Thailand Gas and Utilities

The next big catalyst

Equities

Thailand

Gas Utilities

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Decision on four gas fields is critical to Thailand's macro outlook

Contracts for four gas fields, which supply 45% of Thailand's gas fuel and 30% of the country's electricity generation, will expire in 2022. Failure to reach a decision on the new contracts by 2016 could put Thailand's energy and macroeconomic outlook at risk, in our view. We estimate the loss in gas supply and higher LNG imports could cost the government Bt67.5bn and have a Bt256bn negative impact on the trade balance by 2020. It will also have an impact on the input costs for the industrial sector as well as economic growth.

At the top of the Thai government's reform agenda

Given the urgency, the government has set a one-year timeline and issued broad guidelines. A decision will be made in parallel with amendments to the petroleum law, which would change the fiscal regime of E&P contracts. The guidelines and global trend lead us to believe that the government will increase its ownership in these assets, impose more stringent fiscal terms, and open the bids to existing and new participants.

Challenging Thai gas supply outlook should be a key consideration

On the one hand, the Thai government is under pressure from some sections of society to nationalise E&P assets. On the other, the country is facing a major challenge in supply, given its depleting gas reserves. As the government does not have the technology to recover the gas resources remaining in the Gulf of Thailand, we believe it would need to balance fiscal terms to attract capable E&P partners to recover these reserves. We think the win-win solution is for the government to involve existing operators (Chevron and PTT Exploration & Production [PTTEP]) in the new contracts, to leverage on their expertise and to maximise the value of existing reserves.

Thailand fuel diversification to continue; Buy PTTEP and GLOW

We think PTTEP is well-positioned to capture value upside from gas concession management. We believe the power regulators will continue to push for fuel diversification in favour of coal and renewable energy. If new coal-based power capacity is tendered, we would expect Glow Energy (GLOW) to be a main beneficiary. This could cap the gas demand growth and long-term volume growth for PTT Public.

Valuation (listed in order of preference)

		Price	PT	Upside/	PE (x)			P/BV (x)			Div yield (%)			EV/EBITDA (x)		
	Rating	(Bt)	(Bt)	downside	2015E	2016E	2017E	2015E	2016E	2017E	2015E	2016E	2017E	2015E	2016E	2017E
PTTEP (F)	Buy	108.00	150.00	39%	14.7	12.0	10.6	1.0	0.9	0.9	2.8	2.8	3.4	2.9	2.6	2.4
Glow Energy	Buy	86.50	100.00	16%	13.5	13.2	13.9	2.5	2.3	2.2	4.0	4.2	4.4	9.1	8.7	8.8
PTTGC	Buy	66.00	75.00	14%	12.9	11.6	11.5	1.3	1.2	1.1	3.3	4.7	4.8	7.8	7.3	7.2
PTT Public Company	Buy	344.00	415.00	21%	13.0	11.3	10.3	1.4	1.3	1.2	3.2	3.5	3.8	7.3	6.1	4.9
EGCO	Neutral	153.00	160.00	5%	10.2	10.3	8.9	1.0	1.0	0.9	3.9	3.9	4.6	15.3	15.0	11.2
Ratchaburi	Sell	58.00	47.00	-19%	16.3	12.5	14.2	1.4	1.3	1.3	3.9	4.3	4.3	7.2	7.5	8.6

Above data as at 8 June 2015. Source: Reuters, company data, UBS estimates

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Executive summary

New gas contracts to replace the expiring ones are critical to Thailand's energy supply, economic growth, and industrial competitiveness, in our view

Thailand's four key gas concessions, which supply 57% of domestic gas production and 45% of total gas supply (2014), are due to expire in 2022. These concessions cannot be extended any further according to the existing law and concession terms. We believe the new contracts will be a top priority in the Thai government's reform agenda over the next 12 months.

We believe failure to make a decision on new gas contracts for the expiring concessions by 2016 would put Thailand's energy supply, power sector, and macroeconomic future at risk.

Failure to decide on new contracts could have a major adverse impact on the country

- **Energy supply:** We estimate domestic gas supply loss in 2018/2019/2020 would be 9%/20%/26% of total demand, if the government fails to decide on new contracts by 2016. This is because E&P capex would need to be planned five years ahead to cover the exploration and development period.
- **Power sector:** In the near to medium term, we expect power generation to be maintained with the use of imported LNG, alternative fuels (diesel, etc) and higher electricity imports. However, this would result in significant increases in power tariffs in the country (5.5% CAGR 2015-20E) and the government having to subsidise consumers.
- **Macroeconomic:** We estimate the losses could reach Bt67.5bn to the government and Bt256bn on the trade balance per annum until 2020. That is equivalent to 0.4% and 1.5% of 2020 GDP (IMF estimate), respectively. More importantly, higher gas prices could result in the loss of the Thai industry's cost competitiveness, or a loss in spending power, which would drag down growth. We estimate PTTEP and Chevron might cut investments by Bt25-40bn pa. Lower investment could impact growth, or it could lead to higher spending in other areas of the economy; for example, government energy subsidies.

To mitigate the above risks, we believe the Thai government would have to rapidly decide on the bids and terms of the new contracts. In this report, we build potential scenarios around contract issues and their implications on the economy and stocks.

The worst-case scenario is unlikely, in our view

- Given the abovementioned macroeconomic impact, we think the government would want to avoid the negative impact from gas supply shortages on economic growth as far as possible.
- In the worst-case scenario where the Thai government fails to manage the contract issue, we think PTTEP's production volume could fall by a per annum average of 2.8% in 2017-22E, PTT's gas cost CAGR would be 9.2% over the same period, and PTTGC could lose 13-29% of its domestic ethane feedstock in 2019-23E.
- In the worst-case scenario for the power sector, we forecast a power tariff CAGR of 5.6% over 2015-20, compared with a historical 3.4% CAGR in the past decade. This assumes a reduction in domestic gas supply while Thailand is unable to diversify significantly from gas-based capacity. However, any increase in fuel prices should not impact existing independent power producers (IPPs) because Thai power purchase agreements (PPAs) provide the benefit of 100% fuel cost pass-through. However, in the longer term, we expect high power tariffs to impact demand and also lower returns for new power plants.

Government sets 12-month timeline

The government has set a 12-month timeline to decide on the new contracts. The broad guidelines suggest: 1) the government might increase its stake in the assets; 2) the fiscal terms would be changed, along with amendments to Thailand's Petroleum Act; and 3) the new bids would be also be open to the existing concessionaries as well as new investors.

Higher government ownership, more stringent fiscal terms, and new bids are likely

Need to balance fiscal terms to cope with declining reserves

Although the Thai government will likely increase its stake and collect higher taxes from these gas fields, we believe it will need to balance fiscal terms so that: 1) the terms are attractive enough to interest capable E&P companies that can optimise production in these mature fields; 2) it would help government maximise tax revenue potential; and 3) it would maximise the value of the resources left in the Gulf of Thailand and help manage long-term supply issues.

Due to a challenging domestic gas supply outlook, the government will need to balance fiscal terms to attract E&P investment

We believe the Thai government will leverage on the key tools allowed by existing concession terms, including decommissioning conditions and its ownership of existing infrastructure, to negotiate the desired fiscal terms and gas prices in the new contracts. E&P contractors' (bidders) interests would be attractive returns and low investment costs from existing infrastructure in the areas.

Win-win scenario would be to retain existing E&P concessionaires

Our analysis suggests the win-win scenario for Thailand would be to retain existing E&P operators (Chevron and PTTEP) as participants in the new contracts, so that the government can leverage off their expertise and also maximise gas supply from the remaining reserves. This is given the challenging reserve replacement potential and geology of the gas reservoirs in Thailand. We also believe the Thai government will not be able to build expertise rapidly enough to nationalise the assets, given its lack of resources, especially human capital, in managing and operating the gas fields.

In our view, the win-win scenario for Thailand would be to retain existing E&P operators (Chevron and PTTEP)

Stock implications

PTT Exploration and Production (Buy, Bt150.00 PT) is focusing on expanding its producing asset portfolio in Southeast Asia. We think the company will be bidding in the new contracts given the strategic fit. We believe PTTEP is well positioned to participate and continue its operatorship of the Bongkot project, while it also has opportunities to participate in other contracts. We estimate upside NAV potential could range from Bt1.8/share to Bt31.8/share or 1% to 21% of our NAV-based price target which assumes Bongkot and Contract 3 will expire in 2022. The downside scenario for PTTEP is that it does not participate in any new contracts, which would lead to a 22% fall in production volume post-2022, but this would not have an impact on NAV.

PTTEP is well-positioned to capture long-term upside potential from domestic gas contracts, in our view

PTT Global Chemical (Buy, Bt75.00 PT) relies on wet gas from the Gulf of Thailand as olefin feedstock (the olefin-chain accounts for around 60% of its EBITDA). Our base case assumes no impact on PTTGC as we think supply disruption is unlikely. In the worst-case scenario, where the Thai government fails to have new bids and contracts in place a timely manner, we estimate the loss in gas feedstock could be 13% for PTTGC in 2019 and 23% in 2020. PTTGC could mitigate this impact by converting some of its internal LPG to feedstock.

PTT Public (Buy, Bt415.00 PT) converts cheap gas from the Gulf of Thailand and sells it to different customer groups under different pricing schemes. The gas sold to the power sector (58% of total) is under a cost plus scheme, while prices to the chemical and industrial sector are linked to oil and chemical prices. Our base case is neutral for PTT, as we think supply disruption is unlikely. In the worst-case scenario, where the Thai government fails to smoothly manage contracts, we estimate PTT's gas cost would increase by a 9.2% CAGR over 2017-22, implying 17-53% risk to PTT's core EBITDA. Also, PTT would need to accelerate its LNG terminal capacity expansion to increase LNG imports in light of lower domestic supply. We estimate LNG imports would increase to PTT's full capacity of 13mt in 2020E, should the government fail to manage the concessions by 2017E.

Implications for the power sector

We believe power regulators will continue to push for fuel diversification in favour of coal and renewable energy

PPAs in Thailand provide for 100% fuel cost pass-through, which shields IPPs from fuel cost risks. Hence, we do not expect any major earnings risk to existing IPPs from rising gas prices. However, if power prices increase above a comfortable level (that is, above the 3.38% power tariff CAGR over 2004-14), it could reduce demand in the medium term. This could also lead to lower returns in new PPAs. On the other hand, higher gas prices would strengthen the regulators' push for coal-based capacity, when new capacity is needed. Currently, EGAT is supposed to build all new coal-based plants. If it fails to execute on this large scale, which is possible given its track record with coal, private IPPs may have the opportunity to develop some plants. However, with a higher-than-desired current reserve margin, we expect few growth opportunities for IPPs in near term.

GLOW could be a major beneficiary if new coal-based power capacity is tendered

Glow Energy (Buy, Bt100.00 PT): We believe GLOW is the most experienced in developing coal-based capacity among listed Thai IPPs and it also has effective management. GLOW has a limited mandate from its parent to develop projects only in Thailand and Laos. We believe this makes the company more aggressive in bidding for new coal-based projects. Currently, the company does not have any capex commitments and all its operating plants are contributing healthy cash flows. If new coal-based capacity is tendered, we would expect GLOW to be a frontrunner.

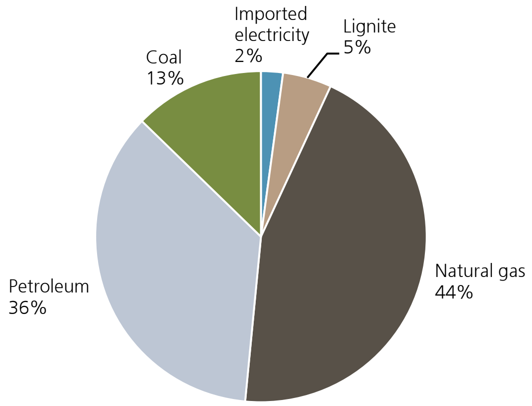
Electricity Generating Co (Neutral, Bt160.00 PT): EGCO owns the highest coal-based capacity among listed peers but still lacks the experience of developing this capacity from scratch, as it has acquired most of the capacity at the operational stage. However, the company is developing new coal-based capacity in the Philippines, which should provide it with some experience. We believe EGCO can also leverage its 50% stake in BLCP Power to win new coal-based capacity, when such opportunity arises.

Ratchaburi Electricity (Sell, Bt47.00 PT): RATCH does not own any coal-based asset in Thailand but it is developing a lignite-based plant in Laos. The first unit began operations in early June and the remaining two should become operational by mid-2016. For some years, RATCH has been struggling to add significant new capacity in the domestic market and has been expanding in overseas. This has resulted in an increase in its risk profile with deteriorating returns, especially from its Australia business. We believe it will take a few major successfully executed value-accretive investments for the stock to deserve a re-rating from the current level.

Thailand gas industry and demand

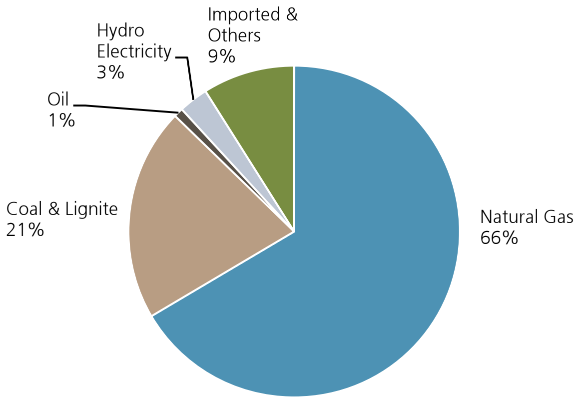
Gas is a key primary fuel for Thailand, accounting for 44% of the country's primary fuel consumption and 66% of its power generation.

Figure 1: Primary fuel used in Thailand



Source: Energy Policy & Planning Office (EPPO)

Figure 2: Power generation by fuel type



Source: EPPO

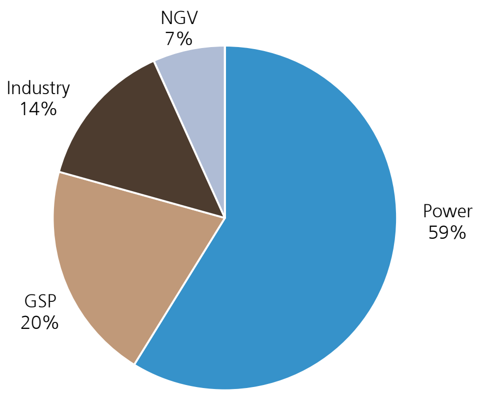
Gas demand should slow

Thailand's gas demand looks set to slow in the next five years, in our view. Strong economic growth, expanding chemical capacity, and the government's transportation gas subsidy drove the demand CAGR of 5.6% in the past five years (2010-14). We forecast demand growth to slow to 1.3% CAGR over 2015-19E (base case), driven by slower economic growth, a lack of chemical capacity expansion, and the subsidy removal on gas for transport sector.

Fuel diversification, slower economic growth, and subsidy removal should slow gas demand

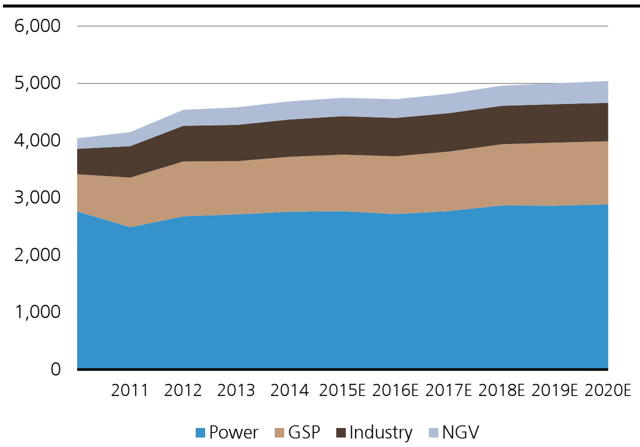
At 59%, the power sector accounted for the largest proportion of Thailand's gas demand in 2014, followed by chemical production (through gas separation plants, or GSPs) at 20%, the industrial sector at 14%, and transport (natural gas for vehicles, NGV) at 7% of total demand.

Figure 3: Gas demand breakdown, 2014



Source: PTT Public

Figure 4: Demand growth should slow in 2015-20E (mmcfd)



Source: PTT Public, UBS estimates

Slower demand growth in 2015-19E, particularly in the power sector, should be partly driven by limited supply and the government's strategy to reduce the reliance on gas fuel, in our view.

Figure 5: Gas demand growth (% CAGR)—base, bear and bull cases

	2010-14	2015-2019E		
	Actual	Base case	Bull-case	Bear-case
Power	2.3%	0.8%	1.2%	0.3%
GSP	9.9%	2.8%	2.8%	2.8%
Industry	11.9%	0.6%	0.6%	0.6%
NGV	18.9%	2.9%	3.1%	2.7%
Total gas demand	**5.6%**	**1.3%**	**1.6%**	**1.0%**

Source: PTT Public, UBS estimates

Figure 6: Gas demand forecasts—UBS base case

	2011	2012	2013	2014	2015E	2016E	2017E	2018E	2019E	2020E
Gas demand (mmcfd)										
Power	2,486	2,677	2,710	2,757	2,766	2,716	2,769	2,867	2,862	2,886
GSP	867	958	930	960	989	1,008	1,039	1,070	1,102	1,102
Industry	549	623	634	652	672	672	672	672	672	672
NGV	246	279	307	317	320	327	338	352	366	381
Total gas demand	**4,148**	**4,537**	**4,580**	**4,686**	**4,747**	**4,723**	**4,818**	**4,960**	**5,002**	**5,040**
% YoY										
Power	-10.0%	7.7%	1.2%	1.7%	0.3%	-1.8%	1.9%	3.5%	-0.1%	0.8%
GSP	33.7%	10.5%	-2.9%	3.2%	3.0%	2.0%	3.0%	3.0%	3.0%	0.0%
Industry	23.4%	13.5%	1.6%	3.0%	3.0%	4.0%	4.5%	4.5%	4.5%	4.5%
NGV	34.1%	13.3%	10.1%	3.4%	1.0%	2.0%	3.5%	4.0%	4.0%	4.0%
Total gas demand	**2.7%**	**9.4%**	**0.9%**	**2.3%**	**1.3%**	**-0.5%**	**2.0%**	**2.9%**	**0.8%**	**0.8%**
% of total demand										
Power	60%	59%	59%	59%	58%	58%	57%	58%	57%	57%
GSP	21%	21%	20%	20%	21%	21%	22%	22%	22%	22%
Industry	13%	14%	14%	14%	14%	14%	14%	14%	13%	13%
NGV	6%	6%	7%	7%	7%	7%	7%	7%	7%	8%
Total gas demand	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

Source: UBS estimates

Gas for the power sector

We forecast a 3.9% power demand CAGR but a 0.9% gas demand CAGR over 2014-36E

The power demand CAGR was 4.4% CAGR in Thailand over 2004-14, supported by an average real GDP growth rate of 3.9% over the period. We assume a long-term GDP growth rate of 4.0%, and we forecast a power demand CAGR of 3.9% over 2014-36.

Thailand has ignored coal for too long

Thailand has long been dependent on natural gas for power generation. We believe environmental opposition to coal and nuclear-based plants coupled with availability of reliable and cheap gas supply from domestic reserves led the regulators to focus primarily on developing gas-based power plants.

In the most recent IPP bidding round, concluded in 2013, bids for only gas-based projects were invited while coal was ignored. However, with the decline in domestic gas reserves, the regulators are now focusing on alternative fuels, including coal. We believe natural gas will lose market share to coal and renewable energy in power generation in Thailand.

We believe natural gas will lose market share to coal and renewable energy

But, the tide has now turned in favour of coal…and against gas

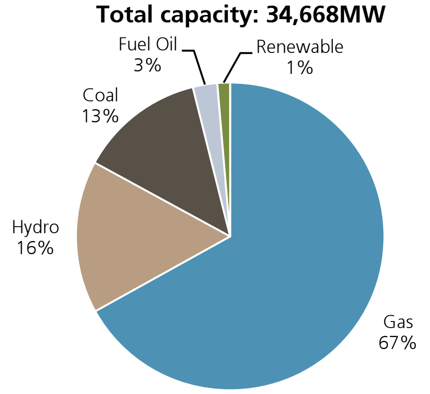
The regulators are finalising a revised version of the national power development plan 2015-2036 (PDP), which could be approved by end-June. Media reports have indicated that in the new version, regulators are targeting reduced dependence on gas for power generation. The reports also indicate that the proportion of gas-based capacity will decline from 67% to 40% and that of coal will increase from the existing 13% to 25% by 2036.

The new power development plan target lowering dependence on gas

We believe the PDP targets for gas and coal are optimistic. We expect the share of gas to decline to 52% and that of coal to increase to 17% by 2036. This implies construction of 16,400MW new gas-based capacity and 8,200MW coal-based capacity over 2015-36E.

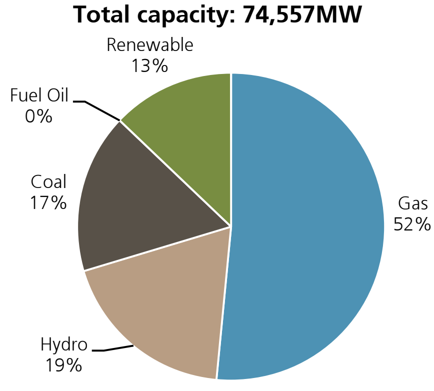
We estimate that to reduce the share of gas to 40% by 2036 would require the cancelling many previously planned gas plants while increasing the rate of coal-fired power plant construction substantially (more than 11,000MW). We maintain our view that every new coal-based plant will be a challenge due to environmental concerns. We expect the regulators to overcome this opposition by educating people on the benefits of the latest clean coal technologies, which emit very low pollution. We also believe that with the current military government, which is not dependent on votes, the regulators will receive support to reform the power sector by slowly diversifying away from 'politically safe' gas to 'politically risky' coal.

Figure 7: Capacity breakdown—2014



Source: Electricity Generating Authority of Thailand, Energy Policy and Planning Office, Thailand, UBS estimates

Figure 8: Capacity breakdown—2036E



Source: Electricity Generating Authority of Thailand, Energy Policy and Planning Office, Thailand, UBS estimates

Hydro and renewable energy could help, but not nuclear

Thai regulators have long targeted tapping the hydropower potential of Laos, and have succeeded in diversifying capacity mix to some extent. Currently, around 16% of Thailand's installed capacity is hydro based, mostly located in Laos. However, execution of projects in Laos most recently has slowed due to delays in regulatory approvals and issues of multiple sovereign claims on river water. Nonetheless, we believe Thai IPPs are in a relatively better position, than operators from other countries, to harness Laos's hydro potential due to their business connections and better historical relations between the two nations.

We continue to assume that construction of nuclear power plants will be difficult even for a military government. Hence, we have not included nuclear power in our estimates, even though the previous version of PDP had assumed the first nuclear plant would begin operations by 2026. We do not think there has been any progress on this plant.

Figure 9: UBS estimates for Thailand power capacity mix

Capacity mix (fuel type, MW)	2014	2015E	2020E	2025E	2030E	2036E
Natural Gas	23,198	26,525	26,713	32,621	38,508	38,418
Coal/ Lignite	4,556	5,538	7,359	8,600	9,860	12,514
Hydro (incl Laos)	5,560	5,612	8,050	9,563	10,969	14,021
Renewable & others	163	863	3,649	5,077	6,305	9,305
Fuel Oil	891	891	891	891	315	-
Nuclear	-	-	-	-	-	-
Import (ex-Laos hydro & coal)	300	300	300	300	300	300
Total	**34,668**	**39,729**	**46,962**	**57,051**	**66,256**	**74,557**
Ratio:						
Natural gas	67%	67%	57%	57%	58%	52%
Coal/lignite	13%	14%	16%	15%	15%	17%
Hydro (incl Laos)	16%	14%	17%	17%	17%	19%
Renewable & others	0%	2%	8%	9%	10%	12%
Fuel oil	3%	2%	2%	2%	0%	0%
Nuclear	0%	0%	0%	0%	0%	0%
Import (ex-Laos hydro & coal)	1%	1%	1%	1%	0%	0%
Total	100%	100%	100%	100%	100%	100%

Source: Electricity Generating Authority of Thailand, Energy Policy and Planning Office, Thailand, UBS estimates

Gas demand estimates

We forecast gas demand from the power sector under three scenarios—base case, upside and downside:

Our base case assumes a 0.9% CAGR for gas demand from the power sector

- **Base case:** we assume 4% long-term GDP growth, lower coal-based capacity construction than indicated in media reports, several new gas plants but no nuclear power.
- **Upside:** we assume a long-term GDP growth rate of 4.5%, very little coal-based capacity construction, more new gas plants than envisioned in the new PDP, no nuclear power and no phasing out of any gas plant (other than scheduled retirement).
- **Downside:** we assume a long-term GDP growth rate of 3.5%, significant building of coal-based capacity but no new gas plant (in addition to the plants proposed in the old PDP), no nuclear power and several inefficient gas-based EGAT plants being phased out (before scheduled retirement).

Figure 10: Gas demand estimates for the power sector

MMCFD	2014A	2015E	2020E	2025E	2030E	2036E
Base case	2,757	2,766	2,886	3,234	3,800	4,858
Upside	2,757	2,766	2,974	3,443	4,257	5,859
Downside	2,757	2,766	2,812	3,055	3,183	3,931

Source: Electricity Generating Authority of Thailand, Energy Policy and Planning Office, Thailand, UBS estimates

Implications from expensive gas on the sector

Typically, Thai PPAs provide for 100% fuel cost pass-through and focus on plant availability for revenue payment than actual generation. This protects Thai IPPs from any fuel cost or demand risk. Hence, we do not expect any major earnings risk to existing IPPs from rising gas prices. However, if fuel prices (and in turn power prices) increase above a comfortable level (say above the 3.38% power price CAGR over2004-14), this could impact demand in the medium term leading to lower supply. This could also lead to lower returns in new PPAs, as the regulators will attempt to control costs. For the capacity tendered in the last IPP bidding round in 2013, we believe the equity IRR offered were in low double digits. In any case, we believe growth opportunities with be few in Thailand in the near term, due to the higher-than-desired current reserve margin.

Higher gas price will not impact power companies' near-term earnings, but could negatively impact medium-term demand

On the other hand, an increase in gas prices will strengthen the regulators' push for coal-based capacity, when new capacity is needed. Currently, EGAT is supposed to build all new coal-based plants. However, we think it will be difficult for EGAT to execute on such a large scale—we estimate around 8,000MW new capacity by 2036—as it has failed in the past building around only 2,400MW until now. In this case, we think IPPs could be invited to build some or all of the plants. Hence, more growth opportunities, than currently visible, may be in store but with probably lower returns. In the company section, we discuss the positioning of the companies if coal-based capacity is tendered.

Rising gas prices would strengthen regulators' push for coal-based capacity

Gas supply and reserve situation

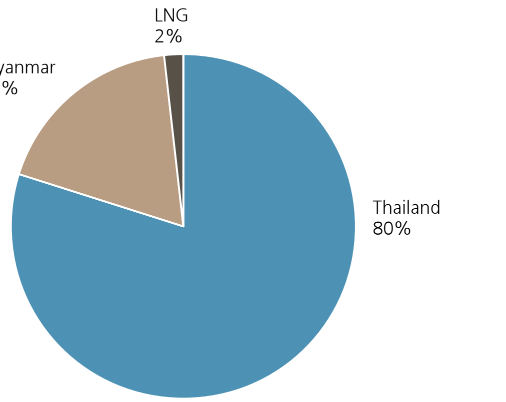
In Thailand, 80% of gas supply is from indigenous reserves (domestic gas fields). These fields have been producing for 8-35 years, and most of them are mature fields, having reached their production plateau. Thailand has been importing piped gas from Myanmar since 1998 (18% of total supply in 2014) and it has also been importing LNG since 2012 to meet growing demand.

Thailand gas reserve has fallen 25% in the past five years

Rapidly growing gas demand in Thailand, coupled with poor reserve replacement led domestic gas reserve (1P and 2P) to fall by an average 5% pa from 2007 to 2013 (25% fall in absolute boe). We attribute this to unexciting discovery prospects and, to a lesser extent, the government's slow progress in awarding E&P concessions. The latest round of E&P concession bids in Thailand was eight years ago in 2007.

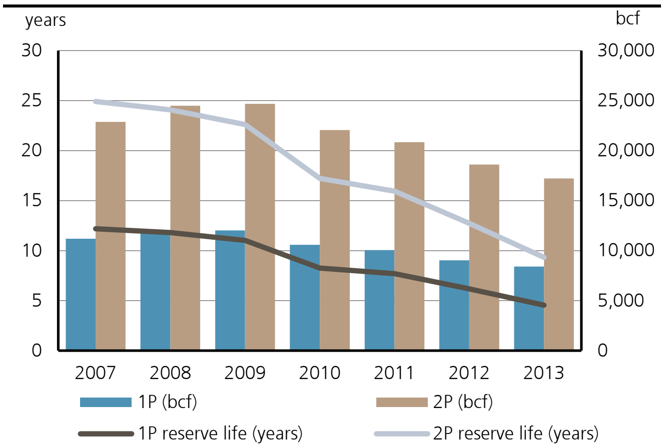
Based on the latest gas reserve data (2013), Thailand 1P and 2P gas reserve life would last only five and nine years, respectively.

Figure 11: Thailand gas supply by source (2014A)



Source: PTT Public

Figure 12: Thailand gas reserves and reserve life



Source: Department of Mineral Fuel

Poor reserve replacement and exploration record

The Thai government has been slow in awarding E&P concessions

With recent demand and production growth, Wood Mackenzie estimates that Thailand has replaced only 23% of its 2.3bn boe of oil and gas reserve produced in the past 10 years.

Thailand also had a poor exploration record over the past decade. According to a Wood Mackenzie survey, the average discovery size in Thailand is the smallest in Southeast Asia at 7mmboe. Exploration activity on the 53 blocks awarded in 2005-2010 has failed to turn up any significant discoveries to date.

Upstream crisis and politics

Some groups favour nationalisation of E&P assets…

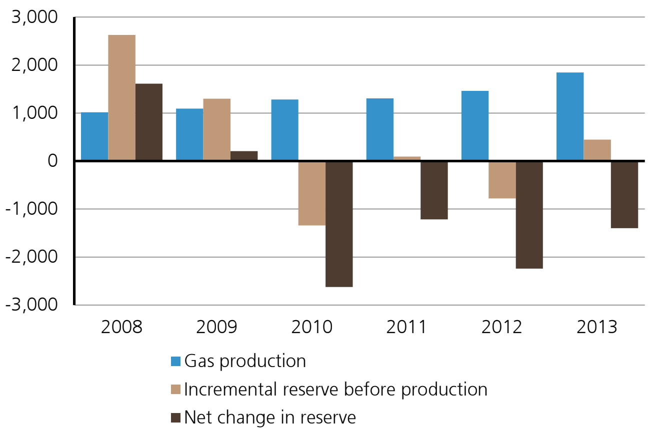
Thailand last launched its licensing round in 2007 (65 blocks, 20th licensing round). The government has been planning to launch the 21st licensing round since 2011. However, plans were blocked and delayed by the political and environmental protests. However, the military government launched the tenders for the 21st round in October 2014.

It later delayed closing the bid just before the deadline in February 2015, due to opposition to the fiscal terms. Activist groups have demanded that the government change the existing concession regime to PSC (production-sharing contracts). The decision on the fiscal regime for licensing round 21 will be key in determining fiscal terms for the new contracts as well, in our view.

...however, doing so would put future gas supply at risk

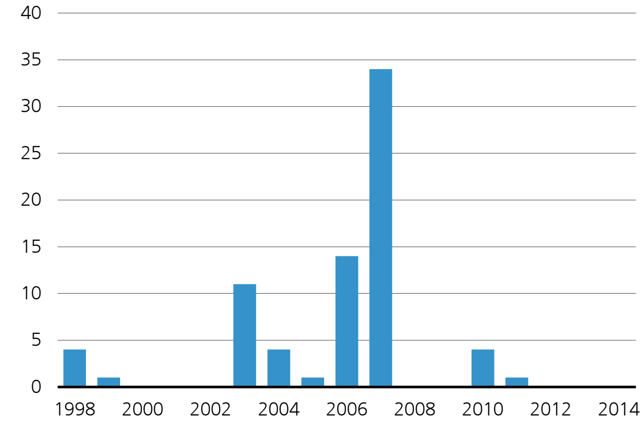
The Thai government will have to balance the country's upstream outlook with the political agenda, in our view. Further delay in the new licensing round and too stringent fiscal terms could add to the risk for the country's already bleak and poor upstream oil and gas exploration and reserve outlook.

Figure 13: Thailand's 2P reserve replacement (bcf)



Source: DMF, UBS

Figure 14: Number of E&P blocks awarded in Thailand



Source: Wood Mackenzie

Four expiring gas concessions

Four key gas concessions in the Gulf of Thailand—Bongkot, Contract 1, Contract 2, and Contract 3 areas—will expire in 2022. The Bongkot concession is majority-owned and operated by PTTEP, while Contract 1, 2 and 3 concessions are majority-owned and operated by Chevron.

The four expiring gas contracts are Contracts 1, 2, 3 and Bongkot

Figure 15: Key gas fields supplying Thailand

Project/ Block	Production (mmcfd) 2014A	Remaining gas reserve (2P) (bcf, at Jan 2015)	Production starts in	Concession expires in	% of total reserve	% of total Production	2P reserve R/P ratio
Domestic							
Bongkot	861	4,011	1993	2022	22%	21%	13
Contract 3 area	677	2,635	1992	2022	14%	16%	11
Contract 2 area	472	1,820	1983	2022	10%	11%	11
Pailin	375	1,497	1999	2038	8%	9%	11
Contract 1 area	245	1,107	1981	2022	6%	6%	12
Arthit	215	1,274	2008	2050	7%	5%	16
Simphuhorm	107	540	2006	2031	3%	3%	14
Benchamas (B8/32)	101	706	1997	2027	4%	2%	19
Sirikit	27	74	1983	2031	0%	1%	7
Namphong	13	21	1991	2033	0%	0%	4
Malaysia-Thailand Joint Development Area (MTJDA)*							
A 18**	365	1,570	2005	(PSC)	9%	9%	12
B 17**	321	930	2010	(PSC)	5%	8%	8
Myanmar							
Yadana	760	2,636	1998	(PSC)	14%	18%	10
M9	91	1,967	2014	(PSC)	11%	2%	59
Yetagun	344	1,440	2000	(PSC)	8%	8%	11
Total	4,113	18,215					12

Note: For MTJDA"s A18 and B17 block, the reserve is split between Thailand and Malaysia.
Source: Wood Mackenzie, Department of Mineral Fuels, PTTEP, UBS

Figure 16: Location and concessionaires of key gas fields supplying Thailand

Project/ Block	Location	Owner
Domestic		
Bongkot	Gulf of Thailand	44.45% PTTEP, 33.33% Total, 22.22% BG
Contract 3 area	Gulf of Thailand	71.25% Chevron, 23.25% MOECO, 5% PTTEP
Contract 2 area	Gulf of Thailand	70% Chevron, 30% MOECO
Pailin	Gulf of Thailand	60% PTTEP, 35% Chevron, 5% MOECO
Contract 1 area	Gulf of Thailand	80% Chevron, 20% MOECO
Arthit	Gulf of Thailand	Arthit: 80% PTTEP, 16% Chevron, 4% MOECO; Aithit North: 100% PTTEP
Simphuhorm	Onshore Thailand	35% Apico, 55% PTTEP, 10% Exxon
Benchamas (B8/32)	Gulf of Thailand	51.6% Chevron, 25% PTTEP, 16.7% MOECO, 4.6% Kris Energy, 2% Sophonpanich
Sirikit	Onshore Thailand	100% PTTEP
Namphong	Onshore Thailand	80% Exxon Mobil, 20% PTTEP
Malaysia-Thailand Joint Development Area (MTJDA)		
A 18	Gulf of Thailand	50% Hess, 50% Petronas
B 17	Gulf of Thailand	50% PTTEP, 50% Petronas Carigali
Myanmar		
Yadana	Myanmar	31.24% Total, 28.26% Chevron, 25.5% PTTEP, 15% MOGE
M9	Myanmar	80% PTTEP, 20% MOGE
Yetagun	Myanmar	40.9% Petronas, 20.46% MOGE, 19.32% Nippon Oil, 19.32% PTTEP

Source: Wood Mackenzie, Department of Mineral Fuels

Reserve prospects and geology of the gas fields

These concessions have been producing gas for the past 22-34 years (22-23 years for Bongkot and Contract 3, 32-34 years from Contracts 1 and 2). They are mature fields, with no production growth.

Based on Wood Mackenzie's 2P and technical remaining reserves estimates, their average reserve life is 12 years. This is longer than the concession of seven years. Assuming the concessions are extended, Wood Mackenzie estimates the reserves should be sufficient to extend production for a further 10 years after concession expiry. We believe there could be upside to reserves, pending the concession terms, gas price, and exploration results. For example, a higher gas price and a more favourable tax regime could allow operators to drill deeper wells to extract reserves in some areas. On the other hand, non-compelling fiscal terms and high E&P costs could discourage ongoing investment and reserve growth.

Our checks with PTTEP (operator of Bongkot, and with a 5% working interest in Contract 3) lead us to believe that operators could maintain the current production rate until at least 2020, based on existing reserve profiles and assuming existing operators continue to invest until then (that is, smooth contract management by the government).

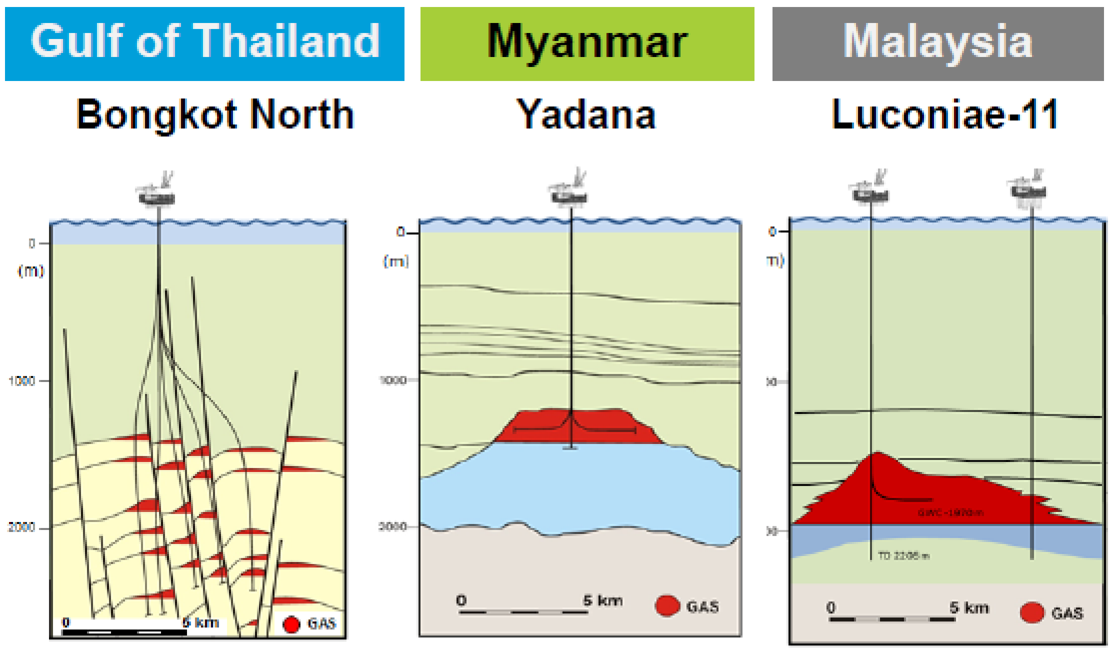
A delay in concession decision could lead to a sharp fall in gas production as early as 2017-18

Once drilling (or capex) stops, reserves could fall very rapidly

Reserve replacement in the Gulf of Thailand is more challenging than other gas fields in other Southeast Asia countries (for example, Myanmar or Malaysia), due to geology, in our view. The Pattani and Malay basins, where these four gas fields are located, comprise many small gas reservoirs with rapid depletion rates. This requires ongoing exploration efforts to replace reserves to maintain production (to meet or marginally exceed daily contract quantity [DCQ] commitments). In other words, producers need to keep exploring and drilling new development wells to extract gas from new reservoirs and maintain production at the DCQ level. A small reservoir implies rapid depletion of reserves.

Once operators stop drilling, reserve and production could fall rapidly below DCQ, resulting in a gas supply shortage in Thailand.

Figure 17: Gas reservoirs—in Myanmar a large reservoir which could rely on only 1-2 production wells. Small gas reservoirs in the Gulf of Thailand require ongoing drilling to extract gas from the reservoirs



Source: PTTEP

The decision on the new gas concessions (which will replace the expiring ones) and the timing are therefore critical. We believe any further delay in the government's decision could lead E&P operators to reduce capex; E&P companies typically plan their capex five years ahead (exploration and development period combined). This means gas production could fall as soon as capex falls.

Their importance to Thailand

We believe these four gas concessions are important to Thailand on five fronts.

The four gas fields are important to Thailand in terms of economic growth, energy supply, and industrial cost competitiveness

- **Supply:** The four fields contributed 57% of domestic gas supply and 45% of Thailand's total gas supply (including gas imports) in 2014.
- **Government revenue:** We estimate they contributed Bt126bn to government revenue in 2014 (Bt108bn from taxes and royalties, plus Bt18bn annual special remuneration revenue [SBR]).
- **Source of cheap gas:** The average gas price of the four fields was 41% below the price of imported gas from Myanmar, and 52% below the contracted LNG price. In 2014, the weighted average price in the four expiring gas field contracts was US$7.1/mmbtu, compared with the average domestic gas price of US$7.3/mmbtu, the imported Myanmar gas price of US$12.0/mmbtu, and the imported LNG price of US$14.6/mmbtu (actual imported price by PTT).
- **Industrial production cost and power price:** As the power tariff structure is under a cost-plus (pass-through fuel cost) mechanism, cheap gas in Thailand contributes to the cost-competitiveness of the industrial sector. Falling domestic gas production, which results in the overall gas price increasing with the proportion of imported gas rising, should drive power tariffs and industrial production costs higher.

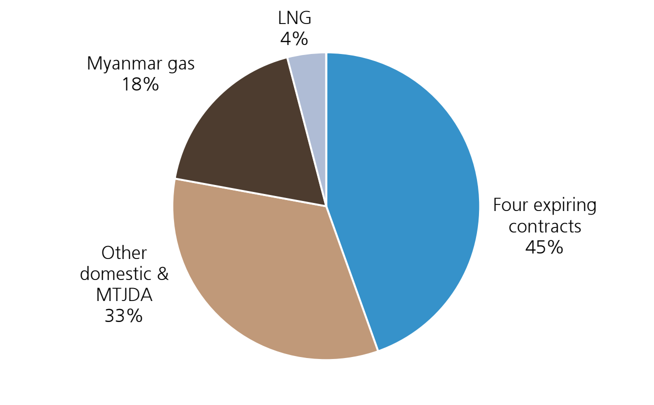
- **Petrochemical sector:** We estimate gas-based olefin products account for 15% of Thailand's petrochemical output (mid-stream). Petrochemicals accounted for 6% of Thailand's export value in 2014, and contributed employment and raw materials to the manufacturing sectors in Thailand, especially the automotive industry.

Figure 18: Four expiring concessions contribute significant gas supply and government revenue to Thailand

Project	Production (mmcfd) 2014A	Remaining 2P (bcf)	% of total domestic reserve	% of total domestic production	Govt revenue* Bt m, 2014e	Remaining NAV* (Bt m) Thai government	Remaining NAV* (Bt m) E&P Concessionaries
Bongkot	861	4,011	22%	21%	44,368	213,530	200,837
Contract 3 area	677	2,635	14%	16%	39,231	193,080	183,081
Contract 2 area	472	1,820	10%	11%	15,892	116,264	119,859
Contract 1 area	245	1,107	6%	6%	8,619	71,938	69,160
			53%	55%	108,109	594,812	572,937

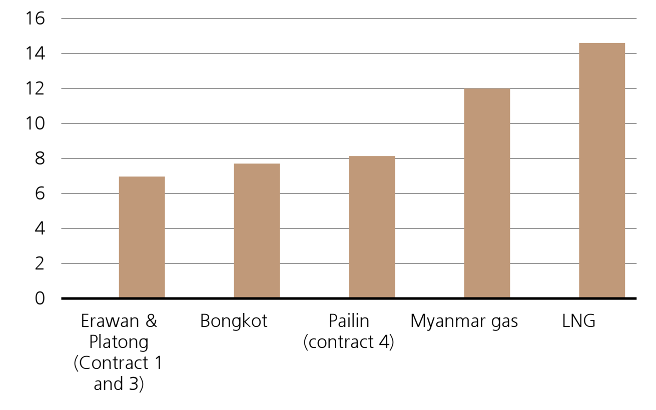
Note: *Combines royalties and taxes, but excludes special remuneration.
Source: PTT Public, Wood Mackenzie, UBS estimates

Figure 19: Four expiring contracts (% of total gas supply, 2014)



Source: PTT Public, Wood Mackenzie, UBS estimates

Figure 20: Gas price comparison—gas from expiring contracts cheaper than other domestic and imported gas



Source: Petroleum Institute of Thailand (PTIT), UBS

Delaying contract decision could cause problems

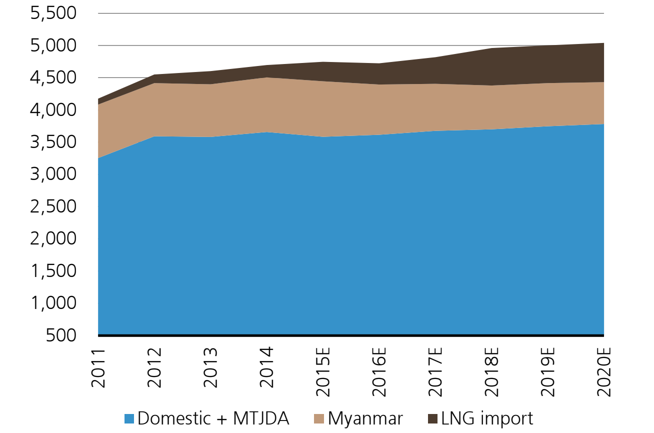
Given the importance of the gas contracts for Thailand, a delay in a decision on concession management could adversely impact Thailand in many ways. This includes a gas supply shortage, its fiscal position, trade and the current account balance, inflation and the competitiveness of the industrial sector.

Higher LNG import and possible supply disruption

A delay in contract management could cause a gas supply shortage

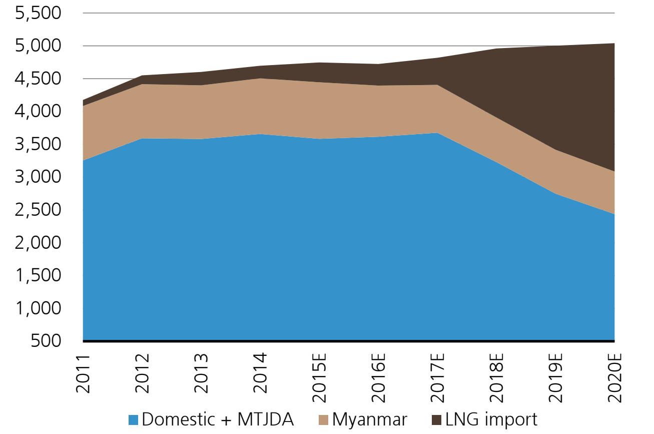
If the government fails to decide on concession management by 2016, we estimate domestic supply would start declining from 2018 onwards, due to the cessation of investments ahead of contract expiration. In this case, we estimate LNG imports would increase from 191mmcfd (1.3tpa) in 2014 to 7mt in 2018. A further delay in concession management to 2018 could lead to supply disruption after 2020, as the required LNG imports (10.6mt in 2019E and 13mt in 2020E) would reach PTT's LNG terminal capacity of 13mt (5mt completed and 8mt under construction). In an upside demand growth scenario, we estimate LNG imports would reach 7.3/11/13.7mt in 2018E/2019E/2020E.

Figure 21: Gas supply forecasts assuming smooth concession management decision (mmcfd)



Source: PTT Public, Wood Mackenzie, UBS estimates

Figure 22: Gas supply forecasts assuming government fails to make a decision before 2017E (mmcfd)



Source: PTT Public, Wood Mackenzie, UBS estimates

Higher gas and electricity prices

Since the domestic gas price is much lower than the imported gas price, replacing domestic supply with LNG imports would more than double gas price inflation by 2020E, in our view. We estimate the gas price would increase to US$11.1/mmbtu by 2020E if the Thai government fails to manage concessions and operators consequently stop investing in the fields.

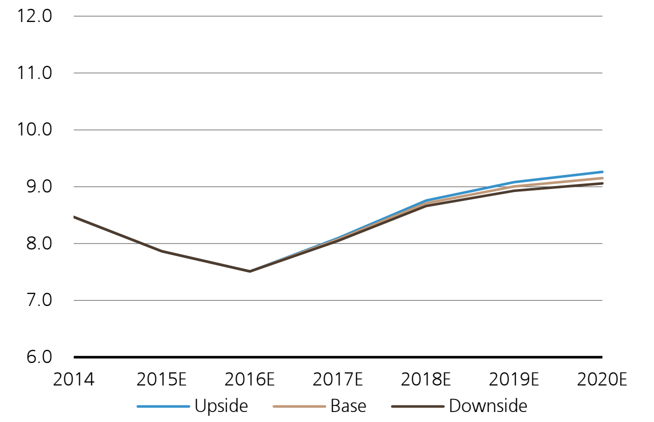
It would push up power tariffs and industrial production costs

Figure 23: Gas price increase and sensitivity

	2015-20E (5-year CAGR)		
	Base case	Upside	Downside
Smooth contract management	3.1%	3.3%	2.9%
No/delayed contract decision	7.1%	7.3%	7.0%

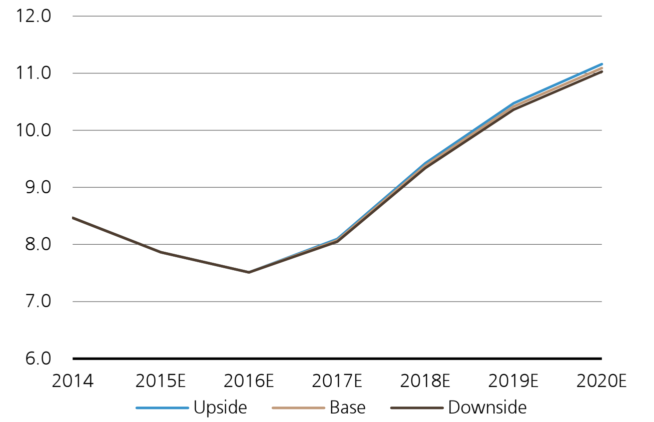
Source: UBS estimates

Figure 24: Gas price (US$/mmbtu)— smooth contract management (no domestic supply disruption)



Source: PPT Public, UBS estimates

Figure 25: Gas price (US$/mmbtu)—delay in contract decision leads to supply disruption



Source: PPT Public, UBS estimates

Power price sensitivity: As Thailand's electricity tariff is under a fuel cost pass-through structure and is adjusted every four months to reflect changing fuel costs, the increase in the gas price would affect power tariffs and inflation.

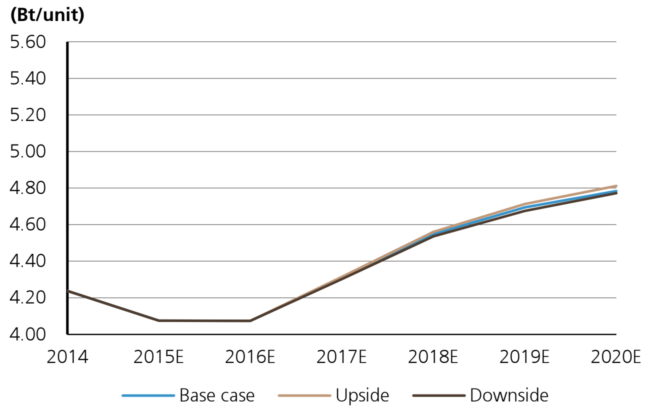
Our analysis suggests that if the expiring gas concessions are renewed, power price increases in the next five years should be within the historical range. The regulators should be able to increase the power tariff in line with the increase in fuel costs. However, if the concessions are not renewed, expensive LNG gas may drive power tariffs above the comfortable level and the government may need to offer some subsidy to consumers.

Figure 26: Power price sensitivity to gas price change—residential segment

	2004-14 CAGR	2015-20E CAGR		
	Historical	Downside	Base case	Upside
With gas concession extension	3.38%	3.21%	**3.26%**	3.38%
Without gas concession agreement	3.38%	5.54%	**5.54%**	5.60%

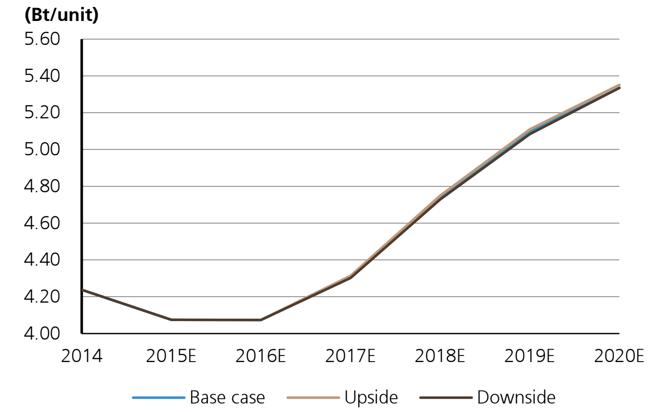
Source: Electricity Generating Authority of Thailand, Energy Policy and Planning Office, Thailand, UBS estimates

Figure 27: Electricity price—smooth contract management (no domestic supply disruption)



Source: Metropolitan Electricity Authority, Thailand, UBS estimates

Figure 28: Electricity price—delay in contract decision leads to supply disruption



Source: Metropolitan Electricity Authority, Thailand, UBS estimates

Loss in government revenue and trade deficit

We estimate failure to manage the concessions smoothly could reduce the trade balance by Bt86-256bn in 2018-20. The government could risk losing Bt24.6-67.4bn in revenue from loss of petroleum tax and royalties.

Figure 29: LNG import value and incremental import value if failing to manage contract smoothly

Bt m	2015E	2016E	2017E	2018E	2019E	2020E
Smooth contract management	49,528	57,101	74,089	106,396	109,359	115,999
No or delay in contract decision	49,528	57,101	74,089	192,598	295,888	372,264
Increase in LNG import value	-	-	-	86,202	186,530	256,265

Source: UBS estimates

Figure 30: Government revenue from four expiring contracts and the loss if managing concessions is not smooth (excluding revenue from SBR)

Bt m	2015E	2016E	2017E	2018E	2019E	2020E
Smooth contract management	94,722	98,216	110,553	120,543	117,399	113,141
No or delay in contract decision	94,722	98,216	110,553	98,846	69,953	45,666
Govt revenue loss	-	-	-	21,697	47,446	67,474

Source: UBS estimates

Analysis and scenarios for contract management

Thailand upstream concessions

Thailand's E&P concession is governed by the Petroleum Act, which regulates the concession life, fiscal regime, decommissioning conditions, and environmental-related requirements.

The four concessions are under the Thailand 1 fiscal regime, which was introduced when Thailand first established its upstream industry in 1971. Subsequently, the regime was adjusted and evolved to Thailand 2 and Thailand 3, which mainly imposed higher taxes and royalties. After Thailand 2 was introduced with too high a tax cost, there was no investment in Thailand's upstream sector. As a result, the government introduced Thailand 3 regime, which has been the regime governing new upstream concessions since 1989.

Figure 31: Thailand E&P fiscal regimes

Fiscal regime	Royalties (% of revenue)	Petroleum tax (% of net profit)	Other payment/ key terms
Thailand 1	12.5%	50%	None
			Royalties applied for domestic sales can be credited as tax expense
Note: Contract 1, 2, 3 and Bongkot concessions are under Thailand 1, plus extra annual lump sum payment			
Thailand 2	12.5%	50%	(1) Annual bonus payment to government
			Production Annual bonus
			10-20kboed 27.5% of revenue
			20-30kboed 37.5% of revenue
			>30kboed 43.5% of revenue
			(2) Annual benefit
			Deductibles (for petroleum tax calculation) must not exceed 20% of annual revenue
Note: There are no commercial projects under Thailand 2 regime due to unattractive fiscal terms			
Thailand 3	Accelerating rate	50%	(1) Special remuneration benefit (SRB) or windfall profit tax
	0-60kboed -> 5%		based on revenue/accumulated depth of wells drilled
	60-150kboed -> 6.25%		(2) Royalty fees and SRB can be deducted from tax revenue, but cannot be credited as tax expense
	150-300kboed -> 10%		
	300-600kboed -> 12.5%		
	> 600kboed -> 15%		

Source: Department of Mineral Fuels

Four expiring concessions and their key terms

The key terms of the expiring concessions, which are under the Thailand 1 regime, include:

- **Existing concessions cannot be extended:** According to Thailand's Petroleum Act, the exploration period for concessions under the Thailand 1 fiscal regime must not exceed 12 years and the production period must not exceed 40 years (30 years, plus 10 years extension).

  Contracts 1, 2, 3 and Bongkot were granted extensions in 2007 and will not be extended further under the existing concession terms. This is one of the reasons for Thai government to amend the petroleum act to enable smooth management of the concessions.

Generous fiscal terms: The fiscal terms of Thailand 1 regime, which were set when Thailand first discovered and developed indigenous gas fields, are relatively favourable compared with international standards and Thailand's existing Thailand 3 fiscal regime. At the time, generous terms were introduced to attract investment and compensate development risks. The generous fiscal terms of the Thailand 1 regime are unlikely to be repeated, in our view.

- **Condition for decommissioning:** According to the Petroleum Act, after the concessions expire, the government has the right to own all the assets (including platforms, equipment, wells, etc) in the concession areas. The Department of Mineral Fuel (DMF) has the right to order concessionaires to decommission all wells and equipment. The burden of decommissioning could be borne by concessionaires, or DMF could collect the decommissioning cost from concessionaires and do the decommissioning work itself.

We think the decommissioning conditions provide the Thai government with flexibility to decide on the expiring contracts. For example, the government could rightly claim ownership over all assets and allow new concessionaires/contractors to use them. Or, it could collect the decommissioning costs from existing concessionaires but keep them to use later, while maintaining the assets in the areas for future use.

Government's stance and progress so far

Higher government stake, change in fiscal terms, and new tenders are likely

We think the Thai government realises the urgency and importance of this issue to the country. Thailand's National Energy Policy Committee (NEPC) on 14 May 2015 agreed on broad guidelines to manage the gas concessions in the Gulf of Thailand. The prime minister has set a 12-month timeline for the energy ministry to decide on concessions.

The four key guidelines agreed by the NEPC are:

(1) The government should take a higher share in these gas fields

(2) Development of the gas fields should continue to prevent supply disruption

(3) Thailand should be open to participation by existing operators and new investors. This should be done in parallel with the terms under the amended Petroleum Act.

(4) The government should prudently manage the sharing of benefits in the best interests of the country and its people.

Amending the Petroleum Act

The management of the new gas contracts will be done in parallel with amendments to the Petroleum Act. The amendments should allow the government to apply new terms or fiscal regimes to new contracts, including the new licensing round 21 (which has been delayed since February 2015) and the management of gas concessions.

We attended a public hearing on the Petroleum Act amendment on 7 May 2015. The key points discussed in the proposal were as follows. Not all the proposals will be accepted in their current form, as they will be amended and proposed to the National Legislative Assembly of Thailand (NLA), which will pass the law.

Adding options or more systems for upstream contract management

Instead of only using the concession system, the NLA has proposed that Thailand add production-sharing contracts (PSCs) and service contracts as options for E&P contract management.

New fiscal scheme such as PSC and service contracts could be added, on top of the existing concession system

To facilitate the new fiscal framework, at a later stage after the amendments, the government might establish a committee or a working group, which will be responsible for setting up or negotiating contract terms. Eventually, if necessary, it may consider establishing a new national oil company to govern or participate in the contracts.

Possible changes in fiscal terms; raising government stake and revenue

The proposals also involve a change in the existing fiscal terms of the concession system. While a concrete proposal has not been discussed, it is clear that the government and the NLA understand that Thailand will need to adjust its fiscal terms so that it remains attractive to private investors and major oil companies. This is due to the country's relatively poor resource potential (mature basins in the Gulf of Thailand).

Contract management scenarios

While the decision on concession management and the expiring contracts can vary in detail, we highlight key options the government might consider:

There are many options for the Thai government to manage the concessions

Scenario 1: Let the concessions expire and introduce service contracts to replace the expiring concessions. We think this option is extreme. It has been discussed by a group of activists, who are against the existing concession system in Thailand and would like to nationalise petroleum assets.

The only positive of this option, in our view, is that it would please the activists and reduce political noise. Nonetheless, doing so could damage economic growth and resource potential in the medium to long term. The nature of the service contract would probably not be attractive to E&P companies, as it implies a low return on investment, especially for mature fields which have limited reserve upside. This would discourage future investment, discourage further exploration efforts and the development of the upstream sector, as well as lead to a gas deficit and macroeconomic problems discussed above.

Scenario 2: Launch a new round of bids, with changes to the fiscal term/regime. Based on NEPC's broad guidelines, we think the government might be open to a new round of bidding on the expiring contracts and introduce a new fiscal regime/term. We believe this would allow the adjustment of fiscal terms that are more favourable to the government and might at the same time be viewed by NGOs as being reasonable.

However, a key drawback of this option is potential gas supply disruption. New bids would mean uncertainty for the existing concessionaires (i.e. uncertain if existing concessionaires will be selected). This would lead existing concessionaires to stop exploration capex investment ahead of the expiration. As a result, Thailand could still face a domestic gas supply shortage for five to 10 years before production from the new investors begins. This is not what the government would want, in our view.

Scenario 3: Involve existing concessionaires in the new contracts. The government could manage the negative impact of a medium-term supply shortage by involving existing concessionaires (PTTEP and Chevron) in the new concessions. By doing so, PTTEP and Chevron could continue investing and ensure ongoing production of gas in 2018-22. Aside from ensuring medium-term supply, we think the advantage of this option is that the government could continue to benefit from Chevron and PTTEP's expertise in maximising gas reserves and supply from the key mature fields.

Scenario 4: Combination of scenario 2 and agreement with the existing concessionaires: We think the Thai government could launch a new round of bids without interrupting medium-term supply by ensuring ongoing investments by existing concessionaires and gas productions in 2018-2022. Decommissioning costs and incentives to participate in the new contracts could be the key tools the government could leverage on, in our view.

What's in it for Thailand's government?

We highlight two key factors which we believe will influence the government's decision on concession management, including: 1) government interests in these contracts; and 2) its key negotiation tools with existing concessionaires or new bidders.

We believe the government would want to avoid supply disruption, increase long-term supply security, raise taxes, and reasonable gas prices

Thai government's interests

(1) **No or little medium-term supply disruption:** Lower domestic gas production would cause significant damage to Thailand, in terms of macroeconomic, fiscal strength, and industrial cost competitiveness. We think the cost of supply disruption is too high for the government to let this occur.

(2) **Long-term supply security and/or government participation:** Given the advantage of domestic resources and to maintain supply security, we think the government will want to ensure that Thailand maximises the value of its domestic gas resources by extracting as much reserve as possible from the fields. Although E&P companies' interest is mainly financial return, we think the government would work together with the operators and concessionaires to ensure that they continue to extract as much gas as possible, despite a lower return when the fields are in declining stage.

(3) **Higher tax revenue:** As highlighted earlier in the report, the Thailand 1 fiscal regime was more generous to concessionaires than the current Thailand 3 fiscal regime. The government might adjust fiscal terms such that it could gain more revenue from these key fields. However, it also needs to balance this with its interest in maximising the value of gas resources. Too high a tax rate would be a disincentive for E&P companies to extract the remaining gas reserves from these fields.

(4) **Gas price:** As gas remains the key fuel source for Thailand's power and industrial sectors, we think the government might want to maintain the gas price at a reasonable level.

The government's negotiating tools

To achieve its goals, we highlight several tools government could use in its negotiations with concessionaires and contractors.

(1) **Infrastructure:** According to the law, the government has ownership over all infrastructure in the concession areas. The government could allow the new concessionaires and contractors to use the existing infrastructure which would help save capex.

(2) **Decommissioning costs:** If the government allows existing concessionaires (Chevron and PTTEP) to participate in the new concessions and contracts, it could allow both companies to defer commissioning costs further. According to existing law, Chevron and PTTEP must decommission all assets, or compensate the government for the decommissioning costs at the end of concession.

(3) **Fiscal terms and incentives, including gas price:** Fiscal terms and gas prices will determine E&P companies' financial returns. It would also be key factors in incentivising E&P companies to continue to maximise gas reserves and production from the fields.

In case E&P companies need to leverage higher technology and investment to extract gas from the fields, it is possible that the government would need to raise the gas price to compensate the companies with a fair return.

What's in it for existing concessionaires?

Based on our checks, we believe both Chevron and PTTEP would continue their investments in these fields, pending clarity on fiscal terms, as they believe there could be potential reserve upside.

Reasonable financial return, low capex, and low project risk would attract E&P investors

Although these are mature fields without large reserve upside, the positives, in our view, include: 1) limited capex on infrastructure as all the platforms and infrastructure exists; 2) low risk and lifting cost (US$2-4/bbl); and 3) decommissioning costs could be deferred.

PTTEP believes there are more gas reservoirs in the Bongkot area that are not commercial under current fiscal terms and gas prices. These are, for example, smaller reservoirs which do not justify production well investment on their own, or deeper reservoirs which would need more expensive wells. With higher technology and fair fiscal terms, these gas reservoirs could become commercial reserves in future.

Most favourable option for Thailand, in our view

Allowing Chevron and PTTEP to participate in new contracts would be best for Thailand, in our view

We believe the best option for Thailand is to allow existing concessionaires to continue their participation in these fields.

- **Avoid supply disruption:** Allowing existing concessionaires to participate in the new contracts could ensure ongoing domestic production and avoid the risk of a sharp fall in gas production and adverse economic impact. The government would be able to avoid an energy crisis and fiscal revenue loss, while having flexibility to negotiate contract terms and change the tax structure and rates.

- **Expertise:** Moreover, Chevron and PTTEP, the long-term operators of these fields have the experience and expertise. We think Thailand could leverage their expertise to maximise the long-term resource potential.

However, the downside risk is that some groups might not be happy with this and may oppose the decision, as they could view it as the government favouring Chevron (a foreign company) and PTTEP (a major target of the protestors).

Recent global trends: nationalising assets and retaining existing operators

Asset nationalisation and retaining existing E&P operators are global trends

Recent government deals after contract expiration in other countries show an asset nationalisation trend, whereby the government increases its stake or control over key E&P contracts. We discuss the Mahakam contract in Indonesia and the ADCO concession in Abu Dhabi as examples. In both cases, the government has taken more control or majority control of the contracts after expiration. However, existing operators are involved or likely to be involved in the new contracts.

The Mahakam contract in Indonesia: The offshore Mahakam PSC is one of Indonesia's largest oil & gas developments, with production volume of 318kboed (including 1.4bcf/day of gas). The PSC is scheduled to expire in 2017. Total and INPEX has 50%-50% working interests in the PSC, with Total is the operator.

In March 2015, the government of Indonesia confirmed that Pertamina, Indonesia's state oil company, will hold a major interest and operate the block from 1 January 2018; that is, after contract expiration. Negotiations on whether Total, the existing operator, will have a participating interest in the contract are ongoing.

ADCO concession in Abu Dhabi: The ADCO (Abu Dhabi Company for Onshore Oil Operations) concession, which produces more than half of Abu Dhabi's production, expired in January 2014. The concession was owned 60% by the Abu Dhabi National Oil Company (ADNOC), and 9.5% each by Total, Exxon Mobil, Shell and BP, and the remaining 2% by Partex. After the concession expired, ADNOC took over 100% ownership of the field and opened bids for the participating interest. In January 2015, it awarded a 10% working interest in the project to Total, while retaining 90% ownership.

Thailand is in a different situation; government needs to balance fiscal regime to attract investors, in our view

Unlike Indonesia and Abu Dhabi, we think Thailand needs capable E&P companies to optimise its mature gas fields

The key difference in the Thailand gas concessions and Mahakam/ADCO is resource potential. Mahakam and ADCO contain significant resources whereas Thailand's gas fields are relatively mature, and would require more advanced exploration efforts to extend the reserve life and maintain production.

We think this puts the Thai government at a disadvantage. To ensure that the country maximises resources, we think the government will need E&P companies that have the technology and experience as its partners to maximise the resource value or monetise the reserves in the Gulf of Thailand.

Malaysia's experience in Enhanced Oil Recovery (EOR)

Since 2005, oil & gas output in the Peninsular Malaysia and Sarawak (93% of total output in 2005) has been in decline. As the bigger companies chase bigger prospects elsewhere, smaller exploration targets and discoveries are seen as economically marginal, and are being left undeveloped.

Over 6bn boe of discovered reserves in Malaysia are categorised as sub-commercial under current fiscal terms. Around two-thirds of these are either too small to support development or too costly to produce due to their location or complex geology. PETRONAS, in 2011, proposed fiscal incentives, applicable to small fields and capital-intensive projects, to stimulate exploration and development activity in areas where the low-hanging fruit has long since been harvested. It is also seeking to encourage investment in mature fields to further enhance recovery levels. The incentives offered include lower tax rates, accelerated capital allowances, and waivers of export duties.

In 2014, Malaysia's oil & gas production from marginal fields exceeded its targets as it achieved average daily production of 58,300 barrels of oil and 175.5mmcfd of gas from marginal fields against respective targets of 40,000 barrels and 120.3mmcfd, according to an Upstreamonline report.

Nonetheless, complex geology and rising industry costs mean developments remain economically challenging. According to the Economic Transformation Programme (ETP) 2014 annual report, Petronas is still looking at specific enhanced oil recovery contracts and tax incentives to help boost crude output, despite the nation beating its marginal field production targets in 2014. This includes Petroleum Income Tax Act (PITA) incentives.

Company pages

PTT Exploration & Production
Risk is to the upside

Equities

Thailand
Oil Companies, Secondary

12-month rating	Buy
12m price target	Bt150.00
Price	Bt108.00

RIC: PTTEP.BK **BBG:** PTTEP TB

Trading data and key metrics

52-wk range	Bt171.00-101.00
Market cap.	Bt429bn/US$12.6bn
Shares o/s	3,970m (ORD)
Free float	45%
Avg. daily volume ('000)	6,056
Avg. daily value (m)	Bt690.0
Common s/h equity (12/15E)	Bt431bn
P/BV (12/15E)	1.0x

EPS (UBS, diluted) (Bt)

	UBS	Cons.
12/15E	7.35	8.05
12/16E	8.99	9.26
12/17E	10.20	9.89

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Best positioned to capture value upside when contracts expire, in our view

Upstream reforms and the potential launch of new bids once current contracts expire will open opportunities for PTTEP to capture value upside from the remaining reserves, in our view. We think PTTEP is well-positioned to continue its operatorship of the Bongkot fields and could participate in Contract 1-2 and 3 as well. We base our view on: 1) the advantages for the government from retaining existing operators; 2) PTTEP's expertise and experience in operating the Bongkot field, and 3) national oil company PTT Public's 65% stake in PTTEP. We estimate NAV upside potential could range from Bt1.8 to Bt32.8 per share (2-30% of the current share price).

Risks might be limited

The disadvantages which might keep PTTEP off the table include: 1) strong opposition to the PTT Group and PTTEP by certain groups in Thailand, and 2) possible asset nationalisation and unfavourable fiscal terms by the government. We think both are unlikely to materialise into major risks, due to the government's recent reform to consider protesters' opinions and the need to balance Thailand's future gas reserve with the desire to nationalise petroleum assets.

Building track records in operating challenging fields

In the long run, we think PTTEP would need to prove itself further, in terms of technology and ability to operate challenging fields. This would help it to extract more value from the mature gas fields in Thailand, as well as add long-term value as the only national E&P company in Thailand.

Valuation: UBS top value pick, Bt150.00 NAV-based price target

PTTEP is trading at a 28% discount to NAV and implying a long-term oil price of only US$58/bbl. Our Bt150.00 NAV-based price target assumes Bongkot and Contract 3 will expire in 2022, as per existing contract terms. We think PTTEP's risk-reward is compelling at the current level, given its discount valuation and potential upside risk to NAV.

Highlights (Btm)	12/12	12/13	12/14	12/15E	12/16E	12/17E	12/18E	12/19E
EBITDX	154,951	166,264	189,842	144,670	155,476	168,072	170,651	174,748
DACF	111,958	116,865	123,118	137,204	141,411	143,137	140,790	144,190
CFPS (UBS, Bt)	27.34	26.84	34.06	31.76	32.99	33.60	33.01	33.71
EPS (UBS, Bt)	15.55	15.88	13.09	7.35	8.99	10.20	10.79	11.04

Profitability/valuation	12/12	12/13	12/14	12/15E	12/16E	12/17E	12/18E	12/19E
Prod per share growth %	-4.9	-4.9	6.0	2.8	0.5	-1.9	-1.5	1.8
ROACE %	15.6	15.3	10.6	6.1	6.9	7.4	7.6	7.8
EV/EBITDX x	3.9	4.2	3.3	2.9	2.6	2.4	2.2	1.9
EV/DACF x	5.4	5.9	5.0	3.1	2.8	2.8	2.7	2.3
P/CFPS (UBS) x	6.1	6.0	4.5	3.4	3.3	3.2	3.3	3.2

Source: Company accounts, Thomson Reuters, UBS estimates. Metrics marked as (UBS) have had analyst adjustments applied. Valuations: based on an average share price that year, (E): based on a share price of Bt108.00 on 08 Jun 2015 20:26 HKT

Investment Thesis

PTT Exploration & Production

12-month rating **Buy**

12m price target **Bt150.00**

Investment case

Due to a lack of volume growth in 2016-17E, we think PTTEP's earnings would move in line with the crude oil price and Thailand and Myanmar's gas price (which lags the crude oil price by 3-12 months) for the next two to three years. We expect PTTEP's cash cost to remain low at US$15-17/bbl, but its depreciation cost could remain high, along with the company's F&D cost, which has been higher in the past few years. PTTEP's strong balance sheet and positive FCF provide it with a relatively defensive dividend yield and opportunity for M&A. We think new gas contracts (which will replace the expiring contracts) in the Gulf of Thailand could provide upside risk for PTTEP's long-term volumes. The potential M&A of shale oil/gas assets in the US could raise the company's earnings risk profile.

Upside scenario

Our upside scenario assumes an average oil price of US$100/barrel (2015 to long term), and that all of PTTEP's existing 2C reserve is proven commercial by 2022. We include six trains of the Mozambique LNG into our upside scenario valuation of Bt175.00/share.

Downside scenario

Our downside scenario assumes the oil price declines to an average of US$60/bbl (2015 to long term), the Myanmar gas price falls 15% from existing levels, Cove's LNG project in East Africa is not commercial and no exploration projects post positive results or development progress. We derive a downside scenario valuation of Bt109.00/share.

Upcoming catalysts

Aside from oil price movements, we believe the key catalysts for PTTEP include a decision on gas concessions in the Gulf of Thailand, and the final investment decision (FID) on the Mozambique area 1 LNG project (target in 2016).

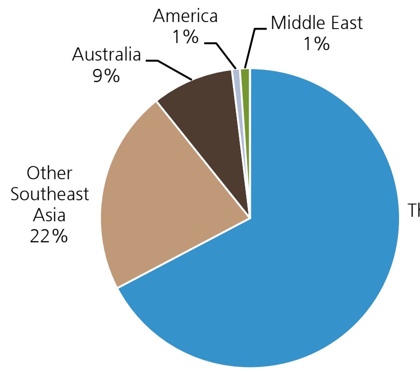
Business description

Listed in 1993, PTT Exploration & Production (PTTEP) is Thailand's major exploration and production company, and it is 65% owned by Thailand national oil conglomerate PTT Public. At the end of 2014, the company had proven petroleum reserves of 777mmboe, consisting of 76% natural gas and 24% liquids. Of the total reserves, 41% is located overseas and 59% in Thailand. In 2014, PTTEP's production rate was 299,716 boe/day. 79% of which was produced in Thailand and 15% was produced in Myanmar and other South East Asia markets.

Industry outlook

UBS expects crude oil prices to recover from the low of US$55/bbl in Q115 to US$67.5/80/90/bbl in 2016/2017 and the long term, respectively. We expect lower crude supply growth from the US to reduce excess supply and improve the demand supply balance in the market. In Thailand, the potential shortfall of domestic gas supply and maturing domestic gas fields should continue to drive government policies and PTT Group's strategies. This includes the potential acceleration of E&P activity in neighbouring countries, as well as the continuation of foreign investment for PTTEP.

Revenue by region (2014)



Source: Company data

EBIT by product segment

We estimate oil & gas sales accounts for c80% of PTTEP's EBIT, while the remaining 20% is pipeline revenue.

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The upside and downside cases for PTTEP

We believe PTTEP has the opportunity to capture value upside from expiring contracts on two fronts. These are: 1) the participation in the new contract to operate the Bongkot field, in which it is an operator (44.5% working interest [WI]); and 2) participation in the three contracts currently operated by Chevron, if the government calls for new bids.

The Bongkot project is the biggest project in PTTEP's portfolio in terms of volume (24% of its total volume in 2014), but less so in terms of NAV (12%).

The disadvantages which could keep PTTEP off the table include: 1) strong opposition to PTT Group and PTTEP by some groups, and 2) possible asset nationalisation and unfavourable fiscal terms by the government. We think both are unlikely to materialise into big risks, due to the government's recent reform to consider protesters' opinions and the need to balance Thailand's future gas reserve with the desire to nationalise petroleum assets.

Risk is to the upside, in our view

We think the risk is more to the upside than downside for PTTEP. As an existing operator in Bongkot, PTTEP could be a contender to participate in new concessions. Moreover, to meet the government's target of being self-reliant in E&P, we believe it will prefer PTTEP to foreign companies in new potential bids.

We estimate total recoverable reserves of 1,333mboe (Figure 32) with combined NPV of US$4.3bn in the four contracts.

Figure 32: Recoverable reserves and NPV estimates

	Recoverable reserves (mboe)		Recoverable reserves left after 2022	
	Total	2015-2022	mboe	NPV (US$)
Bongkot	777	480	297	1,829
Contract 1	241	159	82	344
Contract 2	403	273	129	935
Contract 3	590	420	170	1,148
Total	2,011	1,333	678	4,256

Source: Wood Mackenzie, UBS estimates

Our NPV estimate assumes a discount rate of 10% and a long-term oil price (Brent) of US$90/bbl. By estimating the additional value of NPV of the 1,333mboe reserve, we estimate NPV for two scenarios for each field including: 1) NPV assuming the contracts end in 2022 and decommissioning cost is all spent in 2022; and 2) NPV assuming the contracts last until recoverable reserves run down, and full decommissioning costs are paid in the last year. The difference in NPV of both cases is the US$4.3bn value of extracting the remaining reserves after contracts expire. We also assume additional capex after 2022 for all the fields to match the production profile.

Figure 33: Decommissioning cost and additional capex assumptions

US$ m	Decommissioning cost	Combine capex after 2022 (excluding decommissioning cost)
Bongkot	1,038	2,128
Contract 1	447	517
Contract 2	831	859
Contract 3	1,077	1,145
Total	3,393	4,649

Source: Wood Mackenzie, UBS estimates

In reality, the negotiations over decommissioning costs could be key for value upside. If the existing concessionaires pay all or a significant proportion of the decommissioning cost, then the burden borne by new contractors could be less. Nonetheless, the government could demand higher decommissioning costs from new E&P contractors, to manage the environmental impact. As a result, we try not to pre-empt this when estimating NPV upside potential and simply extend the reserve life of the field.

Based on these assumptions, we estimate potential value upside to PTTEP along with the potential participation stakes in each contract as in Figure 34.

Figure 34: NAV upside sensitivity (Bt/PTTEP share) based on % interest in new contracts

% stake	5%	10%	20%	30%	40%	50%	60%	70%	80%	90%
Bongkot	0.8	1.5	3.0	4.6	6.1	7.6	9.1	10.6	12.2	13.7
Contract 1	0.1	0.3	0.6	0.9	1.1	1.4	1.7	2.0	2.3	2.6
Contract 2	0.4	0.8	1.6	2.3	3.1	3.9	4.7	5.4	6.2	7.0
Contract 3	0.5	1.0	1.9	2.9	3.8	4.8	5.7	6.7	7.6	8.6
Combine	1.8	3.5	7.1	10.6	14.2	17.7	21.2	24.8	28.3	31.8

Note: Assuming Bt33/US$ exchange rate. Source: UBS estimates

PTT Public Company Ltd.

Contract management critical to cost, profit and capex

Equities

Thailand
Oil Companies, Major

12-month rating	**Buy**
12m price target	**Bt415.00**
Price	**Bt344.00**

RIC: PTT.BK **BBG:** PTT TB

Trading data and key metrics

52-wk range	Bt397.00-292.00
Market cap.	Bt983bn/US$29.0bn
Shares o/s	2,856m (ORD)
Free float	49%
Avg. daily volume ('000)	4,539
Avg. daily value (m)	Bt1,563.2
Common s/h equity (12/15E)	Bt727bn
P/BV (12/15E)	1.4x
Net debt / EBITDA (12/15E)	3.0x

EPS (UBS, diluted) (Bt)

	UBS	Cons.
12/15E	26.46	30.43
12/16E	30.33	34.40
12/17E	33.47	36.59

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Cheap gas in the Gulf of Thailand is critical to PTT

PTT is the only gas distributor in Thailand. Cheap gas from the Gulf of Thailand accounts for 78% of its total feedstock by volume, and contributed over half of the gas profit to PTT. This is because PTT earns a high profit margin from converting domestic wet gas into high-value petrochemical products. Hence, we believe management of the four concessions (55% of domestic gas supply, 45% of total gas feedstock) is critical to PTT.

The worst-case scenario is unlikely

In the worst case of supply disruption and difficult concession management, PTT would need to replace cheap domestic gas with imported LNG, which could be more expensive. Also the profit margin from petrochemical could decline due to a lack of feedstock or higher feedstock costs. In this case, we estimate PTT's gas cost would increase to an 11% CAGR over 2018-20E, leading to 17-53% risk to core EBITDA. We think the worst-case scenario is unlikely, as it also means Thailand would be in an economic crisis due to gas supply disruption.

PTT's capex might be geared towards supply security, not capital discipline

PTT continues to invest heavily to expand gas distribution capacity, including LNG terminals, despite the low utilisation rate (66% for the gas pipeline and 40% for the LNG terminals) and expected slower gas demand growth, which it recently cut from a 3.9% CAGR to 1.3% CAGR (2015-19F). Aside from supporting long-term growth, we think this is due to the need to build supply security ahead of a decision on new contracts and declining production in the Gulf of Thailand.

Valuation: maintain Buy rating on near-term positive catalysts

PTT is trading at a 21% discount to our sum-of-the-parts-based price target of Bt415.00. We think PTT's valuation is undemanding at 10.3x 2017E PE and with 3.1-3.7% upside to its dividend yield. Higher dividend and asset divestiture could be positive share price catalysts.

Highlights (Btm)	12/12	12/13	12/14	12/15E	12/16E	12/17E	12/18E	12/19E
Revenues	2,793,833	2,842,408	2,834,732	2,749,089	2,869,356	3,007,009	3,111,860	3,191,785
EBIT (UBS)	157,373	155,661	147,824	91,867	114,506	138,904	152,194	150,757
Net earnings (UBS)	93,631	97,605	80,903	75,575	86,641	95,599	98,322	93,986
EPS (UBS, diluted) (Bt)	32.78	34.17	28.32	26.46	30.33	33.47	34.42	32.90
DPS (Bt)	12.00	12.99	14.00	11.00	12.00	13.00	14.00	14.00
Net (debt) / cash	(311,850)	(325,361)	(412,055)	(547,700)	(576,892)	(618,629)	(610,338)	(610,338)

Profitability/valuation	12/12	12/13	12/14	12/15E	12/16E	12/17E	12/18E	12/19E
EBIT margin %	5.6	5.5	5.2	3.3	4.0	4.6	4.9	4.7
ROIC (EBIT) %	30.3	27.3	18.1	8.5	10.2	12.5	14.2	14.5
EV/EBITDA (core) x	4.7	4.4	4.7	7.3	6.1	4.9	4.1	4.0
P/E (UBS, diluted) x	10.1	9.6	11.4	13.0	11.3	10.3	10.0	10.5
Equity FCF (UBS) yield %	0.9	5.1	(7.9)	(10.6)	0.5	(0.5)	4.9	6.4
Net dividend yield %	3.6	4.0	4.4	3.2	3.5	3.8	4.1	4.1

Source: Company accounts, Thomson Reuters, UBS estimates. Metrics marked as (UBS) have had analyst adjustments applied. Valuations: based on an average share price that year, (E): based on a share price of Bt344.00 on 08 Jun 2015 20:26 HKT

Investment Thesis

PTT Public Company Ltd.

12-month rating Buy

12m price target Bt415.00

Investment case

Thailand's energy reform policy, which includes gas price increases and the restructuring of PTT's refinery assets, should enhance its cash flow position during the low oil price period in 2015E, in our view. The restructuring of PTT's asset portfolio, which includes separation of the transmission pipeline business and possible carve-out of its oil distribution business, could crystallise value of PTT's core assets. This is based on the stable cash flow of the pipeline business, and high growth in non-oil profit from the oil distribution business. PTT plans to use most of its capex to expand the gas pipeline, LNG terminal and oil storage capacity. This should create a stable but lower-return income stream for the company.

Upside scenario

Valuation of Bt450.00/share: We assume a long-term oil price of US$100/bbl, full gas-price liberalisation by 2016E and no conglomerate discount at listed subsidiaries. In this case, we expect a rapid margin recovery of the core gas business after the potential squeeze in H115 due to the oil price correction.

Downside scenario

Valuation of Bt320.00/share: We assume a long-term oil price of US$60/bbl, full gas-price liberalisation by 2018E, a 10% conglomerate discount at listed subsidiaries. If oil prices continue to decline, we believe the recovery of the core gas business margin would be delayed to 2016. If the gas price increases, weak economic growth and political disruption occur in 2015E, and the gas price reform process could slow.

Upcoming catalysts

Higher oil prices, clarity on reform policy, and asset divestiture could be key catalysts for PTT.

Business description

PTT Public (PTT) is a state-owned integrated petroleum company with a monopoly in gas transmission, which includes ownership of about 3,000km of onshore and offshore gas pipelines. This network supplies around 70% of power generation in Thailand. PTT also processes domestic gas as feedstock for its petrochemical associates. It has an oil trading and marketing business and owns a 66% stake in listed exploration and production company, PTT Exploration & Production. PTT's downstream chemical and refining associates account for more than half of the capacity in their respective industries in Thailand.

Industry outlook

UBS expects crude oil prices to decline sharply YoY to average US$53/bbl due to oversupply in the crude market in 2015E. We believe gas demand in Thailand should continue to grow 3% pa, which would be matched by imported supply from Myanmar and LNG. This could drive structurally higher gas costs for PTT Public. We expect olefin-chain chemical to be in tight supply in 2015 but believe aromatic-chain chemical and refining margin would decline.

Revenue by region (%)

About 97% of PTT's revenue is from Thailand, 1% is coal mining revenue from the Indonesia coal subsidiary, and the remaining 2% is PTTEP's revenue from overseas projects.

EBIT by product segment

In Q115, the core gas and oil distribution unit contributed the largest portion of PTT's net profit (29%), followed by PTTEP (25%), the refining business (21%), the petrochemical business (15%), and other businesses (10%).

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PTT Public Company Ltd. (PTT.BK)

Income statement (Btm)	12/12	12/13	12/14	12/15E	% ch	12/16E	% ch	12/17E	12/18E	12/19E
Revenues	**2,793,833**	**2,842,408**	**2,834,732**	**2,749,089**	-3.0	**2,869,356**	4.4	**3,007,009**	**3,111,860**	**3,191,785**
Gross profit	232,516	224,226	227,242	155,675	-31.5	181,361	16.5	208,998	227,540	227,924
EBITDA (UBS)	**222,428**	**231,905**	**256,165**	**180,011**	-29.7	**204,061**	13.4	**238,527**	**259,919**	**266,585**
Depreciation & amortisation	(65,055)	(76,244)	(108,341)	(88,144)	-18.6	(89,555)	1.6	(99,624)	(107,726)	(115,828)
EBIT (UBS)	**157,373**	**155,661**	**147,824**	**91,867**	-37.9	**114,506**	24.6	**138,904**	**152,194**	**150,757**
Associates & investment income	24,133	27,804	3,406	22,456	NM	23,781	5.9	24,540	24,081	24,081
Other non-operating income	0	0	0	0	-	0	-	0	0	0
Net interest	(19,747)	(20,593)	(22,218)	(21,114)	5.0	(22,401)	-6.1	(24,843)	(26,309)	(26,300)
Exceptionals (incl goodwill)	0	0	0	0	-	0	-	0	0	0
Profit before tax	**161,759**	**162,872**	**129,012**	**93,209**	-27.8	**115,886**	24.3	**138,600**	**149,965**	**148,538**
Tax	(47,178)	(44,795)	(41,406)	(7,632)	81.6	(16,995)	-122.7	(29,092)	(36,927)	(39,498)
Profit after tax	**114,581**	**118,077**	**87,605**	**85,576**	-2.3	**98,892**	15.6	**109,509**	**113,038**	**109,041**
Preference dividends	0	0	0	0	-	0	-	0	0	0
Minorities	(20,950)	(20,473)	(6,703)	(10,001)	-49.2	(12,251)	-22.5	(13,910)	(14,716)	(15,055)
Extraordinary items	10,978	(4,513)	(25,108)	0	-	0	-	0	0	0
Net earnings (local GAAP)	**104,609**	**93,091**	**55,795**	**75,575**	35.5	**86,641**	14.6	**95,599**	**98,322**	**93,986**
Net earnings (UBS)	**93,631**	**97,605**	**80,903**	**75,575**	-6.6	**86,641**	14.6	**95,599**	**98,322**	**93,986**
Tax rate (%)	29.2	27.5	32.1	8.2	-74.5	14.7	79.1	21.0	24.6	26.6

Per share (Bt)	12/12	12/13	12/14	12/15E	% ch	12/16E	% ch	12/17E	12/18E	12/19E
EPS (UBS, diluted)	32.78	34.17	28.32	26.46	-6.6	30.33	14.6	33.47	34.42	32.90
EPS (local GAAP, diluted)	36.62	32.59	19.53	26.46	35.5	30.33	14.6	33.47	34.42	32.90
EPS (UBS, basic)	32.78	34.17	28.32	26.46	-6.6	30.33	14.6	33.47	34.42	32.90
Net DPS (Bt)	12.00	12.99	14.00	11.00	-21.4	12.00	9.1	13.00	14.00	14.00
Cash EPS (UBS, diluted)[1]	55.56	60.86	66.25	57.32	-13.5	61.69	7.6	68.35	72.14	73.46
Book value per share	211.43	238.88	239.22	254.68	6.5	273.01	7.2	293.48	313.91	313.91
Average shares (diluted)	2,856.30	2,856.30	2,856.30	2,856.30	0.0	2,856.30	0.0	2,856.30	2,856.30	2,856.30

Balance sheet (Btm)	12/12	12/13	12/14	12/15E	% ch	12/16E	% ch	12/17E	12/18E	12/19E
Cash and equivalents	143,333	160,370	316,757	131,112	-58.6	101,919	-22.3	122,182	110,473	110,473
Other current assets	328,813	363,206	387,484	468,840	21.0	487,436	4.0	508,819	525,249	525,249
Total current assets	**472,146**	**523,577**	**704,241**	**599,952**	-14.8	**589,355**	-1.8	**631,001**	**635,722**	**635,722**
Net tangible fixed assets	650,561	739,785	1,105,147	1,175,331	6.4	1,222,301	4.0	1,290,489	1,317,798	1,317,798
Net intangible fixed assets	0	0	0	0	-	0	-	0	0	0
Investments / other assets	506,804	541,677	441,067	530,787	20.3	634,777	19.6	754,960	893,088	893,088
Total assets	**1,629,511**	**1,805,039**	**2,250,455**	**2,306,071**	2.5	**2,446,433**	6.1	**2,676,450**	**2,846,609**	**2,846,609**
Trade payables & other ST liabilities	323,221	346,250	275,387	274,121	-0.5	282,628	3.1	292,525	300,288	300,288
Short term debt	57,669	60,469	137,118	137,118	0.00	137,118	0.00	219,118	219,118	219,118
Total current liabilities	**380,891**	**406,719**	**412,505**	**411,239**	-0.3	**419,746**	2.1	**511,642**	**519,406**	**519,406**
Long term debt	397,514	425,262	591,694	541,694	-8.5	541,694	0.0	521,694	501,694	501,694
Other long term liabilities	121,211	150,216	191,561	244,287	27.5	311,525	27.5	397,270	506,615	506,615
Preferred shares	0	0	0	0	-	0	-	0	0	0
Total liabilities (incl pref shares)	**899,615**	**982,197**	**1,195,760**	**1,197,220**	0.1	**1,272,965**	6.3	**1,430,606**	**1,527,715**	**1,527,715**
Common s/h equity	603,920	682,311	683,287	727,443	6.5	779,808	7.2	838,274	896,608	896,608
Minority interests	125,976	140,532	371,408	381,409	2.7	393,660	3.2	407,570	422,286	422,286
Total liabilities & equity	**1,629,511**	**1,805,039**	**2,250,455**	**2,306,071**	2.5	**2,446,433**	6.1	**2,676,450**	**2,846,609**	**2,846,609**

Cash flow (Btm)	12/12	12/13	12/14	12/15E	% ch	12/16E	% ch	12/17E	12/18E	12/19E
Net income (before pref divs)	104,609	93,091	55,795	75,575	35.5	86,641	14.6	95,599	98,322	93,986
Depreciation & amortisation	65,055	76,244	108,341	88,144	-18.6	89,555	1.6	99,624	107,726	115,828
Net change in working capital	(16,584)	(11,365)	(95,141)	(82,622)	13.2	(10,088)	87.8	(11,487)	(8,667)	(6,150)
Other operating	(30,545)	24,280	13,341	(26,994)	-	(24,500)	9.2	(20,528)	(14,067)	(5,579)
Operating cash flow	**122,535**	**182,250**	**82,336**	**54,103**	-34.3	**141,608**	161.7	**163,207**	**183,314**	**198,085**
Tangible capital expenditure	(114,087)	(134,184)	(155,261)	(158,329)	-2.0	(136,524)	13.8	(167,812)	(135,034)	(135,034)
Intangible capital expenditure	0	0	0	0	-	0	-	0	0	0
Net (acquisitions) / disposals	0	0	0	0	-	0	-	0	0	0
Other investing	(8,238)	(10,696)	157,020	0	-	0	-	0	0	0
Investing cash flow	**(122,325)**	**(144,880)**	**1,759**	**(158,329)**	-	**(136,524)**	13.8	**(167,812)**	**(135,034)**	**(135,034)**
Equity dividends paid	(42,308)	(46,368)	(48,837)	(31,419)	35.7	(34,276)	-9.1	(37,132)	(39,988)	(39,988)
Share issues / (buybacks)	0	0	0	0	-	0	-	0	0	0
Other financing	0	0	0	0	-	0	-	0	0	0
Change in debt & pref shares	47,359	30,548	243,081	(50,000)	-	0	-	62,000	(20,000)	(20,000)
Financing cash flow	**5,051**	**(15,820)**	**194,243**	**(81,419)**	-	**(34,276)**	57.9	**24,868**	**(59,988)**	**(59,988)**
Cash flow inc/(dec) in cash	**5,261**	**21,550**	**278,338**	**(185,645)**	-	**(29,192)**	84.3	**20,263**	**(11,709)**	**3,063**
FX / non cash items	10,978	(4,513)	(121,951)	0	-	0	-75.0	0	0	(3,063)
Balance sheet inc/(dec) in cash	**16,239**	**17,037**	**156,387**	**(185,645)**	-	**(29,192)**	84.3	**20,263**	**(11,709)**	**0**

Source: Company accounts, UBS estimates. (UBS) metrics use reported figures which have been adjusted by UBS analysts.[1]Cash EPS (UBS, diluted) is calculated using UBS net income adding back depreciation and amortization.

PTT Public Company Ltd. (PTT.BK)

Valuation (x)	12/12	12/13	12/14	12/15E	12/16E	12/17E	12/18E	12/19E
P/E (local GAAP, diluted)	9.1	10.0	16.5	13.0	11.3	10.3	10.0	10.5
P/E (UBS, diluted)	10.1	9.6	11.4	13.0	11.3	10.3	10.0	10.5
P/CEPS	6.0	5.4	4.9	6.0	5.6	5.0	4.8	4.7
Equity FCF (UBS) yield %	0.9	5.1	(7.9)	(10.6)	0.5	(0.5)	4.9	6.4
Net dividend yield (%)	3.6	4.0	4.4	3.2	3.5	3.8	4.1	4.1
P/BV x	1.6	1.4	1.3	1.4	1.3	1.2	1.1	1.1
EV/revenues (core)	0.4	0.4	0.4	0.5	0.4	0.4	0.3	0.3
EV/EBITDA (core)	4.7	4.4	4.7	7.3	6.1	4.9	4.1	4.0
EV/EBIT (core)	6.6	6.6	8.1	14.2	10.8	8.3	6.9	7.1
EV/OpFCF (core)	4.8	4.6	4.8	7.6	6.3	5.0	4.2	4.1
EV/op. invested capital	2.0	1.8	1.5	1.2	1.1	1.0	1.0	1.0

Enterprise value (Btm)	12/12	12/13	12/14	12/15E	12/16E	12/17E	12/18E	12/19E
Market cap.	947,301	934,313	919,032	982,567	982,567	982,567	982,567	982,567
Net debt (cash)	251,448	251,448	368,708	368,708	368,708	368,708	368,708	368,708
Buy out of minorities	106,963	133,254	255,970	376,408	387,534	400,615	414,928	422,286
Pension provisions/other	0	0	0	0	0	0	0	0
Total enterprise value	**1,305,713**	**1,319,015**	**1,543,709**	**1,727,683**	**1,738,809**	**1,751,890**	**1,766,203**	**1,773,561**
Non core assets	(270,979)	(295,341)	(351,519)	(418,783)	(498,991)	(594,634)	(708,682)	(708,682)
Core enterprise value	**1,034,733**	**1,023,675**	**1,192,191**	**1,308,900**	**1,239,818**	**1,157,255**	**1,057,521**	**1,064,879**

Growth (%)	12/12	12/13	12/14	12/15E	12/16E	12/17E	12/18E	12/19E
Revenue	15.1	1.7	-0.3	-3.0	4.4	4.8	3.5	2.6
EBITDA (UBS)	5.4	4.3	10.5	-29.7	13.4	16.9	9.0	2.6
EBIT (UBS)	1.0	-1.1	-5.0	-37.9	24.6	21.3	9.6	-0.9
EPS (UBS, diluted)	-10.0	4.2	-17.1	-6.6	14.6	10.3	2.8	-4.4
Net DPS	-16.9	8.3	7.7	-21.4	9.1	8.3	7.7	0.0

Margins & Profitability (%)	12/12	12/13	12/14	12/15E	12/16E	12/17E	12/18E	12/19E
Gross profit margin	8.3	7.9	8.0	5.7	6.3	7.0	7.3	7.1
EBITDA margin	8.0	8.2	9.0	6.5	7.1	7.9	8.4	8.4
EBIT margin	5.6	5.5	5.2	3.3	4.0	4.6	4.9	4.7
Net earnings (UBS) margin	3.4	3.4	2.9	2.7	3.0	3.2	3.2	2.9
ROIC (EBIT)	30.3	27.3	18.1	8.5	10.2	12.5	14.2	14.5
ROIC post tax	19.9	18.2	12.1	7.6	8.3	9.3	10.0	9.9
ROE (UBS)	16.1	15.2	11.8	10.7	11.5	11.8	11.3	10.5

Capital structure & Coverage (x)	12/12	12/13	12/14	12/15E	12/16E	12/17E	12/18E	12/19E
Net debt / EBITDA	1.4	1.4	1.6	3.0	2.8	2.6	2.3	2.3
Net debt / total equity %	42.7	39.5	39.1	49.4	49.2	49.7	46.3	46.3
Net debt / (net debt + total equity) %	29.9	28.3	28.1	33.1	33.0	33.2	31.6	31.6
Net debt/EV %	30.1	31.8	34.6	41.8	46.5	53.5	57.7	57.3
Capex / depreciation %	175.4	176.0	143.3	179.6	152.4	168.4	125.4	116.6
Capex / revenue %	4.1	4.7	5.5	5.8	4.8	5.6	4.3	4.2
EBIT / net interest	8.0	7.6	6.7	4.4	5.1	5.6	5.8	5.7
Dividend cover (UBS)	2.7	2.6	2.0	2.4	2.5	2.6	2.5	2.4
Div. payout ratio (UBS) %	36.6	38.0	49.4	41.6	39.6	38.8	40.7	42.5

Revenues by division (Btm)	12/12	12/13	12/14	12/15E	12/16E	12/17E	12/18E	12/19E
Others	2,793,833	2,842,408	2,834,732	2,749,089	2,869,356	3,007,009	3,111,860	3,191,785
Total	**2,793,833**	**2,842,408**	**2,834,732**	**2,749,089**	**2,869,356**	**3,007,009**	**3,111,860**	**3,191,785**

EBIT (UBS) by division (Btm)	12/12	12/13	12/14	12/15E	12/16E	12/17E	12/18E	12/19E
Others	157,373	155,661	147,824	91,867	114,506	138,904	152,194	150,757
Total	**157,373**	**155,661**	**147,824**	**91,867**	**114,506**	**138,904**	**152,194**	**150,757**

Source: Company accounts, UBS estimates. (UBS) metrics use reported figures which have been adjusted by UBS analysts.

PTT Global Chemical

Gas feedstock is a key value contributor

Domestic gas is a key source of feedstock and value creation

We estimate 50% of PTT Global Chemical's (PTTGC) EBITDA is derived from gas-based olefin assets, which convert domestic wet gas (ethane, propane and LPG) into petrochemical products (mainly ethylene-chain and MEG). Cheap gas feedstock enables PTTGC to capture high margins for its olefin unit, which earned an 18% higher EBITDA margin than its oil-based peers in 2014. Domestic gas feedstock from PTT accounts for 90% of PTTGC's olefin feedstock.

The worst-case scenario is unlikely

In the worst case of supply disruption and difficult concession management, PTTGC would need to replace cheap domestic gas with LPG from its refinery and this would be more expensive than ethane. In the worst-case scenario, in which the Thai government fails to smoothly manage the gas concessions, we estimate PTTGC could lose 13% of its gas feedstock in 2019 and 23% in 2020.

Long-term strategy driven by lack of growth in gas-based feedstock

Partly due to the maturing domestic gas fields and the lack of volume growth in gas feedstock, PTTGC is diversifying its investments to focus on new products and new geographic areas. This includes the plan to invest in polyol and bio-plastic plants in Thailand, and to build new crackers in Indonesia (oil-based) and the US (shale gas -based). While it could take time for these projects to materialise, we think it is worth closely monitoring the risks and returns of the projects.

Valuation: Bt75.00 price target

We rate PTTGC a Buy in view of the prolonged tightness in ethylene-chain markets driven by delays and cancellation of new projects in China and the US following the oil price. PTTGC remains attractive at 1.2x PBV and yield 9-15% FCF yield, in our view. Our DCF-derived (WACC 9.6%) price target is Bt75.00.

Equities

Thailand
Chemicals, Commodity

12-month rating	**Buy**
12m price target	**Bt75.00**
Price	**Bt66.00**

RIC: PTTGC.BK **BBG:** PTTGC TB

Trading data and key metrics	
52-wk range	Bt68.75-49.50
Market cap.	Bt298bn/US$8.77bn
Shares o/s	4,509m (ORD)
Free float	51%
Avg. daily volume ('000)	11,131
Avg. daily value (m)	Bt681.9
Common s/h equity (12/15E)	Bt238bn
P/BV (12/15E)	1.3x
Net debt / EBITDA (12/15E)	0.7x

EPS (UBS, diluted) (Bt)

	UBS	Cons.
12/15E	5.10	6.02
12/16E	5.71	6.74
12/17E	5.72	6.74

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Highlights (Btm)	12/12	12/13	12/14	12/15E	12/16E	12/17E	12/18E	12/19E
Revenues	565,617	552,881	574,010	378,907	437,834	495,303	527,489	529,929
EBIT (UBS)	39,716	43,562	21,158	30,511	33,612	33,668	33,285	31,792
Net earnings (UBS)	31,488	35,858	16,053	22,992	25,761	25,813	25,458	24,071
EPS (UBS, diluted) (Bt)	6.98	7.95	3.56	5.10	5.71	5.72	5.65	5.34
DPS (Bt)	2.34	4.24	3.35	2.16	3.10	3.17	3.30	3.30
Net (debt) / cash	(76,795)	(75,867)	(67,355)	(35,771)	(21,588)	(3,639)	15,456	34,344

Profitability/valuation	12/12	12/13	12/14	12/15E	12/16E	12/17E	12/18E	12/19E
EBIT margin %	7.0	7.9	3.7	8.1	7.7	6.8	6.3	6.0
ROIC (EBIT) %	13.1	14.1	7.3	11.6	13.3	13.5	13.7	13.6
EV/EBITDA (core) x	6.7	7.0	9.8	7.8	7.3	7.2	7.2	7.3
P/E (UBS, diluted) x	9.1	9.3	18.7	12.9	11.6	11.5	11.7	12.4
Equity FCF (UBS) yield %	9.0	6.9	8.8	13.8	9.3	10.7	11.3	11.2
Net dividend yield %	3.7	5.7	5.0	3.3	4.7	4.8	5.0	5.0

Source: Company accounts, Thomson Reuters, UBS estimates. Metrics marked as (UBS) have had analyst adjustments applied. Valuations: based on an average share price that year, (E): based on a share price of Bt66.00 on 08 Jun 2015 20:26 HKT

Investment Thesis

PTT Global Chemical

12-month rating **Buy**

12m price target **Bt75.00**

Investment case

We expect PTTGC to capture growth from the olefin chain up-cycle in 2014-15E, caused by potentially tighter supply and a recovery in demand. We estimate PTTGC's exposure to olefins and MEG at 63% of its EBITDA. In addition, four key upgrade projects should contribute volume and integrated margin growth in 2014-16E. These include the BD extraction project (2014), PX and EO debottlenecking (2015), and 1mt gas cracker debottlenecking (2016). PTTGC also has a very strong balance sheet and high FCF yields (12% in 2014)—we think it could maintain a high dividend pay-out. Moreover, the company would benefit from Bt/US$ depreciation.

Upside scenario

In our upside scenario, we assume crude oil prices will rise to US$100/bbl, while petrochemical spreads and refining margins rise to their mid-peak levels. These could be achieved by a better-than-expected recovery in demand for plastic and aromatics/polyester chain products. In this case, we estimate a valuation of Bt77.00 per share.

Downside scenario

In our downside scenario, we assume crude oil prices will decline to US$60/bbl, while petrochemical spreads and refining margins decline to their trough or near-trough levels. This could occur through a weaker-than-expected recovery in demand for plastic and aromatics/polyester chain products as well as continued supply additions. We base our valuation on a PE-naphtha margin of US$450/t. In this case, we think the stock could trade below book at 0.9x and we estimate a valuation of Bt50.00 per share.

Upcoming catalysts

We think the potential catalysts include a recovery in crude oil prices, aromatics spreads and refining margins.

Business description

PTT Global Chemical (PTTGC), a 49%-owned subsidiary of PTT Public, is the merged PTT Chemical and PTT Aromatics entity. PTTGC has 2.9mt of olefin capacity, and 2.2mt of benzene, toluene and xylene (BTX) capacity. Its refining assets consist of a 145,000bpd complex crude oil refinery and two condensate splitters with 70,000bpd and 65,000bpd capacity.

Industry outlook

We believe the upcycle in the chemical market will continue in 2015-17, supported by a mild recovery in demand and moderate capacity additions. We believe the up-cycle over the next two years should be driven mainly by olefin products, and the vinyl chain. On the other hand, the propylene, polypropylene and polyester chains (PET, PTA and PX) as well as urea are more likely to face weaker spreads over the next two years.

Revenue by region

In 2014, Thailand accounted for 60% of sales, while exports accounts for 40%. About half of PTTGC's exports were to China.

EBIT by product segment

Excluding the large inventory loss led by oil prices in 2014, refining and aromatics contributed 23% of PTTGC's EBITDA in 2014. Gas-based olefin and MEG contributed 77% of its EBITDA.

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PTT Global Chemical (PTTGC.BK)

Income statement (Btm)	12/12	12/13	12/14	12/15E	% ch	12/16E	% ch	12/17E	12/18E	12/19E
Revenues	**565,617**	**552,881**	**574,010**	**378,907**	-34.0	**437,834**	15.6	**495,303**	**527,489**	**529,929**
Gross profit	49,120	52,208	30,363	41,472	36.6	45,144	8.9	45,929	45,820	44,609
EBITDA (UBS)	**56,530**	**60,299**	**38,529**	**48,258**	25.2	**51,669**	7.1	**52,205**	**52,227**	**51,185**
Depreciation & amortisation	(16,815)	(16,737)	(17,371)	(17,747)	2.2	(18,057)	1.7	(18,538)	(18,942)	(19,394)
EBIT (UBS)	**39,716**	**43,562**	**21,158**	**30,511**	44.2	**33,612**	10.2	**33,668**	**33,285**	**31,792**
Associates & investment income	(44)	(77)	534	50	-90.6	50	0.0	50	50	50
Other non-operating income	0	0	0	0	-	0	-	0	0	0
Net interest	(6,320)	(6,084)	(5,487)	(5,794)	-5.6	(5,912)	-2.0	(5,912)	(5,912)	(5,912)
Exceptionals (incl goodwill)	0	0	0	0	-	0	-	0	0	0
Profit before tax	**33,351**	**37,401**	**16,206**	**24,767**	52.8	**27,750**	12.0	**27,806**	**27,423**	**25,930**
Tax	(1,416)	(1,976)	(559)	(2,225)	-297.7	(2,493)	-12.1	(2,498)	(2,464)	(2,329)
Profit after tax	**31,935**	**35,425**	**15,646**	**22,542**	44.1	**25,257**	12.0	**25,308**	**24,959**	**23,600**
Preference dividends	0	0	0	0	-	0	-	0	0	0
Minorities	(448)	433	407	450	10.6	504	12.1	505	498	471
Extraordinary items	2,514	(2,718)	(1,017)	0	-	0	-	0	0	0
Net earnings (local GAAP)	**34,001**	**33,140**	**15,036**	**22,992**	52.9	**25,761**	12.0	**25,813**	**25,458**	**24,071**
Net earnings (UBS)	**31,488**	**35,858**	**16,053**	**22,992**	43.2	**25,761**	12.0	**25,813**	**25,458**	**24,071**
Tax rate (%)	4.2	5.3	3.5	9.0	160.2	9.0	0.0	9.0	9.0	9.0

Per share (Bt)	12/12	12/13	12/14	12/15E	% ch	12/16E	% ch	12/17E	12/18E	12/19E
EPS (UBS, diluted)	6.98	7.95	3.56	5.10	43.2	5.71	12.0	5.72	5.65	5.34
EPS (local GAAP, diluted)	7.54	7.35	3.33	5.10	52.9	5.71	12.0	5.72	5.65	5.34
EPS (UBS, basic)	6.98	7.95	3.56	5.10	43.2	5.71	12.0	5.72	5.65	5.34
Net DPS (Bt)	2.34	4.24	3.35	2.16	-35.5	3.10	43.5	3.17	3.30	3.30
Cash EPS (UBS, diluted)[1]	10.71	11.66	7.41	9.04	21.9	9.72	7.6	9.84	9.85	9.64
Book value per share	49.33	52.90	49.85	52.79	5.9	55.40	4.9	57.95	60.30	62.34
Average shares (diluted)	4,508.85	4,508.85	4,508.85	4,508.85	0.0	4,508.85	0.0	4,508.85	4,508.85	4,508.85

Balance sheet (Btm)	12/12	12/13	12/14	12/15E	% ch	12/16E	% ch	12/17E	12/18E	12/19E
Cash and equivalents	60,062	44,384	45,788	77,371	69.0	91,554	18.3	109,503	128,598	147,486
Other current assets	100,830	116,130	77,343	49,788	-35.6	57,728	15.9	65,633	70,092	70,500
Total current assets	**160,891**	**160,513**	**123,131**	**127,160**	3.3	**149,282**	17.4	**175,136**	**198,690**	**217,986**
Net tangible fixed assets	240,497	231,249	219,346	216,646	-1.2	210,127	-3.0	199,682	189,157	179,764
Net intangible fixed assets	0	0	0	0	-	0	-	0	0	0
Investments / other assets	34,673	40,599	37,454	37,454	0.0	37,454	0.0	37,454	37,454	37,454
Total assets	**436,062**	**432,362**	**379,930**	**381,260**	0.4	**396,862**	4.1	**412,271**	**425,301**	**435,203**
Trade payables & other ST liabilities	53,241	58,768	32,651	20,281	-37.9	23,600	16.4	27,003	28,942	29,160
Short term debt	16,404	24,438	23,467	23,467	0.00	23,467	0.00	23,467	23,467	23,467
Total current liabilities	**69,645**	**83,207**	**56,119**	**43,748**	-22.0	**47,068**	7.6	**50,471**	**52,409**	**52,628**
Long term debt	120,452	95,812	89,675	89,675	0.0	89,675	0.0	89,675	89,675	89,675
Other long term liabilities	7,920	8,110	7,200	7,200	0.0	7,200	0.0	7,200	7,200	7,200
Preferred shares	0	0	0	0	-	0	-	0	0	0
Total liabilities (incl pref shares)	**198,017**	**187,128**	**152,993**	**140,623**	-8.1	**143,942**	2.4	**147,346**	**149,284**	**149,502**
Common s/h equity	222,433	238,503	224,763	238,013	5.9	249,792	4.9	261,293	271,886	281,098
Minority interests	15,612	6,731	2,174	2,624	20.7	3,128	19.2	3,633	4,131	4,602
Total liabilities & equity	**436,062**	**432,362**	**379,930**	**381,260**	0.4	**396,862**	4.1	**412,271**	**425,301**	**435,203**

Cash flow (Btm)	12/12	12/13	12/14	12/15E	% ch	12/16E	% ch	12/17E	12/18E	12/19E
Net income (before pref divs)	34,001	33,140	15,036	22,992	52.9	25,761	12.0	25,813	25,458	24,071
Depreciation & amortisation	16,815	16,737	17,371	17,747	2.2	18,057	1.7	18,538	18,942	19,394
Net change in working capital	(2,962)	(9,772)	12,670	15,185	19.9	(4,620)	-	(4,502)	(2,521)	(190)
Other operating	(44)	(77)	534	50	-90.6	50	0.0	50	50	50
Operating cash flow	**47,810**	**40,027**	**45,611**	**55,974**	22.7	**39,248**	-29.9	**39,898**	**41,929**	**43,325**
Tangible capital expenditure	(21,969)	(17,173)	(19,114)	(15,047)	21.3	(11,537)	23.3	(8,092)	(8,417)	(10,000)
Intangible capital expenditure	0	0	0	0	-	0	-	0	0	0
Net (acquisitions) / disposals	0	0	0	0	-	0	-	0	0	0
Other investing	(666)	(5,659)	1,701	(50)	-	(50)	-	(50)	(50)	(50)
Investing cash flow	**(22,634)**	**(22,832)**	**(17,412)**	**(15,097)**	13.3	**(11,587)**	23.2	**(8,142)**	**(8,467)**	**(10,050)**
Equity dividends paid	(10,534)	(19,104)	(15,097)	(9,742)	35.5	(13,982)	-43.5	(14,312)	(14,865)	(14,859)
Share issues / (buybacks)	6,123	(6,847)	(18,236)	450	-	504	12.1	505	498	471
Other financing	0	0	0	0	-	0	-	0	0	0
Change in debt & pref shares	16,691	(16,606)	(7,108)	0	-	0	-	0	0	0
Financing cash flow	**12,280**	**(42,557)**	**(40,441)**	**(9,292)**	77.0	**(13,478)**	-45.0	**(13,807)**	**(14,367)**	**(14,388)**
Cash flow inc/(dec) in cash	**37,456**	**(25,362)**	**(12,242)**	**31,584**	-	**14,183**	-55.1	**17,949**	**19,095**	**18,888**
FX / non cash items	0	9,684	13,646	0	-100.0	0	-	0	0	0
Balance sheet inc/(dec) in cash	**37,456**	**(15,678)**	**1,404**	**31,584**	NM	**14,183**	-55.1	**17,949**	**19,095**	**18,888**

Source: Company accounts, UBS estimates. (UBS) metrics use reported figures which have been adjusted by UBS analysts.[1]Cash EPS (UBS, diluted) is calculated using UBS net income adding back depreciation and amortization.

PTT Global Chemical (PTTGC.BK)

Valuation (x)	12/12	12/13	12/14	12/15E	12/16E	12/17E	12/18E	12/19E
P/E (local GAAP, diluted)	8.5	10.0	19.9	12.9	11.6	11.5	11.7	12.4
P/E (UBS, diluted)	9.1	9.3	18.7	12.9	11.6	11.5	11.7	12.4
P/CEPS	6.0	6.3	9.0	7.3	6.8	6.7	6.7	6.8
Equity FCF (UBS) yield %	9.0	6.9	8.8	13.8	9.3	10.7	11.3	11.2
Net dividend yield (%)	3.7	5.7	5.0	3.3	4.7	4.8	5.0	5.0
P/BV x	1.3	1.4	1.3	1.3	1.2	1.1	1.1	1.1
EV/revenues (core)	0.7	0.8	0.7	1.0	0.9	0.8	0.7	0.7
EV/EBITDA (core)	6.7	7.0	9.8	7.8	7.3	7.2	7.2	7.3
EV/EBIT (core)	9.6	9.6	17.8	12.3	11.2	11.1	11.3	11.8
EV/OpFCF (core)	6.9	7.1	10.2	8.0	7.5	7.4	7.4	7.5
EV/op. invested capital	1.3	1.4	1.3	1.4	1.5	1.5	1.5	1.6

Enterprise value (Btm)	12/12	12/13	12/14	12/15E	12/16E	12/17E	12/18E	12/19E
Market cap.	287,768	332,555	299,733	297,584	297,584	297,584	297,584	297,584
Net debt (cash)	87,177	87,177	87,177	87,177	87,177	87,177	87,177	87,177
Buy out of minorities	12,781	12,781	12,781	12,781	12,781	12,781	12,781	12,781
Pension provisions/other	0	0	0	0	0	0	0	0
Total enterprise value	**387,726**	**432,514**	**399,691**	**397,542**	**397,542**	**397,542**	**397,542**	**397,542**
Non core assets	(6,151)	(12,549)	(22,247)	(22,247)	(22,247)	(22,247)	(22,247)	(22,247)
Core enterprise value	**381,575**	**419,965**	**377,445**	**375,296**	**375,296**	**375,296**	**375,296**	**375,296**

Growth (%)	12/12	12/13	12/14	12/15E	12/16E	12/17E	12/18E	12/19E
Revenue	13.1	-2.3	3.8	-34.0	15.6	13.1	6.5	0.5
EBITDA (UBS)	3.9	6.7	-36.1	25.2	7.1	1.0	0.0	-2.0
EBIT (UBS)	-2.7	9.7	-51.4	44.2	10.2	0.2	-1.1	-4.5
EPS (UBS, diluted)	3.0	13.9	-55.2	43.2	12.0	0.2	-1.4	-5.4
Net DPS	-10.5	81.4	-21.0	-35.5	43.5	2.4	3.9	0.0

Margins & Profitability (%)	12/12	12/13	12/14	12/15E	12/16E	12/17E	12/18E	12/19E
Gross profit margin	8.7	9.4	5.3	10.9	10.3	9.3	8.7	8.4
EBITDA margin	10.0	10.9	6.7	12.7	11.8	10.5	9.9	9.7
EBIT margin	7.0	7.9	3.7	8.1	7.7	6.8	6.3	6.0
Net earnings (UBS) margin	5.6	6.5	2.8	6.1	5.9	5.2	4.8	4.5
ROIC (EBIT)	13.1	14.1	7.3	11.6	13.3	13.5	13.7	13.6
ROIC post tax	12.5	13.4	7.0	10.6	12.1	12.3	12.5	12.4
ROE (UBS)	15.0	15.6	6.9	9.9	10.6	10.1	9.5	8.7

Capital structure & Coverage (x)	12/12	12/13	12/14	12/15E	12/16E	12/17E	12/18E	12/19E
Net debt / EBITDA	1.4	1.3	1.7	0.7	0.4	0.1	(0.3)	(0.7)
Net debt / total equity %	32.3	30.9	29.7	14.9	8.5	1.4	(5.6)	(12.0)
Net debt / (net debt + total equity) %	24.4	23.6	22.9	12.9	7.9	1.4	(5.9)	(13.7)
Net debt/EV %	20.1	18.1	17.8	9.5	5.8	1.0	(4.1)	(9.2)
Capex / depreciation %	130.7	102.6	110.0	84.8	63.9	43.7	44.4	51.6
Capex / revenue %	3.9	3.1	3.3	4.0	2.6	1.6	1.6	1.9
EBIT / net interest	6.3	7.2	3.9	5.3	5.7	5.7	5.6	5.4
Dividend cover (UBS)	3.0	1.9	1.1	2.4	1.8	1.8	1.7	1.6
Div. payout ratio (UBS) %	33.5	53.3	94.0	42.4	54.3	55.4	58.4	61.7

Revenues by division (Btm)	12/12	12/13	12/14	12/15E	12/16E	12/17E	12/18E	12/19E
Others	565,617	552,881	574,010	378,907	437,834	495,303	527,489	529,929
Total	**565,617**	**552,881**	**574,010**	**378,907**	**437,834**	**495,303**	**527,489**	**529,929**

EBIT (UBS) by division (Btm)	12/12	12/13	12/14	12/15E	12/16E	12/17E	12/18E	12/19E
Others	39,716	43,562	21,158	30,511	33,612	33,668	33,285	31,792
Total	**39,716**	**43,562**	**21,158**	**30,511**	**33,612**	**33,668**	**33,285**	**31,792**

Source: Company accounts, UBS estimates. (UBS) metrics use reported figures which have been adjusted by UBS analysts.

Glow Energy PCL

No one handles coal better

Equities

Thailand
Electric Utilities

12-month rating	**Buy**
12m price target	**Bt100.00**
Price	**Bt86.50**

RIC: GLOW.BK **BBG:** GLOW TB

Trading data and key metrics

52-wk range	Bt101.00-80.25
Market cap.	Bt127bn/US$3.73bn
Shares o/s	1,463m (ORD)
Free float	31%
Avg. daily volume ('000)	869
Avg. daily value (m)	Bt74.8
Common s/h equity (12/15E)	Bt50.6bn
P/BV (12/15E)	2.5x
Net debt / EBITDA (12/15E)	1.8x

EPS (UBS, diluted) (Bt)

	UBS	Cons.
12/15E	6.41	6.04
12/16E	6.57	6.05
12/17E	6.23	5.98

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Most experienced in coal among listed peers

GLOW has most experience among listed Thai IPPs in developing coal-based power plants in Thailand. The company has successfully developed the GHECO-1 IPP plant in 2012—the second coal-based IPP plant in Thailand after BLCP in 2007—which it claims complies with most stringent emission norms in the world. Currently, 20% of GLOW's total generation comes from coal-based plants. Hence, we believe if IPPs are invited to develop more coal-based plants, GLOW will be front runner.

Limited geographical mandate gives a reason to compete aggressively

GLOW is 69%-held by GDF Suez, a France-based global water and electrical utility. GDF has a presence in almost all of major markets through its associates and has mandated GLOW to invest primarily in Thailand and Laos. This arrangement has limited GLOW's growth opportunities compared to that of its peers, which are able to invest in a good opportunity anywhere. However, from a different perspective, this limitation also drives GLOW to bid aggressively when a suitable opportunity is available in its markets. So far, this arrangement has worked well for investors. In the past 10 years, GLOW's share price has outperformed EGCO/RATCH/SET index by 182%/225%/148%. We believe this outperformance is not done yet and potential increase in dividend payments could be the next catalyst.

GLOW remains our top pick in the Thai power sector, Buy

As of now, GLOW does not have any new project in hand while all its existing projects are generating healthy cash flow. With no major investment opportunities in sight, we believe GLOW could use its free cash flow to increase dividend payments. However, due to uncertain timing, our estimates do not reflect this increase.

Valuation: DCF-based price target of Bt100.00

We derive our price target from DCF-based methodology. Our terminal value assumes a weighted average remaining project life of 12 years and a 5.6% WACC.

Highlights (Btm)	12/12	12/13	12/14	12/15E	12/16E	12/17E	12/18E	12/19E
Revenues	57,204	69,207	72,991	71,427	76,818	80,012	81,916	81,916
EBIT (UBS)	8,190	13,242	15,236	14,707	14,243	13,156	12,290	12,290
Net earnings (UBS)	4,949	8,117	9,196	9,379	9,616	9,109	8,747	8,747
EPS (UBS, diluted) (Bt)	3.38	5.55	6.29	6.41	6.57	6.23	5.98	5.98
DPS (Bt)	2.05	2.15	3.00	3.47	3.64	3.83	4.02	4.22
Net (debt) / cash	(61,825)	(59,545)	(50,644)	(36,140)	(26,387)	(17,366)	(8,873)	(679)

Profitability/valuation	12/12	12/13	12/14	12/15E	12/16E	12/17E	12/18E	12/19E
EBIT margin %	14.3	19.1	20.9	20.6	18.5	16.4	15.0	15.0
ROIC (EBIT) %	7.8	12.5	14.5	14.8	15.3	14.9	14.7	15.6
EV/EBITDA (core) x	12.8	9.6	9.2	9.1	8.7	8.8	8.7	8.3
P/E (UBS, diluted) x	18.5	13.2	13.3	13.5	13.2	13.9	14.5	14.5
Equity FCF (UBS) yield %	4.8	6.1	11.9	14.4	11.9	11.6	11.4	11.4
Net dividend yield %	3.3	2.9	3.6	4.0	4.2	4.4	4.6	4.9

Source: Company accounts, Thomson Reuters, UBS estimates. Metrics marked as (UBS) have had analyst adjustments applied. Valuations: based on an average share price that year, (E): based on a share price of Bt86.50 on 08 Jun 2015 20:27 HKT

Investment Thesis

Glow Energy PCL

12-month rating **Buy**

12m price target **Bt100.00**

Investment case

Glow Energy sells power under long-term contracts that provide predictable cash flow. We believe GLOW's earnings outlook currently depends mainly on the smooth functioning of its GHECO-1 plant and improvement in industrial demand. All the company's plants are operating at normal capacity and generating healthy cash flow. Since the company's debt level is set to drop sharply over the next few years, we believe GLOW could increase dividend payments and still invest in suitable opportunities.

Upside scenario

We estimate Bt112.00 valuation per share, assuming 10% upside to our current tariff and utilisation rate estimates for industrial customers.

Downside scenario

We estimate Bt90.00 valuation per share, assuming 10% downside to our current tariff and utilisation rate estimates for industrial customers.

Upcoming catalysts

Potential increase in dividend payments.

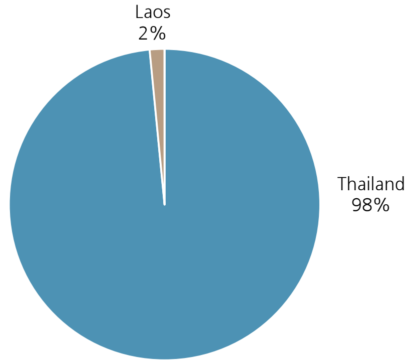
Business description

Glow Energy (GLOW) is the largest small power producer (SPP) and third-largest independent power producer (IPP) in Thailand. Its combined installed capacity is 3,256MW. It also has the capacity to produce steam, clarified water, demineralised water and chilled water. In 2014, it generated 39% of revenue from IPP sales to EGAT, 25% from SPP sales to EGAT, 24% from electricity sales to industrial customers, and 11% and 1% from steam and processed water sales, respectively. GDF Suez, a global water and electrical utility based in France, is the majority shareholder, with a 69% stake.

Industry outlook

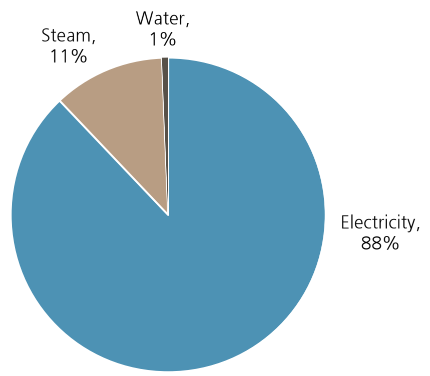
We expect power demand in Thailand to have a 3.9% CAGR until 2030. To meet this demand, the current Thailand power development plan envisions doubling the nation's generation capacity to 70GW by 2030. We expect regulators to announce an updated version of the plan soon. We expect the new plan to give more importance to coal-fired capacity than the current version. However, with a higher-than-desired current reserve margin, growth opportunities will be fewer in near term in Thailand. We expect Thai power companies to continue investing in overseas markets to chase growth.

Revenue by region (2014)



Source: Company data, UBS estimates

EBIT by product segment—2014



Source: Company data, UBS estimates

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Glow Energy PCL (GLOW.BK)

Income statement (Btm)	12/12	12/13	12/14	12/15E	% ch	12/16E	% ch	12/17E	12/18E	12/19E
Revenues	**57,204**	**69,207**	**72,991**	**71,427**	-2.1	**76,818**	7.5	**80,012**	**81,916**	**81,916**
Gross profit	13,259	18,520	20,501	20,180	-1.6	19,651	-2.6	18,557	17,705	17,705
EBITDA (UBS)	**12,584**	**18,248**	**20,002**	**19,648**	-1.8	**19,191**	-2.3	**18,110**	**17,252**	**17,252**
Depreciation & amortisation	(4,394)	(5,006)	(4,766)	(4,941)	3.7	(4,948)	0.1	(4,954)	(4,961)	(4,961)
EBIT (UBS)	**8,190**	**13,242**	**15,236**	**14,707**	-3.5	**14,243**	-3.2	**13,156**	**12,290**	**12,290**
Associates & investment income	0	0	0	0	-	0	-	0	0	0
Other non-operating income	484	0	0	0	-	0	-	0	0	0
Net interest	(2,264)	(3,321)	(3,333)	(2,770)	16.9	(2,093)	24.4	(1,646)	(1,238)	(1,238)
Exceptionals (incl goodwill)	661	(1,003)	(62)	1,089	-	0	-	0	0	0
Profit before tax	**7,071**	**8,918**	**11,841**	**13,027**	10.0	**12,151**	-6.7	**11,509**	**11,052**	**11,052**
Tax	(704)	(1,031)	(1,005)	(1,625)	-61.7	(1,516)	6.7	(1,436)	(1,379)	(1,379)
Profit after tax	**6,368**	**7,887**	**10,836**	**11,402**	5.2	**10,635**	-6.7	**10,074**	**9,673**	**9,673**
Preference dividends	0	0	0	0	-	0	-	0	0	0
Minorities	(823)	(672)	(1,697)	(1,092)	35.7	(1,018)	6.7	(965)	(926)	(926)
Extraordinary items	0	0	0	0	-	0	-	0	0	0
Net earnings (local GAAP)	**5,545**	**7,214**	**9,139**	**10,310**	12.8	**9,616**	-6.7	**9,109**	**8,747**	**8,747**
Net earnings (UBS)	**4,949**	**8,117**	**9,196**	**9,379**	2.0	**9,616**	2.5	**9,109**	**8,747**	**8,747**
Tax rate (%)	10.0	11.6	8.5	12.5	47.0	12.5	0.0	12.5	12.5	12.5

Per share (Bt)	12/12	12/13	12/14	12/15E	% ch	12/16E	% ch	12/17E	12/18E	12/19E
EPS (UBS, diluted)	3.38	5.55	6.29	6.41	2.0	6.57	2.5	6.23	5.98	5.98
EPS (local GAAP, diluted)	3.79	4.93	6.25	7.05	12.8	6.57	-6.7	6.23	5.98	5.98
EPS (UBS, basic)	3.38	5.55	6.29	6.41	2.0	6.57	2.5	6.23	5.98	5.98
Net DPS (Bt)	2.05	2.15	3.00	3.47	15.5	3.64	5.0	3.83	4.02	4.22
Cash EPS (UBS, diluted)[1]	6.39	8.97	9.54	9.79	2.6	9.96	1.7	9.61	9.37	9.37
Book value per share	25.14	27.74	30.99	34.56	11.5	37.49	8.5	39.89	41.86	43.62
Average shares (diluted)	1,462.87	1,462.87	1,462.87	1,462.87	0.0	1,462.87	0.0	1,462.87	1,462.87	1,462.87

Balance sheet (Btm)	12/12	12/13	12/14	12/15E	% ch	12/16E	% ch	12/17E	12/18E	12/19E
Cash and equivalents	12,996	5,760	5,807	8,540	47.1	10,177	19.2	11,066	12,946	16,328
Other current assets	14,310	19,687	19,388	15,437	-20.4	16,602	7.5	17,292	17,704	17,704
Total current assets	**27,305**	**25,446**	**25,196**	**23,977**	-4.8	**26,780**	11.7	**28,358**	**30,650**	**34,032**
Net tangible fixed assets	100,770	97,301	91,888	87,147	-5.2	82,400	-5.4	77,645	72,884	68,116
Net intangible fixed assets	0	0	0	0	-	0	-	0	0	0
Investments / other assets	1,544	2,259	3,238	1,910	-41.0	1,922	0.6	1,934	1,947	1,959
Total assets	**129,619**	**125,006**	**120,322**	**113,034**	-6.1	**111,102**	-1.7	**107,938**	**105,481**	**104,106**
Trade payables & other ST liabilities	11,262	10,837	9,438	8,641	-8.4	9,520	10.2	10,012	10,371	10,306
Short term debt	12,613	10,711	10,757	8,116	-24.56	8,133	0.21	6,613	4,812	1,044
Total current liabilities	**23,875**	**21,548**	**20,195**	**16,757**	-17.0	**17,652**	5.3	**16,624**	**15,183**	**11,350**
Long term debt	62,208	54,594	45,694	36,564	-20.0	28,431	-22.2	21,819	17,007	15,963
Other long term liabilities	589	1,604	1,862	818	-56.1	818	0.0	818	818	818
Preferred shares	0	0	0	0	-	0	-	0	0	0
Total liabilities (incl pref shares)	**86,671**	**77,746**	**67,752**	**54,138**	-20.1	**46,902**	-13.4	**39,261**	**33,008**	**28,130**
Common s/h equity	36,781	40,576	45,330	50,563	11.5	54,848	8.5	58,360	61,231	63,807
Minority interests	6,167	6,683	7,241	8,333	15.1	9,352	12.2	10,316	11,243	12,169
Total liabilities & equity	**129,619**	**125,006**	**120,322**	**113,034**	-6.1	**111,102**	-1.7	**107,938**	**105,481**	**104,106**

Cash flow (Btm)	12/12	12/13	12/14	12/15E	% ch	12/16E	% ch	12/17E	12/18E	12/19E
Net income (before pref divs)	5,545	7,214	9,139	10,310	12.8	9,616	-6.7	9,109	8,747	8,747
Depreciation & amortisation	4,394	5,006	4,766	4,941	3.7	4,948	0.1	4,954	4,961	4,961
Net change in working capital	1,745	(5,816)	(1,101)	3,155	-	(287)	-	(198)	(52)	(65)
Other operating	(322)	1,675	1,759	3	-99.8	1,018	NM	965	926	926
Operating cash flow	**11,361**	**8,079**	**14,562**	**18,408**	26.4	**15,296**	-16.9	**14,830**	**14,582**	**14,570**
Tangible capital expenditure	(6,933)	(1,537)	(1)	(200)	NM	(200)	0.0	(200)	(200)	(193)
Intangible capital expenditure	0	0	0	0	-	0	-	0	0	0
Net (acquisitions) / disposals	2,660	245	94	0	-100.0	0	-	0	0	0
Other investing	292	300	(721)	284	-	(12)	-	(12)	(12)	(12)
Investing cash flow	**(3,981)**	**(992)**	**(629)**	**84**	-	**(212)**	-	**(212)**	**(212)**	**(205)**
Equity dividends paid	(2,996)	(3,148)	(4,835)	(5,077)	-5.0	(5,330)	-5.0	(5,597)	(5,877)	(6,171)
Share issues / (buybacks)	(19)	(271)	449	0	-	0	-	0	0	0
Other financing	0	0	0	0	-	0	-	0	0	0
Change in debt & pref shares	1,768	(10,518)	(8,915)	(10,683)	-19.82	(8,115)	24.03	(8,133)	(6,613)	(4,812)
Financing cash flow	**(1,247)**	**(13,938)**	**(13,301)**	**(15,759)**	-18.5	**(13,446)**	14.7	**(13,730)**	**(12,489)**	**(10,983)**
Cash flow inc/(dec) in cash	**6,133**	**(6,851)**	**633**	**2,732**	331.8	**1,638**	-40.1	**888**	**1,881**	**3,382**
FX / non cash items	(1,821)	(385)	(585)	0	100.0	0	-	0	0	0
Balance sheet inc/(dec) in cash	**4,312**	**(7,236)**	**48**	**2,732**	NM	**1,638**	-40.1	**888**	**1,881**	**3,382**

Source: Company accounts, UBS estimates. (UBS) metrics use reported figures which have been adjusted by UBS analysts.[1]Cash EPS (UBS, diluted) is calculated using UBS net income adding back depreciation and amortization.

Glow Energy PCL (GLOW.BK)

Valuation (x)	12/12	12/13	12/14	12/15E	12/16E	12/17E	12/18E	12/19E
P/E (local GAAP, diluted)	16.5	14.8	13.4	12.3	13.2	13.9	14.5	14.5
P/E (UBS, diluted)	18.5	13.2	13.3	13.5	13.2	13.9	14.5	14.5
P/CEPS	9.8	8.2	8.8	8.8	8.7	9.0	9.2	9.2
Equity FCF (UBS) yield %	4.8	6.1	11.9	14.4	11.9	11.6	11.4	11.4
Net dividend yield (%)	3.3	2.9	3.6	4.0	4.2	4.4	4.6	4.9
P/BV x	2.5	2.6	2.7	2.5	2.3	2.2	2.1	2.0
EV/revenues (core)	2.8	2.5	2.5	2.5	2.2	2.0	1.8	1.8
EV/EBITDA (core)	12.8	9.6	9.2	9.1	8.7	8.8	8.7	8.3
EV/EBIT (core)	19.7	13.2	12.1	12.1	11.7	12.1	12.3	11.7
EV/OpFCF (core)	13.1	9.9	9.5	9.3	8.9	9.0	9.0	8.6
EV/op. invested capital	1.5	1.6	1.8	1.8	1.8	1.8	1.8	1.8

Enterprise value (Btm)	12/12	12/13	12/14	12/15E	12/16E	12/17E	12/18E	12/19E
Market cap.	91,484	107,034	122,544	126,538	126,538	126,538	126,538	126,538
Net debt (cash)	63,428	60,685	55,095	43,392	31,263	21,876	13,119	4,776
Buy out of minorities	6,167	6,683	7,241	8,333	9,352	10,316	11,243	12,169
Pension provisions/other	0	0	0	0	0	0	0	0
Total enterprise value	**161,078**	**174,403**	**184,879**	**178,263**	**167,153**	**158,731**	**150,900**	**143,483**
Non core assets	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)
Core enterprise value	**161,076**	**174,401**	**184,877**	**178,261**	**167,151**	**158,729**	**150,898**	**143,481**

Growth (%)	12/12	12/13	12/14	12/15E	12/16E	12/17E	12/18E	12/19E
Revenue	41.7	21.0	5.5	-2.1	7.5	4.2	2.4	0.0
EBITDA (UBS)	34.3	45.0	9.6	-1.8	-2.3	-5.6	-4.7	0.0
EBIT (UBS)	34.2	61.7	15.1	-3.5	-3.2	-7.6	-6.6	0.0
EPS (UBS, diluted)	18.9	64.0	13.3	2.0	2.5	-5.3	-4.0	0.0
Net DPS	5.0	5.1	39.6	15.5	5.0	5.0	5.0	5.0

Margins & Profitability (%)	12/12	12/13	12/14	12/15E	12/16E	12/17E	12/18E	12/19E
Gross profit margin	23.2	26.8	28.1	28.3	25.6	23.2	21.6	21.6
EBITDA margin	22.0	26.4	27.4	27.5	25.0	22.6	21.1	21.1
EBIT margin	14.3	19.1	20.9	20.6	18.5	16.4	15.0	15.0
Net earnings (UBS) margin	8.7	11.7	12.6	13.1	12.5	11.4	10.7	10.7
ROIC (EBIT)	7.8	12.5	14.5	14.8	15.3	14.9	14.7	15.6
ROIC post tax	7.1	11.1	13.3	13.0	13.4	13.0	12.9	13.6
ROE (UBS)	13.9	21.0	21.4	19.6	18.2	16.1	14.6	14.0

Capital structure & Coverage (x)	12/12	12/13	12/14	12/15E	12/16E	12/17E	12/18E	12/19E
Net debt / EBITDA	4.9	3.3	2.5	1.8	1.4	1.0	0.5	0.0
Net debt / total equity %	144.0	126.0	96.3	61.4	41.1	25.3	12.2	0.9
Net debt / (net debt + total equity) %	59.0	55.8	49.1	38.0	29.1	20.2	10.9	0.9
Net debt/EV %	38.4	34.1	27.4	20.3	15.8	10.9	5.9	0.5
Capex / depreciation %	157.8	30.7	0.0	4.0	4.0	4.0	4.0	3.9
Capex / revenue %	12.1	2.2	0.0	0.3	0.3	0.2	0.2	0.2
EBIT / net interest	3.6	4.0	4.6	5.3	6.8	8.0	9.9	9.9
Dividend cover (UBS)	1.7	2.6	2.1	1.8	1.8	1.6	1.5	1.4
Div. payout ratio (UBS) %	60.5	38.8	47.8	54.1	55.4	61.4	67.2	70.5

Revenues by division (Btm)	12/12	12/13	12/14	12/15E	12/16E	12/17E	12/18E	12/19E
Others	57,204	69,207	72,991	71,427	76,818	80,012	81,916	81,916
Total	**57,204**	**69,207**	**72,991**	**71,427**	**76,818**	**80,012**	**81,916**	**81,916**

EBIT (UBS) by division (Btm)	12/12	12/13	12/14	12/15E	12/16E	12/17E	12/18E	12/19E
Others	8,190	13,242	15,236	14,707	14,243	13,156	12,290	12,290
Total	**8,190**	**13,242**	**15,236**	**14,707**	**14,243**	**13,156**	**12,290**	**12,290**

Source: Company accounts, UBS estimates. (UBS) metrics use reported figures which have been adjusted by UBS analysts.

Electricity Generating Co.
Riskless growth

Equities

Thailand
Electric Utilities

12-month rating	**Neutral**
12m price target	**Bt160.00**
Price	**Bt153.00**

RIC: EGCO.BK **BBG:** EGCO TB

Trading data and key metrics

52-wk range	Bt176.00-132.50
Market cap.	Bt80.5bn/US$2.37bn
Shares o/s	526m (ORD)
Free float	44%
Avg. daily volume ('000)	409
Avg. daily value (m)	Bt62.0
Common s/h equity (12/15E)	Bt77.5bn
P/BV (12/15E)	1.0x
Net debt / EBITDA (12/15E)	11.1x

EPS (UBS, diluted) (Bt)

	UBS	Cons.
12/15E	14.93	14.24
12/16E	14.79	15.77
12/17E	17.29	18.00

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This is a lot of coal
About 30% of EGCO's total attributable capacity is coal-based, even higher than GLOW's. This includes BLCP in Thailand and Quezon and Masinloc in the Philippines. But unlike GLOW, EGCO did not develop any of these plants by itself and had acquired stakes after the plants were built and were operational. However, we believe EGCO should be able to leverage BLCP's experience in developing coal-based plants, if an opportunity arrives. Also, the company is expanding the Quezon power plant and plans to expand the Masinloc plant, which should give it considerable experience with coal.

EGCO has been able to grow wisely; we expect the strategy to be maintained
The company has avoided taking too much risk and has been focused largely on domestic and growing neighbouring markets such as Laos and the Philippines. The company sells most of generation under secure long-term PPAs. Most of its acquisitions have been value-accretive. One of the key reasons of EGCO's growth has been its good relations with the regulators, in our view. This was evident when, in 2012, EGCO received the rights to develop a new IPP in Khanom to replace its expiring plant at same location, without needing to compete.

Most exciting new capacity line up, but share price reflects it all
EGCO is developing a new IPP plant and three new SPP plants in Thailand, the Quezon extension in the Philippines and a wind farm in Australia apart from a few smaller plants. However, as we think the share price reflects all these plants we maintain our Neutral rating on the stock.

Valuation: DCF-based price target of Bt160.00
Terminal value assumes an average remaining project life of 17 years and a 5.3% WACC.

Highlights (Btm)	12/12	12/13	12/14	12/15E	12/16E	12/17E	12/18E	12/19E
Revenues	14,057	17,458	17,201	16,733	19,854	32,706	35,795	35,408
EBIT (UBS)	2,127	4,992	5,584	3,175	3,099	5,572	5,716	5,523
Net earnings (UBS)	6,248	7,330	8,180	7,859	7,784	9,102	9,302	9,434
EPS (UBS, diluted) (Bt)	11.87	13.92	15.54	14.93	14.79	17.29	17.67	17.92
DPS (Bt)	5.50	6.00	6.00	6.00	6.00	7.00	7.00	7.00
Net (debt) / cash	(31,608)	(42,115)	(68,140)	(66,994)	(69,544)	(69,483)	(65,891)	(57,487)

Profitability/valuation	12/12	12/13	12/14	12/15E	12/16E	12/17E	12/18E	12/19E
EBIT margin %	15.1	28.6	32.5	19.0	15.6	17.0	16.0	15.6
ROIC (EBIT) %	5.2	7.4	7.1	3.8	3.5	6.1	6.1	6.1
EV/EBITDA (core) x	8.5	8.9	9.0	15.3	15.0	11.2	9.7	9.8
P/E (UBS, diluted) x	9.4	10.1	9.4	10.2	10.3	8.9	8.7	8.5
Equity FCF (UBS) yield %	(49.3)	(6.2)	(10.9)	(8.7)	(6.6)	(2.5)	3.9	7.9
Net dividend yield %	4.9	4.3	4.1	3.9	3.9	4.6	4.6	4.6

Source: Company accounts, Thomson Reuters, UBS estimates. Metrics marked as (UBS) have had analyst adjustments applied. Valuations: based on an average share price that year, (E): based on a share price of Bt153.00 on 08 Jun 2015 20:27 HKT

Investment Thesis

Electricity Generating Co.

12-month rating **Neutral**

12m price target **Bt160.00**

Investment case

Electricity Generating's (EGCO) major domestic plants have power purchase agreements that provide reliable cash flow but are nearing their retirement age. With limited domestic opportunities, EGCO is pursuing opportunities overseas and recently acquired a wind farm in Australia, signed an agreement to expand capacity in the Quezon Power project in the Philippines and acquired Masinloc power plants in the Philippines. We expect these projects to contribute stable and reliable cash flow from 2015 onwards. We believe the stock is fairly valued at the current price and could provide a reasonable dividend yield.

Upside scenario

Upside valuation of Bt179.00/share, assuming 5% upside to our EBITDA and dividend from associate estimates from 2019 onwards.

Downside scenario

Downside valuation of Bt154.00/share, assuming 5% downside to our EBITDA and dividend from associates estimates from 2019 onwards.

Upcoming catalysts

1) New IPP plant in Khanom will begin operations in 2016.
2) New value-accretive investments, though the timing is uncertain.

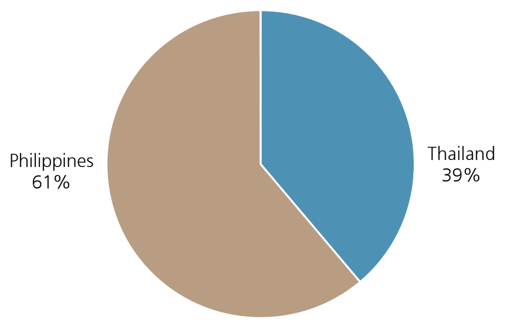
Business description

Electricity Generating Co (EGCO) is an independent power producer that was spun off from the Electricity Generating Authority of Thailand (EGAT) in 1994. Its main assets are one wholly-owned subsidiary Khanom (824MW, CCGT and thermal), 98%-owned Quezon Power in the Philippines (500MW coal fired), a 50% stake in BLCP (1,400MW coal fired), and a 25% stake in Khaeng Khoi 2 (1,400MW gas fired). It sells most of its power to EGAT on long-term power purchase agreements. Its major shareholders are EGAT (25%), Tokyo Electric Power (11%) and Mitsubishi Corporation (11%).

Industry outlook

We expect power demand in Thailand to have a 3.9% CAGR until 2030. To meet this demand, the current Thailand power development plan envisions doubling the nation's generation capacity to 70GW by 2030. We expect regulators to announce an updated version of the plan soon. We expect the new plan to give more importance to coal-fired capacity than the current version. However, with higher-than-desired current reserve margin, we believe there will be fewer growth opportunities near term in Thailand. We expect Thai power companies to continue investing in overseas markets to chase growth.

Revenues by region (2014)



Source: Company data

EBIT by product segment

In 2014, EGCO earned almost all its EBIT from electricity generation.

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Electricity Generating Co. (EGCO.BK)

Income statement (Btm)	12/12	12/13	12/14	12/15E	% ch	12/16E	% ch	12/17E	12/18E	12/19E
Revenues	**14,057**	**17,458**	**17,201**	**16,733**	*-2.7*	**19,854**	*18.7*	**32,706**	**35,795**	**35,408**
Gross profit	4,384	7,062	6,891	5,357	*-22.3*	5,372	*0.3*	7,581	7,787	7,622
EBITDA (UBS)	**5,188**	**8,700**	**8,641**	**6,043**	*-30.1*	**6,083**	*0.7*	**8,135**	**8,773**	**8,708**
Depreciation & amortisation	(3,060)	(3,707)	(3,057)	(2,869)	*-6.2*	(2,984)	*4.0*	(2,563)	(3,057)	(3,185)
EBIT (UBS)	**2,127**	**4,992**	**5,584**	**3,175**	*-43.1*	**3,099**	*-2.4*	**5,572**	**5,716**	**5,523**
Associates & investment income	5,551	5,497	5,735	7,819	*36.3*	7,676	*-1.8*	7,666	7,829	7,910
Other non-operating income	0	0	0	0	-	0	-	0	0	0
Net interest	(942)	(1,578)	(2,023)	(2,066)	*-2.1*	(2,010)	*2.7*	(3,139)	(3,274)	(3,054)
Exceptionals (incl goodwill)	742	(276)	(697)	112	-	0	-	0	0	0
Profit before tax	**7,479**	**8,635**	**8,599**	**9,040**	*5.1*	**8,765**	*-3.0*	**10,098**	**10,272**	**10,378**
Tax	(520)	(1,306)	(792)	(961)	*-21.2*	(859)	*10.5*	(851)	(824)	(800)
Profit after tax	**6,959**	**7,328**	**7,807**	**8,079**	*3.5*	**7,906**	*-2.1*	**9,248**	**9,447**	**9,578**
Preference dividends	0	0	0	0	-	0	-	0	0	0
Minorities	(29)	(164)	(140)	(134)	*4.4*	(121)	*9.2*	(146)	(145)	(144)
Extraordinary items	4,310	0	0	0	-	0	-	0	0	0
Net earnings (local GAAP)	**11,240**	**7,164**	**7,667**	**7,945**	*3.6*	**7,784**	*-2.0*	**9,102**	**9,302**	**9,434**
Net earnings (UBS)	**6,248**	**7,330**	**8,180**	**7,859**	*-3.9*	**7,784**	*-1.0*	**9,102**	**9,302**	**9,434**
Tax rate (%)	7.0	15.1	9.2	10.6	*15.3*	9.8	*-7.7*	8.4	8.0	7.7

Per share (Bt)	12/12	12/13	12/14	12/15E	% ch	12/16E	% ch	12/17E	12/18E	12/19E
EPS (UBS, diluted)	11.87	13.92	15.54	14.93	*-3.9*	14.79	*-1.0*	17.29	17.67	17.92
EPS (local GAAP, diluted)	21.35	13.61	14.56	15.09	*3.6*	14.79	*-2.0*	17.29	17.67	17.92
EPS (UBS, basic)	11.87	13.92	15.54	14.93	*-3.9*	14.79	*-1.0*	17.29	17.67	17.92
Net DPS (Bt)	5.50	6.00	6.00	6.00	*0.0*	6.00	*0.0*	7.00	7.00	7.00
Cash EPS (UBS, diluted)[1]	17.68	20.97	21.34	20.38	*-4.5*	20.45	*0.4*	22.16	23.48	23.97
Book value per share	121.87	131.71	139.16	147.08	*5.7*	155.87	*6.0*	166.15	176.82	187.73
Average shares (diluted)	526.47	526.47	526.47	526.47	*0.0*	526.47	*0.0*	526.47	526.47	526.47

Balance sheet (Btm)	12/12	12/13	12/14	12/15E	% ch	12/16E	% ch	12/17E	12/18E	12/19E
Cash and equivalents	4,282	7,114	7,228	10,441	*44.5*	9,337	*-10.6*	5,540	6,858	9,867
Other current assets	15,565	16,924	16,100	14,128	*-12.2*	16,818	*19.0*	22,698	24,768	24,802
Total current assets	**19,846**	**24,038**	**23,328**	**24,570**	*5.3*	**26,155**	*6.5*	**28,239**	**31,627**	**34,669**
Net tangible fixed assets	38,556	44,521	55,275	40,131	*-27.4*	43,077	*7.3*	62,845	62,819	63,657
Net intangible fixed assets	15,061	15,476	15,086	14,313	*-5.1*	14,063	*-1.7*	13,814	13,564	13,315
Investments / other assets	36,926	47,085	66,998	86,681	*29.4*	89,194	*2.9*	71,696	72,675	69,466
Total assets	**110,389**	**131,120**	**160,687**	**165,695**	*3.1*	**172,489**	*4.1*	**176,593**	**180,685**	**181,107**
Trade payables & other ST liabilities	3,047	3,796	3,052	3,413	*11.8*	4,014	*17.6*	6,413	7,017	6,942
Short term debt	11,724	6,991	15,681	15,935	*1.62*	19,935	*25.10*	19,935	19,935	19,500
Total current liabilities	**14,772**	**10,788**	**18,734**	**19,347**	*3.3*	**23,948**	*23.8*	**26,348**	**26,952**	**26,442**
Long term debt	24,165	42,238	59,686	61,500	*3.0*	58,946	*-4.2*	55,088	52,815	47,854
Other long term liabilities	6,451	7,842	8,048	6,238	*-22.5*	6,238	*0.0*	6,238	6,238	6,238
Preferred shares	0	0	0	0	-	0	-	0	0	0
Total liabilities (incl pref shares)	**45,388**	**60,868**	**86,468**	**87,086**	*0.7*	**89,133**	*2.4*	**87,675**	**86,005**	**80,534**
Common s/h equity	64,160	69,343	73,264	77,460	*5.7*	82,086	*6.0*	87,502	93,119	98,868
Minority interests	841	910	955	1,148	*20.3*	1,270	*10.6*	1,416	1,561	1,705
Total liabilities & equity	**110,389**	**131,120**	**160,687**	**165,695**	*3.1*	**172,489**	*4.1*	**176,593**	**180,685**	**181,107**

Cash flow (Btm)	12/12	12/13	12/14	12/15E	% ch	12/16E	% ch	12/17E	12/18E	12/19E
Net income (before pref divs)	11,240	7,164	7,667	7,945	*3.6*	7,784	*-2.0*	9,102	9,302	9,434
Depreciation & amortisation	3,060	3,707	3,057	2,869	*-6.2*	2,984	*4.0*	2,563	3,057	3,185
Net change in working capital	(4,208)	(666)	80	2,332	*NM*	(2,088)	-	(3,481)	(1,466)	(109)
Other operating	(10,589)	(5,360)	(5,601)	(7,663)	*-36.8*	(7,521)	*1.9*	(7,510)	(7,674)	(6,086)
Operating cash flow	**(496)**	**4,845**	**5,203**	**5,483**	*5.4*	**1,159**	*-78.9*	**674**	**3,219**	**6,425**
Tangible capital expenditure	(28,344)	(9,423)	(13,562)	(12,462)	*8.1*	(6,450)	*48.2*	(2,681)	(100)	(100)
Intangible capital expenditure	0	0	0	0	-	0	-	0	0	0
Net (acquisitions) / disposals	0	0	0	0	-	0	-	0	0	0
Other investing	14,213	(4,013)	(14,204)	12,050	-	5,778	-	5,607	4,012	7,290
Investing cash flow	**(14,131)**	**(13,436)**	**(27,766)**	**(412)**	*98.5*	**(672)**	*-63.0*	**2,926**	**3,912**	**7,190**
Equity dividends paid	(3,000)	(3,159)	(3,159)	(3,159)	*0.0*	(3,159)	*0.0*	(3,685)	(3,685)	(3,685)
Share issues / (buybacks)	4	1,177	(587)	(590)	*-0.6*	0	*100.0*	0	0	0
Other financing	0	69	45	194	*332.86*	121	*-37.29*	146	145	144
Change in debt & pref shares	9,781	13,340	26,139	2,067	*-92.09*	1,446	*-30.06*	(3,858)	(2,273)	(5,395)
Financing cash flow	**6,785**	**11,427**	**22,438**	**(1,488)**	-	**(1,592)**	*-7.0*	**(7,397)**	**(5,813)**	**(8,937)**
Cash flow inc/(dec) in cash	**(7,842)**	**2,836**	**(125)**	**3,582**	-	**(1,104)**	-	**(3,797)**	**1,318**	**4,677**
FX / non cash items	1,438	(4)	239	(369)	-	0	-	0	0	(1,668)
Balance sheet inc/(dec) in cash	**(6,404)**	**2,832**	**114**	**3,213**	*NM*	**(1,104)**	-	**(3,797)**	**1,318**	**3,009**

Source: Company accounts, UBS estimates. (UBS) metrics use reported figures which have been adjusted by UBS analysts.[1]Cash EPS (UBS, diluted) is calculated using UBS net income adding back depreciation and amortization.

Electricity Generating Co. (EGCO.BK)

Valuation (x)	12/12	12/13	12/14	12/15E	12/16E	12/17E	12/18E	12/19E
P/E (local GAAP, diluted)	5.2	10.3	10.0	10.1	10.3	8.9	8.7	8.5
P/E (UBS, diluted)	9.4	10.1	9.4	10.2	10.3	8.9	8.7	8.5
P/CEPS	6.3	6.7	6.9	7.5	7.5	6.9	6.5	6.4
Equity FCF (UBS) yield %	(49.3)	(6.2)	(10.9)	(8.7)	(6.6)	(2.5)	3.9	7.9
Net dividend yield (%)	4.9	4.3	4.1	3.9	3.9	4.6	4.6	4.6
P/BV x	0.9	1.1	1.1	1.0	1.0	0.9	0.9	0.8
EV/revenues (core)	3.1	4.4	4.5	5.5	4.6	2.8	2.4	2.4
EV/EBITDA (core)	8.5	8.9	9.0	15.3	15.0	11.2	9.7	9.8
EV/EBIT (core)	20.6	15.6	13.9	29.1	29.5	16.3	15.0	15.4
EV/OpFCF (core)	9.5	9.6	9.6	16.6	16.6	12.2	10.7	10.7
EV/op. invested capital	1.1	1.1	1.0	1.1	1.0	1.0	0.9	0.9

Enterprise value (Btm)	12/12	12/13	12/14	12/15E	12/16E	12/17E	12/18E	12/19E
Market cap.	58,516	73,853	77,035	80,549	80,549	80,549	80,549	80,549
Net debt (cash)	16,490	36,861	55,127	67,567	68,269	69,513	67,687	67,687
Buy out of minorities	841	910	955	1,148	1,270	1,416	1,561	1,705
Pension provisions/other	0	0	0	0	0	0	0	0
Total enterprise value	**75,847**	**111,625**	**133,117**	**149,264**	**150,088**	**151,478**	**149,797**	**149,941**
Non core assets	(31,924)	(33,975)	(55,771)	(56,958)	(58,701)	(60,604)	(64,265)	(64,729)
Core enterprise value	**43,923**	**77,649**	**77,346**	**92,306**	**91,387**	**90,875**	**85,533**	**85,212**

Growth (%)	12/12	12/13	12/14	12/15E	12/16E	12/17E	12/18E	12/19E
Revenue	83.5	24.2	-1.5	-2.7	18.7	64.7	9.4	-1.1
EBITDA (UBS)	87.4	67.7	-0.7	-30.1	0.7	33.7	7.8	-0.7
EBIT (UBS)	NM	134.7	11.9	-43.1	-2.4	79.8	2.6	-3.4
EPS (UBS, diluted)	19.8	17.3	11.6	-3.9	-1.0	16.9	2.2	1.4
Net DPS	4.8	9.1	0.0	0.0	0.0	16.7	0.0	0.0

Margins & Profitability (%)	12/12	12/13	12/14	12/15E	12/16E	12/17E	12/18E	12/19E
Gross profit margin	31.2	40.5	40.1	32.0	27.1	23.2	21.8	21.5
EBITDA margin	36.9	49.8	50.2	36.1	30.6	24.9	24.5	24.6
EBIT margin	15.1	28.6	32.5	19.0	15.6	17.0	16.0	15.6
Net earnings (UBS) margin	44.4	42.0	47.6	47.0	39.2	27.8	26.0	26.6
ROIC (EBIT)	5.2	7.4	7.1	3.8	3.5	6.1	6.1	6.1
ROIC post tax	3.2	4.3	5.1	0.6	0.7	3.9	4.1	4.1
ROE (UBS)	10.2	11.0	11.5	10.4	9.8	10.7	10.3	9.8

Capital structure & Coverage (x)	12/12	12/13	12/14	12/15E	12/16E	12/17E	12/18E	12/19E
Net debt / EBITDA	6.1	4.8	7.9	11.1	11.4	8.5	7.5	6.6
Net debt / total equity %	48.6	59.9	91.8	85.2	83.4	78.1	69.6	57.2
Net debt / (net debt + total equity) %	32.7	37.5	47.9	46.0	45.5	43.9	41.0	36.4
Net debt/EV %	72.0	54.2	88.1	72.6	76.1	76.5	77.0	67.5
Capex / depreciation %	NM	NM	NM	NM	NM	115.9	3.6	3.4
Capex / revenue %	NM	NM	NM	NM	NM	8.2	0.3	0.3
EBIT / net interest	2.3	3.2	2.8	1.5	1.5	1.8	1.7	1.8
Dividend cover (UBS)	2.2	2.3	2.6	2.5	2.5	2.5	2.5	2.6
Div. payout ratio (UBS) %	46.3	43.1	38.6	40.2	40.6	40.5	39.6	39.1

Revenues by division (Btm)	12/12	12/13	12/14	12/15E	12/16E	12/17E	12/18E	12/19E
Others	14,057	17,458	17,201	16,733	19,854	32,706	35,795	35,408
Total	**14,057**	**17,458**	**17,201**	**16,733**	**19,854**	**32,706**	**35,795**	**35,408**

EBIT (UBS) by division (Btm)	12/12	12/13	12/14	12/15E	12/16E	12/17E	12/18E	12/19E
Others	2,127	4,992	5,584	3,175	3,099	5,572	5,716	5,523
Total	**2,127**	**4,992**	**5,584**	**3,175**	**3,099**	**5,572**	**5,716**	**5,523**

Source: Company accounts, UBS estimates. (UBS) metrics use reported figures which have been adjusted by UBS analysts.

Ratchaburi Electric

To be or not to be – in Australia

Equities

Thailand
Electric Utilities

12-month rating	**Sell**
12m price target	**Bt47.00**
Price	**Bt58.00**

RIC: RATCH.BK **BBG:** RATCH TB

Trading data and key metrics

52-wk range	Bt62.50-52.75
Market cap.	Bt84.1bn/US$2.48bn
Shares o/s	1,450m (ORD)
Free float	38%
Avg. daily volume ('000)	773
Avg. daily value (m)	Bt46.5
Common s/h equity (12/15E)	Bt59.3bn
P/BV (12/15E)	1.4x
Net debt / EBITDA (12/15E)	1.8x

EPS (UBS, diluted) (Bt)

	UBS	Cons.
12/15E	3.56	4.51
12/16E	4.63	5.50
12/17E	4.09	5.45

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All gas, no coal in Thailand

Ratchaburi Electric (RATCH) is the largest IPP in Thailand and all its domestic plants are gas-based. But, in recent years, the company has not been able to add significant capacity in Thailand, because it could not participate in last two IPP bidding rounds for different reasons. However, the company made up for this by developing several power plants in Laos to export power back to Thailand, which essentially provides same PPA benefits as a plant in Thailand. However, we think the company lacked decisive execution capability when needed, in Thailand as well as overseas, especially in Australia. Hence, we believe it will take a few successfully executed major value-accretive investments for the stock to deserve rerating from current level.

Australia exit would be positive, if happens

RATCH entered Australia in 2011 with acquisition of Transfield Services Infrastructure Fund. However, the company has not earned a meaningful return from this business, due mainly to a high interest cost and deterioration in demand and merchant prices. We estimate 2013/2014 recurring net income contribution from this business was only Bt34m/Bt20m, implying a net margin of just about 1%. Recently, few media reports have indicated that RATCH is considering selling its Australia business. We think an exit from Australia would be positive as it could lead management to deploy any proceeds into more productive investments.

Hongsa plant should boost earnings as well as experience in coal/lignite

The first unit of RATCH's 40% owned Hongsa lignite power plant in Laos (1,878MW) began operations in early June 2015 and we expect the remaining two units to be operational by mid-2016. A successful operation will increase RATCH's earnings as well as confidence in handling coal/lignite-based plants. This could come in handy if coal-based capacity is offered to IPPs in Thailand.

Valuation: DCF-based price target of Bt47.00

Our terminal value assumes an average remaining project life of 12 years and a 6.4% WACC.

Highlights (Btm)	12/12	12/13	12/14	12/15E	12/16E	12/17E	12/18E	12/19E
Revenues	56,006	49,885	56,350	53,752	53,606	51,618	50,153	50,153
EBIT (UBS)	7,219	7,417	6,871	6,349	6,370	4,330	2,924	2,924
Net earnings (UBS)	5,737	5,901	5,648	5,157	6,713	5,932	5,549	5,549
EPS (UBS, diluted) (Bt)	3.96	4.07	3.90	3.56	4.63	4.09	3.83	3.83
DPS (Bt)	2.27	2.27	2.27	2.27	2.50	2.50	2.50	0.00
Net (debt) / cash	(17,870)	(13,060)	(8,040)	(17,681)	(12,902)	(8,561)	(3,599)	(3,599)

Profitability/valuation	12/12	12/13	12/14	12/15E	12/16E	12/17E	12/18E	12/19E
EBIT margin %	12.9	14.9	12.2	11.8	11.9	8.4	5.8	5.8
ROIC (EBIT) %	12.9	13.4	12.5	12.7	14.3	10.5	7.7	8.1
EV/EBITDA (core) x	7.0	9.4	9.7	7.2	7.5	8.6	9.9	9.5
P/E (UBS, diluted) x	11.7	13.5	14.1	16.3	12.5	14.2	15.2	15.2
Equity FCF (UBS) yield %	12.2	(5.0)	0.3	15.6	7.9	5.8	5.3	2.0
Net dividend yield %	4.9	4.1	4.1	3.9	4.3	4.3	4.3	0.0

Source: Company accounts, Thomson Reuters, UBS estimates. Metrics marked as (UBS) have had analyst adjustments applied. Valuations: based on an average share price that year, (E): based on a share price of Bt58.00 on 08 Jun 2015 20:27 HKT

Investment Thesis

Ratchaburi Electric

12-month rating **Sell**

12m price target **Bt47.00**

Investment case

While Ratchaburi Electric's (RATCH) Thai and Laotian projects generate predictable and secure cash flow from selling power under long-term contracts, the Australian unit has yet to contribute meaningful earnings. In recent years, RATCH has been unable to increase capacity materially in the domestic market and has been expanding overseas, especially in Australia. We believe exposure to Australia has increased its risk profile, as weak demand in the National Energy Market, coupled with rising supply capacity from renewable power, has resulted in depressed power prices.

Upside scenario

Our upside scenario is Bt51.00, assuming 10% upside to our earnings estimates from an improvement in RATCH's Australian business.

Downside scenario

Our downside scenario is Bt44.00, assuming the Hongsa power plant in Laos is delayed by a year to 2017 and generates lower-than-expected ROE.

Upcoming catalysts

RATCH has said it is looking to make new investments—we think significant acquisitions at reasonable prices would be a positive catalyst. However, the timing and size of acquisitions are uncertain.

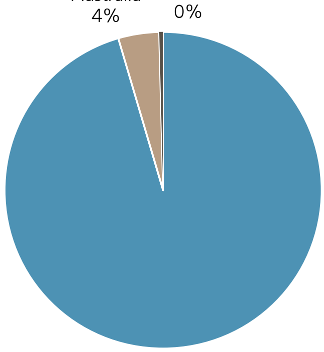
Business description

Ratchaburi Electric (RATCH) is the second independent power producer (IPP) to be spun off from the Electricity Generating Authority of Thailand (EGAT). Ratchaburi's power plant incorporates two thermal units (1,470 MW) and three combined cycle blocks (2,175 MW), making it Thailand's biggest power plant. RATCH also holds a 100% stake in the Tri-Energy (700 MW) power plant and a 25% stake in Ratchaburi Power Company (1,400 MW). EGAT and Banpu hold 45% and 15% of RATCH, respectively.

Industry outlook

We expect power demand in Thailand to have a 3.9% CAGR until 2030. To meet this demand, the current Thailand power development plan envisions doubling the nation's generation capacity to 70GW by 2030. We expect regulators to announce an updated version of the plan soon. We expect the new plan to give more importance to coal-fired capacity than the current version. However, with A higher-than-desired current reserve margin, growth opportunities will be fewer in the near term in Thailand. We expect Thai power companies to continue investing in overseas markets to chase growth.

Revenue by region (2014)



Source: Company data, UBS

EBIT by product segment

In 2014, RATCH earned most of its EBIT from electricity generation.

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Ratchaburi Electric (RATCH.BK)

Income statement (Btm)	12/12	12/13	12/14	12/15E	% ch	12/16E	% ch	12/17E	12/18E	12/19E
Revenues	**56,006**	**49,885**	**56,350**	**53,752**	*-4.6*	**53,606**	*-0.3*	**51,618**	**50,153**	**50,153**
Gross profit	8,737	8,825	8,437	7,942	*-5.9*	7,996	*0.7*	5,988	4,616	4,616
EBITDA (UBS)	**10,718**	**8,850**	**8,146**	**9,656**	*18.5*	**9,222**	*-4.5*	**7,416**	**5,900**	**5,900**
Depreciation & amortisation	(3,499)	(1,433)	(1,275)	(3,308)	*159.4*	(2,852)	*-13.8*	(3,086)	(2,975)	(2,975)
EBIT (UBS)	**7,219**	**7,417**	**6,871**	**6,349**	*-7.6*	**6,370**	*0.3*	**4,330**	**2,924**	**2,924**
Associates & investment income	803	1,062	1,123	1,703	*51.7*	3,351	*96.7*	3,766	4,118	4,118
Other non-operating income	0	0	0	0	-	0	-	0	0	0
Net interest	(1,797)	(1,222)	(1,251)	(1,201)	*3.9*	(1,207)	*-0.5*	(878)	(525)	(525)
Exceptionals (incl goodwill)	2,599	686	667	(233)	-	0	-	0	0	0
Profit before tax	**8,824**	**7,942**	**7,410**	**6,618**	*-10.7*	**8,514**	*28.7*	**7,218**	**6,517**	**6,517**
Tax	(887)	(1,433)	(1,269)	(1,578)	*-24.3*	(1,583)	*-0.3*	(1,057)	(728)	(728)
Profit after tax	**7,937**	**6,509**	**6,140**	**5,040**	*-17.9*	**6,931**	*37.5*	**6,161**	**5,789**	**5,789**
Preference dividends	0	0	0	0	-	0	-	0	0	0
Minorities	(210)	5	139	(116)	-	(218)	*-87.6*	(229)	(240)	(240)
Extraordinary items	0	0	0	0	-	0	-	0	0	0
Net earnings (local GAAP)	**7,726**	**6,514**	**6,279**	**4,924**	*-21.6*	**6,713**	*36.3*	**5,932**	**5,549**	**5,549**
Net earnings (UBS)	**5,737**	**5,901**	**5,648**	**5,157**	*-8.7*	**6,713**	*30.2*	**5,932**	**5,549**	**5,549**
Tax rate (%)	10.1	18.0	17.1	23.8	*39.2*	18.6	*-22.0*	14.6	11.2	11.2

Per share (Bt)	12/12	12/13	12/14	12/15E	% ch	12/16E	% ch	12/17E	12/18E	12/19E
EPS (UBS, diluted)	3.96	4.07	3.90	3.56	*-8.7*	4.63	*30.2*	4.09	3.83	3.83
EPS (local GAAP, diluted)	5.33	4.49	4.33	3.40	*-21.6*	4.63	*36.3*	4.09	3.83	3.83
EPS (UBS, basic)	3.96	4.07	3.90	3.56	*-8.7*	4.63	*30.2*	4.09	3.83	3.83
Net DPS (Bt)	2.27	2.27	2.27	2.27	*0.0*	2.50	*10.1*	2.50	2.50	0.00
Cash EPS (UBS, diluted)[1]	6.37	5.06	4.77	5.84	*22.3*	6.60	*13.0*	6.22	5.88	5.88
Book value per share	36.53	40.20	41.92	40.92	*-2.4*	43.26	*5.7*	44.85	46.18	46.18
Average shares (diluted)	1,450.00	1,450.00	1,450.00	1,450.00	*0.0*	1,450.00	*0.0*	1,450.00	1,450.00	1,450.00

Balance sheet (Btm)	12/12	12/13	12/14	12/15E	% ch	12/16E	% ch	12/17E	12/18E	12/19E
Cash and equivalents	13,932	9,404	14,266	7,400	*-48.1*	6,703	*-9.4*	5,138	3,395	3,395
Other current assets	7,102	14,971	17,142	10,952	*-36.1*	10,331	*-5.7*	10,350	9,981	9,981
Total current assets	**21,035**	**24,375**	**31,408**	**18,352**	*-41.6*	**17,034**	*-7.2*	**15,488**	**13,376**	**13,376**
Net tangible fixed assets	46,228	45,914	42,671	37,463	*-12.2*	34,711	*-7.3*	31,724	28,849	28,849
Net intangible fixed assets	6,421	5,732	4,656	5,059	*8.7*	4,722	*-6.7*	4,386	4,049	4,049
Investments / other assets	23,128	17,853	17,501	37,515	*114.4*	39,950	*6.5*	41,208	41,756	41,756
Total assets	**96,811**	**93,874**	**96,235**	**98,389**	*2.2*	**96,417**	*-2.0*	**92,806**	**88,031**	**88,031**
Trade payables & other ST liabilities	8,314	8,215	10,527	10,469	*-0.5*	10,340	*-1.2*	10,087	9,852	9,852
Short term debt	6,924	14,736	5,523	15,996	*189.63*	12,224	*-23.58*	8,024	3,024	3,024
Total current liabilities	**15,238**	**22,951**	**16,050**	**26,465**	*64.9*	**22,564**	*-14.7*	**18,112**	**12,876**	**12,876**
Long term debt	24,879	7,729	16,783	9,085	*-45.9*	7,380	*-18.8*	5,675	3,970	3,970
Other long term liabilities	2,962	4,068	2,203	2,203	*0.0*	2,203	*0.0*	2,203	2,203	2,203
Preferred shares	0	0	0	0	-	0	-	0	0	0
Total liabilities (incl pref shares)	**43,079**	**34,748**	**35,036**	**37,753**	*7.8*	**32,147**	*-14.9*	**25,990**	**19,049**	**19,049**
Common s/h equity	52,966	58,289	60,782	59,330	*-2.4*	62,727	*5.7*	65,034	66,958	66,958
Minority interests	766	838	418	1,306	*212.5*	1,543	*18.2*	1,782	2,024	2,024
Total liabilities & equity	**96,811**	**93,874**	**96,235**	**98,389**	*2.2*	**96,417**	*-2.0*	**92,806**	**88,031**	**88,031**

Cash flow (Btm)	12/12	12/13	12/14	12/15E	% ch	12/16E	% ch	12/17E	12/18E	12/19E
Net income (before pref divs)	7,726	6,514	6,279	4,924	*-21.6*	6,713	*36.3*	5,932	5,549	5,549
Depreciation & amortisation	3,499	1,433	1,275	3,308	*159.4*	2,852	*-13.8*	3,086	2,975	2,975
Net change in working capital	514	(8,030)	141	6,444	*NM*	491	*-92.4*	(271)	133	0
Other operating	(3,402)	(1,747)	(2,586)	(1,470)	*43.1*	(3,351)	*-127.9*	(3,766)	(4,118)	(3,878)
Operating cash flow	**8,337**	**(1,830)**	**5,109**	**13,205**	*158.5*	**6,706**	*-49.2*	**4,981**	**4,539**	**4,646**
Tangible capital expenditure	(117)	(2,120)	(4,869)	(100)	*98.0*	(100)	*-0.5*	(100)	(100)	(2,975)
Intangible capital expenditure	0	0	0	0	-	0	-	0	0	0
Net (acquisitions) / disposals	(787)	3,061	1,661	(17,081)	-	(672)	*96.1*	(692)	0	4,118
Other investing	(41)	6,133	5,862	54	-	1,924	-	3,537	3,906	0
Investing cash flow	**(945)**	**7,073**	**2,655**	**(17,126)**	-	**1,153**	-	**2,745**	**3,806**	**1,142**
Equity dividends paid	(3,291)	(3,625)	(3,291)	(3,291)	*0.0*	(3,625)	*-10.1*	(3,625)	(3,625)	0
Share issues / (buybacks)	812	2,433	303	(3,093)	-	0	*100.0*	0	0	(5,549)
Other financing	0	72	(420)	888	-	237	*-73.29*	239	242	0
Change in debt & pref shares	(7,522)	(9,338)	(159)	2,776	-	(5,477)	-	(5,905)	(6,705)	0
Financing cash flow	**(10,001)**	**(10,457)**	**(3,568)**	**(2,721)**	*23.7*	**(8,865)**	*-225.8*	**(9,291)**	**(10,088)**	**(5,549)**
Cash flow inc/(dec) in cash	**(2,609)**	**(5,214)**	**4,195**	**(6,643)**	-	**(1,006)**	*84.8*	**(1,564)**	**(1,743)**	**240**
FX / non cash items	2,832	686	667	(223)	-	309	-	0	0	(240)
Balance sheet inc/(dec) in cash	**223**	**(4,528)**	**4,861**	**(6,866)**	-	**(697)**	*89.8*	**(1,564)**	**(1,743)**	**0**

Source: Company accounts, UBS estimates. (UBS) metrics use reported figures which have been adjusted by UBS analysts.[1]Cash EPS (UBS, diluted) is calculated using UBS net income adding back depreciation and amortization.

Ratchaburi Electric (RATCH.BK)

Valuation (x)	12/12	12/13	12/14	12/15E	12/16E	12/17E	12/18E	12/19E
P/E (local GAAP, diluted)	8.7	12.2	12.7	17.1	12.5	14.2	15.2	15.2
P/E (UBS, diluted)	11.7	13.5	14.1	16.3	12.5	14.2	15.2	15.2
P/CEPS	7.3	10.8	11.5	9.9	8.8	9.3	9.9	9.9
Equity FCF (UBS) yield %	12.2	(5.0)	0.3	15.6	7.9	5.8	5.3	2.0
Net dividend yield (%)	4.9	4.1	4.1	3.9	4.3	4.3	4.3	0.0
P/BV x	1.3	1.4	1.3	1.4	1.3	1.3	1.3	1.3
EV/revenues (core)	1.3	1.7	1.4	1.3	1.3	1.2	1.2	1.1
EV/EBITDA (core)	7.0	9.4	9.7	7.2	7.5	8.6	9.9	9.5
EV/EBIT (core)	10.4	11.2	11.5	10.9	10.9	14.7	20.0	19.1
EV/OpFCF (core)	7.0	9.8	10.1	7.2	7.6	8.6	10.0	9.6
EV/op. invested capital	1.3	1.5	1.4	1.4	1.6	1.5	1.5	1.6

Enterprise value (Btm)	12/12	12/13	12/14	12/15E	12/16E	12/17E	12/18E	12/19E
Market cap.	67,330	79,513	79,508	84,100	84,100	84,100	84,100	84,100
Net debt (cash)	21,743	15,465	10,550	12,861	15,292	10,731	6,080	3,599
Buy out of minorities	766	838	418	1,306	1,543	1,782	2,024	2,024
Pension provisions/other	0	0	0	0	0	0	0	0
Total enterprise value	**89,838**	**95,817**	**90,476**	**98,266**	**100,934**	**96,613**	**92,204**	**89,723**
Non core assets	(14,591)	(12,614)	(11,493)	(29,122)	(31,611)	(33,053)	(33,782)	(33,782)
Core enterprise value	**75,248**	**83,203**	**78,983**	**69,144**	**69,323**	**63,560**	**58,422**	**55,941**

Growth (%)	12/12	12/13	12/14	12/15E	12/16E	12/17E	12/18E	12/19E
Revenue	27.8	-10.9	13.0	-4.6	-0.3	-3.7	-2.8	0.0
EBITDA (UBS)	8.9	-17.4	-8.0	18.5	-4.5	-19.6	-20.5	0.0
EBIT (UBS)	9.9	2.7	-7.4	-7.6	0.3	-32.0	-32.5	0.0
EPS (UBS, diluted)	16.7	2.9	-4.3	-8.7	30.2	-11.6	-6.5	0.0
Net DPS	0.9	0.0	0.0	0.0	10.1	0.0	0.0	-

Margins & Profitability (%)	12/12	12/13	12/14	12/15E	12/16E	12/17E	12/18E	12/19E
Gross profit margin	15.6	17.7	15.0	14.8	14.9	11.6	9.2	9.2
EBITDA margin	19.1	17.7	14.5	18.0	17.2	14.4	11.8	11.8
EBIT margin	12.9	14.9	12.2	11.8	11.9	8.4	5.8	5.8
Net earnings (UBS) margin	10.2	11.8	10.0	9.6	12.5	11.5	11.1	11.1
ROIC (EBIT)	12.9	13.4	12.5	12.7	14.3	10.5	7.7	8.1
ROIC post tax	12.2	10.5	9.7	8.8	9.9	7.3	5.4	5.7
ROE (UBS)	11.4	10.6	9.5	8.6	11.0	9.3	8.4	8.3

Capital structure & Coverage (x)	12/12	12/13	12/14	12/15E	12/16E	12/17E	12/18E	12/19E
Net debt / EBITDA	1.7	1.5	1.0	1.8	1.4	1.2	0.6	0.6
Net debt / total equity %	33.3	22.1	13.1	29.2	20.1	12.8	5.2	5.2
Net debt / (net debt + total equity) %	25.0	18.1	11.6	22.6	16.7	11.4	5.0	5.0
Net debt/EV %	23.7	15.7	10.2	25.6	18.6	13.5	6.2	6.4
Capex / depreciation %	3.3	147.9	NM	3.0	3.5	3.2	3.4	100.0
Capex / revenue %	0.2	4.2	8.6	0.2	0.2	0.2	0.2	5.9
EBIT / net interest	4.0	6.1	5.5	5.3	5.3	4.9	5.6	5.6
Dividend cover (UBS)	1.7	1.8	1.7	1.6	1.9	1.6	1.5	-
Div. payout ratio (UBS) %	57.4	55.8	58.3	63.8	54.0	61.1	65.3	-

Revenues by division (Btm)	12/12	12/13	12/14	12/15E	12/16E	12/17E	12/18E	12/19E
Others	56,006	49,885	56,350	53,752	53,606	51,618	50,153	50,153
Total	**56,006**	**49,885**	**56,350**	**53,752**	**53,606**	**51,618**	**50,153**	**50,153**

EBIT (UBS) by division (Btm)	12/12	12/13	12/14	12/15E	12/16E	12/17E	12/18E	12/19E
Others	7,219	7,417	6,871	6,349	6,370	4,330	2,924	2,924
Total	**7,219**	**7,417**	**6,871**	**6,349**	**6,370**	**4,330**	**2,924**	**2,924**

Source: Company accounts, UBS estimates. (UBS) metrics use reported figures which have been adjusted by UBS analysts.

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Buy	FSR is > 6% above the MRA.	45%	37%
Neutral	FSR is between -6% and 6% of the MRA.	43%	33%
Sell	FSR is > 6% below the MRA.	12%	20%
Short-Term Rating	**Definition**	**Coverage[3]**	**IB Services[4]**
Buy	Stock price expected to rise within three months from the time the rating was assigned because of a specific catalyst or event.	less than 1%	less than 1%
Sell	Stock price expected to fall within three months from the time the rating was assigned because of a specific catalyst or event.	less than 1%	less than 1%

Source: UBS. Rating allocations are as of 31 March 2015.
1:Percentage of companies under coverage globally within the 12-month rating category. 2:Percentage of companies within the 12-month rating category for which investment banking (IB) services were provided within the past 12 months.
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Company Name	Reuters	12-month rating	Short-term rating	Price	Price date
Electricity Generating Co.	EGCO.BK	Neutral	N/A	Bt153.00	08 Jun 2015
Glow Energy PCL	GLOW.BK	Buy	N/A	Bt86.50	08 Jun 2015
PTT Exploration & Production[4]	PTTEP.BK	Buy	N/A	Bt108.00	08 Jun 2015
PTT Global Chemical	PTTGC.BK	Buy	N/A	Bt66.00	08 Jun 2015
PTT Public Company Ltd.	PTT.BK	Buy	N/A	Bt344.00	08 Jun 2015
Ratchaburi Electric	RATCH.BK	Sell	N/A	Bt58.00	08 Jun 2015

Source: UBS. All prices as of local market close.
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