# Virtual Power Plants

## Executive Summary

Brazil's Demand Response Market



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# Executive Summary

**Introduction and Scope**

This report, developed by **GreenAnt** with the support of **BASE Foundation** and **Integrate to Zero** initiative funded by **Pooled Fund on International Energy (PIE)**, presents a comprehensive assessment of Virtual Power Plant (VPP) viability within Brazil's evolving Demand Response market, combining regulatory analysis, operational simulation, and market-based performance evaluation. Its central objective is to determine whether aggregated distributed flexibility can participate competitively in real system operations under current market rules, and to identify the conditions required for scalable deployment.

The analysis progresses from structural context to operational reality. Initial sections examine the regulatory environment, market design, and economic mechanisms shaping distributed flexibility participation, establishing the institutional constraints that govern VPP performance. Subsequent simulations evaluate VPP operation across progressively larger and more realistic configurations, moving from prosumer-scale aggregation to industrial portfolios capable of meeting minimum participation thresholds.

**Key Findings Overview**

The results reveal a consistent pattern across all analytical layers. Technical feasibility of aggregation is demonstrated, and reliable flexibility can be constructed from existing corporate demand profiles in selected regions. However, economic outcomes are primarily determined by market structure rather than technological capability. Revenue concentration, pricing competition, dispatch frequency, and regulatory limitations collectively define the boundaries of VPP viability under current conditions.

The integration of centralized distributed energy resources further clarifies this distinction. While additional generation and storage capacity improves operational reliability and enables participation in structurally constrained regions, it does not independently resolve the underlying economic limitations imposed by the present market framework. This confirms that the primary barrier to large-scale VPP deployment is not technical readiness, but the maturity and design of the flexibility market itself.

Critically, the economic gaps identified in this analysis are not abstract: they are quantifiable, and they map to specific regulatory actions and financial incentives already available or under development in Brazil. Part 5 of this report includes a detailed feasibility pathway analysis that

tests whether subsidies, favourable financing, and market design changes could independently or jointly close these gaps. The results show that for some configurations the path to viability requires only one regulatory change, while others require a sequenced combination of policy measures. These findings are summarised in the Feasibility Pathway section of this document.

## PART 1: VPPs IN BRAZIL - ANALYSIS OF MARKET INTEGRATION, TECHNICAL CHALLENGES, AND REGULATORY EVOLUTION

Brazil's electricity market is undergoing a structural transition toward distributed energy resources, creating new opportunities for Virtual Power Plants (VPPs) to aggregate flexible capacity and participate in emerging grid services markets. Part 1 examines the regulatory landscape, business models, and technical infrastructure shaping VPP viability in Brazil today and over the coming decade.

**Regulatory Environment.** VPPs currently operate without formal market recognition, but two developments provide a foundation. The ANEEL-approved Demand Response Regulatory Sandbox (2024–2026) tests a compensation model where participants earn variable payments for demand reduction, the mechanism simulated throughout this report. Law 14.300/2022 formally recognizes shared generation and energy storage, enabling DER aggregation for commercial purposes. Both frameworks remain early-stage, and the rules governing VPP participation are subject to revision based on sandbox outcomes.

**Business Logic.** The near-term revenue opportunity centers on three mechanisms: grid services via DR bids to ONS, tariff arbitrage using battery systems charged at off-peak rates (11.21$/MWh floor) and discharged during peaks (57$–67$+/MWh), and energy trading through the hourly PLD in the free market (ACL). Tariff arbitrage simulations show payback periods ranging from 2.8 years for commercial green tariff customers with storage to 12.2 years for residential white tariff customers with storage alone, improving substantially when combined with PV generation.

**Market Roadmap.** A phased integration path projects VPPs entering energy markets (2025–2030), ancillary services such as frequency regulation and voltage control (2030–2035), and capacity markets (post-2035). The expansion of Brazil's free market to an estimated 89 million residential consumers by 2030 will significantly enlarge the addressable customer base for VPP-enabled products.

**Barriers.** Three categories of constraint limit near-term deployment. Regulatory barriers include the absence of formal capacity markets and compensation ambiguity outside the sandbox. Technical barriers include interoperability gaps (only 40% of substations meet IEC 61850 standards) and cybersecurity risks in proprietary DERMS protocols. Financial barriers center on battery economics, lithium-ion systems at 287$+/kWh yield payback periods exceeding five years when deployed for DR alone, a finding reinforced by the simulation results in Parts 3 and 4 of this report.

**Implication for This Report.** The analysis that follows tests VPP viability within the one market mechanism currently accessible at scale: the ONS Demand Response Sandbox. The results should be read as a lower bound on VPP revenue potential. As regulatory evolution enables stacked revenue models, that is, operating the same physical asset across multiple revenue streams such as DR, tariff arbitrage, and energy trading simultaneously, the economics of the same physical infrastructure will improve without additional capital investment.

## PART 2: THE DEMAND RESPONSE AVAILABILITY PRODUCT IN BRAZIL

### Market Evolution and Operational Evidence (2024-2025)

The Brazilian Demand Response market has undergone significant structural transformation over the analysis period. The data reveals evolution from sporadic, price-based participation in early 2024 to a sophisticated market by end-2025 featuring:

- Product Evolution: Migration from purely price-based D-1 modality (participation only when dispatch occurs) to Availability-based products (fixed compensation for capacity reservation plus variable compensation for delivery)
- Scale Demonstration: Aggregated DR capacity exceeding 500 MW, with single agents offering up to 105 MW (LIASA - January 2025)
- Regional Integration: DR becoming critical for system balance in all four subsystems, with pronounced importance in Northeast (wind variability stabilization) and Southeast (peak demand management)

**Key Findings from Market Data:**

Temporal Patterns - The "Duck Curve" Dominance:

- More than 85% of DR activations occur between 6 PM and 10 PM, precisely aligned with solar generation ramp-down and residential evening peak consumption
- Secondary activations observed during extreme conditions (14:00-15:00 hours on critical days in October 2024 and January 2025)
- This pattern validates the fundamental economic logic behind VPP operations: temporal misalignment between renewable generation and consumption creates demand for flexibility services

Sectoral Participation Leadership:

- Electrometallurgy dominance: CB Aluminio, Rima, Liasa, and Ferbasa form the backbone of Brazil's DR market, with combined offerings frequently exceeding 250 MW
- Petrochemical anchor role: Braskem (Northeast) and Petrobras (multi-regional) provide geographic dispersion and operational consistency
- Emerging aggregation model: Intercement's simultaneous operation of 30-40 MW across six locations demonstrates VPP aggregation is already operationally viable without formal regulatory VPP recognition. Even if the actual operation cannot be considered as a formal VPP Aggregation, the muilti-sites's bids behavior indicates a proxy of it.

Price Stratification and Competitiveness:

- Early 2024: 105-124$/MWh (favorable hydrology, limited demand)
- Peak scarcity (Oct 2024): 172-229$/MWh (severe drought, system stress)
- Late 2025: 0.00$ (Availability fixed compensation) + 57-172$/MWh (variable D-1 bids)
- Competitive analysis: DR weighted average cost approximately 134$/MWh represents significant savings vs. open-cycle thermal dispatch (229-382$/MWh)

VPP Viability Validation:

The Intercement case demonstrates that:

1. Multiple medium-sized loads (5-6 MW each) can be aggregated into a "virtual block" (30-40 MW) with centralized management to maximize gains.

2. Geographic diversification across multiple subsystems reduces operational risk
3. Real-time synchronized activation across dispersed facilities is technically feasible
4. This model anticipates formal VPP regulations while operating within current legal frameworks

The market data establishes that Brazilian industry already operates as a distributed virtual power plant, with infrastructure for load monitoring, communication, and rapid response already in place. The transition from price-based to availability-based products signals industry acceptance of long-term flexibility commitments.

## PART 3: SIMULATION OF VPP OPERATIONS WITH P2P ENERGY TRADING

The third part of this report presents a comprehensive simulation-based analysis of Virtual Power Plant (VPP) operations within the Brazilian energy sector context, integrating peer-to-peer (P2P) energy trading, demand response (DR) participation, and distributed energy resource (DER) aggregation mechanisms. The simulation models 30 days of operations across a portfolio of 70 prosumers (60 residential, 10 commercial) with an aggregate installed capacity of 190 kWp of solar photovoltaic generation and 132 kWh of battery storage.

**Key Findings**

Technical Feasibility: The simulation confirms that virtual power plant operations are technically viable and manageable within current Brazilian regulatory and technical constraints. The aggregated prosumer portfolio generates consistent, forecastable load patterns with a peak-to-minimum demand ratio of 2.4:1, enabling reliable dispatch optimization. Solar generation penetration reaches 45% across the prosumer base (32 prosumers), with 24% achieving hybrid PV-battery configurations that enable temporal load shifting. The pronounced diurnal patterns in both residential (peak evening consumption 9-10 PM) and commercial loads (peak business hours 8 AM-5 PM) create distinct P2P trading opportunities aligned with renewable generation availability.

Economic Viability: P2P energy trading generates approximately 4916,52$ in monthly revenue across the aggregated portfolio under conservative assumptions (50% participation rate), translating to 70$ per prosumer monthly. This represents at least 5% additional return on prosumer energy bills, demonstrating emerging economic value that strengthens as battery costs decline and tariff spreads increase. Demand response represents substantially greater

revenue potential, with simulations indicating monthly participation earnings of 27$ to 158$ per aggregated kW of flexible capacity, depending on baseline availability compensation and event-based delivery performance. The 10 simulated DR events achieved an average 61% participation rate with 98% delivery accuracy, establishing a realistic operational baseline for ongoing DR program engagement. However, the CAPEX needed for such investments on DERs still is a barrier for VPP development, since the generated profit would not be enough to pay for the investments.

Regulatory Constraints: The current Brazilian regulatory framework presents both enabling foundations and significant constraints. Law 14.300/2022 provides essential legal recognition for DER aggregation and energy storage, while ANEEL's Regulatory Sandbox (2024-2026) creates pathways for DR market experimentation. However, the absence of formal aggregator definitions creates legal ambiguity regarding liability allocation, and the minimum 5 MW aggregation threshold effectively excludes smaller-scale VPPs from direct demand response market participation. Furthermore, the planned escalation of grid use charges (TUSD/TUST) to 100% by 2030 will compress profit margins by increasing grid connection costs, partially offsetting distributed generation economic advantages.

Market Development Requirements: Widespread VPP deployment requires three parallel policy interventions: (1) regulatory expansion of aggregator definitions and responsibility clarification, (2) acceleration of smart meter deployment to regions with high DER concentration, and (3) development of capacity market mechanisms that extend VPP revenue streams beyond P2P arbitrage and DR participation to encompass long-term reliability services. Consumer engagement success depends on transparent communication regarding economic returns and flexible contract structures that accommodate heterogeneous prosumer preferences regarding participation intensity.

## PART 4: SIMULATION OF LARGE SCALE VPP AGGREGATION

Part 4 develops and tests a methodology for aggregating industrial and commercial companies into VPPs capable of meeting the ONS Demand Response Sandbox's minimum participation requirements. The central question is practical: given Auren's existing corporate client portfolio, can companies within each electrical subsystem be combined into a VPP that consistently delivers at least 5 MW of demand reduction during peak hours?

**Methodology**. Each company is evaluated across five dimensions: flexibility magnitude, reliability, temporal consistency, balance, and sectoral diversity, combined into a single

attractiveness score. The VPP formation process iteratively selects companies to maximize complementarity to account for daily variability around monthly averages. The process runs independently for each month, producing 24 candidate VPPs that are consolidated into a composite portfolio for year-round participation.

**Southeast Viable**. The SE portfolio of 57 companies across 35 sectors met the 5 MW threshold on 83.8% of weekdays (192 of 229) and achieved hourly compliance in over 90% of peak hours. The Southeast is the only subdivision where the corporate VPP alone can reliably participate in the DR program.

**South Partially Viable**. The South subdivision demonstrated meaningful corporate participation but with lower consistency than the Southeast. The portfolio can meet the threshold on a substantial share of days but falls short of the reliability needed for continuous market participation without supplementary capacity.

**Northeast Not Viable with Corporate Flexibility Alone**. The NE portfolio met the 5 MW threshold on only 6 of 229 weekdays (2.6%), with hourly compliance at just 4.0%. Despite the NE having significant DR market activity (167 ONS requests), the current corporate portfolio lacks sufficient scale to participate. This finding directly motivates the DER integration analysis in Part 5, where centralized PV and battery assets are tested as a means to bridge the capacity gap.

**North Excluded**. The North subdivision showed negligible participation capability (1 complete day meeting threshold) due to insufficient company coverage. It was excluded from further analysis.

**Implication**. Part 4 confirms that VPP formation from Auren's corporate portfolio is feasible in the Southeast and partially viable in the South, but the Northeast and North cannot participate with corporate flexibility alone. This sets the stage for Part 5, which tests whether adding centralized DERs can transform non-viable subdivisions into active market participants, and whether it improves returns in subdivisions where corporate flexibility already works.

## PART 5: SIMULATION OF LARGE SCALE VPP OPERATIONS WITH CENTRALIZED DERS

Part 5 evaluates whether integrating centralised distributed energy resources (DERs), specifically PV generation and battery storage, improves the operational performance and market competitiveness of corporate VPPs within Brazil's DR Sandbox.

To test this, the simulation replays actual 2024 DR market activity. In the DR Sandbox, participants compete for demand reduction contracts by submitting daily offers to the national system operator (ONS), each specifying a volume of demand reduction (in MW) and a price (in $/MWh). ONS accepts offers starting from the lowest price until its reduction target is met. A VPP "wins a bid" when its offer is accepted; it then earns revenue by delivering the committed reduction during the requested hours (typically 18:00–22:00). The simulation uses historical competitor bids from real market participants to determine, for each day in the 2024 dataset, whether the VPP's offer would have been accepted and at what price.

Three configurations are tested in each region: a Baseline using corporate demand flexibility alone, a Small DER scenario adding modest PV generation and battery storage, and a Big DER scenario with larger centralised assets. The simulation period covers 82 days of actual DR activity in the Southeast and 33 days in the Northeast, reflecting the real frequency of ONS demand reduction requests in each region during 2024.

**Southeast: Mature Market, Marginal DER Returns**

In the Southeast, where corporate flexibility already meets the 5 MW participation threshold on most days, adding centralised PV and battery storage produces only marginal improvements. The Baseline scenario achieved a 60.8% bid win rate, meaning the VPP's price-volume offer was accepted by ONS on 60.8% of the days it could participate, and generated $700K in gross revenue over the 82 days of DR activity. The Small DER scenario (+2 MWp PV, +8 MWh battery) improved the win rate to 62.2% and gross revenue to $726K, but net revenue increased by only $4K. The reason: batteries must be charged from the grid daily regardless of whether a DR event occurs that day, creating a fixed daily operating cost (termed "grid charging costs" throughout this report) of $22K over the period. The Big DER scenario (+6 MWp PV, +30 MWh battery) further increased gross revenue to $742K but actually reduced net revenue to $659K, as $82K in grid charging costs exceeded the incremental revenue gain.

The fundamental constraint in the Southeast is competitive market pricing, not physical flexibility. The VPP wins or loses bids based on whether its price undercuts competitors, not whether it offers 5.5 MW versus 5.0 MW of capacity. As DER system size increases, daily charging costs rise proportionally, but bid volume and revenue do not, creating an adverse unit economics problem. The simulation data also reveals $615K in unrealised potential revenue in the Baseline scenario alone, primarily from two sources: capacity the VPP delivers beyond what it can contractually bill for (overdelivery), and instances where the VPP's bid price was lower than the market clearing price (pricing gap). Capturing even 25% of this opportunity through better forecasting and pricing strategy ($154K over 82 days, or approximately $683K annualised) would provide a larger return than adding physical DER assets.

**Northeast: DERs as Enabling Infrastructure**

The Northeast presents a structurally opposite picture. The corporate VPP averaged only 3.3 MW of capacity, well below the 5 MW minimum required by the DR Sandbox, winning just 1 of 33 bids (3.0%) and generating effectively zero revenue. The Small DER scenario (+6 MWp PV, +24 MWh battery) transformed participation: average capacity rose to 5.5 MW, 27 of 33 bids were won (81.8%), and gross revenue reached $48K with $16K net. The Big DER scenario (+8 MWp PV, +32 MWh battery) achieved the same 81.8% win rate and $48K gross, but net revenue fell to just $5K due to higher charging costs.

However, enabling market participation does not ensure investment viability. Grid charging costs represent 68% of gross revenue in the Small DER scenario. When extrapolated to a full year, the Small DER's $177K net revenue cannot cover $833K in annual asset costs plus operating expenses. The Northeast market would require either 3–4 times higher DR request frequency from ONS or significantly higher compensation prices to justify centralised DER investment at current scale.

Across both regions, the findings indicate that technical feasibility is not the primary constraint on large-scale VPP deployment. Instead, economic outcomes are determined by market structure, pricing levels, and revenue stacking opportunities. Under current conditions, demand response alone provides an insufficient financial foundation to justify capital-intensive DER deployment.

**Feasibility Pathway and Subsidy Sensitivity Analysis**

A central question for regulators and investors is whether direct financial incentives could make VPP applications economically viable. Three types of intervention are tested below: CAPEX subsidies (reducing the upfront cost of DER assets through grants or concessional financing), grid charging tariff reductions (lowering or eliminating the daily cost of charging batteries from the grid), and DR price premiums (increasing the revenue VPPs earn per unit of demand reduction delivered). Each mechanism is tested against the actual simulation results to determine whether it independently closes the gap between current revenue and total costs. The "gap" figures shown represent the shortfall between net revenue earned and the full cost of owning and operating the DER assets over the simulation period.

**Southeast Small DER (–$58K gap over the 82-day simulation period)**

The table below tests each subsidy mechanism against the Southeast Small DER scenario, which added 2 MWp of solar PV and 8 MWh of battery storage to the corporate VPP. The "82-day gap" is the difference between net revenue and total asset costs over the 82 days of actual DR market activity in the Southeast during 2024.

| **Subsidy Mechanism** | **Effect on 82-day Gap** | **Viable?** |
|---|---|---|
| No subsidy (current) | –$58K | No |
| 25% CAPEX subsidy | –$43K | No |
| 50% CAPEX subsidy | –$27K | No |
| 75% CAPEX subsidy | –$12K | No |
| Zero grid charging | –$36K | No |
| 50% CAPEX + zero grid charging | –$5K | Near breakeven |
| **8% DR price premium** | **$0** | **Yes** |
| **Revenue stacking (tariff arbitrage)** | **Strongly positive** | **Yes** |

Even a 75% CAPEX subsidy does not close the gap, because daily grid charging costs ($22K over 82 days) consume nearly all the incremental revenue the DER assets generate ($26K above what the Baseline earns without them). The fundamental problem is the variable cost structure, not the capital cost. Revenue stacking, specifically, authorising the same battery to

participate in tariff arbitrage (charging at off-peak rates and discharging at peak rates for energy trading) alongside DR, remains the most direct path to viability, because it generates additional revenue from the same asset without increasing operating costs proportionally.

**Northeast Small DER (–$656K annual gap)**

The Northeast analysis is expressed in annual terms because the 33-day simulation period is extrapolated to estimate full-year economics. The "revenue multiplier" column indicates the factor by which current annual net revenue would need to increase to cover all costs, a multiplier of 1.0× means the scenario breaks even, while 4.7× means revenue would need to be nearly five times higher than current levels.

| **Subsidy Mechanism** | **Effect on Annual Gap** | **Revenue Multiplier Needed** | **Viable?** |
|---|---|---|---|
| No subsidy (current) | –$656K | 4.7× | No |
| 50% CAPEX subsidy | –$302K | 2.7× | No |
| 75% CAPEX subsidy | –$125K | 1.7× | No |
| Zero grid charging | –$302K | 2.7× | No |
| 50% CAPEX + zero grid charging | –$125K | 1.7× | No |
| **75% CAPEX + revenue stacking + 3–4× dispatch** | **Potentially positive** | **~1.0×** | **Conditionally yes** |

The Northeast demonstrates that subsidies and regulatory changes are complements, not substitutes. A 75% CAPEX subsidy, among the most aggressive public financing structures available in Brazil—still requires revenue to nearly double (1.7× multiplier). Only the combination of subsidised financing, revenue stacking authorisation, and a 3–4× increase in dispatch frequency (meaning ONS would need to request demand reduction three to four times more often than it did in 2024) brings the Northeast within reach of viability.

**Available Policy Instruments in Brazil**

The sensitivity tables above use generic subsidy percentages. The following summarises the concrete instruments through which each type of intervention can be delivered in the Brazilian context, and maps each instrument to its approximate effect in the scenarios tested.

**CAPEX reduction: Law 15.269/2025.** Enacted in November 2025, this marks Brazil's first legal framework for energy storage as an independently regulated activity. It introduces zero import tariffs on battery systems and components, and includes BESS (Battery Energy Storage Systems) projects in the REIDI programme from January 2026 to December 2030, which exempts qualifying projects from two federal taxes (PIS/PASEP and COFINS) on contracted services and imported machinery. Industry estimates place the combined effect at a 20–30% reduction in upfront BESS CAPEX, mapping directly to the 25% subsidy scenario in the sensitivity tables above.

**Subsidised credit lines: BNDES Fundo Clima and BNB FNE Sol.** BNDES Fundo Clima (R$10.4 billion available) offers financing at 6.5–8% per year with amortisation periods of up to 24 years, compared to typical commercial bank rates of 12–16% for industrial energy projects in Brazil, effectively reducing annual debt service by 30–40%. For the Northeast specifically, the BNB FNE Sol line offers rates as low as 4.8% per year—the most favourable publicly available rate for energy projects in the country. Financing the NE Small DER scenario at 4.8% over 24 years rather than the report's 15-year straight-line assumption would reduce annual CAPEX cost from $708K to approximately $480K, a ~32% effective reduction without any grant requirement.

**DR price premium: the Availability Product.** As documented in Part 2, the DR market is transitioning from purely variable (pay-per-activation) pricing to an Availability model that adds a fixed reservation payment for maintaining standby capacity, regardless of whether the system operator actually calls on that capacity. For VPPs recognised as eligible providers, this reservation component functions as a continuous per-MW-year revenue stream that does not depend on dispatch frequency. For the SE Small DER scenario, a reservation payment of $3,500/MW-year on 21.7 MW of average bid capacity ($76K annually) would close the 82-day gap at a system cost far below avoided thermal dispatch value.

**Grid charging exemption and free market access.** Law 15.269 assigns ANEEL formal responsibility for regulating storage, creating a legal basis for exempting grid-sourced battery charging from demand charges—a precedent established in comparable jurisdictions (Australia, UK, US FERC Order 841). Separately, the law accelerates Brazil's free market opening to all commercial consumers by November 2027, allowing VPP aggregators to purchase electricity for battery charging through hourly wholesale price (PLD) contracts rather than regulated distribution tariff (TUSD) rates. At PLD minimums of $11.21/MWh versus peak

discharge values of $57–$67+/MWh, this converts the grid charging cost from a fixed operational burden into a tariff arbitrage opportunity.

**Recommended Policy Package by Scenario**

Based on the subsidy sensitivity analysis and the instruments described above, the following table summarises the most effective policy combination for each VPP scenario tested in this report.

| Scenario | Recommended Policy Package | Combined Effect |
|---|---|---|
| **SE Corporate VPP (Baseline)** | Already viable under current rules | No policy change required |
| **SE Small DER** | Revenue stacking authorisation alone | Closes gap without subsidies |
| **SE Big DER** | Revenue stacking + energy trading access | Closes gap; subsidised financing accelerates deployment |
| **NE Small DER** | 50% CAPEX subsidy (BNDES) + revenue stacking + lowered min. threshold | Reduces required multiplier from 4.7× to ~1.5× |
| **NE Big DER** | Not recommended at current market depth | Revisit if dispatch frequency increases 3–4× |
| **South Corporate** | Capacity payment / Availability Product expansion | $300K/yr payment reaches investment-grade returns |

The central insight is that VPP applications in Brazil sit at varying, quantifiable distances from economic viability, and those distances are bridgeable through specific, identifiable combinations of regulatory changes and financial incentives. Subsidies alone are insufficient for all but near-breakeven cases, but they meaningfully reduce the regulatory burden required to reach viability. The most effective near-term projects will combine both financial incentives and market reform.

## CONCLUSION:

This report provides an integrated evaluation of VPP deployment in Brazil by linking regulatory context, observed market behaviour, and simulation-based operational performance. The analysis demonstrates that distributed flexibility can be reliably aggregated, coordinated, and dispatched under real system conditions, confirming that VPPs are operationally viable within Brazil's current energy infrastructure. A key near-term constraint, however, is that Consumer Units in the free market cannot inject electricity into the grid unless classified as retailer self-production units, which cannot participate in aggregated profiles; this structural restriction prevents VPP aggregation under a single profile in line with current DR Sandbox rules.

Across all scenarios, a clear structural insight emerges: the limiting factor for large-scale VPP deployment is not technological capability, but market maturity. While aggregation of distributed energy resources consistently produces reliable flexibility and measurable system value, economic outcomes remain constrained by pricing structures, dispatch frequency, and the limited scope of monetisation mechanisms currently available to flexibility providers. Simulation results further show that asset expansion alone does not resolve this constraint. The integration of centralised DERs enhances participation capability and improves reliability in structurally constrained regions, yet financial performance remains fundamentally tied to market design conditions. Under present rules, demand response functions as an enabling mechanism rather than a sufficient economic foundation for capital-intensive distributed infrastructure.

However, the feasibility pathway analysis demonstrates that these constraints are not permanent. The Southeast corporate VPP is already viable today under current market rules. Southeast DER integration requires only one regulatory change, revenue stacking authorisation, which is expected in the post-Sandbox framework, to reach breakeven without any CAPEX subsidy. The same physical assets, serving the same grid reliability function, would generate substantially more value simply by removing the restriction to a single revenue stream. This represents the strongest near-term case for regulatory evolution.

For the Northeast, the subsidy sensitivity analysis shows that even a 75% CAPEX subsidy leaves a $125K annual gap for the Small DER scenario. Only the combination of subsidised financing (through BNDES Fundo Clima or BNB FNE Sol at rates of 4.8–8%), revenue stacking authorisation, and a 3–4× increase in ONS dispatch frequency brings the region within reach. The regulatory agenda should prioritise these changes as a sequenced package, with subsidies framed as transition mechanisms that reduce risk for early movers while the market matures.

Concrete policy instruments are already available to support this transition. Law 15.269/2025 delivers an estimated 20–30% CAPEX reduction for battery systems. BNDES and BNB provide subsidised credit at rates that reduce annual debt service by 30–40%. The Availability Product introduces fixed capacity reservation payments that decouple VPP revenue from dispatch frequency. Brazil's accelerated free market opening by November 2027 will allow VPP aggregators to access wholesale pricing for battery charging, converting a cost burden into an arbitrage opportunity.

These findings position VPPs not as a speculative innovation requiring favourable conditions, but as an infrastructure model at quantifiable distances from economic viability. The distances are bridgeable through specific, identifiable policy actions. The Southeast is ready now. The Northeast has a clear, sequenced pathway. As Brazil's flexibility market progresses toward structural maturity, the aggregated distributed resources analysed in this report will transition from early-stage demonstration to a core component of the country's power system.