Carbon Taxes and Subsidies with Electrification*

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Abstract

This paper studies the effect of an economy-wide carbon tax when end-use decarbonization requires electrification. Given standard electricity pricing, an economy-wide carbon tax may not implement the planner's allocation due to high electricity prices along the transition that limits end-use decarbonization. Implementation of optimal policy requires a cap or subsidy on the electricity price to avoid an overshooting of prices along the transition path. For a quantitative version of the model calibrated to the US and a $100 per ton carbon tax, cumulative emissions are 9.3% higher absent a policy that implements the efficient price.

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1 Introduction

The standard prescription for addressing pollution is imposing a Piguovian tax that internalizes the unpriced economic damages from the pollution. In the case of climate change, the standard policy prescription is imposing an economy-wide carbon tax that prices the damages from climate change. However, in the presence of other market imperfections, relying solely on the Piguovian tax may no longer be optimal. For example, as emphasized in Acemoglu et al. (2012), a subsidy for innovation may be needed in addition to a carbon tax to implement optimal policy.

This paper studies effects of a carbon tax on electricity prices and its implications for end-use decarbonization. Energy systems models, engineering studies and policy analyses emphasize that reducing greenhouse gas emissions typically requires two distinct steps: 1) reducing emissions from electric power generation via transitioning renewables or other zero carbon energy sources, 2) decarbonizing end-use sectors such as transportation, buildings and industrial emissions via electrification.[1] The decision to decarbonize end-use sectors depends critically on the relative price of electricity versus fossil fuels. While a carbon tax has a direct effect on fossil fuel prices, it may also have large indirect effects on electricity prices.

I start by characterizing a simple macro-energy model with both power generation and an end-use sector that uses either fossil fuels or electricity. Electricity is produced from a combination of power generation capital that either uses fossil fuels or uses renewables/zero carbon sources. An end-use service (like transportation or building heating) is provided by a durable capital stock that is either powered using fossil fuels or using electricity. Both power generation capital and the end-use durable good depreciate slowly over time and are subject to irreversibility constraints - the capital stock cannot be repurposed from fossil fuel to electric or vice versa. These features are both important attributes of the energy system and key for understanding the evolution of the energy system in response to a carbon tax.

Absent a carbon tax, we assume that fossil fuel power generation and end-use capital are cheaper, and the economy is initially in a fossil fuel steady state. Under an economy-wide carbon tax of sufficient size, there is a long-run, zero emissions steady state where power is generated solely from zero carbon sources and the end-use service is fully electrified. Investment in power generation switches to the zero carbon capital stock and fossil investment is zero. Because of capital irreversibility, emissions from both power generation decline at the rate of depreciation.Along the transition path, the price of electricity is determined by the resource cost of providing additional clean power generation. The choice of whether to invest in the fossil fuel durable good depends on the capital and lifecycle operating costs of the fossil fuel good versus the electrified durable.

[1] Even for sectors that cannot be full electrified (like aviation or iron and steel making), electricity is needed to either create hydrogen or other synthetic fuels or to capture carbon to offset fossil fuel emissions.

Interestingly, even if the initial carbon tax is large enough to select a zero emissions steady state, an emissions minimizing transition path (i.e. zero investment in both fossil fuel power and durables) may not be optimal. Transition costs may mean that the planner tolerates some continued investment in the fossil fuel durable before switching to the electrified alternative. In particular, the planner's cost of electricity reflects the current interest rate which may spike due to the resources required to switch from fossil fuel to clean power generation.

Given that provision of electric power is a natural monopoly, the pricing of electricity may not coincide with the planner's shadow cost of providing additional electric power. In the case of publicly provided electric power or in a regulated utility system, power generation is typically paid to recover generation costs with an economic return on capital. When electricity is priced in this way (i.e. average cost pricing), a carbon tax may raise the price of electricity *above* the planner's marginal cost of providing electric power. This higher cost of electricity may result in a lower incentive to electrify end-use sectors and higher emissions along the transition path. Importantly, under average cost pricing, the long-run zero emissions steady state is unchanged, but emissions along the transition path may be higher and end-use sector decarbonization may take longer.

The mechanism emphasized here is distinct from the mispricing of electricity highlighted in Borenstein and Bushnell, who note when various utility fixed costs (transmission and distribution, wildfire mitigation, etc.) are recovered via volumetric charges, the price of electricity may exceed social marginal cost. In this example, the central issue is the passthrough of the carbon tax - a variable cost - to the price of electricity. The planner does not seek to recover this cost, while that regulated utility passes this cost on to the consumer.

While some electric utilities in the US operate in regulated markets, many other utilities purchase power on deregulated wholesale markets. I show that even with deregulated markets, the wholesale price of electricity may exceed the planner's cost of generation. Decarbonization of power generation will likely rely on both low-cost intermittent sources of power generation (solar and wind) paired with higher cost dispatchable power generation (i.e. clean-firm power such as nuclear, enhanced geothermal or natural gas with carbon capture). This higher cost dispatchable power will determine the market price in wholesale markets at times when both intermittent and dispatchable generation are operating. It can be shown that merit order pricing can: 1) distort the mix of intermittent and dispatchable power generation away from the least cost mix, 2) therefore, the average wholesale price of electricity exceeds that of the least cost option. Because the price of electricity is too high, end-use decarbonization may be delayed or prevented.

Even if the long-run (steady state) mix of intermittent and dispatchable generation is the lowest cost allocation, along the transition path, the price of electricity may still exceed the optimal level as unabated natural gas represents the marginal generator on wholesale markets. Given that the carbon tax enters into the fuel cost, the high price of electricity may stall the switch to electri-

fication for the end-use sector. Importantly, relative to average cost pricing, merit-order pricing may deliver a higher cost for electricity both in the long-run and along the transition path.

Why do various pricing mechanisms for electric power fail to deliver the optimal allocation in response to an economy-wide carbon tax? A carbon tax carries a pecuniary externality depending on assumptions on the market structure for electricity markets. In the case of average cost pricing, the need to cover the costs of legacy generators raises the average price of electricity even though all new investment on the margin is in zero carbon power generation. If the planner could shutdown all or some fraction of power generation, the gap between the electricity price and resource cost would close, and prices would implement the optimal allocation. The presence of irreversibility is important in this case.

In contrast, in the case of merit-order pricing and two types of clean power generation, capital irreversibility is not the central issue. Rather, the pecuniary externality stems for the absence of different prices for dispatchable and intermittent technologies. Since power delivered by these two types of capital are not perfectly substitutable, separate prices are needed to provide a premium for dispatchable generation. The mispricing of power generation and misallocation of generation assets between intermittent and dispatchable power persist even in the long-run.

To assess the spillover from carbon pricing to end-use decarbonization, I introduce a richer quantitative model with several types of power generation technology and many types of end-use capital that can be electrified. Specifically, electric power generation is provided by a combination of intermittent and dispatchable power generation technologies via a variable elasticity of substitution production function. As shown in Mehrotra (2024), a variable elasticity of substitution production has the property that intermittent power generation is a perfect substitute for dispatchable power if its generation share is low but becomes progressively less substitutable as its generation share rises. Natural gas with and without carbon capture provide the dispatchable sources of fossil and clean power generation respectively.

I model six distinct types of end-use services that are provided by either a fossil-fuel using capital or an equivalent electrified version. Specifically, I consider surface transportation (i.e. motor vehicles and trucks) for both residential (household) uses and commercial uses, space heating for residential and commercial buildings, and water heating for residential and commercial buildings. Together, these end use sectors account for around 2 gigatons of carbon dioxide emissions with electricity generation account for another 1.5 gigatons. Data from the Energy Information Administration, the Bureau of Transportation Statistics, and the Department of Energy is used to calibrate parameters on service demands, fuel use, fuel costs, and capital costs.

A carbon tax of $100 per ton reduces emissions by almost 80 percent from the initial steady state and raises electricity prices by 40 percent. The planner's allocation results in complete decarbonization of electric power generation and an increase in electrification share ranging from 60 to 100 percent across modeled end-use sectors. Consumption falls by just 0.3 percent and real

interest rates rise by a small amount along the transition path. The relatively modest long-run consumption effects from the carbon tax reflect that higher level of investment in clean power generation capital and electrified end-use capital are nearly fully offset by lower fuel consumption. These modest quantitative effects from a carbon tax of this magnitude mirror findings in Mehrotra (2024). A carbon tax of $200 dollars per ton results in nearly full electrification across end-use sectors and reduces emissions to zero.

Under average cost pricing, the cost of electricity rises significantly above the optimal level along the transition path. This sharp increase in electricity prices is driven by passthrough of the carbon price, particularly via legacy coal production. End-use electrification in the long-run is unaffected but is slowed in the short-run. Emissions remain about 10 percent higher after 10 years than under the optimal policy. Cumulative excess emissions over the transition path are approximately 9 percent higher or 170 million tons per year, showing that the mispricing of electricity and delays in end-use decarbonization are quantitatively significant.

The paper is organized as follows: Section 1.1 briefly summarizes the related literature on electricity markets, decarbonization and carbon taxes. Section 2 presents the analytical model, characterizes the planner's allocation, and shows how electricity market pricing may result in higher electricity prices in both the long and short-run. Section 3 presents the quantitative model, describes the calibration strategy and outlines the data sources used to calibrate the model to US. Section 4 describes the steady state and transition path results from the quantitative model. Section 5 outlines directions for future work.

1.1 Related literature

This paper builds work in macroeconomics and environmental economics that assess optimal climate policy. Nordhaus (1993) provided that first integrated assessment model (IAM) with subsequent updates of the DICE model in Barrage and Nordhaus (2023). Golosov et al. (2014) characterizes analytically and quantifies the optimal carbon tax in neoclassical growth model with damages from climate change. In these models, climate change mitigation is typically represented by a reduced-form mitigation function. This paper models the mitigation process in greater details, particularly the importance of end-use electrification.

The approach in this paper is closer to macroeconomic models with a structural representation of energy production. Fried (2018) considers how a carbon tax induces innovation in clean energy in a model with clean, fossil and non-energy capital. Casey, Jeon and Traeger (2023) study the implications of subsidies to clean energy relative to a carbon tax in a dynamic macroeconomic model where clean and fossil energy are complements. Arkolakis and Walsh (2023) build a spatial model with perfect substitutability between clean and fossil electricity production in a given location, highlighting the growth impacts of rapid price reductions for solar panels and batter-

ies. Mehrotra (2024) examines the macroeconomic cost of achieving net zero emissions in electric power production and derives bounds on the long-run cost of getting to zero emissions.

An extensive literature in energy systems modeling (for example, Bistline, Mehrotra and Wolfram (2023), Bistline et al. (2023), Huppmann et al. (2023), Jenkins et al. (2021)) investigate the evolution of the energy system in response to policies such as the Inflation Reduction Act and in net zero scenarios. These models feature detailed representations of both power generation and energy end-use sectors, with some models allowing for spatial variation in electricity production and technological progress in power generation and end-use capital. This paper seeks to unpack a fundamental spillover at work in these models - how changes in the price of electricity induced by policy can spillover and impact the rate of decarbonization in end-use sectors. A key contribution is to characterize analytically the optimal price of electricity when end-use decarbonization requires electrification.

This paper contributes to a recent literature studying the behavior of electricity and energy prices in response to carbon prices or the energy transition. Ganapati, Shapiro and Walker (2020) estimate the incidence of a carbon tax on energy prices faced by consumers, noting that passthrough to consumers of a carbon tax is incomplete. Gowrisankaran, Langer and Reguant (2024) build a structural model to examine how prudence standards in regulated markets lead to excessive use of legacy coal assets in response to a carbon tax.

Lastly, this paper contributes to a literature studying inefficiencies electricity pricing. Joskow and Wolfram (2012) notes the benefits of dynamic or time-of-use pricing for electricity. Borenstein and Bushnell (2022*a*) document that residential electricity prices exceed social marginal cost of generation due to cost recovery in electricity pricing. Borenstein and Bushnell (2022*b*) note how high electricity prices in California impede end-use electrification, and Schittekatte et al. (2023) emphasize that retail electricity pricing may be a barrier to electrification. This paper emphasizes a similar mechanism but provides an analytical characterization of optimal policy and shows how a carbon price may interact with electricity prices to slow end-use decarbonization. This paper also shows that merit-order/time-of-use pricing may also not necessarily set the optimal price.

2 Analytical Model

In this section, I start by presenting the planner's problem in a simple dynamic model with both electricity production and an end-use service provided by a durable good. The steady state and transition path are characterized for a given carbon tax. I then present two canonical models of electricity pricing: average cost pricing for a regulated utility and pricing under a deregulated wholesale market. Examples are provided in which electricity prices under both types of market design fail to implement the planner's allocation. The section ends with a discussion on how these pecuniary externalities emerge and the role for alternative policies.

2.1 Planner's problem

A representative household gets utility from consumption C_t and from a durable good D_t that provides an end-use services like transportation or heating. The durable good can be powered either using fossil fuel or electricity; the technology is Leontif, so that fixed proportions of fuel must be paired with the durable good to obtain a unit of the end-use service. Electric power is inelastically demanded for the production of the final good and for the electrified end-use durable. Electric power is provided by power generation capital K_t can either be renewable (and, hence, have zero fuel cost) or can be powered by fossil fuels.

The final good can be either transformed into fossil fuel or into different forms of durable or power generation capital. The price $p_{d,i}$ with $i \in e, f$ is the capital price of the electrified and fossil fuel durable good. The price $p_{k,i}$ with $i \in c, f$ is the capital price of clean or fossil fuel power generation. Fossil fuel can be extracted or, equivalently, imported at a fixed price p_f.[2] Emissions from fossil fuels result in non-economic damages via a damage function $d(\cdot)$.[3]

The planner's problem is given below, where the planner chooses investment $I_t^{i,j}$ subject to technological and resource constraints, including capital irreversibility constraints:

$$
\begin{aligned}
\max \quad & \sum_{t=0}^{\infty} u\left(C_t, D_t\right) - d\left(\zeta F_t\right) \\
F\left(\bar{E}, \bar{N}\right) &= C_t + p_f F_t + \sum_{f,c} p_{k,i} I_t^i + \sum_{e,f} p_{d,i} I_t^i \\
K_{t+1}^i &= I_t^{k,i} + (1-\delta) K_t^i \\
D_{t+1}^i &= I_t^{d,i} + (1-\delta) D_t^i \\
D_t &= D_t^e + D_t^f \\
F_t &= \kappa K_t^f + \eta_f D_t^f \\
E_t &= \eta_e D_t^e + \bar{E} \\
E_t &= \theta_e \left(K_t^c + K_t^f\right) \\
I_t^i &\geq 0
\end{aligned}
$$

The setup of the planner's problem attempts to capture the key elements of decarbonization in practice. First, energy use is characterized by slow moving capital stocks, so that both decarbonization of power generation and end-use occur gradually. Second, end-use decarbonization depends on electrification - the alternative to using a durable that combusts a fossil fuel is an al-

[2] Under the interpretation that fossil fuels are imported, the implicit assumption is that trade is balanced period by period.

[3] A more natural damage function would depend on the stock of past emissions, but the implicit assumption here is a small open economy assumption where emissions in any one country are small relative to all other countries have a small effect on the global stock of emissions.

ternative like more expensive durable good that uses electricity. The analogy in the case of transportation is clear: internal combustion vehicles that use gasoline/diesel versus a battery electric vehicle. Lastly, the margin along with emissions are mitigated is primarily via turning over the capital stock. The Leontif assumption on fuel use and the inelastic demand for electricity $\bar{E}$ allows for no margin of reducing emissions via efficiency (same service value with less energy) or conservation (lower service use).

The planner chooses the optimal mix of fossil and clean capital for power generation along with the optimal mix of fossil and electrified durable goods. The first-order conditions are given below:

$$\begin{aligned}
u_1\left(C_t, D_t\right) &= \lambda_t \\
\tau_t &= \frac{\zeta}{\lambda_t} d'\left(\zeta F_t\right) \\
p_{k,c}\lambda_t - \mu_t^{k,c} &= \beta\lambda_{t+1}\left(\gamma_{t+1}\theta_e + p_{k,c}\left(1-\delta\right)\right) - \beta\mu_{t+1}^{k,c}\left(1-\delta\right) \\
p_{k,f}\lambda_t - \mu_t^{k,f} &= \beta\lambda_{t+1}\left(\gamma_{t+1}\theta_e - \kappa\left(p_f + \tau_{t+1}\right) + p_{k,f}\left(1-\delta\right)\right) - \beta\mu_{t+1}^{k,f}\left(1-\delta\right) \\
p_{d,e}\lambda_t - \mu_t^{d,e} &= \beta u_2\left(C_{t+1}, D_{t+1}\right) + \beta\lambda_{t+1}\left(p_{d,e}\left(1-\delta\right) - \gamma_{t+1}\eta_e\right) - \beta\mu_{t+1}^{d,e}\left(1-\delta\right) \\
p_{d,f}\lambda_t - \mu_t^{d,f} &= \beta u_2\left(C_{t+1}, D_{t+1}\right) + \beta\lambda_{t+1}\left(p_{d,f}\left(1-\delta\right) - \eta_f\left(p_f + \tau_{t+1}\right)\right) - \beta\mu_{t+1}^{d,f}\left(1-\delta\right) \\
\mu_t^{i,j} I_t^{i,j} &= 0 \quad \forall i,\ j
\end{aligned}$$

These ten equations determine the following: $\lambda_t, \mu_t^{i,j}, \tau_t, I_t^{i,j}$. λ_t is the Lagrange multiplier on the resource constraint and $\mu_t^{i,j}$ are the non-negativity constraints on investment in the four different types of capital. The last condition are the four complementary slackness conditions - investment is equal to zero in a given type of capital only if the Lagrange multiplier $\mu_t^{i,j} > 0$. The optimal Piguovian tax (carbon tax) is given by τ_t, where damages are expressed in terms of the consumption good. The constraints in the planner's problem determine the remaining quantities: $D_{t+1}^i, K_{t+1}^i, E_t, K_{t+1}, D_{t+1}, C_t, F_t, \gamma_t$.

The Lagrange multiplier γ_t is the multiplier on the market-clearing condition for electricity production and therefore represents the shadow price of electricity (expressed in terms of consumption goods). This will be the key object of comparison in a decentralized (market) equilibrium with the price of electricity. The Euler equations describing optimal investment in power generation are key to pinning down the behavior of the shadow electricity price as they represent the supply curve for power generation.

Perfect substitutability between clean and fossil fuel capital and the fossil fuel and electric durable good means that, in general, the planner's investment choice will be at a corner. That is, the planner will only invest a strictly positive amount in the one type of power generation and durable capital. For each of the Euler equations, iterating forward, imposing the relevant transversality conditions, and taking differences between each type of capital delivers for the fol-

lowing expressions:

$$\tilde{\mu}_t^{k,c} - \tilde{\mu}_t^{k,f} = p_{k,c} - p_{k,f} - \kappa \sum_{j=0}^{\infty} \beta^{j+1} (1-\delta)^j \frac{\lambda_{t+j+1}}{\lambda_{t+j}} (p_f + \tau_{t+j+1})$$

$$\tilde{\mu}_t^{d,e} - \tilde{\mu}_t^{d,f} = p_{d,e} - p_{d,f} + \sum_{j=0}^{\infty} \beta^{j+1} (1-\delta)^j \frac{\lambda_{t+j+1}}{\lambda_{t+j}} (\eta_e \gamma_{t+j+1} - \eta_f (p_f + \tau_{t+j+1}))$$

where $\tilde{\mu}_t^{i,j}$ is the non-negativity Lagrange multiplier for each type of capital good expressed in units of the consumption good (i.e. divided by λ_t). These expressions have a natural interpretation. The planner invests in clean power capital (or equivalently in the electrified durable good) only if the expected lifecycle cost (capital cost + fuel cost) are lower for the clean/electrified good relative to its fossil fuel alternative. Observe that $\beta^t \lambda_t / \lambda_0$ represents in asset pricing the stochastic discount factor (how the consumption good at time t is valued relative to goods today). In general, the right hand side of these equations will be either positive or negative implying a corner solution with $\tilde{\mu}_t^{i,j} > 0$ for one type of power generation or durable capital good.

2.2 Steady state and transition

Given perfect substitutability, it is natural to consider three different cases for the steady state: a laissez-faire (zero carbon tax) steady state and a zero emissions steady state (high carbon tax).[4] If damages from emissions are either zero or non-priced, it is natural to assume that fossil fuel is both the cheapest source of power generation and delivers the cheapest lifecycle cost for the end-use service. In this case, the fossil fuel steady state is given by:

$$\begin{aligned} p_{k,f}(r+\delta) &= \gamma_f \theta_e - \kappa p_f \\ p_{d,f}(r+\delta) &= \beta \frac{u_2(C, D_f)}{u_1(C, D_f)} - p_f \eta_f \\ \bar{E} &= \theta_e K_f \\ C &= \bar{Y} - \delta (p_{k,f} K_f + p_{d,f} D_f) - p_f (\kappa K_f + \eta_f D_f) \end{aligned}$$

In this steady state, all power generation is produced by fossil fuel capital and the demand for the end-use service is provided by the fossil fuel durable. Consumption is the endowment less steady state investment in the durable goods and fuel consumption. Solving for γ_f in the first equation provides an expression for the steady state cost of electricity; the price of electricity is the sum of the fuel cost plus a capital charge (adjusted for the capacity factor θ_e). This is essentially a levelized cost of electricity (LCOE).

[4] There may be intermediate cases under a moderate carbon tax in which only the durable good is electrified or only power generation is decarbonized.

With a sufficiently high carbon tax, there exists a fully decarbonized, zero emissions steady state. This steady state is given by the following equations:

$$\begin{aligned} p_{k,c}\left(r+\delta\right) &= \gamma_{ze}\theta_e \\ p_{d,e}\left(r+\delta\right) &= \beta\frac{u_2\left(C,D_e\right)}{u_1\left(C,D_e\right)} - \gamma\eta_e \\ \theta_e K_c &= \eta_e D_e + \bar{E} \\ C &= \bar{Y} - \delta\left(p_{k,c}K_c + p_{d,e}D_e\right) \end{aligned}$$

The price of electricity γ_{ze} is higher in this steady state; the solution for γ_{ze} in the first equation is again a LCOE. The durable good now solely consists of the electrified version and electricity demand is higher in this steady state versus the fossil fuel steady state. Consumption is the endowment less investment in clean power capital and the electrified durable with zero expenditures on fossil fuel. It is worth noting that consumption may be *higher* in the zero emissions steady state versus the fossil steady state even though the price of energy is higher. Clean power and durables may have a higher capital cost but the higher level of investment required may be offset by lower fuel costs.

The case of primary interest is the imposition of a constant carbon tax $\bar{\tau}$ that is sufficiently high to select the zero emissions steady state. The economy starts in a fossil fuel steady state with no carbon tax and then imposes the socially optimal Piguovian tax - what is the transition to the zero emissions steady state that the planner implements? For simplicity, assume that the carbon tax is sufficiently high such that: $I_t^{k,f} = 0\ \forall t \geq 0$. Then K_t^f and associated fossil fuel use for power generation declines geometrically at the rate of depreciation.

What is the transition path for the end-use durable good? By construction, in the long-run all investment in the end-use durable will be in the electrified durable. Along the transition path, what matters is whether the price of the electricity γ_t overshoots it's long-run level. The Euler equation for clean power capital determines the price of electricity since $\mu_t^{k,f} > 0$ and $\mu_t^{k,c} = 0\ \forall t \geq 0$:

$$\begin{aligned} p_{k,c} &= \beta\frac{\lambda_{t+1}}{\lambda_t}\left(\gamma_{t+1}\theta_e + p_{k,c}\left(1-\delta\right)\right) \\ \Rightarrow p_{k,c}\left(r_{t+1}+\delta\right) &= \gamma_{t+1}\theta_e \end{aligned}$$

Comparing this expression to the steady state expression shows that the short-run response of electricity prices only exceeds the long-run level if interest rates are above their steady state level along the transition path. If this holds, then $I_t^{d,f} \geq 0$ for some $t < \bar{T}$ even though $I_t^{d,f} = 0$ in the long-run. To the extent that consumption in the short-run must fall to meet the additional capital investment required for clean power generation, then consumption rises along the transition path and interest rates fall back towards their long-run steady state level.

This result has the interesting feature that the emissions minimizing transition path to a zero emissions steady state is not implemented even when the carbon tax is set at $\bar{\tau}$. The optimal allocation recognizes short-run transition costs that delay decarbonization of end-use sectors since the short-run price of electricity overshoots its long-run level. The following proposition summarizes the result:

Proposition 1. *Let $\bar{\tau} = \tau_d > \tau_k$ and assume $C_f = C_{ze}$ where f is the initial fossil fuel steady state and ze is the zero emissions steady state. Then $I_t^{d,f} > 0$ for some $t \geq 0$ and the planner's allocation does not implement the emissions-minimizing path to the zero-emissions steady state.*

2.3 Regulated utility pricing

As I have shown, modulo of interest rate effects, the planner wishes to set the price of electricity at the cost of adding additional clean power supply after the imposition of a carbon tax. To what extent does a decentralized electricity market implement the planner's allocation under a carbon tax? To answer this, I need to decentralize the planner's problem and specify the structure of the electricity market. I start by assuming either a nationalized electricity provider or a regulated utility that has a natural monopoly over the provision of electricity. The electric utility chooses the least cost mix of generation assets and is entitled to recover the costs of providing electricity service including both variable costs (i.e. fuel costs) and fixed costs for generation assets. The cost-minimization problem of the regulated utility is given below:

$$\begin{aligned}
\min \quad & \sum_{t=0}^{\infty} \beta^t \lambda_t \left(\sum_i p_{k,i} I_t^i + (p_f + \tau_t) \kappa K_t^f \right) \\
& E_t \geq \bar{E}_t \\
& E_t = \theta_e \left(K_t^f + K_t^c \right) \\
& K_{t+1}^i = I_t^i + (1 - \delta) K_t^i \\
& I_t^i \geq 0
\end{aligned}$$

The utility is choosing the least cost mix of clean and fossil power generation technologies to minimize capital and fuel costs (inclusive of a carbon tax) subject to some exogenous path for electricity demand. The utility faces the same constraints in terms of capital irreversibility as the planner. As can be easily verified, the optimality conditions describing the optimal generation mix coincide with those of the planner's problem.

The regulator ensures that the price of electricity is sufficient for the utility to be compensated for its capital costs and fuel costs. The price of electricity satisfies the following equation:

$$p_t^e E_t = \sum_i (r_t + \delta_i) p_{k,i} K_t^i + (p_f + \tau_t) \kappa K_t^f$$

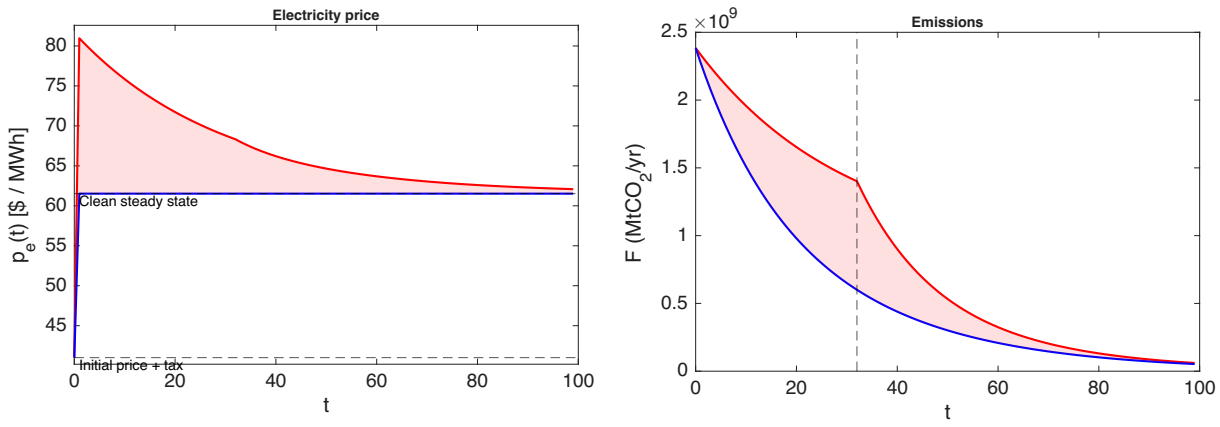


Figure 1: Transition path under average cost pricing

A representative household making its decision between the fossil and electrified durable good takes this price as given.

In general, average cost pricing will present the household a higher cost of electricity than the planner's shadow cost. To see this, observe that the following condition will generically hold: $\gamma_f + \kappa\bar{\tau} > \gamma_{ze}$ where γ_f. In words, the price of electricity generated from fossil electricity inclusive of the carbon tax exceeds the clean price (this is what drives power sector decarbonization). Under average cost pricing, the legacy fossil power generation that continues to operate will be compensated for both it capital and variable costs, driving the price of electricity above the resource cost of additional clean energy. This higher cost will raise the relative cost of the electrified durable good.

Setting $r_t = \bar{r}$ for all t, the price of electricity under average cost pricing can be approximated as:

$$p_t^e \approx w_t^f \left(\gamma_f + \kappa\bar{\tau}\right) + \left(1 - w_t^f\right)\gamma_{ze}$$
$$w_t^f = K_t^f \Big/ \left(K_t^f + K_t^c\right)$$

where w_t^f is the weight of generation from fossil power. This weight is initially high and declining along the transition path, eventually converging to zero. In the long-run, the price of electricity converges to the planner's resource cost, but the degree of short-term overshooting may be considerably larger that the interest rate effect described earlier. Figure 1 shows the transition path of electricity prices and emissions under average cost pricing (red line) versus the planner's price (blue line). The shaded area represents the excess price charge for electricity (LHS) and the resulting excess emissions (RHS) from the slower pace of end-use decarbonization.[5]

[5]This numerical example is calibrated so the initial price of electricity is $40 per MWh and the clean price of electricity is $60 per MWh. The end-use sector model is household surface transportation - approximately 270 million light-duty vehicles with fuel use for traveling 10000 miles per year.

The result is summarized in the proposition below:

Proposition 2. *Assume risk-neutral preferences such that $r_t = \bar{r}$ and $\gamma_f + \kappa\bar{\tau} > \gamma_{ze}$. Let T_{ac} be time after which $I_t^{d,f} = 0$ under average cost pricing, and T_p be the analogous time under the planner's price for electricity. Then, $p_t^e > \gamma_{ze}$ along the transition path and $T_{ac} \geq T_p$. Cumulative emissions along the transition path are higher under average cost pricing.*

It's worth emphasizing that this overshooting of electricity prices has a larger effect on incentives for end-use decarbonization than simply the difference between the average price and planner's price. Because of depreciation and discounting, price differences in the near-term have a higher weight when the household compares the lifecycle cost of the electrified durable against that of the fossil fuel durable. Because the difference in the average price and planner's price is relatively larger in the near-term, this premium carries a larger weight in the household's durables choice. With myopia or credit constraints (i.e. higher discounting), the disincentive effects of high short-run electricity prices worsen.

It should also be noted that the mispricing of electricity described here is not due to frictions in retail pricing emphasize in Borenstein and Bushnell (2022*a*) (i.e. fixed volumetric pricing and the recovery of transmission and distribution costs via volumetric pricing). Rather, the pecuniary externality in this example stems from two issues: the recovery of legacy capital costs for fossil power generation and the nonconvexity due to capital irreversibility. It should also be noted that mispricing due to overinvestment, excess capital charges, or uneconomic dispatch are not present here; the regulated utility modeled here does in fact choose the optimal generation mix and is paid a fair return on its capital, such that there are no excess rents.

2.4 Deregulated wholesale pricing

Several electricity markets in the US and Europe operate as restructured or deregulated markets where generators bid to supply electricity to load serving entities that are regulated and responsible for transmitting and distributing electricity to users. The lowest cost generators of carbon-free power are solar and wind, which, in some regions, provide power generation at a lower cost than any fossil fuel power generator even on an unsubsidized basis. In the presence of a carbon tax, a substantial degree of decarbonization is likely to come from further investments in solar and wind power. However, these renewable power sources are intermittent and must be complement by dispatchable forms of power generation.[6] Full decarbonization of power production requires a dispatchable renewable.

Suppose that dispatchable clean energy - a perfect substitute for fossil energy - is a fixed proportions combination of a zero marginal cost intermittent power generation technology (like so-

[6]Batteries can be used to offset intermittency, particularly for solar which has a natural daily cycle but are likely less practical for addressing more prolonged intermittency or seasonal shifts.

lar) and a "clean-firm" dispatchable technology like natural gas with carbon capture. Let χ be the amount of clean power capital required and $1-\chi$ be the CCS capital required to provide an equivalent unit of electric power generation with zero emissions. Then, from the planner's perspective, the price of dispatchable clean power is:

$$\gamma_t = (r_t + \delta)\left(\chi p_{k,c} + (1-\chi)\, p_{k,ccs}\right) + (1-\chi)\, p_f \kappa_{ccs}$$

Under the natural assumption that intermittent power generation is cheaper than clean-firm power, a higher fraction χ of clean-firm power lowers the average cost of power generation.

In a wholesale market, this marginal dispatchable source typically determines the price of electricity when both the intermittent and dispatchable source are providing power. Assuming that a dispatchable source is always the marginal source of power generation, then free entry for dispatchable generation requires:

$$\begin{aligned}
p_t^e &= w_f^t p_t^{e,f} + \left(1 - w_f^t\right) p_t^{e,ccs} \\
p_t^{e,f} &= (r_t + \delta)\, p_{k,f} + (p_f + \tau_t)\, \kappa_f \\
p_t^{e,ccs} &= (r_t + \delta)\, p_{k,ccs} + p_f \kappa_{ccs} \\
w_t^f &= K_t^f \,/\, \left(K_t^f + K_t^{ccs}\right)
\end{aligned}$$

The price of electricity in the long run does not reflect the share of generation from zero marginal cost intermittent sources, and is therefore too high relative to the planner price (i.e. $p_t^e > \gamma_t$ so long as $\chi > 0$). Moreover, so long as the price unabated natural gas inclusive of the carbon tax is greater than the planner's cost of adding clean dispatchable power, then the price of electricity along the transition path will be too high.

It is worth delving deeper into why the long-run price of electricity may be too high in deregulated power market, since this mispricing does not require any assumption about capital irreversibility. Consider two types of dispatchable power: natural gas and natural gas with CCS. These two types of power generation differ in capital cost ($p_{k,ccs} > p_{k,f}$) and the carbon tax only applies to unabated natural gas generation. Moreover, there exists an intermittent renewable power source with zero fuel cost but that may not produce at all times.

I assume free entry of power generation resources, so that each type of power generator will enter until profits fall to zero. Under free entry, it is clear that, so long as the carbon tax drives the LCOE of unabated natural gas above that of natural gas with CCS, only CCS will remain in the market as the dispatchable power generator. Let $p_{e,ccs}$ be the steady state price of electricity received by a CCS power generator when operating.

Let the hours of the year x be arranged on the unit line from 0 to 1 and, without loss of generality, arrange the hours from highest to lowest intermittent output potential (i.e. sunniest to darkest hours). Let $f(x)$ by a monotone decreasing function that gives the output of a unit of intermittent

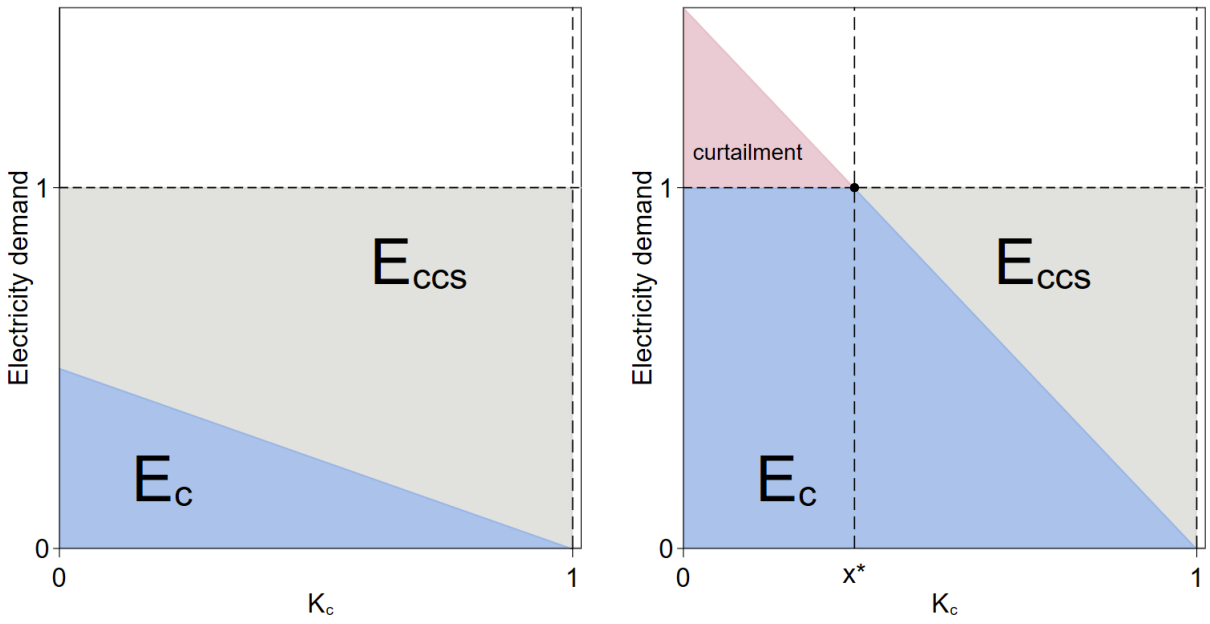


Figure 2: Intermittent electricity supply

power. Assume that power demand is constant at 1 from all hours of the year. For a given level of clean power capital K_c, total power generation is then given by:

$$E_c = \int_0^1 \max\{K_c f(x), 1\} dx$$

Figure 2 shows the fraction of power demand met by intermittent power generation as a function of the capital stock K_c. The left-hand side panel shows the case in which $K_c \leq 1$, while the right-hand side panel shows the case of $K_c > 1$. In the latter case, for x^*, electricity supply from intermittent sources exceeds demand and some power generation is curtailed.

Higher levels of K_c will raise power generation from the intermittent source up until demand is satisfied; any output beyond that must be curtailed. For concreteness, assume the generation function $f(x) = 1 - x$; this is not a particularly realistic generation function for solar, but has the benefit of simplicity. This function means that at $x = 1$, the intermittent source does not produce anything. It then follows that power generation from solar is given by:

$$E_c(K_c) = \frac{1}{2} K_c \quad K_c \leq 1$$
$$E_c(K_c) = 1 - \frac{1}{2}\frac{1}{K_c} \quad K_c > 1$$

For $K_c > 1$, power generation from solar rises but at a declining rate as more and more generation is curtailed. The remaining power demand that cannot met by K_c must be met by natural gas with CCS:

$$E_{ccs}(K_c) = 1 - E_c(K_c)$$

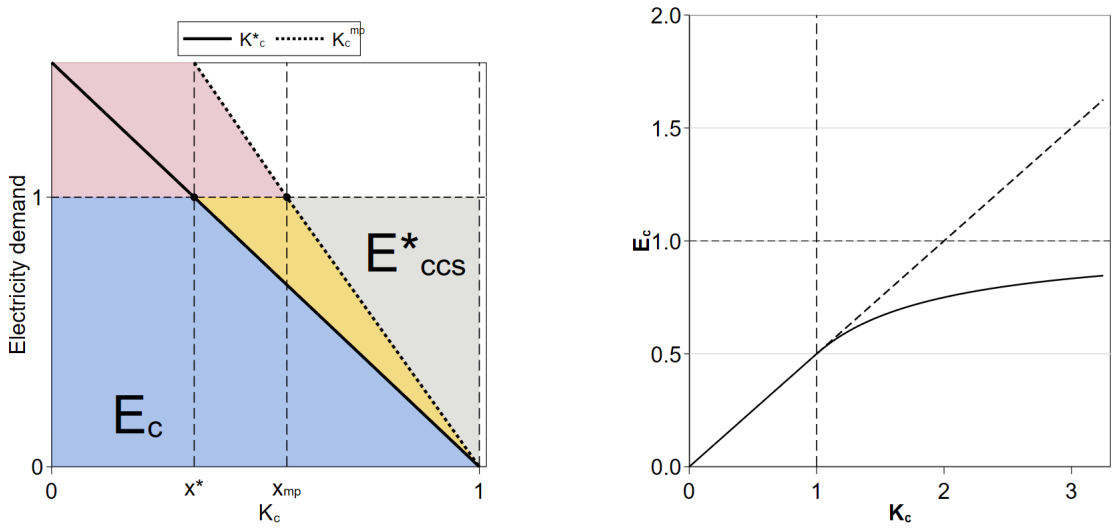


Figure 3: Planner and market electricity shares

The planner will choose a value of K_c that minimizes the cost of providing one unit of electricity at all hours:

Proposition 3. *The planner's choice of K_c satisfies the following condition so long as the LCOE of the intermittent power source is strictly lower than the LCOE of the dispatchable power source:*

$$p_{k,c}\left(r+\delta\right) = \frac{1}{2} p_f \kappa_{ccs} \frac{1}{K_c^2}$$

One interesting feature of the planner's allocation for intermittent and dispatchable power is that $K_c > 1$, meaning that the planner always chooses a level of intermittent power that implies some degree of curtailment. The intuition for this result is that, if the implied cost of electricity for a fully utilized intermittent resource is less than the dispatchable source, then it makes sense to have some fraction of hours with demand fully met by the intermittent source. The left-hand side of Figure 3 shows the planner's optimal choice denoted K_c^* that features some curtailment. The right-hand side of the figure shows how progressively increasing intermittent power capacity has decreasing returns in terms of generation share as curtailment worsens.

How would prices be set in a deregulated wholesale market? For a given level of K_c, there are hours in which all demand is met via intermittent sources and hours in which only some or none of demand is met by intermittent sources. In those hours with curtailment, price falls to zero as intermittent sources have zero fuel cost. In those hours with some or all demand being met by the dispatchable power source, CCS is the marginal bidder and receives a price $p_{e,ccs}$. The intermittent source also receives this price in those hours. Free entry requires that both types of

generator make zero profits:

$$p_{e,ccs} = 2K_c p_{k,ccs}\left(r+\delta\right) + p_f \kappa_{ccs}$$
$$p_c\left(r+\delta\right)K_c = \frac{1}{2}\frac{1}{K_c}p_{e,ccs}$$

where the top line is the average price of electricity required for a CCS generator to break even and the second line is the condition under which the revenues the intermittent generator receives (based on the CCS price) are sufficient to cover its costs.

It can be easily shown that under wholesale markets there is excessive investment in intermittent power generation and, therefore, the wholesale price of electricity is higher than the planner's price. The left-hand side of Figure 3 shows the market allocation with $K_c^{mp} > K_c^*$, implying greater curtailment and, hence, a lower utilization rate for the dispatchable power source. The proposition below summarizes this finding:

Proposition 4. *Let K_c^* be the planner's choice of intermittent power generation and K_c^m be the level of intermittent capital that satisfies the second equation above. Then $K_c^m \geq K_c^*$ with the inequality holding strictly so long as $p_{k,ccs} > 0$. The price of electricity under wholesale pricing excess the price of electricity under the planner's allocation.*

This proposition shows that, even in the long-run, the price of electricity in a deregulated market with free entry may be higher than the price of electricity under the planner's problem. This long-run mispricing may lessen incentives for end-use decarbonization as the price of electricity is too high.

2.5 Discussion

In this section, I discuss briefly the frictions that generate a wedge between the market price of electricity and the planner's optimal price. The carbon tax interacts with market pricing for electricity to push the price above what the planner's resource cost of electricity, distorting the end-use decision to electrify. The potential role for electricity or capital subsidies is also discussed here.

In the case of a regulated utility and cost recovery, the central friction is capital irreversibility - the imposition of the carbon tax renders new investment in fossil power generation unprofitable but leaves legacy generation untouched. In general, the carbon tax will force the price of legacy assets to be strictly higher than that of new clean generation. The planner's problem can be generalized to allow for shutdown of the fossil capital stock beyond what the fraction of the stock that depreciates. The planner will shutdown a fraction of the fossil capital stock so long as the price of electricity γ_t satisfies:

$$\gamma_t = \kappa\left(p_f + \tau_t\right)$$

This equation states that the fossil capital stock is prematurely shutdown until the price of fuel inclusive of the carbon tax equals the price of electricity. If $\gamma_t > \kappa(p_f + \tau_t)$, then none of the capital stock is shutdown and this is in fact efficient since the price of electricity exceeds the social marginal cost of operating the legacy fossil fuel capital stock. If $\gamma_t < \kappa(p_f + \tau_t)$, the planner wishes to completely scrap the fossil capital stock and immediately replace with clean capital. In both cases, a utility that engages in cost recovery is charging too high a price. In the former, that price is inefficiently high because of the legacy capital cost $(r_t + \delta) p_{k,f}$; in the latter, the even the fuel cost should not be collected because if would preferable for all fossil generation to shutdown.

In the case of deregulated electricity markets, the source of inefficiency is the lack of separate prices for dispatchable and intermittent generation. The planner wishes to restrict the reliance on intermittent power generation because it lowers the utilization rate of the clean-firm asset which is needed in any case to provide generation in states of the world in which intermittent power is not producing. Due to overbuilding, the intermittent generator has periods where it is the only producer and the price falls to zero; these periods must be offset by times in which they receive the higher CCS price. But this implies that the capital charge for the CCS price is inefficiently high. A wholesale market with that prices only variable costs and capacity costs are collected separately would implement the efficient price.

What is the role for subsidies in lieu of carbon taxes? Assuming that the efficient outcome is full decarbonization and that the fiscal authority has access to lump sum taxes, the same equilibrium can be implemented solely via capital subsidies. A clean energy capital subsidy renders fossil power generation uncompetitive. A sufficiently large subsidy to the electrified durable likewise induces switching from the fossil fuel durable to the electric durable. The lower price of electricity along the transition path implies a small capital subsidy is required to induce switching. The resulting zero emissions steady state may feature an inefficiently high level of durable goods demand (and, hence, inefficiently high power generation capital) due to the permanent subsidy for the electrified durable.

More generally, any policy that implements the planner's allocation will be efficient. With average cost pricing, a regulatory policy that caps the price of electricity at the resource cost or a subsidy that lower the price seen by end-users to the efficient level would ensure the efficient allocation is realized. In the case of deregulated markets, a similar regulatory cap on the electricity price combined with a policy mandating the efficient mix of intermittent and dispatchable resources would implement the efficient allocation. More generally, a capital tax on intermittent sources would implement the efficient mix of intermittent and dispatchable resources.

3 Quantitative Model and Calibration

This section builds on the simple dynamic model introduced earlier by allowing for a more general representation of power generation and a richer set of durable goods that provide end-use services like transportation and building heating. This section also describes the calibration strategy and data used to inform the calibration.

3.1 Power generation

The planner's problem for the quantitative model is similar to that of the analytical model. A representative household chooses a path for nondurable consumption C_t and experiences damages from climate change in utility terms that are a function of fossil fuel emissions. Damages are varying in the type of fuel combusted; we allow for four types of fossil fuels: coal, natural gas, gasoline and diesel, and ζ_j represents carbon dioxide emissions per unit of fuel. Fuel demand is in fixed proportion to the installed capital stock.

The planner chooses from three types of power generation capital to generation electric power. Clean power K_t^c has zero fuel cost but is subject to an intermittency penalty. The planner chooses between two types of dispatchable power generation is provided either by unabated natural gas power production K_t^f or natural gas power production with carbon capture $K_t^c cs$. There is a third source of dispatchable power K_t^o which represents the other significant sources of power generation: coal, nuclear and hydropower. Nuclear and hydropower are assumed to provide a constant level of dispatchable power indefinitely. Coal and its associated fuel consumption is assumed to be declining at the rate of depreciation. As before, θ_i represents the capacity factor for generation technology i.

The planner's problem is given below, where the planner chooses investment $I_t^{j,i}$ subject to technological and resource constraints:

$$
\begin{aligned}
\max \quad & \sum_{t=0}^{\infty} \beta^t \left(u\left(C_t\right) - d\left(\sum_j \zeta_j F_t^j \right) \right) \\
\bar{Y} &= C_t + \sum_j p_f^j F_t^j + \sum_i p_{k,i} I_t^i \\
E_t^{dis} &= \theta_f K_t^f + \theta_{ccs} K_t^{ccs} + \theta_o K_t^o \\
E_t &= G\left(E_t^c, E_t^{dis}\right) \\
E_t &= \bar{E} + \sum_i \eta_e^i D_{t+1}^i \\
K_{t+1}^i &= I_t^i + (1-\delta) K_t^i \\
I_t^i &\geq 0
\end{aligned}
$$

where $G(\cdot,\cdot)$ is a variable elasticity of substitution function that aggregates intermittent and dispatchable power sources. The variable elasticity of substitution production function is due to Revankar (1971) and used in modeling the energy transition in Fries (2023). The function $G(\cdot,\cdot)$ aggregates intermittent and dispatchable energy sources into an aggregate.

$$E_t = \left(E_t^{dis}\right)^{\alpha} \left(E_t^{int} + \alpha\rho E_t^{dis}\right)^{1-\alpha}$$

where ρ is the key parameter that determines how the elasticity of substitution varies as the share of dispatchable generation falls. This production function has the property that intermittent electric power is non-essential: $E_t > 0$ even when $E_t^{int} = 0$. The production function also exhibits constant returns to scale but diminishing returns to intermittent electricity production. As discussed in Mehrotra (2024), a variable elasticity of substitution production function provides a simple and tractable way to capture the role of intermittent sources in electricity production.

3.2 Durables

Households and firms are assumed to have inelastic demand for a set of energy-using end-use services (i.e. transportation, heating) provided by a combination of a durable capital good (i.e. vehicle, furnace, boiler) and a fuel (electricity, gasoline, natural gas). Specifically, I consider three end-use services: surface transportation, household space heating, and household water heating. I assume two types of end-users: households and firms who have an inelastic demand for these end-use services. The price of capital and fuel use required is allowed to differ across households and firms. Let i represent the index of these six different type of services.[7]

Let D_i represent the inelastic service demand for either residential or commercial transportation or building heating services. For each end-use service i, the planner chooses between a fossil fuel and electric capital to replace the fraction δ_i of capital that is depreciating in the current period. The fraction of the fossil fuel option chosen depends on the lifecycle cost differences between the fossil fuel and electric option and on an idiosyncratic cost shock that is normally distributed with mean zero and standard deviation σ_i. We define operating costs for the fossil fuel and electric capital stock recursively, and define z_t^i as the difference in lifecycle cost between the electric and

[7]For now, transportation and heating services are only considered for non-industrial uses (i.e. outside the goods-producing sector).

fossil fuel capital good that provides service i:

$$
\begin{aligned}
V_t^{f,i} &= \left(p_f + \nu_f + \tau_t^f\right) + \frac{1-\delta_i}{1+r_{t+1}} V_{t+1}^{f,i} \\
V_t^{e,i} &= p_t^e + \nu_e + \frac{1-\delta_i}{1+r_{t+1}} V_{t+1}^{e,i} \\
z_t^i &= p_{k,t}^{e,i} + \eta_e^i V_t^{e,i} - p_{k,t}^{f,i} - \eta_f^i V_t^{f,i} + \mu_i \\
I_t^{f,i} &= \Phi\left(z_t^i/\sigma_i\right) \delta_i D_i \\
I_t^{e,i} &= \delta_i D_i - I_t^{f,i}
\end{aligned}
$$

where $V_t^{j,i}$ is the depreciation adjusted present value of the price of fuel j for a given carbon tax τ_t^f. The parameters ν_f and ν_e represent the cost of delivery/distribution of fossil fuels and electricity; for both electricity and natural gas, there is a substantial difference in delivered cost relative to wholesale cost. Since emissions vary across fuels, the carbon tax is fuel specific. z_t^i is the premium for the electric option (its capital cost and expected fuel cost) relative to the fossil fuel option. Given this lifecycle price premium, investment shares are translated from a standard normal distribution. μ_i is a cost-shifter to capture both monetary and non-monetary differences between electric and fossil fuel capital services such as charging network concerns or taste.[8] All things equal, with low variation σ_i, the electric option will only be chosen if the price premium is low or negative and investment will rapidly shift based on the lower price option. With higher variation, households will continue to purchase fossil fuel capital even with a substantial price premium.

3.3 Electricity prices

As in the analytical model, I consider two ways in which electricity markets price electricity. In a regulated market, a nationalized utility or regulated utility chooses the lowest cost mix of intermittent and dispatchable resources to meet an exogenous path of electricity demand $\bar{E}_t$. In choosing the least cost mix of generation resources, there are no issues of imperfect information or inefficient discounting that distort the choice of generation resources relative to the planner (i.e. excessive capital investment described in Averch and Johnson (1962) or Gowrisankaran, Langer and Reguant (2024) as in or excessively high rate of return as in Werner and Jarvis (2022)). The

[8]The relative difference in fuel cost of space and water heating depends on both average temperature and temperature variability. The presence of an idiosyncratic cost shifter represents a reduced-form way to capture some heterogeneity.

utilities investment choice is:

$$\min \quad \sum_{t=0}^{\infty} \beta^t \lambda_t \left(\sum_i p_{k,i} I_t^i + \sum_j \left(p_f^j + \tau_t^j \right) F_t^j \right) \tag{1}$$

$$E_t^{dis} = \theta_f K_t^f + \theta_{ccs} K_t^{ccs} \tag{2}$$

$$E_t = G\left(K_t^c, E_t^{dis} \right) \tag{3}$$

$$E_t \geq \bar{E}_t \tag{4}$$

$$K_{t+1}^i = I_t^i + (1-\delta) K_t^i \tag{5}$$

$$I_t^i \geq 0 \tag{6}$$

The regulator ensures that the average price of electricity is sufficient for the utility to compensated for its capital costs and any fuel costs inclusive of the carbon tax; the utility makes no economic profits:

$$p_t^{e,cr} E_t = \sum_i (r_t + \delta_i) p_{k,i} K_t^i + \sum_j \left(p_f^j + \tau_t^j \right) F_t^j \tag{7}$$

where $p_t^{e,cr}$ indicates the price of electricity under a market structure where the utility recovers costs.

The second decentralization assumes that electricity is priced by the marginal (most expensive) dispatchable producer. In this case, the price of electricity is the generation-weighted average of the price of unabated natural gas power generation (inclusive of the carbon tax) or natural gas with carbon capture.[9] Since unabated natural gas and natural gas with carbon capture are perfect substitutes and receive the same price, wholesale power producers will minimize costs by choosing whichever generation technology has the lowest lifecycle cost inclusive of the carbon tax. In the long-run, the price of dispatchable power will converge to the price of natural gas with CCS (assuming the carbon tax renders unabated natural gas uncompetitive). Wholesale intermittent power producers do not face any distortion relative to the planner's allocation.

The price of electricity is the generation weighted average of the marginal producers:

$$\begin{aligned}
p_t^e &= w_t^f p_t^{e,f} + \left(1 - w_t^f\right) p_t^{e,ccs}\} \\
w_t^f &= \theta_f K_t^f / \left(\theta_f K_t^f + \theta_{ccs} K_t^{ccs} \right) \\
p_t^{e,f} &= (r_t + \delta_f) p_{k,f} / \theta_f + \kappa_f \left(p_f^{ng} + \tau_t^{ng} \right) \\
p_t^{e,ccs} &= (r_t + \delta_{ccs}) p_{k,ccs} / \theta_{ccs} + \kappa_{ccs} p_f^{ng}
\end{aligned}$$

where w_t^f is the share of unabated natural gas in overall natural gas electricity generation and p_f^{ng} is the fuel cost of natural gas.

[9] I assume that electricity produced from legacy nuclear, hydro, or coal is all inframarginal; these resources receive the same price as natural gas generators.

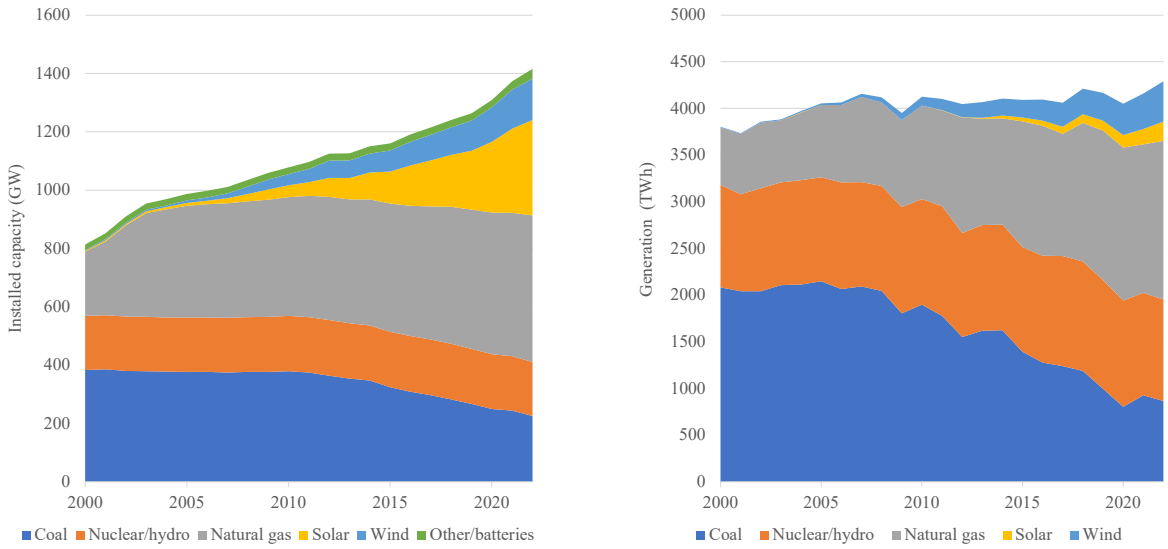


Figure 4: Nameplate capacity and generation by technology

3.4 Data sources

Before describing the calibration strategy, I briefly describe the data sources used to calibrate the quantitative model. Calibration requires detailed data on the relative capital costs, fuel costs and fuel use for both power generation capital and various types of durable goods providing end-use services. Similar to energy systems models, a realistic assessment of the sensitivity of end-use electrification to carbon taxes needs a relatively richly parameterized model. I draw several distinct data sets to obtain these estimates.

Data from the Energy Information Administration's (EIA) Electric Power Annual is used to obtain the initial capital stocks, the capacity factors, and fuel use for different generation technologies. Wholesale fuel costs for coal and natural gas are also obtained from the EIA. The amount of fuel required to produce a unit of electric power - the heat rate - is also obtained from EIA data on total generation and total fuel use. Emissions intensities for thermal coal and natural gas are taken from EIA carbon dioxide coefficients.[10] The capital cost, average capacity factor, and heat rate for current and prospective technologies (like natural gas with CCS) are obtained from the National Renewable Energy Laboratory's (NREL) Annual Technology Baseline (ATB). The 2024 version of NREL's ATB is used to set these parameters.

To calibrate the parameters for surface transportation, I draw on data from the Bureau of Transportation Statistics, Federal Highway Administration, and NREL. These data sources provide estimates for the total stock of light-duty vehicles and medium/heavy-duty trucks. Total miles traveled broken down by vehicle type are also used to infer the demand for transportation services from both residential and commercial sectors. NREL's ATB 2024 is used to for the cap-

[10] Available at: https://www.eia.gov/environment/emissions/co2_vol_mass.php

I. General								
Real interest rate	2%							
Depreciation, power capital	3%							
Variable EIS, ρ	0.38							
II. Fuel cost	Units	Emissions (kg CO2)	Wholesale ($)	Delivered ($)				
Coal	$/MMBtu	96.0	2.16					
Natural gas	$/MMBtu	53.0	2.50	11.50				
Gasoline	$/gallon	8.9		3.15				
Diesel	$/gallon	10.2		3.80				
Electricity	$/MWh		40	150				
III. Electric power generation	Capital cost	Capacity factor	Heat rate					
	$/kW	Fraction nameplate	MMBtu/ MWh					
Onshore wind	1569	0.44						
Utility-scale solar	1492	0.27						
Natural gas (CCGT)	1495	0.55	6.2					
Natural gas with CCS	2811	0.55	7.0					
IV. End-use durables	Fossil fuel used	Emissions	Stock	Sales	Capital cost premium	Fossil fuel use	Electricity use	Lifecycle premium
		Mt/CO2	Millions of units	Thousands of units		Gallons or MMBtu	kWh	$
Residential								
Surface transportation	Gasoline	1013	268	15500	1.4	425	3583	1441
Space heating	Natural gas	227	75	3759	3.4	50	5435	6410
Water heating	Natural gas	85	66	4433	1.9	18	1758	1302
Commercial								
Surface transportation	Diesel	429	15	885	2.8	5278	86055	90304
Space heating	Natural gas	177	3	152	8.1	443	32244	5172
Water heating	Natural gas	26	2	121	1.9	80	7644	6770

Table 1: Calibrated parameters

ital cost of internal combustion and equivalent battery-electric vehicles for both light-duty and medium/heavy duty trucks. Carbon dioxide emissions factors for motor gasoline and diesel are taken from EIA data.

The stock of electric and fossil powered space and water heating in residential and commercial buildings comes from the 2020 Residential Energy Consumption Survey (RECS) and the 2018 Commercial Buildings Energy Consumption Survey (CBECS) both administered by the EIA. These data sources provide estimates of the total number of buildings and the square footage of buildings that rely on non-electric space and water heating. Fuel use per unit or per square footage for space heating and water heating is also available from these surveys. Estimates for the capital cost of household and commercial furnaces, water heaters, and heat pumps and their respective efficiencies are taken from the EIA's "Updated Building Sector Appliance and Equipment Costs and Efficiencies."[11] Residential and commercial (delivered cost) prices for electricity and natural gas are taken from EIA price data.

3.5 Calibration

First, I describe the calibration of electric power generation in the initial steady state with no carbon tax. Figure 4 shows the recent historical evolution of US power generation capacity and power generation. Power generation and capacity for nuclear, hydro and coal are chosen to directly match the data. Capital cost and capacity factors for solar, wind, natural gas, and natural gas with CCS determine the endogenous mix, where the clean intermittent power sources is assumed to be a 70/30 combination of solar and onshore wind. The key parameters in the variable elasticity of substitution production function for electricity are taken from Mehrotra (2024), where cost projections from energy systems models are used to infer share of generation that can be delivered from intermittent sources.

Additional electric generation parameters such as capacity factors (θ_i and heat rates (κ_j) are taken from the NREL ATB estimates shown below in Table 1. All power generation capital except nuclear and hydro is assumed to depreciate with a 30 year lifespan (i.e. $\delta_i = 1/30$ for all i) and the real interest rate is set at 2%. The price p_f^j for fossil fuels used in electricity production represent their wholesale rate. The table shows the levelized cost of electricity across generation technologies. Based on NREL data, natural gas with CCS is the cheapest clean-firm technology. Note that the additional energy required for natural gas CCS to capture carbon emissions is captured in a higher heat rate: $\kappa_{ccs} > k_{ng}$.

Turning to the calibration strategy for end-use services from durables, I start by calibrating the stock, depreciation rate and service flow of fossil fuel durables for end-uses described earlier. The total stock of non-electrified vehicles, space and water heating is shown in Table 1 alongside estimates of the depreciation rates and annual unit turnover. For motor vehicles, the depreciation rate is set at 17 years to match annual vehicle sales. For space and water heating, depreciation rates are set conservatively at 20 and 15 years respectively. The price of gasoline and diesel are set at \$3.15 and \$3.80 based on recent averages; the delivered price of electricity and natural gas are \$0.15 per kWh and \$11.50 per MMBtu, with residential and commercial prices assumed to be same.[12] The upfront capital cost for the natural gas and electrified heating appliances are reported in Table 1.

To calculate fuel use for both the fossil fuel and electrified durable good, estimates of the service flow and fuel efficiencies are needed. Assumed vehicle miles traveled for residential (light-duty) and commercial (medium/heavy duty) vehicles are shown in Table 1. Based on fuel efficiencies from NREL's ATB, the associated fossil or electric fuel use in gallons or kilowatt hours are shown, along with implied annual fuel expenditures. For space and water heating, fossil fuel use is the average natural gas use for space or water heating (per unit) for residential users. This

[11] Available in Appendix A at: https://www.eia.gov/analysis/studies/buildings/equipcosts/.

[12] Commercial delivered prices are typically somewhat lower than residential prices, but the differences are small relative to regional variation in prices.

Steady state	Carbon tax ($/metric ton)				
	0	50	100	150	200
Consumption (base = 100)	100.0	100.0	99.7	99.7	99.7
Emissions (MMT/CO2)					
Electric power	1282	769	0	0	0
End-use	2146	1863	725	53	1
Excess emissions (market price)		0.2	9.3	5.3	0.4
Fuel use					
Natural gas (quad BTUs)	17.9	18.3	28.7	35.1	35.6
Gasoline and diesel (Mbbl/day)	12491	11465	4931	373	5
Electricity use (base = 100)	100	114	171	202	204
Electricity price ($/MWh)	49.41	68.93	69.13	69.13	69.13
Durables electrification (% stock)					
Transportation (residential)	2	13	63	96	100
Transportation (commercial)	1	5	59	98	100
Space heating (residential)	1	5	95	100	100
Space heating (commercial)	1	100	100	100	100
Water heating (residential)	1	86	100	100	100
Water heating (commercial)	1	79	100	100	100

Table 2: Steady state macro and energy outcomes

natural gas use is translated into equivalent electricity use to provide the same heating service. A similar procedure is used for commercial space and water heating except that natural gas use is based on square footage.[13] The last column of Table 1 shows the lifecycle cost premium for the electrified version across six types of fossil durables.

4 Results

In this section, I present the results of a quantitative experiment for different carbon taxes under both the efficient price of electricity versus average cost pricing (i.e. regulated utility's cost-recovery price of electricity). I show both the steady state effects of a carbon tax of varying levels and the transition path under different pricing regimes. These transition path experiments quantify the overshoot in electricity prices and cumulative excess emissions from a suboptimal transition.

4.1 Steady state

Table 2 shows macroeconomic and energy systems aggregates in response to different levels of a carbon tax. The left-hand side column is the initial, fossil fuel steady state that is calibrated as discussed in the previous section. The remaining columns compute the model steady state under different levels of the carbon tax. Emissions drop sharply as a carbon tax rises, with the largest decreases in electric power generation. A carbon tax in excess of \$50 per metric ton of CO_2 is sufficient to result in complete decarbonization of electric power generation. This lower emissions by roughly 1.3 gigatons, close to current US power sector emissions. This reduction in emissions is effectuated by large increases in both clean power generation (solar and wind) and a shift in dispatchable power generation to natural gas with carbon capture.

Electricity prices rise under a carbon tax, but the increase is moderate with the wholesale price of electricity rising from approximately \$50 per MWh to \$69 per MWh, a 38% increase. This modest rise in power generation reflects the relatively low cost of solar and wind and moderate cost of the "clean-firm" alternative to unabated natural gas. Since the cost of other clean-firm alternatives like nuclear, geothermal or solar/wind paired with batteries are comparable, a long-run price increase of this magnitude would likely be similar if a broader mix of technologies is used as the clean-firm power source.

Emissions reductions from end-use sectors fall most sharply once the carbon tax exceed \$100 per ton. For a carbon tax in excess of this amount, water heating and commercial space heating are fully electrified. This is because the decision to electrify for these appliances is most influenced by the relative fuel cost. A \$20 per MWh increase in generation costs only translates to a 2 cents per kWh increase in the cost of electricity for the end-user. The direct effect of the carbon tax on the cost of natural gas dominates this effect on long-run electricity prices, pushing strongly towards electrification. Effects are also sizable for transportation, with both residential and commercial transportation seeing nearly 60% electrification for a carbon tax of \$100 per ton.

Rising electrification raises electricity demand, with the highest carbon taxes resulting in a near doubling of electricity demand. The long-run electricity cost is pinned down by the supply curve for electricity which is flat in the long-run, because electricity is most capital cost and fuel cost. Therefore, this high level of electricity demand does not have long-run implications for the price of electricity. Fossil fuel usage shows opposite trends for natural gas and refined petroleum products. Gasoline and diesel demand drop, with sharper drops around a carbon price of \$100 per ton. Natural gas use however increases sharply as the fuel is used in natural gas with CCS to produce dispatchable electricity. Despite the drop in end-use of natural gas, overall natural gas

[13] Conversion from natural gas to equivalent electricity use requires assumptions on annual fuel utilization efficiency (AFUE) for gas furnaces and heating seasonal performance factor HSPF for heat pumps (i.e. how much natural gas fuel is converted to usable heat and how much electricity is needed by a heat pump to deliver a given level of heating in MMBtu over a heating season.

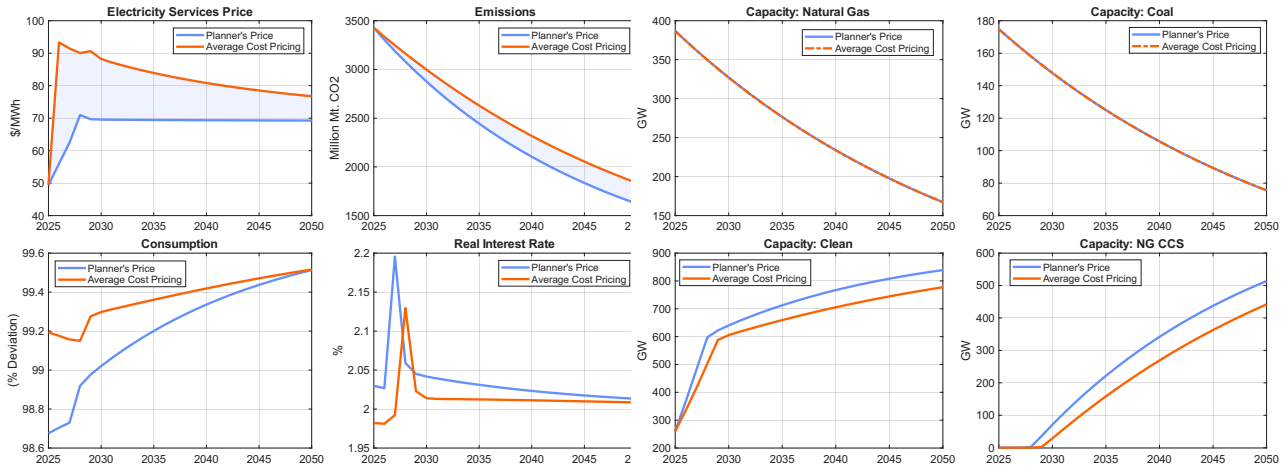


Figure 5: Aggregate and power generation transition paths

usage rises from 18 to 36 quad BTUs.

Lastly, the top line of Table 2 shows the effect of the carbon tax on consumption. Strikingly, consumption falls very little in the long-run as the carbon tax rises. As noted in Mehrotra (2024), long-run consumption may rise under a carbon tax because of lower fuel usage. In short, a given technology for generating power or providing an end-use service may have a relatively high capital cost, but a low fuel cost, with solar and wind being the best examples. This capital cost (inclusive of interest costs) may render those technologies more expensive absent a carbon tax. But, in long-run, the clean technologies may allow *higher* consumption by replacing capital for fuel cost. The top line of table 2 shows small decreases in consumption as lower expenditures on gasoline, diesel and coal offset higher expenditures for natural gas.[14] Note also that, by construction, consumption of all end-use services by households (transportation, space and water heating) are held constant, so households are not experiencing any decline in real services provided by end-use capital.

4.2 Transition path

Figure 5 displays the transition paths for key macroeconomic and energy aggregates and the transition path for the power generation capital stock. The blue lines in each panel display the transition path under the planner's efficient path for the price of electricity. The red lines in each panel display the transition paths when electricity prices are set to recover average costs. The transition paths are shown for 25 years assuming that a $100 per ton carbon tax is implemented in the current year (2025).

The left-hand side panel shows the transition paths for the electricity price, emissions, con-

[14]Our consumption expenditure includes the resource cost of transmission and distribution - the ν_e wedge needed to match the gap between wholesale and delivered electricity prices.

sumption and the real interest rate. Under the optimal path, the price of electricity rises steadily for a couple years before slightly overshooting its long-run level and setting at the new steady state level. By contrast, under average cost pricing, the price of electricity jumps much more abruptly reflecting the substantially higher cost of fossil fuels due to the carbon tax. The price of electricity in the short-run nearly doubles from $50 per MWh to around $95 per MWh. As fossil generation is retired and replaced by clean power generation, the price of electricity falls back towards the planner's price. However, even 25 years later, electricity prices remain nearly $10 per MWh higher under average cost pricing. The carbon intensity of the US power grid has decreased markedly in the past 20 years due to declining reliance on coal; the price spike would be even larger in a coal-dominated power grid like China.

Emissions fall more slowly under average cost pricing relative to the optimal path. The light blue shaded area represents the excess emissions from an electricity price that is too high, discouraging end-use electrification. Overall emissions fall from around 3.5 gigatons in the intiial period to a little under 2 gigatons by 2050. By comparison, under optimal policy, emissions would fall to around 1.6 gigatons by 2050. In the long-run, the average cost of electricity converges to the optimal price and emissions are the same under both pricing regimes in the long-run. Cumulative excess emissions under average cost pricing are 9.3% higher or approximately 170 million tons per year for the first 50 years.

In comparing the path of consumption and the real interest rate, the speed of the energy transition is crucial to understanding these transition paths. Consumption falls by less under average cost pricing and real interest rate rises by less. Under the optimal pricing of electricity, there is faster end-use electrification which drives higher levels of capital investment. Higher capital investment reflects two effects: 1) greater investment in power generation as electricity demand rises and 2) increased expenditures on higher cost electric durables. The higher upfront capital cost of electric durables reduces consumption initially. Faster declines in fuel use mean that consumption growth is faster as a larger part of the durables stock is electrified. The upward path of consumption growth implies that the real interest rate jumps above its steady state level and declines back towards 2%.

The right-hand side of Figure 5 shows the evolution of the power generation capital stock. Under both pricing regimes, investment in fossil fuel power generation ends after the imposition of the carbon tax. Both the natural gas and coal-fired capital stocks decline at the rate of depreciation, falling by over 50% over the next 25 years. Replacing the depreciated fossil capital stock and meeting incremental energy demand is initially achieved by investing only in clean (intermittent) power generation. At time zero, the relative price of dispatchable and intermittent power changes due to the carbon tax. Clean capital becomes relatively cheaper, and the desired ratio of intermittent power to dispatchable power rises. After 3-4 years, the expansion in power generation capital is met through a mix of both dispatchable and intermittent sources. Renewable power rises from

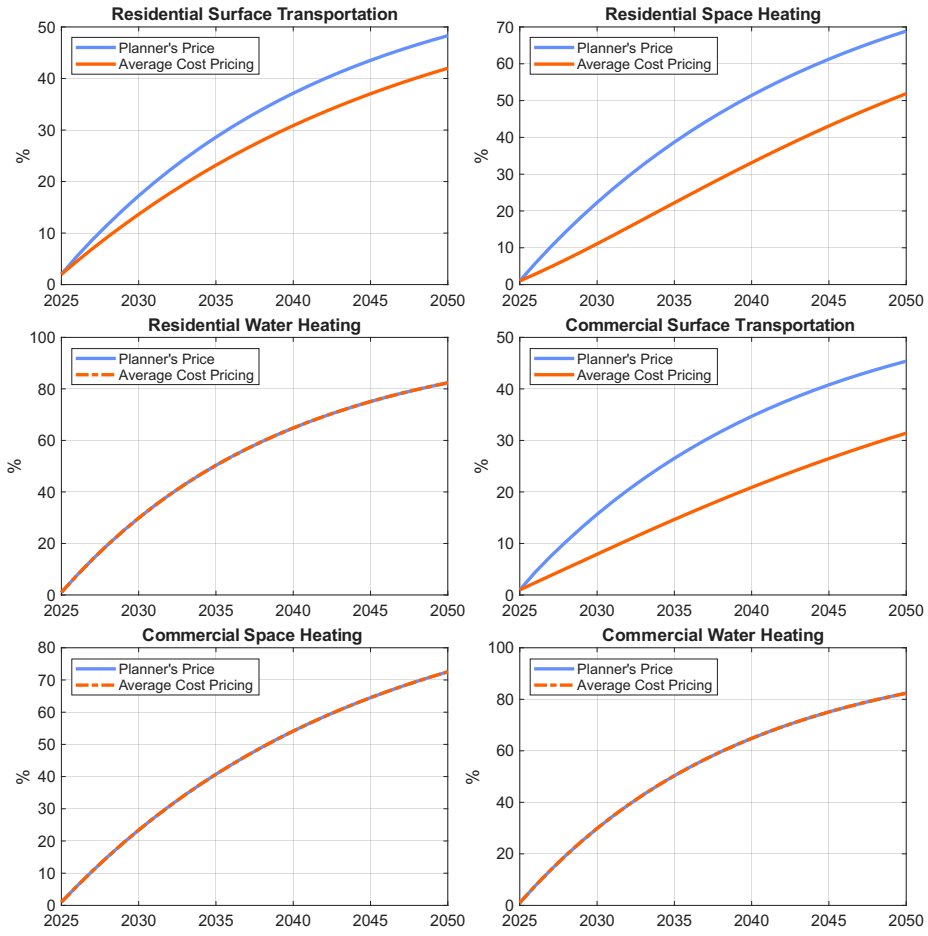


Figure 6: Electrification of durables

less than 300 GW to around 800 GW by 2050. The slower investment in power generation under average cost pricing reflect the slower rate of end-use decarbonization and, therefore electricity demand.

Figure 6 shows the share of durables stock that is electrified over time. The substantially higher electricity price under average cost pricing slows the rate of electrification for 3 of the 6 end-use sectors. Residential and commercial water heating along with commercial space heating are unaffected by differences in the path of the electricity price. This reflects the relative importance of fuel costs in assessing the lifecycle costs of the fossil v. electrified durable. It also reflects the relatively limited effect of even substantial variation in wholesale electricity prices on the delivered price (i.e. going from 15 cents to 19 cents per kWh). For surface transportation and residential space heating, where the calibration has a larger variance for the cost/taste shock, electrification is materially slower under average cost pricing.

For residential surface transportation, the high capital cost relative to fuel cost mitigates the effect of the carbon tax on incentives to switch, but the speed of electrification is similar under both pricing regimes. For commercial surface transportation and residential space heating, the relative importance of fuel prices and the more modest efficiency gains of switching from fossil to electric make differences in the path of electricity prices more important for the transition path. The overall level of electrification is lowest for commercial surface transportation given the high capital premium for electric durables and the relative high use of electricity.

5 Conclusion

This paper characterizes the optimal carbon tax in an environment where end-use decarbonization requires electrification. In this environment, the effect of a carbon tax on electricity prices is key to the decision of whether to switch from direct combustion of fossil fuels to electrification across end-use services like transportation, building heating, and industrial applications. Policy efforts to reduce greenhouse gas emissions have focused on these two distinct steps: reducing emissions from power generation and switching to electricity from fossil fuels to provide end-use services.

I analyze a dynamic macroeconomic-energy model in which fossil fuels are used for both electric power generation and used directly by an end-use sector. A carbon tax strengthens incentives to shift power generation away from fossil fuels towards renewables and zero-carbon power generation. In the end-use sector, the decision to electrify depends, in part, on the price of electricity which is affected by the carbon tax. Under optimal policy, electricity is priced at the marginal cost of adding new clean power generation modulo of interest rate effects along the transition path.

As I show analytically, electricity prices may *overshoot* the new long-run resource cost of clean power generation after implementation of the carbon tax. Since the power generation capital stock turns over slowly, a carbon tax can raise the generation cost from legacy fossil fuel generation po-

tentially in excess of the long-run cost of clean power generation. This increase in cost, if passed along to end-users, will delay end-use electrification and keep emissions higher than would otherwise have occurred under optimal policy. Importantly, this mechanism is distinct from inefficiencies in the retail pricing of electricity due to the inclusion of other fixed costs as emphasized in Borenstein and Bushnell (2022*a*).

Frictions in capital turnover and electricity pricing based on cost recovery are not necessary to generate a divergence between decentralized electricity prices and the implicit price the planner would choose. When clean power generation is produced by a combination of cheaper intermittent renewables and more expensive dispatchable clean power generation, electricity prices in the both the long-run and along the transition path may diverge from the optimal price. In deregulated energy markets, dispatchable power generation typically sets the generation price and wholesale power prices may exceed their optimal level.

I quantify a richer calibrated version of the model that allows for electrification across both residential and commercial transportation and buildings. Under the planner's implicit electricity price, a $100 per ton carbon tax reduces emissions by 79% and boost end-use electrification ranging from 59% in commercial surface transportation at the low end to full electrification in space heating at the high end. When prices are set as in a regulated utility with cost recovery, the electricity price overshoots its long run value and the cumulative emissions reductions are 9.3% less than under optimal policy. The losses are some lower when prices are set by dispatchable generation, as the price overshoot does not persist as long.

Future work will incorporate decarbonization costs in industrial sectors like iron and steel, cement, aviation and shipping fuel. Together these represent the largest remaining sources of US carbon emissions from combustion and process emissions. In these sectors, the amount of electricity required to decarbonize these sectors may be substantially more than for the currently modeled sectors. Additionally, differences in efficiency across electric space and water heating may be important when electricity prices overshoot. Electric resistance heating is both widespread and generally expensive relative to heating with natural gas; in the face of high electricity prices, households may switch in the wrong direction to natural gas.

Future work can also consider the implications of technological progress which may lessen long-run capital and fuel costs for decarbonization, and may interact with electricity prices to changes the losses relative to optimal policy. Lastly, the tradeoff between intensive and extensive margins of energy use deserves further study. High electricity prices, for instance, may slow end-use electrification but may also encourage conservation and greater energy efficiency.

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