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Optimal policies for electromobility: Joint assessment of transport and electricity distribution costs in Norway

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ABSTRACT

This paper develops a stylized economic model for passenger transport in the greater Oslo area, in which the agents' choices of car ownership, transport pattern, and electric vehicle (EV) charging are jointly determined. If enough EVs charge during peak hours, costly grid expansions may be needed. We examine how the distribution system operators can mitigate these costs with different pricing schemes and how this, in turn, affects the transport market equilibrium. We find that applying tariffs differentiated between peak and off-peak periods will help strike a better balance between grid investment costs and EV-owners' disutility of charging during off-peak hours.

1. Introduction

The transport sector accounts for approximately one-quarter of global energy-related greenhouse gas emissions (International Energy Agency, 2017) and about one-third of Norway's.[1] Thus, it is necessary to deliver substantial emissions cuts in this sector to meet the objectives of the Paris agreement.

Norway's strategy is to ensure that all new passenger vehicles are zero-emission vehicles by 2025 (Ministry of Transport, 2017). EV-friendly transport policies, including low vehicle taxes, toll road exemptions, and access to bus lanes, have been put in place, resulting in the highest penetration of EVs worldwide. By January 2021, there were about 337,000 battery electric vehicles (BEVs) and 143,000 plug-in hybrids (PHEVs) in Norway, a country with only 5.3 million inhabitants. In 2021, BEVs accounted for 54 percent and PHEVs for 20 percent of all new vehicles (Norwegian Electric Vehicle Association, 2021).

According to the Norwegian Energy Regulatory Authority, 1.5 million EVs in Norway in 2030 would only amount to a 3 percent increase in domestic electricity consumption (Skotland et al., 2016). Hence, the main challenge is not expected to be that of aggregate electricity generation. However, while an EV's energy consumption may be modest, its power demand could be significant. The current power demand per electricity-consuming unit in a household usually ranges from 2.3 to 7.3 kW (Skotland et al., 2016). The power demand from fast chargers (currently up to 350 kW) will come in addition to that.

Uncoordinated charging (also known as dumb charging) will increase the electricity consumption during the morning and evening peaks (Graabak et al., 2016). De Hoog et al. (2015) and Neaimeh et al. (2015) point out that if vehicle charging is not controlled, adverse impacts on the distribution network are expected: power demand may exceed distribution transformer ratings; line current may exceed line ratings; phase unbalance may lead to excessive current in the neutral line; and voltages at customers' points of connection may fall outside required levels.

Several studies examine how low-carbon technologies such as BEVs and PHEVs (in this study, we group them together as Plug-in Electric Vehicles or PEVs) can affect the electricity market. Hattam and Greetham (2017) looked at how PEVs affect load profiles at the neighborhood level in low voltage networks. Azadfar, Sreeram, and Harries

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[1] Statistics Norway: "Emissions to air", https://www.ssb.no/en/klimagassn.

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(2015) assessed charging behavior of PEV users in terms of the time of day, duration, frequency, and electricity consumption, and its implication for electricity network management. Barton et al. (2013) studied challenges for grid balancing when PEV charging and heat pumps become more prominent. They stressed the importance of demand-side management with time-shifting of electricity loads from periods of peak demand to off-peak and periods of low renewable energy supply to periods of abundant supply. However, in some areas, it may be difficult to shift consumption away from periods of peak demand and, at the same time, avoid periods of high emission intensity in electricity supply (Fang et al., 2018). Other studies also argue for demand-side management (see e.g., Haidar et al., 2014; Masoum et al., 2011), and many argue for pricing schemes that disincentivize charging during off-peak hours (see e.g., Barton et al., 2013; Clement-Nyns et al., 2011; Masoum et al., 2011; O'Connell et al., 2012), as an alternative to costly upgrades of distribution transformers.

In the future, vehicle to grid[2] (V2G) may also provide a means to mitigate capacity problems in electricity distribution (see e.g., Barton et al., 2013; Clement-Nyns et al., 2011; Green II, Wang, & Alam, 2011; Hagem et al., 2019; Mwasilu et al., 2014), but bidirectional PEV charging is in its infancy (Haidar et al., 2014), and seems to come at a relatively high cost due to energy losses, changes in infrastructure, and extra communication between PEVs and the grid (Habib et al., 2015). Drivers may also see a high inconvenience cost associated with committing to a V2G contract (Parsons et al., 2014) or have a relatively low and variable willingness-to-pay for V2G capabilities (Noel et al., 2019).

Most of the reviewed studies assume that transport demand, and therefore PEV users' demand for electricity, is exogenous (see also Daina, Sivakumar and Polak, 2017a; 2017b). This paper contributes to the literature by looking at the mechanisms and outcomes in *both* the transport and energy market, and the feedback between them. We use a stylized transport and energy model for the greater Oslo area to study costs and benefits in both the electricity and transport markets jointly. The model allows the agents to choose the type of car (or no car), their transport pattern, and (if they own a PEV) how much to home charge during power peak and off-peak hours. To our knowledge, it is the first time these features have been applied in the same modeling framework. The importance of the feedback between the transport market and the electricity market depends on the structure of the electricity production sector. When the electricity sector is heavily dependent on intermittent generation or has a pronounced demand peak, PEV charging and V2G operations become crucial. Effective coordination between the transport and electricity sector is needed, see e.g., Hagem et al. (2019). However, when electricity production relies heavily on hydropower and has ample generation capacity, the coordination between EV operation and electricity production is much less important. In that case, the main problems are situated on the electricity distribution cost. In Oslo and Norway, hydropower is the primary source of electricity, and the main coordination issue will be the distribution cost impact of the penetration of PEV's.

Given the context of the Norwegian electricity production sector, this analysis concentrates on the distribution costs associated with a transport system geared to the use of PEVs. Our paper addresses the following research questions: 1) When we factor in the current uniform grid tariff system, what are the welfare impacts of today's EV policies and policies for reaching CO_2 targets at least cost? 2) What is the impact on the welfare costs of more cost-responsive pricing of electricity distribution?

Section 2 briefly discusses policies and market distortions relevant for electromobility and power distribution. Section 3 and 4 presents the theoretical model, the numerical model and describe the scenarios we run. In section 5, we present and analyze model results. Section 6 concludes.

2. Policies for electromobility and power distribution in Norway

The rapid rise in the number of PEVs in Norway, to a considerable degree, results from incentives in Norwegian transport policy (Figenbaum and Kolbenstvedt, 2016; Fridstrøm and Østli, 2018). This growth will entail an increase in power consumption. The focus of this study is solely on the lower end of the electricity sector value-chain, i.e., the power consumption of households and capacity of the low-voltage distribution grid. Electricity generation in Norway (and countries where Norway is a part of an integrated electricity market) will only be slightly affected by the passenger car fleet going electric. If about half of the passenger car fleet is electric by 2030, it will amount to about a 3% increase in electricity consumption (Skotland et al., 2016). Furthermore, Wangsness et al. (2020) found that expansions in transmission capacity to accommodate the large-scale electrification of passenger cars will be negligible over the next decade. It is, therefore, appropriate to focus on the distribution grid, where an econometric analysis by Wangsness and Halse (2021) identified statistically significant cost increases due to higher BEV density already during the period 2008–2017.

The energy sector is preparing for the electrification of transport. The Norwegian energy regulator NVE (The Norwegian Water Resources and Energy Directorate) has produced two technical reports that assess the strain that PEVs put on electricity transmission. The first report (Skotland et al., 2016) paid attention to how their diffusion can impact the electricity distribution network. NVE estimated that 75 percent of the charging of PEVs takes place at home, 15 percent at work, and 10 percent is fast charging. NVE found that 70–80 percent of PEV drivers seldom use fast charging. However, NVE expected the demand for fast charging to increase in the future.

NVE's review indicated that electric vehicle charging primarily occurs at night, while some also charge their vehicle immediately after work. Fig. 1 shows NVE's prediction of a power consumption profile for an average household, with and without home charging of PEVs.

NVE argues that the introduction of power-based tariffs will provide incentives to postpone charging until after peak hours. They have recently submitted an updated proposal for a new electricity tariff structure based on the demand for power.[3] This approach became technologically feasible after January 1, 2019, when smart meters became compulsory for all Norwegian households. The new meters will enable households to closely monitor their temporal electricity consumption profiles and distribution grid companies and electricity retailers to bill accordingly.

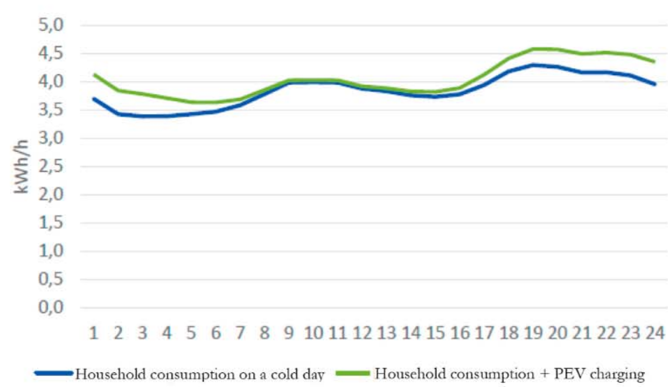

Fig. 1. Average household power consumption per hour on a cold day (blue line) and total household power consumption when the assumed pattern for home charging PEV is included (green line). Source: Figure. 4.3 in Skotland et al. (2016).

[2] V2G involves using EVs as storage for electricity.

[3] NVE-RME legger fram forslag til ny nettleiemodell - NVE [in Norwegian].

NVE developed stress tests for neighborhoods with high PEV-density. Assuming periods in which 70% of the residents charge their EVs simultaneously, it found that the power demand can increase by up to 5 kW per household. This situation results in an overload of more than 30 percent of the transformers currently servicing Norway's distribution network. NVE's follow-up report (Skotland and Høivik, 2017) concluded that full-scale electrification of transport (including buses and ferries) is primarily a threat to the low-voltage grid and transformers. The upgrading of several of these components are planned today, which reduces the problem of overload in the future. However, NVE reported that, as of 2017, few of the distribution system operators account for the electrification of transport when forecasting the power demand.

Increased PEV ownership is expected to lead to higher demand for power that eventually exceeds the local transformer's capacity at the local grid level. The capacity may need to be expanded for the transformer, the cable between the transformer and the households, or both. Over time, some neighborhoods could drive up grid company investment costs as PEV ownership increases, leading to higher tariffs for all customers.

At the time of writing, no household has incentives to postpone charging until after peak hours: Both retail electricity prices and grid tariffs are the same throughout the day. There are many reasons why PEV owners prefer to charge right away after coming home. First, it is convenient. They plug in, and there is no need to spend mental capacity on timing. Second, they maximize the probability of always having the battery charged for any activity later, planned, spontaneous, or emergency.

Many papers look at optimal ways for regulators to handle periods with high power demand and cost recovery for Distribution System Operators (DSOs). Recent contributions include Brown and Sappington (2018) who looked at Maximum Demand Charges (MDCs) and Time-of-Use (TOU) pricing for residential consumers. They found that TOU pricing in most cases secures higher aggregate welfare than MDCs. It can often be beneficial to apply some element of fixed charges in order to induce efficient consumption and at the same time ensure cost recovery to suppliers (Borenstein, 2016; Brown & Sappington, 2017a, 2017b). This feature is common in the billing of Norwegian DSOs. It is also worth mentioning that pricing schemes to shift demand away from peak hours (such as TOU pricing, MDCs, Critical Peak Pricing, or Extreme Day Pricing) can have additional benefits such as increased reliability (Albadi and El-Saadany, 2008). As previously discussed, peak grid tariffs could serve as an instrument to move some of the charging away from peak hours. The peak tariff would have to be large enough to incentivize some PEV owners to postpone their charging. The necessary peak tariff is driven upwards by the fact that Norwegian electricity prices and tariffs on average are lower than in most other European countries (Figenbaum et al., 2019), incomes on average are higher and average incomes of car owners are higher than those of non-car owners, and own-price elasticities for electricity are relatively small (see e.g., Ericson, 2007).

3. The stylized transport and electricity model

3.1. Optimizing grid capacity expansion

We use a theoretical model similar to that in Wangsness et al. (2020b), where the social planner's objective is to maximize the welfare of the model agents. Welfare stands here for the total benefits and costs in society, including the households, the electricity producers, distribution companies, as well as the government and the environment. We extend the model by accounting for the induced cost of demanding higher local capacity for charging PEVs. There is a cost of expanding local capacity that needs to be balanced against the agents' preference for charging during peak hours, modeled as a disutility function of charging during off-peak hours. For the social planner, this can be considered a cost minimization problem. In this section, we solve this problem for a single representative agent. In the stylized first-best solution, the capacity expansion per PEV owner is set to strike a balance between incurred grid investment costs and the disutility of charging off-peak. This balance can be interpreted as if the PEV owner commits to a charging pattern, and the incurred investment cost in optimum can, for the agent, be considered a part of the fixed cost of getting a PEV.

Let kWh^o be the amount of energy required in the off-peak period, and let kWh^p be the energy required during the peak period. The respective unit prices per kWh are p^p and p^o. Assuming that household power consumption (kW) gives a fixed charging speed (3.6 kWh/h) and an exogenous daily charging need of $kWh^o + kWh^p = \Omega$, the problem boils down to how the agents want to divide their charging hours $h = \Omega/kW$ between peak and off-peak: If they want to charge during periods with peak demand, they must pay for capacity expansion.

We introduce the following simple non-linear programming problem, where F is the fixed investment cost for any transformer, β is the investment cost of additional peak capacity, where charging in the off-peak involves some disutility $disU(h^o)$ as a function of off-peak hours charged, and where the control variable is kWh^p. We operate with annualized investment costs, denoting them F^{ann} and β^{ann}. We solve the problem for a representative day.

$$\min_{kWh^p} p^p kWh^p + p^o(\Omega - kWh^p) + disU\left(\frac{\Omega - kWh^p}{kW}\right) + \frac{F^{ann} + \beta^{ann} kWh^p/h^p}{365} \qquad (1)$$

when $kWh^p \geq 0$

This gives us the following Kuhn-Tucker conditions:

$$p^p - p^o - \frac{1}{kW} disU'\left(\frac{\Omega - kWh^p}{kW}\right) + \frac{\beta^{ann}/h^p}{365} + \mu = 0$$

$\mu \geq 0$ ($\mu = 0$ if $kWh^p > 0$), where μ is the Lagrange multiplier of the non-negativity constraint. We get three possible solutions, two corner solutions, and one interior solution:

1. Interior solution: Optimum is where the marginal disutility of charging time during off-peak hours (weighted by kW) equals the price difference between peak and off-peak electricity plus the share of the annuity of the marginal investment cost for expanding peak capacity. With the interior solution, we have that some charging is done during peak hours, $0 < kWh^p < \Omega$, when $\frac{1}{kW} disU'\left(\frac{\Omega - kWh^p}{kW}\right) = p^p - p^o + \frac{\beta^{ann}/h^p}{365}$
2. No charging is done during peak hours, $kWh^p = 0$, when $\frac{1}{kW} disU'\left(\frac{\Omega - kWh^p}{kW}\right) < p^p - p^o + \frac{\beta^{ann}/h^p}{365}$
3. All charging is done during peak hours, $kWh^p = \Omega$, $\frac{1}{kW} disU'\left(\frac{\Omega - kWh^p}{kW}\right) > p^p - p^o + \frac{\beta^{ann}/h^p}{365}$

We denote the cost-minimizing choice of the agent kWh^{p*}. We have depicted the optimal solution where the PEV owner faces the marginal investment cost that their charging pattern (which they commit to or are forced not to exceed) imposes on the local grid. The fixed component of the investment costs is assumed to be financed through lump-sum taxation or a fixed component on the bill from the local grid company. This solution can be considered as the first-best in this dimension. It could be interpreted as a "capacity subscription tariff" to all PEV owners that do not commit to only charge off-peak. This tariff will then optimize incentives not just for purchasing a PEV or not, but also the choice of charging pattern conditional on owning a PEV. The capacities chosen by the PEV owner then give the correct investment signal to the local grid company.

PEV owners are not facing any capacity tariff in the current situation in Norway but pay regular uniform grid tariffs in the form of a fixed component and a price per kWh. In our model, this corresponds to a situation where $p^p = p^o$. In addition, all fixed investment costs are spread across all DSO customers, so the PEV owner does not face the induced cost of capacity expansion, leading to the corner solution where the PEV-owner always charges during peak hours, $kWh^p = \Omega$. In the following sections, we explore numerically the importance of pricing charging capacity.

3.2. Optimizing the transport and electricity distribution systems

Our numerical model is constructed to capture the most relevant aspects of vehicle ownership and transport choices for the population of the greater Oslo area. This population is based on the Norwegian travel survey (documented in Hjorthol et al., 2014).

We utilize the model of Wangsness et al. (2020b), which represents all transport modes used in the Oslo agglomeration. It represents the demand for trips by car as well as public transport (PT). Car users can choose between conventional ICEVs, PHEVs, and BEVs of different sizes. The model optimizes the pricing of car usage, car purchase taxes as well as public transport fares. The optimum balances the households' transport benefits with all the costs, including time costs (congestion), public transport system costs, and environmental costs. Due to space limitations, and since the theoretical foundations, the calibration and the optimization procedure are covered in detail in Wangsness et al. (2020b), we will not spend time on it in this article. An overview of the model concept is depicted in a flow chart in Fig. 2. The modules *Charging demand* and *Grid costs and pricing,* along with the feedback loops between *Energy demand* and *Transport and energy policies* (see Fig. 2), have been added to our model. The rest of the model is the same as in Wangsness et al. (2020b). Some details concerning the numerical model are covered in Appendix A.

Compared to Wangsness et al. (2020b), this paper extends the model by including agents' choices regarding home charging in the case where they end up owning a BEV or a PHEV (i.e., a PEV). PEV-owners demand for electricity is determined by their travel demand (and other exogenous electricity consumption). In equilibrium, agents adapt so that private marginal transport benefit equals private marginal transport cost for all their transport choices, including choice of vehicle, number of trips, and timing of the vehicle charging. When determining the timing of charging, the households consider the electricity fares (electricity costs, grid tariffs, and taxes) only, while for the welfare function, we also include electricity production and distribution costs.

The transport demand of the overall population in the greater Oslo area is modeled by means of three synthetic agents, based on the ca. 10,000 respondents from the area in the Norwegian travel survey 2013/2014. The key characteristics of the model agents are given in Table 1.

In model scenarios where at least one agent group chooses a PEV, the demand for capacity (kW) for charging during peak hours transforms into a need for the local DSO to replace the old transformer with a new one with more capacity. The added cost stemming from this increase in demand depends on how much more additional capacity is needed and how prematurely the old transformer is to be replaced. If it is to be replaced regardless since it has reached the end of its technical life, the latter cost component would be zero. The cost of prematurely replacing the transformer is assumed to be equal to the foregone interest income for the years left of the transformer's technical life.

The consequences of more PEVs will vary from neighborhood to neighborhood. Our stylized model only has one representative neighborhood that is intended to represent the average case where more EV charging during peak hours leads to more investments from the DSO. The parameters for the average case can be considered relatively uncertain. The inclusion of the PEV charging module adds at least two key uncertain parameters in the numerical model, which leads us to ask the following questions:

1. How large is the disutility parameter for PEV-owning agents to charge their car off-peak, i.e., how responsive will they be to peak tariffs?
2. Given the need for new grid capacity, how many years has the investment been moved ahead, i.e., how much of the fixed investment cost can be attributed to the rise in peak power demand from PEV charging?

To illustrate the uncertainty and give an idea of the variation in how costly the grid enhancements for accommodating EV home charging can be, we will provide sensitivity analysis for how the results change with changes in these parameters. Table 2 shows our baseline assumptions for the model extensions regarding PEV-charging:

The investment cost is transformed into an annuity over the new transformer's lifetime. This annuity is what the DSO needs to recover through its tariffs. We will model different pricing schemes for the DSO. As shown in the solutions of Eq. (1), the consumers adapt so that marginal disutility of charging off-peak equals the difference in electricity price (including taxes and tariffs). With uniform prices between peak and off-peak, the consumers will cover all charging needs during peak hours. If the DSO applies peak tariffs, the consumers will shift some of their charging to off-peak. We arrive at an equilibrium with tariffs charged and quantities consumed at peak and off-peak, as well as transport costs and amounts traveled.

4. Scenario description

We use the model for analyzing different scenarios with different policies. Policies can be either fixed or determined endogenously to achieve a policy objective at the least cost. The starting point for the scenarios is the reference situation of 2014. This can be considered an equilibrium before EVs were made available on a large scale. In the travel survey on which the model agents are based, 98% of the cars are conventional. The policies will take us from the reference equilibrium to a new equilibrium in each policy scenario. The time horizon to the new equilibrium can be viewed as the average lifetime of a car, about 17 years (Fridstrøm et al., 2016).

The main policy scenarios considered are the "Business-As-Usual"-scenario (BAU) and the "CO_2-cap"-scenario. The former continues the 2014-policies (which were already very friendly toward purchasing and using PEVs). The latter is where a 50% CO_2 reduction target in the Oslo area is binding, roughly consistent with the official 2030-targets outlined in Oslo Municipality (2016) and Akershus County Council (2016).[4] These scenarios were analyzed in Wangsness et al. (2020b) without any regard for the impact of PEV charging on the local grid. We briefly summarize the key insights from those scenarios in Wangsness et al. (2020b):

In the BAU scenario, Agent X (who works and makes occasional long trips) adapts by switching to a PHEV, Agent Y (who works but makes no long trips) switches to a short-range BEV, while Agent Z (who does not work and makes occasional long trips) sticks to the small ICEV. In sum, this gave substantial emissions reductions (64% reduction relative to the baseline) but higher transport volumes (2.1% relative to the baseline for a constant population). Compared to the reference situation, there is a welfare loss due to higher resource costs for cars and more congestion.

In the CO_2-cap scenario, policies are determined so that the target is reached at least cost leading to Agent X switching to a PHEV, Agent Y sticking to a small ICEV, and Agent Z switching to a small EV. The policies are characterized by; 1) higher tolls for all cars, in particular during peak traffic, 2) higher peak fares and lower off-peak fares for PT, 3) higher purchase taxes for ICEVs, and 4) no tolls for BEVs driving in rural areas. These policies achieve the CO_2 target, but the equilibrium has a lower welfare level than the reference equilibrium. The welfare cost of reaching the CO_2 target amounts to 6690 NOK (about €700) per tCO_2.

[4] The 50% reduction target in 2030 for Akershus County (now a part of the larger Viken County) that surrounds Oslo still remains, while the Municipality of Oslo now has a target of a 95% emission reduction by 2030 (Oslo Municipality, 2020).

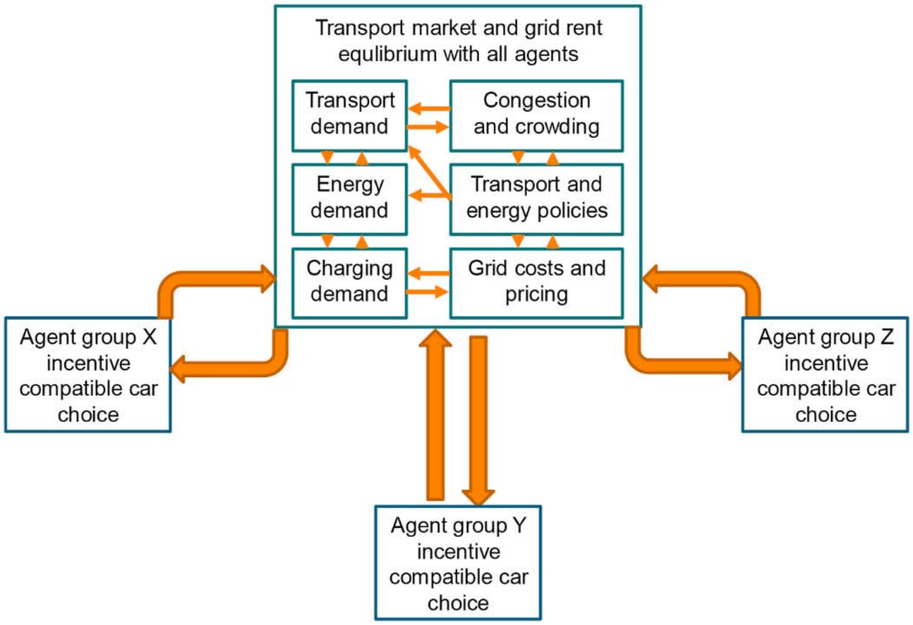

Fig. 2. Overview of the model concept.

Table 1
Key agent characteristics.

Characteristic	Agent X	Agent Y	Agent Z
Estimated number of people	267,955	468,187	210,187
Working/Not working	Working	Working	Not working
Annual gross income (NOK)	591,183	500,972	320,821
Any long trips by car per month	Yes	No	Yes
Number of short car trips per day	1.9	1.38	1.0
Number of short car trip km per day	20.9	15.6	9.8
Average length of a long car trip (km)	191	N/A	175
Number of long car trips per year	19.5	N/A	11.8
Number of PT trips per day	0.4	0.7	0.4
PT km per day	7.6	10.8	6.9
Peak trips car per day	0.9	0.7	0.3
Peak km car per day	10.5	7.7	2.8
Off-peak trips car per day	1.0	0.7	0.7
Off-peak km car per day	10.4	7.8	7.0
Peak PT trips per day	0.3	0.4	0.1
Peak PT km per day	4.5	6.9	2.3
Off-peak PT trips per day	0.2	0.3	0.3
Off-peak PT km per day	3.1	4.0	4.6

We revisit these scenarios, but now the impact of EV charging on the local grid is part of the modeling. We run the model for two different pricing schemes the DSO can apply to respond to increased demand for power for EV charging.

- No ability for DSOs to peak price, i.e., the DSO continues with uniform tariffs
- DSOs apply peak tariffs determined by the *marginal* increase in capacity stemming from charging EVs during peak hours and covers the rest of the costs by a fixed component

5. Results

We now present the results from the numerical modeling to answer the research questions stated in section 1. We will also briefly describe the results from the sensitivity analysis.

When we factor in the current uniform grid tariff system, what are the welfare impacts of today's EV policies and policies for reaching CO_2 targets at least cost?

This research question focuses on the problem of PEV charging with

Table 2
Parameter values for baseline assumptions regarding EV-charging and grid costs.

Parameter	Value	Comment/Source
Cost of a new transformer, fixed component (NOK)	190,000	Sidelnikova et al. (2015)
Cost of a new transformer, per kW capacity (NOK)	79	Sidelnikova et al. (2015)
Return on capital applied for regulation (%)	6	NVE (2018)
Expected years of technical lifetime for transformer station	30	Sneve et al. (2005)
No. of years premature the average transformer needs to be replaced due to home charging	0.5	Discussion meetings with DSOs[a]
Marginal disutility parameter $\alpha$of charging off-peak (NOK per hour), from αh^o (i.e., quadratic disutility function)	0.15	Calibrated from a cross-price elasticity of 0.2, which is applied in the LIBEMOD model[b]
No. of agents per transformer	50	Approx. average for DSO Hafslund Nett in 2018
Charging capacity at home (kW)	3.6	Standard for home charging wall box, see, e.g., Figenbaum (2018)

[a] We have had discussion meetings with representatives from the DSOs Ringeriks Kraft AS and Hafslund Nett. They state that unless households install more in-house capacity, they have not experienced having to replace transformers before schedule even with neighborhoods with high EV-shares. The choice of applying 6 months as our base case is a bit arbitrary but illustrates the low occurrence of early replacement. We decide to dramatically stress test this number to see what happens if replacements happen 10 years ahead of schedule on average.

[b] The cross-price-elasticity parameters are a result of the model calibration. For more information, see https://www.frisch.uio.no/ressurser/LIBEMOD/.

BAU EV policies when there is an incomplete market for using grid capacity, i.e., uniform tariffs between peak and off-peak hours. As shown in Wangsness et al. (2020b), the model simulations conclude that Agent X (working, long trips) switches from ICEV to PHEV and Agent Y (working, no long trips) from ICEV to a small BEV in the BAU scenario without any concern of grid costs. These agents would then start home-charging their vehicles to cover their daily transport needs by car. Their choice of when to charge is reflected by the relative price between charging during power peak and off-peak hours and their disutility of charging during off-peak hours. We test the impact of adding this charging behavior under the different pricing schemes the DSO can respond with, described in section 4.

We find that the main features of the BAU equilibrium remain the same as in Wangsness et al. (2020b), even though the charging issues now have been added. Nevertheless, the added grid costs are tangible, and not including them overestimates the net welfare in the equilibrium. Without any form of pricing of peak power consumption, there will be no incentive for the agents to shift any of their charging to off-peak hours. This situation spurs investment in transformer capacity that amounts to a welfare cost of 18 mill. NOK (approx. €2 mill.) per year in the new BAU-equilibrium, compared to an equilibrium where these costs are not considered (Wangsness et al., 2020b). All agents see a reduction in their net disposable income as tariffs increase. In the new BAU equilibrium, those who drive PEVs get somewhat higher transport costs, and all agents get higher household expenses on their non-car consumption of electricity. The model finds an increase of about 18 NOK (approx. €2) per agent per year in household expenses in non-car electricity due to the increase in uniform tariffs, which is the cost we expect today's EV policies to impose on electricity consumers in the Oslo area.

The cost increase results from some agents' actions, while other agents have not changed their behavior at all: Agents X and Y are driving up their own costs, but they are also imposing costs on Agent Z as tariffs increase. This is a pecuniary external cost in the market for grid capacity, a market that can be considered incomplete as a uniform tariff structure does not signal capacity scarcity and expansion costs. Of the additional total welfare cost of 18 mill. NOK, Agent Z has to bear the brunt of 4 mill. NOK (about €420,000).

Wangsness et al. (2020b) show that reaching a 50% CO_2 reduction target at least cost implies that Agent X switches from ICEV to a PHEV and Agent Z switches from ICEV to a small BEV. Before considering any charging issues, we find a welfare cost of 6,690 NOK (approx. € 700 or USD 850) per tCO_2 for reaching this CO_2-target.[5] Adding PEV charging and costs to the distribution grid in the CO_2-target scenario does not change optimal car combinations under policies for reaching the target at least cost. Like in the BAU scenario, the changes in tariffs amount to such small changes in generalized costs that travel patterns hardly change. Consequently, the policy variables in the CO_2-target scenario are close to unaffected by introducing charging issues.

With uniform tariffs, the welfare cost increases by 16 mill NOK per year (approx. €1.75 mill.), translating into an increase of 27 NOK (approx. € 3) per tCO_2 (i.e., from 6,690 to 6,717 NOK) in order to reach the ambitious CO_2 target. The main results of the analyzes with uniform tariffs are summarized in Fig. 3.

What is the impact on the welfare costs of more cost-responsive pricing of electricity distribution?

The welfare cost can be reduced by allowing the DSO to apply peak tariffs, causing some shifting of PEV charging to off-peak hours. While this reduces investment costs, it also increases the disutility cost of postponing some charging to off-peak hours. Consider the scheme where the added peak tariff is only determined by the *marginal* increase in capacity stemming from charging PEVs during peak hours and where the rest of the costs are covered by a fixed component. In this case, the added welfare cost amounts to 12 mill. NOK pear year in the new BAU equilibrium (approx. €1.3 mill.), lowering the costs by a third compared to the uniform pricing scheme. Now the agents pay approx. 12 NOK (about €1.3) more per year in non-car electricity expenses, with a fixed component of about 9 NOK and a 3 NOK increase in expenses due to higher peak tariffs.

It is worth noting that even though the peak tariffs provide a price signal for grid capacity usage, we still get an equilibrium where PEV owners do most of their charging during peak hours. The Agent Z group still has to pay more in tariffs over their electricity bill, *ceteris paribus*, despite not owning a PEV in the BAU scenario. They have to pay more for their non-car electricity consumption during peak hours, which is assumed to be inelastic. One can still consider this a pecuniary externality, but no longer in an incomplete market, as grid scarcity now has a price signal. However, Agent Z still has to pay a higher fixed component for the grid rent due to the PEV charging actions of the other agents, who still do not have to carry the full cost of their behavior. However, the burden imposed on Agent Z has been reduced to about 2.5 mill. NOK (about €260,000), compared to the case with uniform tariffs.

We also see welfare improvements from applying a better pricing scheme in the CO_2-target scenario. When applying peak tariffs only to the marginal capacity expansion induced by PEVs and covering the rest with a fixed component, the added welfare cost is 17 NOK (about €1.8) per tCO_2, about 37% less than under uniform pricing. The main results are summarized in Fig. 4.

Under both pricing regimes, the agents' car choices are unaffected compared to the results in Wangsness et al. (2020b), and the changes in tariffs never cause more than minor changes (less than 0.1%) in generalized transport costs and subsequently in transport use.

Sensitivity analysis on the investment strategy of the DSO

These added welfare costs do not seem so large for an area with a population of 1.2 mill. people. In discussion meetings with the DSOs Ringeriks Kraft AS and Hafslund Nett, we were told that regular home charging had not spurred many new investments that would not have occurred otherwise (unless co-founded by households wanting to increase their own capacity), corroborating this story.

Our base assumption is that DSOs need to replace the transformer on average six months ahead of its expected life span of 30 years (a shortening of less than 2%). We conduct sensitivity analysis where we assume the replacement of transformers on average has to be done 10 years ahead of its expected life span. An additional 100,000 NOK (approx. € 11,000) needs to be spent on digging up and replacing cables between the transformer and the households. This assumption entails far greater investment costs due to PEV charging and subsequent changes in tariffs and welfare. With the 10-year assumption, the additional welfare cost to the BAU equilibrium is 304 mill. NOK per year (approx. € 34 mill.) under uniform pricing, compared to an equilibrium where grid costs are not considered.

Further, the added cost is limited to only 193 mill. NOK (approx. € 22 mill.) with peak tariffs for the marginal capacity increase and the rest of the cost covered by a fixed component, translating into a higher cost per ton of CO_2 abated in the CO_2-cap scenario. Fig. 5 compares the costs of reaching the ambitious climate goals when we disregard the costs to the local grid and include the costs to the local grid under the six-month and ten-year premature replacement assumptions.

Sensitivity analysis on the heterogeneity of the disutility of charging in the off-peak

The disutility function for charging off-peak is a highly uncertain part of the model, so we first test the impact of doubling the marginal disutility parameter for all drivers. This will only make a difference where peak tariffs are allowed. Higher marginal disutility of off-peak charging leads to less load shifting under the relevant pricing scheme, thus driving up investment costs in transformer capacity. However, the ultimate effect of higher disutility of charging is subtle. Utility investment costs are high, but the low levels of load shifting imply lower absolute disutility costs for PEV owners. From a welfare perspective, the differences in investment costs and disutility costs seem to balance out, so there is hardly any increase in welfare costs (less than 20,000 NOK per

[5] In Wangsness et al. (2020b) we also tested a scenario with 100% electrification, and thus 100% emissions reduction from transport, which resulted in an abatement cost of 12,650 NOK per tCO_2 (about €1,330). Such a scenario would certainly imply higher grid costs than in the scenarios analyzed in this paper, but the abatement cost burden in the transport sector would strongly dominate the burden to the distribution grid sector.

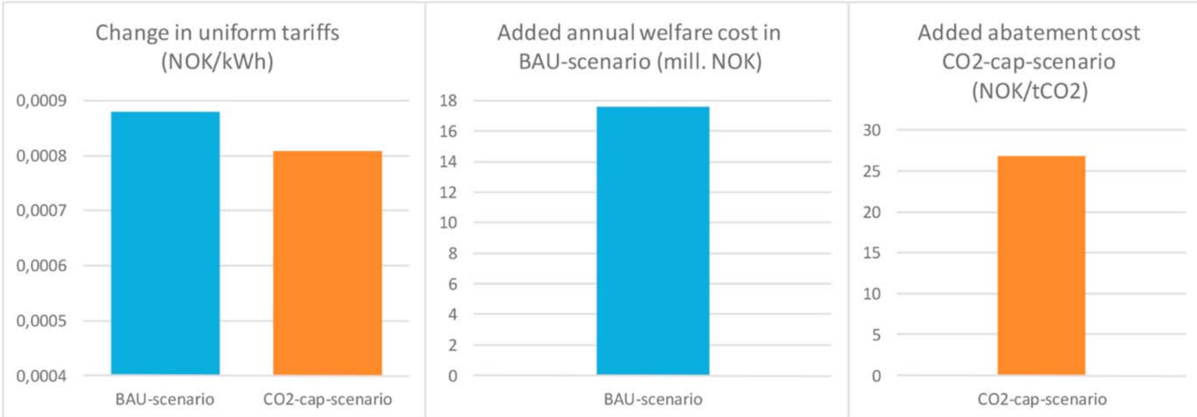

Fig. 3. Main results from simulations with uniform tariffs.

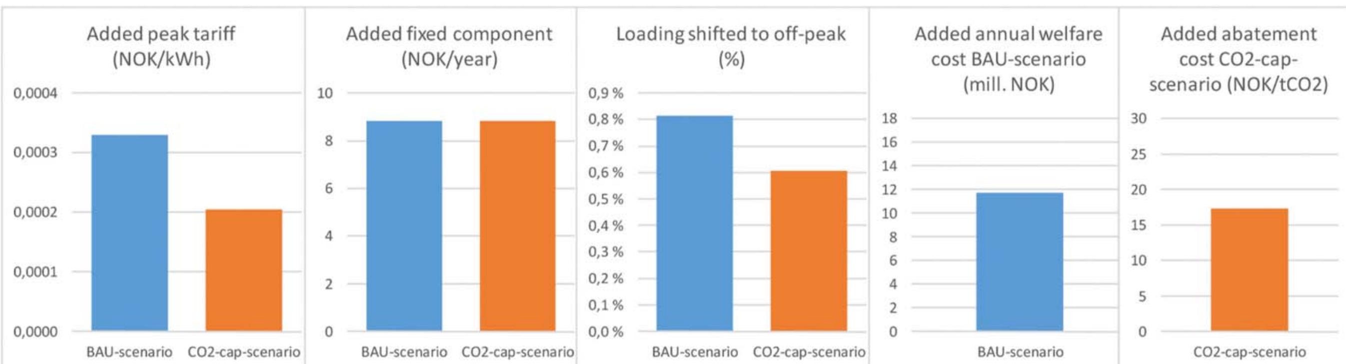

Fig. 4. Main results from simulations with optimal peak tariff.

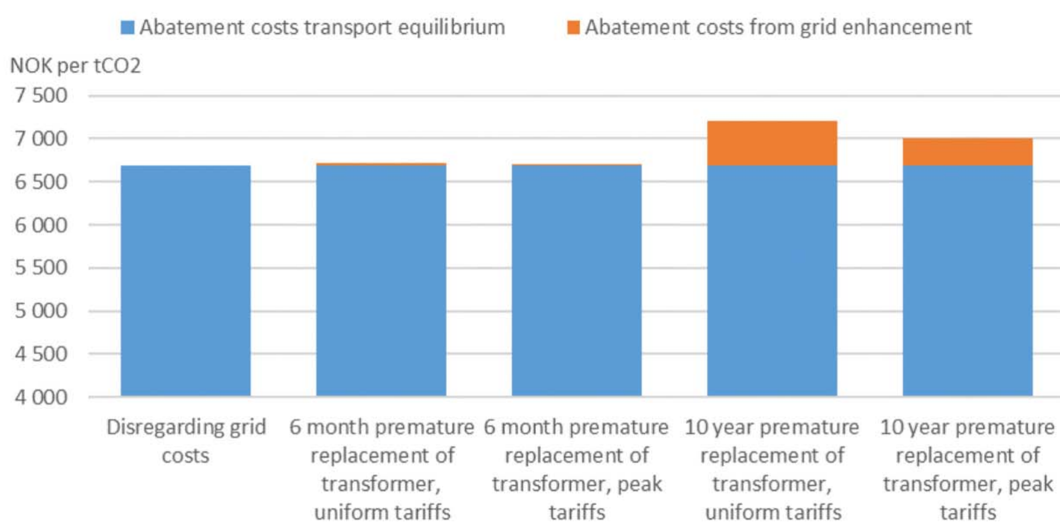

Fig. 5. How grid costs affect the abatement costs of achieving ambitious climate goals under different assumptions.

year for the entire Oslo area)[6] compared to the equilibrium under baseline assumptions. We observe a similar pattern when halving the marginal disutility parameter for all drivers. We see somewhat higher load shifting and somewhat lower capacity investments balance against somewhat higher absolute disutility of charging off-peak. The net effect is a slight reduction in welfare cost.

We also test how heterogeneity in the disutility parameters between agents would affect the results. For this purpose, we build a scenario where only high-income Agent X has a double disutility parameter, and the two other groups of agents stick to the baseline disutility. Compared to the baseline results in the CO_2-cap scenario with peak tariffs, we get that Agent X responds less with regards to charging time, thus driving up distribution investments slightly, leading to slightly higher peak tariffs for all agents, and this means that agent Z makes an additional effort for recharging in off-peak. There is now again a total welfare cost increase, but it is lower than in the first test (less than 10,000 NOK per year for the entire Oslo area), and the transport equilibrium is mainly unchanged.

The three sensitivity tests tell us that the disutility cost of charging off-peak matters for the charging behavior and the network costs. However, with peak tariffs balancing these network costs with the disutility costs of the PEV-users, the overall welfare effect of changing the disutility parameter cost is relatively small. Heterogeneity in the charging costs among groups of users also helps to even out the additional welfare costs (see Table 3).

The main results from the sensitivity analyses can be summarized in Table 3: It shows that the uncertainty regarding the disutility parameter for off-peak charging does not lead to very noticeable changes compared to the baseline calculation displayed in Figs. 3 and 4. The uncertainty regarding the average cost and prematurity of replacing transformers is more of a stress test with a much higher impact on tariffs and added abatement costs.

6. Discussion and conclusion

We find that as today's policies drive up the PEV-share of the car fleet, they also drive up investment costs in the local grid as old transformers need to be replaced prematurely. Our model finds an equilibrium where the replacement leads to between 12 and 18 NOK (approx. €1.3 - €2) in added non-car electricity costs per agent per year, depending on the DSO's pricing scheme.

The sensitivity analysis shows that the cost can get substantially higher if old transformers must be replaced sooner than in the baseline. If the transformers need to be replaced ten years ahead of their technical life and assuming a higher cost for cables, non-car electricity costs per agent increase to between 205 and 310 NOK per year (approx. €22 - €33). While this may be a more noticeable expense for consumers, it is still small relative to overall electricity expenses, and well within fluctuations in such expenses due to normal year-to-year price fluctuations.

The shift to PEVs is an integral part of reaching the ambitious goals of reducing CO_2 emissions by 50% in the greater Oslo area at the least cost. We find that adding home charging issues leads to 17–27 NOK in additional costs per tCO_2e under baseline assumptions. Before adding grid capacity costs, the welfare cost of reaching the emissions target amounted to 6690 NOK (about 700 Euro) per tCO_2 Wangsness et al. (2020b), so adding the grid costs means 0.3%–0.4% extra cost per tCO_2. If the policymakers have committed to the CO_2 target and are willing to pay the cost of reaching it, accounting for the grid costs will not be very discouraging.

6.1. Caveats

The results should be interpreted with some caution due to several caveats. As discussed in Wangsness et al. (2020b) the transport model we use is stylized with significant simplifications, such as having only five stylized car types and three stylized agent groups. The model extensions in this paper, accounting for the capacity of the distribution grid, also introduce new uncertain parameters, such as the investment cost function for transformers and the average number of years of premature replacement of transformers. The model is static, so it ignores the dynamics of DSOs continuously replacing old infrastructure over time according to schedule, along with the year-by-year growth in the number of PEVs.

There is always a trade-off between the model's realism and its tractability and transparency (cf. Frisch, 1964). Despite these caveats, we believe the main findings to be sound and robust. Achieving ambitious emissions reduction targets in the transport sector in the greater Oslo area will come at very high abatement costs. Achieving the targets at least cost will require a substantial share of the population shifting to PEVs, but not all. The shift to PEVs will bring about new costs to the local grid as enhancements will be needed, but the cost of these enhancements will be small compared to the costs imposed on the transport sector. Even with the sensitivity test with dramatically higher grid costs, this result did not change. We do not expect this result to change even if we had a more heterogeneous set of model agents. We would still see significant electrification. We expected the disutility cost of recharging off-peak to be the parameter driving welfare costs for a given level electrification. It appears to drive distribution costs, but these costs are balanced by the saved disutility for the drivers in the presence of peak tariffs.

In sum, the stringency of the emissions reductions target will inevitably imply high abatement costs, with a much higher share of the costs accruing to the transport sector compared to the electricity sector.

6.2. Concluding remarks

This paper gives new insights into some of the ways the transport market and electricity market may affect each other when a large portion of the car fleet is electrified. We find that the increase in demand for electricity and power from PEV owners leads to a limited increase in grid investment costs and tariffs. This finding corroborates a recent empirical study by Wangsness and Halse (2021) on the cost impact of local BEV density on DSO costs, which found that increases in DSO costs were associated with local growth in BEV density. However, this cost impact per BEV was found to be more pronounced for smaller DSOs in rural areas than for DSOs in urban areas, such as the Oslo metropolitan area. While the Oslo area, which is the major hot-spot for the fast-paced rollout of BEVs in Norway, may be only mildly affected by higher DSO costs, other parts of the country (or other countries) may not be so lucky. This concern is an area for future research.

From a policy perspective, our findings can be interpreted with cautious optimism. Ambitious climate goals will entail a significant shift to PEVs as a cost-minimizing strategy, but there is no way to escape high welfare costs. There will be some added abatement cost as local grids need to be enhanced, but these cost additions can be expected to be relatively small compared to the welfare effects in the transport sector. Still, policies that enable better mitigation of these costs for DSOs and their customers should be considered. The Norwegian regulator sets the annual revenue caps for DSOs based on efficiency analysis (NVE, 2015). Higher PEV density will add to DSO costs, which should not be mistaken for inefficiency. Adding "PEV density" as a variable in the regulator's efficiency analysis will enable a more efficient setting of the revenue cap. However, as with all public utility policies, the gains should be weighed against the downsides of added complexity to the regulation.

[6] Welfare in the model mainly consists of the sum of total user benefits from the transport sector over all modes, disposable income after transport-, energy- and grid tariff expenses, minus environmental externalities and net government deficit (public transport operations minus revenues from taxes, tolls and fares), which sums up to very high numbers. Hence, the percentage impact from the disutility of off-peak charging on overall welfare in the model will be small, as can be seen in Table 3.

Table 3
Main results from sensitivity analysis.

Sensitivity analysis	Pricing scheme	Change peak tariff (NOK/kWh)	Change off-peak tariff (NOK/kWh)	Change fixed component (NOK/year)	EV-charging during peak	Added abatement cost (NOK/tCO_2)	Welfare change due to disutility parameter change
Double disutility parameter	Uniform tariffs	0.0008	0.0008	0	100%	27	–
	Marginal peak tariff and fixed component	0.0002	0.0000	9	99.8%	17	−0,0000009%
Halving the disutility parameter	Marginal peak tariff and fixed component	0.0002	0.0000	9	99.2%	17	0,0000018%
Double disutility parameter for only Agent X	Marginal peak tariff and fixed component	0.0002	0.0000	9	99.8%	17	−0,0000005%
Replace ten years prematurely	Uniform tariffs	0.0154	0.0154	0	100%	512	–
	Marginal peak tariff and fixed component	0.0002	0.0000	200	99.6%	320	–

However, we believe that the essential regulatory policy change would be to allow DSOs to use a more efficient system for grid tariffs with time differentiation, which Norwegian regulators are working on at the time of writing. That will enable a better functioning market for electricity capacity, creating a better balance between DSOs investment costs and households' power consumption preferences.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Appendix A. Model details

The cost parameters applied for replacing transformers are taken from the NVE report Sidelnikova et al. (2015). Table 4 summarizes parameter values from that report:

Table 4
Cost parameters for a new transformer. Taken from Tables 9–4 in Sidelnikova et al. (2015).

Rated supply voltage (kV)	Cost for new transformer, capacity independent component (NOK)	Cost for new transformer, capacity dependent component (NOK/kW)
5–24	190,000	79
66	1,125,000	91
132	2,125,000	80
300	6,250,000	90
420	8,750,000	58

For calibration, we need quantities for each agent, generalized prices, and elasticities. The quantities used are kilometers traveled on short trips per day, peak and off-peak, car and public transportation (PT), and long trips (100 km+) by car per year. For short trips, agents can substitute between PT and car, and peak and off-peak. For long trips (e.g., to the cabin), the agents can only choose the number of long trips per year.

The own-price elasticities for short car trips are taken from the newest version of the regional transport model RTM23 (documented in Rekdal and Larsen (2008)). Own-price elasticities for PT and the cross-price elasticities between car transport and PT are taken from the transport model for the greater Oslo area MPMM23 (documented in Flügel and Jordbakke (2017)). The cross-price elasticities for shifting between peak and off-peak, and cross-price elasticities for shifting between both modes and travel time, are the same as those applied in Börjesson et al. (2017). We apply the aggregate elasticity from the National Transport Model (documented in Rekdal et al. (2014)) for long car trips. The elasticity values are given in Table 5. Purchase costs and distance-based costs for the different car types are given in Table 6.

Table 5
Elasticity values

Elasticity Parameter	Value
Own money price elasticity, peak car trips	−0.152
Own money price elasticity, off-peak car trips	−0.152
Own money price elasticity, peak PT trips	−0.255
Own money price elasticity, off-peak PT trips	−0.284
Cross money price elasticity between peak and off-peak car trips	0.100

(continued on next page)

Table 5 (*continued*)

Elasticity Parameter	Value
Cross money price elasticity between peak car trips and peak PT trips	0.100
Cross money price elasticity between off-peak car trips and off-peak PT trips	0.086
Cross money price elasticity between off-peak car trips and peak PT trips	0.096
Cross money price elasticity between off-peak car trips and off-peak PT trips	0.050
Cross money price elasticity between peak and off-peak PT trips	0.050
Own money price elasticity, long car trips	−0.172

Table 6
Car specific parameters for technology, user costs, and externalities, baseline

	ICEV small	ICEV large	PHEV	EV short	EV long
Purchase price (NOK)	273,058	503,614	456,036	263,049	720,468
VPT cost (NOK)	59,977	158,219	44,143		
VAT cost (NOK)	42,616	69,079	82,379		
Producer price (NOK)	170,464	276,316	329,514		
Annual tax (NOK)	2,820	2,820	2,820	455	455
Range (km on full battery)			47.8	190	528
Fuel usage (liters per 100 km)	7.99	9.50	6.15		
Share of city trips in e-mode[1]	0	0	72.7%	100%	100%
kWh-usage per km, summer				0.15	0.17
kWh-usage per km, winter				0.20	0.22
kWh-usage per km, average			0.28	0.17	0.20
Non-fuel costs per km (NOK, including taxes, not tolls)	2.05	2.05	2.05	1.98	1.98
Non-congestion external cost per km in city (NOK)	0.70	0.70	0.36	0.36	0.36
Non-congestion external cost per km far from densely populated areas (NOK)	0.16	0.16	0.16	0.15	0.15

[1] For PHEVs we assume that they run on electricity 73% of the time on short trips in the city area, and on fossil fuel when going on long trips.

With these values, MATLAB solves a system of 16 equations with 16 unknowns to complete the calibration of the utility function for each agent. We obtain the various parameter values for the utility functions for the various agents (see Wangsness et al., 2020b).

The generalized prices for short car trips are the distance-based costs (such as fuel, repair, and lubricants), toll, and time costs. Distance-based costs are the same as those applied in the National Public Road Administration's (NPRA) tool for Cost-Benefit Analysis, documented in Cowi (2014). Toll costs are based on reporting from the toll companies to NPRA. The value of time is based on the Norwegian valuation study, documented in Samstad et al. (2010). For long car trips, the generalized prices are distance and time costs for the average long car trip for a given agent. For BEVs, there is an added cost to the trip related to charging the car to fill the gap between the range and the length of the average trip times two (assuming back and forth). The time cost of charging is assumed to be the value of travel time for long leisure trips, weighted by the same disutility weights as applied for waiting time for PT on long trips (0.6).

The generalized prices for PT are given by ticket costs and time costs (onboard time, access time, and waiting time). Samstad et al. (2010) also provide the basis for the value of time for PT trips, waiting time, and access time. In the presence of a large share of PT users having either 30-day tickets or 12-month tickets and different price zones, we apply the method for calculating average ridership payment used in Dovre Group; Institute of Transport Economics, 2016.

Additional costs: If agents were to buy EVs, a fixed cost is also added for charging equipment and for renting parking close to home for the share of agents who do not have easy access to parking at or close to their home. Charging cost equipment is assumed to have an up-front cost of 10,000 NOK (Norwegian Environment Agency, 2016). Parking rental is assumed to cost 1,400 NOK per month (median rent for parking space in Oslo in October 2017 on website finn.no).

Regarding the rest of the transport system, we have cost functions for PT and speed-flow functions for car transport. The cost function for PT is simply the annual aggregated operating costs for Ruter, the public transport company for Oslo and Akershus, as a linear function of annual frequency. In addition, the travel time cost is weighted by a crowding factor. The crowding factor has been calibrated to be a piecewise linear function where the current peak ridership per hour gives a crowding factor of 1.3, the same as in Minken (2017), and the current average off-peak ridership gives a crowding factor of 1. The crowding factor will not get smaller if ridership falls below this level.

The speed-flow functions are based on model simulations from RTM23 on aggregate car travel and travel speed in Oslo and Akershus for various scenarios but with constant road capacity. The result is an aggregate linear speed-flow function. The linearity simplifies the model calculation, but as shown in Arnott et al. (1993), it also serves as a good approximation for a traffic bottleneck model.

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