Efficient Renewable Electricity Support: Designing an Incentive-compatible Support Scheme

David Newbery[a]

Faced with an economy-wide net-zero carbon target by 2050, the electricity industry will have to reach near zero emissions far sooner. That requires a massive increase in variable renewable electricity (VRE). Most existing renewables support schemes distort location and dispatch decisions. Many impose unnecessary risk on developers, increasing support costs. Existing policies reflect past compromises to reconcile conflicting objectives and to disentangle past unintended consequences. Thus the EU Emissions Trading Scheme fixed a cap on emissions, but the subsequent *Renewables Directive* increased renewable targets without reducing the cap commensurately. The unintended result was the additional renewables had zero impact on EU emissions.

The EU Clean Energy Package (EU 2018/20010, §19) requires that "Electricity from renewable sources should be deployed at the lowest possible cost to consumers and taxpayers. … Market-based mechanisms, such as tendering procedures, have been demonstrated to reduce support cost effectively in competitive markets in many circumstances." Well-designed auctions dramatically reduced the clearing prices of successive auctions for off-shore wind in the North Sea. The paper designs an auctioned contract to deliver Variable Renewable Electricity (VRE) "at the lowest possible cost to consumers and taxpayers".

There is a tension between accelerating investment in renewable electricity (RE) and providing unnecessarily generous payments that risk excessive public cost. Price support schemes like Feed-in-Tariffs (FiTs) that set the price and allow all entrants to claim these FiTs can lead to excessive public cost and rapid cancellation of the scheme, or in some cases, to retrospective withdrawal, notably in Spain. Quantity-based schemes - green certificates - place excessive risk on developers, leading either to under-delivery or over-compensation. The solution is simple but took surprisingly long to rediscover – auction either a fixed volume or a fixed sum of money to secure the least cost solution that meets the target or fits the budget.

The paper applies first principles to identify the market failures and considers how best to correct them. If the only externality facing renewables is a learning spill-over, and carbon is properly priced there is no case for subsidizing current output. The starting point of this analysis is that carbon is correctly priced as there is an appropriate and directed instrument to address that externality, at least in the EU. June 2021 carbon price levels in the EU and UK were over €50/t CO_2, consistent with the Paris target-consistent carbon price.

Least system cost requires that new VRE is the right design, locates in the right place and is dispatched optimally. Least cost to consumers includes the cost of any subsidies to persuade VRE of the commercial case to enter. Auctions are the best way to deliver least cost procurement, while giving control over the volumes of RE or cost of the RE subsidy schemes (RESS). For auctions to work well, bidders need clarity on the future market design, future carbon prices and system rules or Grid Codes (including differential locational transmission charges) that will prevail over a reasonable fraction of the life of the investment.

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The main future sources of renewable electricity are wind and solar PV. They have high capital costs but low running costs. Variable running costs for PV are zero, while for wind they are modest. It follows that their major cost is the financing cost – the weighted average cost of capital, WACC. The more predictable and certain are the costs and revenue streams at the time of final investment decision, the higher the share of debt:equity and the lower the WACC. Risk increases the WACC, so reducing risk is the most effective way of lowering RE costs. Controllable generation hedges risk through Contacts-for-Difference (CfDs) that are purely financial obligations. The CfD transfers $(s - p).M$ to (or from if negative) the generator, where s is the strike price, p the market price and M a fixed amount *independent of generation*. As such output decisions are based on p not s. The main distortion of almost all RE support schemes is that support is paid on metered output and so *contingent on generation*. As a result the subsidized price, not the actual spot value of electricity, drives location and dispatch decisions. The main contribution of this paper is to propose a new long-term financial contract that hedges risk, assures revenue, but ensures location and operation decisions are guided by market prices. It does so by designing a CfD whose covered volume is based on local *predicted* output, providing a hedge that ensures offers to supply will be guided by market, not subsidized prices.

VRE has a peak output that is a considerable multiple of its average output. For wind this might be 3:1; for Northern solar PV 10:1. As VRE penetration increases the surplus output will need to be curtailed. An efficient RESS should encourage VRE to choose not to generate if the value of its output is less than its avoidable cost, partly dealt with by prohibiting VRE making negative offers. Similarly, the value of electricity, not the subsidized price, should guide location decisions.

The proposed solution is a novel auctioned contract to address both location and dispatch distortions: a financial Premium Contract for Difference (PCfD) with hourly contracted volume proportional to the day-ahead forecast local output/MW, with a life specified in full operating hours (e.g. 30,000 MWh/MW). That hedges price risk and the problem of over-rewarding high resource costly locations. If combined with nodal pricing and long-term contracts for transmission charges set at the output-weighted future nodal prices that would provide the incentive to locate where local RE output has a low correlation with national RE output and hence higher value. If transmission charges cannot be made suitably locational and lack long-term contracts then an additional locational premium to replace the correct transmission contract can be added to the resulting long-term PCfD, made by the contract counterparty and announced before the auction. This volume-limited yardstick *PCfD* delivers efficient dispatch while assuring but limiting the total amount of subsidy, providing efficient location and operating signals. The revenue assurance, with a government-backed counterparty, allows a high debt share, dramatically lowering the subsidy cost.

Residential and industrial energy efficiency improvements: A dynamic general equilibrium analysis of the rebound effect

Sondès Kahouli[a] *and Xavier Pautrel*[b]

The aim of this paper is to investigate bi-directional spillovers into residential and industrial sectors induced by energy efficiency improvement (EEI) in both the short- and long-term, and the impact of nesting structure as well as the size of elasticities of substitution of production and utility functions on the magnitude and the transitional dynamic of rebound effect.

Developing a dynamic general equilibrium model, we demonstrate that residential EEIs spillover into the industrial sector through the labor supply channel and industrial EEIs spillover into the residential sector through the conventional income channel. Numerical simulations calibrated on the U.S. suggest that not taking into account these spillover effects could lead to misestimating the rebound effect notably of residential sector EEIs. We also demonstrate how the size and the duration of the rebound effect depend on the elasticities of substitution's values. Numerical simulations suggest that alternative sets of value for the elasticities of substitution may give different sizable patterns of rebound effects in both the short- and long-term.

In policy terms, our results support the idea that energy efficiency policies should be implemented simultaneously with rebound effect offsetting policies by considering short- and long-term economy feedbacks. As a consequence, they require considering debates about what type of policy pathways are more effective in mitigating the rebound effect.

The Rationale for Reforming Utility Business Models

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Over the past two decades, more than half of state public utility commissions reformed utility business models (UBMs) by removing a disincentive to invest in utility-scale demand-side management (DSM) with a revenue decoupling mechanism. These mechanisms allow a utility to recover revenue, otherwise lost due to DSM, through electric rates. Although the effectiveness of UBM reform in increasing DSM investment has been studied at length, the rationale for reform with revenue decoupling during this period has been assumed as straightforward.

Economic models of utility DSM investment regularly assume commissions reform the UBM with revenue decoupling primarily to remove the disincentive for utility DSM investment. Under this assumption, commissions aim to enhance social welfare by increasing avoided costs of electricity usage from a total resource perspective, including electricity generation, transmission, and environmental costs. Others have questioned whether commissions reform the UBM in response to interest group and political pressure.

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This paper tests whether commissions reformed UBMs with revenue decoupling primarily to enhance social welfare or if commissions also respond to other political economy considerations. Controlling for political economy determinants, we model how commissions reformed UBMs with a revenue decoupling mechanism from 1997 to 2012 using a multinomial logit regression. Importantly, we account for whether commission decisions on UBM reform removed disincentives for DSM programs with either a "limited" (allowing case-by-case recovery) or "full" (allowing automatic recovery) revenue decoupling mechanism.

We find limited support for the public interest assumption underlying economic models of commission decisions. Instead, we find statistically significant associations primarily between commission decisions to reform the UBM and the political economy context that exacerbates a commission's political risks. These political risks include higher-than-regional-average residential electricity prices as well as political pressure from interest groups and politicians facing intense competition for partisan control of state legislatures. Beyond questioning the primacy of the public interest rationale for regulation, our results give reason to reevaluate economic models of UBM reform that do not explicitly consider commission interests within a broader political economy context.

Understanding the rationale for UBM reform during the period of 1997 to 2012 is of critical importance as public utility commissions across the United States consider a new wave of reforms. We offer that the rationale for future UBM reform may follow the rationale for past UBM reform. The history of UBM reform demonstrates that reforms were not positively associated with high avoided *environmental* costs. Instead, commission decisions to reform the UBM were positively associated with high avoided *political* costs.

What Duality Theory Tells Us About Giving Market Operators the Authority to Dispatch Energy Storage

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There is a debate about which entity should have the authority to dispatch energy storage that participates in restructured wholesale electricity markets. Some stakeholders raise concerns that market operators' independence can be threatened if they make operational decisions for energy storage. The rationale that underlies this concern is that operating energy storage can affect the balance of the system and price formation. We demonstrate that having market operators make operational decisions for energy storage does not change the fundamental nature of the optimal-power-flow problem. Using duality theory, we show that if market operators co-optimize the operation of energy storage with that of generators and transmission, the optimal-power-flow problem yields short-run dispatch support and incentive compatibility and long-run efficiency. These findings are analogous to those for having market operators co-optimize transmission use with generator dispatch. Our work suggests that concerns around giving market operators the authority to dispatch energy storage are misplaced.

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On the Role of Risk Aversion and Market Design in Capacity Expansion Planning

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In competitive power markets, market participants base their investment decisions on thorough profitability assessments. Thereby, investors typically show a high degree of risk aversion, which is the main argument for capacity remuneration mechanisms (CRMs) being implemented around the world. Such mechanisms aim to reduce the risks for new investments by offering capacity providers supplementary income on top of the earnings from selling electricity on the market. The additional firm capacity is then expected to help improve resource adequacy, i.e., to avoid shortage situations.

These developments illustrate that the interdependencies between investors' risk aversion and market design are crucial when analyzing transformation pathways of electricity systems. However, existing capacity expansion planning models do not cover all aspects relevant for a realistic representation of real-world electricity markets, which are amongst others characterized by heterogeneous risk-averse actors and – particularly in the European case – cross-border effects of asymmetrical market design implementations.

In our article, we therefore extend the agent-based electricity market model PowerACE to account for long-term uncertainties, such that capacity expansion planning can be carried out from an agent perspective and with diversified risk preferences. For this purpose, we construct model-endogenous scenario trees and implement a new decision metric that comprises the expected profitability and the corresponding conditional value at risk (CVaR) of a potential investment. As an exemplary source of uncertainty, we consider the impact of different weather years on the feed-in of renewables and electricity demand.

The enhanced model is then applied in a multi-country case study of the European electricity market. We carry out simulations with different degrees of investors' risk aversion as well as two market designs, namely a European energy-only market (EOM) design and asymmetrical CRM implementations. This allows us to quantify the impact of risk aversion on capacity expansion, wholesale electricity prices, and resource adequacy under both investigated market designs.

For the case of risk-neutral investors, we find substantially higher investment incentives in the countries using CRMs, while the remaining countries relying on EOMs are confronted with negative cross-border effects. As a direct consequence of the model-endogenous capacity expansions, average wholesale electricity prices decrease slightly in the countries with CRMs. At the same time, the levels of resource adequacy increase. In line with intuition, the opposite is true for the countries without CRMs.

Assuming risk-averse investors proves to affect the capacity expansion planning by slightly reducing investments. Interestingly, we find the impact of risk aversion to be substantially higher in an EOM compared to a CRM. This finding stands in line with previous results from the literature. However, our simulations also illustrate that while CRMs dampen the impact of risk aversion in the countries using these mechanisms, neighboring countries without CRMs are affected by nega-

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tive cross-border effects and risk aversion becomes even more relevant there than in the case of a European EOM. This is reflected by higher wholesale electricity prices as well as a lower level of resource adequacy in these countries.

Based on our findings, we strongly recommend that policymakers and regulators consider the impact of risk aversion when evaluating different market design options. While an EOM and a CRM may lead to similar outcomes under rather strong theoretical assumptions, this may no longer be the case when considering the characteristics of real-world electricity markets with risk-averse actors. In light of our simulation results, this could imply that in real-world electricity markets, long-term resource adequacy cannot be maintained when relying on a pure EOM. Moreover, particularly in the European setting, it is crucial to account for – potentially adverse – cross-border effects of a market design. Consequently, decisions on national market designs should always take into account the design of the interconnected market areas. It also seems advisable to consider a coordinated European CRM as an alternative to national attempts to secure resource adequacy. Such a coordinated market design is likely to stand better in line with the European Commission's goal of creating an internal electricity market in Europe.

Strategic Behavior and Market Design in Regional Climate Policy

Brittany L. Tarufelli[a]

U.S. electricity markets vary by region and imperfectly overlap with regional climate policies. Although emissions leakage across emissions-regulated and -unregulated areas may depend on regional market design, and the extent of trading between market designs, previous studies of leakage from regional climate policies have focused on market power and market efficiency within only a centralized region following market rules. I develop a theoretical model which considers a second-best problem where a climate policy to correct for a negative externality from carbon emissions can be distorted by another market failure from the market design itself. My model allows for several types of non-overlapping climate policies and electricity market designs, and generates leakage predictions for these combinations.

Load-Following Forward Contracts

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Electricity is commonly purchased and sold in wholesale (spot) markets. The price of electricity can vary widely in such markets, depending on prevailing demand and supply conditions. Forward contracts can avoid the volatility of wholesale market prices by specifying in advance the unit price at which electricity ultimately will be delivered. Swap forward contracts (SFCs) are common in the electricity sector. A SFC obligates a supplier (e.g., a generator) to deliver a specified *amount* of electricity in return for a fixed payment by the buyer (e.g., a load-serving entity (LSE)).

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Load-following forward contracts (LFFCs) are becoming more popular in the sector. A LFFC obligates a generator to deliver a specified *fraction* of the LSE's ultimate demand for electricity at a pre-determined unit price. To illustrate, under a LFFC, an LSE that is committed to serve the demand of its retail customers might agree to pay a generator a pre-specified unit price for 10% of the customers' realized demand for electricity.

SFCs and LFFCs both promote lower wholesale prices by reducing the amount of output a generator has exposed to the wholesale price. The generator's corresponding reduced concern with declines in the wholesale price motivates the generator to increase its supply to the wholesale market, which reduces the equilibrium price.

LFFCs differ from SFCs by automatically tailoring a generator's forward commitment to the realized demand for electricity. In particular, a generator that signs a LFFC commits itself to remove more output from exposure to the wholesale price as realized demand increases. The generator thereby commits itself to compete particularly aggressively in the wholesale market when demand is high and less aggressively when demand is low. Such tailoring of competitive aggression to realized demand can be valuable for a generator because increased wholesale output can be particularly profitable when the demand for electricity (and thus the generator's equilibrium profit margin) is pronounced.

The ability of LFFCs to tailor a generator's competitive aggression to realized demand can promote their widespread adoption. We show that in a setting designed to reflect conditions that prevail in the wholesale electricity market in Alberta, Canada, risk neutral generators adopt LFFCs exclusively when they have the option to sign LFFCs, SFCs, or both.

The equilibrium adoption of LFFCs serves to increase expected consumer surplus and total surplus above the levels that arise in the absence of forward contracting. However, equilibrium expected consumer surplus and total surplus fall below the levels that would arise if SFCs were the only feasible forward contracts. The reduced consumer surplus and total surplus reflect: (i) the relatively limited competitive aggression that LFFCs induce when realized demand is low; and (ii) the fact that generators tend to sign fewer LFFCs than SFCs because the former enable generators to achieve profit-maximizing levels of aggression with a relatively small level of forward contracting.

Thus, relative to SFCs, LFFCs promote reduced variation in wholesale prices but higher expected wholesale prices. Further research is required to determine when the former benefit to risk averse parties exceeds the latter cost.

How Cost-effective are Electric Vehicle Subsidies in Reducing Tailpipe-CO_2 Emissions? An Analysis of Major Electric Vehicle Markets

Tamara L. Sheldon,[ab] Rubal Dua,[c] and Omar Abdullah Alharbi[d]

Global transport was the fourth largest source of greenhouse gas (GHG) emissions in 2018, producing about 24% of global energy-related CO_2 emissions. About 75% of transport emissions come from road vehicles including cars and trucks. The majority of GHG emission reductions in the transport sector are projected to come from electrification of light-duty vehicles (LDVs), where technology is already commercial.

Governments globally have adopted various policies to support electrification of LDVs. Demand-side fiscal policies - in particular, incentives to reduce the upfront price of plug-in electric vehicles (PEVs), represent one of the most commonly used policy levers. This paper explores the PEV subsidy impact and cost-effectiveness in reducing CO_2 emissions across a range of major PEV markets. In particular, we utilize detailed micro-level data from 2010 to 2017 for 11 countries including China, the U.S. and nine major European countries. These countries have a wide range of PEV market shares, ranging from 1 to 40%, and subsidy percentages (government-subsidized portion of PEV pricing) ranging from 0% to 55%. By contrasting these countries, the paper aims to gain a better understanding of how trends and measures such as tailpipe-CO_2 avoided and subsidy cost-effectiveness may change as subsidy levels, PEV prices, and PEV market shares change. Overall, this study attempts to provide the most comprehensive set of cost-effectiveness estimates available in the literature for multiple countries. It also discusses some of the factors that contribute to cost-effectiveness disparities between countries, as well as the lessons that can be learned from them.

To estimate the tailpipe-CO_2 emissions avoided by PEV adoption, we assume that a PEV buyer would have bought an average ICEV of the same body type as the PEV in the counterfactual case of no PEVs. We couple this counterfactual vehicle assumption with insights from the choice modeling literature to allow for more realistic substitution patterns and more realistic estimates for tailpipe-CO_2 savings.

To estimate the cost per tonne of tailpipe-CO_2 avoided, we divide the total subsidy cost by the total tailpipe-CO_2 avoided over the lifetime of the vehicle. To estimate the cost-effectiveness of the subsidy, we account for the fact that taking away the subsidy would not result in zero PEV sales. In other words, we account for the fact that some consumers would have bought a PEV even in the absence of the subsidy. We do so by incorporating values from the literature on the extent of PEV sales induced by the subsidy. Finally, we also incorporate the CO_2 emissions from the combustion of fuels associated with the generation and distribution of electricity used for PEV charging. This gives us the actual cost per tonne of CO_2 avoided from subsidizing PEVs.

The analysis yielded four major sets of results. First, the average non-PEV fleet is less efficient than the replacement fleet based on the body-type equivalency assumption. This means that if we had not employed the body-type equivalency assumption, we would have exaggerated the tail-

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pipe-CO_2 reductions while underestimating the cost per tonne of tailpipe-CO_2 saved. In other words, the usual use of the standard counterfactual technique in the literature, which does not contain the body-type equivalency assumption, overestimates the cost-effectiveness of PEV subsidies.

Second, we discover that the percentage of tailpipe-CO_2 avoided as a result of PEV substitution varies linearly with PEV market share. This finding suggests that, in the absence of detailed data on new vehicle fleets, the country's PEV market share could be used as a proxy to estimate the percentage of tailpipe-CO_2 avoided through PEV substitution. Two factors contribute to deviations from this linear variation: (i) a higher proportion of PHEVs in a country's PEV mix, and (ii) PEVs replacing relatively cleaner vehicles.

Third, we found that the subsidy cost per tonne of tailpipe-CO_2 avoided varies according to the percentage of PEV pricing subsidized by the government. The Netherlands and Denmark, which subsidized high-priced PEVs including plug-in hybrid electric vehicles, lie above the trend, while the U.S., where PEVs replaced higher-emission vehicles, is below the trend. China is paying the most to decrease carbon emissions through PEV subsidies, costing as high as $1,600 per tonne in the short-run, an order of magnitude more than the social cost of carbon. The high costs suggest that PEV subsidies are more a part of China's industrial policy rather than its carbon policy.

Fourth, the estimated cost per tonne of CO_2 avoided rises even more when the actual extent of electric vehicle sales induced by subsidies and the emissions associated with electricity generation are considered. Accounting for these additional CO_2 emissions results in a PEV sales-weighted average short-run static cost of $1441 per *additional* net tonne of CO_2 avoided for U.S. and Europe combined. Even after accounting for subsidy-induced sales and power generating emissions, a linear link between subsidy costs and government-subsidized PEV pricing remains, with the Netherlands and Denmark staying above the linear variation. Also, Germany seems to be above the variation, whilst the U.S. no longer appears to be significantly below it. This is because power generation in the U.S. and Germany is not as clean as in the other European countries in this study.

The high tailpipe-CO_2 emissions reduction costs of PEV subsidy policies warrants research into and adoption of innovative subsidy designs to improve their cost-effectiveness. Innovative targeted PEV subsidy designs could be incorporated in the COVID-19 economic stimulus packages that are being currently considered in different parts of the world for promoting PEV adoption. Targeted designs based on either consumer income or vehicle price represent viable cost-effective alternatives.

Modeling Multi-horizon Electricity Demand Forecasts in Australia: A Term Structure Approach

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Accurate electricity demand forecasting plays a crucial role in the decision-making process of many market participants. Forecasting is used by the market operator for scheduling and dispatch of generation capacity which is crucial to system stability. For generators, demand forecasts are an important driver of strategic choices involved in bidding and rebidding of capacity, whereas for

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retailers demand forecasting affects decisions about the balance between hedging and spot acquisition of electricity. To aide these decisions the Australian Energy Market Operator AEMO publishes historical electricity demand data that is calculated as the half-hourly average of actual four-second regional operational demand measured in gigawatts. It also generates one-day forecasts of half-hourly average demand for each trading day which are then updated every half hour up to the time of dispatch.

This paper identifies an important property of these official multi-horizon forecasts, namely the tendency to overpredict load at longer horizons. A model is developed that explicitly takes account of the information provided by forecasts generated at all time horizons. A special property of the model is the identification of a set of latent factors describing the evolution of demand forecasts over time. Using the Australian data, the empirical results provide evidence of a three-factor term structure model. The three factors are interpreted as level, slope and curvature factors, a result that is akin to the factor structure of models of the term structure of interest rates.

Having identified a factor structure, the economic value of the official forecasts and the information provided by the factor structure are assessed in terms of a cost-loss decision-making model. It is demonstrated that the official forecasts, although irrational in an econometric sense, do provide economic value over a wide range of the cost-loss ratio. This result is of concern because acting on forecasts that systematically over-predict imposes a social cost on the environment. A simple adjustment to the forecasts is proposed that uses the factor structure to compensate for strategic over-prediction. The information contained in the term structure of multi-horizon forecasts is then shown to add to the economic value of the official forecasts, especially at longer horizons.

Firms and Households during the Pandemic: What do we learn from their electricity consumption?

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In this paper we investigate how electricity consumption patterns have changed during the COVID-19 pandemic. Since electricity consumption has a strong correlation with economic growth, it has traditionally been used as an indicator of economic activity. However, as we show, changes in work and life habits triggered by the lockdown measures have implied a structural break in the relationship between electricity consumption and economic activity. In particular, we provide detailed evidence of a strong reduction in the amount of electricity consumed by firms, which was partly offset by an increase in the amount of electricity consumed by households. Therefore, to the extent that economic activity is better captured by firms' electricity consumption, using total electricity consumption would under-estimate the severity of the economic impacts of the pandemic.

Our analysis focuses on the Spanish economy, which has been hardly hit by the COVID-19 crisis. The fact that not all consumer types have access to the same types of tariffs, allows to decompose electricity consumption by firms and by households. Our empirical analysis captures the departure of (daily or hourly) electricity consumption from what one would predict using previous years' data, while controlling for temperature and seasonality. It shows that total electricity consumption fell substantially during the first wave of the pandemic, reaching declines of 18.2% under the total lockdown. Yet, the reduction in firms' demand was much stronger, 29.1% below

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its normal levels, which was partly offset by the increase in households' electricity demand, 9.0% above its normal levels. Subsequent waves repeated similar patterns, though the size of the effects was on average smaller. We also provide evidence of substantial changes in the hourly patterns of electricity consumption, which again differ across firms and households. In particular, we observe large declines in electricity consumption by firms during working times, which are paralleled by simultaneous increases in households' electricity consumption. Interestingly, we also find changes in households' electricity consumption consistent with longer sleeping times, which could have had positive health and productivity impacts.

The importance of decomposing total electricity consumption into consumption by firms and households will likely extend beyond the pandemic due to a change in people's working habits and the penetration of distributed solar and storage facilities. This paper illustrates how some of the current and future challenges of using electricity consumption as an indicator of economic activity can be, at least partly, overcome.