



A QUARTERLY JOURNAL FOR DEBATING ENERGY ISSUES AND POLICIES

This issue of the *Forum* focuses on the potential outcomes and impact of US energy policy over the next four years, both for the US domestic economy and for international energy markets. The advent of the Trump Administration has marked a dramatic reversal of previous US energy policy, including on regulation, clean energy, and US commitments under the Paris Agreement. Despite this, the emerging consensus from the issue is that markets, rather than US domestic policy, will continue to play the dominant role in shaping outcomes. More difficult to predict, however, is the potential impact that trade protectionism and an inward-looking foreign policy may have on the functioning of international energy markets.

The issue opens with four articles analysing in detail the Trump Administration's rallying around 'energy dominance' as a key policy objective. *Sarah Ladislav* argues that the use of slogans in US energy policy is not uncommon, particularly to galvanize support for policies, regulations, and investments that might otherwise be difficult to achieve on a purely commercial basis. The pursuit of energy dominance involves three elements:

- producing more energy to lower the input cost to the economy,
- removing regulations on the sector to increase production opportunities, and
- pursuing energy trading opportunities with other countries.

The author argues that the administration has a mixed record on all three. *First*, the production of energy resources is a process over which the federal government has limited control, with market forces proving extremely important factors in determining that outcome. *Second*, efforts to roll back regulations using administrative procedures will be a long, litigious, and uncertain operation, with pushback from the private sector which is arguing that stable regulation, rather than too much or too little, is needed to boost investment. *And third*, the emphasis on energy exports through bilateral transactions may well be undermined by the administration's approach to trade.

Meghan O' Sullivan examines the proposition that US energy abundance could render America's need for energy diplomacy obsolete, paving the way for US disengagement in the world. Although it no longer needs to import energy at a huge scale, it continues to have many of the same energy diplomacy priorities as in the past. What is different is that in a new environment of plentiful energy, the USA will find it easier to achieve these objectives, namely:

- ensuring that global energy markets (particularly oil) are well-supplied;
- encouraging allies to diversify their own sources of energy; and,

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- using its power as the largest global consumer of oil to penalize countries, or to compel them to change policies.

At the same time, the author shows that many of the political benefits being enjoyed by the USA as a result of the new energy abundance are *not* because the new environment has presented new instruments of power, but because markets have changed in ways that alleviate past concerns, or are more conducive to US interests. Therefore, US ability to affect particular foreign policy outcomes will continue to be contingent upon the country's capacity to secure the cooperation of other nations. As a result, rather than looking for ways in which they can use US energy prowess as a cudgel to address a particular problem, policymakers should prioritize the smooth functioning of global energy markets.

Jason Bordoff argues that despite the rhetoric, many of the actions Trump has announced to date will have relatively modest impacts on energy markets and greenhouse gas emissions unless market conditions change, and even then there are limits on what the administration can achieve. For instance, reversing rules regulating oil and gas production may help output on the margin, but US oil supply was set to rise sharply in any event – with higher prices and dramatic technology and productivity improvements. It also remains to be seen how much of the sharp deregulatory push will survive judicial review. Furthermore, much energy policy is actually made at the state and not the federal level. This is not to say that all Trump's policy changes are without impact. For instance on the demand side, Trump has signalled that he wants to ease the next round of fuel economy standards from 2022 to 2025; cancelling these would boost US oil demand by around 200,000 barrels per day in 2025. The author concludes that while Trump's energy policy represents a 'sharp shift', market conditions and other domestic policy changes – on sanctions, trade, and taxes – will be of more

significance to both the global energy sector and to the global economy, as will the broader geopolitical consequences of the Trump Administration's 'America First' foreign policy.

Daniel Raimi asks if the USA is on track to become 'energy dominant', and if 'dominance' is desirable. Despite the optimism induced by US shale, the author argues that the answer to both of these questions is 'no'. The US economy, despite improvements in energy efficiency, is still the second-largest energy consumer in the world. And while net energy exports may move into positive territory in the coming years, these new supplies on the global market will not upend the importance of traditional energy powers like Saudi Arabia and Russia. Scale is not the only reason why 'energy dominance' is unlikely, because the logic of the market, rather than the logic of geopolitics, determines energy trade flows. A disruption in one corner of the world will quickly translate into a price spike for *all* consumers, regardless of the amount they produce at home. The author argues that 'energy dominance' is undesirable, as the USA and other energy importers have themselves eschewed the use of oil as a geopolitical weapon, and dominance will not necessarily come at the expense of the USA's geopolitical foes. The author concludes that policymakers should recognize the value of deeper integration into global energy markets, energy resilience, energy efficiency (to curb exposure to volatile energy prices), and reducing greenhouse gas emissions at low cost.

The next two articles in the issue deal with shale gas. *Michelle Michot Foss* assesses the prospects for US domestic shale gas. As oil prices slipped between mid-2014 and early 2016, a persistent question was whether US domestic oil and gas producers – increasingly wedded to tight rock plays – would be able to adjust and forge ahead. In fact, most had already adjusted, and that adjustment process

has continued, with production of liquids and gas remaining at high levels and increasing. The author's research shows that the most significant upstream impacts have come from improvements in acreage portfolios – buying and selling aimed at increasing a company's holdings of the best, prime 'sweet spot' drilling locations. The better the drilling location, the greater the impact from technology deployment. Despite marked improvements in cost performance (achieved through better operational logistics) a key observation has been the inability of producers to hold capex spending within cash flow. The US industry has entered a phase in which debate swirls around which targets investors may prefer, going forward. Thus far, the emphasis has been on production growth, but this past year, a pronounced shift has taken place toward earnings and returns. The author also highlights concerns over the quality of production data, and discusses the upstream–midstream interface following the advent of 'master limited partnerships'. In effect, the US 'shale' gas component is now largely a by-product of the industry's ability to sustain liquids (including natural gas liquids) investment and production. As long as liquids prices are sufficiently attractive, domestic gas supply and commercialization, including exports, can continue.

Howard Rogers investigates the impact of US LNG exports on the international market. The 'First Wave' of US export projects, comprising 91 bcma of gas (not far short of Qatar's 104 bcma in 2016), will flow to global gas markets by 2020 – even at destination market prices as low as Henry Hub plus \$1.5/MMBtu. This represents an increase of 27 per cent over 2015's global LNG supply volumes (by 2021 LNG supply will be 54 per cent higher than 2015), raising the prospects of a 'glut' from 2019 to 2022. From an LNG sector point of view, this is the 'best of times', in that there is a cornucopia of gas discoveries available for feedgas into LNG projects; it is also the 'worst of times'



in that buyers – particularly in Asia – are disenchanted with oil indexation, uncertain of their future demand, and in the case of new LNG importers, of the price they can afford to pay for LNG. Under 'low' and 'high' Asian LNG demand scenarios for 2018–25, new FIDs will need to be taken by 2020 and 2018 at the latest, respectively. Given that Qatar alone cannot satisfy the potential LNG requirement in the 2020s, the fundamental challenge for the 'Next Wave' of US projects is whether they can supply the LNG at a price that consumers are willing, and can afford, to pay – for developing countries, this price has been estimated at around \$6/MMBtu. New business models are emerging in which international LNG buyers/portfolio players are invited to invest in an integrated supply chain (upstream shale gas play, pipeline transportation, and liquefaction) which would deliver LNG on board a ship in the US Gulf at a cheaper cost than conventional projects.

The next two articles move to consider the prospects for US tight oil. *Trisha Curtis* asks whether US shale productivity gains are sustainable – and the short answer is 'yes'. Every year from 2012 to 2017 has seen an uplift in both initial production as well as outer month production, resulting in substantially increased oil output per well. Drilling, completing, and producing shale or tight oil and gas wells has always been both an art and a science. Over the past three years, in a sub-\$60 oil price environment, this has never been more true. The author describes how one of the largest factors contributing to increased well productivity has been a relatively simple completion design change – but this is not the only factor, as operators have also gained years of experience working through their geology, enabling millions of acres across several shale plays to be de-risked, and generating massive data sets to draw upon. The author concludes that while in, the long run, the shale industry will continue to improve well productivity, in the short run, economic constraints could imperil

productivity gains as operator profitability faces renewed scrutiny. But – geologically and technologically speaking – there is certainly room to grow.

Dominic Haywood discusses how US crude exports have continued to beat market expectations, surging to a record high of 1.8 million barrels per day (mb/d) in October 2017. A few months earlier, the market had fervently questioned the ability of the USA to export more than 1.2 mb/d, suggesting capacity constraints would cap departures at this level and result in large inventory builds on the US Gulf Coast. It is expected that exports will average 1.7 mb/d in 2018, with much of the y/y export growth occurring in the first half of 2018 – primarily due to a low base – but also continuing at a robust level thereafter. Achieving these volumes is, however, dependent on several factors.

- US production growth must be sufficient to allow for both an increase in refinery demand in 2018 and incremental export demand.
- There will need to be a sufficient supply deficit in global balances for shale production growth to fill.
- Sufficient infrastructure must exist to allow shale production growth to move from the wellhead to domestic trading hubs and export terminals.
- International markets need to become comfortable with the quality of US crude oil.

While the Asia-Pacific region will be the key destination market for US crude, new markets – such as Latin America – will be needed to absorb the export growth that is expected to materialize.

The next article, by *Scott Irwin*, focuses on the outlook for biofuels. The author discusses how high real crude oil prices made biofuels more competitive in the marketplace, powering legislation on the Renewable Fuel Standard (RFS) through the US Congress. The 2007 RFS statute required the US Environmental Protection Agency (EPA) to establish volume requirements over 2008–22 for cellulosic

biofuel, biomass-based diesel, total advanced biofuel (which includes biomass-based diesel), and renewable fuel ('conventional ethanol'). The RFS mandates have been extremely controversial, particularly in the petroleum refining sector, and subject to almost continuous legal challenge. The author explains three issues underpinning the debate.

- The aggressive targets for cellulosic biofuels relative to low production capacity.
- Disputes between petroleum refiners and biofuel producers over the E10 blend wall (in other words, the ethanol content of gasoline blends is limited to a maximum of 10 per cent by volume) and the explosion in 2013 in the price of Renewable Identification Numbers (EPA tradeable credits) driven primarily by high-priced biodiesel.
- Disagreements over whether the point of obligation for the RFS should be moved upstream from refiners to blenders of biofuel.

The author argues that biofuels consumption in the USA is primarily driven by what happens to the RFS. A political stalemate over the RFS has developed that favours a 'steady state' outlook for the consumption of biofuels over the next five years. While this limits downside risk to US biofuel producers, it means that they will have to look to international markets for significant growth opportunities.

The last two articles focus on prospects for the US electricity sector. *David Schlissel* analyses the Trump campaign's boasts, and subsequently the Trump Administration's efforts, to 'bring back' US coal while creating more mining jobs. An initial wave of optimism did occur in the industry as coal-fired plants generated about 5 per cent more power in the first half of this year than in the first six months of 2016. However, recent data from the US Department of Energy show that year-to-date coal generation through August 2017 was a mere 0.4 per cent

higher than it had been during the first eight months of 2016. The author argues that this does not offer much cause for optimism that coal is in a substantial long-term recovery. The coal industry attacked the Obama Administration, and the Environmental Protection Agency (EPA), for eight years, for waging a 'war on coal'. However, the reality is that coal has become increasingly uneconomic due to sustained low natural gas and energy market prices, increasing market penetration of renewables, very-low-to-flat growth in demand for electricity, and the ageing of the nation's coal fleet. The author analyses each of these factors in detail, concluding that even without explicit federal policies to reduce greenhouse gas emissions, the same inexorable market and economic forces, together with advances in renewables technologies, that have hurt the coal industry in the past decade will continue to undermine the financial viability of US coal-fired plants in coming years.

David Robinson considers the significance of US withdrawal from the Paris Agreement (PA). The US Nationally Determined Contribution (NDC) under the PA is to reduce net GHG emissions by 26–28 per cent of 2005 levels by 2025; the Obama Administration also submitted an emissions reduction target of 80 per cent or more below 2005 levels in 2050. The USA also pledged to contribute \$3 billion to the Green Climate Fund (GCF) to assist developing countries in climate change adaptation and mitigation. The author describes the strong negative political and public reaction to Trump's reversal of PA policies such as the Climate Action Plan and Clean Power Plan, from coalitions such as the '[We Are Still In](#)' platform which represents cities, states, corporations, faith-based groups, universities, and other groups committed to the goals of the PA. The author also argues that the growing economic, financial, and political pressures favouring decarbonization in the USA and abroad

diminish the significance of US participation in the PA. Within the USA, between 2005 and the end of 2016, the US Energy Information Administration (EIA) estimates that annual energy-related CO₂ emissions (80 per cent of GHG emissions) fell by 13.7 per cent; the Rhodium Group estimates that the electricity sector was responsible for about 70 per cent of this. The author describes the substitution of coal with gas-fired power, and the favourable economics of solar and wind power generation, as key enablers of this reduction. One area where Trump's policies could have a negative impact is on efforts to decarbonize the developing world – efforts which are critical to achieving the PA objectives – through reneging on existing and future GCF commitments, export credit guarantees, and potential influence on the lending policies of international institutions such as the World Bank.

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Dissecting the idea of US energy dominance

Sarah Ladislav

For better or worse, US energy policy discussions often include slogans. Much more than a rhetorical flourish, these slogans are meant to galvanize support for energy policies, regulations, and investments that might otherwise be difficult to achieve or hard to justify on a purely commercial basis. For much of the last 40 years, the de facto slogan was **energy independence**, an idea born out of President Nixon's 1973 Project Independence speech which set a national goal to 'meet America's energy needs from America's own energy resources' by 1980 in the wake of heightened sensitivity around oil import security due to the Arab oil embargo. While energy independence has been dominant, other slogans have been used as well. The World War II-era *Manhattan Project*, a research endeavour that made the USA into an atomic power, has often been used as a rallying cry for any number of policy objectives that require dedicated resources and sustained effort in the area of US energy innovation. More recently presidential candidate [Secretary Clinton](#) proposed to make the USA the world's **clean energy superpower** in an attempt to drive more policy measures and investments to advance low-carbon energy source development and use.

Not surprisingly the Trump Administration has rallied around a slogan President Trump used on the campaign trail – **energy dominance**. After being elected, the president laid out his vision for energy dominance in a June 2017 [speech](#) at the US Department of Energy in which he said that energy dominance means the USA will 'no longer be vulnerable to foreign regimes that use energy as an economic weapon; American families will have access to cheaper energy, allowing

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'THE TRUMP ADMINISTRATION HAS RALLIED AROUND A SLOGAN PRESIDENT TRUMP USED ON THE CAMPAIGN TRAIL – ENERGY DOMINANCE.'

them to keep more of their hard-earned dollars; and workers will have access to more jobs and opportunities'.

The three pillars of the energy dominance vision

The first part of this vision is essentially the same underlying goal of energy independence, to which the typical rejoinder is another slogan – **energy interdependence** – the idea that countries derive more economic benefit through efficiency and security through flexibility and mutual reliance. Energy Secretary Rick Perry and Interior Secretary Ryan Zinke have echoed this theme of leverage over foreign adversaries several times since taking office, most often citing the development of US energy resources as a way to avoid getting involved in foreign wars or to help European allies thwart the influence of overreliance on Russian energy supplies.

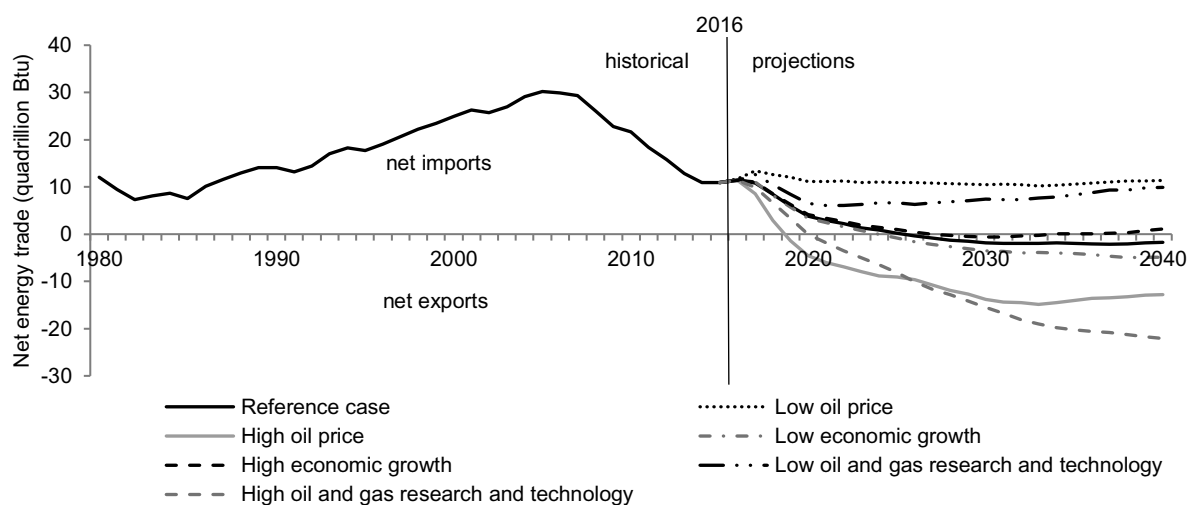
The second and third pillars of the energy dominance vision – cheap energy prices for American households and using energy as a source of job creation – are much more about utilizing domestic energy a source of economic growth. Again, this is a familiar theme for US energy policy as well. Energy naturally plays an important role in the US economy; policymakers at the state and federal level have long sought to decrease the price of energy as an input to economic activity, and also to produce energy resources or create energy

technologies to drive employment and economic growth.

Increased US production and ability to export

So what's new about energy dominance? At its core, energy dominance reflects the administration's optimism about the dramatic changes that have taken place in the US energy systems. Just as energy independence was born at a time when the nation was newly recognizing the vulnerabilities of import dependence, energy dominance has emerged during a period in which the USA is poised to export more energy than it consumes, for the first time in decades. The figure overleaf shows a range of forecasts produced by the Energy Information Administration in 2017. In all but three scenarios, the USA is projected to export more energy than it consumes.

Over the last decade, the US resurgence in oil and natural gas production has been nothing short of remarkable, thanks to the production of tight oil and shale gas resources onshore in the USA. In the World Energy Outlook 2017, the International Energy Agency states that the growth in US oil production over the last decade is the largest ramp-up in oil production in history. In the last 10 years, crude oil production grew by 75 per cent and natural gas production by 45 per cent, making the USA the largest oil and gas producer in the world. As a result, oil exports from the USA are growing (despite the fact that the USA still imports approximately 8 million barrels a day as well). During the [first half of 2017](#), the USA hit a new record by exporting more than 6 million barrels per day of crude oil and products to nearly 27 countries around the world. The EIA also reported that the USA



The USA becomes a net energy exporter in most cases as petroleum liquid imports fall and natural gas exports rise

Source: *Annual Energy Outlook 2017*, US Energy Information Administration.

‘ENERGY DOMINANCE IS ABOUT REAPING ALL THE BENEFITS OF THIS SUPPLY SURGE, BOTH ECONOMIC AND GEOPOLITICAL.’

became a net exporter of gas in 2017, and going forward exports of gas are expected to increase substantially as new liquefied natural gas export facilities come online. Energy dominance is about reaping all the benefits of this supply surge, both economic and geopolitical.

The US pursuit of energy dominance

The relatively simple calculus of pursuing energy dominance is to:

- 1 produce more energy to lower the cost as a basic input to the economy,
- 2 remove regulations on the energy sector to increase production opportunities,
- 3 pursue energy trading opportunities with other countries.

So far, the administration has a mixed track record on all three counts.

The production of energy resources

is a process over which the federal government has limited control. The

US Department of the Interior grants access on federal lands, establishes safety standards, and sets royalty rates on production. The Environmental Protection Agency regulates environmental performance related to air, land, and water. The heads of both organizations have repeatedly asserted that regulation has killed investment in areas of production they would like to see grow – coal production and use in the electric power sector, and drilling and mining for oil, coal, and gas resources on federal lands. Ample evidence suggests that the decline in coal production and consumption in the USA happened because of US shale gas production and other market factors (regulation did play a role but perhaps not the most significant one) and that the decline in US investment in oil and gas development on federal lands occurred while unprecedented amounts of investment and new production were taking place on private lands within the USA. As oil, gas, and coal prices begin to recover, the administration may be able to encourage additional production, but market forces are extremely important factors in determining that outcome.

Making changes to US energy regulation

through administrative procedures is a long, litigious, and uncertain operation, given the pendulum politics of the US political system. Efforts to roll back regulation and attract large-scale new investment are limited by this dynamic and the private sector is pushing back. For example, several utility groups have argued that the administration needs to put in place greenhouse gas emissions regulation on the electric power sector and not simply roll back those regulations. Similarly, influential voices in the oil and gas sector have made similar points about methane regulation, arguing that stable regulation, rather than too much or too little, is needed to boost investment.

The need to trade in energy resources

is emphasized by the administration in order to improve US trade balances, address energy poverty, and thwart foreign adversaries who utilize energy as a tool of influence. The most visible actions taken in this regard are the bilateral memoranda of understanding signed by government officials, or announced as part of a high-level meeting between President



Trump and his foreign counterparts. The administration has referenced energy trade in communiqués coming out of meetings with Japanese, Chinese, and Indian counterparts. Both of the president's major foreign trips have been punctuated by announced energy deals in the Middle East and most recently with China. Many of the official statements merely point to the potential for future trade, particularly in the area of natural gas exports, and many other more concrete deals are simply a repackaging of already concluded business transactions. It is not yet clear that these announcements are anything more than symbolic deliverables for high-level meetings (a customary diplomatic occurrence). However, it is clear that other countries understand these types of bilateral transactions as being valued by the current administration. The ironic part of this emphasis on energy exports is that it may well be undermined by the administration's approach to trade. Far more damage could be done to US energy export relationships and competitiveness if the administration chooses to pull out of, or backtrack on, major trade arrangements like NAFTA or the Korean FTA. Damage could also be caused by pursuing protectionist policies such as tariff hikes on solar PV panels (as a result of the Suniva case recently decided by the International Trade Commission) or additional tariffs on imported steel on the grounds of national security concerns (as is currently being contemplated by the Department of Commerce). The administration must seek a careful balance between export promotion and defence of US industry, and sparking a potentially damaging trade war.

Energy dominance in context

One must take US energy sloganeering with a pinch of salt. Of course, energy dominance, like energy independence, when taken to the extreme, is a bit

THE USA SEEMS UTTERLY TONE DEAF TO MANY OF ITS TRADITIONAL OECD ALLIES – NOT MANY COUNTRIES ENJOY THE IDEA OF BEING DOMINATED.'

absurd. Take for example the idea that US liquefied natural gas exports will revolutionize European gas markets and deal a decisive geopolitical victory against Russia. As one columnist put it '*selling into saturated markets at discounted prices*' does not yield a position of competitiveness or dominance. Moreover, the link between energy power and foreign policy power has always been, at best, tenuous. As my co-authors and I describe in our 2014 Center for Strategic and International Studies report [New Energy New Geopolitics](#), energy can be used as a tool of stability or leverage, but far too often its ability to serve as a decisive point of leverage in the area of geopolitical conflict is vastly overestimated. For example, the shale gas and tight oil revolution has undoubtedly impacted global oil and gas market dynamics over the last several years in profound ways, but these changing market dynamics have not fundamentally rewritten the US relationship with countries in the Middle East; the USA, as an ongoing oil exporter, is still susceptible to market disruptions elsewhere in the world.

How have countries around the world received this notion of energy dominance? The USA seems utterly tone deaf to many of its traditional OECD allies – not many countries enjoy the idea of being dominated – and the concept is antithetical to the system of free and open energy markets that the USA has promoted for decades. For the world's major energy producers, however, it is an admission of what they have suspected all along – that the USA, with its newfound oil and gas wealth, is seeking to gain market share. While this blatant nationalist commercialism

seems like a departure for the USA, it is something that many in the US energy industry are welcoming, at least thus far. As China continues to advance its trade promotion around the world through the Belt and Road Initiative and using the immense power of its 'all of government' approach to provide package deals, US companies have been increasingly concerned over their ability to compete in these markets. A greater role for government in pushing exports and making deals is a welcome change for:

- coal producers looking for a foothold in competitive Asian markets,
- nuclear reactor companies and service providers struggling to compete against China, Russia, and Korea,
- natural gas companies hoping to be competitive against coal and renewables or to find opportunities in smaller markets like the Caribbean and Central America,
- oil industry service providers and petrochemical producers.

Given the contours of America's new energy dominance slogan, here is how to make the most of it.

FREE TRADE IN ENERGY GOODS AND SERVICES IS MUCH MORE IN THE US LONG-TERM INTEREST THAN A PURELY MERCANTILIST APPROACH TO ENERGY DEALS.'

Be strategic, not just tactical.

The USA should continue to support longstanding institutions and arrangements that have served it well over the last several decades. Free trade in energy goods and services is much more in the US long-term interest than a purely mercantilist approach to energy deals. Recognize that the USA has a fair number of energy vulnerabilities – related to oil and gas supply disruptions, physical

infrastructure protection, and cyber threats. The USA can only be strong if we continue to invest in, and protect against, those disruptions. The government should think about resilience to physical disruptions like the hurricanes experienced earlier this year. It should contemplate the value of not only its Strategic Petroleum Reserve but of the global system of strategic stocks. Finally, it should devise a strategy for an energy sector that is becoming more and more dependent on digital controls and sensors in the age of cyber warfare.

- **A truly 'all of the above' approach is warranted** if the USA wants to use energy to drive economic growth,

job creation, and international competitiveness. The US revolution in oil and gas may get a lot of attention, but the growth in jobs and America's real competitive advantage exists in renewables and other advanced technologies as well. The administration would do well to avoid the promotion of only a certain set of fuels and technologies over others. Developing economies in particular are interested in not only fossil-based energy resources but in distributed solar, wind, storage, microgrids, and a suite of other technologies and services that US companies have to offer.

- **Understand the importance of energy diplomacy.** The USA

undoubtedly has an energy advantage at its finger tips that can and should be harnessed as much as possible, but it would be a critical mistake to overestimate how much that advantage can be wielded over other countries, or to believe that bilateral trade deals in energy are more important than the fundamental underpinnings of existing trade policy and decades of energy diplomacy in which the USA negotiated with other countries using energy as a political tool rather than as a weapon.

The USA will get far more out of its amazing energy resources and capabilities through taking these measures.



US energy diplomacy in an age of energy abundance

Meghan L. O'Sullivan

For decades, fears of energy scarcity drove American energy diplomacy. The dependence of the global economy on oil, and America's need to secure ever-growing quantities of this commodity, underpinned complex networks of alliances and intensive diplomatic endeavours. An atmosphere of ever-increasing global competition for resources made these labours all the more urgent and high-stakes. Today, in an age of energy abundance, many anticipate that the new US energy prowess will render such efforts obsolete and pave the way for US disengagement in the world. Yet a sober look at reality suggests that this should be far from the case. Although the USA no longer needs

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'IN AN AGE OF ENERGY ABUNDANCE, MANY ANTICIPATE THAT THE NEW US ENERGY PROWESS WILL ... PAVE THE WAY FOR US DISENGAGEMENT IN THE WORLD.'

to import foreign energy at a huge scale, it continues to have many of the same energy diplomacy priorities that it has had in the past. What is different is that in a new environment of plentiful energy, the USA will have an easier time reaching these objectives. Nevertheless, the USA is not necessarily moving into a period of easy energy diplomacy. It might squander this advantageous moment by politicizing its own energy prowess instead of taking comfort in the fact that transformed energy markets are themselves delivering great benefits to America and her allies.

Objectives are constant, and easier to realize

A look at three objectives the USA has traditionally pursued through its energy diplomacy reveals how the new energy abundance does not annul their relevance, but simply enhances US efforts to realize them.

1 Ensuring that global energy markets – the global oil market in particular – are well supplied

The pursuit of this objective has shaped complex relationships between the USA and many countries, with Saudi Arabia being the most prominent example. While the relationship between Washington and Riyadh has had many dimensions, America has often looked to the kingdom to take action to stabilize global energy markets. Whether this involved increasing Saudi production in advance of military action in Iraq or Libya, or continuing to invest in productive capacity in the face of burgeoning demand from emerging economies in the 2000s, Washington often sought Riyadh's help in calming global oil markets and minimizing the impact of increased energy competition on the global economy. Oil, for better or worse, was always a topic of earnest exchange between



senior policymakers from both countries.

Today, the USA remains connected to global markets, even as it has reached the status of the world's largest producer of oil and gas combined. It continues to have a keen interest in seeing that global energy markets are well supplied and that disruptions to the markets are minimized. Yet, while the objective remains the same, America has other avenues to advance this goal, including ensuring continued production of its own resources. Although the Saudis and other traditional producers remain important players in the global oil market, their spare capacity is less critical in managing global oil markets than it was in the past. While not nearly a perfect substitute, the productive capacity of America's own tight oil can help meet new demands for oil. In addition, given the widespread availability of unconventional resources worldwide, the USA has the option – which it has not yet fully taken advantage of – of working with other countries to bring such resources on line in the future. The USA will remain interested and invested in Saudi stability, as nothing could send a shock wave through the global oil market more than a collapse of the regime or the outbreak of violence in the kingdom. But America will have less of a need to engage the Saudis directly to urge them to increase (or in rare instances to decrease) their production levels; oil will no longer dominate the bilateral agenda between Washington and Riyadh.

2 Encouraging allies to diversify their own sources of energy

Nowhere have US diplomats invested more energy to this end than in Europe. Only months after President Ronald Reagan moved into the Oval Office, he openly opposed Europe's

plans to build extensive pipelines connecting the Soviet Union with Europe, fearing that such links would give the Soviets undue political influence. In the decades that followed, following the break-up of the Soviet Union, American officials sought to convince their European counterparts that the reliance of the continent on energy imports from Russia created dangerous political and security vulnerabilities. Such efforts went beyond diplomatic entreaties and included great exertions to midwife new pipelines to bring natural gas supplies from the Caspian region to Europe. Some – such as the ill-fated Nabucco pipeline – failed, while others – such as the more modest TANAP and TAP pipelines – successfully provided Europe with some element of diversification of supplies. Today, the USA still has keen interests in seeing that the energy supplies of its allies in Europe and elsewhere are diversified. Yet, it (and the allies in question) now have many more options for achieving that diversification. One of these options is the purchase of liquefied natural gas (LNG) directly from the USA. But it is not simply the advent of America as an exporter of LNG that has transformed prospects for many US allies. Even more consequential have been changes in natural gas markets which are beneficial to consumers more generally. Thanks to increases in production of unconventional gas, and reduced costs associated with the liquefaction and transport of natural gas, global markets are more flush with gas than they were five years ago and more integrated with one another. The number of countries exporting LNG more than doubled between 2000 and 2016, while the number importing LNG tripled. The dominance of oil-indexed pricing has begun to give way to gas-on-gas pricing in many parts of the world,

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'THE NET EFFECT IS THAT LEVERAGE HAS SHIFTED FROM THE PRODUCER TO THE CONSUMER, CHANGING THE BALANCE OF POWER IN KEY RELATIONSHIPS.'

also increasing efficiency. The net effect is that leverage has shifted from the producer to the consumer, changing the balance of power in key relationships. In the case of Europe, the energy security of the continent is much improved, not primarily because of new mega-pipelines or even the chance of importing American LNG, but because of changes in the structure of natural gas markets.

3 Using its power as the largest global consumer of oil to penalize countries, or to compel them to change policies

Generally, this somewhat different objective of US energy diplomacy has involved the use of sanctions, often on oil and gas producing nations. Over the past decades, oil producers have been disproportionately represented on the list of countries sanctioned by the USA. The desire and the need to use sanctions to advance foreign policy objectives has not diminished. If anything, in a world where military force is difficult to deploy and where America's ability to secure outcomes through persuasion alone is increasingly questioned, sanctions continue to play a critical role in the tool kit of US foreign policy. Yet, while the desire to use sanctions remains, some might surmise that because the USA imports less oil and virtually no natural gas today, its ability to wield influence through sanctions is diminished in the new world of energy abundance. It is true that America's increased self-sufficiency means that its power to influence outcomes through unilateral sanctions alone is more limited to

exceptional instances and sanctions that go beyond the export and import of oil and gas. However, in a globalized world where most countries have complex linkages to the world economy, unilateral sanctions are of limited value in any case. What matters much more to the US ability to affect particular foreign policy outcomes is the country's capacity to secure the cooperation of other nations to impose *multilateral* sanctions; such sanctions have much better track records of delivering their desired results. Here the new energy abundance actually provides the USA with a distinctive advantage, at least when it comes to imposing sanctions on oil producing countries. As demonstrated by the recent case of sanctions against Iran, securing the support of other countries for sanctions against one of the world's largest oil producers is easier in a climate of well-supplied energy markets. Like the Bush Administration before it, the Obama Administration initially found both domestic and international resistance to ramping up sanctions intended to constrain Iranian exports of oil at a time when oil prices were consistently over \$100 a barrel. Many actors feared such sanctions would spur oil prices to new levels, jeopardizing already-fragile economic growth. It was only through intensive diplomatic efforts that the USA was able to convince countries from India to China and beyond to curb their purchase of Iranian oil. In making the case to foreign counterparts, US officials were able to point to burgeoning US oil production; annual increases of more than one million barrels of oil each year helped persuade initially sceptical officials that greater pressure on Iran need not be synonymous with escalating oil prices and increased strain on the global economy.

Dangers of overreach

For decades, US policymakers considered America's energy predicament a major strategic vulnerability. Now, they are beginning to appreciate that the improved energy environment brings new opportunities and strengths to the USA – among them, a greater ability to deliver age-old energy diplomacy objectives. Yet dangers exist as perceptions and actions related to American energy prowess come into line.

Policymakers may feel that such a dramatic change in energy fortunes should bring with it new, blunt tools better suited to directly shape foreign policy and national security outcomes. For example, senior members of the Trump Administration have reportedly urged European and Asian countries to buy US oil and natural gas as a way to rebalance the trade deficit – or be prepared to face penalties. President Trump himself publicly said that US exports of LNG would push Russian exports out of Europe and make that continent less vulnerable to political blackmail.

In reality, such exhortations will not help the USA meet its enduring energy diplomacy objectives, but will likely hamper its ability to do so. Many of the political benefits being enjoyed by the USA as a result of the new energy abundance are *not* because the new environment has presented new instruments of power, but because markets have changed in ways that alleviate past concerns or are more conducive to US and allied interests.

As a result, rather than looking for ways in which they can use American energy prowess as a cudgel to address a particular problem, policymakers should prioritize the smooth functioning of global energy markets. Any effort, or even intimation, that US energy exports will be used for

political purposes will ultimately work against US interests – and the country's ability to achieve its traditional energy diplomacy objectives. Now that the USA is an exporter of oil and natural gas – and poised to be a major global player in the latter at least – it must be seen as a reliable supplier if it wants global markets to continue to evolve in ways which – as described above – are generally conducive to American interests.

The other danger present in today's American energy diplomacy is that the current administration perceives its energy interests too narrowly and fails to appreciate how its actions and rhetoric in other domains have major bearings on its ability to achieve energy diplomacy goals. The clearest example of this risk is the current question mark around America's willingness to maintain its historical role in ensuring freedom of navigation and safe passage of the seas. President Trump has publicly questioned whether the provision of such public goods is too costly for the USA to sustain; these musings alone could be damaging to the smooth functioning of energy markets.

Conclusion

Fears that America's new energy prowess will contribute to the retrenchment of the USA from abroad are overblown. Although the global energy environment has changed significantly in a few short years, these changes do not suggest that fundamental US energy diplomacy priorities have undergone a similar revolution. If anything, the new

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'POLICYMAKERS MUST RESIST THE UNDERSTANDABLE IMPULSE TO WIELD ENERGY AS A WEAPON ... [AND] FOCUS ON THE SMOOTH FUNCTIONING OF GLOBAL ENERGY MARKETS ...'



energy abundance has simply made these priorities easier for the USA to attain. Nevertheless, the road ahead for American energy diplomacy is not necessarily a seamless

one. Policymakers must resist the understandable impulse to wield energy as a weapon (as many other countries have done) and instead maintain America's traditional focus on

the smooth functioning of global energy markets, which will require a better integration of energy policy with many other elements of national security and foreign policymaking than ever before.



Trump's energy policy: a sharp shift but markets trump

Jason Bordoff

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**'... TRUMP'S ENERGY POLICY HAS
 PRIORITIZED INCREASED DOMESTIC
 ENERGY PRODUCTION AND EXPORTS
 TO ACHIEVE AMERICAN "ENERGY
 DOMINANCE".'**

President Barack Obama's energy policy prioritized climate change as the central piece of its legacy. By contrast, President Donald Trump's energy policy has prioritized increased domestic energy production and exports to achieve American 'energy dominance', by easing regulations, opening new areas to production, and expediting infrastructure, among other actions. Despite the rhetoric, however, many of the actions Trump has announced to date will have relatively modest impacts on energy markets and greenhouse gas emissions unless market conditions change, and even then there are limits on what the administration can achieve. Other domestic policy changes – on sanctions, trade, and taxes – will be of more significance to both the global energy sector and to the global economy, as will the broader geopolitical consequences of the Trump Administration's 'America First' foreign policy.

Unleashing 'energy dominance'

The concept of 'energy dominance' remains murky, but based on policies and rhetoric, its focus is ramping up the production and exports of oil, gas, and

coal, and, perhaps to a lesser extent, supporting American nuclear power. In a joint op-ed, Interior Secretary Ryan Zinke, Energy Secretary Rick Perry, and Environmental Protection Agency Administrator Scott Pruitt explained: *'An energy-dominant America means a self-reliant and secure nation, free from the geopolitical turmoil of other nations that seek to use energy as an economic weapon.'* They went on to argue that *'an energy-dominant America will export to markets around the world, increasing our global leadership and influence'* (*Washington Times*, 26 June 2017).

While 'energy dominance' may leave something to be desired as a slogan (importing countries tend to be wary of suppliers that want to 'dominate' them, after all), the Trump Administration is right to highlight the benefits of increased US energy production. The turnaround in the US energy outlook has been stunning. Over the last decade, natural gas production has increased by roughly 50 per cent and crude oil production has nearly doubled. In 2005, it had been projected that the USA would be importing 27 per cent of its gas use in 2015; instead, the USA just became a net exporter. Net oil import dependence has fallen from around 60 per cent to around 20 per cent in the last decade.

The shale boom has been one of the strongest tailwinds supporting the US economic recovery following the Great Recession, boosting economic activity,

lowering energy prices, and delivering large net benefits even after social costs are considered.

Increased US exports also have significant geopolitical benefits. Exports of liquefied natural gas (LNG) are transforming the USA into a global gas superpower. Moreover, US LNG exports, linked to a hub price and without destination restrictions, are leading to more competition, liquidity, and supply diversity. This in turn is gradually making the global gas market more flexible, efficient, and secure. Europe, for example, will be more able to implement its Energy Union package, allowing it to reduce its vulnerability to Russian gas dependence through market integration, interconnectivity, and diversification. Since the US ban on crude oil exports was ended in late 2015, oil exports, too, have risen sharply – spiking to more than two million barrels per day towards the end of 2017 – allowing markets to work more efficiently and boosting US supply, since producers can sell their oil at less of a discount to global market prices.

Markets trump policy

A key focus of the Trump Administration's energy policy to date has been rolling back regulations seen as hampering domestic energy production. Yet markets will matter far more than scrapping Obama-era

regulations in determining the outlook for US energy supply, exports, and greenhouse gas emissions.

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'COAL'S DECLINE HAS BEEN DRIVEN BY CHEAP SHALE GAS, WEAK ELECTRICITY DEMAND, FALLING RENEWABLES COSTS, AND CHANGING DEMAND PATTERNS IN CHINA.'

Take one high-profile example – reviving the struggling **coal industry**. President Trump has repeatedly promised to bring lost coal jobs back. Yet undoing rules such as the Clean Power Plan (President Obama's signature climate policy to limit greenhouse gas emissions from power plants), or lifting the temporary moratorium on coal leasing on federal lands, won't lift production or bring jobs back to coal country. Coal's decline has been driven by cheap shale gas, weak electricity demand, falling renewables costs, and changing demand patterns in China. US coal's recent rebound resulted from higher natural gas prices and a stronger Asian export market, not from the announced regulatory changes that are yet to take effect. A recent paper I co-authored ('Can Coal Make a Comeback?', Trevor Houser, Jason Bordoff, and Peter Marsters, Center on Global Energy Policy, April 2017) found that even if all the actions in Trump's March 2017 'energy independence' executive order were implemented, coal still won't be able to mount a comeback with current market dynamics. If gas remains cheap, renewables costs keep plummeting, and coal continues to fall, the greenhouse gas targets in the Clean Power Plan will be met even if the rule is scuttled.

Similarly, reversing rules regulating **oil and gas production**, like those aimed at reducing methane emissions, may help output on the margin, but US oil supply was set to rise sharply

in any event – with higher prices and dramatic technology and productivity improvements by American shale producers. Indeed, the outlook for US oil production growth in 2018 has been revised downward, notwithstanding Trump's regulatory rollbacks, to reflect changing market dynamics. Similarly, the administration can open up the Arctic to drilling, but there is unlikely to be much interest to drill in the challenging environment of Alaska's icy waters at recent low oil prices.

By the same token, the administration can accelerate the permitting process for **US LNG** exports, but permits have already been forthcoming for commercially viable projects (even if the process could move more quickly). Rather, the greatest challenge to future projects is weaker incentives to export – due to low global gas prices in customer markets and a slew of additional volumes slated to come into the market by the end of the decade.

To be clear, this is not to say that all Trump's policy changes are without impact. Debottlenecking existing pipeline infrastructure, for example, can help address current constraints and assist production in certain areas. On LNG exports, the administration has been working with multilateral finance institutions to facilitate access to capital for LNG import facilities in gas-hungry countries.

Demand-side policy changes will also matter. Trump has signalled that he wants to ease the next round of fuel economy standards from 2022 to 2025, scheduled for a 'mid-term review' in 2018. Cancelling these would boost US oil demand by around 200,000 barrels per day in 2025, although it is unclear whether the administration wants to go so far as to cancel the increase altogether, or merely to make modifications.

Moreover, expanding access to mining and drilling provides firms with an option if market conditions

change – and the recent price rally is a reminder that this may happen sooner than the 'lower for longer' crowd expects. The flip side, of course, is that environmental regulations provide a hedge against changing market conditions. Without binding policies, the strongest backstop to coal's revival, for example, is continued low natural gas prices. And even if the market doesn't change, Trump's actions also undermine a regulatory framework – notably the Clean Power Plan – that could otherwise have been strengthened over time.

Three branches and federalism

Beyond market forces, there are many other constraints on President Trump's ability to significantly alter the US energy outlook.

It remains to be seen how much of the sharp deregulatory push will survive judicial review. Recent efforts by the Department of the Interior and the Environmental Protection Agency to delay or repeal Obama-era rules related to methane emissions from oil and gas operations have already been reversed by the courts. More legal challenges will come in 2018.

Although Republicans control both the Senate and the House of Representatives, Congress has blocked several Trump energy initiatives. For example, the Trump EPA recently proposed steps to dilute the law requiring that a certain amount of biofuels be blended into the fuel supply, a change strongly supported by the oil industry. Yet powerful opposition from farm-state senators, as well as robust industry lobbying, caused Trump to halt the effort. The Trump budget includes provisions to sharply cut energy R&D spending and some clean energy incentives, yet there remains support for these in Congress. In May, Congress also failed to approve a measure, backed by the Trump



Administration, to repeal a Department of the Interior rule regulating methane emissions from oil and gas production.

Even within the executive branch of the US government, 'independent' agencies partly or wholly insulated from presidential control can impede President Trump's agenda. For example, Energy Secretary Perry recently ordered the Federal Energy Regulatory Commission to consider guaranteeing recovery of costs to prop up uneconomic coal and nuclear plants in the name of grid reliability (although there's scant evidence that the growth of natural gas and renewables at the expense of coal and nuclear has actually led to reliability problems). This move would represent the largest regulatory intervention in electricity market design in decades and could change the coal and nuclear outlook significantly. Yet, the ultimate authority to implement Secretary Perry's order rests with FERC, an agency that acts independently from the White House (although three of the five FERC commissioners will soon be Trump appointees).

Finally, under the US federalist system, much energy policy is actually made at the state level, not the federal level. In the power sector, for example, state public utility commissions regulate retail electric services and rates. Trump may want to unleash shale production, but states are the primary regulators of oil and gas production. In my state of New York, for example, hydraulic fracturing is not currently allowed, and pipelines are very difficult to permit and build. California is entitled to set its own fuel economy standards, which other states can adopt (a dozen have done so). Negotiations with California may limit how much the administration can roll back the next scheduled round of fuel economy hikes. Many states also have standards for renewable energy generation and even their own cap-and-trade systems.

Energy and climate diplomacy

The Trump Administration's highest profile international action on energy and climate change by far was its decision to withdraw from the Paris climate agreement. The Paris Agreement has no binding requirements regarding actual emissions levels. The USA is free to revise its Nationally Determined Contribution (NDC) either up or down. Even if the USA had stayed in Paris, this administration would almost certainly have still reversed many domestic climate change policies. Moreover, the earliest date at which US withdrawal could take effect is four years after the Paris Agreement came into force – which happens to be one day after the US presidential election in November 2020 – and a future president can quickly re-join.

The importance of Trump's decision to withdraw, therefore, is less about US climate policy and more about the damage to America's global leadership, credibility, and diplomatic relationships. Withdrawal from Paris was not only about this administration's scepticism that climate change is an urgent problem. Viewed alongside America's abandonment of the Trans-Pacific Partnership, threats to cancel the North American Free Trade Agreement, refusal to certify the Iran nuclear agreement, or even its initial refusal to endorse NATO Article 5's pledge of mutual defence, the decision to withdraw from Paris reflects a nationalist view of foreign policy whereby American prosperity derives less from cooperation and a rules-based order than from zero-sum competition. As National Security Advisor H.R. McMaster and National

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**'... THE DECISION TO WITHDRAW FROM
 PARIS REFLECTS A NATIONALIST VIEW OF
 FOREIGN POLICY ...'**

Economic Council Director Gary Cohn explained in a joint op-ed: *'[T]he world is not a "global community" but an arena where nations, nongovernmental actors and businesses engage and compete for advantage.'* ('America First Doesn't Mean America Alone', *The Wall Street Journal*, 30 May 2017.) President Trump struck a similar 'America First' chord in his speech to the UN General Assembly in September.

In addition, withdrawing from Paris undermined a framework designed to ratchet up climate ambition over time – as technology advances, the urgency of climate action increases, and experience demonstrates that all major emitters are taking meaningful action and which policies will be most effective. After all, the Paris commitments alone were far from adequate to meet the agreed goal of keeping temperature rise below 2 °C. With the USA out of the agreement, other nations are more likely to worry about bearing even greater costs to reduce emissions while the world's second-largest emitter refuses to do so. US leadership was essential to success in Paris, and it will be harder to sustain momentum for further progress as the USA retreats.

Finally, by withdrawing from Paris, the Trump Administration has handed over a key tool of diplomatic and economic leadership to other nations, notably China. China clearly perceives an opening in international climate negotiations that will enable it to accelerate its strategic alignment with Europe and its pursuit of soft power, just as its massive 'belt and road' initiative aims to enhance its global power and create commercial opportunities for Chinese firms in large energy, infrastructure, and other projects.

In other energy diplomacy realms, the Trump Administration has kept to the course followed by past administrations by reaffirming America's commitment

to global energy governance, continuing strong engagement and support at the International Energy Agency. US energy diplomacy has been hampered somewhat, however, by the slow pace of staffing in the US government and by attrition.

Beyond energy policy

While the impact of energy policy changes on global energy markets may be limited with current market conditions, policy shifts beyond energy will be far more consequential – namely those related to sanctions, trade, tax, and foreign policy.

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'... THE USA IS INCREASINGLY TURNING TO SANCTIONS AS A TOOL OF ECONOMIC STATECRAFT TO ACHIEVE FOREIGN POLICY AIMS.'

As explained in a new book (*The Art of Sanctions*) from the Center on Global Energy Policy by Richard Nephew, to be released in January 2018, the USA is increasingly turning to sanctions as a tool of economic statecraft to achieve foreign policy aims. Having deepened the government's capacity to implement and enforce sanctions following the recent additional sanctions against Iran, policymakers are more prone to turn to sanctions as a policy when confronted by thorny problems, with few other desirable alternative responses.

Such a proclivity for sanctions risks overusing them and may even make them less effective, or run a high risk of unintended consequences. It also poses new risks to the energy sector. Congress recently took action to punish Russia for its interference in the 2016 US elections by passing new sanctions that, among other targets, give the President the discretion to sanction companies that invest in new Russian pipeline

routes to Europe. The implications for international firms backing Nord Stream 2 could be profound (although the Trump Administration is not keen to exercise that authority). The Trump Administration also imposed sanctions in response to Venezuelan President Nicolás Maduro's recent power grab; it also considered, but ultimately rejected, sanctioning Venezuela's oil sales, which would have had significant impacts on the oil market, as well as on US refiners.

The risk of sanctions hitting energy markets is at its greatest following Trump's recent decertification of the Iran nuclear deal. Despite the headlines, the move does not 'tear up' the Iran deal. Rather, it triggered a provision allowing Congress to take expedited action reimposing sanctions on investment in Iran's energy sector or on purchases of Iranian oil. But in January President Trump must decide whether to extend the waivers of the sanctions, whatever action is taken by Congress. Failure to make a decision would also reimpose oil sanctions. However, even if Congress takes no action and Trump does extend the waiver, political pressure to take some tougher action against Iran – perhaps through non-nuclear sanctions (such as targeting Hezbollah) – is likely to build in 2018 if Trump continues to extend waivers but does not certify Iranian compliance. In such a case, Iran's own domestic politics may leave it with no choice but to say that the USA has violated the nuclear deal and act accordingly, which could lead to a complete unravelling of the Joint Comprehensive Plan of Action (JCPOA). And even if sanctions aren't re-imposed, uncertainty around their future will have a chilling effect on new investment in Iran's oil and gas sector.

Changing US trade policy could also have significant effects on global oil and gas markets. Under US law,

exports and imports of natural gas with free trade agreement (FTA) countries undergo a very simple regulatory process. But those with non-FTA countries are subject to a far longer, costlier, and more burdensome regulatory approval process. Trump's threats to cancel the North American Free Trade Agreement (NAFTA) raise the risk of new regulatory burdens on sharply rising US pipeline gas exports to Mexico. And Trump's decision to withdraw from the Trans-Pacific Partnership means that a simpler export approval process will not apply to gas-hungry Asian markets. It is far from clear, however, that NAFTA will be scuttled entirely. As noted above, Trump's rhetoric is often more extreme than the actual policy changes implemented. Indeed, the possibility of renegotiating NAFTA (which barely covered energy) presents an opportunity to liberalize energy trade and investment, boost American exports of natural gas and refined products to Mexico, and steady Mexico's energy sector reforms against shifting domestic political winds.

The potential for tax reform, a top priority of the Trump Administration and Congressional Republicans, might also have significant effects for the energy sector, either through a lower corporate income tax rate or the implementation of reforms to pay for it (these reforms could target existing incentives for oil, gas, and coal, as well as renewable energy). Cuts to these tax subsidies, however, seem unlikely at present given political support for them, and the many challenges to broad tax reform in general.

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'... THE ENERGY SECTOR WILL BE MORE AFFECTED BY MARKET CONDITIONS AND BY OTHER DOMESTIC AND FOREIGN POLICY CHANGES THAN BY THE NEW DIRECTION OF US ENERGY POLICY.'

In foreign policy, Trump's tough talk and 'America First' approach (rhetoric concerning North Korea and Iran, threats of a trade war with China, and mixed messages in key regions like the Persian Gulf – for example on the

Qatar embargo) is straining some US diplomatic relationships and raising uncertainties and risks that could adversely impact some firms in the global energy sector – even as they may create opportunities for others.

In short, Trump's energy policy represents a sharp shift, yet the energy sector will be more affected by market conditions and by other domestic and foreign policy changes than by the new direction of US energy policy.



'Energy dominance': the right goal for US policy?

Daniel Raimi

Over roughly the past decade, natural gas and oil production have increased in the USA at an unprecedented speed and scale. The application of innovations (including horizontal drilling and hydraulic fracturing) to 'unconventional' rock formations such as shale has been the primary cause of this surge. Alongside the robust debate over the economic benefits, environmental risks, and other implications of the shale revolution (explored in my forthcoming book, *The Fracking Debate*), federal policymakers in the USA have introduced a new term into the energy lexicon: 'energy dominance'.

In a June, 2017 op-ed in the *Washington Times*, the leaders of the US Department of Energy, Department of the Interior, and Environmental Protection Agency argued that: 'An energy-dominant America means a self-reliant and secure nation, free from the geopolitical turmoil of other nations that seek to use energy as an economic weapon' (*Washington Times*, 26 June 2017).

These federal officials have good reason to be optimistic about the future of energy in the USA. Growing oil and gas production has:

- boosted the economies of dozens of US regions,
- reduced energy prices for consumers,
- reduced emissions of carbon dioxide and other pollutants by displacing coal-fired electric power (for natural gas).

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'... THE USA HAS SURPASSED SAUDI ARABIA AND RUSSIA AS THE WORLD'S LARGEST PRODUCER OF OIL AND NATURAL GAS, RESPECTIVELY.'

In recent years, the USA has surpassed Saudi Arabia and Russia as the world's largest producer of oil and natural gas, respectively. A net energy importer for decades, the USA could become a net exporter by around 2020, under one optimistic scenario (see the figure below).

So is the USA on track to become 'energy dominant'? And if so, is 'dominance' desirable? Despite the optimism induced by the emergence of US shale, the answer to both of these questions is no.

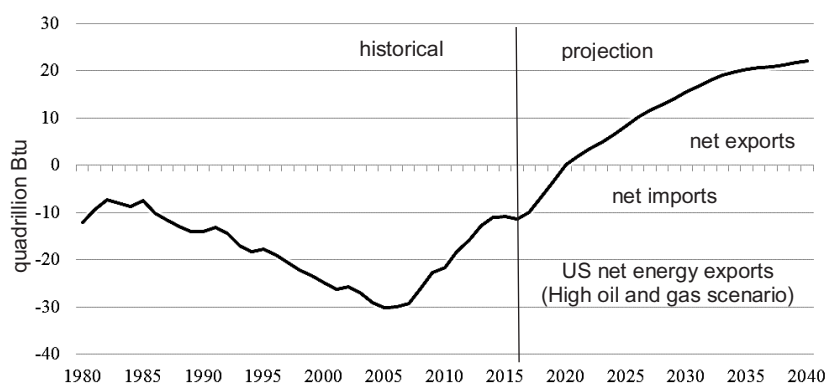
Is the USA likely to become 'energy dominant'?

First, the USA, despite the renewed vigour of its oil and gas sector, is not

about to drown the global market in hydrocarbons. This is due largely to the fact that the US economy, despite improvements in energy efficiency, is still the second-largest energy consumer in the world, trailing only China.

And while net energy exports may move into positive territory in the coming years, these new supplies on the global market will not upend the importance of traditional energy powers like Saudi Arabia and Russia. In 2016, for example, Russia and Saudi Arabia each exported, in net terms, more than 8 million barrels per day (mb/d) of crude oil and refined products such as gasoline and diesel. Compare this with the USA, which in 2016 was a net importer to the tune of 5.3 mb/d (*BP Statistical Review of World Energy*, 2017).

Nor will the shale revolution sate the demand of rapidly growing economies such as China or India. Consider this: in 1980, the USA produced about



US net energy exports

Source: *Annual Energy Outlook 2017*, US Energy Information Administration.

24 per cent of all the energy consumed in the world. In 2016, despite the rise of shale, rapid growth in global energy demand pushed this figure down to about 15 per cent. Look forward another 25 years, and even under an optimistic scenario for US oil and gas production, the number falls further to 13 per cent by 2040 (see the figure below).

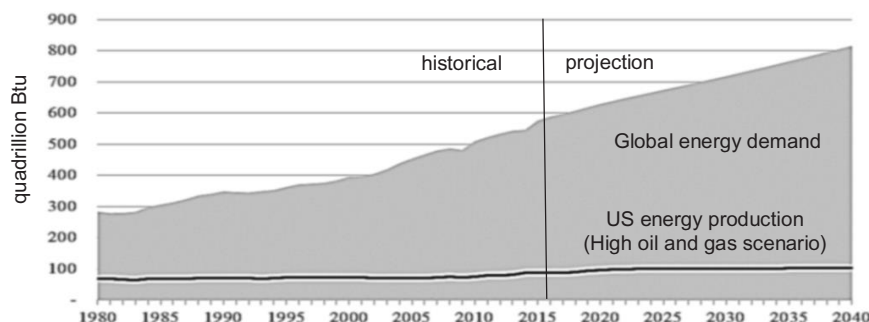
And scale isn't the only reason why 'energy dominance' is unlikely. That's because the logic of the market, rather than the logic of geopolitics, determines energy trade flows. While increased production of oil and natural gas has indeed strengthened the USA's hand in negotiations with nations including Russia and Iran, it does not allow US policymakers to dictate trade flows.

For example, a substantial share of recently increased crude oil exports from the USA has effectively gone to Venezuela, hardly a close ally. (To be precise, these exports go to the island of Curaçao, where a Venezuelan-owned refinery blends US light oil with heavier Venezuelan crudes.)

More importantly, the op-ed mentioned above nods toward another catchphrase – 'energy independence' – when it states that the USA can be a *'self-reliant and secure nation, free from the geopolitical turmoil of other nations'*.

But increased oil production does nothing of the sort. Because global oil prices move more or less in tandem with one another, a disruption in one corner of the world will quickly translate into a price spike for *all* consumers, regardless of the amount they produce at home. Geopolitical upheaval in any major producing nation – say, a coup in Venezuela or a war between Saudi Arabia and Iran – would immediately translate into a price spike for US, and global, consumers. And while a price spike would benefit US producers, it would not stifle the howls of anger that would emanate from petrol stations across the USA.

If it were truly self-reliant in terms of oil production, could the USA somehow isolate itself from the global market? In theory, yes, but such an approach would create far more problems than it would solve. As recent experience with Hurricane Harvey has shown, extreme weather events can cause enormous disruption to energy infrastructure, highlighting the critical importance of access to global markets in the wake of domestic disruptions. What's more, isolating the USA from global markets would deprive domestic oil and gas producers of what they have lobbied to achieve in recent years: access to international buyers through increased exports. In short, deeper integration into – rather than isolation from – global energy markets benefits consumers and producers.



US primary energy production and global primary energy demand

Source: Annual Energy Outlook 2017, US Energy Information Administration, and International Energy Outlook 2016.

DEEPER INTEGRATION INTO – RATHER THAN ISOLATION FROM – GLOBAL ENERGY MARKETS BENEFITS CONSUMERS AND PRODUCERS.'

Before turning to the question of whether 'energy dominance' would be desirable, consider for a moment the word itself. 'Dominance' evokes images of athletes such as Roger Federer, Serena Williams, or Usain Bolt, able to bend opponents to their will or fly past them to the finish line.

In today's energy world, there is no Roger Federer. Even the Organization of Petroleum Exporting Countries (OPEC) – the closest thing the energy world has to a 'dominant' player – has struggled mightily in recent years to exert some control over consistently low oil prices. US oil and natural gas producers, while re-emergent as major players, do not have OPEC's market power, let alone that of John D. Rockefeller in the late 1800s and early 1900s, or the Texas Railroad Commission from the 1930s through the 1960s – see Bob McNally's recent book *Crude Volatility* (Robert McNally, Center on Global Energy Policy, January 2017) for more on this.

Is US energy 'dominance' desirable?

Now we come to the second question: even if 'energy dominance' were achievable, would it be desirable?

Here, again, we need to try and understand what advocates mean when they use the term 'dominance'. If the goal is to become self-reliant, walled off from global markets, it is clear that dominance is not desirable for the reasons described above.

But what if the goal is to become the Serena Williams or Usain Bolt of energy? Why wouldn't the USA want to bend adversaries to its will?



First, the USA and other energy importers have argued for years that *energy should not be used as a geopolitical weapon*. Following the politically motivated Arab oil embargo of 1973, North American, European, and developed economies in Asia banded together to create the International Energy Agency, which was founded in large part to prepare for any future attempt by oil-rich powers to use energy as a cudgel in international negotiations. More recently, US leaders have sought to constrain Russia's ability to wield the energy weapon against allies in Eastern and Central Europe.

With its recent resurgence as an energy producer, is the USA really prepared to abandon these long-held principles and explicitly lord 'energy dominance' over other nations? If so, allies and foes alike would take notice, then wonder whether the USA remains an advocate for open markets, or whether it is moving down the path of the nations whose use of the energy weapon it once scorned.

Second, if it seeks to 'dominate' other nations with its energy resources, that *dominance won't necessarily come at the expense of the USA's geopolitical foes*.

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'DOES THE UK, JAPAN, OR ANY OTHER NATION WANT TO BE "DOMINATED" BY THEIR ENERGY SUPPLIER? OF COURSE NOT.'

Does the UK, Japan, or any other nation want to be 'dominated' by their energy supplier? Of course not. The notion that elected leaders in these nations would be expected to bend the knee to a benevolent energy supplier is politically untenable.

As an analogy, the USA receives the large majority of its imported oil from Canada, but no American leader would accede to being 'dominated' by their northern neighbour. No American leader would be willing to be seen as capitulating to other (non-energy) Canadian priorities for the sake of secure energy supplies. The same logic holds true for US allies, who would never want to be seen as the subordinate partner to US 'energy dominance'.

How can government promote a better energy future?

So if energy dominance is neither achievable nor desirable, what can government do to bolster a better energy future?

- 1 Policymakers must recognize the value of **deeper integration** into global energy markets. Unlike 'energy independence', deeper integration provides newly resurgent US producers with access to the best markets, and adds resiliency against price spikes for energy consumers.
- 2 **Energy resilience** – the ability to respond to disruptions – is a crucial objective, and can be improved by smart planning. Members of the International Energy Agency are obligated to hold a large volume of crude oil in storage, which can be deployed fairly quickly to reduce the harms of energy disruptions, whether caused by geopolitical conflict or natural disasters. But the USA can go further by including gasoline, diesel, and other refined petroleum products as part of its storage

portfolio. As Hurricane Harvey starkly demonstrated, access to crude oil may not be enough to prevent disruptions for consumers, particularly if refineries are rendered inoperable.

- 3 Policymakers can reduce exposure to volatile energy prices by promoting **energy efficiency**, a long-held goal of the IEA. In the USA, Corporate Average Fuel Economy (CAFE) standards mandate certain levels of vehicle efficiency, and their expansion is currently under review by the Trump Administration. Rules on furnaces, air conditioners, and other appliances can also advance energy efficiency (though these would reduce consumption of natural gas and electricity, rather than oil). Such measures enable consumers to get more bang for their energy buck. In other words, the simplest way to reduce 'dependence' on a thing (such as imported oil) is to use less of that thing.
- 4 The shale revolution has provided the USA with abundant natural gas, opening up a remarkable opportunity to displace coal-fired electric power, thus **reducing greenhouse gas emissions** at low cost. But this opportunity will only be realized if well-crafted public policies steer the USA towards a low-emissions future, such as the one envisioned under the 2015 Paris Agreement. Leadership on this issue would position the USA at the forefront of the global community, providing a model for other nations to follow, rather than seeking to 'dominate' its way to the future of energy.



US shale gas: view of the domestic market

Michelle Michot Foss

Snapshot overview

As oil prices slipped during the extended decline between mid-2014 and early 2016, a persistent question was whether the US domestic oil and gas producers – increasingly wedded to tight rock plays – would be able to adjust and forge ahead. In fact, most already had adjusted and forged ahead, moving out of methane-rich locations as the Henry Hub price collapsed during 2007–8. By all accounts, that adjustment process has continued, with US production of liquids and gas remaining at high levels. Crude oil output remains near the 1970s highs, at more than 9 million barrels per day. The tight rock plays tend to be characterized by ‘gas drives’. As wells are drilled, completed and fractured, and pressures drop, gas comes out of solution providing the ‘push’ to move liquids into wellbores for capture. This push creates the hallmark of tight rock production: the very steep initial production rates followed by subsequent, equally steep, declines. In all, the rush to compete for and develop tight oil acreage has sustained US domestic gas supply near 90 million cubic feet per day. In effect, the US ‘shale’ gas component is now largely a by-product of the industry’s ability to sustain liquids (including natural gas liquids or NGLs) investment and production, and must be understood in that context.

The USA is well supplied with domestic oil and gas production, so much so that commercial responses have focused largely on exports. These constitute not only raw materials (light oil and condensate in excess of that needed by US refineries for feedstock; processed natural gas liquids such as ethane and propane;

and methane, shipped as liquefied natural gas or LNG) but also refined products and intermediate chemicals. The Lower 48 states, particularly along the Gulf Coast, are experiencing an historic build-out of midstream – field gathering, processing, pipelines, and storage mainly for liquids – and export-focused projects and capacity.

‘THE VAST US OIL AND GAS INDUSTRY SYSTEM IS MARKED BY COMPLICATED DYNAMICS ACROSS HIGHLY FRAGMENTED VALUE CHAINS ...’

In assessing the situation and prospects for US domestic shale gas going forward, readers should keep several key points in mind – mainly with regard to overall upstream performance and the upstream–midstream interface. The vast US oil and gas industry system is marked by complicated dynamics across highly fragmented value chains that require interdependence among intensely competitive business segments. This situation, along with the predominance of private surface land and minerals ownership, nimble and deep capital markets, and – thus far – light-handed regulation, makes the US situation unique. We wonder, in fact, whether our situation is so unique that our ability to commercialize tight rock plays, at the level achieved thus far, will remain a US-centric experience.

What, really, is happening upstream?

Since 2009, we at the Center for Energy Economics (CEE) have benchmarked a group of ‘best in class’ producers that have become almost completely wedded to onshore tight rock plays. The population of 16 companies

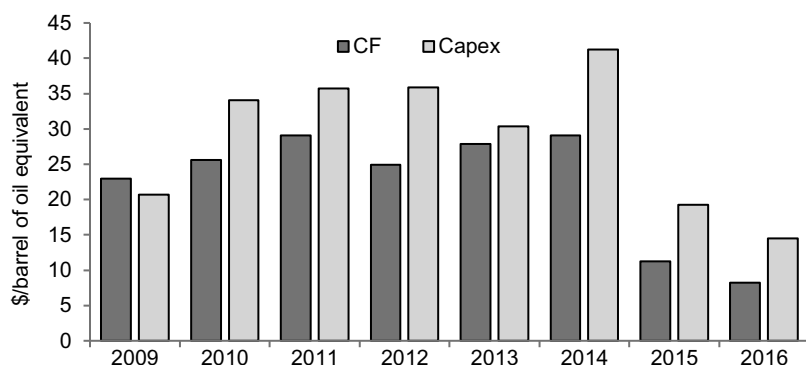
in our sample (‘CEE sample’) has shifted somewhat with mergers and acquisitions over the years, but we have revised our dataset accordingly. These companies represent roughly a third of US liquids and gas output and they have deployed the most advanced technologies and drilling practices as they worked to optimize results.

Most of the chatter about US activity tends to focus on drilling strategies to:

- lengthen horizontal laterals;
- increase the size and improve the positioning of ‘fracs’ along wellbores;
- develop larger pads that enable drilling and completion of multiple wellbores with minimal movement of rigs and improved scheduling of drilling and completion services.

These factors are all important, but results tend to be uneven and highly dependent upon drilling locations, given the marked variability within basins.

From our analysis we can see that the most significant impacts have come from improvements in acreage portfolios – buying and selling aimed at increasing a company’s holdings of the best, prime ‘sweet spot’ drilling locations. The better the drilling location, the greater the impact from deployment of technology. Companies achieving the best performance results have gained considerable ground through supply chain management; this includes driving down the costs of services and supplies, such as sand used to prop open fractures along wellbores and can even cover outright ownership of suitable sand resources. As activity grows within basins and sub-basins, operators are better able to develop efficient supply depots and



CEE sample, operating cash flow and capex, \$/BOE

Source: CEE analysis of SEC annual returns for 16 companies operating in domestic, onshore tight rock plays.

field service contracting. Some of the most marked improvements in cost performance have been achieved in operational logistics. These range from the use of advanced data systems that speed up transfer of real-time data and decision making during drilling, to the more mundane but – in the vast West and South Texas basins especially – significant improvements in reducing the time required to transport people and equipment to drilling locations.

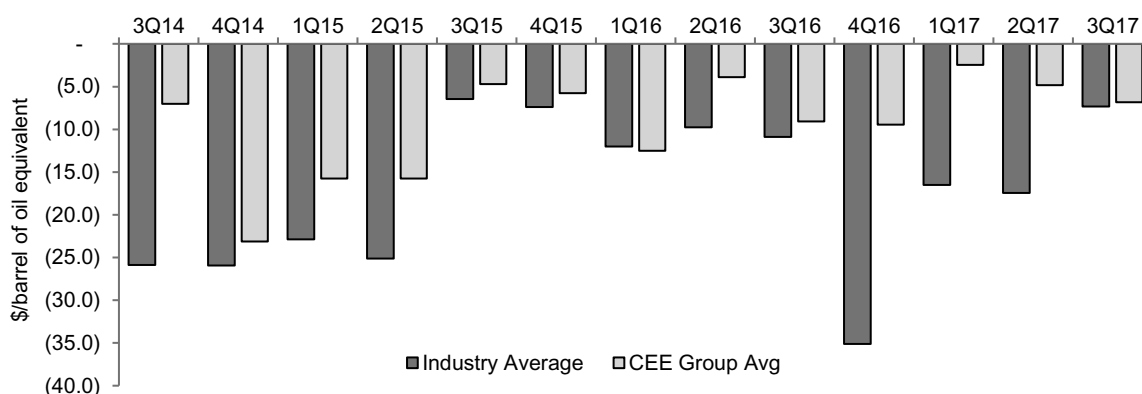
For all of these exciting developments, the most striking observation over time has been the inability for the greater producer community to hold capital expenditure (capex) spending within cash flow (see the figure above). Our monitoring of annual corporate returns on a full-cycle basis reflects

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‘... THE ENTIRE, GLOBAL INDUSTRY FOR YEARS HAS STRUGGLED TO CONTAIN COSTS THAT ESCALATED WITH THE PRICE OF OIL AND OTHER COMMODITIES.’

broader industry patterns on a shorter term, quarterly basis (see the figure below). This reality underlies the current struggle to reconcile reported drilling results and production gains with continued lack of profitability for producers. Indeed, the entire, global industry for years has struggled to contain costs that escalated with the price of oil and other commodities. Given the dominance of plays that are so widely considered to be attractive (and safer) investments in a low oil and gas price world, the lack of operating

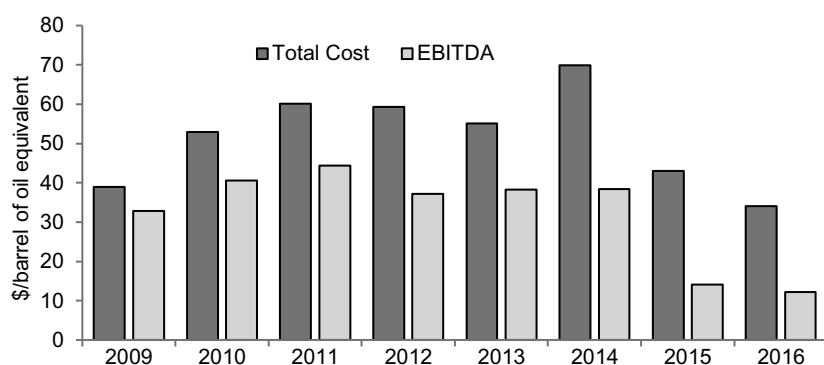
and free (after dividends and capex) cash flow is surprising to many. The lack of cash for reinvestment keeps US producers dependent upon external capital. So long as capital markets remain enamoured of US tight rock plays, funding will continue to be available, in some form, to domestic operating companies. Over time, however, funding has shifted toward more exacting forms, with increasing control demanded by capital providers (mainly those arranging private and public equity). US producers and their backers have been quick to take advantage of any opportunity to hedge forward production, cushioning revenues and cash flows at least to some extent. Hedging has helped to remediate a persistent challenge – most producers do not get the full traded price of their commodities. This is because of ‘field to market’ bottlenecks that create and preserve wide differentials and/or because of production quality (the lighter the oil, the drier or more methane-rich the gas, the lower the value back to the wellhead).

In a low commodity price environment, costs challenge earnings (see the figure overleaf). The US industry has entered a phase in which debate swirls around which targets investors may prefer, going forward. Thus far, the



Quarterly operating cash flow less capex, CEE sample and larger industry group

Source: CEE analysis and author aggregation of data on more than 70 companies covered by Bernstein Research. Data used with permission.



CEE sample, total costs and EBITDA

Notes: Total cost included capex and opex. EBITDA = earnings before interest, income taxes, depreciation, and amortization.

Source: CEE analysis based on company returns.

emphasis has been on production growth, essential if companies are to be able to successfully overcome the fierce decline curves associated with tight rock reservoirs, but costly especially with regard to capex. Large capex spending generates pools of depreciation that in turn constitute the bulk of operating cash flow, the essence of the tight rock 'treadmill'. This past year, a pronounced shift has taken place toward earnings and returns. Pressure has grown on companies to rein in capex but operating expenditures, opex, also is a target.

Clearly, the picture would brighten with commodity price appreciation. US production has become a major factor in how commodity traders and investors worldwide view oil supply-demand balances, principally because the US role as a large importer has diminished. With regard to the quality of production data, there are many vigorous disputes. One camp argues that production estimates, principally those provided to the public domain by the US Energy Information Administration (EIA), are

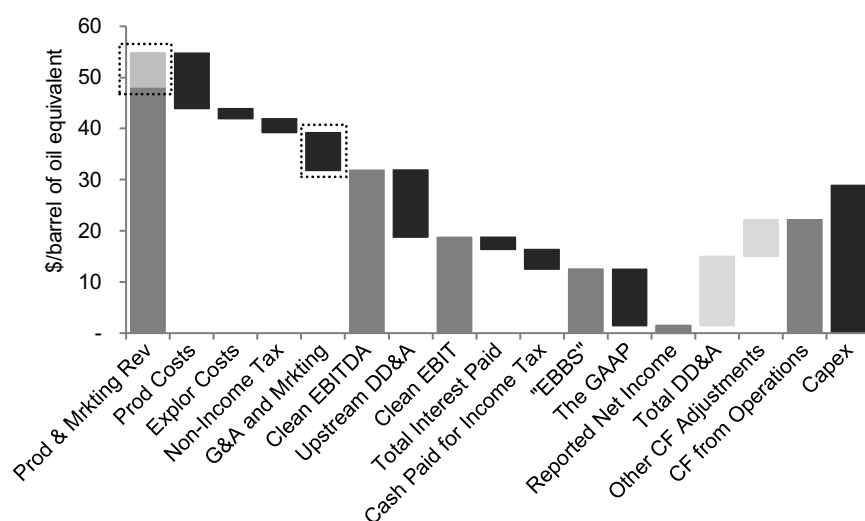
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'PRESSURE HAS GROWN ON COMPANIES TO REIN IN CAPEX BUT OPERATING EXPENDITURES, OPEX, ALSO IS A TARGET.'

too high while another argues they are too low. Flare ups over data and the influence of data on commodity trading occur periodically. A more difficult problem is whether underlying risks and uncertainties in 'unconventional' plays are being vetted properly, given the difficulty of transitioning resource assessment and reserves estimation practices from 'conventional' plays, which are much better understood. Our main concern is how operational data reported by companies is perceived. Producers tend to emphasize their best wells and results. Current well results do not predicate future performance. As drilling strategies become more complicated, in particular with reduced spacing and large multi-well pads, an issue is whether estimated ultimate recoveries may be overstated given the possibilities of interference as new 'child' wells steal from the original 'parents'. Companies can deploy strategies to minimize these impacts, but at a cost. Another worry is whether analysts tend to inflate or overstate their views on estimated ultimate recoveries, given their 'sell side' bias. But finally, when it comes to unconventional oil and gas development, a key consideration is whether *development* risk and uncertainty, as opposed to exploration, is taken too lightly. One of the more significant sources of

development risks and uncertainty lies in the midstream sector.

The upstream-midstream interface: who pays?

The advent of master limited partnerships (MLPs), fostered by a tweak in US income tax rules, led to the emergence of a large and still growing class of independent midstream providers. The USA has always hosted independent midstream businesses, but the MLP structure has supported an acceleration in the scale and scope of independent midstream activities. The attractiveness of income tax implications commended MLPs to investors and encouraged producers to shed their midstream assets because they could monetize them (and obtain much needed capex for drilling). In some cases this meant spinning off midstream assets that producers had newly created, to solve commercialization dilemmas. Wide basis differentials have been the hallmark of US abundance. Strong disparities between the US traded light sweet crude price and Brent, very low to negative wellhead netbacks in most basins, and the influence of the very cheap US traded methane price on domestic natural gas realizations impacted strategies. Basis differentials spurred midstream investment, but a parallel shift in midstream finance, from volatility-based commitments to fee-based contracts, also unfolded. The search for risk mitigation, coupled with supply abundance, shifted midstream investment from 'demand pull' to 'supply push', putting producers on the hook. Producers have had to provide financial backing in the form of volumetric commitments – with take-or-pay (TOP) obligations – in order to ensure sufficient gas processing; liquids and gas transportation (pipelines, rail, trucking, and so on); and liquids storage capacity. This is an ironic circumstance for producers who



CEE consolidated analysis 2009-16 of producer cash flows with midstream revenues and midstream opex costs shown within boxes

Source: CEE analysis based on company financial reports.

once held midstream assets. Once volumetric commitments are taken, producers must meet the throughput TOP fee obligations.

Our producer benchmarking cash flow waterfalls (see figure above) are indicative of both revenues from midstream activities as well as the opex commitments. Midstream costs are incorporated in general and administrative and marketing (G&A and Marketing in the waterfall chart is provided on a 2009-16 consolidated basis for our sample of companies). Some companies report transportation costs separately; we incorporate these

into our category. Costs associated with midstream requirements have grown to become a dominant component of producer opex (see the figure below).

Early into the escalation of tight rock plays, it became clear that 'field to market' connections would need to be re-plumbed to support the growth of onshore production:

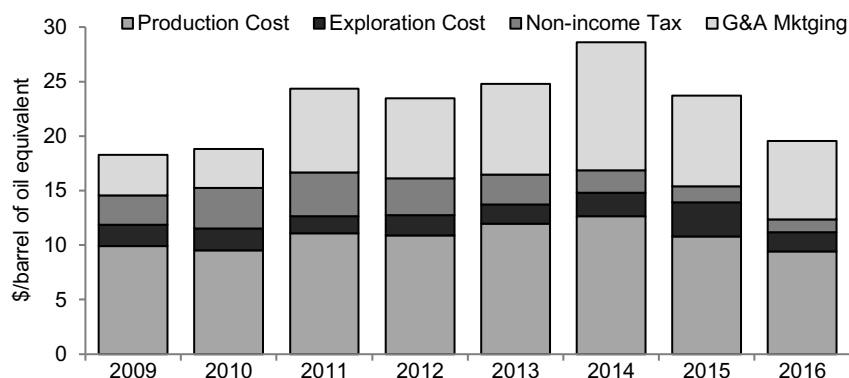
- new rights of way would be needed for pipelines;
- new flows would impact traditional ones, especially for methane;
- the shift in upstream capex to liquids-rich locations and out of

methane-dominant areas meant that gas processing, ethane fractionation, and solutions for condensate would be required.

The lag in midstream build-out exacerbated producer cash flow shortages and ultimately burdened capex and opex commitments. As usual, the upstream, midstream, and downstream all move to the beats of different drummers. The growth of a separate midstream sector involving, in many cases, de-integration of combined producer-midstream assets, may increase the chance of vertical market failure given the very different, and often conflicting, positions of participants.

'THE PUSH TO ENABLE MORE FREEDOM FOR PRODUCERS TO EXPORT ENHANCES THE EFFICIENCY OF THE US PETROLEUM AND GAS SYSTEMS.'

The push to enable more freedom for producers to export enhances the efficiency of the US petroleum and gas systems. Export capacity expansion is dominated by independent midstream, merchant players as well. The gambit to send relatively cheap US methane into global markets as LNG has been as remarkable a reversal in fortunes as the resurgence in growth of crude oil production. The USA had been thought to be gas 'short' and consequently a major prospective LNG importer. We estimate that roughly \$65 billion has been ploughed into LNG export capacity, with possibly more to come. Yet, currently, all of the upside in the LNG value chains resides with the midstream developers and their backers but especially with traders who typically treat liquefaction as sunk cost. Producers take the Henry Hub price, with the central idea being that exports help to provide a floor. For now, LNG exports and robust exports to Mexico and some to Canada appear to be



CEE sample producer opex costs

Source: CEE analysis based on company financial reports.

sustaining the Henry Hub basis.

Certainly, for some time, the drivers usually looked to for guidance on Henry Hub forward prices – seasonality, storage, competition between methane and coal in the electric power sector – have not been reliable.

A distinct unknown is whether US customers and consumers might be susceptible to sharply higher prices for natural gas if international LNG prices prove consistently more attractive while internal demand continues to firm and grow. Analyses of the impact of US LNG exports on domestic prices have largely been sanguine. However, a time almost certainly will come in which US customers and consumers must be willing to pay to keep domestic methane in US markets. Australia's regulatory review of the influence of LNG exports on domestic prices may prove to be a lesson. For this reason, while the build-out of LNG export capacity is the more typical news, the more than \$100 billion being poured into petrochemicals is likely to have a bigger, longer lasting impact.

Closing thoughts on policy inferences

The USA remains the most open, competitive marketplace for oil and gas industry investment. As long as liquids prices are sufficiently attractive, domestic gas supply and commercialization, including exports, can continue. Liquids prices support upstream investment. The large increment of methane associated with liquids-rich drilling targets (roughly 30–40 per cent of supply) ensures cheap feedstock for domestic use, petrochemicals, and exports.

Even with producer commitments for midstream investment, natural gas remains stranded in various locations. Bottlenecks will be more easily solved in the western basins, especially West Texas, where Permian gas supply is expected to surge as midstream processing and transportation constraints are dissipated.

Elsewhere, continued delays and opposition to pipelines and other gas infrastructure represent the more significant policy and regulatory challenges. Pre-2016 national elections,

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'ENORMOUS RUPTIONS ARE TAKING PLACE ... AS GAS GENERATORS, THE ONLY COMPETITIVELY DISPATCHED POWER SOURCE, ATTEMPT TO SURVIVE SUBSIDIZED RENEWABLES.'

arguments that the USA should not remain on the 'gas bridge' any longer than needed became pronounced. Views were, and are, that additional commitments to pipelines would only lengthen fossil fuel dependency regardless of the clean burning attributes of methane. These views persist in spite of new worries about the reliability of gas delivery for direct heating and electric power generation. Enormous ructions are taking place in US power markets, as in the UK and elsewhere, as gas generators, the only competitively dispatched power source, attempt to survive subsidized renewables.

Much of this is aggravated by the persistent low gas price environment – an artefact of the perils (or conundrums) of resource abundance – at least for now.



The impact of US LNG exports on the international LNG market

Howard Rogers

Background and context

In the context of an established, self-sufficient North American natural gas market for most of the 20th century, the onset of a steady decline in US domestic production from 2001 to 2005 prompted two parallel strategies:

- The first was the development of LNG supply chains (most notably from Qatar) and the construction of new LNG import (regas) facilities in the USA. Between 2005 and 2011 US LNG import capacity grew from

36 bcma to 179 bcma (in 2011 US total gas consumption was 693 bcma).

- The second, initiated by the US 'Independent' upstream players, and catalysed by the then high domestic gas price, was to combine horizontal drilling and fracking technologies to exploit shale gas.

By 2011 US domestic production was 27 per cent above its 2005 low point and US LNG regas terminal utilization was just 5.6 per cent. Clearly the US regas investment strategy, wrong

footed by the 'shale gas boom', had resulted in billions of dollars-worth of 'stranded assets'.

From 'lost LNG market' to 'world-scale LNG supplier'

The next chapter in the story exemplifies the arguably unique entrepreneurial characteristics of the US energy sector. As the Henry Hub price of US gas fell (with supply growth outstripping domestic demand), the upstream and supporting service industries embraced

intense technological and operational adaptive learning to reduce drilling times, increase well productivity and stepped-out to develop new shale gas geographies ('plays'). At the same time, the widening spread between Henry Hub and European Hub and Asian LNG prices provided the 'Eureka moment' for some of the US regas owners: namely the conversion of these facilities to liquefy US gas and export it as LNG.

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**'THE OBAMA ADMINISTRATION WAS
 PERSUADED THAT LNG EXPORTS WERE IN
 THE NATIONAL ECONOMIC INTEREST ...'**

The 'first mover' was Cheniere, who initiated applications in mid-2010 and whose Sabine Pass (train 1) facility exported its first LNG cargo in February 2016. The establishment of the regulatory approval process for subsequent projects awaited the conclusion of political debate between the upstream industry, environmental NGOs, and the USA's domestic energy intensive industry. The Obama administration was persuaded that LNG exports were in the national economic interest and became more relaxed in granting export approval to non-FTA (Free Trade Agreement) destinations and in streamlining the environmental and safety approval process under the auspices of the Federal Energy Regulatory Commission (FERC). Critical to this decision was evidence provided by consultants establishing that US domestic gas prices would not rise significantly as a result of LNG export volumes due to the scale of the US shale gas resource which could be developed at sub \$4/MMBtu or thereabouts.

As of early November 2017 three project trains are in operation with a further 12 under construction, estimated to come onstream over the next 26 months. Total nameplate LNG

export capacity of these projects totals 91 bcma, which is not far short of Qatar's 2016 output of 104 bcma (see the table below).

The 'First Wave' US LNG export project economics were based on the fundamentals prevailing prior to the gas and subsequent oil price fall of 2014. At that time the fully built-up cost of US LNG delivered to Asian markets was less than that purchased by Asian buyers on a long-term contract linked to a crude oil price in excess of circa \$80/bbl. The generalized model for the US export projects was that the 'incumbent' terminal owners signed offtake/tolling contracts with LNG importers and 'portfolio players' in order to raise finance to add liquefaction and other incremental facilities to regas terminals (in the case of all but Corpus Christi which is a 'greenfield' development). The off-takers committed to pay a liquefaction fee of between \$2.5 and \$3.5/MMBtu of contracted capacity whether they used it or not, and further variable costs (Henry Hub plus 15 per

cent) of feedgas procurement, representing transport costs to the facility and gas consumed (providing energy) in the liquefaction process. In some cases the terminal owner procured the gas on behalf of the offtaker, in others the off-taker procured and delivered the gas to the facility.

The limitations of this business model became apparent when oil prices (and hence oil-indexed Asian LNG contract prices) and European hub prices (and by arbitrage Asian LNG spot prices) fell in 2014. Suddenly the fully built-up cost US LNG offtake contracts were more expensive in terms of delivered cost than the prevailing destination market alternatives. However, given that the liquefaction fee (\$2.5 to 3.5/MMBtu) was a 'fixed commitment' (along with any long-term chartered LNG shipping and, in the case of Europe, regas capacity charges) it still made sense for offtakers to export US LNG – provided destination market prices were between around \$1 to \$1.5/MMBtu above Henry Hub.

US LNG first wave projects

Operational/under construction	bcma	Estimated onstream
Sabine Pass T1	6.1	Mar-16
Sabine Pass T2	6.1	Sep-16
Sabine Pass T3	6.1	Mar-17
Sabine Pass T4	6.1	Nov-17
Sabine Pass T5	6.1	Sep-19
Freeport T1	6.8	Oct-18
Freeport T2	6.8	May-19
Freeport T3	6.8	Jul-19
Dominion Cove Point	7.9	Jan-18
Cameron T1	5.4	Jan-19
Cameron T2	5.4	Jun-19
Cameron T3	5.4	Jan-20
Corpus Christi T1	6.1	Jan-19
Corpus Christi T2	6.1	Jan-20
Elba Island	3.4	Sep-19
Total	90.9	

Source: Energy Media and Industry Sources.

While such issues are highly pertinent to future US export projects and deal structures, the impact of this 91 bcma tranche of LNG which will flow to global gas markets by 2020 – even at destination market prices as low as Henry Hub plus \$1.5/MMBtu – needs to be addressed by all global market participants. It represents an increase of 27 per cent over 2015's global LNG supply volumes (by 2021, including new additions from Australia and Russia global LNG supply will be 54 per cent higher than 2015). This is a huge volume of 'destination flexible' LNG entering the market at a time when major upstream LNG companies and trading houses are seeking additional supply side optionality to grow their LNG trading businesses. LNG buyers, particularly in Asia, are seeking alternatives to oil indexation. Many are over-contracted to the early to mid-2020s and those which are in the market for spot cargoes and short-term deals have become accustomed to paying prices lower than Long Run Marginal Costs (LRMC) for the commodity. As a consequence there is limited appetite to sign up new long-term contracts (20 years or so), oil indexation is out of favour, and the only Asian LNG price reference indices (JKM et al.) have limited liquidity and curve length. The unexpectedly high LNG demand from China over winter 2016/17, and anticipated in 2017/18, has led to high spreads between Asian spot LNG prices in winter, in contrast to low spreads during summer months. This underlines:

- a) The importance of establishing a recognized Asian LNG price reference with higher forward curve liquidity for use in medium-term (up to five year) contracts.
- b) The potential value to be captured in such an environment by portfolio players and trading houses in the LNG space – namely an incentive to acquire flexible supply.

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'THE SHEER VOLUME OF LNG FROM THE US PROJECTS, [AND] FROM AUSTRALIA AND RUSSIA, HAS RAISED THE PROSPECT OF AN LNG "GLUT" IN THE PERIOD 2019 TO 2022.'

The 'next LNG wave' and the role of US projects

The sheer volume of LNG from the US projects, shown in the table above, together with that from Australia and Russia, has raised the prospect of an LNG 'glut' in the period 2019 to 2022. To date, this has been ameliorated by:

- delays and commissioning problems in some of the Australian projects,
- higher Chinese LNG demand as a consequence of a policy-driven switch from coal to gas in the domestic space heating and industrial sectors, and
- higher gas demand in Europe as a consequence of colder winters and coal-to-gas switching in the power sector due to higher coal prices and the UK minimum carbon price floor.

The main beneficiary of these dynamics has been Russia, which has seen its pipeline gas exports to Europe rise from circa 150 bcma in the period 2012 to 2015, to 170 bcma in 2016, and potentially to 180 bcma in 2017 (after subtracting volumes exported back to Ukraine via the Czech Republic).

In 2010 we witnessed an LNG supply surge from (mainly) Qatar but also from new projects in Russia, Norway, Peru, and Yemen which initially sought Europe as the market of last resort (with more than adequate import terminal capacity) as volumes intended for the USA were not required due to the shale gas boom. Over a period of just three years, however, such 'surplus' volumes were absorbed by LNG demand growth in Asia (particularly as a consequence of the Fukushima disaster).

In the period from 2018 to 2025 we will see:

- **In a low Asian LNG demand scenario:** the formation of an LNG glut which will depress both European Hub and Asian spot LNG prices in order to 'clear the market' by constraining US LNG exports (assuming Russia defends a minimum European market share). This would be followed by a 'tightening' of the market, as Asia 'pulls' LNG away from Europe (as it did post 2010) with a requirement for LNG, from projects as yet unsanctioned, by 2025 at the latest (even with substantially higher flows of pipeline gas into Europe from Russia). This requires FIDs to be taken on such new LNG projects by 2020 at the latest, given the typical five year lead time from FID to production start.
- **In a high Asian LNG demand scenario:** the absence of an LNG glut but a tightening of the market due to Asian LNG demand and a need for LNG, from projects as yet unsanctioned, by 2023 at the latest. This requires FIDs to be taken on new LNG projects by 2018 at the latest.

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'THE "CRUNCH POINT" FOR NEW LNG IS THEREFORE FAST APPROACHING ...'

The 'crunch point' for new LNG is therefore fast approaching, even if the current strong trend of Chinese LNG demand eases over the next year or two. In a Dickensian irony, however, from an LNG sector point of view:

- This is the '**best of times**' in that there is a cornucopia of gas discoveries available for feedgas into LNG projects: in the USA, Qatar (after the recent lifting of the North Field Moratorium), Russia, East Africa, Australia, and Canada – not to mention Senegal, Mauritania, Papua

New Guinea, and the Eastern Mediterranean;

- But at the same time it is the **'worst of times'** in that buyers are disenchanted with oil indexation as a price benchmark, uncertain of their own future demand requirements, and in the case of new LNG importers, uncertain of the price they can afford to pay for LNG.

As the fundamentals through time increasingly indicate the need for new FIDs, who will 'step up to the plate' to undertake investment in new LNG projects in this environment? Logically it should be the oil and gas majors who:

- have professed a strategic desire to shift away from oil into gas in their internal investment capital allocation,
- have developed an LNG portfolio trading capability and business,
- are able to raise debt cheaper and faster on their balance sheets – versus the non-recourse financing route underpinned by a long-term oil indexed contract that is required by independents via banks specializing in the energy business.
- have the confidence to base their LNG FIDs on their assessment of the global gas and LNG market – in that they can sell their LNG output on a mix of medium, short-term, and spot transactions over the life of the investment – using their trading teams to optimize intrinsic and extrinsic value as market conditions change.

To succeed in the next LNG wave requires not only the skills and confidence outlined above but, fundamentally, projects which have an underlying low cost base given the constraint of affordability – namely the elasticity of demand versus price. Bluntly, in the next LNG wave you could invest in an Australian greenfield project requiring a market price of \$12/MMBtu to achieve your target rate of return. But, in the absence of buyers willing to

sign up to an oil-linked price to give you that price expectation, you would have to believe that the Asian spot price, the European Hub index, or a new Asian Hub index would provide such a price level over the life of your project. If, however, Asian LNG demand diminishes rapidly at prices much above \$8/MMBtu, your project will fail to achieve the anticipated return on capital.

The incremental demand for gas appears increasingly to come from (mainly Asian) countries whose domestic production is either negligible or insufficient to keep pace with demand – but that demand is price sensitive. The onus for the upstream players, therefore, given all that has been stated above, is to focus on low-cost LNG. Of the established LNG players:

- Qatar has the advantage of a benign offshore upstream environment, a track record of delivery, and (in the North Field) a high ratio of co-production of NGLs and condensate supplementing the LNG economics.
- East Africa suffers from no liquids co-production (dry gas) and the potential for schedule slippage and cost overrun due to lack of existing infrastructure and inexperienced decision makers.
- Australia and Canada are both prone to cost overruns due to high-cost (scarce) skilled labour and, in the case of Canada, complications relating to pipeline approvals by First Nations and unresolved and overlapping regulatory/fiscal jurisdictions.

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**'... THE CHALLENGE FOR THE
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 SUPPLY THE LNG THE WORLD MAY NEED
 AT A PRICE IT IS WILLING TO PAY.'**

Given that Qatar alone cannot satisfy the potential LNG requirement in the 2020s, the challenge for the 'Next Wave' of US projects is fundamentally whether they can supply the LNG the world may need at a price it is willing to pay. There is no shortage of LNG export projects. The table below shows those awaiting FID. All have non-FTA approval and around half are awaiting FERC approval.

'Next Wave' potential US LNG export projects

Project/train	bcma
Sabine Pass T6	6.1
Freeport T4	6.8
Corpus Christi T3	6.1
Corpus Christi T4	6.1
Corpus Christi T5	6.1
Magnolia T1	2.7
Magnolia T2	2.7
Magnolia T3	2.7
Magnolia T4	2.7
Lake Charles T1	7.5
Lake Charles T2	7.5
Lake Charles T3	7.5
Golden Pass T1	7.1
Golden Pass T2	7.1
Golden Pass T3	7.1
Driftwood T1	7.5
Driftwood T2	7.5
Driftwood T3	7.5
Driftwood T4	7.5
Driftwood T5	7.5
Calcasieu T1	7.1
Calcasieu T2	7.1
Total	137.3

Source: Energy Media and Industry Sources.

The fundamental challenge faced by these projects is simply the fully built-up cost of delivery to destination markets versus what those markets are willing to, or can, pay.

On a benign list of assumptions, the table below indicates how this could run.

Components of fully built-up cost of delivery to destination markets

	\$/MMBtu
Henry Hub price	3.00
Liquefaction energy	0.30
Liquefaction tolling fee	2.00
Shipping (to Asia)	2.00
Total	7.30

In terms of delivered cost, this is already in the 'danger zone' above \$6/MMBtu, espoused by Jonathan Stern in his recent paper '[Challenges to the future of gas: unburnable or unaffordable?](#)' (OIES Paper, December 2017) and the IEA in the 2017 'World Energy Outlook' as being above the level developing countries can afford to pay. It would therefore be subject to demand-price elasticity or (more likely, once capital cost are sunk and LNG

delivered to markets) the market price received would reflect only that which is affordable.

New models for US LNG exports

Tellurian have proposed a model for their Driftwood LNG project (featured in the table 2 on the previous page) which sidesteps Henry Hub as the basis price of liquefaction feedgas. In their model, international LNG buyers/portfolio players are invited to invest in an integrated supply chain (upstream shale gas play, pipeline transportation, and liquefaction) which would deliver LNG on board a ship in the US Gulf at a cheaper cost than conventional projects. The sources of savings are two-fold:

- The claimed ability to explore for, produce, and deliver gas to the liquefaction plant at below Henry Hub prices; and,
- By standardizing ('cookie cutting')

liquefaction trains in a long-term partnership with Bechtel, reducing the critical liquefaction cost component.

The open question is why the major oil/gas/LNG portfolio players have, to date, left such innovations to the former US regas incumbents or (in the case of Tellurian) to entrepreneurial operators expounding new business models? One response could be that the oil and gas majors have been superficially keen to emphasize gas, but slow to assimilate the LNG portfolio rationale and logic into their investment decision making. In many cases, the oil and gas majors will, in effect, subsidize the higher cost of capital of LNG export facility incumbent owners, as a consequence of their failure to make earlier, bolder moves. Future rationalization is possible, but probably only once the LNG market fundamentals are more certain (in terms of timing) and US cost of supply versus apparent affordability is clearer.



US shale productivity gains: can they be sustained?

Trisha Curtis

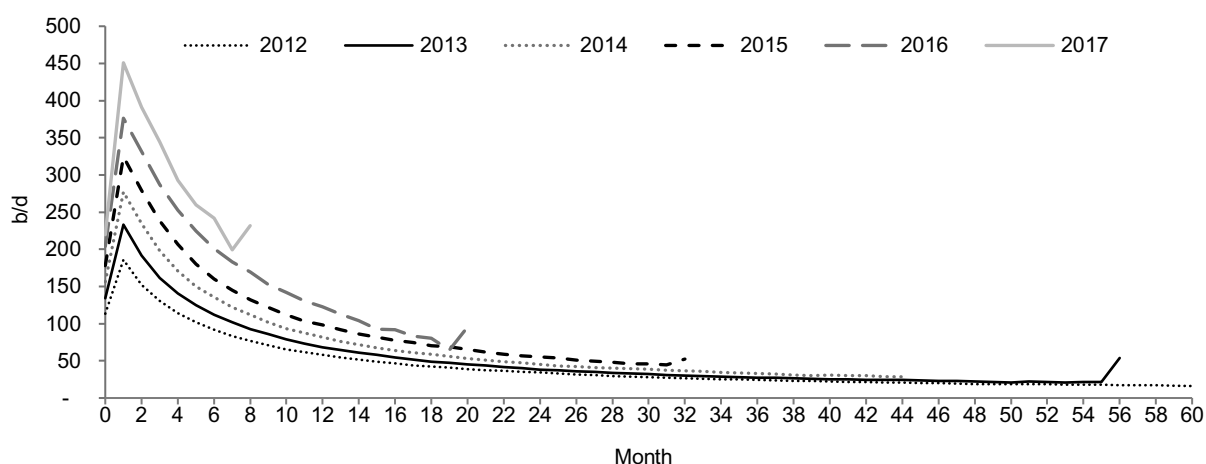
Production growth from horizontal shale oil and gas wells has continued year over year throughout the course of the oil price downturn. The figure opposite shows oil/liquid output for all US horizontal wells each year, from 2012 through 2017. Every year has seen an uplift in both initial production (IP) as well as outer month production, resulting in substantially increased oil output per well.

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'A COMBINATION OF SCIENCE, TECHNOLOGICAL ADVANCEMENT, AND BRUTE FORCE EXPERIMENTATION HAS LED TO BROAD PRODUCTIVITY GAINS ...'

Can these productivity gains be sustained? The short answer is yes. Drilling, completing, and producing shale or tight oil and gas wells has always been both an art and a science. Over the past three years, in a sub-\$60 oil price environment, this has never been more true. A combination of science, technological advancement, and brute force experimentation has led to broad productivity gains across the shale patch and will continue to do so going forward. In the long run, the shale industry will continue to improve well productivity, but in the short run, economic constraints could imperil productivity gains as operator profitability faces renewed scrutiny.

But – geologically and technologically speaking – there is certainly room to grow.

It is quite apparent, based upon our conversations with a number of technical experts and engineers, that there are many 'known unknowns' regarding sub-surface science and that the industry is actively trying to unlock these. Well productivity can and will continue to improve as these enigmas are solved. Furthermore, the short-cycle nature of the shale industry begets massive amounts of data and the unique opportunity to test multiple well design iterations in a production environment across a relatively short timeframe. It is arguably the latter that



US horizontal well decline curve – liquids/oil

Sources: PetroNerds; DrillingInfo Data.

is primarily responsible for the advent of 'high-intensity' completions and the associated productivity gains.

Primary factors behind productivity growth

Shale activity at \$100/b was characterized by the rapid pace at which companies brought new wells online to increase overall corporate production volumes and delineate or hold new acreage. Efficiency and long-term well productivity were a secondary concern. Now, several years into a hunt for further efficiencies and, ultimately, profitability, the industry's activity can be characterized by a mix of innovation, determination, and desperation. Innovation remains a key stepping stone to profitability. The industry's leading operators frequently echo the same sentiment about technological advancement in earnings calls, that is: '*we are still in the early innings*'. Some would argue that more advances have been made in truly understanding the horizontal development of unconventional reservoirs over the last two years than in the past decade (EOG Resources Q2 Earning, Seeking Alpha). As operators have been forced to curb costs, they have also been forced to put more thought into each well.

One of the largest factors contributing to increased well productivity is a relatively simple completion design change. In the past few years, emphasis has been placed on pumping increasingly larger volumes of proppant (sand) and fluid (water) at faster rates (higher pressures) downhole. The relationship between increased proppant and additional productivity is largely accepted, even if the specific factors behind the relationship are less well understood. This is among the most discernible factors contributing to recent productivity gains, but it is hardly the only one.

Operators have gained years of experience working through their geology, enabling millions of acres across several shale plays to be de-risked, and generating massive data sets to draw upon. The experience gained from the tens of thousands of shale wells that have been drilled in recent years has dramatically improved reservoir knowledge and, with it, the ability to better apply the ever-evolving technology. To put it simply, operators, in cooperation with service companies, are better able to identify the best pay zones and land laterals more precisely within them. And they are doing this more quickly than ever before, thus reducing drilling costs. Still, a complete

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'A COMPLETE UNDERSTANDING OF EVENTS HAPPENING DOWNHOLE – COMPLETIONS AND THE FRACTURE NETWORK RESPONSE – REMAINS ELUSIVE.'

understanding of events happening downhole – completions and the fracture network response – remains elusive.

The shale sector has been through many iterations of completion design changes over several years, with varying types of downhole tools ('plug and perf' versus 'sliding sleeves'), proppant, and fluid coming in and out of favour. The ability to experiment and move completions designs in tandem with oil prices and service costs helped many operators to forgo exotic completion designs and components, in favour of simple but effective high-intensity completions. In combination, these factors have positively impacted rising oil output per well.

In tandem with the evolution of more precise geosteering and reservoir targeting, larger completion jobs have been a standout factor in well performance gains. The terminology for applying larger completion jobs, or increasing the quantity of proppant and fluid per foot, has become a bit

hyperbolic and perhaps panders to the investor community. 'High intensity completions', 'upsized completions', 'enhanced completions', 'version 3.0 completion', 'generation x frac', and 'high density fracs', have all entered the E&P vernacular to describe the changing completion matrix over the past three years. These operators are all referring to essentially the same thing: massively increased quantities of proppant (namely sand), massively increased quantities of fluid (mainly slickwater), and the placement of more fractures along the wellbore through tighter cluster spacing of perforations. The industry disagrees on what exactly is happening downhole once all this water and sand is applied, but they agree that larger completions jobs are working to increase the amount of oil and gas output per well.

Operators continue to tweak methods

In their last conference call (Q2 2017), EOG Resources discussed their geosteering technology and rock quality, reiterating the importance of these for well performance. They also discussed smaller changes – such as drill bit designs and mud motors – having a positive impact on cost and productivity: *'taking advantage of our new steering technology that we kind of developed to identify the best rock and then steer the well in the best 10 or 20 feet of that rock. As we mentioned in all these plays, the rock quality makes a huge difference in the productivity of each play ... we are just offsetting the cost inflation with improved technology and the design of bits, design of motors. We have our engineers doing both of those. We've got our own mud systems and mud engineers'* (Q2 EOG, Seeking Alpha).

Centennial Resources discussed their completion design 'evolution' – increasing the amount of perforation clusters per stage, use of only

slickwater as a fluid, and increasing proppant loading per lateral foot – in their last earnings call. *'Centennial's technical team is focused on the continuous evolution of our completion design. All wells completed during the quarter, had 15 clusters per stage, 100% slick water, an average greater than 2,300 pounds of profit per lateral foot. This represents a significant design change from wells completed in the previous quarters'* (Q2 Centennial, Seeking Alpha).

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'THE BASIC LOGIC IS SIMPLE: CRACK MORE ROCK, EXTRACT MORE HYDROCARBONS.'

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In our paper '[Unravelling the US shale productivity gains](#)' (Trisha Curtis, OIES Paper WPM 69, November 2016), we discussed the notable changes in approaches to drilling and completions, such as rock quality assessments, the importance of geosteering in keeping laterals in the highest quality rock, and optimizing the placement of fracs along the lateral. High intensity completions and well spacing were also discussed. A year later, the mantra has not changed dramatically. While each operator tends to focus on their strengths relative to those of their peers, geosteering, lateral placement, rock quality, completion advances, frac optimization, and proppant loadings are all commonalities when operators talk about productivity advances. Some operators are making serious attempts to understand the how and the why behind these factors, but many are simply following the leads of their peers and applying similar methods to their own geology without necessarily performing the research on the front end. Regardless, the basic logic is simple: crack more rock, extract more hydrocarbons.

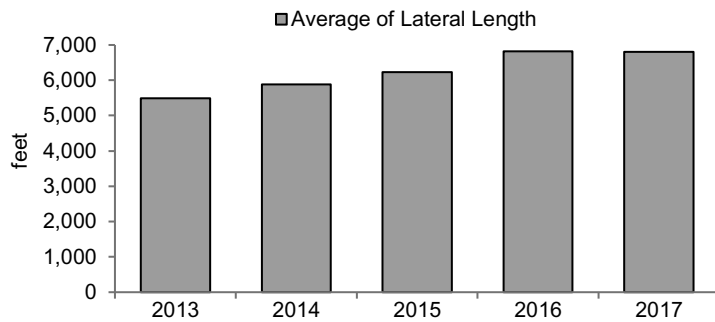
It does not take billions of dollars and a rock lab to identify better lateral placement. EOG Resources' peers

often copy their completion moves without necessarily applying the front-end rock science. While such 'copycat' wells are not necessarily 100 per cent optimal, the end result – increased productivity – more or less transfers over. Better drilling and completions designs are leading to productivity gains across the board. Pump two or three times as much sand down the well as you did in 2014 (using slickwater instead of a gel or hybrid fluid), layer in a better understanding of your reservoir, increase the horsepower and rate you are pumping, and add more perforations per stage along your lateral – then boom, you often end up with a better well than you did in years past. And of course, extend the length of your lateral, where you can.

A note on lateral lengths

The average lateral length of a shale or tight oil well has, for the most part, increased year on year. All things being equal, increasing lateral length will increase well productivity, as it exposes a well to additional pay zone. It is certain that the productivity curves shown in the previous section have benefited from longer lateral lengths (but by far more in some oil plays than in others – Bakken wells have averaged two miles in length for years). The figure opposite above shows the average lateral length for active Permian Basin horizontal wells by year.

The average Permian Basin horizontal well lateral length grew from 5,500 feet in 2013 to 6,800 feet in 2016, but average lateral lengths have not increased through the first half of 2017. However, increasingly long laterals are only part of the productivity story. The figure opposite below shows productivity for Permian Basin horizontal wells by year, isolated by lateral length segments. Within each 1,000 foot segment, productivity has grown each year. This tells us that



Average Permian Basin lateral lengths by year

2017 sample is partial-year data.

Sources: DrillingInfo Data, PetroNerds calculations (for wells with known lateral data).

productivity is growing independently of lateral length expansion.

Investor scrutiny could impact gains in the short term

Productivity gains have been made possible by operators' ability to spend capital, despite a sector that continues to burn billions of dollars in cash each year. Capital is needed for everything from acreage acquisitions to sand purchases. However, as investors begin to focus more on free cash flow and on profitability, capital expenditures, and in turn production growth, could face headwinds.

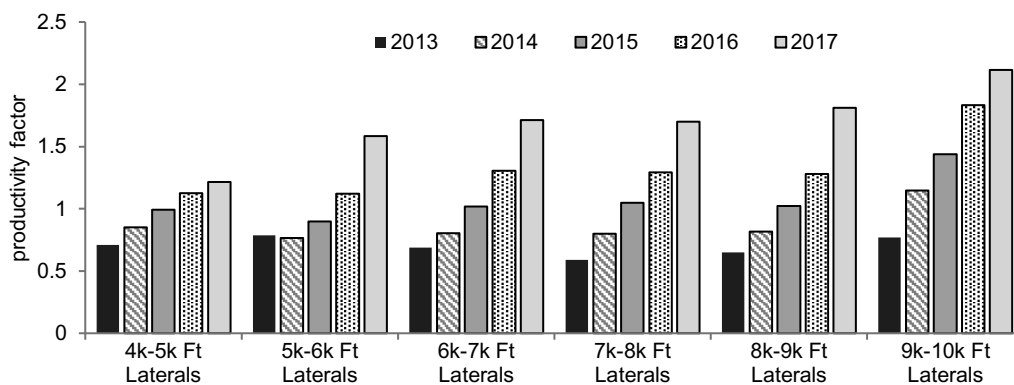
There is a growing sense that the tide is finally turning; investors are now beginning

to look for profits from these publicly traded operators, with the spotlight being on balance sheet stabilization, capital discipline, and ultimately free cash flow. How strong this investor sentiment is and will be over the next couple of quarters is not yet known. In 2015, the activist investor David Einhorn singled out Pioneer Natural Resources as a 'mother-fracker', basically asserting that the industry was a Ponzi scheme and that Texans were 'all hat and no cattle'. Pioneer's stock was impacted, but rebounded and has since been far more impacted by recent discussions around their gas-to-oil ratio (GOR). But lately, more analysts have come out of the woodwork to discuss operator performance and free cash

flow. This summer, an article in the *Wall Street Journal* aptly captured the dilemma with the title 'Shale Produces Oil, Why Not Cash'. Later this summer, BHP Billiton agreed to step out of US shale entirely, due to activist pressure ('BHP bows to activist pressure to exit US shale', Jamie Smyth, Hudson Lockett, and Pan Kwan Yuk, 21 August 2017, *Financial Times*).

'WHILE FREE CASH FLOW IS STILL IN THE RED, MANY OPERATORS ARE TURNING THE CORNER ...'

Clearly, investor sentiment is changing, but this does not mean that the story of US shale has been told. Technologically speaking, this industry has room to grow. The industry is tackling numerous scientific known unknowns, all of which can contribute to greater productivity and efficiency. Different types of investors will view operators differently for several reasons. Some investors may prioritize free cash flow more than production growth. Others may seek expansion of asset bases and look for execution by operators. But in the near term, operators may have to restrain spending, even if that means less sand. Analysts and operators should



Permian Basin horizontal well productivity by lateral length segment

2017 sample is partial-year data.

Note: Well productivity indexed to a base curve, which equals 1.

Source: DrillingInfo Data, PetroNerds calculations (for wells with known lateral data).

appreciate the fact that investors do not always know E&Ps and their activity as intimately as they should. These operators should be viewed as individuals and not lumped together as a whole. While free cash flow is still

in the red, many operators are turning the corner; they are doing so around \$50 WTI. The operators that can rein in spending, maintain production levels, and show how they will get to free cash flow neutrality may well be able

to survive renewed investor scrutiny over the coming quarters. The implications for the industry of such investor scrutiny are meaningful and could propel assets to change hands over the course of 2018.



US crude exports: gaining ground

Dominic Haywood

Introduction

US crude oil exports surged to a record high of 1.8 million barrels per day (mb/d) in October 2017, 1.2 mb/d higher y/y. A few months earlier, the market had fervently questioned the ability of the USA to export more than 1.2 mb/d, suggesting capacity constraints would cap departures at this level and result in large inventory builds on the US Gulf Coast. The viability of export arbitrage, given the prevailing economics at the time, together with the international market's appetite for 'low quality' US oil, also came under scrutiny. But the reality on the ground was different, as physical players re-affirmed their belief in the adequacy of US dock capacity, and the combination of wide WTI–Brent spreads and strong cash differentials in Asia and the North Sea lubricated the gears of arbitrage. Indeed, at the end of October, US exports topped 2 mb/d, exceeding even the most bullish of expectations, as the combination of high export demand and backed-up cargoes following Hurricane Harvey buoyed departures. Despite the October furore, the USA is unlikely to export 2 mb/d of crude oil on a

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'IT IS EXPECTED THAT EXPORTS WILL AVERAGE 1.7 MB/D IN 2018, WITH MUCH OF THE Y/Y EXPORT GROWTH OCCURRING IN THE FIRST HALF OF 2018.'

sustained basis in the near term. It is expected that exports will average 1.7 mb/d in 2018, with much of the y/y export growth occurring in the first half of 2018 – primarily due to a low base. But in the second half of 2018, export volumes should also remain robust, in line with a weak forward WTI–Brent strip that currently averages –\$5.85 per barrel for 2018, which is enough to open the export arbitrage window from the Gulf Coast.

Factors affecting US crude exports

Achieving these volumes is, however, dependent on several factors.

- **US production growth** must be sufficient to allow for both an increase in refinery demand in 2018 and incremental export demand. If US production growth falters on either lower crude oil prices or on a shift towards disciplined growth from shale producers, then export volumes will be constricted.
- There will need to be a sufficient supply deficit in **global balances** for shale production growth to fill. If global demand falters in 2018 or supplies surprise to the upside (either through higher availability of OPEC crude or a recovery in non-OPEC production) then shale exporters will find themselves in a difficult predicament.

■ **Sufficient infrastructure** must exist to allow shale production growth to move from the wellhead to domestic trading hubs and then from these trading hubs to export terminals.

■ International markets need to become comfortable with the **quality of US crude** oil. Well-known grades such as Mars and WTI–Midland are known entities, but tank blends like Domestic Sweet (DSW) are still largely internationally untested and have so far received a poor reception in international markets.

When combined, the above factors should manifest themselves in the spreads between WTI and US cash differentials and between US crude prices and international ones.

US production growth

Forecasting US crude oil production has been a rollercoaster ride over the past 18 months. The market has moved from calling time on shale production in mid-2016 to calling for astronomical growth rates in 2017. Consensus estimates for US crude production growth today are between 0.7 and 1 mb/d y/y for 2018. Assuming production growth of 0.7 mb/d and 0.21 mb/d of refinery runs growth next year and 0.1 mb/d of synthetic crude exports from Canada, the USA will have at least 0.59 mb/d of incremental crude oil length to dispose of. In a backwardated market, there will be



little incentive for traders to store this material. This means exports are likely to be the only option to dispose of this length. It also means the volume of oil exported is directly linked to the volume of oil supplied to US refiners, minus the volume that they run.

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'WHAT IS MORE DIFFICULT TO PREDICT AT THIS STAGE IS WHERE EXACTLY THE NEW CUSTOMERS FOR US OIL WILL BE.'

US crude exports: where to?

Recent volatility in ICE Brent spreads has offered an early insight into the possible clearing mechanism for Atlantic basin markets in the face of high US crude exports. These spreads moved from a strong backwardation of some 45 cents per barrel down to 15 cents per barrel, as US cargoes began to arrive in Europe and as they pushed out North Sea crudes from Asia. Similarly, WAF crudes have struggled to clear, and these differentials have moved lower on a sustained basis as they attempt to price at competitive levels relative to US crudes. Short-term fluctuations aside, and assuming that global liquids balances will draw by 0.2 mb/d, US exporters will continue to find steady demand for their products over the course of 2018. However, what is more difficult to predict at this stage is where exactly the new customers for US oil will be. So far this year, US crude exports have been largely split between Asia Pacific (36 per cent or 0.34 mb/d), Canada (32 per cent or 0.31 mb/d), and Europe (17 per cent or 0.17 mb/d). However, Canada is likely already nearing saturation as it has already backed-out large volumes of US crude this year. Europe may be able to accommodate further US barrels by sending more North Sea oil towards the East, but given the fragile pricing in the region today, it is unclear how well North Sea markets will hold up under

the relentless onslaught of US exports expected in 2018. This leaves Asia Pacific as a key destination market for US crude, particularly as promising demand has already emerged from the region.

Importantly, this Asian demand for US crude is not limited to spot purchases dictated by arbitrage economics. There are already pseudo term arrangements with Asian parties holding equity in US upstream projects, politically motivated purchases made on governmental mandates, and deliberate diversification by Asian buyers keen to move away from reliance on OPEC and Middle East crudes. These flows will likely develop over time and ensure a baseload of demand for US crude in the East. But new markets will also need to emerge to absorb the export growth that is expected to materialize. A key market here may be Latin America, where dwindling domestic production is leaving refineries short of crude. The proximity of these plants to US production, and their less complex refineries, means the region could be a willing buyer of more US oil over the next 12 months. Similarly, there is scope to develop US markets more. The US East Coast (USEC) still relies on almost 1 mb/d of crude oil imported from the Atlantic basin; if Jones Act rates fall, making the arbitrage viable, then there is certainly potential for more Permian oil to supply these refineries.

Infrastructure

A popular angle of analysis around US export infrastructure focuses on dock capacity. While this is an important consideration, it is certainly not the most important potential infrastructure constraint when it comes to US export capacity. Summing the record daily loads for all ports in the USA on any given day shows that more than 3.2 mb/d of export capacity could exist under perfect operating conditions. Clearly this is a theoretical maximum and in practice, constraints would likely

exist at a lower level of around 2.5 mb/d based on current infrastructure. But it is not the size of the docks that limits their ability to export. Instead, it is the tankage at the dock that must unload oil into a ship and the pipelines that feed those tanks that must refill them quickly to ensure a steady rate of loadings. Many of these tanks and pipelines are already used to supply domestic refineries, either by delivering domestic oil to them or by piping imported sour crude. Looking further ahead, the pipeline infrastructure from the wellhead to the export terminal must be sufficient to move production growth to the water.

In order to ensure that this process can occur, a wave of new midstream investments has been made over the last six months. Some 1.1 mb/d of new pipeline projects between mid-2017 and end-2019 have been tracked that aim to transport oil from the Permian basin to the Gulf Coast.

A final important infrastructure constraint is the competition that crude exporters face at the docks from product exporters. As the Gulf Coast refining fleet increasingly gears up to export more refined product overseas, demand for berthing and lightering will rise exponentially. This means crude export schedulers will be forced to jostle with refined products shippers to secure space on the dock for their exports.

US crude quality

In the early days of crude exports, US barrels got a bad rap overseas as foreign refiners complained about high metals content, variable refining yield, and unstable quality. These are issues that US refiners have plenty of experience with as blenders increasingly saw attractive margins by combing heavy sour high TAN Canadian crude with Rockies condensates and Bakken light sweet to create a tank blend known as Domestic

Sweet (DSW). With DSW increasingly shunned by US refiners, some players attempted to export it into international markets as WTI. However, would-be importers of US crude have become wise to DSW and now specify the grades they are willing to accept in their tenders. Indeed, various Asian and Latin American refiners specifically tender for field grades such as WTI-Midland, Bakken, or Eagle Ford and these barrels have proved popular in overseas markets.

Variability is the name of the game

Importantly, there will be a high level of variability in both export volumes and

THE SIGNALS ARE BEING SENT TO BOTH US PRODUCERS AND US EXPORTERS THAT THE WORLD WILL NEED THEIR OIL.

destinations each month, as arbitrage economics shift and the oil market gyrates within seasonal patterns. But, the corollary of US production growth is US exports: one cannot exist without the other. And, the signals are being sent to both US producers and US exporters that the world will need their oil.

- Flat prices have moved sharply higher over the last few months, in

line with the global rebalancing, post-OPEC cuts.

- Forward futures curves have moved into backwardation, signalling that the market will require oil from storage to meet demand.
- Foreign customers have proved impressively receptive to US shale crudes, despite the high light-ends content often associated with these barrels.
- Shale producers are being given the green light to produce: their equity is rallying from the August lows, appetite for their debt is healthy, the market is backwardated, and flat prices are higher.



The outlook for biofuels in the USA

Scott H. Irwin

Production and use of biofuels in the USA during the last decade has grown very rapidly due to a combination of factors, two of which stand out:

- the large increase in real crude oil prices,
- implementation of the Renewable Fuel Standard (RFS).

THE INCREASE IN CRUDE OIL PRICES IS CRUCIAL AS IT MADE BIOFUELS MORE COMPETITIVE IN THE MARKETPLACE ...

The increase in crude oil prices is crucial as it made biofuels more competitive in the marketplace and led to a political reaction that powered the RFS legislation through the US Congress. Much has changed since the heady days of 2005–7 for biofuels. The RFS mandates have been extremely controversial in some quarters, particularly the petroleum refining sector, and have been subject

to almost continuous legal challenge. Crude oil prices have also crashed; starting in the second half of 2014 they plunged to inflation-adjusted levels not seen since the 1990s. The purpose of this article is to assess the outlook for biofuels in the USA for the next five years in light of these changes.

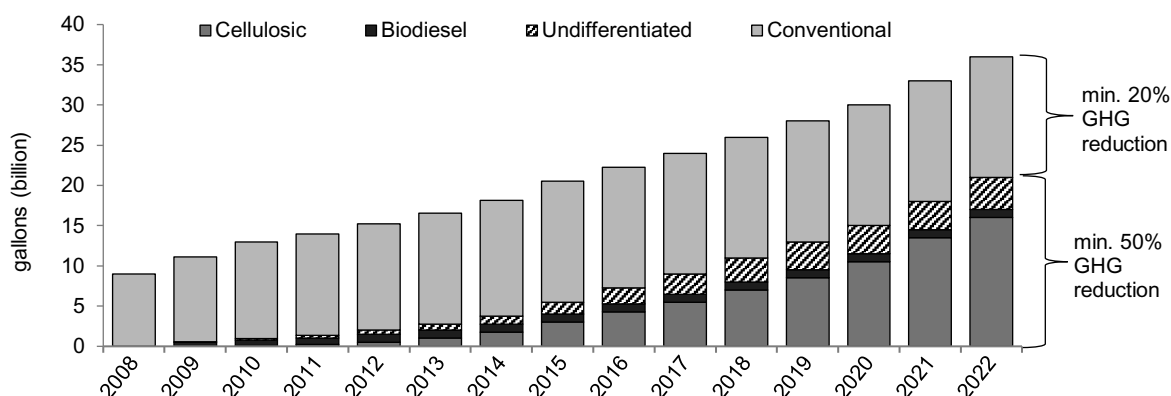
The Renewable Fuel Standard

Since the RFS is central to the outlook for biofuels, it is important to start with some background on the standards. The 2007 statute for the RFS required the US Environmental Protection Agency (EPA) to establish volume requirements for four categories of biofuels for each year from 2008 through 2022:

- cellulosic biofuel,
- biomass-based diesel,
- total advanced biofuel (which includes biomass-based diesel),
- renewable fuel (referred to as 'conventional ethanol' here).

The difference between the 'total advanced' mandate and the total of the cellulosic and biodiesel mandate is referred to as the 'undifferentiated advanced' mandate and can be satisfied by a combination of qualified advanced biofuels. 'Conventional biofuels' are generally assumed to be corn-based ethanol but this is actually not explicitly required by the RFS legislation. Instead, corn-based ethanol has been the cheapest alternative for this category that also meets the environmental requirements of the RFS. The 'conventional biofuels' mandate is referred to as the 'conventional ethanol' mandate for the remainder of this article in order to be consistent with the most common term for this particular RFS mandate.

The figure opposite shows the statutory RFS volume standards from the 2007 legislation. The basic logic behind the standards was to rely almost entirely on 'first generation' conventional ethanol in the early years and then transition to greater reliance on 'second generation'



Statutory US renewable fuels standards 2008–22

Source: 'Overview for Renewable Fuel Standard', Renewable Fuel Standard Program, US Environmental Protection Agency.
<https://www.epa.gov/renewable-fuel-standard-program/overview-renewable-fuel-standard>

advanced cellulosic ethanol. This is seen in the cap on conventional ethanol at 15 billion gallons starting in 2015 and the increase in cellulosic from 3 billion gallons in 2015 to 16 billion gallons in 2022. The total RFS mandate for biofuels maxes out in 2022 at 36 billion gallons. Note that the biodiesel mandate was established as a minimum of one billion gallons per year from 2012 through 2022, with larger amounts subject to EPA approval.

THE MANDATED TARGETS FOR CELLULOSIC BIOFUELS WERE VERY AGGRESSIVE FROM THE OUTSET ...

Issue #1: cellulosic ethanol

The mandated targets for cellulosic biofuels were very aggressive from the outset, given that industrial-scale production was virtually non-existent at the time the RFS was passed in 2007. While several plants have been built in the last decade, cellulosic ethanol production has struggled to reach a few million gallons. The vast bulk of what has been produced in this category is actually captured landfill gas in liquid form, which qualifies as a cellulosic biofuel due to the breakdown of paper lignin in landfills. The low production totals from all sources has

caused the EPA to use its RFS waiver authority to write down the cellulosic mandate to very low levels relative to statutory levels each year to date. The total advanced biofuel mandate has also been written down in conjunction with the write down in the cellulosic mandate.

There is little reason to be optimistic about the prospects for cellulosic biofuel production through 2022. One of the most high-profile cellulosic ethanol plants developed by DuPont in Nevada, Iowa was recently shut down and no new plants are scheduled to begin construction. Some progress is reported in the ethanol industry for using the non-starch parts of the corn kernel for cellulosic production at existing plants, but it is difficult to see anything but very marginal growth in cellulosic production moving forward.

Issue #2: blend wall

The E10 blend wall is the main reason that the RFS has become so contentious in recent years. This issue arose because regulation in the USA has traditionally limited the ethanol content of gasoline blends to a maximum of 10 per cent by volume. Consequently, the theoretical maximum amount of ethanol that can be consumed is 10 per cent of total

gasoline consumption. At the time the RFS was passed in 2007, it was commonly projected that US gasoline consumption by 2015 would be 150 billion gallons. So, it is no surprise that the cap on the conventional ethanol mandate in 2015 was set to 15 billion gallons, exactly 10 per cent of projected gasoline consumption. The problem is that actual gasoline consumption began falling almost as soon as the RFS was passed, due to the combined effects of high real crude oil prices and the onset of the Great Recession. This meant that by 2013, the conventional ethanol mandate as specified in the RFS statute began to surpass the E10 blend wall.

Understanding what happens when the conventional ethanol mandate exceeds the E10 blend wall requires some understanding about how compliance under the RFS works. Obligated parties under the RFS are refiners and importers of gasoline and diesel. On an annual basis, the EPA issues rulemakings about the volume of biofuels that each party must demonstrate is blended into final over-the-road transportation fuel for that calendar year. Compliance is demonstrated by turning into the EPA tradeable credits known as the Renewable Identification Numbers, or RINs for short. The RINs are created

when a biofuel is produced and travel with the fuel as it moves through the supply chain. Obligated parties can obtain RINs by blending biofuels themselves or buying the credits from non-obligated parties.

The price of RINs exploded in early 2013 as the conventional ethanol mandate exceeded the E10 blend wall for the first time. In a matter of months, the price of ethanol RINs went from a few cents to nearly \$1.50 per gallon. While there have been many charges of manipulation, or the generic epithet of 'speculation', to explain the price explosion, there is actually a simple explanation. The RFS contains a safety-valve 'nesting' feature whereby advanced biofuel RINs, principally biodiesel, can be used to not only meet the biodiesel and advanced mandates but also the conventional ethanol mandate if need be. So, when the ethanol mandate began to exceed the blend wall the gap between the two had to be filled by something besides blended (corn-based) ethanol, and that something was biodiesel. In essence, biodiesel became the marginal gallon for filling the conventional ethanol mandate and ethanol RINs began closely tracking the much, much more expensive price of biodiesel RINs.

At this point, the equivalent of political trench warfare broke out between petroleum refiners and biofuel producers. On one side, refiners and their political allies argued that the 'RFS was broken' and that the dramatic increase in RINs prices was substantially harming their operating profits. On the other side, biofuels and agricultural groups argued that the RFS was intended by Congress to be a technology-forcing programme and that the high RINs costs reflected the unwillingness of the petroleum refining industry to make the investments that would lower the cost of breaching the blend wall via higher ethanol blends such as E15 and E85.

Much like the trench warfare of World War I, the last four years have seen an ebbing and flowing of which side had the upper hand in the political battle over the RFS. For example, the Obama Administration EPA cut the conventional ethanol mandate in 2014–16 by a total of 2.24 billion gallons under pressure from refiners. The EPA's authority to make these cuts was immediately challenged by biofuel and agricultural groups, and last July a US Federal Appeals Court ruled against the EPA. Most recently, the Trump Administration EPA signalled, in a September 2017 notice of rulemaking, that it was considering several other measures for reducing the RFS mandates. After a firestorm of protest from biofuel and agricultural groups, the EPA director subsequently took the unusual step of issuing a letter disavowing any of these new measures.

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**'[AN INTERPRETATION OF] THE
 POLITICAL WARFARE OVER THE RFS AND
 THE BLEND WALL IS THAT IT HAS
 REACHED A STALEMATE.'**

A reasonable interpretation of the events surrounding the political warfare over the RFS and the blend wall is that it has reached a stalemate. The political power of biofuel and agricultural groups, particularly in the US Senate, prevents

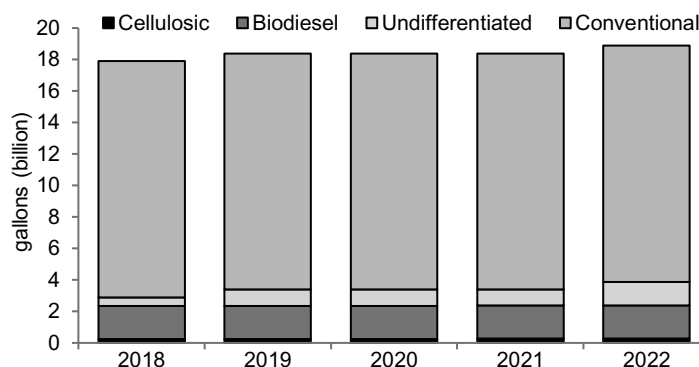
modification of the statutory volumes or outright repeal of the RFS. But the countervailing political power of petroleum refiners is sufficient to prevent the RFS mandate volumes from being set much above the minimums specified in the statute. This interpretation is the basis for the projections of RFS volumes over 2018–22 found in the figure below. The projections assume that:

- i) the conventional ethanol mandate will continue to be set at the statutory maximum of 15 billion gallons,
- ii) the advanced mandate will be set at the minimum level in the statutes, which is 4–5 billion gallons,
- iii) the biomass-based diesel mandate will be set at a constant 2.1 billion gallons,
- iv) the cellulosic mandate will remain below 300 million gallons.

The net result is that the total RFS biofuels mandate increases only marginally from 19 billion gallons in 2018 to 20 billion gallons in 2022. If anything, these projections lean toward the conservative side, with some possibility that the volumes will be slightly higher due to intense lobbying by biofuels and agricultural groups.

Issue #3: point of obligation

The debate about point of obligation for the RFS is really an extension of the debate surrounding the E10



Expected implementation of the US renewable fuels standards, 2018–22

Source: Author's own calculations.



blend wall. As noted in the previous section, petroleum refiners argue that high RINs costs negatively impact their operating margins. One widely discussed proposal is to simply move the point of obligation upstream from refiners to blenders of biofuels, thereby doing away with the RINs obligation at the refining level. This solution does have a certain logic, since the RFS is after all a blending mandate. But the proposal also ignores two important considerations regarding the operation of the RFS.

1 Are refiners are actually harmed by high RINs costs as claimed?

The answer comes down to the degree that refiners can pass through the RINs costs in the form of higher prices for the gasoline and diesel blendstock they sell to upstream blenders. In industry parlance, the RINs costs are said to show up in the 'crack spread'. The available empirical evidence suggests that refiners are able to quickly pass the RINs costs on to wholesale blenders through higher blendstock prices. Outside of the administrative costs incurred, refiners then should not be harmed financially by their RFS obligations. Interestingly,

there is some evidence that blenders in parts of the USA actually gain at the expense of gasoline and diesel consumers in the RINs pass-through process, but this does not affect the impact on refiners.

2 Logistics and administrative costs for the RFS.

From a conceptual standpoint, it would make sense to place the point of obligation for a biofuels blending mandate at the point in the supply chain where biofuels are blended with petroleum fuels. However, there are literally tens of thousands of blenders in the supply chain, ranging from large integrated energy companies with thousands of retail stations to smaller independent firms with a few stations. Moving the point of obligation to the blending level would therefore entail a huge increase in the cost of administering the RFS mandates compared to the current system of obligating a few dozen refining firms.

The bottom line is that the evidence indicates that refiners as a group are not being financially harmed by RINs expenses and it would be very expensive and impractical to move the point of obligation further

'A POLITICAL STALEMATE OVER THE RFS HAS DEVELOPED THAT FAVOURS A "STEADY STATE" OUTLOOK ...'

upstream. So, it is no surprise that the EPA has signalled that the point of obligation is not going to be changed. Since smaller 'merchant' refiners may have less ability to pass through RINs expenses, it may be necessary to increase the number of RFS exemptions for small refineries.

Summary

Biofuels consumption in the USA is primarily driven by what happens to the RFS. A political stalemate over the RFS has developed that favours a 'steady state' outlook for the consumption of biofuels over the next five years. While this limits downside risk to US biofuel producers, it means that they will have to look to international markets for significant growth opportunities. One exception may be domestic biodiesel production, which could increase substantially if countervailing duties are imposed on imports from some countries and/or the biodiesel tax credit is changed from a blender to a producer credit.



Can the US coal industry come back?

David Schlissel

The coal industry in the USA has been in a sharp decline over the past decade. Coal-fired generation fell by over 745 million megawatt hours (MWh), or 38 per cent, between 2008 and 2016, causing its share of the US electricity generation mix to plummet from nearly 50 per cent in 2008 to slightly over 30 per cent in 2016. Over 100 gigawatts (GW) of coal-fired generating capacity, representing more than 250 plants, has been retired since just 2010. This follows on the

heels of the cancellation of more than 150 proposed new coal plants.

The steep decline in coal-fired generation has led to a similar fall in coal production, from 1.17 billion tons mined in 2008 to 728 million tons mined in 2016, a 38 per cent drop. US coal exports declined by 26 per cent. As a result, coal mines have closed and the number of coal mining jobs has continued its long-term

slide. Five large coal companies went bankrupt in 2015 and 2016. A sixth company recently filed for bankruptcy.

Donald Trump campaigned for president boasting that he would bring back US coal, making it 'great' again while creating more mining jobs. His administration has taken a number of actions to bring this boast to life.

To date, however, Trump Administration efforts have not had any significant

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'TO DATE, HOWEVER, TRUMP

**ADMINISTRATION EFFORTS HAVE NOT
 HAD ANY SIGNIFICANT SUCCESS IN
 BRINGING BACK COAL.'**

success in bringing back coal. An initial wave of optimism did occur in the industry as coal-fired plants generated about 5 per cent more power in the first half of this year than in the first six months of 2016. However, more recent data from the US Department of Energy show that year-to-date coal generation through August of 2017 was a mere 0.4 per cent higher than it had been during the first eight months of 2016. This doesn't offer much cause for optimism that coal is in a substantial long-term recovery.

Is it possible, nevertheless, that coal could come back, perhaps through some combination of political actions and/or technology developments? The answer is almost certainly no. Even without explicit federal policies to reduce greenhouse gas emissions, the same inexorable market and economic forces and advances in renewables technologies that have hurt the coal industry in the past decade will continue to undermine the financial viability of US coal-fired plants in coming years.

The coal industry attacked the Obama Administration, particularly the federal Environmental Protection Agency (EPA), for eight years, for waging a 'war on coal'. However, the reality is that even without new environmental regulations, coal has become increasingly uneconomic due to sustained low natural gas and energy market prices, increasing market penetration of renewables, very-low-to-flat growth in demand for electricity, and the ageing of the nation's coal fleet. Without addressing these underlying causes, the most that the coal industry can do is *perhaps* slow coal's decline. But even that is not certain.

The only real hope for reviving the coal industry is for the price of natural gas – coal's major competitor – to spike, and to remain very high for long periods of time. That said, one of the Trump Administration's stated energy policy goals – in addition to making coal great again – is to expand the production of natural gas. If that is achieved, it would prevent sharp gas price spikes, possibly push natural gas and energy market prices even lower than they are now, and further decrease generation at coal-fired plants. This, in turn, would make coal plants even more uneconomical, probably placing a stake through the heart of coal, as nothing could be more harmful to the industry.

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**'THE ONLY REAL HOPE FOR REVIVING
 THE COAL INDUSTRY IS FOR THE PRICE
 OF NATURAL GAS ... TO SPIKE, AND TO
 REMAIN VERY HIGH FOR LONG PERIODS
 OF TIME.'**

Outside the coal industry and its circle of allies, most financial and utility analysts believe there is not much that can be done to bring coal back. S&P Global Ratings has concluded that eliminating or rolling-back federal environmental regulations will be of little help to the coal industry and that such rollbacks would be '*unlikely to quell the economic headwinds that have battered coal companies*' (SNL, 29 June 2017), and has also said that it expects only a '*minor uptick in coal production*' from historic lows in 2016, attributing the closure of 100 gigawatts (GW) of coal-fired generators since 2010 to low-priced natural gas.

Bloomberg New Energy Finance (BNEF) has concluded similarly that there is 'little hope' for coal due to the ongoing shift toward natural gas and renewables, as well as broad increases in energy efficiency. BNEF also has observed that the energy sector of the US economy is undergoing 'a major

transition.' According to Ethan Zinder, head of the Americas at BNEF 'We don't foresee any major comeback for coal anytime soon' in the USA. '*That's going to be a difficult transition for a lot of folks ... but this is a transition, this is a modern economy, and this is displacement, and this is reality*' (SNL, 8 February 2017).

It is also clear that the coal industry itself lacks full confidence in Trump's promises. Despite the actions that the new administration has taken to help coal, an additional 19 GW of coal plant retirements have been announced or included in new utility resource plans just since the beginning of this year, with 15 GW of these retirements scheduled to be completed by the end of 2020.

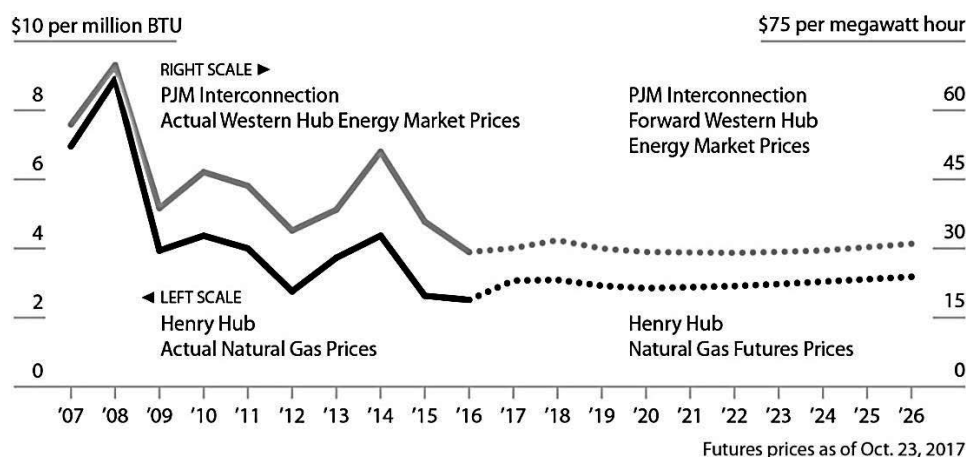
Low natural gas prices have undermined coal

As shown in the figure opposite, natural gas prices collapsed between 2008 and 2009, as a result of what has been called the 'shale gas revolution'. And, except for a few spikes, prices have remained low. Forward prices suggest that natural gas prices will remain low for the foreseeable future.

Low natural gas prices have disadvantaged coal in several significant ways.

Also shown in the figure, low gas prices have led to lower energy market prices in competitive wholesale markets, because they have reduced the cost of operating natural gas-fired combined-cycle plants (NGCC), especially the new, highly efficient units that have come online in the last 15 to 20 years. These units are increasingly setting market prices.

Because these NGCC units are less expensive to operate, they have increasingly been dispatched ahead of power from coal-fired plants, whose operating costs have been flat or rising. This had led to the displacement of energy from coal-fired



Historical and future natural gas and energy market prices

plants. The median capacity factor for coal-fired plants in 2016 was 57 per cent, down from 76 per cent in 2008 (before natural gas prices collapsed).

‘LOWER NATURAL GAS PRICES HAVE MADE MANY FORMERLY PROFITABLE COAL PLANTS OPERATE AT A LOSS ...’

In these ways, lower natural gas prices have made many formerly profitable coal plants operate at a loss – they are generating (and selling) fewer MWh of electricity and, at the same time, earning less from each MWh they are selling. Staff at the US Department of Energy have identified the ‘*advantaged economics of natural gas-fired generation*’ due to low gas prices as the ‘*biggest contributor to [US] coal plant retirements*’ (DOE, Staff Report to the Secretary on Electric Markets and Reliability, August 2017, page 13).

A total of 45 GW of new gas-fired combined cycle capacity was added to the electric grid between 2010 and 2016. An additional 19 GW is scheduled to be added in 2017, with a total of 81 GW of new NGCC plants potentially coming online in the next four years (SNL 1 November 2017). Even if only some of this gas-fired capacity is built, coal-fired generators will face increased competition and heightened risks in energy markets.

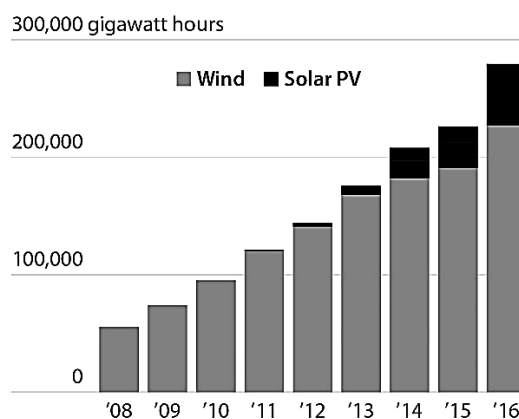
Increased penetration of renewable resources in energy markets poses a substantial financial threat for coal

The electric grid’s reliance on renewables has grown dramatically in the past decade as generation from wind and solar PV resources has increased five-fold between 2008 and 2016 (see the figure below).

In recent years, dramatic increases in wind and solar PV generation have been driven by steep declines in installation costs. For example, the average installed cost of wind projects has dropped 33 per cent, from a peak in 2009 and 2010 (*2016 Wind Technologies Market Report*, Lawrence Berkeley National Laboratory, August

2017). The median installed price for utility-scale solar PV projects has fallen by two-thirds since the 2007–2009 period (*Utility-Scale Solar 2016*, Lawrence Berkeley National Laboratory, September 2017). The installed prices for small-scale distributed solar PV projects have also fallen (*Tracking the Sun 10*, Lawrence Berkeley National Laboratory, September 2017).

The performance of new renewables facilities has improved over those added in earlier years. Wind turbine capacity factors have increased significantly over time as a result of design improvements such as higher hub heights and larger turbine blades. Solar PV capacity factors also have improved.



US annual wind and solar PV generation

Source: US Energy Information Administration.

As a result of lower installation costs and better performance, utility-scale solar PV and wind power purchase agreement (PPA) prices have been declining dramatically over recent years. Average levelized wind PPA prices declined from \$70 per MWh to about \$20 between 2009 and 2016. Average levelized solar PV PPA prices declined by 75 per cent from 2009 to 2016, when they came down to about \$35 per MWh for projects executed in 2016. Further declines in PPA prices are likely as installation prices continue to fall.

Some clean energy investors expect that wind and solar PV installation costs will decline so much that PPA prices will remain low even after wind production tax credits (PTC) and solar investment tax credits (ITC) are gone – with unsubsidized PPA prices of \$20–\$30 per MWh for wind and \$30–\$40 per MWh for solar PV by the early 2020s. These prices would be below the operating costs of many coal-fired generators.

As a result of these cost declines, wind and solar PV have become major contributors to the electric generation mix in large areas of the nation. Eight US states generated more than 15 per cent of their electricity in 2016 with wind: three of these, Iowa, South Dakota, and Oklahoma, generated more than 30 per cent of their electricity from wind. For limited periods in 2017, solar PV resources provided 50 per cent of the power in California, while wind provided more than 50 per cent of the power in Texas and the Southwest Power Pool (which stretches from west Texas to the Canadian border).

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**'WIND AND SOLAR PV CAPACITY POSE
 INCREASING LONG-TERM THREATS TO THE
 FINANCIAL VIABILITY OF COAL PLANTS.'**

Wind and solar PV capacity pose increasing long-term threats to the financial viability of coal plants. With no fuel costs, wind and utility-scale solar facilities are dispatched first in

the competitive markets, helping to keep energy market prices low while displacing energy from coal- and even gas-fired generators. In particular, solar PV generation keeps energy market prices lower during the peak afternoon periods when coal-fired generators would otherwise be earning their highest profits. Generation from wind and solar PV also frequently leads to zero and negative energy market prices during some hours in competitive wholesale markets.

Moody's has concluded that declining wind generating costs puts 56 GW of coal capacity in the Great Plains 'at risk' of retirement ('Rate-Basing Wind Generation Adds Momentum to Renewables', Moody's Investor Service, 15 March 2017). Moody's notes that *'Wind power economics are driving coal generation up the dispatch curve and into early retirement'* (Utility Dive, 23 March 2017). The same can be said for utility-scale solar PV investments.

Distributed rooftop solar PV also undercuts the profitability of coal-fired generators. By reducing the loads on the grid, distributed solar PV leads to lower energy market prices at the same time that it reduces the need for generation from coal.

And more wind and solar PV resources are coming – perhaps as much as 100 GW by 2022 – according to S&P Global Market Intelligence (SNL, 1 November 2017). Studies by regional ISOs show that, with upgrades, the grid can handle substantially more renewables resource than it now has. For example, the Southwest Power Pool believes that, with transmission improvements, it has the potential to serve as much as 75 per cent of its load from wind resources ('SPP Eyes 75% Wind Penetration Levels', RTO Insider, 20 February 2017).

Future growth in renewables will be part of a 'steel for fuel' policy adopted by a growing number of utilities and merchant generators. 'Steel for fuel' means replacing fossil-fired generators

with renewables resources. Because utilities can profit by rate-basing investments in new wind resources, many are replacing older, inefficient coal-fired plants with wind capacity ('Rate-Basing Wind Generation Adds Momentum to Renewables', Moody's Investor Service, 15 March 2017).

At the same time, renewables demand is increasingly coming from the corporate sector as a number of companies (such as Google, Walmart, Facebook, Mars, and Nestle) have set goals to use 100 per cent renewables resources. It is estimated that this direct purchase of renewables from generators, which is outside traditional utility resource procurement, will grow to between 10 GW and 50 GW over the next five to seven years.

Slow-to-flat electricity demand

Growth in domestic US electricity demand has slowed considerably in recent years. After averaging 2.5 per cent annually in the late 1990s, growth slowed first to an annual average of 1 per cent from 2000 to 2008, and has remained relatively flat since then. In some areas, demand has actually declined. This slowing of demand has been due to a number of factors, including:

- the impact of formal energy efficiency programmes and investments,
- increased interest from consumers in saving energy,
- rising generation from distributed 'rooftop' solar PV resources,
- a decoupling between energy consumption and economic growth.

US gross national product grew by 1.6 per cent in 2016 while energy consumption fell by 0.2 per cent. This decoupling has resulted from strategies of industrial customers and large utilities that have enabled them to better manage their power use, and from changing residential consumption habits. All these factors are likely to dampen future demand growth.



This means that as new gas-fired and renewables capacity is added to the grid, competition increases for an electricity demand 'pie' that is not growing much, if at all. This competition will continue to disadvantage coal-fired plants by keeping both energy market and capacity market prices low for the foreseeable future.

Coal plant ageing

The existing US coal fleet is growing old. Less than 8 per cent of the current 263 GW of the existing coal capacity in the USA is less than 20 years old. Only 13 per cent is less than 30. More than half is 40 years of age or older. Ominously for the industry, more coal capacity is older than 50 years (15 per cent) than is younger than 30.

The ageing of the coal fleet means that coal plants risk becoming even more unprofitable, due to the potential for higher operating and maintenance (O&M) expenses (increasing capital expenditures to replace failing or degraded plant equipment), and declining plant performance (such as higher heat rates and/or lower availability) (US Department of Energy (DOE) Staff Report on Electricity Markets and Reliability, August 2017, pages 154–5).

The federal government's proposal to bail out coal plants would be expensive for consumers and taxpayers

In the guise of ensuring electric grid reliability by preventing the premature retirement of 'fuel secure' baseload generators, a proposal by the US DOE would subsidize the continued operation of tens of GWs of financially struggling coal plants.

A large number of groups – even including some coal-fired generators – have opposed the DOE proposal as an expensive bailout for old, inefficient coal and nuclear plants that would damage, or perhaps wreck, the nation's functioning competitive power markets. The Market

Monitor for PJM Interconnection has estimated that, depending on the precise rule adopted, electric customers in PJM could pay an extra \$10 billion to \$288 billion over the next 10 years to subsidize the continued operation of those coal and nuclear plants which fall within the scope of the proposal (Comments of the Independent Market Monitor for PJM in Federal Energy Regulatory Commission Docket No. RM18-1-000).

The DOE has proposed this bailout even though its own August 2017 Staff study found that environmental rules have not been a significant cause of coal and nuclear plant retirements.

Interestingly, the author of the DOE Staff study has said that the coal plants that have closed in response to new environmental regulations '*were all failing economically*' and their operators used the regulations' compliance deadline as a logical date to close them ('Author Describes Writing Controversial DOE Grid Reliability Report', *Forbes*, 12 November 2017). She also explained that the coal and nuclear plants that the DOE proposal was supposed to bail out '*cannot provide the essential resiliency and reliability*' that the grid needs, such as voltage support. '*Coal and nuclear plants are just not good at anything but spinning reserve. They can't do anything except generate electricity that was once cheap and now ain't so cheap relative to the other stuff*' (ibid.).

Carbon capture and storage

All of the bailouts being discussed in the USA today focus on preventing further coal plant retirements. The industry's hope for a long-term way to bring back coal rests on carbon capture and sequestration (CCS) technologies that have not been proven to be either technically feasible or economically viable. At best, some test projects have captured some of the post-combustion carbon dioxide (CO₂) emissions from coal plants. But the cost is high and the technology

‘CARBON CAPTURE AND SEQUESTRATION (CCS) TECHNOLOGIES HAVE NOT BEEN PROVEN TO BE EITHER TECHNICALLY FEASIBLE OR ECONOMICALLY VIABLE.’

remains unproven. Some estimates state that adding capture technology to new or existing coal plants would raise the cost of generating power by 60–80 per cent – meaning that unless heavily subsidized by consumers and/or taxpayers, currently unprofitable coal plants would become even less uneconomic compared to renewable resources with declining costs.

The two completed projects in the USA with the potential for pre-combustion capture of CO₂, the Kemper and Edwardsport projects, have been extremely expensive to build and operate. Southern Company's flagship Kemper coal gasification plant in Mississippi became so expensive to build (over \$7 billion versus an originally estimated \$3 billion price tag) and had so many problems with its gasification system, that the owners have recently decided to stop burning coal there. They will operate it as an extremely expensive natural gas unit with no capture of CO₂.

Duke Energy's Edwardsport project in Indiana also experienced massive cost overruns, and operates unreliably. The power it produces has cost almost five times as much as the cost of buying the same amounts of energy and capacity from the markets. Although Edwardsport was initially promoted as a way to cut greenhouse gas emissions, Duke decided early on that the plant would not attempt to capture any CO₂.

Kemper and Edwardsport show that pre-combustion CCS does not offer any meaningful hope that the large-scale capture and permanent sequestration of CO₂ will be technically feasible or economically viable.

The USA and climate change: the importance of electricity

David Robinson

Introduction

This article considers the significance of US withdrawal from the Paris Agreement (PA) on climate change. The world's combined pledges under the PA are seriously insufficient to meet the aims of the agreement and the withdrawal of any country is bad news. When that country is the USA, there is a concern that other countries will follow. However, the growing economic, financial, and political pressures favouring decarbonization in the USA and abroad diminish the significance of US participation in the PA.

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'TRUMP'S POLICIES, ESPECIALLY HIS SUPPORT FOR COAL, COULD SLOW BUT WILL NOT REVERSE US ELECTRICITY DECARBONIZATION ...'

An analysis of the power sector illustrates the point. Trump's policies, especially his support for coal, could slow but will not reverse US electricity decarbonization, the main source of CO₂ reductions since 2005. Partly, this reflects domestic opposition to Trump's policies and financial reluctance to invest in coal-fired assets. More fundamentally, it reflects two trends:

- gas-fired generation based on low-cost unconventional gas displacing coal-fired generation;
- renewable electricity (RE) displacing conventional generation.

Electricity decarbonization will continue to be a significant source of greenhouse gas (GHG) emission reductions, regardless of whether the USA leaves the PA.

Whatever happens in the USA, accelerated closure of coal-fired generation and the deep penetration of RE are necessary globally to have any chance of meeting the PA targets. Initially,

natural gas will replace coal, although the economics for this are not nearly as attractive outside the USA. Eventually, meeting the PA goals requires deep penetration of RE and electrification of other sectors, starting with transport and buildings. For this to happen, we need new low-carbon storage technologies, market designs, and regulations, as well as falling costs of RE and storage. We also need international climate finance for decarbonized electricity and electrification in the developing world, where most incremental GHG emissions will occur or be avoided.

The first part of this article provides: some background to the PA, US pledges under that agreement, Trump's policies, and forecasts concerning US decarbonization. The next section explains the importance of the role played by electricity in decarbonizing the US economy, along with remaining challenges. The last section draws conclusions.

Background

The Paris Agreement

The aims of the agreement are to strengthen the global response to the threat of climate change, in the context of sustainable development and efforts to eradicate poverty by:

- a) limiting the increase in the global average temperature to between 1.5 °C and 2 °C above pre-industrial levels;
- b) increasing the world's ability to adapt to the adverse impacts of climate change and fostering climate resilience and low GHG development;
- c) making finance flows consistent with a pathway towards low GHG and climate-resilient development.

In Paris in December 2015, more than 180 countries, representing more than 95 per cent of global GHG emissions, pledged to make 'intended nationally determined contributions' (INDCs) to meet the aims of the PA. Over 160 countries, including the USA, have since ratified the PA, converting their INDCs into NDCs. The combined pledges fall well short of the aims of the PA, which explains why the agreement requires all countries to be more ambitious in future. The developed countries, including the USA, committed not only to adopt and meet increasingly ambitious GHG emission reduction targets, but also to make financial transfers to enhance climate resilience and promote sustainable economic growth in developing countries.

The US NDC

The US NDC under the PA is an economy-wide target to reduce net GHG emissions by 26–28 per cent of 2005 levels by 2025; it includes land use and LULUCF – land use change and forestry that acts as a sink absorbing GHG. The NDC builds on a US commitment at the Copenhagen COP to reduce emissions by 17 per cent by 2020 compared to 2005. The USA also pledged in Paris to contribute \$3 billion to the Green Climate Fund (GCF); this fund was established to assist developing countries in adaptation and mitigation practices to counter climate change. As part of the PA, parties should develop long-term strategies. The Obama Administration submitted an emissions reduction target of 80 per cent or more below 2005 levels in 2050.

According to the US Environmental Protection Agency ('[Fast Facts 1990–2014](#)', EPA) net GHG emissions in 2005 were approximately 6,060 million metric tons carbon dioxide equivalent



(MMmtCO₂e), including LULUCF (the author has converted the EPA data from short tons to metric tons). With this 2005 baseline, meeting the targets implies reducing annual emissions by approximately 1,030 MMmt in 2020 and 1,575 MMmt in 2025. Under the US NDC, emission reductions will come primarily from the energy sector, including:

- stricter fuel economy standards for vehicles;
- measures to conserve energy in buildings;
- restrictions on methane emissions; and
- cutting emissions from coal-fired power stations.

Of the 2005 total, electricity generation accounted for 2,177 MMmtCO₂e and transportation for 1,723 MMmtCO₂e, together close to two-thirds of the total.

Trump's PA announcement and policies

President Trump's announcement of the US intention to withdraw from the PA was no great surprise. This was a signal to his domestic political base and especially to supporters from the fossil fuel industry. It was also a further example of his intention to undermine multilateralism and ignore US international commitments.

In the USA, there has been a strong negative political and public reaction to the Trump announcement. In particular, the [We Are Still In](#) platform represents cities, states, corporations, faith-based groups, universities, and other groups that are committed to the goals of the PA. It includes cities and states representing over 56 per cent of the US population. Abroad, COP23 (the UN Climate Change Conference) in Bonn in November 2017 confirmed that the rest of the world appears to be committed to the PA. Other countries, notably China, India, and Canada, together with the EU, appear to be seeking to fill the leadership gap.

..... '[TRUMP'S] ADMINISTRATION HAS BEEN BUSY ROLLING BACK US CLIMATE POLICIES ADOPTED DURING THE OBAMA PRESIDENCY.'

Trump's policies are more important for US efforts to address climate change than his PA announcement. His Administration has been busy rolling back US climate policies adopted during the Obama presidency (see Colombia Law School [Climate Deregulation Tracker](#)). In March 2017, his [Executive Order](#) on 'energy independence' rescinded the Climate Action Plan, which was critical to achieving the US NDC. In October 2017, the EPA Administrator signed a rule to repeal the Clean Power Plan (CPP), whose primary goal was to reduce emissions from coal-fired generation. (This Plan had previously been held up in court following an appeal by states that were opposed to it.) His administration is now considering a new import tariff on solar panels, and Secretary of Energy Perry has [proposed an additional payment](#) to coal plants to compensate for their contribution to system security.

Forecasts with respect to meeting US NDC

The Rhodium Group concluded in May 2017 that the USA was within striking distance of its Copenhagen target of a 17 per cent reduction by 2020, largely due to a reduction of about 684 MMmt (754 million tons) in annual GHG emissions between 2005 and 2015.

But absent new policies, Rhodium's baseline forecast was that the USA was on course for a 15–19 per cent reduction in GHG emissions by 2025 – considerably short of its NDC target of 26–28 per cent compared to 2005 levels. Taking account of uncertainty related to economic growth, the cost of natural gas and REs, policy variables, and LULUCF, their range of

emissions reductions was 13–23 per cent by 2025. The report stressed the potential to reduce emissions further, notably through federal and state policies supporting replacement of coal. In short, these forecasts suggest significant uncertainty about US GHG emissions and pessimism with respect to meeting the USA's international commitments.

The importance of decarbonizing electricity

There is a growing policy consensus that there are two necessary, although insufficient, steps to meeting PA targets: decarbonization of electricity and the electrification of transport and buildings. The remainder of this article focuses on illustrating the importance of electricity decarbonization.

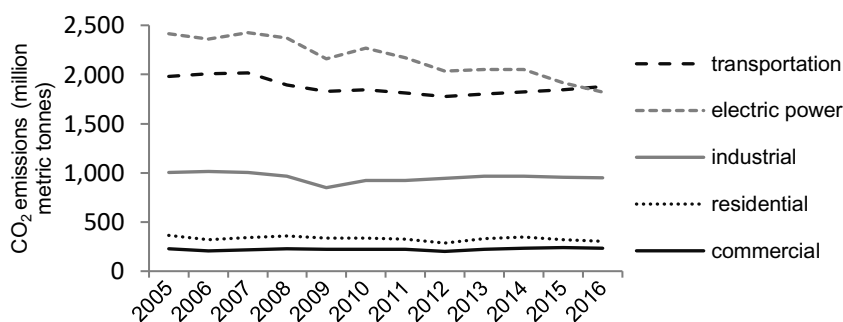
Most US CO₂ emission reductions have come from the electricity sector

Between 2005 and the end of 2016, the US Energy Information Administration (EIA) estimates that annual energy-related CO₂ emissions (80 per cent of GHG emissions) fell by 13.7 per cent, from 5,993 to 5,170 MMmtCO₂e. Rhodium estimates that the electricity sector was responsible for about 70 per cent of these reductions. The figure overleaf reflects the relative importance of electricity decarbonization.

Two factors account for the lower carbon emissions (and lower carbon intensity) of electricity:

- substitution of coal-fired generation by gas-fired plants, and
- growth in wind and solar power.

According to the EIA, ([US Energy-Related Carbon Dioxide Emissions, 2016](#)), between 2005 and 2016 CO₂ emissions from the power sector declined by a *cumulative* 3,176 MMmt. Of that, 2,007 MMmt were due to the shift to natural gas and the remainder to the increase in non-fossil electricity, especially wind and solar. Fossil fuel



US carbon dioxide emissions by sector (2005–16)

Source: <https://www.eia.gov/totalenergy/data/monthly/#environment>.

electricity generation declined by about 9 per cent, non-fossil electricity generation rose by 25 per cent, and electricity demand grew by 1 per cent.

‘THE DECARBONIZATION OF THE ELECTRICITY SECTOR REFLECTS A LONG-TERM TREND AWAY FROM COAL.’

The decarbonization of the electricity sector reflects a long-term trend away from coal. Coal’s share of electricity generation fell from 53 per cent in 1990 to 30 per cent in 2016, while the share represented by natural gas rose from 12 per cent in 1990 to 34 per cent in 2016. Wind and solar have risen steadily, accounting for 16 per cent of non-carbon resources in 2016, up from less than 1 per cent in 2000.

Looking forward – coal versus natural gas

There was an initial sense of optimism among the coal community that coal might make a revival when President Trump arrived, and coal-based generation did rise in the first six months of 2017. However, the latest data suggest that coal-based generation in 2017 is roughly unchanged from last year. The future for coal looks bleak. There are three reasons.

First, the economics now favour natural gas. The switch from coal to natural gas reflects the very low prices of natural gas resulting from the shale gas revolution.

The cost advantage of natural gas over coal reduces the running hours and profitability of coal-fired generation. If this advantage is maintained, which is likely, it will accelerate the closure of existing coal plants, even without the additional regulatory requirements associated with the CPP.

Second, there is strong civil society opposition to coal-fired generation. For instance, the Sierra Club maintains that their *Beyond Coal Campaign* has been responsible for the retirement (or planned retirement) of over 265 plants since 2010. They have another 258 plants in their sights. They argue that the electricity sector alone could reduce US GHG emissions by an additional 500 MMmt by 2025, primarily through demand reduction and by replacing coal-fired power stations by natural gas and RE. If this forecast proves correct, by 2025, electricity decarbonization alone will have reduced US GHG emissions by about 17 per cent since 2005. Groups like the Sierra Club and the World Wildlife Fund (WWF) rely heavily on local grassroots support, but are also ready to challenge in the courts any regulations or policies that favour coal or penalize decarbonization, and to mount powerful campaigns within the USA and abroad. For instance, the WWF is behind the We Are Still In coalition.

Third, even if Trump’s policies manage to prolong the lives of some US coal plants, there is very limited, if any,

financial appetite to invest in plants facing a significant risk of being stranded assets. The assets may soon be uneconomic due to competition from gas and RE, or be stranded if a new administration reversed Trump’s decisions before (or soon after) they come into effect.

Secretary of Energy Perry is pressing for an additional payment for coal-fired generation on the grounds that these plants provide resilience to the system. His proposal faces stiff political and legal resistance from utilities, states, and other lobbies that wish to close the plants. But even if it were introduced, the payment would be for capacity and would probably not affect the variable running cost. Existing coal-fired plants might remain open longer, but run very little because there would be less expensive electricity from other sources, notably natural gas and RE.

Looking forward – renewable energy

The share of RE will definitely increase, although how far and how quickly depends on policy support and increasingly on economics.

First, the economics of RE have improved substantially. The recent IEA World Energy Outlook (WEO-2017) notes that in ‘2016, growth in solar PV capacity was larger than for any other form of generation; since 2010, costs of new solar PV have come down by 70 per cent, wind by 25 per cent and battery costs by 40 per cent’. In their New Policies scenario, which reflects existing policies and announced intentions to 2040, the IEA argue that RE will capture two-thirds of global investment in power plants as they become, for many countries, the least-cost source of new generation.

This view is supported by the financial and corporate sectors. For instance, a recent study by the investment bank Lazards concluded that the levelized costs of energy for wind and utility-scale solar were now lower than for



gas and coal-fired plants. Meanwhile, a growing number of large corporations are committing to buying only RE.

Second, federal tax credits provide important investment incentives for solar PV and wind power. The tax regime will last until 2020, unless modified by new tax legislation, which had not yet been passed at the time of writing this article. These tax credits are unlikely to disappear altogether because of support from states of different political colour. In any case, as the economics of RE improve, the credits become less important.

Third, at the state level, Berkeley Lab reports that renewable portfolio standards (RPS) have accounted for roughly half the growth in US RE since 2000. An RPS requires suppliers to meet a share of consumer demand from RE. Twenty-nine states now have RPS covering 56 per cent of US retail demand. Anticipated RPS growth implies a 50 per cent increase in RE generation by 2030, equating to 55 GW of new capacity. Like most forecasts of RE, this one probably underestimates the growth in the USA. The National Renewable Energy Laboratory, for instance, argues that renewables, combined with a more flexible electric system, will be more than adequate to supply 80 per cent of total US electricity generation by 2050.

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‘RENEWABLES, COMBINED WITH A MORE FLEXIBLE ELECTRIC SYSTEM, WILL BE MORE THAN ADEQUATE TO SUPPLY 80 PER CENT OF TOTAL US ELECTRICITY GENERATION BY 2050.’

Energy sector decarbonization in the USA

Solar and wind energy are intermittent sources of electricity requiring backup, initially from flexible, conventional power stations. To meet the PA goals, deep penetration of intermittent RE requires research and financial support

to develop low-carbon sources of flexibility and storage, from batteries and flywheels to more traditional technologies like pumped storage (which accounts for over 90 per cent of storage today). But introducing RE and low-carbon flexibility is not simply a matter of technological innovation. It is also about market and regulatory reform. At the Oxford Institute for Energy Studies, we are developing new consumer-driven market designs and policies to integrate high levels of RE (see for instance, ‘The decarbonised electricity system of the future: the “two market” approach’, Malcolm Keay and David Robinson OIES Energy Insight: 14, June 2017).

As electricity is decarbonized and storage options become cheaper, the economic and environmental logic for electrifying the rest of the economy will strengthen and, in some cases, be overwhelming. However, electrification will require, *inter alia*:

- new fiscal policies for the energy sector to internalize the local and global environmental externalities associated with the use of fossil fuels,
- new electricity charging structures to minimize the cost of increased use of electricity, and
- new thinking about the role of markets and governments when it comes to dealing with the stranded assets that will result.

Concluding comments

US energy strategy is different

The US energy situation is changing because of the growth of unconventional hydrocarbons and the diminishing concern over energy security. Meanwhile other countries are concerned about growing oil and gas import dependence and may feel greater pressure to cooperate for security reasons as well as to address climate change. The USA may be content to be a bystander in future, as it has in many international

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‘THE GREATEST BARRIER TO MEETING THE THREE OBJECTIVES OF THE PARIS AGREEMENT IS CARBON-INTENSIVE ECONOMIC DEVELOPMENT IN THE DEVELOPING WORLD ...’

agreements, while continuing to reduce GHG emissions, whether or not it is a signatory to the Paris Agreement.

Sustainable development

The greatest barrier to meeting the three objectives of the PA is carbon-intensive economic development in the developing world, especially in countries that face rapid population and economic growth. This is one area where Trump’s policies could make matters much worse. The US decision to withdraw from the Paris Agreement means the USA will not pay the remaining \$2 billion of the \$3 billion it had committed to the GCF. Worse, the USA would presumably be renegeing on the commitment made by the developed countries to mobilize US\$100 billion per annum by 2020 for climate financing for developing countries. Furthermore, the US federal government is in a position to influence energy policies of developing countries, for instance through export credit guarantees, lending policies of international financial institutions like the World Bank, and direct political pressure. Whereas the Obama Administration used this influence to press for energy decarbonization and climate finance for the developing world, the Trump Administration is doing the opposite. This deserves greater attention and remedies. In particular, investors and regulators in the world’s major financial markets should demand disclosure of climate-related risks related to investment in carbon-intensive activities, wherever they occur. Furthermore, signatories to the PA should do what they can to limit efforts by the USA to use international institutions like the OECD and the World Bank to promote the use of coal-based electricity.

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