumptions of the cost–benefit analysis. Section 4.2 explains the methodology of each cost component while Section 4.3 shows the results of the cost–benefit analysis.

4-1-1. General assumptions for cost–benefit analysis

This section outlines the general assumptions for power plant specifications and coal properties used in this analysis. These are summarised in Table 4-1.

Plant capacity is set at 1,000 megawatt (MW). For cash flow calculation purpose, operation is set at 25 years with an average of utilisation rate of 80 percent. Total annual generation is therefore 7,008 gigawatt-hours (GWh). Thermal efficiencies are set at 42.1 percent (USC), 41.1 percent (SC), and 38.2 percent (subcritical). Thermal efficiencies are taken from New Energy and Industrial Technology Development Organization (NEDO) study titled 'Promotion of High-Efficiency Coal-Fired Power Stations in Indonesia' in 2014

Coal specifications are set as follows: calorific value is 4,000 kcal/kg and CO_2 emissions, adjusted from the Intergovernmental Panel on Climate Change (IPCC) default emission factors, are 1.43 kg-CO_2/kg-coal.

Table 4-1. General Assumptions for Cost–Benefit Analysis

		Values	Remarks
Plant	Capacity	1,000 MW	
	Operation	25 years	For cash flow purposes
	Operation rate	80%	
	Thermal efficiencies	42.1% (USC), 41.1% (SC), 38.2% (subcritical)	LHV value from NEDO study “Promotion of high-efficiency coal-fired power stations in Indonesia”
	Annual generation	7,008 GWh	
Coal specifications	Heating value	4,000 kcal/kg	
	CO2 emissions	1.43 kg-CO2/kg coal	Based on IPCC 2006 default emission factors for stationary combustion in the energy sector.

Source: Author’s assumption and calculation.

4-1-2. Cost components and calculation methodologies

This section explains the calculation methodologies for cost components included in this analysis. A breakdown of LCOE is illustrated in Figure 4-1.

For the purpose of this analysis, LCOE consists of base plant costs, desulphurisation and denitrification costs, and financing costs. CO_2 emission costs are also calculated.

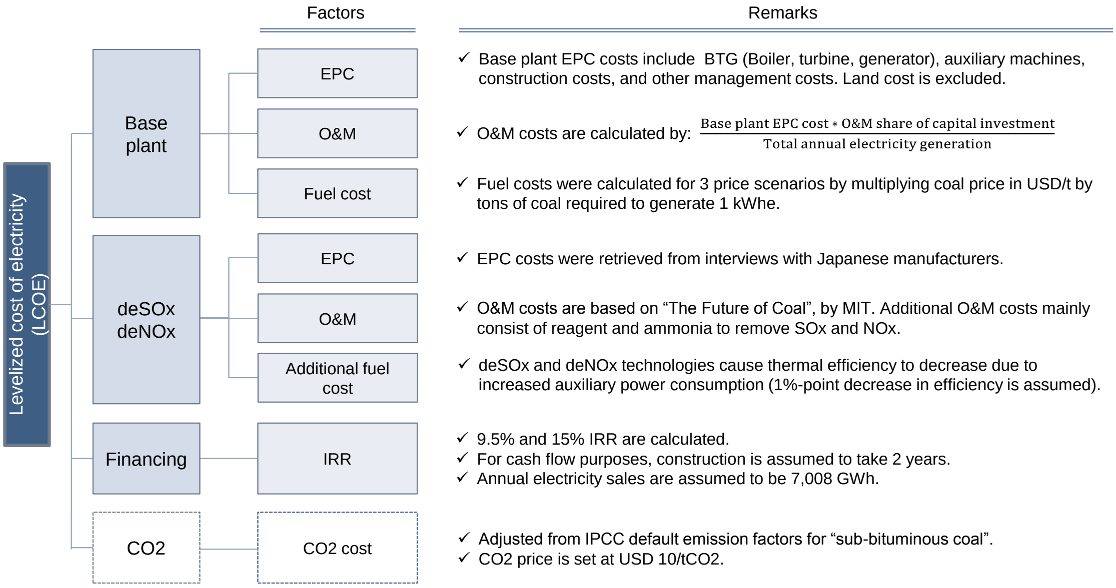
Base plant costs are divided into following costs: (1) engineering, procurement, and construction (EPC); (2) operation and maintenance (O&M); and (3) fuel costs.

Similarly, desulphurisation and denitrification also consist of: (1) EPC costs; (2) O&M costs; and (3) costs of additional fuel requirements.

Financing costs are calculated to generate 9.5 percent of internal rate of return (IRR) and 15 percent IRR. Plant construction is assumed to take two years. To calculate cash flows over operation, electricity sales are set equal to annual generation at 7,008 GWh for a period of 25 years, as mentioned in section 0.

CO_2 emission costs were calculated at US$10/tonne (t)-$CO_2$.

Figure 4-1. Breakdown of Levelised Cost of Electricity (LCOE)



- ✓ Base plant EPC costs include BTG (Boiler, turbine, generator), auxiliary machines, construction costs, and other management costs. Land cost is excluded.
- ✓ O&M costs are calculated by: $\frac{\text{Base plant EPC cost} * \text{O\&M share of capital investment}}{\text{Total annual electricity generation}}$
- ✓ Fuel costs were calculated for 3 price scenarios by multiplying coal price in USD/t by tons of coal required to generate 1 kWhe.
- ✓ EPC costs were retrieved from interviews with Japanese manufacturers.
- ✓ O&M costs are based on "The Future of Coal", by MIT. Additional O&M costs mainly consist of reagent and ammonia to remove SOx and NOx.
- ✓ deSOx and deNOx technologies cause thermal efficiency to decrease due to increased auxiliary power consumption (1%-point decrease in efficiency is assumed).
- ✓ 9.5% and 15% IRR are calculated.
- ✓ For cash flow purposes, construction is assumed to take 2 years.
- ✓ Annual electricity sales are assumed to be 7,008 GWh.
- ✓ Adjusted from IPCC default emission factors for "sub-bituminous coal".
- ✓ CO2 price is set at USD 10/tCO2.

Source: Author's assumption and calculation.

(1) Engineering, procurement, and construction (EPC) costs

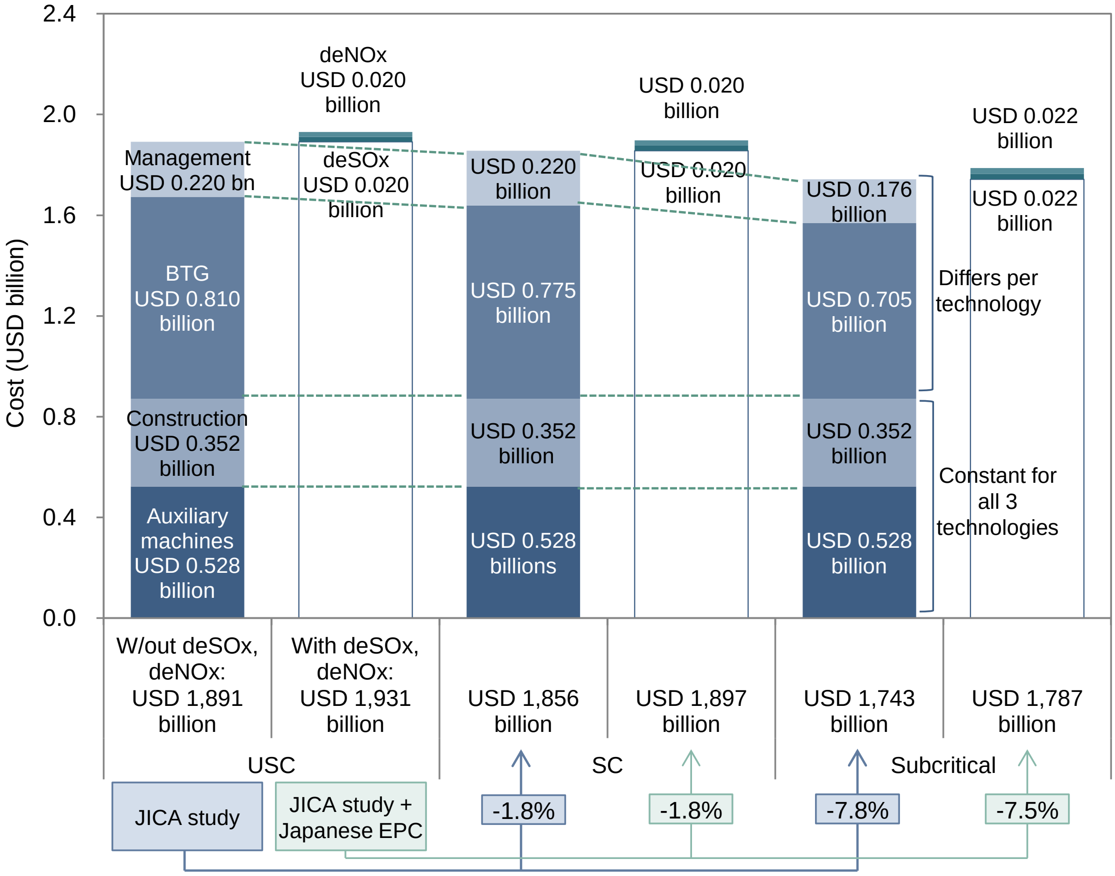
In this analysis, EPC costs consist of boiler, turbine, and generator (BTG), auxiliary machine costs, construction costs, and other management costs. Land costs are not included. Levelised EPC costs are calculated as total EPC costs divided by total electricity generation over the plant's lifetime.

A breakdown of EPC costs is illustrated in Figure 4-2. Based on assumptions in the Japan International Cooperation Agency (JICA) study titled 'Project for Promotion of Clean Coal Technology in Indonesia' (henceforth, JICA study), USC capital cost is estimated at US$1.891 trillion. This amount excludes desulphurisation and denitrification EPC costs, which are discussed below in (4). SC and subcritical capital costs are discounted from USC capital costs based on a cost index from the JICA study. Subcritical power plant capital costs are indexed at 100 while SC and USC are indexed at 106.5 and 108.5, respectively. Based on these indexes, capital costs for SC are estimated at US$1.856 trillion and capital costs for subcritical are estimated at US$1.743 trillion.

Breakdown of total EPC costs is obtained by study team analysis based on expert interviews. BTG costs and management costs differ per technology while auxiliary machine costs and construction costs are assumed to be the same for all three plants.

Excluding desulphurisation and denitrification costs, SC capital costs are 1.8 percent lower than USC capital costs. For subcritical, capital costs are 7.8 percent lower. When desulphurisation and denitrification costs are included, cost divergence amongst USC, SC, and subcritical costs decreases.[4] Note that SC capital costs are 1.8 percent lower than USC capital costs. Subcritical capital costs are 7.5 percent lower than USC capital costs.

Figure 4-2. Breakdown of EPC Costs



EPC = engineering, procurement, and construction.
Source: Japan International Cooperation Agency (JICA), 2014, 'Project for Promotion of Clean Coal Technology in Indonesia' and other resources.

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

Base plant levelised O&M costs are calculated by dividing annual non-fuel O&M costs by annual generation (7,008 GWh). The process of calculating annual O&M costs is shown in Figure 4-3.

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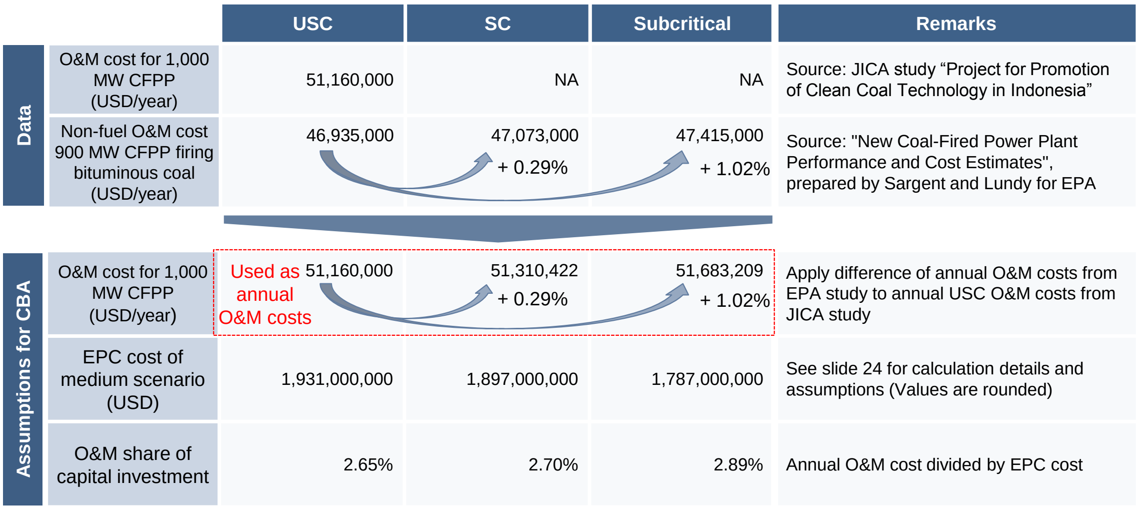
[4] Note that while SC capital costs are 1.8 percent lower in both cases, this is due to rounding. Actual results are 1.84 percent for capital costs excluding desulphurisation and denitrification, and 1.75 percent including desulphurisation and denitrification.

Annual O&M costs for USC are estimated at US$51.2 million based on the JICA study. In order to calculate O&M cost differences between USC, SC, and subcritical types, the annual O&M costs from the US Environmental Protection Agency (EPA) study titled 'New Coal-Fired Power Plant Performance and Cost Estimates' (henceforth, EPA study) were used as references. Annual non-fuel O&M costs for three hypothetical 900 MW coal-fired power plants firing bituminous coal were compared. Compared with USC O&M costs, SC O&M costs are 0.29 percent higher, and subcritical O&M costs are 1.02 percent higher.

Annual O&M costs for this analysis were calculated by applying the O&M cost differences from the EPA study to the annual O&M costs for USC from the JICA study.

There are two major reasons why USC O&M costs are lower than SC and subcritical O&M costs. First, although tubing materials for USC power plants are more expensive, which results in higher maintenance and replacement costs, replacement is only necessary after about 10 years instead of annually. Second, lower thermal efficiencies of SC and subcritical power plants require higher coal and water consumption, which causes auxiliary power use of pumps and fans, leading to higher maintenance costs. Therefore, annual USC O&M costs are lower than SC and subcritical O&M costs.

Figure 4-3. Calculation of O&M Costs



		USC	SC	Subcritical	Remarks
Data	O&M cost for 1,000 MW CFPP (USD/year)	51,160,000	NA	NA	Source: JICA study "Project for Promotion of Clean Coal Technology in Indonesia"
	Non-fuel O&M cost 900 MW CFPP firing bituminous coal (USD/year)	46,935,000	47,073,000 + 0.29%	47,415,000 + 1.02%	Source: "New Coal-Fired Power Plant Performance and Cost Estimates", prepared by Sargent and Lundy for EPA
Assumptions for CBA	O&M cost for 1,000 MW CFPP (USD/year)	Used as annual O&M costs 51,160,000	51,310,422 + 0.29%	51,683,209 + 1.02%	Apply difference of annual O&M costs from EPA study to annual USC O&M costs from JICA study
	EPC cost of medium scenario (USD)	1,931,000,000	1,897,000,000	1,787,000,000	See slide 24 for calculation details and assumptions (Values are rounded)
	O&M share of capital investment	2.65%	2.70%	2.89%	Annual O&M cost divided by EPC cost

O&M = operation and maintenance.
Sources: Japan International Cooperation Agency (JICA), 2014 'Project for Promotion of Clean Coal Technology in Indonesia,' and United States Environmental Protection Agency (EPA), 2014 'New Coal-Fired Power Plant Performance and Cost Estimates.'

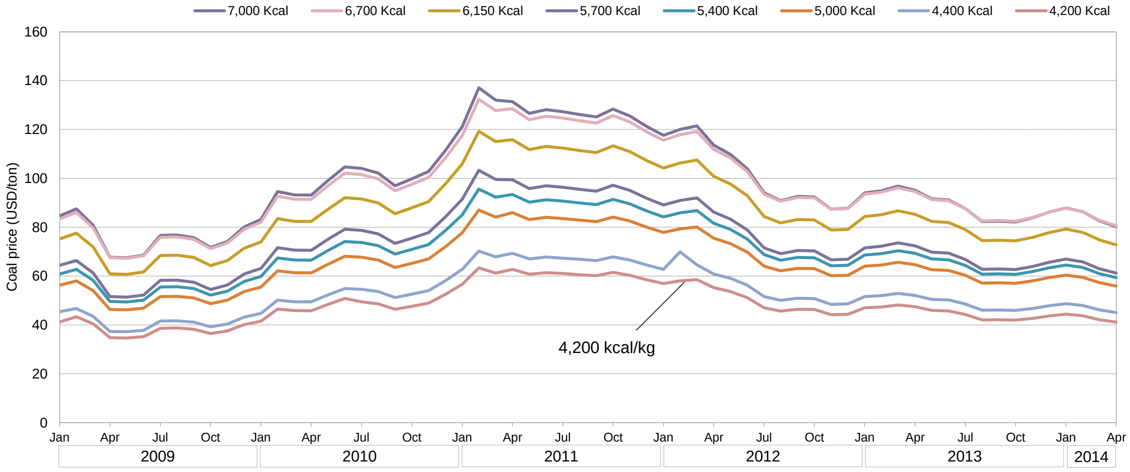
(3) Fuel Costs

In this cost–benefit analysis, LCOEs are calculated for three coal price scenarios. Figure 4-4 displays coal prices for Indonesia's most common markers where 4,200 kcal/kg coal prices (from EcoCoal) are used as a reference to decide the price scenarios. From 2009 up to the first quarter of 2014, coal prices for 4,200 kcal/kg coal ranged from US$35/t to US$63/t.

Based on this price range, price scenarios of US$40/t (low scenario), US$50/t (medium scenario), and US$60/t (high scenario) were chosen.

Levelised fuel costs are then calculated by converting the required weight of coal to generate one kilowatt-hour (kWh) of electricity into kcal and multiplying the result by the price of coal per tonne.

Figure 4-4. Average Monthly Coal Prices in Indonesia (2009–2014)



Source: Directorate General of Minerals and Coal, Ministry of Energy and Mineral Resources, Indonesia.

(4) Desulphurisation and denitrification costs

Desulphurisation and denitrification costs consist of three components: EPC costs, O&M costs and additional fuel requirements. In the final results, these three components are aggregated to form deSOx and deNOx costs. A breakdown of these values and calculations is illustrated in Figure 4-5, and explained below.

Desulphurisation

EPC costs for a 1,000 MW-capacity desulphurisation facility retrieved from interviews with Japanese manufacturers were estimated at US$20 million. This value is assumed as EPC cost for USC. EPC costs for SC and subcritical are assumed to increase accordingly due to higher coal consumption at 2.4 percent and 10.2 percent, respectively. As a result, EPC costs for desulphurisation at an SC power plant are estimated at US$20.5 million. Similarly, for a subcritical power plant, EPC costs are estimated at US$22.0 million.

O&M costs for desulphurisation are based on a study by the Massachusetts Institute of Technology (MIT) titled 'The Future of Coal' (henceforth, MIT study). In the study, O&M costs at an SC power plant are estimated at US$0.22/kWh. Similar to EPC costs, O&M costs are adjusted according to difference in coal consumption. For USC, O&M costs are estimated at US$0.21/kWh, and for subcritical, O&M costs are estimated at US$0.24/kWh.

Denitrification

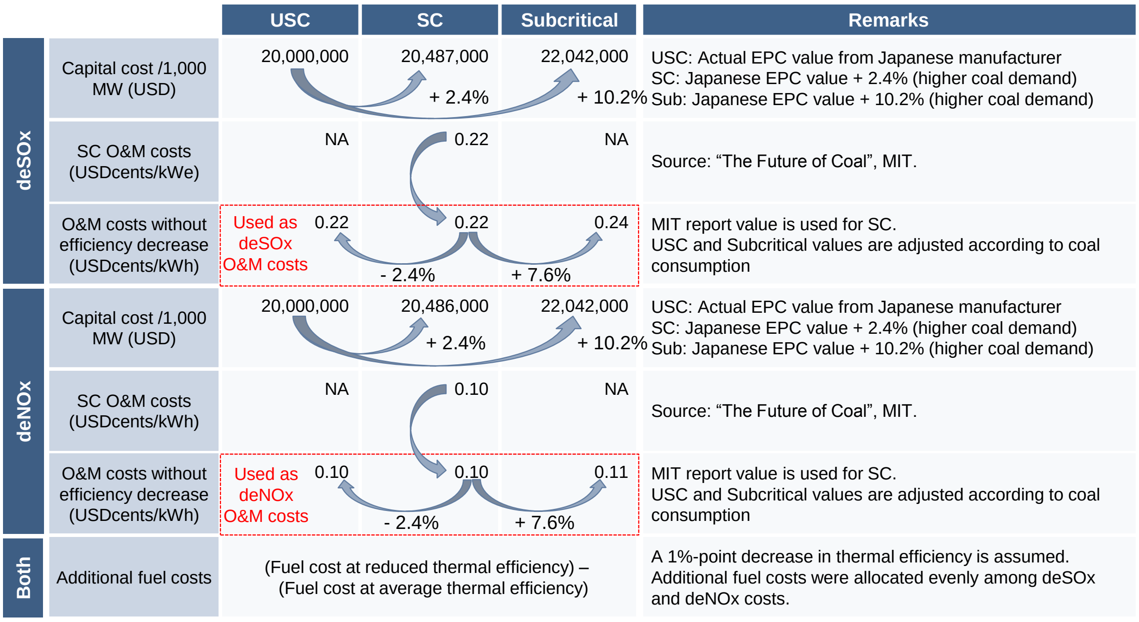
EPC costs for a 1,000 MW-capacity denitrification facility retrieved from interviews with Japanese manufacturers were estimated at US$20 million. Using the same calculations from the desulphurisation facilities, EPC costs for a denitrification unit are estimated at US$20.5 million for an SC power plant and US$22.0 million for a subcritical plant.

O&M costs for denitrification are also based on the MIT study. In an SC power plant, estimate is at US$0.10/kWh. Again, O&M costs are adjusted according to difference in coal consumption. For USC, O&M costs are estimated at US$0.10/kWh, and for subcritical, O&M costs are estimated at US$0.11/kWh.

Additional fuel costs

Installation of desulphurisation and denitrification units reduces thermal efficiency. Based on a study for the European Commission titled 'Efficiency and Capture-Readiness of New Fossil Power Plants in the EU,' this reduction of thermal efficiency is set at one percent. Additional fuel costs associated with desulphurisation and denitrification are calculated as levelised fuel costs at reduced thermal efficiency less levelised fuel costs from (3) above. The total additional fuel costs for both desulphurisation and denitrification are estimated at US$0.07/kWh for USC, US$0.08/kWh for SC, and US$0.09/kWh for subcritical. These values are assumed to be evenly allocated among desulphurisation and denitrification.

Figure 4-5. Calculation Desulphurisation and Denitrification Costs



		USC	SC	Subcritical	Remarks
deSOx	Capital cost /1,000 MW (USD)	20,000,000	20,487,000 + 2.4%	22,042,000 + 10.2%	USC: Actual EPC value from Japanese manufacturer SC: Japanese EPC value + 2.4% (higher coal demand) Sub: Japanese EPC value + 10.2% (higher coal demand)
	SC O&M costs (USDcents/kWe)	NA	0.22	NA	Source: "The Future of Coal", MIT.
	O&M costs without efficiency decrease (USDcents/kWh)	Used as deSOx O&M costs 0.22	0.22 - 2.4%	0.24 + 7.6%	MIT report value is used for SC. USC and Subcritical values are adjusted according to coal consumption
deNOx	Capital cost /1,000 MW (USD)	20,000,000	20,486,000 + 2.4%	22,042,000 + 10.2%	USC: Actual EPC value from Japanese manufacturer SC: Japanese EPC value + 2.4% (higher coal demand) Sub: Japanese EPC value + 10.2% (higher coal demand)
	SC O&M costs (USDcents/kWh)	NA	0.10	NA	Source: "The Future of Coal", MIT.
	O&M costs without efficiency decrease (USDcents/kWh)	Used as deNOx O&M costs 0.10	0.10 - 2.4%	0.11 + 7.6%	MIT report value is used for SC. USC and Subcritical values are adjusted according to coal consumption
Both	Additional fuel costs	(Fuel cost at reduced thermal efficiency) – (Fuel cost at average thermal efficiency)			A 1%-point decrease in thermal efficiency is assumed. Additional fuel costs were allocated evenly among deSOx and deNOx costs.

Source: Massachusetts Institute of Technology (MIT), 2013, 'The Future of Coal.'

(5) Financing costs

Financing cost is calculated to generate 9.5 to 15 percent IRR. For cash flow calculation purposes, the following assumptions were made: Plant construction takes two years. Cash flow is calculated for 25 years of operation with annual electricity sales equal to annual generation at 7,008 GWh.

Financing cost is defined as generation cost that includes non-fuel O&M cost, fuel cost, desulphurisation costs, and denitrification costs less the price of electricity required to generate 9.5 and 15.0 percent IRR, respectively.

(6) Carbon dioxide costs

CO_2 emissions are adjusted from the IPCC default emission factors for stationary sources in the energy sector. Of the four coal types listed, the sub-bituminous coal's heating value of 4,514 kcal/kg is closest to the assumed heating value used in this analysis. Therefore, default CO_2 emission factors of sub-bituminous coal were selected and adjusted to a 4,000 kcal/kg calorific value. This results in 1.43 kg-CO_2/kg-coal. Coal requirements to generate one kWh of electricity are multiplied by this emission factor to obtain levelised CO_2 emissions per kWh.

CO_2 emission cost is then set at US$10/t-$CO_2$. This results in the following levelised CO_2 emission costs: US$0.73/kWh for USC, US$0.75/kWh for SC, and US$0.80/kWh for subcritical.

However, as no CO_2 price is currently implemented, CO_2 emission cost is not weighed heavily in this analysis, and mainly included as a reference.

4-1-3. Sensitivity Analysis

This section summarises the results of the cost–benefit analysis. Figure 4-6 lists aggregated levelised costs, excluding financing and CO_2 costs.

Figure 4-6. Sensitivity Analysis: Overview of Results

		Ultra-Supercritical (42.1%)			Supercritical (41.1%)			Subcritical (38.2%)		
		High EPC (USD 2,076 million)	Medium EPC (USD 1,941 million)	Low EPC (USD 1,867 million)	High EPC (USD 2,043 million)	Medium EPC (USD 1,908 million)	Low EPC (USD 1,796 million)	High EPC (USD 1,925 million)	Medium EPC (USD 1,796 million)	Low EPC (USD 1,688 million)
Coal prices	High (USD 60/ton)	5.39	5.27	5.20	5.46	5.34	5.23	5.68	5.55	5.45
	Medium (USD 50/ton)	4.87	4.74	4.68	4.93	4.80	4.69	5.10	4.97	4.87
	Low (USD 40/ton)	4.35	4.22	4.15	4.39	4.26	4.16	4.52	4.39	4.29

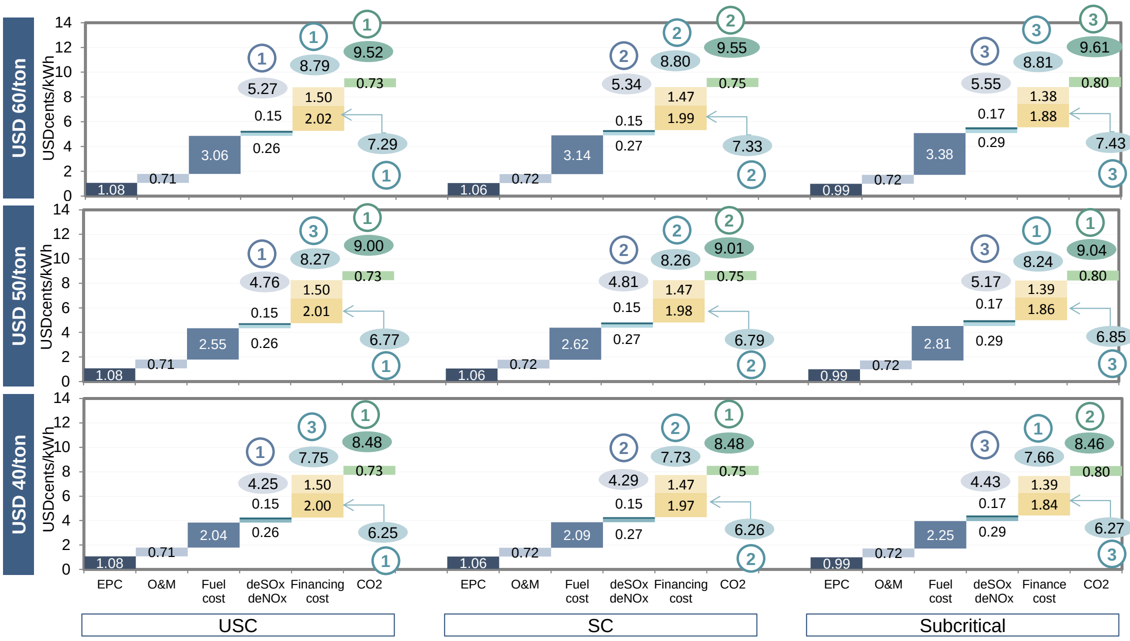
Source: Author's assumption and calculation

Figure 4-7 illustrates costs breakdown for each component from the three coal price scenarios. The graphs include four aggregates and rankings. First, base plant costs plus desulphurisation and denitrification cost. The second aggregate includes financing cost to generate 9.5 percent IRR. The third aggregate includes financing cost to generate 15percent IRR. The fourth aggregate includes a hypothetical CO_2 emission cost. Rankings are also included above the aggregates (below in the case of the second aggregate).

Without financing cost, USC is more competitive in every coal price scenario. However, as initial capital costs are higher, USC is less competitive when financing costs to generate 15 percent IRR are considered. If financing costs are set to generate 9.5 percent IRR, USC is again most competitive even at a coal price of US$40/t.

In conclusion, USC is generally competitive. At any price, it is important to provide concessional loans, especially for advanced technologies with high upfront cost.

Figure 4-7. Sensitivity Analysis: Cost Breakdown Comparison at Per Coal Prices Scenario



Source: Author’s assumption and calculation.

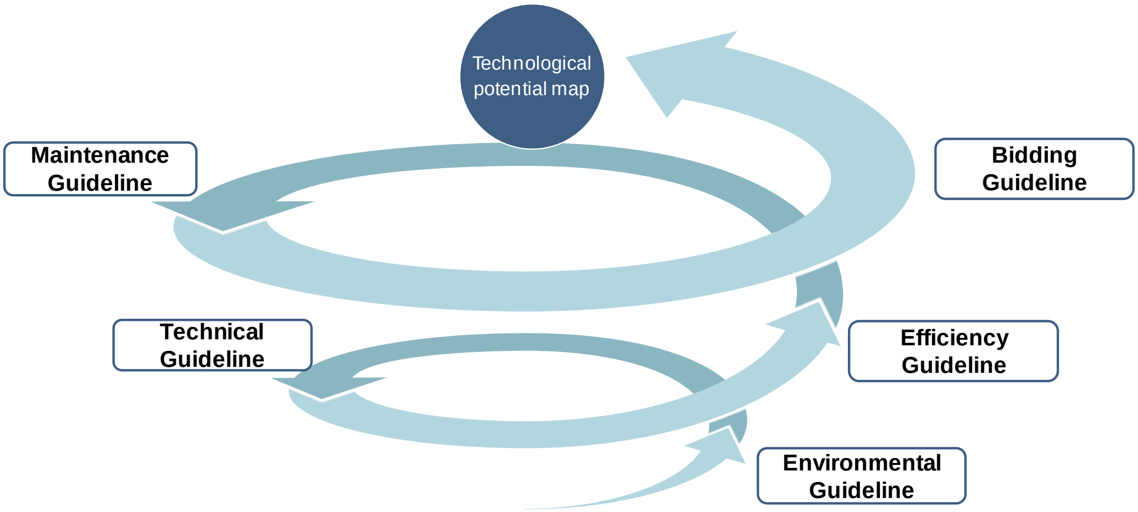
Chapter 5

The Development of Technological Potential Map for Clean Coal Technology Dissemination in the East Asia Summit Region

In order to stimulate investments in highly advanced generation technologies appropriately, several technological potential maps need to be formulated, respecting the different stages of economic development across East Asia Summit (EAS) member countries. Figure 5-1 shows the necessary guidelines which need to be included in the technological potential map. By providing a technological potential map that defines feasible efficiency levels as well as environmental performance and maintenance criteria of clean coal technology (CCT), EAS member countries are able to select and introduce the best CCT appropriate for their current stage of development.

Upon the completion of this research, a 'practical' technological potential map including the above-mentioned items will have been developed.

Figure 5-1. The Technological Potential Map



Source: Author's proposed road map.

5-1. Technological Guidelines

5-1-1. Factors impacting technological guidelines

The cost–benefit analysis results provide useful insights to setting technological guidelines for EAS countries. Table 5-1 displays results from the section on sensitivity analysis, which shows that ultra super critical (USC) is the most cost-competitive in almost every scenario. However, two important observations relevant to setting technological guidelines can be made, namely, the impact of coal prices and the impact of financing cost.

Fuel costs account for the largest share of total generation cost. As fuel costs are solely determined by coal prices, it is important to consider coal supply in EAS countries when setting technological guidelines. Countries with high domestic coal supply can typically procure coal at a much lower price than countries dependent on coal imports. For the former, cost divergence of USC and subcritical is smaller compared to coal-importing countries. As a result, USC may not be viable.

Financing costs also account for a significant share of total generation cost, depending on internal rate of return (IRR). In this analysis, two IRRs were included. Results show that USC loses cost-competitiveness when IRR is higher. For example, at coal prices of USS50/ton, USC is most cost-competitive (at US$6.77/kWh) when IRR is 9 percent. However, when IRR is increased to 15 percent, USC is less cost-competitive (at US$8.27/kWh) than super critical (SC) and subcritical. Therefore, USC may be less viable in countries which do not have access to low-interest loans.

A third factor, although not directly observed in the cost–benefit analysis is electricity demand and grid capacity. Large USC units may not be viable for countries where electricity demand is relatively low. In addition, if electricity demand is low, there may not be enough grid capacity to accommodate a USC unit. Instead, a smaller SC unit may be more suitable.

Table 5-1. Generation Cost by Boiler Type and Coal Price

		Boiler Type		
		Ultra Super Critical (USC)	Super Critical (SC)	Sub-critical
Capacity		1,000 MW		
Coal CV / Price		4,000 Kcal/kg (GAR) / 50 USD/ton		
Thermal Efficiency (LHV)		42.1%	41.1%	38.2%
Initial Cost (million USD)		1,931	1,897	1,787
Coal Consumption (tons/year)		3,578,263	3,665,326	3,943,583
CO2 Emission (tons/year)		5,102,914	5,227,073	5,623,893
Generation Cost (USD cent/kWh) (@USD60/ton)	IRR= 9.5%	7.29	7.33	7.43
	IRR=15.0%	8.79	8.80	8.81
Generation Cost (USD cent/kWh) (@USD50/ton)	IRR=9.5%	6.77	6.79	6.85
	IRR=15.0%	8.27	8.26	8.24
Generation Cost (USD cent/kWh) (@USD40/ton)	IRR=9.5%	6.25	6.26	6.27
	IRR=15.0%	7.75	7.73	7.66

Source: Author's assumption and calculation.

5-1-2. Country categorisation

EAS countries are divided into three categories under the technological guidelines considered in the previous section: Group A, Group B, and Group C. Country characteristics, current technology focus, and future technology focus are summarised in Figure 5-2.

.

(1) Group A

For countries in group A, it is assumed that coal prices are sufficiently high due to high import dependence, low financing costs, and high electricity demand. In addition, USC has already been widely introduced and necessary know-how is available.

Current technology focus should be to utilise USC as standard technology. Future technology focus should be introduction of advanced USC (A-USC) and/or Integrated Coal Gasification Combined Cycle (IGCC).

(2) Group B

For countries in group B, coal prices are also assumed to be relatively high, low interest loans can be provided, and electricity demand is high. The main difference with countries in group A is the current level of USC diffusion.

Current technology focus is to further promote USC diffusion, rather than SC and subcritical. In the future, the aim should be to replace older inefficient units and make USC the standard technology.

(3) Group C

Countries in group C are characterised by factors potentially making USC unviable. This may be due to abundant and cheap domestic coal supply, high financing costs, or low electricity demand and grid capacity.

Therefore, SC may be more viable where domestic coal prices are cheap or where financing costs are high. For countries where electricity demand and grid capacity are low, smaller SC units may be more suitable. However, future technology focus should still be on introducing USC where possible.

Figure 5-2. Technological Guidelines: Country Characteristics and Technology Focus

	■Country Characteristics	■Current technology focus	■Future technology focus
Group A	✓ High GDP/capita ✓ High coal import dependency ✓ Low financing costs. ✓ High electricity demand ✓ USC technology and know-how is already available	✓ USC should be the standard technology.	✓ Promotion of A-USC and /or Integrated Gasification Combined Cycle (IGCC)
Group B	✓ High coal import dependency ✓ Low-interest loans are available ✓ Sufficient electricity demand	✓ USC diffusion should be further promoted.	✓ USC should be become the standard technology, replacing older inefficient units.
Group C	✓ Cheap domestic coal supply and no import dependence ✓ High financing cost ✓ Low electricity demand ✓ Low grid capacity	✓ SC units may be more viable in countries with abundant domestic coal supply. ✓ Smaller SC units may be more viable if domestic electricity demand is low, and grid capacity is limited.	✓ USC should be promoted where possible.

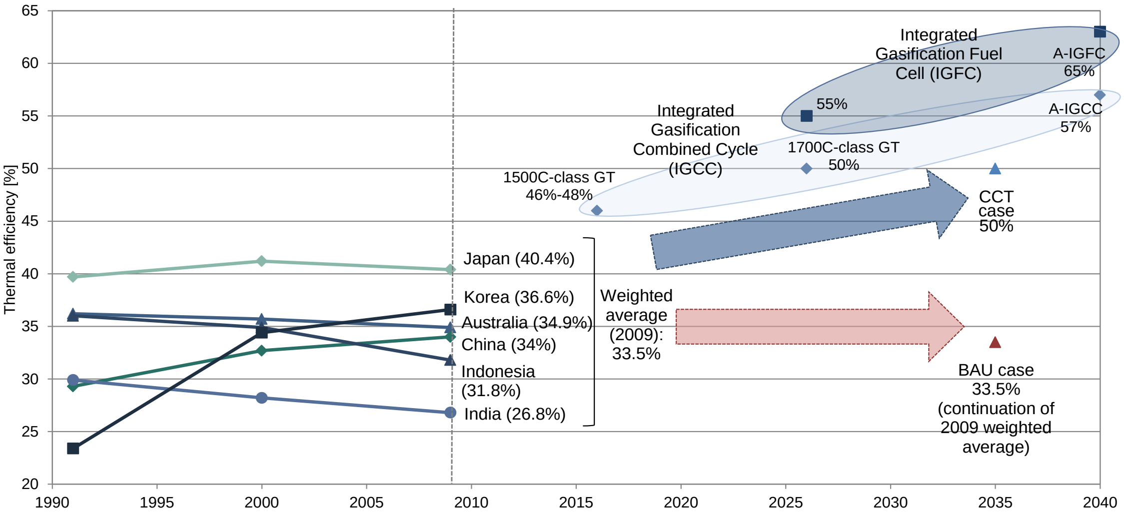
Source: Author’s proposed road map

5-2. Efficiency Guidelines

Thermal efficiency of coal-fired power stations varies greatly across Asia, leaving room for improvement in some Asian countries. Japan and South Korea have incentives to adopt efficient technologies from an investment point of view (in order to decrease coal imports) as well as from a social and environmental point of view. A policy package in other countries to increase the investment benefits would accelerate the adoption of more efficient technologies and close the thermal efficiency gap.

In the first-year study, the benefits of providing a road map for CCT technologies were quantified in two assumed scenarios: the CCT case and the (business as usual) BAU case. Figure 5-3 illustrates the two scenarios and the technology road map as well as the history of thermal efficiency values. In the CCT case, it is assumed that a thermal efficiency of 50 percent will be attained by 2035, through the introduction of CCT. In the BAU case, it is assumed that the weighted average thermal efficiency (based on electricity generation in TWh) in 2009 will remain unchanged at 33.5 percent up to 2035.

Figure 5-3. Thermal Efficiency History and Road Map



Source: Japan International Cooperation Agency (JICA), 2012, Final report of 'The Project for Promotion of CCT in Indonesia.

The ERIA energy savings research project estimates that by 2035, an annual production of 13,497.8 TWh of electricity will be generated from coal for both CCT and BAU cases. Coal heating value and coal prices were assumed at 6,000 kcal/kg and US$90.89/ton according to Newcastle FOB prices for 6,000 kcal/kg coal for January 2013. Annual requirement for coal in the CCT case was 1,905 MT lesser than in the BAU case and US$173 billion in coal procurement costs were saved per year in the CCT case. Moreover, the reduction of coal necessary for power generation will reduce CO_2 emissions. Assuming that 2.30 kg–CO_2/kg-coal was emitted, a massive 4.39 billion tons of CO_2 emissions can be avoided annually.

In addition, coal consumption and CO_2 emission of USC, SC, and subcritical plant were estimated. A higher efficiency plant has less coal consumption and CO_2 emissions than lower efficiency plant.

Therefore, plant efficiency should be considered in the introduction and promotion of CCT from both economic and environmental views.

5-3. Environmental Guidelines

5-3-1. Environmental standards

Table 5-3 gives an overview of regulations related to coal-fired power stations in various countries in the EAS region with the European Union (EU) and the US as references. Environmental regulations on emissions from coal-fired power stations are already in place in most countries. The main difference is the stringency of the emission regulations with developing countries often having less stringent regulations compared to developed countries.

On the contrary, regulations on the thermal efficiency of coal-fired power generators generally have not been implemented in either the developing countries or developed countries. In liberalised markets such as Europe (and US, to some extent, and depending on the state), the economic rationale for efficient technologies is set by the market and therefore the most efficient and economical technologies are usually deployed. In Asia, most markets remain regulated and coordination of policies is necessary to promote the deployment of more advanced generation technologies.

Table 5-3. Regulations of Coal-Fired Power Stations

	Australia	China	India	Indonesia	Japan	Korea	Thailand	Viet Nam	EU	US
CO2 Regulation	Carbon tax: Start 2012 Repeal 2014				Oil and coal Tax				CO2 certificate	Proposed: 1000lb/kWh
NOx and SOx regulation		(mg/m3) NOx 100 W-type, CFB 200 SOx New 100 Existing 200 Key region 50	None	(mg/m3) NOx 750 SOx 750	(ppm) Regulation is determined by local government. Newest and most sever standards are follows; NOx<13 SOx<10	(ppm) NOx 80 SOx 80	(ppm) NOx 350 SOx >500MW 320 300-500MW 450 <300MW 640	(mg/m3) Cmax=C x Kp x Kv C: NOx >VM10% 650 <VM0% 1000 SOx :500 Kp(Scale factor) <300 MW : 1 300-1200MW: 0.85 >1200MW:0.7 Kv(Reginal factor): 0.6 ~1.4	(mg/m3) NOx 500 until 2015 then 200 SOx New 200 Old 400	(mg/m3) NOx New 117 NOx and SOx 160 (1997-2005) 640 (before '96)
Particulate matter regulation (mg/m3)		30 Key region 20	>210MW 150 <210MW 350	100	5 (Newest and most sever standards)	>500MW 20 <500MW 30	120	C: 200	50	22.5
Mercury regulation		0.03	None			None			0.03 (Germany)	0.001 0.002

Sources: Author's compilation from various sources.

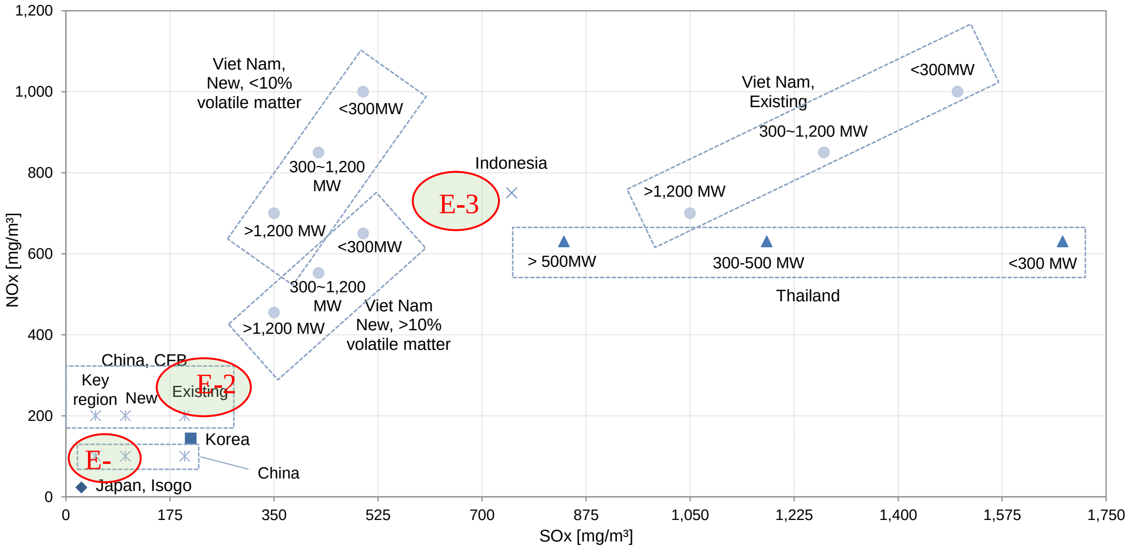
SOx and NOx regulations are already implemented in many EAS countries but CO_2 regulations have not been introduced yet in most EAS countries.

Figure 5-4 gives an overview of SOx and NOx emissions standards applied in countries that operated coal-fired power stations as well as the SOx and NOx emissions of the new Isogo plant in Japan. As can be seen in the figure, standards vary greatly across countries. Therefore, harmonisation of emission standards across Asia is necessary. Furthermore, a road map for future emissions standards is crucial.

Within the EAS region, Australia was the only country that introduced carbon tax in 2012, which was repealed in 2014. In Japan, CO_2 emissions are indirectly regulated through a tax on coal and oil. The tax on coal is higher, accounting for higher CO_2 emissions from coal use. In other EAS countries, CO_2 emissions are not regulated.

If CO_2 emission regulations would be implemented in countries across the EAS region, deployment of more advanced technologies such as CCS, A-USC, or IGCC in addition to USC and SC would be incentivised and commercialisation of such technologies could be accelerated.

Figure 5-4. Comparison of SOx and NOx Emission Standards from Coal-Fired Power Stations



NOx = nitrogen oxide, SOx = sulphur oxide.

Note: A regional factor applies to power stations in Viet Nam ranging from 0.6 (urban areas) to 1.4 (remote areas). Factor 1 is applied in this figure.

Source: Author's compilation from various sources.

5-3-2. Environmental guidelines: environmental standards and available technology

As previously stated, efforts should be made to develop high-efficiency and low-emission CCT, and improve the environment in the future based on harmonised and stringent environmental standards. However, present environmental standards vary from country to country depending on the introduction and promotion of coal-fired power station. Thus, the environmental guideline classified environmental standard targets into three stages: E-1, E-2, and E-3. This is in consideration of the electricity demand and the introduction/promotion of coal-fired power generation facilities in each country, as shown in Figure 5-4. The environmental targets and applicable technologies of pertinent country groups are summarised in Table 5-4.

(1) Environmental standard target 1 (E-1)

This target applies to countries that are already implementing USC and have plans for promoting high-efficiency CCT such as A-USC and IGCC. Those countries belong to group A mentioned in section 5.1.2. This environmental target aims to achieve the levels of standards in Japan and South Korea, and calls for the utilisation of high-efficiency desulphurisation, denitrification, and electrostatic precipitation technologies. In the near future, it will be necessary to introduce technologies for the removal of mercury and other heavy metals and for the reduction of CO_2 emissions using CCS.

(2) Environmental standard target 2 (E-2)

This target is for countries belonging to group B that are already operating coal-fired power plant and have implemented or are planning to implement SC and/or USC. Further deployment of USC is expected in those countries in the future. The environmental target is to attain the level of standard in China where USC has been utilised and is being promoted. Although desulphurisation, denitrification, and electrostatic precipitation technologies are required to achieve the target, it is desirable to design facilities that meet the standards with a large margin. In view of CO_2 emissions reduction in the future, these countries should consider introduction of CCS-ready power stations.

(3) Environmental standard target 3 (E-3)

This target is applicable to countries in group C that have no coal-fired power plants but only have small-scale coal-fired power plants. However, increases in demand for electricity are expected to spur the introduction of SC or USC in those countries. The environmental target is to achieve the environmental standards in Thailand and Indonesia where coal-fired power plants are already in use. Thus, desulphurisation and electrostatic precipitation facilities are required. Although it is desirable to use denitrification facilities for NOx reduction, employment of boilers equipped with low-NOx burners can provide the necessary performance.

Table 5-4 Environmental Guideline: Environmental Standard Targets and Applicable Technologies

Country Group		Group A	Group B	Group C
Guideline		E-1	E-2	E-3
Environmental Target (mg/m3)	SO x	<50	<250	<700
	NO x	<50	<250	<700
	PM	<10	<50	<100
Applicable Technology	SO x	FGD	←	←
	NO x	deNOx Unit	←	Low NOx Burner
	PM	High efficiency EP	EP	←
	Others	Removal of heavy metal elements		
	CO_2	CCS	CCS-ready	

Source: Author's proposed road map.

5-4. Maintenance Guidelines

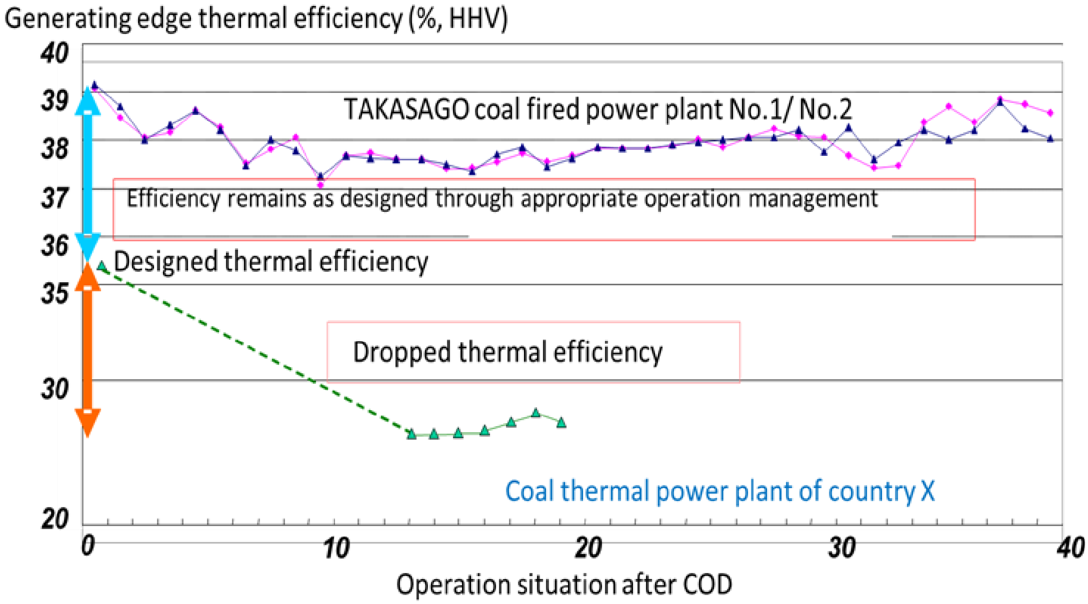
5-4-1. Importance of maintenance

Clean coal technology such as USC has higher efficiency and lower emission compared to conventional coal utilisation technology. The advantage of introducing USC is realising fuel cost reduction and CO_2 emissions reduction over the increment of construction cost.

Figure 5-5 shows the decrease of plant thermal efficiency of coal-fired power plants in ASEAN and Japan. Takasago units #1 and #2 indicated in the figure is an old subcritical power plant with individual unit capacity of 250 MW while the efficiency of country X consists of average data of subcritical plants whose outputs are 300 MW.

The figure shows that the decrease of plant thermal efficiency in country X is down to 10 percent at 10 years into commercial operation. On the other hand, the Takasago power plant in Japan has maintained its designed efficiency for over 40 years and the decrease in plant thermal efficiency is one to two percent only.

Figure 5-5. Thermal Efficiency of Coal-Fired Power Plants in Japan and Asia



Source: Japan International Cooperation Agency (JICA), 2012, Final report of 'The Project for Promotion of CCT in Indonesia.

Table 5-5 shows the cost impact analysis of the decline of plant thermal efficiency and plant load factor (JICA, 2012). Data is based on 1,000MW USC. When plant thermal efficiency decreases by one percent than the base case, then demerit of construction cost becomes US$82/kW. In other words, a decrease of one percent in thermal efficiency is equivalent to US$82/kW of construction cost. Furthermore, when plant load factor decreases by 10 percent than base case due to an outbreak or to unachieved rated output, then the equivalent construction cost is US$76/kW.

Therefore, an assessment of degradation in plant thermal efficiency, plant load factor, and a comparison of the construction cost become indispensable in USC technology.

Table 5-5. Cost Impact Analysis of the Decline of Plant Load Factor and Plant Efficiency

Rated Plant outputs Plant efficiency degradation	100%	99% (▲1%)	95% (▲5%)	90% (▲10%)
0%	base	8	38	76
▲1%	82	90	120	158
▲2%	168	176	206	244
▲3%	259	267	297	335

Source: Japan International Cooperation Agency (JICA), 2012, Final report of ‘The Project for Promotion of CCT in Indonesia.’

5-4-2. Maintenance guidelines

A decrease in plant thermal efficiency and plant load factor overtime due to deterioration affects the economic benefit of CCT and, therefore, a stable and suitable operation and maintenance (O&M) is required in the long term. In order to enjoy the merits of CCT such as USC, IGCC, and other highly efficient power generation facilities, it is necessary to have advanced operation control technologies and to ensure the appropriate maintenance and management of the facilities. To this end, it is also important to start providing personnel with training, such as an on-the-job training on O&M, from construction stage so that relevant personnel can acquire necessary technological know-how.

O&M in consideration of these facts should be implemented as follows.

- Before CCT introduction
  - ✓ Development of O&M engineers via education and training.
- After CCT introduction and operation
  - ✓ Establishment of a training centre to provide education and training on the use of power plant simulators and other training facilities
  - ✓ Development of engineers having advanced O&M skills in training centre
  - ✓ Implementation of daily check and using operation monitoring system combined with periodic inspection for maintaining the stable operation.

5-5. Bidding Guidelines

A bidding system is generally used to select the contractor for a large-scale public facility such as a power plant from the standpoint of fairness. In a bidding process, the bidding winner is determined based on the results of examination of bidders' proposal documents including cost estimations, details of design, and construction plan based on designated technical specifications of the facility as well as the bidders' past track records. However, the highest priority is often placed on the assessment of cost estimations. Therefore, if a bidder with insufficient engineering capability wins a bid, various problems can result and hinder the smooth execution of the project.

Indonesia experienced considerable delay of the two-phased national Fast Track Power (FTP) Development Program, which was caused by prolonged period of construction, mechanical troubles during commissioning or post-commercial operational date (COD). A bidding policy with overwhelming priority on proposed cost rather than on technical appropriateness of a proposal is observed to be blamed for the situation that has ultimately affected the entire power supply security.

Seemingly high-priced, CCT is excellent in terms of efficiency and economy, and will be able to provide a sustainable and high-efficiency operation of a power plant.

In closing, bids should consider the details and other guidelines listed below:

- Apart from cost/price, technology to be employed and technical specification (including efficiency) should be accounted for.
- A minimum one-year performance guarantee period should be imposed so that troubles during commissioning or post-COD period may be addressed.
- A training centre with power plant operation simulator in combination with O&M training at construction phase is recommended.
- Cost evaluation is better conducted only after technology assessment for both independent power producer (IPP) and private–public partnerships (PPP) projects.

Chapter 6

Conclusion

In this study, the importance of coal and the benefits from clean coal technology (CCT) are discussed. In addition, a practical technological potential map is considered and formulated. In summary:

(1) Coal is least dependent on imports from outside the EAS region.

Among fossil fuels, coal is least dependent on import from outside the EAS region, specifically the Middle East. About 31 percent of natural gas imports and 68 percent of oil import is from the Middle East.

(2) Coal has always been more affordable than natural gas and oil in terms of heating value.

Historically, coal has always been around 1.5–3.5 times less expensive than natural gas. Furthermore, coal prices are less volatile than natural gas or oil prices.

(3) Strategic use of low-rank coal creates opportunities to access half of coal reserves in Asia.

About half of Asia's coal reserves are low-rank coals. These reserves are largely undeveloped but have high potential that would increase coal supply in Asia.

(4) Expansion of shale gas production has an impact on the Asian coal market.

Coals from other regions such as South Africa, US, and Colombia can potentially contribute to coal supply in Asian markets through the expansion of shale gas development, which can further enhance supply from existing coal sources such as Australia and Indonesia.

(5) Investment opportunities and job creation in coal-fired power plants and coal mines are possible.

An estimated 898 GW generated from a coal-fired power plant and worth a staggering US$1.692 trillion, and 1,943 MT coal per year worth around US$300 billion in development cost will provide ample investment opportunity. Furthermore, the operation of power stations and coal mines provide jobs to 246,000 and 75,000 workers, respectively. Additionally, jobs in construction jobs and in other sectors not quantified in this study can be created.

(6) EAS countries shall consider using more low-rank coals through high efficiency CCT.

Power plants fired by low-rank coals have lower thermal efficiency due to low coal quality; however, CCT achieves high thermal efficiency and reduced CO_2 emission compared with conventional power plant. Ultra super critical (USC) is cost-competitive but loses cost-competitiveness when the internal rate of return (IRR) is increased. Therefore, financial support such as low-interest loans should be provided to promote USC.

(7) A practical technological potential map for CCT dissemination in EAS region is developed.

A concrete structure for the technological potential map for the advancement of CCT is developed so that it can be quickly introduced to each EAS country.

Chapter 7

Policy Recommendations for the Strategic Usage of Coal

7-1. Clean Coal Technology for Strategic Usage of Coal

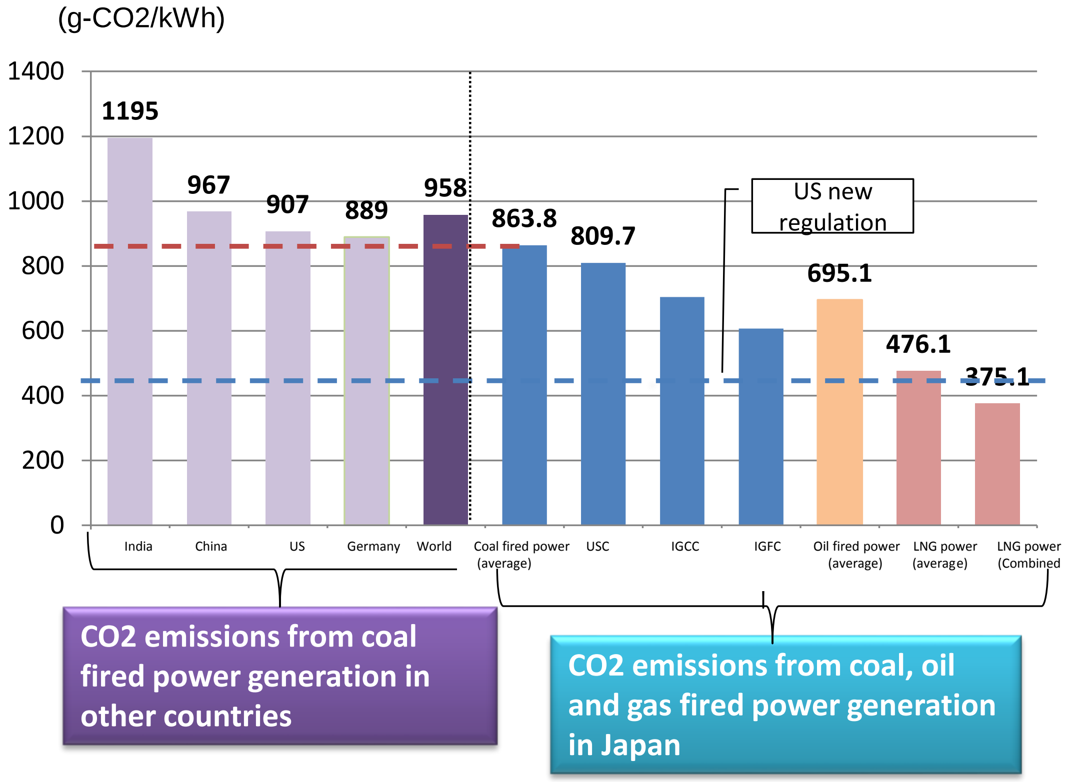
Economic development and growth in the EAS region have been remarkable and demand for electricity is forecasted to increase substantially. In the EAS region, coal is the more secure and affordable energy resource compared to oil and gas as its reserve is abundant. Therefore, coal-fired power generation will continue to play a central role in meeting an increasing electricity demand.

However, half of the regional coal resources are defined as low-rank coals. Low-rank coal has limited use and low utilisation efficiency because of high moisture content and low heating value. In addition, it contains higher carbon content than oil and gas because coal upon combustion generates the biggest amount of CO_2 per unit among all primary energy sources. Considering such conditions, the introduction of clean coal technology (CCT)—which is high efficiency, low emission, and available to low-rank coal—is indispensable. The advantages of introducing high-efficiency CCT are fuel cost reduction and CO_2 emission reduction more than the increment of construction cost. Furthermore, based on low emission in CCT, applicability to credit mechanism such as the joint crediting mechanism can be considered.

In June 2013, US President Barack Obama announced ‘The President’s Climate Action Plan,’ and upon receiving this plan, the US Environmental Protection Agency proposed a new regulation on CO_2 emission for power plant at 1,000 lb/kWh (453.6 g/kWh). As shown in Figure 7-1, it is impossible for fossil fuel power plants to sustain this regulation with the exception of gas-combined cycle power plant. Therefore, it will be necessary for coal-fired power plants to adopt CCS (carbon dioxide capture and storage) technology and high efficiency CCT in the future.

On the other hand, coal-fired power plants will continue to increase in the EAS region as mentioned above. According to an IEA report titled ‘21st Century Coal: Advanced Technology and Global Energy Solution’, an estimated 59 gigatons (GT) of reduced CO_2 emissions from coal power plant could have been achieved had new coal units over the past 50 years used the highest efficiency technology available when built. Therefore, high efficiency CCT with a set of operation and maintenance (O&M) techniques should be introduced. CO_2 emissions and coal consumption will be reduced, which will enhance environmental compliance and energy supply security accordingly.

Figure 7-1. CO_2 Emissions from Fossil Fuel Power Plants



Source: Based on development targets of various research businesses, Central Research Institute of Electric Power Industry (CRIEPI), 2009; International Energy Agency (IEA), 2012, CO2 Emissions from Fuel Combustion.

7-2. Road Map

In order to promote the adoption of suitable CCT in EAS region, a road map for strategic utilisation of coal in each country group in the EAS region has been created based on the technological potential map formulated in this study. The road map for each group is shown in Figure 7-2.

(1) Group A

The countries in group A have already promoted the use and expansion of ultra super critical (USC) and they should focus on the introduction of high-efficiency IGCC (integrated coal gasification combined cycle) from now on. They also need to implement more effective environmental measures including those for the removal of heavy metals. The CO_2 emissions standard for coal-fired power stations proposed by US stipulates an emission level of 1,000 lb/kWh, which is a level not achievable by USC or IGCC. Therefore, there is a need to consider the application of CCS, which is currently under development, by 2025.

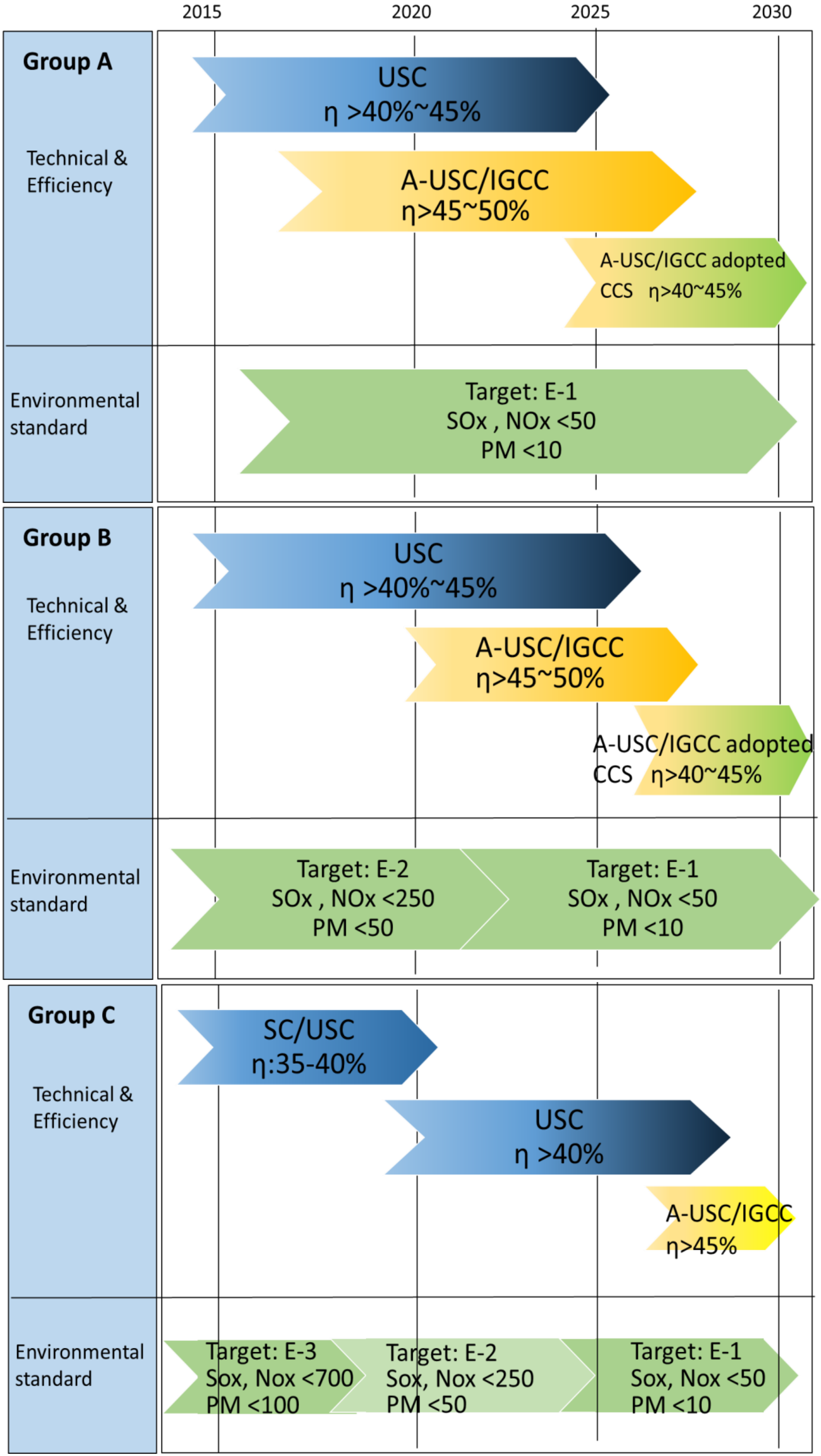
(2) Group B

Countries in Group B have coal-fired power stations that are already in operation and will soon introduce or plan to introduce USC. The promotion of USC is expected in the future. Because these countries' current environmental standards are not sufficient for future environmental protection, more stringent environmental regulations should be put into force. Utilisation of high-efficiency CCT such as IGCC should be planned for the period 2020–2025 or later. Regarding their existing power generation facilities and newly constructed power stations, appropriate operation and maintenance for maintaining power generation efficiency will contribute to the reduction in operating costs, effective utilisation of resources, and improvement of environmental protection.

(3) Group C

In these countries, only small-scale thermal power stations are operating but relatively large power stations will be needed in the future as their economies continue to develop and increase the demand for electricity. Those countries will need to introduce SC or USC and set appropriate environmental standards for power stations exceeding 600 MW in capacity. More stringent environmental standards should be established in line with the progress of CCT promotion. At the time of introducing CCT, efforts should be made for providing advance education and training on equipment operation and maintenance to foster capable engineers, and ensure stable operation and maintenance of facilities.

Figure 7-2. Road Map for Each Country Group in the East Asia Summit Region



Source: Author’s proposed road map.

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