Small-scale LNG

MAN Energy Solutions
Future in the making

Powering the future of
Asia's island communities

Author

Dipl.-Ing. MBA
Carsten Dommermuth
MAN Energy Solutions SE,
Germany

Senior Manager
International Business Development
+49 821 322 2580
carsten.dommermuth@man-es.com

List of abbreviations

ASEAN	Association of Southeast Asian Nations
CO_2	Carbon dioxide
COD	Commercial operating date
DF	Dual fuel (engine type according to the diesel cycle capable of operating on a multi fuel strategy)
EPC	Engineering, procurement and construction
FDI	Foreign direct investment
FSA	Fuel supply agreement
GTCC	Gas turbine combined cycle
HFO	Heavy fuel oil
HHV	Higher heating value
IDC	Interest during construction
IC	Internal combustion engine
IEA	International energy agency
IPP	Independent power producer
IRR	Internal rate of return
LHV	Lower heating value
LNG	Liquefied natural gas
LTSA	Long term service agreement
BTU	British thermal unit
MTPA	Million tons per annum
NO_x	Nitrogen oxides
OECD	Organisation for economic co-operation and development
OEM	Original equipment manufacturer
O&M	Operating and maintenance
PPA	Power purchase agreement
SI	Spark ignited (engine according to the Otto cycle)
SO_x	Sulfur oxide
WACC	Weighted average cost of capital

Table of contents

Executive summary

Small-scale LNG has the potential to support particularly remote areas and islands with the cleanest fossil fuel available for power generation. Due to the operation flexibility it can be seen as a perfect match with the fluctuating renewables like wind and solar power for investment in a sustainable future energy mix.

This paper analyses three decentralized LNG-powered solutions of 67 MW, 95 MW and 220 MW with reference to potential sites in remote locations in the ASEAN region.

These installations have the potential to substitute mainly old diesel or HFO fired installations with electrical efficiencies below 30 % and a high proportion of related emissions e.g. CO_2, NO_x, particulates and SO_x.

An internal analysis showed that engine-based power generation in the ASEAN region in particular has an average age of over 20 years and is mainly based on old diesel engines up to 7 MW. Today's engines offer state of the art dual fuel flexibility above 48 % of electrical efficiency as a two-stage turbocharged prime mover with a single unit output of 20 MW.

The selected sizes of highly efficient dual fuel engines within this paper can add between 526 GWh (67 MW) and 1760 GWh (220 MW) under base load operation to the local communities and support a sustainable economic development with cost-effective base load power available 24/7.

Due to the low per capita electricity consumption in the region, these solutions are able to supply electricity to more than 2 million people in the Philippines and 8 million people in Myanmar, for example, where the electricity consumption per capita is only 217 kWh per annum.

Electricity generating costs and financial profitability for the selected power plant sizes under competitive market conditions

All scenarios with new power plant equipment, taking today's engine performance and costs for the power plant into consideration, could reach a positive result from an investors, prospective.

- The internal rate of return (IRR) for a 220 MW power plant is 18 % and the generating costs under base load operating for 8000 operating hours per annum 73 €/MWh.[1]
- Operating profit with a WACC of 12 % over a project lifetime of 20 years is up to EUR 900 million for the 220 MW solution.
- With a reduced gas price of 35 €/MWh and a sale price of 90 €/MWh the IRR is 8.5 % with related generating costs of 49 €/MWh.
- Operating profit with a WACC of 12 % over a project lifetime of 20 years is up to EUR 400 million for the 220 MW solution.

Financial profitability for new power generation equipment including the LNG infrastructure under ceteris paribus assumptions

Depending on the local at site and logistics conditions, both scenarios indicated a financial situation.

For the LNG transport scenario from a central hub and regasification at the power plant site:

- The IRR for the 220 MW project was 14.8 % with a sale price for electricity of 120 €/MWh and a gas price of 44 €/MWh.
- Operating profit with a WACC of 12 % over a project lifetime of 20 years is up to EUR 600 million for the 220 MW solution and the payback time is approx. 6 years.

For the regasification at a central hub and transport of natural gas to the power plant site via pipeline:

- The IRR was 17 % under the same conditions.
- Operating profit with a WACC of 12 % over a project lifetime of 20 years is up to EUR 800 million for the 220 MW solution and the payback time is approx. 5 years.

[1] Based on a gas price of 44 €/MWh and a sale price for electricity of 120 €/MWh

Success criteria

Competitive market conditions and project management expertise

To reach a profitable and bankable project result for a small-scale LNG-to-power project, an extensive PPA linked to the fuel price must be available to attract investors and secure a debt repayment out of the project cash flow. The overall project IRR should be in the range of at least 12-15 % to attract local and/or foreign direct investments (FDI). Along with the natural gas supply, this must be extensively organized and linked to the PPA and the off-takers agreement. Only companies which are able to supply the entire value chain of project development, LNG handling and power generating equipment should be contracted for these types of complex project structures.

LNG/natural gas offtake – as much as possible

Challenges can be seen in the project complexity, high upfront costs for the LNG infrastructure and the current incentives for small-scale LNG-to-power solutions. Especially if the local use of LNG is limited to a reduced amount of off-take for e.g. a small-scale power plant only. Cross-selling opportunities to sell huge quantities of LNG out of a central hub are needed as a lever to make the entire project feasible and economically attractive for investors.

Policy support for tariff design

In many ASEAN countries, small-scale LNG-to-power needs policy support for introducing and promoting a tariff which supports the high investment costs for the infrastructure and the development costs. It also needs support in promoting additional off-take for LNG/natural gas, for example, for factories, manufacturing plants and hotels and other off-takers such as the transport sector.

Winning strategy

Making use of a "hub and spoke strategy" – or using the local LNG terminal and infrastructure to sell high volumes of LNG to various consumers is currently the most interesting opportunity. For this, project developers must have an overview of the entire value chain from LNG purchase, logistic concepts and local long-term LNG/fuel agreements through to a PPA/FSA connected with a profitable and strong fuel price to reach as many final consumers as possible.

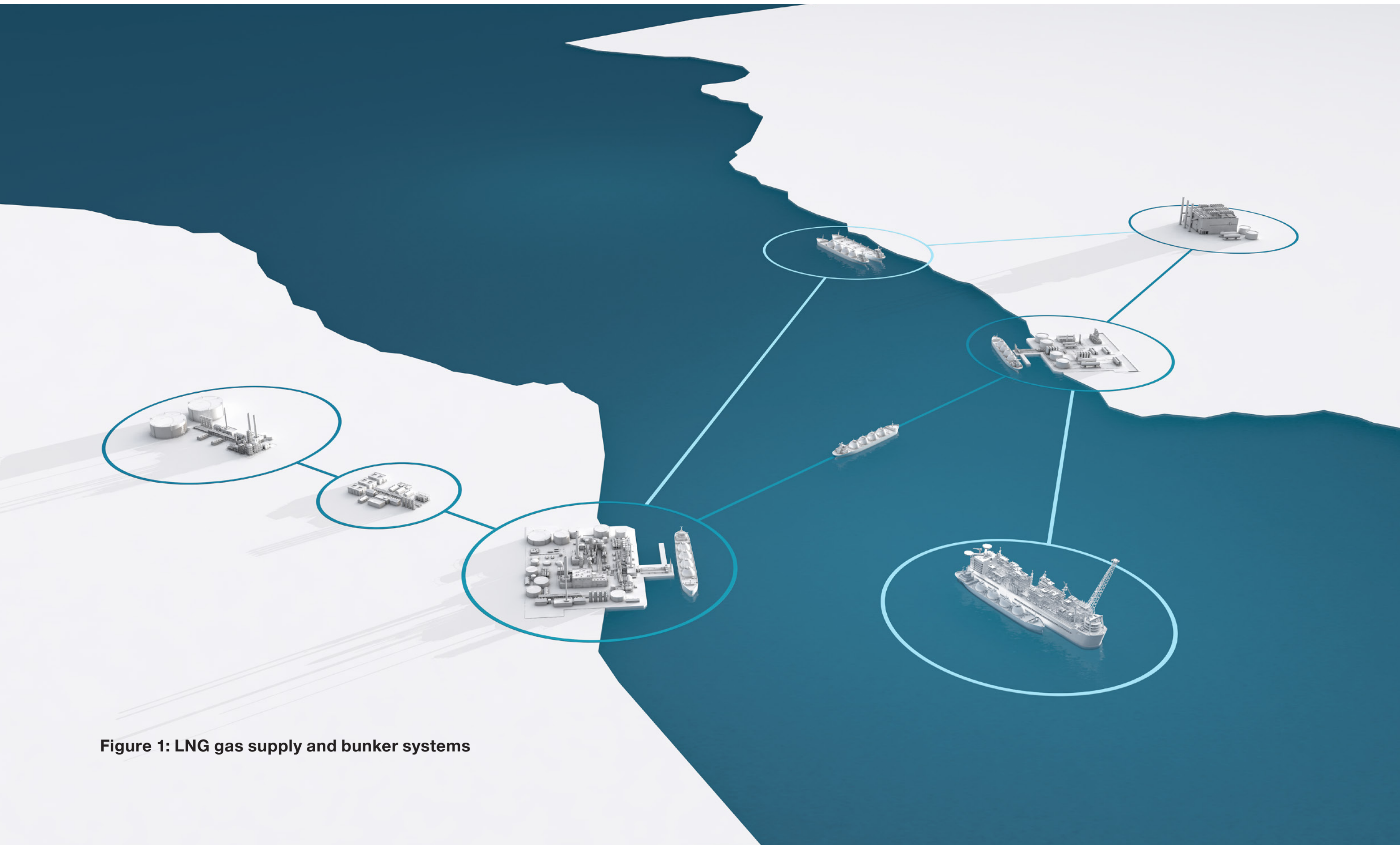

Figure 1: LNG gas supply and bunker systems

From large-scale to small-scale LNG solutions

The commercial success of liquefied natural gas (LNG) as a trading commodity essentially began with the first large-scale production in January 1997 at Train 1 at the north field facility of Qatargas. The LNG was shipped to Japan.

After the first large additional lighthouse projects mainly in the Gulf States, the entire LNG supply chain developed with a tremendous pace.

Natural gas as LNG is now available literally everywhere and offers an attractive alternative to a pipeline supply which always has the risk of being dependent from a single source or one supplier.

In its 2011 World Energy Outlook (WEO), the IEA claimed it was the “Golden Age of Gas”. However, this did not materialize to the expected extent. The renewables, photovoltaics and wind power took over the momentum for new installed capacities on the global power markets and gas as fuel for the energy industry is now an important bridge technology, to support a clean energy mix or a backup if the sun is not shining or the wind not blowing.

The new trend which has emerged from this is the decentralization of power generation, a reduced number of annual operating hours for large power plants and higher requirements with regards to the flexibility of assets.

When the USA entered the global gas market with their huge amount of shale gas in 2010, the entire well-established supply and demand structure no longer existed. [Yergin, 2012]

As one result, global gas and oil prices declined and natural gas for power generation today is more and more competitive and in case of CO_2, NO_x, SO_x emissions and particulates the cleanest fossil fuel available on the market.[2]

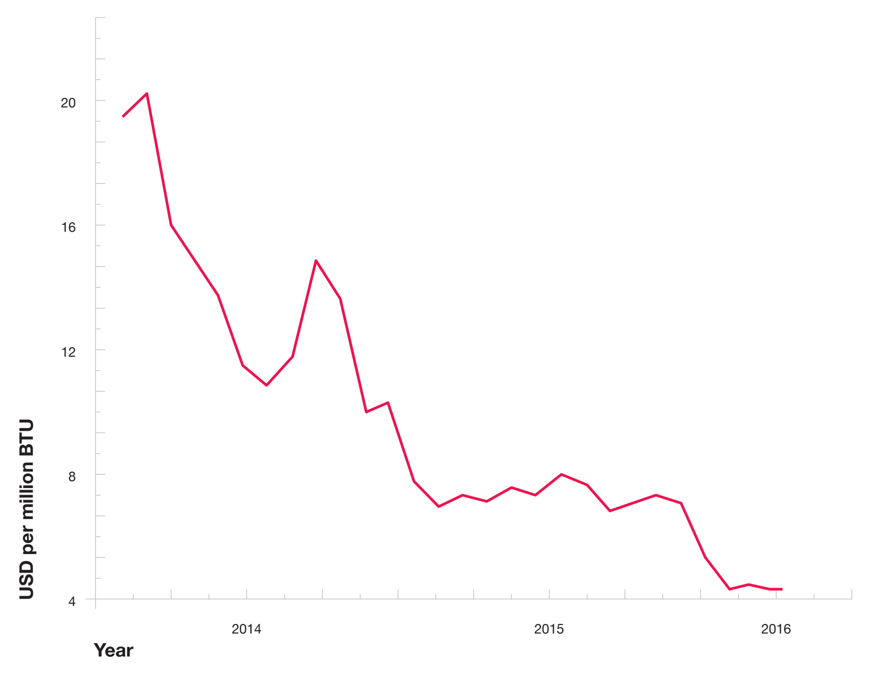

Figure 2: Asian LNG spot price development 2013-2017 in USD/MMBTU

For example the bunker price for HFO380 in Singapore was at the 29th of June: 469 USD/mt converted into USD/MWh - 41,07. In comparison to the same date the Asian LNG sport price was 10,3 USD/MMBTU – 35 USD/MWh.

[2] Current LNG spot price in Asia has rebounded within 2018 to a price of 10.40 USD/MMBTU in September 2018.

In parallel to the game changing development of the LNG market, confidence in technical and commercial handling and establishing the supply chain on a global scale, a smaller market for decentralized small-scale LNG solutions has developed. The main driver for this was the establishment of large local LNG hubs from which LNG is distributed via smaller carriers to decentralized locations. (“Hub and spoke”)

Today, small-scale LNG solutions have huge potential due to their scalable size and flexibility to supply particularly remote locations or small islands with LNG as a complementary fuel or as a new primary fuel for cleaner electricity production in comparison to diesel or heavy fuel oil.

In many regional energy policy scenarios, especially in Asia, LNG is playing a more and more important role because it has the potential to encourage countries to move from a costly liquid fuel to a more flexible fuel strategy which makes use of the global LNG market opportunities. With the included sizeable storage option of small-scale LNG solutions they are also able to cover and “hatch” additional volatility peaks on the global markets. [Sufi, 2018]

Short to mid-term LNG supply contracts provide countries and generating companies with a huge amount of bargaining power vis-à-vis multinational LNG suppliers in negotiating the best gas price for their gas-fired power plant fleet and related consumers.

Large LNG producers like Shell are also using this momentum and establishing themselves in the lucrative value chain in a move from a former exclusive fuel supplier to a now more active solution provider.

Value chain integration is e.g. mentioned by PricewaterhouseCoopers (PwC) as one of the success criteria in strategic positioning in the small LNG business. This establishes a “first mover advantage” which includes the ability to build partnerships alongside the LNG value chain. [PwC, 2017]
For example, in 2016, Shell signed an agreement with the Government of Gibraltar to supply the newly built decentralized and highly efficient engine power plant with LNG.

“This agreement includes the construction of a small regasification unit that will receive, store and re-gasify the LNG arriving by ship for use in Gibraltar’s adjacent gas-fired power plant, which is already under construction. The regasification unit will be operated by Gasnor, a 100 % Shell-owned subsidiary with over ten years of operational experience in LNG for marine and small-scale LNG in North Western Europe. The unit will also include a berth for a small LNG carrier that will supply the LNG at night, minimizing disruption to the neighbouring port, airport and housing estates. There is also potential for LNG bunkering operations in the future, following the appropriate environmental assessments and safeguards.”
[Shell, 2016]

For the new LNG-fired power plant in Gibraltar, MAN Energy Solutions was contracted to supply the engine technology for a perfect match of small-scale LNG infrastructure plus a highly efficient, decentralized power plant, meeting the best in class emission and environmental standards in the region. The new power plant will consist of three 14V51/60G gas and three 14V51/60DF dual fuel engines.

Figure 3: Small-scale LNG-fired power plant in Gibraltar

SWOT analysis for small-scale LNG-to-power solutions

Strengths	Weaknesses
– Available and competitive technology for small-scale LNG-to-power solutions – Scalable to demand development – Meets short term price fluctuations – Prepares the local energy industry with a flexible fuel strategy – Uses the strong bargaining power by purchasing in bulk and from the world market (spot prices) – Creates and stimulates a fuel switch from oil to gas	– Attractiveness for investors: Makes high upfront investment for development attractive for various stakeholders (Sourcing and promotion of FDI) – Challenges in making a small-scale LNG-to-power projects bankable; cross-selling business opportunities for additional off-takers are necessary – High expertise necessary for coordination work of various stakeholders and providing an overview of the entire value chain – High level of business development and technology partnership with foreign companies necessary – Currently a lack of regulatory framework to support small-scale LNG-to-power projects (e.g. lack of attractive combined PPAs, tax incentives, loan support)
Opportunities	**Threats**
– Cost saving potential for entire life cycle and generating electricity – Switch from coal- and oil-based power generating to a clean and lucrative dual fuel strategy based on natural gas – Opportunity to use the LNG-to-power infrastructure as well for “Power-to-X and bio gases” – Support of renewables in the local energy mix with a flexible power plant solution – Reduce emissions, mainly CO_2, SO_x and particulates	– For countries: Missing the right time to restructure the energy industry towards a sustainable and competitive generating mix – Stuck with an aging coal- and oil-based generating mix – Ongoing payment of government cash for a subsidised energy industry in remote areas with technology which is no longer state of the art

Table 1: SWOT for small-scale LNG-to-power solutions

Value chain management as core competence and success criteria for small-scale LNG-to-power solutions

Small-scale LNG-to-power projects

Small-scale LNG-to-power is defined as the solution combining LNG storage[3], transportation[4] and regasification with highly efficient production of electrical power.[5]

From the customer perspective, the business motivation is to receive in a "one stop solution" all equipment needed for converting LNG into electrical power.

The core competence of the OEM and EPC company is to match the right sizing under the current and future demand scenarios for the LNG infrastructure and the related power plant output.

Supplying the entire valve chain can be seen as a core competence of an OEM:

1. Proven track record in executing cryogenic and power plant projects.
2. Proven experience in various unloading solutions for LNG (cryogenic handling).
3. Competence in designing storage solutions and handling gas running profiles, depending on the operation, shipping routes, capacity and supply structure.
4. The design of the regasification system.
5. Boil-off gas handling (only if required).
6. The electricity generating design process based on the best available technology.
7. The entire operating and maintenance (O&M) of the installation to keep the availability and reliability as high as possible.
8. Deliver support in early project development, EPC setup and support in project finance.
9. Establish partnerships alongside the value chain, which also includes possible LNG suppliers and a supply strategy. Only a few companies worldwide offer this core competency. For utilities and/or IPP´s it is important to consider this complex project structure in the very early stages and transfer this into a realistic planning scenario.

From the business experiences of MAN Energy Solutions and their LNG company MAN Cryo, a project timeline of 4-5 years can be seen as realistic from the early project development and tendering phase to the commissioning of the entire small-scale LNG-to-power solution.

Important milestones in developing small-scale LNG-to-power projects

Milestone	Duration in years	Remarks
Pre-development phase and feasibility study	Up to 0.5 years	Depending on the competence and available resources, an extensive business model must be the basis for a positive investment decision
Project development phase up to financial close	Up to 1.0 year	Incl. PPA negotiation, FSA, land-lease agreement, EPC contract, O&M/LTSA contract, loan agreement and project finance
From notice to proceed: Construction period of LNG infrastructure and power plant (in parallel)	1.5 years	Construction phase with related interest during construction (IDC)
Mobilization and commissioning phase: Contractor's Certificate of Completion and handover to the client	0.5 years	LNG and power plant commissioning phase, training, mobilization of operational team, first loading of LNG, start of commercial operation
To ensure project success, it is necessary to guarantee a fast construction time, to lower the IDC and start commercial operation in time to secure an early positive cash flow		

Table 2: Project milestones for a small-scale LNG-to-power project

[3] Below 50,000 m^3

[4] LNG carriers with approx. 30,000 m^3 capacity as supply vessels for small-scale LNG-to-power projects

[5] The sourcing and the best fuel supply strategy and the related contract management and hatching instruments of LNG are excluded from this analysis.

Supporting remote locations in Asia with a hub and spoke strategy for LNG-to-power projects

Current trends, especially in Asia's booming economic areas such as the Philippines and Indonesia, show that these areas are looking very likely to take the lead in introducing LNG as a clean alternative to cheap and polluting coal and expensive diesel- and heavy fuel oil-based power generation.

For example, the current tendering phase in the Philippines for the LNG terminal on the main island of Luzon offers a great opportunity for introducing the hub and spoke approach in supplying remote areas or smaller islands with LNG out of a large central terminal.

Out of these large-scale LNG terminals, LNG can be distributed by smaller LNG carriers – or using a "milk ship/milk-run" system – to supply local small-scale LNG receiving terminals.

Small-scale LNG solutions combined with highly efficient dual fuel power plants to support sustainable regional development

Matching today's electricity demand with future development under various scenarios is the real challenge in sizing a small-scale LNG-to-power project.

The approach within this paper in finding the right size for small-scale LNG-to-power solutions which correlates to the per capita electricity consumption and the opportunity to finance and realize the project under today's market conditions.

For that reason, we will start with the analysis of the per capita electricity consumption of selected ASEAN countries.

Selected ASEAN Country	Electricity consumption per capita in kWh (2014[6])
Philippines	700
Indonesia	812
Myanmar	217
Cambodia	271
Thailand	2540
Vietnam	1411

Table 3: Energy consumption per capita for selected ASEAN countries based on information provided by the World Bank Group, 2014

[6] https://data.worldbank.org/indicator/EG.USE.ELEC.KH.PC?end=2014&name_desc=false&start=2014

The result is a wide range of electricity consumption per capita with the highest in Thailand and the lowest in Myanmar.

By sizing various power plant solutions and the related produced electricity under a base load scenario with 8000 full load operating hours and plant outputs of approx. 67 MW, 95 MW and 220 MW, electricity can be supplied to approx. 8 million people in Myanmar – in comparison to approx. 250000 and 135000 in Germany and the United States as examples of western OECD states with a high level of consumption.

Per 1000 people	67 MW	95 MW	220 MW
Philippines	765	1085	2514
Indonesia	660	935	2167
Myanmar	2470	3502	**8110**
Cambodia	1978	2804	**6494**
Thailand	211	300	692
Vietnam	379	538	1247
Germany	76	108	**251**
USA	41	58	**135**

Installed power	Produced electricity MWh	GWh
67 MW	536,000.00	536
95 MW	760,000.00	760
220 MW	1,760,000.00	1760

Table 4: Potential number of people who can be reached with an electrical power supply of various outputs

The small-scale LNG value chain in combination with highly efficient decentralized power plant solutions has the potential to be a real game changer not only in the ASEAN region.

It offers the potential to pay a “triple dividend” to:

- **The environment with a clean fuel**
  reducing the CO_2 emissions in comparison to coal to a level of approx. 50 % and close to 100 % for particulates.
- **The final consumers in remote locations**
  up to now normally supplied by coal, diesel or oil based heavy fuel power plants, and now supplied with cleaner electricity.
- **The government’s budget**
  which can be reduced by substituting the subsidies of the fuels for power generation in particular with the instrument of a more flexible dual fuel strategy in sourcing from the global spot market in a more short- to medium-term scale.

And last but not least, it will prepare the local energy industry and its mainly state-owned utilities and fuel companies for the upcoming disruptive increasing share of renewables in the power grid. This will require less annual operating hours and more flexibility of the power plant asset from all established stakeholders in the fossil fuel business.

Where to play – potential Asian markets for small-scale LNG solutions

The Philippines

The electricity sector in the Philippines provides electricity through power generation, transmission, and distribution to the final consumers. The Philippine grid is divided into three main electrical grids, one each for Luzon, the Visayas and Mindanao.

Installed power

As of December 2017, the total installed capacity in the Philippines was 22,000 MW (megawatts), of which 14,500 MW was on the Luzon grid.

Fuel for electrical power generation

The dominant fuel for power generation was coal in all three grids, which results in high emissions for CO_2, particulates and NO_x, but in overall lower electricity generation costs due to the currently low coal price. In all three grids, oil-based power generation is number two, which is due to the average age of the installations from a cost perspective the most expensive source of power generation. It constitutes approx. 20 % of the total annual generation mix for all three grids.

Natural gas

Natural gas, as the cleanest fuel for power generation, is only in use in the Luzon grid. The supply is guaranteed via a 550 km pipeline from the Malampaya gas field, operated by Shell. The expectation is that the Malampaya gas field will end production in 2024[7], which means that the newly installed gas-fired power plants on the island will need an LNG strategy or an alternative in place very soon.

[7] Reuters: 14.03.2018: https://energy.economictimes.indiatimes.com/news/oil-and-gas/philippines-says-new-oil-gas-discovery-has-commercial-quantities/63301531

Opportunities due to an LNG supply strategy

An LNG strategy due to the production end of the Malampaya gas field offers a wide range of opportunities for the Philippines electricity sector as a whole in all three grids:

1. It can lower the annual amount of CO_2, particulates and NO_x emissions by replacing old diesel engines and old coal-fired power plants with an electrical efficiency of 30 % and less.
2. On a competitive level in combination with small-scale LNG solutions, it can create a new highly efficient, dispatchable and flexible gas power plant infrastructure using mainly the established sites and sizes for electricity feed-in.
3. Save government money and cut the high level of subsidies for electricity generation on the islands. This is caused by the high price of diesel and HFO supply and low efficiency technology for electricity production.

	Electricity production in GWh (total)	Coal-fired plants (MW)	Gas-fired plants (MW)	Diesel/HFO-fired plants (MW)
Luzon	66,498	5625	3446	2518
Visayas	12,955	1054	–	730
Mindanao	11,345	1370	–	906

Table 5: Power generation indicators by grid in 2017 – fossil-fired only

Sources: Department of Energy (DoE)[8, 9]

Installed base of internal combustion engines (IC) and average age of the installations within the three grids

Installed diesel engine capacity:

- 4100 MW out of 22,000 MW for the total installed capacity on the Philippine grid in 2017
- 22 years average age[10]

[8] Department of Energy, as at June 2018: https://www.doe.gov.ph/sites/default/files/pdf/energy_statistics/01_2017_power_statistics_as_of_20_march_2018_summary_04112018.pdf

[9] https://www.doe.gov.ph/sites/default/files/pdf/energy_statistics/02_2017_power_statistics_as_of_20_march_2018_capacity_per_type.pdf

[10] Based on MAN Energy Solutions internal research by UDI Platts Database

Potential for small-scale LNG-to-power – supporting local business with a stable electricity supply

Mindanao grid

- Mindanao has an installed diesel fleet of approx. 900 MW with an average age of over 20 years.
- The gradual introduction of LNG could substitute the HFO- and diesel-fired installations. The largest diesel power at Mindanao, the Mapalad Power Corp with 103 MW, is as a benchmark, in terms of size, for the introduction of the first new mid-sized LNG-fired gas engine power plant.
- With modern and more decentralized power plant equipment, the high blackout rates at Mindanao could be massively reduced and the installations can attract business which needs a stable and cost competitive electricity supply.

Visayas grid

- The grid has approx. 730 MW of diesel engines installed with an average age of 24 years.
- The CEBU Ermita (Cebu Private Power Corp) with 70 MW of HFO-fired diesel engines is a benchmark for a small-scale design powered by LNG.
- As in Mindanao; With modern and more decentralized power plant equipment, the high blackout rates at Visayas could be massively reduced and the installations can attract business which needs a stable and cost competitive electricity supply. “15-hour blackout cripples businesses in Bohol.”[11]

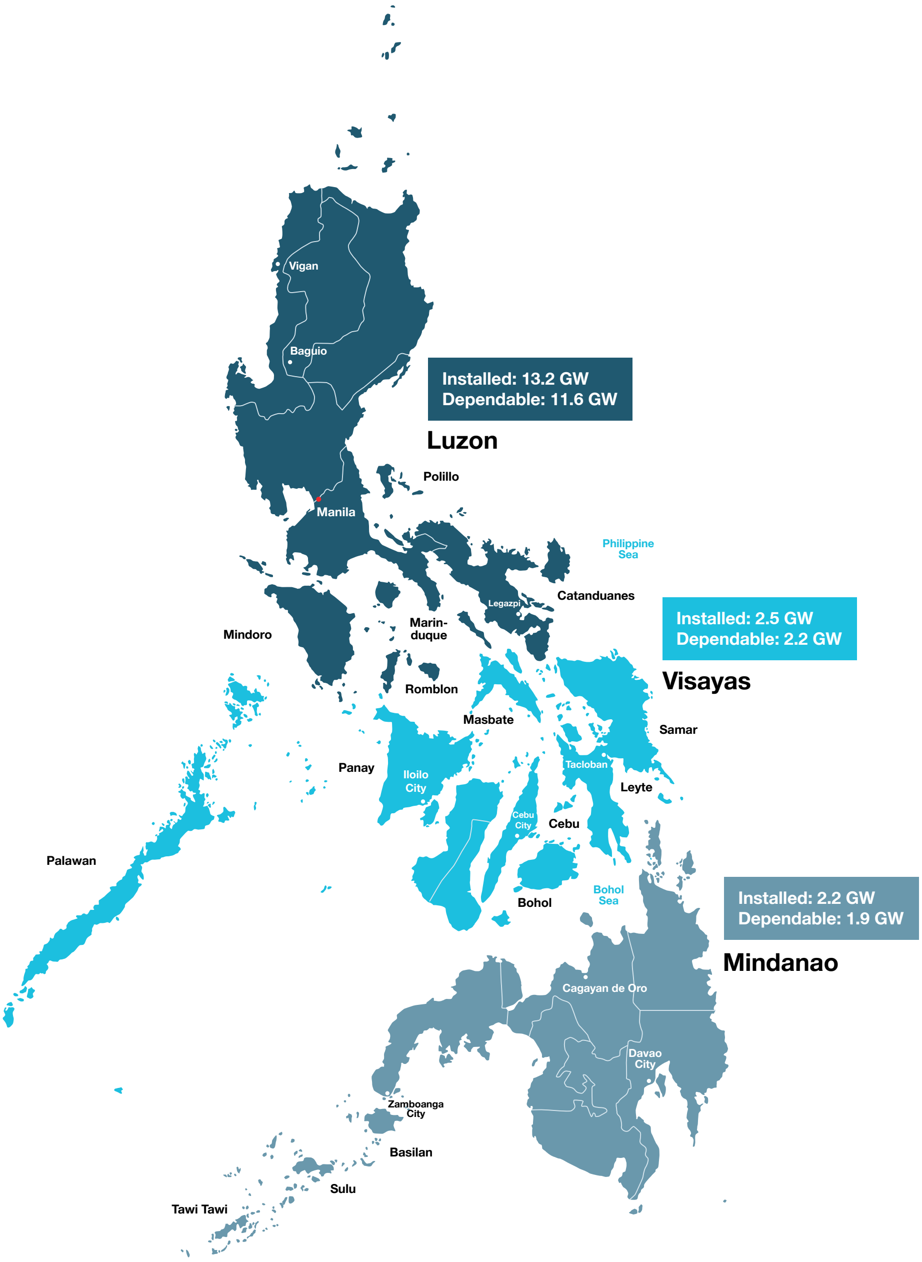

Figure 4: Electricity grids of the Philippines

[11] http://newsinfo.inquirer.net/949290/15-hour-blackout-cripples-businesses-in-boho-ngcp-bohol-power-grid-blackout-tagbilaran

Sizing the right power to demand

In order to support the decentralized areas of the Philippines grid, in this paper we will take the reference sizes for the small-scale LNG-to-power plants and analyze the technical and economic performance:

Milestone	67 MW plant capacity	95 MW plant capacity	220 MW plant capacity
Power plant solution	Dual fuel internal combustion engines type **18V51/60DF (4x)** Single cycle	Dual fuel internal combustion engines type **18V51/60DF (6x)** Single cycle	Dual fuel internal combustion engines type **18V51/60DF (13x)** Single cycle
Pilot fuel (LFO)	1 %	1 %	1 %
Indicative EPC pricing without project-related development and permission costs	750 €/kW	750 €/kW	750 €/kW
Maintenance costs under natural gas operation	4.5 €/MWh	4.5 €/MWh	4.5 €/MWh
Emission regulation compliant with	World Bank 2007/08	World Bank 2007/08	World Bank 2007/08

Table 6: Milestones for each power plant

Reference scenario description for small-scale LNG-to-power in the ASEAN region

The main criteria used within this paper are listed below.

Location and at site conditions:

- For the reference scenarios, we are expecting a remote location for the small-scale LNG-to-power scenario which can be reached with an LNG ship with a transport capacity of approx. 30,000 m³.
- The best case scenario would be to use existing power plant sites with related infrastructure and already available sites and access to the high voltage grid.

Small LNG carriers – TGE Marine References

30,000 m3 LNG carrier:
Owner: CNOOC
Yard: Jiangnan Sipyard
Classification: CSS (ABS)
Completion: 2015
Scope: **cargo systems, fuel gas system, cargo tanks**

15,600 m3 LNG carrier:
Owner: Anthony Veder
Yard: Meyer-Werft
Classification: BV
Completion: 2012
Scope: **cargo systems, fuel gas system**

Figure 5: Small-scale LNG carriers
Source: TGE 2017

Electricity consumption

- We are expecting a maximum electricity consumption of 3000 GWh per annum.

Natural gas price available at site (LHV) for power generation at COD

- 12 USD/MMBTU – 35 €/MWh in a "best price" scenario
- 15 USD/MMBTU – 44 €/MWh in a "high price" scenario Escalation rate for fuel 2 % annual – Euro/USD: 1.16

Electricity tariffs and generating costs on the islands

- With reference to the Philippines as one of the highest in the region:[12]
  - We calculate an expected (subsidized) sale price for electricity of 90 €/MWh (104.4 $/MWh) for larger consumers.
  - Real production costs of electricity are expected to 130-140 USD/MWh or 114-123 €/MWh.

LNG unloading and transportation to the power plant

- In the scenarios, we expect that the LNG will arrive at a central small-scale LNG terminal on an island.
- The longest distance from the LNG terminal to the power plant site will be 25 km.
- From the LNG terminal, we expect two possible scenarios:
  - **Scenario 1:** LNG transport from the central LNG terminal via trucks and regasification at the power plant site.
  - **Scenario 2:** Regasification at the central LNG terminal which includes the investment in the terminal, the regasification and a short distance natural gas pipeline to the power plant site.

Power plant design and operation

- The power plant will be operated under base load with 8000 full load hours per year – a capacity factor of 91 %.
- Prime mover is a highly efficient and flexible dual fuel engine – type 51/60DF in single cycle operation.
- A backup fuel can be used without any impact on efficiency if the LNG ship cannot reach the unloading site e.g. due to bad weather conditions.
  - 67 MW based on 4 x 14V51/60DF
  - 95 MW based on 6 x 18V51/60DF
  - 220 MW based on 3 x 18V51/60DF
- It needs to be possible to store the LNG at the power plant site for two days.

The deliverables derived from this analysis

1. LNG logistics and power plant concept.
2. Technical proposal for the LNG infrastructure.
3. Based on a non-binding assumption, for information only, a calculation of estimated electricity generation costs including CAPEX and OPEX costs for the small-scale LNG-to-power solution.
4. A first indication of the financial profitability (financial modelling) for future tariff calculation based on various sales prices of electricity.

[12] http://www.meti.go.jp/press/2016/03/20170327003/20170327003-1.pdf

Logistic concepts for the fuel supply to the power plant sites

- **Scenario 1:** LNG transport from the central LNG terminal via trucks and regasification at the power plant site.
- **Scenario 2:** Regasification at the central LNG terminal which includes the investment for the terminal, the regasification and a short distance natural gas pipeline to the power plant site.

LNG infrastructure for the supply of the power plant sites

Scenario 1: “LNG from the central hub via trucks”

	67 MW plant capacity	95 MW plant capacity	220 MW plant capacity
	Power plant capacity		
Gas consumption	14,605 Nm³/h	20,224 Nm³/h	47,568 Nm³/h
LNG consumption	24 m³ LNG/h	34 m³ LNG/h	79 m³ LNG/h

Table 7: Power plant capacity

	67 MW plant capacity	95 MW plant capacity	220 MW plant capacity
	LNG storage capacity		
Storage capacity under base load operation at site	2044 m³	2832 m³	6661 m³
Storage requirements at site – emergency reserve	2 days	2 days	2 days
Fuel consumption between unloading	1 day	1 day	1 day
	584 m³	809 m³	1,903 m³
Heel	292 m³	405 m³	952 m³

Table 8: LNG storage capacity

	67 MW plant capacity	95 MW plant capacity	220 MW plant capacity
LNG transport from LNG terminal with trucks to the power plant sites			
Volume in each load	40 m³	40 m³	40 m³
Trucks needed per day (12 hours)	4	5	12

Table 9: LNG transport from LNG terminal to power plant sites by truck

Scenario 2: "Natural gas pipeline"

Gas supply via natural pipeline including one regasification facility at the main LNG terminal.

It goes with saying that a power plant site close to the LNG terminal would be the perfect match. But due to a more realistic scenario, we would introduce the pipeline scenario as well.

The estimated price for the pipeline ("1 million €/km") can easily be eliminated if the power plant site is close to the LNG terminal.

	67 MW plant capacity	95 MW plant capacity	220 MW plant capacity
Distance to power plant site	20 km	25 km	10 km
System pressure	10 bar	10 bar	10 bar
Estimated costs	€ 20 million	€ 25 million	€ 10 million
	1 x main compressor station excluded		

Table 10: Properties of a natural gas pipeline

Please note: In the case of a gas turbine solution, the investment in a single compressor station or one at each site will increase due to the higher gas pressure needed from approx. 30 bar.

Cost information for LNG and gas infrastructure

The expected costs for the LNG infrastructure are listed below:

	67 MW plant capacity	95 MW plant capacity	220 MW plant capacity
EPC[13]	€ 6.75 million	€ 6.85 million	€ 15 million
Specific/kW	100 €/kW	72 €/kW	68 €/kW
LNG hub with truck filling*		€ 14.8 million	
Trailer for LNG-ready trucks 20-25 trucks needed		€ 160 t each – only LNG part	

Table 11: Cost information for LNG and gas infrastructure

* The LNG hub will use 7 x 3000 m³ storage capacity

[13] Without civil costs

Technical and economical assumptions for the power plants[14]

	67 MW plant capacity	95 MW plant capacity	220 MW plant capacity
Natural gas price available at site (LHV) in two scenarios	35 €/MWh 44 €/MWh	35 €/MWh 44 €/MWh	35 €/MWh 44 €/MWh
Light fuel oil (pilot fuel)	40 €/MWh	40 €/MWh	40 €/MWh
Power plant solution	Dual fuel internal combustion engines type **18V51/60DF (4x)** Single cycle	Dual fuel internal combustion engines type **18V51/60DF (6x)** Single cycle	Dual fuel internal combustion engines type **18V51/60DF (13x)** Single cycle
Pilot fuel (LFO)	1 %	1 %	1 %
Indicative EPC pricing without project-related development and permission costs	750 €/kW	750 €/kW	750 €/kW
Maintenance costs under natural gas operation	4.5 €/MWh	4.5 €/MWh	4.5 €/MWh
Emission regulation compliant with	World Bank 2007/08	World Bank 2007/08	World Bank 2007/08
Weighted Average Cost of Capital (WACC)	12 %	12 %	12 %
Equity (to loan)	70 % (30 %)	70 % (30 %)	70 % (30 %)
Loan costs	5 %	5 %	5 %
Construction time	18 months	18 months	18 months

Table 12: Technical and economical assumptions for power plants

[14] Data and results not binding! Data and results intended as an indication and for information only. At site conditions: Reference temperature 25 °C at 50 masl.

LNG infrastructure – Technical concept

LNG vaporization plant

Engineering, procurement, construction and commissioning of a liquefied natural gas (LNG) vaporization plant including LNG storage tank, LNG pump, vaporizers, and control system.

The LNG will be delivered by a LNG ship. The liquid will be stored, vaporized and pressure controlled before being sent out.

Time schedule

Main equipment (LNG tanks) has a manufacturing time of about 12 to 14 months.

Installation time at site is expected to be 12 weeks.

Total project schedule is estimated to 18 months.

Basis for small-scale LNG infrastructure design

Objectives

The objective of this chapter is to establish the principal design data and design criteria for the system. The system comprises the equipment as stipulated in the section on scope of supply. The main objectives of the engineering activities of the contractor for the system are as follows:

- Comply with clients' HSE requirements
- Establish a firm, optimized and cost effective design of the system using "Proven Technology and Equipment"
- Ensure that all requirements concerning occupational health and safety and the environment are met in full by the authorities

Natural gas composition

The system design is based on the following typical LNG composition:

Components		Vol %
Methane	CH_4	94
Ethane	C_2H_6	4.7
Propane	C_3H_8	0.8
Butane	C_4H_{10}	0.2
Nitrogen	N_2	0.3
Carbon dioxide	CO_2	-
∑		**100 %**

Table 13: LNG composition

- Methane number: 83
- Lower heating value: 49.5 MJ/kg

LNG tank filling conditions

The following design conditions shall apply:

Supply at B.L.	Unit	Design data
Pressure	bar(g)	Max 5.0
Flow (max)	m^3/h	100 – 1000
Temperature	°C	-159 @ 1.0 bar
Density	kg/m^3	425

Table 14: LNG tank filling conditions

Send-out capacity of natural gas

	67 MW plant capacity	95 MW plant capacity	220 MW plant capacity	Remark
Regasification capacity	3700 Nm³/h 14,600 Nm³/h	5000 Nm³/h 20,300 Nm³/h	11,900 Nm³/h 47,600 Nm³/h	Min 25 % Max 100 %
Gas pressure @ battery limit	5.5 to 9.0 barg	5.5 to 9.0 barg	5.5 to 9.0 barg	
Gas temperature @ battery limit	+ 5 to 50 °C	+ 5 to 50 °C	+ 5 to 50 °C	Temperature depending on supplied water by the CLIENT
Daily consumption of LNG	584 m³	809 m³	1903 m³	
Annual consumption of LNG	213,200 m³	295,300 m³	694,600 m³	

Table 15: Send-out capacity of natural gas

Operation mode

- **Normal operation:** Continuous operation 24 hours per day
- **Startup time:** Less than 15 minutes
- **Abnormal operation:** In case of send out above or below stated figures; the system is not in normal operation
- **Operation hours:** 8000/year

Minimum LNG storage volume at each power plant

The capacity is based on continuous truck deliveries with a two-day reserve.

	67 MW plant capacity	95 MW plant capacity	220 MW plant capacity	Remark
Required LNG storage volume	2044 m³	2832 m³	6661 m³	For 3 days operation

Table 16: Minimum LNG storage volume at each power plant

LNG storage volume at LNG hub

The capacity is based on continuous LNG carrier deliveries with a two-day reserve.

	3-day turnaround	7-day turnaround	Remark
Required LNG storage volume	7000 m³	12,500 m³	For 3-day operation and 2-day reserve

Table 17: Required LNG storage volume at LNG hub

Scope of supply

LNG tank

Insulated tank with a volume according to the table below.

	67 MW plant capacity	95 MW plant capacity	220 MW plant capacity	Remark
LNG storage volume	3000 m^3	6000 m^3	12,000 m^3	Alternative 1000 m^3 tanks can be offered
Design pressure barg	4	4	4	
Number of tanks (pcs)	2	1	4	
Diameter	8.0 m	8.0 m	8.0 m	
Length	~55 m	~55 m	~55 m	
Weight	~250,000 kg ~1,310,000 kg	~250,000 kg ~1,310,000 kg	~250,000 kg ~1,310,000 kg	Empty Full

Table 18: Properties of the LNG tank

Power plant solution and operating model

Technology selection

The selected technology is based on highly efficient dual fuel (DF) internal combustion engines with a high electrical efficiency in converting natural gas into electricity.

Dual fuel engine technology is selected so that there is always an option of supplying electricity as a "second fuel strategy" the event of interruptions in the gas supply.

Internal combustion engines in comparison to gas turbines for potential sites in the ASEAN countries are selected for the reasons below:

- They have far less impact in case of de-rating due to ambient conditions.
- Higher fuel efficiency per produced kWh of electricity and less associated CO_2 emissions/kWh.
- Dual fuel engines offer the highest efficiency in single cycle operation in comparison to open cycle gas turbines. Approx. 33-38 % for an open cycle gas turbine vs. 45-48 % for a single cycle gas engine solution.
- Less investment in available gas infrastructure at site (gas compressors) – Dual fuel engines need approx. 6-8 bar out of the gas supply system and gas turbines approx. 30 bar of the available gas pressure.

The benefits in the technical assessment for the dual fuel engine solution are:

- Modulated power plant design and flexible in case of a later extension.
- Low de-rating due to ambient conditions in comparison to gas turbines. Gas engines generate the same output in the temperature range from -30 °C to + 40 °C.
- No influence in case of de-rating for the altitude from 0 to 1500 m above sea level.
- No equivalent full-load hours for start-stop scenarios in grid services in comparison to open cycle gas turbines.
- Fast construction time with max. 1.5 years – impact on interest during construction (IDC).
- Reduced water consumption (low environmental footprint with radiator cooling).
- Low CO_2 footprint with natural gas 202 g/kWh.
- High technical availability above 90 % per annum.

For operation under grid support operation:

- Maximum step changes of dual fuel engines: In 5 seconds 10-30 %; and a control range of 40-100 %.
- Fast ramp-up time to 100 % within 25-40 seconds incl. grid synchronization (hot-stand-by).
- High efficiency in part-load operation (reduced CO_2 footprint in load following).

Electricity generating cost model

In electrical power generation, the distinct ways of generating electricity incur significantly different costs.

The cost is typically given per kilowatt-hour or megawatt-hour. It includes the initial capital for the EPC part and project assets and development, the discount rate, as well as the costs of continuous operation, fuel, and maintenance.

It is a measure of a power source which attempts to compare different methods of electricity generation on a consistent basis. It is an economic and technical assessment of the cost to build and operate a power-generating asset over its lifetime.

The electricity generating cost model can also be regarded as the minimum cost at which electricity must be sold in order to break even over the lifetime of the project.

Ceteris paribus analysis of electricity generating costs

In newly built power plant projects, the cost of electricity per produced MWh is most influenced by the operating expenses (OPEX). Within the OPEX, the fuel price has the largest impact on the generating costs. Approx. 80 % of the OPEX are fuel costs.

In this part of the paper, we analyze under a Ceteris Paribus (cet.par.) scenario[15] the impact of different fuel prices on the cost of electricity/MWh.

- **Scenario 1: "Low LNG market price"**
  Natural gas-powered dual fuel power plant with a gas price of 35 €/MWh. (12 USD/MMBTU)
- **Scenario 2: "High LNG market price"**
  Natural gas-powered dual fuel power plant with a gas price of 44 €/MWh. (15 USD/MMBTU)
- **Scenario 3: "Local government-subsidized LNG supply"**
  Natural gas-powered dual fuel power plant with a gas price of 15 €/MWh. (5 USD/MMBTU)
- **Scenario 4: "Emergency electricity generation with heavy fuel oil (HFO)"**
  HFO-fired dual fuel power plant with a fuel price of 36 €/MWh.[16]

The fuel price scenarios are based on experiences and discussions with stakeholders in the local energy industry. A price of 12 USD/MMBTU seems to be realistic in countries where the government has a monopoly mainly for fuel trading and logistics. A fuel price of 15 USD/MMBTU is expected in markets where private investors organize the fuel supply to a potential location or site.

For special projects supported by a local government, a subsidized price of 5 USD/MMBTU can be expected, although this will definitely not be true for the majority of projects.

Two price scenarios are chosen as a sale price for electricity and as a guideline for a power purchase agreement (PPA) or tariff design. Scenario 1 with 90 €/MWh and scenario 2 with 120 €/MWh. Both scenarios are prices for competitive markets.

Normally electricity generation costs on islands are much more expensive than on the mainland. For example, in the Caribbean there is an average electricity price of around 300 USD/MWh [12] – similar price levels are found in the ASEAN region too.

[15] Cet. par. in case of technical and project-related parameters. No changes in the dual fuel scope or design of the power plant.

[16] Including an increase in maintenance costs of up to 6 €/MWh.

Electricity generating cost model for the 67 MW dual fuel power plant

Project KPIs	Value
4 MAN engines, type 18V51/60DF	18V51/60DF: Installed capacity: 68.6 MW net output
Emission regulating according to	World Bank 2007/08
EPC price estimation	750 €/KW
Fuel costs (natural gas LHV) free at site	35 €/MWh and 44 €/MWh at COD Pilot fuel: 40 €/MWh (Escalation rate 2 %/a)
Maintenance (spares plus supervisor)	4.5 €/MWh
Weighted average cost of capital (WACC)	12 %
Construction time	18 months
Equity structure	30 %
Loan cost	5 %
Tax rate	20 %

Table 19: Project KPIs for the 67 MW dual fuel power plant

Electricity generation costs				67 MW (68.6 MW)
	Operating hours per year	**Production costs**	**4 x 18V51/60DF 35 €/MWh for gas**	**4 x 18V51/60DF 44 €/MWh for gas**
Variable costs		€/MWh	45.5	56.6
Fixed costs		€/kWa	135.2	114.0
	5	€/MWh	5945	22851
	10	€/MWh	2995	11454
	20	€/MWh	1520	5755
	50	€/MWh	635	2336
	100	€/MWh	340	1196
	250	€/MWh	164	512
	500	€/MWh	104.5	284.5
	1000	€/MWh	75.0	170.6
	1500	€/MWh	65.2	132.6
	2000	€/MWh	60.3	113.6
	2500	€/MWh	57.3	102.2
	3000	€/MWh	55.4	94.6
	3500	€/MWh	54.0	89.2
	4000	€/MWh	52.9	85.1
	4500	€/MWh	52.1	81.9
	5000	€/MWh	51.4	79.4
	5500	€/MWh	50.9	77.3
	6000	€/MWh	50.5	75.6
	6500	€/MWh	50.1	74.1
	7000	€/MWh	49.7	72.9
Expected running hours per year above	**7500**	**€/MWh**	**49.5**	**71.8**
	8000	**€/MWh**	**49.2**	**70.8**

Table 20: 67 MW – Electricity generation costs based on 35 €/MWh and 44 €/MWh depending on annual full-load hours. Fuel price at COD

Electricity generating cost model for the 95 MW dual fuel power plant

Project KPIs	Value
6 MAN engines, type 18V51/60DF	18V51/60DF: Installed capacity: 103.6 MW net output
Emission regulating according to	World Bank 2007/08
EPC price estimation	750 €/KW
Fuel costs (natural gas LHV) free at site	35 €/MWh and 44 €/MWh at COD Pilot fuel: 40 €/MWh (Escalation rate 2 %/a)
Maintenance (spares plus supervisor)	4.5 €/MWh
Weighted average cost of capital (WACC)	12 %
Construction time	18 months
Equity structure	30 %
Loan cost	5 %
Tax rate	20 %

Table 21: Project KPIs for the 95 MW dual fuel power plant

Electricity generation costs			95 MW (103.6 MW)	
	Operating hours per year	Production costs	6 x 18V51/60DF 35 €/MWh for gas	6 x 18V51/60DF 44 €/MWh for gas
Variable costs		€/MWh	45.5	56.6
Fixed costs		€/kWa	132.3	111.2
	5	€/MWh	5508	22298
	10	€/MWh	2777	11177
	20	€/MWh	1411	5617
	50	€/MWh	592	2281
	100	€/MWh	319	1169
	250	€/MWh	155	501
	500	€/MWh	100.1	279.0
	1000	€/MWh	72.8	167.8
	1500	€/MWh	63.7	130.7
	2000	€/MWh	59.2	112.2
	2500	€/MWh	56.4	101.0
	3000	€/MWh	54.6	93.6
	3500	€/MWh	53.3	88.3
	4000	€/MWh	52.3	84.4
	4500	€/MWh	51.6	81.3
	5000	€/MWh	51.0	78.8
	5500	€/MWh	50.5	76.8
	6000	€/MWh	50.0	75.1
	6500	€/MWh	49.7	73.7
	7000	€/MWh	49.4	72.4
Expected running hours per year above	**7500**	**€/MWh**	**49.1**	**71.4**
	8000	**€/MWh**	**48.9**	**70.5**

Table 22: 95 MW – Electricity generation costs based on 35 €/MWh and 44 €/MWh depending on annual full-load hours. Fuel price at COD

Electricity generating cost model for the 220 MW dual fuel power plant

Project KPIs	Value
13 MAN engines, type 18V51/60DF	18V51/60DF: Installed capacity: 226 MW net output
Emission regulating according to	World Bank 2007/08
EPC price estimation	750 €/KW
Fuel costs (natural gas LHV) free at site	35 €/MWh and 44 €/MWh at COD Pilot fuel: 40 €/MWh (Escalation rate 2 %/a)
Maintenance (spares plus supervisor)	4.5 €/MWh
Weighted average cost of capital (WACC)	12 %
Construction time	18 months
Equity structure	30 %
Loan cost	5 %
Tax rate	20 %

Table 23: Project KPIs for the 220 MW dual fuel power plant

Electricity generation costs			220 MW (226 MW)	
	Operating hours per year	**Production costs**	**13 x 18V51/60DF 35 €/MWh for gas**	**13 x 18V51/60DF 44 €/MWh for gas**
Variable costs		€/MWh	45.5	56.6
Fixed costs		€/kWa	153.8	132.9
	5	€/MWh	5250	26627
	10	€/MWh	2648	13342
	20	€/MWh	1347	6699
	50	€/MWh	566	2714
	100	€/MWh	306	1385
	250	€/MWh	150	588
	500	€/MWh	97.5	322.2
	1000	€/MWh	71.5	189.4
	1500	€/MWh	62.8	145.1
	2000	€/MWh	58.5	123.0
	2500	€/MWh	55.9	109.7
	3000	€/MWh	54.2	100.8
	3500	€/MWh	52.9	94.5
	4000	€/MWh	52.0	89.7
	4500	€/MWh	51.3	86.1
	5000	€/MWh	50.7	83.1
	5500	€/MWh	50.2	80.7
	6000	€/MWh	49.8	78.7
	6500	€/MWh	49.5	77.0
	7000	€/MWh	49.2	75.5
Expected running hours per year above	**7500**	**€/MWh**	**48.9**	**74.2**
	8000	**€/MWh**	**48.7**	**73.1**

Table 24: 220 MW – Electricity generation costs based on 35 €/MWh and 44 €/MWh depending on annual full-load hours. Fuel price at COD

Scenario 1: “Low LNG market price”: Fuel at site 35 €/MWh

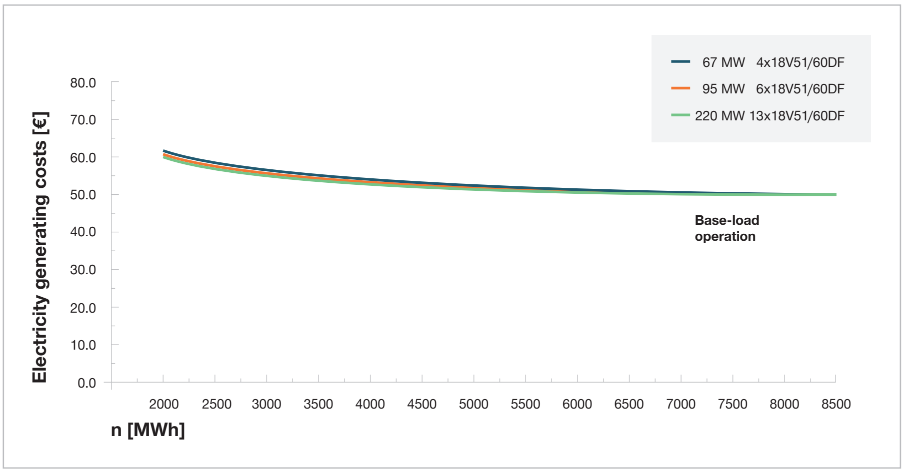

Figure 6: Scenario 1 “Low LNG market price” – electricity cost calculation

Scenario 2: “High LNG market price”: Fuel at site 44 €/MWh

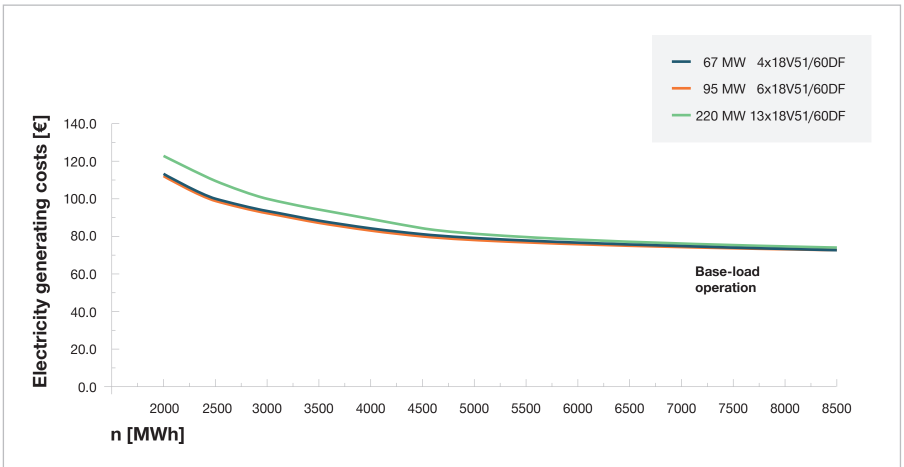

Figure 7: Scenario 2 “High LNG market price” – electricity cost calculation

Scenario 3: “Local government-subsidised LNG supply”: Natural gas-powered dual fuel power plant with a gas price of 15 €/MWh.

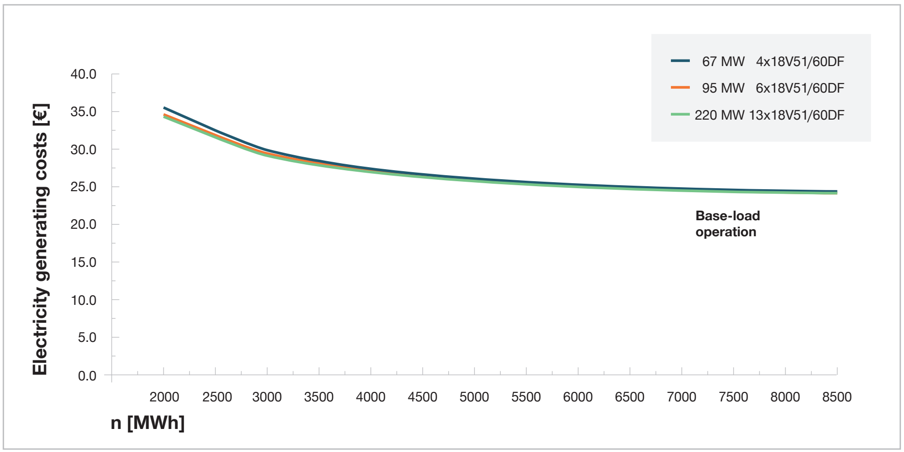

Figure 8: Scenario 3 “Government-subsidised LNG supply” – electricity cost calculation

Scenario 4: “Emergency electricity generation with heavy fuel oil (HFO)”: HFO-fired dual fuel power plant with a fuel price of 36 €/MWh.[17]

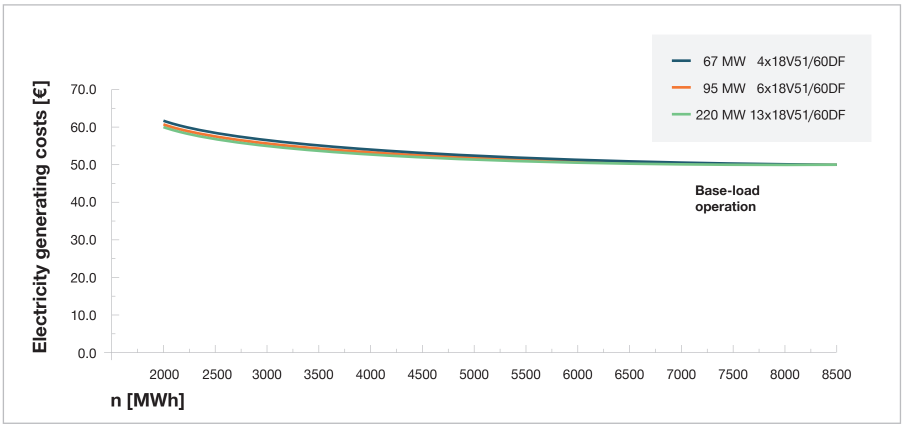

Figure 9: Scenario 4 “Emergency electricity generation with heavy fuel oil” – electricity cost calculation

[17] Based on bunkering price Singapore: IFO380- price range of USD 350/mt to USD 400/mt as of December 2017.

Financial modeling without LNG infrastructure

The financial modeling and financial statement is based on a discounted cash-flow model over the project lifetime of 20 years.

The main steps of the projects are separated into:

1. A project development and tendering phase
2. A construction phase of the LNG infrastructure and the power plant
3. Start of commercial operation (COD)
4. Receiving the first positive cash flow

The price of natural gas and the sale price of electricity both have an important impact on overall profitability. Both parameters are taken under a ceteris paribus with regards to the EPC part of the power plant.

Input parameters

	67 MW plant capacity	95 MW plant capacity	220 MW plant capacity
EPC price	750 €/kW	750 €/kW	750 €/kW
Natural gas price at COD	35 €/MWh and 44 €/MWh	35 €/MWh and 44 €/MWh	35 €/MWh and 44 €/MWh
Efficiency	46 %	46 %	46 %
Escalation rate per annum	2 %	2 %	2 %
WACC	12 %	12 %	12 %
COD	2020	2020	2020
Annual operating hours	8000	8000	8000
Operating years	20 years	20 years	20 years
Expected sale price per MWh electricity	90 €/MWh and 120 €/MWh	90 €/MWh and 120 €/MWh	90 €/MWh and 120 €/MWh

Table 25: Input parameters for each power plant

Results for 35 €/MWh for the natural gas price and 90 €/MWh for the sale price of electricity

	67 MW plant capacity	95 MW plant capacity	220 MW plant capacity
Internal rate of return (IRR)	7.8 %	8 %	8.5 %
Discounted project cash flow	€ 17 million	€ 23 million	€ 54 million
Operating profit	€ 127 million	€ 180 million	€ 417 million
Payback time	Approx. 5.5 years	Approx. 5 years	Approx. 5 years

Table 26: Results for 35 €/MWh and 90 €/MWh

Results for 44 €/MWh for the natural gas price and 120 €/MWh for the sale price of electricity

	67 MW plant capacity	95 MW plant capacity	220 MW plant capacity
Internal rate of return (IRR)	18.0 %	18.2 %	18.5 %
Discounted project cash flow	€ 30 million	€ 43 million	€ 100 million
Operating profit	€ 278 million	€ 394 million	€ 913 million
Payback time	Approx. 5 years	Approx. 4 years	Approx. 4 years

Table 27: Results for 44 €/MWh and 120 €/MWh

Financial modeling with LNG infrastructure

The financial modeling and financial statement is also well based on a discounted cash-flow model over the project lifetime of 20 years. The gas price is chosen with reference to the market price of 35 €/MWh in the low price scenario and a high price scenario of 44 €/MWh for LHV free at site.

Sale price of electricity as sensitivity with:

- 90 €/MWh
- 120 €/MWh

The main steps of the projects are separated into:

1. A project development and tendering phase
2. A construction phase of the LNG infrastructure and the power plant
3. Start of commercial operation (COD)
4. Receiving the first positive cash flow

Input parameters for scenario 1

LNG transport from the central LNG terminal via trucks and regasification at the power plant site.

	67 MW Plant capacity	95 MW Plant capacity	220 MW Plant capacity
EPC price	750 €/kW	750 €/kW	750 €/kW
Natural gas price at COD	35 €/MWh and 44 €/MWh	35 €/MWh and 44 €/MWh	35 €/MWh and 44 €/MWh
Efficiency	46 %	46 %	46 %
Escalation rate per annum	2 %	2 %	2 %
WACC	12 %	12 %	12 %
COD	2020	2020	2020
Annual operating hours	8000	8000	8000
Operating years	20 years	20 years	20 years
LNG terminal, trucks, regasification at site	€ 23 million	€ 25 million	€ 33 million
Expected sale price per MWh electricity	90 €/MWh and 120 €/MWh	90 €/MWh and 120 €/MWh	90 €/MWh and 120 €/MWh

Table 28: Input parameters for scenario 1

Results for 35 €/MWh for the natural gas price and 90 €/MWh for the sale price of electricity

	67 MW plant capacity	95 MW plant capacity	220 MW plant capacity
Internal rate of return (IRR)	4.0 %	4.1 %	4.4 %
Payback time	Approx. 7 years	Approx. 7 years	Approx. 6.5 years

Table 29: Results for 35 €/MWh and 90 €/MWh

Results for 44 €/MWh for the natural gas price and 120 €/MWh for the sale price of electricity

	67 MW plant capacity	95 MW plant capacity	220 MW plant capacity
Internal rate of return (IRR)	14.2 %	14.4 %	14.8 %
Payback time	Approx. 6 years	Approx. 6 years	Approx. 5.5 years

Table 30: Results for 44 €/MWh and 120 €/MWh

Input parameters for scenario 2

Regasification at the central LNG terminal which includes the investment for the terminal, the regasification and a short distance natural gas pipeline to the power plants site.

	67 MW plant capacity	95 MW plant capacity	220 MW plant capacity
EPC price	750 €/kW	750 €/kW	750 €/kW
Natural gas price at COD	35 €/MWh and 44 €/MWh	35 €/MWh and 44 €/MWh	35 €/MWh and 44 €/MWh
Efficiency	46 %	46 %	46 %
Escalation rate per annum	2 %	2 %	2 %
WACC	12 %	12 %	12 %
COD	2020	2020	2020
Annual operating hours	8000	8000	8000
Operating years	20 years	20 years	20 years
LNG terminal, trucks, regasification at site	€ 30 million	€ 35 million	€ 20 million
Pipline costs	(20 km distance)	(25 km distance)	(10 km distance)
Expected sale price per MWh electricity	90 €/MWh and 120 €/MWh	90 €/MWh and 120 €/MWh	90 €/MWh and 120 €/MWh

Table 31: Input parameters for scenario 2

Results for 35 €/MWh for the natural gas price and 90 €/MWh for the sale price of electricity

	67 MW Plant capacity	95 MW Plant capacity	220 MW Plant capacity
Internal rate of return (IRR)	2.7 %	2.9 %	3 %
Payback time	Approx. 8.5 years	Approx. 8 years	Approx. 8 years

Table 32: Results for 35 €/MWh and 90 €/MWh

Results for 44 €/MWh for the natural gas price and 120 €/MWh for the sale price of electricity

	67 MW Plant capacity	95 MW Plant capacity	220 MW Plant capacity
Internal rate of return (IRR)	16.0 %	16.3 %	16.6 %
Payback time	Approx. 5 years	Approx. 5 years	Approx. 5 years

Table 33: Results for 44 €/MWh and 120 €/MWh

Bibliography

[1] Biscardini, Giorgio; Schmill Rafael; Del Maestro Adrian; PricewaterhouseCoopers International. *Small going big: Why small-scale LNG may be the next big wave* (2017)

[2] The Oxford Institute for Energy Studies. *The Outlook for Floating Storage and Regasification Units* (2017) https://www.oxfordenergy.org/wpcms/wp-content/uploads/2017/07/The-Outlook-for-Floating-Storage-and-Regasification-Units-FSRUs-NG-123.pdf (accessed July 2018)

[3] Johnson, Mark W., Clayton M. Christensen, and Henning Kagermann. "*Reinventing Your Business Model.*" Harvard Business Review 86, no. 12, December 2008.

[4] Yergin, Daniel, The Quest: *"Energy, Security, and the Remaking of the Modern World"*– September 2012

[5] MAN Energy Solutions Press release Feb 05, 2015. *Six Engines for a new Power Station in Gibraltar - MAN Energy Solutions to Deliver Gas and Dual Fuel Engines*: https://www.mandieselturbo.com/press-media/news-overview/details/2015/02/05/Six-Engines-for-a-new-Power-Station-in-Gibraltar

[6] Bangladesh Power Cell, Ministry of Power, Energy and Mineral Resources – *Terms of Reference for Technical Advisory for Siting and Basis of design* (Feasibility Study) LNG Regasification Terminal. http://powercell.portal.gov.bd/sites/default/files/files/powercell.portal.gov.bd/page/2008941d_d13e_4f3e_a934_615cfcd6f121/TOR%20for%20Financial%20Advisory.pdf (accessed July 2018)

[7] Shell Press release Aug 22, 2016: *Her Majesty's Government of Gibraltar and Shell have signed an agreement for the supply of liquefied natural gas (LNG) for use in power generation in Gibraltar.* https://www.shell.com/business-customers/trading-and-supply/trading/news-and-media-releases/agreement-for-lng-supply-and-terminal.html (accessed July 2018)

[8] PricewaterhouseCoopers International: *Powering the Nation: Indonesian Power Industry Survey 2017*, May 2017

[9] ARUB Gas and LNG Storage, *The Future of Modular LNG Tanks, April 2017.* Online available: https://www.arup.com/-/media/.../future-of-lng_arup_april17.pdf (accessed June, 2018)

[10] International Energy Agency (IEA). World Energy Outlook (WEO) 2011

[11] Saleque Sufi. *Reviewing LNG plan of Bangladesh, Energy & Power,* April 2018

[12] The Oxford Institute for Energy Studies (2017): *"The potential market for LNG in the Caribbean and Central America"* https://www.oxfordenergy.org/wpcms/wp-content/uploads/2017/12/The-potential-market-for-LNG-in-the-Caribbean-and-Central-America-NG-124.pdf (accessed July 2018)

MAN Energy Solutions
86224 Augsburg, Germany
P + 49 821 322 - 0
F + 49 821 322 - 3382
info@man-es.com
www.man-es.com

All data provided in this document is non-binding. This data is for information only and is not guaranteed in any way. Depending on the subsequent specific individual projects, the relevant data may be subject to changes and will be assessed and determined individually for each project. This will depend on the particular characteristics of each individual project, especially specific site and operational conditions.