NEB Experience with GHGs and Pipeline EA[1]

Usha Mulukutla, Marcus Eyre, Zoe Pfeiffer, Laura Randall

As Canada's federal energy regulator, the National Energy Board (NEB or Board) has oversight of over 73,000 km of interprovincial and international pipelines in Canada. In regulating energy infrastructure, the NEB promotes safety, security, and environmental protection, in the Canadian public interest.

Proponents of new pipeline projects must apply to the NEB. The Board conducts an environmental assessment (EA) under the *National Energy Board Act* (NEB Act) and for larger projects, under the *Canadian Environmental Assessment Act, 2012* (CEAA 2012). Under CEAA 2012*,* the NEB must recommend whether a project is likely to cause significant adverse environmental effects (after taking into account mitigation measures and any conditions of approval), and if so, whether the effects are justified.

The NEB requires applicants to file information on greenhouse gas emissions (GHGs) associated with projects. Guidance now commonly recognizes two areas that should be addressed in EA: mitigation of GHG emissions, and adaptation to climate change (Ohsawa and Duinker, 2014).

This paper focuses on the consideration of GHG emissions from pipeline projects. NEB EAs in which GHG emissions were an issue were reviewed[2] to identify key issues and questions: sources of emissions and their quantification, regulatory conditions, significance determination, and EA scoping.

Sources and quantification of GHGs

The NEB focuses primarily on GHGs directly emitted by projects. Since construction and operation sources differ and have unique quantification methods, regulatory requirements, and mitigation options, distinct conclusions must be made for both project phases.

During project construction, GHG emissions generally stem from land clearing, biomass burning, and operation of construction equipment. Quantification of equipment emissions range from 100 to 250 t CO_2e/km of pipeline constructed, with an average of 175 t CO_2e/km, depending on variables such as terrain and season. Clearing-related emissions are more difficult to characterize and have ranged from 4.3 t CO_2e/km in cropland to 911.3 t CO_2e/km in coastal rainforest, and based mainly on fuel loading assumptions for the ecotype and hectares to be cleared, minus any salvageable timber.

In contrast, operational emissions cannot be compared across projects as they vary based on throughput capacity, individual design, and component counts. For natural gas pipeline operations, compressors are typically the largest direct GHG emission source. Other operational sources are associated with maintenance and inspection activities (including aerial patrols),

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[1] The views, judgements, opinions and recommendations in this paper are those of the authors alone and do not necessarily reflect those of the NEB, its Chair or Members.
[2] Based on applications received between 2008-2016.

heating at facilities, and fugitive emissions from valves, connectors, pumps, and tanks. For oil pipelines, electrically driven pumps result in indirect GHG emissions, which would be reported by a power utility and subject to provincial regulation.

When preparing quantification estimates, proponents factor in their proposed mitigation measures. For example, when estimating construction vehicle run-time hours, mitigation to reduce those hours (e.g., using buses to move crews) are taken into account. For operational estimates, best practices for design, equipment selection, leak detection, and corporate offsetting commitments are typically incorporated.

Mitigation effectiveness varies widely. For example, reducing vehicle idling typically contributes little to overall emission reductions. In contrast, experience suggests that the largest long-term reductions typically come from appropriate facility design given the long lifecycle of energy facilities.

The role of regulatory conditions

NEB EAs often identify mitigation gaps and generate recommendations for further mitigation. If a project is approved, the NEB imposes regulatory conditions to ensure the sufficiency, certainty and effectiveness of mitigation.

For example, the 2003 Georgia Strait Crossing (GSX) Project, in which BC Hydro proposed a natural gas pipeline to generating stations on Vancouver Island, was one of the first NEB hearings in which GHGs were raised as a public concern. Although BC Hydro committed to offset some of its GHGs voluntarily, the Panel imposed a condition making it a binding requirement to track the offsets through an annual report (NEB, 2003).

In 2010, the approval of the Canadian portion of the Keystone XL pipeline included a requirement for a quantitative assessment of all project-related GHG emissions in order to provide greater transparency and accountability (NEB, 2010). Since then, the Board has continued to require quantitative GHG assessments and has sometimes also required post-construction verification of the assumptions used in the initial calculations. Over the years, these have shown that the assumptions used in the estimates (e.g., amount of salvageable timber, equipment run-time hours) are sufficiently conservative to overestimate the predicted emissions as compared with the actual emissions.

Beyond design-based mitigation and reporting of emissions, a benefit of having a regulator conduct EAs is the ability to require best practices over the life of project operations. For example, in 2015 an application to re-route part of the Alliance pipeline included the venting of gas from a 30 km segment of the pipeline. Instead, the Board directed Alliance to flare the gas, avoiding approximately 16,200 tonnes CO_2e (NEB, 2016). This was in line with Board requirements to explore alternatives to venting (i.e., flaring/incineration, or draw-down compressors). Estimates have shown up to 80 per cent reductions in GHG emissions when such alternatives prove feasible.

Offsets are the final mitigation option for any unavoidable emissions. In the Trans Mountain Expansion Project (TMX), given the volume of construction-related emissions (approximately 890,000 t CO_2e) and that these are not reportable under federal GHG regulations, the Board imposed an offset requirement to confirm no-net increase in construction emissions (NEB, 2016).

Significance criteria and determination

Once emission sources, proposed mitigation, and potential regulatory conditions are accounted for, the significance of residual emissions must be assessed. Some proponents have recently used methods to calculate the effects of project GHG emissions on climate change indicators. Estimated project effects on global rainfall or crop yield, for example, are minute and highly uncertain in time and location, and so do not meaningfully inform an EA. In the Keystone XL and TMX projects both Panels noted the distinction between the emissions and the climate change effects, as is now common practice in EAs.

Since several of the criteria typically used for evaluating significance stay constant for GHG emissions (i.e., global in spatial extent and irreversible in temporal extent), the magnitude and duration criteria are key in assessing significance. For construction-related GHG emissions, proponents often rely on the short-term duration of the emissions in proposing significance. Given that construction-related emissions are not reportable federally, proponents have assessed potential significance through comparison to other, similar projects.

Operations-related emission estimates are often compared with provincial and national emission inventories, as Canada does not currently have facility-level GHG emission standards. By comparing a project's emissions to the total national or provincial inventories, the incremental addition is often small. As a more useful comparison, the Board has required proponents to compare emissions estimates to sector-specific industry profiles (NEB, 2010, 2016). Provincial and federal reporting thresholds for operations-related emissions have also been considered in determining significance.

Ultimately what is assessed is the amount or volume of GHG emissions. In determining significance, the challenge is inherently one of cumulative effects: new projects continue to be developed, with additional contributions (however small) to existing global GHG levels that are already significant. Consequently, a broader policy framework is necessary if EAs are to provide consistent and meaningful significance determinations.

Scoping

A recurring issue around pipeline GHGs is whether to consider related facilities. In the GSX hearing noted above, the Panel heard argument on whether it could consider the environmental effects from downstream combustion emissions[3]. Ultimately the Panel explained that because of the direct linkage it should only consider the effects from the proposed new power facility but not from an already operating facility.

[3] under the CEA Act or the NEB Act

Various Panel reviews have since considered similar scoping scenarios and came to similar conclusions (NEB, 2013; 2014; 2015). This approach and rationale has been challenged in the courts and twice been found to be reasonable[4]. Consistent with these decisions, the NEB's Filing Manual explains that the environmental and socio-economic effects in Canada of upstream or downstream facilities may be considered where there is a necessary connection between those facilities and the project.

In early 2016 the Government of Canada, as part of its review of federal EA, announced interim principles for ongoing project EAs, including that upstream GHG emissions not directly linked to a project would be assessed. Environment and Climate Change Canada (ECCC) has completed a number of these[5] following a two-part methodology. In Part A, ECCC provides a quantitative estimation of the associated upstream emissions using data related to product mix and emission factors reflecting extraction and processing methods. Part B discusses the conditions under which the upstream emissions would occur regardless of the project. Part B includes production forecasts given various price scenarios, potential alternative markets and modes of transportation, and other market conditions. Part B highlights the relationship between environmental assessment and economic assessment. For example, global hydrocarbon production can respond to changes in Canadian production, and continental hydrocarbon transportation alternatives such as rail can respond to regional limitations in pipeline capacity.

Conclusions

The Board's assessment of GHG emissions in project EAs has evolved along with the growing public concern regarding energy infrastructure and climate change. This has led to in increasing requirements for GHG quantification and mitigation, including offsetting of unavoidable emissions, within the current legislative framework.

Canadians expect climate change to be considered during energy infrastructure assessments. The challenges are significant and persistent. Going back to 2010 the Mackenzie Gas Project's Joint Review Panel noted that GHG emissions issues "cannot be resolved on a project-by-project basis through the environmental assessment process, but must be addressed by governments through comprehensive climate change strategies."[6]

Overall, three main findings can be drawn from the review presented in this paper:

1. With respect to direct emissions, project-based EAs are useful and effective in identifying, evaluating and mitigating project-level GHG emissions. They are particularly beneficial when conducted by a regulator such as the NEB with a mandate to enforce

[4] See Sumas Energy 2, Inc. v. Canada, 2005 FCA 377; Forest Ethics Advocacy Association and D. Sinclair v. the NEB, Canada (A-G) and Enbridge Pipelines Inc., 2014 FCA 245
[5] As of date, 2 for oil pipelines, 2 for gas pipelines and 2 for LNG facilities.
[6] JRP Report for the Mackenzie Gas Project (A1R2L6)

conditions and regulations that drive emission reductions over the operating life of a project.

2. Emissions from upstream or downstream sectors present a major policy issue that challenges the current project-based EA framework. Regardless of whether an EA is conducted by a regulatory agency or a separate body, important questions need to be resolved. For example, how do EAs and the assessment of GHGs fit within broader government EA legislation (including other jurisdictions and duplication of EAs), climate change policy and decarbonization of Canada's energy systems?

3. Finally, for both direct and indirect GHG emissions, a broader policy framework is needed to clarify "significance". The NEB's experience is consistent with Ohsawa and Duinker's (2014) finding of ambiguous or inconsistent definitions of significance and recommendation for "clear and reasonable" definitions. What is the standard that proponents are expected to meet, and how are EA conclusions regarding GHG emissions to be coherent between assessments?

The issues around pipeline GHG assessments reflect fundamental questions about EA in general in Canada: What should EA be? And what is its role within government's broader legislative and policy framework?

References

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