Singapore Sustainable Finance Association

From Ambition to Bankability: Commercial and Legal Foundations for the ASEAN Power Grid

Prepared by the Singapore Sustainable Finance Association in partnership with

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Executive Summary

From Ambition to Bankability: Commercial and Legal Foundations for the ASEAN Power Grid begin with a simple but critical question: how does the ASEAN Power Grid (APG) move from strategic ambition to bankable cross-border projects? With estimated investment needs of approximately US$800 billion[1] across generation and transmission systems, the APG represents one of the largest infrastructure undertakings in the region's history. Delivering it at scale will require more than political commitment or engineering capability. It will require a shared understanding of how commercial structures, legal frameworks, and risk allocation must evolve to convert regional energy ambitions into projects that capital providers can finance. **This paper seeks to democratise that understanding by examining what it practically takes to make cross-border power projects investable, replicable, and scalable.**

Technology is undeniably an essential enabler of the APG. Advances in renewable generation, grid management, and subsea transmission have made regional power trade increasingly feasible. Yet, experiences across infrastructure sectors consistently show that technology alone does not unlock investment, nor ensure bankability. The decisive factors determining whether projects progress lie in commercial design, regulatory certainty, contractual enforceability, and governance arrangements, particularly when assets, revenues, and risks span multiple jurisdictions and long timeframes. Without clear market rules and legal certainty, technically viable projects will struggle to secure financing. **As such, this paper treats technology as a necessary but given foundation, and instead focuses on commercial and legal frameworks as the critical levers for realising cross-border power trade at scale.**

The paper adopts a deliberate bilateral-first perspective. International experience suggests that integrated multilateral grids rarely emerge fully formed. Rather, they are built incrementally on the back of successful bilateral arrangements that establish commercial precedents, legal norms, and institutional trust. By strengthening bilateral foundations, the region can create the conditions for future multilateral expansion. In this sense, bilateral projects are not a compromise on the shared APG vision, but a necessary and pragmatic mechanism to derisk complexity, demonstrate viability, and create momentum.

While this paper was originally motivated by Singapore's ambition to import low-carbon electricity as part of its energy transition and decarbonisation strategy, the recent energy crisis resulting from the conflict in the Middle East underscores the role that the APG can play in promoting the energy security of the region through diversifying power supply and integrating the region's abundant renewable resources.

This paper examines cross-border power trade through the lens of Singapore's role as an importer, focusing on the Singapore-Malaysia (Sarawak) and Singapore–Indonesia corridors. As a supply-constrained but creditworthy market with strong regulatory institutions, Singapore is well positioned to act as an anchor offtaker for clean energy projects in the region. These corridors reflect current political intent, private sector interest, and near-term execution potential, making them a practical starting point for assessing what bankability entails in the ASEAN context.

The two corridors require the development of subsea transmission infrastructure, which introduces distinct challenges related to cross-border asset ownership, licensing, tariff recovery, regulatory approvals, and dispute resolution mechanisms. These issues sit at the intersection of law, policy, and finance, and cannot be resolved through technical solutions alone. **As such, the paper takes a focused approach: it concentrates on the two import corridors and examines a select set of critical commercial and legal factors that most strongly influence project bankability.** By

[1] ASEAN Interconnection Masterplan Study (AIMS) III Report – ACE, HAPUA, Sep 2021

doing so, it aims to provide policymakers, regulators, financiers, and developers with a clear and execution-oriented framework for advancing cross-border power trade in ASEAN. The findings should therefore be read with that scope in mind: the specific licensing, tariff, and counterparty features discussed are particular to these two corridors, while the underlying lessons on risk allocation, contractual linkage between generation and transmission, and regulatory completeness are intended to be transferable to other APG interconnections subject to their own specific requirements.

This paper sets out that case in three parts. It examines the structural drivers of bankability: integration and stranded asset risk, green demand and revenue economics, and sovereign commitment and regulatory completeness. The objective is to examine where the gaps lie, and what would need to be resolved to move the Singapore–Sarawak and Singapore–Indonesia corridors from political intent towards financial close. These sections are not intended as a final answer, but as a shared starting point: a common vocabulary and framework that policymakers, financiers and developers can build on as the region moves, corridor by corridor, from ambition to bankability.

Key takeaways:

Cross-border power infrastructure is inherently complex. That complexity is financeable. What is not financeable is the ambiguity in risk allocation, regulatory frameworks, and revenue assumptions.

- **Driver 1: Integration and stranded asset risk is the foundational challenge,** particularly for greenfield generation-to-grid projects. Generation and transmission are interdependent assets with limited standalone commercial value. A mismatch in delivery during construction, or under-performance across the projects' operating lives, collapses the revenue case for both assets. Driver 1 finds there is no single ownership that must be adopted. Each of the three models studied can be bankable, as illustrated through successful projects such as UK's Offshore Transmission Owner model, the Monsoon Wind Power Project in Laos and Vietnam, and Jawa Satu in Indonesia. What matters is the integration of cashflow and risk allocation by ensuring revenue continuity is preserved so that neither asset becomes stranded.

- **Driver 2: The challenge of the structural pricing gap with conditional green premium for revenue resilience.** Driver 2 establishes that Singapore has credible and growing demand for low-carbon electricity. Singapore's market-based pricing and regulatory obligations create a genuine commercial incentive for offtakers to procure certified green power. But this demand is conditional, not absolute. Buyers benchmark imports against domestic prices, while developers must recover a fully delivered five-level cost stack. The structural pricing gap can only be closed when each cost component is matched to a differentiated revenue mechanism and to the party best placed to bear it.

- **Driver 3:** On regulatory completeness, **political intent must become durable legal architecture.** Driver 3 finds that **political commitment, while increasingly evident in context of the APG, cannot on its own, support limited-recourse financing.** Both corridors are potentially bankable, but only with a layered architecture of intergovernmental agreements, consistent domestic frameworks, robust back-to-back contracts, and appropriate insurance operating together.

Setting The Scene

The Decarbonisation Imperative for ASEAN

The “P” in the ASEAN Power Grid (APG) stands for **power**, but its ultimate purpose concerns **people** and **progress**. Affordable, reliable, and sustainable energy underpin economic growth, industrial development, and social mobility. The ASEAN Community Vision 2045 made this clear. Through successive energy cooperation plans, regional integration in energy has been positioned not as an end in itself, but as a means to deliver shared prosperity, resilience, and long term socioeconomic benefits across ASEAN.

Total final energy consumption (demand) in ASEAN, by type of supply

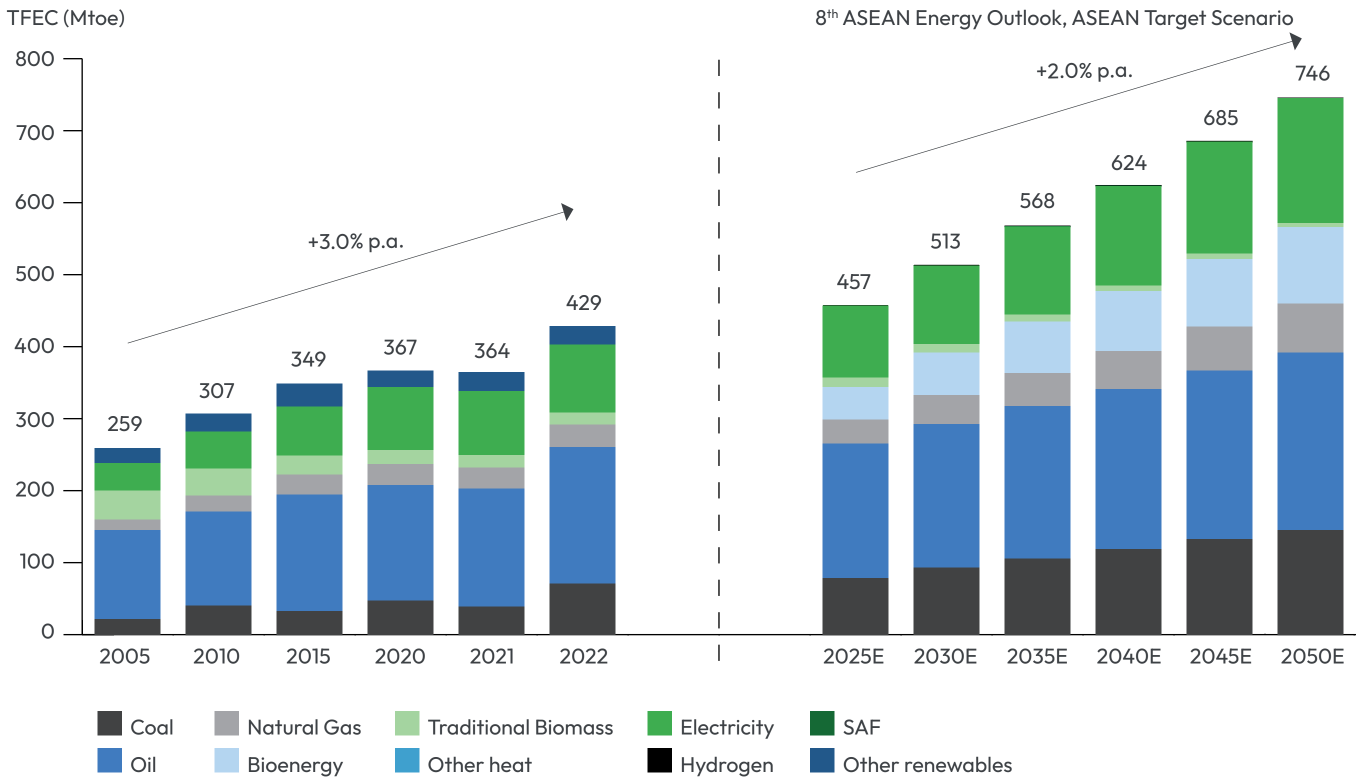


Figure 1: ASEAN energy demand is expected to grow

Source: Baringa’s compilation from ASEAN Centre for Energy resources

This imperative is sharpened by ASEAN's energy outlook. The region is projected to experience one of the fastest rates of energy demand growth globally over the next several decades, driven by population growth, urbanisation, industrialisation, and rising living standards. Projections by the ASEAN Centre for Energy (ACE) (Figure 1) indicate that ASEAN's total energy demand is set to almost double by 2050. Electricity demand is expected to increase rapidly as economies electrify transport, cooling, and industrial processes. Meeting this demand, while maintaining affordability, ensuring security, and meeting climate commitments, will strain national systems if approached in isolation.

At the same time, ASEAN's energy transition is not a direct substitution of fossil fuels with renewables. Energy security and diversity of supply are critical considerations that remain top-of-mind for policymakers. Under the ASEAN Plan of Action for Energy Cooperation (APAEC) 2026–2030, the APG is one of seven foundational programmes, alongside initiatives covering natural gas, fossil fuels, and oil and gas connectivity[2]. This reflects a pragmatic regional approach: decarbonisation must proceed in parallel with reliability, affordability, and energy security. The APG is therefore about optimising them collectively through cross-border balancing, diversification, and efficiency, rather than on displacing national energy strategies.

The APG vision offers a structural solution to this challenge by enabling greater system resilience through source diversity and geographic complementarity. ASEAN's renewable resources are unevenly distributed, and regional interconnection allows surplus clean energy in one sub-region to support deficits in another (Figure 2). For example, Borneo, despite its relatively small population, possesses abundant hydropower resources that position it as a strategic contributor to ASEAN's future clean electricity supply[3]. **Unlocking such resources at scale is only feasible through cross-border transmission and coordinated market arrangements, reinforcing the APG's role as a platform for collective optimisation and energy security rather than national self sufficiency.** Given APG's position as a system resilience infrastructure, there is a strong rationale for regulated cost recovery, availability-based revenue models, public guarantees, concessional capital and Multilateral Development Banks' ("MDB") support.

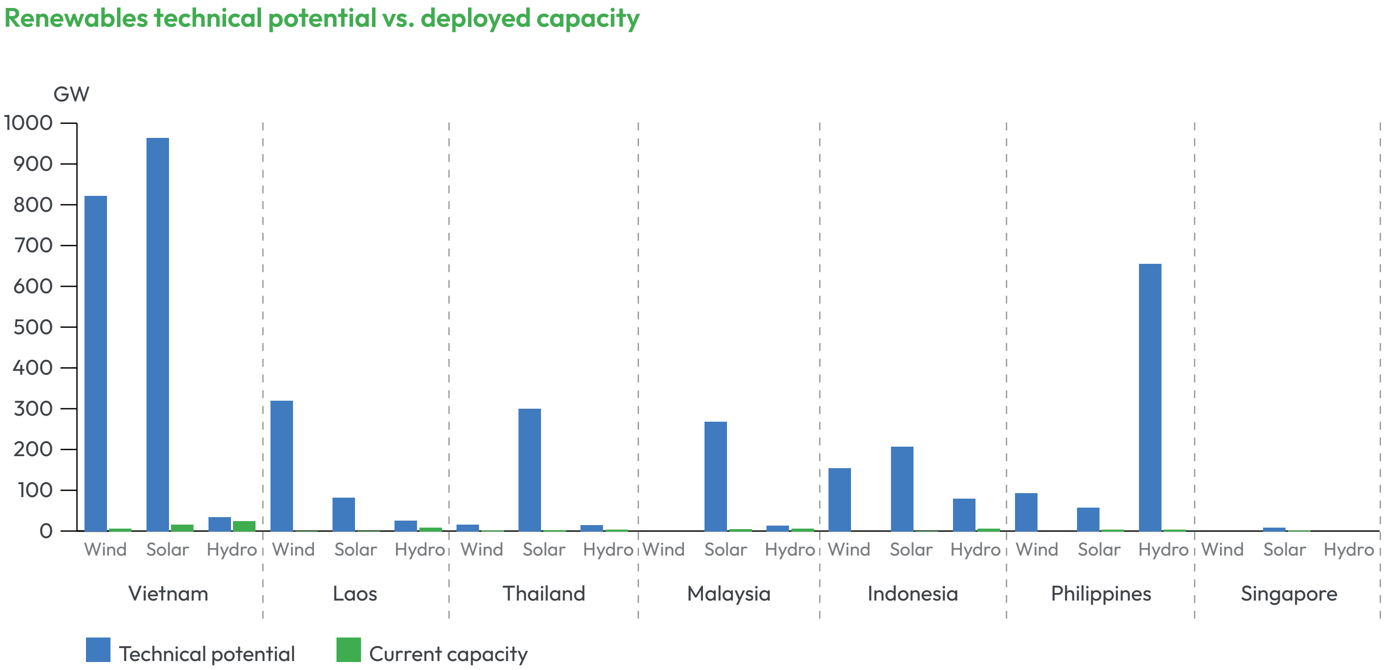


Figure 2: Technical potential vs deployed capacity of renewable energy by country

Source: Baringa's analysis and compilation of public sources

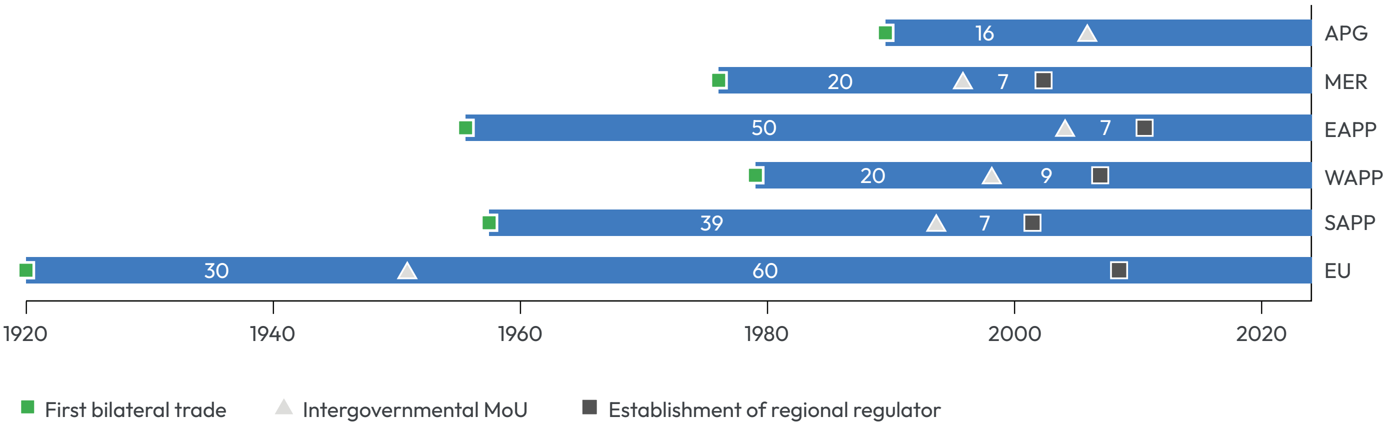
[2] ASEAN Plan of Action for Energy Cooperation (APAEC) 2026-2030 – ACE, Oct 2025
[3] Brunei Darussalam-Indonesia-Malaysia-Philippines East ASEAN Growth Area (BIMP-EAGA), ADB, Sarawak Energy

Beyond energy systems, decarbonisation is also increasingly an economic competitiveness issue. As mechanisms such as the European Union's Carbon Border Adjustment Mechanism (CBAM) come into force, and as other major Western import markets consider similar measures, the carbon intensity of production becomes a material determinant of export competitiveness. For ASEAN countries (especially Thailand, Vietnam and Indonesia) integrated into global manufacturing for CBAM regulated goods (e.g. cement, iron and steel, aluminium, fertilisers) and supply chains, access to low-carbon electricity will directly support the viability and pricing of exports. **In this context, the APG is not only an energy initiative, but a strategic instrument to safeguard ASEAN's position in a decarbonising global economy.**

What Is Different This Time

The APG is not a new idea. First proposed in the late 1990s, the APG has progressed through multiple phases of studies, declarations, and partial implementation over more than two decades. Since its inception, progress has been incremental, constrained by competing national priorities, limited commercial readiness, and an absence of viable cross-border investment models. However, when viewed against the multi-decade development arcs of other regional power markets, such as Europe's progression from bilateral interconnections in the 1950s to today's integrated internal electricity market, the APG is entering a phase where the increasing need for bilateral connectivity is forming the foundation for accelerating development. **The region has moved beyond concept validation and into an execution phase, where early precedents, political alignment, and capital interest are beginning to align.**

Historical milestones of selected regional power system integration initiatives



Notes: APG = ASEAN Power Grid. MER = Mercado Eléctrico Regional. EAPP = Eastern Africa Power Pool. WAPP = West African Power Pool. SAPP = Southern African Power Pool. EU = EU Internal Electricity Market.

Figure 3: In comparison with other regional grids, APG is still relatively young.
Source: Institutional Architecture for Regional Power System Integration - IEA, Nov 23

A key impetus has been the renewed political momentum behind an enhanced APG framework. The recent update to the APG Memorandum of Understanding reflects a more pragmatic, implementation-focused approach, and changing regional priorities. Under Malaysia's chairmanship of ASEAN in 2025, emphasis has shifted towards actionable sub-regional projects, clearer institutional coordination, and tangible progress against defined milestones. **This refreshed commitment signals that the APG is no longer treated solely as a long-term aspiration, but as an active programme with near-term deliverables.**

Additionally, recent projects have demonstrated early traction and proof of concept. The Lao PDR–Thailand–Malaysia–Singapore Power Integration Project (LTMS-PIP) has shown that multi-country power trade is technically feasible and institutionally manageable. Similarly, flagship initiatives such as the Monsoon Wind project and other cross-border renewable developments indicate that commercially led models, anchored by credible offtakers, can bridge differences in national systems. While these projects remain limited in scale, they provide valuable signals to markets and policymakers that **cross-border power trade in ASEAN can move beyond pilots towards replicable structures.**

The current landscape of global volatility, as intensified by the recent 2026 Middle East conflict, has shifted the strategic focus from simple energy procurement to the fundamental necessity of regional resilience. Within this context, the development of the Singapore-Indonesia and Singapore-Sarawak power corridors represents a critical evolution in bilateral cooperation. By establishing these high-capacity links, the region moves towards a model of mutual support where shared infrastructure provides a buffer against external energy shocks, transforming electricity trade into a collective security asset that strengthens the regional energy architecture in the long run, and enabling an investment platform for regional industrial ecosystem development.

Finally, the investment landscape has evolved materially. **There is now stronger and more coordinated support from MDBs,** with institutions such as the Asian Development Bank[4] and the World Bank Group jointly committing approximately US$12.5 billion[5] towards supporting APG related infrastructure and enabling frameworks and multilateral initiatives such as the Partnership for ASEAN Connectivity on Energy ("PACE") that aims to strengthen collaboration between international financial institutions, donors, commercial banks, and philanthropies. This depth of MDB engagement reflects a growing confidence in the strategic relevance of the APG, and provides not only financing, but also risk mitigation, convening power, and institutional credibility. Importantly, it signals to private capital that **cross-border power in ASEAN is entering a phase in which public and development finance can meaningfully crowd in commercial investment.**

Taken together, political recommitment, early proof points, heightened energy security imperatives, and strengthened multilateral financing support mark a decisive break from past cycles of incrementalism. The APG is an increasingly necessary component of regional resilience in a volatile global energy landscape, and no longer a distant aspiration. In this context, bilateral corridors, anchored by credible demand and supported by bankable frameworks, offer the most effective pathway forward. If executed well, these projects can transform bilateral trade into a strategic resilience asset, all while laying durable commercial and institutional foundations for a more integrated ASEAN power system.

> "ASEAN Power Grid (APG) is no longer a nice-to-have, but a must-have to advance the regional energy goals to propel the region's economy. The benefits for our security and decarbonisation are clear, but realising APG requires considerable capital, a robust framework, and close collaboration. Resolving financing and bankability challenges are the immediate frontier to move the APG forward."
>
> *— ASEAN Centre for Energy*

[4] ADB, Singapore renew partnership to accelerate cross-border clean energy in Southeast Asia – ADB, May 2026
[5] ADB and World Bank Group Launch the ASEAN Power Grid Financing Initiative with the ASEAN Secretariat and the ASEAN Centre for Energy (ACE) – ASEAN Secretariat, Oct 2025

Singapore as a Demand Anchor for APG

Singapore has established a strategic ambition to import up to 6 GW of low-carbon electricity by 2035, a target that could potentially represent roughly one-third of its projected energy mix[6]. **This large-scale demand goes beyond a domestic procurement goal, acting as a critical commercial anchor for the development of the APG, particularly the APG South Sub-region**[7]. By committing to these volumes, Singapore's electricity import ambitions could foster a collaborative investment environment in which cross-border infrastructure is mutually beneficial, sustainable, and bankable for all participating nations.

The Commercial Case for Singapore as an Anchor Demand Centre

1. **Investment-grade Counterparties Support Bankability**

   The creditworthiness of Singapore-based offtakers stands as a distinct driver of project viability. Investment-grade counterparties, such as EMA-licensed entities and major energy players, and credible corporate offtakers, provide lenders with confidence in long-term revenue flows. This reduces perceived counterparty risk, which is a critical factor in structuring cross-border infrastructure financing.

   As a result, projects backed by Singapore's demand can potentially achieve a lower cost of capital. This financing advantage improves overall project economics, making large-scale renewable generation and transmission investments bankable not only for Singapore, but also for Malaysian and Indonesian partners involved in the APG.

2. **Pricing Resilience Supports Low-carbon Infrastructure Buildout**

   Singapore's price-driven electricity market, supported by a rising carbon tax, creates a strong incentive for buyers to source low-carbon power. Across ASEAN markets, electricity policies vary in terms of end users' tariffs. Local electricity tariffs could be subsidised, making cross-border investments difficult to justify.

   Yet, in Singapore, developers can earn a green premium above base prices which provides for a commercial case for import of renewable energy. Creditworthy corporate demand provides an important foundation for low-carbon electricity imports and associated infrastructure. Competitive delivery prices, reliable supply, recognition of environmental attributes, appropriate contractual risk allocation and long-term regulatory certainty could potentially convert this demand into financeable offtake that supports long-term financing.

3. **Symbiotic Tripartite Ecosystem Delivers Shared Regional Value**

   The Singapore-Indonesia and Singapore-Sarawak corridors can create value that extend beyond the immediate buyer-seller relationship. By connecting Singapore's demand with the renewable resource base of Indonesia and Malaysia, these projects can support investments in generation, transmission and associated industry ecosystems that may not otherwise be commercially viable on a standalone basis.

   For Indonesia, long-term export demand can help underpin the development of greenfield renewable energy zones in areas such as the Riau Islands. Such demand would create the scale needed to support local investment, employment and supply chain development, with reciprocal benefits valued by some estimates at US$4.2 billion in foreign exchange earnings and US$210 million in tax revenue annually[8]. For Sarawak, this demand would unlock an additional route to monetise surplus hydropower resources that would otherwise remain underutilised, positioning it as

[6] Low-Carbon Electricity Import – MTI, Oct 2025
[7] ASEAN Power Grid Interconnections Project Profiles - ASEAN Centre for Energy (ACE), Sep 2024 South Sub-system defined as projects in the ASEAN sub-region of Singapore, Indonesia and Malaysia. Projects in Malaysia's Borneo region also covered under the East Sub-system, including Brunei and The Philippines.
[8] Maximising reciprocal benefits from Indonesia's green electricity export to Singapore –Institute for Energy Economics and Financial Analysis, Mar 2025.

ASEAN's "green battery"[9], aligned with the Sarawak Corridor of Renewable Energy (SCORE) development strategy[10]. Importantly, such a collaborative model adds capacity rather than displaces domestic supply, strengthening overall system resilience.

The revival of the SIJORI Growth Triangle discussions[11] (Singapore–Johor–Riau Islands) further reinforces alignment, reframing energy trade as part of a broader agenda encompassing industrial development, infrastructure investment, and regional competitiveness.

However, in the long run, Singapore as a demand anchor is only one part of the story. The APG must be able to create a level playing ground for electricity trade around the region. Bilateral and multilateral trading among ASEAN countries would expand over time.

Drivers For Bankability Framework

Capital can tolerate complexity, but it cannot tolerate ambiguity. This is particularly so for private capital. Cross-border power infrastructure is complex by nature, being multi-sovereign, long-tenor, and technically demanding. Despite that, such complexity is priceable. In contrast, what is not priceable is ambiguity: unclear risk allocation or misallocation of risks, unresolved regulatory frameworks, and revenue assumptions that rest on conditions that have yet to materialise. Bankability is ultimately the question of what could put cashflow at risk, jeopardise debt service, or create uncertainties that inflate the risk premium over a 20-year to 25-year financing tenor.

Different infrastructure asset classes attract different types of capital. Generation assets, transmission assets, and storage assets exhibit distinct construction risks, operating characteristics, regulatory exposure, and revenue models. Institutional investors often prefer mature transmission infrastructure, where revenues are regulated or availability-based. In contrast, development capital may be better suited to generation and storage assets during earlier phases. The APG project structures that enable risk to migrate to the most appropriate capital provider at each stage of the asset lifecycle are likely to improve overall bankability and lower the weighted average cost of capital.

Three baseline conditions must be accepted as given. Firstly, technical completeness (i.e. Engineering, Procurement, and Construction (EPC) contracts, marine surveys, and independent technical advisor sign-off) is a standard condition precedent on any project finance transaction. Secondly, sponsor quality (i.e. financial capacity, track record, and equity commitment) affects the risk premium. Thirdly, a bankable revenue structure, comprising sufficient contract offtake, a credible green premium framework, and a demand pool deep enough to sustain both over the financing tenor, must itself be achievable. This third condition is examined in depth later in this paper. All three must be present for a project to be financeable.

Bankability for Singapore's cross-border import projects turns on three structural drivers, each sufficient on its own to prevent financial close if unresolved.

[9] Singapore power plan buoys Sarawak's green energy ambitions – Nikkei Asia, May 2026
[10] The Sarawak Corridor of Renewable Energy (SCORE), established in 2008, is a key economic development initiative by the Federal Government of Malaysia aimed at accelerating growth in Sarawak's central and northern regions.
[11] Singapore and Indonesia renew SIJORI discussions, expand cooperation on trade and energy – Channel News Asia, May 2026

Driver 1 - Integration and Stranded Asset Risks.

Generation and transmission are interdependent assets which have limited standalone commercial value. A mismatch in delivery during construction, or an under-performance over the projects' operating lives, would place the entire revenue case at risk. Managing this interdependency through an integrated project structure, aligned development timeline and clear risk allocation between the Generation Company ("**GenCo**") and Transmission Company ("**TransCo**") would be the very first condition of bankability.

Driver 2 — Green Demand and Revenue Economics Resilience.

The economics of these projects depend on a green premium above a base tariff. Hence, the recognition of cross-border RECs under frameworks such as RE100 and GHG Protocol is integral to sustaining this premium[12]. In an environment with willing buyers and willing sellers, the question is whether buyers have sufficient and durable commercial incentive to pay for imported green power, and whether that incentive is strong enough to support the contracted offtake over a twenty-year tenor. That premium is further contingent on offtake firmness, the depth of Singapore's green demand pool, and resolution of the cross-border renewable energy certificate framework.

Driver 3 — Sovereign Commitment and Regulatory Completeness.

Political endorsements and conditional approvals establish intent. Translating that intent into financial close for an import-export project requires a complete and enforceable regulatory chain across all jurisdictions, from bilateral treaties and export licences to cable landing rights and import licences. Closing the gap between political commitment, commercial certainty and enforceability is what determines whether a project can proceed.

The following three sections examine each driver in depth, identifying the specific risks, resolution pathways, and structural provisions that could impact bankability.

> "Not every component of the ASEAN Power Grid needs — or should be expected — to attract private capital. The role of project preparation is to identify where public financing is necessary, where blended finance and MDBs participation can bridge risk gaps, and where projects can stand on their own and mobilise private investment. Getting this allocation right, project by project, will be fundamental to translating the APG vision into bankable infrastructure."
>
> *— Global Infrastructure Facility*

[12] This topic merits dedicated, detailed treatment and falls outside the scope of this paper. The authors note this in the section "Areas for Future Exploration".

Driver 1: Integration and Stranded Asset Risks

Before examining this driver, it is important to recognise that the import projects of the two corridors are not homogenous. **The Riau Islands (Indonesia) projects are generation-to-grid, where the new renewable generation assets are developed alongside dedicated export transmission infrastructure. In contrast, the Sarawak (Malaysia) project consists primarily of grid-to-grid interconnection, leveraging existing hydropower generation resources.** The technical architecture also differs: the Riau Island projects are based on HVAC subsea transmission, while the Sarawak corridor is centred on HVDC interconnection. These distinctions materially influence the risk profile of each corridor. As a result, **the integration and stranded asset risks examined in this section are primarily relevant to the generation-to-grid archetype,** where new generation capacity and transmission infrastructure must be developed in tandem.

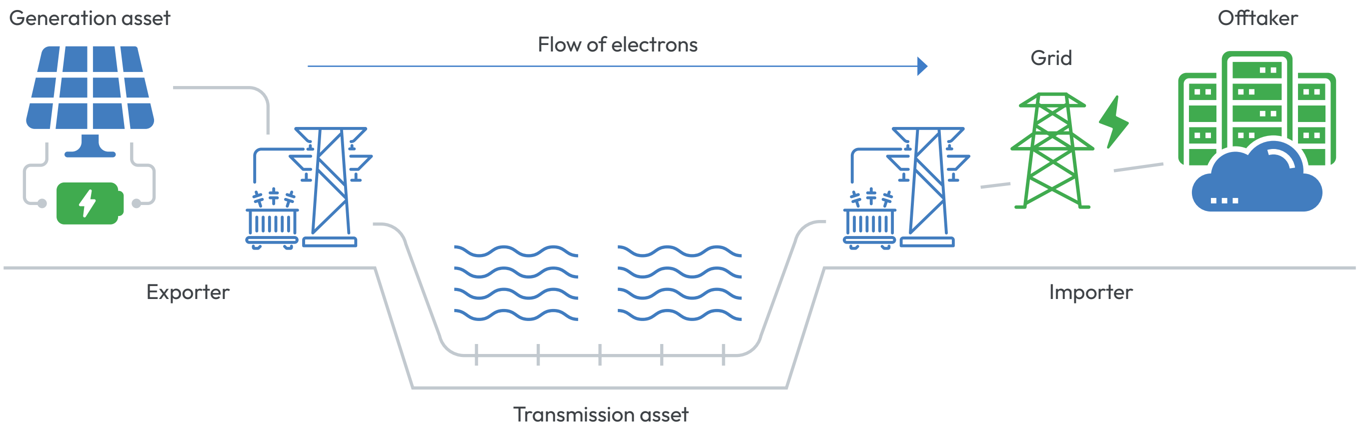


Figure 4: Illustrative diagram of generation-to-grid projects

Cross-border generation-to-grid projects comprise two distinct but interdependent assets: the generation asset and the transmission asset. Unlike domestic power projects, these components may be governed by different legal and regulatory regimes and are often developed by separate entities. **This structural separation introduces a fundamental commercial challenge, in the event that one asset is completed while the other is not.** While the generation asset may have an alternative domestic market for its output, the pricing in local Indonesian or Malaysian markets is typically governed by regulated utility tariffs that are likely substantially below export pricing. This has a significant impact on projects' ability to service their debt obligations. The transmission asset, by contrast, has no meaningful alternative use at all: a completed transmission cable with no operating generation source carries nothing and earns nothing. Therefore, in commercial and financing terms, the values of **both assets are substantially reduced if the export corridor to Singapore does not function as intended, making the viability of each contingent on the coordinated performance with the other.**

This interdependency, commonly referred to as interface or project-on-project risk, must be actively managed for a project to achieve financing. Lenders require confidence that both assets would reach financial close and commercial operation in a coordinated manner. A timing mismatch between the two, whether from construction, regulatory delays or counterparty failure, would create a stranded asset that generates no revenue and cannot service debt. **Critically, this risk does not end at the completion of construction.** It persists across the projects' operating lives, through maintenance cycles, force majeure events, or changes in the regulatory environment on either side of the international border.

Additionally, generation and transmission ownership may not necessarily always sit within the same entity. Some jurisdictions may require unbundling of transmission asset ownership from generation asset ownership, particularly where the transmission asset is considered critical national infrastructure. Beyond the regulatory driver, a generation sponsor group may also have legitimate commercial reasons not to retain long-term ownership of transmission infrastructure. Vice versa, a transmission investor may not want exposure to generation risk.

Three models have been identified from regional and global precedent transactions to address these challenges.

<table>
<tr><th></th><th>Model A:
Integrated Ownership</th><th>Model B:
Integrated Ownership During Build with Post-Completion Separation</th><th>Model C:
Separate Entities with Contractual Linkage</th></tr>
<tr><td>Generation</td><td rowspan="2">Owner 1 across construction and operation (i.e. single owner across all phases and infrastructure)</td><td>Construction phase: Owner 1
Operation phase: Owner 1</td><td>Construction phase: Owner 1
Operation phase: Owner 1</td></tr>
<tr><td>Transmission</td><td>Construction phase: Owner 1
Operation phase: Owner 2</td><td>Construction phase: Owner 2
Operation phase: Owner 2</td></tr>
</table>

Table 1: Summary table of various ownership models

"Moving cross-border power projects from paper to practice takes more than capital and technology. Political alignment, regulatory certainty and durable legal frameworks matter just as much as the underlying infrastructure itself. Projects of this scale and tenor require confidence that commercial frameworks, export arrangements and cross-border cooperation between governments will remain stable and durable over time."

— Cross-border Trade Developer

Model A: Integrated Ownership

One single SPV owning both generation and transmission assets across both construction and operational phases

Model A encompasses a single Special Purpose Vehicle ("**SPV**") owning and operating both the generation and transmission assets under one legal, financial and operational structure. This removes contractual friction between generation and transmission entities and internalises interface risk, making it a structurally clean solution for lenders.

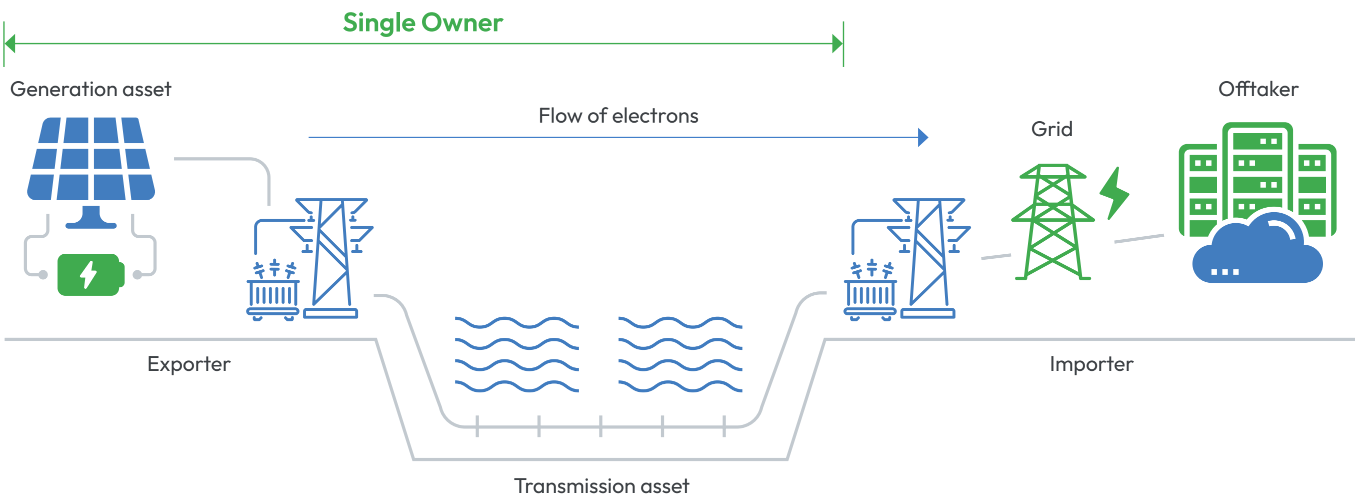


Figure 5: Illustrative diagram of one single SPV owning both generation and transmission assets across both construction and operational phases

The benefits under Model A are:

Management and Operational Risk

A single entity manages construction coordination, operational decision-making, and maintenance scheduling with unified incentives. An integrated owner can readily respond to issues across both assets. This model compares favourably to the alternative scenario where the assets are owned by separate entities (e.g. in Model B or Model C). In a scenario of separate ownership, when issues arise, each party must first determine (and potentially dispute) who bears responsibility, notify each other under the contractual framework, and agree on a response before acting. All the above steps would take time, while a stranded asset generates no revenue and continues to accumulate expenses.

Security and Enforcement

Under integrated ownership, lenders hold a single security package over a unified asset base. Enforcement in a default scenario is straightforward: the lender steps into a single SPV that owns both the generation plant and the transmission cable.

Cashflow Leakage Risk

All revenue flows through a single cash flow waterfall. There is no intercompany payment between GenCo and TransCo that could be disrupted, delayed or disputed.

Despite Model A being structurally simple, it would not address situations where domestic regulations or other circumstances require separate entities to own generation and transmission assets.

Model B: Integrated Ownership During Build with Post-Completion Separation

One single SPV owning both generation and transmission assets during construction. Transmission asset divested to new owner after completion

Under Model B, both the generation and transmission assets are developed by the same SPV under a unified construction programme, capturing the coordination benefits of integrated ownership during the high-risk construction phase of the project. Following commercial operation, the transmission asset is subsequently separated and transferred to a new and separate owner. This model has the potential to address a few practical realities:

Risk Management

Construction is the period when interface risk is most acute. Keeping both assets under unified ownership and management during the construction phase eliminates the inter-entity coordination friction that might arise under separate ownership of the assets. Once the Commercial Operation Date ("**COD**") is achieved on an integrated basis for both assets, the transmission asset's risk profile changes fundamentally as its performance becomes established.

State Ownership and Regulatory Compliance

The transmission infrastructure carrying cross-border power flows could be strategically sensitive for States. For this reason, transmission assets of this nature often sit with state-owned or government-designated entities (although there are examples globally where such assets are owned and operated by specialist private sector parties under appropriate regulatory frameworks). Transferring the transmission asset to a State-affiliated entity post-COD could satisfy domestic regulatory requirements surrounding strategic infrastructure ownership (if they exist). Model B facilitates this by allowing for a separate owner in the transmission asset post-construction.

Capital Efficiency

Construction financing for subsea transmission cables can be expensive. Once de-risked at COD, the cable is a stable and long-term infrastructure asset, suited to low-cost, long-tenor capital from banks, infrastructure funds and pension capital. Separating the transmission asset from the generation asset at COD allows the original project sponsor to recycle its capital while the transmission asset can refinance at utility-grade debt pricing, improving overall project economics. This is predicated on the transmission asset being underpinned by a robust and predictable revenue model — whether through a regulated availability-based framework, a long-term transmission services agreement with a creditworthy GenCo, or a government-backed support mechanism.

Structuring Ownership Around Asset Lifecycles

Subsea cables have a design life of 40 to 50 years. Solar-plus-BESS generation assets are typically financed over 20 to 25 years, with BESS components requiring replacement within 10 to 15 years. Keeping generation and transmission under common ownership for the full asset life creates a structural mismatch: the cable could outlast multiple generations of generation technology on the same corridor. Post-completion separation allows each asset to be owned, financed, and managed on terms appropriate to its own lifecycle, although lenders would expect to have visibility of the transmission asset cash flow after the generation asset is retired.

Model B, similar to the highly successful Offshore Transmission Owner ("**OFTO**") model in the UK, which is discussed in the case study section below, presents a potential model which cross-border interconnectors could transition into. However, such separation mechanism (i.e. transfer mechanism, transfer price methodology, receiving entity obligations) must be contractually documented and legally committed by all State parties involved to be effective.

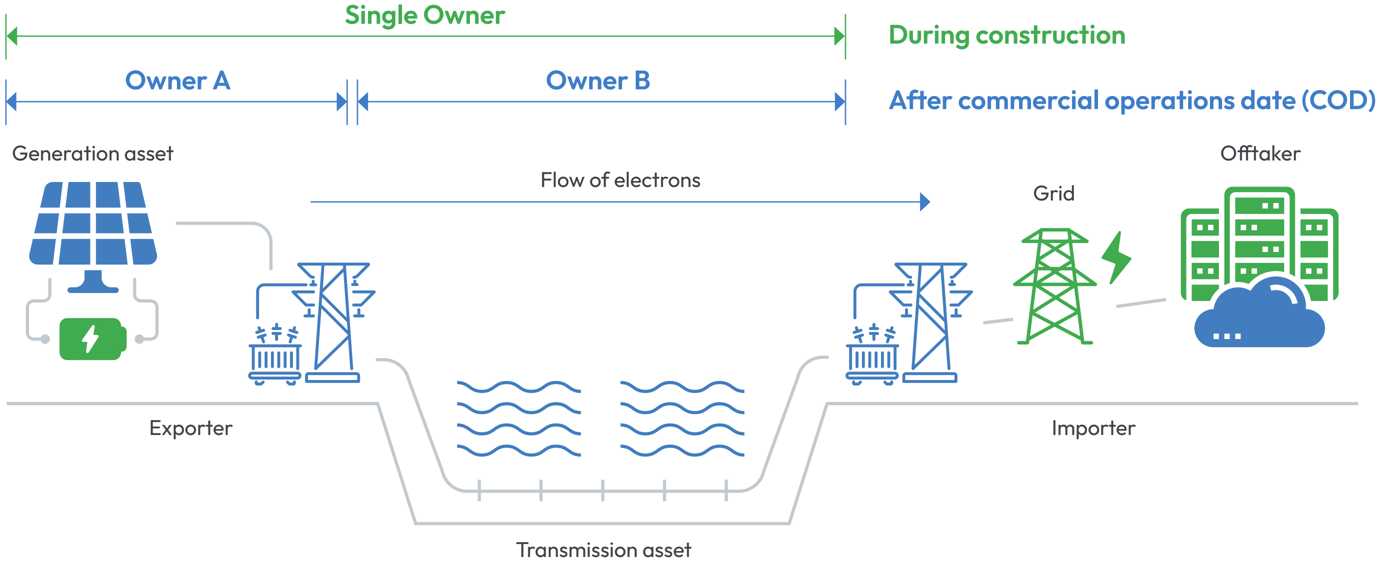


Figure 6: Illustrative diagram showing one single SPV owning both generation and transmission during construction, with the transmission asset divested to a new owner after completion.

Case Study – UK's Offshore Transmission Owner (OFTO) model[13 14 15 16]

Mature blueprint for how structural unbundling can mitigate delivery risks and unlock institutional capital for large-scale transmission.

What is OFTO and why it matters

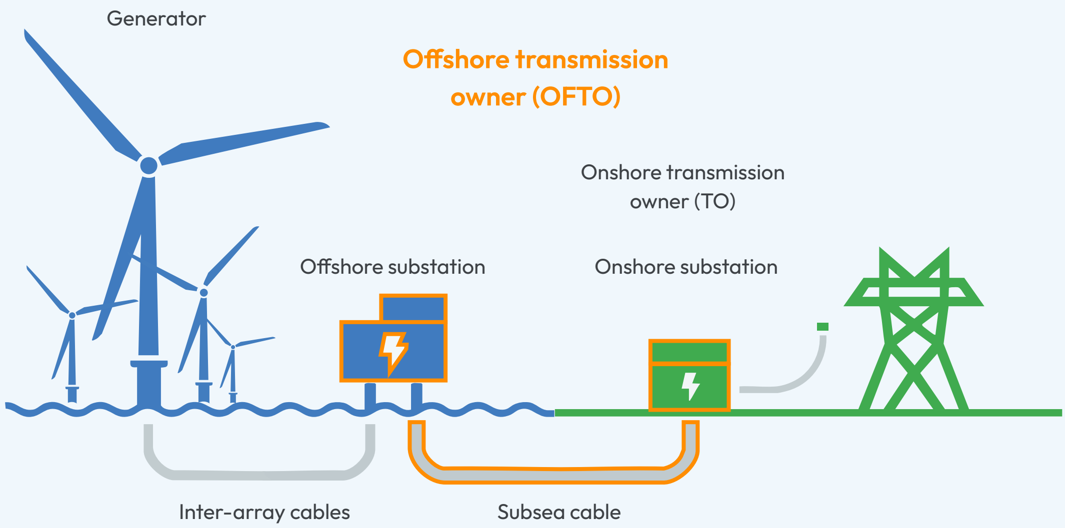
The OFTO regime is the UK's competitive and regulated model for financing and operating offshore transmission assets that connect offshore wind farms to the onshore grid. Introduced in 2009, it separates transmission ownership from generation ownership, allowing developers to recycle capital while attracting private finance. Since the first OFTO licences were granted in 2011, it has delivered >16 GW of offshore wind capacity worth over GBP10 billion.

How the OFTO model works

Combines strong delivery incentives at construction with low-risk ownership in operations.

- Developer build – The wind farm project developer designs and constructs all assets, including the offshore substations and export cables.
- Competitive divestment – Once commissioned, transmission assets are transferred via a regulator-run auction to an OFTO.
- Regulated operation – The OFTO owns, operates and maintains the transmission assets under a 20–25 year Tender Revenue Stream ("**TRS**"), typically via an SPV with non-recourse project finance.

[13] Equipping the OFTO regime for the future – Ofgem, Feb 2026
[14] Transmission grid financing – OECD, Jan 2026
[15] Evolving the OFTO Regime to enable the next wave of offshore wind – RenewableUK, Scottish Renewables, Jan 2026
[16] Ofgem



Source: [Ofgem](), **2022**

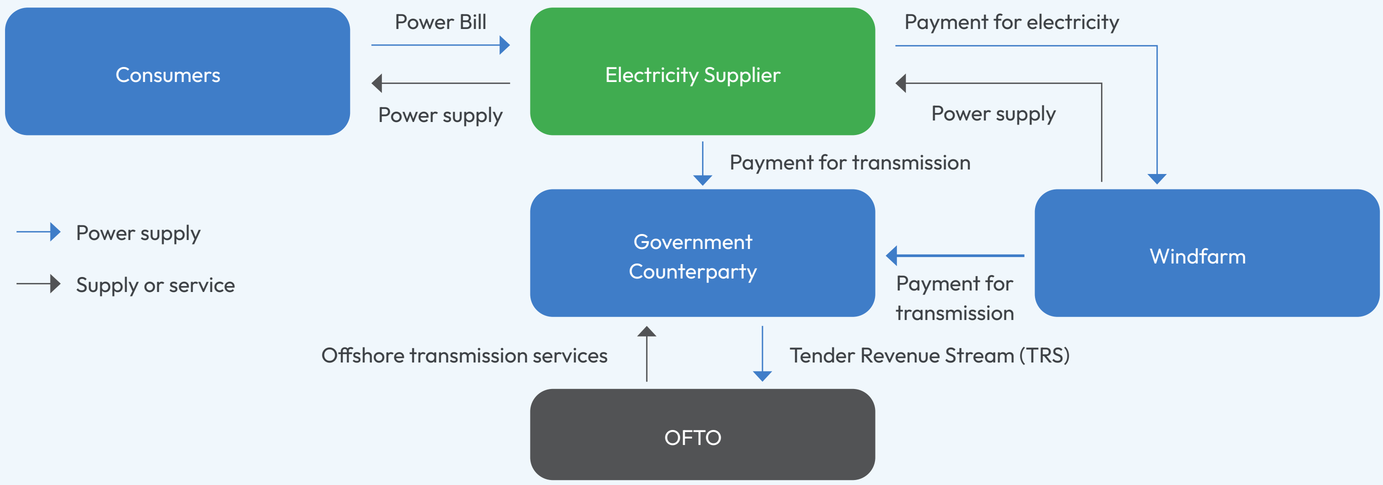


Figure 7: Diagrammatic representation of OFTO structure

Source: OFTO structure, PFI Special Report, Jul 2023

Risks mitigated and benefits created

- Interface risk is managed by having both wind farm and transmission constructed by the same developer.
- Demand risk is removed for investors: revenues are availability-based, not linked to power flows, creating predictable revenue stream.
- Performance is incentivised while operational risk is capped through performance regime.
- Cashflow risk is reduced via long-term, inflation-linked regulated revenues.

Revenue model, government role, and bankability

The government does not fund assets directly. It underwrites credibility through regulation.

- Revenues are a fixed, inflation-linked annual fee (TRS), paid through system charges.
- Availability-based payments from Ofgem (UK regulator) for transmission removes demand risk.
- Ofgem sets transfer-value rules, runs tenders, enforces performance, and arbitrates disputes.

- The clarity and durability of regulation make OFTO assets investment-grade infrastructure, bankable on a standalone SPV basis (project finance loans and institutional equity).

Relevance to Singapore's subsea power imports

An OFTO-inspired model, adapted for cross-border governance, offers a credible blueprint for financing Singapore's power import infrastructure at scale. Singapore's proposed subsea import cables share the same characteristics as OFTO assets: large, point-to-point, capital-intensive, and system-critical.

The OFTO experience shows that:

- Regulated, availability-based revenues can mobilise multi-billion-dollar private capital for transmission cables.
- Removing demand risk materially lowers financing costs versus merchant models.
- A strong regulatory regime is essential to attracting private capital.

Government-to-Government ("**G2G**") agreements will be necessary to provide the regulatory certainty for such a structure to work.

Model C: Separate Entities with Contractual Linkage

Generation and Transmission Assets Owned by Separate SPVs from Outset

Under Model C, the generation and transmission assets are held by separate entities right at the outset of project development. For the projects to be bankable, the entities are bound by rigorous back-to-back agreements.

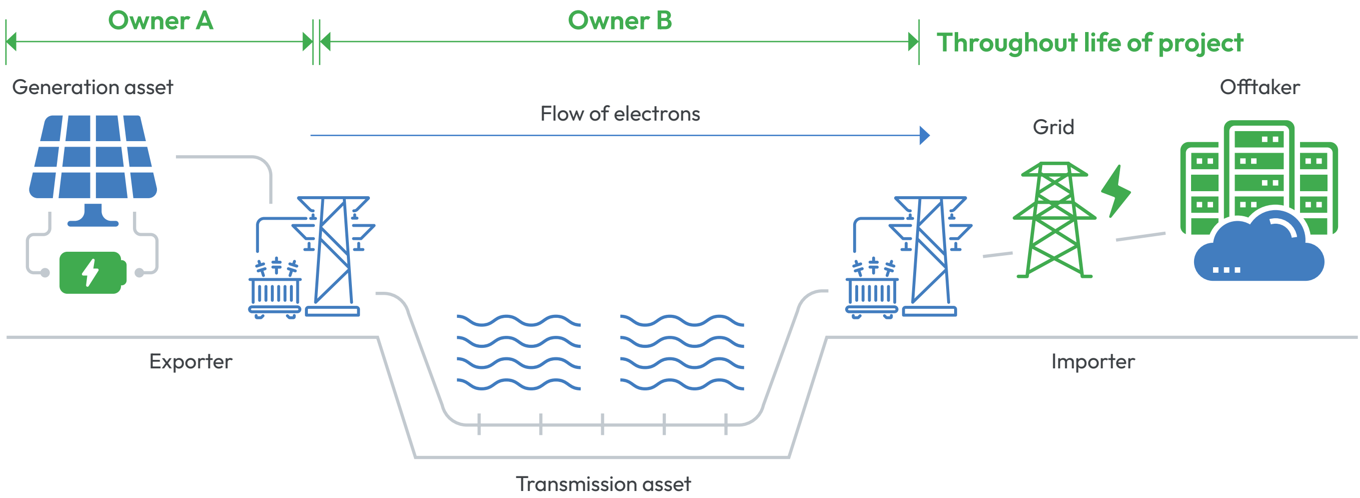


Figure 8: Two SPVs owning generation and transmission respectively from the outset. SPVs are bound by rigorous back-to-back agreements to enhance bankability

In this model, two potential options are often considered.

Model C (i): Deemed Generation as a Backstop

Deemed generation refers to the contractual treatment of electricity that a generator is ready, willing, and able to produce, but is prevented from delivering through no fault of its own. Under a deemed generation clause, the generator is compensated as if the electricity had been generated and delivered, even if it was not physically transmitted. This is a relatively standard provision in power purchase agreements for onshore power generation projects where a State-owned utility company takes responsibility for transmission, for instance.

The precise scope of deemed generation is heavily negotiated because it directly determines who bears the financial consequences of failures outside the control of the generation company, including failures in the transmission asset. Key variables that differ across transactions include:

- Whether grid curtailment by the system operator triggers deemed generation or is treated as an excused non-performance;
- Whether the deemed payment is at the full contracted tariff or reduced rate;
- Whether there is a cap on the number of deemed generation hours in any given period; and
- Whether the clause applies only to specific defined events.

For Singapore import projects, deemed generation clauses are important in that the contractual framework could govern what happens if the transmission cable is damaged. A well-drafted deemed generation clause in the contractual arrangement would protect the GenCo's revenue during cable outage, ensuring that the GenCo is compensated if electrons cannot physically reach Singapore. Without it, a cable outage creates a revenue gap at the GenCo level that directly impairs debt service, regardless of party responsible.

Complexities underlying this arrangement are:

- Financial consequences need to be borne by credit-worthy parties, and recourse to TransCo and GenCo sponsors may be necessary. Such negotiations tend to be lengthy and complicated.
- TransCo would likely require this arrangement to be reciprocal, i.e. TransCo to be compensated in the event that GenCo is not able to dispatch electricity.

Case Study – Monsoon Wind Power Project, Laos and Vietnam[17][18]

Structuring the largest cross-border wind project in Southeast Asia

The Monsoon Wind Power Project is a 600MW wind power farm in Laos PDR that exports electricity to Vietnam. Its US$692.6 million non-recourse financing serves as a real-world case study that mirrors the challenges and solutions for Singapore's power corridors.

1. Proof of "Project-on-Project" Bankability

Monsoon Wind had to solve the risk of the wind farm being ready before the transmission line, or vice versa.

- **Backstop:** Deemed generation clause included in power purchase agreement that provides a financial safety net for the wind project against losses caused by factors beyond owner's control, including the failure of the transmission line to evacuate power.

2. Reciprocal Benefits and Interest Alignment

The project demonstrates how to align an exporter's national interests with an export-led project:

- **Local Community and Economic Multipliers:** The project is a major driver for the Sekong and Attapeu provinces in Laos, creating local jobs and supporting the community. It committed US$ 1.1 million per year for 25 years to improve healthcare, education, and livelihoods, including weekly mobile clinics, school construction, scholarships to international universities, and support for speciality coffee cultivation and processing. This ensured the project contributes to lasting and inclusive local development beyond power generation.

3. Legal "Umbrella" and Inter-Governmental Alignment

A critical factor in Monsoon's success was the inter-governmental alignment between the Governments of Laos and Vietnam.

- **Policy Predictability:** In 2017, the Government of Laos offered the project's electricity generation to Vietnam via a "Nomination Letter" which Vietnam formally accepted[19]. This provided the "legal umbrella" necessary to override local regulatory friction, ensuring that a 25-year Power Purchase Agreement ("**PPA**") with EVN (Vietnam Electricity) was bankable despite the project being physically located in another country.

4. Managed Contract Risks

- **Bespoke PPA:** Unlike local renewable PPAs, the Monsoon PPA contains bespoke terms, such as being governed by English Law, Singapore arbitration for dispute resolution, and US dollar payments by EVN offshore.
- **Concessional support:** A US$160 million concessional finance package was mobilised to reduce project default risk by providing a debt service buffer, and additional cash reserve account in the case of curtailment events. This enhanced Monsoon's curtailment resilience, enabling lenders to be comfortable with a non-recourse financing structure.

[17] Project Finance International, Special Report, Global Energy – Project Finance International, May 2023
[18] Deep Dive Workshop: Enabling ASEAN Power Grid Connectivity and Private Sector Cross Border Financing - YouTube - Asia Clean Energy Forum, Jun 2025
[19] Monsoon Wind Asia - Aug 2026

MONSOON PROJECT FINANCE LENDERS

ADB and ADB-managed concessional funds	
Asian Development Bank:	US$100m
Asian Development Fund (ADF) — Private Sector Window:	US$10m (grant)
Canadian Climate Fund for the Private Sector in Asia:	US $10m
Canadian Climate Fund for the Private Sector in Asia II:	US $20m
Leading Asia's Private Infrastructure Fund:	US$20m
ADB B Lenders	
Siam Commercial Bank:	US$100m
Sumitomo Mitsui Banking Corporation:	US$50m
Parallel Lenders	
Asian Infrastructure Investment Bank:	US$72.55m
Export-Import Bank of Thailand:	US$60m
Hong Kong Mortgage Corporation:	US$30m
Hong Kong Mortgage Corporation Agency:	US$120m
Kasikornbank:	US$100m
Total Project Financing	**US$692.55m**

Table 2: Summary of concessional funds and lenders for the Monsoon Project
Source: Project Finance International, May 2023

Model C (ii) Structural Mitigation

A second option for Model C would see the two separate SPVs bound together through contractual structuring such that project sponsors and lenders share in the risk and reward of the two projects as an integrated project. This results in sponsors and lenders in a single project taking responsibility and risk for the success of the other.

Financial synchronisation is maintained through unified lender groups, aligned financing timelines and cash pooling mechanisms.

Case Study – Jawa Satu, Indonesia[20 21]

How project-on-project risk was managed in Asia's first of its kind LNG-to-Power project

The US$1.5 billion Jawa Satu (Jawa 1) project is a landmark integrated LNG-to-power project located in West Java, Indonesia. It was the first of its kind in the Asia-Pacific region to secure project financing, paving the way for similar integrated schemes globally.

There could be similarities between the Jawa Satu integrated project, and the power importation projects from Riau Island:

- In Jawa Satu, Indonesian cabotage law required that the Floating Storage Regasification Unit ("**FSRU**") unit be majority-owned by Indonesians entities;
- Some sponsors in the FSRU are shipping companies which may not have an interest in owning a power project, and vice-versa.

Project Overview

The project comprises two main integrated components:

- A new 170,000m³ FSRU permanently moored offshore to receive and regasify LNG.
- A 1,760 MW greenfield gas-fired Independent Power Producer ("**IPP**").

The project is structured on a Build, Own, Operate, Transfer ("**BOOT**") basis with a 25-year PPA with the State offtaker, PT PLN Persero ("**PLN**"). The project is also structured on an energy-tolling basis, where PLN is responsible for procuring the LNG and delivering it to the FSRU.

Managing Project-on-Project (Interface) Risks

In traditional energy infrastructure, receiving terminals and power plants are developed as independent projects. In contrast, Jawa Satu brought them together into a single integrated project, mitigating project-on-project risk. The success of one asset (the IPP) was entirely dependent on the other (the FSRU) for commissioning and operations.

The project successfully managed these interface risks, similar to the coordination needed between transmission and generation in cross-border trade, through several structural layers:

1. Aligned Ownership and Shared Sponsors

- **Substantial Alignment:** Two separate SPVs were created, partly due to Indonesian cabotage law requirements: PT Jawa Satu Power ("**JSP**") for the IPP and PT Jawa Satu Regas ("**JSR**") for the FSRU. Notwithstanding, the shareholding groups are substantially aligned.
- **Control:** The IPP sponsors (Pertamina, Marubeni, and Sojitz) retained majority control across both entities to ensure they function as a single project.

2. Integrated Financing Structure

- **Common Lenders:** The lenders for both the IPP and the FSRU were identical.
- **Risk-Sharing Mechanisms:** The financing included cross-guarantees between the two borrowers and cash pooling between their revenue accounts, ensuring interests were aligned across the entire value chain. This protection ensured lenders had priority regardless of which borrower encounters an adverse event.

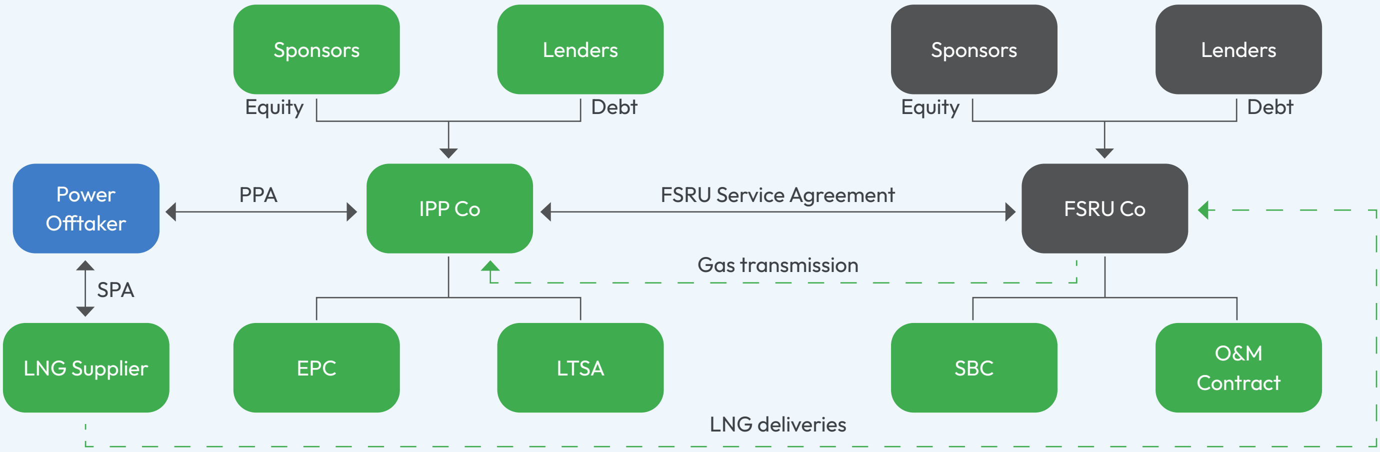
[20] Project Finance International, PFI Awards 2019, Deal of the Year - 2019
[21] PT Jawa Satu Power (JSP)

3. Bespoke Contractual Arrangements

- **Bespoke Scheduling:** Sponsors used a novel approach to scheduling under construction contracts to minimise interface risks during the build phase.
- **Interdependent Revenue:** The FSRU service agreement between JSP and JSR was developed to ensure JSR generates sufficient revenue while remaining flexible enough not to constrain the power plant it depends on.

4. DFI Collaboration (The "No Guarantee" Model)

- **Bankability without Direct Guarantee:** The project reached financial close without a direct guarantee from the Indonesian Government.
- **Consultative Approach:** Early and proactive engagement with export credit and multilateral agencies (JBIC, NEXI and ADB) allowed sponsors to address complex bankability issues and negotiate project documents such as the PPA more effectively.



Notes

1. The Offtaker is responsible for the procurement of LNG.
2. There are two separate companies - one to implement the IPP project and one to implement the FSRU project. The lenders to the IPP project and the FSRU project are the same. The sponsors are substantially the same.
3. The Offtake procures both the IPP project and FSRU project pursuant to the PPA.
4. The Offtaker has customary step-in-rights and buy-out rights and obligations with respect to the IPP project and the FSRU project.
5. LTSA = Long-Term Service Agreement
6. SBC = Ship Building Contract

Figure 9: Structure of Jawa Satu project

Source: Project Finance International, 2019

Comparison of Structuring Models for Cross-Border Power Projects

Model	Structure	Advantages	Disadvantages / Challenges
Model A: Integrated Ownership	Single SPV owns both generation and transmission assets across construction and operations	• Structural elimination of interface risk – no reliance on intercompany agreements • Strong lender bankability – single borrower, security package, and enforcement pathway • Operational optimisation – unified control over dispatch, outages, and maintenance • Cash flow integrity – single revenue stream and waterfall • Alignment of incentives across generation and transmission • Simplified documentation without complex interface agreements	• Regulatory restrictions prevent this in some jurisdictions (e.g. transmission ownership restrictions) • Sponsor capacity mismatch between generation and transmission players • Limited capital recycling opportunities post-COD • Asset life mismatch between transmission and generation • Reduced participation from specialised infrastructure investors
Model B: Integrated Build, Post-Completion Separation	Single SPV during construction; transmission divested post-COD	• Mitigates peak interface risk during construction • Allows transfer to State or regulated owners • Enables sponsor capital recycling • Optimised financing via lower-cost transmission refinancing • Separates assets based on lifecycle characteristics • Attracts long-term institutional investors	• Requires predefined transfer mechanism and valuation framework • Dependent on regulatory clarity and stability • Residual interface risk post-separation • Requires strong inter-government coordination • Risk of disputes at asset transfer stage
Model C(i): Separate Entities with Deemed Generation	Two SPVs linked via contractual framework with deemed generation provisions	• Supports regulatory unbundling from outset • Provides revenue protection to GenCo during transmission outages • Improves bankability via contracted revenue certainty • Widely used in IPP and emerging market projects • No need for ownership integration	• Complex contractual negotiations • Requires strong counterparty or sovereign credit support • Creates contingent liabilities for project developers • Reciprocal compensation structures increase complexity • Does not fully eliminate interface risk due to potential disputes between parties
Model C(ii): Separate Entities with Fully Integrated Financing	Two SPVs economically integrated via common lenders, guarantees, and cash pooling	• Aligns economic incentives across both entities • Mitigates interface risk through financing structure • Strong lender oversight across value chain • Enables compliance with legal separation requirements • Proven in complex infrastructure transactions • Supports coordinated execution and operations	• Complex structuring and documentation • Requires strong sponsor alignment across entities, and confidence in each other's performance. • Longer timelines for negotiation and financial close.

Table 3: Comparison of structuring models for cross-border power projects

Driver 2: Green Demand and Revenue Economics Resilience

Commitment to Energy Transition and Demand for Green Energy

Singapore has a commitment to reach net zero by 2050. While the generation mix of Singapore is currently dominated by natural gas, the composition of power generation is expected to transition towards low-carbon fuels in the future.

The Singapore Government is exploring multiple pathways towards net zero. In the Energy 2050 Committee report[22], three pathways for achieving net zero were set out. These pathways include varying proportions of electricity imports, hydrogen, and other low-carbon solutions (e.g. geothermal, nuclear) (Figure 10). In particular, electricity imports pilots have been ongoing since 2022 and currently includes the import of hydropower from Laos PDR as part of the LTMS-PIP, as well as solar and hydropower from Malaysia as part of the Energy Exchange Malaysia (ENEGEM) scheme.

Fuel mix under Singapore's 3 published energy 2050 scenarios

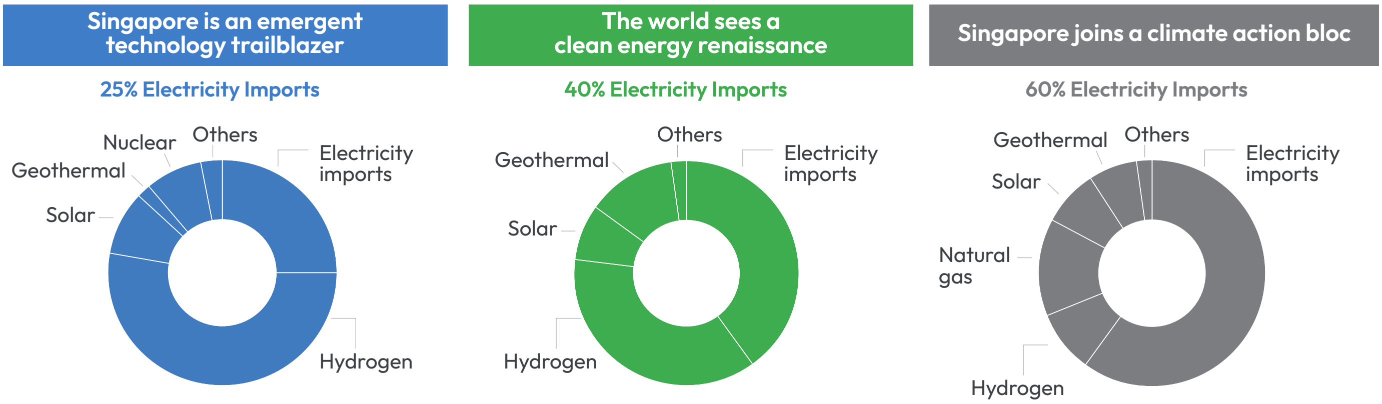


Figure 10: Fuel mix under Singapore's published Energy 2050 scenarios have varying level of imports

Source: Baringa's analysis of Singapore's Published Energy 2050 Scenarios

[22] Charting the Energy Transition to 2050, Energy 2050 Committee Report - EMA, March 2022

The Singapore Government has also identified data centres, semiconductors, and pharmaceutical sectors as key sectors with strong demand for renewable energy (Figure 11). While most large electricity consumers operating in Singapore have set 2050 net zero targets, some companies have also set near-term milestones in the 2030s, which will support demand for clean power ahead of the 2050 target.

For electricity consumers in Singapore, three key factors drive their demand for green electrons: (1) their electricity consumption, (2) ability to pay, and (3) willingness to pay.

Of the three factors, willingness to pay plays a critical decision factor:

- A key consideration of an offtaker's willingness to pay is how critical it is for their operations to be based in Singapore. Currently, presence in Singapore is still largely seen as strategic to corporate users like data centres, semiconductor and pharmaceutical players, due to the lack of supporting soft (e.g. industry policies, IP protections) and hard (e.g. submarine fibre connectivity) infrastructure in the region.
- Along with the decision that Singapore is the right location to be, compliance to sector-specific climate mandates/ commitments in Singapore becomes mission critical.
- For some of these sectors, they will also need to comply with low-carbon energy requirements in government tenders to be considered. The data centre sector in Singapore is one such example.
- Corporates are also driven by their voluntary climate commitments. Pledges such as RE100 and Energy Efficiency National Partnership ("**EENP**") indicate the company's commitment to climate action.

Taking the above into consideration, large corporates would need to weigh their willingness to pay, and how the price for green electrons compares to the retail price available through short-term contracts. This decision is played out across the short, medium and long-term. **These decisions will drive the demand for green energy in Singapore.** It is also important to highlight that the willingness to pay can change due to external environment changes, especially as the region's soft and hard infrastructure catches up with Singapore. Ultimately, corporate users will be driven by their competitiveness in the market and profitability in relation to their utilities operating cost, as well as regulatory and corporate obligations.

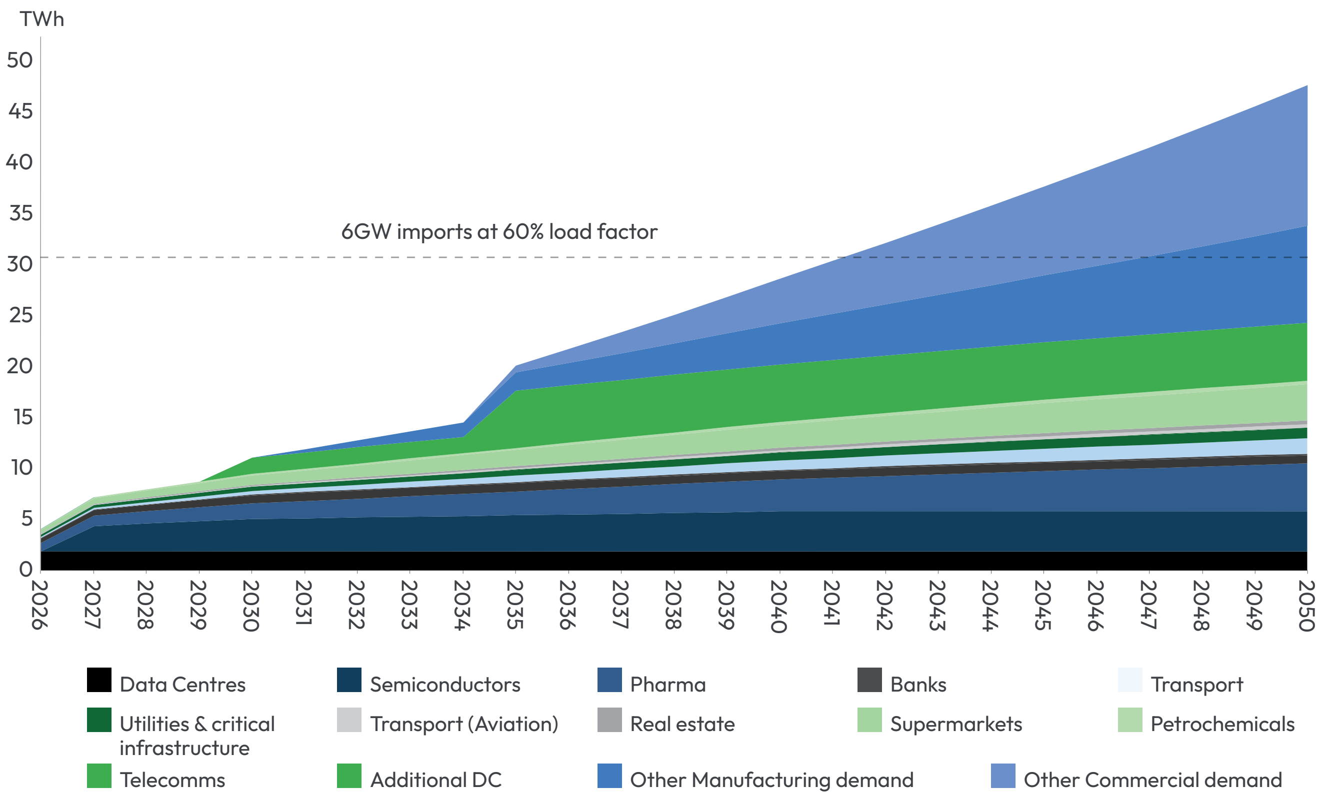


Figure 11: Estimated renewable electricity demand (in kWh per annum) of offtakers by sector

Source: Baringa's analysis

Based on a compilation of the intended decarbonisation trajectories of companies across selected industry sectors, estimates of forward green energy demand in Singapore were developed (Figure 11). Prima facie, these estimates put the demand for green energy at approximately 19.8 TWh per annum by 2035, with estimates erring on the conservative end of the spectrum. This 19.8 TWh per annum would translate into an estimated capacity of 3.6GW of electricity imports, based on the requirements in the conditional electricity imports licenses / approvals awarded by Singapore, at 60% capacity factor. By 2041, the demand for green electricity could exceed the 6GW of targeted import capacity, and other sources of green electricity will be required.

This analysis does not yet take into consideration companies' additional appetite for green energy, which can be influenced by the price of green energy, as well as the counterfactual energy costs they will face. For example, if the cost of "brown power" increases drastically and are at significant premiums to green energy, it will create an impetus for companies to contract for green energy.

Case study – Semiconductor sector demand for low-carbon electricity in Singapore

Anonymous bottom-up member targeted survey conducted by SEMI Energy Collaborative[23] on green offtake appetite, price tolerance and bankability conditions.

Survey context: Anonymised, bottom-up, commercial insights from SEMI, an industry association for the semiconductor industry. SEMI members who responded to the survey comprised fabrication facility owners and hyperscale data centre owners. SEMI helped coordinate the outreach, collated and anonymised the survey results to preserve confidentiality. Responses are indicative, non-binding and presented in aggregate form.

Why this sector matters:

- Large, electricity-intensive operations in Singapore
- Global supply chain pressure to decarbonise
- RE100 / net-zero commitments increasingly linked to investment decisions

Targets set by companies

- Broad alignment with the Semiconductor Climate Consortium (SCC) ambition statement for Asia Pacific - 70% low-carbon electricity by 2035 and 100% by 2040 as sector-wide benchmarks
- Many companies targeting 50–70% renewable electricity by 2030, with full alignment between 2035 and 2050

What buyers need

- Reliable delivery comparable to domestic grid supply
- Clear RE100 / GHG Protocol recognition
- Regulatory certainty across Singapore and exporting jurisdictions
- Bankable long-term contract structures with appropriate risk sharing

The semiconductor survey provides a practical demand-side lens for APG bankability. It indicates that Singapore has credible corporate demand for imported green electrons, but that demand is conditional rather than absolute. Buyers are more likely to support long-tenor offtake where imported electricity is competitively priced, reliably delivered, recognised for sustainability reporting, and backed by stable regulatory and contractual frameworks.

[23] SEMI Energy Collaborative is an industry association connecting companies across the semiconductor and electronics design and manufacturing supply chain.

Indicative delivered price appetite from semiconductor respondents for low-carbon imported electricity

Delivered price	Indicative appetite
Below SGD 150/MWh	Strong appetite; long-term commitment is readily supportable
SGD 150–200/MWh	Willing to contract, but volume and approval thresholds become more selective
SGD 200–250/MWh	Appetite drops materially; energy cost begins to influence location and reinvestment decisions
Above SGD 250/MWh	Difficult to justify under current business cases

Broader conditions for participation in Cross-Border Electricity Trade ("CBET"):
Semiconductor respondents emphasised that price is only one part of the decision. Participation in cross-border electricity imports will also depend on reliable supply comparable to Singapore grid standards, clear RE100 and GHG Protocol recognition, long-term regulatory certainty in both Singapore and exporting countries, and practical procurement structures that reduce development, policy and market risks for individual companies.

"The semiconductor sector's demand for low-carbon electricity is real and growing. However, long-term procurement and investment decisions require confidence not only in sustainability outcomes, but also in affordability, reliability, scalability, and regulatory certainty. Access to competitively priced and reliable low-carbon electricity is increasingly a critical factor in maintaining the semiconductor industry's global competitiveness, supporting future investment, and enabling sustainable industry growth. This paper provides valuable insights into the market and policy conditions needed to expand low-carbon electricity supply, strengthen energy security, and support the industry's long-term competitiveness and decarbonisation goals."

— SEMI Energy Collaborative

Supply Side Revenue Models and Import Economics

On the supply side, PPA prices are driven by project cost, key risks are transferred between the buyer and seller, as well as the demand/supply balance for green electrons (Figure 12). Alongside earlier discussed drivers of demand and willingness to pay, this section turns the lens to supply side considerations.

PPA prices are ultimately driven by project costs, key risks transferred between the buyer and seller of a given contract, and the supply/demand balance for green electricity

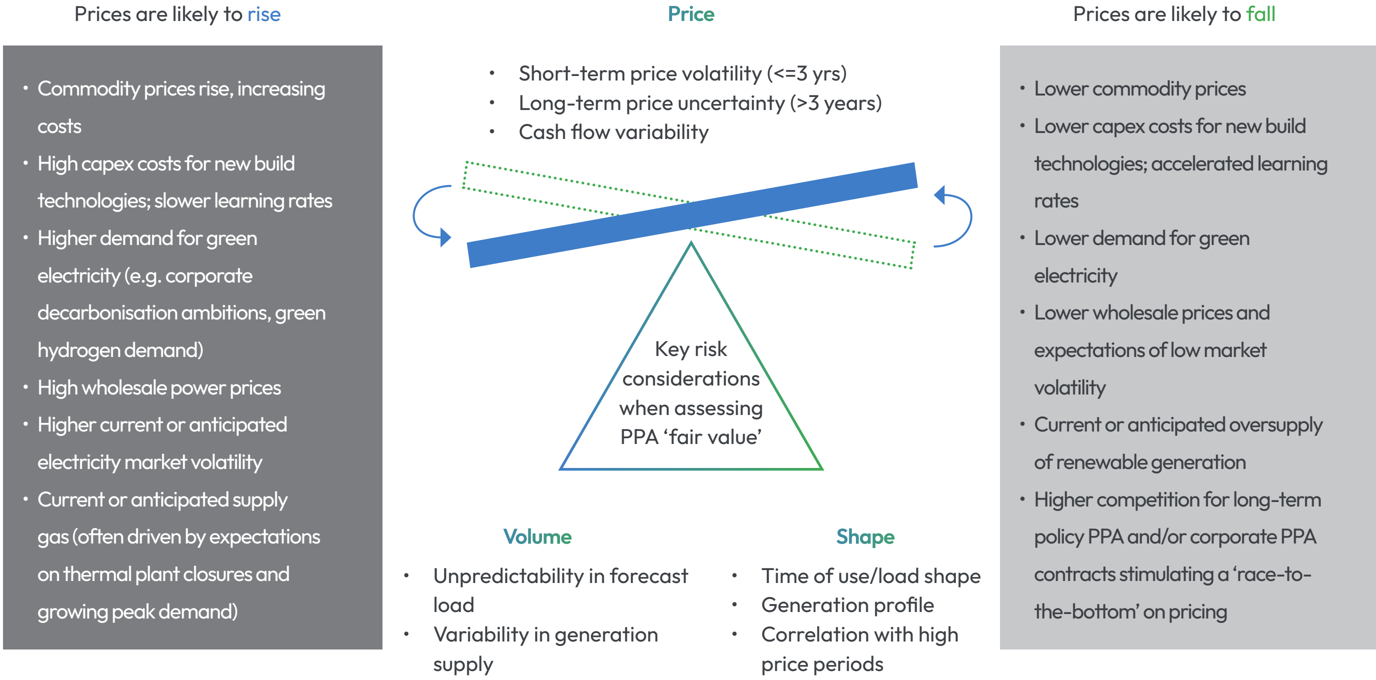


Figure 12: Movement of PPA prices with various factors

As part of its decarbonisation roadmap, Singapore aims to import up to 6GW of low-carbon electricity by 2035. The Energy Market Authority ("**EMA**") has issued Conditional Approvals to 11 projects to import low-carbon electricity (>8GW). Six projects were awarded Conditional Licences[24]. **This initiative is seen as the main source of renewable energy development for Singapore.** The Request for Proposal ("**RFP**") places strong emphasis on reliability and bankability, requiring projects to deliver a minimum 60% annual load factor, demonstrate low-carbon credentials, and satisfy technical, commercial and regulatory requirements. It adopts a market-based approach, with developers responsible for securing offtake arrangements, transmission infrastructure, and backup supply.

These developers can sell into the spot market — directly to offtakers, or to retailers in Singapore. However, the RFP issued by EMA[25] requires that commercial PPAs refer to the contracts that would be signed with end-users of electricity. A contract signed with a retailer will not be considered as a commercial PPA. This is because EMA looks to assess the developers' ability to find end-consumers/offtakers who will eventually consume the electrons.

[24] Regional Power Grids - EMA
[25] The EMA RFP refers to the latest version at the time of writing, dated 22 Mar 2025 (version 1.1).

The EMA RFP encourages developers to develop their project independently of Singapore Government's revenue support. EMA favourably considers proposals that do not request for revenue support, or proposals that request for revenue support with a lower cost, quantity, and duration. In a similar vein, proposals which request for revenue support for quantities exceeding the quantities sold via commercial PPAs, and/or which are proposing a higher revenue support price than that in the commercial PPAs, are viewed less favourably.

Thus, in this competitive environment, **the import project developers currently have two potential routes to market**, with the following considerations:

Route to Market	Considerations
Corporate Offtake *Main route to market*	• Corporate PPAs are expected to be the key route-to-market for electricity imports. • This reflects the need for project financing, which typically requires revenue certainty. • PPAs with import projects provide corporates with a pathway to achieve their renewable energy targets, or regulatory compliance requirements, given Singapore's limited local renewable energy alternatives. • Developers typically look to recover the entirety of these costs through bilateral PPAs
Spot Exposure + RECs Sale	Spot exposure is a possible (but unlikely) route-to-market for electricity imports. Under this model, it is also possible for the associated Renewable Energy Certificates ("**RECs**") to be sold unbundled. • Due to the gross pool nature of the wholesale market, electricity import projects could operate on a full merchant basis (i.e. 100% exposed to the spot market). • However, spot market price volatility would mean that revenues would depend on spot price outcomes. Significant spot exposure is not expected, as this level of price risk is unlikely to be acceptable to lenders.

Table 4: Potential routes to markets for import project developers

Given the supply-demand dynamics, developers need to strike a balance between price competitiveness and revenue certainty in their discussions with offtakers.

Cross-border electricity imports into Singapore are often framed in terms of a headline tariff. **In reality, that tariff is the aggregation of multiple distinct cost components across the value chain, each reflecting a different asset class, risk profile, and financing requirement.** Understanding this full cost stack is critical to assessing the revenue economics and resilience.

Cost stack considerations from the supply side point of view:
An "all-in" PPA price in a renewable generation to grid integrated import project is the sum of:

Cost layer	Description
1. Generation (Levelised Cost of Electricity)	Renewable generation capital expenditure (CAPEX), operational expenditure (OPEX), resource profile and local development costs
2. Storage / Firming (Levelised Cost of Storage)	Battery or other firming costs required to meet delivery and load factor obligations
3. Interconnection (Levelised Cost of Interconnection)	Transmission cables, converter stations, installation, repair contingency and long-life transmission costs
4. Cost of Financing	Risk-adjusted cost of capital across generation, transmission and cross-border overlays
5. Backup and System costs	Backup generation, balancing, ancillary services and other system security costs

Table 5: Breakdown of various cost layers

1. Generation Cost (Levelised Cost of Electricity)

At the foundation of the cost stack is the Levelised Cost of Energy ("**LCOE**") of the generation asset. This includes:

- Capital expenditure for solar / wind (and associated infrastructure),
- Operating costs,
- Resource variability (irradiance, wind profiles),
- Local development constraints (land, permitting, grid connection),
- Cost of capital reflecting emerging market risk.

While Southeast Asia offers relatively low-cost renewable resources, generation cost alone is not sufficient to determine competitiveness. It is only the first layer of a broader delivered cost into Singapore.

2. Storage /Firming Costs (Levelised Cost of Storage)

Given the intermittent nature of renewable (specifically solar and wind) generation, the EMA's requirement for load factor of 60% on an annual basis can only be met with a larger installed generation capacity (significantly larger than the import licence capacity) and onsite Battery Energy Storage Systems ("**BESS**"), or other firming solutions. Storage costs are not therefore optional in this case, but necessary to the delivered cost structure. As such, additional cost components are introduced: upfront capex for storage, degradation and replacement cycles, and operational dispatch optimisation.

Yet, storage cost is not purely due to requirements by the EMA. It is also required to meet certain offtakers' firm delivery obligations at a price premium.

It is worth noting that in the Singapore-Sarawak corridor, the generation asset is likely to be a baseload hydroelectric plant, and therefore the additional BESS cost can be largely avoided.

3. Interconnection (Levelised Cost of Interconnection)

The costs of interconnectors/transmission cables are often overlooked when comparing import tariffs to domestic green tariffs. Yet, they represent a distinct and material cost layer. The interconnection cost will include transmission cable CAPEX marine installation (if applicable) and routing risk, long-life operation and maintenance costs, and repair contingency.

It is worth noting that the interconnection infrastructure for Singapore's electricity imports is a cross-border interconnector, rather than a conventional domestic transmission asset. Its function is to connect generation located in another jurisdiction to Singapore's system through a dedicated bilateral or regional import corridor, with permitting, routing, landing rights, and regulatory interfaces potentially spanning multiple jurisdictions. Economically, this asset compares closer to a transmission asset than a generation asset: long-life, capital-intensive, strategic, and naturally monopolistic over a given route. However, it should not be viewed as part of Singapore's domestic transmission network infrastructure, nor viewed similarly as onshore grid assets built solely for internal system needs. Its treatment should reflect its hybrid role as both a project-enabling asset, and a piece of strategic regional interconnection infrastructure. However, in the absence of an OFTO-style regulated revenue model, transmission costs can only be recovered through the delivered electricity price, rather than through a separate, availability-based tariff.

Developers are effectively looking to recover both generation and transmission costs through bilateral PPAs or market sales. This can make import tariffs structurally less competitive, even when generation cost itself is relatively low.

4. Cost of Financing (Risk-Weighted by Asset Class)

The generation asset and the transmission cable can potentially have two different business models. In reality, investors see them as assets with different risk profiles and requiring different skillsets to build, operate, and manage.

A key but often underappreciated driver of total cost of any infrastructure asset is financing cost, which differs materially across various asset types:

Renewable Energy Generation Assets ("GenCo")	Transmission Assets ("TransCo")
• Typical asset life of not more than 25-30 years • Demand risks: subject to competition if full merchant. Revenue risks can be partially managed by offtake agreements (full or partial) • Price/tariff: Can be fixed through competition, auction or regulations; dependent on viability of RECs; government support (e.g. FIT, CfD) sometimes available to support viability • Volume: Driven by climate and weather and technical specifications and demand	• Typical asset life: Up to 50 years • Tend to be monopolistic in nature due to strategic importance and network economics • Price/tariff: Economic regulated returns, capacity payments or cost plus returns • Volume: Economic regulations protect downside risks in volume. Subject to performance measures

Table 6: Characteristics of renewable energy generation assets and transmission assets

Without a distinction in the revenue model in the Singapore-Indonesia corridor projects, the financing sought for both the generation and transmission projects is tied together. In addition, arising from the cross-border nature of the project, both assets are further exposed to sovereign risk (G2G interface), regulatory / export risk, and contractual enforceability risk across jurisdictions. As a result, the blended cost of capital for the overall project is structurally higher than for domestic infrastructure, and this feeds directly into the delivered tariff.

5. Backup and System Costs

Beyond generation and transmission, there are additional system-level costs:

- Backup generation / capacity support (to ensure reliability during outages or low resource periods);
- System balancing costs;

- Grid integration and ancillary services; and
- Potential curtailment and inefficiency costs.

Under the EMA RFP, the EMA requires the developer to be responsible for the back-up cost. Consequently, the importers will pass this cost on to the offtakers.

This results in a fully delivered cost of imported electricity, which can be materially higher than standalone LCOE benchmarks, or domestic wholesale electricity prices.

The Pricing Gap and Potential Considerations

The core commercial and financial viability challenge is therefore the pricing gap: corporate users and offtakers will benchmark imported green power against current retail or wholesale alternatives, while developers must recover a much broader delivered cost stack across generation, firming, interconnection, financing, and system support. **Put simply, an aggregation of all the cost stacks and the full cost transfer to corporate users may not be acceptable to all users.**

The resulting gap is not simply a pricing problem. Given the capital intensity of the projects and long loan tenors required by developers, lenders require the project to have highly contracted, durable revenue streams, typically through long-term PPAs with creditworthy counterparties. Pure wholesale market revenue will not help raise project financing. Customers in Singapore are used to procuring electricity via retail contracts. Hence, it may be challenging to get all customers to sign long-term PPAs.

The implication is that **matching demand-side price expectations with supply-side costs will require a blend of revenue models.** Potential models could combine long-term bilateral PPAs for the green-energy component with differentiated revenue arrangements for transmission and backup-related components. Options such as regulated, availability-based or other recovery mechanisms would require further assessment against cost-causation and beneficiary-pays principles, consumer affordability, project-performance incentives, and transparent allocation of risks between developers, offtakers and the wider electricity system.

Indicative Framework for Allocating the Cost Stack

Cost component	Potential Treatment/ recovery route	Why it matters for bankability
Generation (LCOE)	Bilateral PPA / commercial offtake	Closest to the core green energy value that buyers are willing to contract for
Storage / Firming (LCOS)	Bilateral PPA premium, firmness product or tailored service charge	Supports dispatchability and delivery certainty required by EMA and some offtakers
Interconnection (LCOI)	Potential unbundling, regulated recovery or availability-based charging	Long-life strategic infrastructure is difficult to recover efficiently through energy price alone
Financing Premium	Reduced through structure, de-risking, support mechanisms or improved risk allocation	Strong contractual and regulatory design can lower overall cost of capital
Backup and System costs	System charge, recovered from broader system users or explicit policy allocation	Clarifies whether energy security costs sit with import users or the wider system

Table 7: Indicative framework for cost allocation

International case studies show that projects become bankable not when buyers absorb the full gap through a flat energy price, but when the gap is narrowed through contract design, risk allocation and differentiated revenue streams that align each cost component with the party best placed to bear it.

Considerations and case studies:

- **CfD-style auctioned revenue support:** Under the UK-style Contracts for Difference ("CfD") mechanism, a generator secures a long-term, auction-cleared strike price through a public counterparty, rather than relying solely on bilateral offtake prices. This model can bridge a residual bankability gap where commercial offtakers are unwilling to absorb the full delivered cost of imported electricity, while still using competition to limit the level of support required. When viewed in light of EMA's preference for proposals with limited or no revenue support, a full CfD-style mechanism may be a useful conceptual precedent for long-life strategic infrastructure, while providing a market mechanism to keep the developers competitive given the demand/ supply dynamics.
- **Revenue unbundling by asset type:** Under the OFTO regime, offshore transmission assets earn availability-based revenues. The UK OFTO model shows that transmission costs need not be recovered solely through an energy tariff. Where interconnection can earn an availability-based or regulated-style return, the energy price seen by the end buyer is lowered, and might be better aligned to what corporates are willing to pay for 6GW of green electrons. This also could help lower the project-on-project risk and subsequently financing cost for transmission infrastructure.
- **Funding of Interconnection/ Transmission costs:** In the UK OFTO model, the availability-based tender revenue stream is not funded directly by the government or commercial offtaker. Instead, it is recovered through regulated transmission charges across the wider electricity system. As such, the cost is ultimately recovered from the broader system users rather than borne solely by the offshore generator or its offtaker. Alternatively, shared infrastructure should be considered where project economics are supportive of pooling resources.
- **EMA backup charges:** The UK provides a useful analogue in showing that supply security costs need not be embedded entirely in the energy or transmission tariff. If an offshore transmission link fails, the cost of maintaining backup generation and operational reserves is ultimately recovered through system-wide charges borne across the market, rather than solely by the offshore wind offtaker. In the context of Singapore, it can be said that EMA backup charges should be understood as the cost of preserving domestic energy security against interconnector outage risk, as opposed to payment due to a defect in the import project itself.
- **Deemed generation:** Curtailment caused by constraints on the Singapore side may be unlikely in reality. Yet, lenders may still require contractual certainty that debt service is not exposed to a non-project-side risk event where the import project is available to deliver but cannot be accepted by the grid. In that context, a narrowly defined deemed generation clause could operate as a targeted backstop for grid-side curtailment or dispatch restrictions beyond the developer's control, helping preserve revenue certainty without turning the PPA into a broad volume guarantee.
- **Backstop offtake / Buyer of last resort:** For remote stress scenarios in which commercial offtake materially fails (due to market conditions or specific default), a limited backstop offtake mechanism could be established. The objective would not be to provide developers with a full sovereign revenue guarantee, but to create a time-limited emergency route to market that prevents a long-life import asset from becoming immediately stranded if private offtake were to disappear. While the wholesale electricity market route is an alternate revenue option, banks are typically wary of the volatility of this market mechanism. Hence bankability may improve with a backup revenue insurance scheme option.

Internationally, the UK Offtaker of Last Resort model provides a useful case study. The scheme is designed to give eligible renewable generators access to a temporary backstop power purchase agreement if they cannot secure offtake through the market, with the associated costs levelised across licensed suppliers rather than left solely with the affected project. While this does not provide a full long-term revenue guarantee, it demonstrates how a regulated last-resort mechanism can improve lender confidence in extreme downside scenarios while preserving market discipline.

> "The UK's experience with interconnected power grids demonstrates how cross-border links can speed up the clean energy transition while improving energy security. The ASEAN Power Grid has similar potential. Realising it will depend on practical solutions to bankability, ensuring the commercial and legal frameworks are in place to attract long-term, private investment."
>
> *— British High Commission, Singapore*

Case Study – UK Contracts for Difference (CfD): De-risking Generation Through a Public Counterparty[26] [27] [28]

A competitive, auction-based revenue support mechanism that underpins large-scale renewable investment by replacing bilateral offtake risk with a long-term, public strike price

What the scheme is and why it matters

The UK CfD scheme is the government's primary mechanism for supporting low-carbon electricity generation. Introduced in 2014, it enables renewable generators to secure long-term, inflation-indexed revenue certainty through a public counterparty, rather than relying on bilateral corporate PPAs.

CfDs have underpinned the UK's rapid scale-up of renewables, particularly offshore wind, by materially lowering revenue risk and the cost of capital, while protecting consumers from windfall profits when power prices are high.

How the CfD works

1. Competitive auction (price discovery)

- The government runs periodic allocation rounds where eligible generators bid a strike price (£/MWh). The CfD auction mechanism has since also been used for low carbon hydrogen and CCUS projects.
- Bids compete within technology "pots". The lowest bids win contracts, subject to budget caps.

2. Public counterparty

- Successful projects sign a 15-year private law contract with the Low Carbon Contracts Company (LCCC), a government-owned entity.
- LCCC provides sovereign grade credit support, replacing corporate offtake risk.

3. Two way price stabilisation

- Generators sell power into the wholesale market as normal.
- If market price < strike price: LCCC pays the difference (top up).
- If market price > strike price: the generator pays back the difference to LCCC.
- Settlement uses transparent market reference prices (e.g., day-ahead indices for wind/solar).

4. Cost recovery

- Net CfD payments are recovered from all electricity suppliers and passed through to consumers.
- During high-price periods (e.g., 2022–23), CfDs reduced bills as generators paid back surplus revenues.

What CfDs de-risk (and what they don't)

De-risked

- Wholesale price volatility: 15 years of fixed, inflation-indexed revenue.
- Offtake/credit risk: sovereign backed counterparty replaces corporate PPAs.
- Financing risk: predictable cashflows materially lower WACC.

Not covered

- Construction and performance risk: remain with the developer.
- Post-contract exposure: full merchant risk after the CfD term ends.

[26] Contracts for Difference - Department for Energy Security and Net Zero, Dec 2025
[27] Contracts for Difference - Low Carbon Contracts Company, Jun 2026
[28] Contracts for Difference (CfD): Allocation Round 8 - Department for Energy Security and Net Zero, Dec 2025

Case Study – UK Offtaker of Last Resort[29][30]

A regulated backstop route to market that improves lender confidence without creating a full sovereign revenue guarantee

What the scheme is and why it matters

The UK Offtaker of Last Resort (“**OLR**”) scheme was introduced in 2015 to provide eligible renewable generators with a credible emergency route to market where they cannot secure a commercial power purchase agreement through normal channels. It is not designed to replace the market or provide a full long-term revenue guarantee. Instead, it creates a regulated backstop that improves bankability by giving lenders comfort over the project’s worst-case route-to-market outcome.

How the model works

- Eligible generators can trigger the scheme if they are unable to obtain a commercial PPA.
- Ofgem runs a competitive auction to allocate a Backstop Power Purchase Agreement (“**BPPA**”) to a licensed supplier.
- The BPPA is intentionally short-term, with a term of no more than 12 months, and priced at a specified discount to the market reference price so that it remains a genuine last resort rather than a preferred commercial route.
- Any incremental costs incurred by the successful supplier for being the backup offtaker are levelised across licensed suppliers, rather than being left solely with the project or the winning bidder.

Risks mitigated and benefits created

- Mitigates route-to-market risk if the offtake market temporarily fails or a generator cannot find a buyer.
- Improves lender confidence by establishing a known downside monetisation route, even if pricing remains unattractive relative to normal market sales.
- Preserves market discipline because support is temporary, discounted and only available in genuine stress scenarios.

APG Takeaway: The OLR route provides a case study for a limited buyer-of-last-resort mechanism in remote downside scenarios. However, OLR has never been used with no applications or BPPA’s entered into since launch. Hence, if policymakers wished to reduce the tail risk that commercial offtakers default, withdraw or materially reduce demand, a time-limited regulated backstop offtake mechanism could help prevent a long-life import asset from becoming immediately stranded, while avoiding the need for a full sovereign guarantee from the outset.

In the Asian context, the Malaysia CRESS program and the Taiwan offshore wind offtake also provide a fallback option in case of failure of corporate offtaker. In Malaysia, this is provided for an interim period (i.e. after the current offtaker defaults before a new offtaker is appointed) via the New Enhanced Dispatch Arrangement fallback mechanism. In Taiwan, the fallback option is provided via a standby PPA by TaiPower for up to 18 months support.

[29] Offtaker of Last Resort (OLR) – Ofgem, Oct 2025
[30] Power Purchase Agreement scheme: Offtaker of Last Resort – DESNZ, Apr 2020

Case Study – NordLink: Norway–Germany Interconnector[31] [32]

A fully regulated cross-border transmission model

What is NordLink

NordLink is a 1,400 MW High-Voltage Direct Current ("**HVDC**") subsea interconnector linking Southern Norway (Tonstad) and Northern Germany (Wilster). Commissioned in 2021, it connects two highly complementary power systems: Norway's flexible hydropower reservoir fleet and Germany's large-scale wind and solar generation.

Nordlink is treated as core transmission infrastructure, fully integrated into the regulated asset bases of the two national Transmission System Operators ("**TSOs**"). Its costs are recovered through system-wide network tariffs, providing long-term revenue certainty, and eliminating exposure to market price spreads or corporate willingness to pay.

Project Overview

- Capacity: 1,400 MW
- Length: ~623 km (including ~516 km subsea cable)
- Technology: ±525 kV HVDC
- Total investment: ~€1.8 bn
- Ownership:
  - 50% Statnett (Norway's state-owned TSO)
  - 50% German side via TenneT TSO and KfW (Germany's development bank)
- Status: Operational since May 2021
- EU status: Project of Common Interest (PCI)

The project was developed as a bilateral TSO-led asset, not as a merchant interconnector SPV.

Charging and revenue recovery: NordLink is treated as regulated transmission infrastructure, not a merchant cable. Market participants trade through market coupling and do not pay a bespoke long-term cable tariff. Each TSO recovers its share of efficient costs, depreciation and allowed return through national transmission tariffs charged to grid users in Norway and Germany.

Congestion revenues: Price differences between Norway and Germany create congestion revenues when power flows across the link. These revenues are collected by the TSOs and shared between the Norwegian and German sides, but are not retained as unrestricted merchant profit. Under European regulatory rules, they must be used for system purposes, including maintaining or increasing interconnection capacity, supporting grid-related investment, or reducing future network tariffs.

Regulatory Framework

NordLink is underpinned by two of Europe's most stable transmission regulatory regimes.

Norway (Statnett)

- Regulated by the Norwegian Energy Regulatory Authority (RME).
- Revenue cap model allowing recovery of:
  - Efficient OPEX
  - Depreciation of RAB
  - Regulated return on capital (WACC based)
- Congestion revenues reduce future tariffs, ensuring consumer benefit.

[31] Nordlink- Statnett, 2025
[32] Nordlink- TenneT, 2026

Germany (TenneT / KfW)

- TenneT recovers costs under German transmission regulation.
- KfW participation provided long tenor, low cost development bank financing for Germany's share.
  As the project was providing benefits to connect German variable renewables with Norway's flexible hydropower, it was considered as a project of common interest, i.e. a status of priority project with wider regional system value.

Cross-Border Governance and Risk Allocation

- Ownership alignment: 50–50 split ensures symmetric incentives.
- Regulatory alignment: Each country regulates its own TSO, with bilateral agreements on asset ownership and congestion revenue sharing.
- Market risk: Eliminated for investors; borne by the system.
- Operational risk: Managed through TSO standards and regulated incentives.
- Political legitimacy: Maintained through tariff pass-through of congestion revenues to consumers.

APG takeaway: NordLink shows that strategic interconnectors for bilateral flows can be financed where they are treated as system infrastructure. For APG Singapore projects, while the flows may be one-way rather than bilateral, the key lesson is that interconnection costs may not need to be fully embedded in bilateral green PPAs. Where the cable provides broader system value, part of the cost could be recovered through regulated or system-level mechanisms, improving bankability while reducing the delivered price burden on corporate offtakers.

Driver 3: Sovereign Commitment and Regulatory Completeness

As noted earlier in this paper, political endorsement creates the conditions for cross-border power trade; legal certainty and completeness create the conditions for financing it. The bankability question within Driver 3 is therefore not whether the political commitment exists. Instead, it revolves around whether the regulatory chain is sufficiently robust, or if it is evolving in the right direction, such that limited-recourse financing structures can underwrite the long-term financing tenors to support the import projects.

Ultimately, each import project will have its own unique set of risks which will need to be addressed and managed. This chapter is not intended as an exhaustive analysis of the bankability issues relevant to an individual import project, and how it might manage those bankability issues to deliver a viable financing solution. Instead, the focus of this chapter is on **some key regulatory issues of general application to export-import projects in the key corridors, that will need to be addressed in order to create the right environment for long-term debt finance to be viable.**

The first part of this chapter outlines the current Singapore-side import regime, as well as some common features and divergences of the export-side regimes. The second and third parts of this chapter examine the Malaysian (Sarawak) and Indonesian regulatory regimes in turn, focusing on the issues most material to lender credit analysis and project structuring, as well as snapshots on legal risk allocation under current regulatory frameworks.

The forward-looking workstreams that are needed to translate this analysis into bankable structures are then set out under (i) The Path to Bankability: Re-allocating Risk – which compares current risk allocation structures to potentially bankable ones; and (ii) Legal Workstreams to Bankability – which sets out key steps to be taken to achieve a regulatory environment, where bankability for both corridors might be achievable.

Current State of Play: Singapore, Malaysia, Indonesia

Singapore's strategic ambition to import up to 6 GW of low-carbon electricity by 2035 relies significantly on two physically and legally distinct import corridors. Each corridor draws on a different generation resource base, channels electricity through a different sovereign interface structure, and operates under distinctly different domestic regulatory regimes. A single regulatory or political dislocation in either jurisdiction can affect the relevant corridor for an import project, even where the technical and commercial design is sound. Bankability for cross-border electricity import projects from a legal perspective therefore depends, not just on the strength of the contracts at the heart of the project, but also on the durability of the domestic and international legal frameworks that surround them (and therefore State commitment on both sides of each corridor).

Unlike a domestic power generation project, a structural feature of both import corridors is primarily *two-regulator dependency*[33]. There is a separate licensing chain in each relevant jurisdiction, with the relevant regulators retaining discretion over the issuance, conditions, renewal, suspension, and revocation of the relevant licences. Each regulator will demand compliance with the terms and conditions of any licence that it issues. All parties (whether the generator, transmission system operator or importing offtaker) will need to ensure that the import project, on an integrated basis, is consistent with and supportive of the licence conditions attached to any individual part of the project. Lenders will also require advance clarity and predictability of all licence conditions, and satisfaction of the relevant licence conditions as a condition precedent to financial close for any financing connected to the project, and will include ongoing compliance with licence conditions as operating covenants under the financing documentation thereafter.

Such a structure creates risks for the import project that need to be managed. It requires the project chain to be documented so that adverse regulatory action in any applicable jurisdiction is either:

a) mitigated contractually (through compensation, termination protection and step-in rights);
b) absorbed at the State level (through direct contractual undertakings or pursuant to a binding intergovernmental framework); or
c) insured (through political risk products and treaty-level protection), though potentially (and ideally) a combination of all three.

The remainder of this Chapter sets out the principal legal and regulatory features of each export-side jurisdiction in turn.

The two corridors being considered in this paper share several common bankability challenges, most notably:

- The current absence of any binding intergovernmental electricity-trade agreement or treaty;
- The lack of a tailored regime for subsea power cables in the region;
- Uncertainty over cross-border REC transferability; and
- The structural difficulty of pricing regulatory and political risk (e.g. change-in-law and lawful sovereign curtailment risk) over a 20-to-30-year financing tenor.

Potential mitigants to some or all of these issues exist, including by way of intergovernmental agreements, are discussed later in this paper.

Both corridors diverge sharply, however, on three structural questions:

a) who is permitted to be the exporter (the question of State control);
b) how long export rights endure (the question of licence tenor); and
c) how directly the foreign offtaker can contract with the generator (the question of intermediation).

Those structural divergences drive the bankability analysis that follows.

[33] The Sarawak-Singapore subsea power interconnector also has Indonesian regulator dependency to the extent it passes through Indonesian waters.

Singapore Legal and Regulations

The regulatory architecture in Singapore that supports the import projects is generally well-developed. Electricity imports into Singapore require a licence issued by the EMA under the Electricity Act 2001 and must comply with stringent low-carbon, technical, reliability, and reporting requirements. The import licence is subject to ongoing compliance obligations, which may cover the source mix of imported electricity, operational reliability standards, grid and infrastructure compatibility to ensure safe and secure supply, and potentially, submission of RECs where electricity is to count as "low-carbon".

Malaysian Legal and Regulations

From a purely regulatory perspective, the Malaysia (Sarawak) – Singapore corridor currently presents a structurally favourable legal starting point, compared with many other ASEAN bilateral pathways. Export is expressly permitted under State law, the likely exporter (Sarawak Energy Berhad ("**SEB**")) is also the State's designated single buyer and system planner, and both Malaysia and Singapore are open, treaty-engaged jurisdictions with mature commercial legal systems. The bankability question is therefore less about whether export is lawful, and more about how durable, compensable, and contractually ring-fenced the export entitlement is over a 20–30-year financing tenor. The discussion below sets out the principal legal findings under the existing framework, organised by the issues most material to lender credit analysis and project structuring.

Export policy and licensing under the Sarawak Electricity Ordinance

Sarawak's electricity sector is governed by the **Electricity Ordinance (Cap. 50)**[34] (the **"Ordinance"**), which establishes a comprehensive licensing requirement for the use and operation of installations, and for the supply, transmission and distribution of electricity in the State of Sarawak. Critically, the Ordinance expressly empowers the Sarawak State Cabinet ("**Majlis Mesyuarat Kerajaan Negeri**" or "**MMKN**") to authorise, by terms incorporated in a licence, the supply of electricity "to any person or party outside the State", subject to such conditions, limitations or restrictions as MMKN considers appropriate. Prior to granting any such licence, MMKN must consult the "single buyer" (defined under the Ordinance as SEB). The 2023 amendments to the Ordinance are publicly described as having been enacted to enable Sarawak's electricity trade and export ambitions, including export to Singapore, as part of Sarawak's energy transition strategy.

From a legal perspective, export is therefore not subject to any general prohibition: it is licence-based and lawful, contingent on MMKN authorisation embedded in a licence. **The principal legal risk is regulatory discretion and durability, rather than legality of export *per* se.** The Ordinance permits MMKN to require security from licensees, and to suspend or revoke a licence at any time upon breach of any of its conditions or for failure to comply with any provision of the Ordinance. It also provides for suspension and revocation in circumstances not involving licensee fault, and confers no right of renewal. The governmental non-liability clause for losses arising from suspension or revocation is not confined to cases of breach. These matters are considered further below. **For lenders, this means that the export authorisation must be explicitly and durably embedded in the licence, with the scope of permitted export, volumes, destination, and counterparty clearly defined on the face of the instrument, and with the licence term aligned with (or extending beyond) the key contractual documents for the project (being a power purchase agreement and/or a transmission services agreement) and financing tenor.**

[34] Electricity Ordinance (Cap. 50), Laws of Sarawak (revised; incorporating amendments to 1 February 2024) – State Attorney-General's Chambers, Sarawak.

Notably, the Ordinance is not the only relevant law in the context of the Malaysia (Sarawak)-Singapore corridor, though it is central to its legal feasibility in the context of generation, licensing and exports from Sarawak. Federal law governs export, the marine environment, cabotage, foreign exchange, taxation and arbitration. Full legal analysis of all relevant laws (including federal vs state legislative layering), however, is beyond the scope of this paper.

Summary of the current risk allocation

- **Risk controlled by:** The Sarawak State, acting through MMKN, as the licensing authority.
- **Loss likely borne by:**
  - SEB directly as licensee;
  - ProjectCo indirectly through the Interconnection Agreement, as ProjectCo has no direct licence exposure but full revenue dependency on it.
- **Challenge:** Loss of the licence would pass straight through to ProjectCo's revenue unless availability payments are structured to survive it, while the State bears none of the consequences

See the full details on the current and bankable risk allocation in The Path to Bankability: Re-allocating Risk.

Grid and transmission: SEB as single buyer and system planner

The amended Ordinance institutionalises SEB as the "single buyer" and a central participant in licence approvals through the mandatory consultation requirement. In practice, this means that any export project must interface with SEB's transmission and system planning arrangements, with SEB acting as grid owner and system planner within Sarawak's single buyer model. In principle, such centralised system planning means export performance can be exposed to dispatch and system-constraint decisions, particularly where export volumes or delivery timing interact with domestic reliability priorities. **The potential participation of SEB as the exporter creates a materially favourable factor for projects in this corridor, in which lender concerns about adverse dispatch decisions are materially mitigated when the system planner is also a key commercial stakeholder.** Equally, concentrating grid ownership, system planning, single-buyer and potential exporter functions within one entity raises governance, operational flexibility and risk management considerations, with lenders likely to seek clarity and transparency in dispatch and curtailment decision-making and functional separation or equivalent safeguards where those roles overlap.

Yet, this alignment must be captured within binding legal agreements. Specifically, the PPA (or transmission services or any other similar agreement) should expressly allocate curtailment risk, and treat export interruptions driven by domestic system considerations to the exporter as compensable events. Where commercially feasible, the compensation should be structured on a deemed availability basis, to immunise debt service against operational decisions taken by SEB acting in its system-planner capacity.

The Ordinance itself does not create a dedicated "export dispatch priority" rule. Export is permitted via licence conditions, with practical outcomes dependent on the licence and the underlying contractual framework.

Sarawak Energy Berhad

- SEB is a government-owned company and is Sarawak's statutorily defined single buyer of electricity.
- It is wholly owned by the Sarawak Government, and is under the regulatory purview of the Ministry of Utility and Telecommunication Sarawak, and the Ministry of Energy and Environmental Sustainability Sarawak.
- Various roles
  - Single buyer — statutorily designated to purchase electricity for sale, supply, transmission and distribution throughout Sarawak.
  - Systems planner – plan, manage, and procure electricity supply for Sarawak.
  - Grid owner — Owner of the grid transmission system in the State.
  - Mandatory consultee on licensing — must be consulted by MMKN, with its recommendations considered, before any licence (including an export licence) is granted.

Summary of the current risk allocation

- **Risk controlled by:**
  - SEB, as system planner and dispatcher;
  - Offtaker (dispatch-based structure only)
- **Loss likely borne by:** Offtaker or, potentially in full, on ProjectCo if the Interconnection Agreement is structured on a dispatch basis rather than an availability basis.
- **Challenge:** The corridor's key structuring point is that a per-MWh charge would make ProjectCo absorb risks it cannot manage, rendering the project unfinanceable.

See the full details on the current and bankable risk allocation in The Path to Bankability: Re-allocating Risk.

Licence duration and tenor mismatch risk

The Ordinance does not prescribe a fixed or minimum duration for electricity licences (including export licences). Rather, a licence may be granted "for such period as stipulated in it", with MMKN retaining discretion as to tenure. Importantly, the Ordinance provides that a licensee has no right of renewal[35], although MMKN may extend the licence period on such terms as it deems fit. Licence tenure and renewal are therefore subject to the conditions of the individual licence and on continuing exercise of MMKN's discretion.

Such a structure introduces a potential misalignment between export licence duration and long-term transmission project economics, particularly given limited-recourse financing tenors typically extending over 20–30 years. If an export licence expires or is not renewed prior to debt maturity, the exporter would lose the legal right to export notwithstanding the continued physical availability of generation, transmission and offtake. **This creates a revenue-continuity risk that lenders to the transmission project will not generally accept.**

Lenders will typically require either:

(i) **The export licence duration to at least align with, or extend beyond, the financing tenor for the transmission project (potentially with long-term government commitment under a government support agreement to preclude the ability to legally justify the use of change in law to truncate licence duration);** or

(ii) **Robust contractual termination compensation mechanisms** that repay outstanding debt (principal, accrued interest and break costs) of the transmission project if export authorisation is lost due to regulatory action.

While SEB's potential participation as exporter is a positive factor and should be actively leveraged to secure long-dated export licensing comfort, it does not substitute for contractual lender protection.

Summary of the current risk allocation

- **Risk controlled by:** The Sarawak State, through MMKN.
- **Loss likely borne by:** ProjectCo indirectly through the Interconnection Agreement, as there is no minimum tenor and renewal remains discretionary.
- **Challenge:** Licence, PPA and financing tenors must align, and because a stranded interconnector has no alternative use, the exposure is effectively unbounded.

See the full details on the current and bankable risk allocation in The Path to Bankability: Re-allocating Risk.

[35] Electricity Ordinance (Cap. 50) – licensing, tenure and renewal provisions – Laws of Sarawak.

Local content expectations

The Ordinance does not impose a numerical local content threshold for export projects. Public statements accompanying the 2023 amendments emphasise Sarawak's objective of broadening participation and generating local jobs and revenues, but do not codify specific local content percentages. In practice, however, there are well-understood expectations of meaningful local benefit.

The primary risk profile is therefore likely to be more political and social, rather than strict legal non-compliance. Further, lenders (for reasons of compliance with their own ESG policy requirements and compliance with the Equator Principles) will likely nonetheless expect to see clear local participation commitments embedded into procurement and EPC structures, supported by documented stakeholder engagement and ESG management plans. **While not a credit "killer" in this corridor, mismanagement of local participation expectations remains a potential schedule and cost risk, and is best treated as part of the bankability considerations of the transmission project rather than as a residual ESG item.**

Summary of the current risk allocation

- **Risk controlled by:** The Sarawak State at a policy and social-expectation level.
- **Loss likely borne by:** ProjectCo and its EPC contractor, as the transmission and subsea cable scopes are least capable of local sourcing.
- **Challenge:** These expectations are political rather than legal, creating execution risk that the statute cannot resolve.

See the full details on the current and bankable risk allocation in The Path to Bankability: Re-allocating Risk.

Absence of statutory Domestic Market Obligation, but de facto domestic priority

Unlike Indonesia (where domestic prioritisation has constitutional and statutory roots; discussed further in the Indonesia analysis below), **Sarawak has no formally codified Domestic Market Obligation ("DMO") applicable to electricity generation and exports.** The Sarawak Government's public position is that the planned expansion of generation to 10 GW by 2030 is specifically designed to support export of surplus generation. Public reports indicate that even with planned exports to Singapore and others, approximately 88% of Sarawak's generation capacity would remain available for domestic use, alongside an approximately 25% reserve margin. [36]

Notwithstanding the absence of an expressed DMO, political expectations to prioritise domestic supply security can translate into de facto curtailment pressure in stress scenarios, particularly where export volumes are large and politically visible. **From a bankability perspective, any such curtailment would need to be either contractually compensated or structurally addressed, through availability-based or take-or-pay revenue mechanisms that protect debt service irrespective of energy dispatch.**

Summary of the current risk allocation

- **Risk controlled by:** The Sarawak State at policy level, together with SEB.
- **Loss likely borne by:** If any, it would be with SEB, but in the absence of a strict requirement, loss would only arise if an obligation existed in the future.
- **Challenge:** A future domestic market obligation, or a reprioritisation introduced during the financing term, would itself constitute a change-in-law risk borne by SEB.

See the full details on the current and bankable risk allocation in The Path to Bankability: Re-allocating Risk.

[36] Premier: Sarawak to generate 10GW by 2030, ready to power ASEAN neighbours with surplus energy – DayakDaily, Jun 2025; see also "Sarawak will have enough electricity for domestic use even after exporting to Singapore, Sabah by 2032" – Malay Mail, Nov 2023.

Land rights, wayleaves and corridor security

Export projects will require onshore and offshore land usage rights, including transmission corridors and substations in Sarawak, and landfall sites for the subsea cable in both Sarawak and Singapore. Key issues include the acquisition of durable rights over private and native customary lands for transmission infrastructure, as well as ensuring a stable legal interest in those lands for the operational life of the transmission project.

The 2023 amendments to the Ordinance empower the Sarawak Land and Survey Department's Superintendent grant SEB (or its grid subsidiary) the rights to use land for electricity infrastructure, exercising powers ordinarily reserved for the State under the Sarawak Land Code (Cap. 81).[37] The amendments also permit registration of caveats on land titles in respect of wayleave agreements (effectively easements) reached with landowners, providing meaningful protection for transmission corridors over project life. Detailed route surveys and title searches will nonetheless remain critical execution items. **Lenders will require evidence of secure, registered land tenure, with tenors matching the financing horizon as conditions precedent and as part of the security package.** However, formal land tenure is only one aspect of land access. Customary rights remain a sensitive area requiring careful diligence and stakeholder engagement. SEB's extensive experience in managing land access for major hydropower developments should help to mitigate these risks.

Summary of the current risk allocation

- **Risk controlled by:** The Sarawak State, through the Superintendent of the Land and Survey Department.
- **Loss likely borne by:** ProjectCo.
- **Challenge:** It remains unclear whether ProjectCo, not being SEB, can access the Ordinance's land powers directly, or must instead rely on SEB or the State, leaving ProjectCo with only an indirect interest.

See the full details on the current and bankable risk allocation in The Path to Bankability: Re-allocating Risk.

[37] Electricity (Amendment) Bill 2023 – Superintendent of Land & Survey empowered under s.37(a), and wayleave caveats under s.173(a), Sarawak Land Code – Ministry of Utility and Telecommunication / DayakDaily, Nov 2023.

Change in law, stabilisation and political risk

The Ordinance (nor any other federal law) does not contain stabilisation provisions which would provide protections against political and regulatory risks (in particular, risks of change in law, which are heightened where long-term financing is involved). To the contrary, the Ordinance preserves executive discretion over licensing and includes a government non-liability clause for losses arising from licence suspension or revocation. There is no equivalent of a project-specific investment stabilisation regime or sectoral investment protection treaty addressing electricity exports. **Change-in-law risk is therefore largely unmitigated and should be addressed, ideally at the statutory/regulatory level. Failing this, it would need to be addressed contractually.**

When considered over a 20–30-year project life, plausible change in law risks could include: changes to Sarawak export policy (including new restrictions or export levies), federal interventions affecting cross-border energy trade, environmental regulations constraining hydropower operations, foreign exchange controls affecting cross-border payments, and political shifts that could affect ownership or control of strategic energy assets.

From a project bankability perspective, the ideal risk mitigation strategy would contain a combination of:

(i) **Contractual change-in-law pass-through and/or termination compensation mechanisms** in the PPA (and any related transmission services agreement or similar agreement) that protect debt service (covering at minimum principal, accrued interest and reasonable break costs);

(ii) **Political risk insurance;**

(iii) **Reliance on appropriate regional frameworks,** such as the ASEAN Comprehensive Investment Agreement (“**ACIA**”)[38] for cross-border investor protection; and

(iv) **The structural alignment provided by SEB’s potential exporter role,** which materially reduces the probability of adverse Sarawak State action against an export project in this corridor.

Summary of the current risk allocation

- **Risk controlled by:** The Sarawak State, through MMKN.
- **Loss likely borne by:** ProjectCo, as there is no statutory stabilisation regime and a governmental non-liability clause excludes State liability.
- **Challenge:** ProjectCo cannot recover increased costs unless the Interconnection Agreement expressly provides for it.

See the full details on the current and bankable risk allocation in The Path to Bankability: Re-allocating Risk.

[38] ASEAN Comprehensive Investment Agreement (ACIA), signed 26 February 2009 (in force 29 March 2012) – ASEAN.

Licence suspension and revocation: the governmental non-liability clause

Separate from the broader change-in-law analysis, the Ordinance contains a specific provision deserving of standalone attention for lender purposes. It provides **that neither the Sarawak State Government nor the relevant licensing authority shall be liable for any loss or damage suffered by a licensee (or any other person) arising out of, or in connection with, the suspension or revocation of a licence.** The provision is broadly drafted and is not, on its face, subject to a cause-or-procedural-fairness qualification. While the principal power of suspension and revocation is expressed to arise on breach of licence conditions or failure to comply with the Ordinance, the Ordinance permits immediate suspension of the operation and use of an installation or apparatus where a defect is considered likely to cause immediate danger. It also permits MMKN to revoke the licence where such a defect cannot be remedied. Neither action require finding of any fault on the licensee's part. A latent defect in cable insulation or in converter equipment is a potential example. The non-liability provision extends to the suspension of the operation and use of an installation, as well as to the suspension or revocation of a licence, and so applies equally to those no-fault cases.

This is a separate issue from licence duration and from change in law risk. Duration risk concerns the risk of expiry of authorisation at the end of the licence term without extension. In contrast, change-in-law risk concerns the legal framework underpinning the project changing (adversely) during the project term. The no-liability clause risk concerns the discrete event of regulatory intervention against a particular project mid-term, and the absence of any statutory entitlement to compensation for that intervention. **It appears that, even if a licensee is in compliance, suspension or revocation of the licence creates no statutory cause of action against the State for the resulting loss of cashflow or stranded investment (save for any rights that might arise under Malaysian law generally).**

The bankable response therefore operates entirely outside the current statutory framework. Lenders would be expected to require:

(i) **A robust termination compensation regime in the PPA or other contractual arrangements for the transmission project,** triggered by any regulatory event that prevents export (and defined to include licence suspension or revocation absent licensee default), and sized to repay outstanding debt principal, accrued interest and reasonable break costs;

(ii) **Direct agreements with SEB (in its capacity as the energy exporter) and any other relevant State counterparty** providing for lender step-in and cure rights before the export contractual arrangements can be terminated by reason of a licence cancellation/non-extension event;

(iii) Where possible, **government support documentation** (whether a guarantee or a more formal Government Support Agreement) addressing the State's position on regulatory intervention against the project; and

(iv) **Political risk insurance** to capture any residual exposure that contractual arrangements cannot transfer (e.g. for unlawful change-in-law, currency-transfer and selected breach-of-contract risks).

Intergovernmental framework

The Sarawak–Singapore corridor is supported by bilateral cooperation between Malaysia and Singapore, by Sarawak State-level policy direction, and by the broader ASEAN Power Grid framework (including the enhanced APG MOU executed in 2025)[39]. **However, there is no single binding intergovernmental agreement ("IGA") that specifically guarantees long-term export rights, pricing or remedies in respect of the corridor.** In the absence of such an IGA, import-export projects in this corridor would rely primarily on:

(i) Sarawak State licensing under the Ordinance;
(ii) the Singapore import licence under the Singapore Electricity Act; and
(iii) the underlying commercial contracts for the individual project (PPA, interconnection/transmission services arrangements, etc).

From a bankability perspective, lenders will prioritise robust domestic licences in each jurisdiction and contracts as the primary risk-allocation instruments.

IGAs (or other equivalent G2G instruments) can materially strengthen lender comfort by providing a sovereign-level overlay. Yet, these are typically additive to, and not a substitute for the contractual package. There is an open question whether Malaysia and Singapore (and potentially Indonesia, where the proposed subsea cable would pass through) may move towards a more formal bilateral (or trilateral) framework to facilitate the import-export projects, as discussed further in *The Path to Bankability: Re-allocating Risk.*

Summary of the current risk allocation

- **Risk controlled by:** The Malaysian and Singapore Governments, but at policy level only.
- **Loss likely borne by:** ProjectCo and its lenders, as the ASEAN APG MOU is expressly non-binding and creates no claim.
- **Challenge:** Sovereign-coordination risk is currently unallocated between the two Governments.

See the full details on the current and bankable risk allocation in The Path to Bankability: Re-allocating Risk.

[39] Enhanced ASEAN Power Grid MOU endorsed at the 43rd ASEAN Ministers on Energy Meeting (AMEM), October 2025 – ASEAN / Partnerships for Infrastructure, 2025.

Subsea cable: multi-jurisdictional transit and UNCLOS framework

Within this corridor, it is expected that import into Singapore would be via a subsea transmission cable, expected to be approximately 700 km in length. Public reporting indicates that approximately **80% of the proposed route would transit Indonesian waters** (specifically the Muri–Midai corridor in the South China Sea), with the remaining approximately 20% within Malaysian and Singaporean waters.[40] Indonesia is therefore de facto a key stakeholder in relation to any import project through this corridor.

The international law framework is set by the United Nations Convention on the Law of the Sea ("**UNCLOS**"), to which Malaysia, Singapore and Indonesia are all parties. Under Articles 58, 79 and 113 of UNCLOS, States generally have the freedom to lay, maintain and repair submarine cables in the Exclusive Economic Zone ("**EEZ**") and continental shelf of another State, although the coastal State may regulate environmental aspects of activity in those areas and may require consent for the portion of the route within its territorial waters.

UNCLOS therefore provides a default legal entitlement, but it is a high-level G2G framework. Crucially, it is not a project-execution instrument: it does not set permit timelines, repair-access protocols, fee regimes or dispute mechanisms in any project-specific way.[41]

Later in this paper it is noted that **the Indonesian domestic regulatory pathway for subsea power cables remains unclear.** Regulation in this space is largely focused on telecommunications cables, and there is no purpose-built regime for subsea electricity interconnectors. While the non-binding ASEAN Guidelines for Strengthening the Resilience and Repair of Submarine Cables (updated 2026)[42] do address coordination, they are again primarily telecommunications focused. Sarawak's Premier has publicly indicated active engagement with Indonesia, including noting that discussions are proceeding "in positive spirit"[43] following diplomatic engagement at the Prime Ministerial level. The ASEAN regional context and Indonesia's own interest in regional grid integration, suggest that Indonesian consent to an electricity transmission cable through Indonesian waters for a project in this corridor is achievable. Beyond the absence of a purpose-built subsea transmission cable regime, Indonesian-water transit risk also needs to be assessed to ensure there is no Indonesia cabotage risk-exposure (see discussion on the cabotage issue later in this paper).

From a lender perspective, the subsea transmission cable is an asset exposed to multi-jurisdictional permitting, marine hazards (shipping, anchor drag, fishing, geohazards), and repair-access constraints.

Lenders can be expected to require:

- (i) **Clear, durable transit and operating permissions** in each of the three relevant jurisdictions;
- (ii) **Pre-agreed rapid-response repair protocols,** including pre-cleared maritime authority arrangements in Malaysia, Indonesia and Singapore for repair-vessel access;
- (iii) **Robust marine insurance** covering both physical damage and business interruption;
- (iv) **Realistically-sized Debt Service Reserve Accounts** ("**DSRA**") calibrated to plausible repair durations; and
- (v) Ideally, **a binding bilateral or trilateral cable protection arrangement** (whether as an extension of the 1983 Malaysia–Indonesia treaty to include Singapore, or as a new project-specific instrument) addressing route protection, repair rights, and emergency response.

[40] Sarawak–Singapore subsea HVDC interconnection (~720 km, Tondong, Sarawak to Changi, Singapore, via the Muri–Midai corridor, Indonesia) – Malay Mail, Nov 2023.
[41] United Nations Convention on the Law of the Sea (UNCLOS), 1982, Arts. 58, 79 and 113 – United Nations.
[42] ASEAN Guidelines for Strengthening Resilience and Repair of Submarine Cables (adopted Vientiane, 24 October 2019; update under the ASEAN Submarine Power Cable Development Framework in progress, 43rd AMEM 2025) – ASEAN.
[43] Premier: S'wak to begin formal talks with Indonesia on undersea power cable connection to Singapore – Borneo Post Online, October 2023

Summary of the current risk allocation

- **Risk controlled by:** The Indonesian Government principally, as the authority for EEZ consenting, transit and repair access.
- **Loss likely borne by:** ProjectCo and its insurers, as roughly 80% of the route transits the Indonesian EEZ with no treaty mechanism allocating transit risk.
- **Challenge:** Permitting delay, rather than repair time, drives the real exposure.

See the full details on the current and bankable risk allocation in The Path to Bankability: Re-allocating Risk.

Renewable Energy Certificates and environmental attributes

Under Singapore's import regulations, the delivery of RECs (or equivalent proof of renewable generation) is effectively mandatory for low-carbon import compliance. The EMA's published *Guide to Electricity Imports* requires that, for electricity imported into Singapore from low-carbon generation sources, the licensee submit relevant RECs annually to the EMA for verification, and that such RECs conform to Singapore's REC standard or an internationally recognised standard approved by the EMA. The EMA has separately announced a partnership with the I-TRACK Foundation to develop a cross-border REC framework, intended to address concerns of double counting, interoperability between national registries, and mutual recognition.

Operational continuity of the green attribute chain, rather than the underlying legality of the attribute itself, is the factor affecting bankability. If the REC chain-of-title, recognition, or retirement is disrupted (e.g. by a registry change in Malaysia, or by an evolving Singapore framework), the imported power may temporarily or permanently lose qualifying low-carbon status, which could in turn affect both pricing and the continuation of the import licence itself.

Lenders will accordingly expect to seek in the PPA (and any related attribute-transfer agreements):

(i) **Clear contractual warranties** as to issuance, transferability and absence of double counting;
(ii) **A mechanism for replacement RECs** in the event of registry or regulatory disruption;
(iii) **Auditability and traceability provisions**; and
(iv) **A clear allocation, between seller and buyer, of the risk** that the cross-border REC framework evolves over the project life.

Current risk allocation snapshot

- **Risk controlled by:** Malaysian Government (regulatory alignment) and EMA/Singapore Government (surrender obligation).
- **Loss likely borne by:** the EMA Licensee and SEB, rather than on ProjectCo directly.
- **Challenge:** Settlement-grade metering at the interconnection points should be scoped as a distinct ProjectCo obligation, rather than left to a general warranty.

See the full details on the current and bankable risk allocation in The Path to Bankability: Re-allocating Risk.

"Corporate demand is an important foundation for investment in the ASEAN Power Grid. The Cross-Border Electricity Trade REC Framework announced in 2025 marked an important step towards credible regional clean electricity trade; bilateral adoption and implementation is now the critical next step. Together with bankable projects and predictable regulation, this can help turn corporate demand into long-term investment across Southeast Asia."

— Asia Clean Energy Coalition

Dispute resolution

There is currently no defined dispute resolution framework specifically regulating disputes across the project interface. Given the cross-border nature of the corridor, no single domestic court has jurisdiction over all aspects, and international arbitration is the natural and bankable default. Both Malaysia and Singapore are parties to the 1958 New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards, and both jurisdictions have well-developed arbitration legislation and pro-arbitration judicial practice.

Disputes are likely to fall into two categories: (a) **commercial / contractual disputes** (for example, disagreements between exporters and importers on PPA or interconnection agreement interpretation, payment, or performance, or between the interconnector co-developers); and (b) **sovereign or regulatory disputes** (for example, where government action affects the project).

Lenders are likely to require:

(i) **Arbitration as the standard dispute resolution mechanism** across the PPA, any interconnection agreement, EPC and O&M contracts and finance documents. The Singapore International Arbitration Centre ("**SIAC**") is the natural primary forum. The International Chamber of Commerce ("**ICC**") or other regional or international arbitral body may be acceptable as an alternative if a more neutral institutional venue is preferred;

(ii) **Express waiver of sovereign immunity** in the project contracts (including in respect of jurisdiction, suit and execution) by State-owned or State-affiliated counterparties;

(iii) **Direct agreements** between lenders, the project company, and key counterparties (in particular the exporter and the offtaker), providing for lender step-in rights, cure periods, and protection against premature termination of the PPA or interconnection agreement in the event of SPV default; and

(iv) **State-to-State dispute resolution** under any future IGA, with appropriate recourse to international arbitration.

Current risk allocation snapshot

- **Risk controlled by:** SEB, as the State-owned counterparty.
- **Loss likely borne by:** ProjectCo and its lenders, as enforcement risk sits with whoever must enforce.
- **Challenge:** This exposure will remain unless SEB expressly waives sovereign immunity from suit and execution.

See the full details on the current and bankable risk allocation in The Path to Bankability: Re-allocating Risk.

Force majeure

Force majeure is not defined in the Ordinance and is therefore **expected to be addressed contractually.** The principal force majeure risks in this corridor are:

(i) Hydrology risk affecting the hydropower generation resource (e.g. severe drought scenarios may materially reduce generation output, even in the absence of any physical fault);
(ii) Prolonged subsea transmission cable faults – given the cable's length and depth, faults may require substantial time to repair, depending on weather windows and repair vessel availability; and
(iii) More conventional disaster, war, sanctions and infrastructure-attack scenarios.

The natural bankable response from lenders is a tightly defined force majeure clause with back-to-back relief across the project supply chain, well-sized DSRA calibrated to realistic outage and repair scenarios, and comprehensive physical damage and business interruption insurance. Critically, contractual protections should contain debt-protective compensation, if prolonged force majeure triggers termination of the PPA or interconnection agreement. Hydrology risk should be addressed both at the structural level (e.g. resource study, diversification of generation, reservoir management commitments by the exporter), and at the contractual level (e.g. allocation of hydrology risk between seller and buyer, with reference to historical resource data and any backup arrangements).

Current risk allocation snapshot

- **Risk controlled by:**
  - For natural events, no single party controls this risk, as it arises mainly from physical events and third-party interference beyond any one party's control.
  - For political events, the Malaysian, Indonesian (for cable transit) and Singaporean governments.
- **Loss likely borne by:**
  - For natural events, ProjectCo, with limited insurance coverage.
  - On the political limb, the loss also falls on ProjectCo, as the host governments are not party to contractual structures under which they can be allocated political risk.
- **Challenge:** For ProjectCo's own asset, the insurance coverage is weak. Political force majeure, including denial of repair access, are not appropriately allocated.

See the full details on the current and bankable risk allocation in The Path to Bankability: Re-allocating Risk.

Indonesian Legal and Regulations

The Singapore–Indonesia corridor is legally more complex than the Sarawak–Singapore corridor in several important respects. Electricity in Indonesia is constitutionally protected as a natural resource that "*shall be controlled by the State and utilised for the greatest benefit of the people*", with implementing legislation (the Energy Law and Government Regulation 40/2025 on the National Energy Policy (**GR 40/2025**)) operationalising that constitutional principle.[44] **The combined effect is that currently, export is legally permissible, with the State retaining significant discretion over whether, when, how, and on what conditions the export occurs.** The discussion below sets out the principal legal findings under the existing framework, organised by the issues most material to lender credit analysis and project structuring.

Export policy and licensing: what is PLN's role

Under Indonesia's Government Regulation No. 40 of 2025 on National Energy Policy (GR 40/2025), cross-border electricity exports may only be undertaken by the state-owned electricity company of the exporting country – in Indonesia's case, PT PLN (Persero) ("**PLN**") – or by a business entity expressly **appointed to represent the Government of Indonesia**. GR 40/2025 does not prescribe the form of that appointment, the issuing authority or the qualifying criteria, and no implementing regulation has been issued. A project company importing under an EMA licence is unlikely to be designated as representing the Government of Indonesia – but in any event, the legal basis and durability of any designation (and which entity will take this role) is a key structuring question. In this regard, following the Singapore-Indonesia Leaders Retreat in July 2026, the Indonesian Government is reported to have expressed stronger policy support by designating Danantara Indonesia (through its investment arm Danantara Investment Management) to spearhead cross-border electricity trade between Singapore and Indonesia.[45] *[At the time of writing, further details of the how this will be implemented from a regulatory perspective are awaited.]*

Private generators are currently not permitted under Indonesian law to export electricity directly to foreign offtakers.[46] While this regulation confirms that electricity exports are legally permissible, it entrenches State control, and positions PLN (or any other Government-appointed entity) as the mandatory intermediary for any Singapore-bound export project. While noting the designation of Danantara Investment Management as a potential exporter per the recent government announcements, the applicable regulatory regime to support this development is not yet clear. There are reasonable expectations that licences will be issued to enable foreign-owned generators to export electricity, but what that regime looks like is not yet clear, with no regulatory framework in place.

The structural implication is that, currently, a project in the Indonesia-Singapore corridor cannot create a clear "foreign owned generator-to-Singapore offtaker" contractual chain for export revenues.

If no clear regulatory solution enabling private sector generation for export emerges, export cashflows are structurally mediated through PLN (or potentially Danantara). This means that project operational performance and Singapore demand are not the sole determinants of revenue for the project. From a lender perspective, they will need to underwrite PLN/Danantara actions as much as asset performance. This in turn may affect debt quantum and pricing relative to a direct-offtake structure.

[44] Article 33, 1945 Constitution of the Republic of Indonesia; Energy Law (Law No. 30 of 2007); National Energy Policy under Government Regulation No. 40 of 2025 – Government of Indonesia.
[45] MTI & Danantara Indonesia Affirm Commitment to Expedite Cross-Border Electricity Trade Between Singapore and Indonesia – Danantara Indonesia, 6 Jul 2025
[46] Government Regulation No. 40 of 2025 on the National Energy Policy – cross-border power trading to be conducted exclusively through PLN or a government-appointed entity – ABNR Counsellors at Law, 2025.

Security over export receivables is notably likely to be more complex if the payer is a State intermediary. Contractual structures will need to convert this exposure into (i) payment security (whether by way of letters of credit, escrow, or step-in protection) and/or (ii) State-backed compensation for any government action that interrupts the project.

Current risk allocation snapshot

- **Risk controlled by:** The Indonesian Government.
- **Loss likely borne by:** ProjectCo, as private generators currently cannot export directly.
- **Challenge:** Absent PLN intermediation, there is no lawful counterparty for export-leg revenue risk.

See the full details on the current and bankable risk allocation in The Path to Bankability: Re-allocating Risk.

PLN grid and dispatch / curtailment exposure

The Indonesia-side structuring has not yet been finalised for this corridor. PLN approval is required for off-grid generation-export and any transmission through the national grid requires PLN's participation by law. As with the right to export, there are reasonable expectations that PLN will approve off-grid generation-export into Singapore.

Policy statements from the Indonesian National Energy Council indicate that **electricity exports are expected to utilise PLN-owned transmission infrastructure, thus allowing the Indonesian Government to preserve domestic energy security and to redirect power during periods of shortage where required.** While not yet comprehensively codified, this approach is consistent with the existing State-control framework under GR 40/2025.[47]

Any lender concerns for this corridor are therefore likely to focus principally on dispatch and curtailment risk, especially where PLN's grid is involved. Even if the export project generates power, export may be curtailed for system priorities and grid constraints determined by PLN, with the amount of delivered electricity dependent on PLN's operational decisions rather than purely on project availability. **Disputes about curtailment in such a context become regulatory and political rather than purely contractual, and are harder to remedy through normal commercial enforcement.**

Unless the risk of curtailment can be mitigated through a change in regulations (even if only specifically in relation to export projects), bankability will require curtailment to be treated as a form of compensated government action (whether by way of deemed energy or availability-style payments), failing which lenders will typically discount projected cashflows materially and require larger liquidity buffers.

Current risk allocation snapshot

- **Risk controlled by:** PLN as dispatcher (under current regulations), subject to confirmation of its involvement in the corridor.
- **Loss likely borne by:** ProjectCo, as PLN has no obligation to compensate curtailment and domestic prioritisation makes curtailment lawful.
- **Challenge:** This risk defaults to ProjectCo absent a robust exemption.

See the full details on the current and bankable risk allocation in The Path to Bankability: Re-allocating Risk.

[47] Inside Indonesia's first renewable power export – National Energy Council guidance that exports utilise PLN-owned transmission to preserve domestic energy security – Reccessary, Jan 2026.

Export licence duration: the five-year statutory cap

A five-year export licence limit is structurally embedded in Indonesia's current electricity framework. Its origin lies in Government Regulation 42/2012 on Cross-Border Electricity Trade (issued under Law 30/2009, the Electricity Law), and it is restated in MEMR Regulation 11/2021 on the Implementation of Electricity Business (Article 37) as part of the consolidated licensing regime.[48] Subsequent national energy policy instruments reaffirm State discretion but do not remove or soften the statutory five-year cap. Presidential Decree No. 4 of 2025 on the 2025 Government Regulation Drafting Programme (PD 4/2025) proposes to introduce legislative changes that may impact electricity export projects. While details are not yet clear, these may include amendments to existing regulations, to enable an extension of the licence term. Notably, PD 4/2025 contemplates legislative changes to regulations that also relate to internal domestic market obligations and also intend to optimise State benefit from the export of electricity. Accordingly, the benefit (if any) of proposed regulatory changes to electricity generators/exporters, is not yet clear.

Recent press reports indicate that a letter of comfort mechanism may be introduced under new National Energy Policy technical guidelines, subject to performance compliance and a 20% DMO[49]. While details have not yet been provided, the legal value of any such letter of comfort would be limited, as these are generally not perceived as enforceable contracts nor comparable to the reassurance given under a guarantee.

As such, export licence duration is one of the key risks for this corridor. **A five-year licence term is fundamentally misaligned with limited-recourse financing with a 20–30-year loan tenor and poses a significant challenge to bankability. Lenders will require, as a condition of any financing, that the export licences have a duration longer than the debt tenor, with mechanisms that provide protection against early termination of the licence (including for non-performance by the exporter).**

Case Study: Export Licence Duration — Nam Theun 2 (Laos–Thailand)[50 51 52]

The Case and the Issue

Nam Theun 2 is a 1,070 MW hydroelectric dam in Laos PDR. Power generated is used domestically, with majority exported to Thailand. It reached financial close in 2005.

The Government of Lao PDR's standalone domestic licensing framework could not provide the contractual stability that a US$ 1.58 billion limited-recourse financing required. Generic export and generation licences in emerging market jurisdictions are typically short-dated, revocable, and subject to renewal at regulatory discretion — none of which commercial or development finance lenders can underwrite against. With 27 financing parties involved, including the World Bank, ADB, and a suite of export credit agencies and commercial banks, the project required a rights framework whose duration and enforceability were entirely insulated from the domestic licence renewal cycle.

How It Was Resolved

The licence tenor problem was addressed by displacing it with a long-dated concession agreement signed directly at the sovereign level. A 25-year BOOT Concession Agreement between the Government of Lao PDR and Nam Theun 2 Power Company (NTPC) granted exclusive rights to develop, operate and export electricity for the full financing tenor, providing the contractual anchor that lenders underwrote against in lieu of the domestic licence. This was reinforced by World Bank Partial Risk Guarantees and US$ 91 million of MIGA political risk cover backstopping the commercial

[48] Government Regulation No. 42 of 2012 on Cross-Border Electricity Trade (issued under Law No. 30 of 2009 on Electricity); MEMR Regulation No. 11 of 2021, Art. 37 – Global Legal Insights, Energy Laws and Regulations: Indonesia, 2026.
[49] TBS Energi's Singapore power export halted by licensing uncertainty – Indonesia Business Post, 12 March 2017
[50] Nam Theun 2 Project Overview – Nov 2019, World Bank
[51] Nam Theun 2 (NT2) Hydroelectric Project – PPIAF
[52] Nam Theun 2 – Finance package – Apr 2008, International Water Power & Dam Construction

debt, and a take-or-pay PPA with the Electricity Generating Authority of Thailand for 25 years coterminous with the concession, with tariff denominated in both US$ and Thai Baht to match debt service currency. The concession term exceeded the debt tenor, meaning lenders were not exposed to licence renewal or rollover risk at any point during the financing period.

Relevance to the Indonesia-Singapore and Sarawak-Singapore Corridors

The Nam Theun 2 precedent is instructive for both import corridors. Indonesia's export licence framework under GR 40/2025 issues export licences on terms that do not match the tenors for long-term project financing needed for these projects, and lenders will not accept rollover risk on a licence that can be withheld, conditioned or lapsed at renewal. The NT2 template points to a potential solution in the absence of any amendment to the regulatory regime to address the issue: a long-dated Concession Agreement or Business Cooperation Agreement ("**BCA**") with the Indonesian State granting project-level export rights to the exporter for the full financing tenor, displacing reliance on the current short-dated export licence as the primary rights document. The benefit of this structure is that the risk of non-renewal or extension of the export licence can be passed to the Indonesian State, with appropriate compensation mechanics being available if non-renewal subsequently occurs during the financing period. Where a full concession contractual structure is not achievable, lenders will likely require an Indonesian Government issued guarantee with binding renewal and termination compensation mechanics, and debt amortisation sized to the confirmed licence horizon.

The Sarawak corridor faces an analogous issue. Export authorisations under the Sarawak Electricity Ordinance are for an undefined duration, and governmental immunity provisions for licence suspension or revocation must be addressed directly in the concession or export agreement, before lenders will underwrite project revenue risk on a limited-recourse basis.

Current risk allocation snapshot

- **Risk controlled by:** The Indonesian Government, through MEMR.
- **Loss likely borne by:** ProjectCo, as the five-year statutory cap cannot lawfully be bound to renewal by any counterparty.
- **Challenge:** This exposure fundamentally cannot be hedged, and is the primary bankability blocker for this corridor.

See the full details on the current and bankable risk allocation in The Path to Bankability: Re-allocating Risk.

Singapore import policy and the Singapore-Indonesia MOUs

Electricity imports into Singapore from Indonesia require EMA licensing and must comply with the same stringent low-carbon, technical and reliability requirements discussed in respect of the Sarawak corridor. Indonesia has indicated that green electricity exports to Singapore may be contingent on reciprocal benefits, although the nature of such benefits has not yet been clarified or codified.

In June 2025, three MOUs were signed between Singapore and Indonesia. Of particular relevance is the **MOU on Cross-Border Electricity Trade ("CBET")**[53], which records the intention of Singapore's Ministry of Trade and Industry ("**MTI**") and Indonesia's Ministry of Energy and Mineral Resources ("**MEMR**") to develop the necessary policies, regulatory

[53] Singapore and Indonesia sign three MOUs on Cross-Border Electricity Trade, Carbon Capture & Storage, and a Sustainable Industrial Zone (13 June 2025) – Rajah & Tann Asia, Jun 2025.

frameworks and business arrangements for CBET **within 12 months** of the signing of the MOU.

In July 2026, further MOUs were signed alongside the Singapore-Indonesia Leaders Retreat. Of note, both countries reaffirmed their commitment to strengthen and expedite cooperation in CBET, with Indonesia designating Danantara Indonesia to spearhead CBET between Singapore and Indonesia.[54] In this regard, Danantara Indonesia, through its investment arm, Danantara Infrastructure Management, signed MOUs with Keppel Electric and Sembcorp Utilities regarding potential collaboration on the offtake of imported low-carbon electricity, and a further MOU with Singapore Energy Interconnections to facilitate information-sharing and potential collaboration on commercial and technical issues relating to cross-border interconnector development. Both Governments agreed to support these projects by developing their respective regulatory frameworks, policies and requirements relevant to cross-border electricity trade, including the enabling conditions for investment.

The 2025 and 2026 MOUs reflect strong political commitment, but the MOUs are non-binding and do not in themselves create enforceable rights. There has been no public clarity as yet on the substantive content or timing of the regulatory framework that is expected to be developed, which will be critical to creating the regulatory certainty necessary for supporting the bankability of import projects in this corridor.

From a bankability perspective, project viability under this corridor heavily depends on regulatory alignment across both jurisdictions, and timing risk arises if project development and financing milestones outpace the implementation of any CBET-enabling regulations.

Lenders are likely to treat this corridor's cross-border "two-regulator dependency" as a heightened completion risk and will treat receipt of a bankable import licence and satisfaction of the conditions attaching to such licence as a condition precedent to financial close.

Current risk allocation snapshot

- **Risk controlled by:** EMA and the Singapore Government, together with the Indonesian Government, though their approval pathways are not synchronised.
- **Loss likely borne by:** The EMA Licensee, as Singapore-side approvals may lapse before the Indonesian framework is developed.
- **Challenge:** This timing mismatch is owned by no party today, and is priced by lenders as completion risk.

See the full details on the current and bankable risk allocation in The Path to Bankability: Re-allocating Risk.

[54] Joint Media Statement, MTI & Danantara Indonesia Affirm Commitment To Expedite Crossborder Electricity Trade Between Singapore And Indonesia – MTI, July 2026

Indonesian Local Content Requirements (TKDN)

GR 40/2025 does not, of itself, create new standalone local content ("**Tingkat Komponen Dalam Negeri**" or "**TKDN**") obligations. It does, however, elevate domestic value creation and national supply-chain prioritisation to the level of the National Energy Policy, consolidating and strengthening the interpretive weight of existing instruments. The most material binding instrument is MEMR Regulation 11/2024[55] on the use of domestic products in electricity infrastructure, operating alongside Indonesia's carbon policy framework (originally Presidential Regulation 98/2021, continued under Presidential Regulation 110/2025). GR 40/2025 itself is policy-level, but it shapes how regulators exercise discretion under these binding regimes, particularly for sensitive or strategic projects.

For cross-border transmission and export-oriented projects supplying Singapore, the policy elevation translates into heightened regulatory and execution risk rather than new black-letter rules. **Developers and lenders supporting them should reasonably anticipate local content considerations to extend beyond generation into transmission and interconnection infrastructure,** covering Indonesian participation in engineering design, EPC roles, workforce deployment, and where feasible domestic sourcing of components. While MEMR 11/2024 permits some flexibility (including potential TKDN relief for projects substantially financed by foreign Development Finance Institutions ("**DFIs**") as well as some carve outs for electricity export), the position for exporting generation and transmission infrastructure is still unclear and underdeveloped, and GR 40/2025 increases the likelihood that such flexibility is applied conservatively in cross-border export scenarios.

Potential bankability consequences include increased capex (particularly for subsea cable components where local supply capacity is limited), schedule extension risk, and contracting complexity (with TKDN obligations needing to be allocated explicitly into EPC and supply contracts). **Lenders will likely require a clear procurement strategy demonstrating TKDN feasibility as part of the credit assessment process and may defer financial close until this is evidenced satisfactorily.** Where domestic supply is genuinely unavailable (as seems to be the case at present), a legal bilateral framework recognising calibrated TKDN flexibility for the export corridor would materially de-risk construction. In the absence of such a framework, sponsors (and supporting lenders) should expect a phased, realistic TKDN compliance strategy and price the residual risk into the EPC contract structure.

Case Study: Hululais Geothermal, TKDN as a DFI Financing Block[56]

The regulatory conflict

The Hululais project is a 110MW geothermal project in Indonesia, Bengkulu Province. The Japan International Cooperation Agency ("**JICA**") provided an Official Development Assistance ("**ODA**") loan for the project.

This project provides the clearest example of TKDN operating as a hard financing barrier. JICA's consideration of ODA loan financing for the project as early as 2015 was abandoned because Indonesia's then-applicable 33% TKDN threshold was structurally incompatible with JICA's multilateral procurement guidelines, which require open international competitive tendering. Satisfying Indonesian domestic content law would have disqualified JICA financing, and vice versa; an impasse that no EPC-level contract drafting could resolve.

The regulatory resolution

The blockage persisted for nearly a decade until MEMR Regulation 11/2024 introduced a material carve-out: TKDN requirements do not apply to projects funded by offshore grants or loans where at least 50% of funds derive from a multilateral or bilateral creditor, with the loan agreement's own procurement terms governing in lieu of domestic TKDN thresholds. TKDN for geothermal projects was also reduced to 24% for projects at or below 60 MW and 29% for projects above 60 MW, further improving the investment case.

[55] MEMR Regulation No. 11 of 2024 on the use of domestic products in electricity infrastructure (including the ≥50% DFI/multilateral-financing local-content exemption) – Hogan Lovells Cadwalader, 2024.
[56] JICA signs loan agreement to support Hululais geothermal project in Indonesia – Think Geoenergy, March 2026

The outcome

The MEMR Reg 11/2024 exemption directly unblocked DFI participation. JICA executed a JPY 29.16 billion ODA loan for Hululais in March 2026 at an interest rate of 0.3%, with a 30-year repayment period including a 10-year grace period, with PT PLN as executing agency and PT Pertamina Geothermal Energy ("**PGE**") responsible for steam field development.

Corridor implication

For generation projects in the Indonesia-Singapore corridor contemplating DFI or bilateral co-financing, parties must confirm at term sheet stage that the MEMR Reg 11/2024 exemption is properly engaged, that the financing plan satisfies the ≥50% bilateral or multilateral threshold, and that the TKDN treatment is reflected explicitly in the PPA. PLN's incorporation of TKDN compliance obligations into PPA terms has historically varied and the practice under the new regime has yet to be established under the current administration. Where a cross-border export overlay applies, including any eventual binding regulation implementing the 60% TKDN signal for Singapore-bound electricity[57], this must be stress-tested against the exemption's scope before financial close.

Current risk allocation snapshot

- **Risk controlled by:** The Indonesian Government under the TKDN regime.
- **Loss likely borne by:** ProjectCo and its EPC contractor, as limited Indonesian equipment supply capacity creates schedule and capital cost risk.
- **Challenge:** This risk reaches lenders via completion risk.

See the full details on the current and bankable risk allocation in The Path to Bankability: Re-allocating Risk.

Constitutional and statutory Domestic Market Obligation

Energy and natural resources in Indonesia are a constitutional matter. Article 33 of the 1945 Constitution[58] mandates that natural resources, including energy, are controlled by the State and utilised for the greatest benefit of the people. The Energy Law (Law 30/2007) operationalises this principle, treating energy as a strategic national asset and requiring that energy management (covering supply, utilisation and commercialisation) prioritise fairness, sustainability, and national resilience. The National Energy Policy ("**KEN**") is established by Government Regulation (GR 40/2025), and forms the binding policy framework for downstream regulation and planning.

GR 40/2025 expressly provides that cross-border exports of electricity may be carried out while "*prioritising the fulfilment of local electricity needs*", and only to improve efficiency, reliability and energy supply security. Combined with the requirement that cross-border export and import be conducted by PLN (or a business entity appointed to represent the State), the result is a regime under which **export rights are conditional, revocable, and system-dependent, not proprietary.** This may change if a statutory framework later creates a clear and reliable exception to that requirement. Export is legally framed as the monetisation of surplus capacity, and what constitutes surplus is defined by State-approved planning assumptions, not by the existence of foreign offtake commitments.

[57] Indonesia to export power plant to Singapore, Demands 60% domestic component ratio – Indonesia Business Post, Sept 2023
[58] Article 33 of the 1945 Constitution of the Republic of Indonesia; Energy Law (Law No. 30 of 2007), operationalising State control over energy as a strategic national asset – Government of Indonesia.

The bankability consequence is structurally significant: under the current statutory regime, **export volumes may be lawfully curtailed or reallocated in circumstances that would not constitute a "breach" in the conventional contractual sense,** exposing the project to lawful sovereign action risk, impacting revenue even where the plant is fully performing.

Lenders will therefore not treat export revenues as fully contractable unless government-directed curtailment triggers compensation sufficient to protect debt service. This issue is a key driver of elevated lender risk-scoring in this corridor and represents a central structural challenge that must be resolved.

Case study: Norway interconnectors (North Sea Link, NordLink, NorthConnect)

The Case and the Issue

Norway provides a relevant precedent for lawful sovereign curtailment of cross-border electricity exports in the name of domestic energy security. Norway holds mature, treaty-grade energy relationships with the United Kingdom and Germany: (1) The North Sea Link (NSL), a 1,400 MW interconnector jointly owned by Statnett and the UK's National Grid, had been operational since October 2021; (2) NordLink, a 1,400 MW Norway-Germany interconnector had been operational since December 2020. Despite this maturity, the Norwegian Government exercised its reserved sovereign powers under the existing Norwegian licence framework to curtail Norwegian export capacity when domestic supply conditions tightened that year.

In March 2023, Statnett reduced NSL's export capacity from its installed 1,400 MW to 1,100 MW in both directions, citing the need to ensure balanced capacity and domestic energy security following low reservoir levels and elevated domestic electricity prices in southern Norway. **The curtailment was entirely lawful, and no contractual breach was involved.** NSL's licence expressly preserved the Norwegian Ministry of Petroleum and Energy's power to direct Statnett on capacity allocation.

How It Was Resolved

In NSL's case, the capacity reduction was absorbed in significant part because of the Ofgem cap-and-floor regulatory regime on the UK side. NSL is regulated under Ofgem's 25-year cap-and-floor regime, which applies to National Grid's 50% share of the interconnector's costs and revenues. The regime sets a floor (determined at approximately GBP59.2 million per year in 2015/16 prices at Post Construction Review) below which Ofgem tops up the interconnector's revenues via the GB System Operator, and a cap (approximately GBP93.1 million per year) above which excess revenues are returned to UK consumers. The floor mechanism meant that National Grid Ventures, as the GB-side owner, was insulated from the full revenue impact of the curtailment. As a result, its downside exposure was structurally limited. The Norwegian curtailment was therefore absorbed as a reduction in gross revenues without triggering an investor compensation claim, as the cap-and-floor regime was designed precisely to absorb revenue variability (whether from market conditions, maintenance, or regulatory capacity restriction) without converting that variability into a host-State liability. The NorthConnect refusal, by contrast, produced no compensation at all, it was a pre-FID project-level risk crystallisation, not a post-FID curtailment, confirming that pre-construction political risk sits outside any regulatory mitigation framework **unless explicitly addressed by guarantee or treaty.**

Relevance to the Indonesia-Singapore and Sarawak-Singapore Export Corridors

The exercise by Norway of its curtailment rights highlights the Domestic Market Obligation / lawful curtailment risk in both the Indonesian and Malaysia (Sarawak) corridors. Indonesia has codified the same residual State right that Norway exercised under its government licence framework: the sovereign right to restrict or curtail electricity exports where domestic energy security requires it, exercisable without constituting a breach of contract or triggering compensation under the generation licence alone. A key takeaway and lesson which is directly applicable to the APG is that curtailment risk can be anticipated and accommodated within the licence and regulatory frameworks to avoid an investor compensation claim.

Three structuring responses follow:

1. First, the NSL cap-and-floor model could be considered as a revenue stabilisation architecture **for the Sarawak-Singapore interconnector**, whether as an EMA-administered mechanism on the Singapore import side or a bilateral regulatory floor mechanism negotiated between the relevant TSOs, giving lenders a bankable revenue floor independent of actual dispatch.
2. Second, **for the Indonesia-Singapore generation corridor**, where a full cap-and-floor regime is unlikely in the near term, the functional equivalent is an availability-based or deemed-energy revenue mechanic in the PPA, ring-fencing debt service from sovereign curtailment decisions.
3. Third, the NorthConnect refusal is a **direct warning for both corridors**: a host State's licensing power can be exercised to refuse or suspend export capacity before FID even where bilateral political support exists and counterpart-side approvals have been secured. While pre-FID risks will be less relevant considerations for lenders (since financing would not occur pre-FID), they represent significant risks to sponsors and developers who will incur substantial pre-FID investment.

Mitigation requires appropriate commitments at a G2G level, binding contractual protections by way of a concession agreement or BCA with the Indonesian State, and (likely) MIGA / ADB or other multilateral political risk cover.

Current risk allocation snapshot

- **Risk controlled by:** Indonesian Government, under the constitutional and statutory domestic market obligation.
- **Loss likely borne by:** ProjectCo, as no counterparty can override constitutional priority.
- **Challenge:** Lenders absorb this risk through a leverage haircut and pricing adjustment.

See the full details on the current and bankable risk allocation in The Path to Bankability: Re-allocating Risk.

Land rights for generation and transmission assets

In practice, foreign-backed power developers (including Singapore electricity import licensees) can obtain long-term land rights for generation assets in Indonesia. This is a well-established structure for power plants, and is generally bankable. Land rights for transmission corridors are materially more complex, however, because Indonesia does not recognise a single registrable easement or right-of-way regime in the common law sense. **Transmission routes are typically assembled through a combination of administrative land-use rights over State or public land, contractual arrangements with private landholders, and most importantly in practice formal designation of the infrastructure as serving a public interest.**

Under the current statutory framework, PLN's involvement is mandatory, given the constitutional requirement that electricity be controlled by the State. Where **transmission assets are planned, owned, or controlled by PLN, land acquisition and corridor access become significantly easier,** as the project can rely on State land, grants over State-owned land, and public-interest land acquisition mechanisms (it is not yet clear whether Danantara might enjoy or benefit from similar rights as a result of its designated role in power export projects, described earlier). However, while PLN's involvement can help with land access, it may also introduce other bankability concerns discussed elsewhere in this analysis (e.g. counterparty risk).

In any event, lenders will require demonstrable, durable land access rights as a condition precedent and where land rights depend on PLN or public-interest designation, direct agreements with PLN and the relevant land authorities will be expected.

Current risk allocation snapshot

- **Risk controlled by:** The Indonesian Government and PLN, through public-interest designation.
- **Loss likely borne by:** ProjectCo, as without PLN there is no mechanism to assemble the route at scale.
- **Challenge:** PLN's absence from the project structure is itself the risk.

See the full details on the current and bankable risk allocation in The Path to Bankability: Re-allocating Risk.

Change in law, nationalisation and stabilisation

Large and capital-intensive projects require (and assume) a stable legal environment. Without this, it is extremely difficult for project developers and their lenders to assess the likely risks and contingencies over the project lifespan. For this reason, it is very common for governments to provide such long-term certainty by way of agreed stabilisation regimes (termed so because they commit to the preservation of stable legal and regulatory frameworks for the project duration). Stabilisation does not preclude a State reserving its sovereign right to make, repeal or amend laws in its jurisdiction, but the stabilisation regime will provide relief from the effects of adverse changes to the legal and regulatory framework. Stabilisation regimes may be specified in legislation or by way of contract (e.g. in a BCA or concession agreement).

There is currently no Indonesia–Singapore corridor-specific stabilisation regime, and no export-focused investment protection treaty addressing electricity exports. Change-in-law risk therefore remains largely unmitigated at the statutory level. Given the constitutional framing of energy as a strategic national asset and the explicit prioritisation of domestic supply, the current regulatory framework appears to preserve regulatory flexibility, potentially extending to changes in law or, in an extreme scenario, nationalisation when the State considers this to be in the national interest.

Plausible downside risk scenarios for a project in this corridor may include:

- Changes to tariffs or pricing rules affecting export economics;
- Changes to export permissions or volume entitlements;
- Changes to ownership structures or licensing criteria;
- New foreign exchange controls affecting cross-border payments; and
- In extreme but credible cases, forced restructuring of ownership or control.

While some of these may seem extreme, the sizeable scale export-import projects in this corridor would mean that these risks are unlikely to be considered exaggerated by lenders who are contemplating participating in any financing.

Lenders will expect these risks to be meaningfully addressed via:
(i) **Contractual compensation regimes** (change-in-law pass-through and termination compensation); and/or
(ii) **Political risk insurance** (including MIGA/ADB cover or comparable products).

Changes-in-law that impair cashflows are core threats to debt service continuity, and Indonesia-Singapore corridor project structures must address this risk directly through both contract and insurance, and where possible through the protections of an IGA or a Government Support Agreement ("**GSA**").

Current risk allocation snapshot

- **Risk controlled by:** The Indonesian Government.
- **Loss likely borne by:** ProjectCo, as there is no stabilisation regime and the Constitution expressly preserves State flexibility, including nationalisation.
- **Challenge:** This risk is currently unallocated.

See the full details on the current and bankable risk allocation in The Path to Bankability: Re-allocating Risk.

Intergovernmental framework and the Indonesia–Singapore Bilateral Investment Treaty (BIT)

There are currently no binding intergovernmental agreements in place that expressly address electricity export, import or underlying facilities between Indonesia and Singapore. Singapore–Indonesia electricity cooperation is presently underpinned by policy-level MOUs rather than binding treaties or intergovernmental agreements — most notably the June 2025 MOU on CBET Trade, together with related MOUs on renewable energy cooperation and sustainable industrial zones. These instruments provide valuable political endorsement and a framework for regulatory coordination, and have been routinely cited by regulators when granting conditional import licences (on the Singapore side) and supporting export-oriented renewable projects (on the Indonesian side). However, they do not confer enforceable rights, stabilisation protections, guaranteed export volumes, or pricing certainty.

Singapore and Indonesia are parties to the Agreement on the Promotion and Protection of Investments signed on 11 October 2018, which entered into force on 9 March 2021 (the Indonesia–Singapore BIT).[59] The BIT is a meaningful sovereign-risk overlay, but should be viewed as a backstop of last resort for projects in this corridor, not a primary

[59] Singapore-Indonesia Bilateral Investment Treaty – Ministry of Trade and Industry, Singapore.

risk-mitigation tool. It contains significant carve-outs and explicit affirmations of each State's right to regulate for legitimate public policy objectives (including energy security, environmental protection, and the public interest), which materially limit its capacity to restrain policy change in sectors like electricity export and transmission. While the BIT may support sovereign-risk analysis or extreme downside protection, it does not materially enhance day-to-day bankability of Indonesia–Singapore power or interconnection projects.

A summary of the key features and differences between GSAs, IGAs and the BIT is set out below.

Model	Government Support Agreement (GSA)	Intergovernmental Agreement (IGA)	Bilateral Investment Treatment (BIT)
What It is	• Contract between the project SPV and the exporting country government (Indonesia / Malaysia) • Exporting country government covenants directly to the SPV	• Agreement between Singapore and the exporting sovereign (Indonesia / Malaysia) — only governments can negotiate this • Protects designated companies / projects	• Pre-existing BIT between Singapore and Indonesia • Protects against: expropriation (direct and indirect); discriminatory treatment; denial of justice; and arbitrary or unreasonable measures
Advantages	• Speed - no bilateral diplomatic process required • Can be negotiated and signed during project development • Provides direct project-level bankability protections lenders can rely upon	• Addresses what a GSA cannot: Exclusive Economic Zone / cable corridor rights, cross-border REC recognition, state-to-state enforceability • Can incorporate all GSA-level project commitments • Can address EEZ access even if a broader IGA is not yet in place	• Already in force • Useful mitigant against outright expropriation or nationalisation of project assets
Critical Gaps	• Enforceability depends on exporting-country domestic law — no international law backstop • Cannot grant Exclusive Economic Zone (EEZ) rights, cable corridor access, or cross-border REC recognition — these require State-to-State agreement • No Singapore government backstop: private importer SPV stands alone if the GSA fails	• Requires bilateral diplomatic process — timeline may not align with project development • Political will on both sides is essential — either State's reluctance can stall the project	• Does not guarantee export licence continuity, curtailment compensation, or cable corridor access • Does not protect against general regulatory change (e.g. DMO imposition, LCR expansion) that falls short of expropriation • BITs are a backstop, not a substitute: project-specific GSA and/or IGA protections are still required for bankability

Table 8: Summary of key features and differences between GSA, IGA and BIT

Until a legally binding framework is developed, financing must rely on domestic instruments: Indonesian licences (including export approvals under GR 40/2025), long-term PPAs or offtake arrangements with PLN, interconnection agreements, and typical risk allocation through change in law, government action and termination compensation regimes. Purely private, export-driven projects without PLN support or other Indonesian SOE involvement will likely, without intergovernmental support, face heightened bankability risk, as there is no treaty-level or IGA, or any government-level protection against changes in law, domestic-priority re-allocation, or shifts in export policy.

Current risk allocation snapshot

- **Risk controlled by:** The Indonesian and Singapore Governments.
- **Loss likely borne by:** ProjectCo, as the CBET MOU is non-binding and the BIT carries broad carve-outs.
- **Challenge:** Sovereign risk remains unallocated beyond the equity cushion.

See the full details on the current and bankable risk allocation in The Path to Bankability: Re-allocating Risk.

Subsea cables: a regulatory gap

As noted earlier in this paper, the regulatory pathway for subsea power cables remains unclear. UNCLOS governs subsea cables at the international level, and Indonesian domestic regulation focuses primarily on telecommunications cables. The Guidelines for Strengthening the Resilience and Repair of Submarine Cables (updated in 2026) are non-binding and oriented toward telecommunications cables. There is no ASEAN-level treaty, and currently, no Singapore–Indonesia bilateral treaty or IGA, that specifically governs subsea electricity interconnectors, including route protection, regulatory stabilisation, cross-border dispatch or priority access during construction and operations. The June 2025 Singapore–Indonesia MOUs do not contain subsea-specific legal protections or considerations.

From a financing perspective, subsea power cables therefore sit within a crucial legal gap. They are clearly lawful under international law, but with limited tangible protection under domestic law. Private parties have limited practical recourse through UNCLOS, ASEAN guidelines, or general cable conventions when assessing or underwriting subsea power-cable risk. In the absence of a binding bilateral interconnector treaty or a government support agreement, subsea electricity transmission cables in this corridor carry significant risk. **This gap gives rise to ambiguity in multi-agency permitting, constraints on repair access, and the risk of prolonged outages without timely remediation. These risks must be addressed through clear project documentation, supported by a robust intergovernmental regulatory regime.**

Current risk allocation snapshot

- **Risk controlled by:** The Indonesian Government, as the authority for EEZ consenting and transit.
- **Loss likely borne by:** ProjectCo and its insurers, facing the same regulatory gap as the Sarawak corridor.
- **Challenge:** There is no domestic regime for subsea power cables, and the applicable ASEAN guidelines are non-binding.

See the full details on the current and bankable risk allocation in The Way Forward below.

Indonesian waters: cabotage and repair-vessel restrictions

A specific issue that warrants standalone consideration is the impact of the Indonesian cabotage law, which directly impacts necessary vessel access for the interconnector over the construction period and its operating life. Cabotage is governed primarily by Law 17/2008 on Shipping and implemented through Ministry of Transportation regulations. **The core principle is that maritime activities in Indonesian waters (including cable-laying, survey and repair operations) must be conducted by Indonesian-flagged vessels with Indonesian crew.** While limited exceptions and waivers exist (notably for specialised vessels not available in Indonesia, subject to approval by the Ministry of Transportation through the *Persetujuan Penggunaan Kapal Asing* (PPKA) mechanism under Minister of Transportation Regulation No. 2 of 2021 (MoT Reg 2/2021)), the waiver regime is discretionary, time-limited, and given on a case-by-case basis.

The bankability significance is arguably operational rather than legal, though it may require a legal solution. **The key risk is not whether vessel access for the installation of the cable is permitted (which could be factored into project timelines during the construction/installation phase), but how quickly the transmission cable can be repaired when (not if) a fault occurs over a 20–30-year operating life.** Specialised subsea cable-repair vessels are a globally scarce asset, and the worldwide fleet is dominated by a small number of operators flagged in non-Indonesian jurisdictions. **If repair operations require a case-by-case Ministry of Transportation waiver each time, the project carries a structural delay risk every time a repair-vessel deployment is needed, heightening the risk of revenue loss and DSRA depletion.**

The bankable structuring response is likely to require multiple angles:

(i) **Pre-agreed repair-vessel arrangements** with named primary and back-up vessels, including Indonesian-flag or Indonesian-crewed vessels under joint-venture arrangements with international cable-repair operators (mirroring the structures used for FPSO operations under the same cabotage regime);

(ii) **Advance engagement with the Ministry of Transportation** to secure either a project-specific class waiver or a standing letter authorising repair operations on the cable, subject to compliance with specified conditions;

(iii) The bilateral framework discussed under "Intergovernmental framework" above should ideally include reciprocal commitments on emergency-response timelines and **pre-cleared repair access**;

(iv) Marine insurance product structuring (physical damage + business interruption) calibrated to a realistic repair-window assumption that accounts for cabotage issues; and

(v) DSRA sizing that reflects a conservative (not best-case) repair window.

Case study: SEA-ME-WE 5 telecommunications cable in Indonesian waters

In April 2024, the SEA-ME-WE 5 telecommunications cable in Indonesian waters in the Strait of Malacca was damaged. Repairs that would ordinarily take approximately three days extended to several weeks, due to cabotage-related administrative delays in permitting the relevant foreign repair vessel to operate.[60]

[60] Subsea Communication Cables in Southeast Asia: A Comprehensive Approach Is Needed – Dec 2024, Carnegie Endowment For International

Renewable Energy Certificates: attribute transferability risk

On the import side, the Singapore REC requirement (discussed in the Sarawak section above) applies equally to imports from Indonesia: for imported electricity generated from zero-carbon sources, the EMA licensee must submit relevant RECs annually for verification. The specific complication for the Indonesia corridor is the **risk that RECs generated in Indonesia are non-transferable** under Indonesian law and policy, given the prioritisation of local decarbonisation objectives. GR 40/2025 contains provisions requiring non-renewable energy industries unable to meet renewable portfolio standards to obtain RECs, and similar provisions appear in the draft New and Renewable Energy Bill ("**NRE Bill**"), which has been publicly circulated and updated since 2020, but has not yet been enacted.

The risk profile is therefore uncertainty as to:

(i) Whether and on what terms RECs generated in Indonesia can be validly transferred cross-border to a Singapore licensee;
(ii) Double-counting risk if the same generation is claimed against domestic Indonesian targets; and
(iii) Non-recognition risk in Singapore if the underlying issuance framework does not meet EMA's requirements.

Singapore and Indonesia have recently re-affirmed their commitment to work together on carbon markets that accelerate climate action, signing a MOU in July 2026 under which they agree to work towards an Implementation Agreement aligned with Article 6 of the Paris Agreement as well as to identify high-integrity carbon credit projects.[61] However, the MOU did not provide further details about how the risks identified above will be addressed by both countries.

Where environmental attributes form part of the project's value proposition (whether by way of premium pricing or by way of compliance with import licence conditions), failure here translates into revenue and termination risk. **Lenders will require robust contractual mechanics (including clear attribute warranties, replacement RECs in event of registry disruption, auditability provisions, and an explicit allocation of regulatory evolution risk) and will likely discount any "green premium" until the cross-border REC framework is operationally proven.**

Current risk allocation snapshot

- **Risk controlled by:** The Indonesian Government, through the REC framework and the pending NRE Bill.
- **Loss likely borne by:** ProjectCo, as transferability is uncertain and lenders will not size debt against green-attribute revenue.
- **Challenge:** Any REC premium is treated as upside only, rather than as bankable revenue.

See the full details on the current and bankable risk allocation in The Path to Bankability: Re-allocating Risk.

> "For many cross-border renewable energy projects, including our Vanda Solar & Battery Project, recognised environmental attributes and the ability to capture a green premium strengthens the economic case and supports long-term bankability. It is therefore encouraging that both Singapore and Indonesia recognise the importance of establishing a framework for cross-border REC recognition, which will enhance revenue certainty, boost investor confidence, and help realise the vision of the ASEAN Power Grid."
>
> *— Gurīn Energy*

[61] Singapore And Indonesia Sign Memorandum Of Understanding On Carbon Credits Collaboration – Ministry of Trade and Industry, July 2026

Dispute resolution

As with the Sarawak corridor, **no single domestic court has jurisdiction over all aspects of the project interface, and international arbitration is the natural preference and the bankable default.** Indonesia is a party to the 1958 New York Convention, and arbitration is governed by Law No. 30 of 1999. The difficulty is enforcement, rather than agreement to arbitrate. Recognition of a foreign award requires an executory order from the Central Jakarta District Court, and **where the State of Indonesia is a party the executory order must be obtained from the Supreme Court.** The public policy exception is broadly framed. Foreign court judgments are not enforceable in Indonesia, so litigation offshore is not a practical alternative.

Two further features distinguish this corridor. First, where the counterparty is PLN or another State-owned entity, execution against assets is constrained by the State finance and treasury legislation, so a favourable award does not translate straightforwardly into recovery. Second, Law No. 24 of 2009 on the National Flag, Language, Emblem and Anthem requires agreements involving an Indonesian party to be executed in the Indonesian language, and a failure to do so has been held capable of rendering an agreement void, which makes bilingual execution and a clear prevailing language provision a documentation requirement rather than a preference.

Lenders are likely to require:

(i) Arbitration under SIAC or ICC rules with a seat outside Indonesia, most naturally Singapore, across the offtake, interconnection, construction, operation and finance documents;

(ii) English or Singapore law for the offshore documents, with bilingual execution and a prevailing language provision for any Indonesian law document;

(iii) United States dollar denomination and offshore payment and account mechanics, so that recovery is not wholly dependent on enforcement within Indonesia;

(iv) Express waivers of sovereign immunity as to jurisdiction, suit and execution from PLN and any other State-owned counterparty, so far as those entities are able to give them; and

(v) Direct agreements conferring lender step-in and cure rights before the offtake or interconnection arrangements may be terminated.

Political risk insurance responding to breach of contract is a supplement, as such cover typically responds only once an arbitral award has been obtained and not honoured. It shortens the recovery period.

Current risk allocation snapshot

- **Risk controlled by:** The Indonesian Government and PLN, as the enforcement pathway, the executory order requirement and the availability of State and State-owned entity assets are all matters of Indonesian law and practice.
- **Loss likely borne by:** ProjectCo, as enforcement uncertainty against a State-owned counterparty qualifies the value of every contractual remedy in the structure.
- **Challenge:** Indonesia is a party to the New York Convention, but enforcement against the State or a State-owned entity requires a Supreme Court order and is subject to a broadly framed public policy exception, while foreign judgments are not enforceable at all.

See the full details on the current and bankable risk allocation in The Path to Bankability: Re-allocating Risk.

Force Majeure

On the natural force majeure, ProjectCo holds both an onshore generation and storage asset, exposed to seismic and volcanic activity, flooding, and extreme rainfall, and a marine link carrying the same repair delay and vessel scarcity exposure described in the Sarawak section (and further discussed above). While insurance coverage is the intended answer, it has a caveat. Indonesian law prescribes local insurance policy requirements, and local markets are not liquid or experienced for major projects such as these. Governing law adds a further layer, as the land, construction, operation and permitting documents are predominantly Indonesian law even where the offtake into Singapore is not, as relief under Indonesian law will operate by reference to the Civil Code principles rather than international / common law principles.

The political force majeure limb presents a structural problem that does not arise in the same form in the Sarawak corridor. As discussed above, GR 40/2025 permits export only while prioritising the fulfilment of local electricity needs, and vests control in PLN and the Government. **Government-directed export suspension is therefore lawful, and in a policy-driven system it is not plausibly unforeseeable.** Accordingly, it is neither a contractual breach nor a true force majeure event. Rather, it sits awkwardly between the two. If a widely drafted force majeure clause is allowed to catch it, the result is relief without compensation, with both parties excused, with no revenue nor debt service. That is the central bankability challenge of the Indonesia-Singapore corridor.

Relief must also be back-to-back across all three project interfaces, being generation, transmission and export, and the interconnector and import into Singapore under the EMA licence. Force majeure scoping that grants relief upstream while performance obligations continue downstream leaves the project unhedged.

Lenders are likely to require:

(i) A narrow, enumerated force majeure definition confined to true event-based impossibility, so that **lawful sovereign curtailment is excluded from it;**

(ii) Treatment of government-directed export suspension as a compensable government action, met by deemed energy or availability payments sufficient to protect debt service, with conversion after a long-stop period into termination with compensation covering principal, accrued interest and reasonable break costs;

(iii) Natural force majeure affecting ProjectCo's own assets to be insured so far as available on commercially reasonable terms, with an uninsurability regime and prolonged force majeure thresholds calibrated to realistic reinstatement and marine repair windows rather than conventional periods, supported by a DSRA sized to a conservative repair case;

(iv) **Government support (such as a Government Support Agreement) and direct agreements with PLN clarifying which events are excluded from force majeure and allocated to the sovereign**; and

(v) Political risk insurance for residual exposure, noting that such cover responds to political force majeure rather than to natural catastrophe, which remains a matter for the marine, property damage and business interruption programme.

Current risk allocation snapshot

- **Risk controlled by:** For natural Force Majeure, neither ProjectCo nor the Importer on the natural limb. For political Force Majeure, the Indonesian Government and PLN through the export approval and curtailment regime.
- **Loss likely borne by:** ProjectCo, as insurance covers only part of the natural force majeure risk and in respect of political risk, unlike domestic projects procured by the State (which can allocate some political risk to the host government), there is no equivalent government support structure here to take on that risk.
- **Challenge:** Lawful government-directed export curtailment is neither breach nor true force majeure, so a widely drafted clause produces relief without compensation, being excused for both parties with no revenue and no debt service.

See the full details on the current and bankable risk allocation in The Path to Bankability: Re-allocating Risk.

The Path to Bankability: Re-allocating Risk

Project finance bankability is premised on the principle that **risk should be allocated to the party best placed to control, manage or price it, rather than left with whichever party happens to hold it by default.**

Read together, the preceding sections show two corridors following a common pattern but diverging in where the risk gaps sit.

1. In the Malaysia (Sarawak) corridor, the principal risks, including export licensing, licence duration, curtailment and dispatch, land rights, change in law and dispute resolution, sit with the Sarawak State and SEB as the State-owned single buyer, with loss typically passing through to ProjectCo indirectly under the Interconnection Agreement wherever a statutory tenor, stabilisation or immunity gap is left unaddressed contractually.
2. In the Indonesia corridor, the dynamic is more pronounced, given the lack of regulatory framework (as it currently stands) to support the corridor: private generators cannot currently lawfully export without PLN (or other SOE involvement) as intermediary, the five-year statutory licence cap cannot be bound to renewal by any counterparty, and the constitutional priority given to domestic supply and to the State's regulatory flexibility leaves several major risks, including change in law and intergovernmental coordination, effectively unallocated or otherwise with ProjectCo by default.

Both corridors currently place the bulk of regulatory, tenor and sovereign risk on ProjectCo and its lenders by default, rather than by considered allocation, which is the central bankability obstacle this paper addresses.

The matrix below titled '**Risk Re-Allocation Matrix: Current and Potential Target Risk Allocation to achieve Bankability**' ("**Risk Re-Allocation Matrix**") sets out, corridor by corridor, the current allocation (as flagged in the previous section) alongside a potential bankable target allocation consistent with that principle.

The two corridors are structured differently, and the tables are not symmetrical: the Sarawak corridor is generally assumed to be a standalone transmission project with an availability-based revenue structure, and the Indonesia corridor is envisioned to either be a separate generation-transmission split project, or an integrated generation and export project. Accordingly, the table is for reference only and is not definitive nor prescriptive for any specific project, which may materially differ based on project-specific structures.

> The ASEAN Power Grid is no longer constrained by a lack of demand or capital. The challenge now is creating the regulatory certainty, sovereign commitment, and bankable structures that will allow private capital to deliver the ASEAN Power Grid at scale.
>
> *— Asian Development Bank (ADB)*

Risk Re-Allocation Matrix: Current and Potential Target Risk Allocation to achieve Bankability

Party allocation key:

ProjectCo SEB PLN Sarawak State Indonesia Govt EMA / SG Govt PRI EPC / Contractor Malaysia Govt Insurers Sponsors EMA Licensee DFI / Multilat. Offtaker

- ***ProjectCo*** *= the SPV entity raising financing in each corridor based on the relevant structure;*
- ***SEB*** *= Sarawak Energy Berhad - SEB is a State-owned company incorporated under the Companies Act 2016. It is the statutory single buyer and system planner under the Electricity Ordinance and, on this structure, the generator and seller under the PPA (if applicable) and exporter under the Interconnection Agreement. It is not a regulator (that function sits with MMKN and the Director of Electricity Supply) and it is not the State: obligations of SEB are corporate obligations and do not carry State credit unless separately guaranteed. The same distinction applies to PLN.*
- ***PLN*** *= PT PLN (Persero);*
- ***EMA*** *= Singapore Energy Market Authority;*
- ***PRI*** *= Political Risk Insurance;*
- ***EPC*** *= construction / O&M contractors;*
- ***Insurers*** *= commercial insurance market (marine, property damage, delay-in-start-up and business interruption), distinct from PRI.*
- ***Sponsors*** *= equity investors, in their capacity as providers of contractual credit support (completion, equity contribution and cost-overrun undertakings); not a party to the project contracts;*
- ***DFI / Multilat.*** *= Development Finance Institution and Multilateral Finance Institutions;*
- ***Offtaker*** *= offtaker under an energy/electricity import PPA*

A. Singapore – Malaysia (Sarawak) Corridor[62]

Risk category	Current likely allocation & challenges (status quo)	Potential bankable target allocation (with mitigants)
1. Export licensing	**Risk controlled by:** Sarawak State (MMKN, as licensing authority) **Loss likely borne by:** SEB (as licensee and exporter); ProjectCo indirectly, through the Interconnection Agreement. The MMKN export licence is required by SEB as exporter, not by ProjectCo. ProjectCo requires its own authorisation for the link, together with the associated marine and land consents. **Challenge:** ProjectCo has no direct licence exposure but complete revenue dependency. If the export licence is not granted, or is later revoked, there is no energy transported through the cable. Whether that is ProjectCo's loss turns entirely on whether Interconnection Agreement availability payments survive loss of the export licence. In absence of an unconditional availability obligation or a compensable termination event, the risk passes straight through to ProjectCo and its lenders, and the Ordinance's governmental non-liability clause means the State bears none of it.	Sarawak State SEB ProjectCo • Export authorisation embedded in SEB's export licence with defined scope, volumes and counterparty; • ProjectCo holds a separate transmission authorisation of (at least) matching tenor; • Interconnection Agreement availability payments expressed to be unconditional and independent of the export licence, failing which loss or suspension of that licence is a compensable Interconnection Agreement termination event.
2. Export licence duration	**Risk controlled by:** Sarawak State (MMKN) **Loss likely borne by:** ProjectCo indirectly, through the Interconnection Agreement. • No statutory minimum tenor; • Renewal at MMKN discretion. • Three tenors must now be aligned with (against a single debt maturity) the export licence, the PPA and the Interconnection Agreement. **Challenge:** The tenor cliff risk is more acute under a standalone structure because a stranded interconnector has no alternative user and effectively no residual value, so recovery on non-renewal depends on the Interconnection Agreement termination compensation regime rather than on the asset. The exposure is unbounded, cannot be absorbed within the equity and reserve cushion.	Sarawak State SEB ProjectCo • The export licence, PPA and Interconnection Agreement tenors exceed debt maturity plus a tail; • ProjectCo's transmission authorisation is granted for the full asset life, failing which, Sarawak State and SEB provide a termination compensation regime sized to outstanding debt plus break costs, payable directly to lenders.

[62] **Note on structural assumption:** For the purposes of the below matrix, this report assumes SEB generates and sells to a Singapore offtaker under a cross-border PPA to which ProjectCo is not a party. ProjectCo, the financed entity, develops, owns and operates the interconnector (converter stations, subsea HVDC cable and onshore works) and is remunerated under a transmission services agreement on an availability basis. ProjectCo's revenue is therefore assumed to be de-linked from energy flow. If the transmission charge, on the other hand, is tolling-based, every generation, dispatch and offtake risk in this table below, reverts (in some part) to ProjectCo and may raise material financing challenges.

Risk category	Current likely allocation & challenges (status quo)	Potential bankable target allocation (with mitigants)
3. Singapore import licensing	**Risk controlled by:** EMA / SG Govt (import licence conditions) **Loss likely borne by:** EMA Licensee, SEB (as generator and seller) EMA licensee holds the import licence. Source-certification and generation-compliance conditions attach to the generation and, under this structure, flow to SEB under the PPA - not to ProjectCo, which neither generates nor sells energy. **Challenge:** ProjectCo's only direct Singapore-side exposure is technical -the connection agreement, grid code and settlement metering at the Singapore converter station. Its commercial exposure is indirect, in that, if EMA Licensee breaches or loses its licence the revenue flow stops.	EMA Licensee EMA / SG Govt SEB • EMA licensee bears licence-holder risk; • SEB bears generation-source compliance under PPA warranties; • ProjectCo bears connection, grid-code and metering compliance for the link only. Interconnection Agreement availability payments should be unaffected by breach elsewhere in the project chain. • EMA provides regulatory predictability. • Risk is appropriately distributed.
4. Grid and transmission: curtailment / dispatch risk	**Risk controlled by:** SEB (as system planner and dispatcher), Offtaker **Loss likely borne by:** Offtaker or ProjectCo potentially entirely if the Interconnection Agreement is dispatch-based. Under an availability-based Interconnection Agreement, curtailment is not a ProjectCo risk: ProjectCo is paid for making capacity available, and dispatch risk sits between SEB and Offtaker under the PPA. **Challenge:** This is the key structuring point of the corridor. If the transmission charge is expressed per MWh wheeled, ProjectCo absorbs every upstream generation and downstream demand risk while having the ability to manage none of them, and the project is not financeable. The exposure turns on a single Interconnection Agreement term.	SEB Offtaker • Transmission charge is ideally expressly availability-based, with deemed availability where the link is available but not used. • Revenue deductions should be limited to ProjectCo's own unavailability measured against a defined availability target. • Curtailment for domestic priority compensated between SEB and Offtaker under the PPA, not at ProjectCo's cost.

Risk category	Current likely allocation & challenges (status quo)	Potential bankable target allocation (with mitigants)
5. **Domestic market obligations**	**Risk controlled by:** Sarawak State (policy) SEB **Loss likely borne by:** SEB **Challenge:** The absence of a codified DMO is the absence of an adverse obligation, not an allocation of risk to the State. The risk described is that Sarawak introduces a DMO or reprioritises domestic supply during the financing term - a change-in-law risk (see relevant row below) that reaches ProjectCo only through reduced energy flow, and not at all if availability payments are unconditional.	Sarawak State SEB • Current position is favourable at policy level: no codified DMO, and the Sarawak Government's public position is that generation expansion to 10 GW by 2030 is designed to support export of surplus generation. • **Required, not existing:** MMKN support letters, transparent reserve-margin disclosure, and PPA curtailment compensation between SEB and Offtaker. None of these is in place today. ProjectCo is insulated provided the Interconnection Agreement is availability-based. Allocation remains with State / SEB at policy level.
6. **Local content expectations**	**Risk controlled by:** Sarawak State (policy / social expectation) **Loss likely borne by:** ProjectCo EPC / Contractor • No codified percentage; • De facto Sarawakian / Bumiputera participation expectations. Risk borne by ProjectCo through procurement strategy and EPC. **Challenge:** Arguably more acute under a standalone structure interconnector structure, because HVDC converter equipment and subsea cable are the scopes least capable of local sourcing and they are substantially the whole project. Expectations are political and social rather than legal, which creates execution ambiguity that cannot be resolved by reading the statute.	EPC / Contractor • Allocated cleanly to EPC contractor through structured local content commitments in the EPC contract concentrated on installation, onshore civils and O&M rather than converter and cable supply; • ProjectCo retains stakeholder management role. • ESG and community engagement plans codify residual expectations.

Risk category	Current likely allocation & challenges (status quo)	Potential bankable target allocation (with mitigants)
7. Land rights / wayleaves	**Risk controlled by:** Sarawak State (Superintendent, under the Ordinance) **Loss likely borne by:** ProjectCo • ProjectCo will likely be required to assemble converter station sites, the onshore cable route, landing points and seabed rights in its own name. • The 2023 Ordinance amendments empower the Superintendent to grant land rights and register caveats, but those powers are exercisable in favour of a licensee under the Ordinance. **Challenge:** The key structural question is whether ProjectCo (being a private entity that is not SEB) can access those statutory powers directly, or must rely on SEB or the State to procure land on its behalf. If the latter, ProjectCo holds an indirect interest in the land underlying its principal asset.	Sarawak State SEB • Registered land rights and wayleaves with caveats matching financing tenor as CPs; • SEB provides support in ProjectCo by leading acquisition and route execution / stakeholder management with State support. • Singapore side Sponsors to take responsibility for land / wayleave obligations.
8. Change in law	**Risk controlled by:** Sarawak State (MMKN) **Loss likely borne by:** ProjectCo • No statutory stabilisation regime; • Ordinance preserves MMKN discretion with government non-liability clause. **Challenge:** No party currently absorbs change-in-law risk over 20–30 years. For a transmission asset, the exposure is to the cost of ownership and operation (licence conditions, marine and environmental requirements, decommissioning obligations and taxes), which ProjectCo cannot recover unless the Interconnection Agreement says so.	Sarawak State EMA / SG Govt PRI • Contractual change-in-law pass-through in Interconnection Agreement – increased costs of ownership/ operation passes to the counterparties through an availability charge: • EMA/Singapore Government absorbs Singapore-side change in law only after licence issued: variation of EMA import licence conditions, carbon pricing, REC surrender obligations and any regime change affecting the delivered tariff - through a defined pass-through and tariff adjustment mechanism • Sarawak/SEB absorb Malaysia-side via termination compensation if change is fundamental. • PRI (MIGA/ACIA-based) provides treaty-level backstop. • ProjectCo retains only foreseeable regulatory compliance.

Risk category	Current likely allocation & challenges (status quo)	Potential bankable target allocation (with mitigants)
9. Intergovernmental framework	**Risk controlled by:** Malaysia Govt EMA / SG Govt (policy level) **Loss likely borne by:** ProjectCo Bilateral cooperation and ASEAN APG MOU 2025 are policy-level only. **Challenge:** An MOU expressly stated to be non-binding allocates no risk and creates no claim to any party. For a standalone interconnector project, the asset is a single-purpose wire whose entire value depends on cross-border trade continuing. Treaty-level and sovereign-coordination risk is unallocated and lands on ProjectCo and its lenders.	Malaysia Govt EMA / SG Govt • Binding bilateral (or trilateral, given cable transit route) IGA addressing export rights, regulatory coordination, stabilisation overlay and state-to-state dispute resolution. • Sovereign-coordination risk allocated to Govts, not Lenders.
10. Subsea cable — multi-jurisdictional	**Risk controlled by:** Indonesia Govt (EEZ consenting, transit and repair access) **Loss likely borne by:** ProjectCo Insurers ~80% of route transits Indonesian EEZ; UNCLOS framework only. Under a standalone structure, this is not a peripheral consenting issue but a key one as the cable is the asset. **Challenge:** No contractual or treaty mechanism currently allocates Indonesian transit risk - ProjectCo bears it via permitting effort and, critically, through repair access. A fault in the EEZ cannot be repaired without Indonesian clearance, and permitting time drives the business interruption exposure far more than the physical repair itself.	Malaysia Govt Indonesia Govt EMA / SG Govt Insurers • Bilateral or trilateral cable protection arrangement (e.g., extension of 1983 MY–ID maritime treaty to include Singapore) or IGAs: as protection, repair-vessel access, emergency response sits with Governments • Robust and comprehensive insurance policies package and DSRA cover physical/operational risk.

Risk category	Current likely allocation & challenges (status quo)	Potential bankable target allocation (with mitigants)
11. Renewable Energy Certificates	**Risk controlled by:** **EMA / SG Govt** **Malaysia Govt** (surrender obligation under Singapore law) **Loss likely borne by:** **EMA Licensee** **SEB** Not a ProjectCo risk under a standalone structure. Chain of title in the environmental attribute runs between SEB and EMA Licensee (Offtaker) under a separate PPA – ProjectCo neither generates nor sells energy and cannot warrant an attribute it does not own. **Challenge:** ProjectCo's only involvement is metering and data. The REC framework will require settlement-grade metering and reporting at the interconnection points, which is a ProjectCo obligation under the Interconnection Agreement and connection agreements and should be scoped as such rather than left to a general warranty.	**Offtaker** **EMA / SG Govt** **Malaysia Govt** **SEB** • Cross-border REC framework agreed between the Malaysian and Singapore governments, operationalised by registries in each country; • Clear rules on double counting and retirement; • Replacement REC mechanisms for registry disruption. • Issuance and chain-of-title warranties given by SEB as generator; • ProjectCo obliged only to provide compliant metering and data. • EMA and MY Govts share regulatory evolution risk.
12. Dispute resolution	**Risk controlled by:** **SEB** (as State-owned counterparty) **Loss likely borne by:** **ProjectCo** Both MY and SG party to NY Convention; mature pro-arbitration practice. Risk allocation works through bilateral arbitration provisions. **Challenge:** Enforcement risk is borne by whoever has to enforce, which is ProjectCo and its lenders. The exposure is concentrated because ProjectCo's revenue rests on one or two contracts: SEB must waive sovereign immunity from suit and execution expressly, failing which enforcement against SEB assets is qualified.	**ProjectCo** **Offtaker** **SEB** • SIAC or ICC arbitration with explicit sovereign immunity waivers from SEB; • Direct agreements with lender step-in and cure rights. • Risk appropriately distributed across commercial parties.

Risk category	Current likely allocation & challenges (status quo)	Potential bankable target allocation (with mitigants)
13. Force majeure	**Risk controlled by:** For natural events, no key party. For political events, Malaysia Govt EMA / SG Govt **Loss likely borne by:** ProjectCo Insurers If ProjectCo's revenue is calculated by reference to energy wheeled, a force majeure disruption anywhere in the structural chain (at the Generator, the Importer, or in the political/regulatory sphere, where the federal and state authorities driving that risk) will directly impact ProjectCo's revenue, with no arrangement in place to give ProjectCo relief. **Challenge:** The orthodox allocation, under which each party bears the consequences of a natural force majeure affecting it, works for ProjectCo's own asset but does not answer the position where the event is upstream or downstream of it, as ProjectCo is neither the affected party nor insulated from the consequences. For ProjectCo's own asset the insurance limb is weak, as delay in start up and business interruption cover for subsea cable and converter outage is difficult to source or expensive, given the scarcity of HVDC manufacturing and specialist repair vessel capacity, and repair windows are further extended by the need for access permits across more than one jurisdiction. Political force majeure and change in law, including denial of repair access, permit revocation and requisition, are a separate question and are not appropriately left with the affected party.	Malaysia Govt EMA / SG Govt Insurers Offtaker SEB ProjectCo • ProjectCo to be remunerated on an availability basis under a long-term transmission or capacity agreement rather than by reference to energy wheeled, with a deemed availability payment supported by credit acceptable to lenders, so that force majeure affecting SEB or the Offtaker does not reduce ProjectCo's revenue. • Natural force majeure affecting ProjectCo's own assets to be borne by ProjectCo, with relief from the availability obligation, extension of term, and prolonged force majeure termination thresholds calibrated to realistic subsea repair timelines rather than conventional periods. • Insurance to be maintained so far as available on commercially reasonable terms, with an uninsurability regime addressing the limited availability and cost of business interruption cover for cable and converter outage. • Political force majeure and change in law to be addressed at the level at which it is controlled, with state and federal approvals each secured as conditions precedent with long stop dates, supported so far as obtainable by state or federal support arrangements and a termination payment sufficient to repay senior debt, with residual exposure laid off through political risk, multilateral or export credit agency cover. • Force majeure definitions, notice requirements and relief periods to be back-to-back through the capacity agreement and the connection and use of system arrangements with each transmission owner. • DSRA sized to that window rather than to a generic six months; tight enumerated FM back-to-back across the Interconnection Agreement, EPC and O&M contracts.

Risk category	Current likely allocation & challenges (status quo)	Potential bankable target allocation (with mitigants)
14. Lender security and step-in	**Risk controlled by:** counterparty defaults. **Loss likely borne by:** ProjectCo Assuming a standalone transmission project structure, Security is taken over an asset sitting partly in Malaysian internal and territorial waters, partly in the Indonesian EEZ and partly in Singapore, with converter stations in two jurisdictions. **Challenge:** Two major constraints. Taking and perfecting security over a cable in a foreign EEZ may not be straightforward and may not be predictably be effective against third parties. More fundamentally, a single-purpose interconnector with one seller and one buyer has no alternative use (in terms of alternative revenue) and effectively more limited enforcement value. Accordingly, lender recovery depends on the Interconnection Agreement termination compensation regime, not on the asset. Direct agreements with SEB and Offtaker are therefore the core of the security package to ensure proper performance and stable and predictable revenue for ProjectCo.	**Offtaker SEB Sponsors** • Direct agreements with all key counterparties including Malaysia and Singapore side generator/ offtaker (in such capacity) and as Sponsors; • Express lender step-in, cure and substitute-sponsor rights; • Robust termination and compensation sized to outstanding debt plus break for each lender; • Share, contract and receivables security taken in each relevant jurisdiction; • Controls and offshore accounts where feasible;

B. Singapore – Indonesia Corridor[63]

Risk category	Current likely allocation & challenges (status quo)	Potential bankable target allocation (with mitigants)
1. Export licensing	**Risk controlled by:** Indonesia Govt (GR 40/2025) **Loss likely borne by:** ProjectCo Private generator cannot export directly under GR 40/2025, as there is no clean allocation path. **Challenge:** In absence of structured PLN intermediation, the export-leg revenue risk effectively defaults to ProjectCo; there is no counterparty that can lawfully take export-leg revenue risk. The exposure is unallocated under the current legal framework.	PLN Indonesia Govt ProjectCo • New regulatory framework to permit and stabilise export rights; • PLN (if involved in the absence of adequate regulatory change) as mandatory intermediary takes export-counterparty risk under a back-to-back offtake structure; • Indonesia Govt provides sovereign overlay (GSA or MoF guarantee); • ProjectCo retains generation performance risk only.
2. Export licence duration	**Risk controlled by:** Indonesia Govt (MEMR, as licensing authority) **Loss likely borne by:** ProjectCo 5-year statutory cap (PP 42/2012; MEMR 11/2021). **Challenge:** No Indonesian counterparty can lawfully bind the regulator to renewal; risk defaults to ProjectCo/Lenders and is fundamentally unhedgeable in current form: a primary bankability blocker.	Indonesia Govt (MEMR) PLN PRI • Resolved by statutory amendment, enforceable guarantee from MoF/ MEMR (or a GSA) with binding renewal terms, or treaty-level commitment. • PLN direct agreement provides termination compensation backstop. • PRI likely responds to non-honouring by the Indonesian Government of a renewal or compensation undertaking, not to non-renewal itself: lawful non-renewal under a statute that always provided for a five-year term is not an insurable peril. PRI is therefore a wrapper for a sovereign commitment, not an alternative to one - absent a statutory or sovereign undertaking there is nothing for PRI to insure.

[63] **Note on structural assumption:** It is important to note that the currently regulatory frameworks are not currently adequate to allow generation and export of electricity from Indonesia to Singapore by ProjectCo. While at policy level there are indications that these may be permitted and that ProjectCo can generate and export, policy is not adequate for long-term project financing structures and from a regulatory position, the fallback assumption must be that the current regulatory regime is the default position (e.g. there is no law that allows for international sponsors to generate and export electricity on a long-term basis on their own, but that this is PLN's role currently and therefore generation/export structures will be subject to PLN counterparty participation.)

Risk category	Current likely allocation & challenges (status quo)	Potential bankable target allocation (with mitigants)
3. Singapore import licensing	**Risk controlled by:** **EMA / SG Govt** **Indonesia Govt** (unsynchronised approval pathways) **Loss likely borne by:** **EMA Licensee** The Singapore import licence is granted conditionally and against milestones, while the Indonesian export framework contemplated by the June 2025 CBET MOU is non-binding and still to be developed, creating unpredictability in the ability to meet such milestones. **Challenge:** Singapore-side conditional approvals may lapse, or milestone dates missed, because the Indonesian framework is not yet in place. This is a timing mismatch between two regulators, neither of whom owes an obligation to the other. No party bears this today; it presents to lenders as completion risk and is priced as such.	**EMA / SG Govt** **Indonesia Govt** **EMA Licensee** • CBET MOU implemented as robust and comprehensive binding bilateral framework; • EMA and Indonesia regulators provide synchronised approval pathway; • Operational compliance allocated to ProjectCo.
4. Grid and transmission: dispatch and curtailment exposure	**Risk controlled by:** **PLN** (dispatch) – subject to confirmation on its involvement in generation structures. **Loss likely borne by:** **ProjectCo** PLN currently legally controls dispatch but currently has no contractual obligation to compensate export curtailment under standard SOE contracting. **Challenge:** Domestic prioritisation under GR 40/2025 makes curtailment lawful. As such, risk defaults to ProjectCo and Lenders unless the regulatory regime or exemption by PLN for long-term generation from off-grid structures is adequately robust and enforceable to preclude PLN dispatch management.	**PLN** **Indonesia Govt** **PRI / MIGA / ADB** • GSA is preferred indicator of Indonesia Govt commitment to counteract any curtailment or dispatch risk (to the extent Indonesian SOE parties are involved in the structure) • Curtailment for domestic priority (where applicable) converted to compensated Government Action under direct agreement – deemed energy or availability payments protecting DSCR. • Indonesia Govt provides sovereign overlay • PRI (non-honouring of financial obligations by a State-owned enterprise, or breach of contract cover) responds to non-payment by Indonesia Govt of the compensation due under the direct agreement

Risk category	Current likely allocation & challenges (status quo)	Potential bankable target allocation (with mitigants)
5. Domestic market obligation	**Risk controlled by:** Indonesia Govt (constitutional and statutory DMO) **Loss likely borne by:** ProjectCo Constitutional and statutory DMO (Article 33, Energy Law 30/2007, GR 40/2025) means export rights are conditional and revocable. **Challenge:** No Indonesian counterparty can override constitutional priority - risk effectively borne by ProjectCo and absorbed by Lenders via leverage haircut and pricing.	Indonesia Govt PLN PRI / MIGA / ADB • Lawful sovereign DMO-driven curtailment converted to compensated event under PLN direct agreement (deemed energy or termination compensation where PLN involved in generation structures); • Indonesia Govt provides backstop under a GSA; • PRI responds to non-payment of that compensation obligation. The DMO itself is lawful sovereign action of general application and is not an insurable peril. • Structural acceptance: DMO cannot be removed but its consequences can be priced and absorbed.
6. Local content requirements	**Risk controlled by:** Indonesia Govt (TKDN regime) **Loss likely borne by:** ProjectCo EPC / Contractor MEMR 11/2024 TKDN binding; GR 40/2025 elevates supply-chain prioritisation. **Challenge:** Generation and transmission/subsea cable components have limited Indonesian supply capacity, leading to schedule and capex risk borne primarily by ProjectCo/EPC; lender exposure via completion risk.	EPC / Contractor Indonesia Govt DFI / Multilat. • TKDN compliance phased and allocated explicitly in EPC; DFI flexibility under MEMR 11/2024 unlocked early; • Bilateral framework (within IGA) recognises calibrated TKDN treatment for subsea cable export infrastructure. Indonesia Govt confirms flexibility.
7. Land rights	**Risk controlled by:** Indonesia Govt (public-interest designation) **Loss likely borne by:** ProjectCo Generation land rights are bankable. **Challenge:** Corridor assembly requires public-interest designation, which can be tied to PLN involvement. PLN's absence from the structure can be a risk, not its allocation: without PLN there is no mechanism to assemble the route at scale and the risk cannot be underwritten.	PLN Indonesia Govt ProjectCo • Transmission corridor assembled via PLN with public-interest designation; • Indonesia Govt provides administrative backing; direct agreements with land authorities. • ProjectCo retains residual private-landholder negotiation risk only.

Risk category	Current likely allocation & challenges (status quo)	Potential bankable target allocation (with mitigants)
8. Change in law	**Risk controlled by:** Indonesia Govt **Loss likely borne by:** ProjectCo No corridor-specific stabilisation; constitutional flexibility expressly preserved in favour of State, including nationalisation. **Challenge:** In current state, change-in-law risk is effectively unallocated and absorbed by ProjectCo.	Indonesia Govt PLN PRI EMA / SG Govt **Layered:** • PLN (where involved) absorbs change-in-law affecting export operability under direct agreement (unless regulatory frameworks or robust exemptions / consents otherwise granted to avoid PLN involvement); • Indonesia Govt provides stabilisation overlay via GSA; • EMA/Singapore Government absorbs Singapore-side change in law only after licence issued • PRI (MIGA / ADB-type cover: expropriation, transfer restriction, political risk, and non-honouring of sovereign or SOE financial obligations) responds to non-payment of the compensation owed, not to lawful regulatory change itself. • The Indonesia–Singapore BIT and the ACIA are shown separately: they are a floor on sovereign conduct and a route to investor-State arbitration, not a mitigant lenders can size debt against. • Layered protection (contractual, insurance and treaty) so that failure of any single mitigant does not leave lenders unprotected.
9. Intergovernmental framework	**Risk controlled by:** Indonesia Govt EMA / SG Govt (policy level) **Loss likely borne by:** ProjectCo June 2025 CBET MOU non-binding; Indonesia–Singapore BIT a backstop with broad carve-outs. **Challenge:** In current state, sovereign-level risks remain at ProjectCo and, beyond the equity cushion, at an unallocated level rather than being addressed by Governments.	Indonesia Govt EMA / SG Govt • Binding bilateral framework crystallising the June 2025 CBET MOU into enforceable obligations; address export rights, licensing, RECs, stabilisation, dispute resolution. • Sovereign risk allocated at sovereign level.

Risk category	Current likely allocation & challenges (status quo)	Potential bankable target allocation (with mitigants)
10. Subsea cable —multijurisdictional	**Risk controlled by:** Indonesia Govt (EEZ consenting and transit) **Loss likely borne by:** ProjectCo Insurers Same Indonesian regulatory gap (no domestic regime for subsea power cables; ASEAN guidelines telecoms-focused and non-binding). **Challenge:** Identical to SG-MY corridor — the Indonesian EEZ transit is a shared structural issue.	Indonesia Govt EMA / SG Govt Insurers • Same intergovernmental cable framework as for Sarawak or a separate bilateral framework: • Route protection and repair access at government level; • Pre-cleared interface with the Indonesian Navy, Coast Guard, MEMR and MAI. • Marine insurance + DSRA cover physical / operational interruption.
11. Renewable Energy Certificates	**Risk controlled by:** EMA / SG Govt Indonesia Govt (surrender obligation under Singapore law) **Loss likely borne by:** ProjectCo Indonesian REC framework prioritises domestic decarbonisation; cross-border transferability uncertain; NRE Bill pending. **Challenge:** Non-transferability and double-counting risk currently sit with ProjectCo and EMA licensee subject to annual REC surrender obligations. A REC is not a precondition to import. The binding licence requirement is an annual emission factor no higher than 0.15 tCO_2e/MWh within five years of commercial operations, with RECs or equivalent proof of generation serving as the means of evidencing it, so the exposure is failure of proof and loss of green value rather than loss of the right to import. Consequence: lenders will not size debt against green-attribute revenue while transferability is uncertain. Provided the project can still adequately comply with its import licence conditions, if there is no REC, from the lenders' perspective the model must stand on energy revenue alone, with any REC premium treated as upside, which directly reduces the project's debt capacity.	Indonesia Govt EMA / SG Govt • Enactment of NRE Bill enabling cross-border attribute transfer; • Bilateral REC interoperability under CBET framework.

Risk category	Current likely allocation & challenges (status quo)	Potential bankable target allocation (with mitigants)
12. Dispute resolution	**Risk controlled by:** Indonesia Govt **Loss likely borne by:** ProjectCo ID party to NY Convention but enforcement against State/SOE requires Supreme Court order; public policy exception; foreign judgments not enforceable. **Challenge:** Enforcement uncertainty against PLN means lender remedies are qualified — risk effectively shared with Lenders.	PLN Indonesia Govt ProjectCo • SIAC/ICC arbitration with seat outside Indonesia; • English-law PPA; • US$ denomination; • Offshore payment mechanics; • Express sovereign immunity waivers from PLN (if involved) or any other SOE. • Direct agreements provide step-in and cure. PRI (breach of contract cover) typically responds only once an arbitral award has been obtained and not honoured: it shortens recovery, it does not avoid the arbitration.

Risk category	Current likely allocation & challenges (status quo)	Potential bankable target allocation (with mitigants)
13. Force majeure	**Risk controlled by:** For natural events, Neither ProjectCo nor the Importer, as the event is by definition outside the control of both. Exposure follows the affected asset. For natural events this is the generation and storage assets and their site in Indonesia, the marine link and converter stations, or the Singapore side of the system. For political events **Indonesia Govt** and to a lesser degree **EMA / SG Govt** in respect of the Singapore regulatory framework. **Loss likely borne by: ProjectCo** ProjectCo in the first instance for natural events affecting its own assets, mitigated by insurance so far as available. For political events ProjectCo bears the loss, as an export project has no equivalent of the government support arrangements that have historically accompanied domestic independent power projects sold to the state utility, so there is no sovereign counterparty standing behind a change in export policy. **Challenge:** On the natural limb, the site is exposed to seismic and volcanic activity, flooding and extreme rainfall, and to among the highest lightning flash densities in the world, which bears directly on solar and battery storage assets, while the marine link carries the same repair delay and vessel scarcity exposure as the Sarawak link. Insurance is the intended answer but is qualified in Indonesia, as Indonesian insurance risks are generally subject to Indonesian policy restrictions. Governing law adds a further layer, as the onshore land, construction, operation and permitting documents are Indonesian law even where the export offtake is not, with Civil Code relief taking precedence. On the political limb, the risk is the export approval and licensing regime itself, which is changeable and has already delayed export projects, and which sits outside the contract structure entirely.	**PLN Indonesia Govt PRI Insurers EMA / SG Govt ProjectCo EMA Licensee** • ProjectCo to bear natural force majeure affecting its own assets, insured so far as available on commercially reasonable terms, with an uninsurability regime, relief from delivery obligations, extension of term, and prolonged force majeure termination thresholds calibrated to realistic reinstatement and marine repair timelines. • Insurance to be maintained so far as available on commercially reasonable terms, with an uninsurability regime, and the package structured for lender security notwithstanding the local placement requirement, through reinsurance cut through, assignment of proceeds and broker undertakings. • Natural force majeure affecting the Importer (or ProjectCo if importing) or the Singapore system to be addressed through a deemed energy regime supported by credit acceptable to lenders. • Political force majeure and change in law, including withdrawal or variation of the export approval, to be carried by the host side so far as obtainable, with a termination payment sufficient to repay senior debt, and residual exposure laid off through political risk or multilateral cover. • Force majeure definitions, notice requirements and relief periods to be back to back across the Indonesian law and offshore documents, and reconciled with the importer's EMA licence obligations, which contractual relief does not excuse. • Indonesia sovereign overlay: GSA support from the Indonesian Government to clarify FM exclusions that allocate sovereign risk to the Indonesian Govt to allow for long-term project structure stability i.e. treated as compensable Government Action - PLN (or other SOE) pays under direct agreement; long-stop conversion to termination with debt-protective compensation. • PRI covers political violence (war, terrorism, civil disturbance) only.

Risk category	Current likely allocation & challenges (status quo)	Potential bankable target allocation (with mitigants)
14. Lender security and step-in	**Risk controlled by:** PLN (receivables and consent), counterparty default **Loss likely borne by:** ProjectCo PLN intermediation complicates security over export receivables; sovereign immunity issues with SOE counterparties; step-in into State-affiliated counterparty contracts is structurally constrained. **Challenge:** Most lender remedies require regulatory and PLN cooperation to be effective.	PLN Indonesia Govt Sponsors PRI • PLN (if involved) or other SOE direct agreement with step-in and cure as critical infrastructure; • Offshore receivables structure where regulatorily permitted; • Sovereign overlay (GSA / MoF guarantee); • PRI backstop. • Layered, lender protections.

Legal Workstreams to Bankability

Building on the risk allocation analysis set out above, this section sets out, corridor by corridor, the principal forward-looking legal workstreams, whether bilateral, statutory, contractual or insurance-based, that would need to be progressed to move each corridor from its current status of "legally permitted" to a fully bankable project finance structure.

Sarawak–Singapore: Workstreams to bankability

The legal architecture supporting the Sarawak–Singapore corridor is at an early but encouraging stage. The 2023 amendments to the Sarawak Electricity Ordinance have provided a workable licensing platform. SEB's structural role as both regulator and likely exporter is unusually favourable from an alignment perspective, and Singapore's import licensing framework is mature, transparent, and predictable. The principal legal workstreams required to take the corridor from "legally permitted" to fully bankable are set out below.

1. Embedding export rights in the licence with bankable durability

The single most important legal action is to ensure that the Sarawak export licence, when issued, contains:

a) An unambiguous export authorisation in favour of the export licensee, with clearly defined volumes, destination, and counterparty;
b) A licence tenor extending beyond the tenor of the PPA/export sales contract and/or the transmission services agreement and the financing tenor;
c) Where b) cannot be achieved, a transparent renewal or extension mechanism with defined consequences of suspension or revocation, including a compensation regime. While the Ordinance preserves MMKN discretion, the licence itself can, and should, be drafted to provide as much commercial certainty as the statute permits.

2. Building out a binding intergovernmental framework

Existing bilateral and ASEAN-level MOUs provide political endorsement but do not create enforceable rights. Over the medium term, the corridor would benefit materially from a more formal IGA between Malaysia (with Sarawak State endorsement) and Singapore. In addition, given the likely cable transit route, a trilateral instrument extending to Indonesia for the subsea cable corridor specifically would be ideal as well. Such an IGA should address:

a) Reciprocal commitments to permit electricity trade across the corridor;
b) Procedural commitments around licensing and approvals timelines;
c) A stabilisation commitment on exercise of curtailment rights, changes in law and "government force majeure" materially affecting project economics;
d) Defined subsea transmission cable protection and emergency-response obligations; and
e) State-to-State dispute resolution via international arbitration.

3. A purpose-built subsea transmission cable framework

Beyond UNCLOS and the non-binding ASEAN Guidelines, a binding bilateral or trilateral IGA is preferable. Failing that, a pair of mutually consistent domestic instruments (in each jurisdiction that the proposed subsea transmission cable will traverse) referencing each other can deliver substantially similar comfort and would materially improve bankability. The objective is to convert UNCLOS-level entitlements into project-execution rights: route designation, permitted maintenance and repair operations, defined permits and timelines, pre-cleared interfaces with coastal-State maritime authorities, environmental approvals, and a cross-border emergency response protocol covering repair-vessel access and cabotage.

4. Termination compensation

The PPA and/or any transmission services agreement (if separately documented) and all related project documents should contain a defined, lender-protective termination compensation regime triggered by:

a) Export licence loss, suspension or non-renewal absent licensee default;
b) Lawful change in law materially affecting project economics;
c) Prolonged force majeure in the case of Government Force Majeure. In the case of natural force majeure, this risk is often allocated also to the State, subject to any insurance that might be available; and
d) Prolonged dispatch-driven curtailment.

Compensation should cover at minimum outstanding debt principal, accrued interest, and reasonable break costs.

5. Political risk insurance

Notwithstanding the favourable structural position of this corridor, political risk insurance may also be considered as a backstop for unlawful changes-in-law and selected breach-of-contract risks.

6. Contractual override of governmental non-liability

Because the Ordinance excludes statutory liability of the State for losses arising from licence suspension or revocation, unless the Ordinance is amended, **lender protection in this dimension must be built entirely at the contractual level.** The PPA and/or transmission services agreement termination compensation regime should expressly cover licence loss (absent licensee default) as a compensable event, with payment quantification anchored to outstanding debt service (as described in point 4 above).

Ideally, this should be reinforced by a commitment from the State, by way of a Government Support Agreement for a specific project or by way of an IGA if a consistent regime applying to all potential projects is preferred, articulating the State's posture on regulatory intervention against the project.

Singapore–Indonesia: Workstreams to bankability

In contrast, the Singapore–Indonesia corridor currently presents a less favourable legal starting point than the Sarawak corridor. The impediments and/or gaps in the current regulatory framework will pose a challenge to the successful financing of an import project in this corridor.

Yet, these are not intractable problems. Both the Indonesian and Singapore Governments have reiterated their support for the development of the import corridor and have, as recently as July 2026, confirmed their commitment to make the necessary domestic regulatory reforms to facilitate it. Furthermore, international precedent, including the Monsoon Wind project between Lao PDR and Vietnam, demonstrates that structurally complex, SOE-mediated cross-border power projects can be made bankable where the legal "umbrella" is properly built.

The principal forward-looking workstreams for this corridor are set out below.

1. A binding bilateral framework on cross-border electricity trade

The June 2025 MOU on CBET committed MTI and MEMR to develop the necessary policy and regulatory framework within 12 months. The July 2026 MOUs have provided some updates to those commitments and have confirmed their respective commitments to resolving the remaining policy and regulatory requirements, and are extremely positive. From the perspective of the lending community, the single most impactful legal development would be the translation of those MOUs into a binding bilateral agreement that addresses:

a) The conditions and procedures for export/import licensing in each country;
b) Amendment of the existing five-year licence cap on exports from Indonesia, with sufficient legal force to be relied upon by lenders;
c) Treatment of cross-border RECs and attribute transferability;
d) Reciprocal regulatory commitments;
e) Commitments in relation to the subsea transmission cable framework that will apply in Singapore and Malaysian waters; and
f) Dispute resolution frameworks.

A binding instrument of this kind would materially shift the bankability assessment for the entire corridor.

2. Resolving the five-year licence cap

Until the five-year statutory cap on the Indonesian export licence is addressed, whether by way of statutory amendment (preferred), a legally enforceable government guarantee, or a State-level commitment to extend or renew the export licence on defined terms, the corridor will continue to face a primary tenor-mismatch bankability blocker.

A targeted solution might include:

a) Statutory amendment to extend the cap for projects serving a defined "strategic export" category, guaranteeing long-term export rights for designated export projects (which, at a minimum, would need to extend beyond the tenor of the financing deployed to develop the generation and transmission projects);
b) A binding regulatory commitment to renew export licences for further terms, subject to compliance with clear, specified criteria;
c) A termination compensation regime which would be triggered if the export licence is cancelled or renewal is withheld without cause; and/or
d) State-level protection of long-tenor export rights.

3. Direct agreements with PLN and the sovereign overlay

Lender direct agreements with PLN will be critical wherever PLN, or another entity authorised under Indonesian law to participate in export projects, is required to be involved. This will remain the case for as long as no clear regulatory framework exists allowing a fully private generation-export project.

These should provide for:

a) Lender step-in and cure rights;
b) Protection against termination of project agreements and State issued licences and approvals during cure periods;
c) Clear treatment of curtailment, with availability-based or deemed-energy revenue mechanics (to the extent not addressed under any IGA that might be agreed);
d) Express waivers of sovereign immunity (subject to PLN's own legal constraints); and
e) Where possible, a sovereign overlay (whether by way of a Government Support Agreement, or an explicit guarantee).

The Monsoon Wind precedent demonstrates that strong sovereign overlay, even without an explicit sovereign guarantee, can unlock limited-recourse financing of large cross-border projects.

4. A purpose-built subsea cable regime

Regulation of subsea power cables is presently undeveloped. A purpose-built domestic framework in each of Indonesia and Singapore, supplemented by a bilateral or trilateral (if Malaysia is also to be involved) cable protection and management arrangement, would address:

a) Cable route designation and protection (also addressing compatibility with shipping lanes and competing marine uses);
b) Repair-vessel access (including pre-cleared interfaces with applicable State agencies);
c) Environmental permitting; and
d) Rights and obligations with respect to cross-border emergency response.

Sponsor and lender advocacy for such a framework, and engagement with ASEAN-level resilience initiatives, would be constructive.

5. Operationalising the cross-border REC framework

Enactment of the long-pending Indonesian New and Renewable Energy Bill, in a form that places the ownership and transferability of environmental attributes on a clear statutory footing consistent with international standards, would address a key element of revenue and compliance uncertainty for the corridor.

In parallel, the certificate instruments used in both markets already support cross-border transfer. The remaining work lies in standardising the rules that govern cross-border certificates to align with internationally accepted standards: how they are matched to physical cross-border flows, which instruments and registries are recognised, and how exclusivity of claim is preserved. Progress on those rules, with clear rules on double counting and retirement, would translate policy intent into operational reality. The Cross-Border Renewable Energy Certificates Framework being developed by the Singapore Government with the I-TRACK Foundation is a welcome step in that direction. The recently re-affirmed commitments of both the Singapore and Indonesian Governments to take the steps to implement the necessary changes in their domestic frameworks to support this are also positive and welcomed.

6. Political risk insurance and the ACIA / BIT overlay

As noted in the commentary on the Singapore–Sarawak corridor, political risk insurance is likely to be a meaningful credit enhancement for the corridor as a backstop for unlawful changes-in-law, issues with currency transfer and/or convertibility, and selected breach-of-contract risks. However, the insurance market must be tested to understand what other mitigating measures are required before insurers can provide adequate comfort to commercial lenders seeking to finance these projects.

The Indonesia–Singapore BIT and the ACIA provide a backstop layer for investor protection but should not be treated as primary mitigants. Layered protection (contract, insurance, treaty/intergovernmental solutions) is the appropriate response to a corridor where the principal sovereign risk exposure is change-in-law via lawful regulatory action.

7. Local content as a structuring item, not a residual

TKDN is best addressed at the procurement strategy stage, with phased compliance commitments, defined contractual allocation in EPC and supply contracts, and active engagement with regulators on any necessary flexibility (in particular for subsea cable components where local supply is limited).

Where DFI financing is contemplated, the MEMR 11/2024 flexibility for DFI-financed projects should be explored early, and the bilateral framework discussed in item 1 above should ideally recognise calibrated TKDN treatment for the export corridor.

8. Cabotage pre-clearance for cable repair

Cabotage requirements under Law 17/2008 / PM 65/2020 are a binding domestic constraint with direct bankability consequences for subsea cable repair timelines.[64] The bilateral framework contemplated under item 1 above should ideally include reciprocal commitments on pre-cleared repair-vessel access and a standing waiver or class authorisation from the relevant State agencies.

Pre-agreed joint-venture or chartering arrangements with Indonesian-flag or Indonesian-crewed operators (modelled on the FPSO precedent in the oil and gas sector) should be in place by financial close, and DSRA sizing and marine insurance should both be calibrated to realistic, not best-case, repair windows.

[64] Law No. 17 of 2008 on Shipping (cabotage principle, Art. 8) and the foreign-vessel (PPKA) exception regime – ADCO Law, 2025.

THE WAY FORWARD

So where does this leave us?

As ASEAN shifts from ambition to execution, the key question is no longer why these projects matter, but whether they are bankable. Despite strong fundamentals, cross-border interconnectors remain highly sensitive to a set of critical factors.

The previous chapters have established what bankability requires across three structural dimensions: managing integration and stranded-asset risk (Driver 1), securing durable green demand and revenue economics (Driver 2), and achieving sovereign commitment and regulatory completeness (Driver 3).

Creating structures that prevent stranded assets

The first requirement for bankability is ensuring that generation and transmission remain economically integrated throughout both construction and operation.

The analysis of Driver 1 demonstrates that there is no one single ownership structure that *has to* be adopted. Integrated ownership, post-completion separation models, and contractually linked structures can all be bankable. The defining consideration is not ownership itself, but whether project-on-project risks have been effectively addressed.

For the generation-to-grid archetype, generation and transmission assets are economically inseparable. A completed generation facility without a transmission pathway cannot generate revenue. Likewise, a completed interconnector without a source of electricity has limited standalone value. Lenders therefore focus on the interface between the two asset classes, rather than the legal form through which ownership is organised.

The critical questions are therefore whether the assets can reach commercial operation together, whether risks are clearly allocated if one asset experiences delay or outage, and whether revenue continuity can be maintained throughout the life of the project. **The case studies presented in this paper demonstrate that there are multiple ways of achieving this objective. What matters is that the chosen structure prevents either asset from becoming stranded.**

Ultimately, bankability requires integration of cashflows and risk allocation rather than integration of ownership. Where project sponsors can demonstrate that the success of one asset is appropriately linked to the success of the other, interface risk becomes manageable and financeable.

Converting green demand into financeable revenue

The second requirement for bankability is revenue resilience.

The analysis of Driver 2 finds that **Singapore possesses credible and growing demand for imported low-carbon electricity.** Demand from data centres, semiconductor manufacturing, pharmaceuticals and other energy-intensive sectors provides a meaningful foundation for future imports. The challenge is therefore whether that demand can be converted into revenue structures capable of supporting project financing, and not whether demand exists. A key finding of this paper is the **existence of a structural pricing gap between the costs developers need to recover and the prices many corporate buyers are willing to pay.** Imported electricity is often evaluated against domestic wholesale or retail electricity prices. However, the full delivered cost of imports includes much more than renewable generation alone. Storage requirements, subsea transmission infrastructure, financing costs, reliability measures and broader system security requirements all contribute to the final cost stack.

Attempting to recover all these costs through a single energy tariff creates a commercial challenge. As more costs are embedded within the delivered electricity price, the resulting tariff may exceed what many voluntary corporate buyers are prepared to commit to over long periods.

This suggests that the path to scale may not be a single all-in pricing model. **Instead, international precedents demonstrate that bankable projects often emerge when different components of the value chain are supported through different revenue mechanisms.** Long-term PPAs can underpin the energy component. Firming and reliability services can potentially be contracted separately. Interconnection infrastructure may justify availability-based or regulated-style cost recovery mechanisms. System resilience and energy security functions may, in certain circumstances, be treated more like systems cost recovered from a broader base of users than purely commercial project costs.

The objective is not to subsidise projects indiscriminately. Rather, it is to **match each cost component with the party that benefits from it and is best placed to bear it.** The closer the revenue structure moves towards this principle, the more likely it is that project economics can support both corporate affordability and lender requirements.

Building on political ambition with regulatory certainty

Political commitment to regional power integration is increasingly evident across ASEAN. However, political support alone is insufficient to support limited-recourse project financing. **Investors require confidence that the underlying regulatory architecture is durable enough to sustain the commercial assumptions throughout the financing tenor.**

The legal findings set out in Driver 3 above describe the regulatory architecture as it stands. It identifies the forward-looking legal workstreams (bilateral, statutory, contractual and insurance-based) that, taken together, would move each corridor from “legally possible” to potentially bankable for project financing.

Both corridors are potentially bankable, but only with a layered legal and regulatory architecture in which government support (by way of IGA or GSA), supportive and consistent domestic regulatory frameworks, robust commercial contracts and appropriate insurance products operate together to allocate and mitigate risk equitably. International experience points to one consistent lesson: they have rarely, if any, proceeded without government support. That support has typically been provided either through (i) a bilateral intergovernmental agreement between participating countries, or (ii) a government support agreement between the host government(s) and the private project sponsors, establishing the regulatory and policy framework necessary for the project to proceed. At present, neither corridor has in place all the necessary elements of this supportive legal and regulatory architecture although public commitments (for example, through the recent MOUs signed between Indonesia and Singapore) to address a number of these gaps are welcome.

The Malaysia-Sarawak corridor already has several elements of the enabling framework in place: express export authorisation, alignment of the regulator and the likely exporter, and a mature Singapore-side import regime. As such, the proposed enhancements outlined in *Legal Workstreams to Bankability* are largely refinements to a workable platform.

The Indonesia corridor has a different set of regulatory challenges: constitutional and statutory framing of energy as a strategic national asset (prioritising domestic supply over exports), mandatory PLN intermediation through approval of exports and utilisation of transmission infrastructure, and the five-year statutory export licence cap. These are just some of the challenges that need to be addressed to provide the necessary enabling framework for the export-import projects to Singapore to succeed. Set out in *Legal Workstreams to Bankability* are key legal and regulatory gaps that we recommend are prioritised to be addressed.

International precedent in comparably complex jurisdictions demonstrates that bankability can best be achieved where:

a) The legal "umbrella" is built deliberately, with binding bilateral or multilateral frameworks, sovereign support (where appropriate, particularly to address government-side risks that cannot be managed by private sector participants), and investor protection treaties providing general investor support, working in combination to provide a stabilised legal and regulatory framework;
b) Curtailment, change in law, and force majeure risks are treated on a back-to-back basis consistently across the project chain and converted (where they are not avoidable) into debt-protective compensation events;
c) Lenders have meaningful direct agreements with relevant government agencies and key contract counterparties to permit step-in rights / cure periods and remedies to minimise the risk of project defaults proceeding to project termination;
d) Political risk insurance provides a layered backstop of credit protection against the risk of government non-performance; and
e) SOE involvement is leveraged on the upside for land access, system planning visibility, and sovereign interface, while being neutralised on the downside through ring-fencing and direct agreements.

For lenders and sponsors, the right posture in each corridor is to engage actively in shaping the legal architecture in parallel with project development, rather than treating it as a pre-condition that must be satisfied externally before structuring work can begin. Progress under the June 2025 and July 2026 Singapore–Indonesia MOUs, the enhanced APG MOU, and the SEB-led Sarawak export programme evidences the political support, converting that political momentum into bankable legal infrastructure is the next phase of the corridor work.

> "The ASEAN Power Grid is a step change in ambition for the region. If realised, it would include the longest subsea interconnectors in the world. Delivering this vision is not only a technical challenge; it requires strong institutional coordination, robust regulatory and commercial frameworks, and the mobilisation of both public and private capital. While regional cooperation continues to strengthen the enabling framework, the success of the APG will depend on the implementation of individual projects. We welcome this paper as a practical, bottom-up perspective on the conditions needed to move APG projects towards bankability."
>
> *— International Energy Agency (IEA) Regional Cooperation Centre*

Areas for Future Exploration

This paper has intentionally focused on the commercial and regulatory drivers of bankability for Singapore's cross-border power import projects from two high-potential corridors, Riau Islands (Indonesia) and Sarawak (Malaysia), with sufficient depth to be actionable for project finance practitioners, and sufficient focus to remain accessible. Covering every dimension of this topic in a single paper risks diluting the core message: **that bankability is achievable, but key structural conditions need to be met.**

Several equally important topics nonetheless sit outside the paper's scope, and merit dedicated treatment as the APG ecosystem continues to develop. It is recognised that these areas are not peripheral to the APG financing challenge. They are part of the same ecosystem this paper has sought to activate, and each merits the same rigour and ground-up analysis applied here.

Cross-Border Renewable Energy Certificates Recognition

The recognition of cross-border RECs under RE100 GHG Protocol and Regional REC framework is a critical determinant of green premium viability and offtake bankability for projects outside the current "market boundary" definitions. Both are moving on different timelines: the GHG Protocol Scope 2 revision has a defined trajectory toward a final standard in 2027-2028[65], while RE100's Technical Advisory Group engagement with Singapore on market boundary recognition is at an earlier and less certain stage. Additionally, Singapore is working with key standard bodies such as the International Tracking Standard Foundation (I-TRACK) to develop fit-for-purpose cross-border frameworks for Southeast Asia[66].

A credible cross-border attribute framework should address REC ownership and transferability, registry interoperability, avoidance of double counting, residual-mix treatment, and recognition under relevant corporate reporting frameworks. Until these matters are operationally resolved, projected green premium revenues and long-term corporate demand should be treated as conditional. The interplay between these frameworks, PPA structuring (and the treatment of RECs under the PPA), and corporate sustainability reporting obligations warrants dedicated analysis as both corridors develop.

Insurance Architecture for Cross-Border Infrastructure

The insurance requirements for cross-border subsea transmission projects across its construction and operating lifespan, spanning construction and erection all risks (CAR/EAR), delay in start-up (DSU), operational all risks (OAR), business interruption (BI), political risk insurance (PRI) and third-party liability across multiple jurisdictions, are complex and not well understood outside specialist circles. It is a misconception that insurance will be available to address all risks that other parties in the project cannot. Insurance is not a "catch all" solution, and it cannot replace sound project structuring, regulatory certainty, and disciplined allocation of risks.

The insurance market will undertake its own due diligence of the projects, and where risks are considered insurable, it will make available products to address insurable risks. Insurance availability is subject to exclusions and limitations, and it may not always be available on commercially reasonable terms. Capacity can also be limited on exposure to specific projects, sectors, technologies and geographies. Early engagement with the insurance market can help to identify and mitigate risks before they become financing constraints. Specialist insurers and reinsurers can provide technical input on construction methodologies, natural catastrophe exposures, supply-chain resilience, operational risk management, and loss prevention measures. Therefore, insurers can add value during project development, and not only after financial close.

[65] Upcoming Scope 2 Public Consultation: Overview of Revisions – GHG Protocol, Sep 2025
[66] Singapore Partners I-TRACK Foundation to Develop a Cross-Border Renewable Energy Certificate Framework – MTI, Oct 2025

From a lenders' perspective, considerable time can elapse between the insurable event occurring and insurance proceeds being received, with direct implications for liquidity planning, debt service sizing and project finance structuring. As such, the views of the insurance sector will be important to progress the APG. A dedicated study of appropriate insurance architecture, underwriter appetite, and coverage benchmarks for APG projects would fill a meaningful gap.

> "Insurance plays an important role in enhancing the resilience and bankability of major cross-border infrastructure projects, but only where risks are appropriately identified, allocated and managed. Commercial, regulatory, sovereign, and operational risks must be addressed through a combination of robust contractual frameworks, supportive public policy, and appropriate risk transfer solutions. This integrated approach is essential to mobilise long-term private capital for the ASEAN Power Grid."
>
> *— SCOR*

Secondary Market and Asset Recycling Mechanisms

As the first wave of APG projects reaches operational maturity, a liquid secondary market for project equity and infrastructure bonds will be essential to recycling capital into the next generation of projects. APG structures should be designed with long-term institutional ownership in mind. Pension funds, insurers and sovereign investors require predictable cashflows, governance transparency, refinancing pathways, and investable operating assets. Designing projects with future asset recycling or regulated ownership models could materially expand the available pool of long-term capital. Additionally, portfolio aggregation models for APG assets could also be evaluated, as a diversified portfolio of generation, transmission, storage and grid-related assets across multiple corridors may be more attractive to institutional investors than single-project exposure, further deepening the capital pools for asset recycling for the original sponsors. The conditions for this are worth examining as a distinct workstream.

Closing Message

The ASEAN Power Grid will not be built by policy or technology alone. It will be built project by project, through the alignment of commercial interests across sovereign borders. Such thinking forms the core thesis of this paper. The frameworks, precedents, and lessons documented here are the building blocks of bankable transactions. **Sharing them openly across the value chain is how policymakers, developers, and financiers move from ambition to execution, giving all participants, from project developers and regulators to financiers and offtakers, a clearer view of what bankability requires in practice.**

The laws of physics that govern cross-border power transmission, cables, converters, and generation assets are well understood. The engineering is solvable. In contrast, the laws of finance that underpin these projects, allocation of risk, clarity of regulatory frameworks, and durability of revenue structures present a clear opportunity for alignment. **With greater definition and coordination across stakeholders, these elements can be structured to unlock capital and bring projects to financial close.**

The Singapore–Sarawak and Singapore–Indonesia corridors of APG are financeable. Demand is real, resources are available, and political will is present. The Indonesia and Malaysia import corridors are not merely supply solutions for Singapore. They are the first concrete expression of what regional energy cooperation looks like when commercial interests, sovereign commitments, and financing structures are properly aligned. **Getting these first projects right, through disciplined structuring, clear regulatory framework and risk allocation, and durable offtake will set the foundation for a truly integrated ASEAN energy market.**

Glossary Of Acronyms

APG	ASEAN Power Grid is a regional power grid initiative driving ASEAN's energy cooperation, promoting multilateral power trade that supports the ASEAN Economic Community goals of enhancing regional energy security, resiliency and connectivity.
ASEAN	Association of Southeast Asian Nations, comprising of eleven member states: Brunei Darussalam, Cambodia, Indonesia, Lao PDR, Malaysia, Myanmar, Philippines, Singapore, Thailand, Timor-Leste, Vietnam.
Cabotage Regulations	Regulations placed on foreign-flagged ships operating in domestic waters of a country.
CBAM	Carbon Border Adjustment Mechanism is the European Union's regulatory tool to prevent "carbon leakage". It ensures imported carbon-intensive goods are subject to the same carbon costs as those produced within the EU, putting all manufacturers on equal footing and encouraging global decarbonisation.
COD	Commercial Operation Date is a critical milestone when a newly constructed facility completes commissioning and starts to generate revenue.
DSRA	Debt Service Reserve Account is a dedicated reserve account mandated by lenders that borrowers to make debt repayments when cash flow available to service debt is too low. It is a safety measure that gives the borrower time to deal with a lack of cash flow available to service debt and prevents them from defaulting.
GenCo	(Electricity) Generation Company
GHG Protocol	Greenhouse Gas Protocol is the world's most widely used international accounting standard for measuring and managing greenhouse gas emissions.
Green Premiums	In the context of power markets, it is the additional cost a buyer pays to purchase electricity generated from zero or low-emissions sources, compared to fossil-fuel generated power sources.
Interconnector	High-voltage cables that allow power to flow between different power grids, enabling power trade between countries.
Merchant Risk	Exposure to volatile wholesale prices when energy is not fully contracted, which increases revenue variability compared to fixed priced, long-term PPAs.
OFTO	First introduced in the UK, an Offshore Transmission Owner is a party that assumes the responsibility for offshore transmission assets.
PPA	Power Purchase Agreement is a contract between an electricity generator (generator) and the party who is purchasing the power (offtaker) which incorporates the commercial terms for the sale and purchase of electricity for a project.
Project-on-Project risk	When mutually dependent projects, whose risk of completion and financing are dependent on each other.
RE100	A global initiative that brings together the corporates committed to using 100% renewable electricity in their operations.
REC	Renewable Energy Certificate is a tradeable, market-based instrument representing the environmental attributes of 1MWh of renewable electricity.
SIJORI	An economic sub-region that seeks to exploit the competitive strengths of the three areas: Singapore, Johor (Malaysia), Riau Islands (Indonesia).
TransCo	(Electricity) Transmission Company

About SSFA

The Singapore Sustainable Finance Association (SSFA) is an industry body established by the Monetary Authority of Singapore (MAS) along with the financial industry in January 2024. Building on the successful work of the Green Finance Industry Taskforce (GFIT), SSFA is established to collaborate across the financial and real economy sectors to support the growth of Singapore as a trusted, vibrant, and inclusive sustainable finance centre.

SSFA has six thematic focus areas (i.e., carbon markets, transition finance, blended finance and impact, natural capital and biodiversity, taxonomy, and adaptation and resilience), reflecting core priorities of the broader sustainable finance ecosystem, involving key stakeholders such as financial institutions, real economy corporates, service providers, government bodies, academia, NGOs and others, essential for advancing the industry.

SSFA welcomes participation from financial services, non-financial sector corporates, academia, non- governmental organisations, policymakers and other industry bodies.

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