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# The development and financing of LNG-to-Power projects

# Overview

The development of the global LNG market and the commoditisation of hitherto expensive floating storage technology (both FSUs and FSRUs) have provided an impetus for a modern twist on power projects, allowing CCGTs to accept gas from international LNG cargoes. This combination of FSU/FSRU and gas-fired generation is particularly suited to jurisdictions where an indigenous gas transportation network does not exist and power prices are sufficient to support the higher capex/opex requirements of what are essentially "back-to-back" projects.

By way of recap, an LNG-to-power project involves the following constituent parts:

- the importation and delivery of LNG, typically on a long-term basis (but please refer to our analysis of the "gas hub" concept below);
- the receipt, storage and regasification of the LNG by FSRU (or an FSU with onshore regasification);
- the delivery of gas (upon regasification) to the CCGT power plant; and
- the supply of the power generated to the off-taker(s).

An indicative contract matrix implementing this structure would include:

- a long-term LNG sale and purchase agreement (LNG SPA) between the LNG supplier and the gas purchaser, assumed to be delivered ex-ship;
- a long-term charterparty or equivalent, by which the FSRU is made available to regasify the LNG;
- where the project is disaggregated (a "gas hub"), a terminal use or regas services agreement, under which the terminal operator receives and regasifies LNG and delivers gas to the power plant (not normally required for a fully integrated project);
- a power purchase agreement (PPA) between the power project and the off-taker.

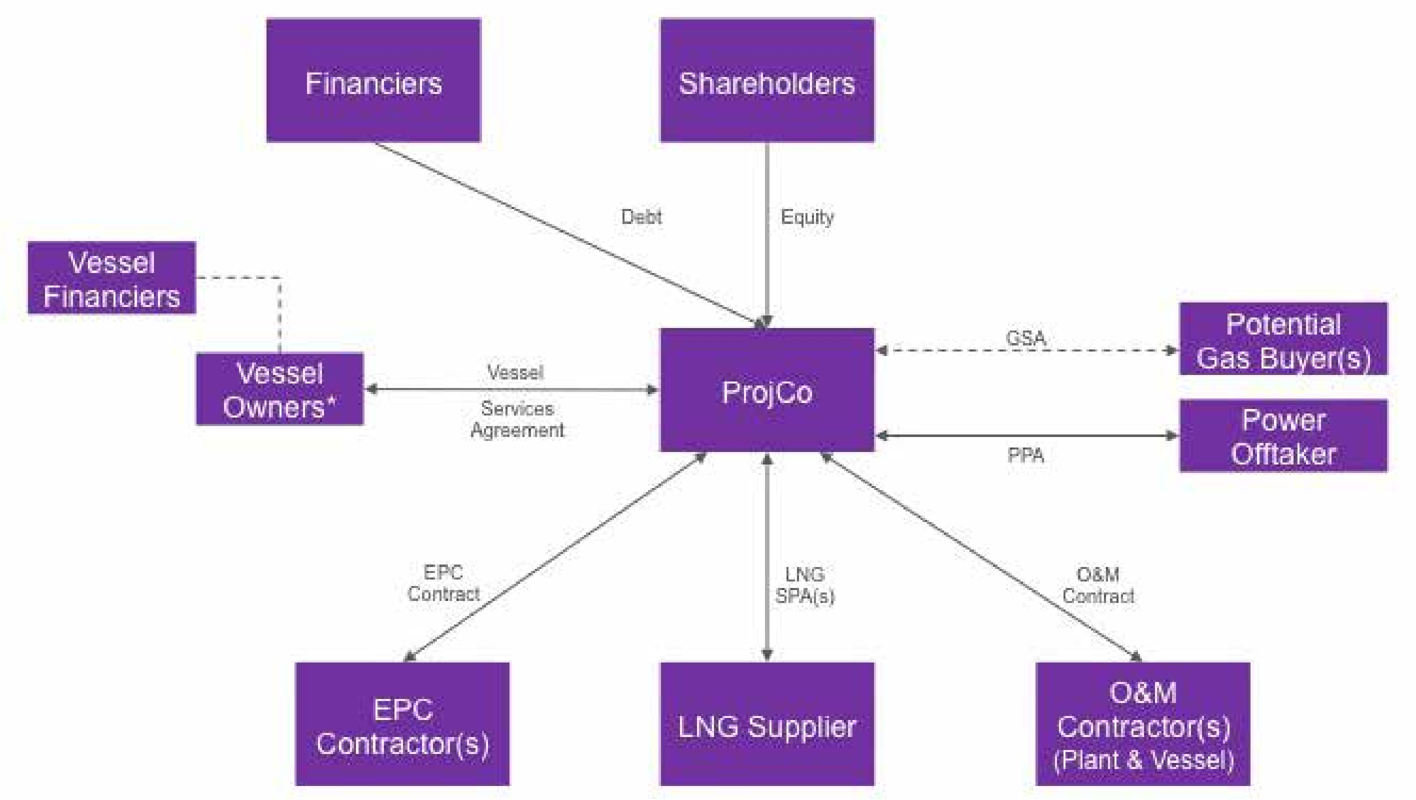
Irrespective of whether the preferred project structure is integrated or disaggregated, each party throughout the "chain" (supply/regas/off-take) will need to be assured of the financial and technical capability of its counterparties. More importantly, financiers will need to be satisfied that the project as a whole is operationally, commercially and financially viable over a period of time sufficient for them to recoup the cost of their loans into the project.

# Integrated projects

The simplest structure adopts the "integrated" model, whereby a single project company purchases LNG, owns/hires and operates both the FSRU and the power plant, and sells power to the power off-takers (typically a state-owned utility). The project sponsors would then seek finance for the entire project. An alternate approach is for the project sponsors to split the development into two parts (the "gas-hub" model) for the purpose of financing: (i) the LNG import project and (ii) the power project. This decision may also depend to some extent on the scope for third parties to have access to the LNG facilities, either for regulatory requirements or for commercial reasons where regasified LNG is to be provided to other gas customers rather than exclusively for the power plant (and thereby providing multiple independent revenue streams to underpin the "hub" financing).

As no two projects are entirely alike, there will be a range of project structuring issues and risks to be addressed in both the project and financing arrangements. For illustration purposes we have focused on three key areas – the pros and cons of the "gas hub" model, construction risk and key concerns with respect to LNG supply and scheduling (the latter two risks applying equally to integrated and disaggregated projects).

## Integrated Structure




* Alternatively, ProjCo can own the vessel and finance collectively with the power plant

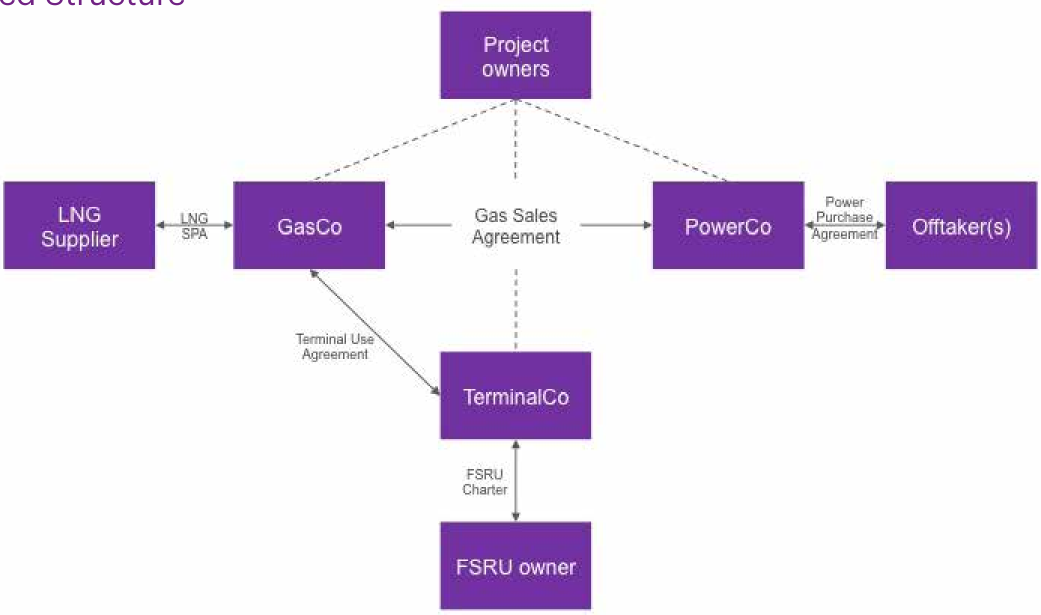
# “Gas Hub” concept

Instead of having a single off-taker (the power plant) who commits to purchase all gas volumes from the regasification terminal, the terminal and associated pipeline infrastructure could be set up as a “gas hub” to provide regasification services for numerous local off-takers. Having other commercial users of the FSRU/jetty helps to mitigate LNG supply and demand risk by providing for multiple LNG suppliers and gas purchasers. The “gas hub” model requires that the regasification terminal is owned separately to facilitate financing, with multiple regas services/throughput agreements effectively “tolling” the capacity of the terminal. Alternatively the terminal can potentially be owned completely independently of the power plant, with an investment from an LNG “aggregator”, who will have flexibility to purchase LNG on both a long-term and spot basis, thereby taking ownership of the gas and supplying customers directly itself.

Provided that there are multiple, truly independent revenue streams available (either by way of gas sales or tolling revenues), then developing the regasification terminal as a gas hub will allow for that part of the project to be financed separately from the power plant. This may significantly improve financing terms for both projects as (i) it reduces pressure on the PPA (as the capex portion of the power price related to the hub is amortised over a number of gas sales/throughput agreements) and (ii) it diversifies the range of end users for the gas (for example, power, industrial, domestic users) thereby reducing risk of a lack of demand and increasing sources of supply as multiple cargoes, both spot and long-term, will deliver to the terminal which reduces both the risk and the impact of non-delivery for force majeure or diversion/market arbitrage.

If an “aggregator” model is adopted utilising a blend of spot and long-term sale and purchase agreements, lenders will undertake a sophisticated analysis (by way of their gas market consultants) to understand the various sources of supply, the demand model and the expected variation between contracted and spot sales. It is important to consider allocation, nomination and scheduling procedures at an early stage. Between each cargo unloading, gas customers collectively will not be able to nominate more gas for delivery than the working LNG stock in tank, and will be obliged to nominate at least enough gas to create the space for the next cargo. In practice this means that once the LNG delivery schedule (annual or quarterly) has been defined, the short-term nomination rules in the gas supply agreements will need to reflect that schedule. For allocation and optimisation between gas customers one approach would be to require them to designate a single nomination agent (and leave the gas customers to write the allocation rules to be applied by that agent).

## Disaggregated Structure



# Construction risk and finance interface


Construction arrangements will be of paramount importance to lenders. Whilst most financiers would prefer to see a single, lump-sum turnkey EPC contract covering the LNG jetty, onshore facilities and the power plant, the project sponsors might, for commercial or economic reasons, choose to disaggregate construction by engaging different contractors for each of these work packages. The FSRU would typically not be purchased outright, but would be chartered or otherwise provided by a third party (and hence financed independently or possibly purchased and financed as part of the wider gas hub financing).

Where the commercial structure involves separate EPCs, lenders will be concerned to see that key technical interfaces and commissioning arrangements are aligned with each other. To ensure that there is no misalignment, close coordination will be needed in the negotiation of the EPCs, including enumerating all major technical interfaces and providing sufficient 'float' to mitigate downstream delays – the role of the sponsors technical teams/technical adviser is crucial in communicating these risks to the lenders clearly. Robust cooperation and coordination obligations must be imposed on each contractor and sufficient protection for delay or non-performance should be provided – usually through liquidated damages for failure to meet completion dates. If at all possible, these should be scoped to keep the entire project whole, but where this is not feasible, a consistent contractual risk allocation must be developed between the agreements addressing both contractor-attributable delays and events of force majeure/non-fault delays and how such consequences are allocated between the contracts. Some form of alliancing or common bonus pool can be used to incentivise both contractors to reach key milestone dates.

Where pursuing an integrated project, it is essential that the LNG jetty (including the storage tanks) and gas pipelines are constructed and ready for operation prior to mechanical completion of the power plant (and certainly no later than its intended commissioning date/reliability run), otherwise one or more items of delayed infrastructure will create a cascade effect (effectively creating project-on-project risk) – thereby delaying the point from which lenders can begin to recoup their investment. For a gas hub project, this requirement is relaxed slightly, provided that the regasification facilities are available before any ship-or-pay obligations under the various long-term gas supply arrangements or throughput contracts enter into force.

Whilst the EPC contract will, in all cases, receive a high degree of scrutiny from the lenders, if opting for a multi-contract strategy, the contracts will be subject to an intensified review. Project sponsors should be prepared to demonstrate that multiple agreements fit together coherently, and within the whole commercial framework.

Given that the LNG-to-power market is nascent, the extent to which lenders will accept full construction risk remains largely untested. Based on recent market experience, a single EPC is preferable from a finance perspective, but multiple contract packages have been considered acceptable in the European market without some form of completion guarantee or debt service, although contingent equity remains a prerequisite. The quantum of this equity is very much dependent upon the degree to which the risks outlined above are addressed by way of the technical and legal analysis. A well-considered construction package involving material, highly experienced contractors and implementing robust construction contracts with clearly enumerated interface risks (and sufficient float) will clearly benefit from a more lenient contingent equity analysis (and viceversa). However, given that the sole source of revenue to support a fully-integrated project is usually the payment stream derived from the power purchase agreement (which will not materialise until all infrastructure is operational), there will be a number of jurisdictions where, to safeguard against construction risk, project financiers will in any event require completion guarantees/DSUs as part of the loan package if there is not sufficient confidence in the designated contractors.

# Charging and credit issues

Sponsors want to structure their projects to minimise the extent of sponsor financial support, so depending upon the jurisdiction in question, the level of government financial support (or other form of partial risk guarantee) will be a key factor in determining the projects viability. Whether it can be financed will ultimately rest on the risk allocation and covenant strength of the various parties, but in particular, the credit quality of the main offtake will be of paramount concern.

The tariff under the PPA will need to be structured to pass through all project costs (including fixed, variable and despatch-related take-or-pay). It may make sense to treat the hire costs of the FSRU as a fixed cost in setting the PPA capacity charge. On that basis the price of LNG will be the main cost to be covered in a variable PPA charge. Currency aspects of the PPA charges will also be important – costs incurred in US$ should be passed on in US$.

As the sole source of revenue to support the project is usually limited to revenues derived from the off-taker under the PPA, each of the principal creditors of the project (its lenders, the FSRU owner and the LNG supplier(s)) will wish to be assured of the financial viability of this entity. A key aspect of this analysis will be the ability of the off-taker to pass on its costs to its customers, and the affordability of those costs for its consumers. This includes both the capacity payments made to the owner of the plant (irrespective of despatch), and the fuel cost component of the PPA charges (including potential take-or-pay payments). Close scrutiny of the basis of regulation of tariffs in the relevant country will be critical to this; additional contractual comfort may be required to sit alongside the regulatory regime and to the extent there is any currency mismatch, then an appropriate hedging regime will need to be developed, failing which, this risk is likely to be borne by the Government or one of the Sponsors (especially if state-owned).

# LNG supply and scheduling

Under the LNG SPA (there may be multiple SPAs under the gas hub model), LNG cargoes will generally be delivered in nominated tankers under an annual delivery programme (ADP) or 90-day schedule derived therefrom, with limited flexibility for the LNG purchaser to deviate from this delivery programme. Failure to take a cargo will (unless its delivery is rescheduled by mutual agreement) give rise to a liability of the LNG purchaser, most likely a "take-or-pay" liability.

The most likely immediate cause of a failure to take an LNG cargo is insufficient space in the storage tanks of the FSRU, because LNG inventory (from prior cargoes) has not been sufficiently depleted. This may have occurred for a variety of reasons, including reduced demand for power generated (or reduced demand from other customers of the gas hub), power plant outage, power transmission failure, or possibly failure of part of the LNG infrastructure (either regasification or gas transmission). This risk may be mitigated if a single party acts as an "aggregator" at the LNG terminal (if pursuing a gas hub model) thereby adopting and managing the mismatch risk. If a series of throughput/regasification services agreements are used, then a much more rigid timetable may be required, thereby allocating capacity within the terminal to each capacity purchaser.

Conversely, if demand is higher than expected, or an LNG cargo arrives late, or if relying upon a single source of LNG and that single source fails to materialise, there will be other adverse consequences (particularly for a fully integrated project). It will be necessary to maintain a heel of LNG in the FSRU tanks (to avoid the need for cool-down). If regasified LNG cannot be sent out, it may result in the power plant having to burn more expensive liquid fuel (assuming it has dual-fired capability), or even having to shut down (with consequent loss of revenue under the PPA). It is therefore critical to have adequate flexibility in the chain from LNG source to power demand to manage these risks. Some factors to consider include:

- it may be preferable to rely on more than one source of LNG, minimising the overall impact to the project should a single LNG supplier call force majeure or deliberately divert a cargo for arbitrage purposes;
- the relationship between the storage capacity of the FSRU and the maximum allowable LNG ship size (or LNG load) is very important. A significant margin of capacity provides a cushion for reduced or increased demand, as well as other unplanned events;
- inability to take a part of the LNG in a cargo may result in a take-or-pay liability for the whole cargo. But it may be possible to negotiate with the LNG supplier some flexibility in terms of part-loaded cargoes (where a programme deviation is foreseeable) or part-unloaded cargoes (where it is not), with the take-or-pay applying only to the part-cargo not taken; or some additional flexibility (potentially at a price) to detain the LNG ship beyond its normal turn-around time;
- any deliberate diversion by the LNG supplier should result in the payment of liquidated damages to the Project to cover any market to market loss for processing replacement cargoes
- the running regime of the power plant or other purchasers of gas is critical. The existence of a take-or-pay LNG liability implies a cost of not running which should make the power plant base-loaded in most cases; and
- the power plant should be both scheduled and despatched in a way which optimises the likelihood of meeting the LNG delivery programme. Passing the take-or-pay liability to the power plant operator should ensure such optimised decision-making.

If there is (initially or later) more than one gas purchaser these arrangements become more complex, not least because the failure of one off-taker to take committed volumes which correspond to a part of an LNG cargo may have the effect of triggering a take-or-pay liability for an entire cargo. Again, a dedicated gas aggregator may arbitrage these positions more successfully than a single dedicated purchaser under a fully integrated project.

# Summary

The development of LNG-to-power is an exciting prospect for the power market, particularly in jurisdictions without a dedicated gas transportation network, or where gas sources are located too far from end customers to be transported economically. The adoption of gas, whilst not carbon neutral, is significantly cleaner than either lignite or coal, and will assist many nations in reaching the ambitious goals agreed as part of COP21 (the Paris Climate Conference).

Should you wish to discuss any of the issues raised in this article, please contact any of the members of Dentons' dedicated oil and gas team using the details below.

## Highlights of our experience

- **Delimara 4:** Advising lenders on the long-term bridge financing for the Delimara 4 power plant in Malta, the first European fully integrated LNG-to-power project.

- **Adgas:** Advising on its long-term LNG sales to Dabhol Power Company.

- **Bontang project participants:** Acted for participants in the Indonesian LNG trade on gas supply, plant operating and gas processing agreements and their base-load and short-term LNG sales contracts with buyers in Japan, Korea and Taiwan.

- **Botswana Power Corporation:** Advising as sponsor of the Morupule Power project, including drafting and holding EPC tender, drafting a coal tolling agreement and advising on coal supply and overall project structure and financing.

- **Chicago Bridge & Iron:** Advised on the LNG expansion project at Bonny Island in Nigeria.

- **China National Offshore Oil Corp and five others:** Acting for the "Joint Executive Office" (JEO) of the sponsors of the Guandong LNG import terminal project, China's first LNG import project (US $600 million) in relation to LNG purchase agreement.

- **DEFA (Cyprus National Gas Company):** Advising on the sale and purchase of LNG in the Republic of Cyprus; involving DEFA, the Government of Cyprus, the Electricity Authority and various international oil and gas sellers.
- **Government of Jamaica:** Advising on procurement of first LNG supplies for the development of a pipeline gas market.
- **Gulf Power:** Advising in relation to the 1,000MW Lamu coal-fired power project in Kenya.
- **Mmamabula power project:** Advising Botswana Power Corporation as the host nation power utility in relation to the proposed US$$5 billion 2,500MW Mmamabula power project, including its PPA as one of the off-takers, power transmission arrangements, grid control arrangements and participation in South Africa power pool, and all of the documentation.
- **National Grid Grain LNG Limited:** Advising on its initial development and second and third expansion projects. This includes advising and negotiating on the construction and commercial agreements for the LNG import facility at the Isle of Grain, UK, including advising on access terms and conditions and open seasons for letting of capacity covering several major access contracts; construction contracts for each phase; and regulatory aspects including RTPA exemptions.
- **Qatargas 1, 2, 3 and 4:** Advising on the negotiation of various LNG sale and purchase agreements and spot sale agreements.
- **RasGas 3:** Assisting Rasgas in negotiating its anchor long-term SPA (c 8mtpa) with ExxonMobil; and on the Golden Pass receiving terminal arrangements, pipeline capacity arrangements and downstream gas marketing.
- **Tomen Power Limited:** Advising on all aspects of the development of the Tomen Power 1,000 MW gas-fired IPP in Iran, including the energy conversion agreement and the construction and financing agreements.
- **Total:** Advising on the Obite IPP in Nigeria.

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