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May 2021

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# No Guaranteed Future for Imported Gas in the Philippines

## *LNG-to-Power Investors in the Philippines Risk Exposure to $14 Billion in Stranded Assets*

## Executive Summary

Natural gas industry players have their sights set on Southeast Asia. The International Energy Agency expects emerging liquefied natural gas (LNG) importers in the region to be the main drivers of global demand growth behind China and India, raising suppliers' hopes for a tighter global market and higher prices.[1] Many Southeast Asian countries have subscribed to the industry-driven narrative that natural gas presents a viable transition fuel from coal-fired generation capacity to a clean energy future.

The Philippines is no exception. Burdened with the highest electricity prices for residential consumers in the region,[2] a high exposure to volatile global coal prices, and increasingly severe natural disasters caused by climate change, the government has signalled its commitment to transition from coal-fired power. And with the expected depletion of the Malampaya deepwater natural gas development—the country's only domestic source of natural gas—officials have endorsed a rapid buildout of LNG import infrastructure.

**The race to develop LNG facilities in the Philippines has gone from a marathon to a sprint.**

The race to develop LNG facilities in the Philippines has gone from a marathon to a sprint. Malampaya is nearing depletion sometime in the mid-2020s, meaning existing gas-fired power plants will need to find a replacement fuel source in the near-to-medium term. Moreover, the country's gross domestic product (GDP) is expected to grow at a high rate of 5-8% over the next decade, adding urgency to the search for new power capacity.[3]

In this context, it is easy to assume that the Philippines' LNG demand will grow rapidly, and that with government support, investments in LNG-fired power plants and other related infrastructure will face negligible development risks and reap all-

[1] International Energy Agency. Gas 2020. June 2020.
[2] Department of Energy (DOE). Philippines Energy Plan 2018-2040, p. 20.
[3] Business Inquirer. Capital Economics: PH to become world's 18th biggest economy in 2050. February 15, 2021.

but-guaranteed returns.

But the picture is much more complicated. The country's long history of incomplete LNG import projects should beg the question: *What changes have been made recently to overcome regulatory and financial hurdles that have beset conventional projects in the past?* To date, a large diversity of industry players with extensive financial capacity and project management expertise—including international oil and gas majors, commodity traders, regasification operators, state-owned oil companies, and regional utilities—have been unable to bring LNG-to-power assets online. Many have made it to advanced stages of project development but to no avail. One project has been over 90% complete for at least five years but has remained offline and stranded due to regulatory delays.

Policymakers have tried increasingly to iron out lower-level administrative hurdles and incentivize investment by issuing permitting rules, publishing investor guides, and proposing legislation to govern the midstream and downstream natural gas sectors. The United States Department of State, through its Asia EDGE (Enhancing Development and Growth through Energy) Initiative, has pushed legal and regulatory reforms to stimulate the creation of a new Philippines market for US LNG exports. Yet the higher-level legal and regulatory regimes for LNG are still in their nascent stages and could take years to refine and implement, adding uncertainty to the future market environment.

**High regulatory and financial uncertainty in the Philippines market contradicts the nature of the natural gas industry.**

For the midstream natural gas industry, which is characterized by low profit margins and long payback periods for high-cost infrastructure, stability is crucial to minimizing gas developers' market risks. Such high uncertainty in the Philippines market contradicts the nature of the industry, especially with almost no existing infrastructure in place.

Moreover, the case of the Philippines shows clearly how LNG importers' reliance on traditional, long-term project financing terms is incompatible with deregulated power market structures being reshaped by rapid technological innovation. Since the country's landmark 2001 Electric Power Industry Reform Act (EPIRA) banned government involvement in power plant contracting, there are no available government-backed power purchase agreements (PPAs) or guarantees, leaving investors in LNG-fired power plants highly exposed to market risks arising from changes in the commercial and regulatory landscape. As more zero marginal cost renewables come online, gas-fired power plants are expected to be dispatched much less frequently, limiting the predictability and continuous need for large volumes of imported gas.

Given rapidly changing market structures and evolving regulatory regimes, project sponsors and financiers must carefully assess the high risk of stranded assets for LNG projects resulting from idle capacity and reduced operating cashflows.

This dynamic is reflected in the ongoing implementation of Retail Competition and Open Access (RCOA), which allows large and medium power offtakers to choose their electricity providers. As the threshold for consumer choice is lowered, increased competition will put pressure on distribution companies to reduce costs for end-users and could ultimately lead to a reduction in contracted capacity required by large utilities. As a result, distribution companies—now competing with retail suppliers—have become increasingly wary of locking-in long-term LNG price volatility and infrastructure costs.

Imported gas has a small role to play in meeting existing demand from anchor gas plants and possibly for additional peaking capacity from open-cycle gas turbines (OCGT). Large baseload LNG-to-power projects, however, will have diminishing opportunities to win conventionally bankable offtake agreements and will have to bear significant market risk. Although some new LNG-to-power facilities are likely to come to fruition over the next decade, success on a project-by-project basis does not signal a national strategic commitment to gas or guarantee sustainable natural gas demand growth in the medium-to-long term.

**There is no existing gas transmission and distribution infrastructure to supply non-power sectors.**

Meanwhile, there is no existing transmission and distribution infrastructure to supply non-power consumers. Industrial, commercial, residential, and transport sectors will require massive investment in gas transportation infrastructure, as well as more complicated contracts for smaller gas volumes. Actual LNG demand is therefore highly likely to undershoot analyst forecasts for rapid growth, leaving investors on the hook for unused mid- and downstream capacity.

History rhymes, and barriers to past LNG ambitions in the Philippines are likely to plague the new wave of projects. Similar to Vietnam,[4] unresolved legal, financial, and structural questions are only now coming into focus for LNG project sponsors, even those that appear to be well advanced. These questions will need to be settled before sustainable sources of funding can flow. Potential investors in LNG projects must proceed at their own risk.

[4] IEEFA. There will be no smooth sailing for LNG investors in Vietnam. January 19, 2021.

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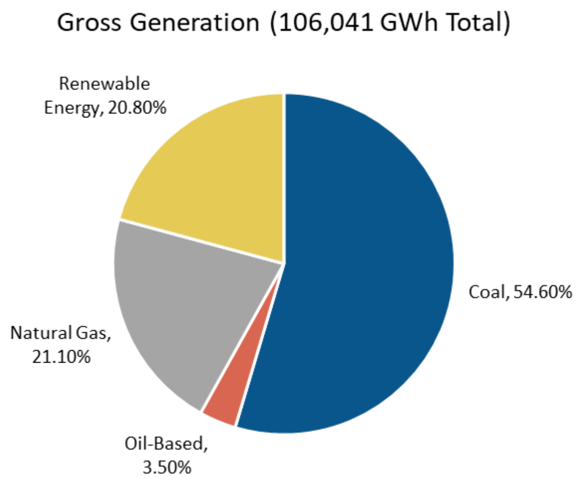
# Market Overview

Coal-fired generation accounted for 54.6% of the Philippines' gross generation in 2019 while natural gas made up 21.1%, all of which is supplied to the Luzon grid (see Figures 1 and 2 below).[5] Five existing gas-fired power plants provide nearly 3,500MW of generation capacity and supplied 29% of the Luzon grid's electricity load.[6] All of the country's natural gas is used in the power sector, as there is no existing transmission and distribution infrastructure that might supply the industrial, commercial, residential, or transport sectors.

### Figure 1: Philippines Installed Capacity and Gross Generation (2019)

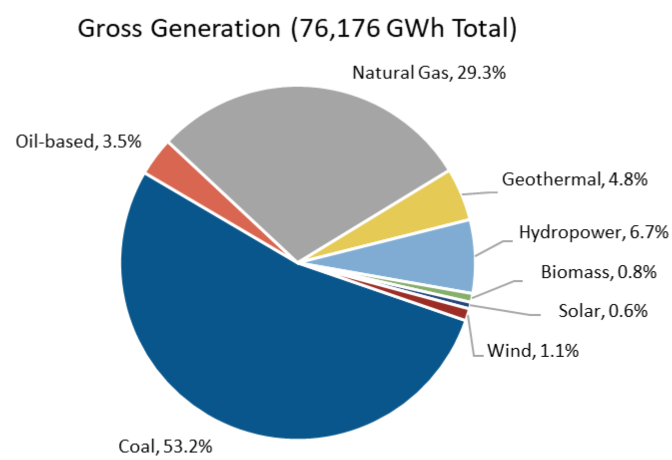
| Fuel Type | Installed Capacity (MW) |
| --- | --- |
| Coal | 10,417 |
| Oil | 4,262 |
| Natural Gas | 3,453 |
| Renewable Energy | 7,399 |
| *Geothermal* | *1,928* |
| *Hydro* | *3,760* |
| *Biomass* | *363* |
| *Solar* | *921* |
| *Wind* | *427* |
| **Total** | **25,531** |
| **Peak Demand** | **15,581** |




*Source: DOE 2019 Power Situation Report.*

### Figure 2: Luzon Installed Capacity and Gross Generation (2019)

| Fuel Type | Installed Capacity (MW) |
| --- | --- |
| Coal | 6,929 |
| Oil-based | 2,585 |
| Natural Gas | 3,452 |
| Renewable Energy | 4,320 |
| *Geothermal* | *865* |
| *Hydro* | *2,593* |
| *Biomass* | *164* |
| *Solar* | *362* |
| *Wind* | *337* |
| **Total** | **17,286** |
| **Peak Demand** | **11,344** |

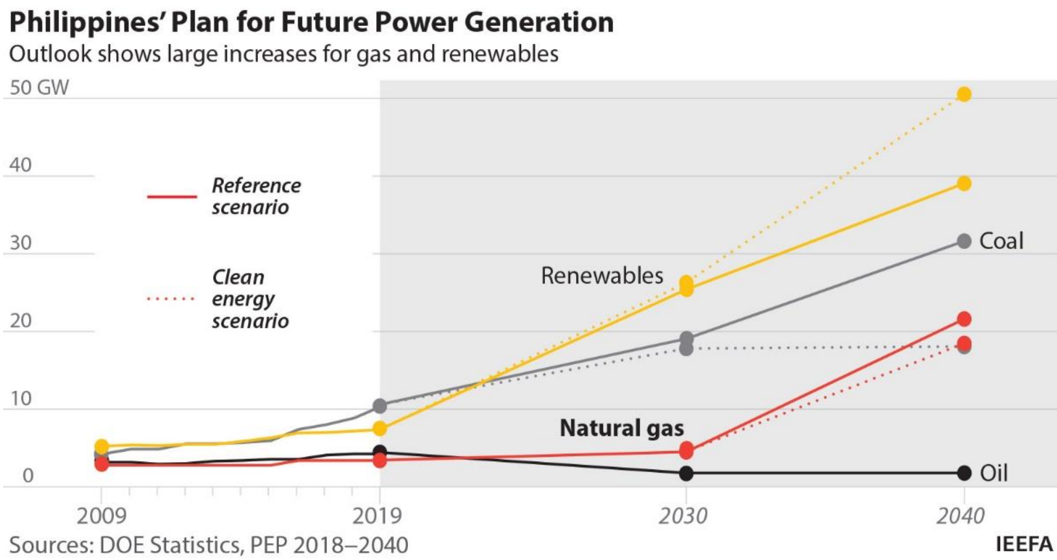



*Source: DOE 2019 Power Situation Report.*

[5] DOE. 2019 Power Situation Report, p. 8.
[6] DOE. Luzon Power Supply and Demand Outlook. March 4, 2020.

The government is aiming to increase total electricity generation capacity in the country from 25GW to over 93GW by 2040. 38GW of that is expected to come from renewable energy sources in a reference scenario and 50GW in a clean energy scenario.[7] A large portion of the remaining capacity is expected to come from natural gas. The Philippines Energy Plan 2018-2040 anticipates natural gas generation to grow at an average rate of 5.63% per year under a reference scenario, increasing to 7.31% under a clean energy scenario. In the low carbon scenario, natural gas is expected to account for 26.6% of gross generation by 2040.[8]

### Figure 3: Natural Gas and Renewables Capacity Additions (MW) by 2040, Reference Case vs. Clean Energy Scenario (CES)




In October 2020, the government announced a moratorium on greenfield coal-fired power plants, opening the door to potentially greater investments in natural gas, viewed as a flexible substitute to coal able to accommodate variable renewable resources such as wind and solar. However, there are still over 11GW of coal projects in the regulatory pipeline, which the government has claimed are still eligible for construction despite the moratorium.[9] In the Philippines Energy Plan 2018-2040 (see Figure 3 above), the reference and clean energy scenarios include 22.6GW and 10.5GW of new coal-fired capacity, respectively. Whether coal-fired power plants already in the pipeline can proceed will be a major determinant of capacity additions for other generation sources.

[7] DOE. Philippines Energy Plan 2018-2040, p.36.
[8] *Ibid.*, p.38.
[9] Manila Standard. DOE issues advisory clarifying moratorium on new coal projects. January 11, 2021.

## *Brief History and Status of the Malampaya Play*

The Philippines began producing its own gas in 2001 with the start of the Malampaya deepwater natural gas development, which was previously owned by a joint venture of Shell Philippines (45%), Chevron Malampaya (45%), and the Philippines National Oil Company (10%). Since 2005, production has ranged between 3-4 billion cubic meters (bcm) per year.

Recently, international players have begun to exit the Malampaya project. In March 2020, Philippines-based Udenna Corporation owned by businessman Dennis Uy acquired 100% of Chevron Malampaya, including its non-operating interest in the field.[10] In September 2020, Shell announced it was also looking to divest its interest following the COVID-19 pandemic.[11]

### Figure 4: Existing Philippine Natural Gas Plants in the Philippines

| Plant Name | Capacity (MW) | Location | Operator | Key Player |
|---|---|---|---|---|
| Avion OCGT | 100 | Batangas City | Prime Meridian Powergen Corp | First Gen |
| Ilijian CCGT | 1,277 | Batangas City | KEPCO Ilijan Corporation | San Miguel |
| San Gabriel CCGT | 430 | Batangas City | First NatGas Power Corp | First Gen |
| San Lorenzo CCGT | 550 | Batangas City | FGP Corporation | First Gen |
| Santa Rita CCGT | 1,100 | Batangas City | First Gas Power Corp | First Gen |
| **Total** | **3,457** | | | |

*Source: DOE.*

Malampaya production is linked to a gas processing platform on the coast near Batangas City via a 500 kilometer subsea pipeline. Gas from the field was initially contracted to supply the Ilijan, Santa Rita, and San Lorenzo combined cycle (CCGT) natural gas plants. The National Power Corporation commissioned the Ilijan plant but later sold it to the Korea Electric Power Corporation (KEPCO) upon privatization of the power generation sector, while a consortium led by First Philippines Holdings developed Santa Rita and the adjacent San Lorenzo plant. In 2016, First Gen, a First Philippines Holding subsidiary, added the 420 MW San Gabriel CCGT and the 97 MW Avion open cycle gas turbine for peaking capacity (see Figure 4 above).

Service Contract 38, the concession for Malampaya, ends in 2024, though Shell has made a formal request to extend it with the Department of Energy (DOE).[12] Approval of an extension could extend some production from the field until roughly 2027 to 2029.[13] [14] There are currently no existing replacement sources of domestically produced gas, and any major natural gas discoveries in the future would likely take ten years to be developed.

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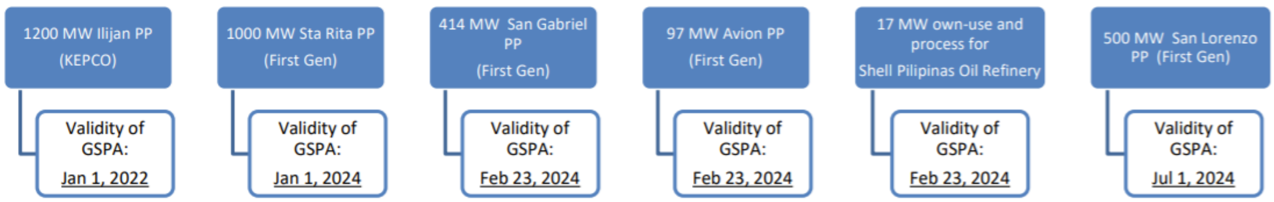
[10] Reuters. Philippines' Udenna says it is buying Chevron's stake in Malampaya gas project. November 13, 2019.
[11] Reuters. Shell looking to sell stake in Philippines' Malampaya gas project. September 24, 2020.
[12] Reuters. Philippines' Udenna says it is buying Chevron's stake in Malampaya gas project. November 13, 2019.
[13] Oxford Institute for Energy Studies. Emerging Asia LNG Demand. September 2020, p. 46.
[14] Power Philippines. Cusi sees no problem with Chevron-Udenna Malampaya deal. December 23, 2020.

**Figure 5: Existing Gas Sales and Purchase Agreements**




*Source: DOE Presentation, The Philippines Downstream Natural Gas Industry.*
*Note: The Shell Pilipinas Oil Refinery closed in August 2020.*

Expiry of the gas sales and purchase agreements (SPAs) for the existing power plants coincide with the expiry of the Malampaya concession. The SPA for the Ilijan gas plant ends in 2022, while the agreements for the four other gas plants owned by First Gen end in 2024. Unless these SPAs are renewed, the entire volume of natural gas will have to be imported. If not, the plants will have to be decommissioned or run on more expensive liquid fuels.

The government estimates that 3.5 to 5 metric tons per annum (mtpa) will be required to continue operating the roughly 3,400MW of existing natural gas plants.[15] [16] However, since the gas SPAs for the three largest facilities include strict take-or-pay clauses that require the power plants to consume the gas, the plants are operated at baseload capacities above 80%. Once the SPAs expire (see Figure 5 above), the plants will likely operate at much lower capacity factors, likely in mid-merit roles. Therefore, actual gas demand from the existing anchor facilities could be much lower. According to the Oxford Institute for Energy Studies, the plants are only likely to consume between 1 and 2 mtpa once the contracts expire,[17] much less than official estimates for regasification capacity required in the near-term. Currently, terminals with a combined throughput capacity of 18.76 mtpa are in various stages of development (see Figure 6).

## *Permitting Process for the Midstream Natural Gas Industry*

There is no clear policy on natural gas in the Philippines or laws specifically governing the industry's development, although DOE issued a circular in November 2017 primarily concerning the permitting process for natural gas midstream projects. The circular covers LNG import terminals, pipelines, and other transmission and distribution-related facilities.

Under the permitting guidelines, project sponsors must first undergo a pre-application screening conference with DOE before applying for a notice to proceed (NTP), followed by a permit to construct, expand, rehabilitate, and modify (PCERM), followed by a permit to operate and maintain (POM). To advance through the stages, sponsors of natural gas midstream projects must obtain more than 40 construction-

[15] DOE. Philippines Downstream Natural Gas Industry: An Investors' Guide. September 2020, p. 3.
[16] DOE Assistant Secretary Leonido Pulido III. Philippines: Tapping into the World's LNG Market. United States Energy Association, September 2, 2020. Webinar.
[17] Oxford Institute for Energy Studies. Emerging Asia LNG Demand. September 2020, p. 49.

related permits from at least 12 agencies. This does not include accreditation requirements from various agencies for LNG importation.

In the first stage of the process, the project sponsor submits an application for an NTP to DOE, which then has 45 days to conduct a legal, financial, and technical assessment of the project. If approved, the developer has 6 months—with a possible 6 month-extension—to secure necessary permits from other national and sub-national agencies. Once NTP conditions are met, the sponsor applies for the PCERM. If granted, the developer can proceed with construction, which must be completed within the allotted construction time. Upon completion, the DOE Secretary can then approve a POM, allowing operation of the project for a period of 25 years, with possible extensions for an additional maximum of 25 years.

### Figure 6: LNG Import Terminal Pipeline

| Project Sponsor | Project | Import Capacity (mtpa) | Location | Target COD | Permitting Status | Corporate Model |
|---|---|---|---|---|---|---|
| FGEN LNG Corporation | Interim FSRU Terminal | 5.3 | Barangays Sta. Clara | 3Q22 | PCERM received Sept. 2020 | Standalone |
| Excelerate Energy | FSRU Terminal | 1.5 | Batangas Bay | 2Q22 | NTP received | Standalone |
| Energy World Corp | Onshore Storage and Regasification Terminal | 3.0 | Pagbilao Grande Island, Quezon Province | 2024 | PCERM received Dec. 2018 | Integrated LNG-to-Power Plant |
| Batangas Clean Energy, Inc. | Onshore Storage and Regasification Terminal | 3.0 | Barangay Pinamucan-Ibaba, Batangas City | Jul-25 | NTP received | Integrated LNG-to-Power Plant |
| Atlantic Gulf & Pacific | FSRU Terminal | 3.0 | Batangas Bay | Jun-22 | NTP received | Standalone |
| Shell Group | FSRU Terminal | 3.0 | Batangas Bay | TBD | NTP received | Standalone |
| VIRES Energy | FSRU Terminal | TBD | Batangas Bay | TBD | NTP received | Integrated Floating LNG-to-Power Plant |
| **Total** | | **18.76** | | | | |

*Source: DOE, Media Reports.*

## Current Trends in the Development of the Philippines Natural Gas Industry

The debate about how LNG would fit into the Philippine power sector is not new. LNG projects in the Philippines have been proposed since 2003, when GN Power first announced plans to construct a 1,200MW power plant fuelled by imported gas.[18] Although the project had firm power offtake agreements, an engineering, procurement, and construction (EPC) contractor, and an approved construction site, the plan was eventually scrapped due to EPIRA reforms, which introduced competition into the power generation sector. According to then-CEO of GN Power Dan Chalmers, LNG was simply not a competitive fuel in a highly competitive,

[18] Energy News Bulletin. GNPower to Build Philippines First LNG Terminal. April 6, 2004.

liberalized market.[19] Despite significant progress and government approval, the project was cancelled due to market reforms combined with unpredictable LNG prices.

In recent years, LNG industry players and government agencies have been particularly active due to the nearing depletion of Malampaya and the transition from coal-fired generation. Seven import terminals have received official NTPs, and one project is currently under construction. In total, ten power projects with nearly 11GW of generation capacity are at various permitting stages, many of which are integrated with regasification facilities and storage (see Figure 7 below). IEEFA conservatively estimates the value of LNG import infrastructure—such as power plants, ports, regasification facilities, and pipelines—to be $1.25 billion per GW. Based on this estimate, the total value of assets implied by the current Philippines pipeline is likely around $13.6 billion.

### Figure 7: Philippines Natural Gas-Fired Power Plant Pipeline (as of Dec 31, 2020)

| Plant Name | Capacity (MW) | Location | Owner | Target COD | Corporate Model |
|---|---|---|---|---|---|
| **Luzon (Committed)** | | | | | |
| EWC CCGT Power Plant | 650 | Pagbilao, Quezon | Energy World Corporation | 2024 | Integrated LNG-to-Power Plant |
| Ilijan LNG Power Plant | 1,750 | Batangas | Excellent Energy Resources, Inc. | Mar-23 | Standalone |
| Natural Gas-Fired Power Plant | 1100 | Batangas City | Batangas Clean Energy, Inc. | Jul-25 | Integrated LNG-to-Power Plant |
| **Luzon (Indicative)** | | | | | |
| Lloyds Energy Philippines Inc. Floating Power Plant | 1200 | San Pascual, Batangas Bay | Lloyds Energy Philippines Inc. | 2023 | Integrated LNG-to-Power Plant |
| SMC Ilijan LNG Power Plant (Expansion) | 3600 | Batangas | SMC Global Power Holdings Corp. | Phase 1: 2024 | Standalone |
| Lucidum Liquefied Natural Gas Power Plant | 300 | Silanguin Bay, Zambales | Lucidum Energy, Inc. | TBD | Integrated LNG-to-Power Plant |
| **Luzon (Proposed)** | | | | | |
| VIRES LNG-Fired Barge Project | 500 | Batangas City | Vires Energy | TBD (2022) | Integrated LNG-to-Power Plant |
| Santa Maria Gas Plant | 600 | Batangas | First Gen | 2023 | Standalone |
| Saint Joseph Gas Plant | 600 | Batangas | First Gen | 2023 | Standalone |
| Subic Power Plant | 600 | Subic, Zambales | MGen, Aboitiz | TBD | Standalone |
| **Total Capacity** | **10,900** | | | | |

*Source: DOE Private Sector Initiated Power Projects, Manila Bulletin.*

[19] Independent Commodity Intelligence Services. GN Power's Philippines Import Proposal Crushed by Price Pressure. February 9, 2007.

Due to the small size of the existing anchor market for LNG, however, first-mover advantage is especially important, and market players have tended to overstate their progress—creating the impression that LNG's position in the market is based on stable fundamentals. By contrast, the Philippines' long history of failed LNG-to-power projects demonstrates that even with government enthusiasm for LNG and even once a facility is in advanced stages of project development, regulatory complications can still delay projects well beyond targeted in-service dates. Due to the complexity of LNG-to-power projects, project developers should continue to expect similar delays and analysts should recognize that regulatory delays are a common occurrence for Philippines LNG projects—even those in "advanced" stages.

## *Meralco's Most Recent Competitive Selection Process*

Meralco is the largest distribution company in the Philippines and supplies 75% of power demand in the Luzon grid, giving the company and its procurement processes a central role in the buildout of electricity infrastructure, including natural gas power plants. With total annual electricity sales of nearly 40,000GWh, the company serves 25% of the Philippine population in an area from which 50% of GDP is sourced.

In its latest competitive selection process (CSP) for 1,800MW of greenfield baseload capacity, Meralco awarded a 20-year PPA to Excellent Energy Resources Inc. (EERI), a subsidiary of San Miguel Corporation which aims to construct a 1,200MW LNG-fired power plant in Batangas. This represents the first LNG-fired power plant in the Philippines to secure a long-term offtake agreement from a creditworthy customer, typically considered a requirement to reach financial close.

EERI's winning bid was PHP4.1462/kWh (USD0.085), but actual generation charges will vary over the contract duration due to fuel price pass through provisions and contractual outage allowances. In corporate disclosures and environmental impact statements for the greenfield project, the company has expressed interest in procuring US LNG linked to Henry Hub.[20] However, San Miguel has also recognized that the currently oversupplied LNG market is likely to tighten over medium-to-long-term, adding upward price risk.[21] The benchmark fuel price used in EERI's winning bid is not yet public.

San Miguel is in the advanced stages of a binding term sheet on a terminal use agreement with Atlantic Gulf & Pacific (AG&P) to supply the existing Ilijan power plant, the Ilijan expansion project, and possibly the EERI project.[22] [23] AG&P, which is minority-owned by Osaka Gas and Japan Bank for International Cooperation (JBIC), received an NTP for its proposed LNG terminal and regasification facility in March 2021.

[20] Excellent Energy Resources, Inc. Draft Environmental Impact Statement Report—Proposed 1,700 MW Batangas Combined Cycle Power Plant Project, p.1-11.
[21] SMC Global Power. Offering Circular. October 14, 2020, p. 107.
[22] Manila Standard. AG&P obtains notice to start LNG terminal. March 5, 2021.
[23] SMC Global Power. Offering Circular. October 14, 2020, p. 118.

To meet the terms of its PPA, EERI's greenfield power project must be in-service by 2024. Currently, the plant and AG&P's LNG terminal facility are structured as standalone projects by separate corporate entities, which creates a high level of project-on-project risk compared to integrated structures, in which one entity owns both the power plant and the import facility. Any delays in one project's implementation can create a cascading effect that prevents related projects from earning revenues. In standalone models, moreover, each project sponsor will be more concerned with passing project risks to other entities, while lenders will not have security over the risk of default for other projects along the value chain.[24] The high risks involved with standalone LNG terminals and power plants could ultimately result in the termination of the PPA.[25]

Meralco is reportedly considering holding another CSP this year for 1,000MW of additional greenfield baseload capacity in 2021 and has suggested it might bid in with LNG-fired power generation assets of its own, through its subsidiary Meralco PowerGen (MGen). However, a company representative said that more recent plans for gas investments have yet to be studied.[26] The company has been investigating investments in LNG-fired power plants since as early as 2012.

## *Portfolio Suppliers Are Looking Further Downstream*

New market entrants in the Philippines reflect a growing trend worldwide: as LNG demand in emerging markets falls short of supplier expectations, global portfolio players—including trading houses, regional utility companies, and international oil companies—have sought to create demand by investing in shipping, storage, and regasification assets (see Figure 8 below). This lowers LNG entry costs for new buyers with constrained access to capital. The portfolio suppliers then use their funding advantage to aggregate LNG supply contracts from various regions, which allows them to offer various pricing alternatives to traditional long-term oil-linked contracts, along with potentially more buyer-friendly terms such as greater volume flexibility, shorter contract terms, and cargo diversion rights.

Even with their financial capacity and project management experience, however, these diversified global firms have struggled to establish regasification facilities and downstream assets in the Philippines due to regulatory and financing hurdles. And despite being well-positioned to provide more flexible LNG supply volume and pricing options in return for a markup, numerous portfolio supplier-led projects have fallen by the wayside. One further risk to the LNG value chain is also worth noting. While the introduction of aggregators may be beneficial to buyers who hope to avoid the front-end loaded costs of LNG liquefaction infrastructure, extended delays in demand creation could ricochet up the value chain and ultimately cause producers to shut-in gas production.[27]

[24] Watson, Farley, and Williams. The Anatomy of an LNG to Power Project—The Risk Matrix Mitigated. October 2020, p. 5.
[25] Meralco. Invitation to Bid—Contract Capacity of 1,800MW (Net), COD 2024-2025. December 2020, p. 5.
[26] Manila Bulletin. Meralco power unit plans investment shift to LNG. March 3, 2021.
[27] Watson, Farley, and Williams. The Anatomy of an LNG to Power Project—The Risk Matrix Mitigated. October 2020, p.13.

## Figure 8: LNG Players and Business Segments

| Segment | Player (Example) | LNG Value Chain | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | E&P | Lique-faction | Shipping | Trading | Regas-ification | Power Gen | Marketing |
| National Oil Companies | Statoil, PetroChina, Petronas, PNOC | | | | | | | |
| Liquefaction Players | Cheniere, Atlantic | | | | | | | |
| Oil and Gas Majors | Shell, Chevron, Total | | | | | | | |
| Shipping Companies | Golar LNG, NYK, Mol | | | | | | | |
| Commodity Traders | Trafigura, Gunvor, Glencore, Vitol | | | | | | | |
| Regasification Operators | Excelerate, Enagas, Elengy | | | | | | | |
| Utilities | JERA, Tokyo Gas, Osaka Gas, KOGAS | | | | | | | |

Mainly Involved
Partly Involved

*Source: Recreated from International Gas Union, Triennium Work Report 2018, p.75.*

The impact of these market development risks is evident in the Philippines' LNG track record. In 2018, UK-based trading group Glencore partnered with China Energy Equipment Company (CEEC) and Limay LNG Power Corporation to build an integrated LNG-to-power facility. CEEC would provide EPC services for the 1,100MW power plant while Glencore would procure the FSRU terminal and supply the LNG.[28] Although the ultimate reasons for cancellation of the project are unclear, the joint venture had requested project incentives, including guaranteed back-to-back coverage for the power purchase component and the gas supply agreements.[29]

Japanese portfolio players, including Mitsui, Mitsubishi, Osaka Gas, and Tokyo Gas, have also been active in Philippines LNG discussions. The combination of contractual oversupply, slowing domestic demand growth, and downstream market deregulation has pushed Japanese LNG industry players to support demand creation in other Asian markets. In 2016, Osaka Gas and Meralco announced a joint venture to build a 1,500MW power plant with an associated regasification terminal. The project was expected to cost over USD2 billion[30] but was paused due to huge costs of associated gas infrastructure, unpredictable LNG prices globally, and the expected entry of low-cost renewables plus storage.

More recently, Tokyo Gas took a 20% stake in First Gen's LNG import facility in Batangas, which would supply First Gen's four existing gas-fired power plants and is expected online in the fourth quarter of 2022. Given the company's ownership of almost the entire existing natural gas anchor market, the project is considered one of the most advanced in the Philippines. However, a remaining barrier to project

[28] Power Links. China Energy, Glencore to build $1-B integrated LNG plant in PH. September 30, 2018.
[29] Power Philippines. Local LNG, two foreign firms team up for $ 1 B LNG plant in PH. October 3, 2018.
[30] Business Mirror. Meralco, Osaka Gas LNG joint venture to await FS completion. August 29, 2016.

implementation is the lack of a long-term PPA, which would also underpin financing for an LNG terminal and provide greater volume certainty for LNG demand. First Gen and Meralco have discussed power offtake agreements but have not reached a solution.[31]

Multinational oil companies, including Chevron, Total, and Shell, have also expressed interest in developing LNG import terminals in the Philippines. In January 2021, four months after announcing it would divest its interest in the Malampaya field, Shell filed for an NTP with the DOE for an FSRU project. Although DOE granted the NTP in March, the agency provided few details about project specifics, making it impossible to assess the project's potential market impact or financing prospects.[32] Shell representatives have also expressed uncertainty regarding the role of gas in the energy transition.[33]

**Inexperienced Philippines LNG buyers will be at a disadvantage in complex purchase negotiations.**

While portfolio players can provide greater optionality for LNG purchasers than traditional bilateral contracts, the lack of experience and credibility among potential LNG buyers in the Philippines is likely to put them at a disadvantage in LNG purchase negotiations. Securing favourable contract terms requires commercial and operational know-how, and buyer inexperience can result in higher prices and/or longer contract periods. For this reason, the Lantau Group recommended in 2014 that potential LNG buyers in the Philippines aggregate their demand to improve their negotiating position with suppliers, then conduct a formal tender to find the lowest LNG prices from aggregators.[34] However, this solution is unlikely given recent competition among portfolio players in the Philippines downstream market.

## *Focus on FSRUs*

As an alternative to more capital-intensive land-based import terminals, several project developers, including AG&P, First Gen, Shell, and Excelerate Energy, have turned to more easily deployable floating storage and regasification units (FSRUs). Although Tokyo Gas and First Gen initially planned to install a land-based terminal in Batangas City to supply gas to the company's three existing natural gas plants, the partners opted to contract an interim FSRU facility. First Gen selected EPC firm

[31] Oxford Institute for Energy Studies. Emerging Asia LNG Demand. September 2020, p. 46.
[32] Manila Bulletin. DOE issues notice-to-proceed on Shell's LNG import facility project. March 26, 2021.
[33] Wall Street Journal. As the Shift to Green Energy Speeds Up, Shell's Big Natural-Gas Bet Is at Risk. March 27, 2021.
[34] The Lantau Group. Philippines Natural Gas Master Plan—Phase Two Report: Design of a transactional structure for initial LNG-to-power infrastructure development for Luzon and Mindanao. March 3, 2014, p. 30.

McConnell Dowell to construct build the adjacent onshore receiving facilities and recently chose BW Gas for the FSRU tender.

The FSRU import facility is targeted to begin operations in the third quarter of 2022. Although First Gen and Tokyo Gas held a ground-breaking ceremony in May 2019,[35] the partners still have not taken a final investment decision (FID).[36] However, First Gen announced recently it expects to begin construction of the interim offshore terminal in April 2021.[37]

In a test of the market's demand potential, Excelerate Energy, one of the largest FSRU providers based in the United States, has partnered with local firm Topline Energy to construct a standalone open-access FSRU project. The partnership received an NTP in late 2019 but has not yet applied for a permit to construct. The project's 1.5-mtpa regasification capacity is expected to be sold to third-party offtakers, and the company is aiming to complete the project by the second quarter of 2022. Without greater LNG demand creation in the Philippines, however, open-access FSRU projects such as the proposal from Excelerate Energy may struggle to find offtake agreements necessary to underpin financial close.

## *PNOC Has Been Unsuccessful in Spearheading LNG Developments*

LNG development challenges have also faced state-backed project sponsors. The Philippines National Oil Company (PNOC) has sought an active role in the establishment of the country's first LNG import facility and has signed non-exclusive agreements with numerous international project developers. However, progress on PNOC partnerships and projects has repeatedly been bogged down by legal requirements under the Build-Own-Transfer (BOT) Law, regulatory guidelines for joint ventures, lack of a clear government policy on LNG development, and a lack of fiscal autonomy from government budgeting procedures.

After completing a framework study for an LNG project in 2017, PNOC received eight unsolicited proposals from various foreign and domestic project developers to construct an import facility. According to PNOC, all offers were rejected due to non-compliance with BOT rules and joint venture (JV) guidelines. The JV guidelines set strict legal, financial, and reputational eligibility requirements, while the BOT law stipulates that unsolicited proposals must involve new technologies and must not require government guarantees or subsidies.

Following the failed unsolicited process, PNOC solicited private sector partners through an open tender in November 2018, to which three firms submitted proposals. However, the PNOC board terminated the competitive selection process "due to the impending DOE issuance of Notice to Proceed to private-led LNG project/s."[38] PNOC leadership expressed public frustration to DOE, stating that legal

[35] Philippine Star. First Gen breaks ground for Batangas LNG terminal. May 29, 2019.
[36] BusinessWorld. First Gen plans LNG distribution expansion. October 30, 2020.
[37] ABS-CBN News. First Gen to begin LNG terminal construction in April. March 18, 2021.
[38] PNOC. PNOC Projects as of March 31, 2020, p. 1.

and fiscal restraints were preventing the company from pursuing LNG projects and that the law requiring Congressional approval of PNOC's budget was limiting the company's financial autonomy.[39]

Rather than spearhead its own LNG project, PNOC signed a memorandum of understanding (MOU) in February 2019 with Phoenix Petroleum—owned by Filipino business tycoon Dennis Uy—and China National Offshore Oil Company (CNOOC) to develop the Tanglawan LNG Hub, which had already received an NTP from DOE in December 2018. One year later, however, the project was put on hold. According to DOE officials, "The Tanglawan project, we were constrained to cancel their NTP as they essentially withdrew their plans as they were not able to reach financial close and had a few difficulties regarding their project proposal."[40]

Cancellation of the project was a shock, as many market watchers thought that with significant funding and a nearly certain market for imported gas due to Malampaya depletion, the project was a sure bet. In a 2018 report, Fitch Solutions posited, "After multiple calls for tenders and plenty of expressions of interest from a vast array of domestic and foreign firms, the keys to the Philippines' second LNG development appear to be held by Tanglawan LNG, which is reportedly winning the race to be the Department of Energy's choice to lead the project."[41] The request for suspension of the project was apparently due to a deal by Phoenix Petroleum's parent company Udenna Corp. to acquire Chevron's 45% stake of the Malampaya deepwater development.[42] There were also indications that suspension of the project was due to "backpedaling" by CNOOC, which reportedly ceased correspondence with other joint venture partners.[43]

In recent years, PNOC has signed MOUs to develop LNG facilities with Dubai-based Lloyd's Energy, China Petroleum Engineering Company Ltd., and, most recently, US natural gas developer New Fortress Energy. However, none of these agreements appear to have progressed beyond the initial stages. At a recent Senate hearing on the pending Midstream Natural Gas Industry Development Act (discussed further below), a DOE representative recommended including a provision to mandate PNOC participation in the natural gas industry. This highlights bureaucratic ambition but does not yet signal a pathway to easier progress on LNG project completion.[44]

[39] BusinessWorld. PNOC cites obstacles hampering LNG terminal project. December 20, 2018.
[40] Philippine Star. More firms to build LNG terminals. January 14, 2021.
[41] Asian Power. Malampaya is Running Out of Gas. What's Next? January to March 2019 edition, p. 24.
[42] Phoenix Petroleum. Clarification of News Article: "Phoenix-CNOOC Venture Junks LNG Terminal Project." December 18, 2019.
[43] Manila Bulletin. CNOOC may backpedal on LNG venture with Dennis Uy. August 31, 2019.
[44] YouTube. S. No. 1819 – Midstream Natural Gas Industry Development Act: Hearing before the Philippines Senate Committee on Energy. 18th Congress (January 12, 2021) (Testimony of DOE Assistant Secretary Leonido Pulido III).

## *Pagbilao LNG: A Cautionary Tale*

The Pagbilao LNG facility located in Quezon Province also provides a cautionary tale for developers considering investments in the Philippines LNG sector without any assurances of financial returns or regulatory certainty. The project is wholly owned by Australia-based Energy World Corporation (EWC), which began development in 2009 by signing a lease for the 215,000 $m^2$ property and disseminating project information to local government units (LGUs).

Initially expected online in 2011, the project has been repeatedly delayed and is now targeting commercial operations by 2024—15 years after EWC signed the original lease.[45] There is still little confidence this project will come to fruition, especially given that EWC has pushed back its target commercial operations date in every annual report for shareholders since 2011.

The project consists of a land-based LNG import terminal with a 3-mtpa throughput capacity, a 650-MW combined cycle power plant with three Siemens turbines (2 x 200MW and 1 x 250MW), and two 130,000$m^3$ storage tanks. In March 2014, EWC signed EPC contracts with Slipform Engineering International Ltd. to build the power plant at a price of $588 million and the LNG hub for $130 million.

Rather than pursue a PPA with Meralco or another offtaker, EWC intended the LNG-to-power plant to sell 100% of its electricity on a merchant basis into the Wholesale Electricity Spot Market (WESM). Gas would be sourced from EWC's Senkang LNG export facility in Indonesia or the international spot market. By 2016 it became apparent that the company had not made any arrangements to connect the power plant to the main Luzon grid, a surprising departure from traditional project finance in which grid connection agreements are secured before breaking ground on a new project.

In 2017, EWC stated it would begin acquiring right of ways from individual landowners to build a 12-kilometer, 230 kV transmission line to a new substation under construction by the National Grid Corporation of the Philippines (NGCP). In its 2016-2040 Major Network Development plan, NGCP said the substation would be operational by November 2019, but the company is now aiming for end-2022.[46] Funding requirements and transmission arrangements with multiple agencies—including DOE, NGCP, the National Transmission Corp., and the Grid Management Committee—have been cited as the main causes of delay for the interconnection.[47]

The failure to complete the grid connection has prevented EWC from drawing down a PHP6.75 billion (USD150 million equivalent) loan facility made available by the Philippines Development Bank, Landbank of the Philippines, and the Asia United Bank in September 2015. Drawdown of the loan is contingent on EWC meeting 49

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[45] Business Mirror. Is the government serious in having 'green' power in our energy mix? December 30, 2020.

[46] National Grid Corporation of the Philippines. Major Network Development Plan 2016-2040.

[47] Business Mirror. Energy woes: The PHL faces a dark future. September 27, 2018.

conditions precedent, of which 48 have been achieved. Grid connection is the last precedent that EWC must complete before accessing the loan.

Even once the power plant is connected, however, there is little guarantee EWC will be able to recover capital and financing costs due to its full exposure to the WESM. In the WESM, plants dispatch according to their short run marginal cost, or the cost of simply running the plant without fixed cost recovery. Given near-term volatility and long-term upward price risk of global LNG prices, imported natural gas is likely to be one of the more expensive marginal fuels, especially when competing directly with the near-zero marginal costs of renewables such as wind and solar (discussed in greater detail below).

As a result, without long-term PPAs, gas-fired plants are only likely to be dispatched in times of peak demand. And although EWC could theoretically sell gas from the regasification facility to other customers, the project is hundreds of kilometers away from other gas-fired power plants, which are all located in Batangas and would require significant additional infrastructure.

Without extended periods of time with high system marginal prices in the WESM, the EWC power plant is likely to have little opportunity to recoup the fixed costs of the power plant, the regasification facility, the associated infrastructure, or debt servicing costs. Moreover, price spikes in the WESM are limited by the regulated cap of PHP32/kWh, providing even less opportunity for capital cost recovery. As such, plants without offtake agreements face a high possibility of being stranded before yielding cost recovery or profitability.

**Given near-term volatility and long-term upward price risk, LNG is likely to be one of the more expensive marginal fuels.**

The lack of market fundamentals to support the LNG value proposition matter because EWC's Pagbilao LNG facility is the most advanced natural gas import project in the Philippines but is not expected to come online until 2024, if at all, due to regulatory delays. As a result of repeated delays, EWC has lost money and investor confidence. EWC's stock price, listed on the Australian Stock Exchange, has plummeted from over 40 cents per share in July 2017 to below 9 cents in January 2021, while the nearly completed assets in Pagbilao have become liabilities, incurring maintenance costs without generating revenues. Even if the project does enter service, there is little guarantee EWC can recover its capital costs or service its debt due to the lack of a long-term PPA and its exposure to the volatile wholesale spot market.

## Rapidly Evolving Legal and Market Structures Create High Risk of Stranded Assets for LNG Investors

Recent trends in the Philippines natural gas industry demonstrate broad-based interest from all types of market players in building out the country's regasification capacity and encouraging natural gas consumption. To date, however, none have been successful due to characteristics of the Philippines market. Some commentators have suggested that political considerations are to blame for project failures.[48] While this may be true to some extent, there are also fundamental financial and legal barriers hindering the outlook for the country's natural gas industry, such as (1) limited opportunities for thermal power projects to earn bankable contracts; (2) uncertain natural gas demand growth outside of the power sector; (3) the still immature legal and regulatory structures typically needed to support LNG; (4) implementation of retail competition and open access; and (5) rapidly declining cost curves for renewables and battery storage technologies.

### *Distribution Utilities' Procurement Processes and Opportunities for Bankable Contracts*

To achieve financial close for a thermal power project, sponsors typically require a bankable PPA from a creditworthy offtaker that guarantees capital cost recovery in the form of take-or-pay clauses, as well as variable fuel cost recovery from ratepayers (known as fuel cost pass-through). If demand for power is less than expected, the offtaker is required to pay for contracted capacity, thereby absorbing all market risk. This two-part structure is widely understood by lenders because it de-risks projects and makes it easier for banks to sell-down project debt to portfolio investors such as pensions and insurance companies. By finding ways to pass fuel price risk to power consumers, independent power producers (IPPs) have benefitted by securing external debt financing on a low-cost non-recourse or limited recourse basis.

In a January Senate hearing, LNG developer First Gen called for additional incentives to stimulate the country's natural gas industry, including provisions to mandate long-term power supply agreements with fixed offtake. According to the company spokesperson, such a provision would ensure project viability and support the development of customers for LNG import facilities.

In response, however, a Meralco representative pushed back: "In terms of mandates, we are extremely wary of proposals that require consumers to take business risks to prospective investors in the gas industry. The power industry has already learned from the effects of long-term take-or-pay provisions in the gas supply and power supply agreements related to Malampaya's development. Over the years the industry has tried to move away from such long-term take-or-pay mechanisms. This is because even when there are more cost-effective options available, long-term take-or-pay mechanisms can prevent industry from pursuing more efficient options."

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[48] Energy Voice. Politics muddy the race for first LNG in the Philippines. March 11, 2021.

The interaction was brief but critical, because it demonstrated the ways in which LNG importers' reliance on traditional, long-term project financing terms is incompatible with deregulated power market structures undergoing rapid technological innovation.

In recent tenders for additional contracted capacity, Meralco has demanded greater flexibility than traditionally more "bankable" terms of reference. In its July 2019 CSP for an additional 1,200MW and 500MW of brownfield generation capacity, the tenders required a straight energy price—also called a "fixed price bid"—rather than a two-part tariff composed of fixed capacity payments and variable costs. In effect, variable fuel costs could not be passed through to consumers, requiring generation companies to bear risks associated with fuel price volatility.

**LNG importers' reliance on traditional, long-term project financing is incompatible with deregulated power markets undergoing rapid innovation.**

The tenders also included carve-out clauses, which allow Meralco to reduce contracted capacity in the event of reduced demand or the implementation of Retail Competition and Open Access, the Renewable Energy Law, or other relevant laws (discussed in further detail below). These contract terms limit guaranteed cost recovery for power generation companies and hence could cause banks to conduct sensitivity analyses for debt service coverage ratios and debt service requirements.

In December 2020, however, Meralco held a CSP for 1,800MW of greenfield baseload capacity, in which it reverted to more traditionally bankable contract terms (see Figure 9 below). Although the terms of reference did not allow take-or-pay fuel volumes, it did return to a two-part tariff structure composed of fixed and variable costs, with variable costs passed through directly to consumers for years 11-20 of the contract.

## Figure 9: Comparison of Meralco CSP Terms of Reference

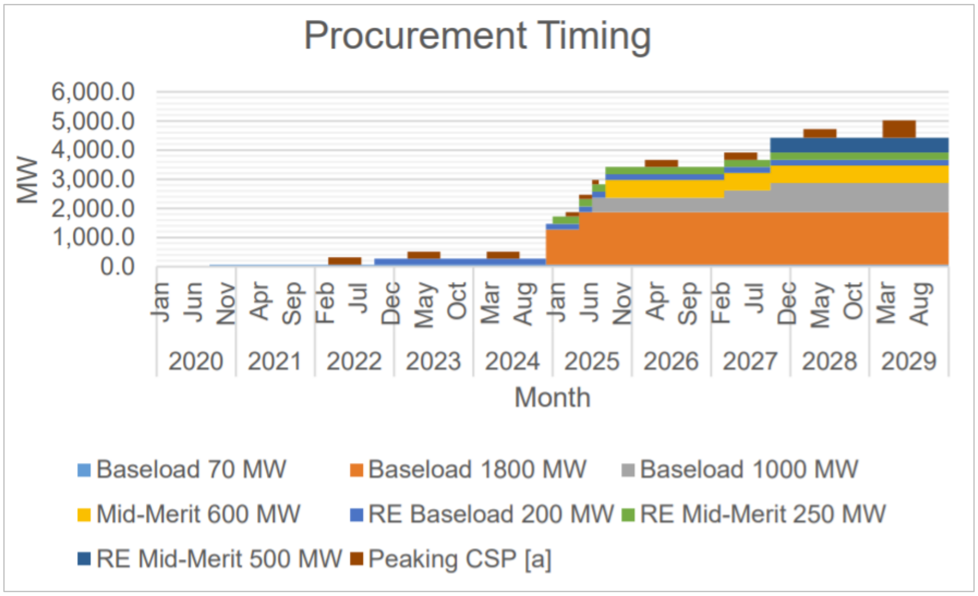
| CSP Criteria | 500MW Tender | 1,200MW Tender | 1,800MW Tender |
|---|---|---|---|
| **Date Posted** | July 17, 2019 | July 18, 2019 | December 3, 2020 |
| **Plant Type** | Mid-merit | Baseload | Baseload |
| **Project Operations Date** | December 26, 2019 (Brownfield) | December 26, 2019 (Brownfield) | Not installed before 2020 (Greenfield) |
| **Minimum Bid Offer** | 100MW | 200MW | 150MW |
| **Contract Period** | 5 years | 10 years | 20 years |
| **Tariff Structure** | Straight energy price (PHP/kWh). Minimum energy offtake no more than 75% plant capacity factor. | Straight energy price (PHP/kWh). Minimum energy offtake no more than 45% plant capacity factor. | Two-part tariff (fixed and variable costs).<br><br>Full fuel cost pass through years 11-20.<br><br>Fuel cost pass through for years 1-10 based on average of previous four quarters compared to initial forecasts.<br><br>No take-or-pay on variable costs. |
| **Outage Allowance** | No | No | Scheduled outages not exceeding 30 days. Forced outages not exceeding 15 days. |
| **Reduction in Contract Capacity (Carve-out)** | Allowed in case of demand reduction due to RCOA implementation or RE laws. | Allowed in case of demand reduction due to RCOA implementation or RE laws. | Allowed in case of demand reduction due to RCOA implementation, RE laws, or to avoid stranded capacity. |

*Source: DOE, Center for Energy, Ecology, and Development (2020).*

According to Meralco's power procurement plan for 2020-2029, the company expects total energy sales to grow 3% per year, notably much less than the country's anticipated 5-8% GDP growth rate. To meet supply growth during the period, the company expects to contract an additional 1,000MW of baseload and 600MW of mid-merit capacity through CSPs.[49] This total is less than 15% of the currently proposed 10,900MW of natural gas-fired power plants in the pipeline, representing a clear mismatch between supplier expectations and consumer demand profiles.

[49] Meralco. Power Supply Procurement Plan 2020-2029, p. 14.

## Figure 10: Meralco Procurement Strategy 2020-2029




| Supply Label | Type | Minimum MW [d] | Minimum MWh/yr | PSA Start | PSA End | Publication |
|---|---|---|---|---|---|---|
| Baseload 70 MW | Base | 70.00 | 537,600* | 09/2020 | 02/2037 | TBD |
| Baseload 1800 MW | Base | 1,800.00 | 13,824,000* | 12/2024 | 11/2044 | TBD |
| Baseload 1000 MW | Base | 1,000.00 | 7,680,000* | 07/2025 | 06/2045 | TBD |
| Mid-Merit 600 MW | Intermediate | 600.00 | 2,190,240* | 09/2025 | 08/2045 | TBD |
| RE Baseload 200 MW | Base | 200.00 | 1,314,000* | 10/2022 | 09/2047 | TBD |
| RE Mid-Merit 250 MW | Intermediate | 250.00 | 985,500* | 01/2025 | 12/2044 | TBD |
| RE Mid-Merit 500 MW | Intermediate | 500.00 | 1,976,400* | 10/2027 | 09/2047 | TBD |
| Peaking CSP [a] | Peaking | | | March | July | TBD |

*Source:* *Meralco Power Supply Procurement Plan 2020-2029.*

This mismatch between the current LNG project pipeline and Meralco's updated demand targets suggests that there is a disconnect between developers' aspirations and market fundamentals. Projects that proceed without offtake agreements will be highly exposed to volatile WESM prices and risk not being dispatched on merit, especially with the anticipated growth of zero marginal cost renewables and long-term upward price risk in global LNG markets. According to Meralco's procurement plan, energy efficiency programs and RCOA implementation are likely to limit the company's energy sales growth,[50] further reducing the need for large, centralized thermal capacity buildouts.

Despite the contrasting procurement methods in previous CSPs, it is clear from Meralco's power procurement plans and public statements that the company recognizes the inefficient price impacts of locking in long-term gas-fired generation capacity given the unpredictable trajectory of LNG prices and the declining cost curve for new renewable energy and storage technologies. As stated in USAID's

[50] Meralco. Power Supply Procurement Plan 2020-2029, p. 4.

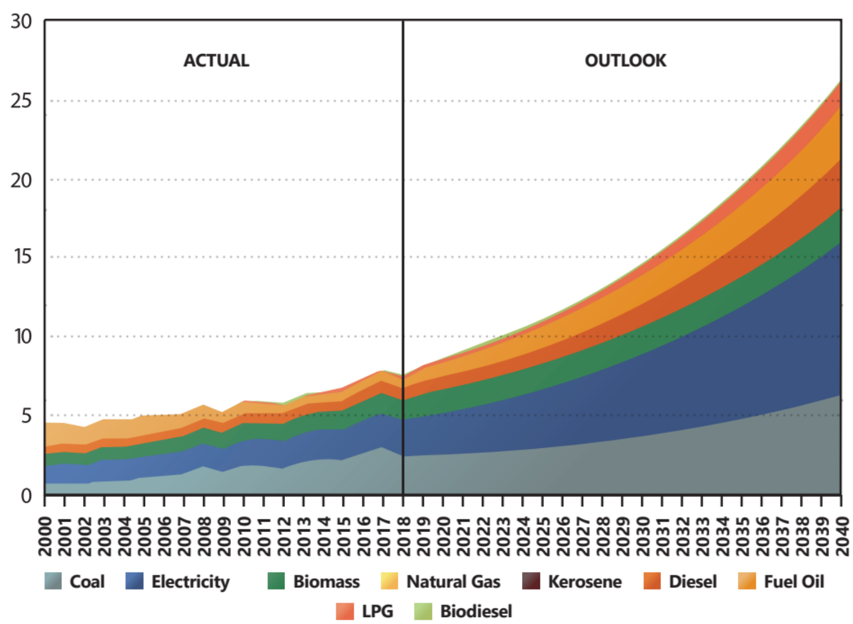
*Roadmap for the Development of Downstream Natural Gas Markets*, "It is notable that there are no real advantages in long term contracting. Long term contracts limit both the buyer's and seller's abilities to benefit from fluctuations in the market, and may limit end users' abilities to pursue alternative options (such as renewable resources)."[51]

## *Demand Creation in Non-Power Sectors*

One surprising gap in the debate about LNG's future in the Philippine energy mix is the question of whether other non-power users are expected to have sustainable demand for gas. This is an important omission because the economics of imported LNG in more mature gas economies is supported by a stable ecosystem of users with complementary demand profiles.

Currently, anchor demand for natural gas only exists in the power sector and there are no existing customers in the industrial, commercial, residential, and transport sectors. The Philippines Energy Plan 2018-2040 envisions almost no growth in natural gas demand in non-power sectors. Among industrial consumers, for example, demand is only anticipated to rise at an average annual growth rate of 0.40% to 2040.[52]

**Figure 11: Industry Final Energy Demand by Fuel (Million Tons of Oil Equivalent)**




*Source: Philippines Energy Plan 2018-2040, p. 31.*

[51] United States Agency for International Development (USAID). Roadmap for the Development Downstream Natural Gas Markets. September 1, 2020, p. 27.
[52] DOE. Philippines Energy Plan 2018-2040, p.32.

Moreover, according to DOE officials, the agency has no long-term demand forecasts for natural gas transport or pipeline services.[53] Long-term demand forecasts typically consider market growth scenarios, alternative fuel displacement, and changes in resource supply growth. As such, they are necessary to determine whether there is a definite need for capacity expansion and to allow the private sector to make key decisions on investments. Demand uncertainty will cause delays or cancellation of LNG import projects.

Recognizing the need to assess potential demand in these other areas, DOE commissioned a survey in 2019 of industries in Special Economic Zones (SEZs) and their willingness to switch fuel supply to natural gas. 63% expressed openness to switching fuels to natural gas.

However, the survey alone does not provide any assurance that industries will switch fuels once supply is made available. The survey was sent to over 1,600 operating firms in 61 manufacturing and agro-industrial SEZs, but only 115 firms responded. Along with this limited sample size, the study suggested that almost half of respondents had limited knowledge on the characteristics of natural gas or the technical and financial requirements to switch fuels.[54] Moreover, it was unclear as to what details, if any, regarding natural gas prices were provided to respondents, or whether respondents had any indication of the timeline or regulatory process involved.

**Limited prospects for high-volume adoption of natural gas in non-power sectors remains a major market risk.**

Given these uncertainties, along with a present lack of any gas transportation infrastructure, the limited prospects for high-volume adoption of natural gas to supply non-power sectors in the Philippines remains a major market risk for investors in LNG projects. This is particularly true given the challenges of formulating a credible post-COVID baseline for Philippine economic growth. Supply profiles must be matched to existing demand profiles, and it is extremely challenging to factor in build-up times for distribution infrastructure and gas demand. Lastly, more geographically diverse customers will require a major expansion of the gas transmission network, and a business model targeting industry and commercial sectors will be more complex, requiring more contracts for smaller offtake volumes.

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[53] YouTube. S. No. 1819 – Midstream Natural Gas Industry Development Act: Hearing before the Philippines Senate Committee on Energy. 18th Congress (January 12, 2021) (Testimony of DOE Assistant Secretary Leonido Pulido III).

[54] Gas Policy Development Project. Market Profiling with Emphasis on the Use of Liquefied Natural Gas (LNG) to Power Economic Zones. March 19, 2020, p. 17.

## *Evolving Legal and Regulatory Regimes for the Natural Gas Industry*

The large investments required to import LNG, construct gas transmission and distribution infrastructure, and create demand in power and non-power sectors make it especially critical to minimize risks in the development process. To do so, private investors often require clear legal and regulatory frameworks to ensure responsiveness and transparent decision-making. Currently, however, there are no laws specific to the natural gas industry in the Philippines, though legislation has been under discussion in Congress since 2018.[55] Legal changes are necessary given the introduction of new technologies and markets but can also result in stranded costs if plants are unable to deliver the economic returns expected during projects' planning stages.

Separate bills governing the midstream and downstream sectors are currently being developed by the Senate and House, respectively, but these are expected to take time to implement and refine for several reasons.

First, the laws are not meant to be standalone bills and will certainly require secondary legislation and implementing regulations that could take years to develop. For example, the midstream law requires gas transmission companies to operate through legislative franchise, which would require additional enabling legislation and could be a controversial process. Franchising allows the government to include the private sector in natural monopoly settings such as gas transmission and distribution, while the government regulator oversees compliance, contractual conditions, and tariffs. But there are currently no guidelines on how franchisees will be selected. Selection processes and requirements for legal clarification could delay the extension of gas supply infrastructure to potential customers and inhibit the growth of a domestic natural gas market.

In addition, the proposed laws assign regulatory functions to agencies that have no background in the relevant activities. For example, the Energy Regulatory Commission (ERC) does not engage in the regulation of natural gas transmission and distribution infrastructure. According to an ERC representative, developing the necessary organizational structure and building capacity could take at least two years.[56]

There are other factors that will take time to iron out before gas demand can grow to a level necessary to justify large investments in LNG infrastructure. Disclosure rules for private sector participants in the midstream gas industry are up for debate. Eminent domain provisions, which allow natural gas transporters to quickly construct and alter gas infrastructure, represent another unanswered question for investors and developers.

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[55] BusinessWorld. LNG law being drafted ahead of Malampaya supply crunch. September 2, 2018.
[56] YouTube. S. No. 1819 – Midstream Natural Gas Industry Development Act: Hearing before the Philippines Senate Committee on Energy. 18th Congress (January 12, 2021) (Testimony of Energy Regulatory Commission Director Sharon Montañer).

Lastly, competition rules for LNG industry players are developed over time, rather than in a single law. Applying third-party access (TPA) rules—defined as market players' legally enforceable right to access energy facilities owned by other companies—to regasification facilities is a widely debated topic. There are several reasons why owners of regasification terminals might not support third party access to their facilities, including potential loss of market share to competitors with access to cheaper LNG in global markets, as well as operational challenges, particularly concerning access and use of storage facilities.[57] With an unclear view on how competition rules will develop, it will be extremely difficult for potential investors in the Philippines gas market to gauge expected returns and payback periods.

## *Implementation of Retail Competition and Open Access*

The implementation of retail competition and open access (RCOA), which allows large power consumers in the Philippines to choose their own retail suppliers, will introduce new market entrants and greater competition for distribution utilities (such as Meralco), which essentially have monopolies over their designated service areas.

**Figure 12: RCOA Implementation Schedule**

| | | |
|---|---|---|
| Phase I | 1 MW and above | Complete |
| Phase II | 750 kW to 999 kW | Complete |
| Phase III | 500 kW to 749 kW | Feb. 26, 2021 |
| Phase IV | 100 kW to 499 kW | Jan. 26, 2022 |
| Phase V | 10 kW to 99 kW | Jan. 26, 2023 |

*Source: Philippines Electricity Market Corporation.*

Beginning in February 2021, large consumers with demand of at least 500kW became eligible to purchase power from retail suppliers outside their franchise area.[58] As the threshold is lowered and more captive consumers become contestable, increased competition will put pressure on distribution utilities to reduce costs for end-users and could ultimately lead to a reduction in contracted capacity required by distribution utilities. As of January 2021, 1,479 eligible customers have registered to participate in the RCOA market, representing 19,500GWh of annual energy consumption.[59]

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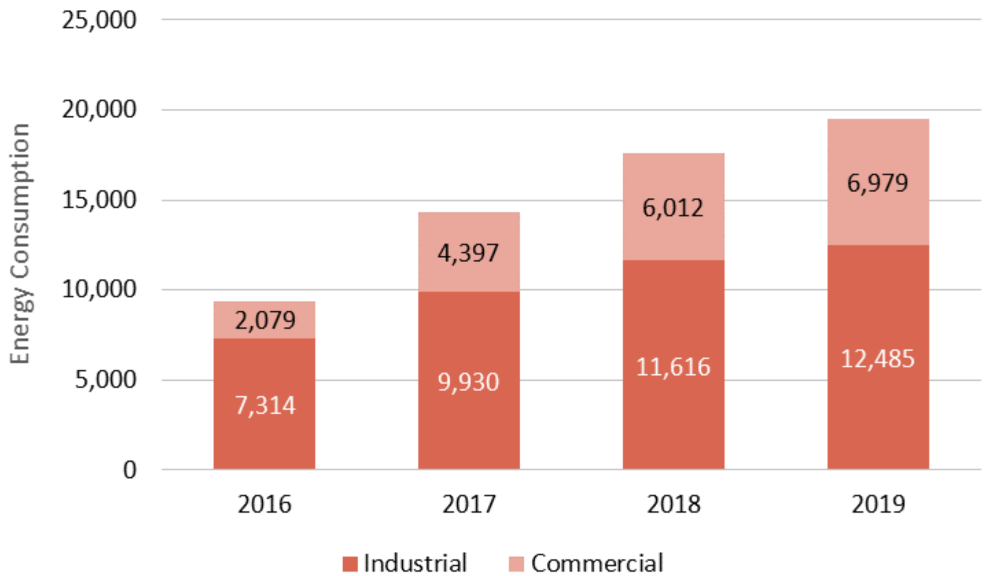
[57]. Sammy Six and Anne-Sophie Corbeau. Third-Party Access to Regasification Terminals: Adapting to the LNG Markets' Reconfiguration. King Abdullah Petroleum Studies and Research Center (KAPSARC)February 2017, p. 17.
[58] Manila Standard. ERC expands coverage of retail competition and open access. December 28, 2020.
[59] Philippines Electricity Market Corporation. Market Surveillance Committee Issues Paper on the Philippine Retail Competition and Open Access (RCOA) Market. January 2021, p. 11.

**Figure 13: Contestable Consumers' Energy Demand Growth (GWh)**




*Source: Philippines Electricity Market Corporation (January 2021).*

As a result of these changes, Meralco has proactively begun instituting carve-out clauses in recent PPAs. These clauses allow the company to reduce contracted capacity "equivalent to the reduction in the demand of captive consumers of Meralco in order to avoid stranded capacity or by reasons of the implementation of Retail Competition and Open Access, the Renewable Energy Law, or other Laws and Legal Requirements."[60] This presents a significant risk for investors and financiers of large, centralized thermal power plants, as curtailment could harm project returns and the sponsor's ability to service debt interest and principal payments. Any execution of the carve-out clause could mean the project is unable to deliver the economic return expected at the outset of the project.

In addition, regulations to make carve-out clauses automatic in all ERC-approved PPAs have been under discussion since 2017.[61] While carve-out clauses are currently triggered once the distribution company notifies the power supplier, automatic implementation would likely increase the frequency of contractual capacity reductions, adding risk to higher-priced thermal power providers.

Other policy developments could also trigger carve-out clauses, allowing distribution companies to reduce contract capacity under long-term PPAs. For example, the Green Energy Option Program (GEOP) will allow end-users with average peak demand over 100kW to contract directly with renewable energy suppliers. Contracts will be unregulated and not subject to ERC approval. In April

[60] Meralco. Invitation to Bid—Contract Capacity of 1,800MW (NET), COD 2024-2025. December 2020, p. 5.
[61] IEEFA. Carving Out Coal in the Philippines: Stranded Coal Plant Assets and the Energy Transition. October 2017, p. 30.

2020, DOE issued a regulation setting rules for issuance of GEOP operating permits for RE suppliers and is aiming to release a regulatory framework to govern the program in April 2021.

## *Declining Cost Curves of RE and Storage*

In light of changing market structures and evolving regulatory regimes, project sponsors and financiers must carefully assess the high risk of stranded assets for LNG projects in the Philippines. Similar to merchant plants without fixed offtake agreements, power producers exposed to carve-out clauses triggered by RCOA implementation can sell power into the WESM. But as the case of EWC's merchant Pagbilao LNG-fired power plant shows, projects will become exposed to price volatility in the spot market, where plants are dispatched according to marginal cost. Volatility in LNG markets is likely to continue in the near-term due to the COVID-19 pandemic and subsequent disruptions to global oil and gas supply chains.[62] As near-zero marginal cost renewables are added to the grid, investors can expect thermal generators at the mercy of volatile global fuel prices to experience lower utilization rates and plant efficiencies.

**As near zero-marginal cost renewables are added to the grid, thermal generators are likely to see lower utilization rates.**

First Gen's 420MW San Gabriel CCGT and 97MW Avion OCGT demonstrate that without PPAs, natural gas-fired power plants are likely to dispatch at lower rates. After coming online in late-2016, both plants were supplied by domestically sourced Malampaya gas and were initially operated on a merchant basis with full exposure to WESM prices. In 2017, San Gabriel's dispatch rate was 38.4%, while the less efficient Avion plant was dispatched only 19.2% of the year. In 2018, however, First Gen signed a six-year PPA (expiring February 2024) to sell San Gabriel's output to Meralco at an annual average capacity factor of 88%. The plant's dispatch rate subsequently increased to 61% in 2018 and 75.6% in 2019. The Avion plant, meanwhile, continues to operate on a merchant basis and was dispatched at rate of 14.7% and 23.2% in 2018 and 2019, respectively. This confirms typical market patterns seen when gas units compete directly in an economically efficient wholesale market: gas-fired plants, especially those running on more expensive imported gas, are likely to occupy peaker roles rather than provide baseload supply.

[62] IEEFA. Over US$50 billion in gas power projects and LNG import facilities at risk of cancellation in Bangladesh, Pakistan and Vietnam. January 14, 2021.

As mentioned, plants dispatch into the WESM according to their short run marginal cost, or the cost of simply operating the plant without consideration of fixed capital or operational expenditures. For thermal power plants, the cost of running the plant is directly related to the cost of fuel, which fluctuates in global markets based on various factors. Plants are dispatched in order of least cost—known as the merit order—until the amount of electricity generated equals the amount demanded at that time. The highest cost generator dispatched sets the system marginal price paid to all generators, while any generators with more expensive marginal costs than the clearing price sit idle.

For an LNG-fired power plant in the Philippines, short run marginal costs will be determined by fuel prices in the global market. According to Morgan Stanley, the Japan Korea Marker (JKM)—the benchmark spot price for LNG in Asia—is expected to average roughly $7.50/MMBtu.[63] Depending on the heat rate of the gas turbines, this fuel price would likely amount to a marginal electricity price of roughly PHP3,000-4,000/MWh (USD60-80/MWh). The average WESM settlement price in 2020 was PHP2,450/MWh (USD50.42/MWh), signalling the clear market risks for merchant gas-fired power plants dependent on global LNG prices. The Independent Electricity Market Operator of the Philippines (IEMOP) recently projected that prices would hover around PHP2,000/MWh (USD41.2) during the summer months of 2021.[64]

Low WESM prices in 2020 can largely be attributed to COVID-related electricity demand destruction, but prices have fallen even while electricity demand has grown. Average yearly settlement prices have dropped significantly from their peak of PHP8,100/MWh in 2010 despite electricity demand growing at an average annual rate of 5.4% between 2010 and 2019. If WESM prices decline further and LNG prices increase, merchant LNG plants will experience lower and lower dispatch rates, along with diminishing returns over their lifetime.

Price volatility in global LNG markets is likely to continue over the near-term. Following the outbreak of the COVID-19 crisis, demand destruction caused JKM prices to plummet to USD1.85/MMBtu in May 2020. However, due to production shut-ins, cold weather snaps in Asia, and shipping delays, prices skyrocketed to a record USD32.50/MMBtu in January 2021. The Texas energy crisis in February and the blocking of the Suez Canal by a container ship in April demonstrate the wide range of international factors that can influence LNG prices.[65] [66] In the long-term, global LNG markets are likely to tighten, adding upward pressure to prices.

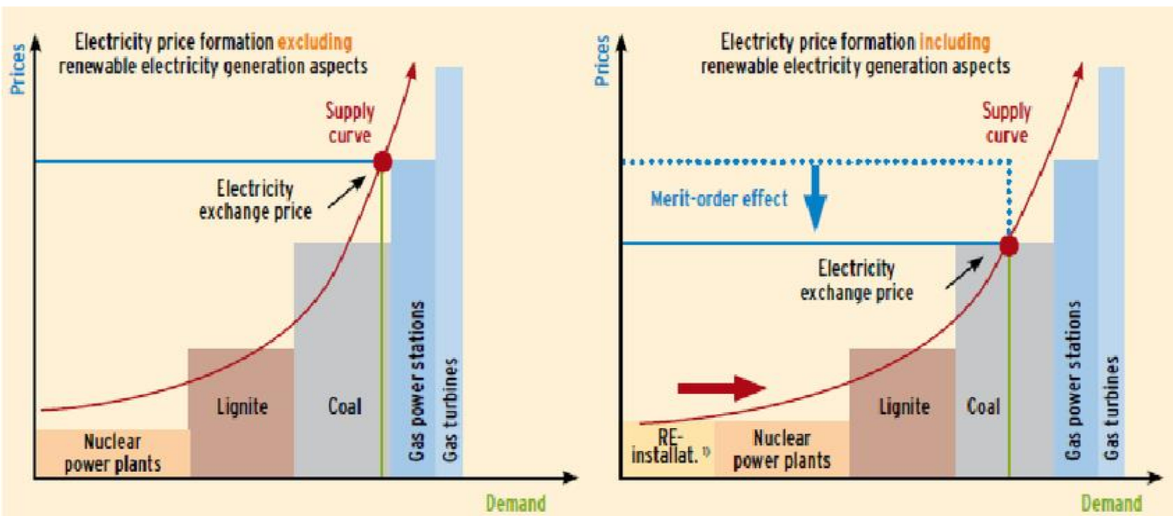
Volatility and long-term upward price risk therefore represent a serious threat to the utilization rates of potential LNG-fired power plants in the Philippines. Moreover, dispatch into WESM only considers recovery of variable fuel costs. For LNG sponsors to recover fixed costs of associated infrastructure—including

[63] Morgan Stanley. Global Gas & LNG: The Start of a New Cycle. January 25, 2021. p. 8.
[64] Manila Bulletin. WESM prices still seen at P2/kWh. March 22, 2021.
[65] IEEFA. Lessons from the Texas energy crisis for emerging LNG importers in Asia. March 1, 2021.
[66] Reuters. Asian spot prices rise as LNG tankers diverted from Suez. March 26, 2021.

regasification terminals, pipelines, and power plants—WESM prices must remain well above gas plants' short run marginal costs for extended periods of time. And while large price spikes in the market often comprise a key source of revenue for merchant generators, WESM prices are capped at PHP32/kWh, limiting opportunities for full levelized cost recovery.

While the short run marginal costs of thermal generators are determined mainly by volatile fuel prices, renewable energy sources like wind and solar can essentially run for free when the sun is shining or the wind is blowing. Renewables will therefore take priority in the merit order, crowding out more expensive thermal generators (see Figure 14 below). As more renewables are added to the market, gas-fired power plants are likely to go unused for longer periods of time.

## Figure 14: The Merit Order Effect

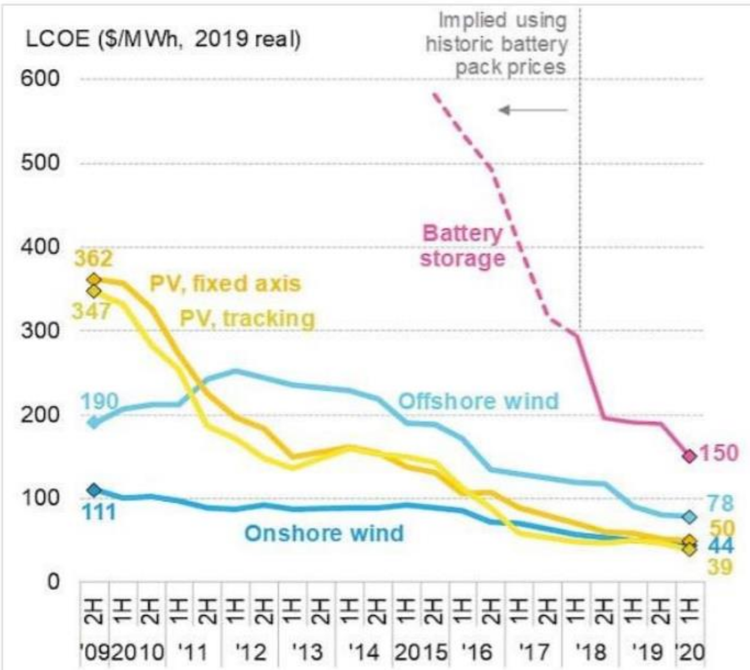



*Source: Benhmad, François. Wind Power Feed-in Impacts on Electricity Prices in Germany 2009-2013. 2015.*

Unless IPPs secure PPAs with guaranteed capacity payments, investors will bear the risk of stranded assets, which the International Energy Agency defines as "investments which have already been made but which, at some time prior to the end of their economic life (as assumed at the investment decision point), are no longer able to earn an economic return, as a result of changes in the market and regulatory environment brought about by climate policy." Even with PPAs, high marginal cost thermal generators unable to dispatch are still considered stranded assets, though the risks are borne by distribution companies and their captive consumers rather than investors in fossil fuel power plants. As such, all 10.9GW of LNG-fired power capacity in the current pipeline—with an estimated value of USD13.6 billion in total investment—is at risk of being stranded as the market adapts to lower cost renewable power generation.

Based on the experience of other markets, declining levelized cost curves for renewables and storage technologies must be expected to impact distribution utilities' procurement practices in coming years, limiting opportunities for thermal generators to win traditionally bankable offtake agreements. Levelized costs for solar photovoltaic and wind power have plummeted 90% and 70%, respectively, far outpacing cost declines in thermal technologies such as coal and natural gas. According to Bloomberg New Energy Finance, battery storage prices have fallen even more sharply since 2016 than wind and solar (see Figure 15 below).

## Figure 15: Battery Prices Have Fallen More Sharply than Wind and Solar




*Source: Bloomberg New Energy Finance.*

Studies of the South Korean and Australian markets found that levelized costs of offshore wind, onshore wind, and utility-scale solar are already cheaper than those of gas turbines.[67] In February 2018, Solar Philippines announced it could construct a solar plus storage facility at PHP2.34/kWh (USD0.044), below Meralco's then average generation rate of PHP4.74/kWh and well below the average rate of First Gen's San Gabriel gas plant at PHP5.44/kWh.[68][69]

The government's upcoming Green Energy Auction, expected in June 2021, is likely to confirm the downward cost trajectory of wind, solar, and other renewable technologies and encourage greater price discovery. Reverse auctions, in which electricity sellers (rather than buyers) submit bids to provide power, have been shown to result in lower electricity market prices in many advanced and emerging markets around the world. The initial auction will be for 2GW of renewable energy

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[67] Carbon Tracker Initiative. Whack-A-Mole: Will South Korea's coal power transition be undermined by overcompensated gas? April 21, 2020, p. 9.
[68] PV Magazine. Philippine utility Meralco receives Southeast Asia's lowest solar bid. August 13, 2018.
[69] PV Magazine. Solar Philippines bids $0.058/kWh in Meralco price challenge. February 2, 2018.

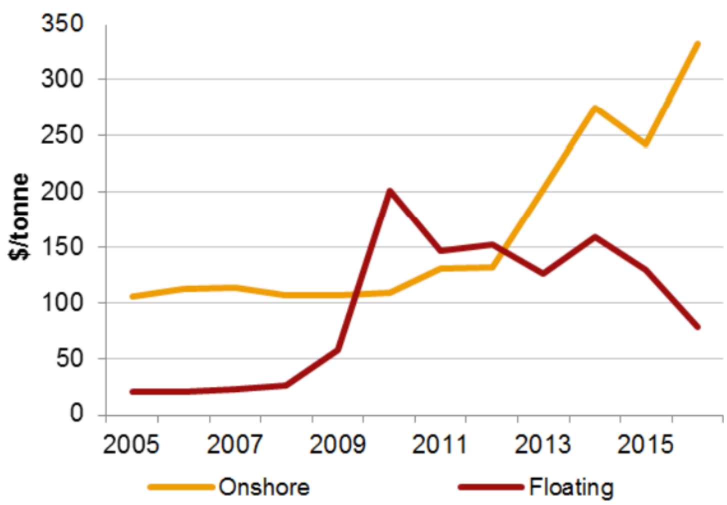
capacity, which, if conducted annually, could generate USD20 billion in clean energy investments by 2030.[70]

Implementation of the country's Renewable Portfolio Standard (RPS) will also stimulate renewable energy deployment at scale and contribute to lower prices in the electricity market. The National Renewable Energy Board's current target of at least 35% of renewables in the energy mix can be achieved with a 1% RPS to 2023, increasing to 2.52% thereafter. Discussions are ongoing to increase the RPS, which would ultimately result in nearly 56% of the energy mix coming from renewables by 2040,[71] reducing the need for large, baseload LNG-fired power plants.

The different tariff requirements of renewables versus fossil-fuel power will also reshape market outcomes. Specifically, renewable energy generators can provide a single, fixed price and do not require two-part tariffs covering fixed and variable costs. Deflationary cost trends for renewable technologies will become material concerns for investors in LNG facilities as large power offtakers shift their procurement strategies to limit PPA opportunities for gas-fired power plants.

The deflationary trends in renewable energy prices contrast upward price trajectories of projects in the LNG supply chain and volatile fuel prices globally. For example, construction costs for onshore regasification terminals rose 12% per year from 2008 to 2018 for both brown and greenfield projects.[72]

### Figure 16: Regasification Costs Based on Project Start Dates




*Source: International Gas Union, 2017 World LNG Report, p. 53.*

While upfront capex requirements of FSRUs are approximately 60% of onshore terminal costs, operating costs are 50% higher and can become more expensive in

[70] IEEFA. Paying Less for More – How Auctions Can Transform the Philippines Power Sector. February 2020.
[71] Business Mirror. Government urged to tweak renewables policy. November 30, 2020.
[72] International Gas Union. Triennium Work Report – Pathway to Liquidity for LNG in the Energy Market. June 2018, p. 29.

the medium to long-term due to higher vessel leasing rates.[73] According to the International Gas Union, "for LNG import facilities required for 10 years or longer, a fixed onshore terminal is usually more cost effective, due to their lower [operational expenditure] costs."[74] FSRUs also have less storage capacity, limiting flexibility of supply and increasing the need for immediate procurement upon consumption. An average onshore terminal has 0.26-0.70 bcm of storage capacity, compared to just 0.17 bcm for FSRUs.[75]

FSRUs are also not immune to project risks, even in the most promising emerging LNG markets. According to data from Global Energy Monitor, the failure rate of FSRU projects since 2012 has been higher than the failure rate for onshore terminals.[76] FSRUs are also difficult, if not impossible, to operate in extreme weather conditions—a critical risk proposition given the Philippines' geographic location on the Pacific Typhoon Belt. Countries such as Bangladesh and Malta have been unable to operate FSRUs and related gas-fired power plants due to inclement weather.

Overall, the risk-return profiles of renewable power should be far more enticing for potential investors in the Philippines energy sector than LNG-related projects. According to Imperial College's Centre for Climate Finance & Investment, renewable companies have demonstrated significantly greater returns for investors across portfolios in advanced and emerging economies. Globally, renewable power companies generated 10-year returns of 422.7%, compared to just 59% for global fossil fuel portfolios (see Figure 17 below). As policies in the Philippines such as RCOA, the RPS, and the GEOP accelerate and allow renewables to compete directly with fossil fuel power plants, LNG-fired power plants are likely to deliver lower-than-expected returns to unsuspecting investors.

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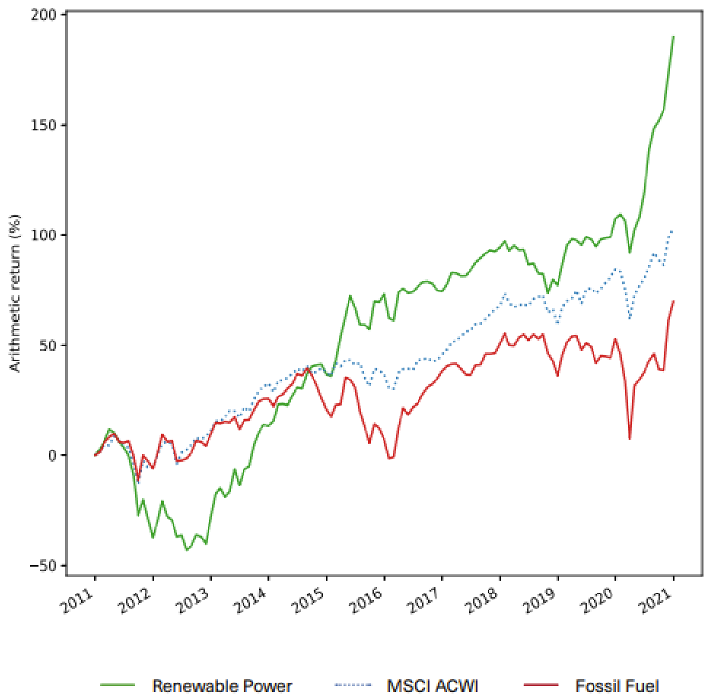
[73] Lydia Plante et. al. Gas Bubble 2020 – Tracking Global LNG Infrastructure. Global Energy Monitor. July 2020, p. 14.
[74] International Gas Union. Triennium Work Report – Pathway to Liquidity for LNG in the Energy Market. June 2018, p. 29.
[75] Asia Pacific Energy Research Center. Changing LNG Market Dynamics—Implications for Supply Security in the APEC Region. August 25, 2020, p. 12.
[76] Lydia Plante et. al. Gas Bubble 2020 – Tracking Global LNG Infrastructure. Global Energy Monitor. July 2020, p. 14.

### Figure 17: Global Markets Portfolio—10-year Monthly Returns




*Source: Imperial College Business School. Clean Energy Investing: Global Comparison of Investment Returns. March 2021, p. 14.*

## Conclusion

Many of the impediments to natural gas market development in the Philippines—such as lack of non-power demand, lack of existing infrastructure, nascent legal and regulatory regimes, etc.—will take years to overcome. As renewables prices continue to drop and global LNG markets tighten to increase fuel costs, LNG-related investments will become increasingly uncompetitive in the Philippines market, especially as smaller electricity consumers become eligible to choose their retail suppliers. Rapidly declining cost curves for renewables demonstrate that long-term pricing has shifted in favour of renewable energy growth. As policies in the Philippines accelerate the transition to clean energy, natural gas-fired power plants reliant on volatile imported fuel prices will realize fewer opportunities for long-term guaranteed returns.

In sum, there is a diminishing argument to be made for an LNG development pathway that could enhance the risk of large-scale fossil gas infrastructure lock-in given current trends in technology development and market structure evolution. And with only a small existing natural gas anchor market, potential LNG investors will have little commercial opportunity without demand growth in non-power sectors. Going forward, investors will have to take on significantly greater market risk. Whether they will be willing to do so remains to be seen.

# About IEEFA

The Institute for Energy Economics and Financial Analysis (IEEFA) examines issues related to energy markets, trends and policies. The Institute's mission is to accelerate the transition to a diverse, sustainable and profitable energy economy. www.ieefa.org

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Sam Reynolds, Energy Finance Analyst for IEEFA, is a former political and regulatory risk analyst focusing on global commodity markets. He has a master's degree in energy economics and international environmental law from Johns Hopkins University. He has also lived and worked throughout Asia and published extensively on Asian energy issues.