

# Memo

To: Interested Parties

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From: Sarah Fairhurst, The Lantau Group

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Date: 21 March 2014

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Subject: Consultation on the Phase 2 Report of the Philippine Natural Gas Master Plan

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## REQUEST FOR FEEDBACK

On 20 March, The Lantau Group conducted a workshop on behalf of the Philippines Department of Energy to highlight the key findings of the Phase 2 report and get feedback from the private sector.

The presentation slides that were used can be found on our website:  
[http://www.lantaugroup.com/pages/publications/presentations\\_1.php](http://www.lantaugroup.com/pages/publications/presentations_1.php)

Please note that the slides are only a subset of the issues that were covered in the Report, and the full Phase 2 Report (with some areas redacted for reasons of confidentiality) can be found here:

[http://www.lantaugroup.com/files/WB\\_Phase1.pdf](http://www.lantaugroup.com/files/WB_Phase1.pdf)

We are now looking for feedback from the private sector.

- Do you think the transaction structure recommended in the Phase 2 Report will work? If not, why not?
- Would you be interested in participating? If so, in what areas?

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Consultation on the Phase 2 Report of the Philippine Natural Gas Master Plan

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- We know that considerable facilitation will be necessary in addition to the LNG Terminal transaction. Have we covered the full list of facilitation required (on gas regulations, electricity regulation of power supply agreements or other areas?).
- Do you have any comments on the facilitation or suggestions as to the best way to effect it?
- Do you have any other comments?

If you require your comments to be treated in confidence, please let us know and replies will be aggregated for the purposes of any further public consultations.

Please provide all feedback and comments via email to Sarah Fairhurst at [sfairhurst@lantaugroup.com](mailto:sfairhurst@lantaugroup.com), and copied to [lsaguin@doe.gov.ph](mailto:lsaguin@doe.gov.ph) on or before 7 April 2014.



# Philippines Natural Gas Master Plan

Phase Two Report:  
Design of a transactional structure for  
initial LNG-to-power infrastructure  
development for Luzon and Mindanao

Prepared for:  
**The World Bank Group**

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Date: 3 March 2014

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## EXECUTIVE SUMMARY

We split our findings into the need for gas infrastructure (an LNG terminal) and the purchase of gas to be wheeled through the terminal. One key reason for this is that existence of infrastructure is a key hurdle in the purchase of LNG. Having a pathway to the terminal will help buyers in the LNG market.

### INFRASTRUCTURE

This report recommends a two-pronged approach to the development of LNG infrastructure by the DOE. First, we recommend that the DOE implement a number of commercial measures that would facilitate the construction of private sector LNG and power infrastructure – and that may be necessary for development to occur at all. The impetus for this development is our finding that there is an economic case for a terminal to be available to supply backup fuel when Malampaya is unavailable. Second, we recommend that the DOE pursue additional regulatory and educational initiatives to facilitate the development of commercial arrangements.

We therefore recommend that the DOE undertake the first half of an open season, whereby the private sector is invited to propose how much terminal capacity it would be prepared to contract for, followed by a tender for an FRSU provider who will provide the backup capacity (paid for by regulated consumers) and additional capacity for the private sector (as identified in the open season). The FRSU provider would be solely responsible for finalising the private sector open season and entering into contracts with customers. The DOE would neither invest in, nor own, nor contract for, any infrastructure.

At the same time, we recommend that the DOE pursue a strategy of improved regulatory effectiveness to facilitate the private sector in developing a mid-merit LNG fired power station. The Phase One report found that a station sized on the order of 600-800MW would be least-cost for the system; however, the current regulatory processes for regulating power supply contracts are not consistent with encouraging such developments. A clear regulatory structure is also required for gas purchasing, as it aids in the credit rating of buyers of gas. The DOE should improve these processes. It should also invest in building up the skills and capabilities of private sector incumbents in generation and retail to assist them to both develop and negotiate contracts for such a mid-merit plant.

### GAS PURCHASING

Our key findings are that the bulk purchasing of LNG should be conducted in two stages. Stage One would be until about 2024, the term of the existing Malampaya gas (including the option to use banked gas). Stage Two would cover the period after the end of the existing Malampaya contract.

In Stage One we recommend that an annual Tender be conducted to select an LNG portfolio player or aggregator. The specifications of the Tender should be tightly set in order to arrive at the least-cost offer. We identified that a key risk with a new LNG buyer

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is that experienced negotiators on the sell side might out-manoeuvre less-experienced parties on the buy side. Using an aggregator reduces this risk.

On the buyers side we recommend that a consortium of LNG buyers be formed who deal as a co-ordinated group during the Tender process and then with the chosen LNG seller. The resulting contract structure would need to satisfy several requirements.

- (1) The duration would be relatively short, from the commissioning of the FSRU through to 2024, and each tender could be for a brief as one or two year's LNG supply. LNG supply contracts of similar duration are becoming more common, as more LNG is being traded on a short term basis.
- (2) As there are likely to be several buyers with different demand profiles, we expect that the sharing of cargoes or LNG borrowing and lending by buyers will be a feature of the local market. So the contract will need to support such flexible commercial arrangements.
- (3) The gas take arrangements must be sufficiently flexible to allow for the range of gas takes that might arise, due to Malampaya shutdown or hydro variation. We believe that an aggregator could offer such a contract, since the amount of LNG that will most likely be needed by the gas off-takers from the proposed Batangas FSRU is sufficiently large to be of significance to the global LNG suppliers.

The key theme for Stage Two of LNG purchasing is maintaining flexibility now. The delivery of LNG in Stage Two is expected to start in 2024, coinciding with the end of contracted supplies of piped gas from the Malampaya field. As this date approaches, the volume and price of any further piped gas that might be available from that field will be clearer. We see no advantage now in trying to guess those volumes or price. In addition, by 2024 we expect a change to the regional LNG market place to unfold that could benefit the Philippines. By that time it will be clearer what supply options are available from the proposed LNG Hubs planned for Southeast Asia. These LNG Hubs might allow buyers to form a mixture of short-to-medium term contracted LNG supplies from an aggregator, with spot purchases from the Hubs that take advantage of pricing opportunities. Moreover, by the time Stage Two arrives it is likely that the LNG buyers in the Philippines should be in a position to deploy the considerable LNG purchasing skills they have learned during Stage One.

Finally, both gas purchasing and tendering for infrastructure require strong, credit-worthy counterparties. In many places the Government stands behind such activities. As this is not possible under the current energy environment in the Philippines, we recommend that the DOE work with World Bank to find alternative credit support or guarantee arrangements that might support these activities.

# 1. BACKGROUND TO THIS REPORT

The Lantau Group, with Ove Arup & Partners, has been chosen by the World Bank Group to develop a Gas Master Plan for the Philippines in conjunction with the Department of Energy (DOE) after a competitive bidding process. The effective date of the contract is 16<sup>th</sup> September 2013.

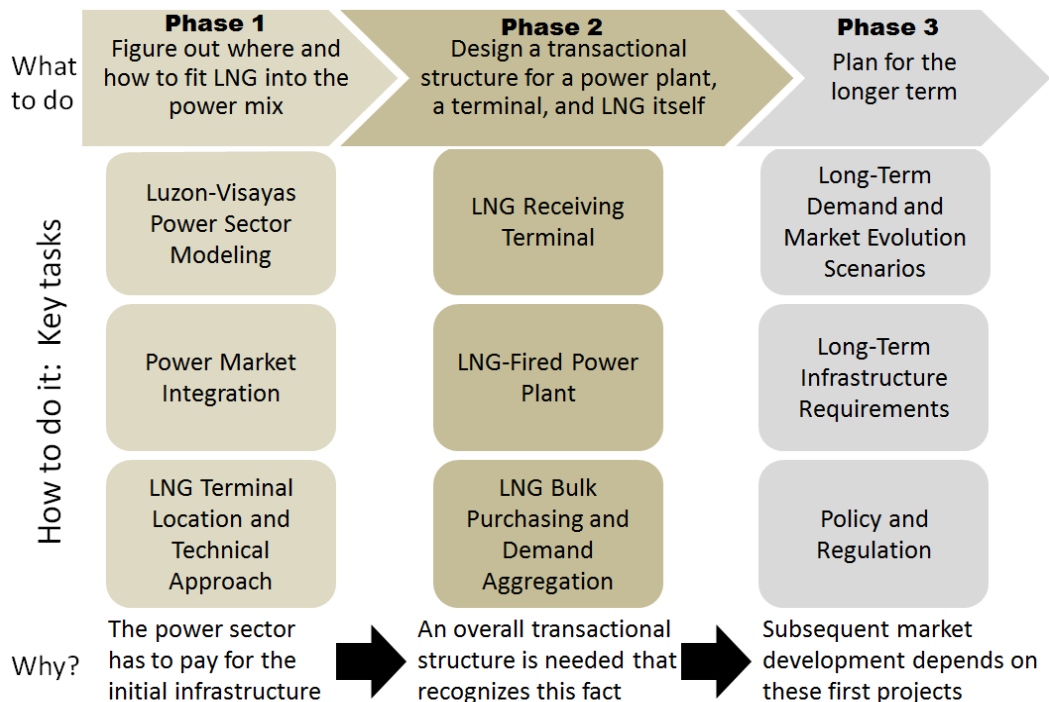
This report constitutes the Phase Two Report – the third in a series of reports, following the Inception Report (dated 17<sup>th</sup> October 2013) and the Phase One Report (dated 29<sup>th</sup> November 2013), that will document the progress of this project. From the Terms of Reference (TOR) of the study, the purpose of the Phase Two Report is as follows:

**Phase 2 report:** covering Phase 2 of the Scope of Work, due 24 weeks after the effective date of contract.

This would normally have meant that this Report was due on the 3<sup>rd</sup> March; however, because of the keenness of the World Bank Group and the DOE to conclude Phases One and Two before the end of 2013, in the Inception Report it was suggested that this Report would be delivered by close of business on the 20<sup>th</sup> December. However, because of the extended consultation period, including an offsite extended workshop on 27<sup>th</sup>/28<sup>th</sup> January to which various Government departments and the ERC were invited, the delivery of this Report was deferred until early March. It is now being delivered on 3<sup>rd</sup> March as originally anticipated.

Phase Two precedes the final phase, which will develop the Plan for the longer term, as illustrated in the high-level workplan schematic given in Figure 1.

**Figure 1: High-level workplan schematic from the TOR**





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The Phase Two Scope of Work, as described in the TOR, is:

- Task 2.1*      *Based on the technical approaches and locations defined in Task 1.4, recommend a transactional structure for an integrated LNG-to-power project.*
  
- Task 2.2*      *Incorporate power sector modeling to define the size and configuration of the power plant associated with each proposed terminal, and recommend the optimal contractual structure for this power plant.*
  
- Task 2.3*      *Address the LNG bulk purchasing role and provide advice on how this should be structured.*
  
- Task 2.4*      *Provide advice on the various monetization strategies available to LNG terminal owners, including using hub terminals to offer trans-shipment services to customers elsewhere in the Philippines and/or in other parts of the regional market. Assess whether there are any strategic options related to other hub terminals emerging in Asia (e.g., Singapore, Thailand).*
  
- Task 2.5*      *As necessary, assist the Department of Energy in applying for transactional support from the PPP Center.*

We note that the majority of the Task 2.2 work was undertaken during Phase One and reported in the various reports and workshops associated with that stage. It will not be explicitly repeated in this report.

A summary of the responses to the public consultation on the Phase One Report is provided in Appendix A. Finally, as a supplement to the Phase One Report, expanding the set of options considered for terminal sites, Appendix B and the accompanying report from Arup describe the technical feasibility of an FSRU located alongside the Ilijan natural gas power plant in Batangas.

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## 2. TRANSACTIONAL STRUCTURE

The TOR describes the objectives of Task 2.1 as:

*Task 2.1 Based on the technical approaches and locations defined in Task 1.4, recommend a transactional structure for an integrated LNG-to-power project.*

The proposed transactional structure follows from the Options identified in the Phase One report. We have reviewed these options, discussed with DOE and other branches of Government, reviewed feedback provided by the private sector through the consultation process and agreed a single preferred option going forward. This section sets out how the transactional structure for that option would work.

Appendix A includes an overview of the feedback received from the private sector on the Options set out in the Phase One report.

The advice we were given by the DOE on policy directions in our various meetings and discussions was as follows:

- A private sector, market-based solution is critical;
- Everyone must have access to the benefits of LNG;
- The burden on regulated power customers must be minimised;
- There is a clear case for Government action to solve market failures in providing Malampaya backup; and
- Improvements in clarity and efficiency of regulations and rules covering gas and gas-to-power are needed.

This, plus our discussions with the private sector and the World Bank, has led us to the following key recommendations of our transaction structure:

- A linked transaction with a long chain of inter-related projects has very large transactional risk and should be avoided. The key to a workable solution will be to delink the LNG terminal decision from specific new power plant capacity decisions.
- A competitive selection process is the key to ensuring the least-cost new terminal entry is encouraged. Meaning that the structure should:
  - Market-test the opportunity through an open season for capacity; and
  - Have a separate process to find least-cost infrastructure supplier.

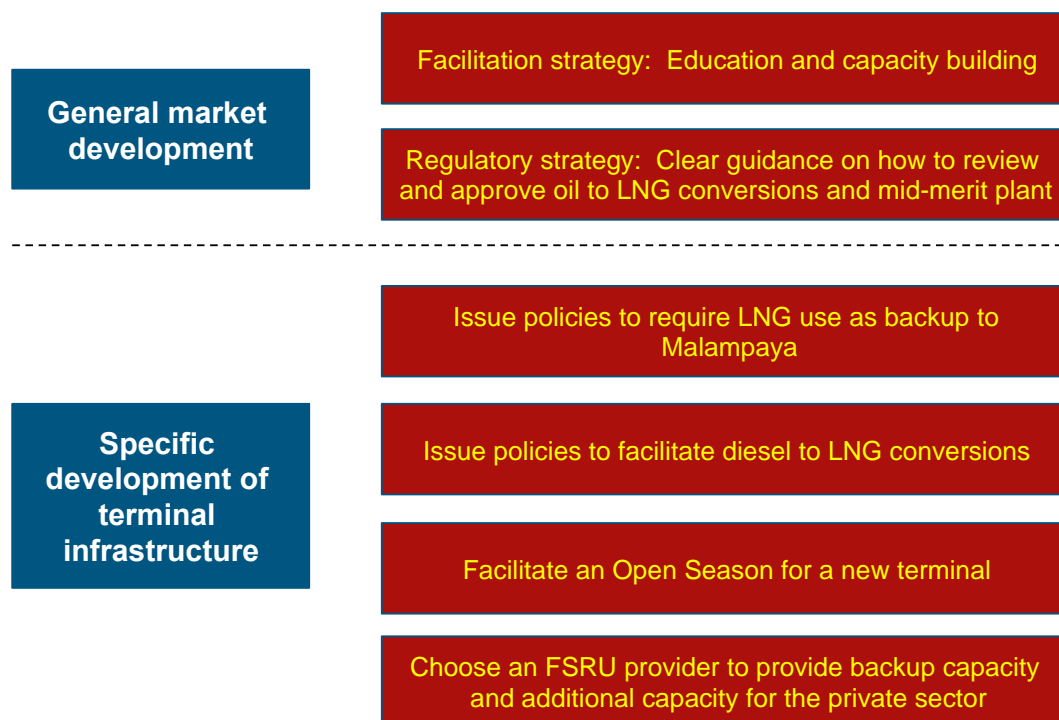
### 2.1. OUTLINE OF THE PREFERRED OPTION

Our proposed final Option is therefore set out below. It draws from the Facilitation Option in the Phase One report (which improves generally the legislative and commercial

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environment within which a terminal and power plant would be planned) and the Tender for a Backup Terminal option.

**Figure 2: Outline of Preferred Option**



The main components of the option are outlined in Figure 2. It is made up of two parts – general market development components and specific infrastructure development components.

Both parts are needed for improvements: the general market development aims to remove the barriers identified in the Phase One report while the development of a terminal aims to focus on a specific piece of infrastructure that can be determined to be economic now.

These two components are discussed in the next sections.

## 2.2. GENERAL MARKET DEVELOPMENT

### 2.2.1. Facilitation Strategy

One barrier to development of power stations that we have noted (both previously and as part of this study) has been the general lack of understanding of market participants and the regulator of the basic economics of electricity. This was rather graphically demonstrated by Meralco’s presentation to the LNG Terminal conference (and again to us the next day) where they started with “power economics 101” because they assumed nobody in the room knew anything about it. It has also been demonstrated repeatedly in ERC decisions, which favour ‘cost-plus’ approaches rather than market- or economic-

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based analysis to the extent that they may actually be counter-productive to market efficiency in the long-run.

Further, a criticism of the excessive development of coal fired capacity is that, given the amount of such capacity being built, some of it will have to run at mid-merit which would be more expensive for the proponents than building gas. Leaving aside the obvious difficulties of building CCGTs to meet demand in the absence of any actual gas supply, this would also tend to highlight that coal fired power proponents may not be undertaking the right kind of analysis of their investments.

We have noted, in discussions generally with participants, that local sponsors of power stations rarely undertake market modelling and appear to do little fundamental analysis of supply and demand or the risks associated with their investment. This is in strong contrast to the international proponents that are also operating in the market and highlights that many of the lessons that international investors have learned by operating in other competitive markets (such as Singapore or Australia) are not being applied by local proponents to the WESM.

To some extent, this may be assisted by education so part of the facilitation is a strategy to assist both market participants and the ERC in understanding the fundamental economics of power and how to analysis projects in a power market.

However, we also note that it is not just a lack of education or understanding which drives these views, but the incentives that proponents see in the market. It is very logical and economic to act in accordance with the incentive regime within which one operates and most of the incentives within the current market are driven by the form and implementation of the regulation of power supply agreements in the market. Thus no facilitation strategy is complete without a corresponding regulatory strategy.

### **2.2.2. Regulatory Strategy**

Several of power plant developers highlighted regulatory issues as being a barrier to developing gas fired generation capacity in the WESM. We have investigated these barriers in more detail in the course of this project and identified some of the underlying issues that are causing the problem. A clear regulatory pathway is not only essential for private sector investment in infrastructure, it is also very important for contracting the purchase of LNG as well as a regulated contract significantly improves the creditworthiness of any buyers of LNG.

A symptom of the problem is that these developers/gencos appear to have little clarity over how the ERC will assess the rates in any proposed power supply agreement (PSA). In practice, as we outlined in more detail in the Inception Report, the ERC has generally taken the approach of establishing base rates at the estimated long-run marginal cost (LRMC) of the generating plant in question, or at the proposed rates if they are below the ERC's assessment of the LRMC. Before 2013, if the proposed rates were below the NPC Effective Rates then they could be deemed as cost effective. The ERC has explicitly

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rejected “market-based pricing” for PSAs<sup>1</sup>, arguing that there are insufficient levels of competition in the supply-side, even though the WESM appears to generally operating well<sup>2</sup>, new entrants are entering and the RCOA privatisation thresholds have been met<sup>3</sup>.

This means, in practise therefore, that there is concern that the ERC will compare any gas fired power station to coal and deem it not cost effective. This fear would appear reasonably well founded given some of the decisions of the ERC in the past, where market based (sensible) solutions have been rejected as not cost effective.

One option therefore is for the DOE to instruct the ERC that gas fired power project are a priority and PSA’s from them should be approved. However, it is rarely that simple.

A PSA for a mid-merit plant would cover only a small (say 40-60%) of the output of the plant. However, because of the current tendency to use physical bilateral contracts very similar in design to PPA’s, the whole of the capacity of the plant would be covered by this contract. This is unlike the situation in other market where financial hedges are the more common way to contract for power supplies and the plant would be free to generate in the market the actual amount that makes economic sense on any day.

The problem with using physical bilaterals that cover the whole plant is that there is a risk of mis-use of regulatory approvals. On the one hand, a contract that is approved may be then used to say such approval covers the whole output of the plant, and the plant run as baseload and passed through to customers even though this would be more expensive than purchasing coal (given that having an approved contract for an expensive plant is often just as good, from a retail perspective for captive customers, as a cheaper contract that is not approved).

This could result in all the low cost power migrating out for the franchise market into the contestable market while franchise customers (who have no choice) are burdened with even higher priced power.

It is also the case that because of the way the contracts are structured, the trading of these power stations effectively lies with the retailer, not the generator. With Meralco’s market share of the power market in Luzon, this means they actually have a monopoly control of generation in the market and can influence market prices by how they require that generation to run.

Therefore, the question of how to approve a mid-merit power contract in the WESM is far more complex than cost-plus and even simple economics. It requires analysis of contract structure, terms and conditions, identity of the proponents and market power.

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1 Decision case no. 2012-119RC, (IFUGAO & SNAP Magat, 28 Jan 2013)

2 Neither PEMC nor the ERC have reported any major failings.

3 Decision, dated 6 June 2011, ERC case no. 2011-004RM

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It is also the case that only the “right” amount of mid-merit generation is required and thus contract approvals for more (or less) than this amount may also negatively influence the operation of the market. If there is a limited number of MW that could be approved, how should such approvals be allocated? On a “first past the post” system like the (not well functioning) FIT scheme or by having some way of finding the best projects to approve?

Taking a step back, it becomes clearer that part of the problem is not just the way that the ERC currently undertakes regulation of specific PSA’s put before it, but the wider problem of how it regulates the purchases of power by retailers for sale to franchise consumers.

The issue is deeper than that of any specific PSA: the issue is how should any retailer be purchasing for supply to consumers?

Although ECs are obliged to supply their captive customers on a least-cost basis<sup>4</sup>, there is currently no objective way that this is measured. The PSAs that are presented to the ERC for approval are the ones with which the EC has decided to proceed. These PSAs may be modified or approved by ERC but there is no comprehensive analysis of what alternatives the EC had or whether the PSA was the right option in the first place<sup>5</sup>. There is nothing, for example, stopping an EC from signing a PSA with an expensive generation option and claiming that this is the only option it has. There are proposals under way to change this slightly and these are discussed later in this section.

There are a number of uneconomic outcomes that flow from the current PSA approval system. As noted above, current approach is focussed on a “cost-based” review of individual projects. However, while this sounds admirable, it may lead to unintended outcomes. For example, although the WACC is applied to the costs in order to come up with the allowed tariff, the debt: equity ratio is typically that used by the project. Thus a project which 100 percent finances with equity has a higher allowed return than a project that (more economically) uses some debt. This leads to a potential outcome that a project may construct on the basis of 100 percent equity, gain a higher tariff because of this, and then refinance after final approval.

This example highlights two flaws with the current approach. Firstly the use of actual project data rather than benchmark data and secondly the fact that the approvals are of a one-off nature and, once approved, the proponents can later optimise around the decision to produce better outcomes for themselves. The singular nature of the review process means that there appears to be little oversight into how the PSAs are used once approval has been granted. For the specific example of a mid-merit LNG fired plant, the ERC’s review might assume a particular capacity factor as the basis for the review, in practice the nominations against that PSA could be very different.

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4 EPIRA sec. 23 para. 3 and its IRR rule 7 sec. 4(h).

5 Other than perhaps comparing the proposed PSA to historical spot market purchases (which may not be a like-for-like comparison if a higher proportion at peak times).

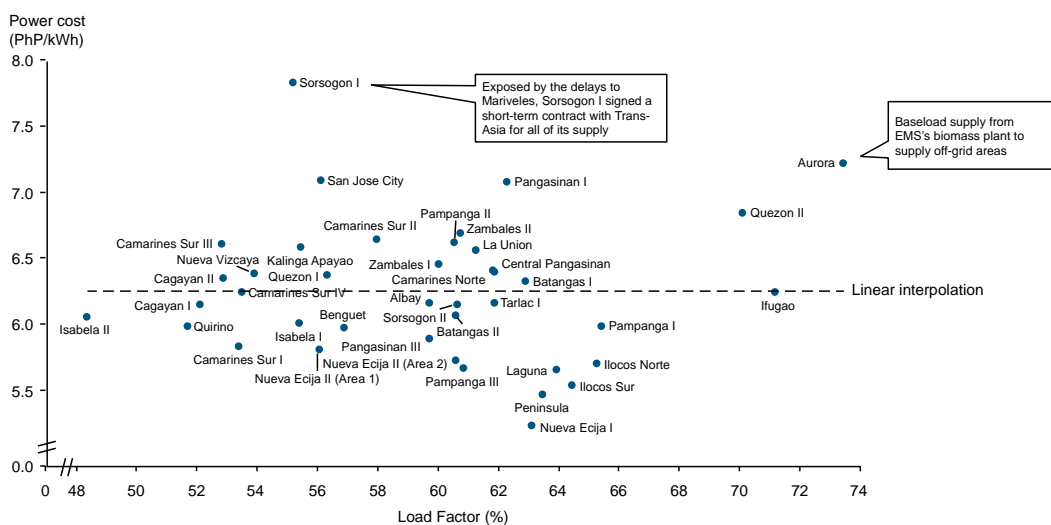
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The current system of regulation of PSAs stems from the history of PPAs in the Philippines. Prior to the market, NPC and Meralco had to enter into PPAs to underpin the financing of the new power stations that were urgently needed. Given that both NPC and Meralco were vertically integrated utilities with an interest in all aspects of the supply chain and an interest in ensuring efficient outcomes, it can be assumed that each of these entities undertook some analysis of the best way to meet demand with supply and then attempted to attract and contract for it. Thus the regulatory role was limited to checking and approving the final contract.

However, the continued use of single 20–25 year PSAs for each new generation project is not consistent with the development of the competitive WESM. Previously, NPC procured on behalf of all retailers (except Meralco). It was a portfolio generator procuring for a portfolio load and the contracts it entered into with the private DUs and ECs were for the “whole of requirement” for each utility. Now we have multiple different privately owned generation companies – some of which own only a single asset – and each individual DU or EC must procure power for its load. The “whole of requirement” contracts with NPC were carried on by PSALM (transition supply contracts) but are required to terminate within one year of open access. DUs now have to re-contract for that load.

Without entities able to supply “whole of load” contracts, such re-contracting will require a portfolio approach: some baseload contracts, some mid-merit and peaking contracts and some purchases from the WESM for residual amounts. Each DU could expect to have a purchasing strategy based on its load factor with companies with peakier load factors having higher average prices than those with less peaky load. In fact, this is not the case, as can be seen from a plot of average EC power costs against the corresponding EC load factors (Figure 3).

**Figure 3: Average purchased power cost vs. load factor for Luzon ECs (2012)**



Note: ECs without 2012 data are not shown  
Source: NEA

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One of the reasons for this is that there is currently only weak incentives for any EC, private DU or other supplier of captive customers to minimise purchase costs. Indeed, the main incentive seen currently (following the recent court case concerning Meralco) would be to minimise political risk – which can be done by over-contracting on an energy basis to avoid any exposure to uncertain WESM prices at the expense of higher average prices all the time – which is completely contrary to the obligation on these utilities to contract at least-cost.

Without incentives to contract at least cost, the obligation is almost impossible to enforce. The ERC has much less information than the market participants about what options are available and the prices of these options. It is constantly trying to push water uphill by enforcing layer upon layer of additional rules to try and enforce least cost outcomes.

The latest of these are seen in the recent changes to approval of PSA's proposed by the ERC<sup>6</sup>, which, among other things, propose mandatory bidding for PSA procurement, and include the generators among the regulated parties.

There is nothing wrong with trying to enforce the existing regulation. It is likely, however, that the existing proposals will not achieve their objectives, may alienate participants and in certain cases (such as the proposal to remove any walk-way rights) drive potential investors out of the market leading to higher costs overall – or worse – shortage of supply.

Instead of forcing 'square pegs into round holes', as the English idiom goes, we would recommend working with the ERC to adapt the regulatory focus to use the profit incentive of generators (and some retailers) to the regulators advantage. To use incentives, rather than rulebooks, to get the least cost outcomes that are required.

This would involve giving retailers incentives to purchase power at least cost and relax the role of the ERC in regulating specific individual contracts on a "stand-alone" basis without taking into account the role in a portfolio. Emphasis should also be placed on encouraging shorter-term and more flexible procurement. Because of the lack of overview, the current regulatory framework does not easily recognise the different types of generation (baseload vs. mid-merit vs. peaking). The ECs, in particular, should be encouraged to develop a portfolio of long-, medium- and short-term contracts from a mix of baseload, mid-merit and peaking generators.

This would achieve an improvement overall in the regulation of the sector, reduce the workload of the ERC and result in better outcomes for consumers. It would also – important for this project – enable LNG-fired mid-merit plant to naturally slot into the procurement of retailers in an economic slot rather than having to be shoe-horned into existing, unwieldy, regulatory practise with high potential for unintended consequences.

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<sup>6</sup> See, for example, the second draft revised PSA rules for public consultation posted by the ERC, dated 17<sup>th</sup> October 2013.



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It would also prepare the sector better for further open access and retail competition. As the sector opens up, the role of customer choice and competition is going to overtake regulation for keeping prices down. Contestable customers are not regulated and they can choose to buy power from whomever offers it at least-cost (or otherwise fitting their purchase criteria). Evolving the oversight and regulation of franchise customers to give incentives for least cost procurement will give retailers the ability to develop the skills, processes and procedures necessary to procure at least-cost when they are exposed to further competition in the future.

### **2.2.3. Oil-to-LNG conversion**

The role of oil-to-LNG conversion is relevant to the longer term development of the master plan because one of the growth areas for LNG outside of Luzon is the role in currently oil-burning plants, most of which are located in the Visayas.

At present, transmission constraints mean that these plants must run to supply customers in their local area. Most of these plants are located in coastal sites and would be ideal candidates for conversion to LNG fuelled by small, “milk-run” style barges (as discussed in Section 5.5.3).

However, as it currently stands, power from these power stations is sold under contracts that have regulatory approval to pass through fuel costs. Thus there is no incentive to adopt a cheaper fuel (because costs are passed through) while there is no mechanism currently in place to pass through the costs of any conversions or the cost of any infrastructure needed to deliver the gas.

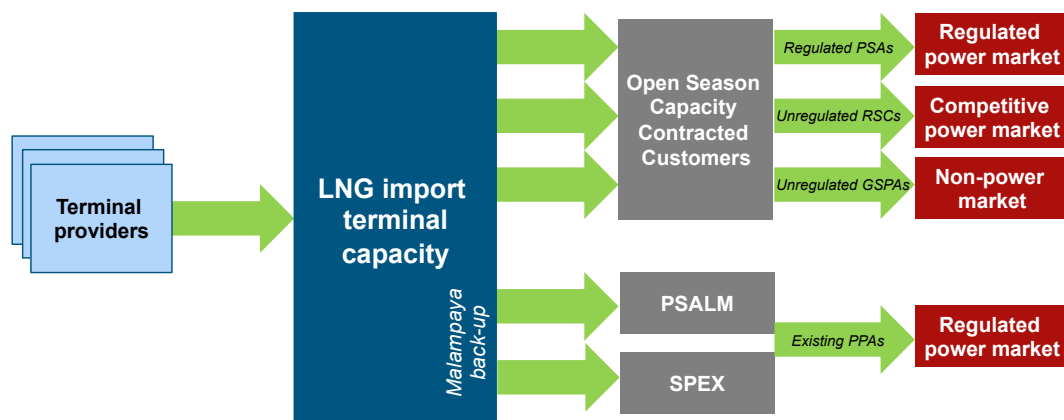
We would recommend that specific attention be focussed on this issue – either by the DOE through a policy change to incentivise conversion or by the ERC through changes to the regulatory framework (as discussed above) that would incentivise purchasers to seek least cost solutions without being forced to by regulation or policies.

## **2.3. SPECIFIC DEVELOPMENT OF TERMINAL INFRASTRUCTURE**

This solution recognises the case for Government action to solve market failures in providing Malampaya backup and structure the transaction around the terminal alone in the first instance with the ability for other players to commit to pay for terminal capacity through an open season. The structure is outlined in the following diagram.

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**Figure 4: Transaction Structure**



The option is implemented in stages:

- The first stage is to test the strength of market demand with a provisional open season on terminal capacity.
- Then a tender is held for a terminal operator – specified to be an FSRU located somewhere capable of delivering gas to the three current gas burning power stations. The tender will include a contract for firm capacity for a portion of the terminal to be dedicated to backup, and paid for via regulated consumers, but the rest of the payments for the terminal would need to be secured by the operator.
- Finally that (private sector) terminal operator finishes the open season and enters into contracts with the players for the capacity in the terminal.

An outline of the transaction process is given in the following diagram:

**Figure 5: Outline of the transaction process**



### 2.3.1. Pre-Tender Phase

During the Pre-Tender Phase the details of the process will be finalised. This would include draw on the suggestions in the Master Plan but expand to cover issues such as:

- Government to determine policies / convening power to use to require PSALM to purchase LNG as backup gas for Ilijan and First Gen to purchase LNG for backup to the saints assets.
- Government to review and assess the Government owned or influenced assets / processes to include as part of the transaction which might include, for example, land for sites, access to the NPC pipeline at Ilijan etc.

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- Meet with the private sector stakeholders to agree their participation, if any. This would be necessary to document how the change from liquid fuels to LNG as backup is implemented in the existing agreements, where the additional fee for the terminal is specified and how all these changes are implemented and regulated. It would also be necessary to gain some co-operation from private sector stakeholders to improve the process – for example – use of the jetty at First Gens power stations may be helpful or co-operation of SPEX regarding gas quality, pressure and connection issues. While the whole structure works with Government assets alone, private sector co-operation could result in a smoother process and a more economic outcome.
- Agree the form and implementation of the Backup Contract and how this is passed through to consumers.
- Choose transaction principal and advisors. The preliminary open season – to assess likely buyers of terminal capacity – can be conducted directly by advisors. However, some transaction principal may be required to run the FSRU tender on behalf of the DOE even though no assets are being procured.
- Discuss the Preliminary Open Season with potential bidders in the FSRU tender to ensure that the Preliminary Open Season will result in information that the potential bidders are capable of using without having to repeat the process.
- Gain any necessary consents / approvals that may expedite or facilitate the process.

Once the details are finalised and all the background directions, players and contracts are in place, the process can start.

### 2.3.2. Preliminary Open Season

The first action step is to conduct a preliminary open season and invite any interested parties to submit details of how much terminal capacity they would be prepared to purchase.

Open seasons are a way to identify potential demand for LNG and help an investor, or “project sponsor” to develop sufficient infrastructure on conditions that fit the market’s needs.

Open seasons are a two-step process which allows a project sponsor to efficiently consult the market about how much infrastructure it needs, and under what terms it would like this infrastructure to be marketed. It also allows resulting capacity to be allocated on a transparent and non-discriminatory basis

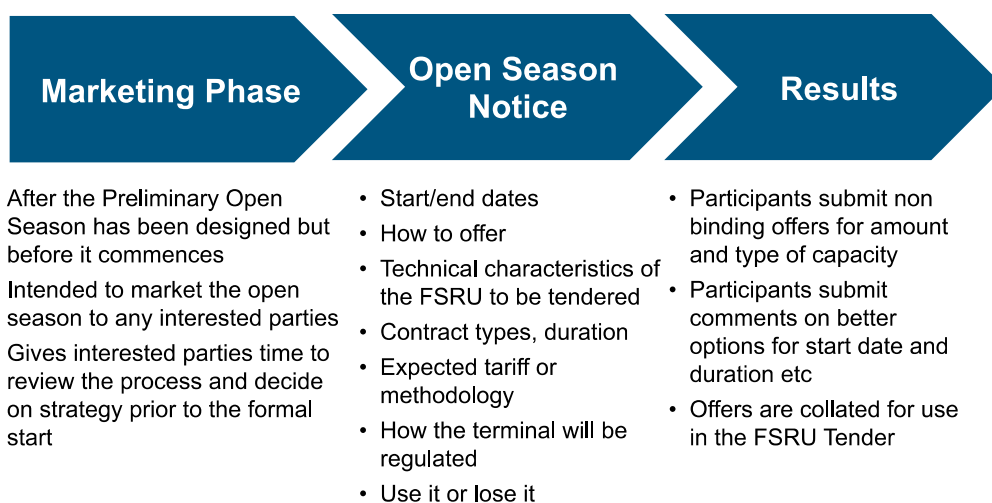
In this case, we would split two-step open season into two phases: the first would be managed by the DOE (or its advisors) in order to first identify indicative demand from the market. This would then feed into the FSRU tender to give potential bidders on the FSRU sufficient information on probable demand to be able to bid competitively in the tender.

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During the first phase – the Preliminary Open Season, the DOE assesses how much capacity the market needs and under what terms. During the second phase (FSRU Open Season), the FSRU provider offers capacity to the open season participants and, if satisfied with this offer, open season participants sign a binding agreement with the sponsor.

The Preliminary Open Season will consist of a number of stages, as set out in the diagram below.

**Figure 6: Stages of the Preliminary Open Season**



### ***Marketing Phase***

The marketing phase is a preamble to the start of the Preliminary Open Season and will involve letting all the potential stakeholders know that the process is coming and where they should look out for the open season notice. It should be done at least one month prior to the start of the formal process in order to allow potential participants to study the process and consider their options. This can be done in parallel with the Pre-Tender Phase above, providing sufficient clarity on the process has been finalised.

### ***The Open Season Notice***

The Open Season Notice is the formal start of the Preliminary Open Season.

The Notice should be sufficiently publicised to attract interest from third parties and to permit their meaningful participation. Avenues used to publicise the notice should include appropriate national and international media, the DOE and advisors website etc. The advisors should also contact as many potential interested parties as possible to ensure that they see the Notice.

The objective of the Open Season Notice should be to give open season participants as much information as possible on the project and service the open season participants are being proposed. It would include the following general information:

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- The start and end dates for making non-binding offers: this period shall be long enough to attract as many market participants as possible; the length of the period should be adapted to the size of the project. A period of two months is suggested;
- How to make non-binding offers;
- Arrangements in place to ensure the confidentiality of information received from open season participants and how this will be used in the FRSU process;
- The methodology, or “economic test” that will be used to decide how much capacity is tendered for in the FSRU Tender or how the FRSU tender will manage the results of the Preliminary Open season;
- Proposed timelines going forward including the date of the FSRU Tender, the expected date on which capacity allocations will be communicated to open season participants and the date by which open season participants will be asked to sign a binding agreement;
- Creditworthiness guarantees and deposits open season participants will be asked to provide when signing binding agreements;
- Drafts of the legally binding agreements open season participants will be asked to sign;
- Depending on the how far the facilitation improvements of gas and LNG regulations have got by this stage, regulatory approval of the binding agreements may be required or possible or the procedures and timetable for ensuing regulatory approvals will need to be included, including approvals of any tariffs.

It would also be normal for the notice must include specific information about the project itself. In this case it would include an outline of the FRSU Tender including key specifications of that Tender such as:

- The FRSU's intake and offtake points and any alternative intake and offtake points under consideration;
- Expected technical and available capacities, as well as operating pressures, at each intake and offtake point, to be defined in the FSRU Tender;
- The in-service date to be defined in the FSRU Tender;
- The type of the ships the terminal will be required to accept including that the FSRU will be required to offer ship reloading capabilities;
- Quality specifications;
- Nomination, renomination and measurement procedures including ship scheduling to the extent it can be defined prior to the FSRU Tender

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- Use it or Lose it arrangements, if any;
- Available contract lengths: these contract lengths need to be compatible with the expected projects wanting capacity from the terminal and so should include a mix of longer term capacities suitable for those underpinning a power station and shorter terms for those looking at more speculative uses.
- Available capacity types (firm/interruptible);
- Minimum lot sizes;
- The tariffs for each service or indicative tariffs and underlying methodologies if the tariffs depend on the level of total subscriptions. We would anticipate that the FSRU Tender would take as input the Preliminary Open Season information and start their own process taking the results into account, meaning that proponents will have another chance to bid prior to signing binding contracts so that having methodologies to cover all subscription outcomes should not be necessary.
- How the capacities and capacity fees will be structured, including whether they will be split into different components of the service.(e.g. docking, storage, regasification and emission components) or in bundled form in which case open season participants should know what the bundles comprise.

### **Results**

The outcome of the Preliminary Open Season will be the indicative amount and type of capacity (throughput, storage, contract duration, firmness) each Interested Party would like for each FSRU option under consideration.

Comments on any modifications to the proposal that would better accommodate their needs; including at a minimum modifications regarding:

- the date of commencement of service;
- the service duration (in years; long term/short term);
- the types of services on offer (firm/interruptible services); and
- the intake and offtake points.

This information is then an input into the FSRU Tender process below.

### **2.3.3. FSRU Tender**

Once the Preliminary Open Season is complete, the final bid documents for the FSRU Tender can be finalised and the Tender process can start.

The FSRU Tender can be run by advisors (directly under the DOE, if allowed) or one of the Energy Family could run the process. The following discussion reviews the possible entities that could run the process.

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### **PSALM**

PSALM is mandated *inter alia* to “administer and conserve the assets transferred to it,”<sup>7</sup> of which Ilijan is one and PSALM already holds the gas purchase agreement associated with the Ilijan power station and has an obligation under the Ilijan IPPA to procure replacement fuels when Malampaya gas is not available. As such, it is responsible for securing replacement supplies for nearly half the Malampaya-fuelled capacity and thus has a keen economic interest in the best outcome of the backup tender process.

PSALM has a good track record of running tender processes with the private sector (proceeds about US\$22bn<sup>8</sup>) and already has the Bid Procedures in place.

It is trusted by the private sector to run a fair and impartial process (which will be important) and it has no competing interests have no mandate to build power stations or run LNG terminals itself.

### **PPP Office**

The PPP office is mandated to facilitate the implementation of the country’s PPP Program and Projects<sup>9</sup>. However, this project is less of a public-private partnership and more a private sector arrangement facilitated by the public; so it is unclear if it falls into the PPP remit.

We also have a concern that a project would need to be on the PPP Priority List for them to devote significant resources, given what we understand is the overstretched nature of the current resources of the PPP office.

There is also some evidence from various sources that the PPP office is overstretched and also unable to secure appropriate transaction advisors because of the way their funding is administered by the ADB, whose procedures are not appropriate for commercial sector advisory procurement. As it would be key that this process be run by appropriate transaction advisors because all potential FSRU proponents are international, this may preclude PPP office from running it.

### **PNOC**

PNOC is mandated *inter alia* to “engage in export and import business of oil, petroleum, other forms and sources of energy, and their derivatives, as well as in related activities”<sup>10</sup> and we understand from DOE that they are the “arm of DOE that carries out DOE instructions”.

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7 EPIRA sec.51(b)

8 Privatisation proceeds (including sales of assets and appointment of NGCP and IPPAs) as of 30 April 2013, 22<sup>nd</sup> EPIRA Status Report.

9 Executive Order no. 8 of 2010.

10 Presidential Decree no. 334

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However, again, there is some concern that PNOC has insufficient institutional capacity and capabilities for this project and other existing attempts at PPP (e.g., coal mine-mouth) are delayed.

Further, PNOC may be seen by some parties as being a competitor in this activity as they are already in discussions with AG&P and Petroleum Brunei regarding LNG terminals<sup>11</sup>; and may indeed be interested in purchasing some capacity in the terminal for the Batman pipeline should they decide to enter into the gas distribution and transmission business.

It would probably therefore be unwise for them to run the tender.

### *DOE*

DOE is mandated inter alia to “prepare, integrate, coordinate, supervise, and control all plans, programs, projects, and activities of the Government relative to energy exploration, development, utilization, distribution, and conservation” (R.A. 7638). Also mandated to “exercise such other powers as may be necessary or incidental to attain the objectives of [the EPIRA]” (R.A. 9136).

Running the Preliminary Open Season and FSRU Tender would appear to fall into this category. However, not having direct commercial experience, DOE would need to rely heavily on transaction advisors to run this project itself.

On balance, therefore, PSALM appears to be a preferable candidate for running the tender process. The alternative might be the DOE with some assistance from PSALM and transaction advisors. We would not recommend that the PPP Centre or PNOC undertake this.

The FSRU Tender can be run generally according to the normal rules of a Philippine Tender however care would need to be taken to ensure that the objective of the Tender is not derailed by the procurement rules, since there is no ownership of assets involved.

Key details of how to proceed are outlined below:

The first task is to prepare the FSRU Tender including details of what is on offer (Backup Contract) and what the obligations of the winning bidder will be.

This would need to include details such as:

- Location of the FSRU.
- Minimum size and minimum technical characteristics of the FSRU. These should be defined in a manner to allow appropriate flexibility to the bidders to bring least cost solutions without being hampered by unnesseary constraints. The minimum

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<sup>11</sup> Philippine Daily Inquirer, ‘Brunei state oil company signs agreement with PNOC’ (25<sup>th</sup> Dec 2012)



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size, therefore, should focus on the minimum needed for the Backup Service (recognising that it would be much more cost effective overall to provide a larger FSRU and have additional private sector clients) and the technical outcomes required (in terms of minimum flow rates to support the Backup Service etc etc). It is generally preferable to allow bidders to know the objective of the process and allow them to come up with the least cost way of meeting that objective than over-specifying the tender such that no least cost options are capable of winning. We note that such over-specification is common in public-sector tenders in the Philippines (for example, the PPP of the Mactan airport) and does result in sub-optimal outcomes which ideally could be avoided in this case.

- Technical details of the site, including how the FSRU will moor, where the gas will come ashore, whether there are any onshore works that the FSRU provider will need to undertake or whether these will be done by someone else.
- What products will need to be delivered – for example – while we would need gas to be delivered to connect with the pipeline system at whichever location is deemed most appropriate, we will also most likely need LNG to be delivered ashore as well to be able to fill LNG Truck to take the LNG to industry in the medium term while additional pipelines are planned. It would most likely be advantageous to identify in the tender the outcomes required (such as, both gas and LNG onshore) and allow the FSRU provider to suggest the most cost-effective way to achieve the objective. This is most likely to be parallel pipelines along the jetty, but depending on the expected size of the LNG load it may be cheaper to just send gas down a single pipeline and have a small liquifaction plant onshore to service the trucks if there are not many.
- Outline of the commercial terms – including providing the bidders with the results of the Preliminary Open Season, a proposed contract (or set of contracts) for the backup terminal obligations and a clear description of how the terminal will be required to operate, including that it should be Open Access, how it may set charges and how it would (or would not) be regulated. All of this could be encapsulated in a Development Contract with the Government, whereby the rights and obligations of the FSRU and the Government would be set out, if a full regulatory framework would be too hard to enact in the time period. All of this needs to be defined in the Pre Tender Phase of the project.

The next task is to market the tender to the various FSRU providers around the world and open the run the Tender and choose a Terminal (FSRU) Provider and Operator.

#### ***Tender Variable for the FSRU Tender***

The tender variable the main variable upon which the decision as to which FRSU provider to choose is based. Typically the selection process would run in two parts. In the first part (technical evaluation or “first bid envelope”) all the bidders would provide details of their technical and financial credentials to confirm that they are bona fide FSRU providers and could actually undertake the project. . The evaluation is pass/fail – bidders are either deemed technical capable, or not. Technical capability is not “scored” on a scale of better

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or worse, because this confuses the evaluation. What is important is to ensure that everyone is capable.

Following the technical evaluation, the second part of the evaluation (financial evaluation / often called “second bid envelope” in the Philippines) takes place. What is important is to ensure that the financial evaluation is simple and compares all offers on a like-for-like basis.

There are a number of variables that could be used for the financial evaluation, including:

- Total cost of the FSRU;
- Annual rental cost of the FSRU;
- Average terminal throughput charge per mmbtu of gas;
- Average capacity charge per mmbtu of capacity allocated in the terminal; and/or
- Amount to be charged for the Backup Service.

These are discussed below.

#### ***Total cost of the FSRU***

The Total Cost of the FSRU is of course the factor that should be minimised. However, this structure requires that a private sector entity (the FSRU provider) brings the FSRU to Philippines and makes it available to various customers. Since nobody in the Philippines will ever own the FSRU, its total cost is not directly relevant unless used in any calculation of throughput charges, in which case the actual throughput charge may be a better indicator of cost. We would not recommend using total cost of the FSRU as the evaluation parameter.

#### ***Annual rental cost of the FSRU***

Most FSRUs operate on an annual rental charge. We have estimated that the value of the backup service in the market is approximately half of the average annual rental charge for a standard sized FSRU. However, the annual rental cost is only of relevance if the FSRU is rented. Under this transaction structure, the FSRU is not rented but rather supplied by the owner to undertake a backup service and other terminal services for the private sector. It is possible that bidders would not be an FSRU provider per se, but someone who proposes to rent an FSRU and then use it in the manner indicated. In this case they would be very interested in the annual rental cost and it would be a factor in what prices they could offer, but would not necessarily be directly relevant for the purposes of this process. Therefore we would not recommend using the annual rental cost of the FSRU as the evaluation parameter.

#### ***Average terminal charge per mmbtu of gas passing through the terminal***

The total cost, and the annual rental charge, eventually flow through into the average throughput charge required by the terminal to recover its costs (either total costs or annual rental costs). However, to determine the throughput charge one needs to estimate throughput. The initial throughput may be estimate from the backup

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requirements and the Preliminary Open Season; however, neither of these has a certain throughput defined.

If we set a throughput charge as the financial parameter, this tends to drive towards bidders requiring minimum throughput guarantees, either from the backup service or the private sector, or both. Given the high value of flexibility and optionality assessed for this terminal, and the high level of uncertainty in both backup throughput and other throughput, this would not be an optimal outcome. We would therefore not recommend using throughput charges for the financial parameter.

#### ***Average capacity charge per mmbtu of capacity allocated in the terminal***

The Preliminary Open Season will focus on how much terminal capacity potential users would like to contract for and the Backup Service will define the amount of capacity needed to be set aside for the Backup Service. Until throughput charges, capacity charges focus solely on the capability of the terminal to provide a service, not the actual usage of it. Obviously, even a terminal charging primarily through capacity charges will need some variable charges but these can be defined on a cost basis and be the same for all users, based just on the actual variable costs of operation not on any fixed cost basis. These can be fixed by contract and would not need to be part of the tender variable.

The average capacity charge therefore represents a sensible parameter to use for bidding purposes. It would ensure that all users pay the same capacity charge and be transparent across both the Backup Service and Private Sector users.

However, the terminal capacity will be substantially higher (using a standard 150,000-170,000 cubic metre FSRU) than actually required by the Backup Service and Private Sector users. This begs the question of what denominator would be used to determine the capacity charge. If the denominator is the firm contracted capacity, this would be the Backup Service and would mean that the Backup Service users would be paying for the whole terminal – which is not the intention of this process.

If it is the size of the terminal, then the terminal owner is incentivised to contract the entire terminal capacity or face a loss if some remains uncontracted – a position that may be unfavourable and deter bidders.

One would expect competitive bidders to estimate the reasonable private sector demand for capacity and use as their denominator the sum of this and the Backup Service. However, this still leaves significant spare capacity and if this capacity is then used, the FSRU may make windfall profits on the capacity, which would not be ideal. The contract could include clauses to claw back some excess revenue; however, these could be messy and would need to be carefully drafted to ensure that the right incentives remain in place.

Thus average capacity charges are a reasonable financial parameter, but would need to be carefully thought through – especially on the subject of additional contracting over and above what was expected at the time of the tender.

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### ***Amount to be charged for the Backup Service***

The amount that is passed through to regulated customers is the amount to be charged for the Backup Service. Given this is the actual focus on the policy, we could use this directly as the tender variable.

The FSRU would then have to (as when the variable is capacity cost) determine what other capacity could be sold to the private sector and bid this amount.

Using the Backup Service charge directly strongly incentivises the bidders to focus on how to minimise this cost, which is a good policy outcome. Further, a reserve price can be set at the calculated value of the Backup Service to ensure that no bidder charges more than the value (or the process will fail and the DOE should move to a fall-back option).

Similar to using average capacity charges, this option still leaves open the risk that the FSRU will gain windfall benefit from contracting additional terminal capacity, but it leaves open the option for differential capacity pricing (for firm, non-firm and other services, rather than having a single price for capacity) and thus leaves the private sector more flexibility in contracting the rest of the terminal which should ensure that the competition to offer least cost Backup Service is a little more stringent than for the pure single price capacity option.

Given that the regulated customers would be protected from paying more than the value of the service through the reserve price, they should not necessarily care if the FSRU operator makes a profit.

On balance, using the price for the Backup Service as the tender variable would appear to be the best option. It aligns the interests of the regulated customer base to least cost while giving the private sector maximum flexibility to use the rest of the terminal. This assumes there is no explicit regulation of terminal charges (as there is none at present) and that none is introduced.

### **2.3.4. FSRU Open Season**

Once selected the FSRU Provider and Operator runs the final firm open season and enters into contracts with parties willing to commit to pay for terminal capacity. This is primarily a private sector activity that the DOE would not be a party to, unless otherwise specified in the FSRU Tender documents. Thus, no details of how it should be carried out are specified in this section, because the FSRU Tender Winning Bidder would carry out the process in the way that it thought most appropriate. It would, however, probably be wise to specify in the FSRU Tender documents that any process should comply with Philippine Law and be open, transparent and non-discriminatory to any party at least.

The FSRU provider sends out the final binding contracts and parties who were willing to commit sign up and pay for the terminal capacity.

It is likely that the best outcome for the FSRU Tender will be if a successful Open Season is a Condition Precedent to the financial close. This would give the bidders in the FSRU

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Tender certainty that they would not be locked into supplying the Backup Service on an uneconomic basis before they finalise the Open Season. It would also be possible, noting the discussion in the section above on the pricing for the Backup Service, that the pricing could be predicated on a minimum contract quantity in the Open Season and that if this minimum contract quantity does not appear, the FSRU Tender winner can walk away. Similarly, if a greater volume appears, this could have a formulaic impact on the Backup Service price – formulaic because it would be difficult to evaluate the FSRU Tender on a like for like basis if each bidder offers different discounts based on the outcome of the final Open Season.

Following a successful final Open Season, the FSRU would move to achieve financial close/financial commitment and bring the FSRU to the Philippines to commence implementation & operation.

It would be required to operate and maintain the terminal in accordance with the provisions of the agreements that are part of the FSRU Tender process with the objective of managing the business and growing the gas business in Philippines.

## **2.4. MINDANAO**

Following a successful FSRU Tender in Luzon, we would recommend commencing a similar process in Mindanao.

The reason for carrying out Mindanao second is that break bulking from Luzon to Mindanao may be an economic way to deliver the amount of gas required for the Mindanao market and having a Luzon terminal locked in place first should assist this process.

The steps in Mindanao would be the same as for Luzon, with obvious differences in the Pre Tender Phase where different government assets, entities and contracts would need to be developed.

A key question for Mindanao is “what is the prize”? In Luzon, the Backup Service contract is a significant enough contract to underpin a terminal to be capable (we believe) of stimulating the market to a successful process. A similar requirement does not exist in Mindanao. The question for Mindanao is whether the DOE feels that delivering LNG to Mindanao is sufficiently important on an overall cost-benefit basis to put in place policies that would be required; for example, oil-fired plants to convert to LNG or offer a similar contract to the Backup Service to incentivise the terminal, recovered from all the electricity customers in Mindanao.

The economic arguments for this are weak, particularly given the newly committed coal fired capacity which is being developed and has been developed since the previous World Bank study identified a role for gas in the Mindanao market.

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However, a sufficient package of benefits could include, for example:

- A site (such as the PSALM site identified by Petroleum Brunei);
- Changes to the way the Government-owned hydros are contracted (to economically “make room” for gas or other baseload fuels); and
- Policies to require oil plants to convert to LNG should it become available.

If the process fails it will highlight that there is not an economic case for gas in Mindanao, even with the benefit of a larger terminal in Luzon that could lower overall costs.

## **2.5. WHAT HAPPENS IF THIS PROCESS FAILS?**

It is possible that this process will not succeed. The business of FSRUs is booming worldwide and the Philippines represents a very small market, especially given the lack of baseload demand for gas-to-power and an established gas market.

However, if the process does not work then the DOE will have learned valuable information about the global LNG terminal market and can use this in any future endeavours.

If this does not work, then little is lost and the DOE can then revisit options for integrating LNG import with power sector. However, this structure has the benefits of being able to secure a portion of the terminal costs on the basis of Malampaya backup (the economics of which were demonstrated in the Phase One report) with the option for others to bid in the open season to underpin the rest of the terminal economics.

This option is also potentially replicable in Mindanao and the Mindanao process would run subsequent to the Luzon process, in order that the outcome of Luzon can be taken into account by players in Mindanao – particularly since terminal capacity in Luzon could be used to break-bulk to Mindanao. This would mean also that the technical specifications for the Luzon terminal would have to include option for small ship loading.

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### 3. CONTRACTURAL STRUCTURE FOR AN INTEGRATED LNG-TO-POWER PROJECT

The TOR describes the objectives of Task 2.2 as:

*Task 2.2            Incorporate power sector modeling to define the size and configuration of the power plant associated with each proposed terminal, and recommend the optimal contractual structure for this power plant.*

The modelling to define the size and configuration of the power plant was undertaken at the same time as the earlier modelling in the Phase One and outlined in the associated reports and workshops. In summary, a power plant of size between 600-800MW operating in mid-merit mode was recommended and was independent of the specific terminal site proposed. All sites proposed by proponents were suitable for terminals and power stations.

To fit with the nature of the electricity market in the Philippines, the contractual structure should be one that is fully private sector – that is, does not rely on any Government funding, off-take contracts or guarantees.

The contractual structure should also be capable of regulatory approvals, and should thus show that the off-take is least cost for the purchaser. Our modelling indicates that in order for LNG to be least cost, it needs to operate in a mid-merit role, thus the optimum contractual structure associated with this power station would be one that supports the mid-merit operation of the plant. We note that a number of proponents of power stations and associated terminals indicated that while they believed the least cost operation of the power station was mid merit, the plant would need to be larger than optimal or run more hours than optimal to be able to support the infrastructure developed and gas purchased.

We do not agree with this assessment. To gain regulatory approval, the power station should contract in a least-cost manner and not be oversized or operated uneconomically to justify unnecessary infrastructure. Thus the better option is to encourage a terminal that is shared by multiple parties and used as back-up for the existing Malampaya gas field and to encourage gas purchasing arrangements that fit with the mid-merit and back-up role for LNG identified and be flexible enough to allow additional LNG to be imported as and when world prices of LNG support its use with the Philippines electricity industry in a least cost manner.

Therefore, the transaction structure outlined in the first section of this report focuses on a terminal structure that is shared by many users with potential constructors of new power stations bidding for regas capacity in the terminal. We would not recommend precluding developers from building their own terminals elsewhere if these are economic, but would recommend that the regulatory tests surrounding the approval of any contracts for power linked to imports from other terminals explicitly review, test and disallow any that result in higher costs than would have been the case should the proponent have developed



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infrastructure capable of being serviced by the terminal to be developed through the Open Season process discussed earlier in this report.

As part of the regulatory component of the preferred option above, we also note that additional support needs to be given to the ERC to enable them to be able to review and assess commercial contracts for mid-merit operation from the power station, or, better set up an incentive based regime that does not require such stringent contract by contract approval. The contractual structure entered into therefore also needs to fit with this requirement. However, the actual “least-cost” capacity factor of operation of the power station is actually dependent on the load factor of the loads being served by the retailer purchasing power from the power station. It is therefore hard to specify in advance exactly what load factor should be included in any contract structure.

It will be extremely hard to devise a contract structure that ensures least-cost outcomes if the regulation remains on a stand-alone contract basis. The following discussion explains why.

The most efficient pricing for contracts of this nature reflects the underlying cost structure of the power, so a standard fixed plus variable tariff (similar to that already used in Philippines) works. The fixed price would be related to a capacity in MW from the power station and the variable costs related to energy from that capacity. This can be used by multiple offtakers providing the sum of the fixed capacities is no greater than the total size of the power station.

The above proposed pricing structures highlight that average power prices fall as capacity factors increase because the fixed component of the price is spread over more kWh. At some point, the contract structure becomes baseload and can then be compared directly with baseload coal, but would obviously not compare favourably unless LNG prices fall significantly. This highlights the current problem with the regulatory structure – by looking at a stand-alone contract, incentives are embedded in the structure to look at the highest load factor possible because this results in the lowest average cost for this contract. It may not, however, result in the lowest procurement cost overall for a particular load factor associated with the purchasing retailer. Thus in the absence of knowing the load factor to be procured, and the other options available in the portfolio, it is almost impossible to show (without modelling) at what load factor the contract is cost effective and it may default to “baseload” in order to appear least cost.

Thus is it hard to recommend the contract terms that should be reviewed from a regulatory perspective to ensure least cost outcomes because it is not the contract terms of any individual contract that drive the answer, it’s the overall procurement strategy of the retailer. Again, it highlights a need for an alternative regulatory strategy – one that focuses on the basket of contracts and not the individual contract – to get the right answer.

In the absence of regulatory reform, it may be possible to determine the economic contracting level of a mid-merit plant through formulas related to actual demand and its place in the retailers merit order stack. Such approaches are complex and unwieldy but



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may be necessary if the (better) option of creating the right incentives for contacting cannot be achieved.

On any day, the right amount of power to be procured from a mid-merit plant will depend on the actual load on that day less other baseload contracts held by the retailer. However, contracting based on ex-post load means that the generator does not know its contracting level when it offers into the market and thus is unable to sell any spare capacity. This inability to trade spare capacity is inefficient and could result in capacity being withheld from the market, which is not the economic outcome.

The second best outcome is to fix contract capacity on the basis of a forecast of load.

For example, the Optima vesting contract (one of the South Australian Vesting Contracts<sup>12</sup>) worked like this. It operated as a one-way swap contract with a capacity fee. When the spot price was higher than the strike price, differences were paid from the generator to the retailer. When the spot price was lower than the strike price, no differences were paid. The volume covered by the contract had a volume fixed on a day-ahead basis on the basis of load forecasts. The entire suite of South Australian Vesting Contracts fitted together through a set of formulae and procedures to ensure that 1) the retailer procured exactly the right amount of supply each hour to match demand without under or over contracting and 2) neither the retailer nor any generators retained market power in the market as a result of these contracts. It should be noted that this design was in response to a fear of market power of generators at least as much as a desire for efficient contracting by the retailer.<sup>13</sup>

The retailer thus purchased power at least cost for the times of day and the volumes of power needed by it for covering loads identified by a verifiable process but did not have unfettered ability to nominate all output of the power station at will, nor the ability to bid the power station into the market and the power station was able to sell any contracted power into the market or to other customers.

However, we also note that the right mix of power also changes if the gas price changes. If the variable portion of the contract cost is linked to fuel prices (and it is hard to see how it could not be) the contracting structure would also need terms that flex the amount purchased that depends also on price (or price relative to the contract price of alternative contracts available to the retailer). Again, this would not be required if the regulation focussed on giving retailers incentives for overall least-cost contracting rather than focussing on individual contracts, however it could be achieved.

### 3.1.1. Other terms and conditions

It is also work examining some other terms and conditions that may be useful in the mid-merit PSA.

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<sup>12</sup> Further details here: <http://www.accc.gov.au/media-release/accc-proposes-authorisation-of-sa-vesting-contracts>

<sup>13</sup> South Australian Vesting Contracts were designed by Sarah Fairhurst when working for PHB Hagler Bailly on the reform and privatisation of the South Australian Electricity Industry.

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One current observation on the operation of the WESM is that it is common for one retailer to purchase the whole output of one plant, and then effectively direct how the power station bids into the market. This undermines the economic dynamics of the market and gives retailers who purchase the output of large power stations (Meralco being the key culprit in this case) more market power in the generation sector than many generators. Market power in generation undermines economic efficiency irrespective of whether it is held by generators or retailers. The economic modelling undertaken in Phases One and Two highlights that the power station should bid into the market in an economic manner, based on its own costs.

Retailer should not have the ability to direct the power stations bidding strategy.

Similarly, the fashion to sell all the output of a power station to a single buyer is not healthy in a competitive market. It results in high levels of credit risk on the part of the generator; reduces the ability of multiple purchasers to gain access to relatively small parcels of mid-merit power and increases the market power of the retailer holding the contract (even if they do not control the bidding). It also tends to give power to Meralco as the preferred contracting party and disadvantage smaller private DUs and ECs. A move to limit the ability of any contract to cover the output of the whole of a power station would assist the dynamics of the market, and particularly for mid-merit, may be an economic outcome.

We would therefore recommend that any single power station should not contract more than 60 percent of the expected output of the station to one customer.

### 3.1.2. Summary Transaction Structure

This section has highlighted that in the absence of a reform of the regulation of power procurement to introduce incentives for least cost procurement, the terms and conditions necessary in a power supply agreement between an LNG fired generator and retailer to ensure least cost procurement under a range of circumstances would be very complex.

A “simple” contract based on the current standard contract terms and conditions would risk unintended consequences that did not encourage least cost purchasing.

The complex contract would need to cover how the amount of energy purchased at any point in time is linked to:

- Availability and price of other contracts held by the retailer relative to the mid-merit contract;
- Retailer load; and/or
- WESM spot price.

We would also recommend that the purchasing retailer should not have the ability to direct the power stations bidding strategy nor that any single power station should not sell more than 60 percent of the expected output of the station to one customer.

Other than these points, the contractual structure for the power station is a matter for the private sector participants to negotiate themselves.

## 4. LNG BULK PURCHASING ROLE

The TOR describes Task 2.3 as:

*Task 2.3 Address the LNG bulk purchasing role and provide advice on how this should be structured.*

This section follows an appendix in the Phase One report to fulfil that task.

### 4.1. SUMMARY

Based upon recent trends, our market understanding, and the observations of LNG sellers, there are expectations for greater volumes of LNG traded on a short-term basis in future. This plays to the needs of LNG demand in the Philippines. Demand, at least in the first few years, will be determined by the requirements of combined cycle power plants competing in the mid-merit part of the load curve. The level of demand could be subject to variation depending on the amount of water in the hydro power plants and the level of competing new build especially from coal-fired plants. If a power sales agreement can be negotiated for a certain amount of electricity then this could underpin a back-to-back agreement for a fixed amount of LNG; however, the uncertainty in the actual level of output in any year means that flexibility remains key. Therefore, the growing level of flexibility that we see in the LNG market is timely for the Philippines.

For the period through to February 2024, we recommend that an annual formal tender is conducted to find the lowest priced LNG supply solution from a portfolio player or aggregator. This date coincides with the end of the current contract for gas supplies from Malampaya and the status of supplies of piped gas beyond from that date from Service Contract (SC) 38 should be clearer at that time. The suggestion to have a formal tender rather than negotiations is due to the limited experience of the potential customers of the LNG with the LNG market place. The likely combined level of demand for LNG, while significant, is nevertheless not large, and so we suggest that the buyers of LNG form an informal buyers' consortium or joint venture which would then conduct the tender, but individually they would contract for the level of demand that matches their requirements.

### 4.2. SELECTED EXAMPLES OF PROJECT STRUCTURE AND LNG PROCUREMENT STRATEGIES RELATED TO SELECTED ONSHORE AND FSRUs TERMINALS

This section examines the procurement methods taken by some of the more recent and potential new buyers of LNG to extract lessons for a Batangas FSRU for Luzon and the Philippines.

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**Figure 7: Selected onshore, FSRUs and FSUs around the world in developing markets**

Source: The Lantau Group

#### 4.2.1. Singapore

##### *Background and LNG procurement*

In Singapore, governance of energy lies with the Energy Market Authority (EMA), which also regulates the sector. Originally, the development and operatorship of the LNG Terminal was given to PowerGas, which in June 2008 selected GdFSuez as its partner for the project. However, the effects of the global financial crisis led the EMA to step in and take over the project to ensure its timely completion. The EMA established a wholly-owned subsidiary called *Singapore LNG* to take over development and operatorship of the LNG terminal. Through a competitive tender Samsung C&T was awarded the contract for the first 3 mmtpa terminal, jetty, and two 188,000 m<sup>3</sup> full containment storage tanks. Work on expanding the terminal by adding two more tanks and another jetty was also awarded to Samsung C&T.

The EMA decided that allowing the generating companies (gencos) to buy LNG directly was probably not going to result in attractive prices because the gencos were inexperienced in purchasing LNG, and so it was likely that they would be at a disadvantage in the unfamiliar field of LNG purchase negotiations. It is also possible that there was concern that individual gencos would have quite smaller loads initially and thus aggregating load would result in favourable pricing. Therefore in 2007 EMA started a two stage a competitive Request for Proposal (RfP). The first stage resulted in 18 proposals from 22 companies. In the second stage EMA selected a shortlist of five proposals, from which it selected a winner based on:

- the capability of the company to perform its role as an aggregator;
- the reliability and suitability of their LNG supply sources;
- the proposed pricing and terms, and
- the added value that would arise from the company's LNG trading proposals.

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The EMA emphasised that it selected the portfolio player offering the best LNG supply solution. The contract to supply the first 3 mmtpa was awarded to the BG Group in 2008.

We understand that the slope on the contract is believed to follow an “S” curve, with the slope at 14.5 at Brent between US\$35 and US\$90 per barrel but flattening out below and above those levels. The relatively high slope reflects that the agreement was awarded to in 2008 when demand for crude oil and LNG was high.

### *Business model*

BG then commenced negotiations with the gencos, although these negotiations went slowly for a year. Based on our discussion with gencos, they correctly assessed that regasified LNG was likely to be more expensive than their contracted piped gas and so none of them wanted to be first to sign for LNG and risk being at a competitive disadvantage. EMA sought to precipitate the development of LNG by introducing the mechanism for Vesting for LNG in 2009. The Vesting Contracts fixed the price at which the gencos could sell LNG-fired generation into the market and thus gave the gencos some certainty to manage the large purchase obligation.

In essence, once LNG arrived in 2013, this allowed the gencos to pass through to end-users any extra fuel cost that they incurred over using piped gas for a certain amount of LNG totalling 1.2 mmtpa. Round One of 0.6 mmtpa was allocated if the genco committed to building a new CCGT; Round Two of another 0.6 mmtpa was allocated based on registered capacity.

### *Lessons for the Philippines*

One key lesson from the Singapore experience is the importance of conducting a tender to select a supply aggregator for the first tranche of LNG into a new market. The LNG delivery system and commercial terms can be quite complex. Therefore, in the early stages of developing an LNG market simplifying the process should increase the chances of success.

At present 2.7 mmtpa of LNG has been presold by the BG Group and the EMA has launched a Post 3-mmtpa Consultation Paper<sup>14</sup>. It found there was no significant price advantage for large volumes compared to 0.5 mmtpa and it also realised that the LNG business is tending towards contracts of shorter duration. It noted that the timing of LNG procurement is a factor that affects LNG pricing and it recommended entering the market regularly and to try to avoid trying to time the market. The paper also noted there are dynamics building up in terms of new supply that could offer buyers more choice, so it was recommended to keep options open where possible.

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14 EMA, ‘Post 3 mmtpa Import Framework Final Determination Paper’ (December 2013)

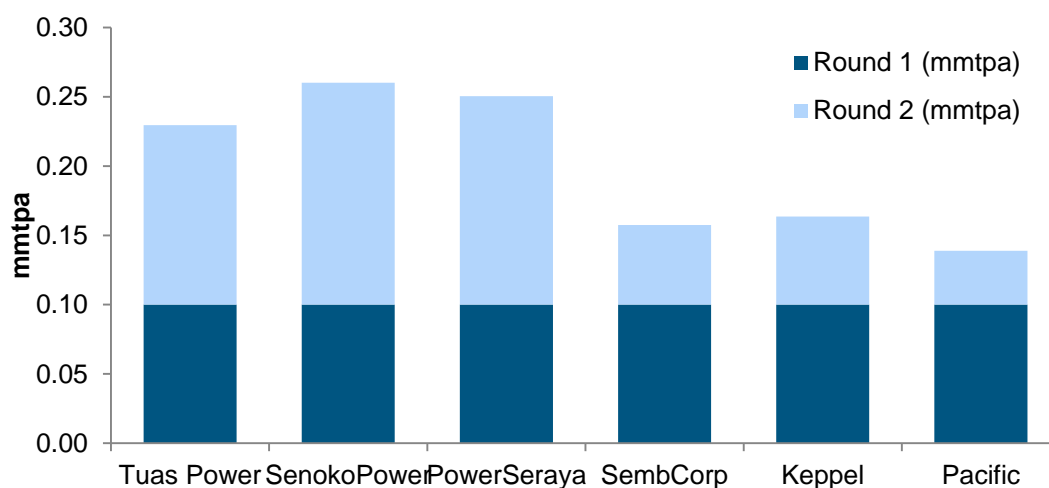
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The structure that the EMA is close to endorsing is the Competitive Licencing Framework, with potentially an unlimited number of licences. This would allow Singapore to:

- test the market on a regular tranche by tranche basis when depending on incremental demand;
- be a competitive process to discover the best deal;
- enhance security by allowing LNG to be procured from multiple sources;
- allow new importers to be introduced to enhance competition; and
- provide gas buyers with more supply options that best fit with their needs.

Regular testing of the market provides options for getting attractive pricing and provides optionality on the duration of contracts.

**Figure 8: Singapore LNG vesting volumes by genco**



Source: TLG estimates

#### 4.2.2. Indonesia

##### *Background and LNG procurement*

In 2009 the Indonesian Government made an in principle agreement to set up Nusantara Regas, and the company was subsequently established in 2010. It owns and operates (with assistance from Golar LNG) the FSRU in Java Bay to supply regasified LNG to an onshore existing power station at Muara Karang. The shareholders in Nusantara Regas are Pertamina with 60 percent and PGN (the listed but Government-controlled gas transmission company) with 40 percent. Golar LNG won the tender to supply a retrofitted LNG carrier 125,000m<sup>3</sup> Khannur and leased this to Nusantara Regas for 11 years for US\$500m. Nusantara Regas was responsible for EPC on the jetty, seabed pipeline (not buried) and onshore receiving facility.

Nusantara Regas contracted approximately 1.5 mmtpa of LNG from TOTAL from the Bontang LNG plant for a period of 11 years with a FOB price with an 11 percent slope to

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Indonesian Crude Oil Price. The low slope is largely due to strong negotiating position of Nusantara Regas. The Oil and Gas Law states that 25 percent of sales of gas from a Production Sharing Contract should go domestically.

The ultimate end-user for the regasified LNG was the state-owned power company PLN. First gas was sent out in May 2012. Ultimately, it took about two-and-a-half to three years from conception to commissioning.

### ***Business model***

The potential weak link in the commercial process might have been the finances of PLN, as it relies on a large government subsidy for about half of its revenues, since power prices are held artificially low for the moment.

Nevertheless, supporting PLN is the Government's Public Service Obligation (PSO), which requires the Ministry of Finance to make good the losses incurred by any state-owned enterprise as a result of government price-setting policies.

Presidential Regulation 2005/67 calls for tariffs to be set to fully recover costs – or if set below this level – for the Government to fund the difference with a Public Service Obligation (PSO) subsidy.

### ***Lessons for the Philippines***

One key factor that the LNG sellers will use in assessing the viability of LNG sales is confidence that the ultimate end-user can afford to pay for the regasified LNG. In the case of Indonesia this confidence in end-user ability to pay extends from the Public Service Obligation that is paid for by the Ministry of Finance to the state-owned power company, PLN.

In the Philippines confidence that the power plant owners will be able to afford the regasified LNG could come in several forms. They could rely on the detailed power simulation on the dispatch of a CCGT using regasified LNG as conducted by a trusted consultancy. A much more bankable alternative would be regulatory approval for the power company to pass-through costs to end-user tariffs. This would come in the form of ERC approval of the power plant's PSAs with Distribution Utilities. (A fall-back option could be a Gas Purchase Obligation).

Such was the success of the first FSRU in Indonesia that a second one leased from Hoegh LNG is planned for installation offshore Lampung in South Sumatra that will send out gas into the South Sumatra to West Java gas transmission pipelines owned and operated by PGN. A third one is tentatively planned for Central Java.

## **4.2.3. Thailand**

### ***Background and LNG procurement***

A National Oil Company often takes the lead as a buyer of LNG on the international stage in a new market. In Thailand the PTT built the terminal and is the buyer of LNG.



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Initially for the first three years of the terminal operations the PTT purchased LNG on a spot basis building up volumes to close to 2 mmtpa. It has now signed a contract starting in 2014 with Qatar for 2 mmtpa for 20 years. While not publicly disclosed, the slope is likely to be 13.5 and linked to oil.

### *Business model*

The terminal tariff was set using a lifecycle approach, which sets a nominal tariff based on the value of cash outflows at an assumed IRR over the project life. Based on previous analysis by a team member, the financial model assumed a gradual ramp up rate from 1 mmtpa in 2011 to 5 mmtpa by the end of the decade, and that a nominal tariff rate of US\$1.1/mmbtu would over a 40 year lifetime generate the project internal rate of return. This analysis indicated that the terminal would be in a negative free cash flow position until its volumes rose to close to 2.5 mmtpa by 2017/18, and could be interpreted as a national oil company taking a position to solve some market failures for the good of the nation.

The sellers of the LNG will take comfort from the large balance sheet and strong financial position of the PTT. Moreover, there is a clear and reliable method by which the LNG will be absorbed and paid for by the power system. The state-owned single power buyer, the Electricity Authority of Thailand, has a fuel cost pass-through mechanism. This will add the extra cost of LNG to its large pool of less expensive piped gas supplies, thus lifting the average cost of gas to all gas-fired power stations only slightly and in a gradual manner.

### *Lessons for the Philippines*

The lifecycle approach to setting LNG terminal tariffs will probably not appeal to the owners of the FSRU in Batangas as it might involve losses in early years. As is the case in Thailand, many terminals are likely to be sized to cope with a rise in future demand. Therefore, it is likely to be oversized in the initial period of operation. This is why stand-alone open access LNG terminals (or for that matter LNG liquefaction plants in the USA) presale capacity rights so that revenues flows from the first day of operation are sufficient to make the terminal profitable regardless of through-put. In addition, based on our knowledge, the revenues of the shipping companies that have leased out FSRUs are mostly comprised of a fixed annual payment that is not linked to through-put.

There is one feature of the Thailand energy market that might be duplicable to an extent in the Philippines. In Thailand the cost of fuel is a pass-through to the end user via the Fuel Transfer mechanism. If the anchor load power station in the Philippines can get a PSA approved by the ERC with fuel transfer written in to it, then this will give sellers added confidence that their LNG will be used and not stranded. Nevertheless, we recognise that such approval must ensure that captive customers are not obliged to pay for anything other than demonstrable 'least-cost' and proper incentives are in place to ensure efficient fuel procurement.

In addition, the Philippines does not have a large National Oil Company that can absorb the risks with long term take or pay LNG contacts.



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#### 4.2.4. Peninsula Malaysia

##### *Background and LNG procurement*

Petronas Gas Berhad, a partly owned and listed subsidiary of PETRONAS, is the owner and operator of the 3.8 mmtpa Lekas FSU terminal located on the west coast of Peninsular Malaysia at Sungai Udang Melaka. The construction of the jetty and associated infrastructure was awarded in 2001 to Malaysia Marine and Heavy Industries and the terminal was operational in late 2013. Two aging LNG carriers were converted to be permanently moored FSUs. PETRONAS will pay Petronas Gas Berhad reservation fee and a handling fee to be set in its fifth gas transportation and processing agreement to be announced on 31 March 2014.

PETRONAS secured up to 3 mmtpa of LNG on a short term basis from Qatar Gas, Statoil in Norway, Brunei, and Nigeria from GdFSuez. Once the ninth train at Bintulu is completed, adding 3.6 mmtpa to capacity and/or two of the small floating production LNG plants off Sabah (1.5 mmtpa in 2016 and 2 mmtpa before 2020 in blocks H and P) are online, imports of 'foreign' LNG may tail off and 'domestic' LNG will instead be transported by carrier from Borneo to Peninsular Malaysia.

##### *Business model*

It is expected that half of this regasified LNG will be sold to the power sector and the balance into non-power. However, it is not clear whether the single-buyer Tenaga Nasional Berhad (TNB) will readily accept higher priced LNG for its plants or accept power from IPPs that have signed up for regasified LNG (in order to extend the life of their PPAs). This is due to delays in implementing the fuel cost pass-through system for TNB.

So far as we understand the business arrangements, PERTONAS has reserved most of the capacity at the Lekas terminal for itself. But, public announcements by Petronas Gas Berhad have made it clear that the terminal has negotiated third-party access

##### *Lessons for the Philippines*

The Philippines does not have a national oil company like PETRONAS with extensive LNG experience and a strong balance sheet to act as an aggregator LNG buyer. Therefore, we believe that the role of aggregator for the Philippines would be best taken by the supply side in the first stage of LNG procurement.

It is expected that the Lekas terminal charges will resemble the capacity rights charging mechanism used in open seasons – a fixed fee for the right to a certain amount of regasification capacity and a variable fee depending on usage. A similar fee structure is expected to be required to attract suppliers of an FSRU for the Philippines.

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#### 4.2.5. Pakistan

##### *Background and LNG procurement*

Pakistan has had plans for an FSRU since 2006. But regulatory confusion and decision-making overlap between different parts of the government has severely hampered progress on the project.

Three sites for the FSRU were shortlisted by the Ministry of Petroleum and Natural Resources and the best site selected by consultants was at Port Qasim. The project was awarded to a subsidiary of the Engro Group, the Elengy Terminal Pakistan Limited which has agreed a term-sheet with Excelebrate Energy for an FSRU.

It is unclear if Southern Sui Pipeline Company is also in charge of LNG procurement or if this has been taken over by the Pakistan State Oil company. Southern Sui Pipeline Company has had three previous tenders (from ExxonMobil, ConocoPhillips and Shell/GdFSuez) rejected by the Economic Co-ordination Committee on the basis that the LNG was too expensive<sup>15</sup>. Pakistan State Oil Company is trying to get a discount on LNG from Qatar, but the response from Qatar had been to say that no special discounts will apply to any LNG sold to Pakistan. Initial demand is estimated at 3.75mtpa by Southern Sui Pipeline Company.

##### *Business model*

The main offtakers of the regasified LNG are expected to be the Southern Sui Pipeline Company and the Sui Northern Gas Pipelines Company. It is believed that they are seeking to be indemnified by the Pakistan State Oil Company if they have to pay for FSRU capacity that they do not use. It is understood that the two pipeline companies will then sell most of the regasified LNG to the power sector. However, we understand that the Ministry of Petroleum and Natural Resources has yet to finalise how LNG will be priced to the power sector.

##### *Lessons for the Philippines*

Define clearly at the start of the process which government agency is responsible for which regulatory approvals in order to help with timely progress of the FSRU and LNG procurement.

LNG suppliers will tend to take a new LNG importing country more seriously if there is just one counter-party to negotiate with or that is organising the tender. Members of the buying consortium in the Philippines should therefore avoid making contact with sellers outside the framework of the buying consortium.

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<sup>15</sup> SSPC also at one point had an MOU with United LNG in America from some liquefaction capacity in the USA.

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#### 4.2.6. Dubai and UAE

##### *Background and LNG procurement*

The Dubai Supply Authority has chartered the converted Golar Freeze FSRU since 2010 from Golar LNG Energy. The Dubai Supply Authority is owned by the government of Dubai. Each Emirate heavily subsidises the prices of water and power. Therefore confidence by the sellers in the LNG procurement process rests on the creditworthiness of the government. The Dubai Supply Authority has adopted an LNG procurement strategy of locking in some volumes (between 1.0 to 1.5 mmtpa) on a long term basis with Shell and Qatar in an agreement signed in 2008. As this contract was signed at a time of general tightness in LNG markets the slope is likely of the order of 14 on purchases from Qatar. But the Dubai Supply Authority has also kept some of its options open and bought short term and spot cargoes from as far away as Trinidad & Tobago and Australia.

##### *Business model*

Pass-through of fuel and regas costs to the power and water companies in the UAE. Each government in the UAE heavily subsidises power and water

##### *Lessons for the Philippines*

Buying some LNG on a contract basis and supplementing this with spot cargoes is a strategy worth considering when the level of demand maybe uncertain. There is some uncertainty on the timing and volumes of LNG needed by the new power plant and as substitute fuel by the existing CCGTs at times of interruptions to piped gas.

#### 4.2.7. Kuwait

##### *Background and LNG procurement*

Excelerate Energy provided an FSRU for the Mina Al Ahmadi GasPort. This utilised an existing jetty that was modified to transport up to 500mmcf/d of regasified LNG. Demand of some 2 mmtpa in 2012 came from six different nations, and Qatar supplied half of total requirements.

Kuwait only needed seasonal supplies from April to October to replace crude oil that was being burned in power plants. As demand is seasonal, no long term LNG contract was signed and gas is purchased on a spot basis.

The Kuwait National Petroleum Company launched a competitive tender for a second FSRU which was awarded to Golar LNG in 2013 for a charter lasting five years. The FSRU Golar Igloo is expected in 2014 and will remain on station for nine months of the year.

##### *Business model*

The fuel cost is passed through to the Ministry of Electricity and Water which provided subsidies to consumers worth a huge US\$ 31bn in 2013.

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### ***Lessons for the Philippines***

Demand for power in Luzon is not characterised by any particular seasonality. So the need for a movable FSRU solution is not needed. The supply of LNG is supported by the balance sheet of the Kuwait National Petroleum Company and losses of vast magnitude on electricity and water are absorbed by the Ministry of Electricity and Water neither of which is an option for the Philippines

#### **4.2.8. Lebanon**

##### ***Background and LNG procurement***

In response to a large decline in supplies of piped gas from Egypt and a soaring bill for replacement liquid fuels for its power plants, the Ministry of Energy and Water launched a tender for a FSRU in 2013. It received three offers from international shipping companies. The site preferred by the Ministry is Beddawi in the north due to its sheltered location, but the two other sites at Zahrani oil installations and the Selaata are also still under consideration. The FSRU is expected to be commissioned by 2015 for a period of 12 years, according to the Ministry of Energy and Water. Putting the FSRU at Beddawi would require new pipelines built to the south to connect with existing power plants. The ministry said it will also be responsible for a high pressure pipeline linking the FSRU to shore, and also the potential construction of an additional breakwater.

The LNG procurement is the responsibility of the Ministry of Energy and Water. Interestingly it has started negotiations with several un-named companies rather than issue a tender. We believe that it will approach Qatar to see if their shared cultural background will result in some supplies at a favourable price. If purchases are made on the world market we believe the risks of selling to the Lebanon will result in that country paying a premium for its LNG. It is not clear if World Bank will offer partial risk guarantees. Demand is expected to start at 1.2 mmtpa and rise to 3.5 mmtpa as pipelines to power plants are built out.

##### ***Business model***

The terminal is proposed to operate under a tolling structure, in which the Ministry of Energy and Water would pay a monthly capacity fee to the FSRU owner regardless of usage, and then a monthly throughput fee for operating costs incurred for actual usage.

Offshore acreage in both Israel and Cyprus have seen very large discoveries of gas. In Israeli waters the Tamar field contains 10 Tcf, and Leviathan 19 Tcf. But duplicating this in the Lebanon in the near term is unlikely. The Lebanon would like to launch an offshore acreage bidding round<sup>16</sup> but is hampered by the lack of a stable government and maritime boundary disputes with Israel. In addition, from initial exploration to commercialisation for gas usually takes at least between six to eight years

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<sup>16</sup> It has received 46 expression of interest and shortlisted 34 companies as operators.

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### *Lessons for the Philippines*

The terminal is proposed to operate under a tolling structure, in which the Ministry of Energy and Water would pay a monthly capacity fee to the FSRU owner regardless of usage, and then a monthly throughput fee for operating costs incurred for actual usage.

Offshore acreage in both Israel and Cyprus have seen very large discoveries of gas. In Israeli waters the Tamar field contains 10 Tcf, and Leviathan 19 Tcf. But duplicating this in the Lebanon in the near term is unlikely. The Lebanon would like to launch an offshore acreage bidding round<sup>17</sup> but is hampered by the lack of a stable government and maritime boundary disputes with Israel. In addition, from initial exploration to commercialisation for gas usually takes at least between six to eight years

## **4.2.9. Europe**

### *Background and LNG procurement*

In general in Europe LNG terminals are regasifying LNG into a very large and liquid market place with many large financially robust users ranging from power companies to industry.

Pricing of LNG to the UK has usually been a netback on the National Balance Point price. Legacy LNG contracts to continental Europe were often linked to the crude oil price, but are now more likely to be linked to hub prices as these have developed in sophistication and depth. Indeed on imported piped gas the EU Commission has launched a probe into the gas pricing methods of Gazprom which were traditionally linked to oil. Many traditional LNG contracts to continental Europe had destination clauses.

### *Lessons for the Philippines*

There is value in the flexibility to change the destination clauses in LNG contracts. There are quite a number of LNG reloadings in Europe as LNG demand has slumped partly due to the poor economy but also due to competition from piped gas. Some of the contracts with destination clauses were worked through by mutual agreement but some nevertheless entered arbitration. The level of discomfort was less than might have been expected as there was a ready market in Japan post-Fukushima for LNG. But not all agreements were restructured. Luckily, the LNG is instead needed elsewhere, with most re-loadings going to Asia or otherwise to Latin America.

We are suggesting a supply aggregator for the first stage of LNG procurement for the Philippines. So evidently the LNG contract would specify the place of delivery. But the buyer should have the option to nominate delivery elsewhere. But this raises the question of who absorbs the risks or rewards of diverting a cargo? Whoever absorbs these risks and/or costs associated with diversion is then exposed to the spot market.

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The last few years diverting a few cargoes to north Asia might have resulted in some profits. Prices for spot LNG in north Asia have been strong since Fukushima accident. But market conditions can change and the portfolio player or the buyer consortium could also be exposed to a loss on a spot market sale from a diversion.

Avoid linkage to crude oil and strive for a mixture of crude oil linkage and reference to the UK National Balancing Point or also some component of Henry Hub. Gazprom has been compelled to lower its prices to Europe by renegotiation with buyers and is also the target of anti-competitive action underway by the EU Commission for linking its gas price to crude oil.

#### 4.2.10. Netherlands – The Gate

##### *Background and LNG procurement*

Expressions of interest and then binding agreements resulted in a final investment decision being taken in December 2007. This open access terminal is owned by Vopak and Gasunie and was operational in September 2011. The capacity rights to through-put of 12 billion Nm<sup>3</sup> of regasified LNG (9 mmtpa of LNG) per year were purchased by Dong Energy, EconGas, RWE Supply & Trading, E.ON Ruhrgas and Eneco. There are the facilities to reload LNG onto smaller carriers for transportation up rivers and to smaller terminals in the Baltic and in Norway. Also more recently truck loading facilities were added to the services at The Gate. The utilisation rate has been very low as LNG demand in Europe has fallen, due to the slow economic conditions in Europe and due to competition from Gazprom lowering its piped gas prices. Nevertheless, based on our research all companies that bought capacity rights have continued to make payments<sup>18</sup>.

LNG is procured by multiple buyers with many different demand profiles and absorbed by the huge European gas market.

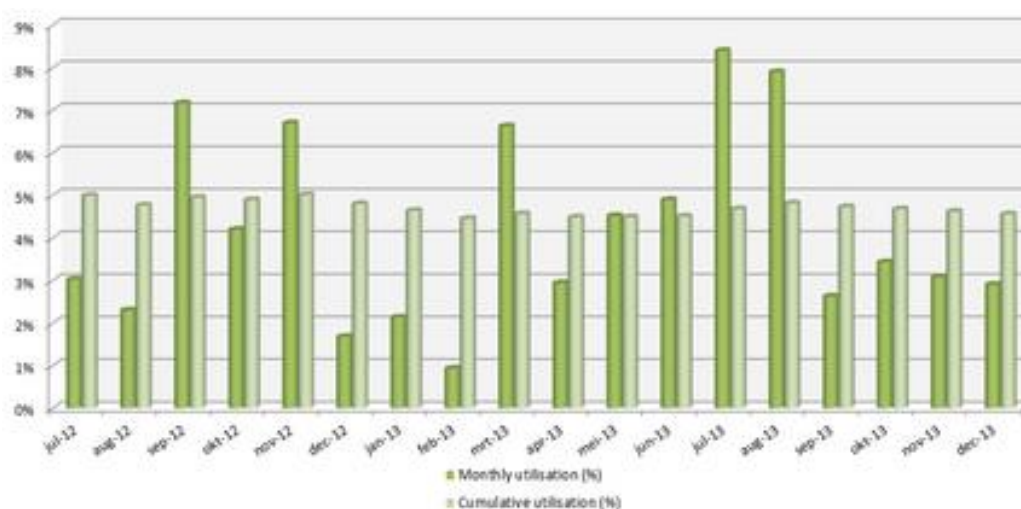
##### *Lessons for the Philippines*

Even if the terminal is not fully used by those that have contracted for capacity rights they will continue to pay for those rights.

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<sup>18</sup> For example, there is no provision for non-payment in Vopak's financial statements.

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**Figure 9: The Gate utilisation rate (% of nameplate capacity)**

Source: Vopak

#### 4.2.11. Dominican Republic

##### *Background and LNG procurement*

The onshore Punta Caucedo LNG Terminal has been operating since 2003 and is owned by AES. There is no third party access. It has an onshore tank of 160,000 m<sup>3</sup> and a with one vaporizer enabling a maximum of close to 1.75 mmtpa of LNG through-put.

Volumes per year are not that large but have been rising: 2010, 0.5 mmtpa; 2011, 0.72 mmtpa and 2012 0.96 mmtpa. This said AES has a 20 year contract for 0.7 mmtpa with BP supplied from Atlantic LNG in Trinidad & Tobago. Given the difference in volumes there must be some flexibility on deliveries or else changes to volumes were negotiated. The price of the LNG is believed to be linked to Henry Hub

##### *Business model*

The regasified LNG is fed mostly to AES' 320 MW Andres combined cycle power plant and its 236 MW open cycle Los Mina power plant. Of this capacity of 555 MW close to 80 percent is contracted by PPAs to government-owned distribution and retail companies and non-regulated customers (with demand over 1.2 MW) until 2017. AES also has an approximately 50 percent stake in the coal-fired 295ME Itabo plant of which 250MW is contracted by PPA. The balance of generation of about 20 percent is required to be sold through the wholesale market. AES has been using some incremental supplies of LNG to sell CNG by truck to industry since 2005 and by LNG truck since 2010.

There is a General Electricity Law, a National Energy Commission which sets policy and legal framework and Superintendence of Electricity which regulates the power market. Overall installed capacity is 3,000 MW of which 85 percent is thermal and 15 percent is hydro. The power market is competitive with regulated rates for transmission and distribution. The government-owned distribution and retail companies are not in a strong



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financial position and sometimes AES has had to accept government bonds in lieu of cash.

### *Lessons for the Philippines*

There are some surprising similarities between the Dominican Republic and the Philippines (WESM - Luzon/Visayas). About a decade ago the Dominican Republic started to liberalise its power sector. PPAs approved by the Superintendence of Electricity allow for the capacity costs and fuel costs to be passed through to the distribution and retail companies. While evidently there are some problems with bill collection and indeed non-technical losses, this mechanism did help make possible the construction of the LNG terminal and the associated gas fired plants. Also of interest for the Philippines is that after a few years demand for gas in other sectors such as industry and commerce has been developed.

However, there are some key differences between the Philippines and the Dominican Republic. Firstly, is that the regasified LNG price is very likely to be higher in the Philippines than in the Dominican Republic. Secondly on Luzon, the credit rating of the main retailers and the willingness of banks to lend to energy projects is strong.

## **4.2.12. Puerto Rico**

### *Background and LNG procurement*

The Penuelas LNG terminal is owned by EcoElectra whose shareholders are Gas Natural Fenosa (47.5%), IP (25%) Mitsui (25%), GE (2.5%). The LNG terminal has one onshore 160,000 m<sup>3</sup> tank and was commissioned in 2000. Gas Natural Fenosa buys LNG at prices linked to Henry Hub from Atlantic LNG on Trinidad & Tobago.

LNG is supplied from Trinidad and Tobago under a 20 year contract with volumes at 0.6 mmtpa. This volume of LNG would correspond to a capacity factor of close to 90 percent and so would require the power plant to be dispatched at close to based load.

The pricing to the Puerto Rico Electric Power Authority has not been publicly disclosed but the LNG price is likely linked to crude oil with a slope of close to 11, plus shipping, and regasification. This gave a delivered regasified LNG price of in June 2012 of US\$14.3 mmbtu<sup>19</sup>. This is still competitive as 70 percent of the rest of the power used in Puerto Rico is oil based.

### *Business model*

The key buyer of the LNG, Gas Natural Fenosa is also the main shareholder in the LNG terminal and the power plant. So bundling LNG procurement, LNG terminal access and power plant ownership together obviously enable co-ordinated decision making.

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<sup>19</sup> Report On The Necessary Measures To Comply With New Epa Regulations, And The Conversion To, And Use Of Natural Gas In, The Northern Power Plants, June 2012, Intersectoral Committee On Environmental Compliance And Energy Alternatives, Government of Puerto Rico



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The regasified LNG is used in the adjacent 540 MW power plant of which 504 MW is contracted to the Puerto Rico Electric Power Authority under a power purchase agreement that is valid from the year 2000 through 2022.

### ***Lessons for the Philippines***

Medium sized power plant with volumes contracted to end users with fuel cost pass through enables signing a long term LNG supply contract. That said the LNG market has developed in the last fifteen years and a LNG procurement strategy that locks in fixed supply at a certain price structure is closing the door on options that might be available from the greater flexibility in supply and in pricing that might emerge in the future.

The main profits for Gas Natural Fenosa in this energy chain are the mark-up on the LNG price between what it pays for LNG in Trinidad & Tobago and the price at which it sells the regasified LNG to EcoElectrica in Puerto Rico. So this is not an LNG procurement strategy that the Philippines should copy. Any LNG supply should be tendered, and the best solution awarded the supply contract. If the LNG supply comes from a company that is also involved in a power station development that is acceptable but the LNG supply would have to go out to tender.

## **4.2.13. Jamaica**

### ***Background and LNG procurement***

Jamaica has tried several times to get an LNG terminal developed in order to supply gas to its power system and lower reliance on costly liquid product. In 2013 Office of Utilities Regulation launched a competitive tender for the supply of power to the Jamaica Public Service from a CCGT using regasified LNG from a new LNG terminal.

The initial winner was disqualified due failure to place a bid bond. This allowed the second-placed bidder Energy World Corporation (EWC) to be awarded the contract with a real levelised price for power of US\$145.5/MWh. Assuming a WACC of 14 percent and an overnight capex of US\$950/kW this would imply a regasified LNG price of close to US\$14/mmbtu. EWC plans to bring in LNG from its Sengkang LNG plant in Sulawesi in Indonesia.

### ***Business model***

One company is developing the power plant, the LNG terminal and sourcing the LNG. Sales of power will be made with a Power Purchase Agreement with the Jamaica Public Service.

### ***Lessons for the Philippines***

Avoid having one party develop the anchor power plant, the LNG terminal and procure the LNG, unless there is a tender for each part of the process and especially on LNG procurement. Jamaica is very close to the USA and a separate solicitation for the supply of LNG might have taken resulted in a company with capacity rights at an LNG plant in the USA offering to sell LNG instead of bringing it all the way from Indonesia.

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The fact that Marubeni and Korea East West Power together own 80 percent of the Jamaica Public Service offers moral financial support to JPS. On the other hand, the Jamaica Public Service, while in reasonable financial health, is still slightly in breach of its obligation to debt holders not to let its net debt to EBITDA exceed a ratio of 3.0 times. This could allow debt holders to call in their loans. A recurring theme is have a creditworthy counter party will help with make available the widest choice of LNG suppliers.

#### **4.2.14. Brazil**

##### ***Background and LNG procurement***

Due to a drought and therefore a shortage of hydro power Brazil has moved rapidly to develop FSRUs to provide regasified LNG to the power sector. Demand varies substantially by year depending on the level of water in the hydroschemes and also by season driven by the weather and hence the need for air conditioning. In 2013 Brazil was expected to have imported 3 mmtpa, slightly higher than the volumes in 2012 of close to 2.5 mmtpa; and much higher than in 2011 when only 0.6 mmtpa was imported; and in 2010 imports were at 2.0 mmtpa. LNG comes from mostly from Qatar and Trinidad & Tobago, but also from Norway and Nigeria. Master Sales Agreements would have to be in place with companies in order to speedily access a spot cargo.

Petrobras charters several FSRUs. At Pecem starting in 2009 with capacity of 2 mmtpa, Guanabara Bay from 2009 with capacity of 4 mmtpa (since lifted temporarily to 4.5 mmtpa by swaping of Exceletrate Exquisite with Golar Winter) and later to be raised to 5.5 mmtpa with arrival of VT3 from Exceletrate Energy, and Salvador Bahia from 2013 at 4 mmtpa (due to relocation of Golar Winter).

Petrobras is very active in the spot market for LNG cargoes. During its southern summer it is competing for spot cargoes with Korea, China and Japan that need the LNG for sales to city gas for heating during their northern winter. To our knowledge Petrobras has not entered into any long term contracts.

##### ***Business model***

Petrobras does not provide detailed numbers, but our analysis would suggest that it loses money on LNG sales to the power sector. This issue has been exacerbated by President Rousseff, who twice in the last few years pushed down retail power prices. Petrobras may get some small relief on these losses via sales of non-contracted power from its power plants to the Brazilian power spot market, which has experienced some very high prices the last two years.

##### ***Lessons for the Philippines***

What this does show is that spot cargoes are available in size in the current market place, but at a price. This supports our view that in the Philippines a baseload take or pay short-term contract for Stage One through to 2024 can be kept at a reasonable level and

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supplemented in the first stage with spot cargo supplies if required when the alternative would be even costlier diesel.

#### 4.2.15. Uruguay

##### *Background and LNG procurement*

GdFSuez and Marubeni have chartered the world's largest FSRU with a storage capacity of 263,000m<sup>3</sup> for 15 years starting in 2016 under a build own operate transfer agreement with Gas Sayago, a subsidiary of state owned companies UTE and ANCAP. The facility to be known as GNL del Plata will be located 4km offshore Montevideo. (As a bridging solution the GdFSuez Neptune will be on station at the GNL del Plata Jetty for one year).

The aim of the Uruguay government is to change the country's energy mix which is highly dependent on hydro power. It used to be able to import power from Brazil and Argentina at times of its own hydro shortage. But over the last few years those countries have faced their own power sector shortfalls. Uruguay has increasingly turned to a rather aging fleet of thermal plant using finished product to cope with seasonal peak demand. Some new gas fired plants are expected to be built by UTE to use some of the regasified LNG. In addition a gas pipeline is planned to Argentina to enable gas exports.

State-owned National Oil Company ANCAP and state owned power company UTE will be conducting negotiations with potential suppliers of LNG. It is not known if these will be one-on-one negotiations or else if an invitation to tender will be issued.

##### *Business model*

It is not clear yet how retail power prices will be adjusted to cope with a greater amount of power generated from power plants using regasified LNG.

##### *Lessons for the Philippines*

This is being financially supported by the balance sheets of the state oil and power companies which is not an option open to the Philippines. But the Uruguay authorities have followed one of our key lessons from our survey of FSRU projects in this report which is to separate the ownership and operation of the FSRU, from the purchase of the LNG, which are two very different commercial transactions. The owner of the FSRU will want high throughput and ideally sell its own LNG. The users of the regasified LNG may want a completely different LNG solution.

#### 4.2.16. Argentina

##### *Background and LNG procurement*

The country has two FSRUs: Bahia Blanca Gas-Port with an Excelerate vessel leased to YPF Repsol which commenced in 2008 and the Escobar Gas-Port with another Excelerate vessel leased to Enarsa which started operations in 2011. These are seen as a temporary solution pending domestic gas pricing reform in order to get new gas exploration under way and to then lift domestic production.

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Most LNG has come from Trinidad & Tobago but the country is very active in the spot market and so Argentina is at times competing with neighbouring Brazil for LNG.

Argentina is estimated by the US Energy Information Administration (EIA) to have the world's second-largest shale gas resources at 802 trillion cubic feet and fourth-largest shale oil resources at 27 billion barrels. But it has been slow to exploit these resources due to historically low gas prices. However approval to raise wellhead gas prices has been forthcoming, with the government in February 2013 saying they would pay US\$7.5 mmbtu at the wellhead for gas.

### ***Business model***

This country's gas market is the one in Latin America that best displays the problems that come with kinky gas price curves<sup>20</sup>. President Cristina Fernandez de Kirchner held prices low at US\$2.5 mmbtu at the well head for domestic political reasons. The response from the gas industry was declining gas production. Exports to Chile ended and imports from Bolivia could not make up the difference.

In 2012 she also oversaw the nationalisation of Repsol's YPF Argentine assets, which included a vast acreage in the Vaca Muerta shale prospect, complaining that Repsol had not been proceeding with exploration and production in a timely manner. Repsol countered that domestic gas prices did not provide the correct incentive. (Just recently the government of Argentina agreed to offer Repsol US\$5bn in compensation, but which would still require a US\$ 1.75bn impairment write-down by Repsol).

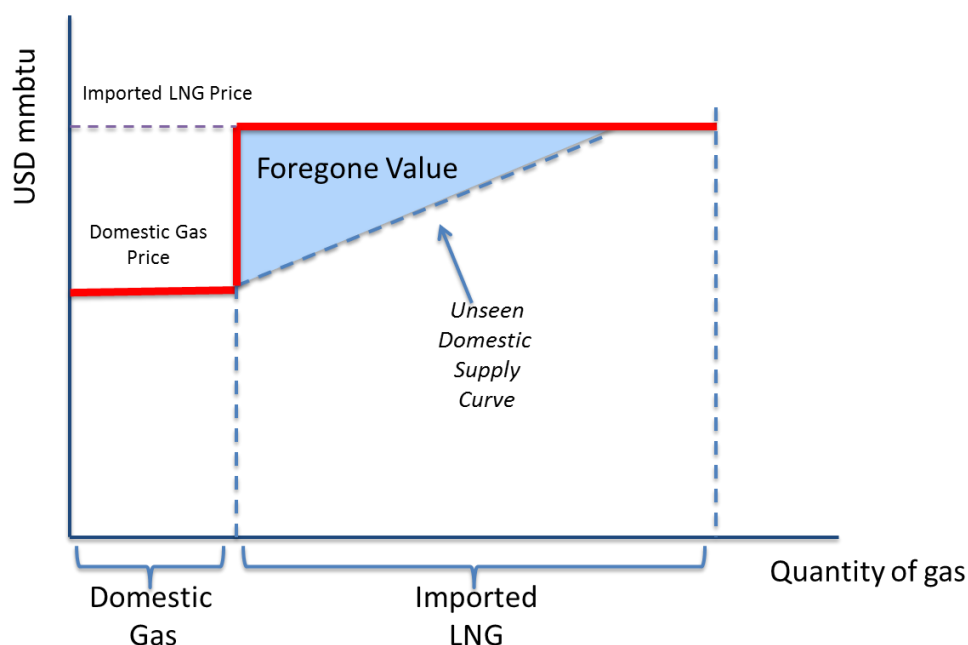
### ***Lessons for the Philippines***

If you want to buy expensive LNG then the lesson from Argentina would appear to be to buy all your gas in the spot market, one cargo at a time. So a balance is required for the Philippines. A short term contract for the first five years for a base load of LNG, with the option to divert some cargoes. The freedom to purchase from the spot market if some emergency supplies of LNG are needed in which case timeliness of delivery rather than price will be key. Even expensive LNG is likely to be less costly than using diesel in a CCGT.

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<sup>20</sup> See The Lantau Group February 2014 Pique on Asia's Kinky Gas Price Curves

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**Figure 10: Kinky gas price curve**

#### 4.2.17. Chile

##### *Background and LNG procurement*

There are two terminals at present in Chile with different structures and LNG procurement strategies.

In the north the Mejillones FSU facility is on the cusp on being converted into a standard onshore terminal, once earthquake tests are complete on the onshore tank. Development of this terminal was fast tracked by GdFSuez in order to meet a shortage of gas following on from the decline in exports of gas from Argentina. GdFSuez owns 70 percent and Coldeco the remaining 30 percent. GdFSuez also brought in all the LNG. Recently the owners have changed the terminal commercial operating system to allow third party access.

There is another terminal further south at Quintero. This offers an interesting commercial structure for a new LNG terminal. The ownership of the terminal, the capacity rights and the LNG buyer of record are all different. Most interesting is that GNLChile buys LNG on behalf of its shareholders, and will sell to others as well. (But likely at a mark-up, hence the intention of power company Colbun to build an FSRU adjacent to Quintero).

##### *Business model*

At the moment all LNG is purchased from the BG Group, but disputes over pricing have led to some compromise being reached which includes an element of Henry Hub in the gas price formula.

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### *Lessons for the Philippines*

An Aggregator on the buy side is a business structure that the Philippines might consider for the LNG to be delivered into the Batangas FSRU. Getting all buyers aligned and then able to present a united front position should strengthen their negotiation position. Perhaps this need not go as far as setting up a special purpose vehicle as Aggregator, but at the very least an informal consortium.

**Figure 11: Quintero terminal, capacity rights and LNG procurement**

Quintero LNG Terminal	Capacity Rights at Quintero LNG Terminal	GNL Chile
<ul style="list-style-type: none"> <li>Owned by Terminal de Valparaíso (40%), ENAP (20%), Endesa Chile (20%) and Metrogas (20%). (Terminal de Valparaiso is Enagás 51% and Oman Oil 49%).</li> </ul>	<ul style="list-style-type: none"> <li>Existing 2.5mmtpa - - Endesa, Metrogas, and ENAP</li> <li>Expansion 1.25mmtpa - Endesa 2.8 mmcm/day, Metrogas, 1.6mmcm/day and ENAP 0.6mmcm/day</li> </ul>	<ul style="list-style-type: none"> <li>Owned one third each by ENAP, Endesa, and Metrogas.</li> <li>Buyer of record for LNG for end use by ENAP, Endesa, and Metrogas</li> <li>GNL Chile will buy LNG on behalf of others.</li> </ul>

Source: The Lantau Group estimates

#### **4.2.18. Korea**

In late 2004 into early 2005 in Korea the then Ministry of Industry and Trade tried to test the market for supplying cheaper LNG than it thought KOGAS could purchase, by allowing the gencos to solicit for supplies of LNG directly. But a combination of factors brought this initiative to a halt. Firstly, the sellers of LNG withdrew from negotiations as they somewhat belatedly realised they were at risk of upsetting the single largest corporate buyer of LNG in the world. Also, the Ministry of Industry and Trade backed down on its rather ill-thought out idea. It realised there is power in being a single-buyer. In addition other regulatory matters were not in place such as third-party access to terminals, regasification and transmission pipelines.

#### **4.2.19. Informal LNG Buyers Club**

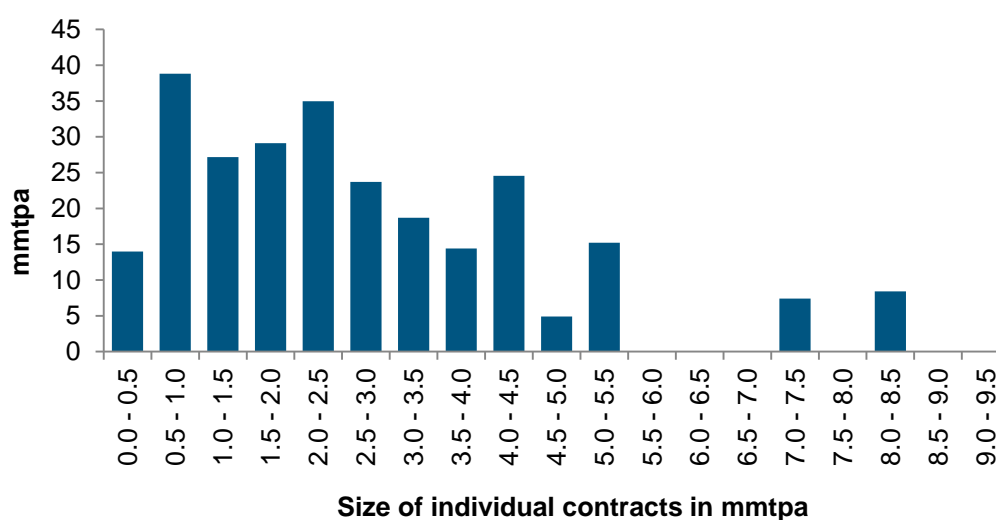
The Japanese and Indian gas buyers have recently decided to try to informally club together to try to present a united front to LNG sellers in order to get LNG prices pushed downwards. However, it is doubtful that such a loose coalition would hold together and grouping together such a large number of buyers of a commodity might fall foul of World Trade Organisation (WTO) rules.

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### 4.3. SIZE OF CONTACTS

Size of LNG contracts is often cited as a reason for the lack of interest that sellers have shown to date to enquiries made by local proponents. But official numbers<sup>21</sup> indicate that in 2012 there was some 13 mmtpa of LNG that was contracted in volumes of less than 0.5 mmtpa and close to 38 mmtpa contracted in volume between 0.5 mmtpa to 1 mmtpa (see Figure 12). Based on our market knowledge and talking to LNG suppliers, a problem to date with the testing of the market by that has been done by Philippine companies, is the lack of infrastructure and concerns over creditworthiness of some potential customers and not the potential size of LNG volumes.

**Figure 12: Size of individual contracts and total amount of LNG contracted**



Source: GIIGNL

### 4.4. CREDITWORTHINESS OF BUYERS

#### 4.4.1. Power

An approved Power Purchase Agreement would help convince LNG suppliers to sign a long term contract with the consortium running the power plant. As is noted elsewhere in this report convincing the Energy Regulatory Commission that a CCGT using LNG is a least cost method to serve mid merit demand does face some challenges.

On the other hand if some sales were also planned to be sold into the WESM on a spot basis then an analysis of the level of dispatch of the CCGT plant could be provided by simulation of the power market to justify a certain level of demand for LNG. Many of the proponents of LNG-to-power projects have done just such a study. In this case LNG could be bought on a short term basis under a master agreement as we discuss later.

<sup>21</sup> Adapted from International Group of LNG Importers (GIIGNL)

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#### **4.4.2. Non-power**

We expect demand for trucked LNG to industry and via LCNG into transport to emerge in time. A key player or players that will need to arise in order to get LNG to industry are gas aggregators. We have seen such new gas players or mini-aggregators emerge to supply gas to industry in Indonesia following the liberalising Oil and Gas Law 22/2001.

#### **4.5. BUYING LNG DIRECTLY FROM ONE SOURCE/PLANT**

These types of contracts have been compared to a “virtual pipeline” linking a specified source of gas with a specified buyer at one receiving terminal. These contracts are usually delivery ex-ship, or if free on board, then will have diversion exclusions written into the contract to prevent the buyer from reselling the LNG elsewhere. Thus avoiding potential competition for new volumes of LNG that maybe marketed by the seller.

We would recommend that for the Philippines where demand is uncertain and given the other favourable dynamics that are evolving in the global LNG market that traditional LNG long term contracts, with high levels of take or pay, and destination clauses are avoided.

#### **4.6. BUYING LNG FROM A PORTFOLIO PLAYER**

The aggregator can also be on the supplier side and take the risk of selling to various smaller users of LNG. The main portfolio players such as BP, BG Group, Chevron, ConocoPhillips, ExxonMobil, GdFSuez, Qatar Gas can fulfil that role. Demonstrating that the price offered is the lowest over the duration of the contract is relatively straight forward. At its most basic, the solicitation could ask for a delivered price per mmbtu to Batangas FSRU given a Brent forward curve for a demand profile volume of LNG. The problems with this method is that we are concerned with other factors than just price. Given the fluctuations in the possible demand for power from using regasified LNG flexibility is part of the requirement for LNG supply. The matter of diversions of unwanted LNG would have to be addressed in the solicitation or for that matter the need for extra cargoes. Extra supplies might be needed if hydro plants were low on water or during times of Malampaya planned (or even unplanned) outages. Given the relatively low initial volumes

An increasing amount of LNG comes from portfolio players such as Total, Shell, GdFSuez, BP and the BG Group. By this we mean that the source of the LNG is not identified in the LNG supply agreement nor is there a destination. It is usually taken onto their books and they will sell it on short term basis or else lock in longer term contracts as market conditions dictate. Delivery would usually be ex-ship so portfolio players are also attempting to optimize their LNG carrier fleet.

#### **4.7. KEY FACTORS IN LNG PROCUREMENT FOR THE PHILIPPINES**

From the arguments presented above we believe the following lessons can be applied to an LNG procurement strategy for users of the Batangas FSRU at Luzon. Buyers acting in concert is one method of trying to improve negotiating position and present a united front to sellers. In fact from the case studies above there are examples of where disparate approaches to sellers by potential buyers from an existing or newly importing country



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have hampered LNG procurement. There is nothing that we are aware of prevents buyers acting in concert under the laws of the Philippines. The power station could be the focal point around which other buyers of LNG could gather. An informal consortium could conduct a tender for LNG. Then they would contract individually for the timing and the volumes. This has similarities to what the Energy Markets Authority is proposing for the post-3mmtpa buying mechanism (see Section 4.2.1 covering Singapore). Alternatively a company could be set up, perhaps called the *Philippines LNG Import Company* (PLIC), that would formally group together buyers, as we understand is the case with GNLChile, but that is a second choice due to likely legal complexity.

Table 1 describes some strategies to strength Philippine LNG procurement.

**Table 1: Strategies to strengthen Philippine LNG procurement**

<b>Informal consortium</b>	Joint buying negotiations via an informal consortium.
<b>Creditworthiness of buyers</b>	Either based on individual capital, bank guarantees, or shareholder cross default guarantees.
<b>Terminal in place</b>	Successful tender for FSRU at Batangas supported by payment of avoided costs on Malampaya outages. Third party access. Capacity rights transferable.
<b>Power station</b>	The LNG supplier can be part of the group owning the power station, but LNG procurement should be via a separate legal entity to ensure pricing transparency and to enable a separate solicitation for LNG supplies. The case for mid-merit plant of 800 MW comes out of our simulations for WESM.
<b>Pass through of LNG costs</b>	If a case can be made with the ERC that allows pass through of LNG costs in a PSA this would improve the robustness of the LNG demand to the seller.
<b>Size of contracts</b>	This is not an issue in our view as there is 14 mmtpa of LNG in contract sizes less than 0.5 mmtpa. Although this might require buyers combining their demand via a consortium.
<b>Tendering</b>	We recommend that the Buyers in the Philippines form a voluntary consortium to purchase gas. This will aggregate demand and improve pricing terms. Tenders should be run regularly (annually or bi-annually) for purchases, as this will ensure gas is purchased on a flexible basis. There would be no prohibition on buying separately – to allow potential sellers to access the Terminal and sell speculatively to any other Buyers.

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#### **4.8. KEY CONSIDERATIONS FOR LNG TENDER PROCESS FOR STAGE ONE**

Running a tender for supplies of LNG is a complex process and we will not attempt to address every aspect of an LNG Sales and Purchase Agreement. But what we believe will be of use is to highlight a few key factors that are likely to be of particular importance to the buyers of LNG in the Philippines.

##### ***Conditions Precedent***

Try and keep these to a minimum of the key essentials. The greater the number of conditions precedent the greater the chances of failure to meet some condition that risks cancelling the entire contract.

##### ***Seller***

We are suggesting that for Stage One that LNG purchases are made annually from whoever wins the tender, which could be a portfolio player or others. Therefore the contract may not specify the source of the LNG. The buyers should satisfy themselves as part of the tender that the Portfolio Player has supply capacity available to meet the buyers' demand.

##### ***Take or Pay***

Ideally, the level of take or pay should be kept to a minimum as the level of demand is subject to uncertainty. But, we recognise that the level of take or pay involves a trade-off between the value of flexibility and the cost competitiveness of commercial terms that might be agreed with LNG sellers. That level of uncertainty could be reduced if the regasified LNG gets ERC-approved fuel pass-through with a minimum annual quantity as part of an approved PSA with a retailer. The demand for regasified LNG to supplement planned interruptions in supply of piped gas is also the subject of some uncertainty. Even the timing of planned maintenance on gas fields might change due to unexpected conditions on the production platform, gathering lines or subsurface equipment.

##### ***Delivery at Terminal and Diversions***

It is unlikely that the buyers will initially have the desire to get into the shipping business or for that matter have the demand to justify a chartering a dedicated large scale LNG carrier. Therefore the LNG is likely to be supplied Delivery at Terminal by the portfolio player. The right of the buyer to request delivery to elsewhere is one method to minimise the potential financial overhang or penalties of take or pay element of LNG supply. It is likely that a geographic limitation on diversion would need to be agreed. LNG demand in Asia is very probably large enough to absorb a few cargoes diverted from the Philippines. A method of paying for any extra shipping costs would need to be agreed. A decision would need to be made whether the LNG supplier or the buyer would absorb the difference between the Philippines contracted price and the price achieved in the spot market.

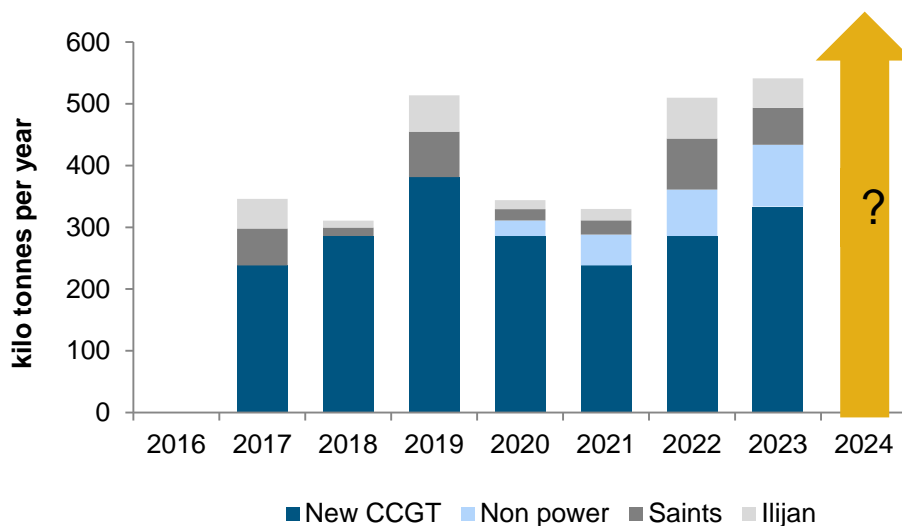
**Buyers – Sharing cargoes or borrowing and lending**

It is likely that demand in Stage One would be made up of the LNG requirements of the new CCGT, LNG supplies to supplement any interruptions to piped gas supplies, and supply to industry and transport. It is likely that several buyers will at times aggregate their demand for LNG into one cargo or else enter into borrowing and lending arrangements. A similar situation will also exist in Singapore in the post 3-mmtpa competitive licencing framework in which multiple buyers will be negotiating with shortlisted LNG suppliers.

For example in Figure 13 we have taken the generation from liquids replacement from the six scheduled Malampaya outages between 2006 and 2013 and sequenced these from 2017 to 2023. What this indicates is that there would have to be jointly purchased cargoes or else borrowing and lending of LNG at Batangas. From 2024 onwards the level of LNG demand would be likely to rise if Malampaya is depleted, but volumes required will be clearer as that date comes closer.

The LNG requirement of the Saints and Ilijan would range from 25,000 tonnes or 55,500m<sup>3</sup> of LNG over four days or a third of a cargo on a 170,000m<sup>3</sup> LNG carrier to 150,000 tonnes or 334,000m<sup>3</sup> over 30 days or two cargoes on a 170,000 m<sup>3</sup> LNG carrier. We also factor in a gradual rise in non-power demand from 25,000 tonnes or 55,000m<sup>3</sup> a year or a third of a cargo on a 170,000m<sup>3</sup> LNG carrier to 125,000 tonnes a year or 277,000m<sup>3</sup> a year or one and a half cargoes on a 170,000m<sup>3</sup> LNG carrier.

**Figure 13: Illustrative uncertainty over LNG demand**



**Gas specification**

The specification of the delivered LNG would have to fall within set parameters. Key elements are the calorific value, and/or Wobbe Index, the composition gas (methane, ethane), and the level of impurities. Also there would have to be a mechanism for rejecting or else compensation for LNG that was out of specification. We understand that the gas delivered to the existing gas fired power plants on Luzon is close to 1,084 btu per

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standard cubic foot. The purchase of LNG compatible with this level of calorific value is not likely to exclude very many LNG plants as potential sources of supply. If the calorific value needs adjusted then nitrogen can be added to lower it or LPG added to raise it, in which case the seller would have to pay associated costs.

#### 4.9. BUYING LNG FROM AN NEARBY LNG HUB AS AN OPTION FOR STAGE TWO

We have made several research visits to Singapore to discuss with various participants in the LNG chain on the LNG Hub ambitions of the projects underway and planned Singapore Straits. Our conclusion from these meetings is that buying LNG from the “Singapore Straits” LNG Hub has too many uncertainties over the next few years to form a central plank in Stage One of the Philippines LNG procurement strategy.

We believe the “Singapore Straits” LNG Hub could form a useful component in Stage Two of the Philippines LNG procurement strategy. It would provide LNG supplies that could be delivered at short notice. The LNG supplies could supplement an underlying main contract for base LNG demand. It would be more of an option once LNG buyers in the Philippines have some experience with LNG markets and LNG shipping.

Singapore has clearly marked out its ambitions to become a LNG trading hub. Singapore LNG is near completion of tank 3 and has started construction on tank 4 with a separate jetty for these tanks to facilitate offloading and reloading of LNG. It is building more storage capacity than it needs for its own domestic use. However very many questions on the commercial structure for the use of these facilities are not yet determined. So factoring this infrastructure as part of the supply chain for LNG to the Philippines by the 2017 to 2018 period would need some certainty right now on how the Singapore LNG facilities would operate, which unfortunately is not the case.

**Figure 14: Singapore LNG with extra tanks for trading**



Source: Singapore LNG

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Singapore LNG will provide the infrastructure and Pavilion Energy together with some other yet to be selected LNG players will be granted access to loading and reloading facilities in Singapore. We note here that Pavilion Energy recently bought 20 percent of Blocks 1, 2 and 4 from Ophir Energy, although first LNG is at best only likely by late this decade.

Gunvor, an Amsterdam based oil trading company, with a large presence in Asia, has signed up for 2 mmtpa of tolling LNG capacity at the Magnolia terminal in USA. One option is to bring it to Asia and trade it into the short term market. It has plans to supply some gas to Panama and/or else build a storage facility in that country.

In addition to Singapore LNG, there is the Vopak/Dialog LNG terminal planned for Pengerang on the southeast tip of Malaysia. Phase one with a tank of 170,000m<sup>3</sup> is due for commissioning in 2016 and phase two with another 170,000m<sup>3</sup> in 2018. Designs have passed front-end engineering and design (FEED) and requests for tenders have gone out to engineering companies for EPC.

**Figure 15: Location of Vopak LNG terminal at Pengerang**



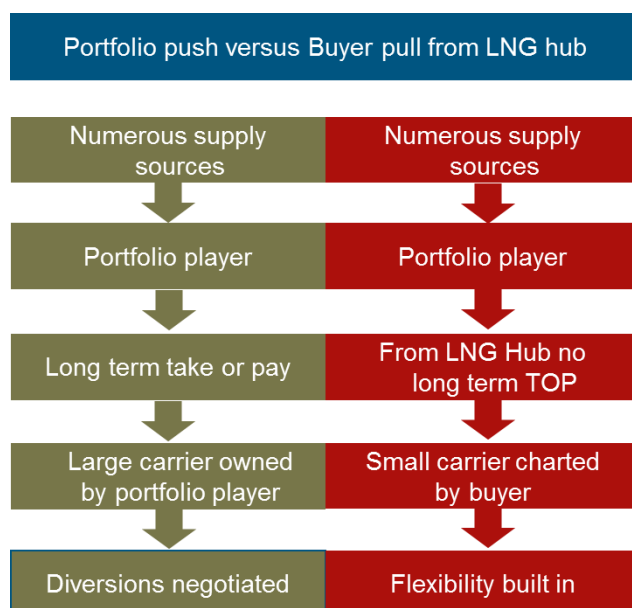
Source: Vopak

The exact charging mechanism for the Vopak LNG for the use of their facilities for LNG offloading and reloading are not clear at the moment. But based on initial discussions with Vopak the terms could be quite flexible. They will offer capacity rights for their two 170,000m<sup>3</sup> tanks. The capacity rights could be structured in many ways. But for example they might offer rights to one tank for three months of the year with a certain number of berthing slots spread over the entire year.

The final buyer of LNG in the Philippines would negotiate with the holder of the terminal capacity rights at Singapore LNG or Vopak LNG, which would mostly likely an LNG portfolio player. The LNG could then be shipped onwards to the Philippines on LNG carriers provided by the portfolio player or else on LNG carriers chartered by the buyer.

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**Figure 16: Buying from a Portfolio player and the option for buying from a LNG hub**



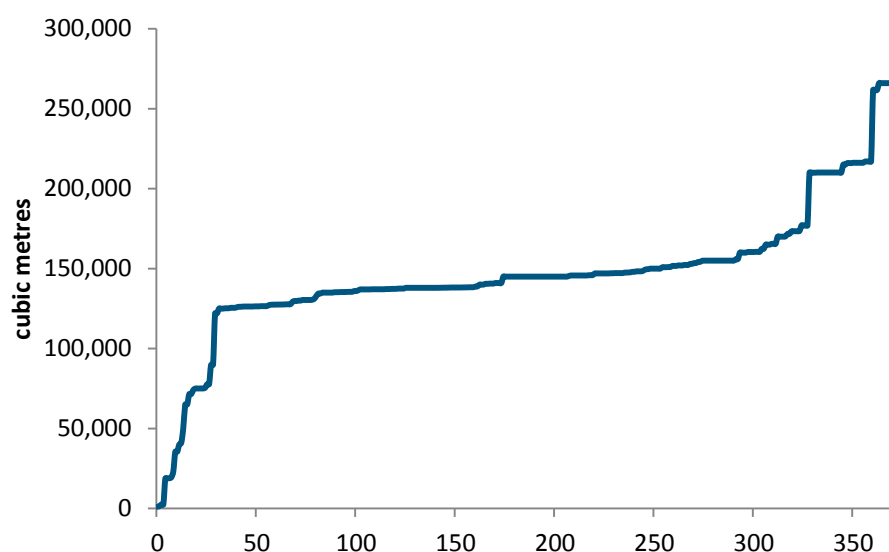
#### 4.10. SHIPPING OPTIONS

A key piece of the delivery mechanism to smaller loads is the shipping. If buying from a portfolio players the shipping cost can be kept low as the portfolio player will be using the LNG carrier on other routes at other times.

In the later years of the LNG procurement process we recommend an investigation of the possibility of purchasing LNG from the Singapore Straits Hubs. At that time we believe the companies that specialise in smaller scale LNG carriers will have a clear idea of the demand from the Philippines and Indonesia (and to a lesser extent Thailand and Malaysia) for their services.

The “Singapore Straits” LNG Hubs will also need probably new smaller LNG carriers dedicated to the Southeast Asia region. We believe there are many uncertainties for the shipping companies to commit to new build small or medium scale LNG carriers dedicated to the Southeast Asia region until there much greater clarity on access to and completion of the two Singapore Straits LNG Hubs. Therefore accessing LNG from the Singapore LNG terminal expansion or the Vopak/Dialog Pengerang LNG terminal will most likely have to wait until later in the decade.

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**Figure 17: Global LNG carrier fleet size**

There has been a growth in orders for traditional small size LNG carriers over the past few years. In late 2012, for example, CNOOC ordered four carriers of 30,000m<sup>3</sup> and ten carriers of 10,000m<sup>3</sup> to serve small satellite LNG terminals situated up rivers. IM Skaugen (Norgas Carriers) and Anthony Veder are also active in the smaller LNG carriers. Norgas Carriers has an office in Singapore and conducts operations in the region. Anthony Veder has used some of its smaller vessels to transport LNG from Korea to Japan and between terminals in Japan. Another player in this field is Argent Marine Management from the USA, and so far as we are aware is not active in Asia at present.

While it is true that these smaller carriers are more expensive per m<sup>3</sup> to build than larger vessels, they have the advantage of delivering a cargo of LNG more appropriate to what is needed to fuel a 800 MW CCGT at peaking to mid-merit capacity factors (from our power market simulations) of around 400 to 600 kilotonnes per year.

**Table 2: Indicative costing of large- versus small-scale delivery and storage solutions**

	Large Scale (2013 US\$/mmbtu)	Small scale via Hub (2013 US\$/mmbtu)
LNG 0.13*90	12.0	12.0
Large scale shipping	2.0	1.5
Portfolio player mark-up	-	0.5
Reloading in Singapore or Malaysia	-	0.5
Small carrier from Hub to Philippines	-	1.5
Terminal	3.0	2.0
Others	-	-
<b>Total</b>	<b>17.0</b>	<b>18.0</b>



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In our forecasts at the moment Brent approximates to real US\$90/bbl in 2020 and we estimate a slope for LNG of 13. In Table 2, we assume that short term and long term LNG are priced the same. But long term comes with take or pay obligations and short term is just buying when needed from the Singapore-Malaysia LNG Hub. (Maybe Thailand is also trying to get in on providing LNG Hub services as they are building a second tank for which they have no immediate domestic use so far as we can tell).

Our large scale shipping cost is somewhat approximate and is a simple real average for deliveries from USA, Qatar, East Africa, and Australia to Manila on a large-scale carrier with some small savings for delivery to the nearer destination of Singapore.

The cargo splitting cost is a guesstimate but based on holding inventory for about 10 days at a large scale LNG terminal. This is triangulates with Thailand and Singapore LNG terminal charges, after stripping out regasification, of close to US\$1mmbtu which we calculate are predicated on an average inventory holding period of 20 days.

When shipping LNG on a small carrier (approximately 45,000m<sup>3</sup>) the buyer would only need to charter the carrier for just over half of the year (20 round trips of ten days to and from Singapore to Philippines each year) and the rest of the time it would be doing other deliveries for the owner. The large carrier would be needed for deliveries to the Philippines for only 15 percent of the year, and so would be used on other tasks for a greater amount of time or 85 percent of the rest of the year. With the large carrier we assume that the LNG comes delivery ex ship (DES or as it is now called DAT, delivery at terminal). For the small carrier the buyer would probably buy the LNG free on board at the Hub and pay the charter separately for shipping.

The terminal charge is a levelised flat real tariff based on 800 MW power plant at 40 percent capacity factor needing 400,000 tonnes a year. Using our estimates for an FSRU this works out at close to US\$3.0/mmbtu for a large vessel with a 170,000 m<sup>3</sup> tank and US\$2/mmbtu for a smaller terminal with a 45,000m<sup>3</sup> tank at the same level of throughput.

What this attempts to do is present a rough base case that the small terminal and small carrier option using LNG from a nearby Hub is not necessarily that much more expensive than the traditional large scale option. But the key feature of the smaller scale option is that it comes with flexibility. As an extreme position, no burdensome 20-year take or pay for LNG needs to be signed with purchases only on the short term market (less than four years). Or if a certain amount of power can be contracted to retailers then the corresponding amount of LNG could be contracted for on a more long term basis, and with the option to buy short term if needed, say to supply industry or if there was a hydro power shortage.

The working capital cost of running down LNG inventory in the large tank for 90 days is less than a cargo that lasts 45 days. In round numbers we calculate this to be a saving of about US\$0.5/mmbtu.



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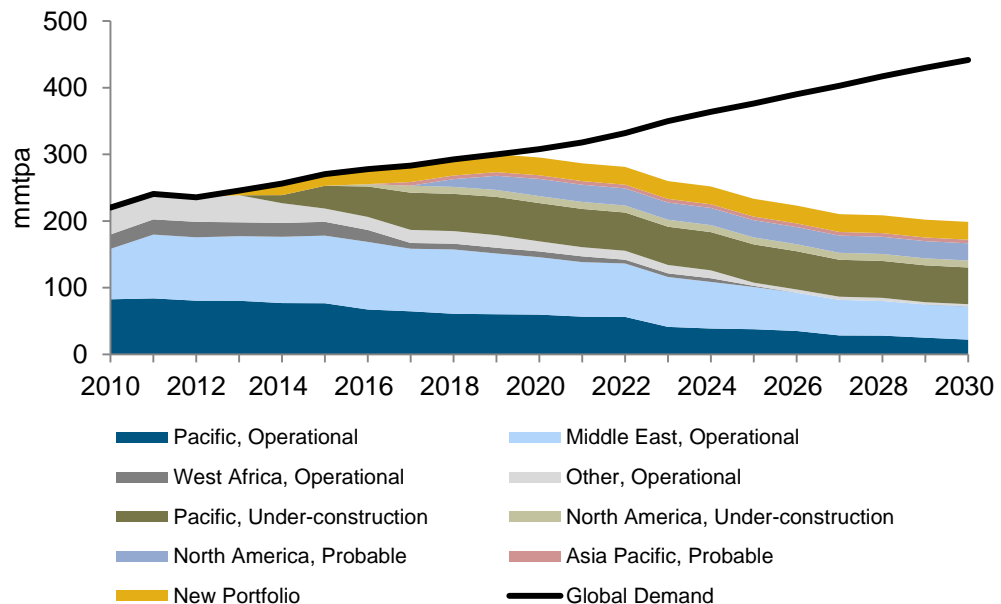
## 4.11. SUPPLY-DEMAND REVIEW

### 4.11.1. Global picture

We built up global demand for LNG by developing a global model for energy demand by country or regional block. This demand was split into power and non-power, which was further itemised for the larger markets into transport, industry, residential and commercial. We then drilled down to further to itemise the different types of fuel used by those sectors and separated piped gas from LNG.

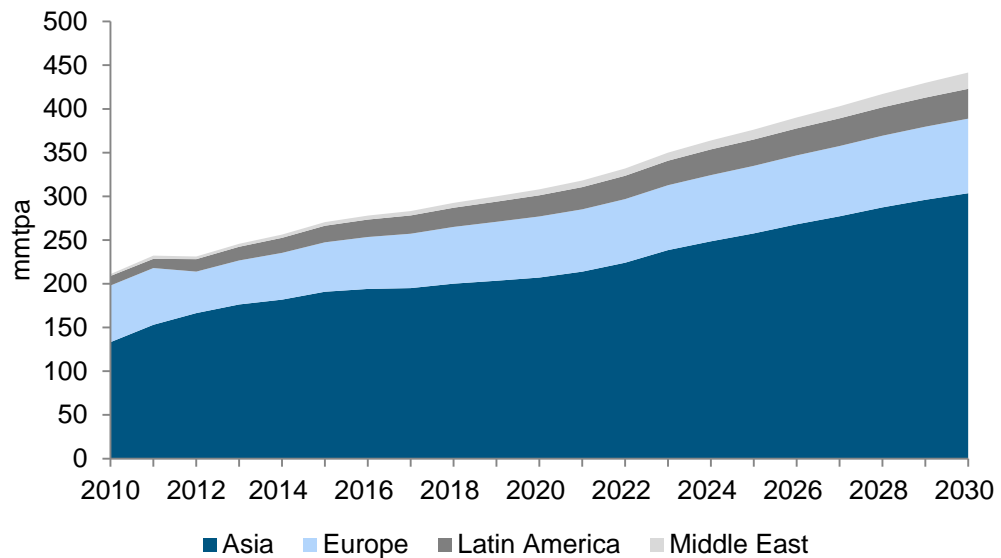
We matched contracted supply to demand by country when there was specific contract. But a key feature of demand is the relatively large and growing amount that we expect to be met by portfolio players or from uncommitted supply. This is the grey area at the top of the graphic.

**Figure 18: Global LNG demand supply**



Asia dominates demand outlook and within that area China, India, Japan and Korea are the main users.

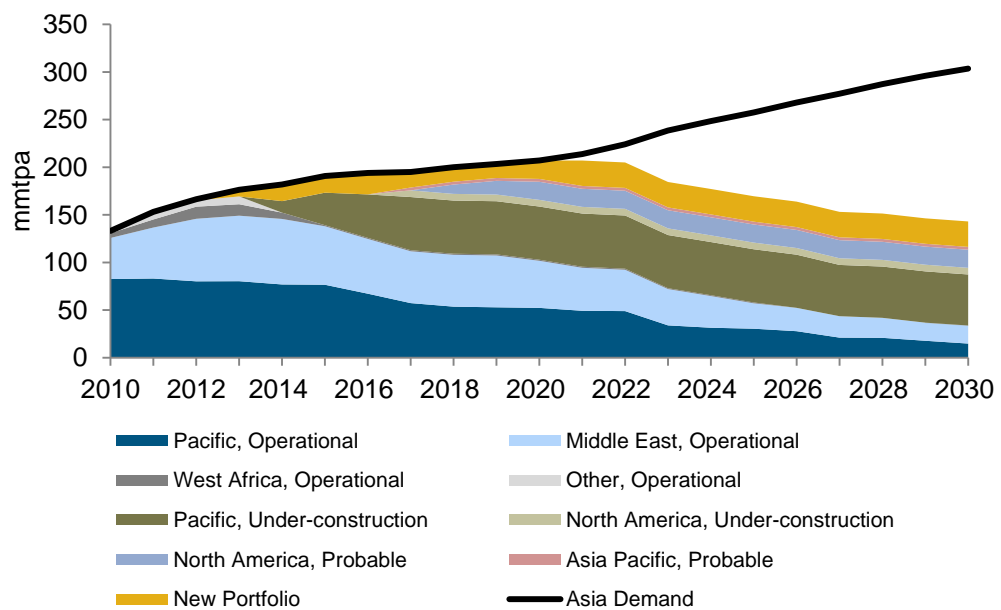
**Figure 19: Global LNG demand**



#### 4.11.2. Asia outlook

We drilled down deeper on the demand supply balance side for Asia. Note again that portfolio supplies account for a large part of the market balance through to 2020. Supply is based on projects that are existing, under construction, or have reached final investment decision and a handful of projects we believe are likely to get final investment decision soon.

**Figure 20: Asia LNG supply and demand**

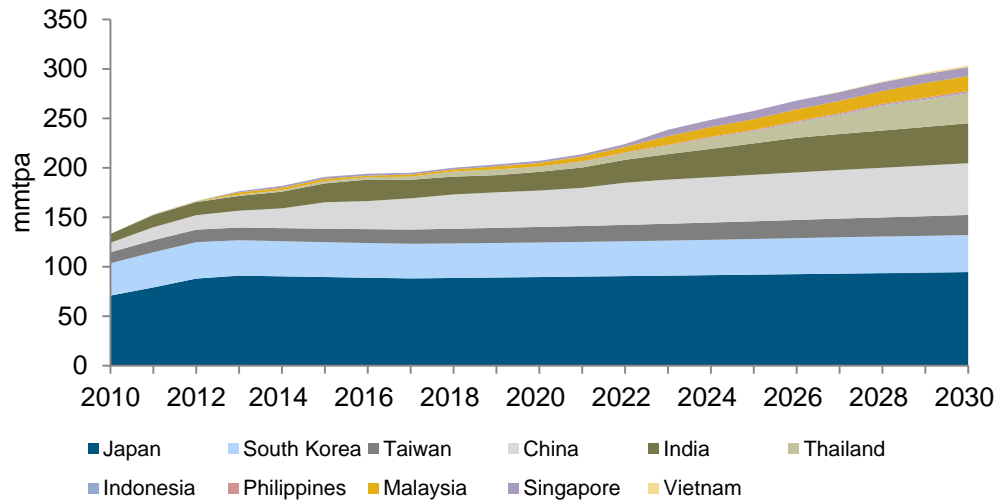


Our Asia demand forecasts are show in Figure 21. As we mention elsewhere in the report all forecasts especially for the larger markets of China, India, Japan and Korea are

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subject to a large amount of uncertainty. What is also of interest is the emergence of the nations of South East Asia as LNG importers. Singapore, Malaysia and Thailand already have operating terminals and later on come the Philippines and Vietnam.

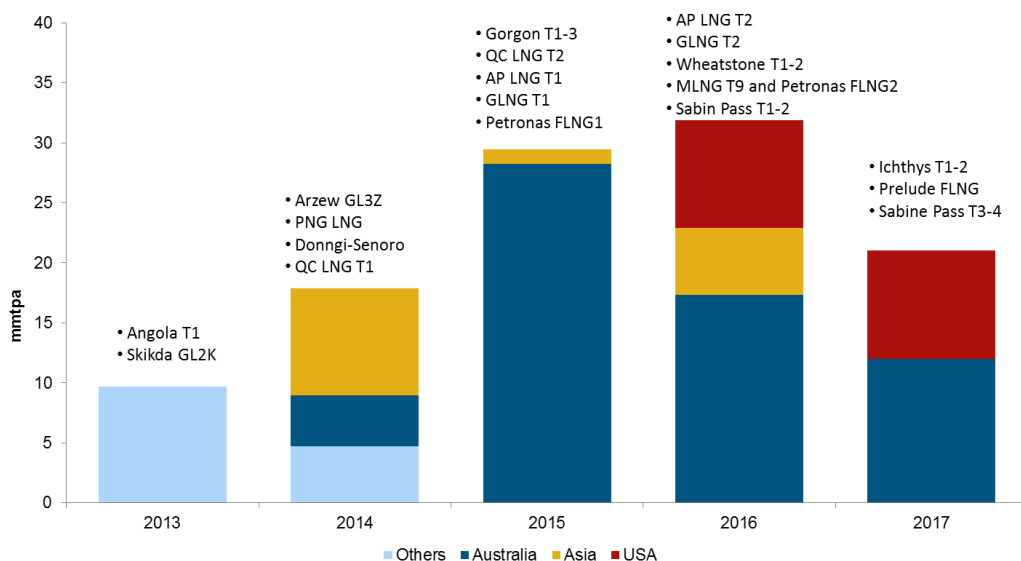
**Figure 21: Asia LNG Demand**



#### 4.11.3. Growing presence of short term and portfolio in supplies

We calculate that there is nearly 110 mmtpa of LNG plant under construction or at final investment decision. A large amount of expensive plant in Australia is expected to be commissioned between now and 2017. But also note the first US LNG plant is expected in 2016 (Cheniere at Sabine Pass). In addition, there are some LNG plants located in South East Asia in Papua New Guinea, Indonesia and Malaysia that are expected to start between 2014 and 2016. Within that South East Asia capacity is Sengkang LNG, led by Energy World Corporation.

**Figure 22: LNG plant capacity under construction or at final investment decision**

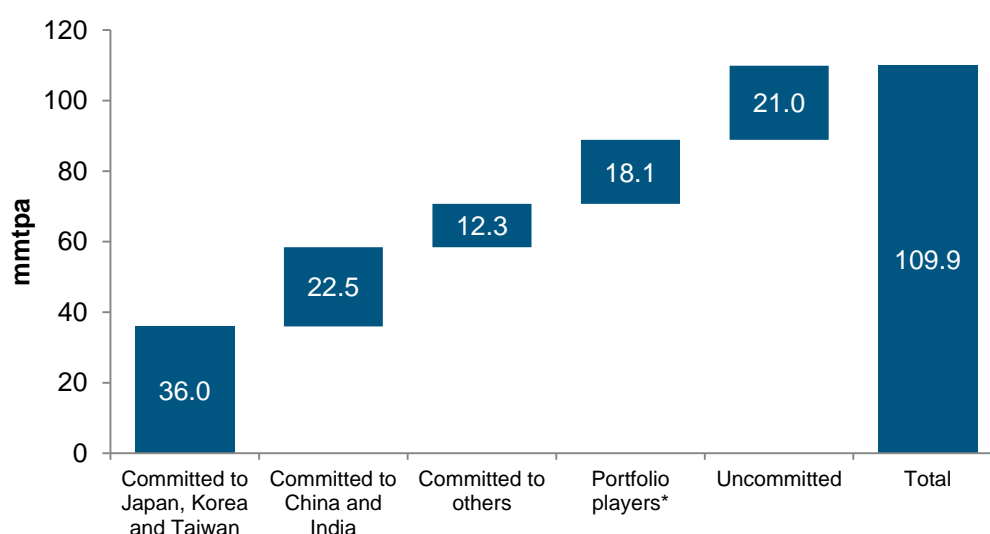


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(Source: The Lantau Group)

A key feature of the 110 mmtpa of LNG plant capacity that is coming to market by 2017 is that 40 percent of that total either goes to portfolio players or else at the time of writing is uncommitted. We believe this 39.1 mmtpa of LNG will mostly be sold on a short term basis.

**Figure 23: LNG Plant volumes committed by destination, portfolio players, uncommitted**



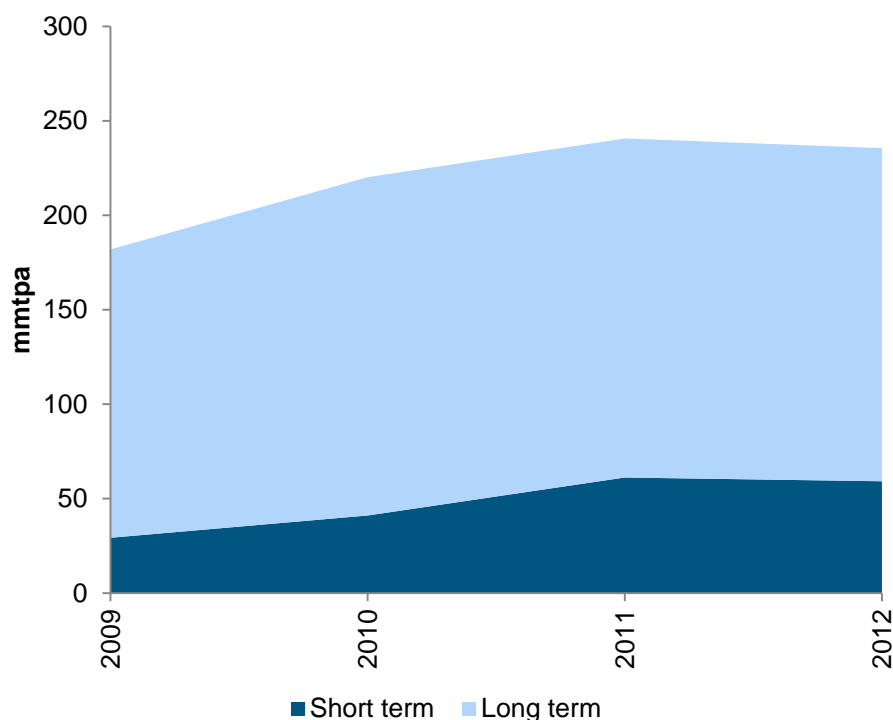
(Source: The Lantau Group)

#### 4.12. SHORT-TERM VOLUMES

Short-term volumes have grown dramatically the last few years. In part this has been forced on the industry as demand in Europe fell dramatically. But by co-incidence demand for LNG by Japan rose by almost the same amount. The rise in demand by Japan is of course a result of the shut-down of nuclear plant in that country.

The experience of renegotiating and diverting committed and portfolio cargoes from Europe to Asia was described to us by one portfolio player as “a huge upheaval”. But we believe it has shown to both seller and buyer the value that exists in flexibility.

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**Figure 24: Mix of short-term and long-term LNG contracting (2009-12)**

Note: Short term means contracts of four years or less and spot.

#### 4.13. LNG DEMAND UNCERTAINTY

We have run various gas demand supply balance forecasts for the big LNG buyers in Asia such as China, India, Japan and Korea. Each one is the subject of large uncertainty. What this means for the LNG business is that like it or not the amount of LNG that will be traded on short term contracts must be set to grow in order to cope with this uncertainty. Some of the key demand uncertainties are listed below:

##### China

- Will shale and coal bed methane deliver significant amounts of gas or will they disappoint, leading to a greater need for LNG and/or Russian imports?
- Will the drive to clean up air quality really gather momentum? If so then there could be very significant demand for gas for power.

##### India

- Will the Rangarajan committee proposals that are set to double local gas prices result in greater supplies of domestic gas and thus lower the need for LNG?

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## Japan

- Each 10 GW of nuclear plant that is restarted lowers the demand for LNG by 4 mmtpa.
- Another initiative by the government is to try to significantly lift the amount of renewables in the power mix. If Japan really can lift renewables to 25 percent from 13 percent of generation then this could lower demand for LNG by close to 6 mmtpa by 2030. (Assuming only 10.6GW of nuclear is restarted).
- Just to further confused the outlook it was recently mooted by government that the de-facto ban on new coal-fired plant might be lifted.

## Korea

- The last power plan contained a large push in favour of nuclear power plants.
- But this all changed just recently in favour of gas and coal. The existing nuclear power plants have been facing reliability problems and there are concerns about the lower quality of parts used for maintenance.

## 4.14. US LNG

### 4.14.1. Flexibility enabler

The point that is worth driving home again is that US LNG is completely different in structure from any other source of LNG. What the buyers are signing up for are capacity liquefaction rights at the different plants on a tolling basis. They will typically sign up for 20 years with a fixed annual payment – this is a ‘take it or lose it’ arrangement. Then there will be a small add-on charge for operations and maintenance charge and berthing based on usage. We expect that these liquefaction capacity rights will be transferable (as was the case with now largely worthless regasification terminal capacity rights).

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**Table 3: US LNG export plants**

Group	Project	DOE application				FERC application			Capacity, mmpa	
		Requested volume, bcf/d	FTA approved	Non-FTA application submitted	Non-FTA approved / DOE order	Pre-filing completed	Filing completed	Filing approved	Terminal total	Group total
Non-FTA	Sabine Pass 1-4	2.2	✓	✓	✓	✓	✓	✓	18.0	62.8
	Freeport 1-2	1.4	✓	✓	✓	✓	✓	8.8		
	Lake Charles	2.0	✓	✓	✓	✓	✓	15.0		
	Dominion Cove Point	1.0	✓	✓	✓	✓	✓	4.6		
	Freeport 3	1.4	✓	✓	✓	✓	✓	4.4		
	Cameron	1.7	✓	✓	✓	✓	✓	12.0		
Non-FTA pending, filed with FERC	Jordan Cove Point	1.2	✓	✓	1	✓	✓	6.0	29.1	
	Oregon LNG	1.3	✓	✓	2	✓	✓	9.6		
	Corpus Christi	2.1	✓	✓	3	✓	✓	13.5		
Non-FTA pending, pre-filed with FERC	Excelerate	1.4	✓	✓	4	✓		8.8	30.4	
	Southern	0.5	✓	✓	6	✓		2.5		
	Gulf LNG	1.5	✓	✓	7	✓		2.1		
	Sabine Pass 5-6 Total	0.3	✓	✓	12	✓		2.0		
	Sabine Pass 5-6 Centrica	0.2	✓	✓	13	✓		1.8		
	Sabine Pass 5-6 Uncommitted	0.9	pending	✓	17	✓		5.3		
Non-FTA pending, no FERC pre-filing	CE FLNG	1.1	✓	✓	8	✓		8.0	73.2	
	Gulf Coast	2.8	✓	✓	5			20.6		
	Golden Pass	2.6	✓	✓	9			15.6		
	Pangea	1.1	✓	✓	10			8.0		
	Main Pass	3.2	✓	✓	11			24.0		
Only applied for FTA license	Venture	0.7	pending	✓	14			5.0	6.8	
	Waller	0.2	✓					1.3		
	Magnolia	0.5	✓			✓		4.0		
	Gasfin	0.2	✓					1.5		

#### 4.14.2. Pricing structure

The buyers will buy gas at Henry Hub (usually plus a small premium) as and when they want to, then liquefy the gas for export. The levelised real liquefaction tariff comes close to US\$3/mmbtu in most cases. Then the final element is the shipping which to Asia is quite expensive and likely to come close to US\$3/mmbtu depending on route and engine technology.

#### 4.14.3. Size of reserves

The Energy Information Agency, drawing on research from various other bodies such as the US Geological Survey, puts the size of US technically recoverable reserves at close to 2,200 Tcf. Demand in the US was 24 Tcf in 2012. There is expected to be a rise in demand for gas from US transport and petrochemicals as these sectors take advantage of low prices. This could add some 6 Tcf to demand by the start of next decade. If all 200 mmpa of LNG export plants go ahead (which is unlikely) then this would require close to 10 Tcf of gas per year. So even 40 Tcf per year of demand still gives the US some 55 years of gas in the ground. Moreover most analysis points to there being further technically recoverable resources to be discovered as and when the Henry Hub price recovers.

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## 4.15. CANADIAN LNG

### 4.15.1. Problems with experience and alignment of players

There has been some rationalisation in the shareholding of some proposed west coast Canadian LNG projects. Some more experienced heavy weight LNG players bought out the original shareholders.

- Chevron now leads the Kitimat LNG project, with Apache as a minority partner and with EOG Resources now departed. This project is located in Bish Cove.
- The Pacific North West LNG project was given a boost when Petronas bought the owner Progress Energy in an agreed takeover. Having JAPEX as a minority shareholder will assist with entry to the Japanese market. This is located in Prince Rupert Sound.
- The BG Group has plans for a large terminal in Prince Rupert Sound.
- LNG Canada led by Shell with Korea Gas Corporation (KOGAS), Mitsubishi Corporation and PetroChina Company Limited that is proposing to build and operate a liquefied natural gas (LNG) export terminal in Kitimat.
- Aurora LNG led by CNOOC with INPEX Corporation and JGC Corporation have plans for a terminal at Grassy Point on Prince Rupert Sound.
- Most recently ExxonMobil entered the list of those with grand ambitions for LNG exports from west coast of Canada either from Bish Cove near Kitimat or else Prince Rupert Sound.
- Woodside has secured land at Grassy Point on Prince Rupert Sound.

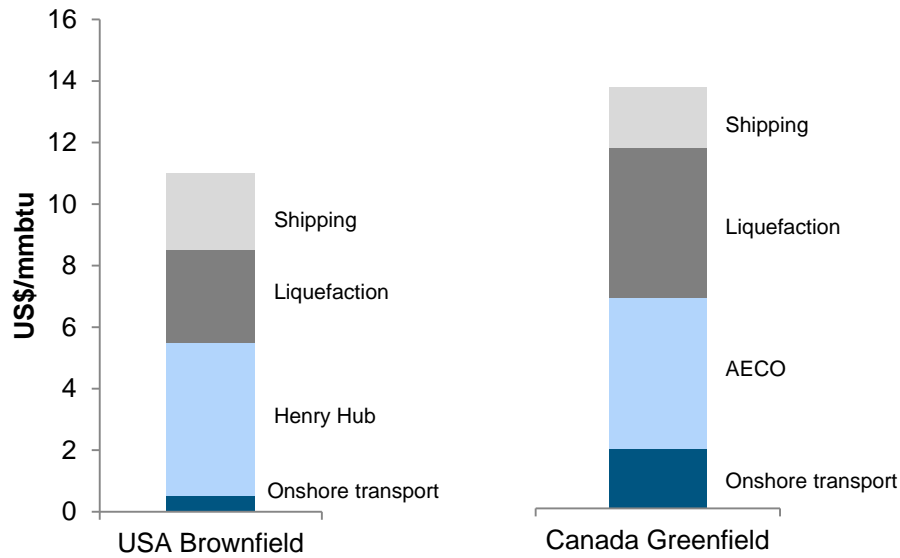
Each of these projects has separate plans for pipelines to access mainly shale gas resources located further inland. With hindsight the three CBM LNG projects at Curtis Island in Australia realise they could have saved costs (and perhaps improved security of supply) by sharing infrastructure. We wonder if this lesson will be applied to those projects clustering around Prince Rupert Sound.

### 4.15.2. Closeness to Asia markets

All the west coast Canadian projects emphasise that they are only 9 to 10 days distant from Japan. Whereas US Gulf Coast LNG plants either face a 20 day trip if using the Panama Canal or 32 days if heading east. But we believe that the extra costs associated with green field new build LNG plants in Canada versus mostly brownfield in the USA, coupled with the need for new pipelines to access sometimes distant gas fields in Canada versus the shorter build out of pipelines needed to access the US pipeline network in the Gulf Coast, outweigh the extra shipping cost faced by US LNG to reach Asia. This is illustrated in Figure 25.



**Figure 25: US versus Canada break-evens**



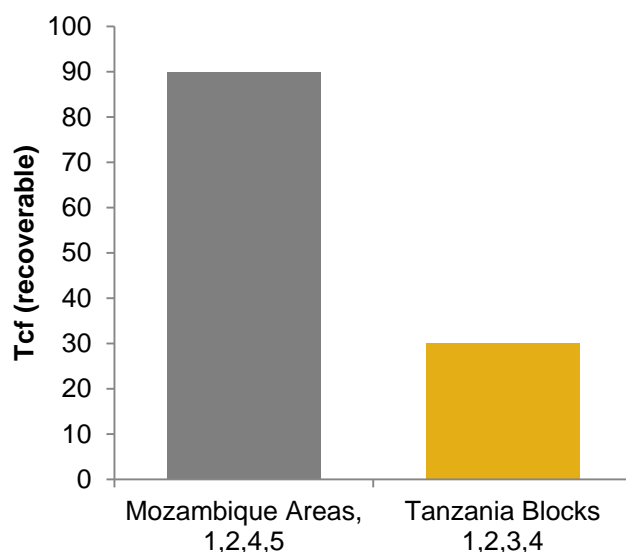
#### 4.15.3. Pricing probably linked to crude

Western Canadian LNG projects which are more typical in that they specify a source of gas, will build dedicated new, usually long, pipelines to get the gas to the coast, and develop liquefaction plants and then sell the LNG. Projects have some buyer participation but at the moment are led by traditional LNG majors and some aspirants. Pricing might be oil linked or linked to AECO (the Canadian version of Henry Hub that refers to gas traded anywhere in TransCanada' Alberta System). Less progress has been made marketing west coast Canadian LNG than is the case with US LNG.

#### 4.16. EAST AFRICA LNG

There have been huge gas discoveries in reserves in Tanzania and Mozambique. These are very much a moving target but a summary is provided in Figure 26.

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**Figure 26: Mozambique and Tanzania gas resources**

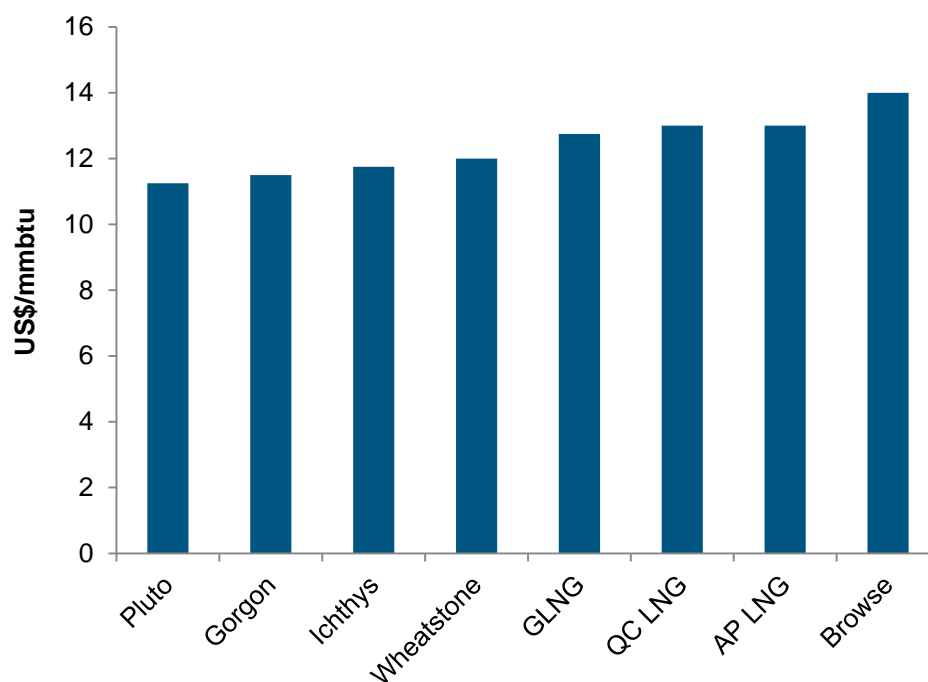
There are many challenges before this gas gets to market as LNG. Firstly, there is regulatory uncertainty which is particularly true for Tanzania. There is confusion over the role of the mooted new National Oil Company (NOC) and existing de-facto upstream regulator Tanzania Petroleum Development Corp, and requirements for gas and infrastructure to support domestic industry. This said, Tanzania has experienced LNG player leading developments in the shape of the BG Group.

Mozambique has less experienced LNG players. Anadarko is relatively new to LNG. ENI has experience via VICO at Bontang in Indonesia and Statoil has cut its teeth in its Snohvit LNG plant. Some customers have bought in such as ONGC, Bharat Oil, PTTEP and Mitsui. On the plus side the country has a master plan sponsored by the World Bank and hopefully this will enable a balanced exploitation of resources. One that supports the build out of domestic industry while at the same time realising that large amounts of the gas will need to be exported as reserves totally eclipse local demand.

#### 4.17. AUSTRALIA LNG

The sharp rise in costs right across the LNG production chain has caused several upwards revisions to project costs as summarised in Figure 27. (The cost of onshore development of liquefaction for Browse in fact resulted in Woodside calling a halt to that project and reworking the project economics for a floating LNG solution). Negotiations by buyers with greenfield and even brownfield developers have quietened down as the focus among buyers has very much swung to getting US LNG.

**Figure 27: Australian LNG plant all-in break-evens at 18% IRR**



#### 4.18. RECOMMENDED STRATEGY

The recommended strategy for gas purchasing has to meet a number of competing demands. Ideally the gas purchased should be as cheap as possible. However, the main value drivers of LNG to the Philippines arise from flexibility and optionality. Lower priced gas supplies are often less flexible. If the gas is used in a mid-merit role, then dispatch can be used to manage the risks of gas price: That is, if the gas price rises, the plant can dispatch less, and vice versa. This is not the case for baseload plant. Thus, given the economic role of gas in the Philippines, the risk of slightly higher gas prices due to shorter contract terms is less problematic.

The backup gas is displacing liquid products. Given the linkages between LNG prices in Asia and oil prices, LNG prices would be related to the price of liquid fuels and would always be the cheaper option. Again, the exact price of gas is not so important in this case, just that it is cheaper than oil.

The initial demand for gas in the Philippines will be large enough to be relevant in the global LNG market, but not that large, meaning the Philippines will be competing with other potential purchasers for the focus of the key players.

Also, credit risk is a key concern of Sellers (and terminal providers) and few parties in the Philippines are well known on a world scale, and there is no National Oil Company that can step in behind the buyers in the same way as other markets.

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Given the above, our strategy focuses on:

- Ensuring that the Philippine buyers test the market regularly to get the lowest cost short-term contract prices;
- Encouraging demand aggregation to the extent it is reasonably possible, recognising that buyers in the Philippines are competing with each other in the market and may not wish to purchase together; and
- Encouraging a healthy competitive dynamic as increasing flexibility and levels of competition increase in the developing Asian market, with its new hubs and multiple options for suppliers.

We would recommend the following:

- A voluntary aggregation of buyers (Buyers Club) to buy regularly from the market, using short-term contracts of one or two years duration.
- That this Buyers Club does not have exclusive rights to purchase, but that anyone else can also buy, and sellers can sell, in the market.
- That we explore how the private sector arm of the World Bank can enhance the credit standing of the less well-known Buyers in the Philippines.
- That the tenders which are run by the Buyers Club include a cargo diversion clause, so that if demand is lower than expected this can be managed.
- That the tenders include the ability to take additional cargoes, or that the Club tenders for additional cargoes on a spot basis, to manage increases in demand.

As demand in the Philippines grows, and as Malampaya winds down, different structures may be appropriate and longer-term contracts may be more attractive. This would need to be decided at that point in time. This strategy enables such a future option to be maintained.

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## 5. MONETIZATION STRATEGIES FOR LNG TERMINAL OWNERS TO INTERACT WITH OTHER REGIONAL TERMINALS AND HUBS OR OFFER HUB/TRANSHIPMENT SERVICES WITHIN THE PHILIPPINES

The TOR describes Task 2.4 as:

*Task 2.4*      *Aim: Provide advice on the various monetization strategies available to LNG terminal owners, including using hub terminals to offer trans-shipment services to customers elsewhere in the Philippines and/or in other parts of the regional market. Assess whether there are any strategic options related to other hub terminals emerging in Asia (e.g., Singapore, Thailand).*

### 5.1. SINGAPORE STRAITS LNG HUBS

As we have mentioned elsewhere we would recommend that in Stage Two of the LNG procurement strategy an investigation is made on the purchase of LNG from Singapore LNG (or its trading arm Pavilion Energy) or via the Vopak/Dialog LNG terminal planned for Pengerang in southern Peninsular Malaysia. In either case the LNG could be contracted for at the terminal by the buyer in the Philippines or else could be bought from a portfolio player with capacity rights at these terminals. This would enable the delivery of smaller amounts of LNG on a more regular basis, which would lower inventory costs. Alternatively a more standardised LNG carrier in the range of 150,000m<sup>3</sup> could be half filled with LNG – this would be enough LNG for 35 days instead of for 70 days (assuming an 800 MW plant with a heat rate of 7 mmbtu per MWh running at a 40 percent capacity factor).

### 5.2. GAS SHARING OR BANKING SCHEME IN LUZON

We certainly think it would be advisable for users of LNG in Luzon to be able to share, trade and bank LNG. For example, one power station may not need regasified LNG for a period of time due to maintenance, and the effect maybe that another power station may need some extra regasified LNG to make up for demand for electricity. On the other hand an unexpected outage of piped gas supplies may result in a greater than expected call on LNG in storage, and so sharing of that inventory among the power stations makes sense.

Demand for LNG by the industrial and LCNG transport sectors will probably may emerge in time, drawing on the effect of other LNG terminals have had on those sectors and given our own analysis that regasified LNG can undercut traditional finished product such as diesel, probably undercut fuel oil and LPG in the Philippines.

### 5.3. FSRU JETTY TO SHORE

To get LNG to shore from an FSRU would require in the first place that the pipe from the FSRU to shore was placed along a jetty, so that a cryogenic pipe could also be installed

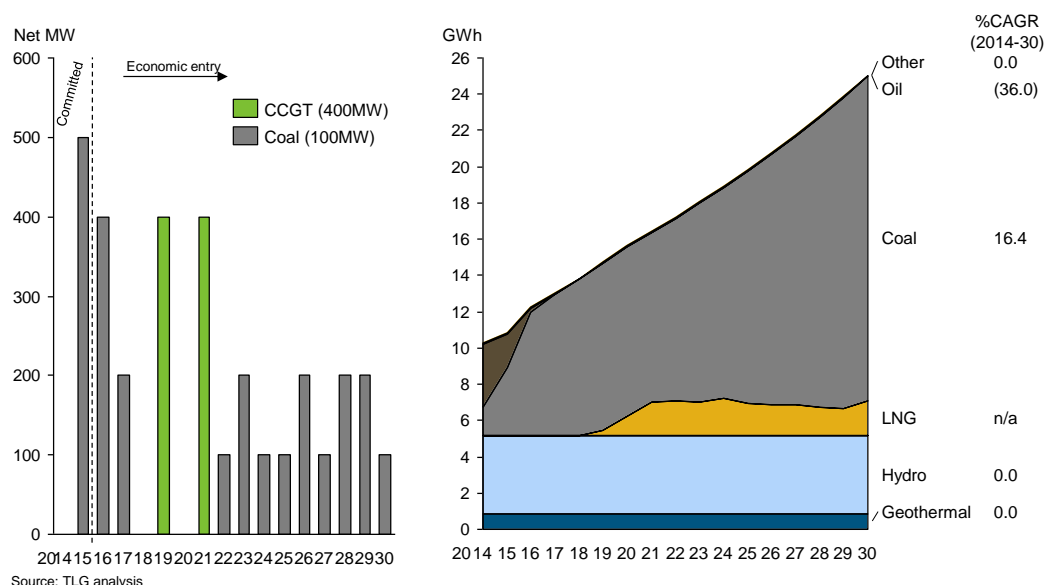
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in the basic design to allow LNG to be sent to ashore and not only regasified LNG. We understand that the FSRU would be between 250 to 500 metres from shore<sup>22</sup> which is a length compatible with a cryogenic pipe. The longest cryogenic pipe on a jetty that we are aware of is at the Hazira LNG terminal which is 1.6km from ship mooring to onshore tank.

#### 5.4. COMMERCIAL OPTIONS BETWEEN LUZON TERMINALS WITH POTENTIAL MINDANAO LNG TERMINAL

The results from our Supplementary Report: Mindanao Power Sector Modelling<sup>23</sup> revealed that the case for new CCGT capacity in Mindanao was less clear cut than in the Prefeasibility Study<sup>24</sup>. This was primarily due to a lower coal price despite a fairly stable crude oil and therefore LNG prices, and a likely higher rate of coal build power plants. Nevertheless we present the main case from our new modelling. This indicates that there is a case for two 400 CCGTs to enter the Mindanao market in 2019 and 2021.

**Figure 28: Least-cost capacity expansion plan (left) and expected generation mix (right)**



It is expected that these two CCGTs would run a capacity factor between 20 to 35 percent, with an average of close to 25 percent through to 2030. Based on this level of electricity generation the demand for LNG is 235,000 tonnes or 520,000 litres per year. This would require only three deliveries a year to a standard 170,000m<sup>3</sup> FSRU. In several years' time industrial and transport demand<sup>25</sup> may emerge of 110,000 tonnes or 244,000m<sup>3</sup>. This total demand 345,000 or 766,000m<sup>3</sup> per annum would only need close

<sup>22</sup> Phase One Philippines Gas Master Plan Report Appendix D

<sup>23</sup> Published by The Lantau Group, December 2013

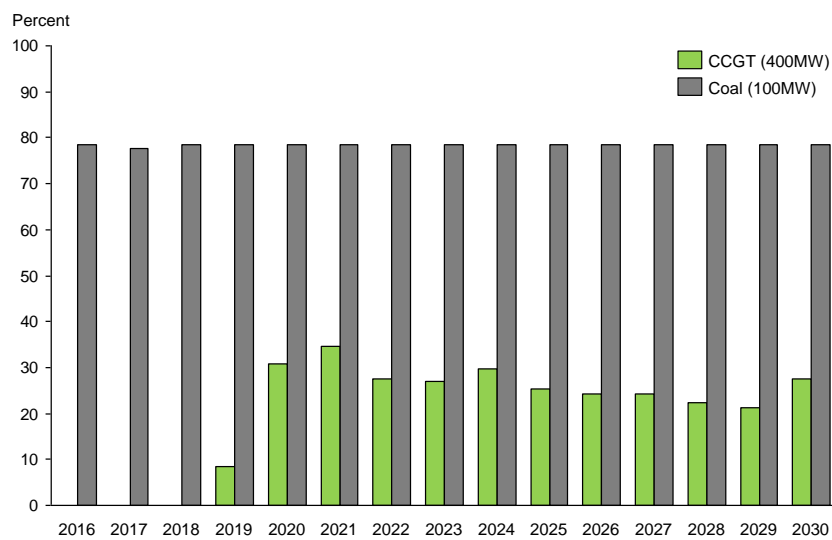
<sup>24</sup> Mindanao Power System Modelling Potential Gas Generation and LNG Terminal, February 2013

<sup>25</sup> Mindanao Natural Gas Market Development Strategy Final Report The World Bank Canadian Gas Services International, January 2013

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to five LNG carrier deliveries of 170,000m<sup>3</sup> a year. An open season could well result companies wishing to have capacity rights in excess of any immediate demand. But if the FSRU was half the size at about 80,000m<sup>3</sup>, the life cycle cost (US\$/mmbtu) for operating a smaller FSRU would fall by 40 percent. This said the appetite for ship yards to build small scale FSRUs might result in a lack of interest, as it is easier for them to use standard designs to build larger FSRUs of 170,000m<sup>3</sup>.

**Figure 29: Expected capacity factors of new economic CCGT and coal plants (2016-30)**



Source: TLG analysis

With regards to shipping there are definitely synergies as a result of co-ordinating with LNG deliveries to Batangas on Luzon. Half a cargo could be offloaded at Batangas and the other half at Mindanao. So long as the offloading at Luzon did not leave any individual tank on the LNG carrier less than 90 percent full, thus risking sloshing, there are no other major technical issues to the delivery of a partial load by an LNG carrier.

#### *Other demand on Mindanao from oil-fired plant*

Based on our modelling, the medium to long term opportunities to replace diesel are very low. This outlook is contingent on: the Agus hydro-scheme is dispatched to meet peak load, the Agus channel upgrade being completed, and once the CCGT using regasified LNG serves mid-merit demand. We assume a potential 50 percent uptake by remaining oil fired plants. The long term decline in potential demand is likely to result in very few oil fired plants changing to regasified LNG.

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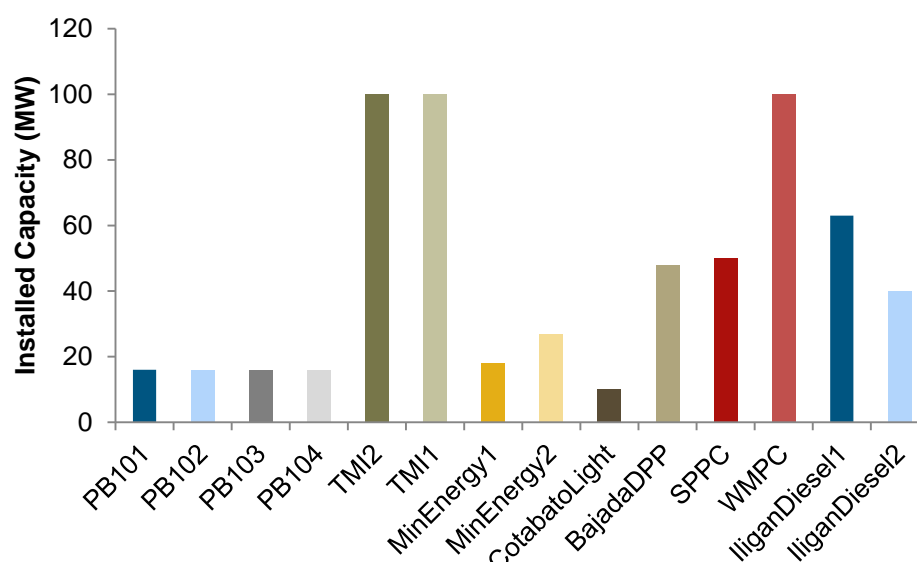
**Table 4: Mindanao potential displacement of liquid product with small-scale LNG**

	2012	2015	2020	2025
Capacity (MW)	620	620	500	400
Annual capacity factor (%)	32	34	23	14
Generation (MWh)	1,719,521	1,872,558	1,000,000	500,000
Heat Rate (HHV, mmbtu/MWh)	9.6	9.6	9.6	9.6
LNG (tpa)	330,148	359,531	192,000	96,000
% conversion	50	50	50	50
LNG (tpa)	165,074	179,766	96,000	48,000

Source: The Lantau Group

We summarise our understanding of the main existing grid connected oil-fired plant on Mindanao in Figure 30.

**Figure 30: Existing oil fired plant on Mindanao**



Source: DOE and The Lantau Group

### 5.5. POTENTIAL DEMAND TO DISPLACE USE OF TRADITIONAL FINISHED PRODUCT BY POWER PLANTS IN REMOTER LOCATIONS IN WITH LNG

As addressed above the likelihood of Mindanao oil-fired plants converting to use small scale LNG is low. So the area of the Philippines outside Luzon with sizable oil product being used is Visayas.



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**Table 5: Generation by liquid product in the Visayas and Mindanao (2012)**

	Visayas	Mindanao	Total
<b>Diesel (GWh)</b>	514,274	1,718,684	2,232,958
<b>Fuel Oil (GWh)</b>	219,899	837	220,736
<b>Total (GWh)</b>	734,172	1,719,521	2,453,694

Source: DOE Power Statistics

Unlike in Mindanao there is no large hydro project awaiting proper dispatch to displace oil fired plants. Moreover, previous modelling of the Visayas has indicated a role for generic new build using regasified LNG. We think the best way to approach this issue is to start off with a demonstration project based on the islands that make up the Visayas part of the WESM.

### 5.5.1. Economics

The economic case to replace existing and often aging gensets with new build gas engines using regasified LNG is fairly clear. The problem is getting all the different players in the energy chain aligned. The different players are: shipping, storage and regasification, power generation, off-takers, and regulators.

The cost stack of regasified LNG is given in Table 6.

**Table 6: Delivered cost for LNG to small power plants**

<b>Brent</b>	2013US\$/barrel	90
<b>Slope</b>	%	13
<b>LNG</b>	2013US\$/mmbtu	11.7
<b>Delivery to Luzon</b>	2013US\$/mmbtu	2
<b>Offloading and reloading</b>	US\$ mmbtu	1
<b>Shipping to Visayas</b>	US\$ mmbtu	2
<b>Storage and regasification</b>	US\$ mmbtu	3
<b>Total delivered cost</b>	US\$ mmbtu	19.7

Source: The Lantau Group

The economic case for new build gas engine such as a Wärtsilä 50SG of 17.5 MW (which could be arranged in multiples of sets to increase capacity at any one site) using regasified LNG is clearly less expensive than continuing to use diesel in an existing genset.

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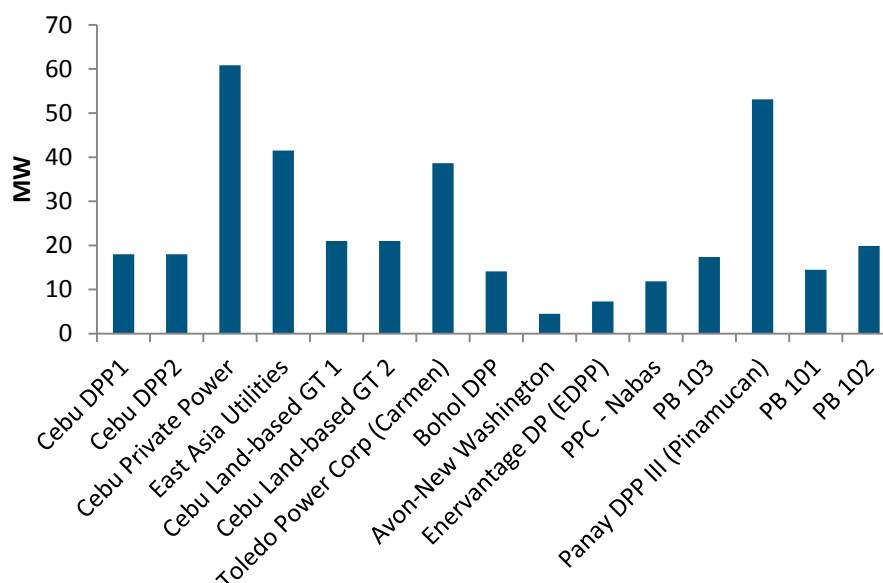
**Table 7: Existing plants compared to new build gas engine using regasified LNG**

	Existing Plant	Gas Engine
<b>Plant Details and Capital Cost</b>		
Capital cost inc. IDC (US\$/kW)	0	560
Economic Life (years)	25	25
Capacity Factor (%)	25	25
Annual capex (US\$/MWh)	0	33
<b>Other Fixed Costs</b>		
Fixed O&M cost (US\$/MWh)	6	6
<b>Fuel Costs</b>	Fuel Oil	Gas
Gross Fuel Cost (HHV, US\$/mmbtu)	23.0	19.70
Heat Rate (HHV, mmbtu/MWh)	10.5	7.3
Fuel cost (US\$/MWh)	246	146
<b>Variable Costs</b>		
Variable O&M cost (US\$/MWh)	3	2
<b>Total short-run marginal cost (US\$/MWh)</b>	<b>249</b>	<b>148</b>
<b>Total long-run marginal cost (US\$/MWh)</b>	<b>255</b>	<b>187</b>

### 5.5.2. Demand

Our demand forecast for regasified LNG into the power sector in Visayas comes in two parts. Firstly displacing diesel and fuel oil in existing plants, of which we suggest that 50 percent may convert and new build gas engines. A list of existing plants in the Visayas is provided in Figure 31.

**Figure 31: Existing oil-fired plants in Visayas**



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**Table 8: Existing oil fired plant on Visayas and conversion to regasified LNG**

	2012	2015	2020	2025
Capacity (MW)	362	308	308	308
Annual Capacity Factor (%)	23	25	25	25
Generation (MWh)	734,172	674,520	674,520	674,520
Heat rate (HHV, mmbtu/MWh)	11.5	11.5	11.5	11.5
Economic market potential for LNG (tpa)	168,860	138,000	155,140	155,140
Conversion to LNG (%)	50	50	50	50
Realisable market potential for LNG (tpa)	84,430	69,000	77,570	77,570

From previous modelling generic new build totalling close to 200 MW might be needed to be added to the system by 2025.

**Table 9: New build plant using regasified LNG in Visayas**

	2012	2015	2020	2025
Capacity (MW)	0	0	100	200
Annual Capacity Factor (%)	0	0	25	25
Generation (MWh)	0	0	219,000	438,000
Heat rate (HHV, mmbtu/MWh)	0	0	7	7
Economic market potential for LNG (tpa)	0	0	31,974	63,948

Pulling the two forecasts for existing plant converting and new build gives us the following forecasts. We believe that a growing market that might rise to 140,000 tonnes per year by 2025 is of sufficient size to attract the gas and shipping companies.

**Table 10: Existing and new build power plants on Visayas using regasified LNG**

	2012	2015	2020	2025
Capacity (MW)	181	154	254	354
Annual Capacity Factor (%)	23	25	25	25
Generation (MWh)	367,086	337,260	556,260	775,260
Heat rate (HHV, mmbtu/MWh)	11.5	11.5	9.82	9.1
Economic market potential for LNG (tpa)	84,430	69,000	109,544	141,518

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### 5.5.3. Shipping

A key piece of the delivery mechanism to smaller loads is the shipping. In order to enable variable volumes to be offloaded onto floating regasification barges at different small power plants the ships used for the small scale LNG supply will probably have to use ISO tanks. Otherwise partial offloading even from small LNG carriers with conventional Moss or Membrane tanks will risk sloshing and damaging the inside of the tanks<sup>26</sup>. These ISO tanks can be pressurised and so can cope with partial loads. Ships sizes range from 5,000 to 30,000 m<sup>3</sup> based on our research.

**Figure 32: LNG carriers can get very small and very expensive**



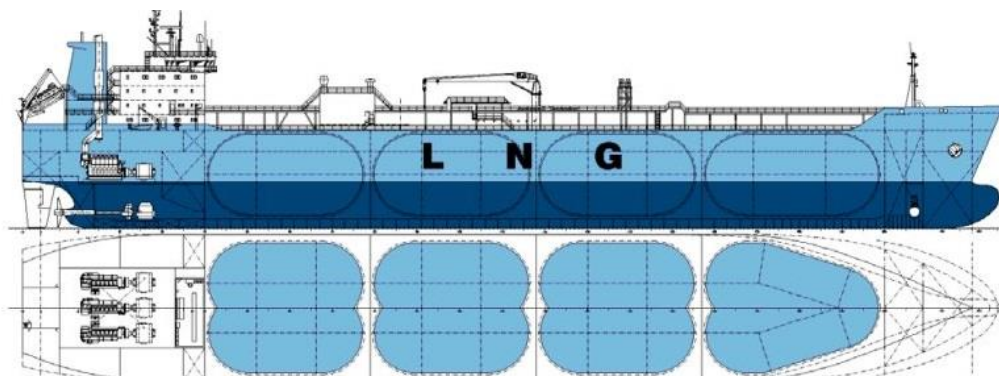
Above we show the 1,100m<sup>3</sup> Pioneer Knutsen next to the 87,000m<sup>3</sup> Hoegh Galleon. The Pioneer Knutsen is chartered to GasNor by Anthony Veder. The cost of this very compact LNG carrier has not been publicly disclosed but we estimate it was about US\$5,000/m<sup>3</sup>. By contrast, a new build 170,000m<sup>3</sup> LNG carrier would cost approximately US\$1,200/m<sup>3</sup>.

Recently there has been growth in gas carriers using pressurized ISO (International Shipping Organisation) tanks for delivery of small amounts of LNG. Recently the US approved export permits for small volumes of LNG from some small terminals to Free Trade Agreement countries in the Caribbean and Latin America. These cost in the region of US\$2,000 to US\$3,000 per m<sup>3</sup>, depending on capacity.

Another option is to get LNG delivered by a multigas carrier that can carry LNG, ethylene, LPG and vinyl chloride monomer. Nevertheless, this latter option is on the expensive end of the range at above an estimated US\$3,750/m<sup>3</sup>, and would therefore reasonably only be an option of last resort.

<sup>26</sup> Although that said GTT of France which holds the patent on membrane tanks has been working on a solution to sloshing in membrane tanks

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**Figure 33: 30,000 m<sup>3</sup> ISO LNG carrier design**

(Source: TGE Gas Engineering)

We would recommend to serve the demand profile we have laid out in the demand section on Visayas is that two 20,000m<sup>3</sup> LNG carriers with ISO tanks are used. Some key assumptions are cost per carrier of US\$50m each (US\$2,600/m<sup>3</sup>) and an utilisation rate of 50 percent. This low utilisation pushes up the delivery costs but it does make sure that if one vessel is out of service the remaining vessel should be able to serve the demand load. We calculate that the total real levelised cost for this shipping solution is close to US\$2/mmbtu. This corresponds with figures shared with us by oil and gas companies that have assessed Visayas power as a market for conversion to regasified small-scale LNG.

#### 5.5.4. Regasification barges

A key issue with the delivery of LNG to smaller remote loads is to avoid placing infrastructure on shore which is subject to much more permitting and can often be more expensive than offshore options. Designs for regasification barges have been approved by DNV but construction of the first regasification barges has only recently gathered momentum.

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**Figure 34: Regasification barge**

Source: TGE, Gasfin Technologies

### 5.5.5. Regulations

There is a question mark over what the incentive is for some of these existing power stations to convert to regasified LNG if their existing PPA allows for a pass through of their fuel costs.

As discussed in earlier reports, DUs are obliged to supply electricity in a least cost manner to their captive customers, subject to approval by the ERC<sup>27</sup>. To do so, they may enter into bilateral power supply agreements (PSAs) subject to review by the ERC<sup>28</sup>. Historically, the ERC's review of PSAs has generally followed a 'cost-plus' approach that has focused on the present costs, the impact on consumers, and occasionally the comparability to some other options. As reflected in the draft PSA rules<sup>29</sup>, "The ERC shall determine the reasonable generation cost under the said PSA taking into account the ... Fuel Fee, [which is] a component to recover fuel costs" (underlining added).

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<sup>27</sup> EPRIA sec. 23.

<sup>28</sup> EPIRA sec. 45(b).

<sup>29</sup> Second draft for public consultation, dated 17 October 2013.



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Whilst many PSA approvals include efficiency caps on the operation of the plant<sup>30</sup>, there has been a general acceptance that otherwise the actual incurred fuel costs should be passed-through<sup>31</sup>. It is the presumption of the recovery of fuel costs that has provided very weak economic incentives for generating companies to procure fuel on a least-cost basis<sup>32</sup>.

Furthermore, once Final Approval has been given by the ERC, there is a general assumption that PSAs can be operated for the rest of their term under the conditions prescribed by the ERC in their Decision. This implies that, for the term of the effective PSAs, there are only very weak economic incentives for a generating company to consider re-powering their plants with lower cost fuel and re-negotiating its PSAs at lower overall rates. Moreover, even if the revised PSAs recognize the capital investment for re-powering, the generating companies face the risk that the capital recovery fees will incorporate a lower equity return because of the declining trend for approved rates, for which there are already precedents below 15 percent<sup>33</sup>.

## 5.6. THIRD PARTY ACCESS TO TERMINALS IN THE PHILIPPINES

The Gas Ordinance<sup>34</sup> from 2002 indicates that all gas transmission and distribution infrastructure in the Philippines should be with open access. There is the possibility to ask for an exemption for five years. There is no mention of LNG terminals, but we expect the same principals to be applied. Moreover, as the plan for the Batangas FSRU is to have an open season, third party access is part of the basic recommended commercial structure.

## 5.7. OPTIONS TO CONNECT LUZON LNG TERMINALS TO BATANGAS POWER PLANTS

From the Energy World Corporation's (EWC) Pagbilao LNG terminal to the offshore Malampaya gas pipeline is a distance of approximately 30 km. A tie-in to that pipeline from the Pagbilao LNG terminal would cost in the range US\$60m to US\$80m<sup>35</sup>. However, there would be gas quality issues to address at the gas from Malampaya in the

<sup>30</sup> For example, 0.25 liter/kWh in case no. 2012-090RC.

<sup>31</sup> For example, "The Commission concurs that the actual fuel cost utilized in generating electricity should be passed on to the customers. There should be no cap on the fuel cost to be passed on to the customers as long as within the efficiency set by the Commission." Decision dated 10 August 2009, KSPC & various DUs (case no. 2009-026RC).

<sup>32</sup> We do note, however, that the aforementioned draft PSA rules, in identifying a fuel indexation method in the tender documents and selecting the lowest calculated bid, may provide more incentives.

<sup>33</sup> ORMECO & Sta. Clara (case no. 2013-164RC, dated 7 October 2013), adopted a cost of equity of 14.95% "based upon an updated market data for CY2013".

<sup>34</sup> CIRCULAR NO. 2002-08-005 Interim Rules and Regulations Governing the Transmission, Distribution and Supply of Natural Gas

<sup>35</sup> 24 inch pipeline at US\$ 100,000 per km inch with an average throughput of 250 mmcf and max capacity of 500 mmcf over 25 years with an IRR of 12 percent would give a life cycle tariff of US\$0.12/mmbtu

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gas transmission line has a high level of hydrogen sulphide. This is removed at an onshore facility.

## 5.8. CASE STUDIES ON LNG HUBS FROM INDONESIA

The government of Indonesia led by the via the Ministry of Energy and Mineral Resources is aware of the potential savings from switching the fuel at some of its power plants outside Java to use domestic regasified LNG.

There are some key features of the initiative in Indonesia is that it is being led by two state-owned companies with government backing. A new company called Perta Daya Gas has been created that is jointly owned by PLN, the National Power Company and single power buyer, and Pertamina, the National Oil Company.

**Figure 35: Power plants on Bali**



At Pesanggaran (PSGRN in the map) PLN has 100 MW of OCGT, 50 MW of gensets and plans to add a new 100MW CCGT. Functioning at a 50 percent capacity factor, the facility would need close to 200,000 tonnes of LNG a year or 540 tonnes per day of LNG or 1,200 kilo litres per day. Perta Daya Gas has secured storage space at the nearby port and would dock the LNG carrier at the harbour berth and offload the LNG. The storage could be in standardised pressurized ISO tanks or a purpose conventional LNG containment tank. It is some 5 to 7 km from the port to the power plant so a small new pipeline would be needed that would be routed along the side of the highway to minimise rights of way problems.

They are considering other demonstration sites at Karin Jawa Island, Bawean Island, Kupang in East Nusa Tenggara and Nunukan. A key optimisation problem they face is where to operate a hub and spoke delivery system or a milk round of LNG from Bontang, Tangguh and later Donggi-Senoro and Abadi floating LNG to the end user power plants.

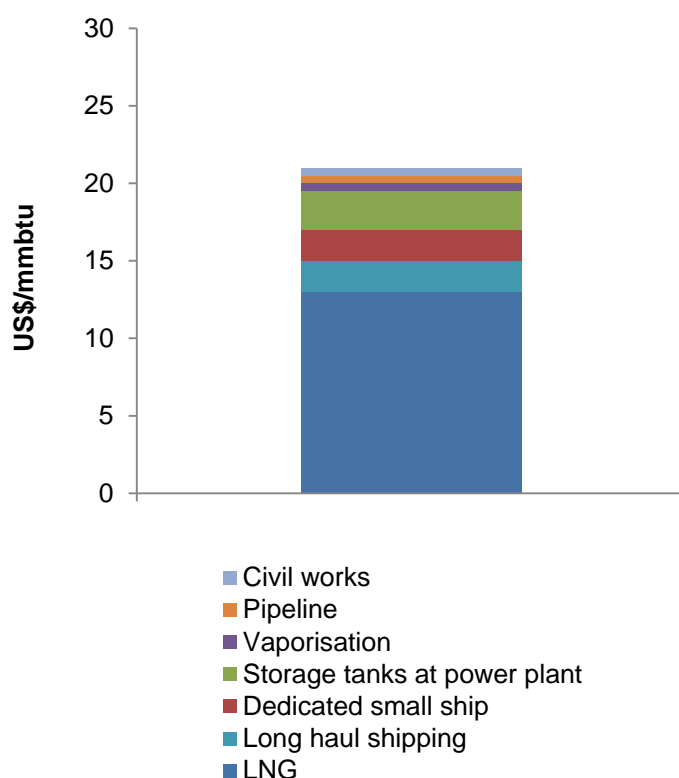


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Therefore any numbers we present here are inevitably approximations but they do demonstrate that domestic LNG to power is an attractive option for PLN compared to diesel (delivered US\$30/mmbtu) or fuel oil (delivered US\$23/mmbtu).

In the cost stack below we assume that domestic LNG is sourced priced at an 11 percent slope to Indonesia Crude Oil price. This follows the trend exhibited on sales from Bontang LNG plant by TOTAL to the Nusantara Regas in Java Bay and planned deliveries from Tangguh LNG Plant by BP to the same facility.

**Figure 36: Approximate cost to serve Pesanggaran with domestic LNG**



(Source: The Lantau Group)

## 5.9. CASE STUDY IN SERVING SMALLER LOADS IN THE CARIBBEAN

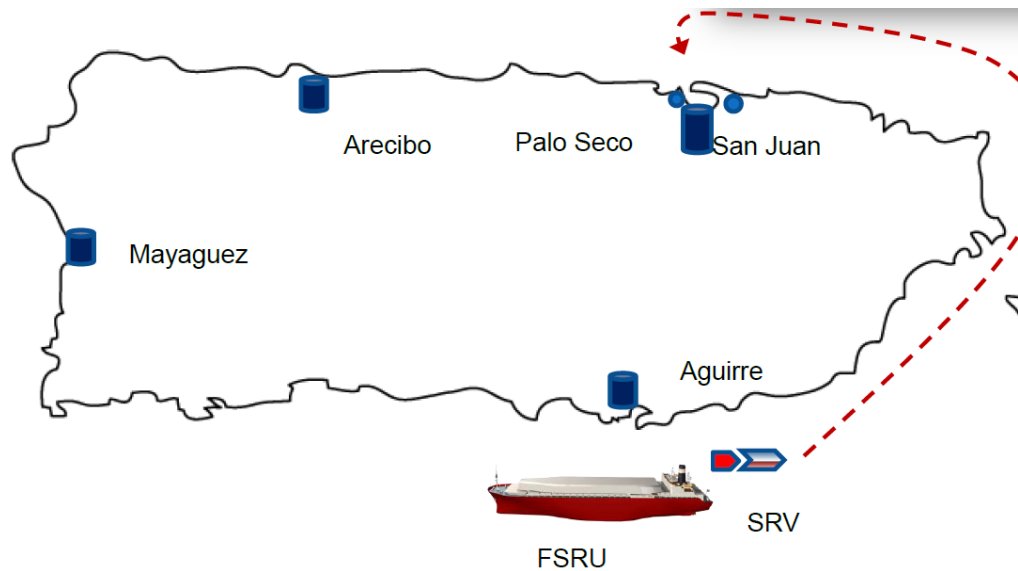
As noted earlier in our discussion on Puerto Rico (Section 4.2.12), there are plans to develop a system of shuttle small scale LNG carriers and floating regas barges to get LNG to power plants along the northern coast of the island. The engineering, environmental, and economics of this initiative have a very great many uncertainties.

The Puerto Rico Electric Power Authority has chartered for 15 years an FSRU from Excelerate Energy located off shore near its Aguirre power plant. Subject to FERC approval the FSRU should be in service by early 2015. At a later stage might involve a shuttle tanker (SRV) to deliver LNG to other power plants around the island. The

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receiving facilities at other power plants will most likely be barges with regasification. But this is the subject of a yet to be launched private-public-partnership solicitation.

**Figure 37: Puerto Rico Aguirre FSRU and SRV plan**



Source: Inter-sectoral Committee On Environmental Compliance And Energy Alternatives, Government of Puerto Rico

## 5.10. CASE STUDY OF SERVING SMALLER LOADS ON FIJI

Otto Power based in Vancouver has plans to take LNG from the Australia Pacific LNG plant in Queensland Australia to Fiji. It is planning to purchase or charter two small 5,000 m<sup>3</sup> LNG carriers which would shuttle between Queensland and Fiji. The power plant in Fiji is currently 42MW but might be expanded to close to 80MW. The power plant currently runs on fuel oil, which would be a back-up fuel in case one of the LNG carriers was out of commission and other LNG unavailable. We understand that the economics of this project are challenging due to the very small size of the LNG carriers and the distances involved in transporting the LNG.

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## **6. NEXT STEPS**

The recommended structures and strategies described in this Report will be discussed in a public consultation hosted by the DOE on Thursday, 20<sup>th</sup> March 2014.

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**APPENDICES**

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## Appendix A: Comments received on the Phase One Report

The DOE requested feedback on the options presented at the Consultation Meeting on December 13<sup>th</sup>, in particular:

- Which of the Options presented do you feel is most suitable, and why?
- Are there any Options you think are not suitable, and if so, why?
- Do you see any obstacles to implementation of the suitable Options?
- Do you have any further comments on the Options or the process generally?

A version of the Phase One report was also posted on the DOE website (see Figure 27).

**Figure 38: Appearance of the Phase One report on the DOE website (as of 22<sup>nd</sup> January)**



Table 11 lists the responses received. In general, the responses to the consultation were not as considered as was hoped, particularly in comparison to those found, say, in Australia or Singapore. Many proponents of LNG projects called upon weak arguments for Government support, although that is not to say that there isn't a case for Government action. Proponents usually rely upon ill-defined concepts / benefits:

- CO2 impacts on health quality;
- Fuel mix diversity; and/or
- WESM dispatch disadvantaging economics of gas-fired generation.

There is also some confusion about differences between 'reserve market' (i.e., the trading of ancillary services in a market structure such as the WESM) vs. 'capacity market' (i.e., additional payment to generating companies purely on the basis of available capacity or such like, rather than services performed). Respondents also used the term 'fuel mix policy' to cover a variety of options not directly related to fuel mix.

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**Table 11: List of responses received**

Type	Company	Company Representative
<b>LNG project proponents</b>	AG&P	
	Energy World Corporation	
	First Gen	
	Meralco Power Gen	
	Mitsui	
	Petroleum Brunei	
	PNOC EC	
	Shell	
<b>Gas industry</b>	Shell Philippines Exploration B.V.	
<b>Aid agency</b>	JICA	
<b>Individuals</b>	n/a	

A summary of the responses to the options presented in the Phase One Report is given in Table 12.

**Table 12: Summary of preferences for the main set of options**

Respondent	Do Nothing	Gas Purchase Obligation	Tender a regulatory approval	Tender a contract for terminal capacity	Information and Education	Clarify rules for access to terminal / pipeline
	x	✓✓		x	x	✓✓
	No comment on options					
	x (by implication)					
	No comment on options					
	x (by implication)					✓✓
	x (for Mindanao)	✓	x		✓✓	
	"Consider all options"					
	x (by implication)	✓✓		✓✓ (Malampaya)		✓✓
	x (by implication)					✓✓
	No comment on relative merits of options					
Individual	✓✓					

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## A.1 Comments on Gas Purchase Obligation option

Project proponents that gave opinions on the options tended to be supportive of this option:

*“... Gas purchase obligation has been demonstrated to work well in Australia and can address needs of power plant developers. We believe this will help jumpstart the industry and need not be perpetual ...”*

*“... This option has been proven in countries such as [Queensland],Australia to dramatically increase the use of natural gas ...”*

*“... If the DOE in the Philippines are seriously looking at LNG as the way forward and there are concerns on carbon emissions, then something has to be done that will discriminate against coal and there is a good justification for that ...”*

The difficulty of building consensus around an option mandates the purchase of a higher short-run marginal cost fuel is highlighted in some responses:

*“... Continued use of expensive natural gas would keep power extremely expensive for the Philippines ...”*

Other proponents advised that this option had the advantage of letting the private sector arrange the commercial transactions:

*“... Gas purchasing by governments rather than private entities has proven to be less effective in most countries ... It is more desirable to leave these commercial transactions to the private sector ...”*

## A.2 Comments on Tender a regulatory approval option

Some project proponents did not see the value of regulatory approval:

*“... This seems unnecessary work for the DOE just to tender a regulatory approval when they can just allow it for everyone. If it is to tender something of value - then it should be something else ...”*

Lack of support might be indicative that: (1) The option as explained in the Report and Consultation was misunderstood; or (2) Proponents see no value in regulatory approval because they think it is ‘guaranteed’.



### A.3 Comments on Facilitation strategy

Many respondents called for clearer regulations:

*“... Among all options provided in the presentation, the most essential is to establish the clear regulations. Otherwise, it is unlikely that private investor will make the investment in the LNG related assets including LNG receiving terminal ...”*

*“... Over the longer term, many regulatory changes will be required in both the electricity and gas industries to maintain a cost effective and efficient industry ...”*

*“... We propose that the Plan also address the development of a robust regulatory framework”*

Some thought that capacity building would support other options:

*“... Information and Education ... only to complement the other options...”*

Although others thought it was more the responsibility of the private sector:

*“... [An information & education strategy] is not required. It should be the responsibility of private investors to educate themselves ...”*

Potentially also work for the DOE internally:

*“... We propose that the Plan address capacity building and technical training for relevant staff in Government ... a capable and independent regulator will help to ensure the success...”*

### A.4 Tender for LNG terminal as a backup for Malampaya

Some respondents were supportive of the idea to tender for a backup LNG terminal

*“... Tender Option to Back up Malampaya is a good idea to supplement other options but this alternative alone is unlikely to incentivize the construction of an import terminal. This will enable the country to manage electricity costs better and reduce unpredictability of such costs. The study recognizes that implementation will not be easy as this requires involvement of many players (Malampaya JV, Malampaya CCGT customers, pipeline owner, back-up gas supplier, and regulator) and therefore Government could play an important role here by stepping in to act as the tender party and intermediating between all these parties. This could simplify the execution and help the country realize the benefits of this back-up gas more quickly ...”*

## Appendix B: Ilijan FSRU Technical Feasibility

### B.1 Summary

As a supplement to the Phase One of the Philippines Natural Gas Master Plan study, an engineering review has been conducted for one additional site suggested for the development of an offshore LNG terminal adjacent to the KEPCO Ilijan site (see accompanying Appendix from Arup for details).

The review considered the construction of a baseline offshore LNG terminal and baseline CCGT power plant at the Ilijan site in Batangas, with site specific parameters from the engineering review feeding into the capex analysis to determine relative cost differential relative to the six other sites. Based on the engineering review and the CAPEX analysis, the conclusions for the KEPCO Ilijan site are summarised as follows:

- Site – From an engineering perspective, the Ilijan site is considered possible for the development of an offshore LNG terminal, but the site's exposure is the location's greatest risk, in particular to wind and waves but also a high tsunami risk. However, the remoteness of the site and the lack of marine facilities in the vicinity reduce marine traffic risks.
- Cost – The analysis undertaken adopting the assumptions described shows that the highest capex for the offshore LNG terminal alone is around 8 percent higher than the lowest offshore capex site, with results indicating that KEPCO Ilijan's site having the highest capex for the FSRU LNG terminal.
- FSRU – Offshore FSRU options are cheaper at all sites, but there are potentially high risks relating to met-ocean and weather conditions (i.e., typhoons) which may require the FSRU to shutdown and/or move away from the terminal leading to supply disruptions. This is a particular risk at the KEPCO Ilijan site, where marine risk mitigation requirements in the form of additional jetty abutment and shore protection are needed, contributing to the relatively higher capex.

The review has investigated the suitability of the site from a high-level engineering perspective and provides factual information in an objective manner which can be used to inform the rest of the study. Commentary and assumptions have been made on the basis of the information provided and further study is required to verify the information.

### B.2 Further Analysis

It has been suggested that the technical feasibility of connecting an FSRU to the Malampaya gas pipeline should be considered for strategic reasons. Ilijan, Santa Rita and San Lorenzo receive natural gas from the Malampaya pipeline. An FSRU moored along and connected to the pipeline may offer the possibility of providing back-up supplies during scheduled and unscheduled outages.