

VIETNAM POWER: TO EXECUTION

PART 2 PROJECT FINANCE AND BANKABILITY

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Vietnam's power investment programme depends on projects that can secure financing and allocate construction, offtake, grid and market risks. This second instalment examines the contracts and incentives that shape bankability, then considers the next phase of system integration and energy transition.

[Part 1](#) examined the legal framework, project development sequence and investor selection. This instalment focuses on the financing and commercial requirements for project execution.

Project Finance & Bankability Framework

A typical energy project in Vietnam will be underpinned by a contractual structure linking the project company, the electricity off-taker, grid counterparties, engineering, procurement and construction (EPC) contractors, operation and maintenance (O&M) contractors, lenders and relevant land/project stakeholders. The key contractual areas and associated inherent risks are as follows:

The power purchase agreement (PPA) is the principal revenue contract for a conventional grid-selling independent power project (IPP). Circular No. 12/2025/TT-BCT, as amended (the “**PPA Circular**”), sets out the principal PPA contents in Appendix III as the basis for negotiation and execution. The parties must assess the applicable pricing rules and negotiate the allocation of performance, dispatch, payment, termination and dispute risks within that

framework. The existence of prescribed PPA contents does not itself establish that the resulting contract is acceptable to lenders.

For projects selling into the national system, the applicable pricing route depends on the technology and investor-selection mechanism. Generation-price frameworks and the rules for determining generation service prices constrain the commercial envelope, while a successful bid may determine the PPA price where the relevant special bidding regime applies. The position should therefore be stated by reference to the relevant project category rather than as a single Vietnam Electricity Group (EVN) tariff model.

Direct power purchase agreements (DPPAs) provide an alternative revenue architecture, but the two mechanisms should not be collapsed into a single 'virtual' or freely priced model. A private-grid DPPA permits direct physical supply with negotiated pricing, subject to the framework under [Decree No. 57/2025/ND-CP](#) (the “**DPPA Decree**”), as amended. A national-grid DPPA instead combines spot-market sales by the generator, physical purchases by the consumer or eligible retailer and a separate forward contract. Bankability therefore turns on different combinations of market-price exposure, counterparty credit, allocation ratios, grid charges and settlement mechanics.

Grid and technical arrangements sit alongside the power purchase agreement. Connection is agreed with the relevant transmission or distribution company, while dispatch is carried out by the National Power System and Market Operation Company, which has been separated from EVN. Confirmed evacuation capacity operates as a practical condition of bankability, and it is assessed against local network conditions rather than against the project alone.

Land, sea tenure and corporate structure complete the security perimeter. Offshore wind requires particular care because the ownership, domestic-participation and concurrence requirements under [Decree No. 58/2025/ND-CP](#) (the “**Renewable Energy Decree**”), as amended are distinct from the project-level equity and investment-contribution tests under [Decree No. 272/2026/ND-CP](#) (the “**Offshore Wind Decree**”). These requirements should be mapped separately when structuring both the project company and its financing.

Key bankability issues

Curtailement remains a material bankability risk, but it should be framed by reference to the applicable regulatory and contractual regime. Vietnam does not provide a general statutory deemed-energy or compensation entitlement for grid- or system-related curtailment applicable across grid-selling renewable projects. Dispatch and market-operation rules govern system instructions and operational compliance, while the PPA Circular leaves material PPA terms to negotiation. The lender issue is therefore the extent to which a particular PPA, market mechanism and project structure allocate or compensate lost revenue when output is constrained for reasons outside the project company's control. For offshore wind and other projects benefiting from minimum contracted-output mechanisms, the relevant exclusions - including system technical conditions or demand limitations - must also be modelled carefully.

Tariff risk is increasingly project-specific. The feed-in-tariff (FIT) era has ended for new projects, and pricing now depends on the relevant generation-price framework, tender result, market mechanism or negotiated private-grid arrangement. Currency and indexation exposure remain important where project costs or fuel obligations are denominated in foreign currency, but the extent of protection is contractual and technology-specific rather than uniform across the sector.

Minimum contracted output mechanisms apply to specified project categories. Article 15(4) of Decree No. 56/2025/ND-CP (“**Decree 56**”), as amended by [Decree No. 100/2025/ND-CP](#), provides a minimum of 65% of average annual generation for qualifying projects using imported liquefied natural gas (LNG) (updating), during repayment of principal and interest and for no more than 10 years from commencement of generation. Eligibility includes the prescribed completion-acceptance notification and commencement of generation using imported LNG before 1 January 2031. The Renewable Energy Decree separately provides mechanisms for qualifying offshore wind (80%, during principal repayment and for no more than 15 years) and qualifying first-of-type green-hydrogen or green-ammonia power projects (70%, during principal repayment and for no more than 12 years). These mechanisms are subject to their respective eligibility conditions, exclusions and permitted contractual variations; they are not a general guarantee for renewable projects.

Termination risk must likewise be analysed scenario by scenario. The PPA Circular does not prescribe a comprehensive, lender-style termination compensation or project buy-out schedule for all IPPs. The parties therefore need to address the consequences of termination - including off-taker default, project-company default, prolonged force majeure and change in law - through the negotiated PPA and the broader financing package, subject to mandatory Vietnamese law. The bankability concern is not that termination is 'unregulated', but that there is no comprehensive statutory termination-payment framework that automatically protects outstanding project debt across the relevant scenarios.

Lender perspective

From a lender's perspective, the central question is how much revenue certainty the project contracts provide and how the financing case accommodates dispatch and market exposure.

Financeable structures typically combine: (i) clear and current planning status; (ii) a valid investment/investor-selection pathway; (iii) an executable offtake and pricing framework; (iv) credible grid-connection and evacuation assumptions; (v) secured land or sea tenure; and (vi) a security and direct-agreement package capable of supporting lender remedies. Experienced domestic participation can be valuable in managing local interfaces, implementation, supply-chain and operational coordination, but should not be presented as conferring preferential treatment in permitting or land clearance.

Financing becomes more difficult where merchant revenue is unsupported by an adequate risk buffer, curtailment exposure cannot be assessed reliably, substantial foreign-currency costs are unmatched by revenue protection, or security over material assets cannot be enforced. The financing outcome depends on the combined revenue, sponsor-support and security package.

Conditions precedent to financial close are transaction-specific and should not be stated as universal legal requirements. In practice, lenders commonly require satisfactory evidence of key investment approvals, land or sea tenure, grid connection, PPA/DPPA arrangements, material project contracts, equity funding, permits on the critical path and an enforceable security package. The availability and form of direct agreements and step-in arrangements remain matters for transaction-specific negotiation rather than a standardised statutory package.

Investment Incentives vs. Real Risk Allocation

Vietnamese law provides a range of investment incentives and support mechanisms, but eligibility is neither uniform nor automatic. The analysis must distinguish general investment incentives under the [Law on Investment](#) No. 143/2025/QH15 (the “**Investment Law**”) and tax/land legislation from special sector-specific mechanisms for particular renewable, offshore-wind or new-energy projects.

Under the Investment Law, renewable, new and clean energy activities may fall within incentivised sectors, while the available forms of investment incentive include tax, import-duty, land-related and depreciation/deductibility measures, subject to the conditions of the relevant specialised legislation. The Investment Law identifies the incentive framework; the actual tax or land benefit must be tested under the applicable tax and land rules.

For corporate income tax, the governing statute is the Law on Corporate Income Tax No. 67/2025/QH15, effective from 1 October 2025. Qualifying income from eligible new investment projects, including relevant renewable/clean-energy projects where the statutory conditions are met, may benefit from a 10% preferential rate for 15 years and associated tax-exemption/reduction periods under Articles 12-14. The standard corporate income tax rate is generally 20%. Eligibility, commencement of the incentive period, income segregation and exclusions must be confirmed for the specific project; the incentive should not be described as automatic for every renewable-energy investment.

Separate sector-specific incentives apply to certain offshore-wind and new-energy projects under the Renewable Energy Decree. These mechanisms are conditional on the project satisfying the relevant statutory criteria, including timing, technology and - where applicable - sale to the national power system. They should be presented separately from general investment incentives.

Land incentives are governed principally by the Land Law 2024 and implementing legislation, with the available exemption or reduction depending on the project's incentivised sector and location as well as the applicable land-payment regime. Accordingly, sector eligibility alone does not necessarily produce the longest land-rent exemption; location and the specific statutory conditions remain material.

For qualifying offshore wind, Article 25 of the Renewable Energy Decree provides, among other incentives, exemption from sea-area use fees during the basic construction period for up to three years and a 50% reduction for the following 12 years, together with specified land-related incentives. The package is subject to the decree's conditions, including the relevant investment-approval timing and planning/capacity requirements for projects selling to the national system.

For the first qualifying project of each type of new-energy electricity using 100% green hydrogen, 100% green ammonia or a 100% mixture of the two and supplying the national power system, the Renewable Energy Decree provides a separate incentive package,

including sea-area fee relief and a minimum long-term contracted-output mechanism. These incentives are technology- and project-specific and should not be extrapolated to renewable energy generally.

Incentives can improve project economics, but they do not substitute for bankable risk allocation. Investors must still address planning and permitting sequencing, land/sea tenure, grid capacity, dispatch exposure, offtake credit, currency and indexation risk, construction interfaces and financing enforceability. The legal framework is substantially more developed than in the FIT era, but implementation practice and commercial structures continue to evolve.

The Next Phase: System Integration & Energy Transition

The planning instruments show the scale of investment required and the importance of system integration. The revised Power Development Plan VIII, approved under [Decision No. 768/QĐ-TTg](#) (the “**Revised PDP VIII**”), targets 183,291–236,363 MW of capacity serving domestic demand by 2030. It estimates generation and transmission investment of approximately USD 136.3 billion for 2026–2030, USD 130.0 billion for 2031–2035 and USD 569.1 billion for 2036–2050, with the later estimates subject to refinement. The National Energy Master Plan, revised under [Decision No. 363/QĐ-BCT](#) (the “**Revised NEMP**”), projects final energy demand of approximately 120–130 million tonnes of oil equivalent by 2030 and a renewable share of total primary energy of approximately 25–30% in 2030 and 70–80% in 2050. These are distinct measures: electricity capacity, final energy demand and the primary energy mix should be evaluated separately.

Grid, storage and flexibility are becoming central investment considerations. The Revised PDP VIII envisages substantial storage deployment, while [Resolution No. 253/2025/QH15](#) (“**Resolution 253**”) permits specified storage projects to be added through its planning adjustment mechanism. Battery energy storage systems (BESS) also have a specific pricing and PPA framework under [Circular No. 62/2025/TT-BCT](#) (the “**BESS Circular**”), effective from 26 January 2026. Its scope includes qualifying standalone systems of at least 10 MW connected at 110 kV or above. Storage integrated with renewable generation and systems invested in by power corporations are subject to separate regulatory treatment.

The BESS Circular establishes methods for generation-price brackets and service pricing, together with principal PPA contents. Bankability therefore requires a project-specific assessment of the applicable pricing route, dispatch and charging arrangements, performance obligations and contractual revenue. Additional merchant or ancillary-service income should be included in a financing case only where the relevant rules and contracts support it.

Imported LNG can support system flexibility, but financing depends on the interaction between electricity revenue and fuel obligations. The minimum contracted-output regime discussed above must be assessed alongside fuel-price pass-through, take-or-pay exposure, terminal arrangements and gas-supply interruptions. The Ministry of Industry and Trade’s [May 2026 consultation](#) proposed increasing the minimum contracted output to 75% and the maximum duration to 15 years. Those consultation figures should not be treated as an enacted entitlement without a final amending instrument applicable to the project.

New-energy and nuclear development has moved into a more concrete legal framework. The Renewable Energy Decree provides specific incentives for qualifying first-of-type green-hydrogen and green-ammonia power projects. Nuclear power has returned to national planning, and the [Law on Atomic Energy](#) No. 94/2025/QH15, effective from 1 January 2026, provides the updated statutory framework. Resolution 253 also provides a basis for

preparation relating to [small modular nuclear reactors](#). These areas remain at an earlier commercial-development stage than conventional renewables and should be framed as emerging opportunities rather than mature bankable asset classes.

Market operation is also evolving. [Circular No. 29/2026/TT-BCT](#) (the “**Wholesale Market Circular**”) now governs the competitive wholesale electricity market, including registration, bidding, dispatch scheduling, metering, market-price determination and settlement. Together with the continued institutional separation of system/market operation from EVN and the evolution of time-of-use and retail-price mechanisms, this reinforces a broader direction: the value of future projects will increasingly depend on when, where and under what market structure electricity can be delivered, not simply on installed capacity.

Strategic Takeaways for Investors

There is no single 'fastest' market-entry route. Investors may pursue new project development through the applicable planning and investor-selection framework, participate in a competitive process for an identified project, or acquire an interest in an existing project company. Convertible financing may also be considered, subject to the applicable investment, corporate and foreign exchange rules. Acquisition can shorten development time where approvals are valid and transferable, but it also shifts the focus to diligence on planning status, investor-selection history, land/sea tenure, grid rights, PPA/DPPA terms, licensing, compliance and outstanding liabilities.

Near-term opportunities remain technology- and location-specific. Utility-scale solar and onshore/nearshore wind are more compelling where grid capacity and dispatch assumptions are demonstrable; rooftop solar has gained additional commercial flexibility following [Decree No. 243/2026/ND-CP](#) (“**Decree 243**”); and DPPAs can support corporate renewable procurement, particularly where the parties can manage the relevant grid, market and settlement interfaces. Imported LNG, offshore wind, storage and new energy offer substantial strategic potential but require more project-specific analysis of offtake, grid, fuel, ownership, financing and implementation risk.

Risk mitigation should begin before investor selection or acquisition. Key diligence points include the legal basis for project allocation; current planning status; grid-connection and evacuation assumptions; curtailment and dispatch exposure; tariff, market-price and foreign-exchange sensitivity; land/sea rights; termination economics; and the enforceability of security, direct agreements and step-in rights. These issues should be modelled against the specific revenue mechanism rather than treated as generic power-sector risks.

Local structuring should be driven by the legal requirements and execution needs of the project, not by an assumption that a domestic or State-owned partner will obtain preferential permitting treatment. Offshore wind is the clearest example: foreign ownership, domestic participation, national-security concurrence, project-level equity and minimum investment-contribution requirements are separate legal concepts and must each be tested under the Renewable Energy Decree and the Offshore Wind Decree.

Looking Ahead: The Bankability Test

Vietnam's power sector presents a substantial investment requirement and an increasingly developed legal framework. The Revised PDP VIII and related planning instruments contemplate major expansion in generation, grids and system flexibility, while the legislative package adopted since 2024 has materially reshaped planning, investor selection, renewable-energy development, DPPAs and market operation.

The constraint has therefore changed in character. Securing a place in planning and identifying a pricing route remain important, but they are no longer sufficient. The principal challenge is increasingly the translation of capacity targets into system-compatible, executable and financeable projects, while parts of the regulatory and commercial framework continue to develop. Curtailment, dispatch, indexation, termination, grid integration and revenue certainty must be assessed through the particular project structure and offtake regime.

For investors and lenders, the next phase is an execution story. Capacity targets identify where investment is required; bankability depends on whether a project can reach financial close and operate with risks allocated to parties able to manage or price them. Vietnam's power market is demonstrably investable, while bankability remains project- and structure-specific and continues to depend materially on risk allocation, grid integration and the applicable offtake framework. That distinction is likely to define the next investment cycle.

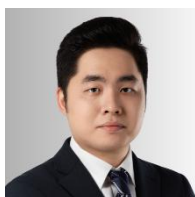
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