

Treasure Hiding in Plain Sight: Launching Electric Transport with the Grid We Already Have

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1. Executive Summary

Electric vehicles (EVs) represent a promising option for decarbonising road transport, especially as the greenhouse gas emissions profile of primary electric energy production steadily improves. As the cost and performance of EVs have seen dramatic improvements in recent years, policymakers have begun to consider not only how to accelerate the commercialisation of this technology, but also how to adapt the transport and energy systems to accommodate increasing levels of adoption.

Central to this discussion is the role of electricity distribution systems. Much of the focus has been on how to incentivise the new investment needed to add “smartness” and additional capacity to distribution networks. Often overlooked in the discussion are the utilisation rates of existing distribution system assets. Deployment of smart grid technologies combined with the inherent flexibility in when EVs can be charged creates the opportunity to accommodate growing EV penetration by significantly increasing the utilisation rates of existing network capacity. Doing so would forestall unnecessary investment and, in so doing, offer benefits to all consumers, not just those who choose to adopt EVs.

There is great uncertainty about how much new network capacity will be needed to accommodate transport electrification, and when, especially as established patterns of vehicle ownership and usage are being challenged on multiple fronts. It thus seems doubly unwise to focus on promoting investment in new capacity when substantial unused existing capacity may be available. A smarter approach would leverage cost-effective information, communication, and control technology, and progressive network tariff designs, to exploit unused existing network capacity and equitably distribute the cost of new investment. “Smart” delivers the transport services consumers and businesses want while affording the opportunity to better

understand what shape electrified transport will take.

The opportunity to promote smart (or beneficial) electrification may become even more important as electrification is deployed as one of the key decarbonisation strategies in the heating sector. Perfecting smart charging of EVs is likely to be relatively straightforward compared to the challenge of beneficially integrating new electric heating technologies. And the benefits of smart electrification go well beyond optimising the value of grid investments. Pricing that sets up perverse incentives for overinvestment in new generating capacity (which is beyond the scope of this brief) has the potential to dwarf the adverse consequences for grid investment.

2. Integrate what? The size and shape of EV loads

Much has already been written on the topic of EV demand on the electricity system. How much? When? And where? Behind these specific questions is a fundamental question about the future of road transport, the answer to which is far from clear: Will the current paradigm persist, in which a large population of vehicles sits idle for more than 90 percent of the time? Or will the paradigm shift to one of a much smaller population of vehicles owned by ride-sharing services that are operating at higher rates of utilisation?

The answers to these questions will drive a number of infrastructure investment decisions, but what will not change is the basic fact that the power implications (the instantaneous incremental draw on the system) have the potential to be far greater than the energy implications (the incremental consumption of energy over time). In other words, assuming a continuation of the current road transport paradigm, if the entire passenger vehicle fleet were converted to all-electric drives tomorrow, demand for energy would increase by only about 20 percent – not insignificant, but manageable without a dramatic increase in investment.¹ But if those same vehicles were all plugged into fast charging systems at the same time – and at the wrong time – the demand for power could be two times current peak power demand. The risk, therefore, is that enormous amounts of infrastructure investment may be made (in production resources, such as power plants and storage, and in grid infrastructure, such as power lines and transformers) that would experience very low rates of utilisation, on top of existing investments in energy system assets that themselves currently experience low rates of utilization, as we will assess a bit further on. There is potential for this to become a barrier to adoption, and for that barrier to be raised even higher if the associated costs are seen to be allocated inequitably.

In considering the disproportionately large potential impact of power demand on power system infrastructure, it is important to note the distinction between “the potential to be far greater” and “will be far greater.” First, of course, is the fact that not all EVs will be charged at the same time, and not all EVs will utilise fast chargers when they are charged. Still, it would seem imprudent simply to assume something close to optimal charging behaviour. Fortunately, EVs are not like lighting or televisions, for which energy must be delivered at the moment the service is consumed; EVs constitute a flexible load and can be charged at any point during the hours when the vehicle is not being used. Under the current personal transport paradigm, that provides a great deal of flexibility without any appreciable negative impact on consumers’

¹ See Amsterdam Roundtables Foundation. (2014). *Electric vehicles in Europe: gearing up for a new phase?* Retrieved from: <https://www.mckinsey.com/netherlands/our-insights/electric-vehicles-in-europe-gearing-up-for-a-new-phase>, at page 41, or Eurelectric. (2015). *Smart charging: steering the charge, driving the change*. Retrieved from: http://www.eurelectric.org/media/169888/20032015_paper_on_smart_charging_of_electric_vehicles_finalpsf-2015-2301-0001-01-e.pdf, pg 14.

access to transport. Even under the ride-sharing paradigm there is likely to be some flexibility, and, where owners see the vehicle more as a business asset than a personal convenience, the imperative of having the vehicle operational when needed is likely to be matched by an even stronger incentive to minimise the cost of charging.

It therefore becomes crucial, from the perspective of sizing the local distribution feeder right up to and including the fleet of large central generating stations, to ask to what extent EV charging decisions can be shifted away from coincident peak periods for these various system assets – that is, avoiding when and, in the case of network assets, where the aggregate power demand for other less controllable energy services is greatest. Although this will be important for getting maximum value out of new infrastructure investments, a more immediate consideration is whether there is under-utilised existing capacity that can be usefully exploited to lower barriers to early adoption, minimise the risk for backlash from non-EV electricity consumers, and buy policymakers and energy regulators time to gain insight into the future shape of road transport services. And if so, how best to make that happen?

3. Exploit what? Estimating how much network capacity is available today

Today's distribution networks developed from a power system in which centralised power plants produced electricity that flowed across high-voltage power lines to consumers via lower-voltage distribution networks. This paradigm has changed significantly in recent years, with distributed resources displacing production from central power plants. As a result, some legacy distribution grid investments are oversized, and others under-utilised, because planners had not anticipated that a considerable amount of demand for both power and energy would be supplied locally.

The main cost drivers of networks are investments rather than operational costs. Concerns about these costs too often focus exclusively on lowering the cost of capital, but optimising the costs of networks to consumers also means using as much of their full capability as possible in meeting the needs of consumers. The first step in optimising the use of grid investments for large new applications is to assess the use of existing grids. This is to better understand how much spare capacity is available to accommodate new loads during system peak and other hours, how flows on the grid vary throughout the day, and where the bottlenecks are.

For the purposes of this paper, we define “network utilisation rate” as we would define the load factor of a power plant. A power plant's annual load factor is defined as the ratio of the actual amount of energy generated to the maximum amount of electricity that could be generated by a plant over the course of a year. Similarly, the utilisation rate of a network indicates the ratio of actual versus the maximum power flow over a network over a specified period.

Although estimating the load factor for a power plant is a relatively straightforward calculation given that its maximum capacity is well defined, doing so for a network is a more complex assessment, as for example the maximum capacity that can flow on a network depends on security limits of locational assets that are affected by operational parameters elsewhere. However, it is possible and prudent for network companies to assess the use of their networks and for regulators to request this information to ensure that investments in network assets are being used to their potential and not wasted. For example, for the period 2016 to 2019 the Swedish regulator introduced a new incentive scheme for the efficient utilisation of grids by

Distribution System Operators (DSOs). One of the three indicators that are assessed is the load factor of the network in the jurisdiction of a DSO.² Currently this information is not widely available for the distribution networks of Europe. In the absence of such information it will be difficult for grid companies and regulators to make informed decisions about the need for and value of investing in expanded grid capacity. Given this current lack of information, efficient market signals will be the most expeditious way to make use of slack capacity where it exists and justify new investment where needed, and as a result will be all the more important.³

In this section, we assess the utilisation rates for three different areas in Europe: the Westnetz and Edis distribution networks in Germany and the distribution network in France.⁴ We estimate the annual utilisation rates of the grids in question, the utilisation rate on the system peak day, and the utilisation rate on a typical summer day. Figure 1 presents these utilisation rates for the different areas and timeframes considered. For estimating the annual load factor of a network, we have made the conservative assumption that the maximum normal capacity of the network equals its annual peak flow. However, it is highly likely that these assumptions lead to an overestimation of the load factors, because (as noted earlier) recent trends have led to many systems being oversized and operating well below their normal limits. Hence the real utilisation rate of the networks is expected to be lower than presented here, perhaps quite a bit lower. Figure 2 presents the load curve for the peak demand day in two of the regions considered. From this analysis we conclude that:

- The annual utilisation of distribution grids is in most cases less than the 50 percent to 70 percent depicted in Figure 1, meaning that for long periods there is a considerable amount of network capacity available, that is, there is significant existing grid capacity to accommodate new loads, especially readily controllable loads such as EV charging.
- As shown in Figure 2, although the grid utilisation is highest on peak days, even on those days there is still significant scope to add load outside the peak hours, which can have a relatively short duration. For example, the difference between the highest and lowest load during the peak day on the distribution network in France is approximately 13 gigawatts

² The load factor for each DSO is estimated at the point of connection between the distribution and transmission network and defined as the ratio of average to maximum load. The other two factors considered are the network losses and the cost of the feeding grid. For more information, see Wigenborg, G., Werther Öhling, L., Wallnerström, C. J., Grahn, E., Alvehag, K., Ström, L., and Johansson, T. (2016). *Incentive Scheme for Efficient Utilization of Electricity Network in Sweden*. 13th International Conference on the European Energy Market (EEM). Retrieved from: https://www.ei.se/Documents/Publikationer/rapporter_och_pm/Rapporter_2016/Incentive_scheme_for_efficient_utilization.pdf

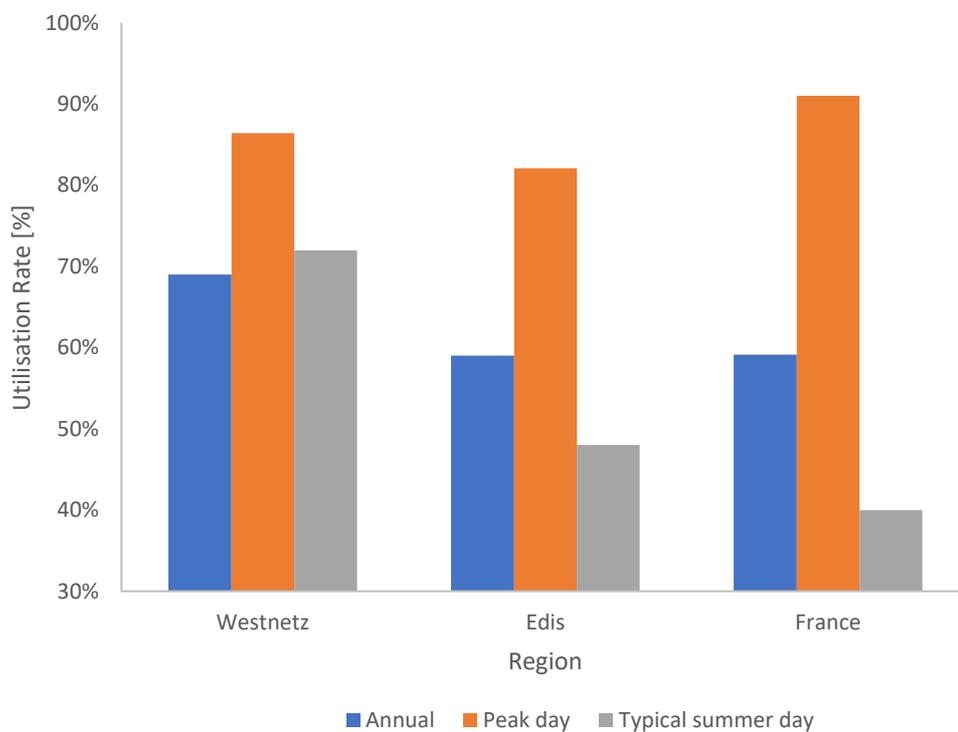
³ In addition to helping the more efficient use of networks, efficient market prices will also help the improved use of existing power generation assets and a more cost-efficient power sector overall. For example, by shifting new loads to non-peak hours, the utilisation and profitability of existing plant will increase, while avoiding the need for new investment in more expensive plants to meet demand at peak time. Filling the demand troughs with new loads will also help to smooth the load curve, leading to lower flexibility requirements for the power system, less start and stop, and as a consequence lower costs to keep the system in balance.

⁴ The data for Westnetz are for 2016; see Westnetz, Teil on Innogy [Westnetz, part of Innogy]. Netzrelevante Daten unseres Stromnetzes [relevant data for our electricity grid]. Retrieved from <https://iam.westnetz.de/ueber-westnetz/unser-netz/netzkennzahlen/netzrelevante-daten-strom>. The data for Edis are for 2016; E.DIS. Netzdaten [Grid data]. Retrieved from <https://www.e-dis-netz.de/de/edis-netz/netzinformation/veroeffentlichungen-strom/netzdaten.html>. The data for France are for 2014 and voltage levels between 1kV and 50kV, see Commission de Régulation de L'énergie [French Energy Regulatory Commission]. (undated). Outils de calcul de la structure des tarifs [Calculation tools for the tariff structure]. Retrieved from: <http://www.cre.fr/reseaux/reseaux-publics-d-electricite/outils-de-calcul-de-la-structure-des-tarifs>.

(GW), and the actual peak spans no more than two hours.⁵

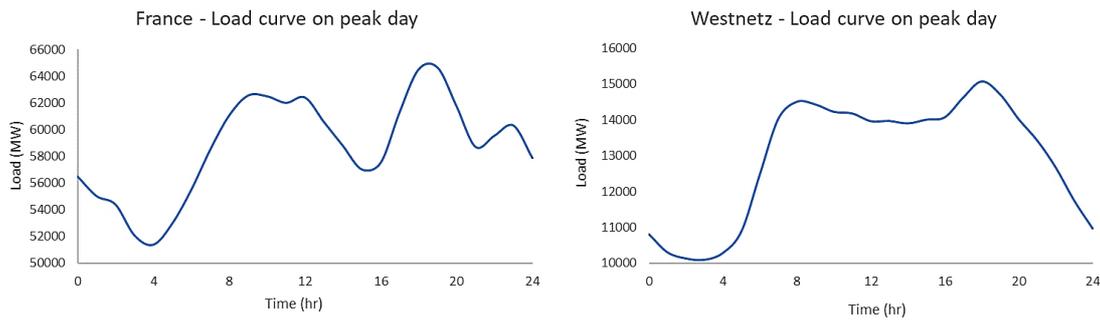
- A typical summer day shows the lowest utilisation rate, implying that there is sufficient network capacity to take up new loads during low-demand seasons (all three areas experience their peak annual demand during the winter). The summer-to-winter peak ratio varies from 0.63 (for France) to 0.92 (for Westnetz) for the three areas considered.
- This is a system-wide assessment, and hence there can be wide differences from one distribution area to the next. It does not preclude the possibility of locations (e.g., neighbourhoods at the low-voltage level) within the area of a network company that experience high utilisation or frequent congestion and that therefore require reinforcements or investments in new capacity.

Figure 1. Utilisation Rates for Selected Distribution Networks for Different Timeframes



⁵ This is equivalent to the capacity needed to charge simultaneously 1.9 million EVs using a Level-2 fast charger (with a load of 7 kilowatts [kW]).

Figure 2. Load Curves on the Peak Day⁶ for the French Medium-Voltage Grid (left) and Westnetz's Distribution Network (right)



4. Getting the most out of what we already have

Given the opportunities presented by the unused capacity of existing networks, the question that arises is: “How can one increase the chances that EV adopters will act in ways that minimise and equitably distribute the costs to integrate electric transport across all electricity and transport services consumers?” The answer relies on two levers, both of which are important – pricing and technology.

Pricing

Demand for goods and services can be “elastic” in response to prices, increasing or decreasing based on consumers’ ability to choose when to buy and how much to buy. Price elasticity traditionally has not been a significant factor in demand for electricity, which was typically sold at flat prices that obscured short-term fluctuations in supply and demand. There have in the past been a number of reasons for the limited price elasticity of electricity demand, including:

- the modest size of a typical electricity bill relative to other household expenses (although this cannot be said of low-income households);
- technical limitations on the ability to provide and respond to real-time pricing information; and
- limited options for consumers to choose when to buy the electricity needed to supply electricity-based energy services.

These traditional barriers to price elasticity of demand are slowly but steadily receding because of advances in the cost and performance of information technology, while at the same time the value of elastic, or flexible, demand is growing as production from variable generation increases and therefore primary electricity supply becomes less controllable. The advent of EVs will further erode these traditional barriers to demand elasticity – they transform the importance of the electricity bill, and they afford consumers wide discretion over when (and even where) they purchase a large fraction of their electricity needs. As primary electricity supply becomes more inherently volatile, the opportunity to save a lot of money (and the threat of spending a lot of money) can become a more significant factor for EV owners as well as a valuable tool in integrating renewable energy – if EV owners are given access to timely pricing information.

⁶ Peak day is defined as the day during which the system experiences its highest instantaneous demand.

Time-differentiated, usage-based pricing both for energy and for delivery is essential.

Time-differentiated, usage-based pricing both for energy and for delivery is essential. The recent Clean Energy for All legislative package includes language promoting dynamic pricing for the energy portion of electricity bills, which would be an important first step. Yet this falls well short of the information EV owners will need to make decisions that benefit not just themselves but the system as well, providing benefits to EV owners and non-EV owners alike. Energy alone constitutes a relatively small share of the total price for electricity, especially where electricity bills include significant fees for taxes and levies of various kinds. More important for the challenge posed here, energy (i.e., commodity) prices, dynamic or otherwise, are of no value in motivating EV owners to take advantage of unused network capacity. Charging for shared network services on a usage-based, time-differentiated basis is both feasible and necessary to extract as much value as possible from network investments.⁷

Sadly, although there has been movement in the right direction on energy charges, recent developments in network charging have often been in the wrong direction. The valid pursuit of “cost-reflectivity” in regulated tariffs has been mistakenly interpreted, in many quarters, to mean that investment-related costs must be reflected in fixed, capacity-based charges, especially because the network industry has an unusually – although not uniquely – high fixed-cost structure.⁸ The fallacy of this is apparent when considering the wide array of industries with comparably high fixed-cost structures that have long functioned profitably and efficiently on usage-based charging. Suffice it to say there is no validity whatsoever to the claim that the fixed costs of shared network investments must or should be recovered via fixed, capacity-based levies on customers. On the contrary, with growing electrification of transport it will become more important than ever that shared network charges be usage-based and time-differentiated.

Usage-based, time-differentiated network charging can take many forms. For strictly volumetric charges, the options range from critical period pricing (CPP), applying super-premium pricing during a limited number of the highest demand hours on the system (and super-discounted pricing during a limited number of hours of greatest system surplus); to time-of-use pricing (TOU), set at different levels during fixed blocks of time reflecting expected patterns of system loading; to full real-time pricing (RTP), with prices changing dynamically from one metering interval to the next, depending on real-time supply-and-demand conditions on the network. The nature of EV demand, where the objective is to shift demand to periods of energy and system surplus on a frequent basis rather than to simply suppress it during scarcity periods, favors the most dynamic option achievable within the specific context.

⁷ We recognise that, in an environment of dynamic energy *and* network prices, there will undoubtedly be times when the proper price signal at the local distribution level will be opposite the proper signal at the wholesale level. We think it is unlikely to occur often, but there is nothing in principle that suggests it should be avoided. Consumption and production (or curtailment) decisions will be resolved in the hierarchy of relative prices: the pricing for energy across a distribution area will reflect the value of energy, and the network charges will shift the resulting demand for energy around within that distribution area, based on network utilisation.

⁸ See Kolokathis, C., Hogan, M., and Jahn, A. (2018). *Cleaner, Smarter, Cheaper: Network tariff design for a smart future*. Brussels, Belgium: The Regulatory Assistance Project. Retrieved from: <http://www.raponline.org/knowledge-center/cleaner-smarter-cheaper-network-tariff-design-for-a-smart-future>

It may make sense in some circumstances to make use of tariff elements (distinct from energy-based charges) that reflect a customer's impact on the size and configuration of the network. Most common are demand charges, which impose a charge based on the customer's maximum recorded demand (in kilowatts) in a specified period, typically a month but in some cases only a day. Most examples relate the charges to the customer's peak demand regardless of when it occurs, which is nearly as ill-advised as capacity-based charges. More sensible (and requiring more sophisticated metering) are charges that are linked to a customer's demand during a relevant system peak – in this case, during the peak of the local network serving the customer (which, as we remark in an earlier footnote, might not always coincide with the peak of the overall system). Such charges, along with time-differentiated commodity charges, would give users an incentive to shift usage away from times of high demand, both generally and locally.

It is important, however, not to design these charges with ratchets, which have the effect of imputing the customer's peak demands in subsequent periods to be as great as, or nearly as great as, the original peak, and which dictate that only after a specified number of billing periods (sometimes as many as 11 months) can a customer's reduction in peak demand be reflected in reduced bills. Rather, demand charges should be only for peak demand in the billing period ("as used" is the term of art to describe this), which give the customer a stronger incentive to shift purchases for controllable loads like EV charging away from peak hours in the periods immediately following. Finally, these charges should be imposed on only high-volume end-uses, such as EV charging or, as is common in some regions, electric space heating.⁹

Technology and consumer preferences

Good pricing is essential, but as numerous pilot projects in a wide range of market environments have shown,¹⁰ good pricing shows best results when coupled with support for deployment of smart technology, just as support for deployment of smart technology shows best results when paired with good pricing. Beneficial electrification of transport thus requires a proactive approach to technology deployment, whereas the design of smart network and energy tariffs needs to follow progress on the availability of enabling technologies and the building of capacity among consumers in the use of those technologies.

One of the key technology challenges in deploying time-differentiated, usage-based tariffs, especially in the residential sector, is the availability of energy storage so that customers can purchase primary energy (electricity) when most beneficial, while consuming the related energy service when most convenient. In the case of electrified transport this challenge is largely overcome, because an EV is inherently an energy storage device, and the use of the transportation service typically takes place over a very limited period of any given day.

Time-varying tariffs cannot be offered in the absence of the appropriate metering technology. Without advanced metering infrastructure (AMI) for charging connections, TOU rates can be offered as a proxy for genuine dynamic tariffs, although this still requires a meter that can track at least two billing periods – peak and off-peak. In the absence of any smart metering options,

⁹ Capacity charges are a variation on this theme, but they are not well suited to encouraging economically efficient usage of the network. They are charges set to customer's maximum allowed demand in a period. They are not time-differentiated or in some way linked to the occurrence of the customer's coincident peak in a period, but the customer does have a choice in setting that maximum demand. Circuit breakers on the premises prevent that allowed demand from being exceeded.

¹⁰ See, for example Faruqui, A., Hledik, R., and Palmer, J. (2012). *Time-Varying and Dynamic Rate Design*. Montpelier, VT: The Regulatory Assistance Project. Retrieved from: <http://www.raonline.org/knowledge-center/time-varying-and-dynamic-rate-design> beginning at pg 27

non-pricing approaches such as direct control of charging (with a customer over-ride option) can be offered to address peak load, but this limited functionality falls short of what will be needed and may offer consumers inadequate incentives. Financial incentives for investing in separate AMI for EVs should be considered as a justifiable cost to achieve desired objectives.

AMI for EV charging can be coupled with in-home displays (IHD) to provide consumers with enhanced information about the consequences of their charging decisions. Although pilot programmes have demonstrated significant changes in consumer behaviour when enhanced information is available, those changes in behaviour have been shown to be deeper and more durable when purchasing decisions can be automated in response to that information.

Deployment of programmable controller technology should be supported through marketing and education programmes, as well as through direct financial support where justified by the achievable benefits. The choice of such programmes will depend on local circumstances, and different approaches should be trialed in pilot projects to assess relative effectiveness.

An alternative pathway to programmable automation by individual EV owners is through direct control of EV charging via demand aggregators. When it comes to transport services this may well prove a more attractive option in many cases, given that management of personal vehicles is often dictated more by ownership and access than by active concerns about the cost of operation. Maximising the aggregation options available should therefore be a priority. This should include the elimination of barriers to entry by independent demand aggregators (including non-traditional actors such as EV vendors), ensuring aggregators have access to all network services markets, and ensuring compensation in those markets reflects the full real-time value of those services in delivering reliable service to consumers. Regulators should ensure consumers have access to a range of contracting alternatives.

Implementing beneficial, smart tariffs equitably and effectively will take time. The growing acceptance and inherent attributes of EVs make them an early and relatively straightforward platform for beginning this process. Doing so will pay dividends in the future as electrification becomes an imperative in other sectors in which both the challenges and the benefits are likely to be even more significant.

5. Conclusions

EVs represent perhaps the most promising avenue for the decarbonisation of road transport. However, the prospect of large-scale transport electrification throws up challenging questions about the scope of investment that will be required in electricity system infrastructure. Demand for EV charging will have unusual characteristics – although it represents a relatively modest increase in the demand for energy, it creates a large but highly flexible demand for power.

At the same time, existing power system infrastructure has historically seen low rates of utilisation owing to the highly variable and relatively inflexible characteristics of traditional electricity demand. EVs could drive the need to invest massively in new power system infrastructure that would experience even lower capacity factors than those seen in current system infrastructure. Or, given the nature of their demand for charging, EVs could leverage the large amount of unused capacity, from the local distribution system right up to central station power plants. Two key levers will determine which path we take – pricing and technology.

Usage-based, time-differentiated charges for both energy and shared network services will be

crucial in driving EV owners to exploit periods when the system is lightly loaded. Fixed, capacity-based charges and non-coincident peak demand charges will have exactly the opposite effect. Demand charges reflecting the timing of individual peak demand relative to system peak demand, and that are reset at frequent intervals, may be a useful component of a smart tariff.

Support for technology deployment will be equally important. The opportunity to benefit from being flexible will be increasingly attractive, especially for EV owners, but actively managing consumption in real time will continue to be impractical and undesirable for all but a very few. Enabling technologies are cheap and getting cheaper, but without strong policy support, effective marketing, consumer education, and common industry standards for connectivity and privacy protection, those technologies may not be deployed in a timely fashion, if at all.

Smart tariff design and smart technology policy can ensure that the incremental costs associated with transport electrification are equitably distributed, while at the same time keeping the need for incremental investment to a minimum, especially during early stages of adoption when uncertainty and the risk for burdening consumers with unnecessary investment costs are highest. Policymakers interested in promoting transport electrification must resist the siren song of lowering the cost of capital by shifting risk from investors to consumers through fixed, capacity-based charges – whatever might be saved in the cost of capital will be small beer compared to the over-investment and consumer backlash that are likely to follow.



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