United States federal and state government policy and regulatory effort to date have been effective in driving early clean energy investments, but many of these tools may be unsatisfactory for use at large scales and over sustained periods of time.

For example, they may distort existing markets and affect the value of existing investments. This can result in wealth transfers or other disruptions, which create constituent opposition that grows alongside the use of that policy. For example, while renewables portfolio standards have induced moderate levels of power generation diversity, extending them to mandate very high levels of renewables purchases in low demand growth environments reduces the addressable market available to other desirable electricity generation technologies. It has been cited as a factor in early asset writedowns for existing nuclear power plants, for example (Carl and Fedor 2017).

Today’s command-and-control regulatory tools may require large and highly skilled bureaucracies that are not easily replicated in different jurisdictions. A recent annual expenditure plan for California’s AB32 cap-and-trade program revenues totaled $2.2 billion for projects distributed over 14 different state departments and 16 programs (ARB 2017).

They may draw on government budgets, making them subject to appropriation uncertainty over time. The federal production tax credit (PTC) for wind power alone, for example, is currently worth about $4 billion annually and has been suspended or retroactively extended numerous times throughout its history. When the PTC last lapsed in 2013, US wind installations fell from approximately thirteen gigawatts per year to just one gigawatt (EIA). Similarly, when a Danish tax break on imported electric vehicles recently expired, Tesla sales fell 94 percent year over year (Bloomberg June 2017).

Finally, traditional clean energy investment policy tools may not be socially cost-effective. A National Research Council study (Nordhaus, Merrill, and Beaton 2013) calculated, for example, that the federal wind production and solar investment tax credits have cost about $250 per ton of avoided carbon dioxide emissions, exceeding most estimates of the social cost of carbon.

One option that has been proposed in response to the issues described above is the revenue-neutral carbon...
tax. In 2017, for example, a federal “carbon dividend” as proposed by out-of-office Republican bureaucrats and academics—including George Shultz, James Baker, Rob Walton, and Martin Feldstein—and was subsequently endorsed by ExxonMobil, GM, and Johnson & Johnson. Another proposal, the industry-oriented Partnership for Responsible Growth, has also promoted a revenue-neutral carbon tax-corporate tax swap. Being a political change year, the proposal have been taken seriously enough to warrant responses: from the White House and from Congress, and from critics and supporters on both the left and the right.

How realistic are these proposals? What dynamics might be expected from these policy tools on clean energy investments? And what current political challenges do they face that could end up affecting the clean energy and infrastructure investment environment?

**INVESTOR IMPLICATIONS**

In terms of overall economic impact, broad-based carbon taxes are massive tools. A $40 US federal carbon tax would result in new direct financial flows on the order of $200 billion per year, plus induced behavior change across nearly all energy supply and demand investments. To compare, that is about 50 times the annual flows motivated under the wind PTC.

A broad literature has described how carbon pricing systems can be designed to minimize economic inefficiencies or administrative costs, compensate politically-favored groups, or collect and redistribute public receipts (see, for example, Parry et al 2015). As of 2013, 40 countries and another 16 states or provinces around the world priced carbon dioxide emissions, collecting over $28.3 billion in government “carbon revenues” in the process, representing additional per capita average spending ranging from just $4 annually (Japan) to $391 (Australia) (Carl and Fedor 2016). And most carbon pricing systems have gradually increased their impacts over time by expanding the scope of their coverage of the economy (e.g., California, Scandinavian countries), intervening in the market to increase the value of cap-and-trade emission permits (European Union, US Regional Greenhouse Gas Initiative), or increasing the rate of a carbon tax (British Columbia, Switzerland, Japan, France, UK, and Scandinavian countries). Australia’s aborted carbon tax scheme stands as one exception to this observation, though it is notable that Australia’s policy was implemented over loud opposition party dissatisfaction and was also the most ambitious—as measured by per capita carbon revenues—such policy globally.

Narrowing our perspective to the level of individual investments, the effect of carbon pricing on low-carbon technologies or operational choices—defined here as having less than the median emission intensity of alternatives in the market—is to (a) increase operational costs in line with the carbon intensity of that activity, while also (b) increasing revenues either marginally in excess of those increased operational costs (for technologies near the fleet median emissions intensity) or significantly in excess of increased operational costs (for operationally zero-carbon technologies). How might these costs and benefits affect today’s energy investment markets?

**CLEAN ENERGY INVESTOR COSTS**

A carbon tax-and-dividend would increase both energy infrastructure capital costs and production costs, even for clean energy investors.

For example, even a zero carbon energy production technology such as a wind turbine would have marginally higher upfront costs given the potential for the costs of embedded carbon emitted during the mining, manufacture, transport, and installation of its components—namely steel, concrete, and foundation steel reinforcement—to be passed through the value
One recent lifecycle carbon meta analysis of wind turbines estimated embodied emissions of turbines from 2 megawatts to 3.4 megawatts ranging from 641 to 1046 metric tons (Smoucha et al 2016). Were full carbon costs to be passed to the final consumer given inelastic demand (in this case, the project developer), this would represent very modest additional costs: $26,000 to $42,000 per turbine at a $40 carbon (dioxide) price, or about 1 to 2 percent the total $2.5 million capital cost of typical 2 megawatt land-based turbine (NREL 2017). Actual additional costs would likely be less given that some carbon costs would likely be absorbed by suppliers.

With full pass-through, incremental capital costs for other technologies at a $40 per ton tax would be on the order of: 3 percent for residential and 8 percent for utility scale solar PV (equivalent to about 2.5 tons embodied carbon per kilowatt capacity, derived from Nugent and Sovalcool 2014, Fu et al 2017); 4 to 5 percent for small hydro (also about 2.5 tons embodied carbon and $2000-2500 total capital costs per kilowatt, from Lenzen 2008, IRENA 2012); 11 percent for nuclear (about 15 tons embodied carbon and $5530 total capital costs per kilowatt—and twice that if considering decommissioning costs—from Lenzen 2008 and EIA 2013); and 29 percent for a natural gas combined cycle turbine (assuming 6.5 tons embedded carbon and $917 total capital costs per kilowatt, from Lenzen 2008, EIA 2013). This final figure for natural gas power generation increases by the highest percentage in part because of the very low baseline capital costs for these plants—which has seen gas plants capture, for example, 36.7 gigawatts out of 46.3 total gigawatts through thirteen recent years of PJM market capacity auctions (PJM 2016). Advocates for competing clean but higher investment risk energy technologies such as nuclear or demand response who have criticized gas’ dominance for overly-depressing the value of this infrastructure development investment incentive may therefore welcome such upfront carbon tax cost increases. Finally, any project using carbon capture technology, with its added ducting and piping, could expect capital cost increases commensurate to those seen for nuclear and natural gas.

Operationally, the cost impact of carbon pricing would vary considerably across projects and technologies. The majority—approximately 75 percent—of lifecycle carbon emissions associated with solar, wind, and hydro (or pumped storage) generation technologies are already accounted for in their construction figures, as noted above. For nuclear, carbon costs associated with ongoing electricity production and maintenance over a plant’s lifetime are roughly four to ten times those from upfront capital costs, depending on fuel supply chains (particularly the level of fuel enrichment required), operations, and plant lifetimes. Even so, these costs remain moderate: a $40 per ton tax would raise production costs by about $1-4 per megawatt hour, or about 3-11 percent today’s average US generation costs. Nonetheless, were a carbon tax-and-dividend introduced rapidly, this increased cost pressure on existing infrastructure could be enough to trigger new rate cases in regulated markets or factor into the renegotiation of power purchase agreements in competitive markets.

Production costs for the operation of natural gas infrastructure, however, would increase significantly. Anywhere natural gas is combusted, such as in a combined cycle power plant, a project developer would face both increased gas gate prices due to the embedded emissions associated with the supply of that fuel—from energy used in extraction and compression in the distribution system, to methane leaks (to the extent covered by the tax system). The National Energy Technology Lab (2015) estimates these upstream emissions at about 14 kilograms carbon-dioxide equivalent per mmbtu: 55 cents at a $40 carbon price or an increase of 17 percent on the
2015 average US delivered cost to power plants of $3.23 if passed through completely to the power plant gate price (EIA 2017). On top of that would be the carbon dioxide emitted directly from the combustion of the gas itself (53 kilograms per mmbtu), and likely paid to the tax collector: $2.12 per mmbtu at a $40 carbon price or an increase of 66 percent on the 2015 natural gas commodity price. For a combined cycle power plant, these additional embedded and direct emissions costs would equate to increased generation costs of $4.20 and $16.20 per megawatt hour respectively. Gas turbine peaker plants, with their lower generation efficiencies, would see cost increases of about $6.20 (upstream) and $24.00 (direct) per megawatt hour from fuel use.

For natural gas infrastructure owners and new investors, such direct cost pressures would provide major incentive for investment in higher efficiency plants. It would also reward natural gas suppliers in the upstream and transmission/distribution phases who could reduce their own energy use or detectable methane leakage in order to capture the spread in prices created by embodied emissions in the broader market. Of course both groups, even if able to make operational or investment choices to minimize their tax exposure, would still face substantial new ongoing operating costs from the tax given that their entire emission stack would be penalized—costs which may nonetheless be outweighed by the increasing costs of alternatives.

Non-power natural gas infrastructure investors, such as LNG, pipelines, hydrogen production, or the chemicals industry, would be likely to face a portion of these costs depending on their own energy use as well as contract structures—the embodied emission content of the fuel to be liquefied for export, for example (this would likely be true even if receiving border adjustment rebates for the direct carbon content of the fuel were the tax to be levied at gas gathering sites). An open question is the effect of these higher operating costs of peaker plants on the market for intermittent renewable power generators: while renewables’ generation profile helps create the overall growth in demand for such dispatchable power, renewable projects themselves would not face these costs. Distribution of costs and rents across market participants would vary, as discussed below.

**CLEAN ENERGY INVESTOR BENEFITS**

So what about the other side of the equation? Profitability among merchant power generators in particular has been poor in recent years amid low demand growth, excess capacity in many markets, and low natural gas commodity prices that have depressed supply curves. This has been identified as an issue threatening existing nuclear power plants, but in fact has affected thermal generators as well, reflected in sagging share prices and driving a rush towards rate-of-return regulated power assets (see Kavulla 2017 for one view on these dynamics). How would a carbon tax fit into this environment?

For straight carbon tax-and-dividend schemes such as the Shultz-Baker proposal, it is important to recognize that there is no free lunch. A carbon tax is a not a subsidy, nor is it mandate that generates guaranteed demand. Moreover, businesses would receive neither the value of “grandfathered” permits that might be available under cap-and-trade schemes (as trade-exposed emission-intensive manufacturers do in the Californian, European, and other cap-and-trade schemes), nor are their added carbon costs directly offset with “green” subsidies funded by the tax’s revenue, since all revenues would be returned to families in lump-sum payments. This contrasts with international experience in carbon pricing systems to date, where “green” spending comprises 27 percent of carbon tax revenues and 70 percent of cap and trade system revenues (Carl and Fedor 2016).
Instead, under a straight tax-and-dividend, the simple cost and benefit framework used above dominates: the level of benefit—primarily extra revenues—available to a clean energy developer are a function of overall increased market prices in areas where carbon-intensive technologies already operate. That is, clean energy investor benefits are a function of carbon-intensive energy competitors’ new costs and the ability of other clean suppliers to meet new demand. The magnitude of these benefits therefore depend upon variables that are potentially predictable over the lifetime of a new infrastructure investment, but ultimately outside the investor’s control—for example the carbon intensity of a regional electric grid.

Consider a simple example in a competitive generation market: a supercritical pulverized coal plant emits about 0.8 tons of carbon dioxide per megawatt hour of produced electricity, while a natural gas combined-cycle plant emits about 0.4 tons: a $40 per ton carbon price would increase costs for the coal plant by around $32.00 per megawatt-hour and for the natural gas plant by about $16.00. Nuclear costs, as described above, might rise by $2. The PJM competitive wholesale market’s average price in 2016 was $29.23 per megawatt-hour from a generation mix split almost evenly between coal, natural gas, and nuclear. While the actual price increase in a competitive market such as this would depend on the shape of the bid stack, the availability of excess capacity that could be brought online, and customer response, this suggests that a 1.5x increase in prices could be possible given that natural gas plants are assumed to be setting today’s clearing prices. So, a new zero-carbon generator in the PJM market might expect similar revenue gains in the short term, far offsetting the increased capital costs described above. A typical 1,000 megawatt nuclear power plant operating at a 90 percent capacity factor, for example, could expect additional net revenues on the order of $100 million in the first year (a level commensurate to state subsidies for existing nuclear plants recently adopted in New York and in Illinois).

Energy infrastructure that is complementary to zero-carbon generation technologies—long distance transmission or large scale energy storage options such as pumped hydro, fuel cells, or batteries, both used to help balance temporal or spatial supply and demand disparities—would benefit from similar increase in demand. In fact, such investments would be required to avoid curtailment or severely depressed hourly prices (and generator revenues) were the deployment of intermittent renewables to substantively increase under a carbon tax. This is an issue that California is already facing from mid-day solar overproduction at deployment levels of about 9 percent: 308 gigawatt-hours of renewables were curtailed in 2016, a figure growing nearly 150 percent year-on-year, such that 20 to 30 percent solar curtailments are now not uncommon (CAISO 2017).

The value to an individual investment of a carbon price is reflected primarily in the future behavior of its competitors. One major uncertainty is how regional power prices would respond over time given decarbonization of that regional grid, such as a shift from coal to gas-fired generation, or even gas-fired to near-zero carbon sources (were the carbon tax high enough to justify it).

In one view, short to mid-term prices would be permanently increased, with the existing (potentially mothballed) coal fleet acting as a “safety-valve” price ceiling that could gradually come back online as needed to fulfill marginal electricity demand. In this case, natural gas generators would likely bid up to that point as long as they remained the marginal power generator in the bid stack. All other generators would then receive this clearing price, approximately equal to
today’s cost of operating the most efficient coal-fired power plants in a regional grid, minus some reduction in coal commodity fuel costs from a nation-wide drop in demand, plus the carbon price as described above. Net costs versus benefits to natural gas plants in this scenario would essentially depend on the continued viability of any coal in the generation mix.

Contrast this situation with today’s regulatory- and subsidy-driven clean energy investment model, in which additional revenues available to zero carbon resources through mechanisms such as the renewables production tax credit, investment tax credits, or portfolio standards actually serve to depress electricity market wholesale prices (but not ultimate consumer costs) by either reducing effective market bidding prices or removing addressable electricity demand from the market altogether. Exelon Corporation, for example, estimated that such measures led to negative wholesale prices for 14 percent of market hours in its territory in 2012 (RTO Insider 2014).

It is important to recognize that such fuel switching could easily occur at a pace within the lifetime of existing infrastructure: even without a federal carbon price, the share of coal fired power generation in the United States, for example, declined from about 48 percent to 32 percent in the decade leading up to 2016, during which time the fuel price differential between gas and coal narrowed from $6 per mmbtu-equivalent to just $1 (EIA 2016); oil-fired power generation saw a similar decline in market share in the late 1970s and early 1980s. For context, a $40 carbon tax would squeeze the coal-gas fuel price difference by about another $2, making gas cheaper than coal for a given heat output at current commodity prices. In the United Kingdom, coal’s share of the power generation mix has declined from 25 percent in 2015 to just 2 percent so far this year alongside a power sector carbon price floor of about $24.

Critics of a carbon tax-and-dividend have pointed to the potential for electricity prices to rise to a “coal ceiling” and stay high over time, despite potential concurrent decarbonization of the grid, as a major flaw of the policy tool from a social perspective given that this would over time reduce the tax revenues available for the consumer cost-offsetting dividend. Others may argue that over the longer term, the presence of a very high carbon price could eventually drive out even significant shares of natural gas fired power generation, were sufficient zero carbon resources able to be built to meet demand. Demand itself could be moderated through energy efficiency given the high cost scenario described above. Meanwhile, additional scale of deployment in a lower regulatory risk investment environment could reduce today’s substantial transaction costs and also drive technology improvements. Were new viable low carbon technologies introduced into the grid technology portfolio—for example, advanced demand response, new nuclear, offshore wind, or large scale electricity storage—this would help drive down costs through competition and diversity of supply, while moderating price volatility. A similar argument has been made in support of existing regulatory tools that have driven solar power deployments: while expensive in terms of carbon savings, they have also had the positive social benefit of reducing technology costs through learning. Ultimately, however, were the power generation mix to be dominated by low- or zero-marginal cost generators with low fuel and carbon costs, cost recovery and allocation would need to be fundamentally revisited in US electricity market designs.

Another investor consideration is that carbon pricing, applied system-wide, can positively affect the profitability of low-carbon competitors as well, and in non-obvious ways. For example, intermittent wind power competes with non-dispatch baseload nuclear power in markets, especially in nighttime hours when demand falls. A carbon price that improves the
economic viability of an existing nuclear plant over its average production in the course of a year, such that a plant stays in business or even expands its capacity rather than shutting down (up to one-fifth of the current US nuclear fleet is now thought to be at risk of permanent closure), could nonetheless end up regularly depressing nighttime hourly wholesale prices when a wind generator may otherwise hope to earn the bulk of its (non-subsidy) revenues. The direction of this effect will vary based upon the generation portfolio of different markets. And while this discussion has focused on power markets, similar dynamics could be expected in other sectors as well—for example the relative attractiveness to consumers of hybrid gasoline-electric vehicles versus full electric under a regime of higher gasoline prices, given that market share is here is dominated by conventional drivetrains.

What about regional and market differences? Electricity market price responses in particular could vary considerably by the resource mix available in that geography: in the Midwest, MISO’s 2016 generation sales mix was 51 percent coal and 23 percent gas; PJM’s, 33 percent coal and 33 percent natural gas; ERCOT was 29 percent coal and 44 percent gas; ISO New England’s was 2.4 percent coal and 29.3 percent natural gas; while CA ISO had negligible coal with 32 percent natural gas. Under a straight carbon tax, some grids would face wholesale price ceilings dictated by coal’s baseline plus carbon costs, while others might face a “gas ceiling.” While higher market clearing prices could improve revenue potential for clean energy investors, it could also threaten political viability given regional disparity in consumer costs (see Hassett et al 2009 or Williams et al 2014 for two models of regional consumer impacts under a carbon price).

Ignoring potential bid stack dynamics, and looking simply at today’s overall electric power generation carbon intensities by state, a $40 per ton tax could increase short term wholesale prices by $22.50 per megawatt hour nationally, but range widely from just $0.40 in Vermont, to $11.10 in New Jersey and California, $19.50 in Louisiana, $23.70 in Texas, $28.20 in Kansas, $31.70 in Colorado, $34.90 in Missouri, and $40.00 in Wyoming (EIA emissions data for 2014). While energy prices only represent about half of final residential bills, they are directly felt by industrial customers. Regional energy price differentials could become another strong driver for improved physical and market integration of today’s balkanized power grids.

Meanwhile, non-reformed electricity markets—the half of US states in which utilities may still hold vertical monopolies with rates of return regulated by public utility commissions and new infrastructure investments guided primarily by their integrated long-term planning processes—could expect substantively different dynamics under a carbon tax-and-dividend. There, the added carbon tax cost on fossil generators might be passed through to customers for the duration of the rate case, as would any other fuel price change. Without a wholesale clearing price, revenues to other generators would not be substantively affected, especially if already operating under long-term power purchase agreements. This might mitigate the short-to-near term customer price impact, but would also dull the carbon price’s incentive for suppliers to shift the fuel and generation mix. Instead, the carbon price’s forcing function would be expressed through the decisions of the regulator, who would weigh the expected added carbon costs of fossil generators when comparing new infrastructure options or the potential early write-down of existing assets. One upside of this more “orderly” approach is that any new clean energy investment benefitting from regulator expectations about a carbon price’s impacts on fossil competitors—in the form of an investment approval that may not have otherwise been possible—would more likely be able to finance project debt around that public guarantee rather than being exposed to the risk of competitive market dynamics over the lifetime of a project.
A final dynamic worth considering is the extent to which a rising carbon tax-and-dividend could drive a wholesale shift in electrification of the US economy. Different tax levels could be expected to drive different technological or operational substitutions across sectors. A high enough level could cause a rush for “less than natural gas”-emissions energy supply technologies in order to avoid potentially onerous taxes on the use of that fuel. Today electricity provides one of the few zero carbon energy sources, even if its characteristics do not always make it an application-desirable fuel. Widespread highway vehicle electrification, for example, would result in United States electricity demand rising about 50 percent from today’s levels. Direct end-uses of fossil fuels, for example in industrial or residential/commercial heating, could also face electrification pressures, a tension already witnessed in California’s recent efforts to reduce oil refinery emissions through the use of electric boilers (vigorously resisted by owners). If tax levels were to rise too fast, this dynamic could create a “rush to the exits” for zero carbon electricity supply, driving up wholesale prices as inter-fuel competition is reduced, and demanding substantive new infrastructure development to replace carbon-stranded assets. In moderation of this view, however, it is worth noting that empirical evidence shows that demand for existing energy consumption patterns remains remarkably sticky given a lack of alternatives to provide the same service: in the United Kingdom as of 2017, motorists pay approximately $3.00 in taxes per gallon of gasoline, compared to a US average of about $0.49. This would be roughly equivalent to carbon price differential of nearly $300 per ton carbon dioxide. UK residents, however, still report annual per capita personal vehicle travel distances just over half US levels despite living in a far denser geography (Miller-Ball and Schipper 2011).

FURTHER RESEARCH QUESTIONS

In sum, each of these dynamics argues for the development of investor and consumer-friendly simulation tools during the ramp-up period of any carbon tax that could help affected parties to better plan for and anticipate potential system dynamics before they actually face them. These “micro” investor planning tools would be a complement to the large body of macroeconomic energy-emissions partial and general-equilibrium models that are meant to aid policymakers in understanding the broad effects of a carbon price (see, for example, EMF 24 2014).

It also prompts the question of “optimal” carbon tax levels and society’s ultimate goal for the carbon tax. One view is that an optimal carbon price is one that internalizes the external social costs of carbon dioxide emissions, though such calculations are fraught with uncertainty and value judgments (Nordhaus 2014). Another view is that a carbon tax should be calibrated to deliver desired outcomes—driving shifts in fuel mixes, for example, or supporting the growth in deployment in popular technologies such as renewables. To this perspective, it is worth noting that available technologies are lumpy, so threshold tax levels may matter: if the primary goal of a carbon tax is to drive out coal fired power generation, for example, then any tax level beyond that outcome may in the short- to near-term drive up total costs without much visible result elsewhere in the power sector. To take another example, there are few good near-term technology options to appreciably reduce the carbon intensity of air travel, a rapidly growing sector. To what extent would different carbon prices incent surprising new technological or operational choices in this mode versus simply raise costs and depress demand?
Since carbon taxes are naturally scalable one outstanding research question would therefore be how far and at what pace these tools can actually be pushed without unduly disrupting existing markets, assets, or social/political support. Because they are broad, and given the potential for revenue recycling to reduce fiscal drag on the overall economy, it is reasonable to expect that their window of viability exceeds that of narrower regulatory mandates or subsidies. But just how much is uncertain and will clearly vary by geography; a new framework is needed to approach this question.

Another question is of course ways in which to improve the political viability of carbon pricing in the first place so as to increase its social palatability in jurisdictions that currently do not support it. The remainder of this discussion paper addresses two such new approaches.

**NEW POLITICAL DYNAMICS**

The body of carbon tax-and-dividend proposals share two main characteristics. First is a gradually rising, broad-based upstream tax on emissions. Second is the progressive dividend—the flat, per capita refund of all such tax revenues collected in each year to the American public. Both elements have been analyzed and even implemented to some degree in other jurisdictions globally (see Metcalf 2017 for a recent comprehensive overview of design considerations).

More recent “second generation” tax-and-dividend proposals, including the Shultz-Baker proposal, have tried to advance that concept by attempting to further appeal to current US federal political conditions. Two elements stand out: (a) a carbon border trade adjustment mechanism, and (b) the pre-emption and roll-back of other environmental authorities, regulations, and specific subsidies that may no longer be justified given the existence of a broad-based tax. How realistic are these mechanisms and would they affect industry investment in clean energy or production infrastructure?

**CARBON BORDER ADJUSTMENTS**

A carbon border adjustment mechanism is intended to maintain US competitiveness under a unilateral carbon price and encourage other countries to follow suit with their own carbon pricing. In 2017, the concept finds itself in a dynamic political environment. President Trump has signaled a hands-on approach to US trade policy with the explicit aim of reducing trade deficits and minimizing direct employment impacts of more liberal trade policies. Second is a renewed push for infrastructure investment—and the money needed to pay for it without the costs being directly placed on individual taxpayers. Meanwhile there is tax reform: Republican proposals for comprehensive revenue-neutral reforms to reduce deductions and lower headline tax rates, particularly the corporate tax, have included novel funding mechanisms including a comprehensive, VAT-like “border-adjusted” tax on the value-added of most imports to the United States. While such proposals have been criticized by consumer groups as being too broad, a carbon border tariff adjustment mechanism could potentially address each of these points: environmental regulatory arbitrage inherent in some of today’s international trade in goods; a new source of revenues for government priorities like infrastructure spending; and more limited than a broad-based import tax. In theory it would even be possible to enact such a border adjustment mechanisms even without first implementing a domestic carbon tax.

How would this work? Tariffs would be applied based upon carbon intensity performance. Carbon emissions associated total fossil fuel use or direct emissions of a particular sub-sector—cement production, for example—would be normalized to activity levels by
dividing those emissions by the total manufacturing output of that sector, either in terms of product tonnage or units where comparable and appropriate, or in terms of value-added. Each domestic manufacturing sector would be applied a carbon index, updated over time with any performance improvements. And each ton or unit or value-added Dollar of imports would then be assessed an equalizing penalty according to a set price of carbon—$40 per ton, for example (see EMF 29 2012 for a deeper discussion of design options).

For example, US steel imports in 2014 reached a record high of 40.3 million metric tons, at a value of about $28 billion, from a wide variety of international trading partners. The United States is the world’s largest steel importer, and imports account for over a quarter of domestic consumption. Moreover, the United States has launched over 150 steel industry anti-dumping trade disputes in recent years.

One ton of United States domestic “iron and steel” production in 2014 required 0.62 tons of carbon dioxide emissions (author calculations from IEA and World Steel Association databases). The Chinese iron and steel industry meanwhile had a carbon production index of about 2.15 tons of carbon dioxide emitted per ton of iron or steel produced—over three times as much as the US domestic figure. A $40 per ton carbon price applied to this would therefore yield a carbon border tariff of about $61—equal to about a 9 percent premium on that year’s US steel import average price of nearly $700 per ton.

Other trade partners would fare differently. Canada’s 2014 index would have been 0.77 tons carbon dioxide emitted per ton iron or steel produced, Japan’s was 0.64, German was 0.54, Mexico’s and Brazil’s were both 0.49, Turkey was 0.36, and Korea’s was 0.31. Of these, only Canada and Japan had higher indices than the United States, equating to border carbon tariffs that would have been $6 and $1 per ton, respectively.

Other emissions-intensive sectors such as aluminum, cement, chemicals, or paper rely on different production technologies and would likely face different carbon differentials.

Whatever its potential short term political appeal, a carbon border adjustment would bring with it both advantages and disadvantages:

- In its favor, a carbon tariff would be policy agnostic: it would be unnecessary to divine costs or impacts to producers from regulatory policies like renewables portfolio standards, for example, or to track industry exemptions from cap-and-trade systems. The carbon border tax would be an independent forcing function for domestic producers to improve their carbon performance—and demand clean infrastructure or technology investments—additional to any domestic carbon tax, or even in the absence of one.

- Being rate-based, overall industry growth or new entry would be less restricted than under a carbon cap-and-trade or absolute emission reduction target-based regulatory framework: the intensity of carbon used per unit of output is essentially under a producer’s long-term control given their ability to invest in new low carbon production infrastructure. Even for carbon intensive manufacturers like paper or cement, new competitive dynamics from a carbon border tax would be the relative to actual performance levels and improvement of foreign producers rather than arbitrary performance targets. Meanwhile, the policy is self-exporting: foreign exporters under any government or regulatory regime, seeing the marginal carbon tariff at the US border, would also be incentivized to reduce their own sectoral carbon emissions.

- Finally, the policy is naturally predictable, which could help resolve investment uncertainty for both domestic and foreign producers or clean infrastructure investors: a carbon border tariff
is not a single short-term trade intervention but rather a long-term framework which would update automatically based upon underlying changes and conditions.

Uncertainties and potential problems nonetheless demand further study:
- First, the scale of impact given administering complexity is unclear: in the iron and steel example above, only imports from China differed enough in carbon intensity from their US equivalents to have seen significant carbon border tariffs applied, resulting in an overall tariff level on the order of 10 percent. The other question is the impact of a border carbon tax on US consumer prices and demand given the country’s reliance on imported goods. A recent macroeconomic analysis of unilateral US carbon taxes (McKibben et al May 2017) found non-intuitive economic responses to the addition of a border adjustment mechanism—the effect of the new tariff on the value of the US Dollar (and the potential for strengthening to depress net exports more broadly) chief among them.
- Second, a carbon border tariff is likely to be gamed in ways both predictable and unpredictable. Were individual producers allowed to petition for certification of lower-carbon production processes in order to avoid a county-wide carbon border tariff, emission shuffling across exports could occur.
- Third is complexity. The estimates backing the carbon order tariff would be data-intensive and require a formal framework for objective evaluation, leading to administrative overhead. While many of the needed data sources already exist in some form, they would need to be standardized and qualified to the satisfaction of the administering agency. One approach to reducing this administrative burden would be to make the carbon intensity process “self-certifying” by trading partner governments or manufacturers, but overall some of the same issues with administrative competence and scale that plague some existing regulatory regimes would likely be challenges for this regime as well.
- Finally, legality. A number of recent analyses (Hillman 2013, Kortum and Weisbach 2016, Trachtman 2016, Flannery 2016) have investigated the potential legitimacy of carbon border adjustments under GATT/WTO rules. Their findings are mixed, speculating that some tariff designs could be permitted, while others would likely incur legal challenge. Trachtman in particular argues that carbon intensity-based tariffs would be difficult to defend, though questions the actual importance of any potential non-compliance with WTO rules given weak and slow enforcement or mitigation mechanisms. Others (Stiglitz 2006, for example) have argued that in spirit and precedent, GATT rules generally permit leeway in border protection measures that are directly justified by environmental concerns, such as with carbon dioxide emission-driven global climate change. Even then, the United States might face retaliation in the form of countervailing carbon border tariffs applied by trade partners to whom we ourselves export manufactured goods (Mittal in FT 2017). Trade partners could focus their own interpretations of a carbon border tariff on those sub-sectors in which the United States is a more competitive exporter, even including services. This is a question that deserves further study.

REGULATORY ROLLBACK
Realist political economy theory argues that a policy is more likely to succeed politically when beneficiaries are few and concentrated, while those who incur costs are dispersed (Schattsneider 1960). Could the reform or rollback of existing or likely climate-oriented environmental regulations—which may be more costly to obligated entities than a similarly-effective revenue-neutral carbon tax—therefore help improve the political
viability of a tax? Environmental regulatory compliance costs have been estimated at exceeding 2 percent of GDP (Jaffe et al 1995, though sensitive to definitions). One recent estimate found that a carbon tax of just $7 per ton would deliver the same emissions reductions of the Renewable Fuels Standard, the Clean Power Plan, and CAFE vehicle fuel economy standards, combined (Knittel 2016).

Policymakers interested in a carbon tax-regulatory swap could consider three screens: 1) Existing or proposed energy or climate regulations with environmental impacts similar to those that could be expected under a carbon tax (efficacy); 2) regulations where cost of compliance, or cost per ton of carbon dioxide emissions reductions, exceeds that of a carbon tax (efficiency); and 3) those with a similar incidence, for example in terms of upstream versus downstream obligated entities, consumer elasticities, or in terms of trading partners (equity).

Existing regulations that already make reference of the Obama administration interagency working group’s standardized “social cost of carbon (SCC)” in their cost-benefit analyses could be considered to have at least some “efficacy” nexus—that is, at least some portion of their benefits have already been described in terms of avoided greenhouse gas emissions. As of early 2017, this list included 90 proposed and 83 finalized regulations across executive agencies including EPA, DOE, and DOT (CRS 2017). It includes major regulations such as the Clean Power Plan and vehicle CAFE standards, but also numerous less-known items such as appliance efficiency standards, federal environmental reviews, and mineral leasing guidelines.

Not every one of these regulations could be described as obsolete under a revenue-neutral carbon tax since their emissions avoidance benefit may be only part of a larger package. At the same time, one might conceive of other major environmental regulations not explicitly relying on the SCC which might otherwise be considered for reform given that a carbon tax could indirectly result in similar overall non-carbon environmental benefits (e.g. a carbon tax that handicapped coal-fired power generation would also effectively reduce airborne mercury emissions).

Considering this, the most significant existing mandates for consideration would include, in the fuels and transport sector, the Renewable Fuel Standard, Corporate Average Fuel Economy Standards, Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles, the 2008 Standards of Performance for Petroleum Refineries, as well as upstream methane rules. In the power sector, major regulations for consideration would include the proposed Clean Power Plan “Existing Source” Rule, the Greenhouse Gas New Source Rule, the Cross-State Air Pollution Rule (for SOx and NOx), Updated National Ambient Air Quality Standards (for PM and ozone), Mercury and Air Toxics Standards, and the 2014 Clean Water Act 316(b) Once Through Cooling guidance (which has contributed to the early retirement or repowering of coastal gas-fired or even nuclear power plants).

Regulations aimed at improving the efficiency of energy-consuming products are a special case. Significant energy savings have occurred across the US economy since the 1970s, with carbon emission savings far outpacing any other emissions mitigation technology (Sweeney 2016). In areas of efficiency where government policy has played a more direct role—for example in vehicle fuel economy standards—agency cost-benefit analyses regularly argue that such regulations actually provide significant private savings over a vehicle’s lifetime because they help address informational market failures and irrational consumer hyperbolic discounting and can therefore be justified independent of climate or other environmental
concerns (see EPA 2017, for example). Critics, on the other hand, have shown that such tools can nonetheless be socially distortionary (Jacobsen 2013, Ito and Sallee 2015, Davis and Knittel 2016) or overly expensive (Knittel 2012) in regard to any climate or even consumer savings benefits; one recent survey of economists found that 93 percent would prefer a carbon tax to the existing regulatory approach (Sapienza and Zingales 2013). This highlights the tension in screening regulatory reforms based on agency cost-benefit analyses alone.

Existing clean energy subsidies are another potential area for reform under a revenue neutral carbon tax. While clean energy advocates might support such a swap if they are concerned about the ability of government-funded subsidies to scale to very high deployment levels, in the short term there could be resistance given the importance of subsidies in driving investment in some technologies today—as described above, the wind PTC has been a significant driver of deployments.

Major such subsidies include: the wind, biomass, and geothermal power generation federal production tax credit (PTC) of $24 per megawatt-hour for the first 10 years of operation, already set to phase out for new projects by 2020; the solar, fuel cell, and small wind investment tax credit (ITC) of 30 percent of upfront investment costs (10 percent for micro gas turbines, CHP, and geothermal), currently set to phase out by 2024; the modified accelerated cost recovery system (MACRS) allowing for five year depreciation of solar, wind, fuel cells, geothermal, and microturbines; the cellulosic ethanol production tax credit of $1.01 per gallon; federal electric vehicle tax credits of $7,500; and, project-level DOE loan guarantees.

Importantly, while this year’s revenue-neutral carbon tax proposals have garnered some corporate support, in part due to the prospect of a regulatory swap, the benefits of this rollback would vary across sectors of the US economy. The incidence of regulatory relief would therefore be another factor for consideration. The largest supporters of a swap are likely to include the power sector, oil and gas, and the automotive industry. All are heavily regulated, and mandates restrict their compliance flexibility in comparison to a carbon tax. For the auto industry in particular, a regulatory swap that lessened fuel economy standards would potentially allow manufacturers to reduce production costs and prices, as the “compliance” burden would instead pass to the consumer who faced high fuel prices over time.

One criticism of the carbon regulatory swap concept is that some of the most impactful US energy and climate regulations are at the state rather than federal level. The power sector is largely the domain of state public utility commissions or legislatures, given historical monopolies granted regional utilities, with the Federal Energy Regulatory Commission’s jurisdiction limited largely to interstate transmission and wholesale markets. Twenty-nine states have adopted renewables portfolio standards, all but one of which have increased over time, and for which there is little federal regulatory equivalent (outside of federal agency procurement targets). Thirty states have adopted energy efficiency targets. States adopt building energy codes of their choosing in commercial and residential properties. California and nine East Coast states have adopted “zero-emission vehicle” regulations forcing manufacturers to meet increasing sales quotas for plug-in hybrid, electric, or fuel cell vehicles (resulting in cross-subsidy from conventional vehicle sales as manufacturers sell these vehicles below cost), while 14 states offer tax credits or other subsidies to consumers of electric vehicles. Meanwhile, California has repeatedly been granted a waiver under the Clean Air Act (notably denied in 2008) to set its own vehicle fuel economy standards that exceed federal standards, and which are currently adopted by 15 other states as well. States
furthermore enact their own energy and environmental regulations on upstream mineral resource extraction as well as manufacturing, some of which have now explicitly incorporated climate rationales. California and the nine Regional Greenhouse Gas Initiative states administer their own carbon cap-and-trade programs.

Given this patchwork, preemption would be a consideration for any federal climate regulatory swap. Congress, were it to arrive at a deal to do so, does have the ability to override various state activities with explicit language to that end. Even without such prohibitions, some may argue that even where a federal carbon tax did not directly conflict with state activities—as it might with overlapping carbon pricing schemes, for example—so-called “field preemption,” where federal actions are judged so pervasive as to “occupy the field” in which the state regulations conflict, might otherwise apply.

Durable political support would nonetheless demand credibility of any such swap. In fact, one recent criticism of the concept from the political right has been that with Republicans in control of White House as well as both houses of Congress, such a trade is no longer necessary given that climate regulations might now be unilaterally repealed without adopting a compensating carbon tax-and-dividend (see, for example, WSJ February 2017). Indeed, the Trump administration has already issued a series of energy regulatory reform-oriented executive orders including a directive to scale back the use of the social cost of carbon in rulemaking as well as increasing White House cost-benefit screening of new energy and environmental regulations through the OIRA executive review process.

At the same time, this approach also shows the limits of non-legislative attempts at regulatory reform writ large. Administrator Pruitt in the EPA, for example, has so far declined to revisit the “endangerment” finding subsequent to Massachusetts vs. EPA, which leaves the door open to future EPA regulatory actions in this sphere. And while President Trump ultimately decided to withdraw from the Paris Climate Agreement, the decision did not include more aggressive steps such as withdrawing the United States from the UNFCCC, as was advocated by some conservative analysts (Loris and Schaefer 2017). In President Trump’s own demonstrations that executive actions not supported by legislation can be easily reversed by a White House successor, he also shows the fundamental limits of his own actions against future challenges. Permanence affects risk. To the extent that energy or environmental regulatory burdens negatively affect profitability, investment, and overall economic growth, then reform will go farther if its longevity can be banked on.

Regulatory complexity can retard investment by increasing transaction costs, but regulatory uncertainty increases investment risk as well. Compromise bipartisan legislation that explicitly pairs the sun-setting or scale-back of existing energy and climate regulations over time to the schedule at which the carbon tax rate increases could be one potential solution to this. Predictable scheduling in this way could also help reduce uncertainty among both regulated entities and clean infrastructure investors wishing to take advantage of the market changes enabled by a carbon tax. It also addresses the political problem witnessed in other carbon pricing systems internationally (for example, British Columbia) of how to constructively revisit the tax rate after its initial introduction and under different political conditions.
CONCLUSION

The United States today finds itself in the fortunate position of having advanced industrial technologies and processes, world-leading management and efficiencies, and increasingly low-carbon energy supplies through resource-unlocking innovations in natural gas fracking and horizontal drilling. It does not, however, today have a broad domestic carbon price. A carbon tax-and-dividend would have many uncertainties and is risky undertaking. A key question though is if it is more or less risky than continuing with business as usual against a rapidly changing technological, regulatory, and cultural baseline. Defining the terms of any future carbon mitigation agenda that are most favorable to US interests, economic competitiveness, and investment friendliness could deliver dividends that extend beyond any one political cycle.
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