Financing the ASEAN Power Grid

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Abstract

The Association of Southeast Asian Nations (ASEAN) has a long history of electricity system connectivity, and the development of the ASEAN Power Grid (APG) is central to achieving a sustainable, secure and affordable energy transition across the region. Delivering the APG will require a significant step-change in investment over the coming 15 years, and unlocking financing from a diverse range of sources will be essential for this to happen. Yet financing approaches and business models have not evolved at the pace required to support an increasingly ambitious and complex pipeline of interconnector projects.

This report examines how interconnectors are approached today from the financing and business model perspective. It explores how, in combination with broad macro-financial and market-specific factors, current approaches may create challenges given the size and characteristics of the APG project pipeline. Rather than focussing on institutions or regulatory frameworks, this report approaches the issue through an investor's lens – asking how these assets are financed in practice and what must change to make them bankable for a wide set of potential investors.

By quantifying total investment needs and potential sources of finance, identifying key barriers and offering clear, actionable recommendations, this report aims to equip policy makers, regulators, utilities, financiers and private-sector stakeholders with the guidance needed to accelerate the financing and implementation of the ASEAN Power Grid.

Foreword

The Association of Southeast Asian Nations (ASEAN) is expected to account for a quarter of global energy demand growth over the next decade, driven by its growing population, rising incomes and expanding manufacturing sector. While the benefits of power connectivity for energy security, affordability, sustainability and economic prosperity have long been recognised, the Age of Electricity, increasing deployment of variable renewables, and rising energy security concerns further strengthen the case for regional power integration.

Momentum continues to build around the ASEAN Power Grid (APG) vision, supported by sustained leadership from successive ASEAN chairs and member states. Yet implementation has lagged political will and power integration remains nascent. Realising the ambitions of the APG will require a substantial scale up of investment in the coming years. As is often the case for many emerging markets and developing economies, mobilising investment is not just a matter of political commitment and effective institutions, but also of access to finance.

This report aims to support ASEAN to translate the APG from vision to implementation. It provides guidance on actionable steps to encourage successful financing and deployment of interconnectors in the region, with reference to international best practice and case studies. We consider the role of innovative financing models, commercial frameworks and robust risk management to meet investment needs. Above all, we believe that success will require strong leadership and close collaboration between policy makers, regulators, utilities, development finance institutions and the private sector.

I would like to warmly thank the Energy Investment Unit in the Office of the Chief Energy Economist and the report's lead author James Bragg for designing and delivering this timely report. We also thank our external partners that contributed to this analysis. We hope it will serve as a practical reference point for stakeholders across the region as they work together to build a more connected, secure and sustainable energy future.

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Acknowledgements, contributors and credits

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Executive summary

Southeast Asia's electricity sector is on the cusp of major changes that underscore the case for regional integration

Rapidly growing electricity demand alongside accelerating momentum behind renewables deployment will require major investment in grids across Southeast Asia. Electricity consumption in the Association of Southeast Asian Nations (ASEAN) region has increased ninefold since 1990 and is projected to continue to grow at annual rate of 3 to 4% through to 2040, considerably faster than the global average. ASEAN member states have committed to a massive expansion of new generation capacity to meet this demand. By 2040, total generation capacity is set to more than double with renewables accounting for 75% of new additions under today's policy settings. This will require over USD 300 billion of investment in the expansion and modernisation of electricity grids from 2025 to 2040 – a 72% increase compared to investment from 2009 to 2024.

Interconnectors are set to be a critical component of this grid build-out. The ASEAN Power Grid (APG) has been a pillar of regional cooperation for decades and has emerged as a cornerstone of the ASEAN energy transition. IEA analysis shows that ASEAN countries are very diverse in terms of electricity demand profiles, power supply mixes, and renewable energy potential. By connecting diverse renewable resources and demand centres across the region, the APG can smooth out the variability of variable renewable energy generation and demand – allowing countries to export surplus energy during periods of excess and import when local resources are insufficient to meet demand.

Regional electricity trade can help deliver a reliable, affordable, and secure energy transition

A well-designed APG can unlock cost savings and promote longer-term energy security objectives. Leveraging geographic complementarity promotes cost-effective development and utilisation of the region's resources. Previous analysis has found that higher levels of connectivity can significantly reduce operational costs, curtailment of variable renewable energy output and total generation capacity needs compared to a scenario of weak power system integration. Better utilisation of low-emissions generation can also prevent deepened dependencies on fossil fuel imports that are prone to supply shocks, as witnessed during the 2022-2023 global energy crisis which caused regional subsidies for fossil fuel consumption to soar. Optimising both variable renewable and flexible resources across countries requires a strong degree of trust, regulatory and technical co-ordination, robust business models, harmonised arrangements for cross-border trade, and substantial investment; but if achieved, it could benefit consumers through lower electricity costs and governments through enhanced energy security.

Regional power trade is nascent today despite the first projects dating back over five decades

Since the first project connecting Lao PDR with Thailand broke ground in the 1970s, only around USD 2 billion has been invested in cross-border interconnectors. An interconnected power system does not yet exist – the reality today is a much more fragmented landscape, composed of multiple subsystems at various stages of development. For comparison, the region invested more into electricity transmission in 2024 alone (USD 3.6 billion) than on interconnectors for the past 50-plus years. Most of the investment in cross-border projects has been for the purpose of one-way power exports, not for the type of bi-directional, grid-to-grid projects envisaged by regional integration plans.

Consequently, financing models and commercial arrangements for cross-border interconnectors have been slow to evolve. While export-oriented interconnections in Lao PDR, typically linked to new hydropower projects, have successfully mobilised international and private investment through project finance structures, similar dynamism has not emerged elsewhere in the region, nor in general for grid-to-grid interconnectors which are the focal point of regional planning. Today, most interconnector projects are developed in the same manner as the 1970 and 1980s: as two separate projects meeting at the border, financed on the balance sheet of state-owned enterprises, and remunerated through bespoke, bilateral contracts.

Yet momentum for the ASEAN Power Grid has never been stronger

Sustained high-level political backing is bearing fruit, with multiple key milestones achieved in recent years. Those include the Lao PDR–Thailand–Malaysia–Singapore Power Integration Project, now in Phase 2, which showcased the technical and commercial feasibility of multilateral cross-border electricity trade in ASEAN; Malaysia's framework for the issuance of cross-border renewable energy certificates for power exchange with neighbouring Thailand and Singapore; the enhanced Memorandum of Understanding on the APG between ASEAN member states; the endorsement of a Submarine Power Cable Development Framework terms of reference to inform regional cooperation for the legal, regulatory, technical, commercial, and governance aspects of subsea interconnectors; and the launch of the APG Financing Initiative, which looks to mobilise capital and strengthen the role of multilateral development banks and other financiers in support of the APG. Taken together, these achievements demonstrate a meaningful commitment to deliver on regional power system integration.

USD 27 billion of interconnector investment is needed by 2040 to realise the ambitions of the APG

The ASEAN Power Grid requires a substantial mobilisation of investment. Reflecting both the scale of the interconnector pipeline and a shift towards more capital-intensive transmission technologies, annual interconnector investment would need to surpass USD 1 billion before 2030 and average more than USD 2 billion per year thereafter. This is around 20-times higher than annual spending levels observed between 2019 and 2024 but only 8% of total projected grid investment to 2040.

The scale and complexity of interconnectors is set to increase. Many projects will span extreme distances and traverse challenging archipelagic geography to link the northern, southern and eastern subsystems of ASEAN. If built today, four interconnectors in the project pipeline would each exceed the length of the Viking Link between the United Kingdom and Denmark: currently the world's longest operational subsea interconnector.

Mobilising financing from diverse sources will be key to meeting this step change. The scale of investment requires new financing models and sources of finance, especially in the context of already sizeable investment needs for domestic transmission and distribution. This is reflected in the APG Financing Initiative, which aims to mobilise de-risking capital, technical assistance, and other supportive instruments to create a pipeline of bankable projects and crowd in investment from public and private sources.

Scale and nature of the project pipeline present a challenge to current financing and business models

A key challenge for the bankability of cross-border projects is lack of standardised and transparent commercial power trading agreements. A reliance on bespoke bilateral agreements means the region lacks the basis for harmonised trading arrangements, thereby limiting transparency and scalability. Heterogeneity among countries in terms of market structures, third-party access, methodologies for determining transmissions tariffs and wheeling charges, and other incentives or penalties make it challenging to ensure a fair allocation of costs and benefits while also delivering a sufficiently high and predictable return for investors.

Historical financing models are not suitable for complex subsea projects. These projects can cost several billion dollars, and are complicated by asymmetric financing capabilities between utilities, subsea cables which pass through the territorial waters of multiple nations, heightened geopolitical and sovereign risks, and regional benefits beyond the countries directly involved. Siloed approaches to financing, concentrated on the balance sheets of state-owned enterprises, are unlikely to support all projects of this type.

These challenges are compounded by a backdrop of acute supply chain issues which are more likely to affect subsea projects. Prices for transformers and cables have nearly doubled since 2018, while manufacturers and cable-laying vessels are operating at or near full capacity. These market conditions increase risks of project delays and higher costs.

Despite challenges, interconnectors can attract diverse sources of capital at scale under the right conditions

There are ways to realise and finance the ambitions of the APG, but this will require mobilising capital beyond state utility balance sheets. Decades of strong economic growth, ample foreign direct investment, and a relatively stable macro-financial environment create the ideal conditions for long-term investment to occur in the region. Institutional investors are increasingly interested in ASEAN's energy transition, and interconnector projects can attract this capital through clear revenue frameworks, affordable long-tenor debt and structured exit pathways.

Interconnector projects can be commercially viable under supportive regulatory and financing models, while retaining strong sovereign oversight and control. Financial modelling identifies tariff certainty and debt pricing as key drivers of returns. Implementing availability-based payments can significantly enhance project bankability and support long-tenor financing. The strategic focus must be on optimising these financial conditions while preserving a strong degree of state oversight and control. Viability can be further enhanced through blended finance structures and capital recycling mechanisms including regional investment platforms that free public capital for the next project.

Seven priorities to scale APG interconnector investment

Strong institutional leadership is essential to kick-start project development. Governments should proactively assess economic and social benefits, incorporate regional interconnector development as part of national power sector and investment planning, and provide leadership throughout early stages of project preparation and permitting. Above all, sustained political support is needed across all countries involved in each project.

Establish transparent, harmonised and predictable commercial arrangements for power trading. These should be guided by regulation, not bespoke contracts. Establishing a regional approach to transmission charges for cross-border trading as seen in the West African Power Pool, potentially including some degree of cross-border regulatory governance and oversight bodies, can create better visibility for investors and reduce transaction costs. Availability payments have been can also help increase the predictability of returns for investors and have proven successful in other countries like Brazil.

Apply alternative financing models, including shared ownership structures and independent transmission project models. Cross-border financing and shared ownership structures have been used in numerous European interconnector projects including the NeuConnect (United Kingdom-Germany), Viking Link (Denmark-United Kingdom) and NordBalt (Sweden-Lithuania), among others. This model can improve end-to-end project management and enable sharing of costs and benefits for capital-intensive, long-distance subsea projects. Independent transmission project models can reduce state-owned enterprise financing requirements and attract private sector capital at scale. For example, Brazil's public auctions for independent transmission projects has attracted participation from over 200 different companies and led to significant discounts from the regulator's initial payment offerings. Regional funding mechanisms like the Connecting Europe Facility for Energy can also be explored for projects that bring regional benefits beyond the countries hosting the asset.

Tackle key investment risks to reduce the cost of capital and improve bankability. Robust risk management is essential. Risks should be allocated to the party best placed to manage them: in particular, governments can play an important role in addressing regulatory, permitting and access risks. Singapore Energy Interconnectors – a government appointed private entity which helps to derisk, develop and crowd-in investment for cross-border interconnector projects – is an example of government-led intervention to promote bankability. Credit enhancement instruments such as guarantees can further mitigate political and off-taker risks, while insurance is critical for costly subsea projects. Where needed, public and concessional financing can be used to bridge bankability gaps.

Strategically deploy catalytic international public finance to bridge financing gaps and crowd in private capital. Multilateral development banks and development financial institutions can provide project preparation support and co-financing to increase project bankability alongside sovereign and other commercial investors. Existing examples from ASEAN include the APG Financing Initiative or the ASEAN Catalytic Green Finance Facility. Successful demonstration projects can establish more bankable structures and catalyse increased private capital participation, complementing ongoing public finance support in the region.

Enable capital recycling through structured exit pathways, allowing early stage investors to redeploy capital into new projects. This can be achieved by embedding refinancing provisions in concession agreements, allowing minority stake sales to institutional investors, and creating regional platforms to consolidate operational assets into secondary markets. Transparent regulatory frameworks for approvals, asset valuations and tax treatment can also play an enabling role.

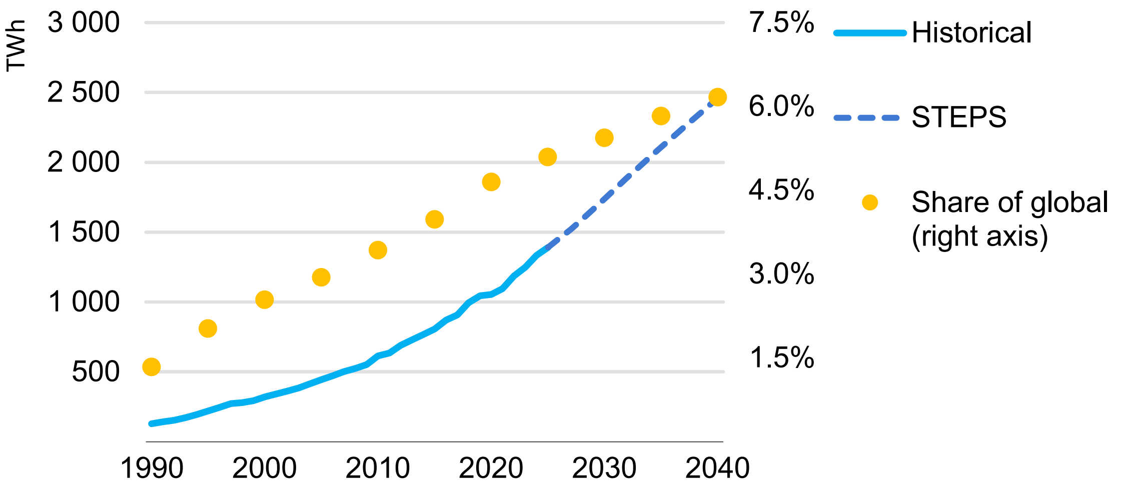
Strengthen supply chain co-ordination and development. Forward planning, early engagement with equipment manufacturers, and co-ordinated procurement across the region can secure production volumes, manage rising costs and construction risk. For instance, long-term framework agreements have allowed Sweden and the United Kingdom to lock-in orders for large power transformers, shunt reactors, and HVDC cables and converter systems for planned and anticipated projects while providing clear visibility for suppliers. Investing in regional manufacturing and workforce development is an opportunity to capture local and regional benefits from the APG.

Introduction and context

Electricity demand is poised to continue its rapid growth across Southeast Asia

The Association of Southeast Asian Nations (ASEAN) has experienced rapid economic change in recent decades.[1] Expanding electricity access, rising incomes and a burgeoning industrial sector are behind the region's growing demand for electricity, which has increased ninefold since 1990. ASEAN accounted for 5% of global electricity consumption in 2024, up from just 1% in 1990.

Historical ASEAN electricity demand and projections in the Stated Policies Scenario, 1990-2040



Note: TWh = terawatt-hours; STEPS = Stated Policies Scenario.

Looking forward, electricity demand growth is projected to remain robust at 3-4% per year through to 2040 in the Stated Policies Scenario (STEPS)[2], driven by the electrification of end-use sectors like road transport and industry, as well as increased demand for modern appliances, cooling and digital services.

[1] ASEAN has 11 member countries: Brunei Darussalam; Cambodia; Indonesia; Lao People's Democratic Republic (hereafter Lao PDR); Malaysia; Myanmar; Philippines; Singapore; Thailand; Timor-Leste and Viet Nam.
[2] STEPS is an exploratory scenario of the International Energy Agency wherein legislated policies, as well as policies and other official strategy documents that have been formally put forward, but not yet adopted, are considered alongside broader socio-economic trends. Full documentation related to the scenario including the assumptions is available at: Global Energy and Climate Model Documentation 2025.

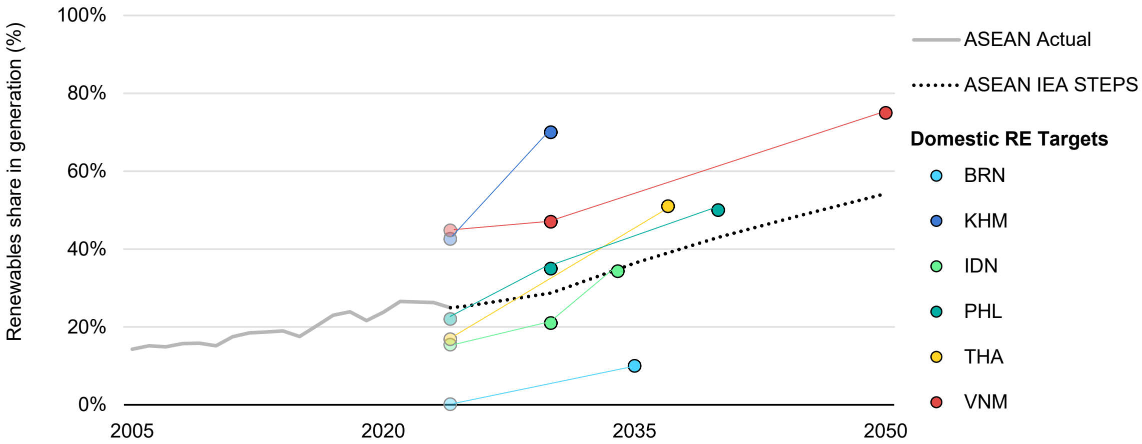
Ensuring that new demand is met in an affordable, secure and sustainable way is imperative for the future prosperity of the region. For the moment, coal is the largest source of electricity generation in Southeast Asia, but there are cost-effective ways to diversify the mix, including development of the region's hydropower, solar, wind and geothermal resources. Their deployment is accompanied with a new set of challenges that underscore the importance of regional power system connectivity.

Momentum is building for renewables

Renewable deployment has grown in recent years in many parts of Southeast Asia, but various regulatory, political, financial and technical challenges continue to constrain their development. For instance, restrictions on private sector participation, fossil fuel subsidies, ineffective procurement frameworks and high financing costs have contributed to slow deployment of renewables in some contexts. As a consequence, most countries in Southeast Asia remain in the early stages of integrating variable renewable energy resources for power generation, specifically for solar photovoltaics (PV) and wind.

Nevertheless, ambitions are high and underpinned by firm political commitments: eight-of-eleven ASEAN member states have made commitments for net zero emissions or carbon neutrality. Positive traction for renewables is clearly emerging as countries accelerate deployment through renewed targets, maturing procurement procedures and market reforms. Solar, wind and battery storage are central to recent and upcoming power sector development plans in Viet Nam, Thailand, Philippines, Indonesia and Cambodia; multiple rounds of successful solar auctions have been held in Malaysia and Philippines; and more flexible regulations for power purchase agreements (PPAs) will allow developers to sell electricity directly to corporate consumers in Viet Nam and Malaysia.

Domestic renewable energy targets by selected countries and ASEAN region in the STEPS, 2005-2050



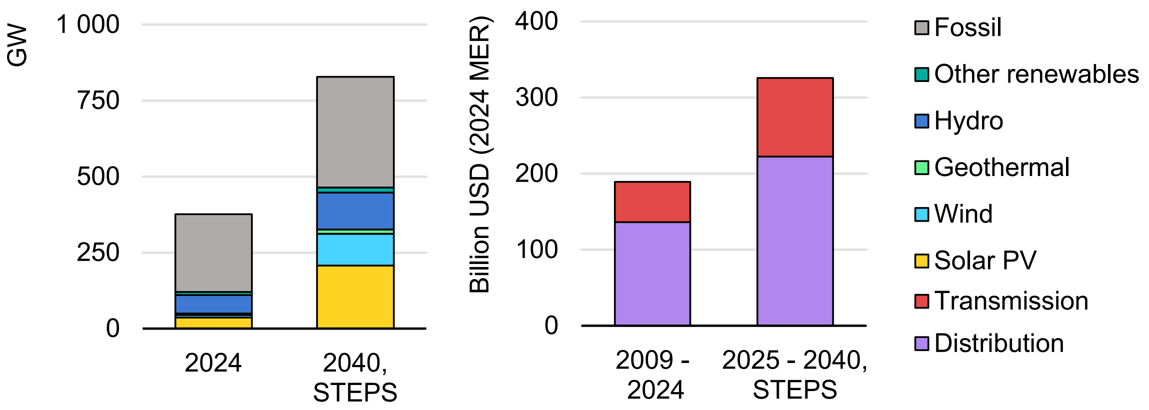
Notes: STEPS = Stated Policies Scenario; RE = renewables. BRN = Brunei Darussalam; KHM = Cambodia; IDN = Indonesia; PHL = Philippines; THA = Thailand; VNM = Viet Nam.
Source: IEA (2025), Integrating solar and wind in Southeast Asia.

Deployment of renewables for power generation is poised to accelerate sharply in response to these recent developments and against the backdrop of rising electricity demand. In the STEPS, total electrical capacity more than doubles over the next 15 years, with renewables accounting for 75% of new capacity additions, of which over 75% are from solar and wind.

Significant grid investments will be needed in the coming years

A 75% increase in electricity demand by 2040 and a doubling of total electrical capacity, mainly from renewables, both point towards a significant increase in grids investment. A cumulative total of about USD 330 billion of new investment for electricity grids is needed in the 2025 to 2040 period in ASEAN in a scenario based on today's policy settings. This is an increase of 63% for electricity distribution investment and a 95% increase for transmission compared to cumulative spending from 2009 to 2024.

Installed electricity capacity and grid investment in Southeast Asia, 2009-2040



Notes: GW = gigawatts; MER = market exchange rate; STEPS = Stated Policies Scenario. Grids are differentiated according to their voltage levels. Distribution grid, up to 69 kilovolts (kV), corresponds to low-voltage lines to supply electricity to residential and commercial users as well as medium-voltage lines serving villages and small and medium-size industrial sites. The transmission grid, over 69 kV, connects utility-size generation, distribution grids and large industrial consumers. In addition, transmission grids include extra-high-voltage and ultra-high-voltage (UHV) lines that transmit electricity over longer distances. Interconnector investment is included within transmission investment.

Regional interconnection can help deliver an affordable, secure and sustainable transition

ASEAN's abundance of untapped renewable energy is not evenly distributed across countries or conveniently situated where demand is highest; consequently, access to low-carbon, low-cost electricity is often constrained by geography or borders. Interconnectors – electricity transmission lines that link electricity systems together, often across borders – can foster the exchange of electricity from resource-rich, but potentially remote areas, to major urban centres or industrial clusters and hence support efforts to decarbonise electricity systems. Meanwhile, from the perspective of investors, interconnections can underpin the business case for renewables projects that might otherwise not be economically viable by expanding access to export markets.

In addition to enabling the integration of variable renewables, interconnections can help to promote more resilient and reliable power systems. Like batteries or dispatchable generation, they are a key option for power system flexibility. Such assets enable countries to smooth fluctuations in electricity output from variable renewables by transferring surplus electricity across borders and between regions, mitigating operational challenges and ensuring that demand and supply remain in balance across varying timeframes. Modern systems that employ high-voltage direct current technologies can also help offset the declining system inertia that has traditionally been supplied by synchronous generators via active provision of synthetic inertia, black start capabilities and voltage support, acting as a firewall that prevents cascading blackouts between interconnected countries.

If regional co-operation is maintained, interconnectors can also lower costs and deliver broader energy security benefits. Today, integration of power systems is nascent in ASEAN, but it can lay the foundation for countries to more efficiently share resources, such as operating reserve capacity, which can defer other types of investment and reduce overall system costs. A more diversified energy supply can reduce exposure to fossil fuel import-related disruptions or price volatility that ASEAN experienced in recent years, for instance by replacing inefficient diesel generators with cheap hydropower imports, as has been seen throughout the region historically.

Unlocking financing is key to realising the ASEAN Power Grid

Decades of strong economic growth and foreign direct investment, a relatively stable macro-financial environment, and broad-based political support create favourable conditions to realise the ambitions of the ASEAN Power Grid (APG). The APG is the key vision for regional power co-operation and connectivity in ASEAN as set out in the APG memorandum of understanding (MoU) signed in

2007 and the Enhanced APG MoU agreed in 2025, and is a programme area under the ASEAN Plan of Action for Energy Co-operation (APAEC) 2026-2030.

However, the long lead times, scale and complexity of future interconnection projects against the backdrop of already significant investment needs for domestic electricity transmission and distribution pose challenges for many countries. This underscores the importance of ensuring access to financing from a variety of public, private and international sources.

The issue of financing is inextricably linked to various other challenges that have been subject to considerable discussion and research. These include better alignment of grid codes, institutional requirements for multilateral market structures, and harmonisation of the regulatory and political frameworks that dictate power market structures across ASEAN member states.

These challenges are discussed in this report and recommendations are put forth in respect of the political realities of the region, but the main focus is not the regulatory or political pathways to establish multilateral power trade. Rather, this analysis aims to contribute to current discussions of ASEAN interconnectors by:

- Examining challenges – specifically for investment and financing – that arise from the current regulatory environment, predominant business and financing models for development, and the inherent characteristics of interconnection projects.
- Quantifying investment and financing needs for the ASEAN Power Grid to enable better planning and target setting by policy makers and other key stakeholders.
- Exploring potential solutions and strategies to overcome barriers and alleviate risks, such that ASEAN interconnection projects can achieve bankability while promoting affordability and energy security through the transition.

Report structure

In this report:

- Chapter 1 provides a detailed overview of related historical investment in ASEAN, and examines the predominant project characteristics, business models and financing models in the region.
- Chapter 2 quantifies investment needs for all interconnection projects expected to reach commercial operation by 2040, and outlines the various challenges to mobilise needed investment and finance for the projects.
- Chapter 3 dives into the technical details of financing interconnections from an investor perspective – including how projects are structured and the role of various actors – and illustrates how different factors can improve project bankability.
- Chapter 4 outlines key priorities and potential actions to improve the bankability of interconnector investment and to unlock new sources of finance.

Chapter 1. State of play

Prior to considering the outlook for the ASEAN Power Grid, it is important to take account of the current state of play in terms of cross-border power system connectivity and how existing interconnectors have been developed. Through the lens of investment, this chapter provides a detailed examination of the characteristics, business models and financing models of all interconnection projects in the region up to 2024. It identifies the distinguishing qualities of the projects including the interconnection type, financing model, cross-border co-operation, sources of financing, trading agreements and revenue structures, as well as to highlight how they have evolved over time. In doing so, this chapter reveals areas where progress has or has not been made towards ambitions for regional connectivity.

Historical investment

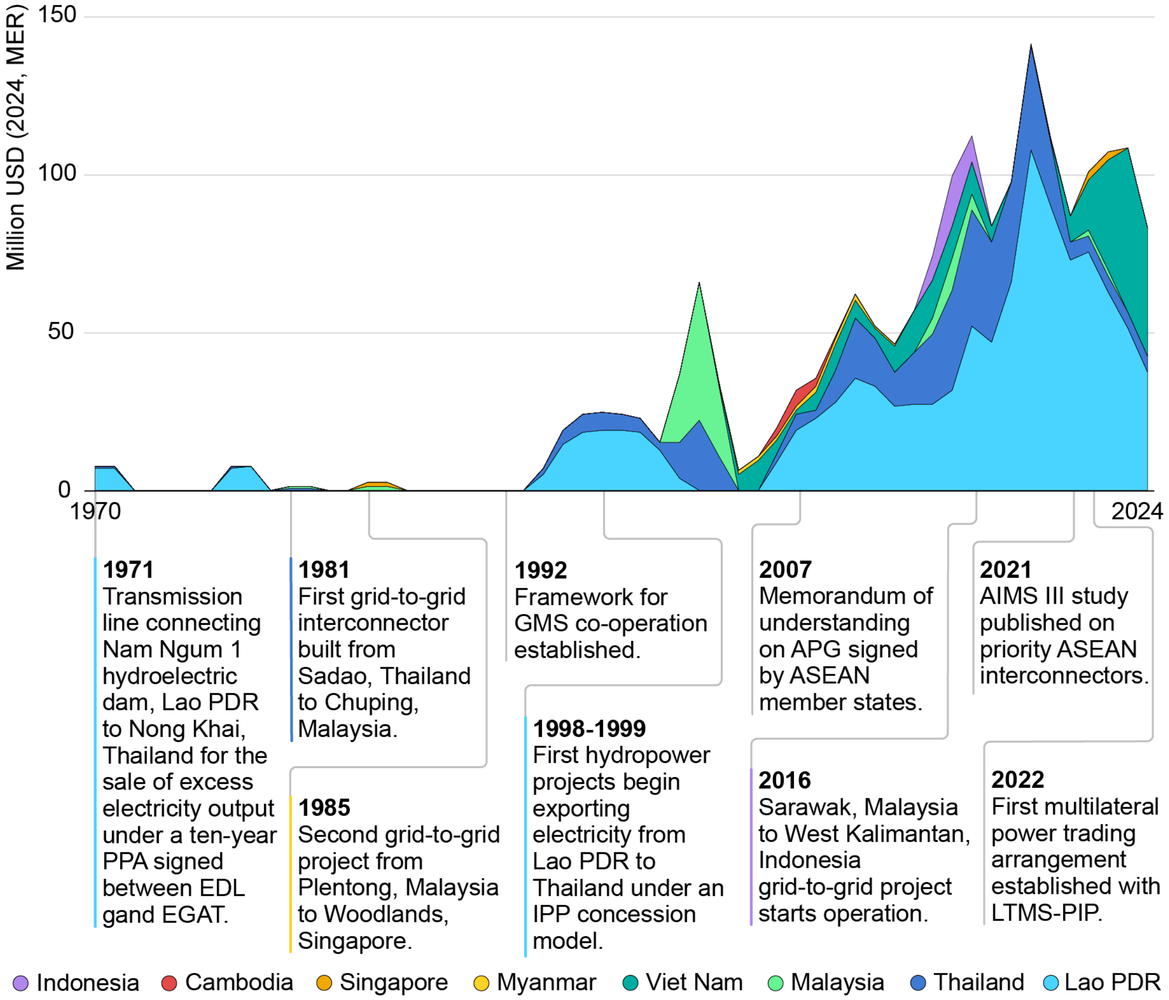
ASEAN cross-border electricity trade dates back to the 1970s

ASEAN has long recognised the importance of interconnections with investment stretching back over five decades. Since the first project connecting Lao PDR and Thailand broke ground in the 1970s, about USD 2 billion has been invested in cross-border interconnections across the region.[3]

Until the 1990s, investment in cross-border interconnections was sporadic and directed to short distances, typically less than 25 kilometres in length, and with voltages between 115 and 230 kilovolts (kV) with total costs on the order of tens of millions of dollars in 2024 nominal terms. While small in scale, these projects proved formative and showcased the potential economic benefits of interconnection projects.

[3] This figure corresponds to investment specifically on transmission lines and power stations that were developed for electricity export, including both the initial line construction and line upgrades. It does not include investment in new power plants. (See Annex A for scope of investment data.)

Annual cross-border interconnector investment by country in ASEAN, 1970-2024



Notes: MER = market exchange rate; PPA = power purchase agreement; EDL = Électricité du Laos; EGAT = Electricity Generating Authority of Thailand; GMS = Greater Mekong Subregion; IPP = independent power producer. AIMS = ASEAN Interconnector Masterplan Study. LTMS-PIP = Lao PDR-Thailand-Malaysia-Singapore Power Integration Project. Investment figures correspond to capital spending on transmission lines and grid equipment only. Where projects provide electricity for both domestic and foreign consumers, only cross-border transmission lines or transmission lines travelling to substations with existing cross-border links are included. Philippines, Brunei Darussalam and Timor-Leste do not have cross-border interconnections today.

Source: See Annex A for full methodology and sources used for investment and financial modelling.

Geography of the ASEAN region, particularly the concentration of hydropower potential along the Mekong River, made interconnectors a natural solution to supply low-cost and reliable electricity to poorly connected demand centres in neighbouring countries where electricity access was constrained by lack of infrastructure or fuel costs. For exporting countries, linking hydro-rich areas to profitable export markets bolstered the financial viability of projects in rural areas that might have otherwise remain unconnected to the domestic grid, while also generating significant foreign exchange earnings.

Other interconnection projects were not commercially tied to exports but instead built to facilitate more limited exchanges of electricity during emergency periods, such as the Sadao (Thailand) to Chuping (Malaysia) line and the Plentong (Peninsular Malaysia) to Woodlands (Singapore) line, which were built in 1980 and 1985, respectively. They helped to demonstrate the role of interconnectors to bolster system stability and were a precursor to more sophisticated projects and commercial agreements in future years, such as the Khlong Ngae (Thailand) to Gurun (Malaysia) line built in 2002 and the Laos-Thailand-Malaysia-Singapore Power Integration Project (LTMS-PIP) in 2022.

Regional collaboration has spurred investment and set ambitious targets for the long term

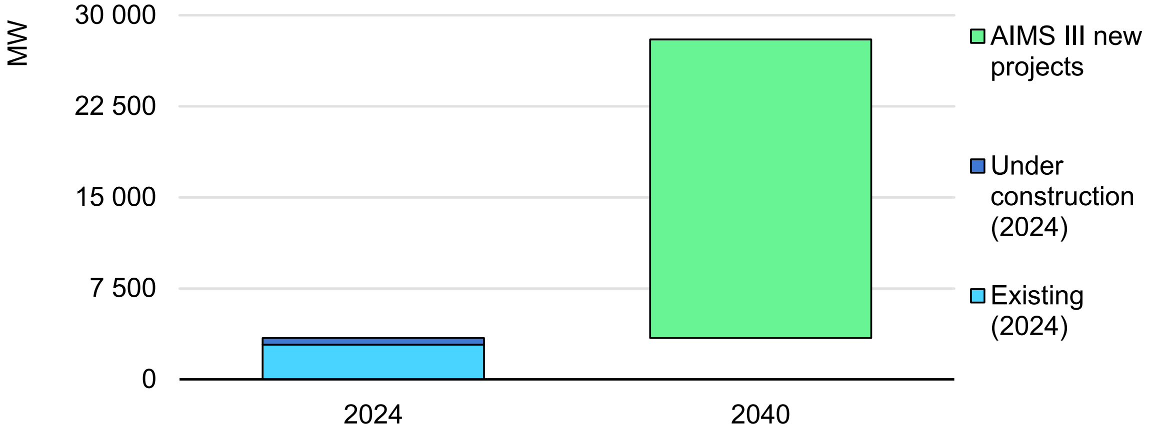
Power infrastructure projects gradually became a focal point for regional co-operation and were used to advance common economic objectives. In 1992, the Greater Mekong Subregion (GMS) was founded by Cambodia, the People's Republic of China (hereafter China), Lao PDR, Myanmar, Thailand and Viet Nam to promote a subregional framework for economic co-operation and integration, for which power connectivity was seen as an essential building block. Regional Power Master Plans (2002, 2010 and subsequent updates) helped to identify and prioritise interconnection projects between member states, and various memoranda of understanding established policy and legal frameworks for power trading.

In parallel, the notion of an ASEAN Power Grid (APG) began circulating in strategic planning documents as part of the ASEAN Vision 2020 adopted by leaders in 1997. In 2007, a formal memorandum of understanding was issued concerning the strengthening of power interconnection and trade vis-à-vis the creation of an APG.[4] Like the GMS, the APG serves as platform to enhance regional integration through power connectivity, but it is distinguished as an ASEAN-led initiative.

The beginnings of the GMS and APG coincide with the construction of major hydroelectric export projects from Lao PDR to Thailand in the 1990s, which contributed to new highs for investment levels for the remainder of the decade. The early 2000s marked a significant acceleration: from 2003 to its peak in 2018, annual investment rose by over 2 000% to over USD 140 million. Since 2000, construction on approximately 50 new lines or line upgrades for cross-border electricity exchange and export have been completed or are under construction, with voltages up to 500 kV.

[4] In 2025, an enhanced memorandum of understanding on the APG was signed which lays the foundation for more power interconnectivity and expansion of multilateral power trade in the region.

ASEAN interconnector capacity in 2024 and in the AIMS III Renewable Energy Target Scenario for 2040



Notes: MW = megawatts. AIMS = ASEAN Interconnector Masterplan Study. Interconnector capacity values for 2024 do not include generation-to-grid projects, i.e. interconnectors linking a generation source to a foreign grid.
Source: ASEAN Centre for Energy (2024), ASEAN Power Grid Interconnections Project Profiles.

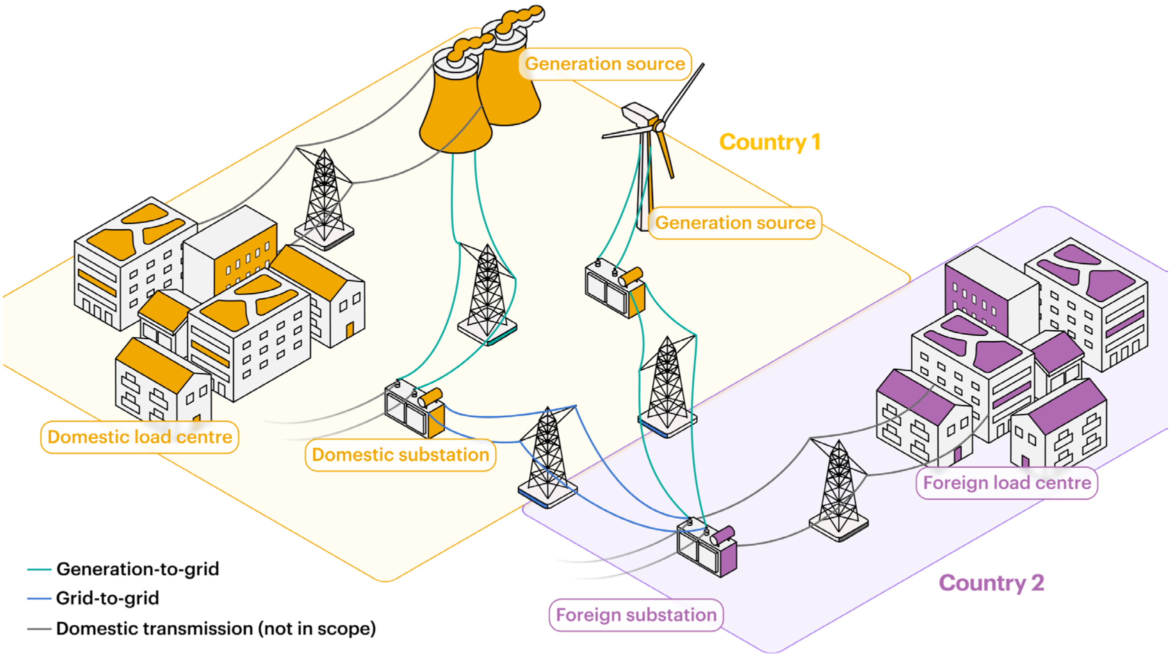
In recent years, the integration of variable renewables and regional power connectivity are framed as not just economic opportunities but also as a strategic necessity to meet rising electricity demand, advance energy transition goals, and support regional resilience in the face of climate and energy security challenges. These opportunities are widely recognised throughout the region and are reflected in the ASEAN Interconnector Masterplan Study (AIMS), which identifies the most promising cross-border interconnections based on their techno-economic viability. With three editions published to date, the most recent AIMS III Phase 1-2 outlines an ambitious target to increase installed interconnector capacity by roughly eightfold by 2040 for its Renewable Target Scenario.[5] This will require an unprecedented mobilisation of new investment towards interconnectors over the next 15 years.

Despite the emphasis on grid-to-grid projects in regional planning, power exports are driving most investment

Interconnection projects developed in ASEAN generally fall into two categories. First are *grid-to-grid* projects, which create a new connection between domestic and foreign substations to facilitate the exchange of electricity and other services from a pool of generation sources. Such projects are developed and financed independently from any one power plant; hence the revenue stream is based purely on electricity exchange.

[5] The ASEAN Power Grid Interconnections Project Profiles interconnector capacity values for 2024 do not include generation-to-grid projects. These projects are within the scope of this study and are included in investment values.

Interconnection project types

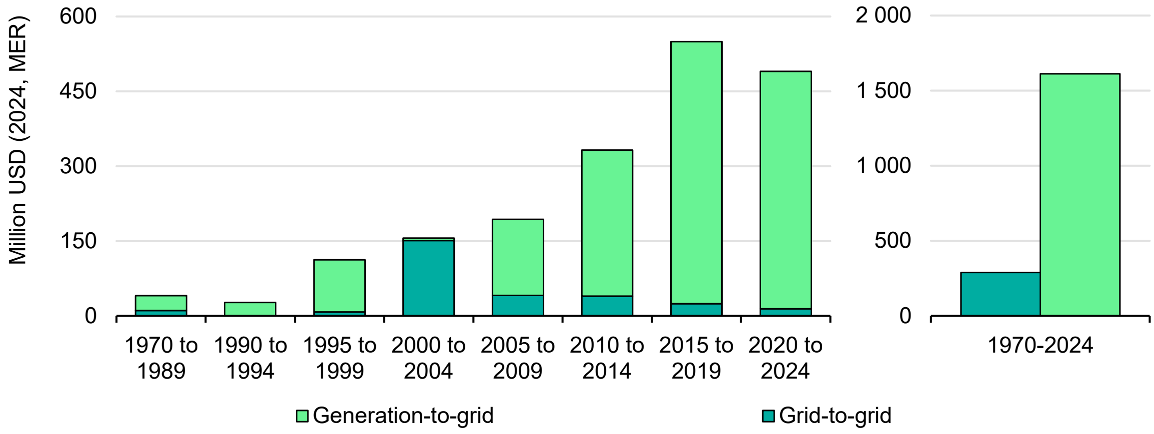


Note: Interconnector projects connecting to large industrial customers are not in scope for this study.

The extent and timing of energy exchange is determined by agreements between countries, but the potential benefits are broad. Grid-to-grid interconnectors can bolster reliability, improve electricity access, alleviate cost differentials and curb supply deficits in countries on both sides of the border. For instance, an abundance of hydropower may provide importing countries with cheap and reliable power in wet seasons, whereas power flows could reverse during drier periods. Their key feature – a two-way channel for trade, pulling from a broad portfolio of generation assets on both sides of the border – closely aligns with the AIMS III Phases 1-2 objective to enhance bilateral and multilateral trade opportunities.

The second category is *generation-to-grid* projects, which are explicitly linked to the export of electricity from a single source, or cluster, of generation. In these projects, a new power plant and transmission line travelling to the border are typically developed and financed together, and hence the revenue stream encompasses both power generation and transmission. Such projects often deliver many of the same benefits as grid-to-grid projects, i.e. boost access, lower prices and displace inefficient fossil fuel generators; however, broader trading and system benefits may be less pronounced given that power flows are typically one-way, from the exporting country to the importing country, and are associated with a single, or few, sources of generation, as opposed to a broader portfolio of assets.

Investment in interconnectors and by project type in ASEAN,1970-2024



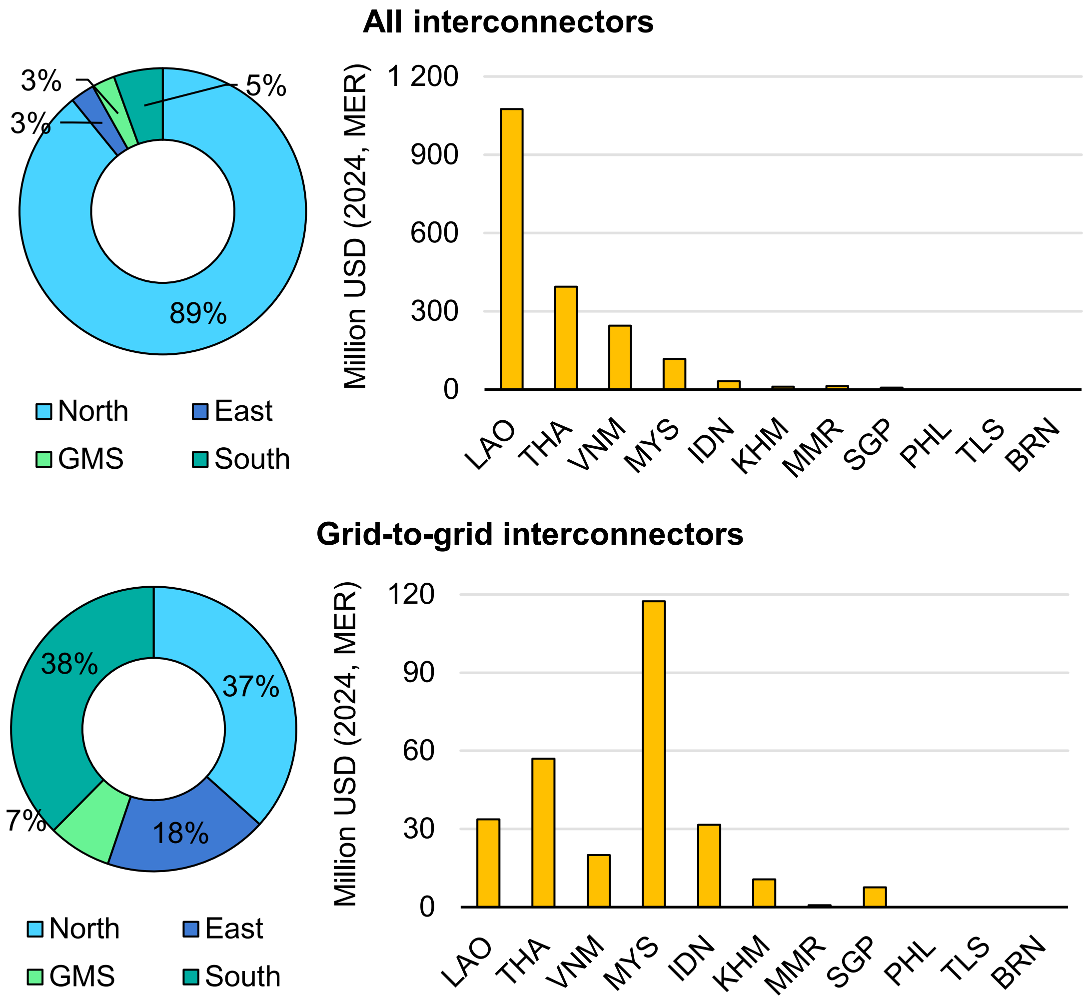
Source: See Annex A for full methodology and sources used for investment and financial modelling.

Although generation-to-grid projects have received less attention in the context of APG planning, they account for 85% of historical investment and essentially all investment growth over the past two decades. Conversely, only 15%, approximately USD 300 million, of interconnection investment since the 1970s is attributable to grid-to-grid projects. This is equivalent to a small fraction, about 8%, of what the region invested in electricity transmission in 2024 alone. Accordingly, while generation-to-grid projects have attracted significant investor interest, the multi-decadal plateau for grid-to-grid interconnectors suggests that a deeper set of political, institutional, technical and financial challenges remain major obstacles for these projects. This is noteworthy given that most priority interconnectors identified for the APG are grid-to-grid projects.

Interconnections are concentrated in the north, with less development in the south and east

An integrated ASEAN power system does not exist today. Rather, the current landscape is characterised by multiple, unconnected or partially connected subsystems. Creating a more integrated regional system is likely to follow a step-wise approach to power trade which first establishes trade between clusters of countries and regions before multilateral trade starts to take shape across the region. The historical distribution of investment, however, has implications for where future investment and financing is needed most.

Cumulative investment in interconnectors by subregion and by country for all interconnections and for grid-to-grid interconnection, 1970-2024



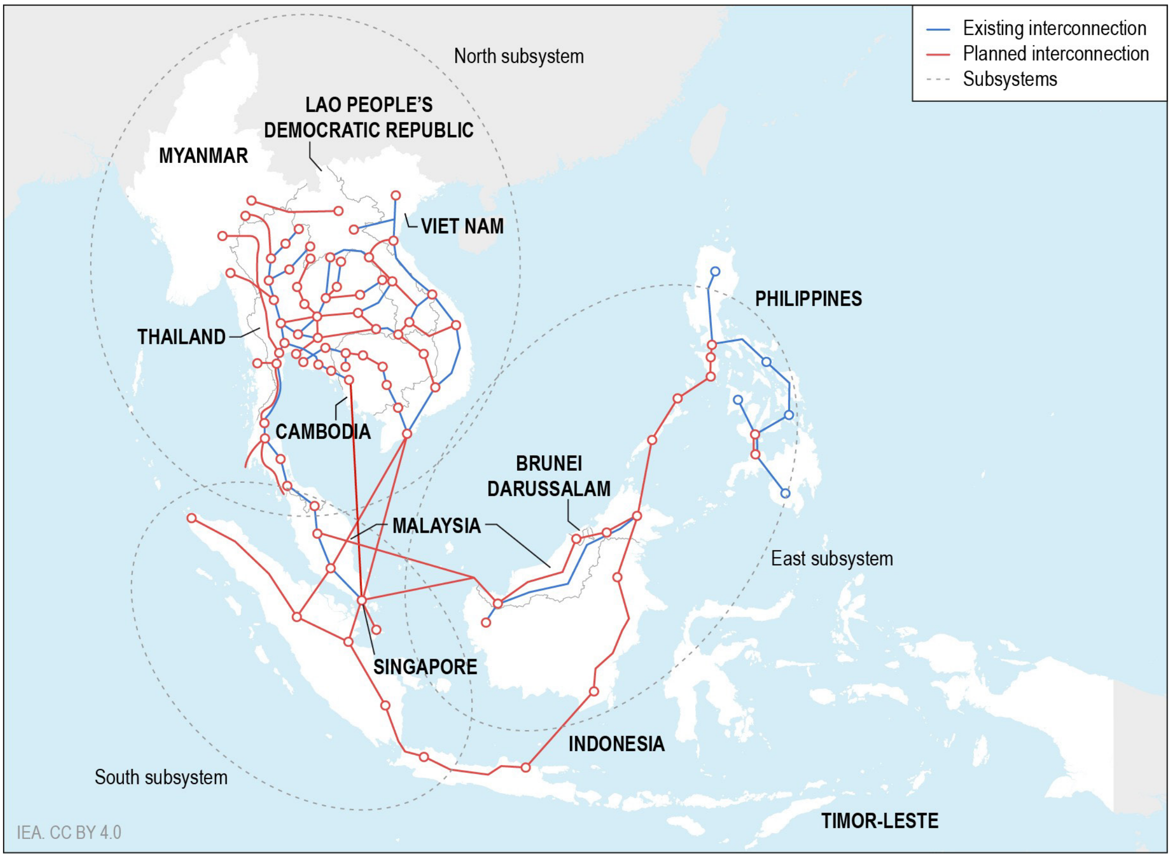
Notes: MER = market exchange rate. GMS = Greater Mekong Subregion projects, which here are bilateral interconnectors between China and ASEAN member states. For these projects, only the portion of the interconnector on the ASEAN member side of the border is accounted. LAO = Lao PDR; THA = Thailand; VNM = Viet Nam; MYS = Malaysia; IDN = Indonesia; KHM = Cambodia; MMR = Myanmar; SGP = Singapore; PHL = Philippines; TLS = Timor-Leste; BRN = Brunei Darussalam.

Source: See Annex A for full methodology and sources used for investment and financial modelling.

APG North

ASEAN Power Grid North subsystem includes Cambodia, Lao PDR, Myanmar, Thailand and Viet Nam and is currently the most developed part of the APG in terms of investment and interconnection capacity. Since the 1970s, around USD 1.7 billion or nearly 90% of historical interconnection investment in ASEAN has been related to these five countries. The vast majority has been for generation-to-grid projects originating in Lao PDR for hydropower export to neighbouring Thailand and Viet Nam. The next 15 years could see the upgrade of several existing lines and the addition of new, but primarily short distance grid-to-grid connections. Financing for these projects should not pose a significant barrier. Several other complex projects linking the North subsystem to Peninsular Malaysia and Singapore via subsea cables are under discussion, the financing for which will be much more challenging.

Selected major cross-border interconnection projects from AIMS III Phases 1-2 and national power sector planning



Notes: The map is not intended to be an exhaustive list of all operational or planned interconnections in the region. Notably, many existing and planned generation-to-grid and domestic interconnectors projects are excluded from this figure. Additional interconnectors which are not listed in the AIMS III Phases 1-2 planning are included in the scope of this study.

Sources: Adapted from ASEAN Centre for Energy (2024) ASEAN Power Grid Interconnections Project Profiles; National Grid Corporation of the Philippines (NGCP) (2025) Transmission Development Plan 2024-2050; Perusahaan Listrik Negara (PLN) (2025) RUPTL 2025-2034.

APG South

The ASEAN Power Grid South subsystem includes connections between Peninsular Malaysia, Singapore and the Riau Islands, Java and Sumatera in Indonesia. Despite being the location for some of the region's first interconnection projects, it accounts for only 6% of investment to date. It has three operational grid-to-grid interconnectors, including one of the region's only operational high-voltage direct current (HVDC) interconnectors linking Peninsular Malaysia to the North subsystem via Thailand, but no dedicated generation-to-grid interconnectors. Given its position as a key juncture between the North and East subsystems, the South is expected to become the focal point for investment over the next 15 years. Singapore has emerged as a key actor, and several highly ambitious subsea projects originating and/or ending in the South subsystem are at various stages of planning, which would connect resource abundant areas in the North, Sumatera and Sarawak to the wider APG.

APG East

The ASEAN Power Grid East subsystem includes: Sarawak and Sabah in Malaysia, Kalimantan in Indonesia, the Philippines and Brunei Darussalam. Like the South subsystem, investment has been limited to date. Excluding domestic inter-island interconnections in the Philippines, there are only two operational interconnectors in the East subsystem: one connects rich hydropower resources in Sabah to West Kalimantan, and the project between Sabah and Sarawak that was energised in late 2025. Elsewhere in the region, the electricity grids of Brunei Darussalam and the Philippines remain fully isolated from their neighbours. Looking forward, financing needs for the East subsystem are considerable given the number of subsea projects connecting to the Philippines, Java, Singapore and Peninsular Malaysia.

Business models and historical financing

New financing models have been applied for generation-to-grid projects, yet state-owned enterprises are paramount for grid-to-grid interconnectors

Existing financing models for transmission and interconnectors in ASEAN

SOE-led financing models		Financing models with private sector participation		
SOE-led vertically integrated	**SOE-led unbundled**	**Whole grid concession**	**Independent transmission project**	**IPP concessions**
SOE owns and operates generation and transmission network	Transmission is legally distinct from generation but still state-owned	SOE leases transmission network assets to private concessionaire	Concession-based transmission project under BOOT type model	Dedicated IPP-funded power evacuation line under BOOT type model
Characteristics	**Characteristics**	**Characteristics**	**Characteristics**	**Characteristics**
Build: Mixed; Finance: Mixed	Build: Mixed; Finance: Mixed	Build: Private; Finance: Private	Build: Private; Finance: Mixed	Build: Private; Finance: Mixed
Own: Public; Operate: Public	Own: Public; Operate: Public	Own: Public; Operate: Private	Own: Mixed; Operate: Public	Own: Mixed; Operate: Public
Capital structure	**Capital structure**	**Capital structure**	**Capital structure**	**Capital structure**
On balance sheet	On balance sheet	Concessionaire: on balance sheet SOE: off balance sheet	Off balance sheet	Off balance sheet, financed together with IPP project
Seen in…	**Seen in…**	**Seen in…**	**Seen in…**	**Seen in…**
Indonesia, Thailand, Sabah, Sarawak, Myanmar, Cambodia, and Brunei	Viet Nam, Peninsular Malaysia, and Lao PDR (grid-to-grid)	Philippines	1 grid-to-grid interconnector between Cambodia and Thailand (Cambodia side)	Gen-to-grid interconnectors in Lao PDR

Notes: SOE = state-owned enterprise; IPP = independent power producer; BOOT = build-own-operate-transfer. The diagram focuses on institutional and financing structures, specifically which financing type owns and operates transmission assets; whether financing is corporate or project-based; and whether the assets sit on the balance sheet of the utility or an independent investment vehicle. In jurisdictions using the regulated asset base (RAB) model, (e.g. European Union and United Kingdom transmission system operators, Singapore and Australia transmission system operators), transmission assets are financed on the corporate balance sheet of the transmission utility, whether state or privately owned. As such, RAB models map directly onto the existing categories: unbundled SOE, when the transmission utility is publicly owned; or whole grid concession, when a private utility operates under regulatory oversight. The distinction introduced by the RAB model relates to how revenues are regulated (weighted average cost of capital × RAB methodology), rather than how assets are financed. Since the diagram classifies models based on financing structure rather than tariff methodology, the RAB model is not shown separately. Likewise, a similar logic underpins the exclusion of the merchant model, which is differentiated based on its revenue structure.

Historically, financing models for cross-border interconnector projects typically belong to two main categories:[6]

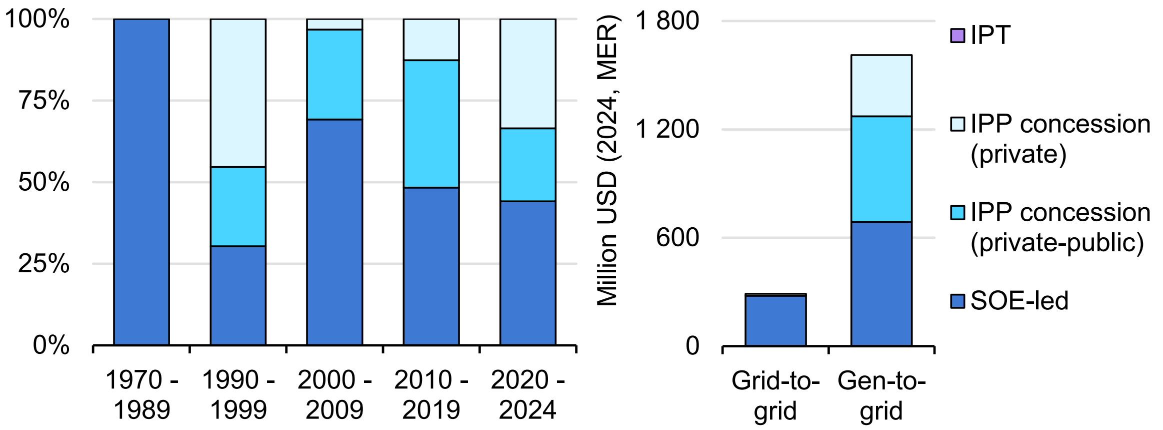
- *State-owned enterprise-led* (SOE-led): In this model, a SOE, either vertically integrated or unbundled, is the sole owner and operator of the transmission line. Financing is consolidated on the SOE balance sheet using retained earnings, debt or equity. The terms of financing and the extent of access to capital are directly linked to the financial health and liquidity of the SOE, and, by extension, to that of the state.
- *Independent power producer (IPP) concessions:* These projects are usually financed off-balance sheet through a special purpose vehicle or a joint venture. A separate entity is created under a shareholder agreement between an SOE and/or private developer(s), with the right to build, operate and potentially own the transmission and generation assets for a fixed concession period. Financing is raised based on project level cash flows, rather than the financial strength of the sponsors. SOEs need not always contribute to the project capital, though they may be counterparties via regulated tariffs or off-take arrangements.

While flagship efforts like the ASEAN Power Grid Financing Initiative (APGF) seek to crowd in investment from a variety of public, private and international actors, almost every grid-to-grid project built to date, which account for the majority of planned cross-border interconnector capacity by 2040, has been developed using the SOE-led financing model. In total, 60% of historical interconnector investments were made by SOEs. Alternative models involving private sector ownership for grid-to-grid projects are limited to a single project between Cambodia and Thailand on the Cambodian side of the border, which is the only example of an independent transmission project (ITP) in ASEAN.

On the other hand, the financing models applied to generation-to-grid projects have been more varied and have evolved over the years. Indeed, the introduction of IPP concession models in Lao PDR coincide with an acceleration of interconnector investment in ASEAN, beginning with the Theun-Hinboun hydropower project. It established a special purpose vehicle, the Theun-Hinboun Power Company, from a shareholder agreement between state-owned utility Électricité du Laos (EDL) and private developers which was awarded 30-year build-operate-transfer (BOT) concession for the power plant and transmission line to the Lao PDR-Thailand border. This was the first known instance of private participation for electricity transmission infrastructure in ASEAN.

[6] Domestic interconnection projects in the Philippines have also been financed under a whole of grid concession model, where a private corporation is entitled to build and operate the transmission grid under a long-term concession awarded by a government entity. However, these projects are not considered in historical investment and financing because there are no cross-border connections. (Inter-island projects in the Philippines are included in Chapter 2.)

Historical investment by financing model and project type, 1970-2024

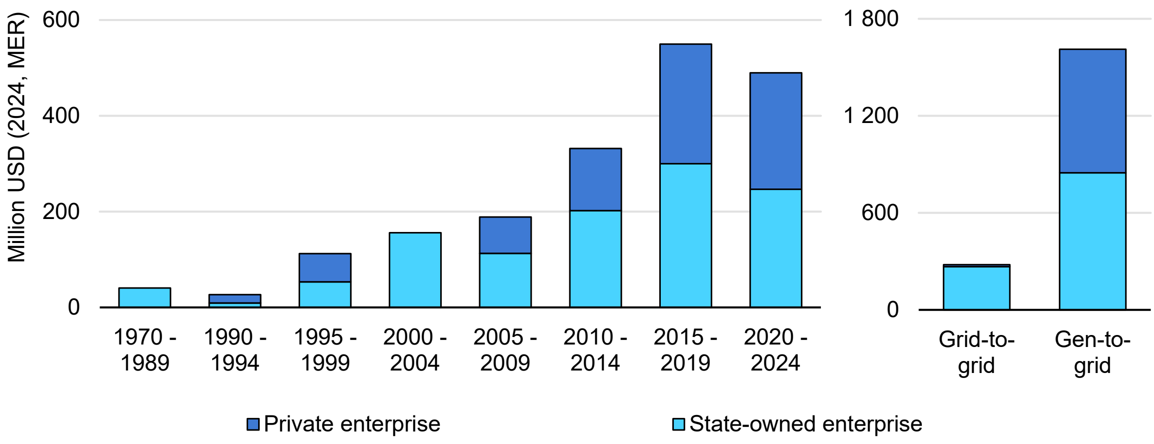


Notes: MER = market exchange rate; ITP = independent transmission project; IPP = independent power producer; SOE = state-owned enterprise; Gen = generation. Domestic interconnector investment made by the National Grid Corporation of the Philippines and PT Perusahaan Listrik Negara in Indonesia not included unless the project is cross-border.
Source: See Annex A for full methodology and sources used for investment and financial modelling.

Fully private ventures also emerged around the same time as concessions awarded to public-private partnerships. The first was the Houay Ho Dam in 1999 and this model has since become more common for generation-to-grid projects in Lao PDR. New variations of the build-own-operate-transfer (BOOT) model have also been used for non-hydroelectric renewable projects such as the Monsoon Wind project for power export from Lao PDR to Viet Nam. Since 2020, 56% of generation-to-grid investment has been for projects that are either public-private or fully private IPP concessions.

As intended, these financing models have proven successful to mobilise private sector investment. Private enterprises have invested about USD 0.5 billion over the past decade – more than six-times the level of the 1990s when these models were first applied. Their impact is most pronounced in Lao PDR, where more than 80% of all private interconnector investment in ASEAN since the 1970s has been within its borders, reflecting the central role of IPP hydropower projects. Private participation outside of Lao PDR and Cambodia has been mostly absent or minor in comparison to SOEs, though a number of private IPP-led projects linking Indonesia to Singapore are at various stages of planning.

Investment in interconnectors by sponsor and project type in ASEAN, 1970-2024



Notes: MER = market exchange rate; Gen = generation. Sponsors are the entities that make the investment decision, usually because they are, or will become, the asset owner. For special purpose vehicles and joint ventures, investment is split between SOEs and private enterprises based on their respective equity shares.
Source: See Annex A for full methodology and sources used for investment and financial modelling.

So far, all interconnectors have been financed as two separate projects, split at the border

All interconnectors in ASEAN, including both generation-to-grid and grid-to-grid projects, have been developed using a *split project model*. In this arrangement, the transmission line is divided at the border, with each party responsible for financing and operating the portion within its jurisdiction. While the split model is suitable for land-based projects, it presents challenges for more complex developments such as long-distance subsea projects. Costs may be allocated arbitrarily by geography rather than by the distribution of benefits or risks, and some jurisdictions may lack the financial capacity to bear a substantial share of the investment. Cost allocation under this model can be particularly complex in cases where the line passes through third-party or international waters.

Alternative models can help address these limitations. A *joint bilateral project* structure allows the interconnector to be financed through a joint venture or special purpose vehicle spanning multiple jurisdictions, with shared ownership between the participating SOEs and/or private enterprises. This model, which has been used extensively for European interconnector projects including the Cobra Cable (Denmark-Netherlands), Viking Link (Denmark-United Kingdom) and NordBalt (Sweden-Lithuania) can provide benefits for project co-ordination, end-to-end risk management, and to reduce the risk of unilateral actions by aligning the financial interests of governments and utilities. Implementation can be complex as these projects may require regulatory changes, particularly in jurisdictions that restrict private or foreign ownership of transmission infrastructure. ASEAN has no precedent for joint bilateral models. However, there are signs of movement in this direction, for example Singapore Energy Interconnections has been appointed by the Government of Singapore to engage in commercial partnerships and joint ventures for cross-border interconnections into the country.

Regional projects may involve equity ownership from utilities in more than two countries where the asset passes through more than two countries, or financial support from a regional body to reflect the benefits provided by interconnectors beyond the countries directly involved. Although common use transmission assets have been the subject of recent policy briefs, this model has not been applied in ASEAN and there are few international case studies to draw from. For example, in southern Africa, the Mozambique Transmission Company was established as a joint venture with equity ownership shared between the state utilities of Mozambique, Eswatini and South Africa. In Europe, mechanisms such as the Connecting Europe Facility provide funding support for strategically important interconnectors designated as Projects of Common Interest or Projects of Mutual Interest. The Central American Electrical Interconnection System established a joint entity to finance the transmission line which traversed six countries.

International public finance bridged early funding gaps and catalysed additional commercial financing

Where financial structure is not isolated from the balance sheet, the government debt ratio and repayment ability plays a crucial role in determining access to financing and the cost of capital.

Concessional finance provided by multilateral development banks (MDBs), development finance institutions (DFIs) and export credit agencies (ECAs) played a crucial role in de-risking early interconnector projects in ASEAN and proving commercial viability.[7] These international public financiers were cumulatively responsible for nearly 70% of financing for interconnectors in ASEAN until 1990, whereas domestic public finance and commercial finance accounted for a respective 15% each.

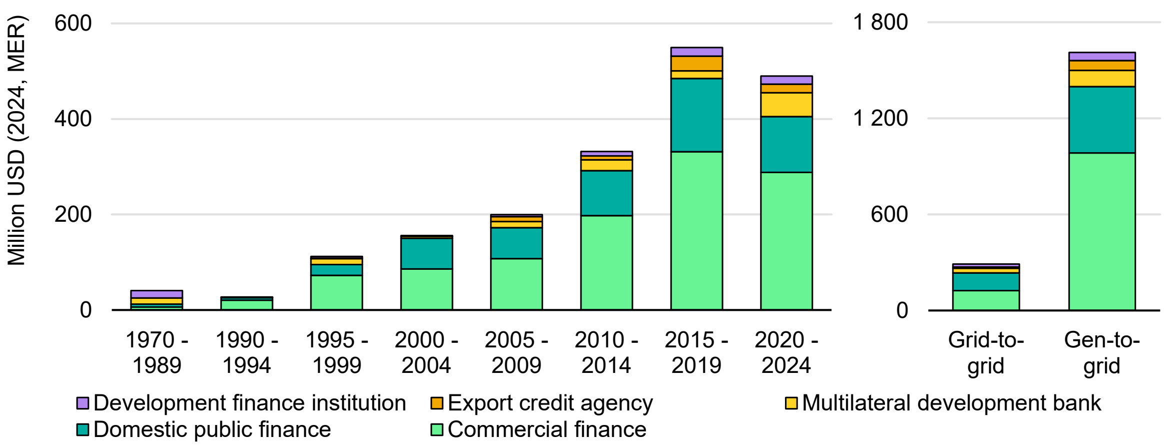
MDBs, DFIs and ECAs maintain an important role in financing regional interconnector projects today. International public financing has increased considerably since 2000 using a variety of instruments such as grants, concessional and non-concessional debt, including on-lending to SOEs, as in the case of the National Power Transmission Corporation (EVNNPT), a subsidiary of Viet Nam Electricity (EVN) that manages the high-voltage transmission network.

Recently, as part of the APGF Initiative, the World Bank committed financing for the APG through its USD 2.5 billion Accelerating Sustainable Energy Transition

[7] Details on financial structures and institutional roles are covered in Chapter 3.

Multi-Phase Programmatic Approach regional initiative,[8] and the Asian Development Bank (ADB) has pledged to invest up to USD 10 billion for the APG over the next ten years. The APGF aims develop a bankable project pipeline, create a centralised platform for investment opportunities, and offer tailored financial instruments and financing models for the creation of an integrated transmission network.

Sources of finance for investment in interconnectors and by project type, 1970-2024

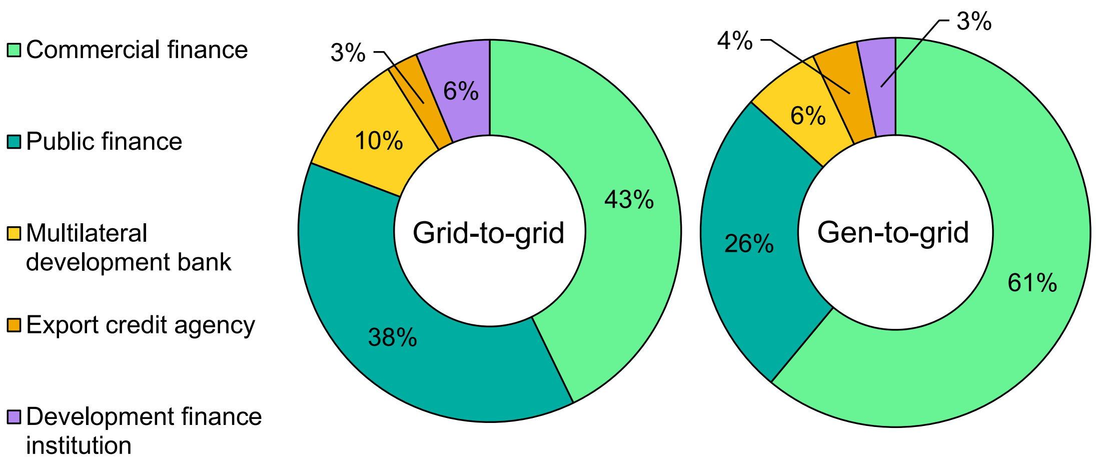


Notes: MER = market exchange rates; Gen = generation. Commercial finance includes equity investment made by private enterprise and debt from financial institutions that is provided at commercial rates. It also includes some investment from state-owned banks, sovereign wealth funds and pension funds, although this includes a degree of state-directed lending. Public domestic finance includes government-owned equity in corporations and SOEs, subsidies, tax incentives and finance from central banks. Development finance institutions, multilateral development banks, and export credit agencies here show total financing provided by these institutions, irrespective of concessionality.
Source: See Annex A for full methodology and sources used for investment and financial modelling.

Mainly due to the expanding volume of investment in IPP concessions, i.e. generation-to-grid projects, commercial finance has increased considerably. Over the last decade, 60% of all interconnection investment has been financed from commercial sources, 26% from public domestic finance, and 14% from international public financing. Segmenting the sources of finance reveals an expected divide between grid-to-grid and generation-to-grid projects: of the USD 1.1 billion of commercial finance invested for ASEAN interconnectors over the last decade, about USD 1 billion has been for generation-to-grid projects. On average, the difference in sources of financing between the two categories is distinctive: whereas 61% of financing for generation-to-grid projects originated from commercial sources, these sources financed 43% of the grid-to-grid projects, mainly due to additional equity financing from private enterprise rather than higher leverage.

[8] The USD 2.5 billion is intended for the first round of projects, with the intention of committing additional resources subject to demand.

Cumulative financing by source for grid-to-grid and generation-to-grid projects, 1970-2024



Notes: Gen = generation. Commercial finance includes equity investment made by private enterprise, alongside debt from financial institutions which is provided at commercial rates. It also includes some investment from state-owned banks, sovereign wealth funds and pension funds, although this includes a degree of state-directed lending. Public domestic finance includes government-owned equity in corporations and SOEs, subsidies, tax incentives and finance from central banks. Development finance institutions, multilateral development banks, and export credit agencies here show total financing provided by these institutions, irrespective of its concessionality.

Source: See Annex A for full methodology and sources used for investment and financial modelling.

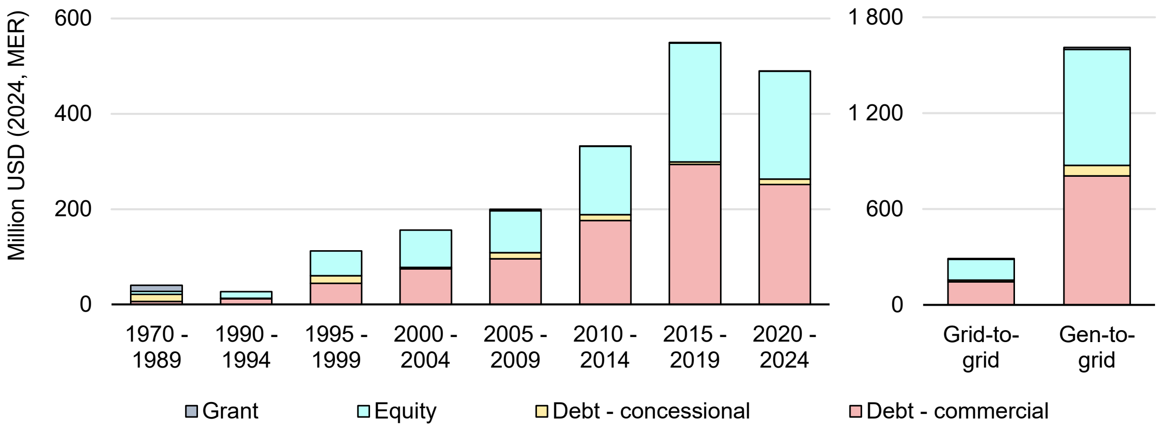
Catalysing additional commercial finance using blended finance instruments has been an explicit objective for international public financiers. For example, the Monsoon Wind Power Project in Lao PDR mobilised significant amounts of commercial capital, largely from private sources, with the help of concessional debt and grants provided by the ADB. A growing share of commercial finance is hence a testament to the effectiveness of various de-risking instruments.

Although these more innovative financing models have not been used for grid-to-grid projects, it is important to note that commercial institutions play a key role even when projects are financed on the balance sheet of an SOE. Borrowing can take the form of loans and credit facilities from banks, or corporate bond issuances for larger projects. In either case, the ultimate source of finance is the lenders or investors that are repaid by the SOE through interest or coupon payments, typically at commercial rates. Additionally, SOEs such as Tenaga Nasional Berhad (TNB) in Malaysia are publicly traded with commercial institutions having partial ownership. In general, countries with the highest levels of finance from commercial sources are characterised by relatively deep capital markets or have allowed some private sector participation for high-voltage electricity transmission infrastructure, such as in Lao PDR.

Debt and equity financing have an important role

ASEAN interconnector projects have been financed with similar shares of debt and equity to date: 54% (USD 1 billion) for debt, 45% (USD 0.9 billion) for equity financing, and 1% for grants. This is largely consistent with global trends for debt finance in electricity transmission, which has ranged 54-57% on an annual basis over the past decade.

Financial instruments used for investment in interconnections and by project type in ASEAN, 1970-2024



Notes: MER = market exchange rates; Gen = generation. Does not include guarantees provided by international financiers. Debt-commercial includes any debt issued at market rates irrespective of the lender. Debt- concessional includes any debt issued at below-market rates or on highly concessional terms, e.g. long tenors unavailable in domestic capital markets. Equity includes government subsidies or equity stakes held in private or state-owned enterprises if the asset is financed on balance sheet, or equity stakes in investment vehicles.

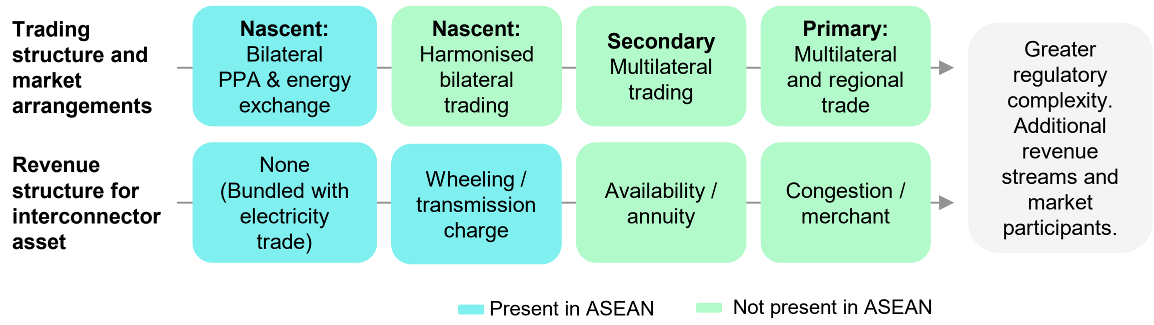
Source: See Annex A for full methodology and sources used for investment and financial modelling.

Revenue for interconnector projects depends on cross-border trading arrangements, multiple regulators and potentially uncertain utilisation. Shorter maturities reduce exposure of the lender to long-term policy and market shifts, while higher coverage ratios, for example the ratio of cash flow to debt servicing costs, ensure more cash flow buffer in case revenue falls or costs overrun. Together, these conditions protect lenders but lower the amount of debt the project can borrow.

This helps explains why the share of debt financing for interconnection projects is lower than for standalone power generation projects. Moreover, it underscores the importance of DFIs and MDBs for interconnector projects which can provide extended loan tenors, offer concessional rates or blended finance to lower debt servicing costs, and/or provide various forms of guarantees and risk coverage. These instruments are likely to play a key role in the future of the ASEAN Power Grid given the number of highly complex first and next-of-a-kind transmission projects.

Most trading is conducted on a bilateral basis with cost recovery bundled with electricity trade

Business models for interconnectors



Notes: PPA = power purchase agreement. Transmission charges may include wheeling charges for transit-only countries.

Trading and market structures

Trading arrangements in ASEAN historically have been negotiated through bilateral power purchase agreements (PPAs) between a seller and a buyer of electricity. In most cases, the seller is an exporting utility, or an IPP in the case of most generation-to-grid projects, while the buyer is an importing utility. In a small number of instances, electricity exchange has occurred without formal commercial arrangements. For example, the Thailand–Malaysia HVDC interconnection, commissioned in 2001, was designed to manage peak loads, provide frequency control and enable power exchange during emergency situations such as supply shortages.

Multiple trading models have been proposed for ASEAN at varying levels of integration. But currently, there is limited standardisation of cross-border trading arrangements and no regional market mechanism. Harmonised bilateral trading would involve standardised contract templates and wheeling methodologies to reduce transaction costs and improve consistency. At higher levels of integration, a regional power market could enable multi-directional trade across a broader set of participants, either as a complement to domestic markets (secondary trading), such as between the United Kingdom and the European Union, or as the primary trading mechanism for electricity trade, such as Nord pool, a commercial power exchange.

Revenue structure

Revenue structure is a crucial component of the business model for an interconnection project. It determines how costs are ultimately recovered across the lifetime of the project and hence is a crucial determinant of bankability of a project.

So far in ASEAN, the most common approach is the cost recovery bundled with electricity sales. This is generally the case where there is no separate transmission or wheeling charge because the exporter and/or importer is also the investor, as in the case of bilateral utility-to-utility projects or generation-to-grid projects.

Cost recovery for generation-to-grid projects typically encompasses both the generation source and interconnection infrastructure. Revenue is through a tariff charged to the importing utility, typically structured as a PPA, wherein payments may include energy charges (USD per megawatt-hour) based on delivered electricity and/or availability-based payments (USD per megawatt), in some cases with guaranteed off-take volumes with take-or-pay clauses. This model is straightforward to apply given extensive experience with PPAs between utilities and IPPs for domestic supply in ASEAN.

A different approach is applied when electricity must transit through the network of a third country, known as wheeling. A wheeling charge is the fee paid to a transmission operator for the use of its network to deliver electricity between two parties. In addition to facilitating trade between non-neighbouring countries, wheeling charges can be set to better reflect the benefits or costs of the interconnector. However, this model has only been applied in ASEAN for the Lao PDR-Thailand-Malaysia-Singapore Power Integration Project (LTMS-PIP) wherein an energy wheeling agreement was signed between EDL, Electricity Generating Authority of Thailand (EGAT), and TNB to facilitate the delivery of power from Lao PDR to Singapore.

Additional revenue models have been employed in other regions, such as availability payments or annuity-based structures, and may merit consideration for future projects in ASEAN. In such models, transmission lines are treated as regulated assets which grant developers fixed payment based on availability rather than usage. An example is the UK Offshore Transmission Owners regime. Congestion (merchant) revenue models, such as the BritNed interconnector, earn revenues based on power price spreads, but requires a liquid wholesale market and open grid-to-grid access, which are not common across ASEAN. Interconnectors using a merchant revenue model are often paired with regulated price ceilings and floors to protect the developer from merchant risk and rate payers from excessive prices. For instance, this semi-merchant model was used for Greenlink (Ireland-United Kingdom), the first fully privately funded interconnector in Europe.

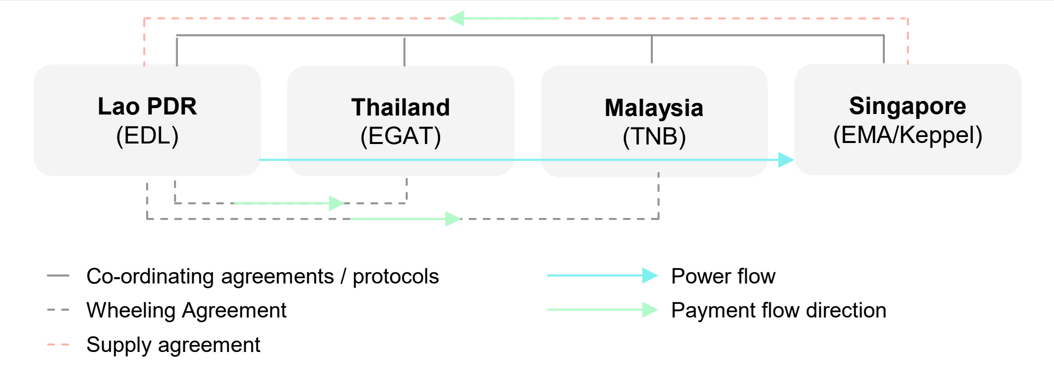
Lao PDR-Thailand-Malaysia-Singapore Power Integration Project

The LTMS-PIP – the first multilateral power project in ASEAN – was initiated in 2022 on an initial two-year trial to import 100 megawatts (MW) of electricity from Lao PDR to Singapore, with wheeling through the grids in Thailand and Malaysia. This expanded to 200 MW in 2024, with an additional 100 MW power import from Malaysia to Singapore. The project utilises existing interconnection infrastructure between the participating countries and did not require construction of new interconnections. While the scope of LTMS-PIP is limited to one-way power trade, it can be an important pathfinder project for future multilateral arrangements in ASEAN.

LTMS-PIP was implemented through a series of bilateral contracts, including:

- PPA between EDL as the exporter and Keppel as the importer of electricity. Keppel holds an electricity importer licence issued by the Energy Market Authority of Singapore.
- Wheeling agreement between EDL and EGAT for wheeling through the Thailand grid.
- Wheeling agreement between EDL and TNB for wheeling through the Peninsular Malaysia grid.

LTMS-PIP commercial arrangements



Source: ASEAN Centre for Energy / Delphos.

The LTMS-PIP is also the first instance in ASEAN in which wheeling arrangements have been agreed for transit through third-party grids. An ISEAS study on lessons from the LTMS-PIP project found differing perspectives on the level at which wheeling charges were set, with some stakeholders seeing the charges as too high compared to operational costs, while others felt it was set at too low a level to encourage investment in cross-border projects. In addition, the two-year duration of the commercial agreements is currently too short to provide certainty to prospective investors in generation projects, which may supply through the LTMS-PIP.

With wheeling charges being one of the key enablers for multilateral power trade in ASEAN, the methodology and process applied to LTMS-PIP serves as an important reference point for the establishment of future project and regional level frameworks, such as in the proposed Brunei Darussalam, Indonesia, Malaysia and the Philippines Power Integration Project (BIMP-PIP).

Chapter 2. Investment needs and challenges

Building the ASEAN Power Grid (APG) will require a significant mobilisation of investment over the coming decades given the number, scale and complexity of new interconnectors. These projects mark a major departure not only in terms of the predominant characteristics and models of development seen in ASEAN to date, but also in terms of the magnitude of potential challenges. This chapter quantifies total investment needs for the current project pipeline and explains key drivers. It also identifies some of the major obstacles and risks that could create challenges for mobilising the needed investment and financing.

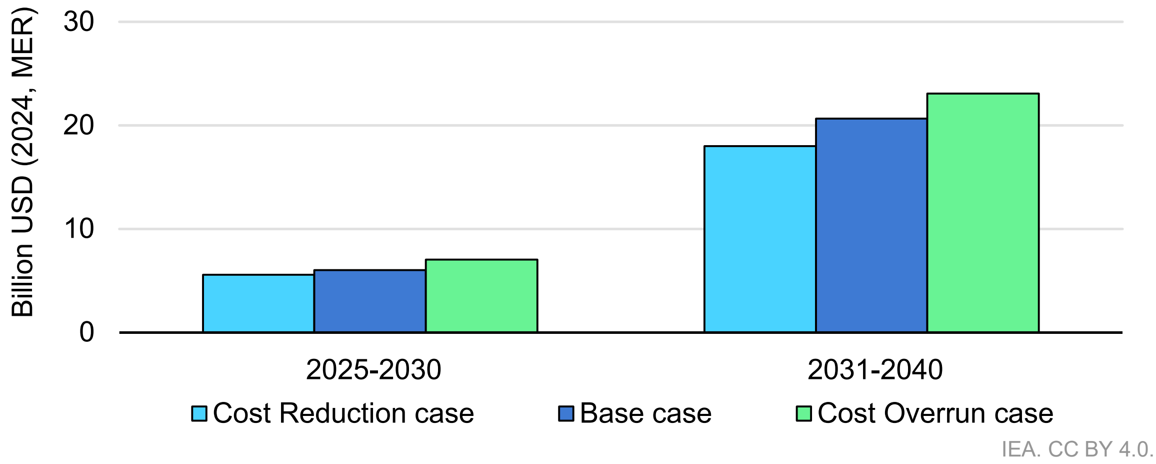
Investment needs

The APG offers substantial economic, security and sustainability benefits. By enabling countries to share generation resources and optimise the use of power system infrastructure, interconnectors can reduce both investment and operating costs through economies of scale, lower redundancy in capacity expansion, and improved access to lower-cost, low-emissions sources of electricity. In Europe, interconnections delivered an estimated EUR 34 billion in benefits in 2021 alone and are routinely used to bolster system reliability. Previous studies have found that ASEAN could save billions of dollars from lower operational costs and less investment into new generation capacity relative to a scenarios where countries remain weakly connected.

Realising these opportunities will require a significant mobilisation of new investment in the coming years. A total of USD 27 billion of investment is needed from 2025 to 2040 in the Base case across the region. This estimate, which includes all major upgrades to existing interconnectors and new projects included in the AIMS III Phase 1-2[9], additional domestic inter-island connections in Indonesia and the Philippines, as well as other announced projects – inclusive of both grid-to-grid and currently known generation-to-grid projects – amounts to a 14-fold increase over investment in all interconnectors in ASEAN from the 1970s to 2024.

[9] AIMS III Phases 1-2 sets out the transmission infrastructure needed by 2040 to enable multilateral trade and integration of variable renewables for the APG.

Interconnector investment needs by case, 2025-2040



Note: MER = market exchange rate.
Source: See Annex A for full methodology and sources used for investment and financial modelling.

There is considerable uncertainty around the exact timing, physical specifications and costs of future projects, particularly those with subsea routes. To capture some of this uncertainty, three cases are modelled:

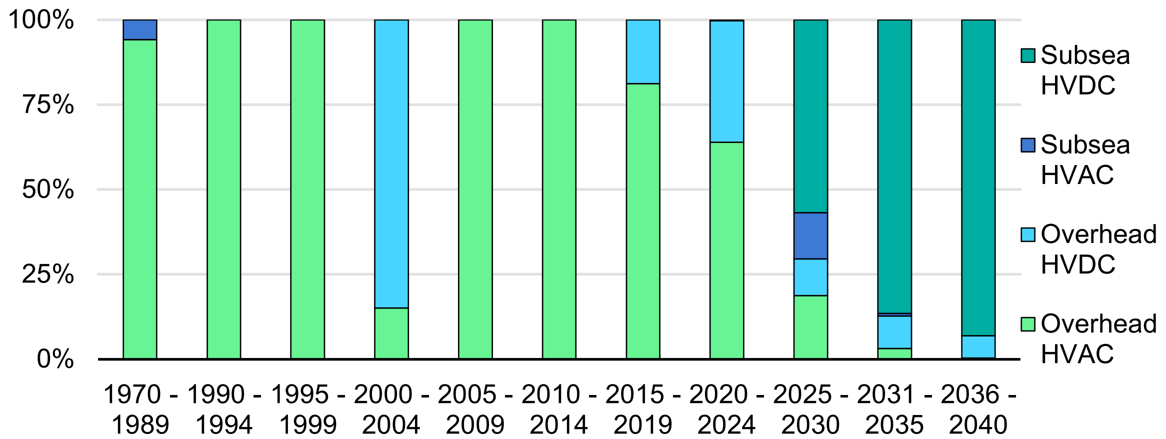
- **Cost Reduction case**: All projects are achieved on time with minimal challenges, keeping overall costs low. Inflationary pressures for subsea cables and converter stations persist in the short term, but prices begin to fall in the 2030s as manufacturing supply chains ease significantly.
- **Base case:** All projects are achieved on time with capital expenditures matching expectations based on historical project costs. The cost of subsea cables and converters rise gradually over time due to sustained demand.
- **Cost Overrun case:** Various challenges lead to longer construction times and higher capital expenditures. Sustained supply chain constraints underpin price inflation for cables and converters which persist in the long term.

Investment in interconnectors to achieve the APG in full must increase sharply relative to recent levels across all three cases. While average annual investment amounted to around USD 100 million in the 2020-2024 period, spending would need to rise substantially to an average of USD 1.5 billion per year in the Cost Reduction case and USD 1.9 billion per year in the Cost Overrun case from 2025 to 2040. This step change reflects not only a significant expansion in the volume of new interconnector capacity, but also a shift towards more capital-intensive technologies for electricity transmission.

Many new projects, including numerous generation-to-grid projects between Indonesia and Singapore, are expected to begin construction before 2030, pushing annual investment level past USD 1 billion as early as 2028 in the Base case. After 2030, construction on a series of large-scale interconnectors from Sumatra to Java in Indonesia, Viet Nam to Peninsular Malaysia, and Sarawak to Singapore, among many others, are expected to begin, leading to a further acceleration of annual investment. In the Base case, average annual investment surpasses USD 2 billion in the 2031-2040 period.

In terms of the technologies employed for interconnectors, a comparison of future and historical investment reveals two notable trends. First is the rise of subsea cable investment. Cross-border subsea cables have not been common to date other than a short 1.5 kilometre (km) HVAC link between Peninsular Malaysia and Singapore. Domestically, subsea cables have been used for connections between islands in Indonesia, the Philippines and Viet Nam. By contrast, subsea cables account for most of the needed investment in 2025-2030 and quickly increase to more than 75% from then onwards. This is mainly because overhead lines are not technically viable for numerous ASEAN interconnection projects which require connection across waterbodies in the south and east subsystems.

Investment in interconnectors by technology in the Base case, historical and projected, 2010-2040

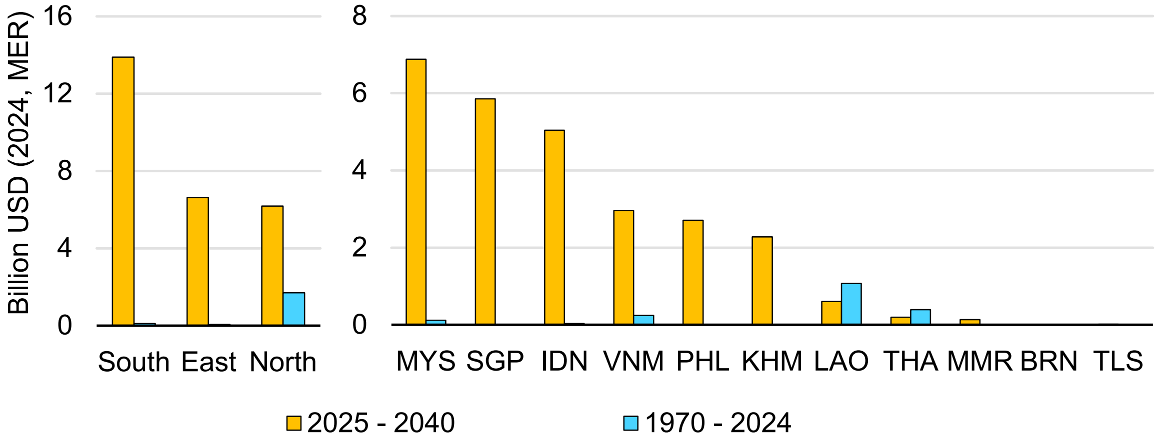


Note: HVDC = high-voltage direct current; HVAC = high-voltage alternating current.
Source: See Annex A for full methodology and sources used for investment and financial modelling.

The second trend is the introduction of high-voltage direct current (HVDC) transmission technologies for long-distance projects. Traditionally, most interconnection projects were based on high-voltage alternating current (HVAC) systems, a mature and relatively cost-effective solution well suited for synchronous connections and generation-to-grid projects where power is produced by synchronous generators, including hydropower and thermal power plants. However, for long-distance transmission routes, particularly those involving subsea cables, HVAC systems become less economically viable due to significant transmission losses. These losses are especially pronounced in underwater sections, where the capacitive effects of the cables and the surrounding environment further increase energy dissipation.

HVDC technology effectively addresses these challenges by reducing transmission losses, enabling efficient and reliable long-distance power transfer and offering independent control of active and reactive power, which stabilises the alternating current grids at both ends. These advantages bring higher initial capital requirements, primarily due to the cost of converter stations needed at each endpoint and, in some cases, the higher price of cables. For instance, the 765 km Viking Link – the world's longest subsea interconnector linking the United Kingdom and Denmark – began construction in 2019 and cost approximately USD 2.2 billion at completion in 2024. Prices for grid equipment have since risen considerably, driven by supply bottlenecks and rising material costs. As a result, long-distance, high-capacity subsea HVDC interconnectors are the biggest driver of the sharp increase in investment needs, with several key projects exceeding USD 1 billion in total costs.

Investment in interconnectors by subsystem and country in the Base case, historical and projected, 2010-2040



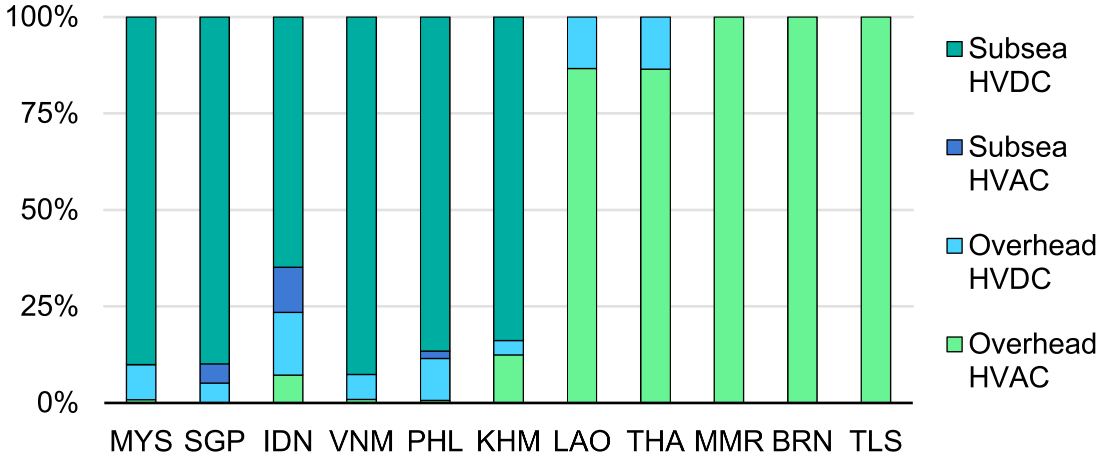
Notes: MER = market exchange rate. MYS = Malaysia; SGP = Singapore; IDN = Indonesia; VNM = Viet Nam; PHL = Philippines; KHM = Cambodia; LAO = Lao PDR; THA = Thailand; MMR = Myanmar; BRN = Brunei Darussalam; TLS = Timor-Leste. For subsea projects, investment needs are estimated to be allocated 50/50 to each country involved. Actual cost allocation will differ depending on agreements between participating countries.

Source: See Annex A for full methodology and sources used for investment and financial modelling.

Although the ultimate cost allocation between countries is uncertain, geographic distribution of future investment is also a clear departure from past trends. Whereas 77% of all interconnector investment before 2025 occurred in either Lao PDR or Thailand, these two countries account for only 3% of investment from 2025 through to 2040. Malaysia, Indonesia and Singapore are set to become the main focus of new interconnector investment and together the three are set to account for more investment over the next 15 years than for all of ASEAN between

1970 and 2024. This reflects the nascent status of interconnectivity of the South and East subsystems and the South-East Corridor relative to the North subsystem today, but also the much higher need for capital-intensive subsea HVDC projects given their archipelagic geography.

Investment in interconnectors by transmission type and country in the Base case, 2025-2040

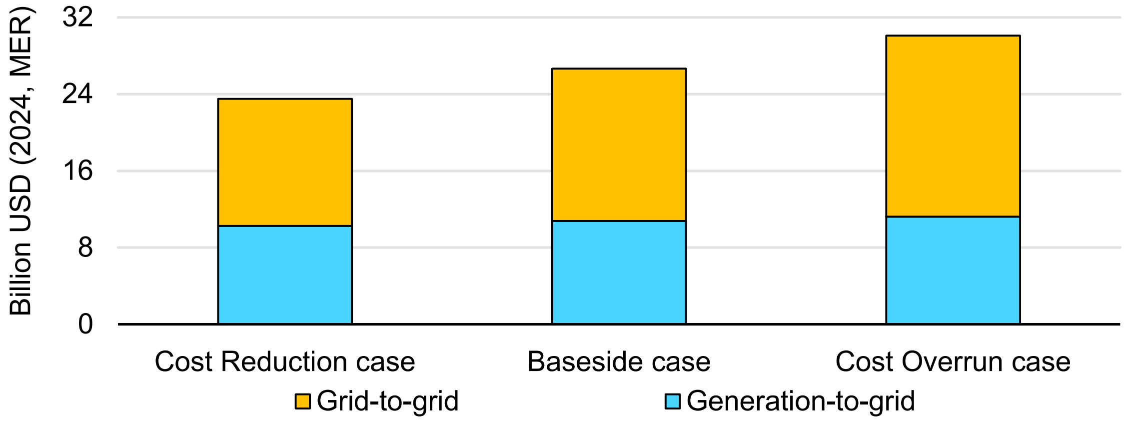


IEA. CC BY 4.0.

Notes: HVAC = high-voltage alternating current; HVDC = high-voltage direct current; MYS = Malaysia; SGP = Singapore; IDN = Indonesia; VNM = Viet Nam; PHL = Philippines; KHM = Cambodia; LAO = Lao PDR; THA = Thailand; MMR = Myanmar; BRN = Brunei Darussalam; TLS = Timor-Leste.
Source: See Annex A for full methodology and sources used for investment and financial modelling.

It must also be noted that additional projects are likely to be announced over this time horizon, which would add to future investment needs. As historical investment in countries like Lao PDR shows, initial grid-to-grid interconnectors can spur further development of new generation sources for power export. Still, unlike historical investment which was mainly for generation-to-grid projects, grid-to-grid projects make up the majority of investment, about USD 16 billion, over the next 15 years. The remaining USD 11 billion of investment is for generation-to-grid projects consisting primarily of further wind and hydroelectric export projects from Lao PDR to Thailand and Viet Nam, solar exports from Indonesia to Singapore, and the ambitious export projects connecting Viet Nam and Cambodia to Singapore.

Interconnector investment needs by case and project type, 2025-2040



Note: MER = market exchange rate.
Source: See Annex A for full methodology and sources used for investment and financial modelling.

Potential challenges

Cross-border trade in electricity can raise political sensitivities, especially in importing countries, given the central importance of electricity in our modern lives. Moreover, ASEAN member states differ considerably in terms of the market structures and regulatory frameworks, and the broader macro-financial conditions, which determine financing and business models. These factors may present challenges for countries where investment needs for interconnectors and other transmission infrastructure are high. On top of this, interconnector projects present more specific risks and technical challenges for project bankability. This section addresses these various challenges, categorised into five themes:

- Financing capacity and access to finance.
- Commercial arrangements and revenue models.
- Elevated investment risks for interconnectors.
- Macro-financial and foreign exchange conditions.
- Supply chains and other technical challenges.

Financing capacity and access to finance may be constrained

Investment in interconnectors faces considerable hurdles under the predominant models of financing current today. Given restrictions on ownership and other financial constraints, a central question is whether and how state-owned enterprises (SOE) in ASEAN will be able to raise the capital needed to finance their ambitious plans, especially against the backdrop of already sizeable investment needs for domestic transmission and distribution over the coming years.

Restrictions on private sector participation

Investment and development of transmission infrastructure is a highly regulated activity. Core transmission lines, including cross-border interconnectors, are seen as strategic national assets, with many ASEAN countries maintaining state control of their main transmission network. This is seen as important for ensuring energy security, retaining control over overall power system planning and design, and as an important instrument for social policy.

Electricity laws typically define which entities are permitted to invest in national transmission assets, which also applies to the portion of cross-border transmission assets falling within national boundaries. While several countries have signalled willingness to increase private sector participation in the domestic transmission sector, there is commonly a competing objective to maintain state control in strategic transmission investment such as interconnectors. For example, the Viet Nam Electricity Law 2024 maintains state monopoly for investment in important transmission grids of 220 kV and above even while it seeks to attract investment from all economic sectors into the construction of power grids. Similarly, in Indonesia, a recent constitutional court decision reaffirmed the role of the state, via PLN, to conduct electricity businesses in an integrated manner, which may pose a barrier to private sector participation in transmission. In practice, private sector concessions for grid-to-grid projects are not permitted in much of the region.

Transmission network ownership and operation for selected ASEAN countries

Country	Transmission ownership and operation
Indonesia	**SOE-led.** National transmission network owned by PT PLN Holding (as stipulated by Electricity Law 30/2009), with ownership from private power utilities permitted outside of PLN business areas.
Viet Nam	**SOE-led.** National transmission network owned by EVNNPT. Electricity Law 2024 (Article 5) establishes state monopoly in national power system dispatch, investment and operation of important transmission grids of 220 kV and above.
Philippines	**Operating lease.** Transmission network owned by TransCo, a government-owned and controlled corporation, with 50-year franchise agreement granted to National Grid Corporation of the Philippines as the operations and maintenance concessionaire.
Thailand	**SOE-led.** Electricity Generating Authority of Thailand (EGAT) serves as transmission owner and system operator for high-voltage transmission.
Malaysia	**SOE-led.** Transmission infrastructure owned by Tenaga Nasional Berhad in Peninsular Malaysia, Sarawak Energy in Sarawak, and Sabah Electricity in Sabah.
Singapore	**SOE-led.** Transmission network owned and operated by SP Power Assets as the transmission licensee.

Notes: SOE = state-owned enterprises. Transmission ownership and operation requirements apply both to domestic transmission assets and the portion of cross-border interconnectors falling within a national border.

Our analysis of historical investment trends shows that concession models involving private actors have been used primarily for generation-to-grid projects. Restrictions on private sector ownership and operations imply that most future investment into grid-to-grid projects will be undertaken by SOE, likely using on-balance sheet financing. Where financing capacity exists, SOE-led models may be faster to implement under current policy environments and allow cross-subsidisation of costs where business models are not fully developed. However, a continued reliance on SOE balance sheets can lead to bottlenecks where investment needs are high and balance sheets are constrained.

Balance sheet constraints

Setting aside generation-to-grid projects where private sector participation is more likely: if the next 15 years were to see a continuation of current financing models for planned grid-to-grid projects, USD 16 billion would need to be financed on the balance sheets of SOE, or their concessionaires, from 2025 to 2040 in the Base case. High levels of public sector ownership in generation-to-grid interconnectors, especially those linking Singapore to Cambodia and Viet Nam, could add billions to that figure.

The financial capacity of utilities in ASEAN varies widely, shaping their ability to provide equity or raise new debt for cross-border interconnectors. Among the ASEAN SOEs examined, SP Group, Tenaga Nasional Berhad (TNB) and Electricity Generating Authority of Thailand (EGAT) show stronger financial fundamentals including relatively low leverage ratios and high operating cash flow (OCF) ratios. For example, EGAT's OCF exceeds its net debt obligations (103%), while SP Group and TNB maintain moderate leverage (net debt/ earnings before interest, taxes, depreciation and amortisation [EBITDA] ratio tracking at 0.9x and 2.3x, respectively), suggesting capacity to support new investment. By contrast, PLN and Viet Nam Electricity National Power Transmission Corporation (EVNNPT) face tighter constraints. Both operate with higher leverage (3.2x and 5.2x net debt/EBITDA ratio) and low OCF to net debt coverage (17-20%), limiting their ability to take on additional borrowing without jeopardising credit quality. Their weaker profitability and lower cash flow margins mean that large capital expenditures such as interconnectors may be difficult to finance on their balance sheet alone.

Balance sheet analysis of selected ASEAN state-owned enterprises

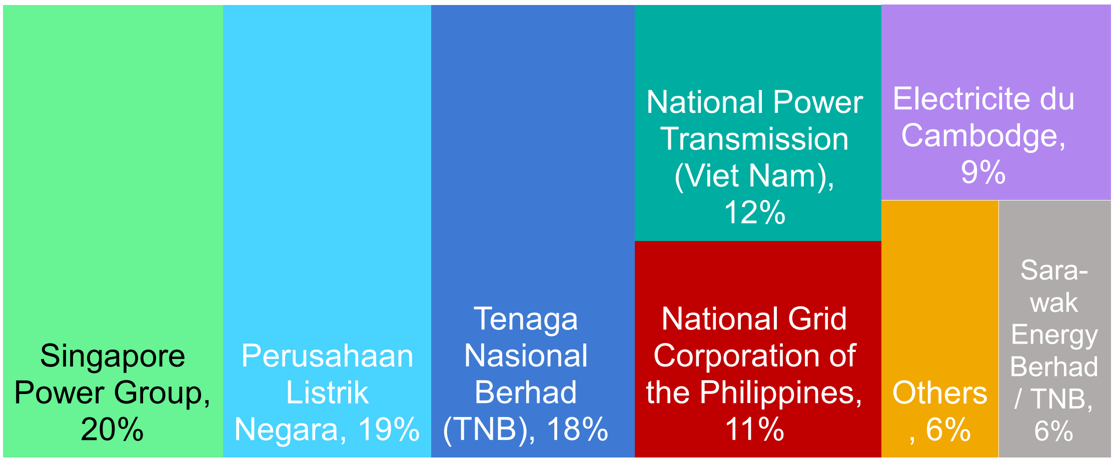
Utility (country)	**Credit rating**	**Operating cash flow** (USD billion)	**EBITDA / revenues** (%)	**Net debt / EBITDA**	**Operating cash flow/ net debt** (%)
SP Group (Singapore)	AA+ (S&P)	1.9	34.7	0.9x	94.5
PLN (Indonesia)	BBB- (Fitch)	6.1	20.7	3.2x	17.5
EVNNPT (Viet Nam)	n/a	2.2	11.1	5.2x	19.1
EGAT (Thailand)	BBB+ (Fitch)	3.3	18.6	1.0x	103.4
TNB (Malaysia)	A- (S&P)	4.7	37.1	2.3x	46.0

Notes: EBITDA = earnings before interest, taxes, depreciation and amortisation. All values based on the average of the most recent three years of data.
Source: IEA analysis based on company annual reports.

Overlaying expected capital expenditure needs for grid-to-grid interconnectors under business-as-usual financing models with balance sheet health reveals mixed implications. On one hand, SOE such as EGAT, which face both low financing needs and high OCF to net debt ratio, are unlikely to face any significant challenges raising finance for future interconnector projects. This may also be true for SOE that face high expected balance sheet expenditure but are in good financial health. For example, under business-as-usual financing models, SP Group and TNB could see considerable financing needs over the next 15 years yet their OCF and borrowing capacity are robust. Other SOE might face greater balance sheet constraints, and evaluating the ability of other SOE to meet future interconnection investment requirements is challenging due to the lack of transparent financial data.

Such investment also comes in the context of already considerable investment needs from utilities for domestic transmission and distribution infrastructure over the coming decades. For example, EVNNPT plans to invest USD 34 billion in the transmission grid from 2026 to 2035; NGCP (Philippines) over USD 10 billion from 2024 to 2050; and PLN USD 24 billion from 2025 to 2034. Cross-border interconnectors must clearly demonstrate benefits to ratepayers to take priority over domestic projects, hence some utilities may face practical limits given competing domestic priorities and fiscal pressures.

Share of total balance sheet financing needs by SOE or transmission concessionaire under current financing models in the Base case, 2025-2040



Notes: Values are intended to be illustrative, not forecasts: bespoke agreements of cost allocation between different utilities and involvement from private sector actors could significantly alter the distribution of investment needs. This figure assumes grid-to-grid projects take the form of the SOE-led financing model, i.e. financed on the balance sheet of SOE (or concessionaire for the Philippines). Financing for generation-to-grid projects extrapolates historical financing patterns into the future, maintaining restrictions on private sector ownership of transmission infrastructure where they exist. Where project level information on sponsors is available for future projects, this information is considered. For example, the Sarawak to Singapore interconnector is assumed to be financed by Singapore based on press releases from Sarawak Energy Berhad; likewise, the Peninsular Malaysia to Sarawak interconnector is suggested to be financed at least in part by TNB.

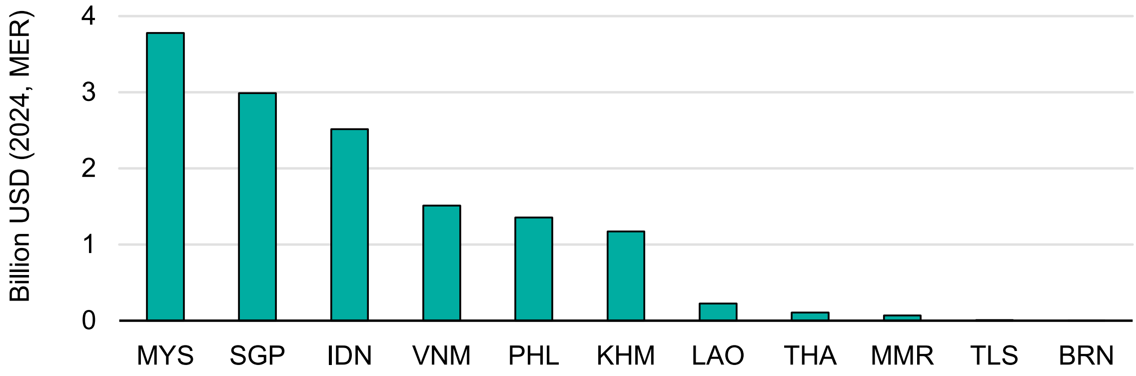
Source: See Annex A for full methodology and sources used for investment and financial modelling.

Domestic capital market constraints

An estimated USD 14 billion of commercial debt could be required for interconnectors over the next 15 years, most of which would be borrowed by SOE for grid-to-grid projects under business-as-usual financing models. Domestic lenders in ASEAN member states may likewise be constrained by prudential banking rules which cap lending to any one borrower or connected group of borrowers as a preventative measure to contain concentration risk. These measures, called single borrower limits, exist in most ASEAN countries and usually set a maximum limit of 15-25% of a bank's eligible capital.

Given the size of state-owned utilities and the highly capital-intensive nature of their activities, it is not uncommon for domestic lenders to hit this maximum limit, especially in countries where domestic capital markets remain relatively underdeveloped. For instance, previous assessments have noted that numerous financial institutions in Indonesia and Viet Nam are approaching or have surpassed the single borrower limit for lending to PLN and EVNNPT, respectively, leading some banks to securitise and off-load exposure using syndicated loans. In contrast, Malaysia, Singapore and Thailand face little pressure because their utilities finance through a deeper local currency deposit and institutional investor base and more mature bond markets.

Total estimated commercial debt needs for interconnectors by country in the Base case, 2025-2040



Notes: MER = market exchange rates. MYS = Malaysia; IDN = Indonesia; SGP = Singapore; KHM = Cambodia; PHL = Philippines; VNM = Viet Nam; LAO = Lao PDR; THA = Thailand; MMR = Myanmar; TLS = Timor-Leste; BRN = Brunei Darussalam. Commercial debt refers to debt from financial institutions that is provided at commercial rates irrespective of the issuing entity, e.g. multilateral development banks or commercial banks. Commercial financing projections assume a continuation of historical financing models and debt-equity splits into the future. Where project level financial information is available for future projects, this information is considered. For subsea projects, investment needs are allocated 50/50 to each participating country.

Source: See Annex A for full methodology and sources used for investment and financial modelling.

Underdeveloped domestic capital markets create additional complications due to the mismatch between short-term nature of deposits and the long-term tenures required by large infrastructure investment. In Indonesia, for example, the tenure on most loans for the private sector are between three and five years, extending to 10-15 years for state-owned entities, whereas the lifetime of a large-scale interconnector project may be considerably longer. A similar skew towards short-term lending has been reported in Viet Nam.

Some emerging market and developing economies have been dependent on sector-specific credit lines from international public financiers to support longer term lending or direct provision of project level debt with concessional terms, including longer loan tenures. While an important tool, support from international financiers alone is not sufficient given the scale of investment needed for the power sector over the coming decades. Debt from non-bank financial institutions including sovereign wealth funds, pension funds and insurers are more likely to provide better alignment concerning asset-liability maturities. Stronger capital market development, potentially with the help of international financiers, is needed to expand longer term fixed income products like infrastructure and corporate bonds and ensure adequate secondary capital markets for refinancing.

Interconnectors may not meet green financing requirements

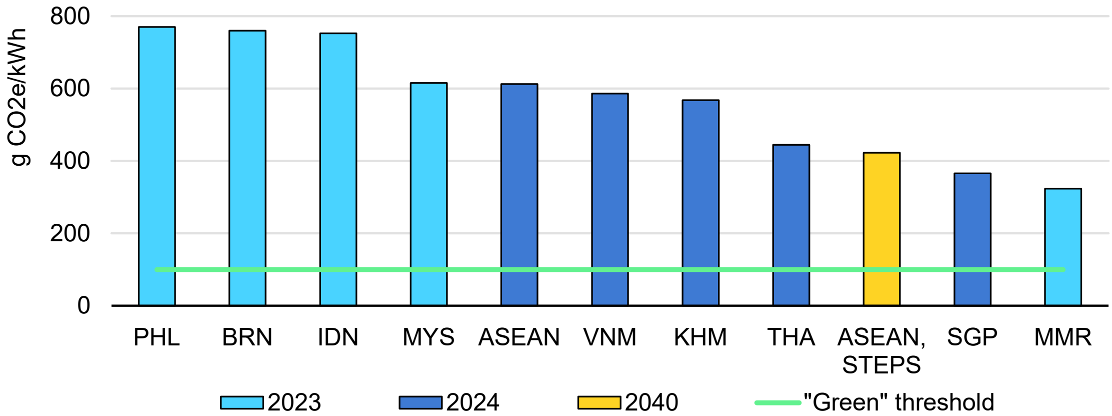
Although interconnectors can enable emissions reductions by maximising the utilisation of variable renewables and displacing fossil fuel generation, these projects may not always meet the immediate requirements necessary to be classified as green.

While taxonomies differ across jurisdictions, electricity transmission – including interconnectors – must generally enable more integration of variable renewables or utilisation to be eligible for green financing. Under the ASEAN taxonomy for sustainable finance, electricity transmission qualifies as green when it is part of a system where 67% of capacity additions in the previous five years are from low-emissions sources, or the lifecycle emissions intensity of the system is less than 100 grammes of carbon dioxide per kilowatt-hour over a five-year rolling period. These frameworks do not provide explicit guidance for connections between systems; hence it is unclear how these criteria will be applied across multiple jurisdictions.

Regardless of how these criteria are interpreted for interconnectors, meeting these requirements may be challenging for countries where the generation mix is mainly composed of fossil fuels and renewable capacity additions will take time to ramp up. No ASEAN country presently has an average carbon dioxide (CO_2) intensity of generation below 100 grammes per kWh, and the average emissions intensity for the region does not fall below 500 g CO_2/kWh until 2034 in the Stated Policies Scenario.

In terms of renewable capacity additions, three countries – Lao PDR, Singapore and Viet Nam – have all seen a renewables share of new capacity additions over the past five years above the minimum 67% requirement, and others such as the Philippines and Cambodia are approaching this marker. On the other hand, renewables have accounted for a quarter or less of capacity additions over the past five years in Malaysia, Indonesia and Thailand. In practical terms, depending on the project, some interconnector may not be eligible for green financial instruments by regional and international standards in the short to medium term.

Recent emissions intensity of generation and future emissions intensity of generation for selected countries in the Stated Policies Scenario, 2024-2040



Notes: STEPS = Stated Policies Scenario; g CO_2/kWh = grammes of carbon dioxide per kilowatt-hour. PHL = Philippines; BRN = Brunei Darussalam; IDN = Indonesia; MYS = Malaysia; ASEAN = Association of Southeast Asian Nations; VNM = Viet Nam; KHM = Cambodia; THA = Thailand; SGP = Singapore; MMR = Myanmar. 2024 emissions intensity values only available for Viet Nam, Cambodia, Thailand and Singapore.

Source: IEA (2025), Emission Factors Package.

This is pertinent for multilateral development banks (MDBs), development finance institutions (DFIs), multilateral climate funds and other investors with a climate mandate. The Joint Climate Finance Tracking Group of MDBs and a group of representatives of the International Development Finance Club member banks have developed their own set of common principles for climate mitigation finance tracking which do provide explicit criteria for interconnectors. Under these screening criteria, generation-to-grid projects for variable renewables power export would be considered fully eligible. Grid-to-grid projects are eligible for climate financing proportional to the share of additional low-emissions (and non-nuclear power) it delivers across subsystems, measured over a ten-year period (comparing the five years pre and five years post operations). While this alternative approach introduces flexibility by moving beyond binary classifications, it too could render some interconnector projects ineligible or only partially eligible for green or climate financing despite their critical role in supporting higher levels of integration of variable renewables and high need for de-risking capital. Previous IEA analysis shows that, in the absence of much higher renewable deployment, a more interconnected system would primarily benefit coal and push up emissions.

These eligibility challenges also highlight a broader constraint: project sponsors and investors may have limited control over whether interconnectors qualify for green financing where taxonomies rely on system level criteria. Eligibility may depend on the level of ambition and coherence of broader climate policy and national power sector plans, which are shaped by government decisions and roadmaps. For example, the Green Grids Initiative Climate Finance Principles for Grids, developed to provide a common set of principles for grid financing and facilitate improved co-ordination between financiers, includes both system level and project level criteria to assess eligibility. System level criteria, the scope of which for interconnectors may include all countries connected, require power sector plans to: include a "sufficiently ambitious" climate contribution; be internally co-ordinated and have consistent planning; and have measurable, time-bound and reported indicators.

Current commercial arrangements and revenue models are not conducive to scaling power trade

The financial viability of interconnectors and cross-border electricity trade in ASEAN depends on clear and predictable business models that allocate costs, risks and benefits among participants. While the technical potential for regional integration is significant, the commercial frameworks that underpin investment are challenging to establish.

Three interrelated challenges are identified:

- Differences in national market structures and tariff design can distort price signals and discourage private investment.
- A lack of explicit, transparent and harmonised revenue models for interconnection services prevents the uptake of third-party ownership models.
- Services provided by interconnectors in providing reliability and system services are not explicitly valued or undervalued.

Trading arrangements can be challenging to establish between countries with diverse market structures and tariff regimes

Scaling power trade does not necessarily require changes in national market structures, but rather the establishment of compatible trading arrangements between participating countries. The diversity of market structures and tariff regimes in ASEAN, which reflect differences in political priorities and national contexts, can make these arrangements more difficult to establish.

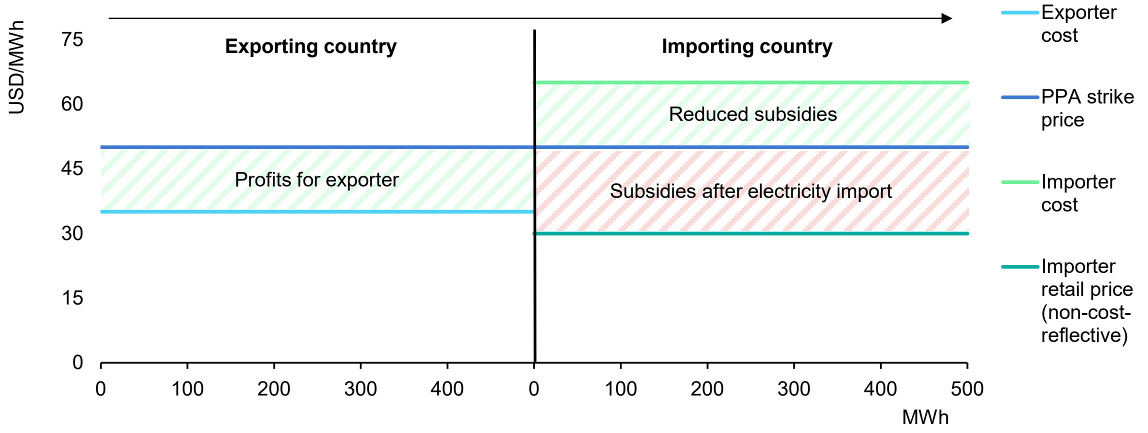
Transmission tariff structures in selected ASEAN countries

Country	Tariff setting body	Cost-reflective retail tariffs	Transparent transmission tariff
Indonesia	Ministry of Energy and Mineral Resources	No	No, bundled in retail tariffs.
Viet Nam	Electricity Authority of Vietnam under Ministry of Industry and Trade	Transitioning to cost-reflective tariffs	Yes, published in decree.
Philippines	Independent regulator	Yes	Yes, published online.
Malaysia	Independent regulator	Yes	Yes, published online.
Thailand	Independent regulator	No	Yes, published online.
Singapore	Independent regulator	Yes	Yes, published online.
Cambodia	Independent regulator	No	No, bundled in retail tariffs.
Lao PDR	Ministry of Energy and Mines	No	No.
Myanmar	Ministry of Electric Power	No	No, bundled in retail tariffs.

The underlying market structure has implications for cost recovery. Liberalised power markets such as Singapore and the Philippines have cost-reflective retail tariffs and regulated transmission tariffs which reflect the costs of building and maintaining the assets, plus some regulated rate of return. Vertically integrated power markets such as Indonesia and Cambodia typically do not have an independent transmission tariff. This means transmission investments are recovered as part of bundled retail tariffs charged to ratepayers. In markets with non-cost-reflective tariffs, subsidies are required to recover investment costs.

Countries with non-cost-reflective retail tariffs may have limited incentive to import electricity at a price higher than the domestic retail tariff, even where it is lower than domestic cost of supply, as they would effectively be subsidising imports. This is despite a reduction in total subsidy required, so long as the import price is lower than the cost of domestic generation and transmission.

Illustrative interconnector benefits with non-cost-reflective tariffs with bilateral trading arrangements

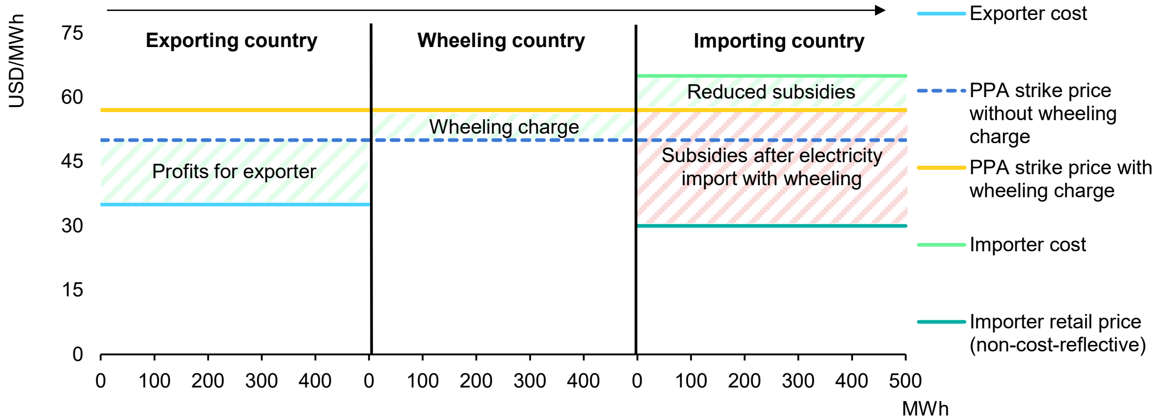


Notes: MWh = megawatt-hours; PPA = power purchase agreement. Diagram illustrates a power trade where the importing country has a subsidised electricity tariff. Level of required subsidy is reduced following import. Displayed strike prices are illustrative.

There are further complexities for multilateral arrangements where power is wheeled through the grid of transit countries. In this case, the utility in the transit country requires compensation for the use of their transmission network. This may take the form of a wheeling charge where the transit country does not otherwise gain access to cheaper electricity from these trades, as in the Lao PDR-Thailand-Malaysia-Singapore Power Integration Project (LTMS-PIP).

The level of this wheeling charge must be agreed by the participating countries, alongside a price for power sales. Agreeing a wheeling charge, and guaranteeing a fair allocation of costs, is challenging when each country along the chain of electricity trade has a separate methodology for determining transmission tariffs, different underlying objectives and limited transparency in how tariffs are set. For example, whereas transmission tariffs in Viet Nam are set at a level required for cost recovery, the Philippines and Singapore allow for higher regulated returns; other countries do not publish their transmission tariffs. Furthermore, importing and exporting countries have an incentive to minimise the wheeling charge, while transit countries have an incentive to maximise it. Inappropriate use of transit fees risks creating tariff pancaking, i.e. the accumulating of fees across borders, which can discourage the very electricity exchange that regional integration seeks to promote. Importing countries with wholesale markets may also have market rules such as penalties for the non-delivery of energy, which can lead to asymmetries in the allocation of commercial risks between domestic and foreign entities.

Illustrative interconnector benefits with non-cost-reflective tariffs with multilateral trading structures using wheeling



Notes: MWh = megawatt-hours; PPA = power purchase agreement. Diagram illustrates a power trade where the importing country has a subsidised electricity tariff, with transit country that charges a wheeling charge, but does not otherwise benefit from the trade. Level of required subsidy is reduced following import. Displayed strike prices are illustrative.

Underdeveloped trading arrangements can lead to underutilisation of interconnection infrastructure. For instance, while the Malaysia-Singapore interconnector has a transfer capacity of around 1 000 MW, only up to 200 MW is currently used for commercial exchange under the LTMS-PIP. This can hinder the commercial viability of interconnection projects in commercial arrangements where revenues fluctuate depending on the volume of energy traded.

A lack of explicit, transparent and harmonised revenue models for interconnection services

At the project level, clear and predictable revenue streams for interconnectors are needed to recover costs of investment and operations. This is important both for private sector developers which expect a certain level of risk-adjusted return on investment, and for SOE which must be able to justify the benefits of investment to the public.

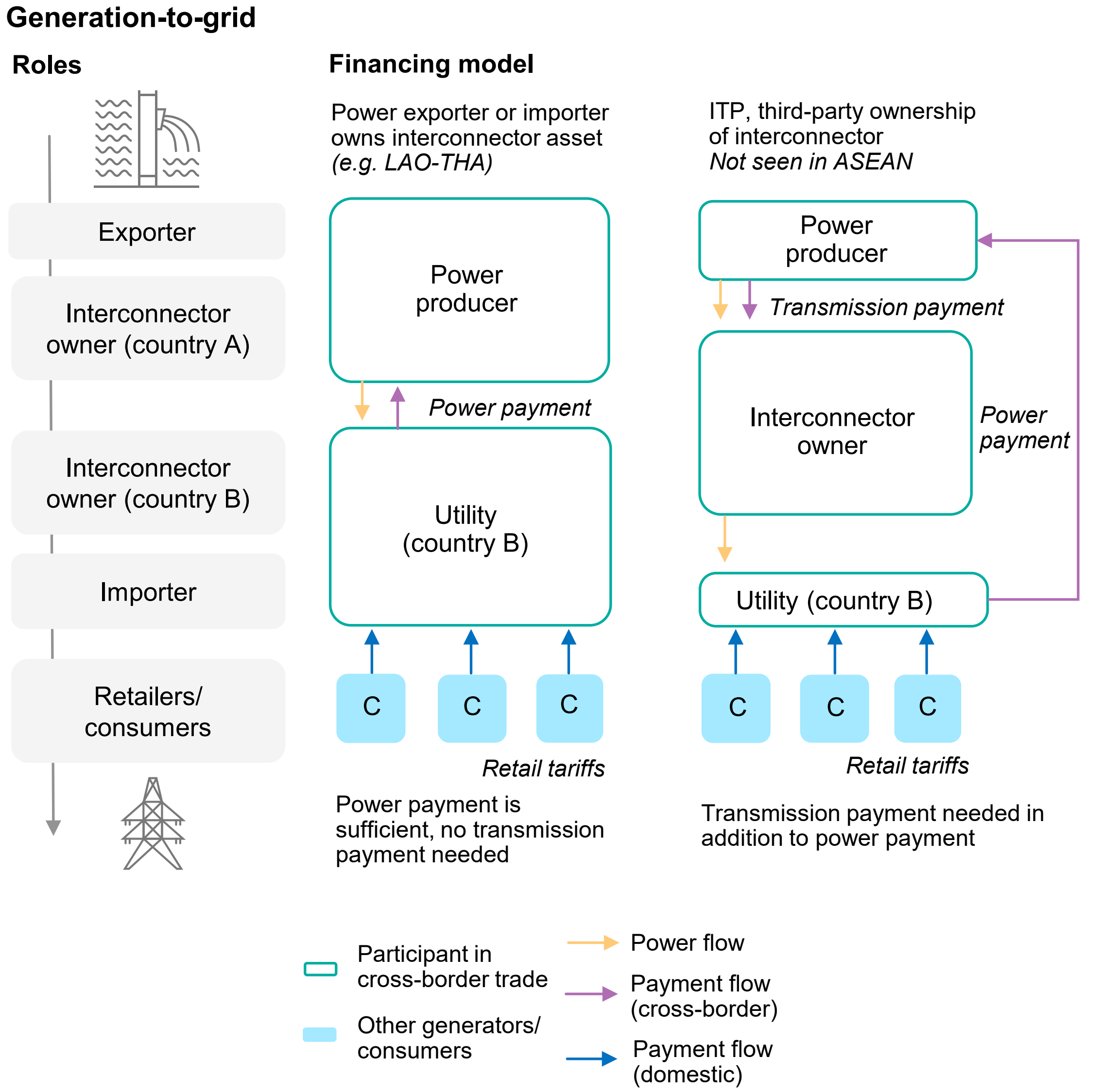
The primary service provided by interconnectors is the transmission of electricity between an exporter and importer of electricity. In ASEAN, this is rarely explicitly priced and compensated as a standalone activity, such as through a transmission charge or availability-based payment. This has different implications depending on ownership of the interconnector asset.

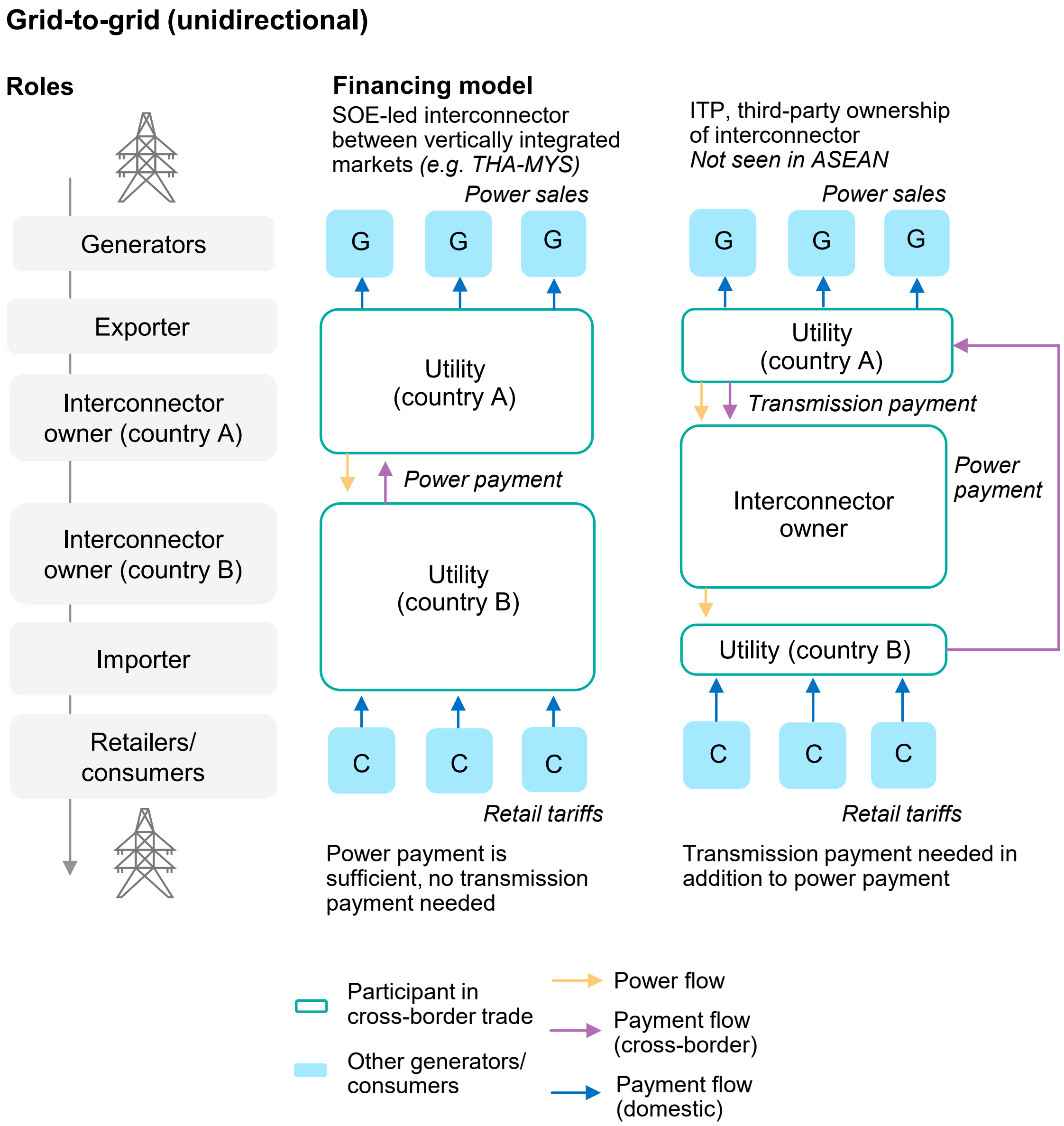
For generation-to-grid projects, the interconnection asset is typically owned by the power exporter under the same project special purpose vehicle (SPV). Investment costs may be recovered at the project level through power sales, with pricing set at a level to recover costs for both the generation and interconnection assets. Transmission services are implicitly valued and/or included within the power purchase agreement (PPA), and no additional revenue agreement is required. Similarly for grid-to-grid projects, a single power sales payment is sufficient where the interconnector asset is owned by the exporting and/or importing utility.

However, where the interconnector is owned by a third-party SPV separate to the importer and exporter, an additional payment is required to compensate the interconnector owner and to recover costs. This is the case both for grid-to-grid projects developed under concession models, and generation-to-grid projects where the transmission line is independently owned to the generation asset. Complexity is further increased where power transits through additional transmission lines or networks owned by third parties, such as where power wheeling through a transit country is required. The owner of each intermediate transmission asset and/or system owner must be compensated the use of their asset.

There are currently no harmonised wheeling charges or power trading arrangements in the region, and to date, power trade has relied on bespoke PPAs and wheeling charges. These are typically negotiated on a case-by-case basis with limited transparency or standardisation of contractual terms or pricing. This is straightforward to apply where there are a limited number of participants in cross-border trade, such as bilateral trading between vertically integrated markets. However, it limits scalability; as the number of participants in power trade increases – including exporters, importers, interconnectors and participating countries – this may result in more complexity, unequal treatment of parties and increased transaction costs.

Illustrative commercial arrangements for power trade between two countries with various financing and power trade models





Notes: ITP = independent transmission project. LAO = Lao PDR; THA = Thailand; MYS = Malaysia; ASEAN = Association of Southeast Asian Nations. Transmission payments may include transmission charges, availability payments, a mix of both, or another type of payment for the services provided by the interconnector asset. The diagram illustrates commercial arrangements through a single interconnector between two countries; complexity will increase where there is power trade through multiple interconnectors and between more than two countries.

Broader system benefits are not explicitly valued in commercial agreements for interconnectors

Power systems in ASEAN countries have traditionally relied on synchronous conventional generators which provide inertia to absorb disturbances and maintain grid stability. As the region increases its reliance on variable renewable energy generation, these grid stabilising services are reduced, raising the risk of grid instability. In this context, interconnectors become increasingly important. The Nordic power system, for example, allows member countries to share various frequency control products and reserves to prevent, contain and restore frequency during disturbances.

Interconnectors allow countries to share low-cost renewables and reduce investment in generation capacity and other resources, e.g. batteries, that would be required to meet the demand and reliability requirements without interconnectors. In the Nordic synchronous system, the reserve requirement is set by the single largest contingency across Norway, Sweden, Finland and Denmark, rather than each country planning to cover for its own largest contingency, e.g. if a large nuclear plant were to trip. This reduces the fuel and maintenance costs associated with keeping backup generation online and the need for investment in peaking units. From a technology perspective, HVDC voltage source converters can provide ancillary services such as black start capability, voltage control and frequency support.

Given the heterogeneous market structures of ASEAN countries, it is not clear whether and how ancillary services and wider system efficiencies are considered for remuneration when a consistent set of cross-border mechanisms do not exist on both sides of a border. For instance, the Philippines and Singapore have established markets for reserves and ancillary markets, but most other ASEAN countries embed these services within grid codes and regulations via PPAs or regulated payments. As such, the interconnector can still enable the transfer of ancillary services, but there is usually no separate settlement line to pay foreign operators for reserves, frequency and voltage support; these services are positive externalities bundled into a PPA.

If ancillary services are not formally valued, and countries cannot benefit from shared reserve capacity, the interconnector asset may be undervalued relative to the services it could technically provide, offering lower incentives for interconnection. Moreover, if the agreement is based primarily on supply and cost differentials, commercial agreements may be biased towards one-way power trading arrangements rather than broader system benefits.

Interconnector projects come with elevated risks

Financing costs, also referred to as the cost of capital, play a vital role in the financial decision-making processes of investors. Given the capital intensity of major infrastructure projects like transmission and power generation, a high cost of capital is often a key barrier to scaling investment in many emerging market and developing economies today. As shown in the IEA Cost of Capital Observatory, the financing costs for even mature technologies like solar and wind in ASEAN member countries can be significantly higher than in advanced economies, reflecting elevated levels of actual or perceived risks to investors.

Among the most frequently cited risk drivers of higher financing costs are political and regulatory in nature. The broader macro-financial environment is often a key factor, as foreign exchange fluctuations may undermine the viability of projects financed in a hard currency. At the same time, transmission projects in general, and interconnectors projects in particular, have qualities which may carry additional risks. This is particularly true for ASEAN given the expected pipeline of first- and next-of-a-kind projects that hold high strategic significance, span multiple jurisdictions and involve long-distance subsea segments.

In addition to financing, interconnectors require high upfront costs during project preparation for detailed feasibility studies. These development costs must be incurred before revenues are earned, and cancellation or re-design of the project during the development stage will mean these costs are not recovered.

Key risks by stage of project development for subsea interconnectors

Key risks	Development		Operations	
	Preparation	Construction	Concession period (IPP projects)	Remaining operations
	7-15 years		25-30 years	15+ years
Political and regulatory	Medium	High	High	Medium
Technical and physical	Low	Medium	High	High
Permitting and access	High	High	Medium	Low
Off-taker	Low	Low	Medium	Low
Currency	Low	High	Medium	Low

High risk - Medium risk - Low risk

Notes: IPP= independent power producer. Risks are indicative. Specific risk ratings and project timelines will differ by project.

Political and regulatory risks

Interconnection projects inherently attract high political interest due to their implications for energy security, cross-border relations and regional power dynamics. While the delivery of shared interconnectors and cross-border trade has been an important symbol of regional co-operation and partnership, dependence on neighbouring countries for electricity supply can be perceived as a risk to energy security.

Sustained political support among all governments involved, sometimes across multiple political cycles, is required. During planning and project preparation, political support is required to facilitate permitting, licensing, development of enabling regulatory frameworks, and drive alignment across all necessary institutions. New interconnector projects require lengthy timelines to plan, prepare and deliver, spanning 7-15 years for subsea projects. For example, the United Kingdom-Norway North Sea Link was completed in 2021, 12 years after the signing of a preliminary agreement between National Grid and Statnett to develop a proposal for the project in 2009. Any changes in policy during these initial stages may cause project delays, cancellations and wasted project preparation costs.

During operations, a stable policy and regulatory environment is needed to maintain stable operations through the lifetime of the asset. Any interruptions in power trade or changes to trading arrangements due to government actions, e.g. export restrictions and imposition of tariffs, may cause economic and financial losses both for countries involved, and for project investors. Interconnector infrastructure may be operational for 40+ years, and, where they are developed under private or public-private concessions, may have long-term concession agreements of 25 years or more. The sanctity of contracts and continuity of domestic and cross-border collaboration therefore is imperative, and participation in projects from public sector investors and MDBs can lend additional comfort to investors.

Technical and physical risks

The utilities in ASEAN have extensive experience in deploying overhead alternating current lines. Key risks during installation include construction, permitting and land acquisition delays. They are exposed to risks of extreme weather, including damage during storms and monsoons. If damaged, overhead lines could be repaired within days or weeks, limiting repair costs and downtime. In comparison, subsea interconnectors are generally more costly and complex to construct than overhead transmission lines. Installation requires specialised cable-laying vessels capable of precisely positioning and burying cables several metres below the seabed. The process carries risks of physical damage to the cable from contact with the vessel, equipment or irregular seabed topography, as well as from human error during laying operations.

Operational risks are higher for subsea cables compared to overhead lines. Cables can be damaged by natural events such as seabed movements, underwater landslides, or strong currents, and by third-party activities including anchor drags, fishing trawlers or dredging operations. The shallow waters of the Sunda Shelf and the high density of maritime traffic in Southeast Asia increase the exposure of subsea cables to accidental damage. Recent incidents of deliberate or suspected sabotage to subsea telecommunications and power cables in the Baltic Sea and Red Sea have further raised awareness of physical security risks to critical underwater infrastructure. Damage to subsea cables may result in lengthy downtime and high costs. Repairs require replacement cables and repair vessels, both of which are in tight supply. For example, damage to a section of the Estlink 2 subsea interconnector between Estonia and Finland was damaged by a ship's anchor in December 2024 and fixed in August 2025 with reported repair costs between EUR 50-60 million to replace a damaged section with a new stretch of cable. Lost revenue due to business interruption may far exceed repair costs if there is lengthy downtime.

Elevated technical and physical risks and the potential for high losses often require mitigation through comprehensive insurance coverage. They contribute to higher insurance premiums, which can form a substantial proportion of total project costs. These risks are further exacerbated by supply chain constraints for cable components and cable-laying vessels, lead to longer timelines and risk of delay for both project development and repairs if not managed through early engagement and agreements with manufacturers.

Permitting and access

Permitting and land acquisition is a key challenge for both overhead and subsea transmission projects. Spanning long distances, transmission line routes may pass through populated or ecologically sensitive areas, and areas with competing economic uses. Community consultation processes, environmental and social safeguards, and alignment with land-use and spatial planning frameworks are required to effectively manage risks and impacts to local communities, local economies and the environment. There may be opposition to the project from local communities, where land acquisition or resettlement is required. These processes often require intensive engagement with multiple permitting bodies both at the national and sub-national level, and the complexity is compounded for cross-border projects which span multiple jurisdictions.

Subsea projects introduce a different set of permitting and access considerations compared to land-based projects. Environmental impact assessments must consider impacts of subsea cables on marine ecosystems and fisheries, such as disturbance to seabed and fish stocks during cable installation and repair, and access to project areas may be limited during certain seasons. In addition, ownership along the cable route is likely to be fragmented. Different entities may own the onshore, foreshore and seabed portions of the project, requiring engagement with multiple entities who may have different permitting processes and requirements. For lengthy subsea projects, the cable route may pass through territorial waters of a third country, which further increases permitting and political complexity.

Unless they are actively managed, permitting and access challenges may lead to elevated project preparation costs, a lengthening of cable routes to avoid sensitive areas, potential delays to cable repairs or installation where access to the project is restricted, and the risk of project cancellations.

Off-taker risk

Off-taker risk refers to payment-related risks where the counterparty that purchases the electricity or pays for the transmission service, typically a SOE in ASEAN, does not honour contractual payment obligations. In generation-to-grid and grid-to-grid models established under PPA arrangements, the off-taker will typically be the importing utility or, where corporate PPAs are permitted, the retailer or consumer. The commercial arrangement between the power producer and the off-taker plays a critical role in securing project financing. Greater certainty of off-take enables the power producer to obtain more favourable financing terms, which in turn supports the delivery of a more competitive power price to the off-taker.

While off-taker risk was not identified as a significant risk driver for power generation projects in ASEAN countries surveyed as part of IEA Cost of Capital Observatory (Indonesia, Viet Nam, Philippines, Thailand and Malaysia), the level of risk is closely linked to the long-term financial health of the utility. This is important to consider throughout the lifetime of the project, particularly for private sector investors.

Currency risk

Foreign exchange risk is a key factor for interconnector projects. This concept refers to risks from changes in foreign exchange rates in cases where a project earns revenue in local currency, but investors and lenders are repaid in a foreign, hard currency such as US dollars. In short, unexpected depreciation in local currency relative to the currency used for financing can diminish project returns. This risk is determined by the broader macro-financial environment of a given country.

Macro-financial conditions are broadly supportive in most, but not all, countries in ASEAN

Sovereign credit and spreads

Sovereign credit profile in ASEAN shows wide dispersion with direct implications for interconnector bankability. Half of the ASEAN economies provide stable, liquid sovereign yield benchmarks with competitive returns, making them more attractive to investors than most emerging markets at comparable income levels. However, some countries lack deep, liquid, long-term sovereign bond markets, a material constraint that effectively limits access to commercial, long-dated finance for interconnector projects involving these countries.

Selected ASEAN country sovereign ratings and ten-year bond yields relative to the European Union and United States

Country	S&P	Moody's	Grade	Ten-year sovereign yield
Singapore	AAA	Aaa	IG	1.95%
Malaysia	A-	A3	IG	3.46%
Thailand	BBB+	Baa1	IG	1.37%
Philippines	BBB+	Baa2	IG	6.03%
Indonesia	BBB	Baa2	IG	6.36%
Viet Nam	BB+	Ba2	non-IG	3.76%
Cambodia	n.a.	B2	non-IG	n.a.
Lao PDR	n.a.	Caa3	non-IG	n.a.
Brunei Darussalam	n.a.	n.a.	n.a.	n.a.
Myanmar	n.a.	n.a.	n.a.	n.a.
United States	AA+	AA1	IG	4.15%
European Union	AA+	Aaa	IG	3.24%

Note: IG = investment grade; non-IG = non-investment grade; n.a. = .not available.
Source: Analysis based on Trading Economics Currencies Database (November 2025).

At the upper end, Singapore holds a AAA rating and borrows at 1.95%, well below the United States. Malaysia, Thailand, Philippines and Indonesia are investment grade (BBB to A range) with ten-year yields between 1.37% and 6.36%. Viet Nam, while sub-investment grade, maintains a functioning ten-year domestic yield curve at 3.76%. In contrast, Cambodia, Lao PDR, Brunei Darussalam and Myanmar lack liquid ten-year sovereign curves, reflecting shallow domestic credit markets and limited secondary trading, a structural constraint for long-tenor infrastructure financing, including interconnectors, even where underlying fiscal positions are strong or currencies are externally anchored, as in Brunei Darussalam.

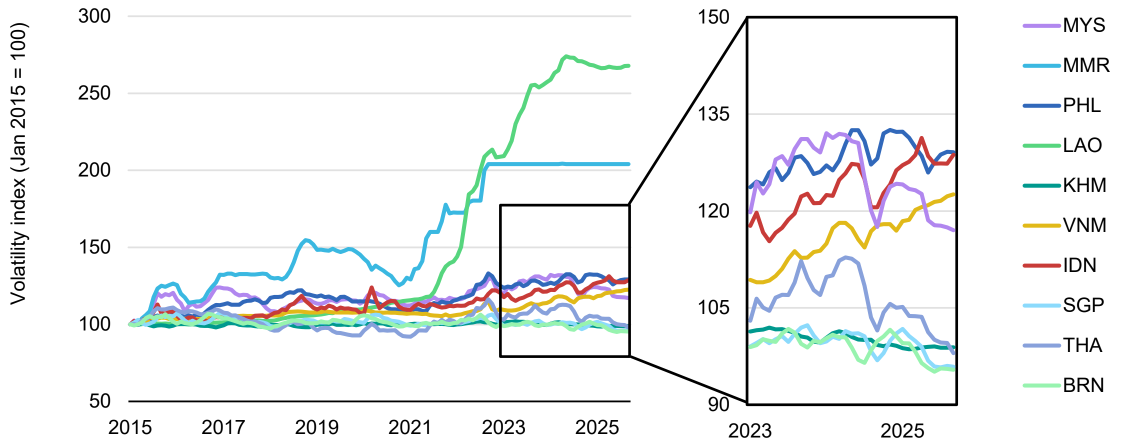
Singapore and Thailand borrow at rates below the US Treasury, underscoring their role as safe, low-cost issuers, while Malaysia and Viet Nam trade close to parity with developed market benchmarks. Meanwhile, the Philippines and Indonesia carry yields around 6% with spreads of around 200 bps. This pattern underlines a clear segmentation within ASEAN: low-yielding investment grade issuers versus high-yielding sovereigns with elevated credit risk.

Foreign exchange stability, hedging capacity and currency risk

Most infrastructure projects in ASEAN generate revenues in local currency but rely partly on foreign currency debt, typically US dollars or euros. Few ASEAN currencies offer a long-term hedge at commercially viable pricing, meaning interconnector projects cannot fully eliminate foreign exchange rate risks over their operational lifetime. This currency mismatch exposes projects to exchange-rate volatility, making the resilience of the local currency and the availability of medium-term hedging instruments critical to bankability.

The foreign exchange rate risk profile of ASEAN is mixed but broadly resilient. Singapore operates as a developed market benchmark with low volatility and deep liquidity. Thailand exhibits moderate volatility with relatively well-functioning hedging markets, while Indonesia and the Philippines show higher volatility but remain liquid and investable. Brunei Darussalam combines strong macro fundamentals with limited market depth. Viet Nam and Cambodia face greater constraints from foreign exchange rate depreciation pressures and shallow hedging capacity. Lao PDR and Myanmar are the least investable on foreign exchange rate risk grounds.

Currency volatility in selected ASEAN countries relative to the US dollar, 2015-2025



Notes: MYS = Malaysia; MMR = Myanmar; PHL = Philippines; LAO = Lao PDR; KHM = Cambodia; VNM = Viet Nam; IDN = Indonesia; SGP = Singapore; THA = Thailand; BRN = Brunei Darussalam. Index calculated based on monthly movement.
Source: Analysis based on Trading Economics Currencies Database (November 2025).

In the 2015-2025 period, most ASEAN currencies depreciated moderately. Singapore, Malaysia and Thailand has remained relatively stable against the US dollar, while Indonesia, Viet Nam and the Philippines saw declines of around 2% annually, consistent with their current account positions. Lao PDR experienced double-digit annual depreciation, reflecting fiscal pressures and thin foreign exchange reserves. Myanmar's nominal stability largely reflects administrative controls rather than market pricing.

Foreign exchange market depth and access to forward market by country

Country	Foreign exchange market depth	Regime type	Forward market
Singapore	Very Strong	Soft peg to multi-currencies	Yes, regional hub, deliverable and NDF.
Philippines	Strong	Floating	Yes, deliverable and NDF.
Indonesia	Strong	Floating	Yes, deliverable and NDF.
Malaysia	Deep onshore; limited access	Floating	Yes, mostly deliverable.
Thailand	Deep onshore; limited access	Floating	Yes, mostly deliverable.
Brunei Darussalam	Restricted	Hard peg to SGD	No, domestic market (hedge via SGD).
Viet Nam	Restricted	Soft peg to USD*	Limited, deliverable for trade, loans, bonds.
Cambodia	Restricted	Soft peg to USD**	Limited, deliverable, shallow.
Lao PDR	Restricted	Managed arrangement to USD	Limited, short maturity deliverable.
Myanmar	Non-functioning	Soft peg to USD, stabilised***	None.

*Managed float (de jure), de facto soft peg to USD (stabilised band +/- 5%). **Managed float (de jure), de facto soft peg to USD (crawl-like). ***Managed float (de jure), de facto soft peg/stabilised to USD.

Note: NDF = non-deliverable forward; SGD = Singapore dollar.

Source: Analysis based on International Monetary Fund Annual Report on Exchange Arrangements and Exchange Restrictions (2024).

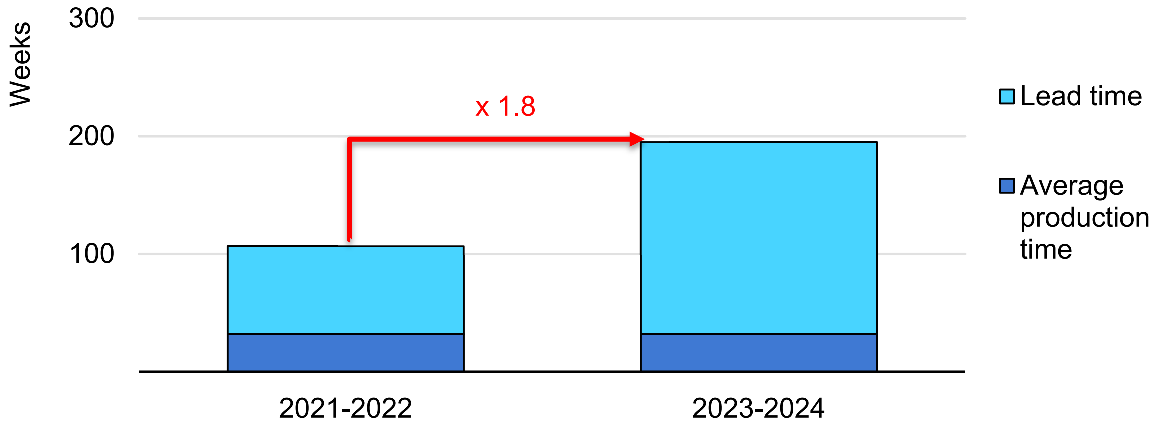
The depth of hedging markets defines the investable universe for institutional investors. Singapore, Indonesia and Philippines offer both deliverable and non-deliverable forwards, providing investors with basic instruments to hedge foreign exchange (FX) risk. Malaysia and Thailand provide broadly functional markets, albeit with regulatory restrictions and limited depth beyond the medium term. Viet Nam and Cambodia offer only short-tenor instruments, while Lao PDR and Myanmar have largely inactive hedging markets.

Supply chains and broad technical integration requirements could create bottlenecks

Supply chain constraints

Globally, all regions face a requirement to scale up investment into transmission infrastructure to develop new transmission lines and upgrade existing grids. Total global annual investment for electricity transmission rises from USD 158 billion in 2025 to USD 219 billion by 2035 in the STEPS. In addition, projected growth of the offshore wind industry will drive further demand for HVDC systems to connect offshore wind generation facilities to power grids. This is putting pressure on global supply chains.

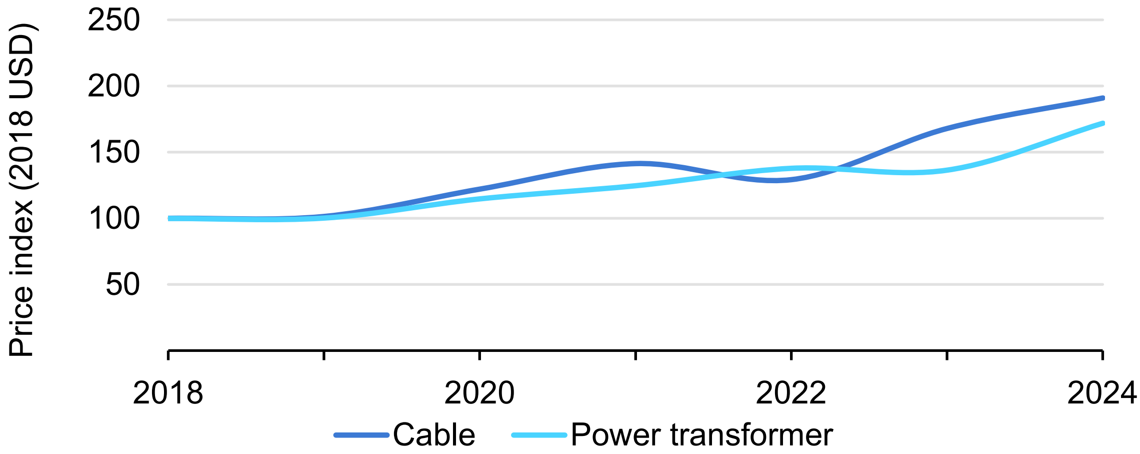
Average lead time for large power transformers, 2021-2024



Source: IEA (2025). Building the Future Transmission Grid

Compared to 2021, in 2024 the global average lead time for large power transformers increased from about 1.5 to 3 years. Prices for key materials such as copper and aluminium remain high. Many cable manufacturers are operating at full capacity, with market participants reporting wait times for subsea cables extending until the early 2030s. A global IEA survey found that prices of power transformers and cables nearly doubled between 2019 and 2024, driven by increasing demand and raw materials costs. Despite some signs of the industry scaling up manufacturing capacity, including the completion of a large-scale HVDC cable manufacturing facility by LS Cable & System in July 2025, the industry must also consider constraints in the supply of equipment and materials required for cable manufacturing.

Power transformer and cables price index, 2018-2024



Notes: Price index is in real terms. Data based on cable auctions >320 kV and IEA survey for underground cables.
Source: Source: IEA (2025). Building the Future Transmission Grid.

In addition, there are a limited number of specialised vessels and skilled operators capable of laying and maintaining subsea cables, with only around 60 vessels worldwide equipped to handle these tasks, which are often booked years in advance by project developers. In a small number of cases, subsea HVDC project companies have acquired vessels for exclusive use, with contracts for construction, maintenance and operation.

These constraints present a significant challenge, leading to greater price uncertainty and longer development timelines. Early planning, and in some cases reservation fees, are required for investors in subsea interconnectors to book factory slots for manufacturing of cable components and to secure vessel availability. On the other hand, supply chain tightness may present an opportunity for ASEAN to attract investment and support the development of cable manufacturing and vessel capacity in the region.

Regional integration of technical standards and procedures

To further advance regional integration while ensuring secure system operations, ASEAN countries are facing the challenge of establishing common grid codes. Although full harmonisation is not required at their current stage of regional integration, a set of common technical standards and procedures across member states is necessary as the APG develops. This issue is widely recognised in the region, illustrated by the AIMS III Phase 3, which includes prioritising the grid code harmonisation to ensure seamless interoperability.

Differences in equipment settings, data exchange formats, operational protocols and emergency procedures complicate efforts to co-ordinate grid operations across borders. Without a minimum level of technical alignment, cross-border electricity flows risk undermining system stability. Some countries allow wider frequency ranges or apply different correction times, i.e. time to restore frequency, while operating voltage levels are not consistently defined. These variations can hinder co-ordinated responses to disturbances and complicate the development and safe operation of integrated systems. A pragmatic, sequenced approach to harmonisation is essential to address these challenges progressively. The fact that most ASEAN countries operate at 50 hertz (Hz) provides a foundation for synchronised operations, with Philippines as the only exception at 60 Hz. In addition, the experience in the Greater Mekong Subregion in grid code alignment provides a valuable starting point for broader ASEAN-wide efforts.

HVDC technology offers a practical pathway to advance regional power trade in ASEAN, even where technical standards are not fully harmonised. One of its principal advantages is the ability to link asynchronous power systems, allowing countries operating at different frequencies or with differing correction times and voltage levels to exchange electricity without needing full synchronisation of their grids. In this sense, HVDC functions as a controlled interface between systems. HVDC should be seen as an enabler rather than a substitute for harmonisation: it allows regional integration to progress while standards converge over time.

Data exchange for planning is another technical hurdle for ASEAN regional infrastructure development. ASEAN countries already have a strong track record of sharing planning stage data, for instance having enabled the recent study for the identification of ASEAN interconnector projects. However, some data is deemed too sensitive to be shared in a regional context, which hinders the planning process. This includes geographic data on existing infrastructure such as natural gas or water lines, electricity generation and grid topology data, environmental and social constraints, e.g. protected lands, parcel boundaries. Enhancing technical data sharing, under appropriate confidentiality agreements, would help develop more accurate regional plans and reduce delays for infrastructure development.

Operational exchanges are also in place between ASEAN countries but lack real-time data to enhance the use and reliability of interconnections. The Lao PDR–Thailand–Malaysia-Singapore Power Integration Project (LTMS-PIP) is a key example, where transmission system operators exchange operational information through telephone, a document management platform and online messaging platforms. However, advancing regional integration with the development of interconnectors regionally requires increased real-time data sharing. This includes continuous exchanges of electricity generation, load and power flows, which would enhance responsiveness to interconnector trips, and system disturbances, as well as to manage congestion.

Beyond technical standards and data, common operational and emergency procedures are needed to ensure reliability as ASEAN interconnections develop. Outage planning, load shedding protocols and frequency deviation correction procedures differ across member states. These inconsistencies can delay co-ordinated responses during emergencies and reduce system resilience as more interconnectors develop. Joint emergency procedures, reserve-sharing agreements and standardised restoration protocols would hold a key role in treating interconnected systems as a unified entity during crises.

Chapter 3. Financing, capital sources and bankability

This chapter bridges the gap between the future APG pipeline and the challenges of financing it – moving towards solutions specific to the region by examining the practical structuring required to make these complex projects bankable. It details the core financing and commercial elements, introduces the key investment stakeholders and their roles, and uses financial analyses to test how these structures perform under different policy and risk conditions. In doing so, this chapter outlines the financial structures needed to attract capital and successfully deliver the ASEAN Power Grid.

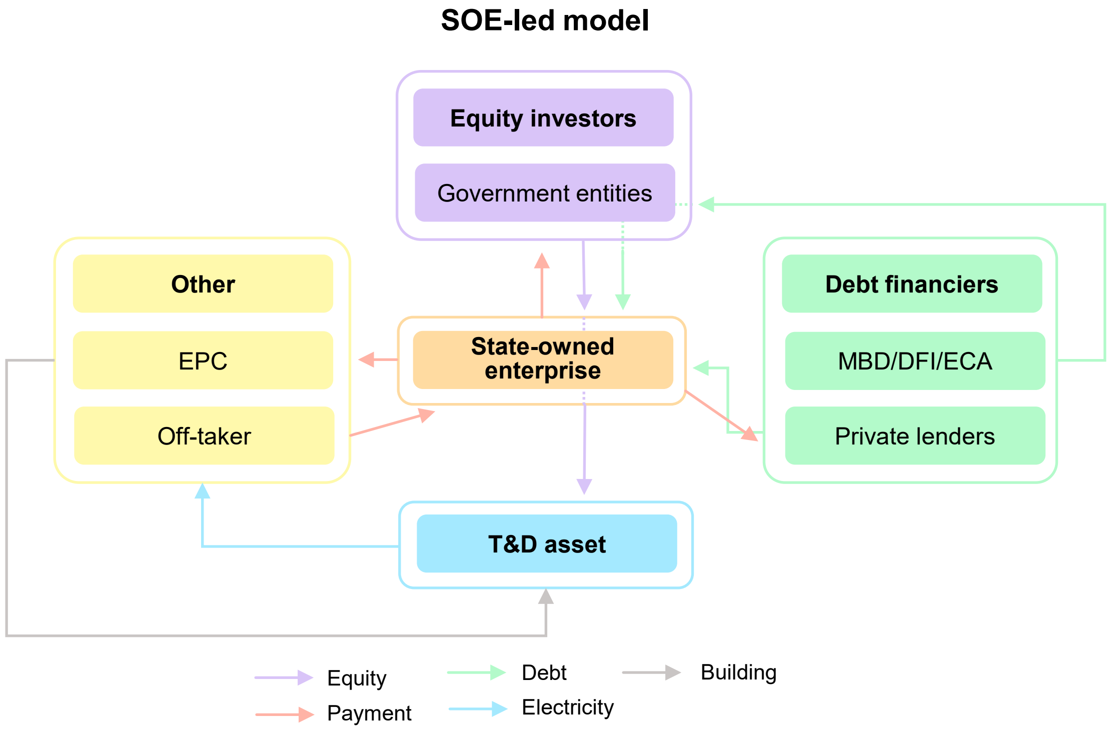
Capital providers and financing structures

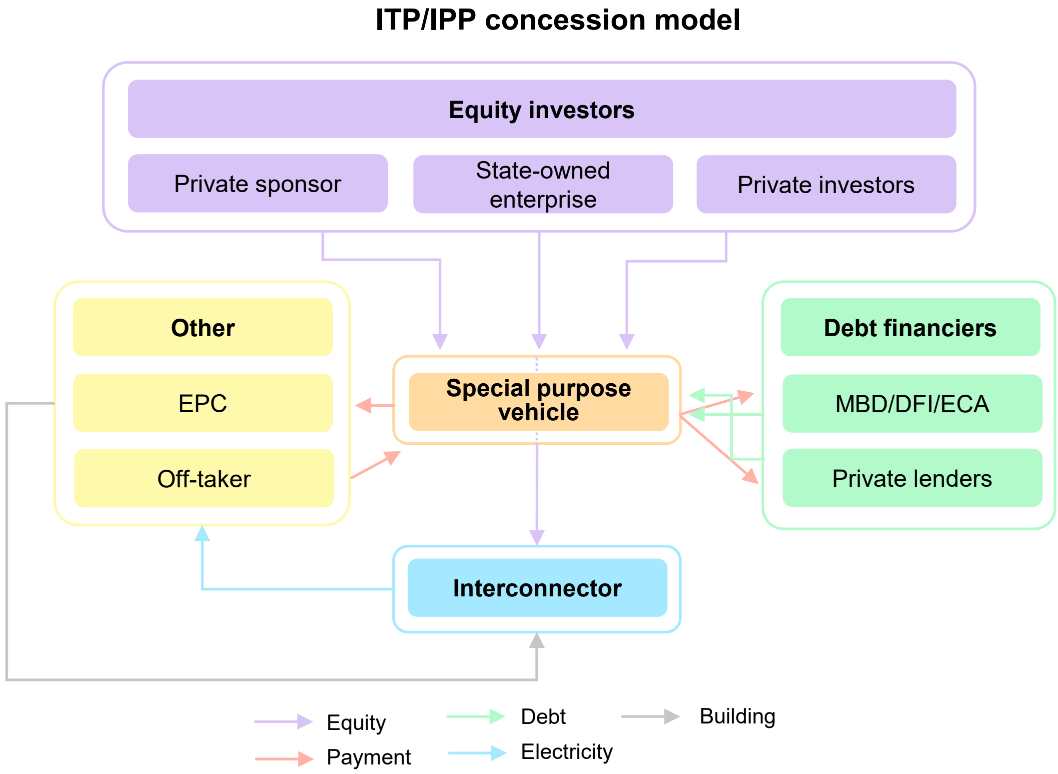
Financing models: balance sheet and project finance

Financing large-scale, cross-border interconnectors requires sequencing various investor groups, each with distinct mandates, ticket sizes and entry points. While the macro-financial environment defines the cost of capital, the composition of stakeholders determines how capital is mobilised. Historically, grid-to-grid interconnectors have been financed on-balance sheet by SOEs with government borrowing, typically through multilateral development bank (MDB) sovereign loans that are on-lent to utilities, or through direct MDB lending to utilities backed by sovereign guarantees via sovereign loans from MDBs. This model has been effective for small, simple projects but is increasingly constrained by SOE balance sheet limits as project scales and technical complexity increase.

For larger, more complex projects, particularly grid-to-grid and subsea high-voltage direct current (HVDC) links, project finance through a special purpose vehicle is a viable approach. A special purpose vehicle structure can mobilise capital at scale and distribute risk across investors. The special purpose vehicle anchors the structure with equity from sovereign and commercial investors; MDBs, development financial institutions (DFIs), export credit agencies (ECAs); other commercial lenders provide project debt often through syndication; governments set the enabling regulatory framework and may provide guarantees; engineering, procurement, and construction (EPC) contractors deliver construction; off-takers make payments that generate revenue; and environmental and social safeguards protect affected communities.

Representative business models for interconnector projects





Notes: SOE = state-owned enterprise; EPC = engineering, procurement and/or construction company; MDB = multilateral development bank, DFI = development finance institution. ECA = export credit agency; T&D = transmission and distribution; ITP = independent transmission project; IPP = independent power producer. Both models show financing structures for cross-border transmission projects. The SOE-led model centres on a state-owned enterprise. The ITP or IPP concession model typically uses a special purpose vehicle.

Regardless of the financing model, sponsors and governments play pivotal roles to structurally align the interests of investors and stakeholders. Governments must provide a transparent and effective regulatory framework with predictable permitting to enable projects to recover costs and earn a suitable, risk-adjusted return on investment through tariffs or service charges. This is particularly critical for commercial sponsors and investors, for which adequate returns are a prerequisite for participation. Based on an effective framework, the sponsor leads project design, capital structure and revenue model development in collaboration with the government, bringing in equity and debt providers. In ASEAN, this sponsor role has been typically filled by a SOE, which may also serve as the off-taker. International public finance institutions have generally complemented these roles by bridging the financing gaps through concessional capital, guarantees and credit enhancement tools.

Debt capital providers: public and commercial lenders

The availability and structure of debt finance for interconnectors in ASEAN is directly shaped by the macro-financial environment. Sovereign credit ratings set the benchmark against which project debt is priced, while exchange rate volatility and hedging depth determine whether local or foreign currency borrowing is feasible. These macro factors explain why MDBs and ECAs are essential: they can lend beyond sovereign ceilings, offer political risk guarantees and provide longer-tenor, i.e. term, loans unavailable from domestic markets. As discussed in Chapter 1, concessional and blended instruments from MDBs and ECAs have historically underpinned interconnector investment, catalysing commercial participation where purely market-based financing remains unviable.

Key characteristics of debt providers by investor type

Investor type	**Estimated ticket size** (USD million)	**Estimated pricing**	**Estimated tenor** (years)	**Key terms and features**
Multilateral development bank	<50-300+	SOFR + 50-350 bps; concessional, below-market	10+ (long term)	Long-tenor, concessional terms, often combined with political guarantee, technical assistance.
Export credit agency	<100-400+	CIRR/fixed export credits	8+ (long term)	Long-tenor, often linked to national suppliers.
National development banks	<50-200+	Local currency or USD-linked, often concessional or policy driven	7-15 (medium to long term)	Focus on domestic priorities, local currency lending.

Investor type	Estimated ticket size (USD million)	Estimated pricing	Estimated tenor (years)	Key terms and features
Local/ regional banks	<50-150+	Local currency benchmark + 200-500 bps	5-10 (medium/ long term)	Preference for brownfield, limited exposure to FX mismatch.
Commercial international banks	<100-300+	SOFR + 200-400 bps	5-10 (medium/ long term)	Limited exposure to FX mismatch.

Notes: SOFR = secured overnight financing rate; bps = basis points;CIRR = commercial interest reference rates; FX = foreign exchange. Ticket size and pricing vary by country and project specific risks.
Sources: Industry interview with regional SOEs, developers, fund managers and MDBs/DFIs.

MDBs and other development finance institutions (DFIs) play a catalytic role in structuring interconnector financing, particularly for greenfield projects where risk-adjusted returns and creditworthiness constrain commercial lenders. Institutions such as the Asia Development Bank and World Bank could act as anchor lenders, offering long-tenor senior loans (15-20 years), concessional capital or political risk guarantees. Their involvement is often a prerequisite to mobilise institutional capital in markets with underdeveloped regulatory frameworks or off-takers with sub-investment grade ratings.

Several ECAs active in ASEAN cross-border projects, such as the Export-Import Bank of Thailand, Export-Import Bank of Korea and Export-Import Bank of China, provide long-tenor debt financing for equipment or EPC sourced from their domestic suppliers. These institutions typically offer fixed or commercial interest reference rates linked export loans in hard currency, often with tenors of ten or more years. Many export credit agencies (ECAs) embed foreign exchange convertibility coverage and political risk insurance, which enhances the overall credit profile and creates space for commercial lenders to enter on a subordinated or commercial basis. Some ECAs also provide comprehensive guarantees covering commercial risks. Export credit agencies thus complement MDBs by providing supplier linked liquidity and credit enhancement, broadening the range of bankable structures available for interconnector projects.

An important addition to this landscape is the potential role of national development banks within ASEAN. These institutions focus on promoting domestic infrastructure development and often provide long-term financing in local currency or US dollars, sometimes on concessional or policy driven terms. National development banks frequently co-lend or syndicate along with other international public financing bodies, helping to catalyse local currency financing and bridge financing gaps that commercial lenders cannot fill independently.

Local and regional banks may support working capital, construction loans or refinancing tranches, particularly post-commercial operation date once projects generate stable cash flows and have strong local sponsors or partial sovereign backing. Their participation has grown mainly through private concessions for generation-to-grid projects but may be limited in greenfield interconnectors due to tenor constraints, currency mismatch and regulatory capital rules. In practice, ASEAN interconnector deals will require hybrid debt structures: long-term loans from MDB or ECA to provide credit enhancement, alongside local currency debt to manage foreign exchange exposure and liquidity risk.

One of the challenges for debt financing is the mismatch between the long asset life of interconnectors (30+ years) and the shorter tenor appetite of commercial lenders (typically five-ten years). Jurisdictional and regulatory complexity, limited hedging instruments and banking constraints (e.g. single borrower limits and liquidity coverage ratios) compound this mismatch. Elevated sovereign spreads, weak off-taker credit profiles, and non-cost-reflective tariff regimes heighten perceived risk, keeping commercial lenders confined to medium-term maturities even for strategic infrastructure assets.

International public financing can temporarily bridge this gap, but unless local and regional capital markets develop deeper long-tenor instruments, interconnectors will remain reliant on concessional and quasi-sovereign debt. Without stronger sovereign credit, lower foreign exchange rate volatility or hedging instruments, and more liquid forward markets, commercial long-term debt will not scale, leaving international public financing as permanent rather than transitional anchors. Over the longer term, developing such capital market depth will be essential to ensure that international public financing support evolves from direct lending toward catalytic, risk-sharing roles, bridging the equity gap to attract long-term institutional capital.

Equity capital: investors and the valley of death

Equity participation in cross-border interconnectors depends on which actors are prepared to absorb risk at various stages of the project lifecycle. In ASEAN, sponsors, typically state-owned utilities, anchor interconnector projects and align them with national energy strategies. They provide the majority equity stake, drive project development and often retain long-term ownership given the strategic importance of transmission assets.

Key characteristics of equity providers by investor type

Investor type	**Shareholding** (%)	**Estimated target IRR** (gross)	**Key terms and features**
State-owned utilities	Strong preference for majority	8-12%	Acts as anchor investor; prefer long-term hold and operational involvement.
Commercial sponsors (IPP or developers)	Majority or minority	14-20%	Bear development risk; require higher returns to compensate for early stage exposure.

Investor type	Shareholding (%)	Estimated target IRR (gross)	Key terms and features
MDB/DFI	Minority	6-10%	Willing to take early stage risk with catalytic, below-market terms.
Infrastructure/ private equity funds	Minority	12-20%	Require stable cash flows, such as signed power purchase agreement, exit clarity and often seek platform opportunities.
Pension/SWF	Minority	8-13%	Prefer brownfield or de-risked greenfield development; seek predictable dividends and inflation protection.

Notes: IRR = internal rate of return; IPP = independent power producer; MDB = multilateral development bank; DFI = development financial institution; SWF = sovereign wealth fund. IRR targets are indicative and vary by market conditions, risks and project stage.

Sources: Industry interview with regional SOEs, developers, fund managers and MDBs/DFIs.

Private infrastructure and private equity funds typically enter at financial close or during construction, seeking development upside alongside stable cash flows and clear exits. They target higher returns and require some growth potential, though they need key risks mitigated through signed power purchase agreements or regulated tariffs. Sovereign wealth funds and pension funds may co-invest with private infrastructure or private equity funds but more commonly enter post-commercial operation date when projects demonstrate stable operations. With large ticket sizes and long-term investment mandates, they prefer operating assets, targeting lower returns but providing scale and patient capital through dividend streams. Listed infrastructure vehicles, insurance companies and renewable energy asset holding companies such as yieldcos may also participate at this stage, attracted by recurring income streams from operational interconnectors.

However, this diversified equity structure remains largely theoretical in the context of ASEAN interconnector projects. To date, the region has not seen commercial sponsors leading grid-to-grid or transmission projects, nor has there been meaningful secondary market trading of interconnector equity stakes. The SOE-led, on balance sheet model has dominated with limited participation from private infrastructure funds or institutional investors in the equity tranche. The investor characteristics outlined represent directional guidance drawn from experience in more liberalised developed markets rather than proven ASEAN precedent.

MDBs such as the International Finance Corporation have equity mandates and could play a catalytic role in demonstrating commercial viability, particularly for first-of-kind or higher risk interconnector structures. While their participation in ASEAN interconnectors to date has been almost exclusively through debt, guarantees or technical assistance, equity investment could help de-risk projects for follow-on commercial investors. However, MDB equity participation depends on sponsor willingness to accept minority shareholders and government commitment to frameworks that allow market-oriented returns. Their effectiveness is ultimately contingent on the enabling environment that governments and sponsors create.

Even where MDBs deploy equity, a critical challenge emerges: bridging the equity valley of death, i.e. the gap between early sponsor commitments and the entry of late-stage institutional capital. MDBs can provide catalytic capital during development and construction, but they typically will not hold equity across the full project life. Their model depends on recycling capital once risks are reduced, exiting to make room for long-term holders such as pension funds and sovereign wealth funds. Without credible exit routes, whether through secondary sales, refinancing or platform integration, MDB equity remains locked, constraining their ability to reinvest in new projects and slowing replication of cross-border interconnectors. In ASEAN, where secondary markets for interconnector equity are undeveloped, this recycling mechanism has yet to materialise, creating a bottleneck in the capital deployment chain.

The central challenge for governments and sponsors is to create conditions that could attract diverse equity capital beyond traditional SOE balance sheets. This requires deliberate policy and structural choices. Governments need to establish regulatory frameworks that provide certainty on cost recovery, cross-border tariff allocation and currency arrangements. These are the foundational elements that determine whether projects can generate risk-adjusted returns for commercial investors. Where build-operate-transfer (BOT) structures are used, governments will also need to develop standardised contractual frameworks that enable private construction financing with eventual transfer of operations and ownership to SOE. Sponsors must structure projects with clear revenue streams, appropriate risk allocation and credible governance arrangements that give confidence to minority investors.

For institutional capital to enter, investors need to assess stable fundamentals: the amortisation profile of project debt; the predictability of regulated revenues across jurisdictions; dividend yield and growth potential; and options for future liquidity. Utilities weigh operational synergies with existing assets, while sovereign wealth funds and pensions prioritise geographic diversification and inflation protection. Without government commitment to enabling frameworks and sponsor willingness to share ownership and returns, equity participation will remain limited to state balance sheets, which would constrain the capital available to finance the USD 27 billion interconnector pipeline of the ASEAN Power Grid (APG) and limit the pace at which ASEAN can scale cross-border power integration.

Assessing project bankability

Having established the key stakeholders and their roles in interconnector financing, it is important to explore options for commercial arrangements that can deliver returns that attract and sustain the needed capital at scale. To illustrate how policy and financing conditions affect project bankability in practice, the IEA developed a simplified financial model to assess three exploratory cases – the Base case, Cost Reduction case and Cost Overrun case – aligned with the investment cost cases presented in Chapter 2. The analysis simulates financial returns for a representative HVDC interconnector project with subsea segments, based on stylised assumptions consistent with current investment conditions and plausible business models across ASEAN.

Modelling returns for three investment scenarios

Scenario design

The financial modelling highlights how critical each variable, i.e. cost recovery mechanisms, financial structure, construction performance and operational efficiency, interact to shape investor returns. Three scenarios test different combinations:

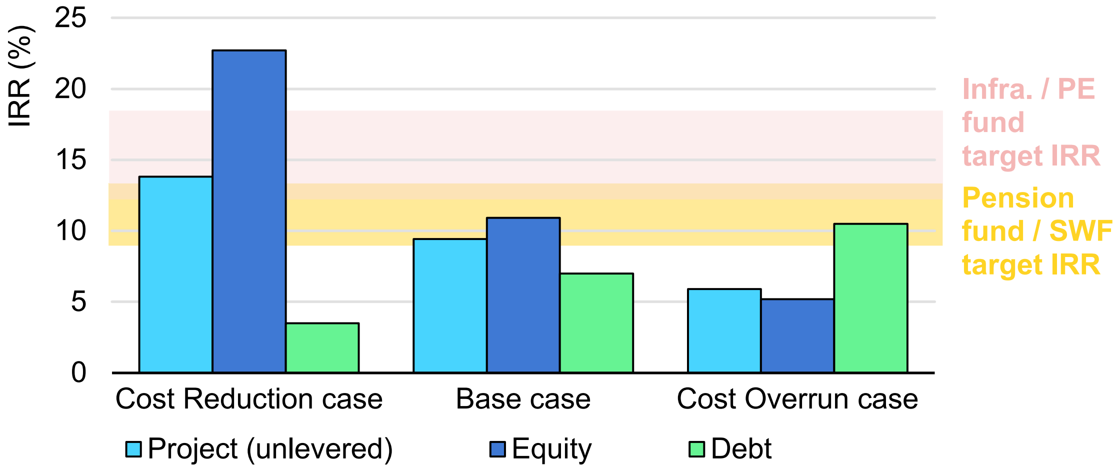
- **Cost Reduction case** is based on concessional capital with strong policy and regulatory support. It represents projects benefiting from a below-market interest rate with concessional capital and stable regulatory framework. Low borrowing costs (3.5% per year), high leverage (70:30 debt-to-equity ratio) and high utilisation (90%) mirror well-prepared, policy-aligned projects in integrated enabling environments with access to concessional financing instruments.
- **Base case** represents commercial capital under regulated but evolving markets. It reflects current ASEAN conditions where policy frameworks are established but markets remain partially fragmented and credit risk is moderate. Borrowing costs of 7% per year, medium leverage (55:45 debt-to-equity), and balanced tariff design (availability plus utilisation-based payments). The tariff benchmark is based on wheeling charges for LTMS interconnector. The case represents mixed regulatory certainty and moderate cost of capital, typical of markets transitioning from public to blended financing.
- **Cost Overrun case** is based on delayed construction and merchant exposure in weak policy settings. It represents challenging contexts where policy frameworks are nascent, tariffs are partially merchant-based, and financing relies on fully commercial terms (10.5% per year debt cost, 40:60 debt-to-equity).

The scenarios demonstrate which policy and structural conditions are necessary to close the gap between required returns and achievable returns, to determine whether projects can mobilise the diverse capital sources identified as needed to realise the APG.

Results and implications

Across the three scenarios, project internal rate of return (IRR) range from 6% to 14% and equity IRRs from 5% to 23%, in line with benchmarks for regulated transmission and distribution (T&D) and renewable independent power producer assets in comparable emerging markets. The results confirm that interconnectors can deliver returns competitive with other core infrastructure assets, but only if certain conditions are met.

Project returns under various investment conditions, business and financial models for a representative HVDC subsea interconnector project



Notes: IRR = internal rate of return; Infra = infrastructure fund; PE = private equity; SWF = sovereign wealth fund. Light coloured areas show target returns at the project level (pre-fee, pre-tax). Full assumptions and sensitivity results in Annex B.

In the Cost Reduction case, interconnectors achieve equity IRRs in the high-teens to mid-twenties, demonstrating that a stable regulatory environment combined with concessional capital can fully crowd in commercial capital. The Base case reflects more realistic expectations for ASEAN utilities, where policy frameworks are improving but foreign exchange and credit risks persist. Project IRR of 10-12% fall short of target returns for some commercial investors, but remain sufficient to be considered bankable for most utilities and potentially some institutional investors.

In markets without clear cost recovery frameworks or tariff stability, however, returns diminish rapidly. The Cost Overrun case illustrates how fragmented and less supportive policy settings compress equity IRRs around 5%, reflecting the compounded effects of higher debt costs, delayed commissioning and unhedged exposure to asset underutilisation. In such settings, projects become not bankable for commercial investors without early international public financier engagement and targeted policy reforms to close the viability gap.

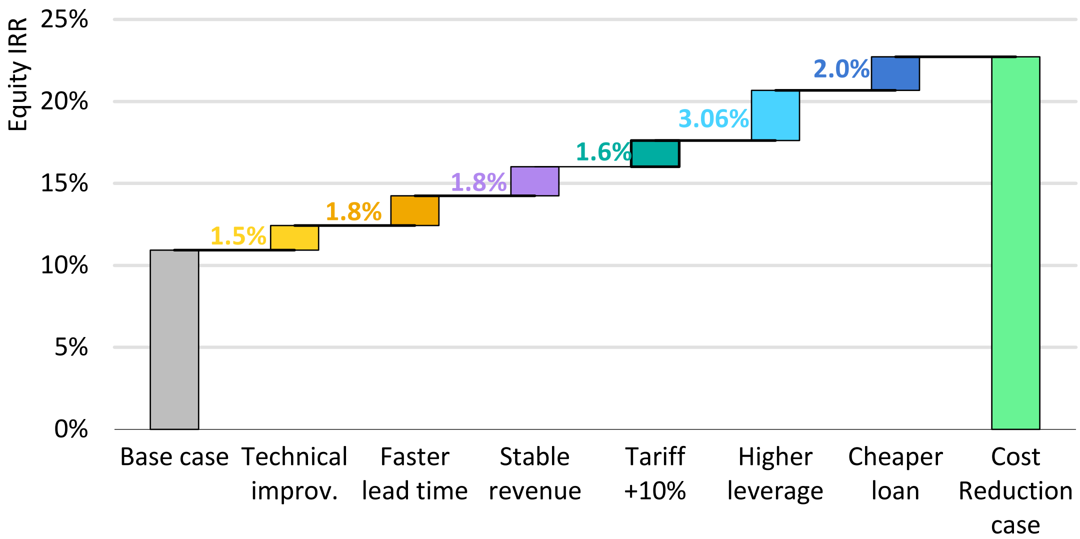
Key drivers: tariffs, financing costs and revenue structure

The sensitivity analysis reveals which factors matter most for project bankability: tariff design, financing structure, debt leverage and operational efficiency. This matters for policy makers considering different business and financing models for future interconnectors and for determining which policy levers have the most significant impact on bankability.

What drives returns in favourable environments?

In the Cost Reduction case, financial structure is the dominant driver of improved returns. Higher leverage (70:30) combined with access to concessional or low-cost debt (3.5% per year) creates powerful amplification effects. When borrowing costs are below project returns, additional debt magnifies equity gains. This combined effect accounts for almost half of the improvement in equity IRR relative to the Base case.

Cumulative improvement in equity IRR from Base case to Cost Reduction case



Notes: IRR = internal rate of return; tech improv = technical improvement. The chart shows cumulative IRR improvements from Base case (11%) to Cost Reduction case (23%). Key parameters: Technical improvement is lower transmission and distribution losses, from 3% loss to 2% per year, and lower operation and maintenance costs, from 1.0% of capital expenditure per year to 0.9% per year. Faster lead time = from six year construction time to four years. Stable revenue = from 25% to 50% availability payment (the rest is utilisation payment). Tariff +10% = 10% tariff increase from Base case. Higher leverage = from 55:45 to 70:30 debt-to-equity ratio. Cheaper loan = from 7% debt cost to 73.5%. Each improvement builds upon previous changes.

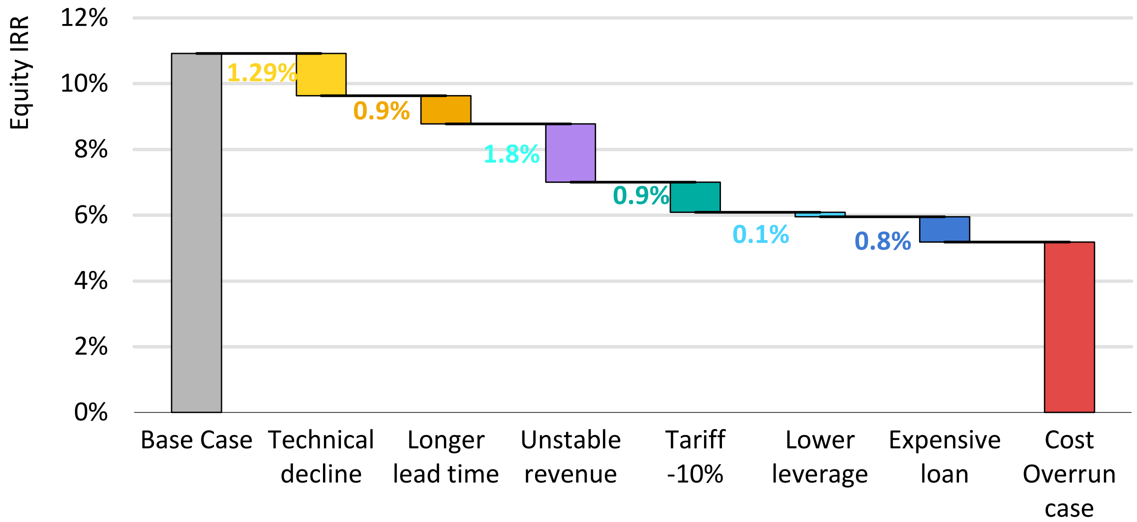
Source: IEA analysis based on financial modelling and stakeholder consultations.

Improved revenue structure provides secondary but meaningful support. In this scenario, the availability-based payments strengthen cash flow predictability and reduce exposure to underutilisation risks. Technical improvements such as streamlined permitting and on-schedule construction timing contribute small but positive gains. The combined message is clear: once a stable policy and regulatory foundation exists, well-structured financing can deliver attractive returns and mobilise the needed institutional capital at scale.

What undermines returns in challenging environments?

In the Cost Overrun case, tariff uncertainty and weak revenue frameworks inflict the most significant damage to returns, compressing equity IRR to around 5%. Construction delays and technical setbacks compound these problems by increasing costs and deferring revenue generation. Notably, the financing structure offers little relief in this scenario: when underlying project fundamentals are weak, debt capacity shrinks and the benefits of leverage evaporate.

Cumulative deterioration in equity IRR from Base case to Cost Overrun case



Notes: IRR = internal rate of return. The chart shows cumulative IRR improvements from Base case (11%) to Cost Overrun case (5%). Key parameters: technical decline = higher transmission and distribution losses (from 3% to 4% per year) and operation and maintenance costs (from 1.0% to 1.1% of capital expenditure per year). Longer lead time = from six years to eight years' construction time. Unstable revenue = from 25% to 0% availability payment (the rest is utilisation payment); Tariff - 10% = 10% tariff decrease from the Base case. Lower leverage = from 55:45 to 40:60 debt-to-equity ratio. Expensive loan = from 7% to 10.5% debt cost. Each deterioration builds on previous changes.

Source: IEA analysis based on financial modelling and stakeholder consultations.

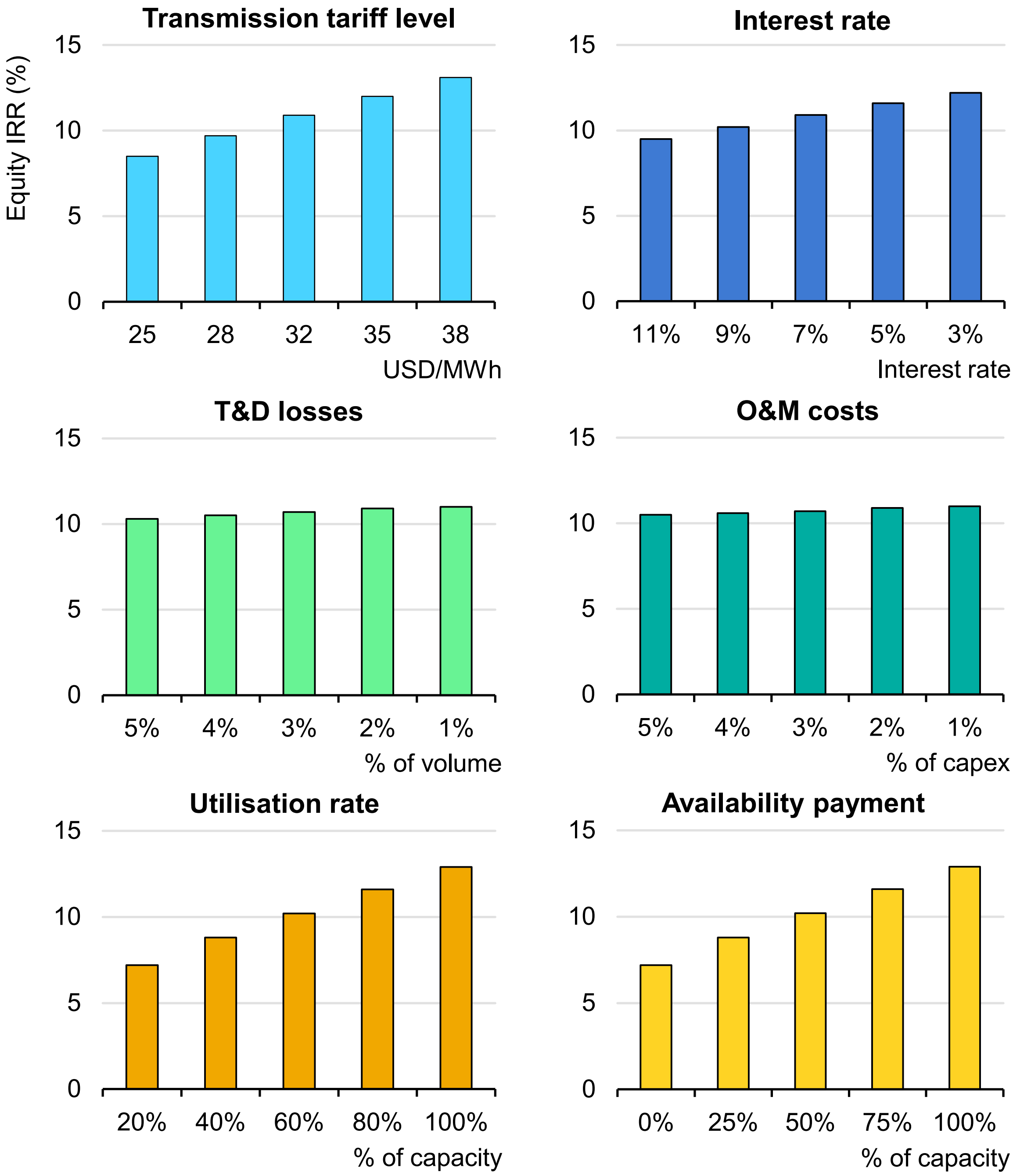
Factors driving bankability and key focus points for policy makers

The cumulative effects charts demonstrate that individual parameters compound to dramatically different outcomes. To understand which factors matter most, sensitivity analysis was conducted by varying individual parameters while holding others constant at the Base case levels. Three findings emerge:

- **Tariff levels and debt pricing are the dominant levers.** A 10% increase in tariff levels improves equity IRR by approximately 1.6 percentage points, while reducing debt cost from 7% to 3.5% annually and increasing debt leverage from 55% to 70% together boost equity IRR by over 5.0 percentage points. Combined, these three factors account for over half of the gap between the Base case and Cost Reduction case returns. Conversely, a 10% tariff reduction paired with expensive commercial debt (10.5% per year) compresses returns toward non-bankable levels. These sensitivities far exceed those of operational parameters such as transmission and distribution losses, confirming that interconnector viability hinges primarily on policy frameworks and access to affordable capital rather than technical execution alone.
- **Stable and predictable revenue streams are essential to manage utilisation risk.** Maximising the utilisation rate of interconnectors, especially subsea HVDC, is critical to earn an appropriate return given the size of investment required. At a utilisation rate of 20% with zero availability payments – about the same utilisation rate reported for the Malaysia–Singapore interconnector today – the equity IRR falls by 12 percentage points relative to a revenue model based purely on availability (see Annex B). Given that utilities will likely retain operational control and ultimately determine the volumes of electricity traded, this implies that big-ticket grid-to-grid interconnectors are non-bankable for some investors unless protection against underutilisation is provided.
- **Operational performance matters, but only at the margin**. Reducing the intensity of transmission losses or operation and maintenance (O&M) costs increases equity IRR. Even in revenue structures with zero availability payment, increasing transmission losses to 5% and O&M to 5% of capital expenditures results in a modest reduction in the project equity IRR, 0.9 percentage points, relative to the Base case. Hence, while these improvements strengthen long-term reliability and cost control, they cannot materially offset unfavourable tariffs, low utilisation or high financing costs.

Overall, the analysis provides valuable insights for financial structuring. Strong policy and regulatory frameworks enable financial structuring to enhance returns, but in weaker settings, even optimal financing cannot offset policy uncertainty or implementation delays. Tariff design and financial structure therefore remain the principal determinants of interconnector viability. Even modest improvements in either can yield disproportionately higher equity returns, while operational factors exert a more gradual influence. Establishing transparent, inflation-adjusted tariffs and ensuring access to competitively priced or blended capital are essential to bridge the gap between strategic infrastructure goals and private sector investment appetite.

Sensitivity analysis of equity IRR to tariff levels, interest rates, T&D losses and O&M costs in the Base case for a representative HVDC subsea interconnector project



Notes : T&D = transmission and distribution; O&M = operation and maintenance; HVDC = high-voltage direct current; MWh = megawatt-hours; capex = capital expenditure. Utilisation rate analysis assumes a 25% availability payment and a 75% utilisation-based payment. Availability payment analysis assumes an 80% utilisation rate. Full assumptions and sensitivity results are in Annex B.

Bankability gap and pathways forward

Investor requirements versus state of play in ASEAN

As identified in the previous sections, the capital providers needed are: state-owned utilities as anchor sponsors; MDBs and ECAs to provide long-tenor debt; infrastructure funds that seek mid-teen level returns; and institutional investors, such as pension funds and sovereign wealth funds as long-term investors. Each entity has distinct return requirements and risk tolerances. The financial modelling tested whether ASEAN interconnectors can meet these requirements and under what conditions.

Four key findings emerge from the analysis. First, interconnectors can deliver competitive returns under realistic commercial conditions. Second, three factors dominate bankability: tariff levels, debt pricing and revenue structure, particularly availability payments, while operational efficiency has a less pronounced impact. Third, an equity valley of death persists: early stage investors cannot recycle capital without demonstrated exit routes that do not currently exist in ASEAN transmission markets. Fourth, achieving bankability requires these diverse capital sources to enter sequentially across project stages, with the right enabling regulatory and market conditions in place.

The current setting in ASEAN looks very different. Interconnector activity is predominantly SOE-led, relying on state balance sheets with minimal commercial equity participation. The financial analysis reveals this is not because interconnectors cannot deliver attractive returns; the Base case demonstrates they can. Fundamentally, most ASEAN regulatory frameworks do not permit majority private ownership of transmission assets, a restriction rooted in legitimate national security and sovereignty concerns. Beyond these regulatory issues, current policy and investment structures do not support the specific conditions that the financial modelling identified as essential, which are: transparent tariff frameworks with availability payments; systematic access to affordable long-tenor debt; and exit mechanisms for capital recycling. These gaps align with the business model uncertainty, access to financing, and macro-financial challenges discussed in Chapter 2.

Pathways within regulatory constraints

The financial modelling confirms interconnectors can deliver competitive returns when appropriate conditions are met. The challenge lies not in fundamental project economics but in gaps in enabling frameworks. Mobilising the USD 27 billion pipeline needed for the APG does not require wholesale privatisation and may not be achievable through the path given regulatory and political constraints across the region.

The types of financing models used in liberalised markets, in which private investors partially or fully own and operate transmission assets through special purpose vehicles, face fundamental regulatory constraints in most ASEAN countries. Realistic capital mobilisation must therefore work within existing frameworks or expand them incrementally. Four pathways emerge, each addressing a specific structural gap.

- **Mobilise capital within state ownership frameworks**. This addresses regulatory restrictions. Governments have legitimate reasons to maintain state control over transmission assets related to national security and cross-border flows. Alternative structures can mobilise capital while preserving state control: Blended finance structures where SOE retain ownership but finance through layered debt – international public financiers anchor tranches at 15-20 years and below-market rates, commercial bank participation, green bonds for operational assets); minority equity stakes (10-30%) in SOE subsidiaries without ceding operational authority can be attractive to domestic pension funds or regional sovereign wealth funds; or regional platforms aggregating multiple interconnector stakes into USD 3-5 billion investment vehicles offering institutional investors the diversification and scale individual projects lack.
- **Establish revenue certainty through policy reform**. This addresses the current revenue framework gap. The 12 percentage point equity IRR difference between merchant and availability-based models demonstrates that this is critical, not marginal. Revenue certainty can be implemented without ownership changes but requires transparent tariff methodologies, independent regulatory oversight and enforceable cost recovery mechanisms. This pathway is achievable through deliberate policy action, though cross-border co-ordination adds complexity.
- **Deploy concessional and blended finance**. This can address debt constraints. Commercial debt, for example at rates of 10.5% per year over 7-10 years, cannot support viable returns, while current climate finance taxonomies may limit access to concessional capital. Concessional finance at below-market rates or more favourable terms can bridge this gap, delivering the IRR improvement that makes projects bankable for investors. As identified in the State of Blended Finance 2025, realising this potential requires several interconnected shifts: first, updating climate taxonomies to recognise interconnectors as transition enablers and enable consistent deployment of concessional capital across international public financiers; second, encouraging market development that engages under-represented local finance by deploying local currency instruments, building capacity within ASEAN commercial and non-commercial financial institutions, and establishing regional blended finance initiatives; and third, building transparent markets by disclosing concessional finance terms where feasible and standardising deal structures and risk mitigation instruments to enable replication across projects. The capacity and instruments exist, but the challenge is deploying them consistently and at scale.

- **Build market infrastructure for capital recycling**. This addresses the exit mechanism gap. Even in state-owned enterprise models, capital must recycle to enable project replication. Pathways include refinancing operational interconnectors to free SOE balance sheet capacity, selling minority stakes to institutional investors post-commissioning, issuing project bonds backed by operational cash flows, or transferring mature assets to infrastructure funds. None requires private ownership during construction, but all need precedents, regulatory clarity on secondary transactions and institutional appetite developed through demonstration projects and deliberate market-building efforts.

Chapter 4. Priorities for scaling investment

Making the ASEAN Power Grid (APG) a reality will require co-ordinated action between policy makers, regulators, utilities, international public financial institutions, commercial investors and industry. This chapter provides practical guidance on how these entities can work together to overcome the challenges highlighted in this report, make interconnector projects bankable, and catalyse the financing needed to build the APG. The guidance is discussed in seven themes.

Embed cross-border projects into national infrastructure priorities and plans

Governments can enhance regional alignment and co-ordination while safeguarding national interests and differences in domestic market structures. Interconnectors often link countries with varied power market designs, institutional arrangements and tariff frameworks, which reflect unique national priorities and historical context. Scaling interconnector development and power trade requires participating countries to agree on revenue mechanisms, contractual arrangements, and common principles and standards that apply across borders. Crucially, alignment does not necessitate fundamental changes to national power market models. Experiences of the Central American Electrical Interconnection System (SIEPAC) and the West African Power Pool (WAPP) illustrate this point. Both initiatives enabled regional electricity exchanges to expand without requiring full harmonisation of national commercial and regulatory frameworks, allowing each country to maintain control over its internal market arrangements. This demonstrates that regional trade can expand even in the presence of institutional diversity, provided cross-border mechanisms are designed to accommodate varied market structures, regulatory capacities and political factors.

Incorporate cross-border power trade and interconnector development into national power sector and investment planning. While valuable, political backing alone is not sufficient to propel development of the ASEAN Power Grid. Interconnectors need to be embedded in national power sector planning and aligned with regional goals. Integrating interconnectors in national power development plans ensures that the projects are evaluated alongside domestic transmission priorities, thereby increasing the focus on sequencing of interconnection projects as part of the national power system investment strategy. It provides an indication of policy support by national governments, which can improve investor confidence and increase the visibility of interconnector projects.

Governments need to proactively assess and articulate the economic and social benefits of interconnector projects. While the ASEAN Interconnector Masterplan Study (AIMS) III Phases 1-2 showcases the positive impacts of integration at the regional level, a clearer articulation of the technical feasibility and potential benefits at project and country level is needed to underscore the business case for investment by public and private financing sources. Quantifying how these projects deliver value through lower prices, improved energy access, increased employment opportunities, greater system stability and climate-related outcomes, can lead to more informed prioritisation against other domestic investment needs. Moreover, demonstrating project benefits for the integration of variable renewable energy and emissions reductions can attract financing sources that have a development or climate focus.

Government leadership during interconnector project preparation and permitting is essential to advance development. Proactive collection and provision of data, such as seabed conditions, environmental baselines and spatial constraints, improves feasibility assessments, reduces risks and enhances investor confidence. Governments should define clear technical parameters, such as cable routing, capacity and connection points, particularly where they intersect with public sector responsibilities such as marine spatial planning. Taking the lead to secure permits and land rights can significantly lower the risk of delay or cancellation, especially for cross-border projects requiring multi-jurisdictional co-ordination where the interconnector passes through third-party waters. International case studies show that regional co-ordination on permitting standards and environmental assessment frameworks can further reduce complexity for multi-country projects. For example, the Central American Electrical Interconnection System interconnector was granted a quasi-sovereign status, which streamlined local permitting and established a harmonised regional framework for environmental and social safeguards.

Establish transparent and harmonised commercial arrangements and approaches to project cost recovery

A positive investment decision hinges on the viability of the business model employed. Without predictable revenue streams and suitable returns on investment, many interconnector projects may be deemed too high risk and high cost to finance. Policy makers and regulators have a central responsibility to establish a viable revenue model that can attract investors while also serving domestic interests on both sides of a border.

Potential revenue related to interconnectors by service provided as evidenced by international examples

Interconnector service	Potential revenue component	International example
Support energy sales	*Power purchase agreements*, where an interconnector asset is bundled with generation.	Established in ASEAN, as in Malaysia-Indonesia (Sarawak-West Kalimantan).
Electricity transmission	*Utilisation-based transmission charges.* Multiple methodologies are available to determine tariff structure, for example, postage stamp, contract path, load flow pricing.	Southern Africa Power Pool uses a load flow model with pricing based on both the load transmitted and the length of lines used.
	Congestion rents that arise from power trade between wholesale electricity markets when interconnection capacity is constrained. They are calculated as the price differential between the intake and off-take points, multiplied by the power flow.	North Sea Link between United Kingdom and Norway.
Asset availability and uptime	*Availability and/or annuity payments* for ensuring the interconnector asset is available to be utilised by the transmission system operator when required, often calculated based on cost recovery and a regulated rate of return. May be linked to performance metrics such as uptime.	Brazil independent transmission project framework. Central American Electrical Interconnection System.
	Explicit capacity auctions used to sell and allocate transmission rights for the interconnector, separate from the sale of power.	BritNed (United Kingdom-Netherlands), Viking Link (United Kingdom-Denmark).
Share ancillary services	*Charges for exchange of ancillary services* may be applied where interconnector capacity is used. This may be determined on a contractual basis or through participation in ancillary services markets.	United Kingdom-France IFA1 and IFA2.

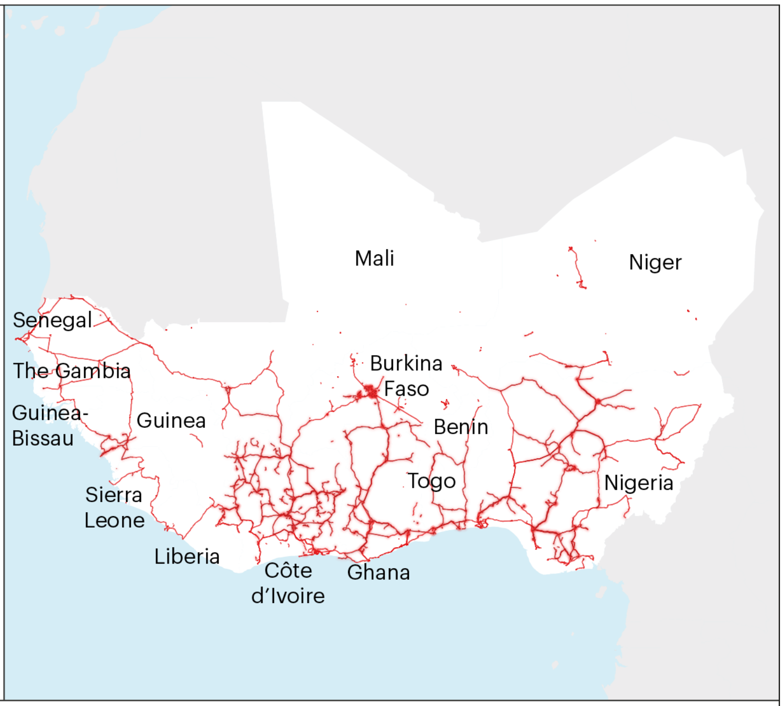
Commercial arrangements and revenue structures should be guided by regulation, rather than bespoke contracts. Establishing a harmonised and transparent methodology for regional transmission charges, specifically for cross-border power trade, can level the playing field for all market participants, strengthen investor confidence through predictable cost recovery mechanisms, and reduce transaction costs associated with negotiating bespoke agreements. A common framework also creates the institutional clarity needed for trade to expand sustainably and to attract new entrants, thereby contributing to better asset utilisation. Countries that have transparent approaches to cost recovery for transmission, for example Malaysia, Philippines, Singapore and Thailand, provide a technical basis for regional alignment. Power markets in other regions, such as SIEPAC and WAPP, demonstrate that a harmonised methodology for regional trade can co-exist with divergent national approaches to tariff setting.

Remuneration should capture multiple services provided by interconnection infrastructure. Transmission of electricity is the main service provided and the primary focus for renumeration. The secondary services that interconnectors can deliver in terms of grid stability, flexibility, emissions reductions and savings from deferred investment into other solutions for flexibility should be taken into due account. As the contribution of variable renewables to generation mixes expands, the relevance of secondary services increases and should be recognised from the outset of interconnector projects.

Case Study 1: Standardised wheeling charges in the West African Power Pool

Countries

- Senegal
- The Gambia
- Guinea
- Liberia
- Ghana
- Guinea-Bissau
- Sierra Leone
- Mali
- Niger
- Benin
- Togo
- Nigeria
- Côte d'Ivoire
- Burkina Faso



Details

- Grid-to-grid
- Programme of regional priority interconnectors
- Master plan outlines 23 000 km of HV transmission lines worth USD 10.5 billion

1999
WAPP created by ECOWAS heads of state at 22nd summit

2003
Articles of Agreement agreed for the establishment and functioning of the WAPP

2008
Establishment of ECOWAS Regional Electricity Regulatory Authority

2013
Directive for design of regional electricity market (REM) is adopted

2015
Regional market rules and tariff methodology adopted

2018
Regional market launched

2025
Testing exercise successfully synchronises all countries for four hours

Marketing and trading structure

- WAPP is a regional trading layer built on-top of existing national power structures.
- Phase 1: mostly bilateral PPAs but with standardised wheeling methodologies.
- Phase 2: Bilateral + day-ahead markets.
- Phase 3: full competitive markets.

Financing structure

- Financial structuring varies.
- Multilateral Project SPV model implemented for some priority projects such as the TRANSCO CLSG where each participating country's state-owned utility has an equity stake.
- SOE balance sheet financing used for other bilateral projects.
- MDB and DFI financing has been key for many projects.

Revenue structure

- WAPP participants pay a standardised transmission charge according to methodology established by ECOWAS regional regulatory authority (ERERA).
- Regional system and market operator (WAPP ICC) calculates regulated tariff to cover O&M, debt service, and a return on equity.
- MER participants (generators, distributors, TSOs) pay WAPP ICC which distributes revenues to TSOs.

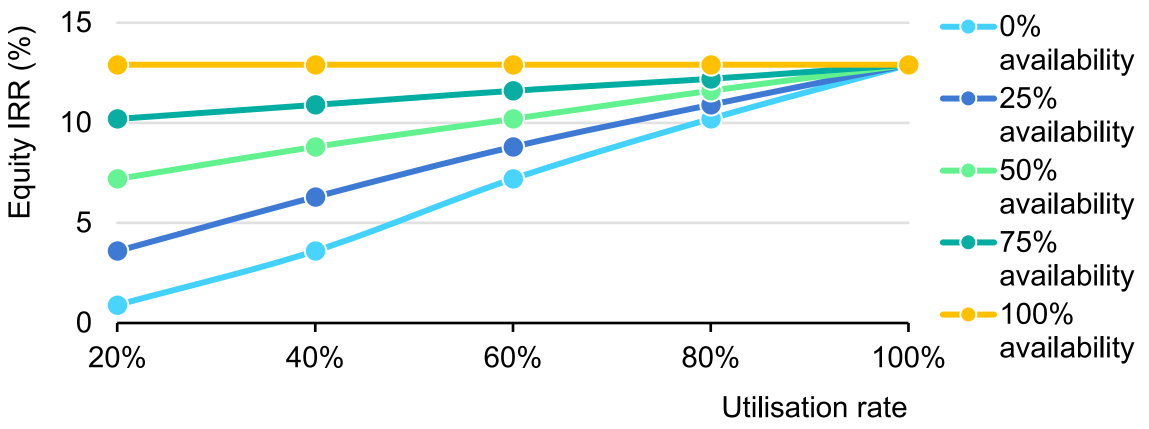
Note: ECOWAS = Economic Community of West African States; HV = high-voltage; WAPP = West African Power Pool; PPA = power purchase agreement; SPV = special purpose vehicle; TRANSCO CLSG = Côte d'Ivoire-Liberia-Sierra Leone-Guinea Transmission Company; SOE = state-owned enterprise; MDB = multilateral development bank; DFI = development finance institution; O&M = operation and maintenance; TSO = transmission system operator.

Sources: ECOWAS Regional Electricity Regulatory Authority (2015), RESOLUTION N°006/ERERA/15; Global Infrastructure Hub (2019), CLSG Interconnector Project; ECOWAS (2020), 2020-2023 WAPP Business Plan; ECOWAS

(2007) DECISION WAPP/17/DEC.26/10/07; G20 South Africa 2025, IEA and AfDB (2025), Booklet of Best Practices on Regional Power System Interconnectivity.

More predictable revenue mechanisms may be needed to enhance project bankability. Governments can scale up investment in interconnectors by establishing revenue frameworks in which sponsors receive guaranteed payments for asset availability or capital invested when performance metrics are met, thereby protecting investors from underutilisation while creating incentives for maximising system availability. Revenue certainty is especially valuable for high cost, subsea high-voltage direct current (HVDC) projects that may strain state-owned enterprise (SOE) balance sheet capacity. Availability payments, typified by the independent transmission project in Brazil, demonstrate how a predictable approach to remuneration can attract more private capital while reducing total development costs. Similarly, SIEPAC and interconnectors in Europe such as the Nemo Link are examples where asset owners, mainly SOE, earn a predictable regulated return on capital invested, which is set by independent regulators. Governments can also blend availability-based payments with utilisation-based charges to balance risk allocation and affordability, reducing fixed payment obligations while maintaining bankability.

Sensitivity analysis of equity IRR to revenue structure and utilisation rate for a representative HVDC subsea interconnector project



Notes: IRR = internal rate of return. Full assumptions and sensitivity results are in Annex B.

Principles for the design of transmission charge methodologies

Commonly proposed principles for transmission tariff design, as set out by the World Bank and Asian Development Bank (ADB), include:

- **Promote efficiency** by providing appropriate price signals to generation and demand, giving incentives for appropriate investment and promoting competition. It is important to consider the link between transmission pricing and the associated electricity trading arrangements, particularly in relation to congestion charging.

- **Recover costs**. The provider of the service should have the opportunity to recover costs incurred, which lowers the risk of investing in the network and hence the cost of capital. Various methodologies can determine the costs to be recovered, for example historic costs versus projected costs.
- **Be transparent, fair and predictable** to encourage new market participants. Ideally the methodology should be easy to explain and should be stable in the long term to avoid price shocks.
- **Be non-discriminatory** to treat network users equally based on their use and impact on the transmission network. For example, transmission pricing should ensure that the recovery of any residual costs, where price signals do not recover the full costs required, is allocated fairly.

Tariffs can change, but the rules for determining the tariffs should be clear and predictable to the extent possible.

As the export of power may involve transmission through multiple networks with various tariff regimes, there must be an agreed allocation of revenues between each utility involved and with the interconnector owner, if it is distinct from the utilities. The application of multiple transmission charges onto a single transaction, known as pancaking, should be avoided to ensure fees paid reflect the cost of system use.

Deploy alternative financing models to improve cross-border collaboration and attract new sources of capital

Governments and utilities, working closely with relevant national and international financial institutions, should develop a forward-looking financing plan for interconnectors to identify financing gaps and determine viable solutions. ASEAN countries vary considerably in terms of their macro-financial settings and capacities for financing. More precise specification of the sources of finance, including whether it will come from public or commercial sources, the types of instruments needed, and the potential contributions from cross-border or regional partners, can help in the early identification of potential financing gaps and solutions. This can inform tailored strategies that fit project specific needs and the regulatory or legal frameworks of a given country.

Shared ownership and cross-border financing structures can be applied for large, long-distance subsea projects. The split project financing model, where the interconnector is financed as two separate projects on each side of a border, is not well suited for high cost, long-distance subsea projects spanning multiple jurisdictions. Shared financing structures, typically involving joint ownership of the subsea asset, can streamline financial structuring, align cross-border interests, and enable fairer allocation of costs and benefits between parties. Subsea interconnectors in Europe provide examples of bilateral financing models, including the Cobra Cable (Netherlands-Denmark), Viking Link (United Kingdom-Denmark) and NordBalt (Lithuania-Sweden), among many others. In each case, the subsea segment is financed and operated under shared ownership, with each utility entitled to a regulated return that is typically proportional to their equity contribution. Multi-country examples such as the CLSG Interconnector Project in Africa illustrates how joint financing can be applied for more than two parties. In this case, Côte d'Ivoire, Liberia, Sierra Leone and Guinea each share equal ownership of a regional special purpose vehicle.

Establish regional funding for projects that provide regional benefits. Cross-border interconnectors that enable multilateral power trade can bring regional benefits beyond the countries hosting the asset. For example, the Malaysia-Thailand interconnector enables power trade between Lao PDR and Singapore through the Lao PDR-Thailand-Malaysia-Singapore Power Integration Project. Regional funding can socialise some project costs for interconnector assets which enable multilateral trade and may lead to improved sizing and investment decisions to reflect potential future use. For example, the Connecting Europe Facility for Energy provides funding support for strategically important projects designated as projects of common interest and projects of mutual interest. A EUR 645 million (USD 754 million) grant was agreed for the Bornholm Energy Island project to supply wind power from Denmark (Bornholm Island) to both Zeeland (Denmark) and Germany via subsea HVDC cables. In ASEAN, the APG Financing Initiative was launched in October 2025, which can support mobilisation of international public finance and other sources of finance for APG initiatives.

ASEAN Power Grid Financing Initiative

The APG Financing Initiative (APGF) was announced in October 2025 at the 42nd ASEAN Ministers of Energy Meeting by the Asian Development Bank (ADB) and the World Bank with the ASEAN Secretariat and ASEAN Centre for Energy. It aims to mobilise large-scale financing for the APG, including both domestic and cross-border transmission projects.

Through the initiative, the ADB committed an initial USD 10 billion for the APG over the next ten years, supported by USD 6 million of technical assistance for activities including project pipeline development and preparation, regional capacity building and co-operation. The World Bank committed an initial USD 2.5 billion through its Accelerating Sustainable Energy Transition Program. The APGF plans to offer a range of financial instruments including grants, concessional and regular loans, guarantees, political risk coverage, advisory services on public-private partnerships and equity.

Case Study 2: Regional financing arrangements in the Central American Electrical Interconnection System

Countries

- Guatemala
- Honduras
- El Salvador
- Nicaragua
- Costa Rica
- Panama

Details

- Grid-to-grid
- 1 800 km
- Overhead 230 kV/HVAC
- Total cost of approximately USD 700 million

1996 Framework treaty signed

1997 Financing approved for transmission line

1999 Empresa Propietaria de la Red (EPR) project company created to execute and operate the line

2000 Regional regulatory commission (CRIE) created

2001 Regional electricity system and market operator (EOR) established

2006 Line construction begins

2014 Final line segment energised

Marketing and trading structure

- SEIPAC created a secondary market (MER) for regional trading which operates in parallel with national markets.
- The MER is a separate market with distinct rules.
- Market participants can freely trade in the MER using regional contracts markets or short-term wholesale markets.

Financing structure

- Project Public-Private SPV (RED) was created from a shareholder agreement between the six state-owned utilities plus three private sector companies.
- Debt financing provided by Interamerican Development Bank, CABEI and Spanish Government.
- EPR given rights to build-operate-transfer the interconnector for an extendable 30-year concession period.

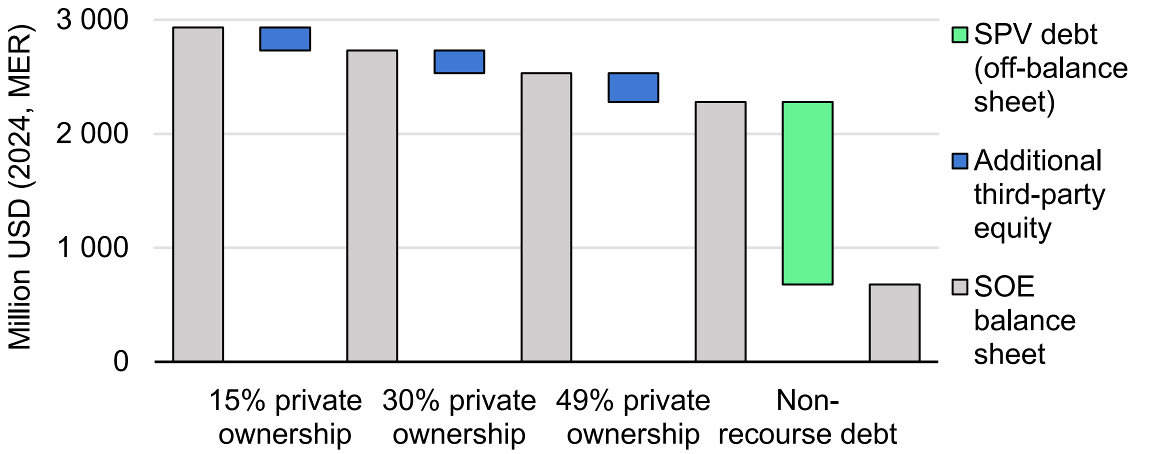
Revenue structure

- RED receives a fixed payment to cover O&M, debt service, a return on equity, and other costs each year; net profits are distributed as dividends to shareholders.
- The regulated payment is set annually by an independent regional regulatory commission (CRIE).
- MER participants (generators, distributors, traders) pay regional transmission charges for use of the line.

Notes: HVAC = high-voltage alternating current; kV = kilovolt; SEIPAC = Central American Electrical Interconnection System; CABEI = Central American Bank for Economic Integration. Values in USD 2024at market exchange rate.
Sources: CRIE (2022), RESOLUCIÓN CRIE-28-2022; IDB (2017), Central American Electricity Integration; GeoComunes data; Economic Consulting Associates (2010), Central American Electric Interconnection System (SIEPAC) | Transmission & Trading Case Study.

The use of independent transmission project business models can help mobilise private sector capital at scale. Independent transmission project (ITP) models can enable state-owned enterprises to raise non-recourse project finance and minority equity from international investors through special purpose vehicles, potentially reducing SOE financing requirements across the APG project pipeline. By ring-fencing projects off SOE balance sheets, ITP structures unlock access to international public finance, private equity, infrastructure funds, pension funds and sovereign wealth funds that would otherwise be unavailable, but which are needed for high cost subsea HVDC projects. Critically, a SOE can maintain majority control of assets by limiting private participation to minority stakes, preserving state ownership of strategic transmission infrastructure while accessing commercial capital. In ITP models, regardless of the ownership shares, the transmission system operator can maintain operational control over the asset while the private entity is mainly responsible for developing, financing and maintaining the asset. Where regulatory frameworks permit and strategic considerations align, ITP models offer a proven path to scale financing. An auction framework in Brazil successfully awarded 350 ITPs to 250 different companies between 2002 and 2022. In India, the Tariff Based Competitive Bidding ITP framework has seen the majority of awarded projects owned and financed by private companies.

Impact of increased private ownership and non-recourse debt on total balance sheet financing for a representative HVDC subsea interconnector project



Notes: HVDC = high-voltage direct current; MER = market exchange rate; SPV = special purpose vehicle; SOE = state-owned enterprise. SOE balance sheet includes project equity owned by the SOE and the project debt. The figure assumes that equity stakes held by the SOE in a special purpose vehicle are retained on-balance sheet, but non-recourse commercial and/or concessional debt are not.

Source: See Annex A for full methodology and sources used for investment and financial modelling.

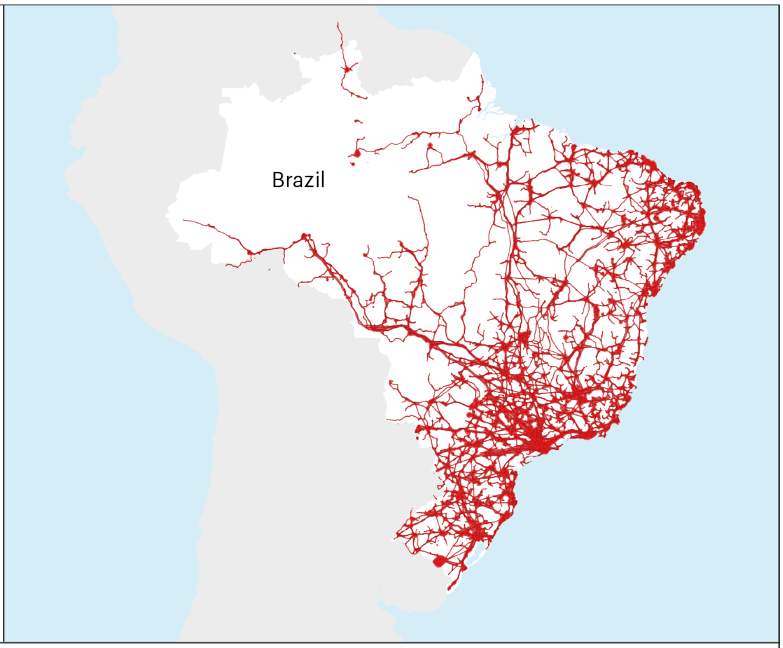
Case Study 3: Independent transmission project model in Brazil

Countries

Brazil – various regions

Details

- Domestic transmission lines
- National network exceeds 180 000 km
- Investment (2026-2035): USD 22 billion



1995
Creation of ANEEL (National Electric Energy Agency) by Law

1999
Transmission market liberalisation begins; competitive auctions begin

1999-2007
16 auctions carried out, competition increases

2008-2022
Nearly 300 individual lots auctioned – 100 percent success rate and 50 percent or more discount from initial revenue offer since 2018

Marketing and trading structure

- The Brazilian transmission market is open to private participation through auctions regulated by ANEEL.
- Livre Acesso (free access) allows any qualified participant to use the grid under regulated terms.
- Transmission and energy trading coordinated by the Chamber of Electric Energy Commercialization, including regulated and wholesale markets.

Financing structure

- Most financing comes from private investors and institutional lenders, often including development banks (BNDES, Caixa, IDB).
- Concessions awarded via auctions are typically under a 30-year BOOT.
- Majority of large projects are privately financed and owned, including asset acquisition by domestic and foreign investors.

Revenue structure

- Fixed annuity payments set by ANEEL through auctions, subject to performance.
- Payments funded via regulated transmission charges paid by grid users, regulated by ANEEL.
- Concessionaires receive stable, regulated annual payments, with profits depending on meeting operational availability targets set by ANEEL.

Notes: km = kilometres; ANEEL = Brazilian Electricity Regulatory Agency; BNDES = Brazilian Development Bank; IDB = Inter-American Development Bank; BOOT = build-own-operate-transfer. Investment value is in USD 2024 at market exchange rate.

Sources: E Serrato (2008) Electricity Transmission Sector in Brazil; RAP (2013) Regulatory Framework and Cost Regulations for the Brazilian National Grid; IEA (2024) Grids in Brazil: Mobilising private capital through a robust regulatory framework; EPE (2025) MME e EPE preveem investimentos de cerca de R$ 120 bilhões para o sistema de transmissão até o ano de 2035

Tackle key investment risks to reduce the cost of capital and improve bankability

Risk management is critical from the project outset. Individual projects will have unique risk profiles based on the geography, technical specifications, contractual structure and parties involved. Governments, developers and others involved in project development should take an integrated approach to manage risks, including through risk allocation, management during project design and operations, and mitigation of residual risk.

Manage risks through early engagement with technical experts, insurance and risk advisers. This is to ensure that key risks can be identified early and appropriately addressed during the project design and contractual phases, limiting residual risks and insurance premiums which are likely to be significant during financing and project operations. For subsea projects, investors consider risk factors such as seabed conditions, maritime traffic and natural hazards to identify a suitable routing and a risk-optimised cable burial depth, e.g. through a cable burial risk assessment. They may also consider selecting best suitable technologies, experienced contractors and an appropriate level of redundancy. During project operations, periodic monitoring of cable conditions, including smart monitoring and predictive maintenance techniques, may be applied to identify and prevent equipment damage.

Allocate risks to the party best placed to manage them. Projects and contractual arrangements should be structured in such a way that risks are allocated to the participant with the capacity to manage those risks. For example, private sector developers may be well suited to manage construction and commissioning risks but have limited control over permitting risks.

Measures to manage and mitigate project risks by type of stakeholder

Key project risks	Indicative risk management and mitigation actions
Political and regulatory	*Government:* Develop stable, transparent regulatory frameworks, including revenue frameworks. Establish bilateral or multilateral agreements and/or treaties with trading partners. Participate in financing transactions as a stakeholder. *International public finance*: Provide political risk guarantee. *Private sector:* Engage with governments on local benefits of projects, e.g. local content.

Key project risks	Indicative risk management and mitigation actions
Technical and physical	*Government:* Share relevant data with developers and those preparing technical studies, e.g. marine spatial planning. *International public finance:* Provide support for project preparation, for example, through technical assistance or project preparation facilities. *Private sector:* Bring international best practice in risk management during project design and monitoring. Develop effective insurance products. Engage in long-term service agreements with manufacturers to guarantee spare part availability.
Permitting and access	*Government:* Ensure transparency and consistency in permitting processes. Define clear accountabilities and timelines, and minimise duplication. *International public finance:* Support environmental and feasibility studies. *Private sector:* Engage early in the project process with all relevant permitting bodies.
Off-taker	*Government:* Provide sovereign guarantees for payment failures. *International public finance:* Provide credit guarantees for downside protections. *Private sector:* Not applicable.
Currency	*Government:* Provide sovereign guarantees for exchange rate risks. *International public finance:* Use of local currency in financing. *Private sector:* Provide currency hedging if available.
Residual risk	*Government:* Provide risk-tolerant capital and/or concessional finance. *International public finance:* Provide risk-tolerant and/or concessional capital. *Private sector:* Develop tailored insurance products for subsea cable projects. Participate in blended finance transactions with concessional capital providers.

Mitigate residual risks through credit enhancement instruments such as guarantees and insurance. While some risks can be managed, others, such as adverse political action, fall outside the control of investors. Moreover, some risk reduction methods, such as redundancy and cable protection through rock placement, may be too expensive to justify the additional cost. Where there are residual market or project risks, investors may seek to obtain credit enhancement instruments such as guarantees and insurance protection to reduce risks to an acceptable level. Products typically provided by multilateral development banks (MDBs) and development financial institutions (DFIs) include guarantee products such as political risk guarantees, including the World Bank MIGA and credit guarantees such as GuarantCo to mitigate off-taker risk. Insurance coverage may be provided by private insurers to guard against risks such as third-party damage to equipment, start-up and repair delays, and business interruption. With the risk profile and perceptions of subsea interconnectors evolving rapidly, in part due to increased geopolitical risks, specialised insurance products and coverage may be developed to suit the ASEAN context. Governments may also issue sovereign guarantees and seek support from DFIs. In 2025, South Africa announced plans to establish a Credit Guarantee Vehicle to support the first phase of a new independent transmission project scheme. The vehicle will issue payment and termination guarantees to de-risk early investments in ITPs.

Public financing for projects and engagement with concessional capital providers can bridge bankability gaps. Even with risk mitigation measures, there may be residual risk due to the complex nature of projects and the jurisdictions in which they are located. Early projects, such as subsea interconnectors, may have elevated perceptions of risk where there is a lack of proof points in the region. Government participation in early projects, either as a sponsor or through strong political backing, can contribute to reducing risk perceptions and attracting private sector interest. An example is Singapore Energy Interconnectors, established in April 2025 to develop and operate cross-border electricity interconnections. A memorandum of understanding was signed with Singa Renewables, a joint venture between TotalEnergies and RGE, for exploration of planning, development, financing, construction, operation and maintenance of a subsea interconnector for power from Indonesia to Singapore.

Share data on project risks and performance. Cross-border subsea interconnectors are new to the ASEAN region. There is limited experience among developers and investors to manage risks and limited data on asset risks and performance specific to the region, contributing to elevated risk perception and cost of capital. As projects develop, investors should be encouraged to share data and lessons learned to support risk pricing and industry development.

Case Study 4: North Sea Link HVDC subsea interconnector

Countries

United Kingdom

Norway

Details

- Grid-to-grid
- 720 km subsea HVDC
- Investment: USD 2.2 billion

2013
Licence application submitted; project designated as project of common interest (PCI)

2015
Final investment decision taken by National Grid and Statnett

2018-2021
Construction and installation of converter stations and cables

2021
Project commissioning

Marketing and trading structure

- Trading through Nord Pool implicit day-ahead auctions, between United Kingdom and Southern Norway bidding zones.
- Intraday auctions to be introduced in 2026.
- Trading formalised through bilateral treaty between United Kingdom and Norway.

Financing structure

- Project funded on utility balance sheets, with 50% contribution from National Grid (United Kingdom) and 50% from Statnett (Norway).
- Raised debt from commercial banks, with guarantees provided by export credit agencies.
- The European Union has provided a USD 42 million grant to support project preparation through its Connecting Europe Facility.

Revenue structure

- Congestion rent paid as revenue to National Grid and Statnett, based on market price differential and volume of flow.
- National Grid's revenues subject to Ofgem's cap and floor regime, setting maximum (cap) and minimum (floor) return, and an allowable return.
- Stattnet's share of revenues subject to a regulated revenue cap set by the Norwegian Energy Regulator.

Notes: km = kilometres; HVDC = high-voltage direct current; UK = United Kingdom; EU = European Union; Ofgem = The Office of Gas and Electricity Markets. Investment value is in USD 2024 at market exchange rate.

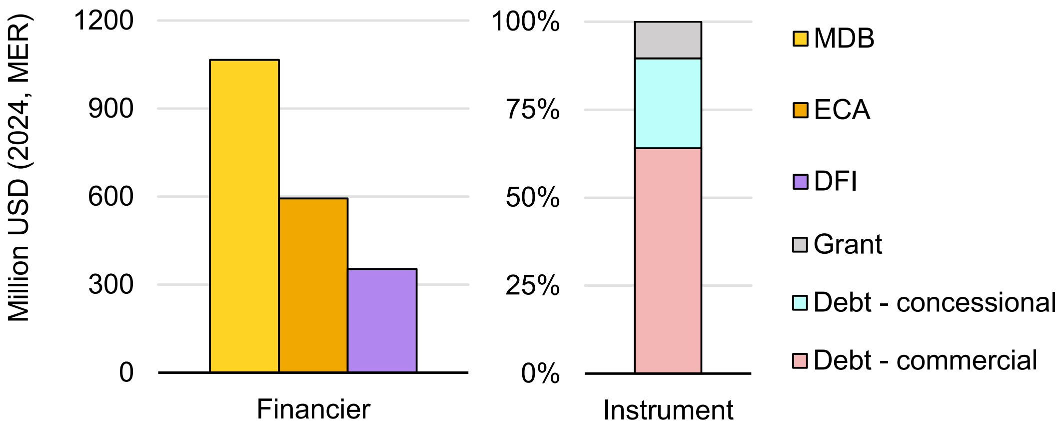
Sources: NS Energy (2021), North Sea Link Interconnector Project; Ofgem (2018), Guidance on the cap and floor conditions in National Grid North Sea Link Limited's electricity interconnector licence; Agreement between the United Kingdom and Northern Ireland and the Kingdom of Norway on Cross-Border Trade in Electricity and Co-operation on Electricity Interconnection (adopted 16 September 2021, entered into force 16 September 2021); National Grid (2021), NSL Access Rules and Charging Methodology; Statnett (2025), Congestion Revenues.

International public finance can bridge financing gaps

International public finance provides anchor financing where commercial lenders cannot. MDBs and DFIs are the primary sources of concessional and long-tenor debt instruments for interconnectors in ASEAN, while export credit agencies (ECA) can offer guarantees and political risk insurance. The ECA mandate is to take on emerging market risks including foreign exchange, political and credit risks in situations in which commercial lenders are constrained.

International public finance is particularly critical in markets with weak fundamentals**.** MDBs and DFIs are important in countries with sub-investment grade ratings or shallow capital markets, where commercial debt is expensive and short tenured. In these contexts, they can offer local currency lending and credit enhancement tools, while an ECA provides convertibility or political risk guarantees that private lenders cannot. National development banks complement this support with local currency financing and domestic market knowledge. These interventions are essential for moving first-of-a-kind projects toward bankability, establishing replicable structures and demonstrating viable returns that can attract follow-on commercial participation.

International public financing for ASEAN interconnectors by type and instrument, 2025-2040



Notes: MER = market exchange rate; MDB = multilateral development bank; ECA = export credit agency; DFI = development financial institution. Future financing projections assume a continuation of historical financing models.
Source: See Annex A for full methodology and sources used for investment and financial modelling.

Support for pipeline development can unlock near-term opportunities**.** In addition to financing individual projects, MDBs and DFIs can support project pipeline development in markets where project preparation capacity is limited. For instance, in convening project concept calls, supporting feasibility studies for priority corridors identified in the AIMS, and providing technical assistance for environmental impact and social benefit assessments. Establishing a dedicated project readiness facility or streamlining existing technical assistance funding processes could finance pre-feasibility studies and early stage design. A targeted effort, for example, backing feasibility studies for a selection of projects over the next three years, could materially expand the regional project pipeline and unlock near-term investment opportunities.

Current climate finance taxonomies present challenges for grid-to-grid interconnectors. The Common Principles for Climate Mitigation Finance, jointly applied by MDBs and the International Development Finance Club, include performance-based provisions for interconnections but focus primarily on the carbon intensity of electricity transmitted over a ten-year reference period. This approach can make it challenging for interconnectors to link systems that are at different stages of decarbonisation to qualify, despite their critical role in the integration of variable renewable generation, system flexibility and regional resilience.

MDBs and DFIs can update taxonomies to recognise interconnectors as enablers of clean energy transition. These institutions can address this by updating their climate finance taxonomies and internal classifications to explicitly recognise interconnectors as clean energy transition enablers based on system level benefits in addition to carbon intensity. Applying these principles would allow the institutions to classify grid-to-grid interconnectors as climate or transition finance eligible to unlock concessional resources, blended finance instruments and green bonds for cross-border projects, which is particularly important given the scale of capital required and the need to move beyond project-by-project financing.

International public finance helps create markets and enable sequential capital entry. Beyond direct project financing, they play a critical market creation role. Their participation provides a credible signal through rigorous commercial and environmental due diligence to lower perceived risks for other financiers. By demonstrating bankable structures, establishing replicable business models, and setting standards for cross-border projects, they help create the conditions needed for the sequential entry of diverse capital sources. This requires deliberate strategies to catalyse, not crowd out, private capital, to ensure that international public finance mobilises, rather than substitutes, for commercial capital. A sequenced approach beginning with commercially stronger corridors combined with integrated financing programmes that bundle development, construction equity, and refinancing facilities can establish proof-of-concept structures and provide clarity for sequential capital entry and exit across the full project life cycle.

Enable capital recycling through structured exit pathways

Recycling early stage capital can sustain project pipelines. Early stage investors often cannot exit operational interconnectors, locking up capital that could finance new projects. For ASEAN governments, this matters because it constrains how much capital the region can mobilise. Even if sponsors and international public financiers fund initial projects successfully, the pipeline stalls unless that capital can recycle. Creating exit paths transforms the limited pools of early stage capital into replicable financing capacity.

Addressing the equity valley of death requires structured exit mechanisms. International public finance cannot serve as permanent equity holders; their model depends on recycling capital to other projects. This creates an equity valley of death where early stage capital cannot exit without demonstrated refinancing mechanisms or secondary markets. Addressing this requires MDBs and DFIs to work with governments and sponsors to pre-structure exit pathways through planned refinancing windows, minority stake sales to institutional investors, or integration into regional investment platforms to enable capital to recycle while maintaining project viability.

Build refinancing into project agreements from day one. Governments could require that new interconnector concessions and power purchase agreements include explicit refinancing provisions. These clauses would specify when projects can refinance debt, how terms can be improved, and how gains are shared among investors and consumers. Without these provisions, investors face regulatory uncertainty about whether refinancing will trigger contract renegotiation. Governments could publish standard refinancing clauses for interconnector agreements, establishing clear rules that protect both investor returns and consumer interests.

Permit and facilitate minority stake sales to institutional investors. Where appropriate, regulators could clarify that state-owned enterprises could sell minority equity stakes in operational interconnectors to institutional investors without triggering foreign ownership restrictions or compromising operational control. Governments could establish streamlined approval processes, transparent valuation methodologies and clear criteria for permitted types of investors, potentially prioritising domestic pension funds, insurance companies and regional sovereign wealth funds. This releases capital to stated-owned enterprises for new projects while maintaining state control and operational oversight.

Establish regional platforms to create secondary markets. Where countries are open to exploring innovative approaches, governments could work with stated-owned enterprises to consolidate operational interconnector stakes into a jointly owned regional holding company that serves as both exit route for early investors and entry point for institutional capital. The platform would acquire minority stakes from sponsors, MDBs or other international public finance sources seeking to recycle capital, then sell to institutional investors. This creates a functioning secondary market while maintaining majority state ownership and control at both the project and platform levels.

Develop enabling regulations for secondary transactions. For countries pursuing capital recycling approaches, regulators can publish comprehensive frameworks for interconnector equity transactions. These frameworks would define approval processes and timelines for equity sales, establish valuation guidelines for operational transmission assets, clarify tax treatment including capital gains and withholding taxes, specify foreign investment limits and permitted investor categories and require transparent financial reporting for interconnector projects. Regional co-operation on common frameworks could reduce transaction costs for investors operating across multiple ASEAN markets. Without this regulatory clarity, transaction costs could remain prohibitively high and potential exits remain uncertain.

Utilities and policy makers need to co-ordinate strategically with equipment suppliers

Spur manufacturing to meet national infrastructure needs through close collaboration between public and private participants. Manufacturers of key equipment can face high uncertainty about future demand. While the AIMS III Phases 1-2 creates the foundations for regional planning, procurement schedules and equipment needs for many projects have not been clearly communicated and are often characterised by opaque details and shifting timelines. With lead times for key grid equipment increasing in recent years and a limited number of cable installation vessels, uncertainty can contribute to project delays if suppliers are not contracted with early in the process. More transparency in forward planning and closer collaboration can provide manufacturers with the confidence to invest in capacity, secure raw materials and expand the skilled workforce. Policy makers and ASEAN co-ordinating bodies should play a role in this process by facilitating formal regional dialogue between suppliers and utilities for priority interconnector projects.

Use framework agreements and strategic partnerships with manufacturers to lock in volumes and pricing over multi-year horizons. Worldwide, utilities are moving from project-by-project tenders to multi-year agreements in response to supply chain tightness for key equipment. This allows suppliers to reserve factory capacity and hedge raw material exposure, offering utilities price certainty and guaranteed delivery slots. For instance, in Sweden, Svenska Kraftnät entered into an eight-year framework agreement with Hitachi Energy to provide transformers and shunt reactors from 2027 to 2032; in the UK, the National Grid has begun awarding parts of a GBP 59 billion (USD 76 billion) HVDC supply chain framework for cables and converters covering both committed and anticipated projects. Similar approaches could help ASEAN utilities de-risk project delivery and reduce exposure to price changes.

Harmonise procurement frameworks and technical standards to unlock scale, while recognising project specific design complexity. Large volumes of overhead lines, cables and other grid equipment will be required to develop the APG. While full technical standardisation is not feasible, as equipment design must be tailored to the routing, environmental constraints and grid characteristics of each project, harmonising functional performance requirements, local content requirements, procurement frameworks and contracting structures can enable regional or multi-country framework agreements. This would boost project pipeline visibility for manufacturers, improving their ability to reserve production volumes and plan for new capacity investment. For utilities and developers, this can reduce project complexity and lower unit costs. The APG can provide a platform for this co-ordination, enabling ASEAN to move toward a more strategic approach to building shared infrastructure.

Invest in regional manufacturing, resilient supply chains and skilled workforce development. Geopolitical and policy driven shocks highlight the importance of supply chain resilience. Investing in regional manufacturing capacity can hedge against supply chain disruptions, reduce transportation costs and contribute to regional industrial development. Recent announcements signal growing interest in the region. For instance, the Korean company LS Cable & System is exploring the construction of a new subsea cable factory in Viet Nam, and Denmark-based NKT has announced plans to build a new subsea cable factory in Chinese Taipei. Resilience also depends on a skilled workforce. The global grid workforce of 8 million today needs to rise by a further 1.5 million by 2030. Today, expertise with subsea HVDC projects is concentrated in Europe where regional integration is most mature and numerous subsea interconnectors are operational. Governments, utilities and established suppliers can proactively invest in local workforce development and manufacturing capacity to build a sustainable ASEAN ecosystem for subsea projects.

Annex

Annex A. Methodology for investment and sources of finance

Overview

Information on capital expenditure for interconnections at a project level in ASEAN is limited. Even with detailed financial documentation in some cases, transmission line and equipment costs are often aggregated with other project components, such as power plant construction in generation-to-grid projects, or broad domestic grid reinforcement and economic development activities. To address these data limitations, all investment and financing estimates in this report are modelled. The modelling process begins by compiling physical specifications for each project and linking them to the IEA electricity grid investment and source of finance models, described in this section.

Project database and scope

The interconnector project database includes operational, under construction and planned projects in ASEAN from 1970 to 2040. The scope and key data sources for historical and future projects are summarised in the table below. The project list was developed primarily from publicly available information, complemented by proprietary datasets and targeted consultations to verify details where information was incomplete.

The database is not intended to be exhaustive for future years. Instead, it reflects the current pipeline of projects at various development stages as of first-quarter 2026. The analysis does not forecast additional interconnector projects beyond this existing pipeline.

The interconnector project database includes key physical characteristics such as line voltage, length, current type and installation type (overhead, underground or subsea). These data are direct inputs to the IEA transmission investment model. Commercial operation and construction start dates are recorded where available, while construction periods for future projects are estimated based on historical patterns and line length.

ASEAN interconnector project database: scope and key sources

	Historical (1970-2024)	Future (2025-2040)
Scope	Generation-to-grid interconnectors: new lines and upgrades.	Generation-to-grid interconnectors: new lines and upgrades.
	Cross-border grid-to-grid interconnectors: new lines and upgrades.	Cross-border grid-to-grid interconnectors: new lines and upgrades.
	Domestic inter-island interconnectors: new lines.	Domestic inter-island interconnectors: new lines.
	Grid-or-generation-to-large load.	Grid-or-generation-to-large load.

Out of scope - In scope

Key sources used to identify projects, physical characteristics and timelines include:

- ASEAN Centre for Energy (2024), ASEAN Power Grid Interconnections Project Profiles.
- Asian Development Bank (2020), Harmonizing power systems in the Greater Mekong Subregion.
- Asian Development Bank (2012), Greater Mekong Subregion Power Trade and Interconnection.
- Electricity of Vietnam (2024), Appendix 1 (compiled and translated on the HoboMaps Lao to Vietnam Hydropower Exporting Projects website).
- Electricity of Vietnam (2024), Appendix 2 (compiled and translated on the HoboMaps Lao to Vietnam Hydropower Exporting Projects website).
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- Global Wind Power Tracker Map, Global Energy Monitor (accessed October 2025).
- IJ Global (accessed September 2025), Global Infrastructure Transaction database.
- International Energy Agency (2019), Establishing Multilateral Power Trade in ASEAN.
- Open Infrastructure Map (accessed August 2025), Power infrastructure data.
- National Grid Corporation of the Philippines (2025), Transmission Development Plan 2024-5050.
- Perusahaan Listrik Negara (2025), RUPTL 2025-2034.
- External consultations.

Distinguishing between cross-border interconnectors and domestic transmission upgrades is not always straightforward. Interconnectors often require new or upgraded domestic equipment, but these costs are excluded from investment and financing results in this report. Similarly, transmission built by independent power producers that export electricity can involve both new evacuation lines and existing domestic infrastructure. In such cases, judgement is applied, such as verifying whether a power purchase agreement with a foreign utility exists prior to construction, to determine which assets serve export-specific purposes.

Number of projects in the ASEAN interconnector database

Period	Type	Number
Historical (1970-2024)	Generation-to-grid	38
	Grid-to-grid	24
	Total	**62**
Future (2025-2040)	Generation-to-grid	17
	Grid-to-grid	31
	Total	**48**
Full database (1970-2040)	Generation-to-grid	55
	Grid-to-grid	55
	Grand total	**110**

Note: Includes new projects and line upgrades.

Projects with expected commercial operation dates beyond 2040 are excluded. In total, 110 projects, both new interconnectors and upgrades to existing links, are included in the investment and financing model.

Grid investment model

Unit costs for electricity network equipment are based on an average of project and national level costs, collected from publications that detail costs per kilometre (km) by line and cable type. These costs are refined to create a 20 different unique combinations of line type (voltage band, current and placement) expressed on a per kilometre basis (USD million/km) for ASEAN on an annual basis dating back to the 1970s.

Although expressed on a per km basis, these costs embed other capital spending on equipment, such as converters. Future prices are dynamic, impacted by inflation and region specific discounters used to differentiate between material use per region as well as labour costs per region, two factors that can greatly influence the costs per km. Special attention is given to verify modelled costs and equipment price projections for high-voltage direct current (HVDC) subsea cables using external literature, recent projects and equipment price trends, as well as an extensive internal and external consultation process.

For this project, three cases are modelled for subsea HVDC equipment prices.

- **Cost Reduction case:** Inflationary pressures for subsea cables and converter stations persist in the short term, but prices begin to fall in the 2030s as manufacturing supply chains ease significantly.
- **Base case:** Inflationary pressures for subsea cables and converter stations persist in the short term but stabilise in the 2030s, after which point the cost of subsea cables and converters rise gradually over time.
- **Cost Overrun case:** Sustained supply chain constraints underpin price inflation for cables and converters that persist in the long term.

Interconnector investment

Investment by project is simply the product of project specific costs and distance:

$$Investment_{t,s} = Cost_{v,c,p,t,s} * Project\ distance_{v,c,p,t,s}$$

Where $Cost$ is a project specific cost expressed in USD 2024 at market exchange rate per km as determined by v (voltage), c (current), p (position), t (year), and s (pricing scenario), and $Project\ distance$ is actual or expected line distance in km (not circuit length). Investment is spread out over the construction period, from the point of a positive final investment decision or the project breaks ground to the point where it reaches commercial operations. All values are expressed in USD 2024 terms. Future projects costs are not discounted.

Interconnector financing

Once investment has been estimated, the next step is to assess financing. The model differentiates between three variables: sponsor, financier and instrument.

Overview of sponsor, financier and instrument options in the sources of finance model

Variable	Options	Description
Sponsor: Type of economic entity that invests in an asset regardless of what entity provides the funds.	State-owned enterprise	A corporation or project that is majority owned by government.
	Private enterprise	A corporation or project that is majority owned by a private sector entities.

Variable	Options	Description
Financier: Ultimate suppliers of funds.	Domestic public financiers	Government-held equity stakes in private corporations and state-owned enterprises, state subsidies and tax incentives.
	Commercial financiers	Equity investment made by private enterprises and households, along with debt from commercial banks and financial institutions.
	Multilateral development banks	Supranational institutions set up by sovereign states with a development focus.
	Development finance institutions	Other national public financial institutions with a development mandate.
	Export credit agencies	Public or quasi-public financial institutions which offer financing to support domestic company exports.
Instrument: Combination of debt and equity, and level of concessionality.	Debt - commercial	Investment financed using debt issued at market rate terms (non-advantageous loan tenures and interest rates), irrespective of the financier.
	Debt - concessional	Investment financed using debt issued on terms which are more favourable than can be found in financial markets.
	Equity	Investment financed using equity, including retained earnings or direct government subsidies.
	Grant	Money provided without interest and without exchange for ownership.

Source: IEA (2025), Global Energy and Climate Model Documentation 2025.

Information on financing primarily comes from the following datasets:

- IJ Global: Project level financial information on project sponsors, financiers and instruments (primarily for generation-to-grid projects).
- World Bank PPI: Project level financial information on sponsors, financiers and instruments (primarily for generation-to-grid projects).
- S&P Capital IQ: Information on corporate ownership and balance sheets (primarily for grid-to-grid projects).
- OECD CRS: Granular financial flows for development finance transactions (used for both grid-to-grid and generation-to-grid projects post-1995).

In general, transaction-level data are used when available as it provides direct information on the financier, instrument and amount. We also use project level financial records provided by multilateral development banks, including:

- Asian Development Bank (1991), Project Completion Report of the Xeset Hydropower Project.
- Asian Development Bank (2002), Project Performance Audit Report on the Theun-Hinboun Hydropower Project (Loan 1329-LAO [SF]) in the Lao People's Democratic Republic.
- Asian Development Bank (2002), Project Completion Report on the Nam Leuk Hydropower Project (Loan 1456-LAO [SF]) in the Lao People's Democratic Republic.
- Asian Development Bank (2003), Technical Assistance to the Kingdom of Cambodia for Preparing the Power Distribution and Greater Mekong Subregion Transmission Project.
- Asian Development Bank (2004), Project Performance Audit Report on the Nam Leuk Hydropower Project (Loan 1456-LAO [SF]) in the Lao People's Democratic Republic
- Asian Development Bank (2007), Proposed Loan (Cambodia) Power Transmission Lines Co., Ltd., Power Transmission Project.
- Asian Development Bank (2016), Lao People's Democratic Republic: Na Bong–Udon Thani Power Transmission Project.
- Asian Development Bank (2019), Lao People's Democratic Republic: Greater Mekong Subregion: Nam Theun 2 Hydroelectric Project.
- Asian Development Bank (2022), The Lao People's Democratic Republic: Greater Mekong Subregion Northern Power Transmission Project.
- Asian Development Bank (2024), Republic of Indonesia: West Kalimantan Power Grid Strengthening Project.
- Asian Infrastructure Investment Bank (accessed August 2025), PSI P000739 Lao PDR Xekaman Cross-border Hydropower Projects.
- International Bank for Reconstruction and Development (1972), A Review of Land and Water Resource Development in the Lower Mekong Basin.
- World Bank (1981), Report and Recommendation of the President of the International Development Association to the Executive Directors on a Proposed Development Credit to the Lao People's Democratic Republic for a Nam Ngum Hydroelectric Project.
- World Bank (2015), Implementation Completion and Results Report (IDA-H3000) on a Grant in the Amount of SDR 6.7 million (USD 10.2 million Equivalent) to the Lao People's Democratic Republic for a Greater Mekong Subregion Power Trade Project.

- World Bank and Ricardo Energy and Environment (2019), Greater Mekong Subregion Power Market Development. All Business Cases including the Integrated GMS Case. Final Report for The World Bank.
- World Bank (accessed September 2025), Nam Ngum 2 Hydro Power Plant.

Because transmission-specific capital expenditure is rarely disclosed separately, absolute, i.e. dollar figure, reported financial values are not directly used from primary sources and datasets. Instead, the financing model classifies sponsors, financiers and instruments into broad categories, aggregates and converts values into a percentage of total project financing, and then applies it to the modelled investment costs for each transmission line.

Where project level financing data is unavailable, corporate level information, i.e. ownership and balance sheet structure, is used. The balance sheet is first split into debt and equity, after which equity is allocated between public and private shareholders. Debt is attributed to international public financiers (IPFs) where applicable; any remaining debt is classified as commercial finance. Thus, for investment financed on corporate balance sheets:

- Commercial finance = non-IPF debt + equity held by the private sector.
- Domestic public finance = government subsidies + equity held by the public sector.
- IPF = on-lending from development banks and development financial institutions to state-owned enterprises, split by type (development finance institution or multilateral development bank).

Financing information for future projects is incorporated when available but is generally limited. The analysis is exploratory, i.e. it reflects current regulatory environments and potential financing pathways rather than forecasts. Business-as-usual assumptions extend historical patterns of sponsors, financiers and instruments, but future interconnector financing could shift significantly due to new agreements, financing models, additional projects or regulatory changes.

Annex B. Methodology for cash flow modelling

Overview

This annex details the methodological framework and quantitative assumptions underpinning the financial analysis presented in Chapter 3. The modelling quantifies how the investment environment affects the bankability of ASEAN power interconnectors. While the main report discusses the strategic implications of these scenarios, this annex outlines the construction of the discounted cash flow (DCF) model used to generate the return profiles.

Model architecture and approach

Methodology

Financial viability is assessed using a standard DCF approach. The model projects annual cash flows over the asset lifecycle to calculate two primary metrics:

- Project internal rate of return (IRR) (unlevered): Measures the intrinsic return of the asset excluding financing structure effects, serving as a proxy for economic efficiency.
- Equity IRR (levered): Measures the return to equity investors after debt service, reflecting the impact of leverage, interest rates and risk premiums.

Time horizon and phasing

The model assumes a full lifecycle analysis spanning 44-48 years:

- Construction phase: Variable construction periods of four, six or eight years reflect execution risks associated with land acquisition, permitting and technical complexity across various policy environments. Capital expenditure is drawn down pro-rata during this period.
- Operational phase: Fixed 40-year operating life following commercial operations date.

Technical specifications

The reference asset is a 600 megawatt (MW) high-voltage direct current (HVDC) interconnector combining subsea and overhead transmission lines. Technical losses range from 2% of total capacity per year in the Cost Reduction case to 4% in the Cost Overrun case to account for sub-optimal technical maintenance or lower grade infrastructure.

Revenue and cost assumptions

A critical model feature is the variation in revenue structure, which dictates risk transfer between the off-taker and the sponsor. The revenue model transitions from de-risked to merchant-exposed structures:

- Cost Reduction case: 50% fixed revenue (availability payment), independent of actual power flow, with the remaining 50% based on utilisation, providing a partial hedge against demand risk.

- Base case: 25% fixed revenue with 75% based on utilisation, increasing exposure to utilisation volatility.
- Cost Overrun case: 100% variable revenue (utilisation payment), fully exposing investors to volume and merchant risk.

Tariffs range from USD 28.4 to 34.8 per megawatt-hour benchmarked against reported wheeling charges for comparable regional interconnector, e.g. Lao PDR-Thailand-Malaysia-Singapore Power Integration Project.

Operational expenditure and taxation

- Operating expenditure: Modelled as 0.9%-1.1% of initial capital expenditure per year, accounting for routine maintenance, insurance and administrative costs, adjusted for efficiency levels in each case.
- Depreciation: Straight-line depreciation at 2.5% per year applied for tax purposes.
- Taxation: Corporate tax rate of 20% applied to taxable income across each case.

Financing assumptions

The model calculates returns using waterfall cash flow logic, where operating cash flows first service debt obligations before distributing residual cash to equity holders.

- Debt sizing: Leverage ratios (debt: equity) range from 70:30 to 40:60, input directly rather than solved via debt service coverage ratio constraints.
- Debt terms: 20-year tenor with fully amortising repayment profiles. No refinancing assumed; debt held to maturity to isolate the impact of primary financing terms.
- Terminal value: No residual or terminal value assumed at end of 40-year operating period.

Investment assumptions for ASEAN interconnector projects

Key assumptions	Cost Reduction case	Base case	Cost Overrun case
Total project size (USD million)	811	911	1 009
Transmission losses (%)	2%	3%	4%
Asset life (years)	40	40	40
Construction period (years)	4	6	8
O&M costs (% of capex per year.)	0.9%	1%	1.1%
Tariff level (USD/MWh)	34.8	31.6	28.4
Tariff structure	Availability basis (50%); utilisation basis (50%)	Availability basis (25%); utilisation basis (75%)	Availability basis (0%); utilisation basis (100%)

Key assumptions	Cost Reduction case	Base case	Cost Overrun case
Utilisation assumption	90%	80%	70%
Debt-to-equity ratio	70:30	55:45	40:60
Debt tenor (years)	20	20	20
Interest rate	3.5%	7.0%	10.5%
Corporate tax (per year)	20%	20%	20%
Returns			
Project IRR (unlevered)	3.8%	9.4%	5.9%
Debt IRR	3.5%	7.0%	10.5%
Equity IRR	22.7%	10.9%	5.2%

Note: O&M = operations and maintenance; capex = capital expenditure; MWH = megawatt-hour; IRR = internal rate of return.

Limitations

The model highlights directional sensitivities and structural drivers of returns rather than replicating a specific bankable transaction. Key simplifications include:

- No refinancing: Commercial projects typically refinance post-completion to improve equity returns; this model assumes the initial debt package remains in place for 20 years.
- No secondary exit: Equity IRR calculated on a hold-to-maturity basis, excluding potential upside from selling the asset to yield-seeking investors, such as pension funds, after construction risk subsides.
- Foreign exchange risk: While foreign exchange risk is qualitatively discussed in the Cost Overrun case as a driver for higher discount rates, the model calculates cash flows in nominal US dollars.

Definitions

APG North: Refers to interconnectors between Cambodia, Lao PDR, Myanmar, Thailand and Viet Nam.

APG South: Refers to interconnectors between Peninsular Malaysia, Singapore and the Riau Islands, Java and Sumatera in Indonesia.

APG East: Refers to interconnectors between Sarawak and Sabah in Malaysia, Kalimantan in Indonesia, the Philippines and Brunei Darussalam.

Build-operate-transfer (BOT): A project financing structure in which a private developer finances, builds and operates an energy asset for a fixed concession period, after which ownership is transferred to the public sector.

Build-own-operate-transfer (BOOT): Similar to the BOT financing structure, but the private sponsor legally owns the asset during the concession period, then transfers ownership to the public sector at the end.

Build-own-operate (BOO): A structure where the private developer builds, owns and operates the energy asset with no obligation to transfer ownership at the end of the concession period. For energy projects, the end of the concession period typically coincides with the end of the asset lifetime.

Commercial operation date (COD): The date when a project begins full commercial operations and starts generating revenue.

Commercial finance: Equity investment made by private enterprises and households, alongside debt from commercial banks and financial institutions.

Debt - commercial: Investment financed using debt which is issued at market rate terms (non-advantageous loan tenures and interest rates), irrespective of the financier.

Debt - concessional: Investment financed using debt which is issued on terms that are more generous than available in financial markets.

Domestic public finance: Government-held equity stakes in private corporations and state-owned enterprises, state subsidies and tax incentives.

Development finance institutions: (DFIs) Other national or international public financial institutions with a development mandate.

EBITDA: Earnings before interest, taxes, depreciation and amortisation. A measure of the operating performance of a company.

EBITDA margin: Measures the operating profitability of a company as a percentage of its revenues.

Electricity distribution: Corresponds to low-voltage lines (less than 70 kilovolt) supplying electricity to residential and commercial users as well as medium-voltage lines serving villages and small and medium-size industrial sites.

Equity: Investment financed using equity, including retained earnings or direct government subsidies. (In this report, grants are reported separately.)

Electricity transmission: Connects utility-size generation, distribution grids and large industrial consumers. In addition, transmission grids include extra-high-voltage and ultra-high-voltage lines that transmit electricity over long distances. Interconnector investment is included within transmission investment.

Export credit agencies (ECAs): Public or quasi-public financial institutions that offer financing to support exports from domestic companies.

Grant: Money donated without interest and/or financial gain.

Grid-to-grid: A type of interconnector project that creates a new connection between domestic and foreign substations to facilitate the exchange of electricity and other services from a pool of generation sources.

Generation-to-grid: A type of interconnector project that links the export of electricity from a single source, or cluster, of generation sources to a foreign demand source.

Independent power producer concession: This type of project is generally financed off-balance sheet through a special purpose vehicle or a joint venture. A separate entity is created under a shareholder agreement between a state-owned enterprise and/or private developer(s), with the right to build, operate and potentially own the transmission and generation assets for a fixed concession period. Financing is raised based on project level cash flows.

Internal rate of return (IRR): A metric used to measure the profitability of an investment, often expressed as an annual percentage return.

Independent transmission project (ITP): A project type in which a single transmission line or a portfolio of transmission lines are built and financed under a BOOT model or a variant of the BOOT model, typically through competitive auctions open to public and private actors. ITPs are typically structured as special purpose vehicles.

Investment grade: A credit rating provided by a rating agency, indicating that a bond has a relatively low risk of default.

Leverage: A financial indicator measuring the ratio of company debt to its earnings, equity or other metrics.

Multilateral development banks: Supranational institutions set up by sovereign states with a development focus.

Non-deliverable forward: Financial derivative used for hedging or speculating on currency exchange rates, which may be used for managing foreign exchange exposure in illiquid markets.

Off-taker: An entity that purchases the services or the output of an infrastructure project, typically under a long-term contract.

On-balance sheet): A financing structure in which a company borrows directly from a lender and the debt appears on its own balance sheet, rather than creating a separate entity. This approach is simpler but limits how much the company can borrow for projects.

Operating cash flow: The amount of cash generated by a company from its normal business operations, representing cash available after paying operating expenses but before capital expenditures and financing activities.

Project finance: A financing structure where lenders provide capital based on the cash flows of the project, rather than the general credit profile of the sponsor company. This structure allows infrastructure projects to be financed without burdening the balance sheet of the sponsor.

Private enterprise: A corporation that is majority owned by private sector entities.

Special purpose vehicle (SPV): a legally independent company created solely to develop, own, finance and operate a specific project, typically formed from a consortium of different investors.

State-owned enterprise: A corporation that is majority owned by the public sector.

State-owned enterprise-led financing model: A financing model wherein a state-owned enterprise is the sole owner and operator of the transmission line. Financing is provided on the balance sheet using retained earnings, debt or equity. The terms of financing and the extent of access to capital are directly linked to the financial health and liquidity of the state-owned enterprise, and, by extension, to that of the state.

Syndication: The process of bringing together multiple lenders to jointly provide a loan. A lead arranger structures the loan and invites other banks to participate.

Ticket size: The amount of capital an investor commits to a single project or investment.

Tenor: Length of a loan.

Wheeling: Cross-border electricity transmission.

Wheeling charge: Fee paid to a transmission operator for the use of its network to deliver electricity between two parties.

Whole of grid concession: Private company obtains long-term concession to manage and operate existing transmission assets and oversees expanding the transmission grid in its area of operation.

Yieldco: A publicly traded company to own and operate a portfolio of operational energy assets backed by long-term contracts. Yieldcos are structured to generate stable, predictable cash flows and dividends to investors.

Abbreviations and acronyms

AC	Alternating current
ADB	Asian Development Bank
AIMS	ASEAN Interconnector Masterplan Study
APAEC	ASEAN Plan of Action for Energy Co-operation
APG	ASEAN Power Grid
APGF	ASEAN Power Grid Financing Initiative
ASEAN	Association of Southeast Asian Nations
BOO	Build-own-operate
BOT	Build-operate-transfer
BOOT	Build-own-operate-transfer
COD	Commercial operation date
CO_2	Carbon dioxide
DC	Direct current
DFI	Development finance institution
EBITDA	Earnings before interest, taxes, depreciation and amortisation
ECA	Export credit agency
ECOWAS	Economic Community of West African States
EDL	Électricité du Laos
EGAT	Electricity Generation Authority of Thailand
EPC	Engineering, procurement and construction
EUR	Euro
EVN	Viet Nam Electricity
EVNNPT	National Power Transmission Corporation (Viet Nam)
FX	Foreign exchange
GBP	Pound Sterling
GMS	Greater Mekong Subregion
HVAC	High-voltage alternating current
HVDC	High-voltage direct current
IEA	International Energy Agency
IFA	Interconnexion France-Angleterre
IFC	International Finance Corporation

IFRS	International financial reporting standards
IG	Investment grade
IPP	Independent power producer
IPF	International public financiers
IRR	Internal rate of return
ITP	Independent transmission project
kV	Kilovolt
Lao PDR	Lao People's Democratic Republic
LTMS-PIP	Lao PDR-Thailand-Malaysia-Singapore Power Integration Project
PLN `	Perusahaan Listrik Negara (Indonesia state utility)
MDB	Multilateral development bank
MER	Market exchange rate
MoU	Memorandum of understanding
NDF	Non-deliverable forward
NGCP	National Grid Corporation of the Philippines
PPA	Power purchase agreement
PV	Photovoltaics
RAB	Regulated asset base
RUPTL	Rencana Usaha Penyediaan Tenaga Listrik (Indonesia: national electricity business plan)
SGD	Singapore dollar
SOE	State-owned enterprise
SOFR	Secured overnight financing rate
SPV	Special purpose vehicle
STEPS	Stated Policies Scenario
TNB	Tenaga Nasional Berhad
UHV	Ultra-high-voltage
USD	United States dollar
VRE	Variable renewable energy
WAPP	West African Power Pool

Units

g CO_2	gramme of carbon dioxide
GW	gigawatt
GWh	gigawatt-hour
Km	kilometre
MW	megawatt
MWh	megawatt-hour

See the IEA glossary for further explanation of many of the terms used in this report.

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