Indonesia

International energy data and analysis

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full report

Overview

Indonesia is reorienting energy production from serving primarily export markets to serve its growing domestic consumption. Indonesia's energy industry has faced challenges in recent years from regulatory uncertainty and inadequate investment.

Indonesia is the most populous country in Southeast Asia and the fourth most populous country in the world, behind China, India, and the United States. Formerly a net oil exporter in the Organization of the Petroleum Exporting Countries (OPEC), Indonesia struggles to attract sufficient investment to meet growing domestic energy consumption because of inadequate infrastructure and a complex regulatory environment. Despite their energy struggles, it was the world's largest exporter of coal by weight in 2012 and the fourth-largest exporter of liquid natural gas (LNG) in 2013. As Indonesia seeks to meet its energy export obligations and earn revenues through international market sales, the country is also trying to meet demand at home.

Indonesia's total primary energy consumption grew by 44% between 2002 and 2012. The petroleum share, although decreasing, continues to account for the highest portion of Indonesia's energy mix at 36% in 2012. In the past decade, coal consumption nearly tripled and surpassed natural gas as the second most consumed fuel.

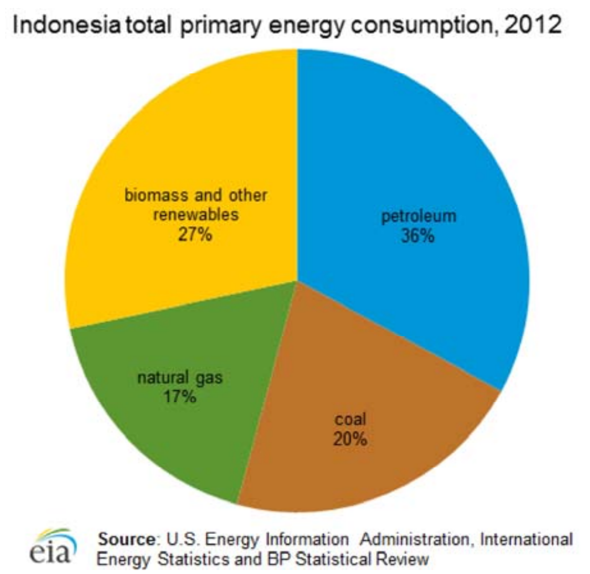
Indonesia is also a significant consumer of traditional biomass and waste in its residential sector, particularly in the more remote areas that lack connection to the country's energy transmission networks. In 2012, Indonesia consumed over 2 quadrillion British thermal units (BTU) of biomass energy, and the government hopes to leverage the country's vast renewable sources of hydroelectricity, geothermal, solar, and biomass and waste, to generate electricity for domestic consumption.

Indonesia's total energy demand is closely linked to the country's economic expansion. According to the International Monetary Fund (IMF), Indonesia sustained relatively strong economic performance throughout the global recession, with an average gross domestic product (GDP) growth rate of just under 6% per year between 2008 and 2012. However, in 2013, GDP growth fell below 6%. Overall, the energy sector (including electricity) constituted 15.6% of Indonesia's GDP in 2012 and has held roughly constant at this level since 2005. Net foreign direct investment (FDI) more than doubled between 2008 and 2012 but shrank by roughly 15% in 2013.

The energy sector continues to influence the economy to a large degree. Oil and gas alone constituted one-fifth of merchandise exports in 2012, according to IHS Global Insight. In addition, revenues from the oil and gas sector accounted for 24% of total state revenues in 2012. A combination of healthy growth, market reforms, and a stable government has encouraged rapid investment, particularly in the commodity sector. Moody's Investors Service and Fitch Ratings both upgraded Indonesia's sovereign risk rating to an investment grade status between late 2011 and early 2012.

On the other hand, investment in infrastructure was around 3% of GDP in 2011, well below most of Indonesia's neighbors, according to IMF data. The government signed land reform legislation in late-2011 to pave the way for more private sector infrastructure development. It also unveiled a new development strategy in 2011 (*Master Plan for Economic Expansion and Acceleration 2011-2025*) that emphasized more private sector involvement in infrastructure expansion, such as wider use of public-private partnerships in the oil and gas sector. Despite these efforts, many infrastructure projects continue to be delayed, and regulatory challenges and uncertainties have reduced predictability for foreign investors.

Source: U.S. Department of State



Petroleum and other liquids

Indonesia's declining oil production and rising domestic demand resulted in the country's exit from OPEC in 2009 and higher levels of petroleum imports to meet demand.

Indonesia ranked as the 24th-largest crude oil producer in the world in 2013, accounting for about 1% of world production. After oil was first discovered in 1885 in northern Sumatra, the hydrocarbon sector became an important part of Indonesia's economy.

Indonesia suspended its membership in OPEC in 2009, after joining in 1962. This exit was prompted by growing internal demand for energy, declining production (most notably in mature fields), and limited investment to increase capacity. Indonesia currently imports crude oil and refined products to meet demand. The country straddles the Strait of Malacca, one of the world's major oil transit chokepoints.

Sector organization

International oil companies, particularly Chevron and Total, dominate Indonesia's upstream oil sector. State-owned energy company Pertamina must balance its needs as a corporation against its mandate as a national oil company to meet domestic demand.

International oil companies (IOCs) in the Indonesian oil market include Chevron, Total, ConocoPhillips, ExxonMobil, and BP. Chevron is the largest oil producer in Indonesia, accounting for about 39% of the country's crude production in 2013. PT Pertamina (Pertamina), Indonesia's state-owned integrated energy supply company, accounted for approximately 17% of domestic crude production through 2012, according to government reports, making the company the second-largest oil producer, followed by Total and ConocoPhillips, respectively the third and fourth largest producers. Other national oil companies (NOCs) such as the China National Offshore Oil Corporation (CNOOC) and South Korea's KNOC also hold significant upstream assets.

In addition to its upstream activities, Pertamina operates nearly all of Indonesia's refinery capacity, procures crude oil and products imports, and supplies petroleum products to the domestic market. Pertamina's monopoly in the retail market ended in 2004, but the company continued to be the sole distributor for subsidized fuels until early 2010. Pertamina must balance its own needs as a corporation, to increase export profits with its mandate as a national oil company charged with meeting domestic demand.

The Indonesian Ministry of Energy and Mineral Resources is responsible for entering into production sharing contracts (PSCs) with interested oil companies. Indonesia's 2001 Oil and Gas Law significantly restructured Indonesia's upstream oil and gas sector, transferring the upstream regulatory role from Pertamina to BPMigas, a state-owned legal entity that was tasked with managing and implementing PSCs. Although Pertamina continues to be wholly state-owned, the 2001 law also established it as a limited liability corporation in 2003.

BPMigas was established following the passing of the 2001 Oil and Gas Law. In November 2012, Indonesia's Constitutional Court deemed upstream regulator BPMigas to be unconstitutional, based on the regulator's role that limited the state full access to maximize the benefits of natural resource management for Indonesia's welfare, and ordered it to be dissolved. The Energy and Mineral Resources Ministry temporarily took over regulatory functions through a special task force, SKK Migas, which will operate until the government amends the 2001 legislation. SKK Migas is tasked with managing and implementing PSCs, determining sellers of government shares of oil and gas, and increasing oil and gas production for domestic demand. The President of Indonesia is ultimately responsible for formulating oil and gas regulatory policy, while parliament possesses the duties of oversight and consent. Following a corruption case within SKK Migas and arrest of its former chairman in late-2013, the entity lost the right to market the country's unused oil and gas designated for domestic use within Indonesia. The government transferred exclusive domestic marketing rights to state-owned Pertamina.

Exploration and production

Oil production continued to decline in 2013 as recent discoveries have yet to reach full capacity. Aging infrastructure and fields suggest the country will struggle to meet production targets in the short term.

Indonesia possessed 3.6 billion barrels of proven crude oil reserves as of January 2014, down from 4 billion barrels at the beginning of 2013, according to *Oil & Gas Journal* (OGJ).

According to SKK Migas, reserve replacement of oil is 52% as a result of declining investment in oil exploration, especially in deepwater blocks. Petroleum and other liquids (or total liquid fuels) production declined from a high of nearly 1.7 million barrels per day (bbl/d) in 1991 to an estimated 928,000 bbl/d in 2013. Crude oil and lease condensate production made up 834,000 bbl/d of this total, a level below the government's original 2013 target of 900,000 bbl/d. The total number of new exploration and development wells fell to 840 in 2012, declining by 12% from 2011, according to IHS Global Insight.

The government's annual crude oil production target, which has been overstated each year since 2009, is 870,000 bbl/d in 2014, although Indonesia reported that it plans to reduce this target to 820,000 bbl/d. Several factors put downward pressure on Indonesia's oil output each year, including: licensing approvals at the regional level of government, land acquisition and permit issues, oil theft in the South Sumatra region, aging oil fields and infrastructure, and insufficient investment in unexplored reserves.

Indonesia's two oldest, largest producing fields are Duri and Minas, located on the eastern coast of Sumatra in the South Sumatra Basin. Duri began producing in 1952 and currently averages around 140,000 bbl/d, according to Facts Global Energy (FGE). The Minas field began production in 1955 and currently produces around 190,000 bbl/d, according to FGE. Chevron operates both fields with a 100% working interest. Production at both fields is declining, even with enhanced oil recovery (EOR) techniques to bolster output. Chevron uses steam injection EOR for 80% of the Duri field, one of the largest steamflood projects in the world. Chevron announced plans to double oil production at the Minas field through the use of EOR to 140,000 bbl/d by 2014.

In addition to the Sumatra Basin, Indonesia produces significant quantities of oil from the East Java Basin with a joint operating agreement between Pertamina and PetroChina. This venture produced approximately 43,000 bbl/d at the end of 2011, and both companies announced plans to raise production by up to 10,000 bbl/d in the next few years.

Pertamina now faces the combined challenges of stemming oil production declines and meeting domestic demand. Much of the reserves remaining under Pertamina's control require EOR techniques, currently beyond the technological capacity of domestic firms, or the development of basic infrastructure in remote areas of the country (mainly in the east). Partly because of an uncertain regulatory atmosphere and government measures to support local companies, foreign investment in extracting these reserves remains limited. In addition, Indonesia's domestic operations have been limited by disputes with IOCs operating within Indonesia.

The 2001 discovery of the Cepu Block in East Java has the potential to counteract some of Indonesia's production decline. Estimated to contain 600 million barrels of recoverable reserves, this block contains three significant fieldsâ€“Banyu Urip, Jambaran, and Cendana. After signing a PSC with Pertamina in 2005, ExxonMobil announced a new oil discovery at an exploration well in the Cepu block in August 2011. ExxonMobil operates the Cepu PSC with 45% interest in a joint venture with Pertamina's Exploration and Development (E&P) unit (45% interest) and four local government companies (combined 10% interest). The partners estimate that Cepu contains 600 million barrels of recoverable liquids and will have a peak production of 165,000 bbl/d. The project has encountered several delays in the development process. Most notably, post-2011 development was hampered by land acquisition and permit obstacles, while SKK Migas declined to extend the work permit of ExxonMobil's head Indonesia executive. Banyu Urip is currently the only producing field in the Cepu PSC and had reached a production level of about 26,000 bbl/d, as of April 2013. SKK Migas expects Cepu to reach full capacity of 165,000 bbl/d by the first quarter of 2015.

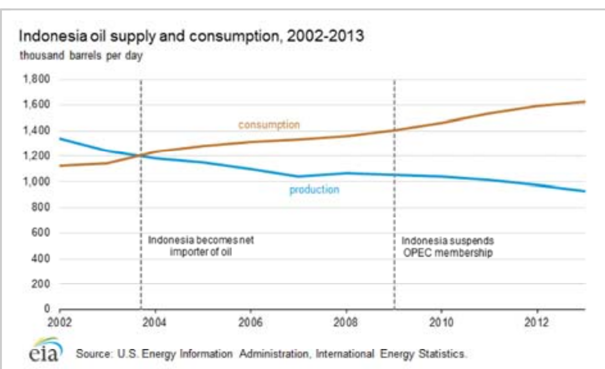
Deepwater exploration and production activity is focused in the Kutei Basin (off the coast of Kalimantan), Western Papua, and the Bonaparte Basin (adjacent to Australia in the Arafura Sea). Chevron, Eni, Niko Resources, Statoil, Total, and Hess are the firms most active in Indonesia's deepwater field development. Chevron is the largest operator in these areas, managing five of the eight deepwater fields currently in development. Currently, technical and commercial success rates have not incentivized further development in deepwater areas.

Aging infrastructure and fields suggest that in the short term, the country will continue to struggle to meet production targets. Future oil extraction will depend on the ability of the country to attract investment for exploration and production, particularly in deepwater offshore and frontier areas and in any technically challenging plays. To this end, in 2012 Indonesia's Ministry of Energy and Mineral Resources asked the country's Ministry of Finance to lift land and building taxes on deepwater oil and gas exploration as a means of increasing future supply.

SKK Migas and the Indonesian government introduced policies aimed at creating investment incentives and improving the flexibility of the PSC bidding process. In particular, the government has pursued EOR and Technical Assistance Contracts (TACs) as part of Indonesia's push to raise crude oil production to 1 million bbl/d. To stimulate development in areas with poor infrastructure, the government has begun to grant PSCs that offer 15% to 20% of revenue to investors.

Western market analysts still consider the upstream investment environment to be risky, and licensing rounds from the past three years have been disappointing. The government only managed to award 21 of the 43 blocks offered in 2009, 10 of the 36 blocks offered in 2011, and 24 of the 42 blocks offered in 2012. As part of one round in 2012, the government awarded exploration rights to 14 out of 16 offered blocks, mostly as a result of uncontested bids. The 2013 bidding round involves 18 oil and gas blocks, mostly contained in the underexplored eastern part of the country.

Under current regulation, local governments retain 15% of net revenues from oil and 30% of net revenues from gas produced within their jurisdiction. Domestic Market Obligations (DMOs) require that a minimum of 25% of oil production be made available to the Indonesian market. In 2011, Indonesia's central bank mandated that foreign and domestic upstream enterprises must pass revenues through local banks, a significant shift for IOCs that created another hurdle for foreign investors.



Refining

Indonesia's refinery output primarily serves the growing domestic market, although current refining capacity is insufficient to meet demand growth.

Indonesia's total refinery capacity was more than 1.1 million bbl/d in late 2013 at nine refineries, according to FGE. The primary refineries in the country are Cilacap (340,000 bbl/d) in Central Java, Balikpapan (250,000 bbl/d) in East Kalimantan, and Dumai (165,000 bbl/d) in Sumatra. Pertamina has delayed plans to expand the non-crude capacity of its Cilacap and Plaju/Musi refineries until 2014.

Indonesia's petroleum consumption reached more than 1.6 million bbl/d in 2013 . Refinery output went primarily to the domestic market but met only about 64% of domestic oil products consumption in 2012, according to FGE. Oil product imports met the remaining demand.

Current refining capacity is insufficient to meet demand growth, as there is a lack of government financial incentives to stimulate foreign investment in the sector. Since the construction of the Balongan refinery in 1994, no refineries have been built in Indonesia. The Minister of Energy and Mineral Resources unveiled plans to build two refineries in Bontang City, in East Kalimantan, and in August 2012, Indonesia approved plans for a third refinery. Each plant is slated to have a production capacity of 300,000 bbl/d. The ministry has also studied the possibility of building a 300,000 bbl/d plant in Sumatra that would come onstream in 2018. If Indonesia is unable to reverse the decline in crude oil production, it is considering investing in refineries to import and refine crude domestically. Also, if the government cannot find private investors to fund the multi-billion dollar projects, it plans to use state funds to complete these facilities. As another measure to increase flexibility, Pertamina plans to construct a US$450 million crude oil terminal in East Kalimantan that will allow the company to blend its domestic crude oil with other grades of imported crude oil and act as an oil stock reserve for the country.

Consumption and distribution

A strong economy, population growth, and state subsidies for fuels have worked together to push domestic oil demand beyond supply. Fuel subsidies have cost the government at least 7% of its annual budget since 2005, pressuring the government to reduce fuel subsidy spending.

A strong economy, population growth, and continued state subsidies for fuels worked together to push domestic oil demand beyond supply. Domestic petroleum consumption totaled 1.6 million bbl/d in 2013, steadily rising from 1.3 million bbl/d in 2007, resulting in higher net imports over the past several years.

In 2013, gasoline and gasoil made up the bulk of demand, accounting for 38% and 36%, respectively, according to FGE. Petroleum use declined in the power and industry sectors while it increased in the transport and household sectors. Indonesian gasoline demand has grown nearly 200,000 bbl/d since 2005, while gasoil demand has risen by 9% since 2005. Liquefied petroleum gas (LPG) use has increased in the past decade because of government subsidization and price regulation, especially in the residential sector. LPG demand grew by 80% from 2007 to 2012 and reached 124,000 bbl/d in 2012.

Fuel subsidies have cost the government between 7% and 25% of its annual public expenditures between 2005 and 2013. To curb oil imports and reduce pressure on the government budget, Indonesia reduced government fuel subsidies in June 2013 for the first time since 2008. As a result, gasoline and gasoil prices rose by 44% and 22%, respectively. This action was partly in response to the government's fuel subsidy bill of $20 billion in 2012 and $17 billion in 2011. In 2011, the government overshot its budgeted amount by about 30% because it spent $17 billion on fuel subsidies, according to Ministry of Energy and Mineral Resources. Inflation rose to an estimated 9.5% following the subsidy reductions. Indonesia's government plans to distribute cash to the poorest households to reduce the effect of these price increases.

Trade

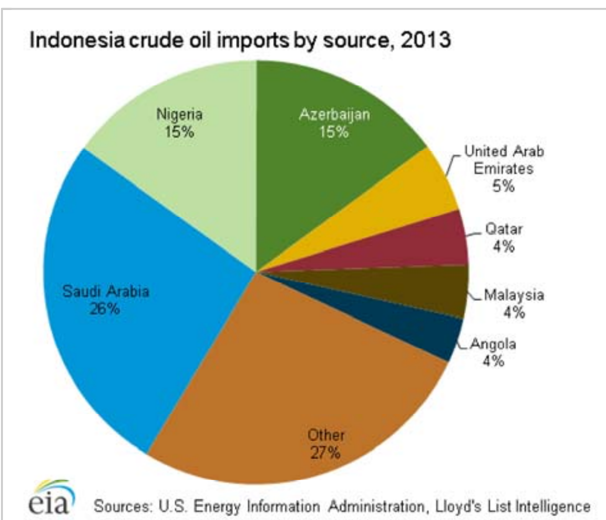
Indonesia's rising domestic demand and waning oil production in the past few years have led to increased import levels of both crude oil and petroleum products.

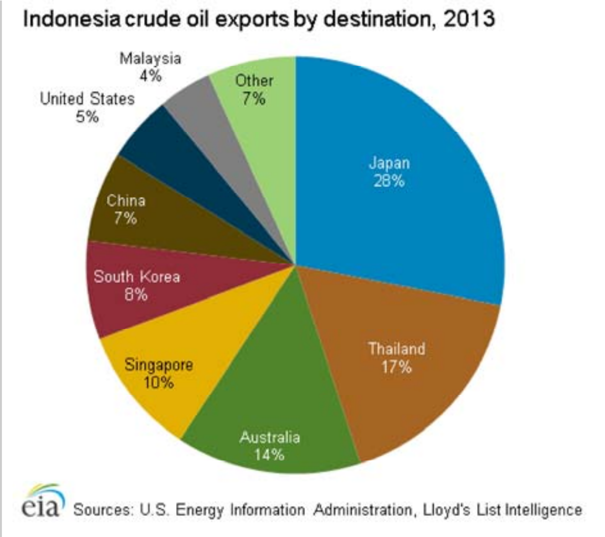
Indonesia has no international oil pipelines and few domestic pipelines, making maritime trade vital. Most petroleum trade is in the form of imports, chiefly motor gasoline and diesel for Indonesia's transport sector. The country exports some fuel oil for electricity fuel generation. The country both imports and exports crude oil and is a net crude oil importer as a result of the regional imbalances and growing demand for crude oil use in refineries and for power generation.

In 2013, Indonesia imported over 506,000 bbl/d of crude oil and lease condensate, according to the Analysis of Petroleum Exports (APEX) tanker tracking service of Lloyd's List Intelligence. Roughly one-fourth of crude oil imports came from Saudi Arabia. Other significant suppliers included Nigeria (15%), Azerbaijan (15%), United Arab Emirates (5%), Qatar (4%), Malaysia (4%), and Angola (4%).

Indonesia's net oil product imports remain relatively high as a result of insufficient refining capacity to handle the growing demand for oil products. The country's oil product imports in 2012 were 435,000 bbl/d and are estimated to be 466,000 bbl/d in 2013, according to FGE. Oil product imports consisted primarily of gasoline (66%), gasoil for transport and power generation, LPG, and jet fuel. Pertamina is responsible for purchasing Indonesia's subsidized gasoline, RON 88 specification gasoline, which currently makes up the largest share of the country's gasoline demand. Japanese demand for Indonesian fuel oil that increased after the Fukushima nuclear accident in 2011, is now subsiding as Japan increases natural gas and coal imports.

Indonesia continues to export crude oil and condensates even though the country has turned into a net importer of oil, partly because of a desire to maintain market access and oil revenues especially when international oil prices are high. In addition, regional imbalance in the archipelago between oil production and demand centers encourages both imports and exports. In 2013, APEX tanker data estimated Indonesian petroleum exports were roughly 455,000 bbl/d, primarily to regional buyers.





Biofuels

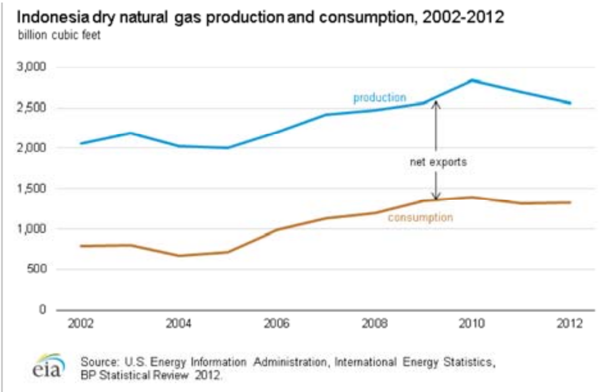
Indonesia plans to replace some oil product imports by promoting greater biofuels production and revising upward the required level for biofuels blending with diesel and gasoline. The government mandated the use of fuel ethanol in the past, requiring a 3% ethanol blend in public vehicles and 7% in private vehicles. Ethanol fuel production ended in 2010 because of high production costs and feedstock prices, according to FGE. Ethanol demand reached 46,000 bbl/d in 2012.

Indonesia is the largest biodiesel producer in Asia. In 2012, output reached roughly 37,000 bbl/d, according to the U.S. Department of Agriculture. Of this, more than 30% was blended within Indonesia while the remainder was exported. Indonesia consumed about 12,000 bbl/d of biodiesel in 2012. Growth of biodiesel consumption is currently hampered by high inter-island transport costs. In spite of this, biodiesel consumption is expected to grow after the government mandated that 10% of diesel use in industry and transportation and 20% of diesel use in the power sector must be blended with biodiesel by 2014.

Natural gas

Natural gas production has increased by almost 25% between 2002 and 2012. While Indonesia still exports about half of its natural gas, domestic consumption is increasing in tandem with production.

Indonesia possessed 104.4 trillion cubic feet (Tcf) of proven natural gas reserves in 2014, down from 108.4 Tcf in 2013, according to *OGJ*. The country ranks as the 13th largest holder of proven natural gas reserves in the world, and the second-largest in the Asia-Pacific region, after China. The country continues to be a major exporter of pipeline and liquefied natural gas (LNG). At the same time, domestic demand for natural gas has doubled since 2005. Natural gas shortages caused by production problems and rising consumption forced Indonesia to buy spot cargoes of LNG to meet export obligations in recent years. The government began constructing new LNG receiving terminals and gas transmission pipelines to address domestic gas needs, although this is likely to reduce the natural gas available for export.



Sector organization

The regulatory structure that shapes Indonesia's upstream oil sector also forms the basis for the natural gas sector (see Oil: Sector Organization). Pertamina accounted for 13% of natural gas production in 2012 through subsidiary Pertamina Gas, according to PricewaterhouseCoopers. IOCs such as Total, Inpex, ConocoPhillips, and ExxonMobil dominate the upstream gas sector. Total and ConocoPhillips produced nearly 50% of dry natural gas in the country in 2010, according to PFC Energy. Other upstream investors in Indonesia's gas sector include various Chinese national oil companies, smaller international oil and gas companies, and local Indonesian energy firms, while the state-owned utility Perusahaan Gas Negara (PGN) carries out natural gas transmission and distribution activities.

Pursuant to a Domestic Market Obligation (DMO) stipulated in Indonesia's government regulations, 25% of natural gas produced from production-sharing contracts in Indonesia must supply the domestic market. The government has imposed larger obligations in recent specific contracts. For example, the planned Donggi-Senoro LNG plans received government approval only after the developers designated 30% of the output explicitly for domestic consumption. Similarly, Inpex designated a third of the output from the planned Abadi floating LNG liquefaction terminal for the domestic market, according to the government.

Exploration and production

EIA estimates Indonesia produced 2.6 Tcf of dry natural gas in 2012, mostly from offshore fields not associated with oil production. In recent years, companies have shifted attention to newer, underexplored offshore areas, particularly in the eastern regions of the country. Production grew at an annual rate of about 4% from 2002 to 2010. In 2011 and 2012, production fell by roughly 5% compared to the previous years. Despite the decrease in production, Indonesia's 2012 gas production was the tenth-highest in the world.

Indonesia's largest fields are located in the Aceh region of South Sumatra and East Kalimantan. The Mahakam block, offshore East Kalimantan and operated by Total since 1970, currently accounts for roughly one-fifth of Indonesia's dry natural gas production. There is uncertainty over whether Indonesia plans to extend the PSC after the contract expires in 2017, and Total has reduced some development and production in the block since 2012. Chevron is developing several deepwater fields offshore East Kalimantan which are expected to produce a maximum of 1.1 Bcf per day (400 Bcf/y) of natural gas and 55,000 bbl/d of liquid condensates and begin operations in 2015.

In recent years, some companies have shifted their attention toward less-explored parts of the country. Pertamina, PetroChina, and ConocoPhillips are key producers in the Natuna Basin within the South China Sea. The companies produced about 200 Bcf of gas from the basin in 2011. As of the beginning of 2014, the partners have not reached a finalized PSC for the Natuna D Alpha block in the eastern section of the basin. The block is technically challenging to develop as a result of its large carbon dioxide concentrations, but it contains a sizeable 46 Tcf of proven reserves. For several years, Indonesia has faced military disputes with China over competing claims to the waters off Natuna Island, located in the northern region of Indonesia. China claims some area around Natuna, as part of its 'nine dash line', which overlaps with Indonesia's exclusive economic zone. These territorial disputes could further delay exploration and development of gas resources around eastern Natuna.

The Bintuni Bay, located in West Papua, and the Central Sulawesi region are emerging as new important offshore gas resource areas. In the area near West Papua, BP oversees proven reserves of 14.4 Tcf. Finally, the Arafura Sea in eastern Indonesia is mostly underexplored and contains the Abadi gas field, estimated to have reserves between 10 and 14 Tcf.

Increasing domestic demand continues to reduce Indonesia's capacity for exports, and the country might not be able to meet its external obligations. Moreover, Indonesia's geography presents a challenge to resource development and makes the switch to natural gas for domestic consumption more difficult. The nation's most prolific blocks of gas reserves are located far from its major demand markets, and regulatory uncertainty delays investment needed for exploration. Foreign upstream investment in PSC areas fell in 2012. ExxonMobil and Statoil relinquished deepwater blocks in 2013 after failing to discover economically viable reserves, a trend that SKK Migas expects to continue.

Gas flaring

Natural gas associated with oil production is often flared when there is no infrastructure in place to make use of the gas. Indonesia ranks 10th in global natural gas flaring, according to the Global Gas Flaring Reduction (GGFR) Initiative. However, Indonesia's flaring volume has dropped in recent years from a high of more than 175 Bcf in 1997 to almost 80 Bcf in 2011, according to satellite data from the National Oceanic and Atmospheric Administration (NOAA). The government publicly committed to reduce its emissions through the use of smaller-scale LNG projects, EOR techniques, and improved gas processing infrastructure.

Coal bed methane and shale gas

Indonesia's government promotes exploration of coal bed methane (CBM) and shale gas, alongside conventional crude oil and natural gas projects. The Ministry of Energy and Mineral Resources estimates that the country has CBM reserves of 453 Tcf based on preliminary studies. In 2007, the Indonesian government started awarding CBM blocks in the South and Central Sumatra basins on Sumatra Island and the Kutei and Barito basins in East Kalimantan. Singapore-based Dart Energy and Indonesian PT Energi Pasir Hitam began CBM exploration activities in East Kalimantan in 2013, with the goal of supplying both power plants and the Bontang LNG facility. The government anticipates CBM production to reach 183 Bcf/y by 2020.

There is currently no shale gas production in Indonesia, but policy makers are interested in exploring the country's shale oil and shale gas potential. In April 2012, the Indonesian government initiated four shale gas study projects and expects commercial shale gas production to begin by 2018. As of December 2013, Indonesia has awarded only two shale gas PSCs for the Sumbagut block in North Sumatra, both to Pertamina. The Sumbagut block is estimated to contain about 19 Tcf of potential shale gas resources. EIA estimates that Indonesia possesses 46 Tcf of total recoverable shale gas resources. A major challenge to the growth of the shale industry is the cost of exploration in Indonesia, estimated to be as much as four times the drilling cost in North America because the deposits are far from demand centers and infrastructure needed to transport the gas.

Consumption and distribution

Indonesian natural gas production initially was exported, but the country's declining oil production led producers to shift increasing gas volumes toward domestic consumption. In 2012, Indonesia consumed 1,329 Bcf of natural gas, or slightly more than half of its total dry gas production. Although the industrial sector accounts for the largest portion of domestic consumption, industry analysts expect the power sector to be the most significant driver of future consumption growth. Indonesia's Ministry of Energy and Mineral Resources stipulates that gas supply be allocated to the needs of enhanced oil recovery, the fertilizer industry, and the power sector before any other sectors.

State-owned Perusahaan Gas Negara (PGN) controls the midstream gas market and the transmission market, operating more than 3,600 miles of natural gas transmission and distribution pipelines. However, domestic distribution infrastructure is almost non-existent outside of Java and North Sumatra. PGN began operating the South Sumatra-West Java pipeline in 2008, providing an important link between the gas-producing region of South Sumatra and the densely populated market of West Java. The Grissik-Duri pipeline is another important domestic transmission pipeline, as it provides gas to Chevron's Duri oil field for its steam flooding and power generation activities.

Natural gas pipeline exports

Although the majority of Indonesia's gas exports are transported as LNG, Indonesia sends about a fourth of its gas exports to Singapore and Malaysia through two pipeline connections: one from its offshore fields in the West Natuna Sea and the other from the Grissik gas processing plant in South Sumatra. In 2012, Indonesia exported about 360 billion cubic feet per year (Bcf/y) via pipelines, with nearly 280 Bcf/y sent to Singapore, according to BP Statistical Review of World Energy 2013. These pipelines have a combined capacity of approximately 400 Bcf/y and deliver gas to Singapore under two long-term contracts, both set to expire around 2020. However, SKK Migas reported that Singapore plans to end gas purchases from Indonesia's pipeline exports once contracts expire. This reduction in exports should allow Indonesia to secure more domestic supply in the next few years.

Liquefied natural gas

Indonesia was the fourth-largest LNG exporter in 2013, following Qatar, Malaysia, and Australia. Expected growth in natural gas demand led the government to pursue policies that secure domestic natural gas supplies for the local market.

After accounting for more than a third of global LNG exports in the 1990's, Indonesia's share of the global market now rests at 7%. In 2013, Indonesia exported approximately 818 Bcf, down from 870 Bcf in 2012. Mostly a regional supplier to South Korea, Japan, Taiwan, and China, Indonesia has lost market share in recent years to LNG producers including Qatar, Malaysia, and Australia. Indonesia was the world's fourth-largest exporter of liquefied natural gas (LNG) in 2013, according to PFC Energy. Indonesian LNG exports to Japan fell by over 50% from 2010 to 2013, as export contracts with Japan expired and Indonesia diversified its markets.

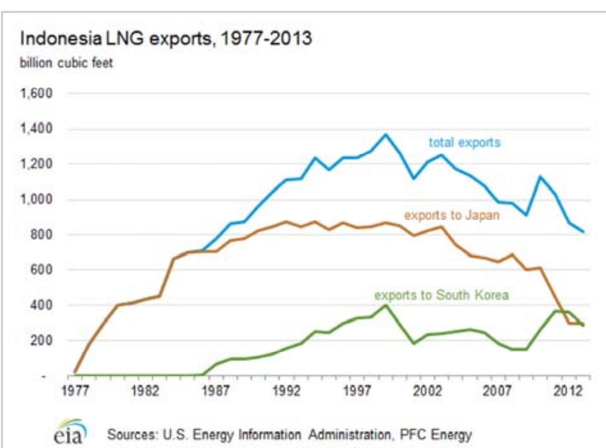
In 2013, regasified LNG from the country's own production in the northern and eastern regions reached 70 Bcf, up from 35 Bcf in 2012. Indonesia has plans to import LNG from other countries by at least 2018. This shift toward imports is emblematic of the country's decreasing energy exports and growth in domestic demand. As a result, Indonesia's share of exports in the global LNG market continued to shrink after peaking in 1994. While the country still exports significant quantities of LNG, export volumes have fallen by 40% since 1999, and internal economic growth has stimulated higher levels of natural gas consumption.

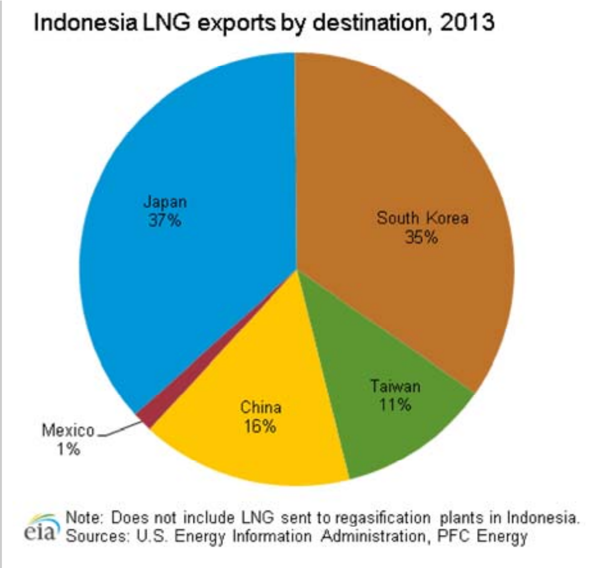
The country's liquefaction plants are located in Northern Sumatra (Arun), Kalimantan (Bontang), and Papua (Tangguh). Combined operating production capacity of these plants is about 1.5 trillion cubic feet per year (Tcf/y) according to IHS Global Insight. The Bontang LNG terminal in East Kalimantan, the largest terminal in Indonesia and one of the largest in the world, has a current operating capacity of 1.1 Tcf/y. A lack of sufficient gas reserve additions in the Arun field has resulted in declining LNG exports from the Arun plant in recent years. Analysts expect the liquefaction plant to stop operating in 2014 as the plant is converted into a regasification facility. The newest addition, BP-operated Tangguh in Western Papua, came online in July of 2009 and has a capacity of 650 Bcf/y. The terminal's operators have proposed plans for an expansion of 182 Bcf/y at Tangguh by 2019. To meet the natural gas domestic market obligation, the government has marked the Bontang and Tangguh LNG plants for domestic production.

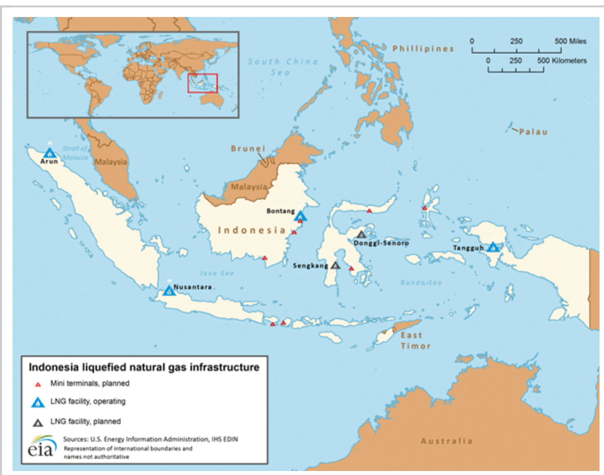
Two liquefaction plants—Donggi-Senoro and Sengkang—are under construction in Sulawesi. The project developers of Donggi-Senoro LNG (Mitsubishi, Kogas, Pertamina, and Medco) expect the 100-Bcf/y plant to come online by early 2015. Sengkang LNG's capacity of 100 Bcf/y is slated to be operational by 2017, according to PFC Energy. Inpex, a Japanese company, has delayed the expected startup date of the floating Abadi liquefaction terminal in southern Indonesia's Arafura Sea until 2019. The terminal is planned to have a capacity of 120 Bcf/y.

The government has sought to meet the increasing gas demand by increasing the country's regasification capacity. Indonesia began processing domestic LNG at its first regasification terminal, Nusantara, in West Java. The Floating Storage and Regasification Unit, or FSRU, is a joint venture between Pertamina and PGN, with a capacity of 500 million cubic feet per day (MMcf/d). All LNG for this terminal has been supplied from Indonesia's Bontang and Tangguh plants. Indonesia also plans to import LNG from other countries. In December 2013, Indonesia signed its first gas import contract with Cheniere Energy (United States) to receive 38 Bcf/y of LNG for 20 years from the company's planned Corpus Christi liquefaction terminal, located in the Gulf Coast of the United States, starting in 2018.

The government has granted Pertamina the authority to convert the Arun LNG plant into a regasification terminal, with an expected capacity of 146 Bcf/y to come online in late 2014, according to IHS Global Insight. Pertamina plans to construct a pipeline more than 200 miles long from the Arun LNG facility to Belawan to serve power facilities and the fertilizer industry. PGN and Pertamina are developing a second floating regasification terminal, Lampung, in southern Sumatra to come online in mid-2014, with the goal of servicing industry and power sector clients. In the eastern regions of the country, Pertamina and PLN (Indonesia's state electricity firm) announced plans to develop eight small mini-LNG terminals by 2015, with a total capacity of 67 Bcf/y. The government intends for these facilities to supply natural gas to domestic electricity plants.



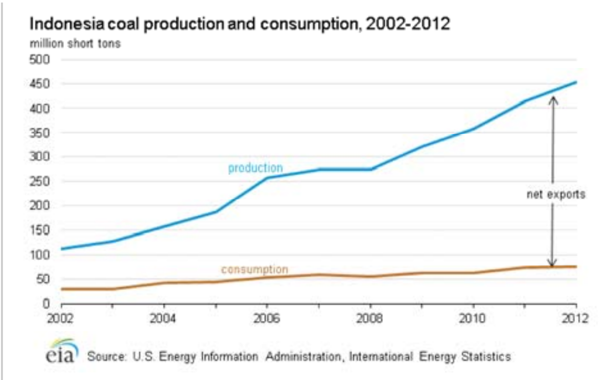




Coal

Indonesia remains the world's largest exporter of coal by weight and exports about 75% of its production.

Indonesia plays an important role in world coal markets, particularly as a regional supplier to Asian markets. It has been the largest exporter of thermal coal, typically used in power plants, for several years. In 2011, it overtook Australia as the world's largest exporter of coal by weight. Indonesia is currently the world's largest exporter of thermal coal, with roughly 75% of production leaving the country.



Sector organization

The government passed the 2009 Law on Mineral and Coal Mining No.4 to stimulate development of the domestic mineral processing industry and to increase foreign investment in the mining sector. The law introduces more transparent and standardized tenders and licenses for mining blocks. As of 2013, the law was not fully implemented, although there have been some increased investments since 2009.

Indonesia is seeking to retain greater revenues from its coal mining industry. In early 2012, the government declared that all foreign investors must sell a majority of existing mine equity to local investors by the 10th year of production. In late 2012, this regulation was followed by a government declaration to raise the mining royalty rate for major foreign-owned mining firms to at least 10%, more than double its ceiling at the time.

In 2010, Indonesia imposed a domestic market obligation on large coal producers, requiring that about 24% of all supply be sold in the domestic market. The primary beneficiary of this policy is the electric power sector, as the government seeks to improve electrification rates in the country. Currently, state electricity utility Perusahaan Listrik Negara (PLN) purchases 70% of DMO coal.

According to IHS, Indonesia's coal exports in 2011 were valued at US$27 billion. This export level represented 13.4% of total merchandise exports and the vast majority of the country's mining exports. Growing demand for coal in China and India continues to fuel supply from Indonesia.

PT Adaro is one of the country's largest coal producers, responsible for more than 50 million short tons of coal in 2012. PT Kaltim Prima Coal (KPC), a subsidiary of PT Bumi Resources, a large Indonesian mining company, owns one of the largest coal mines in the world. Other major producers in the country include PT Kideco Jaya, PT Arutmin (also a PT Bumi subsidiary), and PT Berau. The top six producers in Indonesia accounted for 75% of coal production in 2011, according to Patersons Indonesian Coal Review.

Exploration and production

Indonesia's coal production, mostly bituminous and sub bituminous, has climbed sharply over the past decade.

According to the World Energy Council, Indonesia has 6.1 billion short tons of recoverable coal, located primarily in Sumatra and East and South Kalimantan. Government and industry estimates suggest that the resource base may be considerably higher than this amount. Indonesian coal is primarily bituminous or sub bituminous in rank, and the country produces a small amount of lignite used by the power sector.

Coal production quadrupled between 2002 and 2012, reaching 452 million short tons. Supply growth slowed to 9% in 2012, its lowest level since 2008 as a result of low international coal prices. Approximately two-thirds of Indonesia's coal production comes from East Kalimantan, according to industry estimates.

Consumption

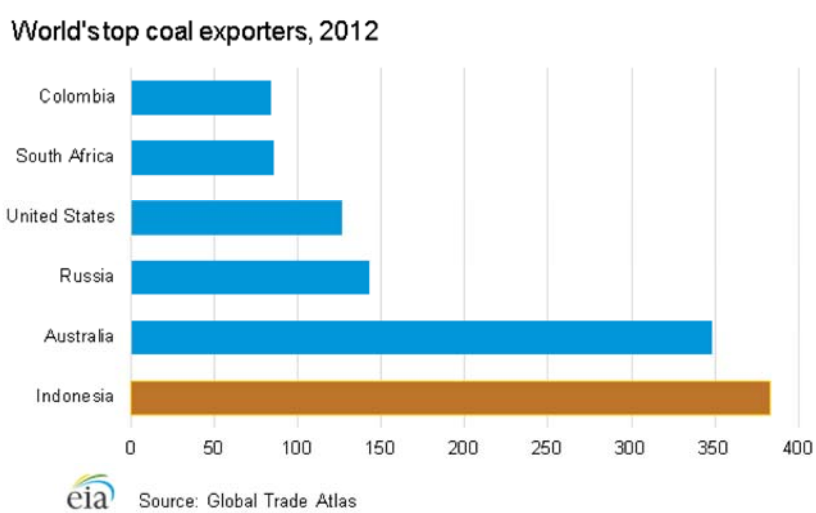
Indonesia's government encourages the use of coal in the power sector because of the relatively abundant domestic supply. Coal use also reduces the use of expensive diesel and fuel oil.

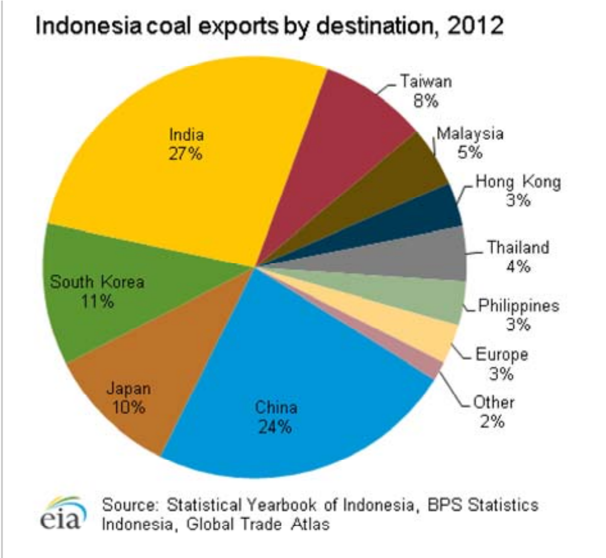
Indonesia's coal consumption grew to 76 million short tons in 2012. The electricity sector is the largest source of domestic coal consumption. Power plants accounted for nearly two-thirds of total coal sales in 2010. EIA expects electricity sector demand for coal to increase in the next few years as a result of coal-fired generation capacity additions.

Unlike many other countries, Indonesia's government encourages increased use of coal in the power sector, because of the relatively abundant domestic supply. Coal use also reduces the use of expensive diesel and fuel oil. Although coal consumption has grown significantly in the past decade, the majority of production (about three-fourths) has gone toward exports. In order to guarantee sufficient domestic supply, the Indonesian government set a DMO of 24% for producers, which it temporarily revised down to 20% in October 2012 as a result of lower than expected consumption.

Trade

In 2012, Indonesia exported about 383 million short tons of coal, making it the world's largest exporter of coal by weight. Indonesia's coal exports serve primarily Asian markets, with about 70% of total exports being sent to China, Japan, South Korea, India, Taiwan, and other Asian markets. In 2012, India became the largest importer of Indonesian coal, surpassing China, according to the Global Trade Atlas. Indonesia has become increasingly important as a source for Chinese coal imports over the past few years.





Electricity

Generation capacity growth in Indonesia has been lower than growth in electricity demand, leading to power shortages and a low electrification ratio. Indonesia is the world's third-largest geothermal generator, although much of this resource potential is still undeveloped.

Although Indonesia's electricity generating capacity has increased by more than 25% in the past decade, the country has a low electrification ratio compared to countries with similar income levels. In 2012, about 73% of Indonesia's population had access to electricity, according to state electric utility Perusahaan Listrik Negara (PLN). Eastern Indonesia lags behind the western area of the country, with some provinces such as Papua only providing electricity to a third of its population. Because capacity growth has not kept pace with electricity demand growth, grid-connected areas have also suffered from power shortages. Inadequate supporting infrastructure, difficulty obtaining land-use permits, subsidized tariffs, and an uncertain regulatory environment all contribute to insufficient generation.

Sector organization

PLN is the most significant company in the electric power sector. It owned and operated about 85% of the country's generating capacity through its subsidiaries as of 2012 and maintains an effective monopoly over distribution activities. Although the most recent 2009 Electricity Law ends PLN's distribution monopoly, there is a lack of sufficient regulations to enforce this law.

The government regulates consumer electricity prices below market levels, forcing PLN to accept losses. To ameliorate the effect of this policy on the state's vertically integrated utility, Indonesia raised prices on a quarterly basis in 2013. This move was also intended to reduce government subsidies to PLN, surpassing $9 billion in 2013. In lieu of subsidies, the government has sought to raise tariffs in the power sector to provide price security to PLN and private investors. Also, feed-in tariffs exist for geothermal, solar, and waste-to-energy power.

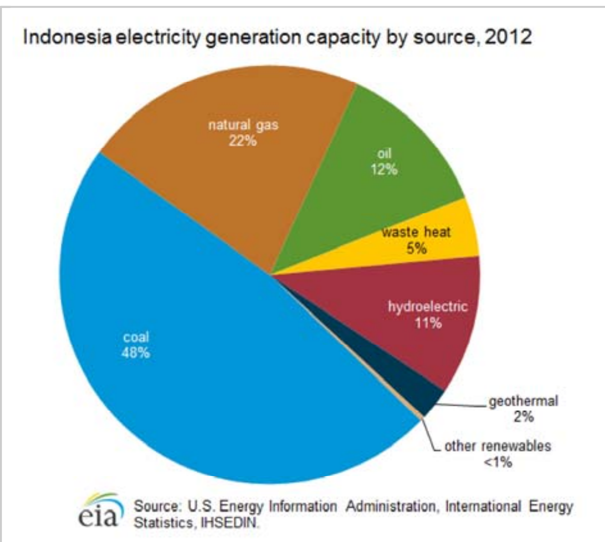
The government is seeking to stimulate foreign investment in the power sector by mandating that PLN offers guaranteed power purchase agreements (PPAs) for independent power producers (IPPs) as part of its supply portfolio. The government projects that IPPs will construct more than half of the power projects in the second phase of its program to add significant generation capacity additions.

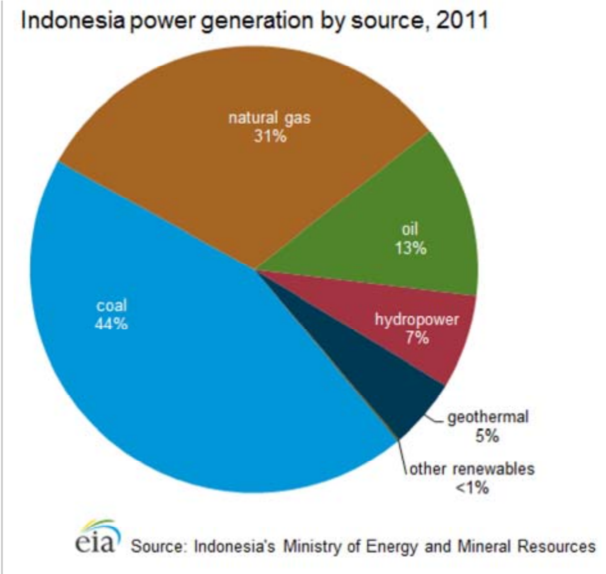
Generation

Indonesia had an estimated 44 gigawatts (GW) of installed capacity in 2012 and generated 200 billion kilowatthours (kWh), according to BPS-Statistics and IHS EDIN. In 2011, roughly 88% of the power generation came from fossil fuel sources, with the rest coming from hydroelectric (7%) and geothermal (5%). Coal accounted for just over half of the power generated from fossil fuels. Oil-fired generation capacity has declined along with Indonesia's oil production.

The Indonesian government has set a national goal that 90% of households will have electricity by 2020. To address the capacity shortage, the policy makers embarked on a fast-track plan in 2006, designed to add 20 GW to the grid. Phase one of this plan includes 10 GW of new coal-based generation. After delays of this project from its original completion date of 2010, the country has added nearly 7 GW of coal-fired capacity since 2011 and plans to complete the first-phase additions by 2015, according to the Jakarta Post. The second phase prioritizes 10 GW of capacity additions that burn cleaner energy sources such as natural gas, geothermal, and other renewables. However, coal-fired generation capacity still constitutes about 35% of the planned second phase, according to IHS Global Insight.

Total electricity sales by PLN grew to about 174 billion kWh in 2012, increasing 10% from the 2011 level. Average annual growth rates have been 7% since 2002. Indonesia's primary power consumers are residential (41% market share), industrial (35%), and commercial (18%).



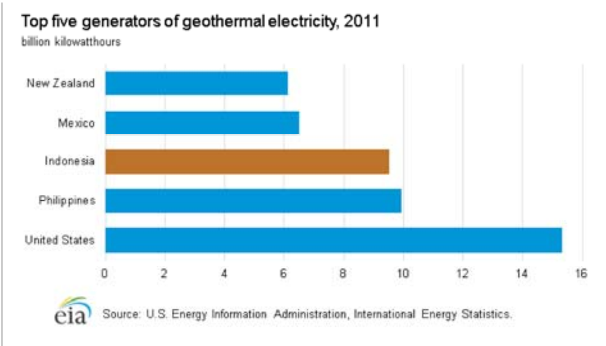


Geothermal and other renewables

Indonesia's power sector is notable for significant levels of geothermal power. Indonesia is the third-largest geothermal energy generator in the world, behind the United States and the Philippines. The country added 130 megawatts (MW) of geothermal capacity in 2012. To promote geothermal development, the country's fast-track electrification plan calls for 4 GW of new geothermal capacity by 2020, to be operated primarily by IPPs. To this end, the government signed a cooperation agreement with New Zealand in 2012 for joint development of geothermal energy projects. In 2013, Pertamina's geothermal energy division signed principles of agreement (PoA) with Chevron and Star Energy (an Indonesian energy firm) to develop six new geothermal plants with a combined capacity of 360 MW. Also, PT Medco Power Indonesia plans to commission the 330-MW Sarulla power plant, which will be the country's largest geothermal plant by 2017.

Plans to increase the use of renewable energy to 15% of the electricity portfolio by 2025 depend on developing the country's geothermal resources. The Ministry of Energy and Mineral Resources has estimated that Indonesia possesses a potential 29 GW of geothermal capacity, only 5% of which is currently being used. One impediment to development is the definition of geothermal development as a mining activity, which restricts new projects in conservation areas.

Hydropower makes up about 11% of the total generation capacity, and there has been little growth from this fuel in the past decade. Indonesia plans to develop several mini-hydropower plants, adding about 2,000 MW of capacity by 2025. Pertamina is currently developing a biomass plant with 120 MW of capacity near Jakarta scheduled to be online in 2016. Indonesia's total biomass capacity in 2013 was estimated at about 95 MW. The country has a very small solar generation capacity (59 MW), although the government is strongly supporting the industry through investment in new plants and favorable regulations for power purchases from solar plants.



Notes

- Data presented in the text are the most recent available as of March 5, 2014.
- Data are EIA estimates unless otherwise noted.

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