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Enhancing distribution hosting capacity in urban microgrids: A coordinated DSM and storage framework for Wellington's Kilbirnie network

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Abstract
The Wellington Electricity distribution network confronts escalating operational challenges from ageing assets, seismic vulnerabilities, and localised capacity constraints amid decarbonisation. This study proposes and validates a coordinated demand-side management and distributed storage framework to enhance distribution hosting capacity, using quasi-dynamic Power Factory simulations of the Kilbirnie network across three scenarios: baseline operations, passive PV-battery saturation, and active demand orchestration. Passive PV-battery integration across residential, retirement home, and industrial bus depot feeders yielded substantial self-consumption, notably 38% at high-occupancy sites, yet triggered critical transformer overloads reaching 90% utilisation during evening peaks. Active demand-side management, synchronising flexible loads like hot water cylinders and EV charging with solar generation, dramatically alleviated these stresses, slashing residential transformer loading to 25% and creating thermal headroom for rigid night-time industrial demands. Key findings underscore that residential load shifting not only restores daytime reverse power flows but also accommodates electric bus depots, which otherwise would risk severe peaks. High-occupancy commercial loads demonstrated inherent flexibility, further amplified by orchestration. Overall, the framework unlocks latent network capacity, defers reinforcement, and bolsters seismic resilience without physical upgrades. Recommendations advocate mandating active control for residential interconnections, prioritising PV in flexible sectors, rightsizing transport storage for arbitrage, and deploying cross-sector dynamic tariffs. This Wellington-specific approach offers a blueprint for urban distributors balancing affordability, reliability, and electrification under N-1 standards.

Keywords: Demand side management; Microgrids; Battery energy storage systems; Electric vehicles; Distribution hosting capacity.

1. Introduction

The Wellington Electricity (WELL) distribution network is entering a period of heightened operational complexity, driven by ageing assets, pronounced seismic and environmental risks, and tightening economic and regulatory constraints (Boston Consulting Group, 2022). System-wide demand growth is now modest, with maximum demand increasing only slightly from about 521 MW in 2024 to a forecast of ~545 MW by 2034, while some urban zones exhibit declining base demand and others, particularly in the northwestern and north-eastern growth corridors, face emerging capacity pressure (Wellington Electricity, 2025). This has created a paradoxical planning environment in which several substations and sub-transmission circuits already operate at or beyond their N-1 capacity limits, even as other parts of the network retain significant spare headroom (Wellington Electricity, 2025).

Decarbonisation pressures are reshaping these challenges. Slower-than-expected uptake of electric vehicles and delays in public transport electrification have temporarily tempered peak-demand growth. However, a possible transition of approximately 65,000 residential gas connections to electricity poses a future risk of a substantial, largely non-discretionary winter-evening load (Wellington Electricity, 2025). In parallel, the proliferation of distributed energy resources (DER), such as rooftop PV, behind-the-meter batteries, and EVs, is progressively transforming traditionally passive feeders into active, bidirectional systems (Wellington Electricity, 2025). These developments tighten thermal margins on already constrained 33 kV circuits and transformers, exacerbate voltage rise and drop at low-voltage levels, challenge legacy unidirectional protection schemes, and expose the limitations of existing monitoring and control infrastructure, particularly on LV networks with poor visibility (Boston Consulting Group, 2022; Wellington Electricity, 2025).

Wellington's geographic and hazard profile amplifies the need for a different operational paradigm. The network remains heavily dependent on fluid-filled and gas-filled sub-transmission cables installed between the 1960s and 1980s, which are maintenance-intensive and vulnerable to seismic damage (Wellington Electricity, 2025). Critical nodes such as the Central Park Grid Exit Point act as single points of failure for large urban loads, while multiple substations are exposed to flood, tsunami, or wildfire risk (Wellington Electricity, 2025). Under these conditions, a purely centralised, reinforcement-led approach to resilience is neither sufficient nor economically sustainable. Although there are emerging microgrid-like arrangements—including embedded private networks, critical infrastructure sites with islanding capability (such as Wellington Regional Hospital's large diesel generation), and virtual community energy schemes—these remain fragmented and are not yet integrated into a coherent, system-level resilience strategy (Wellington Electricity, 2025).

Demand-side management (DSM) and distributed storage are therefore emerging as key non-network instruments for balancing affordability, reliability, and decarbonisation (Kamana-Williams and Bishop, 2024; Zunnurain et al., 2018). WELL's long-standing ripple control schemes for residential hot water cylinders already deliver virtual capacity at an estimated NZD 10–27 per kW of demand reduction, compared with around NZD 130 per kW for equivalent physical reinforcement. More recent initiatives—such as widespread Time-of-Use tariffs (covering roughly 95% of residential customers), the ResiFlex flexibility trials, the EV Connect and FlexForum programmes, and virtual microgrid pilots like the Kāinga Ora multiple-trading project—illustrate a clear shift towards market-based, automated flexibility frameworks (Wellington Electricity, 2025). However, limited LV visibility, incomplete data on behind-the-meter batteries and high-capacity EV chargers, and the early-stage development of flexibility markets currently prevent these tools from functioning as fully dependable substitutes for traditional augmentation (Wellington Electricity, 2025).

Against this backdrop, this study develops and evaluates a coordinated DSM and distributed storage framework tailored to the WELL distribution area. It focuses on three main levers: managed charging of a growing fleet of electric vehicles (Hosseini et al., 2020), controlled operation of residential hot-water cylinders via existing and enhanced ripple-control schemes (Rajbhandari et al., 2024), and the utilisation of household PV–battery systems as a decentralised fleet of nano grids capable of both self-supply and grid support (Nair et al., 2021). The central hypothesis is that intelligently orchestrated flexible demand and storage can de-load thermally constrained transformers and feeders during winter evening peaks, it can increase PV hosting capacity by mitigating daytime voltage rise and absorbing surplus solar generation for later use, and strengthen resilience to seismic and environmental disruptions, while deferring or downsizing capital expenditure within the constraints of the current regulatory regime. By grounding the analysis in documented asset condition, quantified capacity constraints, and existing sector initiatives, the research aims to outline a technically robust and practically actionable pathway towards a more flexible, decentralised, and resilient operating paradigm for the Wellington distribution network.

1.1. Objectives of the paper

The objectives of the paper are:

- To analyse the primary operational challenges in traditional distribution networks and how microgrids provide solutions.
- To review key control and management strategies required for integrating multiple microgrids into a single distribution system.
- To investigate microgrid implementation approaches facilitating high penetration of renewable energy sources.
- To assess the impact of microgrid deployment on power quality and overall grid stability.

2. Literature review

The decarbonisation of power systems is accelerating a structural shift in distribution networks from passive one-way infrastructures towards actively managed, multi-directional systems with high penetration of distributed energy resources (DER) and electrified demand (Boston Consulting Group, 2022). Within this context, four main research streams are directly relevant to the Wellington Electricity (WELL) network and the proposed demand-side management (DSM) and distributed storage framework: distribution hosting capacity; urban microgrids and resilience; DSM and flexibility markets; and battery energy storage systems (BESS) including electric vehicles (EVs) as mobile storage (Boston Consulting Group, 2022; Wellington Electricity, 2025). Together, these strands highlight both the technical potential and the practical constraints of non-network solutions for congestion relief, power quality management, and resilience enhancement in urban distribution systems.

2.1. Review outcomes

2.1.1. Distribution hosting capacity

The concept of distribution hosting capacity is widely used to quantify the additional DER or demand that can be connected to existing networks without violating thermal, voltage, protection, or power quality limits (Kurundkar & Vaidya, 2023). International studies typically distinguish four main classes of constraints: thermal loading of lines and transformers, voltage rise and drop, short-circuit and protection-coordination limits, and power-quality indicators such as total harmonic distortion (THD) (Gulraiz et al., 2025; Mogaka et al., 2020; van Westering & Hellendoorn, 2020). These categories are mirrored in Wellington, where thermal congestion on selected 33 kV circuits, voltage limits on low-voltage (LV) feeders, N-1 security requirements, and harmonic constraints collectively bound the network's ability to host further EV charging, rooftop photovoltaic (PV) generation, and behind-the-meter storage (Wellington Electricity, 2025).

Thermal and capacity constraints are often the dominant limiting factors for additional EV load and PV export, particularly on long radial feeders and older sub-transmission corridors (Kurundkar & Vaidya, 2023; Nair et al., 2021; van Westering & Hellendoorn, 2020). WELL's own data confirm that, while average transformer and feeder utilisation remain modest at the system level—around 42.6% average zone-substation transformer loading and roughly 60% peak feeder utilisation—specific assets such as sub-transmission cables supplying Johnsonville and Kenepuru already operate near their firm-capacity limits (Wellington Electricity, 2025). This combination of low average utilisation with localised bottlenecks is consistent with the broader literature, which emphasises the spatial heterogeneity of hosting capacity and the need for feeder-level rather than system-level analysis.

Voltage constraints constitute a second major limitation, especially in LV networks with high PV penetration and increasing single-phase EV charging (Kurundkar & Vaidya, 2023). Numerous studies report voltage rises at the ends of feeders during sunny midday periods with low local demand, leading to inverter disconnections when statutory upper voltage limits are exceeded (Kurundkar & Vaidya, 2023; Nair et al., 2021). Conversely, concentrated evening EV charging or heat-pump operation in weak network sections can cause voltage drops below the lower bound, creating power-quality issues and potential customer complaints (Wellington Electricity, 2025). The WELL network exhibits this tension precisely: PV-rich feeders face export constraints to prevent overvoltage, while prospective EV-driven evening peaks risk deepening voltage sags in high-growth suburbs such as Porirua, Mana, and Trentham (Wellington Electricity, 2025).

Security and reliability standards, commonly expressed through N-1 criteria, further reduce practical hosting capacity by requiring that networks operate below their physical thermal limits. Wellington's "lean design" philosophy—historically sizing assets closely to prevailing demand to minimise capital expenditure—has left limited headroom in critical corridors, even where nameplate ratings might suggest spare capacity (Wellington Electricity, 2025). At the same time, differentiated security standards between the central business district (CBD) and rural or residential areas result in varying effective hosting capacities across the footprint. Similar patterns are reported in other jurisdictions, where stricter security obligations in high-consequence areas impose tighter operational envelopes and increase the relative value of local flexibility (Wellington Electricity, 2025).

Finally, limited LV visibility is repeatedly identified as a binding operational constraint, even where physical capacity appears adequate. In Wellington, the absence of comprehensive smart-meter voltage data and LV telemetry produces a "blind spot" that prevents operators from confidently quantifying feeder-level hosting capacity or coordinating large numbers of DER (Boston Consulting Group, 2022; Wellington Electricity, 2025). This aligns with international findings that digitalisation—through LV monitoring, data analytics, and digital twins—is a prerequisite for safely exploiting latent capacity via advanced DSM and DER orchestration (Ehsani et al., 2023; Tomaselli et al., 2024a; Wang & Verbic, 2021).

2.1.2. Urban microgrids and resilience

Microgrids have been widely proposed to enhance resilience, integrate local renewables, and provide grid-support services. Core features include the ability to operate in both grid-connected and islanded modes, internal control architectures that manage local generation, storage, and loads, and often a well-defined community or campus boundary (Krkoleva Mateska et al., 2018). Case studies from remote and island systems, including Rakiura–Stewart Island in New Zealand, demonstrate the operational feasibility of microgrids and their potential for high renewable penetration (Mohseni et al., 2021). However, translating such models into dense urban distribution systems remains limited, particularly where existing networks are already heavily meshed and subject to stringent reliability standards (Elsamahy, 2022; Ratnam et al., 2015; Zamora & Srivastava, 2010).

Within the WELL network, there are currently no continuously islanded, commercially operated microgrids serving urban communities, despite several assets that approximate microgrid behaviour (Wellington Electricity, 2025). Embedded distribution networks in apartment complexes and institutional campuses function as private sub-grids but sit largely outside WELL's direct operational scope, so their control and maintenance do not contribute systematically to network-level resilience. Critical infrastructure sites, such as Wellington Regional Hospital and key water treatment plants, have substantial on-site generation and can operate independently during grid outages, providing resilience through a microgrid at a single critical node (Wellington Electricity, 2025). These installations illustrate how targeted microgrid-like configurations can support essential services but, by themselves, do not realise the broader potential of community-scale microgrids in urban settings.

Innovation trials within Wellington are beginning to explore "virtual microgrid" concepts based on market and trading arrangements rather than physical islanding. The Kāinga Ora Multiple Trading Relationships (MTR) trial, involving around 180 social housing properties, allows rooftop PV generation at some dwellings to be virtually shared with others through separate consumption and export relationships at a single installation control point (Wellington Electricity, 2025). This approach supports local energy sharing and economic optimisation while remaining fully grid-connected, aligning with international trends towards transactive energy and community energy schemes that overlay existing distribution infrastructure (Wellington Electricity, 2025). However, the trial stops short of implementing autonomous islanding, local voltage regulation, or frequency control, which are key technical hallmarks of full microgrids.

The literature also points to the growing conceptual interest in "nano grids"—household-scale PV-plus-battery systems capable of limited islanded operation—as building blocks for more resilient urban systems (Kanakadhurga & Prabaharan, 2022; Luo et al., 2018). WELL's strategy of encouraging behind-the-meter storage and EV smart charging, combined with improvements in LV visibility, can be viewed as a pathway towards a network-wide federation of such nano grids (Feng et al., 2023; Wang & Verbic, 2021; Wellington Electricity, 2025). Nonetheless, large-scale deployment of coordinated nano grids in a seismically exposed, topologically constrained network like Wellington's raises unresolved questions regarding protection coordination, black-start strategies, and regulatory responsibilities during extended islanded operation (Wellington Electricity, 2025).

2.1.3. Demand-side management and flexibility markets

DSM has a long history as a tool for peak-shaving, load shifting, and system-security support, with early implementations dominated by direct load control of discrete appliances such as water heaters and air-conditioning systems (Kamana-Williams & Bishop, 2024; Kanakadhurga & Prabaharan, 2022; Vandoorn et al., 2011). In New Zealand, ripple-control of residential hot-water cylinders is a mature and widely deployed mechanism, and WELL continues to employ this scheme as its principal DSM instrument. Cost comparisons indicate that ripple-controlled demand reduction, at around NZD 10–27 per kW, is substantially cheaper than traditional network reinforcement at about NZD 130 per kW of added capacity, illustrating the enduring economic appeal of basic load control (Wellington Electricity, 2025).

More recent literature extends DSM beyond simple peak-shaving towards dynamic, price-responsive and transactive frameworks. Time-of-use (TOU) tariffs, critical-peak pricing, and real-time pricing are commonly used to elicit voluntary demand shifting, often in conjunction with automation via home energy management systems (HEMS) (Kanakadhurga & Prabaharan, 2022; Xi et al., 2025; Zhu et al., 2015). WELL's move to enrol roughly 95% of residential customers in TOU pricing schemes reflects this global shift and aligns with evidence that clear temporal price signals can meaningfully reduce peak demand and enable higher DER penetration when supported by automation (Wellington Electricity, 2025). However, behavioural studies caution that consumer engagement with complex tariffs can be limited, necessitating "set-and-forget" automation to avoid fatigue and ensure persistent response (Mansouri et al., 2021; Tomaselli et al., 2024).

Transactive energy (TE) concepts, including distribution locational marginal pricing (DLMP), peer-to-peer (P2P) trading, and flexibility markets, are increasingly discussed as mechanisms to internalise local network conditions into economic signals (Fattaheian-Dehkordi et al., 2022; Kanakadhurga & Prabaharan, 2022). In such models, aggregators or smart devices act as agents that respond to dynamic prices reflecting congestion and losses across the LV network (Kurundkar & Vaidya, 2023). WELL's participation in the Resi-Flex project and the cross-industry FlexForum indicates early movement in this direction, with a focus on designing products that reward residential customers for deferring EV charging or other discretionary loads in response to network needs (Wellington Electricity, 2025). This aligns with international developments where "nego watt" products—commercially verifiable demand reductions—are treated as tradable resources in capacity or ancillary services markets (Kanakadhurga & Prabaharan, 2022).

On the control-architecture side, the literature emphasises decentralised and hierarchical strategies, including multi-agent systems (MAS) and model predictive control (MPC), to coordinate large populations of flexible devices (Kumar Nunna & Doolla, 2013). MAS approaches assign local intelligence to individual DER or aggregators, negotiating schedules through auctions or distributed optimisation, thus improving scalability and preserving privacy (Karandeh et al., 2022). MPC, by contrast, leverages forecasts of demand, prices, and renewable output to compute optimal control trajectories over a receding horizon, enabling anticipatory EV charging and building pre-heating or pre-cooling (Nair et al., 2021). WELL's strategic focus on automated, hierarchical DSM—linking household-level controllers, neighbourhood aggregators, and system-level objectives—is consonant with these frameworks, but its implementation is currently at an early, trial-based stage (Wellington Electricity, 2025).

Despite the technical maturity of DSM technologies, multiple studies emphasise that operational deployment at scale remains constrained by regulatory, data, and institutional barriers (Boston Consulting Group, 2022). Wellington exhibits these limitations acutely: limited LV visibility hinders safe coordination of decentralised assets; formal frameworks for valuing and procuring flexibility are still emerging; and customers are not yet required to notify the network of significant flexible asset installations, such as EV chargers or domestic batteries (Wellington Electricity, 2025). Consequently, DSM cannot yet be treated as a fully reliable substitute for conventional reinforcement, even though WELL's asset management policy requires it to be considered before new network investment (Wellington Electricity, 2025).

2.1.4. Battery energy storage and EVs

Battery energy storage systems play a pivotal role in many of the DSM and microgrid strategies, enabling temporal decoupling between renewable generation and demand.

The literature distinguishes between behind-the-meter (BTM) storage, utility-scale front-of-the-meter BESS, operational substation batteries for control and protection, and EV batteries acting as mobile storage (Bhattarai et al., 2017; Karandeh et al., 2022). In the WELL network, BTM storage is "becoming more common," often paired with rooftop PV for self-consumption and backup, but there are currently no operational utility-scale BESS projects exceeding 1 MW. Instead, the region's embedded generation portfolio is dominated by the 60 MW Mill Creek wind farm, diesel generation, landfill gas units, and small hydro plants (Wellington Electricity, 2025).

This absence of grid-scale storage distinguishes Wellington from other New Zealand regions where large BESS projects and virtual power plant (VPP) schemes are under active development, highlighting a gap between international best practice and local deployment. At the same time, WELL operates an extensive fleet of substation DC batteries—around 552 banks at 297 sites—but these are dedicated to control and protection functions and are not used for bulk energy shifting or congestion management (Wellington Electricity, 2025). The literature suggests that repurposing or augmenting such infrastructure for system-level services would require substantial redesign of control schemes, safety protocols, and regulatory arrangements (Kurundkar & Vaidya, 2023).

EVs represent a rapidly growing reservoir of mobile storage, with Wellington hosting approximately 13,000 EVs and plug-in hybrid vehicles as of late 2024 (Wellington Electricity, 2025). Global research has demonstrated the theoretical potential of both unidirectional smart charging (V1G) and bidirectional vehicle-to-grid (V2G) to provide peak-shaving, frequency regulation, and local congestion relief (Tushar et al., 2018). However, concerns about battery degradation, user acceptance, and charger availability have limited the extent of real-world V2G deployment (Padmawansa et al., 2023). Wellington's current strategy emphasises managed charging to avoid coincident evening peaks, aligning with evidence that simple charging-window control and TOU tariffs can deliver significant benefits even without full V2G functionality (Wellington Electricity, 2025).

A recurring challenge in the BTM and EV storage literature is visibility and data quality (Jayasinghe et al., 2024). In WELL's case, customers are not formally obligated to inform the distributor when installing residential batteries or high-capacity EV chargers, leading to substantial uncertainty about the aggregate flexible capacity and its spatial distribution (Wellington Electricity, 2025). This mirrors international findings that unreported DER can undermine network models, complicate hosting-capacity assessments, and reduce the reliability of DSM programmes (van Westering & Hellendoorn, 2020). Enhanced registration schemes, data-sharing arrangements, and LV monitoring—such as WELL's planned deployment of 50 transformer monitors in high-growth or socioeconomically vulnerable suburbs—are thus recognised as critical enablers for turning distributed storage into a dependable planning and operational resource (Wellington Electricity, 2025).

2.2. Synthesis and identified gaps

Across these four domains, the literature broadly supports the technical feasibility and economic attractiveness of leveraging DSM, DER, and storage to manage hosting capacity constraints and enhance resilience in distribution networks. At the same time, the WELL case study reveals several important gaps between existing research and practical implementation in an urban, seismically exposed, and economically constrained context.

First, while many studies treat hosting capacity, DSM, and microgrids as relatively separate topics, Wellington's experience underscores their tight interdependence: congestion, voltage limits, N-1 security, and LV visibility jointly determine the value and deployability of flexible resources (Wellington Electricity, 2025). There remains limited work that integrates these facets into a unified, distribution-operator-centred framework tailored to mid-size urban networks with pronounced local bottlenecks but system-wide spare capacity (Boston Consulting Group, 2022; Wellington Electricity, 2025).

Second, existing microgrid literature tends to focus either on fully islanded remote systems or on well-defined campus microgrids, offering less guidance on how to orchestrate a "fleet" of household-scale PV-plus-battery systems and flexible loads within a larger urban grid (Xi et al., 2025). Wellington's lack of formal microgrids but growing portfolio of microgrid-like assets, such as critical-infrastructure generators and virtual trading trials, exemplifies this partial and fragmented evolution (Wellington Electricity, 2025). Research that explicitly addresses incremental pathways from today's embedded networks and DSM pilots to coordinated nano grids and community microgrids in a city like Wellington remains sparse.

Third, despite substantial global work on EV smart charging and DSM algorithms, there is a dearth of studies that embed these techniques into the specific regulatory, tariff, and asset-condition landscape of New Zealand distribution businesses (Wellington Electricity, 2025). WELL operates under Commerce Commission determinations that tightly constrain capital expenditure and explicitly prioritise non-network solutions, while facing ageing infrastructure, single points of failure, and uncertain decarbonisation trajectories (Wellington Electricity, 2025). Few publications analyse how EV-centric DSM and distributed storage can be co-optimised under such regulatory and economic constraints, particularly when base demand is stagnant or declining, as seen in Wellington (Bhattarai et al., 2017; Fattaheian-Dehkordi et al., 2022; Nair et al., 2021).

Finally, the literature increasingly recognises the importance of data and digitalisation, yet concrete models that link LV visibility investments—such as transformer monitors and LV constraint mapping—to quantifiable gains in hosting capacity and deferral of specific reinforcement projects remain rare (Boston Consulting Group, 2022; van Westering & Hellendoorn, 2020; Wellington Electricity, 2025). WELL's ongoing pilots with LV monitoring and digital twin platforms, such as Future Grid, provide an empirical basis for such analysis, but structured methodologies for translating improved visibility into validated operating envelopes and commercially robust flexibility products are still emerging (Padmawansa et al., 2023). Addressing these gaps, the present work positions Wellington as a detailed case study to develop and test an integrated DSM and distributed storage framework that explicitly accounts for local hosting-capacity constraints, resilience risks, regulatory incentives, and data limitations in a real urban distribution network.

3. Research methods

This study employs a quantitative, model-based methodology to evaluate coordinated demand-side management (DSM) and distributed storage solutions to alleviate constraints in Wellington Electricity (WELL) 's distribution network. Detailed line and transformer data were obtained directly from Wellington Electricity, paired with load profiles representative of medium-income households. Representative network models were developed and simulated in Power Factory software, incorporating real-life components for photovoltaic (PV) systems and battery storage, while explicitly modelling distribution lines, low-voltage (LV) cables, and service mains.

The research unfolds through three progressive simulation cases implemented in Power Factory's quasi-dynamic simulation environment, targeting thermally constrained feeders and zone substations. Each case builds incrementally to isolate the impacts of PV-battery integration and DSM on transformer loadings, reverse power flows, and overall network performance.

3.1. Research details

3.1.1. The Kilbirnie network

The Kilbirnie region, supplied by the Evans Bay and Hataitai zone substations, is currently not capacity-constrained but is expected to experience rising electrical loading over the longer term, primarily due to decarbonisation (fuel switching) and urban intensification, even though recent economic conditions have flattened short-term forecasts. In the present state, Evans Bay recorded a 2024 winter peak of 13.1 MVA against an N-1 firm capacity of 24.0 MVA (around 55% utilisation), and Hataitai reached 15.2 MVA against 21.0 MVA firm capacity (about 72% utilisation), with both substations serving a winter-peaking, largely residential load dominated by evening heating. Demand across the wider Southern Area has been flat or slightly declining since 2014, reflecting milder winters, improved efficiency, and a modest population decline. Current planning projections indicate that both substations will remain within N-1 limits through at least 2035 (Wellington Electricity, 2025).

Over the longer term, however, several decarbonisation-related and demographic factors are expected to drive higher loading. First, Kilbirnie and the Southern Area have extensive reticulated gas use for space heating, cooking, and hot water, so the gradual transition to electric heat pumps, induction cooktops, and electric hot-water systems will increase household diversity after maximum demand, especially in the evening peak, as gas water heating and cooking are replaced by electrical demand. Although earlier planning assumed that 50% of residential gas customers would switch to electricity by 2035, current forecasts—tempered by economic headwinds—now assume only a 10% transition over that period, slowing but not eliminating this long-term driver. Second, private electric-vehicle uptake, starting from roughly 13,000 EVs in the WELL area in late 2024 and projected to grow to around 17% of the fleet by 2035, adds about 0.9 kW of ADMD per vehicle, with uncoordinated evening charging posing a particular risk of overloading local transformers; public fast-charging sites contribute further point loads, although emerging "operating envelope" arrangements are expected to limit their draw to around 10% of rated capacity during peaks. Third, urban intensification through infill housing, multi-unit dwellings, townhouses, and apartments replacing single dwellings raises both connection density and load density on existing LV networks, so even with more efficient buildings, the higher number of customers per street transformer tends to increase total loading. Finally, because the area is explicitly winter-peaking, any shift from gas heating to electric heating will sharpen the existing 6 p.m. winter peak rather than smoothing it, in contrast to the CBD's emerging summer-peaking profile driven by air-conditioning (Wellington Electricity, 2025).

Several factors are currently moderating the speed of this load growth. High inflation, elevated interest rates, and weaker economic conditions have slowed both residential development and commercial investment, including decarbonisation projects. Policy changes, notably the removal of the clean car discount and a scaling back of initiatives such as the GIDI fund, have cooled EV uptake and delayed some industrial fuel-switching. In addition, earlier expectations of substantial new demand from electrified public transport have been revised downward, as delays or cancellations of bus and ferry electrification projects have removed an estimated 51 MW of load (forecast) from the wider region's ten-year outlook. Taken together, these mitigating influences mean that immediate capacity pressures in Kilbirnie have eased; nonetheless, the underlying trajectory remains upward as transport and heat progressively electrify on a network that already exhibits strong winter evening peaks (Wellington Electricity, 2025).

3.1.2. Data sources

Core inputs include WELL-supplied line and transformer ratings, impedances, and historical demand data from the 2025 Asset Management Plan, capturing an average zone-substation utilisation of 42.6% (versus New Zealand's median of 38.8%). DER penetration reflects 3,328 PV installations (15.9 MVA total capacity), ~13,000 EVs/plug-in hybrids as of late 2024, and projections for up to 65,000 residential gas-to-electricity transitions adding non-discretionary evening load (Wellington Electricity, 2025).

Medium-income household load profiles provide baseline patterns for residential demand, hot-water cylinder operation (typically 2-6 kW peak draw), and EV charging (typically 7-22 kW, single- or three-phase). DSM parameters are drawn from WELL's programmes: ripple-control economics (NZD 10–27/kW demand reduction versus NZD 130/kW reinforcement), ~95% TOU tariff coverage, and trials such as Resi-Flex, EV Connect, and Kāinga Ora multiple-trading relationships (Wellington Electricity, 2025).

3.1.3. Network and scenario modelling

In this study, Power Factory models were developed for the Kilbirnie supply area, focusing on the feeders and distribution transformers supplied from the Evans Bay and Hataitai zone substations (see Figure 1). The models explicitly represent the local 11 kV and low-voltage (LV) topology, using Wellington Electricity data for distribution lines (ampacities, R/X ratios), LV cables, service mains, and transformer ratings to ensure the simulated network closely reflects actual asset characteristics and constraints in Kilbirnie. Local distribution transformers serving residential loads, the bus depot, and the retirement home were specifically modelled as Points of Common Coupling (PCCs) for microgrid connections to the grid, with loading conditions monitored at these nodes across all cases. Three quasi-dynamic simulation cases were then run sequentially over representative winter and summer weeks at hourly or sub-hourly resolution:

- **Case 1 – Base case:** The existing Kilbirnie network was modelled using only current residential loads, with demand profiles representative of medium-income households. In addition to standard residential demand, the model explicitly includes a local bus depot and a retirement home as separate large customer connections. Bus-charging behaviour was parameterised using publicly available information from Metlink (2023), reflecting the current fleet of 119 electric buses: 9 Yutong E13 vehicles on the AX route, each with a 465 kWh battery (en.yutong.com, 2026), and 110 additional electric buses on other routes, comprising single-deck CRCC ET12-max (Yutong, 2026) and double-deck Yangtze UT200RHDF (Dongfeng, 2026) models. All buses are assumed to charge predominantly between 23:00 and 05:00 (Metlink, 2023). This case quantifies present transformer loadings at the Evans Bay and Hataitai zone substations, as well as on local distribution transformers serving these loads (used as PCCs), and confirms available headroom under current winter evening peaks.

Figure 1. The Kilbirnie area and the transformers under simulation

- **Case 2 – PV-battery saturation:** Rooftop PV systems using Longi Solar LR6-66HVD-640M modules (Longi Solar, 2026), typically 5 kW per house paired with one unit of Sigenergy's SigenStor EC 3.0 TP per residential connection and BESS around 45.2 kWh using SigenStor BAT LiFePO4-10 batteries (sigenergy, 2025a; 2025b) were added to every house in the Kilbirnie area. At the bus depot, a central PV plant of 832 kW with the same Longi modules was integrated with 18 units of Sigenergy's SigenStor EC 30 TP (delivering 2 MWh total storage capacity) and a Sigen Gateway C-1200 for grid connection. The retirement home received a 166.4 kW PV array, 4 units of SigenStor EC 30 TP, and 200 kWh of total storage using SigenStor BAT LiFePO4-10 batteries, with a Sigen Gateway C180-9 (Sigenergy, 2025a) for grid connection. Realistic component models, including inverter efficiency, battery C-rates, and state-of-charge limits, were used to assess the impact of widespread PV-battery deployment on loading of local distribution transformers (PCCs), with particular attention to transformer utilisation, reverse power flows, daytime voltage rise, and potential curtailment under high solar export.
- **Case 3 – DSM optimisation:** Building on Case 2, this scenario applies DSM measures across Kilbirnie by shifting controllable hot-water cylinder operation and EV charging from the traditional evening peak into daytime PV generation hours. This is implemented in the model through ripple control, time-of-use price signals, and V1G (managed) EV charging schedules. In this scenario, the model assumes the entry and exit points for EV's, and Hot Water Cylinders are staggered hourly throughout the PV availability hours. This staggered integration better reflects empirical consumer behaviour and mitigates the risk of overestimating instantaneous peak demand. However, the Bus Depot is operating as usual. Simulations are then used to reevaluate loading on local distribution transformers (PCCs), transformer headroom restoration, reverse power flow mitigation at Evans

Bay and Hataitai zone substations, and compliance with LV voltage limits under coordinated microgrid operation.

4. Results and discussion

4.1. Transformers with residential loading (SO_177 & TS_2036)

4.1.1. SO_177 transformer

- **CASE 1: Base Case Scenario:** The transformer operates near its thermal limits (see the green curve in Figure 2). The loading profile includes residential and EV loads. The transformer is heavily loaded untill 06.00 hrs (between 80% & 90%), whereafterthe EV load starts to decrease and reaches the point where no EVs are being charged (at 07.00 hrs). The transformer loading decreases to 45 % and remains between 40% and 50%. However, at 19.00 hrs, when most people are back home and start charging their EVs, the load rises again, reaching between 80% and 90% by 20.00 hrs and remaining at that level for the rest of the night.

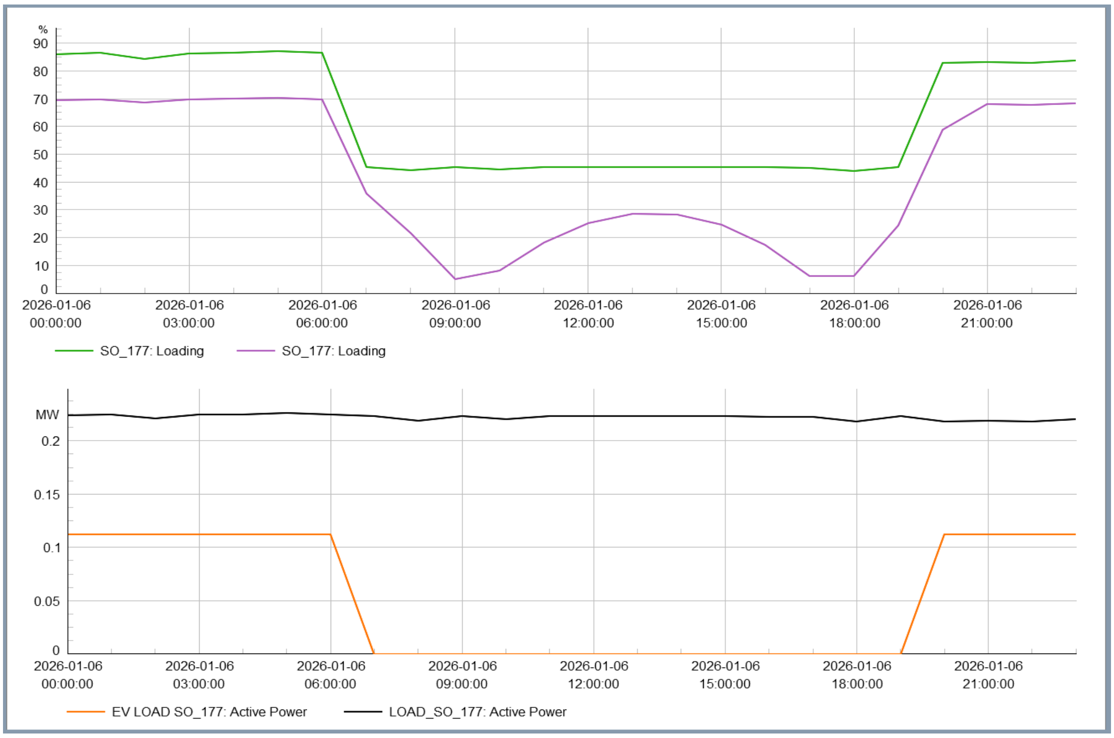

Figure 2. (a) Transformer loading in case 1 (green curve), and case 2 with PV and BESS integration (b) Residential load on the transformer (black curve) and EV loading (orange curve)

- **Case 2: PV + BESS Implementation:** Implementing PV and BESS without DSM introduces the reverse power flow phenomenon (see the purple curve in Figure 2).
    - **Night-time:** The night-time profile sees a drop in transformer loading (decreasing from 85% to less than 70%) as the battery charged during the daytime is being discharged at this time, providing some relief to the asset during night-time operation.
    - **Daytime:** Loading starts to decrease from 06.00 hrs as EV charging declines. At 07.00 hrs, when there is no EV charging, transformer loading decreases and falls below 10% at 09.00 hrs due to PV power, which is enough to offset

almost all residential loads. However, after 09.00 hrs, transformer loading begins to rise, reaching around 30% by midday. At 17.00 hrs, it has fallen below 10%. This time frame, between 09.00 hrs and 17.00 hrs, is the time of reverse power flow. After 18.00 hrs, loading again starts to rise as people start plugging in EVs for charging, and at 21.00 hrs, it reaches its maximum (70%).

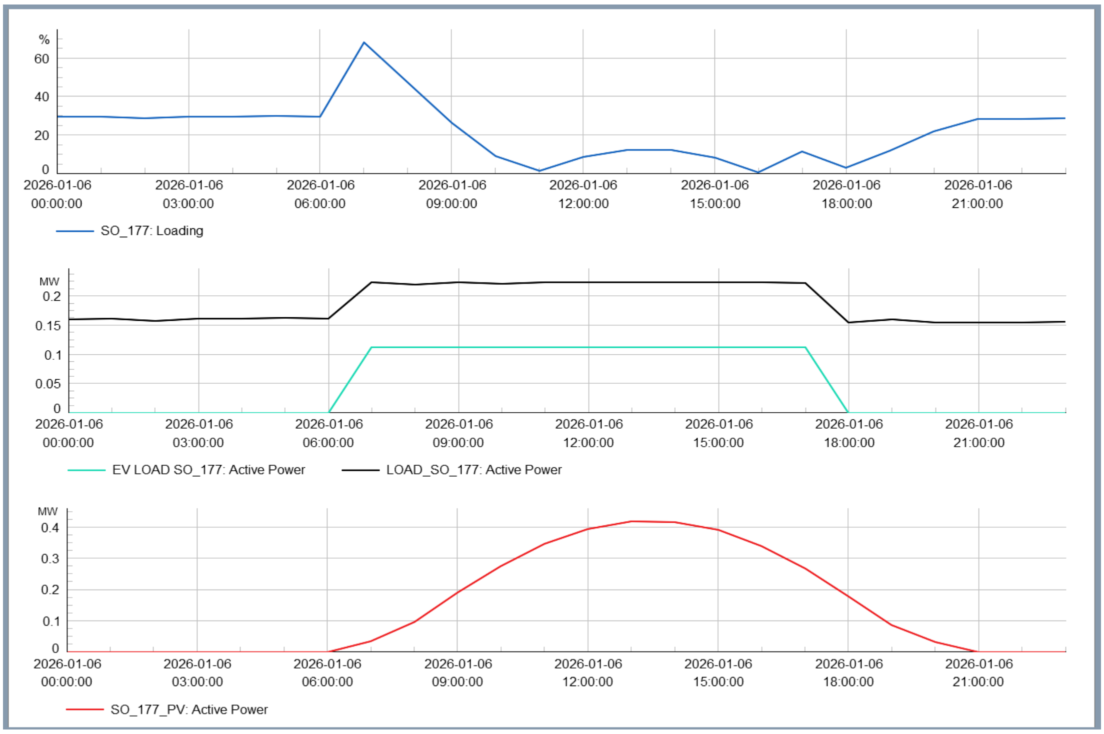

Figure 3. (a) Transformer loading in case 3 (blue curve), with PV and BESS integration along with demand control (b) Controlled or shifted to daytime residential load on the transformer (black curve) and EV loading (sea green) (c) PV output at the respective time of the day

- **Case 3: PV + BESS + DSM:** This scenario (Figure 3) demonstrates the synergistic benefit of shifting heavy loads (EV charging and hot water cylinders) to solar hours.
  - **Night-time relief:** The most significant result is the reduction in base loading during the non-solar hours (till 06.00 hrs). Loading drops from around 85% base to 30 %. This shift essentially saves the transformer, moving it from a critical overload state to a healthy operational zone.
  - **Daytime operation:** After 06.00 hrs, when EV charging begins, and hot water cylinders start operating, loading increases to a maximum of 70% at 07.00 hrs. However, after 07.00 hrs, transformer loading begins to decrease (due to increased PV power), reaching 0% at 11.00 hrs. From 11.00 hrs to 17.00 hrs, the loading again rises as the PV power output peaks, and we reverse the power flow. Transformer loading reaches 0% at 16.00 hrs, as PV power output starts to decrease after 14.00 hrs. At 16.00 hrs, it is only enough to offset all the load, and no power is sent back to the grid. After 16.00 hrs (since PV output decreases as the evening progresses), there is a rise in load until 17.00 hrs (when the grid feeds the load). After 17.00 hrs, when EV charging stops, and no hot water cylinder is operating, the loading is at 5%. After 18.00 hrs, loading again starts to rise as PV power is insufficient to offset the

remaining residential load. At 21.00 hrs, loading reaches 30% as there is no PV power; the grid and the BESS supply the load.

4.1.2. TS_2036 transformer

- **Case 1: Base Case Scenario:** The base case indicates a transformer operating between 70% and 80% (green curve in Figure 4). The loading profile includes residential and EV loads. The transformer is highly loaded till 06.00 hrs (between 70% and 80%), whereafter the EV load starts to decrease and reaches the point where no EVs are being charged (at 07.00 hrs). The transformer loading decreases to 40% and remains between 40% and 50%. However, at 19.00 hrs, when people start charging their EVs, the load rises again, reaching more than 70% at 20.00 hrs and remaining between 65% and 75% for the rest of the night.
- **Case 2: PV + BESS Implementation:** Implementing PV and BESS without DSM introduces the reverse power flow phenomenon (purple curve in Figure 4).
    - **Night-time:** The night-time profile shows a slight drop in transformer loading as the battery discharges. There is no such big difference in night-time operation.
    - **Daytime:** Loading starts to decrease from 06.00 hrs as EV charging begins to decline. At 07.00 hrs, when EV charging is not in use, transformer loading decreases and falls below 5%, with PV power offsetting almost all residential loads. However, after 09.00 hrs, transfer loading starts to increase, reaching around 35% by midday. By 17.00 hrs, it has fallen below 10%. This time frame, between 09.00 hrs and 17.00 hrs, is the time of reverse power flow. After 18.00 hrs, the loading again starts to rise as people plug in their EVs to charge. At 21.00 hrs, it reaches 65% and stays between 65% and 75% for the remainder of the night.

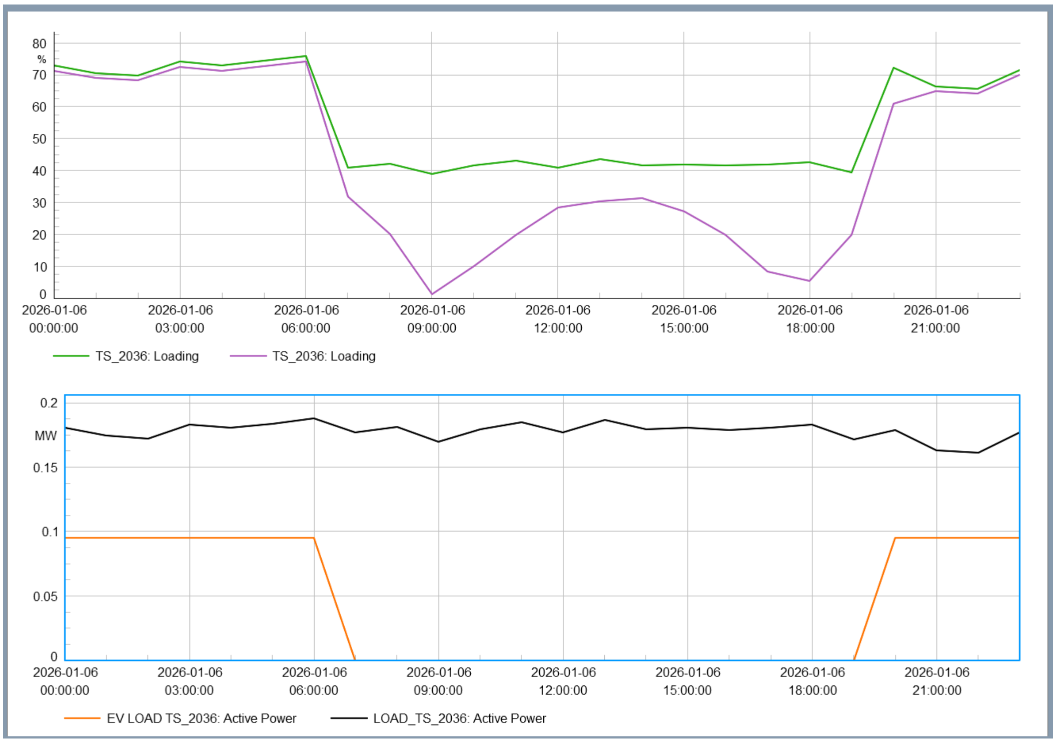

Figure 4. (a) Transformer loading in case 1 (green curve), and case 2 with PV and BESS integration (b) Residential load on the transformer (black curve) and EV loading (orange curve)

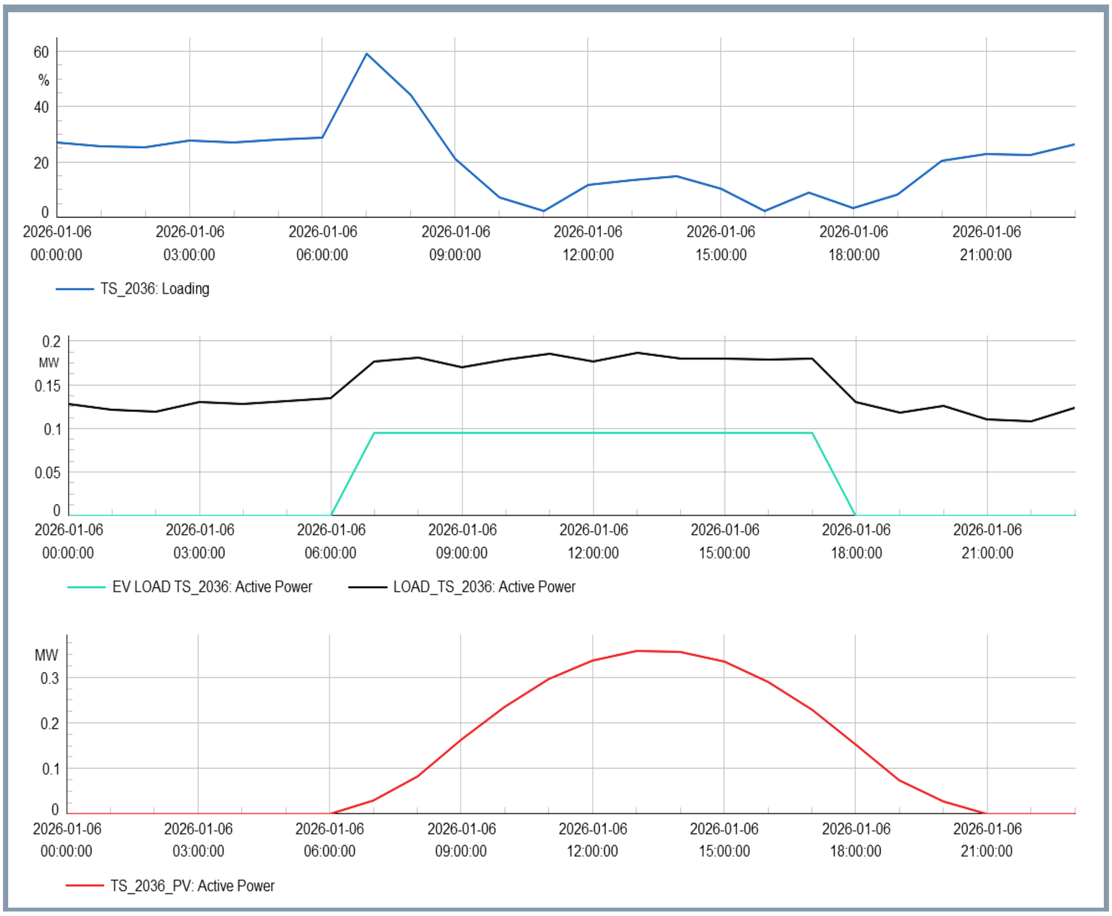

Figure 5. (a) Transformer loading for case 3 (blue curve) with PV and BESS integration and Demand Control (b) Controlled or shifted to daytime residential load on the transformer (black curve) and EV loading (sea green) (c) PV output at the respective time of the day

- **Case 3: PV + BESS + DSM:** This scenario (Figure 5) demonstrates the synergistic benefit of shifting heavy loads (EV charging and hot water cylinders) to solar hours.
  - **Night-time relief:** The most significant result is the reduction in base loading during the non-solar hours (till 06.00 hrs). Loading drops from around 75% base to 25 %.
  - **Daytime operation:** After 06.00 hrs, when EV charging begins, and Hot water cylinders start operating, loading increases to a maximum of 60% at 07.00 hrs (because, until then, PV power is not enough to offset the demand). However, after 07 hours, the transformer loading starts to decrease (an increase in PV power), reaching 5% at 11.00 hrs. From 11.00 hrs to 16.00 hrs, the loading again rises as the PV power output peaks, and we reverse the power flow. Transformer loading again reaches 5% at 16.00 hrs, as PV power output starts to decrease after 14.00 hrs. At 16.00 hrs, it is only enough to offset all the load, and no power is sent back to the grid. After 16.00 hrs (since PV output decreases as the evening progresses), there is a rise in load until 17.00 hrs when the grid feeds the load. After 17.00 hrs, when EV charging stops, and the hot water cylinders are not operating, loading reaches 5%. After 18.00 hrs, loading again starts to rise as PV power is insufficient to offset

the remaining residential load. At 21.00 hrs, loading reaches 25% as there is no PV power; the grid and the BESS supply the load, and loading stays between 25% and 30% for the rest of the night.

4.2. The retirement home

- **Case 1 Base Scenario:** The base case reflects the existing aggregate load of the retirement village.
  - **High baseload:** Unlike standard residential areas, where loads drop significantly during working hours, the retirement home maintains a consistently high loading factor (around 30%) throughout the day (09:00 to 19:00 hrs). This reflects the high daytime occupancy rate, with residents present and utilising heating, cooling, and communal facilities.
  - **Morning and evening peaks:** Distinct peaks are observable at 07:00 hrs (breakfast/morning routine) and 19:00 hrs (dinner/evening heating), reaching approximately 30% loading. This "Domestic-Commercial Hybrid" profile indicates a facility that is well-utilised but operating comfortably within its transformer capacity.

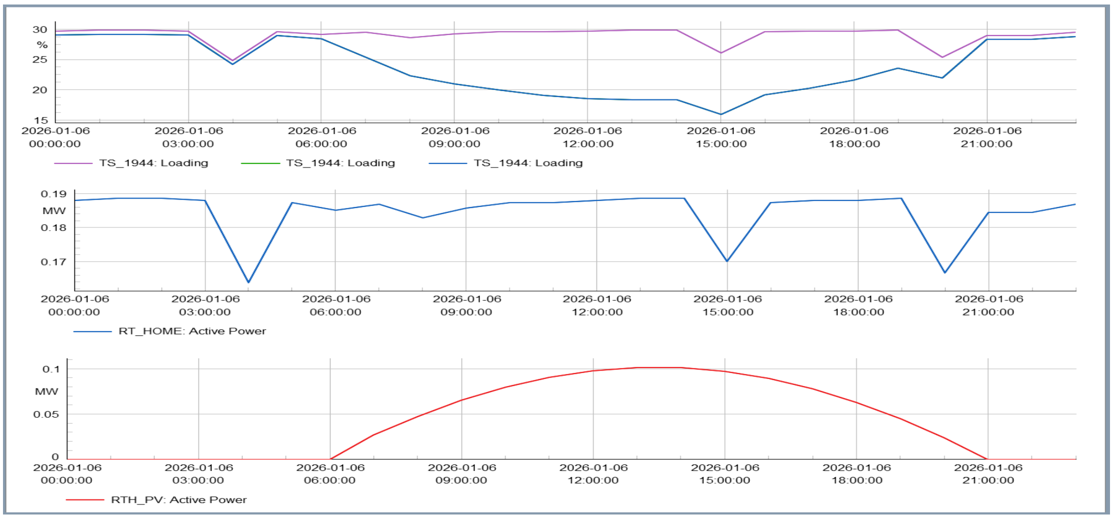

Figure 6. (a) Transformer loading in all cases (case1: purple curve, case2: green curve and case3: blue curve) (b) Retirement home's load profile (c) PV output at the respective time of the day

- **Case 2 and 3 PV + BESS ontegration:** The introduction of PV and BESS creates a significant "Solar Trough" in the load curve. Since no DSM was applied, the green and purple curves are identical, representing a "Passive" integration strategy.
  - **Daytime load reduction:** As solar generation rises, it directly offsets the facility's baseload.
  - **Peak reduction:** At 14:00 hrs, the transformer loading drops from ~30% (Base) to ~17% (PV Case).
  - **Maximum impact:** The widest divergence occurs around noon, where roughly 15 percentage points reduce the load. This confirms that the facility has a high rate of natural self-consumption; the energy generated is immediately used by the daytime loads (HVAC, kitchen, medical equipment) rather than being exported.
  - **The "duck curve" formation:** The steep ramp rates observed between 15:00 hrs and 19:00 hrs (where loading rises from ~16% back to ~28%) introduce

a new stressor. The grid must essentially pick up the entire facility load within 4 hours as the sun sets, and the evening peak begins.

4.2.1. Discussion: The occupancy advantage

A key finding is that retirement homes represent an ideal use case for passive PV integration due to their occupancy profile:

- **Standard residential versus retirement:** In standard residential feeders (like SO_177), the midday load is low because residents are at work, leading to high export/reverse power flow issues.
- **The retirement advantage:** In TS_1944, the residents are home. The "base case" purple line stays high during the day. This means PV energy is naturally absorbed by existing demand. The facility achieves a ~40% reduction in daytime grid power without behavioural load shifting.

4.2.2. Missed opportunities (the lack of DSM)

The identical nature of Case 2 and Case 3 highlights a missed opportunity for thermal storage:

- **Water heating potential:** Retirement homes have a high hot water demand (hygiene, laundry, catering). If DSM had been applied (Case 3), the electric water-heating load could have been synchronised with the 12:00–15:00 hrs solar peak.
- **Result:** This would have raised the "trough" (currently at 16%) and lowered the evening peak (currently at 30%), flattening the curve further. The current "passive" system saves energy but does not reduce the peak demand charge (which is set by the 19:00 hrs peak).

4.3. The bus depot and SO_473 transformer

This section evaluates the grid impact of electrifying a bus depot with a specific "Night Charging" profile (23:00–05:00 hrs). The analysis contrasts two distinct infrastructure setups:

- **Dedicated Feeders (TS_2415, TS_2702):** Transformers supplying only the bus depot.
- **Mixed-Use Feeder (SO_473):** A transformer supplying the bus depot alongside a residential neighbourhood.

4.3.1. The dedicated feeders

These transformers (Figure 7) serve a pure commercial load with a rigid operating schedule. The simulation results reveal a binary operational state: "Idle" during the day and "Heavy Duty" at night. The behaviour of the daytime load curves confirms the reverse power flow.

- **The "camel hump" phenomenon:**
    - **Base case (C1 – purple curves):** During the day (05:00–21:00 hrs), the transformers carry a negligible load (around 10%), reflecting the empty depot.
    - **PV integration (C2/C3 – blue and green):** Instead of dropping to zero, the loading increases significantly, peaking at roughly 20% at noon.
    - **Interpretation:** Since the depot has no significant daytime load to consume the generated solar energy (approximately 0.6 MW peak from BUS_PV), the entire generation output is being forced back through the transformer into the medium voltage grid. The "load" shown on the graph is the exported power (from 09.00 hrs to 18.00 hrs).

- **Inefficiency:** The identical overlap of Case 2 and Case 3 confirms that without DSM, the depot is a passive generator during the day. The transformer is being stressed (albeit lightly at 20%) solely to export energy that is not being used locally.

Figure 7. (a) TS_2415 transformer loading in all cases (case1: purple curve, case2: green curve and case3: blue curve) (b) TS_2702 transformer loading in all cases (case1: purple curve, case2: green curve and case3: blue curve (c) Load profile of the bus depot (d) PV output at the respective time of the day

- **The night-time block load:**
  - **Grid stress:** From 22:00 to 05:00 hrs, the transformers undergo a significant step change, jumping to ~60% loading. This "square wave" profile is characteristic of unmanaged fleet charging.
  - **DSM absence:** Because no DSM was applied to the buses (charging remains fixed at night), the PV/BESS integration offers zero relief to this peak. The batteries charge during the day (contributing to the reverse flow issue), but evidently do not discharge sufficient capacity to offset the massive night demand.

4.3.2. Analysis of mixed-use transformer (SO_473)

Transformer SO_473 (Figure 8) presents a more complex dynamic, as it must balance the rigid industrial load of the bus depot with the flexible domestic load of the residential neighbourhood.

- **Case 1 base case scenario:** The base case indicates a transformer operating between 80% and 85% (green curve). The loading profile includes residential and EV loads. The transformer is highly loaded until 05:00 hrs. Bus charging stops around 05.00 hrs, and as the EV load decreases, it reaches a point where no EVs are being charged (at 07.00 hrs). The transformer loading decreases to 20% and remains around 20%. However, at 19.00 hrs, when people start charging their EVs, the load begins to rise again, reaching more than 30% at 20.00 hrs. However, when buses begin charging around 22.00 hrs, it rises towards heavy loading (around 80%) and stays between 80% and 85% for the rest of the night.

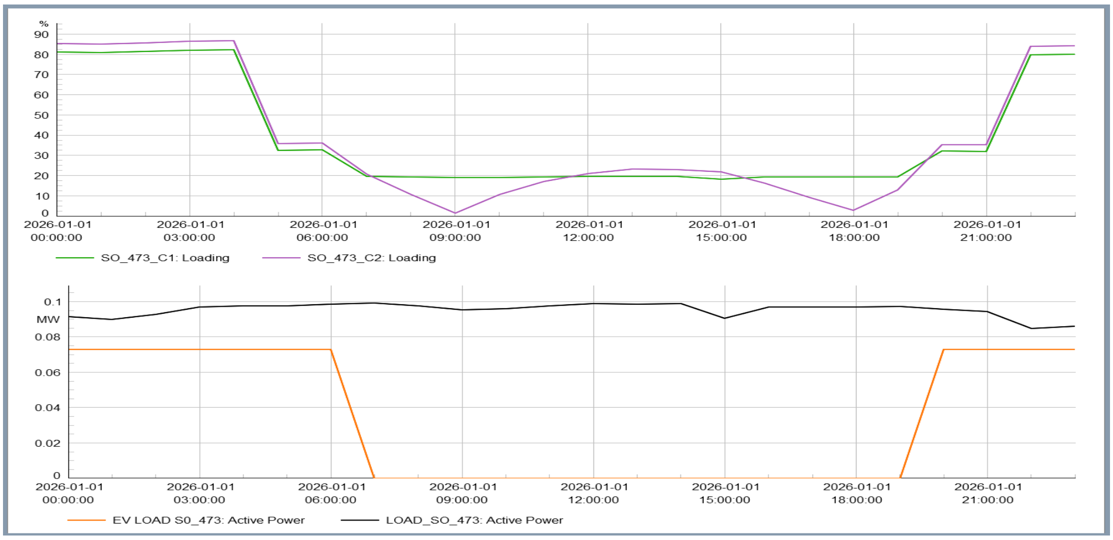

Figure 8. (a) Transformer loading in case 1 (green curve), and case 2 with PV and BESS integration (b) Residential load on the transformer (black curve) and EV loading (orange curve)

- **Case 2 PV + BESS implementation:** Implementing PV and BESS without Demand Side Management introduces the reverse power flow phenomenon (purple curve).
  - **Night-time:** The night-time profile shows a slight increase in transformer loading as the battery discharges.
  - **Daytime:** Loading starts to decrease from 06.00 hrs as EV charging begins to decline. At 07.00 hrs, when there is no EV charging, transformer loading decreases and falls below 5% due to PV power, which is enough to offset almost all the residential loads. However, after 09.00 hrs, the transformer loading starts to rise, reaching around 25% in midday (we have reverse power flow from around 11.45 hrs to 15.30 hrs). After 15.30 hrs, it starts to decrease again and returns to around 5%. After 18.00 hrs, loading again starts to rise as people start plugging in their EVs for charging. BESS discharges, with some reverse power flow starting from 19.30 hrs. At 22.00 hrs, it reaches 85% and remains between 80% and 85% for the rest of the night.
- **Case 3 PV + BESS + DSM:** The most significant finding is the impact of residential DSM on the total transformer peak, which occurs at night due to the bus charging.

The scenario in Figure 9 demonstrates the synergic benefit of shifting heavy loads (EV charging and hot water cylinders) to solar hours.

- **Night-time relief:** The most significant result is the reduction in base loading during the non-solar hours (till 06.00 hrs). Loading drops from around 85% base to 62.5% till 04.00 hrs, and to around 17% at 05.00 hrs due to no bus charging inside the bus depot.
- **Daytime operation:** After 06.00 hrs, when EV charging begins, and Hot water cylinders start operating, loading increases to a maximum of 37% at 07.00 hrs (because, until then, PV power is not enough to offset the demand). However, after 07.00 hr, transformer loading starts to decrease (due to increased PV power) and reaches 5% at 11.00 hrs. From 11.00 hrs to 16.00 hrs, the loading again rises as the PV power output peaks, and we have less reverse power flow than in Case 2.

Transformer loading again reaches 5% at 16.00 hrs, as PV power output starts to decrease after 14.00 hrs. At 16.00 hrs, it is only enough to offset all the load, and we do not have any power to send back to the grid.

- **Night-time operation:** After 18.00 hrs (when PV output decreases), a rise in loading is observed until 20.00 hrs (when the grid feeds the load). At 22.00 hrs, we observe a sudden increase in transformer loading (around 62.5) as buses return to the bus depot and night charging begins. However, the night loading of the transformer remains around 62.5%, indicating our asset is operating in a safe zone.

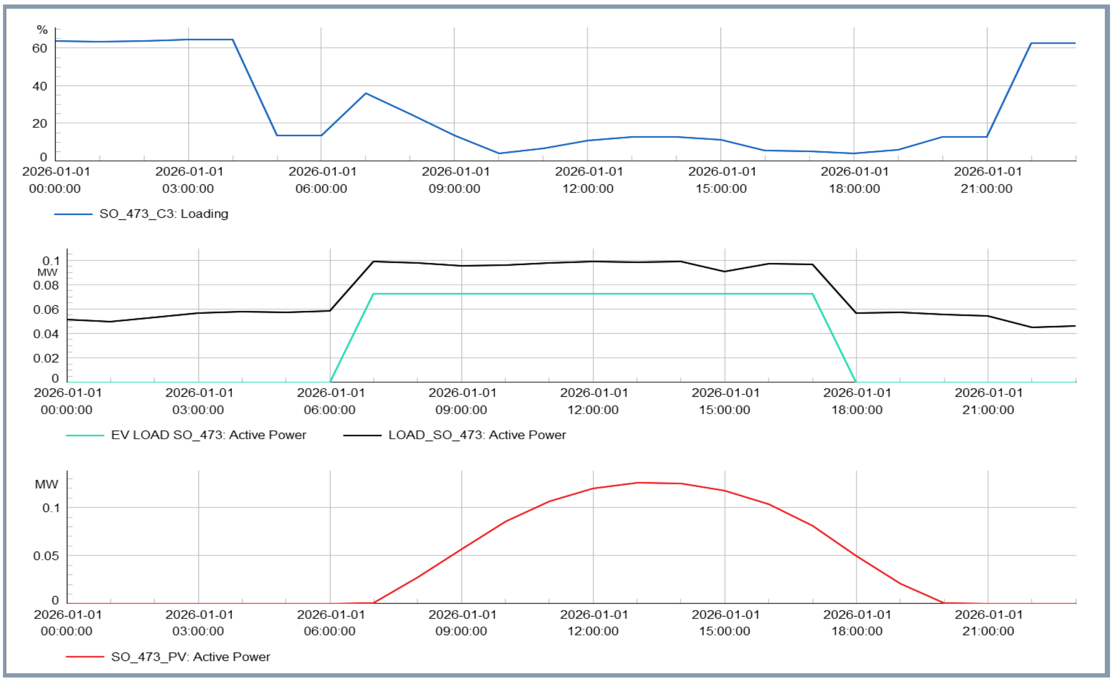

Figure 9. (a) Transformer loading in case 3 (blue curve), with PV and BESS integration along with demand control (b) Controlled or shifted to daytime residential load on the transformer (black curve) and EV loading (sea green) (c) PV output at the respective time of the day

5. Discussion and implications

Highly electrified feeders are limited less by midday PV generation than by unmanaged evening and night-time peaks from EV and fleet charging, and DSM is what materially restores transformer headroom rather than PV+BESS alone.

- **Transformer loading and reverse power flow**
  Across SO_177, TS_2036, and SO_473, base-case transformers remain at 70–90% loading overnight, indicating sustained thermal stress and little margin for further electrification. Passive PV+BESS then drives daytime loading down to below 5 to 10%, with systematic reverse power flow of roughly 10–30% whenever PV exceeds local demand, but night peaks remain in the 65–85% range and continue to govern sizing and ageing. These patterns confirm that PV+BESS mainly reshapes daytime flows and creates bidirectional operation windows rather than resolving the dominant night constraints.
- **DSM impacts on residential and mixed-use feeders**
  DSM that shifts EV charging and hot water cylinder heating to solar hours cuts night-time base loading in SO_177 and TS_2036 from roughly 75 to 85% down to about 25 to 30% before 06:00 hrs, moving transformers from critical to healthy

operating zones. Daytime loading briefly rises to around 60–70% in the early morning before PV ramps, then drops to 0–5% as PV fully covers local loads, with a renewed reverse power flow around midday. In SO_473, residential DSM reduces the combined night peak from about 85% to roughly 62.5%, showing that flexibility on the residential side can meaningfully mitigate inflexible depot charging.

- **Archetypes and occupancy profiles**
  The retirement home behaves as a domestic–commercial hybrid, with high daytime occupancy and a flat baseload, maintaining around 30% loading throughout most of the day, with modest peaks at 07:00 hrs and 19:00 hrs. Under passive PV+BESS, transformer loading falls to about 17% at 14:00 hrs and sees a maximum reduction of roughly 15 percentage points near noon, with high self-consumption and limited reverse power flow, but the evening peak near 30% remains largely unchanged. By contrast, bus depots show a binary pattern, with about 10% loading during the day and around 60% at night under fixed charging from 23:00–05:00 hrs, and PV+BESS mainly turn them into daytime generators without materially reducing the night block load.
- **Interaction in mixed-use feeders**
  In SO_473, the base case sees 80 to 85% loading at night when residential demand and bus charging overlap, and only about 20% during the day once charging ends. Passive PV+BESS suppress daytime loading to below 5% in the morning and 5 to 25% at midday with reverse power flow, yet the night peak still returns to 80 to 85% when buses charge. Adding residential DSM lowers this peak to around 62.5%, illustrating that partial flexibility can shift composite mixed-use assets back into safe thermal bands even when fleet schedules are rigid.
- **Planning and policy directions**
  Planning studies should treat DSM as a first-class instrument alongside PV and BESS, since shifting flexible loads into solar hours both increases PV self-consumption and relieves transformers that would otherwise be exposed to prolonged 70–90% loading. Hosting-capacity assessments and protection settings must explicitly incorporate bidirectional limits, as high PV penetration will create regular export windows coexisting with severe night imports and cumulative ageing in both directions. Policy should differentiate by archetype: high daytime-occupancy sites suit passive PV plus modest storage aimed at energy and emissions reduction, standard residential feeders need strong DSM and potentially coordinated storage to manage reverse power flow and EV peaks, and fleet depots require strategic, coordinated charging and advanced BESS control so that on-site PV actively reduces, rather than merely accompanies, new night block loads.

6. Conclusion

This paper examines how microgrids—deployed as PV, BESS, and DSM on real distribution transformers and load archetypes—address operational challenges in electrified networks. Simulations across residential households, a retirement-home, and bus-depot feeders reveal that passive PV+BESS primarily alters daytime flows and triggers reverse power flow, while coordinated DSM and control are vital for easing night peaks, boosting asset utilisation, and ensuring stability. Transformer limits in future grids stem equally from electrified transport, evening residential demand, and PV exports, underscoring the need for holistic microgrid planning and operation.

6.1. Achievement of objectives

The quasi-dynamic simulations show unmanaged EV charging, night-time bus depots, and ageing transformers cause prolonged 70 to 90% loading and thermal stress. Microgrids counteract this; PV cuts energy imports, BESS buffers peaks, and DSM manages reverse flows, restoring headroom. Coordinated DSM and BESS across residential, mixed-use, and commercial feeders emphasise shift-to-solar tactics, self-consumption, and fleet charging alignment within shared systems, enabling seamless integration.

DSM plus BESS dispatch transforms PV into a peak-relief asset, suiting diverse penetration levels. Loading profiles, reverse-flow periods, and ramps (for example, retirement-home duck curves, and bus depot square waves) indicate the effects of microgrids on thermal behaviour, ramping, and overload risks. While harmonics and voltages are noted for future study, flow patterns indicate shifts in stability. Retirement homes gain reliability; bus depots decarbonise transport but require demand planning to avoid new peaks, while balancing community benefits.

6.2. Recommendations

- *Prioritise DSM with PV and BESS.* Treat DSM (EV scheduling, water heating shifts) as essential, not supplementary, on night-peak feeders. Embed shift-to-solar logic in microgrid EMS to synchronise PV/BESS with flexible loads.
- *Model bidirectional transformers.* Hosting-capacity tools must simulate forward/reverse flows, bidirectional thermal ageing, and cooling asymmetries—update protection for frequent exports in high-PV, low-demand feeders.
- *Co-design fleet depots as microgrids.* Integrate staggered/variable charging and BESS targeting night peaks. In shared feeders, pair with residential DSM to build charging headroom and defer reinforcements.
- *Reward temporal flexibility.* Introduce time-of-use tariffs, peak-demand charges, and incentives for solar-hour shifts. Aggregators and direct control for EVs/water heating scale DSM effectively in residential/mixed feeders.
- *Tailor by archetype.* Customise for residential (strong DSM), high-occupancy sites (passive PV + storage), and depots (coordinated charging). Avoid one-size-fits-all policies.
- *Integrate into planning.* Mandate multi-microgrid scenario analysis for loading, flows, and stability. Define DSO-microgrid coordination, interconnection, and islanding rules.
- *Bolster vulnerable loads.* Prioritise retirement homes/hospitals for resilience, price hedging, and self-sufficiency through high self-consumption PV+BESS+DSM.
- *Synchronise transport electrification.* Couple depot microgrids with grid upgrades; jointly assess charging, generation, and limits to achieve net decarbonisation without reliability loss.
- *Highlight co-benefits.* Promote emissions cuts, reliability, participation, and savings to foster acceptance and DSM engagement across urban/rural settings.

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