RANALAW

SUITE 102, 620 - 12TH AVENUE SW CALGARY, ALBERTA, T2R 0H5
PHONE 403-455-3673 ▪ FAX 403-452-9803 ▪ WWW.RANALAW.COM

Our File No.: 1010-003
October 13, 2011

VIA EMAIL

Ms. Alanna Gillis
Acting Commission Secretary
British Columbia Utilities Commission
Sixth Floor – 900 Howe Street
Vancouver, British Columbia V6Z 2N3

Dear Ms. Gillis:

Re: Project No. 3698640
British Columbia Utilities Commission (BCUC)
British Columbia Hydro and Power Authority (BC Hydro)
Application for a Certificate of Public Convenience and Necessity (CPCN) for the Dawson Creek/Chetwynd Area Transmission Project (DCAT)
Information Requests Round 2

Please find enclosed the second round of Information Requests submitted on behalf of the intervenor, West Moberly First Nations.

As indicated in the attached Information Requests, certain of the IR have been filed by WMFN on a confidential basis, as they refer to information and IR 1 responses filed by BC Hydro on a confidential basis.

Sincerely,
RANA LAW

Emily A. Grier

Encl.

CC: BCUC Distribution List

BC HYDRO – CPCN FOR DAWSON CREEK/CHETWYND AREA TRANSMISSION PROJECT

PROJECT NO: 3698640

BRITISH COLUMBIA UTILITIES COMMISSION

Certificate of Public Convenience and Necessity for the Dawson Creek/ChetwyndArea Transmission Project

---

INFORMATION REQUESTS ROUND 2

DATED October 13, 2011

SUBMITTED BY:

Counsel for West Moberly First Nations

RANA LAW Barristers & Solicitors
Attn.: Allisun Rana
#102 – 620, 12th Avenue S.W.
Calgary, AB T2R 0H5
Tel. 403-455-3673
Fax 403-452-9803

Information Requests – BC Hydro's DCAT CPCN application

REQUESTOR NAME: West Moberly First Nation
INFORMATION REQUEST ROUND NO: 2
TO: British Columbia Hydro and Power Authority (BC Hydro or the developer)
DATE: October 13, 2011
PROJECT NO: 3698640
APPLICATION NAME: Dawson Creek/Chetwynd Area Transmission Project (DCAT)

2.0 Scope of BC Hydro's Assessment and Duty to Consult Regarding Cumulative Effects:

Preamble In its response to WMFN IR 1.2.3, BC Hydro states that,

> "The only issue communicated by First Nations to BC Hydro that ***was significant to the evaluation of the alternatives*** was the difference between the number of structures and decommissioning of the line, which BC Hydro took into account in its selection of the preferred alternative.
>
> As such, ***BC Hydro did not conduct an evaluation of issues raised by First Nations, and no methods, thresholds or measures to make such an evaluation were used***."
>
> This response is a foundation for a number of subsequent BC Hydro responses. This information request relates to BC Hydro's consideration of WMFN information in selecting alternatives as well as broader consideration of all alternatives on the rights and interests of WMFN.
>
> BC Hydro's DCAT First Nations consultation record between BC Hydro and various First Nations, including WMFN, makes clear that a number of key issues important to First Nations were raised over the course of consultations, including, but not limited to:
>
> - induced effects (such as increased shale gas development) that DCAT may contribute to, or cause;
> - the need to consider cumulative effects, including the level of current impacts in the DCAT area from Hydro, as well as oil and gas, private lands, and other taking up of lands, with reference to constitutionally protected Treaty rights;
> - WMFN specifically raised concerns related to effects on wildlife central to WMFN cultural practice including potential fragmentation of habitat (cumulative effects), wildlife corridors, and a wetland area used by moose.

Based on BC Hydro documents, the Blueberry River First Nation clearly raised cumulative effects issues and BC Hydro seems to have considered them "outside the scope" of DCAT.

Similar issues were raised by WMFN. On several occasions, through meetings and in writing, WMFN made clear to BC Hydro that it considers the effects of DCAT on its rights and interests to be potentially specific (depending on results of evidence based research), but also incremental and cumulative in nature, and as such, required more than simply identifying site-specific traditional use and occupancy locations along the proposed route of the transmission line (i.e. the Traditional Use Study ("TUS") proposed by BC Hydro). BC Hydro's Consultation Tracking System, the WMFN portion of which was appended to the end of BC Hydro's Confidential Responses to First Round IRs, identifies that many of these issues were identified as early as June 3, 2010, through initial discussions with WMFN representatives. In Fall 2010, WMFN submitted a proposal, work plan, and budget that it considered adequate to address DCAT within the context of these broader issues. Through multiple versions and over a series of months, BC Hydro worked to reduce the scope of WMFN's proposed DCAT work so that it would conform to a more narrow set of specific expectations on the part of BC Hydro. To date, there has been no agreement between WMFN and BC Hydro on these issues.

BC Hydro has clearly made decisions that some of the issues raised by First Nations were "significant to the evaluation of the alternatives", while others were deemed not significant, or outside the scope of the process.

2.0.1 As First Nations, including WMFN, informed BC Hydro regarding issues and concerns ranging from specific concerns regarding 'a wetland area used by moose' to larger but still specific concerns regarding the cumulative effects that any of the DCAT alternatives would contribute to, why were the only concerns ***deemed significant to the evaluation of the alternatives***, "the difference between the number of structures and decommissioning of the line"?

2.0.2 Given that BC Hydro indicates that **no methods, thresholds or measures** were used to determine which concerns were "deemed significant" (a term BC Hydro appears to use to differentiate between issues to follow up on) how did BC Hydro, as a Crown agency, make decisions regarding which First Nations concerns were significant, and which weren't, or were outside the scope of DCAT?

2.0.3 Can you identify specifically how WMFN was involved, if at all, in ***deeming significance***, or otherwise making decisions regarding what issues raised by WMFN were 'significant' to the assessment process, or were outside the scope of the process?

2.0.4 BC Hydro's consultation log and IR responses regarding interactions with WMFN focus on documenting the process of consultation. In BC Hydro's view, what was the *substance* of WMFN concerns that led to WMFN and BC Hydro not being able to agree on evidence based studies despite more than a year of engagement?

2.0.5 Where decisions regarding acceptable scope or significance of First Nations concern were made, were these part of BC Hydro's decisions regarding the acceptable scope or budget of WMFN studies or information gathering efforts submitted in Fall 2010? Who at BC Hydro made these decisions and based on what information?

2.0.6 As an agent of the Crown, and with respect to DCAT, what is BC Hydro's understanding of the scope of its own duties when faced with issues raised by a First Nation that are, in BC Hydro's view beyond the scope of the consultation it originally anticipated? In particular, please refer to findings regarding the duty to consider cumulative effects discussed in *West Moberly First Nations v. British Columbia (Chief Inspector of Mines)* 2011 BCCA 247.

2.0.7 BC Hydro states in its response to BCUC IR 1.6.3 that "*All First Nations had an opportunity to obtain capacity funding if more information gathering was necessary*"...

BC Hydro's application for CPCN at Section 6.1.5.3 states "BC Hydro has engaged in medium level consultation with Blueberry River, West Moberly, McLeod Lake and Saulteau First Nations by providing notification and making presentations about the Project, engaging in meetings, *providing capacity funding where requested*, inviting the First Nations to participate in the AMEC environmental overview assessment field surveys, sharing the results of those studies, and continuing to provide updates on the progress of the Project."

Each of these statements appear to use the term "capacity funding" to refer to any funding provided to First Nations with respect to the DCAT project. WMFN considers "capacity funding", or consultation funding as those funds provided to the First Nations to allow it to engage in the consultation process with BC Hydro, for example, for meetings (internal and with BC Hydro), review of project proposals and other documentation, legal assistance, etc. In WMFN's experience funding for information gathering and evidence based studies is accounted for separately, as a study is what informs the First Nations' concerns, and enables it to participate in the consultation, mitigation and accommodation discussions that follow.

2.0.7.1 When BC Hydro refers to "capacity funding" as noted above, are those references to consultation funding, study funding, or both?

2.0.7.2 How does BC Hydro reconcile the above statements with the fact that BC Hydro has thus far provided WMFN with only a small advance on its consultation funding to review the project and engage in consultation, and failed to provide WMFN with any funding for the information gathering or evidence based studies that WMFN has been requesting since the fall of 2010?

2.0.7.3 Was the provision of consultation funding and study funding actually contingent on BC Hydro approving a task list and budget for consultation, and a scope, method, and budget for information gathering? How did BC Hydro's stated lack of method, threshold, or measure for identifying the significance of issues raised by WMFN influence decisions regarding provision of capacity funding, and study funding?

2.0.8 In the case of DCAT, was BC Hydro's desire to maintain Project budgets involved in determining the scope of engagement with WMFN? If so, and in the face of WMFN raising issues regarding cumulative effects on Treaty rights, how did BC Hydro balance its desire to maintain budgets with its consultation obligations?

2.0.9 Beyond negotiating regarding budget, did BC Hydro make other efforts (such as revisions to the scope of issues considered, provision of in kind support, confirmation of confidentiality protocols for sensitive information, or other changes) to support the meaningful two-way exchange of information between BC Hydro and WMFN within the DCAT process? Please provide documentation of these efforts.

2.1 Assessment of Potential for DCAT to Impact WMFN Rights Under Treaty No. 8:

Preamble In its response to BCUC IR 1.9.2, BC Hydro notes that West Moberly First Nations is a signatory to Treaty No. 8, and that with Treaty No. 8 the Crown made certain promises to First Nations. While the written text of the Treaty is quoted, the oral promises of Treaty making also recognize particular rights. Such oral promises are recognized by the Supreme Court of Canada in *R. v. Badger*, [1996] 1 SCR 771.

In the 1899 report of the Commissioners of Treaty No. 8, it is stated by the Crown's own representatives that, in making Treaty No. 8:

> ***Our chief difficulty was the apprehension that the hunting and fishing privileges were to be curtailed.*** The provision in the treaty under which ammunition and twine is to be furnished went far in the direction of quieting the fears of the Indians, for they admitted that it would be unreasonable to furnish the means of hunting and fishing if laws were to be enacted which would make hunting and fishing ***so restricted as to render it impossible to make a livelihood by such pursuits***. But over and above the provision, we had to

> solemnly assure them that only such laws as to hunting and fishing as were in the interest of the Indians and were found necessary in order to protect the fish and fur-bearing animals would be made, and that ***they would be as free to hunt and fish after the treaty as they would be if they never entered into it. We assured them that the treaty would not lead to any forced interference with their mode of life.*** (emphasis added)

BC Hydro's Application and subsequent IR responses conclude that BC Hydro's assessment of the scope of the duty to consult with the WMFN in respect of the Project was at the low end of the Spectrum.

BC Hydro's response to BCUC IR 1.6.1 indicates why BC Hydro assessed the duty to consult at the low end of the spectrum. Several factors are identified, including:

- DCAT is located in a context where the vast majority of lands are privately held (80% of Project would run through Private lands);
- multiple layers of industrial infrastructure including pre-existing roads and power lines as well as oil and gas effects are already in place (80% of the Project parallels existing linear infrastructure);
- The project is an area where Treaty rights are in force, but where no special lands have been set aside for Indians or to ensure the future viability of Treaty rights (closest Indian reserve is approximately 19km away);
- there was a lack of specific information ('no evidence') regarding the past, present and potential future use of lands (private or crown) for hunting, trapping, fishing, and other practices upon with the WMFN mode of life relies.
- there was a lack of specific information ('no evidence') that DCAT would interfere with wildlife.

It should be noted that the response to BCUC IR 1.5.1 cites the Environmental Overview Assessment (EOA), "Section two … likely serves as a wildlife corridor connecting larger forested tracts on either side of the river to the north and south of the proposed and existing transmission line," and later with regard to mammals and ungulates, that "habitat within the project footprint may also be suitable to a variety of other species of mammals (Table 2) (Eder and Pattie 2001). However, it is not known if any of these species use the habitat within the project footprint as a wildlife corridor."

WMFN made clear, in writing and in meetings, that the DCAT area was important to them, and expressed specific concerns regarding potential impacts to wildlife including fragmentation, wildlife corridors, and a wetland area used by moose (see BCUC IR 1.9.1, and others), and that WMFN is considering crown lands in the area for the purpose of new reserve lands to be established upon settlement of their Treaty Land Entitlement Claim, which is currently under negotiation.

2.1.1 WMFN expressed specific concerns regarding habitat fragmentation and the

cumulative effects of various industrial impacts in the DCAT area in the context of WMFN rights under Treaty No. 8. What steps did BC Hydro take to address the issue of habitat fragmentation and cumulative effects in its assessment?

2.1.2 WMFN expressed specific concerns regarding wildlife corridors in the context of WMFN rights under Treaty No. 8. BC Hydro's response to BCUC IR 1.5.1 indicates that while the DCAT area likely "serves as a wildlife corridor", the studies conducted were not sufficient to identify "if any of these species use the habitat within the project footprint as a wildlife corridor". What steps did BC Hydro take to address the issue of wildlife corridors in its assessment? If the Environmental Overview Assessment (EOA) was, as stated, insufficient to establish the presence of wildlife corridors, how did BC Hydro deem the issue insignificant enough not to warrant additional fieldwork or analysis?

2.1.3 WMFN expressed specific concerns regarding, "a wetland area used by moose" in the context of WMFN rights under Treaty No. 8. BC Hydro's response to WMFN IR 1.8.1 states that, "In the absence of information provided by WMFN to BC Hydro, AMEC identified relevant VEC's and VSC's based on their experience and expertise." Please indicate how WMFN concerns were considered in determining that moose should not be a VEC?

2.1.4 Another culturally important species, Caribou, which is federally listed, and which BC Hydro and its consultants were aware of (see BC Hydro's Application for CPCN, appendix F, p. 178), or should have been aware of as a result of recent public WMFN legal actions, seems to have been considered, but rejected, as a VEC because human impacts in the DCAT area are already so high that their presence is unlikely (see BC Hydro's Application for CPCN, appendix F, p. 178). How did BC Hydro involve WMFN in deciding to reject caribou as a VEC for the purpose of assessing project and cumulative effects?

2.1.5 Given the high percent of private lands in the DCAT area, and existing levels of effect on rare and culturally important species such as caribou, as well as other resources that meaningful practice of Treaty 8 rights depend upon, did BC Hydro consider that the combination of pre- existing development (cumulative effects), and the lack of other provisions in the area to protect Treaty rights may increase (not decrease) the depth or richness of consultation required with WMFN regarding DCAT? If so, what conclusion did BC Hydro come to?

2.1.6 Given the position of the Supreme Court in *Mikisew* (quoted in BC Hydro's response to IR 1.6.3)1, and the BC Court of Appeal in *West Moberly First Nations v.*

---

[1] "The determination of the content of the duty to consult will, as *Haida* suggests, be governed by the context. One variable will be the specificity of the promises made. Another contextual factor will be the seriousness of the impact on the aboriginal people of the Crown's proposed course of action. The more serious the impact the more important will be the role of consultation. The history of dealings between the Crown and a particular First Nation may also be significant. Here, the most important contextual

British Columbia (Chief Inspector of Mines) what steps did BC Hydro take to assess:

a) the extent to which the ability of WMFN members to meaningfully practice Treaty rights in the DCAT area has already been impacted by existing development and taking up of lands?

b) appropriate threshold(s) at which impacts in the DCAT area on mode of life or other WMFN treaty rights would be considered inconsistent with the written and oral promises made through Treaty No. 8?

c) the extent to which DCAT would further contribute to, or exceed, those thresholds?

2.1.7 How was WMFN involved in the assessments noted in IR 2.1.6?

2.1.8 What conclusions did BC Hydro draw from these assessments? If these assessments were not made, how can BC Hydro be certain that past Crown decisions and 'taking up of lands' in the DCAT area have not already exceeded a threshold of impact incompatible with the meaningful practice of WMFN rights under Treaty No. 8?

2.1.9 If BC Hydro is uncertain whether or not DCAT would contribute to a level of development inconsistent with meaningful practice of WMFN treaty rights in the DCAT area, why did BC Hydro not consider the duty to consult with WMFN regarding the Project's effects to be on the moderate to high end of the Haida Spectrum?

2.1.10 Did BC Hydro ever work with WMFN to identify where on the Haida Spectrum WMFN felt DCAT consultation should be? If so, please provide documentation. If not, why not?

2.2 Actual Level of Consultation Achieved with WMFN

Preamble BC Hydro claims that it has achieved a 'medium' level of consultation with WMFN:

"BC Hydro has engaged in medium level consultation with Blueberry River, West Moberly, McLeod Lake and Saulteau First Nations by providing notification and making presentations about the Project, engaging in meetings, ***providing***

---

factor is that Treaty 8 provides a framework within which to manage the continuing changes in land use already foreseen in 1899 and expected, even now, to continue well into the future. In that context, consultation is key to achievement of the overall objective of the modern law of treaty and aboriginal rights, namely reconciliation".

capacity funding where requested, inviting the First Nations to participate in the AMEC environmental overview assessment field surveys, sharing the results of those studies, and continuing to provide updates on the progress of the Project."

In its response to BCUC IR 1.6.3 BC Hydro further states that:

"BC Hydro has provided all interested First Nations with notice of its intentions, an adequate information package that included discussion of alternatives, opportunities to make any concerns they had known to BC Hydro, ***an opportunity to obtain capacity funding if more information gathering was necessary***, an extended period to identify impacts and a commitment to consider fine tuning the route to accommodate concerns within certain limits. All information obtained was put before the responsible decision-maker."

Elsewhere in its responses, BC Hydro notes that, "BC Hydro remains hopeful that WMFN will provide it with TLU and TK information known to WMFN."

WMFN requested funding for a qualitative, community based, impact assessment study to address the issues it felt were most significant (including cumulative effects) in Fall 2010, but those requests were not considered acceptable by BC Hydro. See Letter of Wendy Aasen, Adjunct Professor in the First Nations Studies program at the University of Northern British Columbia, dated October 14, 2010 (the "Aasen Study Proposal"), forwarded to BC Hydro by email on October 20, 2010), appended as <u>Schedule "A".</u>

To date no information gathering or evidence-based study has been agreed on by BC Hydro and WMFN, or conducted.

2.2.1 Because BC Hydro provided information regarding DCAT to WMFN, but did not receive information from WMFN through consultation or studies, or received information but considered it 'outside the scope' or otherwise not significant to its considerations, how did BC Hydro come to the conclusion that it consulted at a medium level, and not find that consultation between BC Hydro and WMFN remained at the 'lowest' or 'most shallow' end of the *Haida* Spectrum which the Supreme Court (*Haida Nation v. British Columbia (Minister of Forests)*, 2004 SCC 73) describes as: "to give notice, disclose information, and discuss any issues raised in response to the notice"?

2.3 Consequence of Lack of Adequate Consultation or Reconciliation:

Preamble The need for the study as a pre-requisite for WMFN consultation on DCAT is highlighted by Professor Aasen at page 7 of her proposal: "only after a Community Study is conducted and baseline information collected

that WMFN can demonstrate (on paper and by map) any concerns that the leadership, elders, and active land users may have related to that proposed development."

BC Hydro's Application for CPCN (Section 6.1.7) states that it has "concluded that the consultation and, where appropriate, accommodation undertaken in connection with the Project has been adequate to support its decision to file this application for a CPCN."

As quoted in response to BCUC IR 1.6.3, the Supreme Court in *Haida* states that:

> **The controlling question in all situations is what is required to maintain the honour of the Crown and to effect reconciliation between the Crown and the Aboriginal peoples with respect to the interests at stake. The Crown may be required to make decisions in the face of disagreement as to the adequacy of its response to Aboriginal concerns. Balance and compromise will then be necessary.**

The response to BCUC IR 1.13.6 states that:

> **On July 12, 2011, in response to the Notice of Regulatory Filing and Invitation to Workshop, West Moberly First Nations Land Use Manager emailed BC Hydro indicating that in his view the Crown had not meaningfully consulted with WMFN, based on the lack of a preliminary assessment, adequate funding, a cumulative impacts assessment and reasonable accommodation.**

2.3.1 As no WMFN evidence-based study has taken place, WMFN has been unable to demonstrate its concerns related to DCAT to BC Hydro. How can BC Hydro then assess the adequacy of its consultation, mitigation, and accommodation, and the adequacy of its *response to* WMFN's concerns ?

2.4 Load Forecast and Economic Rationale:

Top-Down Forecast

Exhibit B-5, BCUC IR 1 Responses, 1.29.1

> "There was a range of opinions with respect to the rate of decline of gas production. BC Hydro's projection lies within the reasonable range of forecasts, based on available information at that time."

2.4.1 Has the available information changed since that time? In particular, have any projected rates of gas production decline from shale gas changed in recent

months and years, to show steeper decline than initially anticipated?

2.4.2 What is the reasonable range of forecasts today?

2.4.3 Would the top-down forecast be different today?

Range of Current Gas Production Projections
Exhibit B-5, BCUC IR 1 Responses, 1.32.1

> "BC Hydro considered a number of sources of information in constructing the gas production forecast, which included forecasts by industry experts. … BC Hydro used forecasts of regional economically-recoverable gas reserves, which came from government agencies and industry sources."

2.4.4 Name the parties that provided said information and provide full source citations for all publicly available and unavailable sources.

2.4.5 Were the industry sources and forecasts from interested parties or disinterested parties, i.e. parties with or without a financial interest in having higher production forecasts?

2.4.6 If any industry sources were identified as disinterested because they are arms length from directly interested parties, have any of those sources worked as consultants or contractors to directly interested parties, or received research funding or any other contributions from directly interested parties?

2.4.7 Were the government sources and forecasts from an order of government that would receive revenues due to investments made in gas exploration, development or production?

Gas Producer Forecast
Exhibit B-5, BCUC IR 1 Responses, 1.35.3, 1.35.3.1

> BCUC: "The Application mentions that as a mitigation strategy, substituting natural gas drive compression with electric drive compression supplied by low carbon power from BC Hydro's electric system offers the potential to significantly reduce the increase in GHG emissions expected as a result of increased activity."
>
> BCH: "Carbon tax on fuel gas has an impact on the relative economics of gas-fired compression compared to electric-drive compression. When constructing the load forecast, BC Hydro considers at a macro-level the effect of a carbon tax on the economics of natural gas as a combustion fuel."

2.4.8 Did BC Hydro take into account potential reductions to GHG emissions from gas compression due to potential improvements in gas compression technology?

2.4.9 Did BC Hydro take into account potential reductions to GHG emissions from gas compression due to regulatory changes (e.g. carbon pricing) that will be required in order to meet existing stated provincial and federal GHG emission reduction targets?

2.4.10 Did BC Hydro take into account the effects of a carbon tax (or other carbon policy) on the economics of electricity for compression, including costs arising from full life-cycle GHG emissions from all aspects of electricity generation, transmission and distribution to gas producers, including (but not limited to) GHG emissions from manufacture, transportation and installation of lines, towers, stations and all other facilities and equipment, as well as GHG emissions from ongoing operations and maintenance?

2.4.11 Were the effects of anticipated carbon pricing, or of any GHG policy mechanisms likely required in order to achieve stated domestic or US emission-reduction targets, included in projections of future natural gas demand or production from the region? If so, please describe, provide calculations, including uncertainty.

Gas Producer Forecast
Exhibit B-5, BCUC IR 1 Responses, 1.35.4

> "BC Hydro is aware of two gas producers that have committed to use gas driven motors for new compression at some of their sites in the Dawson Creek and Groundbirch areas."

2.4.12 For electricity driven compression, BC Hydro considers not only commitments, but also indications of interest. For gas driven compression, has BC Hydro made any attempt to determine whether there is any interest short of commitment?

2.4.13 If so, what attempts did it make and what were the results? if not what attempts were possible but not made?

Producer High and Low Scenarios
Exhibit B-5, BCUC IR 1 Responses, 1.36.2

> BCUC: "Please provide the assumptions relating to: …1) Customers' load requests: those who have committed and those who have indicated interest but have not yet formally committed"
>
> BCH: "Firm customer commitments for service were assigned more weight than other requests."

2.4.14 What weights were both assigned?

2.4.15 In the past, what percentages of potential customers who have indicated interest have actually entered into legal, binding contracts for delivery?

Producer High and Low Scenarios
Exhibit B-5, BCUC IR 1 Responses, 1.36.2

> BCUC: "Please provide the assumptions relating to: …4) The relative cost of natural gas and electricity at which gas producers will opt for natural gas as fuel for production;"
>
> BCH: "BC Hydro's understanding is that electricity service at tariff rates is competitive relative to self-supply of energy (natural gas for fuel) for gas compression, which is the main energy requirement for the sector. BC Hydro has considered the regional resource potential, current applications for service, and the apparent attractiveness of gas vs. electricity from an overall economic perspective. Both these factors among other considerations help to inform BC Hydro assumption of percentage of gas production that would be electrified."

2.4.16 What is the actual cost of both energy sources, in dollars per unit, at which gas producers will opt for natural gas as fuel for production?

2.4.17 What is the range of projections and the mean projection for the cost of gas, in dollars per unit, for gas producers (not wholesale or retail price) over the projected time period of production in the area? Please include sources, calculations and assumptions of those projections.

Load Forecasting Risk
Exhibit B-5, BCUC IR 1 Responses, 1.36.2

> BCUC: "Please provide the assumptions relating to: …4) The emissions reduction targets in B.C. to be met by gas producers"
>
> BCH: "BC Hydro has not explicitly factored gas producer emissions reduction targets into its load forecast. Carbon pricing at current and reasonably foreseeable levels was part of this consideration."

2.4.18 What levels of carbon pricing did BC Hydro actually consider, i.e. the "reasonably foreseeable levels" in dollars per tonne?

2.4.19 Did BC Hydro consider price levels that would be necessary for the BC and Federal governments to achieve their existing stated goals for GHG emission reductions over the next 40-50 years?

2.4.20 Did BC Hydro consider such price levels, in BC and in jurisdictions where gas could be shipped in respect of estimating future natural gas demand, and consequently future natural gas production from the region?

GHG emissions consequences
Exhibit C8-2, BCSA and SCBC IR 1 Responses, 1.8.1

> "BC Hydro notes that the reference quotation from Exhibit B-1, page 2-16, requires modification. It should read: 'Based on the expected electrical load from gas production that would be served via the Project and future upgrades, the avoided/reduced GHG reductions from using electric compressors rather than gas driven compression is in the range of 1 million tonnes per year in B.C.'"

2.4.21 Do the calculations of avoided/reduced GHG emissions take into account full life-cycle emissions from all aspects of electricity generation, transmission and distribution to gas producers, including (but not limited to) GHG emissions from manufacture, transportation and installation of lines, towers, stations and all other facilities and equipment, as well as GHG emissions from ongoing operations and maintenance?

2.4.22 Whether taken into account or not, please provide such calculations of life-cycle emissions.

GHG emissions consequences
Exhibit C8-2, BCSA and SCBC IR 1 Responses, 1.10.5

> "The choice between gas and electricity for compression will not be the primary determinant of the extent of development in the Montney. At the margin however, it is a significant decision that must be made by producers and the choice of reasonably priced electricity <u>may tip the balance in favour of development in particular circumstances</u>. … If the Project did not proceed, then the absence of reasonably priced electricity as an energy source may tip the balance away from development in particular circumstances. <u>Reduced production, however, may increase GHG emissions in other jurisdictions if other, higher emission fuels are used instead. [emphasis added]</u>

2.4.23 Could reduced (or more accurately, foregone increases in) gas production place upward pressure on gas prices over baseline in those other jurisdictions?

2.4.24 Could a higher gas price in those other jurisdictions encourage adaptations that reduce (or forego increases in) overall energy consumption and GHG emissions, such as through boosting efficiency?

2.4.25 Regarding this sentence "Reduced production, however, may increase GHG emissions in other jurisdictions if other, higher emission fuels are used instead" please provide data and calculations supporting this suggestion.

2.4.26 Does BC Hydro's suggestion regarding "higher emission fuels" take into account

recent research, such as the appended article indicating that shale gas could have higher life cycle GHG emissions than coal? See, inter alia, Howarth, Santoro, and Ingraffea, "Methane and the Greenhouse Gas Footprint of Natural Gas from Shale Formations," *Climatic Change Letters*, DOI: 10.1007/s10584-011-0061-5 attached as Schedule "B".

2.5 Induced or Enabled gas production as a result of the Project

(1) Exhibit C8-2, BCSA and SCBC IR 1 Responses, 1.10.5

(2) Developer's response to WMFN IR 1.6.1

(1) "The choice between gas and electricity for compression will not be the primary determinant of the extent of development in the Montney. At the margin however, it is a significant decision that must be made by producers and the choice of reasonably priced electricity may tip the balance in favour of development in particular circumstances. … If the Project did not proceed, then the absence of reasonably priced electricity as an energy source may tip the balance away from development in particular circumstances.

(2) "BC Hydro has not determined that the level and pace of growth anticipated for the Montney shale gas fields is consistent with the current and future practice of WMFN rights under Treaty No. 8 and pursuant to section 35 of the Constitution Act, 1982. The construction of the proposed transmission line will not be a determining factor in connection with other development of Montney shale gas."

Emphases added.

2.5.1 In the first statement above, BC Hydro indicates that for certain marginal gas developments, the availability of reasonably priced electricity (i.e., the Project) may tip the balance, or be a determining factor, in favour of proceeding. In the second statement, BC Hydro seems to say the opposite: the Project will not be a determining factor in connection with Montney shale gas developments. Which of the above is correct?

2.5.2 Since the Project's feasibility appears to hinge on demand from the Montney shale gas play and the "particular circumstances" mentioned in statement 1 above. Please provide predictions regarding the level of otherwise uneconomic shale gas production that will be enabled or induced by availability of electrical compression.

2.5.3 Based on the prediction of enabled or induced increase in shale gas production, please provide a prediction regarding what impacts on water resources, lands available for WMFN use, wildlife, and other resources important for the

meaningful practice of WMFN rights should be expected if the Project proceeds?

2.5.4 Based on the prediction of enabled or induced increase in shale gas production, please provide a prediction regarding what GHG increases would be as a result of extraction of gas resources that would otherwise remain in the ground.

2.6 Transparency and Completeness of Application Consultation Record

In its response to WMFN IR 1.7.1, BC Hydro identifies that it "fully and fairly as possible" provided an accurate summary of consultation up until end of May 2011 in its original Application.

2.6.1 Please identify the location in the original Application where the WMFN's communications of concerns of June 13, 2010 and February 8, 2011 were reported.

2.6.2 If these communications were not reported in the original Application, how does BC Hydro justify the above statement in response to WMFN IR 1.7.1?

2.7 Need for Appropriate Evidence Based Studies

The Aasen Study Proposal outlines the need for an evidence based study and assessment of the Project area, complete with guidance on the budget, timelines and tasks required in order for the WMFN to have "meaningful documented information related to a proposed transmission line". Among the many detailed elements of the outline are estimates that:

a) the costs associated with "a reasonably in-depth study of a smaller project, such as the one being proposed by BC Hydro, ranges from approximately $80,000 to $175,000"; and

b) "Although a year long study is more appropriate… that may not be possible due to potential times of the process BC Hydro wishes to follow… the research I am suggesting, if adequately funded, can likely be completed in 6 months".

2.7.1 In absence of the study proposed by Professor Aasen, (or any other study to inform WMFN and BC Hydro of WMFN rights and interests) what alternate steps did BC Hydro take to ascertain the nature and extent of WMFN rights and interests in the DCAT area?

2.7.2 Was BC Hydro's rejection of the Aasen Study Proposal based on its budget, or on a disagreement with the methodology of the study? What was the substance of

BC Hydro's disagreement, if any, with the cost range, scope, methodology, or timing of evidence based studies proposed by Professor Aasen, for a project of this size, nature and location? Please provide details of any points of disagreement, along with when and how BC Hydro advised WMFN of each.

2.7.3 Professor Aasen uses language in her letter to the effect that "meaningful documented information" regarding WMFN rights and interests can only be gathered through community based studies based on sound social science.

2.7.3.1 Given that no studies with WMFN have been conducted, and with reference to IR 2.7.2 above, and requirements for adequate information under the *BCUC 2010 FN Information Filing Guidelines for Public Utilities*, what implication does this have for the adequacy of consultation for the Project and provision of adequate information to regulators and the Crown upon which to base a decision on whether the project should proceed and under what conditions? Was there "sufficient credible information", as required by the BC Supreme Court in *Tsilhqot'in Nation v. British Columbia*, 2007 BCSC 1700**,** upon which BC Hydro could rely in its assessment of impact?

2.7.3.2 Please identify any Aboriginal consultation experts and their qualifications that provided advice to BC Hydro that the study proposed by Professor Aasen was not required with respect to the DCAT project, along with their supporting rationale. If no experts were consulted, please provide BC Hydro's rationale for not funding said study in the absence of expert advice contrary to Professor Aasen's.

2.7.4 *CONFIDENTIALLY FILED BY WMFN.*

2.7.5 *CONFIDENTIALLY FILED BY WMFN.*

2.7.6 *CONFIDENTIALLY FILED BY WMFN.*

2.8 BC Hydro Estimation of the Need for a WMFN Evidence-Based Study

Preamble: *FILED CONFIDENTIALLY BY WMFN*

2.8.1 *FILED CONFIDENTIALLY BY WMFN,*

2.8.2 *FILED CONFIDENTIALLY BY WMFN*,

2.8.3 *FILED CONFIDENTIALLY BY WMFN*

2.9 Estimation of Significance of Issues, Impacts or Concerns

In the Application Section 3.3.5.3, BC Hydro identifies that the First Nations, including WMFN, identified "no significant issues" during consultation with BC Hydro. The consultation record that has been provided to date indicates that WMFN consistently focused discussion on the need for a community-based study in order to determine potential impact/issue significance, but that it also raised several issues including wildlife and cumulative effects.

2.9.1 Why, given the lack of meaningful information from WMFN, did BC Hydro not identify that not enough information has been gathered in order to make acceptably accurate determinations of potential significant impacts at this point in time, rather than make an impact significance prediction in the absence of sufficient evidence?

2.10 Offers of Funding for "Consultation Activities" and Associated Negotiations

PREAMBLE: *CONFIDENTIALLY FILED BY WMFN.*

2.10.1 *CONFIDENTIALLY FILED BY WMFN.*

2.10.2 *CONFIDENTIALLY FILED BY WMFN.*

2.10.3 *CONFIDENTIALLY FILED BY WMFN.*

2.10.4 *CONFIDENTIALLY FILED BY WMFN.*

2.10.5 *CONFIDENTIALLY FILED BY WMFN.*

2.11 BC Hydro's Request for TUS Information from the WMFN

Preamble: *CONFIDENTIALLY FILED BY WMFN.*

2.11.1 *CONFIDENTIALLY FILED BY WMFN.*

2.11.2 *CONFIDENTIALLY FILED BY WMFN.*

2.12 WMFN Assertion of Aboriginal or Treaty Rights Issues

Preamble: *CONFIDENTIALLY FILED BY WMFN.*

2.12.1 *CONFIDENTIALLY FILED BY WMFN.*

2.12.2 *CONFIDENTIALLY FILED BY WMFN.*

2.12.3 *CONFIDENTIALLY FILED BY WMFN.*

2.13 BC Hydro's Budget for Consultation Funding and Study Funding

Preamble: *CONFIDENTIALLY FILED BY WMFN.*

2.13.1 *CONFIDENTIALLY FILED BY WMFN.*

2.13.2 *CONFIDENTIALLY FILED BY WMFN.*

2.13.3 *CONFIDENTIALLY FILED BY WMFN.*

2.13.4 *CONFIDENTIALLY FILED BY WMFN.*

2.14 Free and Prior Informed Consent

BC Hydro's response to WMFN IR 1.1.1 includes what appears to be a narrow reading of Sections 28 and 32 of the United Nations' International Declaration on the Rights of Indigenous Peoples.

Article 28 of the Declaration states:

1. Indigenous peoples have the right to redress, by means that can include restitution or, when this is not possible, just, fair and equitable compensation, for the lands, territories and resources which they have traditionally owned or otherwise occupied or used, and which have been confiscated, taken, occupied, used or damaged without their free, prior and informed consent.

2.14.1 WMFN notes that BC Hydro paraphrases Article 28 as "confiscation of lands" when identifying that in its estimation this clause does not apply to the Project. In doing so, BC Hydro suggests that Article 28 is limited to "confiscation of land". Is it BC Hydro's understanding, from the information obtained to date, that WMFN as a people or individual members therein have "traditionally owned or otherwise occupied or used" lands in the East Pine area that may be "taken, occupied, used, or damaged" by the proposed Project? If so, please respond to WMFN IR 1.1.1. in relation to Article 28.

2.15 WMFN Engagement in Mitigation Measure Development

In its response to WMFN IR 1.2.2, BC Hydro identifies that AMEC, BC Hydro's consultant, recommended a number of mitigation measures.

2.15.1 How many of those mitigation measures were generated in part or wholly by engagement or other inputs by WMFN?

2.15.2 How many of those mitigation measures were provided to WMFN for advance comment prior to filing of the Application?

2.16 BC Hydro's Decision to Proceed with the DCAT Application

In BC Hydro's response to BCUC IR 1.3.2, it is established that Mr. Greg Reimer, delegate of the CEO of BC Hydro, made the decision to proceed with the BCUC Application on July 7, 2011.

2.16.1 How and on what basis did he determine that filing of the application was consistent with the honour of the Crown and its duties in relation to WMFN? What did he review in making this decision, with whom did he consult, and what did the consultation produce? Please provide any documents that were developed to inform Greg Reimer's decision, or in the course of his decision.

2.16.2 At the time of Greg Reimer's determination, were any concerns with the consultation with WMFN raised? If so, what were the concerns? How was the sufficiency of consultation determined?

2.17 Cumulative Effects Assessment

BCUC IR 1.11.1 asked for BC Hydro's response to the Blueberry River First Nations request for a regional cumulative assessment for the area. BC Hydro's response consists of a reference to an April 27, 2011 letter from BC Hydro to BRFN. This letter refuses the request for a cumulative assessment, despite the importance placed upon it by BRFN, stating:

- **"As part of the DCAT Project, an assessment of the future needs for transmission lines in this area was undertaken. However, exhaustive assessments of the cumulative impacts of resource development in the area over the past 100 years; and future forestry, mining; pipeline and**

road development in the area are beyond the scope of the DCAT Project."

WMFN refers BC Hydro to its IR 2.5.3 and the following BC Hydro submissions, to consider when reviewing this IR:

(1) Exhibit C8-2, BCSA and SCBC IR 1 Responses, 1.10.5

(2) BC Hydro's response to WMFN IR 1.6.1

2.17.1 In BC Hydro's opinion, is the only possible meaningful assessment of cumulative effects an "exhaustive assessment of the cumulative impacts of resource development in the area over the past 100 years"? If not, what would be a reasonable level of cumulative effects assessment, given First Nations' concerns about past, present and potential future reductions in the available land base for meaningful practice of Aboriginal or treaty rights?

2.17.2 Why does BC Hydro feel that any development induced in whole or in part by the availability of "reasonably priced electricity" provided by DCAT is beyond the scope of this assessment and not the responsibility of BC Hydro to consider in a cumulative effects assessment of the Project? Was WMFN involved in determining the scope of assessment? If so, how?

2.18 Continued Consultation

BCUC IR 1.13.4.1 asks BC Hydro about whether, how and when any First Nations will have further opportunity for input into the routing of the transmission line, and how input will be incorporated.

2.18.1 If potential adverse impacts were identified by a WMFN TUS or related assessment study, how would these impacts be incorporated into the decision on whether to approve the transmission line, and then into the route and construction as well as in the future monitoring and follow-up activities? BC Hydro has stated that "minor" route changes would be possible, but what if a greater deviation is called for by WMFN, and is required to mitigate adverse impacts identified by the study?

2.18.2 If approval from BCUC is given, what assurances can BC Hydro provide WMFN that BC Hydro will consult adequately, and that further input into the transmission line route will be considered and dealt with appropriately?

2.18.3 If approval is granted, what recourse does WMFN have in the future if they feel BC Hydro is failing to engage in meaningful ongoing consultation, or they feel BC Hydro is not taking appropriate steps to accommodate/mitigate their concerns?

2.19 BC Hydro Assessment of Project Cost Risks

In its response to BCUC IR 1.15.1, BC Hydro states that cost risks, in particular schedule delays, due to First Nations issues are low.

2.19.1 If it is determined that additional information is required because one or more of the following deficiencies are determined by BCUC, how would this alter BC Hydro's "risk assessment" related to project delays and associated costs:

- The need for meaningful cumulative effects assessment in relation to the practice of Treaty 8 rights
- The need for full disclosure and review of First Nations consultation documentation
- The need for a WMFN and the lack of adequate evidence for the BCUC to make an informed decision and meet its constitutional duty to consider the adequacy of BC Hydro's consultation, and Project's impact on Aboriginal or treaty rights, as stated in the First Nations Information Filing Guidelines for Crown Utilities*, Carrier Sekani Tribal Council v. British Columbia (Utilities Commission)* 2009 BCCA 67, and *Kwikwetlem First Nation v. British Columbia (Utilities Commission)* 2009 BCCA 68.Inadequate scope of assessment in the EOA, including lack of adequate provision of information about wildlife

2.19.2 How can the prediction of this "risk assessment" of a low probability of time delays be reconciled with the fact that the assessment study WMFN seeks and upon which hinges any meaningful input by the WMFN, has yet to be commenced, and the form of the study is still in contention?

2.20 WMFN Involvement in Environmental Management Planning

BC Hydro's response to WMFN'S IR 1.17.2 states that the WMFN will receive draft copies of the Environmental Management Plan (EMP) for review and comment, and singles out the WMFN as receiving some form of preferential treatment – "BC Hydro has made an effort to provide WMFN with an opportunity for early input into initial drafting of the EMP".

2.20.1 Does the "effort to provide WMFN with an opportunity for early input into initial drafting of the EMP" refer to the September 8, 2011 letter and the deadlines imposed therein?

2.20.2 No mention is made of capacity funding for First Nations in the response to WMFN IR 1.17.2. Will BC Hydro provide adequate assistance or capacity funding to WMFN in order to allow it to meaningfully participate in the drafting, design, and technical review of the EMP?

2.20.3 Will input from WMFN on the EMP be sought in time to allow for meaningful consideration of WMFN comment prior to final submissions to the BCUC on DCAT? If not, what assurances can be provided that WMFN will have meaningful input?

SCHEDULE "A"

October 14, 2010

Wendy Aasen
9623 110th Ave.
Edmonton, Alberta
T5H 1H6

Chief and Council
West Moberly First Nations
Post Office Box 90
Moberly Lake, British Columbia
VOC 1X0

Dear Chief and Council:

I write this letter in response to West Moberly First Nations' (WMFN) Land Use Manager (LUM), Bruce Muir's, request for an outline of a community-based study relating to BC Hydro's potential development of the proposed Dawson-to-Chetwynd Transmission Line (the "proposed Transmission Line") through your territory.

In preparing this outline, I have reviewed the information for the proposed Transmission Line that is available on BC Hydro website as well as BC Hydro's draft Traditional Use Study – Terms of Reference and I have also been informed of BC Hydro's proposed timelines for the study to be completed. Based on my experience, the study proposed by BC Hydro is scientifically and cultural inappropriate. As such, in what follows I provide a general outline of a study and a draft budget that I would recommend as an appropriate response to the nature and scope of the proposed Transmission Line.

As any community-based social researcher is aware, the first step in any study is information and data collection (documentation) and, obviously, for any true community study, Elders and active land users must be heavily involved in all stages.

A study on the proposed Transmission Line ought to include a variety of methodologies, including: Elder/Active land user interviews, community workshops (e.g. land user circles), and fieldwork (site-based visits by vehicle and/or camps including a complete examination of the route of the proposed development), as well as mapping (e.g. user mapping exercise, GIS analysis). Any land base that might be affected by a development should be viewed at various times of the year because, as you are aware, this preferred method allows Elders to use specific knowledge related to the interconnected systems operating in the environment and juxtapose that knowledge to the proposed development.

After the knowledge is documented, transcription and data analysis must occur. Report writing, a third phase in any research, is best left to a well trained professional who can translate project results into a framework understandable to those who come with scientific point of view. The usual amount budgeted for a reasonably in-depth study of a smaller project, such as the one being proposed by BC Hydro, ranges from approximately $80,000.00 to $175,000.00 for a community the size of WMFN.

Although a year long study is more appropriate with respect to socio-scientific validity and likely community standards, I understand that may not possible due to potential times of the process BC Hydro wishes to follow (pers. comm., LUM). Given this potential tradeoff therefore, the research I am suggesting, if adequately funded, can likely be completed in 6 months during the later part of the fall dry-meat hunting season and early and mid-winter trapping season (October to January). If started in October, the entire project could be completed with write up by roughly March or April of 2011.

The following provides a brief outline of the research that could be done to equip your Nation with meaningful documented information related to a proposed Transmission Line. To be truly community-based, the input of the community is required even in this initial project design stage.

Components and Objectives of WMFN's Study of the Proposed Transmission Line

The objectives of a WMFN study should be to document and analyze information from community members related to the development of the proposed Transmission Line. The following are some goals and objectives relevant to such a study.

1. Adhere to WMFN's *Custom Code of Governance*[1];
2. Uphold Treaty No. 8 and the accompanying documents, including the spirit and intent;
3. To retrieve existing information on the area of the proposed transmission line development;
4. To document the different species of plants and animals found in area of the proposed transmission line development;
5. To collect and document knowledge on WMFN's past, present and potential future use of that area;
6. To document present environmental conditions that may be positively or negatively affected if the development were to proceed;
7. To document general and site specific information related to the proposed Transmission Line that could, if appropriate, be mapped; and,
8. To produce a final report (the "Report") that could lead to meaningful communication between WMFN and BC Hydro.

The proposed study could/should draw on information from five sources:

A. Existing sources of information (literature);
B. Individual interviews with Elders and active land users;
C. Community workshops
D. Field study of the area where the development is proposed to occur; and,
E. Mapping.

[1] What makes WMFN different from other First Nations in northeast British Columbia is the manner in which the Nation is governed. WMFN follows a *Custom Code of Governance* (the "Code"), whereas other First Nations by and large adhere to the structure of Indian and Northern Affairs Canada. The Code has requirements that are both procedural and substantive in nature. There are four families within the Nation, all of whom must equally participate in the process and their concerns be treated as part of WMFN's collective voice. This translates into, for example, an equal amount of members from each family being interviewed (pers. comm., LUM).

A. Documents Research

A researcher should review existing studies produced by/for the company (and studies produced by others) that might inform WMFN's study.

B. The Oral Interview Component (Individual)

In order to create a baseline study of WMFN's use (and potential future use) of the area and potential concerns related to the development of the proposed Transmission Line, the study must precede using community consultants. The baseline study should rely on men and women who participate and are knowledgeable in, for example, trapping, hunting, gathering and plant harvesting with special reference the area in and around where the proposed Transmission Line may be located.

Representatives from each of the four major families should be interviewed. Two different methods are proposed: (1) individual interviews (and perhaps small focus groups), and (2) map interviews.

C. Elder/Community Workshops

Information should also be obtained through workshop (community meeting or focus group) discussions. These gathering will maximize community input into scoping out the issues, will increase awareness of the research and methods, and will allow for community direction into the process and content of the study. At the heart of a Community Study are people: their social and economic concerns, their perceptions of risk and health, their recommendation for management and mitigation, and their integrated knowledge about cause and effect.

D. Field Component

Members of the Nation should be directly involved with environmental and biophysical field studies; I recommend that four youth members (or active land users), one from each family, participate in field component of the study. By accompanying knowledgeable harvesters on the land information can be recorded by video or digitally taped. Transcriptions and indexes should be produced from these recordings.

This proposal allows for 8 Elders to be on the land for four day trips (or for the study to be conducted from camps). As part of the Community Study, this opportunity will allow WMFN to document existing conditions on the landscape and along the proposed transmission line route, and to collect and document all forms of data related to the use of the landscape, conditions of habitat, and so forth.

Portions of the information should be transcribed, passed to the GIS team for mapping, and then archived. In the case of some land based observations, information could be recorded by the WMFN field teams with the use of GPS technology.

D. TUS Mapping

With the application of GIS technology, traditional and contemporary land use information should/could be mapped. Where practical, this could include site specific information, however,

Elders' and other harvesters use broad areas (not specific sites) and the GIS methodology should reflect this. A comprehensive plan for GIS mapping ought to be established before the actual commencement of the research. Map interviews could be conducted by one person specifically trained in the methodology. Map Interviews should be recorded for cases where there is the need for information clarification or review. Given the direction of the United Nation pertaining to indigenous knowledge, which has recognized what I consider appropriate practices in my discipline, all of this information would be used and protected at the discretion of the individual and Nation because of its proprietary nature.

STAGES OF RESEARCH AND RESEARCH SCHEDULE

At least 6 months will be needed to complete the WMFN Community Study. While the study will be limited by budget and time constraints a general schedule follows to show how a study could unfold. After the schedule there is a summary of how such a project could be managed and staffed and a budget.

Proposed Schedule

October - November

- Existing Literature Review;
- Setting information flow systems;
- Purchasing equipment;
- Hiring and training;
- Elder/Land User Workshop #1;
- Field Study #1;
- Individual Interviews (starts and continues until January/February);
- Map interviews (starts and continues until the end of January);
- Interview Indexing and transcription (starts and continues until the end February/March); and,
- GIS Mapping starts (and continues until the end of February).

November – December (perhaps January/February)

- Field Study #2; and,
- Field Study # 3.

December – January (perhaps January/February)

- Field Study #4;
- Elder/Land User Workshop #2;
- Acetate mapping/GIS Mapping continues;
- Elder and land users interviews complete; and,
- Field studies complete.

January – February (perhaps March)

- Completion of research; and,
- Completion of transcribing and archiving and mapping.

February – March (perhaps April)

- Analysis of results;
- Report writing;
- Community review; and,
- Dissemination of results.

Please note that the above is an example of a potential schedule. It is my understanding that WMFN is closed for much of December and some of January, which is why I've included "perhaps" and additional months in the example of an outline. Other community matters may influence the schedule as well. It is also important for the parties to take into account other works, such as additional consultation processes and assessments, maybe occurring concurrently and will likely influence the Community Study, and vice versa. So the schedule would have to be adjusted accordingly and be revisited throughout the study when necessary. Clearly, the initial timeline would have to be designed and then agreed to by WMFN and BC Hydro prior to the study starting.

PROJECT MANAGEMENT, ORGANIZATION, AND STAFFING

The following is a list of project personnel that are proposed for use in the WMFN Community Study, including both full-time and part-time positions:

Project Coordinator/Administrator

- Project manager (from inside the community) who would be responsible for keeping activities on schedule and within budget.

Transcriber

- The purpose of this position is for reviewing, transcribing, duplicating, and archiving and filing audio and video/digital material and notes from individual interviews, field studies, and workshops. He/she will assist other duties as assigned by the Project Coordinator.

Community Interviewers

- Individual (and perhaps small groups) interviews will be conducted, when possible, by a family member or another person that is well-known by the Elder and/or Land User. Recommended are at least 4 interviewers who would conduct (for budgeting factors only) a minimum of 6 interviewees within each family.

Translator/Interpreter

- The budget will need to allow for a translator(s) and/or interpreter(s) for each interview. It is important based on time lines to have an English translation recorded as part of the interview for subsequent transcription. Also, the individual(s) will provide translation when the Elders speak Dunne-za or Cree at the workshops.

Workshop Facilitator

- He or she will be responsible for organizing and facilitating the two Elder/Land User workshops.

Elders, Active Land Users, Community members (Workshops)

- The budget needs to allow for the proper inclusion of the community and its four families; for example, a minimum of 24 individuals consisting of Elders, land user and community participants to attend two workshops.

Researcher/Consultant

- He or she will gather material and biophysical studies and review them. It is my understanding that this role is referred to as a "Third Party Reviewer" by WMFN. While the budget for this process is separate from that of the Community Study, the information feeds into the overall process. The specific amount for the Third Party Reviewer ranges and is best determined on a case-by-case basis between the parties.

Field Researchers

- Four people will be selected to drive, participate in, and document the Elders/Land Users while in the field.

Camera and Video technician(s)

- This individual would be responsible for recording WMFN information and observations while in the field and at the Elder Community/Member workshops (for downloading it, and burning it to disc if that is the format chosen).

GIS Technician/Map Interviewer

- A GIS technician will be responsible for establishing the parameters and specifications for TUS mapping, and for ensuring that information is digitized. He/she will also assist the Project Coordinator with the use of GIS technology and with map interpretation.

Consultant

- The role of the consultant will be to train interviewers (where that training is necessary). The training will involve imparting the importance of standardization in research methods and developing survey instruments. The consultant will be responsible for producing the final project report.

In thinking about the design of this project, collaboration and a community-based approach is key. An interview project, site visits, community workshops, and existing literature review, with a mapping component, will collect the information important to the consideration of the proposed Transmission Line that is proposed to be constructed through WMFN's territory.

WMFN is capable of conducting the study themselves (with minimal assistance), using traditional ways and methods, and eloquently communicating that information. However, it is only after a Community Study is conducted and baseline information collected that WMFN can demonstrate (on paper and by map) any concerns that the leadership, elders, and active land users may have related to that proposed development.

Please note that my comments and recommendations are based largely on experience and a brief conversation with your LUM, rather than specific direction from Chief & Council and/or Elders. In view of that, and in the case that the Nation (or perhaps BC Hydro) would like a more detailed proposal for the study and third party review, I would recommend that you request $15,000 in seed funding from BC Hydro to prepare a more comprehensive proposal. Such funding could be used to cover costs relating to proposal development and costs associated with travelling to the community in order to meeting with Chief & Council and community members such as Elders. Such an approach is likely to produce a more culturally appropriate and sound study and review of the proposed Transmission Line.

The general outline of the community-based approach that I have provided is based on over 20 years of directly working with First Nations in the sub-arctic, and as an Adjunct Professor/Lecturer in the First Nations studies program at the University of Northern British Columbia, a position held from 2000 to present.

Please let me know if you have any questions. I look forward to hearing from you.

Sincerely,

Wendy Aasen

PC: Bruce Muir, Land Use Manger, West Moberly First Nations

SCHEDULE "B"

Climatic Change
DOI 10.1007/s10584-011-0061-5

LETTER

Methane and the greenhouse-gas footprint of natural gas from shale formations

A letter

Robert W. Howarth · Renee Santoro · Anthony Ingraffea

Received: 12 November 2010 / Accepted: 13 March 2011

Abstract We evaluate the greenhouse gas footprint of natural gas obtained by high-volume hydraulic fracturing from shale formations, focusing on methane emissions. Natural gas is composed largely of methane, and 3.6% to 7.9% of the methane from shale-gas production escapes to the atmosphere in venting and leaks over the lifetime of a well. 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. 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, dominating it on a 20-year time horizon. The footprint for shale gas is greater than that for conventional gas or oil 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.

Keywords Methane · Greenhouse gases · Global warming · Natural gas · Shale gas · Unconventional gas · Fugitive emissions · Lifecycle analysis · LCA · Bridge fuel · Transitional fuel · Global warming potential · GWP

Electronic supplementary material The online version of this article (doi:10.1007/s10584-011-0061-5) contains supplementary material, which is available to authorized users.

R. W. Howarth (✉) · R. Santoro
Department of Ecology and Evolutionary Biology, Cornell University, Ithaca, NY 14853, USA
e-mail: rwh2@cornell.edu

A. Ingraffea
School of Civil and Environmental Engineering, Cornell University, Ithaca, NY 14853, USA

Many view natural gas as a transitional fuel, allowing continued dependence on fossil fuels yet reducing greenhouse gas (GHG) emissions compared to oil or coal over coming decades (Pacala and Socolow 2004). Development of "unconventional" gas dispersed in shale is part of this vision, as the potential resource may be large, and in many regions conventional reserves are becoming depleted (Wood et al. 2011). Domestic production in the U.S. was predominantly from conventional reservoirs through the 1990s, but by 2009 U.S. unconventional production exceeded that of conventional gas. The Department of Energy predicts that by 2035 total domestic production will grow by 20%, with unconventional gas providing 75% of the total (EIA 2010a). The greatest growth is predicted for shale gas, increasing from 16% of total production in 2009 to an expected 45% in 2035.

Although natural gas is promoted as a bridge fuel over the coming few decades, in part because of its presumed benefit for global warming compared to other fossil fuels, very little is known about the GHG footprint of unconventional gas. Here, we define the GHG footprint as the total GHG emissions from developing and using the gas, expressed as equivalents of carbon dioxide, per unit of energy obtained during combustion. The GHG footprint of shale gas has received little study or scrutiny, although many have voiced concern. The National Research Council (2009) noted emissions from shale-gas extraction may be greater than from conventional gas. The Council of Scientific Society Presidents (2010) wrote to President Obama, warning that some potential energy bridges such as shale gas have received insufficient analysis and may aggravate rather than mitigate global warming. And in late 2010, the U.S. Environmental Protection Agency issued a report concluding that fugitive emissions of methane from unconventional gas may be far greater than for conventional gas (EPA 2010).

Fugitive emissions of methane are of particular concern. Methane is the major component of natural gas and a powerful greenhouse gas. As such, small leakages are important. Recent modeling indicates methane has an even greater global warming potential than previously believed, when the indirect effects of methane on atmospheric aerosols are considered (Shindell et al. 2009). The global methane budget is poorly constrained, with multiple sources and sinks all having large uncertainties. The radiocarbon content of atmospheric methane suggests fossil fuels may be a far larger source of atmospheric methane than generally thought (Lassey et al. 2007).

The GHG footprint of shale gas consists of the direct emissions of CO_2 from end-use consumption, indirect emissions of CO_2 from fossil fuels used to extract, develop, and transport the gas, and methane fugitive emissions and venting. Despite the high level of industrial activity involved in developing shale gas, the indirect emissions of CO_2 are relatively small compared to those from the direct combustion of the fuel: 1 to 1.5 g C MJ^{-1} (Santoro et al. 2011) vs 15 g C MJ^{-1} for direct emissions (Hayhoe et al. 2002). Indirect emissions from shale gas are estimated to be only 0.04 to 0.45 g C MJ^{-1} greater than those for conventional gas (Wood et al. 2011). Thus, for both conventional and shale gas, the GHG footprint is dominated by the direct CO_2 emissions and fugitive methane emissions. Here we present estimates for methane emissions as contributors to the GHG footprint of shale gas compared to conventional gas.

Our analysis uses the most recently available data, relying particularly on a technical background document on GHG emissions from the oil and gas industry (EPA 2010) and materials discussed in that report, and a report on natural gas losses on federal lands from the General Accountability Office (GAO 2010). The

EPA (2010) report is the first update on emission factors by the agency since 1996 (Harrison et al. 1996). The earlier report served as the basis for the national GHG inventory for the past decade. However, that study was not based on random sampling or a comprehensive assessment of actual industry practices, but rather only analyzed facilities of companies that voluntarily participated (Kirchgessner et al. 1997). The new EPA (2010) report notes that the 1996 "study was conducted at a time when methane emissions were not a significant concern in the discussion about GHG emissions" and that emission factors from the 1996 report "are outdated and potentially understated for some emissions sources." Indeed, emission factors presented in EPA (2010) are much higher, by orders of magnitude for some sources.

1 Fugitive methane emissions during well completion

Shale gas is extracted by high-volume hydraulic fracturing. Large volumes of water are forced under pressure into the shale to fracture and re-fracture the rock to boost gas flow. A significant amount of this water returns to the surface as flow-back within the first few days to weeks after injection and is accompanied by large quantities of methane (EPA 2010). The amount of methane is far more than could be dissolved in the flow-back fluids, reflecting a mixture of fracture-return fluids and methane gas. We have compiled data from 2 shale gas formations and 3 tight-sand gas formations in the U.S. Between 0.6% and 3.2% of the life-time production of gas from wells is emitted as methane during the flow-back period (Table 1). We include tight-sand formations since flow-back emissions and the patterns of gas production over time are similar to those for shale (EPA 2010). Note that the rate of methane emitted during flow-back (column B in Table 1) correlates well to the initial production rate for the well following completion (column C in Table 1). Although the data are limited, the variation across the basins seems reasonable: the highest methane emissions during flow-back were in the Haynesville, where initial pressures and initial production were very high, and the lowest emissions were in the Uinta, where the flow-back period was the shortest and initial production following well completion was low. However, we note that the data used in Table 1 are not well documented, with many values based on PowerPoint slides from EPA-sponsored workshops. For this paper, we therefore choose to represent gas losses from flow-back fluids as the mean value from Table 1: 1.6%.

More methane is emitted during "drill-out," the stage in developing unconventional gas in which the plugs set to separate fracturing stages are drilled out to release gas for production. EPA (2007) estimates drill-out emissions at 142×10^3 to 425×10^3 m^3 per well. Using the mean drill-out emissions estimate of 280×10^3 m^3 (EPA 2007) and the mean life-time gas production for the 5 formations in Table 1 (85×10^6 m^3), we estimate that 0.33% of the total life-time production of wells is emitted as methane during the drill-out stage. If we instead use the average life-time production for a larger set of data on 12 formations (Wood et al. 2011), 45×10^6 m^3, we estimate a percentage emission of 0.62%. More effort is needed to determine drill-out emissions on individual formation. Meanwhile, in this paper we use the conservative estimate of 0.33% for drill-out emissions.

Combining losses associated with flow-back fluids (1.6%) and drill out (0.33%), we estimate that 1.9% of the total production of gas from an unconventional shale-gas

Table 1 Methane emissions during the flow-back period following hydraulic fracturing, initial gas production rates following well completion, life-time gas production of wells, and the methane emitted during flow-back expressed as a percentage of the life-time production for five unconventional wells in the United States

	(A) Methane emitted during flow-back (10^3 m^3)[a]	(B) Methane emitted per day during flow-back (10^3 m^3 day^{-1})[b]	(C) Initial gas production at well completion (10^3 m^3 day^{-1})[c]	(D) Life-time production of well (10^6 m^3)[d]	(E) Methane emitted during flow-back as % of life-time production[e]
Haynesville (Louisiana, shale)	6,800	680	640	210	3.2
Barnett (Texas, shale)	370	41	37	35	1.1
Piceance (Colorado, tight sand)	710	79	57	55	1.3
Uinta (Utah, tight sand)	255	51	42	40	0.6
Den-Jules (Colorado, tight sand)	140	12	11	?	?

Flow-back is the return of hydraulic fracturing fluids to the surface immediately after fracturing and before well completion. For these wells, the flow-back period ranged from 5 to 12 days

[a]Haynesville: average from Eckhardt et al. (2009); Piceance: EPA (2007); Barnett: EPA (2004); Uinta: Samuels (2010); Denver-Julesburg: Bracken (2008)

[b]Calculated by dividing the total methane emitted during flow-back (column A) by the duration of flow-back. Flow-back durations were 9 days for Barnett (EPA 2004), 8 days for Piceance (EPA 2007), 5 days for Uinta (Samuels 2010), and 12 days for Denver-Julesburg (Bracken 2008); median value of 10 days for flow-back was assumed for Haynesville

[c]Haynesville: http://shale.typepad.com/haynesvilleshale/2009/07/chesapeake-energy-haynesville-shale-decline-curve.html1/7/2011 and http://oilshalegas.com/haynesvilleshalestocks.html; Barnett: http://oilshalegas.com/barnettshale.html; Piceance: Kruuskraa (2004) and Henke (2010); Uinta: http://www.epmag.com/archives/newsComments/6242.htm; Denver-Julesburg: http://www.businesswire.com/news/home/20100924005169/en/Synergy-Resources-Corporation-Reports-Initial-Production-Rates

[d]Based on averages for these basins. Haynesville: http://shale.typepad.com/haynesvilleshale/decline-curve/); Barnett: http://www.aapg.org/explorer/2002/07jul/barnett_shale.cfm and Wood et al. (2011); Piceance: Kruuskraa (2004); Uinta: http://www.epmag.com/archives/newsComments/6242.htm

[e]Calculated by dividing column (A) by column (D)

Table 2 Fugitive methane emissions associated with development of natural gas from conventional wells and from shale formations (expressed as the percentage of methane produced over the lifecycle of a well)

	Conventional gas	Shale gas
Emissions during well completion	0.01%	1.9%
Routine venting and equipment leaks at well site	0.3 to 1.9%	0.3 to 1.9%
Emissions during liquid unloading	0 to 0.26%	0 to 0.26%
Emissions during gas processing	0 to 0.19%	0 to 0.19%
Emissions during transport, storage, and distribution	1.4 to 3.6%	1.4 to 3.6%
Total emissions	1.7 to 6.0%	3.6 to 7.9%

See text for derivation of estimates and supporting information

well is emitted as methane during well completion (Table 2). Again, this estimate is uncertain but conservative.

Emissions are far lower for conventional natural gas wells during completion, since conventional wells have no flow-back and no drill out. An average of 1.04×10^3 m^3 of methane is released per well completed for conventional gas (EPA 2010), corresponding to 1.32×10^3 m^3 natural gas (assuming 78.8% methane content of the gas). In 2007, 19,819 conventional wells were completed in the US (EPA 2010), so we estimate a total national emission of 26×10^6 m^3 natural gas. The total national production of onshore conventional gas in 2007 was 384×10^9 m^3 (EIA 2010b). Therefore, we estimate the average fugitive emissions at well completion for conventional gas as 0.01% of the life-time production of a well (Table 2), three orders of magnitude less than for shale gas.

2 Routine venting and equipment leaks

After completion, some fugitive emissions continue at the well site over its lifetime. A typical well has 55 to 150 connections to equipment such as heaters, meters, dehydrators, compressors, and vapor-recovery apparatus. Many of these potentially leak, and many pressure relief valves are designed to purposefully vent gas. Emissions from pneumatic pumps and dehydrators are a major part of the leakage (GAO 2010). Once a well is completed and connected to a pipeline, the same technologies are used for both conventional and shale gas; we assume that these post-completion fugitive emissions are the same for shale and conventional gas. GAO (2010) concluded that 0.3% to 1.9% of the life-time production of a well is lost due to routine venting and equipment leaks (Table 2). Previous studies have estimated routine well-site fugitive emissions as approximately 0.5% or less (Hayhoe et al. 2002; Armendariz 2009) and 0.95% (Shires et al. 2009). Note that none of these estimates include accidents or emergency vents. Data on emissions during emergencies are not available and have never, as far as we can determine, been used in any estimate of emissions from natural gas production. Thus, our estimate of 0.3% to 1.9% leakage is conservative. As we discuss below, the 0.3% reflects use of best available technology.

Additional venting occurs during "liquid unloading." Conventional wells frequently require multiple liquid-unloading events as they mature to mitigate water intrusion as reservoir pressure drops. Though not as common, some unconventional wells may also require unloading. Empirical data from 4 gas basins indicate that 0.02

to 0.26% of total life-time production of a well is vented as methane during liquid unloading (GAO 2010). Since not all wells require unloading, we set the range at 0 to 0.26% (Table 2).

3 Processing losses

Some natural gas, whether conventional or from shale, is of sufficient quality to be "pipeline ready" without further processing. Other gas contains sufficient amounts of heavy hydrocarbons and impurities such as sulfur gases to require removal through processing before the gas is piped. Note that the quality of gas can vary even within a formation. For example, gas from the Marcellus shale in northeastern Pennsylvania needs little or no processing, while gas from southwestern Pennsylvania must be processed (NYDEC 2009). Some methane is emitted during this processing. The default EPA facility-level fugitive emission factor for gas processing indicates a loss of 0.19% of production (Shires et al. 2009). We therefore give a range of 0% (i.e. no processing, for wells that produce "pipeline ready" gas) to 0.19% of gas produced as our estimate of processing losses (Table 2). Actual measurements of processing plant emissions in Canada showed fourfold greater leakage than standard emission factors of the sort used by Shires et al. (2009) would indicate (Chambers 2004), so again, our estimates are very conservative.

4 Transport, storage, and distribution losses

Further fugitive emissions occur during transport, storage, and distribution of natural gas. Direct measurements of leakage from transmission are limited, but two studies give similar leakage rates in both the U.S. (as part of the 1996 EPA emission factor study; mean value of 0.53%; Harrison et al. 1996; Kirchgessner et al. 1997) and in Russia (0.7% mean estimate, with a range of 0.4% to 1.6%; Lelieveld et al. 2005). Direct estimates of distribution losses are even more limited, but the 1996 EPA study estimates losses at 0.35% of production (Harrison et al. 1996; Kirchgessner et al. 1997). Lelieveld et al. (2005) used the 1996 emission factors for natural gas storage and distribution together with their transmission estimates to suggest an overall average loss rate of 1.4% (range of 1.0% to 2.5%). We use this 1.4% leakage as the likely lower limit (Table 2). As noted above, the EPA 1996 emission estimates are based on limited data, and Revkin and Krauss (2009) reported "government scientists and industry officials caution that the real figure is almost certainly higher." Furthermore, the IPCC (2007) cautions that these "bottom-up" approaches for methane inventories often underestimate fluxes.

Another way to estimate pipeline leakage is to examine "lost and unaccounted for gas," e.g. the difference between the measured volume of gas at the wellhead and that actually purchased and used by consumers. At the global scale, this method has estimated pipeline leakage at 2.5% to 10% (Crutzen 1987; Cicerone and Oremland 1988; Hayhoe et al. 2002), although the higher value reflects poorly maintained pipelines in Russia during the Soviet collapse, and leakages in Russia are now far less (Lelieveld et al. 2005; Reshetnikov et al. 2000). Kirchgessner et al. (1997) argue against this approach, stating it is "subject to numerous errors including gas theft, variations in

temperature and pressure, billing cycle differences, and meter inaccuracies." With the exception of theft, however, errors should be randomly distributed and should not bias the leakage estimate high or low. Few recent data on lost and unaccounted gas are publicly available, but statewide data for Texas averaged 2.3% in 2000 and 4.9% in 2007 (Percival 2010). In 2007, the State of Texas passed new legislation to regulate lost and unaccounted for gas; the legislation originally proposed a 5% hard cap which was dropped in the face of industry opposition (Liu 2008; Percival 2010). We take the mean of the 2000 and 2007 Texas data for missing and unaccounted gas (3.6%) as the upper limit of downstream losses (Table 2), assuming that the higher value for 2007 and lower value for 2000 may potentially reflect random variation in billing cycle differences. We believe this is a conservative upper limit, particularly given the industry resistance to a 5% hard cap.

Our conservative estimate of 1.4% to 3.6% leakage of gas during transmission, storage, and distribution is remarkably similar to the 2.5% "best estimate" used by Hayhoe et al. (2002). They considered the possible range as 0.2% and 10%.

5 Contribution of methane emissions to the GHG footprints of shale gas and conventional gas

Summing all estimated losses, we calculate that during the life cycle of an average shale-gas well, 3.6 to 7.9% of the total production of the well is emitted to the atmosphere as methane (Table 2). This is at least 30% more and perhaps more than twice as great as the life-cycle methane emissions we estimate for conventional gas, 1.7% to 6%. Methane is a far more potent GHG than is CO_2, but methane also has a tenfold shorter residence time in the atmosphere, so its effect on global warming attenuates more rapidly (IPCC 2007). Consequently, to compare the global warming potential of methane and CO_2 requires a specific time horizon. We follow Lelieveld et al. (2005) and present analyses for both 20-year and 100-year time horizons. Though the 100-year horizon is commonly used, we agree with Nisbet et al. (2000) that the 20-year horizon is critical, given the need to reduce global warming in coming decades (IPCC 2007). We use recently modeled values for the global warming potential of methane compared to CO_2: 105 and 33 on a mass-to-mass basis for 20 and 100 years, respectively, with an uncertainty of plus or minus 23% (Shindell et al. 2009). These are somewhat higher than those presented in the 4th assessment report of the IPCC (2007), but better account for the interaction of methane with aerosols. Note that carbon-trading markets use a lower global-warming potential yet of only 21 on the 100-year horizon, but this is based on the 2nd IPCC (1995) assessment, which is clearly out of date on this topic. See Electronic Supplemental Materials for the methodology for calculating the effect of methane on GHG in terms of CO_2 equivalents.

Methane dominates the GHG footprint for shale gas on the 20-year time horizon, contributing 1.4- to 3-times more than does direct CO_2 emission (Fig. 1a). At this time scale, the GHG footprint for shale gas is 22% to 43% greater than that for conventional gas. When viewed at a time 100 years after the emissions, methane emissions still contribute significantly to the GHG footprints, but the effect is diminished by the relatively short residence time of methane in the atmosphere. On this time frame, the GHG footprint for shale gas is 14% to 19% greater than that for conventional gas (Fig. 1b).

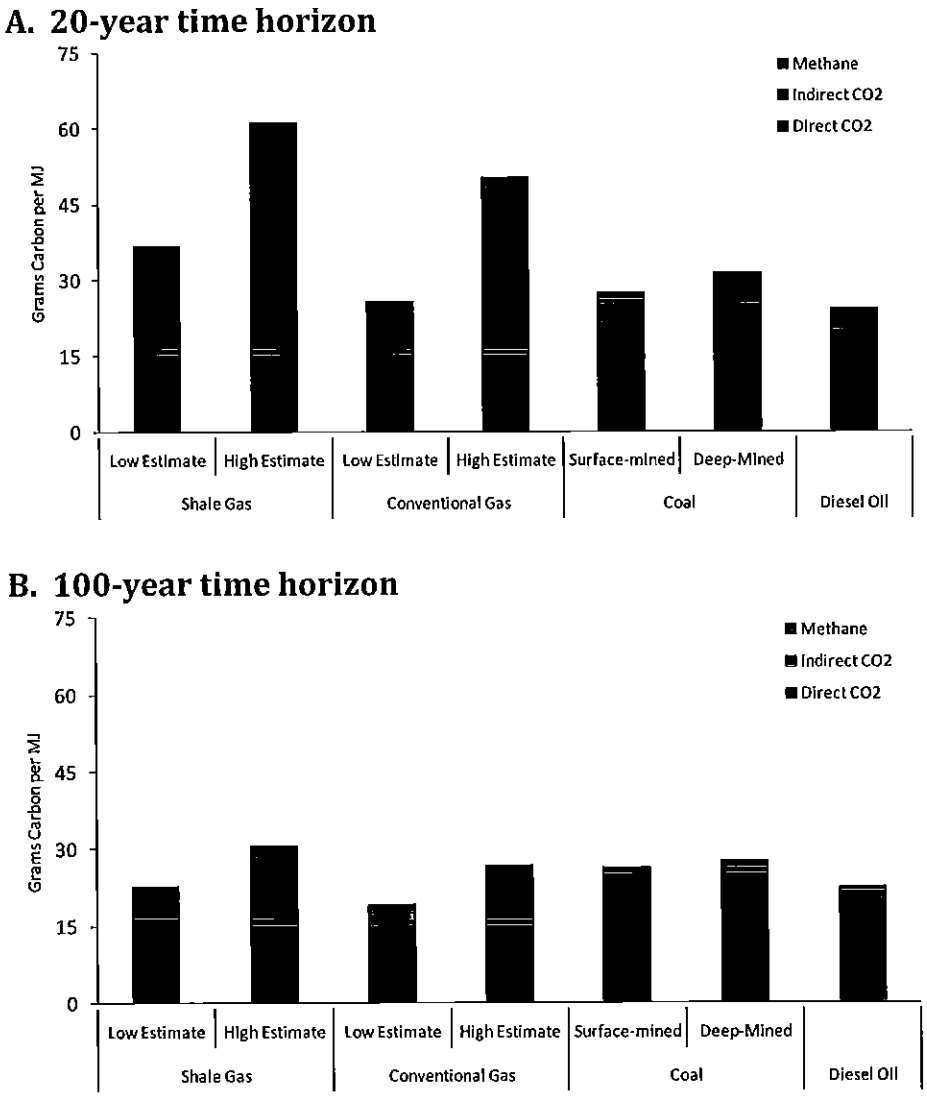

Fig. 1 Comparison of greenhouse gas emissions from shale gas with low and high estimates of fugitive methane emissions, conventional natural gas with low and high estimates of fugitive methane emissions, surface-mined coal, deep-mined coal, and diesel oil. **a** is for a 20-year time horizon, and **b** 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

6 Shale gas versus other fossil fuels

Considering the 20-year horizon, the GHG footprint for shale gas is at least 20% greater than and perhaps more than twice as great as that for coal when expressed per quantity of energy available during combustion (Fig. 1a; see Electronic Supplemental Materials for derivation of the estimates for diesel oil and coal). Over the 100-year frame, the GHG footprint is comparable to that for coal: the low-end shale-gas emissions are 18% lower than deep-mined coal, and the high-end shale-gas emissions are 15% greater than surface-mined coal emissions (Fig. 1b). For the 20 year horizon, the GHG footprint of shale gas is at least 50% greater than for oil, and perhaps 2.5-times greater. At the 100-year time scale, the footprint for shale gas is similar to or 35% greater than for oil.

We know of no other estimates for the GHG footprint of shale gas in the peer-reviewed literature. However, we can compare our estimates for conventional gas with three previous peer-reviewed studies on the GHG emissions of conventional natural gas and coal: Hayhoe et al. (2002), Lelieveld et al. (2005), and Jamarillo et al. (2007). All concluded that GHG emissions for conventional gas are less than for coal, when considering the contribution of methane over 100 years. In contrast, our analysis indicates that conventional gas has little or no advantage over coal even over the 100-year time period (Fig. 1b). Our estimates for conventional-gas methane emissions are in the range of those in Hayhoe et al. (2002) but are higher than those in Lelieveld et al. (2005) and Jamarillo et al. (2007) who used 1996 EPA emission factors now known to be too low (EPA 2010). To evaluate the effect of methane, all three of these studies also used global warming potentials now believed to be too low (Shindell et al. 2009). Still, Hayhoe et al. (2002) concluded that under many of the scenarios evaluated, a switch from coal to conventional natural gas could aggravate global warming on time scales of up to several decades. Even with the lower global warming potential value, Lelieveld et al. (2005) concluded that natural gas has a greater GHG footprint than oil if methane emissions exceeded 3.1% and worse than coal if the emissions exceeded 5.6% on the 20-year time scale. They used a methane global warming potential value for methane from IPCC (1995) that is only 57% of the new value from Shindell et al. (2009), suggesting that in fact methane emissions of only 2% to 3% make the GHG footprint of conventional gas worse than oil and coal. Our estimates for fugitive shale-gas emissions are 3.6 to 7.9%.

Our analysis does not consider the efficiency of final use. If fuels are used to generate electricity, natural gas gains some advantage over coal because of greater efficiencies of generation (see Electronic Supplemental Materials). However, this does not greatly affect our overall conclusion: the GHG footprint of shale gas approaches or exceeds coal even when used to generate electricity (Table in Electronic Supplemental Materials). Further, shale-gas is promoted for other uses, including as a heating and transportation fuel, where there is little evidence that efficiencies are superior to diesel oil.

7 Can methane emissions be reduced?

The EPA estimates that 'green' technologies can reduce gas-industry methane emissions by 40% (GAO 2010). For instance, liquid-unloading emissions can be greatly

reduced with plunger lifts (EPA 2006; GAO 2010); industry reports a 99% venting reduction in the San Juan basin with the use of smart-automated plunger lifts (GAO 2010). Use of flash-tank separators or vapor recovery units can reduce dehydrator emissions by 90% (Fernandez et al. 2005). Note, however, that our lower range of estimates for 3 out of the 5 sources as shown in Table 2 already reflect the use of best technology: 0.3% lower-end estimate for routine venting and leaks at well sites (GAO 2010), 0% lower-end estimate for emissions during liquid unloading, and 0% during processing.

Methane emissions during the flow-back period in theory can be reduced by up to 90% through Reduced Emission Completions technologies, or REC (EPA 2010). However, REC technologies require that pipelines to the well are in place prior to completion, which is not always possible in emerging development areas. In any event, these technologies are currently not in wide use (EPA 2010).

If emissions during transmission, storage, and distribution are at the high end of our estimate (3.6%; Table 2), these could probably be reduced through use of better storage tanks and compressors and through improved monitoring for leaks. Industry has shown little interest in making the investments needed to reduce these emission sources, however (Percival 2010).

Better regulation can help push industry towards reduced emissions. In reconciling a wide range of emissions, the GAO (2010) noted that lower emissions in the Piceance basin in Colorado relative to the Uinta basin in Utah are largely due to a higher use of low-bleed pneumatics in the former due to stricter state regulations.

8 Conclusions and implications

The GHG footprint of shale gas is significantly larger than that from conventional gas, due to methane emissions with flow-back fluids and from drill out of wells during well completion. Routine production and downstream methane emissions are also large, but are the same for conventional and shale gas. Our estimates for these routine and downstream methane emission sources are within the range of those reported by most other peer-reviewed publications inventories (Hayhoe et al. 2002; Lelieveld et al. 2005). Despite this broad agreement, the uncertainty in the magnitude of fugitive emissions is large. Given the importance of methane in global warming, these emissions deserve far greater study than has occurred in the past. We urge both more direct measurements and refined accounting to better quantify lost and unaccounted for gas.

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. We do not intend that our study be used to justify the continued use of either oil or coal, but rather to demonstrate that substituting shale gas for these other fossil fuels may not have the desired effect of mitigating climate warming.

Finally, we note that carbon-trading markets at present under-value the greenhouse warming consequences of methane, by focusing on a 100-year time horizon and by using out-of-date global warming potentials for methane. This should be corrected, and the full GHG footprint of unconventional gas should be used in planning for alternative energy futures that adequately consider global climate change.

Acknowledgements Preparation of this paper was supported by a grant from the Park Foundation and by an endowment funds of the David R. Atkinson Professorship in Ecology & Environmental Biology at Cornell University. We thank R. Alvarez, C. Arnold, P. Artaxo, A. Chambers, D. Farnham, P. Jamarillo, N. Mahowald, R. Marino, R. McCoy, J. Northrup, S. Porder, M. Robertson, B. Sell, D. Shrag, L. Spaeth, and D. Strahan for information, encouragement, advice, and feedback on our analysis and manuscript. We thank M. Hayn for assistance with the figures. Two anonymous reviewers and Michael Oppenheimer provided very useful comments on an earlier version of this paper.

References

Armendariz A (2009) Emissions from natural gas production in the Barnett shale area and opportunities for cost-effective improvements. Report prepared for Environmental Defense Fund, Austin TX

Bracken K (2008) Reduced emission completions in DJ basin and natural buttes. Presentation given at EPA/GasSTAR Producers Technology Transfer Workshop. Rock Springs Wyoming, 1 May 2008. http://www.epa.gov/gasstar/documents/workshops/2008-tech-transfer/rocksprings5.pdf

Chambers AK (2004) Optical measurement technology for fugitive emissions from upstream oil and gas facilities. Report prepared for Petroleum Technology Alliance Canada by Carbon and Energy Management, Alberta Research Council, Edmonton, Alberta

Cicerone RJ, Oremland R (1988) Biogeochemical aspects of atmospheric methane. Global Biogeochem. Cycles 2:299–327

Council of Scientific Society Presidents (2010) Letter from the council to President Obama and senior administration officials, dated May 4, 2010. Council of Scientific Society Presidents, 1155 16th Avenue NW, Washington, DC 20036. Available at http://www.eeb.cornell.edu/howarth/CCSP%20letter%20on%20energy%20&%20environment.pdf

Crutzen PJ (1987) Role of the tropics in atmospheric chemistry. In: Dickinson R (ed) Geophysiology of Amazonia. Wiley, NY, pp 107–129

Eckhardt M, Knowles B, Maker E, Stork P (2009) IHS U.S. Industry Highlights. (IHS) Houston, TX, Feb–Mar 2009. http://www.gecionline.com/2009-prt-7-final-reviews

EIA (2010a) Annual energy outlook 2011 early release overview. DOE/EIA-0383ER(2011). Energy Information Agency, U.S. Department of Energy. http://www.eia.gov/forecasts/aeo/pdf/0383er(2011).pdf. Accessed 3 January 2011

EIA (2010b) Natural gas navigator. Natural gas gross withdrawals and production. http://www.eia.gov/dnav/ng/ng_prod_sum_dcu_NUS_m.htm

EPA (2004) Green completions. Natural Gas STAR Producer's Technology Transfer Workshop, 21 September 2004. http://epa.gov/gasstar/workshops/techtransfer/2004/houston-02.html

EPA (2006) Lessons learned: options for reducing methane emissions from pneumatic devices in the natural gas industry. U.S. EPA/ Gas STAR. http://www.epa.gov/gasstar/documents/ll_pneumatics.pdf

EPA (2007) Reducing methane emissions during completion operations. Natural Gas STAR Producer's Technology Transfer Workshop, 11 September 2007. http://epa.gov/gasstar/documents/workshops/glenwood-2007/04_recs.pdf

EPA (2010) Greenhouse gas emissions reporting from the petroleum and natural gas industry. Background Technical Support Document. http://www.epa.gov/climatechange/emissions/downloads10/Subpart-W_TSD.pdf. Accessed 3 January 2011

Fernandez R, Petrusak R, Robinson D, Zavadil D (2005) Cost-Effective methane emissions reductions for small and midsize natural gas producers. Reprinted from the June 2005 issue of Journal of Petroleum Technology. http://www.icfi.com/Markets/Environment/doc_files/methane-emissions.pdf

GAO (2010) Federal oil and gas leases: opportunities exist to capture vented and flared natural gas, which would increase royalty payments and reduce greenhouse gases. GAO-11–34 U.S. General Accountability Office Washington DC. http://www.gao.gov/new.items/d1134.pdf

Harrison MR, Shires TM, Wessels JK, Cowgill RM (1996) Methane emissions from the natural gas industry. Executive summary, vol 1. EPA-600/R-96-080a. U.S. Environmental Protection Agency, Office of Research and Development, Washington, DC

Hayhoe K, Kheshgi HS, Jain AK, Wuebbles DJ (2002) Substitution of natural gas for coal: climatic effects of utility sector emissions. Climatic Change 54:107–139

Henke D (2010) Encana, USA division overview. Encana Natural Gas, investors presentation. http://www.encana.com/investors/presentations/investorday/pdfs/usa-division-overview.pdf

Intergovernmental Panel on Climate Change (1995) IPCC second assessment. Climate Change, 1995. http://www.ipcc.ch/pdf/climate-changes-1995/ipcc-2nd-assessment/2nd-assessment-en.pdf

Intergovernmental Panel on Climate Change (2007) IPCC fourth assessment report (AR4). Working Group 1, The Physical Science Basis. http://www.ipcc.ch/publications_and_data/ar4/wg1/en/contents.html

Jamarillo P, Griffin WM, Mathews HS (2007) Comparative life-cycle air emissions of coal, domestic natural gas, LNG, and SNG for electricity generation. Environ Sci Technol 41:6290–6296

Kirchgessner DA, Lott RA, Cowgill RM, Harrison MR, Shires TM (1997) Estimate of methane emissions from the US natural gas industry. Chemosphere 35: 1365–1390

Kruuskraa VA (2004) Tight gas sands development—How to dramatically improve recovery efficiency. GasTIPS, Winter 2004. http://media.godashboard.com/gti/4ReportsPubs/4_7GasTips/Winter04/TightGasSandsDEvelopment-HowToDramaticallyImproveRecoveryEfficiency.pdf

Lassey KR, Lowe DC, Smith AM (2007) The atmospheric cycling of radiomethane and the "fossil fraction" of the methane source. Atmos Chem Phys 7:2141–2149

Lelieveld J, Lechtenbohmer S, Assonov SS, Brenninkmeijer CAM, Dinest C, Fischedick M, Hanke T (2005) Low methane leakage from gas pipelines. Nature 434:841–842

Liu AE (2008) Overview: pipeline accounting and leak detection by mass balance, theory and hardware implementation. Quantum Dynamics, Woodland Hills. Available at http://www.pstrust.org/library/docs/massbalance_ld.pdf

National Research Council (2009) Hidden costs of energy: unpriced consequences of energy production and use. National Academy of Sciences Press, Washington

New York Department of Environmental Conservation (2009) Draft supplemental generic environmental impact statement on the oil, gas and solution mining regulatory program. http://www.dec.ny.gov/energy/58440.html

Nisbet EG, Manning MR, Lowry D, Lassey KR (2000) Methane and the framework convention on climate change, A61F-10, Eos Trans. AGU 81(48), Fall Meet. Suppl

Pacala S, Socolow R (2004) Stablization wedges: solving the climate problem for the next 50 years with current technologies. Science 305:968–972

Percival P (2010) Update on "lost and unaccounted for" natural gas in Texas. Basin Oil and Gas. Issue 32. http://fwbog.com/index.php?page=article&article=248

Reshetnikov AI, Paramonova NN, Shashkov AA (2000) An evaluation of historical methane emissions from the Soviet gas industry. JGR 105:3517–3529

Revkin A, Krauss C (2009) By degrees: curbing emissions by sealing gas leaks. New York Times, 14 October 2009. Available at http://www.nytimes.com/2009/10/15/business/energy-environment/15degrees.html

Samuels J (2010) Emission reduction strategies in the greater natural buttes. Anadarko Petroleum Corporation. EPA Gas STAR, Producers Technology Transfer Workshop Vernal, Utah, 23 March 2010. http://www.epa.gov/gasstar/documents/workshops/vernal-2010/03_anadarko.pdf

Santoro R, Howarth RW, Ingraffea T (2011) Life cycle greenhouse gas emissions inventory of Marcellus shale gas. Technical report of the Agriculture, Energy, & Environment Program, Cornell University, Ithaca, NY. To be archived and made available on-line

Shindell DT, Faluvegi G, Koch DM, Schmidt GA, Unger N, Bauer SE (2009) Improved attribution of climate forcing to emissions. Science 326:716–718

Shires TM, Loughran, CJ, Jones S, Hopkins E (2009) Compendium of greenhouse gas emissions methodologies for the oil and natural gas industry. Prepared by URS Corporation for the American Petroleum Institute (API). API, Washington DC

Wood R, Gilbert P, Sharmina M, Anderson K, Fottitt A, Glynn S, Nicholls F (2011) Shale gas: a provisional assessment of climate change and environmental impacts. Tyndall Center, University of Manchester, Manchester, England. http://www.tyndall.ac.uk/sites/default/files/tyndall-coop_shale_gas_report_final.pdf

SCHEDULE "C"

FILED ON A CONFIDENTIAL BASIS BY WMFN