Wider Benefits and Industry Blueprint for the Integration of Solar Power into LNG Plants

Jeremy Trombley and Suresh Thennadil

Energy and Resources Institute
Charles Darwin University

August 2021

ENERGY AND RESOURCES INSTITUTE

CHARLES DARWIN UNIVERSITY AUSTRALIA

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1 Executive Summary

The world has become more conscious of the influence greenhouse gas emissions have on the climate due to intensifying visibility of the impacts. Pressure continues to mount on governments and industry bodies to do more towards finding solutions to halt these effects. Policy surrounding sustainability maintains a focal point in political campaigns and shareholders have demanded more action from corporations to curb their emissions. By utilizing Australia's abundance of solar resources for renewable energy, the local liquefied natural gas (LNG) industry has the opportunity to reduce its emissions and produce a climate-differentiated product.

This work examines the potential for integrating solar power into existing land-based Australian LNG plants to reduce their carbon dioxide (CO_2) emissions. Since these plants have already been built, we investigate technologies to retrofit these facilities. Findings from a study of the Darwin LNG plant were extrapolated to the other LNG plants contained herein to estimate the **emissions reductions, financial savings and employment opportunities** nationwide.

An LNG plant processes and cools raw natural gas (methane or 'feed' gas) to a temperature where it condenses to liquid form, thereby reducing the volume to 1/600th of the initial gas. This process is energy intensive and typically consumes approximately 8% of the input gas which contributes around two-thirds of CO_2 emissions from an LNG plant.[1] The plants run continuously, and a high value is placed on reliability of the power supply. For this reason, many plants produce their own electricity and almost all drive their compressors with their own gas. Integrating any variable form of energy requires firming of the supply. This can be achieved through some form of readily dispatchable energy onsite or by engaging the services of an external provider. Two broad input scenarios were therefore assessed: intermittent solar energy firmed with batteries and onsite gas generation, and a unique firmed (100% capacity factor) solar energy supply by a third-party supplier. In the case of the Northern Territory, the latter is made possible by the Sun Cable project, where a solar farm with between 3.2 and 6.4 GW of dispatchable solar power is planned.

This study found that a considerable amount of solar PV power can be integrated into LNG plants across Australia through retrofitting. If the maximum amount of technically feasible changes identified through this approach are enacted, it is estimated that the onshore LNG plants in the NT would reduce carbon dioxide emissions by 19%, Queensland by 18% and WA by 21% from the emissions arising due to their electricity and stationary energy demand. That equates to around **96 Exajoules per year of natural gas that could be freed up from the liquefaction process chain and emissions reductions of about 5 million tonnes of CO_2 emissions per year at existing production capacities, which amounts to about 1% of Australia's current total emissions.** If all changes were able to be implemented before 2030, these emissions reductions of the current processing volumes would account for 4-9% of those needed for Australia to reach its emissions target.[1] If a continuous renewable electricity supply was available, such as in Darwin via the Sun Cable project, these savings could more than double by fully replacing all

[1] Department of Industry, Science, Energy and Resources. *Australia's emissions projections 2020*, December 2020

electricity requirements and substituting up to half the demand for the compression loads at the plants. The excess natural gas could then be injected into the domestic market supply to substitute existing imported supplies or used to produce more LNG, if there is liquefaction capacity available. The reductions in emissions also lead to global marketing opportunities where cleaner fuel is desired in the export markets. Funding opportunities to help with the expense of these modifications are outlined as well.

> This study suggests that cost savings for integrating solar for electricity generation represents an economically viable project with a lower net present cost than business as usual. However, the additional cost of infrastructure needed to support electrifying the compression equipment, where the largest carbon emissions reductions were found, cannot be completely recuperated at this point from fuel gas savings so some form of government support would likely be needed.

The amount of new infrastructure that would be needed to facilitate the proposed solar power systems would lead to significant employment opportunities. During an installation stage of ten years, 1,890 full-time jobs would be needed, and a further 868 ongoing positions would be created for the operational phase. **Overall, the solarisation of Australian LNG plants would lead to financial, environmental, economic and employment benefits for the country.**

2 Introduction

Australia has become the largest exporter of liquid natural gas (LNG) in the world, delivering 77.5 Mt of natural gas in 2019[2] and has continued this high productivity.[3] A slight increase is expected in the near future, peaking in 2022 followed by a fairly flat rate until at least 2039.[4] Exporting the natural gas in gas form is economically prohibitive due to the low density of the gas. By liquifying the natural gas, the volume drastically decreases, making export a viable option. The process of turning natural gas from a well into LNG is energy intensive because the temperature has to be reduced to -162˚C.[5] Approximately 8% of the natural gas that is processed by an LNG plant is used in the liquefaction process.[6]

Emissions from an LNG plant are primarily from three different sources: electricity generation used by the plant, stationary energy (energy used by the plant other than electrical, i.e. refrigerant compression) and fugitive emissions. Fugitive emissions are mainly carbon dioxide that was separated from the raw natural gas feedstock, but also includes gases that are vented, flared or escape from leaks. In Australia, fugitive emissions account for an average of about one-third of all plant emissions.[7] The remaining emissions result from generating electricity for the plant and thermally driving the refrigerant compressors that liquify the natural gas for export.

While the only option for significantly reducing vented carbon dioxide is capture and storage, there are other options for emissions attributed to the electricity generation and stationary energy. If this power for liquefaction could be taken from a carbon neutral source, the natural gas it displaces would not need to be consumed on site. Benefits of displacing the natural gas with a renewable energy source include freeing up more natural gas for export or for domestic use, a reduction in emissions and job creation.

The purpose of this work was to investigate the feasibility and impact of the integration of renewable energy sources into the on-shore LNG plants across Australia. With the fall in prices of solar photovoltaics (PV) and battery energy storage systems (BESS), along with the large amount of solar radiation received at LNG plant sites across Australia, we focus our studies on using PV-BESS systems to partially power the liquefaction process. We also investigate using power purchase agreements (PPAs) from large renewable energy infrastructure currently in the planning stage.

With support from Santos and EPC Technologies, Wood Group carried out a concept study that included the technical and economic aspects of introducing bespoke large scale solar (LSS) facilities into the Darwin LNG plant. This study is referred to as the DLNG report or DLNG study throughout and forms the basis of this present work. The pertinent details from the DLNG report are outlined in Section 6. These details are then used to estimate the potential solarisation of all land-based LNG plants across Australia. We have also included information garnered from discussions with the project consortia that includes Santos, National Energy Resources Australia (NERA), the Northern Territory Government and Sun Cable. Our methodology is explained in Section 5 and the results for other LNG plants are described in Section 7-9. Following these results, marketing, employment, and funding opportunities are explored.

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[2] Toscano N. Australia tops Qatar as world's biggest LNG exporter, *Sydney Morning Herald*, 6 January 2020

[3] Bethune G. Another Australian LNG export record in 2020, *EnergyQuest*, 19 March 2021

[4] Australian Energy Market Operator, *Gas statement of opportunities*, March 2020

[5] LEVON Group, *Liquified natural gas (LNG) operations: consistent methodology for estimating greenhouse gas emissions*, prepared for Energy API, May 2015

[6] Lewis Grey Advisory, *Projection of gas and electricity used in LNG*, prepared for Australian Energy Market Operator, 15 April 2015.

[7] Department of Industry, Science, Energy and Resources. *Australia's emissions projections 2020*, December 2020

3 Scope

Charles Darwin University (CDU) was tasked with investigating the feasibility and impact of solarisation of on-shore LNG plants across Australia. Analysis of different scenarios were carried out while taking site specific characteristics into account. The core findings based on information contained in a study carried out by Santos on the Darwin LNG plant as part of the overall project were used to guide our scenario modelling.

The study conducted by CDU covered the following aspects:

1. Site specific estimates of cost of solar PV electricity supplied to LNG plants:
   a. Potential third-party PV electricity suppliers to supply renewable energy to the plants
   b. Bespoke PV-BESS installation to supply electricity to LNG plants
2. Identify opportunities arising from solarisation:
   a. Employment opportunities associated with increased utilisation of solar, including operation and maintenance of solar assets by supplier
   b. The amount of gas made available for further use due to solarisation
   c. Potential for marketing low-emissions LNG with a reduction in GHG emissions from the liquefaction portion of the value chain.
3. Estimate Australia wide emissions reduction due to solarisation of LNG plants
4. Investment analysis – potential routes for securing funding
5. Investigation of Australian Carbon Credit Units and Large-scale Generation Certificates generated through solarisation
6. Identify local and national regulatory requirements associated with grid-connections and land development
7. Identify technical, social and economic challenges and barriers to solarisation of LNG plants in Australia.

4 Basic Liquified Natural Gas Plant Characteristics

There are currently nine land-based LNG plants across Australia located in NT (2), QLD (3) and WA (4). There is one sea-based LNG plant (Prelude) off the coast of WA that is not included in this study as there is not a simple way to integrate solar power into it without available land for panels. They vary in production size from 3.24 Mt/year to almost 17 MT/year, a complete list of plants with their nameplate capacity is in Table 1.

Table 1 List of Australian liquid natural gas plants and their nameplate capacity.

LNG plant	Nameplate Capacity (Mt)
Darwin LNG (DLNG)	3.24
Ichthys LNG (ILNG)	8.9
Australia Pacific LNG (APLNG)	9.0
Queensland Curtis LNG (QCLNG)	8.5
Gladstone LNG (GLNG)	7.8
Gorgon LNG (GoLNG)	15.6
North West Shelf LNG (NWSLNG)	16.9
Pluto LNG (PLNG)	4.7
Wheatstone LNG (WLNG)	8.9
Total	83.54

Source: The capacity for DLNG was provided by Santos and not the published value of 3.7 Mt, all others were found in Department of Industry, Innovation and Science, *Resources and Energy Quarterly*, March 2019

In general, LNG plants are located in remote locations due to the locations of the gas fields where the natural gas is extracted and on coasts to aid in shipping and Australia is no exception. Even if a grid connection were available, the importance of uptime for LNG plants is a driver for the plants to ensure their own power supply instead of relying on the grid to prevent unexpected shutdowns. This means that all electricity and mechanical power are typically generated and managed by the plants themselves, usually through the combustion of the natural gas they are processing. However, there are currently two exporting LNG plants that are grid-connected and run entirely on electric motors[8]: Hammerfest LNG (Norway) and Freeport LNG (USA). In the extreme case where if all the LNG plants in Australia were able to fully convert their drivetrains to electric motors, and they imported enough renewable energy to cover their electrical and stationary energy needs, the total carbon reductions would amount to about 24-27 Mt CO_2-e/yr (approximately a reduction of 64-71%).[9] Further reductions would only be possible with carbon capture and storage. However, replacing the mechanical turbines with electric drives requires a very large capital expenditure and was deemed uneconomical for an existing facility by Santos at the very start of this project and was therefore excluded from further analysis.

The LNG plants usually generate electricity using standard gas-fired power generation, such as gas turbine generators (GTGs). The gas is burned to turn a turbine that generates electricity via an alternator. As mentioned earlier, this electricity is used for standard electrically powered equipment such as utilities, lights, control systems and metering tools. The major demand for the gas though is the refrigeration compressors that are used to provide cooling to convert the natural gas into liquid form. A very simplified schematic is shown in Figure 1 of the process, which is known as an LNG train. Most LNG plants have multiple trains that operate in parallel and independent of each other.

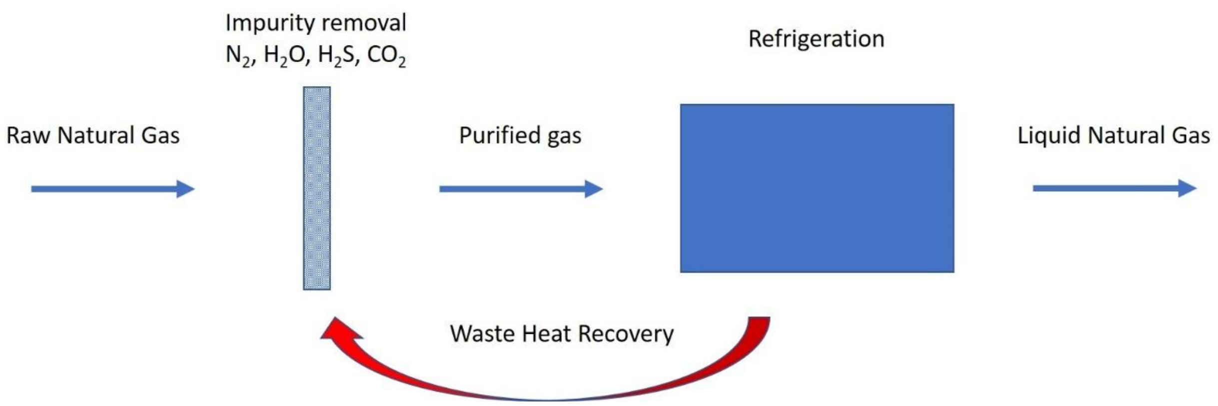

Figure 1 Simplified diagram of a train used to liquify the natural gas.

In the first stage, the raw natural gas (as it enters the LNG plant) has contaminants removed such as nitrogen and carbon dioxide through separation processes. The purified gas is then sent into multiple sequential refrigeration steps at progressively colder temperatures to cool the methane down to -162 °C to liquify it, where it will be stored in the liquid form and loaded onto vessels for transportation. The refrigeration cooling is provided by gas turbine compressors (GTCs) that are powered by the natural gas supply of the LNG plant and are responsible for the majority of plant fuel consumption. The systems used in the purification step are typically regenerated from some of the waste heat of the GTCs or GTGs. It is also possible to install helper motors to reduce the load on the GTCs while maintaining the same

[8] US Energy Information Administration, *Natural gas weekly update*, 12 September 2019
[9] Department of Industry, Science, Energy and Resources. *Australia's emissions projections 2020*, December 2020

output power. However, reducing the load on the gas turbines does reduce the waste heat generated, which will potentially need to be provided through other means. As explained later this is a necessary step to introduce solar power into the refrigeration process. Some Australian LNG plants already have electric helper motors which are used to help 'cold start' GTCs but are also able to supply supplementary power to the GTCs.

5 Methodology

CDU used the details and results from the DLNG study to estimate potential gas and financial savings at other LNG plants across Australia. In the next section, we highlight the relevant, non-confidential information from the study and include additional information obtained from the study participants. The details are then used as the foundation for our estimates of potential solarisation and its benefits to other LNG plants from across Australia.

In the DLNG study, HelioScope software was used to simulate the PV panels and imported into the HOMER Pro® simulation package. HelioScope allows for more control over the panel properties but we did not have access to the HelioScope model, so we used the generic flat plate PV module of the same size with one-axis solar tracking within HOMER Pro® for our simulations. The generic panels had a lower output, equivalent to about 88% of the energy output over a year from the DLNG study. We assumed that other LNG plants used the same PV panels that the DLNG study simulated, so we increased our simulated output using the generic panels to factor in this difference. The derating value is affected by the age of the panels and environmental conditions such as ambient temperature and soiling, so for a more accurate model the local environmental conditions would be needed that were not available for this study.

Emissions reductions are based on the displacement of natural gas by solar power. Although the natural gas sources for the LNG plants differ in composition, it was assumed the actual gas that was combusted to power the plants had the same heating value and emissions intensity as provided in the National Greenhouse Accounts Factors: 2020,[10] since it was used after processing. Emissions from carbon dioxide in the raw gas and other fugitive emissions are unaffected by the power source of the plant so are not included in the scope of this study.

Without access to all the technical details or cost variables of the various LNG plants, a simple model was developed in order to scale the well-defined parameters of the DLNG plant to estimate potential renewable power penetration for the LNG plants. A more robust analysis would be needed to account for all the specific needs of each individual LNG plant to achieve a higher accuracy, but the results presented here should give a reasonable approximation of opportunities within the LNG industry of Australia.

General Assumptions

- The electricity needs of each LNG plant was a constant proportion of the nameplate capacity and can be scaled based on DLNG findings.
- The helper motor's energy demand can be substituted by electricity in the same proportion as DLNG, but scaled based on nameplate capacity

[10] Department of Industry, Science, Energy and Resources, *National Greenhouse Accounts Factors: 2020*, September 2020.

- The gas being consumed by the GTGs and GTCs at all LNG plants have been refined to be of the same gas composition, regardless of gas field source. The natural gas energy content of 0.0393 GJ/m^3 and the emissions from combustion of 51.53 kg $CO_{2\text{-}e}$/GJ were used.[11]
- Emissions reductions are only based on the reduction of the natural gas used in the GTGs and the GTCs with the aid of helper motors.
- Emissions from vented carbon dioxide and other fugitive emissions are independent of the combustion process used for energy demand at the LNG plant, so are not included in this study.
- LNG plant capacity growth is not considered.
- The cost of the installation of LSS systems was based on the values from the DLNG report with PV modules installed at $1.31/W and batteries installed at $1.73/Wh. There may be differences in delivery costs based on locations that were not accounted for.
- The year renewables are installed impacts the value of carbon credits since large-scale generation certificates (LGCs) are only valid up to and including 2030, so the later PV is installed the less the number of LGCs created and thus less value. Australian carbon credit units (ACCUs) do not have this deadline. Since it was not known if any LNG plants had plans to install renewable energy, only ACCUs were calculated for plants aside from DLNG.
- Physical space is available to make all LNG plant modifications necessary.

In the following sections, the technical, economic and emissions aspects are considered for LNG plants based on the state/territory they are located in.

6 Background for Darwin LNG

Darwin LNG (DLNG) is located in Middle Arm, less than 4 km (direct) to the major power station that supplies the Darwin Katherine Interconnected System (DKIS). It started processing LNG in 2006 and currently has smaller capacity than most LNG plants in Australia, at 3.24 Mt per annum. Accounting for only the fuel gas consumed by the GTCs and GTGs on site, the GTCs used in the liquefaction train are responsible for the majority of the gas consumption for combustion used on site at 83%. The electricity needs of the plant fulfilled by the GTGs accounts for the remaining 17% in gas consumption.

Powering DLNG from the local grid would do little to reduce emissions because of its current electricity supply. The DKIS is fuelled mainly by natural gas itself with diesel as a backup.[12] In the 2019-2020 financial year, the electricity supply from the DKIS consisted of 6% from renewable sources.[13] The NT Government has set a target of 50% of the NT's electricity to come from renewables by 2030, so a lot more renewable power is expected, which would make importing electricity more attractive in the future from an emissions point of view.

Santos undertook a concept study into the technical and economic feasibility of converting some of the power demand of the DLNG plant from natural gas turbines to solar-based systems. Here we present some of the results from their DLNG technical and economic report and include additional information garnered from the study participants. Most of the PV modelling in the report was done with microgrid optimization software HOMER Pro®. It is a technical and economic simulation package that models a least-cost solution to meet the energy demands of a given system. The modelling was based on a 25-year timescale with a 2% inflation rate and 8% discount rate. The work done through the internal studies commissioned by Santos are summarised in this section and referred to here as the DLNG report or DLNG study interchangeably.

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[11] *National greenhouse and energy reporting (measurement) determination 2008*, Compilation NO. 9, 3 July 2017
[12] https://territorygeneration.com.au/home/our-power-stations/
[13] Utilities Commission of the Northern Territory, Northern Territory electricity outlook report, 2020

In the DLNG report, custom photovoltaic modules were simulated for DLNG using HelioScope software and imported it into HOMER Pro® for the PV portion of the simulation. HelioScope allows for tighter control over PV specifications and derating.

The DLNG report explored three cases of increasing solar penetration into the natural gas processing:

Case 1: Displacing some of the current electricity needs of the plant generated by the gas turbine generators (GTGs) with power generated by PV-BESS systems.

Case 2: Similar to Case 1, but with an additional 10 MVA of electricity generation to account for potential future growth of the plant.

Case 3: The installation of electric helper motors that were powered by additional solar PV power generation to reduce the gas consumption of the GTCs.

6.1.1 Technical aspects of Case 1: Integration of Solar with GTGs

During the liquefaction process, the DLNG plant has a typically constant electricity demand. When the LNG is being transferred to the ship there is an additional 33% electrical demand. A firmed power supply is needed to meet the electrical requirements of the LNG plant, so a PV-BESS system was proposed in the DLNG report for use during times of high solar radiation to assist with the normal operating conditions to reduce the GTG load and the GTGs run at their current capacity at time of low solar radiation. In the simulations two GTGs are switched off under normal daily operations while the remaining ones are still operated, but at reduced load (~60%) to prevent unnecessary wear and tear caused by cold starting. To account for the extra energy needed during the approximately weekly ship loading, one otherwise dormant GTG is activated.

Based on the undeveloped land and geographical conditions, the optimal site determined for the PV-BESS system in Case 1 is marked in Figure 2. Based on satellite images, there is approximately 100 ha of undeveloped land at this location, but further site inspections would be needed to verify the actual amount of space available. Benefits of this site is that the powerlines connected to the DLNG plant go past this point, so additional cabling could run parallel to the existing infrastructure to connect the LNG plant to the new LSS.

From the modeling in the DLNG report, it was determined that single axis solar tracking PV panels with BESS were the best option. The benefits of solar tracking are that more electricity is produced throughout the day per panel due to them always being oriented toward greatest solar radiation and a more constant output profile throughout the day. This also reduces the amount of land needed for the installation (0.9 ha per MW of PV using 2P configuration), decreasing the cost for land. Based on technical and financial considerations, the optimal PV size was 19.5 MW with a BESS with a power rating of 14.3 MW and total energy of 7.17 MWh. The introduction of this setup to DLNG reduced the emissions from the gas turbine generators (GTGs) by 50% in the simulations, a savings of 46.3 kt $CO_{2\text{-}e}$/yr based on the emissions factor of 51.53 kg $CO_{2\text{-}e}$/GJ found in the National Greenhouse and Energy Reporting scheme (NGERS) legislation.[14]

6.1.2 Technical aspects of Case 2: Integration of Solar with Increased load on GTGs

Case 2 is similar to Case 1 but modelled with a 50% higher demand due to future potential changes in the DLNG process. In this case however, the extra GTG in the Case 1 scenario had to be switched back on

[14] *National greenhouse and energy reporting (measurement) determination 2008*, Compilation No. 13, 1 July 2021

to manage the daily load. The GTGs also must be run at a slightly higher capacity (~67%) to prevent wear and tear from starting the motors. In the expansion of the LNG plant a larger PV-BESS system would be needed. A PV size of 35.3 MW and a BESS with a power rating of 32.9 MW with a storage capacity of 16.5 MWh was found to be optimal, compared to the base case with the planned increased demand but no solar input, the emissions savings, 81.3 kt CO_{2-e} /yr, will be greater than Case 1, however the overall percentage will be lower, 47%, due to the increased load of the GTGs.

6.1.3 Technical aspects of Case 3: Integration of Solar with GTCs

Case 3 investigated using solar power for the refrigerant compression needs of the LNG plant. Replacement of the GTCs with an electric drivetrain would allow the largest renewable energy integration possible, but that was discounted early on as the cost would be so high that there was no economic justification so further analysis was not included in the DLNG report. In this case, helper motors were installed on each of the GTCs that could run on electricity from solar panels. Helper motors reduce the gas consumption of the GTCs by taking on some of the compression load. Helper motors can also operate at variable speeds, depending on the amount of electricity available to them. In this case a firmed power supply is not needed to keep the trains functioning, however the GTCs cannot change their loads instantaneously and so some way to manage the ramp rate is needed. It would also be most economical to include the PV-BESS system from either Case 1 or Case 2 from above if an LSS was going to be built for Case 3. For this reason, a 111 MW PV system without BESS was found to be the most economical way to increase renewable energy penetration for the GTCs, but with the understanding that the BESS from either Case 1 or Case 2 would be available just to manage the ramp rate of the GTC. This led to a reduction of 138.9 kt CO_{2-e} /yr. There is an upper limit to the sizing of the helper motors, based on the physical space available for installation on the GTC packages. The size of helper motor impacts the waste heat recovery needs used across the plant. This potentially means the heat will need to be generated elsewhere if the helper motors were too large, offsetting the emissions reduced through the helper motor installation.

Figure 2 Map of Middle Arm with the optimal location of large-scale solar marked.

Based on the density of solar modules from the DLNG study, we estimated the amount of land size needed for Case 3 to be 100 ha. However, the LSS for Case 3 could not be installed without the inclusion

Carbon emissions reductions for DLNG

Case 1: 46.3 kt/yr

Case 2: 81.3 kt/yr

Case 3: 138.9 kt/yr

of either Case 1 or 2 to take advantage of the BESS. Therefore, we chose the more southern location (Figure 2) as it was the closest available space that was not earmarked for other purposes in the Middle Arm Industrial Precinct Mater Plan.[15]

6.2 Economic Considerations

In addition to the technical characteristics of such a project, there are economic aspects that need to be considered. In the technical simulations above, the HOMER Pro® software already optimizes the modelled system for the best financial outcomes based on the given technical parameters. However, these did not take into account the modifications that needed to be made within the DLNG plant itself to accommodate the integration of an LSS system so further analysis was needed. Both results for each of the three cases are presented below. In each case, the cost of modifications to produce the same amount of LNG is compared to its base case, where the plants run under business-as-usual conditions. Since each plant was assumed to already be running at its maximum capacity, the gas savings was not explored for further sales.

6.2.1 Economics of Case 1: Integration of Solar with GTGs

In Case 1 a portion of the current GTG load was substituted using a bespoke PV-BESS system. The cost of installing a PV-BESS system specified in 6.1.1 are presented in Table 2 and taken from the DLNG study, as modelled by the HOMER Pro® software. These values only incorporate those that occur outside the DLNG plant; the costs for inside the plant were calculated separately (Table 4).

[15] https://landdevcorp.com.au/project/middle-arm-industrial-precinct/masterplan/

Table 2 Costs of the PV-BESS system specified in 6.1.1. Values were taken from the DLNG report. Courtesy of EPC Technologies.

Category	Cost (AUD M)
Design/Project Management/Approvals	0.7
Solar Modules	8.1
Inverters	1.8
Posts/Tracking Systems	3.2
Other Equipment	2.3
Installation	7.0
Distribution substation and line	1.55
Contingency	0.85
PV total	**25.5**
BESS	12.4
PV-BESS Total	**37.9**

The costs in Table 2 represent all the CAPEX costs for Case 1, since the GTGs that supply the remaining electricity were already present they do not add to the CAPEX. These values, along with the other values in Table 3, were used to calculate the net present cost (NPC) of the installation and operation of the PV-BESS system for the DLNG plant. The NPC was calculated over a 25-year lifetime.

The yearly gas consumption of the plant was reduced from 1,792,144 GJ to 894,468 GJ with the addition of the PV-BESS system. With a gas price of $5.50/GJ, an annual savings of $4.94 M could be realized.

Table 3 DLNG plant net present costs including GTGs following Case 1 outlined in 6.1.1. All values are in AUD M. Courtesy of EPC Technologies.

	CAPEX	OPEX	Replacement/ Refurbishment	Salvage	Gas Consumption	Total
GTGs	0	12.73	2.35	-1.17	61.73	**75.64**
Grid	0	-3.60	0	0	0	**-3.60**
PV	25.50	4.11	0	0	0	**29.61**
BESS	12.4	0.43	5.58	-0.34	0	**18.07**
Total	**37.90**	**13.67**	**7.93**	**-1.51**	**61.73**	**119.72**

The NPC of the DLNG plant, if continued with a solely gas-powered electricity generation was $135M, while integrating a PV-BESS system the NPC was lower by $15M. The levelized cost of energy (LCOE), which considers CAPEX and OPEX over the 25-year expected lifespan, is a way of expressing the cost of energy in today's dollars. In this case, the LCOE was lower for the current case at $0.0766/kWh, while the model with the PV-BESS slightly higher at $0.0837/kWh. However, DLNG was assumed to have built a 4 MVA bidirectional connection to the grid. The reason the NPC was lower with the solar power was due to sales of excess electricity to the grid network. These sales may not be available to other LNG plants. These sales were not included in the LCOE calculation but were in the NPC ones, thus the difference in costs.

The costs associated with electrical alterations that need to be made within the plant itself to match the technical specifications of the PV-BESS system are presented in Table 4. All cost estimates associated with the DLNG report have a ±30% accuracy. Here the cost for retrofitting the plant adds about 10% to the CAPEX so would still make solar integration the best option.

Table 4 Total net present costs associated with reconfiguring DLNG to accommodate the PV-BESS system. (Estimates ±30%). All values in AUD M. Courtesy of Wood Group.

Project management, engineering and design	0.5
Equipment cost	1.7
Installation cost	0.9
Base cost	**3.1**
Growth allowance	0.3
Contingency	1.0
Total DLNG plant costs	**4.4**
Solar power costs	119.7
Grand total	**124.1**

6.2.2 Economics of Case 2: Integration of Solar with Increased load on GTGs

In Case 2, a portion of the GTG load was replaced by a PV-BESS system but with a 50% increase in total load to account for future growth of DLNG. The economic analysis of Case 2 was handled in a similar way to the previous section, with the cost of the solar installation outlined in Table 5 and the NPC in Table 6. Case 2 has more solar modules, a bigger battery and utilizes one more GTG than Case 1 because of the larger electricity load.

Table 5 Costs of the PV-BESS system specified in 6.1.2. Values were taken from the DLNG study. Courtesy of EPC Technologies.

Category	Cost (AUD M)
Design/Project Management/Approvals	1.0
Solar Modules	14.2
Inverters	2.9
Posts/Tracking Systems	5.4
Other Equipment	3.9
Installation	14.1
Distribution substation and line	1.55
Contingency	3.05
PV total	**46.1**
BESS	28.5
PV-BESS Total	**74.6**

Table 6 DLNG plant net present costs following Case 2 outline in 6.1.2. All values are in AUD M. Courtesy of EPC Technologies.

	CAPEX	OPEX	Replacement/ Refurbishment	Salvage	Gas Consumption	Total
GTGs	2.60	25.75	5.40	-1.059	125.0	**157.70**
Grid	0	-3.04	0	0	0	**-3.04**
PV	46.1	7.44	0	0	0	**53.54**
BESS	28.5	0.99	6.15	-0.547	0	**35.09**
Total	**77.20**	**31.14**	**11.55**	**-1.61**	**125.0**	**243.29**

In Case 2, both the NPC and LCOE are favorable to the installation of the PV-BESS system. **The base case NPC, without any changes in technology, would be $281 M.** The LCOE for the base case is $0.0887/kWh while integrating solar power decreases it to $0.0876. Gas consumption is also reduced by 1,576,712 GJ/yr. When the internal plant costs in Table 7 are accounted for, the cost of installing the PV-BESS still comes out ahead.

Table 7 Total net present costs associated with reconfiguring DLNG to accommodate the PV-BESS system. All values in AUD M. Courtesy of Wood Group.

Project management, engineering and design	0.6
Equipment cost	1.9
Installation cost	1.1
Base cost	**3.6**
Growth allowance	0.4
Contingency	1.6
Total DLNG plant costs	**5.5**
Solar power costs	243.3
Grand total	**248.8**

6.2.3 Economics of Case 3: Integration of Solar with GTCs

In Case 3, electric helper motors were installed to take some of the load off the GTCs. Since the implementation of Case 3 would not be possible without either Case 1 or 2 already being put into effect, the economics of Case 3 were treated independently and considered as the next phase of solarisation.

The CAPEX was only due to the installation of the PV outside of the plant since the compressors will still be running, but at a reduced rate and the cost of the BESS was covered under one of the previous two cases, CAPEX results are in Table 8. Therefore, the total costs would have to include the chosen case or else a new model would need to be developed.

Table 8 Costs of the PV system specified in 6.1.3 without BESS included. Values were taken from the DLNG study. Courtesy of EPC Technologies.

Category	Cost (AUD M)
Design/Project Management/Approvals	2.9
Solar Modules	45.9
Inverters	10.1
Posts/Tracking Systems	18.1
Installation	37.6
Distribution substation and line	27.8
Contingency	3.0
PV total	**145.4**

The NPC for Case 3 was $643M, as seen in Table 9, less than the current configuration, $694M. The LCOE with the PV for the GTC portion only was $0.0631/kWh compared to the current system that had a value of $0.0681.

Table 9 Total DLNG plant net present costs following Case 3 outline in 6.1.3. All values are in AUD M. Courtesy of EPC Technologies.

	CAPEX	OPEX	Replacement/ Refurbishment	Salvage	Gas Consumption	Total
GTCs	0	1.26	56.2	-7.87	425	**474.59**
PV	145	23.4	0	0	0	**168.4**
Total	**145**	**24.66**	**56.2**	**-7.87**	**425**	**643.0**

The costs associated with installing the necessary equipment, including the electric helper motors, inside the plant are in Table 10. The cost of the helper motors was higher than the NPC of the PV system itself and made the total cost for the hybridization of the system less economical than relying just on the compressors themselves. Over $234M in CAPEX would be needed within the plant in order to implement Case 3, making this case less economically compelling than not adding the helper motors. A carbon price of $53/t $CO_{2\text{-}e}$ would be the break-even point for making the necessary modifications to allow for solar power versus the base case where the GTCs continue to run solely on natural gas.

Table 10 Total net present costs associated with reconfiguring DLNG to accommodate the PV system. All values in AUD M. Courtesy of Wood Group.

Project management, engineering and design	4.7
Equipment cost	97.7
Installation cost	61.7
Base cost	**164.1**
Growth allowance (10%)	16.4
Contingency (30%)	54.2
Total DLNG plant costs	**234.7**
Solar power costs	**643.0**
Grand total	**877.7**

A comparison between the three cases outlined above with their NPC and the base cases are presented in Table 11. Cases 1 and 2 come out ahead while the high cost of the helper motors in Case 3 means that these changes would incur a loss.

Table 11 Comparison of NPC between the base case of the current DLNG plant configuration with the integration of a solar powered electricity system.

	Case 1	Case 2	Case 3
Base case	$135M	$281M	$643M
PV integration	$124M	$249M	$694M

6.3 Carbon credits

One incentive for reducing carbon emissions is found by claiming large-scale generation certificates (LGCs) under the *Renewable Energy (Electricity) Act 2000*. An LGC is equivalent to 1 MWh of eligible electricity generated each year. LGCs are only valid up to and including 2030 where new certificates will no longer be created. The value of LGCs is set by the open market and the values used here were based on internal projections that are commercial in confidence but have the price of an LGC decreasing to much less than the current value[16] of $35 for the project's lifespan. The renewable energy created by the PV-BESS system are eligible for LGCs.

There are other carbon credits that also have a value set by the open market that further the economic benefits of solarisation. Under the *Carbon Credits (Carbon Farming Initiative) Act 2011*, the Clean Energy Regulator (CER) issues Australian carbon credit units (ACCUs). Each credit represents one tonne of carbon dioxide equivalent that is either stored or avoided by a project. Under the facilities method, ACCUs are valid for seven years. The credits were valued at $16.10 per ACCU. While the spot price has risen above $18 in the beginning of 2021[17], we will continue with the more conservative value used in the DLNG report.

While the emissions savings from the integration of the PV-BESS systems described above would all be eligible for ACCUs, LGCs and ACCUs cannot both be claimed for the same activity. Therefore, the DLNG report found the maximum return was based on a mixture of LGCs for the renewable energy and ACCUs for a reduction in fuel consumption attributable to the reduced spinning reserve, whose values are shown in Table 12.

By integrating the PV-BESS into the GTGs, one GTG can be shut off for both Cases 1 and 2. The remaining GTGs will operate at a higher capacity and a higher efficiency, i.e. less fuel consumption per total output power. The fuel savings translated to emissions reductions of 13.5 kt $CO_{2\text{-}e}$ /yr for Case 1 and 9.8 kt $CO_{2\text{-}e}$ /yr for Case 2. In Case 3, the helper motors count as new business that reduces emissions so the PV would acquire LGCs and the reduction in fuel consumption from the GTCs would be eligible for ACCUs based on a reduction of 54.9 kt $CO_{2\text{-}e}$ /yr.

[16] https://www.demandmanager.com.au/certificate-prices/
[17] https://www.accus.com.au/

Table 12 Value of carbon credits expected if solar power is integrated by 2023 with a price of $16.10 per ACCU (for 7 years) and an average price of $6.25 per LGC until 2030. Courtesy of EPC Technologies.

	Case 1	Case 2	Case 3
ACCUs	$1.5M	$1.1M	$6.2M
LGCs	$1.8M	$3.3M	$10.3M
Total	**$3.3M**	**$4.4M**	**$16.5**

6.4 Third Party Suppliers (e.g., Sun Cable)

An alternative to constructing a bespoke renewable energy supply for DLNG is accessing third-party generation. The DLNG study looked at integrating a firmed solar power electricity supply, which had a higher capacity factor which could lead to further decarbonisation of the LNG process. Direct connection to local grid network, the Darwin-Katherine Interconnected System (DKIS), was dismissed in the early stages due to the retail cost of electricity being much higher than onsite production and because the DKIS is currently 95% gas powered.

The Northern Territory is in a unique situation where the largest solar and battery farm in the world is planned to be built, transmitting firmed solar power past Darwin to Singapore through a subsea cable. Sun Cable is progressing in its plans to install around 17 GW of PV in the NT with batteries that will provide between 3.6 GW and 6.4 GW of dispatchable power 24 hours per day.[18] Included in the plans is a connection to third party customers, including the DKIS, as a supplier. That amount of solar power would potentially greatly reshape the renewable component of the DKIS. At this point, the renewable energy proportion in the DKIS under such a circumstance is not known.

Sun Cable has designed its LSS to be located near Elliott, NT, about 750 km from Darwin. Batteries will be located on the generation site and at the Darwin supply point. The electricity will be transmitted via high voltage DC (HVDC). A portion of the electricity will be split off and converted to AC via a substation at Murrumujuk. This substation will feed into the DKIS and could also supply DLNG, as well as other industries at Middle Arm directly if enough demand is found.

The cost of delivering electricity to DLNG by Sun Cable are commercial in confidence but is potentially competitive. Notably, the CAPEX costs would be considerably less because bespoke LSS and BESS would no longer be required. The CAPEX costs for outside the plant to accommodate importing electricity would be much lower: $3.9M for Case 1, $5.5M for Case 2 and $30M for Case 3 compared to $37.9M, $77.2M and $145.4M, respectively, but involve higher OPEX costs to purchase the electricity. The internal plant costs were assumed to be the same as those associated with bespoke systems since similar retrofits (e.g., helper motor installations) would still be needed to utilize the imported electricity.

Additional benefits connecting via Sun Cable would be an increased renewable energy penetration over a bespoke PV-BESS system. Land size and battery storage place limits on the size of the PV-BESS systems outlined in Cases 1-3 above. By importing from a third party these limits are lifted and more electricity could be imported. Most critically, it would also extend the time over which solar power is available with a 24-hour supply and could lead to the larger carbon emissions reductions found in Table 13. The bespoke PV-BESS systems mainly operate during sunlight hours, but Sun Cable is planning a 24-hr firmed supply. This option is worthy of further investigation.

[18] Sun Cable, *Notice of significant variation: Australian-ASEAN power link project*, NT EPA submission, August 2021

Table 13 Carbon emissions reductions for the cases outlined above if the bespoke PV-BESS systems were replaced with a firmed 24-hour supply.

Case 1	Case 2	Case 3
92.3 kt $CO_{2\text{-}e}$ /yr	174.7 kt $CO_{2\text{-}e}$ /yr	447.3 kt $CO_{2\text{-}e}$ /yr

There are plans for Middle Arm to be a heavily industrialized area.[15] If there is a high enough electricity demand in the planned industrial district on Middle Arm, including DLNG, Sun Cable could consider directly supplying these industries. If the demand were not high enough, industries interested in Sun Cable's generation would receive it through the DKIS.

6.5 Regulatory Considerations with a Grid-connected Third-party Supply

The DLNG plant currently reports its emissions through NGERS.[14] Under the scheme, DLNG reports any emissions produced onsite, known as Scope 1 emissions, and the emissions of any imported electricity, Scope 2, using the specific grid emissions factor published under the National Greenhouse Account Factors for the given year. The grid emissions factor is based on the average emissions of the grid electricity so even if a PPA were in place to purchase 100% renewable energy, if that electricity goes through the grid network the grid emissions factor must be used. The sum of these two emissions sources is reported publicly as the plant's emissions. Currently, the DLNG emissions are solely from Scope 1 since it is not connected to the DKIS.

If Sun Cable finds it viable to offer electricity to Middle Arm through a separate connection, one concern is that if a direct connection is made to the substation, which would also be connected to the DKIS, if that would still classify DLNG as "grid-connected." This leads to questions regarding NGERS emissions reporting the liability of needing to surrender LGCs and STCs under the Renewable Energy Target (RET). If the electricity is supplied directly to DLNG using a power purchase agreement (PPA) but it is still considered grid-connected, then DLNG must report Scope 2 emissions as those of the entire DKIS average. This may not be an issue if Sun Cable and other renewable energy companies supply almost all the DKIS demand, but it is a matter that needs attention. Of course, if this substation is not considered part of DKIS, these issues are avoided. Sun Cable could also be an option for ILNG since it is located on Middle Arm as well.

7 Northern Territory

Figure 3 Map of the LNG plants located near Darwin. The city and nearby power stations are marked as well.

The results from the DLNG study were used to estimate similar changes to LNG plants from around Australia. The energy needs were scaled depending on nameplate capacity; PV supplies were additionally modelled based on local conditions. Since HOMER Pro finds the least-cost system, including CAPEX and OPEX, plant specific simulations should be done for more accurate results. Without that information available, we only scaled the PV size based on nameplate capacity, so the electricity output with the same size PV system varied depending on the local meteorological conditions.

7.1 Ichthys Liquid Natural Gas

The DLNG plant was summarised above and the other LNG plant in the NT is considered here. The Ichthys Liquid Natural Gas (ILNG) plant started production in 2018.[19]. With ILNG's position on Middle Arm it also would have the potential to have its electricity supplied by Sun Cable like DLNG. The other option would be a bespoke LSS like modelled above for DLNG. Since there has been no publicly available information on plans for expansion of the facility it was assumed that expansion will not occur in the near future. Therefore, two cases were investigated for ILNG:

Case 1: Displacing some of the current electricity needs of the plant generated by the GTGs with power generated by PV-BESS systems (analogous to Case 1 in the DLNG case).

Case 2: Introduction of electric helper motors to reduce the gas load on the GTCs (analogous to Case 3 in the DLNG case).

[19] https://www.inpex.com.au/projects/ichthys-lng/

7.1.1 Technical aspects of Case 1: Integration of Solar with GTGs

It is assumed that ILNG runs at optimum efficiency, similar to DLNG. Without having access to the specifications of the ILNG plant, calculations based on the proportional size difference to DLNG of the nameplate capacity leads to a fair estimate of the electricity supply to the plant. The capacity of ILNG is 2.75 times larger than that of DLNG.

Due to the close proximity of the two LNG plants near Darwin, the location for the PV-BESS system would be in the larger area seen in Figure 2, where ILNG and DLNG could perhaps share some infrastructure to reduce costs. Scaling up the PV-BESS system from Section 6.1.1, a system with 53.6 MW of PV and a BESS with a 19.7 MWh capacity. LNG plants receive their gas supply from various basins with different gas compositions, however it is assumed that the gas displaced by renewable energy is only the carbon dioxide product from the burning of gas composed of mainly methane. The reduction in carbon emissions would be 127 kt $CO_{2\text{-}e}$ /yr.

7.1.2 Technical aspects of Case 2: Integration of Solar with GTCs

Case 2 is analogous to Case 3 in Section 6.1.3, but scaled up to match the nameplate capacity of ILNG. A key benefit for ILNG, and a few other LNG plants, is that they already have electric helper motors installed,[20] making integration of renewables much simpler and at lower cost. For this case, a 305 MW PV array with one-axis rotation could be used. This leads to 642,000 MWh/yr of solar power generated saving 382 kt $CO_{2\text{-}e}$ /yr of carbon emissions. Both LNG plants near Darwin could partner in the development of an LSS on Middle Arm and reap its benefits together.

7.1.3 Economics of Solarisation of ILNG

In Sections 6.2.1-6.2.3 the costs are outlined for the PV-BESS systems for each simulated case for the DLNG plant. While the individual categories had varying costs across the different systems, the overall installation cost of the PV modules was $1.31/W and $1.73/Wh for the BESS. These values were used to estimate the cost of installation for ILNG based on the system sizes described above.

The total cost for PV systems (including any associated BESS) for ILNG for Case 1 is $104M and $399M for Case 2 as shown in Table 14, while acknowledging the fact that Case 2 values depend on Case 1 already being installed. The internal plant costs for the ILNG plant were based on the nameplate scaling factor and the internal costs of DLNG. Since the DLNG values had an accuracy of ±30%, and the costs likely increase at lower than a linear rate due to economies of scale, these numbers should be considered on the basis of magnitude and not definitive. The internal plant costs for Case 1 were a direct scaling of the DLNG Case 1 costs based on nameplate capacities. The ILNG plant already has helper motors installed, though with a smaller capacity than our technical model for solar power integration.[21] For Case 2 a range is given to allow for using the existing helper motors and to the addition of new ones. If ILNG were able to take advantage of **the third-party supply from Sun Cable instead of constructing their own solar power facility, then the CAPEX costs will be significantly lower being $11M for Case 1 and $83M for Case 2, but the internal plant costs would not change**.

[20] GE Oil & Gas completes tests on LNG compressor trains in Australia, *NS Energy*, 02 February 2012
[21] Inpex has informed us they have four 20 MW helper motors already installed.

Table 14 The net present cost of the PV systems for ILNG outlined above.

	Case 1	**Case 2** (not including Case 1 costs)
PV ($M)	70	399
BESS ($M)	34	-
Plant costs ($M)	12	505-645
Total ($M)	**116**	**904-1,044**

8 Queensland

There are three LNG plants in Queensland: Australia Pacific LNG (APLNG), Queensland Curtis LNG (QCLNG) and Gladstone LNG (GLNG). All three LNG plants are located adjacent to each other on Curtis Island near the city of Gladstone. The island is near the electricity grid, however the island itself has no electricity connection to the grid or to the mainland. All three plants were constructed in concert using the same liquefaction technology for the trains.[22]

Figure 4 Map of the Queensland LNG plants on Curtis Island, near the city of Gladstone. The proposed site for an LSS is shaded in yellow.

[22] Cathcart A, Harbeson M. Successfully delivering Curtis Island LNG projects, GTI LNG Conference, Perth 2018

8.1 Technical aspects of the solarisation of LNG plants in Queensland

The LNG plants in Queensland were constructed adjacent to each other on Curtis Island using similar trains to that of the DLNG plant (LM2500+G4, GE), therefore results based on scaling by nameplate from the DLNG report should give a reasonable estimate. However, since these plants are located in a distant location, differences in solar radiation effects must be accounted for.

All three plants were treated similarly to ILNG calculations, with the electricity demand scaled to the DLNG plant by the nameplate capacity. For the difference in PV production a basic model of the Case 1 of the DLNG plant was constructed in HOMER Pro software. A basic model was used since we did not have access to the original simulation files, and it was only needed to scale the PV output. It consisted of a converter, PV modules and batteries, all to the same size as the DLNG model for Case 1 and an auto-sized generator to make up the difference between the PV-BESS simulated output and the electricity demand (Figure 5). This simple model was first run in the location from Section 6 to generate the DLNG baseload of the generic system. The system was then relocated to near the LNG plants on Curtis Island and local weather files were imported to simulate the location's output. A similar process was used later with the Western Australia LNG plants.

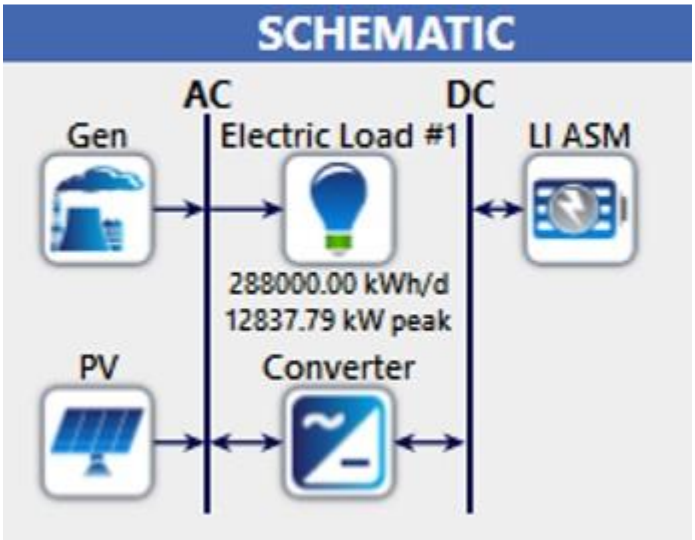

Figure 5 HOMER model schematic of the generic PV-BESS system that used to scale output based on geographic locations.

The PV-BESS system was located on the island along with the LNG plants because there is no electrical connection to the main land at present. Getting zoning approval for construction on the island is expected to be highly unlikely as most of the island is parkland but it is used here to give a visualization of the scale. The chosen site was near the plants but located in a conservation zone (ALUM code 1.3.0) according to QLD Development assessment map.[23]

With the expectation that further development of Curtis Island would not be a possibility, the site was chosen for our simulation purposes because moving the PV-BESS to the mainland should not appreciably alter the solar power output calculations. A study was announced to look at the potential of connecting the LNG plants to the Queensland grid,[24] so it may be feasible to place the PV-BESS on the mainland and connect through the grid connection if it goes ahead. There is also a 300 MW solar farm planned near

[23] https://dams.dsdip.esriaustraliaonline.com.au/damappingsystem/

[24] Filatoff N. Federal funds flow to test feasibility of Queensland HELE coal and pumped-hydro projects, *PV Magazine*, 10 Feb 2020

Gladstone that could potentially be used to power the LNG plants if an electrical connection were made to the island.[25] However, there are still issues associated with the added liability of being accountable to the Renewable Energy Target legislation as discussed in the DLNG section.

8.1.1 Results for Case 1: Integration of Solar with GTGs

The difference in the PV-BESS system's total output between the DLNG and Curtis Island location was used to scale the geographical difference. Based on the simple model, the PV output was 7.5 % less than in the NT. Therefore, the PV-BESS system scaled to nameplate capacity was used, but the output was scaled down to account for this location difference. The results based on this modelling is found in Table 15.

Table 15 Results from the model of partial offset of the electricity demands of the LNG plants in Queensland.

	PV (MW)	PV (MWh/yr)	BESS (MWh)	Emissions reduction (kt/yr)	ACCUs ($/yr)	Land size (ha)
APLNG	54	114,801	20	119	1914024	49
QCLNG	51	108,424	19	112	1807689	46
GLNG	47	99,495	17	103	1658821	42

8.1.2 Results for Case 2: Integration of Solar with GTCs

The same location scaling factor was used as in Case 1. The nameplate scaling factor was applied to all plants in a similar manner to that of ILNG in Section 7.1.2. The results on the size of the PV system are shown in Table 16 and are dependent on the BESS from Case 1 being available to manage ramp gates of the GTCs.

Table 16 Modeling results of electrifying helper motors for the LNG plants in Queensland.

	PV (MW)	PV (MWh/yr)	Emissions reduction (kt/yr)	ACCUs ($/yr)	Land size (ha)
APLNG	308	600,621	357	5,748,726	278
QCLNG	291	567,253	337	5,429,353	262.
GLNG	267	520,538	310	4,982,230	241

8.2 Economics of Solarisation of Queensland LNG Plants

The CAPEX costs for the Queensland LNG plants were calculated based on the technical specifications above and a price of $1.31/W of PV and $1.73/Wh of BESS. The costs for Case 1 are found in Table 17 and for Case 2 in Table 18. The costs of Case 2 are in addition to Case 1 and only valid if the Case 1 infrastructure had already been installed.

The costs associated with modifications needed inside the plants were based on the costs of the appropriate DLNG costs multiplied by the nameplate scaling factor. These values should be considered as ballpark figures since the original costs from the DLNG study had a large uncertainty of ±30% and the linear scaling likely overestimates as economies of scale would likely reduce the costs. A more thorough investigation would need to be done for each individual plant for a more accurate result.

[25] Ho K. Investment boost for Gladstone solar farm, *Energy Magazine Online*, 10 July 2020.

Table 17 CAPEX costs of solarisation for Case 1 of the Queensland LNG plants.

	APLNG	QCLNG	GLNG
PV ($M)	71	67	62
BESS ($M)	35	33	30
Solar power total ($M)	**106**	**100**	**92**
Plant costs ($M)	12	11	11
Total ($M)	**118**	**111**	**103**

*These values do not include the estimated $100M to connect to the mainland through an undersea electricity cable. This cost could be spread between the plants.

Only the APLNG Environmental Impact Statement had enough technical details of their trains to show they did not have helper motors. Since all the Queensland plants use a similar LNG train to each other and DLNG, it is assumed that none of them have helper motors, so installation costs are expected to be higher than would be economical like DLNG. On the other hand, the total PV proposed for the three plants combined is over 1 GW. As Sun Cable has shown there can be large cost reductions when scales this large are reached. It may even prove economical to increase the battery capacity further than described and boost the renewables penetration to more than what was modelled here. It was estimated that the cost of a subsea cabling would be around $100M but were not included in these calculations. The expense of subsea cable for a single plant may prove to be too high, but if the cost were spread between the Curtis Island plants it may be a much more desirable expenditure. Greater certainty around costs will be available when the government report is released about a grid connection to the island.

Table 18 CAPEX costs of solarisation for Case 2 of the Queensland LNG plants. The total cost includes those associated with Case 1.

	APLNG	QCLNG	GLNG
Case 2 PV only ($M)	404	382	350
Case 2 plant costs ($M)	652	616	565
Case 1 costs ($M)	118	111	103
Total ($M)	**1,174**	**1,109**	**1,018**

*These values do not include the estimated $100M to connect to the mainland through an undersea cable. This cost could be spread between the plants.

If a third party were available to delivery renewable electricity to the LNG plants on Curtis Island, the external CAPEX would be considerably reduced (Table 19). These costs are based on the nameplate capacity factor and the DLNG costs but do not include the internal plants costs, which remain unchanged but necessary.

Table 19 CAPEX costs for external modifications to allow for importing renewable electricity from a third-party supplier.

	APLNG	QCLNG	GLNG
Case 1 ($M)	11	10	9
Case 2 ($M)	83	79	72
Total ($M)	**94**	**89**	**81**

9 Western Australia

Western Australia has four LNG plants located in the north of the state in the Pilbara region: Gorgon LNG (GoLNG), Wheatstone LNG (WLNG), North West Shelf LNG (NWSLNG) and Pluto LNG (PLNG). The NWSLNG and PLNG plants are located near each other, but the WLNG and GoLNG plants are separated by large distances and sea in the case of GoLNG. Cases 1 and 2 are similar to ILNG and the Queensland LNG plants above.

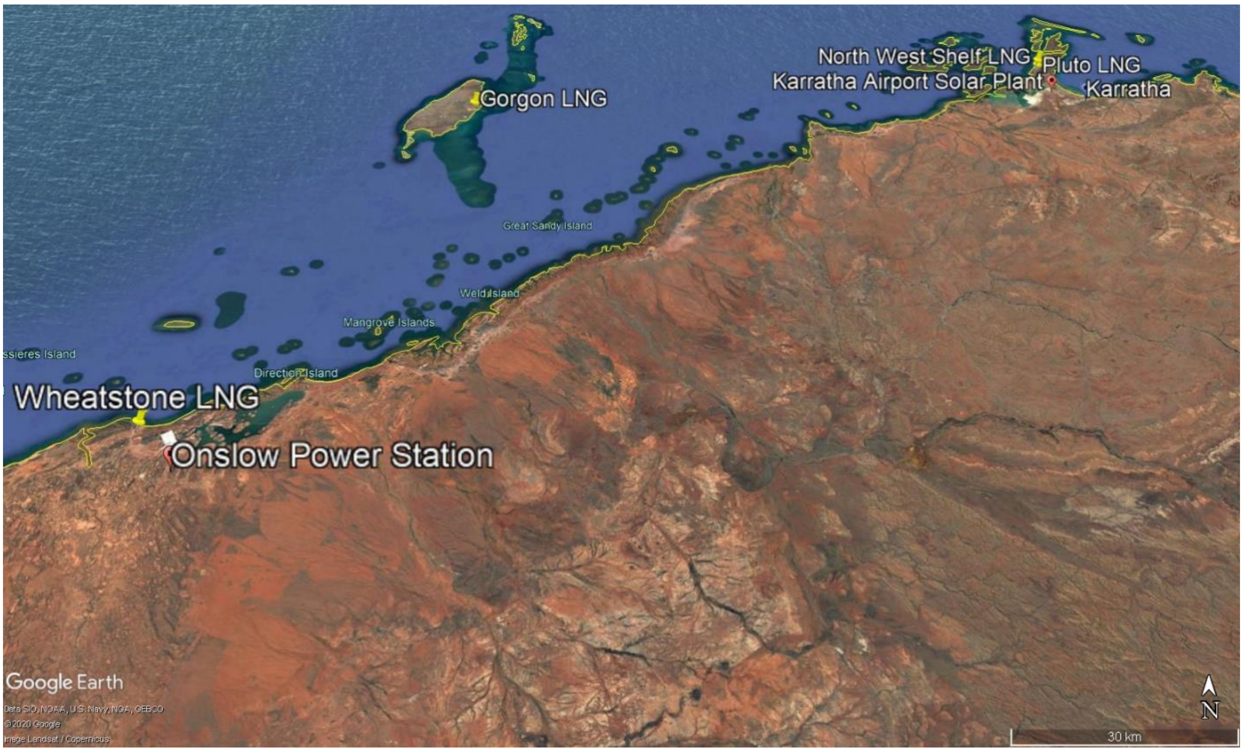

Figure 6 Map of the Western Australia LNG plants. The nearby large-scale solar facilities and power stations are also marked.

9.1 Results for Case 1: Integration of Solar with GTGs

The difference in the PV-BESS system's total output was used to scale the geographical difference. All LSS sites were chosen to be a close as practical to reduce transmission costs. There are some zoning issues associated with the sites outlined below.

The whole island where GoLNG is located is zoned as Reserve (Type 3 R) [26] by the WA government so additional construction may not be possible. With this in mind, the LSS system was located directly next to the plant for modelling purposes as there was no other logical location, as seen in Figure 7. Without an installation on the island, there would be no practical solution as the cost of a subsea cable to the mainland would be cost-prohibitive.

[26] https://espatial.dplh.wa.gov.au/PlanWA/Index.html?viewer=PlanWA

Figure 7 Location for an LSS to service GoLNG. Currently zoned as Reserve (Type 3 R).

Since the NWSLNG and PLNG are next to each other, they were simulated with a single PV system as seen in Figure 8. This land was classified as Type 1 Crown Land so there may be an option for further construction.

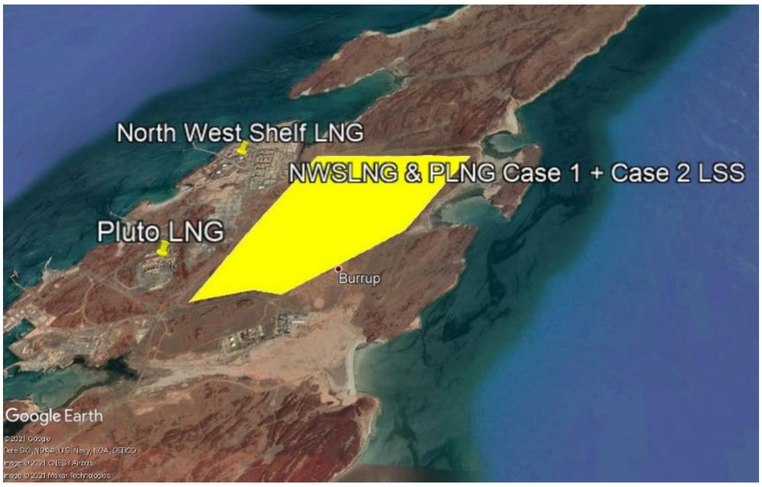

Figure 8 Location for an LSS to service NWSLNG and PLNG. Currently zoned as Type 1 Crown Land.

All of the nearby land that was big enough for an LSS to service WLNG was currently either leased or zoned as Reserve,[26] so the best geographical leased location was chosen with the knowledge that further arrangements would be needed (Figure 9). If the LSS must be moved, it is not expected to have a large impact of the simulated PV output but would increase delivery costs.

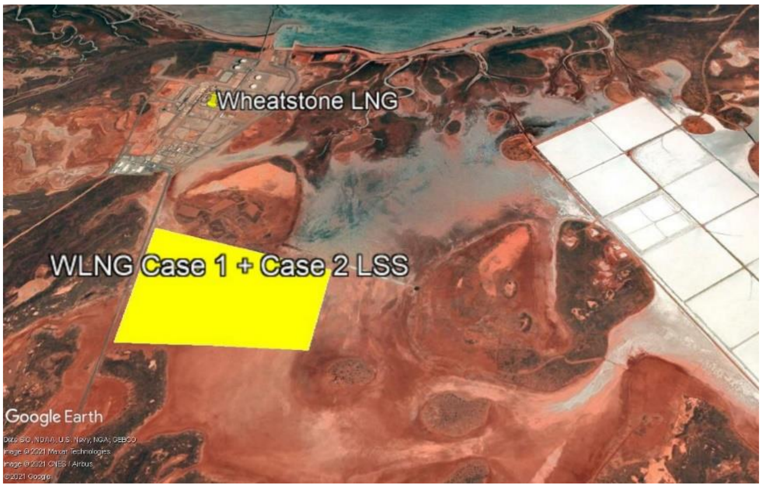

Figure 9 Location for an LSS to service WLNG. Currently zoned as Lease (Type 3 L).

All results showed the WA plants to have a higher PV energy output by approximately 11% than the NT plants. The PV-BESS system energy was scaled up to account for the extra output; the scaling factor for nameplate capacity was applied as well. The results based on these estimations are in Table 20.

Table 20 Results from the model of partial offset of the electricity demands of the LNG plants in Western Australia.

	PV (MW)	PV (MWh/yr)	BESS (MWh)	Emissions reduction (kt/yr)	ACCUs ($/yr)	Land size (ha)
GoLNG	94	238,208	35	247	3,971,524	85
NWSLNG	102	259,494	37	269	4,326,401	92
PLNG	28	72,167	10	75	1,203,200	26
WLNG	54	135,852	20	141	2,264,988	48

9.2 Results for Case 2: Integration of Solar with GTCs

The same location scaling factor was used as in Case 1. The nameplate scaling factor was applied to all plants in a similar manner to that of ILNG in Section 7.1.2. The results on the size of the PV system are shown in Table 21.

Table 21 Results from the model of partial offset of the electricity demands of the LNG plants in Western Australia

	PV (MW)	PV (MWh/yr)	Emissions reduction (kt/yr)	ACCUs ($/yr)	Land size (ha)
GoLNG	534	1,246,265	741	11,928,381	481
NWSLNG	579	1,357,625	807	12,994,245	521
PLNG	161	377,564	225	3,613,784	145
WLNG	305	710,754	423	680,2841	274

9.3 Economics of Solarisation of Western Australia LNG Plants

The CAPEX costs for the Western Australia LNG plants were calculated based on the technical specifications above and a price of $1.31/W of PV and $1.73/Wh of BESS. The costs for Case 1 are found in Table 22 and for Case 2 in Table 23. Case 2 can only go ahead if Case 1 were already completed, therefore the economics of Case 2 are in addition to Case 1. The costs of modifications internally to the LNG plants to accommodate these cases were based on the DLNG costs and the nameplate scaling factors of each plant. GoLNG,[27] NWSLNG (trains 4 and 5)[28] and PLNG[29] all already have electric helper motors that could reduce the CAPEX costs inside the plant.

Table 22 CAPEX costs of solarisation for Case 1 of the Western Australia LNG plants.

	GoLNG	NWSLNG	PLNG	WLNG
PV ($M)	123	133	37	70
BESS ($M)	60	65	18	34
Solar power total ($M)	**183**	**198**	**55**	**104**
Plant costs ($M)	21	23	6	12
Total ($M)	**204**	**221**	**61**	**116**

Table 23 CAPEX costs of solarisation for Case 2 of the Western Australia LNG plants. The total cost includes those associated with Case 1.

	GoLNG	NWSLNG	PLNG	WLNG
Case 2 PV only ($M)	700	759	211	399
Case 2 plant costs ($M)	1,044-1,129	1,147-1,220	235-340	645
Case 1 costs ($M)	204	221	61	116
Total ($M)	**1,948-2,033**	**2.127-2,200**	**507-612**	**1,160**

If a third party does arise that can supply electricity to the LNG plants in the Pilbara region, the costs associated with connecting to that supply are outlined in Table 24. These costs do not include those associated with the internal plant modifications that would still need to be carried out. It was deemed that any connection to the mainland would not be economically feasible for GoLNG due to the large distance a subsea cable would have to span.

Table 24 CAPEX costs for external modifications to allow for importing renewable electricity from a third-party supplier. Costs for internal plant modifications are not included.

	GoLNG	NWSLNG	PLNG	WLNG
Case 1 ($M)	-	20	6	11
Case 2 ($M)	-	157	44	83
Total ($M)	-	177	50	94

[27] *Gorgon gas development and Jansz fed gas pipeline: best practice pollution control design report*, 22 January 2015

[28] North West Shelf (NWS) LNG trains 4-5, *Mechademy Engineering Solutions*, https://www.mechademy.com/lng_plant/north-west-shelf-nws-lng-trains-4-5/

[29] *Pluto LNG project: greenhouse gas abatement program*, Rev 2, 20 June 2011

9.4 Third Party Electricity Providers

A second major renewable energy project planned for Australia is the Asian Renewable Energy Hub (AREH), which received major project status from the WA government in 2018.[30] The project hopes to achieve a total capacity of 26 GW from both solar and wind leading to a higher capacity factor. The majority of the electricity generated will be used to generate hydrogen for export but up to 3 GW could be available in the East Pilbara region, where the WA LNG plants are located. The distance from the planned site to Karratha, near where the two closest LNG plants are located, PLNG and NWSLNG, is roughly 400 km away and a further 200 km to WLNG. Transmitting electricity is expensive over these large distances but the large amount of predictable demand may prove economical for installing transmission lines. Sun Cable estimates that the cost of two HVDC 525 kV converter stations would be around $1.3B and the overhead HVDC transmission lines approximately $1.6M/km. Since AREH is already planning to electrify this region, connecting to the LNG plants may be seen as a measure to reduce the overall costs. If this were to happen, the decarbonisation of the NWSLNG, PLNG and WLNG plants could be much greater than the values shown in Table 20 and Table 21. AREH claims they will have a firmed capacity that exceeds 6,000 MW, many times greater than the LNG plants would use at full capacity if all changes described above were implemented. The carbon emissions savings from a 24-hr third-party supply is shown in Table 25, with a total reduction of 5,088.9 kt CO_{2-e}/yr.

Table 25 Carbon emissions reductions that could be achieved if the plant changes from ins Sections 9.2 and 9.3 but the renewable electricity was sourced from a 24-hr third-party supplier.

	Case 1 (kt/yr)	Case 2 (kt/yr)
NWSLNG	482.9	2,337.1
PLNG	134.1	649.2
WLNG	254.4	1,231.2

10 Marketing opportunities

Some leading scientists and engineers, including Australia's Chief Scientist Alan Finkel, believe that natural gas is key to transitioning the world's reliance on carbon intensive fossil fuels for power generation, like coal and petroleum, to ones that mainly rely on sustainable sources such as solar and green hydrogen. Natural gas is a fossil fuel itself, albeit one with a lower carbon footprint, and much of the world still see the carbon emissions, even as a transition fuel, as undesirable in the age of climate change awareness. This has led to a push to have an accounting process for the total carbon emissions of the LNG chain to give countries the information they need to help them achieve their emissions targets.[31] For example, Chevron just announced a deal to provide Australian LNG to Singapore along with an accounting of the emissions from wellhead to delivery.[32] Tokyo Gas and GS Energy in Japan have gone a step further and received shipments of carbon neutral LNG. The Canadian LNG industry has investigated its advantage in the clean LNG market by utilizing its ample amount of renewable energy available to electrify the LNG process and market clean LNG.[33] While reduced-carbon natural gas has a higher cost there is evidence of a market for it.[34] It has even been suggested that carbon neutral LNG

[30] https://asianrehub.com/
[31] BloombergNEF, Carbon neutral LNG: suppliers focus on optionality, transparency and CCS, 19 April 2021
[32] https://www.boilingcold.com.au/chevron-sells-greenhouse-impact-certified-lng-to-singapore/amp/
[33] Canada's Green LNG Advantage, *Canada and the Natural Gas Economy*, Special Report 2, November 2019
[34] Macdonal-Smith, Interest grows in carbon-neutral LNG, *Fin Rev*, 29 Dec 2020

could attract a premium through a climate differentiation factor[35] and these premiums could expedite further emissions reductions from producers.[36] By reducing the emissions associated with the LNG process, natural gas could gain a higher acceptance as a low-emission fuel in the transition to a renewables-based electricity market. The Asian market is calling for more lower carbon LNG[37] and Australia could leverage its proximity to the Asia market with shorter shipping routes.

11 Employment opportunities

Job growth and employment opportunities are other benefits of the solarisation of the LNG industry. In 2020, the Institute for Sustainable Futures (ISF) released a report linking job number to LSS installations based on size for the Australian industry.[38] They found the job numbers associated with LSS was lower than the world average but still significant. For the three phases an LSS project: construction and development, manufacturing and operation and maintenance they found that there 2.28 job-years/MW, 0.096 job-years/MW and 0.11 jobs/MW, respectively. A job-year is the equivalent of one full time job for one year. These values are for PV only and do not include jobs associated with batteries. Using these values, we tallied the total employment opportunities if the maximum amount of the bespoke LSS systems for were installed, that's the sum of Cases 2 and 3 for DLNG and Cases 1 and 2 for all the others. The results are in Table 26.

Table 26 Total amount of Australian employment predicted if the maximum amount of bespoke PV systems were implemented.

Construction and Development	Manufacturing	Operation and Maintenance
7,708 job-years	325 job-years	372 jobs

The figures from the ISF study for batteries were 7.6 job-years/MW for installation and 0.96 jobs/MW for operation and maintenance. The totals for the maximum battery installation at all LNG plants are in Table 27. Combined with PV installations, if it took a 10-year timeframe to install PV-BESS at all nine LNG plants it would lead to employment of 1,098 full-time roles during this period with 868 ongoing jobs for operations and maintenance upon completion.

Table 27 Total amount of Australian employment predicted if the maximum amount of batteries for the bespoke PV systems were implemented.

Installation	Operation and Maintenance
2,858 job-years	496 jobs

The job numbers could be even higher if these major projects come to fruition. Sun Cable predicts their project would employ approximately 1,500 personnel during construction and provide about 350 ongoing jobs.[39] For a 17 GW solar farm, the jobs to MW ratio is much smaller than that found by the ISF

[35] Demoury, V. LNG carbon offsetting: fleeting trend or sustainable practice?, *International Group of Liquefied Natural Gas Importers (GIIGNL)*, June 2020
[36] Krupnik, A., Munnings, C. Differentiation of natural gas markets by climate, *Resources of the Future*, April 2020
[37] Thompson, G. What is carbon-neutral LNG?, Wood Mackenzie, 18 November 2020
[38] Rutovitz, J., Briggs, C., Dominish, E., Nagrath, K. (2020) Renewable Energy Employment in Australia: Methodology. Prepared for the Clean Energy Council by the Institute for Sustainable Futures, University of Technology Sydney
[39] Northern Territory Government News Release, *Major Milestone Reached for Renewable Energy Project*, 28 January 2021

but the total number of jobs for the NT is larger than predicted if both DLNG and ILNG installed their own PV-BESS.

One way to attribute employment numbers would be to take the total portion of energy the LNG plants would use compared to the total demand on the Sun Cable system. However, the contribution of having DLNG and ILNG, among other industries in Middle Arm, may be larger than just their own usage. Sun Cable's business case to supply cheap, renewable power is based on the economies of scale. Without enough demand a venture of this size would not be viable. The economics of HVDC transmission is improved when large scale power is needed on the demand end. The considerable demand from the LNG plants, coupled with the demands of the DKIS, would therefore improve the business case, helping to bring high penetration of green energy supply to the Top End. This would make solarisation of the Darwin LNG plants more valuable to emissions reductions than just their own gas displacement. The overall demand of LNG plants could be the deciding factor in the financial investment decision on if these large solar farms proceed, so they could play a much larger role in employment numbers than just their own usage.

12 Funding opportunities

Securing funding for the integration of solar power into the LNG process aligns with many government goals and initiatives. The Australian government recently announced their Technology Investment Roadmap that they will use to determine funding for new technologies in an effort to meet their emissions reductions targets under the Paris Agreement.[40] One of the categories noted for importance was the electrification of industry. The details of the plan will be detailed soon but the two obvious places to first look for financing would be the Clean Energy Finance Corporation (CEFC) and the Northern Australia Infrastructure Facility (NAIF). Both are Australian government funded agencies that are dedicated to providing loans to sound business plans to achieve their particular goals. The CEFC is tasked with funding initiatives that move Australia toward a low emissions future, such as through investment in renewable energy and technology to lower emissions. The NAIF provides loans to infrastructure projects to grow the economies of Northern Australia. As all the LNG plants are in Northern Australia, and the solarisation of the plants would result in public benefits and lead to increased renewable energy, reduced emissions and higher employment these agencies may be able to provide the necessary funding for implementation. NAIF already has a track record in the renewable energy field by offering funding the 10 MW Batchelor Solar Farm near Darwin.[41] We have spoken with NAIF and they were interested in further discussions about the details of such a project as it fits in with their project selection criteria, though an Indigenous engagement strategy would have to be developed for project implementation. Even with interest rates for borrowing at all-time lows, NAIF can provide further benefits than traditional lending institutions without competing with them. The risk appetite for NAIF is higher, which allows for different loan structures, such as repayment holidays and longer-term loans up to thirty years. This flexibility could be an important lever for LNG plants to invest in the needed infrastructure without the extremely large upfront capital costs that may make the projects untenable at the start.

While the CEFC and NAIF may be able to provide loans, they do not provide grants to cover any of the costs associated with the integration of the technologies. One potential funding body worth approaching is the Australian Renewable Energy Agency (ARENA). While the PV-BESS systems in cases above for replacing some of the electricity demand from GTGs are no longer considered innovative, and thus unlikely to get funding, the case for installing helper motors powered by renewables may garner funding approval. Retrofitting helper motors onto a GTC and powering them with solar power is novel enough

[40] Department of Industry, Science, Energy and Resources, *Technology investment roadmap discussion paper: a framework to accelerate low emissions technologies*, May 2020

[41] https://naif.gov.au/media-releases/naif-approves-seventh-deal-in-northern-territory-with-loan-to-new-gas-and-solar-projects/

that it may qualify under the Advancing Renewables Program. Under this program DLNG may be able to secure matched funding for the helper motor modifications, which could be used as a demonstration case proving the technology to other LNG plants.

Other additional funding may be available for these energy projects under the newly announced federal budget.[42] The details are not yet clear but there is potential for funding of $42.2M for gas infrastructure, $50.7M for fuel security and $1,020M for emissions reductions technology that these projects may fall under. There is an additional $173.6M for funding gas infrastructure in the Northern Territory.[43] Once the specifics of how the money will be allocated the applicability to the introduction of solar power into LNG plants would have to be determined.

13 Conclusion

The prospects of the partial solarisation of Australian LNG plants from an environmental, financial and employment viewpoint are promising. Australia's LNG assets are major emitters and have lifespans conservatively estimated to be thirty years, which would stretch to at least the late 2040's and maybe longer.[44] If the maximum incorporation of bespoke solar power into the LNG plants delineated above were made, fuel savings of **96,887,650 GJ/yr of fuel savings could be realised, which equates to 5 Mt/yr in carbon emissions that could be avoided – around 1% of Australia's total emissions**.[45] Furthermore, if the very large capital costs of replacing the GTCs with electric drivetrains in all land-based LNG plants could be overcome, total carbon emissions savings would be about 23 – 26 Mt $CO_{2\text{-}e}$ /yr for all electrical and stationary energy needs of the plants.[46] Reducing the gas used in liquefaction process frees up gas that could instead be made available to the Australian market causing downward pressure on natural gas prices. If the gas was used to displace coal-fired power the emission reductions would be even larger.

As with any large infrastructure project there are employment opportunities to be had. During the planning and construction phase a total of 1,089 full-time jobs over a ten-year period could be expected across Australia if the maximum solar hybridisation is achieved. In the operational phase, 868 new permanent jobs are predicted.

This study has shown that implementing the integration of solar power into the electricity demands of LNG facilities around Australia could be cost-effective and produce financial savings for facility operators.

> A significant change in Australia's energy economics landscape, driven by precipitous declines in the cost of renewables, means that LNG producers can now import electricity more cheaply than they produce it. This liberates more of their product for higher value use in markets lacking the renewable resources of Australia.

[42] Taylor, Angus; *Investing in reliable affordable energy and reducing emissions to secure Australia's recovery*, media release, 11 May 2021

[43] APPEA, *Media release: Federal Budget – Some ticks but new levy a blow to Australian jobs*, 11 May 2021

[44] APPEA, LNG in Australia: global and national benefits

[45] Department of Industry, Science, Energy and Resources. *Australia's emissions projections 2020*, December 2020

[46] These emission values are based on the values from the DISER report with an adjustment made to account for Prelude LNG. Since Prelude LNG is a floating plant, it would be impractical to supply solar power to it.

Each plant would have their own technical needs that would have to be investigated on a case-by-case basis, but with the small amount of internal modifications to the plants themselves needed, it is likely Case 1 could be applied to all plants with a financial savings, permitted there is adequate land for an LSS.

Further decarbonisation requires additional electrification of the LNG process, and with it comes higher costs. Case 3 for DLNG (Case 2 for other plants) required a much greater CAPEX that was not recuperated by the reduction in OPEX over the 25-year lifespan. Outside financial support would therefore be needed to make the installation of electric helper motors and their solarisation economic.

> With the Australian government's commitment to achieve its Paris Agreement climate goals through technological advances, and the large amount of emissions abatement found through the solarisation of LNG plants, supporting these initiatives could be a justifiable investment.

It should be also noted that many plants already using helper motors (ILNG, GoLNG, NWSLNG and PLNG) have a lower hurdle for incorporating renewable electrification into their GTCs.

Businesses and governments are under increasing pressure to reduce emissions. For Australia, solarising LNG presents a major step towards net-zero emissions while creating jobs and downstream opportunities. For the LNG industry it presents an opportunity to produce a climate-differentiated product and leverage Australia's renewable resources for competitive advantage in a carbon constrained world.

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