IN PROCEEDINGS BEFORE THE ONTARIO ENERGY BOARD

EB-2012-0451 (EGD – GTA Project)

EB-2012-0433 (Union – Parkway West)

EB-2013-0074 (Union – Brantford-Kirkwall/Parkway D)

SUBMISSIONS of THE COUNCIL OF CANADIANS

November 15, 2013

PART I - OVERVIEW

The Council of Canadians (the "Council")

The Council was founded in 1985 and has, since that time, been primarily sustained by volunteer energy and financial contributions from its members. Those members reside in every province and territory, and more than 26,000 of them live in Ontario where many participate in one of the 17 local Ontario chapters of the Council.[1]

Since its inception, much of the Council's work has focused on the eroding capacity of governments to perform effectively as regulators, service providers (including energy services) and stewards of natural resources, including energy and water. The Council's work is focused on a few key areas which it considers to be of strategic importance, and one of these is energy use and policy.

In this regard, a primary commitment of the Council is the promotion of a "made in Canada" energy security strategy that is consistent with meeting climate change and other environmental imperatives and respecting First Nation rights.

The Council has participated previously in proceedings before the OEB, including the IPSP, and the Natural Gas Market Review. In the latter, it introduced expert evidence concerning the impact of natural gas extraction from shale gas formations.

The Purpose of the Council's Intervention

[1] Application to Intervene in these proceedings.

The Council intervened in these proceedings (the Enbridge GTA & Union Parkway Projects, or the "Applications") for the purpose of providing assistance to the Board with respect to issues concerning the need for the proposed facilities, the appropriateness of project costs, and the energy efficiency and conservation alternatives to the proposed facilities. The particular focus of its intervention has been to illuminate the risks associated with increasing the reliance of Ontario consumers on natural gas derived from shale reserves in the United States.

It is common ground that the North American energy economy is being transformed by technological innovations that have provided access to largely untapped reservoirs of natural gas. These developments have dramatically reduced the price of natural gas, and have led to proposals to restructure the natural gas infrastructure of both Canada and the U.S.

As described by Union Gas Limited ("Union"), technological advancement in horizontal well drilling and hydraulic fracturing ("fracking") "has resulted in a fundamental change in North American natural gas supply dynamics and a shift in market behavior. These changes have taken place very quickly, primarily within the last 5 to 6 years."[2]

While mature production from conventional sources of natural gas is declining, there has been prolific growth in emerging gas supplies from shale gas formations in the U.S. According to the Congressional Research Service report "Natural Gas in the U.S. Economy: Opportunities for Growth", dated November 6, 2012, shale gas has increased from 10% of U.S. natural gas reserves in 2007 to about 32% in 2010.[3]

Union also describes the particular importance of shale gas reserves in the U.S. northeast.

> One of the most prolific gas supply growth areas in North America has been in the Appalachian basin. Appalachian shale gas is produced mainly from the Marcellus in Pennsylvania, Ohio and West Virginia and more recently from the Utica in eastern Ohio and eastern Pennsylvania. Marcellus shale gas production alone has increased nearly 7 Bcf/d since the beginning of 2007 and has been widely described as "the game changer".[4]

As the evidence in these proceedings demonstrates, shale gas development is fundamentally transforming supply relationships and systems that have endured for many decades and served Ontario consumers well. The result has been a "paradigm shift in natural gas supply [with] dramatic impacts to North America's pipeline infrastructure system [that] will continue to drive changes in Ontario's energy landscape."[5]

[2] EB-2012-0433 SCHEDULE B UPDATED Page 2 of 3, Adobe 7/392
[3] Ibid., 2013-01-29 EB-2012-0433 Page 26 of 121, Adobe 38/392
[4] Ibid., Page 27 of 121, Adobe 39/392
[5] Ibid., Page 30 of 121, Adobe 42/392

The proximity of U.S. Northeastern shale gas reserves and attendant transportation cost savings have driven Canadian demand for greater access to the Marcellus and other U.S. shale gas reserves. However, there are two inherent supply risks associated with the present applications. The first arises from questions about the reliability and cost of shale gas supply from U.S. sources; the second, from the potential adverse impact of the projects on future access to gas supply from the Western Canadian Sedimentary Basin ("WCSB"), whether from conventional or non-conventional sources.

These risks bear directly upon the issues of these proceedings, and in particular those concerning the need for, and alternatives to, the Applications. They also bear upon several of the Board's objectives with respect to natural gas, including those concerning the price and reliability of gas service, the rational expansion of transmission and distribution systems, and the promotion of energy conservation and energy efficiency.

The Council submits that the Applications fail to properly address these risks. Accordingly, for the purpose of assisting the Board, it retained three experts to assess the availability and cost of natural gas supply from shale reserves in general, and from the Marcellus and Utica shale deposits in particular.

The Council's Expert Evidence

Mr. David Hughes

> Mr. Hughes is a geoscientist with decades of experience in the area of energy resource assessment. Over the past decade, he has published and lectured widely on global energy and sustainability issues in North America and internationally. A particular area of focus has been on shale gas, tight oil, coalbed methane and considerations for long term energy security and sustainability.
>
> The Board accepted Mr. Hughes as qualified to give expert evidence with respect to the matter of energy resource assessment concerning the potential contribution of unconventional energy resources such as shale gas and tight oil to North America's energy supply.[6]
>
> Mr. Hughes' evidence is comprised of a report he prepared for these proceedings,[7] responses to interrogatories from the Applicants,[8] and his *viva voce* testimony before the

[6] Transcript Volume 8, October 9, 2013, p. 10.
[7] Exhibit L, EGD, COC.3 (filed in all three applications.)
[8] Exhibits M. COC. EGD.1, M.COC.UGL.1

Board.[9] This evidence addresses supply risks associated with reliance upon U.S. shale gas.

Ms. Lisa Sumi

Ms. Sumi is an environmental consultant who has, over the past 15 years, specialized in the analysis of regulatory and policy measures related to energy and extractive industries including hard rock minerals, coal tar sands, natural gas and oil. Her work investigating links between shale gas development and health impacts has been published and peer reviewed.[10]

The Board accepted Ms. Sumi's qualifications as an expert on the question of U.S. regulatory policy as it applies to shale gas development.

Ms Sumi's evidence is comprised of a report she prepared for these proceedings, [11] responses to interrogatories from the Applicants,[12] and her *viva voce* testimony before the Board.[13] This evidence addresses regulatory risks, and attendant costs, associated with reliance upon US shale gas.

Professor Anthony R. Ingraffea, PhD, PE

Professor Ingraffea is the Dwight C. Baum Professor in Engineering and serves on the faculty of the School of Civil and Environmental Engineering at Cornell University. His research concentrates on computer simulation and physical testing of complex fracturing processes including hydraulic fracturing. Together with his co-authors, Professor Ingraffea has published seminal and peer reviewed reports concerning the greenhouse gas footprint of shale gas development.

The Board accepted Professor Ingraffea's qualifications as an expert with respect to the recovery of natural gas from high-volume fracturing from shale formations and the assessment of methane emissions and the related greenhouse gas footprint from the development, transportation and use of natural gas derived from these sources.[14]

[9] Transcript Volume 8, October 9, 2013, 4-25
[10] Transcript Volume 8, October 9, 2013, p. 13
[11] Exhibit. L. UGL.COC.2, (filed in all three applcations)
[12] Exhibits M. COC. EGD.1, M.COC.UGL.1
[13] Transcript Volume 8, October 9, 2013, 4-25
[14] Transcript of Proceedings Vol 8, October 9, 2013, at p. 7.

Professor Ingraffea's evidence is comprised of a report he prepared for these proceedings,[15] responses to interrogatories from the Applicants,[16] and his *viva voce* testimony before the Board.[17] This evidence addresses regulatory risks, and attendant costs, associated with reliance upon U.S. shale gas.

The Position of the Interveners

For reasons set out below, it is the Council's submission that:

Supply and Price Risks in Respect of U.S. Shale Gas

1. There are significant supply risks associated with the Marcellus, Utica and shale gas resources that are expected to supply the pipeline infrastructure the Applicants have proposed. These risks arise from i) overly optimistic supply projections in respect of these sources; ii) a failure to consider competing demand for this gas; and iii) the risk that regulatory measures will significantly reduce the availability and the raise the costs of shale gas that does remain available.

2. The over-estimation of shale gas supply reflects a failure to acknowledge the fall-off in overall well productivity and field production that occurs within a half decade of the development of a particular shale play.[18] It also reflects a failure to account for the fact that shale plays are not homogenous, but have relatively small areas of high productivity.

3. There are also significant regulatory risk in respect of U.S. shale gas supply that arises from the large gap that now exists between the environmental impacts of shale gas production and the establishment of measures to mitigate those impacts. As governments act to require the industry to protect groundwater, improve air quality, adopt responsible waste management practices and curtail greenhouse gas measures, the cost of shale gas is likely to rise, significantly. At one end of this continuum, certain reserves may become too expensive to develop while others are put or kept off limits by governments unwilling to take the risks that fracking presents.

4. The uncontroverted evidence of Ms. Sumi is that until significant regulatory measures are put in place, the extraction of shale gas from the Marcellus and Utica shales will

[15] Exhibit L, EGD, COC.1 (filed in all three applications.)
[16] Exhibits M. COC. EGD.1, M.COC.UGL.1
[17] Transcript of Proceedings Vol 8, October 9, 2013, at pp. 4-25.
[18] A "Play" is a term commonly used in the oil and gas industry for production from a common reservoir in a restricted geographic area from one or more fields.

adversely impact the environment, including groundwater, air quality and public health. According to Professor Ingraffea, it will also result in substantial greenhouse gas emissions.

5. The Applicants have failed to properly assess these risks and have accordingly overestimated the benefits to be derived from their proposed projects, while understating their potential adverse impacts on the reliability and cost of gas service to Ontario consumers.

<u>Supply Risks in Respect of the TransCanada Mainline</u>

6. The proposed projects will exacerbate factors that have already dramatically reduced the demand for services on the TransCanada mainline, and therefore put further at risk the long term availability of that pipeline to serve Ontario and Quebec. The TCPL mainline is certainly the most reliable conduit for eastern Canadians to access western Canadian gas supply, which, for at least the immediate future, is largely derived from conventional sources.

<u>The Failure to Properly Assess These Risks</u>

7. A proper consideration of these supply and price risks underscores the importance of thoroughly assessing the potential for conservation and efficiency measures to provide an alternative to some or all of the elements of the proposed system expansion. For reasons set out in the submissions of the Green Energy Coalition and Environmental Defense, we that assessment has yet to be carried out.

8. Given the imperatives of confronting climate change, and in the face of Ontario policy that commits the province to a dramatic reduction in greenhouse gas emissions, it is important and appropriate for the Board to take into account the greenhouse gas footprint of the natural gas that is expected to flow in even greater volumes into Ontario markets. It is not unprecedented for a Canadian regulator to consider such ‘upstream’ impacts, and U.S. regulators adopted the approach by taking into account such impacts associated with the Keystone XL pipeline project.

9. Therefore, in addition to the supply and price risks associated with greenhouse gas emissions from shale gas, the Board should also have regard to the contradiction between Ontario’s commitment to reducing GHG emissions and Applications that will increase the reliance of provincial consumers on an energy source that has a disproportionately high and unregulated greenhouse gas footprint. This factor also militates in favour of requiring an more assiduous assessment of efficiency and conservation than has been

undertaken by the Applicants.

10. In light of the supply and price risks engendered by the proposed projects, and the failure of the proponents to assess the potential role that efficiency and conservation measures can play in meeting system requirements, the Applications should be denied.

PART 2 Supply Risk – US SHALE GAS

2.1 VOLUME

The Role of US Shale Gas Supply

It is clear that providing access to currently abundant supplies of natural gas extracted from shale deposits in the US is a central rationale of the Applications. While presented in terms of creating more supply diversity, it is clear that greater access to gas from the Marcellus shale deposit is the principal objective of increasing the flow of gas across the US border. There are no less than 78 references to the Marcellus shale gas reserve in Union's updated application of this past July, and 36 more to the Utica Shale.

Gaz Metro explains why greater access to the Dawn Hub at the US border matters:

> Having a greater access to Dawn is important to Gaz Métro for two main reasons. First, Dawn is located closer to its service territory and second, it provides a greater security and diversity of supply to Gaz Métro' customers as it connects directly with the Marcellus and Utica productions. [19]

It is true that the Dawn Hub provides access to diverse sources of natural gas but all of the projected increase in North American supply is to come to shale deposits, and none is larger or closer than the Marcellus shale.

Are Price and Supply Projections for US Shale Gas Reliable?

As noted, the natural gas supply picture has recently changed dramatically with the development of multi-stage hydraulic-fracturing of horizontal wells capable of producing natural gas from previously inaccessible impermeable shales.

As Mr. Hughes relates, "shale gas has gone from representing approximately two percent of U.S. natural gas production a decade ago to nearly 40 percent in 2012. Projections from organizations such as the Energy Information Administration (EIA) are for shale gas production to double from 2010 levels and make up half of a greatly expanded natural gas supply by 2040, at which time the EIA projects that over ten percent of U.S. natural gas production will be available for export."[20]

In its "Annual Energy Outlook 2012", the EIA indicates that the largest contributor to natural gas production growth in the United States will be shale gas for the next two and a half decades. Specifically, the EIA expects gas production in the US Northeast to increase from about 1.5 tcf

[19] Exhibit L.EGB.SCGM.1, Page 11 of 16

[20] Exhibit L.EGD,COC,3 (Filed in all three applications) Adobe p. 2/14. Energy Information Administration, 2013, Annual Energy Outlook 2013, http://www.eia.gov/forecasts/aeo/ .

(4.2 bcf/d) in 2010 to approximately 5.4 tcf (14.7 bcf/d) in 2035. Marcellus production is expected to account for roughly 3.0 tcf (8.2 bcf/d) of this projected production increase. Furthermore, the EIA is projecting production growth, relative to other natural gas production regions in the U.S., to be greatest for the Northeast region.

However, a detailed assessment of production characteristics of shale gas plays in the U.S. indicates that the supply projections of the EIA are unlikely to be realized, and as Mr. Hughes concludes, natural gas prices in the medium to long-term will be need to be much higher than at present, and much higher than EIA projections, if production levels are to be maintained.[21]/[22] According to Mr. Hughes' uncontroverted evidence on production figures from shale gas plays, these characteristics include:

- High well decline rates, ranging from 77%-89% over three years with an average of 84%. This necessitates high levels of drilling and capital expenditure even to maintain production.

- Overall field declines ranging from 28%-47% each year, which must be replaced by more drilling just to keep production flat. The annual capital expenditure to do this as of mid-2012 is estimated at $42 billion.[23] This amounts to a drilling treadmill.

- The fact that all shale plays have relatively small, high productivity, "sweet spots", which are drilled first and provide the lowest cost natural gas. These sweet spots have been nearly exhausted in plays older than about five years. This means that drilling to replace field declines must move into progressively lower productivity portions of the reservoir requiring even more wells to maintain production as a play matures.

These factors account for the fact that four of the five shale gas plays that comprise 80% of shale gas production in the U.S., are in or near decline. The Marcellus continues to grow, but is a relatively new play and is likely to follow the pattern of declining production after maturity observable in other shale gas plays.[24]

This evidence strongly suggests that U.S. supply growth assumptions made by Enbridge[25] and Union Gas[26] are overly optimistic at the natural gas prices assumed.

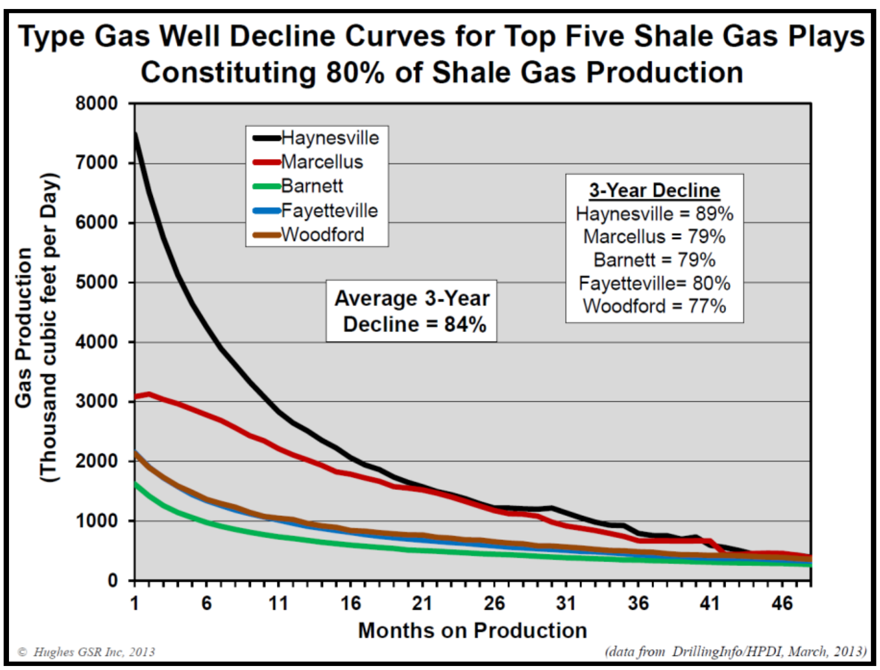
[21] Exhibit L.EGD,COC,, Adobe p. 2-3/14. Hughes, J.D., 2013, A Reality Check on the Shale Revolution, Nature, Volume 494, p 307-308.
[22] Exhibit L.EGD,COC,3 Adobe p. 2/14 Hughes, J.D., 2013, Drill Baby Drill: Can Unconventional Fuels Usher in a New Era of Energy Abundance?, Post Carbon Institute, 166 pages, http://www.postcarbon.org/reports/DBD-report-FINAL.pdf .
[23] Ibid.
[24] Ibid.
[25] Ibid. – and see Exhibit A, Tab 3, Schedule 5, Paragraph 31, in Enbridge application
[26] Ibid. and see EB-2012-0433, Section 23, pages 27-28 of 121 in Union application

On the supply side, given the nature and life cycle of shale plays explained above, the price of natural gas required to maintain production is likely to be considerably higher over the medium- and longer-term than that commonly assumed.[27] Moreover, as discussed below, the environmental impacts of shale gas production are becoming an increasingly high-profile public concern, and are likely to lead to greater regulation of the industry, which in turn will generate further price pressures.

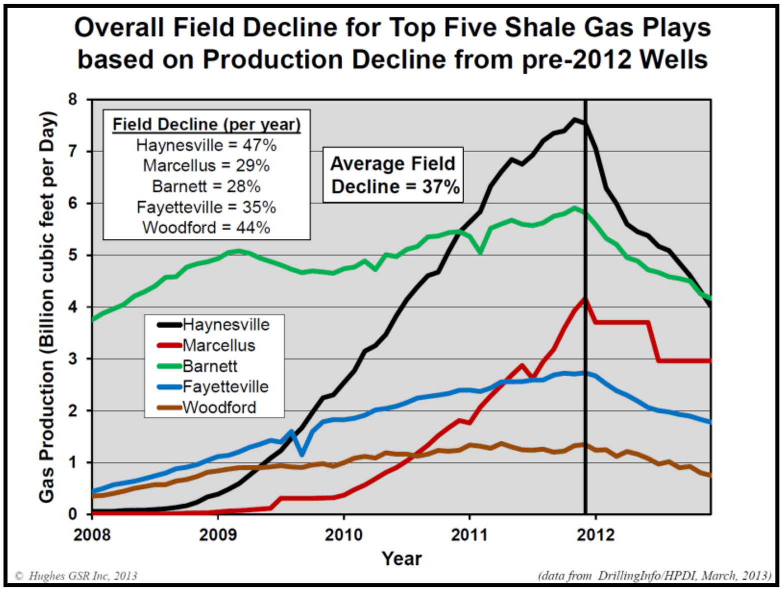
On the demand side, the U.S. is considering LNG exports of natural gas, based on projections of future growth in shale gas production, although it is currently a net natural gas importer. Furthermore, considerable amounts of new domestic U.S. natural gas demand have arisen due to the recent low prices (coal-to-gas switching, petrochemicals, etc.). U.S. LNG exports and rising domestic consumption will put further upward pressure on prices, including prices of exports to Canada.[28]

Explaining Production Decline From U.S. Shale Plays

A considerable number of interrogatories were put to Mr. Hughes by both Enbridge and Union. None questioned the validity of his description of the decline in production from four of the five major shale plays in U.S. as shown in Figures 1 and 2 of his evidence, which are reproduced here.[29]



[27] Ibid., Adobe p.13/14. Energy Information Administration, 2013, Annual Energy Outlook 2013, http://www.eia.gov/forecasts/aeo/ .
[28] Exhibit L.EGD. COC.3, Adobe p. 12/13
[29] Ibid., Adobe pp. 3 and 4/13



<u>The Role of Technological Innovation</u>

Rather than challenge the validity of this description of production decline, Union interrogatories probed alternative explanations for why this might be taking place. Thus, Union questioned the impact of technology improvement on shale gas production as follows:

Reference:

Exhibit L.EGD.COC.3 Page 2: "Four of five shale gas plays comprising 80% of Shale gas production in the U.S. are in or near decline."

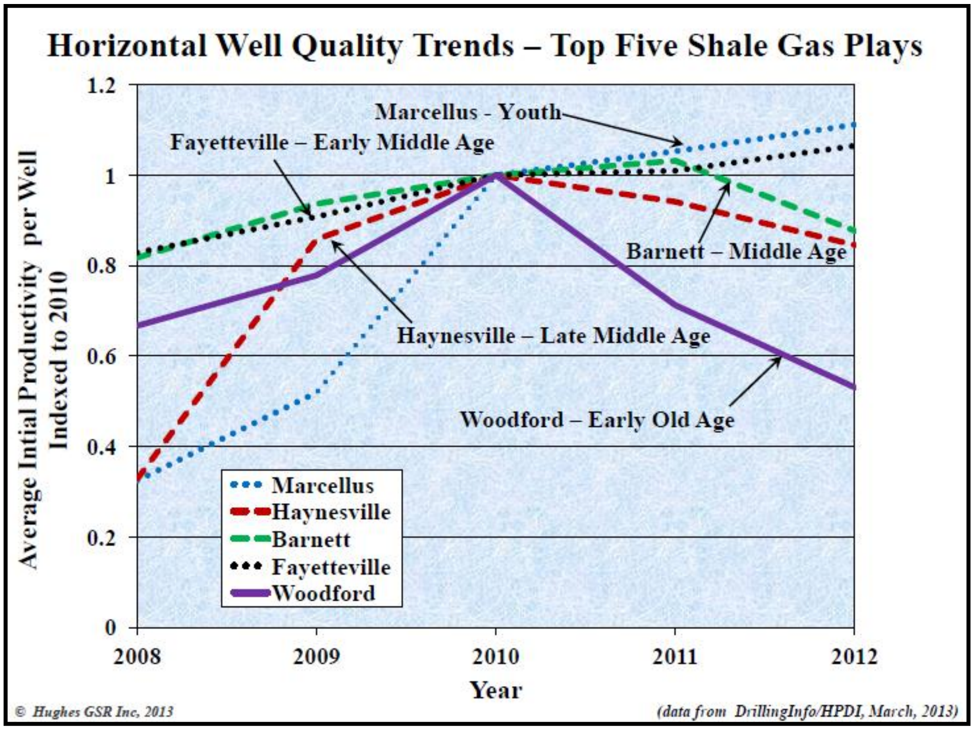
Question:

i) Please provide Estimated Ultimate Recovery (EUR) per well for the shale plays described in the above reverence for the years 2006 through 2012.

a) How does technology improvement impact the EUR per well in shale gas development?

Response:

Several of these five shale plays did not exist in 2006. The initial productivity (IP) of a well is an indication of how much gas that well will produce over its lifetime (estimated ultimate recovery or EUR). As pointed out in my evidence, the average IP increases early in the life of a shale play as sweet spots are defined and better technology is applied. I reproduce below the figure included in my evidence for these five shale plays, which explained this. In the early phases of development average IP (as a proxy for EUR) increases rapidly. In three of these plays average IP peaked in 2010 or 2011 and has declined since. This proves that better technology is having no effect and sweet spots are becoming saturated with wells so that average well quality is declining due to the fact that lower quality reservoir rock is being drilled.[30]



The above graph is important because it clearly demonstrates that quite apart from the number of wells being drilled in the older shale plays, the quality of new wells in those plays is declining.

The Role of Lower Gas Prices

Similarly, Union probed the relationship between declining natural gas prices on the level of production from shale plays.

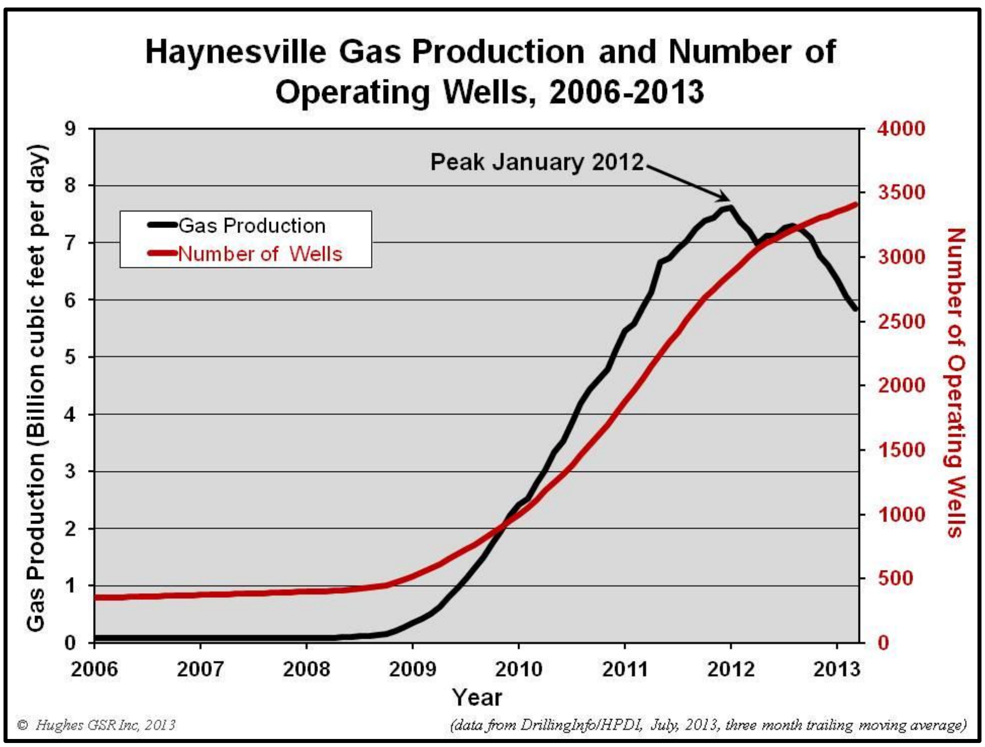
Request: (11(d))

[30] Exhibit M.COC.UGL.1, p. 6 of 24.

How did lower gas prices in 2010, 2011 and the extremely low gas prices in 2012 impact the level of production in the shale plays?

Response:

The following charts illustrate the relationship of the number of wells operating and the level of production for each of these four plays based on data from January 2006 through February-March 2013. Gas prices appear to have had little effect as in all cases the well count grew rapidly in the 2010 to 2012 period and in all cases production peaked in the 2011 to 2012 period. All four plays appear to be past peak production. It is conceivable that considerably higher gas prices could allow enough wells to be drilled to stop production declines and even grow production but this would be a relatively short term phenomenon as these plays, even though only a few years old, are extensively drilled and, as noted above, well quality is declining as drilling moves into lower quality parts of the reservoirs – meaning that progressively larger numbers of wells will be required to offset field declines going forward. [31]



[31] Exhibit M.COC.UGL.1, p. 7-8 of 24. There is an uncorrected typo in this exhibit, 11 a) should read 11 d).

Similar graphs are provided for production volumes from the Woodford, Fayetteville, and Barnett shale plays. The graphs clearly show that notwithstanding an overall increase in the number of wells drilled, production from the particular shale play tailed off and began to decline, corroborating Mr. Hughes analysis of the role that sweet spots play in the rapid growth of shale gas production, but only for the first few years of development.

The Role of Sweetspots

Finally for present purposes, Union questioned the basis for Mr. Hughes' theory that shale reserves have areas of disproportionately high productivity, or "sweetspots":

Reference:

Exhibit L.EGD.COC.3 Page 4: "These sweet spots typically comprise 5 to 10 percent of a play's total area and are drilled first."

Question:

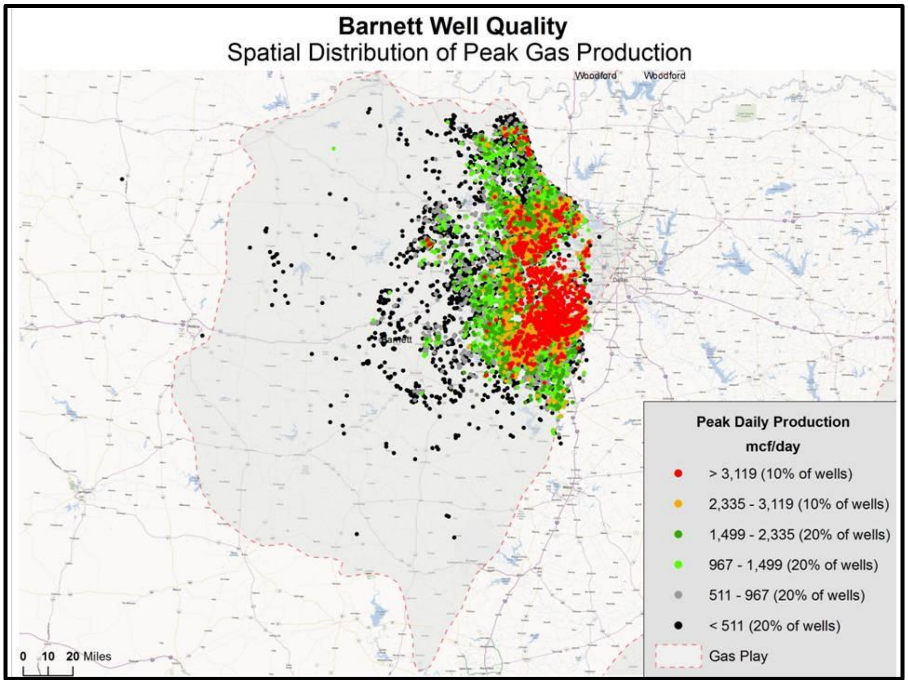
i. Please provide the basis for the statement.

a) Please provide any and all published studies specific to shale development used to support the statement.

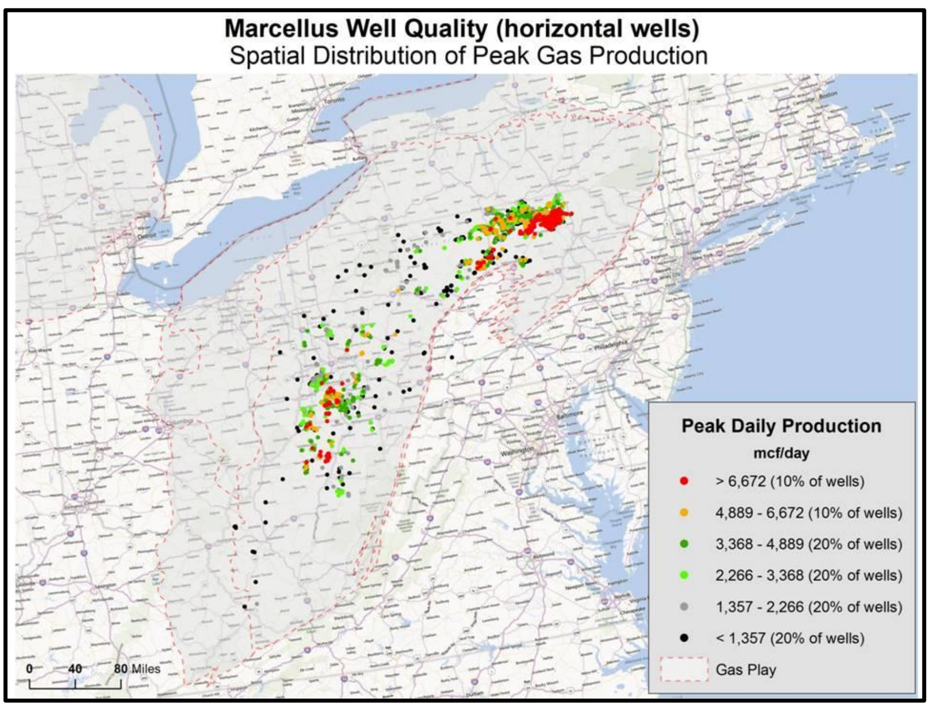
Response:

GIS maps of shale plays outlining the highest 20 percent of wells by productivity for the Haynesville, Barnett and Marcellus shale gas plays are published in http://www.postcarbon.org/reports/DBD-report-FINAL.pdf . The Energy Information Administration has published data files delineating the extent of shale plays (in shape file format) at http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/maps/shalegasplay.zip . These files have been integrated with drilling data current through yearend 2012 in the following maps. Well productivity is color coded on these maps which clearly illustrates that sweet spots (ie. highest productivity wells) comprise 5-10 percent of the total play area or less. The Barnett shale (the oldest shale gas play) and the Marcellus shale are illustrated below (the EIA play area is in light gray bounded by a dashed red line on these maps).[32]

[32] Ibid. pp. 12-13/24



As Mr. Hughes also showed, a similar pattern can be observed in respect of the development of the Marcellus shale play. [33]



[33] Ibid., p. 14 of 24

Mr. Hughes Oral Evidence

On October 9, Mr. Hughes appeared before the Board to give oral evidence. During a brief examination in chief he was asked to comment on the testimony of Mr. Henning, who appeared as a witness for Union and is the author of the ICF report filed in these proceedings. During cross examination, Mr. Henning described Mr. Hughes as being in a small minority of experts who question EIA projections for burgeoning shale gas supply. Mr. Hughes provided this response:

> MR. HUGHES: I think Mr. Henning, in terms of categorizing me as an outlier, is talking about the commonly held belief in terms of forecasts of the future, of rising, continually rising production from shale for a long time.
>
> I'm not a forecaster. If you look at figures of my evidence there is no forecast there. I'm a data analyst, so I've actually gone back and looked at all of the production data for all of the shale plays in the U.S. I looked at 30 different shale plays. And I characterize the productivity profile, well declines, field declines for each of those plays, to really find out what was going on from actual production data.
>
> So I didn't make forecasts, but I did elucidate the trends, the production trends in this data. And when I think back over it, nobody has really criticized, that I know of, the data analysis that I've done. I've used data that's available widely in the industry.
>
> One can, I suppose, look at those trends and make suggestions about how credible the forecasts of continually rising supply are in the future, which tend to be contradicted by those trends in some cases.
>
> If you look at the figure that you referred to on page 231 of the compendium, Exhibit L.EGD.COC.3, you can see first of all that shale plays in the U.S. are very young. The oldest is the Barnett shale play in Texas. It's about a decade old. The Haynesville is only about five years old, and it's gone through what I term the life cycle of a shale play.
>
> And what my work has found out is that shale plays inevitably are not homogeneous. They're not uniform in terms of productivity. They have high productivity sweet spots and they have much larger areas of much lower productivity.
>
> So when a shale play like the Haynesville is initially discovered, we don't know where the sweet spots are at that point in time. The drilling discovers those sweet spots.
>
> If you look at well productivity or well quality, which is defined as the initial production rate of wells, you'll find that the average productivity by year of wells climbs as those sweet spots are discovered and drilled off. And as the sweet spots become saturated with wells, the average productivity declines. And that's happening with four out of the five top shale plays in U.S.

> So those are the trends from the data. I didn't make any particular forecasts, although I have used third-party forecasts from agencies like the EIA to sort of balance what the trends from the data are showing versus the commonly held belief that shale gas is going to grow for a very long time to come.[34]

Evidence on Cross Examination

The only questions put to Mr. Hughes during cross examination sought his acknowledgement of estimates by the U.S. Energy Information Administration which project continued, and uninterrupted growth in U.S. shale gas supply for the next 25 or more years. Mr. Hughes acknowledged these estimates, and in fact presented them in his own evidence.[35]

At only one point was Mr. Hughes asked to comment on the reports he was being asked to acknowledge. On that occasion he answered as follows:

> MR. SMITH: Now, you are critical in your report, sir, of the EIA and its forecast and those of other organizations. That's a fair summary?
>
> MR. HUGHES: When I look at the actual data and what is happening in these plays, you can see that they are very young, they have grown very quickly. There's no question that shale gas has been a game changer in the U.S. It grew from 2 percent of production in the early part of the century to about 40 percent in 2012. That's an incredible growth.
>
> But if you look at the data for some of these individual plays, like the Haynesville, which was unknown in 2008, it was the largest shale gas play in the U.S. in 2012. And production is collapsing. The Haynesville is now down 27 percent.
>
> What the EIA has done has basically assumed that those growth profiles for those plays are going to keep -- are going to be continuous and going to keep rising. And what I've seen by an analysis of the historical data is that they may have relatively short lives. If you look at the Haynesville it looks like it's gone through middle age into old age in only five years.
>
> If -- we've gone through a litany of different forecasts from the EIA. And I would say that's one of the downfalls of forecasting. You know, every year they have tried to build in that very rapid growth projection, and an analysis of the data shows that that growth is not continuing for four out of five plays.
>
> Growth in the Marcellus is certainly continuing. It's now close to 10 bcf a day, which is, you know, up from virtually zero in 2007. It's a stellar growth.

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[34] Transcript Volume 8, Oct. 9, 2013, pp. 18-19

[35] Exhibit L.EGD.COC.3 Adobe p. 2/13, and Exhibit M.COC.UGL.1, p. 3 of 24.

> But again, if you look at it closely -- and I have; I've looked at it on a county-by-county basis. And you can see that, rather than being a broad, homogeneous field, it's broken down into sweet spots. And the sweet spots are being disproportionately drilled. Let's put it that way.
>
> And in essence, if you look at what I showed you for the overall plays, rising quality of wells until the sweet spots are located and drilled off, and then quality falls. That's already happening for the two best counties in the Marcellus; productivity is beginning to fall, irregardless of the application of better technology.[36]

Are Shale Reserves Recoverable?

The difference in expectations about the eventual supply of shale gas is at least in part explained by very different assumptions about the recoverability of those natural gas resources. During cross examination, Mr. Henning commented on the size of the Marcellus shale play, and had this to say:

> In the context of the Marcellus, the resource in place is so large, well over a thousand trillion cubic feet. I would suggest that we have a very, very long way to go.[37]

When he appeared to give evidence, Professor Ingraffea was asked to comment on this estimate, and answered as follows:

> DR. INGRAFFEA: Yes, I can. Correctly, he uses the word "resource" to describe the amount of shale gas. A resource is different than a provable reserve or an actual supply. Current industry estimates, as documented by industry publications, are that only about 10 percent of the shale-gas resource is currently recoverable at today's prices and today's technology.
>
> So it might or might not be true that there might be a thousand trillion cubic feet of natural gas in the Marcellus, but using today's technology and prices only about 10 percent of that is recoverable.[38]

<u>In Sum:</u>

The expert evidence adduced on behalf of the Council raises serious questions about the validity of the supply and price projections from the U.S. shale plays that figure so prominently in the rationale for both the projects before the Board. We submit that in light of this evidence, the Board adopt a very cautious approach to the confident supply projections that are being urged upon it. Moreover, while supply diversification is generally a good thing, large volumes of shale

[36] Transcript Volume 8, Oct. 9, 2013, pp. 38-40
[37] Transcript Volume 3, Sept. 17, 2013, p. 107
[38] Transcript Volume 8, Oct. 9, 2013, p. 16

gas currently flow into Ontario markets, and the proposed projects would only increase the dependence of provincial consumers on such flows.

2.2 REGULATORY RISK

Both Applicants have acknowledged the relevance of regulatory risk in respect of the supply of shale gas to Ontario. However, neither has carried out an analysis to assess this risk. For example, Union states that, "The new Contracts will obtain supply from the Dawn Hub. Changes in legislation or regulation might limit the available supply from shale basins. This risk is mitigated by the fact that the Dawn Hub is connected to many diverse supply basins."[39] The company does not, however, elaborate on the nature of prospective regulations or on the extent of their effect on shale gas supplies.

It a similar vein, Enbridge's application cites EIA projections for future shale gas production and supply without providing an analysis of the assumptions made by EIA, such as the failure of EIA to analyse potential regulatory initiatives in its projections of shale gas supply.[40]

In responses by Union and Enbridge to Council interrogatories, neither company provides further insight into the costs of mitigating or remediating the environmental and public health impacts of shale gas production or of compliance with federal, state and local regulations.[41]

For example, in a response to a Council interrogatory, Union responded that:

> While it is not possible to anticipate specific legislative or regulatory measures that may affect Shale Basin gas supply in the United States and/or Canada, we note that there have been a variety of proposals regarding the environmental impacts of shale development and the appropriate response to protect the environment. . . Additional regulation has the potential to add some additional costs to the development of shale gas wherever it is located. This would include shale from the Marcellus and Utica formations in proximity to Ontario, but also the shale formations in western Canada.[42]

[39] Union Gas Application EB-2013-0074. Section 11, p. 35.
[40] Enbridge Gas Distribution Inc. EB-2012-0451. Exhibit A, Tab 3, Schedule 5 - "Natural Gas Demand, Supply & Expected Gas Supply Benefits," p. 14.) For example, Enbridge did not mention that EIA stated: "The potential impacts of pending or proposed legislation, regulations, and standards (and sections of existing legislation that require implementing regulations or funds that have not been appropriated) are not reflected in the projections." (U.S. Energy Information Administration. 2012. *Annual Energy Outlook 2012 with Projections to 2035.* DOE/EIA-0383. p. ii. http://www.eia.gov/forecasts/aeo/pdf/0383(2012).pdf)
[41] Exhibit I.A1.EGD.COC.1 and 2. Enbridge Gas Distribution Inc. Response to Council of Canadians Interrogatory #1. June 7, 2013. EB-2012-0451/EB-2012-0433/EB-2013-0074.
[42] Exhibit I.A1.UGL.COC.3. Union Gas Limited. June 7, 2013. Answer to Interrogatory from Council of Canadians. EB-2012-0451/EB-2012-0433/EB-2013-0074,

The proposed projects promise greater access to abundant shale gas in the U.S., in particular from the Marcellus and Utica shale deposits. The question is whether environmental and public health regulations will significantly diminish this supply.

Air, Water and Public Health Protective Measures

The report prepared by Ms. Sumi provides an overview of the potential environmental and regulatory issues that may affect gas production from shale basins in the United States, and in particular, supply from those basins presented as significant future sources of natural gas for the residents of the Ontario and the GTA.[43]

Ms. Sumi's evidence is that environmental impacts and regulatory safeguards are viewed as major challenges with respect to shale gas development. For example, she cites a 2011 KPMG poll, oil and gas industry executives perceived environmental and sustainability concerns as the biggest challenge facing shale gas development (41 percent), with regulatory concerns voted as the second (27 percent).[44]

Having surveyed the landscape of regulatory measures, and initiatives that now, or may in future bear upon the development shale gas in the U.S. northeast, Ms. Sumi presents the following conclusions:

1. Information about the environmental and public health impacts of shale gas development continues to grow, revealing a diverse array of very serious effects, including:
    - regional water shortages, which may impact the ability of Marcellus operators to obtain the large volume of water needed to drill and fracture wells;
    - contamination of drinking water from shale development;
    - air pollution, which has affected local and regional air quality and threatens public health;
    - the large volume of wastewater generated from shale gas wells, which is already overwhelming existing disposal options;
    - earthquakes, which have been linked to shale gas wastewater disposal via underground injection; and
    - toxic and radioactive chemicals in wastes, which are posing disposal challenges and concerns.

[43] Exhibit L.UGL.COC.2 (filed in all three proceedings)/
[44] Ibid., p.2: KPMG International. 2011. *Shale Gas - A Global Perspective*. p. 19. http://www.gses.com/images/documents/shale-gas-global-perspective.pdf

2. State regulatory agencies in Pennsylvania, West Virginia and Ohio (Marcellus jurisdictions) were ill-prepared for the pace of drilling, and the environmental impacts that accompanied the shale gas boom. Not only were regulations inadequate to protect the environment and public health from shale gas development, but state agencies tasked with overseeing drilling, production and waste disposal were, and in many cases remain, underfunded and understaffed. Consequently, these states are still in "catch-up" mode, and tightening of regulations can be expected.
3. Both state and federal governments continue to develop and strengthen regulations to address some of the impacts, but there is a large gap between known impacts and existing regulations means more safeguards are needed.
4. Voluntary and regulatory mechanisms to mitigate environmental impacts can impose significant costs on shale gas development. With almost every new regulatory initiative proposed, the shale gas industry has expressed concerns related to the costs of compliance, and has argued that some proposed regulations will result in decreases in drilling. One potential federal regulation related to ozone is said to be the most costly regulation ever proposed for the industry.
5. If governments respond with effective regulatory and economic measures to the environmental challenges facing the shale gas industry, the cost of shale development will certainly rise, and in some cases is likely to become uneconomical. In other cases, the risks associated with shale gas development may be considered too great to allow for any development of this energy resource, and moratoriums now in place in the Marcellus shale may become permanent and spread to other jurisdictions.

Of these areas of environmental and public health regulation, Union's expert witness, Mr. Henning,[45] only considered the potential cost of water pollution abatement in assessing the cost of shale gas supply. These he estimated might add between 7 to 11 percent to the cost of a well.[46] While his estimates contemplate some form of carbon or equivalent charge, he does not expect that to be established for another decade.[47]

The applicants have not refuted the conclusions presented by Ms. Sumi, and given the opportunity to cross examine on her report, declined to do so.

<u>Greenhouse Gas Reduction Measures</u>

As mentioned, another important regulatory risk arises from the potential establishment of measures to curtail greenhouse gas emissions. Professor Ingraffea's evidence reveals that the such measures, and related costs, will be particularly onerous in respect of shale gas production.

[45] Transcript Vol.3, Sept. 17, 2013, p. 66 and 68.
[46] Ibid., p. 97
[47] Ibid., p. 94

He and his colleagues are responsible for carrying out and publishing seminal research and analysis of greenhouse gas emissions from shale gas development. That work is attached to the report he prepared for this proceeding, which offers the following summary:

- Natural gas is composed largely of methane, and 3.6% to 7.9% of the methane from the shale-gas life-cycle escapes to the atmosphere in purposeful venting and leaks over the lifetime of a well. This predicted range is being validated recently by actual measurements reported in the peer-reviewed literature.[48] These methane emissions are at least 30% more than, and perhaps more than twice as great as, those from conventional gas.

- The higher emissions from shale gas occur at the time wells are hydraulically fractured—as methane escapes from flow-back return fluids—and during drill out following the fracturing. Shale gas wells are fractured with 50 to 100 times the volume of fluid used in non-shale wells, making the flowback period much longer.

- Methane is a powerful greenhouse gas, with a global warming potential that is far greater than that of carbon dioxide, particularly over the time horizon of the first few decades following emission. Methane contributes substantially to the greenhouse gas footprint of shale gas on shorter time scales than traditionally mentioned, dominating it on a 20-year time horizon where its global warming potential is greater than 72 times that of carbon dioxide.

- The footprint for shale gas is greater than that for conventional gas or oil and for coal used for electricity generation when viewed on any time horizon, but particularly so over 20 years. Compared to coal, the footprint of shale gas is at least 20% greater and perhaps more than twice as great on the 20-year horizon and is comparable when compared over 100 years.

- The large GHG footprint of shale gas undercuts the logic of its use as a bridging fuel over coming decades, if the goal is to reduce global warming. This does not justify the

[48] Exhibit L.EGD.COC.1 Adobe p. 3/38 See, Petron G, et al., 2012. *Hydrocarbon emissions characterization in the Colorado front range*: a pilot study. J Geophys. Res.,117,D04304, http://dx. doi.org/10.1029/2011JD016360; Townsend-Small A, et al., 2012. *Isotopic measurement of atmospheric methane in Los Angeles, California, USA*: *Influence of "fugitive fossil fuel emissions*, J. Geophys. Res., 117, D07308, doi:10.1029/2011JD016826; Wennberg PO, et al., 2013, *On the sources of methane to the Los Angeles atmosphere,* Environ. Sci. Technol., doi:10.1021/es301138y; and Wunch D, et al. 2009. *Emissions of greenhouse gases from an American megacity*, Geophys. Res. Lett., 36, L15810, doi:10.1029/2009GL039825.

continued use of either oil or coal, but rather demonstrates that substituting shale gas for these other fossil fuels may not have the desired effect of mitigating climate warming.

The following figure[49] taken from the Climatic Change report illustrates the relative GHG footprint of natural gas extracted from shale deposits.

EB 2012-0451/2021-0433/2013-0074
Exhibit L.UGL.COC.1

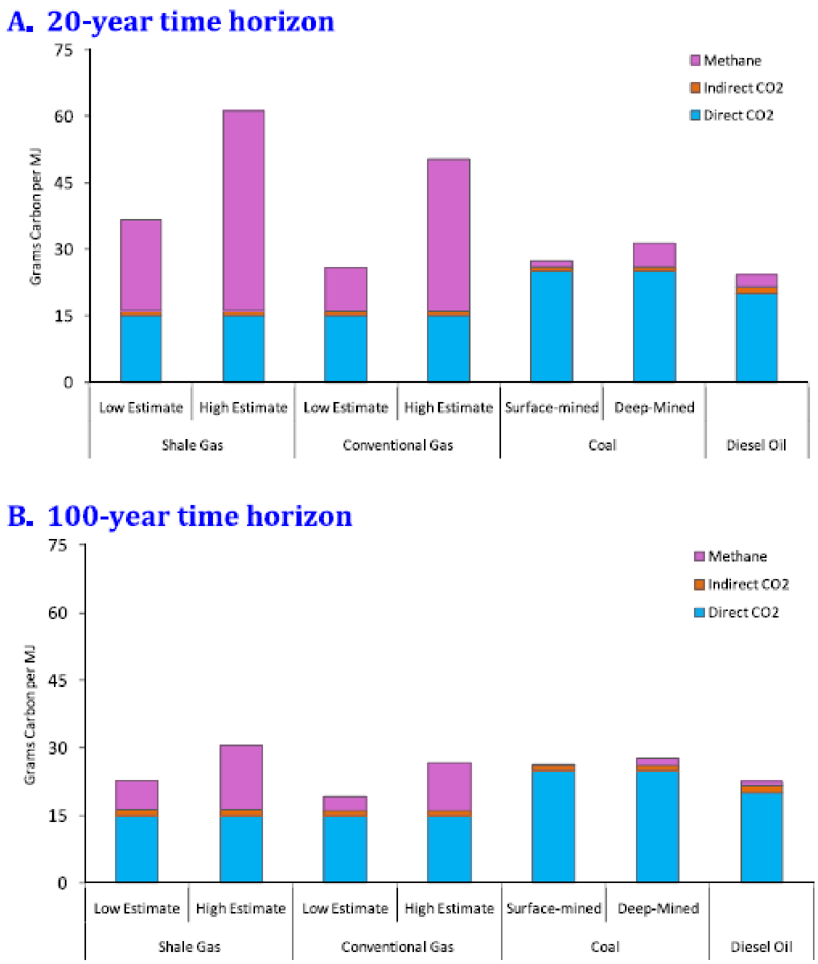

Fig. 1 Comparison of greenhouse gas emissions from shale gas with low and high estimates of fugitive methane emissions, conventional natural gas with low and high estimates of fugitive methane emissions, surface-mined coal, deep-mined coal, and diesel oil. **a** is for a 20-year time horizon, and **b** is for a 100-year time horizon. Estimates include direct emissions of CO_2 during combustion (*blue bars*), indirect emissions of CO_2 necessary to develop and use the energy source (*red bars*), and fugitive emissions of methane, converted to equivalent value of CO_2 as described in the text (*pink bars*). Emissions are normalized to the quantity of energy released at the time of combustion. The conversion of methane to CO_2 equivalents is based on global warming potentials from Shindell et al. (2009) that include both direct and indirect influences of methane on aerosols. Mean values from Shindell et al. (2009) are used here. Shindell et al. (2009) present an uncertainty in these mean values of plus or minus 23%, which is not included in this figure

[49] Ibid., p. 14/38

Remedial Measures to Address CH_4 Emissions from Shale Gas Development

Professor Ingraffea's report also comments on the availability of remedial measures to address life-cycle methane emissions from shale gas development. Some of these measures are technical, some economic. None, in his view, are currently effective.[50]

Nevertheless Professor Ingraffea acknowledges that shale gas methane emissions can be reduced and points to proposed EPA regulations to require capture of gas at the time of well completions as a potential important step. But he points that reducing methane emissions from shale gas development, transmission and distribution systems may be extremely expensive and concludes:

- Meanwhile, shale gas competes for investment with green energy technologies, slowing their development and distracting politicians and the public from developing a long-term sustainable energy policy.

- With time, perhaps engineers can develop more appropriate ways to handle fracking-fluid return wastes, and perhaps the technology can be made more sustainable and less polluting in other ways. Meanwhile, the gas should remain safely in the shale, while society uses energy more efficiently and develops renewable energy sources more aggressively.[51]

Is the Greenhouse Gas Footprint of Shale Gas Higher than Coal?

Professor Ingraffea responded to several interrogatories from Enbridge and Union[52]. None of these questioned the analysis and conclusions of the reports he co-authored. Rather the interrogatories served mostly as a vehicle for having Professor Ingraffea introduce four reports that he did not author on the topic of methane emissions, which in general terms arrived at different conclusions concerning the extent of methane emissions from shale gas development. In complying with these requests Mr. Ingraffea offered his comments about the nature of those reports and whether they represented an assessment comparable to one he and his colleagues carried out. In his expert view, they did not, nor did they cast into any legitimate doubt the validity of the analysis of he and his co-authors.[53]

[50] Exhibit L.EGD.COC.1, Adobe p. 4/5
[51] Ibid., Adobe pp.4-5/5.
[52] Exhibit M.COC.EGD.1 and Exhibit M. COC. UGL.1
[53] Exhibit M.COC.EGD.1. page 2-3/4, and Exhibit M. COC. UGL.1 , pp. 1-3/3

During cross examination Mr. Henning noted studies suggesting that the peer-reviewed reports of Professor Ingraffea and his colleagues overstated methane emissions, and that “the U.S. Environmental Protection Agency has lowered their estimate of methane emissions associated with conventional gas production estimates.” During his appearance, Professor Ingraffea was asked to comment on this critique of his work, and had this to say:

> The report he [Mr. Henning] refers to from Cornell University is a peer-reviewed journal paper of which I am co-author, and it was the first paper on the topic of methane emissions from shale gas ever to appear in the peer-reviewed literature. Subsequent to that, he is correct, there have been at least four peer-reviewed papers, actually more like 12. And in many of those papers the estimates in those papers are quite in agreement with ours. Some of them are quite in disagreement with ours.
>
> But the first point I want to make is that all of these papers, including ours, were the result of estimation, not actual measurement.
>
> The principal conclusion of our paper was that measurements need to be made, and they have not yet been made even as we sit here today, completely, but there have now been four peer-reviewed papers published in the last year on actual measurements, and in each of those papers the actual measurements of methane emissions are higher than those that we estimated. I want to point out the difference between measurement and estimation.
>
> The second point he refers to is that EPA had lowered its estimate of methane emissions. And again, the word "estimate" is important here. The EPA does not measure methane emissions, has never measured methane emissions, so they lowered their estimate, but they have not yet completed, nor has anyone completed, measurements across the entire life cycle of methane emissions. That work is currently underway by many researchers in the U.S., and it will be a few years before we know the complete story of how much methane is being emitted across the entire life cycle.
>
> But I emphasize again that the peer-reviewed publications that have occurred in the last year in which actual measurements are made at various locations across the U.S. and at various locations in the life cycle all indicate that methane emissions are higher than those that we estimated.[54]

Neither Enbridge nor Union adduced expert evidence relating to the issues Professor Ingraffea addressed. Furthermore, having put several interrogatories to Professor Ingraffea, neither applicant chose to question the Professor when he appeared before the Board.

As discussed further below, Professor Ingraffea cautions against further development of shale gas, but offers this assessment of the costs risks of the present course:

[54] Transcript Vol. 8, October 9, 2013, pp. 14-15

> However, if we proceed further down the present path, the imperative to reduce shale-gas methane emissions will add significantly to the costs of natural gas from this source. These costs, when considered together with those of remedial measures needed to address other environmental impacts of shale-gas development (Sumi), call into question the economic viability of shale-gas development and hence present projections for future supply expansion.[55]

Finally in this regard, Mr. Henning suggests that concern about risks pertaining to U.S. of shale gas has little bearing on the present projects because incremental supply from western Canada would likely also be shale gas. To begin with, for the foreseeable future, the majority of gas supply from the WCSB will be from conventional sources. Moreover, as Mr. Henning describes, if shale is in fact developed in large volumes in western Canada, present plans are to transport that gas to the west coast. However, and most importantly, the risks of shale gas development, whether from U.S. or Canadian sources, underscores the importance of thoroughly assessing the viability of alternatives that can obviate such risks. Unfortunately that assessment has not been carried out by the Applicants.

Prospective EPA Regulation

In 2009, EPA found that greenhouse gas pollution endangers public health and welfare by leading to long lasting changes in the climate that can have a range of negative effects on human health and the environment.[56] In March 2012 the EPA used section 111(b) of the *Clean Air Act* as the basis for a proposed air quality standard for greenhouse gas emissions from new power plants.[57] In December 2012, Attorneys General from seven Northeast states—New York, Connecticut, Delaware, Maryland, Massachusetts, Rhode Island, and Vermont— announced their plans to sue EPA for its failure to use section 111(b) of the *Clean Air Act* to directly regulate methane emissions from the oil and gas industry.[58] As of June 26, 2013, no suit has been filed.

The oil-and-gas-related air regulations passed by EPA in April 2012 were designed to limit harmful air pollutants from oil and gas operations. EPA estimated that a side-benefit of reducing these harmful pollutants would be a reduction of methane on the order of approximately 19

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[55] Exhibit L.EGD.COC.1, (Ingraffea) Adobe p. 5/5
[56] Exhibit ..UGL.COC. (Sumi) p. 15
[57] Ibid.
[58] Ibid.: Letter from New York Attorney General Eric T. Schneiderman, Connecticut Attorney General George Jepsen, Delaware Attorney General Joseph R. Biden, II, Maryland Attorney General Douglas F. Gansler, Massachusetts Attorney General Martha Coakley, Rhode Island Attorney General Peter Kilmartin and Vermont Attorney General William H. Sorrel to EPA Administrator, Lisa Jackson. Dec. 11, 2012. Clean Air Act Notice of Intent to Sue for Failure to Determine Whether Standards of Performance Are Appropriate for Methane Emissions from Oil and Gas Operations, and to Establish Such Standards and Related Guidelines for New and Existing Sources. http://www.ag.ny.gov/pdfs/ltr_NSPS_Methane_Notice.pdf

million metric tons of carbon dioxide equivalent (CO2e).[59] This is a fraction of the 145 million metric tons of CO2e (released as methane) that EPA estimates were emitted from the natural gas sector in 2011.[60]

In 2013, the Congressional Budget Office released a report showing that lawmakers could increase federal revenues and help mitigate climate change by establishing a carbon tax.[61] In February 2013, U.S. Senators Bernie Sanders and Barbara Boxer introduced comprehensive climate legislation that proposes to put a $20/metric ton price on carbon pollution.[62] According to the Congressional Research Service, a tax of $20/metric ton of carbon dioxide could increase the price of natural gas by approximately $1.00 per thousand cubic feet of gas**.**[63] The proposed tax could cost the natural gas industry at least $3.16 billion dollars per year.[64]

The success of a tax on carbon currently hinges on support from a substantial portion of Republican congressional members. The Republican Party has long been against a carbon tax to address climate change, but some members of the party have begun to speak out in support of a carbon tax on industry. Some analysts have said that it's possible a carbon tax could be part of broader negotiations around federal taxes in the coming years.[65]

Future regulation of greenhouse gases such as carbon and methane have the potential to influence the pace and extent of shale gas development in the U.S. In a 2011 report on shale gas, KPMG wrote that in order to meet carbon reduction targets, there is a risk that governments could compel the industry to make these investments through regulation. “Such moves could

[59] Ibid.: U.S. Environmental Protection Agency. 2012. “Overview of final amendments to air regulations for the oil and natural gas industry.” Fact Sheet. http://www.epa.gov/airquality/oilandgas/pdfs/20120417fs.pdf

[60] Ibid.: U.S. Environmental Protection Agency. April 2013. *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2011.* Chapter 3, p. 3-3. http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2013-Chapter-3-Energy.pdf

[61] Ibid.: Congressional Budget Office. May 2013. *Effects of a Carbon Tax on the Economy and the Environment.* http://www.cbo.gov/publication/44223

[62] Ibid.; ” http://www.sanders.senate.gov/newsroom/news/?id=2a869a44-1597-42a8-b625-1a88db3febbc

[63] Ibid., p. Ramseur, J., Leggett, J., and Sherlock, M. Sept. 17, 2012. *Carbon Tax: Deficit Reduction and Other Considerations.* p. 11. Congressional Research Service Report for Congress. R42731 http://www.fas.org/sgp/crs/misc/R42731.pdf

[64] Ibid. This is based on 2011 carbon dioxide and methane emissions from natural gas systems in the U.S. (Data are from the most recent greenhouse gas inventory from the U.S. EPA. The agency did not separate out shale gas emissions, so it was not possible to determine the cost to Marcellus and/or Utica shale producers). In EPA’s inventory, natural gas systems released 145 million metric tons (145 Teragrams) of carbon dioxide as methane, and 32 million metric tons as carbon dioxide. If we subtract the 19 million metric tons expected to be captured or reduced by the 2012 EPA oil and gas air regulations promulgated in 2012, that leaves 159 million metric tons of carbon dioxide equivalent. At $20/metric ton, the carbon tax would equal $3.16 billion for the natural gas industry. (EPA. April 2013. *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2011.* Chapter 3, p. 3-3. http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2013-Chapter-3-Energy.pdf)

[65] Ibid..

dramatically increase costs across the entire oil and gas industry, with particular impact on highly cost-sensitive shale gas development operations."[66]

The importance of reducing methane emissions to the overall project of confronting climate change is illustrated by the following table taken from a report by Professor Ingraffea and his colleagues.[67]

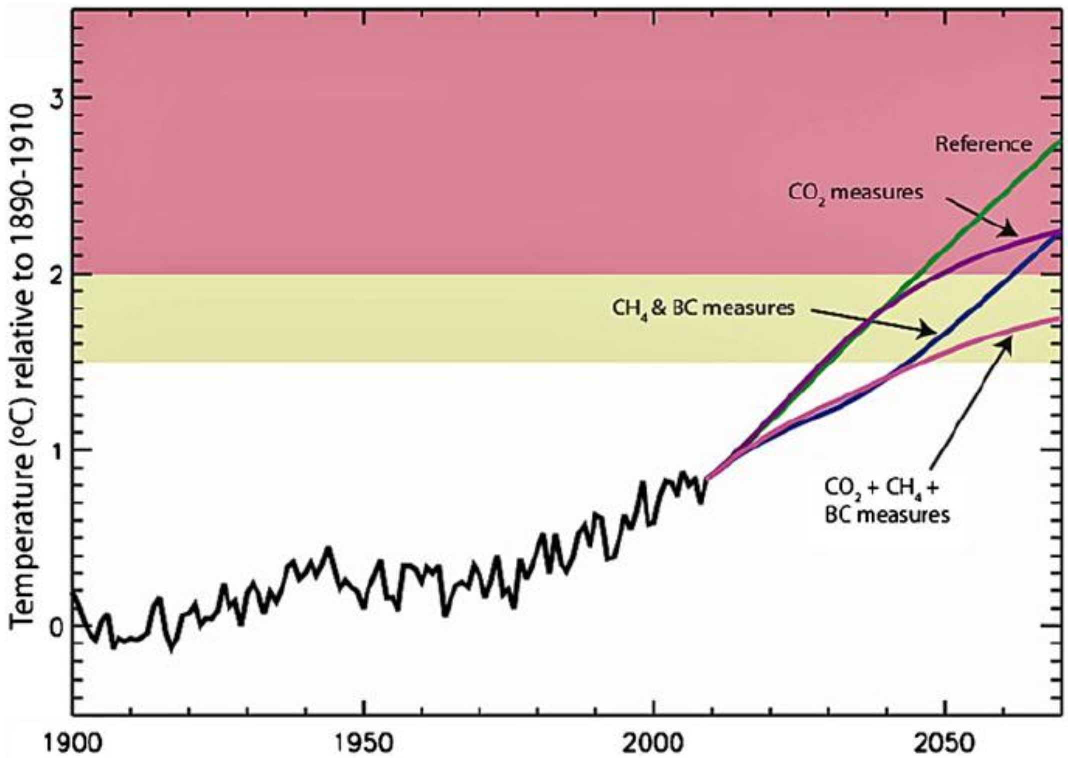

Fig. 2 Observed global mean temperature from 1900 to 2009 and projected future temperature under four scenarios, relative to the mean temperature from 1890–1910. The scenarios include the IPCC (2007) reference, reducing carbon dioxide emissions but not other greenhouse gases ("CO_2 measures"), controlling methane and black carbon emissions but not carbon dioxide ("CH_4 + BC measures"), and reducing emissions of carbon dioxide, methane, and black carbon ("CO_2 + CH_4 + BC measures"). An increase in the temperature to 1.5° to 2.0°C above the 1890–1910 baseline (illustrated by the yellow bar) poses high risk of passing a tipping point and moving the Earth into an alternate state for the climate system. The lower bound of this danger zone, 1.5° warming, is predicted to occur by 2030 unless stringent controls on methane and black carbon emissions are initiated immediately. Controlling methane and black carbon shows more immediate results than controlling carbon dioxide emissions, although controlling all greenhouse gas emissions is essential to keeping the planet in a safe operating space for humanity. Reprinted from UNEP/WMO (2011)

As the Professor concludes: "… if we proceed further down the present path, the imperative to reduce shale-gas methane emissions will add significantly to the costs of natural gas from this source. These costs, when considered together with those of remedial measures needed to address other environmental impacts of shale-gas development (Sumi), call into question the

[66] Ibid.: KPMG International. 2011. *Shale Gas - A Global Perspective*. p. 19. http://www.gses.com/images/documents/shale-gas-global-perspective.pdf
[67] Exhibit L.EGD,CIC,1M Adobe p. 26/38

economic viability of shale-gas development and hence present projections for future supply expansion."[68]

Can U.S. Shale Gas Emissions Otherwise Be Taken Into Account?

The greenhouse gas footprint of shale gas development is clearly an important consideration for assessing the regulatory/cost risks of future supply of such gas resources. The prediction that shale gas will be abundant and cheap provides much of the rationale for the present Applications. The evidence of Ms. Sumi and Professor Ingraffea strongly suggests that the costs of reducing greenhouse gas emissions from this gas resource will materially alter that assessment.

However, in addition to the impact that such emissions may have on the cost and availability of shale gas supply in Ontario, there is another factor we believe the Board should take into account: the impact of greenhouse gas emissions associated with this resource, from extraction to use. As noted, Professor Ingraffea's evidence is that fugitive emissions of methane that occur during the extraction process result in the 'cradle to grave' greenhouse gas profile for shale gas being higher than the corresponding profile for coal or oil, when compared over a 20 year horizon.

This evidence clearly challenges the popular wisdom that the climate change impacts of natural gas are significantly more modest than for other fossil fuels. As we know, Ontario has established clear policy objectives for reducing greenhouse gas emissions. Ontario's GHG policy calls for reductions in GHG emissions relative to 1990 levels of 6% by 2014, 15% by 2020; and 80% by 2050.[69] The submissions of Environmental Defense address the contradiction between the premise for the present projects which foresee substantial growth in natural gas demand and the reduction goals of Ontario policy.[70] Ontario's commitment to reducing greenhouse gas emissions can also be seen in its commitment to phasing out coal generation, and its promulgation of the *Green Energy and Green Economy Act*.

The Green Energy and Green Economy Act, was introduced in 2009. Among many other matters it amended section 2 of the OEB Act, to repeal paragraph 5., and replace it with the following text:

> To promote energy conservation and energy efficiency in accordance with the policies of the Government of Ontario, including having regard to the consumer's economic circumstances.

This change was not specifically discussed by the Legislature or in Committee. However, debate on the Bill generally peppered with references to climate change and the need to protect the

[68] Ibid., p. 5/48
[69] Government of Ontario, Ontario's Action Plan On Climate Change, August 2007
[70] Ibid., p. 6

atmosphere. In first reading, the Minister, George Smitherman, referred to objectives related to climate change:

> "Since 2003, the government of Ontario has been moving forward with the most ambitious climate change initiative in North America: the elimination of coal. Our progress to date, a renaissance of our energy system, reflected by billions in new investments, has been so successful that today Ontario is raising the bar on our collective ambitions.
>
> […]
>
> This bill, this Green Energy Act, continues to transform Ontario's electricity generation system into one of the cleanest, greenest energy supply mixes in the world. Indeed, we've made great strides already, and the Green Energy Act would stimulate an even greater focus in this area. Make no mistake: The things that we want, that all Ontarians want, are a cleaner climate, jobs in the green economy, enhanced productivity, a culture of conservation and a break for Mother Nature."

At Second Reading, the then Premier declared:

> "We are very pleased and proud to be able to introduce the bill, as we did yesterday. It is going to enable us to create new, clean, green jobs, it's going to enable us to generate clean, green electricity and it's going to enable more of us to do our part in the fight against climate change. So I really think it is the sweet spot of sweet spots."

Approval of the present applications will cause greenhouse gas emissions that will confound Ontario reduction objectives. The fact that the lion's share of emissions from gas destined for Ontario will originate in the US does not obviate the need to take them into account. No doubt the Applicants will argue the Board lacks jurisdiction to consider such 'upstream' environmental impacts, but we believe there are significant precedents that would allow it to do so.

In *Sumas Energy 2. Inc. v. Canada* (National Energy Board),[71] the Federal Court of Appeal considered the jurisdiction of the National Energy Board to consider the potential environmental impacts in Canada of a proposed power plant in the United States, when considering an application for an international power line (IPL) running from that plant to Canada. The Board's approach, upheld by the Court, was to take those impacts into account in light of the close connection between the power plant and the IPL, and the environmentally sensitive but limited area in Canada that would be impacted by the project.

Reflecting the issues in *Sumas*, the present applications deal with the cross border flow of energy, and environmental effects that originate in one country but which will impact another.

[71] 2005 FCA 377 (CanLII)

Although the NEB regime differs from that of the OEB it is significant that in *Sumas,* the Board found that it had the jurisdiction to consider environmental effects whose source was outside Canada.[72] The Federal Court of Appeal agreed.[73]

Unlike the present Applications, in *Sumas* an American review of the U.S. Power plant had previously been conducted by the Washington State Energy Facility Site Evaluation Council (EFSEC). In that case the NEB and the Federal Court of Appeal both agreed that it was nevertheless appropriate to assess the environmental effects in Canada. The case for review in the present circumstances is even stronger in light of the absence of effective regulation in the U.S. - let alone any consideration in that jurisdiction of impacts on Canada.

Central to the decision of the Board was the interlinked nature of the power plant and the IPL, and the proximity to impacted areas. Unlike *Sumas* there no single facility that will be the source of gas flowing through the proposed pipelines at issue and indeed that gas will come from various sources, Canadian and U.S., conventional and from fracking. There is however no denying the critical importance of U.S. shale gas as a principal driver of the proposed projects. Nor, in light of the expert evidence adduced during these proceedings, can there be any argument that the rapid development of shale gas has been properly assessed or regulated – hence the moratoria in place in both New York State and Quebec. For these reasons, the underlying rationale of *Sumas* applies equally well to the present projects.

Another and more recent precedent that supports the approach we propose the Board adopt is found in the U.S. State Department assessment of the Keystone XL pipeline project. The State Department was charged with preparing a draft supplementary environmental impact statement (DSEIS) of the proposed international pipeline.

The DSEIS report is noteworthy in that under its analysis of cumulative effects, it explicitly considers extraterritorial concerns, including Canada's environmental assessment of the project.[74] It summarizes four main topics in this respect: 1) the NEB environmental analysis of the Keystone KL Project in Canada; 2) the potential influence of the Project on oil sands development in Canada; 3) the environmental impacts of oil sands development in Alberta; and 4) legislative protections for migratory bird species in Canada (and the U.S.).[75]

The report explains that the Department of State was not legally required to consider an extra-territorial environmental analysis or activities outside the United States, but the information was included nonetheless: "as a matter of policy, and in response to concerns that the proposed

[72] See Sumas FCA decision at para. 12.
[73] Sumas FCA decision, at para. 13.
[74] Draft Supplemental Environmental Impact Statement- Keystone XL Project, online: <http://keystonepipeline-xl.state.gov/documents/organization/205618.pdf>, at 4.15.4. "Extraterritorial Concerns", page 109.
[75] *Ibid.* at pages 109 – 117.

Project would contribute to certain continental scale environmental impacts".[76] It is particularly notable that the DSEIS considered how the proposed project might impact the development of Albertan oil sands and consequently GHG emissions.[77]

The US Environmental Protection Agency approved of this approach and commended the State Department for having:

> "estimated the lifecycle GHG emissions associated with oil sands development and the proposed Project, analyzed the effect of the Project on Canadian oil sands production and considered measures to reduce GHG emissions."[78]

As it is for the US Department of State, it is entirely appropriate for the OEB to consider extra-territorial activities and impacts of an international project, even more so when the environmental impacts in question are atmospheric, as they are in this case. The impacts will not be confined by artificial territorial demarcations. They will affect a great many beyond the U.S. border.

The evidence in this proceeding has demonstrated that the proposed projects will substantially increase the flow of shale gas from US sources to and through Ontario. This gas is likely to have a greenhouse gas footprint considerably higher than the energy resources it will displace. This is certainly true in respect of conventional natural gas from the WCSB, but on Professor Ingraffea's evidence it is to a certain extent also true for coal fired generation as well. The inherent contradiction of this result with Ontario's commitment to reduce greenhouse gas emissions is also quite stark. Of course, to the extent that such supply will displace conservation and efficiency investments it is that much more problematic.

The question for the Board is whether it can turn a blind eye to these contradictions. In our view it cannot.

This is not to propose a full quantitative environmental assessment be carried out of the impact of the proposed projects. But it is to suggest that the Board recognize the global environmental impacts on the present proposals. In this regard the Board must take such impacts into accountin determining whether the proposed projects are compatible with the objectives of the Act as set out in section 2. In particular, the Board must ask whether the proposed projects would facilitate

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[76] *Ibid.*, at page 109.

[77] *Ibid,* at s. 4.15, page 78, "Indirect Cumulative Impacts and Life-Cycle Greenhouse Gas Emissions- Overview and Summary" .

[78] Cynthia Giles – Assistant Administrator for Enforcement and Compliance Assurance, United States Environmental Protection Agency, Letter to Jose W. Fernandez and Kerri-Ann Jones, U.S. Department of State, April 22, 2013, online :<http://www.epa.gov/compliance/nepa/keystone-xl-project-epa-comment-letter-20130056.pdf>, at page 2.

rational the expansion of Ontario's transmission and distribution systems. The Board must also ask whether they promote energy conservation and energy efficiency in accordance with the policies of the Government of Ontario. In our view the answer to both questions is negative.

In these circumstances the Board should give considerable weight to the conclusion that Professor Ingraffea draws from assessing the relative risks engendered by proposals such those now before the Board. In that regard, he asks:

> … given present risks, should society invest massive capital in such improvements for a so-called "bridge fuel" that is to be used for only 20 to 30 years, or would the capital and fuel expenditures be better spent on conservation and efficiency improvements, and switching end uses to more sustainable, efficient energy sources?

Answering his own question the Professor concludes:

> I think not. A " bridge" in time is not necessary as all of these sustainable measures are available now.

PART 3: SUPPLY RISK, TCPL MAINLINE

There is significant evidence that the dramatic transformation of natural gas markets caused by the rapid expansion of shale gas has put the security of supply to Ontario on the TCPL mainline at risk. This is particularly true in light the NEB's recent decision [RH-003-2011] that TCPL has no obligation to provide service to its customers, although TCPL has stated that it will do so for those customers that enter into long-haul contracts.[79]

Responses to interrogatories by the Council reveals that the extent and nature of those supply risks was a matter of discord among the parties.

For example, each of the applicants was asked about the potential supply risks associated with the conversion of certain TCPL mainline facilities to oil service – the "Energy East Project".. Each was asked whether " the reduction or loss of gas supply service on the TCPL Mainline undermines supply diversity to the GTA, and if not, why not?" [80]

To this question Enbridge anwered:

> Enbridge does not agree that reduction of gas service on the TCPL undermines supply diversity to the GTA. Enbridge plans to increase access to supply basins and market hubs

[79] Transcript Vol 9, October 10, 2013, pp. 45 – 47.
[80] See Exhibit M.TCPL. COC 1 and 2

which will increase supply diversity rather than reduce it. Enbridge has no plans to eliminate supply from the WCSB.

Union Gas stated:

> No, Union disagrees with this statement. Replacing supplies from one basin, the WCSB, with access to multiple supply basins, through additional access to Dawn, creates increased diversity. Through the GTA project and the Union facilities being proposed, Enbridge will be gaining additional access to Dawn based supplies which may include WCSB supplies delivered via TCPL. Dawn is a diversified and liquid supply point with many pipeline connections providing access to multiple supply basins.

The Council then asked whether TCPL agreed with these responses and it replied as follows:

> TransCanada does not agree with the responses.
>
> Any loss of firm gas supply service on the TransCanada Mainline is entirely the choice of Enbridge and Union. Enbridge and Union supply from the WCSB through TransCanada will be reduced as a result of the contractual changes proposed by Enbridge and Union in these proceedings. Both LDCs will be more reliant on supply from Dawn and Union's Dawn-Parkway system.
>
> To the extent that the eastern LDCs choose not to contract for long term firm service on the Mainline, TransCanada may not maintain capacity that accesses WCSB supplies over time (also please refer to the response to SEC 1). There is no requirement for TransCanada to maintain capacity above the level required for firm contracts.
>
> As a result of the potential reduction in Mainline capacity accessing WCSB supplies, the eastern LDCs become almost totally dependent on the Union system for gas supply. Although the Union System accesses gas supplies from different basins, an operational incident on the Union System or on the Vector Pipeline could make these supplies unavailable to the eastern LDCs. This as a reduction in supply diversity.

Questioned about whether its view changed as a result of negotiating the settlement agreement, Mssrs. Clark and Schultz indicated that TCPL's response would consequently be somewhat nuanced now[81] and that maintaining a minimum of 13% of the LDC market committed to long haul means that "there's less risk as a result of this [the term sheet] than there is in the absence of this." [82] However, witnesses for TCPL, Enbridge and Gaz Metro on the joint panel stressed that

[81] Transcript Vol. 9, Oct. 10, pp. 46-47
[82] Ibid. p. 48

considerable uncertainty remains in light of present plans to convert the largest and newest of the Mainline pipes to oil service. Given this uncertainly the parties decided to exclude the Energy East project from the settlement.[83] Nevertheless, Mr. Clark did confirm that the conversion of that pipeline might leave the Eastern Triangle with a marginal shortfall.[84]

There was a similar difference of opinion among the parties with regard to the impact of TCPL's decision to suspend certain integrity work on the Northern Ontario Line. Of this matter, both Enbridge and Union Gas took the view that TCPL's actions presented "consumers in Ontario and/or the GTA with a supply risk with respect access to WCSB gas resources'. TCPL disagreed.[85]

There is obviously considerable difficulty in making confident predictions in the present dynamic energy context. The challenge of exercising prudent regulatory oversight is made even more difficult by the bifurcation of regulatory authority over pipeline projects.

The Council places a high priority in maintaining access for eastern Canadians to conventional natural reserves in western Canada. In the worst case scenario, that access will be lost in the stampede to access shale gas from US sources that may prove to be far less abundant or affordable than projected. In that event, the TCPL mainline assets would be removed from gas service, WCSB gas resources would be diverted to other uses, and much diminished US shale gas supply would be spoken for by other consumers.

Given these risks, it would be imprudent to put at any greater risk the security of supply the TCPL mainline currently provides eastern Canadian consumers. We submit that the proposed projects would have that effect.

Submitted on Behalf of the Council of Canadians

Steven Shrybman
Sack Goldblatt Mitchell
Nov. 15, 2013.

[83] Ibid. P. 49
[84] Ibid P. 49
[85] Exhibit, M.TCPL.COC 2.