Is gas the right fuel for power in the Philippines?

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Gas currently fuels a third of the power generated in the Philippines and there is 2700MW of installed CCGT capacity that may have no fuel when the contracts for the supply of gas run out in 2024.

Other than a couple of minor finds, the current gas supply in Philippines comes from the Malampaya gas field off Palawan. The gas is sold via long term take or pay contracts to First Gen (to power the Santa Rita and San Lorenzo power stations) and to PSALM (to fuel the Ilijan power station, contracted via an IPPA arrangement to San Miguel). Both of these operators sell their power to Meralco, the largest distributor and retailer of electricity in the market.

The concession for the gas field runs out in 2024 and while there may be some additional gas available after that time, as yet no agreements have been reached for continuation of the concession and so there is considerable uncertainty over the supply of gas. There is also no additional capacity for extracting additional gas now from the field, meaning that for additional gas prior to 2024, LNG is the only feasible solution.

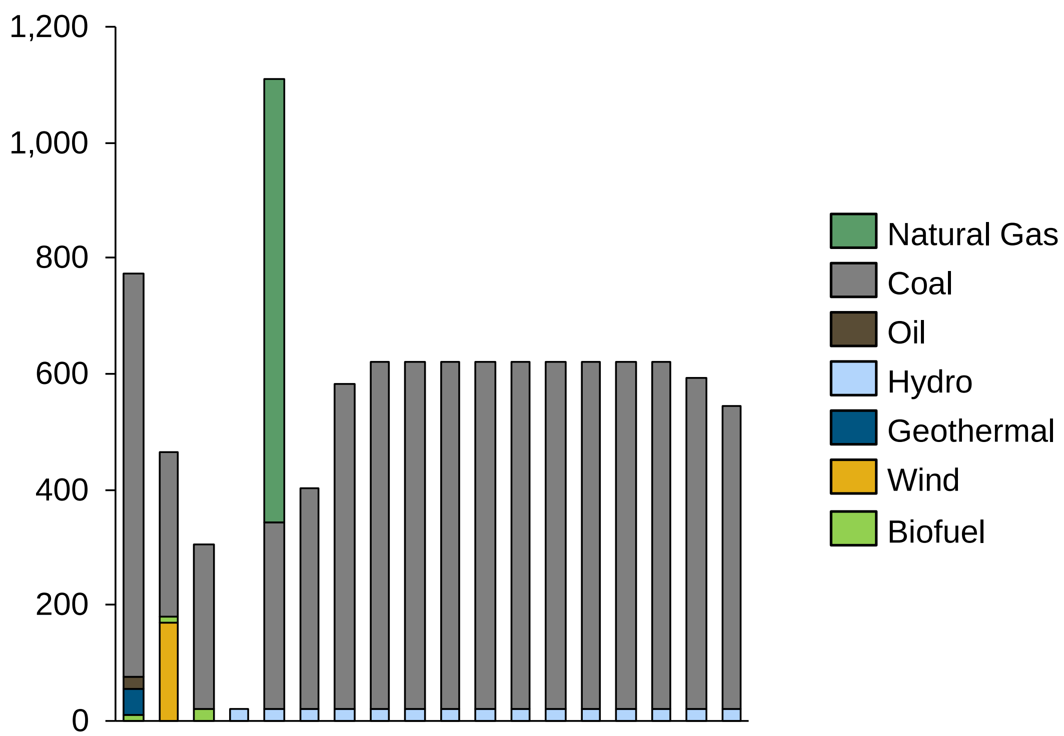
Bringing LNG into the Philippines is complex: The power sector is the only source of a large anchor load but the EPIRA (the electricity law in the Philippines) prevents the Government from building, contracting with or supporting (via guarantee) any power sector projects. This means that new power projects must be built by the private sector, on a commercial basis, to operate in the electricity market (WESM).

Gas is perceived as being clean; however, gas is also more expensive at current LNG prices than coal by some margin. The current environmental legislation covers only traditional pollution and standards are not particularly stringent. Effectively this means there are no limitations on coal build in the market. Given that coal is therefore cheaper than gas, how can it be built? Should developing economies import such an expensive fuel, when cheaper options abound? These are the questions The Lantau Group has explored while developing the Natural Gas Master Plan for the Philippines, funded by the World Bank with Australian Aid.

Our first question was "what is the economic case for LNG in the market"?

We undertook this through economic modelling of the power system in the Philippines – the WESM in Luzon and Visayas and the IMEM in Mindanao. The answer was very clear and consistent across a range of scenarios of fuel prices, demand growth and other factors: Gas is not economic for baseload under the majority of conditions, but it is economic to build new gas fired mid-merit and peaking plants (CCGT's, OCGT's and/or reciprocating engines) in the short term for a relatively small capacity – in the range of 600 to 800 MW.

Figure 1: Least cost expansion plan for Luzon under our "Expected" case



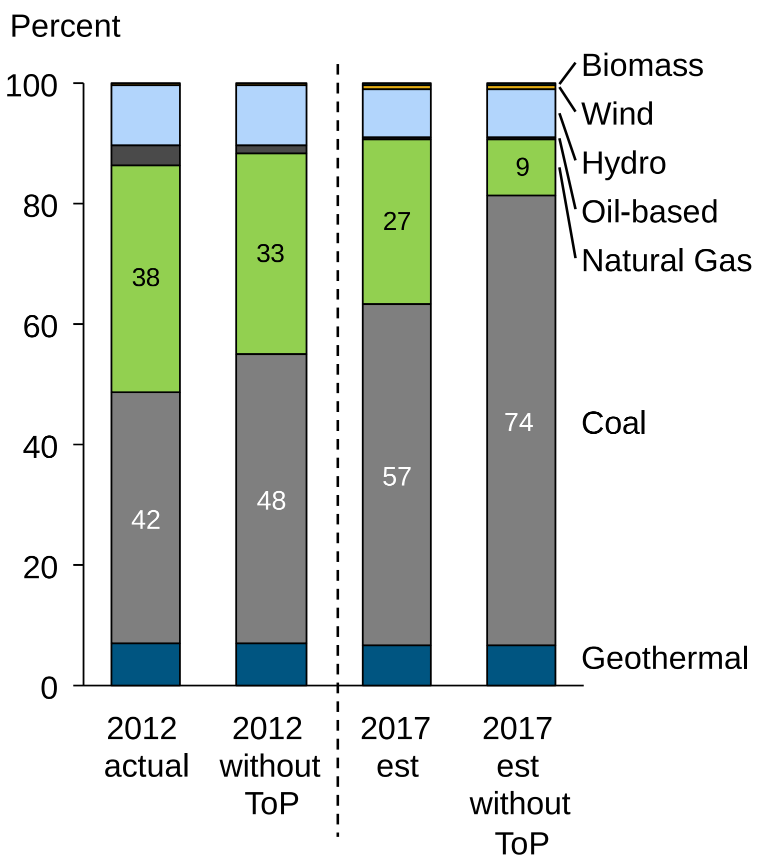
Note: EWC plant assumed to not be committed
Source: DOE (committed plants as of Aug 2013); TLG analysis

In the medium and longer term, additional mid-merit and peaking capacity is also required. However the most economic way that this additional mid-merit capacity can be achieved is by changing the operation of the existing 2700MW of CCGT, which currently operate baseload for contractual reasons, to mid-merit when the gas supply contracts expire between 2022 and 2024. Thus the opportunity for new gas fired build in the Philippines is limited.

Our analysis also highlighted a potential role for 400MW of gas fired capacity in Mindanao – although the economic case for this was less robust under a range of different scenarios than the case in Luzon.

In addition to the economic case for new build, we also looked at the existing operation of the gas-fired assets. One striking outcome from the analysis was the cost of the existing baseload operation – between 2007 and 2013, for example, running the gas baseload (out of merit) instead of running it mid-merit and using the cheaper coal plants for baseload has added USD300m to the cost of procuring power for Meralco alone.

Figure 2: Optimum operation of CCGT's if there were no take-or-pay constraints



It was clear from our analysis that such an outcome would be unacceptable for a future LNG project. The need for Malampaya to have take-or-pay contracts was understandable in the context of the precedents at the time when it was developed: gas was much cheaper than current prices and the new plants was expected to be similarly priced, or even cheaper than, the alternative coal plants. Also, being a domestic gas field, even though it runs out of merit, some of this loss is recycled back into the Philippine economy through the Malampaya Fund; and using domestic fuel instead of imported coal also aids balance of payments (forex) issues. Neither of these mitigants is true for LNG and thus any new LNG would need to be economic in its own right.

The other issue with Malampaya, however, which provided some useful economic foundation for LNG is that because Malampaya is the only source of gas, when it is unavailable for scheduled maintenance liquid fuels must be burnt in the CCGT's in order to maintain power security. Over the years this has proved expensive. Not only must the liquids be purchased, but also the use of liquids in the existing plant causes additional maintenance costs and outages; capacity must be derated for some period and this also has knock-on effects on the market. The most serious of these was seen in November 2013 during a gas outage, resulting in very high market prices, potentially high consumer prices and a very negative legal, policy and regulatory response that severely disrupted the market.

We calculated that the avoided costs of buying liquids during Malampaya outages were in the range of USD20 – 25m per annum. The market costs of the outages were additional to this. This highlighted an economic case for importing LNG to back up the existing gas fields.

Figure 3: Cost of Malampaya outages

	Start date	Duration	Estimated additional system cost (mPhP)
Scheduled Malampaya maintenance outage	22 Nov 2006	25 days	2,500
	27 Jun 2008	4 days	1,000
	10 Feb 2010	30 days	1,300
	20 Oct 2011	7 days	900
	13 Jul 2012	8 days	600
	11 Nov 2013	30 days	4,000
		Subtotal:	10,300
Unscheduled Malampaya supply outages	Average curtailment of 1,700MW over about 287 hours since 2006		740
		Total:	**11,040**

In summary, therefore, the economic case for LNG was 600-800MW of new mid-merit capacity plus about USD20-25 million for backup supplies.

The next question was "can we develop a terminal on this basis"?

In reviewing this question it is important to note that there are already a number of proponents of commercial LNG terminals in the Philippines. One of them (Energy World) is already under construction. Many others (including Shell, Meralco and First Gen proposals) are undertaking detailed feasibility studies. Most of the discussions with participants highlighted agreement that the economic case for LNG was for a mid-merit role; however most proponents believed that a higher capacity of mid-merit plant was necessary to make the terminal economic. Part of our study involved reviewing these proposals to understand what barriers participants were facing in their commercial activities. If the answer was "none" then the answer for the DOE would be simple: leave the market to work. On the other hand, what we actually found was (with the notable exception of Energy World, who are undertaking development in a unique manner) most participants were seeing barriers in the market.

These barriers included:

- Lack of environmental legislation to encourage the use of gas;
- Lack of a regulatory framework to allow a new mid-merit plant to obtain regulatory approvals in the market;

- Lack of gas-specific regulations to allow certainty to developers in how a new gas terminal may be regulated (if at all) and how any downstream gas assets would be treated (or even who might be allowed to build them); and
- Lack of clarity around tax incentives and taxation of gas.

We also found a level of immaturity and lack of understanding in the market when discussing mid-merit options in general – many of the potential buyers and the regulators had less understanding of why "more expensive" gas plant would actually lower system costs if used in the right way. Indeed, the newspaper headlines following publication of our first report focussed mainly on the average costs of an LNG fired power station and how this was more than coal, than on the finding that gas would be economic if used in a limited mid-merit capacity. This highlighted that education and capacity building among participants and the regulator would also be needed to overcome these barriers.

We developed a number of options to test with the private sector and the DOE that could be used to encourage LNG into the power sector.

These included ideas such as:

- Introducing a "fuel mix policy" to highlight the need for additional gas;
- Introducing a mandatory gas purchase obligation; that would require retailers of electricity to source a proportion of their electricity from gas fired sources;
- Introducing environmental requirements for carbon emissions – that would give gas an economic benefit compared to coal;
- Tax incentives for gas infrastructure;
- Improving the regulatory framework to encourage the entry of an economic amount of mid-merit capacity;
- Various options for tendering "something of value" to a terminal (such as a gas offtake or terminal capacity agreement, regulatory approval) to encourage a terminal to be built;
- Gas regulations and legislation to remove the uncertainties that currently existed; and
- Education and capacity building to ensure buyers and regulators understood the economic case for gas.

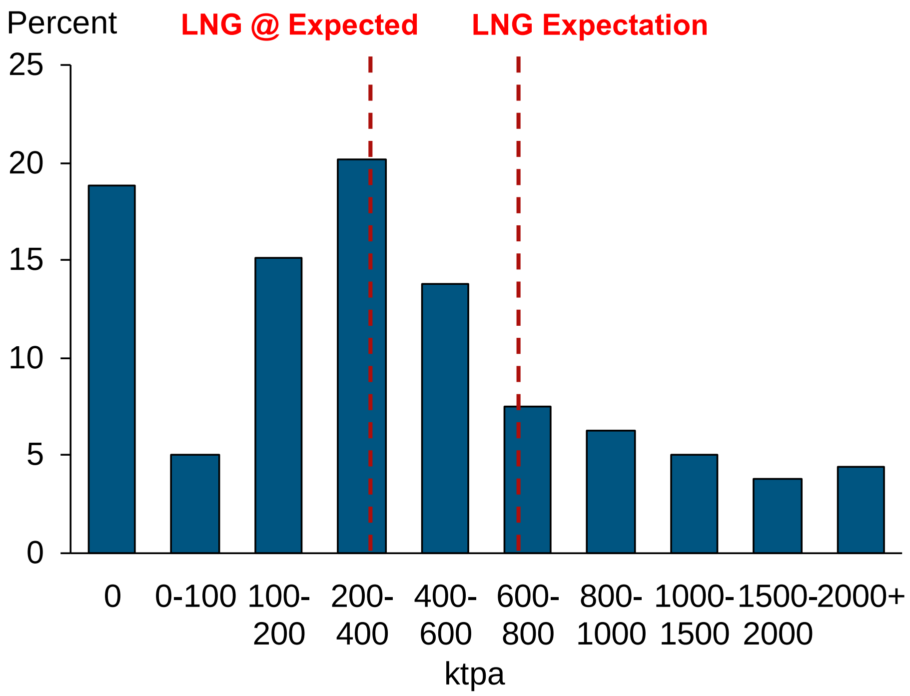
Following public consultation (where the private sector tended to prefer ideas such as “ban new coal build”; “fuel mix policy” and give LNG terminals incentives or contracts) we undertook extensive consultation with the Government. This highlighted a strong preference for solutions that were driven by the private sector and required no Government intervention or support; that new legislation (of any kind) was highly unlikely and that new tax incentives would be impossible to procure. This rather limited our options!

What remained was a mix of soft options (improving regulation and education) that may be possible for DOE to back and taking the value that was found from the economic analysis (USD20-25m from backup, plus 600-800MW of new build) and parcelling it into something that private sector could potentially swallow.

Our solution was to focus on the infrastructure – separating gas purchasing from the LNG terminal. To focus on the cheapest possible infrastructure to just “open the door” to LNG into the Philippine market and trust that once this door is open, market forces would bring the right amount of gas into the market.

The actual amount of gas that would be economic in any year remains very uncertain: particularly somewhere subject to typhoons, earthquakes or outages that limit generation from other sources and hydro resources that may be very variable on a year to year basis.

Figure 4: Variability of gas supplies from different modelling scenarios



The existence of a terminal is an option – giving a country flexibility to change fuel sources at short notice to manage events or to arbitrage fuel prices. Thus the terminal infrastructure was the first step.

However, the questions remained:

- Was LNG demand from mid-merit generation sufficient to underpin the cost of the infrastructure needed?
- Who benefits from the optionality and flexibility and how can these be captured commercially?
- How can the infrastructure associated with LNG be practically implemented in a country where the Government no longer controls the energy sector, no longer offers long term PPAs and where a market is in place?

The solution proposed requires the Government to assist by requiring LNG to be used as a backup to existing Malampaya gas (a relatively small change to the status quo requiring no legislation, but some regulation) in order to monetise the value of LNG as a backup. This value is then sufficient (more or less) to cover about half the annual cost of an floating storage and regasification unit (FSRU), which could moor near the existing power stations and supply backup gas when required.

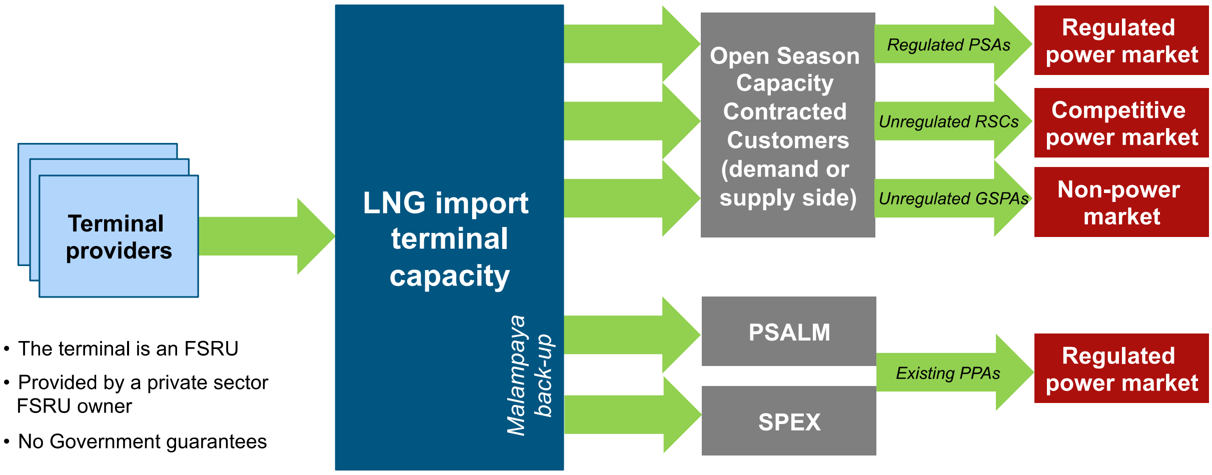
Such an FRSU would obviously have a huge amount of spare capacity, and so the other half of the solution was to allow the private sector to purchase this spare capacity to use for supplying gas to the other commercial activities – the mid-merit power stations and in the future, industry (via trucks or new pipelines) and for use in road transport as LNG or CNG, and in marine transport as a bunker fuel etc etc.

Our proposal was for the Government to facilitate a tender for a private sector operator to bring an FSRU to Batangas, underpinned by a) a contract with First Gen and PSALM for backup capacity and b) by contracts with the private sector for additional terminal capacity.

This structure was outlined in the Phase 2 report in March of this year and has been the subject of further consultation.

At the time of drafting this (June 2014), these proposals are still under consultation. Further details of the current situation will be providing at the presentation in September.

Figure 5: Proposed commercial structure of terminal



If the proposals succeed, what implications would it have for other terminals around Asia?

Until recently, the majority of the worlds LNG supply sailed right past many countries in Asia – from Qatar, Indonesia and Australia to Japan and Korea. Now, many countries in Asia, even those with existing domestic gas, are looking to use LNG (mainly in the power sector). Singapore has already built a terminal and is importing LNG. Malaysia and Thailand also have terminals. Except for Singapore, which was already burning expensive pipeline gas and oil in the power sector, the situation in the power sector is similar to Philippines.

Coal remains cheaper for baseload than LNG in any country in Asia that allows coal to be built. Even Singapore has looked at coal – albeit as export projects from either Malaysia or Indonesia. This means that use of LNG in the power sector is economic in the mid-merit or peaking sectors only: A conclusion that has significant implications for gas purchasing. By definition, mid-merit and peaking is uncertain and wholly unsuitable for take-or-pay style contracts. It is also generally a much smaller volume in total than baseload operations.

This means that for economic purchasing of LNG in Asia, flexibility will be important. Merely having an import terminal gives a degree of flexibility, but may often not be sufficient.

Development of flexible gas purchasing will require more flexible sales. Although the short term and spot market sales in Asia have increased in the past two years due to the increased short term purchases from Japan, and the entry of the US in to the LNG market may also encourage this, more is needed. A hub for spot purchases of gas in Asia would be an excellent development.

Many have touted Singapore as a potential for such a hub. Clearly, Singapore has many attributes that would make it ideal: it is centrally located; already familiar with trading and markets on the oil side and has a large terminal with existing (and planned additional) spare capacity. The terminal has both import and export capability and a large amount of storage.

Unfortunately however, there are self-imposed constraints that may prevent Singapore from becoming a hub. The users of LNG do not currently have the flexibility to re-export their LNG if not needed because the Government does not want to "lose" the LNG – even though the terminal has the capability to re-export and even has services available for anyone wanting to. Additionally, the ability to contract for capacity in the terminal is limited to short term contracts only because the Government wants to keep the whole of the terminal "in reserve" for security for supply reasons. This will limit the ability of Singapore to develop into a real hub for LNG in Asia.

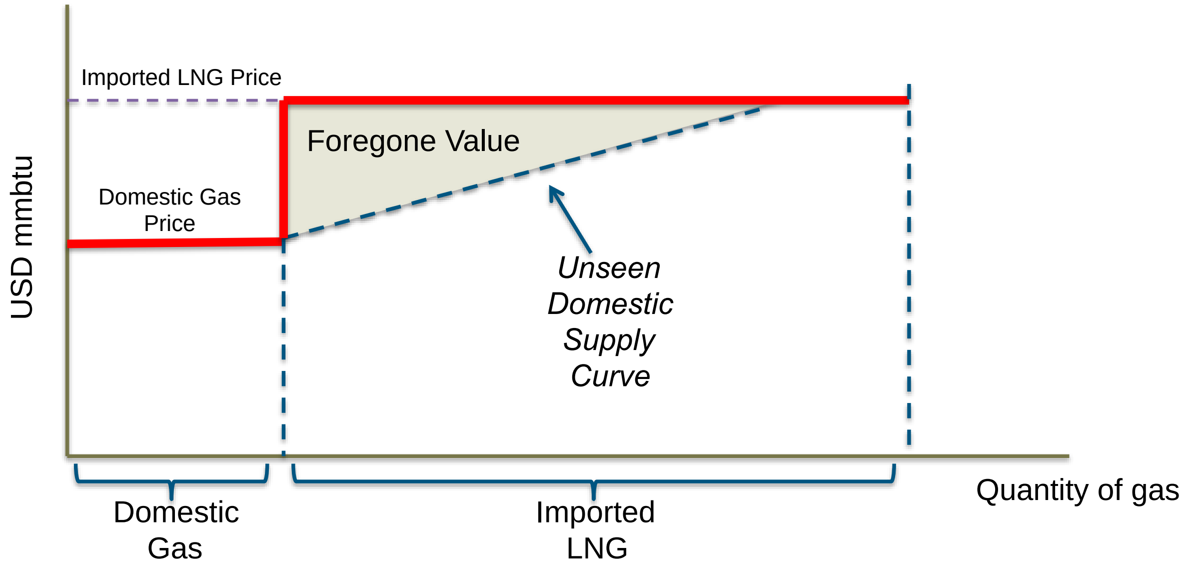
In other places, terminals are being developed by the national oil company of the nations – which tends to limit the access of anyone else wanting to use the terminal. On the one hand, the advantage of this is that many NOC's are highly bankable organisations with both the financial and technical capability of building and operating terminals. On the other hand, if they do not allow economic access to the terminal, the benefits to the country may be much more limited.

A key issue in many of these markets is how to integrate LNG with domestic gas. Domestic gas pricing around Asia is in something of a mess. Each market (except Singapore) used to be relatively isolated from world influences. Contract by contract negotiation was the norm, with policies to encourage the lowest price that could be achieved and this helped limit returns on upstream investment. The Philippines is a notable exception to this rule. But it also ended up restricting supply. Formerly relatively isolated markets are impacted by world prices as they import LNG. What we see is a discontinuous domestic supply curve, with very different (lower) prices offered to domestic resources, as compared to the (higher) prices paid for LNG. Countries are now starting to address this problem by offering higher prices for domestic gas to get more local supply but we still come across issues…

In Thailand, we see LNG being used in preference to new domestic gas for reasons we understand to be "because LNG has a benchmark price that can be justified but domestic gas is negotiated so higher prices for new supplies of domestic gas might come under scrutiny".

This is resulting in economic costs to the country – because lower cost sources are not being developed and more expensive imports used instead.

Figure 6: Thailand's "kinky supply curve" highlights the foregone value of using LNG in preference to domestic supplies



Gas prices are different in different countries in Asia, yet LNG is set by external benchmarks.

Figure 7: Gas pricing in Asia

Singapore	• Imported piped gas prices are set with reference to the fuel oil price times a factor, plus offshore and onshore transportation. LNG price on the first 3 mmtpa from the BG Group has an S-slope and can be more or less expensive than piped gas depending on oil price.
Indonesia	• Piped gas prices usually have a starting price & then escalate by a few % a year. To incentivize more gas production (and honoring existing agreements) in 2011/12 the authorities lifted many upstream prices by 50 to 100 percent. Downstream prices followed suit later. Domestic LNG price has a lower slope than exports of LNG
Malaysia	• Power – is intended to continue to pay a low price for the first 1,000 mmcfd for several years. For any gas above this level the average ex-Bintulu LNG price, plus transport, plus regasification. Non-power – passes on a blended price of any domestic gas and imported LNG to industry, plus marketing margin and transportation
USA	• All pricing is based on one of the various Hubs plus transport. The transportation or “cost of service” formula can get quite complicated.
Europe	• The UK uses the National Balancing Point for spot pricing. European hubs are now developing – continental Europe is moving from oil linked gas pricing to gas on gas pricing based on hubs. EU Commission is taking legal action against Gazprom for setting piped gas prices linked to oil

A key question is “what is the correct price of domestic gas”?

Pricing on a domestic only or cost-plus basis may result in underinvestment in gas infrastructure and over investment in gas fired power stations as gas can be cheaper than alternative fuels. This has been seen in Malaysia where the previously very low domestic price of gas resulted in gas being diverted from the domestic market to LNG at the same time as encouraging new gas fired power stations to be built.

Conversely pricing on a "market price basis" where gas prices are linked to oil (as seen in Philippines and Singapore) results in much higher power prices - but less of a step when LNG is required.

When Asian gas markets were purely domestic (or bilateral) affairs, this was less important. But with LNG now linking these markets to a single price, variations within the markets matter. Where gas can be converted to LNG and sold, it may be if under-valued in the home market and with floating liquefaction looking increasingly economic, even small fields may start to eye this option. Is the answer to Thailand's kinky gas supply curve that those marginalised domestic fields develop into LNG?

The ability to liquefy and transport gas as LNG is effectively a virtual pipeline. Technology in the form of FLNG and FSRU's are driving down both the costs and the scale required for this "pipeline". Private sector gas developments and pipelines without Government support are not uncommon around the world, so if the private sector driven, open access and merchant terminal succeeds in Philippines (and it's a big "if" !) it may serve as an example for other places in Asia and elsewhere. If the terminal development is also matched by more flexible gas purchasing, so much the better. The Philippines is the only developing country in Asia to move forward with an electricity spot market – a development that many say the country was not ready for. Yet the market has spurred significant new growth in capacity and improvements in operations – despite having significant "issues" as well. Could it similarly act as a model for private sector LNG development in Asia?