CASE
for Southeast Asia

On behalf of:
Federal Ministry
for the Environment, Climate Action,
Nature Conservation and Nuclear Safety

of the Federal Republic of Germany

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EMERGING TECHNOLOGIES SERIES

Virtual Power Plants and Southeast Asia

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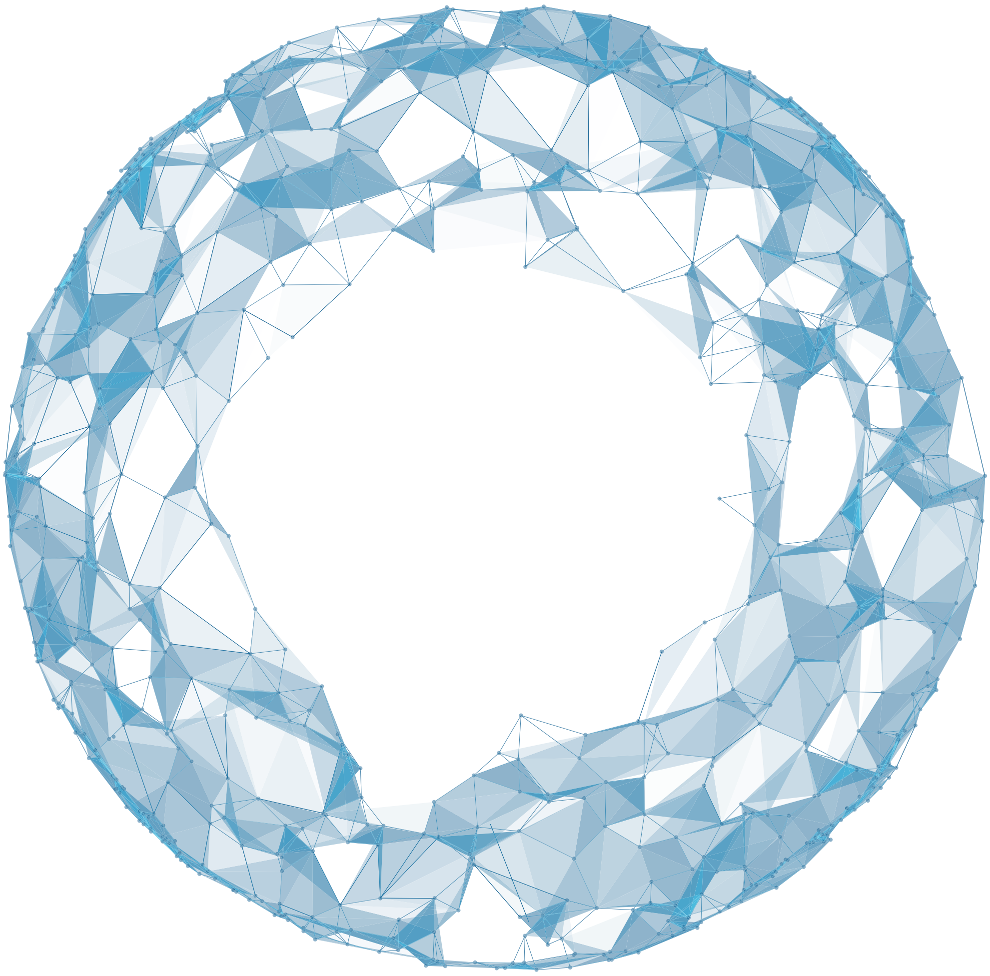

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Key insights

1

Distributed energy resources (DERs), small-scale energy assets connected to distribution grids, are growing rapidly across Southeast Asia and are reshaping how power systems operate. As DERs, which include rooftop solar, batteries, electric vehicles and smart cooling systems—cluster on local distribution networks, they can create new operational challenges if left uncoordinated. Managed well, however, they can strengthen reliability, reduce electricity costs and lower overall investment needs.

2

Virtual power plants (VPPs) coordinate multiple DERs as a single resource to deliver services that support a more reliable, affordable and clean power system. A VPP digitally aggregates and coordinates multiple DERs, enabling the power system to draw on practical services such as shifting demand, storing surplus solar PV and supplying power during peak hours. This eases grid congestion, improves power system reliability and reduces reliance on expensive peak generation. Well-designed programmes ensure value for utilities, end-users and the wider power system alike.

3

VPPs already operate across the globe under different regulatory and market models. Experience from power systems in Germany, the UK, Australia and the US shows that VPPs can function in both vertically integrated utilities and competitive markets – whether through tariff-based schemes and programme-based aggregation led by utilities, contracted flexibility services procured by system operators, or aggregated participation in wholesale and ancillary service markets. This range of implementation options makes VPPs adaptable across institutional contexts, provided that roles, performance requirements and settlement rules are clearly defined.

4

With supportive policies and enabling infrastructure, VPPs can help Southeast Asia make better use of its growing DER base and unlock more value from low-cost distributed energy assets for households, industries and businesses. As DERs continue to expand across Southeast Asia, VPPs can unlock greater value from these assets: accelerating renewable integration, supporting electrification, and strengthening energy security at lower overall system cost. Realising this potential requires clear regulatory roles, smart metering, transparent market access, and aligned incentives.

Introduction

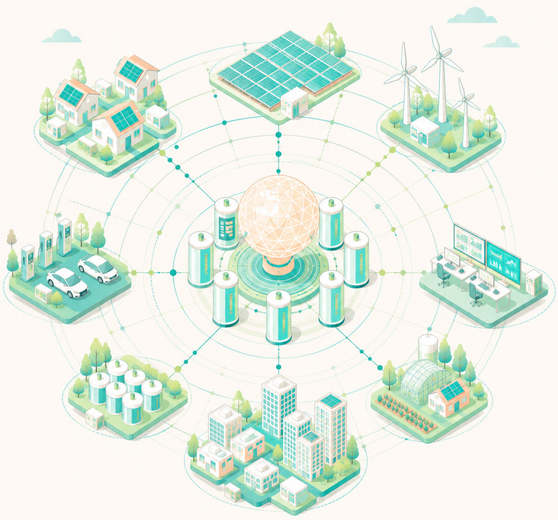
Distributed energy resources (DERs) – including rooftop solar photovoltaic (PV), battery storage, electric vehicles, and heat pumps for heating or cooling – are reshaping how power systems operate across the world, and Southeast Asia is no exception. As deployment accelerates across the region, the way these resources are rolled out and managed will be critical to grid reliability and energy affordability.

DERs are smaller, more numerous and more dispersed than conventional generation. Comprising supply, demand and even storage resources, they typically connect to distribution networks close to consumers and range from a few kilowatts for a single household to around 10 MW for an industrial site. Many sit behind the customer's meter—limiting their visibility to grid operators, while others are utility- or third-party-owned ("front-of-the-meter") assets. But with the right tools, they can be made dispatchable, meaning their output can be adjusted to meet system or customer needs.

At low penetration levels, individual DERs are too small and fragmented to significantly affect grid operations. However, as deployment scales up, unmanaged DERs can increasingly strain conventional distribution network operation. Conversely, with the right tools, aggregated and coordinated DERs can become a cost-effective source of flexibility and other grid services – creating value for utilities, end-users and the power system as a whole.

Virtual power plants (VPPs) are among the most promising of these tools. A VPP is a software-driven system that coordinates a portfolio of DERs, enabling them to be dispatched as a single resource to deliver defined grid services — such as peak shaving, reserve provision, voltage support, and congestion relief.

Evidence from operational deployments across multiple power systems shows that VPPs can be an important complement to conventional grid modernisation solutions including grid infrastructure investment, new dispatchable generation and utility-scale batteries[1].



Well-designed VPPs can:

- **integrate more rooftop solar PV by managing ramps and midday curtailment**
- **shave peaks and reduce outage risks**
- **lower system costs while creating new revenues for consumers**
- **cut CO2 emissions by displacing peakers and inefficient backup generators**
- **defer substation/feeder upgrades**
- **provide fast reserves and voltage support**

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[1] *US DOE Pathways to Commercial Liftoff: Virtual Power Plants 2025 Update* compares the net cost of providing 400 MW of resource adequacy from three options. It finds, roughly, VPPs can provide resources at about 40% cheaper cost and at ~60% lower cost than a battery.

[2] Source: International Energy Agency (2024), Electricity 2024; see also IEA regional outlooks for Southeast Asia

[3] International Energy Agency (IEA) (2024): Integrating Solar and Wind in Southeast Asia. Online available at: https://www.iea.org/reports/integrating-solar-and-wind-in-southeast-asia/executive-summary (accessed 5 April 2026)

VPPs in Southeast Asia: a timely opportunity

Regional electricity demand is projected to grow at roughly 4% per year, rising from just over 1300 TWh today to more than 2000 TWh by 2035[2], driven primarily by cooling, industrial activity and transport. This rising demand coincides with the expansion of renewables and electrification, as countries seek to strengthen energy security, reduce dependence on fossil fuel imports[3], and meet climate targets. Distributed solar capacity is growing across the region: Viet Nam, which already has around 7.7 GW of rooftop solar PV, has targeted 50% of office buildings and 50% of residential dwellings to use self-consumption rooftop solar by 2030[4]. Elsewhere, the Philippines targets 35% renewable power by 2030 and 50% by 2040[5], and Thailand and Indonesia are expanding their own rooftop solar programmes. IEA projections indicate that distributed PV could add around 20 GW across Southeast Asia between 2024 and 2030.

At the same time, many power systems in the region still have limited flexibility, grid visibility or advanced metering at the distribution level. This makes the coordination of DERs increasingly important, especially where rooftop solar and other consumer-side resources are beginning to cluster on local networks.

VPPs remain largely underutilised across the region. Concerns about DER impacts on grid reliability and utility revenue models have slowed the regulatory and market reforms needed to unlock their potential. Key barriers include gaps in enabling infrastructure – notably the limited rollout of advanced metering – as well as institutional constraints. For example, in some systems, incumbent utility business models may not incentivise the active integration of consumer-side flexibility.

These barriers are not insurmountable. A range of VPP models exist, varying in operational complexity, infrastructure requirements and compatibility with different ownership structures and market configurations – from vertically integrated utilities to liberalised markets. This means that Southeast Asian countries can pursue VPP deployment in ways suited to their own institutional contexts, even as those contexts continue to evolve. With the right policy and regulatory frameworks in place, VPPs offer a practical pathway to turn the region's growing DERs into a reliable, cost-effective asset base for the entire power system.

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[4] Government of Viet Nam (2023) 'Approving the National Electricity Development Plan for the 2021–2030 period, with a vision to 2050 (PDP8)'. Available at: https://vepg.vn/wp-content/uploads/2023/05/PDP8_full-with-annexes_EN.pdf

[5] Department of Energy Republic of the Philippines (2025) 'Power Development Plan 2023–2050'. Available at: https://doe.gov.ph/site/epimb/articles/2128063--power-development-plan-2023-2050

How VPPs work

A VPP is not an actual power plant, but a software-driven system that connects a portfolio of distributed energy resources and coordinates them to deliver similar services to those of conventional generators such as peak shaving, reserve provision, voltage support, and congestion relief. Understanding how VPPs work means looking at three interconnected functions: asset participation and enrolment, data exchange and dispatch, and interaction with the wider power system.

1. Asset Participation and Enrolment

Depending on the VPP model and the regulatory environment, participants in a VPP can include households, small and medium enterprises, commercial and industrial sites, fleet operators, community energy systems, and utility-owned assets. Participants can join a VPP either at the time of new installations or by enrolling existing assets. Enrolment typically involves contracts between the VPP operator and participant that define availability and performance requirements, operational constraints, opt-out rules and payment arrangements – ensuring that participation is transparent and predictable for all parties.

2. Data Exchange: Monitoring, Dispatch and Verification

Once enrolled, each asset connects to the VPP platform through a secure communications link – typically via a smart meter[6], gateway device[7], or manufacturer's cloud platform[8]. This two-way connection allows the VPP to continuously monitor asset status and availability and enables it to send dispatch instructions: telling a battery to charge or discharge, adjusting a building's cooling load, or managing when an EV charges. The connection also supports performance measurement and settlement, providing a verifiable record of what each asset delivers.

The effective dispatching of VPP assets is supported by a foundational layer of data integration, forecasting, and optimisation. The VPP platform combines meter readings (site-level import, export or consumption data) and asset telemetry (asset-level operating data such as battery state of charge, EV charger status, or inverter output) with external inputs such as weather forecasts, solar generation outlooks and real-time or anticipated grid conditions. Based on these inputs, it estimates when flexibility will be available and most valuable. Dispatch planning also respects customer preferences and device constraints – for example when an EV must be fully charged, how far a building's temperature can be adjusted, or the operating limits of a battery.

Drawing on forecast flexibility and customer and device constraints, the VPP determines which assets should increase or decrease their output, by how much and for how long. The goal is to meet a defined objective – such as reducing peak demand on a specific feeder or within a constrained local network zone – by a target volume of megawatts at a particular time.

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[6] A smart meter measures electricity use and, in some cases, electricity export at the site level.

[7] The gateway device, referred to here, is a local communications and control interface that connects one or more DER devices to the VPP platform.

[8] The manufacturer's cloud platform is a remote software layer through which device makers can monitor and control enrolled assets without direct integration to every device onsite

3. Interaction with the Power System

How a VPP interfaces with the wider power system depends on the regulatory framework and market design. In vertically integrated or single-buyer systems, this typically means responding to utility requests under bilateral contracts or regulated demand response programmes (for example, Hawaiian Electric's battery programmes, where the batteries are called to discharge during evening peaks to reduce demand during system stress events). In more liberalised markets, VPPs can aggregate DERs into defined market products – covering energy, capacity, or ancillary services such as frequency response or reserve services as seen in Great Britain and Australia.

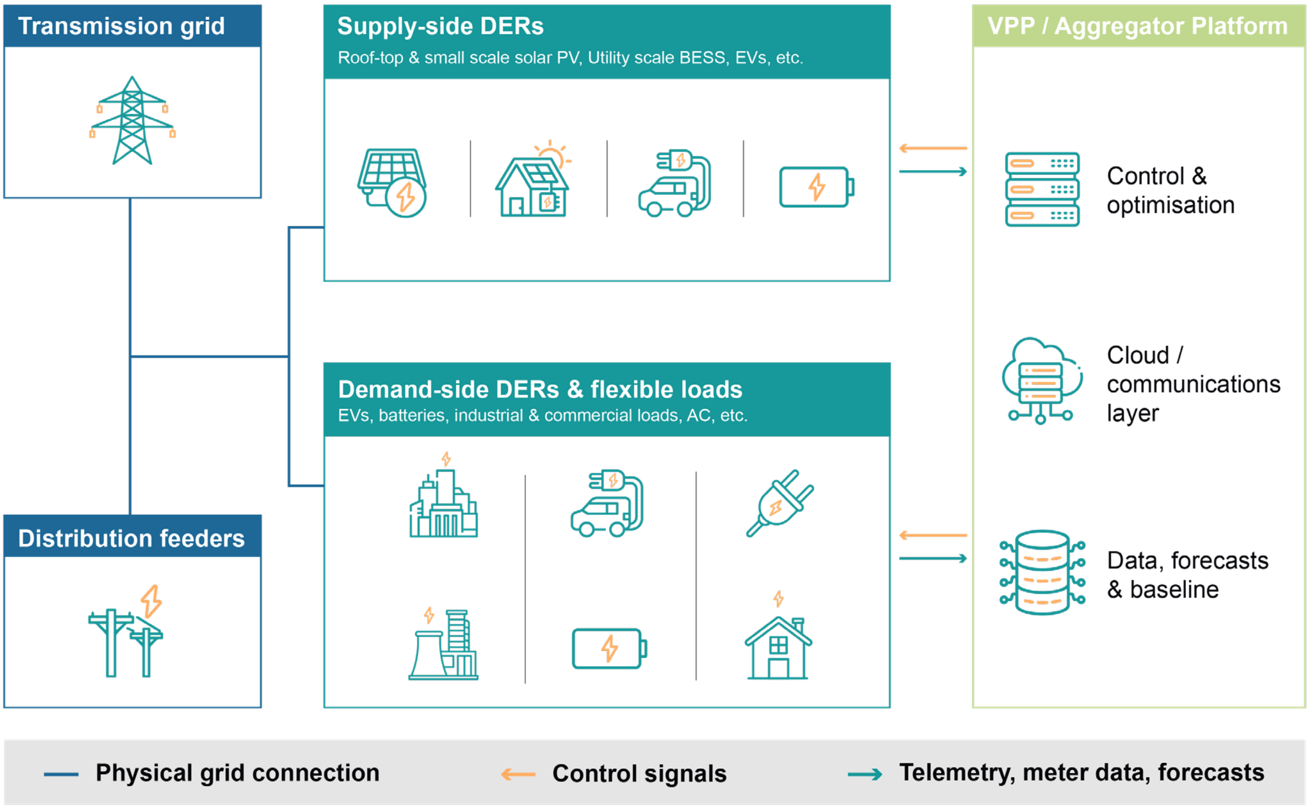
The signals through which a grid operator or utility coordinates with a VPP – or directly with its assets – vary considerably in sophistication. At the simplest end, grid operators or utilities can influence DER behaviour through price-based or programme-based signals. Price-based signals include time-of-use (ToU) tariffs, which vary prices by time period on regular schedules, and critical peak pricing, which applies much higher prices during a limited number of system-stress periods. Programme-based signals include event-driven demand response, where participants are asked or instructed to reduce load or change device behaviour during a predefined dispatch event. These approaches require limited infrastructure and place most of the decision-making with the asset owner. A more complex approach involves automated device control – for example, direct scheduling of EV charging or battery dispatch – where the VPP issues direct instructions and can measure and verify the response. At the most sophisticated end, where regulatory frameworks permit, VPPs can actively bid aggregated capacity into wholesale or ancillary service markets (where minimum product sizes can be as low as 100 kW in advanced markets), with near-real-time dispatch and settlement.

The appropriate level of complexity is not fixed; it depends significantly on how much DER capacity is present in a given part of the grid and the existing institutional arrangements. At lower penetration levels, simpler approaches are often sufficient because the aggregate system impact of distributed assets remains modest. But simple approaches can also remain effective at higher penetrations where consumption or generation patterns are relatively predictable or where institutional agreements make more complex coordination difficult to implement. As DER penetration grows, however, the stakes change. Higher spatial concentrations increase the potential for local congestion, voltage excursions, and other constraint violations. At these levels, more explicit monitoring of grid availability and more precise verification of how assets respond to dispatch instructions become necessary to keep the network within safe operating limits.

This is where the coordination between VPPs and distribution system operators becomes increasingly important. As DER penetration grows, VPPs must operate within the physical constraints of the distribution grid. This is managed by distribution system operators using platforms such as Distribution Management Systems (DMS)[9], Advanced Distribution Management Systems (ADMS)[10], and Distributed Energy Resource Management Systems (DERMS)[11]. In brief, DMS and ADMS are grid operations platforms supporting real-time monitoring, switching, outage management, and voltage control, while DERMS is a DER coordination layer that translates network conditions into operational boundaries for distributed assets, such as location-specific export limits or ramp rate constraints.

In practice, this creates a clear division of responsibilities. The distribution utility or system operator uses its systems to determine what the network can safely accommodate and communicates this to VPPs as dispatch boundaries, such as export or import constraints at the feeder or zone level. The VPP then optimises and dispatches its portfolio within those limits, sharing its schedules, expected availability, and measured delivery back to the DSO for verification and settlement. This layered approach – where the DSO manages grid constraints and the VPP handles asset-level optimisation – allows both functions to be performed efficiently, without requiring the distribution utility to issue instructions to every individual device.

Figure 1:
Virtual power plant structure



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[9] Distribution Management Systems are software used by distribution utilities or system operators to monitor and operate the distribution network, supporting functions such as real time network status or alarms, switching operations, outage restoration support and feeder level operational analysis – often integrated with SCADA (Supervisory Control and Data Acquisition), the digital control systems utilities use to monitor and operate grid equipment in real time.

[10] Advanced Distribution Management Systems are integrated distribution operations platforms, typically combining DMS capabilities with SCADA and outage management functions, and adding more advanced applications.

[11] Distributed Energy Resource Management Systems are software used to provide visibility of connected DERs and to coordinate or constrain their operation to stay within distribution network limits. DERMS can translate network conditions into DER operating limits – such as export/import caps or, in more advanced cases, dynamic operating envelopes – and may interface with aggregators/VPPs and/or be integrated within an ADMS.

Technology outlook and operating models for VPPs

How VPPs are used today

VPPs are already operating at meaningful scale across multiple regions. In the United States, several companies such as Tesla, Sunrun and Generac, as well as utilities working with aggregators, orchestrate hundreds of megawatts of behind-the-meter batteries – particularly through California's Emergency Load Reduction Program, which pays participants for reducing demand or increasing electricity supply during grid emergencies. In Europe, Germany hosts some of the world's most advanced VPPs, with platforms like Next Kraftwerke aggregating almost 15000 distributed energy resources representing more than 15 GW of flexible capacity across renewables, combined heat and power (CHP), storage and flexible demand to participate in wholesale and balancing markets[12]. Australia's National Electricity Market has become a global testbed for residential VPPs, where state-supported programmes in South Australia and Victoria have enrolled tens of thousands of rooftop PV-plus-battery systems to help stabilise frequency and respond during major grid events. These examples demonstrate that VPPs are already mobilising significant volumes of DERs, while providing system-level value at scale.

The key differentiator across countries is therefore not technology – smart devices, communications infrastructure, cloud platforms and forecasting tools are all commercially available – but how VPPs are organised and governed: who aggregates the assets, what services VPPs target, how performance is verified and remunerated, and how VPP dispatch is aligned with distribution network constraints.

Utility-Led Programmes

These utility-led VPP programmes do not require a fully liberalised wholesale market. They can function in vertically integrated and single-buyer systems, where utilities either operate programmes directly or contract specialised providers to deliver defined services. The system operator or utility must specify the services it needs and have the means to verify and remunerate delivery.

Several vertically integrated utilities are already doing this. Hawaiian Electric (HECO), which operates island grids, runs several VPP-style mechanisms tailored to specific operational needs. Its Battery Bonus programme requires participants to make battery discharge available for two consecutive hours each evening, providing predictable peak demand reduction as solar output falls. HECO also operates a fast demand response programme, through which eligible commercial and industrial participants commit to reducing load during periods of high demand or grid stress, helping to stabilise the system and

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[12] Markets used to keep supply and demand in balance in near real time

prevent unplanned outages. A similar model exists on the US mainland: Rocky Mountain Power (PacifiCorp) operates Wattsmart Batteries, a VPP-style approach in which enrolled customer batteries are automatically managed as part of broader utility operations.

Market-Facing Aggregators

Where retail competition and wholesale market access allow aggregation, VPPs are increasingly operated by retailers and third-party aggregators[13]. In these settings, portfolios of DERs (as low as 100 kW) are coordinated to respond to price signals, and where permitted, to bid into defined market products covering energy, capacity or ancillary services. Rather than being dispatched only under a utility programme, these VPPs are operated to stack multiple revenue streams, such as shifting demand to low-cost periods alongside providing system services. Clear performance requirements and verification remain essential, but the commercial driver is market value rather than bilateral utility contract.

Octopus Energy in the United Kingdom illustrates this model. Through its Kraken platform and smart tariffs, it orchestrates large fleets of flexible devices (most visibly EV charging) so that demand is automatically shifted to times that are cheaper and better for the system. Australia offers a further example: the South Australia Virtual Power Plant, developed with Tesla, which has been documented as delivering both energy and contingency frequency control services through direct market participation enabled by its software platform. In parallel, the Australian Energy Market Operator (AEMO) has conducted dedicated VPP demonstrations to test market participation capabilities, improve operational visibility and better understand how VPPs interact with distribution network constraints.

The two tables below are intended to be read together. Table 1 provides a guide to the common VPP archetypes, showing how each model works and which market settings it is best suited to. Table 2 provides a more detailed overview of these VPP deployment archetypes, and what each implies for ownership structures, operational capabilities and practical entry points.

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[13] A retailer's primary role is to buy electricity on wholesale markets and sell it to end-customers, while a third-party aggregator focuses on pooling and optimising distributed energy resources to provide flexibility services. Although distinct, the two roles can overlap when retailers also aggregate and control customer-side DERs, effectively operating as both supplier and flexibility provider.

Table 1:
Examples of common VPP archetypes[14], and where they fit best.

Common VPP Archetype	How it works	Best-fit market
Tariff-driven VPP logic	Participants respond to time-varying prices or event notifications by shifting EV charging, cooling, water heating, or other flexible loads away from constrained hours.	Single-buyer or regulated retail systems first (can also work in competitive retail markets through supplier offers)
Utility-run device programmes	Utility or its platform operator directly manages batteries, EV charging, smart air-conditioners, or water heaters to reduce peaks, improve reliability, or respond to system-stress events.	Single-buyer or vertically integrated systems (also, relevant where utilities retain strong demand-response or distribution roles).
Utility contract with a VPP provider	Utility buys a defined service from an aggregator, and VPP provider delivers it using a portfolio of DERs.	Single-buyer/vertically integrated systems (especially where utilities have the mandate but limited digital capability)
Market-facing aggregator	Competitive-market model in which an independent aggregator combines DERs and bids them into market products.	Competitive or liberalised markets
Locational / distribution system-aware VPP	A network-aware model in which DERs are dispatched not only for system-wide value, but also within feeder, transformer, congestion, or voltage constraints.	Can work in both single-buyer and competitive settings, but depends on stronger feeder visibility, coordination, and data.

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[14] Source: Authors' compilation based on public examples and programme documentation, including National Grid ESO, Hawaiian Electric, Rocky Mountain Power, Swell Energy, Tesla South Australia VPP, AEMO Project EDGE, South Australia Power Networks, UK Power Networks, and Con Edison. Please also see "Further reading on real-world examples" in Reference section of this brief.

Table 2:

Common VPP deployment archetypes, ownership, capabilities and entry points.

Deployment archetype	Typical ownership	What it can deliver	Complexity[15] & entry point	Real-world examples[16]
Tariff-driven VPP logic (TOU / critical peak / peak events)	Mainly customer behind-the-meter (residential + C&I), can apply broadly via tariffs	Load shifting and peak reduction; improved use of midday solar	Low – when TOU or event-based incentives exist, for solar midday surplus / evening peaks	• National Grid ESO Demand Flexibility Service - United Kingdom (Great Britain)
Utility-run device programmes (managed EV charging, water heaters, smart AC)	Customer devices enrolled under utility rules, sometimes utility-owned assets	Peak shaving, reliability support, targeted demand response, potentially fast response if enabled	Low/Medium – when the utility wants quick peak reduction without market reforms	• Rocky Mountain Power Wattsmart Battery Program - United States (Utah / Rocky Mountain Power service territory) • Hawaiian Electric Battery Bonus - United States (Hawaii)
Utility contract with a VPP provider (single-buyer compatible)	Mixed portfolios (behind-the-meter assets + utility-owned DER), often can be started with commercial and industrial (C&I) sector	Defined services under contract (peak, reserves, local congestion relief, island fuel savings)	Medium – when the utility has the mandate but limited digital capability	• Swell Energy operating HECO's Home Rewards Battery Program - United States (Hawaii)
Market-facing aggregator (where rules/ products allow)	Often customer behind-the-meter batteries / EVs + C&I, can include front-of-meter DERs	Energy, capacity, ancillary products	Medium/High – when rules allow aggregation and there is a buyer for services	• Tesla South Australia VPP - Australia (South Australia)
Locational / distribution system-aware VPP (constrained optimisation within feeder limits)	Any type of ownership, increasingly relevant with PV clustering and two-way flows	Congestion/ voltage management, non-wires alternatives, hosting capacity[17] improvement	High – when PV clustering, voltage issues, transformer overloads are real constraints	• AEMO Project EDGE - Australia (Victoria) • South Australia Power Networks Flexible Connections Trials - Australia (South Australia) • UK Power Networks Flexibility Tenders - United Kingdom. • ConEdison BQDM - United States (New York)

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[15] Complexity here refers to how advanced an archetype is in terms of the institutional, regulatory, digital and operational capabilities needed for implementation, including metering and telemetry, coordination and control, settlement arrangements and the maturity of the supporting market or utility framework.

[16] For further reading on the real-world examples listed in this table, see the "Further reading on real-world examples" section in the references of this brief.

[17] Hosting capacity refers to the amount of DER a local network can accommodate without creating problems

Potential and risks of VPPs for Southeast Asia's clean energy transition

Growing DER deployment and rising flexibility needs

Southeast Asian countries are at different stages of the energy transition, but most are seeing increasing deployment of rooftop PV, battery storage, EVs and other flexible loads, alongside surging cooling and air-conditioning demand. These trends create both opportunities and operational challenges: higher variability, sharper net load ramps and localised distribution constraints – particularly in areas where DERs are clustering – are placing new demands on power systems that were not designed to accommodate them.

The nature of these pressures varies by context. Countries with growing rooftop solar PV and rapid urban demand growth are likely to experience local hosting capacity constraints on distribution feeders and transformers. Countries with island grids or weak interconnections often face higher fuel costs and reliability risks that make flexibility at the distribution level especially valuable. In many systems, inflexible generation and long-term contract structures further constrain the short-term value of flexibility. VPP programmes must therefore be designed to work within existing procurement and operational realities, while supporting the longer-term reforms needed to unlock their full potential.

What VPPs can deliver in Southeast Asia

System capacity and reliability

Across Viet Nam, Thailand, the Philippines and Indonesia, electricity demand is rising quickly, while heatwaves and urban load pockets, and in some cases wider system reliability challenges, are already stressing networks. Aggregated DERs that can shave peaks in the afternoon and evening and provide fast reserves can meaningfully help reduce this stress. In many Southeast Asian systems, the afternoon peak is growing in importance due to cooling demand, while evening demand surges remain critical as solar generation falls. Because VPP capacity is modular and distributed, it can often be enrolled and scaled faster than new supply-side assets, particularly where suitable DER fleets already exist, and targeted to specific provinces, islands or feeders experiencing operational challenges. This is particularly relevant in Southeast Asia, where cooling demand is a major driver of peak load growth. Aggregating air-conditioners, building cooling systems, rooftop solar PV and batteries can create a highly relevant VPP bundle for the region: solar PV can reduce daytime grid demand, batteries can shift energy supply into later hours, and flexible cooling can help shave afternoon and evening peaks while maintaining user comfort within agreed limits.

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[18] A dynamic operating envelope is a flexible export/import limit that changes over time based on local grid conditions.

Distribution network relief and solar hosting

Where rooftop solar PV and electrified loads concentrate on specific feeders, VPPs can help manage congestion and voltage issues – especially when dispatch is location-specific and coordinated with distribution system operations. In some contexts, dynamic operating envelopes[18] and targeted flexibility procurement can delay or reduce the scale of network upgrades, though in many cases grid reinforcement remains essential and should be seen as a complementary, cost-effective approach rather than something that VPPs fully replace.

Benefits for households and businesses

As rooftop solar PV, batteries, EV chargers, cold storage and efficient air-conditioning spread across Southeast Asia, VPPs offer a way to turn these assets into new income streams without requiring additional investment beyond what participants already own. In specific programmes, utilities can even shoulder the capital outlay for select end-users, offering further scope for a more equitable development of the region's developing power systems.

Energy security and resilience

Across Indonesia, the Philippines and remote parts of other Southeast Asian countries, many systems still rely on expensive diesel for primary supply, peak supply and backup. Coordinating solar PV, batteries and controllable loads through a VPP can reduce reliance on imported fuels and provide targeted support during contingencies such as heatwaves, generation outages or storms – offering a faster and often cheaper route to greater power system resilience than through the expansion of dispatchable generation capacity.

Risks and how to manage them

Repeating the "build first, integrate later" pattern

VPPs can complement grid investment but cannot substitute for it. If DER deployment accelerates without adequate distribution planning and operational tools, local constraints and reliability incidents can increase. The resulting backlash could set back DER and VPP programmes, and potentially wider energy transition ambitions. The practical solution is to scale DERs and flexibility programmes in tandem with targeted network reinforcement, improved operational visibility and updated operating procedures.

Benefits can skew towards urban and higher-income customers

In many Southeast Asian markets, early VPP adoption may be more viable in commercial and industrial sites, campuses, public buildings and higher-consumption urban customer segments before broader residential participation becomes feasible. If VPP participation is limited to customers who already own DERs, benefits will skew toward wealthier households and urban areas. Weak retail price signals can also limit participation. In systems with subsidised or flat tariffs, households and businesses may see little incentive to shift demand or enrol flexible assets unless programmes offer clear direct payments, bill credits, or utility-led participation models.

In countries where electricity tariffs are politically sensitive and cross-subsidies already exist, this creates genuine distributional and political risks. Poorly designed VPP incentives could deepen existing inequities and generate public resistance to broader DER and clean energy reforms. Mitigation measures include targeting pilots early in mixed-income urban districts, designing programmes that support low-income cooling or community batteries and carefully aligning tariff reforms with VPP design to avoid regressive outcomes.

Inflexible fossil capacity can crowd out VPP value

VPPs can shave peaks and reduce curtailment, but they cannot offset the structural constraints created by inflexible generation portfolios and take-or-pay contracts. There is a real risk that VPPs in Southeast Asia become primarily a tool for managing residual demand fluctuations, while the wider system remains locked into inflexible coal or gas capacity. This would reduce the value of flexibility, limiting the revenue that VPPs can realistically earn, and risk delaying more fundamental market design reforms—including coal retirement, coal PPA renegotiation, and capability payments. To manage this risk, VPP rollout should be paired with broader flexibility reforms, including more flexible dispatch practices, better procurement of balancing and reserve services, and, where relevant, reforms to rigid long-term power purchase arrangements.

Overcoming digital, data and governance gaps

Most Southeast Asian power systems have limited smart meter penetration and digital infrastructure compared to what large-scale VPPs require. Without clear data governance frameworks, VPP operators – especially non-utility aggregators – cannot reliably access the meter and network data they need. Consumers could also be exposed to privacy and cybersecurity risks if appropriate safeguards are not in place. Addressing these gaps requires coordinated investment in metering infrastructure alongside regulatory refinement in data governance, access and use. At the same time, VPPs can help accelerate the adoption of smart meters and digital upgrades, because participation typically requires smart meters and opens the door to more attractive tariffs or flexibility payments.

Ensuring consumer protection and trust

VPP programmes can be complex for consumers to navigate. Rules around baselines[19], performance measurement, penalties, and payments can be difficult for most participants to understand. In many Southeast Asian countries, regulators and policymakers are still gaining experience with retail energy products and consumer-facing DER programmes. Where rooftop solar and other distributed technologies scale rapidly, weak consumer protection can undermine trust through unclear contract terms, unrealistic savings claims, poor service quality or difficult complaint resolution. VPP programmes should therefore build trust from the outset through simple and transparent contracts, a clear explanation of risks and rewards, robust dispute-handling procedures, and strong alignment with existing consumer-protection frameworks.

Key enablers: Lessons from global experience

Simple enrolment and transparent payments

Large-scale VPP programmes, such as the Demand Flexibility Service in Great Britain, demonstrate that households and businesses participate when offers are straightforward and payouts are credible. The key enablers are easy enrolment (often through installers, retailers or digital channels), transparent programme rules, timely settlement and payment or bill credits that participants can easily understand. Without these foundations, even technically well-designed programmes struggle to retain participants over time.

Feeder visibility and local operating limits

As DER penetration grows, the limiting factor is often not the VPP platform itself, but the ability of distribution operators to monitor and manage local network conditions. Integrating VPP dispatch with distribution operations, and using tools like dynamic operating envelopes, can help avoid voltage and congestion issues while enabling higher DER utilisation. Australia’s Project EDGE and South Australia Power Networks’ Flexible Exports programme show that dynamic operating envelopes can keep VPP dispatch within safe limits, though progress is still needed on data sharing, transparency and operational integration before these tools become routine practice. The UK’s flexibility market experience also points to the importance of zone-specific procurement and better network data to avoid local overloads while procuring services efficiently.

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[19] A baseline is the reference level of electricity consumption against which a demand response or flexibility event is measured.

Telemetry (data) quality and control reliability

Consumer-grade communications infrastructure (home Wi-Fi routers, standard broadband connections) can be a recurring constraint on VPP performance. AEMO’s VPP Demonstrations in Australia found that operators received 70% to 98% of expected real-time data (telemetry) at any given time, with dropouts linked to home Wi-Fi and mobile connectivity. This highlights the need for programmes to set clear DER interface requirements[20], particularly as performance verification becomes more consequential at scale.

Measurement, verification and baselines

Measurement and verification[21] methods should be practical, auditable and proportional to the service being delivered. For many early-stage programmes, simple performance metrics and conservative baselines can reduce the scope for disputes and build credibility with both participants and regulators.

Cybersecurity, privacy and consent

As millions of customer devices become grid-interactive, cybersecurity, privacy and informed consent become foundational requirements rather than afterthoughts. Stronger authentication (ensuring only authorised users and devices can access the system), regular software updates, audit logs that record access and actions, and data minimisation practices (that limit collection to what is strictly necessary) become essential and grow even more important as AI-based forecasting and optimisation draw on both operational and personal data.

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[20] These requirements refer to the gateways that connect the DER to the VPP,

[21] Measurement and verification refer to the rules and methods used to check whether a flexibility service was actually delivered.

How VPPs can be introduced in single-buyer systems in Southeast Asia

Most power systems in Southeast Asia are built around single-buyer or vertically integrated structures, where utilities and state-owned entities remain central to planning and operations. This does not prevent VPP adoption. VPPs can be introduced as a natural extension of existing demand-side management and distributed generation programmes, with clearer dispatch rights, performance requirements and settlement mechanisms layered on top. Typical early entry points include:

- Commercial and industrial clusters, where telemetry and controllability tend to be more developed.
- PV-rich constrained feeders where voltage and congestion issues are emerging.
- Diesel-reliant islands where fuel savings and reliability benefits of aggregated flexibility can be demonstrated quickly; and
- Areas where smart meters or feeder-level visibility are already in place.

The three delivery models described below are well suited to these contexts.

Model 1: Utility-run VPP programme with regulated cost recovery

In a utility-run model, the distribution utility typically owns the customer relationship, covering billing, programme enrolment channels and customer support. It remains accountable for how dispatch affects reliability and network constraints. The utility either develops VPP capabilities in-house or procures it as a service but retains control over programme rules and operational objectives. The division of responsibilities is comparatively straightforward: the utility defines what is needed and when, manages dispatch requests and operational coordination, and verifies delivery against agreed performance obligations.

The financial logic of this model is regulatory. Platform and programme costs (both capital and operational) can be treated as regulated expenditures, with cost recovery through tariffs where the programme can be justified as least-cost compared to alternatives such as new peaker plants or grid reinforcements. Customer incentives are typically simple: for example, an enrolment bonus for enrolled flexible capacity, combined with ongoing bill credits or event payments tied to measured delivery. This structure is particularly well suited to early pilots on specific feeders, in industrial zones or on diesel-reliant islands, where the avoided cost case (fuel savings, deferred upgrades) is easy to quantify and demonstrate.

Policy and regulatory requirements are also clear. Regulators must authorise the utility to run aggregation programmes and must define dispatch rights, data access entitlements and measurement and verification rules. Minimum telemetry and metering standards are also needed to support performance tracking.

Model 2: Competitive procurement of VPP services

In a procurement-led model, the single-buyer or utility continues to define system needs and pay for outcomes, but it procures flexibility from third-party aggregators through tenders or bilateral contracts. The customer relationship can be structured in two ways: either the aggregator manages enrolment and customer services, or the utility retains the primary customer relationship while the aggregator operates behind the scenes. In both cases, the division of responsibilities is clear: the utility specifies the service, while the aggregator assembles a portfolio, manages device-level dispatch and carries performance responsibility under the contract.

Remuneration is typically contract-based and performance-linked, often combining a capacity payment for availability with a performance or energy payment for delivered response during dispatch events. This model can introduce meaningful competition even within a single-buyer system, as multiple providers bid to deliver the same defined service. Customer incentives should remain simple and transparent regardless of the commercial arrangement upstream. Programme complexity that is invisible to the end-user is manageable, but complexity that reaches the customer tends to erode participation.

This model typically requires a more explicit regulatory framework than utility-run programmes. Regulators must define who can aggregate, how aggregators are licensed and supervised and how they interface with the distribution utility, including a clear allocation of who is responsible for respecting network limits. Procurement processes also require standardised product definitions and robust measurement and verification frameworks.

Model 3: Hybrid models combining utility leadership and third-party expertise

In a hybrid model, the utility retains the lead role, typically owning the customer relationship, setting programme rules and coordinating with the system operator (if distinct), while outsourcing parts of the delivery to third parties. This differs from Model 2, where the utility mainly procures a defined flexibility service outcome and the aggregator takes primary responsibility for assembling and operating the portfolio. In Model 3, by contrast, the utility remains programme owner and system integrator but relies on third parties for specific functions such as software provision, device integration, optimisation engines, customer acquisition support or aggregation of particular device classes. This could represent a particularly practical approach for systems in Southeast Asia where utilities have strong operational roles but varying levels of digital maturity. A common hybrid pattern is a “bring your own device” arrangement, in which multiple device manufacturers and service providers integrate into a utility-run scheme, allowing the platform to scale without locking the system into a single platform vendor.

Remuneration in hybrid models typically blends elements of the first two. The utility may recover programme costs through regulated tariffs where it remains the programme owner, while paying third-party providers service fees and performance-linked components for reliable dispatch and platform performance. Customer incentives follow the same logic as in other models, as sustained participation continues to depend on clarity and timely settlement regardless of the underlying delivery structure.

The key regulatory requirement in a hybrid model is a clear allocation of roles and liabilities, given that multiple parties interact with customer devices and data. Interoperability[22] and "VPP-ready" device requirements – such as communication protocols, control standards or inverter functions – become especially important to avoid vendor lock-in[23] and keep integration costs manageable. Distribution utilities must also be able to communicate local operating limits to VPP operators, whether through defined flexibility zones, dynamic operating envelopes, or equivalent mechanisms, so that portfolio-level optimisation does not inadvertently create local network overloads even while delivering system-level services and value.

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[22] Interoperability refers to the ability of devices and software systems to work with each other.
[23] Vendor lock-in refers to dependence on one supplier's technology.

Key recommendations for scaling VPPs in Southeast Asia

For Southeast Asian countries, VPPs are not just a new technology layer – they are a new operational and institutional way of coordinating DERs, enabling greater use of low-cost renewables and decentralised assets such as EVs and batteries, while supporting a secure, affordable and clean energy supply. While the potential is significant, successful deployment requires laying solid foundations for systemic integration.

1. Establish clear foundations before scaling

Before setting ambitious targets, regulators must establish a clear framework for VPPs. Trust is key for scaling and depends on confidence among regulators, utilities, aggregators and consumers.

- **Define clear roles:** Explicitly define the rights and responsibilities of VPP aggregators versus traditional utilities.
- **Standardise measurement & verification:** Implement robust, transparent protocols for how services are measured and settled.
- **Prioritise operational legitimacy:** Early-stage pilots should prioritise telemetry and performance reliability over pure scale to prove that VPPs can respond as predictably as conventional alternatives.

2. Treat VPPs as part of a broader flexibility toolkit

VPPs can be a powerful tool but should be seen as one solution in a broader range of options to support further infrastructure development and power system reform.

- **Work within existing arrangements:** Southeast Asia's landscape of long-term, take-or-pay fossil fuel power purchase agreements and other long-term supply contracts limits immediate flexibility. VPPs can still provide system value in this context – such as through ancillary services – and regulators should ensure that they are enabled to do so.

- **Promote overall system flexibility to strengthen VPP value:** VPPs cannot offset the deeper structural inflexibility created by rigid generation portfolios and long-term coal and gas contracts. Without broader reforms, VPPs risk being confined to smoothing residual demand while the bulk system remains locked into inflexible capacity. Enhancing system-wide flexibility – through coal retirement pathways, power purchase agreement (PPA) renegotiation, market design updates and more dynamic operational practices – is essential to unlock the full value of VPPs and ensure they can support the energy transition.

- **Complementary infrastructure:** VPPs should be co-optimised with other infrastructure upgrades, such as grid reinforcements. They can defer costly upgrades in congested urban centres but cannot replace the need for fundamental "backbone" investments in rural or underserved networks.

3. Start where feasibility is highest

To build momentum, countries in Southeast Asia should start where the opportunities for VPPs are most immediate. Urban areas with concentrated and flexible cooling demand can be attractive early entry points, especially where commercial buildings already have building management systems and controllable loads.

- **Industrial clusters and data centres:** These hubs offer concentrated loads, sophisticated onsite controls, and high telemetry – making them ideal for rapid VPP aggregation.

- **Island grids and remote areas:** In diesel-reliant archipelagic regions (prevalent in Indonesia and the Philippines), VPPs can orchestrate solar and storage to reduce expensive fuel imports.

- **PV-rich feeders:** Focus on neighbourhoods where high rooftop solar penetration could cause or is already causing voltage and congestion issues.

4. Ensure security and privacy by design

As the grid becomes more decentralised and digitised, there are growing cybersecurity and privacy risks that must be managed proactively. Digital trust is a key prerequisite for scaling.

- **Data sovereignty and privacy:** Establish clear frameworks for consumer consent, data ownership, access and protection.

- **Cybersecurity mandates:** Requirements for cybersecurity, including a clear assignment of roles and responsibilities, must be established from the outset.

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The project Clean, Affordable and Secure Energy for Southeast Asia (CASE) supports power sector transitions in Indonesia, Thailand, Viet Nam and the Philippines through evidence-based analysis and narrative change. The project supports decision-makers, industry leaders and consumers in enacting strategic reforms in the power sector in pursuit of the Paris Agreement goals and a just transition.

About Emerging Technologies Series
The 'Virtual Power Plants and Southeast Asia' is the second part of Emerging Technologies Series published by Clean, Affordable and Secure Energy for Southeast Asia (CASE) project. The series will take up topics on present energy policy discussions and unbundle some myths. The series explores key topics in current energy policy debates and aims to unpack common misconceptions around emerging technologies. Designed for policymakers, practitioners, and energy transition stakeholders, each fact sheet provides a concise summary of current discussions and key facts to support informed decision-making in the region.

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