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Financing a world scale hydrogen export project

GAS

ENERGY TRANSITION

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Executive Summary

A very substantial amount of capital will need to be invested in green hydrogen production to meet the 2050 net zero target and a significant proportion of this is expected to be used for export projects. Each green hydrogen import tender is expected to attract many supply bids and achieving the lowest delivered cost will be critical to success. Efficient financing can make an important contribution to minimising this cost.

This paper examines the financing of an ‘Archetype’ world scale hydrogen export project, where 1 GW solar power is used to make green hydrogen which is converted to 250,000 tpa green ammonia for export with a capital cost in the region of USD 2 billion. Lenders and investors will look to precedents when assessing the nascent green hydrogen sector and foremost will be LNG and offshore wind, which both represent large-scale, technically complex projects. However, LNG is for export while offshore wind is generally domestic, and LNG is economic on a stand-alone basis whereas both offshore wind and green hydrogen will require government support for many years to come and do not expect a return in excess of their cost of capital. LNG is also exposed to commodity prices whereas green hydrogen is more likely to be contracted at a fixed price, similar to offshore wind, at least into the late 2030s. Price indexation of green hydrogen to competing fossil fuels could be considered but given green hydrogen is intended to contribute to the phasing-out of these commodities, this solution seems inappropriate, introducing exogenous risks, and would lead to an increased cost. The commercial structure of the green hydrogen business is therefore expected to borrow more from the precedents of offshore wind, particularly in relation to price, but also from LNG where this is relevant, such as take-or-pay contracts.

The key issues that will need to be addressed to make a green hydrogen export project bankable are the political, offtake, and completion risks. Given that the project will rely for its viability on support from the importing country’s government in terms of both market and price, lenders will first and foremost need to be able to assure themselves that the legislation is robust and durable. In terms of offtake, it will be critical that: (i) the offtaker entity is strongly creditworthy, as it will act as a conduit for the government support and it is unlikely that an alternative buyer could be found on similar terms; and (ii) that there is no exposure to price or market demand risk for an extended period given that these will both depend heavily on government intervention. Lenders will wish to satisfy themselves that they are not exposed to unproven technology and that the risk of the project failing to come in on budget and schedule are satisfactorily mitigated. Lenders to LNG projects have almost always enjoyed completion guarantees from the sponsors. However, this has not been the case for offshore wind and, while completion guarantees do offer simpler and faster execution, it is considered that, provided that there is a robust contracting structure, they are unlikely to be an absolute requirement for the Archetype project but could well be if liquid hydrogen were chosen for the transportation medium. Lastly, if a project is located in a less developed country – and there are many that have excellent solar and wind resources – measures will also be required to mitigate the political risk of the host country.

Most lender and investor groups are highly incentivised to invest in energy transition projects. Subject to meeting the bankability requirements above, it is anticipated that there will be more than adequate liquidity to fund the Archetype project – and, indeed, substantially larger projects. Critical to achieving the lowest cost of capital, and consequently lowest cost of hydrogen, will be maximising the level of debt throughout the life of the project. This is best done by achieving the highest possible initial debt:equity ratio (DER) and minimising the rate at which the debt must be repaid. This last can be done either by securing debt with a long maturity (15+ years) and/or by ensuring that the debt can be refinanced one or more times over the life of the project. Lenders are expected to be somewhat conservative in the early transactions (especially if completion guarantees are not offered) but to offer more favourable terms as they become more familiar with the sector. Additionally, projects will be able to choose from a number of different types of lenders to optimise their financing. Concessionary lenders, typically owned by the importer country, may be willing to offer long maturities at concessionary pricing while export credit agencies can offer both mitigation of host country political risk, if necessary, and long maturities to promote exports from their home country. Commercial debt from either commercial banks or project bonds can help create competition and supply the balance of the financing need.

The sponsors who develop the project as initial investors should also consider selling a portion of their equity, at a premium, to investors who have a lower risk/return appetite (such as infrastructure funds) at the point when the project has been materially de-risked. This has the double benefit of increasing their return on equity and allowing capital to be recycled more quickly into new projects.

Looking ahead, based on the development of the LNG and renewable sectors, it is not expected that green hydrogen will become generally commercially viable without government support until the late 2030s at best (although in some sectors earlier) nor become a globally traded commodity until a decade or more later. Regional markets, with local hydrogen pricing or indexation to electricity, could develop earlier, however. Assuming no other market interventions, this would lead to an increase in the cost of hydrogen due to the increased cost of capital following increased risk exposure.

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1. Introduction

The global green hydrogen market has been forecast by the IEA to grow from almost zero in 2021 to 9-14 mtpa in 2030[1] and 125-300 mtpa by 2050.[2] The wide range is due to many uncertainties including: (i) end-user demand which will be, at least initially, largely a function of government policy; (ii) competing technologies and the rate at which costs fall, and (iii) certification and decisions over which types of low-carbon hydrogen will qualify for government support. The IEA also projects exports of 12mtpa of low-carbon hydrogen by 2030, of which almost 90 per cent is expected to be green hydrogen and the majority transported as green ammonia.

While necessarily uncertain, it is generally expected that the cost of producing green hydrogen will fall rapidly, as it has for solar and wind power generation. The IEA forecasts that current green hydrogen production costs of USD 3-8/kg will fall to USD 1.3-4.5/kg in 2030 and USD 1.0-3.0/kg by 2050. While some hydrogen projects are competitive at current high fossil fuel prices, at present almost all low-carbon hydrogen projects will require government support (whether by subsidy, other forms of financial support or statutory obligations, or carbon pricing) to attract investment, especially at the rate required to meet net zero targets by 2050. This is expected to remain the case for at least another 15-20 years in most end-use sectors.

Substantial capital will be required to develop this new industry. Estimates range from USD 80-300 billion from now until 2030[2] with very much larger numbers through to 2050 (the IEA estimates USD 2,500 billion for low-carbon hydrogen production alone) although it is hard to say what percentage of this will be for export projects.

The use of low-cost capital (debt and equity) will play its part in lowering the cost of green hydrogen, and both debt and equity investors have a substantial appetite to invest in the hydrogen sector. As an indication, just five of the leading US banks[3] have together stated commitments to raise USD 5.75 trillion by 2030 for the energy transition in general. Infrastructure fund investors similarly report strong investor demand with one leading fund[4] reporting sustainable investments doubling to over USD 500 million in 2021 in their funds alone with ongoing strong investor demand.

This paper analyses what is likely to be required in terms of government support and commercial arrangements for a project to be able to attract project finance – specifically, on a standalone basis, without direct funding or support from the project's shareholders – and what features would optimise the financing terms. A 1GW (50 ktpa hydrogen/250 ktpa green ammonia) export 'Archetype' project is used as an illustration of how lenders would analyse such a project.

There are parallels, in terms of commercial and financial arrangements, between the anticipated hydrogen export projects and LNG and offshore wind projects in the past. These will be reviewed in the paper, and it is worth noting that the majority of both LNG and offshore wind projects developed to date have sought project finance as a key part of their capital structure.

As of October 2021, only five low-carbon hydrogen projects of 100MW or more had reached an investment decision[5] and these are all purely domestic. No cross-border projects have been committed to date. While an export project raises additional issues, for example the bulk of the government support is likely to be provided by the importing nation rather than the host country, most of the conclusions apply equally to large-scale domestic projects.

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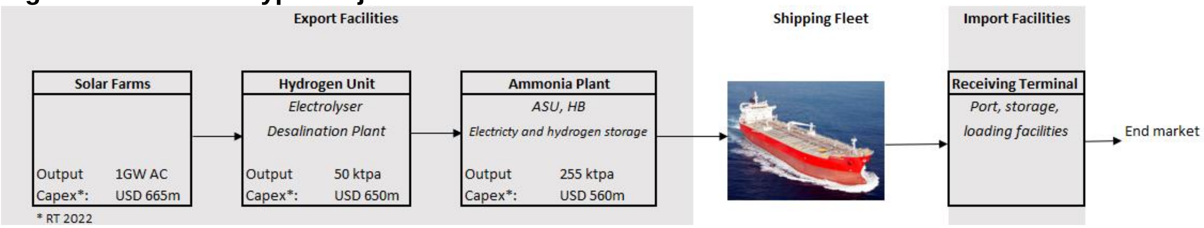
[1] IEA Global Hydrogen Review 2022
[2] IEA Global Hydrogen Review 2021, Announced Pledges and Net Zero Emissions by 2050 scenarios
[3] JPMorgan, Bank of America, Citibank, Goldman Sachs and Wells Fargo
[4] BlackRock
[5] Source: IEA (2021), Hydrogen Projects Database. All rights reserved https://www.iea.org/data-and-statistics/data-product/hydrogen-projects-database

2. Archetype hydrogen export project

For the purpose of illustration, an archetypal hydrogen export project (the 'Archetype' project) will be considered, comprising 1 GW solar power generation, hydrogen electrolysis, and a 250 ktpa ammonia plant with the ammonia exported by ship to a remote single market. The assumed total capital cost is USD 1,875 million (RT 2022).

Figure 1: The Archetype Project



Source: the author

The assumptions made for the Archetype project are set out in Appendix II and are largely taken from Cesaro et al[6] assuming linear scaling. The cost assumptions taken are those forecast for 2025 and include a degree of 'learning' from current cost levels.

The ammonia plant capacity is somewhat below what would today be considered world scale (currently, the largest new plants are over 1 million tpa capacity) but the near-term growth in the market is not judged fast enough to support that volume of offtake from a single project. The recent JERA auction only called for 500 ktpa and that may well be split between more than one exporter. In practice, real world projects may well use capacity in an existing ammonia plant, producing a blend of grey and green ammonia that might require more sophisticated certification to market, but could capture the benefits of an amortised plant, increased load factor/reduced hydrogen storage.

The total project cost, including financing costs, is assumed to be USD 2,100 million in money of the day. Assuming a debt:equity ratio (DER) of 60-70 per cent, USD 1,250-1,450 million of debt would be required.

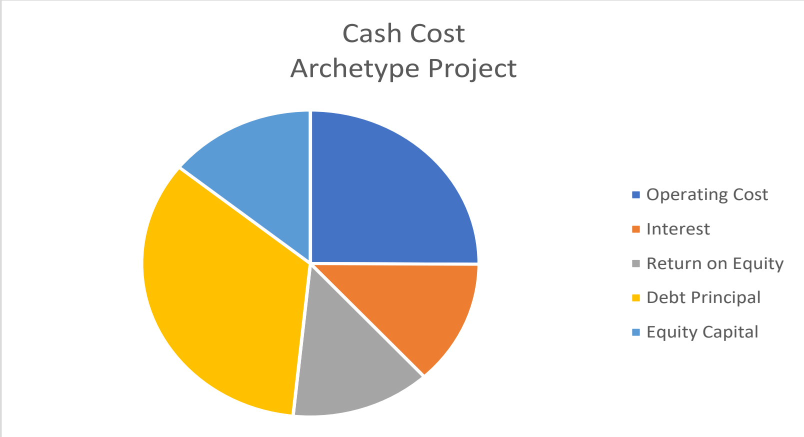
3. The impact of the cost of capital

3.1 Contribution to cash cost

For any renewable project, the cost of capital, both debt and equity, is a significant component of the cash cost. Figure 2 illustrates the relative contribution of the cost of servicing debt and equity to the total cash cost of produced ammonia for the Archetype project. Servicing debt and equity comprises 75 per cent of the total cash outgoing with operating costs amounting to only 25 per cent. Debt service has been split into principal and interest and the dividends have been allocated between the return of equity capital (with no return) and the return on equity (per cent p.a.) to allow comparison. The variable components, being interest and return on equity, are the components the project should seek to minimize and represent slightly more than the total operating cost.

[6] Cesaro et al, 2020, Ammonia to Power: Forecasting the Levelized Cost of Electricity from Green Ammonia in Large-scale Power Plants

Figure 2: Cash Costs of the Archetype Projects



Source: the author

3.2 Minimising the cost of capital

According to the capital asset pricing model, the cost of capital is a function of the perceived riskiness of a project compared to the average market risk. The risk exposure, and hence cost of capital, of the project company can be minimised by efficient allocation of the various risks among the project parties best placed to manage them to develop a robust, ‘bankable’ risk allocation structure that allows the level of debt to be maximised. This is addressed in Section 4 below.

Debt is not only cheaper than equity but, in most jurisdictions, is also tax deductible making the after-tax cost significantly lower. Thus, the cost of capital can be reduced by increasing leverage, the percentage of debt in the capital structure at the start of the project. The cost of capital can then be further reduced by continuing to optimise the capital structure over time by: (i) refinancing the debt to increase leverage and maturity, and (ii) introducing new equity investors with lower risk/return investment criteria as the project is de-risked.

4. Risks and Risk Allocation

4.1 Introduction

The overall project, from power generation to end user, has an inherent risk profile. The risk profile of the project company (the entity that will raise the equity and debt capital, own the export project, and be party to the project agreements) can be mitigated for the benefit of its investors by a combination of:

- government support from both importer and exporter countries
- allocation of risks among the project parties by the project agreements (including insurance)
- (principally for the benefit of debt) further allocation of risks between debt and equity and the sponsors (the project company’s ultimate shareholders) effected by the finance agreements.

This section sets out the principal options for ownership and commercial structure of the project and the key project agreements, the analogues which lenders will look to for precedents, the key risks to which the project is exposed and how these compare with the precedents, and lastly, how these might be allocated to other project parties in the project agreements to minimise the risk profile of the project company to make it ‘bankable’.

While theoretically there should be a continuous spectrum of risk/return available from investors ranging from equity through mezzanine to debt, in practice senior lenders, in particular, have a limited risk tolerance. This is largely developed from experience on prior analogous transactions or precedents. There may be certain risks that are not acceptable to senior lenders and which it may not be possible, or desirable, to allocate among the project parties. These are addressed in section 5.4.2.

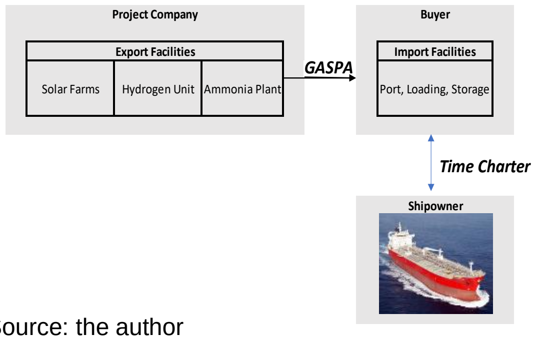
4.2 Project Ownership and Commercial Structure

While a number of models could be considered, this paper considers the following three which are based on the three main models seen in LNG.

4.2.1 Integrated Merchant Model

This is the model under which all the export facilities (solar farms, hydrogen unit, and ammonia plant are owned by the project company and the green ammonia is sold by the project company, as seller, to the buyer under a Green Ammonia Sales and Purchase Agreement (GASPA). It is anticipated that the buyer will own or lease the import facilities. This would give them control over what, for them, is a strategic asset and facilitate their ability to import ammonia from different suppliers.

Figure 3: Integrated Merchant Model



Source: the author

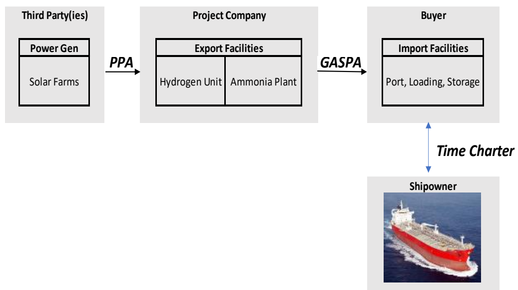
The shipping capacity, a fleet of ammonia carriers, is expected to be owned by a specialist shipowner as the vessels are of a relatively standard design and a specialist shipping company already has the expertise to procure new vessels and operate a fleet. They could also offer greater flexibility if they have existing ammonia carriers. The ships would then be provided to the project on long-term time charters. Either the buyer or the seller could be the charterer and thus control the shipping. This is principally a strategic issue – who keeps the shipping capacity in the event the supply chain breaks down. It has been assumed, for the early projects at least, that the buyer will wish to control the shipping and purchase FOB. Given they provide the subsidy, it is expected that they will win on this point. However, it has limited impact on financing and, where the seller is looking to sell to a number of different buyers in different countries, it may prefer to control the shipping and sell on DES terms.

4.2.2 Segregated Merchant Model

The Segregated Merchant Model is the same as the Integrated Merchant Model other than that the renewable power generation, solar farms in the case of the Archetype project, are owned by one or more third parties who sell power to the project company under long-term power purchase agreements (PPAs).

Given that the expertise required of a solar developer is quite different to that of a green hydrogen or ammonia/fertilizer company, a Segregated Merchant project could offer several benefits such as the greater purchasing power and more sophisticated trading capabilities of a dedicated solar developer.

Figure 4: Segregated Merchant Model



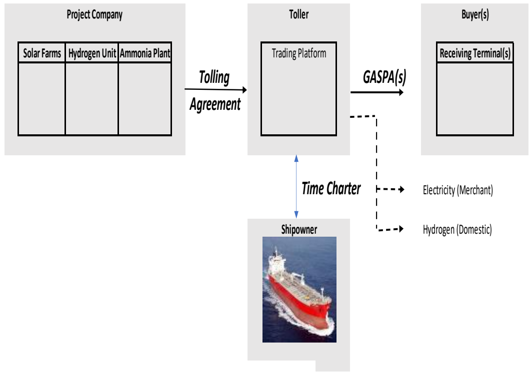
Source: the author

4.2.3 Tolling Model

The two models described above are both 'merchant' models, where the project company acts as a seller and sells green ammonia to a buyer and may either purchase or self-generate the required electricity. The merchant model has been used by offshore wind projects and the bulk of LNG projects; the choice of Segregated vs Integrated was largely for LNG where the production and liquefaction of gas are independent processes.

A new commercial model was developed for LNG projects in the US around 2010, where the party that would traditionally have been the buyer of LNG instead signs a tolling agreement with the project company. The toller then pays a capacity and operating fee to a liquefaction plant for liquefaction services, purchases its own natural gas, sells the LNG produced but retains the optionality not to produce LNG if margins are unfavourable. This model could equally be applied to green ammonia production where the project has the capacity to produce 100 per cent green ammonia but also has the optionality, if grid-connected, to sell power at times of peak price or buy power at times of negative prices and also, potentially, sell hydrogen into its domestic market.

Figure 5: Tolling Model



Source: the author

Given the optionality a grid connection provides, it is expected that at least a portion of the electricity requirement would be sourced from third parties. The tolling model requires a greater degree of flexibility in the ammonia offtake and would therefore be most likely to be adopted by parties active in each of the markets and thus able to realise the value of the optionality it affords. The toller would therefore be more likely to prefer to control the shipping arrangements.

4.3 Key Project Agreements

This section sets out the key agreements that the project company will need to enter into with third parties or sponsors in order to implement the project (the 'project agreements'). These do not include the agreements with the lenders which comprise the finance agreements. The key project agreements are divided into those that govern the construction or pre-completion phase and those that govern the post-completion phase. Completion is the point in time when the project has been constructed and has performed in accordance with its specification for a period of time such that there is no reason to expect that it will not continue to perform in accordance with the forecasts made in the financial model at FID. It is an important project finance concept, usually defined in detail by a series of tests.

This section is only intended to cover the key agreements that may have features specific to a hydrogen export project. The project will, in practice, have many project agreements, some of which (such as land leases) will span both the construction and operational phases of the project. However, these are common to many infrastructure projects and are not expected to be specifically relevant to hydrogen export.

The tolling agreement is not discussed in any detail in this paper as it represents a significantly different allocation of risk, where most of the commercial risk of a green hydrogen project is borne by the toller, and the project company is exposed substantially only to its completion and technical performance risk and can raise debt substantially based on the credit of the toller.

4.3.1 Pre-Completion Phase

A large-scale project such as the Archetype would generally be constructed by a number of contractors under Engineering Procurement and Construction (EPC) contracts. Both LNG and offshore wind projects comprise very different components: upstream gas developments and cryogenic gas plants in the case of LNG, and wind turbines, offshore structures, and subsea cables in the case of offshore wind. As a result, it has not been practical to have a single EPC contractor build the entire project under a single lump sum contract thus 'wrapping' the whole project risk. Given the complexity of an integrated green ammonia plant, with renewable electricity generation, electrolytic hydrogen production and storage and ammonia synthesis, it is assumed that no single EPC contractor would be able or prepared to cost-effectively ‘wrap’ the whole project. Construction will, therefore, likely be carried out under a number of separate EPC contracts for each of the key components. (In the case of the Segregated Project, where the solar farms were in a separate company, it might be possible to build each project under a single EPC contract. However, the resulting interface risks, in this case managed through a PPA, would remain). These EPC contracts would, in turn, be managed by a project management agreement with an external project manager, or by the project company itself. In the latter case, the project company would likely draw upon the expertise of one or more of the sponsors through technical support agreements to provide experienced staff on secondment, technical advice, etc.

The project company will also generally organise a comprehensive insurance package covering the typical range of construction risks, possibly including delay in start-up. Other project agreements such as process licences and permits to construct and operate will be critical to the project. However, these would, ideally be ‘wrapped’ by the relevant EPC contractor who would take responsibility for the performance of the relevant units under the process licences and for obtaining the necessary permits.

4.3.2 Post Completion (Operational) Phase

Offtake

For a Merchant Project, the key project agreement will be the Green Ammonia Sales and Purchase Agreement (GASPA) between the project company as seller and the buyer. This will be a long-term contract that will underpin the entire project, both setting out the terms under which the buyer will purchase the green ammonia but also acting, indirectly, as a conduit for support from the buyer’s host government.

Governments are looking at a range of options to deliver support to hydrogen projects including CfDs, carbon pricing, and mandates for the use of green hydrogen or state-supported aggregator/buyers (such as Germany has with HINT.CO[7]) with the focus to date being mostly on domestic (or intra EU) projects. Depending on the chosen scheme, the buyer could be either a state-supported aggregator or a utility/end user buyer. In the case of the buyer being a utility/end user under a CfD mechanism, the CfD payments could be made directly to the seller under a separate agreement with a government-owned entity (as for UK offshore wind) or to the buyer. For an import project, it is expected that the host government would prefer to work directly with a domestic utility and thus the project would only contract with the buyer and have no direct relationship with its host government.

Power Purchase

For a Segregated Project, the Power Purchase Agreement (PPA) will also be critical, and its terms will need to closely match those of the GASPA.

Operation

Operation of the project could be carried out directly, by staff hired by the project company with support from the sponsors through technical support agreements, as is common for LNG projects. Alternatively, operation could be carried out by a contractor under an Operation and Maintenance (O&M) agreement under which it would operate the project for an agreed price and to agreed key performance indicators (KPIs). This is the more common model in the power industry. However, as for the EPC contracts, given the complexity of the project and range of competences required, it may not be practical to have a single O&M contractor and consequently two or three separate O&M agreements might be required.

Insurance

As for the construction phase, the project company would need to place comprehensive operational phase insurances which could include business interruption insurance (BII). Under BII, if an extended insured event leads to a loss of revenue, the insurer pays compensation.

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[7] HINT.CO acts as a principal, entering into long-term hydrogen import SPAs as a buyer and shorter-term domestic hydrogen SPAs as a seller calling upon committed government funding to meet the expected shortfalls between the two sets of contracts. HINT.Co https://www.h2-global.de/project/h2g-mechanism

Shipping

As noted in 4.2.1 above, a key issue will be whether the buyer or the seller would be the charterer and thus control the shipping. If the GASPA requires DES, the project company will enter into long-term charters for the shipping capacity it requires. These could be a charter for individual vessels dedicated to the trade or a contract of affreightment under which the ship owner would guarantee the availability of shipping capacity from its fleet.

4.4 Analogies/Precedents

Lenders and investors tend to look for precedents when analysing any new project. That is not to say that they are not capable of analysing a new industry, rather that it is easier and more efficient to consolidate the views of a large group of lenders or investors around known structures where possible. There are clear analogies between the emerging green hydrogen export projects and both LNG and renewable power (offshore wind in particular), but also key differences.

LNG

Green hydrogen is like LNG in that: both are technologically complex with some similarities (especially with liquefied hydrogen); both are large-scale, capital-intensive energy businesses where sellers and buyers must make substantial, long-term capital commitments; and both are export oriented. However, green hydrogen is unlike LNG in that: (i) green hydrogen technology has no track record at this scale whereas LNG plants have been operating for over fifty years; (ii) green hydrogen is not cost competitive with fossil fuel alternatives and will require government support, and (iii) there is no traded market yet for green hydrogen nor any transparent price.

Furthermore, the economics are very different. Until green hydrogen no longer requires government support (not expected until the mid-late 2030s), it is expected that it will require a fixed price that will allow it to meet its cost of capital but no more i.e., it will not generate any economic profit or EVA (defined as the surplus above the cost of capital). On the other hand, LNG projects are exposed to commodity prices (typically indexed to oil or natural gas) and are expected, at FID at least, to yield a return on capital well above the cost. (Unlike renewable energy projects, this profitability is required to stimulate the substantial investment in exploration required for fossil fuel projects). LNG is now also a mature industry and there are not expected to be material reductions in capital costs for new projects, whereas green hydrogen is expected to follow a sharp learning curve of cost reduction, leaving early projects relatively low in the cost competitiveness rankings. Another important feature of an integrated LNG project is the value of the gas resource, i.e., once the gas has been discovered, the project has material value even before the LNG project is developed and this value is not reflected in the DERs. While never overtly subsidised, the LNG business in its early days bore a closer resemblance to green hydrogen now. Liquefaction and cryogenic shipping at that scale was relatively new; LNG was only traded bilaterally as buyers developed their domestic markets and, in the very earliest days of the Alaska-Japan trade of 1969,[8] the offtake agreement had a fixed price. The LNG industry also went through a process of cost reduction in the 1980s and 1990s, as plants used ever larger gas turbines, which contributed to the phenomenon of concurrent LNG cargoes being delivered to Tokyo Bay, for example, at widely varying prices depending on the date on which the SPA had been signed. Therefore, to the extent that LNG is used as a precedent for the emerging green hydrogen industry, it would be best to look to the early days, namely before the 1980s. (Although the gas and financial markets have both developed since then and some of the older contract terms would be outdated now.)

Offshore Wind

Green hydrogen is also similar to offshore wind in a number of respects: they are both large-scale, capital-intensive energy businesses, with emerging technologies (although offshore wind is much more advanced now) and rapidly reducing capital costs; both require (at least until very recently) government support and have no exposure (or are not expected to, in the case of green hydrogen) to commodity prices but are only marginally profitable. Green hydrogen is different to offshore wind in that it is export

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[8] IEEJ April 2002 1 LNG Market and Price Formation in East Asia Kazuya FUJIME, The Institute of Energy Economics, Japan

oriented, whereas offshore wind is essentially domestic, and there is a deep and transparent market for electricity unlike hydrogen. Table 1 summarises the key similarities and differences.

Table 1: Comparison of LNG and offshore wind as precedents for green hydrogen

Feature	Green Hydrogen	LNG (pre 1980 s)	LNG (post 1980 s)	Offshore Wind
Capital Intensive	✓	✓	✓	✓
Multi-Component	✓	✓	✓	✓
Export	✓	✓	✓	×
Requires long term Buyer capital commitment	✓	✓	✓	×
Market - depth and transparency	×	×	✓	✓
Commodity Price exposed	×	✓	✓	×
Emerging technology	✓	×	×	✓
Learning Curve - declining costs	✓	×	×	✓
Requires Government Support	✓	×	×	✓
Profitable (EVA)	×	✓	✓	×

Source: the author

Ammonia

For a green ammonia project, one could also look at the existing ammonia industry. Ammonia is a sizeable (190 mtpa[9]) globally traded commodity. The market is smaller than LNG (380 mtpa in 2021[10]) and, more importantly, only 10 per cent is globally traded versus almost all LNG. It is principally used as a feedstock for fertilisers and other industrial purposes, and it might appear logical to price green ammonia simply at a premium to traded 'grey' (made using natural gas or coal as feedstock) ammonia. However, ammonia pricing is quite volatile, and while new ammonia projects do raise project finance, it is typically at a lower DER of 50-60 per cent vs 70+ per cent for LNG and +/- 80 per cent for offshore wind. Also, if the green hydrogen/ammonia industry does grow at anything like the levels forecast, it will largely be serving a different market i.e., fuel rather than fertiliser, and will overtake the current grey ammonia market. Thus, indexation to the current market would create a 'tail wagging the dog' problem and would introduce an unnecessary, exogenous risk and associated increase in the cost of capital.

Conclusion

In terms of precedents, green hydrogen is more complex than either LNG or offshore wind (or indeed conventional ammonia) in that it has more components: power generation, electrolysis, storage of power and/or hydrogen, ammonia manufacture and shipping, as well as facilities to receive and, potentially, crack ammonia back into hydrogen in the buyer's country. It also has a greater degree of optionality, although less than a refinery or petrochemical plant. Therefore, for green hydrogen projects, commercial and financing models will emerge that do not follow any specific precedent but will likely borrow heavily from renewable power, especially offshore wind, and LNG where relevant.

4.5 Key Risks

The key risks lenders and investors need to address fall into the categories below. These are outlined in this section and compared with the level of exposure typically seen in the analogous sectors in Section 4.6. Possible methods to allocate the risks though the project agreements to create a 'bankable' project structure, largely based on the precedents, are presented in Section 4.7. It may not be possible to allocate all the risks to other project parties through the project agreements to the satisfaction of lenders, in particular. Such risks will then have to addressed in the financing, e.g., by allocation to the sponsors or specialist lenders and these are addressed in Section 5.4.2. A more detailed discussion of the risks, precedents, and rationale for the allocation is presented in Appendix III.

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[9] Fertecon 2022 https://ihsmarkit.com/products/fertilizers-ammonia.html

[10]

The risks are divided into pre-Completion, post-Completion and General, which apply throughout the life of the project.

4.5.1 Pre-Completion

Completion Risk is the risk that the project fails to achieve completion by the expected date, within budget, or to perform to specification (in particular, the requirements of the GASPA). Given the complexity and scale of the project and the likelihood that some of the technology used, while not unproven, will almost certainly involve scale-up or technical improvements of key components, completion risk will be a significant concern for lenders. In particular, because the satisfactory completion of a green hydrogen project will rely on the successful completion of a number of other projects, over which it has limited control, such as the shipping, the buyer's receiving facilities and the electricity supply project in the case of a Segregated project, there will be a significant element of 'Co-Completion' risk which adds to the risk and complexity.

4.5.2 Post Completion

Offtake

Offtake risks principally comprise:

- **Volume risk,** which can be divided into:
    - **Market Volume (Underlying) risk -** the risk that the buyer will not take the expected quantity of product due to a lack of market demand before considering the terms of the offtake contract. This is particularly critical for green hydrogen where there is currently no market, and significant government intervention is likely to be required to create and sustain that market.
    - **Volume (post-contract) risk -** the extent to which the seller is exposed to market volume risk under the terms of the GASPA.
- **Price risk,** which can be divided into:
    - **Market Price (Underlying) risk -** the risk that the market price of the product is not what was forecast at FID and is insufficient to generate sufficient revenue to service debt and provide a return to equity. This is another key concern for hydrogen where there is currently no liquid traded market for hydrogen at scale.
    - **Price (post-contract) risk -** the extent to which the seller is exposed to Market Price risk under the terms of the GASPA.
- **Buyer Credit-** the risk that the buyer is unable to meet its financial obligations under the GASPA. This is particularly important for green hydrogen, given that the contract price is likely to be 'off market' i.e., at a higher price than that of the fossil-fuel alternative and also later vintage green hydrogen contracts. Thus, if the buyer defaults, it would be unlikely that the seller could find a replacement buyer on the same terms. Furthermore, in the case of green hydrogen, any government support from the end-user country will most likely be channeled through the buyer in the GASPA.

Government support risk

Government support will primarily come from the government of the buyer's country and will most likely be provided indirectly via the buyer in the GASPA. It could come through a variety of mechanisms and in each case, there is a risk that the government amends the support for policy or economic reasons, or amends the mechanism for such support, e.g., to conform with a newly established regional or global standard and consequently the amendment has an adverse effect on the price or terms of the GASPA.

It is also likely that there will be some degree of host government support for the export project e.g., in the form of exemptions from certain import/export duties and/or tax holidays or grants for local manufacturing. These are expected to be secondary, both in terms of materiality and duration, compared to the support required of the buyer's country.

Resource risk

The risk that the solar or wind resource falls below the levels forecast at FID impacting the project's ability to deliver contracted quantities.

Certification Risk

The risk that the project company is unable to provide the certification required under the GASPA to demonstrate that the ammonia is 'green' and qualifies for government support and the associated price premium.

Operational risk

The failure to achieve the production quantity and quality at the cost, each as forecast at FID. For hydrogen, whether exported as green ammonia, LOHC or LH2, the coordinated operation of a number of different facilities (generation, electrolysis, and ammonia) some of which may entail emerging technologies, will pose a risk that lenders will need to address.

4.5.3 General Risks

Shipping

The principal shipping risks comprise: (i) timely delivery of the ships to specification, if they are new-build; (ii) technology risk where the ships use ammonia as a fuel (as seems likely); (iii) availability of the vessels to operate to the planned capacity and schedule; (iv) availability of replacement shipping in the event that the term of the charter party is less than the project life, and (v) changes to the charter rate outside the forecast. The charter rate could change for many reasons, including an increase in the operating cost, if the time charter expires and the market has tightened or if shipping regulations governing, for example, emissions or safety impose additional costs.

Interface Risk

The project will comprise numerous separate components; some of these will be owned by different parties and even where they are owned by the same party, may have multiple contractors that will be required to work together but with differing scopes. The risk in the construction phase is that a mismatch of technical specifications or legal obligations in the EPC contracts could lead to delays in achieving satisfactory start up or increases in cost. In the operating phase, there are similar risks ensuring a seamless operation through the different components of the project. In particular, in the segregated project model where power would be purchased from a third party, it will be critical to align the terms of the PPA and the GASPA to minimise the risk of the project company incurring liabilities under one contract without a matching claim under the other.

Macroeconomic Risk

The project will be exposed to a range of macroeconomic factors including interest rates, foreign exchange rates, and inflation. Interest rates can be addressed by hedging with derivatives or borrowing on a fixed rate basis. Foreign exchange exposures could arise where the project incurs costs in the currency of the host country (for example if power were purchased from the grid) but payment under the GASPA is in a different currency, for example US dollars.

In the event that the buyer and seller choose to index link the price to a commodity e.g., oil, gas, electricity or ammonia, this would present an additional macro-economic exposure.

Political Risk

In addition to the specific government support risk noted above, where the seller's country is not an OECD/wealthy country, commercial lenders will have concerns about political risk. This covers issues such as: their ability to repatriate hard currency, the risk of their debt being caught up in a broader debt restructuring program, expropriation (whether physical or economic e.g., by increasing taxes) or political violence. A number of countries with very attractive levels of solar irradiance (for example in North Africa or Latin America) will fall into this category.

4.6 Comparison of key risks with LNG and offshore wind

Table 2 sets out a comparison of the risk profile of green hydrogen in comparison to LNG and offshore wind projects. It is necessarily broad given that every project has its specific features, and we can only make assumptions about the green hydrogen project at this point.

Table 2: Comparison of the risk profiles of LNG and offshore wind versus green hydrogen

Risk	Green Hydrogen	LNG	Offshore Wind
Pre-Completion			
Completion			
Post Completion			
Offtake			
• Volume (underlying market)			
• Volume (post offtake contract)	(i)		
• Price (underlying market)			
• Price (post offtake contract)	(ii)		
• Buyer Credit			
Government Support			
Resource			
Certification			
Operation			
General			
Shipping			
Interface			
Macroeconomic			
Political			

(i) Assumes a committed annual quantity offtake
(ii) Assumes a fixed price offtake.

High	Medium High	Medium Low	Low

Source: the author

A green hydrogen project presents a risk profile with a number of similarities to both LNG and offshore wind. These are discussed in more detail in Appendix III. Overall, the risk profile is greater than either LNG or offshore wind given that the technology is less mature, the project has more critical components (some of which will be owned and operated by other parties), there is no current market for green hydrogen, and it will largely be created by government policy. While there is no traded price for green hydrogen at the moment, it has been assumed for this analysis that offtake agreements will be fixed price (with government support) leaving no material price exposure as is the case with the bulk of offshore wind generation. As offshore wind projects become generally competitive in their electricity markets, the price risk exposure will rise markedly. Ultimately, this is also expected to happen for green hydrogen but that is not expected to occur until well into the 2040s (see Appendix IV).

This analysis also assumes the export of hydrogen as green ammonia. For new technologies such as LH2 and, to a lesser extent, LOHC, the completion and operation risks would both be higher.

4.7 Financeable Risk Allocation

The principal risks are set out in Appendix III together with precedents from LNG and offshore wind and conclusions as to how they might best be allocated in the project agreements to create a 'bankable risk allocation'. It may not be possible to allocate certain risks through the project agreements and this will be noted below and covered further in section 5.4.2. This section summarises the key conclusions from Appendix III in terms of which party should bear which material risk and the recommended contractual mechanism to do so.

4.7.1 Risk Appetite

Lenders' risk appetite will depend on the type of lender/investor and the degree of competition among the lenders. At present, many banks have established targets for lending to support the energy transition and therefore may be prepared to accept a level of risk that they might not in other sectors in order to achieve these targets. However, the larger the project, the more lenders it will require and the less risk exposure that can be tolerated to satisfy the marginal bank. The Archetype project, with a likely debt requirement of around USD 1.5 billion, is well within the capacity of the commercial bank market. However, it may be desirable to include other lenders, especially bilateral/multi-lateral lenders (discussed in Section 5.3 below) which, while offering other benefits, might be more conservative in terms of risk appetite. For larger projects that exceed the capacity of the bank market, export credit agencies would typically be involved which can exhibit a lower risk tolerance. However, if well managed, this need not be the case. The Dogger Bank offshore wind project, for example, raised GBP 4.8 billion in 2021 – a record amount at the time – and required three export credit agencies together with a consortium of 28 commercial banks. However, the lender group *did* accept pre-completion risk. Lastly, project bonds could also be considered, as in line with banks, a strong appetite for hydrogen projects would be expected among bond investors. However, their desire to participate will be limited by the typical need for an investment-grade credit rating from one or two of three leading credit rating agencies who will wish to maintain credit standards across sectors.

Project finance lenders have a body of precedent of what is and is not generally an acceptable risk exposure. Based on these precedents, it is expected that material exposure to certain risks will not be acceptable to lenders (or infrastructure funds) and are likely to be allocated among the project parties as set out below. However, the precedents from LNG are not fully aligned with those from renewables such as offshore wind where the risk appetite seems to be somewhat greater and thus the proposals below cannot be viewed as definitive. Note this section only addresses the mechanism for risk allocation among the project agreements.

4.7.2 Key Risks: Allocation and Proposed Mechanisms

Leaving host country political risk aside (it is dealt with in more detail in Section 5.4.2), the primary risks for a green hydrogen export project are the closely related Buyer Government Support and the Offtake Risk. Other risks that may be more or less critical depending on the detail of the project, relate to Completion and Operation. These are discussed in turn below (and in more detail in Appendix III).

4.7.2.1 Buyer Government Support Risk

The commercial viability of the project relies on the ongoing support of the buyer's government to provide direct financial support or maintain a framework to socialise the cost. Given its criticality, lenders would be expected to do significant due diligence to assure themselves of the robustness and durability of the legislation ahead of making any loans. It is unlikely that the government would enter into any direct agreement with the lenders, however.

The risk of the buyer's government changing the support mechanism such that it has a material adverse effect on the GASPA should be allocated to the buyer unless the government chooses to provide such support directly e.g., via a CfD. An act of government might often be classified as force majeure but, in this specific case, should be explicitly excluded. The seller may not be aware of all the detail of the government support underpinning the project and would have only limited rights of action against the government.

4.7.2.2 Offtake Risk

Offtake Risk has three main components: buyer credit, volume, and price.

Buyer Credit

A number of material risks need to be allocated to the buyer under the GASPA and that can only be meaningful if the buyer is financially (and operationally) able to fulfil its obligations over the term of the contract. Lenders typically require that the buyer has an investment grade credit rating (BBB-/Baa or better) or provides a guarantee from another company with that level. Depending on the degree of reliance, lenders may also wish to place obligations or covenants on the buyer or its guarantor to seek to preserve its credit rating.

Volume

The underlying market for green hydrogen or ammonia is nascent, and its growth is heavily dependent on the policies of the buyer's government. Lenders will not be able to accept this risk, which is the situation for LNG and, materially, for offshore wind. Green hydrogen seems well suited to the 'take or pay' mechanism used in nearly all LNG contracts under which, following a build-up period, the buyer is obliged to: (i) take and pay for fixed contracted quantities in a period; and (ii), if it fails to take such quantities for any reason other than force majeure or seller failure to supply, to pay for the contracted quantity as if it had been taken. Such take-or-pay payments may then be used as a credit against any quantities taken above the contract level in the future. This mechanism offers the seller an assured cash flow with no exposure to the market volume risk but gives the buyer some ability to recover in future if the market growth is slower than expected. The concept of priority dispatch which gives offshore wind projects protection against market risk is not applicable to green hydrogen.

To provide a reasonable basis for financing, the contract term will need to be at least 15 years and preferably longer (20-25 years as for LNG) as lenders will give little or no credit to forecast sales beyond the take-or-pay period.

Price

There is currently no traded market for bulk hydrogen - brown, blue or green - so no price benchmark. The price for green hydrogen could be indexed to another commodity, similar to LNG being priced against oil. However, hydrogen has multiple uses unlike LNG which was, at least originally, primarily used to displace oil in power generation. Furthermore, LNG did not require a subsidy to compete against alternative fuels, a requirement for hydrogen for some time to come. Therefore, offshore wind provides the more relevant precedent, as a subsidised product with a price that is fixed and flat for an extended period of 15-20 years. For an export project, it is most likely that the buyer would simply enter into a fixed price contract with the seller and would receive support from its government either in the form of a direct subsidy (perhaps in the form of a CfD) or a mandate allowing it to pass on the cost to its customers. As for offtake volume risk, a contract term of at least 15 years with a fixed price would be required for bankability.

Price indexation to an alternative fuel/feedstock (coal, gas, oil or even ammonia) plus a premium could be considered but, with the journey towards net zero, the price of fossil fuels will become increasingly volatile and difficult to forecast. It would also seem inappropriate to link the price to a commodity that the project is ultimately aimed at making redundant. This would introduce additional risk that would reduce the level of debt that a project could raise and increase the levelized cost of the green hydrogen/ammonia. In the future, hydrogen might be indexed to other zero-carbon indices such as electricity prices or a green hydrogen traded market price will eventually evolve.

Recent LNG SPAs typically include a price review mechanism under which the price can be adjusted periodically to bring it into line with the market. While lenders have accepted this for LNG, it will not be acceptable for green hydrogen given that it is generally accepted that the levelized cost of green hydrogen will fall over time due to the 'learning curve'. This would make a price review essentially a one way, downward, option. Offshore wind PPAs have no such mechanism to change the fixed price.

4.7.2.3 Completion Risk

Completion risk has four components: cost overrun, delay, failure to meet design criteria, and co-completion (the risk that third-party projects on which the project depends fail to complete on time). The completion risk of a green hydrogen project is higher, at least at this time, than either LNG or offshore wind given the combination of complexity, relatively new technology, interfaces between intermittent renewable power and processes that work more reliably in baseload operation, plus reliance on third-party owned assets such as solar or wind farms (in the case of a Segregated Project) and ships and handling and storage facilities in the buyer's country.

Lenders will expect that much of the risk of cost and delay will be borne by the EPC contractors under lump-sum, date-certain EPC contracts. Given the complexity and range of disciplines required for a green hydrogen project, it is most unlikely that the whole project can be developed under a single EPC contract. Lenders will, therefore, carry out due diligence to ensure that the construction risk has been minimised by having a limited number of EPC contracts with well-defined interfaces between them.

An important related issue is that the buyer cannot be expected to maintain indefinitely its commitment under the GASPA to purchase on the agreed terms in the face of prolonged delay. This risk needs to be minimised both by negotiating as late an end-stop date as possible but also employing the information exchange and 'window' periods seen in LNG SPAs. For a Segregated Project, the PPA would need to have similar provisions mirroring those in the GASPA.

Ultimately, lenders may determine that the EPC contacts and other project agreements do not adequately mitigate the risk. In this case, they make look to the sponsors for additional support. This is addressed in more detail in Section 5.4.2.

4.7.2.4 Operational Risk

A green hydrogen project will require a number of different areas of engineering expertise, ranging from: solar or wind power generation, green hydrogen production, hydrogen processing (either into ammonia, LH2 or LOHC) and, possibly, shipping. It is unlikely that these will all be found in a single O&M contractor. Sponsors could follow the renewable power model of having an O&M contractor, or probably one for each facility, seeking to allocate some of the risks, e.g., operating cost. Alternatively, and possibly more likely given the involvement of a number of oil or mining majors, they would look to staff the project company to operate on a standalone basis with support agreements with the sponsors for technology support and secondment of key staff. Either model, properly structured, would be expected to be satisfactory to lenders.

As for completion, it will be important to ensure that the risk of the GASPA being terminated for poor operation, e.g., prolonged shut down, is minimised.

4.7.3 Impact of different commercial structures

In Section 4.2, three different commercial models were considered. The conclusions above refer to the Integrated Merchant Model.

In the case of the Segregated Merchant Model, the power generation would be owned by third party(ies) and supplied under Power Purchase Agreements (PPAs). This model would have a slightly different risk profile in that the completion risk of the solar/wind farms would be allocated to the power suppliers and the price of power would be fixed. However, any damages due under the PPA would likely not be sufficient to compensate fully for the losses incurred by the project company in the case that it could not produce green hydrogen. Additionally, the ability to fix problems in the upstream project, if required, would be more limited. Overall, however, the risk profile would not be very dissimilar and, subject to acceptable PPA terms which would largely mirror the GASPA, should be acceptable to lenders.

In the case of the Integrated Tolling Model, subject to having a financially strong toller and a robust tolling agreement that allocates co-completion, price, and volume risk to the toller, the overall risk profile would be lower, akin to that of US LNG projects. The risk structure should be acceptable to lenders subject to some awareness of whom the ultimate end buyers of the hydrogen would be.

5. Financing – Debt

5.1 Introduction

This section addresses the two fundamental approaches to debt financing: using project or corporate finance and their pros and cons. It then focuses on project finance and how much debt the project can support, what the term could be and how the pricing will be determined. These will be required to calculate the return on equity discussed in the following section. The financing process will be set out and comparisons made, where relevant, with the project financing of LNG and offshore wind projects.

5.2 Project vs Corporate Finance

A project carried out by a joint venture of more than one sponsor can be structured either: (i) as an unincorporated joint venture (UJV) where each sponsor holds a direct, undivided interest in the project assets or (ii) as an incorporated, special purpose company (an SPC or Project Company) which owns the project assets with the sponsors owning shares in the project company. Upstream projects in the resource sector tend to be held in tax transparent UJVs, while both LNG and offshore wind projects tend to have been developed using SPCs.

With a UJV, each sponsor raises debt, if it wishes to, independently. Whereas, with a project company, the sponsors must jointly agree on the project company's financing and have the option to: (i) fund it with a mixture of equity and intercompany loans or guarantees pro rata to their shareholdings (Corporate Finance) or (ii) to require the SPC to raise debt in its own right with only limited and contractually defined support from the sponsors (Project Finance).

With corporate finance, lenders look to the credit of the sponsors, and this offers the benefits of flexibility and speed, as it avoids the relative complexity of project finance, and, if they have strong credit ratings, the benefit of lower debt costs.

With project finance, lenders are exposed to the credit of the project and will require more extensive diligence and structuring. Where one sponsor is relatively weaker than others, this approach gives all parties a greater confidence in securing debt for the entire project. It also means that the sponsors may not need to consolidate their share of the project on their balance sheets but only treat it as an equity investment.

The majority of LNG projects[11] and 86 per cent[12] by value of offshore wind projects in Europe to date have been funded using project finance and for this reason, this paper focusses on financing hydrogen export projects on a standalone, project finance basis. For LNG projects, the choice of project finance was often due to the presence of weaker partners, especially national oil companies, in non-OECD countries or, in the case of the US Gulf Coast projects, in situations where the sponsors did not have strong credit ratings but the tollers did. For offshore wind, the driver is believed to have been more to avoid dilution of the earnings of their core, higher risk/higher return businesses and to provide a leveraged vehicle to sell down equity. It is assumed that this will also be the case for green hydrogen projects.

5.3 Lender Universe

The principal sources of debt for a hydrogen export project would be: concessional finance; international and domestic commercial banks; the project bond market; export credit agencies; and multilateral development banks.

[11] Natural Gas World Nov 2017, http://www.poten.com/wp-content/uploads/2017/12/Natural-Gas-World-Nov-22-2017.pdf
[12] PWC, Financing Offshore Wind 2022, https://www.pwc.nl/nl/actueel-publicaties/assets/pdfs/pwc-invest-nl-financing-offshore-wind.pdf (Calculation by the author)

Concessional lenders, banks that make loans below market rates to further the aims of their institution, where available, could be an important contributor to the government support required to make the project viable. Such finance could come from: (i) the host country e.g., for regional development or (ii) the buyer's country from bilateral institutions such as JBIC or KfW or KDB, or (iii) from regional development institutions (e.g., in Europe, the EIB). With the acceleration of government support for the energy transition, it is reasonable to expect that such programs will be increasingly available to support a hydrogen export project.

International and domestic commercial banks. Some 25-30 commercial banks are highly experienced in project finance lending with a track record of financing both LNG and renewable power projects. While these banks lend for profit or to support broader banking relationships, many have declared targets to support the energy transition and some, such as the Europeans, benefit from central bank policies that favour loans that support the energy transition.

The project bond market is a subset of the very deep debt capital market. Like the commercial banks, bond investors are returns driven but again, many investors have ESG targets or dedicated funds. The main differences between bonds and commercial bank loans are: (i) that the bonds are fixed interest (vs floating for banks, although these can be 'swapped' into fixed with derivatives at additional cost), (ii) they tend to offer a longer term and place simpler restrictions on the borrower and (iii) require a third-party credit rating. The US project bond market is the most sophisticated and liquid market offering long maturities and greater flexibility (such as amortisation).

Export Credit Agencies (ECAs) are government owned or supported agencies set up to support exports of goods and services from their country. This is done either by offering direct loans or guarantees (under which banks or bond investors can offer low-cost debt) linked to the value of the exported goods or services. Such loans are generally not at concessionary rates but can be very valuable. This is because ECAs can accept political risks that commercial lenders would not and thus often form the bedrock of a financing for a project in a non-OECD country and the larger agencies can offer very substantial loans or guarantees and thus support very large projects where the capacity of the international bank or bond markets would be insufficient. These projects are typically in the region of USD 2-3 billion, more than required for the Archetype project, but well within the bounds of many contemplated export projects.

Multilateral Development Banks (MLDBs) are banks such as the World Bank or IFC which are owned by several countries with a mandate to support the development of less developed countries either globally or in specific regions. They typically focus on lower income countries and are valuable in countries where the commercial banks have a limited appetite to lend.

The lending capacity and key features of the lender groups discussed above are summarised in Table 3:

Table 3: Relative capacity of lender groups

Lender	Capacity (USD billion)	Term (years)	Feature
Concessional Lender	Up to 1	Up to 20	Offers below market pricing Accept political risk
ECAs	Up to 3	Up to ca 16	Linked to procurement Accept political risk
MLDBs	0.1 – 0.2	Up to 20	Focussed on developing countries
Commercial Banks*	Up to 3	7 – 20	Flexible
Project Bonds*	Up to 2	Up to 20	Require credit rating

* Collectively

Source: the author, based on transactions over the last 15 years.

Given that the debt requirement of the Archetype project would be less than USD 1,700 million, even assuming an 80 per cent DER, this would be well within the capacity of the ECAs, commercial banks or project bonds. There would be ample capacity in the market and sufficient to promote real price tension.

The process to select lenders is addressed in Section 5.4.3 below.

5.4 Lenders' Credit Process

Banks' credit processes will vary but broadly follow the same approach: (i) due diligence – an assessment of the project, the risks to which it is exposed and some quantification of those risks (downside cases); (ii) development of a risk allocation acceptable to the bank; (iii) an assessment of the value creation of the project; (iv) assessment of the debt capacity of the project; (v) development of the terms of the financing, essentially determining the relationship between debt and equity.

The credit process is not dissimilar between commercial banks, development banks, and ECAs although their risk appetites differ, with the development banks and ECAs having a greater tolerance for political risk due to their mandates but generally being more conservative on other credit issues. The leading project finance credit rating agencies (Fitch, Moody's, and S&P) follow slightly different methodologies not only from banks but also from one another. Helpfully, they publish their evaluation methodologies[13] [14] [15] with regular updates but understandably have yet to publish a hydrogen-specific methodology. For that reason, this section focusses on the banks' approach based on relevant precedents.

5.4.1 Due Diligence

Lenders need to assess all the key aspects of the project and, while they may have considerable experience, they are not experts. Also, given that a large project will require a significant number of different lenders, it is useful to have a common understanding among the lenders. To this end, due diligence reports are generally commissioned to cover key areas of the project, to support the base case assumptions and suggest reasonable sensitivities to be used in the lenders' financial model. For the Archetype project, the reports would likely include:

- A resource report on the solar and/or wind resource (as well as water if the plant does not use desalinated seawater)
- A technical report on all the engineering aspects of the project, the design, technology, the budget, schedule, and operation
- An environmental report (possibly included in the technical report) which would address the project's compliance with applicable law in terms of permitting etc., but also compliance with the Equator Principles (in the case of commercial banks) and each agency's own environmental standards in the case of ECAs or other bilateral or multilateral lenders. For a project in a relatively new industry, there may be specific areas of concern that would need to be addressed, for example water resource, impact of the amount of land required, and increased NOx emissions at the power plant due to firing with ammonia).
- A market report on the buyer's end market for the hydrogen/green ammonia and description of the government support mechanism. This is likely to be required even if the contract quantity and price are fixed to assess the buyer's ability to fulfil its volume obligations and the economic 'gap' and how it is anticipated to change over time. If the price is to be indexed to a commodity or contemplates a traded hydrogen market price, perhaps after a period at a fixed price, it should include a relevant price forecast

[13] Fitch Ratings, https://www.fitchratings.com/research/infrastructure-project-finance/infrastructure-project-finance-rating-criteria-23-08-2021
[14] Moody's Investor Services, https://ratings.moodys.com/api/rmc-documents/361401
[15] S&P Global Ratings, https://www.spglobal.com/ratings/en/about/criteria/rfc-project-finance-2022

- A shipping report, reviewing the adequacy of the shipping arrangements for the export of ammonia.
- A legal report which would provide a legal review of the project agreements and, critically, the government support arrangements in the buyer and host countries.
- An insurance report that would address the proposed insurance arrangements for the project.
- A model audit report on the financial model confirming that it accurately reflects the terms of the project and finance agreements
- A tax report (possibly included in the model audit) confirming the validity of the tax calculations in the financial model.

5.4.2 Lenders' Risk Allocation

The fundamental project risk allocation is performed by the project agreements and was discussed in detail in Section 4. However, project risks may remain that are not acceptable to the lenders, specifically completion risk and political risk. These risks may be mitigated by other parties, principally the sponsors or export credit or multilateral agencies, in the finance agreements.

Completion Risk

As noted in Section 4.7.2.3, the completion risk for a green hydrogen project will be higher than for either LNG or offshore wind, especially if it is transported as LH2.

For integrated LNG projects, lenders have not taken completion risk since the North West Shelf financing for Woodside Petroleum in 1986, but have received completion guarantees from creditworthy sponsors. It is not fully clear whether lenders were not prepared to accept the risk or whether the sponsors, typically oil majors, simply preferred to avoid the cost and additional complexity of a fully non-recourse project. However, it has set a strong precedent. For the structurally simpler, tolling projects in the US which were fully wrapped by single EPC contracts and insulated from upstream and downstream risk by their tolling contracts, lenders have accepted completion risk since 2012.

By contrast, in the offshore wind sector, from the earliest days in 2006, about a half of new projects[16] have achieved pre-completion financing without sponsor support. While less complex than a green hydrogen project, the technology was also relatively new, was set in a challenging environment offshore and, due to the very different components (turbines, towers, subsea cables, offshore installation etc.), could not achieve a single EPC 'wrap'. This supports the view that some lenders, at least, will be prepared to accept completion risk provided they have a higher level of due diligence, a greater degree of monitoring and control rights in the construction period, higher margins, and a satisfactory level of contingency funding. Given the offshore wind experience and the enthusiasm for banks to participate in green hydrogen, it is expected that lenders will not make completion guarantees an absolute requirement and that pre-completion finance will be available from sufficient banks to finance the Archetype project assuming no deterioration in the financial markets. This will be valuable where the sponsors do not have strong balance sheets to finance or guarantee completion or alternatively wish to introduce new equity partners before completion. The continuing availability and terms of pre-completion financing will be dependent on the track record of the early projects.

However, assuming that many of the early green hydrogen export projects will be sponsored by strong creditworthy companies from the oil, mining, or utility sectors, it is likely that such sponsors will choose to avoid the cost, complexity, and risk of delay in obtaining limited recourse financing prior to completion. There are two mechanisms available to achieve this:

1. **Sponsor funding**, where the sponsors simply fund the project from corporate sources (Corporate Finance) until the project has been physically completed and is performing reliably in accordance with the financial model forecasts, at which point lenders are approached to raise project finance to replace the corporate finance.

[16] OFFSHORE WIND DEBT 15 YEARS ON March 10, 2022, Jérôme Guillet, PFI Yearbook 2022

2. **Sponsor Completion Guarantees**, where the lenders finance the project from the outset but the sponsors provide 'Completion Guarantees' proportional to their shareholding which will fall away once the project has met a series of pre-agreed tests. These are typically: physical completion, no outstanding liabilities, all commercial contracts in force and a period of satisfactory operation. The completion guarantees are not strictly guarantees of debt but provide a soft landing of a grace period (typically up to two years beyond the scheduled completion date) for the sponsors to rectify any problems and to make up any shortfall in cashflow to meet debt service. At the end of the grace period, however, if completion has not been achieved, the debt must be renegotiated or repaid in full.

The second option has been widely used in LNG financings because ECAs mandates generally preclude them from refinancing and, for larger financings or in less developed countries (LDCs) (see Political Risk below), ECAs are likely to be a critical component of the financing plan.

Political Risk

Another area of concern will be political risk, which relates to both the buyer and seller's countries. The primary concern for the buyer's country, especially for a hydrogen project, will be the risk of loss of the government's support for green hydrogen. While this risk should primarily lie with the buyer under the GASPA, commercial lenders would also take greater comfort if the lender group were to include agency lenders from the buyer's country. There are precedents for letters directly from the government providing lenders with some assurance e.g., in the event of a change in the legislation supporting the project, that the underlying economics would not be materially adversely impacted. However, it is not expected that this is likely to be forthcoming from the governments of the most likely offtake countries (Japan, South Korea, and the EU), especially since the buyer, a local company, bears the primary risk.

Where the seller's country is not an OECD or high-income country, commercial lenders will have greater concerns about political risk issues such as their ability to repatriate hard currency, the risk of their debt being caught up in a broader debt restructuring program, or expropriation or political violence. These concerns will reduce their appetite to lend and the terms that they can accept. A solution to this is the greater involvement of ECAs and/or development banks. They not only have the capacity to accept such exposure and for long term loans but also the fact of their presence in financing a project increases the appetite of commercial lenders.

5.4.3 Overall assessment of the project

A key starting point of lenders' credit analysis is an overall assessment of the project to determine where it brings real value to all the stakeholders, revenue and employment to the host government, adequate expected returns to the investors, a competitive source of a commodity to the buyer, etc. Simply put – is the contractual and legal structure of the project fair and durable?

For many resource projects this largely comes down to an analysis of the project's cost competitiveness and tax regime. For hydrogen at this stage, like offshore wind until very recently, the driver is not about pure economics but a government's policy requirement, e.g., to achieve net-zero carbon emissions by a fixed date. Lenders will therefore want to assure themselves that the project will indeed meet the government's objectives and will be reasonably competitive against other zero-carbon alternatives. It is almost inevitable that the first mover hydrogen projects will have a higher cost than those that follow and will be perceived as 'expensive' in retrospect. Therefore, lenders will wish to be assured of the long-term commitment of the buyer country to its net-zero target and of its ability to continue to provide support, both financially and politically.

5.4.4 Assessment of project debt capacity

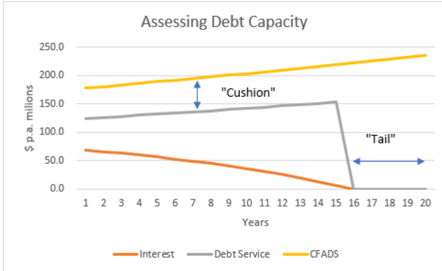
To assess the amount of debt that a project can repay to a high degree of confidence, banks develop a financial model that accurately reflects the terms of the project agreements and, later, the finance agreements. The model will be used to project a base case cash flow for the life of the project based on assumptions supported by the due diligence reports. It is likely to be slightly more conservative than the sponsors' case used to analyse their equity investment. The bank will then run a number of downside sensitivity cases largely informed by due diligence reports. These cases would likely include: a delay in start-up, a reduced renewable resource (P90 or P99), reduced operating efficiency, reduced operating hours, a lower commodity price (if applicable), reduced offtake quantities (within the terms of the GASPA), and higher interest rates and adverse exchange rate movements (if relevant). A plausible combination of downside scenarios (‘Acid Test’ case) would then be selected to determine the minimum amount of debt that the project could reasonably be expected to repay. This would be the net present value of future cash flows (in the Acid Test case) to the expected maturity of the debt, discounted at the expected cost of debt. It would be calculated for each period of the loan to establish the maximum outstanding acceptable on such date.

Assessing Debt Capacity

The loan maturity date is set to provide a ‘tail’ period of at least two years prior to the maturity of the GASPA to accommodate delays or interruptions. Lenders then determine the ‘cushion’ or Debt Service Cover Ratio (DSCR) they require to ensure that debt service can be maintained, even in the Acid Test case, to repay the debt by maturity. Typical DSCRs for an integrated project are:

For offshore wind (no commodity price exposure): **1.25 – 1.40**
For LNG (an integrated project with commodity price exposure): **ca 2.0**

Figure 6: Assessing Debt Capacity



Source: the author

In addition, project finance lenders want to ensure that sponsors have ‘skin in the game’, namely an ongoing economic interest in the project to provide an incentive to fix problems that might arise. Lenders therefore typically cap the level of initial debt advanced to a project. LNG projects have typically raised debt of approximately 70 per cent of the total project cost and this has been relatively constant over time. Offshore wind projects initially raised 60-65 per cent debt but this has increased to up to 80 per cent over the last 15 years as lenders have become increasingly comfortable with both the completion and operational risks and have been prepared to lend for longer maturities and applied less severe downside sensitivities.

Figure 7: Offshore Wind – Increase in leverage over time

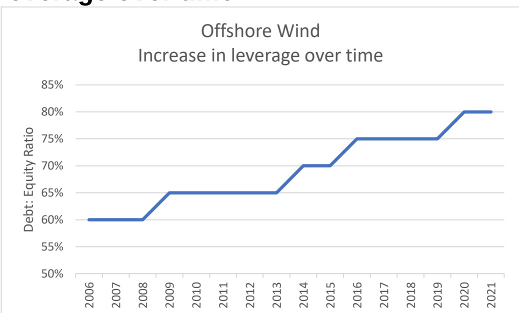
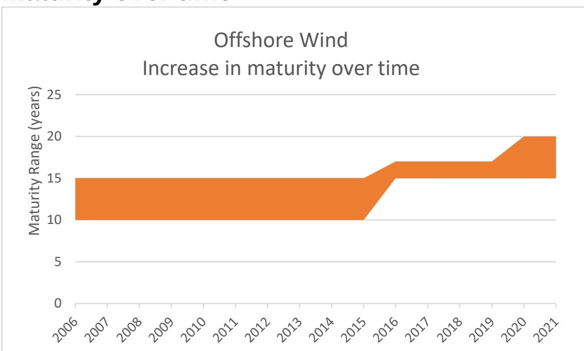


Figure 8: Offshore Wind – Increase in maturity over time



Source Jerome Guillet, 2022 PFI Yearbook

5.4.5 Development of Financing Terms

Project financing documentation of the relationship between the borrower, its sponsors, and the lenders can be quite complex and is a subject in itself. This section seeks to address the key terms and where there may be specific issues for a hydrogen export project.

Term of the Loan. An attraction of project finance is that lenders are generally prepared to offer long-term loans of up to 20 years which better matches cash flow, maximises leverage, and reduces the need to refinance. In some jurisdictions, such as the US where there is a strong debt capital market, commercial banks typically offer a shorter term (3-5 years), with the expectation that the loan will be refinanced once the project has been completed, often with long-term bonds.

Given that lenders are generally relying on an offtake or tolling agreement, the term of the loan is generally capped at the term of that contract, less a ‘tail’ of 1-2 years to provide for unforeseen events.

In a power project with price support, lenders may accept some limited ongoing exposure beyond the fixed price period on the basis that the breakeven price by that time is well below any conservative forecast of spot market prices. In the case of hydrogen, given the lack of a market price at present and any sense of how long a market will take to develop, lenders should not be expected to assume any residual risk at the end of the fixed price period. The concern is exacerbated by the expectation that each future hydrogen project will have a lower production cost.

Cash Flow Waterfall. In project financing, the cash flow and priority of payments is strictly controlled. All revenues are paid into a project account and disbursed according to an agreed priority, a process known as the 'Cash Flow Waterfall'. At the top of the waterfall are those costs necessary for the safe operation of the project (operating costs, maintenance capital, emergency repairs, etc). In addition, if the project company is liable to tax, taxes due would also be paid as a priority. Payments to the lenders for interest, repayment, and any specified reserve funds would fall immediately after this. Finally, cash may be distributed to the shareholders provided that certain conditions are met (typically to give lenders assurance that there are no problems that might affect future cash flow). Otherwise, cash would be retained in the project account.

Where the project company is responsible for the shipping, time charter payments would be paid at the top of the waterfall, along with other operating costs. In the case of FOB sales, the revenues would essentially be reduced by the amount of the time charter, so the net cash flow would be unchanged. Hence there is no impact on debt capacity.

In the case of a segregated project, where the project company purchases electricity rather than self-generates, such payments would usually rank at the top of the waterfall, along with other operating costs. This results, of course, in lower cash flow available for debt service. It is worth noting that having the payments locked into the cash flow waterfall will be critical for the upstream power generation project as it gives them a 'cut-through' to the credit of the GASPA buyer, rather than simply the credit of the project company, a special purpose company.

Drawing and Repayment. Drawings are subject to a range of conditions, largely to ensure that the project is progressing as expected, the funds are being applied to the purpose intended, and it is meeting the agreed DER. These conditions will be more stringent where there are no completion guarantees. Certain lenders will also have specific conditions attached to their loans, e.g., for export credits, ECAs will require evidence that goods and services have been procured from their respective countries.

Repayments will be made according to a schedule in the finance documents that would have been developed to ensure that the debt should always repaid below the amount that could be repaid in the Acid Test case. It will also be desirable, for such a complex project, to negotiate some flexibility in the repayment schedule to accommodate any delay in start-up, to whatever extent possible.

Covenants and Events of Default. Project finance tends to have a relatively standard set of covenants and events of default that set out what the borrower must and must not do (namely to develop and operate the project in accordance with the development plan and abide by the terms of the project and finance agreements but to maintain the borrower as a special purpose company and not to take on additional debt other than as agreed) and what the remedies of the lenders are in the event of a breach. For a green hydrogen project, the terms will be similar to those of both an LNG and an offshore wind project. However, there will need to be provisions to address any specific issues related to hydrogen production and export. These could range from technical problems such as faster than expected degradation of an electrolyser to legislative changes in both the host and buyer countries.

As noted in Section 3, the ability to maximise leverage through the life of the project is key to minimising the cost of capital. For early projects, the initial DER may be constrained by green hydrogen's lack of track record. However, as the project and other projects successfully complete and operate, lenders are likely to accept a higher DER. Therefore, the ability to refinance and re-leverage needs to be carefully considered noting that neither concessionary lenders, ECAs nor MLDBs can refinance their loans.

5.4.6 Overall Project Finance Process

The credit process set out above will apply broadly to all lenders. However, the project will probably wish to approach several different potential lenders in order to: (i) secure finance on concessionary terms (but this is unlikely to be sufficient to meet the whole debt capacity of the project); (ii) create competition to ensure the best terms from commercial lenders, and (iii) maximise the term of the loans.

To do this, the project company, working with financial and legal advisers, would prepare a preliminary information memorandum that would contain a description of the proposed project and the financing plan, along with a package of due diligence reports, a financial model, and a proposed term sheet. Potential lenders would then be asked to bid against the proposed terms and, if bonds were also contemplated, the package would also be provided to selected credit rating agencies to get an indicative credit rating and to selected investment banks to get an indication of bond pricing. Use of common experts and legal counsel has the advantage, especially for a hydrogen project where there may be a limited number of qualified experts acceptable to the lenders, of a common basis of information against which to assess the project.

Given its scale and the potential availability of concessionary finance, it is expected that the Archetype project would follow this process and be financed by different groups of lenders under coordinated terms and conditions (multi-source financing).

For projects located in a non-OECD country or larger than the Archetype project, with a debt requirement greater than USD 2-2.5 billion, the finance process would generally focus on obtaining ECA support initially and agreeing broad terms prior to approaching commercial lenders/bond investors.

6. Financing – Equity

Successful green hydrogen/ammonia export projects will have been selected by a buyer on the basis of a formal or informal competitive process as the supplier of reliable low-cost hydrogen. The ability to deliver at a low cost will be a function of: the availability of low-cost, high load factor green power; the cost and efficiency of the hydrogen and ammonia plants; and the cost of capital. Section 5 addressed the process of obtaining low-cost debt. This section looks at how the cost of capital can be minimised on the equity side.

6.1 Initial Investors

The initial investors in the project are likely to be companies that have the engineering and project management skills along with sizeable balance sheets required to develop a project of the scale and complexity of the Archetype project. They are likely to be major resource companies or global utilities, such as Engie, ENEL or Iberdrola. The resource companies, with typically volatile commodity prices and high costs of capital, tend to evaluate projects on the basis of the return on capital (in accordance with a capital asset pricing model that proposes that the cost of capital for a project is dependent on its risk profile and not, other than at the extreme, on its leverage). Utility companies, used to regulated returns and/or fixed price renewable contacts, tend to model debt explicitly and evaluate their projects based on equity returns. Given that the cost of capital applied in determining the bid price of green ammonia will be critical and that the project leverage will be high (assuming a fixed price offtake) and that the impacts of concessionary finance and tax would be significant, it is anticipated that many investors will evaluate the projects on the basis of the return on equity.

If using a return on equity analysis, it is important to model the debt as accurately as possible. This would involve not only the terms of any committed financing, but also the forecast terms of refinancings. For example, if a project has a 3-year construction period and 20-year operating life with a 16-year financing deal, it would be possible to refinance at year 5, extending the term by an additional 5 years. This could significantly increase the overall leverage of the project and equity return.

6.2 De-Risked Investors

Everything else being equal, the cost of equity should fall significantly at each de-risking milestone, the principal milestones being (i) FID when the project would have a contractual framework substantially fixing the capital cost and the offtake price and (ii) completion of the project. There is a substantial pool of investors, typically institutional investors such as infrastructure funds, that has the appetite to invest in low-risk infrastructure assets with lower investment return hurdles than resource companies. IRENA, in their 2020 paper 'Mobilising institutional capital for renewable energy' about the importance of being able to attract such institutional capital, noted that of the USD 300bn invested in renewables in 2019, only 2 per cent (likely to be around 6 per cent of the equity) was directly from institutional investors and that there was significant scope for this to grow.

In the early stages of the green hydrogen industry, many institutional investors would not be expected to have the appetite for completion risk. Therefore, following completion, the initial investors should contemplate selling a significant portion of their equity in the project at a premium. Such recycling of capital also allows them to achieve a higher return on equity as well as to develop further projects more quickly. As the track record develops, institutional investors are expected to consider investment from FID, albeit at a higher equity return, offering further flexibility to the initial investors.

Further options to de-risk the incoming equity can also be considered, if it meets the initial investors' objectives. For example, if there is a merchant tail (i) between the fixed price period and the term of the GASPA or (ii) beyond the term of the GASPA where the project is still considered to have a useful operating life but there is no fixed contracted price or in (ii) no obligation to take either, the initial investors could offer the incoming de-risked investors a fixed, preferred/senior return but keep the upside of the hydrogen revenue exceeding that level for themselves.

As for taking debt refinancing into account in the initial investors' economic analysis for FID, a similar equity refinancing should also be considered as it would allow the project to meet their cost of capital at a lower hydrogen price.

7. Illustrative Debt and Equity Economics for the Archetype Project

A simplified financial model was run using the assumptions set out in Appendix II to illustrate the economics of the Archetype project and the impact of both debt and de-risked equity. In each case the Integrated Merchant project is assumed with a GASPA with a term of 20 years for a fixed annual quantity (with 100 per cent take or pay). The modelling has been done on a pre-tax basis and the cost of capital reflects the pre-tax cost of debt (rather than post-tax) for consistency. Although this is perhaps a simplification, it is not an uncommon approach where the project is owned by a tax transparent vehicle and tax is managed at the shareholder level.

Base Case	This assumes a green ammonia price of USD 770/mt rising with inflation for the period of the contract to give a return on capital of 6.85 per cent per annum just equal to the assumed cost of capital i.e., there is no economic value added. A level of 65 per cent debt is assumed with a term of 15 years and a margin of 1.85 per cent per annum.
Case 1	Examines the impact of the margin on the debt reduced by 0.5 per cent per annum.
Case 2	Examines the impact of an increase in DER to 70 per cent (higher is not possible with a 15-year term due to the resulting DSCR).
Case 3	Examines the impact of increasing the debt term to 18 years, which also permits a further increase in DER to 80 per cent.
Case 4	Looks at the extent to which a lower green ammonia price could be bid and still maintain a satisfactory return to investors.

The sensitivities were chosen to represent realistic variations in leverage and debt term that might be achieved by, for example, minimising the price risk in the offtake agreement, favouring lenders that offer longer maturities or attracting concessionary lenders that offer lower cost debt.

The results of the analysis are summarised below:

Table 4: The impact of financing terms on equity returns						
Archetype Project (Integrated Merchant)		**Base Case**	**Case 1**	**Case 2**	**Case 3**	**Case 4**
Assumptions:						
Cost of capital	(% p.a. MOD)	6.85%				
Cost of De-Risked Equity	(% p.a.)	7.5%				
Ammonia price	(USD/mt RT 2022)	770	770	770	770	**732**
Loan Term	(years)	15	15	15	**18**	**18**
DER:	%	65%	65%	**70%**	80%	80%
Margin	(% p.a.)	1.85%	**1.35%**	1.85%	1.85%	1.85%
Results:						
Average DSCR		1.3	1.3	1.2	1.25	1.2
Return on total equity	(% p.a.)	8.5%	8.9%	8.8%	10.7%	9.5%
Return to Initial Investors	(% p.a.)	9.4%	10.1%	10.0%	14.1%	11.4%

Base Case

The results show that in the Base Case, a DER of 65 per cent is achievable while maintaining DSCRs at 1.3. If the price were linked to, for instance, the oil price, the required DSCR would rise to around 2.0 and this would reduce the DER to around 40 per cent, with a corresponding increase in the cost of capital.

Cases 1 and 2

Reducing the margin or increasing the leverage (to the extent possible within the DSCR constraints), provides similar, but limited, benefits.

Case 3

A significantly greater benefit to equity returns is achieved if a longer term can be negotiated with the lenders as this not only permits a higher initial DER to be achieved but also to be maintained for a longer period. (Note that a similar effect could be achieved with shorter-term financings that are re-financed at intervals.)

In each case, the introduction of de-risked investors, especially in the higher return cases, gives significant leverage of the initial investors' returns.

Case 4

Finally in Case 4, which illustrates the potential benefit of financing terms in an auction, the more aggressive financing of Case 3 (an 18-year term and an 80 per cent DER) would permit the sponsors to accept a 5 per cent lower green ammonia price in the GASPA while still having higher returns than the Base Case or Cases 1 and 2.

The offshore wind precedents suggest that for the initial hydrogen export financings and/or in the case of a loan with no completion guarantees, initial DERs could be in the 60-65 per cent range with a term limited to 15-16 years. However, as lender familiarity is developed, DERs would be expected to increase to 70-80 per cent and loan terms to 18 years. It is therefore important to maintain re-financing flexibility to capture the expected benefits of improving terms over time.

8 Conclusions

Background

Green hydrogen is a nascent industry using emerging technologies that needs to grow from almost no production currently to 9 – 14 mtpa in 2030 and up to 300 mtpa by 2050 to meet the IEAs net zero emissions trajectory. The cumulative capital requirement for green hydrogen production to meet these levels is estimated to be up to USD 300 billion by 2030 rising to USD 2,500 billion by 2050. At present, there is an 'economic gap' between the cost of producing green hydrogen and the price of the fossil fuel alternatives in all end-use cases. However, the cost of hydrogen production is anticipated to fall as the industry scales up allowing green hydrogen to become progressively competitive in its different end-use cases in the course of the 2030s-40s (based on the timescales achieved by offshore wind). All projects this decade and most in the next are expected to require government support to be able to attract investment.

Finance is important for competitiveness

For a green hydrogen project to secure a long-term offtake (with the associated government support) in what is likely to be a global competitive auction, it will need to offer a very competitive delivered price. In addition to low-cost electricity and a low capital cost, the cost of capital (both debt and equity) will play an important role in reducing the levelized cost, in particular the maintenance of a high level of debt throughout the life of the project.

What are the relevant precedents?

Lenders will typically look to analogous sectors for precedents. Green hydrogen has many features in common with LNG: they both require the export of an energy product/industry feedstock to a remote market in another jurisdiction and they are both large-scale, complex, and technically challenging industries requiring significant investment by both seller and buyer. However, they are materially different in two key respects: (i) LNG is competitive with fossil fuel alternatives - there is no 'economic gap' – so no government support is required for LNG whereas green hydrogen is expected to require government support for another two decades, and (ii) for LNG, a global traded market already exists whereas there is currently no market for green hydrogen/ammonia and its evolution is uncertain, depending to a great extent, while the economic gaps exist, on government policy.

Another analogous sector is offshore wind. It is also large scale and, although more advanced, it has until recently been an emerging technology. It is also economically similar, with very limited economic profitability but no expected exposure to commodity prices and most projects will require explicit government support for some years to come. However, unlike hydrogen, there is an established deep market for electricity and offshore wind projects tend to be domestic.

The commercial and financing models for green hydrogen are therefore expected to draw from the relevant parts of offshore wind and LNG, with offshore wind in some respects being the better precedent given the reliance on government support and being more of an emerging technology with the prospect of a continuing 'learning curve'.

What is required for Bankability?

It is not possible to be precise about what will be required, with lenders strongly incentivised to participate in energy transition projects and very keen to support the early hydrogen financings and consequently likely to be more flexible than in traditional sectors. However, one can be confident that all lenders will need to be satisfied as to the key risks: Buyer Government Support, Offtake, and Completion.

The most critical issue will be the support legislation of the government of the importing country which will underpin the project in terms of both creating a market for green hydrogen and supporting a long-term price likely to be well in excess of the fossil fuel alternative. Lenders will need to fully assure themselves that such legislation is robust and durable. For OECD countries, it is unlikely that any direct contractual assurance to the project or its lenders would be offered. However, sponsors should prefer host countries that are signatories to either bilateral investment treaties or other treaties such as the European Energy Charter as these will give some protection against actions by the host government that would have a material adverse impact on their project.

To support long-term project financing, the project will also require a long-term offtake agreement, a GASPA (at least 15 and preferably 20 years) with a highly creditworthy buyer that gives the project no material exposure to volume or price risk. Additionally:

- The buyer will need to be, and remain, highly creditworthy (investment grade as a minimum) not only to support its usual obligations as a buyer but also to the extent that it acts as a conduit for the government support. Given that the contract price is likely to be 'off market' versus fossil fuel alternatives and future, lower cost green hydrogen exporters, it would be challenging to replace the GASPA in the event the buyer could no longer perform. Lenders may additionally require certain covenants to seek to ensure that the creditworthiness is maintained through the life of the GASPA.

- Lenders will not accept any material volume risk as there is currently no market and it is expected to be created by the buyer's host government policy. The best mechanism to address volume risk is believed to be the take-or-pay approach found in LNG that obliges the buyer, in the event that the market does not develop as rapidly as expected, to pay for fixed contracted quantities, whether taken or not. However, such quantities, once paid for, may be taken at some time in the future.
- Again, lenders will not accept any material hydrogen price risk as there is currently no market and green hydrogen is expected to require subsidy/support for many years to come. To address price risk, a mechanism that ensures a fixed price (preferably in real terms) to the seller, with no price review provision, for a period of at least 15 years is recommended, as is generally seen in offshore wind. Lenders probably could accept price indexation to a traded energy product (such as coal, gas, oil or electricity) but this would introduce a new risk exposure for the seller, that would probably not significantly reduce the buyer's risk but would significantly reduce the level of debt the project could support and, consequently, increase the cost of capital and hydrogen.

Commercial lenders have limited appetite for long-term political risk. This will be an issue if the project's host country's credit rating is sub-investment grade. This cannot be addressed by the project agreements but can be mitigated by the financing structure - keeping the debt repayment flows offshore - and the involvement of institutional lenders such as ECAs or MLDBs.

Will completion guarantees be required?
At least until some track record has been demonstrated, lenders will have a heightened concern about completion risk. Experience from offshore wind, initially also very much an emerging technology, suggests that some lenders, at least, will be prepared to accept completion risk if there is a robust underlying framework of EPC and other construction agreements and strong contractual commitments from the buyer or third parties providing critical services such as shipping, receiving facilities or, in the case of a segregated project, renewable power. However, such a non-recourse financing would come at some cost in terms of the time to negotiate the financing, reduced leverage, and greater monitoring and control by the lenders. As has generally been the case for LNG projects, it is expected that financially strong sponsors will prefer to provide completion guarantees or to postpone financing until after completion.

What commercial models are envisaged?
- Integrated Merchant, where all the export assets (electricity, hydrogen, and ammonia) are owned by a single project company that sells green ammonia to a buyer
- Segregated Merchant, where the project company owns the hydrogen and ammonia facilities and sells green ammonia, but purchases renewable electricity from third parties rather than self-generating
- Integrated Tolling, where the project company owns all the export assets, as for the Integrated Merchant case, but provides a processing service to a third-party toller. The toller is then responsible for all sales and pays a substantially fixed fee for the service. It can request the project company to produce green ammonia but would also have the option to request it produce domestic hydrogen or electricity at times of high prices.

The models reflect those that have been used in the LNG industry. The Tolling model, in particular, could allow a trader to maximise the option value of the project. Subject to PPA terms that mirror the GASPA in the case of a Segregated Merchant model and tolling agreement terms that do not expose the project to volume or price risk, each of the models should be financeable.

What financing terms will be available?
This paper, for illustration, examines an Archetype project, using 1GW of solar generation to produce 250 ktpa green ammonia be sold at a fixed price of USD 770/tonne (just sufficient to meet the assumed cost of capital). This compares with a 5-year average price of a little over USD 600/tonne but over USD 1,300/tonne at the time of writing. Assuming a 20-year offtake contract and a 15-year loan (with a 3-

year construction period), the Archetype project can support a DER of around 65 per cent. For early projects and especially if no completion guarantees were available, the DER might be closer to 60 per cent. However, the DERs achieved by projects are expected to increase over time as more experience is gained with the technology and lenders can accept longer term loans. In the event that the price was indexed to oil or gas, for example, the DER would be reduced to around 40 per cent.

How can financing be optimised?

The debt financing can be optimised to minimise the cost of capital by: (i) maximising the initial DER; (ii) continuing to maximise the DER through the life of the project, and (iii) minimising the interest margin.

Of these, the initial DER is very much set by the robustness of the offtake agreement. However, in terms of impact on the cost of capital, maintaining a high DER throughout the project life is even more important. This can be achieved either by seeking to maximise the term of the initial financing or planning to refinance one or more times over the project life (and ensuring the terms of the initial financing will permit this). Minimising the margin is broadly as important as the initial DER and can be done by prioritising concessionary lenders and running a competitive process.

The equity financing can be optimised by refinancing a portion of the sponsors' initial equity, when the project has been de-risked, perhaps at completion, with lower cost equity from investors with a lower risk/return appetite. The sponsors can then receive a premium, giving them a higher return for the development risk they have assumed and enabling the re-cycling of capital for future projects.

The analysis indicates that with the combination of an increased loan term, a higher DER, and the introduction of de-risked investors at completion, the initial investors could bid a 5 per cent lower green ammonia price (significantly increasing their competitiveness) and still achieve a better return on equity than in the Base Case.

Which lenders should be targeted?

The debt requirement for the Archetype project, around USD 1,500 million, should be well within the capacity of the commercial bank market provided it is located in a wealthy country. However, priority should be given to concessionary lenders such as JBIC, EIB or KfW to the extent that they are prepared to offer better terms on both loan term and margin. Export Credit Agencies (ECAs) should also be considered to maximise the loan term to the extent that it does not require distorting the preferred procurement. Otherwise, the bond market could be considered to create competition at the outset or to refinance the banks after completion.

If the Archetype project were to be located in a less developed country, where commercial banks had concerns about political risk, the initial priority would need to be given to ECAs, concessionary lenders and, potentially, multilateral development banks to assure funding.

The future

The conclusions above apply to financing projects early in the development of the green hydrogen industry and will undoubtedly change in the future as the industry matures:

- Based on experience from the offshore wind industry, lenders will likely be prepared to accept completion risk where the technology is reasonably established - as can probably be argued for green ammonia - and if there is a robust contracting strategy. Less mature technologies, such as liquid hydrogen, would be expected to demonstrate a successful track record of construction and operation before lenders would accept pre-completion exposure. However, this could be addressed in less than five years.
- As the learning curve reduces capital costs, the need for government support will reduce and ultimately no longer be required. For offshore wind, it took about 15 years for the first zero-subsidy project to emerge. While some end-use cases might reach breakeven earlier, it is reasonable to expect that it will take 15-25 years until new green hydrogen projects no longer require government support.
- Long-term, fixed price, government supported contracts provide a strong basis for financing and have proven very successful in attracting capital into the emerging offshore wind sector. As that support is removed, investors will be required to accept price risk for an emerging green hydrogen market. This would lead to lower DERs and could slow investment until commercial long-term contracts or a long-term futures market emerge.

- Green hydrogen is expected to become, eventually, a global, traded commodity. However, from the first LNG trade in 1969, LNG has taken over 50 years to move from a purely bilateral trade to the widely traded, but not yet fully commoditised, market that it is now. It is worth noting that no LNG financing has been closed to date that was not underpinned by long-term offtake contracts. It is not expected that there will be a globally traded green hydrogen market until the 2040s at the earliest (although regional markets may well develop earlier in the US or NW Europe).

Appendix I – Glossary of Terms

Archetype Project	The project defined in Section 2 and used as an illustration.
BII	Business Interruption Insurance
Buyer	The buyer under the GASPA
CfD	Contract for Differences
Completion	Completion is the point in time when the project has been constructed and has performed in accordance with its specification for a period of time such that there is no reason to expect that it will not continue to perform in accordance with the forecasts made in the financial model at FID.
Completion Guarantees	Defined in Section 5.4.2
Concessionary Lenders	Lenders that offer debt on terms more favourable than the market.
Corporate Finance	Defined in Section 5.2
Debt	Senior secured debt obligations of the project company
DER	Debt:Equity Ratio
DES	Delivered ex ship: of a Sale and Purchase Agreement, where the seller has the obligation to deliver the cargo to the buyer
De-Risked Investors	Equity investors who only invest in a project after the development risk and, perhaps also, completion risk are in the past and accept a lower return.
ECAs	Export Credit Agencies
Economic Profit/EVA	Economic Value Added: the additional value a project creates above its cost of capital.
EPC Contract	Engineering Procurement and Construction contract
Equity	All capital contributions to the project company other than debt – can include subordinated loans (likely to be provided by the sponsors) or other instruments provided by de-risked investors in addition to equity provided by the initial investors.
EVA/Economic Profit	Economic Value Added – the return of a project above the cost of capital
FID	Final Investment Decision – the point at which the initial investors financially commit to the project.
Finance Agreements	All the agreements between the lenders, their agents, project company and (if relevant) sponsors in relation to the debt.
FOB	Free on Board: of a Sale and Purchase Agreement, where the seller only has the obligation to deliver the cargo onto a ship at its home port (as opposed to DES)
GASPA	Green Ammonia Sale and Purchase Agreement

Government Support	Legislation by the government of the buyer's country to promote the use of hydrogen e.g., via carbon pricing, industry sector mandates, and subsidies or legislation to socialise the incremental cost of green hydrogen over fossil-fuel alternatives.
Green Ammonia	Ammonia produced in a process that is 100 per cent renewable and carbon-free using green hydrogen as a feedstock.
Green Hydrogen	Hydrogen produced by splitting water into hydrogen and oxygen using renewable electricity.
Initial Investors	The parties that invest in the project from the outset, typically the sponsors.
Integrated Project	A project structure under which the project company owns all the export facilities (power generation, hydrogen electrolysis unit, and ammonia plant).
LDCs	Less Developed Countries
Learning Curve	The expectation that the cost of a product will fall as a function of the cumulative quantity manufactured.
Lenders	The providers of debt to the project company (including banks and bond investors) and parties to the finance agreements
LH2	Liquid Hydrogen (cryogenic at atmospheric pressure)
LOHC	Liquid Organic Hydrogen Carriers
Merchant Project	A project that relies, for the repayment of its debt and return on equity, on sales of its product (whether electricity or hydrogen) that have not been contracted at FID. A project will have some merchant exposure if, for example, a percentage of its offtake is contracted at FID but it relies on the spot market for the remainder of its sales to fully service debt and equity.
MLDBs	Multi-lateral Development Banks
MOD	Money of the Day (inflated vs RT)
mtpa	Million tonnes per annum
O&M	Operations and Maintenance
Political Risk	Defined in Sections 4.5.2 and 4.5.3
PPA	Power Purchase Agreement
Project Agreements	The agreements between the project company and the other project parties (but not the lenders) that define the project.
Project Company	The SPC that owns the export facilities and is a party to the project agreements
Project Finance	Defined in Section 5.2
Project Parties	All the parties to the project agreements
RT	Real Terms, i.e., deflated to a specified date

Segregated Project	A project structure under which the project company owns the hydrogen electrolysis unit and ammonia plant but purchases renewable electricity from third parties.
Seller	The seller under the GASPA
SPA	Sale and Purchase Agreement
SPC	Special Purpose Company
Sponsors	The ultimate shareholders of the project company, likely to provide credit and technical support if required.
Term	The effective life of a contract, from the date it becomes effective until its expiry. For the GASPA, typically the period from which sales start. For a finance agreement, typically the date from when it is signed until the date by which the debt must be repaid also known as its maturity.
UJV	Unincorporated Joint Venture

Appendix II – Archetype Project Assumptions

Technical Assumptions	**Units**	**Assumption**	**Source**
	(all USD are RT 2019)		
Solar Generation			
Output	MW AC	1,000	Choice for Archetype
Unit Capex	USDm/MW DC	0.493	Cesaro et al estimates for 2025
DC/AC Ratio		1.25	" "
Capacity Factor (SAT)	%	31%	" "
O&M cost:	USD/MW_{DC} p.a.	6,800	" "
Degradation:	% p.a.	0.4%	author
Hydrogen Making			Cesaro et al estimates for 2025
Unit Capex	USD/kW	576.4	" "
Hydrogen energy (LHV)	kWh/kg	33.33	" "
Efficiency (LHV)	%	67%	" "
O&M	% of capex (p.a.)	1.5%	" "
Stack life	*operating hours*	95,000	" "
Ammonia Plant			Cesaro et al estimates for 2025
HB Unit Capex	USD/kg/hr NH3	3,300	" "
BOP (Desal, ASU, Battery, H2 storage) capex (multiple of HB)		3.91	Cesaro et al, (simplified by author)
H2 required (100%)	kg/kg NH3	0.1765	" "
Conversion efficiency	%	90%	" "
Operating days		330	" "
O&M	% of capex (p.a.)	3.0%	" "
Economic			
Long term USD inflation	% p.a.	2.0%	IMF,2022 https://www.imf.org/en/News/Articles/2022/07/11/CF-US-Economy-Inflation-Challenge

Discount Rate	% p.a. (MOD)	6.88%	IEA https://www.iea.org/articles/the-cost-of-capital-in-clean-energy-transitions (adjusted to mid-2022 by author)
Bank Base Rate (10yr)	% p.a.	2.90%	Swap rates.
Margin	% p.a.	1.85%	Authors estimate (based on IEA)

Appendix III - Risk Allocation

The comparative risks for green hydrogen (H2), LNG and offshore wind (OW) are indicated below in columns 2-4.		High	Medium High	Medium Low	Low	

Risk Description	H2	LNG	OW	Comparison with LNG and Offshore Wind and Precedents	Financeable Allocation and Mechanism
Pre-Completion General					
Completion risk is the risk that the project, or other projects upon which it relies, fails to be built to budget or schedule or to perform to specification (such specifications both in the construction contracts or, more importantly, in the GASPA).				In comparison to LNG and offshore wind, green hydrogen is more complex with more components including power generation, electrolysis, ammonia, and shipping and receiving facilities. In addition, for the early projects at least, the electrolysis unit and its integration with variable generation and the ammonia unit will be viewed as emerging technology (or at least as scaled up and/or use of proven technology in a new configuration). LNG technology is quite mature, while only 10-15 years ago offshore wind presented not only an emerging technology in terms of scale up, but also operation in a hostile offshore environment. Lenders are now becoming quite comfortable with these risks, including the increasing scale of the turbines. For the full LNG value chain to operate, other components such as the ships and the receiving facilities must be completed to schedule and these components are substantially outside the sponsors' control. This is 'co-completion' risk, see below. This presents additional risk compared to offshore wind. Green hydrogen will be similar to LNG and, possibly more complex if additional facilities are required, for example to crack ammonia at the receiving terminal. Thus, completion risk for green hydrogen is considered to be higher than for LNG or offshore wind. Although where ammonia is used as a carrier, the risk will be lower than for newer technologies such as LH2 or LCOH.	While it will depend on the specifics of each project, especially the extent to which the technology used would be viewed as unproven, given the experience in offshore wind, it is not expected that lenders will have an absolute requirement for completion guarantees, even for the early projects. Where there is a strong contractual structure with experienced EPC contractors and a conservative financial structure with adequate controls and financial reserves, lenders are expected to accept some pre-completion exposure. However, many stronger sponsors are likely to consider that the cost, time, and restrictions required are not worth the benefit and are expected to offer completion guarantees or simply delay raising debt until completion. Once a track record of successful delivery of projects to budget and schedule has been established, non-recourse, pre-completion

				Lenders rarely accepted completion risk on LNG projects until the simpler tolling projects in the Gulf of Mexico in 2012. It is not entirely clear whether this was due to lender risk appetite or the sponsors' choice to avoid the complexity and cost of a pre-completion financing. For offshore wind projects, lenders accepted completion risk from a relatively early stage. However, for a significant number of projects, the sponsors chose to equity finance until completion to avoid the onerous conditions being imposed by the lenders and their associated costs.	finance is expected to become more attractive.
Completion Risk – Components					
Completion - Cost overrun				In terms of cost overrun, LNG projects have suffered substantial cost overruns (33 per cent globally and 40 per cent in Australia) [17] in recent years while offshore wind costs have been more contained (around 20 per cent in Germany against 73 per cent for German large-scale projects in general).[18] However, a number of EPC contractors are understood to have sustained significant losses on a number of offshore wind projects, perhaps hiding greater underlying overruns. Both LNG and offshore wind precedents indicate that the risk of a cost overrun is borne by the seller and cannot be passed on to the buyer/offtaker as a variation in the sales price (other than very specific points, for example relating to externally imposed legal requirements). Under a Tolling Model, some tolling agreements do provide for the toll level to be fixed at completion, rather than at signing, based on the outturn cost of the project. But this is more typical for related parties not for an agreement with a third party.	Under the GASPA, the ammonia sales price would be fixed on signing the contract, leaving the cost overrun risk with the seller/project company. The project company should then seek to lay off the cost overrun risk with the EPC contractors through fixed price construction contracts. However, due to the scale and wide scope of the hydrogen project, it will almost certainly not be possible to obtain a single EPC contract to cost effectively 'wrap' the whole project scope. Since the contractors will not take risk on each other's performance, the more EPC contracts that are required, the greater risk of cost overrun. There also remains the risk of variations, where cost increases arise from factors outside the EPC contactors control.

[17] Wood-Mackenzie in LNG Industry 2019 https://www.lngindustry.com/liquid-natural-gas/25042019/wood-mackenzie-study-shows-lng-sector-acting-to-curb-cost-inflation/

[18] Offshore Wind Industry https://www.offshorewindindustry.com/offshore-wind-farms-moderate-cost-overruns

				Offshore wind projects have generally been constructed under a number of different fixed price EPC contracts and, provided they are well integrated, this has been satisfactory for non-recourse finance.	The Segregated project model does allow the risk of a cost overrun in the generation project to be allocated to a third party through a fixed price PPA.
Completion - Delay				In the LNG industry, both buyer and seller are exposed to delay risk under a typical SPA and each takes liability for delay in the projects for which it is responsible. Under an LNG SPA contracts, a series of time 'windows', under which each party notifies the other of progress on their respective projects and agrees narrowing date ranges for the windows, provides some mitigation of the delay risk. However, the risk of delay in the export facilities ultimately lies with the seller as, at a final longstop date, the seller's obligation to supply starts along with the consequent liabilities for failure (absent force majeure). For both LNG and offshore wind EPC contracts, the project company typically seeks liquidated damages for delay (and performance see below) sufficient to cover its anticipated costs arising from the delay. However, as projects become very large (multi-billion), this has not been practical.	The risk of delay of construction of the export facilities would ultimately lie with the seller under the GASPA, although a series of time windows to coordinate the seller's and buyer's projects and reduce the risk of one project completing before the other, would be desirable. The project company/seller would seek to lay off the delay risk on the EPC contractors through delay liquidated damages in the EPC contracts. These should, ideally, be set at a level to match the seller's anticipated liabilities (e.g., liabilities to the buyer under the GASPA, operating costs and interest expense). In the case of multiple EPC contracts, it is not possible/practical to hold one contractor liable for the delays of another and thus the allocation of delay risk is weakened.
Failure to meet design criteria				A failure of the plant to meet its design criteria and have the capacity to deliver the contracted quantity and specification (of LNG or electricity) would be the seller's risk, for any reason other than force majeure under the offtake agreement.	In the operating phase, the seller will have obligations to the buyer under the GASPA to deliver the contracted quantity and specification of green ammonia. The seller should seek to mitigate this risk through the EPC contracts under which the EPC contractor would usually guarantee that the plant would meet a series of acceptance

					tests, typically lasting up to 72 hours, and would be obliged to perform any rework required to meet the test at their expense. Beyond such acceptance tests, there should be a range of warranties of performance of all the key units. However, with multiple EPC contracts, if one unit depends on the performance of another, constructed under a different EPC contract, the performance guarantee is significantly weakened.
Co-Completion The risk that projects, owned by second or third parties and on which successful operation of the project depends, fail to complete on schedule (or at all).				For LNG, this typically includes the risk of completion problems with the shipping or receiving facilities, where new facilities are required. Where the project is segregated, it would also include the risk that the upstream gas development encounters problems. The completion risk of the buyer's receiving facilities and LNG ships, where the buyer is responsible for the shipping (an FOB SPA) lies with the buyer (other than force majeure). For offshore wind, the co-completion risk would comprise completion of the offshore transmission facilities, to the extent required. Again, this risk would typically be assumed by the power purchaser. For green hydrogen, co-completion risk will vary significantly from one project to another. An integrated green ammonia project would present limited risk - probably similar to LNG - given that shipping and receiving/storage facilities for ammonia are well-established technologies. If the hydrogen were to be shipped as LH2 or the ammonia had to be cracked to sell gaseous hydrogen in the buyer's country, the risk could be significantly higher.	In each case the buyer should be responsible for the completion of facilities it has committed to provide. Under the GASPA, it would be liable to make take-or-pay payments after a longstop date even in the event that it could not take the ammonia unless under force majeure. The buyer or seller could mitigate this exposure by selling the ammonia into the global market, but likely sacrificing the green premium.

Risk Description	H2	LNG	OW	Comparison with LNG and Offshore Wind and Precedents	Financeable Allocation and Mechanism
Post Completion					
Offtake					
Volume risk is the risk that the buyer does not take the expected quantity of product due to a lack of market demand.					
Underlying Market				Underlying market volume risk is clearly highest for green hydrogen where the market has yet to be established and will be heavily dependent on government policy and support for many years to come. In the earlier days of LNG, the market was growing rapidly but was price sensitive and had quite a range of uncertainty; there was also some reliance on government policy positioning LNG vs coal or nuclear. These days, LNG is widely traded, and the risk is much reduced (but still relies on having shipping and terminal capacity available). The underlying power market presented very limited risk given it was deep and transparent and, additionally, most renewable projects were displacing existing generation.	This risk will not be accepted by lenders. Strong precedent in the LNG and power markets suggest it should be allocated to the buyer under the GASPA.
Post offtake contract				In practice, both LNG and offshore wind projects were substantially protected from the underlying market risk by their offtake contracts; take-or-pay provisions in the case of LNG and obligations to take all power generated supported by priority of dispatch, in the case of renewables.	In the natural gas and LNG industries, the buyer accepts a 'take-or-pay' obligation under which, if it fails to take nominated quantities for any reason other than force majeure, buyer shortfall or off-spec product, it pays for such missed quantities as though they had been taken but with the right to take them in the future. This is preferable to the simpler

				For green hydrogen, it is expected that the buyer will bear the market volume risk and therefore there is little difference between the three in terms of risk exposure.	obligation to take whatever the project can deliver, within limits, as is the case for offshore wind, as it offers the buyer some flexibility in the event the hydrogen market develops more slowly than expected.
Price risk is the risk that the price paid for the product is not what was forecast at FID and is insufficient to generate sufficient revenue to service debt and provide a return to equity.					
Underlying Market Price				Until the early 2000s, LNG was traded bilaterally with the price indexed to oil but with widely ranging indices; there was no real underlying traded market. Since then, the market has started to commoditize and widely traded natural gas hubs in Europe and the US, and increasingly LNG hubs in Asia, have started to create a liquid underlying market. The electricity market is deep and transparent with well-defined prices. Electricity prices, however, tend to be more volatile than those of oil or gas given that the pricing of electricity is often driven by marginal fossil-fuelled generators. Given that there is no traded market for hydrogen at scale, the underlying price risk is clearly much higher than for either LNG or offshore wind. Like offshore wind but unlike LNG, green hydrogen will also be exposed to the learning curve resulting in all future projects having lower costs.	Lenders will not be able to accept material exposure to the hydrogen market price - given it is largely unknown. In time they might accept some exposure in the contract tail (e.g., the final years after a 15-year fixed price period) when the debt has been sufficiently amortised.
Post Contract Price				In the LNG industry, export projects have generally borne the oil price exposure with some contracts offering caps and floors to mitigate it. Different vintages of SPA have different indices resulting in a range of prices prevailing for the same trade at the same time.	Price risk should be allocated to the buyer under the GASPA as a fixed price or to a sovereign related entity through a CfD contract. (The CfD contract could not refer to a traded hydrogen price at this point but

				More recent SPAs tend to have price review clauses where the price can be reviewed periodically to align it with the current market. Offshore wind projects, however, have generally benefitted from mechanisms that effectively offered a fixed price for a period of 15-20 years (whether CfDs or renewable energy certificates). This was not only to provide an effective subsidy mechanism, given the relatively high cost of offshore wind compared to all other generators (bar nuclear) in the system but also to ensure that the projects would be financeable given lenders poor experience with lending to merchant power projects in the 1990s. We assume here that green hydrogen will have to follow a similar model to offshore wind given the need for a support mechanism to make the projects commercially viable. The projects will, therefore, be less exposed to price risk than LNG after their contractual terms are taken into account.	would require a surrogate such as oil or natural gas until such time as an acceptably transparent, liquid traded hydrogen index had developed.) Other similar support mechanisms developed for offshore wind, such as RECS, could also be considered but would be less applicable in an international context. The fixed price would need to last for an extended period (at least 10-15 years) as with sales at this nascent stage, lenders will give no credit for any sales for which there is no contract at the time of signing the financing. The GASPA could have a longer term, say 20 years, with the price reverting to a market price, assuming such a price had emerged by then. Lenders to a refinancing in the future might give some credit to merchant sales. It should be noted that lenders could not accept the price review mechanism seen in LNG contracts given the uncertainty about how the green hydrogen/ammonia market will develop and the generally accepted view that the levelized cost of green hydrogen will fall over time. This would make a price review essentially a one-way (downwards) option. For a project being developed in a number of stages but selling under a single GASPA, the fixed price could be agreed to fall by agreed amounts to reflect the 'learning curve'.

Buyer Credit risk is the risk that the buyer is unable to meet its financial obligations under the GASPA. This becomes particularly important where there is any potential for the contract price to be 'off market'. The creditworthiness of the buyer/offtaker is critical for any project financing.				The dependence on the buyer's credit reduces as the market becomes more liquid and alternative offtakers can be readily found in the event of a credit problem with the buyer. In the earlier days of LNG, lenders looked to highly credit worthy, usually monopsony, offtakers. Since the LNG market has developed a lot since then, with 48 per cent [19] sold spot or short term in 2019, lenders should be less concerned but in practice, they still give little credit to a sub-investment grade offtake. For offshore wind, the revenue stream is in two parts: the floating power price from what is usually a very deep traded power market, and the support payment (whether CfD or some other mechanism but in each case expected to provide an effective subsidy). Therefore, there is limited reliance on the offtaker for the first revenue stream but heavy reliance for the second (if the support payments are paid through the offtaker). In the event that the CfD (or similar) counterparty is a separate entity, it has typically been a government-related entity. For green hydrogen, at least in the early years, the price will be significantly higher than that of the fossil-fuel alternative. Furthermore, in the case of hydrogen, any government support from the end-user country will most likely be channelled through the buyer in the GASPA, thus the credit standing of the buyer will be a key consideration. The buyer credit risk is critical for green hydrogen and offshore wind (at least in relation to subsidies) and less so for the unsubsidised and increasingly widely traded LNG markets.	The GASPA underpins the entire project financing, so the creditworthiness of the buyer/offtaker will be of critical importance. Lenders have generally demanded an investment grade rating of the buyer (BBB- or Baa3) or its parent as a minimum. Some prominent hydrogen players do not, currently, enjoy an investment grade rating and this will be a significant issue to be addressed. The lenders' initial position will be to require an initial investment grade credit rating for the buyer, or a guarantee from an investment grade rated entity (usually a parent company) and an ongoing rating requirement. Where neither the buyer nor its parent has an investment grade credit rating, the options would be to: (i) have a 'cut-through' to the credit of a major end buyer, which was investment grade, whereby the end buyer would make payments directly to the project company and/or (ii) to have bank guarantees in support of payments over an agreed period of time (less than the term of the GASPA itself).

[19] Robin Baker, OIES, LNG Finance – will lenders accommodate the changing environment. November 2020. *https://a9w7k6g9.stackpathcdn.com/wpcms/wp-content/uploads/2020/11/Insight-78-LNG-Finance-will-lenders-accommodate-the-changing-environment.pdf*

Failure of Government Support This is the risk that the government support from the importing country, in whatever form, is amended with an adverse effect on the price or terms of the GASPA. Such amendments could be made for: policy or economic reasons; because of unintended consequences (such as occurred for biofuels); or to conform with a newly established regional or global standard (e.g., carbon price).				LNG projects do not require support from the importer governments for their viability although they may receive some support from their host nation to make them cost competitive with other LNG exporters. The bulk of offshore wind projects do still require price support from the host government and typically provisions for preferential dispatch. However, the need is declining as costs continue to decline. Green hydrogen, as an emerging technology, will have a greater requirement for government support. The risk is also greater in that the support is not expected to be provided directly by the host country, as for offshore wind, but by the buyer's government and the relationship is, therefore, less direct. It is also likely that there will be some degree of host government support for the export project e.g., in the form of exemptions from certain import/export duties and/or tax holidays or grants for local manufacturing. However, these are typically a lesser risk, being more front-end loaded towards the construction phase of the project.	The risk should be allocated to the buyer i.e., any act of the buyer's government to materially and adversely change the support mechanism should ***not*** constitute force majeure and hence excuse the buyer from its obligations under the GASPA. For a major project, lenders, in particular MDBs or ECAs, may also seek some direct acknowledgement from the buyer's government. For a purely domestic project in an OECD country, lenders would accept the risk of change of law, after satisfactory due diligence. However, in that situation, they have more direct rights against the relevant government.
Failure to provide certification The risk that the seller is unable to provide the certification, required under the GASPA, to prove that the ammonia is 'green'.				For LNG, if the product does not satisfy the SPA specifications (e.g., heat content, Wobbe index, etc), the buyer has the right to reject the cargo or claim damages for the costs required to achieve the specification. Similarly, any generator has to meet the standards of the grid. For green hydrogen, the buyer will be paying a premium for green ammonia and is likely to suffer losses in the event that it cannot satisfy authorities in its own county that the ammonia is 'green'. Given that green certification will be new for hydrogen and may well be defined differently in the exporting and importing countries, lenders will require significant due diligence prior to be able to accept this risk. The risk is then that the certification standards could change, and this creates a higher risk than for LNG or offshore wind.	The risk of failure to deliver the green certification specified in the GASPA should fall on the seller. Under the GASPA, the buyer would be likely to either have the right to reject the cargo or pay at a reduced price to reflect the additional costs it would have to bear (e.g., carbon taxes). If such certification is no longer acceptable in the buyer's country due to a change in law, this should be a buyer's risk but would require best efforts on both parties to resolve. In the case of a segregated project, where green certification would be required for the electricity, some risk would be allocated to the power supplier under the PPA. The

					project company would seek matching rights to reject or pay a reduced price for an electricity that was not certified green (on terms that would satisfy the GASPA).
Operation - General				While the operation of an offshore wind farm requires significant expertise, it does not have the complex value chain nor requirement to handle hazardous materials compared to an LNG plant. In terms of complexity and hazard, hydrogen is similar to LNG. However, a green hydrogen value chain requires expertise from a number of quite different industries (power generation, electrolysis, and ammonia manufacture) which will present greater initial challenges to assemble a single, streamlined, operating team.	The project company should consider having technical support agreements with its sponsors such that it can call upon experienced staff on secondment and their research capabilities and purchasing power.
Failure to deliver – due to reduced resource This is the risk that resources, gas in the case of LNG and solar or wind resource in the case of offshore wind or green hydrogen, fall below the levels forecast at FID.				Most LNG projects rely on a small number of gas fields for their feedstock. SPAs are usually negotiated on the basis of P50 reserves. Most place the risk of a shortfall in reserves with the seller but there are precedents where such risk is considered force majeure. In assessing downside risk, lenders look at P90 reserves which are typically 70-75 per cent of the P50 (expectation) estimate. Similarly, offshore wind and most green hydrogen projects will also rely on a dedicated resource. However, renewable resources, wind or solar, averaged over a period of time (one year or the life of the project) show a lower level of uncertainty than natural gas reserves, with P90 typically over 90 per cent of the P50 estimate. Renewable projects typically allocate the resource risk to the buyer, albeit sometimes with an undemanding minimum quantity.	It is expected that the buyer will wish to have a stronger commitment than the 'take whatever is produced (within limits)' model of offshore wind, and the project is likely to be required to have an agreed level of storage to provide some assurance of supply. However, the risk of the solar or wind resource falling below P90, or even P99 levels for a period of time, beyond that covered by storage, cannot be excluded. This 'Dunkelflaute' risk should be treated as force majeure and a shared risk under the GASPA. Having carried out appropriate due diligence, the seller and lenders would be expected to accept this risk.
Failure to deliver– due to plant availability This risk is the failure to deliver the contracted quantity and quality, as				For LNG, any failure to deliver other than for reasons of force majeure or agreed maintenance, are seller risks in the SPA. This is mitigated by a degree of overdesign in the plant. In newer SPAs, the seller can source third party LNG to meet its obligations. Damages are usually limited to the cost of the buyer sourcing	This risk would likely be allocated to the seller under the GASPA. Following the LNG model, after a build-up period, there would be a plateau period with a pre-agreed annual contract quantity with a monthly nomination

forecast at FID, due to a technical failure of the export facilities.				alternative supplies of fuel. However, after an extended period of operational failure, the buyer would generally have the right to terminate the SPA. In the renewables sector, but less so with LNG, some weight is placed on long-term warranties from the manufacturers of key equipment (solar panels, turbines etc). For hydrogen, unlike LNG, it is very unlikely that the buyer would be able to find replacement green ammonia. It can, potentially, use fossil-fuel based ammonia, or other fossil fuels, but that is likely to be at a cost (e.g., carbon price or penalty).	procedure, allowing for anticipated seasonal changes in resource and demand. The buyer would be obliged to take, or pay for, all such nominated quantities and the seller would be obliged to deliver them with damages due for any failure to deliver. Any damages should be limited to the actual economic loss of the buyer. In the case that the project is operated by a contractor, or contractors, under O&M agreement(s), some risk should be allocated to the O&M contractor. Liabilities under an O&M agreement would not, however, be expected to be sufficient to match losses under the GASPA and the use of multiple O&M agreements would further reduce any risk mitigation. Accelerated degradation of key equipment (solar panels but especially electrolysers) should be covered to the extent possible by long term manufacturers' warranties although these may not be available for the life of the project. For early projects, this may reduce the maturity of the loans. This risk is expected to be acceptable to lenders subject to satisfactory due diligence and completion testing. In the case of a segregated project, damages should be due under the PPA for failing to deliver power (other than for force majeure). However, they will not be sufficient to match the damages due under the GASPA and ongoing operating costs and debt service.

Operational Cost Increase The risk that operating costs exceed those forecast at FID.				For both LNG and offshore wind, operating costs are a relatively small percentage of revenue and the project can tolerate significant increases. Most LNG projects have been self-operated with the project company recruiting its own staff supported by agreements with the sponsors, typically for secondment of key staff and technical support. Given sponsors with a track record of operating complex, world scale projects, self-operation is expected to be acceptable to lenders subject to due diligence and appropriate maintenance reserves. Offshore wind projects tend to be operated by a contractor under fixed price (with inflation indexation) O&M contracts. For green ammonia, due to its complexity and emerging technology, the cost overrun risk will be higher than for either LNG or offshore wind. However, subject to meeting completion tests, it is also expected to be acceptable to lenders.	The cost increase would be allocated to the seller under the GASPA which typically takes its own performance risk. The sales price would be fixed with the possible pass through of additional costs required to meet changes in legislation (especially if in the buyer's country) Where the project is operated by a contractor, or contractors, some cost risk would be allocated by a fixed price in the O&M agreement. However, a single O&M agreement may not be practical given the range of different activities required. Precedent would also suggest that a contract term which matched that of the GASPA is also likely to be difficult to achieve on cost effective terms. In the case of a segregated project, the operating cost risk of the solar or wind farms would be allocated to the generator under the PPA.

Risk Description	H2	LNG	OW	Comparison with LNG and Offshore Wind and Precedents	Financeable Allocation and Mechanism
General					
Shipping The principal shipping risks comprise: (i) timely delivery of the ships to specification, if they are new-build; (ii) availability of the vessels to operate to the planned capacity and schedule; (iii) availability of replacement shipping in the event that the term of the charter party is less than the project life and (iv) increases to the charter rate that could arise for reasons such as an increase in the operating cost, if the time charter expires and the market has tightened, or if shipping regulations governing, for example, emissions or safety, impose additional costs.				According to LNG precedent, the risks of capital and operating costs of the ships and their operating performance would be allocated largely to a ship owner under a time charter with a term equal to the GASPA. Further, if the SPA were on DES terms, any residual risks would lie with the buyer. These have not been proven to be a material risk over time. Offshore wind does not require shipping; the equivalent would be the offshore transmission system if owned by a third party which poses a lower risk than shipping. For hydrogen, where shipped as ammonia (as assumed for the Archetype project) or LOHC, the risks are probably lower than for LNG as the ammonia and oil product trades are very well established. However, the use of ammonia as a fuel, if chosen, will be new technology especially regarding safety, and thus will require additional due diligence based on trials and some track record. If shipped as liquid hydrogen, however, a new class of ship and research into safety issues would be required before large vessels are commissioned, and the risks would be similar to those of the earliest days of LNG.	Lenders will likely accept either DES or FOB SPA arrangements; the choice being largely a commercial one for the sponsors. Under FOB, the shipping risks would typically lie with the buyer, and this would slightly reduce the risk profile for the project. If the project company chose the DES route, the shipping risks should be allocated to one or more shipping companies under long-term (matching at least the debt term) time charters on fixed rates (with clearly specified provisions for cost inflation and the costs of meeting agreed new regulatory requirements). In the expected case that new-build ships with ammonia fuelling would be selected for a large-scale project, lenders are expected to accept the risk given satisfactory due diligence and the involvement of highly experienced shipowner/operators and shipyards.
Interface Risk The project will comprise several separate components; some of these will be owned by different parties and even where they are owned by the same				A green hydrogen project has some key engineering interfaces, namely between intermittent renewable power generation, the hydrogen electrolysis unit, and the ammonia plant. Each of these has very different technologies and suitability to intermittent operation. Additional legal issues may arise at each interface if there are separate construction operation or commercial agreements among the different units. An LNG project has a major	If the seller chooses to create interfaces in the export project, e.g., by purchasing power under a PPA from third parties, any risk should remain with the seller. In the same way, the seller would not expect to be exposed to any risks associated with the buyer's ship charters or port or storage

party, may have multiple contractors that will be required to work together but with differing scopes. The risk in the construction phase is that a mismatch of technical specifications or legal obligations could lead to delays in achieving satisfactory start up or increases in cost. In the operating phase, there are similar risks ensuring a seamless operation across the different components of the project.				interface between upstream gas production and the LNG plant, so has some complexity but less than green hydrogen. Offshore wind has the least with a direct connection to the grid via an offshore cable, typically (but not always) owned by the project.	arrangements. Following satisfactory due diligence, lenders would be expected to accept these risks on the seller side. The GASPA would not transfer any risk between the parties due to performance of third parties. Typical events of force majeure affecting key project assets, including those belonging to third parties (e.g., loss of a ship, fire, flood, etc) would likely be included in the definition of force majeure. In particular, in the segregated project model where power would be purchased from a third party, it would be critical to align the terms of the PPA and the GASPA to minimise the risk of the project company incurring liabilities under one contract without a matching claim under the other.
Macroeconomic The project will be exposed to a range of macroeconomic factors: interest rates, foreign exchange rates, and inflation. Foreign exchange exposures could arise where the project incurs costs in the currency of the host country (e.g., if power were purchased from the grid) but payment under the GASPA is in a different currency e.g., US dollars.A secondary exposure is where payment under the GASPA is in a different currency to that				LNG projects have exposure to commodity prices (with the price being indexed to oil or natural gas or emerging LNG indices) as well as interest rates and foreign exchange rates. Commodity price is generally the predominant exposure and lenders do not generally demand interest rate hedging post completion (other than in tolling projects). Offshore wind projects are predominantly domestic and, until the most recent zero-subsidy projects, typically only have exposure to interest rates and foreign exchange rates in the construction period. Lenders typically require these to be substantially hedged throughout the term of the debt. There is also some secondary macroeconomic exposure since the project requires government support that will be at risk if general economic conditions make it harder for the host government to sustain. Assuming the green hydrogen project has a fixed price offtake for a significant period, its macroeconomic risk profile is similar to that of	Lenders are expected to accept the macroeconomic risks but will require that interest and foreign exchange rate exposures be hedged to the greatest possible extent.

of the buyer's country. Where the buyer is located in an economically strong, say OECD, country, this is not a material risk. However, for a less developed country, this can become an issue.				offshore wind with some greater exposure to government support due to the higher 'economic gap'. There will also be a higher foreign exchange exposure as the price of hydrogen is likely to be denominated in US dollars, a different currency to that of the project's operating costs, in particular if operating as a segregated project purchasing power in the currency of the host country.	
Political risk In addition to the specific buyer country government support risk above, where the seller's country is not an OECD/wealthy country, commercial lenders will have concerns about issues such as: their ability to repatriate hard currency; the risk of their debt being caught up in a broader debt restructuring program or unlawful expropriation (whether physical or economic e.g., by increasing taxes).				LNG projects are located in countries with abundant natural gas reserves, many of which are LDCs and for which the LNG project is a major contributor to the economy. Offshore wind projects to date have been predominantly domestic and required substantial government subsidy and have therefore have only been developed in wealthy, OECD countries. Green hydrogen export projects will be located in countries with abundant renewable resources, many of which (e.g., in North Africa or Latin America) are in the LDC category. Green hydrogen, therefore, will generally face the highest political risk of the three sectors in both buyer and host countries.	Host country political risk cannot be allocated materially to other project parties by the project agreements. However, it can substantially reduce commercial banks' appetite to lend and thus, for a large project, such as the Archetype, will need to be mitigated by the involvement of ECAs, MDBs and/or political risk insurance. This is discussed further in Section 5.4.2

Appendix IV Hydrogen Market Evolution

Postulated development of the hydrogen market, substantially based on the work of Patrick Heather.[20]

Evolution of Energy Markets																	
Period starting:	**1985**	**1990**	**1995**	**2000**	**2005**	**2010**	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**			
Market Evolution																	
Electricity (UK)	Regulated	Liquid Traded Market with ongoing reforms															
Domestic Gas	Regulated		Transition						Liquid Traded Market								
LNG/International Gas	Bilateral Trade		Transition							Liquid Traded Market							
Hydrogen Domestic									Bilateral Trade		Transition			Liquid Traded Market			
Hydrogen Export									Bilateral Trade			Transition			Liquid Traded Market		
Subsidy Evolution																	
Onshore Wind		Subsidised					Transition		Unsubsidised								
Offshore Wind					Subsidised			Transition		Unsubsidised							
LNG		Unsubsidised															
Hydrogen									Subsidised			Transition					

[20] How a traded hydrogen market might develop—lessons from the natural gas industry, Patrick Heather, OIES May 2021 https://a9w7k6q9.stackpathcdn.com/wpcms/wp-content/uploads/2021/05/OEF-127.pdf