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Unlocking Cost-Effective Grid Flexibility in Thailand: Virtual Power Plants and the Role of Regulators

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Executive Summary

Virtual power plants (VPPs) are coordinated networks of distributed energy resources (DERs) that can deliver grid services. They can include an array of different technologies such as behind-the-meter batteries, rooftop solar panels, electric vehicles (EVs), smart thermostats and water heaters. They have two primary benefits: They can provide grid services at a lower cost, and can be deployed faster, than conventional generation. Studies have found that VPPs can provide resource adequacy at 40% to 60% of the cost of alternatives like gas-fired peaking plants or peak shaving batteries. In addition, they can be deployed in a matter of months, far faster than the 3–5+ years that it takes to deploy conventional generation.

This policy brief[1] offers regulatory lessons from Australia and Hawaii, who are leaders in developing VPPs. It aims to provide members of the Regulatory Energy Transition Accelerator (RETA) — with a focus on Thailand's regulators — with information on how to integrate VPPs into their regulatory frameworks across a range of market structures.

The approach to the regulation of VPPs is influenced by the structure of the electricity market in each jurisdiction. Vertically integrated jurisdictions primarily use a utility-led business model as in Hawaii, while jurisdictions that have competitive wholesale and/or retail markets typically use a market-led business model, as see in Australia. This report finds that Thailand's vertically integrated structure lends itself to the utility-led model, and that VPP

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development could be led either by the country's distribution utilities or by its generation and transmission utility.

We offer four recommendations for Thailand's regulatory environment:

1. **Conduct a study on potential flexibility across the entire electric system,** to estimate the amount (MW) of cost-effective capacity and flexibility that can be developed.
2. **Consider the utility-led business model**. This model requires fewer major regulatory reforms to Thailand's enhanced single-buyer market structure than would be the case for a market-led model.
3. **Consider using competitive distributed capacity procurement**. This emerging procurement approach treats DERs as core utility infrastructure, relying on utility planning to strategically and geographically target specific grid infrastructure needs. This requires **integrated distribution system planning** to identify needs and costs at specific locations on the grid.
4. **Establish working groups**. These groups should advance VPP regulations and standardize procedures for seamless data-sharing between utilities, aggregators and regulators to accelerate enrollment, improve planning, and enable dispatch and financial settlement.

By implementing these recommendations, Thailand can transform DERs from passive customer assets into active system resources – VPPs – that reduce costs and accelerate the clean energy transition.

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List of Acronyms

AEMS	Australian Energy Market Commission
AU	Australia
BTM	Behind-the-Meter
BYOD	Bring-Your-Own-Device
CA	Canada
CPP	Critical Peak Price
DCP	Distributed capacity procurement
DER	Distributed Energy Resources
DR	Demand Response
EPPO	Energy Policy and Planning Office, Thailand
EGAT	Electricity Generating Authority, Thailand
EM&V	Evaluation, Measurement and Verification
EV	Electric Vehicle
IESO	Independent Electricity System Operator, Canada
IGP	Integrated Grid Planning
LSE	Load Serving Entity
MEA	Metropolitan Electricity Authority
MW	Megawatt
NMI	National Meter Identifier, Australia
PPA	Power Purchase Agreement
PEA	Provincial Electricity Authority
PUC	Public Utilities Commission, Hawaii
RETA	Regulatory Energy Transition Accelerator
SPP	Small Power Producer
VPP	Virtual Power Plant
VSPP	Very Small Power Producer
VSR	Voluntarily Scheduled Resources

Introduction

As energy systems evolve toward decentralization and decarbonization, regulators face increasing pressure to unlock the potential of distributed energy resources (DERs) in a manner that supports grid reliability, customer engagement and system affordability. One of the most promising tools for doing so is the virtual power plant (VPP), a digitally coordinated and managed network of DERs that can deliver utility-grade grid services in near real time.

This report is designed to provide policy-relevant guidance to energy regulators around the world on how to effectively enable VPPs within their regulatory frameworks. It draws on international experience, including utility-led programs in the United States and market-led models in Australia, and responds specifically to the request of the Energy Regulatory Commission of Thailand which is seeking a clear regulatory pathway to enable VPPs as part of its Smart Grid Master Plan.

For Thailand, the implementation of VPPs is especially relevant. According to the International Energy Agency's Global EV Outlook 2025, Thailand is the largest electric vehicle (EV) market in Southeast Asia, accounting for nearly 80% of new EV sales in the region in 2023 (IEA, 2025). This accelerating adoption of EVs, along with solar rooftops and smart appliances, is generating a growing fleet of flexible, customer-sited resources. Without a regulatory framework to aggregate and control these resources, their full value to the grid will remain untapped — and they could instead pose operational challenges to grid stability.

In this evolving landscape, both regulators and utilities must take on more active and strategic roles. Utilities can no longer operate as passive infrastructure providers; instead, they must become engaged market actors who enable DER integration, manage flexibility throughout the grid and ensure secure interoperability with the system. The successful deployment of VPPs will also depend on regulatory leadership. Regulators must define and clarify the roles that utilities and other market actors play within the evolving electric system. Together, regulators and utilities must work together to ensure that system planning is integrated from the distribution system up through the generation and transmission system, and that both system planning and operation capture the full, system value of distributed resources.

Rather than prescribing a single model, this document explores a pair of viable business models and regulatory approaches, including both utility-led and market-led pathways. It offers:

- A technical and policy overview of VPPs and their key enabling technologies.
- A structured analysis of regulatory options across different electricity market contexts.
- Case studies from leading jurisdictions that demonstrate practical implementation.
- And concrete recommendations for Thailand, aligned with its enhanced single buyer structure and long-term DER deployment goals.

By leveraging global best practices while tailoring them to Thailand's specific market and policy environment, this report aims to support regulators in the international community in integrating VPPs as a strategic element of a modern, resilient and decarbonized power system.

VPP Overview: What are They? Why do They Matter?

VPPs are aggregations of DERs that can balance electricity demand and supply, as well as provide utility-scale and utility-grade grid services (RETA, 2024). A variety of DERs are currently used in VPPs, including behind-the-meter (BTM) batteries, rooftop solar panels, smart thermostats, EVs, and electric water heaters. (See Figure 1.)[2]

Figure 1. Primary distributed energy resource technologies that aggregate into a virtual power plant

Source: Garth et. al. (2025). *Decoding DERMS: Options for the future of DER management*

A central feature of modern VPPs is that they can be signaled[3] remotely by grid operators (both distribution and transmission system operators) with low latency. This is what enables them to be a grid-balancing resource. Grid operators and VPP aggregators can send control signals to a fleet of DERs, and the fleet can provide near real-time grid-scale services such as energy, capacity,[4] frequency, and voltage regulation.

Why do VPPs Matter?

VPPs have two primary benefits. They are a low-cost source of grid services, and they can be deployed quickly (Hitchens, 2025). Several studies have demonstrated their cost-effectiveness. For example, the Brattle Group estimates that VPPs can provide a series of grid services at a cost of 40%–60% of the two leading alternatives: a peak shaving battery or a gas-fired peaking plant. (U.S. DOE, 2025). These services range from avoided energy and ancillary services costs to deferred investment in the transmission and distribution system. Moreover, if the societal benefits of reduced air emissions[5] are included, VPPs are capable of

[2] Although mini-grids could potentially be utilized in VPPs, there are currently no examples at a commercial stage.

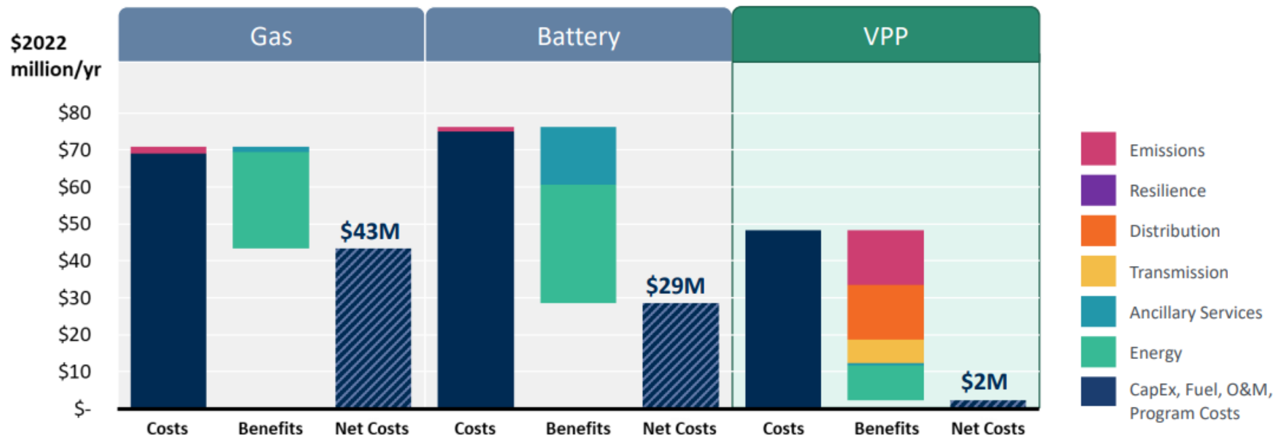
[3] The word 'signaled' implies either a price signal to the owner of the grid asset or a control signal to the grid asset itself.

[4] Capacity refers to the generation capacity or resource adequacy that can be provided by reducing peak loads, also known as peak shaving.

[5] Reduced air emissions lower investment in healthcare costs and is considered a benefit.

providing resource adequacy at a near-zero net cost (see Figure 2) (The Brattle Group, Inc., 2023).

Figure 2. Annualized net cost of 400 MW resource adequacy with virtual power plants vs other assets



Source: Hledik, R., & Peters, K. (2023). *Real Reliability: The Value of Virtual Power.*

VPPs create value in three ways. First, they reduce the cost of the generation, transmission and distribution systems by reducing energy, ancillary and transmission and distribution costs. This reduces costs for all electric customers, including non-participants. Second, VPP programs provide payments to participating customers to provide services to the grid operator. Finally, VPPs provide societal benefits in the form of decreased air emissions (which reduces healthcare costs) and increased system resilience.

VPPs can also be deployed quickly and at scale. Two examples illustrate the point. In 2023, the independent electricity system operator (IESO) in Ontario, Canada, partnered with EnergyHub to enroll 100,000 homes in its Save on Energy Peak Perks program within six months of its initial launch. This VPP aggregates smart thermostats, and reduced IESO's peak demand by an estimated 180 MW in 2024. By June 2025, enrollment in the program had reached 250,000 (Energy Hub, 2025).

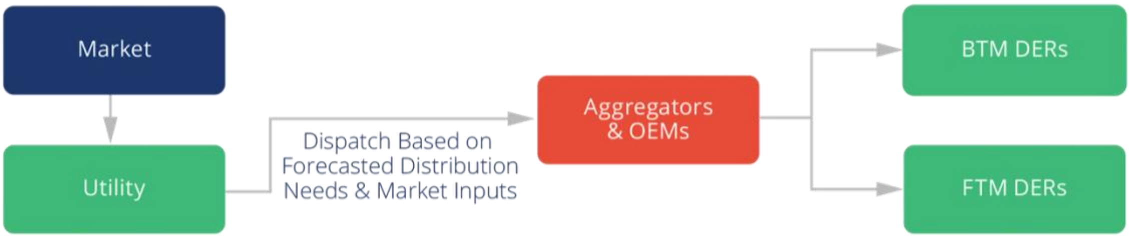
The second example is the California Public Utilities Commission's Demand Side Grid Support program. This plan enables customers with a BTM battery to participate in emergency reliability programs. In its first year of operation (2022), the program enrolled 142 MW of committed capacity (Brehm et al., 2024), and now the nameplate capacity under the program's Option 3 has reached 700 MW, "similar in size to a gas plant" (Hledik et al., 2025).

VPP Business Models

There are two primary business models for VPPs: utility-led and market-led (see Figure 3). Both involve the same actors and technologies. The difference is in the relationship between the wholesale market (or the generation and transmission operator where there is no market), the distribution utility, and the aggregator. In the utility-led model, the distribution utility forecasts its customers' loads and the grid services that its distribution system needs and then sends a dispatch signal to the aggregator, which dispatches its VPPs accordingly. In the market-led model, the aggregators offer (bid) the VPP's capabilities to the market, and it is the market that decides what the dispatch order becomes (Garth et al., 2025).

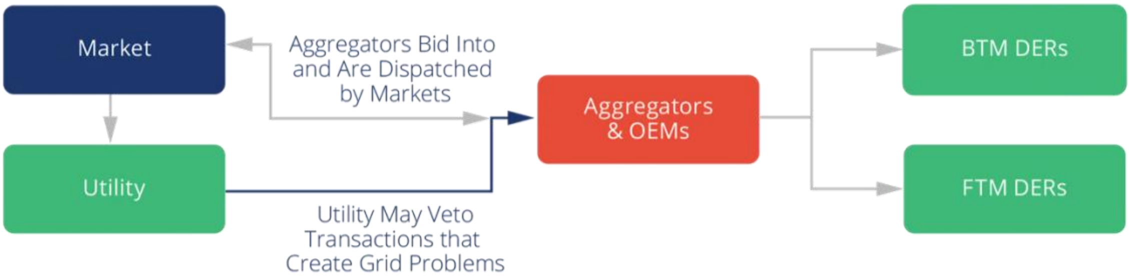
Figure 3. Two primary virtual power plant business models

Utility-led model



Source: EnergyHub (2025). Recreated by SEPA.

Market-led model



Source: EnergyHub (2025). Recreated by SEPA.

Source: Garth et. al. (2025). *Decoding DERMS: Options for the future of DER management*

- In the utility-led model, utilities typically pay aggregators a percentage of their avoided costs for the grid services that the VPP can provide. Payments are often performance-based and usually include both a capacity payment ($/kW-month) and an energy payment ($/kWh).
- In the market-led model, aggregators collect the market revenues for the grid services that their VPP provides. These revenues are sometimes shared with the retail customer or DER owner, as well as with the utility, in return for their participation and partnership.

Importantly, other business models can be followed. As shown in Figure 3, the market actors are the same in both models, and hybrid models — where market actors play one or more roles — are also possible. For example, the wholesale market operator could be both a buyer from a third-party aggregator (as in IESO's Peak Perks Program in Ontario, see Table 1), and could accept bids from independent aggregators and/or distribution utilities. Furthermore, distribution utilities often run multiple programs, and in some jurisdictions, they may elect to act as aggregators for one program while choosing to contract with a third-party aggregator to implement another.

For regulators, the key is to create a clear and consistent framework where the roles of each market actor are clearly defined and serve the public interest.

Examples of Leading VPP Programs

There are hundreds of examples of successful VPP programs in the United States, Europe and Australia. Selected examples of these programs are listed in Table 1., which is organized by the type of DER and the business model used to aggregate them.

Table 1. Examples of distributed energy resources in leading virtual power plant programs

Distributed Energy Resources	Business Model	VPP Program
Behind-the-meter batteries	Aggregator-led	PG&E/Tesla, Demand Side Grid Management VPP (USA)
	Utility-led	Rocky Mountain Power, WattSmart Battery Program (USA)
Solar + behind-the-meter batteries	Aggregator-led	Tesla, South Australia Virtual Power Plant (AU)
	Utility-led	Pacificorp, WattSmart Program (USA)
Smart thermostat	Aggregator-led	EnergyHub and IESO, Peak Perks Program (CA)
	Utility-led	Arizona Public Service, Cool Rewards Program (USA)
Electric vehicles	Aggregator-led	Octopus Energy, Intelligent Octopus Go for EVs (UK)
	Utility-led	Green Mountain Power, In-Home Level 2 EV Charger (USA)
Water heaters	Aggregator-led	Hawaiian Electric, Shifted Energy Water Heater VPP (USA)
	Utility-led	Portland General Electric, Connected Water Heaters (USA)
Multiple distributed energy resources	Aggregator-led	Tiko Energy, Home Energy Management System (HEMS) (smart thermostat, solar, electric vehicle charger) (EU)
	Utility-led	Roanoke Cooperative, Smart Energy Savings Program (water heaters, smart thermostat, energy efficiency) (USA)

Regulatory Topics for VPPs

Regulators overseeing the development of VPPs must consider an array of topics. These range from setting up the high-level conditions for greater DER adoption, to more detailed customer, technology and program-specific design choices. The following two sections describe how regulators can approach their role in fostering VPP development.

Setting Up the High-Level Conditions for VPP Adoption

Successful VPP programs share three high-level characteristics: simplicity, consistency, and profitability.

Simplicity means that both the aggregators and the retail customers can easily understand and participate in the program. Care must be taken to keep the program design, the enrollment process and the payment mechanism simple and easy to understand.

Consistency is a characteristic that is more focused on aggregators. Regulators should fund VPP programs for multiple years, and the incentives should not fluctuate from year to year. This sends a consistent signal to aggregators, giving them confidence to market their services to customers. Uncertainties about the term of the program, or the incentives or the program design may diminish trust and reduce installer/customer confidence in investing in a DER or VPP.

Profitability has three meanings depending on the market actor. For an aggregator, it means that the investment in the distributed energy assets and the VPP itself are expected to generate a positive return, competitive with other business opportunities. For participating customers, it means that the incentives are a significant proportion of the installed cost. For non-participating customers, profitability means that the VPP program should be cost-effective for the electric system as a whole and reduce costs for everyone. This can be ensured by conducting a cost-benefit analysis during program design and by conducting regular impact evaluations.

These elements also represent common pitfalls that regulators should seek to avoid. Overly complicated or inconsistent program designs discourage customer and aggregator participation, and if incentives are only marginally profitable it may slow the pace of DER and VPP adoption.

In the United States, the Department of Energy has identified five conditions that are necessary before VPP adoption can be expected to scale up (U.S. Department of Energy, 2025). These conditions are broadly applicable to all jurisdictions, and regulators have a strong role to play in each of them.

- **Expand DER adoption**: Because DER adoption is still in its early stages, the priority is to increase it. To accomplish this, regulators must assess all the costs and benefits and be willing to design tariffs and programs that pay out enough to encourage customers to adopt DERs. This requires regulators to have up-to-date estimates of avoided costs and other benefits, and a series of business cases that help them decide on the overall level of compensation necessary to increase adoption.

- **Simplify VPP enrollment**: Regulators can ensure that the financial benefits are communicated clearly and concisely, that customers can opt out of events, and that they are enrolled either at the point of sale or automatically with an opt-out provision.

- **Increase VPP standardization**: This condition spans multiple aspects of VPP operations, including data privacy and sharing, aggregator interfaces with customer DERs, aggregator-utility interfaces, connection procedures and cybersecurity. Regulators can participate in, encourage and lead many of these standardization efforts.

- **Integrate VPPs into utility planning and incentives**: VPPs can only substitute for conventional resources if they are fully included in the utility's planning and regulators can require in-depth analysis of VPPs in the planning process. Similarly, utilities and their regulators need to understand how much value VPPs can generate in terms of avoided costs before appropriate incentives can be designed; regulators will require a thorough cost-benefit analysis before doing so.

- **Integrate VPPs into wholesale markets**: This means creating the regulatory, technical and commercial conditions so that VPPs can directly participate in energy, capacity and ancillary services markets. In the United States, the implementation of the Federal Energy Regulatory Commission's Order 2222 has resulted in greater DER integration into wholesale markets, and a recent report has identified what state regulators can do to advance DERs under the order (Forrester et al., 2025). In jurisdictions that have no wholesale market, wholesale integration is still needed so that VPPs can influence generation and transmission planning and dispatch decisions.

- **Other regulatory measures**: Other regulatory measures that can set up favorable conditions for VPP development include implementing time-of-use tariffs and smart-meter installations (Oliveira et al., 2025).

Detailed topics for regulators to consider

Utility-led VPP programs are not significantly different from demand response or energy efficiency programs, and they can be regulated accordingly. Table 2 lists a series of topics that regulators commonly consider when investigating VPP program proposals from their utilities. These are significantly different from the topics that regulators would focus on in the context of competitive wholesale and retail markets (see Table 3), and are focused on utility planning, program design, and cost-effectiveness.

Table 2. Regulatory topics and questions for VPP development under utility-led model

Topic	Key Questions
Grid services and utility planning	▪ What grid services are needed? ▪ Which utility planning processes should analyze VPPs?
Technical requirements connection and cybersecurity	▪ What are the technical requirements for DERs to provide the various grid services? ▪ What are the technical requirements for cybersecurity? ▪ What are the terms and conditions for connection?
Cost-benefit analysis	▪ What costs and benefits are to be considered? ▪ What cost-effectiveness test(s) should be used?
Business model	▪ Who is leading the development of the VPP? ▪ Is a utility-led or a market-led (system operator) model preferred?
Procurement approach	▪ Is a volume-based goal (megawatt, megawatt hour) or a price-based offer ($/megawatt hour, $/kilowatt) preferred? ▪ Is a volume-based goal with a price cap or a price-based offer with a volume cap appropriate?
Program design and compensation	▪ What kind of programs will be offered? For example, point-of-sale, tariff-based, upstream. ▪ What level of compensation is appropriate?
Rate design	▪ What kind of electric rates can increase DER adoption? Consider, for example, time-of-use, critical peak pricing, peak-time rebate, variable peak pricing or real-time rates.
Cost recovery	▪ How will the program be funded and its costs recovered? (e.g. through rate cases, wholesale markets, or a system benefit charge?)
Customer and aggregator enrollment	▪ What customer classes are eligible and how are they enrolled? ▪ What are the terms and conditions for aggregators?
Data access and privacy	▪ How is data shared between the utility and the aggregators? ▪ What privacy protections are required?
Evaluation, measurement and verification	▪ How much funding is dedicated to evaluation, measurement and verification (EM&V)? ▪ Is an independent EM&V contractor required?

Grid Services and Utility Planning

Which grid services are needed and can a VPP provide them as a substitute for conventional resources? This is foundational information that regulators and their utilities must develop. Avoided-cost studies should be conducted to estimate the value of the various grid services. This information can then be used in technology characterizations,[6] in potential studies and in integrated resource plans. The objective is to compare, for each grid service, the costs of a VPP with the cost of the conventional resource providing the same service.

Technical Requirements and Connection

Different DERs can provide different types of grid services. Because VPPs are still an emerging technology, connection standards and other technical requirements – including baseline cybersecurity requirements (e.g., secure device identity and authentication and encrypted communications) often need to be created. Some jurisdictions are opting to develop VPP programs that are focused on aggregating a single DER technology — primarily thermostats and batteries — which narrows the scope of the technical requirements somewhat. However, other jurisdictions are taking a broader approach and are assessing VPP potential for a wider range of technologies, which would come with a correspondingly wider set of technical, interoperability and cybersecurity requirements.

Cost-Benefit Analysis

In the United States, a comprehensive approach to cost-benefit analyses for DERs has been published in the National Standards Practice Manual (National Energy Screening Project, n.d.). Regulators and utilities should consult the manual and decide on which benefits to count and which cost-effectiveness tests to consider.

Business Model

Once the grid services, technologies, costs and benefits have been analyzed, the next question that regulators must address is, “Which entity should lead the development of VPPs?” In the United States, vertically integrated jurisdictions without robust wholesale markets typically use a utility-led model where the utility contracts with an aggregator to develop the VPP. Where wholesale markets and retail competition are well established, as in the European Union and the state of Texas in the United States, a market-led model is more common.

Procurement Approach

Regulators often set volume-based goals for their energy efficiency programs, and the same approach can be applied to utility-led VPP programs. Alternatively, a market-based approach requires the regulator to set up pricing mechanisms (auctions, competitive procurements or feed-in tariffs) to send a price signal. Regulators should also consider hybrids and caps, where volume-based procurement is subject to a price cap or where price-based procurement is subject to a volume cap.

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[6] A technology characterization is an analysis (an estimate) of the energy and cost savings that can result from switching from a baseline technology to a more efficient technology. (e.g., from an internal combustion engine vehicle to an electric vehicle.)

Program Design and Compensation

For utility-led programs, regulators should require utilities to submit a comprehensive program plan and budget. This is similar to the way in which energy-efficiency and demand-response programs have historically been regulated. For market-led programs, the program design is a pricing mechanism and market development policy. In all these cases, regulators should closely examine the terms, conditions, and level of compensation that are likely to be required to increase DER and VPP adoption.

Rate Design

For utility-led programs, regulators should consider what kinds of time-based rate designs can increase the adoption of DERs. The full spectrum of time-based rates may include time-of-use prices, critical peak prices, peak time rebates, variable peak prices and real-time prices.

Cost Recovery

Utility-led programs are typically funded through a conventional rate case, a rider mechanism, or a system benefit charge. Market-led programs are typically funded by wholesale market revenues. In both cases, regulators should send clear and consistent signals to the utility and aggregators about the source and terms of program funding.

Customer and Aggregator Enrollment

For utility-led programs, customer enrollment should be detailed in the program design. For market-led programs, customer enrollment is primarily concerned with consumer protections, which should be specified in the aggregator enrollment process.

Data Access and Privacy

For utility-led programs, data access and privacy can be a part of the normal standards of service that the regulator requires. However, if aggregators are involved, then data access and privacy protections become a larger issue and must be specified by the regulator.

Evaluation, Measurement and Verification

Regulators should determine the level of funding required for evaluation, measurement and verification, and decide if an independent evaluator is needed.

Regulatory Case Studies

The following pair of case studies illustrate how standard regulatory approaches can be applied to each of the two business models. Australia illustrates the market-led model in the context of a competitive wholesale and retail market, while Hawaii illustrates the utility-led model in the context of a vertically-integrated market.

The Market-Led Model in Australia

In December 2024, the Australian Energy Market Commission (AEMC) finalized a rule change that enabled aggregated consumer energy resources — such as household batteries, EVs and industrial demand response — to actively participate in the national electricity market through a new "dispatch mode" (AEMC, 2024a). This change allowed smaller, distributed assets to be scheduled like large generators: submitting bids, receiving dispatch instructions, setting prices, and providing ancillary services. The intent was to create a level playing field for all energy resources, improve competition, and enhance grid flexibility. (AEMC, 2024)

The Dispatch Mode Rule

The key features of dispatch mode and its benefits are that it:

- Is voluntary. No consumer or market participant is required to participate. Instead, it allows participants to nominate and aggregate small resources to participate in dispatch (AEMC, 2025).[7]

- Leverages existing rules and processes to minimize costs and increase certainty. It builds on the existing bidirectional unit framework, allowing bids for generation and load, and the underlying classification for resources participating as voluntarily scheduled resources (VSR) does not change. It also follows existing conventions regarding decision-making, which creates certainty for market participants.

- Provides greater flexibility for participants than existing scheduling requirements. It recognizes that continuous operation may be difficult and creates flexibility to allow participants to drop in and out of dispatch. It sets out principles for AEMO (Australian Energy Market Operator) to follow when setting technical and operational parameters to ensure requirements on VSRs are only to the extent reasonably necessary to manage the power system.

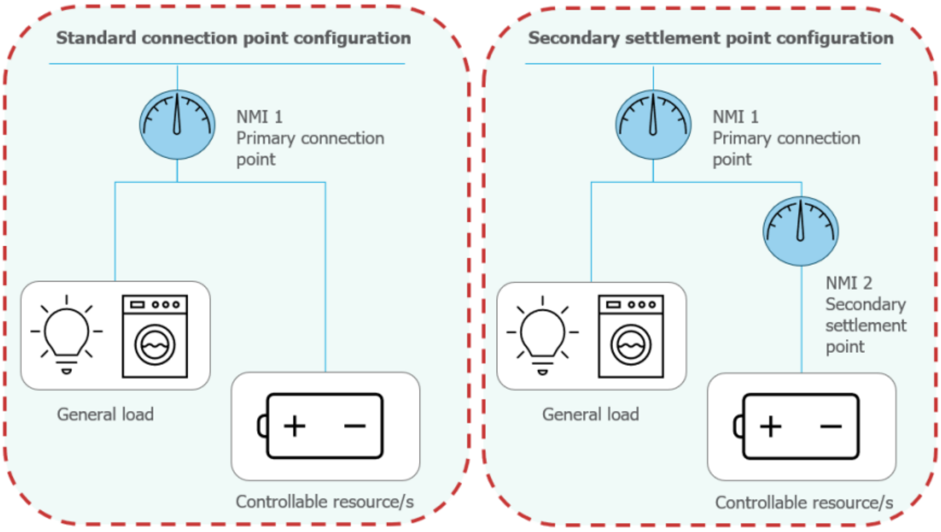
By enabling more active market participation from aggregated resources, the reform is expected to lower electricity and ancillary service costs, reduce emissions, and ultimately benefit consumers through lower prices. The Commission's modelling and analysis demonstrate that dispatch mode is likely to result in net benefits to consumers of AU$800m (AEMC, 2024b).

Customer Compensation and Settlement

Under the Dispatch Mode Rule, secondary settlement points will sit behind a retail connection point and allow customers to separately meter and settle their flexible and inflexible resources, as shown in Figure 4 (AEMC, 2024a, p.48). This enables retailers to aggregate flexible resources into "voluntary scheduled resources" and to keep them separate from their inflexible retail loads.

[7] These resources include solar, batteries, EVs, flexible hot water systems, pool pumps and industrial loads with components of controllable demand. For more information, see AEMC, 2025, page 67.

Figure 4. Comparison of standard versus secondary settlement point configuration



Note: NMI=National Meter Identifier

AEMC. (2024a). *Rule Determination: National Electricity Amendment (Integrating Price-Responsive Resources into the NEM)*

The LSE's inflexible retail loads continue to be settled using existing processes, while the LSE's VSRs would be settled at the secondary connection point. Specifically, the retailer would *pay* the regional energy price when its VSR is a net load and would be *credited* with the regional energy price when its VSR results in net generation. The LSE's VSRs would also be paid for ancillary services.

Finally, customers are compensated by the LSE. The LSE can offer a variety of pricing structures, including fixed prices, variable prices, discounted prices, sign-up bonuses and performance-based rebates. For example, Origin Energy provides its retail customers with its 'Origin Loop' program, which offers customers a AU$200 sign-up bonus and AU$1/kWh for exporting energy from their battery during grid events.

The Regulatory Process and Key Topics

The AEMC followed its standard multi-stage rule-making procedure under the National Electricity Law. With the aim of moving toward the National Electricity Objective, it used the principles of transparency, stakeholder engagement,[8] and cost-benefit analysis. The process began when the Australian Energy Market Operator submitted a rule change request seeking to enable the voluntary scheduling of aggregated, price-responsive resources in the national electricity market. The AEMC initiated the rule change process in February 2023 by publishing a consultation paper that invited stakeholder feedback on the proposal's scope, potential impacts, and regulatory implications.

[8] Following the consultation period, the AEMC released a draft determination in August 2023 outlining its proposed rule, rationale and expected benefits. This was followed by an extended period of public consultation, including industry forums, technical working groups, and written submissions from retailers, aggregators, consumer advocates, and government agencies. Based on this feedback, the AEMC refined key design elements such as compliance obligations, incentive mechanisms, and implementation timelines, and published the Final Determination and rule in December 2024.

The AEMC considered a series of regulatory topics during its “dispatch mode” rulemaking, as summarized in Table 3 (AEMC, 2024a). These topics are different from the topics that regulators consider regarding utility-led programs and are focused on fostering competitive wholesale market operations and efficient pricing.

Table 3. Regulatory topics and questions for virtual power plant launch under market-led model

Topic	Key Questions
Market scheduling and price formation	▪ How can price-responsive resources be integrated into central dispatch to improve price formation and market efficiency?
System and cybersecurity	▪ How can the Australian Energy Market Operator gain better visibility and control over distributed resources that materially impact grid reliability? ▪ What are the technical requirements for cybersecurity?
Technology and competitive neutrality	▪ How can the rules ensure a level playing field between scheduled and unscheduled participants?
Voluntary participation and participant flexibility	▪ Can a new dispatch framework be introduced that is optional and scalable for different types of market participants?
Compliance and enforcement	▪ What obligations and penalties should apply to voluntarily scheduled participants to ensure fairness and system integrity?
Demand forecast accuracy	▪ How can demand forecasts be improved by accounting for previously invisible, price-responsive behavior?
Access to ancillary services markets	▪ Should aggregated DERs be eligible to provide frequency and system services?
Settlement and cost allocation impacts	▪ What procedures can ensure that aggregated DERs are settled accurately and fairly?
Consumer protections and aggregator responsibilities	▪ How should consumers participating via aggregators be protected, and what standards should aggregators follow?
Implementation complexity and transitional support	▪ How can the rule avoid being overly complex? ▪ How can the rule be implemented smoothly and affordably across the market?

The Utility-Led Model in Hawaii

Hawaii has over a decade of regulatory history investigating DER-related issues, which has resulted in two tariffs that promote DERs and the formation of VPPs.

The Smart DER Tariff

The Smart DER Tariff is a new rate structure that governs all future DER programs as of April 1, 2024 (Hawaii Public Utilities Commission, 2019a). It consists of two participation options (riders) that define how customers may operate their solar and battery systems.

- The **Non-Export Rider** allows customers to self-consume all the energy their systems produce without sending any excess back to the grid. This is intended to simplify connection and reduce grid integration challenges.

- The **Export Rider,** in contrast, enables customers to export energy to the grid and be compensated at time-varying export rates designed to reflect the value of energy to the system at different times of day (see Table 4) (Hawaii Public Utilities Commission, 2019a).

Under the Export Rider, customers receive higher compensation during the evening peak (5 – 9 p.m.) and lower compensation during times of solar overproduction (9 a.m. – 5 p.m.). These rates are intended to encourage customers to install storage and shift energy export when it is most needed. By aligning DER customer consumption behavior with operational grid needs, the Export Rider supports reliability and maximizes the integration of clean energy.

Table 4. Smart DER tariff export rider rates (US$/kWh)

Island	Overnight (9 p.m. – 9 a.m.)	Daytime (9 a.m. – 5 p.m.)	Evening peak (5 p.m. – 9 p.m.)
Oahu	$0.189	$0.135	$0.329
Hawaii	$0.148	$0.106	$0.231
Maui	$0.131	$0.066	$0.182
Lanai	$0.259	$0.267	$0.408
Molokai	$0.174	$0.179	$0.272

Note that the average residential rate in Hawaii is about US$0.43/kWh, and that these rates are lower. This is because they reflect the avoided cost of electricity delivered to the grid, not the full retail price that includes transmission, distribution and customer service costs. The tariff is designed to pay DER owners based on the actual system value of their exports while ensuring all customers continue to contribute fairly to grid maintenance. This structure replaces the net metering program and promotes more economically and physically efficient use of distributed resources.

The Bring-Your-Own-Device Tariff

The Bring-Your-Own-Device (BYOD) program allows customers with eligible battery storage systems to provide grid services in exchange for financial incentives (Hawaii Public Utilities Commission, 2019a). It is designed to make energy storage more accessible, especially for underserved customers, and to increase grid reliability by aggregating distributed batteries. **Customers must be enrolled in the Smart DER Tariff or a time-of-use rate** and can choose between three levels of participation.

- **Level 1 Rider (Flexible User Dispatch):** Requires customers to schedule their battery energy storage system device to discharge a promised amount of power for two consecutive hours each day.
- **Level 2 Rider (Utility Dispatch):** Requires customers to respond to utility-determined events by providing a promised amount of power for one hour.
- **Level 3 Rider (System Grid Services):** Requires customers to respond to utility-determined events by charging (load build) or discharging (load reduction) their battery for up to two consecutive hours.

In exchange for participation, customers receive upfront and ongoing compensation in the form of three different incentives, as shown in Table 5: an upfront incentive, a monthly incentive, and credits for controlled energy exports during BYOD events.

Table 5. Bring-your-own-device tariff overview (in US$)

Term	Level 1: Flexible User Dispatch	Level 2: Utility Dispatch	Level 3: System Grid Services
Description	Daily scheduled capacity load reduction for **two hours**, typically during evening peak	Capacity load reduction for **one hour** in response to utility events	Capacity load reduction or load build for **up to two hours** in response to utility events
Upfront Incentive	$100 per kW committed capacity, up to $500 Low- and moderate-income adder: additional $100 per kW, up to $500 (may also be applied to monthly incentives)		
Monthly Capacity Performance Incentive	$5/kW	$5/kW	$10/kW
Credit for Controlled Energy Exports	Smart DER Tariff Export Rider's evening peak export rate		

The Regulatory Process and Key Topics

In 2014, the Hawaii Public Utilities Commission (PUC) opened a proceeding to investigate the "technical, economic, and policy issues associated with distributed energy resources…[and] the commission made significant progress addressing the issues associated with promoting and integrating customer-sited DER onto the State's electric grids" (Hawaii Public Utilities Commission, 2019b). From 2014 to 2019, DERs and demand response (DR) were advanced in separate proceedings. However, in 2019, the PUC chose to combine the two proceedings into one based on the following rationale:

> "The success of integrating additional distributed energy resources onto the electric system is highly dependent on coordinating the design and implementation of new grid service programs. As such, combining the DR and DER efforts into a single investigative proceeding should ensure conformity in the implementation of communication, outreach, and customer feedback efforts for distributed generation and grid service programs" (Hawaii Public Utilities Commission, 2019b).

As a result, the Hawaii PUC initiated Docket No. 2019-0323 in September 2019 (Order No. 36538) to modernize policies for DERs. This launched a multi-year, three-track investigation focused on (1) advanced rate design, (2) DER programs, and (3) technical issues. Importantly, the Commission explicitly noted that DER-related issues were also being explored in other ongoing proceedings. These included dockets concerning Integrated Grid Planning (Docket No. 2018-0165), Grid Modernization Strategy (Docket No. 2018-0141), and Performance-based Regulation (Docket No. 2018-0088). **As a result, almost no aspect of utility regulation remained untouched or unaffected by DERs.**

The Commission initially focused its DER investigation on five questions.

- What types of new DER programs should be examined and developed?
- What advanced rate designs will be offered to customers?
- How should existing DER programs and tariffs be addressed (maintained, phased out, grandfathered)?
- What improvements can be made to the connection process and technical standards to better facilitate the integration of DER into the companies' systems?
- Should legacy equipment be updated or retrofitted to current equipment settings?

These questions led the Commission to focus on a series of key topics.

- **Grid Services and utility planning**: The Commission evaluated how customer-owned DER devices (batteries and controllable solar inverters) could reliably provide grid services such as load shifting, capacity and frequency regulation through programs like the BYOD tariff. The Commission addressed the integration of DERs into utility planning and operations.
- **Program design and compensation**: The Commission examined how to structure export-based DER programs that are sustainable, fair, and responsive to system value. This included determining appropriate compensation for exported energy and ensuring cost-effectiveness for non-participating customers.

- **Rate design**: Through the Advanced Rate Design track, the Commission explored how time-of-use rates, non-export options, and customer incentives could better align behavior with grid needs, while supporting equitable participation across income groups.

- **Technical Requirements and Connection**: The Commission addressed technical issues such as advanced metering infrastructure, telemetry requirements, and inverter standards.

- **Cost Recovery**: The Commission also considered how utilities should recover costs for DER programs, including customer incentives and grid service payments, and how to allocate those costs fairly across ratepayers.

- **Transition Plan** A major focus was managing the transition from legacy DER programs (e.g., national electricity market, customer grid supply) to new tariffs, with policies to ensure stability in the clean energy market and avoid disruptions for installers and customers.

Case Study Observations

Three key insights can be drawn from these two case studies. First, Australia and Hawaii have fundamentally different electricity market structures (see Table 6). Australia's market is retail-competitive and features an unbundled, competitive wholesale market, whereas Hawaii's market is vertically integrated. As a result, Australia adopted a market-led business model, while Hawaii used a utility-led approach. In these cases, it seems that the electricity market structure largely determines the VPP business model.

Second, the choice of business model influences the topics and questions that regulators need to address, but some issues remain common. Australia's concerns included price formation, fairness, and promoting a smooth transition to a more functional and competitive wholesale market. Hawaii focused on ensuring that DERs are well integrated into the distribution utility's planning, operations, retail rate structures, and cost recovery processes. In both cases, the range of topics was broad and effectively covered the full spectrum of utility regulatory issues. Consequently, regulators should be prepared to address the full spectrum of utility issues, regardless of which market structure and business model apply in their jurisdiction.

Third, despite these differences, both Australia and Hawaii utilized standard regulatory processes to enhance the role that DERs play in their respective jurisdictions. Furthermore, their processes were quite similar. Australia initiated its regulatory process with a consultation paper and subsequently employed its multi-stage stakeholder process to refine and finalize its "dispatch mode" rule. Hawaii initiated its process by consolidating a series of interrelated DER proceedings into one; it then employed a three-part approach to engage its stakeholders through a series of focused workshops and hearings.

Table 6. Comparison of Australia and Hawaii case studies

Element of the Process	Market-led model (Australia)	Utility-led model (Hawaii)
Market Structure	Competitive wholesale and retail market. Unbundled, competitive wholesale market.	Vertically integrated jurisdiction.
Leading Entity / Buyer	The market (wholesale market operator, AEMO).	The utility/distribution company (Hawaiian Electric).
Central Mechanism	Aggregators offer (bid) the VPP's capabilities directly to the market. The AEMC finalized a rule for "dispatch mode" allowing aggregated resources to actively participate in the national electricity market.	The utility forecasts customer loads and distribution system grid service needs. The utility uses specific tariffs (such as the Smart DER Tariff or the BYOD Tariff) to contract and incentivize participation.
Dispatch Process	The market determines the dispatch order. Distributed assets are scheduled like large generators, submitting bids and receiving dispatch instructions.	The utility sends a dispatch signal to the aggregator, who then dispatches their VPPs accordingly. Customers respond to utility-determined events (e.g., in BYOD Levels 2 and 3).
Revenue Source (Aggregator)	The aggregator collects market revenues for the grid services provided by their VPP.	The utility pays aggregators a percentage of their avoided costs for the grid services the VPP provides.
Customer Compensation	Compensation is offered by the retailer (aggregator). This can include fixed/variable prices, discounts, sign-up bonuses, and performance-based rebates (e.g., AU$1/kWh for exporting energy during grid events).	Payments are typically performance-based, often including both a capacity payment (kW/month) and an energy payment (kWh). Payments reflect the avoided cost of electricity delivered to the grid, not the full retail price.
Key Regulatory Focus	Integration of VPPs into the wholesale market. Focus on price formation, competitive neutrality, and flexibility.	Integration of VPPs into utility planning, operations, retail rate structures, and cost recovery processes. The focus is on avoided cost studies.

VPP Implementation for Thailand’s Single Buyer Model

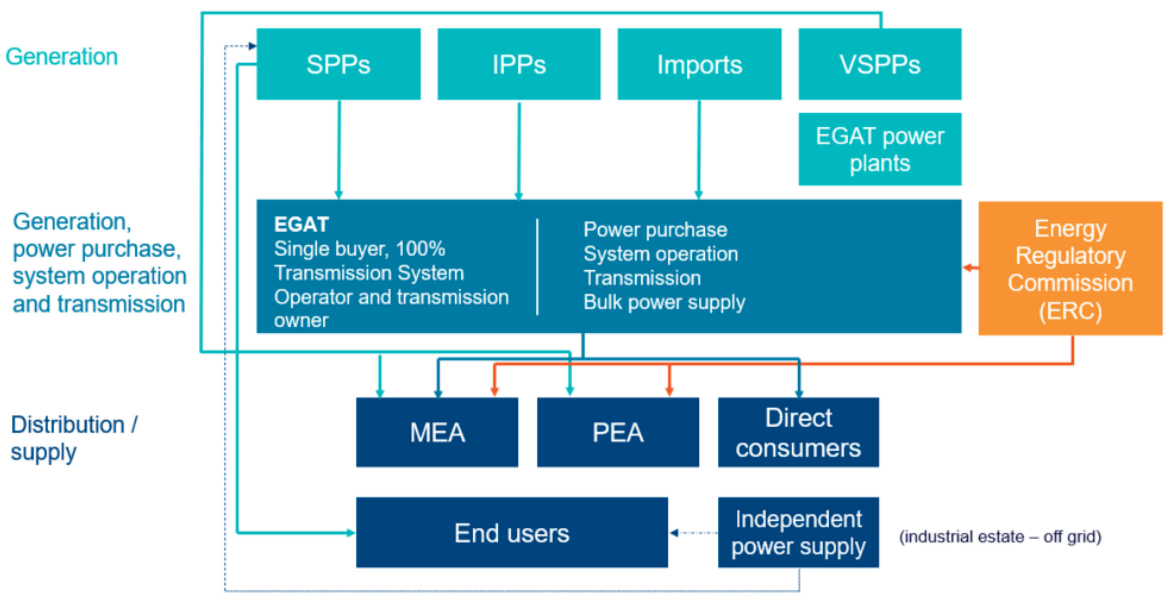
The government of Thailand has decided that, after 2031, VPPs and the prosumer-aggregator model should become the standard, providing services through DERs (Ministry of Energy of Thailand, 2022). The country has developed DR programs and is working on some VPP pilots to encourage DER contributions to the electricity sector, supporting the national goals of reaching carbon neutrality by 2050 and net-zero emissions by 2065 (Office of Natural Resources and Environmental Policy and Planning, 2022). This section outlines the structure of Thailand’s electricity sector, the country’s long-term public policies, and the Thai experience in DR programs, providing a contextual framework for the recommendations that Thailand’s regulators could consider to achieve their VPP implementation goal.

Thailand’s Electricity Sector Structure

The electricity sector in Thailand is state-owned and vertically integrated (see Figure 5). The Electricity Generating Authority of Thailand (EGAT) is at once the generation and transmission system operator, the sole owner of the transmission network and the owner of approximately one-third of the installed generation capacity. Two distribution network operators provide electricity to consumers: the Metropolitan Energy Authority (MEA) for Bangkok, Nonthaburi and Samut Prakan provinces, and the Provincial Energy Authority (PEA) for the remainder of the country.

In Thailand’s government structure, the two distribution-and-retail utilities MEA and PEA are overseen by the Ministry of Interior, while EGAT is a state enterprise supervised by the Ministry of Energy.

Figure 5. Thailand’s enhanced single-buyer electricity market structure



Source: Guyon, J. et al. (2018). *Thailand’s Clean Electricity Transition*

Figure 5 illustrates Thailand's Enhanced Single-Buyer structure. Almost all electricity is sold to or generated by EGAT. However, small power producers, producers with installed capacity above 10 MW and up to 90 MW, and very small power producers, producers with installed capacity limited to 10 MW, may sell their generation to either MEA/PEA or to eligible large customers. These producers primarily generate renewable energy, are connected to the distribution grid, and represent about 24% of all contracted generation capacity as shown in Table 7.

Table 7. Contracted generation capacity in Thailand as of July 2025

Type of producer	MW	%
Electricity Generating Authority of Thailand	16,235	28.86%
Independent power producer (> 90 MW)	20,299	36.08%
Small power producer (10-90 MW)	9,196	16.35%
Very small power producer (1-10 MW)	4,293	7.63%
Import	6,235	11.08%
Total	56,258	

Source: Energy Policy and Planning Office Thailand. (2025.) *Energy Statistics*

Experience with Demand Response

Thailand has over a decade of experience with DR programs. Since 2013, crises in natural gas supply have forced the country to implement temporary, voluntary measures to reduce electricity consumption. In 2014, the first DR pilot programs offered incentives to industrial and residential customers to reduce their electricity consumption. Only 70 MW of the expected 200 MW demand reduction was realized, representing 35% of the target (Sonsaard, 2023).

Thailand's second demand response pilot began later in 2014 to curb electricity use amid gas-supply shortages for power generation. This pilot introduced an incentive scheme while keeping the same target groups of industrial and residential customers. The scope narrowed from nationwide coverage to a single region in the South. Ultimately, the program delivered a 48 MW reduction against an expected target load of 250 MW.

In 2015, Thailand piloted an incentive-based DR program that combined real–time–pricing–type signals with emergency DR, paying rebates based on verified load reductions. In April, a nationwide program reduced peak demand to 500 MW from an expected 561 MW (a 61 MW reduction), while in July it reduced peak demand to 25 MW against an expected 100 MW, in the Southern region only.

The DR framework was supported by long-standing time-of-use tariffs — fixed in advance with daily/seasonal variation and integrated into monthly operational planning — and an interruptible service offered to large commercial and industrial customers with demand above 5,000 kW and at least 1,000 kW of interruptible capacity.

More recently (2022-2023), the Energy Policy and Planning Office (EPPO) and the public utilities (EGAT, MEA, PEA) collaborated on implementing the Firm Response Program, also known as the Capacity Bidding Program, a pilot project to reduce system-peak demand (MEA, 2023). Eligible consumers were medium to large-sized businesses able to curtail at least 50 kW. The distributors acted as aggregators and offered participants a predetermined and fixed availability payment per kilowatt each month, as well as an energy payment for every verified kilowatt-hour reduced. These payments were based on the avoided cost of operating peak power plants. Using advanced metering infrastructure data, participant performance was compared to a baseline load that was established at the beginning of the participation period.

The performance of Thailand's DR pilots has already been evaluated, and a 2023 study co-authored by the School of Renewable Energy and Smart Grid Technology and the Provincial Electricity Authority in Bangkok offers a clear roadmap for moving forward (Sonsaard et al, 2023). Their findings stress that a successful DR framework hinges on long-term policy direction that is integrated into national power plans, transparency with stakeholders and a regulatory environment that enables secure data-sharing while reforming restrictive Enhanced Single Buyer model rules (Figure 6). Standardized procedures, strong customer incentives from the start, and coordinated collaboration among utilities, policy–makers, and third parties are equally vital. Taken together, these measures can build trust, ensure fair benefit-sharing, and unlock the full economic and operational potential of DR programs in Thailand.

Figure 6. Success factors for a demand response program

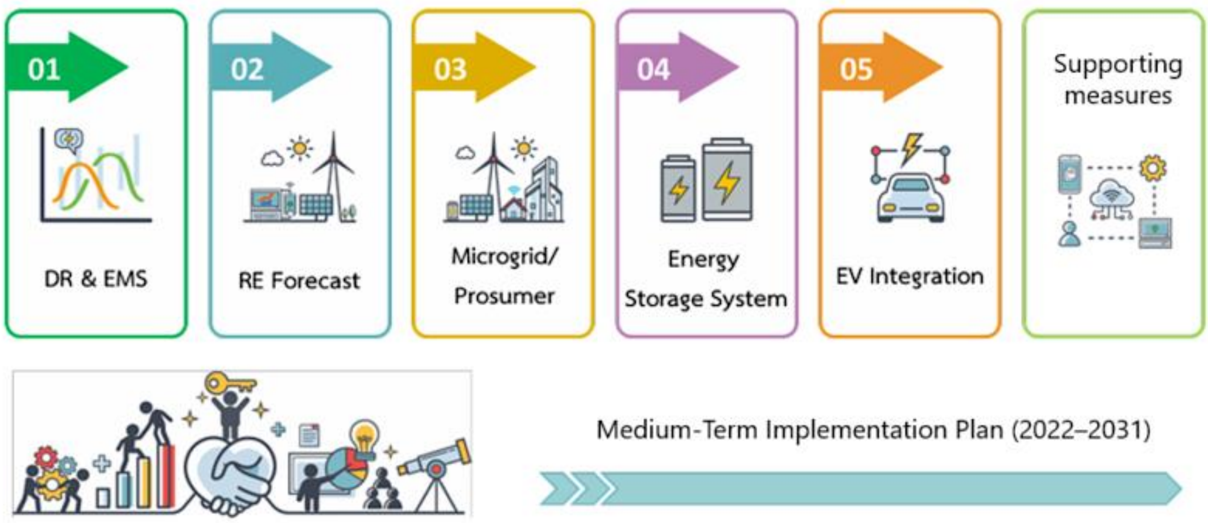
Note: ESB = enhanced single buyer, DR = demand response.

These recommendations are applicable regardless of the business model that is ultimately chosen.

National Smart Grid Master Plan and the Smart Grid Action Plan

The public policy to modernize Thailand's electricity infrastructure is the National Smart Grid Master Plan 2015–2036. The plan is in its medium-term phase (2022–2031), organized into five pillars as shown in Figure 7: Demand Response and Energy Management Systems, Renewable Energy Forecast, Microgrids and Prosumers, Energy Storage Systems, and Electric Vehicles Integration (EPPO, 2022).

Figure 7. Pillars under the medium-term Smart Grids Implementation Action Plan



Note: EMS = energy management systems, DR = demand response.

Source: (EPPO, 2022) *Thailand Smart Grid Action Plan – Medium Term, 2022–2031*

Although the medium-term action plan does not address directly the development of VPPs as a single pillar, it outlines a strategic and technical roadmap for developing VPPs as a key element in the energy transition. The overall goal of the medium-term implementation plan is divided into 2 phases: Phase 1 – 5 years (2022–2026) and Phase 6 – 10 years (2027–2031). Then, each pillar includes key milestones that drive Thailand's smart grid implementation under the medium-term action plan, which is further divided into four phases. Consequently, the development of VPPs, which support Pillars 1, 3 and 4, is structured across various time horizons, reflecting a progressive rollout strategy:

- The first phase (2022–2023) focused on foundational readiness for VPP infrastructure. Under Pillar 1 (DR & EMS), the plan highlighted the successful launch of semi-auto demand response for large commercial and industrial customers. This period resulted in the creation of load aggregators operated by state electricity utility agencies. MEA initiated a pilot project that utilizes the VPP format to expand hybrid energy management systems in buildings, supporting semi-automatic or automatic DR. This strategy effectively established the necessary groundwork by piloting aggregation mechanisms and technology integration for subsequent VPP deployment.

- The medium term (2024–2026) is the pivotal period for commercializing the VPP architecture and integrating private players. The plan explicitly pilots the market and business model for aggregators and VPPs under the Microgrid & Prosumer Pillar. Concurrently, regulatory efforts begin to establish rules for microgrid connection to utilize energy services via the aggregator business model and VPPs. In the Demand Response Pillar, the ecosystem matures with the entry of private, level 2 load aggregators, enabling the expansion of DR programs to smaller customers. Furthermore, policy studies examine VPPs in conjunction with energy storage systems, and new regulations are drafted to permit these new VPP and peer-to-peer trading businesses.

- The long term (2027–2031) is the commercialization phase for VPP infrastructure. The Microgrid Pillar formally pilots the market and business model for aggregators and VPPs, aiming for VPP frameworks to deliver essential energy services. Development projects, such as those by PEA, implement VPP systems and grid analytics for broad microgrid deployments. Concurrently, the DR Pillar achieves full-scale auto DR deployment capable of providing diverse grid services (e.g., balancing/contingency management). Crucially, the Energy Storage Systems Pillar expands the utilization of behind-the-meter storage, beginning the process of connecting these BTM assets to provide services to the grid. Finally, regulatory bodies draft rules specifically authorizing these new VPP and peer-to-peer trading business models.

In this strategy, distributors are tasked with piloting and expanding VPP-related infrastructure (e.g., advanced metering infrastructure, control systems). However, the plan emphasizes regulatory support for aggregator business models to enable DER management. By the end of the long-term phase, prosumer-aggregator models and VPPs are expected to be operating commercially across both urban and industrial sectors.

Our recommendations align with the demand response targets to address the challenges currently facing VPPs in Thailand (Table 8).

Table 8. Demand response targets in the medium-term Smart Grid Action Plan in Thailand

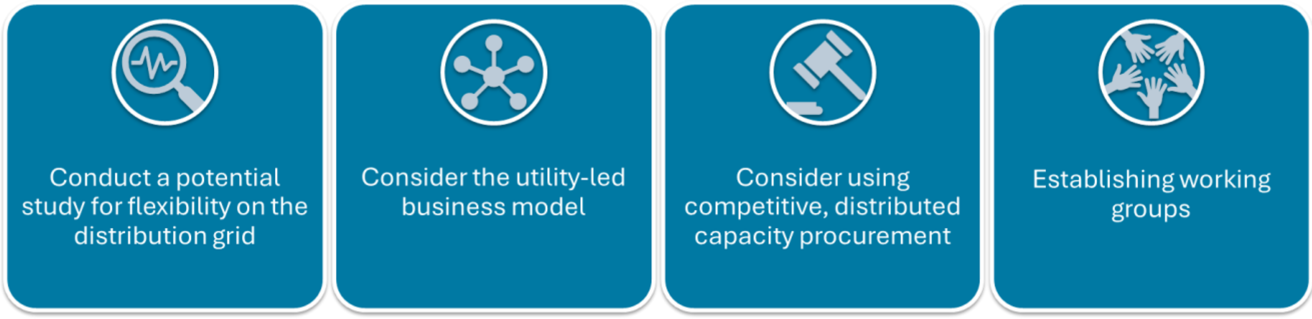
Status	1–2 years	3–5 years	6–10 years	10+ years
▪ No permanent DR program exists ▪ 2023 pilot by EGAT with PEA/MEA as aggregators ▪ Poor data sharing ▪ Feed-in tariffs for VPPs ▪ Wide time-of-use tariff design	▪ Semi-auto DR for large commercial and industrial users ▪ DR purchases from the electricity market create utility-led aggregators	▪ Semi-auto DR (350 MW) expands to medium/small commercial and industrial + residential ▪ Auto DR starts for large commercial and industrial users ▪ Aggregators: utilities (Level 1) and private (Level 2)	▪ Expected DR capacity >350 MW ▪ Expanding semi-auto DR and ▪ Auto DR extends to medium/small commercial and industrial + residential. ▪ DR capacity auctions begin ▪ DR used for balancing, contingencies, and ancillary services ▪ Private aggregators in Level 1	▪ Full Auto DR for all users and services ▪ DR market fully automated ▪ Aggregators: L1 utilities/private, L2 private ▪ DERs participate directly in the market

Source: Ministry of Energy of Thailand. (2022, February 8). *Thai Smart Grid*

Regulatory Recommendations for VPP Adoption in Thailand

Building on the contributions of the aforementioned study on market strategy options to implement Thailand demand response program policy, and in alignment with the country's medium-term Smart Grid Action Plan for Demand Response, the regulatory reforms targeted to foster a conducive environment for the commercial deployment of VPPs in Thailand are summarized in Figure 8.

Figure 8. Summary of recommendations for VPP adoption in Thailand



Recommendation 1: Conduct a study for flexibility potential on the entire electric system.

Potential studies are routinely used to regulate energy efficiency and demand response programs, and they can be used to regulate VPPs as well. Thailand has already conducted a system flexibility study (IEA, 2021) that looked at technical and contractual sources of flexibility for EGAT at the transmission level. However, very small power producers were out of scope because they are connected with MEA and PEA. Using the avoided costs of the transmission, generation *and* distribution system, a study of flexibility potential that includes the distribution system can estimate how much capacity and flexibility can be cost-effectively developed and deployed to the benefit of the entire grid (Hledik et al., 2025a). This would complete the technical and economic picture for the ERC and give all stakeholders the visibility that they need to make investment decisions.

Recommendation 2: Consider the Utility-Led Business Model

Thailand's enhanced single buyer market closely resembles a vertically integrated market. Regulated utilities serve most of the retail load. Furthermore, wholesale electricity supply costs are primarily determined by PPAs, where generation dispatch follows a merit order that starts with must-run and must-take resources followed by least-cost generation (IEA, 2021; CASE, 2024).

These characteristics suggest that a utility-led business model, or a hybrid based on the utility-led model, could be implemented at this early stage in VPP development without requiring major regulatory reforms to the enhanced single-buyer market. This is not to say that the market-led model does not apply to Thailand, only that the reforms needed to implement it would be different. We note that aggregators play a central role in both business models: the primary difference is the choice of the aggregator's counterparty.

If the utility-led model was applied to Thailand, then the aggregator's counterparty would most likely be the distribution utilities (MEA and PEA). Similarly, if the aggregator-led model was applied to Thailand, the wholesale market operator (EGAT) would most likely be the counterparty.

As noted earlier under topics for regulators to consider, hybrid models can be envisioned too. For example, EGAT could procure VPPs for energy, capacity and ancillary services at the same time that MEA and PEA could procure VPPs to avoid investments in the distribution system. Because MEA and PEA ultimately pay for the full cost of the electric system, they could not only offer aggregators the avoided cost of investment in distribution, but also the avoided cost of investment in generation and transmission. This means that the distribution utilities are in a natural position to offer a higher price to VPP aggregators than EGAT. For this reason, vesting some VPP procurement in the distribution utilities is consistent not only with VPP market development, but also with least-cost planning principles. In any case, EGAT's role as the system operator – and as the Demand Response Control Center specifically – remains unchanged. As long as data is shared between the utilities and system planning is well coordinated, EGAT could continue to act as the coordinating entity for all VPPs, regardless of their counterparty.

To reinforce the last point, planners at MEA, PEA, EGAT and the EPPO must share data and coordinate system planning. Furthermore, the ERC must establish avoided costs and design appropriate pricing and tariffs that take into account all costs across the transmission and distribution system. The ERC is uniquely positioned to establish this coordination through workshops, rulemaking, and/or the facilitation of emerging planning processes such as the integrated distribution system planning developed in a number of frontrunner jurisdictions.[9]

Recommendation 3: Consider Using Competitive, Distributed Capacity Procurement

Distributed capacity procurement (DCP) is an emerging approach to DER procurement that appears to be well suited to the structure of Thailand's electricity system and to the utility-led business model. Similar to all-source procurements that are sometimes run after an integrated resource plan is approved, the DCP model begins with utility planning (Wilson et al., 2020). An integrated distribution system plan establishes the system needs and is followed by a competitive procurement process. Under Thailand's market structure, the DCP concept should be included in the power development plan, and implemented by EGAT, the distributors MEA and PEA, or the three of them. Regardless of who the implementer is, the underlying processes are the same: integrated system planning followed by competitive procurement.

The DCP model treats DERs in the same way that core utility infrastructure is treated. Utilities control the dispatch of the DERs that are procured, and the costs of those resources are included "as capital assets in the rate base and earn their standard regulated rate of return through the utility-led model" (SEPA and Sparkfund, 2025).

According to SEPA and Sparkfund, "DCP is not a traditional utility construction model where utilities build DERs using their own in-house engineering and construction resources. Instead,

[9] See Lawrence Berkley National Laboratory's framework and reports for more information (Lawrence Berkley National Laboratory, n.d.)

the DCP relies on competitive bidding from local DER companies. DCP does not eliminate or preclude private ownership of DERs, as both utility- and customer-owned distributed resources can coexist within the same energy ecosystem." This mix of competitive procurement and mixed ownership aligns well with Thailand's existing plans to utilize Level 1 and, eventually, Level 2 aggregators.

Furthermore,

> "…DCP is not a broad, demand-side management customer program open to all ratepayers; instead, it is strategically and geographically targeted to address specific infrastructure needs of the grid, with participation opportunities determined by utility planning requirements rather than universal customer eligibility, but with the system benefits shared with all ratepayers through the positive impact on system function and cost.
>
> "…In its simplest form, the utility directly owns, dispatches, controls, and maintains customer-sited DERs, taking full responsibility for the distributed resources. Alternatively, customers [or other 3rd parties] can retain legal ownership of the assets while the utility handles dispatching, control, and maintenance to deliver grid value, with the utility paying the customer for operational control and grid services" (SEPA and Sparkfund, 2025).

Because the DCP model relies on traditional utility planning and procurement processes, as well as conventional cost-of-service regulation, it may require relatively few changes at the regulatory level. The EPPO's power development plan and/or the utility's existing planning processes can establish avoided costs for each location on the grid, and then the utilities can competitively procure the DERs that best serve the system. The benefits of this approach are threefold:

- **Existing frameworks apply**: Because system planning is already a core utility function, relatively few changes may be required of the regulatory or enhanced single buyer market frameworks. The EPPO and the utilities could include DCP in their planning and the ERC could require compliance filings to implement the plan(s). In any event, some degree of coordination between the ERC and the EPPO would be likely to remain necessary.

- **Utility planning right-sizes VPP investment**: The scale of DER procurement can be right-sized with integrated system planning processes that include both the transmission and the distribution system (EPRI, 2024). DERs can be scaled up to meet significant percentages of the peak demand using competitive procurements that stimulate the market for Level 2 aggregators.

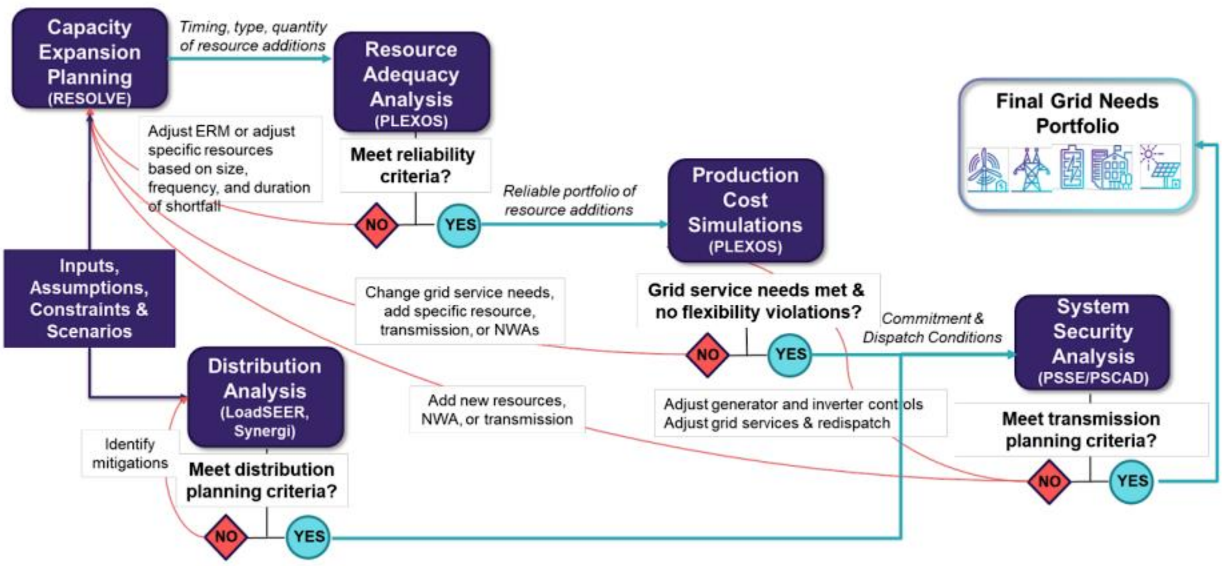
- **System value**: System value is captured using competitive procurement whose costs are capped at the avoided costs that are established in the integrated system plan for each location on the system.

Consider Integrated Distribution System Planning

As renewable energy and DER adoption increase, all aspects of the electric system will be impacted. Because DERs are typically small-scale and often behind the retail meter, they will impact the distribution system first. As DER adoption on the distribution system increases, power flows on some distribution networks will reverse and increasingly impact the generation and transmission system as well. For this reason, data sharing and integrated system planning will become increasingly important.

Managing these impacts and designing cost-effective solutions is the domain of integrated grid planning (IGP), (Lawrence Berkley National Laboratory, n.d.). As practiced in Hawaii, IGP integrates generation and transmission system planning with distribution system planning (see Figure 9) (Hawaiian Electric Company, Inc., 2025). IGP is time-granular (hourly) and location-specific and enables utilities and aggregators to see what infrastructure is needed, in what locations, and at what cost. In Thailand's context, this kind of planning would enable the utilities and aggregators to target their DER aggregations where they are most cost-effective and most urgently needed.

Figure 9. Hawaiian Electric's Grid Needs Modeling Framework



Source: Hawaiian Electric Company. (2025, 1 August). *Docket No. 2018-0165. Draft Integrated Grid Planning Second Cycle Workplan*.

Recommendation 4: Establish Working Groups

Both Australia and Hawaii established working groups to advance their VPP regulations, and we recommend that Thailand does the same. Working groups should include all of the major stakeholders including the utilities, their regulators, aggregators and customers. They can be charged with making recommendations to the ERC on a range of topics including the choice of business model, the requirements for IGP and the terms of the DCP process. They can also work to standardize procedures for data sharing as discussed in the following section.

Create Standardized Procedures for Data Sharing

The successful implementation of VPPs requires seamless data sharing between utilities and aggregators. Data sharing accelerates customer enrollment, improves planning and competitive procurement, and enables scheduling, dispatch and financial settlement. The ERC, through the working groups, can establish standardized procedures to better enable all these processes.

Data Sharing Procedures

The grid operators EGAT, MEA, and PEA need access to accurate, real-time data from VPPs to ensure reliable and predictable flexibility services. Additionally, private owners of DERs — households and businesses — require clear and transparent data on how their assets are used, how revenues are calculated, and what incentives they receive. Open data flows build confidence and encourage more participants to enroll in VPP programs. This is important as the demand side of the system becomes an active, flexible part of grid operations.

The ERC should organize workshops that involve relevant stakeholders — such as EGAT, MEA, PEA, potential investors in VPPs and DERs, as well as DER and meter manufacturers — to discuss the minimum information requirements for VPP implementation. The goal is to establish a common data-sharing framework that includes four main components:

- **Agent-specific data responsibilities:** This section should specify what data distributors and aggregators need to collect, who requires access to this data, and how it can be shared. It should also include network information that allows private aggregators to anticipate the operation of the distribution network. Furthermore, it must define the price[10] and/or control signals EGAT needs to share to activate VPP participation and operate these aggregated assets, as well as how this information should be published and used.

- **Avoided Costs**: The avoided costs of energy, capacity and ancillary services should be known with as much temporal and spatial granularity as possible. Furthermore, they should be used not only to make dispatch decisions for VPPs but also as a price cap for competitive distribution capacity procurements.

- **Governance and security**: Clear ownership of each data type, whether measured or aggregated, must be established, along with who can access this information and at what level of detail. Protocols for data sharing and cybersecurity requirements should also be defined.

- **Technical architecture**: Discussions should cover technical standards for smart meters and communication protocols to ensure interoperability among DERs, aggregators, and utilities.

The ERC could establish a national VPP data platform where utilities and aggregators can securely exchange information. The Demand Response Control Centre at EGAT could serve as the host for this platform under ERC supervision, or an independent third party could be used. In any case, the ERC must take care to ensure robust data sharing, independence and transparency in both the administration of VPP data and in their operation.

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[10] Price signals would ideally be at least hourly and location-specific.

Conclusion

The successful integration of virtual power plants (VPPs) into Thailand's electric grid holds the potential to unlock cost-effective grid flexibility and help accelerate its clean energy transition. To facilitate this transition, the ERC should first conduct a flexibility potential study across the entire electric system to determine the amount of cost-effective VPP capacity that can be deployed. The ERC may want to consider the utility-led business model because it is a good fit with its market structure and would require fewer major regulatory reforms than a market-led approach.

To foster a locationally-targeted and competitive market for VPPs, the ERC may want to consider developing an integrated grid plan, with an emphasis on the distribution system. A comprehensive integrated grid plan could form the foundation for and enable the utilities to use distributed capacity procurement. This approach appears to be compatible with the Smart Grid Action Plan because it can enable the utilities to be aggregators under the utility-led business model and is flexible enough to include third-party aggregators as the market matures.

Finally, the ERC should establish working groups that include all major stakeholders. These groups can advance VPP regulations by clarifying roles and standardizing procedures, particularly for data sharing between utilities (EGAT, MEA, PEA) and aggregators. By implementing these recommendations, Thailand can align its VPP strategy with its long-term goals for a modern, resilient, and decarbonized power system.

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