Evaluating the Capabilities and Value of V2G Grid Services in Fleet Operations

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Executive summary

The University of Delaware designed, and with Exelon and Delmarva Power, built and ran four V2G-capable EVs to provide grid services. These were tested operating both as individual EVs and aggregated into a virtual power plant (VPP). The project goal was not merely to demonstrate, but to test a matched set of new factors we believe will create a V2G industry that is low-cost, high revenue, and scalable. The project tested and evaluated new standards, interconnection requirements, and policies applied to existing EDC and RTO markets.

Engineering modifications to a standard production Ford Mach-E were designed by UD, with consultation from Ford Motor, to add bidirectional onboard chargers, three-phase charging connectors, and LIN-CP communications with extensive V2G controls and reporting. The UD design was then used by Autoport to retrofit four Delmarva Power fleet Mach-Es. Nuvve supplied four advanced AC charging stations and operated an aggregator capable of V2G control and reporting in either EDC or RTO markets. New standards tested include SAE J3068, LIN-CP, and SAE J3072, which together provide rich communications between the EV and EVSE and high-power AC charging.

PJM approved dispatch operations as a "pilot project," so that they could test the capabilities of V2G running under PJM market rules complying with FERC Order 2222. The EVSEs were registered and interconnected for discharge and net metering by Delmarva Power, under existing state law and regulations. Six grid service markets were reviewed and two were implemented in the pilot, considering potential revenue, technical requirements, and near-term expected rules to enter and operate. Grid services are needed by the electric system to balance generation and load, adjust frequency and voltage, stand in readiness in case of unexpected failure, and to shift energy from times of surplus to times of shortage. Most or all of these services (depending on local rules) are markets that pay the provider for grid services. In this project, the EVs operated as providers in two grid service markets: PJM Regulation, and Arbitrage matched to a Delmarva Power time-of-use rate. For each market, the equipment standards, metering, interconnection and dispatch complied with the appropriate rules. In-operation efficiency of the on-board bidirectional charge was calculated from meter readings to quantify energy losses during grid services. The EVs' operational data was used to calculate the economic value in each market, including market revenue minus energy cost. EVs were run in each market during separate times; some value stacking would have been possible for these two markets but was not tested in this pilot project.

Under the rules of a PJM pilot project, we used a real but recorded dispatch signal, entered bids on the aggregator but did not send bids to PJM, and calculated value from utility-grade power and energy meters, as no payment was made by PJM. For the PJM market, the aggregator treated all vehicles together as a "dispatch group" or VPP. Each EV continuously calculated its dynamic capacity to provide or absorb real power. Those limits were sent to the aggregator, which then tailored dispatch requests to each EV's capability. Thus, the aggregator ensured that the set of EVs jointly met the PJM dispatch request and each EV produced or absorbed power within its capability. Analysis of the dispatch group showed that the combined group response to requests is extremely accurate and low latency, better by both metrics than current thermal generators in similar markets and well within PJM's allowed tolerances. Unexpected events of single EVs have less effect on the dispatch group total, and progressively less as the group gets larger. During the one-year pilot project, EVs spent most of their time providing Regulation, yet using the OEM's metric for battery health, no reduction in battery capability was measured over the one-year operational period.

For the TOU Arbitrage market in Delmarva Power, the EVs were again dispatched by Nuvve's aggregator. TOU service was dispatched according to the tariff's fixed clock times and preset kW rates, with the aggregator additionally constraining power to avoid extreme values and to prioritize trip needs. Since the TOU "market" is paid via reducing the utility customer's bill, proportionally to performance, this market involves no bidding, no obligation to perform, and no payment by a 3rd party (such as PJM or an aggregator paying the asset owner). Due to this project's design of interconnection and metering topology, switching from the wholesale PJM market to the retail EDC market, and back, was accomplished in a few minutes remotely, by the aggregation platform.

To calculate net revenue, the actual market rates were used for both markets; no subsidy or incentive payment was assumed. For Regulation, the 2021 through 2025 average market clearing prices were used. For TOU Arbitrage, the existing 2025 Delmarva Power TOU EV rate was used. The vehicles were assumed to be driving all work days but otherwise plugged in and performing grid services as they did in the pilot. We used local TOU rates for bill reduction, then separately calculated PJM Regulation value based on the range from the low to high years' market prices ($21.15 to $54.97 MW-h). For a passenger vehicle (10 kW) TOU Arbitrage would earn $874/year, and PJM Regulation would earn from $1102 to $3359/year. For a heavier vehicle, using the now-standard 3-phase AC connector on the pilot vehicles (33 kW), TOU Arbitrage would earn $1043/year and PJM Regulation would earn $3195 - $9741/year. These figures are net of energy losses but do not include costs of customer support, aggregator fees or any allowance for battery wear. Beyond the markets tested, the PJM Capacity market may be comparable in value to PJM Regulation, but specific calculation awaits PJM's definition qualifying DERs for Capacity under FERC Order 2222. Nevertheless, just the two markets tested yielded substantial revenue, suggesting several viable business models.

The value of mass-produced EVs providing these grid services is much more than the added cost to the EV and charging station equipment. This has two implications. First, when EVs are produced with this combination of equipment and policy allows their interconnection and participation, electric customers can reduce their electricity bills by providing grid services from their parked EVs. Second, EVs providing grid services will reduce the cost of running the electric system (because grid services will be lower cost and higher quality), which over time will reduce costs to all electric customers.

Multiple lessons learned are described in the final section, encompassing technology, interconnection process, market qualification, operations, and practice qualifying new standards for interconnection. This experience suggests several criteria for planning V2G implementation and/or trial customer offerings.

In summary, the design, components, policy and operations of this demonstration created a high-value virtual power plant, now proven in two markets. Production EVs and EVSEs using these designs and standards would yield V2G-capable fleets of lower cost and higher scalability than prior demonstration projects. A great deal was learned about implementation and operation. Thus, we believe that this project's results provide guidance as to the expected capabilities and potential business models for practical modern V2G systems.

1. Approach

The goal of this project was to combine the technical, standards, and regulatory conditions needed for cost-effective, high-value grid services from electric vehicles (V2G), and operate those in an electric utility fleet environment. This design differs from prior US V2G demonstrations in that all components had to meet near-term availability of equipment, standards, market rules, and regulatory conditions available within two years of project completion. These goals required V2G via AC rather than DC charging equipment, because AC is much lower cost and generally higher reliability during unattended long-duration operation (e.g. overnight and weekends). Until recently, AC V2G has been difficult regulatorily. For AC V2G to work well and meet standards, it also required a new communication standard between EV and charging station plus multiple SAE standards for interconnection. Building upon new standards, new regulations, and products just being commercialized, made this project more complex. But its success now proves the full combination of elements needed for scalability at low-cost and high revenue. By carrying out the project on actual fleet vehicles at Delmarva Power (DPL), an Exelon Company, it also yielded direct experience from the company and additional learnings relevant for fleet application.

2. Unique Elements of this project

This project has proven that EVs with V2G, managed as an interconnected distributed resource, are a viable and lucrative resource for fleets while participating in RTO and EDC markets. The specifications and design all were focused on scalability after the initial demonstration. Two high-value markets have been demonstrated, PJM Regulation and EDC Arbitrage. To support the low cost and scalability objectives, the following components were implemented: 1) AC V2G charging stations fully interconnected for bidirectional power flow, 2) LIN-CP (Local Interconnection Network over Control Pilot), a new SAE[1] standard for high-functionality communication between EV and EVSE, 3) consistency with policies enabling V2G already being finalized in PJM and in Delaware, and 4) all components configured to match for V2G-ready EVs expected to be commercially available.

New technologies and standards first being tested

The following new technologies were used in this project:

- A high-function bidirectional onboard charger (BMPU-R2-500-32 from Watt & Well)[2] with extensive grid controls, high efficiency, continuous reporting of power capacity, real and reactive power control (4-quadrant power), etc.

[1] SAE, originally Society of Automotive Engineers, develops standards used by manufacturers of road vehicles. SAE J3068 is an SAE standard that defines both 3-phase connectors and the LIN-CP communications protocol between the EV and the EVSE.

[2] Watt & Well, “BMPU-R2-500-32 Specification Datasheet (revAW), 11 kVA Bidirectional Power Unit, 4-phases”, High Power Series. Accessed January 2026 at https://wattandwell.com/app/uploads/BMPU-R2-datasheet.pdf.

- LIN-CP, which provides rich communications & control between EV and EVSE, including interconnection configuration, many power controls, sleep for energy efficiency, error reporting and capability to switch among all V2X use cases (V2G, V2L, V2V and backup power). The EVSE's communication of the extensive LIN-CP data and control with aggregator also allows more effective monitoring & dispatch. In this report LIN-CP also enables us to monitor and analyze more EV variables than would other existing or legacy communications.
- A North America-certified EVSE providing 3-phase power up to 50 kW, and revenue-grade metering within the EVSE. (Tested as revenue-grade to 1% accuracy by ANSI C12.1; revenue grade is also referred to as utility grade accuracy.)

The following new standards were used:
- SAE J3068 which defines a US-standard 3-phase EV plug and inlet.
- SAE J3068 which also defines LIN-CP communications, now incorporated by reference in SAE standard J3072, and in J3400 (NACS) and J1772.
- SAE J3072, making it possible for the station to check the EV's certification for IEEE1547-2018, and optionally to IEEE 1547-2003 and IEEE 1547.1-2005.

This combination of standards and now-tested technologies makes possible low-cost AC, interconnection, comprehensive data and controls for charging and V2G, and access to multiple V2G electric grid markets. Although an equipment cost analysis is beyond this report, a recent draft paper estimates the incremental manufacturing cost of our designed configuration, in mass-market quantities, to be less than $200 incremental cost for a 10kW bidirectional charger and station, or $20/kW[12].

New policies and revenue models enabling market-qualified V2G

This project explores several new policies that promise to make V2G more practical. Regarding the wholesale market, in 2020, FERC Order 2222[3] directed all US RTOs to revise their tariffs so that DERs can participate in wholesale markets, as long as the applicant is technically capable of doing so. It also explicitly allows DERs to participate in both retail and wholesale markets, providing there is no "double counting" (being paid twice for the same service). Order 2222 also generally prohibits "unjust and unreasonable" barriers. In response to Order 2222, PJM and the other five FERC-regulated RTOs have adjusted tariffs with the intention to allow DERs in their markets.

In Delaware, existing state law requires that EDCs offer net metering for V2G meeting specified criteria, and specifies that SAE standards can be used for interconnection (the choice of whether UL or SAE is the appropriate standard is left to the EDC). In the mid-Atlantic, the Maryland legislature passed similar legislation with MD PUC hearings starting 2024, and the

[3] United States Department of Energy, Federal Energy Regulatory Commission, 2020, 18 CFR Part 35. [Docket No. RM18-9-000; Order No. 2222, Final Rule], "Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators" (Issued September 17, 2020) URL:https://www.ferc.gov/sites/default/files/2020-09/E-1_0.pdf

New Jersey BPU has begun discussion of V2G tariffs in late 2025. Our UD EV group in 2025 proposed a bill to further clarify Delaware's V2G-related rules, including more clear guidelines for working within FERC Order 2222 (independently of the present project).

Qualification to participate in RTO service markets is different from retail utility markets. Both equally require an interconnection at each site; in PJM and most areas the interconnection is via the EDC. But for RTO market participation, an aggregator or VPP is generally required to group across sites rather than each individual EV owner directly participating in the PJM market. The aggregator's role is to: 1) Group customer EVs to achieve sufficient power for market qualification (100 kW, per Order 2222). 2) Predict available capacity from a group of EVs and bid RTO markets, possibly optimizing bids across markets. 3) Dispatch among many subscribed EVs, thus reducing the risk of insufficient EVs to satisfy bid kW. 4) Collect RTO payment for wholesale grid services, retain an agreed-to portion, and distribute payments to the participating EV owners. 5) Pay RTO entry and membership fees (thousands of dollars per year).

By contrast, EDC grid services, such as arbitrage using TOU rates, can usually be metered with an existing TOU premises meter. The customer is incentivized because providing EDC grid services lowers their electric bill. Even for EDC services, an aggregator may offer some advantages to individual signup. In this case they would charge a fee to the EV owner or ratepayer, for example as a proportion of the bill benefit. Alternatively, if the EDC is directly incentivizing an EV owner, as for example utility Direct Load Control (DLC) programs, the EDC credits the customer a set yearly payment. Traditionally, DLC has not included discharge, and the fixed yearly remuneration has been much lower than revenue from the markets we analyze here.

EVs Managed as a Virtual Power Plant (VPP)

Figure 2.1 below illustrates the components of a Virtual Power Plant (VPP) as implemented in this project. A VPP coordinates multiple Distributed Energy Resources (DERs)—in this diagram, the DERs are electric vehicles (EVs) used for energy storage. DERs are connected to the distribution grid through physical power lines (solid lines in the figure) and communicate via internet or cellular networks (dashed lines) to an aggregator that manages them as a single controllable resource. The left side of the figure shows EVs within a fleet at a single location, sharing a 480V three-phase transformer. On the right side, EVs are individually owned, each with different equipment and grid connections.

Through the aggregator, the Regional Transmission Organization (RTO) or Electric Distribution Company (EDC) can view the VPP as if it were one large power plant—or, in this case, one large controllable battery. A VPP is called "virtual" because physically it consists of many small devices spread across a service territory but in controls and power reporting it behaves as a single entity. The aggregator divides a single control request into many separate requests sent to each DER, and tailored to the individual DER's capabilities. For example, if the RTO sends a command such as "Discharge at 10 MW," the aggregator will divide this into smaller requests in kW and send a proportionate command to each available EV. Conversely, to measure the total response, the aggregator adds up readings from individual meters to one sum of power, presenting a single response to the RTO or EDC.

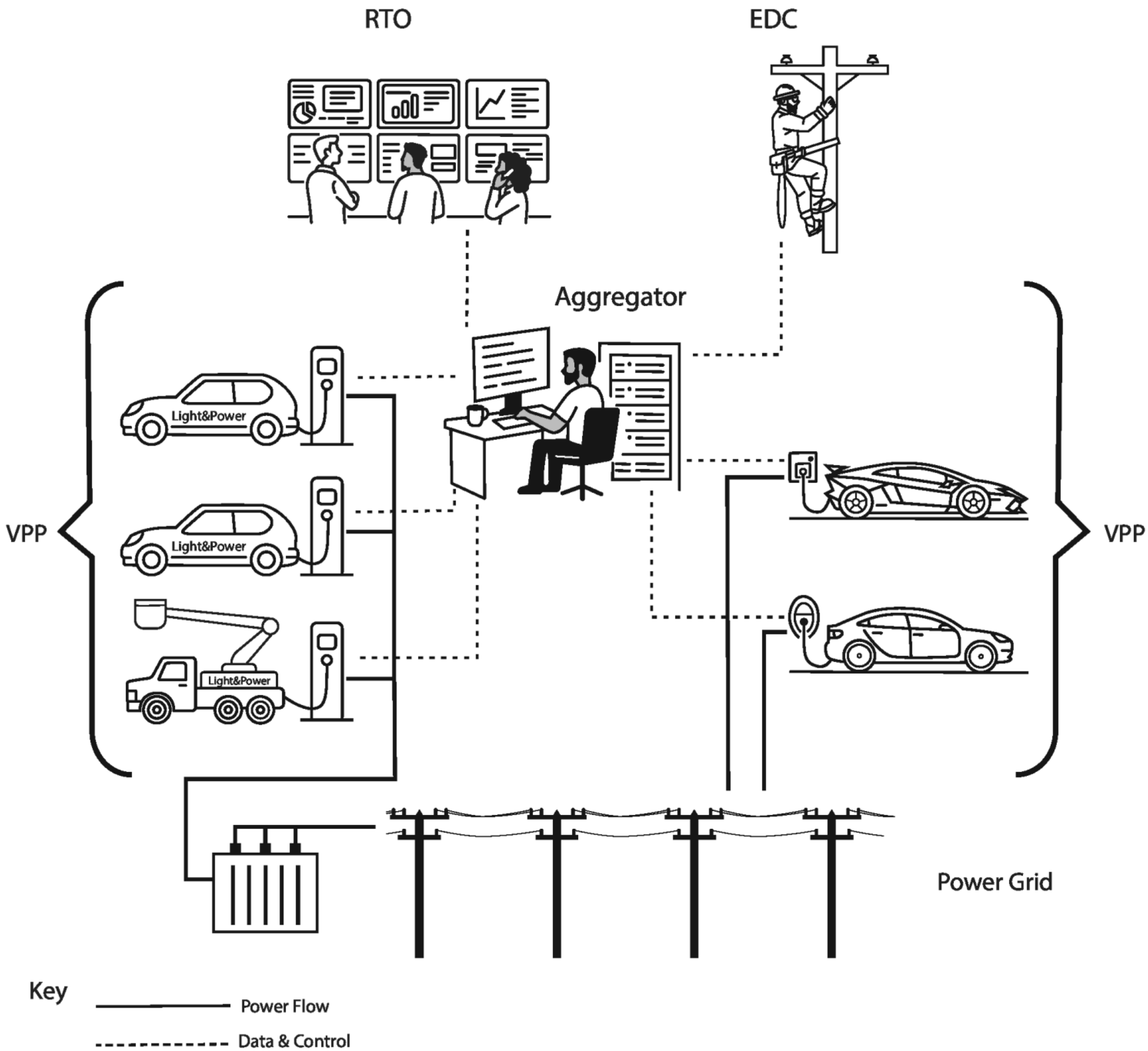

Figure 2.1. Components of a Virtual Power Plant. At the top the RTO and EDC are shown, two potential users of a VPP.

Overall, the VPP consists of the aggregator and all the DERs. The aggregator used for this project had additional capabilities, including managing EV trip schedules, forecasting availability, placing bids in energy markets, and optimizing dispatch based on grid needs, market conditions, and EV usage patterns.

VPPs can also be used for other controllable storage, load, or distributed generation. This project is focused on EVs because our prior analysis and experience shows them to be significantly less expensive than other storage, yet EVs are complex in interconnection, in applicable standards and regulations and in control of moving electrical resources within a territory. Essentially, if the interconnection and other problems can be solved for EVs, the aggregator will have most or all the capabilities needed for other distributed energy resources.

Key Takeaways: This project was designed for economic viability and scalability of V2G, and to produce information needed for decision-making going forward. It uses new standards, technologies and policies that reduce cost and increase revenue. Thus, the purpose was not to demonstrate V2G, but to test it in a scalable, cost-effective design with economically measurable grid benefits. Using an aggregator to combine EVs with V2G into a VPP allows distributed resources to act as a single, flexible asset for the grid, which may be essential for RTO grid services, not necessarily essential for EDC services.

3. Project stages, location, interconnection

Participant roles, EV engineering design, fleet setup

After scoping and initiating this pilot project with Exelon, UD carried out engineering design compliant with new SAE standards at our labs on the UD campus in Newark. Next, with documentation and consultation from Ford Motor, UD designed a retrofit to a stock Mach-E, adding bidirectional onboard AC charging and complete LIN-CP communications, modified one production EV at UD as a prototype for the project, and wrote a manual for the retrofit process.[4] Four Delmarva Power (DPL) fleet EVs, 2022 Ford Mach-E “Select” model, were retrofitted to the UD specifications by Autoport Inc in New Castle, and returned to fleet use at DPL’s New Castle Regional Office (NCRO), in Newark, Delaware. Nuvve Corp was contracted by DPL to install four AC charging stations at NCRO, capable of 50kW three-phase charging and discharging and utilizing LIN-CP communication between the EV and EVSE. The stations met the project’s advanced requirements of 3-phase power up to 100 kW at 480 VAC, and implemented standard communications authorized for interconnection and compliant with LIN-CP, SAE J3068, and SAE J3072. Nuvve also licensed their aggregator, with functions parallel to those shown in Figure 2.1.

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[4] Marleen Toney and Garrett Ejzak, 2022, “Modifications for 2021-22 Mach-E” Retrofit design by Garrett Ejzak, Allen Mowbray, Marleen Toney, Updated March 8, 2024. EV R&D Group, University of Delaware, 79 pp.

<u>Figure 3.1</u>. Photograph of the four Watt & Well BMPU-R2 converters (bidirectional chargers) installed in the front "frunk" of a Ford Mach-E. The converters are recognized by their red front panel, each with two cooling fans. To the right of the rightmost converters is a UD junction box with power connections and UD's logic board to run LIN-CP and CAN communications.

For the project, the Mach-Es retained the stock characteristics of average driving consumption rate of 329 Wh/mile (3.04 mile/kwh), and a traction battery pack with 70 kWh of usable energy[5] and 75.7 kWh total physical energy[6]. The stock unidirectional 11 kW single-phase charger was replaced with a 3-phase bidirectional, four-quadrant converter from Watt & Well, with a maximum power of 50 kW at 480 VAC charging or discharging. At present, the available 3-phase inlet for the Mach-E limits the car's maximum AC power to 33 kW charging or discharging, even though the EVSE and other EV components could charge and discharge at 50 kW. UD implemented the new SAE standard for communication from EV to EVSE, LIN-CP, as defined in SAE J3068 (and by reference in J3400 and J1772). The SAE J3072 protocol for interconnection was also implemented. Per these standards, LIN-CP identifies the EV and EVSE to each other, meets distributed energy interconnection requirements, enables and regulates a connected EV to engage in multiple grid services, and provides safe signaling to

5 "Usable battery energy" is the amount the OEM allows from max charge to min discharge. From Ford Motor Company. 2021 Ford Mustang Mach-e Technical Specifications. 2021. Available online: https://www.ford.com/cmslibs/content/dam/brand_ford/en_us/brand/suvs-crossovers/mache/3-2/pdf/seo-pdfs/Mustang-Mach-E-Tech-Specs.pdf (accessed on 29 February 2024).

6 From earlier Ford Europe specs, which included total battery energy, https://media.ford.com/content/dam/fordmedia/Europe/en/2020/12/Mach-E_AWD/Ford_Mustang_Mach-E_2020_TechSpecs_EU.pdf

switch among modes–including simple charging, vehicle-to-grid, backup power, and vehicle-to-load–when both EV and EVSE approve each mode.

Once the pilot EVs were performing regulation reliability, we began the long-term test of the four EVs and EVSEs in grid markets. The market test period was delimited as calendar 2025 (Jan 1 through Dec 31, 2025), although this report occasionally draws data from adjacent months before or three weeks after the calendar 2025 test period.

Communication from the charging stations to the Nuvve aggregator utilized a standard CAT6 cable from each station to a single on-site router and modem, connected to a standard Comcast cable service. For security of utility operations, this was a separate account and separate physical connection from all existing communications for DPL NCRO. DPL and PHI security staff also reviewed all security specifications from Nuvve. The single internet connection for the site provides low-latency and high bandwidth, valuable for some grid services and at lower cost than cellular. However, the Comcast connection had more outages than desirable and could be analyzed for options for improvement in the future.

Key Takeaways: The setup of the pilot project uses a UD-designed retrofitted bidirectional EV within the DPL fleet, with new communication standards between EV and EVSE. To reduce costs and maximize revenue, the project uses AC charging and AC V2G, high-power (3-phase AC) charging, takes advantage of new SAE and UL standards, and of Federal and state policies. For higher reliability and better utility interconnection compliance, the new LIN-CP communication standard is used, and to document market value, the EVs participated in both an RTO and an EDC market.

Interconnection of EVs for V2G with injection

The UD EV Group has previously worked with FERC, PJM, and states to develop a safe yet low friction process to interconnect storage behind the meter (BTM). As we have noted elsewhere, previous PJM and state interconnection requirements made it difficult or impossible for EVs as DERs to participate in either RTO or EDC markets (see Metz and Kempton[7] 2024, Kempton et al[8] 2017; Kempton and Metz[9] 2023). In response, our group has worked for 10 years to influence the interconnection process, with the result being that FERC requirements on RTOs and existing or proposed state tariffs or law (implemented in DE and MD) would include the

[7] Metz, J.G.; Kempton, W. (2024) Vehicle-to-Grid Revenue from Retail Time-of-Day Rates, Compared with Wholesale Market Participation under FERC Order 2222. *Energies 17*, 2664. https://doi.org/10.3390/en17112664

[8] Kempton, W., Rowe, M., and Nakano, H. (2016). “Response of EV R&D Group, The University of Delaware before the Federal Energy Regulatory Commission, Electric Storage Participation [in] Regions with Organized Wholesale Electric Markets” Unpublished comments on Docket No. AD16-20-000. Note: Eight of the UD comments are subsequently addressed by FERC in Notice of Proposed Rulemaking, November 17, 2016: https://www.ferc.gov/sites/default/files/2020-06/rm16-23-000_ad16-20-000.pdf and then incorporated into FERC Order 841.

[9] Kempton, W. and Metz, J. (2023). “Comments by the University of Delaware EV Group” FERC Docket No. ER22-962-005, PJM Interconnection, LLC, Second compliance filing. 3 November 2023, https://elibrary.ferc.gov/eLibrary/docinfo?accession_number=20231106-5105

needed requirements to allow V2G vehicles to interconnect, inject power, and participate in PJM markets from behind a retail meter. If the interconnection, registration, and market participation rules of RTOs continue to be adjusted to comply with FERC Order 2222 (as PJM expects to do between 2026-2028), the resulting low-cost storage opportunities will expand V2G as an economically valuable grid resource across RTO markets.

DPL negotiated with PJM, in consultation with UD, to create this project as a PJM "pilot project". To allow operation under future expected rules, PJM provided a recorded signal for Regulation from one year earlier rather than the real-time signal, and made no payments for service provided. The recorded signal nevertheless caused injection to the grid and thus required interconnection by the EDC. Even for providing PJM services, if V2G is connected behind a retail meter, the EDC is responsible for approval of interconnection, not PJM, per FERC Order 2222.

In most EDCs, the interconnection process has been designed for solar power, but not yet adapted for battery systems, much less for EV storage. This project serves as a case study. For the project's required interconnection, we used the standard DPL forms, which are divided into Levels 1 through 4, based primarily on the nameplate power of the DER.[10] The first thing to understand is that a V2G system must interconnect the charging station, which provides the needed grid protections and limits. The EV is a roaming battery plus inverter, and different EVs may connect at different times. The EVSE is fixed in one utility service territory, responsible to meet that utility's interconnection and operational rules and standards. Thus it is the EVSE that is evaluated and approved for interconnection. With AC, the inverter is in the EV, so as we describe later, standard SAE-J3072 has been (and in the future UL-1741-SC will be) developed to enable the EVSE to insure the EV's inverter is compliant.

DPL has four levels of interconnection requirements. Level 1 uses a simplified form with two pages of blanks to fill in, as appropriate for an already-certified consumer device. Levels 2, 3, and 4 were structured for a construction project installing larger generators. Unfortunately, the level 1 interconnection is allowed only if the "generator" is under 10 kW. This project, with EVSEs capable of 50 kW, was required to file for Level 2 interconnection using a 34-page form, beginning with a 16 page legal contract, the remaining pages with questions to answer and forms to fill in. For example, the Level 2 form requested substantially more technical information, component settings, and construction process, including the sequence of installation operations.

Currently, the simpler Level 1 interconnection is restricted to systems smaller than 10 kW. Since the project EVs were 33 kW, and the EVSEs were capable of 50 kW, a single EVSE would require the complex level 2 interconnection process. Granted, this project was at an industrial site, drawing from a 480 V line, and with four EVs. Nevertheless, the wiring to the EVSEs was straightforward, each behind a breaker, and involved only standard components already certified to required electrical standards, and installation of the charging stations was the same

[10] Delmarva Power, Apply for Interconnection, PDF Forms, (accessed Mar 30, 2026), https://www.delmarva.com/smart-energy/my-green-power-connection/developers-contractors/applying-for-interconnection/de-application-forms-and-fees

process as would be used for a 10 kW single-phase station. The <10 kW power cutoff will be even less appropriate given the new SAE J3400 standard, which allows even a single-phase premises to support 20 kW to 42 kW per vehicle EVSEs.[11] Old rules that shift a 10+ kW EV from Level 1 to Level 2 interconnection add an administrative burden on new interconnections that would dampen V2G interconnections. We believe safety and distribution can be met along with reduced interconnection time and cost if the simplified Level 1 form were available only for installations with standards-compliant, certified EVSE's--even for EVSE of higher power, say up to 50 kW. Safety is enforced through standards--and inspection when needed--and distribution reliability is improved if the interconnection requires a distribution capacity check (discussed below).

The other problem with today's typical electric utility interconnection process is that the questions are geared to solar and to generation. In this example, both Level 1 and Level 2+, asked some questions (e.g. model #, circuit protection, maximum output power, nominal voltage) appropriate for solar or EV, but those questions are interspersed with questions only relevant to solar (e.g. azimuth, tracking angle, energy production). Similarly, the only safety standard referred to is UL1741, appropriate for solar installations and small generators but inadequate for AC-charging EVs. (See below on new SAE and UL standards for V2G.) Further, current forms only request power of generation, whereas for batteries one must ask both maximum discharge ("generation") and maximum charging ("load"). A single interconnection form could continue to be used but it is essential to add questions needed for battery systems, and the form would be much easier to use if solar-only were separated from battery-only sections.

Although hosting capacity was not directly evaluated by this project, another in-progress UD analysis of V2G interconnection (Kempton and Gilman, n.d.)[12] recommends that interconnect can be sped up if the utility evaluating the application has already prepared systemwide "hosting capacity maps". DPL, for example, already has "(solar) hosting capacity maps"[13] (which show how much new BTM generation can be added to each distribution feeder), and "(EV) load capacity maps"[14] (ability to interconnect more load on each feeder). For V2G or other battery interconnection, a quick check could simply require that, at the applicant's point of interconnection, both capacity maps show that distribution there has sufficient capacity. These maps are approximations, so marginal cases may need additional power flow analysis, nevertheless in most cases reference to existing maps would tremendously speed up V2G interconnection in comparison to a line capacity analysis initiated for each application.

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[11] Table 1 in Kempton, W.; R.T. McGee, G.A. Ejzak, A Universal Electric Vehicle Outlet and Portable Cable for North America. *World Electr. Veh. J.* 2024, 15, 353. https://doi.org/10.3390/wevj15080353
[12] W. Kempton and Catherine M. Gilman, n.d. "Policies to Allow Grid Services from Behind-the-Meter Electric Vehicles and Other Storage" Draft manuscript of 22 January 2026
[13] DPL hosting capacity map at https://www.delmarva.com/smart-energy/my-green-power-connection/developers-contractors/technical-consideration/hosting-capacity-map
[14] DPL EV Load Capacity Map at https://www.delmarva.com/smart-energy/innovation-technology/ev-load-capacity-map

Although storage will always be net load (no net kWh provided when summed over a month), net metering ensures that discharged energy is credited against the consumption originally used to fill the battery. Net metering is another potential barrier in other jurisdictions, but it was not a barrier in this project due to existing Delaware law, which specifies that EVs providing grid services for a utility or RTO qualify for interconnection and for net metering. For revenue to motivate high-value grid services, EDC net metering is important. NEM is explicitly required by Delaware law for EVs providing grid services but is not yet required for V2G in most states. Our prior calculations for markets in this area show that without NEM, revenue from participation in the Regulation market can be cut in half and providing services through energy arbitrage can become a net loss (see Metz and Kempton 2024).

Delaware code, and Maryland PSC policy, also allow the interconnecting utility to use either SAE or UL standards to qualify the EVSE to interconnect. This is important for AC V2G because the SAE standard applies to both the car and charging station, requires IEEE1547 compliance for the onboard converter, and requires the car to send that certification to the station. A UL standard will be available (UL1741-SC) to specify how the EVSE can check that the on-board charger is following SAE J3072 if the EV manufacturer's certification is not considered sufficient. (Legally a UL standard cannot apply to the EV, where the inverter resides). As noted, all these should be check-able on application forms for V2G interconnection.

We derive several practical and scalability suggestions from the project's interconnection application to DPL. In current Level 1 forms the questions are oriented toward solar or small generation, not storage or EVs. We suggest a re-organization of those application forms, to make the generation section one option, and add a second alternative section with questions appropriate for battery systems. EV questions should additionally clarify that the EVSE, not the EV, is the device being registered for interconnection, ask the applicant whether it is AC or DC charging, then let the applicant check whether they have certification to SAE J3072 and/or UL 1741-SC as standards. (Delaware and Maryland rules already allow their utilities to use either UL or SAE standards for EV interconnection.) The applicant could be asked for useful background information, such as whether EV to EVSE communication uses LIN-CP, ISO/IEC 15118, IEEE1030.5 and/or J1772 analog signals. If net metering is requested, the form could have a checkbox for the applicant to state whether the premises has only battery, only generation, or both storage and generation located BTM.

Key Takeaways: From the practical experience of the pilot, several improvements are suggested for existing utility interconnection processes. In brief, the process and forms for this interconnection, like those of most electric utilities, have questions oriented toward solar or small generation, not toward EVs. Utility interconnection should request additional information specific to batteries and V2G EVs, including their appropriate standards compliance. The quick interconnection form cannot be used for 10 kW and above, we suggest it could be allowed up to 50 kW if the system is built from standards-compliant components. To regulate higher power, the interconnection process should review distribution hosting capacity with streamlined process, such as DPL's Solar "hosting capacity maps" and "EV Load capacity maps" to approve (or decline) interconnection. A site-specific powerflow analysis should be reserved for large interconnections and marginal cases. Also, Delaware law and Maryland PSC policy specify appropriate SAE or UL standards for V2G to interconnect. These are the only states with interconnection standards for V2G already codified, so for utility operating companies outside those states, policy reform may be recommended to enable time-efficient and standards-appropriate interconnection of V2G.

Fleet operations during the project

As with any demonstration with new standards and hardware, there were several practical glitches and unexpected hardware and software problems. The EVs used in this study had previously been used as transportation for site inspectors and managers. The users would depart from Delmarva Power's (DPL) NCRO office and travel to sites across DPL's territory or other PHI facilities. The project design was for this to continue, showing grid services around the hours of real operations. However, during this project's long period of debugging and improving the grid performance of the EVs, departments transitioned to not relying on these modified EVs for routine work trips. A few trips were taken during the project test period, but none of the pilot EVs were used for frequent, recurring trips as we anticipated. Therefore, for examining vehicle use for travel and the consequent reduction of vehicle availability for grid services, we use experience during normal operation reported by the site fleet manager. Thus although we report each EV's actual distance traveled based on our automated odometer readings, for earned revenue value calculations we use the fleet managers' statement that NCRO vehicles are on average driven 11,000 miles (17,700 km) per year, and that in normal fleet use, the cars would be traveling and thus not be available for grid services 8 hours per work day.

Data sources

Data analysis for this project was unusually complex due to data streams coming from multiple sources and at different sampling time intervals. To give the reader a sense of the underlying data sources, we itemize them below with brief consideration of each:

- EVSE - This is always connected to the internet and has both fixed data about the station and location (EVSE serial number, GPS location, grid location e.g. substation and service drop, nominal line voltage, maximum circuit power, whether discharge is permitted here, etc.) as well as variable data such as readings from the station's revenue-grade meters for power and energy in and out of a plugged-in EV. The EVSE is the entity for which interconnection is applied for (not the EV); the EVSE is always in a single, location-defined EDC and single RTO.
- EV - Includes fixed data (make, model, VIN, owner's vehicle "name" or fleet vehicle number, certification of on-board charger), as well as variable data from on-board measurements (kWh in battery, dynamic power capacity of the on-board charger, grid services capability, battery, charger and power inlet temperatures, odometer, DC power flow, etc.). All of this data is communicated from EV to the EVSE via LIN-CP codes. On a production EV, most of this data would also be transmitted over the OEM's telematics to the OEM back office.

- Transaction - An ephemeral event lasting from when one EV plugs in to one EVSE up to its disconnection. The transaction reports EVSE ID, EV ID, odometer reading, start and stop energy readings, start and stop timestamp, SOH, cause of disconnect (unplug vs. loss of data stream, etc).
- Aggregator - The aggregator is the only entity receiving data from the EV, EVSE, and grid entity (RTO, EDC, or site). For example, an aggregator would have the total power request from the RTO or EDC, whereas each EV and EVSE would have only the request proportioned to that one entity. The aggregator also manages bids to RTOs and corresponding obligations. We consider it desirable for an aggregator to be able to manage driving schedules (e.g. through driver input to an app), so as to never compromise driving needs due to grid services. (LIN-CP also allows a simplified "next trip" schedule to be entered on the EV dashboard or an EV app and transmitted to the EVSE and/or OEM.)
- RTO or EDC - In this demonstration, PJM provided their signal request for Regulation, and the EDC provided the time schedule for TOU rates. In both cases the grid entity is providing a changing request for power flow over time. Regarding metering, a revenue-grade meter in the EVSE tabulated all power and accumulated kWh for each attached EVSE. Because each transaction logs the EV's identify (via VIN), the EVSE measurements can be attributed to the connected EV (on the road refueling would not be logged, but that was rare in the pilot.) We did not use the premises meter, as there was only one, connected to all EVSEs together and unable to distinguish among them (typical of a building or parking lot). Nor did we use the meter in each car, as that was not certified to be of revenue-grade, and generally a meter in a fixed location is more susceptible to inspection or audit.
- DEOS - LIN-CP can transmit ambient temperature from the EV and EVSE. However, in this project neither car nor EVSE had a connected ambient temperature sensor, so we used hourly local temperatures from the Delaware Environmental Observing System.

All of these data sources but DEOS and the premises meter were available to the Nuvve aggregator, which stored them in a single data base for this project. One year of this data in compressed SQL format occupies 13 GB. The different sources above complicate processing and interpretation. For example, EV data is sent to the EVSE, and thus to the aggregator, only when a transaction is in progress, that is, when the charging cable carrying data connects EV to EVSE. Different intervals also must be adjusted before analyzing, for example, metered power in kW can change quickly and is recorded every 2 seconds, whereas energy in the battery in kWh changes slowly and is recorded only every minute. So to place those two variables in a single graphic, either power must be averaged over one minute and collapsed to a single value, or else a single reading of battery kWh must be assumed to continue the same value every 2 seconds over the whole minute. Our analysis makes these and other adjustments and synchronization in the background; we explain it here so the underlying data cleaning process is understood.

4. Markets Tested, How Value is Calculated

The EVs at NCRO provided services compliant with one PJM Interconnection wholesale market and one DPL retail market. Dispatch followed current rules (for the DPL market) or currently planned rules (for the PJM Regulation market, created to be compliant with FERC Order 2222). Revenue for the EDC market (via bill savings) was estimated using revenue-grade energy meters in the charging stations as a utility TOU meter was not installed for this circuit. For the PJM market, the revenue-grade meters in the charging stations are used, as they would be for production PJM Regulation, but since this was a pilot project the signal is from a prior year and the meter readings are not transmitted to the PJM payment system. Switching from this pilot mode to the live Automatic Generation Control (AGC) signal and remuneration meter is a simple software change from the current pilot configuration, which UD has performed several times and would be available should Exelon and DPL decide to do so. We will use capital letters for the names of each grid service, to distinguish from other uses of the same words (example: Regulation Ancillary Service versus state regulation).

Potential grid services from these EVs

The following markets could be served by the set of EVs for this project. Market operation with remuneration, in some cases would require additional refinement to state law or tariffs (none fundamental), or waiting for PJM to complete compliance with FERC Order 2222. The NCRO stations were interconnected via DPL to allow discharge and were market qualified under expected FERC Order 2222 rules as PJM DER resources, without remuneration during the pilot project. Timelines for market availability are given after the bulleted list of grid services.

- Smart Charging: Based on time of use (TOU) rates. Charges off-peak, but neither interconnection nor discharge to the grid. Very low remuneration compared to other markets, as analyzed in Metz & Kempton, 2024.
- Arbitrage: Driven by TOU rates by charging off-peak and discharging on-peak. Now operating in this pilot, see analysis herein.
- Override by EDC: EDC requests charging and discharging by an aggregator, potentially overriding a market-based service in progress. This can be controlled similarly to direct load control (DLC), but V2G can control both load and discharge. For DPL specifically, EVs could be dispatched as part of the pilot program “Bring your own Battery” (BYOB) with a couple of minor additions to the program. If there is an aggregator, the EDC could send a single signal to the aggregator to control many EVs. FERC Order 2222 requires that aggregators in PJM markets accept override requests from the relevant EDC, as does proposed Delaware code. Depending on the tariff and the contract between EDC and aggregator, the EDC might be provided with this service at no charge, for example, as compensation for use of the distribution system. The EVs and interconnection for the pilot project are already capable and ready to provide this service, but the aggregator and EDC would need to agree on a means for signaling and the agreement under which it would be provided.

- PJM Regulation: - Now operating in this pilot, see analysis below. On October 1, 2025 (during the project), PJM collapsed Reg-A and Reg-D into a single market, Regulation. This document will refer to this market by the single label "Regulation" as that will be correct going forward.
- PJM Reserves - We believe that the current NCRO vehicles set up for Regulation are also already set up to provide Reserves, but would need to be tested. As of 2025, the PJM market value of reserves is very low, but it would be prudent to have registrations and technologies able to take advantage of this if bid prices rise in the future.
- PJM Capacity - Our understanding is that, in terms of technology and interconnection, PJM Capacity could be bid from the NCRO vehicles as set up in the pilot, but confirmation will require further interaction with PJM and testing.

In this document we describe performance of the NCRO vehicles in two of the above markets, TOU Arbitrage and Regulation, then use our revenue-grade meter readings to calculate the bill savings or revenue that would be achieved per vehicle. PJM has estimated that Regulation will be open for market participation in Summer 2026. If Delaware passes proposed bills for V2G, the market for Arbitrage could be available by late 2026. The markets for PJM Reserves and PJM Capacity are currently projected to be open by 2028, with Capacity potentially requiring a related declaration in state law (currently under investigation by the UD team). The Override by EDC service would require an agreement between the aggregator and the EDC, and Smart Charging is already a market EVs can participate in as long as they have access to TOU rates.

The above are not an exclusive list of services that could be useful and could be remunerated. A few additional examples are: deferral of distribution system upgrades, active VAR control, integration of variable renewable energy sources and others.

For many pairs of grid services, it is possible to usefully provide both services at the same time. This is explicitly allowed by FERC Order 2222 for EDC and RTO services, as long as different functions are being met. Both the market qualification and the real-time dispatch must take care to follow each market's requirements, which sometimes requires a reduction in duration or capacity of one of the two services. This is referred to as "stacking" services.

RTO Service: PJM Regulation

Regulation is an Ancillary Service, which the U.S. regional transmission operators (RTOs) make a market by soliciting competitive bids. Regulation has the function of maintaining a stable grid frequency and balancing inter-regional power transfers. Up until October 1, 2025, there were two Regulation markets, Reg A which allows resources with slower response but may require longer running time, and Reg D, which requires fast response and provides signaling which balances discharging energy with charging energy. The latter is more amenable to batteries as a resource. As of October 1, PJM has collapsed the two into a single market, called Regulation, parameterizing the differences needed.

To control generators doing Regulation, PJM uses an Automatic Generation Control (AGC) signal that fluctuates from negative (Regulation down) to positive (Regulation up), abbreviated as RegUp and RegDown. When there is excess power on the grid, PJM requests RegDown, signaling battery systems to charge or generators to reduce production. When there is not enough power on the grid, PJM requests RegUp, signaling battery systems to discharge or generators to increase production. (Note: From an EV perspective, the sign often seems backward–RegDown is negative which pulls down from the grid and the AGC has a negative sign, yet that is charging the EV. Positive RegUp is discharging the EV. Positive for discharge is consistent with PJM's generator sign conventions.)

Data from the historical PJM winning bids (market clearing price) are available in the PJM "data miner" under "Regulation". The expected market price for regulation was calculated from the average market clearing price per MW-h over five years, calendar 2021 through 2025. MW-h measures MWs held available for PJM control for an hour, not to be confused with MWh which is an energy measure. The MW-h unit is used for PJM regulation, reserves, and capacity (capacity may be in kW-year). For example, a 5 MW generator held available for 3 hours is bid as 15 MW-h. Our recorded 2024 signal was the one the EVs followed for the duration of the test project. In revenue calculations. We use a year rather than a shorter time interval, in order to minimize the effect of seasonal variation of Regulation prices, which can range from $10 to nearly $1000 per MW-h depending on both grid imbalance and climate conditions.[15] To calculate yearly revenue, the market value was multiplied by the hours per year running EV V2G operations. The Regulation AGC signal and EV response are shown in Section 6, and the formulae and calculations of revenue are in Section 7.

EDC service: Time of use arbitrage

If a customer with BTM batteries (EV or other device) has a retail time of use rate (TOU), they can reduce their electric bill by Smart Charging, storing electricity during off-peak hours when prices are low. Most V2G demonstrations up until now have stopped at that point. This project makes more complete use of TOU rates beyond smart charging; the EVs also discharge on-peak, when rates are high, a market strategy known as Energy Arbitrage. The Nuvve aggregator's algorithms also allow for a user- or operator-setting for a lower and an upper limit on battery state of charge during grid services. The lower setting is particularly important to reserve for unanticipated trips, and both limits minimize time spent at extreme low or high state of charge, thus prolonging battery life (to be analyzed in Section 6). These limits may constrain other grid services but they are exceptionally influential in arbitrage, because (as we will show) they limit the number of kWh transferred during each time of use rate period.

To calculate the remuneration from TOU arbitrage, we used the applicable TOU rate for the site, as follows. DPL's TOU rates change periodically, but these were the prices from October 2025. On-peak hours were from 12:00 p.m. to 8 p.m., Monday through Friday. All other hours,

[15] PJM, Real-Time Ancillary Service Market Results, (accessed October 16th, 2025), https://dataminer2.pjm.com/feed/reserve_market_results/definition

weekends and holidays were off-peak.[16] For summer versus winter, the hours were the same but the price varied, shown in Table 4.1.

Table 4.1. Peak and off-peak rates (TOU) for the DPL service territory of the pilot project.

	Summer (Jun -Sept)	Winter (Oct-May)
On-Peak	\$0.2725/kWh	\$0.2967/kWh
Off-Peak	\$0.1481/kWh	\$0.1596/kWh

For the EVs in this project, the energy moved for arbitrage was calculated from days when the aggregator's TOU arbitrage signal was controlling the EVs. The resulting changes in energy in the battery are seen in Sections 5 and 6 of this report. Section 7 details the TOU dispatch signal, as well as the bill savings formulas and calculations.

Key Takeaways: The pilot EVs, in technology, interconnection, and aggregator control, are expected to be able to provide the six grid services itemized here of value to the EDC and/or the RTO. Each of these are described and defined, with our expected dates that V2G EVs like these would qualify. This demonstration goes beyond the scope of most EV smart charging projects to date in that the vehicles as set up qualify for six markets, and they actively participate in two markets that require discharge and interconnection: PJM Regulation and Arbitrage based on EDC TOU rates. We describe specifics of meeting requirements of those two markets and the basis for our revenue calculations (detailed formula and value calculations are in Section 7).

5. Vehicle Performance

This section describes the performance of the Mach-Es while running grid services, including summary quantitative statistics on how much charging and discharging, how many transactions, how much energy flowed through the vehicles, how much transferred each way for transactions, and the distance driven by the cars. There was not sufficient driving by DPL staff to analyze patterns of work trips and how they do or do not conflict with grid services, so we based driving time and total distance analysis on verbal reports by the fleet manager of typical usage rather than metered distances of the pilot vehicles.

Measurements of EV usage, for driving and for power transfer

We have direct measurements of each EV's driving, from odometer readings available over LIN-CP whenever a Mach-E plugs into one of the NCRO charging stations. We also have the fleet manager's report of the average distance their fleet vehicles are driven. This data stream begins in September 2024.

[16] Delmarva Power, How Our Plug-in Vehicle Time Of Use Rate Works in Delaware, (accessed October 16, 2025), https://delmarva.upgrade.guide/ev/de-benefits-section/tou/

Table 5.1 shows the odometer readings with dates and the total driving miles for each EV. Comparing the rightmost column with fleet average confirms staff verbal reports that the vehicles were not used regularly for ongoing tasks. The average driving of fully in-use NCRO vehicles averages 17,700 km or 11,000 miles per year–whereas Table 5.1 odometer increments in the rightmost column are much less than normal work driving.

Table 5.1. Odometer records showing the km and miles driven by each EV. EV 1146 distance driven is near-zero because it started recording odometer readings just before the end of data collection, in November 2025.

Vehicle ID	First report	Last report	First odometer	Last odometer	Km driven	Miles driven
01146	11/11/25	1/2/26	7859	7860	1	0.63
01149	9/27/24	1/3/26	12038	12373	335	209
01200	9/27/24	10/24/25	5507	5875	368	230
01205	9/27/24	6/30/25	9266	9408	142	89

A transaction lasted from plug-in to unplug, and could persist from a few minutes to a few weeks, depending on fleet driving, UD testing, and technical errors causing an EV to drop offline. We next report accumulated time in transactions, percent of the time that the EV was connected, and the number of transactions. As shown in Table 5.2, transaction data was available from September 2024 through December 2025 or January 2026. Based on the transaction data in Table 5.2, most EVs were responding to the PJM market signal less than half the time. This is due to a combination of some transactions not recording properly in the Nuvve database as well as ongoing testing and debugging when the EVs were not operating. Unfortunately, we do not have a quantitative estimate of the relative effect of the two factors.

Table 5.2. Each EV's time spent in transactions (each single plug-in, plug-out), percent of time connected (hours reporting connected / hours from first to last dates), and count of transactions per car. Transaction records are available from September 2024 to January 2026; tabulated here for calendar 2025. Car 1146 transaction records begin late in year, July 2025.

Vehicle ID	First transaction started at	Last transaction stopped at	Hours in transaction	Days in transaction	Time connected (%)	Number of transactions
01146	7/17/25	1/7/26	2719.2	113.3	65.1	16
01149	2/3/25	1/9/26	4302.6	179.3	52.7	53
01200	1/7/25	12/15/25	2954.5	123.1	36.0	49
01205	1/9/25	12/24/25	3835.3	159.8	45.8	40

Data from EV 1146 was not available until July 2025 because this EV required a repair of a warranted component damaged during retrofit modifications, and repair completion was significantly delayed. These repair delays were due, first, to the dealer contacting Ford Motor to confirm that the UD/Autoport retrofits were a project the Company was participating in, and second due to a mix-up in confirming that payment from DPL was received by the dealership. The EV was finally returned in restored working order in July 2025 and produced data for the remainder of the project.

Battery energy flow and state of health during grid services

To assess the performance of the four vehicles in the experiment, data on total energy charging and discharging (measured at EVSE) and SOH were retrieved from January 1, 2025 through December 31, 2025, shown in the tables below.

Table 5.3 summarizes the energy transfers of each vehicle throughout the calendar year 2025. Readings are taken by the revenue-grade meter on the charging station during transactions, attributed to the vehicle via the VIN number recorded for each transaction. Note that "energy down" measures the energy the EV consumed from the grid (charging), while "energy up" denotes the energy that the EV exported to the grid.

Table 5.3. Vehicle energy transfers over the period January 1, 2025 to December 31, 2025. Energy measurements are taken at the beginning and end of 2025, then subtracted for the year ΔEnergy values. "Energy up" is discharging, "down" is charging.

Vehicle ID	Initial Energy Down (kWh)	Last Energy Down (kWh)	ΔEnergy Down (kWh)	Initial Energy Up (kWh)	Last Energy Up (kWh)	ΔEnergy Up (kWh)	Down - Up / Down
1146	542.81	24666.75	24124	114.52	19450.36	19336	.198
1149	656.04	14269.19	13613	91.06	10284.93	10194	.251
1200	1175.31	14285.57	13110	0	11024.43	11024	.159
1205	634.85	24562.95	23928	91.06	19449.95	19359	.191

During the measured year, each car's energy charged is higher than that car's energy discharged, with the percentage of loss (last column) varying from 16% to 25%. With measured converter loss of 10% (calculated subsequently in this report), there appears to be additional standby loss (6% to 15% over the 10% expected operating loss). This may be due to not-yet implemented LIN-CP commands that reduce losses ("Sleep" and EV-controlled "normal charging"[17]); the cause of these losses was not identified within the scope and time limits of this project. In OEM mass-produced EVs, standby losses are normally much lower.

[17] In SAE J3068/1, "Deep sleep", "Light sleep" and "Active/on" are defined in Section 6.1.3 EvInverterState, and the mode of "Normal Charging" (under EV control) is defined in Section 9.4 and

As reported by project staff and seen in Table 5.1, these vehicles were driven infrequently, only 1-2% of the 11,000 miles reported for other fleet vehicles. If the pilot vehicles were fully driven over a year, that would add to the energy down column due to charging for driving. To estimate that amount, we use the fleet managers' report, that typical driving is 11,000 miles per year. Based on the manufacturer's advertised driving efficiency of 3.04 mi/kWh, 11,000 miles of driving would consume 3,618 kWh energy from the grid. In other words, the measured energy transfers for PJM Regulation (ΔEnergy up column), an energy-transfer-intensive grid service, are 3 to 5 times more than driving energy, calculated as 3,618 kWh/yr. This means that energy transfers for Regulation must be considered in estimating battery wear, as we do in Section 6 and must be tabulated as an energy cost against revenue from energy services income, as we do in Section 7.

Next, we consider state of health (SOH), the OEM's measure of the battery's ability to store energy, compared to that ability when it was new. Battery wear, expressed as a reduction in SOH, is caused by being left at high or low SOC, by total throughput, by operating temperature, and other factors. Note: State of charge (SOC) is the amount of energy remaining in a battery versus SOH, the battery's ability to store energy.

Table 5.4 presents data on the state-of-health (SOH) measurements of the vehicles after eight months of nearly continuous V2G operation. SOH is measured by EV on-board diagnostics as defined by the OEM. The OEMs do not publish their algorithms, but we take them as reasonably accurate, since expensive warranty payments depend on them being correct. Usually, SOH would be only available by manually plugging in to the EV's diagnostic port (OBC). The LIN-CP protocol we use sends SOH from the EV's controller area network (CAN) bus to the charging station, thus it is in the data base we analyze here. Table 5.4 shows that none of the vehicles experienced any measurable battery degradation during this period of continuous V2G operation. This also confirms the 2024 Gong et al study that found that V2G operations do not significantly impact battery degradation[18].

9.4.2. Sleep could be set when the aggregator expects to not require dispatch for some time (e.g. Arbitrage for TOU rates) but to be effective, EVSE and on-board vehicle systems must refrain from subsequent actions that would automatically wake the EV bidirectional charger.

[18] Gong, Jingyu, et al. "Quantifying the impact of V2X operation on electric vehicle battery degradation: An experimental evaluation." Etransportation 20 (2024): 100316.

*Table 5.4. Change in battery state of health (SOH) for each of the four EVs, from earliest record in 2025 through the latest, Dec 2025 or Jan 2026. *Given our analysis described subsequently and in Figure 5.1, the initial SOH of EV 1149 is more likely 100 rather than 96, making ΔSOH more likely to be 0.*

Vehicle ID	Initial Date	Initial SOH	Final Date	Final SOH	Δ SOH
1146	Jul-25	100	Jan-26	100	0
1149	Feb-25	96*	Jan-26	100	+4*
1200	Jan-25	98	Dec-25	98	0
1205	Jan-25	99	Dec-25	99	0

Although none of the vehicles exhibited a loss of battery health during this period, two EVs, 1205 and 1149, displayed anomalous changes in SOH, as graphed as a time sequence in Figure 5.1. Vehicle 1205 began with an SOH of 96%, but after about 6 weeks jumped back to 100% SOH and stayed at a high value. Vehicle 1205 had a very short transient drop from 100 SOH down to 96 SOH, then a prompt return to 100%. Both are shown in Figure 5.1, with EV 1205 on the top graph and 1149 the bottom graph. Both patterns suggest transients or inaccuracies in the OEM's state of health algorithm rather than a true sudden rise (1149) or drop and return (1205). These two transitory events are likely to be explained by the imperfect SOH estimation algorithms present in each vehicle, since both are transitory and neither is plausible as an actual sudden change in SOH. Another question about the OEM's SOH measurement is that some algorithms update SOC or SOH measurements when the battery is charged to 100%, an SOC rarely reached during the test period as shown in Section 6.

Key Takeaways: Automatic odometer readings confirm verbal reporting that the vehicles were driven much less than normal fleet use. Aggregate energy flows (charging and discharging) suggest some excess standby loss. The LIN-CP communication protocol used in this demonstration allows for ongoing recording and analysis of the EVs' SOH. Energy transfers for PJM Regulation were greater than charging energy for typical driving by a factor of 3 to 5 times, requiring attention to any effects of throughput energy on losses and on battery wear (both addressed subsequently). After twelve to 24 months of V2G operation, running from 36% to 65% of the hours in the day, none of the vehicles showed measurable battery degradation.

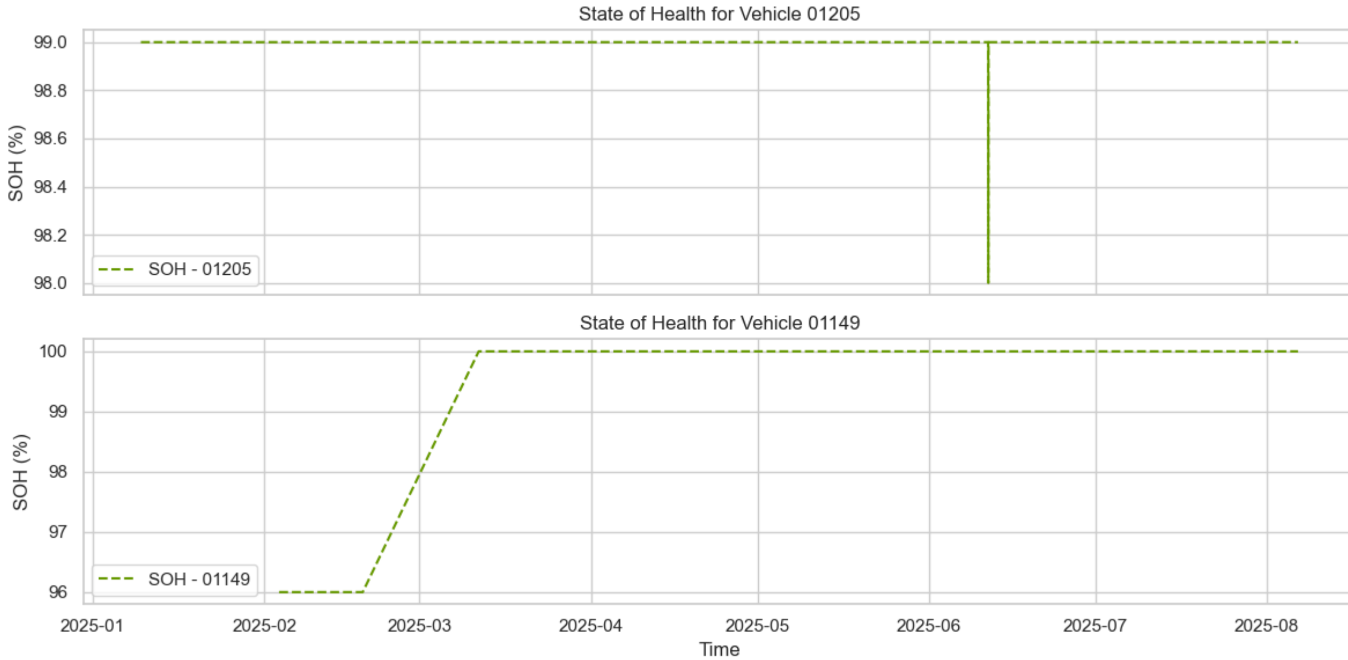

Figure 5.1. Anomalous transients in SOH reported for EV 1205 (top graph) and EV 1149 (lower graph). We attribute these fluctuations to anomalies generated by the car manufacturer's algorithm for reporting SOH, rather than to actual change in the battery's SOH.

Between January and September 2025, all vehicles were dispatched for PJM Regulation. In October, UD asked Nuvve to change all EVs to the TOU Arbitrage market for two weeks, then switched them back to Regulation with a new algorithm specified by UD. Figure 5.2 compares battery energy data for vehicle 1149 across Regulation and Arbitrage services and old and new Regulation algorithms. Each of the three sub-graphs shows a single service within the range from September 21 to October 28, 2025, specifically, the old Regulation dispatch (top), TOU dispatch (middle), and the updated Regulation dispatch (bottom).

The top graphic of Figure 5.2 captures some of the days operating under the original Regulation algorithm. For vehicle 1149, the large "jagged sawtooth" pattern is due to the battery energy drifting lower over approximately a day's time–due to losses and active vehicle loads–then when the battery reaches either a preset "too low" about 10 kWh or it is time to charge for a daily scheduled trip, it shifts to recharging quickly until it reaches 40 to 60 kWh. This sawtooth partner pattern repeats once a day or so.

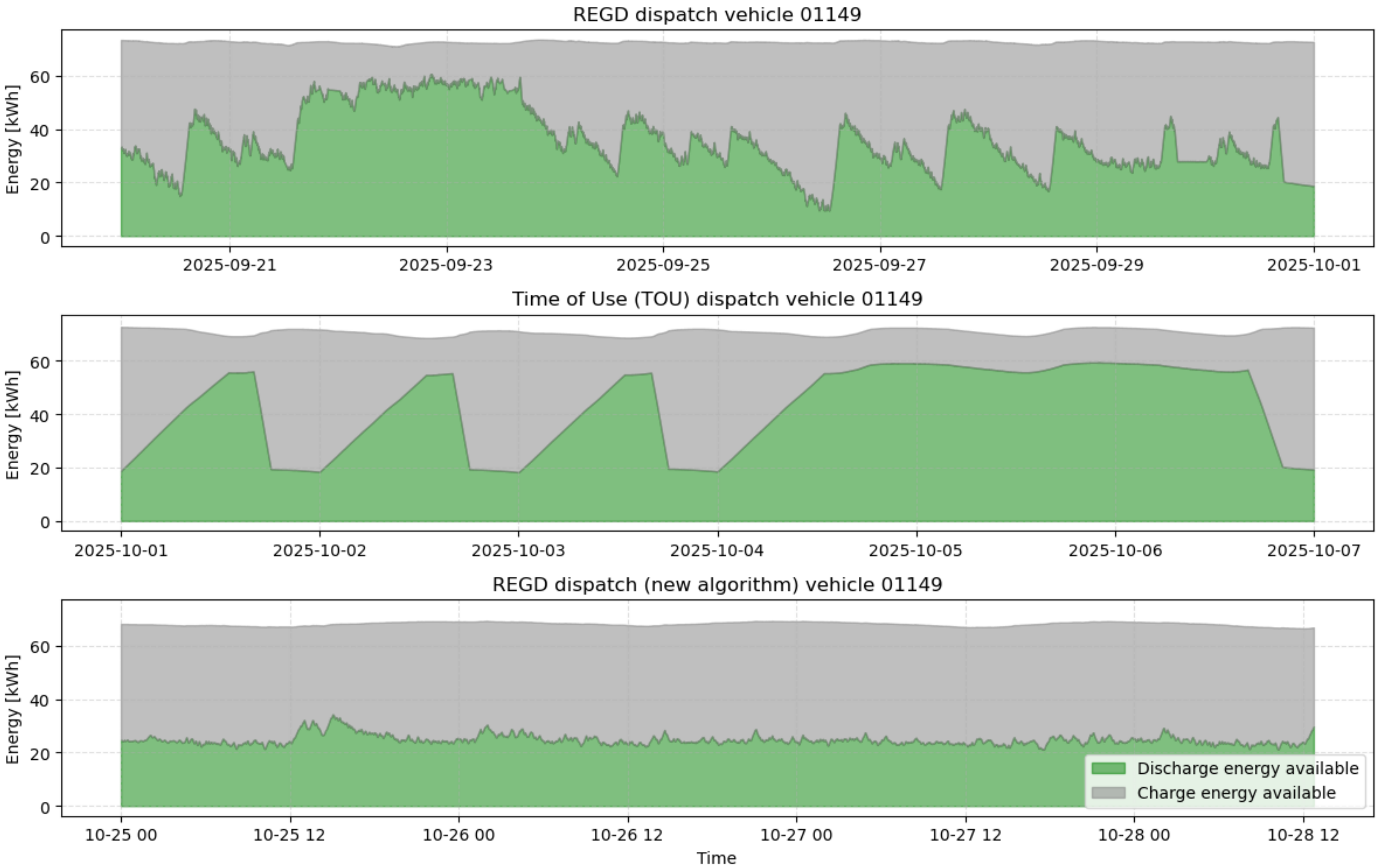

Figure 5.2. Battery energy of EV 1149 over 6 to 7 days. The green area is the amount of energy stored in the battery that can be discharged, and the grey area is the remaining battery storage that can be further charged (both in kWh).

In the middle graph of Figure 5.2, the vehicle was operating in the TOU Arbitrage market. In this mode, the charging and discharging cycles are timed to take advantage of differing costs per kWh at different times of day. On weekdays, October 1 through October 4, the vehicle charged when energy prices were lower and discharged when prices were higher. From October 5 and October 7, the battery level remained relatively flat because the TOU rate was unchanging over the weekend. This makes the TOU rates during weekdays versus weekends very clear in this graph.

The bottom graph of Figure 5.2 shows the battery behavior under Regulation with the new algorithm. Due to the undesirable slow drift to lower charge seen in the top graph, UD specified a replacement Regulation dispatch algorithm and requested that Nuvve make this programming change during the project. Under the new algorithm, the bottom graph shows that available battery charge remained very close to 20 kWh throughout the three graphed days; UD calls this algorithm maintaining “ideal energy.” Again, the top graph in Figure 5.2 is providing the same service, Regulation, as is the bottom graph in 5.2. In both top and bottom graphs, the vehicle performs small, continuous charge/discharge cycles in response to the regulation signal (seen as small bumps in both graphs), but in the lower graph it is also maintaining the battery level near this predefined setpoint. Maintaining an ideal energy level has the advantages of a more user-predictable SOC and thus available range, and also reducing battery wear (effects on wear are discussed later).

For PJM services that use AGC to only discharge (Reserves and Capacity), the “ideal energy” could be 100% full to be able to provide maximum energy when dispatched, which would also always be ready with full driving range. Or to provide services, have most of the range ready, and maximize battery life, ideal energy could be at 70% or 80%.

Key Takeaways: For either PJM Regulation or TOU Arbitrage, the charging and discharging of the vehicle can be controlled by an aggregator. Analyzing the difference between the old and new Regulation algorithm, we show that the aggregator can satisfy the Regulation market while controlling around an “ideal energy” point–adjusting power to automatically stay close to a mid-charge or other operator-set value. This algorithm runs the grid service, while reducing battery wear and automatically keeping the state of charge about mid-range, ready for the majority of trips.

Battery capacity

As a separate observation, the sum of discharge energy available and charge energy available at any given time corresponded to the battery’s capacity at that time. Discharge energy available is the number of kWhs in the battery that can be discharged, while the charge energy available is the remaining battery ability to store more energy. These are the stacked green and grey areas of Figure 5.1 above. This value varied across the three operating scenarios (Regulation under old algorithm, TOU Arbitrage, and Regulation under new algorithm) due to the temperature sensitivity of lithium-ion batteries. In the TOU scenario, for example, periods of faster discharge naturally lead to an increase in battery temperature, temporarily raising the available capacity. Conversely, when the battery was idle, meaning it underwent little or no charging or discharging, the capacity tended to remain relatively flat or decreased slightly. In addition to power flow, these small variations were also influenced by changes in ambient temperature, as capacity is reduced during colder periods.

Figure 5.3 below illustrates this behavior from January to September 2025 for vehicle 1205, which had ambient temperatures from 10° to 97° F. Because battery capacity was reported only when the vehicles are plugged in, the dataset includes gaps, and the capacity curve was linearly interpolated. Nonetheless, whenever the vehicle was connected, the system recorded the actual capacity at that moment. Capacity values remain close to 60 kWh in winter, during days averaging 20°F, and reach roughly 73 kWh in summer, an 18% reduction due to ambient temperature.

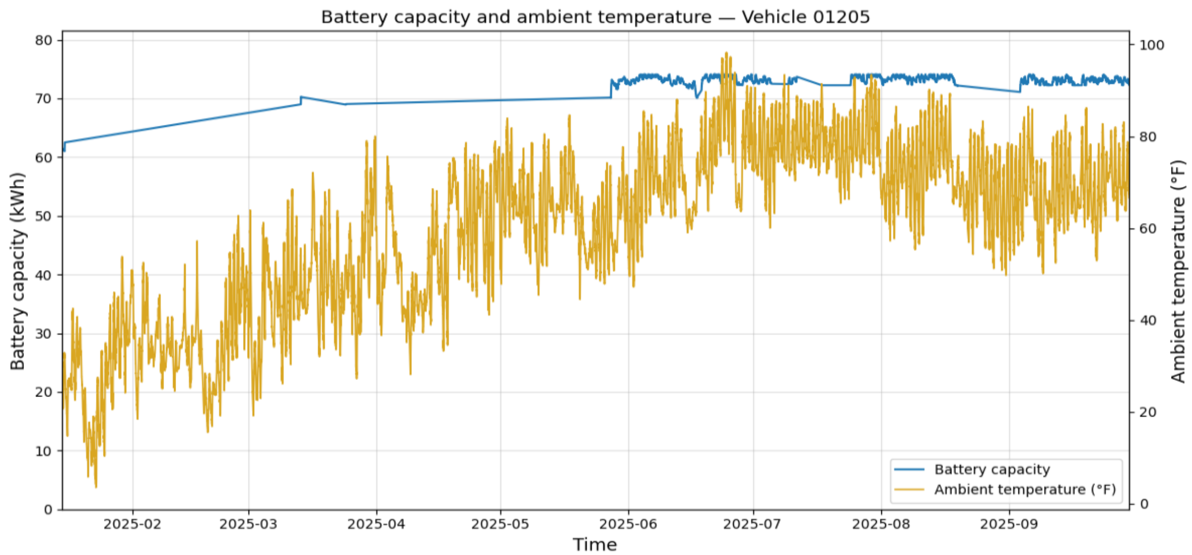

Figure 5.3. The blue line represents EV 1205's battery capacity in kWh, and the gold line represents the ambient temperature ºF. The number values on the Y axis apply to both kWh and ºF measurements. Straight line segments for battery capacity indicate interpolation between points.

The battery performance is determined by the temperature of the battery, which is not equal to ambient temperature. Figure 5.4 shows ambient temperature in gold, and the internal battery temperature in purple. Internal battery temperature appears to be from 10°, up 15°F warmer than exterior temperature. The temperatures were only available when plugged in, most of which time the EVs were either charging and/or doing grid services, thus the consistently higher battery temperature.

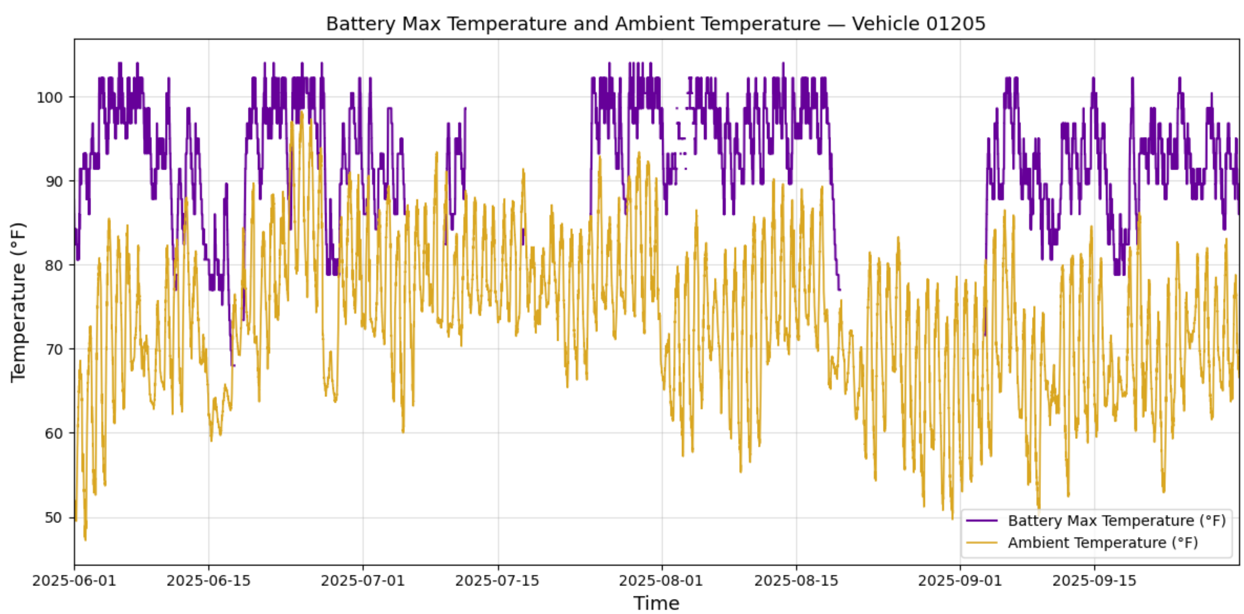

Figure 5.4. The purple line represents the battery max module temperature of vehicle 1205, and the gold line represents the ambient temperature.

Key Takeaways: Understanding the effect of temperature on battery capacity is relevant for V2G fleet management and drivers' planning, particularly with regard to range. Assuming a fleet with similar battery characteristics, for example, at temperatures around 20°F, drivers and managers could expect reduced range and reduced kWh available by 18%.

Efficiency of bidirectional converter

To calculate the financial benefit of grid services, it is essential to estimate energy losses during charging and discharging. This section uses the project data to calculate efficiency. A bidirectional charger is referred to in the power electronics field as a "converter", terminology that we occasionally use here. (The converters used in this project are pictured earlier, in Figure 3.1.) Since we use AC charging to reduce the costs, the converter is in the EV, not in the EVSE.

The efficiency of a power converter is the ratio of output over input. In charging mode, that is DC power / AC power, and in discharging mode it is the reciprocal. In this setup, we had a revenue-grade power meter for AC within the charging station, essentially the same as current going into the converter. The DC current and voltage measurements were between the converter and the battery, so those measurements were from within the EV, then relayed via LIN-CP to the charging station, then the aggregator. DC power (P_{DC}) is not measured directly, but is calculated from the measurements of current (A_{DC}) and voltage (V_{DC}):

$$P_{DC} = A_{DC} * V_{DC}$$

Once the DC power is calculated, efficiency of charging ($\eta_{charging}$) can be computed as:

$$\eta_{charging} \ = \ P_{AC} \ / \ P_{DC}$$

And efficiency for discharging is:

$$\eta_{discharging} \ = \ P_{DC} \ / \ P_{AC}$$

Given the operating environment, efficiency of bidirectional grid-to-battery transfers are most strongly dependent upon the amount of power being converted. Other factors such as battery temperature, power-factor, battery voltage, and grid voltage also affect efficiency, but less so than power in the typical automotive environment[19]. Therefore, we plotted efficiency against power in Figure 5.5. Internal converter design, such as choice of active components, switching losses, etc. also affect efficiency, but can't be varied once the equipment is picked. In this case the Watt & Well unit we selected is one of the most efficient ones available.

[19] Elpiniki Apostolaki-Iosifidou; Paul Codani; Willett Kempton. 2017. "Measurement of Power Loss During Electric Vehicle Charging and Discharging" *Energy.* 127: pages 730-742. doi: 10.1016/j.energy.2017.03.015

Figure 5.5 shows the charging and discharging efficiency against power for EV 1200 on station NCRO-01, from August 5 to August 15, 2025. Each EV had 4 converters in it, dispatched as a single EV. In this figure, EV 1200 had only two operating, making the maximum power 20 kW. During this time, the EVs were running in the Regulation market (with the original algorithm), so they varied power levels frequently, providing a spread of data values for analysis.

Each of the yellow dots in Figure 5.5 represents a single measurement, taken at 5 second intervals. As more measurements (dots) appear in the same place, the dot color gradually turns from yellow to purple (right scale). The red line is a smoothed curve, like a least-squares curve but created using the LOWESS[20] (Locally Weighted Scatterplot Smoothing) method (here drawn from the Python statsmodels library). This nonparametric technique estimates a smooth curve $\hat{y}(x)$ from a noisy dataset (x_i, y_i) by fitting locally weighted linear regressions. Observations closer to each evaluation point x receive higher weights according to a tricube kernel function, which decreases with distance. The maximum value of the fitted curve was then identified and used to draw the blue dotted line, representing the rated maximum efficiency of the bidirectional charger.

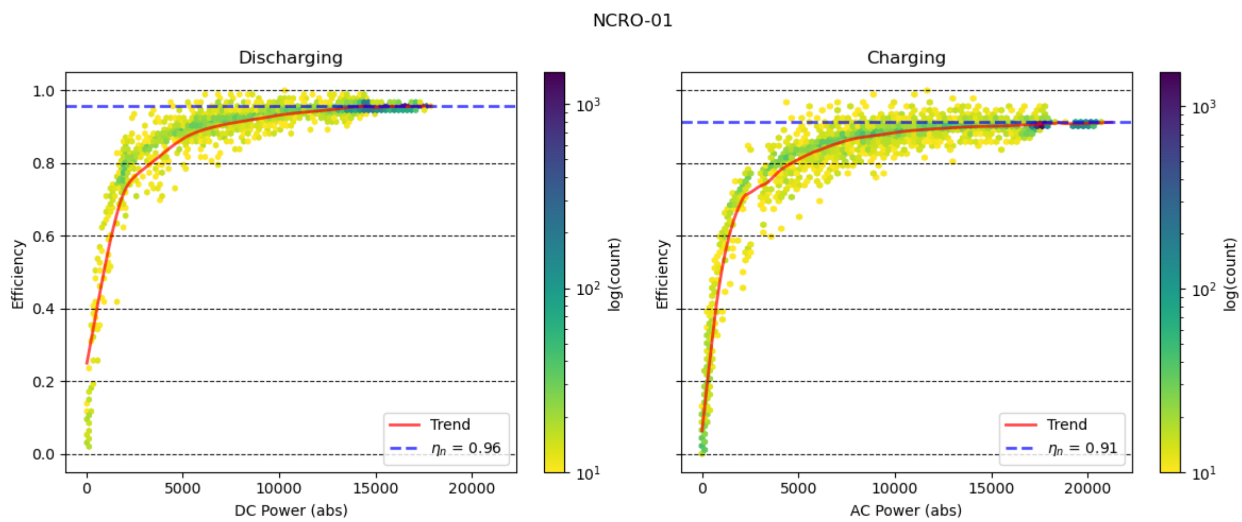

Figure 5.5. Discharging (left) and Charging (right) efficiency of the bidirectional charger in EV 1200. Maximum power for EV 1200 at the time of this test was 20 kW (2000 Watt).

We observe in the left graph of Figure 5.5 a maximum efficiency of 0.96 for discharging EV 1200, persisting over most of the upper half of the range of power. This matches the value reported in the datasheet of the BMPU-R2 bidirectional charger[21] supplied by the manufacturer. Charging efficiency asymptotes a bit lower than discharging, about 92%

[20] Cleveland, W. S. *Robust Locally Weighted Regression and Smoothing Scatterplots. Journal of the American Statistical Association,* **1979**, 74 (368), 829–836. https://doi.org/10.2307/2286407

[21] Watt & Well. (2023). *BMPU-R2 specification datasheet* (revAW). Retrieved from https://wattandwell.com/app/uploads/BMPU-R2-datasheet.pdf

Figure 5.5 also shows that the efficiency is much higher at higher power. As this unit is a high quality one, it exhibits relatively high efficiency (e.g., η > 80%) at power above 4 kW for discharging and above 5 kW for charging. At very low power, e.g. < 1 kW, the efficiency can be extremely low, below 30% down to near zero (at 2 sec sampling, some of the very low efficiencies may be transients). The drop in efficiency at low power has been measured in prior work on EV dispatch[22]. This suggests that an aggregation, when requested to operate at low power, e.g. an AGC request below 60% of capacity, should be dispatched such that a smaller set of units are called, each at higher power, while the remainder are put into low-power sleep mode. Thus, a future well-designed aggregation dispatch need not operate any individual EV at low power. To equalize usage of all EVs being dispatched, the set of EVs selected to be active at high power should be rotated over time. This type of dispatch for EVs was first suggested by Apostolaki-Iosifidou et al in 2017, who calculated a 7-10% efficiency savings.

Although this efficiency maximizing algorithm is not utilized in the pilot system, we assume that it would be likely in a production system and thus in our subsequent cost calculations use η =.96 for one-way efficiency and η^2 or $\eta_{roundtrip}$ = 0.92 for converter round-trip efficiency. Although the converter accounts for most of efficiency loss in the system (Apostolaki-Iosifidou et al, 2017, Appendix B), for round-trip efficiency we add an approximate factor for battery round trip losses of 0.02 (Apostolaki-Iosifidou, Figure B.5), making the round-trip converter+battery efficiency $\eta_{roundtrip}$ = 0.90, or equivalently a loss of 10%. (Used in net revenue calculations in section 7.)

We also compared ambient temperature with efficiency over the same period, during which temperature ranged from 55°F to 90°F. Unlike the clear relationship in figure 5.5, no notable correlation of ambient temperature with efficiency was visible.

Key Takeaways: Efficiency of charging and discharging is much higher at higher power levels, meaning that an aggregator should design the dispatch of a group of vehicles so that low-power requests are met by subsets of EVs, each at higher power. With such a dispatch algorithm, a low-power request need not require vehicles to operate at inefficient lower power levels. The overall round trip efficiency calculated here and used in calculations elsewhere in the paper is 90%, not considering influences of low-power operation, ambient temperature, nor the slightly higher efficiency during discharging.

6. Grid Services Dispatch and Response

During the demonstration project, the project EVs were run in two grid services modes, PJM Regulation and DPL’s TOU rates. In the next sections we explain first the control signal for time of use, then analyze the EVs responses.

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[22] Elpiniki Apostolaki-Iosifidou; Paul Codani; Willett Kempton. 2017. “Measurement of Power Loss During Electric Vehicle Charging and Discharging” *Energy.* 127: pages 730-742. doi: 10.1016/j.energy.2017.03.015

For Regulation, in the non-pilot, on-line market, Nuvve or UD place day-ahead bids to PJM offering how much power is available each hour and at what price. When on the PJM market (versus the pilot project, as now) we typically bid $0 M/W-h price, because the market clears at the highest bid price, a $0 bid assures acceptance, and we are still paid the “market clearing price”. Our current pilot project does not actually bid to PJM, but the Nuvve operator types the bid into the aggregator, which causes a dispatch signal to be sent from aggregator to EVs the same as if bids had been placed with PJM. This process and aggregator have already been market tested–UD created the original version of the aggregator, licensed to and further developed by Nuvve, and UD has run a fleet in Newark, Delaware with both UD and Nuvve aggregators, both making live bids and receiving financial payments from PJM.

Since PJM’s minimum bid is for 100kW of power, we usually bid and dispatch a group of all four EVs as none of these cars alone can make 100kW. (We sometimes bid only 50 kW internally, for testing a smaller group of EVs.) The Nuvve aggregator is set up to group the four EVs as a “dispatch group” and can dynamically strategize how much to draw from each EV, for example drawing less from a vehicle that has a malfunction causing lower power availability, or whose user has scheduled a trip requiring charging.

For TOU Arbitrage, the remuneration would typically be to an individual utility account at one premises, and there is no bidding nor minimum power. Consistently, the individual EVs and chargers can be treated as separate DERs. Alternatively, TOU Arbitrage can be dispatched via dispatch groups by an aggregator, which would have the advantage of being able to give the utility coordinated override and allows optimizing power flow across EV resources within a dispatch group. For this pilot, the EVs are dispatched by an aggregator and are smart about trips overriding the schedule. For PJM service, the market performance would be that of the entire dispatch group, whereas for TOU grid service, they are shown as individual EVs, due to limitations on the current Nuvve aggregator.

Below we describe the two control methods, the AGC from PJM for regulation, and the TOU dispatch from the aggregator to each EV. Then we analyze the EVs’ responses to both signals, and the dispatch group’s response to Regulation.

Dispatch signals

Dispatch for PJM Regulation

PJM continuously determines short-term need for adjustments in active power systemwide, based on interregional power transfers and to a lesser extent deviations in frequency from 60 Hz. This is converted into an AGC control signal, apportioned to each generator with an active Regulation bid in the market. Each generator receives a number between -1 and 1, with negative indicating a request to absorb power and positive being a request to produce power. The generator multiplies the AGC number by the bid capacity in MW to get the dispatched MW. Then, to be with its bid, the generator must produce or absorb that number in MW. Since a physical generator cannot absorb real power, negative and positive are with reference to each generator's "preferred operating point", or POP.

Similarly, a VPP aggregator will multiply the AGC -1 to 1 signal by its bid Regulation capacity in MW to yield the number of MW it needs to dispatch. An aggregator then has a second step, to apportion the needed MW to all active resources under control at that moment. The aggregator can move the POP of individual EVs above or below the 0 point, which causes net charging or discharging over time. The aggregator can also adjust the POP of its entire VPP, as can a generator, but this change must be reported to PJM during operations.

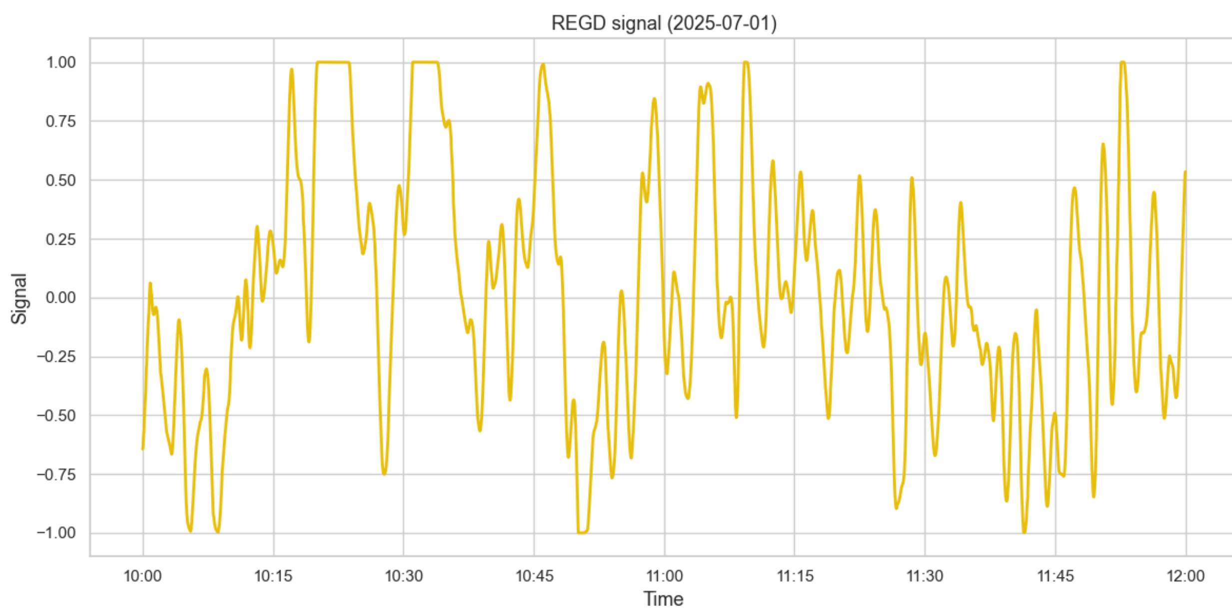


Figure 6.1. PJM Reg D dispatched the AGC signal over 2 hours on July 1. The Regulation signal is a real number from -1 to +1 and can change every few seconds.

For Regulation, PJM constrains the AGC signal so that over time, a battery resource is unlikely to be forced to empty nor to full. To achieve this, the AGC needs to balance energy discharged with energy charged. Two months of the PJM regulation signal are analyzed in Figure 6.2 and Table 6.1 to determine whether the PJM signal maintains this balance.[23] Two months at 2 second dispatch intervals gives a total number of dispatch signals of 2,498,116. The figure is a histogram binned in 0.1 units. The dispatch signals are given at regular intervals (every 2 seconds). We display in each 0.1 interval the total number of requests within that interval. Comparing each opposite sign sum (e.g. the sum between -.4 and -.5 is about the same sum as between .4 and .5, making the distribution approximately symmetrical around 0. The extreme -1

[23] In the analysis of data for Figure 6.2, we made the unexpected finding that, although sequential AGC signals often crossed through zero and many values were very close to zero (e.g. 10^{-5}), we found no AGC signal with the value of zero in the data. It is possible this is due to a non-rounding error. This will be further analyzed as it affects how to most efficiently allocate power dispatch across multiple cars.

and +1 values (bins 0.9 to 1.0 and -1.0 to -0.9) occur roughly twice as often as values in the intermediate bars.

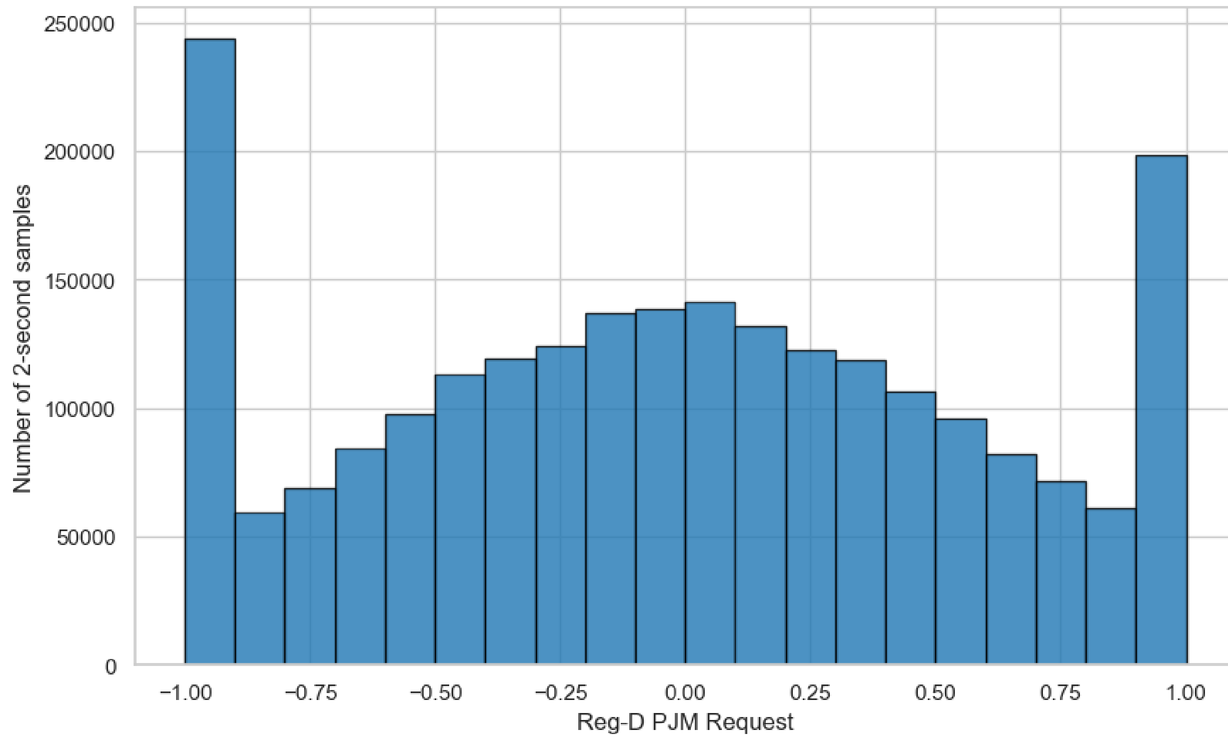


Figure 6.2. Reg-D PJM AGC signal, ranging from -1 to +1 and binned by tenths. Sample is from June 1st through July 31th. Number of measured signals n=2,498,116.

Table 6.1 is an analysis of the PJM Regulation AGC signal, counting positive and negative events, and averaging the quantity requested for up (discharging) and down (charging), accumulated over almost 2.5 million dispatch signals. The rightmost column shows that the

Table 6.1. PJM AGC dispatch requests from June 1 through July 30, tabulated as counts of negative or positive, and averaged as quantity of negative and quantity of positive dispatched energy, over a total of 2,496,434 requests.

	Number of positive events	**Number of negative events**	**Positive dispatch (>0…+1), average value**	**Negative dispatch (-1 … <0), average value**	**All dispatch (-1 …+1), average value**
All day	1214928(48.7%)	1281506(51.3%)	0.53	-0.54	-0.02
6 am to 9 am	155578 (49.7%)	157680 (50.3%)	0.51	-0.51	-0.01
2 pm to 7 pm	260680 (50.3%)	257482 (49.7%)	0.53	-0.53	-0.01
5 pm to 9 pm	205293 (49.2%)	212365 (50.8%)	0.52	-0.52	-0.01

quantity of up and down energy was very close to balanced, differing by only 2%. Comparison across blocks of daytime hours (last three rows) show close to uniform distribution during each range of daytime hours.

The practical result of this slight asymmetry toward negative requests would be that about 2% of dispatched energy would go toward charging the battery over time. If accurate over time, this is a nice bonus but is less than half the round-trip efficiency losses (see section 7) so loss of battery energy while doing Regulation would still need to be compensated by other mechanisms in an aggregator. The updated Nuvve Regulation dispatch now does this, using preferred operating point (POP) and ideal energy, as described earlier.

Dispatch for Time-of-day Arbitrage

The Nuvve aggregator dispatched TOU Arbitrage according to clock time, to take advantage of either smart charging or TOU Arbitrage via a simple spreadsheet entered by the operator. The spreadsheet lists each hour of the week, and for that hour, whether the EV should be charging, idle, or discharging, and at what power level. The week repeats beginning on Mondays, until changed by the operator. Any scheduled trips immediately take priority over the fixed TOU spreadsheet, but otherwise there is no look ahead or adjustment for the current level of energy already in the battery. Rather, the TOU dispatcher just follows the set schedule until the battery reaches its low or high limit set for grid services.

As a charging time schedule appropriate for the DPL “Plug-in Vehicle Time of Use Rate”, we created a spreadsheet with discharging and charging times corresponding to the high and low rate periods. The amount of power to be discharged or charged was determined by assuming a likely worst case of late arrival in the afternoon or unexpectedly needing to take a trip. This meant faster rates of charge and discharge in case of late arrival; charging faster also means that even unexpected trips are more likely to be met. Initially, for Oct 1, we set charge to 4 kW and discharge to 17 kW, but after running several days, on Oct 6 we adjusted the discharge rate to only 8 kW, which we saw allows a full charge even plugged in late in the day while reducing the abrupt power changes on the grid. Figure 6.3 shows the revised schedule set up in the aggregator. A minor detail is that the TOU dispatch is given to each car individually, unlike Nuvve’s Regulation dispatch which can be assigned to a defined dispatch group. Thus we show Regulation, not TOU, by dispatch group.

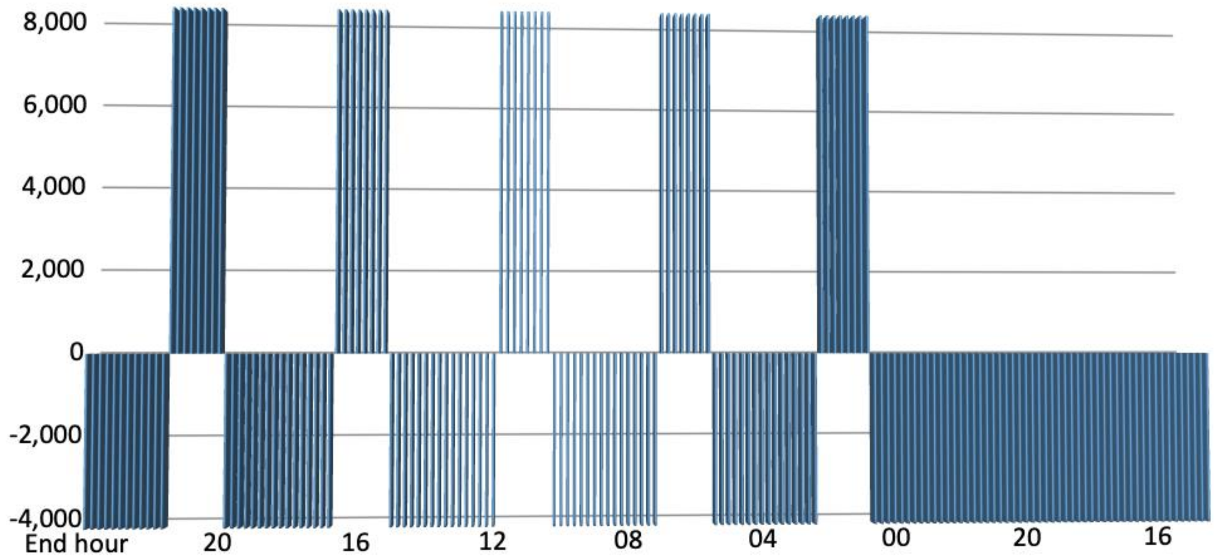


Figure 6.3. The defined TOU dispatch signal for each of the seven days of the week. The X axis is time of day through one week. The Y axis is watts, with negative numbers for charging (set at -4000 Watt = -4 kW off peak) and numbers above 0 for discharging (after Oct 6, 2025 discharge on peak was set to 8 kW as shown here). Off-peak and all weekend hours are set for charging.

Key Takeaways: For PJM Regulation, the Nuvve aggregator aggregates all four EVs as a single dispatch group and responds to the recorded PJM request by dispatching EVs for Regulation. To understand the signal, we sampled two months at two second dispatch intervals, totaling 2,498,116 Regulation dispatch signals. In this large sample, we find the total energy between up and down calls to differ by only 2%, in favor of charging. For the TOU Arbitrage service, the EVs follow a set schedule according to clock time to take advantage of DPL TOU rates. The TOU signal is assigned to each EV individually. For either service, the Nuvve aggregator manages trip requests and prioritizes user requests to charge over the grid service requests.

Response of EVs and Dispatch Group

LIN-CP provides signals for data reported from the car and can send controls from EVSE to the car. In this document, LIN-CP data give a detailed window on operation of the EVs performing grid services, which can be understood by the graphical displays we provide below. From an aggregator perspective, the rich LIN-CP data set also allows consideration of operating conditions of each car, EVSE, ambient conditions, and trips, allowing the aggregator to optimize dispatch and battery life among all EVs in a dispatch group. We discuss first single EV response, then the response of a dispatch group.

EV Responses to Regulation

The EVs' response to Regulation is compared over time and at different time scales. Figure 6.4 shows a 24-hour period on October 25, 2025, when charging station NCRO4 was dispatching EV 1146 for PJM Regulation, using the new algorithm (explained previously regarding Figure 5.2) . The dark blue line shows the dispatched power in kW, as measured by the charging station's revenue-grade meter. As seen, power jumps up and down frequently, in response to the rapid PJM regulation AGC control signal.

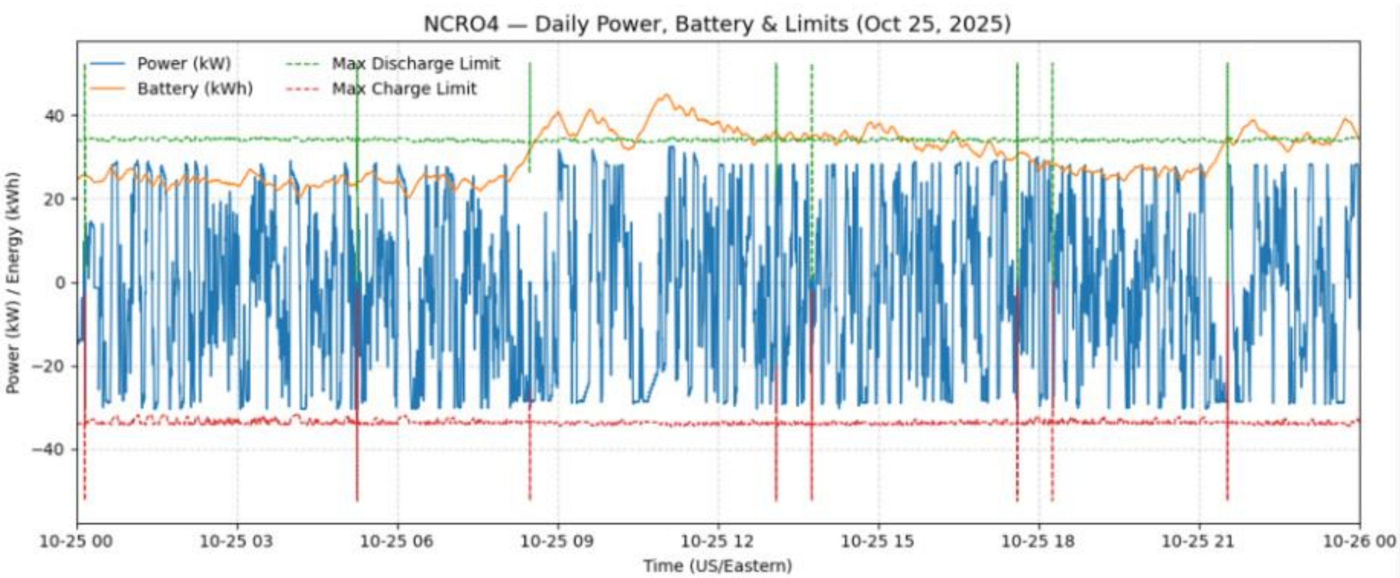
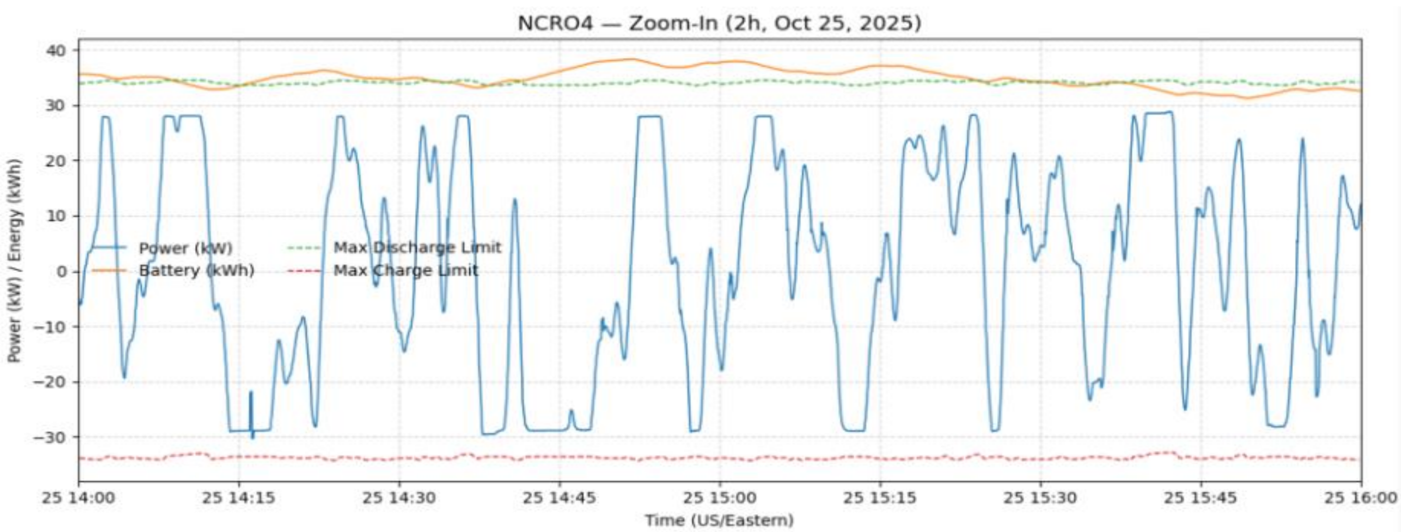


Figure 6.4. EV 1146 at station NCRO4 over 24 hours, responding to the PJM regulation signal with the new Regulation algorithm. The kW maximum discharging and charging power capability of the EV are shown by the green and red dotted lines, respectively. These are about 33 and -33 kW respectively. The EV's response to the AGC signal is measured by the revenue meter in the EVSE (blue line). The red-orange line at the top represents the battery's energy; you can use the numerical scale marked in kWh to interpret the exact amount. The red-orange line at top is the energy in the battery–to read, interpret the numeric scale as kWh.

The dotted lines for max charging and max discharging (red and green in Figure 6.4) are reported by this single EV over LIN-CP. Note that the aggregator-driven response of the EV stays within the max charge and max discharge limits (e.g. blue line stays above red and below green). (A minor anomaly in Fig 6.4 is that there are seven soft resets, seen as the green and red max power lines temporarily dropping to 0 kW then spiking to 50 kW, the station's maximum, with no practical effect.) Having the EV accurately report its dynamic changes in kW power capacity (red and green lines), and the aggregator correctly using that to limit dispatch, is extremely valuable for the VPP.

The top red-orange line in Figure 6.4 is the amount of energy in the battery. In this figure, the Y axis scale can be read in KW of power for the max capacity and measured power lines, and read as kWh energy for the red battery energy line. The red battery energy line makes small deviations up and down (about 4 kW max fluctuations), as expected. During the PJM regulation market service, occasionally PJM will request a series of Reg down (e.g. 9:30 to 10:30) which raises the energy in the battery to about 40 kWh. A similar pattern can be seen when regulation up is above average and the battery is discharged slightly. As noted, the PJM signal should balance up and down, but regardless Nuvve's new Regulation algorithm will also gradually bring the battery back to the user-set ideal energy over time.

In Figure 6.5, performance of the same EVSE and EV as in Figure 6.4 is shown on an expanded (shorter) time scale of 2 hours. This gives a more detailed picture of the power response (blue line) to the Regulation AGC signal. Again we see that the dispatched power stays within the max limits advertised by the EV, and that several sequential AGC signals in the same direction pull the battery energy up or down, but again only a small amount in the new dispatch algorithm, subsequently corrected. We can also see from Figure 6.5 that the dispatched amount was about 29 kW, whereas the capacity was 33 kW. Since this was consistent, we used the dispatched amount of 29 kW in our revenue calculations (Section 7), although this appears to be a fixable software bug in either the on-board charger's reporting maxima or in UD or Nuvve's use of that maximum.



<u>Figure 6.5.</u> Expanded time scale, 2 hours extracted from Figure 6.4 with the same variables.

PJM gives scores to Regulation providers based on accuracy and latency of the metered response to the AGC signal. To measure response at the sub-second level, we draw from Nuvve's real-time monitor rather than the data base used for other figures (thus the change in appearance of the next few graphs).

Figure 6.6 shows the regulation request (green) and metered three-phase power response (yellow), over one hour. (Red and blue lines are charge and discharge kW capacity.) The response from the EVs is so fast that, at the one-hour scale of the graph, the request and response lines overlap.

<u>Figure 6.6</u>. Regulation service by EV 1146 on station NCRO 4, December 1, 2025, Midnight to 1:00 am. Green is power request, yellow is metered power response. (Red is the charging maximum and blue the discharging maximum.)

PJM Regulation is now provided primarily by gas turbines. For comparison with our battery response data in Figure 6.6, a similar graph of response to a regulation signal from a combustion turbine (CT), also during one hour, is shown in Figure 6.7. (This CT has chosen to run under the more lax Regulation service, formerly called Reg-A, which pays less per MW-h, requests fewer changes, and allows slower ramps. The lower stringency of requests can be seen by comparing the power request lines in Figure 6.6 versus 6.7, power request being the green line in both figures.)

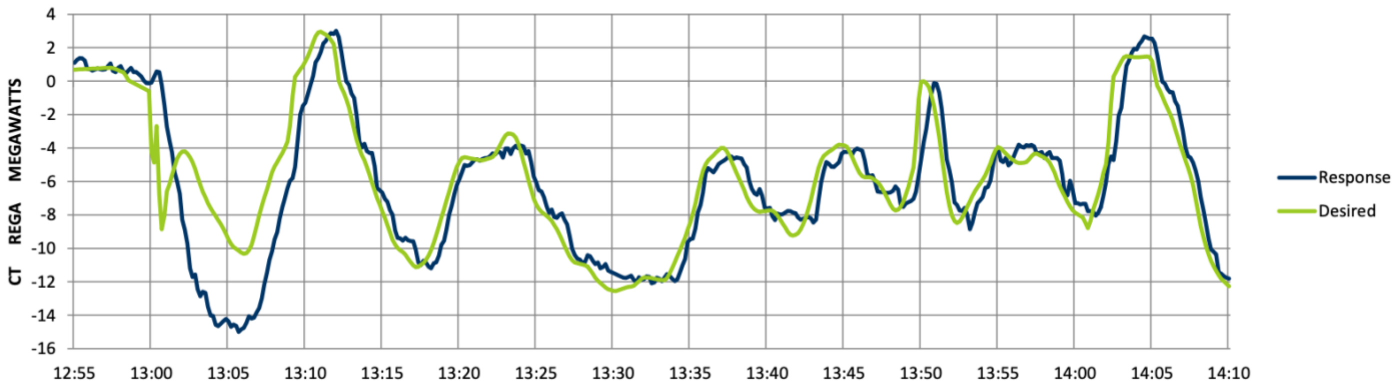


Figure 6.7. PJM Regulation service provided during one hour by a combustion turbine. The lag and inaccuracies between request (green) and power response (black) are visible even at the one hour scale. Figure from Lee 2017.[24]

From Figure 6.7 we measured response delay using a ruler to measure horizontally from signal to response. By this simple measurement, the CT's response varies between 30 seconds and a minute, with some substantial inaccuracies–for example, at 13:05, -10 MW down was requested but the CT's measured output dropped to -15 MW. Among thermal generators, CT's actually provide the best response, whereas other Regulation resources, like combined cycle and steam turbine, have 10x slower response times than CTs (Lee 2017, Table 1). PJM has found that faster response and greater accuracy earn battery systems higher performance scores and have enabled PJM to significantly reduce needed Regulation MW requests, leading to lower overall costs to ratepayers (Lee 2017).

To approximate the response speed of the V2G system, we want to quantify the time from the charging station receiving a dispatch signal, then from station to EV, then EV internally adjusting power output, finally to the end time when the station's revenue meter reads the change. That lag is measured simply as the time from the EVSE receives the dispatch signal from the aggregator, to the time the EVSE measures the same quantity in response at the EV's power meter. (The latter, meter reading with timestamp, is reported to PJM as the response to their AGC.) To measure the time lag here we expand part of the one hour in Figure 6.6 to 40 seconds of a fast ramp up, 00:30:30 to 00:31:10. This expanded time axis is in Figure 6.8, revealing that both signal and power response are more gradual than appears in the apparently instant response of Figure 6.6.

The entire transition in request signal, from requested maximum charging to maximum discharging, is complete in 35 seconds. That is, when we expand the time scale from Figure 6.6 to that in Figure 6.8, we see the request signal is a ramp, not an instantaneous vertical line. To

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[24] Thomas Lee, 2017, Energy Storage in PJM: Exploring Frequency Regulation Market Transformation. Kleinman Center for Energy Policy, U Pennsylvania, Report, July 27, 2017. https://kleinmanenergy.upenn.edu/wp-content/uploads/2020/08/Energy-Storage-in-PJM_0-1.pdf. Graphic originally attributed to Benner, Scott, 2015. "Performance, Mileage and the Mileage Ratio." PJM Report. Nov 11, 2015.

measure the EV’s response time, we started measuring from when both request and response lines began to change slope up to when either flattened out—in Figure 6.8 this is from 00:30:37 to 00:31:13. During that change interval, there were six recorded points of the request signal (green dots). From each request dot, we measured horizontally (same kW) to the metered response (yellow line). The average of those six measured intervals from signal to response is 1.5 seconds. That is, the time for an EV to respond to the PJM AGC signal, with all delays between EVSE and EV and included, is 1.5 sec, compared to the previously seen CT in Figure 6.7 which takes about 50 – 60 seconds to respond.

<u>Figure 6.8</u>. The rapid shift from full charge to full discharge seen in Figure 6.6 as a vertical line, now expanded to the two minutes after 00:30, showing at this scale that the shift of both request and response lasts from 00:30:37 to 00:31:13.

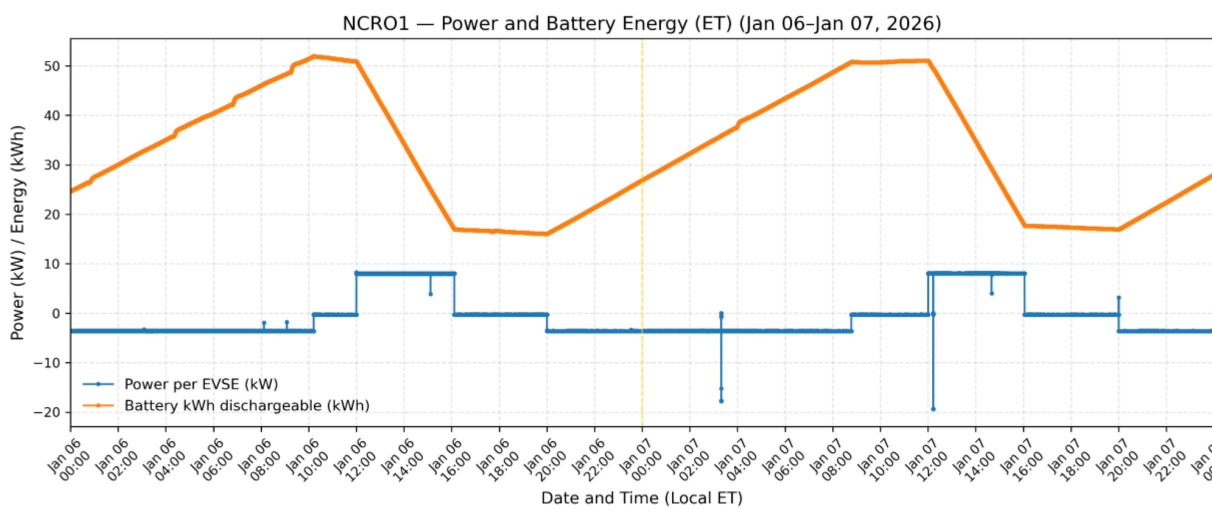
Key takeaways: Regulation is a good test of a power resource for multiple RTO services because it requires rapid and accurate response to an AGC signal. This analysis demonstrates that well-designed V2G systems are a high-quality Regulation resource, much better than any thermal generation in both response speed and accuracy. Purpose-built large batteries provide high-quality Regulation comparable to V2G, but at much higher capital cost. RTO services are typically procured based on market clearing price and evaluated by performance. This means that V2G VPPs should be able to compete with purpose-built batteries in bid cost, and with thermal resources in both performance and bid cost. Nevertheless, any battery system will have a duration limit, measured by the kWh/kW ratio. Generally, EVs have a higher kWh/kW ratio than purpose-built grid batteries, due to EVs’ battery kWh being sized to meet driving range requirements.

EV Responses to Dispatch for TOU Arbitrage

Figure 6.9 shows EV 1149 on EVSE NCRO1 doing time of use Arbitrage for two full days, from 12 midnight January 6, 2026 to midnight January 8, 2026. Dispatch is based on TOU rates for DPL per Figure 6.3, limited by the upper and lower SOC limits and any trip scheduling, as noted previously. On-peak hours are 12:00 noon to 8 p.m. Monday through Friday; all other weekday hours, plus weekends and holidays, are off-peak. These inputs result in a dispatch signal causing the power flow shown in Figure 6.3. Again, blue is power flow and orange is the energy in the battery.

At the beginning of the time-series graph in Figure 6.9, on the left, the -4 kW charging signal is continuing to fill the battery from the night before. It stops about 10:00 am, when the battery reaches the TOU algorithm's SOC maximum (87%), so the aggregator sets the charge rate to zero, resulting in the battery SOH staying approximately constant. Noon begins the on-peak rate, so discharging starts–the blue line shifts to +8 kW and the battery line begins to move down due to aggregator-directed discharge. When the battery reaches its SOC minimum, about 16:00, again the aggregator-requested power returns to zero. At 20:00 (8:00 pm) the off-peak rate begins, charging resumes, and the TOU cycle repeats.

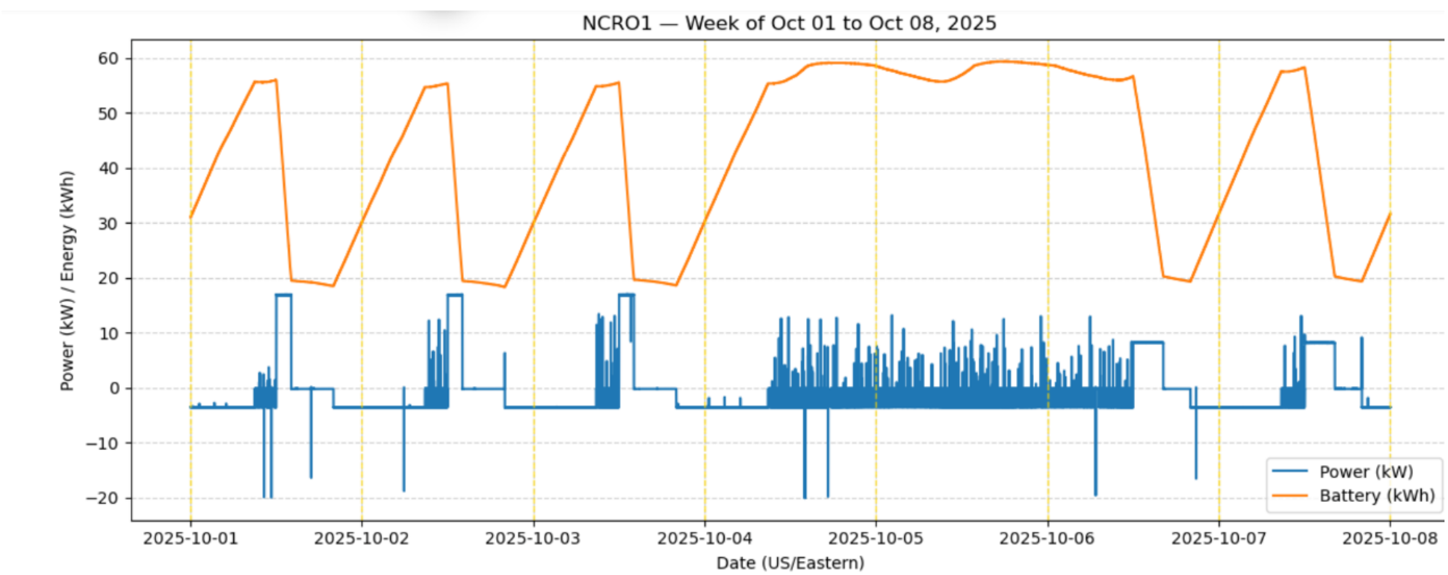
Figure 6.9 also shows two graphic anomalies in the dispatch or response, neither consequential. The two vertical blue lines down to -20 were automatic resets, which caused the EV to briefly charge at full power. (A reset occurs when either the EVSE or EV circuits suspect an unrecoverable error and does a reset to clear that error, a common failsafe.) The second anomaly is about six instances of charge or discharge dropping to zero momentarily due to transients, seen as a very brief jump in the blue power line with no visible effect on battery energy (orange line).



<u>Figure 6.9.</u> Two full weekdays, Jan 6 up to Jan 8, 2026 show EV 1149 running the new TOU Arbitrage algorithm. The blue line (power request) switches among -4 (charging off peak), 0 (battery at min or max for this TOU dispatch) and +8 (discharging on peak). The dischargeable energy in battery (orange line) moves between about 12 and 50 kWh.

On a wider time scale, Figure 6.10 shows TOU Arbitrage over a full week for EV 1149 on EVSE NCRO1 from October 1 to October 8, 2025. The pattern of weekday versus weekend is clear, cycling the first three days, charging to max starting Friday evening (date 2025-10-04), battery energy stays at max over the weekend, awaiting discharging until the next peak rate, Monday at noon.

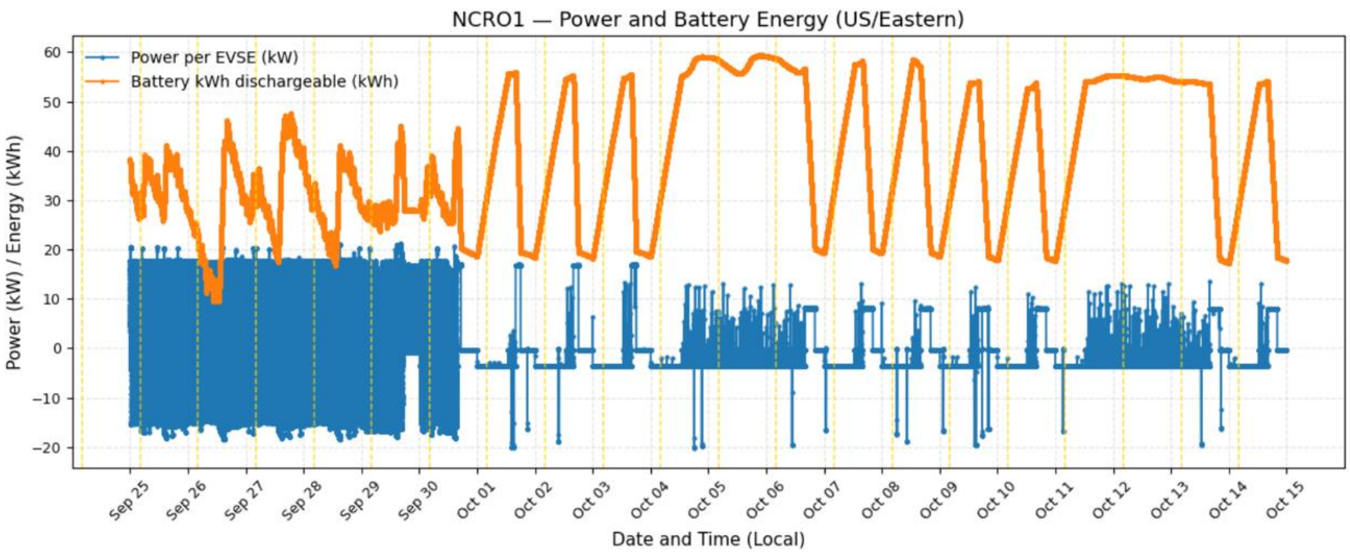
To explain two details in Figure 6.10, the blue charging line shows switching “noise” when the battery is full, due to a bug in the old TOU algorithm. This was corrected by Nuvve as seen previously by the flat 0 kW line in Figure 6.9, using the January 2026 new TOU algorithm. The second anomaly in Figure 6.10 is that weekdays from October 1 through October 4 were set to discharge at 17 kW, which was faster than needed when the EVs were not in use, so on October 6 we manually reset discharge to 8 kW. The higher discharge rate is seen in the left of Figure 6.10, and the lower discharging rate can be seen in right, differing in the higher and shorter “blue box” on the first three weekdays, compared with the last two weekdays



<u>Figure 6.10.</u> One week of Arbitrage, EV 1149 on EVSE NCRO1, October 1 to October 8, 2025. The blue charging rate is negative kW (charging) off-peak and the battery is not yet full. Power is above zero (discharging) on-peak rates and the battery is not yet empty. The orange line shows kWh in the battery. The noise in the charging rate during battery full was a bug in the TOU algorithm, fixed in Figure 6.9.

The TOU dispatch is working to shift load off-peak, as seen in the substantial shift in kWh in the battery. Reading kWh off the left scale, we see that on each daily cycle the charge goes from 20 to 56 kWh, that is about 36 kWh are being shifted from off-peak to on-peak per car per day. This measurement is used in the TOU value computations in Section 7.

A clear view of the difference between Regulation and TOU Arbitrage is seen in Figure 6.11, from NCRO1 during 3 weeks. The figure shows the transition from this EV providing Regulation from September 25 to October 1, then switching to TOU Arbitrage from October 1 through October 15. This change was done entirely from the aggregator side, taking a few minutes by the operator of the aggregator, requiring no work on site whatsoever, nor any type of shutdown. This demonstrates that with proper interconnection and market qualification, and with a capable aggregator, a single interconnected car or fleet can qualify to serve multiple markets and can even switch among markets as often as desired. (Regulation and TOU are each using their old algorithm in this figure.)



<u>Figure 6.11.</u> NCRO1 from Sept 25 through Oct 15, showing the rapid transition on Sept 30 from this car providing PJM regulation to providing TOU Arbitrage. Each service is here using it's old algorithm.

Key Takeaways: Using LIN-CP, we were able to accurately report the EVs dynamic charge and discharge capacity to the aggregator, and the aggregator utilized it dynamically. This data is not available in other AC communication protocols such as IEC 15118 or the original J1772 PWM, nor can most aggregators utilize this information. From analysis of the PJM Regulation response, we found that the power response was 29 kW rather than 33 kW due to minor bugs, so we use 29 kW to be realistic in our revenue calculations later in the paper. For TOU Arbitrage, we manually set the charging and discharging power rates in order to finish charging or discharging within the TOU time cycles; within these constraints we found that each daily cycle the charge moves 36kWh from on- to off-peak, so this is the amount used in TOU Arbitrage revenue calculations later. The Nuvve operator was able to easily switch the EVs and dispatch group from responding to the PJM Regulation signal to the TOU Arbitrage control, illustrating that a correctly interconnected single EV or dispatch group of EVs can switch among markets rapidly, without intervention at the vehicle site.

Dispatch group response to Regulation

The dispatch group (DG) is a dynamic entity composed of multiple EVSEs, in which vehicles may connect and disconnect throughout the day. The DG behaves as a single controllable asset for the aggregator or VPP, thus can also be a single asset as seen by PJM. A dispatch group's real-time power output is measured as the sum of all EVSEs active in that DG at any moment. As a result, the DG's available charge/discharge capacity varies over time. A single aggregator may have multiple dispatch groups, essentially multiple VPPs, with each DG separately monitored and controlled. The aggregator may bid multiple DGs into multiple markets or bid multiple DGs into the same market. By FERC Order 2222, a dispatch group operating for an RTO cannot cross utility service territory boundaries (the Order gives a more precise definition of the geographical boundaries allowed).

This subsection shows the performance of the entire dispatch group made up of the project's four EVs, responding to the regulation dispatch signal from the aggregator. Figure 6.12 shows the way in which each EV contributes to the dispatch group providing the requested power. Here the power of each car is shown by a different color, in a stacked graphic. In other words, the top of the stacked 4 cars is the total power provided by the DG, also shown by the dashed blue line. The request for the dispatch group is the red dotted line, and the metered power readings, summed for the combined dispatch group, are the dashed blue line. The request and metered response lines almost perfectly overlap–showing the fidelity of the multi-vehicle dispatch group's power response to the AGC request.

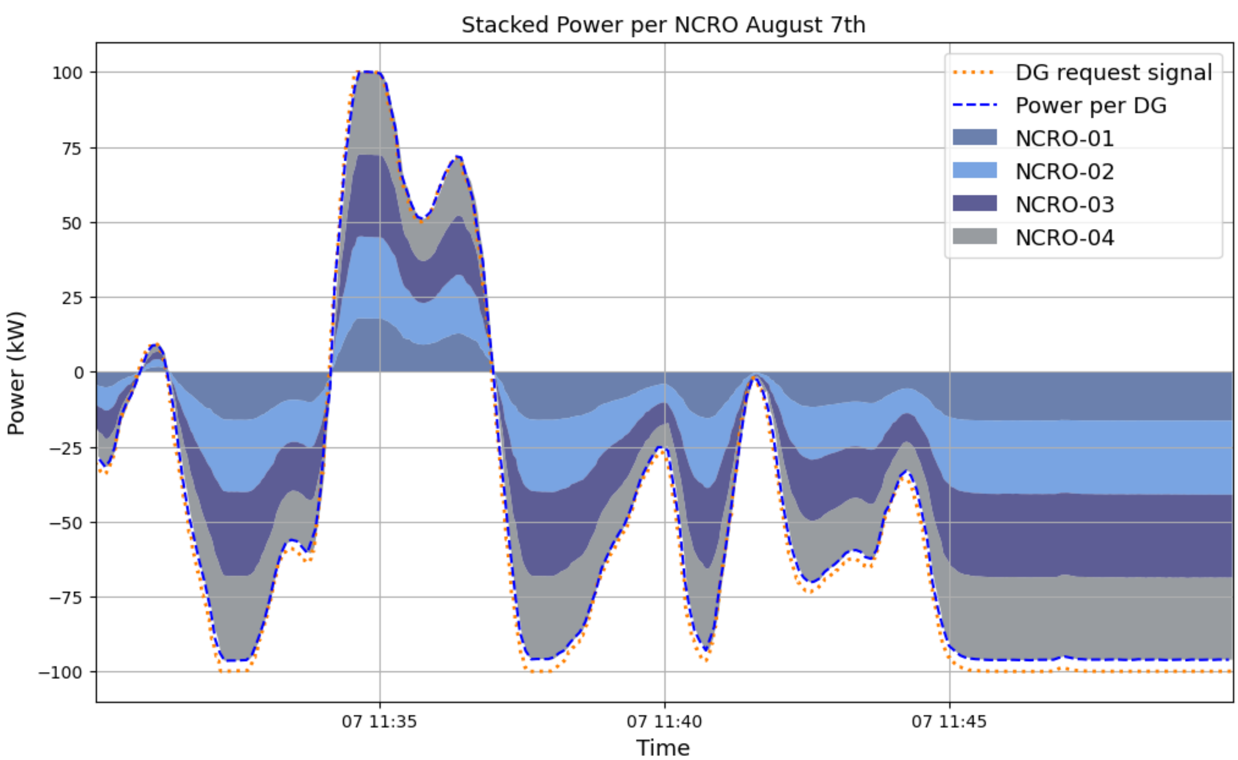
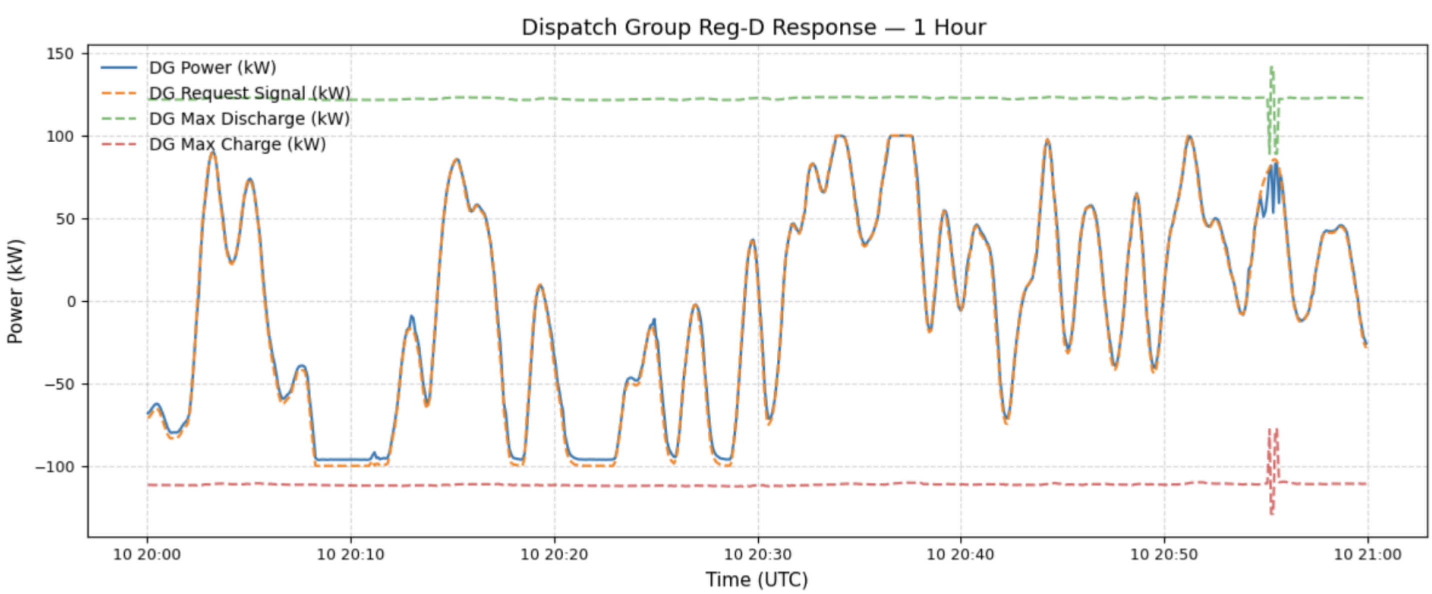


Figure 6.12. All four EVs here perform Regulation as a single dispatch group. This shows 20 minutes from 11:30 AM, August 7, 2025. Each filled color is a separate car. Comparing the relative heights of color areas shows that the EV at NCRO1 has less capacity. Nevertheless the aggregator meets PJM's request by allocating power per car within the dispatch group as a proportion of each car's ability.

Next, one hour of Regulation dispatch is shown in Figure 6.13 for this dispatch group, for a longer time and without breaking out each EV. Note that the power provided by the whole group (blue line) tracks the request (orange dotted line) so closely that they appear to be one line most of the time. The green and red dotted lines at top and bottom in Figure 6.13 are max discharge and max charge power, which maintain about 110-120 kW max discharge and about 110 kW max charge. These capacity lines show that the DG capacity was greater than the bid, on both negative and positive sides, leaving a small margin of reserve. Yet, if one 33 kW EV drove away, the dispatch group would no longer be able to make the 100 kW bid consistently, nevertheless it would likely be just within the allowed performance criteria for error to provide PJM Regulation (accuracy of 70%).

Figure 6.13 also shows that when PJM requests max charging (negative power), there was a small deviation in that the blue power line was about 4 kW above the request line, consistently at high charging levels (max negative values). This is a known inaccuracy due to either the UD or the onboard charger systems estimating max power, again too small to affect the PJM performance criteria and not prioritized for repair in the limited time of the pilot project.

At time 20:55 in Figure 6.13, the response diverges briefly from request. This illustrates an apparent failure by one EV, presumably 2-3 minutes of automatic resets, causing capacities (green and red dashed lines) to loose about 30 kW of the group's 115 kW capacity for 2-3 minutes, 30 kW being the amount due to losing one EV. Yet, even in this small group of only 4 cars, these deviations from the request were so small, and/or brief, that the DG's total power (blue) fluctuated but was still within PJM allowed inaccuracy. (Compare with the inaccuracy and duration of deviations by the CT in Figure 6.7.) We note that effects of individual car dispatch failures or unscheduled driving, and their effect on capacity and power of the dispatch group, become smaller as the dispatch group is set up to be larger.



<u>Figure 6.13.</u> A dispatch group of four EVs provided Regulation for one hour (20:00 to 21:00), meeting a 100 kW bid with ~110 kW to 120 kW capacity (dotted green and red lines). The metered power (blue) so closely matched the requested power (dotted orange) that they usually overlap, indicating high accuracy and low latency.

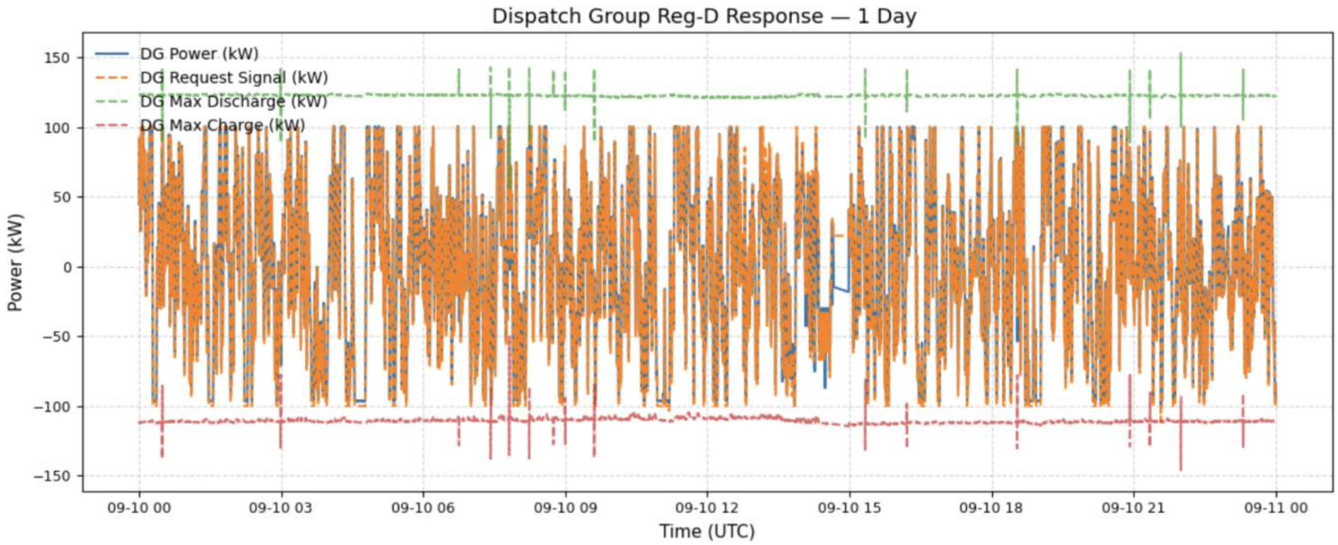


Figure 6.14. Dispatch group running regulation for one day.

Expanding from the 1-hour view, Figure 6.14 shows the dispatch group running regulation for one day. As seen in Fig 6.13, the DG capacities-the green and red dashed lines—are steady almost all day, with a very small capacity drift up and down, plus 16 automatic resets over the whole day. Again, the blue power line is usually so accurate it is overwritten in the graph by the request (orange dashed line).

Key Takeaways: The dispatch group behaved as a single controllable asset for the aggregator, showing high accuracy and fast response to PJM AGC signals. An aggregator's use of dispatch groups solves two problems: minimum power capacity required to bid RTO markets (100 kW) and unexpected unavailability of individual vehicles. In a dispatch group, controlled by a sophisticated VPP, groups of V2G-capable EVs respond quickly and accurately and can adjust to loss of capacity due to device failure, extreme temperatures at some sites, or user trips. A dispatch group, controlled by a VPP, currently is essential to bid in RTO markets, especially for small-capacity resources (under 100 kW), and those whose grid service may be interrupted (notably EVs, due to travel needs). A dispatch group and VPP is not essential for EDC service such as TOU Arbitrage, but may still have advantages (e.g., optimization across cars, reporting, accepting EDC override requests, etc.).

Dispatch and effect on battery wear and state of health

Many analysts assume that the primary impact on Li-ion battery life is the kWh throughput. We showed in section 5 on vehicle performance that over a year, for an energy-flow intensive service such as PJM Regulation, the energy throughput could be 3-4 times greater than driving alone. Fortunately, lab research over the past decade has shown that a bigger factor in battery wear is time duration at the state of charge (SOC). That lab research shows that loss of capacity is more strongly related to how long the battery remains at extreme states of charge, high or low.[25] A similar guideline comes from the Renault Mobilize's Netherlands manager, after operating a fleet of V2G vehicles: "Our tests show that wear and tear isn't too bad ... As long as the battery charge is kept between 20 and 80 percent, batteries hardly degrade with use. The battery warranty terms of eight years or 160,000 kilometers [100,000 miles] therefore remain unchanged."[26] Renault's practical experience is consistent with the lab work cited.

Therefore, to reduce the wear on the battery, whether from ordinary driving, from V2G, or other factors, one would prefer a charging management system that is able to keep the state of charge in the middle range as much as practical, keeping away from the full or empty states unless needed for an upcoming trip. We make a preliminary investigation of this by comparing time duration at each state of charge for both Regulation and TOU Arbitrage.

The distribution of SOC during regulation is shown in Figure 6.15, a histogram showing how often the battery is at each level of charge. The X axis is kWh in the battery (grouped into 5 kWh intervals) and the Y axis is hours that the battery is at each kWh level. Figure 6.15 shows Nuvve's new regulation algorithm, also seen previously for fewer days in the time series of Figure 5.2. The distribution is tight; specifically, within the possible battery energy storage from 0 to 70 kWh, the vast majority of the time is spent between 20 and 30 kWh (29-43% SOC). (The old Regulation algorithm was more spread out but still peaked in the middle, with mode of 30-40 kWh and 77% of hours within 20-45 kWh.) The small tail of higher states of charge to the right was due to an internet failure that led to charging up to 53 kWh, gradually brought back down when the Regulation algorithm was reactivated. Although this excursion to nearly full was an equipment malfunction, similar excursions to full would be seen whenever a driver requests maximum range (full charge) for a trip.

In short, we find that the aggregator is keeping the EV well within the SOC range recommended to minimize battery wear, a recommendation based on published lab experiments as well as Renault Mobilize's practical experience.

Another metric for battery wear is that these EVs spent most of calendar 2025 performing regulation, ¾ of it under the old algorithm, and yet the OEM's own metric for battery state of health (SOH) showed no SOH reduction at all from doing regulation (see prior Table 5.4).

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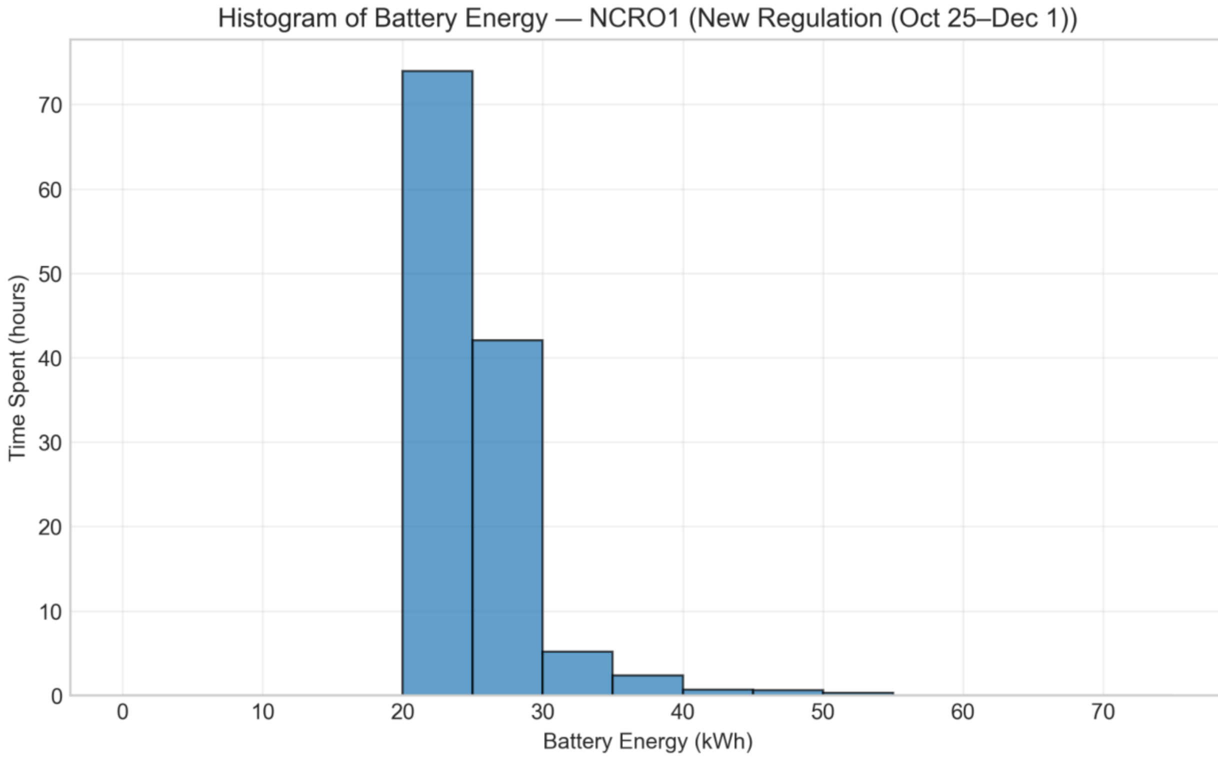
[25] Rahmat Khezri, David Steen, Evelina Wikner, and Le Anh Tuan, 2024, "Optimal V2G Scheduling of an EV with Calendar and Cycle Aging of Battery: An MILP Approach" IEEE Transactions on Transportation Electrification, Vol. 10, No. 4, December 2024. DOI: 10.1109/TTE.2024.3384293

[26] Bard van de Weijer,2025, "Binnenkort kunnen e-auto's ook elektriciteit teruggeven aan het stroomnet", de Volkskrant, 27 November 2025. (The quotation in text was translated from Dutch.) URL: https://www.volkskrant.nl/economie/binnenkort-kunnen-e-auto-s-ook-elektriciteit-teruggeven-aan-het-stroomnet-renault-start-hier-als-eerste-automerk-mee~b996d90f/



<u>Figure 6.15.</u> Histogram of hours the EV spends at each level of battery energy, while running Regulation under the new regulation dispatch algorithm. EV at NCRO1 from Oct 23 through Nov 4, 2025.

Turning to TOU Arbitrage, Figure 6.16 shows the state of charge for NCRO1 while running TOU Arbitrage. The histogram is U-shaped, avoiding extreme values but with many hours spent at the middle range's edges (15-20 kWh and 50-60 kWh). This makes sense by reviewing again the earlier Figure 5.2 and comparing these two grid services' time series of battery kWh. Although the algorithm for TOU Arbitrage kept within 15 to 60 kWh of the 70 kWh battery (about 21% to 86% SOC), more time was spent at the ends of that range than in the middle; thus, the TOU algorithm could be improved to maximize battery life. For example, charging or discharging could proceed in two steps with waiting time in the middle rather than waiting after arriving at the target SOC. The time may be adequate for charging overnight at only 4 kW, but for discharging during afternoon, the 8 kW discharge rate might well be insufficient when there is driving on utility peak hours. If we want in the future to pause at mid-battery energy during discharge (to lengthen battery life), or to stack services (for higher revenue), would require a higher discharge power capability than the 8 kW used here.

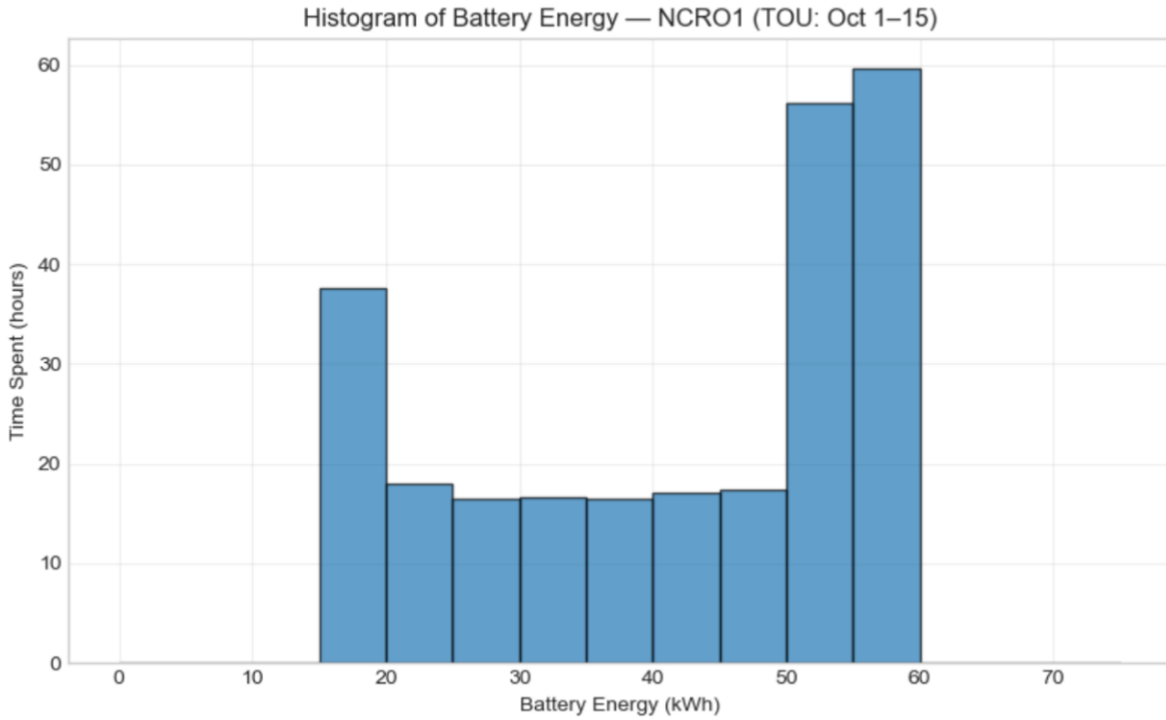


Figure 6.16. Histogram of hours the EV spends with battery at each level of energy, while running TOU Arbitrage. EV at NCRO1 October 1 to October 15, 2025.

Regulation and TOU Arbitrage are high-value services but they transfer substantial energy. Therefore, we have analyzed time spent in each state of charge while doing these services, in order to measure that major contributor to wear. The graphical results suggest that the new Regulation algorithm graphed in Figure 6.15 should minimize wear. The existing TOU Arbitrage algorithm at least avoids extreme SOC values, but could be improved, and may require a discharge power rate higher than 8 kW.

The above state of charge histograms show that these VPP smart algorithms reduce wear by minimizing state of charge residence at high or low kWh values. Our earlier SOH measurements show no battery wear effect at all. Additionally, many coming EV models will be using $LiFePO_4$ batteries (also called LFP batteries). These batteries are a little heavier per kWh, but less expensive and appear to have battery lifetime several times that of current Li-Ion automotive traction batteries. Together, these factors suggest that battery wear due to V2G is manageable, even for grid services at high kWh throughput levels.

Key Takeaways: Both Regulation and TOU Arbitrage transfer substantial energy, so attention to wear factors is important to minimize any battery capacity loss due to V2G. Maximizing mid-range SOC during grid services has been shown to minimize wear on the battery, and this pilot study achieved this very well for the new Regulation algorithm, and reasonably well for TOU Arbitrage algorithm. Both avoided extreme SOC values as shown in the histograms, although the TOU algorithm could be improved at a discharge rate over 8 kW. Our table of the OEM's SOH values (prior Table 5.4) also show no measurable reduction in SOH during a year spent doing high-throughput grid services. From published lab results, experience from Renault Mobilize, and this project's lack of measurable battery wear over a year, that the combination of smart dispatch algorithms and coming LFP batteries is likely to be eliminate prior concerns about V2G causing material battery wear.

7. Value of Grid services

PJM Regulation, like most other ancillary service markets, is compensated based on the amount of power bid (in MW) and kept available and ready to respond to a signal anytime during a contracted time interval, abbreviated as MW-h. For example, a vehicle with a 10 kW charge/discharge capability that remains connected for one hour provides 10 kW-h of regulation, even if little or no energy is delivered. Regulation as it currently exists in PJM is broken into two payment components one part being standby power over time and the other being "mileage", essentially how closely the resource power response follows the fluctuating signal. In value calculations for Regulation, we use the sum of these two payments as reported by PJM[27].

By contrast, Time-of-use rates (TOU), an EDC tariff, are based on fixed times (on- and off-peak) and differing prices for energy at those times. The TOU rate used in this study was DPL's EV TOU rate, a rate separate from their normal TOU rate and reserved for EVs. The amount purchased for Arbitrage was calculated by measuring the energy discharged during all high-value hours, and assuming that the same amount (plus losses, from Section 5) had to be purchased to charge the batteries to later supply the measured discharge. The charging energy was allocated in the following ways: 1) energy charged for later discharge through arbitrage; 2) round-trip losses due to discharge, and; 3) energy charged for driving, including losses. To calculate efficiency, we need to separate out items 1) and 2), despite no separate metering of 1) versus 3).

The discharge rate affects revenue during TOU dispatch only if discharge is too slow to reach full discharge by the end of the on-peak rates period. As seen previously in Figures 6.9 and 6.10, sufficient kWh transfer occurred at modest power, 4 kW charging and 8 kW discharging. This is true in part because these EVs were driven infrequently. The round trip inefficiency is 10%, the off peak rate for winter is \$0.1596/kWh, and the on-peak rate for winter is \$0.2967/kWh. These are values used to calculate TOU Arbitrage.

Revenue from Regulation

We examined 12 weeks of EV participation data to assess reliability of the EVs to perform regulation services. The EVs at charging station numbers 2 ,3, and 4 were used for most calculations because their onboard chargers were working at full power. Although all these retrofit EVs are rated for 33 kW, in operation the Nuvve aggregator dispatched them so that the

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[27] PJM, Real-Time Ancillary Service Market Results, (accessed October 16th, 2025), https://dataminer2.pjm.com/feed/reserve_market_results/definition

revenue-grade meters registered power flow from -30 kW charging to 28 kW discharging power. Therefore, for the calculation of Regulation revenue we used 29 kW, the actual performance in this project. One EV had only two of the four chargers running, showing capacity of 20 kW but dispatched at 17 kW. The target bid for the dispatch group is 100 kW; the four cars provided 29+29+29+17=104, and the aggregator successfully adjusted for variations in individual vehicle performance such that the dispatch group of four made the 100 kW bid successfully.

Regulation market prices fluctuate, so we reviewed the PJM market each year from 2021 through 2025 to get yearly average market clearing prices. (PJM changed the bid intervals during this time; for 2021 and the first half of 2022, we averaged 8760 hours per year. For the remainder of 2022 through 2025 there were 105120 five-minute intervals per year.[28]) These five years had average regulation clearing prices of, respectively, $24.93, $54.97, $21.15, $29.90, and $50.37 per MW-h.[29] In our Regulation revenue calculations, we use the minimum (2023, $21.15/MW-h) and maximum (2022, $54.97/MW-h) to show a range of actual prices in the regulation market, resulting in the ranges of annual revenue in Table 7.1. The mean value for all five years is $36.26/MW-h. In equations here we use equivalent $/kW-h (that is, kW rather than MW) to match other units in the equations.

Thes EVs were available during the pilot almost 100% of the hours each week they were running grid services. We compute revenue comparing 100% available on the top row of Table 7.1. On the second row we calculate as if they were driving and unavailable 40 h/week, as reported by the fleet manager.

Round trip efficiency was 90%, as calculated in Section 5. Throughput is the percentage of real power going through the system at any given time, empirically we determined that to be 26% of bid power. The retail energy price for DPL is $0.1786 /kWh,[30] used to calculate recharge cost of the energy losses. Net regulation revenue is value per hour times power, times hours in market, minus electrical losses, times retail cost of electric energy (kWh), per the two equations below.

To calculate net yearly revenue from regulation, we first calculate kW loss during regulation bid from the power capacity of accepted bids $P_{dispatch}$.

$$P_{loss} = P_{dispatch} * Q * (1-\eta_{roundtrip})$$

Where

P_{loss} power losses in kW during regulation at bid of $P_{dispatch}$

$P_{dispatch}$ Power bid and provided by this one vehicle (up and down)

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[28] PJM, Real-Time Ancillary Service Market Results, (accessed October 16th, 2025), https://dataminer2.pjm.com/feed/reserve_market_results/definition

[29] We average the price for each time period of bidding. The PJM Market Monitor weights each time period by that period's MW capacity. Results from the two methods are within $2/MW-h.

[30] Delmarva Power, How Our Plug-in Vehicle Time Of Use Rate Works in Delaware, (accessed October 16th 2025), https://delmarva.upgrade.guide/ev/de-benefits-section/tou

Q flow of power during PJM regulation as a dimensionless ratio of average power dispatched to power bid (empirical, measured to be 0.26)
$\eta_{roundtrip}$ round-trip efficiency to charge, then discharge, $\eta_{roundtrip}$= 0.9

Then net revenue, R_{net}, is calculated using revenue as the first term and cost (due to electrical losses, P_{loss}) as the second term. Each term is price times hours times power:

$R_{net} = (\pi_{reg} * H * P_{dispatch}) - (\pi_{retail} * H * P_{loss})$

Where

R_{net} net of revenue from PJM less energy cost
H hours participating (8760 h)
π_{reg} regulation price average (\$/kW-h) (using π for price, not the geometric constant)
π_{retail} Price of retail electric energy (average rate if TOU) (\$/kWh)
$P_{dispatch}$ Power bid and provided by this one vehicle (up and down)
P_{loss} power losses (in kW) during regulation at bid of $P_{dispatch}$

Thus for the 2023 reg price (\$21.15/MW-h), 100% hours per year participating in the pilot, and dispatched power bid of 29 kW we calculate loss and net revenue, respectively, as:

The amount of kW lost in energy throughput is:
P_{loss} = 29 kW * 0.26 * (1 - 0.9) = 0.754 kW

And net revenue per EV is:
R_{net} = (\$0.02115/kW-h * 8760 h * 29 kW) - (\$0.1786/kWh * 8760 h * 0.754 kW)
= \$5372.95 - \$1179.66
= \$4193.29

To calculate for a 10 kW EV, dispatched at 10 kW, substitute $P_{dispatch}$=10kW and keep other terms of above equations the same, yielding R_{net} =\$1445.96/yr. These two R_{net} values are entered in the first row of Table 7.1. The right column shows the test Mach-Es, capable of 33 kW, but they dispatched only 29 kW. The left column shows a hypothetical passenger 10 kW EV being dispatched at 10 kW. The upper row is under pilot conditions, no driving during grid services. The second row is for vehicles unavailable during work hours, reported by fleet to be 40h/week driving. In the second row, the 40 missing hours are simply removed as the corresponding fraction ((168-40 hrs)/168hrs) = 0.7619 of the values for the two 100% cases.

Table 7.1. Yearly net revenue (R_{net}) for the range of yearly PJM Regulation market prices, 2021 through 2025. The EVSE and EV are rated for 33 kW power, but due to software constraints aggregator dispatch was limited to 29 kW.

Rated Charge/discharge power	10 kW	29 kW (dispatched of 33 kW rated)
Available 100% of hours, for 1 year	\$1446 - \$4409	\$4193 - \$12785
Unavailable 40 hours per week (not 9 - 5 M-F)	\$1102 - \$3359	\$3195 - \$9741

The revenue shown in actual operation may seem high, but it is consistent with earlier projections for these markets (Metz and Kempton 2024).

We close the revenue from Regulation section with a quick list of practical considerations: Regulation requires EDC interconnection and PJM market access, a time cost to a commercial implementer that we recommend should be streamlined. Regulation is a high-value but relatively small market (600 to 800 MW in 2024), so early entrants will capture high value, but this market will eventually saturate, and Regulation prices will drop. Arbitrage and other RTO markets are together two orders of magnitude larger--e.g. in 2024, PJM Reserves required procuring 20 GW and Capacity required 182 GW. The capabilities of the EVs, charging stations, and aggregator used in this pilot can be used for any of these markets. Starting with OpCo fleets may be a practical start to learn and streamline interconnection and market access processes.

A passenger car or light truck could be in the 10 kW AC charging power range, and a service van or bucket truck could be 33 to 50 kW. The revenue for trucks at ~30 kW is so high that it may make sense to provide some incentive for custom production of EV utility trucks with bidirectional AC charging and LIN-CP.

Bill savings from TOU arbitrage

TOU arbitrage could reduce the bill of each customer connection on which the DER is located. The financial gain to the ratepayer is the value of energy sold by discharging on-peak, minus the amount paid to purchase off-peak the energy for that discharge. The amount discharged is directly metered by the revenue meter in the charging station. In contrast, the energy purchased for discharge is not separately measured, as charging mixes energy for discharge with energy for driving; also, the charging amount is necessarily more than that discharged due to inefficiencies in the converter and the battery, previously calculated in Section 5. Nevertheless, one can calculate the energy needed to purchase for arbitrage as the amount of energy discharged (metered by EVSE), plus losses (calculated as energy discharged over round-trip efficiency).

First, the amount of energy charged at off-peak rates, to allow later discharge to grid at peak rates, is

$E_{offpeak} = E_{peak} \ / \ \eta_{roundtrip}$

Where

$E_{offpeak}$ energy charged off-peak, in order to later provide E_{peak}

E_{peak} energy discharged on-peak

$\eta_{roundtrip}$ round-trip efficiency to charge, then discharge, $\eta_{roundtrip} = 0.9$

Savings on the bill is calculated as the value of energy discharged minus cost of energy to supply that discharge:

$S = (E_{peak} * r_{peak}) - (E_{offpeak} * r_{offpeak})$

Where

S is bill savings

E_{peak} energy discharged on-peak

π_{peak} retail price during peak period ($/kWh)

$E_{offpeak}$ energy charged off-peak, in order to later provide E_{peak}

$\pi_{offpeak}$ retail price off-peak ($/kWh)

The DPL retail tariff has one TOU price for summer and a different one for winter, so we calculated savings separately for summer and winter. Peak hours occur from 12 noon - 8 PM on workdays.[31] Thus, the TOU savings are achieved on 250 days (365 days - (52 weeks * 2 days/weekend) - 11 holiday days = 250 days). Summer rates are one-third of the months per year, and Winter rates are the rest of the year. Thus, the cars participate in Arbitrage on average 166.67 days (250 * ⅔) at the Winter rate and 83.33 days (250 * ⅓) at the Summer rate.

$S_{year} = (S_{WinterDay} * 166.67) + (S_{SummerDay} * 83.33)$

Where

S_{Year} is bill savings per year from arbitrage.

$S_{WinterDay}$ savings per day under the winter rate (Oct - May)

$S_{SummerDay}$ savings per day under the summer rate (Jun - Sept)

Based on actual EV TOU performance, by reading values off the kWh axis in the previous Figure 6.10, we calculate that during Arbitrage operation, an average of 36 kWh were discharged to the grid during each peak rate period. To fill enough for that discharge requires:

$E_{offpeak} = 36 \text{ kWh} / 0.9 = 40 \text{ kWh}$

Based on this 40 kWh of energy charged during off-peak times each day, the daily savings in Winter and Summer are the value of 36 kWh discharged on-peak, minus the cost of 40 kWh

[31] Delmarva Power, How Our Plug-in Vehicle Time Of Use Rate Works in Delaware, (accessed October 16th 2025), https://delmarva.upgrade.guide/ev/de-benefits-section/tou/

charged off-peak. From daily savings each season, the above equation for S_{year} yields the whole-year savings. Calculating for 100% of hours at 33 kW.

S_{Winter} = (36 kWh * $0.2967/kWh) - (40 kWh * $0.1596/kWh) = $4.30/day
S_{Summer} = (36 kWh * $0.2752/kWh) - (40 kWh * $0.1481/kWh) = $3.98/day
= ($4.30/day * 166.67 days) + ($3.98/day * 83.33 days) = $1048.33/year

This calculated S_{Year} value is filled in the upper right cell of Table 7.2. The same bill savings applies to both columns in the top row, because 10 kW is sufficient to fill 40 kWh over the off-peak duration and discharge 36 kWh on-peak. However, the lower left cell shows lower bill savings because 10 kW is not sufficient to fully discharge the available 36 kWh within the remaining 3 hours on-peak, after driving is done at 5 pm.

Table 7.2. Yearly bill savings from TOU arbitrage.

Rated Charge/discharge power	10 kW	33 kW
Available 100% of hours for 1 year	$1048	$1048
Unavailable 40 hours per week (not 9 - 5 M-F)	$873	$1048

The value of TOU arbitrage is lower only for the left-lower cell, the modeled 10 kW EV that is unavailable working hours (9-5 on weekdays). For all other cells, a higher charge rate and/or more time plugged in on-peak means the battery can be fully charged and discharged. The peak hours for DPL are from 12n-8pm, leaving three hours after the car returns at 5pm, more than enough to fully discharge 36 kWh at the 33 kW rate. However, at 10 kW, the EV would only be able to discharge 30 kWh on-peak during the 3 hours after 5pm, reducing savings.

Unlike dispatch for Regulation, we were not able to control and measure the Mach-Es as a single dispatch group for TOU arbitrage, due to limitations currently in the Nuvve aggregator's TOU dispatch. The advantages of aggregating EVs doing TOU Arbitrage would be in the abilities to account for trip charging needs, monitor operations, optimize, report, and service override requests from the EDC. Although TOU aggregation has advantages, the pilot shows that EVs can be separately dispatched because, unlike Regulation market rules: there is no minimum capacity requirement, ability to optimize is more limited, and payments and savings are accomplished by inherent EDC account billing. For Arbitrage, the revenue calculated here for an individual vehicle would be approximately the same if the EVs were in a dispatch group.

Key Takeaways: Of the listed six potential grid services that the interconnected project vehicles are technically capable of--listed in Section 4--during the pilot they were operated in two of those. We selected the two that we expected to have high revenue and to be commercially available by 2026, namely, PJM Regulation, and Arbitrage based on the DPL TOU rates for EVs. These markets are also technically challenging, and systems like those used in this pilot would have the ability to perform all of these six grid services. Both tested services include significant round trip energy transfers and thus our economic analysis is net of charging energy and efficiency losses as costs. Assuming fleet vehicles, driving all work days and calculating both low and high regulation market values over five years, a passenger vehicle (at 10 kW) would earn $874/year from TOU Arbitrage, or $1102 - 3359/year from Regulation. A heavier vehicle, using the now-standard 3-phase AC connector at 33 kW used on the pilot vehicles, would earn $1048/year from TOU Arbitrage or $3195 - $9741/year from PJM Regulation (Regulation is calculated only at the 29 kW achieved in the pilot). These figures deduct energy losses but not business costs such as customer acquisition and support, aggregator fees, or any allowance for possible battery wear. The PJM capacity market may be similarly lucrative; specific planning awaits a defined procedure from PJM to qualify DERs for capacity.

8. Lessons learned

Technologies, equipment design and standards

Unlike prior demonstrations of V2G, this project tested technologies, standards, and regulatory policies capable of scaling and commercially implementing a version of V2G that is low-cost, high-revenue and market-qualified. The technologies tested include a bidirectional AC charger in the EV (thus AC charging-discharging), EVSE power capability three-phase up to 50 kW, and modern EV to EVSE communication (LIN-CP). LIN-CP enables interconnection for discharge under IEEE 1547-2018 and can control the EV for use in multiple modes: simple charging, grid services, backup power for a building, and remote site power (e.g. power for a construction site).

These technologies are available for mass production due to our use of published standards SAE J3072, SAE J3068, SAE J3400, and under-revision standards SAE J1772 and UL 1741-SC. These are all public standards, not requiring licensing. No legacy or proprietary standards for AC EV to EVSE communications have the capabilities of LIN-CP, plus LIN-CP is easier to implement, has more inherently secure signaling, and is lower cost than legacy standards. As more EV and EVSE manufacturers adopt these standards, more cars and stations will both have full V2G/V2H/V2L capabilities and have interchangeability across companies to provide these services.

Learnings regarding technology, design and standards include:

- Stock EVs were satisfactorily retrofitted as specified by an experienced shop with EV expertise.
- In operation, the EVs were available for driving and for V2G grid services when not driving.
- The EVs provided grid services during about 1.5 years, with 1 year thoroughly analyzed.
- Both grid services provided were high-energy-throughput, yet there was no measured battery wear over the year.

- Despite using an aggregator with dispatch experience with both grid services, UD analysis and advising led to the aggregator making improvements in the aggregator's dispatch software for each service.
- The use of LIN-CP permitted standards-compliant interconnection and qualification for the two markets in which the pilot fleet operated.
- LIN-CP also provided more grid operations data to improve the performance of the VPP aggregator than do legacy protocols.
- EV charging and discharging was demonstrated over a year at 33 kW. If the EV inlet were upgraded to 50 kW (possible on the test vehicles, probably necessary on a heavy vehicle), then the entire system would operate at 50 kW charging and 50 kW V2G.
- A standard 480V 3 phase transformer, already on site, supplied power; a standard CAT6 cable connected each EVSE to a Comcast router. All installations were routine, handled by existing DPL contractors, electricians or service providers.
- The AC V2G system design here, including both EV and EVSE on a mass production basis, requires a minimal increase in costs over standard one-way uncontrolled AC charging at the same power level (estimated to be a $20/kW increment).
- Round-trip (grid-battery-grid) energy efficiency was measured at 90%. This is a reasonable expectation for a high-quality bidirectional charger.
- Standby losses ranged across EVs from 6% to 15%. Reduction of standby loss would reduce energy cost of running most V2G services. Loss might be reduced, for example, by the aggregator's use of existing LIN-CP commands for charger "Sleep" and EV-controlled "normal charging", these are available in LIN-CP but were not implemented in the pilot project. As noted, energy loss can also be reduced by asymmetric dispatch allocation to EVs.
- The dispatch group design, consistent with a VPP, was very successful. The aggregator created a dispatch group of logically connected EVs to make a resource with a single point of reporting and control. The dispatch group reported its combined power capacity, adjusted dynamically as EVs plug-in, unplug, reach extreme temperatures, require charge for trips, and reach full or empty. The aggregator controls the DG as if it were a single battery, and reports power to and from the active EVs in the aggregate as a single number. As the DG gets bigger, individual EV usage becomes more statistically predictable and the combined resource's reliability increases. These capabilities should be requested in picking an aggregator.

Policy and standards

The main policy areas are RTO and FERC rules for market access, and state rules for EDC interconnection and retail tariffs. Use of appropriate standards facilitate all these policy areas. Learnings include:

- Interconnection for discharge is essential for high-value markets.
- Interconnection was accomplished using the above-named standards. These new standards are now recognized in both Delaware and Maryland code. Other states may have requirements that imply them (e.g. IEEE 1547) or anticipate them, but many states

will require a tariff change to assure V2G providers that they can utilize these new standards.
- Interconnection was complex and time-consuming. Several suggestions to streamline the process and collect more EV-specific information are found in Section 3.
- Both services moved substantial energy back and forth between EV and the grid. Thus the Delaware law providing net metering during V2G grid services was essential fiscally to prevent the grid services revenue from being absorbed by zero or low credit for export of electricity. High throughput also means that minimal converter loss helps fiscally as well as for energy efficiency.
- The RTO service provided, PJM Regulation, is consistent with FERC Order 2222 and with PJM's current and planned manual changes in compliance with Order 2222. (Prior to Order 2222, UD fleet learning from qualifying V2G for RTO markets was that it was allowed only in Munis not IOUs—among other strange restrictions.)
- We expect coming rules for PJM Reserves and Capacity will also allow interconnection and market entry for the technical design and standards used in this pilot, but PJM implementation should be tracked as it develops.

Market performance learnings

The fleet of four modified EVs participated in one RTO market, Regulation, and one EDC market, TOU Arbitrage.

- Qualification and operation in both RTO and EDC markets appeared to meet all requirements, given some rule clarifications still pending.
- With expected rule changes during 2026-2028, as anticipated in this pilot, future production EVs and production charging stations would be able to cost-effectively participate in the six markets identified, if they are using identical or very similar technology (without retrofit) and standards to those created and operating for this pilot.
- Revenue is significant in the selected PJM and EDC markets. For Regulation, with the tested 33 kW connectors and calculating for the low and high PJM market clearing prices the past 5 years, the pilot vehicles would have earned $3195 - $9741 yearly net after cost of electrical losses.
- Regulation revenue is directly proportional to power; an otherwise similar 10 kW vehicle would net $1102 - $3359 yearly.
- Under current DPL EV TOU rate (proportionally for summer and winter rates and assuming credit for export) these EVs would earn $1048 at 33 kW and $873 yearly at 10 kW. Higher charging power enables full revenue even for cars that are driving during some on-peak rate hours.
- It is possible to stack these two services if charging power is in the 15 kW range, with some reduction in revenue.
- RTO services will require an aggregator who would presumably invoice for a proportion of the earnings. (Informally ⅓ to ½ of revenue may be reasonable.)
- EDC services are probably desirable to manage through an aggregator if not absolutely required. In any case EDC service provider-customers can be directly compensated by

their premises EDC meter and a TOU rate including credit for export. Some EDC services like direct load control might be a separate credit on the bill, with service validated either by premises meter or a device meter in the charging station.
- Each of the two services tested, even with net of energy losses and after some aggregator fees, could become a significant incentive to purchase an EV, and to keep a V2G EV plugged in when not in use.

Practical and operational learnings

The pilot project revealed some potential problems that require planning to resolve or manage for a commercial rollout, as well as some that are simply found with any pilot project creating new equipment and implementing new standards.

- This was a pilot project adhering to new standards, creating new equipment for the project, and qualifying for rules during the implementation of those rules. Such a project is likely to have, and did have, unexpected equipment problems. This caused unscheduled delays and increased development and debugging cost.
- For continuing revenue over time, the EV and EVSE should be able to run continuously overnight or over several days. This imposes more technical requirements on the equipment than typical EV charging. It also means that all reporting and control systems, including aggregator, EVSE and EV, should be tested over time in actual markets, as in this pilot, to ensure continuous reliable operation.
- Operationally, repair personnel who are diagnosing grid services may need service access to the lot, charging stations, and EVs. This is because, at least in early V2G deployment phases, diagnosis may require testing the car and EVSE together at the electrical location where the problem occurs. This is different from the gasoline vehicle repair model for which the vehicle is driven to the service shop and tested in isolation. (In this project, UD engineers had access to the lot and EVs only when the project manager was on site, sometimes slowing diagnosis and repair.)
- Communications should be more reliable than the pilot's on-site separate Comcast connection. The problem specifically shown in the pilot was connection drop for prolonged time (e.g. >10 minutes, often >2 hours, and no connection means no grid services). Possible solutions include a better service contract with network provider or a EVSE with cellular fallback when the cable connection drops temporarily.
- Under very cold ambient conditions, battery kWh is noticeably reduced, which is indicted in the dashboard display of miles but not in the % charged gage. This should be included in planning for longer trips (e.g. 18% reduction in energy capacity when ambient is under 20°F). These temperatures would also slightly reduce capability for grid services requiring deep discharge.

Considerations for next steps

Points to consider for business planning:

- What are the revenue models, considering revenue from PJM payments via aggregator and/versus credits via premises meter and account?
- How do business models relate to choice of EDC markets (e.g. TOU) and/or RTO markets?
- Potential to start immediately (Q2 2026) with revenue from PJM Regulation, and later shift to the much larger Capacity market when that market opens (2027 or 2028).
- Acquire V2G EVs for OpCo fleet(s) and/or customer offering? Which OpCo(s)? What type of customer?
- Develop V2G EV requirements for fleet purchasing of light, medium, and heavy EVs. (Example specifications: Onboard AC bidirectional (or four-quadrant) charger, LIN-CP, required efficiency of charger, minimum operating power, etc)
- Consider collaborating with other OpCo's, within Exelon as well as other regional utilities, to collectively agree on V2G EV requirements. A larger group will push more EV manufacturers to offer these in new cars and light trucks. A utility group has credibility in such requirements.
- Consider engaging a utility vehicle OEM (e.g. to build or modify bucket trucks) to make that body type with the V2G EV requirements, potentially to be purchased by multiple utilities. (Regulation revenue is so high it could justify a customized production run with V2G specifications if not already available as stock.)
- Similarly, consider writing out requirements for an aggregator or VPP service.

Potential near-term preparation and/or use of existing four EVs, EVSEs, and aggregator:

- Consider using existing EVs to test full driving at same time as grid services
- By summer, connect existing pilot EV setup for PJM Regulation market with payments, making it a complete on-line market operating and producing actual revenue.
- Test ability for aggregator to respond to EDC requests to override aggregator control during grid emergencies (e.g. on DPL critical peaks). Could be simple, e.g., a phone call two hours ahead, versus a secure login to aggregator or an API.
- Test a second aggregator for control of pilot Mach-Es and for interaction with PJM and EDC markets.
- Survey one or two OpCo fleets to understand how many and which upcoming vehicle replacements could be met by coming mass-produced stock EVs meeting above V2G EV requirements. Survey could match vehicle needs to known body types with built-in V2G coming in next 2-3 years.
- Write out information needed for Exelon OpCos considering V2G in fleets. Hold seminar and Q&A for interested OpCos.

Glossary[32]

Automatic Generation Control Signal (AGC)

A signal sent (e.g. by an RTO) that automatically adjusts the power output of generating resources to meet real-time load or otherwise manage the electrical grid.

Aggregator

An entity who contracts with an EDC or RTO to provide energy services from distributed energy systems. The set of all distributed resources plus the aggregator's monitoring and controls is called a "Virtual Power Plant" (VPP).

Behind-the-meter (BTM)

An electricity production or storage device located on the customer side of the electric distribution company's premises meter.

Converter

A device that converts AC to DC, in an EV, this is colloquially called a bidirectional charger.

Credit for Export (CfE)

Payment for electric energy exported through a premises meter.

Delmarva Power (DPL)

The investor-owned utility that serves about 80% of electric load in the state of Delaware. DLP is an Exelon operating company. The pilot project was located at the DPL New Castle Regional Office (NCRO).

Device meter

A meter or submeter measuring energy and/or power of a device within a customer premises, for example, a solar panel or a storage system.

Dispatch Group

The group of four bidirectional electric vehicles for the demonstration project clustered as one resource via an aggregator. By doing this, we were able to strategize how much can be drawn from each vehicle to participate in the PJM Regulation market as one entity.

Distributed Energy Resource (DER)

A resource that provides energy or grid services, including small-scale generation or storage, and typically located behind-the-meter.

Electric Distribution Company (EDC)

An organization that builds and maintains the distribution networks that deliver electricity to end-customers. Commonly known as an electric utility.

Export

Energy flowing from a DER through the premises meter and into the grid. Also referred to as injection (of power into the grid) or discharge.

Flat rate

[32] Most definitions here are drawn from the draft paper: Willett Kempton and Catherine Gilman (2026). "Policies to Allow Grid Services from Behind-the-Meter Electric Vehicles and Other Storage." *UD Draft Working Paper.*

A utility tariff with the same cost per kWh during all hours of the day. Contrasted with a time-of-use rate.

Local Interconnection Network over Control Pilot (LIN-CP)

A Society of Automotive Engineers standard for high-functionality communication between the EV and EVSE. This standard meets the requirements for DER interconnection, provides intelligent monitoring and dispatch, extensive control capabilities, and exchanges lots of data with the vehicle.

Net Energy Metering (NEM)

A tariff that credits kWh exported toward kWh imported, “netting” the energy import with export. NEM assumes a flat rate over all hours of the day, with the export rate equal to the import rate.

New Castle Regional Office (NCRO)

The DPL main offices and operations center in New Castle, Delaware. The pilot program vehicles were parked at this office.

Premises meter

The EDC-owned meter that measures electricity consumption of an entire customer premises, typically located at the point where electric power enters the building.

State of Charge (SOC)

The current proportion of energy remaining in a battery.

State of Health (SOH)

An EV battery’s present capacity to hold energy (kWh), usually expressed as a percentage of (current capacity) / (new capacity).

Regional Transmission Organization (RTO)

A federally regulated, non-profit entity that operates transmission of electricity across high-voltage power lines within large regions and manages some wholesale electricity markets. The United States calls this an RTO or an Independent System Operator (ISO). In Europe these organizations are called Transmission System Operators (TSOs).

Time of Use (TOU)

An EDC tariff that sets prices differentially for on-peak and off-peak times. Traditionally these have been set only for consumption; if combined with credit for export (CfE), payments would also appropriately be at a higher rate on-peak than off-peak.

Virtual Power Plant (VPP)

A power resource that consists of many small devices spread across a service territory combined to become one controllable resource. Can be used as controllable storage, load, or distributed generation. Here we use the term aggregator to refer to the controlling and monitoring systems of a VPP.