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This edition of Forum is dedicated to an exploration of developments in US energy.

Javier Solana begins by exploring the geopolitical implications of the USA becoming less reliant on Middle East oil. Energy self-sufficiency facilitates a withdrawal from the Middle East, allowing the USA to shift its attention to Asia, where China is increasingly powerful. The USA will never entirely cut itself off from Middle East tensions, not least because of its relationship with Israel and its interest in maintaining stable world energy prices. Nevertheless, it has every reason to want a peaceful resolution of the many conflicts in the region, especially related to the nuclear standoff with Iran. Meanwhile, China is increasingly dependent on Middle East oil and gas, and will be strongly motivated to contribute to peace in the region, even if that gives the USA greater freedom to concentrate its attention in Asia.

Richard Mallinson analyses key features of President Obama's approach to the energy sector. The recent prediction that the USA will soon become a net exporter of energy is optimistic. The sustainability of US oil and gas production levels depends on prices being high enough to cover long-run costs. The President will be cautious in approving exports of oil and natural gas. Renewable energy and energy efficiency may well be his legacy issues, but the political emphasis will be on reducing America's dependence on fossil fuels, both foreign and domestic.

Amrita Sen analyses whether US shale oil production might usher in a new era of cheap oil. Although non-OPEC production has been disappointing, US oil production has grown substantially, thanks largely to hydraulic fracturing (fracking) and horizontal drilling. Furthermore, the US accounted for almost a quarter of global CAPEX on E&P in 2012. However, shale oil production is costly. Maintaining or increasing production levels will require prices of around $90 per barrel (Brent). Below that, non-OPEC supply will struggle again. On the other hand, the potential to increase US production is likely to put a cap on long-term oil prices at about $110–115 per barrel.

Charles Ebinger and *Govinda Avasarala* review the debate about whether to restrict US natural gas exports. 'Protectionists' argue that exports would substantially raise the domestic natural gas price and put at risk the economic benefits of low-cost natural gas, especially for major gas-consuming industries. Those who favour exports argue that LNG projects will have a very modest impact on domestic US gas prices, will promote investment in the upstream and midstream gas sector, and will have wider macroeconomic and geopolitical benefits for the USA. The

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authors conclude that market forces should be allowed to determine the level of exports.

Jim Henderson shows that market forces will limit US natural gas exports. Domestic natural gas prices are expected to rise from their current levels of about US $3/mmBtu, making exports to Europe less attractive. In Asia, competition from new projects will limit US export potential and margins. Domestic production of shale gas in China could also significantly reduce US export potential. US exports will therefore be significantly less than the potential LNG capacity now seeking permits. Nevertheless, potential exports linked to Henry Hub prices will encourage a 'psychological' shift away from oil-based contracts, and help to establish a ceiling on internationally traded gas.

Kevin Hassett and *Aparna Mathur* argue the economic case in favour of fracking. The 'left' has characterised fracking as dangerous, unhealthy and potentially nefarious, whereas the 'right' considers it to be the best hope for a struggling economy. Direct benefits include the value of increased oil and gas production, along with the impact on employment and the trade balance. The indirect economic impact of lower natural gas prices includes reduced emissions from a shift to natural gas in the power sector, cheaper electricity, the multiplier effect on local economies, and the increased value of land in shale gas regions. The debate about fracking should focus more on the economic benefits and explore the environmental consequences carefully.

Joseph Aldy argues the case for a federal US carbon tax to drive more climate friendly economic activity, especially given the fiscal constraints on future clean energy subsidies and the prospect of inefficient, costly, and uncertain regulatory mandates. The proposal is for an upstream carbon tax reflecting the CO2 content of coal, oil and natural gas, set at a politically feasible social cost of carbon. The tax will provide certainty about the marginal cost of compliance and drive changes in investment and use of emission-intensive technologies. The tax revenues could be recycled back into the economy to compensate low-income households or to lower corporate income tax rates, and thereby stimulate economic activity.

David Buchan analyses the significance and limitations of California's new cap and trade regime. One of several measures in California's Global Warming Solutions Act, it aims, by 2020, to cut the state's greenhouse gas emissions by around 15 percent from 2012 levels. It is the first serious state cap and trade system in the USA designed to reduce greenhouse gases, but will only contribute about a quarter of the reductions. The remaining reductions come mainly from efficiency standards and regulation to reduce energy emissions. Consequently, California will face similar problems to those experienced in the EU: reduced demand and depressed prices for CO2 emission permits, and incentives for leakage of carbon intensive activities. Nevertheless, the regime has the potential to reduce political resistance to similar regimes, and to provide decarbonisation incentives for those sectors not covered by direct regulation.

Peter Fox-Penner explores the future of U.S. electricity utilities. Low natural gas prices and access to low cost finance have left U.S. utilities in good financial shape, unlike their counterparts in Europe, and their decarbonisation has begun without national climate change legislation. The cost of decarbonisation may be lower than thought as U.S. utilities continue reducing coal-based generation and searching for new regulatory models to maintain financial health. Among the challenges remaining, the greatest will be changes in technology and governance from the application of digital control and storage technologies to the grid.

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GEOPOLITICS AND US ENERGY POLICY

America's Perilous Pivot

JAVIER SOLANA

The Pacific or the Middle East? For the United States, that is now the primary strategic question. The violence in Gaza, coming as President Barack Obama was meeting Asia's leaders in Phnom Penh, perfectly encapsulates America's dilemma. Instead of being able to focus on US foreign policy's 'pivot' to Asia, Obama was forced to spend many hours in conversation with the leaders of Egypt and Israel, and to dispatch Secretary of State Hillary Clinton from Asia, in order to facilitate a cease-fire in Gaza.

Of the two geopolitical focal points demanding America's attention, one represents the future and the other the past. Whereas Asia played an important role in a US presidential election campaign that was marked by often-heated references to China's rise, the Middle East has kept the USA bogged down for decades. In addition to the eternal Israel-Palestine conflict, Iraq's instability, the Arab Spring, Syria's civil war, and the ongoing nuclear standoff with Iran all demand America's attention.

Indeed, the revolution in non-conventional hydrocarbons, particularly shale gas and oil, which the International Energy Agency recently predicted would make the USA the world's largest oil producer by 2020, and the top energy producer overall by 2030, will have enormous global repercussions. For the USA, energy self-sufficiency is the perfect excuse for a phased withdrawal from the Middle East; freed from energy dependency, America should be able to concentrate on the Pacific.

Although maintaining stable global energy prices and its alliance with Israel means that the USA cannot cut itself off completely from the Middle East's troubles, the shift in focus to Asia began early in Obama's first administration, with Clinton announcing America's strategic reorientation even before US troops began withdrawing from Iraq. Following his re-election, Obama's first foreign visit was to Myanmar, Thailand, and Cambodia – a choice that cannot have pleased China, as all three are ASEAN members, while Myanmar was, until it began its democratic transition, a close Chinese ally.

> ***"China has a large strategic interest in working with the USA to avoid a showdown."***

Asia is, of course, experiencing rapid economic growth, but managing the region's strong nationalist tensions calls for the creation of regional security structures, together with closer economic integration. Complicating matters even more is what US scholar Kenneth Lieberthal and Wang Jisi, the dean of international studies at Peking University, called in a recent paper for the Brookings Institution 'strategic distrust'.

Cultivating strategic trust between the twenty-first century's leading powers will be fundamental to the international system's harmonious functioning. But how can this be achieved? As China will be importing three-quarters of its oil from the Middle East by 2020, one step forward would be China's cooperation in finding solutions to the region's problems.

After the January 2013 Israeli elections, Iran will again move to the top of Obama's foreign-policy agenda. Military intervention in Iran – which itself will be holding a presidential election in June – would incite not only regional, but global, instability. The Arab world, Russia, and China would be forced to take sides, straining global relations between the different poles of power and raising tensions in the Pacific. So China has a large strategic interest in working with the USA to avoid a showdown.

> ***"Both sides may believe that their best option – at least for now – is to negotiate."***

Beyond Iran, the volatile situation throughout the Middle East urgently demands solutions. The latest eruption of violent conflict between Hamas and Israel underscores the importance of reviving the peace process. Syria's civil war, in which a growing number of regional players have become involved, is beginning to look increasingly like a trial run for all-out war between Sunni Muslims (Saudi Arabia and the other Gulf States, Turkey, and Egypt) and Shia Muslims (Iran and Hezbollah) for regional dominance

Iran's leaders appear to believe that the USA, having incurred extremely high economic and human costs from more than a decade of war, would rather avoid another military intervention. US public opinion seems to confirm this. A recent survey by the Chicago Council on Global Affairs indicated that 67% of Americans believe that the Iraq war was not worthwhile. Moreover, 69% do not believe that the USA is safer from terrorism since the war in Afghanistan, and 71% say that the experience in Iraq shows that the USA should take greater care in how it uses force.

But, if Americans seem unlikely to be willing to invest billions of dollars in another dead-end foreign adventure, Iran's leaders, for their part, are increasingly hemmed in by international sanctions, which are beginning to wreak havoc on the country's economy. Both sides may believe that their best option – at least for now – is to negotiate.

Peaceful resolution of the Iranian question would help the USA to complete its shift toward Asia. China may not wish for that outcome, but its own vital interest in the security of Middle East energy supplies should compel it to cooperate. After all, another Middle East conflict would poison and distort relations in the region for decades, which would be the worst of all possible consequences – for the USA and China alike. ■

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GEOPOLITICS AND US ENERGY POLICY

Obama's Energy Policy

RICHARD MALLINSON

In an interview with Time Magazine in December, President Obama made the bold assertion that '[t]he United States is going to be a net exporter of energy because of new technologies and what we're doing with natural gas and oil.' Although he did not place a timescale on this prediction or specify what new technologies he meant, his comment reflects a radical shift that has been taking place in US energy policy thinking.

The largest single cause of the shift has been the boom in US unconventional oil and gas production over the last six years. Domestic natural gas production is at record levels, averaging 65.9 bcf/d in 2012, while total oil production exceeded the 10 mb/d mark in October, for the first time in over 20 years. The rapid growth in production has led to speculation, in Washington and among market analysts, that the USA might achieve energy independence. No longer relying on imports, particularly from Middle Eastern countries, holds strong political appeal, especially when it offers additional domestic jobs in oil and gas production and an improved balance of trade. However, despite the positive outlook for US production, there are several factors limiting the prospects for America's energy exports.

Starting with supply; across oil, gas and coal the balance of domestic production to demand has improved recently. US coal production exceeded consumption by 93 million short tons in 2011 (or 9.2 percent) and 129 million short tons in 2012 (14.4 percent). Natural gas production is growing faster than demand and, in 2012, equalled 94.8 percent of US consumption. However, liquids consumption, particularly gasoline, remains the Achilles heel for America. Total US liquids production was an average of 8.915 mb/d below US demand in the year-to-October, despite growing y/y by 0.942 mb/d. However, increasing production and declining demand have together led US coal, oil and gas output to rise from around 71 percent of combined domestic consumption in 2010 to nearly 79 percent in 2012 (comparing barrels of oil equivalent (boe) volumes). This trend will continue, with shale expected to add a further 1.5 mb/d of crude production by 2017 under current leasing policies, but these increases in output will not fully close the gap with domestic demand over the next decade and certainly not position America to become a net energy exporter during Obama's second term.

The growth in domestic oil and gas has had a sharp impact on prices. Natural gas prices averaged $2.75/mmBtu in 2012, far below the highs of 2005. Politically, this has brought several benefits such as the resurgence of the US petrochemicals industry, which uses gas as a feedstock, and a shift from coal to gas in power generation that is helping to cut carbon emissions. For producers, the low gas prices have made the economics of drilling challenging, with many shifting their focus to oil despite WTI prices remaining depressed relative to Brent. Indeed, the impact of output on price is a major reason why forecasts of straight line growth in US output at recent rates are flawed. Increasing production presses down on prices, and as recently seen with coal and to some degree with shale gas, lower prices remove the incentive for operators to increase production. Given the relatively high costs associated with shale oil, if WTI prices were to fall below $85 per barrel for any length of time, crude output growth would begin to flatten off and, if prices fell significantly, could even reverse.

In response to the rapid changes caused by US shale oil and gas, producers have been at the head of growing calls on US policymakers to revise current restrictions on US energy exports. At present, apart from the approval for the Sabine Pass terminal to export 2.2 bcf/d globally, LNG exports are only permitted to 19 countries that America has a Free Trade Agreement with. Meanwhile, crude exports to any country are prohibited under Short Supply Controls and other legislation. (There are certain exemptions to permit shipping on the Trans-Alaska Pipeline, movement of crude of foreign origin or from the Strategic Petroleum Reserve if the export will directly result in the import of a refined product that would not otherwise be available.) Exports of certain types of refined products are allowed and volumes have risen to over 2.6 mb/d, although the rules are complex.

The clamour to change policies is growing louder over gas exports, in the form of LNG. The huge increase in volumes of shale gas and the collapse in price have led producers to lobby hard for approval of exports to non-FTA countries. They are being echoed by firms that invested heavily in regasification plants in anticipation of growing LNG imports, prior to the shale boom. These plants are being repurposed for liquefaction, but the economics depend on global export markets, not just the FTA countries. Advocates on LNG exports received a boost in December when a DoE-commissioned study was published stating the impact of increasing exports on domestic prices would be limited and would have a net benefit for the US economy (relying heavily on an economic theory approach).

There are also vocal opponents to exports. The petrochemical industry, which as noted is benefiting from low gas feedstock prices, immediately criticised the report for fundamental errors and argued that increased LNG exports would damage their industry and therefore US manufacturing jobs and investment. There is also resistance to exports in Congress. Several prominent Democrats have spoken against authorising exports, including Representative Markey and Senator Wyden, the new chair of the Energy and Natural Resource Committee. Although, recent comments suggest Wyden might accept limited LNG exports provided price increases could be managed and providing projects do not go ahead in his home state of Oregon. In an unusual alignment, several Hawkish Republicans also oppose exports, on the grounds that natural gas is a strategic asset that should be reserved for domestic use.

The DoE has not yet finalised recommendations on LNG exports and 16 applications for non-FTA export approval remain under review. Given the balance of supporters and opponents, the President is unlikely to grant blanket approvals for worldwide LNG exports. Instead, a case-by-case approach, with close monitoring of the impact on domestic gas prices, seems the most plausible approach, meaning a handful of projects would get the go ahead in 2013 and 2014.

For crude, although the USA is still a major net importer, a case can be made in favour of permitting exports. The chief reason is the mismatch between the volumes of light sweet crude that shale plays are producing and the US refining slate, which has been expensively upgraded to handle heavy crude. Logically, the excess light sweet crude could be exported while heavier crudes continue to be imported from Canada, Brazil and elsewhere. But politics is rarely that simple. Opponents of LNG exports would resist allowing crude exports for similar reasons, perhaps even more strongly. In addition, there would be the political challenge of justifying sending US crude abroad while America is still perceived to be, if not in practice, dependent on oil imported from the 'unstable' Middle East. Finally, unlike LNG exports, the administration would need legislative changes to be able to authorise crude exports, requiring a daunting public fight. Even with US crude production surging and the mismatch issues, there is little chance that the President will decide to expend his political capital fighting for powers to export crude oil.

Another politically sensitive issue is the increase in midstream capacity, especially pipelines, required in response to the changing landscape of US liquids. A series of pipelines are coming on stream, being reversed and being expanded to increase US access to Canadian oil sands output and to ease the inventory builds at Cushing. TransCanada's Keystone XL pipeline stands out because, as it crosses the US–Canadian border, the northern leg requires federal approval. The President rejected an application in January 2012, but signalled he would reconsider an amended route. With the election behind him and a generally favourable evaluation of the revised route for the pipeline by the state of Nebraska, Obama looks set to disappoint environmental groups by approving Keystone XL this year.

Environmentalists were similarly frustrated by how little focus Obama placed on renewable energy and energy efficiency measures in the 2012 election, despite their prominence in his 2008 campaign. However, they have not been forgotten by the President and may well prove to be legacy issues he focuses on in his second term. Already, wind energy tax credits were extended as part of the limited fiscal cliff deal signed at the start of January, a sign that Democrats will fight to maintain subsidies for renewable power generation. Obama's re-election has also secured the implementation of new CAFE standards by 2025, the first increase in fuel economy requirements since the 1970s, which is the single measure that can create the greatest reduction of American oil consumption in the long term by bringing down gasoline consumption.

Thus, while Obama's prediction that the USA will become a net exporter of energy seems optimistic and his approach to authorising exports will probably be cautious, he is presiding over a rapid reversal in American oil and gas fortunes and, in parallel, will keep pursuing policies to reduce America's future dependence on fossil fuels, whether domestic or foreign.

OIL AND NATURAL GAS

Shale Plays – Sitting High on the Cost Curve

AMRITA SEN

In recent years, a key theme in the oil market has been that of disappointing non-OPEC supply growth, despite an environment of high oil prices. Oil companies are struggling to generate substantial returns on their investments; decline rates have stepped up in various areas like the North Sea and Brazil; and existing fields are requiring a higher CAPEX spending on maintenance. This has resulted in challenging issues of feasibility and scalability and hence it has been harder for producers to generate capacity to offset declines in production. Moreover, planned capacity investments might not be achievable at the current budgeted costs. In recent years, infrastructure, material and manpower constraints have been significantly underestimated, leading to substantial cost overruns and project delays. Rising security costs have also played a part, as companies are increasingly operating in countries that are politically unstable.

Amidst the disappointments, US oil production offers a glimmer of hope, with production growth in 2012 at a phenomenal 1 mb/d. Today, US crude oil production has surged past 7 mb/d, the highest in nearly two decades, thanks largely to hydraulic fracturing ('fracking') combined with horizontal drilling that have allowed shale hydrocarbons to be produced more economically. The rapid pace of development has fuelled ideas of energy independence in the USA and a widespread belief that shale production will revolutionise an otherwise ailing non-OPEC supply. For over a year now, the perception has shifted from the notion of oil scarcity to a world awash in oil, thanks to the shale revolution. The natural extrapolation from a world awash in oil is that prices will fall, perhaps quite sharply, as shale revolutionises an otherwise ailing non-OPEC supply and puts to rest the argument of peak oil once and for all. Yet, while shale oil will be a source of substantial new production over the next decade, perhaps the most significant one, it will only do so if the price of oil does not fall too far. Therefore, shale oil is not going to be the reason that we return to an era of cheap oil, simply because if oil (Brent) falls below $90 per barrel for a sustained period of time, it would not be profitable to produce from these sources.

Although exploration success and the shale revolution are providing a new life for the US oil industry, the sector's cost curve remains high. It is the short lead times to bring production online from when the first well is drilled that work in favour of shale. In theory, US shale production breaks even at $50–$75 per barrel on average, depending on the different shale wells that make production theoretically viable. However, funding the upfront capital costs to hold acreage, to add infrastructure into plays, to do the science required to delineate sweet spots/completion and to drive growth, together with the high running costs of fracking processes, make the total variable cost far more expensive. This has driven break-evens for some of the independent companies well into the $90s. Eventually, offsetting decline in the base also becomes an additional cost burden. A drop in oil prices to $70 per barrel would take some $60 billion out of the system, worth a full year's CAPEX in unconventional oil across the USA. Instead of growing, overall US production would then flatline at best, if not start to taper downwards. A Brent price of $88–$93 per barrel is required to generate enough cash flow to sustain current US CAPEX spend.

The nature of tight oil drilling is very different from conventional production. For example, the natural decline rate of a Bakken well is extremely high, in most cases between 50 percent and 70 percent per annum, producing a severe fall in output in a field unless further fracturing is carried out and new wells are brought in. In this, Bakken is not alone. Judging by production results published by producers, first-year decline rates in unconventional basins look of the order of 50–80 percent, varying by basin and even within basins. They decline steeply thereafter, as well. Thus, the technique is particularly intensive in the use of fracturing crews and other oilfield service industry inputs.

Various CAPEX studies have found that oil and gas companies are likely to invest a record of more than $1 trillion worldwide in exploration and production activities in 2012, a year-on-year increase of 13.4 percent, with North America leading the way. Across that region, CAPEX is set to reach $254.3 billion, representing a share of 24.5 percent of the 2012 global total. Upstream spending in North America grew by 15.7 percent, outpacing the global average rate, with the bulk of the growth coming from shale producers, marking the third consecutive year of US spending gains. Surveys by IHS Herold, Dahlman Rose & Co, and others, offer similar estimates. An oil price of around $90 per barrel (Brent) is a minimum requirement for investments of such scale to be economical and justifiable.

The rapid response of shale oil producers to the sharp fall in oil prices (although Brent still averaged in the high $90s for just two months) in mid-2012, with some rapidly abandoning rigs, was evidence for the high breakeven price. So what makes shale expensive? As highlighted above, the cost of acreage, building out infrastructure, investment in R&D required to delineate sweet spots/completion and high decline rates all make the overall costs for shale production high. Surveys of independent US operators indicate that their drilling plan this year is based on a WTI price projection of above $82 per barrel, while producers start reducing their drilling programmes south of $70 per barrel.

These findings are also supported by the price levels at which US independents have tended to carry out their hedging programmes. Across 2012, an extensive list of US independents had swap contracts in place with an average price of $96 per barrel. The wave of producer hedging for calendar year 2013 began only when WTI prices climbed near and above $95 per barrel in October last year, with the average swap price at $97.5 per barrel. Of course, as plays develop, the industry is becoming more efficient and increasing the number of wells drilled by each rig per year. Increased efficiency is a key reason that the oil rig count might not need to rise substantially from current levels to keep production growing. If downspacing tests (i.e. drilling more wells per acre) are successful in the Eagle Ford and even in the Bakken fields, where new improved recovery techniques are also being trialled, production could grow further. However, hyperbolic decline rates remain a reality in shale plays and this contributes significant costs for shale oil producers, compared to the more conventional oil fields, making high prices a necessity for the viability of shale.

In conclusion, it is high prices that have led to the development of shale oil in the USA just as they have facilitated the growth of oil sands and sub-salt deposits in Brazil. If we move away from $90+ Brent prices, non-OPEC supply will be struggling again. So in a way, shale oil could put a floor on the oil price. However, the growth in these marginal barrels is also likely to put a cap on long-term oil prices, making any runaway increase in average prices much above $110–115 per barrel, beyond deteriorating geopolitical backdrop or in an environment of rapid economic growth, increasingly difficult. ■

OIL AND NATURAL GAS

The Case for US LNG Exports

CHARLES EBINGER and GOVINDA AVASARALA

The recent natural gas 'revolution' in the United States has encouraged a nationwide shift in its energy consumption patterns. An abundance of unconventional natural gas (with help from a patchy economic recovery) has allowed for sustained low natural gas prices. With prices currently hovering just over $3/mmBtu, many energy consumers – most notably power generators, manufacturing and petrochemical producers, and potential consumers of natural gas for transportation – are turning their attention to natural gas. But one natural gas consumer is generating the most controversy for its demand for the new bounty: natural gas exporters.

In May 2012, we co-authored a report, 'Liquid Markets: Assessing the Case for Exports of Liquefied Natural Gas'. In that study, we argued that the US government should neither prohibit nor promote liquefied natural gas (LNG) exports and that, by allowing the free market to allocate gas to its most economically efficient end-uses, the United States will reap both economic and geopolitical benefits. We still firmly support that conclusion. As we stated then: 'As a principal advocate and beneficiary of a global trading system characterized by the free flow of goods and capital, the United States has a long-term economic and political incentive to refrain from intervention in the market wherever possible.'

The Protectionist's Argument

As the policy currently stands, prospective exporters must submit applications to the US Department of Energy (DoE) for the right to export LNG to countries that have a free-trade agreement (FTA) with the United States and to those that do not. DoE is required to approve any application to export LNG to FTA nations 'without delay'. With respect to countries that do not have an FTA with the United States, DoE reviews each proposal and can only deny the application if it finds that exports are not in the public interest. (It is important to note that aside from South Korea, the United States does not have an FTA with any major LNG importing nation.) To date 17 projects have applied to DoE to export a total of more than 24 billion cubic feet of LNG a day (bcf/d) to countries that do not have a free-trade agreement with the United States. Only one of these projects – Cheniere Energy's Sabine Pass terminal – has received full approval from DoE to export to non-FTA nations; it has also received regulatory approval and is expected to begin exports from its Louisiana terminal by 2016.

Opponents of Cheniere's project and other prospective LNG exports are a diverse group. Some industrial gas consumers, manufacturers, and petrochemical producers argue that LNG exports will hurt the competitive advantage provided to them by abundant, cheap domestic natural gas feedstocks, a benefit not enjoyed by their Asian and European competitors. Dow Chemical, the industrial giant that is one of the more vocal industry critics of LNG exports, frequently asserts that the natural gas 'revolution' will trigger a manufacturing renaissance, which it estimates will add $90 billion in new investments to the US economy. 'We are all for exporting natural gas. We just want to see it exported in solid form instead of liquid form' said Andrew Liveris, Dow's CEO at CERA Week, an industry conference, in 2012.

Mr. Liveris' views are shared by some politicians in Washington. The most vocal opponent of LNG exports on Capitol Hill is Congressman Edward Markey of Massachusetts, the Minority Leader of the House Committee on Natural Resources. His campaign, 'Drill Here, Sell There, Pay More: The Painful Price of Exporting Natural Gas,' reflects his concern that exporting natural gas will mean 'exporting our manufacturing jobs along with the fuel'. Congressman Markey's views are shared – albeit with slightly more nuance – by Senator Ron Wyden of Oregon, the new Chairman of the Senate Committee on Energy and Natural Resources. Senator Wyden's hesitations about LNG exports apparently stem from the speed at which new project proposals are coming forth, and he has called for a 'timeout' on approving projects until the implications of exports are better known. Part of his concern stems from how the legislation 'rubber-stamps' proposals to export LNG to FTA nations, an acute concern given that the United States is in negotiations to establish a Trans-Pacific Partnership trade agreement that may include major LNG importers. (It is also important to note that the Senator's home state hosts one prospective LNG export facility that is opposed by many local groups.) Dow, Congressman Markey and Senator Wyden are joined in their opposition by many in the environmental community, who believe that shale gas production is harmful to the environment and that LNG exports would only increase US shale gas production.

Those in Favour

It is predictable that prospective exporters like Cheniere, Dominion Resources, and Sempra Energy all argue that natural gas exports will help, rather than hurt, the US economy. Exports, their argument goes, will require billions of dollars of investment in liquefaction plant infrastructure, new pipeline infrastructure, and will promote additional gas production, all of which would boost domestic employment. They maintain that any domestic price increases resulting from exports would be marginal and would not hamper the growth of domestic manufacturing. Prospective exporters are supported in their views by gas production companies, including Exxon Mobil (which has plans for petrochemical plant expansions and for an LNG export terminal), and the American Petroleum Institute (API), the oil and gas sector's trade association.

"... the prospects of large volumes of new supply suggest that the industrial sector's competitiveness is stable regardless of US export policy."

Companies and groups in favour of exports make some noteworthy points. First, a host of reports by third party analysts have found that the pricing implications of exports are indeed modest. Studies from three consulting firms – Navigant, ICF International, and Deloitte – and the Department of Energy's Energy Information Administration (EIA) have all found that under reasonable expectations for export volumes natural gas prices in 2035 would be between 2 and 11 percent higher if the USA does export LNG than if it does not. (Most analysts, including us, estimate that 4–6 bcf/day of LNG would be exported under reasonable market conditions.) These price increases should not sway the profitability of multi-billion dollar industrial investments. According to Kevin Book, Managing Director of ClearView Energy Partners, another consulting firm, 'if your margins are so thin that [modest price increases] could break them, then there isn't much benefit to putting up a plant here. Conversely, if it is so beneficial to do it here, then a small change in price probably won't undermine those benefits.'

Even if one cannot fault the industrial sector for being worried about potential price increases, given the high natural gas prices experienced in the 2000s, the prospects of large volumes of new supply suggest that the industrial sector's competitiveness is stable regardless of US export policy. Today the ratio of the price of oil to the price of natural gas is over 30:1, well over the 7:1 oil-to-gas price ratio at which US petrochemical and plastics producers are generally considered to be globally competitive. (Competing European and Asian petrochemical producers use oil-based products such as naphtha and fuel oil as feedstock, as they lack access to cheap natural gas.) Moreover, the majority of gas used for exports will come from new production, according to both Deloitte and the EIA. Increased drilling will likely result in greater production of natural gas liquids such as ethane, a valuable feedstock for industrial consumers. According to a study by the American Chemistry Council, an industry trade body, a 25 percent increase in ethane production would yield a $32.8 billion increase in US chemical production. To the extent that increased gas production linked to exports results in increased production of such natural gas liquids, they will benefit the petrochemical industry.

In addition to the economic benefits of more domestic natural gas production, LNG exports may have additional macroeconomic benefits, including to the balance of payments and foreign exchange. In December 2012 NERA, an economic consultancy, released a report commissioned by DoE modeling the macroeconomic implications of LNG exports under a variety of scenarios. The study found that in each scenario 'the US would experience net economic benefits from increased LNG exports.' To be sure, these are net economic benefits, and certain segments of the population are projected to be adversely affected by LNG exports. Both the benefits and the costs, however, are marginal. Welfare, represented in NERA's report as the amount that households are made better or worse off over the time horizon modeled, is estimated to increase between 0.004 percent and 0.03 percent, depending on the scenario. The greatest achievable net increase in GDP as a result of exports is 0.26 percent of GDP.

Opponents of LNG exports were quick to dismiss NERA's long-awaited report. Mr Liveris of Dow argued that the report 'fails to consider the tremendous competitive advantage that affordable, abundant domestic natural gas offers to the nation'. In an official letter to Secretary Chu, Senator Wyden expressed concern that the model uses 2010 EIA demand data, which do not reflect new forecasts for greater industrial sector natural gas demand. While this is true, the model also uses 2010 supply data, which has been subsequently revised dramatically upward to illustrate the increases in domestic gas production.

Finally, there is an additional benefit to LNG exports that is unquantifiable: its impact on geopolitics. Additional volumes of US LNG will be beneficial to the global gas market, potentially helping US allies in Europe and Asia that are dependent on natural gas for energy. While US export volumes are unlikely to transform the fragmented structure of existing LNG trade, US exports will provide liquidity to natural gas consumers around the world, potentially improving the energy costs for consumers in LNG-dependent countries like Japan and India. The US natural gas 'revolution' has already helped the prospects for European gas consumers: Gazprom, Russia's state-owned natural gas corporation, has been forced to revise many of its long-term contracts with European customers owing to the availability of cheaper spot-LNG cargoes once destined for the United States.

"Political interference and market intervention to prevent LNG exports will come at a cost."

Free Markets

At a more fundamental level, the USA has a responsibility as a principal advocate for and beneficiary of free trade. Political interference and market intervention to prevent LNG exports will come at a cost. The USA would forego any economic benefits realised through free trade and its reputation as a supporter of a global market characterised by the free flow of goods and capital would be damaged. (This is without even considering the potential for legal action against such a decision in international fora such as the World Trade Organization.) In response to objections to exports from industrial consumers, Jack Gerard, the President and CEO of API, stated: 'Restricting exports of energy as a "strategic resource" makes no more sense than unnecessarily restricting the export of chemicals, agriculture products or cars.' Moreover, government intervention in the allocation of rents (banning exports is a de facto subsidy to domestic consumers) often comes with unintended consequences.

This Might all be Hot Air – or Gas

As Kenneth Medlock, a leading energy economist at Rice University argues, the debate surrounding natural gas exports may be misguided. 'Allowing exports does not mean exports will occur in any particular volume,' he explains. Solely attempting to quantify how much LNG the United States can export misses a more important point. If allowed to work, the domestic and international gas market will determine the economically efficient amount of exported LNG. As we stated in our 2012 report, 'the economics of US LNG exports – both the costs associated with producing, processing, and transporting LNG, and the competitive nature of the global market – are likely to impose market-determined boundaries on their viability.' Moreover, export facilities are capital-intensive projects, requiring financing contingent on a confidence that the arbitrage opportunity will exist for the life of an LNG facility. Increases in domestic natural gas prices as a result of marginal increases in demand will have a negative impact on the economics of additional export projects, thereby protecting domestic consumers from unlimited exports and price rises.

Determining how much LNG should be exported, therefore, is not the responsibility of the US government, which should neither prohibit nor promote exports. In refraining from intervention in the gas market, the government will ensure that US gas is allocated to its most efficient end uses, many of which will bring ancillary political and economic benefits to the United States and its partners and allies around the world.

Note: Part of this essay is adapted from a May 2012 Brookings report, 'Liquid Markets: Assessing the Case for Exports of Liquefied Natural Gas'

OIL AND NATURAL GAS

The impact of Gas Exports from North America is likely to be more Psychological than Physical over the Next Decade

JAMES HENDERSON

Interest in potential gas exports from North America has risen sharply over the past few years as the combination of rising US gas production, increasing gas demand in Asia and a wide divergence of gas prices across the world's major consuming regions has created an arbitrage opportunity that US and Canadian producers and Asian and European customers have been keen to exploit.

In the first ten months of 2012, according to the Energy Intelligence Group database, the price of imported LNG to Japan averaged just under $17 per mmBtu compared to a US Henry Hub price of below $3/mmBtu, implying a significant margin for any company that could bridge the gap, even after accounting for the cost of liquefaction and transport. Furthermore, customers in Asia have become increasingly keen to access gas from a market where prices are set by gas-on-gas competition rather than the traditional link to oil prices, in particular because the cost of new gas supplies to Asia appears to be on the rise. A number of Japanese, Chinese and Korean companies in particular have already signed contracts to purchase gas from the USA and Canada at gas market related prices, and have also begun to invest in the upstream and midstream assets that could potentially supply the gas exports.

However, despite the commercial enthusiasm to see gas exports emerge from North America, the US and Canadian authorities have to date only authorised one liquefaction project each, at Sabine Pass in Texas and at Kitimat in British Colombia. The main reason for this reticence has been uncertainty over the economic, environmental and political impact of gas exports, as the respective governments have tried to balance the clear benefit of higher export revenues against the possible negative domestic impacts that could occur from higher gas prices and increased drilling activity. In the USA the debate has been particularly acute as domestic consumers and politicians have only recently started to enjoy the benefits of lower energy prices as the country has reduced its dependency on the imports of both gas and oil, and many are reluctant to put this domestic boon at risk by allowing potentially unlimited export sales.

As a result of this debate the US Department of Energy was instructed to produce a report on the potential economic impact of gas exports; this report, prepared by NERA Economic Consulting, was finally published in December 2012. In it NERA concluded that under any viable scenario LNG exports would bring net economic benefits to the US economy, as although domestic gas prices would be expected to rise the increase would not be significant and any losses to US consumers would be more than outweighed by the beneficial impact of increased export revenues as well as economic activity in the upstream and midstream gas sectors. However, this conclusion has not stopped a number of lobby groups, mainly representing industrial consumers concerned about the impact of higher prices on their businesses, from registering their horror at the thought that US gas prices could double or more over the next decade if unconstrained gas exports are permitted. For example, the lobby group Industrial Energy Consumers of America argued that the NERA report contained serious flaws, while the CEO of Dow Chemical, a major gas consumer warned that large-scale LNG exports would allow high Asian gas prices to 'bleed back into the US economy'.

As a result of the findings of the report the US DoE is expected to re-start the process of considering export applications that had been put on hold during 2012. At present 15 projects have applied for the vital non-FTA export licence that would allow them unfettered access to the global gas market, and if all these schemes were to be approved then over 230 bcm of new LNG export capacity could be available from the USA by 2020 (including the already approved Sabine Pass terminal). Most of the new facilities would be constructed on the sites of the many regasification plants that were built in the early 2000s, at a time when the United States was expected to become a major gas importer. Much of this regasification plant was left redundant following the dramatic turnaround in US production caused by the surge in shale gas output, but this historical example of market forces in action in turn highlights the risks for the developers of new gas export facilities and suggests that commercial reality will ultimately restrict the amount of new US gas export infrastructure that is actually built.

In particular it seems to be clear that, irrespective of its gas exports, the gas price in the USA is likely to rise over the next few years, and as this happens so the attraction of US gas to Asian and European buyers will decrease. In a October 2012 OIES paper 'The Potential Impact of North American LNG Exports', a range of estimates for the future cost of US production was analysed to produce a consensus range for future US gas prices of US$4–7/mmBtu, with a most likely mid-range of US$5–6/mmBtu. As can be seen in Table 1 the likely delivered price of gas to Europe at a US gas price of US$6/mmBtu would be US$10.6/mmBtu, while the delivered cost to Asia would be US$12.4/mmBtu.

While both of these prices appear very competitive compared to the average oil linked prices in both continents during 2012, comparisons with spot prices suggest that although US gas would be competitive in export markets it would not be as spectacularly cheap as current prices might suggest. For example, at the 7 January 2013 UK gas price at NBP of just over $10/mmBtu US gas exports would only be competitive if the US gas price remained below $5.50/mmBtu, implying that although some exports might reach Europe it is unlikely to be a flood. The January 2013 LNG spot price in Asia of $17.25/mmBtu clearly suggests that US gas exports would be very attractive to consumers there, but it is interesting to note that as recently as September 2012 the LNG spot price in Asia was as low as $12.80/mmBtu, close to the level at which US gas exports would only be marginally attractive.

As a result it would seem that market forces rather than political constraints could act as a reasonable limiting factor for North American gas exports, and this has been emphasised by the publication by the EIA of its Annual Energy Outlook for 2013. The report highlights how rising US gas production and low US gas prices are causing a surge in gas demand in the country, with the latest estimate forecasting US gas consumption to reach 761 bcm by 2025, a level that is almost 40 bcm higher than that predicted only a year ago in the EIA's 2012 Outlook. This estimated surge in demand is likely to provide an additional spur to domestic gas prices in the USA, again reducing the incentive for large-scale exports. Furthermore, an additional catalyst for higher US prices could also be created by growing environmental concerns over the hydraulic fracking techniques and chemicals used in shale gas development. The US Environmental Protection Agency (EPA) has begun a study on the possible impact of fracking on freshwater aquifers which could lead to increased federal regulation of the upstream industry in the USA, providing another potential cause of extra costs and higher gas prices.

Market forces in export markets could also come into play of course, as if all 230 bcm of possible US LNG exports were to arrive in the global gas market by 2020, accounting for approximately two-thirds of current LNG trade, the downward price impact could be very dramatic. Furthermore, US LNG export schemes are not the only new developments planned for the global LNG market over the next few years, with projects in Australia, East Africa, the East Mediterranean, Russia and Canada also scheduled, and US gas priced at $5–6/mmBtu sits in the middle of the potential supply cost curve. As a result, it is likely that the market forces of supply and demand both within the USA and in export markets will create an equilibrium price that will limit the extent of US gas exports to well below the capacity of all 15 new projects currently being proposed. Indeed this is reflected in the recent EIA Outlook where, although the USA is seen as being a net gas exporter by 2020 the actual net export volumes even by 2027 are relatively low at around 40 bcm, and certainly well below the potential for LNG export facilities.

One of the reasons for the improving balance of gas trade in the United States is that imports of gas from Canada are set to continue to fall, being replaced by rising US production. However, this outlook has left the Canadian gas industry searching for an alternative source of export revenues, with the Asian LNG market being the obvious source of demand. The Canadian government has provided significant support for the establishment of a gas export industry in British Columbia, and the potential construction of up to four plants with a total liquefaction capacity of over 40 bcm/a demonstrates the possible size of LNG exports by 2020. Gas would be sourced from the unconventional gas resources that are currently being explored and developed in the Horn River and Liard Basins and piped up to 800 km to the west coast before being shipped the relatively short distance to the main Asian markets.

However, a number of obstacles are appearing that may delay or even permanently interrupt the potential for some or all of the Canadian projects from proceeding. Firstly, the Canadian government's attitude towards its Asian neighbours has been called into question following the recent investigations into CNOOC's bid for Nexen Energy and Petronas' bid for Progress Energy. Although both bids have now been approved, the Canadian Prime Minister's somewhat sobering caveat that 'this is not the beginning of a trend, but rather the end of a trend' has left some market participants questioning Canada's commitment to its potential Asian customer base. Secondly, the prevalence of unconventional gas as a major feedstock has raised environmental questions about Canada's potential LNG export industry, which have been compounded by the need to build extensive pipelines through virgin territory currently owned and populated by native Canadian tribes. The negotiations to resolve land rights and environmental permit issues could significantly delay any projects. Finally, the fact that all of the Canadian projects are greenfield schemes with a relatively high capital cost means that, although they will benefit from short transport distances they will still not be the cheapest gas available in Asia. To date this fact has also been compounded by the demands of the Kitimat project partners for oil-linked gas prices that would clearly put the cost of Canadian LNG on a par with other higher cost producers. Overall then it would seem that, although the commercial logic for Canadian gas exports to Asia is strong and has attracted a number of key industry players such as Shell and Chevron to participate in projects alongside potential

Table 1: The delivered Cost of US Gas to Europe and Asia at various US Gas Prices (US$/mmBtu)

Henry Hub Price	**2.0**	**3.0**	**4.0**	**5.0**	**6.0**	**7.0**	**8.0**	**9.0**	**10.0**
Liquefaction	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Transport to Europe	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Transport to Asia	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Regasification	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Full cost Europe	**6.6**	**7.6**	**8.6**	**9.6**	**10.6**	**11.6**	**12.6**	**13.6**	**14.6**
Full cost Asia	**8.4**	**9.4**	**10.4**	**11.4**	**12.4**	**13.4**	**14.4**	**15.4**	**16.4**

Source: Henderson, J., October 2012, "The Potential Impact of North American LNG Exports", *NG-68, OIES*

Asian customers such as PetroChina and KOGAS, progress towards physical exports may be slower than the industry in Canada might have hoped.

In conclusion, then, the recent price differentials between North American gas prices and those in Europe and Asia have encouraged a broad energy industry initiative to create export opportunities for US and Canadian gas. Although only one US and one Canadian project currently have full export and construction approval, many others have applied for licences or been proposed, with a potential overall impact that could swamp the current global LNG market. Politicians in the USA are very concerned about the impact that any exports could have on their domestic gas price and as a result on the US economy, with the consequence that an extensive review process is now underway which is unlikely to reach any definitive conclusion until later in 2013.

However, international trade theory suggests that the politicians should not be overly concerned, as the interaction between gas markets is likely to find an equilibrium price that will not be far removed from the price that would be needed in any case to sustain US gas production. In fact, at the $5–6/mmBtu price that most commentators believe will be needed to make US gas producers profitable, gas exports to Europe immediately become less interesting. Indeed the most obvious influence of potential US exports based on this level of Henry Hub prices could be to provide a benchmark price of $9.5–10.5/mmBtu for Europe's higher cost suppliers such as Russia, who would have a clear signal as to the price below which they would likely exclude a new rival source of supply or above which they would encourage its arrival in Europe. On the other hand physical exports to Asia look much more likely, as North American gas exports would remain competitive with the oil-linked LNG contract price even if Henry Hub prices jumped to $8/mmBtu.

The implication, therefore, of North American gas exports to Asia is that higher cost sources of imports will be pushed down the supply chain, reducing the marginal cost of gas in the region. The situation could be complicated by a number of other factors, such as increased demand if prices stay low or the introduction of new indigenous production such as shale gas in China, which could certainly reduce the volumes of North American gas arriving in the Asian market. However, even if actual volumes are small, the impact of North American gas, and in particular that produced or purchased directly by consumers in Asia, may be as much psychological as physical. The introduction of gas at prices set by supply, demand and the cost of production, rather than based on a link to an alternative fuel, is likely to increase the focus on cost-of-supply-related rather than oil-related pricing. While it would probably be wrong to suggest that the oil link will disappear completely, given that oil is a competing fuel in some markets and has been used as the basis of contract negotiations for decades, nevertheless it would seem to be likely that, while the introduction of North American gas exports may not have as dramatic an impact on global gas prices as expected it could significantly change the way in which prices are negotiated. ■

OIL AND NATURAL GAS

Benefits of Hydraulic Fracking

KEVIN HASSETT and APAMA MATHUR

If an average American heard the word 'fracking' ten years ago, chances are he or she would have worried about the manners of the speaker. Today, however, opinions about fracking are solidifying, and battle lines are being drawn, even if understanding remains sketchy. For many on the American left, fracking connotes something dangerous, unhealthy – even, as in a recent Hollywood production, potentially nefarious. For those on the right, fracking is often regarded as the best hope for a struggling economy.

While the outcome of the policy struggle is impossible to predict, the economic stakes could hardly be higher.

Hydraulic fracturing, or fracking as it is more commonly called, is a process that's been used to extract oil and natural gas since it was first introduced by Standard Oil in the 1940s. Over the past decade, as other technologies have combined with the use of fracking to make the tapping of shale profitable, it has contributed to a resurgence of oil production in the USA and a dramatic increase in natural gas production. Proponents of fracking have hailed it as a major development in the energy industry, one that has allowed for tapping of reserves of gas and oil that were previously prohibitively difficult to reach. In some parts of the country, most notably in North Dakota, this has lead to massive expansions of energy production, and gold rush level increases in economic activity.

As enthusiastic as are its supporters, fracking faces equally determined opponents who view its environmental consequences as excessively negative, and there is significant variation across the United States in policy. The most notable focal point of opposition to fracking is New York state, which placed a moratorium on it in 2008, but other states have been as aggressive. Vermont has formally banned the practice, and New Jersey has enacted a moratorium as well. Many other states seem likely to follow.

To date, much attention in the debate has focused on the potential negative local impacts. There is ongoing investigation into the costs of fracking to the environment, infrastructure, and health of workers and citizens near drill sites. Less attention has been paid to discussion of the likely scale of the benefits, and a rational assessment of proper policy, of course, requires inspection of both costs and benefits.

Our focus, therefore, is on the benefit side of the equation, which hopefully can be used to better weigh costs when they are debated in the future.

Fracking in the United States

The process of hydraulic fracturing involves the injection of a mixture of water, a proppant such as sand, and chemicals into an oil or gas well. The fluid creates fractures in a pre-drilled well, allowing greater permeability of the stone surrounding it. The proppant fills the small cracks created by the water to keep them open after the water flows back out. The chemicals, such as gelling agents, are used for a variety of purposes, most importantly to gel the water on its entry so that the proppant remains suspended in the mixture and does not sink to the bottom of the solution. Other chemicals (which can even be unidentified and a trade secret) enhance the solution's fracturing abilities. It is these chemicals that form the basis of concern for fracking opponents, who worry about possible contamination of water sources from the fracking fluid, not all of which eventually makes its way to the top of wells to be captured by drillers.

Although the first version of hydraulic fracturing was patented in the USA in 1949, it has come into greater use over the last decade in combination with other advances in drilling technology (such as horizontal drilling), which have made many reserves of oil and natural gas economically viable that were previously considered prohibitively difficult to exploit. These reserves are in many cases contained within shale, a formation low in permeability and porousness, which previously made tapping the gas and oil held within the formations very difficult. Fracking, along with horizontal drilling, has made many of these previously known formations commercially viable, and has facilitated the discovery of new reserves as companies seek gas and oil in new locations.

A few numbers illustrate how fracking has contributed to a turnaround in US energy production over the past decade. In 1990, the USA produced in total 70.706 quadrillion Btu of energy, a number which remained fairly steady through 2006, when total production was 69.443 quadrillion Btu. After that year, however, as fracking, in combination with horizontal drilling and other new technologies in energy production became more widely spread, total production of the energy sector eventually reached 74.812 quadrillion Btu in 2010, accelerating even faster to 78.091 in 2011. A large part of that was an increase in domestic production of natural gas and crude oil. Natural gas, after previous steady production of around 19 quadrillion Btu per year, experienced an increase beginning in 2007, with production reaching 23.608 quadrillion Btu in 2011 and the industry on track to exceed that in 2012. This made the USA the second largest natural gas producer in 2011 – just behind Russia, according to the World Factbook. The third highest producer, the European Union, produced only about a quarter of the natural gas produced in the United States.

Oil, on the other hand, gradually declined in production from 1980 onward, and only recently has experienced annual increases, largely attributable to fracking and new drilling techniques. In 1980, the USA produced 18.249 quadrillion Btu of oil, which decreased to 12.358 in 2000 and 10.615 in 2008. Since then, however, it has risen to 11.598 quadrillion Btu in 2010 and 11.955 in 2011, and, like natural gas, the industry was on pace to exceed that figure in 2012.

This significant increase in production of oil and gas energy has direct economic effects that are relatively easy to quantify and potentially broad reaching indirect effects as well. However, direct and indirect effects are often misrepresented in public discussions. Below, we describe what is known of fracking's potential impact and a guide to an economically rational discussion of the total benefits.

Direct Economic Impact

The direct benefit of increasing oil and gas production includes the value of increased production attributable to the technology. In 2011, the USA produced 8,500,983 million cubic feet of natural gas from shale gas wells. Taking an average price of $4.24 per thousand cubic feet, that's a value of about $36 billion, due to shale gas alone.

This increase in value produced can also increase the number of people employed directly in production and delivery activities. These numbers will often be pointed to in political debates. In an economy with full employment, such an increase would not be considered a 'benefit' per se, but a state such as New York with a high unemployment rate of 8.2 might wish to weigh the potential employment effects when evaluating the merits of a moratorium. At its peak in 1980, the oil and gas extraction sector supported 267,000 employees, according to data from the Federal Reserve Bank of St. Louis. As more easily tapped oil reserves grew scarcer and domestic oil production gradually declined over the following two decades, so did employment, with the number of employees in oil and gas extraction shrinking by over 50 percent to 118,400 in 2003. Since 2003, however, there has been a steady upward climb in employment, slowing only slightly during 2009 and reaching 198,400 by December 2012 – over a 67 percent increase. As other industries have sputtered in the aftermath of the 2008 recession, oil and gas has been a remarkably bright spot in the US economy, with employment at the end of 2012 at its highest since 1987.

"… opinions about fracking are solidifying, and battle lines are being drawn …"

There is also a direct effect of this production on the trade balance. The increase in oil and natural gas extraction has directly impacted the energy trade balance between the USA and other countries. Natural gas imports decreased by 25 percent between 2007 and 2011, while petroleum imports dropped from a high of 29.248 quadrillion Btu in 2005 to 24.740 in 2011. By 2020, the Energy Information Administration predicts that the USA will become a net exporter of natural gas, and as more natural gas reserves are discovered and tapped, that date may yet be pushed earlier. Trade balance, of course, is not a measure of welfare, and, while interesting, should not be considered a direct benefit, but often will be.

Indirect Economic Impact

Along with its direct effects within the extraction industry, fracking has had a traceable effect on other industries as well. The first notable area is electricity generation. As natural gas production has increased over the past five years, so has its consumption within the USA – moving from a historical centre at about 23 quadrillion Btu per year to 24.256 in 2010 and 24.757 in 2011, according to data from the EIA. Much of this increase is attributable to electricity generation, where plants have switched some input from coal to natural gas as natural gas prices have dropped in the wake of its increased supply. While natural gas use in electricity generation gradually increased from 5.3 quadrillion Btu in 2000 to 6.38 in 2006 and 7.7 in 2011, coal experienced a small increase from 19.6 in 2000 to 20.5 in 2006 before dropping off quickly to 18.04 in 2011.

According to the Environmental Protection Agency, natural gas-fired electricity generates half the carbon dioxide of coal-fired production. An estimate of the indirect benefit of fracking should include an estimate of the potential social gains from this reduction. Historically, CO_2 emissions grew alongside GDP, reaching a peak of just over 6 billion metric tons in 2007, according to data from the EIA. Since then, however, emissions have fallen off, and were expected to total less than 5.3 billion tons in 2012, a full 10 percent decrease over five years. Although some of this drop was related to a faltering economy in 2008, emissions have remained lowered even while GDP has recovered its previous size and then some. The EIA even projects that CO_2 emissions will remain below their 2005 level (just under 6 billion metric tons) through 2040 – in some part because of increased reliance on renewables but in large part because of substitution of natural gas for coal.

The drop in natural gas prices worldwide would normally lead to a reduction in electricity prices in the United States. To the extent that geographic complementarities produce inframarginal benefits over and above the reductions in electricity prices that would normally follow from a reduction in price, these also should be included in net benefit calculations. If, for example, local electricity generation is a much higher value use than exporting the gas, then the inframarginal gains from that use would be included in any cost benefit calculus. The same would be true for other industries as well, such as the chemicals industry, fertiliser producers, and the steel and aluminum industries. To the extent that employment increases in these sectors, one would apply the same caution about interpreting this as a net benefit that applied to the direct employment effects.

Two additional indirect effects should also be mentioned, and considered by policymakers as they assess the benefits of regulatory interventions. First, a surge in production could well have Keynesian multiplier effects on a local economy. Second, land prices will surge throughout a state if fracking is suddenly allowed, and the higher prices will affect all relevant landowners' wealth and thus their consumption. This would have near-term economic effects on local economies (North Dakota luxury car dealers are presumably doing quite well) that may well be larger than the direct impact of production.

Several reports have attempted to quantify the impact of the expansion in fracking on the US economy but it is an extremely nascent literature. A 2010 study by Considine, Watson, and Blumsack of Pennsylvania State University used an input-output model to estimate that investment into natural gas extraction in the Marcellus shale region contributed 44,000 jobs to the economy. A 2012 study by IHS Global Insight made an attempt to model both the direct and indirect effects, employing a macroeconomic model. The study, which was funded by America's Natural Gas Alliance, is the most exhaustive study available to date. It concluded that the shale gas industry supported 600,000 jobs in 2010, a number which would increase to 870,000 by 2015. The study also found that three indirect jobs are created for each energy sector job, suggesting that the employment effects could be enormous. Looking at GDP growth, the IHS study found that, 'The shale gas contribution to GDP was $76.9 billion in 2010, will increase to $118 billion by 2015, and will nearly triple to $231 billion in 2035,' all in 2010 dollars. Alternatively, a study by economist J.G. Weber published in Energy Economics in 2012 estimates that 2.35 local jobs are created for every million dollars in gas production. If one assumes that total production increases by the approximately $68 billion from 2010 to 2035 assumed by the IHS study, then this would suggest a net increase of employment of only 159,859. Whether either of these jobs numbers reflects an increase in aggregate employment, of course, is another question, but the scale of the possible GDP gain is very large indeed, and sets a very high bar for opponents of fracking. If the debate over fracking is to be dominated by reason rather than emotion, researchers must refine our thinking of the economic benefits of rapid expansion of energy production, and improve our estimates of the potential environmental costs as well. ■

CLEAN ENERGY, ELECTRICITY AND CLIMATE CHANGE

The Case for a US Carbon Tax

JOSEPH E. ALDY

Every aspect of economic activity affects greenhouse gas emissions and, hence, the global climate. Since individuals and businesses bear virtually no cost for emitting greenhouse gases in the absence of public policy, and thus have no incentive to reduce these emissions, the government has a strong case for climate change policy. US policymakers may choose among three general approaches to drive more climate-friendly economic activity: (1) subsidise businesses and individuals to invest in and use lower-emitting goods and services; (2) mandate businesses and individuals to change their behaviour regarding technology choice and emissions; or (3) price the greenhouse gas externality, so that decisions take account of this external cost. Let's consider these options in turn.

In the United States, state and federal subsidies have supported the deployment of clean energy technologies for decades. The 2009 economic stimulus, the American Recovery and Reinvestment Act, represented the largest energy bill in US history by providing about $90 billion for investments in efficiency, renewable power, mass transit, smart meters, transmission lines, electric batteries, and other clean energy technologies. Among the energy sector impacts, US wind power generation doubled in about three years and lowered the electricity sector's greenhouse gas emissions by about 2 percent in 2010. Some clean energy subsidy programs were better designed and implemented more effectively than others. Nonetheless, the stark constraints in the current US fiscal outlook effectively preclude another major round of subsidies to promote the development and deployment of clean energy technologies.

Various regulatory agencies have the authority to require significant changes in the emission-intensity of cars and trucks, appliances, power plants, refineries, and other manufacturing facilities. For example, recent standards will effectively double the fuel economy of US passenger vehicles by 2025. Yet, pursuing a strategy of regulatory mandates one industry (and even one type of source within an industry) at a time can result in higher costs than necessary to drive emission reductions. Some industries may face a multitude of regulatory constraints and high emission reduction costs, while others face low costs, and all industries experience weaker incentives for clean energy innovation than they would under a more efficient policy approach. Moreover, a regulatory approach risks exposing businesses to uncertainty for a considerable time as a result of political challenges in Congress and legal challenges in the courts. The legal challenges will be potentially thorny since some of the likely regulatory proposals to address existing sources of greenhouse gases in the power sector and manufacturing would employ provisions of the Clean Air Act for the first time in its 40+ year history. In contrast to an economy-wide policy approach, an industry-specific regulatory approach would take many years to develop the dozens of rules necessary to cover most industrial sources of greenhouse gas emissions, which would then be subject to periodic regulatory revision. Moreover, eventually millions of small sources of greenhouse gas emissions – such as apartment buildings, corner grocery stores, and business offices – will need to apply for greenhouse gas emission permits absent new legislation, imposing significant administrative costs on small businesses and the government.

Given the fiscal constraints on subsidies and the prospect of inefficient, costly, and politically and legally uncertain regulatory options, the most effective policy approach to combat climate change is to price the greenhouse gas externality. In other words, it is time to tax carbon dioxide emissions in America.

Designing a Carbon Tax

A well-designed carbon tax should be cost-effective, efficient, and administratively simple. A cost-effective carbon dioxide tax would cover all emission sources. The government could set a tax in terms of dollars per ton of CO2 on the carbon content of the three fossil fuels (coal, petroleum, and natural gas) as they enter the economy. An efficient carbon tax would be set equal to the marginal benefits of reducing CO2 emissions, i.e., the social cost of carbon, and would increase over time to reflect the greater incremental damage from an additional ton of CO2 as atmospheric concentrations rise. Analysts – in academia and the government – have produced a wide array of estimates of the social cost of carbon. Nonetheless, the US government's current central estimate of the social cost of carbon of about $21 per ton CO2 is in the ballpark of what may be politically feasible given recent legislative proposals (see below).

Applying the carbon tax to the carbon content of fossil fuels targets the bottleneck in the product cycle of fossil fuels. Under such an upstream approach, refineries and importers of petroleum products would pay a tax based on the carbon content of their gasoline, diesel fuel, or heating oil. Coal-mine operators would pay a tax reflecting the carbon content of the tons extracted at the mine mouth. Natural-gas companies would pay a tax reflecting the carbon content of the gas they transport or import via pipelines or liquefied natural gas (LNG) terminals. This carbon content of fuels scheme would enable the policy to capture about 98 percent of US CO2 emissions by covering only a few thousand sources as opposed to the hundreds of millions of smokestacks, tailpipes, and so on that emit CO2 under a system targeting actual emissions.

A US carbon tax would be administratively simple and straightforward to implement, since it could incorporate existing methods for fuel-supply monitoring and reporting to the government. The US Energy Information Administration already tracks on a weekly, monthly, and annual basis the production, import, export, storage, and consumption of fossil fuel products. United States refineries and importers of petroleum products already pay a Federal per barrel tax (to finance the Oil Spill Liability Trust Fund) and coal mine operators already pay a Federal per ton tax (to finance the Black Lung Disability Trust Fund), so a national carbon tax could easily piggyback on these existing tax reporting systems. Monitoring the physical quantities of fuel combustion yields precise estimates of carbon dioxide emissions given the molecular properties of fossil fuels.

A crediting system for downstream carbon capture and storage technologies could complement the carbon tax system. A firm that captures and stores CO2 through geological sequestration, thereby preventing the gas from entering the atmosphere, could generate tradable CO2 tax credits, and sell these to firms that would otherwise have to pay the emission tax. Such a system of tax credits could provide a transparent means to finance such carbon capture and storage technologies.

While stimulating the investment in low-carbon, zero-carbon, and energy efficient technologies, the implementation of a carbon tax could adversely affect the competitiveness of energy-intensive industries. This competitiveness effect resulting from higher energy prices can lead to firms relocating facilities to countries without meaningful climate change policies, thereby increasing emissions in these new locations and offsetting some of the environmental benefits of the policy. Such 'emission leakage' may actually be relatively modest, because a majority of US emissions occurs in non-traded sectors, such as electricity, transportation, and residential buildings. Energy-intensive manufacturing industries that produce goods competing in international markets may face incentives to relocate and will advocate for a variety of policies to mitigate these impacts.

Additional emission leakage may occur through international energy markets – as countries with climate policies reduce their consumption of fossil fuels and drive down fuel prices, those countries without emission mitigation policies increase their fuel consumption in response to the lower prices. Since leakage undermines the environmental effectiveness of any unilateral effort to mitigate emissions, international cooperation and coordination becomes all the more important. Political concerns about competitiveness may call for a carbon border tax that effectively imposes a tax on the carbon content on goods imported into the United States. If the government implemented a carbon tax and threatened to impose a border tax on imports, then it could provide some negotiating leverage in multilateral fora to secure more stringent emission reduction policies among major trading partners, and thus minimise the competitiveness impacts. Also, it is important to keep in mind that these emission leakage effects exist with any meaningful climate policy, whether through carbon tax, cap-and-trade, or command-and-control.

The Impacts of a Carbon Tax on Energy Markets and the Economy

Energy suppliers will increase the price of the fuels they sell in response to the carbon tax. This will effectively pass the tax down through the energy system, creating incentives for fuel-switching and investments in more energy-efficient technologies that reduce CO2 emissions. The real-world experience of firms and individuals responding to changing energy prices demonstrates the potential power of a carbon tax to drive changes in the investment and use of emission-intensive technologies. The higher gasoline prices in 2008 resulted in larger market share of more fuel-efficient vehicles, while reducing vehicle miles traveled by drivers of existing cars and trucks. In recent years, electric utilities responded to the dramatic decline in natural gas prices (and the associated increase in the relative coal-gas price ratio) by switching dispatch from coal-fired power plants to gas-fired power plants that resulted in lower carbon dioxide emissions and the lowest share of US power generation by coal in some four decades. Historically, higher energy prices have induced more innovation – measured by frequency and importance of patents – and increased the commercial availability of more energy-efficient products, especially among energy-intensive goods such as air conditioners and water heaters. Imposing a carbon tax would provide certainty about the marginal cost of compliance, which reduces uncertainty about returns to investment decisions and eliminates the regulatory uncertainty that inhibits energy sector investment. Of course, certainty over costs results in uncertainty over emission reductions.

Consider a hypothetical, economy-wide carbon tax that starts at $15 per ton CO2 and increases annually by 5 percent plus inflation. Such a scenario is very similar to the Republican proposed carbon tax in the US House of Representatives in 2009 (H.R. 2380, “Raise Wages, Cut Carbon Act of 2009” would set a carbon tax of $15 per ton CO2 and increase it 6.5 percent annually for thirty years) and is generally consistent with US Environmental Protection Agency estimates of the allowance prices expected under the 2009 Waxman-Markey cap-and-trade bill (H.R. 2450). Over the first decade, such a carbon tax program would impose an average price on carbon of nearly $20 per ton CO2 and generate revenue of about $100 billion per year according to the 2012 Annual Energy Outlook published by the Energy Information Administration (EIA).

In doing so, energy prices would increase on average about 10 percent over this first decade, with coal bearing a greater price impact while natural gas, renewables, and nuclear would bear smaller impacts. In light of the more than two-thirds increase in real energy prices over the decade ending in 2008, this change of about 10 percent would not deliver significant economic costs, and productive uses of the tax revenues through tax reform could eliminate most if not all of the costs of mitigating greenhouse gas emissions. Even in energy-intensive, trade-exposed industries such as steel, aluminum, chemicals, and cement, the declines in output would be much less than the annual swings they have experienced over the past two decades. Based on the impacts of historic energy price changes on industry output, Billy Pizer and I have estimated that a tax of $15 per ton CO2 would reduce production on the order of about 2 to 3 percent in these industries. The changes in relative energy prices and the certainty about the carbon price are important, since they will drive investment in new, clean energy technologies. As a result, the EIA estimated that US carbon dioxide emissions would decline to 18 percent below 2005 levels in 2020 under such a carbon tax scenario.

“Applying the carbon tax to the carbon content of fossil fuels targets the bottleneck in the product cycle of fossil fuels.”

Carbon Tax and Tax Reform

Some observers of the US body politic may note that carbon pricing through a cap-and-trade program suffered political defeat in 2010 in part because opponents labeled it ‘cap-and-tax’. If cap-and-trade appeared more politically appealing than a carbon tax a few years ago and any proposal to raise taxes suffers the inherent problem of being called a tax, how could a carbon tax represent a viable option today? The relevant legislative policy debate in America today is not about the path forward on climate policy but instead the path forward on fiscal and tax reform. The choice is not between a carbon tax and cap-and-trade, but rather between a carbon tax and other means of raising revenues or cutting spending.

The approximately $100 billion in annual revenues from the hypothetical carbon tax above could play an important role in making a fiscal and tax reform add up. It is roughly equal to the so-called budget sequestration that calls for blunt, politically unpopular cuts to US domestic and defence spending. It is slightly less than the revenues generating by eliminating the politically popular if economically inefficient home mortgage interest deduction in the US tax code. It is on par with the 2 percent payroll tax reduction enjoyed by all workers over the past two years, but that expired on 31 December 2012. These revenues could also help reduce significantly the deficit, which effectively translates into lower future taxes.

The effects of a carbon tax on emission mitigation and the economy will depend in part on the amount and use of the tax revenue. Using carbon tax revenues to finance tax reforms that improve the efficiency of the tax code could stimulate economic activity and offset some or all of the costs of cutting emissions. In addition, a relatively small percentage of the annual carbon tax revenues could also support the research and development of climate-friendly technologies, which suffer underinvestment by the private sector.

Raising energy prices could disproportionately impact low-income households, since a larger fraction of their budgets is dedicated to energy expenditures. The regressive nature of a carbon tax can be mitigated through the recycling of revenues back to the economy. For example, British Columbia's economy-wide carbon tax program returns all revenues to the economy by cutting corporate and individual income tax rates and through a means-tested Low Income Climate Action Tax Credit. If a carbon tax is part of a broader fiscal and tax reform, the overall progressivity of the package will depend in part on the use of carbon tax revenues, but more substantially on decisions regarding entitlement spending (especially means-tested Medicaid) and changes to the tax code for businesses and individuals.

Businesses that face the possibility of a carbon tax would likely oppose it, especially if they also must comply with greenhouse gas regulations under the US Clean Air Act. Lowering the tax rate on corporate income may address some business reservations. Moreover, a meaningful, economy-wide, long-term carbon tax would obviate the need for many if not all greenhouse gas regulatory options. A carbon tax would deliver more cost-effective and efficient emission reductions and promote innovation more effectively than the Clean Air Act regulatory authority, as well as avoid some of the potential legal and political pitfalls and administrative costs of regulations. Exchanging regulatory authority for a carbon tax could also improve the political viability of taxing carbon dioxide emissions.

Price Carbon Now

This case for pricing carbon through a tax regime rests on the understanding of the best scientific scholarship that shows that increasing atmospheric concentrations of greenhouse gases are posing and will continue to pose substantial risks to the planet. Uncertainties about climate science certainly still exist, but such uncertainties are no reason for inaction. Indeed, the prospect, albeit uncertain, of sea-level rise, more frequent extreme storms like Hurricane Sandy in the US East Coast in 2012, reduced agricultural productivity, and so on, justify action now. Prudent first steps are cost-effective, no-regrets approaches. A carbon tax that can send signals for long-term innovation, deliver efficient emission mitigation, and finance tax reform that promotes economic growth fits this bill. ■

CLEAN ENERGY, ELECTRICITY AND CLIMATE CHANGE

California Starts Trading Carbon

DAVID BUCHAN

California has again proved itself to be a pioneer in climate and energy policy. On 1 January it launched the first serious state cap-and-trade system in the USA designed to reduce greenhouse gases. A similar scheme already exists at the other end of the country – under their Regional Greenhouse Gas Initiative (RGGI or Reggie as the acronym is pronounced) nine New England states have been capping and trading CO2 emissions from their power plants since 2008. But the RGGI cap only covers electricity generation, and is so loose – in its first phase of 2009–2014 it is only aimed at stabilising the level of emissions – that permits trade for less than $2 a tonne of carbon. By contrast, the California scheme's cap will eventually cover almost the entire economy of the state; it tightens in its first year with a 2 percent reduction; and its minimum auction price is $10 a tonne. The cap-and-trade system is one of several measures in California's Global Warming Solutions Act of 2006 which is aimed at returning the volume of the state's greenhouse gas emissions to that of 1990 by 2020, a cut of around 15 percent from 2012 levels.

However, the immediate importance of the California system's launch will be more political than environmental. RGGI was launched in the period of relative benevolence towards climate action of the mid-2000s. But after the largely abortive Copenhagen climate summit in December 2009, climate politics turned poisonous in the USA, as Republicans denounced emission trading as 'cap-and-tax', cowed Democrats and the Obama administration into acquiescence, and killed the plan for a federal cap-and-trade system in Congress. Once re-elected, Barack Obama has dared to mention climate policy again, but he is a cautious man and will proceed slowly.

In these political circumstances, it is a minor miracle that the Californian initiative has come to fruition. It survived a referendum vote in 2010 and numerous court challenges that led to the postponement of emissions permit trading by a year until 2013, but it still faces new legal appeals that have been launched by business groups in the past few weeks quite deliberately to destabilise the trading system.

> ***"California has again proved itself to be a pioneer in climate and energy policy."***

Yet California's cap-and-trade system is expected to have much less impact on emissions than the political sound and fury over its introduction would seem to indicate. The California Air Resource Board (Carb) has estimated cap-and-trade will contribute less than a quarter of the total emission reduction from the state's various climate measures. This is a far smaller contribution to emission reduction than the European Union had initially hoped to get from its Emission Trading System over the decade up to 2020 (though, as we now know, this hope was over-optimistic).

Part of the reason is that the California cap-and-trade scheme gets off to a relatively soft start in 2013. The first phase, beginning in January 2013, covers all electric utilities and industrial facilities producing more than 25,000 tonnes of carbon dioxide equivalent, amounting to just over a third of total state GHG emissions; they will get free allowances covering, at the start, 90 percent of their historic emissions, paying for only 10 percent at auction. In a second phase in 2015, the cap will be extended to cover emitters accounting for 85 percent of all GHGs, including making oil distributors and refiners responsible for the emissions from the fuel they supply; transport, in California's car culture, accounts for a very large share of emissions.

But the other reason why Californians have more modest expectations for emission capping and trading schemes than Europeans is that the US state is relying more on direct regulation to 'do the heavy lifting' of emission reduction. In order to deal with its particular problem of smog in southern California, the state was given by the federal government the right, unique among US states, to develop its own emission-reducing standards. As a result, California has pioneered efficiency standards for energy appliances, ranging from fridges to cars, which have usually been adopted at the federal level subsequently.

California has also led the USA in trying to clean up its sources of energy in three ways. First, it aims at a 33 percent renewable share of electricity by 2020; some other states also have set themselves renewable quotas, but California's is about the most ambitious. Second, California has imposed an Emissions Performance Standard on electricity generators that is set at what an efficient combined cycle gas turbine produces and therefore effectively precludes coal-generated electricity without carbon storage. For comparison, in Europe, the UK is only just now getting around to proposing a similar standard. Third, California has imposed a Low Carbon Fuel Standard, which requires fuel refiners, importers, blenders to cut the emissions per unit of the fuel which they supply by 10 percent by 2020. A similar standard exists in the EU, but not in the rest of the USA where there have been many objections to the Californian standard on the ground that it often discriminates against fuel from other states and therefore illegally obstructs interstate commerce.

All these non-market emission-reducing mechanisms and regulations – which have a longer history and are wider in scope than in most European states – will inevitably reduce demand for carbon or CO2 equivalent allowances in the California emission trading system. It would not therefore be surprising if the allowance price were to stay relatively low – in the first auction for 2013 allowances the price was only 9 cents above the $10 a tonne floor price – and if the cap-and-trade system were to contribute relatively little to emission reduction in the state in its first years.

So has introducing cap-and-trade been worth all the hassle in terms of legal challenge and political opposition, when existing regulation can produce bigger emission cuts? The answer is yes, for two reasons. The economic argument is that putting a price on carbon acts, like any price, simultaneously on supply and demand – it encourages low carbon supply and discourages use of high carbon fuels – while a regulation can usually only impact supply or demand and usually at a higher cost. So, no matter how comprehensive regulations are on both supply and demand sides, it makes sense to add an overlay of carbon pricing to sweep up the emission reductions that regulation cannot reach.

The political argument, in the USA, is that a successful Californian emission trading system would help de-demonise cap-and-trade in the rest of the country. In the short term, it is most unlikely that other US states or the federal government are going to follow California on emissions trading, as they have so often on product efficiency standards. (It once seemed that several other US states and Canadian provinces, as part of something called the Western Climate Initiative, would follow California in introducing cap-and-trade this year – but only Quebec, with its huge share of carbon-free hydro-electricity, actually has). Yet if California can operate a cap-and-trade system smoothly for a few years, it is possible that legislators in Washington DC may come to shed their fear of a mechanism that was, after all, 'invented in the USA' to deal with sulphur and nitrogen emissions.

California has the advantage of learning from Europe's mistakes. The California system permits allowances to be carried forward or 'banked' (avoiding the EU mistake in preventing the carry-over of allowances from one phase to another that led to a price crash). It is also more restrictive than Europe on 'offsets', the degree to which Californian emitters can earn emission allowances or credits by reducing emissions outside California. Whereas the EU scheme has been open to offsets from, in theory, any developing country, California restricts such offset credits to projects within the United States, a move that should limit over-supply in the state system.

But California also faces the same problem as Europe in minimising the economic disadvantage that comes from imposing a carbon price on its own companies in a world where rivals carry no such burden. For California, this problem of 'carbon leakage', the possibility of companies losing market share to rivals free of carbon pricing or companies shifting production to avoid losing market share, is even more acute than in Europe. It is obviously easier for companies to move out of California to somewhere else within the American single market than to move within the EU or outside it. California has already got itself in a tangle in trying to prevent its electricity suppliers in the rest of the USA from indulging in 'resource re-shuffling' – the possibility of a supplier switching its cleaner (renewable or hydro) power to California and dispatching its dirtier (coal-burning) power to another state. In terms of global emissions, such switching would nullify the effect of Californian reductions. California has, so far vainly, been trying to get out-of-state suppliers to foreswear such reshuffling.

This extra-territorial attempt to prevent carbon leakage is similar to the EU's attempt to corrall all emissions from all flights into and out of Europe into the ETS and to make all airlines pay for emission allowances. Both these moves reflect the challenge for both California and the EU of operating cap-and-trade schemes in a world without an international climate regime. And it is a challenge they are both condemned to struggle with for at least some years to come.

CLEAN ENERGY, ELECTRICITY AND CLIMATE CHANGE

The Future of US Energy Utilities, AD 2012

PETER FOX-PENNER

Four years ago in *Smart Power* I predicted that utilities in the developed world would soon face a wrenching transformation. I posited that very low growth in sales, combined with the costs of decarbonisation and 'Smart Grid' would cause a backlash against higher prices and poor utility financial health. My goal was to prevent a financial weakening of the sector that would hamper our ability to achieve the key outcomes we ask from our power industry: universal access at affordable rates, rapid decarbonisation, continued reliability, and greater source flexibility and customer choice.

In the European Union, a scenario something like this has come to pass. Load growth and high investment to meet policy goals have left most of Europe's utilities in grim financial shape. In a recent interview for the European Energy review, Enel's CEO called the European energy sector 'uninvestable'. In the United States, however, utilities' near-term finances are generally reasonably good, and there are even some signs that traditional utilities (including public and cooperative firms) are gaining market share.

The reason, in a nutshell, is the growth of unconventional gas alongside record low interest rates. Natural gas prices have fallen so far, so fast that electricity prices, which are linked to gas prices in many parts of the country, have barely increased despite slow sales growth and high investment needs. In 2012 natural gas prices were at their lowest price levels since 1999 – so low that the dispatch costs of many gas-fired power plants are lower than that of baseload coal plants. EIA reports that last year 30 percent of US power generation came from gas-fired generators, the highest share ever. Gas-fired generation now almost equals coal and oil generation, which contribute 38 percent with the remaining balance coming from nuclear (19 percent) and renewable sources (13 percent).

Low gas prices, state and federal renewable energy policies, and environmental rules directed at coal plants have also contributed to surprisingly large investment in decarbonisation, despite an absence of a formal national climate policy. During 2012, solar and wind installations grew by approximately 3,000 and 12,000 MW, respectively, the state of Texas surpassed the 10 percent level for renewable supplies, and the state of California announced it was on course to achieve 33 percent renewables by 2020. Conversely, plans were announced to retire about 30 GW of coal plant capacity (roughly 10 percent of total coal capacity) by 2016, along with two aging nuclear power plants, all requiring replacement supplies. This trend is set to continue with The Brattle Group projecting total retirements to reach between 59 GW to 77 GW by 2016. Coal stockpiles are continuing to grow and nearly a dozen coal industry companies have fallen into serious financial difficulties. At the same time, spending for utility efficiency programs has grown over 25 percent annually for five years. Distribution investment is also strong, with the USA on track to achieve 50 percent smart meter penetration by 2015.

Most remarkably, this decarbonisation and smart grid investment occurred in a period of nearly zero sales growth and relatively stable rates. National electric sales growth was about 4 percent and 0.4 percent in 2010 and 2011, respectively, and is forecast to average only about 0.7 percent/yr or less through 2035. Meanwhile, real average electric prices are continuing to decline. Electricity prices in the residential sector have risen slightly due to rising capital expenditures but, overall, increases have been very modest thanks to lower fuel costs. Wholesale electricity prices have seen larger declines for the same reason.

In short, falling natural gas prices and the lowest interest rates in generations have created a windfall the industry has chosen to devote to decarbonisation and the smart grid – all without either significant high sales growth or substantial rate hikes. But can this golden era last?

The Pressures Continue

US utilities are enjoying a reprieve, but the main drivers of industry transformation appear to be as strong as ever. First, demand growth appears to have hit a new, lower plateau, due to continued efficiency improvements in nearly every type of electric process and continued modest economic growth. Even with the gradual addition of electric vehicles, some utilities, like the Sacramento Municipal Utility District, show slightly declining sales through 2030.

The decline (and perhaps reversal) of growth rates is likely to accelerate as distributed generation (notably rooftop PV) becomes more widespread. A draft report prepared for the US association of investor-owned utilities notes that rooftop PV is at parity with total retail rates in about 16 percent of the USA already, with cost reductions likely soon to expand the market five-fold. Adding in microturbines, geothermal heat pumps, and other distributed renewables, it is entirely possible that self-generation will lower the net demand placed on the central grid. Already California projects that by 2020 the average new home in its state will generate as much power as it uses ('zero net energy'), with commercial buildings reaching this threshold by 2030.

Low natural gas prices, EPA rules, and the growth of renewables have already taken a toll on the utilities heavy in coal and nuclear generating assets. Each of these factors acts on the asset-heavy central generators differently. Low-priced gas displaces coal (though seldom nuclear) in the merit order, lowering sales from these plants, while the largely fixed costs of ownership are unchanged. With essentially zero variable costs, renewables displace both coal and nuclear power, lowering their sales. Worse still, in areas with central auction-style spot power markets, wind generators with production subsidies sometimes bid negative prices to run and receive their subsidies. If the market clears in negative territory, coal and nuclear plants – which cannot adjust their output substantially hour by hour – must pay (receive a negative price) to keep their power flowing to the grid. In addition, EPA and other government rules impose new fixed costs on plants, while the aging fleet of US nuclear plants is at the point where prohibitively expensive repairs are causing shutdowns.

The impact of renewables has been most apparent in Europe, where, according to UBS, 'half to two-thirds of central European generation EBITDA may be wiped out' by renewables-driven low prices, even without cheap gas. The USA, however, is not immune; most generators with large coal-fired and nuclear fleets have announced multiple plant closures to prevent growing losses from these plants. Most recently Georgia Power, subsidiary of Southern Company and a premier coal-generating utility with relatively stable growth, announced the closure of no less than ten coal-fired units during the next three years.

Finally, the Smart Grid has sparked a wave of innovation that continues to press utilities to invest in their distribution systems while raising the threat that new companies will take over electric sales or related services. Interest in a smarter and more resilient grid has also jumped in the wake of Hurricane Sandy, which caused the largest and longest power outage in US history and prompted many governors to ask whether bold new grid designs are worth exploring.

The Awakening Giant

For an industry thought to be perpetually stodgy, there is now within it an amazingly widespread agreement that both a technological and business model transformation is underway. While the pace of change varies dramatically across the country, most utilities are moving away from coal-based central generation and are starting to search for new regulatory models that will allow them to remain healthy as sales growth declines and investment continues. The industry's leading trade group, the Edison Electric Institute, now discusses these issues openly within its members. The US Department of Energy has started to promote study and discussion on the issue, and several major US NGOs are getting into the act, including the Energy Future Coalition, the Utilities 2020 Project, and the Rocky Mountain Institute.

At present, there is more awareness than action. As I noted in Smart Power, changing the utility business model in the USA is made difficult by the fact that utilities have fifty different state regulators, and there is little prospect for federal legislation that sends all states in a common new direction. It is also worth noting that the US economic recovery is still weak, power prices are low, and there remains much disagreement over whether the last change to the utility sector, Enron-led deregulation, was worth the trouble. Most state officials are simply not of a mind to try a bold new approach to utility regulation even if it is obvious that it will be needed sooner or later as the drivers cut deeper into the sector. In this regard, the USA clearly lags the United Kingdom, where regulators are rolling out a new regulatory model designed for the oncoming era.

"California projects that by 2020 the average new home in its state will generate as much power as it uses."

In fact, there are some signs that the US industry is moving towards a more integrated and even public utility model. The independent generator (or 'merchant power') sector is rapidly consolidating into a handful of huge, highly diversified players while traditional utilities are acquiring more of their own supply. Texas aside, markets with retail competition are trending towards 'municipal aggregation', where a community or city forms a company or co-op that buys power on behalf of its customers. States and cities are generally more interested in plentiful, cheap, green power and economic development than they are in promoting individual customer choice – the battle cry of the 1990s.

Yet even without much concrete regulatory change to date, it is unwise to describe the US industry as hopelessly frozen into the traditional business model-regulatory paradigm. The high degree of information-sharing and dialogue among the states, utilities, NGOs and federal policymakers makes it a virtual certainty that change will continue in both the technology and the business-regulatory model for the industry.

Technological progress will continue in all segments of the industry and with all forms of generation, with the greatest changes occurring in renewables and how power is transmitted, controlled, and stored. Thermal generation from fossil fuel sources is a relatively mature technology; though improvements continue, only a breakthrough leading to the economic sequestration of carbon dioxide emissions would constitute a disruptive change. Meanwhile, several renewable sources continue to evolve rapidly, with concomitant reductions in cost. However, as I argue at length in Smart Power, the greatest changes in technology and governance will come from the application of digital control and storage technologies to the grid.

As these technologies evolve the business and regulatory model will inevitably follow, probably not far behind. If gas remains plentiful and cheap, sales growth is slow to negative, and zero-carbon sources and storage achieve grid parity in the near future, the cost of decarbonising the power sector by 2050 will be much less than worst-case scenarios posit. Whereas it was difficult to foresee a soft landing into a zero-carbon, smart grid future a decade ago, it is now clearly within the realm of possibility – at least on one side of the Atlantic Ocean. ■

The opinions expressed are solely those of the author and do not necessarily reflect those of The Brattle Group or its clients. Please see my full disclosure at www.smartpowerbook.com.

Asinus Muses

Glory at last

After decades of toiling modestly but tirelessly, the Oxford Institute for Energy Studies has finally achieved fame and glory: according to the 2012 Global Go To Think Tanks Report, published by the Think Tanks and Civil Societies Program at the University of Pennsylvania, our humble institution is the world's top-but-one Energy and Resource Policy Think Tank. After recovering from the grammatical atrocity of the title of the report, Asinus remained puzzled. What is a Think Tanks and Civil Societies Program? Do they think about thinking? Socialize (politely) about society?

Frackturred Policy Making I

Further developments in the ongoing story of shale gas fracking in the UK: Ed Davey, energy and climate secretary, has remarked that recently-approved plans for shale gas would reduce imports of gas 'to the benefit of the economy', while a spokeswoman for the Prime Minister claimed 'there is great potential for prices to come down and that is something that is attractive about finding another source of energy.' Unfortunately, the government's own Advisory Committee on Climate Change has found that the new dash for gas was not only 'completely incompatible' with climate change targets, but that increased reliance on gas would raise household energy bills by £600 a year in future, in contrast to a rise of £100 that would result from concentration on renewables. Not exactly what one would call joined-up government.

Frackturred policy making II

There must be something about shale gas fracking that confuses governments. Just like characters in an interweaving-lives movie, several of Asinus's regular and apparently-independent themes have crossed paths: shale gas has collided with the Ecuadorean suit against Chevron for pollution, and the Argentine nationalisation of YPF. For Chevron has made a $1bn deal with YPF to drill 100 pilot wells in the Vaca Muerta shale oil formation, just as a panel of Argentine judges have upheld a decision to freeze the assets of Chevron Argentina, in response to the Ecuadorean judgement that its parent company must pay $19bn in damages. It's not that one hand gives while the other takes: it's that one hand stuffs the other in the ice box.

Big Payouts, Bad Politics, and Beware Peshmerga

Poor old BP is still taking flack over the Deepwater Horizon oil spill, with US coastal states putting in a claim for an additional $34bn, on top of the $42bn the company has already set aside for the clean-up bill and various penalties. The interesting development is that the states are suing, not over damages, but over lost tax revenue – presumably from the businesses that were sent under beneath the lake of oil. With its usual fine political judgement, the company responded by arguing that with the clean-up operation, 'we probably provided one of the biggest fiscal stimuluses that the Gulf has ever seen.'

Tony Hayward, who lost his reputation and job as CEO of BP over the spill, has rehabilitated his career by setting up Genel Energy and making it the largest independent producer in Kurdistan. Asinus, who has treated Mr Hayward less than gently in the past, is now wondering if his fundamental problem may have been his former employer. Unlike Mr Hayward, who has eschewed non-Kurdish Iraq, and even Exxon, who sold up in Southern Iraq when it moved north to Kurdistan, BP has placed itself in the least congenial oil field in the region: Kirkuk, straddling Kurdish and non-Kurdish Iraq, and contested by both sides. With the regional conflict occasionally flaring up into actual gun fights between Iraqis and Kurds, the oil company would be wise to Beware the Peshmerga – the Kurdish term for their nationalist army.

Russian Roulette or American cigarettes

Nick Stern, author of the scarifying Stern Review on the Economics of Climate Change, has admitted he got it wrong. On hearing the news, Asinus was preparing to kick back and light up a tar barrel. Yet the error, apparently, was on the upside: climate change is going to be even worse, says Professor Stern, than he had thought. Rather than 2 or 3 degrees, he now thinks the world is on track for a rise in temperatures of 4 or 5 degrees, a development he compared to playing Russian roulette with two bullets instead of one. US president Barack Obama contributed to the drama in his second inaugural speech with reference to 'the devastating impact of raging fires and crippling drought and more powerful storms' and an exhortation to take care of an earth 'commanded to our care by god'.

Asinus, though reluctant to promote a competitor, feels compelled to report an elegant solution to Professor Stern and President Obama's concern, from the fertile imagination of the satirical publication, The Onion: Marlboro Earths, cigarettes marketed as the solution to global warming – because they kill off the number one cause, viz., the human being. A nice way to take the heat off the oil industry, for a change.

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