ENERGY REGULATION QUARTERLY

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MISSION STATEMENT

The mission of the Energy Regulation Quarterly is to provide a forum for debate and discussion on issues surrounding the regulated energy industries in Canada including decisions of regulatory tribunals, related legislative and policy actions and initiatives and actions by regulated companies and stakeholders. The Quarterly is intended to be balanced in its treatment of the issues. Authors are drawn principally from a roster of individuals with diverse backgrounds who are acknowledged leaders in the field of the regulated energy industries and whose contributions to the Quarterly will express their independent views on the issues.

EDITORIAL POLICY

The Quarterly is published by the Canadian Gas Association to create a better understanding of energy regulatory issues and trends in Canada.

The managing editors will work with CGA in the identification of themes and topics for each issue, they will author editorial opinions, select contributors, and edit contributions to ensure consistency of style and quality.

The Quarterly will maintain a "roster" of contributors who have been invited by the managing editors to lend their names and their contributions to the publication. Individuals on the roster may be invited by the managing editors to author articles on particular topics or they may propose contributions at their own initiative. From time to time other individuals may also be invited to author articles. Some contributors may have been representing or otherwise associated with parties to a case on which they are providing comment. Where that is the case, notification to that effect will be provided by the editors in a footnote to the comment. The managing editors reserve to themselves responsibility for selecting items for publication.

The substantive content of individual articles is the sole responsibility of the contributors.

In the spirit of the intention to provide a forum for debate and discussion the Quarterly invites readers to offer commentary on published articles and invites contributors to offer rebuttals where appropriate. Commentaries and rebuttals will be posted on the Energy Regulation Quarterly website.

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EDITORIAL

Rowland J. Harrison, Q.C. and Gordon E. Kaiser
Managing Editors

Traditional economic regulation – involving interminable hearings on issues such as cost of capital, rolled-in versus incremental tolls, system access and unbundling, all in quest of the holy grail of "economic efficiency" – no longer dominates the business of Canadian energy regulation tribunals, at least not to the extent it did in the 1980s. Today, the focus of government policy-makers is largely on the review processes for proposed infrastructure projects and the pervasive role that climate change plays on the public agenda, with direct consequences for energy regulators.

Stephen Littlechild's article on "Electricity privatization and restructuring in Ontario and abroad: Some lessons from UK and elsewhere" offers comparative lessons on industry restructuring. His broad observations on the role of effective regulation also have particular resonance as Canadian governments continue introducing measures to address the issue of climate change, which will result in extensive restructuring of segments of the energy industries, with obviously significant implications for those industries and the tribunals that regulate them. Littlechild reminds us that, while governments will find ways to use regulation to further their policy ends, "regulation is probably not the main means by which Government implements its policies." Furthermore, "[g]overnment cannot be expected to follow a consistent course over time…."

In their article on "Alberta's Electricity System: Carbon Policies and the Risk of Unintended Consequences," Donna Kennedy-Glans and Brian Bietz address the challenges of implementing the provincial government's recently announced Climate Leadership Plan. The Plan is widely considered to be a necessary development to help address continuing opposition to major oil pipeline projects in particular. Implementing the Plan, however, presents its challenges, particularly in the current Alberta economic climate. With the risk of unintended consequences, Kennedy-Glans and Bietz ask if this is the right time to assess the implications of a transition back to a fully regulated electricity system for the province.

The dominant role now played by climate change in shaping energy policy is also highlighted in Erik Richer La Flèche's report on Quebec's *2030 Energy Policy*, released in April, with its ambitious greenhouse gas reduction goal to decarbonize the province.

Nigel Bankes analyzes two cases in which the Supreme Court of Canada has granted leave to appeal decisions of the Federal Court of Appeal involving the jurisdiction of the National Energy Board (NEB) and the Crown's duty to consult. The two appeals will be heard together. The Court will have to decide, *inter alia*, whether a tribunal's processes can satisfy the duty to consult. Bankes concludes that, while both appeals arise from decisions of the NEB, the outcomes will be relevant for energy tribunals throughout the country.

We are particularly fortunate in this issue of *ERQ* to have "The Washington Report" from our regular contributor Robert Fleishman. The interconnection of North American energy markets means that policy, regulatory and judicial developments in the U.S. generally have direct, significant implications for the Canadian energy industry, perhaps even more so today than in the past. The developments discussed in Fleishman's comprehensive review include LNG exports, fracking, crude-by-rail and the end of the U.S. ban on oil exports - each as topical and relevant in Canada as in the U.S. Scott Hempling's case comment effectively complements this year's "Washington Report" as it provides a closer look at how the US Supreme Court has delineated the interplay between state and federal jurisdiction in the regulation of American energy markets.

Just in the past few weeks, as this issue of *ERQ* goes to press, further political and regulatory developments make it clear that the business of energy regulation will continue to play a predominant role in the nation's public discourse. In the wake of the National Energy Board's recommendation for approval of the proposed expansion of the TransMountain pipeline, attention has shifted to the federal government's interim revised process for the approval of major new pipeline projects and what that process will mean, not just for that particular project, but also for other current and future projects that are essential to provide market access for Canada's oil and natural gas resources. Developments with respect to climate change initiatives continue apace in various provinces, particularly in Alberta and Ontario which have just announced a cooperation agreement that they are teaming up on measures to address climate change. It is our expectation that future issues of *ERQ* will continue to make a significant contribution to the continuing debate. ■

ELECTRICITY PRIVATIZATION AND RESTRUCTURING IN ONTARIO AND ABROAD: SOME LESSONS FROM UK AND ELSEWHERE[1]

*Dr. Stephen Littlechild**

Ontario is in the process of privatizing Hydro One. How is this best done? What role should restructuring play? And should other privatizations follow? This paper seeks to learn some lessons from experience in the UK and elsewhere over the last thirty years. Topics covered include the reasons for privatization, the significance of ownership, the implications for regulation, the promotion of competition, the role of restructuring, the particular situation of electricity transmission companies, the operation of markets after privatization, the benefits and costs of privatization, the nature and limitations of regulation, the evolution of regulation, the emergence of "customer engagement" as part of regulation, and the role of government.

1. Why privatize?

In the 1980s Margaret Thatcher's Government put privatization in central place on the political agenda. Why? It was certainly controversial. Her predecessor, Conservative Prime Minister Harold MacMillan, accused her of selling the family silver. Was privatization just for the proceeds it brought? There is no denying that was helpful: all governments need sources of revenue. However, there was much more to it. Margaret Thatcher argued that "There Is No Alternative": the economic survival of the UK was at stake.

There were particular advantages to be gained in particular industries. In the case of British Telecoms, a central aim was to improve customer service, to make telephones available on demand rather than on a long waiting list, and to encourage innovation. In the water sector there was a need to fund a massive investment programme to meet new European water quality standards. In the coal and steel industries it was important to stem financial losses and reduce costs for the rest of UK industry.

In contrast, the electricity industry seemed well run and was not loss-making. What was the case for privatizing it? In 1988 the White Paper on Electricity Privatization said that "[d]ecisions should be driven by the needs of customers." What exactly did that mean? It planned to restructure the Central Electricity Generating Board (CEGB), the monopoly provider of all generation and transmission, in order to enable competition. This would be more efficient: recent reports had found significant time and cost overruns in the building of new power stations. And regulation would be introduced to promote competition and protect customers.

Lesson 1: Although the UK had many reasons to privatize different industries, the aim of greater efficiency was a central reason, that applied in all cases

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1 This paper is based on a presentation "Electricity Privatisation and Restructuring in Ontario and Abroad: Lessons from the UK and elsewhere" (delivered at the Ivey Business School, Toronto, 30 November 2015).

2. Does ownership matter?

The answer is *yes*. This is particularly the case for competitive markets, as in generation and later in retail markets. Ownership affects incentives, both to compete and also to operate efficiently, which is equally applicable in monopoly sectors. A lesson we have learned is that incentive regulation only works if companies respond to it, and the response is much greater if the company is privately owned.

For example, the privately owned energy and water network companies have responded to a series of price controls by reducing costs significantly and consistently over the last quarter century. In contrast, when Royal Mail was government owned it failed to respond to a tough price control, and its losses simply mounted. Significant cost cutting and rationalisation started after it was privatized.

In fact, government ownership compromises regulation, because the regulator does not have to worry about objections from private shareholders, the company can always appeal to its owner, and a regulator cannot take on a government. I have seen examples in Guernsey and Northern Ireland, where regulators imposed measures that in my view were unreasonable and reflected a lack of due process, the Government-owned company appealed to the Government, and the regulator was effectively bypassed.

In addition, private companies tend to be more innovative and flexible. National Grid Company is an example here, to be discussed below. Although I also show below that Scottish Water, another government-owned entity, has been particularly innovative and flexible in the matter of involving customers and improving quality of service.

Some countries are keen on joint government-private ownership. Do government majority or minority shareholdings ever work? Do they provide the best of both worlds? Or the worst of both? In the UK, joint ownership is seen as risk, a situation where private owners are vulnerable to overriding and typically non-commercial decisions by government. In consequence, such arrangements have been only temporary – for example, as part of a phased privatization because the stock market would be unable to cope with privatizing the whole industry at once. (British Telecom's flotation value was about equal to the value of all companies floated in a year.)

Lesson 2: Ownership does matter, with respect to efficiency and competition, and regulation of government-owned companies is less effective than regulation of private companies

3. The development of regulation

A key question at privatization is how to reassure both customers and potential investors. The UK faced this in privatizing British Telecommunications (BT). At that time there was little or no competition in the telecommunications sector, so customers naturally feared that BT would exercise its market power and increase prices. The answer, as in the US, might seem to be regulation. But US regulation seemed problematic: we characterised it as "cost-plus" regulation, not conducive to efficiency in a context where increased efficiency was one of the main aims of privatization. But any different and unknown kind of regulation might frighten off investors. I was asked to advise on what kind of regulation might be appropriate.

In 1983 I recommended that the Government introduce an incentive price cap that acquired the name RPI-X regulation. BT would be automatically allowed to increase its average price by the rate of inflation (RPI stands for Retail Price Index) minus a specified number X, which would be set by Government. The Government set X at 3. This meant that, after allowing for inflation, BT had to reduce its average price at 3 per cent per year. This formula meant that investors were protected against inflation – the risk that a regulator would not allow them to increase prices with inflation was a real one in the days when double digit inflation was not uncommon – and the real price reduction of 3 per cent per year was a tangible benefit to customers from privatization.

What about the future? Would investors be at risk of asset expropriation or the imposition of unreasonable costs or restrictions? The regulatory framework was constructed so that regulation was independent of government: the regulator reported to Parliament, not a Minister. The regulatory body had a duty to promote competition and protect customers. The obligations and restrictions on the regulated company (e.g. the price control) were set out in a licence. What was to stop the regulator from simply changing the licence after investors had bought the company? Changes to the licence could only be made by agreement with the company. Did that mean that the company could simply refuse to accept any changes, and the regulator would be powerless? No, because there was provision for the regulator to refer any disputed licence modification to the Competition Commission, which would carry out a fresh review and had power to impose appropriate licence modifications.

The impending privatization thus forced the Government to develop a regulatory system that protects both customers and investors. In practice, this system has been applied to all the regulated sectors, and has worked well. Regulators and companies have seen what kinds of licence changes the Competition Commission has been willing to accept – mostly, with respect to revised price controls. Mostly, the Commission has supported the regulator, but has not hesitated to impose either more or less onerous conditions on the company. So, companies do not lightly oppose a regulator's proposed licence changes, and regulators do not propose ill-considered modifications that they could not justify before the Commission if necessary.

The result is that, in recent years, there have been relatively few appeals to the Commission. Regulation has proceeded by agreement. In fact, some have suggested that regulation has become too cozy, that there have been too few appeals. Some recent changes have been made to the appeal arrangements that may have the effect of stimulating more appeals – some fear too many. We shall see.

Lesson 3: Privatization forced the development of a form of regulation to protect both customers and investors

4. Creating competition

Competition has been described as a rivalrous discovery process taking place over time. The number of competitors in an industry at any time is perhaps less critical than the ability of new producers to enter an industry if existing competitors are not providing what customers want, or providing it only at excessive prices. Privatization is an opportunity to remove barriers to new entry (notably statutory ones) and to restructure the existing industry (often a monopoly) to form several competing successor companies.

The initial utility privatizations - of telecommunications, airports and British Gas – removed the main barriers to new entry. However, the opportunity to restructure the industry was not seized. Critics began to deplore the lack of competition, arguing that the benefits of privatization were going to investors rather than customers.

In contrast, the Secretary of State decided that competition would be a key characteristic of electricity privatization. To achieve this, the initial plan was that the transmission system would be taken out of the CEGB to form a separate and independent National Grid Company that would treat all generators, distribution companies and retail suppliers on a non-discriminatory basis. The generating stations would be divided into two companies: so-called Big G which would have about 70 per cent of the generating capacity (more precisely, capacity producing about 70 per cent of total output), and Little G with the other 30 per cent. Big and Little G became known as the Duopoly.

What was the thinking behind this slightly odd arrangement? The problem was that although most generating stations were coal-fired, about 15 per cent of total output was provided by nuclear stations. These were regarded as more risky, particularly since their future decommissioning costs, and even their present running costs, were unknown. There was a case for leaving them out of the initial privatization, but the Prime Minister was insistent that they be included, because of the importance of making them commercially viable. The initial view was taken that investors would be reluctant to buy nuclear stations, but they could be sold as a relatively small part of a larger company. Hence Big G at 70 per cent had to be big enough to hide the nuclear stations, and Little G was given the remainder in order to create a company large enough to compete with Big G.

As the preparations for privatization progressed, the future costs and risks of the nuclear stations became ever more apparent. At the last minute, the nuclear stations were pulled from the privatization. This left Big G (later named National Power) with 55 per cent of capacity, Little G (named PowerGen) with 30 per cent and a new government-owned Nuclear Electric with 15 per cent.

Over time, new companies entered the market building gas fired power stations. The rate of entry was so fast that this became known as the Dash for Gas. Nevertheless, the incumbent companies National Power and PowerGen still had significant market power. There was increasing regulatory and public concern. As regulator, I took steps to encourage/force the two large generators to sell off generating stations to other players. This was not straightforward: it required a mixture of carrots (permission to purchase distribution and supply businesses) and sticks (threat of reference to the Competition Commission). There is no doubt that it would have been better and much easier to have restructured the industry more radically at the time of privatization, when the government could simply divide up the company as it wished. Such an approach was indeed subsequently taken in Argentina and the state of Victoria (Australia).

Lesson 4: Restructure a to-be-privatized company or industry to create competition while you have the chance

5. Is transmission boring?

Hydro One is an electricity transmission and distribution utility. Some might argue that privatization might be relevant for a company that is actively engaged in the competitive market, but is unnecessary or unsuitable for a transmission and distribution business. UK experience suggests otherwise.

National Grid Company (NGC) was created to own the England and Wales national transmission grid. As a transitional measure, because it did not have its own financial record as an independent entity, it was initially owned by the 12 distribution companies. A few years later it was floated as a separate company.

In the following years NGC bought the national gas transmission and distribution network company (Transco). The concept of a single owner of both electricity and gas distribution networks raised some concerns, but it was argued that NGC was more efficient that Transco, and would improve efficiency in the latter business. National Grid was, however, required to sell off some of the regional gas distribution networks. This enabled comparative regulation: the regulator, the Office of Gas and Electricity Markets (Ofgem), was able to compare the efficiencies of different networks in different ownership. As it happens, NGC is at this moment in course of voluntarily selling the remaining gas distribution networks that it kept.

In order to maximise the pressure of competition, Ofgem proposed that all new transmission investments exceeding £100m in value should be put out to tender. It is presently in course of implementing that proposal during the present price control review.

NGC has invested in US networks and in new interconnectors to the UK. Its increased scope of activities has raised the question whether there might now be a conflict between its roles as transmission operator and system operator. Consideration is presently being given to splitting those roles into separately owned entities.

Lesson 5: Transmission Companies too can be major players in a fast-changing world, but to do so effectively they need the flexibility and control that private ownership brings

6. Distribution & retail companies

Before privatization, the nationalized electricity sector in England and Wales had 12 Regional Electricity Companies (RECs) that were responsible for local distribution and retail supply. Was any restructuring needed before they were privatized? Some advocated merging them into one single company, to provide a more effective counterweight to the CEGB, had that been privatized as a single entity. But the decision to split the CEGB invalidated the case for such a merger. There were also suggestions that they be merged to form six double-sized companies. But the Government decided instead to privatize the companies as they were: there was no adequate basis for deciding whether and how far there would be economies of scale in the new more competitive environment, and more decision-makers were preferable to fewer.

The Government did, however, decide to restructure each REC into separate distribution and retail supply businesses. This meant that, over time, each company could decide whether to specialize in engineering (distribution) or in retail markets. For an initial five year period, each of these companies had a “Golden share" owned by the Government, which the Government would use to prevent a change of ownership. After that period, however, mergers and takeovers were allowed. Some companies were keen to expand, in other cases the investors were happy to be bought out. Over time, the market established a "going market price" for distribution and retail supply businesses. Interestingly, potential buyers and sellers found this very important in order properly to evaluate their decisions.

With various modifications, UK regulators continued the RPI-X incentive regulation scheme. In doing so, it was important to evaluate the scope for future efficiency improvements. The regulators developed concepts of comparative competition: comparing the efficiencies of the 12 distribution businesses and setting targets for the less efficient ones to match the more efficient ones over the next five year price control period.

The ability to buy and sell distribution and retail businesses, and the pressure of incentive price controls, led to numerous takeovers and mergers in the sector. The larger generating companies bought into distribution and retail supply, partly as a means of stabilizing their income, partly as a means of achieving economies and reducing risks via vertical integration. New entrants from the US, France, Spain and Germany took over yet other businesses. Businesses were sold and resold. Ownership thus evolved, as in other markets. To some extent this reflected a search for scale economies: There are now 4 distribution companies, each with 3 or 4 networks, and supply is mainly concentrated in the so-called Big 6 retailers, although new entrants over the past few years now account for over 10 per cent of supply to domestic customers. Similar phenomena are observed in other successful competitive markets around the world, such as Victoria, New Zealand and Texas.

Lesson 6: Let the market determine the most efficient and constantly evolving structure of the industry, rather than expect government or a regulatory body to determine this

7. The overall impact of privatization

The main aims of privatization included to increase efficiency and to better meet the needs of customers. Is there evidence that privatization of the UK electricity industry achieved that aim?

An examination by the National Audit Office[2] found that price cap regulation of the networks had delivered substantial benefits, as a result of providing strong incentives to increase efficiency. For example, it found cuts in operating costs (opex) of about 25 per cent from 1994/5 to 1997/8, and cuts in transmission (controllable) operating costs of about 50 per cent since 1990. It also found other benefits including improved reliability.

In 1997, an academic cost-benefit analysis of the privatization of the CEGB generation and transmission business found the total net present value ranged from £4 billion to £10 billion, depending on the precise assumptions, but estimated that all of this went to investors.[3] A colleague and I carried out a similar study in 2004, taking into account later developments in the industry and making alternative assumptions about the counterfactual (what would have happened in the absence of privatization).[4] We calculated that the net present value was about £23 billion, of which about half went to customers. In either case privatization was a beneficial policy[5] and, over time, customers benefited more than seemed to be the case initially.

My own recollection is of a much simpler and more striking measure. In the decade or so after privatization, total manpower in the industry fell by about two-thirds (part of which was accounted for by contracting out of meter-reading). One might have expected resistance from the work force, but this was not the case. The unions had negotiated good severance terms, many were happy to leave and work elsewhere. Those that stayed in the industry found they had more satisfying and varying careers, for example as a result of multi-skilling and better industrial relations within smaller, more flexible companies compared to a nation-wide monopoly.

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2 UK, House of Commons, National Audit Office, *Pipes and Wires,* by the Comptroller General and Auditor General, in HC 723 Session 2001-2002 (10 April 2002).
3 David M Newbery & Michael G Pollitt, "The Restructuring and Privatisation of Britain's CEGB - was it worth it?" (1997) 45:3 Journal of Industrial Economics 269; see Stephen Littlechild, "Competition and Regulation in the UK Electricity Market" (2004) 14(1) Économie Publique 3 at pp 8-10 [*Competition and Regulation in the UK Electricity Markets*].
4 *Competition and Regulation in the UK Electricity Markets, ibid.*
5 *Ibid* at p 10.

Lesson 7: Privatization can be beneficial for customers and employees as well as investors

8. UK energy price control reviews

In 2008 the energy regulator Ofgem carried out a Review of Network Regulation, called RPI-X@20.[6] It noted a number of significant achievements, notably improvements in efficiency, 30 per cent lower network prices, 30 per cent greater reliability, more investment, and good rewards to shareholders.

But there were also significant weaknesses. Price control reviews were time-consuming, costly and complex. Innovation was good but narrow, focusing on opex efficiency and lower cost financing. The record was not so good in network design, operation and pricing, and the latter would be more important in future, with the advent of low carbon technologies. There was no incentive for companies to put forward good business plans because companies went through the same tedious review process regardless of quality. And finally companies were led to focus on the regulator instead of their customers.

Lesson 8: Regulation may be effective in many respects but may have downsides, and may need refreshing over time

9. A new regulatory approach

Ofgem decided that in future there would be a need for more innovative and flexible networks to work with and respond to customers. This would necessitate more incentives to encourage more innovation. For example, it proposed funding competitions to reward companies for innovations.

The focus should be on outputs not inputs. For example, regulation and revenues should be based on actual capacity and reliability provided, not on expenses incurred and investment. The focus should also be on total costs (totex) not on Opex & Capex separately.

Ofgem proposed a fast-track price control review for companies that had well-evidenced business plans with good customer engagement. Such companies could complete the price control review in six months instead of 18 months.

Lesson 9: Regulation can evolve significantly to address previous concerns and to deal better with new issues in future

10. Negotiated settlements in North America

What exactly does good customer engagement mean, and where did the idea come from? There are antecedents in North America, and more recently in the regulation of UK airports.

In the U.S., so-called negotiated settlements between the regulated company and its customers originally arose to reduce the time, cost and risk of litigation before the federal or state regulator. The parties would agree a proposed rate increase to put to the regulator. This seems to have been initiated by the Federal Power Commission (FPC) in the 1960s, but has since happened elsewhere, particularly in Florida in the 1990s. Amongst other settlements there, the Office of Public Counsel and the electricity companies agreed tariff cuts worth over $4 billion.

At the Federal Energy Regulatory Commission (FERC), when companies proposed a rate increase in the 2000s, FERC staff would propose, within three months, an alternative rate increase based upon their own assumptions of what would be reasonable. Staff would then lead discussions between companies and their customers. The parties often settled in the next six months.

At the National Energy Board (NEB) in Canada, the NEB considered that setting a cost of capital formula would avoid long hearings. In the light of it, pipelines and their customers were generally able to negotiate a settlement. In fact, since 1997 almost all pipeline rate cases have settled. These settlements also introduced multi-year incentive systems, and often also required the provision of information and set quality of service obligations. The outcome was better information and customer relationships in the industry. The NEB's policy was that, if the process of negotiation was sound, it would accept the outcome, and not substitute its own view of the public interest.

[6] See Alistair Buchanan, "OFGEM's 'RPI at 20' Project" (speech at SBG, 8 March 2008), online: OFGEM <https://www.ofgem.gov.uk/ofgem-publications/64130/sbgi-6-march.pdf>.

Other jurisdictions in Canada, including Ontario, and in Australia and Germany have similarly used negotiated settlements.

Lesson 10: Regulators do not need to take all the decisions: regulation can work by "holding the ring" and allowing the parties to negotiate

11. First UK constructive engagement

In the UK, price control reviews are typically more complex than in North America. Prices are not based on the actual costs in a recent test year. Rather, the review seeks to assess the efficient level of operating costs over the next five year period, together with the most efficient plan for future capital investment. This process can be extremely challenging, since the regulated companies will typically challenge all or most of the regulator's assumptions.

This was the case with airport regulation. The 2003 review of charges was particularly confrontational, the airports and airlines disagreed with each other, and left the Civil Aviation Authority (CAA) to take all the major decisions, which it was not equipped to do.

In 2005 the CAA changed its approach. It proposed what it called a process of "constructive engagement." It suggested that each regulated airport and its airlines seek to agree a number of major elements underlying the price control, notably traffic forecasts, desired quality of performance standards and the future investment programme. The CAA would then make assumptions about efficient future opex, decide the cost of capital and financing assumptions, and set the final price control.

Initially there was suspicion and reluctance by all parties, and the process was not without difficulties. But by 2007 these aims were largely achieved at the two main London airports (Heathrow and Gatwick). There was an early failure to reach agreement at the third London airport (Stansted), but the process was later repeated successfully (under the jurisdiction of the Competition Commission) once the hotly disputed issue of a new runway was off the table. The regulator also reported improved relationships and understanding between the parties.

From 2009 onwards the CAA as regulator continued to use this approach. Following advice from the Competition Commission, the CAA gave more structure to the negotiation process, with a view to better facilitating it. For example, it specified what information was to be provided by whom and when, and set and monitored a timetable for reaching agreement, with periodic reports by the parties.

Lesson 11: Regulation can be adjusted to enable informed customers to play a greater role in the process of setting price controls by negotiating specified elements with the regulated company

12. Latest developments in customer engagement in the UK

The constructive engagement process in airport regulation involved a relatively small number of relatively informed customers. Can a similar process work with an electricity distribution network with, say, two million residential customers?

As noted above, one result of Ofgem's 2008 review of regulation was a decision to offer fast-track reviews to those companies that provided well-evidenced business plans with good customer engagement. The water regulator Ofwat adopted a similar policy. These reviews started in about 2012 to determine price caps for the period beginning 2015. (Ofgem had earlier tried out a similar approach with the electricity and gas transmission networks which provided encouragement to extend the idea.)

The regulated network companies and their customer representatives were very keen and engaged strongly and constructively. Company business plans were much revised in light of this interaction, and customers supported them. However, the regulators fast-tracked only one company in each sector. Their explanations were that the other companies' business plans embodied insufficient future cost reductions. These other companies were then put through the conventional slow-track route, with the regulator indicating what level of future cost reduction would be acceptable.

Does this represent a failure of the approach? Will it discourage companies and customer representatives from engaging in future? Should the process be run a different way next time? All these questions have been under discussion in the UK, as regulators and companies prepare their thinking for the next review process. Meanwhile, it is important also to consider an alternative version of the approach.

The Water Industry Commission for Scotland (WICS) was also interested in a new approach to the Strategic Review of Charges that involved customers working constructively with the single government-owned Scottish Water company, and the company was prepared to accept a new approach. WICS, Scottish Water and Consumer Futures (later Citizens Advice Scotland, the statutory customer body) together created a Customer Forum. The Forum had a formal role: to work with Scottish Water to carry out research into customer preferences, to represent these preferences to the company and the regulator, and to seek to secure the most appropriate outcome for customers in the Strategic Review.

Part-way through the process, the regulator invited the Forum to seek to agree a business plan with the company, consistent with a series of regulatory guidance notes that the regulator would provide. These notes covered a variety of relevant topics, including views on cost and efficiency, and levels of investment. The process proceeded well, there was good and constructive engagement, not least involving fairly active participation by the regulator. Agreement was reached on a business plan, and this formed the basis of the price control that the regulator set. The process is widely regarded as a great success.

Discussion in the UK thus includes whether some version of the "Scottish model" could and should be applied in England and Wales. Is it feasible for regulators there to give formal and informal guidance – say on acceptable future cost efficiencies – to a dozen companies and their customer groups? How far should regulators delegate their responsibilities to customer groups? What should be the guidelines as to the composition of the customer groups? How far should each company and its customer group report their thinking and agreements or disagreements for consideration by other companies and customer groups? There are many questions to consider, but the general feeling seems to be that customer engagement has been a qualified success and ought to be at least continued in future, and some would argue for extending it.

Lesson 12: In the energy and water sectors too, regulators may achieve more by encouraging companies and customer groups to negotiate, subject to regulatory guidance, than by taking all the decisions themselves

13. UK Government and regulation

Does government have an impact on a regulated industry, and indeed on regulation itself? At the time of the 1989 privatization of the electricity industry the Conservative Government's energy policy was not to have an energy policy. The Government did not see its duty as being to plan the evolution of the sector. The competitive market was the most effective means to ensure that supply was sufficient to meet demand, in the most efficient way. The duties of the Government and the regulator were relatively simple: to promote competition and protect the interests of customers.

Over the period 1997 to 2008 successive Labour Governments modified these regulatory duties, primarily to place greater weight on environmental considerations and also on fairness as between different types of customers. The regulatory duty was modified to promote competition "wherever appropriate." There was a new duty to contribute to achieving sustainable development. The Government took power to issue guidance to the regulator on social and environmental policies.

Between 2008 and 2010 the Government further modified the regulatory duties, in the same directions. For example, it now specified that the interests of customers included their interest in lower greenhouse gas emissions. And before promoting competition, the regulator should consider whether other ways of regulation could achieve the same effect. The Government also supported Ofgem's intervention in the retail market to remove "unfair price differentials."

In 2013 the Coalition Government indicated its intention to provide a Strategy and Policy Statement, together with a new duty on Ofgem to further the delivery of this government policy. The regulator was also required to explain at the beginning of each year how it would discharge this remit. At the end of each year, it would have to explain whether and how far it had succeeded, and if it had not delivered as promised, it had to explain how it would remedy the situation the next year. In the event, the Coalition Government did not issue a statement before it left office, and it remains to be seen whether the present Government will do so.

Lesson 13: Governments will find ways to use regulation to further its policy ends, though regulation is probably not the main means by which

Government implements its policies

14. UK Government energy policy

In 2008 the Labour Government announced a complete rewrite of energy policy. The Minister indicated that "important decisions cannot be left to the market". In 2010 it introduced an Energy Market Reform policy. This included targets for renewable energy, contracts for low-carbon energy, a 35 year contract for a new nuclear generation station (at about twice the wholesale market price), and a capacity mechanism. The Coalition Government continued a similar approach over the period 2010 to 2015.

In 2015 the incoming Conservative Government seemed to some extent to be reconsidering energy policy. It made cuts to some subsidies to renewable energy, but continued to support nuclear and offshore wind. The Government's non-binding strategic Steer to the Competition and Markets Authority emphasised deregulation, but there has been little sign of this in the energy sector. There were arguments that government policy was increasing risk, and questions whether unsubsidized investment was any longer viable.

Lesson 14: Government cannot be expected to follow a consistent course over time and successive governments will change policy regardless of type of ownership, but privatization means that the government has to act explicitly rather, and Parliament can thereby better hold it to account

15. Lessons for other jurisdictions

Privatization has been a politically contentious policy in many sectors and countries, not least the UK. Experience suggests that it has many potential efficiency benefits. But it is an important beginning to a reform programme, it is not the end of the story.

Privatization offers a valuable opportunity to restructure an industry to better facilitate competition and comparison between more successor companies. In the electricity sector, competition is indeed possible in generation and in retail supply. There is also a need to find efficient arrangements for the monopoly transmission and distribution networks. In both cases, there is advantage in allowing the market to continue to evolve via mergers and takeovers.

Initially, regulation of the network businesses aimed at incentivising greater efficiency, which was indeed achieved, albeit at the cost of time-consuming and burdensome price control reviews. Increasingly, the focus has been more on incentivizing companies to discover what customers want, and to innovate and adapt to a changing world. Initially, it was most important to design the regulatory role to protect both customers and investors. Increasingly, it is also important that regulation be flexible, innovative and responsive.

One has to accept that political concerns will have an impact on a regulated industry and on regulation itself. But I would argue that government and political intervention would be worse in the absence of privatization. Hopefully these lessons will be of some assistance in designing a way forward in Ontario. ■

ALBERTA'S ELECTRICITY SYSTEM: CARBON POLICIES AND THE RISK OF UNINTENDED CONSEQUENCES

Donna Kennedy-Glans, Q.C. and Dr. Brian Bietz***

Introduction

In advance of the COP21 climate change meetings in Paris last December, and in concert with the carbon policies announced by the new federal Liberal government, on November 22, 2015 Alberta Premier Rachel Notley advanced several climate related policies for Alberta. Her government's Climate Leadership Plan[1] set out four ambitious targets:

- A broad-based levy on all carbon dioxide ("CO_2") emissions;
- A 100 megatonne cap on total oil sands CO2 emissions;
- Accelerated shut-down of coal-fired electricity generation; and
- Target quotas for renewable electrical energy generation.

These policies appear to have been well received on the world stage and should go some way towards improving Alberta's social licence to operate. However, when combined with the economic impacts in Alberta of current low commodity prices for oil and natural gas and a parallel increase in delivered electricity prices, the latter two electrical energy related policy changes have many potential implications for Alberta's competitive electricity generation market and its regulated transmission and distribution systems.

With the release of the provincial budget in April 2016, how these broad electrical energy policies are to be implemented, particularly under current economic conditions, would appear to be the next process step for government. Key process related questions regarding the effects of these new policies on the Alberta electrical system that both regulators and government will need to address include:

- *How* will coal plant shutdowns be accelerated without creating unacceptable levels of stranded assets, compromising reliability, or overly burdening electricity consumers?
- H*ow* will the mandated increase in renewable energy generation capacity be incentivized without compromising Alberta's competitive electricity generation market? and
- *How* will we prevent costly duplication of transmission and distribution infrastructure as we increase the proportion of renewable electricity in the system?

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1 Government of Alberta, *Climate Leadership Plan*, (Edmonton: 22 November 2015) [*Climate Leadership Plan*], online: Government of Alberta <http://www.alberta.ca/climate-leadership-plan.cfm>.

In addition, in an economy where revenue from energy exports has been slashed, Albertans are also asking government to ensure that to the extent possible they are protected from other rising costs. Some of the questions raised by the proposed climate change policy include:

- *How* do we continue to retain and attract new investors in generative electricity capacity, increasing supply and therefore presumably reducing costs?

- *How* do we ensure that transmission and distribution costs better match other economic indicators in Alberta? and

- *How* will consumers be affected when power wholesalers shed their Power Purchase Arrangements (PPAs) and return these obligations to the Balancing Pool?

To explore at least some of these questions, we have chosen to break them into three broad areas of analysis. These are:

1. **Electricity Generation**: The potential impacts of accelerated coal plant closure and renewable energy integration for Alberta's market-based generation system.

2. **Electricity Transmission and Distribution**: The costs, reliability and logistical consequences of bringing more distributed and intermittent renewable energy sources into the electricity grid.

3. **Power Purchase Arrangements:** The consequences of early terminations of PPAs for coal-generators in particular and the marketplace in general.

Underlying all three of these themes we also believe that there is a final policy question with profound regulatory consequences that also needs to be addressed by government before it moves forward with any significant changes to the current system. We wonder, given the direction and potential magnitude of the energy policy changes that will result from the implementation of the Climate Action Plan:

Is this the right time for government to assess the implications of a transition back to a fully regulated electricity system in Alberta?

Electricity Generation

Unlike other jurisdictions in Canada, electricity in Alberta is generated within a competitive market. The transition of Alberta's electricity generation to a market-based system began in 1996 and was purportedly pursued to encourage efficiencies in the sector via a healthy infusion of competition. However, the expected larger new entrants into the commercial generation market have largely failed to appear with the few that did enter the market having fairly rapidly exited again.

New generation in Alberta has for decades been built with private capital but since 2001, the owners of electricity generation plants have been fully at financial risk for new investments in generation. Under deregulation, the Alberta Utilities Commission (AUC) now only approves:

> generation at the facility level, i.e. a generator must comply with regulations such as safety, environmental, design standards and public consultation. The AUC does not regulate where generation is located in the broad sense, what type of generation is built, how much generation is built, who builds generation, nor ultimately the rate of return earned by owners.[2]

The Alberta Electricity System Operator (AESO) which plans for and operates most of Alberta's electric system, including a competitive wholesale electricity market, also has no ability to dictate if, when or where new generation will be built or what returns the plants will engender for their owners. Investment decisions are driven solely by the revenues generators hope to realize from energy sales – hence the term "energy only market."

Between 2002 and 2008, following a sharp price spike and subsequent decline as deregulation was being introduced, the price paid by Albertans for the generation portion of their power bills has risen relatively steadily. In some years, despite the earlier argument

2 Alberta Utilities Commission, "Alberta's Energy Market" online: AUC <http://www.auc.ab.ca/market-oversight/albertas-energy-market/Pages/default.aspx>.

that competition should reduce power price, generation costs have also risen more rapidly than in other jurisdictions. However given that the real cost of generation was not hidden elsewhere, as also happens in some jurisdictions, the actual increases were likely reasonable and also likely reflective of the relatively strong economy.

More recently electricity prices have dropped sharply in this case in alignment with declines in the economy, first in 2009 and later in 2014. This suggests that unlike what can happen in regulated markets, the price for power generation in Alberta is at least now reflective of broader market signals, including supply relative to demand. Currently Albertans are enjoying very low generation costs presumably due to an increase in supply relative to demand and given the current economic climate, Albertans are very unlikely to welcome any changes to the system that increase these costs. This of course raises questions about the potential implications of the Climate Leadership Plan on the principles unpinning Alberta's deregulated electricity generation market.

There are two commitments in the government's plan that particularly trouble proponents of deregulated electricity generation. The first is an artificial acceleration of the shutdown of coal-fired electricity plants. Government has stated that by a 2030 target date "coal-fired plants will be phased out and replaced by renewable energy and natural gas-fired electricity, or by using technology to produce zero pollution."[3]

The second commitment is the prescription of renewable energy targets for electricity in Alberta with government's stated goal that: "By 2030, renewable sources like wind and solar will account for up to 30 per cent of electricity generation."[4] By dictating the make-up of future generation both of these policies imply a significant re-entry by government into the generation marketplace.

Albertans are now asking serious questions about how these undertakings will be implemented. With respect to the fixed retirement date for all coal-fired power plants, one major issue is the economic impact of stranded investment. Currently 18 coal-fired generating stations operate in the province. Twelve of these plants are already expected to retire without provincial intervention by 2030. These retirements will occur at the nominal end of their economic life as a result of federal regulations and hence the province should be at little or no financial risk.

However, if the provincial cut-off date for coal-fired power in Alberta remains at 2030 this leaves six plants to be retired early, before federal requirements come into effect and in some cases well before the end of their economic life. For example, the newest plant in the fleet, Keephills#3, was commissioned in 2011 and under current market forecasts and regulations would be both economic and federally compliant as late as 2051. Its potential forced early retirement to meet new provincial climate change requirements represents a major risk of stranded assets to the owners and a major risk of future costs to Alberta consumers who may ultimately become responsible for these costs. Conservative estimates of remaining net book value of these plants is in the billions of dollars should the government or the courts determine that compensation is owed.

Alberta consumers are also concerned about how price and reliability will be maintained as the various coal-fired power plants are shut down. Albertans currently depend on coal-fired power for about 65 per cent of all of the province's base load electrical generation and in a deregulated market there is of course no publicly driven mechanism to ensure that they will be replaced. Whether due to provincial or federal requirements, a less than orderly shutdown creates the potential for reduced supply, higher prices and even more importantly, a publicly unacceptable reduction in reliability.

The 2015 Climate Leadership Report[5] to the Minister of Environment and Parks may, quite wisely, offer at least a partial solution to this dilemma. The report does not call for shutting in of coal-fired power plants *per se*. Rather the Panel recommended:

3 *Climate Leadership Plan*, *supra* note 1 at "Ending Coal Pollution" section.
4 *Ibid*.
5 Government of Alberta, *Climate Leadership Report to Minister*, (Edmonton: 20 November 2015) at p 48 under "Implementation of Regulated Coal Phase Out".
6 *Ibid*.

> that government pursue a predictable phase out of coal-fired power, should it determine that this will not occur solely as a result of the combined effects of carbon pricing, renewables policy and air quality regulations and federal end-of-life performance standards for coal plants.[6]

Since there continue to be significant advances in CO_2 capture technologies, with 14 years to implement those technologies, it would seem very reasonable for government, rather than insisting that shutting down is the only option, to also provide a second alternative. That alternative would be to afford coal-fired plant owners the option of meeting new stringent emission standards by 2030 through technology improvements.

Adopting this option would raise costs but would avoid stranded investments and maintain generation levels. Unfortunately the government has potentially limited this option by indicating that coal-fired power plants would need to have "*zero pollution*"[7] to remain in operation post 2030. However, since this is a patently unfair target that no source of power, renewable or otherwise can meet, it should be possible to apply common sense and work towards optimizing the value of these remaining power plants.

Mr. Terry Boston, a recently retired power executive in the U.S., has been named by Premier Notley as the Coal Phase-Out Facilitator to advise on how the economic and power reliability implications of these early plant retirements can best be addressed. His work is very important as a government driven shutdown program that treats shareholders poorly could easily be the death knell for future private investment in the Alberta generation market.

Similar questions are being raised with respect to government's approach to delivering its mandated increase in the province's renewable energy portfolio with the associated answers having a wide range of potential impacts. For example, it is as yet unclear whether government expects the AESO to demonstrate that 30 per cent of produced electricity is actually generated from renewables. Or is their task to ensure that renewable sources account for 30 per cent of generation capacity? These two interpretations of the government's target yield quite different answers with significant implications for both price and reliability.

The rate at which increased renewables are introduced is another issue. If government settles on an aggressive schedule for renewable energy transition, some look to other jurisdictions, the U.K. for example, and question Alberta's ability to successfully integrate such significant incremental levels of wind and solar energy into the grid. The levels of dispatchable generation required to backstop the renewable production will also be significant and will likely have to be gas-fired to provide sufficient flexibility. This will require a sizable capital investment and in the absence of additional new government policy, will have to be made by private investors without any guarantee of a return. Others question the continued interest of landowners in Alberta, especially in the windy southern regions, to release vast swaths of land to wind turbines.

And like the case for mandated shut down of coal-fired generation, other significant broader policy questions remain. For example, how will the AESO accomplish either of these goals while maintaining a deregulated generation system where economics are the key signal for new private investment? Any time government chooses to incent one form of generation significantly, there is clearly a risk of dis-incenting investment into other forms of generation. For example, Layzell *et al* [8] of the University of Calgary have recently proposed that by significantly increasing cogeneration at existing and future SAGD operations, Alberta could achieve even larger CO_2 emission reductions more quickly and with much less impact to power reliability.

There is no doubt that the Alberta government wants to advance a solutions-based approach to the policy driven shut-down of coal-fired electricity generation and integration of increased levels of renewable energy into our

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7 *Supra* note 3.

8 David B Layzell et al, "A Strategy to Reduce the Carbon Footprint of SAGD Production", (Industry Trends and New Technology delivered at the Annual Conference of the Canadian Heavy Oil Association, Calgary, 5 April 2016) [unpublished].

electricity generation market. The challenge though will likely be much greater than simply finding the right pace for the transition if government also wishes to maintain both a competitive and reliable generation market.

Electricity Transmission and Distribution

Recently, Albertans have become increasingly focused on the relative costs of transmission and distribution. Unlike generation costs, transmission and distribution costs are regulated and unlike generation, have not been sensitive to the decline in the economy.

Renewable energy tends to be both more intermittent and distributed than non-renewable energy and a significant increase in renewable supply will require different transmission and distribution infrastructure than the more traditional larger power plants. For example, if a significant portion of the new renewables come from micro generation, they will rely on the distribution system to flow into the grid. These new power sources will need to be integrated into existing systems that were primarily built to support non-renewable base load power sources and/or send power into homes, not out.

The AESO has already successfully integrated wind power into Alberta's transmission grid, especially from southern Alberta. However, the Climate Leadership Plan proposes a significant further increase in renewables. A major challenge going forward will be ramping up the pace of this integration of renewable energy into the existing infrastructure, without creating a dual system and/or major new costs to consumers.

Since transmission and distribution costs have already been rising rapidly in Alberta relative to generation costs, one question that does appear to be already up for consideration is whether even the current costs of transmission and distribution are justified. Alberta is presently divided into several regions where individual companies have the exclusive right to transmit and distribute electricity without competition. As is the case in other regulated power systems, these companies have "an obligation to serve" and so are subject to government policy directives. However, unlike generation in Alberta, these transmission and distribution companies are largely protected from the economic risks of these new policies. Provided their investments are deemed to have been "prudent" by their regulator, in this case the AUC, both capital and operating costs will normally be covered in rate base.

As a quid pro quo for the obligation to serve, regulated utilities are awarded an opportunity to earn a return on investor equity (ROE) at a rate set by the AUC. The approved ROE to 2015 was 8.3 per cent, based on 2013 economic conditions. Since the prescribed utility ROE is forward looking - i.e. it is designed to try to reflect future economic conditions based on real data from a test year, the next review of utility ROE is set for 2017, using 2015 data.

While the 2015 data will presumably reflect a fair portion of the effects of the recent economic slowdown, for many companies in today's economy an 8.3 per cent ROE would of course be considered exceptional. Therefore in setting a new ROE for the utilities, although the AUC is expected to rely only on data for the test year, there will likely be significant pressure on the AUC from consumers to take into account data post 2015 as well in determining what future ROE during a provincial wide recession is "just and reasonable." The AUC will undoubtedly be asked to consider the question: "Since other companies operating in Alberta are doing more, for less, shouldn't our regulated utilities be expected to at least do the same?"

Even under less stressful conditions, there is always pressure from consumers in rate cases to ask the regulator to look beyond the test year, particularly if this will lead to lower costs. However, in our view, while this is tempting, setting the "right" ROE is never easy since too low a return on investment can often raise other costs, including growing costs which are also passed on to consumers.

Nor does Alberta need even more uncertainty in the electricity marketplace, which a politically driven rate case would surely create. Utilities have an obligation to transmit and deliver electricity to Albertans; in that way, they are captive. So, fairness, all round, and a long view, are essential.

However, there may be other mechanisms available to either government or the AESO which could potentially have an even more significant positive impact on future transmission rates. If increased costs of adding significant amounts of renewables cannot be avoided, then there is particular incentive for government, as it implements the Climate Leadership Plan, to actively look at these options.

Of particular note is the potential to reconsider the need for as yet unbuilt transmission lines.

In 2009, in the midst of several years of "hockey-stick" economic growth projections, rancorous debate about the appropriate apportioning of roles between government and regulators with respect to new transmission decisions culminated in Bill 50.[9] This legislation moved responsibility for establishing whether there was a need for new transmission from the AUC to the government, and eventually led to approval of an ambitious build of new transmission in Alberta, including two major North-South lines between Calgary and Edmonton and two from Edmonton to Fort McMurray.

The two southern transmission lines have already been completed and are now partially reflected in utility bills. However, the application for the first line to Fort McMurray, which is budgeted at $1.433 billion, comes before the AUC in June. Although the AUC is currently no longer allowed to determine whether this line is needed, others parties can. It would seem to be extremely prudent for this government to ask its officials, particularly in the face of a sharp decline in oil sands activity, to very carefully re-examine the need for this massive expansion in transmission as it is currently designed. Albertans may clearly prefer to spend on other priorities.

A second option the government has for reducing transmission costs is to take a close look at the "zero congestion" directive of the AESO and the impacts this policy is having on costs. In the February 2012 Government of Alberta Powering Our Economy: Critical Transmission Review Committee Report, an uncongested network and the role of the AESO in delivering that network are described as:

> A robust and unconstrained transmission system…that provides equal access so all consumers and generators can connect to the grid….. The AESO is required to plan a transmission system that is sufficiently robust so that **100 percent of the time** [emphasis added] transmission of all anticipated in–merit electrical energy can occur when all transmission facilities are in service…..[10]

The "zero congestion" policy was conceived on the premise that by removing transmission constraints, the success of the then fledgling competitive power generation market would be much more likely. It was also expected to lower the cost of generation by ensuring the cheapest power was also dispatched.

Zero congestion would appear to be a wonderful ideal - if you are a generator - but is it sound policy for consumers? This question becomes even more relevant as transmission costs take up an ever greater portion of the total consumer utility bill. Since as a result of government policy consumers foot the entire bill for new transmission, a very simple yet potentially very beneficial step by government may be to ask the AUC to re-examine the need for and efficacy of this policy. For example, it may now be significantly more cost effective to build less infrastructure and backfill any constrained flow with improved contracting and short term use of higher priced electricity, including imports from B.C.

A third opportunity to better control the transmission and distribution costs being passed directly on to consumers would be to better ensure that the associated capital costs are kept as low as possible. Currently, the "prudency" of these costs are assessed after the fact by the AUC and the AUC is understandably reluctant to apply the luxury of 20-20 hindsight to already incurred costs. A simple additional step in this process would be to require that utilities have independent cost managers in place to oversee costs on transmission and distribution projects as they are being built rather than after the fact. The idea of an independent cost oversight manager, not dissimilar to what in industry is referred to as an "owner's engineer," has been tested in other jurisdictions, with positive outcomes.

9 Bill 50, *Electric Statutes Amendment Act*, 2nd Sess, 27th Leg, Alberta, 2009.

10 Government of Alberta, *Powering Our Economy: Critical Transmission Review Committee Report*, (Edmonton: February 2012), online: Government of Alberta <http://www.energy.alberta.ca/Electricity/pdfs/CTRCPoweringOurEconomy.pdf>.

It may be time for sober second thought on Alberta's electricity transmission and distribution policies. More than ever, Albertans need to be smart in how we bring on new kinds of power, including more wind and other intermittent renewable energy, and how we connect that power to consumers. Part of that wisdom includes managing all of the costs.

Cancellation of Power Purchase Arrangements

Transitioning from a regulated to a deregulated energy market in the late 1990s created a number of legacies. To accomplish its goals, government was forced to artificially create a power market (the Power Pool operated by the AESO) as well as reduce the market power of the incumbent operators (generators). Since government also hoped to accomplish this reduction in market power without forcing the operators to sell their assets, the PPA was introduced as a tool to accomplish this goal. The PPA was intended to carry on the previous regulatory compact between government and operators by providing the owners of these already approved and previously regulated generating assets the opportunity to recover their fixed and variable costs for a pre-established "life of the project."

The PPAs were sold at auction to buyers who believed that the revenues they could receive from electricity sales through the Power Pool over the life of the arrangement would be sufficiently greater than the purchase price for the PPA. However, not all of the PPAs offered for sale received an acceptable bid and the buyer obligations for the unsold PPAs were assumed by the Balancing Pool. The Balancing Pool was created by statute as the legislative entity responsible to fill the void if no purchaser bid to acquire a PPA at the time of deregulation. The Balancing Pool is also required, if certain conditions are met, to assume a PPA that had previously been acquired by power buyers.

It is this latter option which is currently creating consternation in the Alberta power market. The PPAs include a clause giving the power buyer the right to terminate the PPA under certain pre-agreed conditions, including a change in environmental laws that make the PPA "unprofitable or more unprofitable". Recently in Alberta there has been a spate of PPA terminations between four power buyers, ENMAX, TransCanada, AltaGas and Capital Power and two coal-fired electricity generators, TransAlta and ATCO. These cancellations were ostensibly the result of recent changes in Alberta's climate change policies, in this case the *Specified Gas Emitters Regulation ("SGER").*[11] These changes, the power buyers have argued, have effectively made the PPAs "more unprofitable".

These terminations by the power buyers have in turn triggered the requirement that the Balancing Pool, and through the Balancing Pool, the public, reassume responsibility for these PPAs. This assumption of contracts by the Balancing Pool and the linkage back to government climate change policies as the trigger for the terminations, has raised significant media attention and a number of interesting questions. Although Albertans are likely unfamiliar with most if not all of the terms and concepts, if they are listening to the media coverage, they are likely now wondering about the implications of these terminations for consumers and about the role of the Balancing Pool, until now a relatively obscure entity.

While there are a number of contentious issues associated with the early termination of the PPAs, there appears to be general agreement on the following three points:

1. *In the context of current power pool prices, coal-fired generation PPAs are not generally considered economic.*
   There appears to be little doubt that few generators, irrespective of fuel source, are finding current prices to be acceptable. This is likely particularly true for large base load coal-fired power plants unable to take advantage of short term price variability. Of note, however, these same PPAs have been economic in the past and should electricity prices increase to past levels, these PPAs may very well be economic again in the future, even with the increased costs triggered by the new rules under SGER and/or its future replacement, the carbon levy.

2. *The new SGER provisions (or any similar form of carbon levy) will increase costs for the holders of the PPAs.* Since available energy efficiencies have likely already been tapped to satisfy earlier SGER

11 *Specified Gas Emitters Regulation,* Alta Reg 139/2007.

requirements, meeting these incremental requirements almost undoubtedly will require coal-fired power generators to reduce their emissions by deploying new technology (and therefore capital) or alternatively to pay an increased per tonne price. Furthermore, these costs seem to be transferable, through the PPAs, from the generators to the buyers. If so, profitability of the PPAs for the buyers will be further reduced by the new SGER requirements.

3. *If the PPAs are legally terminated, the Balancing Pool is legislatively obligated to assume the responsibilities of the buyer to the operator.* There appears to be little debate about this last point. Rather the question hinges more on what options the Balancing Pool might have in addressing these PPAs. The three options appear to be:

   i. **Continue to offer the electricity into the Power Pool.** If this option is chosen, electricity consumers would pay the difference between the contract price and the price actually received for the electricity in the pool.

   ii. **Attempt to sell the PPA.** To accomplish this, the Balancing Pool would have to find another willing buyer. In the current marketplace, this option seems highly unlikely to be successful in the near term but may become feasible over time.

   iii. **Terminate the PPA.** The Balancing Pool can choose to end the relationship with the generator and pay the net book value of what is left to run under the individual contract. This has been done before and can be expensive. In 2005, the Clover Bar PPA was terminated by the Balancing Pool and the owner of the facility was paid $83-million, the remaining net book value.

Clearly none of these options are likely to benefit Alberta consumers. And, if not addressed, the long term impacts of these terminations remain uncertain. For example, currently, the Balancing Pool issues a credit to consumers on their electricity bills, in the range of $3/month. If all of the electricity under the recently terminated PPAs was sent to the Power Pool, this credit could flip to a charge on consumer bills in the range of $5 to $10/month. While the Balancing Pool may be able to offset some of these costs, to the extent the PPA terminations trigger increases in power costs, the political space available to government to advance its Climate Leadership Plan is likely to be reduced.

Based on the initial response from government to the early termination of the PPAs, it would appear likely that this was an unintended consequence of the requirement for additional carbon reduction under SGER. A key question now being asked is whether the recent changes to SGER do in fact allow the buyers to legally terminate their PPAs. While the Alberta Government appears to be suggesting that this is a question still open for discussion, our initial reading of the language in the PPAs suggests this argument may be a difficult one for government to successfully advance. Of course, given the significance of this issue, it's likely that courts will ultimately be weighing in on the question.

That said, since it was government that introduced the SGER changes, in our view, government may also be able to mitigate or reverse the impacts by removing the trigger for the PPA terminations. Presumably government could exempt coal-fired power plants from the new SGER requirements entirely. The rationale for this exemption would be that, unlike other industries, coal-fired power plants are already being treated separately and in fact more aggressively as they are subject to complete shutdown within a fixed timeline. To require already approved coal-fired power plants to now meet both sets of regulatory requirements may be quite unfair, especially as original investments were made in a regulated environment and there are few near-term opportunities to manage these incremental economic costs.

Conclusions

Moving forward to implement its ambitious Climate Leadership Plan is a priority for Alberta's Government, and as a means of improving how Alberta is perceived in the world market, is certainly justified. However, the electricity systems in Alberta are unique, and the implications of climate change policies for generation, transmission and distribution are inter-twined and sometimes difficult to predict. As the government makes changes to carbon levies and policies, it will be essential to scrutinize the impacts and be adaptive, to assure that the intended outcomes (e.g. emissions reductions) are actually achieved and unintended consequences (e.g. loss of investor confidence or system reliability) are understood and managed.

As the "legacy" power plants gradually reach the end of their economic life, the electricity being produced in Alberta is increasingly being generated by companies that chose to invest in an open and competitive market. An even further accelerated shut-down of coal-fired plants, coupled with a legislated and aggressive ramping up of renewable energy sources (presumably through the use of incentives), will need to be carefully orchestrated if we are to preserve this desire to invest. Too much uncertainty, including a lack of full understanding of the consequences of inter-connected policies and overly rigid rules when more flexibility could meet the same goals, will unnecessarily put levels of future investment at risk.

The proposed changes in power mix under the Climate Leadership Plan - triggered by the shutting down of large base-load plants and the introduction of new tranches of more distributed and intermittent renewable energy sources into Alberta's electricity grid - will also impact electricity costs, reliability and logistics. Taxpayers are assuming a new carbon levy, effective 2017, and will understandably be wary of funding even further costs to green the grid. This is all the more true in the midst of an economic recession. These concerns may significantly limit the government's ability to implement its policies over the longer term.

We encourage government to comprehensively review the full life cycle costs of their recommended changes to the electrical energy matrix. As well, we strongly encourage government to evaluate the impacts of existing policies (e.g. AESO's zero congestion directive) and infrastructure plans (e.g. the transmission build from Edmonton to Fort McMurray) to identify other sources of savings to help offset some of the economic impacts of the Climate Leadership Plan.

Finally, the early terminations of PPAs with coal-fired generators are very likely an excellent example of an unintended consequence of the government's focus on reducing emissions. Challenging the legality of these terminations in court is one option, but we would urge government to consider easier solutions, including simply reinstating the previous SGER requirements for coal-fired generation. This recalibration would be fair and an easily justifiable small step "backward" particularly if it allows the overall Climate Leadership Plan to move forward.

Underlying all of these themes, we also believe that there is a final policy/regulatory question that needs to be addressed by government before it moves forward with any significant changes to the current electricity system. Given the direction and potential significance of the energy policy changes being proposed, is this the right time to proactively assess the implications of a transition back to a fully regulated electricity system in Alberta?

It is quite possible that the proposed changes are already sufficiently substantive to trigger the end of future investment in Alberta's power market, absent some form of price guarantee. If this happens, without a plan in hand, these impacts may prove to be by far the most costly and unintended consequences of the Climate Leadership Plan. ■

QUEBEC RELEASES ITS *2030 ENERGY POLICY*

*Erik Richer La Flèche**

On April 7, 2016, the Government of Quebec released its much-anticipated *2030 Energy Policy*[1] before 500 guests at Montreal's *Place des Arts*.

Since its election on April 7, 2014, Premier Philippe Couillard's Liberal Government has issued a steady stream of economic and industrial policies that would put *dirigiste* France to shame. In the last 18 months, it has issued policies, strategies, guides and papers on a broad range of subjects. To name only a few, these include the *Maritime Strategy*[2], the *Quebec Aluminium Development Strategy 2015-2025*[3], the *Strategic Vision for Mining Development* in Quebec[4], the *Transportation Electrification Action Plan 2015-2020*[5], the *Plan Nord toward 2035, 2015-2020 Action Plan*[6], and the *Green Paper on Social Acceptability*[7].

But the Energy Policy is first among equals. It is Quebec's keystone policy and, while it has been the subject of considerable debate within government, it is likely to be the foundation of Mr. Couillard's political legacy. At the express request of the Premier, it was delayed and re-written to take into account the conclusions of COP 21, held in Paris from November 30 to December 12, 2015.

The Significance of Government Policies in Quebec

Why are such expressions of government thinking important, if not crucial, in Quebec? There are two reasons. The first and most obvious is that the documents serve to enlighten as to how government will legislate and regulate a sector. The second is that, in Quebec, the three levels of government (federal, provincial and municipal) account for nearly half of all investment and control nearly 50 per cent of the provincial economy. The Quebec government is in effect the private sector's joint venture partner and these documents are akin to joint venture business plans.

In neighbouring Ontario and in the western provinces, the role of the state is more discreet, standing at most at 40 per cent in Ontario and decreasing as one moves westward. Thus, the question of how government plans to spend its money (and which economic sectors it favours) has a greater impact in Quebec.

In addition, much of Quebec's venture and

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1 Gouvernement du Québec, *The 2030 Energy Policy- Energy in Québec: A Source of Growth,* (Quebec: Gouvernement du Québec, 2016).

2 Gouvernement du Québec, *The Maritime Strategy by the year 2030,* (Quebec: Gouvernement du Québec, 2015).

3 Gouvernement du Québec, *The Future is Taking Shape: The Quebec Aluminium Development Strategy 2015-2025,* (Quebec: Gouvernement du Québec, 2015).

4 Gouvernement du Québec, *Strategic Vision for Mining Development in Québec,* (Quebec : Gouvernement du Québec, 2016).

5 Gouvernement du Québec, *Propelling Québec Forward with Electricity: Transportation Electrification Action Plan 2015-2020,* (Quebec: Gouvernement du Québec, 2015).

6 Gouvernement du Québec, *The Plan Nord toward 2035, 2015-2020 Action Plan,* (Quebec: Gouvernement du Québec, 2015).

7 Gouvernement du Québec, *Green Paper on Guidelines of the Ministère de l'Énergie et des Ressources in the Area of Social Acceptability,* (Quebec: Gouvernement du Québec, 2016).

expansion capital is governmental or quasi-governmental and such capital will perforce favour projects that conform to government policies and guidelines.

While it can be frustrating to wait for the issuance of a policy and to experience the administrative silence and sectorial stagnation that precedes it, one can take satisfaction in the fact that Quebec has a very positive track record when it comes to implementation. All one has to do is look at how Quebec, despite sometimes strident opposition, rolled out 4,000MW of wind power, as announced in its *2006-2015 Energy Policy*.[8]

What is in the Energy Policy 2030?

The new Energy Policy represents a departure from previous ones. It is at the same time far more complex and less detailed than former policies. Previous policies covered shorter periods and focused on additional electricity production and transmission.

The new policy has four primary objectives:

1. to decarbonize Quebec;
2. to reduce energy consumption and improve energy efficiency;
3. to make full use of Quebec's natural resources; and
4. to innovate and develop its green economy.

Decarbonization

Quebec has set a very ambitious greenhouse gas (GHG) reduction goal. Quebec wants 2030 GHG levels to be 37.5 per cent less than in 1990[9]. To date Quebec has achieved a 8-9 per cent reduction from 1990 levels. This was done with little sacrifice on the back of technology breakthroughs and energy choices made 50 years ago (e.g, 730kv transmission lines that allowed remote Big Hydro to be cost effective) and lower demographic and economic growth than in the rest of Canada during the last 25 years. Now comes the hard part. To meet its reduction objective, Quebec must – in half the time – reduce GHGs at a rate three times greater than in the last 25 years.

The Quebec Government wants renewable energy to meet 61 per cent of Quebec's needs by 2030 (it currently stands at a little more than 47 per cent). Quebec wants to reduce fossil fuel usage, particularly in transportation. Measures will include the electrification of transportation (Quebec has half of Canada's electric cars), the use of natural gas in trucking and the expansion and increased use of public transit (e.g., Montreal's subway is the third busiest in North America after New York and Mexico City).

Reduction and Efficiency

The Quebec Government wants to eliminate the use of thermal coal and reduce by 40 per cent the quantity of oil products used in the province. Quebec wants to improve by 15 per cent the efficiency with which energy is used. To achieve this Quebec will assist households and industry to reduce energy consumption and expects to spend $4 billion doing so over the next 15 years. Among other things building codes will be modified and energy efficient renovations encouraged.

Natural Resources

The Quebec Government will encourage the use of Quebec-sourced energy, including hydro, wind, biomass and geothermal. Households may produce solar and wind electricity and obtain credits against their consumption. Future Hydro-Québec rate increases will be limited to inflation. Quebec wants 25 per cent more renewable energy, including 50 per cent more biomass energy. A new hydrocarbon law is planned and revenues generated from natural gas and oil production will be used to support further decarbonization. Finally, Quebec is willing to allow wind power projects to supply export markets. This is quite a departure from current practice.

8 Gouvernement du Québec, *Using Energy to Build the Québec of Tomorrow: Québec's Energy Strategy 2006-2015*, (Quebec: Gouvernement du Québec, 2006) at p 30.

9 Ministère du Développement durable, Environnement et Lutte contre les changements climatiques du Québec, Press Realease, "Québec adopte la cible de réduction de gaz à effet de serre la plus ambitieuse" (27 November 2015), online: Gouvernement du Québec <http://www.mddelcc.gouv.qc.ca/infuseur/communique.asp?no=3353>.

Innovation

Quebec will establish research priorities and fund research and development, including in the electrification of transportation.

Conclusion

2030 Energy Policy is more than an energy policy. It is also a climate change policy, a regional development policy and an industrial policy. Quebec hopes that "green energy" will boost innovation, entrepreneurship and foreign investment. In order for it to work, Quebec must ensure that it remains competitive whilst implementing its ambitious plan. ■

THE SUPREME COURT OF CANADA GRANTS LEAVE IN TWO CASES INVOLVING THE NATIONAL ENERGY BOARD AND THE RIGHTS OF INDIGENOUS COMMUNITIES

*Nigel Bankes**

On March 10, 2016 a panel of the Supreme Court of Canada comprising Chief Justice McLachlin, and Justices Moldaver and Gascon granted leave (with costs in the cause) in *Chippewas of the Thames First Nation v Enbridge Pipelines Inc*[1] (hereafter *COTTFN* or the *Line 9/9B case*) and (without costs) in *Hamlet of Clyde River v Petroleum Geo-Services Inc (PGS)*[2] (hereafter *Clyde River*). Both are appeals from decisions of the Federal Court of Appeal, both involve the jurisdiction of the National Energy Board (NEB or Board) and both engage the Crown's duty to consult. They will be heard together.

There are at least three distinct questions to be answered in cases dealing with the role of a regulatory tribunal in satisfying the Crown's duty to consult accommodate Aboriginal Peoples. First, does the tribunal itself have the duty to consult? Second, even if the tribunal does not have a duty to consult, can the tribunal's procedures for public engagement etc (perhaps as implemented by the proponent) satisfy the Crown's duty to consult? And third, and in any event, does the tribunal have the duty to satisfy itself that the Crown has fulfilled its duty to consult prior to exercising any statutory power that the tribunal may have? There has been considerable litigation on all three questions.[3] Currently the leading Supreme Court of Canada cases are *Rio Tinto Alcan Inc v Carrier Sekani Tribal Council*[4] and *Taku River Tlingit First*

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1 *Chippewas of the Thames First Nation v Enbridge Pipelines Inc,* 2015 FCA 222, Ryer JA, Webb JA concurring, Rennie JA dissenting.

2 *Hamlet of Clyde River v TGS-NOPEC Geophysical Company ASA (TGS),* 2015 FCA 179, Dawson JA, Nadon and Boivin JJA concurring. I commented on *Clyde River* on ABlawg under the title "The Federal Crown Fulfilled its Consultation Obligations when the National Energy Board Approved a Seismic Program in Baffin Bay", online: <http://ablawg.ca/wp-content/uploads/2015/09/Blog_NB_TGS_ClydeRiver_Sept2015.pdf> .

3 I first commented on these issues in a note in "Regulatory Tribunals and Aboriginal Consultation" (2003)82: spring 2003 *Resources: the Newsletter of the Canadian Institute of Resources Law*, online: <http://dspace.ucalgary.ca/bitstream/1880/47059/1/Resources82.pdf> dealing inter alia with the Supreme Court of Canada's decision in *Quebec (Attorney General) v Canada (National Energy Board)*[1994] 1 SCR 159,112 DLR (4th) 129. ABlawg has continued to follow these issues in a long series of posts in particular "Who decides if the Crown has met its duty to consult and accommodate?" (6 September 2012), ABlawg (blog), online: <http://ablawg.ca/2012/09/06/who-decides-if-the-crown-has-met-its-duty-to-consult-and-accommodate>. For a thorough review in this journal see Keith B. Bergener, "The Crown's Duty to Consult and the Role of the Energy Regulator" (2014) 2:Winter 2014 Energy Regulation Quarterly; see also David Mullan, "2015 Developments in Administrative Law Relevant to Energy Law and Regulation" (2015) 4:1 Energy Regulation Quarterly 19.

4 *Rio Tinto Alcan Inc v Carrier Sekani Tribal Council*, 2010 SCC 43, [2010] 2 SCR 650 [*Carrier Sekani]* I commented on *Carrier Sekani* on ABlawg, " The Supreme Court of Canada clarifies the role of administrative tribunals in discharging the duty to consult" (2 November 2010), ABlawg (Blog), online: <http://ablawg.ca/wp-content/uploads/2010/11/blog_nb_riotinto_nov2010.pdf>.

Nation v British Columbia (Project Assessment Director).[5]

This comment examines the decisions in *COTTFN* and *Clyde River* and offers some brief concluding remarks.

A. COTTFN: Enbridge Line 9B

Line 9 connects Sarnia and Montreal. It was originally constructed by Interprovincial Pipeline Inc (now Enbridge) in the mid-1970s as part of the Government of Canada's response to the OPEC crisis so as to permit the delivery of Canadian oil to refineries in Montreal. In 1997, IPL obtained and implemented the NEB's approval to reverse Line 9 to permit shipment of oil from Montreal to refineries in Ontario. There, matters stood until 2011 when Enbridge applied to reverse (i.e. reinstate an easterly flow) from Sarnia to North Westover (west of Toronto). This (Line 9 Reversal Phase I) took effect in 2013, but prior to that, Enbridge made the further 9B application under s 58 of the *National Energy Board Act*[6] (*NEBA*) to reverse the balance of Line 9 into Montreal and to increase the capacity of the entire line from 240,000bpd to 333,333bpd. It is important to emphasise that this application was considered under s 58 of the *NEBA* and not under s 52 of the *NEBA*. Section 52 deals with the construction of new pipelines and requires the Board to make a recommendation to the Governor in Council with respect to the issuance of a certificate of public convenience and necessity. The Board's report under s 52 is not a final decision. Section 58 authorizes the Board to exempt an applicant from otherwise applicable provisions of Part II of the *NEBA* (construction and operation of pipelines). A section 58 decision is a final decision (subject to appeal, with leave, as here on a point of law or jurisdiction (*NEBA*, s 22)).

The Board issued its reasons for decision recommending the approval of this application in March 2014.[7] The Board's proceedings in this matter have been the subject of an earlier judicial review application commenced by Forest Ethics Advocacy Association and Donna Sinclair and dealing principally with the scope of the Board's review of the project. The Federal Court of Appeal provided a reasoned decision on this application in December 2014.[8]

COTTFN conceded that Enbridge had discussed its project with the First Nation but concluded that these discussions had not addressed its concerns. Indeed, in September 2013 COTTFN wrote to a number of federal ministers, including the Minister of Natural Resources, requesting that the Crown consult with them as to the impact of the project on their Aboriginal and treaty rights. COTTFN argued that the Crown needed to consult directly because the Board was not in a position to discharge the Crown's obligations - both because the Board lacked the statutory mandate to do so and because the issues that the COTTFN wanted to address included cumulative impacts which fell outside the remit of the Board. COTTFN did not receive a reply from the Minister until the end of January 2014 by which time the Board had concluded its hearing. The federal Crown did not participate in the hearing. COTTFN did participate, and led evidence as to its use of the land including its spiritual connection to the land. The Minister's January letter stated, *inter alia*, that "the Government relies on Board processes to address potential impacts to Aboriginal and treaty rights stemming from projects under the Board's mandate."[9] In light of the Board's assessment of the prospects for the safe operation of the line and contingency plans, the Board concluded that any impact on COTTFN's rights would be "minimal and appropriately mitigated."[10]

On the appeal, Justice Ryer for the majority stated the issues as follows:[11]

a. Whether the Board itself has been delegated the power to undertake the

5 *Taku River Tlingit First Nation v British Columbia (Project Assessment Director)*, 2004 SCC 74, [2004] 3 SCR 550.
6 *National Energy Board Act,* RSC 1985, c. N-7.
7 Enbridge Pipeline Inc. (March 2014), OH-002-2013, online: NEB <https://www.neb-one.gc.ca/pplctnflng/mjrpp/ln9brvrsl/index-eng.html>.
8 *Forest Ethics Advocacy Association v National Energy Board,* 2014 FCA 245. I commented on this decision in this journal. Nigel Bankes,"Pipelines, the National Energy Board and the Federal Court" (2015), 3:2 Energy Regulation Quarterly 59 at 73 [*Pipelines*], online: <http://www.energyregulationquarterly.ca/wp-content/uploads/2014/12/ERQ-Volume-3-Issue-2-2015.pdf>; See also David Mullan, "2014 Developments in Administrative Law Relevant to the Energy Law and Regulation" (2015) 3:1 Energy Regulation Quarterly 17.
9 *COTTFN*, *supra* note 1 at para 16.
10 *Ibid* at para 17.
11 *Ibid* at para 20. Justice Rennie dissented on the second issue.

fulfilment of the *Haida* duty on behalf of the Crown in relation to the Project; and

b. Whether the Board was required to determine, as a condition of undertaking its mandate with respect to Enbridge's application for approval of the Project, if the Crown, which was not a party to the application, was under a *Haida* duty and, if so, whether the Crown had discharged that duty.

Justice Ryer dealt with the issues in the reverse order. In his view the Federal Court of Appeal had already decided the second question in the negative some years previously in his own decision in *Standing Buffalo Dakota First Nation v Enbridge Pipelines Inc.*[12] Since there had been no relevant amendments to the *NEBA* since then, the principal issue for the Court was whether the Supreme Court's decision in *Carrier Sekani*[13] had undermined the authority of *Standing Buffalo*. The *Carrier Sekani* court concluded that where a tribunal had the authority to decide questions of law, then by necessary implication, such a tribunal had the authority to determine whether the Crown had discharged its duty to consult, and presumably might be *required* to make that determination prior to making its decision on the merits of an application which had potential adverse impacts on Aboriginal or treaty rights (just as an administrative decision-maker must observe applicable rules of natural justice and procedural fairness rules prior to making its decision since otherwise any resulting decision will be void.[14])

Justice Ryer distinguished C*arrier Sekani* principally on the grounds that the applicant for approval from the tribunal (the BC Utilities Commission, BCUC) in *Carrier Sekani* was BC Hydro which was an agent of the provincial Crown. That was not the case in either *Standing Buffalo* or this application from Enbridge. Since the Crown did not appear before the Board, the Board had no evidence on which to make a *Haida* determination as to the level of consultation required and thus the matter was not "properly before" the Board.[15]

In addition to the general proposition that *Carrier Sekani* is distinguishable on the basis that the applicant in *Carrier Sekani* was the Crown (whereas the applicant here is *Enbridge*), Justice Ryer also emphasises the remedial implications that might flow from the differing legal status of the two applicants. His point here is that in *Carrier Sekani* the Crown was a party to the application and there was therefore no difficulty in the tribunal, the BCUC in that case, issuing an order against the Crown (albeit a very distinct emanation of the Crown i.e. BC Hydro). In *Standing Buffalo*, as in *COTTFN*, the Board has no remedial authority against the Crown since the Crown is not before the Board. This is all true; but as I understand it COTTFN is not seeking an order against the Crown. Instead, it is seeking something in the nature of a declaration that the NEB has failed to fulfil its duty to determine if the Crown has fulfilled its obligations and consequential relief quashing the Board's approval.[16] Justice Ryer evidently consider this to be an inappropriate "sort of leverage over the Crown, so as to force it become a participant,"[17] and not only inappropriate but also something that will not pursue "the reconciliation of interests"[18] as between the Crown and First Nations.

As for the first-listed issue above, the principal question was whether the Crown had delegated its duty to consult to the Board. There was and is nothing in NEBA that had that effect[19] and Justice Ryer concluded that the Minister's letter (quoted in part above) could not serve as an

12 *Standing Buffalo Dakota First Nation v Enbridge Pipelines Inc,* 2009 FCA 308, [2010] 4 FCR 500 [*Standing Buffalo*].
13 *Carrier Sekani, supra* note 4.
14 *Cardinal v Director of Kent Institution*, 1985 CanLII 23 (SCC), [1985] 2 SCR 643, at 661.
15 *COTTFN, supra* note 1 at paras 33 – 42. For the *Haida* determination or spectrum pertaining to the content of the duty to consult, see *infra* note 46. This is not the first time we have seen the argument that *Carrier Sekani* should be confined to projects where the Crown is the proponent. Alberta's Energy Resources Conservation Board found the distinction to be compelling in its reasoned decision on a Notice of Question of Constitutional Law brought by Cold Lake First Nations in relation to *Osum Oil Sands Corporation's Taiga Project*, Reasons for July 17, 2012 Decision on Notice of Question of Constitutional Law, Osum Oil Sands Corp., Taiga Project, August 24, 2012, online: Ablawg < http://ablawg.ca/wp-content/uploads/2012/09/Application-1636580-ERCB-Reasons-NQCL.pdf >. I offered a detailed critique of that conclusion in "Who Decides if the Crown has met its duty to consult and accommodate", *supra* note 3.
16 *COTTFN*, *supra* note 1 at para 2.
17 *Ibid* at para 46.
18 *Ibid*.
19 *Ibid* at para 65.

effective delegation.[20]

Justice Rennie agreed that the Board had no duty to consult[21] but dissented on the question of the Board' duty to assess whether the Crown had fulfilled its duty to consult. In his view:

> The Board's jurisdiction to assess consultation does not vary according to project proponent. This conclusion makes sense because at a practical level, the section 58 process culminates with a final decision, and any Aboriginal or treaty rights that might be affected by the proposed project are affected in the same way, regardless of the project proponent. [22]
>
> * * * *

As a final decision maker, *Carrier Sekani* requires the Board to ask, in light of its understanding of the project and Aboriginal title and treaty interests, whether the duty to consult was trigged. If so, it was required to ask whether the consultations had taken place. The answers to those two questions, on the facts of this case were respectively affirmative and negative. Given its understanding that there was an outstanding unfulfilled duty to consult, it ought not to have rendered its approval.

Justice Rennie dismissed the majority's concerns that a Board decision to reject an application for the Crown's failure to consult would be somehow unfair to the applicant. Justice Rennie gave five reasons for this: (1) inconvenience to the proponent pales in significance when compared with the constitutional values underlying COTTFN's position,[23] (2) the courts are always able to assess whether the duty to consult has been discharged,[24] (3) the Crown is required to engage in the reciprocal process of consultation which neither party can frustrate by refusing to engage,[25] (4) meaningful consultation requires early engagement in the process,[26] and (5) consultation should evolve in parallel with the regulatory process.[27]

For Justice Rennie that left the question of the appropriate remedy. Justice Rennie was clearly of the view that a declaration that the Board's order was of no effect would be an appropriate remedy but there was a problem with this since the applicant had apparently not sought that relief and it would therefore be "inappropriate" to make a declaration in these circumstances. But, said Justice Rennie, the NEB has the legislative mandate to ensure that the duty to consult is discharged before a final decision is made.[28] I think that it must follow from this observation that if the decision had already been made (and I thought that it had here[29]), then the Board must have the duty under s 21 of the *NEBA* to review its own decision either of its own motion or on the application of COTTFN. Justice Rennie also considered whether the matter might have been more appropriately dealt with by way of an application for judicial review of the decision embedded in the Minister's letter. Both counsel for the Crown and Justice Rennie seemed to be of the view that this might have been a possible way of proceeding, but in the circumstances, Justice Rennie was clear that it would have been "an empty remedy" since the Board's decision was final.[30]

The appellants in *COTTFN* have stated the issues for consideration by the Supreme Court as follows:

1. What is the role and jurisdiction of an administrative tribunal, where it is the final decision maker, to ensure that the Crown's duty to consult is fulfilled?

20 *Ibid* at para 68.
21 *Ibid* at para 120.
22 *Ibid* at paras 104, 112.
23 *COTTFN*, *supra* note 1 at para 114.
24 *Ibid* at para 115. I confess that I am puzzled by the import of this. Perhaps Justice Rennie is simply suggesting that there will always be risk for the proponent, and whether the decision as to whether the risk has been realized is delivered by the NEB or the ordinary courts hardly matters.
25 *Ibid at paras 116 – 117.*
26 *Ibid* at para 118; see also *ibid* at para 124.
27 *Ibid* at para 119.
28 *Ibid* at para 128.
29 *Ibid* at para 18.
30 *Ibid* at para 122.

2. The question of whether the administrative exercise of final decision-making authority amounts to "government conduct" triggering the Crown's duty to consult and accommodate ….

3. Whether an administrative tribunal's regulatory process can rectify the absence or inadequacy of Crown consultation …

***B. Clyde River*: The facts**

TGS-NOPEC Geophysical Company ASA (TGS), Petroleum Geo-Services Inc (PGS) and Multi Klient Invest AS (MKI) (the proponents) applied to the Board for a Geophysical Operations Authorization (GOA) under the terms of paragraph 5(1)(*b*) of the *Canada Oil and Gas Operations Act*[31], (*COGOA*). The proponents proposed to undertake a 2-D offshore seismic survey program in Baffin Bay and the Davis Strait (the Project) over a period of five years. The Board granted the GOA subject to terms and conditions. As part of its decision-making on the GOA, the Board also had responsibilities under the *Canadian Environmental Assessment Act*[32], and in fulfillment of its responsibilities under that statute the Board conducted an environmental assessment (EA) before concluding that:

> [...] with the implementation of [the project operator's] commitments, environmental protection procedures and mitigation measures, and compliance with the Board's regulatory requirements and conditions included in this [Environmental Assessment] Report, the Project is not likely to result in significant adverse environmental effects.[33]

The applicants, Hamlet of Clyde River, Nammautaq Hunters and Trappers Organization (HTO) – Clyde River and Jerry Natanine (a resident and the Mayor of Clyde River) brought this application for judicial review.[34] Justice Dawson for the unanimous panel summarized the issues as follows:[35]

A. Do the applicants have standing to bring this application?

B. Was the Crown's duty to consult with the Inuit in regard to the Project adequately fulfilled?

C. Did the Board err in issuing the GOA? Specifically:

   a. Were the Board's reasons adequate?

   b. Did the Board reasonably conclude that the Project is not likely to result in significant adverse ronmental effects?

   c. Did the Board fail to consider Aboriginal and Treaty rights?

D. Was the Crown obliged to seek the advice of the Nunavut Wildlife Management Board?

This comment focuses on the consultation issues.[36]

Justice Dawson began by considering the applicable standard of review with respect to the duty to consult and accommodate. She concluded that "[q]uestions as to the existence of the duty to consult and the extent or content of the duty are legal questions, reviewable on the standard of correctness. The consultation process and the adequacy of consultation is a question of mixed fact and law, reviewable on

31 *Canada Oil and Gas Operations Act,* RSC 1985, c O-7.
32 *Canadian Environmental Assessment Act, SC 1992, c 37* [*CEAA, 1992*] (no longer in force but it was at the relevant time and none of the parties took issue with its applicability); *Clyde River, supra* note 2 at para 53.
33 *Clyde River*, *supra* note 2 at para 6. The EA report is available on the Board's website online : National Energy Board <http://www.neb-one.gc.ca/nrth/dscvr/2011tgs/nvssssmnt/nvssssmnt-eng.pdf>.
34 The application belongs before the Federal Court of Appeal because of s 28(1)(f) of the *Federal Courts Act*, RSC 1985, c F-7. For more general discussion of judicial supervision of the NEB see Bankes, *supra note 8.*
35 *Clyde River, supra* note 2 at para 8.
36 *Ibid* at paras 15-16. On the standing issue Justice Dawson concluded that the applicants (and apparently all of them, the HTO, the Hamlet itself and the mayor) had standing on the basis that they were all directly affected. She would also have held that the HTO was entitled to public interest standing. For further discussion see Bankes, *supra* note 2. Some of the following commentary on the case also draws from that ABlawg post.

the standard of reasonableness...."[37]

Parliament may structure the way in which the Crown discharges its duty to consult and in doing so may impose consultation obligations on regulatory tribunals such as the NEB. Whether it *has* done so is ultimately a matter of statutory interpretation.[38] Parliament may also authorize a tribunal such as the NEB to make determinations as to whether or not the Crown has fulfilled the duty to consult and accommodate. Parliament may do this explicitly or implicitly (by authorizing a tribunal to decide questions of law).[39] Section 12(2) of the *NEBA* confers on the NEB the jurisdiction to determine all matters before it "whether of fact or law.[40] "When the Crown relies on a regulatory or environmental assessment process to fulfil the duty to consult, such reliance is not delegation of the Crown's duty. Rather, it is a means by which the Crown can be satisfied that Aboriginal concerns have been heard and, where appropriate, accommodated ...."[41]

In this case, the Board had both the power and the duty to discharge the Crown's obligation to consult and accommodate. The Court reached this conclusion by pointing to an amendment to *CEAA, 1992* which redefined the term "environmental effect" of a project so as to include the effect of any change in the environment caused by the project which might in turn affect the "current use of lands and resources for traditional purposes by aboriginal persons."[42] Justice Dawson framed her conclusion this way:

> I conclude that the Board has a mandate to engage in a consultation process such that the Crown may rely on that process to meet, at least in part, its duty to consult with Aboriginal peoples. Of course, when the Crown relies on the Board's process, in every case it will be necessary for the Crown to assess if additional consultation activities or accommodation is required in order to satisfy the honour of the Crown.[43]

In this case the Crown apparently conceded that it did not engage in any additional activities of consultation and accommodation.[44] Thus Justice Dawson concludes that the *Board* had a duty to consult but that it was then for the *Crown* to assess whether that was sufficient to discharge the duty. In the absence of any specific Crown conclusion on this point the Court itself moved directly to assess "whether [...] the Crown's duty to consult was properly discharged through the Board's process."[45]

The Court held that the consultation required was at the deep end of the *Haida* spectrum.[46] The right was treaty based (the Nunavut Land Claim Agreement) and the potential impacts on those rights were serious. These impacts were summarized by Justice Dawson referring to the Board's EIA report:[47]

> As to the potential effect of the

37 *Ibid* at para 34 and referring to *Haida Nation v British Columbia (Minister of Forests)*, 2004 SCC 73, [2004] 3 SCR 511 at paras 61-62; and *Carrier Sekani, supra* note 4 at paragraph 64.
38 *Clyde River, supra* note 2 at paras 43-46.
39 *Ibid* at para 43.
40 *Ibid* at para 51.
41 *Ibid* at para 46 and referring to *Haida*, *supra* note 37 at para 53.
42 *Clyde River, supra* note *2* at paras 53-61
43 *Ibid* at para 65. The Court was careful to note that its conclusion on this matter applied to the 1992 Act only, see para 64(ii).
44 *Ibid* at para 70.
45 *Ibid*.
46 *Clyde River, supra* note 2 at para 74 and also at paras 41-42 explaining the *Haida* spectrum: The depth or richness of the required consultation increases with the strength of the *prima facie* Aboriginal claim and the seriousness of the potentially adverse effect upon the claimed right or title (*Haida Nation* at paragraph 39; *Rio Tinto* at paragraph 36). [...] When consultation duties lie at the low end of the consultation spectrum, the claim to title is weak, the Aboriginal interest is limited or the potential infringement is minor. In such a case, the Crown may be required only to give notice of the contemplated conduct, disclose relevant information, and discuss any issues raised in response to the notice (*Haida Nation* at para 43). Where the duty of consultation lies at the high end of the spectrum, a strong *prima facie* case for the claim is established, the right and potential infringement is of high significance to the Aboriginal peoples, and the risk of non-compensable damage is high. In this type of case, while the precise requirements will vary with the circumstances, a deep consultative process might entail: the opportunity to make submissions; formal participation in the decision-making process; and, the provision of written reasons which show that Aboriginal concerns were considered and how those concerns impacted on the decision (*Haida Nation* at para 44).
47 *Ibid* at para 73.

Project upon this right, migratory marine mammals harvested by the Inuit move through the Project area. Potential adverse environmental effects found by the Board include:

i. Sensory and physical disturbance to marine mammals causing: temporary reduction in hearing sensitivity; permanent hearing impairment; masked communication; and, changes in behaviour and distribution including avoidance of the seismic ship and alteration of migration routes.

ii. Potential disturbance to traditional and commercial resource use if the survey changes the migration routes of marine mammals or fish.

iii. Adverse changes to marine life presence due to spills or accidents releasing hydrocarbons into the marine environment.

Justice Dawson concluded that the Crown, through the Board, had discharged its obligations. In reaching that conclusion Justice Dawson rejected the applicants' contention that the Board or some other entity should only have considered the GOA application following a strategic environmental assessment.[48] More generally, Justice Dawson held that the Board's consultation activities were adequate because: "the process provided timely notice[…]";[49] "[t]he proponents were required to provide […] [adequate] information[…] and to [respond] to [their] questions";[50] "[t]he Board held meetings at which community members could address concerns to the Board";[51] "[t]he proponents changed aspects of the Project's design" in response to articulated concerns;[52] "[t]he Board's regulatory process was designed to facilitate […] [Aboriginal] participation";[53] the CEAA assessment addressed concerns raised by Aboriginal participants;[54] and the terms and conditions to which the GOA was subject were responsive to the concerns that had been raised.[55]

But that still left outstanding some more specific questions with respect to: (1) the adequacy of the reasons offered in support of the Board's decision, (2) the Board's conclusions with respect to the significance of the adverse environmental effects of the project, and (3) the Board's consideration of Aboriginal and treaty rights. Justice Dawson was of the view that the standard of review in relation to these questions was reasonableness.[56]

On the reasons issue, the principal difficulty for the Attorney General and the NEB was that in a purely formal sense there were no reasons accompanying the issuance of the GOA.[57] Instead there was simply a cover letter (1.5 pages) and the actual GOA itself (three pages in length and consisting of some 15 conditions). But Justice Dawson was evidently not prepared to consider the GOA in isolation given the Board's detailed consultation exercise and the principal deliverable of that exercise which was the Board's 30 plus page EIA Report (referred to above). That broader context provided the necessary reasons:[58]

> I see no merit in this submission. The Board's reasoning is found in the environmental assessment and the terms and conditions imposed on the GOA. These reasons deal with the real controversy: what are the potential impacts of the Project

48 *Ibid at paras 77-81.*
49 *Ibid* at paras 92-100.
50 *Ibid* at para 93.
51 *Ibid* at para 94.
52 *Ibid* at para 95.
53 *Ibid* at para 96.
54 *Ibid* at paras 97-100.
55 *Ibid*.
56 *Ibid* at paras 35-36.
57 Re Geophysical Operations Authorization (GOA) for TGS-NOPEC Geophysical Company ASA (TGS), Petroleum GeoServices (PGS) and Multi Klient Invest AS (MKI) NorthEastern Canada 2D Seismic Survey (letter) (26 June 2014), *GOA letter with terms and conditions, File OF-EP-GeopOp-M711-5554587 0201,* online NEB: <http://www.neb-one.gc.ca/nrth/dscvr/2011tgs/nvssssmnt/2014-06-26trmcndtn-eng.pdf>.
58 *Clyde River*, *supra* note 2 at paras 102-103.

> on the section 35 Aboriginal right to harvest wildlife.
>
> When the GOA is read in the light of the environmental assessment, the terms and conditions imposed upon the GOA and the entirety of the Board's record, this Court is well able to understand why the GOA was issued.

While the EIA report did not deal with all of the issues that the Board needed to consider under *COGOA,* Justice Dawson seems to have been of the view that these other issues were either not of core significance or were such that the reasons could be inferred from the terms and conditions that had been attached.

As for the remaining issues (significance of the environmental effects and Aboriginal and Treaty rights) Justice Dawson had little difficulty dismissing the applicants' claims. It will always be a challenge to raise any assessment of "significance" to the level of a reviewable error and, given all of the background here, the failure of the EIA report to mention Aboriginal and treaty rights and the Crown's duty to consult was not material:[59]

> I see no merit in this submission. As explained above, the Board engaged in lengthy consideration about the extent of Aboriginal consultation and the potential impacts to traditional harvesting. The Board knew the Inuit had section 35 protected harvesting rights that had to be taken into account.

There is a remarkable degree of deference embedded in this summary dismissal of this aspect of the applicants' argument, especially in a case where the Crown is trying to discharge the duty to consult through a Board-led EIA process. When put together with the complete delegation of all consultation obligations to the Board, the absence of any assessment by the Board itself as to where the case lay along the *Haida* spectrum, and the Board's failure to provide reasons that spoke to an assessment of the Crown's duties, Justice Dawson's conclusion suggests that a decision-maker can meet its constitutional obligations without articulating the normative quality of the interests at stake. I am not convinced that the Crown or a delegated authority of the Crown can discharge its obligations in such a non-reflective manner.

That said, *Clyde River*, along with *Taku River,* is authority for the proposition that in the appropriate circumstances the Crown can discharge its obligation to consult and accommodate *entirely* through a regulatory board such as the NEB. Justice Dawson concedes that this will not always be the case,[60] but she gives little if any guidance as to when something more might be required.[61]

The appellants in *Clyde River* have stated that "require clarification" by the Supreme Court as follows:

a. the substantive aspects of accommodation that are engaged in a case where deep consultation is required;

b. the relationship between the common law duty of procedural fairness and the constitutionally-entrenched duty to consult.

c. whether, and to what extent, the Crown may rely on a tribunal's regulatory process to discharge the duty to consult and accommodate;

d. the proper role of the reviewing court where a tribunal has (or ought to have) considered Aboriginal rights and/or the duty to consult in discharging its mandate; and

e. the proper standard of review of a tribunal's decision on the duty to consult;

Conclusions

These two appeals will give the Court the opportunity to clarify the application of

59 *Ibid* at para 112.
60 *Ibid* para 65.
61 I offer some suggestions as to possible tests in Bankes, *supra* note 2.

Carrier Sekani and the duty to consult in the context of energy regulatory tribunals. While both cases engage the National Energy Board, the outcome of the appeals will be relevant for energy tribunals across the country. The Court will have to decide whether *Carrier Sekani* only applies where the Crown, or an agent of the Crown, is the applicant for an authorization. This is the principal issue in *COTTFN* although not specifically referred to in COTTFN's statement of the issues. It is hard to imagine that the Court will countenance confining *Carrier Sekani* in this way. Second, the Court will have to decide when (if ever) a tribunal's processes can satisfy the Crown's duty to consult. This the principal issue in *Clyde River*.

Both cases deal with decisions in which the tribunal is the final decision-maker. It will be interesting to see if the Court's decision confines itself to these scenarios or whether it will also address those statutory scenarios in which the tribunal makes a recommendation to a minister or to the Governor General (or Lieutenant Governor) in Council who in turn makes the final decision. This is a matter of considerable significance not only for applications under the *NEBA* for a certificate of public convenience and necessity under s 52 (including the Northern Gateway Project[62]) but also for a variety of other resource project approvals (including oil sands projects[63]). ■

62 At the time of writing the the Federal Court of Appeal has under reserve a series of appeals and applications relating to this project. Preliminary rulings in relation to these appeals and applications are canvassed in Bankes, *supra* note 8.
63 *Oil Sands Conservation Act*, RSA 2000, c O-7, ss 10-11.

MARYLAND'S SUPREME COURT LOSS: A WIN FOR CONSUMERS, COMPETITION AND STATES

*Scott Hempling**

Due to generation shortages in transmission-constrained areas, PJM capacity auctions were producing high wholesale prices in Maryland. The Maryland Commission designed a three-part solution: (1) Select through competition a wholesale generator to serve in the constrained area. (2) Order Maryland's retail utilities to contract for long-term capacity from the winning generator, at the price offered by that generator in that competition. (3) Draft the contract so that the utility, using retail ratepayer dollars, will pay the generator any difference between the FERC-authorized PJM price and the generator's contract price—with the payment conditioned on the generator being selected in the PJM capacity auction. New Jersey passed a statute mandating a similar solution.

Federal district courts and circuit courts struck both efforts, holding that the Federal Power Act preempted the state actions. Maryland appealed to the U.S. Supreme Court.

In April 2016, the Supreme Court invalidated Maryland's order.[1] By guaranteeing the wholesale generator a level of compensation different from PJM's FERC-authorized compensation, Maryland had "disregard[ed] an interstate wholesale rate required by FERC."[2] Because under the Federal Power Act, Congress had made wholesale rate-setting FERC's exclusive domain, the state order was invalid under the doctrine of "field preemption." The Court's vote was 8-0.

The real winners

Consumers: The decision blocks states from using captive ratepayers to subsidize generator bids in organized wholesale markets. States facing high wholesale prices will need to turn to more productive paths. One such path is reducing customer demand: through time-of-use rates that align prices with costs; through new meters and thermostats that help consumers control their costs; and through solar panels and energy efficiency investments for our lower-income citizens, so that they too can control their costs.[3] States also may, wrote the Court, use "tax incentives, land grants, direct subsidies, construction of state-owned generation facilities, or re-regulation of the energy sector.... So long as a State does not condition payment of funds on capacity clearing the auction, the State's program would

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1 *Hughes v PPL EnergyPlus*, No 14-614 (Apr 19, 2016).
2 *Ibid* at p 15.
3 On this last subject, don't miss the remarkable report by the National Association for the Advancement of Colored People, *Just Energy Policies: Reducing Pollution and Creating Jobs* (2014), <http://www.naacp.org/pages/just-energy-policies-report>.

not suffer from the fatal defect that renders Maryland's program unacceptable."[4]

Competition: Competition promotes the public interest when sellers compete on the merits—on quality and cost. In organized regional markets, quality is covered through minimum standards for reliability and through penalties for failure to show up. So in the actual auctions, competition is based on cost. The Maryland-ordered financial assistance, when conditioned on the generator being selected by the auction, enabled the generator bid below its cost—the precise behavior that defeats the theory of competition. Maryland's favored generation source can still compete and win—but it must compete and win on its inherent merits, not on artificial merits assisted by Maryland's captive customers. When the winners are the least cost rather than the most subsidized, competition works and the public benefits.

States: The decision eliminates one way in which one state can act adversely to other states. Yes, Maryland's legal position was supported by multiple states. Think circular firing squad. For if each state did what Maryland did—substitute state-preferred compensation for FERC-authorized compensation—then each state-assisted bidder would bid below its actual cost. The PJM price for generation capacity would fall below the long-term replacement cost. Short-term price drops would lead to long-term generation shortages.

States could address shortages, and protect against high wholesale prices, by ordering their utilities to build their own generation rather than buy from wholesale markets. But then we would return to rate-of-return regulation rather than regional competition, risking both loss of regional scale economies and over-spending by utilities—the latter due to utilities' well-known "Averch-Johnson" bias toward rate-based assets.[5] As any practitioner from the 1980s knows, the regulator's only weapon against rate base bias is cost disallowance. But cost-disallowance does not work well in too-big-to-fail settings. Indeed, the Louisiana Supreme Court once upheld a state commission decision allowing imprudent costs in rates, on the grounds that disallowance would weaken the utility to an extent inconsistent with the public interest.[6] Want a current example? Check out Mississippi Power Company's Kemper plant. In seeking state commission approval, company witnesses insisted they were "confident" in their cost estimate of $2.4 billion but opposed a Commission-set cost cap. The cost now exceeds $6 billion and the company is asking for ratepayer help.[7]

State boundaries constrain creativity. When we act as states, we think small rather than big—relieving a local constraint rather than building a regional market. We think us vs. them—favoring renewable projects built in our state over lower-cost projects built in other states. And we think of our own-state costs vs. total costs—opposing projects that help a region because we don't like the cost-share assigned to our state.[8]

Price-setting vs. curve-shifting

Some skeptics of the Supreme Court's reasoning are wondering: What distinguishes Maryland's version of generation support from other state actions the Court left untouched? My understanding: States are preempted from *setting* the wholesale price, but they are not preempted from *affecting* the wholesale price. The *Federal Power Act*'s "bright line"[9] separates (a) policies that *fix compensation* for particular wholesale sellers from (b) policies that *shift supply and demand curves* in the wholesale market for all buyers and sellers. The FPA

4 *Hughes, supra* note 1 at p 15.
5 Harvey Averch & Leland L Johnson, "Behavior of the Firm Under Regulatory Constraint" (1962) 52:5 Am Econ Rev 1052.
6 *Gulf States Utilities Co v Louisiana Public Service Commission*, 578 So (2d) 71 (La 1991) (upholding commission allowance of imprudent River Bend nuclear costs).
7 Full disclosure: I was a consultant to the Commission in the case approving the plant.
8 For reasons to reduce the influence of "state," see Parag Khanna, "A New Map for America", *The New York Times* (Apr. 17, 2016). The author writes:

> "The states aren't about to go away, but economically and socially, the country is drifting toward looser metropolitan and regional formations.... [We should] focus[] not on state lines but on existing lines of infrastructure, supply chains and telecommunications routes.... [T]oo often, decisions about infrastructure investment are made at the state (or even county) level, and end at the state border."

9 *Federal Power Commission v Southern California Edison Co*, 376 US 205, 215-16 (1964) (holding that "Congress meant to draw a bright line, easily ascertained, between state and federal jurisdiction").

separates price-setting from curve-shifting. Curve-shifting *affects* the market price but it does not *set* the market price. Nothing prevents states from acting on the supply curve and the demand curve. Consider these two examples:[10]

State shifts supply curve. A state can lower the cost of inputs for in-state generation: It can, for example, reduce taxes on property, sales or income; donate or subsidize land and improvements; provide employee training; and reduce environmental requirements. Each such state action shifts the state's generation company supply curves rightward. This supply curve shift means that at any given market price, the state's companies will be willing to increase supply because their production costs will be lower (all else equal). This rightward shift in one state's generator supply curves will lead to a rightward shift in the regional market's supply curve, thus lowering the regional market price (all else equal). The state's policies will have affected, indirectly, the FERC-jurisdictional market price. But each seller's compensation will still be determined, directly and entirely, by that FERC-jurisdictional market price. There is no "correcting" of any wholesale seller's compensation through a state-ordered, ratepayer-subsidized payment, as occurred with Maryland's invalidated order.

State shifts demand curve. The state can give away sweaters and compact fluorescent lightbulbs, tighten building codes, tax consumption, set high retail prices during peak periods, or pay consumers to reduce demand and consumption. These actions shift that state's demand curve leftward, causing it to intersect the wholesale market supply curve at a lower price. Again, that lower price—a FERC-jurisdictional price—is *affected* by the state but it is not *set* by the state. The state's effect on price is indirect, not direct.

So here are the relevant distinctions for states: between curve-shifting (yes) and price-setting (no), between affecting the price (yes) and setting the price (no), between affecting prices indirectly (yes) and directly (no). There was never an issue about states being able to give financial assistance, in some way, to sellers or buyers—that's curve-shifting. Maryland's mistake was to change the compensation for a specific wholesale seller, by tying the ratepayer-guaranteed subsidy to the seller's participation in the wholesale market.

Useful soul-searching

A lot of time and money went into a losing case—even after two trial courts and two circuit courts—eight judges total—explained the states' error in nearly identical terms. As detailed in my last month's essay, *FPA "Power Grab": On Whose Foot is the Shoe?,* nearly every modern state challenge to FERC jurisdiction has failed.[11] State commissions, and we who advise them, will need to identify and correct the internal cultural forces that lead to these losses. Such soul-searching will be more productive than persisting in the view that every one of 16 jurists—each of whom addressed Maryland's and New Jersey's decisions—got it wrong.

The right form of cooperation

"[T]he Federal Power Act, like all collaborative federalism statutes, envisions a federal-state relationship marked by interdependence."[12] Interdependence requires cooperation. But "cooperation" must mean cooperation toward the statutory goal of just and reasonable rates.[13] "Cooperation" does not mean states cooperating to undermine FERC's policies. And "cooperation" does not mean FERC deviating from its own obligations just to buy peace with states. If granting a state-requested exemption from the minimum offer price rule would lead to sub-competitive prices, that is not useful cooperation. If ordering RTOs to reject demand response bids from states that ban them leads to supra-competitive prices, that also is not useful cooperation. (The latter was Order 745's[14] only error. When a state limits

10 The next two paragraphs are based on my article, "Pricing in Organized Wholesale Electricity Markets: Can We Make the Bright Line any Brighter?" in *Infrastructure* (American Bar Association Spring 2015).

11 Scott Hempling, "FPA 'Power Grab': On Whose Foot is Show?", <http://www.scotthemplinglaw.com/fpa-power-grab>. That essay listed 8 losses. There are actually 10: This Supreme Court's *Hughes* decision, and a Third Circuit decision I omitted from last month's essay: *New Jersey Board of Public Utilities v FERC*, 744 F (3d) 74, 79-80 (Third Cir 2014) (rejecting New Jersey's challenge to FERC's elimination of the state-supported generation exemption).

12 *Hughes*, *supra* note 1, Sotomayor, J., concurring.

13 *Ibid*, see again Justice Sotomayor's concurrence, explaining that the Court "[u]se[d] the purpose of the Federal Power Act as the 'ultimate touchstone' of its pre-emption inquiry"

14 *Demand Response Compensation in Organized Wholesale Energy Markets*, Order No 745, 134 FERC 61187 (15 March 2011).

demand response participation, the demand curve remains artificially rightward, causing unnecessarily high prices for consumers in all the region's states.) FERC should not say "yes" to states just to win points for "cooperation."

* * *

Taking office in August 1974, President Gerald Ford said: "Our Constitution works." So it did here. The Constitution's Supremacy Clause protects the commons—the national good as defined by Congress—from actions by one state that can harm citizens in other states. The Supreme Court got it right. Now it's the states' turn. ■

THE WASHINGTON REPORT

*Robert S. Fleishman**

Energy regulatory developments in the United States impact numerous sectors of the energy industry and address a wide swath of issues. We reported on key federal and state energy regulatory developments in the United States during 2014 in Volume 3, Issue 1 of the ERQ in 2015. This report highlights significant developments in 2015 and early 2016 which should be of interest to readers of the ERQ.

I. LNG EXPORTS

In 2015 and early 2016, the U.S. Department of Energy, Office of Fossil Energy ("DOE") authorized the sponsors of two LNG projects located in Nova Scotia, to export natural gas produced in the United States to Canada, where it would be liquefied and re-exported to countries that do not have in place a free trade agreement with the United States requiring national treatment for trade in natural gas ("non-FTA" countries).[1] A threshold issue that DOE had not previously addressed was whether the exports should be deemed to be exports to Canada – which has in place a free trade agreement ("FTA") with the United States – or to the non-FTA countries to which the gas, as LNG, would be delivered when re-exported. Under Section 3 (c) of the *Natural Gas Act*, applications for authority to export LNG to FTA countries are deemed consistent with the public interest and must be granted "without modification or delay."[2] Under Section 3(a) of the *Natural Gas Act*, DOE must undertake a public interest review and provide notice and opportunity for public participation to find that an application to export LNG to non-FTA countries is not inconsistent with the public interest. DOE determined that "[t]he destination of the U.S. sourced natural gas or LNG for end use is critical to [DOE]'s determination, as is the trade status of that destination country or countries."[3] DOE required, as a condition of the export authorization, that contracts for the sale of LNG require the purchaser to provide a report to the authorization holder that identifies the country into which the re-exported LNG is "actually delivered and/or received for end use…."[4] Unless it based its determination on the trade status of the "end use" country, DOE opined, exporters would be allowed "to evade the public interest review and opportunity for public participation afforded in non-FTA export proceedings under *NGA* section 3(a), simply by transiting the natural gas or LNG through a FTA country en route to a non-FTA country," and it did not believe Congress intended the "dual-track scheme" in the NGA to be "so easily evaded."[5]

In Order No. 3769,[6] DOE addressed for the

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[1] *Pieridae Energy (USA) LTD*, DOE/FE Order No 3639 (22 May 2015) [*Order No 3639*]; *Bear Head LNG Corp*, DOE/FE Order No 3681 (17 July 2015)(authorizing re-export of United States gas, as LNG, to FTA countries); *Pieridae Energy (USA) Ltd.*, DOE/FE Order No 3768 [*Order No 3768*]; *Bear Head LNG Corp*, DOE/FE Order No 3770 (5 February 2016) (authorizing re-export of United States gas, as LNG, to non-FTA countries) [*Order No 3770*].

[2] 15 USC 717b(c).

[3] *Order No 3770*, *supra* note 1 at 194. "End use," as defined by DOE is "combustion or other chemical reaction conversion process (e.g., conversion to methanol.)"; *Order No 3639*, *supra* note 1 at 3 n7.

[4] *Order No 3768*, *supra* note 1 at 229; *Order No 3770*, *supra* note 1 at 190.

[5] *Order No 3639, supra* note 1 at 4.

[6] *Bear Head LNG Corporation*, DOE/FE, Order No 3769 (5 February 2016) [*Order No 3769*].

first time its jurisdiction under Section 3 of the *Natural Gas Act* with respect to "in-transit shipments" of Canadian natural gas, travelling by pipeline through the United States on the way back to Canada, the country of origin. The Canadian gas would pass through the United States only "temporarily" on its way back to Canada where it will be liquefied for subsequent export as LNG. DOE's analysis focused on whether these shipments were "imports" or "exports" within the meaning of Section 3 of the *Natural Gas Act*. DOE concluded that Congress likely did not intend the words "import" and "export" to capture any movement of natural gas across the U.S. border, but to be applied only to categories of shipments "that, by their nature, could have a material effect on the U.S. public interest."[7] In-transit shipments, DOE concluded, are "categorically unlikely" to materially impact the U.S. public interest, and any environmental or economic issues such shipments create for the U.S. natural gas pipeline system could be addressed by FERC or state regulators.[8] DOE also noted the 1977 Agreement between the Government of the United States of America and the Government of Canada Concerning Transit Pipelines, which "generally espouses a laissez-faire policy between the two governments for in-transit shipments of hydrocarbons."[9] DOE concluded that in-transit shipments returning to the country of origin – shipments of natural gas through the United States between points of a single foreign nation that are physical and direct – are not "imports" or "exports" within the meaning of section 3. Virtual shipments including exchanges by backhaul or displacement are not "in transit" shipments for purposes of Order 3769.[10] While DOE dismissed the application for lack of jurisdiction, it directed the applicant to submit specific information on its in-transit shipments, including an explanation to DOE to show that no deliveries into United States commercial markets have occurred.[11]

Both the United States Senate and House of Representatives passed legislation in 2015 and early 2016 that expedites DOE's processing of applications for authorizations for exports to non-FTA countries under Section 3 of the *Natural Gas Act*. DOE would be required to issue a final decision no later than 30 days (the House bill) or 45 days (the Senate bill) after the conclusion of the review required by the *National Environmental Policy Act of 1969* (*NEPA*).[12] For an LNG export project that requires an Environmental Impact Statement (i.e. the most substantial review), the bills specify that such *NEPA* review is considered "concluded" after the publication of a Final Environmental Impact Statement. The bills will need to be addressed by a Conference Committee before further action by Congress.

On March 11, 2016, FERC issued an order denying applications filed by Jordan Cove Energy Project under Section 3 of the *Natural Gas Act* to site, construct and operate an LNG export terminal at Coos Bay, Ore. and by Pacific Connector Gas Pipeline to construct an interconnected interstate natural gas pipeline.[13] FERC found that "Pacific Connector has presented little or no evidence of need" for the pipeline, stating that it had "neither entered into any precedent agreements for its project, nor conducted an open season, which might (or might not) have resulted in 'expressions of interest' the company could have claimed as indicia of demand."[14] Having found that the pipeline did not meet the requirements under Section 7 for a certificate of public convenience and necessity, FERC determined that it would be impossible for Jordan Cove's liquefaction facility to function" as it would not be able to access natural gas supplies and, therefore, the Jordan Cove project "can provide no benefit to the public to counterbalance any of the impacts which would be associated with its construction."[15] The applicants have filed requests for rehearing, citing new commitments they contend satisfy the requisite criteria under Section 7(c) and Section 3 of the *Natural Gas Act*.

As required under Section 3, FERC's authorizations to site, construct and operate

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[7] *Ibid* at 9.
[8] *Ibid* at 9-10.
[9] *Ibid* at 10.
[10] *Ibid* at 10.
[11] *Ibid* at 11.
[12] 42 USC § 4321 [*NEPA*].
[13] *Jordan Cove Energy Project LP, Pacific Connector Gas Pipeline LP,* 154 FERC 61190 (11 March 2016).
[14] *Ibid* at 39.
[15] *Ibid* at 43-44.

LNG export facilities and interconnected interstate pipelines are based upon an analysis, pursuant to *NEPA*, as to whether there are significant environmental impacts from the proposed facilities and how such significant impacts should be mitigated. FERC has consistently rejected environmental intervenors' contentions that FERC must analyze the potential environmental impacts from increased natural gas production resulting from the proposed LNG export projects, greenhouse gas emissions, and other environmental issues that could be attributed to a project and the project's effects on domestic natural gas prices. The adequacy of FERC's environmental review of applications for authorization to site, construct and operate LNG export facilities is the subject of multiple petitions for review pending before the United States Court of Appeals for the District of Columbia Circuit. In 2015, the court heard oral arguments in appeals filed by the Sierra Club of FERC's orders authorizing construction of the Freeport liquefaction export facilities in Texas, and expansion of the Sabine Pass liquefaction facility's capacity.[16] In May 2015, FERC denied Sierra Club's request for rehearing of FERC's order granting authorization for construction of the Corpus Christi Liquefaction LNG export terminal in Texas, and an interconnected pipeline.[17] Sierra Club has filed a petition for judicial review of FERC's authorizations for the Corpus Christi project.[18]

In May 2015, FERC denied rehearing of its order that authorized expansion of the LNG export facilities at the Dominion Cove Point facilities in Maryland. In that case, Sierra Club and other environmental intervenors had asked FERC to grant a stay of its authorization pending appeal.[19] FERC denied the request for a stay. The environmental intervenors filed a petition for judicial review challenging FERC's authorizations and, in addition, filed with the court an emergency motion for a stay of construction of the project pending judicial review. The motion was denied, and the court ruled that the parties "neither satisfied the stringent requirements for a stay pending court review … nor articulated 'strongly compelling' reasons justifying expedition."[20]

In *Pivotal LNG*,[21] FERC issued a declaratory order finding that liquefaction and transportation facilities being developed by Pivotal would not be "LNG terminals" and that it would not exercise jurisdiction under Section 3 of the *Natural Gas Act*. Pivotal explained that the LNG it plans to sell will be: (1) produced at inland LNG facilities or supplied by a third party; (2) transported by Pivotal, an affiliate, or third party in interstate and intrastate commerce by means other than interstate pipeline; and (3) subsequently exported, or resold for ultimate export, by a third party. Pivotal asserted that none of the facilities constitute an "LNG terminal" as defined by NGA section 2(e), since they are all located inland unlike border crossing pipelines and coastal LNG terminals that FERC has traditionally regulated under Section 3. FERC noted that it has only exercised its authority under section 3 to regulate (1) pipelines constructed at the place of entry for imports or exit for exports and (2) coastal LNG terminals such that the LNG is transferred to ocean-going, bulk-carrier LNG tankers and that are connected to pipelines that deliver gas to or take gas away from the terminal. FERC noted that Pivotal's facilities are located inland and are therefore not capable of transferring LNG directly onto ocean-going tankers.[22] FERC found that no "regulatory gap" to justify an "over-expansive application" of section 3 to the LNG facilities owned by Pivotal and its affiliates, noting that the facilities are regulated by various federal, state and local agencies.[23] In a dissenting opinion, FERC Commissioner (now Chairman) Norman Bay argued that the plain language of Section 3 of the NGA provides FERC jurisdiction with respect to "export" and "import" facilities, Pivotal's facilities are "export facilities," which are not the same as

[16] *Sierra Club v FERC*, No 14-1249 (DC Cir filed 17 November 2014); *Sierra Club v FERC*, No 14-1190 (DC Cir filed 29 September 2014).
[17] *Corpus Christi Liquefaction LLC*, 149 FERC 61238 (2014), *reh'g denied*, 151 FERC 61098 (2015).
[18] *Sierra Club v FERC*, No 15-1133 (DC Cir filed 11 May 2015).
[19] *Dominion Cove Point LNG LP*, 148 FERC 61 244 (29 September 2014), *reh'g and motion for stay denied*, 151 FERC 61095 (May 4, 2015).
[20] *Earthreports Inc v FERC*, No 15-1127 (filed 7 May 2015), order denying emergency motion for stay filed June 12, 2015.
[21] *Pivotal LNG Inc*, 151 FERC 61006 (2015) at 5.
[22] *Ibid* at paras 11-12.
[23] *Ibid* at paras 13.

"LNG terminals," and "nothing in Section 3 conditions the Commission's jurisdiction upon the existence of a pipeline running to the point of export."[24]

Finally, in 2015 the sponsors of some of the proposed LNG export projects in the United States chose to delay, or terminate altogether regulatory proceedings on their projects in response to changes in market conditions, including falling oil prices and competition from Australia and other foreign LNG supply sources. Early in 2015, Excelerate Liquefaction Solutions announced that it would postpone its proposed floating LNG export terminal at Port Lavaca-Point Comfort, Texas. Subsequently, Excelerate asked FERC to hold its application proceedings in abeyance. Finally, in September 2015, Excelerate withdrew its application, stating it had evaluated the economic value of the project and determined not to proceed further.[25] In November 2015, the sponsors of the Downeast LNG proposed export terminal to be located in Robbinston, Maine asked FERC to hold its proceedings in abeyance until February 29, 2016 while the sponsor and its investors undertake an economic analysis of current market conditions and the associated impact on the proposed Downeast LNG project."[26] The hold was subsequently extended to June 1, 2016.

II. FRACKING

A. Colorado State Supreme Court Decision

On May 2, 2016, the Colorado Supreme Court overturned local hydraulic fracturing ("fracking") bans in two separate decisions that may have far reaching implications for local governments seeking implementation of, or defending, existing fracking bans nationwide.[27]

Two Colorado cities, Longmont and Fort Collins, had previously instituted local bans on fracking. Longmont's permanent ban on fracking cited several concerns including public health, safety, the environment and local property values. In contrast, Fort Collins implemented its fracking ban as only a five-year moratorium to permit the locality additional time to study the impact of fracking. The Court held that the bans were preempted by state law, rendering each unenforceable and invalid, and affirming the lower courts' rulings. The Court held that the local bans were preempted due to the prevalence of fracking in Colorado and the existing regime of regulation by Colorado regulatory authorities of such practices. Although the Colorado decision will not directly govern future cases regarding fracking bans in other jurisdictions, the ruling may shape how other state courts will address the issue.

Overturning the local fracking bans may have shifted the energy of Colorado's fracking opponents to seek a ballot measures restricting fracking – three separate ballot initiatives are currently gathering the required 100,000 signatures to be placed on Colorado's November 2016 ballot. One proposed measure would effectively reinstate local control over fracking and related activities and another would impose significant limitations on the ability to conduct fracking operations by banning such activities within 2,500 of occupied buildings, waterways and other open public spaces.

B. New Federal Fracking Regulations

With the rapid increase of fracking development in the U.S., the Obama Administration has attempted to implement new measures designed to improve regulatory oversight of the industry. In March 2015, the U.S. Department of the Interior ("DOI") drafted new rules regarding drilling safety of fracking operations. The rules sought to improve the ability of the federal government to inspect the safety of concrete barriers used to line fracking wells, as well as require companies to publicly disclose the chemicals used in their fracking operations.[28] However, in September 2015, Judge Scott Skavdahl, a District Court

[24] *Ibid* at p 2-3 (Commissioner Bay dissenting).
[25] Notice of Withdrawal of Application, *Excelerate Liquefaction Solutions (Port Lavaca I) LLC*, Docket No CP14-71-000 et al. (3 September 2015).
[26] *Downeast Liquefaction LLC et al*, Letter to FERC Secretary Bose, Docket Nos PF14-19-000 et al (2 November 2015).
[27] *City of Fort Collins v Colorado Oil and Gas Association*, 2016 CO 28; *City of Colorado v Colorado Oil and Gas Association*, 2016 CO 29; see also "Colorado High Court Ban on Fracking Bans Could Set Precedent", Law360 (10 May 2016), online: Law 360 <http://www.law360.com/projectfinance/articles/794721?nl_pk=e2b345d3-2e9e-4d72-8a22-a19e4d6ba3d5&utm_source=newsletter&utm_medium=email&utm_campaign=projectfinance>.
[28] 44 Fed Reg 16128 (2015); Coral Davenport, "New Federal Rules Are Set for Fracking", *The New York Times* (20 March 2015), online: New York Times <http://www.nytimes.com/2015/03/21/us/politics/obama-administration-unveils-federal-fracking-regulations.html>.

Judge in the U.S. District Court for Wyoming, issued a preliminary injunction preventing DOI from carrying out the rules.[29] The Court cited concerns with creating an "overlapping federal regime" that interferes with state sovereign interests in regulating fracking absent any congressional mandate.[30] DOI has since appealed the ruling to the Tenth Circuit Court of Appeals.

III. DEMAND RESPONSE

On January 25, 2016, the U.S. Supreme Court reversed a May 2014 decision of the U.S. Court of Appeals for the D.C. Circuit which had vacated in its entirety FERC's Order No. 745, its final rule on wholesale demand response compensation for the curtailment of electric use during periods of peak demand and high system marginal cost.[31] The Supreme Court held that FERC has the authority under the *Federal Power Act (FPA)*[32] to regulate demand response bids in wholesale markets, and that FERC's Order No. 745 was not arbitrary and capricious by requiring that demand response providers be paid the same amount for conserving electricity as generators are paid for producing it ("the *EPSA* decision").

The D.C. Circuit had vacated Order No. 745 in a highly controversial opinion, on two separate grounds. First, the Court held that the order directly regulates retail markets which are outside of FERC's jurisdiction, because demand response involves retail customers and their decisions whether to purchase and consume electricity at state-jurisdictional retail rates. Second, the D.C. Circuit had ruled that, even if FERC had jurisdiction to adopt Order No. 745, the Order was "arbitrary and capricious" in violation of the *Administrative Procedure Act*[33], in part because the required payment mechanism over-compensated demand response resources.[34] Order No. 745 directed Regional Transmission Organizations and Independent System Operators (RTO/ISOs) to pay suppliers of cost-effective demand response resources in their day -ahead and real-time wholesale power markets the full locational marginal price (LMP) used to compensate generation suppliers to these markets.[35]

Supporters of FERC's rule argued that participation by demand response resources in wholesale electric-power markets is an "integral feature" of those markets and that FERC regulation of demand response is critical to proper market functioning to ensure just and reasonable rates for wholesale power. Opponents argued that it encroached on states' authority over retail power markets, because end-use consumption and demand response are fundamentally retail activities, and that FERC was effectively setting retail rates. Justice Elena Kagan, who delivered the 6-2 majority opinion for the Supreme Court, wrote that FERC acted within its powers enumerated under the *FPA* in issuing Order No. 745, reasoning that "[i]t is a fact of economic life that the wholesale and retail markets in electricity, as in every other known product, are not hermetically sealed from each other. To the contrary, transactions that occur on the wholesale market have natural consequences at the retail level. And so too, of necessity, will FERC's regulation of those wholesale matters."[36]

The *EPSA* decision stands for the proposition that FERC is within its powers to regulate the wholesale markets even when such regulation has indirect consequences on retail market conditions.[37] The Court held that because the *FPA* delegates responsibility to FERC to regulate

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[29] *Wyoming v US Department of the Interior*, No 2:14-CV-043-SWS, 2015 WL 5845145 (D Wyo 2015) [*Wyoming*]; see Coral Davenport, "Judge Blocks Obama Administration Rules on Fracking", *The New York Times* (30 September 2015), online: New York Times <http://www.nytimes.com/2015/10/01/us/politics/judge-blocks-obama-administration-rules-on-fracking.html>.

[30] *Wyoming*, *supra* note 29 at p 40.

[31] *FERC v Electric Power Supply Ass'n*, 577 US (2016); For a case comment on this decision previously included in this quarterly, see Scott Hempling, "The Supreme Court Saves Demand Response: Now What?" (2016) 4:1 Energy Regulation Quarterly 35.

[32] 16 USC 791a.

[33] *Administrative Procedure Act*, Pub L 79-404, 60 Stat 237 (1946).

[34] *Electric Power Supply Ass'n v FERC*, 753 F (3d) 216 (DC Cir 2014) [*EPSA*].

[35] *Demand Response Compensation in Organized Wholesale Energy Markets*, Order No 745, 134 FERC 61187 (2011), *order on reh'g*, Order No 745-A, 137 FERC 61215 (2011). The Order required that demand resources actually be capable of supplying the claimed reduction in demand, that the resources pass a 'net benefits test' and that the applicable state regulatory commission permit the bidding of the demand in an organized wholesale market.

[36] *Ibid* at p 18.

[37] See *ibid* at p 19 ("When FERC regulates what takes place on the wholesale market, as part of carrying out its charge to improve how that market runs, then no matter the effect on retail rates, §824(b) [of the *FPA*] imposes no bar.")

the interstate wholesale market for electricity—"both wholesale rates and the panoply of rules and practices affecting them"—the *FPA* establishes a scheme for federal regulation which "means FERC has the authority—and, indeed, the duty—to ensure that rules or practices 'affecting' wholesale rates are just and reasonable."[38] The Court based its decision in part on the reality that adopting EPSA's position would be the death knell for demand response programs by forcing them into a "gap" beyond the regulatory reach of either FERC or the states. The Court reasoned that such an outcome would contravene the structure set up by the FPA, which "makes federal and state powers 'complementary' and 'comprehensive.'"[39]

The decision eliminates uncertainty about the future of the demand response industry in the United States since the D.C. Circuit opinion. The decision also will potentially catalyze the development of emerging technologies including distributed generation and energy storage, because products and services operating "behind the meter" will be able to capture demand response payments as part of their revenue streams.

Although the *EPSA* decision characterized FERC's Order No. 745 as an exercise in "cooperative federalism," the decision may have broader implications for federal preemption of state regulation. More than a half century ago, the Supreme Court described the FPA's division of federal and state jurisdiction over electric energy transactions as a "bright line, easily ascertained ...."[40] That bright line is becoming increasingly "hazy" as legal and regulatory frameworks necessarily adapt to an ever-evolving industry.[41] The *EPSA* decision could be interpreted to support federal jurisdiction over electric markets preempting state regulation in other contexts, depending on how broadly courts construe the decision's holding that the "FPA leaves no room either for direct state regulation of the prices of interstate wholesales or for regulation that would indirectly achieve the same result."[42]

IV. STATE SUBSIDIES OF ELECTRIC GENERATION

A. *Hughes v Talen*

In another U.S. Supreme Court case regarding federal jurisdiction over electric markets the Court unanimously ruled in favor of federal jurisdiction.[43] The State of Maryland had implemented an incentive program which subsidized the participation of a new power plant in the wholesale energy market administered by PJM Interconnection (PJM). That subsidy was deemed preempted by the *FPA* because it conflicted with FERC's exercise of its authority over the field of wholesale electricity markets and the state program had the effect of distorting an interstate wholesale rate required by FERC.

The *Hughes* decision limits the extent to which state actions in the retail market are allowed to impinge on federal-jurisdictional wholesale markets and affect wholesale rates set by mechanisms approved by FERC. The key holding is that "Maryland's program invades FERC's regulatory turf" by impermissibly infringing on the FERC "exclusive jurisdiction over 'rates and charges [...] received [...] for or in connection with' interstate wholesale rates."[44] The Court was careful to narrowly tailor its ruling in *Hughes*: "Neither Maryland nor other States are foreclosed from encouraging production of new or clean generation through measures that do not condition payment of funds on capacity clearing the auction."[45] Many energy market participants had been concerned that an expansive ruling by the Court would negatively impact scores of state programs designed to promote clean energy. Justice Sotomayor wrote a concurring opinion to reiterate the limited nature of the Court's ruling and emphasize that the *FPA* envisioned a cooperative federal-state relationship, but that the Maryland program impermissibly infringed on that relationship.[46]

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[38] *Ibid* at p 15.
[39] *Ibid* at pp 26-27.
[40] *Federal Power Commission v Southern California Edison Company*, 376 US 205 (1964).
[41] See Robert R. Nordhaus, "The Hazy Bright Line: Defining Federal and State Regulation of Today's Electric Grid" (2015) 36 Energy Law Journal 203.
[42] *EPSA*, *supra* note 34 *slip op* at 26.
[43] *Hughes v Talen*, 578 US (2016).
[44] *Ibid* at 12.
[45] *Ibid* at 3.
[46] *Ibid*. (Sotomayor, J, concurring).

B. Ohio PPAs

In a pair of orders issued on April 27, 2016, FERC blocked two power purchase agreements (PPAs) approved by Ohio state regulators to subsidize coal and nuclear plants owned by FirstEnergy and AEP Ohio on the basis that they were inconsistent with FERC's polices on transactions by affiliated entities. The PPAs sought to guarantee income for aging generating plants, under the guise of ensuring system reliability.[47] Opponents of the utilities' PPA arrangements had argued to the Public Utilities Commission of Ohio that the proposals were preempted by the *FPA* as interfering with FERC's exclusive jurisdiction over wholesale electricity markets and rates, much like the subsidies at issue in *Hughes v Talen*. FERC's orders are perceived as avoiding another round of extended state-federal jurisdictional turf war over electricity regulation.

V. DODD-FRANK AND CFTC DEVELOPMENTS

There have been a number of developments impacting energy companies with regard to U.S. derivatives regulation under the *Dodd-Frank Wall Street Reform and Consumer Protection Act* ("Dodd-Frank").[48]

On March 16, 2016, the U.S. Commodity Futures Trading Commission ("CFTC") approved a final rule that eliminates the reporting and recordkeeping requirements in current CFTC regulations for trade option counterparties that are neither swap dealers nor major swap participants ("Non-SD/MSPs"), including commercial end users such as energy companies that transact trade options in connection with their businesses.[49] Significantly, the final rule eliminates the requirement that such counterparties annually file a Form TO in connection with their trade options, and does not require them, as had been proposed, to notify the CFTC's Division of Market Oversight if they enter into trade options that have, or are expected to have, an aggregate notional value in excess of $1 billion in any calendar year.

In a related development, the CFTC last year issued a final interpretation clarifying its interpretation concerning forward contracts with embedded volumetric optionality ("Final Interpretation").[50] The Final Interpretation appears to signal that, going forward, the CFTC will take a more relaxed view of which transactions constitute "forward contracts" that are not subject to regulation as swaps. This view should be helpful to many commercial parties entering into contracts that provide for volumetric optionality, which means the right to receive or deliver a commodity in an amount that is more or less than was originally contracted for, including many types of energy supply contracts. Under the Final Interpretation, so long as the embedded volumetric optionality is primarily intended, at the time that the parties enter into the contract, to address physical factors or regulatory requirements that reasonably influence demand for, or supply of, the nonfinancial commodity, and the contract otherwise qualifies as a forward under the Final Interpretation, it will be considered a forward contract exempt from swaps regulation.

The CFTC (along with the Prudential Banking Regulators) took action to exempt from the uncleared swaps margin rules swaps between swap dealers and commercial end users, including energy companies, that are eligible for the exemption from mandatory clearing, in accordance with the *Business Risk Mitigation and Price Stabilization Act of 2015*. Under an interim final rule issued by the agencies, so long as the counterparty qualifies for the exemption from mandatory clearing under Section 2(h)(7)(A) of the *Commodity Exchange Act*,[51] uncleared swaps with that counterparty are not subject to the uncleared

[47] *Electric Power Supply Association v FirstEnergy Solutions Corp*, Order Granting Complaint, 155 FERC 61101 (2016); *Electric Power Supply Association v AEP Generation Resources Inc*, Order Granting Complaint, 155 FERC 61102 (2016). The orders rescinded affiliate abuse waivers which had allowed FirstEnergy and AEP to avoid proving that the PPAs were at competitive prices, such as by showing evidence that unaffiliated buyers were willing to pay similar prices for the same generation, or that unaffiliated generators have made sales at similar prices.
[48] *Dodd-Frank Wall Street Reform and Consumer Protection Act*, Pub L No 111-203, 124 Stat 1376 (2010).
[49] 81 Fed Reg 14966 (2016) (to be codified 17 CFR Part 32); See US Commodity Futures Trading Commission, News Release, PR7343-16, "CFTC Approves Final Rule to Amend the Trade Option Exemption by Eliminating Certain Reporting and Recordkeeping Requirements for End-Users" (16 March 2016) online: CFTC <http://www.cftc.gov/PressRoom/PressReleases/pr7343-16>.
[50] Forward Contracts with Embedded Volumetric Optionality, Final Interpretation, 80 Fed Reg 28239 (2015).
[51] 7 USC §§ 1 *et seq* [*CEA*].

swaps margin rules.[52]

Another issue of concern to many energy companies involves the CFTC's proposed position limits rules, which were re-proposed in November 2013, and, if adopted, would impose position limits on four energy reference contracts, including economically equivalent futures, options and swaps. Last fall, the CFTC issued for public comment a supplement (the "Supplemental Aggregation Proposal") to its proposed aggregation rules for position limits for related entities that were issued in November 2013.[53] The Supplemental Aggregation Proposal, if adopted, will in many cases make it easier for closely affiliated entities to obtain an exemption from aggregation of their derivatives positions, which otherwise would be required under the rules, and, therefore, will permit affiliated entities to engage in a larger amount of overall trading. Under the Supplemental Aggregation Proposal, the key change from the 2013 proposed rules is that a market participant that owns greater than 50 per cent of another entity would be allowed to obtain an exemption from aggregation with respect to positions of the owned entity by filing a notice that includes certifications regarding trading independence with the CFTC under the same process that market participants with 10 per cent to 50 per cent ownership interest are permitted to use. By contrast, under the 2013 aggregation proposed rules, in order to obtain an exemption for majority-owned entities, market participants would have been required to obtain affirmative approval from the CFTC and to provide certain additional certifications.

VI. FERC AND CFTC ENFORCEMENT AND COMPLIANCE

FERC's Office of Enforcement (Enforcement) continued to focus its efforts during 2015 in four principal areas: (1) fraud and market manipulation; (2) serious violations of mandatory reliability standards; (3) anticompetitive conduct, and (4) conduct threatening the transparency of regulated markets.[54] In FY 2015, Enforcement continued to prosecute matters under FERC's authority to impose civil penalties of up to $1 million per day for market manipulation and fraud.[55] FERC opened 19 new investigations and obtained monetary penalties and disgorgement of unjust profits totaling approximately $27 million. With the pending litigation in U.S. federal district courts and before the Commission, Enforcement is seeking to recover more than $544 million in civil penalties and disgorge more than $42 million in allegedly unjust profits.

The Commodities Futures Trading Commission (CFTC) also continued to aggressively exercise its enforcement authority in FY 2015, initiating more than 220 investigations and brining 69 enforcement actions, resulting in more than $3 billion in monetary sanctions. A significant portion of the CFTC's enforcement actions continue to involve the energy sector, and the CFTC has prohibited disruptive trading practices on the commodities exchanges under its jurisdiction. Notable FERC and CFTC matters are briefly described below.

A. Berkshire Power Co. (FERC)

On March 30, 2016, FERC approved a settlement agreement for more than $3 million in civil penalties and disgorgement from Berkshire Power Co. and its management company, Power Plant Management Services LLC, after the companies admitted to intentionally misrepresenting the availability of a gas-fired generating facility located in Massachusetts.[56] FERC found that the companies violated the Commission's Anti-Manipulation Rule,[57] Market Behavior Rules,[58] the ISO New England (ISO-NE) Tariff, and certain Commission-Approved Reliability Standards by concealing plant maintenance. The companies also pled guilty to felony violations of the *Clean Air Act*[59] for tampering with emissions monitoring equipment at the plant. This case is notable as an example of increasing cooperation between FERC Enforcement and U.S. Attorneys at the

[52] 81 Fed Reg 635 677 (2016); 80 Fed Reg 74915 (2015).
[53] 80 Fed Reg 58365 (2015).
[54] Federal Energy Regulatory Commission, *2015 Report on Enforcement*, FERC Docket No AD07-13-009 (19 November 2015), online: FERC <http://ferc.gov/legal/staff-reports/2015/11-19-15-enforcement.pdf>. The Report provides additional transparency and guidance for regulated entities and the public.
[55] See 16 USC § 824v(a) (2012); 15 USC § 717c-1 (2012).
[56] *Berkshire Power Company LLC*, 154 FERC 61259 (2016).
[57] 18 CFR § 1c.1 (2015).
[58] 18 CFR § 35.41(a),(b).

Department of Justice.

B. Maxim Power Corporation (FERC)

On May 1, 2015, FERC issued an Order Assessing Civil Penalties against Maxim Power Corporation, several of its affiliates, and one individual employee, alleging that they had violated the Commission's Anti-Manipulation Rule through a scheme to collect approximately $3 million in inflated payments from ISO-New England (ISO-NE) for reliability runs by charging the ISO for costly oil when it actually burned much less expensive natural gas.[60] FERC also found that Maxim had violated FERC's false statements regulation by misleading and omitting material omissions in its communications with the ISO-NE Market Monitor.[61] FERC assessed civil penalties of $5 million against Maxim and $50,000 against an individual employee, with one Commissioner dissenting from the Commission's Order.

On July 1, 2015, Enforcement staff filed a petition in the United States District Court for the District of Massachusetts to enforce the Commission's Order, and the respondents filed a motion to dismiss the petition on September 4, 2015.[62] That motion is pending before the court.

C. BP America Inc. *et al.* (FERC)

On August 13, 2015, an Administrative Law Judge at FERC issued an Initial Decision, finding that BP America Inc., BP Corporation North America Inc., BP America Production Company, and BP Energy Company (collectively, BP) illegally manipulated a certain natural gas market in Houston from September to November 2008. Enforcement Staff alleged manipulation by citing, among other things, markedly changed market activity by BP at points in Texas following Hurricane Ike, and a recorded telephone demonstrating that a junior trader realized BP's trading was manipulative and expressed concern to his supervisor.

The Initial Decision assessed penalties totaling $28 million; and disgorgement of $800,000 in unjust profits, which is equal to the amount sought in the Commission's Order to Show Cause issued on August 5, 2013.[63] The hearing lasted approximately two weeks, and was the first evidentiary hearing in several years regarding alleged market manipulation. Pre-trial discovery included testimony by 23 witnesses, including several expert witnesses offered by both Enforcement staff and BP, and the hearing record consisted of 325 exhibits and 2,657 pages of transcripts. The Initial Decision and the parties' post-hearing briefs are pending before the Commission.

D. Lincoln Paper and Tissue *et al.* (FERC)

On August 29, 2013, FERC issued orders[64] assessing civil penalties of $5 million, $7.5 million, and $1.25 million against Lincoln Paper and Tissue LLC (Lincoln), Competitive Energy Services, LLC ("CES"), and Richard Silkman (Silkman), CES' managing partner, respectively, alleging that these parties manipulated ISO New England's demand response markets.[65] The orders also sought disgorgement of unjust profits of approximately $380,000 from Lincoln and $170,000 from CES.

On December 2, 2013, FERC filed petitions in the U.S. District Court for the District of Massachusetts seeking orders affirming the imposition of penalties against Lincoln, CES, and Silkman.[66] On December 19, 2013, and February 14, 2014, the parties moved to dismiss FERC's complaint, arguing that: (1) FERC's claim for civil penalties is barred by a five-year statute of limitation; (2) FERC lacks jurisdiction over Lincoln's conduct because

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[59] 42 USC §701.
[60] *Maxim Power Corporation*, 15 FERC 61094 (2016).
[61] 18 CFR 35.41(b) (2015).
[62] *FERC v Maxim Power Corporation*, No 15-cv-30113 (D Mass.)
[63] *BP America Inc*, 152 FERC 63 016 (2015); *BP America Inc.*, 144 FERC 61100 (2013).
[64] *Lincoln Paper & Tissue LLC,* 144 FERC 61 162 (2013); *Competitive Energy Servs LLC*, 144 FERC 61163 (2013); *Richard Silkman*, 144 FERC 61164 (2013).
[65] "Demand response" refers to a reduction in customers' consumption of electricity from their anticipated consumption in response to an increase in the price of electricity or to incentive payments designed to induce lower electricity consumption.
[66] Petition for an Order Affirming the Federal Energy Regulatory Commission's August 29, 2013 Order Assessing Civil Penalty Against Lincoln Paper and Tissue LLC, *FERC v Lincoln Paper & Tissue LLC*, No 1:13-cv-13056-DPW (D Mass) (2 December 2013).

the States have exclusive control over demand response regulation; (3) FERC failed to provide fair notice of the conduct it now considers improper; and (4) FERC's complaint fails to plead its claim with particularity.[67]

The Supreme Court's decision in *EPSA*, discussed above, upholding FERC's authority over demand response compensation in organized wholesale energy markets eliminated speculation over whether the courts would dismiss the demand response enforcement litigation for lack of jurisdiction. On April 11, 2016, the court denied the Motions to Dismiss and transferred the demand response litigation to the federal district court for the District of Maine.[68]

E. Barclay's Bank PLC (FERC)

On July 16, 2013, FERC assessed civil penalties totaling $435 million and ordered $34.9 million in disgorgement against Barclays Bank PLC (Barclays) and further assessed civil penalties totaling $18 million against certain individual traders for allegedly manipulating energy markets in and around California between 2006 and 2008.[69] The penalty assessed against Barclays marks the largest of its kind in the agency's history. Barclays and the individual traders have denied FERC's allegations and elected to challenge the penalties in federal court.

On October 9, 2013, FERC petitioned the U.S. District Court for the Eastern District of California to issue an order affirming the assessment of penalties against Barclays and the individual traders. Barclays and the individual traders responded on December 16, 2013 by filing a motion to dismiss FERC's petition.[70] On May 20, 2015, the court denied the Motion to Dismiss.[71] The matter is still pending before the court, which has not yet determined whether the defendants are entitled to full discovery rights as part of the *de novo* review mandated by the FPA. Defendants' appeal of two preliminary district court orders to the U.S. Court of Appeals for the Ninth Circuit was dismissed as premature.[72]

F. Up-To Congestion Investigations, Settlements, and Proceedings (FERC)

FERC has continue to pursue allegations of "gaming" of market rules in the PJM market under the Anti-Manipulation Rule with respect to so-called Up-to Congestion ("UTC") transactions. FERC defines UTC transactions as a "product that enables a trader to profit if the congestion price spread between two nodes changes favorably between the Day Ahead Market (DAM) and the Real Time Market (RTM)."[73] To be profitable, the spread change must exceed the costs of the trade. Notable investigations and litigation are discussed below.

1. Powhatan Energy Fund, LLC

On May 29, 2015, the Commission issued an Order Assessing Civil Penalties, in which it assessed penalties against Powhatan Energy Fund, LLC ($16.8 million), HEEP Fund Inc. ($1.92 million), CU Fund Inc. ($10.08 million), and the companies' principal trader Houlian "Alan" Chen ($1 million) (collectively,

[67] CES and Richard Silkman's Motion to Dismiss Complaint, *FERC v Lincoln Paper & Tissue LLC*, No 1:13-cv-13056-DPW (D Mass) (19 December 2013); Lincoln Paper and Tissue LLC's Motion to Dismiss Complaint, *FERC v Lincoln Paper & Tissue LLC,* No 1:13-cv-13056-DPW (D Mass) (14 February 2014).
[68] Memorandum and Order Regarding Motions to Dismiss, *FERC v Lincoln Paper & Tissue LLC,* No. 1:13-cv-13056-DPW (D Mass) (11 April 2016). The order contained rulings favorable to FERC Enforcement on the issues of statute of limitations, waiver of all defenses and arguments not raised during the Commission penalty assessment process, applicability of the Anti-Manipulation Rule to individual persons, and fair notice of which fraudulent conduct is proscribed. The Court did not provide clarity sought on the scope of *de novo* review under the FPA.
[69] *Barclays Bank PLC*, 144 FERC 61041 (2013).
[70] Notice of Motion and Motion to Dismiss, *FERC v Barclays Bank PLC*, No 2:13-cv-02093-TLN-DAD (ED Cal) (16 December 2013). The motion raised a number of important legal questions relating to FERC's authority to police electricity markets. The motion, for example, argued that FERC lacks jurisdiction over the relevant transactions because they were commodity futures transactions over which the CFTC has exclusive jurisdiction under the Commodity Exchange Act, and because they did not result in physical delivery or transmission of electricity, as the movants claim is required for FERC jurisdiction under the FPA.
[71] Order, *FERC v Barclays Bank PLC*, No 2:13-cv-02093-TLN-EFB (ED Cal) (20 May 2015). The court found, among other things, that FERC's petition was not time-barred by the statute of limitations, that FERC has adequately established its jurisdiction under the FPA, that the CFTC does not have exclusive jurisdiction over the trades at issue, that individual persons are "entities" subject to the anti-manipulation rule, and that open-market trades can be manipulative.
[72] *FERC v Barclays Bank PLC*, No 15-17251 (9th Circuit) (08 March 2016).
[73] Re PJM Up-To-Congestion, Order Approving Stipulation and Consent Agreement, 14 FERC 61088 (2015) at para 3.

"Powhatan Respondents") and ordered the corporate entities to disgorge allegedly unjust profits. The order followed FERC's December 17, 2014, Order to Show Cause and Notice of Proposed Penalty alleging that the Powhatan Respondents engaged in manipulative UTC trading by "plac[ing] UTC trades in opposite directions on the same paths, in the same volumes, during the same hours for the purpose of creating the illusion of bona fide UTC trading and thereby to capture large amounts of MLSA that PJM distributed at that time to UTC transactions with paid transmission," and proposing civil penalties of the same amounts.[74]

In 2014, following FERC's issuance of a Notice of Alleged Violation against the Powhatan Respondents alleging violations of the Anti-Manipulation Rule based on UTC trading,[75] Powhatan took an unprecedented step by launching a website publicly responding to a the allegations.[76] The website contained a summary of communications between FERC and Powhatan's legal representatives, position papers and videos from experts, and other materials related to Powhatan's defense. The website claimed that FERC's investigation violates due process because there were no pre-existing FERC rules stating that the trades were unlawful. Powhatan also claimed that the Fund entered into the subject transaction in an open, transparent manner without concealment or misrepresentation, and that such actions to take advantage of market flaws are not manipulative.[77]

On July 31, 2015, Enforcement staff filed a petition in the United States District Court for the Eastern District of Virginia to enforce the Commission's Order.[78] On October 19, 2015, the respondents filed a motion to dismiss the petition, and that motion was denied on January 8, 2016. The Powhatan Respondents have also submitted a motion for leave to file supplemental material beyond what was included in FERC's investigative record, and the court has not yet ruled on that motion or determined the scope of the *de novo* review required by the *Federal Power Act*.

2. City Power Marketing LLC

On July 2, 2015, the Commission issued an Order Assessing Civil Penalties against City Power Marketing, LLC (City Power) and its owner, K. Stephen Tsingas.[79] The Commission found that City Power and Tsingas had violated the Commission's Anti-Manipulation Rule by engaging in fraudulent Up-To Congestion trades in the PJM market during the summer of 2010. As part of that finding, the Commission determined that City Power and Tsingas had engaged in three types of trades to improperly collect MLSA payments intended for bona fide Up-To Congestion trades: (1) "roundtrip" trades that constituted wash trades, (2) trading between export and import points (SOUTHIMP and SOUTHEXP) that had the same prices, and (3) trading between two other points (which had minimal price differences) not to profit from spread changes but instead for the purpose of collecting MLSA payments. The Commission reasoned, in part, that City Power's trades were inherently fraudulent because they were pre-arranged to cancel each other out and involved little to no economic risk.

The Commission also found that City Power had violated section 35.41(b) of the Commission's regulations by making false and misleading statements and material omissions in its communications with Enforcement staff to conceal the existence of relevant instant messages. The Commission assessed $14 million in civil penalties against City Power and $1 million against Tsingas and ordered disgorgement of $1,278,358 in unjust profits, plus interest.

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[74] *Powhatan Energy Fund LLC*, 149 FERC 61261 (2014).
[75] FERC, *Staff Notice of Alleged Violations* (5 August 2014), online: FERC <http://ferc.gov/enforcement/alleged-violation/notices/2014/houlian-08-05-2014.pdf> (Enforcement alleges that the principal trader made "millions of megawatt hours of offsetting trades" between the same two trading points, with the same volumes and for the same hours, to cancel out the financial consequences from any spread between the points and capture marginal loss of surplus payments from PJM).
[76] See FERC Office of Enforcement, *Preliminary Findings of Enforcement Staff's Investigation of Powhatan Energy Fund LLC* (9 August 2013), online: FERC <http://ferclitigation.com/wp-content/uploads/0005-FERC-Preliminary-Findings-August-9-2013-2002899_1.pdf>.
[77] See Powhatan Energy Fund LLC, *FERC v Powhatan Energy Fund LLC* (last visited 18 May 2016), online: <http://ferclitigation.com>.
[78] *FERC v Powhatan Energy Fund LLC*, No 3:15-cv-00452 (ED Va).
[79] *City Power Marketing LLC and K. Stephen Tsingas*, 152 FERC 61012 (2015).

On September 1, 2015, Enforcement staff filed a petition in the United States District Court for the District of Columbia to enforce the Commission's Order.[80] On November 2, 2015, the respondents filed a motion to dismiss the petition, and that motion remains pending. As in the other pending federal litigation, Respondents have challenged FERC's enforcement procedures and have briefed the issue of the appropriate scope and nature of *de novo* review.

3. Settlements for Reliability Standards Violations (FERC)

FERC continues to actively oversee and enforce Reliability Standards compliance, in coordination with the North American Electric Reliability Corporation (NERC), an industry self-regulatory organization, and NERC's regional reliability entities. Reliability enforcement is of particular interest because the Reliability Standards are also mandatory and enforceable in the provinces of Ontario, New Brunswick, Alberta, British Columbia, Manitoba, and Nova Scotia and are in the process of being adopted in Quebec.[81]

In 2015, FERC reached major settlements with four entities related to a widespread power outage on September 8, 2011 which caused over 30,000 MWh of lost firm load in the San Diego area, as well as parts of Arizona and Mexico. For their significant violations stemming from inadequate operational procedures and failures to take necessary emergency measures to limit cascading failures and blackouts during the event, CAISO, Southern California Edison Company, the Western Area Power Authority-Desert Southwest Region, and Western Electricity Coordinating Council paid civil penalties totaling more than $22 million and agreed to numerous mitigation activities and compliance monitoring.[82]

4. Panther Energy / Coscia Spoofing (CFTC)

The CFTC filed and settled charges, collecting a $2.8 million civil penalty and ordering disgorgement totaling $1.4 million, against commodities trading firm Panther Energy Trading LLC and its trader Michael J. Coscia in 2013. The entities engaged in the disruptive trading practice of "spoofing" by using a computer algorithm to illegally place and quickly cancel bids and offers in exchange-traded futures contracts, including for crude oil and natural gas, to create the false impression that there was significant buying interest in the markets.[83] Coscia was convicted on federal criminal charges in November 2015 involving the same allegations that formed the basis for the civil penalty, in the first criminal prosecution for spoofing.[84]

VII. CRUDE BY RAIL

As an alternative to transporting crude oil via pipeline, the North American crude oil industry has increasingly turned to transportation by rail to supply crude in the U.S. Between 2008 and 2014, crude by rail ("CBR") tank car loads have increased approximately exponentially. However, corresponding with the surge of CBR, derailments and explosions have also increased, raising significant public safety and environmental concerns. In perhaps the most prominent CBR disaster, a CBR train transporting crude oil from North Dakota exploded in Lac-Mégantic, Quebec killing 47 people in July 2013. Since the 2013 disaster, several more derailments and explosions have occurred across the U.S., endangering the lives of approximately 25 million American citizens who live within the evacuation area surrounding CBR transportation routes.

In the U.S., several regulatory agencies exercise the ability to implement rules and guidelines shaping CBR safety. In general, the U.S. Department of Transportation ("DOT") is charged with regulatory oversight of CBR as a means of rail transport. The DOT also oversees two important sub-agencies to assist with its regulatory mandate – The Pipeline and Hazardous Materials Safety Administration ("PHMSA") and Federal Railroad Administration ("FRA"). The PHMSA retains regulatory authority of hazardous materials transport packaging, including the tank cars used for CBR transportation, while the FRA

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[80] *FERC v City Power Marketing LLC*, No 15-cv-01428 (DDC)
[81] NERC, *Canada*, online: NERC <http://www.nerc.com/AboutNERC/keyplayers/Pages/Canada.aspx>.
[82] *CAISO*, 149 FERC 61189 (2014); *Southern California Edison Co*, 149 FERC 61061 (2014); *Western Area Power Authority-Desert Southwest*, 149 FERC 61157 (2014); *Western Electricity Coordinating Council*, 151 FERC 61175 (2015).
[83] *Panther Energy Trading and Michael J. Coscia*, CFTC Docket No 13-26 (22 July 2013).
[84] See *United States v Coscia*, No 14-cr-00551 (ND Ill).

implements the DOT's promotion of rail safety in regional safety offices.

Concerns regarding CBR transportation safety have led to the implementation of several new administrative rules and policies over the past few years. Most recently, on May 1, 2015, the DOT announced a final rule for safe transportation of flammable liquids by rail. The rule requires: (1) more stringent tank car standards and retrofitting requirements for older CBR tank cars; (2) new braking standards to reduce accident severity and "pile-ups"; (3) new operational protocols for CBR trains, including routing requirements, speed restrictions and information for local government agencies; and (4) new sampling and testing requirements to improve the classification of energy products placed into the rail transportation system.[85] The rules apply to a new category of transport, high-hazard flammable trains, which are defined as a "continuous block of 20 or more tank cars loaded with a flammable liquid or 35 or more tank cars loaded with a flammable liquid dispersed through a train."

VIII. END ON BAN OF CRUDE OIL EXPORTS AND EXTENSION OF CERTAIN RENEWABLE ENERGY TAX CREDITS

On December 18, 2015, the President Obama signed into law a $1.8 trillion spending bill which contained a reversal of a 40-year ban on crude oil exports from the U.S. Pursuant to the *Energy Policy and Conservation Act of 1975*,[86] exportation of crude oil was prohibited absent specific exceptions granted by the U.S. Commerce Department in response to the 1973 oil crisis.

Inclusion of the reversal in the spending bill was considered a compromise between Republicans and the oil industry, who had long called for the end of the ban, in return for several environmental measures broadly supported by Democrats and environmental organizations, including the extension and eventual phasing out of certain renewable energy tax credits, reauthorizing a conservation fund for three years, and the exclusion of other measures designed to thwart President Obama's environmental regulatory efforts. In particular, the spending bill extended the expiration date for the production tax credit to December 31, 2019, for wind facilities commencing construction, with a phase-down beginning for wind projects commencing construction after December 31, 2016.

Pressure to reverse the crude oil export ban was partially due to the rapid increase in U.S. oil production in recent years. Between August 2008 and the end of 2015, U.S. oil production increased approximately 90 per cent. Although the Obama Administration had previously threatened to veto legislation including a reversal of the ban, the White House noted that the U.S. is already a major exporter of refined crude oil products. Certain domestic oil refiners expressed their disapproval of the ban, citing concerns that lifting the ban will negatively impact their businesses by driving crude oil overseas to be refined. Oil refiners have also noted that the ban will increase costs to consumers and will reduce U.S. energy independence by increasing reliance on foreign oil refiners to provide the U.S. with products derived from crude oil.

The impact of reversing the crude oil ban reflects a new geopolitical reality of America's increased crude oil security. Supplying global markets with U.S. crude oil may improve the global community's hand in dealing with Russia and Iran, as the threat of losing Russian and Iranian crude oil supplies for Europe, India and Japan could be mitigated by the potential for replacement by U.S. exports. Domestically, environmental groups have expressed concern about the ban's reversal, citing corresponding increases to fracking, air and water pollution, and decreased support for renewable energy.

IX. CLIMATE ACTION PLAN

The Obama Administration's signature climate rule under its Climate Action Plan —the Clean Power Plan (CPP)—is largely on pause as legal challenges wind their way through the federal courts. In the meantime, states are responding in a variety of ways, some moving forward with implementation of the CPP, while others have halted their efforts. The ultimate fate of the CPP may depend greatly on the next person to

[85] U.S. Department of Transportation, Press Release, DOT 42-15, "DOT Announces Final Rule to Strengthen Safe Transportation of Flammable Liquids by Rail (1 May 2015)", online: Transportation.gov <https://www.transportation.gov/briefing-room/final-rule-on-safe-rail-transport-of-flammable-liquids>.
[86] Pub L No 94-163, 89 Stat 871.

fill the U.S. Supreme Court seat vacated upon the death of Justice Antonin Scalia, which will, in turn, likely depend on the outcome of November's presidential election.

A. Overview of the CPP

The U.S. Environmental Protection Agency (EPA) issued a final rule adopting the CPP in August 2015, citing "immediate risks" to national security, public health, and the economy.[87] These ambitious policies, adopted pursuant to Section 111(d) of the *Clean Air Act*, establish the first ever national standards to limit greenhouse gas (GHG) emissions from existing power plants. If fully implemented, the rule will have significant implications for how energy is generated, transmitted, and consumed in the United States.

Under the CPP, states are required to reduce GHG emissions from power plants 32 per cent below 2005 levels by 2030, achieving interim emissions reduction targets for 2022 through 2029. Final compliance targets for 2030 are to be maintained thereafter. Individualized targets for each state are established by analyzing pounds of carbon emissions per megawatt-hour (MWh) of electricity generated based on 2012 historical data.

The CPP gives states flexibility to adopt individually tailored approaches for meeting compliance goals. By allowing conversion of rate-based target emission goals into standards based on tons of emissions per year (mass-based standards), the rule leaves the door open for adoption and further elaboration of market-based programs such as the carbon cap-and-trade program in California and Regional Greenhouse Gas Initiative in the Northeast.

The final rule set a deadline of 2018 for states to submit final implementation plans for achieving their compliance targets, and a deadline of 2022 for states to take action. However, it is unclear whether the CPP's goals will be achieved in the established timeframes, as it has been the subject of a number of legal twists and turns. In October 2015, several states and industry groups challenged the rule in the Circuit Court of Appeals for the D.C. Circuit, which declined to stay the rule pending decision. The challengers then sought a stay from the U.S. Supreme Court, which surprised observers by granting the stay in February 2016. That decision was seen by many as an indication of the high court's concerns about the CPP and seemed to bode well for the challengers. But that stay was granted in a 5-4 decision, with Justice Scalia voting in favor of the stay, just days before his death.

Another surprise came in mid-May 2016, just weeks before the D.C. Circuit was scheduled to hear oral argument, when that Court announced its decision to push arguments to September 2016 and to have the case reviewed en banc (that is, before a full bench of ten judges rather than the usual three.) An en banc hearing is unusual, and an en banc hearing in the first instance—as opposed to on rehearing from a three-judge panel—seldom happens.

Despite the stay, the Obama Administration and nineteen states continue to plan for implementation of the CPP. For example, the EPA is moving forward on its Clean Energy Incentive Program, which is a voluntary program that allows states to incentivize early investments in wind and solar power generation, as well as energy efficiency measures in low-income communities. However, another twenty states have suspended their efforts, and three states and Washington, D.C. are exempt from the rule. Legislators in nearly 20 states have introduced legislation, with support from industry-funded groups, which would prohibit any work on CPP compliance planning activities.

B. Methane Emissions Regulations

The Obama Administration finalized three new rules aimed at curbing methane emissions from new, reconstructed, or modified oil and gas wells.[88] Methane is a prevalent GHG, second only to carbon dioxide, with 25 times the global warming potential on a pound-for-pound basis.[89] This is the first time that the EPA has regulated methane in any industry.

These rules are designed to prevent 510,000

[87] The Final Rule was published in the Federal Register in October 2015. 80 Fed Reg 64662 (23 October 2015).
[88] EPA, *Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources* (12 May 2016), online: EPA <https://www3.epa.gov/airquality/oilandgas/may2016/nsps-finalrule.pdf>.
[89] *Ibid* at 31; see also EPA, Overview of Greenhouse Gases, online: EPA <https://www3.epa.gov/climatechange/ghgemissions/gases/ch4.html>.

short tons of methane—11 million metric tons of carbon dioxide equivalent emissions—by 2025. EPA estimates these regulations will result in $690 million of climate benefits, as compared to the rule's estimated costs of $530 million, in 2025. EPA also expects reductions in volatile organic compounds and other air toxics, which would yield health benefits.

The first rule establishes methane emissions standards for new, reconstructed, and modified sources under Section 111(b) of the *Clean Air Act*. The second rule clarifies the rules for determining whether oil and gas equipment and activities are part of a single "stationary source. The third rule finalizes and amends regulations regarding minor sources on Federal Indian lands.

While environmentalists applaud these steps, the oil and gas industry has criticized EPA for basing the rules on inconsistent data regarding current methane emission levels. The industry is also bracing itself for future rules that may be imposed on existing sources, as indicated by EPA's Information Collection Request for information from oil and gas companies regarding their existing operations.

X. NEW ELECTRIC DISTRIBUTION PLATFORMS

New York Public Service Commission's Reforming Energy Vision

The New York Public Service Commission ("NYPSC") in 2014 initiated Case 14-M-0101, *Reforming the Energy Vision (REV)*, along with a companion proceeding (Case 14-M-0094). The REV is intended to improve customer knowledge, market animation, system-wide efficiency, fuel and resource diversity, system reliability and resiliency, and reduce carbon emissions. The companion proceeding is to address the future of New York clean energy programs currently funded by a surcharge on the delivery portion of customers' utility bills. This proceeding is being closely watched by many states across the U.S.

The NYPSC adopted a two-phase schedule for Case 14-M-0101. Track 1 considers issues related to the concept and feasibility of a DSPP, as described in the NYPSC Staff preliminary framework. Track 2 focuses on regulatory changes and ratemaking issues. Task Forces and working groups have been formed and are working on both tracks. In a February 26, 2015 Order in the REV Proceeding, the NYPSC instituted a REV large-scale renewable (LSR) track as well.

The NYPSC has issued a series of orders over the last two years on various REV issues. The orders serve principally to establish analytical frameworks for issues such as how to conduct cost-benefit analyses, and also to expand the scope of the proceeding.[90]

The NYPSC made a Determination of Significance, noting that the REV and CEF actions could potentially have one or more significant adverse impacts on the environment, and called for the preparation of an Environmental Impact Statement. A draft EIS was issued on October 14, 2014. The NYPSC accepted the EIS as complete on February 24, 2016.[91]

XI. ENERGY STORAGE

Energy storage continues to draw ever greater attention from state and federal governments, as utilities and grid operators wrestle with how best to integrate large volumes of intermittent resources like wind and solar into power grids designed for more traditional energy generation sources. Storage, whether at the utility scale, the customer scale, or sizes in between, offers one additional way to balance and shape output from intermittent resources to meet customer demands.

However, storage poses unique regulatory challenges. Energy storage systems allow individual storage units to be classified as generation, as transmission or distribution, and/or as load, making it difficult to fit into existing regulatory structures.

A. Federal Developments

FERC issued Order 784[92] in 2013. That order

[90] The NYPSC has collected its REV orders here: *DPS - Reforming the Energy Vision*, online: Government of New York State <http://www3.dps.ny.gov/W/PSCWeb.nsf/All/C12C0A18F55877E785257E6F005D533E?OpenDocument>.
[91] New York Public Service Commission, Resolution Accepting Draft Generic Supplemental Environmental Impact Statement as Complete (24 February 2016), online: Government of New York State <http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7b3998B18C-D493-447B-8E28-6067D0CFF8B5%7d>.
[92] *Re Third-Party Provision of Ancillary Services; Accounting of Financial Reporting for New Electric Storage Technologies*, 144 FERC 61056 (2013).

directed wholesale market operators to find ways to monetize "fast response" resources; code for storage devices such as batteries and flywheels. After a number of orders in various RTOs/ISOs implementing Order 784, FERC issued a follow-up order on April 11, 2016, in Docket Number AD16-20-000 concerning the "participation of electric storage resources in the organized wholesale electric markets, that is, the regional transmission organizations or RTOs and the independent system operators or ISOs." FERC is seeking input on "whether additional action is necessary to address potential barriers to electric storage participation in the RTO and ISO markets."

B. California

As detailed in last year's Washington Report, California has taken the lead to include energy storage in resource planning by its electric utilities and energy suppliers. Assembly Bill ("AB") 2514[93] required the California Public Utilities Commission ("CPUC") to determine appropriate targets, if any, for each load serving entity ("LSE") to procure viable and cost-effective energy storage systems. The CPUC opened Rulemaking ("R.") 10-12-007 to implement AB 2514. R.10-12-007 culminated in Decision ("D.") 13-10-040 in 2013. That decision requires California's three large investor-owned electric utilities ("IOUs") to procure 1,325 MW of energy storage capacity by 2020. The CPUC divided the 1,325 MW into biennial procurement targets by "grid domain" in 2014, 2016, 2018, and 2020:

- IOU targets: 1,325 MW of storage by 2020 in 4 biennial solicitations (starting December 2014)
    - PG&E 580 MW
    - SCE 580 MW
    - SDG&E 165 MW
- Above targets divided into three "storage grid domains":
    - Transmission-connected,
    - Distribution-level and
    - Customer-Side of the Meter applications
- Non-utility load serving entity targets ~ 1 per cent of peak load by 2020

In September 2013, the California ISO ("CAISO"), CPUC, and the California Energy Commission announced they were partnering to develop a joint energy storage roadmap to advance energy storage in California. The roadmap will propose action and venues to address identified barriers related to storage. Based on inputs received from various stakeholders, a draft roadmap was made available and a workshop was held in October to discuss the draft and solicit feedback. The final roadmap was completed by the end of 2014.

D.13-10-040 directed a comprehensive evaluation of the Energy Storage Framework and Design Program no later than 2016, and once every three years thereafter. In compliance with D.13-10-040's direction, the CPUC last year opened a new rulemaking as part of its ongoing implementation of AB 2514. The new OIR is docketed as R.15-03-011, and is entitled "Order Instituting Rulemaking to consider policy and implementation refinements to the Energy Storage Procurement Framework and Design Program (D.13-10-040, D.14-10-045) and related Action Plan of the California Energy Storage Roadmap." As the proceeding's name implies, it is a broad review of all CPUC policies (and associated IOU practices) relating to energy storage.[94] The CPUC has conducted a workshop in the proceeding, and further workshops are anticipated. The CPUC has not yet issued any decisions in the new rulemaking.

The CPUC has also encouraged acquisition of storage resources in its proceeding addressing the premature retirement of the San Onofre Nuclear Generating Station (SONGS). D.13-02-015 directed SCE to undertake an "all-sources" bidding process for resources to address local reliability needs resulting from SONGS' closure. The Commission authorized SCE to procure between 1,400 MW and 1,800 MW

[93] Stats 2010, ch 469.
[94] *Order Instituting Rulemaking to consider policy and implementation refinements to the Energy Storage Procurement Framework and Design Program (D.13-10-040, D.14-10-045) and related Action Plan of the California Energy Storage Roadmap, CPUC, Rulemaking* 15-03-011, online: CPUC <http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M157/K541/157541764.PDF>.

of electrical capacity in the West Los Angeles subarea and between 215 MW and 290 MW in the Moorpark subarea. Of the total 1,800 MW authorized, the Commission mandated that at least 50 MW be procured from energy storage resources and said that an additional 750 MW of new capacity could be satisfied by energy storage.

On November 5, 2014, SCE announced that it had signed contracts for 2,221 MW of power in compliance with D.13-02-015. Of this total, SCE signed contracts with storage providers for 260 MW, involving 24 separate contracts. This is five times the amount mandated by the CPUC for SCE in D.13-02-015 for energy storage resources, though only slightly more than a third of the maximum SCE might have procured. In November 2015, the CPUC approved SCE's filing for approval of these contracts.

XII. DISTRIBUTED GENERATION AND NET METERING

State public utility commissions across the United States continue to grapple with how to incorporate distributed generation and "net metering" into rate design. Traditional utilities contend that giving consumers credit for energy produced with distributed generation (such as residential solar panels that connected with the grid) unfairly reduces utility revenues. Utilities recover a large portion of costs through per-KWh charges. Such utilities also contend that distributed generation users, and particularly net metering customers, do not pay a fair share of the fixed costs needed to provide the electricity they use. Advocates of distributed generation counter that high fixed prices a(coupled with lower variable prices) encouraged energy use and would allow the utilities to avoid competition from distributed generation. Different states are addressing these issues in divergent ways.

A. Distributed Resources Rulemakings

1. Distribution Energy Resources and Distribution Resources Plan Proposals

For more than a decade, California has required each of its IOUs to consider nonutility-owned Distribution Energy Resources (DERs) as a possible alternative to investments in its distribution system to ensure reliable electric service at the lowest possible cost.[95] In 2013, the California legislature enacted PU Code Section 769 requiring IOUs to submit Distribution Resource Plan Proposals ("DRPs") to the CPUC. Section 769 requires IOUs to submit DRPs that recognize the need for investment, to integrate cost-effective DERs and for activity identifying barriers to the deployment of DERs. The CPUC is authorized to modify and approve an IOU's DRP "as appropriate to minimize overall system costs and maximize ratepayer benefit from investments in distributed resources."[96]

In August 2014, the CPUC opened Rulemaking 14-08-013 to establish policies, procedures, and rules to guide IOUs in developing their DRPs and to review, approve, or modify and approve the plans. The goal of the plans is to begin the process of moving the IOUs towards a more full integration of DERs into distribution system planning, operations, and investment. Section 769 requires that DRPs must provide a roadmap for integrating cost-effective DERs into the planning and operations of IOUS' electric distribution systems with the goal of yielding net benefits to ratepayers. In their DRPs, the IOUs are required to define the criteria for determining what constitutes an optimal location for the deployment of DERs, and then to identify specific locational values for DERs, augmented or new tariffs, and programs to support efficient DER deployment, and the removal of specific barriers to deployment of DERs.

R.14-08-013 remains open, and is consolidated with the large utility applications for approval of individual DRPs: A.15-07-002 (SCE), A.15-07-003 (SDG&E), and A.15-07-006 (PG&E). The CPUC projects a decision in this proceeding in early 2017.

In parallel, the CPUC is moving forward with R.14-10-003, the "Order Instituting Rulemaking to Create a Consistent Regulatory Framework for the Guidance, Planning and Evaluation of Integrated Distributed Energy Resources." Issues in that proceeding include:

> "1) a determination of how the distributed energy resources, needed to fill the required

[95] Cal Pub Util Code § 353.5.
[96] Cal Pub Util Code § 769(c).

> characteristics and the values—to be determined in R.14-08-013 et al.—will be procured;
>
> 2) a focus on the integration of distributed energy resources in a holistic way; and
>
> 3) a consideration of the adoption of localized incentives and the methodology used in determining the incentives."[97]

2. Net Energy Metering

Under A.B. 327,[98] enacted in 2013, CPUC had until December 31, 2015 to develop a standard contract or tariff that applies to customer-generators who own rooftop solar installations or other distributed generation.

On January 28, 2016, the CPUC approved Decision (D.) 16-01-044, adopting a NEM successor tariff that continues the existing NEM structure while making adjustments to align the costs of NEM successor customers more closely with those of non-NEM customers.[99] The CPUC's decision:

- largely preserves retail payments for residential rooftop solar generators;
- adds new interconnection costs and non-bypassable charges to distributed solar systems;
- and imposes new minimum bill requirements.

The proposed decision declines to "impose any demand charges, grid access charges, installed capacity fees, standby fees, or similar fixed charges on [net energy metering] residential customers, while the [CPUC] continues to evaluate the need for them." Also, solar projects larger than 1 megawatt are eligible for net metering provided they can pay related interconnection and upgrade fees.

Utilities filed Advice Letters with the CPUC implementing the new requirements on February 29, 2016. The Advice Letters are currently under review by CPUC staff.

Senate Bill 793,[100] The Green Tariff Shared Renewables Program, was enacted October 8, 2015, and requires the CPUC to require that a participating utility's green tariff shared renewables program permit a participating customer to subscribe to the program and receive a reasonably estimated bill credit and bill charge, as determined by the commission, for a period of up to 20 years.

B. Nevada - Rooftop Solar Installations and Net Metering

In 2015, the Nevada legislature enacted SB 374.[101] This law directed utilities to prepare a cost-of-service study for rooftop solar installations, and to prepare a new tariff to go into effect once solar rooftop installations in Nevada exceeded a cumulative 235 MW of installed capacity. Nevada's two major utilities, NV Energy and Sierra Pacific, filed cost-of-service studies, and, on December 23, 2015, the Public Utilities Commission of Nevada (PUCN) entered an order approving tariff filings by the two utilities.[102]

The tariffs contain the following departures from the relevant prior tariffs.

- The approved tariffs net customer generation and customer load hourly, rather than monthly, as had previously been the case.
- The approved tariffs value of the excess energy that rooftop solar customers "sell" to the utilities at 2.6 (NV Energy) and 2.7 (Sierra Pacific) cents per kWh—a 76 per cent and 71 per cent reduction, respectively, in the value that

[97] *Order Instituting Rulemaking to Create a Consistent Regulatory Framework for the Guidance, Planning and Evaluation of Integrated Distributed Energy Resources*, CPUC, Rulemaking 14-10-003 (2 October 2014), online: CPUC <http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M158/K886/158886810.PDF>.
[98] AB 327, *An Act to Amend Sections 382, 399.15, 739.1, 2827, and 2827.10 of, to Amend and Renumber Section 2827.1 of, to Add Sections 769 and 2827.1 to, and to Repeal and add Sections 739.9 and 745 of, the Public Utilities Code, Relating to Energy*, 2013-2014, Reg Session, Cal 2013 (enacted).
[99] *Decision Adopting Successor Tariff to Net Energy Metering Tariff*, CPUC, Decision 16-01-044 (28 January 2016).
[100] SB 793, Green Tariff Renewables Program, 2015-2016 Reg Sess, Cal, 2015 (enacted).
[101] SB 374, Revises Provisions Relating to Energy, 78th Legislature, Reg Session, Nev, 2015 (enacted).
[102] *Order Re: NV Energy and Sierra Pacific Power Applications*, Nos 15-0741 and 15-0742 (December 23, 2015).

rooftop solar customers were previously credited.[103]

- The approved tariffs nearly triple the fixed charges that net metering customers must pay the utilities. In Sierra Pacific's service territory, the basic monthly service charge for residential solar customers rose from $15.25 to $44.43, and in Nevada Power's service territory, the monthly fixed charges imposed on residential solar customers increased from $12.75 to $38.51.[104]

The PUCN declined to "grandfather" the approximately 17,000 existing solar customers who had already installed and interconnected rooftop solar systems into the pre-existing rate regime.[105] Thus Nevada is the first state in the country to significantly change the economics of net metering without grandfathering existing customers. This decision is being challenged in the Nevada state courts. ■

[103] Docket 15-07041, Advice Letter No 453-R at 2 (Dec 30, 2015), 6 ROD 006938.
[104] *Ibid*; Docket 15-07041, Advice Letter No. 453-R at 2 (Dec. 30, 2015), 6 ROD 006938.
[105] *Order Re: NV Energy and Sierra Pacific Power Applications*, Nos 15-07041 & 15-07042, at p 108 (23 December 015), 7 ROD 007515.