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Reducing emissions from fossil-fired generation

Indonesia, Malaysia and Viet Nam

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INTERNATIONAL ENERGY AGENCY

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Executive summary

In 2013, Southeast Asia's power mix was dominated by fossil fuels, with over 44% of electricity generated from natural gas, 32% from coal and 6% from oil (IEA, 2015a). Coal is expected to overtake gas to become the number one fuel source for power generation in the coming years, as several Southeast Asian countries are in the process of adding significant coal power capacity to take advantage of the relative abundance and competitive price of coal resources available for regional consumption. Indeed, providing affordable electricity to support rising electricity demand and industrial development is a key government objective, compelling several Southeast Asian countries to enact national power development plans that are premised on the expectation that coal-fired generation is, and will remain, the cheapest and most readily available solution for expanding electricity access – at least in the short term. Meanwhile, many clean energy technologies remain at the small-scale development stage[1] and no carbon price has been introduced in the region to reflect the environmental costs of fossil-fired generation and deter its use.

Yet, taking a localised, short-term approach to power planning runs the risk of perpetuating a reliance on coal-fired generation that may potentially extend far beyond the point at which low-carbon technologies present a viable and cost-effective alternative. Most reasonably maintained coal-fired power plants can run for a lifetime of around 40 years, and longer with upgrades. With the existing coal fleet in Southeast Asia still relatively young and many new coal plants planned to come online in the next five to ten years, proceeding with this trend of unabated coal-heavy power development to fulfil electrification targets could result in the long-term lock-in of high levels of carbon dioxide (CO_2) emissions or the prospect of early retirements of profitable assets.

This study focuses on the CO_2 emission impacts of operating existing and planned coal generation capacity in three countries – Indonesia, Malaysia and Viet Nam – according to plants registered in the Platts database and power development targets outlined in government plans. Many International Energy Agency (IEA) studies elaborate extensively on the role of natural gas and renewable energy in supporting the clean energy transition in the power sector (such as the *World Energy Outlook [WEO]*, *Energy Technology Perspectives* and the *How2Guide* and *Technology Roadmap* series). However, no IEA study has to date examined in detail the CO_2 emission impacts of coal-fired generation in Southeast Asia, or the extent to which these emissions could be reduced by implementing high-efficiency, low-emissions (HELE) coal technologies. Given the increasingly prominent and, if current plans proceed, soon-to-be dominant role of coal in Southeast Asia's power mix, it is important to make a critical assessment of the long-term environmental impact. This study seeks to complement other IEA studies on system-wide emission-reduction possibilities by focusing specifically on the role and impact of coal-fired generation. It addresses the gap in existing literature by highlighting options for Southeast Asian countries to improve the sustainability of coal-fired power generation in the present (and still prevalent) circumstances where existing or planned coal plants cannot quickly or easily be replaced by lower-carbon generation technologies, without impeding more rapid reductions in emissions in coming decades as policies and costs evolve.

Indonesia, Malaysia and Viet Nam are selected as they currently plan to add the most significant coal generation capacity in Southeast Asia over the next decade. As of the end of 2015, Indonesia, Malaysia and Viet Nam already have a combined 54 gigawatts (GW) of coal-fired capacity, of which 91% features subcritical technology constructed after 2000. While HELE coal-

[1] The exception to this is hydro, which continues to be a key feature of the power mix in just about all Southeast Asian countries apart from Singapore and Brunei, which are heavily reliant on gas for electricity.

fired plants – e.g. supercritical (SC) and ultra-supercritical (USC) plants – have been commissioned since 2012, the scale of existing and planned coal-fired generation capacity in Indonesia, Malaysia and Viet Nam is so large that initiatives to phase out or retire early subcritical units and replace them with HELE technologies would not significantly improve the environmental impact.

It is recognised that coal is a key feature of the Southeast Asian power mix due to cost and resource considerations, and that HELE technologies play an important (albeit limited) role in reducing the emissions intensity of coal-fired power generation. Accordingly, it is of critical importance that governments recognise that ultimately, to meet their climate obligations, carbon capture and storage (CCS) will need to be fitted to a high proportion of the remaining coal-fired fleet. In preparation for that eventuality, as well as ensuring that new coal-fired power plants would be capable of accommodating CCS when the necessary regulatory and/or economic drivers were in place. To construct CCS-ready power plants requires developers and governments to carefully evaluate the proximity to suitable geology for safe, secure CO_2 storage and the infrastructure required to transport captured CO_2 to the sites.

While upgrading the efficiency of coal plants and, in due course, adopting CCS would move Indonesia, Malaysia and Viet Nam closer to future domestic climate targets, improving the environmental sustainability of coal-fired power generation in isolation from the rest of the power system would ultimately be insufficient to meet them. It is clear that current plans to expand coal-fired generation are inconsistent with commitments to lower CO_2 emissions and obligations to the Paris Agreement following the 21st Conference of the Parties (COP21) to the United Nations Framework Convention on Climate Change (UNFCCC). While this study emphasises the importance of preventing locked-in emissions from existing and planned coal-fired power generation, it should not detract from the need for an integrated approach to reducing emissions in the power sector as a whole.

Governments must consider the potential for energy efficiency and the mix of fuels and technologies that, in the longer term, will best achieve the energy security, economic development and environmental protection to which they aspire. Network and demand-side efficiency would lead to reduced consumption for all fuel types, while strengthening the grid network would permit existing capacity to be used most effectively. Given their declining costs, the deployment of renewable energy technologies must be accelerated. Gas-fired generation would need to remain an integral part of the generation mix. Governments have a pivotal role in incentivising the transition to low-carbon generation by creating an enabling environment.

The study concludes that the power mixes in Indonesia, Malaysia and Viet Nam must be sufficiently diversified, with currently anticipated levels of coal-fired generation scaled back. Implementing HELE coal technologies and CCS to reduce emissions from remaining coal-fired power generation will require both capacity building and significant funding. Private-sector participation and international support will be instrumental if governments are to realise this potential. Recommendations are proposed on policy measures and investment opportunities that governments may consider to address coal-fired generation, promote fuel diversification, and achieve the appropriate levels of emissions reduction in their power sectors.

Introduction

Southeast Asia is a fast-growing region that has nearly doubled the size of its economy since 2000 to reach 6.1 trillion US dollars (USD) in 2013,[2] which is comparable to that of Japan and Korea combined (IEA, 2015a). The region has recorded a remarkable average annual growth in gross domestic product (GDP) of more than 5% over this period, compared to the average for member countries of the Organisation for Economic Co-operation and Development (OECD) of 1.6%. Electricity demand has increased rapidly as countries in the region continue to urbanise and shift their economy from agriculture to manufacturing and services, with generation nearly tripling from 280 terawatt hours (TWh) in 2000 to 789 TWh in 2013. The fast pace of growth in electricity demand is expected to continue in the coming decades; the IEA New Policies Scenario (NPS) (Box 4) projects that electricity generation will almost triple again from 2013 to reach 2 212 TWh in 2040 (IEA, 2015a). On this basis, the power sector would account for 56% of the increase in primary energy demand between 2013 and 2040 in Southeast Asia (IEA, 2015a). The buildings and industrial sectors would lead the growth in electricity consumption.

Coal is expected to overtake gas and emerge as the dominant fuel in the region's power sector by 2030 (IEA, 2015a), even as Southeast Asian governments seek to diversify their generation mix through increased deployment of non-oil-fired generation technologies. The key government objective of delivering affordable electricity to support growing industries and urban areas has compelled several Southeast Asian countries to enact national capacity development plans that significantly increase coal-fired power generation. This is on the premise that coal is, and will remain at least in the medium term (next five to ten years) or even beyond, the cheapest and most readily available fuel source for power generation in the absence of a price on emissions or on other environmental externalities. Additionally, a common perspective on the part of regional energy ministries is that capital costs for constructing coal plants remain cheaper than those for new and renewable energies today, even though the costs of deploying the latter have been steadily decreasing across the globe and, in certain resource-rich areas of Southeast Asia, are already competitive.[3] Given these considerations, current power-sector development trends in Southeast Asia suggest that coal will predominate over other sources in power generation, such as gas and renewables, and will lead to the long-term “lock-in” of greenhouse gas (GHG) emissions if left unabated.

As it stands, the shift towards a coal-dominant power sector in Southeast Asia is already well underway, with coal plants accounting for more than half of gross thermal capacity additions over the past five years. The majority of these coal plants are located in the coal-producing countries, Indonesia and Viet Nam, but are increasingly being built in gas-producing (but coal-importing) Malaysia, and in the net electricity exporter Lao PDR. With this rising use of coal, Southeast Asia’s power sector would account for around half of the 2.5 gigatonnes (Gt) of CO_2 emissions in Southeast Asia in 2040 if no additional policy measures were taken (IEA, 2015a). Recognising that absolute CO_2 emissions will inevitably increase as most Southeast Asian

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[2] In 2014 USD, adjusted for purchasing power parity.

[3] For example, in Lao People’s Democratic Republic (PDR), hydro is considered by the government and by the state utility company – Electricité du Laos - to be the most cost-effective power-generation technology in the country. For Indonesia, the IEA calculates the overnight capital costs for onshore wind power in the range of USD 1770-2050/kW and utility-scale solar plant between USD 1500-2000/kW, compared to USD 1300/kW for supercritical (SC) coal plant and USD 1800/kW for an ultra-supercritical (USC) coal plant. These calculations are for plants commissioned in 2015, expressed in real dollars for 2014.

countries also increase electricity coverage for underserved communities, efforts to reduce the CO_2 emissions intensity[4] of power generation must be addressed urgently.

Southeast Asian governments recognise the importance and potential of gradually shifting away from coal-fired power generation, particularly following COP21. The governments are progressively updating their power development targets and policies to incorporate more low-carbon, renewable and energy-efficient technologies as they become economically viable. Where coal plants cannot be readily replaced by cleaner alternatives due to economic or fuel resource concerns, several Southeast Asian countries are also advocating the use of HELE coal technologies (IEA, 2012). The next step would be to limit GHG emissions from power generation by strengthening CO_2 emissions standards and regulations, which do not yet exist in Southeast Asian countries.

Ultimately, the greatest challenge for Southeast Asia's policy makers is how to meet their emerging economies' fast-growing electricity demand while simultaneously pursuing government objectives to reduce the power sector's GHG emissions intensity. This paper has two principal aims: first, to provide analysis to support policy makers tasked with assessing the long-term environmental and financial impacts of expanding power capacity that is overly reliant on coal-fired – and particularly subcritical coal-fired – power generation; and second, to propose policy recommendations to mitigate the long-term lock-in of emissions and stranded assets in power generation.

The emissions impacts of government power development plans are examined for the three Southeast Asian countries – Indonesia, Malaysia and Viet Nam – that are anticipating the most significant additions to coal-fired power capacity over the next 20 years. Data from Platts are used to model the potential emissions reduction that can result from fuel and technology switching, as well as upgrading the least-efficient coal-fired power plants to more advanced technologies that are commercially available today. In this study, the targets in government power development plans and the existing or planned capacity additions in Platts are all taken at face value. Projections on CO_2 emissions, as calculated from Platts data on existing and planned power plants, are intended to be illustrative of the serious environmental impacts of proceeding with coal capacity additions as currently anticipated by local governments and utilities.

The last section highlights selected investment policies and trends for power-sector development in progress in the region, and considers the extent to which they can effectively curtail the proliferation of least-efficient coal power plants. The paper concludes with recommendations on the types of development and investment policies that would have the highest impact on reducing emissions intensity.

The analysis and discussion in this paper follow a number of in-country consultations with local power-sector stakeholders in June 2015, and discussions at two regional workshops held in Jakarta and Hanoi in November 2015.

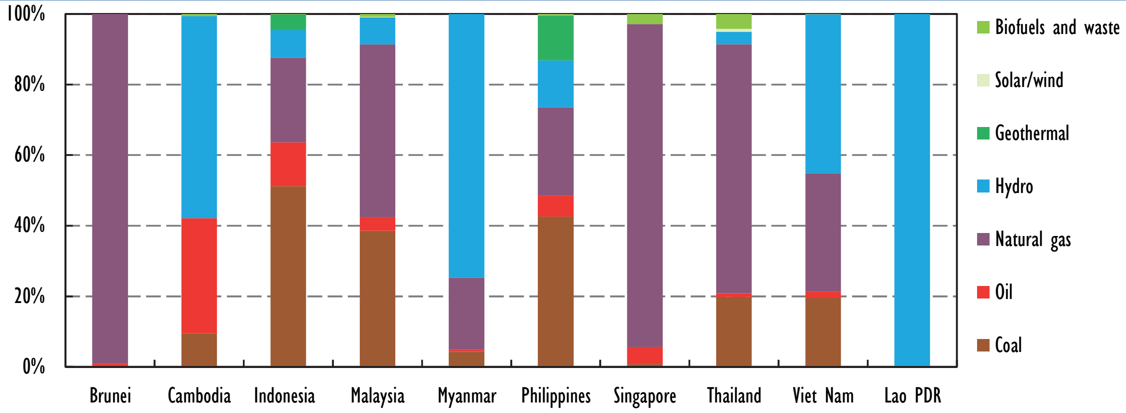
[4] CO_2 emissions intensity refers to the quantity of CO_2 emitted per unit of electricity generated. In this report, the units used are grammes of CO_2 per kilowatt hour (gCO_2/kWh). In countries where electricity generation from fossil fuels – and therefore absolute emissions – is set to rise, measuring the emissions intensity of a power unit, fleet or technology type is a useful indicator of progress made to improve environmental performance.

Power generation in Southeast Asia

The power mix in Southeast Asia is presently dominated by fossil fuels, with electricity generated from gas (44%), coal (32%) and oil (6%) in 2013 (IEA, 2015a). The share of coal is increasing rapidly, with coal-fired generation accounting for more than half of the gross thermal capacity added in the region over the past five years. Coal is expected to overtake gas to become the number one fuel source for power generation by 2030 (IEA, 2015a). Southeast Asian countries are turning to coal because of its low cost and high availability, as well to enhance electricity security through fuel and technology diversity, particularly where previous reliance on gas and, in some cases hydro, has proven expensive or insufficient to meet growing demand.

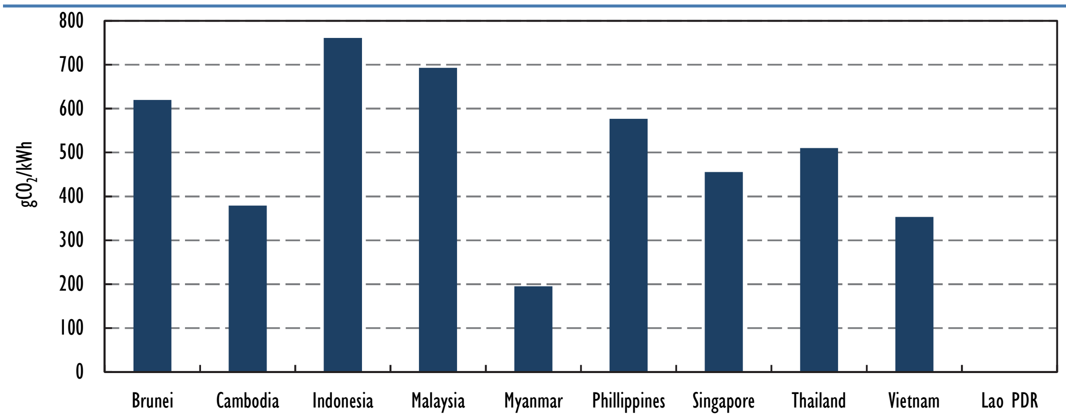
Figure 1 shows the generation mix in 2013 for Southeast Asian countries, and Figure 2 the corresponding average emissions intensity (or specific CO_2 emissions) of their power sectors. While hydropower allows Lao PDR and Myanmar to keep the emissions intensity of their power sectors low – at zero[5] and 200 gCO_2/kWh, respectively – the intensities of Indonesia, Brunei and Malaysia, where fossil-fuel power generation predominates, are in excess of 600 gCO_2/kWh.

Figure 1 • Generation mix for Southeast Asian countries in 2013



Source: IEA (2015f), *Electricity Information*, www.iea.org/statistics/.

Figure 2 • Emissions intensity of power sector in Southeast Asian countries in 2013



Source: IEA (2015h), *CO_2 Emissions from Fuel Combustion*, www.iea.org/statistics.

[5] The emissions intensity of renewable energy, including hydropower, is assumed to be zero. In Lao PDR hydropower is the most abundant and cost-effective source of electricity, accounting for some 97% of power generation in 2011 (IEA, 2015c). However, more than two-thirds of hydro electricity generated in Lao PDR is exported to neighbouring countries – primarily to Thailand and Viet Nam, but also to Cambodia.

Proposals by the governments of almost all Southeast Asian countries to increase reliance on fossil fuels – and increasingly unabated coal – in power-sector development present potentially serious environmental implications both for the region and the globe. CO_2 emissions from fossil-fired power generation contribute to long-term climate change. Furthermore, several air pollutants are also released, prominent among these being sulphur dioxide (SO_2), nitrogen oxides (NO_X), mercury and particulate matter (PM). Their release into the local environment may cause substantial detriment to health, crops and building infrastructure. Damage caused by air pollution therefore affects the wider community, and not only the producers or consumers of the electricity. Such "externalities" are generally not accounted for by power utilities or plant owners when considering what technology to install or which plant to operate. If externalities were internalised, they would significantly increase the unit cost of electricity (Box 1).

Box 1 • Estimating the cost of externalities in the power sector

Estimating the value of externalities is important as it offers a guide on what level of action, if any, is appropriate for making sustainable policy and investment decisions in the power sector. A large body of literature has assessed the full life-cycle social and environmental costs of diverse power generation technologies and arrived at various estimates for the cost of externalities in power generation in Europe and Australia.

For example, according to the EU ExternE assessments for Europe, total external costs in 2005 terms for black and brown coal power generation amounted to 41 euros (EUR) per megawatt hour (MWh) and EUR 58/MWh, respectively. By comparison, total external costs for renewables and nuclear were significantly lower than those of any fossil-fired generation technology, with the external costs of onshore wind as low as EUR 0.9/MWh and light water nuclear reactor at EUR 4/MWh (European Commission, 2005; ExternE-Pol, 2005). For China, Zhang et al. (2007) estimated the external costs of non-fossil-fired generation to range from USD 2.65/MWh for wind to USD 8.75/MWh for nuclear. A report by the Australian Academy of Technological Sciences and Engineering (ATSE, 2009) estimated that the combined costs of GHG and health damage for existing brown coal, black coal and natural gas technologies in Australia were 52 Australian dollars (AUD) per MWh, AUD 42/MWh and AUD 19/MWh, respectively. Given that the average wholesale electricity cost in Australia was roughly AUD 40/MWh, the relative cost of these externalities in the Australian context was very significant.

The wide range of estimates on externalities for different countries reveals the challenge of pricing externalities. Monetary values assigned to GHG, health, and other social costs tend to vary according to methodology as well as local context and, by extension, open up uncertainties and gaps. Nonetheless, estimates on externalities serve as valuable indicators to guide a more comprehensive assessment of the long-term benefits or negatives of choosing one type of power generation technology over another.

Source: European Commission (2005), *ExternE: Externalities of Energy, Methodology 2005 Update*, EUR21951, Edited by Peter Bickel and Rainer Friedrich, Institut für Energiewirtschaft und Rationelle Energieanwendung — IER Universität Stuttgart, European Commission, Luxembourg; ExternE-Pol (2005), "Externalities of energy: Extension of accounting framework and policy applications: New energy technologies", Final Report on Work Package 6, European Commission, www.externe.info/expolwp6.pdf; ATSE (2009), *The Hidden Costs of Electricity: Externalities of Power Generation in Australia*, Australian Academy of Technological Sciences and Engineering, Victoria; Zhang et al. (2007), "External costs from electricity generation of China up to 2030 in energy and abatement scenarios", *Energy Policy*, Vol. 35, pp. 4295-4304.

So far, the cost of externalities has not been integrated into power development planning in any Southeast Asian country and, as such, fossil-fired power generation – and, in particular, coal-fired power generation – has proliferated in recent years, being deemed the least-cost option. At present, the region's coal-fired power fleet is overwhelmingly subcritical, despite the fact that more efficient technologies are commercially available and, in many major markets around the world, already the industry standard (Box 2).

Box 2 • Coal-fired power generation technologies

Subcritical technology: For conventional pulverised coal (PC) combustion technology – the type most commonly used in coal-fired plants – powdered coal is injected into the boiler and burned to raise steam for subsequent expansion in a steam-turbine generator. Water flowing through tubing within the body of the combustor is heated to produce steam at a pressure below the critical pressure of water (22.1 megapascal [MPa]). Subcritical units are designed to achieve thermal efficiencies typically up to 38% (lower heating value [LHV], net) and would not be considered to meet the performance necessary to be described as a high-efficiency, low-emissions (HELE) technology.

HELE technologies

Supercritical (SC) technology: Steam is generated at a pressure above the critical point of water, so no water-steam separation is required (except during start-up and shut-down). SC plants typically reach efficiencies of 42% to 43%. The higher capital costs of SC technology are due largely to the alloys used and the welding techniques required for operation at higher steam pressures and temperatures. The higher costs may be partially or wholly offset by fuel savings (depending on the price of fuel).

Ultra-supercritical (USC) technology: This is similar to SC generation, but operates at even higher temperatures and pressures. Thermal efficiencies may reach 45%. At present, there is no agreed definition: certain manufacturers refer to plants operating at a steam temperature in excess of 600°C as USC, although this varies according to manufacturer and region. Current state-of-the-art USC plants operate at up to 620°C, with steam pressures from 25 MPa to 29 MPa. The overnight cost of USC units may be up to 10% higher than that of SC units, again due to the incremental improvements required in construction materials and techniques.

Advanced ultra-supercritical (A-USC) technology: Using the same basic principles as USC, development of A-USC aims to achieve efficiencies in excess of 50%, which will require materials capable of withstanding steam conditions of 700°C to 760°C and pressures of 30 MPa to 35 MPa. The materials under development are non-ferrous alloys based on nickel (termed super-alloys), which cost much more than the steel materials used in SC and USC plants. Developing super-alloys and reducing their cost are the main challenges to commercialisation of A-USC technology.

Integrated gasification combined cycle (IGCC): Coal is partially oxidised in air or oxygen at high pressure to produce a fuel gas. Electricity is then produced via a combined cycle. In the first phase, the fuel gas is burnt in a combustion chamber before expanding the hot pressurised gases through a gas turbine. The hot exhaust gases are then used to raise steam in a heat recovery steam generator before expanding it through a steam turbine. IGCC incorporating gas turbines with 1 500°C turbine inlet temperatures are currently under development, which may achieve thermal efficiencies approaching 50%. IGCC plants require appreciably less water than PC combustion technologies.

Source: IEA (2012), *Technology Roadmap: High-Efficiency, Low-Emissions Coal-Fired Power Generation*.

Much of the regional growth in coal-fired power generation is being driven by Indonesia, the world's largest exporter of thermal coal. Of the 57 GW of installed unabated coal capacity in Southeast Asia in 2015, Indonesia accounted 32.7 GW (57.4%), with Malaysia and Viet Nam accounting for a further 21.7 GW of coal capacity between them.[6] Altogether, the three countries had a combined coal capacity of 54.4 GW by the end of 2015, with around 91% of that employing

[6] To a lesser extent, Thailand and the Philippines also have some coal power capacity and are planning to increase coal-fired power generation, with both countries at times facing heavy public opposition against coal plant construction.

subcritical technology and over nine-tenths of these coal plants constructed after the year 2000 (Platts, 2015). The concentration of the bulk of Southeast Asia's coal plants in Indonesia, Malaysia and Viet Nam, coupled with the relative youth of their coal fleets, highlights the critical importance to the region of addressing the sustainability of their power development plans.

The upward trajectory of total CO_2 emissions from the Southeast Asian power sector will continue as countries add unabated fossil-fired generation capacity to meet rapidly increasing electricity demand. Nevertheless, it is possible to reduce CO_2 emissions intensity by deploying CCS, diversifying the power mix and investing in energy efficiency.

Fortunately, while current power development plans include a significant expansion in coal-fired power generation in the three countries for the foreseeable future, these policies are not set in stone. Cognisant of their pledges to COP21, the governments of Indonesia, Malaysia and Viet Nam are mindful of the opportunities to transition to a greener electricity sector, as clean and energy-efficient technologies become increasingly affordable and available. Indeed, they have already started to review their policies and targets to scale down coal capacity additions in favour of lower-carbon alternatives, such as gas, renewables and nuclear.

At the 33rd ASEAN[7] Ministers of Energy Meeting in October 2015, ministers endorsed the ASEAN Plan of Action for Energy Cooperation (APAEC) 2016-25 (ACE, 2015). This sets out specific energy intensity and renewable energy targets for the region in order to achieve common goals to limit the use of fossil fuels and address their environmental challenges. APAEC 2016-25 targets an ASEAN-wide energy intensity reduction target of 20% by 2020 and 30% by 2025 (from 2005 baselines), and a 23% renewable energy target for the Southeast Asian energy mix by 2025.

By the end of COP21 in December 2015, all ten Southeast Asian countries were co-signatories of the Paris Agreement (UNFCCC, 2015). Each country accepted responsibilities to meet pledges made in the form of Intended Nationally Defined Contributions (INDCs) to support global efforts to stabilise GHG emissions in the atmosphere "at a level that would prevent dangerous anthropogenic (human-induced) interference with the climate system […] within a time-frame sufficient to allow ecosystems to adapt naturally to climate change" (UNFCCC, 1992). The INDCs from Southeast Asian countries outlined specific measures to reduce their energy-related GHG emissions. This marked an unprecedented engagement of Southeast Asian countries in global efforts to address climate change. Furthermore, following COP21, many Southeast Asian countries, including Indonesia, Malaysia and Viet Nam, significantly increased their efforts to achieve their national emissions reduction targets by improving energy efficiency and increasing the share of renewable energy technologies in their energy mix. To ensure countries are on the pathway to meeting their INDCs, accounting is due to begin in 2020. Then, signatory countries agreed to move quickly to net-zero emissions of energy-related CO_2 from 2050.

While these government targets to reduce energy intensity and increase the use of renewable energy are encouraging, higher ambition is needed to reduce emissions and improve the sustainability of the power sector overall. In particular, unabated coal-fired generation needs to be addressed today if the lock-in of emissions over the long term is to be avoided.

Power generation in Indonesia, Malaysia and Viet Nam

In this section the power sectors of Indonesia, Malaysia and Viet Nam are discussed. The current generation mix is presented for each country, together with respective government plans for the next five to ten years.

[7] The Association of Southeast Asian Nations.

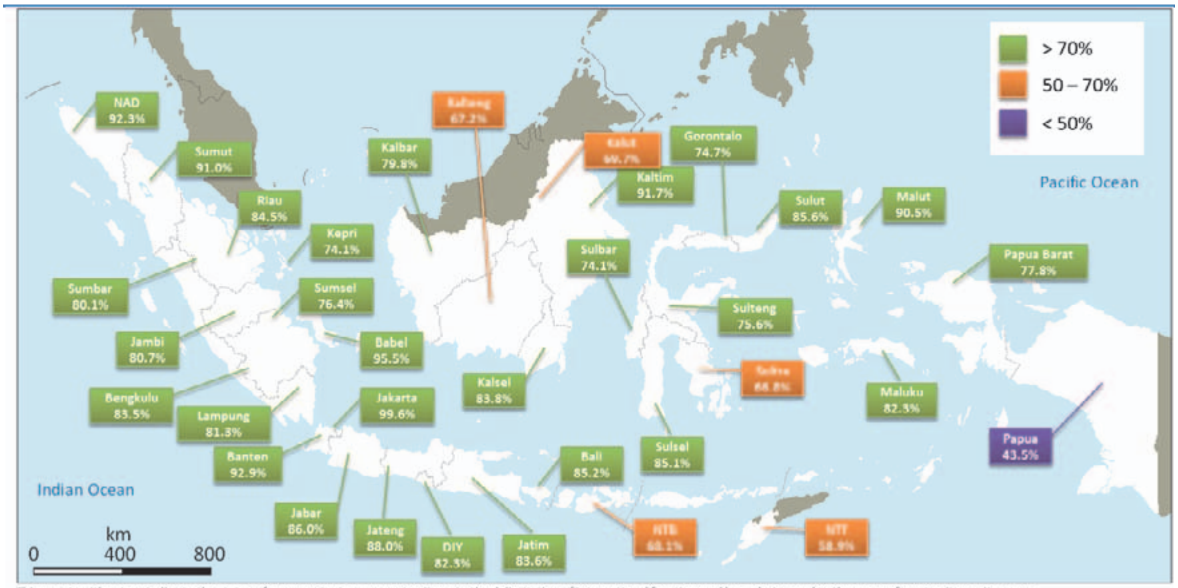
Indonesia's power development and domestic plans

Current development context

The power sector is the largest consumer of energy in Indonesia, having underpinned the archipelagic nation's rapid economic development over the last decade. Between 2004 and 2014, Indonesia almost doubled its electricity generation from 117 TWh to 229 TWh (DG Electricity, 2016). The main consumers of electricity in Indonesia in 2015 were the residential sector (43%), followed by the industrial sector (32%) and commercial sector (18%) (DG Electricity, 2016). Of these three highest electricity consumers, for the period 2004-14 the commercial sector saw the strongest growth in demand at around 9% compound annual growth rate, followed by the residential sector at around 8.1%, with industry slowest at around 6.1% (DG Electricity, 2016).

The government's primary objective for power-sector development is to ensure the availability and affordability of a stable supply of electricity to improve social welfare (Electricity Law No. 30/2009). The Indonesian government, together with the vertically integrated state-owned power utility PT Perusahaan Listrik Negara (PLN), have made remarkable progress in improving the country's electrification rate from 66% in 2009 to 88.3% in 2015 (DG Electricity, 2016). The Ministry of Energy and Mineral Resources (MEMR) is currently aiming to reach a national electrification rate of 97.4% by the end of 2019 (DG Electricity, 2016), to make basic service provision to the whole population and support industrial development across the country. In February 2016, MEMR launched a "Bright Indonesia" (Indonesia Terang) program aimed at increasing the electrification rate in the eastern provinces, with priority to the following six provinces: Papua, West Papaua, East Nusa Tenggara, West Nusa Tenggara, Malaku and North Malaku (Jakarta Globe, 2016).

Figure 3 • Electrification rates in Indonesia in 2014



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries, and to the name of any territory, city or area.

Notes: NAD = Nanggroe Aceh Darussalam; NTT = Nusa Tenggara Timur (province); NTB = Nusa Tenggara Barat (province); DIY = Daerah Istimewa Yogyakarta.

Source: DG Electricity (2014), *National Electrification Plan (RUKN) 2015-34*, www.djk.esdm.go.id/pdf/Draft%20RUKN/Draft%20RUKN%202015%20-%202034.pdf.

While Indonesia's national electrification rate is already high, electrification rates vary significantly across the country's 34 provinces and over 17 000 islands – particularly between urban and rural regions (Figure 3). Electrification rates spike in higher-income industrial centres in Java-Bali and Surabaya, and taper off in less developed or underserviced grids and communities in the eastern provinces, the latter of which still rely on a scattered number of small diesel power plants. While Jakarta has nearly full electrification, at over 99%, the electrification rates of the far eastern regions of Nusa Tenggara Timur and Papua are just 59% and 43%, respectively (DG Electricity, 2014). Moreover, a large number of households have unreliable or low-quality access to power in terms of the number of hours of continuous electricity. MEMR has assigned PLN to lead a rural electrification programme, which will prioritise extending electricity access to provinces with low electrification rates (MEMR, 2015).

In 2015, fossil fuels dominated the generation mix, accounting for 89.6% of total generation, with coal generating 56.1%, gas 24.9% and oil 8.6% (DG Electricity, 2016). The share of generation from renewable energy was 10.4%, or around 6% of total energy consumption. The bulk of renewable electricity generation came from hydro (57%), followed by geothermal (41%), with solar, wind, biofuels and waste together contributing less than 2%.

Coal in particular has increased its role in the electricity mix, with capacity additions outpacing those of any other type of power generation. The proliferation of coal use in power generation is supported by its resource abundance across Indonesia and its lower levelised cost of electricity (LCOE) relative to other sources of electricity.

The substantial growth in coal-fired power in the past decade stems from the implementation of two legacy Fast Track programmes, referred to as Phase I and Phase II. The two phases are part of PLN’s Electricity Supply Business Plan (RUPTL) strategy to boost generation capacity. Phase I 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; it was initially expected to be completed by 2009 but is still incomplete. Phase II was launched in 2009 to develop a further 10 GW of capacity by 2014, this time with private sector participation, but this phase too has faced severe delays due to difficulties with land access, grid infrastructure constraints, complex government policies and regulation.

Indonesia’s power development plans

Indonesia’s power planning is underpinned by three key policy documents: the National Energy Plan (KEN), the General Plan for National Electricity Development (RUKN), and PLN's Electricity Supply Business Plan (RUPTL). The three plans are formulated by different government entities, with each updated annually, albeit with different projection periods and sometimes different targets (Table 1). The KEN addresses the entire energy sector in Indonesia and is formulated by the country’s principal energy co-ordinating body, the National Energy Council (DEN), which is chaired either by the President or Vice President. The KEN sets a target to achieve a 23% share of renewables in the country’s overall energy mix by 2025 (Table 1), which is considered highly ambitious by both MEMR and the state utility company PLN.

The Directorate General of Electricity (DG Electricity) in MEMR is responsible for developing the RUKN, which sets out targets and actions specific to the power sector. The RUKN is the main policy document guiding electricity sector development in Indonesia, as PLN also uses the RUKN as a framework for developing the utility company’s own business plan (RUPTL). The RUKN proposes a power mix that features a much higher share of coal at 50%, with the remaining half roughly split between gas and renewable energy. PLN is currently developing its business plan to support RUKN targets, although not without difficulty, particularly in achieving the gas and renewable energy targets, while also meeting company objectives concerning sales growth, plant development, and transmission and distribution (T&D) investments.

Table 1 • Generation mix targets in Indonesia's key power sector development plans

Fuel Type	National Energy Policy (KEN) Target by 2025	PLN Electricity Supply Business Plan (RUPTL 2015-24) Target by 2024	Draft National Electricity Development Plan (Draft RUKN 2015-34) Target by 2025
Coal	30%	63.7%	50%
Gas	22%	19.2% (including LNG)	24%
Oil	25%	1.5%*	1%
Renewable energy	23%	15.6%**	25%***

Note: LNG = liquefied natural gas.

* Includes "oil and other fuels", others being biomass, high-speed diesel and medium fuel oil (MFO).

** Comprises 9% geothermal and 6.6% hydroelectric.

*** Revised upward from 23% in July 2015.

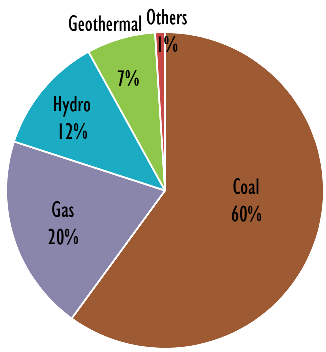
Sources: DEN (2014), *Kebijakan Energi Nasional (KEN)*; DG Electricity (2014), *National Electrification Plan (RUKN) 2015-34*, www.djk.esdm.go.id/pdf/Draft%20RUKN/Draft%20RUKN%202015%20-%202034.pdf; PLN (2015), *Rencana Usaha Penyediaan Tenaga Listrik 2015-2024.*

At present, Indonesia is still constructing several of the power plants planned in Phase I of the Fast Track programme, with most of the Phase II projects also incomplete. Phase II is targeting 40% coal, 34% geothermal, 11% hydro and 15% natural gas, with completion now expected during the RUPTL 2015-24 period.

In 2014, in addition to the two Fast Track programmes, MEMR announced a target to add another 35 GW of capacity across Indonesia by 2019 (the "35 GW Plan"), of which half would be coal-fired, a quarter renewable energy and a quarter gas. These capacity additions would be undertaken primarily by independent power producers (IPPs), which are expected to contribute 30 GW, while PLN contributes the remaining 5 GW (DG Electricity, 2014). At the end of 2014, some 6.6 GW were under construction and another 17 GW committed (PLN, 2015: 88). A further 18.7 GW were in the planning stage. If PLN targets are realised as planned, Indonesia could expect nearly 60% of the total capacity installed by PLN and the IPPs to be coal-fired by 2019.

According to RUPTL 2015-24, further general capacity additions target a total increase of 70.4 GW over this period (Figure 4). According to RUPTL, PLN and the IPPs will develop 21.4 GW and 35.5 GW of generation capacity, respectively, while the remaining 13.5 GW have yet to be allocated (PLN, 2015). By 2024, RUPTL projects that some 60% of Indonesia's capacity additions would be coal-fired, 20% gas-fired, and the remaining share from renewables and other fuels or technologies. By 2025, Indonesia anticipates reaching 146 GW of installed generation capacity, of which 134 GW would come from the PLN system and the other 12 GW from outside the PLN system (DG Electricity, 2014).

Figure 4 • Share of generation capacity additions in RUPTL 2015-24



Source: PLN presentation to IEA on 3 June 2015 in Jakarta.

MEMR aims to increase the share of renewables in the power mix from around 12% to 23% in 2025 (draft RUKN 2015-34), consistent with the National Energy Plan (KEN), and has introduced a number of investment incentives including feed-in-tariffs (FITs) for all types of renewables. As of 2009, MEMR had mobilised a USD 400 million Clean Technology Fund, which brings significant financial support to the development of large-scale geothermal power projects. While there have been scattered discussions about nuclear power in Indonesia, current plans remain uncertain amid considerations of safety following Fukushima and the complicated geography of the archipelagic country.

In the country's overall energy mix, Indonesia had originally aimed to achieve a 23% target for new and renewable energy by 2025 in both the draft National Energy Plan (draft RUKN 2015-34) and the INDC that Indonesia submitted to the UNFCCC in 2015 ahead of COP21 in Paris. However, since then, both the RUKN and PLN have adopted a higher 25% renewable energy target for the power sector.

In order to achieve the capacity additions envisaged in Indonesia's power development plans, it is crucial that land permits and finance be secured in a timely manner, with equipment mobilised and construction tenders discharged more effectively. Following the experience of the two Fast Track power development programmes in Indonesia, there is a strong likelihood that the capacity additions envisaged in the 35 GW Plan will also be delayed and, perhaps, offer the opportunity for Indonesia to emerge with a greener power mix as the government continues to advocate and facilitate increased renewable energy deployment.

Malaysia's power development and domestic plans

Current development context

Malaysia's power sector is divided into three distinct systems, with Peninsular Malaysia physically separated from Sabah and Sarawak by the South China Sea, and individual power development plans developed for each of the three systems. Reflecting the population density and industrial activity of the country, approximately 90% of demand is centred in Peninsular Malaysia.

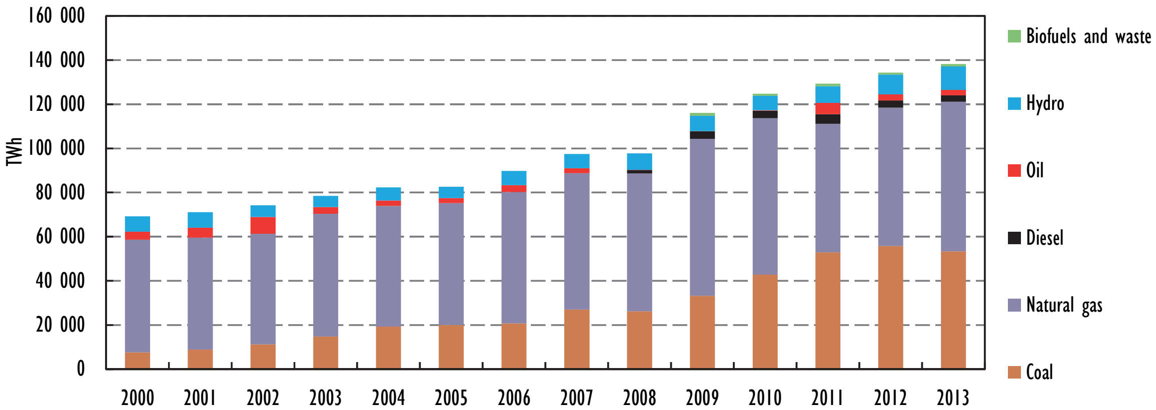
The economic shift from agriculture and primary commodities to manufacturing and services has underpinned much of the growth in Malaysia's electricity demand, which has more than doubled this century, from 61 TWh in 2000 to 124 TWh in 2013. As of 2013, the largest electricity-consuming sectors in Peninsular Malaysia are the industrial (43%), commercial (35%) and residential (22%).

Malaysia currently has one of the highest overall electrification rates in Southeast Asia, although rates vary by location: Peninsular Malaysia has nearly full electrification; Sabah has 94.08% and Sarawak 93%. The small share of the population still without grid access tends to be located in remote, hard-to-reach areas, and is therefore more reliant on distributed generation from small hydro, biomass, biogas and solar, as well as the innovative solar hybrid (solar and diesel) system.

In Sarawak, hydropower has the highest share of generation capacity, although there are also diesel engines, coal-fired power plants, open-cycle gas turbines (OCGTs) and combined-cycle gas turbines (CCGTs). While coal makes up only 21% of the installed capacity, it generates 31% of Sarawak's electricity, signalling the importance of coal-fired power generation.

While Malaysia is the region's second-largest oil and gas producer, and has traditionally relied on gas for the bulk of its power generation, the trend of power development in Peninsular Malaysia and Sarawak is increasingly shifting towards coal-fired generation, due to the cheaper cost of coal relative to gas, as well as concerns about depleting gas resources that have underscored government objectives to diversify the power mix. Between 2000 and 2013, the share of gas in Malaysia's generation decreased from 74% to 49%, while the share of generation from coal increased from 11% to 38% (Figure 5).

Figure 5 • Malaysia's generation mix 2000-13



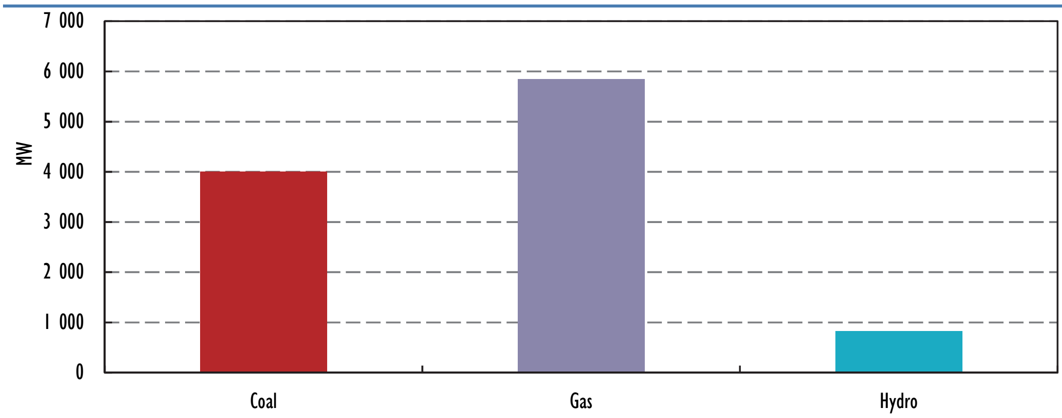
Source: IEA (2015d), *Energy and Climate Change – World Energy Outlook 2015 Special Report*, www.iea.org/publications/freepublications/publication/WEO2015SpecialReportonEnergyandClimateChange.pdf.

Malaysia's power development plans

The three regional power systems in Malaysia each have their own power development plans. Those of Peninsular Malaysia and Sabah are planned and approved by the energy industry regulator, the Energy Commission (Suruhanjaya Tenaga), while Sarawak's power plans are developed by the vertically integrated Sarawak Energy Berhad (SEB) and approved by the state government.

According to the Energy Commission's power development plans for Peninsular Malaysia, planned and approved capacity additions to the system in the period 2016-23 will feature: 4 000 megawatts (MW) coal, 5 846 MW CCGT and 830 MW hydropower (Figure 6). Malaysia aims to continuously improve the efficiency of both gas and coal-fired power plants by using advanced technologies as they are introduced, which would help further alleviate resource consumption in the power sector.

Figure 6 • Malaysia's capacity additions 2016-23



Source: Single Buyer (2016), Single Buyer Department, Tenaga Nasional Berhad, Kuala Lumpur, personal communication.

In Sarawak, the addition of hydropower capacity is expected to be much more significant than that of both gas and coal. The 2008-30 Sarawak Corridor of Renewable Energy (SCORE) development plan estimates that approximately 1 500 MW of coal capacity will be added to the system, with a similar addition expected from gas (SEB, 2015).

Sabah, which has no coal capacity installed or planned, will continue to rely on gas turbines – both OCGT and CCGT – for more than three-quarters (77%) of its capacity additions up to 2025 (Energy Commission, 2015). While OCGTs are not the most efficient power generation option, their main purpose is to offer a low-cost alternative to Sabah's dependency on diesel plants. Hydropower will contribute a further 19% of Sabah's generation capacity in 2025, aided by the implementation of the Upper Padas Hydroelectricity Project after 2020.

At the national level, the purpose of the National Renewable Energy Policy and Action Plan (NREAP) (KeTTHA, 2009) is to increase the share of renewables in total generation capacity from approximately 9% in 2009 to 13% in 2030 and 34% in 2050. The 11th Malaysia Plan for 2016-20, devised by the Economic Planning Unit (EPU) of the Prime Minister's Office, helps advocate support for increased renewable generation capacity by setting a target of 2 080 MW by 2020 (EPU, 2015). Other policies that support renewable energy growth include the Five-Fuel Policy enacted in 2001, the 2009 National Renewable Energy Policy and Action Plan, and the 2011 Renewable Energy Act.

The Malaysian government offers FITs for small hydro, solar photovoltaic (PV), biomass and biogas, and the FIT scheme has been particularly successful in increasing solar PV deployment. From the 11th Malaysia Plan onward, the government plans to shift the incentive measure for solar PV from FITs to net metering.

Of all government intentions to reduce emissions, Malaysia has proposed one of the more ambitious INDC targets in Southeast Asia, namely to reduce the GHG emissions intensity of GDP by 45% in 2030 relative to the 2005 baseline. While the main target sector for Malaysia's INDC is transport, it does aim to reduce overall emissions of GHGs, CO_2, methane and NO_x, as well as supporting renewable energy deployment via FITs and increasing investment in green technologies, all of which influence the greening of Malaysia's power sector.

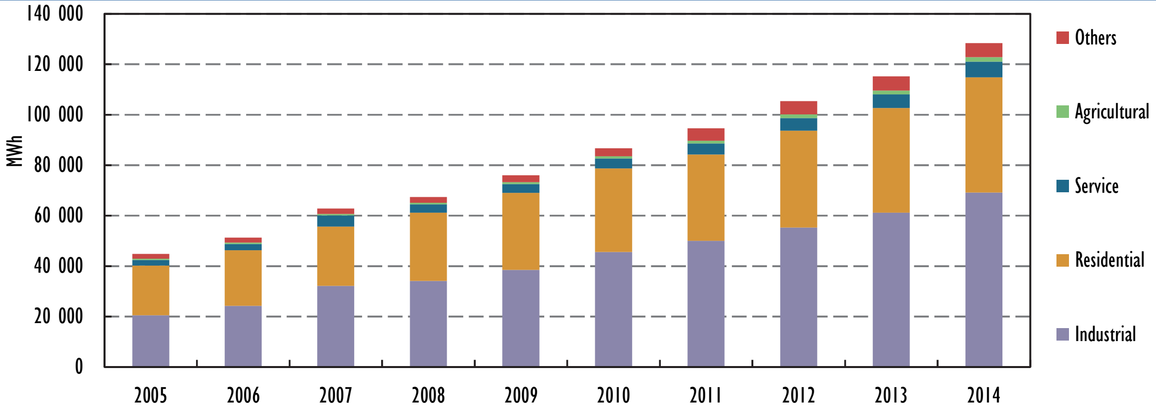
Generally speaking, Malaysia's emissions reduction plans for the power sector will primarily focus on energy efficiency gains in coal- and gas-fired power generation, while continuing to increase renewable energy deployment – particularly hydropower, solar PV and biomass – where resources permit. As well as encouraging the growth of renewable energy capacity, the EPU also plans to formulate a demand-side management plan to promote energy efficiency, specifically in the power sector (Private communication with EPU, 2015).

Viet Nam's power development and domestic plans

Current development context

Viet Nam's power sector has experienced a high rate of growth over the past decade, as strong economic growth continues to underpin rising electricity demand. The largest electricity-consuming sectors in Viet Nam are industry and residential, which, in 2014, accounted for 69 TWh (54%) and 46 TWh (36%) of the country's electricity demand, respectively (Figure 7).

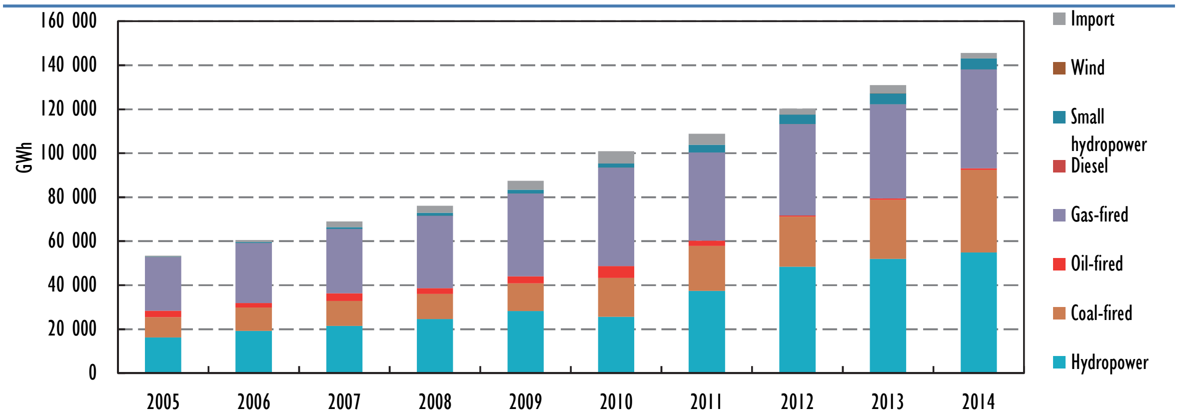
Figure 7 • Viet Nam's electricity consumption by sector, 2005-14



Source: EVN (2015), "Vietnam Power System: Key Performances and Development", presentation from May 2015, presented to IEA on 4 June, Hanoi.

To meet Viet Nam's rising demand for electricity, total electricity generation in the country almost tripled between 2005 and 2014, with the most significant increases coming from coal-fired plants and hydropower (Figure 8). At present, Viet Nam generates some 40% of its electricity from hydropower, followed by coal at 29% and gas at 22% (EVN, 2015). As Viet Nam's hydropower capacity approaches its maximum potential and gas production remains stable, coal-fired power generation is expected to meet increasing demand and, ultimately, surpass hydropower and gas within the next five years.

Figure 8 • Viet Nam's electricity generation mix, 2005-14



Note: GWh = gigawatt hour.

Source: EVN (2015), "Vietnam Power System: Key Performances and Development", presentation from May 2015, presented to IEA on 4 June, Hanoi.

The state utility company, Electricity of Viet Nam (EVN), reports some 35 GW of installed generation capacity as of December 2014, comprising 45% hydropower, 28% coal, 21% gas, 3% oil and 3% imported electricity (EVN, 2015). While hydropower boasts the largest share of installed capacity in Viet Nam, seasonal variability in rainfall during wet and dry seasons effectively means that the share of generation from hydropower has varied between 29% and 46% over the past decade (IEVN, 2015c). During the dry season, CCGT plants play an important role in supplying electricity. However, Viet Nam's CCGT plants are mainly located in the south of the country, close to developed offshore natural gas fields, while uneconomic gas resources with high CO_2 content are located in the north. This means that, pending further investment in gas development and the electricity grid network, gas plants have only limited potential to offset fluctuations in hydropower. Consequently, the Vietnamese government considers coal-fired power generation to be essential for electricity security.

Currently, the installed capacity of small hydro and other renewable energy sources, such as wind, solar and biomass, is approximately 1 876 MW (Table 2). Solar and wind deployment have been particularly weak. Most solar installations to date are small off-grid pilot projects. According to the Ministry of Industry and Trade (MOIT), Viet Nam has around 8 000 MW of wind potential (≥6 metres per second [m/s]) but, as yet, only 52 MW have been installed (MOIT, 2015a). MOIT, with support from the German and Danish governments, is actively encouraging wind power development, and has registered plans to construct an additional 3 000 MW of wind power projects (MOIT, 2015a). Overall, Viet Nam has strong potential to scale up its renewable energy deployment, particularly given the government's support for increasing renewable energy capacity in the coming decades.

Table 2 • Breakdown of installed capacity for small hydro and other renewables in Viet Nam, 2014

Renewable energy	Installed capacity (MW)
Small hydro	1 670
Wind	52
Solar	4*
Biomass	150

* 0.6 MW grid-connected.

Source: MOIT (2015a), "Renewable Energy in Vietnam", presentation by Nguyen Ninh Hai to the European Commission on 15 April, Hanoi.

Viet Nam's power development plans

Viet Nam's power development planning and investment must be consistent with the terms of the 2004 Electricity Law, which applies to all government entities involved in the electricity sector. The law prescribes all rights and obligations relating to national power production, distribution and sales. Specific power development plans are outlined in the country's Master Power Development Plan (PDP), led by the MOIT, and the Renewable Energy Development Plan to 2030 with outlook to 2050 (hereafter the Renewable Energy Plan), which was signed by the Prime Minister in 2016. Viet Nam's power development plans are also shaped by a number of other important legal documents that include clauses related to the power sector, including the National Energy Development Strategy 2007, Law on Environment Protection 2005, Law on Energy Efficiency and Conservation 2010, and the Viet Nam Green Growth Strategy. Table 3 highlights selected policies from various legal documents that shape Viet Nam's outlook for power-sector development.

Table 3 • Selected laws and strategies encouraging sustainable power sector development in Viet Nam

Document	Policy
Law on Environment Protection	Article 6: Develop and utilise clean and renewable energies and reduce emissions from gases that pollute the environment, cause greenhouse effects, deplete the ozone layer or contribute to climate change; Article 33: Gradually increase the percentage of renewable energy in total energy production, and enhance national energy security by conserving natural resources.
National Energy Development Strategy 2007	Increase the share of new and renewable energy to 3% of primary energy consumption by 2010; 5% by 2020 and 11% by 2050. Prepare nuclear development with the aim that nuclear power will account for 15-20% of total energy consumption by 2050.

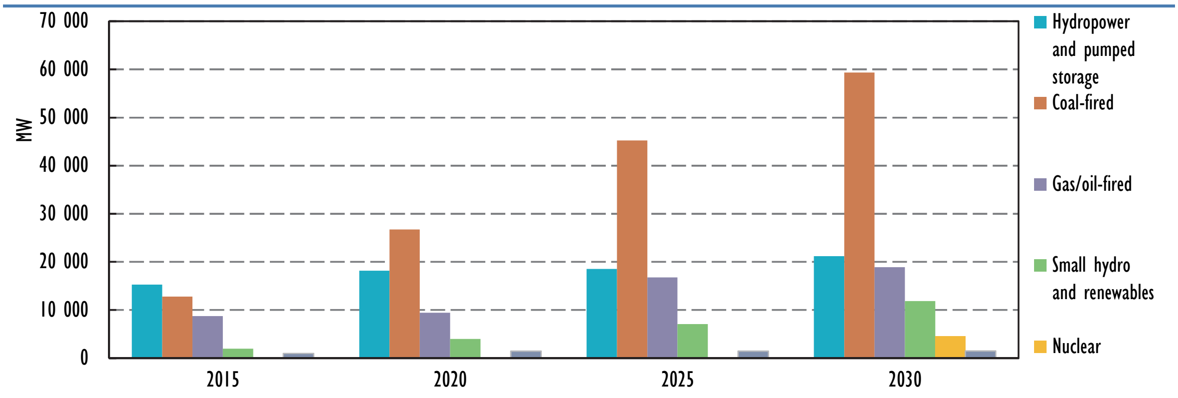
Law on Energy Efficiency and Conservation 2010	Article 13 states that power producers must: select high-efficiency technologies; use waste heat and hot vapour for the burning process; dry fuel to enhance plant efficiency; establish a plan to reduce energy consumption for the plant's own use.
Viet Nam Green Growth Strategy	Aims to reduce total GHG emissions per unit of GDP by 8-10% by 2020 (compared to 2010 baseline), and GHG emissions from energy activities by 10-20% compared to the business-as-usual (BAU) case. By 2030, the strategy aims to reduce total GHG emissions per unit of GDP by at least 1.5-2% per year, and GHG emissions from energy activities by 20-30% compared to BAU.

Sources: Viet Nam Law on Environmental Protection (2014), *Law No. 55/2014/QH13*; Prime Minister's Decision No. 1855/2007/QD-TTg (2007), *Approval of National Energy Development Strategy up to 2020 with outlook to 2050*; Viet Nam Law on Energy Efficiency and Conservation (2010), *Law No. 50/2010/QH12*; Prime Minister's Decision No. 1393/2012/QD-TTg (2007), *Approval of National Green Growth Strategy*, Hanoi.

The MOIT and Institute of Energy (IEVN) are currently revising the seventh Master Power Development Plan for the period 2015-30 (hereinafter referred to as the revised PDP VII). The revised PDP VII estimates that electricity generation will continue to grow at an average rate of 8.8% per annum until 2030. Therefore, between 2015 and 2030, the revised PDP VII envisages a dramatic expansion of generation capacity, which will primarily be led by coal-fired power plants.

The heavy reliance on coal-fired generation stems from the government's aim to expand electricity access at affordable rates for the prosperity of its industries and citizens. In the absence of a carbon price, coal-fired power generation is considered by Viet Nam to be the least-cost option for electricity provision, at least where hydropower resources are unavailable. Total installed capacity for coal-fired power plants is expected to increase at an average rate of 8% per year to reach 57 GW by 2020 and 115 GW by 2030. Some 45 GW of additional coal-fired capacity are projected to be added to Viet Nam's power sector by 2030 (Figure 9), with a significant proportion of this expected to be added within the next five years. Coal-fired capacity is anticipated to account for around 75% of total capacity additions by 2020 (IEVN, 2015b). However, IEVN suggests that these planned additions may not be fully implemented if electricity demand growth slows in tandem with Viet Nam's transition towards a more efficient or service-oriented economy, or if nuclear power is successfully introduced after 2028 (IEVN, 2015b).

Figure 9 • Capacity expansion by plant type in Viet Nam's revised PDP VII



Source: IEVN (2015b), *Revised Master Plan for Power Development in Vietnam 2011-2020 with Outlook to 3030* (Revised PDP VII, pending approval).

Current supplies of renewable energy are dominated by large hydropower and pumped storage plants, but their rate of expansion will be slower than that of small hydro and other renewables in the projection period of 2015-30.

Since 2007, MOIT has continuously increased its renewable energy target. The Renewable Energy Plan, signed by Prime Minister Nguyen Tan Dung, aims to increase the share of renewable energy in power generation (including large hydropower) from 35% in 2015 to 38% in 2020 and 43% in 2050 (Prime Minister's Decision No. 2068, 2015). The main targets in the Renewable Energy Plan are summarised in Table 4. .

Table 4 • Main targets in Viet Nam's Renewable Energy Development Strategy to 2050

Renewable energy (RE)	2015	2020	2030	2050
RE production (Mtoe)	25	37	62	138
RE share of total primary energy consumption	31.8%	31%	32.3%	44%
RE in electricity production (GWh)	58 (35%)	101 (38%)	186 (32%)	253 (43%)
Hydro (GWh)	56	90	96	
Pumped storage capacity (MW)	n/a	n/a	2 400	8 000
Biomass (toe)	0.3	1.8	9	20
Wind (GWh)	0.180 million kWh	2.5 (1%)	16 (2.7%)	53 (5%)
Solar (GWh)	0.01	1.4 (0.5%)	35.4 (6%)	10 (20%)

Notes: kWh = kilowatt hour; Mtoe = million tonnes of oil-equivalent.

Source: Prime Minister's Decision No. 2068 (2015), *Viet Nam's Renewable Energy Development Strategy up to 2020 with an Outlook to 2050*.

In January 2016, the Prime Minister announced Viet Nam's intention to cap new coal-fired power generation projects (Viet Nam News, 2016). According to the IEVN (IEVN, 2015b), this announcement will have limited effect on the PDP VII, which is currently being revised, as Viet Nam needs to add coal capacity to meet increasing demand for at least the next five to ten years until renewable and gas-fired power generation become more affordable for Viet Nam. The country's power sector has not yet reached the development level of Malaysia or Indonesia and, therefore, remains more dependent on cheaper coal-fired generation for the short-to-medium term. However, the government's public announcement of its commitment to scale back new coal development sends a strong signal that the country's coal capacity additions are likely to continue to be revised downwards.

With regard to policy support for emissions reduction in the power sector, Viet Nam has more stringent standards for stack emissions than both Indonesia and Malaysia, but weaker standards compared to China (Table 5). Additionally, new thermal plants cannot be approved after 10 February 2014 unless they meet minimum efficiency standards (Box 3).

Table 5 • Representative emissions regulation limits for Indonesia, Malaysia, Viet Nam and China

Country	SO_2 (mg/m^3)		NO_x (mg/m^3)		PM (mg/m^3)	
	Lower	Upper	Lower	Upper	Lower	Upper
Indonesia	750	750	750	850	100	150
Malaysia	500	500	500	500	400	600
Viet Nam	500	500		600	200	200
China	100	200	100	100	30	0

Notes: Above emissions limit values are expressed at 25°C, 101.3 kilopascal with 6% oxygen in the flue gas; mg/m^3 = milligrammes per cubic metre; TBA = to be announced.

Source: IEA CCC, (2016), "Emission standards", IEA Clean Coal Centre Database Section. Retrievable: http://www.iea-coal.org/site/2010/database-section/emission-standards

Box 3 • Minimum efficiency standards for new coal- and gas-fired power plants in Viet Nam

In 2013, the Vietnamese Prime Minister approved a roadmap to employ efficient technologies in power generation. This decision came into effect on 10 February 2014. After this date, new power plants that do not meet the minimum efficiency standards below cannot be approved. In this roadmap, the minimum efficiencies of thermal power units are as follows:

Coal-fired

- Rated capacity >50 MW and <150 MW: 34%
- Rated capacity ≥150 MW <300 MW: 38%
- Rated capacity ≥300 MW and <600 MW: 39%
- Rated capacity ≥600 MW and <800 MW: 41%
- Rated capacity ≥800 MW: 43%.

Gas OCGT

- Rated capacity >100 MW and <150 MW: 33%
- Rated capacity ≥150 MW <200 MW: 34%
- Rated capacity ≥200 MW and <300 MW: 37%
- Rated capacity ≥300 MW: 39%.

Gas CCGT

- Rated capacity >100 MW and <150 MW: 49.5%
- Rated capacity ≥150 MW <200 MW: 51%
- Rated capacity ≥200 MW and <300 MW: 55.5%
- Rated capacity ≥300 MW: 58.5%.

Note: LHV efficiency with cooling water temperature of 30°C and ambient temperature of 28°C.

Source: Prime Minister's Decision No. 78/2013/QD-TTg (2013), 25 December, Hanoi.

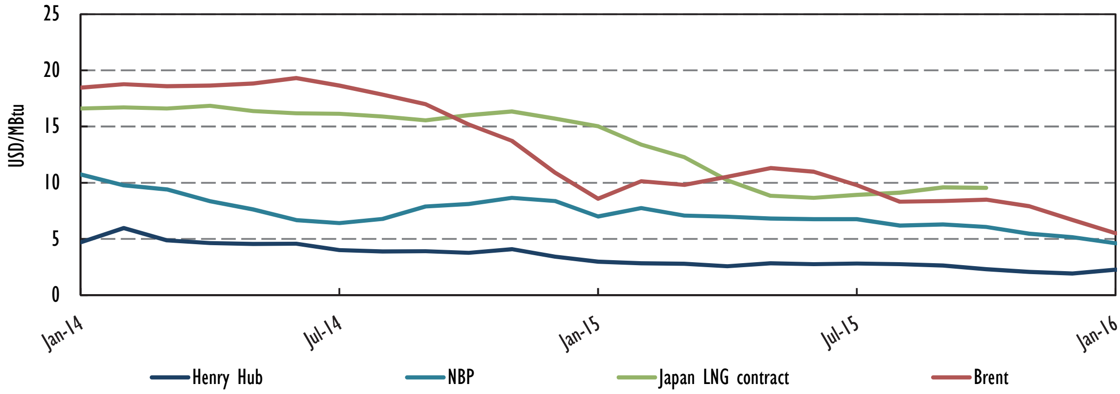
However, Viet Nam has no target for carbon reductions that relates specifically to the power sector, and its INDC submission to COP21 shows a weak commitment to reducing its overall GHG emissions – an 8% reduction compared to BAU by 2030, although the target increases to 25% with international support. Overall, Viet Nam could aim for much more ambitious emissions reduction targets in its power sector, although the government does appear committed to progressively cutting back on generation from coal.

Fuel competition: Shaping power sector development

The shift towards coal-fired power generation in Southeast Asia is underpinned by coal's price advantage and availability relative to natural gas and other fuel sources. International coal prices have been in decline since 2011 and are at their lowest levels since 2005; at the end of 2015, they were hovering around USD 50 per tonne (t) (IEA, 2016c). Price recovery in the medium to long term is uncertain given the oversupply in the global coal market (IEA, 2015e). Furthermore, Indonesia, the world's fifth-largest coal producer and largest exporter by tonnage (second-largest exporter in terms of energy content), is ready to supply the region and beyond with low-cost coal. For Southeast Asian governments aiming to gradually scale back electricity subsidies while keeping retail tariffs low, coal offers the most economic fuel choice for providing stable and affordable electricity but, crucially, only insofar as the cost of externalities (damage to health and the environment) are not factored into the cost of power generation.

While Indonesia and Malaysia are the top two producers and net exporters of gas in the region, the higher relative cost of using gas rather than coal for power generation, along with the tighter availability of gas, have compelled both countries to increase coal consumption and increase gas exports. Viet Nam is the only other coal exporter in Southeast Asia, but is increasingly redirecting exports to its own domestic power sector and, since 2011, has already been importing coal for this purpose. It is expected that rising domestic demand will turn Viet Nam into a net coal importer by 2017 (IEA, 2015e). Viet Nam is already anticipating that Indonesia and Australia will be its dominant coal suppliers in the decades to come.

Figure 10 • Global gas price developments in key regions, Jan 2010-Jan 2016



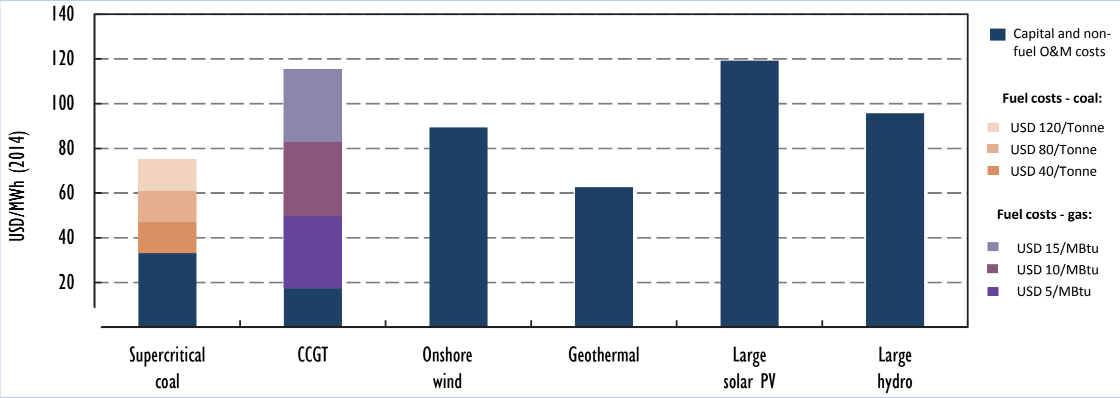
Note: MBtu = million British thermal units; NBP = National Balancing Point.
Source: Bloomberg (2016a), Bloomberg Commodities, accessed 8 February.

However, even though the price of gas is presently more expensive than coal, this could change as more gas is made available on the market, particularly as LNG plays an increasingly important role in meeting global gas demand and satisfying fuel supply security. The role of gas in Southeast Asia should not be underestimated, with LNG expected to become increasingly accessible within the next few years. In fact, 2014 appears to have been a turning point in the global LNG market: prices dropped after three years of tightness, shaped primarily by the glut of new supplies coming from Australia and soon to come increasingly from the United States, concurrent with a weaker demand from major Asian countries, such as China and India, as well as the United States and Europe (Figure 10).

Sustained drops in gas price may alter the fuel dynamics in the three countries under study. Over time, it is possible that a decline in the price of gas and in the capital and levelised costs of renewable energy will make alternative generation technologies increasingly competitive with coal (see Box 4). The continuous phase-out of subsidies on fossil fuels and electricity is essential to address price distortions that presently encourage wasteful consumption and bias the generation mix in favour of fossil fuels – both of which increase CO_2 emissions.

Box 4 • Outlook on fuel cost competitiveness in the Southeast Asia power sector

The IEA projects that by 2030, should both coal and natural gas prices remain relatively cheap at, say, USD 40/t for coal and USD 5 per MBtu for gas, the difference in the LCOE for an SC coal plant and a CCGT plant would be minimal, shrinking to within USD 3/MWh, even without assuming a carbon price. The figure below shows the cost of electricity generation in Southeast Asia under different gas and coal price assumptions in 2030:



As gas and coal prices increase, certain types of renewable energy technologies become competitive; for example, geothermal energy, which is abundant in Indonesia (and also in the Philippines), can be competitive if gas is priced in a medium range (above USD 10/MBtu) and coal is priced high (above USD 80/tonne).

In the meantime, the present combination of ample supply and low cost of coal relative to gas and renewables continues to shape regional power development plans with a bias towards coal-fired power generation. In the absence of a carbon price, the potential for a proliferation of coal-fired power generation in Indonesia, Malaysia and Viet Nam, could augur a long-term dependence on fossil fuels as well as the lock-in of carbon emissions in the region.

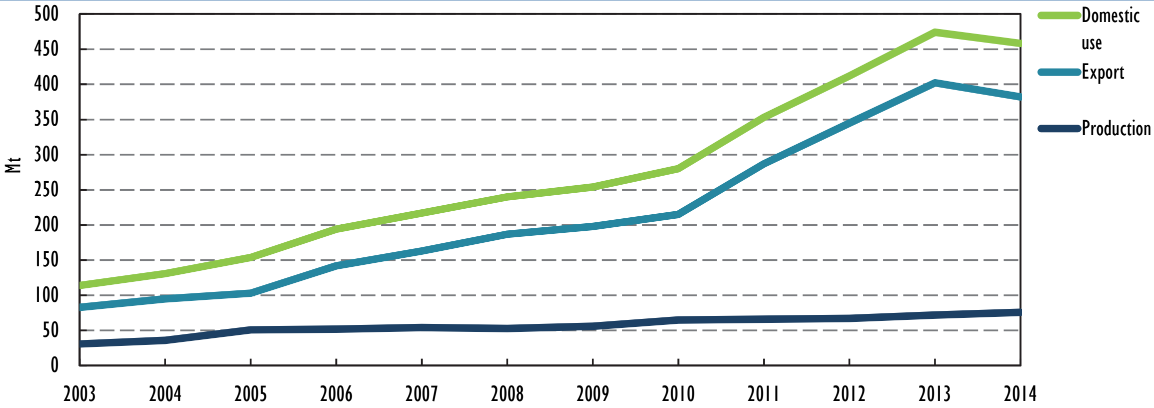
Source: IEA (2015a), *Southeast Asia Energy Outlook – World Energy Outlook 2015 Special Report*.

Role of Indonesian coal in the domestic and regional power markets

Indonesia, the world's fifth-largest coal producer and second-largest coal exporter, has estimated reserves of 14 gigatonnes (Gt), with the largest reserves located in East Kalimantan and South Sumatra. Its coal production has almost tripled over the past decade, and exports to the rest of the world have risen dramatically (Figure 11). Between 2003 and 2013, Indonesia’s coal production grew at an average of 15% per year, with most of the production supplying the international market. In 2014, Indonesian coal exports totalled 411 million tonnes (Mt), with some 50 Mt directed towards Southeast Asian countries and other developing countries of Asia (IEA, 2015e).

Most of Indonesia’s coal is bituminous and sub-bituminous, although lignite is also produced. Being relatively low in calorific value and high in moisture content, Indonesian coal is priced at a discount on the international market once adjusted for energy content, making it attractive to other Southeast Asian countries interested in importing coal for power generation. Viet Nam, for example, expects Indonesia to be a major source of coal for its expanding coal power fleet. In fact, Indonesia is one of the lowest-cost coal producers in the world, and the price of Indonesian coal has continued to drop along with the general decline in coal prices on the international market.[8] In the past three years alone, free-on-board costs for Indonesian coal have decreased by around 17% from a weighted average of USD 47.90/t in 2012 to USD 39.80/t in 2015 (IEA, 2015e). The majority of coal-mining companies in Indonesia are currently operating at a loss.

Figure 11 • Indonesian coal production, domestic use and exports, 2003-14



Source: DG Coal (2015), "Rencana produksi dan pemanfaatan: batubara nasional tahun 2015-2019", presented to IEA on 3 June.

Partly to sustain its domestic coal industry during a period of low prices, Indonesia's MEMR is planning to increase the direct supply of coal for domestic consumption. Coal dominates domestic power generation with a share of around 56.1%, followed by gas at 24.9%, oil 8.6% and the rest renewable energy (DG Electricity, 2016). Domestically sourced coal will continue to hold a strong competitive advantage relative to gas, as well as to other fuel sources, even in the current environment of low oil and gas prices, and this is expected to remain the case over the medium term. Between 2015 and 2022, PLN expects coal consumption by Indonesia's power sector to double from approximately 75 Mt to 150 Mt.

Despite the significant coal reserves that exist in Indonesia, concerns about the availability of coal resources for domestic consumption in the long term prompted the Indonesian government to cap coal exports at around 400 Mt per year between 2013 and 2030, while the share of domestic consumption steadily increases (DG Coal, 2015). Indonesia's coal export cap is intended to redirect coal inward for domestic use – particularly in the power sector – as well as to limit the export of raw materials in favour of encouraging the export of value-added products. In February 2016, MEMR set the domestic market obligation (DMO) for coal at 85 Mt for 2016, as PLN has estimated that Indonesia will need around 81 Mt of coal for domestic power generation (including IPPs) (Indonesia Investments, 2016).

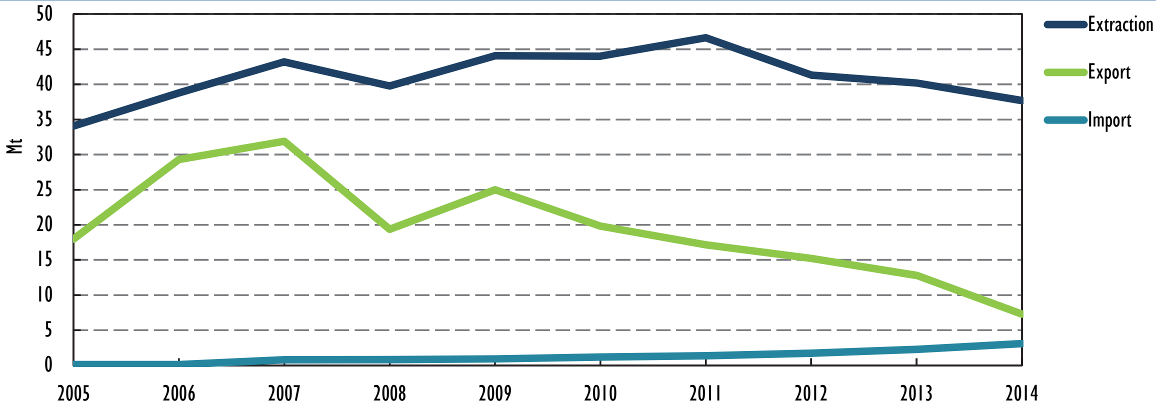
While coal is expected to dominate Indonesia's power development plans, gas is still anticipated to benefit from the government's broad intention to significantly expand the country's gas generation capacity. Gas is well positioned to displace expensive oil-fired power generation, which still accounts for 17% of the country's electricity mix, particularly in the far-eastern provinces, as well as being the preferred fuel for plants located near gas-producing centres or gas import facilities.

[8] A number of reasons stand behind the declining price of coal, including: slowing coal demand in China, traditionally the largest coal consumer and importer in the world; increasing gas production in the United States; and increasing cost competitiveness of renewable energy sources. For further analysis see the IEA *Mid-Term Coal Market Report 2015* (IEA 2015e).

Viet Nam turns from hydro to coal for baseload generation

Viet Nam currently generates some 40% of its electricity from hydro, followed by coal (29%) and gas (22%). However, Viet Nam is anticipating a large-scale transition to coal for baseload power generation, as the potential to add to its existing large hydro resources is limited and domestic gas resources face difficulties in further development. Besides Indonesia, Viet Nam is the only notable coal producer and the only coal exporter in the Southeast Asia region. However, its coal production will be able to meet domestic demand for only a few more years. Similarly, coal exports have already peaked at 31.8 Mt in 2007, and contracted to 7 Mt in 2014 (Figure 12). Viet Nam has, in fact, been importing coal since 2005.

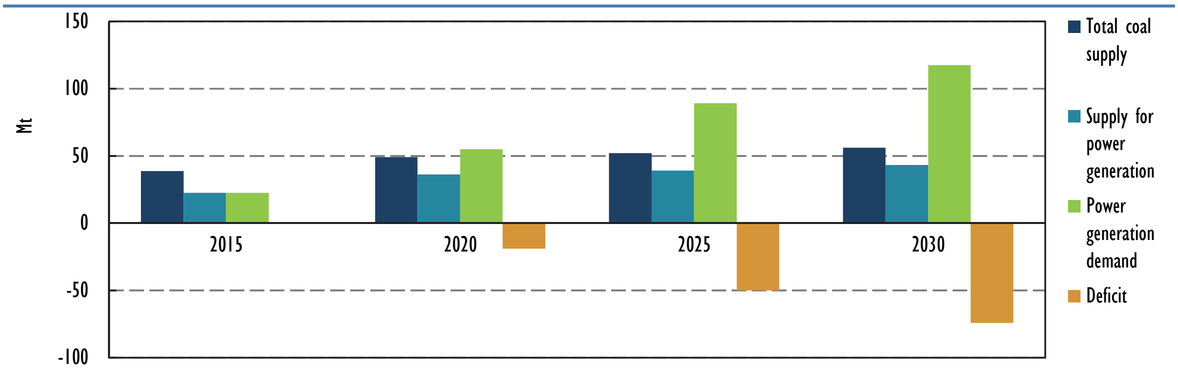
Figure 12 • Vietnamese coal extraction, import and export trends, 2005-14



Source: General Statistics Office (2015), *International Merchandise Trade Vietnam 2013*; General Statistics Office (2014), *Statistical Handbook*.

While Viet Nam has traditionally relied on its own coal for domestic power generation, domestic supply is insufficient to meet projected demand. Between 2015 and 2030, Viet Nam's newly revised Master Coal Development Plan expects coal demand for power generation to increase five-fold, from some 23 Mt in 2015 to 118 Mt in 2030 (Figure 13). Meanwhile, its coal resources are estimated at around 46.9 Mt, of which proven and recoverable reserves account for 8%, probable reserves 5% and possible reserves 87% (Vinacomin, 2015).

Figure 13 • Viet Nam's coal supply and demand for power generation, 2015-30



Source: Vinacomin (2015), *Revised Master Plan for Coal Development in Vietnam up to 2020 with Outlook to 2030* (pending approval).

In the context of the looming coal shortage, the government has recently deregulated Viet Nam's coal market and introduced a coal reserve policy to reroute coal previously destined for exports to meet domestic consumption where possible. Now only coal types with a high value and no domestic demand are permitted to be exported. While its coal exports had already decreased to around 7 Mt in 2014, Viet Nam plans to further limit coal exports to 2-3 Mt per year between 2020 and 2030.

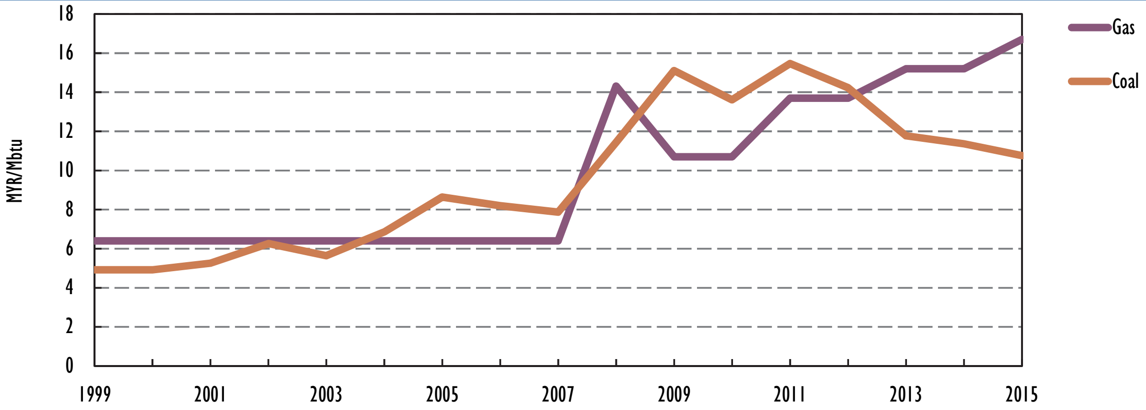
Viet Nam envisages that its coal imports will rise by a factor of four, from 18 Mt in 2020 to 74 Mt in 2030. The development of large power plants in the south of Viet Nam could further increase coal imports to more than 100 Mt by 2030 (Vinacomin, 2015). Indonesia and Australia are Viet Nam's preferred sources due to advantages of proximity, extent of reserves and cost of transport. Petro Vietnam has reportedly signed three agreements to import 9 Mt per year from Australia and Indonesia (IEVN, 2015b). Petro Vietnam is negotiating two additional agreements with Indonesian partners for an anticipated 4 Mt in 2015, 9 Mt in 2017 and 12 Mt from 2018 onwards (IEVN, 2015b).

Malaysia's transition away from gas as baseload power

A number of considerations are driving the shift from gas to coal-fired generation in Malaysia. First, although Malaysia remains a net exporter of natural gas as of 2014, the country's proven natural gas reserves are expected to last only around another 35 years. Second, the geographic distance between natural gas supplies in Malaysia (produced primarily in the eastern states of Sarawak) and demand centres (primarily in Peninsular Malaysia) has at times threatened the continuity of gas provision for electricity generation. For example, from 2011 until the commissioning of the a 5 billion cubic metre (bcm) per year LNG re-gasification terminal (RGT) in Melaka in May 2013, the power sector in Peninsular Malaysia encountered several occasions of acute gas curtailment, which prompted the fuel-switch to distillate and MFO, and consequently led to increased electricity generation costs. The successful commissioning of the RGT has markedly improved gas supply stability to the Peninsular system and reduced the volumes of distillate and MFO needed to support generation. Efforts to enhance energy security through fuel diversification are therefore one of the key reasons the Malaysian government has aimed to limit gas consumption and expand coal-fired power generation.

Another key driver of the shift from gas to coal-fired power generation in Malaysia concerns the higher cost of gas relative to coal. The Malaysian government regulates the price of gas provided to the domestic power sector, which is currently MYR 18.20/MBtu (USD 4.64/MBtu) but is expected to rise by MYR 1.50/MBtu (USD 0.38/MBtu) every six months to eventually converge with the market price. The price increase has been planned in view of Malaysia's stagnating and eventual declining gas production, particularly as subsidies continue to be gradually phased out. For comparison, the price of coal for the power sector for the period 1999-2015 is presented alongside that for gas in Figure 14.

Figure 14 • Malaysian average piped gas and coal prices, 1999-2015



Source: Single Buyer (2016), Single Buyer Department, personal communication.

The economic impact of using gas to generate power is therefore a function of the opportunity cost of gas, whereby switching to coal as a cheaper source of fuel for power generation and exporting gas abroad or selling gas to non-power sector users in Malaysia would generate profit to support the country's economic growth. If the price of gas rises while that of coal stays low, the price gap between the competing fuels will increase and ultimately further affect the economics of the system's merit order, such that gas-powered generation will serve as peaking units while coal covers baseload and mid-merit duties. A balance therefore has to be reached on whether Malaysia should opt for greater use of coal in power generation, increase allocation for gas and/or revise the electricity tariff upwards to reflect the actual cost of electricity generation with the contribution of gas. Future prices may also be affected by the implementation of Third Party Access (TPA), which will enable an open gas market in Peninsular Malaysia.

Reducing emissions from coal-fired power generation

Coal is currently favoured as the fuel of choice to support Southeast Asia's rapid economic growth and growing demand for electricity. Consequently, one of the principal challenges for the region's policy makers is to address whether this approach would build a sustainable and affordable power sector that could also be consistent with environmental protection and social well-being.

This section explores the CO_2 emission implications of proceeding with the national plans introduced in the previous sections, in which coal is seen to be dominant. The approach is targeted at supporting policy makers tasked with assessing the long-term environmental impacts of expanding power capacity with a heavy reliance on coal-fired power generation. Technology selection is important and the benefits of increasing the share of HELE coal-fired technologies are examined.

While under typical European conditions, well-maintained and well-operated stations return the efficiencies indicated in Box 1, efficiencies achieved by plants in Southeast Asia could be 2 to 3 percentage points lower, as they may generally be required to operate at higher ambient temperatures and with poorer quality coal. In 2013, the weighted efficiency of the coal-fired fleet in Southeast Asia was 33%, while that of the global fleet was 37% (LHV, gross).[9] A plant operating at 44% efficiency would emit 25% less CO_2 per MWh than one operating at 33%.

In this section, the emission impacts of current and planned power development are investigated in the three Southeast Asian countries – Indonesia, Malaysia and Viet Nam – that are anticipating the largest additions to coal-fired power capacity in the region over the next 20 years. The potential emission reductions available by upgrading from the least-efficient coal-fired power plants to more advanced, commercially available technologies are modelled. The analysis follows a number of in-country consultations with local power sector stakeholders, and discussions at a regional workshop held in Jakarta in November 2015.

Emissions from coal-fired power generation

While the adverse impacts CO_2 emissions on the climate are of global concern, for most developing countries with a high share of coal-fired power generation, air pollution is the primary concern. Exposure to elevated levels of air pollutants or long-term exposure can impair human health, affect biodiversity and crop yields, and damage local infrastructure. Almost all air pollutants, however, can be controlled and reduced to low levels using existing technology. Depending on the sophistication of the equipment used, it has been demonstrated that emissions of air pollutants to the atmosphere from coal-fired plants can be reduced to levels below those from an equivalent capacity gas plant. However, while the best-performing coal-fired plants already meet exacting air pollution standards, reducing their CO_2 emissions remains a global challenge.

[9] European and IEA statistics on plant or unit efficiencies are often reported based on the coal's lower heating value (LHV). For coal-fired power generation, efficiencies based on the higher heating value (HHV) are generally around 2% to 3% lower than those based on LHV. Gross output refers to the total electrical output from the plant, cf. net output, which refers to the gross output less the plant's internal power consumption (typically, 5% to 7% of gross power). The average efficiency of the global fleet of coal-fired power plants was calculated using data from 2013 and was based on the formula given in the IEA Information Paper, "Energy efficiency indicators for public electricity production from fossil fuels" (IEA, 2008).

Increasing efficiency

As a starting point to address externalities, from an economic perspective it is often more attractive to increase power-plant efficiency. Increasing efficiency brings a number of benefits: specific[10] fuel consumption is reduced, and the plant's environmental and physical footprints are reduced. A smaller footprint can reduce the cost per MW of a power plant and its component parts, including pollution control equipment. If these fuel savings and size benefits are sufficient to offset the additional costs associated with a higher efficiency unit, then cost savings would be there to be made. Even before the health and environmental benefits of lower pollution are accounted for. Importantly from an environmental standpoint, the use of consumables, e.g. water, would also be reduced. Historically, the significance assigned to lowering emissions of air pollutants has been an important driver for the development of more efficient coal-fired power generation technologies. It should be noted, however, that, while higher efficiency does reduce the specific emissions of pollutants, such reductions are relatively modest compared with the benefits of adding downstream air pollution control equipment, which can be added to any plant and is associated with a small efficiency penalty. Air pollution-control equipment is required to satisfy any meaningful emissions limits, for example for SO_2, NO_X and particulate matter.

In countries where low levels of air pollution from coal are achieved, even though the impact may be relatively modest, the first step before adding pollution-control equipment is often to ensure the unit is operating as efficiently as possible – whether it is operating under subcritical, SC or USC steam conditions. Over time, in the absence of an effective operating and maintenance regime, plant efficiencies deteriorate. While the CO_2 reductions achieved (per unit of electricity generated) by maintaining or increasing operating efficiency rather than allowing it to decay are limited, it is nonetheless a positive step.

As the average coal-fired plant, particularly in Indonesia and Viet Nam, operates at an efficiency well below its design value, improving existing capacity would require a programme of upgrading and retrofitting while, at the same time, closing the smallest, most inefficient units. This would lessen the environmental impact and may or may not reduce costs. By reducing specific fuel consumption, it would notionally place less pressure on fuel resources and lessen the impacts of the coal supply chain on the environment. Baseload demand would also favour the more expensive SC or USC technology. Where the option to construct a coal-fired unit has been selected, choosing SC and USC over subcritical technology would lead to a more efficient coal fleet. In this respect, it is encouraging that some Southeast Asian nations are making significant advances in recognising the need for high-efficiency thermal power through the deployment of HELE coal technologies.

Examining the trajectories of CO_2 emissions, based on their targets for growth, is essential to understanding how Indonesia, Malaysia and Viet Nam could shape their CO_2 reduction policies in the future. Under current plans, the three countries all see a significant rise in unabated coal-fired power capacity and, as a result, a rise in CO_2 emissions. Measures must be taken if the CO_2 emissions from growing coal-fired fleets are to be curbed effectively. In this respect, CO_2 emissions intensity (or specific CO_2 emissions), measured in gCO_2/kWh, is a key indicator. Targeting a reduction in the emissions intensity of a coal-fired power generation unit recognises the benefits of higher efficiency and incentivises the development and implementation of cleaner, more efficient technologies.

[10] "Specific" in this sense refers to the generation of one unit of electricity. Therefore the specific fuel consumption is the fuel required to generate one unit of electricity; the specific emissions are the emissions arising from the generation of one unit of electricity, etc.

Measurement of emissions intensity can provide information useful at various levels, from plant operators to government policy makers. The emissions intensity of an individual unit provides a measure of its performance, which may be used to monitor its operation over time to indicate improvement or deterioration, as a comparison with the performance of other units in the fleet or, at the design stage, as a criterion to decide whether to proceed or to select a more efficient (lower-carbon) technology or fuel. At the country level, the emissions intensity value of power generation provides a benchmark against which the pathway to a lower-carbon, more sustainable future might be devised.

Deployment of best-practice plant operation and maintenance could yield significant CO_2 savings without compromising security of electricity supply. Coal-fired plants are most efficient when operating at maximum output (or load) but at present they are predominantly operated at part-load. As the T&D network is extended and becomes more robust, operation at higher utilisation levels may be possible – depending on electricity demand and the power generation fuel/technology mix.

Nonetheless, even if present plans to increase coal-fired capacity are only partially met, a rise in CO_2 emissions appears inevitable. Due to their young age, replacing coal-fired units prematurely with low-carbon alternatives to offset rises in emissions would be difficult. Power plant operators would expect compensation and a programme to redeploy labour would be required. This problem would intensify as more coal-fired capacity is commissioned.

Deploying CCS

CCS is a set of technologies that can be used in combination to reduce CO_2 emissions from large point sources, such as coal- and gas-fired power stations and natural gas processing facilities. In coal-fired power stations, CO_2 is separated from the flue gases, compressed to a liquid or liquid-like state, then transported to a suitable storage site and injected into a deep geologic formation. The injection site would need to be monitored to demonstrate retention of the CO_2.

The amount of CO_2 to be transported would depend on many factors, for example, the technology and condition of the power plant, the coal characteristics, the electricity demand and the ambient conditions. Typically, an unabated coal-fired unit might emit annually 5 000-6 000 tonnes of CO_2 per MW – and with the low average efficiency of the coal fleets, albeit a little higher in Malaysia, and the generally poor quality of fuel used in the region, CO_2 emissions are likely to tend towards or exceed the higher value. So, assuming 90% CO_2 capture from a 600 MW plant (either a single large unit or multiple smaller units), at least 3 $MtCO_2$ would require transport to a storage location.

Malaysia's natural gas consumption in 2012 was around 2.5 bcm or 20 Mt. If just the 4 GW of coal capacity that is currently planned in Malaysia were fitted with CCS, around 30 $MtCO_2$ might be captured per year from these plants alone. This represents a volume that is greater than the the volume of gas that passes through Malaysia's gas network each year. If more CCS were deployed, the size of the infrastructure would need to grow accordingly. Comparing the two values provides some context for the scale of infrastructure that would be required to transport captured CO_2. Indonesia and Viet Nam similarly would need to consider very carefully what capability they would have to develop the industrial capacity required.

Coal-fired generation in Indonesia, Malaysia and Viet Nam

From 2000 to 2012, coal-fired generation in Indonesia, Malaysia and Viet Nam grew annually by between 9% and 18% – significantly outpacing the growth of power generation as a whole. While continuing this trend may satisfy short-term energy security, regional development and electricity access needs, it raises serious concerns for the environment. An immense responsibility lies in selecting the technology for power generation; the planning of stations now will not only lock in supply of electricity into the future, but also the cost and environmental burdens associated with them.

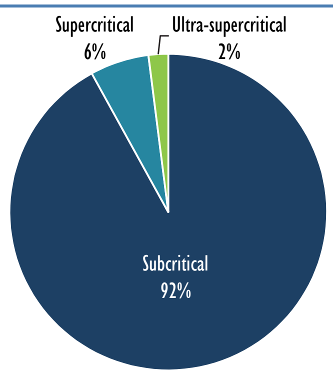
At present, the emissions intensity of Viet Nam's generation portfolio is around 350 gCO_2/kWh, while it is approximately double that value in Indonesia and Malaysia (Figure 2). If current plans to increase generation from coal were followed, the CO_2 emissions intensity for each country would rise markedly. For Southeast Asia as a whole, the projected CO_2 emissions intensity in 2040 would need to be around 550 gCO_2/kWh under the NPS and less than half that in a 2°C scenario (Figure 16).

While future coal-fired capacities, particularly in Indonesia and Viet Nam, are unlikely to reflect current national plans, they will nonetheless be substantial. For the next two or three decades at least, a substantial share of generation in Indonesia, Malaysia and Viet Nam will come from coal. Accordingly, while the deployment of lower-carbon technologies will be extremely important, they will be insufficient to reduce CO_2 emissions intensity to the levels required. CCS will be essential, predominantly for coal-fired plant, but also for some gas-fired capacity.

Existing coal fleets in Indonesia, Malaysia and Viet Nam

At the end of 2015, Indonesia, Malaysia and Viet Nam had a combined coal-fired capacity of 54 GW, almost 40 GW of which comprised units of ≥300 MW, with the remainder ranging in size from 2 MW to 220 MW. Around 91% of the combined capacity employed subcritical technology (Figure 15), and nine-tenths was constructed after 2000 (Platts, 2015).

Figure 15 • Shares of coal technologies in Malaysia, Indonesia and Viet Nam in 2015



Source: Platts (2015), *World Electric Power Plant Database*.

The majority of the subcritical fleet is young with many years of economic life remaining. All the SC and USC plants were commissioned from 2012 onwards and, if regularly maintained and operated, need not be retired until sometime around 2050 or 2060. The only coal stations that are reaching the end of their operating lives within the next decade or so are a group of small 55 megawatt electrical (MW_e) units in Viet Nam with a total capacity 330 MW that were constructed in the 1970s. Consequently, opportunities to retire ageing coal plant immediately are few. Therefore, unless or until early retirement becomes an option, it is important to maintain a proactive approach to best-practice operation and maintenance of the existing fleet to prevent significant deterioration in performance throughout the remaining economic life of the units.

For Indonesia, Malaysia and Viet Nam, coal is abundantly available at relatively low cost. Domestic plans to increase coal capacity are as follows:

- Indonesia will see a delayed but successful implementation of its Fast Track programme, which could see its coal capacity increase from 32.7 GW to 74.8 GW by 2024 (RUPTL, 2015).
- Malaysia expects an increase of 4.6 GW in its coal-fired capacity between 2016 and 2020, with total installed capacity of 15.2 GW by 2023.
- Viet Nam will experience the highest growth of the three study countries, with a target to grow its coal capacity from 12.8 GW to 59.3 GW by 2030, a large proportion of which is planned to be SC and USC (Revised PDP VII).

While it is unlikely that these plans would be achieved in their entirety, particularly for Indonesia and Viet Nam, they are used in the subsequent analysis to illustrate the challenges presented by the strong emphasis on coal.

Illustrative scenarios for coal

A "what if?" analysis was undertaken to illustrate the escalation in CO_2 emissions that could result if the planned growth in unabated coal capacity in the region was realised – and just what impact a greater contribution from HELE coal technologies might have. Future emissions of CO_2 were estimated from data for existing power plants, plants under construction and plants envisaged as part of longer-term official development plans. Establishing accurate CO_2 figures relies on adopting the best-available emission factors for CO_2, preferably country-specific and indicative of the technology and fuels used in those countries. Emission factors for the existing coal fleets, extracted from IEA statistics (IEA, 2015h), are indicative of the subcritical units that have been operating in Southeast Asia in recent years. As future trends would be shaped by the emergence of SC and USC plants, emission factors appropriate to those technologies are applied as appropriate (Barnes, 2014).

To improve the economics of plant operation, baseload generation was assumed, with subcritical plants operating for 75% of the year and SC and USC plants operating for 85%. Underpinning assumptions were that there was sufficient grid capacity, and the plants exhibited good operational reliability and availability.

Two scenarios for CO_2 emission and capacity development were employed in the analysis:

Scenario 1: Power plants are built as currently planned and all plants operate over a typical lifetime (of 50 years). A standard life for coal plants of 50 years is conservative and quite feasible if a plant is well maintained and even upgraded during its life.

Scenario 2: Power plants are built as currently planned and subcritical plants have a shorter life of 25 years. To maintain generation at the required level, it is assumed that decommissioned subcritical plants are replaced by (fewer) USC plants with the same electrical output. Such a programme of plant closure would be targeted at the least efficient plants in the fleet.

In most cases, retiring a plant prematurely, with economic lifetime remaining, would not be considered. However, China has operated a programme of closure of its older, least efficient units for the past 10 years (Box 5).

Box 5 • China's "Large Substitutes for Small" Programme

Policies in China's 11th Five-Year Plan (2006-10) centred on an investment-driven growth model. Typical of this was its "Large Substitutes for Small" (LSS) Programme, launched in 2006 by the National Development and Reform Commission of China (NDRC), to help meet the national target of a 20% reduction in energy intensity. The intention was to decommission 50 GW of small thermal units. To support the closure programme, NDRC required any power company investing in, say, 1 000 MW of new coal-fired capacity to decommission 600 MW of small, inefficient plant. The programme was successful and led to the closure of many plants before the end of their economic operating life; this only applied to inefficient plants that fell into a particular category relating to their efficiency, age and emissions performance.

In the scenario where plants were replaced after 25 years, individual (ageing) plants would be grouped together and replaced in five-yearly increments, in 2020, 2025, and 2030. For example, plants brought offline in 2030 would probably have been built in the five years prior to 2005. To carry out such a retirement plan it would be necessary to perform an extensive programme of due diligence of all relevant plants and auditing of emissions and performance.

Given the relative youth of their coal fleets, Malaysia and Indonesia would see the closure of 3.9 GW and 8.5 GW, respectively, by 2040 under a 25-year plant life scenario. Viet Nam's even younger fleet would see retirement of just 1.5 GW over the same period. While new subcritical plants due online between 2015 and 2019 would partially offset this decrease, it is assumed in this analysis that the remaining loss of capacity would be replaced with HELE plants, i.e. either SC or USC.

Replacing subcritical plants with SC or USC technology is not simply a case of upgrade or retrofit. Plants must be completely replaced or, possibly, repowered – both of which are expensive options. Repowering is where the major components – the boiler, steam circuit and steam turbine – are replaced, with as much as possible of the balance of plant reused. The efficiency gains of repowering may be somewhat less when compared with a complete new-build, but there may be administrative savings and cost gains.

In principle, the concept of early retirement for coal-fired generation carries some important caveats. Estimating when to retire a plant is not an exact science; the decision to retire is partly based on cost and partly on local circumstances. A group of small plants, for example, could be retired and replaced with a larger HELE plant but, in remote areas, this would require investment in a more robust T&D grid including, possibly, interconnectors. Furthermore, the impending premature closure of less efficient plant might lead to deferment of maintenance or investment to improve emissions performance while it is still operational. Clearly, alongside a robust business plan, the premature retirement and replacement with lower-carbon alternatives would require well-defined criteria for implementation.

Coal-fired generation in Indonesia

In this section, the 50-year and the 25-year scenarios are used to explore the potential impact of Indonesia's plans to expand its coal-fired capacity on CO_2 emissions intensity.

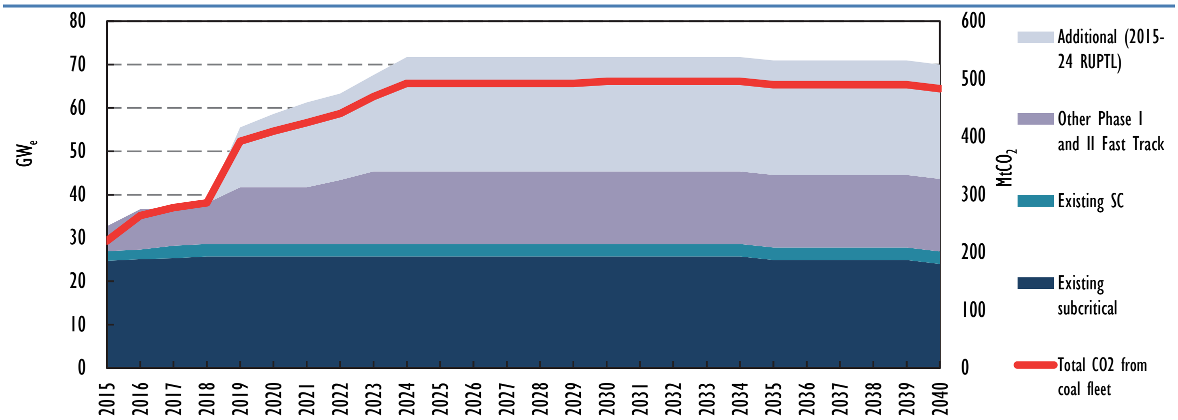
The 50-year scenario in Indonesia

The 50-year scenario, essentially the "business-as-usual" scenario, assumes Indonesia's current plans to increase its coal-fired capacity are followed, with plants operating for their full economic lifetimes.

According to RUPTL 2015-24, 70.4 GW of new generating capacity is to be constructed, 42.1 GW of which will be coal (Figure 16). While the designs of many plants are still being formulated, it is likely that the larger units, ranging from 600 MW to 1 000 MW (planned by PLN and IPPs), would mainly comprise SC or USC, with units less than 300 MW capacity likely to be subcritical. As a conservative estimate, remaining developments in Phases I and II of the Fast Track programme mainly comprise subcritical stations, with just 2.8 GW being SC units.

Present plans would see Indonesia's coal-fired fleet more than double between 2015 and 2024, after which no other plants are currently scheduled. A small amount of capacity is retired over this period. This is an ambitious programme, equivalent to building almost 5 GW of new coal capacity each year until 2024.

Figure 16 • Indonesia's coal-fired capacity and CO_2 emissions trajectories in the 50-year scenario



For the purposes of calculating CO_2 emissions, Phases I and II of the Fast Track programme were assumed to include just 2.8 GW of SC and no USC, with the balance subcritical. The additional 26.4 GW of coal-fired capacity identified in the 2015-24 RUPTL, scheduled to come online later, is assumed to deploy USC technology. Any delay in the addition of new coal-fired capacity would see the same trend in CO_2 growth, but over a longer timescale.

The results show emissions rising from 220 $MtCO_2$ in 2015 to 410 $MtCO_2$ in 2020, 496 $MtCO_2$ in 2030, and 483 $MtCO_2$ in 2040, by which time most existing subcritical plants would be approaching the end of their operating lives. Maximising the deployment of SC and USC technologies, equipped with pollutant controls, would limit further growth of stack emissions.

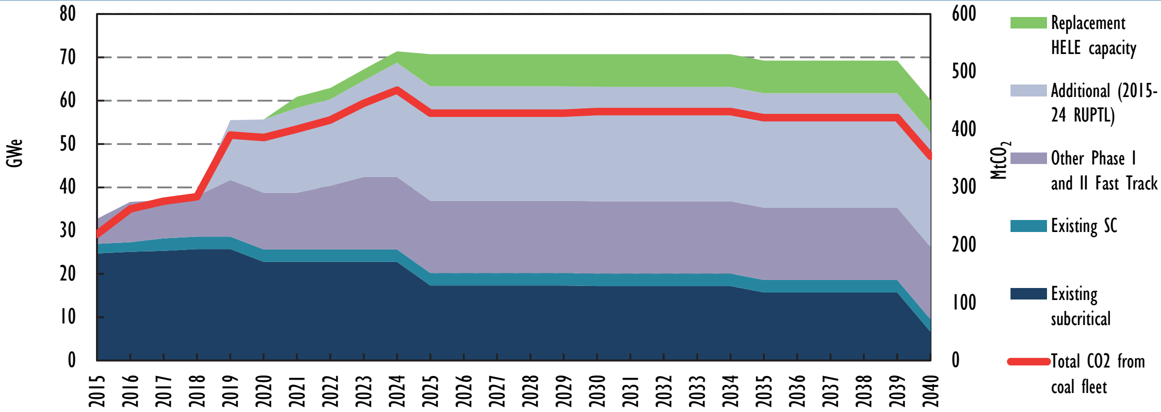
The 25-year scenario in Indonesia

Between 2015 and 2018, plant additions push subcritical capacity up from 24.7 GW to 25.7 GW. Assigning a 25-year maximum to the life of a subcritical unit would see the retirement of 8.5 GW by 2030. This level of subcritical retirement would lead to a net capacity reduction of 7.5 GW which, in this analysis, is assumed to be replaced by USC plants. Using the same criteria, almost 18 GW of subcritical stations could be approaching retirement by 2040.

A fifth of the retired capacity would comprise units less than 300 MW capacity, averaging 36 MW per unit. However, some of these plants make use of wood as a secondary fuel and full conversion to biomass might be feasible.

With a majority of the older units being larger than 300 MW_e, a replacement regime with USC technology would slow the growth in CO_2 emissions much sooner (Figure 17). Emissions resulting from the overall net growth in coal-fired capacity between 2015 and 2030 would still reach 431 $MtCO_2$ in 2030.

Figure 17 • Indonesia's coal-fired capacity and CO_2 emissions trajectories in the 25-year scenario



On average, approximately 23 $MtCO_2$ could be avoided every year by retiring subcritical units early – after 25 years rather than 50 years – and replacing them with HELE units. While cumulatively the emissions reduction would be significant, and while each tonne of CO_2 avoided is important, it is highly unlikely that the relatively modest annual reductions resulting from early retirement would be economically palatable.

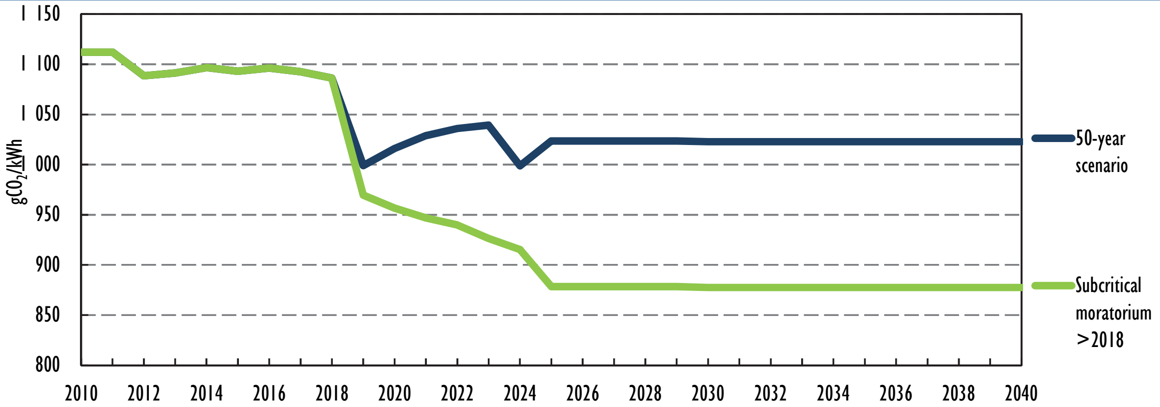
Comparing Figures 17 and 18, the main benefits would begin to arrive only in 2040. However, one result of replacing subcritical plants with HELE plants is that the economic lifetime of the overall coal fleet would be extended, if the HELE plants operate for a further 50 years. This could lead to a continuation of lock-in to coal-fired power into the second half of the century and raise the need for early retirements or deployment of CCS.

Indonesia's projected CO_2 emissions intensity for coal-fired generation

To explore the impact of reducing the planned build of subcritical units on the emissions intensity of coal-fired generation, a further two scenarios are considered, where moratoria are placed on the construction of subcritical units in 2018 (Figure 18). The 50-year scenario is used as the base case for comparison.

In 2010, the emissions intensity of Indonesia's coal-fired fleet was around 1 110 gCO_2/kWh, equivalent to an average coal fleet efficiency of around 31% (LHV, net). This implies a fleet with a predominance of low efficiency, subcritical units. Apart from ensuring that new coal capacity additions are HELE units, there is much potential to raise the efficiencies of existing plants through better maintenance, cost-effective upgrades and improved operation. While subcritical plants are still being constructed, Indonesia is adding some SC plants to its fleet and discussing a new regulation that will require future plants approved thereafter to be SC or USC (or equivalent). By 2016, the analysis indicates that the planned addition of more efficient units had already reduced the emissions intensity of coal-fired generation.

Figure 18 • Projected CO_2 emissions for Indonesia's coal-fired plants up to 2040 (including plants in the planning stage)



Note: Subcritical Moratorium > 2018 = no new subcritical plants are built after 2018.

The year 2019 sees a drop in emissions intensity even in the 50-year scenario as more SC and USC plants come online. However, in the 50-year scenario, the large share of existing subcritical plant means that, around 2025, the emissions intensity plateaus at approximately 1 020 gCO_2/kWh – equivalent to a fleet average efficiency of about 33%. A moratorium on building new subcritical plant post-2018 would result in the emissions intensity dropping to 970 gCO_2/kWh (34.5%) in 2018, continuing to decrease to 870 gCO_2/kWh (38.5%) in 2025. From 2025 onward, providing the plants are well maintained and well operated, the emissions intensity plateaus as the plants continue to run over their lifetime.

If retired subcritical units were replaced early by lower-carbon technologies, i.e. ahead of the assumed 50-year lifespan, emissions intensity could, of course, fall below 870 gCO_2/kWh.

Coal-fired generation in Malaysia

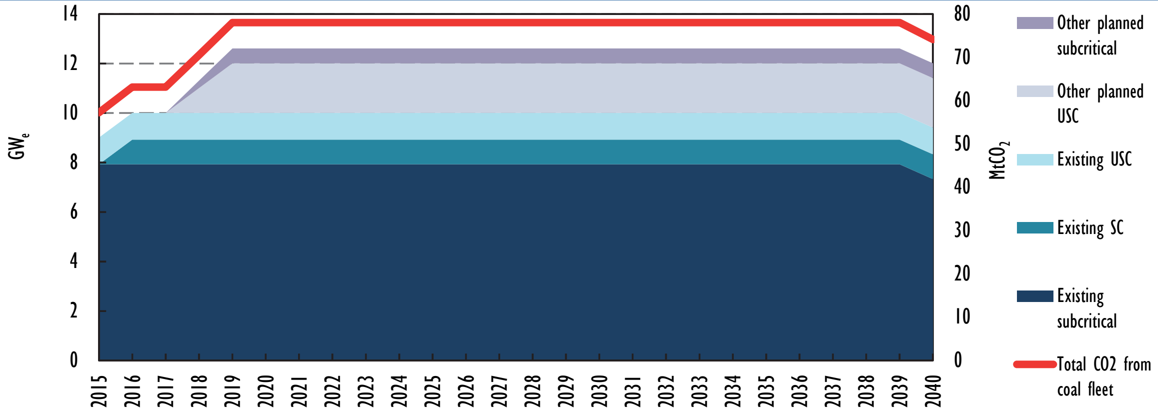
A similar exercise was undertaken to explore the impact on the emissions intensity of coal-fired generation in Malaysia.

The 50-year scenario in Malaysia

By 2016, Malaysia's coal generating capacity reaches 10 GW, with a further 2 000-2 600 MW of USC capacity coming online by 2018-19 – mainly as a result of the proposed 2x1 000 MW_e Jimah East plant (Shermer, 2015). Also proposed is the 2x300 MW Balangian plant in Sarawak, which would use local lignite. The latter, however, may not be part of the 11th Malaysia Plan (EPU, 2015), which is underpinned by the government's Vision 2020 programme to transform Malaysia into a modern developed economy.

After 2019, Malaysia currently appears to have no firm plans to add further coal capacity (Figure 19). CO_2 emissions from coal-fired generation in 2015 were estimated at 57 Mt, rising to 78 Mt in 2019, and remaining at that level thereafter. Subcritical plants predominate in 2030, accounting for two-thirds of the coal fleet. All units in Malaysia's coal fleet are equipped with environmental pollution equipment to control emissions of SO_2, NO_X and PM.

Figure 19 • Malaysia's coal-fired capacity and CO_2 emissions trajectories in the 50-year scenario

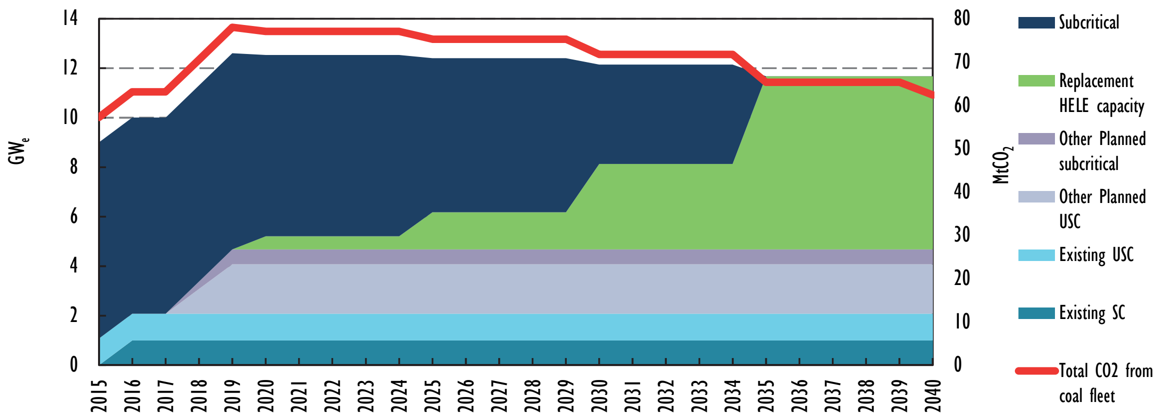


The 25-year scenario in Malaysia

Under an early retirement scenario, Malaysia's coal fleet would see a succession of retirements in 2020, 2025 and 2030. Overall, 3.9 GW of subcritical plants would be taken offline, to be replaced with 3.4 GW of USC units. Virtually all retired units are larger than 300 MW and, by 2035, all of the country's subcritical plants could be approaching retirement.

In this scenario, CO_2 emissions would fall from a peak of 78 Mt in 2019, followed by a further drop to 72 Mt in 2030 (Figure 20). By 2040, CO_2 emissions could drop by a further 10 Mt with HELE plants replacing the remaining subcritical plants.

Figure 20 • Malaysia's coal-fired capacity and CO_2 emissions trajectories in the 25-year scenario

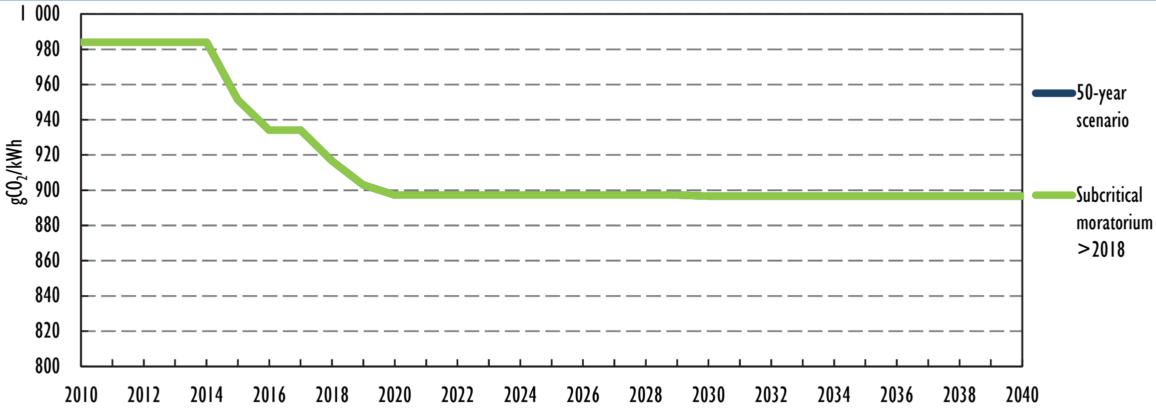


The increased efficiency would save 6 Mt of CO_2 every year to 2030 compared with the standard 50-year scenario, and save almost 12 Mt per year by 2040. Over the period to 2040, subcritical units would steadily lose share to HELE plants. CO_2 savings would be particularly pronounced in Malaysia which, compared with Indonesia or Viet Nam, had a greater share of subcritical units prior to 2015.

Malaysia's projected CO_2 emissions intensity for coal-fired generation

In 2015, Malaysia's emissions intensity was 990 gCO_2/kWh, equivalent to an average efficiency for its coal fleet of around 34% (LHV, net) – slightly higher than the global average. As it steps up its generation from coal, Malaysia plans to deploy more efficient coal power plants. The emissions intensity resulting from these plans is explored via two scenarios (Figure 21).

Figure 21 • Projected CO_2 emissions for Malaysia up to 2040 (including plants in the planning stage)



Note: Subcritical Moratorium > 2018 = no new subcritical plants are built after 2018.

Based on Malaysia's current plans, the reduction in the emissions intensity in the 50-year scenario – or business-as-usual scenario – closely parallels the scenario that places a moratorium on the construction of subcritical plants from 2018.

Of course, as for Indonesia, yet further reductions would be possible if retired subcritical plants were replaced with lower-carbon alternatives.

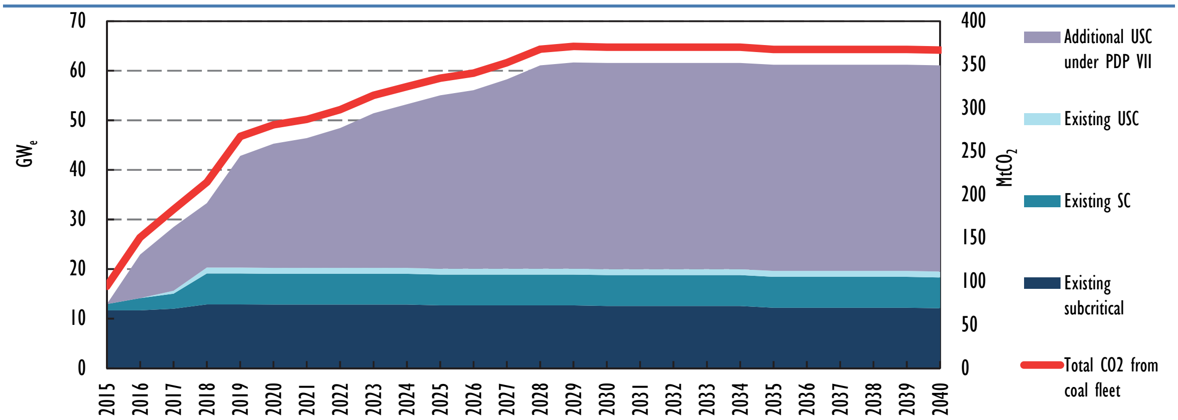
Coal-fired generation in Viet Nam

As for Indonesia and Malaysia, scenarios examining the impact of decisions regarding the construction of subcritical units on Viet Nam's CO_2 emissions are explored.

The 50-year scenario in Viet Nam

Between 2013 and 2015, Viet Nam saw its coal-fired power capacity almost double, increasing from 6 GW to 11.7 GW and, if present plans were assumed to succeed, would see an increase to 61.6 GW by 2030 (Figure 22). Given the present low capacity and youth of Viet Nam's coal fleet, if these highly ambitious plans were achieved, by 2030 at least 70% of the country’s coal-fired capacity would be HELE plants.

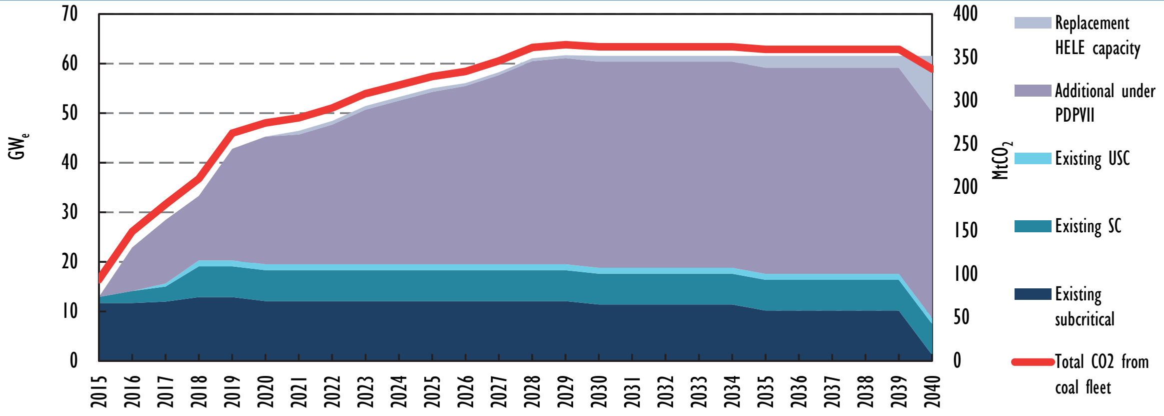
Figure 22 • Viet Nam’s coal-fired capacity and CO_2 emissions trajectories in the 50-year scenario



The 25-year scenario in Viet Nam

In 2015, Viet Nam's fleet of coal plants comprised 11.7 GW of very young units, which should rise to 12.9 GW in 2019. In the 25-year scenario, where subcritical units more than 25 years old would be retired, 1.5 GW of capacity would come near to or be at the end of its operational life by 2019, a net reduction of just 0.3 GW. According to its plans, Viet Nam could have 61 GW of coal-fired capacity by 2030, with the decommissioning of subcritical plants having little effect on the emission profile (Figure 23). Benefits would only begin to arise towards 2040, when plants start to come off line.

Figure 23 • Viet Nam's coal-fired capacity and CO_2 emissions trajectories in the 25-year scenario



EVN has no formal programme for upgrading older plants. At present, if considered necessary and if it were economic to do so, a proposal to upgrade, retrofit or repower could be submitted to the government on a unit-by-unit basis. With the potential for impacts on employment and social welfare, provision for alternative employment would be an important consideration in the event of plant closure. While EVN can propose upgrades, the General Department of Energy (GDE) must review and authorise any closure even if the change in status were temporary. Plants near cities that posed excessive air pollution problems would be the first units to be reviewed.

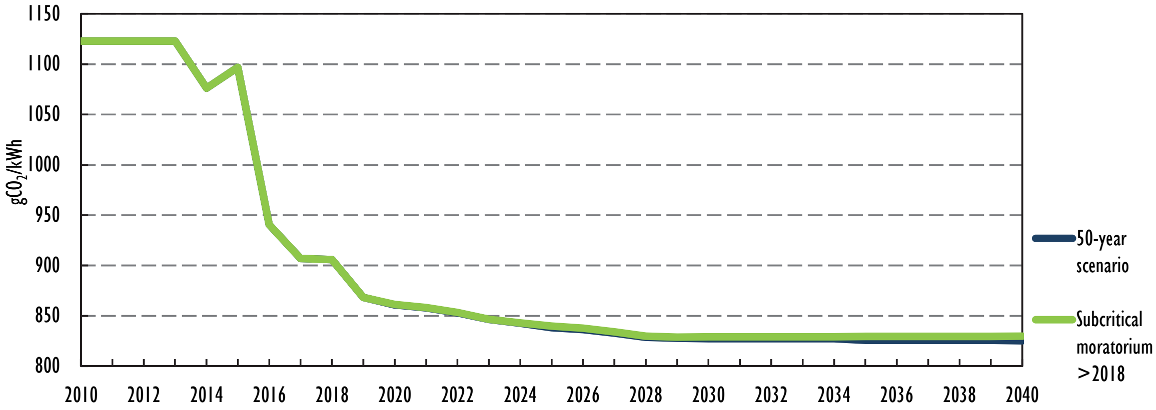
Viet Nam's projected CO_2 emissions intensity for coal-fired generation

In 2013, the CO_2 emissions intensity of coal-fired power generation in Viet Nam was 1 120 gCO_2/kWh, equivalent to an average fleet efficiency of around 30% (LHV, net) – very low by global standards (Figure 24). Some of EVN's subcritical units operate at efficiencies as low as 24%. However, some recent steps have been taken to address the performance of its fleet; from February 2016, the minimum efficiency standards imposed will no longer permit the construction of new subcritical units – although those plants with prior authorisation would be completed. Constructing only SC/USC coal plants will significantly increase the average fleet efficiency without compromising security of supply of electricity.

While just 10% of Viet Nam's coal fleet comprised SC and USC plants in 2015, upgrading the rest of the existing fleet and installing new HELE units over the next few years would improve performance markedly. By 2020, if Viet Nam were to meet its highly ambitious plans, the rapid development of SC and USC plants would result in an attendant drop in emissions intensity.

Based on detailed assessment for each plant for the years 2012-14, an average emissions intensity of 1 120 gCO_2/kWh was calculated for Viet Nam's coal fleet in 2015. While the best-performing plants were capable of returning an emissions intensity of 930 gCO_2/kWh, almost 20% less than the average, some clearly would have been performing much worse than the average This high variation in performance is partly attributed to the quality of coal used and partly to the age and efficiency of the plant; in some cases, the efficiency had deteriorated to as low as 24%. By 2030, however, the subcritical fleet could be a small proportion of the overall fleet, with emissions intensities reflecting more closely the performance of SC and USC technologies.

Figure 24 • Projected CO_2 emissions for Viet Nam up to 2040 (including plants in the planning stage)



Note: Subcritical Moratorium > 2018 = no new subcritical plants are built after 2018.

If construction proceeds as planned, Viet Nam would make strong progress in limiting its share of subcritical units, with the bulk of coal power capacity additions in the 50-year scenario being SC or USC. As such, the emissions intensity for Viet Nam's coal fleet already begins to decrease significantly from 1 120 gCO_2/kWh in 2013, when 90% of the coal fleet was subcritical, to around 900 gCO_2/kWh in 2017, by which time a number of SC and USC plants would have come online. The moratorium imposed on the construction of new subcritical units after 2018 is reflected in Figure 25, with the two scenarios following a single trajectory.

As noted, there is currently a wide variation in the performance of Viet Nam's coal-fired generation units. While there would be a greater choice of SC/USC boiler designs for Indonesian coal types than for Vietnamese anthracite, Indonesian coal would result in a higher emissions intensity. Should Viet Nam follow up on its intention to import Indonesian coal for power generation, the projections portrayed in Figure 24 may be optimistic.

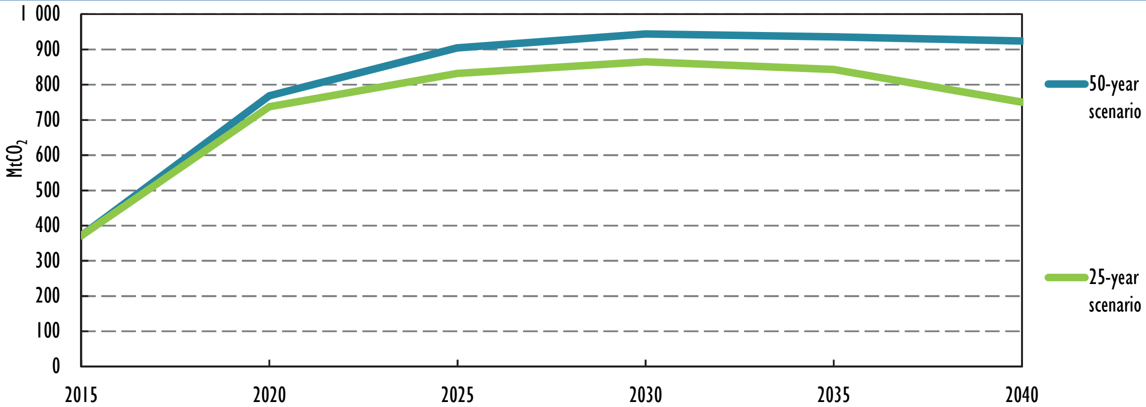
Reducing the impact of increasing coal-fired generation

A high share of unabated coal in power generation results in high emissions of both air pollutants and CO_2. If imposed by rigorous air emission standards, commercially available pollution control equipment can effectively combat air pollution. As a high efficiency power plant produces more electricity from a given amount of coal and has smaller environmental and physical footprints, it is often favoured over a less efficient plant. Except where fuel is cheap and potential savings insufficient to offset the higher costs associated with more complex designs, more efficient plants offer an advantage. At present, in many parts of the world HELE plants present an attractive option, e.g. they are commonplace in China, Europe, Japan, Korea and the United States. Importantly though, high standards of engineering capability are required to design, construct and operate these units.

Maximising efficiency is important, not least in Indonesia, Malaysia and Viet Nam, where ambient conditions and local fuel quality have a deleterious impact, with efficiencies quite significantly below those obtained with similar technology in many other parts of the world. Increasing efficiency has a beneficial, albeit limited, impact on reducing emissions of CO_2 from coal-fired plant. If deep cuts in CO_2 emissions are sought, more potent and costlier steps are needed. Nevertheless, increasing the thermal efficiency of a typical plant in Southeast Asia by just one percentage point can lead to a drop in CO_2 emissions of around 3%. And, conversely, a fall in efficiency leads to a rise in emissions. With ineffective operation and maintenance, the performance of a coal-fired unit suffers and efficiency deteriorates. So, primarily, if the choice is made to construct a coal-fired unit, it is important to select one offering the highest efficiency practicable at the time, and then, secondly, to maintain or even improve upon the efficiency over the lifetime of the unit by effective operation, maintenance and, where appropriate, upgrading.

Looking ahead, each country has choices to make regarding the portfolio of fuels and technologies that generates their power. In Indonesia and Viet Nam in particular, but also in Malaysia, scope exists to improve average coal fleet efficiency and, in so doing, reduce emissions of CO_2 by millions of tonnes each year. At present, each country foresees a desire to increase coal-fired generation, a consequence of which would be to raise emissions of CO_2 (Figure 25). According to present policies, coal is projected to play a major role, but the signing of the COP21 Paris Agreement by each of the countries in December 2015 may well temper this ambition.

Figure 25 • Combined CO_2 emissions from coal power generation in Malaysia, Indonesia and Viet Nam



Indonesia is the principal coal producer in the region, although the coal it produces is characterised by high ash and low heat content. Viet Nam is also a coal-producing nation, but its coal is predominantly anthracite that, while having a high heat content, is more difficult to burn and requires boilers designed for the purpose. Boilers designed for Indonesian coal cannot burn Vietnamese coal without efficiency losses and operational problems, and vice versa. In fact, boilers are not particularly tolerant; each is designed to operate efficiently and effectively for a particular specification of coal and is tolerant only where the properties of the coal used do not stray far from the design specification. HELE boilers are less tolerant than subcritical units, so, as the efficiency increases, it is even more important for the fuel to remain close to the design specification.

When burning coal, opportunities are available that may reduce CO_2 emissions. Coal blending may be used to bring off-specification coal closer to specification and, as a result, improve performance. Blending is used in the target countries but is a complex process and to work effectively requires dedicated instrumentation and continuous monitoring. Co-firing biomass can reduce CO_2 emissions significantly. In theory, 10-15% biomass by mass may be co-fired, which would, of course, reduce the CO_2 emissions by 10-15%. However, the more efficient HELE technologies are more sophisticated and are less tolerant of fuel diversity. In addition, there are important regional sensitivities regarding the use of biomass for energy.

As has been demonstrated clearly in the analysis, the retirement of coal-fired plants before the end of their commercial lifetimes would have little real impact on stemming the rise in CO_2 emissions if they were simply replaced by more efficient, but still unabated, coal plants. Furthermore, the early retirement and replacement of lost capacity with more efficient coal plant would be very expensive, closing profitable units and locking remaining emissions in for longer with unabated replacement coal. A moratorium on subcritical construction may help, but, if simply replaced with more efficient coal plants, would eventually need to be fitted with CCS to achieve deep cuts in CO_2 emissions.

Enhancing the sustainability of Southeast Asia's power-sector developments

The previous section shows that building and operating coal plants as currently planned by the governments of Indonesia, Malaysia and Viet Nam will result in locking in a very high level of CO_2 emissions from power generation over the next decades. The analysis also shows that, while introducing more efficient coal technologies will help reduce emissions intensity from power generation, its impact will be limited. Furthermore, the implementation of the three countries' coal power development plans would be inconsistent with IEA scenarios (Box 6), which feature enhanced efficiency and diversity of the Southeast Asian power sector with a conservative implementation of planned government policies (NPS), a more ambitious implementation of renewable energy and energy efficiency (Bridge Scenario), or a cap on limiting the long-term global temperature rise to 2°C (450 Scenario).

Box 6 • IEA *WEO* policy scenarios

The IEA **New Policies Scenario (NPS)** is the central scenario of the *WEO*. It incorporates the policies and measures that affect energy markets and that had been adopted as of mid-2015, plus other relevant intentions, e.g. *WEO 2015* included energy-related components of the INDCs submitted by national governments by 1 October as pledges in the run-up to the UNFCCC COP21.

The Bridge Scenario incorporates enhanced action by policy makers in five areas, including efficiency, subsidy removal, phasing out of inefficient coal and support for renewables, and delivers a near-term peak in global energy-related GHG emissions. In this scenario, Southeast Asia's energy demand is 5% lower by 2030 compared with the NPS, mainly due to a reduction in oil and coal consumption, while the share of renewables in electricity generation is 7 percentage points higher, providing energy security and environmental performance benefits.

The 450 Scenario takes a different approach, adopting as an outcome the international goal to limit the rise in the long-term average global temperature to 2°C and illustrating how that might be achieved up to 2050. The 450 Scenario assumes a set of policies that bring about a trajectory of GHG emissions from the energy sector that is consistent with a temperature rise of 2°C.

It is important to recognise that the projections are functions of the underpinning assumptions. For the *WEO* scenarios, assumptions were based on the existing policies in 2015, projected to 2040. The projections made in these scenarios may not wholly reflect current reality if, for example, the policies have changed or current discussions hold out prospects that changes will be made. For more details on the IEA scenarios, refer to the *WEO* and *Energy Technology Perspectives* series.

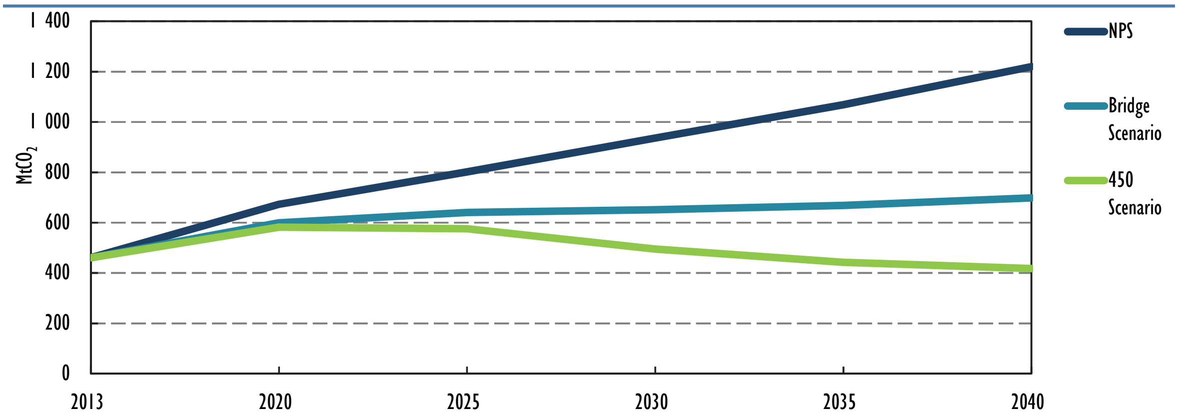
Source: IEA (2015g), *World Energy Outlook 2015*.

Notably, Indonesia and Viet Nam's plans to add some 88 GW of coal capacity between 2015 and 2030 amount to the same coal capacity additions that the IEA projects for the whole Southeast Asian region up to 2040. In Indonesia, PLN intends to increase its coal capacity from 32.7 GW to 74.8 GW by 2024 (RUPTL 2015), while the MOIT in Viet Nam aims to increase coal capacity by nearly 47 GW by 2030 (revised PDP VII). Considering that total installed coal capacity in Indonesia and Viet Nam to date are 54 GW and 35 GW, respectively, these plans signify a 78% increase in Indonesia by 2024 and 133% increase in Viet Nam by 2030. Given the delays and revisions that have affected previous and ongoing power capacity building programmes in both countries – such as Indonesia's two Fast Track programmes and Viet Nam's PDP VII - it is unlikely that these coal addition targets will be met.

Compared to Indonesia and Viet Nam, Malaysia's planned coal capacity additions are moderate at 4.6 GW between 2016 and 2020. However, Malaysia's total installed capacity would nevertheless reach a not insignificant 15.2 GW by 2023. This development trajectory essentially means that coal is steadily catching up with gas as a baseload power source in Malaysia, and is slated to surpass gas as the number one fuel for electricity generation by 2020. Altogether, Malaysia, Indonesia and Viet Nam's coal power development plans will add over 103 GW of coal power capacity by 2030. The emission impacts of these coal power development trajectories are immense – not only for the three countries but for Southeast Asia as a whole, given the overwhelming dominance of their planned coal capacity additions in the regional power mix.

At present, the emissions intensity of Viet Nam's generation portfolio is around 350 gCO_2/kWh, while it is approximately double that value for Indonesia and Malaysia (Figure 2). If current national plans to increase generation from coal were followed, the CO_2 emissions intensity for each country would rise markedly. In fact, even considering the coal power development plans of the three study countries alone, the emissions impact of their implementation would exceed the emissions cap that is needed to achieve the conservatively diversified and moderately efficient NPS scenario, not to mention the more ambitious Bridge or 450 Scenarios (Figure 26). For Southeast Asia as a whole, the projected CO_2 emissions intensity in 2040 would need to be around 550 gCO_2/kWh (NPS) and less than half that in the 450 Scenario (Figure 27).

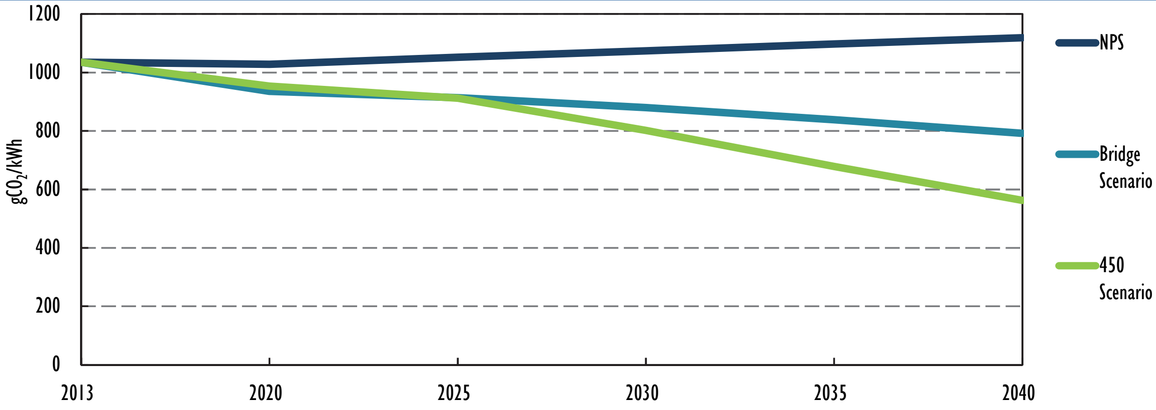
Figure 26 • Projected CO_2 emissions from power generation in Southeast Asia



Note: For country breakdown of projected CO_2 emissions and emissions intensity from the NPS and Bridge Scenario for Indonesia and Malaysia, see Annex. Emissions projections for Viet Nam are modelled separately according to the revised PDP VII.

Source: IEA (2015a), *Southeast Asia Energy Outlook – World Energy Outlook 2015 Special Report*, www.iea.org/publications/freepublications/publication/WEO2015_SouthEastAsia.pdf.

Figure 27 • Emissions intensity of coal-fired power generation in Southeast Asia



Note: For country breakdown of projected CO_2 emissions and emissions intensity from the NPS and Bridge Scenario for Indonesia and Malaysia, see Annex. Emissions projections for Viet Nam are modelled separately according to the revised PDP VII.

Source: IEA (2015a), *Southeast Asia Energy Outlook – World Energy Outlook 2015 Special Report*, www.iea.org/publications/freepublications/publication/WEO2015_SouthEastAsia.pdf.

While future coal-fired capacities, particularly in Indonesia and Viet Nam, are unlikely to fulfil targets in current national plans for a number of reasons (including technical, financial, political and regulatory barriers as well as commendable efforts by governments to continuously decrease the share of coal in the power mix) the capacity additions that are achieved will nonetheless be substantial. Accordingly, the deployment of higher efficiency technologies will be extremely important to reduce emissions from coal-fired generation, and CCS will be essential for coal and gas-fired capacity. Ultimately, however, the share of fossil-fired generation needs to be displaced by greater renewable energy and energy efficiency in the overall power mix, in order to reduce CO_2 emissions intensity from power generation sufficiently to set Southeast Asia's power-sector development on a sustainable pathway. The next section highlights the importance of CCS, energy efficiency and fuel diversification in reducing emissions from the power sector as a whole, and which priority actions could be considered to scale up their implementation from today.

For Indonesia, Malaysia and Viet Nam to continue to grow their electricity generation capacity while, at the same time, satisfying their obligations under the COP21 Paris Agreement, the choices are essentially to:

- Modify present policy and reduce the amount of new coal-fired capacity in national plans.
- Eventually deploy CCS on a significant share of the coal fleet (and in the meantime ensure all new-build units are CCS-ready).
- Retire coal-fired units before the end of their economic life and replace with lower-carbon fuels and technologies to sufficiently reduce emissions, accepting the associated economic losses of early retirements

In practice, the strategy of each of the target countries is likely to be some mix of these choices appropriate to the national requirement to maintain energy security, meet economic development goals and comply with environmental demands. Based on the previous sections and current policy, it appears essential for these countries to ensure that CCS can be deployed at the appropriate time.

Retrofitting CCS

To ensure that it is possible to accommodate CCS at a power plant without incurring unnecessary additional costs at the time when the necessary regulatory and/or economic drivers are in place, the concept of CCS readiness has been developed (Box 7). A new coal-fired unit that is designed to be CCS ready must demonstrate much more than a technical suitability for the addition of post-combustion CO_2 capture (IEA/CSLF, 2010). Since it is technically feasible to retrofit almost any unit with CO_2 capture as long as space on site is available, CCS readiness relates just as much to the commercial opportunity and the access to CO_2 storage as it does to the power plant design.

Box 7 • Planning for CCS readiness in power generation

The following essential requirements represent the minimum criteria that should be met before a facility can be considered CCS-ready (GCCSI, 2010). The project developer should:

- Carry out a site-specific study in sufficient engineering detail to ensure the facility is technically capable of being fully retrofitted for CO_2 capture, using one or more choices of technology which are proven or whose performance can be reliably estimated as being suitable.
- Demonstrate that retrofitted capture equipment can be connected to the existing equipment effectively and without an excessive outage period and that there will be sufficient space available to construct and safely operate additional capture and compression facilities.
- Identify realistic pipeline or other route(s) to storage of CO_2.
- Identify one or more potential storage areas which have been appropriately assessed and found likely to be suitable for safe geological storage of projected full lifetime volumes and rates of captured CO_2.
- Identify other known factors, including any additional water requirements that could prevent installation and operation of CO_2 capture, transport and storage, and identify credible ways in which they could be overcome.
- Estimate the likely costs of retrofitting capture, transport and storage.
- Engage in appropriate public engagement and consideration of health, safety and environmental issues.
- Review CCS-ready status and report on it periodically.

Source: IEA/CSLF (2010), *Carbon Capture and Storage: Progress and Next Steps*, Report to the Muskoka 2010 G8 Summit, OECD/IEA, Paris.

Regulations on CCS readiness have already been implemented in some parts of the world. In Canada, new units that are designed to permit integration with a carbon capture and storage system are temporarily exempted from the national emission performance standard (420 g/kWh) until 2025 or until the conditions for retrofitting the unit with CCS become attractive (Environment and Climate Change Canada, 2013). As a result, CCS ready or CCS-equipped plants are the only new coal-fired plants that can be permitted in Canada.

The Canadian regulation also recognises an important factor of CCS readiness: it needs to be maintained over time. Operators of CCS ready units in Canada must submit an implementation report each year that describes the steps towards retrofitting that have been taken that year and any changes to plans or economic outlook. CCS ready status is not maintained if the allocated space on site is not continuously reserved and if the storage sites and transport routes are not monitored for any developments that could affect the implementation plan.

CCS readiness is complicated by the fact that almost any power plant can technically be retrofitted with CCS at some cost. Therefore, it has proved difficult to generate definitions that influence the investment decisions of power plant developers facing an uncertain and economically discounted future. The key feature of CCS readiness is the minimisation of future retrofit costs through a plant-by-plant consideration of the proximity to CO_2 storage and regulations that serve to maintain available space on site and potential pipeline routes in the period before retrofitting.

Characterising the potential for CO_2 storage can easily take five years before enough information is available to provide sufficient confidence to proceed. Once suitable sites are identified, time-consuming negotiations might ensue before they may be made available for storage – whether onshore or offshore. Similar negotiations may be required to identify and agree land and sea routes for CO_2 transport. Then there are the practical engineering operations to undertake to ensure the geology is prepared such that the CO_2 may be stored safely and permanently. Given these prerequisites, for CCS to be deployed in a timely manner, preparations must begin immediately. Furthermore, work may need to be undertaken in the near-term to ensure that no unforeseen issues arise relating to public or local opposition to CO_2 storage activities. Such opposition could undermine CCS readiness and the social foundation for the construction of new coal plants in the near term.

Building new coal-fired plants and modifying existing plants to be CCS-ready reduces the risk of carbon emission lock-in or of being unable to fully utilise them in the future (stranded assets), but it is important to recognise, however, that making a coal-fired unit CCS-ready is not a CO_2 mitigation option, but a means to facilitate CO_2 mitigation in the future.

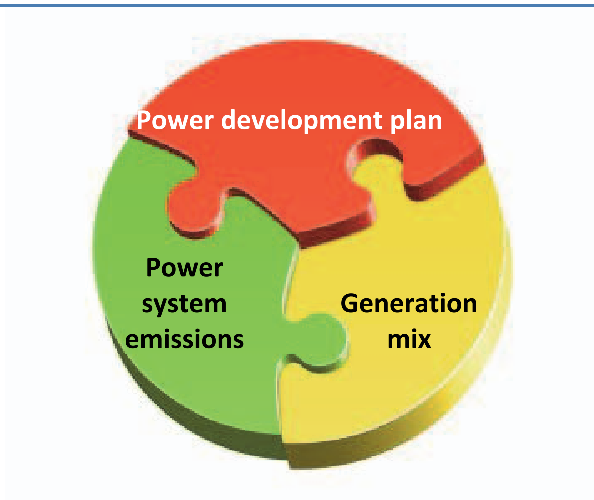
Diversifying the power mix

Although current policy suggests generation from coal will be dominant, for a sustainable power sector the focus must extend beyond coal-fired generation. Given increasing concerns regarding the environment, and the commitments agreed by the three countries at COP21, existing plans are actively being reassessed. Even though coal plants can be low CO_2 emitters by deploying CCS, a far greater emphasis is likely to be placed on the alternatives of energy efficiency, gas and renewables. Minimal nuclear generation is projected within the time horizons considered in this report. Rather than be too intently focused on short-term imperatives, governments must consider the potential for energy efficiency and the mix of fuels and technologies that, in the longer term, will best achieve the energy security, economic development and environmental protection they aspire to. It is important to explore potential pathways at a sufficiently early stage in planning, before locking in to one that may satisfy short-term objectives but is not consistent with longer-term ambitions.

As the focus evolves from supplying electricity in a cost-effective manner to also addressing sustainability concerns and diverse customer energy needs, power development plans have to be treated as "living" documents that are continually revised according to improved policies and changing economic and environmental circumstances. Energy efficiency plays a vital role in reducing demand, while diversifying the generation mix can play an important role in supporting emission reduction targets.

Targeting consistency between power development plans, the generation mix and emissions intensity is essential (Figure 28). This requires co-ordinated and integrated effort from multiple agencies to minimise regulatory oversights and overlaps.

Figure 28 • Harmonising national plans and targets

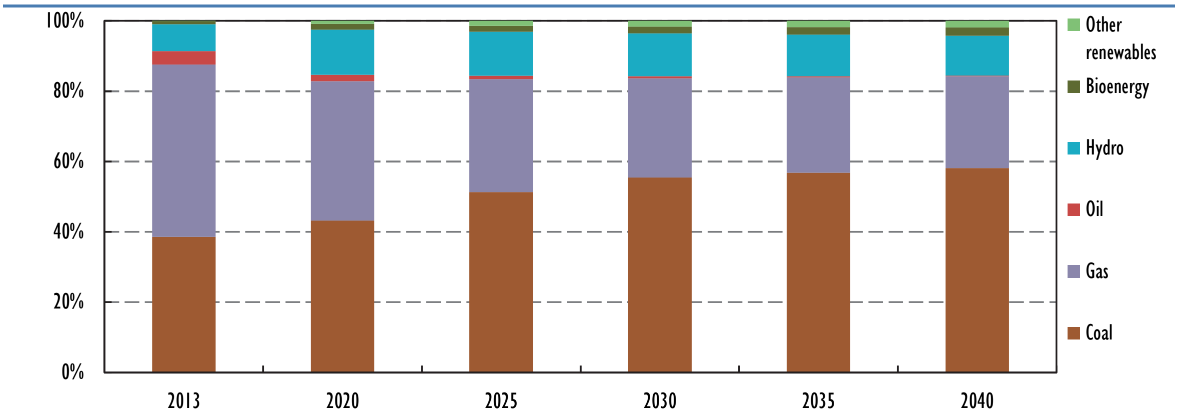


Diversification will have an impact on the high load factor currently enjoyed by the coal-fired fleet. With a higher share of renewables in the power system, part of the base load will be replaced by this renewables generation. This is especially true if substantial solar power generation is deployed in the three countries, because the peak hours for solar power output generally coincide with hours of high demand. Subsequently, coal units may operate at reduced load factors – they will run for a lower number of hours and below their maximum capacity. This situation will affect coal-fired generation in two ways: they will receive less income due to their reduced energy output, which may not cover the costs of maintaining and operating ageing units; and the profitability of investment for the more recent units with HELE technologies (with higher capital costs) may be negatively affected.

Case study: Malaysia

Malaysia has long recognised its heavy dependence on fossil fuels and the consequent high emissions intensity of its power generation. In 2014, more than 90% of its electricity was generated from fossil fuels. In projections of Malaysia's generation mix (Figure 29), according to the NPS the share of fossil fuels remains well above 80% in 2040 (IEA, 2015a). Whereas the share of natural gas gradually decreases, coal's share rises above 50% by 2025, increasing to close to 60% by 2040. Efforts to increase the share from other fuels and technologies have been restricted by resource availability and high investment costs.

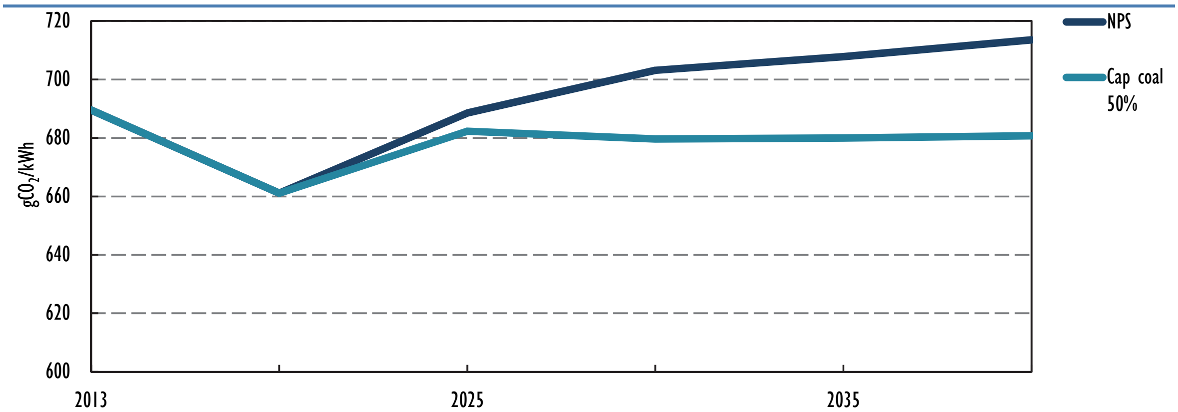
Figure 29 • Malaysia's generation mix under the NPS



Source: IEA (2015a), *Southeast Asia Energy Outlook – World Energy Outlook 2015 Special Report*.

An alternative future, with a policy of capping the share of coal at 50% from 2025 while projecting the same total generation, is shown in Figure 30. This diversification is in line with the existing practice for Peninsular Malaysia whereby diversity is continuously monitored using the Herfindahl-Hirschman Index (HHI)[11] target, which is set to less than or equal to 0.5 by 2020, and 0.4 by 2025. These targets demonstrate the country's commitment to avoiding dependence on any particular fuel or technology. If the share of coal is capped at 50% until the end of the projection period, the cumulative emission savings in 2040 compared to the NPS are estimated at 13 $MtCO_2$. Further reductions would be achieved by deploying a higher share of renewables.

Figure 30 • Illustrative trajectory of emissions intensity scenarios for Malaysia's power sector, 2013-40



Energy efficiency in the power sector

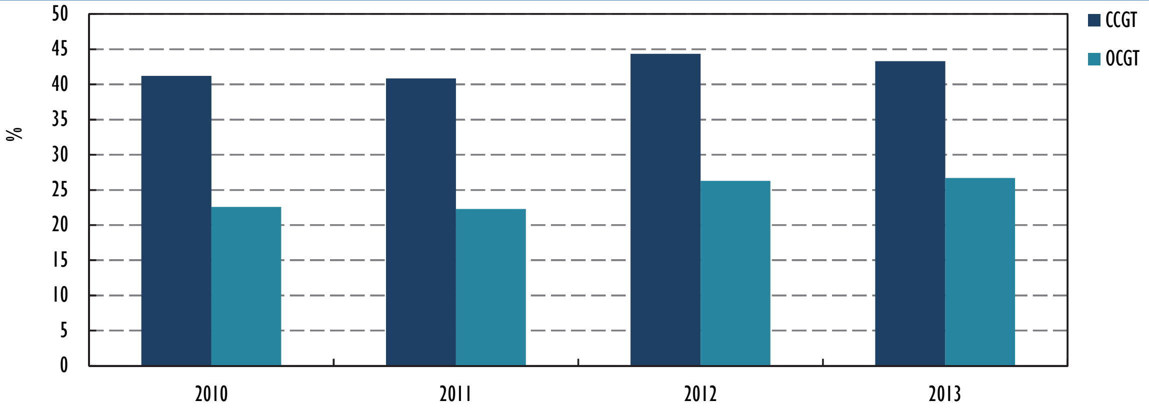
Efficiency gains, both on the supply side and the demand side, can play an important role in limiting increases in demand growth and, consequently, in the scale of generation and capacity expansion required to meet future needs. In short, efficiency gains are essential to achieving an optimal energy system, reducing the power sector's impact on the environment.

Generation efficiency

Improving the efficiency of generation brings many advantages, not least its impact on cost reduction; this applies across the spectrum of fuels and technologies used to generate electricity. For fossil-fired technologies, it reduces emissions of CO_2 and conventional pollutants; it reduces resource consumption, thus prolonging the life, say, of fuel reserves; and it increases the power output from a given size of unit, thus reducing capital costs and, potentially, operating costs. The benefits of the shift to HELE coal technologies are discussed in the previous section. Employing more efficient gas-fired technologies brings similar benefits. Moving to the highly-efficient H class of turbines raises the efficiency of CCGTs to around 60%. The average efficiency of CCGTs in Peninsular Malaysia is around 43%, and for OCGTs it is 27% (Figure 31). For both coal and gas, the average efficiency of plants increases as older plants are retired and newer plants with higher efficiencies are commissioned.

[11] HHI is commonly used to determine market concentration in an industry as well as economic diversity. In this context, HHI measures the extent to which the generation mix is dominated by a few types of fuel. An HHI value exceeding 0.5 reflects overdependence on certain fuel resources.

Figure 31 • Average efficiency of TNB gas units in Malaysia, 2010-13



Note: TNB = Tenaga Nasional Berhad.
Source: Energy Commission (2014), Malaysia Energy Information Hub (MEIH), http://meih.st.gov.my/.

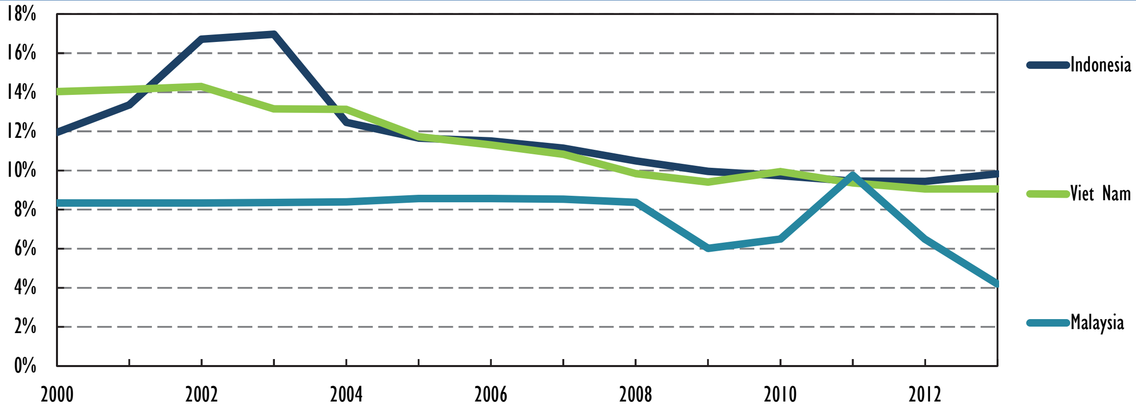
Generally speaking, plants operating at lower loads operate at lower efficiencies than their full-load design efficiency. Variations in efficiency may also arise from differences in plant design and maintenance practices and from practical and operational constraints associated with different fuel sources, while local ambient conditions are also a significant factor. Therefore, for all generation assets, regular maintenance and effective operation are important to keep plant performance from deteriorating over time. Options to upgrade plant equipment should also be reviewed periodically as new technologies present opportunities to improve upon the design efficiency of existing generation assets.

Different countries tend to develop certain types of generating resource for geographic reasons (for example, the Mekong region offers significant hydroelectric potential), for economic reasons (for example, Indonesia has significant low-cost domestic coal deposits) or even political reasons (such as seeking greater energy security through national self-sufficiency). Consequently, an optimal mix of fuels and technologies is more likely to be achieved at the regional level. Integrating power systems across borders, or at least allowing for the trade of electricity between regions, can increase the overall efficiency of generation by allowing each plant to run more often when it is optimal to do so while simultaneously enhancing energy and supply security.

Network efficiency

Achieving network efficiency usually takes the form of reducing T&D grid losses. In the case of Indonesia and Viet Nam, T&D losses have markedly improved over the past decade (Figure 32). Geographical factors and network characteristics are the main constraints to achieving lower network losses. Long transmission lines and archipelagic geography may limit the potential for grid-loss reductions, for example, in Indonesia. In Malaysia, loss rates have been maintained at less than 10% for quite some time and remained consistently below 6.5% since 2009, with the exception of 2011, when inadequate gas supplies led to disruptions that increased loss rates.

Figure 32 • T&D loss rates for Indonesia, Malaysia and Viet Nam



Source: IEA (2015f), *Electricity Information*, (database), www.iea.org/statistics/.

Reductions in T&D losses result in the need for less electricity to be generated. For example, in 2012, transmission losses amounted to 9% of the gross electricity generated in Indonesia. If this were 7%, 3.9 TWh of yearly generation or 447 MWh of hourly generation could have been saved, equivalent to the output of one medium-sized thermal generation unit running at full capacity for a year.

Power losses occur due to technical and non-technical factors. Technical losses may be due to energy dissipated in the conductors and equipment used for the transmission, transformation and distribution of power. Minimising these losses would require less generation to meet the same power demand. Losses can be reduced by better network design, material selection and minimising circuit length.

Non-technical losses result from power theft, defective meters, and errors in meter reading and in estimating unmetered electricity supply. Such losses reduce the utilities' income, while consumption on the part of consumers and the total energy generated do not change. These issues can be partly mitigated by smart meter installations. In Malaysia for instance, the nationwide rollout of smart meters was projected to begin from the first quarter of 2016, with completion expected by 2023. The deployment of smart meters would allow remote recording of meter readings using wireless communication technologies, thereby reducing manpower costs and metering errors. With smart meters, utilities can identify the real-time energy consumption patterns of users and therefore assist in managing load efficiently. Additionally, smart meters can also facilitate the smooth supply of surplus domestic power generated from renewable energy sources, such as wind energy and rooftop solar panels, back to the grid, thereby enhancing the efficiency of the overall grid system.

Indonesia, Malaysia and Viet Nam would also benefit from using information and communication technology (ICT) infrastructure to enhance system control and monitoring, as well as data mining techniques, in all aspects of power sector operation. For power sectors such as Indonesia's, where some consumers are subsidised by charging them a lower tariff rate, determining which consumers qualify for the preferential rate could be facilitated by employing a suitable data acquisition system.

Demand-side efficiency

Demand-side efficiency is a growing area with great potential to reduce future electricity demand and, in particular, to smooth out the peaks in demand. It may be achieved by applying policy measures to different target areas, including buildings, lighting, industry, electrical transport, lighting, appliances and equipment, as well as across sectors. Retrofitting existing buildings also provides an opportunity to reduce demand; for example, four government buildings located in Putrajaya, Malaysia, were retrofitted between 2011 and 2014 and successfully reduced their electricity consumption by between 4% and 19%, equivalent to monthly savings of MYR 7 000 to MYR 130 000 (USD 2 100 to USD 39 000). A further example, also in Malaysia, saw air-conditioner temperatures set at a minimum of 24°C, reducing the electricity bills of all government buildings by 5%.

In 2013, Malaysia published the National Energy Efficiency Action Plan (NEEAP) to cut electricity demand by 6% in ten years via appliance labelling, minimum energy performance standards (MEPS), energy audits and grants. One of the main initiatives under NEEAP is a programme of energy audits in buildings and industries, whereby large government buildings as well as medium-sized to large commercial and industrial buildings undergo free energy audits and are required to establish energy management programmes.

Comparable initiatives are seen elsewhere, for example the Viet Nam Energy Efficiency Standards and Labelling (VEESL) programme for appliances, which started in 2013. Similarly, Indonesia is currently developing MEPS as well as energy labels for application in a variety of appliance categories. Under an earlier initiative, in 2011, the SAVE programme was implemented in Malaysia to encourage utilisation of energy-efficient equipment. A total of MYR 44.3 million (USD 14.1 million) was allocated to the programme to offer rebates on any purchase of new energy-efficient refrigerators and air conditioners for domestic use, as well as chillers for industry. The total energy saved from this equipment for the period from 2011 to 2013 was estimated at 307 GWh (EPU, 2015).

As many of the incentives and measures were run for a limited period, after the offer elapsed customer choice may well have reverted to the “cheaper” options. Medium- and long-term national plans on energy efficiency are more likely to ensure a lasting shift to optimising electricity usage.

Gas-fired power generation

In Indonesia, the use of gas for power generation is expected to increase, albeit at a modest rate due to strong competition from cheap domestic coal. The principal planning document is Indonesia's National Gas Transmission and Distribution Master Plan, which contains an inventory of planned pipeline infrastructure for the period 2012-25 (IEA, 2015b). Malaysia’s gas demand is also expected to increase modestly, with new and planned LNG regasification facilities improving gas supply availability. Several infrastructural projects have been planned to strengthen its gas supply security and connectivity. These include: the deployment of the second regasification terminal at Pengerang, Johor; the establishment of a pipeline connection from the Sabah-Sarawak gas pipeline to the Labuan Federal Territory; and the construction of other pipelines, for example, from Indonesia and the Malaysia-Thailand Joint Development Area to the gas-receiving terminal in Kerteh, Terengganu. The Gas Supply Act 1993 (Act 501) is due to be amended in 2016 to ensure third-party access to the Peninsular Gas Utilisation pipeline and regasification terminal. Unlike the trend of the last two decades, however, Malaysia's additional capacity plans are now dominated by coal rather than gas. In the absence of new policies, as additional coal generation capacity ramps up, utilisation of Malaysia’s gas fleet is expected to decrease.

In contrast, Viet Nam is benefitting from both rising domestic production and new LNG import facilities. Development priority will be given to LNG import infrastructure in the southern part of the country, where important gas-fired plants are located. Thi Vai port, with a capacity of 1 Mt/year, and Son My port, with capacity of 3-6 Mt/year, are currently being developed, with operations expected to commence in 2018 and 2023 respectively. Up to 2025, natural gas demand for power generation is estimated at 15-20 bcm per annum. Gas consumption in the power sector is expected to rise, albeit at a slower pace than coal. However, if energy policy were to become more favourable towards gas, Viet Nam's oil and gas discoveries in recent years should allow it to meet stronger demand.

According to PLN's RUPTL 2015-24 (Electricity Supply Business Plan), 14 GW of new gas capacity is to be constructed in Indonesia, amounting to approximately 20% of overall capacity addition within that ten-year period. In Peninsular Malaysia, 5.8 GW of gas capacity is planned between 2016 and 2023, contributing around 55% of overall capacity addition, while, in Viet Nam, 10 GW of gas-fired plant, or around 13% of new capacity, is expected to be added by 2030. The contributions from gas and coal to generate electricity will depend crucially on future policy. At present, apart from Viet Nam, the share of gas in the generation mix is projected to drop, as it is for the region as a whole.

Gas will continue to play an important role from the perspective of fuel supply security, aided by the drop in LNG price which may open up the possibility of larger import volume as discussed earlier in the fuel competition section. The overall trend of low gas prices may also mean diminishing opportunity costs from exporting gas as compared to domestic consumption by the power sector, at least in the case of Malaysia. Therefore, this may encourage more domestic gas to be allocated to gas-fired plants, which will affect the balance between the fuel mix.

Gas turbines offer greater operational flexibility than coal, especially in systems with high variations between peak, shoulder and non-peak hours; and in the future they would complement the higher shares of variable renewable energy that are planned, e.g. wind and solar. While electricity systems have always required flexibility to respond to unforeseen outages, an increasing amount of variable renewables connected to the transmission grid requires a greater proportion of the generating fleet to be able to cycle effectively and efficiently.

Domestic gas production in the region is somewhat dependent on gas exploration activity and production growth. Infrastructure planning and development will be a major determinant in ensuring accessibility of gas to the power industry. Gas production areas may be located far from demand centres, as is the case between Sarawak, where the gas is produced, and Peninsular Malaysia, where it is used. The locational mismatch will require either an expansion of pipeline infrastructure or of facilities to ship and receive LNG.

The Trans-ASEAN Gas Pipeline project aims to establish broader gas interconnections throughout the region, although progress has been slowed by a shortage of gas sources and the magnitude of investment required. Meanwhile several countries are building or are considering plans to build floating liquefied natural gas (FLNG) facilities to develop remote resources and regasification terminals to receive imports. For example, the commissioning of two FLNG units in offshore Sabah and Sarawak are among the projects in the 11th Malaysian Plan, covering 2016-20.

The main technologies deployed for gas turbines are OCGTs and CCGTs. While OCGTs are simpler and less costly, they are much less efficient and consequently use more fuel and produce more emissions than their CCGT counterparts. The efficiency of CCGT plants has also been improved continuously over the past 20 years. Technological advances, such as higher turbine inlet temperatures and increased pressure ratios, have greatly raised performance, with newer units in the region operating at efficiencies in excess of 55%. CCGT units are important when evaluating the technology options for new capacity addition. In Viet Nam, CCGTs predominate, representing more than 90% of all gas turbines installed, whereas in Indonesia and Malaysia, only around two-thirds of the turbines are CCGTs (Platts, 2015). However, all new-build gas turbines in Malaysia are planned to be CCGTs and Indonesia is increasingly moving in the same direction.

Gas turbines offer a wide range of capacities and, with their quicker construction times, may better complement the needs of the power systems than coal. While coal plants, capable of unit sizes up to 1 GW, can offer economies of scale, such large units may not be appropriate, for example in smaller islands and remote communities, and smaller coal-fired units suffer from diminished performance.

Renewable energy

Indonesia, Malaysia and Viet Nam are endowed with extensive renewable energy resources. Making greater use of these resources, whether hydropower, geothermal, wind, solar or biomass, diversifies the generation mix and at the same time enhances energy security and reduces CO_2 emissions. In addition, renewable energy technologies can play an important role in bringing electricity to remote areas, e.g. to mountainous areas and islands. While the challenge of connecting renewable resources to areas of demand throughout Indonesia's 6 000 inhabited islands is not to be underestimated, renewable energy technologies could significantly enhance the provision of basic energy needs to isolated islands and rural off-grid areas, particularly given the high cost of transporting fossil fuels to distant island communities.

Renewable energy has been growing rapidly in a number of developed and developing countries around the world, supported by drivers including strong policy, advance in technology, declining cost and competitive financing. While most renewable energy technologies run with no fuel costs, they are generally capital intensive. Much of their deployment in the region to date has been driven by preferential policies and support schemes. As resources are location-dependent, estimating their potential and resource mapping become very important precursors to investment decisions. Governments in the study countries can play a greater role in accelerating the deployment of these technologies not only by setting realistic targets for renewable energy generation, but also backed by a transparent regulatory framework and good quality data.

Renewable energy potential

Currently, hydropower is by far the most firmly established renewable energy source in Southeast Asia, contributing 14% of electricity generation in 2013, with the potential for a much higher contribution. It has been estimated that Indonesia alone has the potential for 75 GW of hydropower; much of this potential, however, is located in areas such as West Papua, far from the demand centres. The geographical mismatch between supply and demand is the main reason that total installed hydropower capacity stands at just 5% of overall potential. Similarly in Malaysia, while the bulk of the demand is concentrated in the Peninsular, most of the untapped hydropower potential is located in the state of Sarawak. The long lead time for the development and construction of large hydropower plants has been taken into account in the SCORE programme (see previous section on Malaysia's power development planning and outlook), which is driven by comparing the economic benefits of these projects to the overall cost of generation. In Viet Nam, the total hydropower potential is estimated around 35 GW with 14.6 GW of existing operational capacity. Approximately 3.05 GW of additional capacity is currently under construction and expected to be operational by the end of 2017 (Platts, 2015).

Developing small hydropower stations ranging from 1 MW to 30 MW for local use may be an alternative; in Viet Nam, the total small hydropower potential has been estimated at about 4 GW, with 1 GW estimated for Indonesia. In Malaysia, the potential is significantly lower, at around 500 MW (Academy of Sciences Malaysia, 2013). While small hydropower has a much lower capital cost per MW compared to large stations, the estimated LCOE for Indonesia is almost double (BREE, 2014). Viet Nam also plans to develop pumped storage plants, which will improve the flexibility and efficiency of its power system operations. The total capacity of pumped storage plants is projected to reach 2.4 GW by 2030 and 8 GW by 2050 (Prime Minister's Decision No. 2068, 2015).

Sources of geothermal, wind and solar power are also significant. The potential of geothermal in Indonesia, for instance, is estimated at 28 GW, which is around 40% of the world's geothermal potential; less than 2 GW has been realised to date. The country's geothermal resources have the benefit of being situated near demand areas, with the highest potential to be found on Sumatra (14 GW), Java and Bali (9 GW) and Sulawesi (2 GW) (IEA, 2015b). According to its roadmap for geothermal development, Indonesia plans to install of 6 GW by 2020, rising to 9.5 GW by 2025. Geothermal power in Indonesia also benefits from having the lowest LCOE estimate compared to other renewable energy sources, including large hydropower (BREE, 2014). However, costs associated with both hydropower and geothermal can be very site-specific and, in the case of the latter, can also vary based on associated exploration and development costs. Although the estimated geothermal potential in Viet Nam is significantly less, at 400 MW, there are plans to develop 200 MW of capacity by 2030. Limited potential has also been found in Malaysia, with the discovery of a 12 square kilometre geothermal field in Apas Kiri, Sabah (EPU, 2015).

All three countries also have considerable year-round solar energy potential. For example, as an equatorial country, Indonesia has an average solar radiation of 4.8 kilowatt hours per square metre (kWh/m^2) per day, Viet Nam 4.6 kWh/m^2 per day and Malaysia 4.5 kWh/m^2 per day. Solar power has been increasingly tapped to supply not only the distribution grid but also islands and remote/isolated communities with no grid access.

In Indonesia, wind power potential is estimated at 9.3 GW, against less than 2 MW installed at present. Indonesia has constructed 12 wind farms across the country, each with a capacity of 80 kilowatts, located in North Sulawesi, the Pacific Islands, Selayar Island and Nusa Penida, and Bali (IEA, 2015b). Indonesia's target is to install 970 MW of wind capacity by 2025. With its long coastline, at more than 3 000 kilometres in length, and being located in a monsoon region, Viet Nam has excellent wind potential along the south central coast, in the central highlands, and on the south coast; consequently, it is planning to increase its total generation from wind sources from around 180 GWh in 2015 to 2.5 TWh in 2020, 16 TWh in 2030 and 53 TWh in 2050. In Malaysia, a national wind mapping exercise is underway, which is expected to be completed in 2016.

The three countries also have a considerable bioenergy potential (comprising solid biomass, biofuels and biogas), especially Indonesia where the potential for electricity generation from biomass alone is estimated at 32.7 GW (IEA, 2015b). However, there are several challenges that could constrain the use of bioenergy, including uncertainty about the availability of supply and its quality, and concerns about the environmental sustainability of production (IEA, 2015a).

Support schemes and opportunities for large-scale renewables deployment

Indonesia, Malaysia and Viet Nam are commended for their efforts to reposition policy within the last decade so as to accelerate the deployment of renewable energy. To support the renewable energy targets outlined in their development plans, the three governments have introduced several support schemes, which include FITs, tendering exercises and capital subsidies. Among these, the FIT is the most widely used, usually combined with priority grid access and a guaranteed purchase of electricity (IEA, 2015c).

A FIT is a regulated tariff granted by the government to the producers of renewable energy in the form of a price per unit provided for a certain period of time that ensures profitable operation and pay-back of the capital cost to the producers. For instance, since 2012 the FIT for geothermal in Indonesia has been USD 0.10-0.185/kWh, depending on the location of the plants and in which voltage the electricity is supplied. Ministerial Regulation No. 04/2012 also introduced a FIT for biomass, biogas and municipal solid waste which guarantees access to the grid and obliges PLN to purchase up to 10 MW of electricity from these sources. In 2013, the Indonesian government also introduced a new FIT awarded through competitive bidding for solar PV systems, ranging from IDR 2 840/kWh (USD 0.27/kWh) if imported systems are used, to IDR 3 480/kWh (USD 0.34/kWh) if the system has a 40% domestic component share.

The Ministerial Regulation on Small Distributed Power Generation using Renewable Energy, mentioned in the first section of this publication, allows enterprises to sell their power production or surplus power to the local utility's power grid (if readily accessible). The maximum allowable capacity of the power plant is up to 1 MW and the electricity price is 60% of the utility's production cost if it is connected to the low-voltage grid, or 80% if it is connected to the medium-voltage grid. The Indonesian government also provides incentives for the development of local renewable energy industry in areas such as West and East Nusa Tenggara, Molukken and Papua.

Similarly, the FIT is the main support instrument in Viet Nam. Additionally, the annual avoided costs for all small renewable resources have been established since 2009.[12] This is based on the avoided cost (marginal cost, based on peaking CCGT), with price differences influenced by season (wet or dry) and diurnal slices (peak, shoulder or low load).

A newly announced Strategy for Renewable Energy Development in Viet Nam also includes several other supporting measures (Box 8).

Box 8 • Strategy for Renewable Energy Development in Viet Nam

According to Viet Nam's Strategy for Renewable Energy Development, a number of policy measures will be implemented to facilitate renewable energy deployment. These include FITs, which will take into account the conditions in different regions and the characteristics of various renewable energy technologies. Renewable energy power generation projects will be given prioritised connection to the national power system, and power entities will be responsible for purchasing all electricity produced from grid-connected renewable energy generation within their jurisdiction on the basis of the regulated power-purchase agreement. The electricity purchase cost will then be added to the power entity's electricity tariff and recovered from sales revenues.

A new "Sustainable Energy Promotion Fund" will be established to provide financial support for renewable energy projects in isolated or independent power systems within the country. The fund will be financed by the state budget, revenue from environmental fees levied on fossil fuels, various sources and contributions from domestic and foreign organisations/individuals, as well as other legitimate funding sources.

To support the Renewable Portfolio Standard (RPS), the strategy also outlines the minimum percentage of electricity that has to be generated from renewable resources (excluding hydropower sources greater than 30 MW) by power generation entities with more than 1 000 MW of installed capacity, which will be 3%, 10% and 20% in 2020, 2030 and 2050 respectively. For power distribution entities that generate or purchase electricity from renewable energy sources, and end-use customers who self-generate electricity from renewable energy sources (excluding hydropower sources with capacity greater than 30 MW), the percentage has to be higher than 5%, 10% and 20% in 2020, 2030 and 2050, respectively.

Other planned measures include the establishment of a net-metering mechanism for end consumers with behind-the-meter renewable energy generation, with simplified connection processes/procedures in order to encourage the investment. Additional planned fiscal instruments

[12] When a utility buys power from independent companies that can produce power for less than what it would cost for the utility to generate additional power itself, this is called the "avoided cost". If a renewable power generator is willing to sell power to the utility at the avoided cost, it saves the utility from having to build additional generation capacity to meet demand.

comprise exemption from import tax for equipment and material for renewable energy projects and corporate income tax exemption and reduction.

Source: Prime Minister's Decision No. 2068 (2015), *Viet Nam's Renewable Energy Development Strategy up to 2020 with an Outlook to 2050*.

In Malaysia, the FIT covers various technologies, including solar PV, small hydro, geothermal, biomass and biogas. The maximum installed capacity of any eligible renewable energy installation is 30 MW, unless special approval from the Minister is obtained. The FIT rate is reduced as installed capacity increases, due to cost optimisation from economies of scale. A bonus FIT rate applies when particular criteria are met; for example, in the case of solar PV, the bonus rate is applicable if the solar PV panel is installed on buildings or building structures, used as building material and/or if the modules or inverters are locally manufactured or assembled.

To complement the current FIT mechanism in encouraging the take-off of renewable energy, a new instrument termed Net Energy Metering (NEM) will be implemented in the 11th Malaysia Plan 2016-20 (EPU, 2015). The objective of NEM is to promote and encourage more renewable generation by prioritising internal consumption before any excess electricity generated is fed to the grid. The NEM is anticipated to encourage manufacturing facilities and the public to generate electricity without any restriction on their generation capacity.

Beyond the above measures, the countries could hold further auctions for large-scale wind or solar projects which could start as technology-specific auctions, but may evolve over time into those that are technology neutral, e.g. location-specific auctions that allow all technologies to compete to see who can provide the cleanest generation option at the lowest cost in a given location (IEA, 2015c). Both the auction and the resulting power purchase agreements for utility-scale renewables need to be properly defined and devised to complement the smaller capacity installations covered by FITs in achieving national targets.

Taking advantage of declining costs and technological advancement, governments have a major role in facilitating rapid and wide-scale deployment of renewable energy, for example, in easing approval procedures and regulatory requirements. Significant room for improvement in procedures exists. For example, multilayer national and regional-level approvals for land acquisition and land ownership can cause significant delays and even cancellation of renewable energy projects. Procedures can be aligned and simplified, overlaps can be reduced, and the number of government institutions involved in a particular project can be minimised.

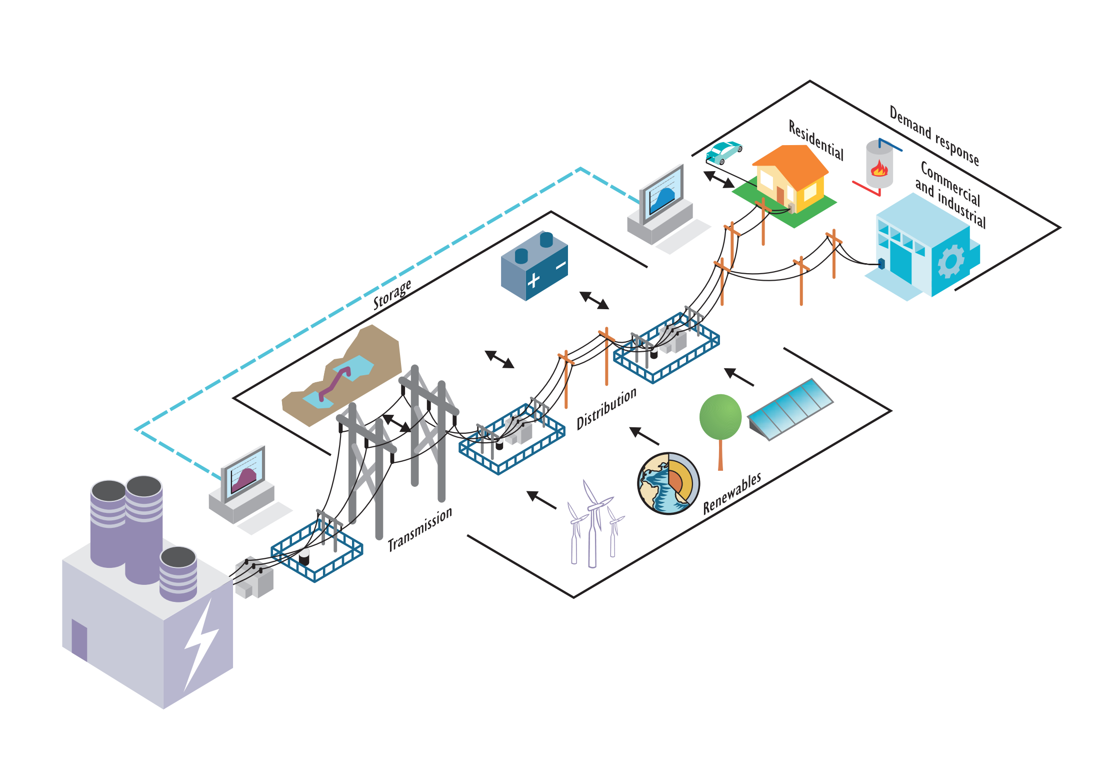
Indonesia has recently revised its law pertaining to geothermal generation, whereby geothermal projects would no longer be considered as mining operations. About 42% of geothermal resources are located in forest conservation areas (IEA, 2015b), where mining operations are prohibited and require presidential approval to proceed. The declassification of geothermal exploration as a mining activity is therefore intended to facilitate the deployment of this renewable energy.

Governments can also help de-risk exploration of renewable resources such as geothermal, wind, hydropower and solar. By providing or certifying reliable assessments of available renewable resources, governments can give much-needed assurance to investors.

Compatibility with electricity grid infrastructure is essential for renewable generation to have the necessary impact. Governments must consider upgrading existing grids, especially in regions with a high renewable energy potential located far from major demand loads. For example, for wind power in Viet Nam to be effective, grid-connected smaller-scale facilities may require local low-voltage grids to be upgraded. Authorities may also encourage renewable penetration by relieving grid congestion, as the network capacity may be fully utilised for several hours in a day during periods of high renewables generation. Decentralised expansion, whereby smaller distributed generation capacities are connected to distribution grids, should be encouraged to further spur the deployment of renewable generation (Box 9). It also offers an attractive option for countries with a complex geography – such as Indonesia – while simultaneously minimising power losses.

Box 9 • Decentralised power system expansion

Future power systems are likely to become more decentralised, with distributed generation such as rooftop solar PV playing an important role in meeting new demand. Investment in building the required infrastructure is expected to grow rapidly. The IEA projected that under the 450 Scenario for OECD Europe, investment in renewables will reach close to USD 1.6 trillion between 2015 and 2040, the majority of which will go to solar and wind power at USD 1.2 trillion. Cumulative investment for distribution systems will more than triple the transmission system in the same period (IEA, 2015g). Such an outlook significantly supports the prospect of power-system decarbonisation (Figure 34). Having decentralised resources closer to load centres brings multiple benefits, including a reduction in the power losses that result from long-distance transmission and voltage transformation. For countries where daily peak-load hours coincide with the solar PV output pattern, a high penetration of distributed generation may also lead to lower annual peak load needs. This could reduce the reserve margin required and, consequently, could defer the need for additional centralised generation capacity and associated transmission line upgrades. The figure below shows a concept of a power system with more decentralisation:



Source: IEA (2016b), *Re-powering Markets: Market Design and Regulation during the Transition to Low-Carbon Power Systems*.
Source: IEA (2015g), *World Energy Outlook 2015*.

Enhancing the workforce skillset is a pressing need for the wider adoption of renewable technologies such as wind and solar. Training needs to be provided by both the government and the private sector. In Indonesia, for example, a lack of local expertise resulted in operational problems on a number of mini- and micro-hydro projects (IEA, 2015b). The Malaysian government is adopting an initiative to equip its workforce with the necessary skills by providing training to 1 740 skilled and semi-skilled personnel through the Sustainable Energy Development Authority Malaysia (SEDA) within the 2016 to 2020 horizon. The training is aimed at developing expertise in the fields of biomass, biogas, mini-hydro and solar PV, and is directed at, for example, project developers, financial institutions and potential service providers.

Reconsidering investment in coal-fired power generation

Each year, more than USD 70 billion is invested in Southeast Asia's energy supply projects, representing an increase of nearly 60% in spending over the past decade in real terms (IEA, 2015a). Half of the investments are targeted at the power sector, with the rapid growth in electricity demand prompting a massive expansion of the region's thermal power fleets, hydropower stations, wind turbines, solar farms, biofuels facilities, and its electricity T&D lines.

According to the NPS, developing the power sector will require more than USD 1.3 trillion of cumulative investment between 2015 and 2040, or roughly USD 52 billion each year (IEA, 2015a). At the regional level, investment needs for T&D (USD 710 billion) will exceed those for power plants (USD 635 billion), although in individual countries this may not be the case (see next section on reconsidering investment in coal capacity in Viet Nam). Of the cumulative investments in power plants, the NPS projects that coal-fired generation capacity will require the greatest share – at 37% (or some USD 235 billion).

To ensure the power sector is developed sustainably for the long term, it is important not only to prioritise low-carbon generation technologies, but also system-wide upgrades to ensure that power T&D and information systems are effectively supporting existing and expanding central and distributed, grid-connected and off-grid power systems. Increasing generation capacity without a well-planned, efficient and reliable T&D network to deliver electricity to consumers leads to sub-optimal resource and asset utilisation and, in the case of fossil-fired technologies, higher emissions. Better data mapping and monitoring systems would also have system-wide benefits for power producers and power development planners to understand where, when and how much electricity is needed and at what price.

Although more efficient coal technologies can play an important role in reducing emissions intensity in plants that would or might otherwise run less efficiently, there is nevertheless a clear limit to the long-term emissions reduction opportunities that can be realised in a power mix heavily reliant on unabated coal. Recognising that any new coal plants, even equipped with HELE technologies, may still be run for an average lifetime of 50 years, there is a serious need to reconsider the costs – economic, environmental, social or otherwise – of potentially running a sizeable coal fleet for several decades to come.

While diversifying the power mix would allow for some scaling back of coal-fired capacity additions, remaining coal-fired plants would nevertheless eventually need to be fitted with CCS in order to be consistent with a low-carbon scenario. As discussed in previous sections, deployment of CCS will take time and strong policy support, not least for the development of the geological CO_2 storage resource in Southeast Asia, which is not yet well understood. It will also be closely linked to the accumulation of experience with CCS technologies globally. Some examples of important policy instruments governments can endorse to support the different elements of the CCS value chain include: capital grants, production subsidies, investment and production tax credits, FITs, portfolio standards and credit guarantees (IEA, 2013).

Over the longer term, governments could consider providing an incentive for the decarbonisation of the power sector via technology-neutral mechanisms, such as putting a price on CO_2 emissions. Carbon pricing can be introduced in a number of forms including cap-and-trade schemes, carbon taxes, and baseline and credit schemes. In the meantime, in the absence of a carbon price, a shadow price on carbon (Box 10) would guide decisions on capital expenditure as a means to manage the economic risk associated with a carbon-constrained future. This is particularly important when investing in energy-intensive long-lived facilities such as power plants. Shadow pricing also signals a commitment that climate change mitigation is a serious matter.

Box 10 • Shadow price on carbon

Imposing a price on GHG emissions, such as through a tax on the carbon content of fossil fuels, is an essential response to the growing risk of disastrous climate change (World Bank, 2016). Applying a shadow price on carbon (or CO_2) is an explicit way to anticipate future policies and avoid stranded assets. It is a method of investment or decision analysis that adds a hypothetical surcharge to market prices for goods or services that involve significant carbon emissions. For example, for a new power plant, the price would be the sum of the market price plus a charge associated with the CO_2 that would be emitted. Shadow prices reveal the benefit of options that are more emissions efficient, other things being equal.

As well as several countries, cities, states and provinces across the world, a growing number of companies are also putting a shadow price on carbon to reduce their carbon footprint cost effectively (CDP, 2014). Gradually, standard approaches for carbon shadow pricing are emerging, with the price per tonne of CO_2 emissions varying according to approach, scope of coverage and pricing methodology.

This is particularly important when it comes to investing in energy-intensive long-lived facilities such as power plants. Shadow pricing is a concrete way to signal to investors and the public that the commitment to climate change mitigation is being taken seriously. It can also induce more consistently cost-effective abatement than alternative approaches such as targets for efficiency standards or for renewable energy procurement.

Sources: CDP (2014), "Global corporate use of carbon pricing: Disclosures to investors", CDP North America, New York; World Bank (2016), "What is carbon pricing?", retrievable: www.worldbank.org/en/programs/pricing-carbon (last accessed: 22 April 2016).

With a shadow price on carbon in place, a decision could then be taken on the most cost-effective plant to construct, whether it be the most cost-effective coal-fired technology or a lower-carbon option. Presently, none of the target countries in this study applies a shadow price on carbon in their planning.

Reconsidering coal capacity additions in Indonesia, Malaysia and Viet Nam

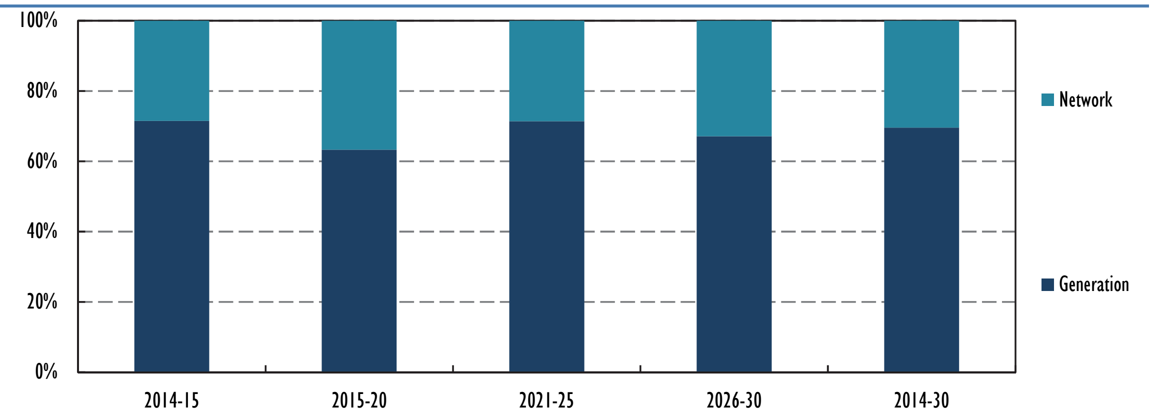
In **Indonesia**, coal-based projects take the dominant share of all power sector-related investment envisaged between now and 2019. Of 42.9 GW of generation capacity to be added in 2015-19, 25.8 GW (60%) will be coal-fired (DG Electricity, 2015). These additions include regular projects, ongoing projects from Fast Track Phase I, some projects from Fast Track Phase II, as well as the 35 GW Plan. For the 35 GW Plan alone, DG Electricity's (2015) estimated investment needs are USD 3.7 billion for 291 power plants, USD 10.9 billion for electricity transmission infrastructure and USD 8.4 billion for electricity substations. Given that half of the generation capacity additions in the 35 GW programme will be coal, the financing needs that DG Electricity aims to direct towards coal far exceeds those for other plant types or segments of the power sector.

However, the Indonesian government has been increasing its investment support for renewable power generation. It is increasing direct budgetary support to the Directorate-General of New, Renewable Energy and Energy Conservation (EBTKE) to implement green energy policies and programmes, introducing new lending regulations for the financial sector (see next section on financing the low-carbon transition), and continuing to work with international partners and development banks on project-based, results-based or policy-based loans (see next section on the role of international partners).

In **Viet Nam**, while financing for coal power plants continues to dominate the government's power generation investment agenda in the short term, the government is intent on limiting coal capacity additions in the future (Viet Nam News, 2016). As well as encouraging more gas and renewable power development, the government is also envisaging a dramatic increase in investment in nuclear plants after 2020. In the period 2014-30, according to Viet Nam's revised PDP VII, nuclear is expected to account for 23% of total investment in power generation.

Given the long lead time for licensing, construction and training for nuclear power generation, however, it is unlikely that Viet Nam will be able to start its nuclear generation programme within the next decade. Furthermore, even if the necessary investments for nuclear power generation were successfully contracted, the construction and operation of the plants would still take many more decades to come online, meaning that other power generation options would be needed to meet electricity demand in the interim. According to investment plans outlined in the revised PDP VII, the bulk of investment needs are allocated to generation assets rather than the power network (including T&D and ICT) (Figure 33).

Figure 33 • Estimated power sector investment needs in Viet Nam



Note: Network includes T&D and ICT.

Source: MOIT (2015b), "National Energy Development Strategy: Revision of Power Master Plan No. VII", presentation by Thang to the European Commission on 15 April, Hanoi.

Between 2014 and 2030, investments in power generation account for more than two-thirds of total investment in the power sector in Viet Nam. However, due in large part to network losses and forced outages, Viet Nam's current power fleet has a low utilisation rate and high reserve margin. It is worth considering whether, by redirecting part of the investment to improving the performance of existing plants and enhancing the power infrastructure, its fleet might operate more effectively, reducing the amount of capacity addition anticipated to meet projected demand.

Forecast growth in electricity demand growth is already beginning to flatten as **Malaysia** approaches near-universal electricity access and peak demand. As the tenure of power purchase agreements for its coal plants is just 25 years, several of Malaysia's older fossil-fuel power plants are expected to be retired from 2030. The timely introduction of relevant policies to incentivise investment in replacing coal-fired power plants with low-carbon options could progressively place Malaysia on a greener power-development pathway.

Fortunately, there is already much active political, technical and financial will to increase generation from gas and renewables. The public and private sectors have demonstrated their interest in helping Indonesia, Malaysia and Viet Nam bring low-carbon, energy-efficient technologies to market more quickly. Governments in the target countries are increasingly vocal about the importance of increasing the deployment of clean energy technology, noting the importance of public-private partnerships, as well as regional and international co-operation in facilitating technology and knowledge transfer.

Policy makers must continue to emphasise the importance of investing in a diverse generation mix that, while meeting demand growth, also satisfies the need for affordability, environmental protection and energy security. Establishing clear, transparent, consistent and dependable regulatory support is essential to incentivise, as well as reduce the risk of, investments, particularly for deploying low-carbon technologies that are capital intensive or require longer lead times to implement.

Creating an enabling environment for investment

Governments cannot meet the high level of investment needed in the power sector with public funds alone. Private investors have an important role to play in decarbonising the power sector, with policymakers creating the enabling environment that attracts them to participate. Presently, the majority of power systems in Southeast Asian countries operate under a single-buyer market structure. The only two exceptions are Singapore and the Philippines, both of which have competitive wholesale markets. The single buyers in the other eight countries are therefore increasingly reliant on IPPs to help meet growing electricity demand. Active participation by IPPs not only alleviates government budgets by contributing private investments to power-sector development, but also promotes competition and ultimately greater power sector efficiencies and lower tariffs for consumers.

In the three study countries, IPPs are expected to build the bulk of power capacity additions in the coming decades (see previous sections on power generation in Indonesia, Malaysia and Viet Nam). In Malaysia's case, IPPs already own the dominant share of generation capacity. In Indonesia and Viet Nam, IPPs are expected to play a greater role in investing in and developing power assets. This expectation can only be realised if the governments set up appropriate investment and regulatory environments to encourage IPP participation. Such measures may include providing government support and guarantees, institutional support, regulatory certainty, electricity tariff subsidy reform and other financial incentives.

Below are selected examples of how the governments of Indonesia, Malaysia and Viet Nam have pursued different policy measures that help to encourage private investment in the power sector.

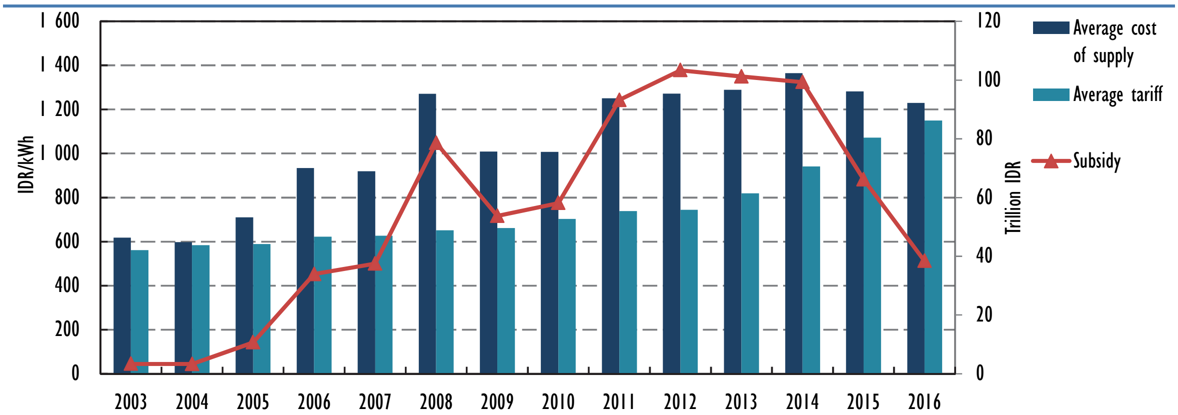
Indonesia scales back electricity subsidies

One of the key barriers to attracting sufficient private investment in Indonesia's power sector – particularly for clean energy – is the low electricity price. Electricity prices are determined by the government as stipulated in the Electricity Law No. 30, with any differences between the average cost of electricity generation by PLN and the price paid by consumers subsidised by the government. In 2014, electricity subsidies in Indonesia were estimated at around USD 6.5 billion (IEA, 2016a). While the subsidy is mainly targeted towards low-income residential consumers, they also apply to the public, commercial and industry categories, according to their respective usage limits. Fossil fuels used for power generation, mainly coal and gas, are also subsidised.

Ultimately, the imposition of subsidies leads to electricity tariffs that do not adequately reflect the cost of generation. This creates a lose-lose situation where, when fossil fuel prices are high, governments are left to shoulder the significant financial burden of electricity subsidies and, when fossil fuel prices are low, power producers are not incentivised to divert investment towards the relatively more expensive clean-energy technologies.

Encouragingly, since 2003, Indonesia has gradually reduced the number of customer classes eligible for subsidised electricity, scaling back electricity subsidies significantly. While in 2005 all 5 customer and 37 tariff classes were subsidised, by 2016, only customers consuming less than 900 volt ampere (VA) from 25 (out of 37) tariff classes were still eligible for subsidised prices (DG Electricity, 2016). As a result of this reform, the government managed to dramatically reduce subsidy spending from a peak of IDR 103 trillion (USD 7.8 billion) in 2012 to IDR 38 trillion (USD 2.9 billion) in 2015 (Figure 34).

Figure 34 • Cost of electricity subsidies in Indonesia, 2003-16



Source: DG Electricity (2016), "Electricity subsidy reform in Indonesia", presentation to the IEA in Mexico 22-23 February.

Indonesia intends to reform electricity tariffs so that, in 2017, only residential customers consuming less than 450 VA per month will be eligible for subsidised electricity (DG Electricity, 2016). Ultimately, cost-reflective electricity pricing is necessary to incentivise competition among power producers to invest in diversified power generation, as well as to improve demand-side energy efficiency by electricity consumers.[13]

Malaysia: Encouraging IPP investment through a sound regulatory framework

In Malaysia, regulated grid operators are responsible for investment in the network, while the main utilities and IPPs are responsible for investment in generation. Malaysia has a well-established regulatory framework and creditable market, which have been successful in attracting investment from IPPs.

In Peninsular Malaysia, the electricity sector has been open to IPPs since 1994. According to the 2013 National Energy Balance of Malaysia (Energy Commission, 2013), the combined installed capacity of power plants owned by IPPs reached 15 402 MW, which is approximately 66.6% of the total capacity. Virtually all IPPs in Malaysia are local companies and most of the financing and inputs are derived locally. State pension funds and state banks have played an important role in financing IPPs.

The Energy Commission serves as the regulator, while the Single Buyer department determines how much and by when new facilities are needed via negotiations or competitive bidding on new projects. Power purchase agreements are issued to safeguard the interests of both the plant

[13] For further analysis on Indonesia's ongoing electricity sector reform, refer to: IEA (2016, forthcoming), "Fossil fuel subsidy reform in Indonesia and Mexico", IEA/OECD, Paris.

owner and the Single Buyer in obtaining financing agreements. In recent years, since the first generation of IPP contracts were awarded to encourage further private investment, the issuing process and terms of agreements have evolved. For example, in 2011 new legislation, the Competitive Bidding Mechanism, was passed to allow foreign equity participation in all segments of the electricity network (including distribution) to increase from 30% to 49%.

The bidding mechanism was introduced to encourage competition in the generation plant expansion exercise in the Malaysian electricity supply industry. The transformation from the previous mechanism was aimed at creating an equitable and competitive bidding mechanism directed towards achieving least cost and, thus, greater efficiency in the industry. The new mechanism offers a much more transparent and efficient means to procure future capacity. The new legislation has proved a great success, with more than 40 different companies bidding on the tender for the Prai power plant, which was elevated to an international bidding exercise. A restricted version was later introduced for the Genting Sanyen Power and Segari Energy Ventures plants (both seeking 10-year extensions) and the Pasir Gudang plant (seeking a 5-year extension), all of which also received positive domestic participation.

Malaysia is currently in its fourth generation of IPP bidding, with the Energy Commission holding competitive tenders for new projects in Peninsular Malaysia rather than the state utility operator, TNB. A series of amendments to the contractual process over the years has significantly improved the investment outlook for IPPs, with recent IPPs yielding internal rates of return averaging 7-8%, which are sufficiently high to entice the private sector but not so high as to be an excessive burden on TNB (OECD, 2012).

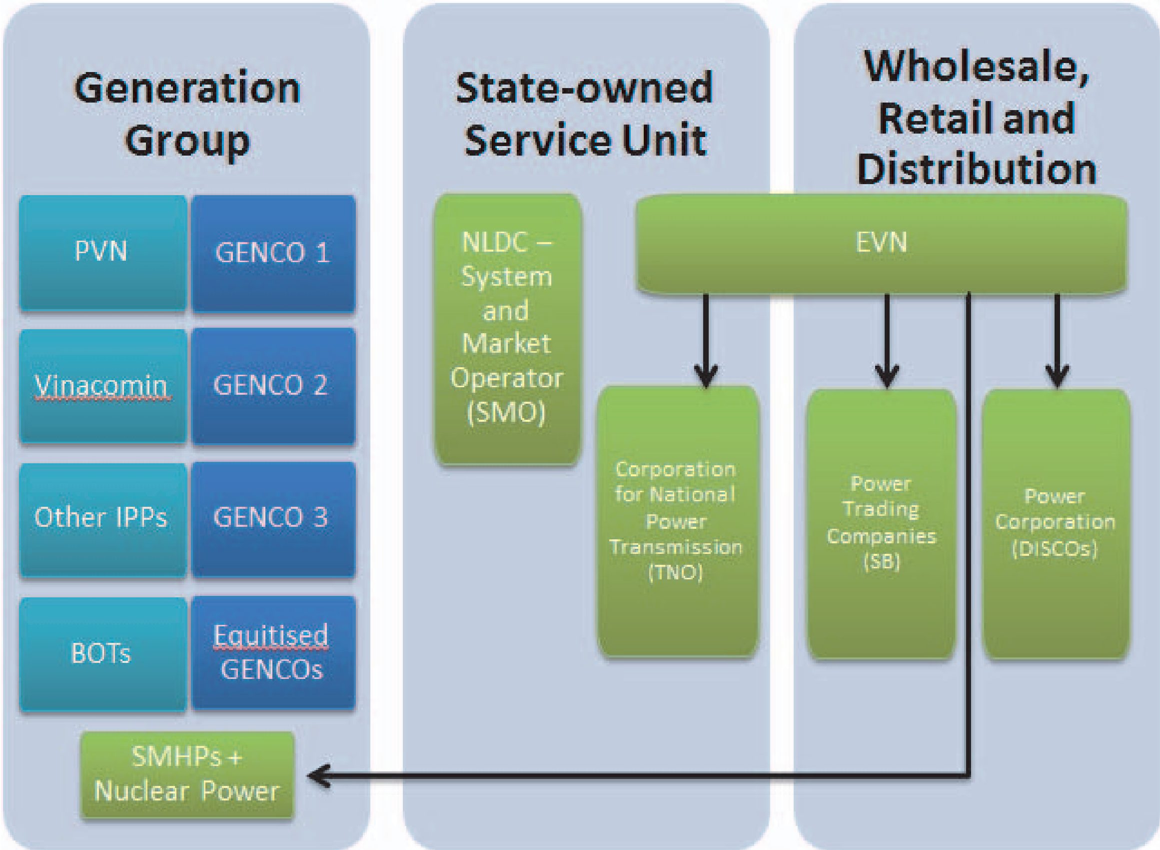
Since 2010 the national utilities, especially TNB, have been equally as capable in acquiring competitive financing to assist them in the competitive bidding environment. Besides working on new generation projects, the utilities have also been encouraged to ensure greater operational efficiency from their existing generating units, which may be candidates for extension and continuation of their revenue streams.

The share of coal, natural gas and renewable power generation supported by IPPs is high. Gas-fired power plants are the project of choice for many IPPs, due to their lower capital and operating costs, relatively short gestation period, and subsidised prices for natural gas supply from the state-owned oil and gas company, Petronas. To date, the renewable energy sector is also mostly driven by private investment, with financial incentives provided in the form of FITs by SEDA. Malaysia's FITs are considered especially attractive for solar PV, with applications for the solar PV FIT scheme consistently exceeding quotas and challenging the sustainability of the provision. In the 11th Malaysia Power Plan, the government is considering abolishing the FIT for solar and retaining them only for biogas, biomass and small hydro, which have seen a comparably weaker uptake (IEA, 2015a).

Reforming the electricity sector in Viet Nam

Viet Nam is one of the eight Southeast Asian countries that currently feature a single-buyer power market. In Viet Nam, as in the other seven, the structure of the vertically integrated, state-managed electricity sector is regarded as a key barrier to a competitive electricity market. Since 2005, with support from the Asian Development Bank, the Vietnamese government has been implementing electricity sector reforms to improve the efficiency of the state grid and to mobilise private capital by encouraging IPP participation. The objective is to eventually establish a wholesale retail and distribution market (Figure 35).

Figure 35 • Structure of the Viet Nam electricity sector reform



Notes: BOT = build, operate, transfer; DISCO = distribution company; GENCO = generation company; NLDC = National Load Dispatch Centre; SB = single buyer; SMPH = strategic multi-purpose hydropower plant.

Source: Nguyen, A.T. (2012), "A case study on power sector restructuring in Viet Nam", Pacific Energy Summit Papers. Retrievable: http://www.nbr.org/downloads/pdfs/eta/PES_2012_summitpaper_Nguyen.pdf; IEVN (2015c), personal communications

In the past, the government has relied on the public sector for investment in generation and, to date, only a limited number of privately owned plants are in operation, with only one of them having a major international power company as the main shareholder. According to Viet Nam's revised PDP VII, the investment needs for power generation between 2014 and 2030 are about USD 81 billion (IEVN, 2015b); the need for private participation in power sector investment is an imperative.

Consequently, power sector reform aims to attract a broader range of participants to invest in, expand and modernise the electricity industry. The government plans a transition to electricity prices that, on the supply side, enable the financial viability of efficiently managed and operated companies and, on the demand side, provide pricing signals for the efficient use of electricity. The reform programme focuses on four complementary areas:

Introduction of competition in the power sector. Competition would encourage efficiency in both production and distribution.

Restructuring the power sector to facilitate the introduction of competition, including unbundling to create competing businesses and to eliminate conflicts of interest due to cross-ownership.

Introduction of tariff-setting mechanisms for electricity that reflect a cost-effective supply chain, including suitable power-purchase costs in the competitive market, and regulated network and system operation costs.

Establishment of a legal framework for energy efficiency and conservation, of pricing regulations to promote the efficient use of electricity, and of programmes to reduce electricity consumption on the demand side.

Sector restructuring will enable competition that, together with cost-reflective tariffs, will promote efficiency and, with a stable and predictable mechanism for setting efficient tariffs, will provide the predictability required to finance new and maintain existing power generation and T&D assets. On the demand side, cost-reflective tariffs will promote the efficient use of electricity. In the longer term, the results of these policies will be a major transformation of the structure of the sector, including arrangements for the selling and buying of electricity, electricity pricing and how projects are decided and financed, and the integration of consumer choice and demand response programmes.

The role of international partners

The international community can play an important role in supporting Southeast Asian countries to develop their power sectors along a sustainable pathway. While many international development partners, including OECD member countries, have historically been some of the biggest funders of coal-fired power plants in Southeast Asia, the political appetite for coal-fired power generation has dipped significantly in the past few years. Certain OECD member countries now strongly advocate a switch away from investing in coal-fired power generation and are increasingly withdrawing or even banning funding for coal-related projects in Southeast Asia (Box 11). For countries like Indonesia and Viet Nam, which draw significant financial and technical support from international funders for local power development, the implementation of strict coal-financing criteria could affect both the short- and long-term outlook for realising national power development plans.

Box 11 • OECD limitations on coal financing

On 18 November 2015, after two years of negotiations (OECD, 2015), OECD member countries party to the Arrangement on Officially Supported Export Credits* agreed to substantially limit official export credits for coal-fired power plants. Under the new agreement, large subcritical and SC power plants over 500 MW would no longer be eligible for public funding, while small subcritical plants under 300 MW in poorer developing countries were still permitted. Medium-sized SC plants between 300 MW and 500 MW might still be eligible for public financing on a case-by-case basis, for example where a service area is experiencing energy poverty. Plants equipped to operate with CCS (CCS-ready) could be exempt from these limitations in coal-financing. This OECD agreement needs to be approved by the European Union internal decision-making process and should come into effect from 1 January 2017, with further review after 2019.

Meanwhile, several OECD member countries and international organisations have already started to implement more stringent limitations on public financing of coal-fired plants than stipulated in the agreement. In June 2013, President Barack Obama issued a “Climate Action Plan” advocating the end of government support for most new coal-fired power plants overseas. France, the United Kingdom, Germany, the Netherlands and the Nordic countries followed suit. Many international financing institutions have also already dramatically decreased or halted financial support for new coal-fired power plants since 2013 in efforts to cut global GHG emissions and move global power generation towards a more sustainable trajectory. Among the institutions that have halted or limited coal-fired project funding are the World Bank Group (WBG), the European Investment Bank (EIB), the Export-Import Bank of the United States (EX-IM), the European Bank for Reconstruction and Development (EBRD), and the UK Export Credits Guarantee Department (ECGD). As international financing institutions and governments have provided over USD 73 billion worth of direct and indirect financial support for coal projects around the world between 2007 and 2014 (Bast et al., 2015), this shift in the coal financing landscape could have a severe impact on developing countries dependent on foreign funding to build power plants.

While the decision by the institutions to withdraw or limit funding for coal-fired power generation removes a sizeable source of funding for new coal build, it is unlikely to halt coal power development in and of itself. Firstly, the two largest financiers of overseas coal projects in the world – Japan and China (each of which financed some USD 20 billion of coal-related projects during the period 2004-13) – continue their support for developing countries to build coal-fired power plants. In Southeast Asia, Japan is a key provider of HELE coal plant, which it continues to promote throughout the region. China, which is not party to the OECD, continues to finance coal-related projects. It is also possible that the China-led Asian Infrastructure Investment Bank (AIIB) or the New Development Bank (NDB or BRICS bank) may be willing to provide financing for clean coal projects in the years to come, although the procurement criteria for the AIIB or the NDB are as yet unspecified.

The influence of limited international public financing on coal-related projects in Southeast Asia may also be attenuated as countries increasingly entice private investment into the sector. In Malaysia, the power sector investment environment is already primarily funded by local interests and it is not rare for a plant tender to attract multiple bidders from local and multinational companies. This is not necessarily the case for Indonesia or Viet Nam, both of which continue to turn to development banks to build domestic power projects.

While some critics have cautioned that imposing limitations on coal financing, such as those in the OECD agreement, may drive Southeast Asian countries to work more closely with Japan and China to develop coal-fired power projects (Ueno, Yanagi and Nakano, 2014), it is worthwhile noting that Chinese companies are also increasingly exporting more efficient technologies, even if current best-practice equipment in the region is predominantly Japanese. Moreover, the implications of a scenario where Japanese and Chinese coal technology compete for deployment should not be overstated, particularly as both Japan and China actively support renewable energy development in addition to coal-fired power projects. For example, Japan's Sumitomo Corporation is working with Indonesia's PLN to develop geothermal energy, while China is by far the biggest international investor in Southeast Asian hydropower projects and an increasingly prominent solar PV supplier to the region.

Sources: Bast, E. et al. (2015), *Under the Rug: How Governments and International Institutions are Hiding Billions in Support to the Coal Industry*; OECD (2015), "Statement from participants to the arrangement on officially supported export credits," OECD, Paris; Ueno, T., Yanagi, M. and Nakano, J. (2014), "Quantifying Chinese public financing for foreign coal power plants".

* OECD member countries that are party to the agreement are: Australia, Canada, the European Union, Korea, Japan, New Zealand, Norway, the United States and Switzerland.

On the one hand, a widely adopted global consensus to restrict financing for coal-fired power plants, with no support to build cleaner but potentially more expensive power plants, could signal a delay in expanding electricity access to communities that currently have none. On the other hand, a global consensus to limit coal financing, coupled with offers to finance CCS technologies and lower-carbon alternatives, could fundamentally reshape the development trajectory of the power sector in Southeast Asia, where electricity demand is still set to rise rapidly but plans for ambitious fossil-fuel capacity additions have yet to be fully realised. This is the approach that many development banks are currently taking.

Many international funders, including the United Kingdom, Japan, Denmark, Germany, and other governments or development partners are providing significant financial contributions and policy support to bridge the investment gap required to make a cleaner power sector a reality in Indonesia, Viet Nam and other Southeast Asian countries. For example, the Asian Development Bank (ABD) has recently increased its loans in support of Indonesia's clean energy transition from USD 750 million per annum between 2010 and 2014 to as much as USD 2 billion per annum over the next five years (ADB, 2016). ADB funding will support a government-led agenda which prioritises physical and social infrastructure, but also policy development. In 2015, ADB provided a policy-based loan worth USD 400 million devoted to the energy sector, which included support for Indonesia's clean energy and energy efficiency transition towards meeting its COP21 goals (ADB, 2016). In Viet Nam, the ADB is supporting the government in its reform of the electricity sector. The World Bank has also contributed significant funding to Viet Nam and Indonesia for energy development through loans and trust funds. The Agence Française de Développement (AFD) provided USD 800 million to Indonesia from 2008-11 in the form of a Climate Change Policy Loan, targeted at projects that directly support GHG gas emission mitigation efforts by the government. In 2010 and 2013, AFD (2014) also signed two environment credit lines with Bank Mandiri to support gas and renewable energy projects in Indonesia. All three development agencies – AFD, ADB and the World Bank – no longer support coal financing other than in exceptional circumstances.

Policy recommendations

Southeast Asian countries will continue to experience strong economic growth and improved consumer access to electricity, resulting in significant increases in electricity consumption. Therefore, the governments of several Southeast Asian countries are planning large-scale coal-fired power expansions and upgrades to meet the rising demand.

It is encouraging that the governments of Indonesia, Malaysia and Viet Nam are continuously reassessing and strengthening their ambitions to increase the deployment of clean energy and energy-efficient technologies. Meanwhile, policy makers must take measures to abate the significant emissions from the coal fleets that have already been built or will be built in the coming years. Given the scale of new coal capacity planned for construction, and the commitments undertaken in the COP21 Paris Agreement, this may be a critical window of opportunity for the three countries to scale back on existing plans in favour of lower-carbon alternatives. With this in mind, the following policy recommendations are mainly geared towards government action to address the long-term environmental impacts of unabated coal-fired power generation.

1. Continue to phase out subsidies on fossil fuels and electricity: Fossil-fuel subsidies encourage inefficient consumption and bias the generation mix in favour of fossil fuels – both of which increase CO_2 emissions. Electricity subsidies distort prices and give the wrong signals to investors and consumers. Periods when fuel costs are low offer the ideal opportunity to reduce or eliminate these subsidies.

2. Enhance the overall efficiency of the generation fleet: If the decision is taken to build unabated thermal plants fuelled by coal or gas, operating plants at higher efficiencies reduces fuel consumption and results in lower emissions. Consequently, for coal- or gas-fired capacity additions or replacements, preference should be given to the more efficient technologies. However, it is important to recognise that, while HELE technologies reduce emissions from coal, the scale of capacity additions currently planned would not only leave a huge quantity of CO_2 emitted, but would also lock in a high-emissions infrastructure. Governments should strongly consider a moratorium on the construction of new subcritical coal-fired units, with a gradual phasing out of generation from the least efficient oil-, gas- and coal-fired plants. For all generation assets, regular maintenance and effective operation are important to keep plant performance from deteriorating over time. Options to upgrade plant equipment should also be reviewed periodically as new technologies present opportunities to improve upon the design efficiency of existing generation assets.

3. Review and enforce more stringent air pollutant emission standards: In many Southeast Asian countries, emission standards from fossil fuel-fired power plants are less stringent than those applied in other countries in the region, such as Japan and China. Funding agencies set stricter emissions standards for power projects than do national regulatory bodies. As governments aim to tackle local air pollution challenges, more stringent emissions standards should be mandated, alongside regular monitoring and strong penalties for non-compliance. Standards should also be reviewed and strengthened regularly, both to broaden the number of pollutant species covered and as more effective emissions reduction technologies enter the market.

4. Monitor and limit CO_2 emissions at the power-sector and power-plant level: Currently CO_2 data tend to be collected and aggregated at the national level. As an important indicator to effect change, CO_2 emissions should ideally be measured and collected at the plant level or, at the very least, at the sectoral level. This would require effective monitoring of carbon emissions and make it more likely that, when required, the appropriate action to reduce emissions would be taken.

5. Ensure that, when required, CCS can be deployed effectively on fossil-fired power plants: Today, deploying CCS on power generation plant is expensive and challenging. In preparation for the time when CCS becomes sufficiently economically attractive to be deployed, new fossil-fired power generation plant should be designed and constructed to be CCS-ready. Geological characterisation should be undertaken to identify the most likely sites for CO_2 storage. Stakeholders would need to identify agreed routes to transport captured CO_2 to storage. Governments would need to ensure appropriate regulation was in place.

6. Ensure that investments in T&D are sufficient to support low-carbon technologies: Adding generation capacity without a well-planned, efficient and reliable T&D network to deliver the electricity to the consumer leads to sub-optimal resource and asset utilisation and, in the case of coal- and gas-fired technologies, higher emissions. Cross-border interconnections are important to an effective T&D network, as they offer the opportunity to enhance the diversity and security of power systems by matching supply and demand across geographical and political borders. Decentralised expansion, whereby smaller distributed generation capacities are connected to distribution grids, should be encouraged as it offers attractive options for countries with a complex geography – such as Indonesia – while simultaneously minimising power losses and encouraging the growth of renewable energy.

7. Establish carbon pricing mechanisms to support the decarbonisation of the power system: Presently, no Southeast Asian country has set a price on carbon. While introducing carbon pricing will take time, it should nevertheless be considered as a medium-term objective, prefaced or accompanied by the phase-out of fossil fuel and electricity subsidies, as well as the liberalisation of the electricity market. In the meantime, implementing a shadow price for carbon, as part of the evaluation procedure to select suitable technologies for capacity addition, would offer a no-regrets route to reducing CO_2 emissions from the power sector.

8. Reduce risks and revenue uncertainty for low-carbon energy investors by establishing consistent and reliable long-term policy frameworks: Setting realistic targets for low-carbon generation, backed by good quality data and a transparent regulatory framework, would boost investor confidence. Offering competitive long-term power purchase agreements can help establish revenue certainty and improve financing conditions for investors in what can be capital-intensive technologies.

Next Steps

For several years, the IEA has worked closely with Southeast Asian governments and utilities on detailed analyses of key issues facing the power sector, with increasing emphasis on improving energy efficiency, renewable energy integration and grid performance. Recent IEA publications on the *Development Prospects of the ASEAN Power Sector – Towards an Integrated Electricity Market* (IEA 2015c) and the *Thailand Electricity Security Assessment* (2016d) have focused on the opportunities and challenges of developing an integrated electricity market in Southeast Asia and enhancing the security, stability and sustainability of Thailand’s power system, respectively. A number of IEA flagship publications regularly address Southeast Asia’s energy sector developments and outlook, such as the World Energy Outlook, Energy Technology Perspectives and the Medium-Term Market Reports. At present, Southeast Asia is the only region in the world for which the IEA publishes a dedicated energy outlook highlighting the global importance of energy developments in this region. Previous editions of the Southeast Asia Energy Outlook were published in 2013 and 2015.

A series of policy recommendations have been made in the current report that often build on and complement earlier analysis. If these policy recommendations were adopted, each one would require substantial further analysis. As the IEA remains committed to supporting Southeast Asian countries in transitioning to a low-carbon power sector, it would welcome opportunities to cooperate further within the framework of its multilateral partnership with ASEAN at the regional level and via bilateral work programmes or joint activities with Southeast Asian countries at the national level.

Acronyms, abbreviations and units of measure

Acronyms and abbreviations

ADB	Asian Development Bank
ACE	ASEAN Centre for Energy
AFD	Agence Française de Dévéloppement
AIIB	Asian Infrastructure Investment Bank
APAEC	ASEAN Plan of Action for Energy Cooperation
ASEAN	Association of Southeast Asian Nations
A-USC	advanced ultra-supercritical
BAU	business as usual
BOT	build, operate, transfer
BREE	Bureau of Resources and Energy Economics (Australia)
CAGR	compound annual growth rate
CCGT	combined cycle gasification turbine
CCS	carbon capture and storage
CO_2	carbon dioxide
COP21	21^{st} Conference of the Parties
CSLF	Carbon Sequestration Leadership Forum
DEN	National Energy Council (Indonesia)
DG Coal	Directorate General of Coal (MEMR, Indonesia)
DG Electricity	Directorate General of Electricity (MEMR)
DISCO	distribution company
EBRD	European Bank for Reconstruction and Development
ECGD	Export Credits Guarantee Department of the United Kingdom
EIB	European Investment Bank
EPU	Economic Planning Unit, Prime Minister's Department (Malaysia)
EVN	Vietnam Electricity
EX-IM Bank	Export-Import Bank of the United States
FIT	feed-in tariff
FLNG	floating liquefied natural gas
GDE	General Directorate of Energy (MOIT, Viet Nam)
GDP	gross domestic product
GENCO	generation company
GHG	greenhouse gas
HELE	high efficiency, low emissions
HHI	Herfindahl-Hirschman Index
IEA	International Energy Agency
IEA CCC	IEA Clean Coal Centre
IEVN	Institute of Energy (Viet Nam)

ICT	information and communications technology
IGCC	integrated gasification combined cycle
INDC	Intended Nationally Determined Contributions
IPP	independent power producer
KEN	National Energy Plan (Indonesia)
KeTTHA	Ministry of Energy, Green Technology and Water (Malaysia)
LCOE	levelised cost of electricity
MEMR	Ministry of Energy and Mineral Resources (Indonesia)
MEPS	minimum energy performance standards
MOIT	Ministry of Industry and Trade (Viet Nam)
NDB	New Development Bank
NEEAP	National Energy Efficiency Action Plan (Malaysia)
NEM	net energy metering
NLDC	National Load Dispatch Centre (Viet Nam)
NO_X	nitrogen oxides
NREAP	National Renewable Energy Policy and Action Plan (Malaysia)
OCGT	open-cycle gas turbines
OECD	Organisation for Economic Co-Operation and Development
PDP	Power Development Plan
PLN	Perusahaan Listrik Negara (Indonesian State Electricity Company)
PM	particulate matter
PPA	power purchasing agreement
PV	photovoltaic
RPS	renewable portfolio standard
RUKN	National Electricity Development Plan
RUPTL	PLN Electricity Supply Business Plan
SEB	Sarawak Energy Berhad
SC	supercritical
SEDA	Sustainable Energy Development Authority (Malaysia)
SMPH	strategic multi-purpose hydropower plant
SO_2	sulphur dioxide
SUB	subcritical
T&D	transmission and distribution
TNB	Tenaga Nasional Berhad (Malaysia)
TPA	third party access
UNFCCC	United Nations Framework Convention on Climate Change
USC	ultra-supercritical
VEESL	Viet Nam Energy Efficiency Standards and Labelling

WBG	World Bank Group

Units of measure

bcm	billion cubic metres
gCO_2/kWh	grammes of carbon dioxide per kilowatt-hour
Gt	gigatonne
GW	gigawatt
GWh	gigawatts per hour
kWh/m^2	kilowatt-hour per metre square
LHV	lower heating value
MBtu	million British thermal units
mg	milligramme
mg/m3	milligrammes per cubic metre
MPa	megapascal
$MtCO_2$	million tonnes of carbon dioxide
MW	megawatt
MWh	megawatts per hour
MW_e	megawatt electrical units
TWh	terawatts per hour
VA	volt-ampere

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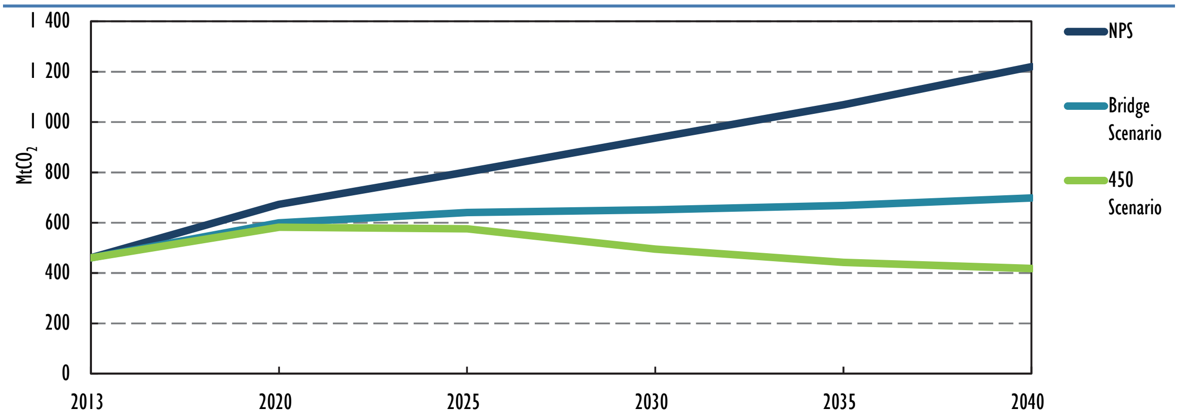
Annex

Emissions impacts from IEA power generation scenarios for Southeast Asia

Between 2013 and 2040, according to the NPS, Southeast Asia's electricity generation is projected to grow at a rate of 3.9% to reach 2 212 TWh at the end of the period. Fossil fuels dominate the generation mix – while the share falls from 82% in 2013 to 77% in 2040, generation from fossil fuels increases in absolute terms by a factor of 2.6. The share of coal-fired power generation would increase particularly quickly, with a compound annual growth rate of 5.6% over this period, and would account for half of the region's total generated electricity by 2040 (IEA, 2015a). Gas-fired power generation would decline from 44% to 26% of the region's total electricity generation by 2040 (though it would still increase in absolute terms), while oil-fired generation would decrease from 6% to 1%.

While countries are endeavouring to deliver affordable electricity, they also need to consider the impact on energy security, economic development and environmental protection. While, in the short term, the current trend of using coal to meet the bulk of electricity demand growth promises lower generation costs, it will negatively affect environmental protection, not only in the three countries under study, but also at the regional level. Under the NPS, out of the projected 2 212 TWh in 2040, almost half would come from coal, which means a substantial increase – both in absolute and percentage terms – from the 32% share from coal in 2013. Total emissions from power generation in Southeast Asia would climb from 461 $MtCO_2$ in 2013 to a projected 1 220 $MtCO_2$ in 2040 (IEA, 2015a). In the Bridge Scenario, the growth of total CO_2 emission from power generation in Southeast Asia would almost plateau within the 2030 to 2040 time frame, and result in emission savings of 522 $MtCO_2$ in 2040 compared to the NPS level (Figure A1). In fact, compared with the NPS, CO_2 emissions from the Bridge Scenario are consistently more than halfway to achieving the ambitious 450 Scenario.

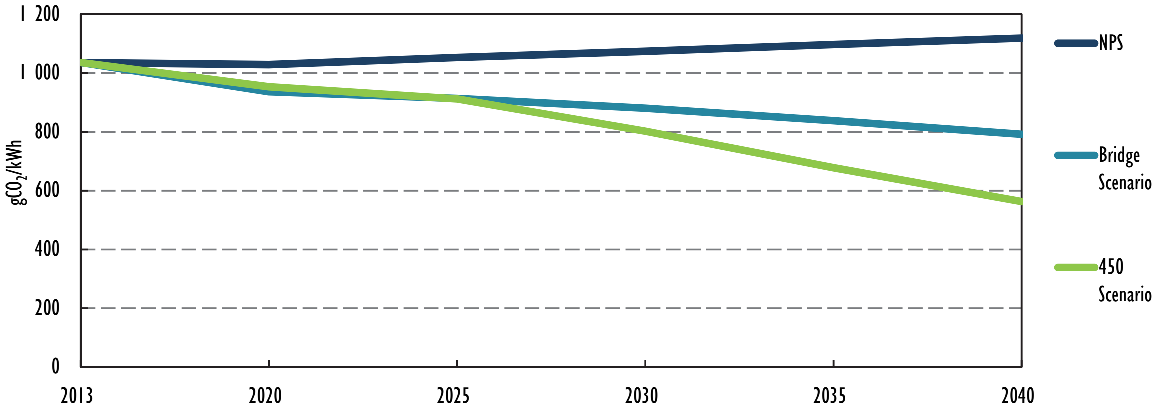
Figure A1 • Projected CO_2 emissions from power generation in Southeast Asia



In the 450 Scenario, the projected decline in total emissions from power generation begins in 2020. By 2040, projected CO_2 emissions would be 9.3% lower than 2013, with total power generated almost 2.5 times higher. Meeting these reductions would require the deployment of technologies not yet commercially mature, such as electricity storage and CCS. The 450 Scenario is also dependent on gas-to-coal fuel switching from around 2025 such that, in 2040, the share of gas in the generation mix would be 34%, compared with 17% coal. This scenario assumes 89 GW of coal capacity in 2040, 21% of which uses USC technology, while 23% of the total capacity is fitted with CCS. The 450 Scenario results in 221.7 $MtCO_2$ emission savings from the coal plants alone, as compared to the Bridge Scenario.

Under the NPS, the growth in coal-fired generation and the dominance of ageing subcritical plants would lead to a slight increase in coal emissions intensity (Figure A2). By comparison, between 2013 and 2040, the Bridge Scenario projects a 23.5% reduction in emissions intensity. This scenario assumes 136 GW of coal capacity in 2040, 27% of which uses USC technology, while no units with CCS are deployed yet. Although a significant reduction, it is insufficient to realise the 35% reduction in overall power sector emissions intensity projected under this scenario.

Figure A2 • Emissions intensity of coal-fired power generation in Southeast Asia



Diversifying the generation mix plays an important role. In the Bridge Scenario, generation from coal reduces to 27.6% by 2040 (Figures A3 and A4). This would be achieved by a gradual phasing out of fossil-fuel subsidies to end-users by 2030 and increasing investment in low-carbon technologies. The increased contribution from low-carbon technologies would include higher shares of hydropower, variable renewables and nuclear. Solar PV is projected to be the dominant renewable energy technology under both the Bridge and 450 Scenarios; the Bridge Scenario includes 33.4 GW of wind capacity, 13.8 GW of geothermal capacity and 54.9 GW of solar capacity, while the 450 Scenario includes 47.6 GW of wind capacity, 18.9 GW of geothermal capacity and 71.3 GW of solar capacity.

Figure A3 • Southeast Asia's generation mix under the Bridge Scenario

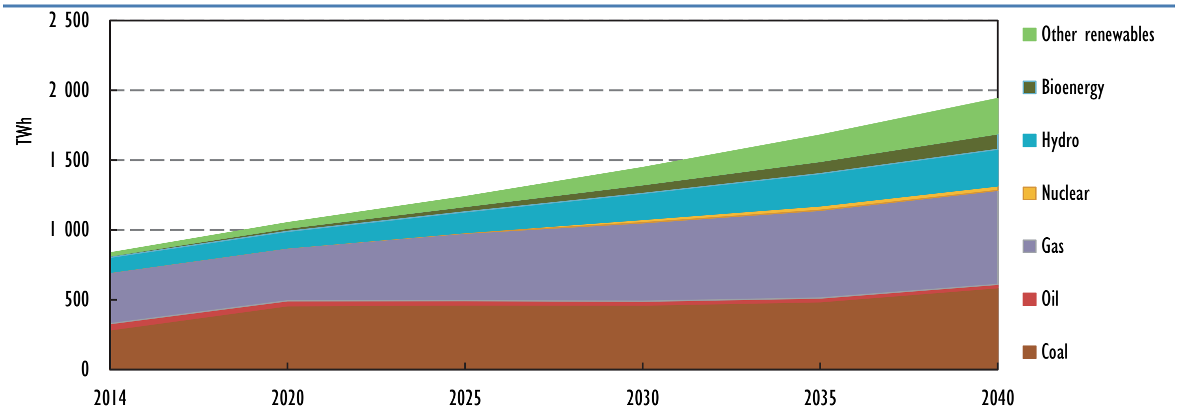
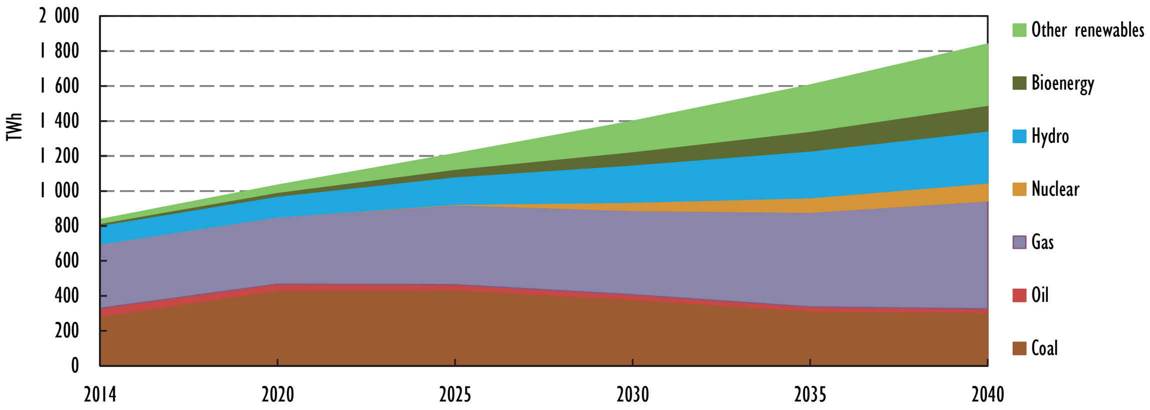
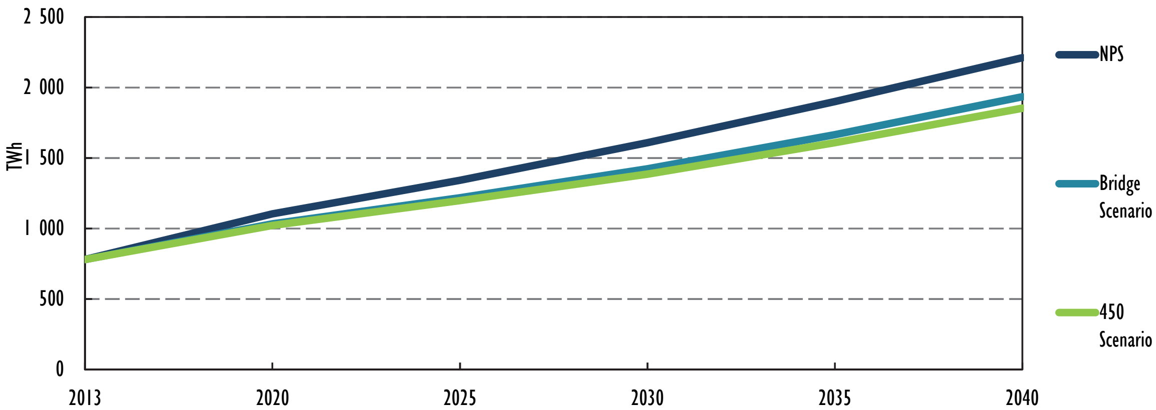


Figure A4 • Southeast Asia's generation mix under the 450 Scenario



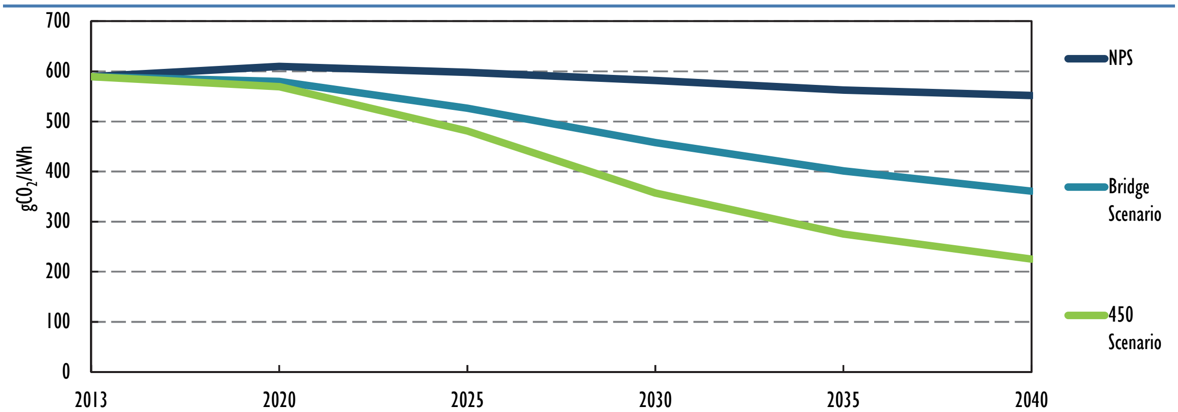
Increases in energy efficiency would lead to a projected 12.5% reduction in generation in the Bridge Scenario compared with the NPS in 2040 (Figure A5). By comparison, the total generation in the 450 Scenario would be just 4.2% less than in the Bridge Scenario.

Figure A5 • Comparison of power generation under different scenarios



These measures would reduce emissions intensity in the Bridge Scenario by 38% compared with the NPS by the end of the projection period, falling from 582 gCO_2/kWh in 2013 to 360 gCO_2/kWh in 2040 (Figure A6).

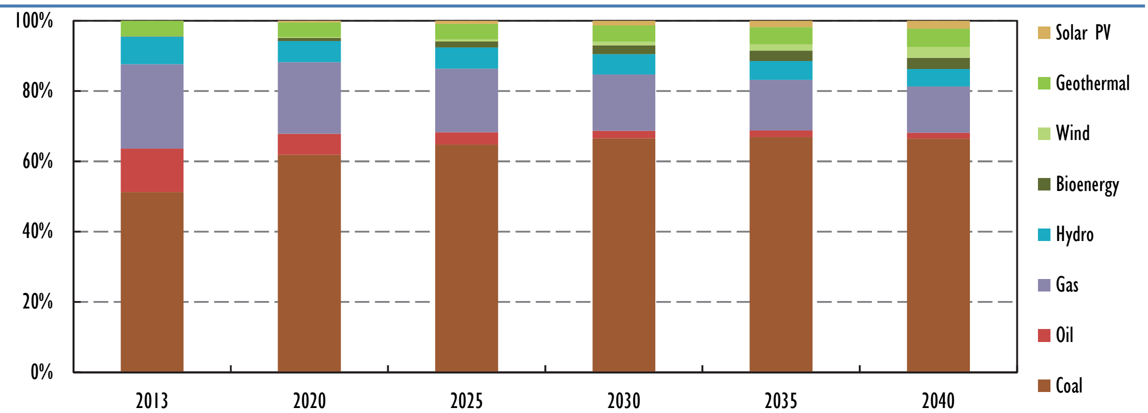
Figure A6 • Emissions intensity of power sector under different scenarios



Indonesia's power generation under the NPS

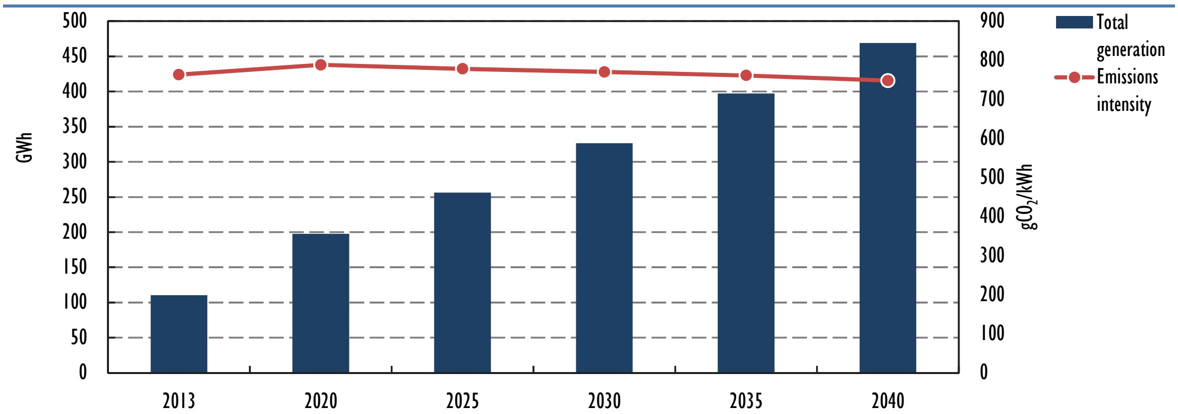
According to the NPS, the share of coal-fired generation in 2020 would exceed 55%, whereas the share of generation from any other single source would be less than 15% (IEA, 2015a). By 2040, coal would be responsible for almost 65% of electricity generation (Figure A7). Gas would retain the second-highest share, although reduced significantly from the current 20%. Diesel oil would be phased out other than for stand-alone generators in remote locations. Increases in renewable energy, especially in the 2030 to 2040 timeframe, would broadly negate the impact on emissions intensity due to the rise in coal-fired generation.

Figure A7 • Projected breakdown of generation mix in Indonesia under the NPS



With the increase in generation from renewables and the reduction in diesel-powered generators, the emissions intensity plateaus after 2030. However, while investment in renewable capacity additions results in a slight reduction in the emissions intensity, absolute CO_2 emissions would triple (Figure A8).

Figure A8 • Emissions intensity and total generation in Indonesia

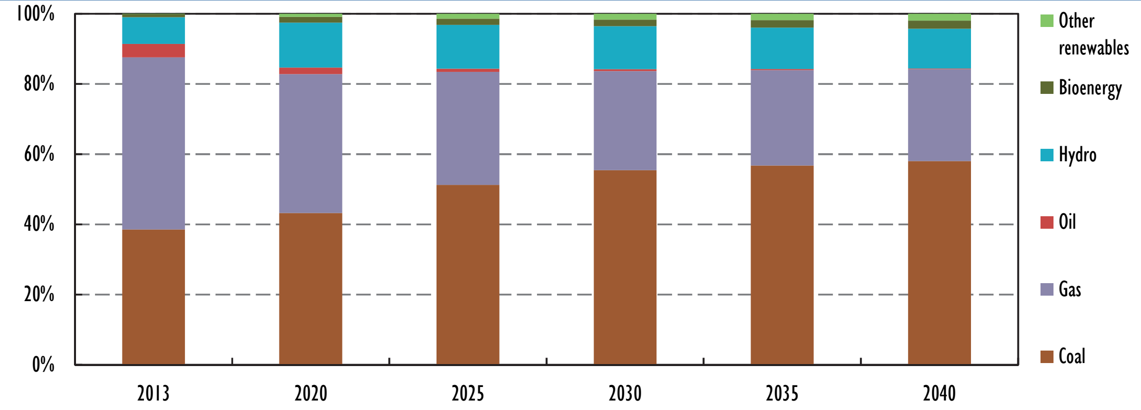


Clearly, for Indonesia to be consistent with its COP21 pledges, meaningful modifications to its present policies are needed.

Malaysia's power generation under the NPS

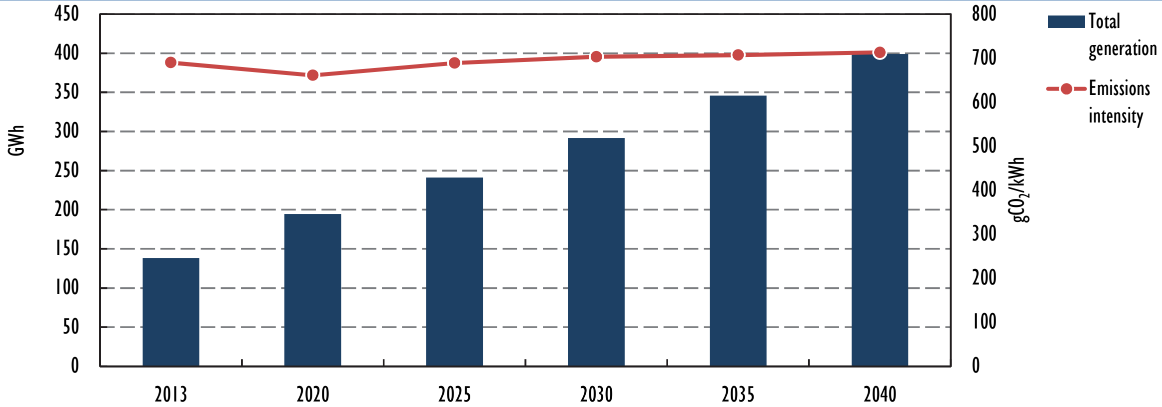
According to the NPS, there would be a gradual decrease in Malaysia's share of generation from natural gas to 2040 (Figure A9). On the other hand, coal's share of generation would steadily rise and, from 2025, be consistently higher than 50%.

Figure A9 • Projected percentage breakdown of generation mix in Malaysia under the NPS



Malaysia has long recognised its overdependence on fossil fuels, which exceeded 90% in 2014, and efforts are underway to increase the share of other sources, albeit these efforts are hampered by resource availability and high investment costs. The growth in hydro and renewables would reduce the country's CO_2 emission intensity in 2020, compared to the 2013 level (Figure A10). The share of generation from oil-fired plants is projected to be negligible by 2035. It should be noted that no nuclear generation is projected in the period to 2040 and, as a consequence, low-carbon generation comes only from renewable sources.

Figure A10 • Emissions intensity and total generation in Malaysia

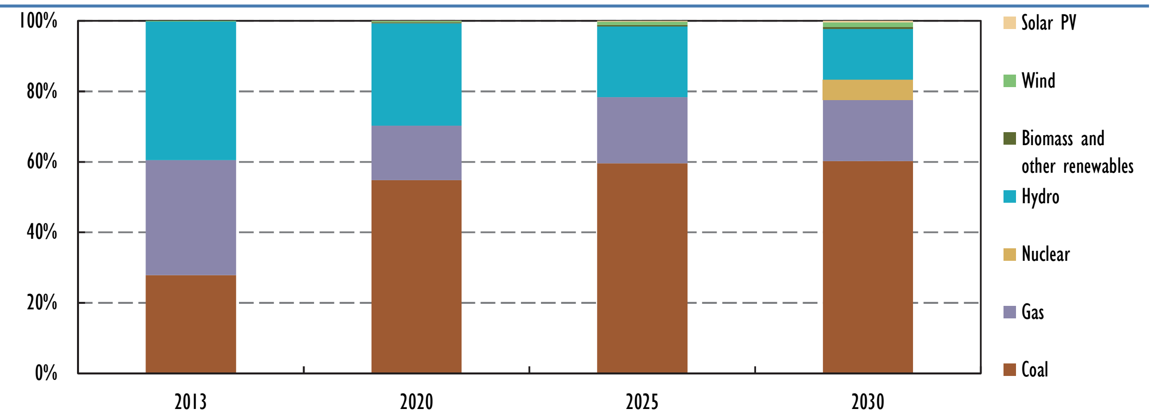


If the generation mix were allowed to follow these projections, emissions intensity would continue to rise, even though the share of hydro and other renewables was growing.

Viet Nam's power generation under the revised PDP VII

Based on Viet Nam's revised PDP VII, the share of coal in the generation mix will increase substantially, growing from 30% in 2014 to around 60% in 2030 – with the shares of gas and hydropower falling (Figure A11). The dominance of domestic anthracite rather than bituminous coal for generating electricity results in significantly higher emissions. Of the three target countries, only Viet Nam's emissions intensity markedly worsens over the next two decades, with its plans for the contribution of renewables to be cut by half. However, if nuclear power were to enter the generation mix after 2025, the emissions intensity would plateau.

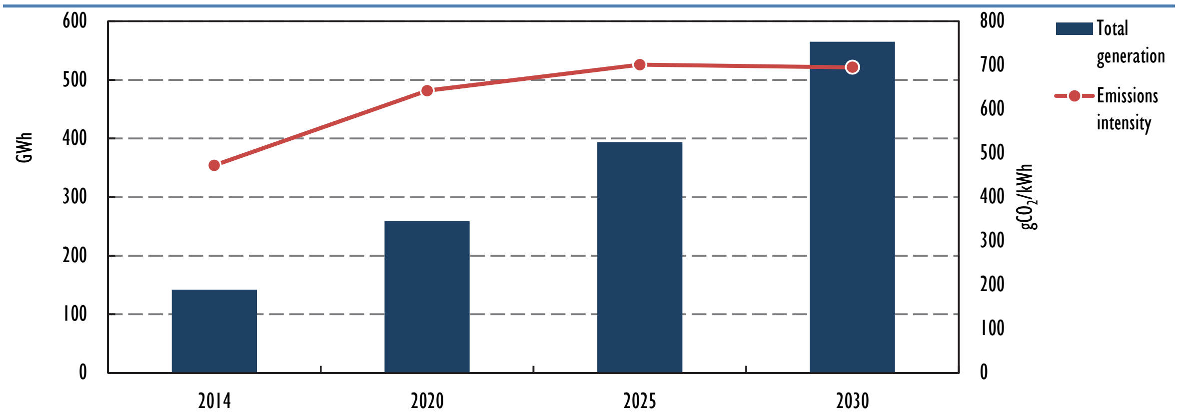
Figure A11 • Projected generation mix based on Viet Nam's Revised PDP VII



Source: IEVN (2015b), *Revised Master Plan for Power Development in Vietnam 2011-2020 with Outlook to 2030* (Revised PDP VII, pending approval).

As generation increases, the share of hydro gradually declines; over the six years, from 2014 to 2020, the reduction in the projected share of hydro is estimated at around 10 percentage points. The same trend is also projected for natural gas, whereby the share in 2020 is almost half that in 2014. With total generation projected to quadruple over the next decade and a half, the emissions intensity rises considerably (Figure A12).

Figure A12 • Increases in emissions intensity and electricity generation



Source: IEVN (2015b), *Revised Master Plan for Power Development in Vietnam 2011-2020 with Outlook to 2030* (Revised PDP VII, pending approval).

With Viet Nam's coal-fired capacity growing apace, imported bituminous coal will be required from 2020 to supplement the limited reserves of anthracite. However, given the undertaking to address CO_2 emissions intensity from power generation, Viet Nam will need to reconsider its present policies.

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