IN THE MATTER OF AN ARBITRATION UNDER CHAPTER ELEVEN OF THE NORTH AMERICAN FREE TRADE AGREEMENT AND THE ICSID ARBITRATION (ADDITIONAL FACILITY) RULES

BETWEEN:

MERCER INTERNATIONAL INC.

Claimant

AND:

GOVERNMENT OF CANADA

Respondent

WITNESS STATEMENT OF MICHAEL W. MACDOUGALL

21 March 2015

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I, Michael W. MacDougall, declare as follows:

1. I was born on [redacted] I presently reside at [redacted]

2. I am the Director of Trade Policy & Information Technology for Powerex Corp, a role that I will describe in more detail below.

3. I hold a Bachelor of Arts in International Relations from the University of British Columbia and a Master of Arts in Economics, majoring in Energy & International Trade, from the University of Calgary.

4. Since the beginning of my professional career, I was employed in a number of capacities relating to trading energy commodities, in particular natural gas and electricity. From May 1990 to August 1993, I was employed by the Canadian Energy Research Institute ("CERI"), where I worked, first, as a Research Analyst, then as an Economist and ultimately as a Senior Economist. As part of my responsibilities, I contributed to the maintenance and update of the North American Regional Gas Model used for forecasting North American natural gas supply, demand, and prices.

5. From 1993 to 1998, I was employed by Westcoast Energy Inc., where my responsibilities culminated in a lead position responsible for Contracts, Pricing and Financial Analysis. Among other things, I was responsible for monitoring United States natural gas regulatory developments, including the development of open access under the Orders of the US Federal Energy Regulatory Commission ("FERC").

6. From 1998 to 1999, I was employed by BC Hydro as a Senior Regulatory Analyst, where I switched my focus from natural gas to the electricity industry. My responsibilities included the monitoring of developments related to open access transmission and wholesale market access.

7. I have been employed by Powerex since February of 1999, which I first joined as an analyst in the Trade Policy group. I have since held a number of different positions, with increasing responsibilities over time. My current roles and responsibilities at Powerex include being a

member of the Powerex Executive Team and leading the Trade Policy, Transmission Access and Information Technology departments.

8. I am also currently participating in the Leadership Committee for the Northwest Power Pool Market Assessment and Coordination Committee Initiative. From June 2012 to February 2014, I was a Board Member for the Western Electricity Coordinating Council ("WECC"). I was also a member of the Steering Committee of the Market Interface Committee of the WECC, the chair of the Power Marketers Council of the Canadian Electrical Association, and the Representative for the Power Marketers Council on the Canadian National Energy Board's Cost Recovery Liaison Committee. I have also participated as a member of the Alberta Electric System Operator's Market Advisory Committee, the Alberta Market Surveillance Administrator's State of the Market Advisory Committee, and the Alberta Department of Energy's Electricity Coordination Forum.

9. I attach my resume as **Appendix A**.

10. In Section A of this witness statement, I will explain Powerex' mandate and experience with respect to electricity trading activities, including wholesale power trading in the United States and transactions involving green or renewable power.

11. In Section B, I will explain how electricity is exported outside of British Columbia, and what the implications are in terms of transmission capability, transmission costs and line losses borne by the exporting generator.

12. In Section C, I will explain the different opportunities that exist for the sale of electricity on the Mid-Columbia market and the extent to which a British Columbia-based self-generator could enter into profitable power sales from 2007 onward. I will also explain the different markets for renewable energy that exist in the Western US states, and the extent to which these markets are available to British Columbia biomass electricity producers.

13. I have personal knowledge of the matters described in this witness statement, except where based on information and belief, in which case I indicate the source of the information and my belief that it is true.

14. I have reviewed the documents cited for the purposes of preparing this witness statement. I am a fact witness in this NAFTA arbitration.

A. Powerex Corp

15. Powerex is the energy marketing subsidiary of BC Hydro, established in 1988. Powerex' initial task was to market BC Hydro's surplus energy, as it existed from time to time, in the Western Interconnection grid.[1] Since 1988, Powerex' revenues have exceeded US$40 billion. Including purchases from third parties, Powerex' total transactional volume since 1988 is in excess of US$76 billion. In 1997, the US Federal Energy Regulatory Commission ("FERC") provided Powerex with Power Marketing Authorization (now called "Market-based rate authority"), thus allowing it to enter into wholesale power sales and purchases directly in the US. Throughout the years, Powerex' mandate has evolved from that of solely marketing BC Hydro's surplus electricity, to also trading and marketing electricity acquired from third parties, natural gas and environmental products. However, Powerex' activity remains predominantly based on trading and moving physical power, as opposed to financial trading, in Western North America. Powerex is one of the most active participants on the electric transmission grid in Western North America.

16. Powerex has been marketing green/renewable energy products since August of 2002. It was the first Canadian energy marketing company to market renewable energy products to California. Powerex' renewable energy product sales since 2002 have amounted to over US$625 million.

17. As indicated above, my responsibilities involve being a member of the Powerex Executive Team and leading the Trade Policy group, Transmission Access, and Information Technology departments. Powerex' trade policy activity is driven by our participation in electricity, natural gas and renewable energy/greenhouse gas markets. The Trade Policy group is mandated to actively monitor and participate in regulatory forums at the State/Provincial and Federal levels in the United States and Canada where Powerex has business interests. For instance, I am regularly called-upon to participate, develop submissions and, when necessary, testify before governmental regulatory agencies (including the FERC, the Bonneville Power Administration ("BPA"), the British Columbia Utilities

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[1] Powerex Corp, About, online: <http://www2.powerex.com/AboutUs.aspx>, **R-420.**

Commission (“BCUC”), and the Alberta Utilities Commission (“AUC”)) in order to in represent Powerex’ interests in proceedings in both the US and Canada.

18. Further, the Trade Policy group monitors and participates in State policy development as it relates to renewable energy markets. This would include whether BC-sourced renewable energy might qualify for individual State Renewable Portfolio Standards. The Trade Policy group also works with sales and marketing staff to review whether proposed transactions from any source location meet the established criteria for a given State.

19. The Transmission Access group is comprised of electrical engineers and is aimed at maintaining and expanding Powerex’ access to transmission service throughout the Western Interconnection power grid (“Western Interconnection”)[2] by participating in transmission planning, operations and reliability forums or interacting directly with transmission service providers.

20. As part of my involvement in the Trade Policy and Transmission Access groups, I have acquired direct knowledge of the technical, regulatory and financial requirements that a utility or a power marketer must meet in order to gain transmission access into the different wholesale power markets of the Western Interconnection.

B. Exporting Electricity out of British Columbia and into the Western US States: Market Opportunities and Technical Challenges

1. Generic versus Renewable Power

21. There are two relevant markets for electricity in the Western Interconnection: generic wholesale power on the one hand, and renewable power on the other. The former refers to power that is offered for sale at a particular location, of a specific functional quality (e.g., delivery period, level of interruptibility or firmness) without an indication as to the type of resource from which it was generated (e.g., coal, natural gas, or wind). The latter refers to

[2] The Western Interconnection is one of the two largest alternating current power grids in North America, and comprises the generating stations, high-voltage transmission lines and distribution lines of power producers and electric utilities in the Canadian provinces of Alberta and British Columbia, and the US states of Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, Wyoming, a parts of Texas and South Dakota, and the Baja California Norte region of Mexico.

power that is generated from renewable sources and for which a renewable energy credit is associated with the green generation. As discussed more fully below, the definition of what qualifies as renewable power can vary by jurisdiction.

a) Generic Power

22. Most electricity in wholesale markets is generic power and is typically contracted at trading hubs. In the power industry a trading hub is defined as a common location where electricity is bought and sold by numerous parties. Trading hubs frequently occur where large transmission transfer capability exists.

23. The principal electricity trading hub in the Pacific Northwest is known as Mid-Columbia ("Mid-C"). Mid-C is a power trading hub comprised of the control areas of three public utility districts in Washington that run hydroelectric projects on the Columbia River (Grant County, Douglas County and Chelan County). Mid-C is the second most liquid electricity trading hub in Western North America and the most liquid trading hub in the Pacific Northwest.

24. The "Mid-C" market is a bilateral market, i.e. a market where trades are made between different counterparties, as distinct from sales into organized markets or pools. Market Participants at Mid-C represent a wide variety of utilities, independent power producers, financial institutions and "marketers" who specialize in moving power between regions. Transactions at Mid-C occur either directly (one company phoning another) or through a broker (in which case companies are matched after agreeing to basic contract terms such as price, quantity, delivery quality, and duration).

25. The Mid-C market is a market for generic wholesale power. Transactions obligate buyers and sellers to deliver a particular standard of power (typically firm block power)[3] during the contracted period and delivered to the agreed upon location pursuant to standard forms of

[3] Block refers to a quantity that does not vary from hour to hour (e.g., 16 hour block), firm refers to the fact that the seller is responsible for liquidated damages if it fails to deliver.

contract.[4] Buyers and sellers trade "Mid-C" power in hourly intervals, daily intervals, in monthly blocks or for future years. Hourly and daily transactions are considered "spot" transactions, whereas longer term transactions are considered "forward" transactions. Spot transactions identify and "schedule" the generation source immediately[5] following the deal. Forward transactions are financially backed by the seller until the power is delivered in the spot market (at which point seller's source of supply is scheduled to the buyer's load). The market standard for forward electricity contracts[6] in the WECC requires sellers to deliver firm energy to the buyer (such firm deliveries are only interruptible for reasons of reliability, service to native load, Force Majeure or as mutually agreed between the parties). More specifically if a seller sells power forward at Mid-C, and its source of supply cannot reach that market, the seller must buy replacement power in the market to fulfil its commitment or be responsible for financial damages. Other types of contracts exist in which the buyer assumes the risk of the seller's inability to deliver, but they are almost exclusively bilaterally negotiated, and of lower value since the pricing tends to reflect the buyer's capability to absorb the risk of losing access to a source of supply with little or no compensation.[7]

26. Forward sales at Mid-C beyond 3 to 4 years tend to be bilaterally negotiated transactions where issues of creditworthiness and the seller's ability to perform (i.e. the strength and credibility of the seller's portfolio) are important considerations in the negotiation.

b) Renewable Power

27. As indicated above, renewable power is a combination of generic wholesale power sourced directly from a qualifying facility and the renewable energy certificates ("RECs") associated

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[4] The WSPP is the most commonly used form of agreement in the west. Schedule C is the most commonly traded product under that agreement. WSPP Agreement Description, available online at: <http://www.wspp.org/documents_agreement.php>, **R-421.**

[5] For next day transactions, convention is to complete the schedules by 2 p.m. on the day of the trade.

[6] *See for example* WSPP Inc., *WSPP Agreement*, Service Schedule "C", **R-422.** *See also* Edison Electric Institute, Master Power Purchase & Sale Agreement, available online at: <http://www.eei.org/resourcesandmedia/mastercontract/Documents/contract0004.pdf> ("EEI Agreement"), **R-423.**

[7] e.g., WSPP Inc., WSPP Agreement, Service Schedule "A" or Schedule "B", **R-422**. *EEI Agreement*, **R-423.**

with the power from that facility. RECs are the renewable energy “attributes” associated with such power where this power is generated from renewable sources such as wind, water, solar or – in some instances – biomass. RECs can be sold together with the underlying power as “bundled renewable power”, or be dissociated from it and sold separately as “unbundled RECs”.[8]

28. Sales of bundled renewable power are transmitted directly from the generator to the buyer, which, depending on the circumstances, may pose a number of challenges in terms of transmission availability.[9]

29. Selling unbundled RECs does not require energy to be delivered to a buyer and consequently does not require transmission access. The relative ease of bringing unbundled RECs to the market has historically resulted in the supply of unbundled RECs in the US outstripping demand. Data provided by the US Department of Energy suggests that, between 2009 and 2014, unbundled RECs traded for approximately $1 US per MWh.[10]

30. In the US, bundled renewable power is typically marketed into “compliance markets”, which are markets created by the authority of a jurisdiction’s legislature. In most instances such jurisdiction’s programs, most often dubbed “Renewables Portfolio Standard” (“RPS”) or “Renewable Energy Standard” (“RES”), impose on their electric utilities the requirement that they must meet a given portion of their load with renewable energy. Therefore, in order to comply with an RPS or an RES, the utility must not only demonstrate that it sources its power from a specific (and often very narrow) class of renewable sources, but also that the renewable power procured accounts for the required proportion of its load in accordance with the statutory provisions. Compliance market programs, in addition to the broad goal of displacing non-renewable generation, typically favour in-state generation (for reasons of

[8] In the Western Interconnection, a registry hosted by the Western Energy Coordinating Council (“WECC”), dubbed “Western Renewable Energy Generation Information System” (“WREGIS”) keeps track of renewable generation and facilitates the trading of RECs. California Energy Commission, *WREGIS – Western Renewable Energy Generation Information System*, available online at: < http://www.energy.ca.gov/portfolio/wregis/>, **R-424**.

[9] Evidence of delivery from the facility is more than “contractual” – a NERC “e-tag” is typically used to demonstrate delivery.

[10] *United States Department of Energy*, “Renewable Energy Certificates (RECs) – REC prices”, available online at: <http://apps3.eere.energy.gov/greenpower/markets/certificates.shtml?page=5>, **R-425.**

local clean air, local jobs and taxes, etc.) and, for this reason, are often more difficult to access for any facility located outside the jurisdiction concerned.[11] Because compliance markets are typically more difficult for sources of renewable supply to access, the value of renewable energy products traded in these markets is generally higher.

2. Transmission Access into and within the US

31. Any transaction of physical power requires the power producer to be capable of transmitting its power over the transmission networks of the different utilities located between its plant and either the buyer's load, or any agreed-upon location in between. In this regard, utilities that own transmission and have open access transmission tariffs ("OATT") are required to allow third parties to use their high-voltage transmission lines in order for such transmittal to occur to the extent those lines are not reserved or required to serve utility commitments.

32. In 1996, the US FERC issued two orders pursuant to which FERC jurisdictional electric utilities were required to make their transmission networks available to all producers wishing to engage into the transmission of wholesale power. Pursuant to the first order, utilities were required to implement an OATT providing for non-discriminatory access to transmission,[12] and under the second order, utilities were required to create or participate in an open-access same-time information system (or "OASIS") providing potential open-access transmission customers with information, posted electronically, regarding available transmission capacity.[13] Foreign and domestic non-jurisdictional utilities seeking access to FERC-regulated wholesale power markets or to open access transmission on FERC-regulated utilities were also subject to these obligations as part of FERC's reciprocal access requirements.

33. FERC's Order No. 888 included a *pro forma* OATT, which utilities could elect to use in order to comply with the open access transmission requirements. BC Hydro, for example,

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[11] On the other hand, "voluntary markets" refers to any market for renewable energy products that is not created by authority of a jurisdiction. Unbundled RECs are typically traded in voluntary markets.

[12] Federal Energy Regulatory Commission, Order No. 888, available online at: <http://www.ferc.gov/legal/maj-ord-reg/land-docs/rm95-8-00w.txt>.

[13] Federal Energy Regulatory Commission, Order No. 888, available online at: <http://www.ferc.gov/legal/maj-ord-reg/land-docs/rm95-9-00k.txt>.

implemented an OATT capturing most of the provisions of the FERC's *pro forma* tariff in 1998.[14] The majority of the major transmission service providers in the Pacific Northwest also implemented OATTs in line with the provisions of the FERC's *pro forma* tariff.

34. In accordance with the FERC's *pro forma* OATT, utilities provide two types of products that a customer can purchase in order to transmit power on high-voltage transmission lines: Network service and Point-to-Point service. Point-to-Point service is additionally differentiated into long-term and short-term firm rights and into non-firm rights. Generally, network service is used by utilities to serve load in their local control area from multiple generation sources. For the purpose of moving electricity out of one utility's system onto another, Point-to-Point is the service used, with limited exceptions.

35. Firm Point-to-Point service can be purchased in different durations of service, the most significant being "long term" meaning one year or longer and "short-term" meaning less than one year[15]. While long-term service reservations are handled in the order received, short-term firm Point-to-Point service reservations can be displaced by longer duration firm reservations (e.g., monthly displaces weekly, which displaces daily, which displaces hourly) up until the close of relevant conditional windows. Once any conditions are removed from a firm Point-to-Point reservation, the firm transmission service will offer the rights holder virtually unfettered access to the transmission path for the duration of the reservation, which the utility may curtail only in the event it is necessary to maintain reliable operation of its system,[16] i.e., in case of *force majeure*. In the event that a curtailment does occur, it must be implemented on a pro-rata basis amongst all firm rights holders.

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[14] BC Hydro has since amended its OATT on a number of occasions. The most recent version is dated April 18, 2013, available online at: http://transmission.bchydro.com/regulatory_filings/tariff/tariff_documents/open_access_tariff.htm .

[15] There is further differentiation in short-term service based on monthly, weekly, daily and hourly time periods.

[16] Federal Energy Regulatory Commission, Order No. 888, Appendix D, *Pro Forma Open Access Transmission Tariff*, available online at: < http://www.ferc.gov/legal/maj-ord-reg/land-docs/rm95-8-0aa.txt>. The FERC's transmission policies were further refined in orders on rehearing of Order No. 888 and in Order No. 890. *See* Federal Energy Regulatory Commission, Order No. 890, Appendix B, *Pro Forma Open Access Transmission Tariff*, available online at: *http*://www.ferc.gov/industries/electric/indus-act/oatt-reform/order-890-B/pro-forma-open-access.pdf ("FERC Pro Forma OATT"), Sections 13.2 and 13.6, **R-426.**

36. Importantly, the ability to purchase firm transmission service depends upon there being firm "available transmission capacity" ("ATC") on the utility's system. Under the *pro-forma* OATT access to long-term firm ATC is granted on a first-come, first-served basis typically administered through an OASIS that provides all parties non-discriminatory access to information regarding ATC. For long-term firm Point-to-Point transmission, when there is insufficient ATC to meet a particular request, a queue is established until that request can be studied pursuant to the tariff procedures and a determination made whether: (1) the request can be accommodated in whole or in part, (2) an expansion of the transmission system is necessary and at what costs; and (3) the customer is willing to sign a contract for that service subject to conditions arising out of the studies. In practice, on transmission paths where there is no long term firm ATC available, long queues get established. Parties entering the end of the queue must wait until the requests by parties ahead of them are dealt with pursuant to the tariff provisions.[17]

37. I have been asked to comment on whether there was sufficient ATC on the transmission lines from British Columbia to Washington State to accommodate the reservation of 40 MW firm Point-to-Point service commencing in the summer of 2008 and onward. In order to enter into long-term sales of electricity in the US market, a seller must be able to supply its power to the buyer at the point of delivery in every hour of every day for the duration of the contract, failing which, the seller will incur liquidated damages. Therefore, the fulfilment of long-term sales of BC-generated electricity in the US is contingent on obtaining continuous, round-the-clock transmission from the generating plant to the point of delivery. My conclusion is that a reservation for 40 MW could not have been made due to a lack of long-term firm ATC.

38. This conclusion is based, in part, upon Powerex' direct experience and involvement with BPA, from which I know that no sufficient capacity exists on BPA's transmission network from the BC/US border into the United States that would allow Celgar or its agent to purchase firm transmission rights. In fact, in 2008, Powerex participated in BPA's Network

[17] These provisions of the *pro-forma* OATT have been modified over time to include concepts of "open seasons" where requests for transmission service in the queue during a particular time window will be studied together ("clustered") to see if efficiencies might exist in planning an expansion of the transmission system. Bonneville Power Administration has such provisions in its tariff, which FERC found to comply with its reciprocity standards on June 13, 2008, and again on August 18, 2009.

Open Season process, i.e., a study process initiated by BPA in order to identify the infrastructure and system upgrades necessary to offset the gap between the demand for transmission capacity and BPA's capability to supply.[18] Because of the limited available capacity on BPA's transmission lines, a number of customers having placed a request for firm services had been queued.[19] Under the Network Open Season, BPA informed the queued customers that their requests for service would be removed from the queue if parties did not sign a precedent agreement for a possible system expansion[20].

39. Accordingly, Powerex signed precedent agreements requesting service from January 2009 through to 2014[21] and was eventually awarded 100 MW of Conditional Firm Service, subject to the completion of other expansion projects within the BPA system. However, to this day, service under this precedent agreement has not yet commenced and Powerex has been informed that the earliest start date has now been pushed back to January 1, 2016 (and could still be deferred to a later period).[22] Powerex' other 100 MW request from the 2008 Network Open Season is still pending.

40. The Network Open Season process was repeated in 2009 and 2010, and Powerex again submitted precedent agreements. However, on October 29, 2013 BPA notified its customers that it was unable to complete the Network Open Season process, and that it would cancel its expansion project for facilities related to the B.C. Intertie. As a result, all 2010 precedent

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[18] *See* Bonneville Power Administration, *Transmission to offer Network Open Seasons*, March 2008, available online at: < http://www.bpa.gov/news/pubs/FactSheets/fs200803-Network%20Open%20Season.pdf> **R-427.**

[19] In 2008 BPA's transmission service request queue contained 9,262 megawatts (MW) of requests for service on BPA's network. This backlog of requests made it so Bonneville was unable to process new long-term requests in a timely manner. *See* Letter from the Department of Energy to the Federal Energy Regulatory Commission, Re: Bonneville Power Administration Petition For Declaratory Order Granting Reciprocity Approval for Certain Terms and Conditions of Open Access Transmission Service, for a Waiver of Certain Existing Tariff Provisions, and for Exemption From Filing Fee in Docket No. NJ09-___-000, March 28, 2008, p. 4, available online at : <http://www.bpa.gov/transmission/CustomerInvolvement/NOS/NOS2008/Documents/Cover_Letter_and_Petition_4_2_08.pdf>, **R-428.**

[20] Parties could resubmit their requests for consideration in future open seasons.

[21] Powerex was the only customer to submit such requests from the BC-US border on BPA's transmission facilities.

[22] Letter from Bonneville Power Administration to Powerex Corp, dated November 19, 2014, **R-429.**

agreements requiring the Northern Intertie plan of service identified in the 2010 cluster study were terminated,[23] and no solution is currently being implemented in order to make more transmission capacity available on BPA's network.

41. Another transmission provider, Puget Sound Energy ("PSE") also administers transmission rights off the BC-US Border. However, the following extract from the PSE OASIS shows that there was zero capacity available in 2008, 2009 and 2010 from the BC-US Border to PSE's interconnection with BPA on a long-term firm Point-to-Point basis[24].

[redacted]

42. Mercer's witnesses introduce a number of statements or purported facts regarding the ability to move power out of British Columbia into the US on firm transmission. For instance, Mr. Friesen in rebuttal to Mr. Rosenzweig states: "From the time I began working with Celgar to broker its electricity sales until present day, there has always been firm transmission access available out of British Columbia for periods of up to twelve months"[25]. There are two nuances to this statement. First "out of British Columbia" may be referring to the BC Hydro system (i.e., from within BC to the US border), but not the BPA side of the border (i.e., the ability to move power away from the BC-US border into the US). As noted above, it takes a continuous path from the source to the point of delivery to affect the delivery of electricity at the quality of service required by the buyer. The simple reason that firm transmission capacity was available on the BC side of the border is that the US side was constrained (as

[23] Bonneville Power Administration, *Legacy Network Open Season Update*, Transmission Customer Forum 38, October 29, 2013, p. 7, available online at : <http://www.bpa.gov/transmission/CustomerInvolvement/Documents/Legacy-Network-Open-Season-Update-102913.pdf>, **R-430.**

[24] Puget Sound Energy Open Access Same-Time Information System ("OASIS") archive site taken on March 9, 2015 (screen print), **R-431.**

[25] Witness Statement of Robert Friesen, ¶ 11.

described in the preceding paragraphs) and the purchase of firm transmission service from BC Hydro did not convey any ability to move it beyond the BC Hydro system. Purchasing such service would result in fixed costs without necessarily creating the ability to utilize the service. Secondly, the phrase "up to twelve months" implies short term service (i.e., less than one year) which meant there would be gaps in the capability to deliver. As noted above, the long-term firm Point-to-Point service was fully subscribed, or zero ATC was posted.

43. Mr. Kaczmarek also introduces a graph in paragraph 75 (p. 27) of his second expert report which purports to show BC Intertie Transmission Hourly Capacity Utilization[26]. He concludes in paragraph 76 based on his review of the graph that: "As adequate transmission capacity appears to have existed for Celgar to export 40 MW of below load self-generated electricity during 2008-2009, we think it is reasonable that Celgar could secure long-term transmission capacity to export its below load electricity generation."

44. I have reviewed the exhibit NAV-124 which is the footnoted source for Figure 4 and conclude that this document does not support Mr. Kaczmarek's assertions.[27] Exhibit Nav-124 appears to be a collection of screen shots of various BPA graphs showing on a monthly basis the BC Intertie (West+East) availability and utilization rather than a worksheet actually showing the underlying data used to produce the graphic in Figure 4[28]. Regardless, it appears from the chart itself that Mr. Kaczmarek selected two data elements from the BPA graphs: the path rating, which he labels as "Capacity" and which results in the red dashed line at a value of approximately 3150 MW; and the BC CAPACITY: N to S (529994), which he labels as "Utilization" and which results in the blue line that varies substantially in value up to the 3150 MW limit.

45. Unfortunately Mr. Kaczmarek may have misunderstood what the path rating and the BC Capacity data points represented. The path rating is the upper boundary of the reliable

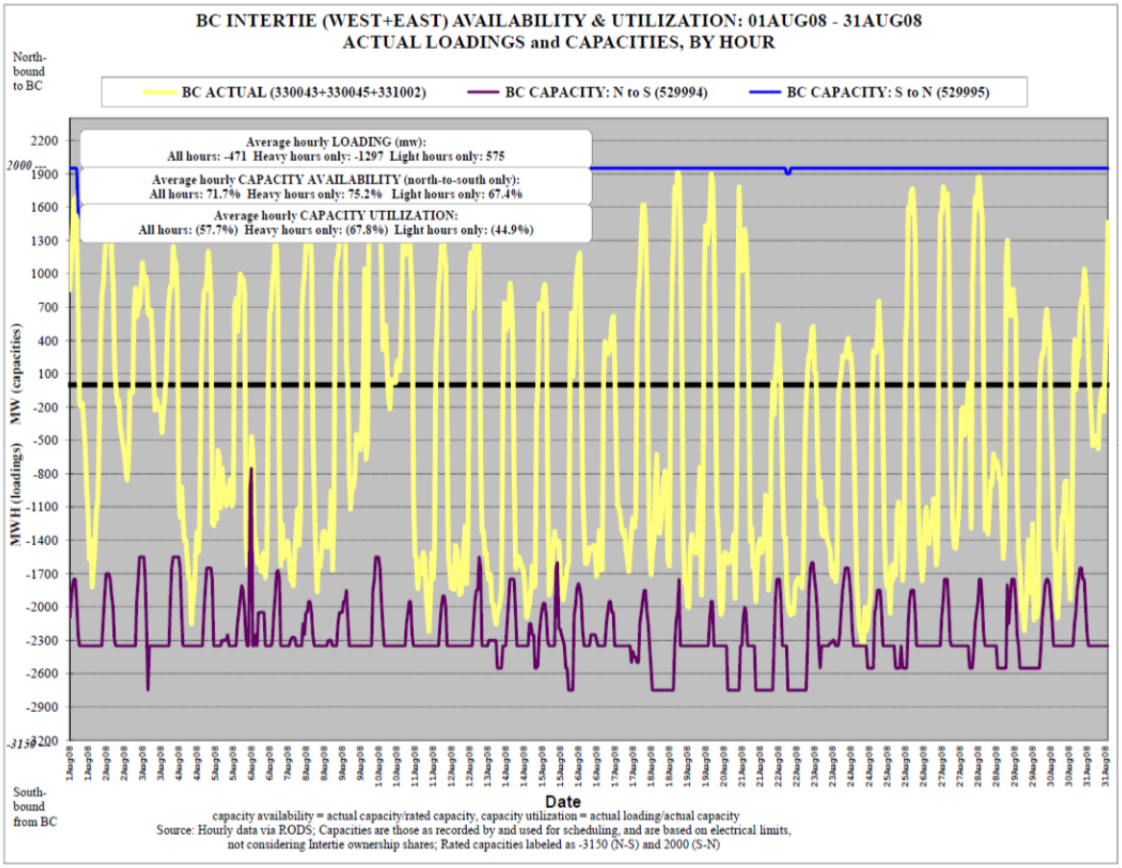
[26] Second Navigant Report, ¶ 75. Bonneville Power Administration, *Rolling 30 Days and Monthly History for Interties and Flowgates*, **NAV-124**.

[27] Second Navigant Report, footnote 79.

[28] The actual worksheets can be found on BPA's website. Bonneville Power administration, *Rolling 30 Days and Monthly History for Interties and Flowgates*, available online at: http://transmission.bpa.gov/Business/Operations/Paths/

operating limit on a particular transmission path. It is set by the Western Electric Coordinating Council for reliability purposes and takes into account the impact of flows on that path to other transmission providers in the WECC. In short, the path rating is the maximum level to which a transmission line is expected to be operated for scheduling commercial transactions. However, the actual operating limit is often much below that level depending upon the circumstances that the path operators find themselves in. The operating limit in this case is the BC Capacity value[29]. It appears Mr. Kaczmarek has simply graphed the operating limit against the path rating. What I believe Mr. Kaczmarek's graph shows is the level to which the operating capability of the path was de-rated below the WECC path limit, representing additional limitations on the ability to flow electricity from BC to the US using the Northern Intertie facilities. What Mr. Kaczmarek's graph does not show is the actual utilization, which was also provided in the BPA worksheets and is shown as the yellow line in the graphs in NAV-124 and labelled as BC Actual. The figure below is from NAV-124 and shows the month of August 2008. The yellow line illustrates the more typical utilization of the Northern Intertie facilities which show imports into BC predominantly during the evening hours and exports from BC predominantly during the daytime hours. The yellow line approaching either of the blue or purple lines shows actual flows approaching the operating limit of the facilities. The bottom of the y-axis has a value -3150, which is the WECC North to South path rating for the Northern Intertie facilities.

[29] From BPA worksheet in text denoting source: "Capacities are those as recorded by and used for scheduling, and are based on electrical limits, not considering Intertie ownership shares".



BCINTER.XLS bc rolling chart System Operations/TOON/x2964 12/16/2014

46. Notwithstanding the above clarification, even the yellow line (BC Actual) is not a good representation of what transmission capacity is available for reservation or scheduling, especially on a firm Point-to-Point basis. The reason is that the charts reflect after the fact outcomes including the actions that transmission operators take, such as setting ATC to zero and curtailing schedules, to prevent the actual flows from exceeding the operating limits. If the yellow line exceeded either of the blue or purple lines then the transmission operator would be in danger of violating a reliability limit. This chart does not reflect what transmission capacity was available on a day-ahead or hour-ahead basis to be purchased from BPA.

47. I believe Powerex' direct experience in trying to purchase long-term firm Point-to-Point transmission service from BPA via its OATT processes and the Puget OASIS information is a better representation of what long-term firm transmission capacity was available to third

parties attempting to move power from the BC-US border into the US. Based on my experience, it is highly unlikely that Celgar could have procured firm transmission rights from BPA or Puget Sound from the BC-US border into the US.

48. Another option available to acquire firm Point-to-Point transmission rights into the US would have been to seek to purchase those rights off an existing rights holder (also known as an "assignment"). However, such purchases are not subject to the tariff rates of the transmission providers but rather are made at a negotiated amount between the parties. The only parties that hold long-term firm transmission rights on the BPA system from the BC-US border are Powerex and Snohomish County public utility district[30]. As the BPA system was constrained and new transmission rights were subject to lengthy delay (if available at all), the scarcity value of the transmission would likely have been reflected in any negotiation for the sale of the transmission rights, particularly on a long term basis (if a party would consider assigning the long term right at all). Parties might have been able to agree to assignments on a shorter term basis.

49. I have also been asked to address whether non-firm Point-to-Point transmission would have provided an alternative means of access to U.S. markets during this period. In this regard, non-firm transmission rights holders have lower priority when reserving capacity and when using the transmission system. Specifically, non-firm transmission reservations may be displaced by firm reservations and the use of non-firm service must be curtailed before any curtailments to firm service occur. Further, different reservation priority levels are afforded to non-firm right holders depending on the circumstances. The priority of non-firm rights is generally ordered as follows: non-firm transmission service for Network Customers to use for purposes other than designated Network Resources; second, right holders with the longest duration of reservation; and finally, non-firm transmission over secondary points of receipt and points of delivery.[31]

50. Therefore, sporadic reservations of short-term, non-firm transmission capacity in order to enter into opportunistic hourly or daily spot sales of power is awarded one of the lowest

[30] Other parties hold rights at points south of the border, but rules regarding "redirecting" transmission service generally results in the redirected capacity becoming "non-firm".

[31] *FERC Pro Forma OATT*, section 14.7, **R-426.**

reservation priority levels under the FERC's *pro forma* OATT, including as it is applied to BC Hydro, BPA and other transmission providers in the Pacific Northwest.

51. Thus while non-firm transmission service was available in many periods, those periods generally reflected times when the value of energy in the US was lower than average. When the value of energy in the US was higher than average, then the use of transmission rights by firm rights holders would have limited the availability of non-firm ATC and that which was released would have been subject to much greater curtailment risk.

3. Transmission Costs and Line Losses

52. In accordance with the FERC's Order No. 888, open access transmission tariffs are regulated tariffs pursuant to which a utility must provide a non-discriminatory service in consideration for the payment of the appropriate transmission rate. The transmission rates are those agreed to by the utility's regulatory agency (e.g., the British Columbia Utilities Commission in the case of BC Hydro) and made public by the utility.

53. In BC Hydro's service area, the scheduled rates for long-term Point-to-Point transmission rates currently amount to approximately C$7.06/MWh,[32] and transmission losses to 6.28% on the energy delivered to the point of receipt.[33] There are discounted hourly Point-to-Point rates available, which are $3.93/MWh for Heavy Load Hours and $1.93/MWh for Light Load Hours plus the transmission losses. In BPA's service area, transmission rates applicable for a delivery at Mid-C (i.e., using the Network Segment) range from approximately

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[32] Comprised of $53,698/MW/year for Point-to-Point (Schedule 1) plus $0.102/MW for Scheduling (Schedule 3) and $0.825/MW for Reactive Control (Schedule 4). *See* BC Hydro, *Open Access Transmission Tariff, Schedule 01*, available online at : http://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/tariff-filings/open-access-transmission-tariff/schedule-01-oatt.pdf ,**R-432.** *See also Schedule 03*, available online at: http://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/tariff-filings/open-access-transmission-tariff/schedule-03-oatt.pdf, **R-433.** *See also Schedule 04*, available online at: http://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/tariff-filings/open-access-transmission-tariff/schedule-04-oatt.pdf, **R-434.**

[33] BC Hydro, *Open Access Transmission Tariff, Schedule 10, Real Power Losses*, http://transmission.bchydro.com/NR/rdonlyres/D494DA34-25D6-4238-B0A7-9630B25C98F3/0/41Schedule10.pdf, **R-435.**

US$2.38/MWh to US$5.00/MWh,[34] and transmission losses to 1.9% of the energy delivered to the point of receipt.[35]

54. The rates charged by transmission providers vary through time as rates are approved by the various regulators. In the case of BC Hydro, the pricing for the short-term Discount Rate until January 1, 2010 was designed to vary depending upon the price differential between the Mid-C and the Alberta markets.[36] The short-term firm rate was designed to capture approximately one quarter of the price differential between the two markets with a minimum rate of zero. Non-firm used the same formula less $1/MWh. As of January 1, 2010, this method was replaced by the discounted hourly Point-to-Point rates noted above. The long-term Point-to-Point rates (combination of Schedule 1, 3 & 4) also varied during this period as follows[37]:

Rate Period	Sched 1 (PTP) $/MW per hour	Sched 3 (Scheduling) $/MW per hour	Sched 4 (Reactive) $/MW per hour
Apr 1 2008 to Mar 31 2009	$5.40	$0.106	$0.825
Apr 1 2009 to Mar 31 2010	$5.70	$0.109	$0.825
Apr 1 2010 to Mar 31 2011	$5.50	$0.129	$0.825
Apr 1 2011 to Mar 31 2012	$5.85 (effect. 1 May 2011)	$0.129	$0.825

[34] *See* Bonneville Power Administration, *2014 Transmission, Ancillary, and Control Area Service Rate Schedules and General Rate Schedule Provisions (FY 2014-2015)*, noting that Reactive rates are set on a quarterly basis and not included in the quoted figures, available online at: <http://www.bpa.gov/Finance/RateInformation/RatesInfoTransmission/2014%20Transmission%20Rate%20Schedules(FINAL).pdf>, **R-436**.

[35] Bonneville Power Administration, *Open Access Transmission Tariff, Schedule 9, Real Power Loss Calculation*, p. 109, available online at: http://www.bpa.gov/transmission/Doing%20Business/Tariff/Documents/bpa_oatt.pdf, p. 109, **R-437**.

[36] *See* British Columbia Transmission Corporation, *Open Access Transmission Tariff Business Practices*, Section 3.0 Pricing Methodologies for Short Term (ST) Service, **R-438**.

[37] Transmission loss percentage did not change from the 6.28%.

55. For BPA the rates that were in effect from October 2007 until September 2011 ranged from approximately US$2.06/MW per hour for long-term Point-to-Point service to US$4.33/MW per hour for hourly service[38].

56. As discussed above, there was no new long-term Point-to-Point service available from BPA and so Celgar would have been limited to buying shorter term service such as hourly, daily, weekly or monthly service. However, in the case of services other than hourly, the buyer must pay that rate even if it chooses not to use its service in any given hour. The hourly rate on BPA is designed to reflect less than 100% utilization of the other rates. The most reasonable estimate of transmission costs from BC to Mid-C would be the short-term hourly rates of BPA and BC Hydro. If considering the Alberta market, then the short-term hourly rate of BC Hydro would be the appropriate one to consider. As an example, as of January 1, 2010 the cost to transmit power from BC to Mid-C during heavy load hours[39] would have been at around C$11.94/MW (based on C$8.26/MW (C$3.93 + C$4.33)[40] for transmission costs plus 8.18% for losses (6.26% + 1.9%) which had an approximate value of C$3.68 based on C$45 power).

57. Buyers and sellers to an energy transaction can agree, for example, to a point of delivery at the BC-US Border. In such instances, the buyer will be responsible for securing the transmission from the border to its load. In my experience, and given the limited availability of firm transmission rights from the BC-US border into the US, a US buyer will seek a discount in the purchase price for the seller's energy to at least account for the costs incurred in securing transmission on the US side of the border.

[38] As indicated, the reactive power rates varied and were set by quarter. Original documents can be found on BPA's website. Bonneville Power Administration, Rate Case, available online at: <https://www.bpa.gov/secure/Ratecase/default.aspx>.

[39] Heavy Load Hours refer to the 16 hours commencing at hour ending 7 until hour ending 10 on Monday thru Saturday.

[40] This does not include BPA's Reactive Power charge and uses C $1 = US $1 as simplifying assumption.

C. Power Sales Opportunities for Celgar in the Western US States and Other Canadian Provinces

1. Power Sales Opportunities for Celgar in the Mid-C or Alberta Market

a) Celgar's Facility

58. I understand that Celgar operates a biomass facility fuelled by black liquor and a small amount of natural gas, in Castlegar, British Columbia, with two turbine generators, one of which (52MW) achieved Commercial Operation Date ("COD") in 1993. Celgar has stated electricity from this generator could have been used to enter into market sales of power, absent the measures complained of in this arbitration. The second generator (48MW) achieved COD in 2010. I understand that Celgar wished to enter into sales of approximately 40 MW of self-generated power on the Mid-C market generated with Celgar's first (52MW) turbine generator, which achieved COD in 1993.

b) Mid-C prices 2008 to end of 2012

59. Electricity prices in the Pacific Northwest wholesale markets are highly correlated to the price of natural gas. This is because gas-fired power plants are typically the marginal suppliers of electricity, except during the spring run-off, when an overabundance of water provides for excess hydro generation (in which instances hydro-electric or coal power becomes the marginal supply).

60. Prior to around 2008, it appeared North America was running out of "conventional" natural gas. Liquefied natural gas and import terminals were constructed to facilitate the importation of natural gas to make up for an expected domestic shortfall in natural gas production. Natural gas prices in British Columbia in 2007 ranged from [redacted] MMBTU, with prices spiking in 2008 up to [redacted]>[41] In the power market, the correlation between natural gas prices and wholesale electricity prices remained strong during the bulk of the year. For instance, in March and April 2008, spot

[41] Market Data Workbook (Confidential), *Platts Spot Gas Prices (Jan1, 2002 through to March 15, 2015)*, Monthly average of daily spot prices, based on data provided by Platts, a division of McGraw Hill Financial, Inc., **R-439**. [redacted]

prices of natural gas averaged [redacted] at Sumas, providing for average peak electricity prices at Mid-C daily spot at [redacted]>[42] Sumas spot natural gas prices hit a maximum of [redacted] for June of 2008.[43] During this period of high "spot" prices, the market's perception of the forward value of electricity was also high. On June 13, 2008 forward prices of Mid-C power delivered in 2009 through 2012 during peak periods was US $91.69/MWh.[44]

61. However, over the course of 2008, prices of natural gas decreased substantially, due in part to the recession (as a function of lower natural gas demand during the recessionary period), and due in part to a technology revolution in natural gas production that brought tremendous quantities of "shale gas" to the market.[45] Very quickly, the price of natural gas fell to US [redacted] in B.C. and under [redacted] in October 2008 at Sumas,[46] bringing down the average peak price of Mid-C wholesale electricity to [redacted] the same timeframe.[47]

62. Post-2008, the costs of producing shale gas have continued to fall in North America as the recovery technology continued to improve. This brought down the price of natural gas to where it is today - around [redacted] with a corresponding electricity price at

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[42] Market Data Workbook (Confidential), *Monthly average Market Prices*, Monthly Spot Summary Sheet based on data provided by Platts, a division of McGraw Hill Financial, Inc., **R-440**.

[43] Market Data Workbook (Confidential), *Monthly average Market Prices*, Monthly Spot Summary Sheet based on data provided by Platts, a division of McGraw Hill Financial, Inc., **R-440**.

[44] Market Data Workbook (Confidential), *ICE Forward Curve*, based on data provided by Intercontinental Exchange, Inc., June 13, 2008, **R-441**. [redacted]

[45] The technology revolution was driven by improvements in both hydraulic fracturing technology ("fracking") and horizontal well drilling. These two technologies converged to allow previously known but previously uneconomical "shale" gas to be harvested economically.

[46] Market Data Workbook (Confidential), *Platts Spot Gas Prices (Jan1, 2002 through to March 15, 2015)*, Monthly average of daily spot prices, based on data provided by Platts, a division of McGraw Hill Financial, Inc., **R-439**.

[47] Market Data Workbook (Confidential), *Monthly average Market Prices*, Monthly Spot Summary Sheet based on data provided by Platts, a division of McGraw Hill Financial, Inc., **R-440**.

Mid-C of around [redacted] for peak delivery[48]. The forward power market also reflected this revolution and by the end of 2008 – forward power was worth [redacted]>[49] as opposed to [redacted] previously, in June 2008.[50]

c) Opportunities for Sales of Power based on the Mid-C Market In or Around 2008 and thereafter

63. As previously discussed, the wholesale "generic" electricity market in the Pacific Northwest is based on electricity prices at "Mid-C" and entails transactions as short as one hour to many years, depending on the needs of sellers and buyers. The ability of a seller to access the "spot" market depends on 1) generation availability 2) transmission access 3) ability to contract.

64. Celgar may have been able to access to "spot" market during the 2008 period and beyond on the available transmission (non-firm, or short term firm if it was available). However, the profitability of such sales would be contingent on the evolution of prices in this market. As indicated above, Mid-C prices decreased substantially from 2008 onward because of the financial crisis and the previously unforeseen development of the North American shale gas resources. Furthermore, given the lack of long-term firm transmission, it is not reasonable to assume that Celgar could have accessed sales in all the hours, in particular in the highest priced hours when use of the transmission system was greatest. Also without access to transmission rights away from the BC-US border into the US, Celgar would have faced a further discount to the Mid-C price to account for the US transmission cost.

65. In the event that Celgar (or its agent) would have entered into forward sales (i.e., a forward fixed-price commitment lasting for a period of at least one month and needing to be met

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[48] Market Data Workbook (Confidential), *Recent Monthly Average Market Prices,* Monthly Spot Summary Sheet based on data provided by Platts, a division of McGraw Hill Financial, Inc., **R-442**. For [redacted], *see* Market Data Workbook (Confidential), *Daily MidC Peak and Off Peak Prices,* Monthly Spot Summary Sheet based on data provided by Platts, a division of McGraw Hill Financial, Inc., **R-443**. *See also* Market Data Workbook, *Daily Peak MidC Price (by Day),* data provided by the US Energy Information Administration, **R-444**.

[49] Market Data Workbook (Confidential), *ICE Forward Curve,* based on data provided by Intercontinental Exchange, Inc., June 13, 2008, **R-441**.

[50] *See* above paragraph 60.

regardless of failures in transmission access or failures of supply) in the Mid-C forward market in 2008, it would have faced the same transmission challenges. Celgar (or its agent) would therefore have had to bear the liability for the payment of liquidated damages in case of any failure to deliver.[51]

66. It is highly unlikely that Celgar could have secured a long term sale (i.e., greater or equal to three years in length) in the Pacific Northwest based on its lack of firm transmission, its lack of any track record as a seller, its lack of experience and the weakness of its portfolio.[52] Thus it would not have accessed the high forward prices that prevailed before the 2008 steep drop in energy prices.

d) Alberta

67. In Alberta, electricity is traded in a "power pool" system created by statute,[53] the Power Pool of Alberta ("PPA"), pursuant to which energy importers compete as a price takers at the border. In other words, generators from outside the province wishing to import into Alberta must make electricity available at the border without knowing in advance the price at which their energy will be sold. Prices are determined after the fact and the system operator is responsible for reporting on the hourly pool prices and making this information available to the public.[54] Unlike most generators located within Alberta, who may offer their energy into the PPA at a specific price of their choosing, all imports to Alberta are scheduled in a fixed quantity for the hour[55]. This means that even if the PPA is showing high prices before the start of an operating hour, importers to Alberta receive the pool price as it is calculated after the fact.

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[51] Furthermore, Celgar would also have had to either have met the credit requirements of any counterparty it transacted with to undertake this sale or face a discount to its energy price if the buyer self-insured the risk of default.

[52] These are bilaterally negotiated contracts and counterparties typically have stringent credit requirements and make assessments on a parties capability to fulfill the contract over the life of the contract. The costs of insuring for default on long term contracts depends on the credit rating of the counter party and the potential exposure under the contract, which is potentially large for multi-year contracts.

[53] Alberta *Electric Utilities Act*, 2003, Chapter E-5.1 ("Alberta Electric Utilities Act"), section 18, **R-445**.

[54] *Alberta Electric Utilities Act*, section 18(4), **R-445**.

[55] There are exceptions for sales of ancillary services.

68. On occasion, the system operator reports high enough prices to induce imports. However, the prices on the power pool exhibit a high degree of volatility even within a given hour as well as between hours[56] and can range from zero to C $1000/MWh in any given hour. Annual prices also vary, averaging: [redacted] in 2008; [redacted] in 2009; [redacted] in 2010; and [redacted] in 2011. These annual averages have an underlying volatility as shown for example in 2011 where the lowest monthly average price was [redacted] in May and the highest was [redacted] in August[57].

69. Generation from B.C. and the Pacific Northwest is incented to import power to Alberta, provided generators can access the limited available transmission to the PPA. The amount of long-term firm Point-to-Point transmission sold by BC Hydro for delivery to Alberta has been in many instances greater than Alberta's ability to receive energy from B.C.[58] As a result there is very limited opportunities to sell into Alberta unless a market participant has firm transmission over the BC/Alberta border.

70. Celgar would not have been able to secure firm transmission to Alberta from BC Hydro on a continuous basis as it was fully subscribed, but Celgar could perhaps team up with a marketer that owns firm transmission rights to Alberta and avail itself of opportunities that may arise in the PPA from time to time. However, under this type of arrangement, a marketer will typically purchase electricity from the generator and use its firm transmission rights into Alberta in order to make a profit. The marketer would therefore generally choose the cheapest energy it can get in order to maximize its own margin. In order to be competitive, Celgar's energy must then be no more expensive than what it would cost the marketer to purchase the same amount of power at Mid-C (factoring in also the transmission costs on

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[56] Prices are impacted on the low end by numerous price taker (i.e., zero dollar) bids from the imports and wind facilities within Alberta, plus low marginal cost units such as coal, and on the high end by a relatively steep offer curve from dispatchable units, such as natural gas, and unit outages at the relatively large coal plants (which suddenly removed large quantities of supply from the market).

[57] Market Data Workbook (Confidential), *Monthly average Market Prices*, Monthly Spot Summary Sheet based on AESO data, **R-440**.

[58] Just as noted in the case with the BC-US intertie, the BC-AB intertie has operating limits substantially below the nominal path rating established by WECC (1200 MW), with the scheduling limit varying from 400 MW to 650 MW.

BPA's network). Therefore, in most instances, Celgar would not be able to achieve a better price than Mid-C (plus transmission), even if the Alberta price were much higher.

71. As in the case of Mid-C, it is highly unlikely that Celgar could have engaged in a forward sale into Alberta without access to firm transmission. Such transactions would entail Celgar's liability for the payment of liquidated damages in case of non-delivery, which on the Alberta market can be as high as $1000/MWh.

2. Renewable Electricity Markets in the Western US States and Other Canadian Provinces

72. As I indicated above, there two relevant markets for electricity in the Western Interconnection, namely the market for generic or wholesale power, and the market for renewable power. I have been asked to comment on the proposition that Celgar could have sold its self-generated power, otherwise used to service its own load, in the RPSs or RESs of the Pacific Northwest US states or in other Canadian provinces. For the reasons indicated below, it is highly unlikely that Celgar could have entered into such sales. Celgar's energy is most often ineligible under the different RPSs considered. Further, even if Celgar's energy was eligible, its transmission access was highly limited. Finally, even in cases where Celgar's energy might have been eligible under the RPS of some states, the opportunities for lucrative sales were unlikely to be available. The US states that have Renewable Portfolio Standards (RPS) or Renewable Energy Standards (RES) are Washington, Oregon, Montana, California, Arizona, New Mexico, Utah and Colorado, I address each of these states below.

a) Compliance markets in Western US States

i) Washington

73. Washington State is the nearest state to British Columbia and has the most proximate transmission access to Celgar. Washington State's RPS was created by the passage, in 2006, of the *Initiative* 937 enacting the *Energy Independence Act*,[59] pursuant to which large utilities

[59] *Initiative 937* (Washington), *AN ACT Relating to the requirements for new energy resources; adding a new chapter to Title 19 RCW; and prescribing penalties* ("Initiative 937 (Washington)"), **R-402**.

are required to obtain meet a small proportion (3%) of their electricity from an "eligible renewable resource" starting in 2012 and growing to 15% of load by 2020.[60]

74. The *Energy Independence Act* defined a "renewable resource" when it was enacted, in 2006, in the following manner:

> "Renewable resource" means: … biomass energy based on animal waste or solid organic fuels from wood, forest, or field residues, or dedicated energy crops <u>that do not include … black liquor by-product from paper production</u>; …[61]

75. This definition of a "renewable resource" included biomass energy but explicitly excluded black liquor from pulp mills as a form of biomass. The *Energy Independence Act* in turn defined an "eligible renewable resource" at that time as electricity from a generation facility powered by a "renewable resource" subject to a variety of conditions but most importantly:

> "Eligible renewable resource' means: (a) Electricity from a generation facility powered by a renewable resource other than fresh water that commences operation <u>after March 31, 1999,…</u>" [62]

76. The *Energy Independence Act* was subsequently amended in March 2012 to broaden the definition of "biomass energy" to include black liquor, but the definition of "eligible renewable resource" maintained, at subparagraph (a), the March 31, 1999 threshold, which Celgar's facility does not meet.[63] However, the amendment also introduced another category (at subparagraph (d)) within the definition of "eligible renewable resources" for "(q)ualified biomass energy". Therefore in certain circumstances, biomass plants that commenced

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[60] *Initiative 937 (Washington)*, Section 4, **R-402**.

[61] *Initiative 937 (Washington)*, Section 3(18), **R-402**.

[62] *Initiative 937 (Washington)*, Section 3(10), **R-402**. ("'Eligible renewable resource' means: (a) Electricity from a generation facility powered by a renewable resource other than fresh water that commences operation after March 31, 1999, where: (i) The facility is located in the Pacific Northwest; or (ii) the electricity from the facility is delivered into Washington state on a real-time basis without shaping, storage, or integration services; or (b) Incremental electricity produced as a result of efficiency improvements completed after March 31, 1999, to hydroelectric generation projects owned by a qualifying utility and located in the Pacific Northwest or to hydroelectric generation in irrigation pipes and canals located in the Pacific Northwest, where the additional generation in either case does not result in new water diversions or impoundments.")

[63] *Washington Revised Code*, Title 19, Section 285-030(12)(a), **R-447**.

operation before March 31, 1999 may be eligible under the RPS, but none of these circumstances apply to Celgar.[64]

77. In fact, "(q)ualified biomass energy" is defined to include electricity produced from biomass energy facilities that commenced operation before March 31, 1999 if these biomass facilities contribute to the load of a utility and are owned either by the qualifying utility or are directly interconnected with electricity facilities that are owned by a qualifying utility.[65] Since Celgar is located within FortisBC's service territory, it requires at least two sets of transmission rights to access the electrical facilities of qualifying utilities. Celgar is clearly not a qualifying utility[66] nor an industrial facility directly interconnected with the electrical facilities of a qualifying utility, and therefore Celgar's energy does not fit within the definition of "qualified biomass energy" that would make it an "eligible renewable resource" within the definition of the RPS, even after the 2012 amendment.

78. Further, even Celgar could somehow avoid the March 31, 1999 threshold at subparagraph (a) of the definition, its generation would be considered to be an eligible renewable resource under the Washington RPS only if its facility was located in the Pacific Northwest region[67] (which it is not) or otherwise delivering electricity to a utility in Washington on a real time basis without shaping, storage or integration services.[68]

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[64] *Washington Revised Code*, Title 19, Section 285-030(12)(d), **R-447**.

[65] *Washington Revised Code*, Title9, Section 285-030(12)(d) and (18), **R-447**.

[66] The *Energy Independence Act* defines "qualifying utility" as a utility "that serves more than twenty-five thousand customers in the state of Washington". *Washington Revised Code*, Title 19, Section 285-030(19), **R-447**.

[67] The "Pacific Northwest" is defined as having the same meaning as this term in the *Pacific Northwest Electric Power Planning and Conservation Act. See Washington Revised Code*, Title 19, Section 285-030(16). In turn, the *Pacific Northwest Electric Power Planning and Conservation Act* defines the "Pacific Northwest" to include: "(A) the area consisting of the States of Oregon, Washington, and Idaho, the portion of the State of Montana west of the Continental Divide, and such portions of the States of Nevada, Utah, and Wyoming as are within the Columbia River drainage basin; and …any contiguous areas, not in excess of seventy-five air miles from the area referred to in subparagraph (A), which are a part of the service area of a rural electric cooperative customer served by the Administrator on December 5, 1980, which has a distribution system from which it serves both within and without such region." *United States Code*, Title 16, Chapter 12H (1994 & Supp. I 1995), Section 839a(14), **R-448.**

[68] *Washington Revised Code*, Title 19, Section 285-030(12)(a), **R-447**. Furthermore, even if Celgar could pass the post-1999 commercial operation data test, to qualify for Washington's RPS, a facility must also

79. In the recent past, Powerex had entered into discussions with a Washington State utility for Powerex to potentially supply energy from a BC biomass plant that appeared to meet the definition of "eligible renewable resource", in contemplation of a sale that would be used for Washington State RPS compliance purposes. Both Powerex and the Washington State utility ultimately abandoned the negotiations when the costs and complications of a meeting the *"these facilities are located outside that region, but deliver electricity on a real time basis without shaping, storage or integration services"* requirement of an "eligible renewable resource" made it unfeasible to take the discussions through to transaction.

80. In conclusion, in order to qualify for the Washington RPS, Celgar's electricity must meet the definitions of "renewable resources" and "eligible renewable resources". Celgar's power met neither from the enactment of the *Energy Independence Act* in 2006 until its amendment in 2012 because of the black liquor restriction originally enshrined in the definition of "renewable resources" (and therefore did not fall within the category of an eligible renewable resource).[69] Further, even after the 2012 amendment, Celgar's energy did not fall within the definition of "eligible renewable resources" due to: (1) the statutory cut-off date for commencement of operations of March 31, 1999, (2) Celgar's most likely incapability of delivering power without shaping, integration or storage, and (3) the fact that it does not fit within the category of "qualified biomass energy" under this definition.

ii) Oregon

81. Oregon's RPS was created in 2007 with the passage of *Senate Bill No. 838*.[70] In accordance with this Act, electric utilities are required to include a proportion of renewable electricity as

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be located in the "Pacific Northwest" (*see* definition in footnote 67) otherwise the electricity from the facility must be delivered into Washington State on a real-time basis. That is the electricity is delivered into Washington State "without shaping, storage, or integration services". While this is technically feasible, it is costly, requires firm transmission up to the amount in question and an agreement amongst the transmission providers to notionally transfer the facility from one operator to the other via real-time telemetry and other operating procedures.

[69] In addition, under *Initiative 937*, regulated entities did not have a compliance obligation (i.e. had no need to show progress towards their statutory goals until 2012, so there would have been limited use in a regulated entity purchasing renewable energy from Celgar before 2012 (assuming all the other areas that would have made the facility ineligible did not exist.)

[70] *Senate Bill 838* (Oregon), 2007, **R-449**.

part of their portfolio.[71] However, in order to qualify under the RPS requirements, the renewable electricity used must be "generated by a facility that becomes operational on or after January 1, 1995"[72]. As indicated above, I understand that Celgar's generation assets used to generate the electricity it intends to sell in US markets became operational in 1993, and it therefore appears unlikely that its generator's output would be eligible under Oregon's RPS.

iii) Montana

82. In 2005, the legislature of Montana passed the *Montana Renewable Power Production and Rural Economic Development Act*, which put in place the state's RPS.[73] In accordance with this Act, renewable resources are eligible if they originate from a facility located within Montana or "delivering electricity from another state … that commences commercial operation after January 1, 2005".[74] The use of the word "state" logically implies another US state and would seem to exclude facilities located in British Columbia. Further, the eligibility of energy from biomass sources is limited to facilities that have a nameplate capacity of 5 megawatts or less.[75] I understand that Celgar's facility has a nameplate capacity in excess of 5 megawatts and its energy would have therefore been ineligible to the Montana RPS.

83. Further, even if Celgar had been entitled to sell its biomass-generated electricity to the Montana RPS, the value of renewable energy credits under the RPS is, in effect capped at USD $10 per MWh, which significantly reduce opportunities for profitable market sales under the RPS. The reason is that, under the *Montana Renewable Power Production and*

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[71] *Senate Bill 838* (Oregon), 2007, Sections 6 and 7, **R-449**.

[72] *Senate Bill 838* (Oregon), 2007, Section 2, **R-449**. This provision was later amended by Oregon's House Bill 3674 providing that electricity from a generating facility that uses biomass and that achieved COD before January 1, 1995 could be used for compliance with the RPS starting in 2026. However, this exception applies to biomass plants located within the State of Oregon, such that Celgar's energy would still not be eligible under the RPS. *House Bill 3674* (Oregon), 2010, Section 1, **R-450**.

[73] *Montana Code Annotated, Title 69, Chapter 3, Part 20*, available online at : http://leg.mt.gov/bills/mca_toc/69_3_20.htm ("Montana Code Annotated"), **R-451**.

[74] *Montana Code Annotated*, Section 69-3-2003(10), **R-451**.

[75] *Montana Code Annotated*, Section 69-3-2003(10)(g), **R-451**.

Rural Economic Development Act, utilities are held to a penalty of US $10 per every MWh of power they should have procured, but failed to do so, under the RPS.[76]

iv) California

84. In 2002, *Senate Bill No. 1078* [77] created California's RPS, requiring investor-owned utilities to procure 20% renewable energy by 2017. Senate Bill 1078 included a provision requiring local, publicly owned utilities to "be responsible for implementing and enforcing a renewables portfolio standard that recognizes the intent of the Legislature to encourage renewable resources, while taking into consideration the effect of the standard on rates, reliability, and financial resources and the goal of environmental improvement." In 2006, the legislature passed *Senate Bill No. 107*,[78] which accelerated the implementation of the RPS.[79] *Senate Bill No. 107* amended a number of existing statutes concerning the generation of renewable energy so that the proportion of renewable energy procured by California investor-owned utilities on a yearly basis would increase to 20% by December 31, 2010.[80] Senate Bill No 107 also added strict limitations on the criteria for renewable energy resources to qualify as "eligible renewable resources". On December 10, 2011 Senate Bill 2(X1) further expanded the scope and stringency of California's RPS by increasing the renewable requirement for all load serving entities to 33% of total load by 2020. Most pertinent to this matter is California's Renewable Portfolio Standard under SB 107.

85. In accordance with *Senate Bill No. 107*, biomass facilities with a COD after January 1, 2005 (and meeting certain other criteria) may be certified as Eligible Renewable Resources.[81] The California Energy Commission is charged with certifying eligible facilities as eligible for the

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[76] *Montana Code Annotated,* Section 69-3-2004(10), **R-451**.

[77] *Senate Bill No. 1078* (California), 2002, available online: <http://www.energy.ca.gov/portfolio/documents/documents/SB1078.PDF>, **R-452**.

[78] *Senate Bill No. 107* (California), 2006, available online: <http://www.energy.ca.gov/portfolio/documents/documents/sb_107_bill_20060926_chaptered.pdf> ("Senate Bill No. 107 (California)"), Legislative Counsel's Digest, **R-453**.

[79] *California Public Utilities Commission*, "RPS Program Overview", available online: <http://www.cpuc.ca.gov/PUC/energy/Renewables/overview.htm>, **R-454**.

[80] *Senate Bill No. 107* (California), 2006, Section 2, **R-453**.

[81] *Senate Bill No. 107 (California),* Section 3, **R-453**. The COD limitation may be waived if the electricity is an expansion/repowering or part of the existing baseline of a retail seller.

California's RPS and maintains a list of all applicants for such eligibility status.[82] I understand that only two Canadian biomass facilities have ever applied: Canfor's pulp and paper mill in Prince George, British Columbia (COD May 12, 2005), and Mustus Energy Limited's MEL1 biomass power plant in La Crête, Alberta (COD July 1, 2011).[83] The 1993 COD Celgar facility pre-dates the Jan 1, 2005 eligibility threshold and consequently it is highly unlikely that the facility would have been certified an "eligible renewable resource."

86. While the law purports to include out-of-country plants as potentially eligible renewable energy facilities,[84] in practice it is exceedingly difficult to gain such eligibility status for biomass facilities located outside of the US. In fact, all out-of-country facilities with any emissions bear a high burden in demonstrating their eligibility under California's RPS due to the complexity of demonstrating that they are "developed and operated in a manner that is as protective of the environment as a similar facility located in the state."[85] Powerex is very familiar with the CEC Certification process having taken three British Columbia wind facilities through to successful certification. Of the two biomass facilities mentioned above, Canfor's pulp and paper mill and Mustus Energy Limited's MEL1 biomass power plant, the former withdrew its application, and the latter's was disapproved.[86]

87. It is possible that a local publicly owned utility may have contracted for a facility that was not certified by the California Energy Commission as an Eligible Renewable Resource. Prior to the passage of SB 2 (X1) in 2011, local publically owned utilities had been charged with

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[82] *Senate Bill No. 107 (California)*, Section 15, **R-453**.

[83] California Energy Commission, *Renewables Portfolio Standard (RPS) Certification*, available online: http://www.energy.ca.gov/portfolio/documents/rps_certification.html, **R-455**. California Energy Commission, *California's Renewable Portfolio Standard (RPS) List of Facilities*, available online: http://www.energy.ca.gov/portfolio/documents/List_RPS_CERT.pdf ("California Energy Commission, RPS List of Facilities"), Entries No. 61053A and 60986C, Commercial Operation Dates from CEC posted Certification Status list, **R-456**.

[84] *Senate Bill No. 107 (California)*, Section 3, **R-453**.

[85] Out-of-country facilities must demonstrate consistency with California environmental quality laws, ordinances, regulations, and standards (collectively referred to as "LORS") regarding: Cultural Resources; Land Use; Traffic and Transportation; Visual Resources; Air Quality; Public Health; Hazardous Materials Handling; Waste Management; Biological Resources; Water Resources; Agriculture and Soil; Paleontological Resources; Geological Hazards and Resources; Transmission System Safety and Nuisance; and Noise.

[86] California Energy Commission, RPS List of Facilities, Entries No. 61053A and 60986C, **R-456**.

"implementing and enforcing a renewables portfolio standard that recognizes the intent of the Legislature to encourage renewable resources, while taking into consideration the effect of the standard on rates, reliability, and financial resources and the goal of environmental improvement."

88. An example of a publicly owned utility that adopted an eligible resource standard as restrictive as that required of the IOU's is the Sacramento Municipal Utility District(SMUD), the largest publicly owned utility in Northern California. In its October 2008 "Resources Eligibility Guidebook" it states:

> Out-of-State Facilities : Generation facilities are considered out of state if their first point of interconnection to the WECC transmission system is outside of the state. Only those out-of-state facilities which connect to the transmission network within the geographic area serviced by the WECC and which are scheduled for consumption by California end-use retail customers are eligible for SMUD's RPS. To be eligible, the renewable energy facility must have <u>commenced initial commercial operation on or after January 1, 2005</u>.[87]

89. It is unclear how many publicly owned utilities adopted a lesser standard than the California Energy Commission's standard for Eligible Renewable Resources while still complying with the "intent" of SB107. Further, in 2011, SB 2 (X1) repealed the provision pursuant to which the governing bodies of local, publicly owned utilities were responsible for implementing and enforcing their own renewable portfolio standards.[88] Therefore, since 2011, all utilities in California are subject to either CPUC or California Energy Commission oversight for the enforcement of the RPS.

90. Further, even if Celgar's electricity might have been eligible for renewable sales, Celgar would have been required to secure the transmission rights from its plant to California. However, transmitting power from British Columbia to California entails having recourse to

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[87] Emphasis added. Sacramento Municipal Utility District (SMUD), *Renewable Energy Resources Eligibility Guidebook*, pp. 9-10, available online: https://www.smud.org/en/about-smud/environment/renewable-energy/documents/SMUD%20RPS%20Guidebook%20-%20FINAL-1.pdf, **R-457**. SMUD's guidebook offers limited exemptions to this requirement for a repowering of the facility after Jan 1, 2005 and for a facility that is already selling its output to a California load.

[88] *Senate Bill No. 2* (California), 2011, available online: http://www.leginfo.ca.gov/pub/11-12/bill/sen/sb_0001-0050/sbx1_2_bill_20110412_chaptered.html, Section 12**, R-458**.

four different transmission lines, including BC Hydro's and BPA's transmission networks in order to bring Celgar's power across the Canadian-US border, which, as indicated above, was highly constrained in the relevant time frame.[89] After securing BC Hydro transmission to the BC/US Border, further transmission would be required on two additional paths, (i.e., the primary route would be 1) BPA transmission from the BC/US Border to John Day, and 2) BPA transmission from John Day to the California Oregon Border. The last leg of transmission from the California Oregon Border to inside California would typically be arranged by the utility buyer. It is highly unlikely that the required transmission could have been sustained over continuous periods of time booking non-firm transmission. Further, in my experience, utilities purchasing renewable power seek assurances from the seller that its power will be delivered on a constant and reliable basis, which Celgar could have hardly done without the proper transmission access rights.

v) Arizona

91. The State of Arizona's Renewable Energy Standard ("RES") was created by the *Arizona Administrative Code* in 2007.[90] A utility may use bundled renewable energy acquired in any year to meet its annual requirement. With very limited exceptions for hydropower[91], facilities commissioned before January 1, 1997, are not eligible. Energy produced by eligible renewable-energy systems must be deliverable to the state.

92. The State of Arizona is over 1400 km from the Celgar facility and would require at least five independent sets of transmission rights to access Arizona load.[92]

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[89] *See* Section B.2 above.

[90] *Arizona Administrative Code*, "Renewable Energy Standard and Tariff", Title 14, Chapter 2, Article 18, available online: http://www.azsos.gov/public_services/Title_14/14-02.htm#ARTICLE_18 ("*Arizona Administrative Code*"), **R-459**.

[91] *Arizona Administrative Code*, Section R14-2-1802, **R-459**.

[92] One in BC Hydro's service area (from the point of receipt to the BC/US Border), two in BPA's service area (first from the BC/US border to the Big Eddy substation, and second from the Bid Eddy substation to the Nevada/Oregon border), one on the Los Angeles Department of Water and Power's transmission network (from the Nevada/Oregon border to Palo Verde), and then one of the many Arizona transmission paths within Arizona to load.

vi) Colorado, New Mexico and Nevada

93. Colorado has a renewable energy standard that in theory permits generation (including biomass) to be located anywhere in WECC. However, Colorado assigns a 25% premium to renewable electricity generated in-state, thus providing a very strong disincentive to import renewable energy.

94. New Mexico defines renewable energy as electric energy generated by low- or zero-emissions generation technology with substantial long-term production potential; solar; wind; biomass; geothermal; hydropower facilities brought in service after July 1, 2007.

95. Nevada has an RPS that allows for the use of biomass for compliance. However, solar generation receives a multiplier of at least 2.4 times for the purposes of calculating compliance. In addition, it is highly unlikely that Celgar would have been able to transmit its electricity to these states, even if its electricity was eligible under their RPSs with distances and transmission requirements similar to those required to deliver into Arizona's Renewable Energy Standard.

vii) Idaho, Wyoming and Utah

96. There are no compliance markets for renewable power in Idaho or Wyoming and therefore no substantial opportunities exist for a biomass facility from British Columbia to engage in green power sales in these states. Utah has implemented a renewable portfolio "goal", but unlike statutory RPSs, this program does not provide for utilities to imperatively comply with given standards of renewable power procurement. In particular, the US Department of Energy Database of State Incentives for Renewables & Efficiency indicates, in relation to Utah, that: "(w)hile this law contains some provisions similar to those found in renewable portfolio standards (RPSs) adopted by other states, certain other provisions in S.B. 202 indicate that this law is more accurately described as a renewable portfolio goal (RPG)". Specifically, the law requires that utilities only need to pursue renewable energy to the extent that it is "cost-effective" to do so. The guidelines for determining the cost-effectiveness of acquiring an energy source include an assessment of whether acquisition of the resource will result in the delivery of electricity at the lowest reasonable cost, as well as an assessment of

long-term and short-term impacts, risks, reliability, financial impacts on the affected utility, and other factors determined by the Utah Public Service Commission (PSC)".[93] This requirement therefore limits the lucrative opportunities that could otherwise exist for a BC-based electricity generator to enter into profitable power sales in Utah under this renewable energy goal.

viii) Alberta

97. The Province of Alberta does not have a Renewable Portfolio Standard or Renewable Energy Standard. A variety of retail entities procure unbundled RECs for use in Alberta. I believe that the unbundled REC market would have been available to Celgar independent of access issues for Celgar's generated electricity.

98. The Province of Alberta regulates the large greenhouse gases emitters under Alberta's Specified Gas Emitters Regulation[94]. This Regulation allows certain types of renewable energy to be considered an offset for compliance purposes under the Regulation. Section 7(1) of the Regulation states:

> 7(1) The following requirements must be met in order for a reduction in specified gas emissions to constitute one or more emission offsets: (a) the specified gas emissions reduction must occur in Alberta;[95]

99. Thus, the energy as generated by Celgar in B.C. would not be eligible under any offset protocol in Alberta even if its energy had been delivered into Alberta and as a result, would have been unlikely to garner any premium over and above the Alberta Pool Price.

ix) Ontario and Quebec

100. I have been asked to comment on the proposition that Celgar may have entered into power sales in the Canadian provinces of Ontario and Quebec. I believe it to be highly

[93] US Department of Energy, Renewables Porfolio Goal, Program Info, Utah, <http://energy.gov/savings/renewables-portfolio-goal>, **R-460**.

[94] Alberta *Specified Gas Emitters Regulation*, 2007, Alberta Regulation 139/2007, available online at: <http://www.qp.alberta.ca/documents/Regs/2007_139.pdf> ("Alberta Regulation 139/2007"), **R-461**.

[95] Alberta Regulation 139/2007, Section 7(1), **R-461**.

unlikely that Celgar could have entered into profitable sales of power on such markets in light of the transmission difficulties that such an endeavour entails. Wheeling power from British Columbia to Ontario and/or Québec, while in principle feasible, is prohibitively expensive and requires pulling together a complex transmission path comprising many transmission providers, including the Alberta Electric System Operator, SaskPower, Manitoba Hydro, Hydro One, and – in the case of power sales in Québec – Hydro Québec. Such a path would require Celgar and/or its marketer to have credit with all the transmission providers and to pay the transmission costs and incur the line losses in connection with the use of each service provider's network. I have substantial doubts that such sales (for generic energy or bundled renewable energy) could have been made and delivered upon in any material way. If Celgar had managed to find a buyer that did not require transmission access for an eligible sale (i.e. an unbundled REC) then those sales would likely already have been available to Celgar.

101. I affirm that the information provided above is true and correct.

SWORN BEFORE ME at the City of Vancouver, in the Province of British Columbia, this 21 day of March, 2015.	)))))	
A Commissioner for taking Affidavits for British Columbia.	))	Michael MacDougall

JAY RATZLAFF, LAWYER