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Fuel Electricity and Plug-In Electric Vehicles in an LCFS

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Discussion Draft

National Low Carbon Fuel Standard Study

National Low Carbon Fuel Standard Study

The document examines approaches for calculating fuel electricity carbon intensity and incentives fo increasing electricity fuel usage in a National Low Carbon Fuel Standard framework

About the National LCFS Study

The National LCFS Study has two objectives: 1) compare an LCFS with other policy instruments that have the potential to significantly reduce transportation GHG emissions from fuel use; and (2) propose a policy structure for an LCFS that would be most effective and implementable. The study is a collaboration between researchers from the following institutions: Institute of Transportation Studies, University of California, Davis; Department of Agricultural and Consumer Economics/Energy Biosciences Institute, University of Illinois, Urbana-Champaign; Margaret Chase Smith Policy Center, and School of Economics, University of Maine; Environmental Sciences Division, Oak Ridge National Laboratory; Green Design Institute of Carnegie Mellon University; and the International Food Policy Research Institute.

A series of white papers present analyses conducted over the past year regarding possible impacts of a national LCFS and design and implementation issues. These topics include:

- Economic Costs and Benefits of a National Low Carbon Fuel Standard and Implications for Greenhouse Gas Emissions
- Energy Security and a National LCFS
- Analysis of Indirect Land Use Change (iLUC) Impacts under a National LCFS iLUC Policy Options, and Policy Design Issues for a National LCFS
- Costs and Credit Trading of a National LCFS
- Handling Uncertainty in Life-Cycle Carbon Intensity in a National LCFS
- Policy Design Considerations for Electricity in a National LCFS

Our goal is to propose the design of a robust national LCFS policy that balances environmental, political, and economic goals and is readily implementable and enforceable in terms of data availability, simplicity, etc. The specific design recommendations will be summarized in a forthcoming Policy Design Report (PDR). The results of the above white papers will also be summarized in a forthcoming Technical Analysis Report (TAR).

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Executive Summary

This paper introduces and discusses many important issues and considerations that will influence how an LCFS policy will interact with the market for plug-in electric vehicles (PEVs), the existing electric power sector and the use of electricity as a low-carbon fuel. We have three sets of conclusions:

Incentives for vehicles and use of electricity fuel

- **When the efficiency of PEVs is accounted for in the LCFS, electricity is a low-cost and low-carbon fuel relative to gasoline –** Its use will help with LCFS compliance, and is dependent on the adoption of PEVs and the fraction of vehicle use that is powered by electricity.

- **While the value of LCFS credits for electricity could be substantial, the role of the LCFS in incentivizing additional fuel electricity usage is unclear –** Fuel electricity usage is primarily limited by demand, so to increase the use of fuel electricity, the LCFS would need to induce additional PEV sales. It is not clear to what extent the value of LCFS credits, which may amount to a few hundred dollars ($100-$500) per BEV charged per year would be used in ways to incentivize additional PEV sales.

- **Electricity could contribute a small to moderate amount to LCFS compliance in the near- to medium-term (before 2030)** - Two different optimistic scenarios for PEV adoption were considered (independent of LCFS incentives), and PEVs can make up only a modest fraction of the total light-duty vehicle fleet before 2030. The electricity used by these PEVs (PHEVs and BEVs) is expected to power a small percentage (ranging from 2% to 12% for moderate to optimistic scenarios) of total light-duty miles by 2030.

- **In the near-term, the LCFS is unlikely to lead to significant changes in electricity carbon intensity –** Electricity, with an appropriate energy efficiency ratio (EER), is already a low carbon fuel and electricity providers are not likely to be regulated parties under the LCFS and thus under no obligation to reduce carbon intensity. Additionally, electricity providers will not have a strong incentive to substantially change the overall regional generation mix for PEVs they service, since they will constitute a small portion of the total electricity generation.

Calculation of electricity carbon intensity:

- **There are multiple ways to allocate emission to a given demand, and policy makers must choose how they want to calculate the CI of electricity for PEVs –** The choice of allocation method will influence the regulatory CI value. An average emissions approach treats all demands equally, while the marginal emissions approach estimates the change in emission that result from PEV demands – on either a short-term or long-term basis.

- **An average allocation method for calculating carbon intensity would be the simplest and easiest to implement in a regulatory framework –** Retrospective, annual average emissions are also the most transparent since they can readily be calculated from power plant emissions data that is available from EPA and EIA.

- **The marginal system response approach for emissions allocation would provide a more accurate assessment of the change in emissions associated with adding PEV charging –** This approach, which attributes changes in total system emissions resulting from the addition of PEV charging, would also be more consistent with the CI calculation of indirect land use change for biofuels.

- **There is significant regional variability in average emissions that will affect the incentives and LCFS credits that electricity providers receive –** Most regional electricity in the US has an average carbon intensity between 450 and 850 gCO_2/kWh (40-80 g/MJ with energy efficiency ratio (EER) of 3). The difference between these two values will result in approximately a factor of four in LCFS credit value for a kWh of electricity.

- **The spatial boundaries for determining CI values will impact incentives for electricity providers –** Larger levels of aggregation (e.g. NERC regions) will reduce the variability of CI in different regions and lead to more consistent incentives for fuel electricity use; the use of smaller regions will increase variability and lead to greater incentives in low-carbon regions.

- **Temporal resolution will influence determination regulatory electricity CI** – Some methods of emissions allocation may not require detailed monitoring of the timing PEV electricity demands (i.e. average CI) while others require detailed temporal representation of electricity demands and supplies in order to accurately determine carbon intensity (i.e. marginal emissions). In addition, accounting for the timing of vehicle charging and intermittent generation when calculating carbon intensity will influence the value.

- **Renewable sources may be part of the marginal mix, though it depends on the allocation method –** In a short-term analysis, with fixed renewable generation capacity, renewables are generally fully utilized so adding demand cannot increase the output of renewable electricity. In a longer-term (system response) analysis, if additional renewables were built to meet regulatory requirements for the added PEV demands, then renewables would be part of the marginal mix.

- **Nationally, the marginal mix is likely to be made up primarily with coal and natural gas –** these two resources have sufficient underutilized capacity to charge hundreds of millions of PEVs without building additional generation.

LCFS policy framework and electricity

- **The technologies, business models and market value for PEV charging services, metering, data collection and smart grid management are in their infancy –** These technologies and markets will be evolving over the next few years and decades and the ability of regulators to accurately monitor and assess electricity demands, supply and carbon intensity should improve as well. Policy frameworks need to be flexible enough to account for this rapid evolution.

- **The LCFS is a technology and fuel neutral policy –** if vehicle efficiencies is properly accounted for and the carbon intensity of fuels are accurately assessed, the market, via the decisions from fuel providers, automakers, and consumers, will determine which fuels are used to reduce carbon emissions and meet policy targets.

- **As long as efficiency of PEVs is accounted for, other aspects of policy design should not affect the role of electricity as a low-cost method for meeting the LCFS –** Policy design considerations, such as choice of spatial boundaries and emissions allocation method, can influence the specific incentives for electricity providers and PEV drivers, but will not change the fact that fuel electricity is a low-cost fuel that will lower GHG emissions and can be used to help meet LCFS compliance.

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1 Introduction

Electricity is a unique fuel among those being considered as potential alternatives to help in compliance with the LCFS. Electricity has many important differences from other alternative, low-carbon fuels that require careful consideration. The overall goal of this paper is to lay out the important considerations for electricity in an LCFS and to highlight some of the major factors of interest and important distinctions relevant to electricity as a fuel in the context of how it may be handled within an U.S. LCFS policy.

Four sets of issues are discussed in this paper. The first is the role electricity might play in an LCFS. The second relates to various approaches for calculating a carbon intensity (CI) value for electricity. The third focuses on understanding regional variability and boundary issues in electricity carbon intensity. The fourth has to do with highlighting key questions about the role of an LCFS in incentivizing the use of electricity as a fuel, related regulatory issues and how these might be reflected in an LCFS policy.

This analysis of electricity within the LCFS should not be construed as an endorsement of electricity as the best way to meet an LCFS policy. This analysis does not attempt to answer the question of which fuel(s) should be used to reduce GHG emissions or comply with an LCFS policy. Instead, accurately and appropriately setting a regulatory carbon intensity value for electricity, including accounting for relative vehicle efficiency, will allow the market, industries and consumers to decide for themselves which fuels and vehicle technologies will be used to comply with an LCFS.

Throughout this paper, the term plug-in electric vehicles (PEVs) is used to describe vehicles that use grid electricity to charge. PEVs can include plug-in hybrid electric vehicles (PHEVs), which can run on gasoline or electricity and battery electric vehicles (BEVs), which run entirely on electricity. The term fuel electricity is used to differentiate electricity that is used as an alternative transportation fuel from electricity that is used in other, more conventional applications.

2 Electricity and PEVs in the LCFS

2.1 Energy efficiency ratio (EER)

The energy efficiency ratio (EER) is an important tool for comparing fuels based on their carbon-reduction potential within a framework that focuses on fuels as opposed to vehicle and fuel combinations. Electricity is a fuel, along with hydrogen that require the use of an EER in order to be appropriately incentivized in the LCFS. In 2005, the life-cycle average electricity carbon intensity for the US as a whole was 656 g/kWh, which translates into 181 g/MJ on an equivalent energy basis, nearly double that of gasoline (93 g/MJ). Thus electricity is not inherently a low carbon fuel when evaluated solely on an energy basis. However, electricity is a higher quality fuel than liquid fuels and as a result can be used much more efficiently in a vehicle than liquid fuels (Kromer 2007). The combination of an electric vehicle running on average US electricity is lower carbon than a conventional vehicle running on gasoline, so the vehicle/fuel combination is a low-carbon option that should be incentivized. In order to do that in the LCFS, an adjustment factor is needed, which was developed in the California LCFS as the EER, which represents the relative efficiencies of drivetrains using the different fuels. As shown in Figure 1, the value of the multiplier has a big impact on the regulated carbon intensity of electricity. A multiplier of 4 would make any electricity source favorable to gasoline, while using multiplier of 3, all electricity sources except coal-steam power would be favorable to gasoline. An EER of 1, i.e. no efficiency adjustment, would effectively disincentivize the use of most electricity under the LCFS.

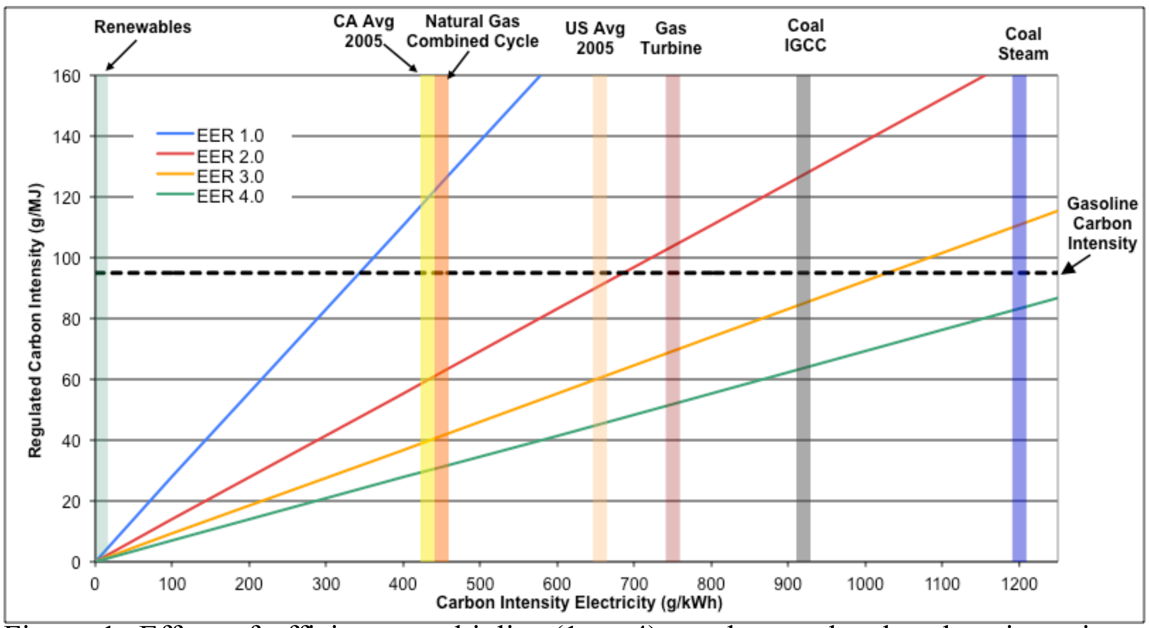

Figure 1. Effect of efficiency multiplier (1 to 4) on the regulated carbon intensity of electricity.

California chose a value of 3.0 for electricity based upon a straightforward comparison of several equivalent gasoline vehicles and PEVs and adjusting for vehicle GHG regulations that require new gasoline vehicles to become approximately 30% more efficient by 2016 (CARB 2009a). Oregon proposed a value of 4.1 for 2012 that will decline linearly to 3.1 by 2022 to explicitly take into account the greater efficiency of the fleet of gasoline vehicles over time (ORDEQ 2010). More recent data from EPA testing of the Nissan Leaf and Chevy Volt and comparable gasoline vehicles yields EERs of 3.3 and 3.7 (Lutsey 2011 and see Appendix A), which also leads to a value of around 3 when accounting for improvements expected in gasoline and electric vehicles expected over the next few years.

A key question regarding the energy efficiency ratio is how the value should be calculated. For the purposes of the California LCFS, the Air Resources Board calculates EER based upon an equivalently sized vehicle. However, equivalence can be challenging to define because so many attributes can differ: size, range, power, performance, etc. Most notably, because batteries have a far smaller energy density than gasoline, the average PEV will have significantly lower range than any comparable gasoline vehicle. Another important consideration is whether the efficiency multiplier is calculated based upon the average vehicle using each specific fuel or the newest, best and most efficient vehicles using the respective fuels (i.e. comparing a PEV to a fleet average conventional gasoline vehicle or a new hybrid vehicle)? Using fleet averages rather than specific equivalent vehicles will also lead to different EER values since the average PEV is likely to be smaller than the average gasoline vehicle. Using a fleet average would give an efficiency multiplier based upon how the fuels are actually used among all vehicles, while using equivalent vehicles would give an efficiency multiplier that is more reflective of the technical efficiency of the respective drivetrains.

Regardless of which approach that is taken, the EER is likely change over time the underlying drivetrain technologies improve and vehicles in the fleet mix change. Thus, it is important to periodically revisit the regulated EER value for PEVs and other alternative drivetrains (e.g. H_2 FCVs) so that they accurately reflect the state of vehicle technologies over time. It is likely that the EER would decline somewhat over time because the fuel economy of gasoline powered vehicles can improve faster than PEVs due to fuel economy and greenhouse gas standards and greater potential for ICE engine and drivetrain efficiency improvements (including hybridization). As a result, plausible future values for EER are in the range of 2.5 to 3.5 (Lutsey 2011).

Note that all subsequent calculations and discussions of electricity carbon intensity will use an assumed EER value of 3.

2.2 Incentives for increasing electricity use in the LCFS

The principal goal of the LCFS is to incentivize the use of low-carbon fuels in the transportation sector. A key question for the LCFS with respect to fuel electricity is whether the policy interacts with the current and expected future market and industry conditions for electricity and PEVs in such a way that it provides incentives to increase the use of electricity as a low carbon fuel as it would with other low-carbon fuels[1].

Electricity is unique as an alternative transportation fuel in that it is already produced and sold in very large quantities for purposes other than transportation fuel. Electricity use as a transportation fuel requires the purchase of PEVs that store

[1] This question is not meant to identify ways for the LCFS to promote electricity over other fuels, but rather identify factors or barriers that could prevent the LCFS from providing the equivalent incentives to electricity as with more conventional liquid low-carbon fuels.

electricity from the power grid in batteries[2]. Full battery electric vehicles (BEVs) can only use electricity, while a plug-in hybrid electric vehicle (PHEV) can also use gasoline and an owner could switch between fuels. The primary challenge of using electricity as a transportation fuel is not a result of supply issues (i.e. electricity's cost or availability). Rather, the challenge is a demand issue (i.e. the amount of fuel electricity will be dictated primarily by the number of PEVs in the fleet). Thus, unless the LCFS can influence the market penetration of PEVs, it may not have a significant impact on the use of electricity as a fuel.

The adoption of PEVs is likely to be influenced most strongly by the purchase price of vehicles (and the cost of home-based charging). As shown in Table 1, PEVs are projected to have a higher capital cost than conventional gasoline-powered vehicles even with high-volume manufacturing. PEV price premiums are currently even higher than indicated in Table 1, by a factor of two or more (NRC 2010). Additionally, the purchase and installation of home recharging equipment could add up to several thousand dollars to the initial investment for a PEV driver.

Because of the efficiency of electric drive and the cost of electricity, drivers will have significantly lower fuel costs per mile of travel. However, consumers exhibit very high discount rates when it comes to weighing purchase price of a vehicle versus fuel cost savings for more efficient vehicles. The primary policy mechanisms that are being discussed to increase adoption of PEVs focus on reducing the purchase price for consumers. These include direct subsidies, tax credits, and feebates. Technology mandates can also be used, such as California's zero emission vehicle (ZEV) mandate, which will likely result in vehicle suppliers cross-subsidization of PEVs relative to conventional vehicles so that the purchase price of the vehicles is lower than the manufacturers' vehicle production cost.

Table 1. Incremental vehicle cost for PEVs relative to a conventional gasoline vehicle in 2030 (Kromer and Heywood 2007)

	PHEV10	PHEV30	BEV (200mi)
With standard battery projections	\$3000	\$4300	\$10200
With optimistic battery projections	\$2700	\$3700	\$6900

PEVs running on electricity have significantly lower fuel costs per mile compared with conventional gasoline vehicles. At \$3.50/gallon[3], the cost of driving an average conventional vehicle on gasoline is approximately \$0.12/mile, compared with \$0.03/mile on electricity assuming electricity at \$0.09/kWh[4]. This translates to a fuel savings of approximately \$1100/vehicle in annual fuel savings for consumers

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[2] Similarly, other alternative fuels including hydrogen and natural gas also require the purchase of fuel cell vehicle (FCV) or hydrogen internal combustion engine vehicle (H_2ICEV) and natural gas vehicle (NGV), respectively.

[3] Gasoline prices include taxes that average around \$0.50/gallon. Imposing equivalent taxes on electricity (to achieve the same revenue per mile traveled) would nearly double the price of electricity.

[4] Electricity cost could be lower if PEVs are charged at night and have access to off-peak or time-of-use rates.

assuming 12,000 miles per year of all-electric driving (i.e. BEV). PHEVs would have lower annual fuel savings because they only use electricity for part of the time, though because they operate more efficiently in charge-sustaining hybrid operation as well, they'll have lower gasoline operating costs per mile.

It is believed that regardless of the existence of the LCFS, there will be some level of PEV sales, due to consumer preferences, and other more substantial PEV incentives. These PEVs will demand fuel electricity and lead to the generation of LCFS credits to utilities and load serving entities (LSEs), which have some value. This value, however, may or may not be utilized in a way that leads to additional usage of fuel electricity (see section 5.4). To the extent that most PEV purchases are not a direct result of LCFS incentives, revenue from LCSF credit trading becomes a windfall for electricity providers rather than a means for increasing low-carbon fuel usage.

Since increasing PEV adoption is the only way to substantially increase the use of fuel electricity, if the LCFS credit revenues are to increase the use of fuel electricity, it would need to be directed towards vehicle purchase, infrastructure deployment, fuel cost subsidy or other measure which incentivizes PEV purchases. In practical terms, it will be quite difficult to quantify the incremental level of adoption and thus additional electricity usage that would result from LCFS incentives specifically, given that there are a multitude of other, larger and more direct incentives (both state and federal) for PEV adoption, aggressive pricing from auto manufacturers and incentives and support for PEV charging equipment and stations.

2.3 Incentivizing reductions in electricity carbon intensity

Another important question about the LCFS is the extent to which it incentivizes reductions in carbon intensity of electricity, rather than merely the switch from gasoline to electricity. It is not clear that the incentives provided by the policy will have a significant impact on reducing the carbon intensity of electricity.

Parties regulated under the LCFS will generally have direct incentives to use lower carbon resources and processes in their fuel supply chain. For a refiner, this could mean producing or purchasing a quantity of biofuels with a known CI with which to blend into their fuel mix. For electricity, there may be a disconnect between the electricity provider and the regulatory fuel CI if the region used for determining CI is larger than the company's (e.g. the utility or load serving entity) service territory. If emissions are calculated in the LCFS at the load balancing area[5], or at an even larger level of aggregation (e.g. NERC or eGRID region level), each region can encompass up to several dozen investor-owned and municipal utilities. It seems likely that the entities that obtain LCFS credits (e.g. electricity providers and utilities) will be part of a much larger region that is used to calculate the carbon intensity of electricity

[5] One reason that is might be the case is that it is easier to calculate the carbon intensity of a larger regional grid, in part because power transfers become less important for a larger region.

(i.e. load balancing area or even larger region) because of the nature of how regional electricity systems work. Grid operations are typically controlled at the regional scale rather than utility scale and utilities are generally not aware of the source of their spot and wholesale market purchases. In addition, there are thousands of electric utilities in the US, and while it would may be possible to track real-time carbon intensity for each of these electricity providers, from a regulatory standpoint, determining and monitoring CI values for several dozen regions would likely be far easier.

As a result, if it is the case that electricity CI is calculated for large regions, changes that one entity will make to lower emissions from their mix of generation will have a relatively small impact in terms of the carbon intensity of the larger region, reducing the incentive to make changes based upon benefits that may accrue from the LCFS.

Additionally, the amount of electricity used for charging vehicles will be quite small relative to total electricity sales at least for the next two decades. However to impact the carbon intensity of electricity used to charge PEVs, an existing electric utility would need to change the entire generation mix of their system. Electricity providers likely would not make these significant changes just to gain some additional revenue associated with a small portion of overall electricity sales. Alternatively, it would be possible for PEV charging to be contractually linked to lower-carbon electricity generation. This could enable a mechanism for the LCFS to influence the financing of generation from low-carbon resources (which would in turn, increase the value of the LCFS credits they generate). However, given the current availability of low carbon electricity in the grid mix, appropriate regulatory restrictions need to first be put into place in order to ensure that this practice leads to additional low-carbon generation rather than shuffling of electricity resources.

Because electricity generation is a large contributor to GHG emissions, there are already existing incentives and policies that target electricity sector emissions in many states, including renewable portfolio standards (RPS), as well as the eventual likelihood of economy wide carbon policies (such as cap-and-trade). These will play a much larger role in decarbonizing electricity than the LCFS can.

2.4 PEVs will play a small role in near-term LCFS compliance

Two scenarios for PEV fleet growth were developed to understand the potential role that PEVs and fuel electricity could play in helping to achieve LCFS compliance[6]. These scenarios were based, in part, on scenarios of PEV adoption from the California Air Resources Board (CARB 2009b) and the National Research Council's PHEV report (NRC 2010).

[6] These adoption scenarios are not meant to reflect the impact of the LCFS on PEV adoption. Rather, they are scenarios that could unfold due to a number of policies incentivizing PEVs (such as the ZEV mandate or direct tax incentives and subsidies), independent of the LCFS. The goal is to understand how much PEVs might contribute to compliance, without necessarily being brought about by the LCFS.

A *Less Aggressive* scenario was based upon from the NRC's Probable fleet trajectory, which projects 12 million PEVs in the fleet by 2030. We assumed the mix of PHEV10s, PHEV40s and BEVs was 60%/30%/10% and the electricity CI was the average US value (calculated using an EER of 3) from the AEO2010 for 2010 to 2035 (including upstream emissions from the GREET model (Wang 2010)). An *Aggressive* scenario was built based upon an analysis by the ARB for their Zero Emission Vehicle (ZEV) regulation. The scenario assumes that much of the country follows California's lead and adopts PEVs (50 million by 2030) such that California represents about 20% of the country's PEVs. The mix of PHEV10s, PHEV40s and BEVs was assumed to be 15%/55%/30% and PEVs are assumed to be preferentially adopted in regions of the country with lower electricity CI (i.e. it is calculated from the seven AEO regions with the lowest CI). Both of these scenarios have significantly more PEVs than the AEO, which only assumes about 3.3 million PEVs in the fleet in 2030 (about 1% of the total fleet). Significant improvements in vehicle technology, cost reductions and substantial policy intervention are likely needed for PEVs to achieve the adoption levels in these scenarios, as opposed to the adoption seen in the AEO[7]. These scenarios are not projections of the most likely adoption of PEVs but instead they are meant to demonstrate a medium and optimistic upper bound on the impact of PEVs on CI reduction.

Using an energy efficiency ratio (EER) of 3.0, PEVs in these scenarios reduced the CI of the fleet in 2023 by 1.4% or 0.2% for the *Aggressive* and *Less Aggressive* scenarios respectively. By 2030, the reduction was 5.9% and 0.7% (See Appendix B for more detailed information). In the most optimistic case, PEVs can make a substantial contribution to LCFS compliance, while in the moderately optimistic scenario, the contribution is fairly small. In either case, most of the LCFS compliance will need to come from other sources in the near to medium-term, due to the challenge in ramping up PEV fleet share in the next decade or two. However, the longer-term effect could be more substantial depending upon the long-term trajectory of PEV penetration.

While the above analysis looks at the US as a whole, an important point to note is that the PEV contribution to LCFS compliance could vary dramatically across different regions. In those areas with greater PEV penetration and lower than average electricity CI, PEVs would be responsible for larger reductions in fleet CI.

2.5 Complementary PEV policies

As discussed in previous sections, the LCFS is not the most direct policy for incentivizing the use of electricity as a transportation fuel or for reducing the carbon intensity of electricity. There is a great deal of interest in PEVs from manufacturers,

[7] It's important to note that AEO doesn't include all state-level incentives for PEVs, nor does it take into account infrastructure incentives.

governments and other stakeholders, and this translates into a number of policies that are enacted or being proposed that incentivize PEVs, both directly and indirectly.

2.5.1 Vehicle Policies

Vehicle policies can be directed at the consumer or automobile manufacturer. Consumer policies generally focus on incentivizing vehicle purchases by reducing the purchase price of PEVs through tax benefits, rebates, or feebates, which help to offset the high incremental cost of PEVs relative to gasoline cars. There is currently a federal tax credit of up to $7500 depending on battery size and numerous state tax incentives as well. Consumer policies can also provide other incentives such as preferential parking and carpool lane access, which can provide significant additional utility to PEVs.

A number of direct PEVs policies affect the automakers, typically through technology mandates and performance standards. PEVs are one of the few technologies that can meet California's zero emission vehicle (ZEV) mandate. Mandating that automakers sell a certain number of ZEVs likely means that they will lower the cost of PEVs initially by cross-subsidizing across their entire vehicle line. In addition, fuel economy or greenhouse gas performance standards can also incentivize PEVs because they will generally out-perform the standard by a significant amount. PEVs can also be given "extra credit" in regulatory calculations of fuel economy or greenhouse gas calculations in order to further incentivize their sales by automakers. Additional policies can directed at automakers to provide incentives to vehicle or battery manufacturing through tax benefits and loans. Another important policy contribution is government support of R&D, which can provide funding for research and development in batteries and other PEV-related components.

2.5.2 Infrastructure Policies

Policies for charging infrastructure deployment encourage the deployment PEV chargers by reducing the costs and/or barriers associated with purchase and installation. Tax benefits and rebates for home and public charging are currently being provided by the federal government and several states. These policies can increase PEV adoption by lowering the cost of home recharging equipment, which is an additional upfront cost that PEV drivers must pay, and by increasing the utility of PEVs and reducing "range anxiety" through the deployment of widespread public infrastructure.

In addition to direct monetary support, other policies are aimed at reducing barriers for infrastructure deployment. One important barrier for consumers who wish to purchase PEVs is the installation of the home charging unit, which can involve electrical upgrades and permits from local building departments and take weeks or even months to complete. Policies could be implemented to standardize installations and expedite the permitting, installation and inspection process. In addition, policies are being proposed to update building codes for new homes so that the required electrical wiring is installed at the time of construction to allow for easy installation of a PEV recharger at a later date.

2.5.3 Electricity Policies

Lastly, there are policies that influence the electric sector and the carbon intensity of electricity. Specific carbon policies such as carbon taxes or cap and trade will reduce the carbon emissions from the electric sector, while policies such as the renewable portfolio standard (RPS) require regions to supply a certain amount of zero- or low-carbon renewable electric generation into their grid mix. While these policies do not specifically target electricity used as transportation fuel, they will lead to lower carbon intensity of electricity used to charge PEVs and thus influence the GHG benefits from the use of PEVs.

2.6 Long term importance of PEVs

While the previous section lays out why PEVs and electricity may play only a modest role in LCFS compliance in the near to medium term, it is important to realize the potential importance of advanced electric-drive vehicles and PEVs in the longer term. As the demand for electricity from PEVs increases, the use of smart grid technologies allows these vehicles to contribute to managing the electricity grid. Additionally, PEVs represent one of the few vehicle/fuel pathways that can enable very deep reductions in greenhouse gas emissions from light-duty transportation.

2.6.1 PEVs and smart grid

The role of the electricity grid is to provide power to customers and the primary challenge that comes with operating the grid and the primary goal of its operators is to match supply and demand in real time. While this is done on the current grid, the promise of the 'smart grid' is that it will be a more intelligent method of matching supply and demand by using information technology, communications and intelligence in meters, electric appliances and grid operations. With appropriate information about the operation of the grid, power plants and consumer demands can respond dynamically to help maintain balance between supply and demand, lowering costs and improving operations. The model of the current grid consists of 'active' generators being controlled in order to follow 'passive' demands from electricity consumers. However, with the increase in 'passive' generation (i.e. intermittent renewables which cannot respond to system conditions), an increase in active loads, which can be controlled, can improve the operation of the grid (Yang and McCarthy 2009).

PEVs are potentially a key contributor to a smart grid future for several reasons: they will consume large amounts of electricity, PEVs or the PEV chargers will likely have built-in intelligence and communications with the grid operator enabling the timing of their charging to be deferred or controlled, and PEVs will have the potential to feed electricity back to the grid and provide regulation services.

A large number of PEVs in the fleet could potentially respond to large swings in the output of intermittent wind and solar renewable power plants. Modeling of grid operation with PEVs has shown they have the potential to increase the amount of wind generation because of their flexibility in load timing (Short 2006). Similarly PEVs can lower costs of renewable integration by reducing the requirement for back up peaking natural gas plants (Yang 2009).

2.6.2 GHG mitigation

PEVs and electricity are one of the few vehicle fuel combinations that have the potential to enable deep reductions in GHG emissions from transportation. Hydrogen and biofuel powered vehicles are two other key options. Analysis of the entire transportation sector (including aviation, heavy trucks, marine, rail, etc) has shown that an important strategy in the face of limited biofuels is that light-duty vehicles should be electrified as much as possible, either PEVs or H_2-powered fuel cell vehicles (Yang et al 2009, McCollum and Yang 2010). This is because many transportation subsectors, including airplanes, large ships and heavy trucks, cannot be electrified because of weight, power or range limitations. Thus, while PEVs and FCVs are not the most cost-effective options for reducing GHG emissions in the near-term and will likely contribute little to near-term GHG reductions in the light-duty sector they are likely to be critical technologies for achieving deep, longer-term (2050 and beyond) reductions.

3 Determining carbon intensity of electricity

The electricity grid consists of a large number of diverse generation sources and numerous electricity loads, with a large, complex transmission and distribution system connecting them to match supply and demand in real-time. As a result, it is practically impossible to determine what loads are powered by electricity generated in a given power plant.

Dealing with this complexity requires simplifying assumptions about the assignment of power plants to specific loads. There are a number of different approaches to dealing with this complexity that lead to several methods for allocating electricity from a given supply to a given demand. It is important to note that there is no one “correct” method for this assignment as there is no means to verify or evaluate the results. Instead, deciding on a specific method for regulatory purposes will require balancing tradeoffs between data availability and modeling requirements (detailed monitoring, system modeling vs estimated average), incentives that policymakers wish to provide, and differing points of view about the how vehicle charging emissions should be treated (average vs marginal). This section deals with a number of these important considerations.

3.1 Life-cycle emissions

The EPA's eGRID database, DOE's Annual Energy Outlook (AEO) and other sources provide useful information about regional electricity emissions. However, these sources, along with many others, only include direct plant combustion emissions rather than the full life-cycle emissions. The GREET model, along with other life-cycle analyses, provides estimates for the additional emissions (primarily associated with feedstock extraction and transport) associated with supplying electricity from different types of power plants (Wang 2010). These are critical to include if accurate comparisons of the full fuel-cycle[8] impacts of the adoption and use of transportation fuels are to be made.

Figure 2 shows generic lifecycle power plant emissions, rather than location or plant specific values based upon values from Wang (2010). The upstream emissions can be added to the power plant specific values given in the more detailed analyses in AEO and eGRID to provide an estimated life-cycle value for these data sources. The size of the upstream emissions are relatively small, between 0 g/kWh (0 g/MJ[9])for wind, solar and geothermal to over 100 g/kWh (9 g/MJ) for oil, biomass and natural gas combustion turbines.

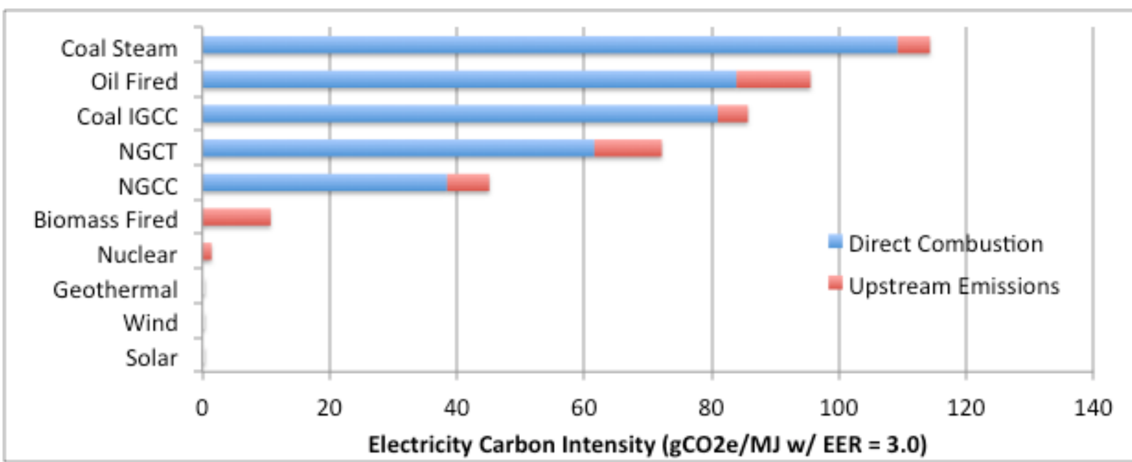


Figure 2. Generic lifecycle emissions values for electricity generation from numerous resources and powerplants (Source: Wang 2010).

[8] Carbon intensity values for fuels in the LCFS include only include emissions associated with fuel production, delivery and refuelling and do not include emissions associated with vehicle manufacturing, recycling and disposal.

[9] Conversion from electricity emission on a g/kWh basis to g/MJ basis assumes an EER of 3.0

3.2 Marginal vs average emissions

One of the key questions for those interested in the emissions from the electricity used for charging vehicles is how to treat the demand from vehicles. The answer to this question will have a large impact on the emissions that are assigned to PEVs and their benefits relative to other vehicle and fuel pathways. If electricity and emissions that represents the average grid mix is assigned to vehicles, then vehicles are being treated the same as any other electricity demand. On the other hand, if marginal electricity generation and emissions are assigned to vehicles, then vehicles are being treated as a separate class of demand that is being added to existing, conventional demands.

A primary rationale for treating PEV-related electricity use equivalently to any other demand (i.e. the average approach) is the inability to track power flows on the electric grid. Without the ability to differentiate the original sources of electricity, the argument goes, all end-uses should be treated identically and assumed to use the aggregate grid mix. The rationale for treating PEV-related electricity use as a special case is that policy-makers and analysts want to understand the consequences of policies or decisions that will enable and encourage the use of electricity as a fuel. The addition of PEV recharging will require additional electricity generation, which can be identified and their emissions allocated to PEVs (i.e. the marginal approach). This approach is similar to the approach for estimating indirect land use change values for biofuels (i.e. a consequential analysis).

The distinction between average and marginal electricity is important because most electricity is used for non-fuel purposes and there can be large differences between associated CI values. In some locations, the marginal electricity will have a higher carbon intensity than average electricity, while in other regions, the reverse will be true.

3.3 Marginal short-term vs long-term system

If one chooses to allocate emission based upon the marginal approach, a key issue with determining the marginal emissions impact of additional demand from PEVs is that there are several ways that the analysis can be performed. The goal of calculating marginal emissions is to see the impact of adding vehicle demands to the electric grid in terms of what plants are being operated (and their emissions) to meet this demand. But the impact will depend on the analysis time-frame and what aspects of the grid are considered as variable.

For example, if the analysis is focused on the very short term, where there is no potential for building new power plants, the only decision is which plants to operate at any given time. The addition of PEV demands will induce some existing power plant(s) to generate more electricity than they otherwise would have, to meet the additional demand. Thus, an approach to marginal emissions that focuses on short-run response looks primarily at the system as it exists and the short-term marginal impact assigns the last plant(s) dispatched in a given time period to the PEV recharging demand.

With a longer-term focus (i.e. years to decades), the results of an analysis will change. In this case, the addition of PEV charging to the overall demand profile may, if it is large enough, induce structural as well as operational changes to the electricity grid, relative to the case where no PEV demand was added. This second approach, which requires an understanding of how the system responds over a longer period of time, looks at the system from a holistic standpoint and attempts to determine all of the changes (including changes in the mix of generating plants) that may occur as a result of the addition of significant levels of PEV charging.

The choice of which approach to use for the purposes of setting a carbon intensity value for marginal electricity in a regulatory context is a subjective judgement. However, it also has important implications on how emissions are actually calculated/estimated and the resulting CI values. Emissions from the short-term approach are easier to calculate and could be estimated from data from entities that manage dispatch for the regional grid. The latter approach is helpful for understanding the "what-if" question about two distinct scenarios, one with and one without PEV recharging, in order to understand the net impact of PEVs. However, it introduces a great deal more uncertainty because it relies on detailed modeling of the electric grid and asks how the behavior of hundreds of power plant owners and operators might change between the two cases. In addition, the regulatory value for carbon intensity will likely be determined and updated on a regular (e.g. annual) basis, so using a longer-term system response approach may not make sense.

3.4 Temporal considerations for carbon intensity

Decisions regarding temporal resolution of carbon intensity calculations are also important. Because demand for electricity varies on hourly[10], daily and annual timescales, the mix of power plants (both conventional and renewable), and resulting emissions rates will also vary. Given that vehicle recharging demands will also vary in time, an accurate assessment of electricity carbon intensity would take into account the coincidence between PEV demand and time-varying supply. Detailed analyses of electricity systems tend to focus on short timescales (hourly to subhourly) in order to capture important variations that can occur with supply and demand. A regulatory value for electricity carbon intensity may be defined as an annual average value, but calculating emissions at a fine level of temporal resolution is preferable if the demand and supply data is available since it is possible to aggregate up to any other time period.

Currently there is no historical data on the timing of vehicle recharging so estimated charging profiles are often used. Temporally detailed metering would be helpful so

[10] While the term "hourly" is used here, it is meant to represent any timescale that is much less than a day

that the timing patterns of PEV charging can be established. If a temporally detailed approach is used, it is equally important to adequately represent the supply side in order to capture the variations in power generation and emissions from different power plants over the course of the day.

Also important is whether electricity carbon intensity is calculated retrospectively (ex post) for a past time period, or is estimated prospectively (ex ante) for a current or future time period. The former relies on data while the latter requires data, modeling capabilities and assumptions about electricity supplies and demands.

3.5 Renewable contributions to PEV charging

3.5.1 Coincidence between renewable supply and demand

Another question of interest is to what extent renewable electricity contributes to PEV charging. The choice of the time resolution of the analysis will impact the answer and the resulting carbon intensity. For example, if an annual timescale is used for calculating average emissions, then the renewable contribution to PEV charging would equal the annual percentage of renewable generation on the system. However, if shorter timescales are used, the issue of coincidence and divergence of supply and demands becomes important, since both PEV charging and renewable supply will have highly variable profiles. If PEV charging occurs in hours when renewable generation is more likely to occur (i.e. they are coincident), then the percentage of PEV charging coming from renewable generation may exceed the annual renewable percentage, whereas if the profiles are divergent, the percentage can be well below the annual renewable percentage.

An important potential option for ensuring renewable contributions to PEV charging is to purchase renewable energy certificates (RECs). Electricity providers in the LCFS could achieve zero carbon electricity if they generate electricity directly (i.e. solar panels on top of a charging station), directly contract with renewable power suppliers (i.e. a wind farm or solar power installation) to purchase their power, or purchase grid electricity and the RECs. Using RECs would also allow the electricity provider to ignore the issue of convergence between renewable supply and PEV charging. However, the use of RECs raises the question as to whether their use in this context would result in additional renewable generation or merely shuffling of existing generation. Without additional policies to discourage fuel shuffling, direct linking of PEV charging to specific generators likely would not lead to additional low-carbon generation and true reductions in emissions.

3.5.2 Are renewables on the margin?

There are several marginal allocation methods that can be used to determine the additional generation and emissions for PEV charging and these methods can give very different answers regarding the renewable contribution.

When marginal emissions are defined as the short-term response of an existing system to an unexpected additional demand, then the power plant(s) that will generate the electricity to meet this additional demand are the last power plants that are dispatched in a given hour. The low variable cost and the uncontrollable nature of intermittent renewable resources means that renewable power sources are among the first power plants dispatched in an economic dispatch scheme. Thus, once a given amount of solar generation has been built, it's output will likely be fully utilized and the addition of PEV charging won't change the amount of energy that comes from this built capacity.

However, if instead the marginal allocation includes changes in how the system might respond on a longer-term basis (i.e. the system response approach), then renewables may be included in this marginal mix. If an RPS policy is in place, each additional unit of PEV demand should yield additional renewable generation. There may be other changes to the system that need to be accounted for as well (e.g. if the greater capacity of intermittent renewables requires more backup and the intermittency of renewable supply shifts more of the load-following generation to come from peaking plants). Other analyses have indicated that the inclusion of flexible charging can enable the use of intermittent renewables (Short 2007). In this sort of analysis, an important question is whether there are constraints on the system and how the system responds under those circumstances. One important constraint is whether the RPS policy goal is being met. In the near term, it appears likely that certain regions may not be able to meet their target RPS percentages (CPUC 2011) perhaps because projects cannot be approved and brought online fast enough. If this is the case, then adding additional demand will not actually lead to any additional renewable generation, but rather generation will need to come from other conventional sources.

3.6 Emissions differences based upon allocation method

Based upon the previous considerations, which each lead to multiple methods for allocating emissions, there are as many as five different categories of allocation methods. Two other considerations need to be addressed when calculating average emissions: (1) whether the average emissions are calculated only weighted by when vehicles are charging or weighted over all times and all loads and (2) whether additional vehicle demands are considered when calculating average system emissions.

Table 2. Categories for emissions allocation from electric vehicle recharging demands

1) System-wide average – no vehicles	This value is taken from historical data on a given region's average emissions and doesn't account for the fact that increasing electricity usage, due to PEV demands, would likely change the average carbon intensity of electricity. This approach uses existing data to calculate a retrospective CI value and is the easiest method to use.
2) System-wide average – Added vehicle demand	This method does take into account the fact that adding PEV charging demands could change the mix of generation sources and affect electricity CI relative to (1). It calculates an average electricity carbon intensity over all electricity demands. A retrospective approach would use existing data, while a prospective approach would need to make an assumption about RPS compliance.
3) Vehicle specific emissions – temporally explicit dispatch - Average	This method accounts for PEV charging demands and calculates the electricity CI as an average of all emissions weighted by the timing of vehicle recharging. This requires explicit data on the timing of power plant generation and PEV charging. Like (2), for a prospective approach, one must make an assumption about RPS compliance.
4) Vehicle specific emissions – temporally explicit dispatch – Marginal short-run	This method accounts for PEV charging demands and calculates the electricity CI as an average of emissions from marginal plants that meet PEV demands weighted by the timing of vehicle recharging. This requires explicit data on the timing of power plant generation and PEV charging and assumptions about which plants are providing marginal power[1]. Like (2), for a prospective approach, one must make an assumption about RPS compliance.
5) Vehicle specific emissions – temporally explicit dispatch – Marginal system response	Like (4), this method accounts for PEV charging demands and calculates the electricity CI as an average of emissions from marginal plants that meet PEV demands weighted by the timing of vehicle recharging. This requires explicit data on the timing of power plant generation and PEV charging and assumptions about which plants are providing marginal power. However, it is based upon the system response approach, which also requires assumptions about what would have happened in the absence of PEV demands. Like (2), one must make an assumption about RPS compliance.

[1] E.g. in a system with economic dispatch, one could assume that the plant with the highest variable cost would be providing marginal electricity

The effect of different allocations methods was assessed for the carbon intensity of electricity in California using the LEDGE-CA model (McCarthy 2009 and Yang 2009). Electricity carbon intensity was calculated (direct combustion emissions only, not life-cycle) for four different PEV charging profiles for California in 2030, assuming an RPS policy of 33% renewables was put in place (see

Table 3 and Appendix C for more details about the model and scenario assumptions). Vehicle demands accounted for an additional 2% to total electricity demand, which is representative of 10% PHEV40s in the fleet. The results shown here depend upon the mix of power plants on the regional grid and will vary for other regions. The absolute numbers aren't critical and the important takeaway from this is that the different allocation methods can lead to significant variation in electricity CI.

Table 3. Electricity carbon intensity (gCO_2/kWh) for different allocation methods and several different vehicle charging profiles for California calculated by LEDGE-CA model. Numbers correspond to categories in Table 2.

	System-wide averages			Vehicle specific emissions - Temporally explicit dispatch					
	Average					Marginal			
	No vehicles	Added vehicle demand							
						Short-run		System response	
	1	2		3		4		5	
	System Based	RPS *not* met for vehicles	RPS met for vehicles	RPS *not* met for vehicles	RPS met for vehicles	RPS *not* met for vehicles	RPS met for vehicles	RPS *not* met for vehicles	RPS met for vehicles
Off-peak	168.3	174.5	170.3	185.0	180.9	418.4	416.0	428.3	252.0
Load-level	168.3	174.2	169.9	188.7	184.6	410.8	408.4	412.6	236.5
Min cost	168.3	174.0	169.7	160.7	156.0	401.6	398.8	404.0	227.4
Workplace	168.3	174.6	170.3	177.8	173.6	424.2	421.9	429.3	252.8

Marginal emissions for California tend to be much higher (~2x) than average emissions. This is because there is a significant amount of renewable and nuclear power assumed in the generation mix in 2030. These zero-carbon sources bring down average emissions, but do not show up in the marginal mix (except for category 5, with RPS met, where 33% of marginal emissions in the system response approach are from renewables). Marginal emissions are calculated to come primarily from natural gas combined cycle plants, though at some peak hours, there is some contribution from simple cycle natural gas turbines as well.

In this example, calculating average emissions with added vehicle demands tends to raise average carbon intensity relative to ignoring vehicle demands because natural gas capacity is underutilized and tends to increase generation to meet the additional demands. Having the RPS met for the added vehicle demand will obviously reduce emissions relative to the case where the RPS does not contribute. The difference is small for the average emissions case because emissions are averaged over all loads (of which PEVs are only a small proportion ~2%), while the difference is large when 33% of PEV demand is assumed to come from renewables (i.e. in 5b, the System Response approach).

3.7 Choosing an allocation method

To a large extent, the choice of an allocation method will depend upon policy objectives and important considerations about the appropriate levels of complexity, transparency and consistency of the policy design. Policy complexity and ease of regulatory implementation will be affected by the extent to which it is reliant upon existing data resources, additional monitoring and data reporting requirements, and modeling and simulation needs. Transparency will depend upon the availability of verifiable data and the tradeoffs associated with detailed modeling and simulation. Finally for consistency, it is important that policy design use similar emissions allocation methods across all fuels and over time.

Unfortunately, there is no one allocation method that can simultaneously meet all of these criteria. Arguments can be made for each of the different methods that have been discussed here and certain approaches will look more or less favorable from different perspectives. For example, the system-wide average emissions approach (1, 2 and 3) can rely entirely on data and are fairly transparent and are consistent with the CI calculation of most fuel pathways (i.e. attributional approach). The marginal, short-run approach (4) can rely on data as well, but requires some determination of the marginal power plant(s), reducing its transparency. Finally, the marginal, system-response approach (5) requires significant data but also requires system modeling to compare electricity system operation with and without the additional demand from PEV recharging. While this last item is the most challenging to implement and least transparent, given the use of models rather than only data, it is consistent with the approach that is used for the calculation of the iLUC factor for biofuels (i.e. consequential approach). It is also arguably the most accurate assessment of the GHG impacts of the choice to charge PEVs with electricity, thus ensuring that regulatory impacts are aligned with policy incentives. In all cases, it is important to account for regional imports/exports, but reporting requirements and methodology would still need to be developed.

Approach 4 (marginal short-run) could be a good compromise as it is an approach that could be calculated on a retrospective basis primarily with data. While this approach also requires the determination of the last plants that are dispatched in any given hour, this could be done in a relatively straightforward manner. Given data about average heat rates and fuel costs for specific power plants, one approach would be to assign marginal generation to the plant(s) with the highest variable costs that are operating in a given hour.

4 Regional Electricity Supply and Demand

4.1 Regional electricity demands

There is considerable variation of hourly electricity demand profiles across different regions of the country as well as for different seasons of the year. Differences in lifestyles, climate, energy prices and efficiency in different regions of the country lead to different profiles of electricity demand in these different regions.

It is likely that the adoption and spatial distribution of PEVs will not occur everywhere with equal probability. Like the adoption of hybrid vehicles, PEVs are expected to have preferential adoption in certain regions of the country, such as the West coast and the Northeast states. In addition, a number of factors will influence the demand for electricity from these vehicles, which will have a geographic component. These include regional differences in vehicle miles traveled (VMT), vehicle size preferences, climate differences and the deployment of charging infrastructure. See Appendix D for more details.

The shape of the electricity demand profile and peak demand are important demand parameters because they determine total generation capacity requirements and the mix of generation resources that are suited to meet the demand.

4.2 Regional electricity supply

Electricity cannot easily be stored so electricity must be supplied in real-time to match demand and this requirement has shaped the structure of the electric supply sector. Regional electricity grids consist of a number of different types of power plants with different operating, cost and emissions characteristics in order to meet this time-varying demand. Because electric capacity is determined by the peak demand, most electricity generation is underutilized. The overall capacity factor of US power plants is 44% (EPA 2007), meaning that in theory, these power plants could increase their output and generate more than twice as much electricity without adding any additional capacity. Practically, this additional output could only be generated when existing plants are idle, which depends upon the existing electricity demand profile.

The eGRID database provides details about capacity and generation for all power plants in the US and it is possible to look at which plants are underutilized (EPA 2007). This can be a crude method of estimating marginal power generation and emissions, since these underutilized plants could provide more generation if demand from PEVs were added. Most of the underutilized capacity is from natural gas and oil-fired power plants since they are expensive to operate and are therefore less likely to be dispatched when demand is lower. However, there is also significant underutilized coal capacity, which is cheaper to operate. As a result, if dispatch were ordered on a least-cost basis, then much of the additional demand would be met by underutilized coal. An important caveat is that underutilized capacity is calculated on an annual basis but it assumed to be available when PEVs would charge (which is a simplification since demand and thus, plant utilization varies seasonally).

Of course, PEVs are not actually plugged into an electricity grid that looks like the US average. There are significant regional differences in electricity generation mix from different resources and the carbon intensity of electricity will vary depending upon the mix of power plant capacity, and primary energy and renewable resources within an electricity region. It will also depend upon how those resources are managed and utilized in order to meet the demand for electricity in those regions.

4.2.1 Regional variability in electricity supply systems

Determining the regional carbon intensity of electricity requires a definition of the regional system boundaries. Electricity systems in the US are extremely heterogeneous and regionally specific. The choice of boundaries will have an impact on the mix of power plants and their emissions. One of the challenges in defining regional boundaries is accounting for cross-border power flows, which are necessary in order to accurately account for the source and emissions of electricity consumed in a region (Weber 2010, Jiusto 2006). Electricity regions can be defined and aggregated in a number of different ways. Figure 3 shows a sample of several commonly used boundaries for electricity analysis in the US.

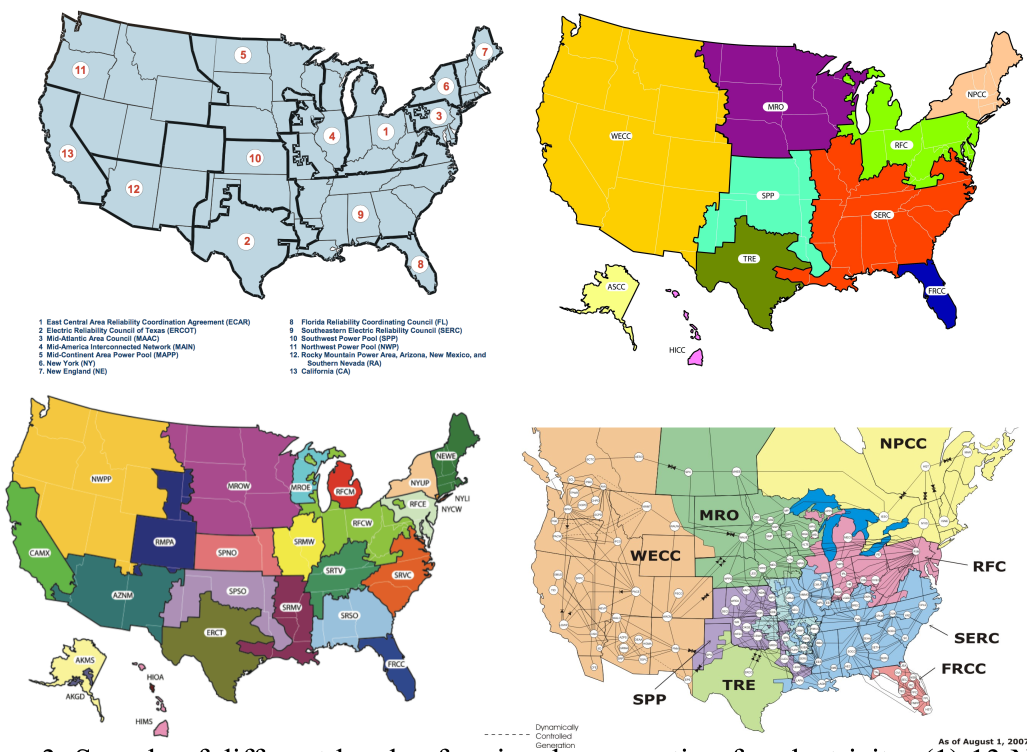


Figure 3. Sample of different levels of regional aggregation for electricity: (1) 13 NEMS and AEO regions, (2) 10 NERC regions (3) 26 EGRID subregions and (4) 133 NERC balancing authorites

Emissions from these regions can vary significantly. In addition, moving to larger regions of aggregation for determining electricity carbon intensity reduces variability in CI between regions (see Figure 4). There is significantly greater spread in average carbon intensity when looking at the eGRID power control area (PCA) disaggregation compared to the 10 NERC regions. Thus the choice of spatial boundary for electricity allocation purposes will have important implications for the electricity CI value and the incentives that will result. In each of these possible regional arrangements, the regions that are used for calculating electricity CI are larger than the service territory for an individual electricity service provider (utility or other load-serving entity). Given that the assigned CI value will be the same for all providers in a specified region, this compromises the ability of LCFS incentives to motivate investments by individual load servicing entities to introduce more low-carbon sources into their electricity mix.

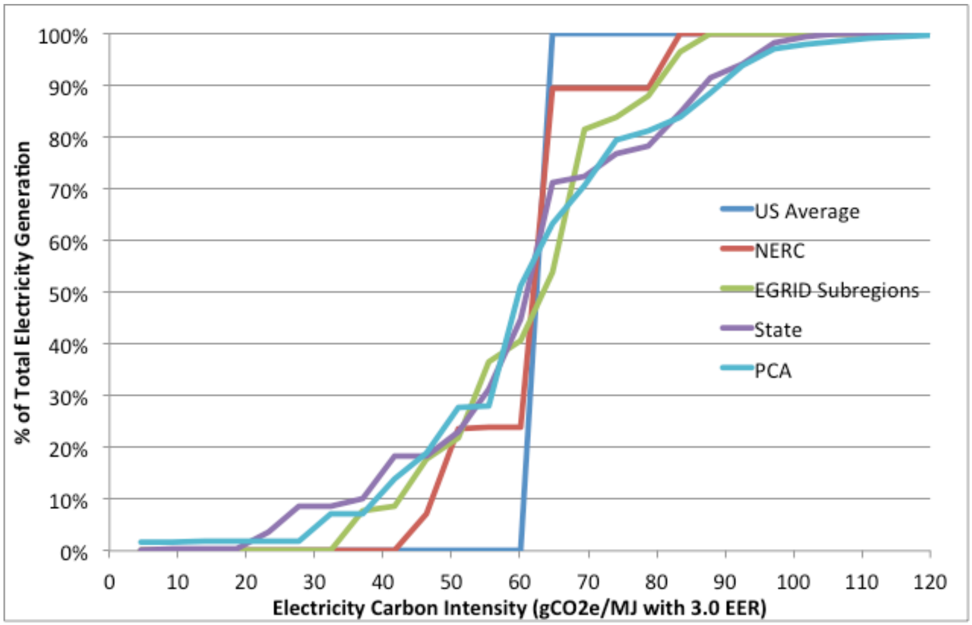


Figure 4. Cumulative distribution of lifecycle carbon intensity of electricity for different levels of regional disaggregation.

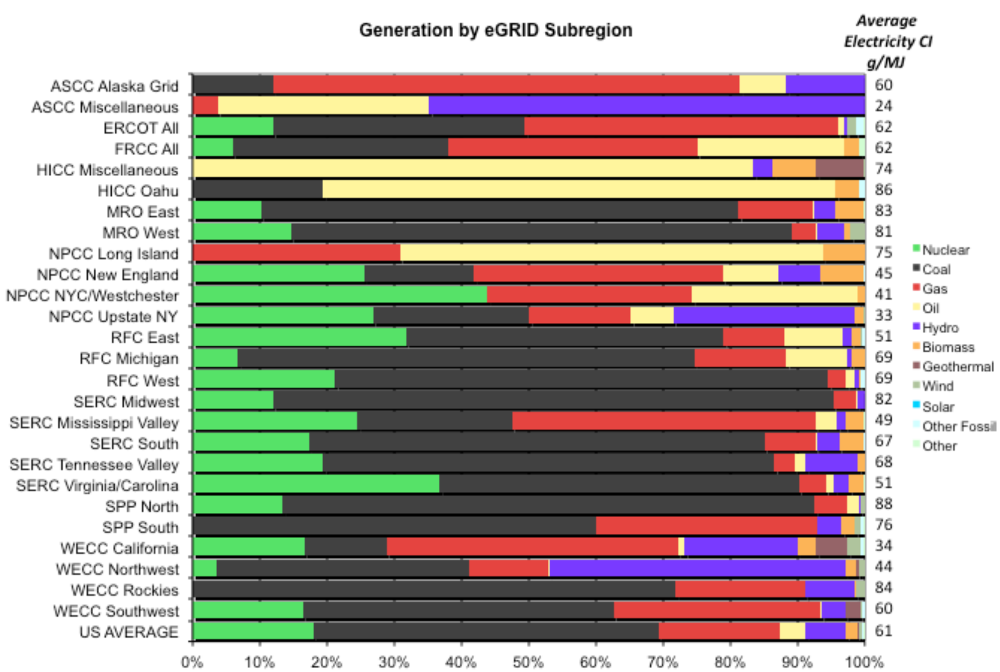
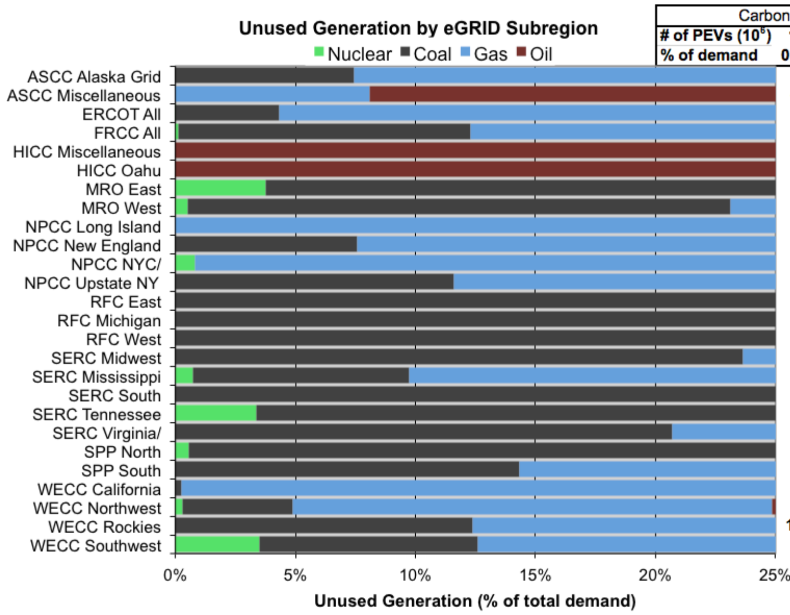


Figure 5. Electricity generation in 2005 by resource type and resulting life-cycle carbon intensity (gCO_2e/MJ with EER 3.0) for eGrid subregions.

US average life-cycle carbon intensity in 2005 is approximately 656 gCO_2e/kWh (61 g/MJ). There is, significant deviation from this value depending upon the region in question (see Figure 5). For example, carbon intensity of electricity in California, the Northwest and the Northeast is significantly below average while parts of the Midwest and Rocky Mountains have carbon intensities well above average.



Carbon Intensity (g/MJ) for charging PEVs						
# of PEVs (10^5)	1.4	6.9	13.8	69.2	138.3	345.8
% of demand	0.1%	0.5%	1.0%	5.0%	10%	25%
ASCC Alaska Grid	82	82	82	82	78	69
ASCC Miscellaneous	42	42	42	42	46	55
ERCOT All	87	94	95	88	65	51
FRCC All	0	59	71	80	81	61
HICC Miscellaneous	72	72	72	72	72	72
HICC Oahu	75	75	75	75	75	75
MRO East	0	0	0	25	63	86
MRO West	0	0	49	90	95	94
NPCC Long Island	51	51	51	51	51	51
NPCC New England	86	86	86	86	74	53
NPCC NYC/	0	0	9	45	49	52
NPCC Upstate NY	89	89	89	89	89	56
RFC East	87	87	87	87	87	87
RFC Michigan	89	89	89	89	89	89
RFC West	87	87	87	87	87	87
SERC Midwest	90	90	90	90	90	88
SERC Mississippi	0	0	27	83	89	60
SERC South	87	87	87	87	87	87
SERC Tennessee	0	0	0	30	60	78
SERC Virginia/	84	84	84	84	84	76
SPP North	0	0	42	88	94	97
SPP South	91	91	91	91	91	71
WECC California	91	68	55	44	42	42
WECC Northwest	0	39	68	90	65	50
WECC Rockies	100	100	100	100	100	70
WECC Southwest	0	0	0	28	61	53
US Average	59	64	69	78	78	72

Figure 6. Unused generation by eGrid subregion and carbon intensity of unused generation (gCO2/MJ with EER 3.0) as a function of % of electricity demand in each region (and the corresponding number of PEVs nationally) subject to the prescribed loading order.

Figure 6 shows the mix of unused generation in each eGrid subregion as a function of total demand in the region. It also provides an estimate for the carbon intensity of this unused generation, which could be used to represent marginal generation, at different levels of demand assuming a loading order for generation resources (nuclear, coal, gas and then oil).

Table 4 shows the results of a more rigorous analysis that looks at the composition of marginal generators to charge PEVs in different electricity regions (Hadley and Tsvetkova 2008). Analyses such as this one rely on detailed dispatch models that simulate the operation of the electricity grid, and are necessary to accurately calculate the marginal generation and thus emissions associated with PEV charging in different regions. Based upon this analysis and others, marginal emissions will likely come primarily from coal and natural gas and as a result, may not exhibit as much regional variability as average emissions.

Table 4. Estimated composition of marginal generation for charging PHEVs in different AEO regions for 2020 and 2030 (Hadley and Tsvetkova 2008).

		2020		2030	
		10 p.m. charging	5 p.m. charging	10 p.m. charging	5 p.m. charging
1	ECAR	70% coal	50% coal	50% coal	30% coal
2	ERCOT	gas	gas	gas	gas + unserved
3	MAAC	gas + coal	gas + oil	gas + coal	gas + oil
4	MAIN	75% coal	50% coal	40% coal	25% coal
5	MAPP	50% coal	gas	40% coal	gas
6	NPCC-NY	oil + gas	oil + gas	gas	gas
7	NPCC-NE	gas + coal	gas + oil	gas	gas + oil + coal
8	FRCC	gas	gas + oil	coal + gas	gas + unserved
9	SERC	50% coal	20% coal	60% coal	20% coal
10	SPP	gas	gas	gas + coal	gas
11	WECC-NW	gas	gas	gas	gas
12	WECC-RMP/ANM	gas	gas	80%coal	25% coal
13	WECC-CA	gas	gas	gas	gas + unserved

Note: "Gas" may be used for combustion turbines, steam turbines, or combined cycle plants.

4.2.2 Spatial boundaries and incentives

Giving every electricity provider the same average carbon intensity value (e.g. by defining one national region with equal carbon intensity) would provide a uniform incentive to all electricity providers to incentivize the use of electricity as a transportation fuel. Using smaller spatial boundaries would lead to greater variability of electricity CI and differential incentives in different parts of the country. In theory, regions could even be defined as the individual utilities/electricity providers themselves, but it would require better information about their supply, specifically wholesale market purchases. Regions with low carbon electricity supply would have a much greater incentive under the LCFS for the use of PEVs than high carbon regions (by a factor of 4 or more).

The size of the region used to calculate the carbon intensity of electricity will affect the incentives for lowering the CI of electricity. It is generally true in the LCFS that regulated parties will have direct incentives to use lower carbon resources and processes in their fuel supply chain and each regulated party would have direct control over their company's average CI across all fuels sold. However, electricity CI will likely be set for a region/area that is larger than the electricity provider service territory. Thus, multiple companies will have the same carbon intensity and thus any changes made to the electricity generation mix by an electricity provider will affect the carbon intensity of all electricity sold in the region not just that sold by the individual electricity provider.

4.2.3 Data Availability and Spatial Boundaries

Adequate data is required for determining the carbon intensity of electricity in a simple and transparent way. Thus one consideration for identifying the best or most appropriate spatial boundaries for determining carbon intensity is to look at how the grid currently operates and the current availability of data. Unfortunately, the power sector is highly heterogeneous and electricity markets are not organized into uniform and equivalent regional entities across the country.

While there are a number of agencies that have jurisdiction over parts of the electric sector, including the North American Electricity Reliability Corporation (NERC), the Federal Energy Regulatory Commission (FERC), the Environmental Protection Agency (EPA) and the US Department of Energy's Energy Information Agency (EIA), none of them require the data to be reported that would allow for calculation of electricity carbon intensity at a high level of time-resolution.

NERC defines balancing authority areas as "the responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area" and whose essential purpose is to continually manage the grid in real-time by matching supply and demand. They track power generation and demand in the region as well as power flows into and out of the region in order to maintain balance between supply and demand and manage transmission, maintain power quality and reliability. While they are required to be notified when any power sales lead to power flows across their boundaries, they do not require information about the generation source of the imports/exports which could help define carbon intensities. Accounting for cross-boundary flows is important for the accuracy of carbon intensity calculations, especially in the case of marginal allocations.

Data that is relevant to calculation of carbon intensity includes EIA form 923 which requires power plants to report on fuel, cost, generation and emissions information. EPA's eGRID database provides capacity, generation and emission information for all power plants at different levels of regional aggregation. While none of these data sources provides all the information needed to calculate the emissions associated with electricity consumption in the balancing authority area, especially on a sub-annual basis, primarily due to the lack of source and emissions data for power flows across boundaries, it is possible to estimate emissions from existing data. If balancing authorities were to obtain detailed information about the generation source of power transfers, it would provide a useful basis for calculating real-time carbon intensity for the balancing area.

4.2.4 Default and opt-in values

Some electricity providers and regional grid operators have done detailed analyses of their generation and import/export mix and as a result, may be aware of the carbon intensity of the electricity they provide to their customers[11]. Over time, as

[11] In many cases, they are aware of the generation source for much of their electricity, but to the extent that they purchase electricity off of a competitive "spot" market, they may not be able to fully account for all the emissions associated with the electricity that they provide to their customers.

more data regarding generation sources and emissions is provided for all electricity transactions, including wholesale market power purchases, it may become possible for individual utilities or even individual customers to estimate electricity carbon intensity values on a real-time basis. However, in the near-term, a regulatory value for electricity CI will likely be calculated for a region that encompasses many such utilities, so the CI value assigned to an electricity provider may be different than their actual CI value. An important question arises as to whether it will be allowable for electricity providers to provide an opt-in value, which is different from the regional CI, if they can provide details about their electricity generation mix.

Moreover, opt-in could take several forms. In one form, opt-in can occur at the utility scale, encompassing an entire load serving entity's electricity mix. In this case, a utility could opt-in if it believed that its overall generation mix (accounting for imports, exports and spot market purchases) is lower carbon than the regulatory CI value for the region they are in. Opt-in values for electricity are potentially much more complicated than allowing opt-in values for other alt fuels. This is because default values for electricity are fundamentally different from default values for other fuels. Default values for most fuels in the LCFS are pathway dependent and based upon a generic representation of the energy inputs and emission sources for that pathway. The default values for electricity in the LCFS should be calculated for the specified region based upon the generation mix and electricity demands in that region, which will include a number of distinct electricity providers. If an electricity provider were allowed to provide an opt-in value, the composition of the remaining region's supply and demand would change. Thus, to maintain an accurate assessment of remaining regional (i.e. default) CI value, opt-in by a load serving entity would require a recalculation of a new default CI value.

In another form, opt-in could occur at the vehicle charger scale, targeting only the electricity used to power PEVs. This form could occur when a charging provider, like a workplace or retail establishment, specifically purchases electricity of a given type (e.g. renewable or from other low-carbon sources) to provide to customers at its public charger. Since electricity for charging PEVs is a small fraction of the total electricity demand, shuffling of generation sources to supply low carbon electricity to PEVs is an important concern and the additionality of the renewable or low-carbon generation would need to be addressed.

Opt-in that results in shuffling of generation should not be permitted in the LCFS. And given the complexity of opt-in, it may make sense, especially in the near term as data collection and availability is still being developed to account for electricity emissions, to restrict the use of opt-in CI values because of the issues of shuffling and additionality and also the difficulty in recalculating these average regional values in the absence of some electricity providers. Over time as the capabilities for accounting for the electricity generation mix improves, it may become easier to allow distinct CI values for sub-regional entities such as individual utilities and electricity providers.

The use of offsets is another related issue of how providers could influence the CI of electricity in a given region. The LCFS is designed to allow for flexibility and trading within the transportation fuel market. And since the goal of the LCFS is to incentivize innovation and GHG emissions reductions from the fuels sector, offsets that could come from many other sources beyond transportation fuels could circumvent this and should be avoided.

4.3 Future electricity carbon intensity

While the LCFS may not have a strong influence on the carbon intensity of electricity in the future (see discussion in section 2.3), economics and other key policies will influence the evolution of the electric sector and its associated emissions intensity. Reference case projections for electricity by the DOE in the Annual Energy Outlook (AEO 2010) project that average electricity carbon intensity declines about 10% from 2008 to 2035 primarily because of growth in renewable electricity generation.

The exact impact of RPS policies on the electricity carbon intensity is complex and uncertain because RPS policies can be met with a number of different renewable generation technologies and because it is unclear what generation the new renewables would be displacing. Current RPS policies act at the state level and the mix of renewable generation to meet these policies will vary throughout the country.

Beyond state-level RPS, other policies on the horizon could even more dramatically influence the emissions from generation of electricity. The American Power Act (APA) from 2010 is an example of one policy that is currently being discussed that targets US greenhouse gas emissions. While it has not been implemented, the EPA performed an analysis of the impacts of this proposed climate legislation, including a detailed look at the electric sector. The EPA analysis provides a useful benchmark for understanding cap and trade policies on the power sector. The analysis used the Integrated Planning Model (IPM) to estimate the near-term impact (to 2025) of this policy on the power sector (EPA 2010).

Another important factor will be the availability of low-cost natural gas. Shale gas, which is not included in AEO or EPA projections, could become an economically and environmentally attractive alternative to coal.

The EPA's APA analysis shows a more significant reduction in electricity carbon intensity than the AEO reference case (14% vs 6.7% for the period 2012 to 2025). Figure 7 shows the distribution of carbon intensity by region and that the regional variability declines somewhat during the analysis time period. In the disaggregation shown below, electricity in even the most carbon intensive region has a CI almost 20% lower than gasoline in 2025.

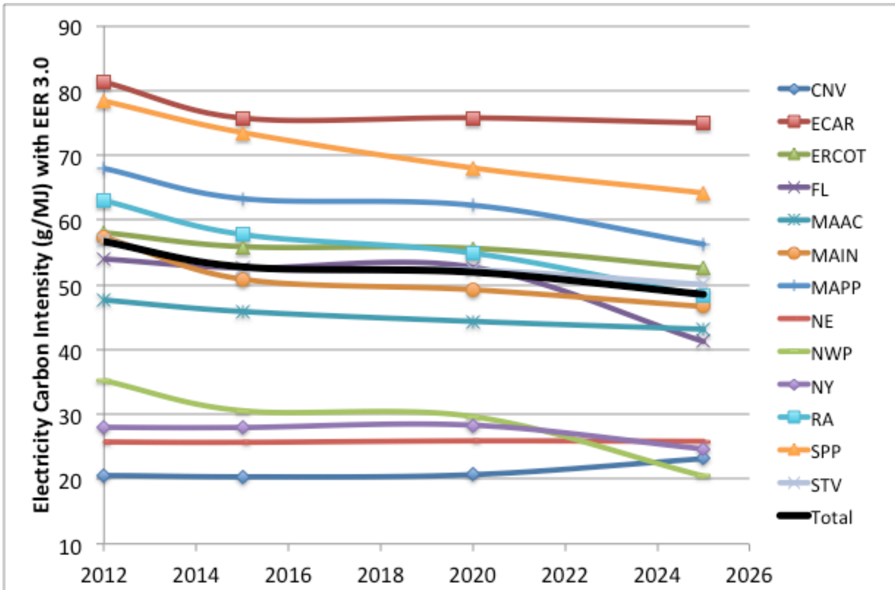


Figure 7. Projection of electricity carbon intensity by region for 2010 American Power Act.

The EPA's analysis also performed a longer-term, but less detailed electric sector analysis to 2050 with ADAGE, a general equilibrium model of the US economy and found significant potential for reduction in electric sector carbon intensity by 2050 from the APA (around 80% reduction from 2010 carbon intensity) (EPA 2010).

4.4 Regional variability and implications for national policy

The adoption of PEVs and their energy use is likely to be regionally specific, due in part to consumer environmental attitudes, preferences for vehicle size, range and utility, and driving distances and auxiliary demands. This adoption rate may be influenced somewhat by the LCFS policy, but will likely be driven primarily by technology development, consumer preferences, cost reductions and other PEV-specific policies and subsidies.

Regional differences in generation technologies and resources leads to spatial variability in electricity carbon intensity, which in turn leads to differential incentives for electricity usage in PEVs. This may lead to a reinforcing, positive feedback. In regions with low-carbon electricity like California and the Northeast, the value of LCFS credits from electricity fuel sales would be higher than in other locations, so greater investments can be made in charging infrastructure and purchase incentives, which can help spur additional PEV sales. In higher carbon regions like the Midwest, the value of electricity in the LCFS would be much lower (by a factor of 5 or more) and thus the LCFS would provide less of an incentive for electricity providers to try to speed PEV adoption. This regional variability could lead to regional differences in the types of fuels used for LCFS compliance. Electricity could make up a greater portion of the fuel mix in certain regions, because of consumer preferences as well as the economic value of lower-carbon electricity in the LCFS.

The choice of spatial boundary also influences the amount of variability in electricity carbon intensity. And while this may not be a significant issue for the PEV driver, it has important implications for the entities that provide electricity to the drivers and incentives to deploy infrastructure or promote PEV sales.

The challenge for a national policy is to develop a framework for calculating electricity emissions intensity for individual regions that will be consistent across the range of power systems and operating units in the US. The methods for determining emissions need to work in both large and small power systems and in regions with regulated and deregulated markets. Determining carbon intensity will require significant data input for the region in question but some methods will also require detailed modeling capabilities in order to simulate grid operation on a regional basis.

5 Point of regulation considerations

This section discusses some of the important considerations related to how the point of regulation and associated regulated parties may be defined for fuel electricity under an LCFS policy. It is important to highlight these issues so that an effective policy can be designed. Part of the challenge with regulation in the PEV vehicle, charging and electricity provider space is that this is a nascent and rapidly changing market. The PEV charging market and business models are expected to look very different in a few years and it is critical that any regulations do not impede or adversely affect the evolution of this market. Metering, billing, providing access to charging and other essential aspects are still being developed.

This section is meant to identify areas where the market for electricity, charging infrastructure or PEVs prevents or hinders the operation of the LCFS from adequately incentivizing fuel electricity as it does other low carbon fuels. By properly minimizing these issues, determining accurate CI values for fuel electricity (including appropriate EERs for PEVs), industry and consumers can decide which fuels provide the best means for meeting the LCFS.

5.1 PEV market – who can obtain the LCFS credit

Electricity providers will generally not be regulated parties under the LCFS. As a result, there is no obligation for electricity providers to provide electricity to PEVs or comply with LCFS targets. However, it is presumed that electricity providers would trade LCFS credit because of the potential revenues that can be accrued from trading. Regulated parties could then purchase these credits to aid in their company's compliance.

A central question in considering the point of regulation is who will obtain the LCFS credit for providing fuel electricity. There are several steps in the chain of providing electricity to the vehicle battery and a number of important parties involved in the process, including the power plant owner and operator, the utility that aggregates power flows and operates of the transmission system to meet customer demands, the charging device owner and the driver who recharges. In theory, any of these parties could potentially obtain the LCFS credit depending upon how the policy is set up. Under the California LCFS, load serving entities (i.e. utilities and municipal electricity providers) and third party providers would likely be the two primary recipients of the credit. A third party could be a local government, organization or business that wants to provide vehicle recharging infrastructure or service to its constituents, employees or customers. It will be up to the national policy design to lay out who may be able to obtain the credits associated with recharging of PEVs.

Utilities are a logical choice for obtaining the credit, especially since they are responsible for procuring electricity and providing it to their customers and have metering and billing systems for data reporting. However, some have argued that because supplying electricity to PEVs will be a small part of the utility's business, they may not have strong incentives, or even be allowed to spend revenue from the LCFS to provide extra infrastructure to a small segment of their customer base. There are over three thousand distinct utilities in the US and their decisions about what to do with LCFS credit will vary between these different institutions and their governing regulatory bodies, e.g. public utilities commissions. Some utilities may decide that providing incentives for vehicles is a good business model and provide subsidies for PEVs, much as some utilities provide customer incentives for insulation and energy efficient appliances. However, there will likely be a range of outcomes in terms of how much these LCFS credit revenues given to utilities would be used to further the goals of increasing the use of low carbon fuels.

Another approach is to make the charging equipment owner the recipient of the credit, since they are providing the actual point of refueling. Since most all PEV charging will likely occur at such a device, it provides a consistent point of regulation. It also provides a means for requiring appropriate metering and reporting requirements for charging equipment in order to obtain credits. Thus any utility or third party that installs charging equipment will obtain credits for the fuel that is dispensed through the device. This approach may preclude some utilities from participating if rules are put in place to prevent unfair competition between third-party charging equipment suppliers and utilities, who may be able to spread costs over a large pool of non-EV customers. Another critical question is who would obtain the LCFS credits for home based charging equipment owned by the PEV owner. It's not clear that individuals will have the desire or ability to participate in a regulated credit market or that a market should accommodate thousands or millions of individual small credit traders and transactions. One interesting option would be to allow PEV owners who own their charging equipment to sign away credit generation to a third party credit aggregator that, in return, subsidizes the equipment, vehicles or fuel purchases.

One means of deciding who should obtain LCFS credits is to consider who is likely to use the proceeds from the sale of credits in a manner that will enhance the goals of the LCFS, i.e. lowering the fuel carbon intensity and increasing the amount of alternative fuels being consumed. Some have argued that smaller third party providers may influence the PEV market more than large utilities would. This is because the only way that third party charging providers will receive LCFS credits is to deploy charging infrastructure that is used by PEV drivers whereas utilities could obtain LCFS credits by virtue of their customers purchasing PEVs. And increased infrastructure deployment can increase the amount of fuel electricity used, either by spurring additional PEV sales or increasing charging opportunities for existing PEV drivers. third party providers can include companies who provide charging to employees, retailers who provide charging to customers, charging equipment manufacturers, and local governments. Even LCFS regulated parties, such as refiners and energy companies, may decide to deploy PEV charging equipment at gasoline stations or other locations in order to help their LCFS compliance instead of purchasing credits from the market[12]. In each of these cases, allowing a third party to obtain the LCFS credit, rather than the electric utility, potentially increases the level of investment in infrastructure or provides subsidy to PEV purchasers.

A number of smaller companies are getting into the business of making and deploying PEV chargers. LCFS credits could be a significant revenue source for these companies. If these companies continue to innovate and provide unique values, such as networking, smart charging and utility integration, etc. they may spur competition in this space that ultimately benefits the PEV consumer and enables greater PEV sales and fuel electricity usage.

5.2 Are electricity providers regulated as public utilities?

An important question that is related to who can obtain LCFS credits is who is allowed to sell electricity to PEV drivers. In some places, providers who "sell" electricity to consumers would be regulated as public utilities, which could limit charging infrastructure deployment to utilities and other load-serving entities.

Some charging companies have gotten around this by selling "access" to the charger or parking at a spot with a PEV charger, which is based upon time rather than the amount of electricity that is used by the PEV. Other companies see a business model of selling subscriptions to access a network of stations such that users will pay a flat fee per month for the ability to charge at any of the network stations. These business models are still being developed and will continue to evolve as the market for PEVs and charging grows. If third-party charging providers are unable to operate because they are labeled public utilities, it could restrict competition,

[12] Regulated parties are in no way obligated to provide electricity, install charging infrastructure or subsidize vehicles, although they may choose to, for a number of different reasons,

innovation and deployment of widespread public infrastructure and reduce the use of electricity as a fuel.

In California, for example, this question was recently decided by the Public Utilities Commission (CPUC), such that companies that sell vehicle recharging services would not be regulated as public utilities. However, a big question for a national LCFS is whether or not a similar process will need to take place in each state or regional public utilities bodies or whether a national policy can and should preempt this local review process (CPUC 2010).

5.3 Tracking electricity use from PEVs?

If an LCFS is to be effective, accurate accounting of the usage of fuel electricity is needed. Unlike conventional fuel sales with a dedicated pump, most electricity is used for non-PEV purposes and not all PEV charging will be separately metered or even utilize a dedicated PEV charger. While much of the charging is likely to occur at a home or public charging station, it is also possible to plug current PEVs into a standard 120V outlet. As a result, near-term PEV charging is not likely to be completely captured by a separate meter. One solution is to allow for electricity providers to estimate the level of unmetered PEV charging, as the California Air Resources Board (CARB) is allowing until 2015. The accuracy of such estimates is somewhat unclear.

However, as more PEV charging infrastructure is deployed, a greater fraction of PEV charging will pass through a PEV charger. Since PEV chargers are now being built with utility-grade meters, it makes sense to tie the generation of LCFS credits to metered charging at a PEV charger. This would require electricity providers to supply regulators with verifiable, metered data and detailed PEV charging timing profiles that can be used for planning and carbon intensity calculations. The type of data required to satisfy LCFS regulators will dictate the type and cost of meters to be installed in charging equipment.

Since the market for PEV chargers is just emerging, there will be a great deal of innovation in the arena of metering and billing for PEVs in the coming decades, with more widespread use of PEV chargers and dedicated submeters, and the ability to track PEV charging will improve. It may be necessary to wait until these systems are in place before robust regulations on monitoring can be implemented for PEV charging. Requirements for metering and reporting for the purposes of credit generation in an LCFS may provide an inducement for these changes.

5.4 Value of LCFS electricity credits

5.4.1 LCFS credit market and value of electricity

The value of electricity in an LCFS is dependent upon the carbon intensity of the electricity and the credit trading price in \$/tonne of CO_2 displaced. In one national market, there would be one fuel that sets the market clearing credit price for the LCFS trading, which is determined by the marginal (i.e. most expensive from a CI reduction standpoint) fuel that is used to satisfy the regulation. LCFS credits for low-carbon fuels can be arranged as a supply curve with various fuels having different prices per ton of reduction. Given expected prices for biofuels, electricity will be at the low end of the supply curve, but would be able to obtain the market-clearing price for their carbon reductions.

Figure 8 shows the revenue for selling permits on a per unit (kWh) basis as a function of the cost of carbon permits and the carbon intensity of electricity. Given that electricity prices nationally range from \$0.06 to \$0.20/kWh with a national average of \$0.10/kWh, the value of the permits are in the range of the cost of electricity. Generally, the cost of electricity correlates with the carbon intensity of the electricity such that cheaper electricity tends to have higher carbon intensity values. The exception is for areas with abundant hydroelectric power, which is inexpensive and has no carbon emissions.

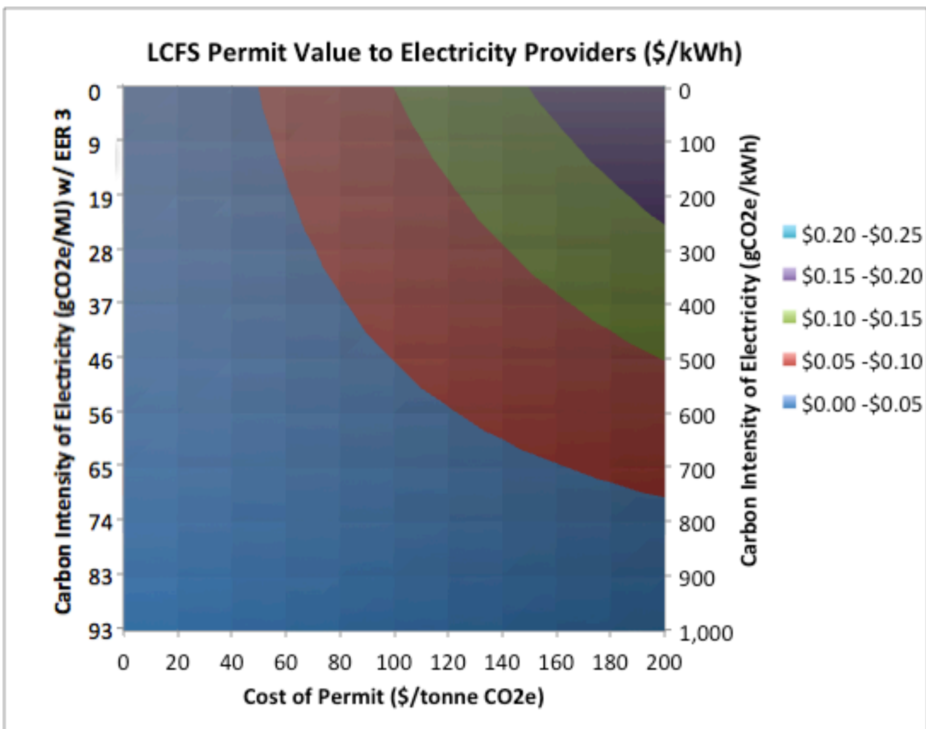


Figure 8. Value of LCFS permits (in \$/kWh) for electricity providers as a function of permit price and electricity carbon intensity.

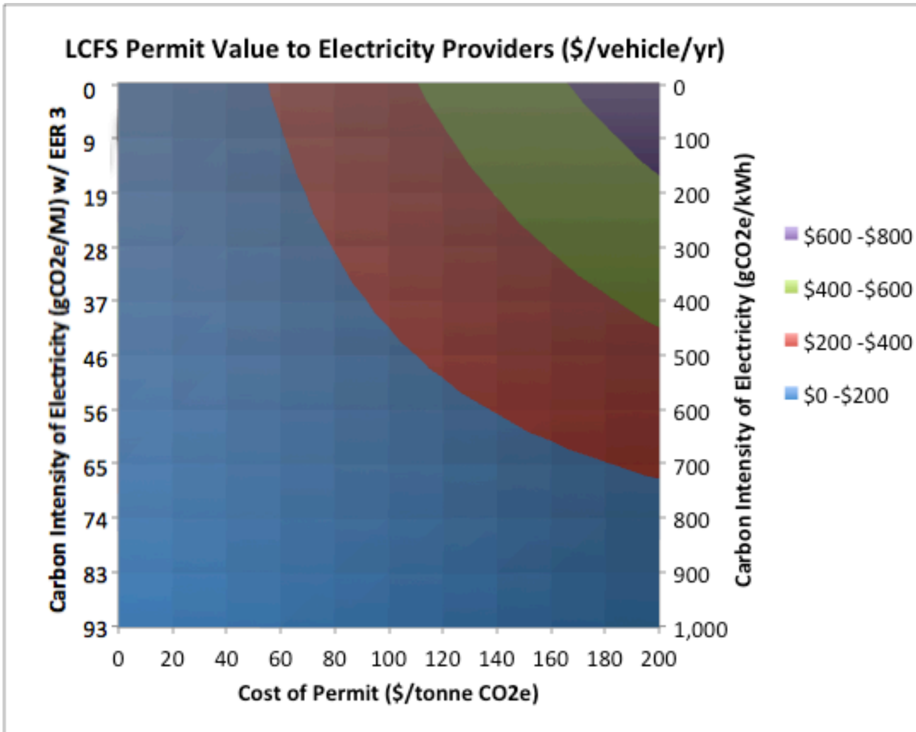


Figure 9. Annual value of charging one BEV for electricity providers under the LCFS as a function of permit price and electricity carbon intensity

Figure 9 translates the per kWh revenue into the annual total revenue that an electricity provider would expect to generate from the sale of credits for the electricity being provided to charge one BEV. The value in the figure would be correspondingly lower for charging a PHEV40 or PHEV10 by a factor of 60% and 20%. This figure assumes 12,000 miles/vehicle/yr. This figure indicates that for a permit price of $100/tonne, an electricity provider that has an average electricity CI value (e.g 656 g/kWh or 61 g/MJ) could obtain around $125 per BEV/yr or $75 per PHEV40/yr. A permit price of $200/tonne and cleaner electricity (300 g/kWh or 28 g/MJ) would obtain around $500 per BEV/yr or $300 per PHEV40/yr.

5.4.2 Using LCFS credits to increase the use of fuel electricity

Increasing the usage of fuel electricity is likely to be the primary means of increasing the use of low carbon fuels from electricity-generated LCFS credit revenues. Revenues that accrue to electricity providers from LCFS credit trading could be used in many different ways, such as using all or a portion of the value for subsidizing the price of fuel electricity, providing a purchase incentive to PEV buyers, using it to fund public or private vehicle recharging infrastructure, upgrades for electricity generation, transmission or distribution or increasing profits. The recipient of the LCFS trading credit will need to decide, dependent upon their business model, how to use these revenues that they may accrue, especially in light of the uncertainty in future credit values and revenues.

However, as stated previously, the most effective means of increasing the amount electricity that is used for transportation is to direct LCFS credit revenues towards a direct incentive at the time of vehicle purchase to get more PEVs on the road. One challenge is that the electricity provider would need to provide a substantial incentive at the time of purchase in exchange for an uncertain future stream of revenue that comes from the usage of a vehicle over its lifetime. The electricity provider would also need to guarantee that the PEV driver would recharge primarily through that provider in order to ensure a continued revenue stream of future LCFS credits. This arrangement would make the most sense for providers of home-based recharging equipment, where the majority of PEV charging is likely to occur.

Increasing the deployment of public PEV recharging infrastructure is another option that could directly increase fuel electricity usage if their installation allows vehicles to make trips powered by electricity that they otherwise would not have been able to make because of limitations in battery storage. Infrastructure could also indirectly spur adoption of PEVs by increasing the utility and use of PEVs, both by allowing them to drive greater distances and also by reducing "range anxiety".

Subsidizing the cost of electricity for PEV recharging, which could induce additional PEV sales is another option for increasing the use of fuel electricity. Finally, this value of LCFS credits could also be used to purchase renewable energy credits (RECs) or procure other forms of low-carbon electricity and lower the carbon intensity of electricity if this form of opt-in is allowed and additionality can be verified, as driving a truly zero-emission vehicle could be a compelling incentive to many PEV drivers and would also lead to greater LCFS credit generation.

6 Policy recommendations

Based upon the discussion and analysis highlighted in this paper, a number of policy recommendations are presented. These recommendations are meant to promote two goals: (1) targeting LCFS incentives towards increasing the use of low-carbon fuels (i.e. fuel electricity), and (2) calculating electricity CI in a simple, transparent and consistent manner.

- **Electricity should have an energy efficiency ratio (EER) multiplier in order to make sure electricity is accurately valued within the LCFS –** this value should reflect the efficiency improvement and resulting GHG benefits for using electric drive vehicles and should be revisited periodically to make sure it is reflective of the current state of technology.

- **A wide range of potential parties should be allowed to provide charging services and obtain LCFS credits –** Entities providing charging services should not be considered public utilities, which would place significant regulatory restrictions on the deployment of home and public infrastructure. Allowing these entities to also obtain LCFS credit will ensure that they invest in in well-utilized PEV recharging infrastructure which will increase utility for PEV drivers.

- **LCFS credits generated as a result of providing fuel electricity should be directed towards additional vehicle purchases and infrastructure deployment** - these should yield the greatest benefit in terms of increasing the use of low-carbon fuels resulting from the LCFS.

- **In the near-term, a minimum useful regional aggregation for determining carbon intensity is the balancing authority area –** Given the operation of regional electric grids, carbon intensity should be calculated at the balancing authority level, responsible for matching regional generation with supply and managing inter-region power flows. However, aggregating to a larger spatial region for determining carbon intensity would be easier to manage, with somewhat fewer resources needed to monitor and model emissions, and reduces the level of regional variability and differential incentives for use of fuel electricity.

- **The source and emissions of power imports and exports across regional boundaries should be tracked** - there is currently no standard requirement for accounting for tagging the generation source and emissions of cross-boundary power flows. Providing a mechanism for this data to be monitored and reported would enable much easier calculation of region-wide carbon intensity. This could be especially important for the marginal allocation approach.

- **A retrospective marginal short-run approach to determining electricity CI could be an appropriate balance between simplicity, transparency**

and consistency – marginal short-run calculations of regional CI would rely heavily on data from PEV charging profiles and hourly generation mix but also requires determination of the marginal plant(s) supplying PEVs in every hour. One approach is to designate operating plant(s) that have the highest variable costs in a given time period as the marginal plant(s).

- **The LCFS should eventually require detailed reporting of EV charging patterns from electricity providers and high-resolution supply mix and import/export data from load-balancing authorities –** LCFS credits should be tied to reporting requirement of metering data from PEV chargers**.** This data will be necessary for accurate and detailed determination of electricity carbon intensity and also to assess other impacts (operational, reliability and economics) of PEVs on the electric power grid.

- **Opt-in reporting of CI values for electricity providers should initially be restricted as it affects the "default value" and unregulated low-carbon electricity credits could lead to shuffling –**Removing an electricity provider from the regional mix would require recalculation of the "default value", which is not based upon a specific pathway but rather the mix of electricity generation in a region. Appropriate regulatory measures are needed to ensure that when an electricity provider opts-in using renewable energy credits or other credit for sourcing low-carbon electricity, this results in additional low-carbon electricity generation rather than shuffling of existing generation.

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