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APPLICATION OF EL PASO ELECTRIC COMPANY FOR APPROVAL OF ITS TEXAS ELECTRIC VEHICLE- READY PILOT PROGRAMS AND TARIFFS	§ § § § §	STATE OFFICE OF ADMINISTRATIVE HEARINGS

REBUTTAL TESTIMONY

OF

ANGELINA RODRIGUEZ

FOR

EL PASO ELECTRIC COMPANY

MARCH 12, 2024

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EXHIBITS

I. Introduction and Qualifications

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Angelina Rodriguez. My business address is 100 N. Stanton Street, El Paso, Texas 79901.

Q2. HOW ARE YOU EMPLOYED?

A. I am employed by El Paso Electric Company ("EPE" or the "Company") as the Supervisor of Electrification.

Q3. ARE YOU THE SAME ANGELINA RODRIGUEZ THAT PREVIOUSLY PROVIDED TESTIMONY IN THIS CASE?

A. Yes, I provided Direct Testimony on January 31, 2023, and Supplemental Testimony on September 22, 2023.

II. Purpose of Testimony

Q4. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my rebuttal testimony is to respond to testimony presented by Office of Public Utility Counsel ("OPUC") witness Evan D. Evans and Commission Staff ("Staff") witness Adrian Narvaez and to support EPE's Application for Approval of its Texas Electric Vehicle ("EV")-Ready Pilot Programs and Tariffs. My rebuttal is organized to address OPUC's and Staff's testimony by program.

Q5. ARE YOU SPONSORING ANY EXHIBITS IN YOUR TESTIMONY?

A. Yes, I sponsor the exhibits identified in my table of contents.

III. EV Smart Rewards Pilot Program

Q6. DO YOU AGREE WITH STAFF WITNESS NARVAEZ'S DESCRIPTION OF THE INCENTIVES INCLUDED IN EPE'S PROPOSED SMART REWARDS PILOT PROGRAM AS UNJUST AND UNREASONABLY PREFERENTIAL AND DISCRIMINATORY SUBSIDIES (PAGE 11, LINES 14-17)?

A. No. The purpose of this pilot program is to provide EPE with information and experience in relation to its growing EV load so that EPE can manage its electric system more efficiently for the benefit of all customers. As further explained below, the proposed incentives are reasonably based on industry-best practices and average incentives offered by other utilities for similar programs. The Smart Electric Power Alliance ("SEPA") "Managed Charging Incentive Design" guide, excerpts of which are provided as my Exhibit AR-R-1, summarizes findings of approximately 40 managed charging programs. The proposed EV Smart Rewards Pilot Program enrollment and ongoing annual participation incentives ($125 and $50, respectively) are consistent with these findings regarding relevant utility-offered enrollment incentives, which typically range from $25 to $450 with a median incentive of $125 and annual participation incentives, which typically range from $20 to $250 with a median annual incentive of $50.

Further examples of utility enrollment and participation incentives are highlighted in the Table 1 below.

TABLE 1 UTILITY ENROLLMENT AND PARTICIPATION INCENTIVES

Utility Managed Charging Programs	Enrollment Incentive
Arizona Public Service (AZ) SmartCharge Program	$25 bonus for enrolling with up to $5/ month
CPS Energy (TX) FlexEV Rewards	$250 enrollment credit on utility bill. $5 credit/ month for each participating month.
CPS Energy (TX) FlexEV Off-Peak Rewards	$125 enrollment credit on utility bill. $10 credit per month
Salt River Project (AZ) EV Smart Charge program	$200 sign-up incentive and $50 incentive for each additional participating year
Xcel Energy (NM) Optimize Your Charge	$50 annual bill credit
Xcel (CO) **Charging Perks**	$100 enrollment incentive and $100 annual participation incentive for L2 charging

Moreover, it is important to note that in order to participate in the proposed program, EV customers may incur additional costs for networked level 2 charging equipment (which can cost from $500 to $700, although some may be even more expensive) or enable vehicle telematics subscription (which can cost up to $149 per year).

Q7. WHAT ARE THE EVENT INCENTIVES IN THE SMART REWARDS PILOT PROGRAM BASED UPON?

A. EPE's proposed event incentives are based on the selected vendor's recommendation of $5/month, which aligns with SEPA's report findings of event incentives offered by other utilities ranging from $5 to $20.

Q8. DOES EPE HAVE OTHER COMMISSION-APPROVED PROGRAMS WITH A SIMILAR INCENTIVES BASIS?

A. Yes. EPE has other Commission-approved programs with a similar incentives basis. For example, EPE's Energy Wise Savings Program allows EPE to actively manage participating residential customers' smart thermostat to mitigate peak loads during times of need, by offering a one-time thermostat rebate of $75 or an enrollment incentive of $25 plus $25 per year for each additional season of participation.[1] This program was initially approved in Docket No. 46967, EPE's Notice of Filing of a Pilot Program Template, with a $125 upfront incentive plus $25 per thermostat annual incentive. This program uses incentives consistent with existing programs to elicit the desired behaviors.

To the extent the Commission determines that its previously approved incentives for load management programs should be the maximum incentive for any load management program, EPE would limit the incentives in its Smart Rewards Pilot Program to those levels, but, as noted above, the Smart Rewards Pilot Program may require the participating customer to make new investments in additional equipment to participate in the program, which EPE believes justifies the higher level of incentives.

Q9. DOES EPE BELIEVE THAT PROVIDING INCENTIVES TO ENCOURAGE LOAD MANAGEMENT SUCH AS THROUGH THE TECHNOLOGY OF THE SMART REWARDS PILOT PROGRAM IS CONSISTENT WITH TEXAS LAW?

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[1] *See* Energy Wise Savings Program https://www.epeenergywisesavings.com/

A. Yes. Incentives for load management programs are addressed in PURA Section 36.204, which states as follows:

> In establishing rates for an electric utility, the commission may:
>
> (1) allow timely recovery of the reasonable costs of conservation, load management, and purchased power, notwithstanding Section 36.201; and
>
> (2) authorize additional incentives for conservation, load management, purchased power, and renewable resources.

In addition, Section 8, Ch. 1095 of HB 2129 as adopted by the Texas Legislature in its 79th Regular Session (2005) (uncodified), states that "in recognition that advances in digital and communications equipment and technologies, including new metering and meter information technologies, have the potential to increase the reliability of the regional electrical network, encourage dynamic pricing and demand response, make better use of generation assets and transmission and generation assets, and provide more choices to consumers, the legislature encourages the adoption of these technologies by electric utilities in this state."

Q10. DO YOU AGREE WITH MR. EVANS'S PROPOSAL (PAGE 12, LINES 20-21) THAT THE PROGRAM BE RESUBMITTED TO REVISE THE INCENTIVES?

A. No, the program incentives as proposed are reasonable. There is no need for resubmittal, and there is an important and pressing need for its approval as detailed below.

Q11. WHY DO YOU SAY THERE IS AN IMPORTANT AND PRESSING NEED FOR EV SMART REWARDS PILOT PROGRAM?

A. It is important to implement this pilot program before EV adoption is too high to enable the Company to obtain information and experience to help mitigate potential negative grid impacts that may be present if EV load is unmanaged. Taking a proactive role in preparing for transportation electrification now - while EV adoption remains relatively low - is important for EPE to ensure that EV adoption in the future is integrated efficiently with the grid. Moreover, the proposed managed charging programs offers EPE the opportunity to (a) gain operation experience over charging to better avoid load peaks at specific locations and times, including seasonal peaks, and (b) evaluate whether customers prefer managed charging programs as compared with EV rate programs such as EPE's existing Electric Vehicle Charging ("EVC") rate schedule or the proposed WHEV pilot incentive credit rider.

Q12. WHAT WOULD HAPPEN IF EV LOAD WAS LEFT UNMANAGED?

A. As more and more EVs are adopted, the costs of failing to manage these loads may result in increasingly extreme, pricey peaks and cause reliability challenges and issues. Charging EVs can use between 3.3 kW to 20 kW of electricity, which can exceed the total peak demand of a home without EVs. Utilities have two options: 1) to react to increased demand after problems occur and invest in additional generation, transmission, and distribution system upgrade costs; or 2) to be proactive and develop information and operational capabilities to enable it to strategically manage EV charging load to optimize grid investment and functionality. This optimized charging behavior might be that charging occurs according to certain grid conditions, in order to take advantage of renewable energy generation when available and/or shift load away from times of peak demand. Studies have shown that managed charging of EVs provide various benefits which include peak load reductions of 0.2 to 3.3 kW per EV, on average.[2] If unmanaged, the increase in peak load can significantly strain the local distribution system, particularly when several EVs are clustered on a single transformer, which all customers would have to pay for. If several EVs are to be plugged in at the same time, in the same neighborhood, there may not be enough capacity on the residential transformer, which may result in transformer failure. EPE's typical cost of a residential transformer is greater than $3,000.

Q13. CAN YOU PROVIDE FURTHER SUPPORT REGARDING THE IMPORTANT AND PRESSING NEED FOR THE COMPANY'S PROPOSED PILOT PROGRAMS, INCLUDING THE COMPANY'S SMART REWARDS PROGRAM, AND REBUT MR. NARVAEZ'S TESTIMONY THAT THE PROGRAMS ARE NOT NEEDED (PAGE 8, LINES 14-19)?

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[2] *See* Assessing the value of electric vehicle managed charging: a review of methodologies and results, page 15 and 29 of 52: https://pubs.rsc.org/en/content/getauthorversionpdf/d1ee02206g

A. Yes, as indicated in my direct testimony, the Board of Directors of the National Association of Regulatory Utility Commissioners ("NARUC") have adopted resolutions recommending that State departments of transportation and federal and state officials work with utilities regarding EV infrastructure development. Additionally, as highlighted in my Exhibit AR-R-2 (the "Mini Guide on Transportation Electrification: State-Level Roles and Collaboration among Public Utility Commissions, State Energy Offices, and Departments of Transportation" issued by National Council on Electricity Policy and administered by NARUC), as the adoption of EVs accelerate, utilities and their regulators not only need to ensure sufficient power supply availability, but also that distribution networks can accommodate the increased electricity demand from EV charging during key time periods. Intentional rate design will play a key role in leveraging existing grid assets and mitigating potential negative impacts by enabling charging flexibility to benefit both the grid and consumers. The principles that underlie EV rate design typically encourage the efficient use of existing grid capacity to mitigate costly distribution system upgrades and avoid bill increases for non-participating customers due to EV infrastructure needs. Commissions often consider time-varying rates (e.g., time-of-use, real-time pricing, and managed charging) to support EV charging.

Q14. IN SUMMARY, HOW DOES THIS PROGRAM BENEFIT ALL EPE CUSTOMERS AND NOT JUST PROVIDE SUBSIDIES TO A SUBSET OF CUSTOMERS AS SUGGESTED BY MR. NARVAEZ (PAGE 10, LINES 8-10)?

A. When EVs are added to the grid efficiently, it can provide economic and reliability benefits to all customers. EPE's proposed EV Smart Rewards Pilot Program will help EPE learn how to better target efficient integration of EVs into the grid, allowing EPE to schedule EV charging during off-peak hours or other hours when the grid has lower-cost energy and available capacity, improving economics and avoiding potential transformer overloading, thus helping to ensure continued service reliability.

Q15. DO YOU AGREE, AS PROPOSED BY OPUC WITNESS EVANS (PAGE 13, LINES 2-5), THAT THE TARIFF SHOULD TERMINATE AT THE EARLIER OF TWO YEARS OR THE EFFECTIVE DATE OF NEW BASE RATES UNLESS EXTENDED IN EPE'S

NEXT BASE RATE CASE OR OTHER FUTURE PROCEEDING?

A. No, I do not agree that the tariff should terminate at the earlier of two years or the effective date of new base rates. The full two-year period of the EV Smart Rewards Pilot Program, as requested by EPE, is needed and appropriate to allow EPE to collect the necessary data to evaluate the effectiveness of an active EV managed charging program. During the first year of program deployment, EPE will focus on program implementation, marketing, customer enrollment and begin data collection process. During the first and second years, EPE will perform data gathering and evaluation of the results of the pilot program, e.g., reduction of EV charging impacts on the electric grid during peak hours, mitigation of new load spikes after peak hours, evaluation of the potential to absorb excess renewable energy or energy during low carbon hours; and the ability to increase customer engagement with the utility and help customers control charging costs.

Q16. ARE THERE OTHER STATES THAT HAVE SIMILAR PROGRAMS APPROVED BY STATE REGULATORS?

A. Yes, there are many approved managed charging programs in the U.S. as seen in the Appendix excerpt included in Exhibit AR-R-1 and in Table 1 above.

IV. PowerConnect Pilot Program

Q17. DO YOU AGREE WITH MR. NARVAEZ (PAGE 10, LINES 13-16) THAT THE CREDITS PROVIDED UNDER THIS PROGRAM ARE NOT COST BASED?

A. No, I do not agree that the credits provided under this program are not cost based. The credits provided under this program would never exceed the actual cost of upgrades or improvements to EPE's distribution system and will be based on the costs of such upgrades to the extent the costs are not already covered by EPE's line extension policy.

Q18. WHAT IS THE BASIS FOR THE PROPOSED CREDITS UNDER THIS PROGRAM AND WHY ARE THEY REASONABLE?

A. The proposed credits are based on the utility-side infrastructure upgrade costs for commercial customers installing EV charging stations to the extent those costs are not already covered by EPE's line extension policy (Section 3 of EPE's Tariff[3]). The program was designed to cover no more than 100% of the non-covered costs related to utility-distribution system improvements that are needed to support the EV charging infrastructure up to the maximum rebate amount as shown in in my Direct Testimony with no more than 20% of the overall PowerConnect Pilot Program budget going to any one entity.[4] EPE believes that utilities can play a valuable role in planning and infrastructure build-out. Make-Ready programs help ensure that the utility is involved in the planning for the EV charging stations and helps to ensure adequate local distribution infrastructure. Make-Ready programs lower the costs of the infrastructure investments and can help avoid any future upgrades (and rework).

Q19. PLEASE DESCRIBE WHETHER THE RATES OF EPE'S CUSTOMERS MAY BE IMPACTED BY THE REBATE CREDITS UNDER THIS PILOT PROGRAM IN THE MANNER SUGGESTED BY MR. EVANS (PAGE 16, LINES 12-18)?

A. To effectuate this program, EPE's Electrification department will pay the rebate amount at issue to EPE's Distribution department on the behalf of the participating customer-recipient of the rebate credit to cover amounts that the customer would have otherwise covered under EPE's line extension policy. Accordingly, from the perspective of non-participating customers, and as indicated in Company witness Carrasco's rebuttal testimony, there is no immediate impact to rate base as compared to the standard situation of the participating customer itself paying the cost that is not covered by the line extension policy. Whether EPE may ultimately seek cost recovery for the amounts paid by the Electrification department on behalf of the participating customers would be an issue for a future rate proceeding as indicated in Mr. Novela's rebuttal testimony.

Q20. ARE THERE OTHER STATES THAT HAVE SIMILAR PROGRAMS APPROVED BY STATE REGULATORS?

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[3] Under EPE's line extension policy, customers are generally responsible for a customer contribution for the line extension costs not covered by the first four years of the revenues expected from the line extension.

[4] Direct Testimony of Angelina Rodriguez pg. 17-18 (of 22).

A. Yes. As of January 2024, there are currently over 70 utility Make-Ready programs including programs in Georgia, Florida, North Carolina, and New Mexico, as seen in the table of such programs included in my Exhibit AR-R-3.

Q21. DO YOU AGREE WITH MR. NARVAEZ'S TESTIMONY (PAGE 10, LINES 19-21) THAT BECAUSE THERE ARE ALREADY FEDERAL AND STATE INCENTIVES TO SUPPORT EXPANSION OF EV CHARGING INSTALLATIONS, IT IS NOT REASONABLE TO PROVIDE SUPPORT IN EXCESS OF THOSE PROVIDED IN THE FEDERAL AND STATE INCENTIVES?

A. No, I do not agree. The goal of the PowerConnect TX program is to be complementary to Federal and State incentives. The program will provide incentives that are not covered by Federal or State incentives to non-residential customers for infrastructure upgrades on the utility side of the meter. Consider, for example, the federal Clean School Bus Rebates Program, which I discuss in my direct testimony, and which did not allow for funds to be used for any infrastructure costs associated with work on the utility side of the electrical meter, but only provided funding for "EV related infrastructure installation and equipment from the electrical meter to the charging port of the bus."[5] See below, Figure 1. Even with the assistance on the customer side of the meter, the high upfront costs of EV infrastructure on utility-side of the meter, not covered by such funding, may discourage some school districts from participation, which underscores why it is crucial for utilities to be able to offer make-ready programs to its customers.

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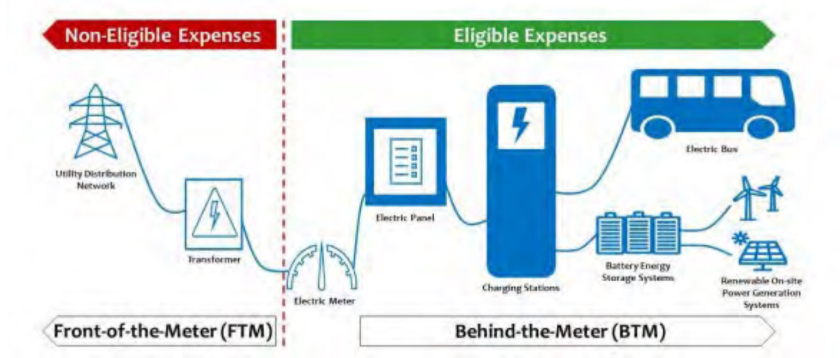
[5] *See* EPA Clean School Bus https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P1018JIT.pdf

FIGURE 1 EPA'S CLEAN SCHOOL BUS REBATES PROGRAM ELIGIBLE EXPENSES



Q22. PLEASE DESCRIBE FURTHER THE NEED AND BENEFITS THAT MERIT THE REBATE CREDITS PROVIDED UNDER THIS PILOT PROGRAM NOTWITHSTANDING MR. NARVAEZ'S ALLEGATIONS OF UNWARRANTED SUBSIDIES.

A. Many non-residential customers already have plans to electrify their fleets and reach out to EPE to ask about available programs. As I explain above, there are currently over 70 utility Make-Ready programs. Accordingly, if EPE has no make-ready programs similar to the ones offered by other utilities across the U.S., the entity may consider deploying EV infrastructure in other states.

In addition, ensuring EPE's engagement with non-residential entities early in the process of the customer installing EV charging equipment is essential to potentially lower the costs of any distribution system upgrades. For example, without conversations with EPE, some customers may desire the fastest charging infrastructure possible which would require significant distribution upgrades on EPE's side of the meter (e.g., 8 Direct Current Fast Charging stations rated 150kW, would require more than 1MW of hosting capacity). By being engaged with the customer through the proposed PowerConnect Pilot Program, EPE can help to ensure that customer is considering appropriately sized charging infrastructure and is aware of EPE's approved EVC rate[6] to encourage that charging occurs during off-peak hours, which can improve system utilization rate, and thus create

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[6] See EPE's EVC rate:
https://www.epelectric.com/files/html/Rates_and_Regulatory/TX%20Rates/Section%201%20-%20Sheet%2039.0%20-%20Schedule%20EVC%20Electric%20Vehicle%20Charging%20Rate.pdf

downward pressure on rates that would benefit all customers.

Q23. IS THE NEED FOR THIS PROPOSED PROGRAM ALSO SUPPORTED BY THE EV GOALS DEVELOPED BY THE CITY OF EL PASO AS A PART OF CITY'S CLIMATE ACTION PLAN?

A. Yes, the proposed program is consistent with the measures identified in the preliminary Priority Climate Action Plan developed by the City of El Paso[7]. The plan specifies the necessary measures to support the EV transition, improve air quality and community health and reduce noise pollution. El Paso County is currently designated as non-attainment with National Ambient Air Quality Standards ("NAAQS") for particulate matter and ozone. EPE's proposed PowerConnect Pilot program provides a great opportunity to support the reduction of local emissions consistent with these goals.

V. Take Charge TX Pilot Program

Q24. IS MR. EVANS CORRECT (ON HIS PAGE 19, LINES 12-13) THAT THE COMPANY WILL INCUR COSTS UNDER THIS PROGRAM FOR PERFORMING SITE VISITS AND MEETING WITH CUSTOMERS, ADMINISTERING THE PROGRAM, AND MARKETING THE PROGRAM TO CUSTOMERS?

A. Yes. EPE will incur costs under this program for performing site visits, meeting with customers, administering and marketing the program. EPE will record the incurred costs by EPE employees or representatives who consult with the Take Charge TX Pilot Program by using program specific workorder numbers and project codes to keep separate accounting for all investments in EV infrastructure and equipment to ensure that only customers who participate in the program are paying for those costs. Company witness Novela further addresses how EPE will track and account for the costs of the proposed pilot programs.

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[7] See El Paso Priority Climate Action Plan, pages 25 and 36 (see upper right hand corner page numbers): https://www.elpasotexas.gov/assets/Documents/CoEP/Community-Development/Climate-Action/EP-Priority-Climate-Action-Plan-03.01.2024.pdf

Q25. IS MR. EVANS CORRECT (ON HIS PAGE 19, LINES 14-15) THAT EPE WILL INCUR COSTS UNDER THIS PROGRAM TO RESPOND TO CUSTOMER REQUESTS TO CHANGE EQUIPMENT AND PROVIDE SERVICES AFTER THE EQUIPMENT HAS BEEN INSTALLED.

A. Yes. However, EPE will only do maintenance based on Customer selections indicated in Exhibit A of the Take Charge TX Pilot Program agreement during the term of the contract, with all costs charged to and recovered from participating customers only. Please refer to Part 6, Section 6.3 Monitor and Maintain, in the Take Charge TX tariff included as Exhibit MC-1S to the Supplemental Testimony of Company witness Manual Carrasco. Company witness Novela further addresses how EPE will track and account for the costs of the proposed pilot programs.

VI. Summary and Conclusion

Q26. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. EPE's proposed Texas EV-Ready Pilot Programs and Tariffs are important next steps that should be approved and undertaken to help ensure efficient integration of EV charging into the grid. If EV load is not managed, it can create negative impacts on the grid, which may result in transformer overloads and/or significant system upgrades, that all customers would pay for. Electric companies have an important role in designing and implementing programs that best meet the needs of all customers. This concept was endorsed by the Texas Legislature in PURA Section 42.101(c), which states, "The legislature finds that electric utilities, transmission and distribution utilities, competitive entities, and the commission have important roles to fill in supporting the installation and use of infrastructure for electric vehicle charging." EPE believes its proposed pilot programs are consistent with Texas law generally, and with new Chapter 42 of PURA in particular, and that the programs are necessary first steps for EPE to gain information and experience with management of EV load.

Q27. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Smart Electric Power Alliance

Managed Charging Incentive Design

Guide to Utility Program Development

October 2021

Managed Charging Incentive Design

that the long-term benefits of a program outweigh the program costs. A utility program design team might consider similar customer programs their state regulators or other jurisdictions have approved, and understand the characteristics of those programs. They might also review programs that have been filed, but not approved, and evaluate the reasons for rejection.

Incentive Design

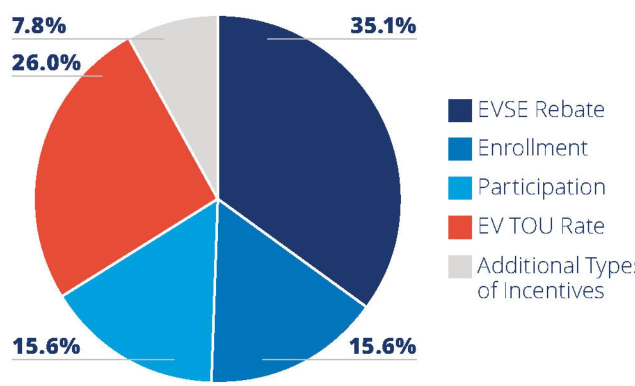
Next, a utility needs to determine the price signals and incentives to offer customers to most effectively shift charging behavior to meet program objectives. Utilities have implemented a variety of incentive structures to successfully and economically reach program goals. SEPA reviewed market studies of the incentive structures of managed charging programs to understand the sizes and types of incentives. Our findings will support utilities in their selection of incentive values that are both effective and economical.

SEPA identified and classified forty managed charging programs, twenty-five active managed charging programs, and fifteen passive managed charging programs. We classified programs by their incentive structure (i.e., which types of incentives the program offers to customers in order to get them to enroll and participate). For each program, we evaluated the incentive dollar value offered to participants. The following section summarizes the range and average incentive size by each incentive type.

It is important to note that all of the programs assessed reached their enrollment goals, regardless of the type and size of incentives offered to their participants. As programs transition from pilot to full scale, utilities and commissions will need to assess the specific costs and benefits of different program approaches and design program incentives that have benefits that exceed costs. Pilots are different in that they are, by design, trying to understand the costs and benefits of different approaches, so it is not feasible to design pilot incentives using a cost benefit analysis (CBA). This report provides guidance on potential incentive ranges that a utility pilot could use as a starting point, but the pilot outcomes will determine what incentives should be used at scale.

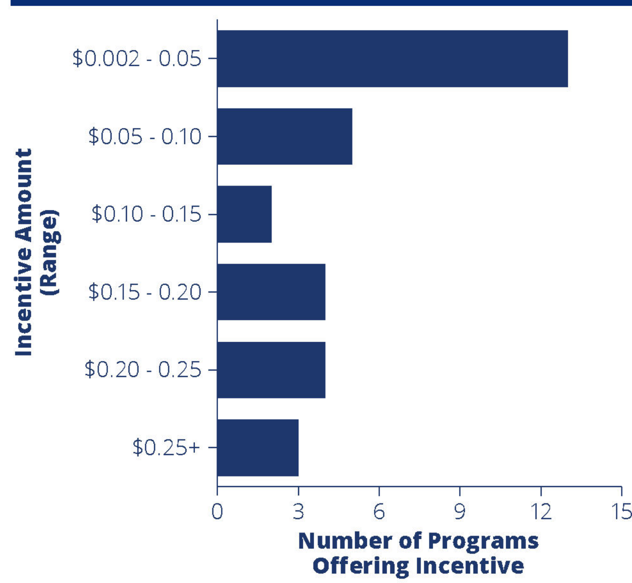
The following sections discuss SEPA's findings from our incentive data analysis and provide context for utilities in deciding which types of incentives to include in their managed charging program design.

Figure 4. Percentage of Programs That Offer Each Type of Incentive



Source: Smart Electric Power Alliance, 2021.

Figure 5. Difference in On-Peak and Off-Peak Price per kWh within an EV-specific TOU Rate



Source: Smart Electric Power Alliance, 2021.

On/Off-Peak Spread

Time-of-use rates that are specific to electric vehicle charging serve as an effective tool in encouraging EV owners to shift their behavior to benefit the grid and save them money. Earning approval of EV-specific TOU rates is relatively simple when compared to approval for customer compensation in exchange for direct control of their charging, since the customer retains control over their charging habits. Additionally, the concept of a TOU rate is not new to utilities, unlike other managed charging incentives, so it is easier to implement through a billing system. This type of incentive is a safe choice for utilities when forming an incentive structure within their managed charging program.

EVSE Rebate

Utility rebates for networked smart chargers reduce the upfront cost of EV ownership, and can be used to entice customers to share charging data with the utility and give the utility control over their charging. **SEPA noted that 64% of the active managed charging programs we assessed offer some type of charger rebate.**

While smart chargers are a valuable piece of equipment that utilities can use to balance grid conditions through direct load control, providing customers with a large rebate may become expensive for the utility. It is important to recognize that direct load management through a networked smart charger is most lucrative at single-family homes and at workplaces, where vehicles are connected for long periods.

Figure 6 provides information about the size of rebates that utilities offer to participants that install a Level 2 charger in their single-family home. **The median charger rebate for residential program participants with a single-family home is $600.**

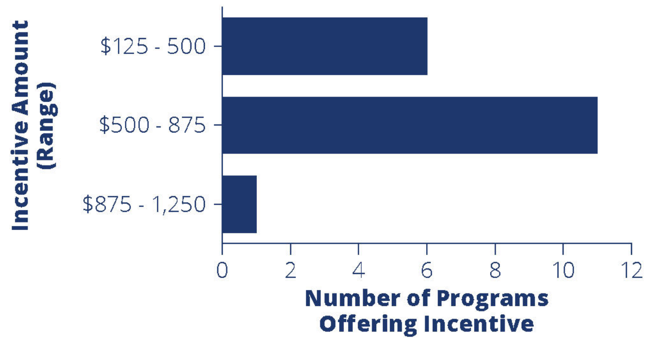
SEPA also assessed the rebates offered to Multi-Unit Dwellings (MUD) to help with the cost of Level 2 charger installation, which are summarized in Figure 7. The median rebate value is $4,000.

The Level 2 charger rebates offered to workplaces and public host sites are summarized in Figure 8 and Table 1, respectively.

The median charger rebate for workplace applications is $4,000 per port and the median charger rebate for public applications is $4,900 per port, which can help host sites offset the increased costs associated with commercial installation.

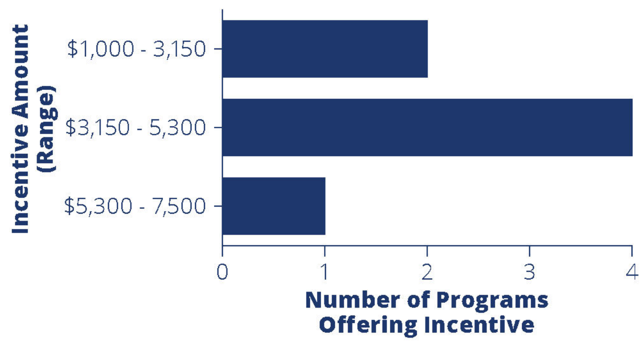
Figure 9 shows all Level 2 charger rebate incentives offered by active managed charging programs assessed within the sample. The rebate types, represented on the chart above from left to right, include those offered for the following applications: single-family homes, multi-unit dwellings, workplace/fleet, and public. Each dot on the graph represents a program that offers that size and type of rebate; the larger the dot, the more programs that offer that type and magnitude of rebate.

Figure 6. Level 2 Rebate Offerings for Residential Program Participants (Single-Family Homes)



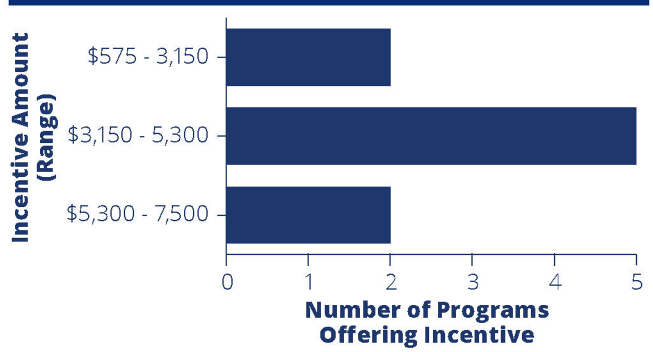
Source: Smart Electric Power Alliance, 2021.

Figure 7. Level 2 Rebate Offerings for Residential Program Participants (Multi-Unit Dwellings)



Source: Smart Electric Power Alliance, 2021.

Figure 8. Level 2 Rebate Offerings for Workplace/Fleet Program Participants



Source: Smart Electric Power Alliance, 2021.

5.0 Appendix

Table 2. Utility Managed Charging Programs Assessed in Market Research

Utility	Program
American Electric Power	Kyte Works EV Home Charging Program
American Electric Power	EV Charging Incentive Program
Austin Energy	Plug-In Austin Electric Vehicles
Avista	Commercial Electric Vehicle Charging Equipment Program
Avista	Residential Electric Vehicle Charging Equipment Program
Barron Electric Cooperative	Electric Vehicle Charging Station: 2021 Energy Efficiency Rebate
Baltimore Gas and Electric	EVsmart
Consolidated Edison	SmartCharge
Consumers Energy	PowerMIDrive
Delaware Electric Cooperative	Beat the Peak
Delmarva Power	EVsmart
Dominion Energy	EV Charger Rewards
DTE Energy	Charging Forward
Eversource	EV Home Charger Demand Response
Green Mountain Power	eCharger Program
Hawaiian Electric Company	Smart Charge Hawaii
Los Angeles Department of Water and Power	Charge Up LA!
Marin Clean Energy	MCEv

Table 2. Utility Managed Charging Programs Assessed in Market Research	
Utility	**Program**
Massachusetts Municipal Wholesale	Scheduled Charging Program
National Grid	Connected Solutions
New York State Electric and Gas Corporation	Residential EV TOU Rate
Orange & Rockland	Charge Smart Program
Pacific Power	EV Charging Station Grant Program
Pepco	EVsmart
Pacific Gas and Electric Company	emPower EV
Pacific Gas and Electric Company	EV Charge Network (Load Management Plan)
Portland General Electric	Business EV Charging Pilot Program
Portland General Electric	Residential EV Charging Pilot Program
Platte River Power Authority	Smart Electric Vehicle Charging Study
Rocky Mountain Power	EV Charging Station Grant and Rebate Program
Salt River Project	Plug In and Save EV Rebate
Salt River Project	SmartCharge Arizona
San Diego Gas and Electric	Power Your Drive
Snohomish County Public Utility District	SmartCharge
Sonoma Clean Power	GridSavvy
Southern California Edison	Charge Ready Program
Southern California Edison	Honda SmartCharge Program
Xcel Energy	Charging Perks

Source: Smart Electric Power Alliance, 2021.

National Council on Electricity Policy
MINI GUIDE

Mini Guide on Transportation Electrification: State-Level Roles and Collaboration among Public Utility Commissions, State Energy Offices, and Departments of Transportation

Prepared for the National Council on Electricity Policy (NCEP), administered by the National Association of Regulatory Utility Commissioners (NARUC) Center for Partnerships & Innovation (CPI)

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Many states across the country have set ambitious electric vehicle adoption goals and are working to establish policies and programs to support transportation electrification. State Energy Offices, Public Utility Commissions (PUCs), and Departments of Transportation (DOTs), as well as State Environmental Agencies, Consumer Advocates, and other important state-level partners each have a unique and vital role to support electric vehicle (EV) rollout. Frequently, these agencies have been working together to coordinate EV infrastructure planning and design incentive programs, as well as launch ambitious policy and regulatory frameworks in the EV space.

Recent federal legislation, including the Infrastructure and Investment in Jobs Act (IIJA) and Inflation Reduction Act (IRA), has provided states with additional opportunities to advance transportation electrification efforts.[1] The IIJA will provide $7.5 billion for investments in EV charging infrastructure; of the total, $5 billion is dedicated to the National Electric Vehicle Infrastructure (NEVI) program that directs funds to state DOTs to build a network of EV chargers across the country. The remaining $2.5 billion is set aside for the Discretionary Grant Program for Charging and Fueling Infrastructure in which states, localities, tribes, territories, and metropolitan planning organizations are eligible to apply for funding to support publicly accessible EV charging and alternate fuel infrastructure.

The EV Master Plan is a notable example of a product that could not be completed without cross-agency collaboration. The purpose of the EV Master Plan was to create a plan for charging infrastructure across the state highway system. The DOT has expertise in state highways, unlike the other two agencies. The plan, however, required information regarding appropriate regulatory models for getting electricity to the charging stations, which is where the PSC was able to assist.

— Andrew Fay, Chairman of Florida PSC

1 A summary of vehicle electrification funding and related provisions is available at: U.S. Department of Energy Alternative Fuels Data Center, 2021, *Bipartisan Infrastructure Law (Infrastructure Investment and Jobs Act of 2021)*, https://afdc.energy.gov/laws/infrastructure-investment-jobs-act.

About the NCEP Mini Guide Series

The National Council on Electricity Policy (NCEP) is a platform for all state-level electricity decision makers to share and learn from diverse perspectives on the evolving electricity sector. The NCEP mini guide series promotes this dialogue by highlighting examples of successful engagement across its members. Each mini guide features collaborative approaches, lessons learned, and interviews with leading state and local decision makers.

In addition, $500 million in State Energy Program (SEP) funds through the IIJA are directed via formula to State Energy Offices to fund programs that, among other things, reduce greenhouse gas emissions in the transportation sector and accelerate the electrification of mass transit, state government vehicles, and privately-owned passenger, and medium-and heavy-duty vehicles. The IIJA also requires each state's PUC to consider amending rates to promote affordable and equitable EV charging, improve customer experience with EV charging, accelerate third-party investment in electric vehicle service equipment (EVSE), and recover marginal costs of electricity delivery to EVSE.[2]

While funding for IIJA EV programs is directed to different state agencies, collaboration among State DOTs, State Energy Offices, PUCs, and other stakeholders is vital to strategically plan and implement charging infrastructure and its use across the states.

Overview of State Agency Roles

State PUCs, Energy Offices, and DOTs each play a unique role in supporting transportation electrification planning and adoption. The roles of each agency also vary across states.

Public Utility Commissions (PUCs)

State PUCs are regulatory bodies mandated by state legislatures to oversee the rates and services of utilities—typically investor-owned utilities (IOUs) and, generally not consumer-owned utilities—to ensure that they are fair, just, and reasonable for all customers. PUCs regulate IOUs for services such as electricity, natural gas, telecommunications, and water. For electric utilities, this oversight includes the utility's involvement in transportation electrification, primarily regarding the siting and ownership of electric vehicle charging infrastructure connecting to the distribution grid and electric rate structures for vehicle charging. While EV charging stations provide for the sale of electricity, in most states, charging stations themselves are not subject to commission regulation as public utilities. Instead, PUCs are concerned with two primary questions:[3]

1. Who may own EV charging infrastructure?
2. What rate designs and other load management strategies are appropriate to mitigate EV's potential grid impacts and maximize potential grid benefits?

> *We have a very good working relationship with both state agencies, DOT, and PSC. Our relationship with the PSC has gone back several years as many State Energy Office staff have previously worked for the PSC. Several years ago, the PSC completed a report on how EVs would impact the electric grid and included the Energy Office in their report and workshops. When the State Energy Office completed Florida's EV Roadmap in 2019, the PSC was also involved in the State Energy Office's workshops and conversations pertaining to the roadmap.*
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> *— Kelley Smith Burk, Director, Florida State Energy Office*

Questions around the ownership of EV charging infrastructure explore whether regulated utilities can own, operate, and/or provide make-ready infrastructure investments in charging infrastructure and are allowed to earn a rate of return on these investments. These decisions require PUCs to balance the interests of all stakeholders, taking into consideration concerns such as market transformation and competition, costs of installation, equity of siting locations, and integration of EV electricity load onto distribution grid infrastructure. The various ownership models for EV infrastructure are typically:[4]

- Full utility ownership and operation where the utility invests in both the make-ready components and the charger
- Make-ready, where the utility invests in infrastructure up to, but not including, the charging equipment (up to the meter)
- Disallowing utility ownership (with or without incentives for third-party infrastructure investments)

It is increasingly common for states to explore EV charging infrastructure investment strategies within PUC-designated stakeholder working groups or proceedings that review holistic utility transportation electrification plans.

As the adoption of EVs accelerate, utilities and their regulators not only need to ensure sufficient power supply availability, but also that distribution networks can accommodate the increased electricity demand from EV charging during key time periods. Intentional rate design will play a key role in leveraging existing grid assets and mitigating potential negative impacts by enabling charging flexibility to benefit both the grid and consumers. The principles that underlie EV rate design typically

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2 Public Law 117-58. Synopsis available at: U.S. Department of Energy Alternative Fuels Data Center, 2021, *Bipartisan Infrastructure Law (Infrastructure Investment and Jobs Act of 2021)*, https://afdc.energy.gov/laws/infrastructure-investment-jobs-act.

3 Harper, C., McAndrews, G., and Sass Byrnett, D. NARUC, 2019, *Electric Vehicles: Key Trends, Issues, and Considerations for State Regulators.* https://pubs.naruc.org/pub/32857459-0005-B8C5-95C6-1920829CABFE

4 Ibid

encourage the efficient use of existing grid capacity to mitigate costly distribution system upgrades and avoid bill increases for non-participating customers due to EV infrastructure needs. Commissions often consider time-varying rates (e.g., time-of-use (TOU), real-time pricing (RTP), and managed charging) to support EV charging. It is becoming increasingly common to explore EV rate design options within distribution system planning, integrated distribution planning, or distributed energy resource (DER) planning processes overseen by commissions. State-designated consumer advocates are important stakeholders in these processes, among others.

> *Policy work is a great example of the type of work the DOT can accomplish by working with the State Energy Office and the PSC. Understanding the roles and expertise of each agency is essential in policy work. The PSC can help with utility regulation and rates, whereas the State Energy Office can assist with education and outreach regarding EV programs. It is all about working together with the same goal in mind.*
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> *— April Combs, Statewide Planning Coordinator, Florida DOT*

State Energy Offices

The 56 Governor-designated State and Territory Energy Offices often lead policy development related to electric vehicles and charging infrastructure, as well as planning and program implementation to invest in charging stations around the country and coordinate with the private sector. Their engagement in transportation electrification is in support of a range of state policies, including, but not limited to reducing transportation-related energy costs and emissions, expanding EV-related manufacturing for economic development and job growth, and ensuring multiple fueling options for consumers and businesses.

While each state's approach is tailored to its specific economic, geographic, and community needs, many State Energy Offices have developed roadmaps or statewide strategies to support transportation electrification, addressing use cases for charging, community needs and objectives for electrification, infrastructure investment recommendations, and strategies to engage consumers and enhance adoption of EVs. As the lead agency for state energy planning efforts, State Energy Offices often create their EV Roadmaps in the context of other state plans, such as comprehensive energy plans, and energy assurance and resiliency planning. In addition, State Energy Offices often lead stakeholder engagement activities in support EV planning and EV program implementation, convening EV working groups or advisory groups to inform policy and program development. Because State Energy Offices are at the fulcrum of energy policy development and stakeholder engagement, they often work closely with both regulated and unregulated utilities to explore options for enhancing electric system and grid readiness for widespread EV adoption.

Beyond planning, State Energy Offices play a vital role directly managing or supporting charging programs, partnering with other state agencies, electric service providers, and private developers and site hosts to support the growing EV industry. Most State Energy Offices administer state-led EV infrastructure programs, and either lead or work closely with their state's environment agency to inform EV infrastructure investment under the state's portion of the settlement of the Volkswagen Diesel Emissions Environmental Mitigation Trust. This coordination extends beyond state boundaries as well. Nationally, there are six state-led regional collaborations between State Energy Offices and partner agencies: the West Coast Electric Highway, REV West, REV Midwest, the Southeast Regional Electric Vehicle Information Exchange, the Transportation and Climate Initiative, and ZEV Task Force. In addition, State Energy Offices often develop and implement education and outreach activities to raise awareness of EVs and collaborate with their state's economic development agency to identify and promote EV-related workforce development opportunities.

Departments of Transportation (DOTs)

State DOTs are state agencies that oversee programs and policies related to intermodal transportation networks. The purview of state DOTs can be vast: most are responsible for building, maintaining, and operating their state's roads, bridges, and tunnels. Additionally, the DOT can have oversight over programs affecting urban and rural public transportation, airports, railroads, ports, and waterways. In addition to managing multimodal infrastructure, state DOTs are charged with managing the safety and efficiency of the transportation systems.

In the past, a few state DOTs were tasked with creating statewide electrification plans or efforts to prepare for increased EV deployment. For most states, DOTs have played a supporting role in prior EV projects, with State Energy Offices taking the lead, for example, in joining the previously mentioned regional EV groups to learn from and collaborate with their regional partners.

Because NEVI funds will be distributed by the U.S. Department of Transportation (USDOT) to the state DOTs, the NEVI program represents an opportunity for state DOTs to take on a more substantial role in charging infrastructure deployment to fulfill the program goals within their respective states. The state DOTs have worked to stay informed on EV charging technology and pertinent information. DOTs have also created mapping tools to help determine ideal locations for corridor charging and are actively engaging with and soliciting input on their plans from a broad array of stakeholders. State DOTs were required to submit plans to USDOT by August 1, 2022, specifying infrastructure investments that will be made leveraging NEVI funds. Because NEVI funds will cover 80 percent of the project's cost, states will need to explore additional funding options to cover the remaining cost (e.g., state matching funds designated by the legislature, funds already budgeted within state agencies, and utility/ratepayer investments approved by the PUC).

State Environmental Agencies

While this report focuses on the roles of State Energy Offices, Public Utility Commissions, and State Departments of Transportation in EV planning and coordination, it is worth noting that State Environmental Agencies often play a unique leadership role in advancing transportation electrification. In states that have adopted California's Clean Car Standards, the state air quality agencies are, in most cases, the regulatory agencies tasked with designing and implementing zero-emission vehicle regulations. In addition, in many states, the Environmental Agencies were the designated administrative lead for the state's portion of the Volkswagen Settlement Environmental Mitigation Trust, and for the last five years have been funding EV infrastructure installations and EV replacements for medium- and heavy-duty vehicles within their state. In many states, the Environmental Agency works closely with their State Energy Office and other sister agencies to coordinate transportation electrification program development.

Realizing the Benefits of Collaboration

To research this Mini Guide, the American Association of State Highway and Transportation Officials (AASHTO), National Association of State Energy Officials (NASEO), and National Association of Regulatory Utility Commissioners (NARUC) conducted interviews with the state DOT, State Energy Office, and PUC in three diverse and representative states: Florida, Utah, and Michigan. A few key themes emerged from the interviews: recognizing each agency's strengths supports progress, formal and informal collaboration is valuable for each agency to meet its mission, and collaboratively engaging public and private sector stakeholders increases opportunities for a state to benefit from transportation electrification.

Identify and Leverage Each Agencies' Key Strengths and Gaps

State DOTs, PUCs, Energy Offices, and other stakeholders play unique roles in transportation electrification. Identifying the specific roles each agency and stakeholder play allows for smoother progress as agencies leverage relevant strengths among their partners.

Agency	Typical Responsibilities within Transportation Electrification
State Energy Office	• Assist the Governors and Legislatures in developing EV policies and programs • Convene state agencies, private-sector infrastructure developers, and automakers to build consensus and identify opportunities • Create EV roadmaps
Department of Transportation	• Lead application for and disbursement of NEVI formula funds • Partner with State Energy Offices and other agencies on EV rollout • Contribute to regional EV committees
Public Utility Commission	• Oversee utility role in EV infrastructure siting and charger ownership • Approve or deny utility investments to support EV deployment • Determine rate designs and other load management strategies for EV charging

DOTs have vast knowledge and expertise in transportation planning as it pertains to traditional transportation infrastructure: roads, bridges, gas-powered cars, trucks, freights, etc. State Energy Offices have extensive experience with building coalitions and engaging key partners across the energy sector to support energy planning activities broadly and EV infrastructure planning and deployment specifically. The DOTs can lean on the State Energy Offices to fill knowledge gaps related to the EV industry, including how funding mechanisms (e.g., VW settlement funds) have been used in the past. Similarly, State Energy Offices can rely on State DOT's transportation planning and modeling expertise to ensure that transportation and siting considerations are addressed during federal EV infrastructure investment decisions.

PUCs set the regulatory frameworks for utilities to follow when evaluating electric grid needs and making upgrades. EV-friendly rate structures have been flagged in many states as essential tools needed to encourage EV adoption. Moreover, regulatory action is often needed to ensure that private sector actors can compete in the EV infrastructure market (e.g., by ruling that EV charging station providers should not be regulated as utilities). PUCs are the states' decision makers when it comes to customer rates, utility business models, and other utility investment decisions for investor-owned utilities that influence EV charging. PUC processes gather information from diverse stakeholder interests to consider the impacts of new tariffs, rate designs, and performance metrics associated with EV charging infrastructure and EV adoption. State Energy Offices and State DOTs, with significant implementation experience in this space, can provide valuable and impartial information to their PUCs to aid in their regulatory decision-making process.

> *Cross-agency collaboration works best when agencies and stakeholders meet regularly to discuss issues and project updates. It is important to be proactive and organized about collaboration and keep all stakeholders informed. Bringing multiple agencies into the same meeting is beneficial in keeping all stakeholders engaged and up to speed on projects, programs, and policies.*
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> *— Tremaine Phillips, Commissioner, Michigan PSC*

Formal Collaboration is Necessary and Worthwhile

Formal collaboration was mentioned as an essential tool in cross-agency communication. Strategies that foster formal and worthwhile collaboration across agencies include creating joint offices that convene leaders across government and the private sector, establishing lead agencies to direct projects and stakeholders, and implementing directives from Executive Orders or legislation.

While formal collaboration between commissions and agencies has historically been infrequent, in recent years the deployment of EV infrastructure has prompted the need for enhanced discussion between agencies. For example, Michigan has created new offices, positions, and frameworks to coordinate EV programs across agencies. The Office of Future Mobility and Electrification (OFME) was created in 2020 to increase mobility investment in Michigan. The OFME works across state government agencies, academia, and the private sector to accelerate EV adoption, expand smart infrastructure, enable the mobility workforce, and bolster EV manufacturing in the state. For NEVI planning, Michigan's DOT is the appointed agency to head the plan, while the PUC is overseeing and advising on electric grid upgrades to support EV charging, and the Michigan Department of Environment, Great Lakes, and Energy (the State Energy Office) is working on data models for program implementation.

Florida created an EV master plan that outlines steps for investing in charging infrastructure across the state's highway system. While the Florida DOT is the lead agency overseeing the EV master plan, the Florida Department of Agriculture and Consumer Service's Office of Energy (the State Energy Office) and the Public Service Commission (PSC) were named in statute as key partners to engage during plan development. During plan development in 2019, the Florida DOT met with the State Energy Office and the PSC regularly to discuss details of the plan and coordinate on energy-specific items.

In Utah, the state legislature required collaboration on the creation of an EV Charging Network Plan. Utah DOT and Utah's Governor's Office of Energy Development (the State Energy Office) worked together on the EV Charging Network Plan and recommended the creation of an EV Steering Committee that convened a broader range of stakeholders. The legislative directive of the EV Charging Network Plan established the starting point for cross-agency collaboration, including setting goals, discussing how funds are spent, and what specific roles agencies will play in future transportation electrification in the state.

Informal Engagement Can Be a Valuable Supplement to Formal Collaboration

Establishing and maintaining a connection with an individual at a sister agency provides for quick access to stay informed on an agency's goals or priorities. As mentioned above, the creation of Utah's EV Charging Network Plan established an extensive partnership between Utah's State Energy Office and DOT. Prior to plan rollout, agencies in Utah were collaborating on EV infrastructure investment through the Volkswagen (VW) Settlement. Utah's State Energy Office worked closely with the Utah Department of Environmental Quality—the agency responsible for VW program rollout in the state—to inform the design of

EV charging programs funded with VW dollars. The formal collaboration established under the VW Settlement created the foundation for informal engagement that continues and supports each agency's coordination and effectiveness.

In addition, Utah's State Energy Office and PSC have a long history of informal and frequent communication on energy policy and regulatory issues. Although the Utah DOT and State Energy Office are allowed to intervene in PSC processes, both agencies more often participate in meetings to provide informal input. This level of informal communication allows agencies to communicate and collaborate when appropriate and when it aligns with their area of expertise.

Michigan's agencies also have a strong history of informal collaboration, with the Michigan State Energy Office noting the importance of building solid relationships with someone in each agency or Governor's office.

> *Florida created an energy equity plan that has helped integrate equity in transportation electrification planning and implementation. It would be beneficial to include workforce innovation in EV planning to address equity in disadvantaged communities. It will be vital to build a skilled workforce in rural and disadvantaged communities to support EV infrastructure installation and repairs, so EV drivers do not have to drive long distances to seek assistance.*
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> *— Tony Morgan, Deputy Director, Florida State Energy Office*

Include Additional Public and Private Sector Stakeholders to Increase Benefits

Engaging with multiple stakeholders like other government agencies, community groups, manufacturers, workforce boards, and the private sector is necessary to ensure equitable and holistic EV program design and implementation. Each agency and its leaders have various sets of relationships with other state, local, and regional entities, and stakeholders. By working together to determine who to reach out to when developing and implementing EV plans, states can tap into broader networks of groups and individuals with valuable insights to contribute. States can also reduce "meeting fatigue" by making sure each agency is not tapping the same key people for separate and duplicative engagements.

The benefits of transportation electrification are relevant to many government agencies and entities. By engaging with a broad range of stakeholders, multiple perspectives are included in the conversation, which amplifies the multitude of transportation electrification benefits, including improving human health, advancing equity, spurring economic development, and increasing electrical system affordability.

> *We have a strong relationship with state agencies regarding mobility and electrification. We have a partnership between the Energy Office, DOT, and PSC, and are all actively involved in mobility and transportation issues, particularly as it pertains to NEVI plans and the Federal Highway Administrations request for comments. We are working jointly to write comments on behalf of the state of Michigan to address concerns shared by all agencies. Regarding the completion of the NEVI plan, each agency plays a role in the coordination of the plan.*
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> *— Robert Jackson, Assistant Division Director, Michigan Department of Environment, Great Lakes, and Energy*

In Michigan, the Department of Environment, Great Lakes, and Energy, the Michigan Department of Labor, the Office of Future Mobility and Electrification (OFME), the DOT, and Public Utility Commission (PUC) have been working closely on the rollout of the Lake Michigan EV Circuit plan. Working with a broad range of stakeholders has allowed agencies to divide up tasks and receive input based on each group's expertise. For example, in the NEVI planning process the OFME is handling the policy issues related to the plan and coordinating with relevant stakeholders like utilities, charging companies, manufacturers, site owners, etc., and the PUC is overseeing and advising on utility electric grid upgrades as it pertains to supporting EV charging. The State Energy Office is playing a significant role in connecting economic development with transportation electrification, focused on ensuring Michigan businesses—particularly those located in underserved communities—are competitive in the marketplace and that they have a share in the buildout of EV charging networks.

Engaging multiple stakeholders is also beneficial for workforce development. The growing EV industry will require a robust workforce trained to install EV chargers, as well as maintain and repair equipment. Coordinating with DOTs, State Energy Offices, PUCs, and local communities, as well as chambers of commerce, economic development boards, universities, and others, will be essential in building an innovative workforce that can meet the demands of the EV industry, particularly in rural and disadvantaged communities.

In Florida, the State DOT and State Energy Office are working to expand EV charging access to all users through their transportation electrification plans by emphasizing the many co-benefits of EVs. The first co-benefit the state is highlighting is the improvement in air quality. By increasing the number of electric vehicles on the road, air quality is improving for all Floridians, particularly communities most impacted by poor air quality. In addition, overall emissions from the transportation sector are decreasing, partially due to the increased access to alternative fuels and electric vehicles. Workforce development is another co-benefit Florida is focusing on through their EV plans. The state is collaborating with community colleges and certification programs to train individuals from a variety of backgrounds and skill sets. The agencies, as part of their plans, are also looking at ways that EV deployment will enhance Florida's overall transportation system, including roadways within rural and disadvantaged communities.

Regional Collaboration

Regional collaboration among bordering states is also an effective strategy to plan EV infrastructure. As mentioned above, the Michigan Department of Environment, Great Lakes, and Energy is working on a Lake Michigan EV Circuit plan with multiple agencies in their state, as well as bordering states Wisconsin, Illinois, and Indiana. Coordinating with neighboring states has allowed Michigan to plan EV chargers along routes that intersect state borders. For example, U.S. Route 2 in the upper peninsula serves a sizeable portion of both Michigan and Wisconsin, thus both states agreed to nominate Route 2 as an alternative fuel corridor to ensure EV infrastructure can support EV drivers and tourism in the region.

Regional collaboration can also be helpful in planning EV infrastructure for emergency scenarios. For example, in the event of a natural disaster like a hurricane or major flooding, neighboring states can coordinate EV infrastructure planning along borders to support drivers across state lines that may experience power outages. Florida, for example, is working across agencies and with other states in the region through the Southeast Regional Electric Vehicle Information Exchange (SE REVI) to support EV infrastructure rollout in the Southeast. SE REVI has developed a shared EV infrastructure map to assist with regional planning which, among other things, includes data on evacuation routes to enable EV infrastructure planning along key corridors during emergencies.

Regional collaboration can also include inter-agency collaboration focused on economic development in the transportation sector. Eight states in the Intermountain West, including Utah, signed the Regional Electric Vehicle Plan for the West (REV West) Memorandum of Understanding to coordinate across state lines on EV infrastructure deployment with the goal of facilitating regional EV travel and tourism. Utah's State Energy Office and Utah DOT have worked together through the REV West collaboration to inform region-wide action on EV infrastructure rollout (e.g., through developing a region-wide EV infrastructure map and by providing joint comments in response to various federal solicitations). The relationship created through coordination on REV West helped establish a mutual level of trust between agencies and has fostered more frequent collaboration and a continued dialogue that has been instrumental in both state and regional EV planning.

Conclusion

State agencies play a significant role in supporting transportation electrification across the country. Both formal and informal collaboration is an essential tool in ensuring State Energy Offices, State DOTs, and State Public Utility Commissions work together to build-out strategic EV infrastructure within their state. Identifying each agency's responsibility and area of expertise is imperative in organizing the varying phases of transportation electrification planning and implementation. By working collaboratively across all relevant areas of expertise, states can anticipate and handle the unprecedented opportunities and challenges associated with developing entirely new infrastructure at the intersection of energy, transportation, and the grid. The recent passage of the IIJA and the Inflation Reduction Act has created a historic moment for states to advance transportation electrification, and state agencies have the opportunity to engage with a broad range of stakeholders to build an equitable, reliable, and accessible national EV charging network.

Mini Guide Examples

To illuminate how these relationships work in practice, the following section presents condensed excerpts from interviews with state DOTs, State Energy Offices, and PUCs from three states: Florida, Michigan, and Utah.

Table 1. Mini Guide Interviews

Name	Position	Organization	Organization Type
April Combs	Statewide Planning Coordinator	Florida Department of Transportation	State Department of Transportation
Andrew Fay	Chairman	Florida Public Service Commission	State Public Service Commission
Judd Herzer	Strategic Policy Director	Michigan Department of Labor & Economic Opportunity	State Labor Office
Robert Jackson	Assistant Division Director	Michigan Department of Environment, Great Lakes, and Energy	State Energy Office
Thad LeVar	Chairman	Utah Public Service Commission	State Public Service Commission
Lyle McMillan	Strategic Investments Director	Utah Department of Transportation	State Department of Transportation
Tony Morgan	Deputy Director	Office of Energy, Florida Department of Agriculture and Consumer Services	State Energy Office
Tremaine Phillips	Commissioner	Michigan Public Service Commission	State Public Service Commission
Kelley Smith Burk	Director	Office of Energy, Florida Department of Agriculture and Consumer Services	State Energy Office
Bailey Toolson	State Energy Program Manager	Utah Office of Energy Development	State Energy Office

Each person interviewed expressed his or her own opinions. Inclusion in this document does not indicate an author's or organization's endorsement of any statement or suggestion.

Florida

The following text is an abridged transcript of interviews conducted with Kelley Smith Burk, Director of the Florida Department of Agriculture and Consumer Services Office of Energy (State Energy Office); Tony Morgan, Deputy Director of Florida's Office of Energy; April Combs, Statewide Planning Coordinator for the Florida Department of Transportation; and Hon. Andrew Fay, Chairman of the Florida Public Service Commission.

Can you share some examples of the working relationship between the Florida Energy Office, Florida DOT, and the Florida PSC?

Kelley Smith Burk, Director, Florida State Energy Office: We have a very good working relationship with both state agencies, DOT, and PSC. Our relationship with the PSC has gone back several years as many State Energy Office staff have previously worked for the PSC. Several years ago, the PSC completed a report on how EVs would impact the electric grid and included the Energy Office in their report and workshops. When the State Energy Office completed Florida's EV Roadmap in 2019, the PSC was also involved in the State Energy Office's workshops and conversations pertaining to the roadmap.

Tony Morgan, Deputy Director, Florida State Energy Office: The relationship between FDOT and the State Energy Office has grown in the last several years. Starting in 2018, FDOT began reaching out to the State Energy Office for assistance with transportation electrification planning since the State Energy Office had experience working in the EV space. FDOT has also included the State Energy Office in their working groups and workshops. April Combs, Florida Department of Transportation, previously worked for the State Energy Office so she has provided valuable communication between the State Energy Office and FDOT on the work both agencies are doing with EVs.

April Combs, Statewide Planning Coordinator, Florida DOT: We have a great working relationship with the State Energy Office and the PSC. We have never established a formal relationship through an MOU, but we have been working together on projects for decades. We have had alternative fuels in Florida for quite some time, and each entity shares a responsibility for alternative fuels' programs and EV projects. With EV projects, there has been a great deal of inter-agency communication and engagement with multiple stakeholders. EV projects affect a broad range of stakeholders, so it is important to hear the perspectives of all parties involved in EV infrastructure coordination.

Andrew Fay, Chairman of Florida PSC: We have several avenues of communication between agencies, and it is primarily informal relationships. Historically, we have been able to easily reach out to both the State Energy Office and DOT if we have questions or need someone to point us in the right direction on a particular issue. An example of collaboration between agencies is through Florida's EV Master Plan. The DOT was the lead agency on the EV Master Plan, but PSC staff consistently met with them and contributed to the text of the EV Master Plan. During the development of the report, DOT facilitated meetings that brought together the PSC, the Energy Office, and stakeholders from the industry.

Can you share examples of projects that you have been able to complete with the other two agencies that you would not have been able to accomplish on your own?

Kelley Smith Burk: Together we can accomplish much more. The PSC plays a significant role in transportation electrification planning because they have the knowledge and expertise of regulating utilities, and they understand the process of updating critical grid infrastructure like transformers and transmission lines. The State Energy Office has expertise as it pertains to utility engagement and grid infrastructure modernization, in addition to comprehensive energy planning. The State Energy Office and PSC can then work with Florida's DOT to ensure that electric system considerations are adequately addressed when planning for and investing in EV charging.

April Combs: Policy work is a great example of the type of work the DOT can accomplish by working with the State Energy Office and the PSC. Understanding the roles and expertise of each agency is essential in policy work. The PSC can help with utility regulation and rates, whereas the State Energy Office can assist with education and outreach regarding EV programs. It is all about working together with the same goal in mind.

Andrew Fay: The EV Master Plan is a notable example of a product that could not be completed without cross-agency collaboration. The purpose of the EV Master Plan was to create a plan for charging infrastructure across the state highway system. The DOT has expertise in state highways, unlike the other two agencies. The plan, however, required information regarding appropriate regulatory models for getting electricity to the charging stations, which is where the PSC was able to assist.

What is Florida doing to address equity in transportation, and what are the various roles of each of the state agencies in addressing those issues?

Tony Morgan: Florida created an energy equity plan that has helped integrate equity in transportation electrification planning and implementation. It would be beneficial to include workforce innovation in EV planning to address equity in disadvantaged communities. It will be vital to build a skilled workforce in rural and disadvantaged communities to support EV infrastructure installation and repairs, so EV drivers do not have to drive long distances to seek assistance. The municipalities are also examining workforce development from a mass transit perspective and have previously included workforce development in their equity workshops. Working with municipalities and other state agencies can help address workforce development challenges and equity concerns.

Can you share any advice for a new commissioner coming into your role and anything they might need to know about transportation electrification in Florida?

Andrew Fay: The structure of the Florida PSC is such that our jurisdiction covers an estimated 17 million people. Because Florida's regions are all vastly different, it is important to take a "holistic Florida" approach when making decisions. It is also important to stay up to speed with emerging technologies, events impacting the state, and what is happening in other agencies as it pertains to transportation electrification.

Michigan

The following text is an abridged transcript of interviews conducted with Robert Jackson, Assistant Division Director for Michigan Department of Environment, Great Lakes, and Energy; Judd Herzer, Strategic Policy Director for Michigan Department of Labor & Economic Opportunity; and Hon. Tremaine Phillips, Commissioner at the Michigan Public Service Commission.

Can you share some examples of the working relationship between the Michigan Energy Office, Michigan DOT, and the Michigan PSC?

Robert Jackson, Assistant Division Director, Michigan Department of Environment, Great Lakes, and Energy: We have a strong relationship with state agencies regarding mobility and electrification. We have a partnership between the Energy Office, DOT, and PSC, and are all actively involved in mobility and transportation issues, particularly as it pertains to NEVI plans and the Federal Highway Administrations request for comments. We are working jointly to write comments on behalf of the state of Michigan to address concerns shared by all agencies. Regarding the completion of the NEVI plan, each agency plays a role in the coordination of the plan. For example, the DOT is the appointed agency for the plan, the PSC oversees the electric grid components of the plan, and the Energy Office is responsible for the modeling and program implementation.

Tremaine Phillips, Commissioner, Michigan PSC: Over the past two years, the State of Michigan has kicked off several mobility initiatives that have brought the PSC closer to working with agencies throughout state government. In 2020, the Governor established an Office of Future Mobility and Electrification to focus on mobility and transportation electrification within the state. The Governor also established a Council on Future Mobility and Electrification that is comprised of various agency heads throughout the state that have an interest or regulatory or fiscal responsibilities related to vehicle electrification and mobility issues. The Council also consists of auto manufacturers like Ford, GM, and Rivian. I am the representative from the PSC on the Council, so I work alongside automakers, state agencies, and the Office of Future Mobility and Electrification to strategize transportation electrification programs and policies in the state.

What are some lessons you have learned in working with other agencies on transportation electrification issues?

Judd Herzer, Strategic Policy Director, Michigan Department of Labor & Economic Opportunity: When working with multiple agencies, it is important to manage the expectations and perspectives of each agency. Each agency has a unique perspective and set of interests as it pertains to transportation electrification. It is important for agencies to listen to the perspectives of all stakeholders when making decisions, especially if it runs counter to the default opinion of an agency.

Can you share an example of activities that are enabled by cross-agency collaboration?

Tremaine Phillips: Cross-agency collaboration works best when agencies and stakeholders meet regularly to discuss issues and project updates. It is important to be proactive and organized about collaboration and keep all stakeholders informed. Bringing multiple agencies into the same meeting is beneficial in keeping all stakeholders engaged and up to speed on projects, programs, and policies.

What is Michigan doing to address equity in transportation, and what are the various roles of each of the state agencies in addressing those issues?

Robert Jackson: The State Energy Office is coordinating with the Office of Future Mobility and Electrification on mapping out mobility needs in the state. The Energy Office also has an agreement with the World Renew Church Christian Reform to implement energy efficiency and renewable energy in 10 houses of worship within Michigan. The work addresses energy efficiency and providing solar access to low-income families. We are looking to add another component to the program that incorporates EVs and vehicle to grid technologies. We are also working with other agencies to incorporate mobility into other projects that can better serve disadvantaged communities.

Judd Herzer: There is an opportunity with EV infrastructure planning to provide economic opportunities and workforce development in disadvantaged communities. By working across multiple agencies (DOT, State Energy Office, and PSC), the state can develop economic and workforce opportunities that expand transportation electrification and benefit disadvantaged communities.

Utah

The following text is an abridged version of interviews conducted with Bailey Toolson, State Energy Program Manager for the Utah Office of Energy Development; Lyle McMillan, Strategic Investments Director with the Utah DOT; and Hon. Thad LeVar, Chairman of the Utah PSC.

Can you describe the working relationship between the Utah Energy Office, Utah DOT, and PSC?

Bailey Toolson, State Energy Program Manager, Utah Office of Energy Development: The State Energy Office has been meeting frequently with the DOT to put together the NEVI plan. In January 2022, the Governor put together a state-wide EV steering committee, and the State Energy Office and DOT have been the lead agencies of the group. As far as working with the PSC, the Executive Director of the Energy Office and other Energy Office officials work closely with the PSC on other energy related issues.

Lyle McMillan, Strategic Investments Director, Utah DOT: We started working closely with the State Energy Office through the VW Settlement Fund Program. The State Energy Office's role in the VW Settlement Program was to be the conduit between the energy providers and the policymakers to advocate for additional funding from the state legislature. The DOT and the Energy Office worked together for years to advocate for funding from the legislature and was able to get funding this previous legislative session. This collaboration helped lay the groundwork for a strong working relationship for NEVI planning.

Thad LeVar, Chairman, Utah PSC: We collaborate with the DOT on an ad hoc basis, but as it pertains to transportation electrification, we have provided some input. We have been involved with EV infrastructure planning as it relates to utility regulations. The DOT was asked to provide input on the PSC process for ratepayer funding and design. The PSC has a working relationship with the State Energy Office as they take the lead on policy issues and stakeholder outreach.

Can you share an example of activities that are enabled by cross-agency collaboration?

Bailey Toolson: The Utah legislature ordered the DOT to put together a state-wide EV planning document. The document enabled state agencies to collaborate on EV infrastructure planning. The state-wide EV plan helped create a foundation for cross-agency collaboration for the NEVI plan.

What is Utah doing to address equity in transportation, and what are the various roles of each of the state agencies in addressing those issues?

Thad LeVar: In the EV development plan, the main transportation corridors are obvious and intuitive in Utah, however, getting access to rural communities is more of a challenge. Placing emphasis on dispersing chargers and resources in rural communities will be a priority in addressing equity in transportation electrification. Each of the agencies has a role to play in making that happen.

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NATIONAL COUNCIL ON ELECTRICITY POLICY

About the National Council on Electricity Policy
The National Council on Electricity Policy (NCEP) is a platform for all state-level electricity decision makers to share and learn from diverse perspectives on the evolving electricity sector. Our community includes over 200 representatives from public utility commissions, air and environmental regulatory agencies, governors' staffs and state energy offices, legislatures, and consumer advocates. We are an affiliate of the National Association of Regulatory Utility Commissioners (NARUC) Center for Partnerships and Innovation (CPI).

NCEP serves as a forum for collaboration around grid-related topics at state, regional, and national levels, offering a unique opportunity for state electricity decision makers throughout the country to examine the ways new technologies, policies, regulations, and markets impact state resources and the bulk power system.

NCEP facilitates an annual meeting, connections to virtual resources, and ongoing learning opportunities for members to explore multiple perspectives on complex electricity system issues.

NARUC
National Association of Regulatory Utility Commissioners

About the NARUC Center for Partnerships & Innovation
The NARUC Center for Partnerships & Innovation (CPI) identifies emerging challenges and connects state utility commissions with expertise and strategies to navigate complex decision-making. We accomplish this goal by building relationships, developing resources, and delivering training that provides answers to state commissioners' questions. CPI works across four key areas on a wide range of projects: energy infrastructure modernization; electricity system transition; critical infrastructure, cybersecurity, resilience; and emerging issues. CPI is funded by cooperative agreements with the U.S. Department of Energy (DOE), the U.S. Department of Commerce's National Institute of Standards and Technology (NIST), and charitable sources.

NASEO
National Association of State Energy Officials

About the National Association of State Energy Officials
NASEO is the only national non-profit association for the governor designated energy officials from each of the 56 states and territories. Formed by the states in 1986, NASEO facilitates peer learning among state energy officials, serves as a resource for and about state energy offices, and advocates the interests of the state energy offices to Congress and federal agencies.

AMERICAN ASSOCIATION OF STATE HIGHWAY AND TRANSPORTATION OFFICIALS
AASHTO

About the American Association of State Highway and Transportation Officials
AASHTO is a nonprofit, nonpartisan association representing highway and transportation departments in the 50 states, the District of Columbia, and Puerto Rico. It represents all transportation modes including air, highways, public transportation, active transportation, rail, and water. Its primary goal is to foster the development, operation, and maintenance of an integrated national transportation system.

AASHTO works to educate the public and key decision makers about the critical role that transportation plays in securing a good quality of life and sound economy for our nation. AASHTO serves as a liaison between state departments of transportation and the Federal government. AASHTO is an international leader in setting technical standards for all phases of highway system development. Standards are issued for design, construction of highways and bridges, materials, and many other technical areas.

State	Utility	Title	Status	Type	Vehicle Type	Description
Arizona	Tucson Electric Power	Smart EV Charging Program	Active	Make-Ready	L&MHDV	Level 2 - Workplace: Standard: $4,000/port; up to 75% of project cost DAC Eligible Project: $6,000/port; up to 75% of project cost Level 2 - Multifamily, Nonprofit: Standard: $5,400/port; up to 85% of project cost DAC Eligible Project: $9,000/port; up to 85% of project cost Level 3 - DC Fast Charger: Standard: $20,500/port; up to 75% of project cost DAC Eligible Project: $40,000/port; up to 75% of project cost
California	Southern California Edison	Charge Ready	Active	Make-Ready	L&MHDV	Construction Options: SDG&E Ownership - SCE pays for, constructs, owns, and maintains all infrastructure up to the charging station. Customer Ownership - SCE pays for, constructs, owns, and maintains all infrastructure up to the meter. Customer pays for, constructs, owns, and maintains all equipment beyond the meter, including charging station. SCE provides rebate for 80% of cost excluding charging station.
California	Southern California Edison	Charge Ready Schools	Active	Make-Ready	L&MHDV	Equipment Ownership Options: Turn-key Option - SCE pays for, constructs, owns, and maintains all infrastructure ***including*** the charging station. Customer Ownership - SCE pays for, constructs, owns, and maintains all infrastructure up to the charging station. School districts own, maintain, and operate charging station and recieve rebate.
California	Southern California Edison	Rule 29: Electric Vehicle	Active	Make-Ready	L&MHDV	Separate utility tariff that will cover utility infrastructure for EV projects up to the customer's meter
California	San Diego Gas & Electric	Power Your Drive for Fleets	Active	Make-Ready	L&MHDV	Construction Options: SDG&E Ownership - SDG&E pays for, constructs, owns, and maintains all infrastructure up to the charging station. Customer Ownership - SDG&E pays for, constructs, owns, and maintains all infrastructure up to the meter. Customer pays for, constructs, owns, and maintains all equipment beyond the meter, including charging station. SDG&E provides rebate for 80% of cost excluding charging station. Either option also includes rebates for 50% of the cost of charging stations up to the maximums below, with transit agencies, school districts, and fleets located in disadvantaged communities eligible for an additional rebate of up to 50% of the costs to purchase charging stations: Up to 19.2kW - $3000 per charger 19.3kW to 50kW - $15,000 per charger 50.1kW to 150kW - $45,000 per charger 150.1kW and above - $75,000 per charger
California	San Diego Gas & Electric	Power Your Drive for Schools, Parks, and Beaches	Active	Make-Ready	L&MHDV	Equipment Ownership Options: SDG&E Ownership - SDG&E pays for, constructs, owns, and maintains all infrastructure ***including*** the charging station. Customer Ownership - SDG&E pays for, constructs, owns, and maintains all infrastructure up to the charging station. School districts own, maintain, and operate charging station and recieve rebate.
California	San Diego Gas & Electric	Power Your Drive for Workplaces	Active	Make-Ready	LDV	Construction options: SDG&E Ownership - SDG&E pays for, constructs, owns, and maintains all infrastructure up to the charging station. Customer Ownership - SDG&E pays for, constructs, owns, and maintains all infrastructure up to the meter. Customer pays for, constructs, owns, and maintains all equipment beyond the meter, including charging station. SDG&E provides rebate for 100% of cost excluding charging station. Either option also includes rebates for Level 2 chargers of 50% of charger cost up to $2000, or 100% of charger cost up to $2000 for DACs and/or small businesses
California	San Diego Gas & Electric	Rule 45: Electric Vehicle Infrastructure	Active	Make-Ready	L&MHDV	Separate utility tariff that will cover utility infrastructure for EV projects up to the customer's meter
California	Pacific Gas & Electric Company	EV Fleets Program	Active	Make-Ready	L&MHDV	PG&E will construct, own, and maintain all infrastructure up to the meter. Fleet operators will be responsible for material behind the meter. Charger Rebates: Up to 50kW - 50% of charger cost, up to $15,000 50.1kW to 149.9kW- 50% of charger cost, up to $25,000 150kW and above - 50% of charger cost, up to $42,000
California	Pacific Gas & Electric Company	EV Charge	Closed	Make-Ready	LDV	Deployment of 7,500 L2 chargers. Financial Incentives: 50% Rebate for MUDs in Underserved Communities, 100% Rebate for MUDs in Underserved Communities, 25% rebate for EVSEs in Workplaces. 15% minimum in underserved communities.
California	Pacific Gas & Electric Company	EV Fast Charge	Active	Make-Ready	LDV	DACs: Utility will pay for and own infrastructure up to parking space. Chargers may qualify for up to $25,000 rebate.

State	Utility	Title	Status	Type	Vehicle Type	Description
California	Pacific Gas & Electric Company	EV Charge Schools	Active	Make-Ready	L&MHDV	Schools are provided two options: PG&E Ownership - PG&E owns, operates, and maintains EVSE and network fees for up to eight years. Site Host Ownership - Host owns, operates, and maintains EVSE and recieves a rebate from PG&E ($11,500 for single port L2 charger, $15,500 for dual-port)
California	Pacific Gas & Electric Company	Rule 29: Electric Vehicle Infrastructure	Active	Make-Ready	L&MHDV	Separate utility tariff that will cover utility infrastructure for EV projects up to the customer's meter
California	Liberty Utilities	Schools/State Park Charging Program	Active	Make-Ready	L&MHDV	"Liberty is installing charging for school buses, staff, students and visitors at schools and parks throughout the Liberty region." Additional Progam details were not available. Please contact Liberty for more information.
California	Liberty Utilities	Rule 24: Electric Vehicle Infrastructure	Active	Make-Ready	L&MHDV	Separate utility tariff that will cover utility infrastructure for EV projects up to the customer's meter
California	Bear Valley Electric Service	Bear Ready Commercial	Active	Make-Ready	LDV	Project will support up to 5 Level 2 Chargers at a commercial location. Site owner is responsible for the EVSE. Utility will own the make-ready infrastructure.
Colorado	Xcel Energy	EV Supply Infrastructure	Active	Make-Ready	L&MHDV	Two Options: Xcel Energy provides charging station (including installation and maintenance) for a monthly fee Customer procures charging equipment from prequalified list and is reimbursed
Colorado	Black Hills Energy	Commercial Electric Vehicle Charging Rebate	Active	Make-Ready	L&MHDV	Rebates for EV charging equipment and installation: Business - $2000 per port (Level 2) Government/Nonprofit - $3000 per port (Level 2) Commercial/Industrial - $20,000 to $35,000 per charger (DCFC)
Connecticut	The United Illuminating Company	Connecticut Electric Vehcile Charging Program (Commercial)	Active	Make-Ready	L&MHDV	Offers rebates on 50% of EVSE charger cost plus 100% of make-ready installation costs up to site maximum ($20,000 for Level 2 chargers, $150,000 of DCFC; $40,000 and $250,000 for underserved communities)
Connecticut	Eversource	Connecticut Electric Vehcile Charging Program (Commercial)	Active	Make-Ready	L&MHDV	Offers rebates on 50% of EVSE charger cost plus 100% of make-ready installation costs up to site maximum ($20,000 for Level 2 chargers, $150,000 of DCFC; $40,000 and $250,000 for underserved communities)
Florida	Duke Energy	Commercial Charger Rebate	Active	Make-Ready	L&MHDV	Rebates for EV charging equipment and installation: Fleet Level 2 - $1175 School Bus DCFC - $20,889 Transit Bus DCFC - $24,423 Fleet DCFC - $35,600
Georgia	Georgia Power	Workplace Charging Infrastructure	Active	Make-Ready	LDV	Georgia Power will offer commercial customers incentives of $500 and $250 dollars to install L2 chargers and 120 - volt Level one ("L1") chargers, respectively, at new and existing facilities.
Hawaii	Hawaiian Electric Company	eBus Make-Ready Infrastructure Pilot Project	Closed	Make-Ready	ESB	The Comission Approved with Modification the three-year eBus make-ready infrastructure pilot program, with modifications made almost exclusively to the reporting requirements. The Company was required to file projected treatment of revenue requirement 30 days from the order. As such, Hawaiian Electric is approved to spend $4.25 million (including O&M costs) on a small pilot to install make-ready infrastructure (utiity and customer side up to charger) to support 20 high-capacity charging stations at 5-10 sites across the service territories of the three affiliated utilities.The Company is approved to recover program expenses through the ratebase using the Renewable Energy Infrastructure Program Surcharge mechanism, and was approved to waive Company Rule 14 Service Connections for pilot participants to provide electrical service up to the EVSE. The Company anticipates the 20 chargers will serve between 20-60 eBuses. Elligible customers must operate a Class 5-8 bus and commit to purchasing at least one public transit bus during the pilot period, and installing one charging station. Customers will own and maintain the onsite EVSE and are required to take power on an existing bus TOU rate or an additional TOU rate with approval. Customer EVSE must meet utility qualifications. As of April 2023, the Hawaii PUC approved extending the pilot program through the end of 2025. Based on an adjusted timeline, completion of make-ready infrastructure is expected in 2024 to support electric bus operations and data collection in 2025.
Hawaii	Hawaiian Electric Company	Charge Up Commercial	Active	Make-Ready	L&MHDV	Hawaiian Electric will discount costs of installing electric infrastructure up to $90,000 for all work up to the charging station (includes behind the meter and switchgear costs)
Hawaii	Hawaii Energy	Electric Vehicle Charging Stations Rebate	Active	Make-Ready	L&MHDV	Rebate Amounts: Level 2 (Single Port) - $2000 new, $1300 for retrofit Level 2 (Dual Port) - $4500 new, $3000 for retrofit DCFC - $35,000 new, $28,000 retrofit
Indiana	Duke Energy	Comercial Charger Rebate	Active	Make-Ready	L&MHDV	Credits available for electric infrastructure based on chargers installed: Workplace Level 2 - $500 Fleet Level 2 - $500

State	Utility	Title	Status	Type	Vehicle Type	Description
Maine	Central Maine Power Company	EV Charging Infrastructure Investment Program Pilot: L2 Make-Ready	Closed	Make-Ready	L&MHDV	The Commission approves a program in which CMP would provide a subsidy for make-ready costs for 60 L2 chargers. CMP will perform the make-ready work up to the point of the meter or charger itself (at the customer's discretion), essentially providing a turn-key solution. The customer would be responsible for installing the charger. The Commission will approve a subsidy of no more than $4,000 per individual customer site.
Maryland	PEPCO	Electric Vehicle Fleet Program	Active	Make-Ready	L&MHDV	50% of cost for Level 2 charger, up to $5000 50% of cost for DCFC, up to $15,000 Maximum of $30,000 per location
Maryland	PEPCO	Electric Vehicle Fleet Program	Active	Make-Ready	L&MHDV	PEPCO offers discounted fleet advisory services, with fees refunded if project moves forward
Maryland	PEPCO	Electric Vehicle Fleet Program	Active	Make-Ready	L&MHDV	PEPCO will cover 90% of costs for infrastructure upgrades, up to $15,000. Will cover 100% of cost in disadvantaged communities.
Maryland	PEPCO	Program Enhancements: Workplace Charger Rebate Program	Closed	Make-Ready	LDV	The PHI Utilities are requesting fleet and workplace rebates for 50% of the EV charging stations and installation up to $5,000 per L2 port. The maximum incentive per location would be $30,000 and the program would provide for rebates at 25 fleet and workplace locations for at a budget increase of $750,000. The Commission approved this program with modification, mandating a rebate cap of 25 and that they be awarded to Maryland-based companies that qualify as small business or nonprofits. The installed chargers must be "smart chargers" and any eligible fleet must have at least five EVs.
Maryland	Delmarva Power	Electric Vehicle Fleet Program	Active	Make-Ready	L&MHDV	50% of cost for Level 2 charger, up to $5000 50% of cost for DCFC, up to $15,000 Maximum of $30,000 per location
Maryland	Delmarva Power	Electric Vehicle Fleet Program	Active	Make-Ready	L&MHDV	Delmarva Power offers discounted fleet advisory services, with fees refunded if project moves forward
Maryland	Delmarva Power	Electric Vehicle Fleet Program	Active	Make-Ready	L&MHDV	Delmarva Power will cover 90% of costs for infrastructure upgrades, up to $15,000. Will cover 100% of cost in disadvantaged communities.
Maryland	Delmarva Power	Program Enhancements: Workplace Charger Rebate Program	Closed	Make-Ready	LDV	The PHI Utilities are requesting fleet and workplace rebates for 50% of the EV charging stations and installation up to $5,000 per L2 port. The maximum incentive per location would be $30,000 and the program would provide for rebates at 25 fleet and workplace locations for at a budget increase of $750,000. The Commission approved this program with modification, mandating a rebate cap of 25 and that they be awarded to Maryland-based companies that qualify as small business or nonprofits. The installed chargers must be "smart chargers" and any eligible fleet must have at least five EVs.
Maryland	Baltimore Gas & Electric	Commercial Customer Charger Rebate	Active	Make-Ready	L&MHDV	50% of cost for Level 2 charger, up to $5000 50% of cost for DCFC, up to $15,000 Maximum of $30,000 per location
Maryland	Baltimore Gas & Electric	Electric Vehicle Fleet Program	Active	Make-Ready	L&MHDV	BGE offers discounted fleet advisory services, with fees refunded if project moves forward
Maryland	Baltimore Gas & Electric	Electric Vehicle Fleet Program	Active	Make-Ready	L&MHDV	BGE will cover 90% of costs for infrastructure upgrades, up to $15,000. Will cover 100% of cost in disadvantaged communities.
Massachusetts	National Grid	Fleet Electric Vehicle Charging Program	Active	Make-Ready	L&MHDV	Program covers up to 100% of utility side infrastructure, up to 100% of customer-side infrastructure (up to $6700 Level 2, $30,000 50-149kW DCFC, $60,000 150+kW DCFC), and offers rebates for chargers (up to $3600 Level 2, $40,000 50-149kW DCFC, $80,000 150+kW DCFC)
Massachusetts	Eversource	Grid Modernization Base Commitment	Closed	Make-Ready	L&MHDV	The Companies plan to support the deployment of EV charging ports by installing electrical equipment and components necessary to connect EV chargers to the Companies' distribution system. Site Makeup, L2 (3955 total). DC (72 total): 1-3/site - these are the expected number of sites. 1 EJC criteria in Western Mass, 2 EJC criteria in Eastern Mass. 10% for underserved communities.
Michigan	DTE Energy Company	eFleet Charger Rebate	Active	Make-Ready	L&MHDV	$2500 per Level 2 Port $70,000 per DCFC Charger
Michigan	Consumers Energy	PowerMIFleet: Make-Ready	Active	Make-Ready	L&MHDV	Through the PowerMIFleet program, Consumers Energy will pay for, own and maintain all electric infrastructure from the transformer to the customer's meter (TTM) infrastructure.
Minnesota	Xcel Energy	Fleet EV Service Pilot: EVSE Service & Charging Infrastructure	Closed	Make-Ready	L&MHDV	The Fleet EV Service Pilot will be available to non-residential customers who operate fleets that include light-, medium-, and/or heavy-duty EVs over three years. The Company proposes to install, own, and maintain the make-ready infrastructure for the new, dedicated EV service which includes everything from necessary transformer upgrades up to the charger stub. Customers can opt to either acquire, install, and maintain their own charging equipment that complies with applicable safety standards, or select chargers from the Company's pre-qualified list and have the Company acquire, install, own, and maintain the charging equipment for the term of the service agreement. Reporting will be submitted to the Commission with the June 1 annual report.
Missouri	Ameren Missouri	Charging Station Incentives	Active	Make-Ready	L&MHDV	50% of project costs, $5000 per Level 2, $20,000 per DCFC up to $500,000 per site

State	Utility	Title	Status	Type	Vehicle Type	Description
Nevada	NV Energy	Transit, School Bus and Transportation Electrification	Closed	Make-Ready	L&MHDV	The Transit, School Bus, and Transportation Electrification Custom Program provides funding to serve the electrification needs of transit agencies, metropolitan planning organizations, the DOT, public school districts and nongovernmental commercial customers. Another program objective is to demonstrate V2G integration with electric school buses. The program is expected to result in 3 additional sites and 40 additional chargers, not included the Transit Electrification Grant and the Transportation Electrification Custom Program.
New Jersey	Public Service Electric and Gas Company	Electric Vehicle Charging Program	Active	Make-Ready	LDV	$7500 credit per Level 2 charger (up to $30,000), as well as $10,000 towards utility-side upgrades.
New Jersey	Jersey Central Power & Light	EVDriven: Commercial Program	Active	Make-Ready	L&MHDV	Incentives for charging stations and utility side work: Level 2 - $11,000 make-ready work, $6700 per port up to 10 ports DCFC - $50,500 make ready-work, $25,000 per port up to 10 ports
New Jersey	Atlantic City Electric	Fleet Charger Rebate	Active	Make-Ready	L&MHDV	Incentives to cover 50% of make ready costs up to $2500 per charging port.
New Jersey	Atlantic City Electric	Workplace Charger Rebate	Active	Make-Ready	L&MHDV	Incentives to cover 50% of make ready costs up to $4500 per charging port.
New Mexico	PNM	Electric Vehicle Charger Rebate	Active	Make-Ready	L&MHDV	$2500 per Level 2 charger, $25,000 per DCFC charger
New York	Rochester Gas and Electric Corporation	EV Charger Make-Ready Program	Active	Make-Ready	L&MHDV	RG&E reimburses up to 100% of cost for utility-side and customer-side infrastructure up to EVSE (customer responsible for EVSE). NYSERDA may cover EVSE costs
New York	Orange and Rockland Utilities	MHDV Fleet Make-Ready Pilot Program	Active	Make-Ready	L&MHDV	Covers up to 90% of utility-side make-ready costs
New York	Orange and Rockland Utilities	POWERREADY	Active	Make-Ready	L&MHDV	Will cover up to 100% of costs (utility-side and customer-side) for installing Level 2 and DCFC chargers for light-duty vehicles
New York	New York State Electric & Gas Corporation	EV Charger Make-Ready Program	Active	Make-Ready	L&MHDV	NYSEG reimburses up to 100% of cost for utility-side and customer-side infrastructure up to EVSE (customer responsible for EVSE). NYSERDA may cover EVSE costs
New York	National Grid	Electric Vehicle Charging Station Make-Ready Program	Active	Make-Ready	L&MHDV	National Grid will fund up to 100% of utility-side and customer-side infrastructure (customer will be responsible for EVSE, though NYSERDA funds may be available)
New York	Consolidated Edison Company	REV Demonstration Project: Electric School Bus V2G	Closed	Make-Ready	ESB	In this demonstration project, Con Edison and its third-party partners seek to test a new business model for electric school buses. The bus operator, National Express, will operate five electric school buses in White Plains during the school year. During the summer months, when the buses are not used for transportation purposes, they will serve as grid-connected energy storage assets. Costs: Payment for rights to use vehicle as grid asset (1/4 of bus purchase costs), 1/4 of EVSE equipment, EVSE upgrade cost for V2G, analysis and reporting, administration.
New York	Consolidated Edison Company	Medium- and Heavy-Duty Electric Vehicle Charging Infrastructure Program	Active	Make-Ready	L&MHDV	Covers up to 85% of utility-side make-ready costs, with maximum of $1.2 million
New York	Consolidated Edison Company	POWERREADY	Active	Make-Ready	L&MHDV	Program offers incentives for utility-side and customer-side construction costs up to the EVSE
New York	Central Hudson Gas & Electric Corporation	MHDV Make-Ready Pilot Program	Active	Make-Ready	MHDV	Participants in the Medium- and Heavy-Duty Fleet Make-ready Pilot Program that purchase the vehicle through NYSERDA's Truck Voucher Incentive Program will receive up to 90 percent of the utility-side make-ready infrastructure upgrade costs up to the customer's electric panel
New York	Central Hudson Gas & Electric Corporation	Light-Duty Make-Ready Program	Active	Make-Ready	LDV	Program will cover up to 50% of costs up to the EVSE
North Carolina	Duke Energy	Commercial Charger Prep Credit	Active	Make-Ready	L&MHDV	Credits available for electric infrastructure based on chargers installed: Workplace Level 2 - $725 Fleet Level 2 - $886 School Bus DCFC - $13,630
Oregon	Portland General Electric	PGE Electric School Bus Fund	Closed	Make-Ready	L&MHDV	Provides funding for ESBs and up to $150,000 for infrastructure costs
Oregon	Portland General Electric	Business EV Charging Rebates	Active	Make-Ready	L&MHDV	Up to $1000 for each Level 2 charging port
Pennsylvania	PECO Energy Company	Commercial Charger Rebate	Active	Make-Ready	L&MHDV	Rebates for Level 2 and DCFC chargers for 50% of the total project cost, up to $60,000
Pennsylvania	PECO Energy Company	Pilot Discount for Fast Charging Infrastructure	Active	Make-Ready	L&MHDV	50% discount on distribution charges when installing DCFC chargers
Pennsylvania	Duquesne Light Company	Community Charging	Active	Make-Ready	L&MHDV	Covers utility-side and customer-side make-ready costs up to the EVSE. Customer is responsible for installing EVSE.
Pennsylvania	Duquesne Light Company	Fleet Charging	Active	Make-Ready	L&MHDV	Covers utility-side and customer-side make-ready costs up to the EVSE. Customer is responsible for installing EVSE, may be eligible for 50% rebate

State	Utility	Title	Status	Type	Vehicle Type	Description
Rhode Island	National Grid	Electric Transportation Initiative: Charging Station Demonstration Program	Closed	Make-Ready	L&MHDV	43 DCFC ports and 319 Level 2 ports across a number of sites and sectors. National Grid will supply the make-ready and site hosts are given the option to install their own equipment or have the utility do it. DCFC sites will all be owned by National Grid. Fleet sites will all be make-ready. Three year program includes O&M.
Virginia	Dominion Energy Virginia	Fleet Electrification	Active	Make-Ready	L&MHDV	Dominion constructs and maintains all EVSE. 50% upfront discount on EV charging construction. Customer pays monthly service payment
Virginia	Dominion Energy Virginia	Smart Charging Infrastructure Pilot Program: Utility owned rideshare stations	Closed	Make-Ready	LDV	The program proposes four utility-owned charging stations sited strategically to enable additional vehicles to participate in rideshare platforms. Procurement will be through an RFP process. Stations will be accessible to both rideshare drivers and the public. The utility will install and own the charging stations and the site hosts will be responsible for electricity bills and any fees collected from drivers for the use of the charging stations will be provided to the site hosts.
Washington	Puget Sound Energy	Up & Go Electric: Fleets	Active	Make-Ready	L&MHDV	Two options: PSE owned - PSE installs and maintains chargers, $10,000 per Level 2 port, $125,000 per DCFC port up to $250,000 per location Customer Owned - customer owns, installs, and maintains chargers, incentive of $4000 per Level 2 port, $60,000 per DCFC port, up to $250,000 per site
Washington	Puget Sound Energy	Up & Go Electric: Workplace	Active	Make-Ready	LDV	PSE covers up to 100% of costs to install and maintain Level 2 charging at a commercial location for employees
Washington	Avista Utilities	Electric Vehicle Charging Equipment Incentive Program	Active	Make-Ready	L&MHDV	Avista will cover 50% of cost for installing Level 2 charging up to 50% of project cost

Smart Electric Power Alliance

Managed Charging Incentive Design

Guide to Utility Program Development

October 2021

Managed Charging Incentive Design

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About SEPA

The Smart Electric Power Alliance (SEPA) is dedicated to helping electric power stakeholders address the most pressing issues they encounter as they pursue the transition to a clean and modern electric future and a carbon-free energy system by 2050. We are a trusted partner providing education, research, standards, and collaboration to help utilities, electric customers, and other industry players across three pathways: Electrification, Grid Integration, Regulatory and Business Innovation. Through educational activities, working groups, peer-to-peer engagements and custom projects, SEPA convenes interested parties to facilitate information exchange and knowledge transfer to offer the highest value for our members and partner organizations. For more information, visit www.sepapower.org.

Disclaimer

Acknowledgements

SEPA would like to thank Exelon for the opportunity to conduct this study and participate in the design process of its smart charge management program. SEPA wrote this report to contribute market research, share managed charging program design best practices, and provide key insights and lessons learned that will guide utilities in the design of managed charging programs. The study was made possible by funding provided by the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy.

Two of Exelon's operating utilities, Potomac Electric Power Holdings (PHI) and Baltimore Gas and Electric (BGE) are developing a managed charging demonstration project in their Maryland distribution utility service area with support from partners. Exelon's partners in this demonstration project include Greenlots, Qmulus, Weave Grid, Argonne National Laboratory, and SEPA. SEPA's role in the demonstration project development is to gather market research, support the development of unique incentive structures and smart charge actions to reward participation for each customer segment, and work in conjunction with the utilities to formulate a marketing strategy to increase enrollment. This white paper was composed in a way that complements the research and insights included in the latest SEPA research report on EV Managed Charging, which can be accessed through SEPA's website.

1.0 Introduction

Electric vehicles (EVs) are entering the U.S. market in increasing numbers. In 2020, buyers registered 295,000 new EVs.[1] EV sales are projected to reach 1.4 million by 2025, increasing to over 3.5 million by 2030.[2] As more EVs enter the market, utilities across the country are preparing to accommodate the increase in electric load from vehicle charging. One challenge this additional load presents is the potential for increased electricity demand at times of day or in locations that are already constrained.

To meet the additional electric demand required to support the expected growth in EV sales, utilities have two options. The first, hereafter known as unmanaged charging, is to react to increased demand and invest in additional generation and needed transmission and distribution system upgrades. The second, hereafter known as managed charging, is to be proactive and strategically manage electric vehicle charging load to meet electric vehicle charging needs and optimize grid investment and functionality. Utilities that choose the second option are designing programs that passively or actively manage the charging of electric vehicles in their service territory, aiming to shift load away from times of peak demand and toward times that are more optimal for the grid.

Passive managed charging (also known as behavioral load control) relies on customer behavior to affect charging patterns. For example, EV time-of-use (TOU) rates provide predetermined price signals to customers to influence when they choose to charge their vehicles (i.e., the driver selects when the vehicle is charged). An EV owner may manage their charging session by delaying when they connect their vehicle to the charger or by setting a predetermined charge start time using software enabled options on the vehicle or charger to automate when charging begins.

Active managed charging (also known as direct load control) relies on communication (i.e., "dispatch") signals originating from a utility or aggregator and sent to a vehicle or charger to control charging in a predetermined manner. Active managed charging can be events-based to control load during a limited number of events in a given time period (season or annually) or use continuous management to control load when the vehicle is connected to the charger.

In this white paper, SEPA provides program design recommendations and best practices, derived from market research, to support utilities in the development of their managed charging programs. SEPA identified rate design and marketing best practices through a review of reports that contain primary research data. We assessed approximately forty managed charging programs across a variety of customer segments to identify how utilities are designing their program incentive structure and the value of incentives that customers might receive. SEPA also conducted interviews with twenty utilities that have executed or participated in managed charging projects. During those interviews, we explored their customer identification, marketing, and incentive structure design strategies. Additionally, utilities provided key insights and lessons learned from their experience with implementing managed charging programs. These can serve as valuable guidance for other utilities designing a managed charging program.

The following sections in this report share the results of the market assessment, the design options for a managed charging program, and program design recommendations. This information can assist utilities as they design programs using various managed charging approaches to achieve high enrollment, optimize grid functionality and change customer behavior through effective incentives.

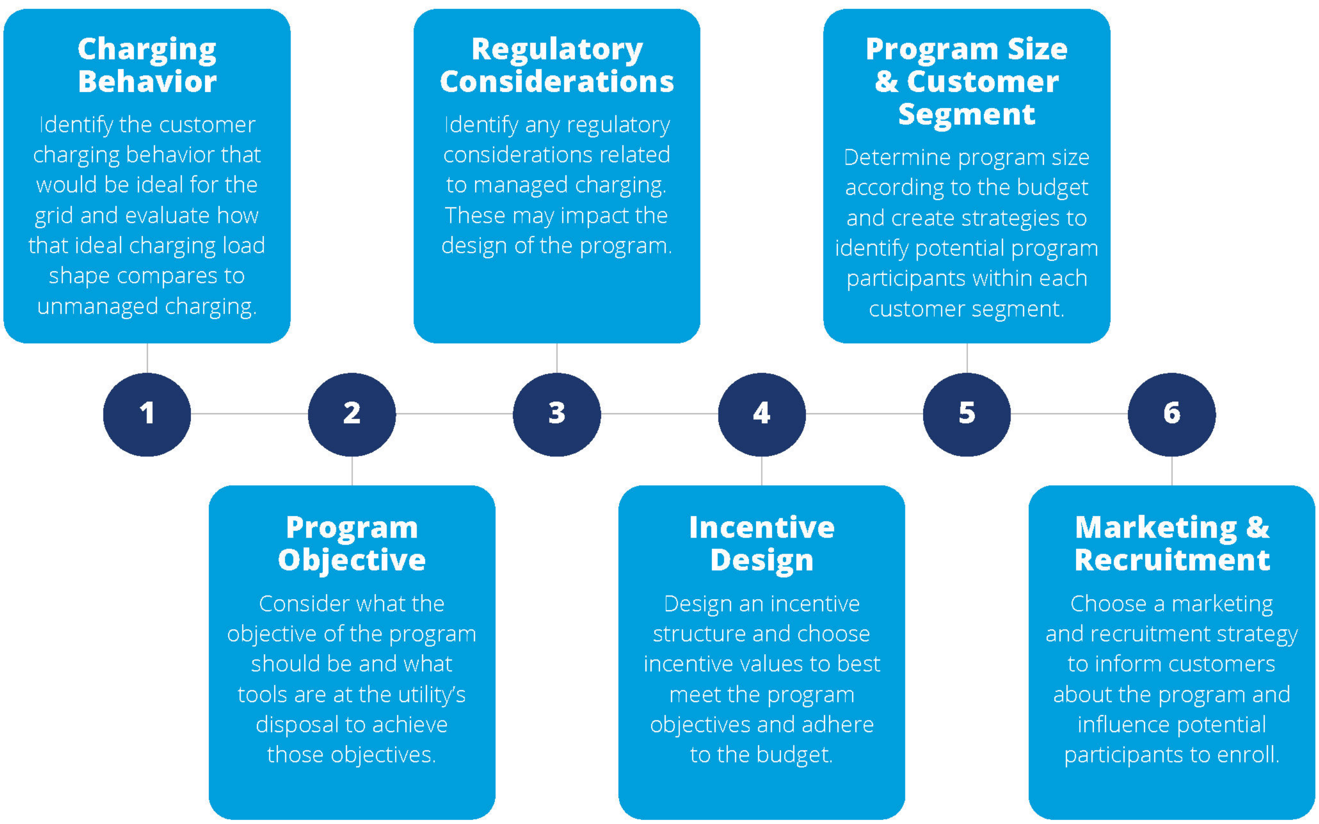
1 International Energy Agency, Global EV Outlook 2021: Accelerating Ambitions Despite the Pandemic (2021) p. 20.

2 Edison Electric Institute, EEI Celebrates 1 Million Electric Vehicles on U.S. Roads (2018).

2.0 Managed Charging Program Design Options

Designing a managed charging program can be intimidating, especially when this type of program is entirely new to a utility. To simplify the design process, we segment it into six manageable steps, as shown in Figure 1.[3]

Figure 1. Managed Charging Program Design Process



Source: Smart Electric Power Alliance, 2021

Desired Charging Behavior

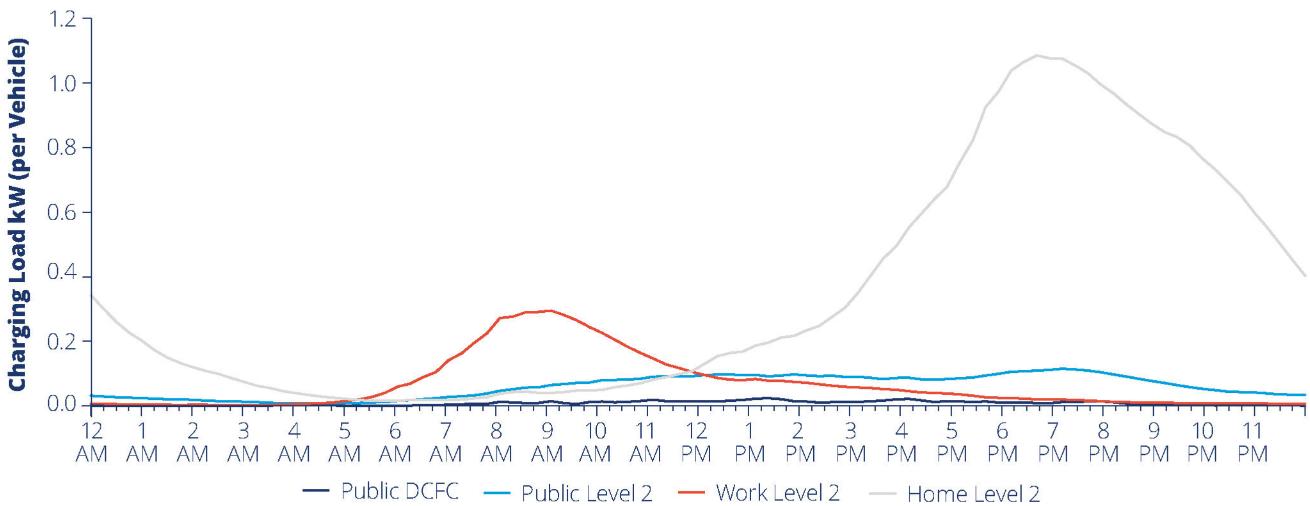
The first step in designing a managed charging program is to assess current understanding of the baseline charging behavior across the service territory and at the feeder level, and characterize the uncontrolled charging behavior. If this data is not available, assume that the baseline charging behavior mirrors the weekday and weekend EV demand profiles under uncontrolled charging conditions shown in Figures 2 and 3.

The next step is to identify the profile of optimized charging behavior, and the factor(s) around which the utility wants to optimize charging. Optimized charging behavior refers to the charging behavior that utilities would

3 The design process was developed based on learnings from consumer light duty vehicle programs, but can be utilized for other customer segments.

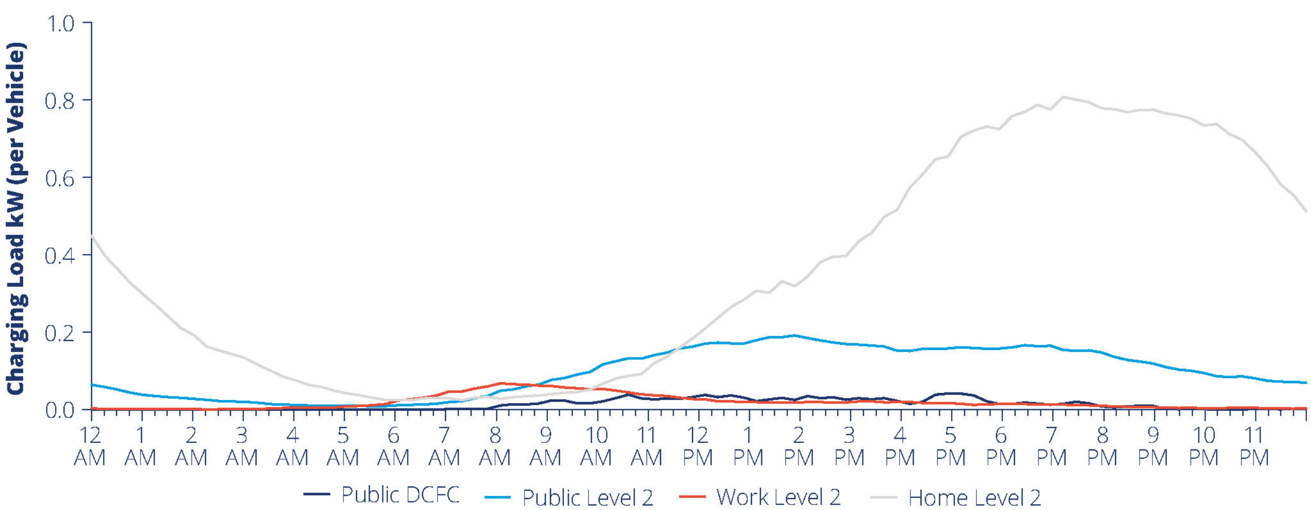
Managed Charging Incentive Design

Figure 2. EV Aggregate Demand Profiles Under Weekday Uncontrolled Charging Conditions



Source: SEPA, data generated using the DOE Electric Vehicle Infrastructure Projection Tool (EVI-Pro) Lite, accessed Sept. 22, 2021.

Figure 3. EV Aggregate Demand Profiles Under Weekend Uncontrolled Charging Conditions



Source: SEPA, data generated using the DOE Electric Vehicle Infrastructure Projection Tool (EVI-Pro) Lite, accessed Sept. 22, 2021.

like customers to adopt. This optimized charging behavior might be that charging occurs according to certain grid conditions, in order to take advantage of renewable energy generation and shift load away from times of peak demand. As EVs proliferate, multi-layer optimization becomes necessary. Optimizing only at the bulk system level may inadvertently cause distribution level issues, such as overloaded transformers or substations. A utility can first optimize at the system level to leverage renewable energy, cost, or transmission infrastructure, and next, evaluate the distribution level impacts, and then smooth the charging profile at the feeder level to avoid local system congestion.

Utilities should consider optimizing charging behavior to achieve a specific quantifiable goal. A quantifiable charging behavior goal will enable the utility to measure success and adjust certain components of the managed charging program as needed.

Once optimized charging behavior is identified, utilities need to consider whether the optimized, theoretical behavior will meet customer charging needs. Charging behavior goals often require modification to ensure customer needs are balanced with utility desires, so the managed charging program provides an optimal customer experience. The customers' ability to use the car for its primary purpose—driving—must be at the center of program design. Customers will not participate in a managed charging program that causes them to feel that their driving ability is impacted.

Active managed charging programs do not need to, and should not, impact the driver's ability to use their car. Their battery should be sufficiently charged to meet daily driving needs, and the utility direct load control should be unobtrusive and in-sync with driver preferences so that the driver does not know when active managed charging is taking place. Utilities should aim to design a managed charging program that minimizes the need for the driver to make decisions, as well as to enable seamless program enrollment, continuous managed charging, and infrequent user communications. Such program design will make program participation simple for the customer, and will build customer trust in the utility to effectively handle charging for them.

The Impact of Long-term Remote Work on Charging Behavior

Utilities may discover that increased work from home has significantly impacted when and where customers are using electricity.[4] As a result of a shift from in-office to remote work and company decisions to relinquish private office space, EV owners may spend less time utilizing networked chargers at a physical workplace or public site. Utilities should consider how the time and location of demand is impacted by an increasingly common work-from-home environment.

This change in baseline charging behavior and electric demand may have implications for utilities when designing their managed charging program, and they will need to reevaluate where chargers are needed. Utilities can benefit from making use of vehicle telematics in addition to, or coordinated with, networked charging stations. Implementing programs that integrate telematics alongside networked chargers increases the ability to manage charging across a broader set of charging use cases and provides increased flexibility in the location where charging can be managed.

Program Objective

After considering optimized charging behavior possibilities, the next step in program design is to identify what elements the program is testing, the desired outcomes, and how to measure progress in reaching those outcomes. For example, a utility may seek to minimize incremental electric vehicle load on the system through system-wide and feeder-level load control, and test customer willingness to participate in active managed charging programs.

If the goal is to actively manage charging load on a feeder level, the utility must consider how different methods of load control will require different levels of resources. Managing load control through demand response events versus continuous managed charging will entail partnerships with different third-parties as well as different billing processes, utility-customer communication, regulatory challenges, marketing messages, and incentive structure design.

Additionally, the method of load control that a utility implements in their managed charging program will face certain limitations that should be considered in the program design. For example, direct load control through a networked Level 2 charger allows collecting charging data and translating real-time grid conditions into charger throttling. However, individual Level 2 chargers are stationary, and when vehicles are not connected to the chargers, they provide no data and the vehicle cannot be used to benefit the grid. On the other hand, direct load control through automaker telematics enables near-constant data collection and throttling capability regardless of the location of the vehicle and the charger to which it connects, as long as the vehicle has cell reception and is connected. For this reason, OEM telematics can be problematic in underground parking or areas with low cell coverage. At present, automaker telematics are more available in higher-end electric vehicles.

Regulatory Considerations

For most utilities, the approval of a new managed charging program is at the discretion of their public service commission, board of directors, city council, or other oversight body. Utilities are in an ideal position to educate the commission and staff about the benefits of managed charging programs. Utilities will also need to demonstrate

4 This concept is explored in greater depth in SEPA's forthcoming report expected to be published November 2021.

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that the long-term benefits of a program outweigh the program costs. A utility program design team might consider similar customer programs their state regulators or other jurisdictions have approved, and understand the characteristics of those programs. They might also review programs that have been filed, but not approved, and evaluate the reasons for rejection.

Incentive Design

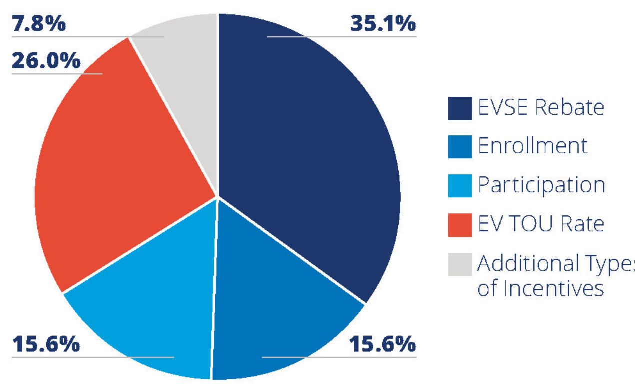
Next, a utility needs to determine the price signals and incentives to offer customers to most effectively shift charging behavior to meet program objectives. Utilities have implemented a variety of incentive structures to successfully and economically reach program goals. SEPA reviewed market studies of the incentive structures of managed charging programs to understand the sizes and types of incentives. Our findings will support utilities in their selection of incentive values that are both effective and economical.

SEPA identified and classified forty managed charging programs, twenty-five active managed charging programs, and fifteen passive managed charging programs. We classified programs by their incentive structure (i.e., which types of incentives the program offers to customers in order to get them to enroll and participate). For each program, we evaluated the incentive dollar value offered to participants. The following section summarizes the range and average incentive size by each incentive type.

It is important to note that all of the programs assessed reached their enrollment goals, regardless of the type and size of incentives offered to their participants. As programs transition from pilot to full scale, utilities and commissions will need to assess the specific costs and benefits of different program approaches and design program incentives that have benefits that exceed costs. Pilots are different in that they are, by design, trying to understand the costs and benefits of different approaches, so it is not feasible to design pilot incentives using a cost benefit analysis (CBA). This report provides guidance on potential incentive ranges that a utility pilot could use as a starting point, but the pilot outcomes will determine what incentives should be used at scale.

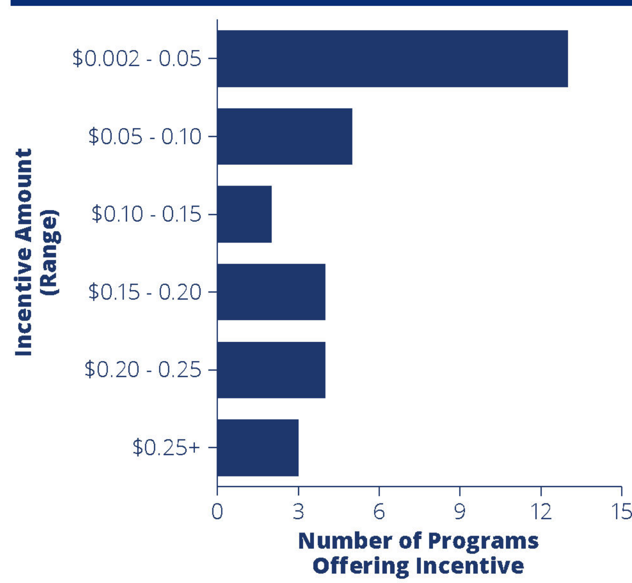
The following sections discuss SEPA's findings from our incentive data analysis and provide context for utilities in deciding which types of incentives to include in their managed charging program design.

Figure 4. Percentage of Programs That Offer Each Type of Incentive



Source: Smart Electric Power Alliance, 2021.

Figure 5. Difference in On-Peak and Off-Peak Price per kWh within an EV-specific TOU Rate



Source: Smart Electric Power Alliance, 2021.

On/Off-Peak Spread

Time-of-use rates that are specific to electric vehicle charging serve as an effective tool in encouraging EV owners to shift their behavior to benefit the grid and save them money. Earning approval of EV-specific TOU rates is relatively simple when compared to approval for customer compensation in exchange for direct control of their charging, since the customer retains control over their charging habits. Additionally, the concept of a TOU rate is not new to utilities, unlike other managed charging incentives, so it is easier to implement through a billing system. This type of incentive is a safe choice for utilities when forming an incentive structure within their managed charging program.

EVSE Rebate

Utility rebates for networked smart chargers reduce the upfront cost of EV ownership, and can be used to entice customers to share charging data with the utility and give the utility control over their charging. **SEPA noted that 64% of the active managed charging programs we assessed offer some type of charger rebate.**

While smart chargers are a valuable piece of equipment that utilities can use to balance grid conditions through direct load control, providing customers with a large rebate may become expensive for the utility. It is important to recognize that direct load management through a networked smart charger is most lucrative at single-family homes and at workplaces, where vehicles are connected for long periods.

Figure 6 provides information about the size of rebates that utilities offer to participants that install a Level 2 charger in their single-family home. **The median charger rebate for residential program participants with a single-family home is $600.**

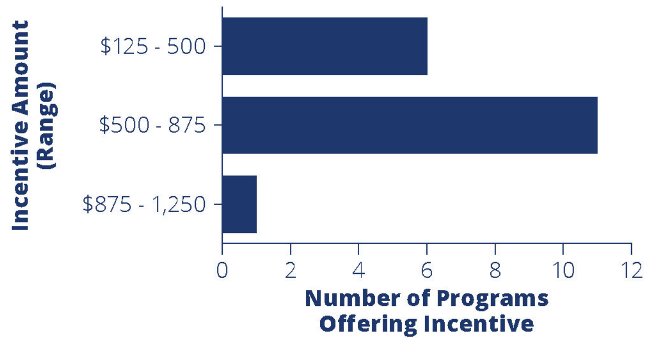
SEPA also assessed the rebates offered to Multi-Unit Dwellings (MUD) to help with the cost of Level 2 charger installation, which are summarized in Figure 7. The median rebate value is $4,000.

The Level 2 charger rebates offered to workplaces and public host sites are summarized in Figure 8 and Table 1, respectively.

The median charger rebate for workplace applications is $4,000 per port and the median charger rebate for public applications is $4,900 per port, which can help host sites offset the increased costs associated with commercial installation.

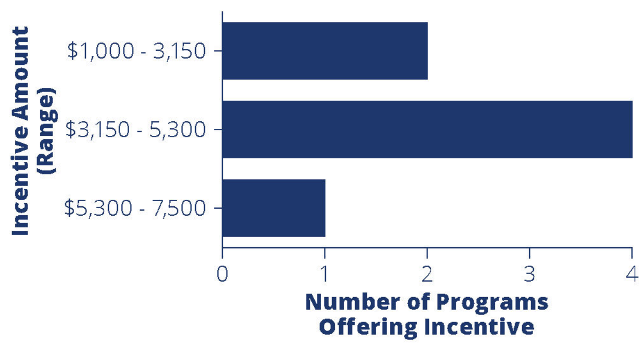
Figure 9 shows all Level 2 charger rebate incentives offered by active managed charging programs assessed within the sample. The rebate types, represented on the chart above from left to right, include those offered for the following applications: single-family homes, multi-unit dwellings, workplace/fleet, and public. Each dot on the graph represents a program that offers that size and type of rebate; the larger the dot, the more programs that offer that type and magnitude of rebate.

Figure 6. Level 2 Rebate Offerings for Residential Program Participants (Single-Family Homes)



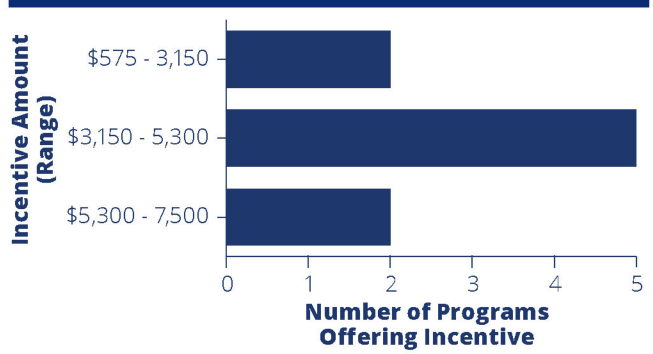
Source: Smart Electric Power Alliance, 2021.

Figure 7. Level 2 Rebate Offerings for Residential Program Participants (Multi-Unit Dwellings)



Source: Smart Electric Power Alliance, 2021.

Figure 8. Level 2 Rebate Offerings for Workplace/Fleet Program Participants



Source: Smart Electric Power Alliance, 2021.

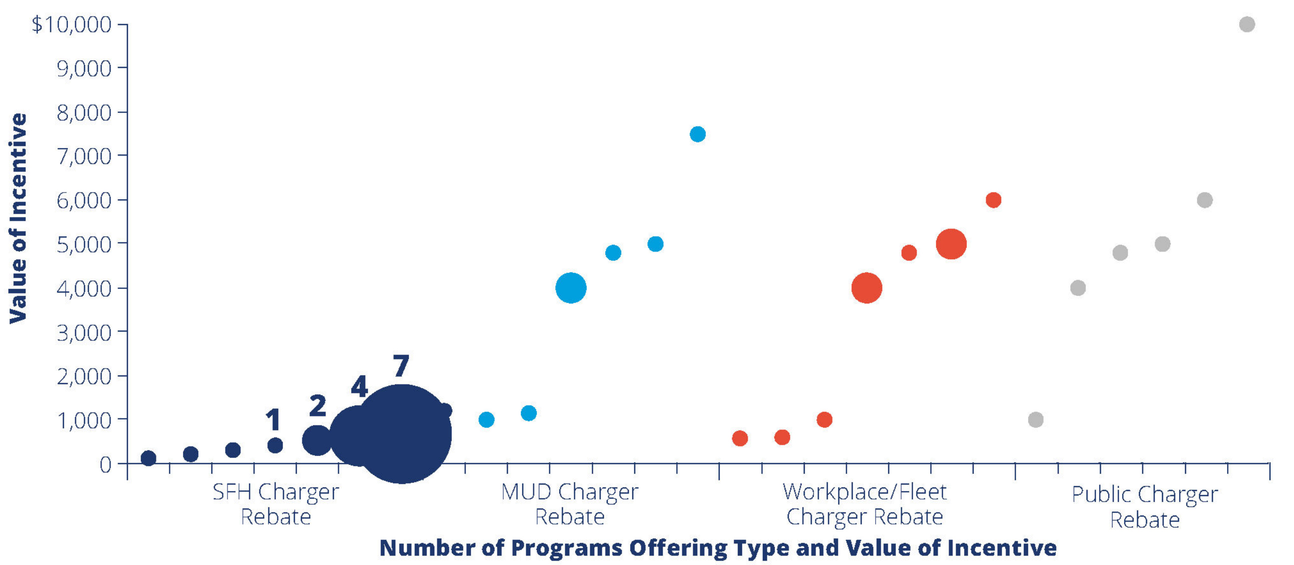
Managed Charging Incentive Design

Table 1. Level 2 Rebate Offerings for Public Program Participants

Utility	Program Name	Level 2 Rebate Per Port
Portland General Electric	Business EV Charging Pilot Program	$1,000
Los Angeles Department of Water and Power	Charge Up LA!	Up to $4,000 with $750 for each additional port
Southern California Edison	Charge Ready Program	$4,800
Consumers Energy	PowerMIDrive	$5,000
Pacific Power	EV Charging Station Grant Program	$6,000
American Electric Power	EV Charging Incentive Program	$10,000

Source: Smart Electric Power Alliance, 2021

Figure 9. Number of Programs Offering L2 Charger Rebates by Size and Customer Segment



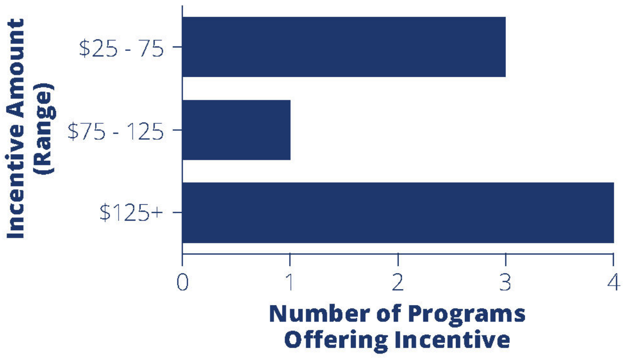
Source: Smart Electric Power Alliance, 2021.

Monetary Enrollment Incentive

A monetary enrollment incentive is a one-time offering to entice EV owners to enroll in a managed charging program and is distinct and separate from the EVSE charger rebate. Reducing upfront costs of EV ownership is important to customers, which is why an enrollment incentive is effective in reaching managed charging program size goals. In many programs, the EVSE rebate serves multiple purposes including to enable utility control, to incentivize program enrollment, and for data collection. All monetary enrollment incentives require some level of guaranteed participation; however, not all managed programs tie the charger rebate to mandatory program participation.

Of the programs SEPA assessed in our market research, 30% of programs (active and passive) offer an enrollment incentive, while 32% of active managed charging programs offer an enrollment incentive. The lowest enrollment incentive is $25,

Figure 10. Enrollment Incentive Offerings



Source: Smart Electric Power Alliance, 2021.

the median is $125, and the highest is $450. Offering incentives in the upper range requires the program to demonstrate or justify significant expected benefit or value.

Demand Response Event Participation Incentive

Some utilities choose to offer program participants the opportunity to participate in demand response events in exchange for a per-event incentive. Customers agree to give the utility the ability to throttle their charging during these demand response events, whether non-emergency or emergency events, in order to relieve grid stress. If the incentive is sufficiently large, utilities might find that they are able to make a significant difference in the load at a certain feeder, while only having to pay the higher incentive amount to a handful of customers. Utilities should consider applicable limits on the number of DR events they can trigger per year. They may need to provide customers with some type of limited opt-out provisions, and also determine whether the stress on the grid is significant enough to initiate the DR event. The number of DR events declared will be limited by the cost of awarding each customer to participate in each event.

Of the two (5%) active managed charging programs we assessed that offer this incentive type, one program offers a $5 incentive while the other offers a $20 incentive.

Instead of paying customers per DR event, programs might offer a charger rebate, or monthly and annual participation incentive in exchange for their guaranteed participation in several DR events.

Monthly or Annual Participation Incentives

Monthly and annual participation incentives are given to program participants to reward them for their participation and encourage continued participation in the program. What defines participation in a program is determined by the utility, and in active managed charging programs, it usually means that the participant has agreed to allow the utility to control charging a predetermined number of times per year through demand response events or to control charging continuously, whether through a networked charger or automaker telematics. The utility also has a choice in whether they reward customers with smaller sized participation incentives at the end of each month, or a larger sized participation incentive at the end of each year or season.

These types of incentives provide the utility with flexibility to increase or decrease the number of DR events they activate, since participation is rewarded at the end of a month or year rather than at the conclusion of each DR event. **Additionally, monthly and annual incentives are well-suited to continuous load control, if the utility prefers to use that managed charging method rather than isolated DR events.**

It is worth noting that implementing DR events as the method of load control places a higher cognitive burden on the program participant, as they are notified when their charging will be throttled and asked whether or not they would like to participate. Continuous managed charging is a more proactive way of managing the grid, while specific, infrequent DR events are more reactive. Continuous managed charging places a smaller cognitive burden on program participants because their charging is constantly being managed in the background, and is so unobtrusive that they might forget they are enrolled in the program.

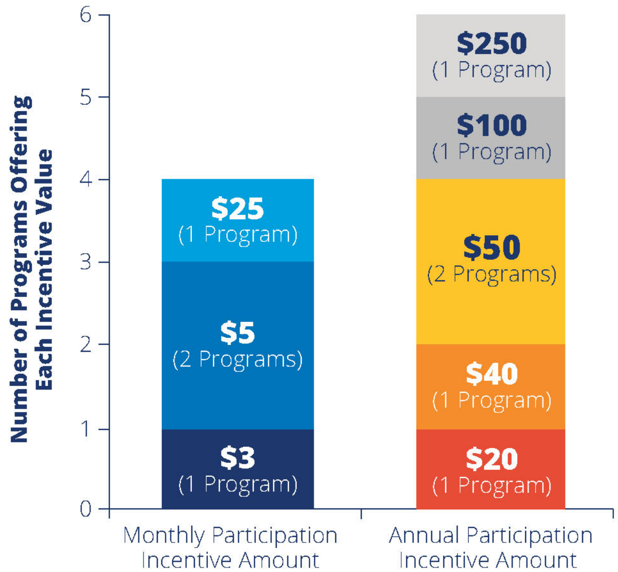
Because monthly and annual participation incentives are used to reward compliance with both DR events and continuous load control, they offer a powerful incentive option for utilities that want to control load through either Level 2 networked chargers or automaker telematics.

SEPA found that 40% of the active managed charging programs we assessed offer a monthly or annual incentive. The lowest monthly incentive is $3, and the highest is $25, as shown in Figure 11.[5]

5 It is important to note that two of the programs assessed offered participation incentives at the end of a season (five months) or every two months, so those incentive values were divided by the number of months or participation they were rewarding.

Managed Charging Incentive Design

Figure 11. Monthly (left) and Annual (right) Participation Incentive Offerings



*All programs assessed offer participation incentives each month, with the exception of two programs that offer incentives every two months or at the end of a season.

Source: Smart Electric Power Alliance, 2021.

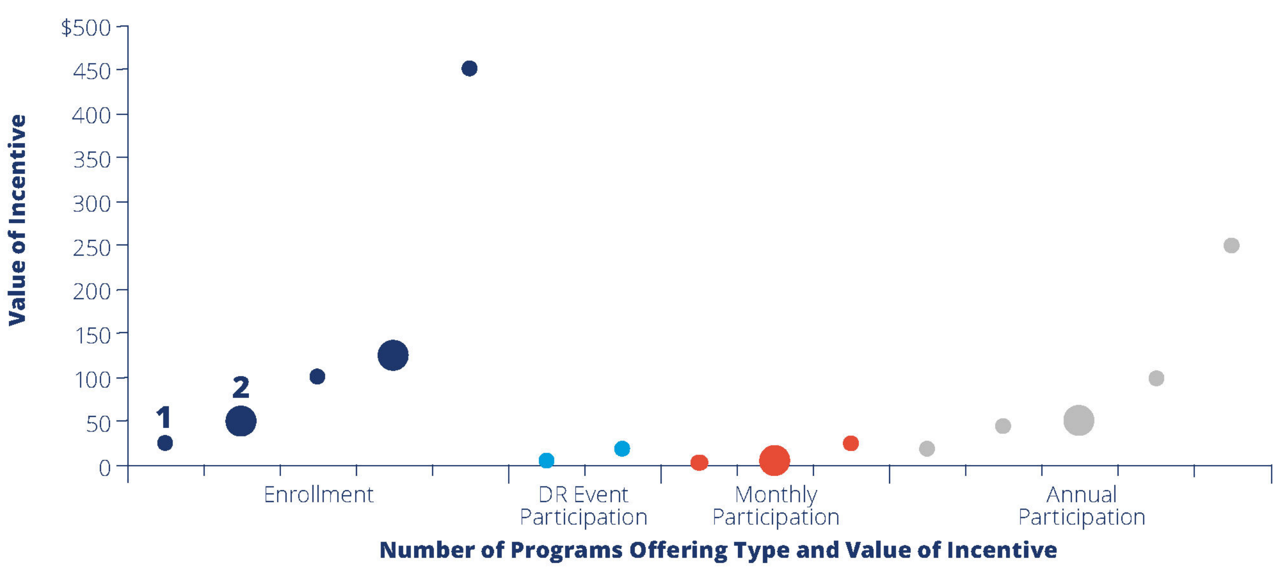
Annual incentive values range from $20 to $250, as depicted in Figure 11. The median annual incentive value is $50.

SEPA evaluated the sizes of enrollment and participation incentives offered by active managed charging programs assessed within the sample. The incentives types, represented in Figure 12 from left to right, include: enrollment, DR event participation, monthly participation, and annual participation. Each dot on the graph represents a program that offers that size and type of incentive; the larger the dot, the more programs that offer that type and magnitude of incentive.

Additional Incentives

The incentives reviewed above do not capture all variations of incentives offered in the market. Some programs offer their participants extra rewards when they refer another person to enroll in the program, or when participants take both an entry and exit survey. These incentives were less common in the sample of managed charging programs SEPA assessed, though utilities may find it useful to assess their needs and design creative incentives to reward customers for helping meet those needs.

Figure 12. Number of Programs Offering Each Type and Size of Incentive



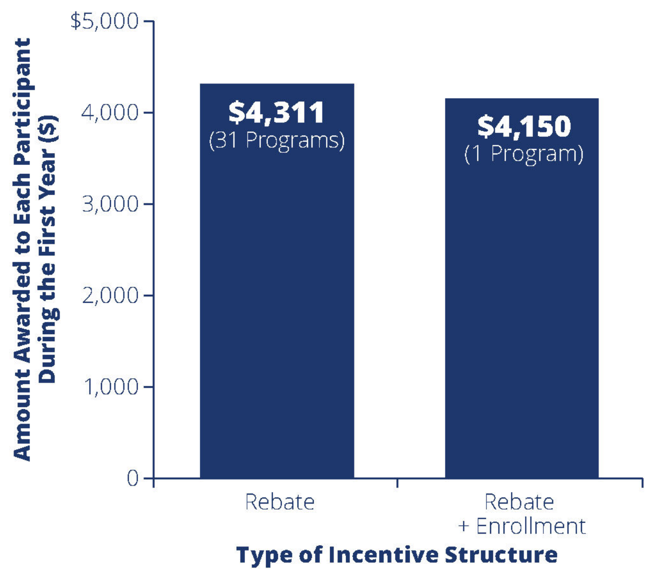
Source: Smart Electric Power Alliance, 2021.

Program Incentives Structures

SEPA categorized each of the forty managed charging programs in the sample by incentive structure to determine which incentive structure designs were most prevalent. Out of the forty programs, nine (22.5%) offered charger rebates only. Ten (25%) of the programs offered charger rebates along with an EV-specific TOU rate. Other incentive structures include an enrollment incentive and annual incentive (offered by 7.5% of programs assessed) and an EV purchase incentive, charger rebate, and EV-specific TOU rate (offered by 7.5% of programs assessed). There were several more incentive structures that the other programs offered. Utilities may find it useful to use these common incentive structures as guidance and add incentives as they see fit and their budget permits.

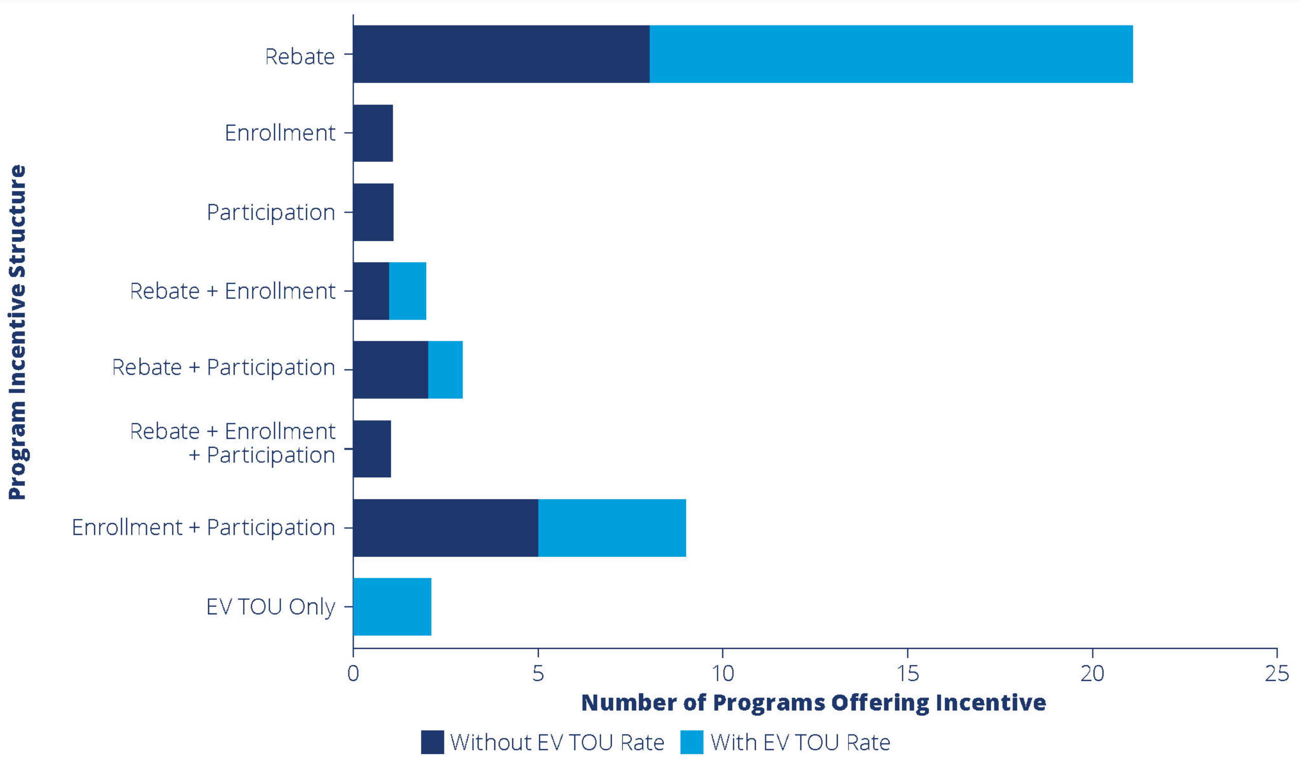
After categorizing each program in the sample by incentive structure, SEPA then calculated the average amount awarded to each participant during the first year of enrollment in the program. Those calculations are represented in Figures 13, 14 and 15. Programs that solely offer a charger rebate provide more to their participants during the first year, compared to other programs that also award participants with some sort of enrollment or participation incentive.

Figure 13. Average Total Incentive Amount Provided to Each Commercial Program Host Site During the First Year, Based on Incentive Structure



Source: Smart Electric Power Alliance, 2021.

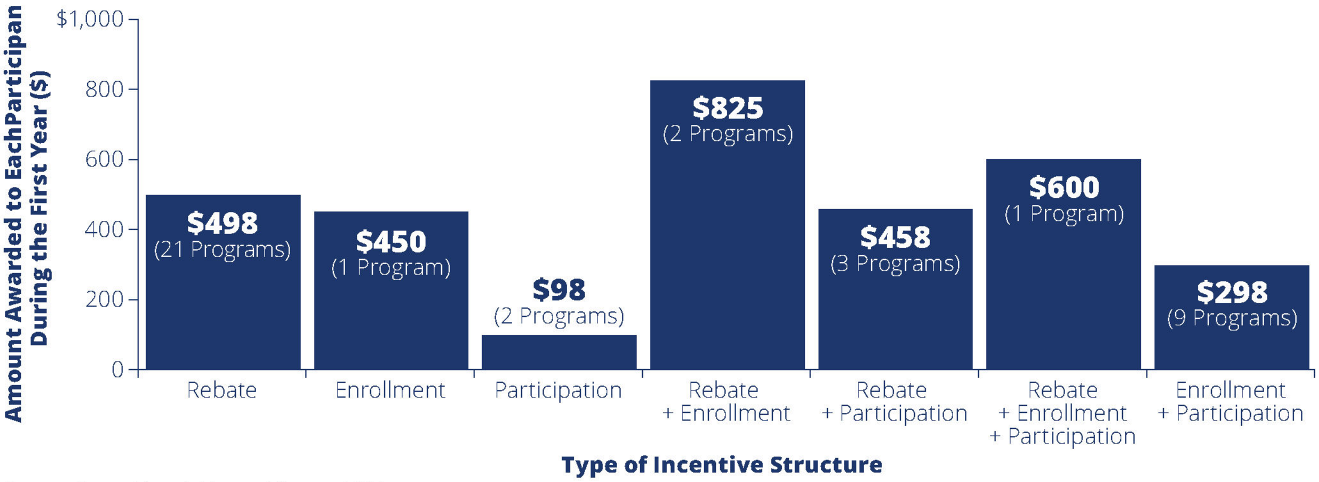
Figure 14. All Programs Categorized by Incentive Structure



Source: Smart Electric Power Alliance, 2021.

Managed Charging Incentive Design

Figure 15. Average Total Incentive Amount Provided to Each Residential Program Participant During the First Year, Based on Incentive Structure



Source: Smart Electric Power Alliance, 2021.

Program Size and Customer Segment Approaches

Utilities will need to determine the size of their managed charging program, and methods to identify customers as potential program participants. The size of a managed charging pilot is typically determined by the approved budget. As managed charging programs evolve from pilots or capped programs to programs available to all customers, their program size will be determined by the number of customers willing to participate. To determine which customers should be targeted in marketing efforts, utilities use propensity modeling to predict which of their customers own EVs, or are likely to purchase an EV based on known customer characteristics. Another avenue to identify prospective customers is through a self-registration form on the utility website or gathering EV owner information from a third party. Customers that have previously participated in other utility energy efficiency programs might also be identified as potential program participants.

To identify potential MUD, workplace, or public charging sites, a utility might connect with multi-family property owner groups, real estate trade groups, or a commercial real estate agent that directs the utility to the property manager. Properties that already envision EV charging as an amenity in their developments are ideal participants. Account executives at the utility can assist the potential participant identification effort by contacting major customers with whom they have a pre-existing relationship, such as city governments, schools, hotels, commercial customers, and industrial customers.

Marketing & Recruitment

After identifying potential participants, the utility should market their program directly to them through ride and drive events, webinars, and educational materials. In workplace and public charging applications, it is helpful to ask that the workplace or building managers distribute marketing materials to people within the building to solicit participation. When developing marketing messages for workplaces and public charging programs, it is important to consider that the business owner may value their financial return on investment for participating in the charging program more than the environmental benefits.

Utilities should use dealer partnerships, targeted emails, events, social media groups, enthusiast groups, and community engagement leaders to promote their managed charging program. For example, a utility could host a Ride & Drive event at a local EV dealership to drive customer interest. An ideal marketing approach would serve the purpose of recruiting participants as well as creating awareness for those customers who are not EV owners. A marketing approach that targets EV owners and also reaches a broader audience is optimal because it is inclusive of all consumers, regardless of whether they are EV owners, and customers receive some level of education about managed charging and EV ownership.

Program Design In Action: BGE & PHI

In the development of their EV active managed charging programs, BGE and PHI worked through the six-step process described above. This section describes the considerations for program characteristic development that are unique to BGE and PHI, and ultimately provides an example of the application of the process to utility program development.

Step One: Identify Charging Behavior

Following the first step of the six-step program design process, the BGE and PHI teams discussed their customers' current unmanaged charging behavior, and identified a goal for optimized charging behavior in single-family residential, public charging, and fleet charging applications. Unmanaged charging is initiated immediately upon EV connection, regardless of the grid conditions and often without a specific need from the driver for the session to start immediately. Unmanaged charging sessions are assumed to follow the behavior described below:

- **Single-Family Home:** At the single-family home, unmanaged charging typically begins upon arrival home from work between the hours of 6pm - 9pm with an expected disconnect the next morning; vehicles are typically connected for at least 12 hours.
- **Public DCFC:** Customers use public DC fast charging for a variety of reasons from convenience to necessity. Convenience charging, also known as opportunistic charging, is a form of charging where the driver is not making a dedicated trip to use the charger. Opportunistic charging has the greatest potential for managed charging. Necessity-based charging occurs when the driver makes a dedicated trip to use a public charger either because they do not have access to other forms of charging or require a fast recharge. Necessity-based charging has the least potential for managed charging.
- **Fleet:** Vehicles are charged as required to meet business needs. Charging is likely to happen overnight when vehicles are not in use between 6pm - 8am; vehicles are typically connected for 12 hours at a time.

Step Two: Identify Program Objective

Next, the teams identified the objectives of the programs and what tools the utilities' have available to achieve those objectives. The residential programs' objectives considered technical feasibility, customer behavior, and managed charging benefits:

- **Technical Objective:** To demonstrate the technical feasibility of various aspects of managed charging to support a larger deployment of managed charging. The feasibility of the program will be assessed by the performance of cyber security, communications, distribution level orchestration, and other measures.
- **Customer Behavior Objective:** To demonstrate customers willingness to give managed charging control to the utility and to understand customer responsiveness to continuous and event-based managed charging incentives.
- **Managed Charging Impacts Objective:** To shift EV loads from times and locations of high distribution level congestions to times and locations with excess distribution capacity.

Step Three: Identify Regulatory Considerations

The utilities operate in the state of Maryland and are regulated by the Maryland Public Service Commission. After defining the objectives of the managed charging programs, BGE and PHI reflected on the MPSC's recent decision-making to identify reasons previously proposed programs were approved or denied. That regulatory history helped the teams identify the bounds of experimentation for their program, in order to earn MPSC approval. BGE and PHI both have EV TOU smart charge rates and smart thermostat demand response programs, but not EV active managed charging programs. BGE and PHI's program design also considered the potential for the MPSC to favor "opt-in" programs over "opt-out" programs. Additionally, the regulator may not favor managed charging programs that are only compatible with a specific make of vehicle.

Step Four: Create Incentive Design

BGE and PHI next created the incentive structure of their program to best meet their program objectives and stay within their budget. They designed the residential incentive to:

- Encourage enrollment via an EVSE charger rebate or cash incentive.
- Encourage participation in continuous management via a predetermined annual incentive that is paid out monthly, based on participants meeting a minimum participation threshold.
- Encourage participation in DR events via unique messaging and additional event-based compensation.
- Ensure a positive customer experience by providing a simplified active management experience that reduces the customer's cognitive burden.

Managed Charging Incentive Design

The incentives included in the program were explicitly designed to test a customer's willingness to not opt out of specific demand response events when the grid is excessively strained.

Step Five: Identify Program Size & Customer Segment Approaches

The utilities agreed on a program size of 1000 - 3000 participants to ensure a program that is large enough to have an appreciable impact on system performance and to ensure a sufficient number of vehicles are connected and charging during managed charging events. A majority of the participants would enroll in the residential program, and it is expected that the remaining participants would be distributed across the other program types. The utilities expect to provide fleet customers about 200 L2 chargers at no cost to the customer.

Step Six: Build Marketing & Recruitment Strategy

BGE and PHI are still formulating their marketing and recruitment strategy and plans. However, they have decided to use a self-registration portal on their websites to recruit individual and fleet EV owners in their service territories. Additionally, BGE and PHI agreed that all marketing messages will use industry standard terminology. To keep customers engaged throughout the program, the utilities plan to provide ongoing education, which will include sending customers occasional messages about the program and reminders about how to participate.

BGE and PHI plan to recruit fleet customers by offering a free charging assessment, through which the utilities identify the customer's charging needs, build a custom charging schedule for them, and reward them with incentives for following the charging schedule. The charging schedule will give the program the flexibility to help the distribution system, depending on grid conditions at specific feeders. Utilities can market the demand charge savings from this method. Additionally, this method benefits BGE and PHI because it balances fleet load with grid conditions instead of forcing a local infrastructure upgrade at the site.

While BGE and PHI have yet to finalize their program plans, their work highlights the usefulness of the six-step process, especially in the design of a new program. The process serves as a guide to help utilities evaluate the charging landscape within their service territories, assess current regulatory conditions, and design a viable new program.

3.0 Program Recommendations

Depending on the use case, utilities may develop different incentive structures and load management strategies for their managed charging program. While managed charging programs can differ significantly from one utility to another, we have identified several evidence-based best practices that every utility can use in the development of their own program.

Build the incentive structure for explicitly defined objectives and be intentional about which incentive types are paired together. Utilities may use charger rebates to encourage EV adoption, collect data on EV ownership, encourage program participation, or provide the technical requirements for the managed charging program. Cash or cash equivalent incentives are typically effective in initial recruitment, rewarding per event participation, or encouraging retention beyond the first year of the program. An individual incentive can achieve multiple objectives but multiple incentives should not be offered to address a single objective. For example, a program utilizing a charger rebate to enable (technically) participation can also use the rebate as an enrollment bonus and should avoid additional enrollment rebates since that objective is already addressed via the rebate.

Use the minimum number of different incentive types required to achieve desired outcomes, and aim for simplicity. Programs with two or more incentive types increase the level of complexity and create additional cognitive burden on the customer and potential confusion, which can negatively impact recruitment and retention. If a single incentive can accomplish all program objectives, then no additional incentives are needed.

Be thoughtful about program customer segmentation and evaluate the level of technical and behavioral flexibility in each segment. Residential charging, workplace charging, and public charging all represent different levels of potential load flexibility. Home charging likely has the longest potential connect time from after work through the next morning (roughly 12-14 hours), and represents the greatest potential for shifting load. Workplace charging is slightly shorter duration and typically occurs during the day (roughly 8 hours). Public charging offers the lowest level of flexibility, especially DC fast charging which typically requires the EV owner to make a dedicated trip and is expected to be completed in the shortest possible time. Programs should consider the typical connect time and the driver's willingness to use managed charging for each charging segment and design incentive sizes accordingly.

Design incentive sizes and structure considering large scale programs, and consider the feasibility of expanding a pilot program to cover all customers. Many programs are designed initially to test customers' willingness to participate and to quantify the effectiveness of managed charging incentives. However, utilities should design programs with incentive amounts that are likely to be cost effective and feasible to distribute when rolled out to all EV owners and eventually all residential customers. Utilities should avoid piloting incentives that are expected to be too generous to deploy at a large scale.

Customer education and awareness that articulates the importance of managed charging must begin well before utilities implement programs at a large scale, and should address all customers, not only EV owners.

Future EV owners have not yet developed charging habits and will default to what is most convenient for them, rather than what is good for the grid. Creating a common understanding that when and where customers charge EVs impacts charging cost can help promote and recruit for managed charging programs.

Most EV drivers are seeking a 'set it and forget it' experience where they simply connect immediately upon parking and expect a minimum battery capacity when they disconnect. In many cases, the EV owner does not care or even think about how their vehicle is charged. Utilities should market programs as providing customers charging needs at the lowest cost possible, and not focus on the idea that the charging is delayed or shifted.

Be cautious of over subsidizing home chargers or offering an excessively high enrollment incentive; focus first on marketing and education. Although several programs assessed as part of SEPA's market research have offered steeply discounted or free Level 2 chargers, utilities noted during interviews that this magnitude of incentive can be cost prohibitive for larger pilots and may not be necessary to achieve desired outcomes.

Leveraging existing connections with EVSE providers will support utilities in their education effort. Utilities should share marketing messages through at least four different marketing channels to effectively reach all potential program participants.[6] Participants will be more likely to enroll in the program if it offers incentives that keep up-front costs of participation low, a seamless transition from unmanaged to optimized charging, and flexibility with regard to participation, technology, and incentive opportunities. Additionally, a user-friendly interface available on both mobile and desktop platforms will greatly improve the customer experience as they interact with the program.

4.0 Conclusion

When designing a managed charging program for the first time, utilities will benefit from building extra time into their schedule for customer enrollment, negotiations, and paperwork, which can all require unpredictable amounts of time to execute effectively. Additionally, a utility will benefit from following a development process that segments the program design into several steps, as outlined in section one of this report. Utilities can use market research as a guide to inspire program design at each step, and then pursue additional customization of the program to best suit their service territory. When designing the incentive structure of the program, it is important that a utility consider the objective and desired outcomes, and understand how each type of incentive can deliver those outcomes. Rebates and incentives can serve many different purposes.

SEPA derived the market research and best practices included in this report from a wide variety of managed charging programs. The creation of a program that follows the research-based six-step process for program design strategies highlighted in this paper while allowing for customization to the utility's service territory will likely enjoy the most success.

6 SEPA, Residential Electric Vehicle Rates that Work: Attributes that Increase Enrollment (2019) p. 26.

5.0 Appendix

Table 2. Utility Managed Charging Programs Assessed in Market Research	
Utility	**Program**
American Electric Power	Kyte Works EV Home Charging Program
American Electric Power	EV Charging Incentive Program
Austin Energy	Plug-In Austin Electric Vehicles
Avista	Commercial Electric Vehicle Charging Equipment Program
Avista	Residential Electric Vehicle Charging Equipment Program
Barron Electric Cooperative	Electric Vehicle Charging Station: 2021 Energy Efficiency Rebate
Baltimore Gas and Electric	EVsmart
Consolidated Edison	SmartCharge
Consumers Energy	PowerMIDrive
Delaware Electric Cooperative	Beat the Peak
Delmarva Power	EVsmart
Dominion Energy	EV Charger Rewards
DTE Energy	Charging Forward
Eversource	EV Home Charger Demand Response
Green Mountain Power	eCharger Program
Hawaiian Electric Company	Smart Charge Hawaii
Los Angeles Department of Water and Power	Charge Up LA!
Marin Clean Energy	MCEv

Table 2. Utility Managed Charging Programs Assessed in Market Research

Utility	Program
Massachusetts Municipal Wholesale	Scheduled Charging Program
National Grid	Connected Solutions
New York State Electric and Gas Corporation	Residential EV TOU Rate
Orange & Rockland	Charge Smart Program
Pacific Power	EV Charging Station Grant Program
Pepco	EVsmart
Pacific Gas and Electric Company	emPower EV
Pacific Gas and Electric Company	EV Charge Network (Load Management Plan)
Portland General Electric	Business EV Charging Pilot Program
Portland General Electric	Residential EV Charging Pilot Program
Platte River Power Authority	Smart Electric Vehicle Charging Study
Rocky Mountain Power	EV Charging Station Grant and Rebate Program
Salt River Project	Plug In and Save EV Rebate
Salt River Project	SmartCharge Arizona
San Diego Gas and Electric	Power Your Drive
Snohomish County Public Utility District	SmartCharge
Sonoma Clean Power	GridSavvy
Southern California Edison	Charge Ready Program
Southern California Edison	Honda SmartCharge Program
Xcel Energy	Charging Perks

Source: Smart Electric Power Alliance, 2021.

Smart Electric Power Alliance

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Assessing the value of electric vehicle managed charging: a review of methodologies and results

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Abstract
Driven by technological progress and growing global attention for sustainability, the adoption of electric vehicles (EVs) is on the rise. Large-scale EV adoption would both disrupt the transportation sector and lead to far-reaching consequences for energy and electricity systems, including new opportunities for significant load growth. Unmanaged EV charging can stress existing grid infrastructure, possibly leading to operational, reliability, and planning challenges both at the bulk and distribution levels. However, effective management of EV charging can resolve these challenges and provide additional value. The demand-side flexibility provided by managed EV charging offers significant potential benefits for the grid over multiple timescales and applications. Managed charging can support power system planning and operations during normal and extreme conditions, benefitting EV owners and other electricity consumers. However, the costs of enabling these services must be weighed against the benefits they provide. We summarize the benefits of managed EV charging, provide an overview of the landscape of existing implementations and costs of managed charging in the United States, critically review the state of the art of methodologies in analysis/modeling studies, and quantify the cost and benefits of managed charging as reported in the reviewed studies. Finally, we distill several key insights outlining the factors affecting the value of managed EV charging and identify critical gaps and remaining challenges to fully realize effective EV-grid integration.

Keywords
Electric vehicle, managed charging, smart charging, V1G, V2G, demand response, flexible loads, bulk power system, distribution system, power system modeling.

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1 Introduction

The adoption of electric vehicles (EVs) has increased rapidly over the last few years, thanks to major cost reductions and performance improvements in battery and electric drive technologies and a wide range of supportive measures including charging infrastructure buildout, incentives and other policies, and support or pledges from local communities and various stakeholders for reducing transportation emissions.[1,2] EVs offer demand growth opportunity for the electric industry (increase in retail electricity sales) after decades of stagnation in the United States and other regions.[3,4] Although the rapid rise in EV adoption can cause possible integration challenges, EV loads are highly flexible and offer unique opportunities for synergistic improvement of the efficiency and economics of electromobility and electric power systems as the two sectors become more integrated.

A vast body of literature has examined the possible impact of adding new EV loads to existing power systems, showing that if unmanaged or uncoordinated (assuming each EV charges as soon as it is plugged in without any consideration of electricity supply and grid conditions), EV charging may exacerbate net-load variability, impacting resource adequacy and attendant long-term planning, as well as contributing to bulk-level (generation and transmission) operational challenges.[4–8] However, based on historical growth rates, sufficient energy generation and generation capacity is expected to be available to support high EV market growth in the United States,[9] and the bulk power system is expected to be able to support widespread EV adoption. Because EV charging usually takes place at distribution systems (DSs), DS planners and operators could face challenges in effectively integrating EVs.[10–13] However, the impact of EVs on DSs is varied, given high heterogeneity in DS characteristics, and also dependent on the magnitude, timing, and location of charging events.[11,14–18] The impact of EVs on DSs might become more critical with high-power charging and concentration of EV loads, such as clusters of residential charging[10] and possibly depots for commercial vehicle charging. Proper planning and consideration of EV loads can likely resolve integration issues but might require expensive and time-consuming upgrades.[19]

Besides increasing loads, the demand-side flexibility provided by managed EV charging potentially offers significant benefits for the grid over multiple timescales and applications, supporting power system planning and operations during normal and extreme conditions and benefitting EV owners and other electricity consumers alike. Managed EV charging is a potential alternative to conventional power system solutions, such as peaking generators or stationary energy storage, and can broadly serve as a flexible resource.[20] In 1997, Kempton and Letendre[21] offered the first description of the concept of EVs providing grid services, either in the form of smart charging or bidirectional vehicle-to-grid (V2G) services. Since then, several studies have explored the value of managed EV charging as the prospect for EV adoption has increased and the transformation of the power system has highlighted the value of flexibility and demand-side resources. However, the value managed charging can provide will depend on the scale at which EVs are deployed, the grid policy and regulatory framework, and enablement costs, as well as how vehicles are used and charged (determining the flexibility in charging loads). Muratori *et al.*[1] summarize a range of future projections of EV adoption in the U.S. light-duty market (see Figure 1 in the cited article), showing multiple studies projecting rapid EV uptake and long-term opportunity for large-scale EV adoption. The potential for rapid growth in EV adoption and ultimately widespread success highlights the need for timely research on the value proposition for vehicle-grid integration and the growing potential benefits of managed charging, especially under scenarios with inadequate grid resources and high system stress.

EV-grid synergies are driven by two key factors: the value of demand-side flexibility in electricity systems and the ability of EVs to charge flexibly. Demand-side flexibility, including loads that can be shifted over time, are valuable for power system planning and operations since they reduce peak loads on the electricity supply side, reducing costs and increasing system efficiency and reliability. This is becoming more important as electric power systems are undergoing profound changes: Variable renewables are displacing conventional generation sources, distributed generation is disrupting utility business models, and the traditional system based on the premise that generation is dispatched to match an inelastic demand is evolving to create a system with greater participation in power system planning and operations from traditionally passive consumers.[22]

In addition, EV loads can be flexible and may be shifted in time and space without impacting the ability of EVs to accomplish their primary goal: providing mobility services. Most personal vehicles are driven for a small proportion of the day.[21,23] For example, an analysis of the 2017 National Household Travel Survey data[24] shows that personal light-duty vehicles in the United States are parked, on average, 95.8% of the time. Commercial vehicles are sometimes driven more, but several medium- and heavy-duty applications still offer ample charging flexibility.[19] If EVs are grid-connected for extensive periods (i.e., when a vehicle is not driven and a charging plug is available), they can provide demand-side flexibility in the form of managed charging or bidirectional power transfer to/from the grid and/or other loads.[25]

While managed EV charging can benefit the operation and planning of the power system across a broad range of spatiotemporal needs, it also requires targeted programs and compensating EV users for providing flexibility. Therefore, the costs of enabling managed EV charging must be weighed against the benefits provided. Cost-effectiveness assessments should adhere to basic principles, such as treating benefits and costs symmetrically, ensuring impacts are incremental to proper counterfactuals, and avoiding double counting.[26] As such, estimating managed EV charging costs and benefits is difficult, given the nascent markets for demand-side resources and different perspectives among stakeholders.

This paper provides a critical and comprehensive review of the value of EV managed charging, including context for the value of demand-side resources in rapidly evolving power systems; an overview of EV managed charging strategies, including current demand response programs focusing on managed EV charging in the United States, implementation options and mechanisms, and enablement costs; and a summary of methods, assumptions, and results in modeling and analysis studies and cost-benefit analyses. Finally, we identify critical gaps and remaining challenges, indicating research opportunities to properly assess the value of EV managed charging and fully realize the value of EV-grid integration.

2 Value of demand-side flexibility in the evolving power system

All power systems are designed and operated to match electricity supply and demand at all timescales and in all places, and utilities generally deploy a mix of generator types to minimize overall cost while maintaining adequate flexibility and reliability.[27] Operating the power system involves committing and dispatching generators to meet the variability of both supply and demand, while also maintaining adequate operating reserves for response to forecast uncertainty and contingencies.[28,29] However, with increasing deployment of variable generation (VG) (e.g., wind and solar photovoltaics [PV]) and associated increase in net load variability and uncertainty, power systems require greater system flexibility, including the need for greater ramping and operating reserves.[30–32] There is also a greater need to address the diurnal and sometimes seasonal mismatch between demand and VG supply to ensure sufficient capacity is available during net peak demand periods and avoid excessive generation during periods of low demand.[31,33–35]

While there has been a large focus on supply-side options for increasing grid flexibility, including energy storage, demand-side resources are another valuable and cost-effective source of power system flexibility that can support power system planning and operation.[36–43] It is sometimes more efficient to have demand match supply, as opposed to the more traditional approach of making supply match demand. There are numerous historical examples of demand response (DR) programs and market participation,[44,45] with DR applications starting in Europe as early as the 1950s.[46–48] Traditional DR provides load reductions at peak and other critical times, essentially providing a capacity service with additional infrequent but high-value energy benefits.[49]

There are numerous existing examples of DR programs in practice today that provide bulk power system services, including large commercial and industrial curtailable or interruptible load programs; peak shedding direct load control programs for air conditioners, water heaters, or pool pumps; critical peak pricing or critical peak rebates[44,49]; and energy shifting with time-of-use (TOU) pricing or direct load control programs.[50–53] More recently, DR has been used to provide operating reserves, especially in wholesale markets,[44] and to mitigate localized congestion, including at the transmission level.[54,55]

In addition to bulk system benefits, DR can support the distribution system, which delivers power to final users.[56] Alone or in combination with other resources, DR can alleviate localized congestion and defer other upgrades.[54,57] DR and other distributed energy resources (DERs) that interface the grid through power electronics (e.g., PV systems, battery energy storage, and EV chargers) can also provide voltage and frequency support[58–60] and supplement hardware-based techniques (e.g., voltage regulators, capacitors) that manage distribution system voltage and losses on an ongoing basis.[56]

Managed EV charging could provide a large and valuable source of system flexibility, with the potential to help address the challenges of balancing net load on both bulk power and distribution systems across multiple timescales (Fig. 1). Like traditional DR that addresses system peaks, managed EV charging can reduce systemwide or localized peak demand, thereby offsetting generation, transmission, or distribution capacity that might otherwise be needed at higher EV penetration levels. In particular, EV managed charging can provide a variety of services, including energy shifting, operating reserves, and voltage and frequency support, and offers opportunities to EV users to reduce charging costs while also lowering electricity costs for all.[61,62] Scheduling charging across timeframes of up to 1 week, sometimes providing power from EVs to the grid or other loads, or pairing EV managed charging with other DERs, would increase value over long timescales (but in turn limit charging flexibility) and potentially mitigate long outages associated with extreme events.

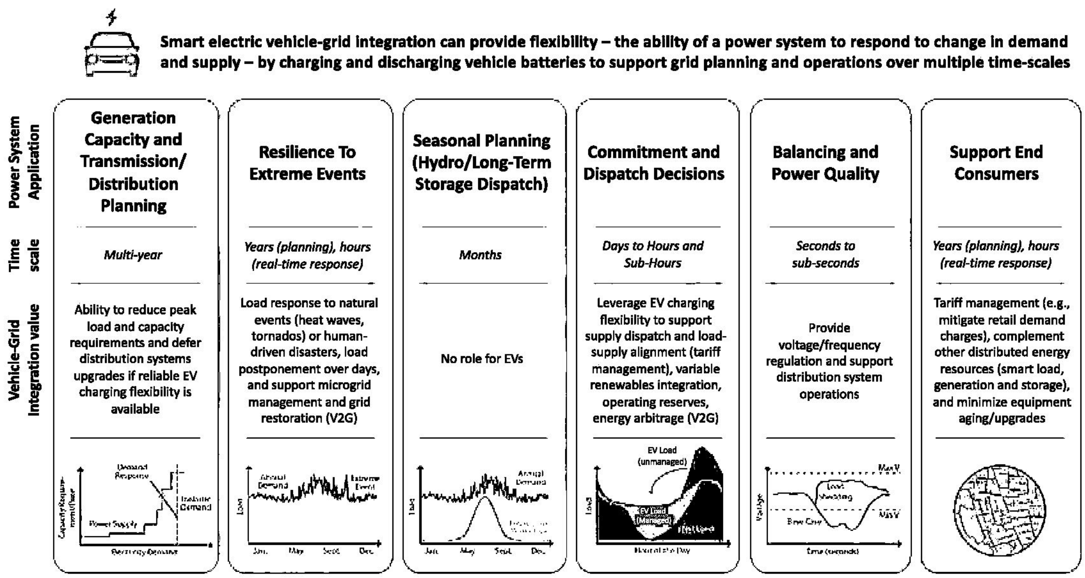

Fig. 1 Managed electric vehicle charging has the potential to support power system operations during normal and extreme conditions and benefit EV owners and non-owners alike.[1]

The value of demand-side flexibility depends on the value of the service provided, the cost of enabling DR, and the analogous costs for alternative resources, especially those of the most expensive unit, which sets price in least-cost planning and operational practices. The costs of enabling demand-side resources to provide grid services (e.g., new metering and control infrastructure costs; customer-side transaction costs, inconvenience, or foregone business; and utility program administration and marketing costs) have been catalogued and sometimes quantitatively estimated in various reports[63–65] (see Section 3.2 for EV-specific enablement costs). Capacity and energy services, which provide the megawatts and megawatt-hours to meet demand, are collectively the largest and most valuable electricity markets.[66,67] Enabling peak load reductions or energy shifting can be relatively low-cost, whereas enabling provision of ancillary services is often more costly due to higher communication and control requirements, and typically subject to stricter performance-based regulations (see Table 2 for a summary of ancillary or essential reliability services).[68] Because ancillary services represent a small percent of the total costs of operating the power system and the market opportunity is limited, this is a less promising but potentially complementary source of demand-side flexibility value.[66,67] On a practical level, the net costs of demand-side flexibility may be reduced by co-benefits.[68,69] On the other side of the ledger, grid service value may be reduced if the combined effects of retail tariffs (e.g., demand charges, time-of-use rates, or PV compensation policies) and DR programs are not aligned with bulk (e.g., capacity, energy, ancillary services) or more localized (e.g., distribution reinforcement deferral/avoidance, backup power, or local resiliency) grid needs.[66,70]

EV managed charging should be considered in the context of alternatives to provide equivalent services. For example, based on current DR deployment levels and recent studies,[45,68,71] some forms of DR are cost-effective alternatives to traditional peaking resources such as combustion turbines. In the future, lithium-ion batteries may define the competitive landscape for peaking resources if current trends continue.[72,73] If that is the case, managed charging can be competitive if charging infrastructure buildout, retail tariffs, and DR programs to compensate EV users (while satisfying users' mobility requirements) can be designed to provide grid services from managed charging at a lower cost than building and operating stand-alone stationary battery energy storage.

3 EV managed charging

EVs can be charged in a multitude of ways depending on vehicle characteristics, user preferences, trip requirements, infrastructure availability, and other factors. Unmanaged (or uncoordinated/uncontrolled) charging assumes each EV charges as soon as plugged in without any consideration of electricity supply (i.e., no charge management: park, plug in, and charge). Most studies postulate an "unmanaged" charging scenario where the grid is stressed by many EV drivers coming home from work and plugging in at roughly the same time, which happens to be coincident with daily peak load. With managed charging, EV charging is controlled considering electricity supply, within the constraints of the EV user's mobility needs. Managed charging, also referred to as "smart" or "coordinated" charging, most often occurs unidirectionally (V1G). This often involves shifting the EV charging times based on electricity pricing or other incentive signals. More advanced forms of managed or "smart" charging could include changes to charging locations on top of timing in response to dynamic grid signals or utilize inputs from the EV owner and the grid to develop optimal charging to meet mobility needs and support the grid. Managed charging can also occur bidirectionally between vehicles and the grid (V2G) or other loads (V2X) e.g., buildings turning EVs into temporary electricity suppliers to provide additional local benefits and improve resiliency (e.g., power appliances during power outages).

Managed charging of electric vehicles can be differentiated by (1) how charging is controlled (passive or active) and (2) the direction of electricity flow (unidirectional or bidirectional), as shown in Table 1. Managed charging relies upon signals between a utility and an EV user (or a third party, which in turn interacts with the EV user) to control charging events and can be used for measurement and verification (M&V) of the associated response. Under passive managed charging, the EV owner responds to prices or other signals to alter charging behavior, which could be accomplished automatically (e.g., EV owner could set a timer for charging) or manually (e.g., EV owner unplugs the vehicle). Passive managed charging has the added advantage that EV-specific M&V is typically not required and leverages other metering systems. Under active load control, the charger or vehicle responds directly to a signal from a utility or a third party (e.g., direct load control), or autonomously acts upon local conditions (e.g., under-frequency relay or power factor correction). However, EV owners still retain some level of control (e.g., an option to opt out of a managed charging event), blurring the distinction between active and passive controls. Active managed charging may or may not require dedicated M&V; even when required, M&V may be accomplished ex post rather than in real time. Technology requirements for managed charging vary depending on the implementation approach, which grid service is being provided or targeted, and availability of enabling technologies such as EV onboard communications and controls, smart metering, and elements of the smart grid.

Table 1 summarizes the different implementation strategies considered, comparing the potential for grid services; the requirements for communications and controls, measurement, verifications, and settlement; and additional key differentiators. For example, active load control may provide a wider range of grid services; however, it requires increasingly complex communication and control technology.

From a load flexibility perspective, there are trade-offs between different charging solutions. En-route charging, for example, involves a forced stop to charge an EV, usually at high power to minimize dwell time, limiting the opportunities for managed charging. The higher charging power requirements at en-route charging stations (usually DC fast charging) can, on the other hand, adversely impact the operation of power systems, including in terms of asset overloading, higher ramping requirements, and reduced power quality.[74] These challenges call for careful consideration of the techno-economic and infrastructure challenges attributed to placement and operation of high-powered fast charging stations, including coupled energy storage to decouple charging behavior from grid loads.[74,75] Opportunity charging,[76] on the other hand, leverages times during which a vehicle would be parked anyway (e.g., residential overnight charging) to provide Level 1 or Level 2 charging, and offers more flexibility. The higher the charging power (within opportunity charging), the faster and potentially more flexible the charging event can be in terms of time postponement, but higher peak loads are introduced. Vehicle charging can also occur dynamically while driving, via catenary or wireless charging, which allows for minimal flexibility. There are major technology and infrastructure barriers to implement dynamic charging, but it could eliminate most range limitations and require smaller batteries.[77–79] Charging flexibility also depends on the vehicle utilization; personal EVs, for example, may have higher flexibility due to longer parked periods compared to ride-hailing or other fleet vehicles that are driven more.

Table 1 Summary of managed charging strategies and considerations

Managed Charging Control	
Passive Static TOU and dynamic time-varying retail rates	**Active** Direct load control, under-frequency relay
Potential grid services • Limit generation, transmission, and distribution capacity expansion, energy arbitrage ***Communications and controls*** • Manual or automated controls • No dedicated communications required • Low complexity ***Measurement, verification, and settlement*** • EV-specific M&V typically not needed • Requires interval meter for settlement	***Potential grid services*** • All; however, smaller loads typically require aggregation (utility or third party) ***Communications and controls*** • Automated controls • Dedicated one-way or two-way communications required • Distribution system services require additional utility-side equipment • Low to high complexity depending on implementation ***Measurement, verification, and settlement*** • Real time, ex post, or statistical-/engineering-based M&V • May require direct telemetry or interval meter depending on implementation
Vehicle-Grid Power Flow Directionality	
Unidirectional (V1G) • Similar to demand response • No power injection to the grid	**Bidirectional (V2G)** • Similar to distributed storage • Power injection to the grid or support other loads providing additional benefits • Additional technical (e.g., battery degradation, distribution system protection equipment, onboard power converters) and nontechnical (e.g., vehicle warranties, lack of enabling regulations and standards, round-trip efficiency losses) barriers.

3.1 Implementation Strategies and Programs

There are a number of managed charging implementation strategies and programs at various levels of research, development, demonstration, and deployment (see Table 3 for a summary of exiting implementation programs in the United States). Passive load control through time-varying retail electricity rates (such as TOU electricity tariffs) is common, and there are many demonstration projects focused on developing real-time pricing, active managed charging through direct load control, and V2G. Managed charging to support distribution system services is limited to research and development and is discussed in Section 4.

The most basic implementation of managed charging is TOU electricity tariffs. With TOU, electricity prices are higher during peak electricity usage times and lower during off-peak times, incentivizing shifts in the timing of electricity use. Enrollment in TOU and other dynamic pricing programs has steadily increased over recent years, comprising 7% of residential, 11% of commercial, and 18% of industrial customers in 2019.[80] In 2017, 9% of all U.S. commercial tariffs applicable to DC fast-charging stations included TOU components.[81] Utilities also offer EV-specific TOU rates to encourage EV charging at off-peak times.[82–85] TOU rates have been successful in changing charging behavior in the United States. For example, a California Public Utilities Commission study concluded that charging load successfully shifted from peak evening hours to off-peak hours (overnight) by using TOU rates.[86] Similar results were shown for other locations.[87,88] A greater price variation between peak and off-peak rate has been shown to increase the shift in charging.[89,90] Among EV owners with access to TOU rates, a Smart Electric Power Alliance survey indicated that over 65% are enrolled in utility programs, and 87% of consumers charge off peak 95%–100% of the time.[84] Although TOU rates are well established and have been effective in modifying charging behavior, pricing signals may create a rebound peak. This may occur if many EVs consistently shift charging from the traditional peak period to a lower price period, thereby creating a new peak.[91–93] Additionally, ill-designed TOU rates can exacerbate both ramping concerns and the net load "duck curve" phenomenon if not aligned with renewable availability.[94,95] More intelligent and dynamic pricing mechanisms, supported with real-world testing and demonstration, can mitigate these issues.[91–93]

Beyond TOU rates, managed charging through unidirectional direct load control is a growing area of interest.[85] Some entities enable load control by subsidizing charging equipment for residential and commercial customers to ensure the equipment is compatible with direct load control requirements.[85,96–99] For utilities with existing DR programs, subsidization of the EV charger also requires enrollment and participation in DR programs.[85] Others offer incentive payments and/or bill credits for participating in DR events.[85,100–102] Customer satisfaction and participation in these programs in the United States have been high. For example, BMW reported 90%,[103] Avista 85%,[104] and Eversource 95%[105] of participation in call events. However, challenges have been reported for some implementations, including low resource availability (i.e., small fraction of vehicles plugged in at one time),[85,103,106] communication outages and latencies,[104] and high program costs.[104,107]

In order to provide other services, managed charging needs to participate in wholesale electricity markets. However, wholesale market participation may require aggregation to meet minimum size requirements: 100 kW under Federal Energy Regulatory Commission Order 2222.[108] Through aggregation, multiple EVs and chargers are pooled and collectively follow dispatch instructions. A number of managed charging demonstration projects utilize a non-utility third-party aggregator. For example, BMW piloted this capability in its ChargeForward project, leveraging their existing vehicle communications,[103,109] and Enel X's eMobility incorporates 35 MW of remotely controlled EV chargers in its DR.[110,111] Both projects bid into the California Independent System Operator (CAISO) energy market as proxy demand resources, but BMW implemented managed charging through the vehicles and Enel X used the charger—highlighting a range of potential approaches and enabling technologies.

To date, examples of managed charging with V2G in the United States are generally limited and focused on testing capabilities, such as provision of frequency regulation services by V2G-capable EVs.[105,112–115] Traditionally, regulations and market structures have not been established to handle bidirectional power flows. However, new partnerships and projects are being established.[116–118] Specifically, electric school buses have been targeted in multiple projects to provide V2G services given their large battery capacities and long scheduled idle time.[119–121] While bidirectional flow increases grid services from managed charging, uncertain battery impacts[122,123] and issues with vehicle warranties make implementation challenging. V2G also offers opportunities to power other loads, especially valuable during emergency events, and complement other DERs.[124]

Current direct load control of other loads may provide perspective on similar opportunities for managed charging. Particularly, the scale (power level) of the resource is an important factor in evaluating implementation strategies.[125] Power ratings of EV chargers vary from ~1 kW for Level 1 charging to several hundred kilowatts for DC extreme fast charging. Level 2 charging (~7 kW), common for residential homes, is higher power than typical residential central air-conditioning load but still relatively similar in scale. At this scale, common active DR strategies utilize one-way communications with direct load control (e.g., remote switches on pool pumps, air-conditioning units, and electric water heaters) and programable communicating thermostats. At the other end of the spectrum, DC fast chargers and fleet chargers have substantially larger loads (but might have more limited flexibility) and are similar in scale to commercial building equipment and industrial process loads. These larger loads are commonly controlled manually, but varying levels of supporting automation are also utilized.[68,126] Some facilities have under-frequency relays that shed load when power system frequency falls below some threshold value.[127] To date, DR providing frequency regulation is mostly limited to larger facilities, such as industrial electrolysis[128–130]; aggregations of industrial pumps; commercial heating, ventilating, and air-conditioning (HVAC) equipment; and commercial lighting.[131] Aggregations of smaller loads for frequency regulation have been proposed in the literature,[132] but due to the nascent nature of existing markets and technologies, have not been implemented.[133,134]

Across all sectors, fully automated DR with networked two-way communications between customer equipment or facilities and utilities, third-party aggregators, or power system operators remain limited. Still, there are many deployments in the field, and such implementations may grow in the near future.[66,135–138] Rather than real-time telemetry (that may be required for providing operating reserves[139]), ex post M&V is common and accomplished with interval metering (an interval meter measures and records data on either predetermined or remotely configurable time intervals). In the absence of interval meters, deemed values or statistical estimates from historical system data may suffice.[140]

There have been a handful of instances where DR has been proposed for distribution system services to defer capacity upgrades, as part of so-called non-wires alternatives[54]; however, on balance, successful DR implementations for the distribution system have been rare to date. Some projects have been successful in deploying DR.[141] Others, like the Brooklyn Queens Demand Management Program by Con Edison, have struggled: Although its DR auction procured significant load reductions, awardees have not been able to meet their obligations.[142] Utilizing geographically targeted DR for distribution system services faces a number of challenges,[143] and DR has been a minor contributor compared with other options such as energy efficiency, distributed generation, and conservation voltage reduction.[144]

3.2 Enablement Costs

Although managed charging can technically provide a wide range of grid services, there are potentially significant enablement costs. The costs of enabling managed charging are mostly associated with the incremental sensing, communication, and control costs. At the charger and vehicle levels, the incremental costs may depend upon factors such as the availability of interval metering, whether or not separate EV metering is required,[85] and whether or not there is a need for networked two-way communications[145] (e.g., to enable direct load control). Studies have reported incremental costs of $679 and $1,563–$1,945 for a networked residential and commercial Level 2 charger, respectively.[65,104,146] For distribution system services, there are further costs depending on whether specific locations within the distribution system have the necessary equipment for monitoring and responding to network conditions.[143] Aside from the infrastructure costs, there may be additional costs such as customer acquisition, data charges, and network management and other backend services.[147] One study reports network support and communications costs of $250/yr.[104]

Current estimates of costs may not be reflective of future costs, and many costs depend on allocation across multiple applications. For instance, widespread deployment of advanced metering infrastructure capable of distribution system state estimation and situational awareness or automated distribution system management could dramatically reduce the costs for managed EV charging to provide distribution system services.[148] Network access could also be widespread through EVs, avoiding upgrades to the charger and thereby embedding network access costs within the broader digital services provided to EV users.[145] Given the high costs of real-time telemetry, many load management strategies have sought to eliminate their need through statistical aggregation.[140,149] However, such approaches would tend to be applicable only to certain bulk power system services and may not be appropriate for distribution system services.[143] Managed charging costs scale differently among components. For instance, program administration and backend and network service costs decline on a per-user basis. However, other costs like real-time telemetry are fixed on a per-unit basis, supporting individually large managed charging enrollees.[150] How managed charging cost components scale may inform which implementation strategies are most important for different EV market segments.

4 Value of managed charging in analysis/modeling studies

As discussed in Section 2, EV managed charging can synergistically improve the efficiency and economics of electric power systems and electromobility. This section presents an overview of the electric vehicle load representation in analysis studies and a critical review of the modeling methodologies proposed in the literature for assessing the various managed charging (MC) value streams. The value of MC reported in the reviewed literature usually focuses on a future state and is based on specific modeling choices, assumptions, and test system configurations; therefore, we also discuss the key factors driving the differences in the value estimation of MC across studies. A summary of the number of studies categorized by their geographic scope, modeling perspective, model type, and methodology is presented in Fig. 2.

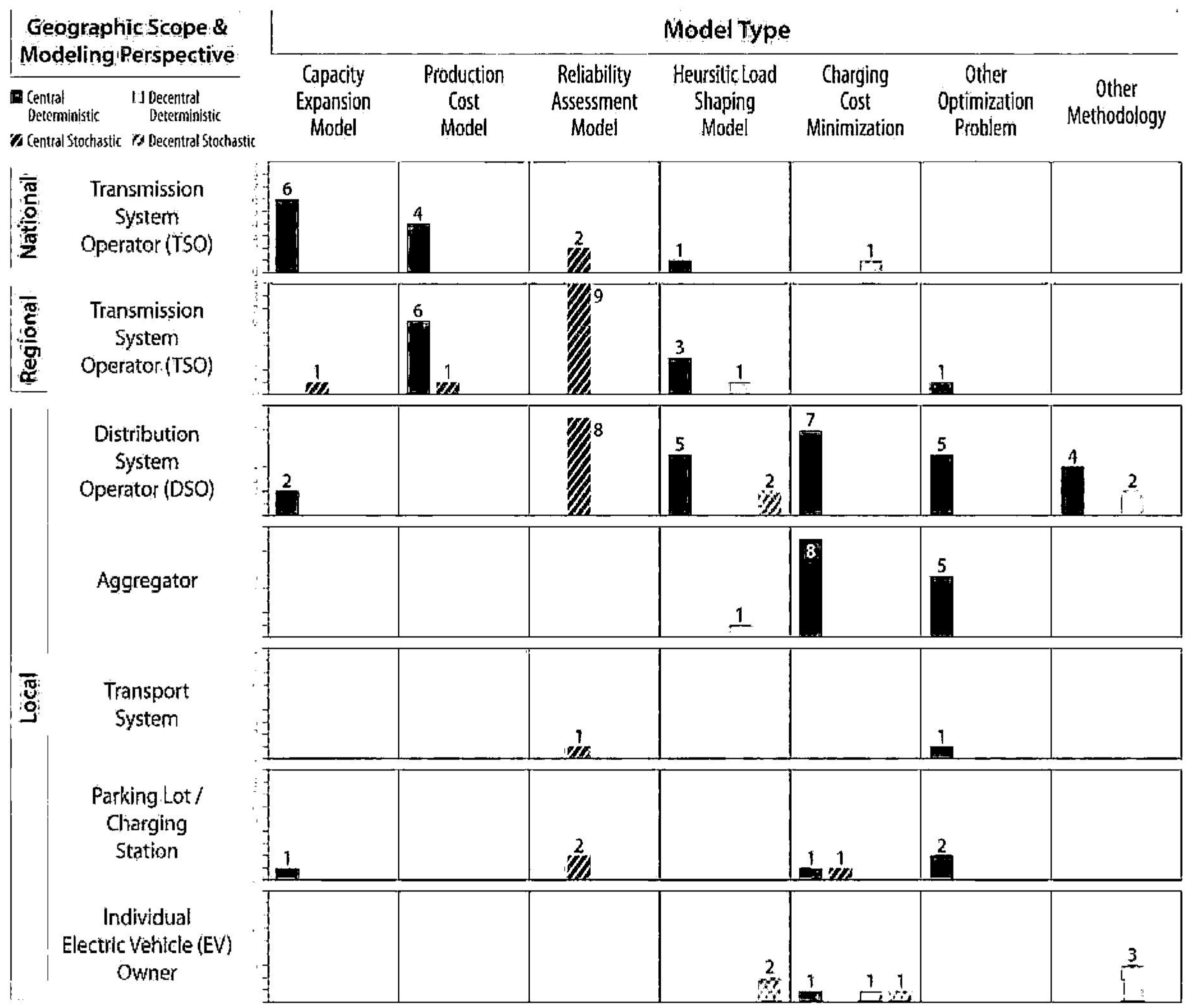

Fig. 2 Summary of the reviewed modeling/analysis studies by their geographic scope, modeling perspective, model type and methodology. Capacity Expansion Models and Production Cost Models are typically used for optimizing bulk power system planning and operation, respectively. Reliability Assessment Models predominantly utilize Monte Carlo Simulation, both at the TSO and DSO levels. Heuristic Load Shaping models usually follow some pre-defined set of rules for modifying EV charging load shapes. On the other hand, Charging Cost Minimization problems optimize the EV charging behavior based on external price signals. There can be other optimization objectives for managing EV charging (e.g., distribution losses minimization, peak load minimization, etc.), which are categorized under Other Optimization Problems. Other Methodologies include other, not very commonly used, methodologies (e.g., Droop-based Control, asset loss-of-life probability assessment, etc,).

At the national and regional levels (bulk power system), studies are typically performed from the perspective of the transmission system operator (TSO) and implement standard model types. For instance, analyses focusing on bulk system planning, operation, and reliability predominantly use capacity expansion models (CEMs), production cost models (PCMs), and Monte Carlo simulations, respectively. On the other hand, studies at the local level have focused on multiple perspectives including that of the distribution system operator (DSO), aggregator, transport system, parking lot/charging station, and/or individual EV users. To capture several topics of interest and objectives, studies exploring the value of managed charging at local scales leverage a wide variety of model types/formulations, with charging cost minimization typically based on optimal power flow formulations, heuristic load-shaping models, and other optimization problems being the most common. It is also evident that models even looking at local scales are primarily formulated in a centralized framework assuming that a central entity such as the DSO, aggregator or parking lot owner can directly manage/control the charging pattern of the entire EV fleet. The computational complexities associated with decentralized methodologies limits them typically to smaller-scale local studies primarily focusing on individual EV owners. Additionally, Fig. 2 reveals that a majority of model types are formulated as deterministic problems, with the exception of reliability assessment. A more detailed summary of the reviewed studies, including other details such as study goals, EV population/penetration assumptions, and implementation schemes, is presented in Table 4 in the Appendix.

4.1 Electric vehicle charging loads

To determine the value of managed charging, studies must first develop profiles for electric vehicle charging and their flexibility based on EV adoption, traveling demand, charging opportunities, and MC implementation. All these elements are uncertain given nascent EV markets, and different studies have made widely differing assumptions.

The simplest approach for modeling EV loads is based on annual travel statistics, such as vehicle miles traveled (VMT) and typical usage times, which have often been used to determined average daily charging loads.[151–153] Such annual methodologies based on vehicle miles traveled might be appropriate for aggregate impact studies (e.g., greenhouse gas emissions benefits), but they lack the temporal granularity required for most power sector analyses. Several MC analyses use more granular data from travel surveys to model EV loads.[154–158] Historical trip data and/or GPS measurements have also been used to model EV use and charging needs and opportunities,[159–161] providing spatiotemporally resolved information about vehicle use, including arrival and departure times and locations. The travel pattern statistics or empirical distributions obtained from travel surveys, GPS measurements, or historical data can be used to generate deterministic or stochastic vehicle use and charging profiles. Travel data can also be combined with demographical data to derive more insights on charging.[162] In the absence of survey or other information, some studies have also used exogenous assumptions about travel demand probability distributions for determining EV load profiles.[163–165] Finally, agent-based models have also been used to project EV loads,[166,167] but their application requires complex calibration and these models are usually intractable for regions bigger than a city or metropolitan area.

Besides using varied methodologies to project EV charging loads, different studies focus on different levels of aggregation. Typically, studies focusing on bulk power system require aggregate loads for reducing computational burden, and therefore consider aggregate charging profiles for the whole EV population or large clusters of vehicles rather than tracking the behaviors of individual vehicles, thereby missing heterogenous behaviors. The aggregate EV charging constraints are often based on a range of charging scenarios and usually assume that EV charging flexibility resembles a grid-connected battery with effective parameters, such as power and energy limits.[156,160,166,168] On the other hand, studies focusing on localized phenomena, such as impacts on distribution networks or single facilities, usually track charging profiles of individual vehicles such that travel patterns are enforced explicitly.[158,159,169,170]

Finally, widely differing assumptions are made on charging behavior, managed charging strategies and flexibility constraints, and consumer participation in DR programs. Studies often rely on collective rule-based approaches (e.g., nighttime charging only,[171,172] full vehicle availability and participation[173–175]), exogenous time-varying electricity tariffs,[166,176] or scheduled EV charging based on optimization models considering EV charging constraints at different levels of resolution.[166,170,177]

4.2 Bulk power system operation

EV managed charging can provide various operational benefits for bulk power systems (BPSs), including reducing system operation costs, greenhouse gas emissions, and peak loads, and curtailing variable renewable generation. These potential benefits of MC in improving BPS operation are usually analyzed using PCMs, such as unit commitment (UC) or economic dispatch, which typically model a single future year and focus on macro regions with fixed generation portfolios. These models co-optimize the scheduling of electricity generators and EV charging, typically at an hourly resolution, by minimizing system operation costs subject to operational constraints (e.g., power balance, reserve requirements, transmission network constraints), generation units' constraints (e.g., minimum and maximum generation, ramping capabilities, minimum up and down times), and aggregate EV demand constraints.[178–180] Although there is not a standard set of aggregate EV constraints, PCMs generally include such constraints as daily energy demand constraints, charging/discharging power limits, and battery state-of-charge limits.[178,181,182]

BPS operation studies often use commercially available tools. For example, Zhang et al.[173] use the PLEXOS model[183] to assess the value of MC in California's 2030 power system under high renewable scenarios with varying degrees of grid flexibility. Szinai et al.[166] also use PLEXOS for the 2030 California system; however, in contrast to Zhang et al., which considers a simplified representation of EV load (using the same daily aggregate EV demand profile for the whole year and assuming that charging can be temporally shifted without any constraints), Szinai et al. use a transportation agent-based model that explicitly considers constraints on mobility and charging infrastructure. PLEXOS has also been used to study the value of MC for the 2025 Irish power system,[152] 2030 Barbados power system,[184] and a hypothetical system with large-scale variable renewable energy (VRE) generation.[168] While PLEXOS allows customization of the UC objective function and constraints, the UC model in these PLEXOS-based studies typically minimizes total system operation costs subject to typical PCM and aggregate EV constraints, as discussed. Among the PLEXOS-based studies, both Taibi, del Valle, and Howells[184] and the International Renewable Energy Agency[168] consider V2G in addition to V1G, but only the former considers the associated battery degradation costs. These studies report a noticeable reduction in system operation costs due to V2G (as compared to V1G), as well as reduced participation of EVs in load shifting when battery degradation costs are considered.

Other PCMs besides PLEXOS have also been used. For instance, the value of V2G services (considering battery degradation costs) in the ERCOT system is studied using a deterministic UC tool in several studies.[155,185,186] Whereas Sioshansi and Denholm's 2009 article[185] focuses on emissions reduction benefits, their 2010 article[186] examines the system cost savings and V2G value for plug-in hybrid electric vehicle (PHEV) owners, and Sioshansi's 2012 article[155] compares the performance of optimal charging profiles estimated by the UC model with those obtained based on time-varying tariffs. The value of V1G with large-scale VRE integration in the German and Beijing systems is studied using bespoke deterministic UC models in Schill and Gerbaulet[187] and Chen et al.,[188] respectively. Vaya and Andersson[189] compare a centralized optimal power flow model (without discrete UC variables) against a decentralized TOU-based EV charging methodology in which optimal nodal TOU tariffs are determined accounting for the feedback impact of TOU tariffs on nodal charging profiles. The authors report that although centralized charging control leads to the least-cost solution, the results of the decentralized nodal TOU-based scheme were comparable, both in terms of costs and shape of the system load.

In contrast to the aforementioned deterministic PCMs, Liu et al.[157] present a stochastic UC model to assess the value of MC in the Illinois BPS under wind uncertainty, whereas Saber and Venayagamoorthy[190] consider both EV load and generation (wind and solar) uncertainty in a stochastic UC model. Similarly, a stochastic UC tool is used in Khodayar, Wu, and Shahidehpour[191] to assess the value of V2G in mitigating the impacts of wind power uncertainty. These studies report that stochastic models are computationally more expensive than their deterministic counterparts, and they report a slight increase in the value of MC (in terms of reducing system operation costs) under uncertainty.

In addition to PCMs, other methodologies have also been used to capture specific BPS operation benefits. For instance, Denholm and Short[151] and Fitzgerald, Nelder, and Newcomb[90] evaluate the peak load and power plant cycling reduction potential of MC by dispatching EV load to lowest-demand periods (referred to as valley-filling). However, such rule-based MC approaches cannot properly capture spatial, infrastructural, and demand-satisfaction constraints of EV loads and other system-level operational constraints. In contrast, Coignard et al.[154] use centralized quadratic optimization for minimizing either peak load or net load ramping, subject to constraints on EV SOC limits and charge point availability, for assessing the benefits of V1G and V2G in reducing ramping and VRE curtailment in the 2025 California BPS. Similarly, centralized quadratic optimization for flattening the demand at BPS and DS levels in Great Britain is presented in Crozier, Morstyn, and McCulloch.[192] Instead of the commonly used centralized methodologies, a decentralized Lagrangian decomposition-based approach is proposed in Ma, Callaway, and Hiskens[169] to control a large population of PHEVs in the Midwest ISO region. The authors show that the proposed decentralized control methodology can provide similar outcomes as centralized control, and therefore could be particularly useful in applications where fully centralized control is not possible, Finally, the operational benefits of MC have also been reported in studies using BPS planning models,[177,160] which aim to capture the impacts of MC on both system operational and investment costs, as discussed in Section 4.5.

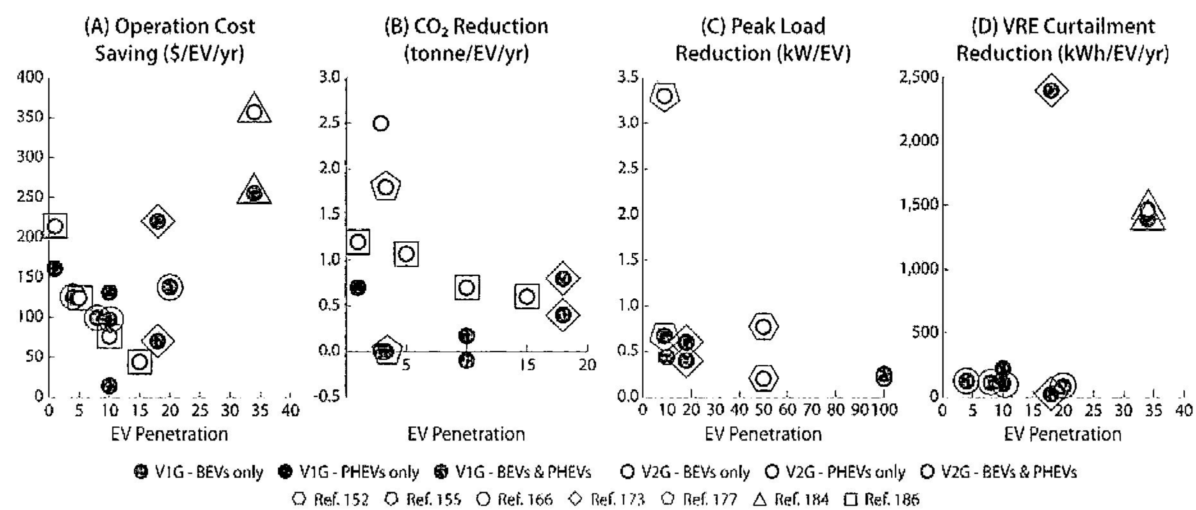

Fig. 3 Benefits of EV managed charging (compared to unmanaged charging) in improving bulk power system operation in terms of (A) system operation cost, (B) CO_2 emissions, (C) system peak load, and (D) curtailment of VRE. Each colored dot represents a data point from 14 studies. Multiple values from the same reference are enclosed within the same shape (defined in the legends) for more direct comparison. The impacts vary significantly across studies, based on EV penetration assumptions, vehicle type (BEV or PHEV), charging direction (V1G or V2G), system characteristics, and charging strategies.

Fig. 3 summarizes the BPS operational value of MC estimated in the studies reviewed. It is important to note here that the benefits of MC in improving bulk power system operation apply for a given generation portfolio. Therefore, they do not consider how the power system generation portfolio could optimally evolve with increasing EV adoption. Such analyses can be performed using BPS planning models, such as CEMs, which are discussed in detail in Section 4.5. The BPS operation benefits of MC vary significantly across studies: cost savings between \$15–\$360/EV/year, CO_2 emissions of −0.1 to 2.5 tons CO_2/EV/year, peak load reductions of 0.2–3.3 kW/EV, and VRE curtailment reduction of 23–2,400 kWh/EV/year. Studies consistently find that system cost reduction per EV decreases with increasing EV penetration.[166,186] The only exception to this declining trend is the sudden increase in cost savings potential at around 20% EV penetration in Szinai et al.,[166] because unmanaged charging in this case causes loss of load (resulting in very high costs), which can be avoided by MC. The declining marginal value of MC with increasing EV penetration is also observed in the CO_2[186] and VRE curtailment reduction potentials.[166] These trends indicate the presence of shallow value streams that could become saturated at certain EV penetration levels.

Fig. 3 also shows that V2G can further reduce operation costs, CO_2 emissions, and peak load (compared to V1G) by displacing inefficient peaking generators.[154,177,184] The benefits of V2G, however, are not clear in terms of reducing VRE curtailment.[184] Different BPS characteristics also affect the value of MC. For instance, the operation cost savings due to MC would likely be significantly lower in systems that have other flexibility competitors (e.g., pumped storage, stationary batteries, other sources of DR).[173] Additionally, VRE curtailment reduction can also vary considerably, with curtailment reduction due to MC noticeably larger in systems with high VRE penetrations and limited flexibility.[173] CO_2 emission reduction benefits of MC would be highly sensitive to the generation mix. Although large-scale VRE integration and limited grid flexibility can result in significant emission reduction benefits,[173,177] MC might have marginally positive to even adverse impacts on emissions (e.g., −0.1 tons CO_2/EV/year) if off-peak generation units have greater emission rates than on-peak units and if the charging algorithm doesn't account for the impacts/costs of emissions.[105,187,193]

It is also interesting to note the underlying relationships between the value streams shown in Fig. 3. For instance, reductions in CO_2 emissions due to managed charging are typically accompanied by operation cost savings as well, as demonstrated in Zhang et al.[173] and Sioshansi and Denholm.[186] This is primarily because CO_2 emissions have associated costs (e.g., fuel costs of CO_2-emitting plants, carbon taxes), and therefore reducing emissions inherently reduces operation costs. Similarly, reductions in peak loads reduce peak capacity needs, and therefore also operation costs (e.g., as shown in Zhang et al.[173]), because of the reduced need for running expensive peaking generators. Moreover, reduced VRE curtailment due to managed charging also tends to correlate with operation cost savings,[166,173,184] as VRE generation resources such as wind and solar have almost zero marginal costs. Finally, results in Zhang et al.[173] indicate that reduction in CO_2 emissions would also be aligned with reduced VRE curtailment, as higher VRE utilization inherently reduces the CO_2 content of the generation mix.

Different charging strategies can also lead to different MC value propositions. For instance, Sioshansi[155] reports that randomized EV charging start times outperformed TOU-based and real-time pricing (RTP)-based MC in reducing operation costs and emissions. The authors demonstrate that RTPs (determined using marginal prices from UC) performed the worst among different time-varying prices because RTPs cannot capture power plant operational non-convexities (e.g., binary on/off decisions, minimum up/down time constraints), causing significantly more startups (and associated costs). Similarly, Szinai et al.[166] show that if TOU tariffs are not aligned with periods of VRE generation availability, MC based on TOU tariffs can shift EV loads to periods of low VRE generation, thereby resulting in greater VRE curtailment than unmanaged charging.

MC can also improve other aspects of BPS operation, such as increasing the load factors of base-load and mid-merit generators and reducing their daily cycling.[186] Additionally, MC can reduce net load ramping, which might be particularly beneficial in systems with high VRE penetration.[154] Finally, MC can reduce other harmful emissions such as NO_x and SO_2, but the magnitude of these reductions would also be system-dependent.[185]

4.3 Distribution system operation

At the DS level, MC can alleviate the negative impacts of unmanaged charging, such as reducing the overloading of DS components/assets, improving voltage quality, and reducing energy losses. These benefits not only facilitate safe and reliable operation of the DS but can also increase the feasible EV penetration (also called the maximum hosting capacity) without violating network operational constraints.[194] However, the vast variability of DS design and conditions, lack of detailed models of actual DSs, and the uncertainty associated with electricity loads and their flexibility make it particularly challenging to simulate the real-world value of MC and generalize results from single simulations. Furthermore, the significant differences in modeling detail and methodologies also make comparison of the value of MC across different studies rather difficult. The following discussion describes the various methodologies reported in the literature, highlighting their relative strengths and limitations.

The operational value of MC in DSs has been assessed for various charging strategies using power flow analysis/simulations, which determine the DS's operating state (e.g., voltages, line flows, energy losses) for given loads (including EV charging profiles) and generation conditions.[171,172,175,195–197] Leemput et al.[172] use a valley-filling approach for determining EV-managed charging profiles, whereas Voumvoulakis et al.[196] compare valley-filling with "peak-curtailment" charging, whereby EVs can charge only when the total DS load is below a predefined value. It is shown that while peak curtailment charging results in higher energy losses compared to the valley-filling approach, it leads to lower peak DS loads, and therefore higher feasible EV penetrations.[196] Kamruzzaman, Bhusal, and Benidris[175] assume a "fully controlled" MC profile, such that EV charging can be completely shifted as long as the maximum capacities at selected nodes are not violated. Compared to these demand-based approaches, EV managed charging profiles in Hu, Li, and Bu[171] are modeled based on cost minimization under TOU tariffs, and the authors also explore a V2G strategy, whereby EVs are allowed to discharge to the grid during the evening peak. Mehta et al.[197] compare charging cost minimization and demand peak-to-average ratio (PAR) minimization strategies while considering battery degradation costs due to V2G services. They demonstrate that MC profiles based on PAR minimization result in significantly lower DS peak loads and higher feasible EV penetrations as compared to the charging cost minimization approach.

Although power flow-based studies are helpful in comparing charging profiles, they can lead to suboptimal results because the MC profiles are not co-optimized with DS operation. This suboptimality can be reduced by including some critical DS constraints when determining "optimal" EV charging profiles under MC. For instance, maximum power limits specified by the DSO are included in the cost minimization problems of EV aggregators in Hu et al.[161] and Wang et al.[164] Compared to Hu et al.,[161] where only active power limits are considered, Wang et al.[164] also include reactive power limits. Alternatively, Sundstrom and Binding[159] propose an iterative coordination methodology that considers the interactions of a charging service provider (CSP) with the DSO and a retailer. The retailer issues a reference power profile to the charging service provider, who tries to minimize the deviation from this profile. The output is sent to the DSO to check operational feasibility. If infeasible, constraints are generated and sent to the charging service provider for re-optimization until the charging profile is feasible for the DS.

EV charging can be further optimized for DS operation through endogenous representation of power flow constraints (in addition to EV demand constraints) in MC optimization problems, which comes at the cost of additional computational burden. Such optimization problems with power flow constraints are referred to as optimal power flow (OPF) problems. Steen et al.[162] compare loss-optimal (minimizing DS energy losses) and cost-optimal OPFs for MC in residential and commercial DSs. Similarly, De Hoog et al.[170] compare OPFs for maximization of stored energy in EVs and minimization of charging costs. However, in contrast to Steen et al.,[162] which models nonlinear AC power flow constraints, De Hoog et al.[170] implement linearized approximations for improving computational tractability. A hierarchical corrective disconnection control methodology is proposed in Quirós-Tortós et al.,[198] which is shown to provide similar results as AC-OPF while using significantly limited information. An OPF for maximizing EV penetration is presented in Lopes et al.,[199] whereas a multi-objective OPF minimizing EV charging costs, PAR, and voltage deviation is proposed in Mazumder and Debbarma.[200] Liu et al.[201] present a distribution locational marginal pricing scheme (based on a linear DC-OPF) for reducing DS congestion.[2] The distribution locational marginal prices are included in EV aggregators' cost minimization problem, rendering EV charging more expensive during periods of high DS loading. The strategic interactions between a parking lot owner and DSO are modeled using bilevel optimization in Sadati et al.,[163] where the DSO maximizes its profits subject to network constraints in the upper level, while the parking lot owner maximizes its profits (considering battery degradation costs) in the lower level. The results demonstrate that the DSO makes greater profits and incurs lower energy losses in the bilevel model as compared to centralized optimization. In contrast to the aforementioned studies where only the power system aspects are considered, the methodology in Geng et al.[202] coordinates the operation of transportation and power distribution systems for reducing peak load and traffic congestion while incorporating EV demand elasticity.

Decentralized methodologies have also been used for providing DS services through MC.[158,203–206] For instance, Le Floch, Belletti, and Moura[159] and Le Floch et al.[206] use a dual-splitting technique for distributed coordination of EVs to minimize load variance while considering battery degradation costs. Similarly, a decentralized algorithm for reducing PAR is proposed in Rassaei, Soh, and Chua,[204] in which aggregated demand profiles are broadcasted to EV owners who sequentially solve their individual optimization problems. In contrast to optimization-based decentralized schemes, the methodology in Knezović and Marinelli[205] involves droop-based EV reactive power control as a function of active power consumption and phase-to-neutral voltage. Similarly, Martinenas, Knezović, and Marinelli[206] propose and experimentally validate a droop-based methodology for controlling EV charging current as a function of phase-to-neutral voltage.

Fig. 4 summarizes the DS operational value of MC reported in several studies. Since different DSs can handle different numbers of EVs, it is hard to normalize results and these data are difficult to compare. As shown in Fig. 4A, MC can noticeably reduce DS peak loads and congestion, with total peak load reduction potential increasing with increasing number of EVs in the DS.[199] However, the marginal peak load reduction (for each additional EV) might decrease with increasing EV penetration in cases where rising diversification effects of a larger number of EVs lead to reduction in simultaneity. Additionally, V2G can achieve higher reductions in peak load as compared to V1G,[204] but the magnitude of these benefits can be substantially different. For instance, Wang et al.[164] report that V2G can reduce peak loads by 67%, but only 10% peak load reduction is observed in Sadati et al.[163] These variations can be attributed to different DS characteristics

[2] Locational marginal prices represent the incremental cost of additional energy at a specific location. This concept is used in all wholesale markets in the United States but has not been applied at the distribution system level, which requires much finer resolution.

and different charging schemes. While Wang et al.[164] optimize EV charging subject to DS active and reactive power limits, Sadati et al.[163] consider time-varying prices, which can increase charging simultaneity, thereby reducing the peak reduction potential. Indeed, charging EVs based on wholesale market prices (without considering DS constraints) can even result in higher congestion and peak loads than unmanaged charging.[163,207]

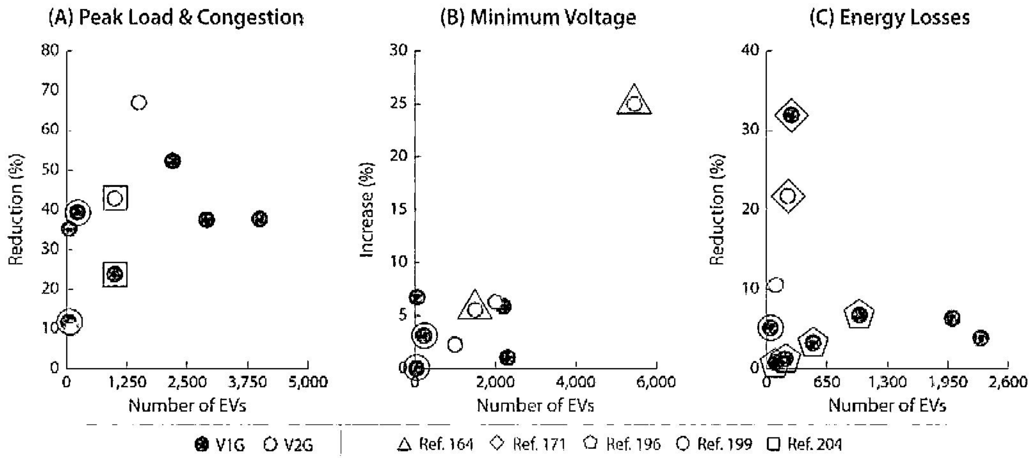

Fig. 4 Benefits of EV managed charging (compared to unmanaged charging) in improving distribution system operation in terms of (A) peak load and congestion, (B) minimum voltage, and (C) energy losses. Each colored dot represents a data point from 13 studies. Blue circles represent V1G and orange triangles V2G. Multiple values from the same reference are enclosed within the same shape (defined in the legends) for more direct comparison. The impacts vary significantly across studies, based on different EV penetration levels, charging direction (V1G or V2G), DS characteristics, and charging strategies.

MC can also reduce voltage drops caused by uncontrolled EV charging, as shown in Fig. 4B. However, the magnitude of voltage quality improvement can also vary considerably. MC can avoid potentially larger magnitudes of voltage drops at higher EV penetrations.[164,199] DS characteristics also play a major role, and the voltage support value of MC is higher in DSs with longer electrical distances between the substation and the loads.[192,196] Voltage improvements also depend on the charging strategies considered. For instance, optimal EV charging under voltage constraints is more likely to reduce voltage drops compared to charging based only on cost minimization.[162] Finally, provision of reactive power from EVs also leads to greater improvements in DS voltage.[164,200,205]

Fig. 4C shows that the total reduction in energy losses due to MC usually increases as more EVs are connected to a DS.[196,199] Interestingly in Hu, Li, and Bu,[171] V1G leads to a greater reduction in network losses compared to V2G. This is primarily because the V2G case in this study does not shift the EV load, but only allows discharging energy to the grid during peak load hours. Indeed, other studies have also shown that the impacts of charging strategies on DS losses can be fairly substantial. For instance, charging cost minimization under wholesale prices can, in some cases, even lead to higher losses than unmanaged charging.[162,207] Finally, the highest loss reductions due to MC are typically observed in networks with significantly overloaded assets and/or voltage unbalance issues.[196,205,208]

The value of MC for DS operation is also revealed by the increase in maximum feasible EV penetration (also called EV "hosting capacity") without violating DS constraints or implementing network upgrades, as shown in Fig. 5. Feasible EV penetration in a specific DS significantly depends on the system characteristics and the EV loads. For example, the three studies grouped at the top of Fig. 5 suggest that in DSs with higher levels of redundant capacity,[162] lower load density,[172] and underutilized transformers,[198] full (100%) EV adoption can be accommodated without DS upgrades with MC. In other cases, much lower

EV adoption can be supported by DS without upgrades if EV charging is unmanaged. While the literature reports that MC can noticeably increase the maximum feasible EV penetration for such DSs, additional network upgrades/reinforcements are projected in these cases to accommodate full EV adoption (or EV charging for applications not considered in these studies, such as commercial vehicles). In addition to the DS characteristics, EV load modeling/assumptions also play a major role in these results. For instance, the value of MC is higher in scenarios with higher-rated (faster) charging (as unmanaged fast charging can overload DS components even at low EV penetrations)[172,197] and when consideringV2G capability.[200] Finally, charging strategies and MC objectives also play a critical role in determining the EV hosting capacity in a specific system. EV charging based on peak curtailment resulted in higher feasible EV penetration, without requiring network upgrades, compared to valley-filling charging in Voumvoulakis et al.[196] Additionally, charging based on cost minimization under wholesale prices was not only significantly outperformed by PAR minimization in Mehta et al.,[197] but it even led to lower feasible EV penetration than uncontrolled charging in Steen et al.[162]

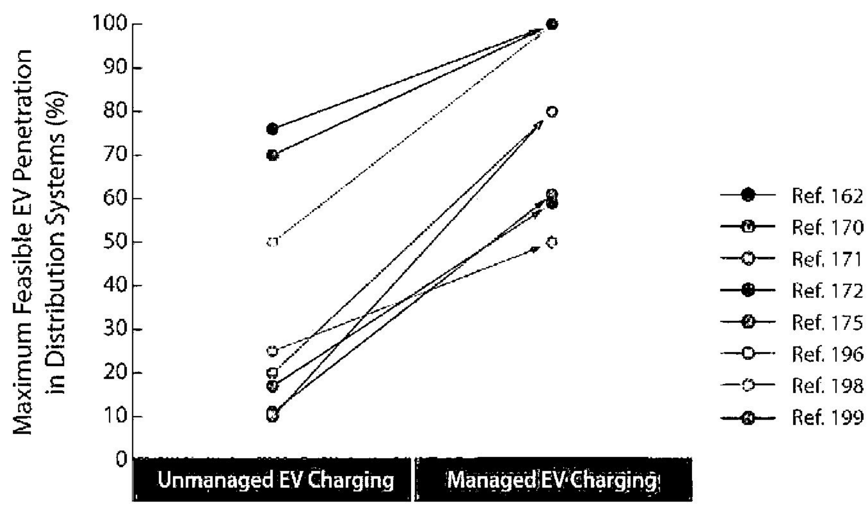

Fig. 5 Results from eight studies highlighting the potential of EV managed charging to increase the maximum feasible penetration of EVs in distribution systems without implementing additional network upgrades or violating operational constraints. The increase in the maximum feasible EV penetration due to MC would depend on the redundant capacity in the DS, load density, charging direction (V2G vs. V1G), charging speeds (faster unmanaged charging can overload DSs even at low penetrations), and charging strategies.

The results presented in this section highlight that DS characteristics and MC strategies would play a critical role in shaping the value of MC for DSs. It is also evident that MC profiles determined based on wholesale market signals could be detrimental for DS operation, which points to the need for developing holistic strategies that consider the value proposition and trade-offs across the whole power system. Finally, considering the limited benefits of MC in some DSs, it would be critical to assess the benefits of MC on a given system in comparison to the costs of MC implementation.

4.4 Power system reliability

The reliability of a power system is defined as its ability to provide an adequate supply of electricity to customers with a reasonable assurance of continuity and quality.[209,210] To be reliable, the power system must have adequate power generation and balancing resources to keep pace with changing consumer demands, retiring plants, and addition of new resources and technologies.[211]

At the BPS level, system contingencies (e.g., plant outages) can lead to loss of load, and in extreme cases set off cascading failures causing large-scale blackouts.[212] Reliability of a BPS can therefore be measured by the adequacy of its generation capacity to meet total system load. The most commonly used BPS generation adequacy indices are Loss of Load Probability (LOLP), Loss of Load Expectation (LOLE), and Expected Energy Not Served (EENS) (also called Loss of Energy Expectation [LOEE]), which reflect the probability, expected frequency, and magnitude of lost load over a certain time period, respectively.[213]

Unmanaged charging of large EV loads has been projected to increase both frequency and magnitude of lost load.[174,176,214–217] However, these studies also report that by shifting the EV load and injecting energy into the grid during capacity shortfalls, MC can improve BPS reliability relative to unmanaged charging. Evaluation of reliability benefits of MC is usually done using Monte Carlo simulation, which involve simulating a large number of realizations of uncertain system attributes, such as generator outages, variations in load and VRE output, and EV charging parameters. Considering the inter-temporal dependence of EV battery SOC levels, EV-based reliability studies typically use sequential Monte Carlo simulation (c) as it allows capturing these chronological aspects. Bremermann et al.[214] compare the value of valley-filling and centrally optimized smart charging through SMCS, considering generator outages (using Markov models) and system load and wind uncertainty (based on normally distributed error forecasts). The results demonstrate that the centralized smart charging strategy can significantly improve BPS reliability compared to valley-filling.[214] Similarly, Božič and Pantoš[218] demonstrate the benefits of MC based on system reliability maximization (compared to charging cost minimization). Colonetti et al.[215] compare the reliability impacts of rule-based MC strategies (including valley-filling, charging postponement, and V2G during scarcity events), whereas Liu et al.[216] compare the reliability benefits of V2G against V1G. In addition to the typical reliability indices, Liu et al.[216] also propose new load-oriented indices that measure the expected frequency and magnitude of energy compensation by EVs for providing reliability services. The impacts of using different probability distributions (for modeling the EV load) on generation adequacy are analyzed in Bremermann et al.[174] The authors demonstrate that utilization of non-homogenous Poisson distribution can better represent end-user mobility and the EV opportunity to provide spinning reserves compared to the standard Poisson distribution.[174] The effectiveness of changing PHEV charging start times on improving system reliability are studied in Wang and Karki,[219] whereas a framework for comparing EV charging responses under TOU tariffs and dynamic scarcity pricing is proposed in Almutairi and Salama.[176] Compared to the static transmission network topology assumed in the aforementioned studies, Li et al.[220] allow optimal network reconfiguration, in addition to MC, for improving BPS reliability. Finally, in contrast to other BPS reliability studies, Hou et al.[221] capture the impacts of the interaction between the transportation and power systems and propose new indices for capturing the extra time spent by EV drivers in finding charging stations or calling for help during insufficient EV charging situations.

BPS reliability benefits of MC can also be evaluated using analytical approaches. Compared to running a multitude of simulations, analytical techniques use direct mathematical formulations for evaluating the reliability indices.[222] da Rosa et al.[217] present a convolution-based analytical approach for estimating the reliability value of centrally controlled smart charging, whereas Hajebrahimi and Kamwa[223] propose a Combined Outage Probability Table-based approach for assessing the impacts of advanced metering infrastructure failure. Although these analytical approaches might not capture complex interactions of stochastic variables, they significantly reduce the computational burden associated with SMCS.

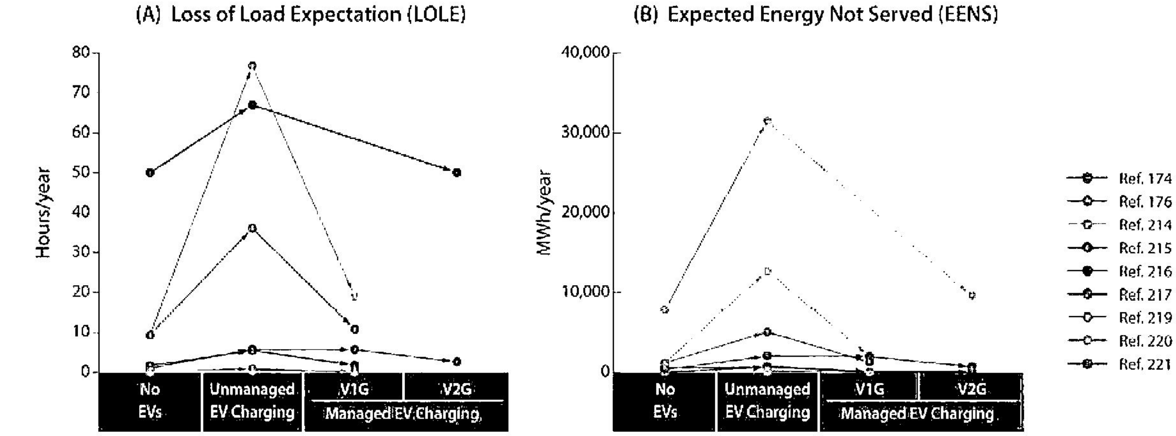

Fig. 6 Impacts of unmanaged and managed EV charging (with V1G and V2G capability) on bulk power system reliability indices (LOLE and EENS) from 9 studies (direct comparison of absolute results across studies is complex, but trends are consistent and informative). Unmanaged EV charging invariably worsens BPS reliability, while MC can bring the reliability indices down to values close to the case without EVs. The improvement in reliability indices due to MC depends on BPS characteristics, EV adoption assumptions, charging direction (V1G vs. V2G) and charging strategies.

Fig. 6 summarizes the value of MC in improving BPS reliability. Although unmanaged charging is usually projected to cause more frequent (higher LOLE) and severe (higher EENS) loss of load events (mostly as a result of EV loads being added to a system without considering any network upgrades; similar results could be expected when analyzing the addition of other electricity loads in isolation), MC (both V1G and V2G) can bring the indices down to values close to the case without EVs, allowing for a similar reliability of the baseline system but serving a larger demand. The extent of reliability improvement depends not only on power system characteristics (e.g., generation mix, VRE penetration,[221] network topology,[220] and weather conditions[214]), but also on EV load modeling/assumptions. Wang and Karki[219] show that increasing EV penetration increases the reliability benefits of MC; however, a saturation effect was observed in Hou et al.,[221] where the reliability improvement kept increasing until 20% EV penetration, beyond which the marginal improvements started to decline. V2G capability also increases the reliability benefits of MC.[215,216] Finally, different MC schemes lead to different reliability outcomes. Optimally controlled EV charging outperformed valley-filling charging in Bremermann et al.,[214] whereas dynamic DR signals significantly improved BPS reliability compared to TOU tariffs in Almutairi and Salama.[176] Conversely, strategies based on minimizing EV owners' charging cost under static tariffs and worst-case scenarios like synchronizing EV charging start times to peak periods could lead to reduced system reliability compared to uncontrolled charging.[218,219]

Reliable operation of DSs is also very important, as component failures in DSs are the most frequent cause of customer interruptions.[211,224] Compared to systemwide indices used for BPS reliability, DS reliability indices are usually customer-oriented. The most commonly used DS reliability indices are System Average Interruption Frequency Index (SAIFI), System Average Interruption Duration Index (SAIDI), and Customer Average Interruption Duration Index (CAIDI).[225] Whereas SAIFI reflects the frequency of customer interruptions, SAIDI and CAIDI capture the interruption durations normalized by total number of DS customers and number of interrupted customers, respectively. In combination with these indices, magnitude-based indices such as EENS are also used for assessing DS reliability.

Whereas unmanaged charging of EVs can reduce DS reliability compared to the no-EV case,[226,227] studies have shown that MC can improve the reliability indices (compared to unmanaged charging), particularly by injecting electricity to the grid (V2G) and/or into customers' homes (V2H). Therefore, bidirectional charging/discharging is a topic of significant interest in DS reliability studies. SMCS is the preferred approach (implemented in all studies discussed below) for assessing the DS reliability value of MC. The impacts of EV penetration with fast and slow charging and V2G capability on the reliability of urban and rural DSs are analyzed in Galiveeti, Goswami, and Choudhury.[228] In addition to DS reliability indices, the authors also propose indices for capturing the impacts of DS outages on EVs' expected energy not charged.[228] Similarly, indices for average frequency, duration, and magnitude of EV charging interruption are proposed in Guanglin et al.[227] Compared to Galiveeti, Goswami, and Choudhury,[228] where the methodology decides whether all EVs need to provide V2G during network failure (considering the energy needed for load restoration), the methodology in Guanglin et al.[227] allows all EVs to provide V2G as soon as an islanding situation is detected. The methodologies in Xu and Chung[232] and Al-Muhaini[233] consider the value of EVs directly injecting energy into customers' homes (V2H), in addition to V2G services. The DS reliability value of EV parking lots providing V2G services during typical office hours is explored in Guner and Ozdemir[234] and Zeng, Gao, and Zhu.[235] Unlike the aforementioned studies, the methodology in Tan and Wang[233] uses a condition-dependent outage model that explicitly considers the impact of EV charging strategies on DS component failure rates. Finally, the model in Zhang et al.[234] incorporates the impacts of traffic congestion on DS reliability by integrating a quasi-dynamic traffic flow model with a reliability assessment tool.

Fig. 7 shows the value of MC in improving DS reliability. By allowing EVs to provide grid support during network outages, MC with bidirectional capability (V2G and V2H) can reduce EENS not only compared to unmanaged charging, but also relative to the case without EVs. Similarly, MC with bidirectional capability can also reduce interruption duration (lower SAIDI) through load restoration. Conversely, most of the studies (except Al-Muhaini[233] and Tan and Wang[236]) report very limited to no improvement in the frequency of customer interruption (SAIFI) due to MC. This is because these studies (except Tan and Wang[233]) do not capture the dependence of network outages on EV charging, and unlike SAIDI (where partial load restoration would improve the metric), SAIFI can only be improved if MC can fully restore the network load.

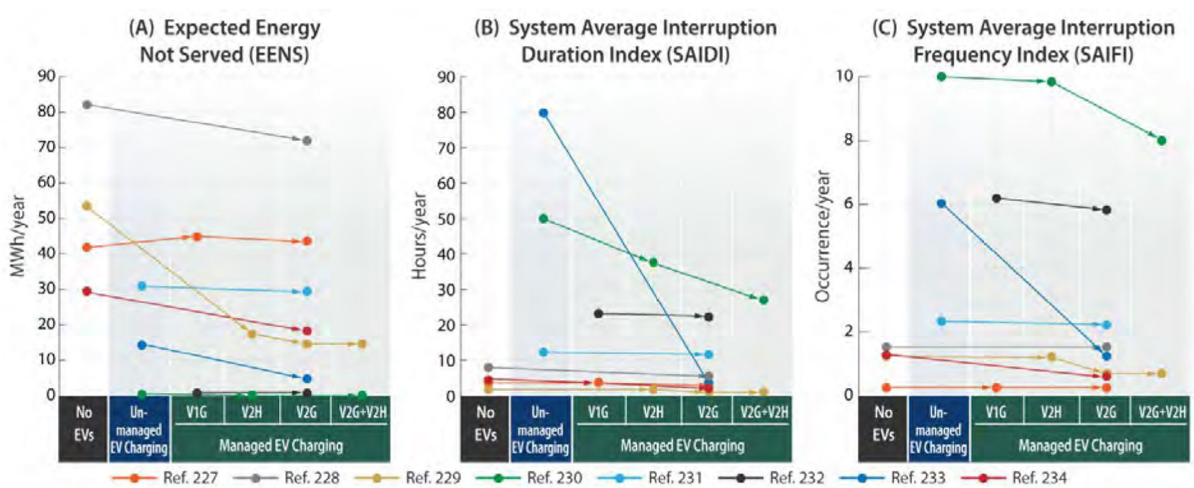

Fig. 7 Impacts of unmanaged and managed EV charging (with V1G and V2G capability) on distribution system reliability indices ((A) EENS, (B) SAIDI, and (C) SAIFI) from eight studies. Unmanaged EV charging worsens DS reliability, wheras MC—particularly by injecting electricity to the grid (V2G) and/or into customers' homes (V2X)—can result in greater DS reliability, even compared to the case without EVs. The improvement in reliability indices due to MC depends on DS characteristics, EV adoption assumptions, charging direction (V1G vs. V2G), charging speed, and charging strategies.

The DS reliability value of MC also depends on EVs' mode of operation during outages. Fig. 7 shows that V2H provides limited improvement in DS reliability indices, primarily because the reduction in energy not supplied is capped by the consumption of each household.[230] Also, V2H would not be able to restore the loads of households without EVs and would not be useful if the household is not affected by the outage. On the other hand, V2G can significantly reduce the duration and magnitude of customer interruptions.[229,230] Additionally, the number of EVs allowed to discharge during network outages also noticeably affects the reliability benefits of MC.[228] Finally, the total value of MC in improving DS reliability is reported to increase with increasing EV penetration.[229,233]

The results presented in this section highlight, not surprisingly, that in simulation studies introducing EV load without any system upgrades, unmanaged charging typically worsens system reliability, at both the BPS and DS levels. However, managed EV charging, particularly through bidirectional charging, can significantly improve reliability indices for a given system. Still, the extent of the benefits would significantly depend on whether the EVs provide support only to selected homes/buildings or also to the grid, as well as whether the improved reliability comes at the expense of EV users' mobility. In particular, the reliability value of MC, particularly of V2G/V2H, would reasonably diminish under scenarios with high, inflexible mobility requirements and prolonged system outages where users might be unwilling to forego the transportation utility of EVs. Consequently, further experimental validation needs to be performed to assess the realistic potential of bidirectional charging to increase system reliability considering mobility requirements, user preferences (especially during extreme events), and the complexity of equipment/controller installation.

4.5 Bulk system planning

Simultaneous uncontrolled charging of large EV populations can increase system peak loads, which could necessitate expansion of generation capacity, all else equal.[90,168] By reducing energy consumption during peak hours, MC can potentially reduce the need for additional generation capacity, thereby reducing BPS planning/investment costs and improving system efficiency. MC can also complement greater investments in VRE generation and could thus have significant implications for long-term planning and support decarbonization policies.

The systemwide planning benefits of MC are usually evaluated using centralized CEMs. These models typically minimize total system costs (including investment and operation costs) comparing the value of competing technologies subject to some policy constraints and/or reliability targets.[235] Manríquez et al.[236] use a CEM that optimizes investments in both generation and transmission capacity to assess the value of MC under various EV penetration levels for the 2030 Chilean power system. Kiviluoma and Meibom[237] use a linear CEM (Balmorel) coupled with a stochastic UC tool (WILMAR) to evaluate the potential of V1G and V2G in reducing generation investment and operation costs for the Finnish system. A similar sequential approach is used in Taljegard et al.,[160] where the BPS planning outputs from a CEM (ELIN) are used in a PCM (EPOD) to evaluate MC benefits in future Scandinavian-German power systems. BPS planning benefits of V1G and V2G for Central West Europe, Nordic and Baltic countries, and the United Kingdom are studied in Gunkel et al.[156] using the Balmorel model with battery degradation costs and transmission investments. In contrast to other CEMs, the model in Ramírez, Papadaskalopoulos and Strbac[238] co-optimizes generation investments and the percentage of flexible EVs by explicitly modeling EV flexibility enabling costs (including metering, control and communication, and battery degradation costs). Carrión, Domínguez, and Zárate-Miñano[239] introduce a stochastic CEM for capturing the impacts of long- and short-term uncertainties on the value of MC. In comparison to the aforementioned models, a whole-system assessment methodology is used in Aunedi and Strbac[177] that quantifies the planning and operational benefits of V1G and V2G not only on BPS generation and transmission, but also on DS reinforcement costs, which are modeled using calibrated functions of net peak load in each DS. Instead of using a CEM, Donadee et al.[240] maximize the utility's avoided costs under exogenous prices of different value streams (e.g., energy and ancillary service prices, generation capacity prices, DS capacity values). Although the model does not capture the evolution of installed generation and transmission capacities, it provides a computationally tractable framework for estimating the business case of MC infrastructure investments.

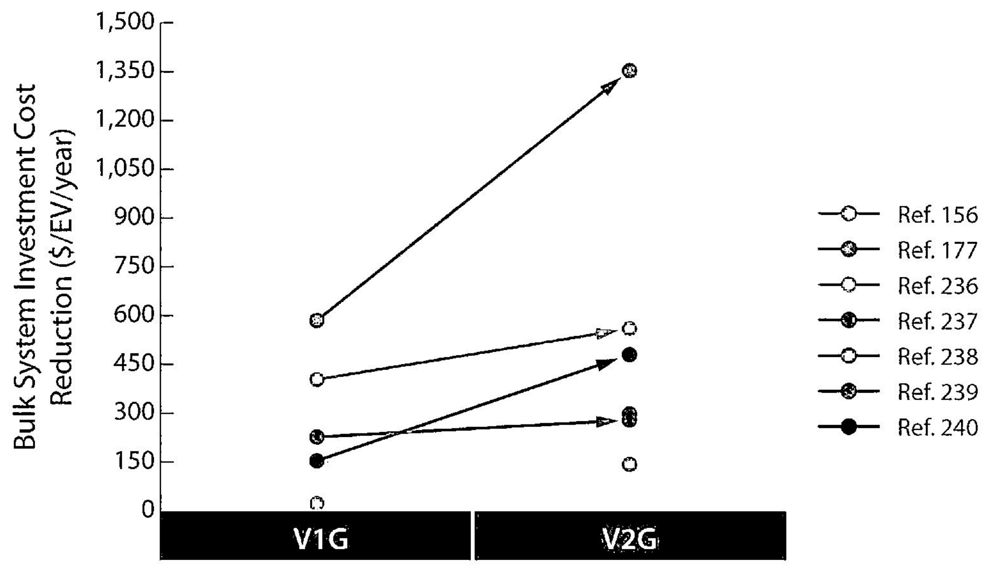

Fig. 8 Comparison of managed EV charging (V1G and V2G) in terms of reducing bulk system investment costs relative to unmanaged charging reported in seven studies. Managed charging is shown to consistently provide hundreds of dollars in investment cost savings per EV each year. V2G capability tend to enable greater investment cost reductions compared to V1G; however, the extent of these benefits depends on BPS characteristics, EV adoption assumptions and EV flexibility modeling, and enablement costs (usually not explicitly considered in these studies).

Fig. 8**Error! Reference source not found.** summarizes the marginal BPS investment cost reduction benefits of MC, which highlights the significantly greater potential of V2G (over V1G). Several other factors are also important in determining BPS planning benefits of MC. In addition to cases with bidirectional capability, the marginal benefits are higher under lower EV penetrations.[236,238] Although the presence of other sources of flexibility (e.g., energy storage) can reduce the planning benefits of MC,[177,237] MC can also outcompete other flexible resources.[156,239] Moreover, investment cost reduction due to MC noticeably increases if transmission expansion is also considered.[156] Conversely, the cost reduction potential of MC reduces if battery degradation costs are considered[240] and could completely disappear beyond certain values of flexibility enabling costs.[238]

In addition to investment cost reduction, MC can also increase installed VRE capacities.[156,160,168,236] However, the type of resource facilitated by MC depends on the indigenous resource quality. For instance, higher solar availability factors in the regions modeled by the International Renewable Energy Agency[169] and Manríquez et al.[239] lead to greater installation of PV units (compared to wind generation) due to MC. Conversely, European studies[156,160] show that MC benefits wind development and might even reduce PV capacities compared to unmanaged charging. This is primarily because in Northern Europe, solar PV mainly produces during peak price hours, and therefore the load shifting capability of EV reduces the revenues for solar PV, resulting in reduced investments in PV capacities.

The results presented in this section highlight that by reducing system peak loads, MC can noticeably reduce the need for investments in new generation capacity, particularly in cases with V2G capability. However, the value benefits of MC could be limited in systems with other flexibility competitors and under assumptions of high battery degradation and enablement costs.

4.6 Distribution system planning

DS planning involves determining the reinforcements/upgrades required to distribution systems to ensure reliable power supply to all customers. Considering that the challenges attributed to uncontrolled charging would likely manifest at the DS level first (due to "clustered" EV adoption), long before affecting BPSs,[90,241] MC would be of utmost importance for avoiding/deferring DS upgrades.

The typical approach for assessing DS planning benefits of MC is running power flow analysis/simulations, whereby asset/component loading and voltages are assessed under different EV charging profiles. Subsequently, reinforcement requirements are estimated for avoiding the potential overloading/voltage issues. The reduction in number of DSs requiring upgrades based on MC profiles determined using peak demand minimization and load flattening is evaluated in Coignard et al.[195] and Crozier, Morstyn, and McCulloch,[192] respectively. However, these studies do not evaluate investment cost savings due to MC. To this end, Verzijlbergh et al.[208] use power flow analysis to determine the reduction in percentage of overloaded transformers and cables by shifting the EV load to night hours, and subsequently use marginal component costs for determining the total investment cost reduction. Similarly, the impacts of MC profiles under dynamic pricing on the reduction of DS reinforcement costs in German DSs are analyzed in Kühnbach et al.[167] The authors then estimate the reduction in household electricity bills due to reduced reinforcement costs. Veldman and Verzijlbergh[207] compare the impacts of different charging strategies (unmanaged, peak load minimization, and charging cost minimization) on component loading, replacement costs, and energy losses in 48 Dutch DSs with high EV penetration. In contrast to studies that only consider the impacts of transport electrification, Pudjianto et al.[242] analyze the value of managing the power consumption of heat pumps, in addition to EVs, in residential DSs under different future electrification scenarios in the United Kingdom.

Although power flow-based methodologies are useful, they do not optimize the MC profiles for reducing DS reinforcement costs, which might lead to suboptimal results. This limitation can be avoided by using integrated optimization problems, similar to CEMs, for minimizing DS investment and operation costs. For instance, the model presented in Fernandez et al.[243] minimizes DS investment and operation costs, subject to constraints on EV energy requirements, voltage limits, and transformer/line capacities. Similarly, Lin et al.[244] minimize annual investment, maintenance, depreciation, and operation cost considering V2G services provided by an EV charging station.

In contrast to methodologies assessing the replacement/upgrade requirements of multiple DS assets, the methodology in Soleimani and Kezunovic[245] implements a detailed thermal model to determine the value of MC in reducing the loss-of-life probability and failure hazard of a single transformer.

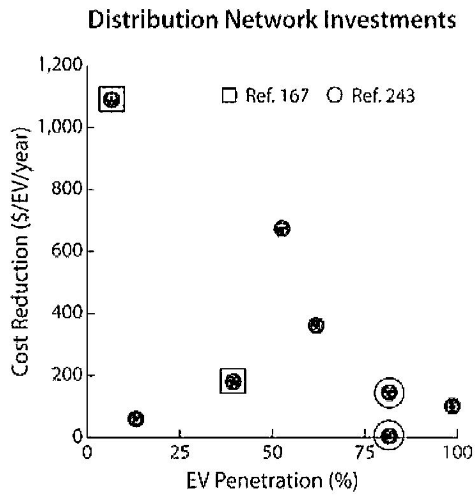

Fig. 9 Reduction in distribution system investment costs due to managed EV charging. Each colored dot represents a data point from six studies. Multiple values from the same reference are enclosed within the same shape for more direct comparison. The DS planning benefits of MC have been shown to be higher under lower EV penetrations and in DSs with high load density.

Studies have shown a wide range of DS investment cost reduction values of MC, ranging from $5–$1,090/EV/year, as shown in Fig. 9. These substantial variations can be attributed to several factors. The marginal investment cost reduction benefits of EVs may diminish with increasing EV penetration.[167] Also, the value of MC in reducing DS investments is shown to be higher ($145/EV/year) in an urban area with high load density and underground cables, but fairly limited ($5/EV/year) in a rural area with highly dispersed loads.[243] Studies have also reported that DS reinforcement deferral values of MC would be higher under scenarios with widespread fast charging.[167,208] Finally, charging management schemes also affect the outcomes. For instance, charging based on EV owners' cost minimization led to almost 70% higher reinforcement costs compared to uncontrolled charging, and ~260% higher costs compared to charging based on peak load minimization.[207] Also, Crozier, Morstyn, and McCulloch[192] report that while 28% of the DSs in the United Kingdom would require updates if EV charging is not managed, managing EV charging to flatten the load at the BPS level reduced this percentage to 19%, which can be further reduced to 9% if EV charging is managed to flatten the load at the DS level. This also points to the fact that MC based on improving BPS operation might not be optimal in terms of DS performance. Therefore, MC strategies need to be carefully designed considering the trade-offs at the BPS and DS levels.

4.7 Charging costs and revenue from grid services

Many of the benefits of MC described above can provide revenue to charging station operators and aggregators, and offset some of the costs of charging to the EV owner. A number of studies have analyzed these benefits from the perspective of these entities. This analysis evaluates how different MC approaches might impact revenue opportunities

As an example, Donadee and Ilić[246] present an approximate stochastic dynamic programming problem for maximizing the expected profits from price arbitrage (charging during lowest price periods) and providing frequency regulation (FR) for an EV owner under market price uncertainty. Similarly, an optimal control problem is implemented in Rotering and Ilic[153] to maximize an EV owners' price arbitrage and FR profits while considering the impacts on battery degradation. Sioshansi and Denholm[186] use marginal prices of energy and reserve and optimal EV participation values from a PCM to assess the value of V2G for EV owners. In contrast to optimization-based methodologies, a droop-based scheme for provision of FR using

EVs is presented in Calearo and Marinelli.[247] The droop-based charging/discharging power of EVs is then used to calculate the associated revenues (based on FR prices) and battery degradation costs (using semi-empirical functions). Wu and Sioshansi[248] maximize the profits from price arbitrage and FR for an EV charging station using stochastic optimization, whereas the impacts of a charging station's strategy (cost minimization vs. PAR minimization) on charging costs and DS operation are compared in Mehta et al.[197] Similarly, the impacts of different pricing schemes not only on the profitability of a parking lot owner and DSO, but also on DS operation, are evaluated using bilevel optimization in Sadati et al.[163]

The potential of MC in minimizing an EV aggregator's (EVA's) charging costs is analyzed in Le Floch, Di Meglio, and Moura[249] using an optimization problem based on partial differential equations subject to individual EVs' charging requirements and constraints on provision of contracted FR services. Similarly, Hu et al.[162] and Wang et al.[165] analyze the impacts of considering power consumption limits set by the system operator on EVA's charging costs, whereas Clairand, Rodríguez-García, and Álvarez-Bel[165] incorporate penalties associated to the violation of such power consumption limits in the objective function of an EVA. Instead of constraint violation penalties, distribution locational marginal prices are included in the EVA's cost minimization problem presented in Liu et al.[201] Compared to including power consumption constraints and/or costs associated to the grid services provided by the EVA, Steen et al.[163] and De Hoog et al.[171] include DS power flow constraints within the EVAs' optimization problems, transforming them into OPFs.

Several studies show that MC can reduce EV charging costs for the EV owners and aggregators by about 10%–60% depending on intra-day price variability, charging schemes,[162,170] V2G capability,[186,200] participation in FR,[246,249] and participation in unmonetized DS services. Results also show that if EV charging is controlled to provide unmonetized DS services, the charging costs can increase by ~5%–90% (compared to cost minimization without considering DS operation). This is primarily because EV charging based on lowest wholesale prices might cause DS congestion, voltage quality issues, and/or energy losses.[162,163,207] Therefore, charging EVs while avoiding these impacts tends to be more expensive. These results highlight that it would be imperative to holistically consider the trade-offs between BPS and DS benefits of MC, and to adequately monetize DS services to incentivize the participation of EVs in improving network operation.

4.8 Benefit-cost analyses

While Sections 4.2–4.7 highlighted the numerous benefits of MC across various aspects of the power system, the value of managed charging is a function of benefits and costs (see Section 3.2 for MC enablement costs) and how they are allocated to different entities, including EV users, electric utilities, general ratepayers, and others. Numerous benefit-cost analyses have been performed by utilities to assess the impacts of increased EV adoption in a region. These are often used to inform investment decisions, rate designs, and other regulatory processes, and to better understand consumer and societal benefits (e.g., value of emissions reductions, consumer fuel cost savings). Some of these analyses also considered the value of MC, even though limited to passive implementations, mostly involving TOU tariffs. Under baseline charging assumptions, these studies have reported utility benefits exceeding costs by hundreds of dollars per EV.[250] MC has been estimated to roughly double those net benefits, with annual value of MC ranging from \$34/EV to \$166/EV.[251–256] This large variability in the value of MC for utilities is driven by a number of factors, ranging from analysis scope, approaches, EV adoption projections, and assumed flexibility and heterogeneous characteristics of different power systems. A single case even projected declining value for the utility with implementation of MC.[251] The same study, however, reports EV users' net benefits of participating in a managed charging program (lower cost of off-peak TOU charging) ranging from \$148/vehicle to \$571/vehicle, not including the one exception discussed previously.

Across benefit-cost analyses, a number of common themes emerge. When examining the long-term utility perspective, avoided generation capacity is typically the largest benefit of managed charging, followed by either avoided distribution infrastructure costs or avoided generation energy costs.[251–256] The utility financial impacts of managed charging, however, may vary due to the characteristics of the retail and wholesale electricity markets in which utilities operate. Most utilities can take advantage of MC to reduce peak demand and capacity-related costs. However, there may be instances where distribution-only and retail choice utilities cannot directly realize the benefits of MC due to how they procure electricity supply on behalf of their retail customers. Ultimately, the incentive to invest in managed charging programs will be based upon the value proposition or regulation.

Overall, a critical review of these benefit-cost analyses highlights limitations and major uncertainties, mostly driven by limited information on MC cost given nascent EV markets (most benefit-cost analyses assume zero enablement cost since they focus on TOUs), simplifications needed to capture the complex managed charging approaches and implications, and a lack of holistic consideration and detailed modeling of benefits of MC across various elements on the power system. Moreover, benefits and costs will likely evolve as technologies develop, EV adoption increases, and power systems and other loads evolve, making analysis more complex. Synergies between EVs and renewable integration, for example, might enhance the value of MC in high-VRE systems.[58,168,184,191] As such, developing a broader assessment of managed charging value continues to be an active area of research.

5 Conclusions, key insights, and research gaps

Increasing EV adoption is a great opportunity for utilities, and it is often projected to be the main driver of future electricity demand growth in the United States.[4,55] While EVs can pose operational challenges for existing electric power systems when charging is unmanaged, management of EV charging offers unique opportunities to support power system operation and planning. The increased load (and retail sales) from EV deployment may require investments to upgrade various parts of the power system, but several studies have shown that widespread EV adoption coupled with managed charging can reduce average retail electricity rates for all consumers. [54,55,157,245] Managed charging is particularly valuable in systems with high levels of variable renewables to provide flexibility to match supply and demand. The value of managed charging, however, must consider both the benefits that MC can provide as well as the costs of implementation. Benefits have been estimated in many studies, but not in a holistic framework that consistently considers all the values that managed charging can provide and their trade-offs. Individual estimates might therefore be underestimating the full value of managed charging. On the other hand, combining individual benefits reported in different studies can lead to overestimation of benefits, primarily due to the lack of consideration of trade-offs between multiple value streams. Enablement and implementation costs remain highly uncertain due to limited market implementations. Overall, a complete benefit-cost assessment, even at a regional level, is still missing that considers the entire extent of values, enablement costs, and the perspectives of all stakeholders, including utilities, EV owners, charging station operators, and rate payers.

This paper reviews numerous studies that quantify the value of managed charging across the power system. Here, we synthesize several insights from these studies:

Benefits of Managed Charging:

- Compared to unmanaged EV charging, managed charging can provide significant benefits, reducing operation costs for bulk and distribution systems, improving reliability and voltage quality, supporting renewable integration and reducing curtailment, and potentially reducing the need for additional generation, transmission, and distribution capacity, thereby reducing planning/investment costs and times.
- Modeling studies show that EV managed charging can provide various operational benefits for bulk power systems, including reduction of system operation costs (\$15–\$360/EV/year), greenhouse gas emissions (−0.1 to 2.5 tons CO_2/EV/year), peak loads (0.2–3.3 kW/EV), and curtailment of variable renewable generation (23–2,400 kWh/EV/year).
- Managed EV charging can support and complement the expected large-scale VRE deployment, with significant implications for long-term planning and to support decarbonization policies.
- While the increased load from EV deployment may require investments to upgrade various parts of the power system, which could in principle increase electricity costs, several studies have shown that widespread EV adoption coupled with managed charging improves overall system efficiency and can reduce average retail electricity rates for all consumers.
- The benefits of EV managed charging vary significantly across studies due to different approaches, assumptions, and heterogeneity in power systems, EV adoption, use, and charging flexibility scenarios, making direct comparison difficult.
- Studies consistently find that the marginal operation and planning benefits of managed charging diminish with increasing EV penetration, owing to the presence of shallow value streams and competition with other technologies or approaches that provide flexibility cost-competitively.
- Differences in charging management schemes and time-varying tariffs lead to substantial differences in the benefits managed charging can provide. Without careful consideration, managed

charging can lead to unintended operational problems. Particularly, EV charging solely based on cost minimization (under wholesale market prices) can be worse than uncontrolled charging for the distribution system.

- Different power system characteristics also affect the value of managed charging. For instance, the managed charging operation cost savings could be significantly lower in systems that have other cost-completive sources of flexibility (e.g., energy storage). Also, the value of managed charging is computed with respect to a baseline. As strategies and other flexibility options are employed, the incremental value of increasingly complex managed charging implementations may decline as the baseline evolves in step.
- The value of managed charging will likely change over time as power systems evolve, more EVs are deployed for different applications, and charging approaches and consumer behavior evolve.
- V2G can potentially further reduce operation costs, CO_2 emissions, and peak load (compared to V1G) by displacing inefficient peaking generators.
- Unmanaged charging of large EV loads can increase both frequency and magnitude of lost load. Managed charging can support grid reliability by reducing loss of load and energy not served, particularly by injecting electricity to the grid (V2G) and/or to customers' homes or buildings (V2X). While managed charging can reduce both the severity and frequency of loss-of-load events at the BPS level, the reduction in frequency of outages at the distribution level are only evident if condition-dependent component outage models are used, and/or if managed charging can completely restore the local network load. Challenges due to unmanaged EV charging could manifest at the distribution system level first. However, the monetary value of managed charging at the bulk power system may exceed those of the distribution system in the long run.
- The range of benefits for distribution systems is particularly wide—where issues are location- and system-specific. Managed charging can noticeably reduce distribution system peak loads and congestion, and consistently increase the maximum feasible EV penetration for existing systems, even though "hosting capacity" is location-specific and also impacted by EV use, consumer participation, and managed charging programs. Generalization of the insights from modeling and analysis studies require simulating the impacts of managed charging in more diverse and realistic distribution systems under varying assumptions.

Managed Charging Implementations:

- While V1G is similar to demand response for other loads, there are significant differences in the EV market that suggest experiences may diverge.
- Benefits of more complex implementations (e.g., active V2G) are greater but more costly to implement. Full benefit-cost analyses to date, which rely on simplified approaches, are limited to passive V1G.
- The V2G benefits reported in the reviewed literature represent an upper bound achievable under ideal situations. In realistic applications, the V2G capability of EVs may be significantly restricted by the mobility requirements, particularly for long-duration value streams, such as reliability and capacity value.

These insights suggest a number of **gaps as well as research and development/demonstration needs:**

- Characterizing the needs of different EVs used for different applications is the first step to study managed charging. Most managed charging literature has focused on personal light-duty vehicles using average statistics, with earlier studies focusing on PHEVs. It is important to capture differences in vehicle use and charging opportunities. Also, with growing interest for battery electric vehicles in ride-hailing fleets and medium- and heavy-duty applications that might charge at higher power levels, it is important to consider these emerging trends. Additional data, modeling, and analysis studies are needed to better estimate charging needs, customer participation, and constraints for various vehicle types and applications that will ultimately determine charging loads and ability to provide demand-side flexibility

- Since the value of managed charging is impacted by the characteristics of both the bulk power and distribution systems (as well as other flexible loads and energy storage technologies) and looking at these systems independently may result in discrepancies and suboptimal solutions, a comprehensive analysis across the entire power system is needed to better understand the total benefit managed charging can provide. Conflicting charging solutions might maximize different value streams, suggesting the existence of trade-offs and an overall optimal solution for assessing the systemwide benefits of EVs when simultaneously providing multiple grid services. This would, however, require development of methodologies for improving the computational tractability of modeling such complex system holistically.
- Capturing these system benefits (not always explicitly monetized in today's markets) will require ways to demonstrate and market mechanisms to pass on these savings to participants and compensate EV users for providing flexibility while ensuring other stakeholders are also benefitting from managed charging.
- The role of charging infrastructure in enabling and supporting managed charging remains an open research question, with limited insights informing cost-benefit trade-offs and guiding investment decisions (e.g., what are the trade-offs between residential and workplace/public charging considering infrastructure costs as well as cost and benefits for the power system).
- While the impacts of managed EV charging on power system reliability have been analyzed in several studies, there is a dearth of literature on the benefits in improving grid resilience under high-impact, low-probability events such as natural disasters, as well as the value of local resilience (e.g., residential building backup power during such events).
- Estimation of the value of managed EV charging under different regulatory requirements, particularly for evaluating the potential of V2G in improving power system reliability, remains an unexplored area to inform evolving regulations and the design of future power markets.
- Realizing the central role of EV owners' behaviors and preferences in shaping the flexibility of managed charging, a multidisciplinary assessment approach is required to evaluate managed charging in the context of the social sciences and humanities.
- As the EV market rapidly evolves, it is important to consider new technologies and charging solutions in assessing integration challenges and managed charging opportunities. Future work should consider more EV applications and emerging mobility trends, such as ride-hailing, autonomous vehicles, and e-commerce, and their impact on EV charging needs and flexibility.

Appendix

Summary of Ancillary or Essential Reliability Services

Table 2 Summary of ancillary or essential reliability services

Operating Reserves	
Frequency-Responsive Reserves	Services that act to slow and arrest the change in frequency via rapid and automatic responses that increase or decrease output from generators providing these services. These services include inertial response and primary frequency response (PFR). An emerging product is "fast frequency response," which may replace some fraction of traditional inertia/PFR.
Regulating Reserves	Also known as frequency regulation. Rapid response by generators used to help restore system frequency. These reserves may be deployed after an event and are also used to address normal random short-term fluctuations in load that can create imbalances in supply and demand.
Contingency Reserves	Reserves used to address power plant or transmission line failures by increasing output from generators. These include spinning reserves, which respond quickly and are then supplemented or replaced with slower-responding (and less costly) non-spinning/replacement reserves.
Ramping Reserves	An emerging and evolving reserve product (also known as load-following or flexibility reserves) that is used to address "slower" variations in net load and is increasingly considered to manage variability in net load from VRE.
Other Services	
Black-Start	Capacity that can be started without either external power or a reference grid frequency, and then provide power to start other generators.
Voltage Support	Used to maintain voltage within tolerance levels and provided by local resources.

Summary Table of Existing Implementations of Managed Charging

Table 3 summarizes existing implementations of managed charging, as discussed in Section 3. The following summary is not intended to be exhaustive or comprehensive, but rather provides an overview of programs and projects across differing MC strategies. Examples range from established utility-scale pricing schemes to exploratory, small-scale demonstration projects for emerging technologies (e.g., V2G). Examples for the following table were primarily identified from more comprehensive summaries presented in other references.[85,90,105,115]

Table 3 Summary of existing implementations of managed charging

Direct/ Indirect	Charging Direction	Mechanism	Sector(s)	Project/Program and Timeframe	Goal(s)	Size	Participation	Compensation	Value
Direct	V1G	Demand response signal	Residential light-duty vehicle (LDV)	BMW/PG&E ChargeForward Pilot, 2015–2020[103,109]	Potential for grid services to reduce EV costs, support renewable energy integration	Phase 1: 96 drivers, Phase 2: >400 drivers	90% success in call events	$1,000 upfront, ongoing incentive for each day with no opt-out	$325/vehicle per year in grid savings 1,200 kWh of renewable energy/vehicle per year
			Residential LDV, commercial LDV	Avista EVSE Pilot, 2016–2019[104]	Understand LDV EV load profiles, grid impacts, costs, and benefits; support EV adoption	439 charging ports	85% opt-in rate	Installation and operation of EVSE	75% curtailment of peak EV load
Indirect	V1G	EV TOU	Residential LDV	NV Energy, Active[258]	Not specified	Not specified	Not specified	TOU rate, credit for difference from flat rate for first 12 months	Not specified
			Residential LDV	SDG&E PEV TOU, 2014[87]	Understand impact of EV charging and mitigate negative impacts	Not specified	86%–94% off-peak or super off-peak charging	TOU rate	Not specified
		EV day-ahead pricing	Residential LDV, workplace LDV	SDG&E Power Your Drive, Active[99]	Not specified	Not specified	Not specified	Day-ahead time-varying rates	Not specified
		Charging rebates	Residential LDV, Commercial light-, medium-, and heavy-duty vehicle	ConEdison SmartCharge New York, Active[85]	Incentivize off-peak charging, understand customer response	Not specified	Not specified	Monthly and per-kWh rebates for off-peak charging	Not specified
Direct	V2G	Frequency regulation market	Commercial LDV, medium-duty vehicle	Los Angeles Air Force Base Vehicle to Grid Demonstration, 2016–2017[113]	Explore cost savings potential of plug-in electric vehicles via V2G	29 vehicles	Not applicable	CAISO regulation market tariffs	$2,200 per season for fleet (29 vehicles)—likely not economical

Meta-Analysis Table of Managed Charging Modeling/Analysis Studies

Table 4 summarizes the modeling/analysis studies reviewed in this paper. In particular, it presents the geographic scope, modeling perspective, study goal(s), methodological details (including model type, formulation framework, and treatment of uncertainty), value streams, number/penetration of EVs, implementation mechanisms, and charging direction(s) (V1G and/or V2G) considered in these studies. The table is primarily organized by the type of analysis (indicated by different row colors), starting with bulk system operation, followed by distribution system operation, bulk system reliability, distribution system reliability, bulk system planning, distribution system planning, and charging costs and revenues. Within each analysis type, the studies are arranged according to geographic scope, starting with national scope and followed by regional, local, and individual scopes. Studies with the same geographic scope are subsequently ordered according to the modeling perspective(s) starting at the TSO level, going down to individual EV owners' perspective. Finally, studies with the same analysis type, geographic scope, and modeling perspective(s) are arranged in the order in which they appear in the manuscript.

Table 4 Summary of managed charging modeling/analysis studies

Legend:

Geographic Scope: National Regional Local Individual

Modeling Perspective: TSO DSO Aggregator Transport System Parking Lot/ Charging Station Individual EV Owner

Value Stream:
R: Reliability IC: Investment Costs MP: Maximum EV Penetration OC: Operation Costs PL: Peak Load E: Emissions
RC: RE Curtailment AO: Asset Overloading EL: Energy Losses FS: Frequency Support VQ: Voltage Quality CC: Charging Cost

Methodology:

Uncertainty:
Deterministic Model: D- Stochastic Model: S-

Model Type:
Capacity Expansion Model: CEM
Droop-based Control: DBC
Charging Cost Minimization: CCM
Load Shaping Model: LSM
Production Cost Model: PCM
Monte Carlo Simulation: MCS
Other Optimization Problem: OOP
Other Methodology: OM

Framework:
Centralized: Blue Decentralized: Red N/A: Black

Ref.	Geographic Scope & Modeling Perspective(s)	Study Goal(s)	Methodology	Value Streams	No. of EVs/ Penetration	Implementation Mechanism	Charging Direction(s)
152		Evaluating the impacts of managed charging on overall system operation based on minimization on operation costs	D-PCM	OC, E	260,000 (10%)	Not Specified	V1G
160		Evaluating the impacts of V2G on long- and short-term system performance based on minimization of investment and operation costs	D-CEM	IC, OC, E, RC	76 million	Not Specified	V2G
177		Evaluating the impacts of V1G and V2G on long- and short-term system performance based on minimization of investment and operation costs	D-CEM	IC, OC, E	1 million	Not Specified	V1G, V2G

184		Evaluating the impacts of V1G and V2G on overall system operation based on minimization of operation costs	D-PCM	OC, RC	27,000	Not Specified	V1G, V2G
187		Evaluating the impacts of managed charging on overall system operation based on minimization of operation costs	D-PCM	PL, E, RC	4.8 million	Not Specified	V1G
189		Comparing the impacts of centralized and decentralized EV charging on overall system operation	D-PCM, D-CCM	OC, PL	1 million (25%)	Optimal Control compared to TOU tariffs	V1G
192		Evaluating the potential of smart charging in flattening transmission and distribution network load	D-LSM	PL, EL, VQ, AO	100%	Not Specified	V1G
151		Evaluating the benefits of V2G in terms of peak load reduction and improving power plant operation	D-LSM	PL	Up to 50%	Not Specified	V2G
154		Evaluating the benefits of V1G and V2G in terms of reducing net load ramping and VRE curtailment	D-LSM	PL, RC	1.5 million	Not Specified	V1G, V2G
155		Comparing optimal EV charging profiles with those obtained using time varying rates	D-PCM	OC, E	1%	Time-varying prices	V1G
157		Evaluating the impacts of managed charging on overall system operation based on minimization on expected operation costs under uncertainty	S-PCM	OC	735,000 (10%)	Not Specified	V1G
166		Evaluating the impacts of MC on overall system operation based on minimization on operation costs. Also, comparing optimal EV charging with TOU-based charging	D-PCM	OC, RC	0.95–5 million (4% to 20%)	Dynamic pricing compared against TOU tariffs	V1G
168		Evaluate the impacts of V1G and V2G on overall system operation based on minimization on operation costs	D-PCM	PC, PL, RC, E	50%	Not Specified	V1G, V2G
169		Evaluating the effectiveness of a decentralized charging strategy for valley filling	D-LSM	PL	10 million	Coordination Pricing	V1G
173		Evaluating the impacts of managed charging on overall system operation based on minimization of operation costs	D-PCM	OC, PL, E, RC	3 million	Not Specified	V1G
185		Evaluating the impacts of V2G on emissions based on minimization on operation costs	D-PCM	E	0.075–1.14 million (1% to 15%)	Not Specified	V2G
186		Assessing impacts of V2G on system operation cost savings and value for EV owners	D-PCM	OC	0.075–1.14 million (1% to 15%)	Not Specified	V2G
90		Evaluating the peak load reduction potential of managed charging	D-LSM	PL	23%	Not Specified	V1G
171		Evaluating the impacts of different charging schemes on DS operation and maximum EV penetration	D-CCM	MP, PL, VQ	80%	TOU-tariffs	V1G, V2G
172		Assessing impacts of EV charging rates on maximum feasible EV penetration	D-LSM	MP, AO, PL, VQ	100%	TOU-tariffs	V1G
175		Evaluating the potential of managed charging in increasing the maximum feasible EV penetration	D-OM	MP	1,510	Not Specified	V1G
195		Evaluate the benefits of managed charging for reducing DS upgrades	D-LSM	PL, AO, VQ	4,000–8,000 (100%)	Not Specified	V1G

196		Evaluating the impacts of different charging schemes on DS operation and maximum EV penetration	D-LSM	MP, PL, EL	1,000–2,000	Not Specified	V1G
198		Demonstrating the effectiveness of the proposed control algorithm for simultaneous thermal and voltage management	D-OM	MP, AO, VQ	86	Direct Load Control	V1G
199		Evaluating the benefits of managed charging for improving DS operation	D-OOP	AO, EL, E	227 (67%)	Direct Load Control	V1G
202		Coordinate the operation of DS and transport network to reduce charging costs, peak loads, and traffic delays	D-OOP	PL, VQ, CC	Not specified	Dynamic Coordination Pricing	V1G
159		Operation of a charging service provider in coordination with a retailer and DSO	D-OOP	PL, AO, VQ	2,200	Direct Load Control	V1G
161		Coordinating the operation of DS operator, fleet operator and EV owners using a distribution grid capacity market scheme	D-CCM	CC, PL	36 (60%)	Direct load control	V1G
162		Assessing impacts of EV charging strategy (uncontrolled, price optimal or loss optimal) and demographic data on DS operation	D-OOP, D-CCM	MP, PL, VQ, EL, CC	254 in Area A, 2,306 in Are B	Price Optimal: Dynamic spot prices; Loss Optimal: Direct load control	V1G
164		Optimally coordinate the active and reactive power dispatch of EVs for minimizing charging costs improving DS operation	D-CCM	CC, VQ, PL	1,500	Not Specified	V2G
201		Assessing the effectiveness of distribution LMPs for reducing DS congestion	D-CCM	CC, AO	100%	Direct load control	V1G
163		Assessing the value of bilevel optimization as compared to centralized optimization for maximizing the profits for the distribution company and PL owner	D-OOP	CC, EL	100	Critical Peak Pricing	V2G
158		Comparing the effectiveness of a decentralized methodology TOU and external marginal cost pricing for reducing peak loads and load variance	S-LSM	PL	500	Coordination Pricing	V1G, V2G
203		Evaluating the effectiveness of a decentralized methodology for reducing peak loads and load variance	S-LSM	PL	315	Coordination Pricing	V1G, V2G
205		Evaluate effectiveness of a droop control methodology for improving DS voltage quality	D-DBC	VQ	100%	Droop Control	V2G
206		Experimental validation of a droop control methodology for improving DS voltage quality	D-DBC	VQ	3	Droop Control	V1G
170		Comparing impacts of charging cost minimization and maximization of total stored energy in EVs on DS operation	D-OOP, D-CCM	MP, PL, AO, VQ, CC	57 (50%)	Not Specified	V1G
200		Comparing impacts of charging mechanism (V1G or V2G) and charging rate (fast or slow) on maximum feasible EV penetration	D-OOP	MP, AO, PL, VQ, CC	1,000	Not Specified	V1G

204		Evaluating the effectiveness of decentralized algorithms for reducing energy consumption and peak loads	D-LSM	PL	1,000	Demand shaping signal	V1G, V2G
197		Comparing impacts of charging cost minimization and PAR minimization on maximum feasible EV penetration	D-CCM, D-OOP	MP, AO, PL, CC	1,000	Direct Load Control	V1G
214		Evaluating the adequacy of BPS with electric vehicles and high wind penetration	S-MCS	R	2%	Direct Load Control	V1G
217		Comparing the proposed analytical methodology with SMCS for evaluating the reliability benefits of managed charging	S-OM	R	10%	Not Specified	V1G
174		Evaluating the effectiveness of the proposed stochastic EV charging model in capturing the reliability impacts of EV charging	S-MCS	R	5.5%–11%	Not Specified	V1G
176		Evaluating the effectiveness of the proposed framework is assessing the reliability impacts of EV charging	S-MCS	R	0%–50%	TOU tariffs and Critical Events Call	V1G
215		Evaluating the impacts of V1G and V2G on BPS reliability	S-MCS	R	100%	Not Specified	V1G, V2G
216		Evaluating the benefits of V2G on BPS reliability	S-MCS	R	15,000	Direct Load Control	V2G
218		Evaluating the impacts of EV charging objective on BS reliability	S-MCS	R	69,000	Direct Load Control	V2G
219		Evaluating the impacts of managed charging on BPS reliability	S-MCS	R	50%	Not Specified	V1G
220		Evaluating the impacts of different charging strategies and transmission network operation strategies on BPS reliability	S-MCS	R	480,000 (25%)	Not Specified	V2G
221		Evaluating the impacts of VRE and EV penetration on BPS and EV charging reliability	S-MCS	R	10%	Not Specified	V2G
223		Evaluating the impact of Advanced Metering Infrastructure (AMI) failure on BPS reliability assessment.	S-OM	R	21,000	Scarcity Pricing	V1G
227		Evaluating the impacts of EV penetration and charging rate on DS reliability	S-MCS	R	30%, 50%	Not specified	V1G, V2G
228		Evaluating the impacts of EV penetration and charging scheme on DS reliability	S-MCS	R	Up to 62%	Direct Load Control	V2G
229		Evaluating the impacts of EV mode of operation on DS reliability	S-MCS	R	100%	Direct Load Control	V2H, V2G
230		Evaluating the impacts of EV mode of operation on DS reliability	S-MCS	R	31%	Direct Load Control	V2H, V2G

233		Evaluating the benefits of V2G on DS reliability considering a condition-dependent outage mode	S-MCS	R	10%–100%	Real time pricing, Reliability incentives	V2G
234		Evaluating the impacts of EV penetration on DS reliability while considering traffic congestion	S-MCS	R	0% to 100%	Not specified	V2G
231		Evaluating the benefits of PL V2G charging on DS reliability	S-MCS	R	1 Parking Lot	Direct Load Control	V2G
232		Evaluating the benefits of PL managed charging on DS reliability considering behavioral aspects	S-MCS	R	1 Parking Lot	Direct Load Control	V1G, V2G
156		Evaluating the impacts of V1G and V2G on generation and transmission system investments	D-CEM	IC, OC, E	36 million	Not Specified	V1G, V2G
236		Evaluating the impacts of EV charging schemes on generation and transmission system investments	D-CEM	IC, OC, PL	0.18–0.56 million	Not Specified	V1G
238		Evaluating the impacts of co-optimization of BPS investments and proportion of flexible EV demand	D-CEM	IC, OC	0%–100%	Direct load control	V2G
237		Evaluating the benefits of managed charging in reducing long-term investment and operation costs	D-CEM	IC, OC, E	1 million	Dynamic Marginal Pricing	V1G, V2G
239		Evaluating the impacts of EV charging controllability on generation and storage expansion	S-CEM	IC, OC	30,000 (30%)	Direct load control	V2G
240		Quantifying the potential investment and operation cost reduction benefits of V1G and V2G	D-OOP	IC, OC	5	Not Specified	V1G, V2G
208		Evaluating the impacts of managed charging on DS investments and energy losses.	D-LSM	IC, AO, EL	720,000 (75%)	Not Specified	V1G
242		Evaluating the benefits of different DR technologies for improving DS operation and asset management	D-LSM	IC, PL	3.42 million (10%)	Not Specified	V1G
243		Evaluating the impacts of EV penetration on DS investments and energy losses.	D-CEM	IC, EL	Area A: 2,335, Area B: 17,748	TOU or RTP	V1G
245		Evaluating the impacts of EV charging on distribution transformers	D-OM	IC, AO	10 (40%)	Direct Load Control	V1G
244		Evaluating the benefits of V2G in reducing DS investments	D-CEM	IC, OC	3,000	Direct Load Control	V2G
167		Evaluating the impacts of charging power and management on DS investments end electricity procurement costs	D-CCM	IC	2–12 million (5%–30%)	Dynamic Pricing	V1G
207		Assessing the financial impact of various EV charging strategies on distribution grids.	D-CCM, D-OOP	IC, AO, EL	430,000 (47%)	Not Specified	V1G
165		Minimizing aggregator's charging cost	D-CCM	CC	Up to 1,000	Direct Load Control	V1G
249		Minimizing the cost of charging plug-in EVs, subject to supplying sufficient energy to the grid and sufficiently charged EVs to the drivers	D-CCM	CC, FS	2,225	Direct Load Control	V1G

248		Maximizing the profits from energy arbitrage and frequency regulation services	S-CCM	CC, FS	1 Parking Lot	Direct Load Control	V1G
153		Maximizing profits from energy arbitrage and frequency regulation services	D-CCM	CC, FS	1	Dynamic Energy and Reserve Pricing	V1G
246		Maximizing expected profits from energy arbitrage and frequency regulation services considering price uncertainty.	S-CCM	CC, FS	1	Dynamic Energy and Reserve Pricing	V1G
247		Maximizing profits from frequency regulation while considering battery degradation	D-DBC	CC, FS	1	Droop Control	V2G

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